U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

# NOTICE OF PROBABLE VIOLATION,

# PROPOSED CIVIL PENALTY
and
PROPOSED COMPLIANCE ORDER

**CERTIFIED MAIL - RETURN RECEIPT REQUESTED**

March 29, 2007

Walter Ferguson,
Senior V.P and C.O.O. Pipeline Services
CenterPoint Energy Gas Transmission
525 Milam
Shreveport, LA 71101

**CPF 4-2007-1004**

Dear Mr. Ferguson:

During the weeks of 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 your integrity management program in Shreveport, Louisiana.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violations are:

1. **§ 192.917 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 (ibr, see §192.7), section 2, which are as follows:**

Department of Transportation
Pipeline and Hazardous Materials Safety Administration
**Compliance Registry: Anitra Brown**
400 7th Street, SW
Room 2103
Washington, DC 20590

**(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.**

CenterPoint Energy Gas Transmission (CE) did not identify or evaluate the potential for interactive threats to each covered pipeline segment. The regulation specifically requires that CE identify and evaluate the threats listed in ASME/ANSI B31.8S, section 2, which includes the following:

> ASME B31.8S 2.2 Integrity Threat Classification
> The interactive nature of threats (i.e., more than one threat occurring on a section of pipeline at the same time) shall also be considered. An example of such an interaction is corrosion at a location that also has third party damage.

While CE's procedure PS-03-01-216, "Threat Identification and Risk Assessment," Section 2.2 states that, "The results from the evaluation together with the criteria used to evaluate the significance of this threat or interaction of threats to the covered pipe segment shall be used to prioritize the integrity assessment," there is not a process to ensure the evaluation of interactive threats is accomplished.

2. **§ 192.917 (see above)**

**(c) Risk assessment. An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment.**

CE did not provide specific documentation *requirements or documentation* to support conclusions to eliminate threats from HCAs in accordance with the minimum requirements specified by each of the relevant sections of ASME B31.8S. At the time of the inspection, CE did not provide the inspection team with any documentation in support of this requirement. The regulations require that threats be identified and that a risk assessment based on those threats be performed according to section 5 of ASME B31.8S.

3. **§ 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.**

**(1) Third party damage. An operator must utilize the data integration required in paragraph (b) of this section and ASME/ ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in**

**conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment. An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.**

CE does not have a formal procedure or process by which it integrates inspection tool or external corrosion direct assessment data with data related to encroachments or foreign line crossings to define where potential indications of third party damage may exist in covered sections. CE procedures PS-03-01-110, "Gather, Review, and Integrate Data," and section 2.4 of PS-03-01-216, "Threat Identification and Risk Assessment," describe the collection and evaluation of data for the risk analysis. However, neither procedure describes requirements for data integration of ILI and ECDA data with data related to encroachments of foreign line crossings prior to any post assessment review. Additionally, the inspection team did not identify any evidence that this data integration had been performed.

4. **§ 192.917 (e)(1) (see above)**

   CE did not integrate ECDA and ILI data with data related to encroachment and foreign line crossing data to evaluate the covered segment for the threat of third party damage. CE procedures PS-03-01-232, "External Corrosion Direct Assessment," and PS-03-01-230, "Direct Assessment Plan," describe how ECDA assessments are to be conducted, the data to be collected, and what documentation needs to be retained. PS-03-01-268, "IMP Quality Assurance", Appendix A requires that the data elements used for ECDA be gathered and integrated. These plans and procedures reference the NACE RP 0502-2002 ECDA assessment standard but do not reference the need to integrate encroachment and foreign line data as required in §192.917 (e)(1) and §192.925 (b) for Pre-assessments, Indirect Inspections and Direct Examinations undertaken on ECDA for a region or a segment. Three ECDA assessments were reviewed (line ALE, line BT-1, and A-206); and in each case, there was no documentation that this data integration was performed.

5. **§ 192.917 (e) (see above)**

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

CE's Baseline Assessment Plan (BAP) did not consistently specify an assessment method(s) for each covered segment that is appropriate for identifying anomalies associated with specific threats identified for the segment. The rule requires that an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. Further, ASME B31.8S states in section A4, "Manufacturing Threat (Pipe Seam and Pipe), A4.4 Integrity Assessment," "...pressure testing must be performed to address the seam issue." CE allows for either a Hydrotest or the use of TFI based on their "BAP – Integrity Assessment Selection Guide." However, according to ASME B31.8S, a TFI tool is not an acceptable method of integrity assessment for this threat. CE describes the various assessment methods in PS-03-01-224, "Assessment Methods Selection Process" which references CE's, "BAP – Integrity Assessment Selection Guide." The assessment path on the flow chart in the Guide allows for a hydrotest, pipe replacement, or use of a TFI tool. The ASME B31.8S guidance states that only a hydrotest is appropriate. A pipe replacement is an acceptable approach to eliminate the seam integrity threat, but for those instances where CE does not elect to replace the pipe, only the performance of a hydrotest would satisfy the requirements of the rule and the ASME guidance document.

6. **§ 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).**

**(1) Preassessment. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002, section 3, ...**

CE's plan did not adhere to the requirements of NACE RP 0502-2002, Section 3 by not defining minimum data requirements. CE procedures PS-03-01-232, "External Corrosion Direct Assessment," PS-03-01-230, "Direct Assessment Plan," and PS8140 "ECDA Data Elements" describe what data elements should be considered to perform an ECDA. However, the minimum data elements that are needed to determine if an ECDA can be conducted are not documented as required by NACE RP 0502, Section 3.2.1.1 which states, "The pipeline operator shall define minimum data requirements based on the history and condition of the pipeline segment. In addition, the pipeline operator shall identify data elements that are critical to the success of the ECDA process."

CE's plan did not adhere to the requirements of NACE RP 0502-2002, Section 3 by not documenting conservative assumptions. CE procedures allow conservative assumptions be made where data is not available to address data sufficiency requirements. Three ECDA assessments (completed through the third step, Direct Examination, at the time of the inspection) were reviewed (lines ALE, BT-1, and A-206); and in each case, there was no documentation on the *minimum required data*, what the basis was for any of the conservative assumptions, and if the ECDA was feasible with the data elements available. CE stated that they only have 10 years of data available for integrity management but that additional historic data may be at field locations. Past cathodic protection data is needed to determine if active corrosion is taking place or if corrosion was the result of past inadequate cathodic protection. Under other sections of §192, much of the cathodic protection data should have been retained for the life of the pipeline and thus should be available for these ECDA purposes. NACE RP 0502, Section 3.2.4 states, "In the event that the pipeline operator determines that sufficient data for some ECDA regions comprising a segment are not available or cannot be collected to support the Pre-Assessment Step, ECDA shall not be used for those ECDA regions."

CE's plan did not adhere to the requirements of their own procedures and NACE RP 0502-2002, Section 3 by not documenting that a feasibility assessment was undertaken. CE procedures PS-03-01-232 §4.0, "External Corrosion Direct Assessment," PS-03-01-230, "Direct Assessment Plan," and PS-03-01-268, "IMP Quality Assurance", Appendix A require that the feasibility of each ECDA conducted be assessed and documented. In the three ECDAs reviewed by the inspection team (lines BT-1, ALE, and A-206) that CE started and completed through the Direct Examination step, there was no documentation that a feasibility assessment was undertaken. Documentation on what was considered during the feasibility review is critical to determine the applicability of the ECDA process to other covered segments and for feedback as required by NACE RP 0502, §192.925 and CE procedures PS-03-01-232, "External Corrosion Direct Assessment," and PS-03-01-268, "IMP Quality Assurance", Appendix A.

CE's plan did not adhere to the requirements of their own procedures and NACE RP 0502-2002, Section 3 by not documenting the specific indirect inspections tools chosen and if they were complementary to each other. 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 require that the indirect tool selection for each ECDA conducted be verified and documented. In the three ECDAs reviewed by the inspection team (lines BT-1, ALE, and A-206), there was no documentation regarding why the specific indirect inspections tools were chosen and if they were complementary to each other. NACE RP 0502, Section 3.4.1.1 states, "The pipeline operator shall select indirect inspection tools based on their ability to detect corrosion activity and/or/ coating holidays reliably under the specific pipeline conditions to be encountered." NACE RP 0502, Section 3.4.1.2 states, "The pipeline operator should endeavor to select indirect inspection tools that are complementary. That is, the operator should select tools such that the strengths of one tool compensate for the limitations of another."

7. **§ 192.925 (b) (see above)**

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

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

**(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;**

**(b)(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;**

CE, in their ECDA plan, did not document the more restrictive criteria, as required by §192.925, when they conducted ECDA for the first time on a covered segment. These more restrictive criteria are for pre-assessment, indirect inspection, and direct examination steps of the ECDA process. CE did not document for each specific assessment how the more restrictive criteria were applied. CE procedures PS-03-01-232, "External Corrosion Direct Assessment," and PS-03-01-230, "Direct Assessment Plan," describe how ECDA assessments are to be conducted, the data to be collected and what documentation needs to be retained. These plans and procedures reference the NACE RP 0502-2002 ECDA assessment standard but do not reference the need to document the more restrictive criteria as required in §192.925(b)(1) subparts (i), (ii) and (iii) for Pre-assessments, Indirect Inspections and Direct Examinations undertaken on an initial ECDA on a region or a segment. Three ECDA assessments were reviewed by the inspection team (line ALE, line BT-1, and A-206), and in each case there was no documentation of the more restrictive criteria for this initial ECDA on these segments.

8. **§ 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 -**

- **i. All data elements listed in Appendix A2 of ASME/ANSI B31.8S;**

CE's ICDA plan did not adhere to the requirements of their own procedures and Appendix A2 of ASME/ANSI B31.8S. 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 require ICDA feasibility be performed in the pre-assessment step; and no feasibility evaluation results were documented on the ICDA pre-assessments performed on lines FT-11 and ADT-8 that were completed prior to the inspection. CE did not document the results of the feasibility analysis, and there was not sufficient evidence to conclude that the lines selected for ICDA met the ICDA criteria. CE did not provide sufficient documentation to support the use of ICDA on the lines reviewed. CE did not document the basis for selecting the feasibility criteria for pigging, water upsets, and introduction of sludge. In Figure 2, "DG-ICDA Feasibility Filter" of procedure PS-03-01-238, "Dry Gas - Internal Corrosion Direct Assessment," there are several numerical values for some of the feasibility issues, such as "Routine pipeline pigging (more than 3 times per year)," etc. but there is no explanation on where these values come from or how they are to be generated.

Based on a review during the inspection of the data elements for lines FT-11 and ADT-8, the data was of poor quality, and CE did not review the data as required in their procedures. During the review of several ICDA pre-assessments, data quality was determined to be poor or data was missing. 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 require that the data elements used for ICDA be gathered. This poor quality data could lead to the incorrect critical angles being calculated and to ICDA regions being improperly determined.

**9. § 192.927 (c) (see above)**

**(5) Other requirements. The ICDA plan must also include -**

> **ii. provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience;**

CE did not document where the more restrictive criteria were used in their ICDA plan, as required by §192.927, and which are required when conducting ICDA for the first time on a covered segment. These more restrictive criteria are for pre-assessment, indirect inspection, direct examination, and post assessment steps of the ICDA process. 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 describe how ICDA assessments are to be conducted, the data to be collected and what documentation needs to be retained. These plans and procedures reference the ASME B31.8S for ICDA assessment requirements and §192.927. Although not referenced, the draft NACE RP on Dry-Gas ICDA was also utilized. The CE procedures do not document the more restrictive criteria as required in §192.927(b)(5)(iii) for each of the four steps undertaken on an initial ICDA on a region or a segment. The rule is clear that these criteria must be documented. CE also did not document how the more restrictive criteria were applied in ICDAs for lines FT-11 and ADT-8.

**10. § 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.**

CE's SCCDA plan does not require the gathering and evaluating of data related to SCC 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 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 these procedures mandate that CE obtain data on non-covered pipelines that may be susceptible to SCC as required in §192.929.

Based on some of the data elements in CE's SCCDA program that were inspected, CE did not review the data as required in their procedures. 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. During the review of SCCDA pre-assessments, data quality was determined to be poor or missing. B31.8S, Section A3.3 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's IMP does not provide for notification to PHMSA regarding its near-neutral SCC plan. ASME B31.8S, Section A3.1 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 to notify PHMSA 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". As such, CE must notify PHMSA and/or local regulatory authorities 180 days before proposing to use the technology. CE has not yet used its near neutral pH SCCDA process nor has it notified any regulatory authority.

CE's IMP does not specify the performance of a spike test, per ASME B31.8S, when it has experienced an in-service leak or rupture attributable to SCC. ASME B31.8S, Section A3.4 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.

11. **§ 192.935 What additional preventive and mitigative measures must an operator take?**

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

CE did not follow its procedure requiring that an analysis completed in conjunction with the annual assessment inspection shall result in documentation of results from any feasibility analysis of alternatives, including the installation of ACVs and RCVs. The operator did not provide any documented technical justification either to install or not to install ACVs or RCVs. CE's procedure PS-03-01-258, "Preventive and Mitigative Measures," specifies that the operator shall document all actions considered and taken to enhance public safety and/or environmental protection as identified from the risk assessment and/or specific threat factors on each of the HCA pipeline segments. The flow charts provided to the inspection team for preventive and mitigative evaluations did not take into consideration segment specific risk data when determining measures to implement. CE confirmed in discussions that rather than reviewing each segment individually for preventive and mitigative measures that they applied more "global" preventive and mitigative decisions across their system.

Proposed Civil Penalty

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations and has recommended that you be preliminarily assessed a civil penalty of $95,000 as follows:

| Item number | PENALTY |
|---|---|
| 1. | $17,000 |
| 2. | $17,000 |
| 4. | $22,000 |
| 5. | $17,000 |
| 7. | $22,000 |

Proposed Compliance Order

With respect to items 1 through 11 pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to CenterPoint Energy Gas Transmission. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

Response to this Notice

Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

In your correspondence on this matter, please refer to **CPF 4-2007-1004** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous
Materials Safety Administration

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

## PROPOSED COMPLIANCE ORDER

Pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration (PHMSA) proposes to issue to CenterPoint Energy Gas Transmission a Compliance Order incorporating the following remedial requirements to ensure the compliance of CenterPoint Energy Gas Transmission with the pipeline safety regulations:

1. In regard to Item Number 1 of the Notice pertaining to potential threats to pipeline integrity and specifically interactive threats, CE must implement their procedure PS-03-01-216 and develop and implement a process to ensure that the evaluation of interactive threats is addressed. CE must provide an evaluation of the threat of interactive threats for all covered segments.

2. In regard to Item Number 2 of the Notice pertaining to ASME B31.8S, Section 5 and the requirement to develop minimum data requirements, CE must implement their procedure PS-03-01-216 for all of the described threats and develop and implement a procedure that also addresses Cyclic Fatigue. CE must develop specific documentation requirements and provide documentation to support conclusions to eliminate threats from HCAs in accordance with the minimum requirements specified by each of the relevant ASME B31.8S section.

3. In regard to Item Number 3 and 4 of the Notice pertaining to third party damage and requirements of ASME B31.8S, CE must develop the appropriate procedure(s) to integrate inspection tools or external corrosion direct assessment data with data related to encroachments or foreign line crossings to define potential indications of third party damage in covered sections. CE must integrate ECDA data and ILI data with data related to encroachment and foreign line crossing to evaluate the covered segment for the threat of third party damage and provide documentation that those procedures have been implemented related to each of the covered segments.

4. In regard to Item Number 5 of the Notice pertaining to ERW pipe and requirements of ASME B31.8S, CE must revise its procedures to address the manufacturing threat by specifying an assessment method(s) for each covered segment that is best suited for identifying anomalies associated with specific threats for the segment. CE must identify those locations where it may have used TFI technology for the identification of the manufacturing threat; and where CE used TFI technology for the assessment of the manufacturing threat, CE must reassess the segment using appropriate and approved technologies.

5. In regard to Item Number 6 of the Notice pertaining to ECDA general requirements, CE must modify its procedures where appropriate; it must define and provide minimum data requirements; it must document its conservative assumptions; it must document all required feasibility assessments; and it must provide documentation for all indirect inspection tools chosen relative to each of the HCAs in all covered sections.

6. In regard to Item Number 7 of the Notice pertaining to ECDA more restrictive criteria, CE must document the requirement for more restrictive criteria required for pre-assessment, indirect inspection, and direct examination when ECDA is applied for the first time. CE must provide documentation for the application of more restrictive criteria on all locations where ECDA was implemented.

7. In regard to Item Number 8 of the Notice pertaining to the implementation of ICDA procedures, CE must document the results of its feasibility analysis related to the ICDA process and procedures, and CE must review the quality of pre-assessment data for all completed IC direct assessments and develop quality controls for use of data in future pre-assessments. CE must provide documentation of its feasibility analysis and it must provide documentation to ensure that the application of the ICDA procedure to HCAs in covered segments was adequate to ensure that the procedures were followed and that the critical angles were properly calculated and evaluated.

8. In regard to Item Number 9 of the Notice pertaining to more restrictive criteria required for first time ICDA use, CE must provide documentation for the application of more restrictive criteria required for pre-assessment, indirect inspection, direct examination, and post assessment on all locations where ICDA was implemented. CE must document for each specific assessment how the more restrictive criteria were applied.

9. In regard to Item Number 10 of the Notice pertaining to using DA for Stress Corrosion Cracking, CE's procedures must require the gathering and evaluating of data related to SCC at all sites it excavates. CE must review the quality of pre-assessment data for all completed SCC direct assessment and develop quality controls for the use of the data in future pre-assessments. CE must provide for notification to PHMSA of its intent to use its near-neutral SCC plan as a use of "Other Technology". CE must specify the performance of a hydrostatic spike pressure test per ASME B31.8S for the event of an in-service leak or rupture. CE must provide documentation to ensure that SCC is being properly evaluated for all HCAs in covered segments.

10. In regard to Item Number 11 of the Notice pertaining to preventive and mitigative measures, CE develop documentation associated with their technical justification either to install or not to install ACVs or RCVs and provide the required documentation to support its technical justifications with regard to ACVs or RCVs.

11. CE must address the issues within this compliance order within 90 days after receipt of a Final Order and submit to R. M. Seeley, Director, Southwest Region, Pipeline and Hazardous Materials Safety Administration.

12. CE shall maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to R. M. Seeley, Director, Southwest Region, Pipeline and Hazardous Materials Safety Administration. Costs shall be reported in two categories: 1) total cost associated with preparation/revision of plans, procedures, studies and analyses, and 2) total cost associated with replacements, additions and other changes to pipeline infrastructure.