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U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

12300 W Dakota Ave , Suite 110
Lakewood, CO 80228

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

July 9, 2007

Ms. Rebecca B. Roberts
President
Chevron Pipe Line Company
4800 Fournace Place
Bellaire, TX 77401

CPF 5-2007-1010M

Dear Ms. Roberts:

Between September 11-15 and September 25–29, 2006, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of Title 49 United States Code, inspected your Integrity Management (IM) Program in Bellaire, Texas.

On the basis of the inspection, PHMSA identified apparent inadequacies within Chevron Pipe Line Company's (CPL's) Integrity Management Program; these procedural inadequacies are described below. Probable violations resulting from that same inspection were already sent to you in our letter, CPF 5-2007-1007, dated June 11, 2007.

1. **Identification of High Consequence Areas**

   §192.911 What are the elements of an integrity management program?
   (a) An identification of all high consequence areas, in accordance with §192.905.
   (p) A process for identification and assessment of newly-identified high consequence areas. (See §192.905 and §192.921.)

   §192.905 How does an operator identify a high consequence area?
   (a) General. To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in §192.903 to identify a high consequence area. An operator may apply one method to its entire

pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (See appendix E.I. for guidance on identifying high consequence areas.)
(b) 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.
(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.

- **Item 1A: §192.911(a) and §192.905(a)**

CPL's processes for implementing method 1 and 2 to identify High Consequence Areas (HCAs) lack sufficient guidance regarding how and when its personnel evaluate potential "identified sites," utilize existing class location information, and determine building counts within potential impact radii.

- **Item 1B: §192.911(a) and §192.905(c)**

CPL's processes do not contain adequate details regarding how and when its personnel will gather new data and information which may identify newly covered segments. In addition, CPL procedures do not describe how its personnel will identify construction in the vicinity of the pipeline that results in newly occupied buildings changes in the use of existing buildings (e.g., hotel or house converted to nursing home), or the creation of other "identified sites."

2. **Baseline Assessment Plan**

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

§192.921(a)(4) 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.

- **Item 2A: §192.911(b) and §192.921(a)(4)**

CPL's procedures provide for the potential use of an Electro-Magnetic Acoustic Transducer (EMAT) In-Line Inspection (ILI) tool. This tool is not included within the ILI tools currently listed in B31.8S. CPL must ensure its processes provide for notification to PHMSA regarding use of "other technology" such as the EMAT-based ILI tool.

3. **Identify Threats, Data Integration, and Risk Assessment**

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

§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?
(a) Threat identification. An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (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.
(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.
(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.

§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.

- **Item 3A: §192.911(c) and §192.917(a)**

The original risk analysis used to support CPL's baseline assessment prioritization did not address all of the threat categories specified in the IM rule and ASME B31.8S-2001 Specifically, the original program risk manual did not address incorrect operations and equipment failures CPL's latest risk model includes these threats; however, at the time of the inspection CPL had not developed risk results based on this new approach.

- **Item 3B: §192.911(c) and §192.917(b)**

CPL procedure did not require all of the data sets to be assembled and evaluated for threat identification and risk assessment as required by ASME B31.8S-2001, Sections 4 2, 4.3, 4.4, and Appendix A (summarized in ASME B31.8S-2001, Table 1). In part, CPL did not consider the following on covered segments and similar non-covered segments:

- Past incident history
- Corrosion control records
- Continuing surveillance records
  Patrolling records

- **Item 3C: §192.911(c) and §192.917(c)**

The treatment of incident/leak data in the risk analysis process is not appropriate for assessing risk on covered segments. Incident/leak data are applied only in the risk scoring of the segment containing the precise location of the leak or incident. The potential applicability of the leak/incident to other segments with similar characteristics is not considered

- **Item 3D: §192.911(c) and §192.917(e)(5)**

CPL's IM program manual and procedures did not include methods to determine what may constitute similar pipe segments, or requirements to establish a schedule for evaluating similar non-covered and covered segments should corrosion detrimental to the integrity of a covered segment be discovered.

4. **Remediation**

§192.911 What are the elements of an integrity management program?
(e) Provisions meeting the requirements of §192.933 for remediating conditions found during an integrity assessment.

§192.933(a) General requirements. An operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. If pressure is reduced, an operator must determine the temporary reduction in operating pressure using ASME/ANSI B31G (ibr, see §192.7) or AGA Pipeline Research Committee Project PR-3-805 (``RSTRENG"; ibr, see §192.7) or reduce the operating pressure to a level not exceeding 80% of the level at the time the condition was discovered. (See appendix A to this part 192 for information on availability of incorporation by reference information). A reduction in operating pressure cannot exceed 365 days without an operator providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline.

§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.

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

§192.933(d) Special requirements for scheduling remediation.
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. (1)(ii) A dent that has any indication of metal loss, cracking or a stress riser.
3. Monitored conditions. An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:
i. A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).
ii. A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.
iii. A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

- **Item 4A: §192.911(e) and §192.933(d)(1)**

The CPL IM program specifies that a pressure reduction shall be implemented for pipeline segments with an immediate repair condition. However, the program document does not state that the pressure be reduced, or the line be shut down, as soon as practicable once an immediate repair condition is identified. "As soon as practicable" means as soon as pressure can be safety reduced, and without undue delay.

- **Item 4B: §192.911(e) and §192.933(d)(3)**

The IM program requirements addressing "monitored conditions" do not have sufficient detail to explain how these conditions are tracked and monitored during subsequent risk or integrity assessments for any changes in their status that would require remediation. In addition, process does not define when these conditions are re-reviewed.

- **Item 4C: §192.911(e) and §192.933(a)**

The IM program document does not state that when calculating the needed pressure reduction under ASME B31.G or "RSTRENG" that the pressure must be lowered to the calculated "safe pressure" (Psafe or Pfailure with the use of the appropriate safety factor).

- **Item 4D: §192.911(e) and §192.933(c)**

The CPL IM program document does not include a requirement that for any time a remediation schedule requirement cannot be met, the operator must document the reasons for the delay and why the delay does not jeopardize pubic safety.

5. **Preventive and Mitigative Measures**

§192.911 What are the elements of an integrity management program?
(h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence area.

§192.935 What additional preventive and mitigative measures must an operator take?
(a) General requirements. An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (ibr, see §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

- **Item 5A: §192.911(h) and §192.935(a)**

CPL's IM program does not include a systematic, documented decision-making process to determine which preventive and mitigative measures are to be implemented. The current IM program describes how CPL's personnel complete the PTRAP process, however, the procedure does not adequately describe the process details regarding:

- How or when pre and post assessment evaluations occur;
- How personnel use a risk analysis to evaluate potential preventive and mitigative measures;
- How the results of the decision-making process are documented, and
  What requirements and/or guidelines apply to the development of an implementation schedule.

6. **Management of Change**

§192.911 What are the elements of an integrity management program?
(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.

§192.909(b) Notification. An operator must notify OPS, in accordance with §192.949, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. 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. An operator must provide the notification within 30 days after adopting this type of change into its program.

ASME B31.8S-2001, Section 11
(a) Formal management of change procedures shall be developed in order to identify and consider the impact of changes to pipeline systems and their integrity. These procedures should be flexible enough to accommodate both major and minor changes, and must be understood by the personnel that use them. Management of change shall address technical, physical, procedural and organizational changes to the system whether permanent or temporary. The process should incorporate planning for each of these situations and consider the unique circumstances of each.

A management of change process includes the following:
(1) Reason for change
(2) Authority for approving changes
(3) Analysis of implications
(4) Acquisition of required work permits
(5) Documentation
(6) Communication of change to affected parties
(7) Time limitations
(8) Qualification of staff

(b) The operator shall recognize that system changes can require changes in the integrity management program and conversely, results from the program can cause system changes. The following are examples that are gas pipeline specific but are by no means all inclusive...

- **Item 6A: §192.911(k) and ASME B31.8S-2001, Section 11(b)**

The CPL IM program did not include measures to ensure that new information/data is incorporated into the risk analysis process in a timely and effective manner

- **Item 6B: §192.911(k) and ASME B31.8S-2001, Section 11(a)**

CPL's IM program requires notifications to PHMSA and State/local pipeline safety authorities when significant changes are made to its IM program or program implementation. However, the IM program does not provide any guidance regarding what is considered significant

Response to this Notice

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 30 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In correspondence concerning this matter, please refer to **CPF 5-2007-1010M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

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

cc: PHP-60 Compliance Registry
PHP-500 J. Gilliam (#116459)