U.S. Department
of Transportation
**Pipeline and
Hazardous Materials Safety
Administration**

233 Peachtree Street Ste. 600
Atlanta, GA 30303

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

November 23, 2010

Mr. David Goodwin
Vice President Compliance and Operations Services
Gulf South Pipeline Co., L.P.
9 Greenway Plaza, Suite 2800
Houston, TX 77046

CPF 2-2010-1011M

Dear Mr. Goodwin:

Between June 22, 2009, and October 9, 2009, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) inspected Gulf South Pipeline Co., L.P. (Gulf South) procedures for Operations and Maintenance, Operator Qualification, and Integrity Management in Gulf South's offices and field locations in Louisiana, Texas, and Mississippi pursuant to Chapter 601 of 49 United States Code.

On the basis of the inspection, PHMSA has identified apparent inadequacies found within Gulf South's Operations and Maintenance (O&M) procedures as described in Items 1 - 11 below:

1. **§ 192.739 Pressure limiting and regulating stations: Inspection and testing.**
   (a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is -
   (1) In good mechanical condition;

   Gulf South's written O&M relief valve inspection and testing procedures were inadequate because they did not provide enough detail to instruct personnel on how to properly determine if pilot-operated relief valves were in good mechanical condition.

   Relief valves on pipeline systems must be inspected each calendar year for, among other things, good mechanical condition. Gulf South's work instruction procedure *WI-00074, Regulation and Over-Pressure Protection* (rev. 06/15/09) did not contain the detail required to instruct personnel on how to properly determine if pilot-operated relief valves were in good mechanical condition. Instead *WI-00074* refers Gulf South's technicians to the relief valve manufacturer's operating and maintenance manuals for inspection and testing. This reference was insufficient to perform the required task.

PHMSA inspectors observed Gulf South's technicians performing a pilot-operated relief valve test at the Amite Town Border Station. The technicians explained that the referenced manufacturer's documentation did not provide inspection and testing requirements, and therefore, they did not known how to determine if the relief valve was in good mechanical condition. Also, information provided by Gulf South relating to a different relief valve manufacturer for a relief valve located at the International Paper Meter Station did not specifically require the valve to be tested and observed to be in good mechanical condition; i.e. to test and observe for the valve plug to move off of the seat when required.

2. **§192.739 Pressure limiting and regulating stations: Inspection and testing.**
(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is -
.... (4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

Gulf South's written O&M relief valve inspection and testing procedures were inadequate because they did not require inspections and tests to determine if pilot operated relief valves were properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

Relief valves on pipeline systems must be inspected each calendar year to determine if the relief valves were properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation. While Gulf South's work instruction procedure *WI-00074, Regulation and Over-Pressure Protection* (rev. 06/15/09) required relief valve vent flapper and weep hole inspections of some relief valves, it did not require these inspections for pilot operated relief valves.

3. **§192.461 External corrosion control: Protective coating.**
(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must—
(1) Be applied on a properly prepared surface;

Gulf South's written O&M external corrosion control protective coating procedures were inadequate because they were incorrect, unclear, and lacked specificity.

Gulf South's work instruction procedure *WI-00089, Apply Approved Coatings to Above- and Belowground Piping* (07/13/09) was incorrect in that it stated that a company approved coatings list was provided in the Company Coating Specification while no such document was provided. In lieu of the approved coatings list, Gulf South provided a June 10, 2004, email which included a list of approved underground coatings, with an attached undated draft procedure for selecting and applying below grade field coatings. The draft procedure was incorrect because the application of 3M hot melt patch sticks on thermal welded test lead installations was included (epoxy and non-epoxy coated pipe) but the vendor's literature specifically stated that patch stick applications should be restricted exclusively to the repair of pinholes and abrasions on epoxy coatings.

Also, while protective coating surface preparation standards and specifications were listed in Gulf South's *WI-00089*, including preparations for hand and power brush, it was not clear what specific levels of surface preparation were required when small coating repairs were made with products such as Enviroline 124 or Ceilcote 252. That is, Section 5.3 of the undated draft procedure, *Clean Small Areas by hand or Power Brush,* was unclear in that it required surface preparation by hand or power brush for small areas such as taps, test lead connections, UT test areas and longitudinal seam repairs, etc. but it did not include specific levels of surface preparation.

The draft procedure also lacked specificity. For example, one of the approved products was Tapecoat TC 7100 Wet Bond Gray Epoxy. Detailed application procedures for this product were not defined or directly referenced in the draft procedure. Moreover, the Tapecoat published product information provided by Gulf South contained very little detail, and recommended that a technician see the *"detailed Field Specification for complete instructions"* and further indicated that Tapecoat agents were strategically located throughout the world to provide technical service.

4. **§192.463 External corrosion control: Cathodic protection.**

(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

Gulf South's cathodic protection procedures were inadequate because they did not provide the detail necessary to determine how Gulf South considers voltage (IR) drop.

Gulf South's O&M Manual, Section 3.3 - *Criteria for Cathodic Protection* states the following as it relates to the current-applied - 0.850v criterion, "*Interpretation of voltage measurement: Voltage (IR) drops other than those across the structure-electrolyte boundary shall be considered for valid interpretation of the voltage measurement in paragraphs.*" Yet, nothing in the procedure explains how Gulf South actually considers the IR for valid interpretation of the voltage measurement.

The inadequacy of these procedures was further supported by evidence in Gulf South's cathodic protection survey records. For example, Gulf South performed annual cathodic protection surveys in 2007, 2008, and 2009 in the Jackson, MS area. A review of the annual survey cathodic protection records showed numerous readings ranging from - 0.850v to - 0.900v. While these readings were deemed acceptable by Gulf South using the designated criterion of - 0.850v, there was no documentation explaining how Gulf South considered IR drop with regards to these readings.

5. **§192.465 External corrosion control: Monitoring.**

.... (c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked

for proper performance six times each calendar year, but with intervals not exceeding 21/2months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

Gulf South's external corrosion control monitoring procedures were inadequate because they did not provide specific criteria on how to determine if an interference bond was "critical" to the Gulf South pipeline system. As used here, the term "critical" means a bond whose failure would jeopardize structure protection; i.e. jeopardize cathodic protection of the Gulf South pipeline.

An operator must electrically check each critical bond six times a calendar year, while non-critical bonds must be checked only once each calendar year. Therefore, an operator must have procedures to differentiate critical bonds from non-critical bonds. While Gulf South's procedures discussed critical bonds, the procedures did not describe how Gulf South personnel were to differentiate critical from non-critical interference bonds.

The inadequacy of these procedures was further supported by evidence in Gulf South's cathodic protection survey records. Gulf South's interference bond records in the Sterlington area indicated significant electrical current through the bonds and were labeled as "FROM US." Gulf South subsequently determined that the current flow direction across these bonds in these records was incorrect and that the bonds were not critical. Yet, Gulf South's records did not indicate that these bonds had been identified as needing to be investigated further to determine if they could have been critical based on the initially recorded bond electrical current and current direction.

6. **§192.473 External corrosion control: Interference currents.**
(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

Gulf South's external corrosion control interference current procedures were inadequate because they did not provide the guidance and detail necessary to identify areas of potential stray current so the detrimental effects of stray currents could be minimized.

Gulf South had a detailed interference current procedure which it used to comply with special permit interference survey and remediation requirements but these procedures were not included or referenced in Gulf South's O&M manual or Work Instructions.

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 of 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.

Gulf South's internal corrosion control procedures were inadequate because they did not require the examination of all removed pipe coupons for evidence of internal corrosion when hot taps were made.

Gulf South's O&M manual Chapter 9 described hot tapping procedures, but did not require the examination of removed pipe coupons for evidence of internal corrosion. This deficiency was further evidenced in Work Order No. 23660726, dated 02/20/09 (Bistineau-Clarence area), which did not indicate that a removed coupon was examined for the presence of internal corrosion.

8. **§192.709 Transmission lines: Record keeping.**
Each operator shall maintain the following records for transmission lines for the periods specified:
.... (c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

Gulf South's record keeping procedures were inadequate because they did not require the full documentation of performance tests conducted on gas detection and alarm systems at compressor stations.

Gulf South's work instruction procedure *WI-00085 Test/Maintain Gas Detection & Alarm Systems* and the referenced *Engine Protective Devices Test Report* form (Form #PS5576, rev. 06/10/09) did not require adequate documentation of performance test results. Also, Form #PS5576 did not provide enough detail to show 1) that the gas detection and alarm system alarmed at not more than 25% of the lower explosive limit (LEL), and 2) that each of the audible and visual alarms performed (or did not perform) as required during the test.

9. **§192.736 Compressor stations: Gas detection.**
.... (c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

Gulf South's compressor station gas detection and alarm system performance test procedures were inadequate because they did not detail all the steps necessary for conducting gas detection and alarm system performance tests when a compressor unit was running.

Gulf South's work instruction procedure *WI-00085 Test/Maintain Gas Detection & Alarm Systems* did not list certain required steps necessary to conduct the referenced performance tests when the compressor units were running. For example, *WI-00085* did not require opening the fuel gas bypass valve between step 3 and step 4, or placing the PLC into bypass mode between step 4 and step 5 when the compressor units were running during a PHMSA-observed test at the Montpelier Compressor Station. A PHMSA inspector witnessed the technician performing these required steps to prevent the compressor units from shutting down during the test. However, the steps were not listed in the work instruction.

10. **§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 procedures for the following, if applicable, to provide safety during maintenance and operations.
…. (8) Periodically reviewing the work done by operator personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance and modifying the procedure when deficiencies are found.

Gulf South's O&M procedures were inadequate because they did not include the periodic review of work done by Gulf South gas control personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance and to modify the procedures if deficiencies were found.

At the time of the inspection, Gulf South management personnel expressed that only a verbal review of normal operation and maintenance procedures was conducted with Gulf South gas controllers.

11. **§192.605 Procedural manual for operations, maintenance, and emergencies.**
…. (c) Abnormal operation. For transmission lines, the manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:
…. (4) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

Gulf South's O&M procedures were inadequate because they did not include the periodic review of the response of Gulf South gas control personnel to abnormal operations to determine the effectiveness of abnormal operation procedures and to correct deficiencies if found.

At the time of the inspection, Gulf South management personnel expressed that only a verbal review of the response to abnormal operations was conducted with gas controllers. They also expressed that corrective actions were adopted when deficiencies were found.

On the basis of the inspection, PHMSA has identified apparent inadequacies found within Gulf South's Operator Qualification (OQ) program as described in Item 12 below:

12. **§192.805 Qualification program.**
Each operator shall have and follow a written qualification program. The program shall include provisions to:
…. (i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section.

Gulf South's Operator Qualification (OQ) program was inadequate because it did not require all the notifications an operator was required to make to PHMSA to comply with the OQ regulations.

Gulf South's OQ program was covered under the Boardwalk OQ Plan (Boardwalk is the parent company of Gulf South). The OQ Plan, Section 3.6, *Management of Change,* contained the subsection entitled *"Communication of Significant Modifications of Program to Office of Pipeline Safety or Applicable State Agency."* The OQ Plan then defined *"significant change"* as being *"a change that would weaken the program."* Therefore, the OQ Plan required a notification to be made to PHMSA only when plan modifications were made *"that would weaken the program."* This is not consistent with the regulations, which require notification to PHMSA of any significant modification, regardless of the outcome or results of the modification.

For example, Gulf South did not notify PHMSA of the March 3, 2008, merging of the Texas Gas and Gulf South OQ plans into a common Boardwalk OQ plan.

On the basis of the inspection, PHMSA has identified apparent inadequacies found within Gulf South's Integrity Management Program (IMP) as described in Items 13-17 below:

13. §192.911 What are the elements of an integrity management program? .... (b) A baseline assessment plan meeting the requirements of §192.919 and §192.921.

§192.919 What must be in the baseline assessment plan?
An operator must include each of the following elements in its written baseline assessment plan:
.... (b) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the covered segment. (*See* §192.917.) More than one method may be required to address all the threats to the covered pipeline segment;

- **Item 13A: §192.919(b)**

  Gulf South's IMP was inadequate because it did not include in the assessment portion (Chapter 6) of its IMP the process it used to assess for hard spot/sleeve interactive threats on applicable pipelines. Gulf South should have documented this process to provide a basis for its past use and to facilitate any modifications of the process for ongoing assessments.

- **Item 13B: §192.919(b)**

  Gulf South's IMP was inadequate because Gulf South's process for assessing for third-party damage (TPD) when hydrostatic pressure testing was used as the assessment method was not adequately documented in its IMP.

  Chapter 6, Table 3-1 in the Gulf South IMP indicated that hydrostatic pressure testing was not applicable to assess the TPD threat, with footnote 10 stating, "*Third-Party Damage is identified by data integration and managed by Preventative and Maintenance Measures.*" But, footnote 10 did not provide sufficient detail as to what was required to assess the TPD threat. There was no mention of the required data sets that should have been used (e.g., one-call tickets, foreign line crossings, encroachments, survey results, etc.), or how Gulf South integrated the data. There was also no mention of the methods Gulf South used to gather additional information for the data integration (e.g., CIS, DCVG, etc.). It is important to note that TPD was the dominant weighted threat of Gulf South's IMP, with an assigned threat weighting factor of 0.43.

14. **§192.911 What are the elements of an integrity management program?**
.... (c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§192.917) and to evaluate the merits of additional preventive and mitigative measures (§192.935) for each covered segment.

§ 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.

(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.

§192.935 What additional preventive and mitigative measures must an operator take?

(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.

- **Item 14A: §192.917(a)**

  Gulf South's IMP was inadequate because Gulf South's practice of identifying hard spot related threats was not adequately documented in its IMP.

  The Gulf South threat identification process indicated that hard spots did not meet the threshold for being a threat of concern. However, given past instances of leaks at Type A sleeve-repaired hard spot locations on the Gulf South pipeline system (e.g., Index 129) and the ongoing potential for additional leaks, it would appear that certain repaired hard spots represent a type of time dependent threat that, in fact, rises to a level of concern.

  Gulf South appeared to recognize this and was utilizing magnetic flux leakage (MFL) in-line inspection (ILI) assessments to provide indicators that corrosion and/or coating deterioration had occurred near Type A sleeve repaired hard spots, which could then potentially lead to hydrogen induced hard spot cracking. This practice, however, was not adequately addressed in the IMP Chapter 4, *Threat Identification, Data Integration, and Risk Assessment.*

- **Item 14B: §192.917(a)**

  Gulf South's IMP was inadequate because Gulf South's process for evaluating the threat of potential pipe seam defects on certain vintage pipe was not properly documented in its IMP, which resulted in inconsistencies.

  Gulf South's IMP had two different algorithms that addressed potential seam defects and the two algorithms conflicted with each other in certain scenarios. Gulf South's primary risk algorithm used to address potential seam defects was contained in Appendix 1, Section 2.5.2 of its IMP. This risk algorithm generated a *Seam Defect Score*. The secondary threat assessment algorithm used to address potential seam defects was a flow chart shown in Chapter 4 Figure 2-7of the IMP, i.e. *Manufacturing Threat Criteria*.

  The source of the inconsistencies related to pressure tests requirements. The *Seam Defect Score* risk algorithm indicated that pressure test applicability was only a function of maximum test pressure. It did not, however, consider if the pressure test was equivalent to a Part 192, Subpart J test, which has many requirements in addition to maximum test pressure. Conversely, the *Manufacturing Threat Criteria* in Figure 2-7 did indicate that a Subpart J pressure test was required to address potential seam defects.

This process inconsistency was reflected in the *Seam Defect Score* for Index 129, a 1952 A.O. Smith flash welded pipeline located in HCA 809. Because this pipeline was not subjected to a Subpart J test, the algorithm used for *Manufacturing Threat Criteria*, i.e. Figure 2-7 indicated this pipe to be a threat. Yet, the *Seam Defect Score* was zero, which effectively eliminated this pipe at the time as a candidate for assessment.

In the absence of a Subpart J pressure test, the federal pipeline safety regulations and incorporated references consider seam defects to be stable threats only when there has been no MAOP increase, the 5-yr historical maximum operating has not been exceeded, the pipeline was not subjected to cyclic fatigue or other interacting threats, and there was no failure history of similar pipe. If a pipeline meets all these criteria, integrity assessments capable of assessing seam integrity are not required. Instead the pipe must be monitored for MAOP increases, pressure increases exceeding the 5-yr historical conditions, cyclic fatigue, seam failures elsewhere in the system, and other interacting threats.

- **Item 14C: §192.917(b)**

  Gulf South's IMP was inadequate because Gulf South's procedures did not require the integration of ILI tool tolerance in making decisions regarding remediation of anomalies.

  Gulf South's IMP addressed ILI tool tolerance in Appendix 4 Section 13 only in the context of determining reassessment intervals, not with regards to making decisions regarding remediation of anomalies. PHMSA inspectors discussed this with Gulf South during the inspection and were told it was being evaluated by Gulf South.

- **Item 14D: §192.935(a)**

  Gulf South's IMP preventive and mitigative (P&M) measures processes were inadequate because they did not address all the threats to pipeline integrity that Gulf South has identified. Gulf South's processes only specifically evaluated Third-Party Damage, Corrosion, and Outside Force threats for P&M measures, though Chapter 8, Section 2, Table 2-1 of its IMP lists other threats for which candidate measures are available.

15. **§ 192.911 What are the elements of an integrity management program? .... (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.**

    § 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 pre-assessment 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.

(2) Indirect examination. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 4, the plan's procedures for indirect examination of the ECDA regions must include—

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

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and

(iv) Criteria for scheduling excavation of indications for each urgency level.

(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—

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

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE RP0502–2002), or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE RP0502–2002);

(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

(iv) Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE RP0502–2002.

(4) Post assessment and continuing evaluation. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502–2002, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include—

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in §192.939. (See Appendix D of NACE RP0502–2002.)

§ 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.

(1) Preassessment. In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to—

(ii) Information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur. (See paragraph (a) of this section.) This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on covered segments such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline;

§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

.... (b) General requirements. An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must have a plan that provides, at minimum, for—

.... (2) Assessment method. The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4.

- **Item 15A: §192.925(b)**

Gulf South's IMP was inadequate because the definition of the word *"should"* was not consistent throughout its IMP.

The definition of *"should"* in Gulf South External Corrosion Direct Assessment Plan (ECDAP), Section 1.10, Definitions, was not consistent with the definition of *"should"* used in Gulf South's overall IMP. That is, Gulf South's ECDAP did not require written technical justification for deviations from *"should"* statements or recommendations in incorporated documents, including NACE Standard RP0502-2002 *"Pipeline External Corrosion Direct Assessment Methodology."*

- **Item 15B: §192.925(b)(3)(i)**

  Gulf South's IMP was inadequate because the manner in which Gulf South implemented the §192.925 (b)(3)(i) requirement for *"more restrictive criteria when conducting ECDA for the first time on a covered segment"* in the direct examination phase of ECDA was not apparent to PHMSA inspectors who reviewed Figure 4-2, Table 4-1, and the narrative found in ECDAP Sections 4.1 and 4.2.

- **Item 15C: §192.925(b)(3)**

  Gulf South's IMP was inadequate because the verbiage in ECDAP Sections 4.1 and 4.2 and associated Table 4-1 and Figure 4-2 was not consistent and did not clearly define the intent of the number of required digs for each case.

  For example, Table 4-1 heading *"For Each ECDA Region"* was not consistent with Containing/Action verbiage for the *"most likely corroded region"* in the Monitored Only and No Indication cases. Table 4-1 did not address the Figure 4-2 description of *"Were any of the above digs found more severe than IMMEDIATE and have >20% wall loss?"* In addition, the word *"uprated"* (i.e. *"If Indications Are Uprated")* in Table 4-1 was not defined in the ECDAP.

- **Item 15D: §192.925(b)(4)**

  Gulf South's IMP was inadequate because its ECDAP did not properly include the requirements of NACE RP 0502–2002, Section 6, as required by §192.925(b)(4). The following statement, found in ECDAP Section 5.1 was incorrect: *"Calculation: The largest scheduled indications for ECDA Region after the reprioritization process shall have their remaining life determined."* NACE RP0502-2002 Section 6.2.2 actually requires the largest non-unique corrosion defect found to be applied regardless of whether or not it has been repaired.

- **Item 15E: §192.927(c)(1)(ii)**

  Gulf South's IMP was inadequate because the minimum requirements to provide accurate line and feature location elevation information to support Internal Corrosion Direct Assessment (ICDA) were not well defined in its Internal Corrosion Direct Assessment Plan (ICDAP), as required by §192.927(c)(1)(ii).

  Gulf South's ICDAP (effective 08/01/09) Section 3.6 states, *"USGS maps represent a minimum profile accuracy requirement."* This general reference to USGS, however, did not specify a minimum accuracy needed to adequately perform ICDA while the ICDAP Section 3.6 specifically states, *"Collecting accurate information regarding the elevation and inclination of a pipeline is particularly important in DB-ICDA."* PHMSA has inspected ICDA plans using USGS maps for the calculation of inclination angles and has found the method to be insufficient in some applications.

- **Item 15F: §192.929(b)(2)**

  Gulf South's IMP was inadequate because its Stress Corrosion Cracking Direct Assessment Plan (SCCDAP) was not in accordance with the threat remediation requirements of §192.929(b)(2). The SCCDAP was not clear in Sections 4 and 5 that all areas of detected SCC indications (including those not defined as "significant") must be mitigated in accordance with §192.929(b)(2) and ASME B31.8S Section A3.4.1.d.2.

  Also, the SCCDAP did not clearly specify actions Gulf South should take based on conditions it identified during the direct examination phase. SCCDAP Sections 4 and 5 were not consistent with descriptions of certain SCC severity categories and how they relate separately to mitigation and assessment intervals. For example, Section 4.4 states, *"A category 2 crack has a failure pressure that is greater than Boardwalk's [Gulf South's] safety tolerance and less than 110% SMYS. This crack would fail a hydrostatic test and poses a future safety threat to the pipeline. Its estimated life at MAOP is greater than 5 years."* Also, Section 5.3 states, *"The service failure for a category 2 crack is possible within 3-5 years; therefore, perform a hydrostatic test, crack in-line inspection, more excavations, pipeline replacement or recoat within 2 years of discovery."* And, Section 5.3 adds, *"Category 2 cracks are estimated to have a life of 5-10 years at MAOP."*

16. **§192.911 What are the elements of an integrity management program? .... (f) A process for continual evaluation and assessment meeting the requirements of §192.937.**

    §192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?
    (a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section...

    §192.939 What are the required reassessment intervals?
    An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments.
    (a) Pipelines operating at or above 30% SMYS. An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with §192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.
    (3) Internal Corrosion or SCC Direct Assessment. An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must

determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3.

- **Item 16: §192.939(a)(3)**

  Gulf South's IMP was inadequate because its August 18, 2009, updates to IMP Chapter 6 Section 4.3 were not consistent with the requirements of §192.939(a)(3).

  Gulf South revised Note 2 in Table 4-1 of its IMP by deleting the sentence *"Unless all indications are examined and repaired, the maximum interval for re-inspection is 5 years for pipe operating at or above 50% SMYS and 10 years for pipe operating below 50% SMYS"* and adding the sentence *"See the Company DA Plans for the appropriate re-inspection intervals. At no time may the interval exceed seven (7) years."*

  Per Gulf South's IMP Chapter 6 Section 4.3, however, the most limiting case of either Table 4-1 (see ASME B31.8S Section 5, Table 3, Footnote 4) or the NACE standard (per DA Plan) must be used (i.e., Step 1 Option A or Option B). The change to the Table 4-1 Note 2 redefined the Table 4-1 maximum interval for DA from five to seven years for pipe > 50% SMYS, which is not consistent with §192.939(a)(3).

17. **§192.911 What are the elements of an integrity management program?**
    (l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.

    From ASME/ANSI B31.8S, Section 12; 12.2(b)(5):
    .... (b) Specifically, activities that should be included in the quality control program are as follows:
    .... (5) the operator shall determine how to monitor the integrity management program to show that it is being implemented according to plan and document these steps. These control points, criteria, and/or performance metrics shall be defined.

    Gulf South's IMP was inadequate because its quality assurance program did not include an in-house anomaly reclassification performance measure process.

    Gulf South had an *"Inspection tool vendor performance"* measure in its IMP quality assurance program that it used to track ILI vendor performance and to review the vendor's performance during annual integrity management review meetings. However, Gulf South re-graded certain ILI vendor-identified anomalies but did not have an anomaly reclassification performance measure process to track and review its own performance.

Gulf South provided documentation to PHMSA showing changes it made to its O&M Manual and to its Integrity Management Plan. After a thorough review of the material provided, PHMSA determined these modifications were adequate and no further action is required relating to the following items in response to this Notice.

- Items 1 and Item 2, in an email attachment dated December 9, 2009;
- Item 13B, in revised IMP dated July 24, 2009;

- Item 14A, in correspondence dated October 14, 2009; and,
- Item 15E, in correspondence dated October 14, 2009.

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 60 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 2-2010-1011M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Wayne T. Lemoi
Director, Office of Pipeline Safety
PHMSA Southern Region

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