



U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

8701 South Gessner, Suite 1110
Houston, TX 77074

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

June 10, 2009

Kevin Sullivan
Senior V.P. Chemicals
PPG Industries, Inc.
440 College Park Drive
Monroeville Pennsylvania, 15146

CPF 4-2009-1016M

Dear Mr. Sullivan:

On August 27 - 31 and November 5 - 9, 2007, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code inspected PPG Industries, Inc. (PPG) procedures and records for the Integrity Management Plan in Westlake, Louisiana.

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

1. §192.905(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 (1) or (2) from the definition in §192.903 to identify a high consequence area. An operator may apply one method for 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.)

PPG must amend its High Consequence Area (HCA) identification process and procedures to ensure that they adequately describe how to identify HCAs. The amended HCA identification process must include:

- Sufficient details of the processes it uses to determine identified sites The Criteria of the HCA identification process
- Clearly indicate how it determines identified sites including roles and responsibilities, methodology, and documentation of its activities
- Must require that the method it uses to identify its HCAs for each segment of its pipelines be documented Description of how key elements of the HCA identification are documented

2. §192.921 (b)(1) Identified sites. An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.

PPG must amend its Integrity Management Plan (IMP) to ensure that the HCA process language describes how it carries out the gathering and input of information from routine operation and maintenance activities regarding the identification of potential identified sites.

3. §192.905(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.

PPG must amend its process for Identification and Evaluation of Newly Identified HCAs, program requirements to ensure that to ensure that it addresses the breadth of factors to be monitored and evaluated for changes.

4. §192.921(a)(4) Other technology. Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. 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.

PPG must amend its IMP procedures to ensure it notifies PHMSA of its use of "other" technology associated with Direct Assessment (DA), specifically the use of Long Range Ultrasonic Testing (LRUT) for cased piping.

5. §192.919(e) Risk minimization procedure. A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

PPG must amend its IMP to include specific references to detail specific environmental and safety requirements and procedures.

6. §192.917(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:

- 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.

PPG must amend its IMP's threat identification and risk analysis section to ensure that it addresses all of the threats. The memos/documents provided to the PHMSA inspection team regarding elimination of the threat due to SCC prepared by Don Haines needs to be included or specific wording that addresses SCC elimination within the IMP. Additionally, PPG must amend its IMP to ensure that it addresses how interactive threats are addressed.

7. §192.917(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.

PPG must amend its IMP's data gathering and integration section to ensure that it provides details of how it gathers data and information for its pipeline systems. The apparent results of this effort have been assembled on data collection spreadsheets and are analyzed within the risk analyses by threat index. Without the details of PPG's process for data and information gathering, it is unclear how PPG will address this should PPG acquire new assets. Additionally, PPG must amend its IMP's data gathering and integration section to ensure that it addresses the quality of data or missing data and how its risk model addresses the quality of its data, assumptions made about its data, and ensure conservative design values are used when data is missing or unknown.

8. §192.917(c) Risk assessment. An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.

- A) PPG must amend its IMP's risk assessment section to ensure that it provides details as to what will be accomplished during an annual meeting to update its BAP, its risk analysis and other activities, who will participate in the meeting, and how this will be documented and followed up on, including any documentation of changes to the plan.
- B) PPG must amend its IMP's risk assessment section to ensure that it performs a check on the risk results to determine whether they are logical and consistent with PPG's and industry's experience.

9. § 192.917 (e)(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.

PPG must amend its integrity management third party damage process and procedures to ensure that it integrates foreign line crossing information and locations with results of ECDA and ILI runs.

10. §192.925(b)(1) Preassessment. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502-2002, section 3, the plan's procedures for preassessment must include-

- i. Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and
- ii. The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE RP0502-2002, the operator must demonstrate the applicability, validation basis, equipment used,

application procedure, and utilization of data for the inspection method.

PPG must amend its ECDA pre-assessment process and procedures to define the criteria for conducting the feasibility assessment when using other tools not listed in the NACE table.

11. §192.925(b)(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.**

PPG must amend its ECDA Indirect Examination process and procedure, 2305-IM-5401 11-5-2007, to include a specific process for using indirect survey tools to address decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected. Additionally, the procedures must adequately address the following:

- Must include further details of how the results of its indirect inspection tools will be analyzed to correlate the magnitude of readings and associated classifications
- Must include details of how it will specifically integrate ECDA data with encroachment and foreign line crossing data to evaluate the covered segment for the threat of third party damage

12. §192.925(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;**
- 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.**

PPG must amend its ECDA Direct Examination process and procedure, 2305-IM-4007 11-5-2007, to ensure that it includes a process to establish and implement criteria and internal notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the period for direct examination of indications. Additionally, the procedures must adequately address Requirements to consider the use of assessment methods other than ECDA (e.g., ILI or pressure test) to assess the impact of defects other than external corrosion (e.g., mechanical damage, SCC) discovered during direct examination.

13. §192.925(b)(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.)**

PPG must amend its ECDA Post assessment and continuing evaluation process and procedure, 2305-IM-4007 11-5-2007, to ensure that it includes specific criteria or guidance for performing the post assessment and ensuring feedback at all appropriate opportunities throughout the ECDA process to demonstrate feedback and continuous improvements.

14. §192.933(b) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

PPG must amend its Discovery of Condition process and procedure, Section 5.7 of 2305-IM-5500, to ensure that it includes specific criteria and data necessary to

determine discovery, including when discovery will be determined for ILI, Hydrotest and ECDA assessments. Additionally, the procedures must contain a requirement to document the date when discovery occurs.

15. §192.933(d)(1) Immediate repair conditions. An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, Section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

- i. A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991); AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)); or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in Appendix A to Part 192.
- ii. A dent that has any indication of metal loss, cracking or a stress riser.
- iii. An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

PPG must amend its Response to Immediate Repair Conditions process and procedure, Section 5.8.2 2305-IM-5500 11-06-2007, to ensure it requires that upon discovery of an immediate condition, it reduce its operating pressure (or shut down the pipeline), and conduct an examination within 5 days of the date of discovery. If an examination cannot be conducted within 5 days of discovery, a justification must be provided as to why the schedule can not be met and the basis for the companies' belief that this delay will not jeopardize safety.

16. §192.935(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.

PPG must amend procedure 2305-IM-5800, 11-7-2007, Preventive and Mitigative Measures to ensure that evaluations of preventive and mitigative measures specify how these evaluations will use risk assessment results to identify measures and determine where they should be implemented. Additionally, PPG shall amend the IM plan to specify how both likelihood and consequence will be considered, how the risk results will be used in a cost-benefit analysis, and what decision criteria will be used to determine which measures will be implemented. Such a procedure should include a systematic, documented decision-making process that involves input from relevant parts of the organization such as operations, maintenance, engineering, and corrosion control.

17. §192.935(b)(1) Third party damage. An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum-

- i. Using qualified personnel (see §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.**
- ii. Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under Part 191.**
- iii. Participating in one-call systems in locations where covered segments are present.**
- iv. Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP-0502-2002 (ibr, see §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B318.S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.**

PPG must amend procedure 2305-IM-5800, 11-7-2007, Preventive and Mitigative Measures, section 8.10. PPG must have a detailed procedure to address the activities it conducts to implement and document those activities. PPG needs to develop a procedure describing the details of the preventive and mitigative measures and activities it performs when 3rd party excavation activities are performed near their pipelines. The procedure must include details of how PPG determines whether

damage to its pipeline resulted from the excavation activity and the actions PPG will take to address this threat.

18. §192.935(b)(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.

PPG must amend procedure 2305-IM-5800, 11-7-2007, Preventive and Mitigative Measures, Section 8.12 Outside Force Damage. PPG must revise its procedure to identify those activities that it conducts to address outside force damage and cross reference relevant procedures such as 2305-DT-1008, PPG Pipeline Manual-Emergency Plan and 2305-DP-1700, Inspect Surface Conditions of ROW.

19. §192.935(d) Pipelines operating below 30% SMYS. An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.

1. Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and
2. Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.
3. Perform semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical).

PPG must amend procedure 2305-IM-5800, 11-7-2007, Preventive and Mitigative Measures, Section 8.10.1.1. to ensure that PPG procedure contains details of the actions it performs when 3rd party excavation activities are performed near their pipelines which addresses how it determines whether damage to its was caused by the excavation and the actions PPG will implement relative to pipelines operating below 30% SMYS.

20. §192.935(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.

PPG must amend procedure 2305-IM-5800, 11-7-2007, Preventive and Mitigative Measures to evaluate as an option, installing Automatic Shut-off Valves or Remote Control Valves as preventive and mitigative measures.

21. §192.917(e)(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.

PPG must amend procedure 2305-IM-5800, 11-7-2007, Preventive and Mitigative Measures, Section 8.13 Controlling Corrosion. PPG must revise its procedure to reference PPG's corrosion control procedures and remediation procedures to address instances when corrosion conditions are identified. The amended procedure must clearly indicate how the evaluation and remediation criteria will be consistently applied to pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics.

22. §192.947(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.

PPG must amend procedure 2305-IM-6000, 11-7-2007, Record Keeping, to require that documents be developed and maintained to support the many decisions, analyses, and processes that are carried out to support the entire IM plan. Documents that must be included are those needed to support identification, calculation, amendment, modification, justification, deviation and determination made, as well as actions taken to implement and evaluate program elements.

23. §192.909 (a) General. An operator must document any change to its program and the reasons for the change before implementing the change.

PPG must amend its Management of Change (MOC) process and procedures to ensure that it adequately addresses requirements to maintain a formal MOC log or document trail for integrity management plan changes contained in ASME B31.8S, Section 11.

24. §192.911 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.**

PPG must amend its MOC process and procedures to ensure that changes are properly reflected in the pipeline system and that pipeline system changes are properly reflected in the integrity management program. The amended procedures must include details of how it addresses changes made to its BAP, and that for all changes, to document reason, authority for approving, analysis of implications, and communication of changes to affected parties. Additionally, changes to the Integrity Management Program or changes to other operating manuals need to be reviewed by persons that can assess safety impact, assess IM program element impact, and determine if operating system/equipment changes are needed.

25. §192.911 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.)

- l. A quality assurance process as outlined in ASME/ANSI B31.8S, Section 12.**

PPG must amend their quality assurance plan to ensure that the responsibilities and authorities under this program shall be clearly and formally defined. Additionally, their quality assurance plan shall ensure that, when they choose to use outside resources to conduct a process that affects quality of the IM program, the operator shall ensure control of such processes and document them within the company's quality assurance plan. Operator management and other appropriate operator personnel must understand and support the integrity management program. This should be accomplished through the development and implementation of an internal communications aspect of the plan. Performance measures must be reviewed on a periodic basis and resulting adjustments to the integrity management program must be part of the internal communications plan.

Post Inspection Actions

With respect to items 1, 2, 3, 5, 6, 8A and 9 above, PPG revised these procedures in the Integrity Management Plan procedures. PPG submitted these procedures to the inspection team. The inspection team reviewed all the revised procedures and verified that the procedures were adequate.

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 4-2009-1016M** 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*