ConocoPhillips
Pipe Line Company

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April 25, 2007

Ivan Huntoon
Director, Central Region
Pipeline Hazardous Materials Safety Administration
901 Locust, Room 462
Kansas City, MO 64106-2641

RE: CPF No. 3 -2007-50014M

Dear Mr. Huntoon
This letter is in response to the Notice of Amendment, received by ConocoPhillips Pipe Line Company (CPPL) on March 27, 2007.

Amendment of Procedures:

1.(a) §195.406 Maximum Operating Pressure.
(b) No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (a) of this section. Each operator must provide adequate controls and protective equipment to control the pressure within the limit.

ConocoPhillips Pipe Line Company response:
It appears that the your office has concerns regarding CPPL's procedure that allows the use of a SCADA administrative control set point and/or alarm for managing a temporary pressure deration of an IMP repair condition until it can be remediated. Specifically, CPPL allows an administration control for 90 days and you feel that we should limit the use of administrative controls to 30 days. We are somewhat confused by this sudden concern over CPPL's deration procedure since the procedure was reviewed and determined to be adequate by PHMSA during the 2003 and 2005 Integrity Management comprehensive audits which included participants from the Central Region. Attached are the documents that indicate acceptance of CPPL's procedure and listed below is a summary or excerpt from the documents:

• CPF 3-2004-5013: Item 6B required revision to Appendix K of CPPL's IMP and the revisions were accepted by your office in a letter dated February 15, 2007. The required revision was not regarding our use of the 90 days administrative control.

• PHMSA stated in the ConocoPhillips Pipe Line IMP Inspection Summary Report on August 8, 2005 the following: "The IE follows MPR-4104, Derating a Pipeline to a Lower Operating Pressure for operating pressure reductions or shutdowns for immediate repair conditions. This procedure provides a consistent approach for implementing a pressure reduction or shutdown after an assessment of the ILI tool vendor's preliminary or final report."

The use of administrative controls for 90 days has been successfully used by CPPL in managing the continued safe operations of the pipeline for IMP repair conditions. While CPPL agrees that limits should be place on administrative controls, CPPL believes that a 90 day limit provides a reasonable approach to providing adequate controls to manage pressure derations. It would appear the audit team members in our last 2 IMP audits felt the same.

If it would help in resolving your concerns over this matter, we would be pleased to make a visit to your office. Please feel free to contact me to discuss further or schedule a visit.

Randy Beggs

Randy Beggs
ConocoPhillips Pipe Line Company
Attachments

cc:
File
M. Drumm
T. Fuksa
C. Hill
M. Miller

ConocoPhillips Pipelines and Terminals Integrity Management Inspection
Final Inspection Summary Report

Report Issue Date:	January 14, 2004
Operator:	Conoco Pipeline and Phillips Pipe Line both subsidiary companies of ConocoPhillips
Corporate Address:	600 N.Dairy Ashford Houston, TX 77079-1175
Operator ID Number(s):	31684
Dates of Inspection:	September 8 -12, 2003 (Week 1) September 22 – 26, 2003 (Week 2)
Location of Inspection:	ConocoPhillip Pipelines and Terminals' Office 1000 South Pine Ponca City, OK 74602-1267
Primary Contact:	Keith Wooten Director, Pipeline Integrity Phone: (580) 767-7489

Persons In Attendance:

Operator Representatives:

David Wilson, Integrity Engineer
Dennis Schulze, Integrity Engineer
Bob Daniels, Risk Assessment Coordinator
Mark Bentson, Integrity Engineer
Jay Williams, GIS Analyst
Stephen Ellison, Senior Counsel
Keith Wooten, Pipeline Integrity Director
J Brian Allison, Mapping Coordinator
Linus Schmitz, Pipeline Integrity and Reliability Manager
Spencer Philo, Integrity Analyst
Richard Parker, Leak Detection & Models Specialist
Mark Brogger, Director Corrosion Control
John Garrison, Tech Services Engineer
Steve Koenig, Director Automation
John Reems, Senior Operations Coordinator
Paul Butler, Senior Controller

OPS Inspection Team:

Don Moore, Team Leader, OPS Central Region
Terri Binns, OPS Southwest Region
Zach Barret, OPS Western Region
Gregory Hindman, OPS Southern Region
David Lykken, WUTC
Anthony Tome, Cycla
Roger Huston, Cycla

Inspection Objectives

The purpose of this inspection was to provide assurance that ConocoPhillips Pipelines and Terminals (CPPT) has developed and implemented an Integrity Management Program as required by 49 CFR 195.452. Specifically, this inspection reviewed the operator's processes for:

- Identifying pipeline segments that could affect High Consequence Areas (HCAs);
- Integrating information from all relevant sources to understand location-specific risks for these segments;
- Developing and implementing a Baseline Assessment Plan;
- Reviewing the results of integrity assessments;
- Identifying and implementing remedial actions for anomalies and defects identified during integrity assessments;
- Identifying and implementing additional preventive and mitigative measures to reduce risk on pipeline segments that can impact HCAs;
- Performing on-going assessments of pipeline integrity; and
- Evaluating Integrity Management Program performance.

This inspection also reviewed the implementation and results of CPPT's Integrity Management Program to date including a review of completed integrity assessments, and the repair and mitigation actions taken as a result of these assessments.

This inspection summary report is divided into two major sections. The first section summarizes the key features of the CPPT approach for each of the Integrity Management Program Elements in 49 CFR 195.452 (f). The second section summarizes the issues and observations developed by the inspection team during the review of CPPT's program and its implementation.

Integrity Management Program Overview

Conoco merged with Phillips Petroleum Company in 2002. As a result of that merger, Phillips Pipe Line Company and Conoco Pipeline Company were consolidated into a new entity, ConocoPhillips Pipelines and Terminals (CPPT). At that time each entity was operating a separate Integrity Management Program. Conoco Pipeline's Integrity Management Program was inspected by OPS in September, 2002. The Conoco Summary Inspection Report is available on IMDB. At the time of the inspection of CPPT, the two programs had not been completely merged. An integrated IMP was in the process of being developed, but several major decisions were still to be made.

CPPT has a combined total of 11,066 miles of which 5137 miles are HCA "could affect" miles. The schedule presented in the Baseline Assessment Plan indicated that more than 50% of the HCA "could affect" mileage will be assessed by 9/30/04 and all of the mileage will be assessed by 3/31/08.

The CPPT Integrity Management Program is described in the ConocoPhillips Pipelines and Terminals Integrity Management Program manual. The CPPT IMP describes the methodology used by both Heritage Conoco (hConoco) and Heritage Phillips (hPhillips) since each uses unique methods and software in their IMP. For hConoco the discussion in the following sections will concentrate on programmatic differences made since their inspection in September, 2002.

1. Segment Identification – hConoco had not made any significant changes to their segment identification process since September of 2002. hPhillips used NPMS data to establish the location of HCAs. No additional HCAs were identified from other sources. For hPhillips' pipeline locations were developed from pipeline surveys and alignment sheets. A Phillips Petroleum proprietary software package, EMap, developed from ArcView was used to show the location of pipelines in relation to HCAs. CPPT has developed a web-based mapping-viewing tool, TRANMAP. TRANMAP will show the location of all hConoco and hPhillips pipeline and HCAs.

hPhillips used the 2000 census data available in NPMS for their segment identification. Both hConoco and hPhillips used a buffer zone approach to identify pipeline segments that "could affect" an HCA. For overland transport both used a ½ mile buffer zone. hConoco's justification was a review by a Subject Matter Expert Team that considered maximum spill volume, topography, pipeline operating characteristics, and mitigation measures.

hPhillips used the worst-case spill volume for each pipeline as calculated in their pipeline Emergency Response Plans. The worse spill volume calculated for any pipeline was 43,081 barrels on the 18" Standish Pipeline. This compares to a maximum historical spill volume of 9,868 barrels. The spill radius was determined from the worse case spill volume using a depth of 1 centimeter and a circular spread pattern. The maximum spread radius was calculated to be ¼ mile which was less than the assumed spread radius of ½ mile; therefore, ½ mile was chosen as the buffer zone to be applied for overland spread for all pipelines.

For water transport, hConoco used a 34-mile buffer where the discharge was directly into a stream and 17 miles where the waterway was within ½ mile of the location of the spill. CPPT has employed a contractor to conduct a combined overland transport, hydrographic flow and spill volume analysis for all of their pipelines. Currently they have performed random analysis of the hConoco water transport method to validate that the method was conservative and it was found to be conservative. All of the hPhillips pipelines were analyzed using the hydrographical flow model. Once all of the hPhillips pipelines have been converted into a geo-spatial format, all CPPT pipelines will be reanalyzed using the contractor's overland spill and hydrographical flow process. As part of a phased approach this reanalysis is to be applied to the hConoco segments in the future.

For air dispersion, CPPT used the Process Hazard Analysis Software Tool (Phast) on all of their HVL pipelines to determine the buffer zone distance that should be used for segment identification. The analysis, using historical release data, worst case volume releases in each pipeline system, and worse case product and stability class, resulted in a ½ mile buffer zone being demonstrated as conservative.

As noted above, CPPT is in the process of verifying the hConoco and hPhillips segment identification process by validating the overland and water transport assumptions of hConoco and performing a combination overland/water transport-using subcontractor developed transport models.

A Notice of Amendment (NOA) – CPF 120003-5007 – was issued to Phillips Petroleum in July, 2002. The NOA addressed issues identified during the Quick Hit inspection of Phillips segment identification process. The NOA is still in the process of being resolved. Issues identified by the NOA pertained to several of the segment identification protocol questions. These issues were not repeated as part of this inspection. Issues identified during the inspection are delineated in the OPS feedback attached to this report.

CPPT identified a total of 5137 (hPhillips and hConoco combined) could affect HCA miles out of a total of 11066 system miles.

2. Baseline Assessment Plan – The hPhillips BAP lists each individual could affect HCA segment. Each segment has been ranked based on risk using the PRAS risk assessment methodology (see discussion in Section 5 below). hPhillips scheduled segments for assessment by choosing the HCA segments with the highest risk, identifying the testable pipeline section they were in, assigning the HCA segment risk ranking to the entire section, and then prioritizing the testable sections for assessment starting with those with the highest risk.

The method chosen for most assessments was an MFL tool with a geometry tool. hPhillips had elected to use a number of prior assessments as baseline assessments. In the process of reviewing these assessments, which were performed using ILI tools, it was discovered that gauging plates instead of geometry tools had been used. OPS's position is that either a geometry tool must be run or 100 percent of the dent indications identified by the MFL tool vendor's report must have a verification dig.

CPPT will have assessed 50% of their total HCA mileage by September 30, 2004 and 100% by March 31, 2008. This is contingent upon reconciling the issue described above.

3. Integrity Assessment Results Review – CPPT uses three engineers and an analyst to perform evaluations of assessment data. Two of these are hConoco employees whose capabilities were familiar to the inspection team. During the course of reviewing hPhillips assessment data, the hPhillips' Pipeline Integrity Engineers demonstrated their knowledge of IM repair criteria and data evaluation process. hConoco was still using the CPL-AID software to evaluate assessment data. hPhillips was employing a manual system of data tracking and evaluation. CPPT was still evaluating the use of CPL-AID on a company wide basis. Qualification and training requirements for these personnel is still under development.

CPPT creates an individual vendor contract for each assessment. Each contract specifies the type of tool to be used, tool tolerances, vendor reporting requirements, report format, etc. A review of typical contracts indicated the omission of several key requirements. The first was the requirement for the vendor to provide a final report within 180 days of the completion of the assessment. The second was a requirement that the vendor notify CPPT as soon as possible of any anomalies that meet immediate repair criteria. The hPhillips Inspection and Repair Process indicates that the vendor is to notify CPPT of any anomalies that are greater than 70% metal loss within two weeks of completing the assessment. The Inspection and Repair Process document indicates that the Integrity Engineer should determine if repairs are required and if pressure should be reduced.

CPPT had defined the "Date of Discovery" to be the date the transmittal report is sent to the field. The inspection team reminded CPPT that the date of discovery is the date at which sufficient information is available to categorize the anomaly.

hPhillips does not generally perform calibration digs. Instead, hPhillips anticipates that the results of the assessment will require a number of digs for either verification or repair and that calibration digs are not needed.

The IM rule repair criteria were captured in both hConoco and hPhillips Maintenance procedures.

4. Remedial Action – The inspection team reviewed a total of 11 baseline assessments. Of these, six were prior assessments. There were three hydrotests and eight ILI tool runs. On all but one of the ILI runs a sizing plate was run in lieu of a geometry tool. OPS's position on these runs is that either a geometry tool had to be run or 100% of the dents identified by the ILI tool run had to have a verification dig. CPPT has not made a final decision on their response to this issue; however, CPPT is looking to possibly run a geometry tool or re-perform the assessment. (CPPT has taken the step to modify their baseline assessment plan to include a geometry tool as part of ILI assessments. They also will either run geometry tools or evaluate assessment data and perform verification digs of deformation calls.)

No anomalies were identified by the vendor for any of the ILI tool runs. In one case, on the Bonita to Kansas City section of the Paola to Kansas City 8" line, no anomalies were identified by the vendor for repair; however, four anomalies were found to be dents on the top side with metal loss after verification digs. These would qualify as immediate repairs in accordance with the IM rule repair criteria. Each of these anomalies was repaired upon discovery.

In another situation, in a section labeled 721-42+25 to 744.42 in the Gold Line, CPPT decided, in 2002, to take a portion of the line out-of-service based on the results of the assessments performed in 2000. An evaluation of previous tool runs led to the conclusion that the growing number of corrosion anomalies made testing and maintenance of the pipeline impractical. CPPT is treating the 2000 assessment as a Baseline Assessment for the purpose of meeting the 50% of HCA mileage being assessed by 9/30/04 requirement. The Inspection Team suggested that moving this segment to the idle pipeline list and not including the associated pipeline mileage would be more appropriate. OPS will elicit opinion from the regional offices on the correct approach and provide feedback to CPPT.

5. Risk Analysis Process – hConoco was still using PIRAMID to perform their risk assessments for the purpose of risk ranking pipeline sections and identifying areas for implementing potential Preventive and Mitigative measures. hPhillips uses the Pipeline Risk Assessment System (PRAS), which is a modified Mulbauer risk assessment methodology.

PRAS utilizes four hazard index categories:

- Third Party Damage
- Corrosion
- Design
- Incorrect Operations

Each of these hazard categories has several weighted risk factors that contribute to a risk index score for each category. A Risk Impact Factor (RIF) is calculated from a product factor, a population factor, and a spill factor. The relative risk score is the risk index divided by the RIF. The higher the risk a pipeline segment poses, the lower the risk score.

hPhillips has developed a questionnaire that allows a Subject Matter Expert to assign a weighting factor to each of the risk factors. In addition, following the completion of a risk analysis the results are reviewed by Operations, Maintenance, and Pipeline Integrity personnel. If the results appear to be inconsistent with their knowledge of the pipeline system, data quality is rechecked and adjustments are made to the risk analysis if found to be incorrect.

At the time of the inspection CPPT was in the process of determining what risk assessment model to use for both hConoco and hPhillips pipelines. CPPT has subsequently elected to use the PIRAMID risk model as the sole risk assessment methodology.

6. Preventive & Mitigative Measures – CPPT has not used its risk assessment to define any Preventive and Mitigative measures for individual could affect HCA segments. CPPT claims that they have historically had a viable P&M program in place. These programs include:

- Inspection of spans and exposed piping
- Microbiological Influenced Corrosion Control
- Cathodic Protection
- Internal Corrosion Monitoring and Control
- Overpressure Protection
- EFRD Block Valve Program
- Depth of Covering Monitoring
- Excavation Risk Management

CPPT has developed an Assessment Plan (AP) History Document to aid in making P&M decisions. The History Document contains all of the historical information on assessments, repairs, spills, and incidents. This document also contains all of the information from decisions made by operations, maintenance, corrosion control, etc. that have been made regarding this pipeline.

Using the information contained in the AP History Document, the Pipeline Integrity Engineer follows the decision process detailed in the "Flowchart to Evaluate Preventive and Mitigative Measures". The recommendations of this evaluation are then prioritized based on cost of benefit and administered under the appropriate capital or expense budget.

Leak Detection

CPPT had recently finished consolidating the control rooms for hPhillips, hConoco, and TOSCO at the Ponca City site. CPPT had also performed a major upgrade and renovation of the control room facilities. Leak detection methods used by CPPT include:

1. Visual Observation
   - Line walkers
   - Line flyovers on a weekly basis
2. External field sensors
   - Tank & sump overfill protection
   - Vent flow alarm on HVL lines
   - Pump seal failure detection
   - Atmospheric hydrocarbon sensors
3. SCADA Based Techniques
   - Remote monitoring and control
   - Flow and pressure deviation alarming
   - Manual volumetric balance of pipeline receipts an deliveries
   - Manual shut-in analysis
   - Automatic uncompensated line balance (Used by hConoco)
   - Automatic compensated line balance (Used by hConoco)
4. Online Modeling
   - Transient model based (Used by hConoco)
   - Model based shut-in (Used by hConoco)
5. Gain/Loss Analysis

CPPT has not used their IMP in making any decisions with respect to Leak Detection; however, according to their Integrity Management Plan, they intend to do so. The Plan contains a placeholder for a Leak Detection Evaluation Procedure that is to be developed.

EFRDs

CPPT has developed a procedure – TSD-3203, "CPPT Mainline Block Valve Standard Summary" – that provides criteria for evaluating the need for additional block valves.

7. Continual Process of Evaluation and Assessment – CPPT has not performed any reassessments to date; however, based on the use of 1999 assessments as Baseline Assessments the first reassessments will have to occur in 2004. There are currently no plans to request a variance from OPS for an interval longer than 5 years.

The AP History Document described previously, in conjunction with the "Reassessment Evaluation Process" flowchart, is to be an integral part of the reassessment interval determination decision process. At the time of the inspection only two AP History Documents had been developed. CPPT had elected to use a number of assessments performed in 1999, 2000, and 2001 as Baseline Assessments with reassessments beginning in 2004. At the rate that AP History Documents can be developed, a reassessment may be performed after five years before the AP History Document is developed; whereas an interval less than five years may be specified using the "Reassessment Evaluation Process" when the AP History Document is developed.

8. IM Program Performance Monitoring and Evaluation - The CPPT Integrity Management Plan calls for the IMP to be evaluated annually but not to exceed 15 months. CPPT has developed guidelines for evaluating the IMP. These guidelines are included in the Integrity Management Plan. The communication of the results of the evaluation is not currently defined in the IMP.

CPPT has currently identified 12 Performance Measures modeled after those identified in API 1160. The inspection team felt that CPT specific performances measures needed to be developed. Examples given include: near misses, cause specific pipeline leaks, spills caused by operator error, etc.

Root cause analysis is performed as part of CPPT's Incident Notification and Investigation Policy. A root cause analysis is only required for an incident with a Risk Ranking of IV. A root cause analysis for Risk Rankings less than IV is performed at the request of supervision. The IM Plan calls for a root cause analysis to be performed "when failure or damage occurs in the pipeline that could affect an HCA". This is not necessarily consistent with a Risk Ranking of IV and the Incident Notification and Investigation Policy should be made consistent with the IM Plan.

Summary of Inspection Issues and Observations

The following is a summary of the issues and observations that were made during the comprehensive inspection of the CPPT Integrity Management Program:

General Issues:

1. OPS recognizes the challenge involved in developing and implementing a single formalized, robust integrity management program in a large organization with significant diverse and distributed pipeline assets and people. We believe that the work activities in this plan, along with the issues identified in this exit interview, are important to the further development of a fully mature program. Based on feedback received during this inspection, OPS anticipates that ConocoPhillips' management will support the program with necessary resources to meet the currently documented program and assessment schedule.

2. The CPL-AID program, and the process in which it is used, appears to be a very effective and comprehensive approach for reviewing in-line inspection results. CPPT is encouraged to continue use of the CPL-AID program. OPS recognizes CPL-AID to be an effective data integration tool

3. It is recognized that hConoco and hPhillips had made some progress regarding their individual integrity management programs. However, at this time in the development of the integrity management process OPS is unable to determine if the highest risk pipelines in ConocoPhillips system are being addressed as required by the integrity management rule. It is imperative that the complete merger of the two programs be completed promptly to ensure the safety of the HCAs on these pipelines.

4. Several issues were identified during the quick hit inspection. These items cannot be discussed due to being included in an open case (CPF 1-2002-5007).

5. ConocoPhillips has not instilled sufficient formality of operations and procedural controls to assure quality and that a consistent evaluation and communication of integrity management processes. Documentation and specificity need to be improved in most areas of the program.

6. ConocoPhillips has not consistently addressed facilities. Consideration of additional preventive and mitigative actions for non-pipe facilities that can affect an HCA is not adequately addressed.

Specific Comments

1. HPhillips idle pipelines are not treated in accordance with OPS policy. The HCA mileage associated with the Gold Line (which was idled after being assessed) should not be included in the total HCA mileage that must be assessed by 9/30/04 or 3/31/08. This handling of an assessed line that is subsequently idled will be reviewed with the entire OPS IMP inspectors to ensure consistency on this issue and feedback will be furnished to CPPT.

2. Baseline Assessments performed with a sizing plate in lieu of a Geometry tool do not appear to be valid assessments unless it can be shown that all dent indications have been dug, evaluated, and, if necessary, repaired. Prior ILI assessments that are credited as Baseline Assessments must be capable of detecting all anomalies delineated by the Integrity Management repair criteria.

3. ConocoPhillips was not treating A.O. Smith Flash Weld pipe consistent with the OPS policy. (CPPT has subsequently revised their procedures that negated this issue).

4. Guidance should be developed for the use of the seam susceptibility flowchart.

5. Individual HCA segments are not individually ranked as required by the rule.

6. The CPPT process for data integration needs to be formalized to ensure that all available information about the integrity of the entire pipeline and the consequences of a failure is analyzed. Documentation of the overall results of integrated data analysis and conclusions regarding the integrity of the segment, including the nature of the integrity threats, needs to be improved.

7. No formal process is in place to assure that input information is current, prior to running PRAS/PIRAMID analysis.

8. The primary risk threats for each assessed segment must be identified.

9. The risk analysis used to support preventive and mitigative measures also needs to identify HCA segments specific risk drivers.

10. ConocoPhillips should consider all operational modes in considering risk.

11. No process in place to cover qualifications. (CPPT has revised their procedures that negate this issue).

12. While OPS recognizes both hPhillips and hConoco have vendor specifications in place for internal assessment tools, the quality of the data to be received from the vendor is highly contingent upon the quality of the vendor contract. A generic ILI vendor contract needs to be developed for ConocoPhillips. A suitable model to consider would be that developed by hConoco. For example: 1) The hPhillips vendor contract does not contain a requirement to provide final report within 180 days of the completion of the assessment, 2) The hPhillips vendor contract does not contain a requirement for preliminary notification of all immediate repair conditions identified by the vendor.

13. The process needs to be expanded to reflect ConocoPhillips current practices for determining date of discovery. Discovery, as currently defined in the IMP, does not cover all potential situations that constitute date of discovery as implied by the IM rule.

14. The hydrostatic test procedure needs to be developed as soon as possible. The procedure should include the requirement to perform metallurgical analysis of failures. The hydrostatic test procedure must capture all of the requirements of 195 Subpart E.

15. The IMP needs to reword the pressure reduction calculation process to be consistent with 451.7 of B31.4. (CPPT has resolved this issue).

16. CPPL needs to define the process for making decisions regarding preventive and mitigative measures to be implemented.

17. Process for reevaluation of leak detection capability has not been completed. The process should consider the potential for risk reduction on HCA could affect segments that are in close proximity to the pipeline.

18. The process to evaluate the need for additional EFRDs needs further development. The process for EFRD evaluation needs to be expanded to include guidance for utilization of the "Flowchart to Evaluate Preventive and Mitigative Measures".

19. CPPT has only completed two AP History and Planning documents. With the number of assessments that have already been completed, or taken credit for, the reassessment interval that may be established by the AP History document could be exceeded.

20. OPS recognizes that CPPT has a flowchart that selects the appropriate assessment method; however, documentation needs to be provided to support the decisions made in progressing through the flowchart. Additionally, if an ILI tool is selected as the assessment method, documentation needs to be provided too support the ILI tool that is selected and that this tool is capable of detecting all of the threats that have been identified for each pipeline section.

21. CPPT should complete development of the corporate document retention policy as soon as possible.

22. CPPT has not developed a formal process for communicating the results of performance evaluations nor for the review and follow up of evaluation results.

23. CPPT has defined some of the performance goals that address general IM Program areas, as specified in API 1160, but has not addressed segment specific issues related to the operator's unique operating environment. For example, near misses, operator error, and cause specific leaks are not being tracked as performance measures.

24. CPPT's root cause analysis process needs to be tied into the Integrity Management Program.

Appendix K-Procedure for Implementing Pressure Reductions or shutdown for HCA Immediate Conditions

Purpose:

To provide for additional protection against failure of features as determined to meet the DOT 195.452(h)(4)(i) definitions for "immediate repair conditions" while repairs are being made. This procedure may be applied to other conditions the company determines needing an additional level of safety other ILI features.

Scope:

Provide the Integrity Engineer a consistent process for implementing a pressure reduction or shutdown after an assessment of the ILI Tool Vendor's Final Report has been completed for accuracy and completeness and "Immediate Repair Conditions" per DOT 195.452 Section (h)(4)(i) have been identified. A pressure reduction is limited to duration of 365 days after the implementation date and therefore, repairs must be completed within this time frame or additional remedial action will be required. In the event additional remedial action is required the Integrity Engineer will consult with the Director of Pipeline Integrity or Technical Services Manager to determine appropriate action. The process step that follow are required to implement a pressure reduction included are steps to restore pressures reduction or shutdown to normal operating conditions:

Step 1 - Identify ILI features that meet the Immediate Conditions per DOT 195.452 Section (h)(4)(i)

Step 2 – For dents, obtain operating history for 2-months prior to the tool being run to the present from the SCADA system or in the case of non-SCADA monitored systems, obtain pressure data from local pressure records[1]

Step 3 - The pressure reduction can be determined per one of the calculations below:

Calculation Methods:

3a) Metal Loss features 80% or greater of nominal wall thickness regardless of dimensions,

Pressure Reduction= use the pressure reduction equation found in section 451.7 of the 1994 Edition of ASME B31.4.

3b) Metal loss features where remaining strength calculation predicts the Burst Pressure to be less than the established maximum operating pressure (MOP) of the pipe at the location of the metal loss feature use the pressure reduction equation found in section 451.7 of the 1994 Edition of ASME B31.4.

3b) Topside dents with any indication of metal loss, cracking or stress riser

Or

Topside dent[2] that is greater than 6% of the nominal O.D.

[1] A review will be conducted of operating pressure history based on records retained in their SCADA system, at control points along the pipeline, at local control points and interpolate that data for the appropriate pressure reduction at the location of the feature.

[2] CPPT will not reduce pressure of topside dents w/o metal loss when identified by the MFL tool vendor, since these type of ILI tools cannot provide enough information to determine whether the dent like feature

Pressure Reduction= highest operating pressure over the last 2 months less 20%.

3c) If other features are identified by the ILI vendor that are deemed to be a concern by the Integrity Engineer, a suitable pressure reduction methodology will used or developed in consultation with the Director of Pipeline Integrity.

If a pressure reduction cannot be achieved using one of the above methods, the pipeline segment may need to be shutdown until repairs are completed. Contact the Director of Pipeline Integrity or the Technical Services Manager.

Step 4 - Compare the pressure reductions for each "immediate repair condition" features against the control points of the pipeline segment containing the features. Examples of acceptable actions to support a pressure reduction:

Administrative Control:

- Control Center or location can achieve the pressure reduction by monitoring and maintaining an upstream and/or downstream set point or deviation alarm in the SCADA or Local controls.

Control Device Set Point:

- Temporary pressure set point change is required of the primary control device

Step 5 – Notify Director of Pipeline Integrity or Technical Services Manager and the Oil Movements Group, Senior Controller that a pressure reduction or shutdown must be implemented. Issue an "Administrative Control" or "Control Device Set Point Change" Email Notification Memo for the pipeline system requiring a pressure reduction. Use the "Administrative Control" Memo format in Appendix A.

Step 6 – "Administrative Control" or "Control Device Set Point Change" Email Notification distribution:

- Oil Movements Operations Supervisor
- Manager of Technical Services
- Director of Pipeline Integrity
- Technical Service Engineer
- District Director
- Facility Supervisor (if system is not monitored/controlled by the Ponca City Control Center)

Step 7 – After confirmation that the feature has been assessed and required repairs made, issue Email Notification memo to remove administrative or control device controls on the pipeline system. Issue this memo to the same distribution list in Step 6.

Limitation of Administration Controls
Administrative controls for pressure reductions are limited to a 90 day. A review will be required by the Director of Pipeline Integrity to determine if an administration is allowed to continue for up to an additional 90 days or if a temporary pressure control set point change should be implemented. In no case are pressure reductions to extend past 365 days without repairs until notification is provided to appropriate the DOT/OPS region office.

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is injurious, therefore, the pressure reduction will not occur until the feature has been excavated and field evaluated.

U.S. Department of Transportation

Research and Special Programs Administration

Central Region, Pipeline Safety

901 Locust , Room 462
Kansas City, MO 64106-2641

NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
PROPOSED COMPLIANCE ORDER
AND
NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

April 26, 2004

Mr. David Ysebaert
General Manager of Pipelines and Terminals
ConocoPhillips Pipelines and Terminals
600 N. Dairy Ashford
CA Building 209
Houston, Texas 77079-1175

CPF No. 3-2004-5013

Dear Mr. Ysebaert:

On September 8-12 and September 22-26, 2003, representatives of the Office of Pipeline Safety (OPS), Central, Southern, Southwest, and Western Regions, pursuant to Chapter 601 of 49 United States Code, conducted an inspection of the ConocoPhillips Pipelines and Terminals (CPPT) integrity management program (IMP) in Ponca City, Oklahoma.

As a result of the inspections, it appears that you have committed probable violations, as noted below, of pipeline safety regulations, Title 49, Code of Federal Regulations, Part 195. The items inspected and the probable violations are:

1. § 195.452 (b) (1) Each operator of a pipeline covered by this section must:
(1) Develop a written integrity management program that addresses the risks on each segment of pipeline in the first column of the following table not later than the date in the second column: (March 31, 2002)....
(4) Include in the program a framework that--
(i) Addresses each element of the integrity management program under paragraph (f) of this section, including continual integrity assessment and evaluation under paragraph (j) of this section; and
(ii) Initially indicates how decisions will be made to implement each element.
(5) Implement and follow the program.

The process for documenting baseline assessment results and completion dates needs to be formalized. CPPT was using voice mail messages and emails to serve as principal documentation. CPPT did produce evidence that selected assessments were being performed as scheduled in the Baseline Assessment Plan (BAP). The BAP is maintained electronically on an Excel spreadsheet. The column for assessment completion date had not been filled in for all the assessments that had been completed.

2. § 195.452 (c)(1)(a) An operator must include each of the following elements in its written baseline assessment plan:

(a) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;

CPPT did not always use a deformation tool capable of detecting and identifying those deformations in the pipe that must be repaired as required by §195.452(h). The CPPT process and documentation for selecting assessment methods must be improved. At the time of the inspection, CPPT was performing pipeline excavations to evaluate only top side dents identified in HCAs. Five of eight ILI tool runs reviewed by the OPS inspection team, indicated that only a gauging plate had been used to identify deformation in the piggable segments. These eight assessments were all identified as prior assessments in the BAP and will require the running of a geometry tool to qualify as a prior assessment.

3. § 195.452 (e) (1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (see paragraphs (d)(1) and (j)(3) of this section). An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The factors an operator must consider include, but are not limited to { (e)(1)(i) through (e)(1)(ix) }.

(A) CPPT is using two different risk models to risk rank the heritage Phillips and Conoco pipelines. The OPS inspection team was not furnished enough information to determine that the highest risk pipeline segments were being assessed in a prioritized manner as required. Heritage Conoco listed segments in their BAP that had little correlation to the HCA could affect segments contained within the BAP segment. Heritage Phillips pipelines were grouped into batches with all the segments in the batch containing the same risk rank. After the inspection, CPPT made a decision to utilize the Pyramid model used by heritage Conoco for all CPPT pipelines and upgrade the model to allow a correlation of the HCA could affect segments. CPPT's Integrity Management Program (IMP) needs to contain detailed processes/procedures on how to conduct the risk ranking of their HCA could affect segments and the risk ranking of the segments listed in their BAP.

(B) Heritage Phillips has not identified or documented the primary risk threats for each assessed segment as required. CPPT indicated that they plan to develop a means to make the risk drivers more apparent.

4. § 195.452 (f) An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program { (f)(1) through (f)(8) }.

(A) There was no process for reviewing and updating assumptions that were being used in risk analysis.

(B) Documentation of the overall results of integrated data analysis and conclusions regarding the integrity of the segment, including the nature of the threats, needs to be improved. CPPT's process lacks detail in how to perform a detailed review of assessment results, generate a repair schedule, and perform an integrated evaluation of overall pipeline integrity.

(C) Factors for risk ranking facilities do not include the presence of HCAs. Both heritage Phillips and Conoco plan to perform Process Hazard Analysis on all of their facilities.

(D) CPPT processes should assure that vendors relay preliminary notifications of immediate repairs to the company. CPPT may want to develop a generic ILI vendor contract that addresses this issue. It should also contain language to ensure that a final report is received by CPPT within 180 days of completing the ILI tool run.

(E) The process for defining qualification requirements for integrity results reviewers, and other IMP positions had not been developed. Qualification needs assessments for these positions had not yet been completed. CPPT also plans to develop skill-set job descriptions for all of their risk personnel, that includes assigned responsibilities and distribution lists for results generated by this position.

5. **§ 195.452 (g) In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. This information includes:**
(1) Information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline segment;
(2) Data gathered through the integrity assessment required under this section;
(3) Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys; and
(4)...

(A) The information analysis process needs to be expanded to provide for the timely use of the Assessment Plan History and Planning Document. This document has been developed to capture data from the information analysis; however, the rate at which these documents were being generated, lagged the rate at which actual assessments were being completed.

(B) There was no formal process, at the time of the inspection, to assure input information is current prior to running the risk analysis. The previous data obtained from prior ILI tools was not being used as required for input to the risk model or as validation of the risk results.

(C) Since CPPT uses Subject Matter Experts (SME) in its Integrity Management Program, a formal process should be developed that provides a logical documented structure for conducting SME evaluations.

6. § 195.452 (h) (2) **Discovery of condition. Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.**
(3)...
(4) Special requirements for scheduling remediation.
(i)...To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the formula in section 451.7 of ASME/ANSI B31.4 (incorporated by reference, see Sec. 195.3)....
(4)(iv)...

(A) The process for declaring discovery needs to be expanded to reflect CPPT's current practice for determining the date of discovery. Discovery as currently defined in CPPT's IMP does not cover all potential situations that constitute discovery. CPPT needs to review the separate heritage Conoco and heritage Phillips inspection and repair procedures and develop a CPPT procedure.

(B) Appendix K of Part 3 of CPPT's IMP needs to be revised to be consistent with the requirements of 451.7 of ANSI B31.4 regarding implementation of a required pressure reduction.

§ 195.452 (i) (1) General requirements. An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing EFRDs on the pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls.
(i) (4)....

(A) CPPT's Preventive and Mitigative Process needs to be expanded to identify HCA specific risk drivers. CPPT indicated that they had preventive and mitigative (P&M) measures in place prior to the integrity management rule; but did not evaluate these in terms of specific threats that exist in each HCA.

(B) The CPPT IMP manual references a Decision Flow Process that is to be used to evaluate implementing preventive and mitigative measures; but, does not provide any details for the process. This decision process requires an assessment of the impact on risk of implementing the project; however, this evaluation appears to be subjective since the process requires the risk model to be updated after projects are implemented. CPPT's Assessment Plan History and Planning document does not provide any assessment of risk reduction from the suggested projects. P&M measures for non pipe facilities must also be included in the procedure.

(C) CPPT's risk analysis is not integrated with the preventive and mitigative process for HCA segments as required.

(D) CPPT needs to develop a process for evaluating leak detection capability. The process needs to evaluate the potential for risk reduction on HCA segments that are in close proximity to the pipeline.

(E) The existing process for EFRD evaluation needs to be expanded to include guidance for utilization of the flow chart to evaluate preventive and mitigative measures.

8. § 195.452 (j) (1) General. After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area. (2) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section).
(j)(5)...

(A) CPPT has a flow chart to assist with the selection of the appropriate assessment method and selection of the appropriate ILI tool if applicable. The process for using this flow chart needs to be expanded to provide for documentation and justification of the decisions made in progressing through the flow chart. The Spokane Terminal to N. Spokane Pipeline was reviewed by the inspection team as an example of using the above mentioned flow chart.

This pipe segment was initially assessed with a medium resolution MFL and caliper tool in 1999. The reassessment of this same segment (to be completed in 2004) indicated the use of a high resolution MFL tool but did not require any appropriate deformation tool, as required.

(B) CPPT had only completed two Assessment Plan History and Planning documents at the time of the inspection. Given the number of assessments completed by CPPT or credited as prior assessments, the reassessment interval that may be established by the Assessment Plan History and Planning documents could already be exceeded. The CPPT process for determining reassessment intervals must be re-evaluated or additional resources committed to ensure timely completion of this evaluation.

(C) CPPT developed procedure MNPR6105 regarding hydrostatic testing. If CPPT intends to use hydrostatic testing in its Integrity Management Program, the CPPT procedures need to be amended to address how test failures will be evaluated, i.e. metallurgical testing.

9. § 195.452 (k) **An operator's program must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. See Appendix C of this part for guidance on methods that can be used to evaluate a program's effectiveness.**

(A) CPPT's process for evaluating the effectiveness of their IMP needs to be expanded. CPPT has defined some of the performance goals that address general integrity management areas but, has not addressed segment specific issues.

(B) CPPT has not developed a process for communicating the results of performance evaluations within the company. The review and required follow-ups of evaluation results should also be covered in this process.

(C) CPPT's root cause analysis process needs to be integrated into the Integrity Management Program.

10. § 195.452 (l) (1) **An operator must maintain for review during an inspection:**
(i) A written integrity management program in accordance with paragraph (b) of this section.
(ii) Documents to support the decisions and analyses, including any modifications, justifications, variances, deviations and determinations made, and actions taken, to implement and evaluate each element of the integrity management program listed in paragraph (f) of this section.

(A) CPPT's Management of Change Process needs to be expanded to specifically address revision control in the Integrity Management Program.

(B) The corporate document retention schedule needs to be revised to include the various documents required by CPPT's Integrity Management Plan.

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 it is recommended that you be preliminarily assessed a civil penalty of $35,000.00 broken down as follows:

2 - $20,000
3(A) - $10,000
4(C) - $ 5,000
Total - $35,000

Regarding item 8(B), the inspection disclosed this as an item of concern.

Regarding items 1, 4(D) and 4(E), we have reviewed the circumstances and supporting documents involved in this case, and have decided not to assess you a civil penalty. We advise you, however, that should you not correct the circumstances leading to these violations, we will take enforcement action when and if the continued violations come to our attention.

Regarding Items 3(A, B), 4(A), 5(A, B, C), and 7(A, C), however, pursuant to 49 United States Code §60118, the Office of Pipeline Safety proposes to issue ConocoPhillips Pipelines and Terminals a compliance order in the form of the Proposed Compliance Order that is attached to and made a part of this Notice of Probable Violation.

Also, attached to and made a part of this Notice is a description of the available procedures for responding to this Notice. Please note that if you elect to make a response, you must do so within 30 days of your receipt of this Notice or waive your rights under 49 CFR 190.209. No response or a response which does not contest the allegations in the Notice authorizes the Associate Administrator for Pipeline Safety to find the facts to be as alleged herein and to issue appropriate orders. The 30 day period for response may be extended for good cause shown, and submitted within the original 30 day period.

Regarding Items 2, 4(B, C), 6(A, B), 7(B, D, E), 8(A, C), 9(A, B, C), and 10 (A, B) as provided in 49 CFR §190.237, this notice serves as your notification that this office considers your procedures/plans inadequate. Under 49 CFR 190.237, you have a right to submit written comments or request an informal hearing. You must submit written comments or request for a hearing within 30 days after receipt of this Notice. If you do not wish to contest this Notice of Amendment, you may provide your revised procedures within 30 days of receipt of this Notice. After reviewing the record, the Associate Administrator for Pipeline Safety will determine whether your plans or procedures are adequate. The criteria used in making this determination are outlined in 49 CFR 190.237.

Please refer to CPF No. 3-2004-5013 in any correspondence or communication on this matter.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

PROPOSED COMPLIANCE ORDER

Pursuant to 49 United States Code § 60118, the Office of Pipeline Safety proposes to issue to ConocoPhillips Pipelines and Terminals (CPPT) a Compliance Order incorporating the following requirements to assure compliance with the pipeline safety regulations applicable to its operations.

1. Respond within 30 days to provide OPS with a proposed schedule for establishing and implementing the required amendments as specified in items 3(A, B), 4(A), 5(A, B, C), and 7(A, C), as cited in the Notice of Probable Violation.

2. In regard to item 1 above, written procedures and proof of implementation of those procedures meeting the requirements of Part 195 must be submitted to the Director, Central Region within 180 days of receipt of the Final Order by ConocoPhillips Pipelines and Terminals.

I. Procedures for Responding to a Notice of Probable Violation:

The requirements of 49 C.F.R. Part 190, Subpart B govern your response to this Notice of Probable Violation ("Notice").

Within 30 days of receipt of a Notice, the respondent shall respond to the Regional Director who issued the Notice in the following way:

(a) When the Notice contains a proposed **civil penalty*** --

(1) Pay the proposed civil penalty, authorizing OPS to make findings and to close the case with prejudice to the respondent. Payment terms are outlined in Attachment A;

(2) Submit written explanations, information, or other materials regarding the merits of the allegations and seek elimination or mitigation of the proposed civil penalty; or

(3) Request a hearing as described below to contest the allegations and proposed assessment of a civil penalty.

* Failure of the respondent to respond within 30 days of receipt of a Notice containing a civil penalty constitutes a waiver of the right to contest the allegations in the Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in the Notice without further notice to the respondent and to issue a Final Order.

(b) When the Notice contains a proposed **compliance order** --

(1) Notify the Regional Director that you intend to take the steps in the proposed compliance order;

(2) Submit written explanations, information, or other materials in answer to the allegations in the Notice and object to or seek clarification of the proposed compliance order items in whole or in part;

(3) Request a hearing as described below to contest the allegations in the Notice; or

(4) Request consideration of a consent order as described below pursuant to 49 C.F.R. § 190.219.

(c) When the Notice contains an **amendment** of plans or procedures --

(1) Notify the Regional Director that you intend to take the steps in the proposed amendment of plans or procedures;

(2) Submit written explanations, information, or other materials in answer to the allegations in the Notice and object to or seek clarification of the proposed amendment items in whole or in part; or

(3) Request a hearing as described below to contest the allegations in the Notice.

(d) When the Notice contains **warning** items -- These items may be addressed at the operator's discretion; however, no response is required.

II. Procedure for Requesting a Hearing

A request for a hearing must be in writing and accompanied by a statement of the issues which the respondent intends to raise at the hearing. The issues may relate to the alleged violations, new information, or to the proposed compliance order or proposed civil penalty amount. A respondent's failure to specify an issue may result in waiver of the right to raise that issue at the hearing. The respondent's request must also indicate whether or not respondent will be represented by counsel at the hearing. Failure to submit a request for a hearing in writing waives the right to a hearing. In addition, if the amount of the proposed civil penalty or the proposed corrective action is less than $10,000, the hearing will be held by telephone, unless the respondent submits a written request for an in-person hearing. Complete hearing procedures can be found at 49 C.F.R. § 190.211.

III. Extensions of Time

An extension of time to prepare an appropriate response to a Notice may be granted, at the agency's discretion, following submittal of a written request to the Region Director. The request must indicate the amount of time needed and the reasons for the extension. The request must be submitted within 30 days of receipt of the Notice.

IV. Freedom of Information Act

Any material prepared by RSPA/OPS, including the violation report, this Notice, and any order issued in this case, and/or any material provided to OPS, may be considered public information and subject to disclosure under the Freedom of Information Act (FOIA). If the information you provide is security sensitive, privileged, confidential or may cause your company competitive disadvantages, please clearly identify the material and provide justification why the documents, or portions of a document, should not be released under FOIA. If we receive a request for your material, we will notify you if RSPA/OPS, after review of the materials and your provided justification, determines that withholding the materials does not meet any exemption provided under the FOIA. You may appeal the agency's decision to release materials under the FOIA at that time. Your appeal will stay the release of those materials until a final decision is made.

V. Small Business Regulatory Enforcement Fairness Act Information

The Small Business and Agricultural Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small businesses about federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the enforcement actions of the Research and Special Programs Administration, call 1-888-REG-FAIR (1-888-734-3247).

ATTACHMENT A -- PAYMENT INSTRUCTIONS

Civil Penalty Payments of Less Than $10,000

Payment of a civil penalty of less than $10,000 proposed or assessed, under Subpart B of Part 190 of the Pipeline Safety Regulations can be made by certified check, money order or wire transfer. Payment by certified check or money order should be made payable to the "Department of Transportation" and should be sent to:

General Ledger Branch (AMZ-300)
Federal Aviation Administration
U.S. Department of Transportation
Mike Monroney Aeronautical Center
P.O. Box 25082
Oklahoma City, OK 73125-4915

Wire transfer payments of less than $10,000 may be made through the Federal Reserve Communications System (Fedwire) to the account of the U.S. Treasury. Detailed instructions are provided below. Questions concerning wire transfer should be directed to the General Ledger Branch at (405) 954-4719, or at the above address.

Civil Penalty Payments of $10,000 or more

Payment of a civil penalty of $10,000 or more proposed or assessed under Subpart B of Part 190 of the Pipeline Safety Regulations must be made wire transfer (49 C.F.R. § 89.21 (b)(3)) through the Federal Reserve Communications System (Fedwire) to the account of the U.S. Treasury. Detailed instructions are provided below. Questions concerning wire transfers should be directed to the General Ledger Branch at (405) 954-4719, or at the above address.

1. RECEIVER'S ABA NO. 021030004	2. TYPE SUBTYPE (provided by sending bank)
3. SENDING BANK ARB NO. (provided by sending bank)	4. SENDING BANK REF NO. (provided by sending bank)
5. AMOUNT	6. SENDING BANK NAME (provided by sending bank)
7. RECEIVER NAME: TREAS NYC	8. PRODUCT CODE (Normally CTR, or as provided by sending bank)

9. <u>BENEFICIAL (BNF)- AGENCY</u> **<u>LOCATION CODE-/ AC 69-00-1105</u>**	
10. <u>REASONS FOR PAYMENT</u> OBI = Payment for Civil Penalty/RSPA CPF #	

<u>INSTRUCTIONS:</u> You, as sender of the wire transfer, must provide the sending bank with the information for Block (1), (5), (7), (9), and (10). The information provided in blocks (1), (7), and (9) are constant and remain the same for all wire transfers to Research and Special Programs Administration, Department of Transportation.

<u>Block #1</u> - RECEIVER ABA NO. - "021030004". Ensure the sending bank enters this nine digit identification number, it represents the routing symbol for the U.S. Treasury at the Federal Reserve Bank in New York.

<u>Block #5</u> - AMOUNT - You as the sender provide the amount of the transfer. Please be sure the transfer amount is punctuated with commas and a decimal point. **<u>EXAMPLE; $10,000.00</u>**

<u>Block #7</u> - RECEIVER NAME- "TREAS NYC." Ensure the sending bank enters this abbreviation, it must be used for all wire transfer to the Treasury Department.

<u>Block #9</u> - BENEFICIAL - AGENCY LOCATION CODE - **"BNF=/AC-69001105"** Ensures the sending bank enters this information. This is the Agency Location Code for Research and Special Programs Administration, Department of Transportation.

<u>Block #10</u> - REASON FOR PAYMENT - "OBI = Payment for Civil Penalty/RSPA CPF number and your company's name. Example: OBI = Payment for Civil Penalty/RSPA CPF #1-2002-5001/ ABC Pipeline Co.

<u>Note:</u> - A wire transfer must comply with the format and instructions or the Department cannot accept the wire transfer. You, as the sender, can assist this process by notifying, at the time you send the wire transfer to the General Accounting Division (405) 954-4719.

Linus Schmitz
10/24/05

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

RECEIVED

OCT 21 2005

Margaret A. Yaege

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

October 13, 2005

Ms. Margaret Yaege
President
ConocoPhillips Pipe Line Company
600 North Dairy Ashford
Houston, TX 77079

Re: Request for time extension to prepare and implement Integrity Management Program revisions as required by CPF No. 3-2004-5013 dated April 26, 2004.

Dear Ms. Yaege:

On August 26, 2005, the Final Oder for CPF No. 3-2004-5013 was issued to ConocoPhillips Pipe Line Company (CPPL). The Final Order required that CPPL's written Integrity Management Program must be amended to achieve compliance with the requirements of § 195.452.

ConocoPhillips Pipe Line Company submitted a request for a time extension dated September 27, 2005, that provided a schedule for completing the required amendments and implementing them.

The following items in your letter dated September 27, 2005, require further revision/ implementation:

Compliance Order items 3(A-B), 4(A), 5(A-C), and 7(A-C):

I. Not complete - proposed implementation schedule is acceptable.
II. Not complete - proposed implementation schedule is acceptable.
VII. Not complete - proposed implementation schedule is acceptable.

Amendment of Procedures items 2, 4(B-C), 6(A-B), 7(B,D,E), 8(A,C), 9(A-C), 10(A-B):

1. Item 2 - requires further revision.
4. Item 6A - requires further revision.
7. Item 7D - Not complete - proposed implementation schedule is acceptable.
8. Item 7E - Not complete - proposed implementation schedule is acceptable.
15. Item 8B - Not complete - proposed implementation schedule is acceptable.

We have reviewed the information submitted and have found it to be acceptable for granting the time extension requested for each item in the Notice. It is our understanding that a quarterly status report of your progress will be presented to the Central Region Director. The first report is to be sent in November 2005. All required revisions and implementation of processes/procedures will be completed by December 2006.

Thank you for your continued cooperation and remedial actions to ensure the pipeline integrity of ConocoPhillips Pipe Line Company's pipeline systems.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

02/21/07 - Original to: Mark Drumm

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

901 Locust Street, Suite 462
Kansas City, MO 64106-2641

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

RECEIVED

FEB 2 1 2007

Margaret A. Yaege

February 15, 2007

Ms. Margaret Yaege
President
ConocoPhillips Pipe Line Company
600 N Dairy Ashford St
Houston, TX 77079- 1175

CPF 3-2004-5013

Dear Ms. Yaege:

As a result of an inspection conducted between September 8-26, 2003, by representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) Central, Southwest, and Western Regions, a Notice of Probable Violation, Proposed Civil Penalty, Proposed Compliance Order, and Notice of Amendment (Notice) was issued on April 26, 2004. The Final Order on this case was issued on August 26, 2005 and required changes of certain processes/procedures within ConocoPhillips (CPPL) Integrity Management Program. We received correspondence on the required actions described in the Compliance Order and copies of the amended pages of the CPPL Integrity Management Program, submitted by CPPL in 2004, 2005, 2006 and the last submittal dated February 12, 2007. The revised processes/procedures and required actions have been reviewed and found to be acceptable. The assessed civil penalty has been paid

This letter is to inform you that no further action is necessary and that this case is being closed. Thank you for your staff's cooperation in this matter.

Sincerely,

Ivan A. Huntoon

Ivan A. Huntoon
Director, Central Region
Office of Pipeline Safety

ConocoPhillips Pipe Line Company IMP Inspection Summary Report

Report Issue Date:	August 8, 2005
Operator:	ConocoPhillips Pipe Line Company (CPPL)
Corporate Address:	2010 Tarkington, 600 North Dairy Ashford, P.O. Box 2197, Houston, TX 77252
Operator ID Number(s):	31684 (Phillips Pipe Line Company (15490), South Texas 66 (31458), West Texas 66 (1044), Chisholm (2350), Conoco Pipe Line Company (13131), Pioneer Pipeline Company (15603), Yellowstone Pipeline Company (24025), Tosco Distribution – West (31328), Tosco Corporation (26145))
Dates of Inspection:	June 7-9 & June 20-24, 2005
Location(s) of Inspection:	Ponca City, OK
Primary Contact:	Keith Wooten, Director, Pipeline Integrity
	Phone: 580-767-7489; Keith.h.wooten@conocophillips.com

Persons in Attendance:

Operator Representatives:

Keith Wooten, Director, Pipeline Integrity

Amy Gross, Pipeline Integrity Engineer

Bob Daniels, Risk Assessment Coordinator

Dennis Schulze, Integrity Engineer

Mark Benson, Integrity Engineer

David Wilson, Integrity Engineer

Brian Allison, Mapping Coordinator

Randy Beggs, Director, Pipeline Regulatory Compliance

Paul Hermann, Manager, Eagle Information Mapping

David Martin, Technical Services Engineer

Charles E. Eickele, Pipeline Integrity Engineer

Stephen Ellison, Senior Counsel

Linus Schmitz, Manager, Pipeline Integrity & Reliability

Jeremiah Komell, PHA Engineer

John Bergeron, PHA Director

Mark Brogger, Director, Corrosion Control

Steve Koenig, Director, Automation

Richard Parker, Leak Detection & Model Specialist

OPS Inspection Team:

Chris McLaren (Lead) (Office of Pipeline Safety (OPS) Southwest Region)

Don Moore (OPS Central Region)

Wade Nguyen (OPS Western Region)

Jason Terry (OPS Southwestern Region)

Joe Subsits (Washington State (Week 1))

Dave Lykken (Washington State (Week 2))

Anthony Tome (Cycla Corporation)

Inspection Objectives:

The purpose of this inspection was to provide assurance that ConocoPhillips Pipe Line Company (CPPL) has developed and implemented an Integrity Management Program as required by 49 CFR §195.452 and to review the changes required by Enforcement Letter CPF 3-2004-5013 from the initial Integrity Management inspection performed in September, 2003. Specifically, this inspection reviewed CPPL's processes for:

- Identifying pipeline segments that could affect High Consequence Areas (HCAs);
- Integrating information from all relevant sources to understand location-specific risks for these segments;
- Developing and implementing a Baseline Assessment Plan;
- Reviewing the results of integrity assessments;
- Identifying and implementing remedial actions for anomalies and defects identified during integrity assessments;
- Identifying and implementing additional preventive and mitigative measures to reduce risk on pipeline segments that can impact HCAs;
- Performing on-going evaluations and assessments of pipeline integrity; and
- Evaluating Integrity Management Program performance.

This inspection also reviewed the implementation and results of CPPL's Integrity Management Program to-date including a review of completed integrity assessments, and the repair and mitigation actions taken as a result of these assessments.

This inspection summary report summarizes the key features of the CPPL approach for each of the Integrity Management Program Elements in 49CFR 195.452(f) as well as feedback provided to CPPL by the inspection team regarding the issues identified by and observations of the inspection team during the review of CPPL's program and its implementation.

CPPL's Pipeline System Overview

ConocoPhillips Pipe Line Company (CPPL) owns and operates 11176 miles of hazardous liquid pipeline. In 2002 Conoco and Phillips Petroleum Company merged to form ConocoPhillips Company. CPPL's Integrity Management Plan (IMP) is applicable to the following assets:

Phillips Pipe Line Company, Phillips Texas Pipeline, Phillips Petroleum Company – 4019 liquid pipeline miles

South Texas 66 – 749 liquid pipeline miles

West Texas 66 – 711 liquid pipeline miles

Chisholm – 184 liquid pipeline miles

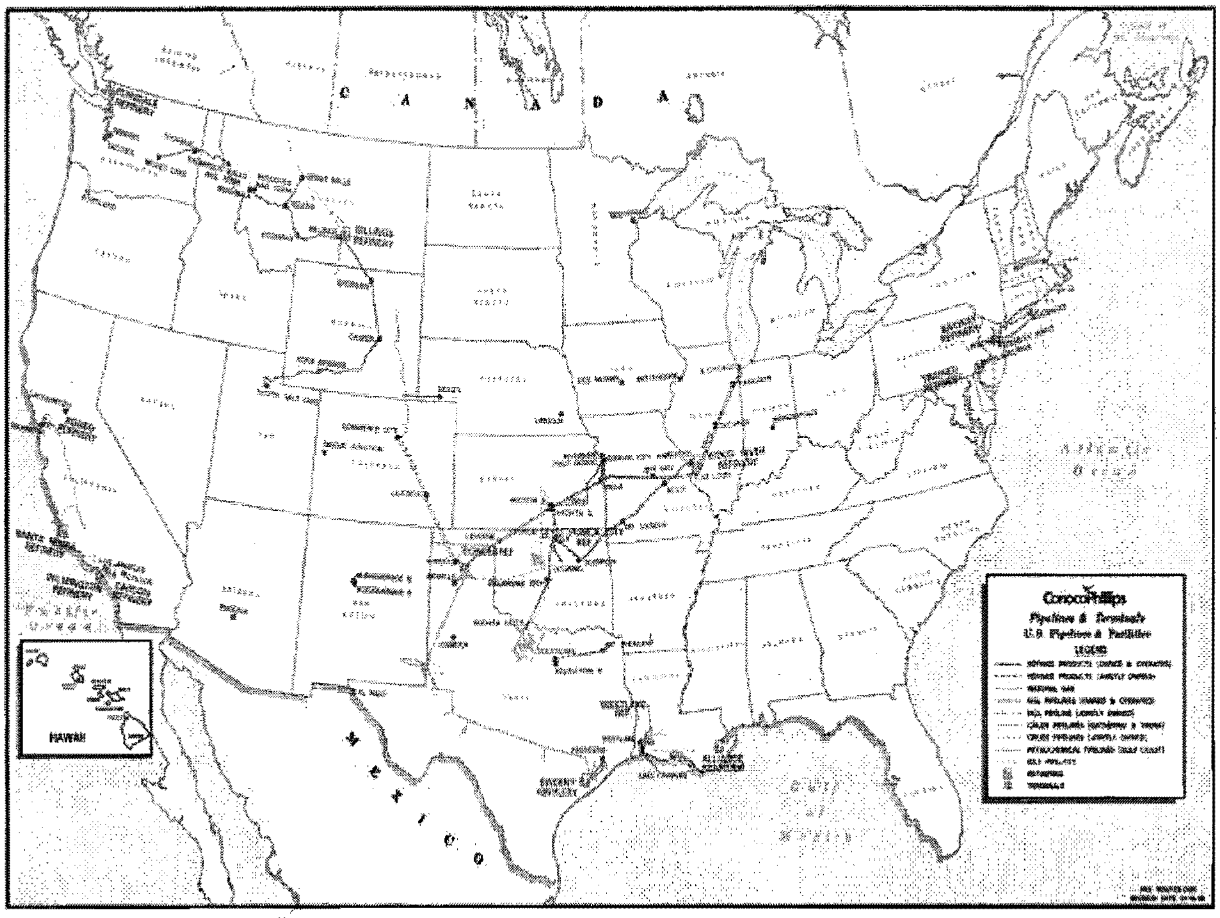
Conoco Pipeline Company – 3689 liquid pipeline miles

Pioneer Pipeline Company – 307 liquid pipeline miles

Yellowstone Pipeline Company – 662 liquid pipeline miles

Tosco Distribution – West – 855 liquid pipeline miles

A map of the CPPL pipeline system is presented below: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ConocoPhillips Pipeline IMP Inspection Summary Report

The following Table provides an overview of the assets included in CPPL's IMP as of June, 2005:

System Name	Segment Begin	Segment End	Segment Total Miles
AM-08	Borger	Amarillo	46.68
AM-10	Borger	Amarillo	46.68
BD-01	Borger Rocky	Denver	355.36
BL-01	Spearman	Paola	373.87
BL-02	Paola	East St. Louis	264.98
BP-01	Dupo	East Chicago	267.21
CC-30	HS&P	Suey Junction	14.00
CC-31	Sisquoc	Santa Maria	10.00
CC-32	Santa Maria	Santa Maria Refinery	19.00
CH-01	Cheyenne Station	Sydney Terminal	97.89
CH-11	Cheyenne Station	Kaneb Terminal	4.34
CM-01	Kingfisher	Conway	184.55
CP-01	Sweeney	Mt. Belvieu	84.74
CP-02	Clemens	Webster	50.85
CP-03	Shell	HCC	2.62
CP-08	Clemens	Pasadena	64.94
CR-02	Clifton Ridge Crude Line BV	COC Westlake refinery	10.15
CR-03	Pecan Grove	Clifton Ridge Marine Terminal (CRMT)	.70
CR-04	Equilon BV	CRMT	.64
CW-01	Witchita	Conway	54.43
DE-02	Denver Junction	Chase	.94
DE-03	Denver Junction	Wyco/Kaneb	.61
EC-01	East Chicago Terminal	Buckeye Delivery	.58
EC-02	East Chicago Terminal	Citgo Delivery	.32
ET-01	Greenville	Mt. Pleasant	75.25
EZ-01	Menard	Sweeney	380.55
EZ-10	Ozana	EZ-01	25.08
EZ-20	Sonora	EZ-01	23.00
EZ-30	Luling	EZ-01	30.60
EZ-40	Giddings	EZ-01	1.22
GD-01	Borger	Witchita	273.20
GD-02	Witchita	Paola	143.05
GD-03	Paola	East St. Louis	264.92
GL-01	Laurel	Billings	16.77
GL-02	Byron Pump Station	Billings Refinery	82.22
GL-03	Canadian Border	Cut Bank	56.79
GL-04	Murphy Station	Cut Bank	56.73
GL-05	Canadian Border	Murphy Station	6.91
GL-07	Cut Bank	Round Up	234.43
GL-08	Round Up	Billings Pump Station	53.21
GL-09	Cut Bank	Billings	276.81
GL-11	Billings Pump Station	Exxon Refinery	3.69
GR-01	East St. Louis	Dupo	3.03
GR-02	Kankakee	East Chicago	46.16
LA-01	Gillis BV	COC Westlake Refinery	6.7
LC-01	COC Westlake Refinery	Lake Charles Pipeline	8.92
LC-02	Citgo Refinery	LCPL	.57
LC-03	LCPL	Citgo refinery	1.05
LC-04	Lake Charles	LC Colonial Gasoline Segment	.28

System Name	Segment Begin	Segment End	Segment Total Miles
LC-05	LCPL	Colonial	.15
LC-06	Colonial	LCPL	.28
LC-07	LCPL	Explorer	.59
LC-08	Explorer	LCPL	.54
LO-01	Buxton	Borger	276.85
LO-10	Cushing Seaway	Buxton	.46
LO-11	Cushing Basin	Buxton	.54
LO-12	Cushing BP	Buxton	.04
LP-01	LARW	Torrance Products #1	3.8
LP-02	LARW	Torrance Products #2	3.8
LP-03	LARW	LAT	15.18
LP-04	Torrance (12")	LAT	10.50
LP-05	Torrance (20")	Watson	8.90
LP-06	LARW	LAX	19.76
LR-01	LARC (B Line)	LARW (B Line)	4.4
LR-11	LARC (Bi-Directional)	LARW (C Line)	4.40
LR-12	LARC (B Line)	LARW (B Line)	3.82
LR-13	LARC (E Line)	LARW (E Line)	3.82
LR-14	LARC (G Line)	LARW (G Line)	3.82
LR-15	LARC (U-1 Line)	GATX (U-1 Line)	1.40
LR-16	Pier T (Long Beach)	LARC	5.40
MX-01	DEFS Linam Ranch	Gaines Station	13.79
MX-02	MAPCO Hobbs	Gaines	10.15
MX-10	DEFS Artesia	Gaines	69.60
MX-11	East Vacuum	Jayhawk	19.68
MX-20	Goldsmith	MP 15	13.08
MX-21	Eunice DEFS Plant	MX-20	17.73
MX-22	Fullerton	MX-20	4.63
MX-30	Goldsmith	Spraberry	51.79
MX-31	Goldsmith	Chaparrel	.11
MX-32	MX-30	Huntsman	6.22
NC-10	Sunset	Midway	6.00
NC-11	Midway	Transition-Shale	12.00
NC-12	Transition-Shale	McKittrick	5.00
NC-13	Elk Hills	McKittrick	18.87
NC-14	McKittrick	Middlewater #1	15.00
NC-15	McKittrick	Middlewater #2	15.00
NC-16	Middlewater	Junction #1	13.00
NC-17	Middlewater	Junction #2	13.00
NC-20	Junction	Coalinga	45.00
NC-21	Coalinga	Rodeo Refinery	183.50
NC-40	Santa Margarita Refinery	Santa Margarita #2	32.00
NC-41	Santa Margarita	Shandon #1	51.00
NC-42	Santa Margarita	Shandon #2	51.00
NM-01	Hobbs	Gaines	4.92
NM-11	Buckeye	East Hobbs Junction	18.66
NM-16	Valve @ 950+14	Valve @ 883+71	1.26
NM-19	NIB	NM-01	1.14
NP-01	Rodeo Refinery	Richmond Terminal	13.00
NT-30	Carson Station	Witchita Falls Terminal	11.00
NT-40	Deer Creek Station	Wichita Falls Terminal	6.00
NT-50	Clear Fork	Graham	5.00
NT-60	Graham	Jacksboro	58.00
NT-95	Holiday	Carson Station	7.00

System Name	Segment Begin	Segment End	Segment Total Miles
OK-01	Witchita Falls Crude Station	Ponca City (South Tank Farm)	217.24
OK-03	Kingfisher	Orlando	28.29
OK-04	Cushing	Ponca City (South Tank Farm)	62.04
PH-10	Shernan Plant	Borger NGL Center	76.82
PH-11	DEFS Rock Creek Plant	PH-10	1.06
PH-12	Sunray	Ray Booster	.95
PH-13	Sneed Plant	Sneed Junction	.68
PH-20	Gray Plant	Borger	33.89
PH-22	Shafer	G-202	.22
PH-23	Oneok	PH-20	.86
PH-30	Rock Creek	Borger NGL Center	3.05
PH-40	Shernan	BPT 6"	79.26
PH-41	Rocky	Borger NGL Center	2.80
PH-44	BP Amoco Plant	Ray Booster	4.95
PH-50	Skellytown	Borger	16.15
PH-60	Skellytown	Borger	16.26
PH-61	Philrock	Skellytown	15.03
PK-08	Paola	Kansas City	53.47
PK-10	Paola	Kansas City	53.53
PN-01	Sinclair	North Salt Lake	306.29
PN-11	North Salt Lake Terminal	Chevron Manifold	2.56
PN-12	North Salt Lake	Chevron Manifold	2.56
PN-13	North Salt Lake	Chevron Manifold	2.56
PP-01	Ponca City (Cherokee Pump Station)	Arkansas City Manifold	28.57
PP-02	Ponca City (Cherokee Pump Station)	Arkansas City Manifold	28.57
PP-03	Arkansas City Manifold	Witchita Terminal	47.57
PP-04	Pawnee Junction	Kaneb 8" Tie-in	5.96
PP-05	Ponca City (Cherokee Station)	N. Cimarron River BV	54.64
PP-06	Ponca City (Cherokee Station)	Medford Station	42.49
PP-12	Wichita Terminal	McConnell AFB	.72
PP-13	Wichita Terminal	Midcontinent Airport	13.65
PP-14	Oklahoma City Product Terminal	Tinker AFB	5.42
PP-15	Oklahoma City Product Terminal	Will Rogers Airport	13.48
PR-01	Sage Creek Injection	Rocky	643.39
RP-01	Paola	Ringer	2.07
RP-02	Paola	Ringer	2.07
SC-01	West Mountain	South mountain	.83
SC-60	Ventura	Santa Paula	15.90
SC-61	Sulphur Crest	Santa Paula	7.80
SC-62	South Mountain	Santa Paula	4.00
SC-63	Santa Paula	Torrey	18.70
SC-64	Torrey	Torrance	62.90
SC-65	Tennessee Ave.	Torrey Line at Pico Tie-in	2.29
SC-66	Las Cienegas Trunk Line	Torrey Line at Venice Tie-in	11.80
SC-67	Torrance	LARC (A Line)	6.20

System Name	Segment Begin	Segment End	Segment Total Miles
SC-70	Stewart	LARC	31.02
SC-71	REDU	Stearns	2.60
SC-76	Butler Road	Norwalk	3.08
SC-80	Mandalay	Ventura	3.24
SD-11	Cushing Seaway	Buxton	.57
SD-12	Buxton	Marland Junction	56.00
SD-13	Ponca City	Marland Junction	4.26
SD-14	Marland Junction	Wichita	91.60
SM-01	Billings	Casper	244.78
SM-02	Casper	Sinclair	90.76
SM-11	COC Billings Refinery	SPL Billings Pump Station	1.32
SM-12	Exxon Refinery	SPL Billings Pump Station	2.89
SM-13	Casper Pump Station	Kaneb Manifold	.26
SM-14	Casper Pump Station	Kaneb Manifold	.26
SM-15	Casper Pump Station	Kaneb Manifold	.26
SM-16	Kaneb Manifold	Sinclair Refinery	.25
ST-12	Sweeny	Pasadena	60.17
ST-18	Sweeny	Pasadena	59.76
WC-02	Wood River Terminal	Cushing/Equilon 12"/8"	449.18
WC-11	Koch Terminal	Woodriver Terminal	.63
WL-01	COC Westlake Refinery	CITCON	5.57
WL-02	COC Westlake Refinery	CITCON	4.58
Wl-03	COC Westlake Refinery	Citgo Refinery	5.87
WR-01	Ponca City	Wood River terminal	524.49
WR-03	Glenpool	Glenpool South	2.6
WR-11	Woodriver Terminal	Triangle Manifold	2.49
WR-12	Woodriver Terminal	Triangle Manifold	2.49
WT-10	Odessa	Borger	288.75
WT-12	Exxon Gate Plant F	Odessa	9.30
WT-40	Harper	Odessa	10.92
WT-50	Wasson	Weems	10.88
WT-80	Gaines	Borger	205.25
XX-01	Cheviot Hills	Fox Hills	.20
XX-02	LCR Blending Station	Dupont SRW	35.84
XX-04	Chevron Delivery Facility	Conoco Albuquerque Station	1.81
XX-07	Hole Lease	Stewart	3.16
XX-08	Richfield	Sterns	5.18
XX-09	Sterns	Stewart Station	2.65
XX-10	East Naranjal	Sterns Junction	1.04
YP-01	Billings	Missoula	331.76
YP-02	Thompson Falls	Spokane	116.20
YP-03	Parkwater Terminal	North Spokane Terminal	5.08
YP-04	Spokane	Moses Lake	108.40
YP-05	Helena Pump Station	Great Falls	82.10
YP-11	COC Billings Refinery	YPL Billings Pump Station	1.36
YP-12	Exxon Refinery	Billings Pump Station	2.94
YP-13	Yale tank farm	Billings Pump Station	.32
YP-14	Alk Cr Junction off of YPL 10" Mainline	Laurel MRL Delivery Facility	17.41
YP-16	Hillyard Manifold	North Spokane Terminal	1.37

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System Name	Segment Begin	Segment End	Segment Total Miles
YP-17	North Spokane Terminal	Hillyard	1.77
YP-18	Geiger Junction	Spokane International Airport	3.00
YP-20	Missoula Terminal	MRL Terminal	2.34
YP-21	Moses Lake terminal	Grant Co. Airport	2.04

1. Segment Identification:

CPPL has outlined its process and methods for identifying segments that "could affect" an HCA in Section 2 of the ConocoPhillips Pipe Line Company Integrity Management Program. Previously, segment identification had been performed separately by Conoco Pipe Line Company and Phillips Pipe Line. At the 2003 inspection of the combined company, CPPL was still using two independent methodologies for the identification of "could affect" an HCA segments. CPPL has employed the services of Eagle Information Mapping (EIM) to use a dynamic software package to identify "could affect" an HCA segments for all of their pipeline systems. At the time of the inspection this process had only been completed for two of CPPL's 44 pipeline systems. The systems completed were the Yellowstone and Seminoe systems. The schedule for completing the "could affect" an HCA analysis of all pipeline systems is currently lagging. CPPL is formulating a strategy for accelerating completion of the EIM process.

CPPL is currently implementing a phased approach to creating an integrated Integrity Management program for all of its merged entities. The first phase is the identification of "could affect" an HCA pipeline segments. CPPL initiated this process in June of 2003 by improving the accuracy of the known location of their pipelines. CPPL employed one of three methods for locating their pipelines. They are:

- Geo-positioning of the pipeline;
- As-built survey records derived from a physical land survey of the pipeline survey; and
- Utilizing "other" existing in-house records such as ILI tool positioning, alignment sheets, pipe tally reports and custom detail drawings and maps.

A description of each process, as taken from the CPPL IM Program Plan, is presented below:

Geo-positioning:

"Pipeline centerline locations and above ground features and facilities," utilizing geo-positioning, "were captured using the Trimble 12-Channel ProXL Global Positioning System (GPS) Rover units and TDC1 Data logger. The GPS data was differentially corrected using PFinder and PathFinder Office Software and base station data gathered from various sources. In 1999–2000, the Trimble ProXL GPS Rover units and TDC1 Data Loggers were replaced with Trimble 12-Channel ProXRS rover units and TSC1 Data Loggers. The ProXRS is a differential Global Positioning System (DGPS) capable unit that receives both satellite based differential correction signals and US Coast Guard Beacon differential correction signals. Since the adoption of the Trimble ProXRS DGPS units, the GPS data is no longer required to be post processed, differentially corrected, unless the satellite or beacon correction signal is unavailable.

The data was then converted into attributed blocks in AutoCAD, edited for content and to eliminate obvious data collection errors and placed on digital USGS 7.5' quad sheets also in AutoCAD. The QA/QC process consisted of comparing the digital quad sheets with the hand drafted quad sheets and alignment sheets as well as field verification that the data appeared to be correctly located on the digital quad sheets. As digital orthophotography became available, the digital pipeline centerline and events in the form of attributed blocks would be placed on the photography for a more rigorous QA/QC.

The 3D pipeline centerline represented on the USGS 7.5' quad sheets in AutoCAD drawing format was reexamined and edited in both plan and profile and all obvious errors were removed. The centerline and all events were re-stationed and the data in AutoCAD drawing format was sent to New Century Software to be loaded into" the Pipeline Open Data Standard "(PODS). The QA/QC process of the data after it was loaded into PODS consisted of visual inspection and comparison of the alignment sheets made from the data in PODS to the digital 7.5 minute quad sheet and alignment sheet PODS source files.

All Company pipeline centerline location data captured to date, utilizing Method 1, has been submitted to the NPMS with a Quality Code of "E". This code stipulates that the positional accuracy of the data is +/- 0 to 50 feet or better."

Land Surveyed Pipeline Centerline:

"Pipeline systems converted to PODS Database through the use of aerial alignment sheets, as-built drawings, in-line inspection data, and plat sheets are completed using New Century Software's (NCS) PipeInfo Capture Software. Quality control of the captured data is achieved by performing a series of electronic checks of the data to ensure that there are no gaps or overlaps in the linear pipeline attributes and by direct comparison of the imputed data to the original source material. Data entry verification is performed on an attribute by attribute basis. Data unknowns and exceptions are reviewed by CPPL for resolution.

Centerline geometry coordinates for each line converted is obtained after all data capture processes are completed. Where no electronic centerlines are available, NCS utilizes CLRoute to manually route the centerline relative to USGS aerial photography provided by CPPL. The CLRoute program extracts the field survey notes, ties, and monuments entered into the PipeInfo Capture Software to route the appropriate pipe centerline in relation to the base map. CLRoute increases centerline routing accuracy by automatically computing pipe inflections based upon survey information and known monuments, and provides for quality control verification of the routed centerline.

Independent visual inspection of the centerline is performed to ensure conformity with the survey data and the aerial imagery. NCS uses CLRoute to quantify centerline accuracy and is dependent upon many variables including but not limited to the following:

- original survey quality;
- as-built source data;
- frequency of base map ties;
- base map accuracy;
- supporting features;
- GPS availability.

Upon completion of the centerline routing, the data is converted to a database format and loaded into PODS. Digital elevation models are obtained and the existing centerline geometry is draped over the elevation model to derive an elevation. These derived elevations are also loaded into the PODS database. CPPL utilizes these digitized centerlines through its Oracle database.

Pipeline systems developed from as-built resurveys and pipeline alignment sheets are submitted to the NPMS with Quality Code "E". This code stipulates that the horizontal positional accuracy of the data is +/- 0 to 50 feet or better."

Other Methods:

"If adequate as-built survey plats and records did not exist, pipeline centerlines were then captured and converted to the PODS Database through the use of aerial alignment sheets, in-line inspection data, Pipe Tally Reports and custom detail drawings and maps. This process was completed using pre-defined basic guidelines created by New Century Software (NCS) and CPPL Mapping personnel. Appendix 2A of the CPPL IM Program Plan provided guidelines for implementing the New Century Software.

Quality control of the captured data was achieved by performing a series of electronic checks of the data to ensure that there were no gaps or overlaps in the linear pipeline attributes and by direct comparison of the imputed data to the original source material. Data entry verification was performed on an attribute-by-attribute basis. Data unknowns and exceptions were reviewed by CPPL for resolution.

Centerline geometry coordinates for each line converted was obtained after all data capture processes were completed. Where no electronic centerlines were available NCS utilizes CLRoute to manually route the centerline relative to USGS aerial photography provided by CPPL. The CLRoute program extracts the field survey notes, ties, and monuments entered into the PipeInfo Capture Software to route the appropriate pipe centerline in relation to the source documents. CLRoute increases centerline routing accuracy by automatically computing pipe inflections based upon source document information and known monuments, and provides for quality control verification of the routed centerline.

Independent visual inspection of the centerline was performed to ensure conformity with the captured data and the aerial imagery.

Upon completion of the centerline routing, the data is converted to a database format and loaded in PODS. Digital elevation models are obtained and the existing centerline geometry is draped over the elevation model to derive an elevation. These derived elevations are also loaded into the PODS database. CPPL utilizes these digitized centerlines through its Oracle database.

Pipeline systems developed from as-built resurveys and construction records, as described in Method 3, are submitted to the NPMS with Quality Code of "E". This code stipulates that the horizontal positional accuracy of the data is +/- 0 to 50 feet or better."

Once an accurate location of the pipeline is known, positioning of the pipeline can then be compared to the HCA locations provided by the National Pipeline Mapping System (NPMS).

Eagle uses EIM to determine if a pipeline segment is a direct intersect of an HCA or an indirect intersect based on overland/water transport, or air dispersion analyses.

Direct Intersection:

The pipeline centerline data is compared to the NPMS HCA shapefile data to identify direct intersect begin and end points. This information is then stored in a datafile that records the enter (begin) and exit (end) points of the intersection and the type of HCA that has been intersected.

Indirect Impact:

The indirect impact of a pipeline segment on an HCA is determined using the properties of the product transported in the pipeline, topography, and distance. Liquid products (non-HVLS) will tend to be driven by overland and water transport and HVLs by air dispersion.

Per the CPPL IM Program Plan:

"CPPL is conducting an intersection analysis with defined HCA datasets as part of the Overland Spread and Hydrographic Flow analysis developed by EIM. Each HCA encountered, either directly by the pipeline or indirectly through the overland and hydrographic analysis, is captured. The result is a database containing comprehensive analysis information per sample point. This includes information such as HCA intersection counts per HCA type, time for the release to intersect each HCA, associated volume at entry, and total HCA counts per each sample point. The results contained in the database are then evaluated to create linear HCA could affect pipeline segments by HCA type and by intersection type (Direct, Overland, or Hydrographic).

The impact of a release on an HCA is proportional to the magnitude of the release. CPPL calculated the volume of product released every 30 meters along their pipelines. At every sample point, a drain volume is calculated based on the local topography of the pipeline, flow restriction devices and connected pipelines. Topographic variations are an integral part of the Overland Flow and Hydrographic Transport analysis being performed. This modeling uses an underlying elevation model, the National Elevation Dataset (NED), as the basis for the propagation of the released product across the terrain. Each release point will have a unique product flow path based on the topography encountered. The flow paths will continue until one of the following conditions is met:

- Product runs out due to losses (evaporation, adhesion, infiltration), or
- Response time is met

Total release volumes and rates are calculated at each sample (release) point and consist of the following two components:

- Pumping Volume – volume calculated from the operating flow rate prior to pipeline shutdown

- Drain Down Volume and Rate – volume and flow rate calculated after shutdown due to gravity drain of the pipeline (this takes into consideration any connecting pipelines or tanks that free-flow into the release area).

Pumping volumes are calculated assuming a full line rupture using the operating flow rate and the emergency response time required to shutdown the pipeline. Gravity drain down volume is calculated at each sample point as a function of elevation profile and valve type and placement. The elevations and measures of the boundary conditions (nearest upstream and downstream valve) are retained for the associated gravity drain down rate calculations.

When the release volume has been calculated, the dispersion distance can be computed for non-HVL and HVL products. The dispersion mechanisms are Overland Transport, Water Transport , and Air Dispersion. The mechanisms used by the EIM are discussed below."

Overland Spread of Liquid Pool:

The Overland Flow and Hydrographic Transport methodology in EIM is based on an analytic approach utilizing ESRI Spatial Analyst Hydrography and Cost Distance modeling tools. The overland transport analysis is divided into two distinct regimes:

- Overland, or Channelized, flow
- Lateral Spread

Overland or Channelized Flow

Overland, or channelized flow, is flow that is confined within an existing topographic drainage feature. Lateral spread is gravity spreading on a roughly horizontal surface. In general, channelized flow is restricted to higher slope environments, and lateral spread is restricted to low slope environments.

Channelized flow uses a flow accumulation grid and flow direction grid to calculate a least cost path route for a release. For each sample (release) point, a drain down volume and flow rate are calculated and the flow path is determined by evaluating the slope and distance to each cell in the flow path raster.

This provides the Overland Flow trace for which normal flow depth, normal flow velocity, and product losses (evaporation, infiltration, adhesion) are calculated from cell to cell. Additionally, the time required for the release to reach the next cell is determined, allowing for an accumulated time value to be provided as an output. The analysis is graphically depicted by red line traces and continues until:

- Product runs out
- Response time is reached
- Proximity to an NHD water body is below tolerance - transitions to Hydrographic
- Critical slope for Lateral Spread (pink polygon) is reached - transitions to Lateral Spread

Lateral Spread:

The Lateral Spread is a stepwise time/distance processing of "flat" regions to provide a model of the realistic spread of release product in these terrains versus simply terminating the analysis. The transition from Channelized Flow to Lateral Spread occurs by examining the local planform curvature against the defined terrain slope value. Once this occurs, all cells within the slope uncertainty window (flat spot) are located and a cost distance grid is created over the flat spot. This is done using either a Euclidean Distance or Cost Distance function. Spread depth, spreading velocity, and product losses (evaporation, infiltration, adhesion) are then determined by iterating through the cost distance raster; for each time increment. This process continues until:

- No product remaining due to losses
- Response time is reached
- Proximity to an NHD water body is below tolerance - transitions to Hydrographic Transport
- Extent of cost distance raster is reached - transitions to Overland Flow.

Water Transport:

The terrain-based release modeling HCA analysis performed by EIM assesses all water crossings to the pipeline. Release locations are assigned every 30 meters along the pipeline centerline. Each release location is then modeled using EIM's Overland Flow and Hydrographic Transport analysis tools.

During the analysis, once a flow path is within 30 meters of a water feature (the resolution of the underlying elevation model), the remaining volume is transferred to the hydrographic modeling analysis. In the case of direct pipeline water crossings, the full drain volume is transferred to the hydrographic analysis. The National Hydrography Dataset (NHD) is used as the source for water features.

The Hydrographic Transport analysis is incorporated to determine the maximum potential downstream transport distance of the remaining product and intersections with High Consequence Areas. The analysis relies on the National Hydrography Dataset (NHD) for water body parameters.

Water velocities are determined through the analysis of historical velocity measurements at locations within 100 miles surrounding the pipeline centerline. The measurement data used is from the USGS National Water Information System (NWIS) dataset. These values are analyzed to determine the appropriate velocities to be used in the different geographic regions where the pipeline exists. The sub regions are supersets of the watersheds that the CPPL pipelines intersect. The second standard deviation is used to determine the water velocities.

The Hydrographic Transport path begins at one of the following:

- Pipeline - stream intersection,
- Channelized Flow trace – stream intersection, or
- Lateral Spread – stream intersection

The trace is measured downstream using NHD data attributes and algorithms calculating transport path shape, total response time, sampling point ID, remaining product volume, remaining time, percent evaporated and flow path length as some of the model's outputs. The downstream trace analysis continues until:

- No product remaining due to losses
- Response time is reached

The time to interdict a release is computed by CPPL using an estimated time to mobilize, time to travel, time to locate the leak, and time to interdict. For the calculations of time to respond to a release on the Yellowstone Pipeline, it was felt that the assumptions used might be non-conservative and should be compared to emergency response drills and to actual releases in the industry. CPPL did have their Emergency Responders review the calculations and they felt that they were conservative. The most conservative time calculated to date has been 8 hours on the Yellowstone pipeline. The inspection team reviewed the calculation and agreed with the assumptions and result. Some of CPPL's pipelines are located in remote regions and an assumption that interdiction can occur based strictly on time might be unrealistic. Potentially terrain might be a limiting factor and require interdiction to occur at a specific location that is unrelated to time constraints.

Air Dispersion Analysis:

Since HVLs are prone to vaporize at atmospheric pressure, special consideration must be taken to determine the potential impacts of an HVL release. The Process Hazard Analysis Software Tool (PHAST) is the standard modeling methodology used by CPPL for heavier than air flammable gas releases. This software tool is used to determine the appropriate "could affect" buffer zone for HVL pipelines using detailed vapor cloud modeling.

PHAST is a state-of-the-art Unified Dispersion Model (UDM) capable of modeling flammable releases of hydrocarbons including jet fire, pool fire, BLEVE and vapor cloud explosions. PHAST allows the user to input different scenarios of conditions such as material, volume, flow rate, pressure and temperature, which may exist if a failure of the pipeline occurs. PHAST then calculates the level of flammable concentrations of a dispersing vapor cloud, based on user defined weather and surface type conditions, and determines toxic and flammable concentration, fire radiation and explosion pressure radii. This data can then be used to determine the potential impact to the surrounding environment, people and building structures inside and outside the release perimeter in the event of a vapor cloud ignition.

For pipeline releases, CPPL uses the Baker-Strehlow method within PHAST to model vapor cloud explosions. Since PHAST does not handle mixtures in the pipeline mode, hydrocarbon mixtures, such as natural gas liquids (NGLs), are modeled as a single component. In consultation with experts, the conservative approach is to use the single component that makes up the largest percentage of the heavier than air component of the mixture. In the case of CPPL pipelines, propane is consistently the largest single hydrocarbon component found in the NGL transported and was used for all modeling scenarios. A range of scenarios was used to establish an accurate but conservative buffer zone for the CPPL HVL pipelines. The range of conditions varied includes weather conditions and an analysis of transport mechanisms for HVL through waterways that potentially could reach an HCA.

The impact of a pipeline segment on an HCA is calculated every 30 meters and varies as a function of product characteristics, topography, and distance of the HCA from the pipeline.

The worse case result was .44 miles for Pasquill stability categories C, F, and G for pipelines 12 to 16 inches in diameter based on 507 Btu/ft2-hr heat of radiation from a late pool fire.

CPPL also looked at the location of their facilities to determine if they "could affect" an HCA. CPPL took an exception to the impact of an HVL release on a Drinking Water HCAs. This is discussed in detail below.

Exceptions for Pipeline Facilities Located within HCAs:

Based on dispersion modeling, CPPL has determined that where a Highly Volatile Liquid (HVL) release could reach a drinking water HCA, the HVL material released would not have a significant impact on that HCA. This is based on the physical characteristics of the HVLs that CPPL transports having boiling points that result in the product rapidly evaporating at atmospheric conditions. It is recognized that some HVLs (such as butanes) can pool during large releases when ambient temperatures are below the boiling point temperature of the material. However, based on the high vaporization characteristics, it is expected that a release that creates a liquid pool would leave an insignificant amount of hydrocarbon residue and thus no significant contamination.

Technical sources for determining an HVL's impact upon drinking water included Material Safety Data Sheets (MSDS) for each HVL and TOXNET's (Toxicological Data Network) HSDB (Hazardous Substances Data Bank). TOXNET indicated HVLs transported by CPPL are not considered to be an important fate mechanism in the environment including water. In addition, the specific MSDS information for HVLs manufactured and/or transported (except for crude butadiene) state the following: "There is no information available on the ecotoxicological effects of petroleum gases. Because of their high volatility, they are unlikely to cause ground or water pollution. Petroleum gases released into the environment will rapidly disperse into the atmosphere and undergo photochemical degradation" therefore no significant impacts is expected.

The MSDS information for crude butadiene revealed that no industry testing has been conducted as to any ecotoxicological effects. However, TOXNET's HSDB generalizes a release into water as not being an important fate mechanism and has yet to be quantified by the USEPA for drinking water. Therefore, it is CPPL's position that crude butadiene would not have a significant impact on drinking water HCAs.

CPPL has performed a literature search in an effort to identify technical support that a release of ignited HVLs would impact a water source either due to burned hydrocarbons or from fire-extinguishing chemical agents that may be used during fire fighting activities. Consultation was conducted with CPPL Environmental and Safety experts to determine if there were other information that would support or dispel the potential for HVLs to impact a drinking water HCA. MSDS sheets for Dry Chemical fire extinguishing agents were reviewed for testing data on impact to ecological receptors. It was found that the impact categories listed were either not applicable or no testing had been performed by the manufacturer. In absence of industry testing data and based on no knowledge of any HVL release that impacted a water source, it has been concluded that HVLs are basically clean burning hydrocarbons and any air contaminants by product due to fallout from firefighting chemicals would not be significant contaminate.

Identification of New "Could Affect" An HCA Segments

CPPL utilizes TranMap, a web based mapping application, to validate and review all identified HCA's that directly intersect or could affect company owned pipelines and facilities. TranMap was developed by CPPL in an effort to correctly identify and evaluate all company assets. TranMap is an AutoDesk Map Guide application that provides up to date information to CPPL personnel. This information includes, but is not limited to, the following key Company pipeline specific attributes:

- Centerline Location;
- Facility Location;
- Valve Location;
- Casing Location;
- HCAs (Includes buffered HCAs);
- Line Crossings;
- Aerial Alignment Sheets (PDF);
- Above Ground Reference Locations (AGRs).

CPPL's process requires that field personnel be involved in the periodic identification, review and validation of potential new HCAs. The most likely opportunity for field personnel to become aware of changes that may result in new or changing HCAs is through observation made during their routine operations and maintenance activities. Observations that could indicate the location of new or changing HCAs may include, but are not limited to:

- Population growth;
- Utility construction;
- Changes in the number of One Calls received;
- Other encroachments occurring along the pipeline rights-of-way (ROWs).

CPPL periodically evaluates and update the data it uses to identify HCAs. Primary focus is on changes that occur directly intersecting the pipeline, since this is the only time that field personnel become knowledgeable of changes to the land use our pipeline cross. When an individual, group, or division within CPPL becomes aware of changes that create or expand an HCA, the information would be reported to the Pipeline Integrity Group to be factored into the integrity assessment planning, risk analysis, and consideration of the need for additional preventive and mitigative risk controls. The location, including pipeline milepost and stationing, should be sent to the Mapping Group for comparison against current HCA maps. Newly identified HCAs or changes to existing HCAs are added to TranMap for Company use. For additional guidance on this procedure, see CPPL Transportation Pipelines and Terminals, Right-of-Way Encroachment Procedure, MPR-2701.

The Mapping Lead notifies the Pipeline Integrity Group of the new HCA segment. The IMP Engineer updates the AP History and Planning Document with the new information. The Integrity Engineer responsible for the line updates the BAP and identifies any additional verification digs that may be required. Incorporation of the newly identified HCA segment(s) into the BAP takes place within one year from the date the segment is identified.

Segment Identification Results

As of June 1, 2005, CPPL had identified 4629.93 miles of "could affect" an HCA pipeline segments in non-idle pipeline. Another 676.23 miles were identified in idle pipelines

2. Baseline Assessment Program:

The development of a Baseline Assessment Plan is discussed in Section 4.0 of the CPPL Integrity Management Program Plan. In 2003, CPPL was using the Pipeline Risk Assessments for Maintenance, and Inspection Decisions (PIRAMID) risk model to prioritize the former Conoco Pipe Line Company pipeline segments and Pipeline Risk Analysis System (PRAS) for the Phillips Pipe Line pipeline segments. CPPL has decided to use revised version of PIRAMID for risk assessments of all of its pipelines; however, at the time of the inspection only 75% of the Yellowstone pipeline system (6% of total pipeline system) had been analyzed using the revised PIRAMID. Prioritization of CPPL's pipelines for performing baseline assessments was still based on the use of separate models. This required an SME approach be used to determine the order in which pipeline segments should be assessed.

The use of PIRAMID and PRAS to perform risk assessments has been discussed in the reports created from the 2003 Integrity Management inspection. The discussion here will focus on CPPL's future plans for maintaining the Baseline Assessment Plan.

Baseline Assessment Schedule

CPPL will use the PIRAMID software as its primary tool to rank pipeline segments according to the risks associated with each segment. PIRAMID uses industry standard risk factors to prioritize segments for assessment and Preventive & Mitigative Measures purposes.

PIRAMID allows the pipeline to be segmented by HCA and then it identifies the risk driver(s) for each HCA segment within a piggable section. Using PIRAMID HCA segment results along with any other applicable risk factors not included in the PIRAMID risk analysis, the Integrity Engineer (IE) is able to consider all of the risk factors to determine ranking for each line segment that affects or could affect an HCA. The Integrity Engineer then schedules the highest risk segments first with consideration of operational downtime and resource availability as well as continued supply to customers and the public.

Hazardous liquid pipeline segments are divided into two groups according to their relative risk ranking and total HCA segment mileage. This is done by totaling the HCA segment mileage for all segments and grouping the segments into the top 50 percent risk ranked group and the bottom 50 percent risk ranked group ensuring the segments that present the highest risk to an HCA are identified.

Selecting the Assessment Method

ConocoPhillips Pipe Line (CPPL) conducts assessments of line pipe by:

- Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges, and grooves,
- Pressure test conducted in accordance with subpart E of CFR 49 Part 195 for hazardous liquid lines, or
- Other technology that CPPL demonstrates can provide an equivalent understanding of the condition of the line pipe. Use of this option requires notification to the Office of Pipeline Safety (OPS), State and/or local authorities prior to the assessment being performed.

Since most of the CPPL operated pipelines consist of relatively small diameter (12" and below) pre-1970s ERW or lap welded pipe, hydrostatic testing has been chosen as the primary method of performing a baseline assessment for these segments when they met the seam susceptibility criteria for baseline assessments. Primary seam defects currently identified for the pipe operated by CPPL are those due to manufacturing flaws such as hook cracks. In-line seam crack detection technology is currently only available in 10" and larger pipe diameters. CPPL is currently evaluating the use of this approved technology as an alternative to hydrostatic testing.

As a business consideration, CPPL evaluates if a corrosion tool or tools should be run in conjunction with the hydrostatic test to attempt to minimize hydrostatic test failures and therefore improve the efficiency of hydrostatic testing, optimize downtime required and repair costs, and improve the integrity of the pipeline. Of particular note to this course of action, some internal survey(s) that have occurred prior to March 31, 2002, will not be declared a baseline assessment due to the fact that, while older ILI inspections may provide information where likely corrosion failure could occur at hydrostatic test pressures, they may not provide reliable data due to the technology available at the time of the inspection, the completeness of the analysis of the tool data, and the interval of time that has passed to apply all of the IMP repair criteria. CPPL did use some assessments performed after January, 1996 but before March, 2002 as baseline assessments. Anomalies meeting the Integrity Management repair criteria in these baseline assessments were remediated in accordance with the IM rule requirements.

AP History and Planning Document

CPPL had planned to use the Assessment Plan (AP) History and Planning Review Process to facilitate and document the selection of appropriate inspection methods, tool types, assessment schedules and recommended preventive & mitigative actions. The Integrity Engineer (IE) along with the Integrity Review Team (IRT) uses the AP History and Planning process to select the specific inspection tool(s) for the baseline integrity assessment and re-assessment. Currently, the AP History and Planning documents are being created after the baseline assessment has been performed to determine the reassessment interval and to select the appropriate tool. Based on the current schedule for creating AP History and Planning documents, pre baseline assessment use of the documents will not occur until 2007. All of CPPL's pipelines that "could affect" and HCA will be assessed by March, 2008. Section 8.0, Data Integration, of the CPPL Integrity Management Program Plan details the process for data integration. CPPL is investigating the application of additional resources to expediting the review and approval of the 140 AP History and Planning documents that have been developed.

In general, CPPL compiles all available information regarding the integrity of the pipeline into the AP History and Planning Document to be evaluated during review cycles. All available information to identify integrity threats, including all completed and scheduled assessments, needed and/or completed repairs, corrosion control history, preventive and mitigative measures taken, future assessment plans and the associated completion dates are included in the AP document. The technical justification(s) for the re-assessment methods and intervals are recorded in this document as well. In the event that CPPL applies for a variance from the specified re-assessment interval, the technical justification and other documents supporting that decision will also be made part of the AP Document.

Baseline Evaluation Process

In conjunction with the AP History and Planning Document, CPPL uses a Baseline Evaluation Process for the selection of the appropriate assessment methodology. The criteria for analyzing pipeline segments is used as a resource during the evaluation process. The criteria includes checklists of the data and information to be reviewed to determine if the following threats are present in the pipeline segments being analyzed and whether these risk factors are detrimental to the integrity of the pipeline:

- Evidence of seam related defects or other cracking
- Evidence of metal loss, and
- Potential outside force damage.

The criteria for analyzing segments for evidence of seam related defects or other cracking focuses on risk factors that, in general, could be assessed using a hydrostatic test or a crack detection tool. The criteria for analyzing segments for evidence of metal loss (or past circumstances that could have caused metal loss) is focused on risk factors that, in general, could be assessed using a metal loss detection tool. The criteria for analyzing segments for potential outside force damage focuses on risk factors that, in general, could be assessed using a geometry tool.

The Baseline Evaluation Process consists of the following steps:

1. Verify that the results of all historical assessments have been integrated into the CPPL databases, risk models, and AP History and Planning Document as specified in Section 8, Data Integration, of the CPPL Integrity Management Program Plan.

2. Determine if the pipeline segment is susceptible to seam-related defects, using the Long Seam Susceptibility Criteria for Baseline Assessment Flowchart.

3. If not seam susceptible, or a crack tool will be selected, determine if the line can currently accommodate an ILI tool or can be modified, within reason, to accommodate an ILI tool.

4. If the line will be assessed using ILI:
    a. Select the appropriate tool(s) based on risk threats utilizing API 1160, Section 9.2, *Pipeline Anomalies and Defects* and 9.3, *Pipeline Internal Inspection and Testing Technology* and Table 9.1 – *Anomaly Types and Tools to Detect Them.*

5. Determine the need for running an ILI deformation tool using the Geometry Tool Decision Criteria Flowchart.

6. If the line will be assessed using hydrostatic testing, it shall be done in accordance with the provisions of Part 195 Subpart E.

7. Document the selected assessment method(s) and year in the BAP.

Assessment Results

Since September, 2003 to April, 2005, CPPL has conducted 67 baseline and continual assessments. As of September 30, 2004, CPPL had 4870.04 miles of "could affect" an HCA pipeline segments. They had assessed 2534.79 miles or 52.06%. They met the requirement to assess 50% of their "could affect" and HCA pipeline segments by September 30, 2004.

For assessments performed using an MFL tool, CPPL has chosen to run a gauging plate to ensure the MFL tool run will be unimpeded. If deformation is detected, CPPL will then run a geometry tool. If there is no deformation detected, CPPL will decide on the basis of the MFL tool run whether to run a geometry tool. If there are few deformation anomalies identified by the MFL tool, CPPL may chose to evaluate and remediate each anomaly. If there are a large number of deformation anomalies detected by the MFL tool, they would probably run a geometry tool.

In May, 2004, CPPL ran an Ultrasonic Crack Detection tool in the Buxton to Okarche pipeline section. The purpose of the tool run was to detect cracks in the longitudinal seam. No seam cracks were found; however, the UT tool did detect 21 cracks in the body of the pipe. CPPL was in the process of investigating these anomalies at the time of the inspection. Preliminary indications were that some of the cracks could be indicative of Stress Corrosion Cracking (SCC). CPPL is continuing to investigate these anomalies.

3. Integrity Assessment Results Review

The requirements for Integrity Assessment Results review are delineated in Sections 5.0 and 7.0 of the CPPL Integrity Management Program Plan (IMPP). Per Section 5.5 of the IMPP:

"The Integrity Engineer is responsible for the review and verification/correlation of the preliminary reports and the issuance of findings back to the ILI vendor for inclusion into the final report, if applicable. Upon completion of a tool run, the ILI vendor submits the preliminary report to the CPPL Integrity Engineer. When a separate geometry tool is run, the ILI Contractor may be used to generate one combined report or CPPL-AID (the **ConocoPhillips** Pipe Line Asset Integrity Database) is used to align MFL and Geometry features. The IE performs preliminary processing and analysis of the ILI Contractor's dig sheets. The process involves the identification of those immediate features that will be communicated to the field for further evaluation and repair. The IE follows the Preliminary Report Process and Procedure outlined in Appendix 5M, ILI Assessment Procedure, to review and verify the results.

When results are received in the form of a Final Report the IE will evaluate the data and charts according to the ILI Assessment Procedure, located in Appendix 5M, within 20 - 30 business days from receipt of the report. No later than 5 business days from receipt of the final report, the IE will determine if any additional immediate conditions, not reported in the Preliminary Report, exist and issue a Transmittal Letter to begin the dig program. Anomaly conditions will be categorized and an ILI Integrity Worklist Spreadsheet, Appendix 5D, prepared and distributed to the appropriate district individuals for remedial action. The field office receiving the notice of immediate repair condition will determine if the condition constitutes a reportable safety related condition, see MPR-3201, Safety Related Condition Report. "

Integrity Engineer Qualifications Requirements

Only qualified individuals shall review integrity assessment results, analyze information generated during integrity assessments, and define criteria for interpretation of inspection results. The training and qualification requirements for employees and their involvement and/or responsibilities are outlined in greater detail in Section 7, Qualifications and Training, of the CPPL IMPP. All personnel reviewing integrity assessment results will have specific training and/or experience to allow such evaluation.

A Qualification Needs Assessment (QNA) is conducted for each position associated with the IMP processes. The needs assessment is conducted by the Human Resources department or Director of Pipeline Integrity and includes the following elements:

- Job tasks relevant to the Integrity Management Program;
- Key skill areas required;
- Specific training and/or education necessary to perform the job function;
- Requisite experience necessary to perform the designated job function;

- Process for ensuring that additional skills and training are incorporated as identified

Copies of QNA for IMP-related functions are maintained with other IMP documentation by the Director of Pipeline Integrity and the assigned Human Resources representative.

The selection of personnel assigned to perform tasks covered by the IMP rule, are based on one or more of the following:

- General and pipeline specific background experience;
- Education and technical expertise;
- Task specific work experience; and
- Performance history

Documentation of education, work experience, industry training or evidence of qualification are maintained in the individual's personnel records for the time they are in the IMP role. Pipeline Integrity Position Charters and Resumes are located in Appendix 7B of the CPPL IMPP.

CPPL requires that personnel responsible for reviewing integrity assessment results have relevant pipeline operational experience (as defined in the QNA), such as in the areas of cathodic protection, hydrostatic test design, pipe strength evaluation, and applicable in-line and direct-assessment technologies.

Each qualified person must have training and/or industry recognized certification in respective areas of assigned review. It is not necessary for each candidate to be certified to review procedures outside of their specific area of responsibility.

CPPL requires individuals performing listed tasks to have a 4-year engineering or applied-science degree, or equivalent years training and experience in "Responsible Charge" of performing the listed or related tasks. In this context "Responsible Charge" means having primary responsibility for performing a listed or related task and accountability for the associated results.

Persons performing listed tasks must have at least 2 years work experience in performing the listed or related task either in "Responsible Charge" or under the direct supervision of a qualified individual.

Individuals not meeting the education, training, or work experience requirements cited above may be designated as qualified through a performance review process. The Director of Pipeline Integrity, in consultation with Human Resources, can confirm an individual's ability to perform an IMP task by any one of, or a combination of, the following:

- Written or oral examination, either in-house or industry recognized examination
- Work performance history review
- Observation during performance of the job, on the job training, or simulations
- Other forms of assessment

Vendor Qualifications and Specifications

Appendix 5H, Setup Project Work Order in SAP-PM and Issue PO's Procedure, of the CPPL IMPP includes a section entitled, Create Purchase Order, that describes the minimum requirements to be included in the scope of work for each ILI vendor. CPPL expects all subcontractors used by the primary ILI vendor to comply with the Terms and Conditions supplied to CPPL ILI vendors as part of their contract and purchase order.

The SAP Purchase Order states that CPPL relies on their qualified ILI vendors to interpret the raw ILI data and create a preliminary and final report. The SAP PO requires the vendor to provide the final report within 180 days after the tool has been received out of the pipeline. For the preliminary report, CPPL requires the ILI vendor to report the following immediate conditions within 14 days after the tool run is determined to be successful:

- MFL Tool Runs: All metal loss features greater than 80% wall thickness, all dents with metal loss above the 4 o'clock and 8 o'clock position of the pipeline and any other features that the vendor identifies as injurious to pipeline integrity.

- The IE may request the preliminary report submitted by the ILI vendor for MFL tools to include 20-30 additional external anomalies between 15-60% wall loss for correlations digs. The correlation features will be field evaluated and the data provided to the ILI vendor to help improve the vendor's log data accuracy before issuing the final report. In some cases CPPL will perform verification/correlation after the final report is received.

- Geometry Tool Runs: All dent features on the top of the pipe (above the 8 and 4 o'clock positions) exceeding 6% of the nominal pipeline diameter, and any other features that the vendor identifies as injurious to pipeline integrity.

In the assessments reviewed from September, 2003 to April, 2005, the vendors consistently met the requirement to delivery a final report within the 180 day timeframe. The vendors were also meeting the requirement to identify immediate repair conditions in the time frame specified by the Purchase Orders.

Calibration/Validation Digs

Inspection data obtained during an ILI run is subjected to the Dig Program Verification Procedure, Appendix 5N in the CPPL IMPP, which involves the evaluation of field data based on verification digs, historical digs, actual repair features and metal loss as compared to ILI log data. The results are used to verify the ILI vendor's detection capability and accuracy with regard to location and sizing. If accuracy is not within tool tolerances, the vendor will be required to re-issue the report or re-test the line.

Per CPPL's IMPP, while correlation digs are beneficial in determining the performance of an ILI tool, there may be situations where there are few anomalies reported by an ILI tool and no correlation digs are made. This is acceptable as long as the ILI vendor has a process to ensure that each tool is run through a series of pre-run and post run checks to verify that the variables established during the data calibration pull through are within a specified acceptable range.

Discovery

Discovery generally occurs when the IE has enough information; this may be after either the preliminary report or final report is received from the ILI vendor or after field verification. Discovery will be communicated on the date it occurs in writing by way of the issuance of a Transmittal Letter.

Discovery also occurs when adequate information about a condition is available to determine that a condition presents a potential threat to the integrity of the pipeline. Sufficient information must be obtained promptly to make this determination, but no later than 180 days after the integrity assessment has been performed unless it can be demonstrated that the 180-day period is impractical. The following are actions to be taken by the IE when the 180-day Discovery period cannot be met:

- The 180-day period will be exceeded due to the IE being unable to begin the Discovery review process. In this case, the IE will begin reducing the repair condition schedule by the number of days it takes to complete the review from the date the final ILI vendor's report is received.

- The 180-day period will be exceeded and any of the repair schedules cannot be met, in which case a pressure reduction will be implemented.

- The IE determines that it is impractical to meet the 180-day period, i.e. the ILI vendor's ability to provide a report within the 180-day period takes longer due to the complexity of the analysis. In this instance, the justification for why the 180-day period was exceeded will be documented in the Transmittal Letter.

Discovery of immediate conditions, as listed in the following sections, commonly occurs after Preliminary Reports are received while all remaining immediate, 60 day, 180 day and other conditions are discovered after Final Reports are received from ILI vendors. All of the discovery dates are clearly listed in the Transmittal Letter and the Required Repair Dates shown on the ILI Integrity Worklists reflect the individual discovery date of each feature. The discovery of a condition will be no later than 180 days after the successful completion of the assessment.

One issue identified, and discussed in Section 4.0 of this report, was the categorization of deformation anomalies found by the MFL tool. As mentioned, CPPL reserved the right to excavate these anomalies instead of running a geometry tool. In these cases there is insufficient information to categorize the anomaly until the excavation is complete. At times, when the anomaly is found to meet the immediate, 60 day, or 180 day repair criteria, discovery has exceeded the 180 day discovery period.

The CPPL IMPP requires that discovery of immediate repair conditions be identified when the preliminary report is received or within 5 days of receipt of the vendor's final report. Discovery of 60 and 180 day repair conditions are to be made within 20-30 business days of receipt of the vendor's final report.

In many cases it was found that the discovery (categorization) of 60 and 180 day anomalies was not occurring until the end of the 180 day discovery period rather than 20-30 days after receipt of the final report. This seemed to be a function of the large number of assessment results that had to be reviewed and the lack of resources within CPPL to perform those reviews. CPPL had dedicated four Integrity Engineers to the setup and review of ILI assessments and their results and one engineer to the setup and review of hydrostatic tests and their results.

The assessments where discovery was at the end of the 180 day discovery period are delineated in the table below. The transmittal letter date indicates when the ILI Integrity Worklist Spreadsheet was sent to the field to initiate repairs or evaluations and defines the date of discovery of a condition.

Categorization of Anomalies

The Integrity Engineer (IE) processes and analyses the ILI Contractor's electronic data to determine which features are integrity concerns. The **ConocoPhillips** Pipe Line Asset Integrity Database (CPPL-AID) and form GPL-513B, Addendum to GPL-513 for the Selection of Anomaly Features as defined by ILI Tool Vendors are used to assure consistent evaluation and categorization of features reported by the ILI vendor. In addition, the decision flowcharts found in Appendix 5F, Evaluations Based on Vendor Calls, are used to further evaluate additional features identified by the ILI vendor. The ILI vendor does not classify the features per the IM Repair Criteria, and the IE is required to classify the features. It was suggested by the Inspection Team that this requirement on the IE of classifying the features could be performed by the ILI Vendor and reduce the workload on the IE by making the IE's review a QA/QC step. CPPL disagrees with this suggestion feeling that if they provide the tool vendor with all the data required to prepare dig schedules and dig locations, the final reports would take longer to prepare adding time to how soon they would receive a report to take action, in addition they had discussed this approach with their vendor and found that they produce very few reports for customers that identify all IMP features indicating that most company do there own analysis.

All features that are determined to be integrity concerns, such as metal loss, dents and gouges detected by the ILI Assessment Procedure, Appendix 5M, and using CPPL-AID, are automatically and/or manually evaluated and are reported together with other pipeline anomalies such as pipeline fittings, in the ILI Integrity Worklist Spreadsheet, Appendix 5D.

The CPPL IMPP delineates the immediate, 60 day, and 180 day repair criteria of the Integrity Management rule. In all of the assessments reviewed that were performed from September, 2003 and April, 2005, no instances of an anomaly being mis-categorized were found where there was sufficient data in the ILI vendor's report to support categorization. It was found, as stated above, that for anomalies found by MFL tools, or gauging plates, there was insufficient data to categorize them immediately and categorization was not made until the anomalies were excavated. The Inspection Team also noted that CPPL does not include tool tolerance when categorizing an anomaly.

Pipeline Section	Final Report Date	180 Day Discovery Deadline	Transmittal Letter Date
Hardtner to MP271	12/14/03	6/11/04	7/9/04
Leeton to Harrisonville	7/19/04	1/24/05	1/24/05
Rosebud to Jefferson City	9/27/04	1/24/05	1/24/05
Harrisonville to Paola	10/5/04	1/25/05	1/24/05
Villa Ridge to Rosebud	9/7/04	1/24/05	1/24/05
Jefferson City to Syracuse	9/15/04	1/13/05	1/11/05
Kankakee to East Chicago	1/5/04	6/2/04	5/28/04
Chocolate Bayou to Webster	11/1/04	3/1/05	3/1/05
Austin to LaGrange	12/13/04	3/1/05	2/28/05
Brookshire to Sweeney	11/16/04	3/2/05	3/1/05
Fredricksburg to Austin	11/29/04	3/1/05	2/28/05
MP50 to Laverne	1/3/05	4/13/05	4/13/05
Villa Ridge to E. St. Louis	7/30/04	12/20/04	12/16/04
Coalinga to Rodeo	12/23/04	2/25/05	4/14/05
Archer #1 to Witchita Falls Terminal	3/1/04	6/6/04	6/6/04
Sneed to Borger	1/3/05	4/24/05	5/2/05
Rock Creek to Borger	12/3/03	4/20/04	4/19/04
Skellytown to Borger	1/3/05	4/26/05	5/16/05
Paola to Kansas City	1/27/04	6/18/04	7/21/04
Douglas to Wheatland	1/3/05	4/19/05	4/26/05
Sweeney to Pasadena	1/5/04	6/5/04	6/11/04
Odessa to Gaines	12/15/03	5/16/04	5/13/04
Canyon to MP250	1/15/04	4/26/04	4/27/04

In addition to anomalies that are in a "could affect" an HCA pipeline segment, that meet the immediate, 60 day, or 180 day repair criteria, CPPL identifies an extensive list of "other" conditions in "could affect" an HCA pipeline segments and anomalies in non impacting pipeline segments that meet the 60 day, and 180 day repair criteria as conditions that must be repaired within 12 months of discovery. Anomalies meeting the immediate repair criteria in a non-HCA pipeline segment, is considered a priority repair condition. After "could affect" an HCA pipeline segment anomalies are repaired, then priority conditions are normally addressed.

The "other' category includes:

- Data that reflects a change since last assessed
- Data that indicates mechanical damage on the top of the pipe (outside of the immediate repair and 60 day repair criteria)
- Data that indicates anomalies abrupt in nature
- Data that indicates anomalies longitudinal in orientation
- Data that indicates anomalies over a large area
- Anomalies located in or near casings, foreign crossings, areas with suspect cathodic protection.

The 12 month repair condition in non-HCA pipeline segments includes all repairs that meet the 60 and 180 day repair criteria. In addition, it includes:

- Inclusions
- Laminations
- Hard spots
- Puddle welds
- Close metal objects
- Touching metal objects
- Patches,and half soles, and
- Others

Hydrostatic Pressure Testing

Successful completion of 49 CFR 195 subpart E hydrostatic pressure test demonstrates the pipeline's integrity for that point of time. Analysis of test failures provides information on the condition of the pipe and the threats to its integrity. After failure results review, the IE is responsible for determining and documenting the cause of the test failure. ConocoPhillips maintains its own metallurgical laboratory in Bartlesville, OK and used by CPPL for performing metallurgical analyses of hydrostatic test failures. They also use third party facilities to perform metallurgical analysis.

The process used by CPPL to conduct hydrostatic testing involves the preparation of information and specifications by the Pipeline Integrity Group for implementation by Field Operations. The Integrity Engineer issues 2 main deliverables to the Project and/or Operations personnel who are responsible for implementing the hydrostatic test project:

1. Detailed Hydrostatic Testing Integrity Plan/Spreadsheet – This document is typically in the format of a spreadsheet that defines the hydrostatic test sections and target test pressures to be used for the hydrostatic test assessment project. The spreadsheet contains pertinent pipeline attributes and historical data for the specific pipeline system used in designing the testing plan.

2. Hydrostatic Testing Objectives Document – This document primarily defines the technical basis for selecting the test sections and pressures defined in the Detailed Hydro Integrity Plan/Spreadsheet. MPR-6105, Mainline Testing Procedure is the CPPL maintenance procedure that presents the general company guidelines and policies for mainline hydrostatic testing objectives. In addition to the testing requirements outlined in MPR-6105, the Hydrostatic Testing Objectives Document serves to provide additional explanation of the testing objectives, describes the technical basis for the objectives, presents any contingency plans associated with the test, and defines the acceptable pressure fluctuation limits. This document also outlines the contingency plans to be utilized in the event that a successful test cannot feasibly be achieved at the initial targeted pressures.

Successful specification of the hydrostatic testing integrity objectives for a CPPL hydrostatic test assessment project is dependent on the completion of the following primary execution steps:

- Gather all required data, including PODS elevations and pipe properties, leak history, past hydro test files, past metallurgical failure analyses and pressure cycle fatigue studies.
- Paste input data into hydro spreadsheet.
- Design the segmentation and pressure plan for the hydro test based on the company policies outlined in MPR-6105.
- Obtain District and Field reviews of the test plan (District Director, District Engineer, Area Supervisor, Project Engineer, and Construction Superintendent)
- Develop the hydro objectives document for each hydro project.
- Obtain approval of hydro documents from Director of Pipeline Integrity.
- Issue the hydro spreadsheet and objectives documents to the Project Lead.
- Place the hydro documents into the official electronic filing system, EDMS.

CPPL is performing spike tests when it is appropriate. The Objectives Document is used to determine if a spike test should be performed. The spike test, performed at 1.39 MOP for 20 minutes, is being used to justify longer retest intervals. Pressure cycle fatigue analyses are being performed on all LF ERW pipe. All seam susceptible pipe is run through Kiefner's decision analysis.

4.0 Remedial Actions

CPPL uses MPR 4103, General Line and Equipment Maintenance Evaluation of External/Internal Pipeline Defects and Anomalies, to select repair methods. The repair procedures contained in MPR-4103 are designed to provide the minimum guidelines for performing pipeline repairs on anomalies and defects.

CPPL utilizes the Transmittal Report as a tool to document discovery, capture the assessment results and disseminate the data to persons performing the field repairs. The Director of Pipeline Integrity or authorized representative is responsible for reviewing, approving and signing the report, before the results of the inspection/testing are sent to the field. The Integrity Engineer prepares a preliminary Transmittal Report to the field that includes the following hardcopy documentation:

- Summary of features requiring further evaluation
- ILI Analysis Checklist and Schedule
- ILI Integrity Work List Spreadsheet

Communications concerning variances, changes, site conditions and/or other issues that may affect the report continues between the field and the IE during the evaluation and repair phase. This continual communication also serves as a quality check on the assessment results. Communication is usually in the form of an ILI Integrity Worklist Spreadsheet, Appendix 5D in the CPPL IMPP, but could also include electronic, paper or phone communication.

The ILI Analysis Checklist, Appendix 5L, is used to communicate which features require further evaluation and/or mitigation and the appropriate deadlines for repair of these features. In the event that CPPL identifies an immediate repair condition in an HCA, the IE will provide sufficient information to the field operations personnel to allow for location and evaluation of the immediate repair and, if warranted, a temporarily reduction in the operating pressure of the affected pipeline will be initiated as described in the following section.

<u>The IE follows MPR-4104, Derating a Pipeline to a Lower Operating Pressure for operating pressure reductions or shutdowns for immediate repair conditions. This procedure provides a consistent approach for implementing a pressure reduction or shutdown after an assessment of the ILI tool vendor's preliminary or final reports.</u>

The Pipeline and Maintenance Leak Reports (PMLR), along with the ILI Integrity Worklist Spreadsheet, Appendix 5D, are used to track completion of repairs. Form 3933, Pipeline Maintenance & Leak Report (PMLR) and companion Form 3933B, Field Anomaly Evaluation are completed and submitted for any of the following tasks and distributed as detailed in MPR-2809, Instructions for Completing Form 3933 - Pipeline Maintenance & Leak Report (PMLR), and 2809 B, Instructions for Completing Form 3933B Field Anomaly Evaluation:

- Completion of repairs on a leak or break
- Reconditioning
- Inspection of Pipe
- ILI Feature Evaluation
- Tie ins of all types

- Lowering of lines
- Installing or removing valves
- Casing or protecting lines under roads or waterways
- Installing or repairing anodes, ground beds or test leads
- Welding collars or special connections on the lines
- Extending vents on casings
-

The IE monitors the results of the initial anomaly excavations performed on the pipeline. This is done through communications between the IE and the field operations personnel. Appendix 5D, ILI Integrity Work List Spreadsheet allows the IE to monitor the weekly progress at which the anomalies are being addressed and that HCA repair schedules are being met. Additionally, it provides information that allows the IE to create a Unity Graph to compare the dimensional characteristics of the anomaly measured in the field with the characteristics reported by the inspection tool.

In the event that the ILI Integrity Work List Spreadsheet does not show agreement between the tool report and the field measurements, then the IE communicates the findings to the Vendor and works with them to resolve the problem. Work stoppage may be required until Vendor results improve.

If the repair schedule cannot be met for any condition, CPPL will justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety. CPPL will notify OPS in accordance with Section 11.4.1.1 of this IMPP, Notifications, if it cannot meet the schedule and cannot provide safety through a temporary reduction in operation pressure or other action. CPPL will also notify appropriate state and local pipeline safety authorities when appropriate.

As has been noted in Sections 2.0 and 3.0 of this Summary Report, CPPL had chosen in some cases to excavate anomalies identified by the MFL toll as deformations in lieu of running a geometry tool. In some cases these digs are not conducted on a schedule consistent with an immediate, 60 or 180 day repair. In one case, the Rock Creek to Borger assessment, four deformation anomalies were identified by the MFL tool. They were excavated 7 months after discovery. When they were excavated, one of the anomalies was a dent with metal loss which is an immediate repair condition.

On 7/23/2003, the Villa Ridge to E. St. Louis pipeline section was assessed using a geometry tool, the tool measured depth but it could not give orientation. Twenty-four anomalies ranging from 6.31% to 25.9% were reported. Discovery was on 12/30/03 and the anomalies were placed in the 180 day repair category with a repair by date of 6/19/04. Since the orientation was unknown and all were above 6%, the anomalies should have been treated as immediate repairs and a pressure reduction taken until they could be evaluated. Pipe repair records did not list orientation and the measured depths, post evaluation, ranged from 2.8% to 10.44% which could place them in the immediate, 60 day, or 180 day categories depending on orientation. The repair dates ranged from 8/1/03 to 3/23/04 with some of the deepest dents not being evaluated until 2004.

5.0 Risk Analysis

The process for risk analysis is detailed in Section 3.0, Risk Analysis, of the CPPL Integrity Management Program Plan. CPPL performs risk assessments of both its pipeline and facilities. Pipeline risk assessment uses the PIRAMID risk model. Facility risk analysis is performed using a Process Hazards Analysis (PHA) approach.

PIRAMID is a licensed software package, designed to prioritize and optimize maintenance decisions. PIRAMID is a risk estimation model that calculates failure probabilities and consequences. The failure probabilities are developed using a combination of adjusted failure rate and structural reliability algorithms.

The consequence of failure model uses an event tree approach. The impact of small, medium, and large ruptures is determined based upon historical data and consequences are determined based on the High Consequence Area impacted.

CPPL's objectives in using PIRAMID are:

- Risk rank pipeline segments that could affect HCAs by HCA segment results
- Identify the significant risk drivers for each HCA segment
- Evaluate the effectiveness of existing preventive and mitigative measures
- Compare various additional preventive and mitigative measures in an effort to reduce the risk of failure
- Support the development of integrity assessment schedules; and
- Support the maintenance budgeting process

PIRAMID currently has 6 major failure causes, These are:

- Equipment Impact (Outside Force and Third Party Damage)
- External Corrosion
- Internal Corrosion
- Manufacturing Cracks
- SCC
- Geotechnical

On the consequence side of the model, PIRAMID considers the impact on public health and safety and the environment. Financial losses are not considered. The output of the consequence model assigns severity points/unit length to the output parameter. Total risk is expressed in the point/segment year.

CFER will be updating PIRAMID in 2005 to add additional failure causes. These are:

- Operator/Procedure Errors

- Equipment Failure
- Construction Errors.

PIRAMID was previously used by Conoco Pipe Line Company and PRAS was used by Phillips 66 Transportation. ConocoPhillips Pipe Line Company has since opted to use a revised version of PIRAMID for all of their pipelines. CPPL has currently undertaken an effort to reanalyze all of their pipeline systems. Of a total of 44 pipeline systems, CPPL, at the time of the inspection, had completed reanalyzing 75% of the Yellowstone Pipeline system (6% of their total pipeline system). The risk assessment of a pipeline is dependent on the "could affect" an HCA segment identification process that is also in progress (see the discussion in Section 1, Segment Identification) and the revalidation of all of the input in the risk model for each pipeline system.

PIRAMID was developed by C-FER Technologies utilizing historical industry data. With this data, C-FER developed a referenced pipeline with a set of attributes, along with the probability and consequence of failure for that referenced pipeline. The user's input attribute data is then compared against the referenced pipeline, and through statistical and quantitative analysis, the results are calculated.

CPPL ran several pilot studies and analyzed the results of the risk analysis using the data in the PIRAMID Equipment Impact module. Results from this analysis indicated probabilities of failures that were much higher than CPPL had historically seen. As a result, revised pipeline failure probabilities, along with leak history was supplied to C-FER to redefine the referenced pipeline pipe associated attributes.

CPPL also went through a process of validating the input variables (attributes) used in PIRAMID. PIRAMID has a set of required attributes and an optional set of attributes. The CPPL PIRAMID model has 59 required attributes and 17 optional attributes.

The required attributes are in the areas of:

- Corrosion
- Geotechnical
- Land Use
- Right of Way
- Public Awareness
- Pipeline physical characteristics
- Foreign line crossings
- Geotechnical

The optional attributes are related to:

- ILI Assessments
- Hydrostatic Pressure Tests

Required attributes must be populated with data, and optional attributes are not required to be populated with data.

Attribute data is obtained from various sources such as the Pipeline Open Data Standard (PODS), 3rd Party databases, or field interviews. Prior to loading the data into the program, it is verified to be the most current data available for that asset. Should it be determined that the data does not represent the most current information available, then the most current information is requested from the appropriate source.

CPPL has identified which attributes exist in PODS. Additional databases such as Land Use, Soils, Heating Degree Days, and Geotechnical were obtained to satisfy most of the attributes. Conducting field interviews populates the balances of the attributes. Appendix 3A, Pipeline Risk Assessments for Maintenance and Inspection Decisions (PIRAMID), Input Data provides detailed listing of the attribute data utilized in this process. The table provides a description of the attribute, choices that are available, where the data for the attribute can be sourced, along with some other general information pertaining to the attribute. Where defaults or assumptions are made concerning attributes, this is noted in the table.

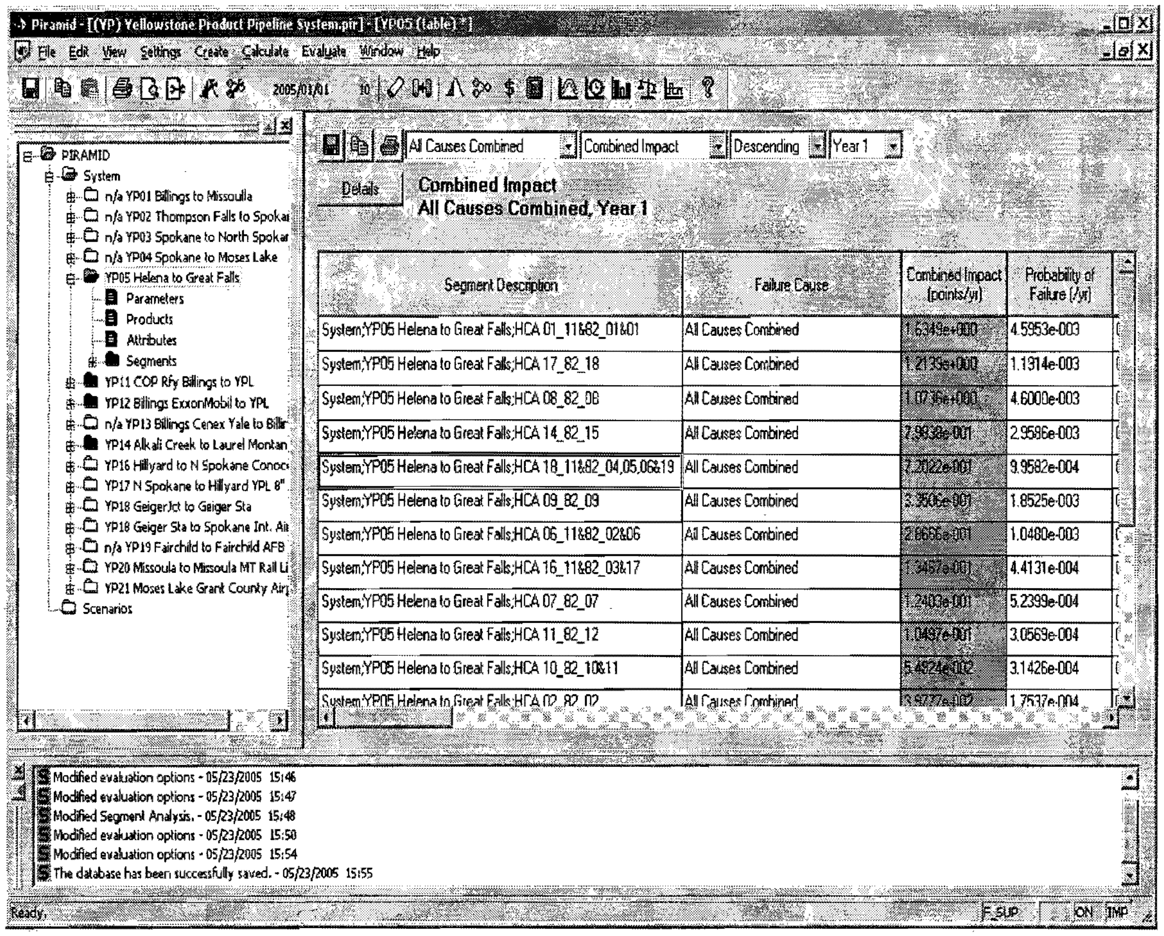
Information needed for the consequence analysis is also input into PIRAMID. This includes pipeline product data and meteorological information on wind direction and temperatures.

PIRAMID uses dynamic segmentation. A new segment starts each time there is a change in an attribute. The attributes for any one pipeline segment are constant. This can result in segments that are very long as well as very short depending on the frequency with which an attribute changes. PIRAMID output parameters (Combined Impact Numbers and Probability of Failure) are calculated, respectively, for each section within a HCA segment and then weighted on an annual per-segment basis. Combined Impact Numbers, the sum of all risk factors for a HCA segment, are sorted in descending order, thereby listing the highest risk HCA segments first. An example of the segment analysis report is presented below.

PIRAMID output parameters (Combined Impact Numbers and Probability of Failure) by default are displayed in a segment analysis with a combined output for all failure causes. By changing the segment analysis to display the results individually by failure cause, the user can then determine the dominant risk factor of the HCA segment by identifying the failure cause with the highest result.

The results of the risk analysis are reviewed by the Integrity Review Team (IRT - see Definitions Section) to validate that the output reasonably represents all applicable risk factors.

- If the IRT identifies unreasonable or unrealistic results from the risk analysis tool, the input attributes and model settings are reviewed to identify the error in the analysis or to incorporate considerations/risk factors that are not adequately represented by the model.
- If additional considerations/risk factors are identified (e.g., segment specific leak history data), the IRT decides the course of action to properly integrate the additional considerations with the risk analysis.



Once per year, not to exceed 15 months, results from integrity assessments, HCA boundary changes, major maintenance and IMP P&MM activities that have been completed, are updated in the PIRAMID files. Prior to conducting an HCA Integrity assessment, other attribute data are verified, and if there have been any changes, these are incorporated into the files. The files are then re-analyzed to ensure there have not been any major changes in the risk resulting in a change of the overall risk ranking or the dominant risk factor.

For non-pipe facilities, CPPL uses a Process Hazards Analysis (PHA) to determine the risks that must be addressed. CPPL uses the Process Hazards Analysis (PHA) procedure, described in Section 3.0, Risk Analysis, to identify and implement risk reduction measures for non-pipe facilities. All non-pipe facility PHAs are scheduled and conducted by the Health, Safety and Environmental, group of CPPL, typically on a five-year basis. Some non-pipe facilities may have the potential to impact HCAs. In order to determine which non-pipe facilities are included in the PHA process, an initial comparison of HCAs and covered non-pipe facilities are conducted. The Integrity Engineer responsible for IMP Coordination, or their designee, contacts the PHA coordinator to obtain a listing of non-pipe facilities undergoing PHAs. The list includes facility name, location, type and sub-listing of nodes for that facility. The IMP Engineer will compare the PHA locations to identified HCAs.

Each facility is broken into nodes that specify a particular area or operational aspect of the facility. Using the HAZOP methodology of node evaluations, the Team evaluates various operational scenarios in an effort to identify measures that would enhance the safe operation of the facility and minimize the risk associated with events that could have an adverse affect on personnel, the environment and surrounding community (HCAs). A Priority Risk Ranking Matrix is employed to evaluate risk rank recommendations that have the highest potential to reduce risk. CPPL District Directors responsible for the facilities prioritize risk-ranked items for scheduling and implementation. An implementation due date and responsible person is assigned to each item, which is tracked through the budgeting process until completed.

The Inspection Team noted that CPPL was still using the results of two separate risk models to prioritize their pipelines for assessments and that development of PIRAMID as the single risk model was behind schedule due to the new segment identification process being behind schedule and a lag in data collection.

6.0 Preventive and Mitigative Measures

CPPL uses the AP History and Planning document, and the updated risk models in PIRAMID, as the basis for evaluating the risks associated with each HCA segment. Because each AP History and Planning document lists each "could affect" line segment, and it contains all the historical information on assessments, repairs, and incidents, the AP History and Planning document provides the most current information available on any given line segment.

Output from the PIRAMID risk analysis, (see Section 3.0, Risk Analysis, of the CPPL IMPP), is displayed as a Combined Impact number and the Probability of Failure. The Combined Impact number is the risk score that includes the Consequence result and the Probability of Failure occurrence. HCA Segments whose risk is based on consequences are evaluated for mitigative measures. HCA Segments whose risk is based on probability are evaluated for preventive measures. In each case, various measures are postulated and "what if" scenarios (worst-case as well as those most likely) are evaluated using the PIRAMID software to determine their affect on risk.
The various elements considered as applicable in this evaluation could include, but are not limited to, the following:

- Terrain surrounding the pipeline segment (including drainage, small streams, and smaller waterways that could act as a conduit to a HCA),
- Elevation profile,
- Characteristics of the product transported,
- Amount of product that could be released,
- Possibility of a spillage in a farm field following the drain tile into a waterway,
- Ditches alongside a roadway the pipeline crosses,
- Physical support of the pipeline segment such as by a cable suspension bridge,
- Exposure of the pipeline to operating pressure exceeding established maximum operating pressure,
- External and internal corrosion,
- Third party damage,

- Operator or procedures error,
- Equipment failures,
- Natural force damage,
- Stress corrosion cracking,
- Materials problems,
- Construction errors,
- Various operating modes,
- Population impacts,
- Environmental damage,
- Property damage.

Potential improvements evaluated are those which reduce the consequence and/or probability of a pipeline failure (i.e., a release). Possible P&MMs include, but are not limited to, the following:

- Installing or modifying emergency flow-restricting device (EFRD),
- Improving leak detection,
- Improving training on response procedures,
- Conducting emergency response drills with local emergency responders,
- Improving management controls,
- Damage prevention enhancement,
- Increased monitoring or application of cathodic protection, and
- Shorter inspection intervals.

CPPL has developed and implemented standard preventive and mitigative maintenance programs to reduce, eliminate, or control risks associated with their pipelines. The following is an overview of the programs and/or processes that are part of the existing P&MM effort:

- Span and exposed piping Inspection
- Aerial and foot patrols
- Public Education
- Microbiological Influenced Corrosion Monitoring and Control
- Cathodic Protection
- Internal Corrosion Monitoring and Control
- Overpressure Protection
- Block Valve (EFRD Upgrade) Program
- Depth of Cover Monitoring

- Excavation Risk Management
- Emergency Response
- Geotechnical Hazards
- Leak Detection Capabilities and Effectiveness
- Near Miss and Incident Investigations

During the AP History and Planning document review process, each HCA segment is evaluated to verify that all of the Threat Prevention and Repair Methods listed in Appendix 6D of the CPPL IMPP are being utilized, if applicable. In addition, the PM&M evaluation portion of the AP History and Planning document review serves as the basis for determining if additional P&MM's need to be employed, or if existing programs need to be improved to manage the specific risk drivers identified by the current assessment. This is achieved by evaluating data from the integrity assessments, risk assessment and AP History and Planning documents as outlined in the Flowchart to Evaluate Preventive and Mitigative Measures in Appendix 6C of the CPPL IMPP.

IMP regulations require that additional preventive and mitigation measures be considered. This includes mitigation measures that would reduce the risk associated with not just a pipeline release, but also a release from pipeline associated equipment such as pumps, transfer lines and valve stations. Utilizing information from the Risk Analysis process, integrity assessments and the AP History and Planning document, CPPL conducts a risk based evaluation of other P&MMs that could reduce the impact of a release on HCAs. Other P&MMs that are considered include, but are not limited to, the following examples:

- Enhanced monitoring of cathodic protection
- Improved damage prevention programs
- Depth of cover surveys
- Upgraded facility security
- Increased ROW surveillance
- Shorter integrity assessment intervals

In general, the results of the risk analysis process are reviewed to identify the most significant risk drivers for the pipeline segments that could affect an HCA. Operations and Maintenance personnel are then consulted to identify the existing P&MMs in place to address the risk drivers as well as any additional P&MMs to be considered. Once the existing and additional P&MMs are identified, the Integrity Review Team evaluates the benefits to be expected from these measures and documents those providing significant benefit into the AP History & Planning document. It is the responsibility of the IRT to include the pipeline integrity & reliability (PIR) related P&MM actions in the next applicable budget cycle for review.

The Inspection Team felt that the identification of Preventive and Mitigative measures was behind schedule because development of AP History and Planning documents, a key factor in the identification of P&M measures, was behind schedule. In addition, CPPL had not demonstrated that heritage P&M programs are sufficient to protect HCAs.

Leak Detection Evaluation

CPPL has developed guidelines for evaluating the effectiveness of existing leak detection systems and ways in which they may be enhanced to protect HCAs. Appendix 6A in the CPPL IMPP, Process for Evaluation of Leak Detection Capability, and Appendix 6C, Flowchart to Evaluate Preventive and Mitigative Measures serve as the basis for these evaluations. In addition to procedures aimed at evaluating the effectiveness of existing surveillance and monitoring efforts, CPPL has established guidelines detailing the actions and reactions that operations' personnel are expected to take in the event of a potential release. Appendix 6E, Operator Reaction Documents, provides examples of the type of guidelines provided for pipeline operators in the event of a potential release. Together, these guidelines provide the foundation of CPPL's leak detection system and provide a means for continually evaluating and upgrading the system to protect HCAs

CPPL reviews the existing leak detection methods for each segment in accordance with the above mentioned guidelines and in conjunction with results from the Risk Analysis process (PIRAMID) and information recorded on the AP History and Planning document.

Additionally, the need for a re-evaluation may be triggered as the result of identified changes to operations, changes to HCAs and/or the identification of improvements to available leak detection systems. During the review process to ensure that the established leak detection system is adequate, the following factors are considered:

- Results of the consequence analysis,
- Length and size of pipeline,
- Type of product carried,
- Proximity to the HCA,
- Speed of the leak detection,
- Leak history,
- Transient nature of the pipeline and
- Whether or not the pipeline is often blocked in.

After evaluation, CPPL applies the appropriate leak detection technique(s). The various types of leak detection methods currently supported within CPPL include:

- Visual observation,
- Field detection sensors,
- Transient Model Leak Detection (TMLD),* and
- Compensated Line Balance Leak Detection (CLBLD).

Leak detection improvements identified by this process are evaluated based on the amount of risk reduction achieved. PIRAMID input variables are updated with the enhanced leak detection system information, and the resulting changes to the risk profile are evaluated in an effort to determine the amount of benefit received from the upgrades. The leak detection methods and frequency of inspection that are currently being used on each of the pipeline segments are identified in files that have been uploaded to the Integrity Management Database (IMDB) - http://primis.phmsa.dot.gov/imdb/.

CPPL evaluates the following factors when considering the spectrum of leak detection scenarios:

- Current leak detection method in use for HCA areas,
- Use of SCADA,
- Thresholds for leak detection,
- Flow and measurement pressure,
- Specific procedures for lines that are idle but still under pressure,
- Additional leak detection methods for areas in close proximity to sole source water supplies,
- Idle lines,
- Slack condition,
- Evaluation of leak detection performance under transient conditions,
- Evaluation of the operational availability and reliability of the leak detections systems,
- Evaluation of the operator's process to manage system failure,
- Considerations of enhancements to existing leak detection capability.

CPPL is currently in the process of having competing firms develop software that will improve their leak detection capability. The Yellowstone Pipeline System has been selected as a test site for the software packages. The Yellowstone Pipeline System was chosen because CPPL is required to have a system capable of detecting a leak of 1%. Once a vendors leak detection package has been selected the leak detection capability will only be applied to those HCA segments that are identified as needing more than volumetric leak detection accuracy through the Leak Detection evaluation process. Upgrades of instrumentation may be needed in some cases to meet the software's accuracy requirements where a higher level of leak detection accuracy has been determined. The final decision on the software vendor is expected to be made in late 2005.

Even with new SCADA software being developed, the inspection team felt that CPPL had not performed an evaluation of their leak detection system in accordance with the IM rule and as outlined in their IMPP.

EFRD Evaluation

CPPL has established processes for evaluating the effectiveness of existing EFRDs as well as the need for adding new ones. CPPL's Block Valve Upgrade Program and TSD-3203, Mainline Block Valve Standard, are part of the Asset Integrity Program and form the basis for consistent application of these evaluations.

The following general areas are addressed as part of TSD 3203 - *Mainline Block Valve Standard*:

- Addition of new or relocation of existing block valves,
- Addition of new remote actuators,
- Replacement of certain models of valves that are found to be problematic and
- Relocation of buried valves to above ground locations to improve access during emergency response.

When evaluating the effectiveness of existing EFRDs and the need for additional ones, the Technical Services Engineer (TSE) responsible for the program begins the process by requesting a list of potential valve upgrade sites from the various operating districts. Using TSD-3203, Mainline Block Valve Standard, as a guide, the district representative compiles a list of potential sites and forwards to the TSE. Once the TSE has received the listings of proposed sites he confirms that they meet the criteria listed in the standards mentioned above.

An established risk ranking procedure is employed to maintain consistency across the various operating districts. A relative risk number is assigned to each proposed site and the modification/installation is prioritized based on the assigned risk ranking. The Integrity Management rule requires that the following factors be considered when conducting the risk-based evaluation of the EFRDs:

- Type of commodity carried,
- Rate of potential leakage,
- Volume of the potential release,
- Topography or pipeline profile (captured in HCA "could affect" analysis, see IMP Section 2, *HCA Identification*),
- Potential for ignition,
- Proximity to power sources,
- Location of the nearest response personnel,
- Proximity to HCAs,
- Specific terrain between the pipeline segment and high consequence area,
- Results of the consequence analysis and
- Benefits expected from spill size reduction.
- Relative reliability of existing or proposed EFRDs,
- Relevant operating modes beyond nominal full flow conditions,
- Risk analysis results, including identification of highest-risk segments,
- System detection times, operator response times, remotely controlled valve response characteristics, and system isolation time,

- Need for additional EFRDs to respond to releases during transient conditions, and
- Potential effects of additional EFRDs.

When the evaluation process is completed and the potential valve upgrade sites are identified and prioritized, it is the Technical Services Engineer's responsibility to ensure that these P&MMs are submitted for consideration during the CPPL annual budget cycle. If approved, the applicable district or project personnel are responsible for ensuring that the identified valve/EFRD enhancements are implemented.
The Inspection Team noted that CPPL had not conducted an EFRD evaluation as outline in their IMPP. CPPL intends to perform a sensitivity analysis, using EIM, to determine where additional EFRDs might reduce risk.

7.0 Continual Process of Evaluation and Assessment

CPPL uses the AP History and Planning review process to determine and document the re-assessment intervals for each covered pipeline segment. Once the assessments (baseline, re-assessments or other mitigative-type inspections) are complete and the AP History and Planning documents updated, the Integrity Engineer and Integrity Review Team use the process described in Appendix 4J, AP History and Planning Document – Creation, Preparation & Review and illustrated in Appendix 4H, Assessment Plan History & Planning Document Example to review the lessons learned and benefits of the assessments to determine the type and frequency of future assessments. This review process is typically done from 1 to 18 months after each integrity assessment.

Assets with active modes of deterioration (e.g., external and internal corrosion, fatigue cracking) may necessitate a shorter re-assessment interval than assets without them. Examples of factors that are considered when determining the re-assessment interval include, but are not limited to, the following:

- Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate
- Pipe size, material, manufacturing information, coating type and condition, and seam type
- Leak history, repair history, and cathodic protection history
- One call activity and 3rd party damage history
- Product transported
- Consequence of failure analysis
- Operating stress level
- Existing or projected activities in the area
- Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic)
- Geo-technical hazards
- Physical support integrity of the segment such as by a cable suspension bridge

CPPL currently does not use a "defect growth rate" factor, however, corrosion remaining strength calculations are base on the most conservative B31G method. This approach accounts for some corrosion growth based on fewer anomalies remaining than if a less conservative method was used such as B31G Modified. The number of leaks that have occurred since the last internal inspection and the adequacy of the corrosion protection program are evaluated to determine if historical performance should dictate a shorter reassessment interval.

Unless evidence of one or more of the following: active corrosion, CP histories, assessment results (such as anomaly quantity and significance), micro-biologically induced corrosion (MIC), leak history or results of other methods used to quantify the corrosion or crack growth severity indicate that a shorter interval is appropriate, the current CPPL policy is that re-assessment intervals default to 5 years for hazardous liquid lines. This is based on the technical analysis that supports CPPL's policy to repair to B31G criteria, which provides for sufficient corrosion growth over other acceptable recurring strength calculation (RSC) methods.

The inspection team felt that B31G may not be conservative in all cases, especially for wall losses greater than 45 to 50% and long defect dimensions. The inspection team felt that CPPL should consider defect growth rate when determining reassessment intervals, especially as a history was developed based on consecutive ILI tool runs. CPPL considers crack growth in their IMP for those lines deemed susceptible to cracking (e.g., pipelines susceptible to seam integrity issues receive pressure cycle analysis and lines susceptible to SCC are being inspected with UT crack tools). CPPL has already ran UT crack detection tools on some of their pipelines including the Buxton to Okarche pipeline as discussed in Protocol 2.

As previously stated, CPPL was running geometry tools if the MFL tool identified a considerable number of deformation anomalies. In some instances the time between an MFL tool run and a geometry tool run could exceed 180 days. When the second tool run was greater than 180 days the first tool run was used as the basis for establishing the reassessment schedule. When the second tool run was less than 180 days after the first tool run, the date of the second tool run was used to establish the date of the reassessment. The Inspection Team was not comfortable with this approach and CPPL agreed to use the date of the first tool run when the time between tool runs was greater than 30 days.

8.0 Program Evaluation

CPPL considers evaluation of the IMP and associated management systems as critical to improving the performance of CPPL and help answer the following questions:

- Were all integrity management program objectives accomplished?
- Were pipeline integrity and safety effectively improved through implementation of the IMP?

Overall Program goals and performance measures are established by the Asset Integrity Management Team on an annual basis for a wide range of integrity issues or concerns for CPPL, the Director of Pipeline Integrity is a team member and communicates and uses the Integrity Management Program status and results of previous assessments, audits and evaluations as guidelines for consideration by the team. Initial program goals are established to benchmark the program against current standards and define timeframes for additional work to be accomplished. As the program matures and more is learned about the integrity of individual assets, segment specific goals and measures are included in the program. Examples of the goals the Asset Integrity Management Group sets are as follows:

- Reduce the total volume of unintended releases with an ultimate goal of zero;
- Document the percentage of integrity management activities (e.g., implementation of identified Preventive and Mitigative Measures) completed during the calendar year as compared to the initial set of objectives;
- Track and evaluate the effectiveness of the community outreach activities and
- Prepare a summary of performance improvements, both qualitative and quantitative.

CPPL identifies performance measures that allow CPPL's staff to evaluate the performance of the Integrity Management Program. The measures are used to demonstrate that the IMP is effectively controlling risk on pipeline segments that could affect an HCA.

Performance measures generally fall into three categories:

- Process Measures;
- Deterioration Measures or
- Failure Measures/Leak History

Process Measures are those that monitor the surveillance and preventive activities CPPL has implemented. These measures are used to indicate the success of CPPL in implementing the various elements of its IMP. Process measures are often referred to as "Leading" performance measures as they are directed toward preventing releases and failures from occurring. Leading measures are proactive and provide an indication of how the plan may be expected to perform.

Deterioration measures are operations and maintenance trends that indicate when the integrity of the system is weakening despite well-executed preventive and mitigative measures. Deterioration measures can give a sense of how well the pipeline system is responding to the IMP.

Failure Measures include leak history, responses to incidents, and product loss. These measures indicate progress towards fewer spills, less damage, faster response and more effective cleanup. Failure measures are also known as "Lagging" measures as they are in response to a release or failure. Lagging measures are reactive and may provide an indication of past integrity management performance limitations.

CPPL currently tracks 15 performance measures. These are:

- Reduce the total volume from unintended releases of pipelines located in HCAs.
- Reduce total number of unintended releases of pipelines (based on threshold of five gallons) located in HCAs
- Reduce total number of unintended releases at Pump Stations and Terminals (based on threshold of five gallons) located in HCAs

- Number and type of releases per mile against pipeline industry benchmarks
- Number of releases caused by Operator error
- Miles of pipe assessed by hydrostatic testing (actual vs. scheduled)
- Number of failures per hydrostatic test (per mile)
- Mile of pipe assessed by Inline Inspection devices (actual vs. scheduled)
- Number of metal loss anomalies found requiring repair in HCAs
- Achievement of API-653/5210 goals (planned vs. completed)
- Effectiveness of CPPL's public awareness program (number of 3rd party hits on pipelines)
- Types of failures to establish trends and effectiveness of assessment tools
- Summary of performance improvements
- Number of pipeline P&M activities scheduled vs. completed
- Number of non-pipeline P&M activities scheduled vs. completed.

Program Evaluation

Periodic reviews of the Integrity Management Program are conducted by the Integrity Management Group in order to comply with 40 CFR 195.452. This review includes an analysis of the Performance Measures that are being tracked. The Integrity Management Group meets annually to evaluate the progress of CPPL's IMP. At a minimum, the following is reviewed:

- CPPL's IMP goals and objectives;
- IMP documentation;
- Changes to CPPL's IMP since the last review session;
- Status of any changes to the Integrity Management rules (see 49 CFR 192, Subpart O and 49 CFR 195.452)
- Comparison of CPPL's actual performance to the documented performance objectives;
- Identification of necessary follow-up or improvement opportunities;
- IMP evaluations conducted since the previous annual review, including review of the effectiveness of corrective action and follow-up measures;
- Current status of action plan developed during the previous annual review; and
- Communication of changes in the program to affected employees.

At the end of the review session, information is complied and the Integrity Management Group evaluates the organization's status against the prior year's goals and establishes the appropriate performance measures for the upcoming year. The lessons learned and performance measures are documented and communicated throughout the organization via a formal report.

Program evaluation also uses internal and external comparisons. Comparing data from the pipeline segments affecting HCAs with that segment's performance data and that obtained from pipeline segments in other areas of CPPL's system can be used to indicate the effectiveness of the IMP. At a minimum, the following annual program measurements are made and documented:

- Number of miles (HCA and non-HCA) of pipeline inspected and tested;
- Number of immediate conditions found and repairs completed as a result of the IMP inspection;
- Number of all scheduled conditions found and repairs completed as a result of the IMP inspection and
- Number of leaks, failures and incidents.
- Primary root cause of leaks, failures, and incidents

Collecting data external to the CPPL pipeline systems provides information on how CPPL's IMP efforts compare to other operating companies. These data also allow periodic comparison of CPPL systems to the pipeline industry as a whole. The Director of Pipeline Integrity and the Integrity Management Group utilizes industry reports and/or findings published by the Association of Oil Pipelines (AOPL), American Petroleum Institute (API), Pipeline Performance Tracking System (PPTS) and DOT's Annual Pipeline Safety Report to compare performance metrics.

Root Cause Analysis and Lessons Learned

CPPL uses identification of the root-cause(s) of incidents, releases, near misses, or other unplanned events to provide a direct indication of the items that require attention within CPPL systems. When pipeline failures or damage occurs that could affect an HCA, CPPL root-cause analysis method is applied and root cause(s) affecting pipeline integrity documented. Root cause methods can be performed by metallurgical analysis of the failure or use of more structured methods such as TAP Root when operational errors were involved or the results of equipment or pipe failure analysis are inconclusive as to the cause.

Based on identified integrity related root cause(s), specific corrective action items are established and implemented to prevent the recurrence. Each corrective action is assigned to a specific individual or group with responsibility for implementation. Corrective actions are documented in the AP History and Planning Document and reviewed by the Integrity Review Team during the AP document review. CPPL Transportation HSE Incident Notification and Investigation Policy documents the conditions that trigger and guidance for performing a root cause analysis of any applicable pipeline failure or incident. HSE Incidence/Near Miss reports are stored in IMPACT and are reviewed for any adverse trends.

Identification of the integrity related lessons learned from incidents, near misses, releases, or other situations both within and outside the CPPL organization is a key element in the continuous improvement of CPPL's IMP.

Lessons learned can come from a variety of sources, including:

- Action items from near miss and/or incident reports;
- Action items from internal/external system evaluations or compliance reviews;
- Action items from regulatory reviews;
- Reports of incidents along the pipeline;
- Reports of incidents from other pipeline operators;

- Reports from industry association such as API, AOPL, NACE, PRCI
- Reports from governmental sources.

Reports are periodically evaluated for their applicability to pipeline system integrity. If the report indicates that a similar action and/or reaction could have occurred within CPPL system, the lesson learned is evaluated in the context of whether cause could be experience by the company or indicates a gap in the IMP and then communicated to those levels of management that have the direct responsibility for implementing appropriate actions. Applicable lessons learned are included in the annual review of CPPL's IMP and the associated annual report.

The Inspection Team noted that CPPL is addressing issues in Program Evaluation based on enforcement actions from the 2003 inspection; however, the Inspection Team was not provided sufficient information to determine the adequacy of the IM Program because many process were still not fully mature.

OPS Feedback at Exit Interview

OPS Inspection Team provided the following feedback to CPPL's Integrity Management Team and Corporate Management:

General Observations

1. OPS notes that CPPL has made significant progress in developing the process required to successfully implement their Integrity Management Plan since the 2003 Integrity Management inspection. The Enforcement resulting from the previous Integrity Management inspection in 2003 (CPF 3-2004-5013) is still open and OPS anticipates a final order being issued in the near future. This open enforcement resulted in many changes to the IMP processes and this inspection provided additional guidance to ensure the revised processes include all of the required elements and that they will be completed in a timely manner.

2. The Inspection Team noted many instances when completion of tasks outlined in the IMP would not be completed for several years. The recent completion of revisions to the PIRAMID risk analysis model, use of Eagle Mapping technology to determine pipeline segments that can affect an HCA, and finalizing of AP History review process has created a cascading affect that has resulted in CPPL being behind the industry in implementing key elements of their IMP. Appropriate resources must be dedicated to expedite completion of fundamental elements of the IMP in order for CPPL to move forward/successfully implement an IMP program that ensures the integrity of the pipeline in the future rather than documenting compliance

Protocol 1 – Identification of pipeline segments that could affect HCAs

1. CPPL has developed a four part analytical approach to determining response times. Response time is one of the criteria used to determine the extent of the spread of a release via either an overland or water transport. A review of the response time calculations indicates that an 8 hour response time is the worse case scenario for the Yellowstone Pipeline based on time to mobilize, time to drive to the area of the release, time to locate the release, and time to contain the release. The Inspection Team feels that CPPL should monitor real time situations along their pipeline, and industry situations where applicable, to ensure that their response time estimates bound actual performance. The inspection team noted that CPPL documented their methodology for calculating response time in their Integrity Management Plan during the inspection. [Protocols 1.04, 1.05]

Protocol 2 – Baseline Assessment Plan

1. At the time of the initial IMP inspection in 2003, CPPL had only finalized two AP History and Planning Documents and have not finalized any additional AP History and Planning Documents. The Inspection Team noted CPPL has developed 140 AP History and Planning Documents that still require review with field personnel and final approval by the Integrity Assessment Team. The development and finalization of the

AP History and Planning documents are currently reactive (post baseline assessment) rather than proactive (pre baseline assessment). The AP document provides the information analysis component of CPPL's IMP that is the basis for many decisions and actions required to comply with many elements of the IM rule (e.g., assessment method selection, assessment interval determination, identification of preventive and mitigative measures, data integration). The Inspection Team is concerned that the development, review, and approval of Assessment Plan History and Planning Documents is not progressing in a timely manner. [Protocol 2.01]

Protocol 3 – Integrity Assessment Results Review

1. OPS Inspection Team noted to CPPL that the lack of use of ILI tool tolerance in identifying and categorizing anomalies could result in immediate repairs not being categorized correctly, and the consideration of ILI tool tolerances when evaluating an anomaly in an HCA for remediation per the repair criteria will help ensure the safe operation of the pipeline system. FAQ 7.19 provides guidance on this topic as follows, "Operators are required to integrate relevant information on the condition of the pipeline in making decisions on excavation timing and other mitigative actions. Tool tolerances should be considered as part of the data integration process." [Protocol 3.05]

2. While the Inspection Team realizes that the discovery process is being revised based on an enforcement action from the 2003 inspection, the discovery process currently in use is not adequate and has led to implementation issues. In twelve of the 67 ILI assessments provided to the Inspection Team, categorization of the 60 and/or 180 day anomalies was on the maximum discovery deadline date. It appeared that the CPPL Pipeline Integrity Engineers had to prioritize their activities based on available resources and work load. The IM rule defines discovery as when sufficient knowledge is available to allow categorization of an anomaly. CPPL needs to ensure that anomalies that occur in an HCA are categorized in an expeditious manner. [Protocol 3.05]

Protocol 4 – Remedial Action

1. In lieu of running a geometry tool, in some instances CPPL has chosen to excavate deformation anomalies identified by the MFL tool in HCAs. CPPL is currently considering these anomalies as not being categorized until excavation is performed. It is PHMSA's position that deformation anomalies with unknown depth or orientation be excavated in a timely manner or a pressure reduction be taken until excavation can occur. Process changes were made during the inspection to dig all topside dents within 60 days of discovery, and CPPL discussed changes to their process to require the running of a deformation tool in combination with the metal loss tool on future ILI integrity assessments.

   The following instances are provided:

- Four deformation anomalies were identified from the MFL tool run performed on the Rock Creek to Borger segment of PH-30 in October, 2003. These anomalies were not excavated until May, 2004. One of the anomalies was a dent with metal loss which meets the immediate repair criteria.

- CPPL performed a geometry tool run on the Villa Ridge to East St. Louis segment of the Gold Line in July, 2003. Twenty four dents over 6% with unknown orientation were detected. The CPPL identified deadline for excavating and categorizing these dents was June, 2004. After excavation, many of these defects exceeded the immediate, 60 day, and 180 day repair criteria for top side and bottom side dents. [Protocol 4.02]

Protocol 5 – Risk Analysis

1. CPPL continues to prioritize their pipeline segments using both PIRAMID and PRAS to develop a baseline assessment plan. Based on the current schedule, the full implementation of the revised PIRAMID model is not scheduled for completion until after the required deadline for CPPL to have completed a baseline assessment of 100 percent of their pipeline system as required by the IM rule (March 31, 2008). The true assessment of CPPL's pipeline segments according to risk is not being realized due to lagging implementation of the revised PIRAMID model, and the OPS Inspection Team was not furnished enough information at the time of inspection to determine that the highest risk pipeline segments are being assessed in a prioritized manner. [Protocol 5.05]

2. Risk analysis of CPPL's pipeline systems using the revised PIRAMID risk model follows the identification of "could affect" HCA segments by the EIM mapping software. At the time of the inspection, segment identification had been completed for the Yellowstone and Seminoe Pipeline Systems. The populating of the revised PIRAMID risk analysis of the Yellowstone Pipeline System was reported as being 75 percent complete with the remainder still to be completed. The Inspection Team is concerned that the segment identification process and the collection and input of data into the PIRAMID risk model is not progressing in a timely manner. [Protocol 5.05, 6.02]

Protocol 6 – Preventive and Mitigative Measures

1. CPPL is identifying Preventive and Mitigative measures as part of the AP History and Planning Document. The lagging review and approval of these documents is preventing the AP document from being utilized as a tool in CPPL's IMP in a proactive manner to ensure the integrity of the pipeline system. Performance of the determination of P&M measures needed to protect HCAs is a continuous process. Currently, the P&M process is part of the AP History and Planning Document, and CPPL should consider this as parallel to the AP process to be treated in a similar manner as the evaluation of leak detection and EFRDs. [Protocol 6.01]

2. The OPS Inspection Team realizes the P&M measure identification process is being revised based on enforcement actions from the 2003 inspection. The Inspection Team also notes that CPPL has many heritage programs designed to provide preventive and mitigative measures to the entire pipeline system. The Inspection Team was not provided adequate information to determine if the appropriate P&M measures had been selected to protect HCAs. CPPL must develop adequate criteria for the selection of appropriate P&M measures. The revised PIRAMID risk model will be a key component in the decision process for the selection of P&M measures when fully functional and implemented. [Protocol 6.02, 6.03]

3. While CPPL has outlined a leak detection evaluation process, CPPL has not performed a leak detection evaluation that considers all of the required factors in 195.452(i)(3). Leak detection evaluation is a continuous process required by the IM rule and is expected to have been performed. [Protocols 6.04, 6.05]

4. While CPPL has outlined an EFRD evaluation process that combines the use of the existing block valve program and the EIM mapping tool, CPPL has not performed an EFRD evaluation that considers all of the required factors in 195.452(i)(4). EFRD evaluation is a continuous process required by the IM rule and is expected to have been performed. [Protocol 6.06]

Protocol 7 – Continual Process of Evaluation and Assessment

1. CPPL's use of B31G for repair and remediation decisions helps ensure the safe operation of the pipeline system, and CPPL utilizes this repair strategy as the reason that corrosion and crack growth does not have to be factored into the reassessment interval determination. However, CPPL should realize that with certain axial defect lengths and depths of wall loss greater than 45 to 50 percent, B31G (PR3-805 Case 3) may be less conservative than PR3-805 Case 1 or 2, and it is deeper defects that would be most affected by external corrosion growth and affect the reassessment interval determination. The reassessment interval determination process should consider corrosion and crack growth in a quantitative manner to understand when it is a constraining factor on the length of time between integrity assessments. [Protocol 7.01]

2. It was noted by the Inspection Team that during the inspection CPPL modified the existing reassessment interval determination process to begin the reassessment interval at the completion of the earliest ILI tool run if the time differential was greater than 30 days rather than when it was greater than 180 days. [Protocol 7.02]

Protocol 8 – Program Evaluation and Process Formality

1. The OPS Inspection Team notes that the Program Evaluation process has been revised based on enforcement actions from the 2003 inspection. The Inspection Team was not provided sufficient information at the time of the inspection to determine adequacy of the program because many of the processes are not fully mature and have not been fully implemented. The lack of resources appears to be the primary driver for lagging

implementation. Some processes integral to the success of CPPL's IMP that are lagging in implementation include:

- Use of the EIM mapping tool to enhance HCA could affect segments
- The population of the PODS database
- The implementation of the GIS system
- Finalization of AP History review documents
- Evaluation of leak detection capabilities
- Evaluation of EFRD needs determination
- Population of the revised PIRAMID risk model
- Identification of additional P&M measures to protect HCAs
- Further refinements to CPL-AID

[Protocol 8.01, 8.06]