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VIA COURIER

Mr. R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous Materials Safety Administration
US Department of Transportation
8701 South Gessner, Suite 1110
Houston, TX 77074

Re: Notice of Amendment, CPF 4-2007-1008M
Response and Request for Hearing

Dear Mr. Seeley:

On or about July 30, 2007 El Paso Pipeline Group (EPPG) received the above referenced Notice. The Notice refers to inspections conducted on ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Southern Natural Gas Company, and Tennessee Gas Pipeline Company during 2006 by representatives of the Pipeline and Hazardous Materials Safety Administration ("PHMSA").

On or about August 29, 2007 PHMSA granted EPPG and ANR an extension till November 30, 2007 for the following:

- The period in which EPPG and ANR must request a hearing, note how inadequacies will be addressed, or submit written answers/objections on any or all of the 23 items specified in the Notice;
- The period EPPG and ANR have in which to revise their procedures as specified in the above referenced Notice;
- Any other deadlines resulting from the Notice which would otherwise expire on or about August 29, 2007 including but not limited to the time period in which to request a hearing.

At the time of the inspection, ANR Pipeline Company (ANR) was a member of the El Paso Pipeline Group. On February 22, 2007, ANR was acquired by a wholly owned subsidiary of TransCanada Corporation. As of this writing ANR is no longer part of EPPG. Pursuant to the terms of a transition services agreement, however, the Integrity Management Program and Baseline Assessment Plan will continue to be managed under the existing EPPG IMP Manual and processes during a transition period ending December 2007.

Hearing Request

As provided in 49 C.F.R. sec. 190.209 (a) (3) and 190.209 (b) (4), EPPG and ANR request a Hearing on items 18 and 22 in that Notice of Amendment.

EPPG and ANR will be represented by counsel at the Hearing.

Pursuant to 49 C.F.R. sec. 190.211 (e), EPPG and ANR request that the material in any case files or other files in the actual or constructive possession of PHMSA pertinent to Items 18 and 22 in the Notice be provided to EPPG as soon as possible, but no less than 30 days prior to the Hearing. This includes but is not limited to inspector notes, supporting documentation, and guidance materials provided to the inspectors.

EPPG and ANR intend to raise the following issues at the Hearing because these NOA items are outside the requirements of the rule and do not add to the safety or integrity of the pipeline system:

- NOA 18: Whether El Paso Pipeline Group (EPPG) and ANR complied with 192.933 for defining the response within 5 days of discovery for immediate repair conditions, determining the pressure reduction, and defining the immediate conditions per 192.933(d)(1).

- NOA 22: Whether EPPG and ANR must utilize FEMA data in order to comply with 192.935 as related to determing what areas are prone to outside forces.

We look forward to the opportunity to present information on these issues to PHMSA at the Hearing.

Response to NOA Items

The following is a list of each of the NOA items that have not been requested for hearing, Items 1 through 17, 19 through 21, and 23. Along with the text of the NOA item is EPPG and ANR's response to the item.

When EPPG is used from this point forward in the document it represents both EPPG and ANR.

NOA Item 1

Regulatory reference: 192.909(b)
Text of NOA: EPPG must revise its procedures to adequately define criteria in the IMP to establish what significant changes to the integrity management program, program implementation, or schedules, require PHMSA or the State or local pipeline safety authority notification within 30 days after EPPG has adopted the change.

EPPG Response: As part of continuous improvement to the IMP processes, EPPG has modified Section 18.2 of the IMP Manual by adding examples of items that would constitute a significant change requiring notification to authorities. Specifically, the following items were added to the end of the second paragraph under the heading "Significant Changes to the program:"

> Examples of items that would be considered a significant change requiring notification are:
> - Change in HCA mileage for any one company by more than 20%.
> - Change in HCA calculation method for one operating company.
> - A single acquisition or divestiture of facilities resulting in a change in HCA mileage greater than 10%.

See attachment 1.

NOA Item 2

Regulatory reference: 192.911(k)
Text of NOA: The EPPG MOC process and procedures must be revised and must require and develop documentation which adequately addresses procedures for:

a. *consideration of impacts of changes to pipeline systems and their integrity,*
b. *analysis of the implications of planned changes,*
c. *ensuring that integrity management program changes are properly reflected in the pipeline system and that pipeline system changes are properly reflected in the integrity management program, and*
d. *requiring that equipment or system changes be identified and reviewed before implementation.*

EPPG Response: EPPG has numerous policies, practices and procedures in place to ensure evaluation and communication of changes which may affect the pipeline system or the IMP. Some of these are specifically addressed in the IMP, i.e. Chapter 15 and Chapter 4; and through activities described in the IMP, i.e. the HCA annual review process (Figure 1-4). Other policies, practices and procedures are covered in other manuals or department guidelines and are referenced in sections 15.6 and 15.8. In addition, many of EPPG's manuals (Section 15.6) include their own Management of Change sections which include communication requirements designed to inform not only those responsible for the IMP program of any changes that may affect the program or pipeline integrity but any department or individual contributor who may need to be aware of changes in company procedures or facilities.

As part of continuous improvement, EPPG has modified the IMP Manual Chapter 15, Management of Change, by adding examples to the Physical Changes management of change section to more clearly identify processes meeting the requirements noted in this NOA item.

See attachment 2.

NOA Item 3

Regulatory reference: 192.911(l)
Text of NOA: EPPG procedures must be revised and must adequately address the following components of a quality assurance process outlined by ASME B31.8S:

a. *Detailed responsibilities and authorities for all key elements of the integrity management program shall be adequately defined in IMP documentation;*
b. *Criteria and guidance for the conduct of QA audits shall be adequately specified by EPPG. The IMP identifies program elements that "would" be appropriate for review without specifying the minimum set that must be reviewed in each annual review. Verifaction of threat identification, data, and risk results for specific segments indicated errors in process implementation:*
    - *SNG South Colquitt Lnie LN-03, HCA 1380 was incorrectly indicated as a production area in the internal corrosion evaluation*
    - *CIG Line 59A HCA had the incorrect pipe type in the threat/Risk data base.*
c. *EPPG must develop adequate qualification requirements for outside contractors. When EPPG uses outside resources to conduct processes that affect the quality of the integrity management program, the quality of*

such processes shall be verified by EPPG and these processes shall be documented within the quality program.

EPPG Response:

a. On June 23, 2006 John Pepper e-mailed EPPG noting that this issue had been addressed. See Attachment 3.

b. To more clearly communicate the requirements of the annual Quality Control review, Section 16.5 of the IMP Manual was changed to clearly state all the items under each part of the IMP processess that would be included in this review. This was done by removing the "would" statements and replacing them with "that are used" statements and confirming the items included under each category.

   See attachment 4.

c. In Section 16.7 of the written IMP, EPPG explains that when EPPG hires a contractor to perform a covered task in conjunction with integrity management activities that the qualifications are documented through Veriforce, our contracted agent for maintaining OQ qualification records. These individuals are evaluated against El Paso task standards or equivalent by qualified evaluators. Other contractor qualifications that do not overlap with OQ and that EPPG believe are necessary are covered under the procurement specifications. Based on the above, EPPG believes adequate specifications are in place for contractor qualifications that could affect the quality of the program and are unaware of specific examples of where qualification specifications are missing. However, if PHMSA has specific examples of where EPPG is missing these specifications, EPPG would appreciate the feedback.

NOA Item 4

Regulatory reference: 192.915(a)
Text of NOA: EPPG'S training and qualifications program must be revised and must adequately address the following:

a. EPPG must adequately specify the specific requirements such that supervisory personnel have the appropriate training or experience in order to perform their assigned responsibilities;

b. EPPG must have provisions requiring documentation that is sufficiently explicit to verify the qualifications of personnel that carry out assessments and who evaluate assessment results;

c. *EPPG must develop and specify requirements for training and qualification requirements for personnel who execute the activities within the integrity management program.*

EPPG Response:

a. Rule 192.915 states "The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible." EPPG has existing procedures established in the Human Resources staffing process and performance evaluation process for these positions within the Company.

   To clearly tie this process to the IMP the following paragraph has been added to IMP Manual Section 20.3 under the "Supervisory Personnel" heading:

   > The training or experience requirements for someone performing a supervisory role are based upon EPPG's Human Resources staffing process and performance evaluation process for their position within EPPG. Management selects individuals based on their demonstrated knowledge, skills and abilities in performing position responsibilities (documented in the EPPG evaluation process) that would be applicable for performing in a supervisory role that includes IMP responsibilities.

b. Specific qualifications for personnel who carry out assessments and evaluate results are clearly and comprehensively established in Section 20.3 under the heading ""Persons who carry out assessments and evaluate assessment results." As part of continuous improvement and to document a process step that has already been taking place the sentence "The list of qualified persons will be reviewed each year and authorized by the IMP Committee" has been added to the end of this section.

c. As with individuals performing supervisory roles in the IMP described in response "a" above, training and qualifications of individuals executing activities within the IMP are specified in EPPG's Human Resource staffing processes. Individuals that execute IMP activities are selected based on management's assessment of their competency to perform these duties. These competencies are reviewed annually through the Performance Management Process. EPPG agrees, as part of continuous improvement, to add specific qualification for key positions within the IMP. These qualifications have been added to the IMP Manual Section 20.3 under a new heading entitled "Qualifications of IMP Team and Committee Leaders."

See attachment 5.

NOA Item 5

Regulatory reference: 192.917(a)
Text of NOA: EPPG must revise its procedures to ensure better documentation of its process for utilizing the TIP charts and related steps to evaluate threats and setting threat risk levels in order to assure consistent application by different analysts. As described by EPPG, this is a large-scope, complex task requiring the assembly, review, and application of multiple large data sets and the use of detailed technical decision logic; and the procedure requires clear and complete definition of all steps.

EPPG Response: EPPG, as part of continuous improvement, will include additional detail for the Threat Identification Process (TIP) charts to describe criteria for decision boxes, tie specific data to questions, and provide additional explanatory notes as necessary. See attachment 6 for a draft of the detailed tables for the TIP charts to be included in Appendix A of the IMP Manual. These tables are being reviewed internally as part of the Management of Change process outlined in the IMP Manual Chapter 15. Once the MOC process is complete these changes will be published and we will provide PHMSA with a copy.

However, EPPG does consistently apply the TIP charts across the five pipelines and across all HCAs through centralized data collection and centralized initial answering of the TIP questions plus automated calculation of the threats. Then, after receiving the IMP Training to emphasize consistency, the Subject Matter Experts (SME) review the threats to each HCA. Any changes made to the TIP questions (during SME review or at anytime) require a comment to document the change. Without a comment, the IMP Database will not accept the change. Also, to ensure consistent application, the BAP MOC process in Chapter 4 is followed for approval and communication of changes to the Baseline Assessment Plan.

PHMSA noted in the NOA that TIP charts A-1 (External Corrosion) and A-4 (Manufacturing) were completed.

NOA Item 6

Regulatory reference: 192.917(c)
Text of NOA: EPPG must revise its procedures and "TIP" flow charts where the claim is made that the threats "do not exist" for segments specifically with regard to the following:

a. *Treatment of failure/leak history for both external and internal corrosion - the elimination from consideration of all segment leak/rupture history before ILI has been conducted on the segment has not been justified, (Appendix A-1, A-2 TIP charts) and potentially leads to the non-conservative elimination of threats.*
b. *Incorrect operations - this threat category was ruled out for all covered segments without a segment-specific evaluation of risk factors.*

EPPG Response:
EPPG has modified the external corrosion TIP chart to indicate that external corrosion is a threat for each HCA. Also, the manufacturing threat in certain circumstances has been changed from a "No Threat" to a "Stable Threat" to indicate the threat exists but appropriate actions have been taken. For instance, if pre-1970 ERW pipe has been pressure tested, it is consider a stable threat. These changes to TIP charts A-1 and A-4 were provided to PHMSA on March 30, 2007.

a. EPPG's use of leak history in the external (A-1) and internal (A-2) corrosion TIPs is both valid and appropriately conservative based on the fact that ILI tools are a proven technology for evaluating both external and internal corrosion on a pipeline. Therefore, since ILI is a confirming evaluation of the external and internal corrosion threats in the pipeline segment at that point in time and both of these threats are time dependent threats, the ILI information supersedes the past corrosion leak history. Please note that past leak history is utilized if an ILI has not been conducted for an HCA.
b. EPPG has completed three reviews of the incorrect operations threat for the entire EPPG pipeline system and provided the first two reviews to PHMSA during the audit. The relevant information, processes, and procedures related to a review, analysis, and determination of the incorrect operations threat are broader than a specific pipeline segment. Therefore, it is appropriate to perform this type of review or study of the entire system to determine if any specific locations or operating areas have this threat. In the system wide review, if any areas are determined to have the incorrect operations threat, the HCAs in that area are designated with the incorrect operations threat. In fact, by not limiting the study to

HCAs or nearby locations and reviewing data on the entire system, this approach is more conservative. This process is described in Appendix A-8.

NOA Item 7

Regulatory reference: 192.917(c)
Text of NOA: EPPG must revise its procedures to ensure better documented support for the risk assessment approach documented in Chapter 3 in order to assure all objectives of risk assessment specified in ASME B31.8S, Section 5 are addressed. Specifically, the risk assessment msut adequately support:

a. *Assessment of the benefits derived from mitigating action,*
b. *Determination of the most effective mitigation measures for the identified threats,*
c. *Assessment of the integrity impact form modifiedinspection intervals,*
d. *Assessment of the use of or need for alternative inspection methodologies, and*
e. *Facilitation of decisions to address risks along a pipeline or within a facility.*

EPPG Response: EPPG has modified the list of objectives for risk assessment and threat identification to include all those listed in B31.8S and to add specific references to where these objectives are being met in the IMP Manual. The changes to Section 3.2 of the IMP Manual were provided to PHMSA on March 30, 2007.

NOA Item 8

Regulatory reference: 192.917(e)(1)
Text of NOA: EPPG must revise its procedures to ensure an adequate process exists to provide for the additional preventive measures appropriate for the threat of third party damage within an HCA.

EPPG Response: EPPG has revised the preventive and mitigative (P&M) measures selection process to provide additional definition for adequate levels of P&M for threats associated with an HCA, including third party damage. It includes a complete replacement of Table 12-1 with a more detailed table that is the new Appendix I. Also, the P&M measures for each individual HCA have been identified, documented in the IMP Database, and communicated to the Operating Areas. The changes to Chapter 12 and the new Appendix I were provided to PHMSA on March 30, 2007.

NOA Item 9

Regulatory reference: 192.921(a)(1)
Text of NOA: EPPG must revise its procedures to better document evaluations required per ASME B31.8S Section 6.2, regarding the general reliability of selected in-line assessment methods by looking at factors including but not limited to: detection sensitivity; anomaly classification; sizing accuracy; location accuracy; requirements for direct examination; history of tool performance; ability to inspect the full length and full circumference of the section; and ability to indicate tie presence of multiple cause anomalies.

EPPG Response: EPPG has over 20 years of experience in the utilization of ILI tools for the purposes of inspecting pipelines to locate areas of wall loss and/or dented pipe. In the BAP, the term ILI is intended to provide for caliper/deformation inspections as well as high resolution MFL inspections. These assessments will address the corrosion threats as well as some latent third party damage.

EPPG has working relationships with established ILI vendors who have demonstrated their ability to provide both capable tools and analysts to produce quality inspection results. Individual tool and system specifications are available and understood prior to awarding contracts. Individual pipeline segment data is provided to and reviewed by the vendors before inspection tools are mobilized and set up for the inspections.

As part of EPPG's ILI Technical Procurement Specification, tool vendors are required to provide specification summary sheets that address anomaly detection and sizing capabilities, location and orientation accuracy and anomaly classification criteria.

NOA Item 10

Regulatory reference: 192.925(b)(1)
Text of NOA: EPPG must revise its procedures to more clearly specify the following ECDA requirements:

a. *the minimum data requirements that must be collected to support ECDA pre-assessment;*
b. *the necessary data integration and analysis needed to conduct an ECDA feasibility assessment;*
c. *the more restrictive criterion that must be applied when conducting an ECDA pre-assessment for the first time on a covered segment.*

EPPG Response: EPPG has modified language in Section 6.5 and Table 6-1 to better define which data elements are required for feasibility and which are required for tool selection and defining regions. Also, language was added to Section 6.5, Feasibility Assessment, to describe data integration and analysis for determining ECDA feasibility.

The language in each of the 4 steps of the ECDA process were modified to provide more guidance when applying the more restrictive criterion for first time ECDA assessments.

These changes to Chapter 6 were provided to PHMSA on March 30, 2007.

NOA Item 11

Regulatory reference: 192.925(b)(2)
Text of NOA: EPPG must revise its procedures to provide sufficient detail to ensure the following:

a. *Applying criteria for classification of the severity of each indication and the urgency level with which excavation and direct examination of indications will be conducted based on the likelihood of current corrosion activity plus the extent and severity of prior corrosion;*
b. *Specifying more restrictive criterion that must be applied when conducting an ECDA indirect inspection for the first time on a covered segment.*

EPPG Response: PHMSA noted that this item was complete based on the modifications made to Chapter 6 (ECDA) of the IMP Manual and the ECDA Workbook that is used when conducting an ECDA project.

NOA Item 12

Regulatory reference: 192.925(b)(3)
Text of NOA: EPPG must revise its procedures to more clearly develop the following:

a. *A structured process defining how the ECDA root cause analysis is conducted, who performs the analysis, or how the conclusions are documented. A process has not been adequately defined that precludes future external corrosion resulting from signficant root causes.*
b. *An established and implemented 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*

time frame for direct examination of indications, other than through the MOC process;

c. *Specific processes to consider the use of assessment methods other than ECDA (i.e., ILI or Subpart J pressure test) to assess the impact of defects other than external corrosion (e.g., mechanical damage and stress corrosion cracking) discovered during direct examination. Feedback mechanisms are expected to be more expedient than the EPPG "flags and alerts" process allows.*
d. *A more restrictive criterion that must be applied when conducting an ECDA direct examination for the first time on a covered segment.*

EPPG Response: PHMSA noted that this item was complete based on the modifications made to Chapter 6 (ECDA) of the IMP Manual.

NOA Item 13

Regulatory reference: 192.925(b)(4)
Text of NOA: EPPG must revise its procedures to develop a more formal feedback process to ensure all appropriate opportunities throughout the ECDA process demonstrate feedback mechanisms and continuous improvement.

EPPG Response: PHMSA noted that this item was complete based on the modifications made to Chapter 6 (ECDA) of the IMP Manual.

NOA Item 14

Regulatory reference: 192.927(c)(4)
Text of NOA: EPPG must revise its ICDA process and procedures to better address all §192.927(c)(4)(ii) requirements that must be taken if any evidence of corrosion products is found in a covered segment and specifically needs to address the following:

a. *Remediate the conditions the operator finds in accordance with §192.933, and*
b. *Implement one of the two following required actions: (1) conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe, or (2) assess the covered segment using another integrity assessment method allowed by Subpart O.*

EPPG Response: PHMSA noted that this item was complete based on the modifications made to Chapter 7 (ICDA) of the IMP Manual. These modifications included adding a new paragraph to Section 7.7 “Identification of Locations for Excavation and Direct examination” that describes the specific actions taken if internal corrosion is found during the ICDA process. They also included adding language specifying monitoring for internal corrosion for segments where ICDA was conducted and internal corrosion was found. Requirements for subsequent actions if internal corrosion is found during the ICDA process were included.

NOA Item 15

Regulatory reference: 192.933(a)
Text of NOA: EPPG IMP must revise its procedures to better establish conditions when they are unable to meet time limits for evaluation and remediation of anomalous conditions. Procedures are required to determine the appropriate pressure reductions using ASME B31G, or “RSTRENG”, or to reduce pressures to levels not exceeding 80% of the level at the time the anomalous condition was discovered.

EPPG Response: EPPG has revised pressure reduction calculations in the Pipeline Operating Procedures Manual (POP) Section 306 procedure. The modifications were provided to PHMSA on March 30, 2007. Also, see attachment 7.

NOA Item 16

Regulatory reference: 192.933(b)
Text of NOA: EPPG must revise its procedures to better describe responsibilities, guidance or criteria for what constitutes having adequate information to declare discovery of anomalous conditions or what is meant by the integrity assessment date (completion date).

EPPG Response: To provide clarity, EPPG modified the language in POP 306 to provide more detail and guidance to the reviewer of the ILI final report data on what is adequate information to declare "Discovery of Condition." It includes what information is required to be reviewed and correlated to determine whether immediate integrity concerns exist within an HCA and when discovery of condition is identified. The modifications were provided to PHMSA on March 30, 2007. Also, see attachment 7.

NOA Item 17

Regulatory reference: 192.933(c) and 192.933(d)(1)
Text of NOA: EPPG must better define the following:

a. *The establishment of timeframes and the basis for such timeframes, for evaluation of vendor ILI reports in order to establish discovery of anomalies with special regard for immediate conditions.*
b. *A process satisfying 192.933(c) & (d) or ASME B31.8S on how anomalies in HCAs are prioritized for remediation.*

EPPG Response: EPPG does define the maximum timeframe for evaluation of assessment data for ILI reports in section 10.4 of the IMP Manual and in practice promptly reviews the ILI results to trigger the Discovery of Condition. However, in the spirit of continuous improvement, EPPG has modified the POP 306 procedure to provide guidance on the expected timelines required for review of ILI data and the corresponding timelines associated with establishing a Discovery of Condition.

EPPG prioritizes anomalies in POP 306 as immediate, one-year, scheduled, and monitored conditions. In addition to performing remediation on immediate conditions before scheduled conditions within HCAs, it is EPPG's intention to perform all scheduled remediation within an HCA during the same mobilization, and all scheduled remediation will be completed on a pipeline piggable segment within two calendar years of the assessment date. Because of this quick action on all actionable anomalies per POP 306 an additional prioritization of scheduled anomalies does not add to the safety or integrity of the pipeline. If there are multiple HCAs within a pipeline piggable segment, EPPG uses work efficiency and practical construction scheduling to prioritize anomaly remediation.

The modifications to POP 306 were provided to PHMSA on March 30, 2007. Also, see attachment 7.

NOA Item 19

Regulatory reference: 192.933(d)(3)
Text of NOA: EPPG must revise its procedures to provide a more comprehensive definition of "monitored conditions." Additionally, the procedures must include a more descriptive process for monitoring anomalies classified as "monitored conditions" during subsequent risk or integrity assessments to identify status changes that would require remediation.

EPPG Response: EPPG does conduct a review of these monitored conditions to determine if excavation is warranted under the additional scheduled conditions step in POP 306. However, in the spirit of continuous improvement, EPPG added language and guidance for definition and identification of "monitored conditions" as part of the review of final ILI report data in POP 306. These "monitored conditions" will be listed in the final response report and documented such that they can be included in future risk assessments and monitored for change during any subsequent integrity assessment. This was primarily a nomenclature change. The modifications to POP 306 were provided to PHMSA on March 30, 2007. Also, see attachment 7.

NOA Item 20

Regulatory reference: 192.935(a)
Text of NOA: With regard to P&M measures, EPPG must revise its procedures to make them more comprehensive with regard to the following:

a. *A systematic, documented P&M measures decision-making process to decide which measures are to be implemented, involving input from relevant parts of the organization such as operations, maintenance, engineering, and corrosion control;*
b. *A P&M measures decision-making process that considers the consequences of pipeline failures;*
c. *Identified and documented additional measures that have actually been implemented, or scheduled for implementation on a HCA specific basis. Measures have only been identified on a global system-basis.*
d. *A comprehensive process for evaluating and documenting the need for Automatic Shut-off Valves or Remote Control Valves.*

EPPG Response: EPPG has revised the preventive and mitigative (P&M) measures selection process to provide additional definition for adequate levels of P&M for threats associated with an HCA. It includes a complete replacement of Table 12-1 with a more detailed table that is the new Appendix I. Also, the P&M measures for each individual HCA have been identified, documented in the IMP Database, and communicated to the Operating Areas as of June 2007. The changes to Chapter 12 and the new Appendix I were provided to PHMSA on March 30, 2007.

EPPG completed an initial Automatic Shut-off Valve (ASV) and Remote Control Valve (RCV) analysis and identified in the IMP Database the P&M measure for each HCA currently protected by one of these devices.

NOA Item 21

Regulatory reference: 192.935(b)(1)
Text of NOA: EPPG must revise its procedures to ensure that enhancements to the §192.614-required Damage Prevention Program with respect to covered segments to prevent and minimize the consequences of a release, and that detail the enhanced measures, must include all of the minimum requirements such as the use of some criterion for what is considered a holiday or a non-standard reading on the electrical survey, see §192.935(b)(1)(iv). The tool selected by EPPG's IMP Plan (CIS) is not the best for determining coating holidays per NACE RP 0502-2002.

EPPG Response: Whenever EPPG is made aware of an excavation (in or out of HCAs) that could affect our pipeline (through One-Call or through direct notification), there is someone present to monitor excavations to ensure that the facilities are not damaged. When EPPG finds evidence of an excavation that was done without notification, EPPG generally excavates the area of indication to determine whether the pipeline was damaged. If such an area is not excavated by EPPG, an above-ground electrical survey is conducted to determine whether coating damage has occurred or whether additional investigations might be needed.

EPPG has modified language for above ground surveys related to unmonitored excavations near our pipeline (192.935(b)(1)(iv) situations) to remove close interval survey (CIS) and more clearly define our processes for above ground surveys if we do not dig the pipeline. This exact change was completed in IMP Manual Sections 12.5 and 12.10, plus in O&M Manual Section 301 Item 2. The revised IMP Manual sections were provided to PHMSA on March 30, 2007.

NOA Item 23

Regulatory reference: 192.937(a) & (b)
Text of NOA: With regard to the periodic evaluation process, EPPG must revise its procedures to better address the following:

a. *The periodic evaluation process is not specified to be conducted on a continuous basis or that periodic evaluations be conducted based on a data integration and risk assessment of the entire pipeline as specified in §192.917; It is recognized that EPPG has actions occurring on a routine basis but EPPG has not appropriately credited some of these actions in the IMP.*
b. *Further, no periodic evaluations of data have been conducted for establishing reassessment methods and schedules.*

EPPG Response:

a. EPPG utilizes the HCA Final Review process described in section 11.4 of the IMP Manual as the primary action item for periodic evaluation. The HCA Final Review process goes into great detail about the assessment, follow-up mitigation, re-assessment interval, and preventive and mitigative measures review. This process will be completed within 2 years after the last assessment date for an HCA. In addition, at the beginning of each year EPPG collects and documents the assessment information on HCAs assessed in the previous year and re-evaluates the threats for those HCAs based on the assessment and immediate remediation data. At the time of the IMP Audit this was not specifically identified in the IMP Manual even though it was scheduled and tracked in EPPG's work management system (Maximo). This step has been officially added to Chapter 11 as "First Quarter HCA Integrity Assessment and Threat Review" and to the Calendar in Appendix D. The revised procedures in Chapter 11 and Appendix D were provided to PHMSA on March 30, 2007.

b. The HCA Final Review for all HCAs with integrity assessments and completed follow-up remediation were finished in August 2007.

If you have any questions or need additional information, please contact Charlie Childs at 713-420-4236.

Sincerely,

Dan Martin
Senior Vice President Operations
El Paso Pipeline Group

On Behalf of ANR Pipeline Company

David Montemurro
Vice President