U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

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Houston, TX 77074

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

March 29, 2007

Walter Ferguson
Senior Vice President and COO, Pipeline Services
CenterPoint Energy Gas Transmission
525 Milam
Shreveport, LA 71101

CPF 4-2007-1005M

Dear Mr. Ferguson:

On September 12 - 16 and November 14 – 18, 2005, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected CenterPoint Energy Gas Transmission's (CE) procedures for Integrity Management in Shreveport, Louisiana.

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

1. **§ 192.903 What definitions apply to this subpart?**

   The following definitions apply to this subpart:
   High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

   1. **An area defined as—**
      - i. **A Class 3 location under § 192.5; or**
      - ii. **A Class 4 location under § 192.5; or**
      - iii. **Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or**

iv. Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

2. The area within a potential impact circle containing—

i. 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or

ii. An identified site.

§ 192.905 How does an operator identify a high consequence area?

(a) General. To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (a) or (b) from the definition in CFR: 192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (*See* appendix E.I. for guidance on identifying high consequence areas.)

CE must modify its procedures to describe how and when either of the two HCA identification methods in document PS-03-01-200, section 2.6 will be utilized and where the information will be maintained or stored.

2. **§ 192.903 (see above)**

(c) Newly-identified areas. When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in §192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

CE must modify its procedure so that it clearly describes the process for updating and documenting the HCA analysis. It must include procedures which clearly define reviews for changes in pipeline systems which could impact HCA identification results, and it must provide sufficient detail to ensure all new HCAs are identified through processes CE describes as routine. Accordingly, CE procedure PS-03-01-105, "HCA-Class Review" describes the process for updating the HCA analysis. However, it was noted that the annual and ongoing updates to the HCA identification did not include a review of appropriate informational sources for changes in building use that may impact identified site determinations. Additionally, changes in pipeline systems must be reviewed for potential impact to HCA identification results. These types of changes are not adequately addressed in CE's procedures. Finally, CE's procedure is not sufficiently detailed to provide the needed level of specificity to assure that all HCAs are routinely found.

3. **§ 192.907 What must an operator do to implement this subpart?**

(a) General. No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in CFR: 192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

A. With regard to the following CE Procedures, CE must modify its procedures beyond a framework into more detailed and comprehensive programs which describe the 'who,' 'what,' 'where,' 'how,' and 'when' of the procedures to ensure that they are consistently implemented. Currently the procedures do not sufficiently detail the implementation of the processes to ensure that they are consistently implemented. CE must modify the following procedures and ensure that each provides the necessary specificity to ensure consistent application across the CE pipeline systems.

- PS-03-01-105 HCA-Class Review
- PS-03-01-110 Gather, Review, and Integrate Data
- PS-03-01-200 HCA Segment Identification
- PS-03-01-216 Threat Identification and Risk Assessment
- PS-03-01-258 Preventive and Mitigative Measures
- PS-03-01-264 IMP Communications Plan

B. In order to assure that there are continual improvements made to the program, CE must modify procedures to ensure that there is continual feedback from the performance of ongoing direct assessments on future direct assessments. Accordingly, CE must modify procedures PS-03-01-232, "External Corrosion Direct Assessment," PS-03-01-230, "Direct Assessment Plan," and PS-03-01-268, "IMP Quality Assurance." CE must modify these procedures to ensure that the continual improvement process is implemented consistently. Accordingly, these requirements are due to the fact that during the inspection there was no documentation that feedback from direct assessments performed early in the schedule was used for assessments performed later. CE procedures PS-03-01-232, "External Corrosion Direct Assessment," PS-03-01-230, "Direct Assessment Plan," and PS-03-01-268, "IMP Quality Assurance", Appendix A states that CE will apply the lessons learned on one ECDA assessment to future assessments via the continual improvement process and the in-process evaluation step. NACE RP 0502 §6.5 and §192.925(3) (iii) require operators to continually improve and use feedback to improve ECDA assessments. On the lines that have had ECDA assessments, there were no completed post assessments, no documentation that the lessons learned on one or more the ECDA assessments were factored into future assessments, and there were no notifications of changes made in the ECDA process as the result of any lessons learned.

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

An operator's initial integrity management program begins with a framework (see CFR: 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 for more detailed information on the listed element.)
(k) A management of change process as outlined in ASME/ANSI B31.8S, Section 11.

ASME /ANSI B31.8S, Section 11
(a) Formal management of change procedures shall be developed in order to identify and consider the impact of changes to pipeline systems and their integrity. These procedures should be flexible enough to accommodate both major and minor changes, and must be understood by the personnel that use them. Etc.
(b) The operator shall recognize that system changes can require changes in the integrity management program and conversely, results from the program can cause system changes. Etc.

CE must modify its Management of Change procedure and process to ensure that impacts of changes to organizations and changes to pipeline systems and their integrity are considered before being implemented. Accordingly, CE addresses their Management of Change (MOC) process in procedure PS-03-01-266. The "Purpose" section of the document limits the MOC process to changes in the IMP Program. Additionally, the MOC process does not ensure that integrity management changes are properly reflected in the pipeline system and that pipeline system changes are properly reflected in the integrity management program. CE's procedure PS-03-01-266, "IMP Management of Change," describes the types of changes covered by CE's company-wide management of change process, including changes to a process, policy, procedure, standard, handbook or manual. However, changes to organizations and changes to pipeline systems and their integrity are not addressed in this process and CE must modify these procedures to address these requirements. Further, while the CE IMP management of change process discusses impacts from pipeline equipment additions, deletions or modifications, changes to product being transported, and operating condition changes, the procedure does not adequately address how these types of changes are monitored and evaluated for IMP impact. Thus CE must change the procedure to address how these changes are monitored and evaluated for IMP impact.

5. **§ 192.911 (see above)**

(l) Quality assurance process as outlined in ASME/ANSI B31.8S, Section 12.

ASME/ANSI B31.8S, Section 12.2 Quality Management Control
(b) Specifically, activities that should be included in the quality control program are as follows:

(7) Corrective actions to improve the integrity management program or quality plan shall be documented and the effectiveness of their implementation monitored.

CE must modify its procedures to ensure it has an effective quality control program to determine the criteria and methods needed to ensure that both the operation and control of IM processes are effective and accurate through documentation, implementation, and maintenance. Accordingly, CE's IM quality control procedure, PS-03-01-268, section 2.2 states that the operator has assessed and developed processes to determine the criteria and methods needed to ensure that both the operation and control of IM processes are effective. However, the inspection team identified numerous processes where the lack of established quality criteria contributed to poor process implementation, including: risk analysis data collection and evaluation; direct assessment minimum data requirements; preventive and mitigative decision-making; post assessment evaluations; documentation of remediation efforts; and periodic evaluations.

6. **§ 192.911 (l) (see above)**

12.2 Quality Management Control
(c) When an operator chooses to use outside resources to conduct any process, for example pigging, that affects the quality of the integrity management program, the operator shall ensure control of such processes and document them within the quality program.

CE must modify its procedures to ensure a formal process exists which can be implemented consistently for providing oversight of outside resources. Accordingly, CE procedure PS-03-01-268, "IMP Quality Assurance" describes the quality assurance activities related to the IM program. This process does not adequately address quality requirements for providing oversight of outside resources, such as assessment, excavation, and remediation of pipeline anomalies.

7. **§ 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.

A. CE must modify its procedures to ensure that it provides technical justifications for assumptions used in the risk assessment process. In addition, CE must modify its procedures to ensure data integration is thorough, complete, and consistent and it must develop evaluation procedures to ensure the consistent application of data integration. This requirement is consistent with Section 4 of ASME/ANSI B31.8S, 4.4 "Data Collection, Review, and Analysis" states "A plan for collecting, reviewing, and analyzing the data shall be created and in place from the conception of the data collection effort. These processes are needed to verify the quality and consistency of the data. Records shall be maintained throughout the process that identify where, and how unsubstantiated data is used in the risk assessment process so its potential impact on the variability and accuracy of assessment results can be considered." Similarly, Section 2.4 of CE procedure PS-03-01-216, states that "When data is missing or is questionable, conservative assumptions shall be used when performing the risk assessment or alternatively the pipe segment shall be prioritized to a higher level. For missing or questionable data, default values shall be used. The default values shall be documented and the reason for their selection shall also be documented. Efforts shall be taken to replace missing or questionable data with reliable, accurate data. These efforts may include additional field surveys or inspections to obtain the data." At the time of this inspection, CE had pulled all of the data available from segments in HCA areas. CE expected that they would complete their data acquisition on the entire pipeline system in about one year. The risk model fields reviewed by the inspection team (Line MRT ML2) contained numerous examples where actual data was not entered. CE used a default value of 0.49 (from 0 to 1.0) when data was missing (refer to PS-03-01-216 Appendix B, section 6.0 and Table, "Risk Variables Used for Threat Calculations"). This default value puts the risk factor in the middle of the possible risk range. No technical justification was provided that supported the use of this value for all instances when data was missing from the risk analysis.

B. CE must develop a process to incorporate new data into the risk analysis when changes in data occur (e.g., assessment results such as identification of MIC). The frequency should be sufficient to ensure that risks are appropriately addressed for any applicable HCAs. In addition, the identification of missing risk data in the risk analysis must be expedited and tracked in a more formal manner. Accordingly, the inspection team reviewed data in the risk analysis data-base (vertical slice review of line MRT ML2) and determined that data was missing or unavailable. At the time of this inspection, CE had pulled all of the data available from segments in HCA areas. CE expected that they would complete their data acquisition on the entire pipeline system in about one year. In response to inquires made by the inspection team regarding the tracking of missing data, CE stated that they were not formally tracking missing data and could not provide a status of what data was missing for which segments.

8. § 192.917 (see above)

(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.**

CE must modify its procedures to assure that threats to specific pipeline segments from manufacturing and construction defects are reviewed against any MAOP increases in order to eliminate potential threats. Accordingly, neither section 2.3 nor section 2.5 in CE's document no. PS-03-01-216, "Threat Identification and Risk Assessment" addressed how the need for review against MAOP increases would be addressed. CE was unable to produce documentation related to MAOP increases for the last five years. CE's procedure PS-03-01-216, "Threat Identification and Risk Assessment" must address how MAOP will be reviewed to eliminate the threats from manufacturing and construction defects.

9. **§ 192.917 (e) (see above)**

(5) Corrosion. If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair.

CE must modify its procedure, PS-03-01-258, "Preventive and Mitigative Measures," to include the necessary specificity to address the need to evaluate other covered and non-covered segments when corrosion exists on a covered segment that could adversely impact the integrity of the line. During the inspection, the Inspection Team reviewed CE's preventive and mitigative flow chart which provides structure to this undocumented process.

10. **§ 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.

(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 B31.8S, Section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

CE must modify its procedures to differentiate between the various types of ILI tools. Accordingly, CE's procedure only indicates to "Perform ILI." CE describes the various assessment methods in PS-03-01-224, "Assessment Methods Selection Process" which references CE's "BAP – Integrity Assessment Selection Guide." Neither the procedure nor the Guide specifies the type of ILI tool to be used for the threats to be assessed. ASME B31.8S, Section 6.2, "Pipeline In-Line Inspection," describes tool section for the various potential threats. According to ASME B31.8S section 6.2, "In-line inspection (ILI) is an integrity assessment method used to locate and preliminarily characterize indications in a pipeline. The effectiveness of the ILI tool used depends on the conditions of the specific pipeline section to be inspected and how well the tool matches the requirements set by the inspection objectives." To assure that the assessment method matches the requirements set by the inspection objectives, CE must specify the appropriate ILI tools planned for its assessments.

11. § 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 (ibr, see §192.7), section 6.4, and in NACE RP 0502-2002 (ibr, 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).

(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 -

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.

CE must modify procedures PS-03-01-232, "External Corrosion Direct Assessment," PS-03-01-230, "Direct Assessment Plan," and PS-03-01-268, "IMP Quality Assurance", Appendix A to ensure that whenever the spacing of the indirect tool readings is changed, that the reason for the change will be documented and technically justified. CE must modify procedures PS-03-01-232, "External Corrosion Direct Assessment," and PS-03-01-230, "Direct Assessment Plan," to ensure that CE uses the latest information to prioritize the urgency of the excavations based on the severity of the indication.

Accordingly, for the ECDA assessments performed on lines ALE, BT-1 and A-206, there was no documentation on the tool spacing changes for the indirect inspection tools. §192.925 (b) (2) (ii) requires that operators specify and document when the tool spacing is changed over areas that have indications. The reason for the change must be specified. In addition, the table which was presented to the inspection team and was said to be used on one or more of the ECDA assessments regarding prioritization needs to be formally incorporated into one of CE's procedures concerning ECDA.

12. **§ 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.

(2) ICDA region identification. An operator's plan must identify where all ICDA Regions are located in the transmission system, in which covered segments are located. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. An ICDA Region may encompass one or more covered segments. In the identification process, an operator must use the model in GRI 02-0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines - Methodology." An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02-0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations down stream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas.

CE must modify its procedures to properly identify the source of the flow model used in the ICDA Plan. Accordingly, the inspection team noted that the model specified in CE procedure PS-03-01-238, "Dry Gas – Internal Corrosion Direct Assessment" section 3.4, was described as the GRI model but the model in the procedure is not the GRI model but rather the NACE model. There was no specific concern here because the NACE model has been validated against the GRI model and allowed for use. However, CE needs to properly describe the model as the NACE model and not one that is based on the Foude Number as in the GRI report.

13. **§ 192.927 (c) (see above)**

(4) Post-assessment evaluation and monitoring. An operator's plan must provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. The evaluation and monitoring process includes:

i. Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in §192.939. An operator must carry out this evaluation within a year of conducting an ICDA;

CE must modify its procedures to ensure that post assessments for completed Internal Corrosion (IC) direct assessments are complete and consistently applied. There is no documentation that feedback from IC direct assessments performed early in the schedule was used for assessments performed later. Accordingly, CE procedures PS-03-01-238, "Dry Gas - Internal Corrosion Direct Assessment," PS-03-01-230, "Direct Assessment Plan," and PS-03-01-268, "IMP Quality Assurance", Appendix A state that CE will apply the lessons learned from each ICDA assessment to future assessments. §192.927 requires operators to continually improve and use feedback to improve ICDA assessments. For the lines where the ICDA was complete there was no documentation that the lessons learned were factored into future assessments and there was no notification of changes made in the ICDA process as the result of any lessons learned. CE procedure PS-03-01-238, "Dry Gas - Internal Corrosion Direct Assessment," §6.2.1.2 states that improvements from one ICDA will be incorporated into future ICDA assessments.

14. § 192.927 (c) (4) (see above)

ii. Continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the covered segment. If an operator finds any evidence of corrosion products in the covered segment, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with §192.933.

(A) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe; or

(B) Assess the covered segment using another integrity assessment method allowed by this subpart.

CE must modify its procedures to ensure that the ICDA process provides assurance that the monitoring actions for future internal corrosion will be accomplished. Accordingly, CE procedures PS-03-01-238, "Dry Gas - Internal Corrosion Direct Assessment," §5.10 states that "once a dig site has been excavated and the Direct Examination activities have been completed, corrosion monitoring devices such as a coupon, electronic probe, ultrasonic sensor, or electrical resistance matrix may be installed. The Corrosion Manager shall determine whether or not to install a corrosion monitoring device and the appropriate location within the DG-ICDA Region." CE must modify its procedures to ensure mechanisms exist to inform the Corrosion Manager or other relevant personnel what has been discovered at direct examination sites and if there is a need for corrosion monitoring on this pipeline. One instance was identified where this information was not forwarded to the Corrosion Manager.

15. **§ 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 -

(1) Data gathering and integration. An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. This process must include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S, Appendix A3.3 indicate the potential for SCC. This data includes at minimum, the data specified in ASME/ANSI B31.8S, Appendix A3.

A. CE must modify its SCCDA and related procedures to ensure that the gathering, evaluation, and quality control of data related to SCC is consistently applied and documented at all sites it excavates during the conduct of its pipeline operations (not just covered segments) where the criteria indicate the potential for SCC. CE must provide a notification to OPS and modify procedures as necessary to ensure the notification or any future modifications of its proposed near-neutral SCC plan. Finally, CE must modify its procedures to ensure the performance of a spike test, per ASME B31.8S, when it experiences an in-service leak or rupture attributable to SCC. Accordingly, CE procedures PS-03-01-240, "Stress Corrosion Cracking Direct Assessment," PS-03-01-230, "Direct Assessment Plan," and PS-03-01-268, "IMP Quality Assurance", Appendix A describe how SCCDA assessments are to be conducted, the data to be collected and what documentation needs to be retained. None of those procedures mandate that CE obtain data on non-covered pipelines that may be susceptible to SCC. Studies have shown that the screening criteria for both near neutral and high pH SCC only cover 2/3 to 3/4 of the segments susceptible to SCC. Thus, operators are expected to be looking for SCC in all areas of their pipelines. §192.917(e) (5) has look beyond previsions for operators who have a history of any corrosion. These previsions require operators to look at both covered and non-covered segments that have sustained corrosion damage that is similar in physical and environmental characteristics.

B. CE must modify procedures to ensure the quality of pre-assessment data for all completed SCC direct assessments and develop quality controls for use of data in future pre-assessments. During the review of SCC DA pre-assessments, data quality was determined to be poor or missing. Accordingly, section A3.3 of B31.8S states, "Where the operator is missing data, conservative assumptions shall be used when performing the risk analysis or alternatively the segment shall be prioritized higher." CE procedures PS-03-01-240, "Stress Corrosion Cracking Direct Assessment," PS-03-01-230, "Direct Assessment Plan," and PS-03-01-268, "IMP Quality Assurance", Appendix A require that the data elements used for SCCDA be gathered. Based on some of the data elements that were inspected, CE did not review the data as required in their procedures. This poor quality data could lead to the incorrect bell hole locations being excavated. An ineffective SCCDA may be the result of the poor quality data.

C. CE must modify its procedures to ensure the notification of OPS and/or local regulatory authorities 180 days before proposing to use "other technology."

Accordingly, CE has not yet used its near neutral pH SCCDA process nor has it notified any regulatory authority. However, section A3.1 of ASME B31.8S states, "Near-neutral type of SCC similarly would require an inspection and alternative mitigation plan." CE procedures PS-03-01-240, "Stress Corrosion Cracking Direct Assessment," and PS-03-01-230, "Direct Assessment Plan," require CE notify OPS and/or local regulatory authorities if CE plans to use "Other Technology" as defined in §192.921 (a)(4) (and follow the notification procedure in §192.949). ASME B31.8S for SCCDA covers only high pH SCC and requires operators to develop a plan for near neutral pH SCC, which CE has done by following the procedure in NACE RP 0204 for near neutral SCC. This recommended practice is not referenced in the rule and thus is considered an "Other Technology."

D. CE must modify its procedures to ensure that a spike hydrostatic pressure test consistent with ASME B31.8S is conducted after an in-service leak or rupture occurs which is attributed to SCC. Accordingly, section A3.4 of ASME B31.8S states, "If the pipeline experiences an in-service leak or rupture, which is attributed to SCC, the particular segment shall be subjected to a hydrostatic test (as described below) within 12 months." CE procedures PS-03-01-240, "Stress Corrosion Cracking Direct Assessment," and PS-03-01-230, "Direct Assessment Plan," state that CE can use a pressure test to check for SCC. There is no procedure requirement to perform a spike test following an in-service leak or rupture attributable to SCC. ASME B31.8S specifically mandates that operators use a spike hydrostatic pressure test following an in-service leak or rupture attributable to SCC.

16. § 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 or RSTRENG 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.

A. CE must modify its procedures to ensure that ILI information is communicated to the relevant departments in a timely manner to ensure the proper application of any and all necessary remedial actions. Accordingly, ILI assessments completed by CE identified internal corrosion but this information was not forwarded to corrosion group for consideration of additional remedial actions. CE should formalize this action within the IM program. CE procedure PS-03-01-250, "Pipeline Evaluation and Remediation" describes the process for addressing anomalous conditions identified through integrity management assessments. CE procedures PS-03-01-110, "Gather, Review, and Integrate Data," describes the process for data integration. Neither procedure specifies requirements to forward internal corrosion information identified during ILIs to the corrosion group for evaluation. During the review of an ILI assessment (e.g., AT-5), the inspection team identified an instance where internal corrosion was identified and this information was not forwarded to the corrosion group for evaluation. CE provided documentation to the inspection team that they had forwarded internal corrosion information from other ILI assessments to the internal corrosion group although the process was not formalized.

B. CE must modify its procedures to ensure the proper communication and documentation of the operating pressure at the time of discovery related to an immediate repair anomaly so that the required pressure reduction can be accurately determined and documented. Accordingly, records reviewed by the inspection team did not provide proper communications associated with operating pressure at the time of discovery. Section 2.5 of CE procedure PS-03-01-250, "Pipeline Evaluation and Remediation" specifies the requirements for temporary pressure reduction when an "immediate" repair anomaly is identified. However, this procedure does not require that the operator document the operating pressure at the time of discovery of the anomaly. During review of assessment results, the inspection team noted that the operator did not document the operating pressure at the time of discovery of anomalies. This lack of documentation made it difficult to confirm that the pressure reduction was appropriate.

17. § 192.933 (see above)

(c) Schedule for evaluation and remediation. An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (ibr, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety. An operator must notify OPS in accordance with §192.949 if it cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure or other action. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

A. CE must modify its procedure to ensure that it adequately describes the process and documents the date that repairs are made to anomalies in order to ensure compliance with 192.933 requirements. Accordingly, CE procedures PS-03-01-232, "External Corrosion Direct Assessment," PS-03-01-230, "Direct Assessment Plan," PS-03-01-268, "IMP Quality Assurance", Appendix A, and PS-03-01-252 "Schedule of Repair Requirements", specify the timing and urgency of completing repairs to anomalous areas on the pipeline discovered during an ECDA assessment. In the review of ECDA assessments it was difficult to determine when repairs were made and if the repairs met all of the requirements of §192.933. The paper work trail that CE provided was disjointed and did not document the key dates needed to assure compliance with the regulatory requirements. In one line, ALE in East St. Louis, a temporary repair was made but there was no documentation in the file on the date of the repair. A copy of the supervisor's calendar and the charge number were submitted to the inspection team as proof that the repair was completed as specified. Several different organizations are assigned responsibility for repairs and remediation activities but there seemed to be little follow-up to document each had completed their assigned task.

B. CE must modify its procedures to ensure that it keeps track of the assessment completion schedule and the documentation of the associated completion for each assessment method (e.g., SCCDA, ILI, ECDA, ICDA) so that reassessment intervals remain within rule requirements. Accordingly, CE's BAP, following CE procedure PS-03-01-220, includes HCA segment start and ending points, segment threat scores, assessment type, and year to be assessed. CE's current BAP requires completion of 50% of the required HCA mileage by 12/17/07 and the remainder by the end of 2012. The current schedule to complete the 50% milestone calls for six (6) more miles than 50% of the total. The inspection team noted that this small amount of mileage doesn't provide much margin in case of scheduling problems. The inspection team noted that CE needs to differentiate in the BAP completion dates for the different assessment types (when performing more than one type of assessment on a segment) so that reassessment intervals can be properly calculated.

18. § 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, 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.

A. CE must modify its procedures to ensure that it properly evaluates and documents the threats of corrosion (external, internal, stress corrosion cracking) on individual segments for preventive and mitigative actions prior to completion of assessment activity. Accordingly, the flowchart referenced in CE's procedure PS-03-01-258, "Preventive and Mitigative Measures," describes the preventive and mitigative evaluation process. This flowchart states that the consideration of preventive and mitigative measures to address corrosion issues (external, internal, stress corrosion cracking) is not initiated until after the completion of segment's first assessment. During the inspection, CE confirmed this was their policy, and this policy is contrary to PHMSA's expectation that operators should not wait until after the baseline assessment to determine preventive and mitigative measures, especially for segments not scheduled for assessment in the near term.

B. CE must modify its procedures to ensure that it evaluates and documents potential enhancements regarding the application of computerized monitoring and leak detection systems. Accordingly, in making the determination regarding the need for additional ACVs/RVCs, an operator must consider, in part, swiftness of leak detection and pipe shutdown capabilities. CE's procedure PS-03-01-258, "Preventive and Mitigative Measures" addresses the need to evaluate the swiftness of leak detection in the consideration of additional ACVs/RCVs. However, in response to a request for documentation in this area, CE stated that they had not completed evaluations of the leak detection system. Furthermore, the associated flowchart used to complete the preventive and mitigative process does not address this requirement.

19. § 192.935 (see above)

(b) Third Party Damage and Outside Force Damage.

(2) Outside force damage. If an operator determines that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

CE must modify its procedures to ensure that it properly evaluates and documents that it has a mechanism to track the implementation of preventive and mitigative measures, including those to address third party damage and outside force damage. Accordingly, CE's preventive and mitigative measures procedure describes the requirements for documentation to support enhancements including documentation verifying the actions considered and taken by the Company to minimize third party damage as well as records of equipment enhancements installed for the protection of the public and/or the environment (for example, automatic shut-off valves, leak detection, replacing pipe segments, etc.). When asked by the inspection team to produce records of preventive and mitigative action implementation or records that indicated such improvement actions were not yet complete but were being tracked, CE could not provide such documentation.

20. § 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.

CE must modify its procedure to ensure that it properly develops, implements, and documents periodic evaluations based on data integration and risk assessment. Accordingly, the results of this evaluation are needed to determine reassessment intervals, assessment method tools, and preventive and mitigative measures. CE procedure PS-03-01-260, "Continual Evaluation and Assessment" states that the operator evaluates the pipeline as frequently as required based on the following to ensure pipeline integrity

- The evaluation frequency is determined by the integration of pipeline data as specified in the Baseline Assessment Plan and re-assessment schedules are developed.
- During the evaluation, the results of previous baseline and periodic integrity assessments, gas pipeline risk assessments and decisions/findings during Pipeline Evaluation and Remediation.

However, the inspection team did not identify any procedure that described how the above-stated evaluation is to be performed. Additionally, the inspection team was not provided any evidence that such a periodic evaluation had been completed for any lines.

21. **§ 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;

A. CE must modify its procedures to ensure that it properly develops and documents adequate technical justification for the selection of reassessment intervals. Accordingly, CE procedure PS-03-01-260, "Continual Evaluation and Assessment" describes the process for determining reassessment intervals. The language in this procedure is consistent with the rule requirements. However, the procedure does not require that technical justification be developed when selecting the appropriate reassessment interval. During review of proposed reassessment intervals (i.e., the draft continual assessment schedule provided by CE), the inspection team asked for but was not provided any technical justification for the intervals selected. None of the intervals was greater than seven years, but the basis for going to seven years was not documented by the operator.

B. CE must modify its procedures in order to define a formal list of IM records along with an associated records retention program that includes retention timeframes and personnel responsibilities as would be required to satisfy the requirement to maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. Accordingly, CE's IM program, PS-03-01-001, did not have a formal list of IM records nor did it specify a retention program for each record. Under section 4.4, "Minimum Document Requirements," there are general categories of documents that are listed but not specific types of records; no retention requirements and no personnel responsibilities for each record are specified. For example, CE should specify what records are critical to the documentation of individual qualifications to perform IM tasks. The IM program should also indicate retention requirements for these records as well as who is responsible for their retention.

C. CE must modify its procedures to ensure that a process exists to document the technical support of any decision, analysis, and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Accordingly, supporting documentation should include that 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. During the review of numerous IM program elements, the inspection team identified instances where records were not created to support important IM decisions. Examples were reassessment intervals, threat exclusions, preventive and mitigative decisions, risk analysis default values, and DA feasibility results. The IM program document and the implementing procedures did not clearly describe critical decision points in the process and what documentation was needed to support resulting decisions.

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.

In correspondence concerning this matter, please refer to CPF 4-2007-1005M 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*