08-25-09A11:55 RCVD

ConocoPhillips
Pipe Line Company

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August 24, 2008

Mr. Chris Hoidal, P.E.
Director, Western Region
Pipeline Hazardous Materials Safety Administration
12300 West Dakota Avenue, Suite 110
Lakewood, CO 80228

RE: CPF No. 5-2008-5040M
Response of ConocoPhillips Pipe Line Company
To Notice of Amendment

Dear Mr. Hoidal,

This letter constitutes the response of ConocoPhillips Pipe Line Company (CPPL) to the October 15, 2008 Notice of Amendment (NOA) regarding an inspection of CPPL's Integrity Management Plan (IMP) conducted in Ponca City, Oklahoma, on May 13-19 and June 2-5, 2008. CPPL received the NOA on October 20, 2008 and the Final Order on June 24, 2009. This response will address the additional items that the Western Region office found needing further amendment.

By submitting this response, CPPL does not waive any right, privilege or objection that it may have in any separate or subsequent proceeding related in any way to the information provided in this response.

Item 1: CPPL has modified the existing procedure to provide sufficient guidance regarding how to collect the data for a pipeline that may or may not be susceptible to stress corrosion cracking through CPPL's screening process. Along with that we have updated this process to show guidance regarding how often data is to be collected.

Item 2: A corrosion checklist process has been developed and implemented that enables CPPL to identify specific portions of the system that represents the highest risk to each HCA.

Item 2B: PHMSA has stated that the inadequacies outlined in the Process Hazardous Analysis Program (PHA) have been corrected and no further action is required for item 2B.

CPPL considers the information in the attached response to be business confidential and proprietary and requests that the Agency maintain it as such.

Notice of Amendment States:

1. §195.452 Pipeline integrity management in high consequence areas.

(e) What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?
(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:

(i) Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate;
(ii) Pipe size, material, manufacturing information, coating type and condition, and seam type;
(iii) Leak history, repair history and cathodic protection history;
(iv) Product transported;
(v) Operating stress level;
(vi) Existing or projected activities in the area;
(vii) Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic);
(viii) geo-technical hazards; and(ix) Physical support of the segment such as by a cable suspension bridge.

(2) Appendix C of this part provides further guidance on risk factors

Item 1, CPPL's revised written procedures provide sufficient guidance regarding how to collect the data for the pipeline that may or may not susceptible to stress corrosion cracking form the CPPL screening process, but fail to provide appropriate guidance regarding how often data is collected. The procedures do not specify the need to perform magnetic particle testing (MPI) or collect appropriate data on all digs resulting form the Magnetic Flux Leakage (MFL) and Deformation surveys and Part 195.452 (h)(4) remediation requirements. Your company's process should include a method to collect the data and/or perform MPI during each exposed pipe evaluation.

Response to item 1

- **Program/Procedural changes:** Provide below are the changes that you will find highlighted in Integrity Management Procedure 05M. In order to provide additional screening for indications of SCC beyond the non-destructive testing outlined for identified crack fields, this process requires that all dents being excavated as part of the IMP program are inspected for indications of SCC through magnetic particle or dye penetrant inspection. Additional metal loss anomalies will be inspected on all pipeline assessment segments which have IMP required excavations regardless of the SCC susceptibility ranking. CPPL TAD – 7011, Line Pipe External Stress Corrosion Cracking Threat Assessment and Mitigation Program, is the process used to manage Stress Corrosion Cracking.

Pipeline Segments which have been identified as susceptible to SCC. History of failure due to SCC or a current crack tool data indicates feature that could be SCC.

- Evaluation of crack fields:
  - Perform CIS (close interval survey) of area (minimum 1500 ft run-in and run-out).
  - Collect photos of each location.
  - Perform the following tests – coating condition ranking, pH under coating, magnetic particle/dye penetrant testing, soil pH, pipe to soil potential, and field metallography of confirmed crack fields.
  - Perform either phased array TOFD (Time of Flight Diffraction) or grind out crack field to determine type and size.

Pipeline Segments which have been identified through screening process as susceptible, but no history of SCC failures or no crack field anomalies identified from a current or previous ILI crack tool data.

- Identify locations with highest stresses and susceptible coating type:
  - Because of the potential for high local stresses and coating damage in dents, all dents in HCA's will be inspected for cracks by magnetic particle or dye penetrant methods. Because dents tend to be randomly distributed along the pipeline, this inspection will provide additional screening for indications of SCC for the pipeline system.
  - Additionally, a minimum of three additional metal loss anomalies which have IMP required excavations in the assessment segment will be inspected for cracks as part of CPPL's current MFL/Caliper inspection program (specifically target areas with prior failure history, high stress areas, low corrosion levels).
  - Perform coating condition ranking, pH under coating, magnetic particle/dye penetrant testing, soil pH, pipe to soil potential. Field metallography, phased array or grinding will only be required if cracks are found.
  - If crack fields are found at an excavation, correlate data with ILI data and inform ILI vendor for re-analysis of data.
  - If crack fields are found at an excavation, consult with Corrosion Engineer to identify three additional anomalies for excavation/evaluation with similar characteristics/environment as found at crack locations.

Pipeline Segments not susceptible to SCC based on CPPL Screening Process:

- Identify locations with highest stresses and susceptible coating type
  - Because of the potential for high local stresses and coating damage in dents, all dents in HCA's will be inspected for cracks by magnetic particle or dye penetrant methods. Because dents tend to be randomly distributed along the pipeline, this inspection will provide additional screening for indications of SCC for the pipeline system.
  - Additionally, a minimum of three additional metal loss anomalies which have IMP required excavations in the assessment segment will be inspected for cracks as part of CPPL's current MFL/Caliper inspection program (specifically target areas with prior failure history, high stress areas, low corrosion levels)
  - Perform all tests listed above except field metallography, phased array or grinding is only required if crack fields are found.
  - If crack fields are found at excavations, correlate data with ILI data and inform ILI vendor for re-analysis of data.
  - If crack fields are found at excavations, consult with Corrosion Engineer.

- Based upon outcome of examinations, revise susceptibility ranking of pipeline segment for SCC.

- Schedule ILI crack tool or hydrotest as appropriate.

- Pipeline segments will be re-assessed for SCC threats a minimum of every five years.

2. §195.452 Pipeline integrity management in high consequence areas.

(f) What are the elements of an integrity management program? 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:

(1) A process for identifying which pipeline segments could affect a high consequence area;
(2) A baseline *assessment plan meeting the requirements of paragraph (c) of this section;*
(3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);
(4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section);
(5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);
(6) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph (i) of this section);
(7) Methods to measure the program's effectiveness (see paragraph (k) of this section);
(8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).
(g) What is an information analysis? 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) Information about how a failure would affect the high consequence area, such as location of the water intake.

Item 2: §195.452(f)(3)&(g)

Item 2.A. CPPL must complete the process for the corrosion checklist and submit the process for review.

Response to Item 2A

CPPL has developed a process and checklist (Evaluation of Pipeline Corrosion Protection Effectiveness) that will identify the corrosion mechanisms that represents the highest risk to high consequence areas.

CPPL believes that the additional action items will help to insure that SCC is being managed. CPPL respectfully submits that with the implementation of the actions described above, the action items specified in CPF No. 5-2008-5040M have been completed, subject to concurrence of the Western Region.

If you or anyone in your staff have questions about the information that has been provided please contact myself or Mike Miller at 832-379-6214.

Sincerely,

Todd Tullio

Todd Tullio
Manager, Regulatory Compliance

CC. Huy Nguyen
Mark Drumm
Mike Miller
Van Williams

Attachments: For your convenience we have highlighted the areas in these documents to reflect the changes made to address this NOA.

IMP Appendix 05M
CPPL-TSD 8000
Checklist for Evaluation of Pipeline Corrosion Protection Effectiveness

CPPL

ConocoPhillips Pipe Line Company

IMP Appendix 05M
ILI Assessment Procedure

For

Anomaly Assessments and Selection

Using

ILI Smart Tool's Pipeline Inspection Preliminary and Final Reports

An Integrity Engineer's Procedure

Rev. 46 – Effective Date: 2009-08-11

Developed for

ConocoPhillips Pipe Line Company

Document Owner:

Matthew Nimmo

Upon Receipt of Preliminary ILI Vendor Reports

P1) Copy (or save email as an Outlook Message Format), the Vendor information received to the S:\ drive folders including the dig sheets, where applicable.

P2) Update BAP Database with preliminary report receipt date

P3) Upon receipt of Vendor's preliminary report via email, determine if Immediate or Priority features are present. Once identified, apply tool tolerance to Immediate features only; do not apply tool tolerance to non-HCA anomalies. If Immediate or Priority features are identified as defined by GPL-513 and CPL-AID Supplement A, use MPR 4104 to determine the required deration pressure for the line. Work with the District Engineer (SCD), Logistics and/or Technical Service Engineer, where applicable, to determine current MOP and operating conditions of the pipeline to aid in the determination of deration pressure:

- a) Review requirements of MPR-4104 and if pressure deration calculations will take some time to perform, take a interim pressure deration as instructed in MPR-4104 otherwise:
- b) For dent and crack categories:
  - i) Using the @web2 program and PI, determine the historical pressures at the closest monitoring points upstream and downstream of the features beginning from 60 days prior to when the ILI tool was removed from the trap to the present.
    - **(1)** Using the historic high pressure at the limiting monitoring point(s), set the deration pressure in accordance with MPR-4104.
      - **(a) Note: It is up to the IE to work with the Control Center and Scheduling to determine which monitoring point(s) should be used as the limiting point.**
      - **(b) Note: Use "Sampled Data" with a 5 minute interval for the PI data retrieval.**
      - **(c) Note: The controlling pressure shall be based upon the pressures at the monitoring points which are taken at the same sampling time.**
- c) For metal loss features categories:
  - i) The deration pressure shall be in accordance with MPR-4104.
- d) For any other features the tool vendor reports as injurious to the pipeline:
  - i) A suitable pressure reduction methodology will be used or developed in consultation with the Pipeline Integrity Manager.

Save copies of the pressure deration calculations as working copies in the appropriate pipeline folder on S:\Transportation\Tech_Ser\Internal Inspections

P4) Issue the Initial Pressure Deration email to the following distribution list: (See the appropriate organizational chart(s) for potential recipients)

- a) Senior Pipeline Controller – Recipient, others are on the .cc list
- b) Manager of Engineer and Projects
- c) Pipeline Integrity Manager
- d) Asset Integrity Manager
- e) Technical Services Engineer
- f) Pipeline Division Manager
- g) Major Maintenance Supervisor
- h) Logistics Manager
- i) Scheduling Director
- j) Pipeline Scheduler
- k) Controller Center Manager
- l) Regulatory Compliance Manager
- m) DOT Coordinator
- n) DOT SRC Coordinator
- o) Pipeline Integrity Analyst
- p) Integrity Engineer Lead
- q) Environmental Coordinator

This Initial Pressure Deration email shall be **released the same day as receipt** of the Preliminary Report email or shortly thereafter, so that the field crews can begin planning the repairs and evaluating for a Safety Related Condition (SRC). Address the SRC portion of the email to the Area Supervisor. This email becomes the Date of Discovery for these features. Save a copy of this email in *.msg format in the appropriate pipeline folder on S:\Transportation\Tech_Ser\Internal Inspection. See link below for standard email templates.
http://livelink.conocophillips.net/livelink.exe?func=ll&objId=48523956&objAction=browse&sort=name&viewType=1

P5) Once the pressure deration email above has been issued, contact the Major Maintenance Supervisor by phone or leave voice message. Also contact the District Engineer, if required (SCD).

P6) If the line cannot be derated and remain in service, follow the instructions in Section F36 through F39. Once you have completed performing the steps in Section F39, return and continue with step P(8).

P7) Update the BAP with the Preliminary Derate Date. Include a note in the comments to indicate the number of Immediate and Priority repairs identified off of the preliminary report. Check PnT utilities to determine if multiple segments are derated within the system. If this is the first de-ration for the system, no de-ration log needs to be created. If one or more segments are derated in PnT utilities, create a new de-ration log using the template located in the IE Template folder of EDMS or modify the existing de-ration log. When creating a new de-ration log, save the de-ration log in the folder of the corresponding tool run of the de-ration. Or, if a de-ration log already exists, simply add the de-ration to the existing de-ration log and create a short cut in the folder of the corresponding tool run to the de-ration log located in other folder. The title of the folder for the log is "De-ration Log".

P8) Develop the ILI Integrity Work List and associated dig sheets, if applicable (developed by hand from vendor's dig sheets) for Immediate and/or Priority Features. Insert a note in the IE's comment field to perform magnetic particle/dye penetrant testing of all dents in any ILI tool run worklist. For crack-like anomalies, request from the tool vendor a listing of any other anomalies on the same joint for use as verification/correlation anomalies. Correlate vendor dig sheets to HCA location in order to assign the correct priority code (use the data in PnTUtility to determine the could-affect HCA list). **Notify the Corrosion Control Engineer of locations if crack fields are found so that Close Interval Surveys can be scheduled. For all crack fields identified perform the analysis in the section "Stress Corrosion Cracking Dig Procedures" found at the end of this appendix.** For non-HCA anomalies, do NOT add tool tolerance when classifying the anomalies; only add tool tolerance to anomalies located in HCAs. Use the official manual template copy of the "ILI Integrity Worklist" (located at C:\Apps\Data\cplaid\HelpFiles\). Save the completed worklist in the appropriate pipeline inspection file on the S:\transportation\tech_ser\Internal Inspections drive.

P9) Issue a transmittal of "Immediate/Priority Features – Preliminary Report" approved by the Pipeline Integrity Manager. **If no Immediate or Priority features are present, also issue transmittal as such, for documentation.** Use the report template and Access Database located at S:\Transportation\tech_ser\Internal Inspections\0 Forms\Transmittal Templates to develop the Transmittal Report.

P10) Move the following documents to the appropriate EDMS workspace:

Note 1: The following is a list of the documents associated with ILI inspections that should be stored in EDMS as part of the Preliminary Reporting. Working copies of all of these documents should be located in the applicable tool run file on s:\\Transportation|tech_ser\Internal Inspections. The names below are intended to be standard naming conventions to be used within the EDMS file structure.

a) Set up new folder using the year of the ILI run and the type of ILI tool (ie 2006 MFL; 2006 Caliper, 2006 Combo, etc.) Into this folder, copy:
   (1) Transmittal Letters

(2) ILI Integrity Worklist (if applicable)
(3) Dig Sheets (if applicable)
(4) Pressure deration emails (if applicable) (Store emails using Outlook Message Format (*.msg))
(5) Pressure deration calculations (if applicable)

Note 2: From time to time, single Transmittals may be made for multiple runs in the same segment (ie., MFL and Caliper tools run separately). In those cases, the EDMS location for the MFL run should contain the transmittal documents. The folder for the other technology, i.e. the caliper run, should contain shortcuts to link to the documents in the MFL run folder. The shortcuts should be named as follows:

Combined Transmittal Letters
Combined ILI Integrity Worklists
Combined Dig Sheets

The existing folder names can remain unchanged.

Note 3: After the above files have been moved to EDMS, delete the working copies from the S:\ drive

P11) Use the standard email transmittal template located at ILI Report Template to transmit the report by email.

a) Distribute the Transmittal email with a link to the documents stored on the EDMS file location as follows:
   i) Region Manager – Recipient, others are on the .cc list
   ii) Major Maintenance Supervisor
   iii) Regulatory Manager(as necessary)
   iv) DOT Coordinator (as necessary)(**for California projects, include coordinator anytime that an ILI Worklist is issued so that the CSFM can be informed**)
   v) DOT SRC Coordinator (If Immediate or Priority Features are on worklist)
   vi) Environmental Coordinator (If worklist is to be issued)
   vii) Corrosion Control SME (If Worklist is issued)
   viii) Corrosion Engineer of appropriate area (If Worklist is issued)
   ix) Corrosion Team Leads of appropriate area(If worklist is to be issued)
   x) Pipeline Integrity Analyst
b) Retain originals documents listed in P10)) above in PIR files

P12) Issuance of the transmittal letter will be the trigger for the Integrity Engineer to do the following tasks from the documents placed in the IE folder or on EDMS for the applicable tool run:

a) Update BAP Database as follows:
   i) From the "BAP Segment Data Entry" Form:
      (1) Review Baseline Assessment (BA) Completed Date field. If empty update with baseline assessment completion date.
         (a) If BA consists of one ILI tool run, date is completion date of tool run.
         (b) If BA consists of more than one tool run, and time separation is less than 30 days, date is completion data of last tool run.
         (c) If BA consists of more than one tool run, and time separation is greater than 30 days, date is completion of first tool run.
   ii) From the "BAP Assessment Data Entry" Form:
      (1) Run dates
      (2) Preliminary report receipt date
      (3) Preliminary transmittal date
      (4) Preliminary pressure deration date, if applicable

P13) Add features to the Anomaly Counting Database (ACD) using the ACD Load procedure located in the back of this procedure.

P14) If Immediate and/or Priority features are identified and you have not done so already, contact the field Maintenance Supervisor and/or Pipeline Integrity Project Engineer to identify if the PLE group or the field maintenance group will be responsible for the repairs.

Note: If the PLE group will be responsible for the repairs, the Pipeline Integrity Project Engineer will write a work order to capture excavation and repair costs; otherwise the *IE* will:

a) Request a repair cost estimate from the appropriate field personnel of that segment. If crack-like anomalies require evaluation, the field should include cost of non-destructive evaluation contractor as well as abrasive blasting pipe preparation.
b) Using the procedures listed in Appendix 05H, prepare a Work Order for all repairs
c) Once released, communicate the SAP WO number for repairs and/or cutouts to the individual responsible for performing the work.

P15) Update hours worked developing worklist and transmittals in the SAP work order for the specific tool run.

Preliminary ILI Vendor Reports – Follow-up on Immediate and Priority Feature

P16) Upon receipt from the field, the Pipeline Integrity Analyst (IA) loads the ILI worklist to S:\Transportation\tech_ser\Internal Inspections\0 ILI Worklist Review. The IE will review the worklist within one week after it is posted to the S:drive, following the steps outlined in **the ILI Worklist Review Procedure** in the back of this appendix.

P17) Once a deration is in effect, the Integrity Analyst will monitor the length of time the deration has been in place. If the deration is still in effect after 60 days, the Integrity Analyst will monitor the Administrative Controls deadline as listed in **the Administrative Controls Extension** Procedure in the back of this appendix.

P18) After written notification of completion of all Immediate and/or Priority repairs, issue rescinded deration email.

P19) Update BAP with rescinded deration email date. Update the removal of the de-ration in the de-ration log and EDMS with rescinded deration email.

P20) Each time a worklist is returned with new completions, the IE will review it for compliance with API 1163 as outlined in **the API 1163 Compliance Review Procedure** located in the back of this appendix.

Upon Receipt of Final ILI Vendor Reports – Immediate and 60-Day Feature Selections

F1) If applicable, Fax vendor's Report Receipt Confirmation form back to the vendor with signature and date documenting receipt of final report.
F2) Document receipt date on the cover and first page of the report with the Integrity Engineer's initials and date.
F3) Update BAP Database with final report receipt date.
F4) Confirm that the Final Report is correct as follows
  a)Check ILI odometer run length against map distance. If necessary, determine if odometer distance is within allowable tolerance. If odometer is out of tolerance, have a conversation with the tool *vendor analyst* to determine if there were any operational issues with the odometers. Continue with step F4 B); however, review the Reference Point graph produced during data upload to the CPL-AID program to determine if the discrepancy is linear. Use engineering judgment to determine if the amount of discrepancy will affect the ability to accurately locate anomalies based upon distance.
  b)Check interaction rules used. If incorrect, contact vendor for new report.
  c)Check pipe properties including location of marker plates.
  d) Confirm the final report includes Process Validation documentation. Review the document(s) for unresolved or previously unreported inconsistencies with the tool run. These may include system errors such as loss of sensors, odometer discrepancies, and other data capture issues. Contact the ILI tool vendor with any items that require further evaluation and/or resolution. **If the inconsistencies cannot be resolved, the inspection results are not verified.**
    i) TDW Magpie Process Validation documentation includes:
      (a) Tool Preparation Build Sheet
      (b) Field Technician Run Report
      (c) Run Results Report
      (d) Incoming Run Data Quality Check
F5) Load from Vendor's CD the following files to the appropriate S:\Drive pipeline folder
  a)Inspection Report
  b)Pipeline Listing Spreadsheet(s)
  c)Access files as necessary
F6) Send email to Bryon Vassen that the final report is available on the S:\ Drive for loading into CPL-AID. In the email, log your user ID and the work order number in the appropriate locations. The invoice will be sent in as an ePayable SAP invoice, so not PO is required. .
F7) Evaluate the Final report for Immediate and Priority Repair features as follows:
  a) MFL tools:
    i) Top-sided dents with metal loss
      (1) Vendor call regardless of HCA *impact*
      (2) Insert a note in the IE's comment field to perform magnetic particle/dye penetrant testing of all dents in any ILI tool run worklist
    ii) > 80% metal loss features
      (1) Add tool tolerance to vendor-called depth
    iii) Burst < MOP
      (1) Calculate the burst pressures using each of the three pressure calculators. One method to do this is to:
        (a) Take the anomaly with the lowest Rstreng value from the vendor supplied pipe list file. Using the effective Rstreng depth and Rstreng length, add tool tolerance and calculate the burst pressure
        (b) Use the peak depth and length, add tool tolerance to each dimension and calculate the burst pressure using B31G modified equation

(c) Use the peak depth and length, add tool tolerance to each dimension and calculate the burst pressure using the B31G equation

(2) If any one of the above calculated pressure values results in a burst pressure that is greater than the MOP of the feature at that location, the anomaly passes the analysis and is not an Immediate or Priority feature.

(3) If the anomaly above does not pass at least one of the above pressure calculations, a full analysis of the anomalies for Immediate, Priority and 60 Day features must be performed using an appropriate pressure calculating spreadsheet located at http://livelink.conocophillips.net/livelink.exe/ILI_Metal_Loss_Evaluation.xls?func=doc.Fetch&nodeId=48524177&docTitle=ILI+Metal+Loss+Evaluation&viewType=1

b) Caliper tools:
   i) Top-sided dents greater than 6%
      (1) ONLY applies to areas that could affect HCAs
      (2) Use vendor-called depth with the vendor tool tolerance added.
      (3) Use Vendor orientation tolerance during anomaly selection (where tolerance information is available from vendor). Subtract the tolerance on the 3:00 o'clock side of the pipe and add the tolerance on the 9:00 o'clock side of the pipe.
      (4) Insert a note in the IE's comment field to perform magnetic particle/dye penetrant testing of all dents in any ILI tool run worklist.

c) Crack tools (Ultrasonic or Transverse Flux)
   i) **Notify the Corrosion Control Engineer of locations if crack fields are found so that Close Interval Surveys can be scheduled. For all crack fields identified perform the analysis in the section "Stress Corrosion Cracking Dig Procedures" found at the end of this appendix.** If depths are reported in ranges, then any anomalies that are in the top, unbounded depth band (example: "greater than 0.160 inch") if not already reported in Preliminary Report will be added to the ILI Worklist
   ii) If depths are reported with specific percentage, then anomalies greater than 80% minus the tolerance of the tool (example: 80% - 20% depth tolerance = greater than 60%) if not already reported in Preliminary Report will be added to the ILI Worklist
   iii) Cracks which have a calculated failure pressure below Maximum Operating Pressure
      (1) Enter tool run anomaly data into the Kiefner & Associates log secant equation spreadsheet http://livelink.conocophillips.net/livelink.exe?func=ll&objId=120235609&objAction=browse&sort=name&viewType=1. Use the **KAPA2005.xls** spreadsheet
      (2) Use Charpy impact energy (toughness) from previous Pressure Cycle Fatigue Analysis unless actual pipe test data is available
      (3) If depths are reported in ranges, enter the depth in the spreadsheet as the deeper of the two values
      (4) If depths are reported as a specific percentage, enter the sum of the reported depth plus tool depth tolerance

F8) **If Immediate or Priority features are discovered:**

a) If Immediate or Priority features which were not discovered during the Preliminary Report review are identified, perform the following steps as soon as possible but no later then 5 days after receipt of the final report. If a final worklist and transmittal letter for all features in the ILI run can be developed and released in 5 days or less, the Immediate, Priority and 60 Day Features transmittal can be combined with the All Features transmittal. **Any required pressure deration must be completed within the 5 day allowable window**.

b) Review requirements of MPR-4104 and if pressure deration calculations will take some time to perform, take a interim pressure deration as instructed in MPR-4104 otherwise:
   i) For dents and crack categories:

(1) Using the @web2 program and PI, determine the historical pressures at the closest monitoring points upstream and downstream of the features beginning from 60 days prior to when the ILI tool was removed from the trap to the present.
(2) Using the historic high pressure at the limiting monitoring point(s), set the deration pressure in accordance with MPR-4104.
(a) Note; It is up to the IE to work with the Control Center and Scheduling to determine which monitoring point should be used as the limiting point.
(b) Note: Use "Sampled Data" with a 5 minute interval for the PI data retrieval.
(c) Note: The controlling pressure shall be based upon the pressures at the monitoring points which are taken at the same sampling time.

ii) For metal loss features categories:
(1) The deration pressure shall be in accordance with MPR-4104.
(2) Save copies of the pressure deration calculations as working copies in the appropriate pipeline folder on S:\Transportation\Tech_Ser\Internal Inspections

iii) For any other features the tool vendor reports as injurious to the pipeline:
(1) A suitable pressure reduction methodology will be used or developed in consultation with the Pipeline Integrity Manager.

c) Prepare Digs Sheets, (developed by hand) and email them to the individuals responsible for doing evaluations and repairs.
d) Issue Final Pressure Deration email to the following distribution list, if applicable:
i) Senior Pipeline Controller – Recipient, others are on the .cc list
ii) Manager of Engineer and Projects
iii) Pipeline Integrity Manager
iv) Pipeline Integrity Manager
v) Technical Services Engineer
vi) Pipeline Division Manager
vii) Major Maintenance Supervisor
viii) Logistics Manager
ix) Scheduling Director
x) Pipeline Scheduler
xi) Controller Center Manager
xii) Regulatory Compliance Manager
xiii) DOT Coordinator
xiv) DOT SRC Coordinator
xv) Pipeline Integrity Analyst
xvi) Integrity Engineer Lead
xvii) Environmental Coordinator

e) Contact the Major Maintenance Supervisor by phone or leave voice message notifying him/her of the deration. Please address the Area Supervisor in the SRC portion of the duration email.
f) If the line cannot be derated and remain in service, follow the instruction in Section F36 through F39. Once you have completed performing the steps in Section F39, return and continue with step F9.

F9) Evaluate the Final report for 60-Day Repair features as follows:
a) MFL tools:
i) Insert a note in the IE's comment field to perform magnetic particle/dye penetrant testing of all dents in any ILI tool run worklist
ii) Top-sided dents
(1) ONLY applies to areas that could affect HCAs
(2) If caliper data is available, reduce the list of all MFL dent calls to those which are greater than 3% with the vendor tool tolerance added.

(3) If no caliper data is available, include all top-sided MFL dents calls in the ILI Integrity Worklist
(4) Use Vendor orientation tolerance during anomaly selection (where tolerance information is available from vendor). Subtract the tolerance on the 3:00 o'clock side of the pipe and add the tolerance on the 9:00 o'clock side of the pipe

iii) Bottom Side Dents with any indication of 1) metal loss, 2) cracking or 3) a stress riser
(1) Only applies to areas that could affect HCAs
(2) Use vendor-called depth with the vendor tool tolerance added.
(3) Use Vendor orientation tolerance during anomaly selection (where tolerance information is available from vendor). Subtract the tolerance on the 3:00 o'clock side of the pipe and add the tolerance on the 9:00 o'clock side of the pipe

b) Caliper tools:
i) Insert a note in the IE's comment field to perform magnetic particle/dye penetrant testing of all dents in any ILI tool run worklist
ii) Top-sided dents greater than 3%
(1) ONLY applies to areas that could affect HCAs
(2) Use vendor-called depth with the vendor tool tolerance added.
(3) Use Vendor orientation tolerance during anomaly selection (where tolerance information is available from vendor). Subtract the tolerance on the 3:00 o'clock side of the pipe and add the tolerance on the 9:00 o'clock side of the pipe.

F10) Develop transmittal of Immediate/Priority/60-Day Feature Evaluation of Final Report approved by Pipeline Integrity Manager.

a) Store the following documents on the appropriate EDMS workspace and include a link to the EDMS file location in the transmittal email.
(1) Transmittal Letters (store on EDMS)
(2) ILI Integrity Worklist (if applicable, store on EDMS)
(3) Dig Sheets (as required, store on EDMS)

b) Distribute the Transmittal email with the link to the documents stored on the EDMS file location as follows:
(1) Region Manager – Recipient, others are on the .cc list
(2) Major Maintenance Supervisor
(3) District Engineer (California only)
(4) Regulatory Manager (as necessary)
(5) DOT Coordinator (as necessary) **(for California projects, include coordinator anytime that an ILI Worklist is issued so that the CSFM can be informed)**
(6) DOT SRC Coordinator (if Immediate or Priority features are included on worklist)
(7) Corrosion Control SME (If Worklist is issued)
(8) Corrosion Engineer of appropriate area (If Worklist is issued)
(9) Corrosion Team Leads (If Worklist is issued)
(10) Environmental Coordinator (If Worklist is issued)
(11)Pipeline Integrity Analyst

c) Retain originals documents listed in a) above in PIR files

F11) Issuance of the transmittal letter will be the trigger for the Integrity Engineer to do the following tasks:

a) Update BAP Database with:
i) Enter the Final Transmittal Immediate Date, if an Immediate, Priority and 60 day features transmittal has been completed.
ii) Enter the Final Immediate deration date, if applicable
iii) Add a note in the Analysis Comment field as to how many anomalies are being reported in the transmittal report and ILI Integrity Worklist.

b) Update EDMS with:
(1) Pressure deration emails (if applicable)
(2) Pressure deration calculations (if applicable)
(3) Transmittal Letters (if not previously done)

(4) ILI Integrity Worklist (if applicable and if not previously done)
(5) Dig Sheets (if applicable and if not previously done)

c) Check PnT utilities to determine if multiple segments are derated within the system. If this is the first de-ration for the system, no de-ration log needs to be created. If one or more segments are derated in PnT utilities, create a new de-ration log using the template located in the IE Template folder of EDMS or modify the existing de-ration log. When creating a new de-ration log, save the de-ration log in the folder of the corresponding tool run of the de-ration. Or, if a de-ration log already exists, simply add the de-ration to the existing de-ration log and create a short cut in the folder of the corresponding tool run to the de-ration log located in other folder. The title of the folder for the log is "De-ration Log".

Note 1: From time to time, single Transmittals may be made for multiple runs in the same segment. In those cases, the EDMS location for the MFL run should contain the transmittal documents. The folder for the other technology, i.e. the caliper run, should contain shortcuts to link to the documents in the MFL run folder. The shortcuts should be named as follows:

Combined Transmittal Letters
Combined ILI Integrity Worklists
Combined Dig Sheets

The existing folder names can remain unchanged.

Note 2: After the above files have been moved to EDMS, delete them from the S:\ drive

F12) Add features to the Anomaly Counting Database (ACD) using the ACD Load procedure located in the back of this procedure.

F13) If Immediate, Priority and/or 60-day features are identified and you have not done so already, contact the field maintenance supervisor and/or Pipeline Integrity Project Engineer to identify if the PLE group or the field maintenance group will be responsible for the repairs.

Note: If the PLE group will be responsible for the repairs, the Pipeline Integrity Project Engineer will write a work order to capture excavation and repair costs; otherwise the IE will:

a) Using the procedures listed in Appendix 05H, prepare a cost estimate and work order for all repairs.

b) Once released, communicate the SAP WO number for repairs and/or cutouts to the individual responsible for performing the work.

F14) Update hours worked developing worklist and transmittals in the SAP work order for the specific tool run (not the repair work order).

Final ILI Vendor Reports – Follow-up on Immediate & 60-day features

F15) Upon receipt from the field, the Pipeline Integrity Analyst (PIA) loads the ILI worklist to S:\Transportation\tech_ser\Internal Inspections\0 ILI Worklist Review. The IE will review the worklist within one week after it is posted to the S:drive, following the steps outlined in **the ILI Worklist Review Procedure** in the back of this appendix.

F16) Once a deration is in effect, the Integrity Analyst will monitor the length of time the deration has been in place. If the deration is still in effect after 60 days, the Integrity Analyst will monitor the Administrative Controls deadline as listed in **the Administrative Controls Extension** Procedure in the back of this appendix.

F17) After written notification of completion of all Immediate and/or Priority repairs, issue rescinded deration email.

F18) Update BAP with rescinded de-ration email date. Update the removal of the de-ration in the de-ration log.

F19) Update EDMS with rescinded deration email.

F20) Each time a worklist is returned with new completions, the IE will review it for compliance with API 1163 as outlined in the **API 1163 Compliance Review Procedure** located in the back of this appendix.

Final ILI Vendor Reports - All Remaining Feature Selections

Note: If user is going to be using Appendix 05Q CPL-AID Procedures Manual – Procedure 8 – Dig List Creation, please proceed with the steps F21 through F24 below. However, if user is going to use Appendix 05R Spreadsheet Analysis Procedure, skip steps F21 to F24 and use the steps included in the Spreadsheet Analysis Procedure instead, then return to step F25 of this procedure and continue below.

If selecting anomalies from a crack tool final report, provide tool run electronic data and report to Hydro-test Engineer. Hydro-test Engineer or consultant will perform fatigue analysis of reported anomalies in accordance with TRP-3005 to determine if any additional anomalies require excavation prior to the desired re-inspection interval. If additional anomalies require excavation from this analysis, manually add them to dig list using Appendix 05Q CPL-AID Procedures Manual – Procedure 8 – Dig List Creation after proceeding with the steps F21 through F24 below.

F21) If not previously sent, send Bryon Vassen an email that the final report has been loaded to the s:\ drive and is ready for him to load into CPL-AID. Include your user ID number and the work order number of the tool run for invoicing purposes.

F22) Bryon Vassen will load HCA data into CPL-AID.

F23) **Please Note**: Bryon Vassen currently loads the MOP point by point values if available. There must be at least one value in the tblMOP in CPL-AID. It is preferred that the IE use the point by point MOP values and load tblMOP with these values! Check for Point by Point MOP values on EDMS for the system being analyzed. If point by point values are not available, use the default value and load it into tblMOP. CPL-AID does not currently minimize the pick list without at least one value in this table.

F24) For MFL and Caliper tool runs, the IE is to use CPL-AID and select the remaining features (Using criteria below)

a) Use "Appendix 05Q CPL-AID Procedures Manual – Procedure 8 – Dig List Creation" to perform feature selections and to be exported from CPL-AID as an ILI Integrity Worklist and Log Data Dig Reports. Once finished with the above procedure, return here and complete the remaining procedural steps below.

b) Insert a note in the IE's comment field to perform magnetic particle/dye penetrant testing of all dents in any ILI tool run worklist

c) If the worklist does not contain any dents, select three metal loss features from the worklist and insert a note in the IE's comment field to perform the SCC susceptibility tests listed Stress Corrosion Cracking Dig Procedure

d) For tool runs with less than six field verification results (combination of current run and historical correlation/verification features), the tool run will need to be verified by ILI Tool Vendor System Results Verification. Use standard language on the ILI Report Template to request this documentation from the ILI tool vendor. Upload these documents to the appropriate EDMS workspace.

F25) For Crack Tools (Ultrasonic or Transverse Flux), the IE is to perform the following steps which provide data for Pressure Cycle Fatigue Analysis (PCFA).

a) Produce a copy of the Elliptical Crack Spreadsheet (http://livelink.conocophillips.net/livelink.exe?func=ll&objId=120235615&objAction=browse&sort=name&viewType=1) and notify Hydrostatic Test Engineer by email that the data and original vendor final report have been loaded to the S: drive for use in PCFA.

i) Follow directions on tab 1 in spreadsheet for loading CPL-AID data into appropriate named ranges within spreadsheet.

ii) Enter all crack anomaly data (reference Vendor Calls for Crack Detection Tools spreadsheet) into Elliptical Crack Burst Calculator spreadsheet.
iii) Use default of 25 ft-lb for Charpy impact energy (toughness).
iv) For Ultrasonic Tools (UT), enter the wall thickness as the measured wall thickness.
v) For Transverse Flux (TFI) and Axial Flaw (AFD), enter the wall thickness as the nominal wall thickness.
vi) For depths reported in ranges, enter the depth in the spreadsheet as the deepest part of the range.
vii) For depths reported as a specific percentage, enter the depth as the sum of the reported depth and tool depth tolerance.
viii) For lengths, consider the tool vendor's tolerance as a constant or percent depending on the feature's size.

F26) For Crack Tools, the IE is to add anomalies manually through CPL-AID to the ILI Integrity Worklist based on the Vendor Calls for Crack Detection Tools Spreadsheet.

a) **Notify the Corrosion Control Engineer of locations if crack fields are found so that Close Interval Surveys can be scheduled. For all crack fields identified perform the analysis in the section "Stress Corrosion Cracking Dig Procedures" found at the end of this appendix.**

b) If crack anomaly depths are reported in ranges, then all anomalies that are in the top, unbounded depth band (example: "Greater than 0.16 in") if not already reported on the Preliminary Report, will be added to the ILI Worklist as Priority 2005A.

c) If crack anomaly depths are reported with specific percentage, then anomalies with added tool tolerance greater than 80% if not already reported on the Preliminary Report, will be added to the ILI Worklist as Priority 2005B.

d) Crack anomalies which have a calculated failure pressure below Maximum Operating Pressure (MOP) shall be added to the ILI Integrity Worklist as Priority 2005C.

e) Gouges, grooves, and scratch (ie: Notch-like) feature anomalies with a depth greater than 12.5% with tool tolerance shall be added to the ILI Integrity Worklist as a iiiI if inside an HCA or a 1205A if not within an HCA.

f) Dent features shall be added to the ILI Integrity Worklist as Priority iiiB for bottom side and Priority iiA for top side if located inside an HCA and no deformation tool data exist. If data exist, then a correlation effort within CPL-AID is required and only new dents not in the comparison deformation tool data shall be added to the list. All non-HCA dents will not be added to the ILI Integrity Worklist.
    i) Insert a note in the IE's comment field to perform magnetic particle/dye penetrant testing of all dents in any ILI tool run worklist

g) If pipe segment has had a hydro to 1.25 x MOP, then repair of laminations is not required. If not, then reference ASME B31.4 Paragraph 451.6.2.6 PROCESS. Flowchart to determine if laminations shall be added to the ILI Integrity Worklist as Priority 2100A.

h) Metal Loss anomalies affecting seam or girth welds can not safely use the B31-g calculator and therefore shall be added to the ILI Integrity Worklist as iiiH and 1005E.

i) SCC (ie: Crack-field) feature anomalies on pipeline segments that do not meet 2005A, 2005B, and 2005C criteria, shall be added to the ILI Integrity Worklist as Priority 2015A regardless of size, length and width until the Corrosion Group determines a method to further assess SCC. For all crack fields identified perform the analysis in the section "Stress Corrosion Cracking Dig Procedure" found at the end of this appendix.

j) Tool Verification is achieved with a minimum of six (6) features that are excavated and evaluated. An attempt shall be made to identify six (6) external features should the IE not identify a minimum of six (6) features with the above criteria. These shall be added to the ILI Integrity Worklist as Priority 8000.

1) The initial choice of anomalies to excavate should include the deepest listed external anomaly along with all other anomalies identified on the same pipe joint.
2) The second choice of anomalies to excavate should include external anomalies that are closest to the outlet of a pump station.

k) Upon completion of the PCFA, the reassessment interval for the crack tool shall be determined and all crack anomalies with a shorter safe life shall be added to the ILI Integrity Worklist as Priority 8200 unless the feature is used for the tool verification above.

NOTE: If Appendix O5R Spreadsheet Analysis Procedure was used above, return to Step F25 and continue by completing the remaining procedural steps below:

F27) For crack tools, the IE is to perform the following steps which provide data for Pressure Cycle Fatigue Analysis (PCFA).

a) Using CPL-AID, produce a copy of the Log Features All Joints report and export to the appropriate S: drive folder.
   i) Notify the Hydrostatic Test Integrity Engineer by email that the Log Features Report and the original vendor final report have been loaded to the S: drive for use in PCFA

F28) For crack tools, any crack with a calculated SOP less than MOP (SOP<MOP) shall be added to the ILI Integrity Worklist

a) **Notify the Corrosion Control Engineer of locations if crack fields are found so that Close Interval Surveys can be scheduled. For all crack fields identified perform the analysis in the section *"Stress Corrosion Cracking Dig Procedures"* found at the end of this appendix.** .
b) Use the Kiefner & Associates log secant equation spreadsheet (**KAPA2005.xls** spreadsheet) located on the EDMS site, load the crack features and calculate the safe operating pressure for each crack feature.
   (1) Use Charpy impact energy (toughness) from previous Pressure Cycle Fatigue Analysis unless actual pipe test data is available
   (2) If depths are reported in ranges, enter the depth in the spreadsheet as the deeper of the two values
   (3) If depths are reported as a specific percentage, enter the sum of the reported depth plus tool depth tolerance
   (4) If depths are reported as a specific percentage, enter the sum of the reported depth plus tool depth tolerance
c) Any crack feature which has a Safe Operating Pressure (SOP) less than the Maximum Operating Pressure (MOP) shall be added to the ILI worklist using a priority code of "2005".
d) Upon completion of the PCFA, the Hydrostatic Test Integrity Engineer will provide a listing of all crack features which require excavation and evaluation. All of the features identified by the Hydrostatic Test IE will be added to the ILI Integrity Worklist with an anomaly code of 8200.
e) If no features are identified by either the static crack calculations listed this step or with Pressure Cycle Fatigue Analysis, identify a group of anomalies to excavate for verification of the tool run. An attempt should be made to identify six (6) features for excavation and evaluation.

i) The initial choice of anomalies to excavate should include the deepest listed anomaly along with all other anomalies identified on that pipe joint
ii) The second choice of anomalies to excavate should include anomalies that are closest to the outlet of a pump station
iii) Should no features be identified using the two items above, attempt to identify acceptable anomalies using the following:
(1) A minimum of 2 digs with the longest and deepest features. Since excavation of the entire joint is required, all anomalies listed on the joints identified should be added to the ILI Integrity Worklist

f) For all crack fields identified perform the analysis in the section "Stress Corrosion Cracking Dig Procedures" found at the end of this appendix.

F29) Issue transmittal letter documenting receipt of Final Report and actions to be taken, approved by Pipeline Integrity Manager with a link to the following EDMS-stored attachments:
a) Dig Sheets (if applicable)
b) ILI Integrity Worklist (if applicable)

F30) Distribute the Transmittal email with the link to the documents stored on the EDMS file location as follows:
a) Region Manager – Recipient, others are on the .cc list
b) Major Maintenance Supervisor
c) Regulatory Manager (as necessary)
d) DOT Coordinator (as necessary) (**for California projects, include coordinator anytime that an ILI Worklist is issued so that the CSFM can be informed**)
e) Corrosion Team Leads (If Worklist is issued)
f) Environmental Coordinator (If Worklist is issued)
g) Pipeline Integrity Analyst

F31) Issuance of the transmittal letter will be the trigger for the Pipeline Integrity Engineer to do the following tasks from the documents placed in the IE's folder for the applicable tool run on the S: drive:
a) Update BAP Database with:
i) Assessment Table and Segment Table if the run completes a Baseline Assessment
ii) Final Report receipt date
iii) Final remaining features transmittal date
iv) Statement in comment field about number to digs in the repair program
b) Update EDMS with:
i) Corrosion Items
(1) Internal Corrosion Histogram
(2) External Corrosion Histogram
(3) Casing Report
(4) Corrosion near pipeline crossings (ivF2 report)
ii) Dig Sheets from CPL-AID (if applicable, previously stored on EDMS)
iii) GPS Waypoint Files
iv) ILI Integrity Worklists (if applicable, previously stored on EDMS)
v) Pressure deration calculations (if applicable)
vi) Pressure deration emails (if applicable)
vii) Tool run validation emails from vendors (if applicable)
viii) Anomaly Due Date Extension Emails (if applicable)
ix) Transmittal Letters
x) Administrative Controls Extension emails (if applicable)
xi) Reference Points Validation Spreadsheet
xii) Anomaly Due Date Extension emails (if applicable)
xiii) RIA Economical Analysis

xiv) Dig Verification Program

c) File the following original documents in appropriate PIR file folder and put in box by Analyst's Desk, along with tool run final reports, to go to basement filling system
   i) Signed Transmittal Letters (Preliminary Immediate, Final Immediate, and Final All)
   ii) ILI Integrity Worklist (Preliminary Immediate, Final Immediate, and Final All) (if applicable),

Note 1: From time to time, single Transmittals may be made for multiple runs in the same segment. In those cases, the EDMS location for the MFL run should contain the transmittal documents. The folder for the other technology, i.e. the caliper run, should contain shortcuts to link to the documents in the MFL run folder. The shortcuts should be named as follows:

Combined Transmittal Letters
Combined ILI Integrity Worklists
Combined Dig Sheets

The existing folder names can remain unchanged.

Note 2: After the above files have been moved to EDMS, delete from the s:\ drive

F30) Add features to the Anomaly Counting Database (ACD) using the **ACD Load Procedure** located in the back of this procedure.

F31) If anomaly features are identified and you have not done so already, contact the field maintenance supervisor and/or Pipeline Integrity Project Engineer to identify if the PLE group or the field maintenance group will be responsible for the repairs.
Note: If the PLE group will be responsible for the repairs, the Pipeline Integrity Project Engineer will write a work order to capture excavation and repair costs; otherwise the IE will:
   a) Using the procedures listed in Appendix 05H, prepare a cost estimate and work order for all repairs.
   b) Once released, communicate the SAP WO number for repairs and/or cutouts to the individual responsible for performing the work.

F32) After completion and release of the Final Report Transmittal, the IE shall:
   a) Update the AP History document to reflect the tool run in Section 5.2 ILI Tool Runs
   b) Update the AP History document to reflect the tool run date in Section 10 Baseline Assessment or Section 11 Reassessment Sections as appropriate
   c) Send an email to the Integrity Management and Risk Assessment Engineer to add the next reassessment to the AP History Document.

F33) Update SAP with hours worked in work order that original tool run was perform under.

Final Reports – Follow-up on Remaining Repairs

F34) Once a de-ration is in effect, the IE will update the de-ration log (if a de-ration log has not been created for this segment, create a new log for the de-ration – See F11) and the Integrity Analyst will monitor the length of time the deration has been in place. If the deration is still in effect after 60 days, the Integrity Analyst will monitor the Administrative Controls deadline as listed in **the Administrative Controls Extension** Procedure in the back of this appendix. When any change from Administrative Controls to Pressure Controls is made, note this change in the de-ration log.

F35) If required repairs cannot be completed by the scheduled due date, perform the following tasks:
   a) Non-HCA areas
      i) Contact the Field Maintenance Supervisor and request email documentation of why the repairs cannot be completed on time and when the repairs can be realistically expected to be completed.
      ii) Forward the received email, with a request to extend the due date(s), to the Pipeline Integrity Manager for approval.

iii) Upon approval, changes may be required in the ACD.
   (1) If the anomaly is a Priority indication, do not change the original due date in the worklist on EDMS; however, change the due date to the new date in the ACD.
   (2) If the anomaly is not a Priority feature change the required completion date(s) in the Integrity Worklist to the new due date(s), and load the updated list into EDMS.
iv) Post the extension approval letter in EDMS under the Anomaly Due Date Extension heading.
v) The IE will send an email transmittal and link to the revised work list to the individual responsible for making repairs. Copy the Integrity Analyst on this transmittal email.

b) HCA areas
   i) Anomalies that are not evaluated/repaired prior to the required due date, will require deration of the pipeline if they are within an HCA.
   ii) Upon notification that repairs will exceed the required due date, perform deration calculations as outlined in MPR 4104, section 5. Use the "B31.4 451.7 Deration Calculator Single" located at s:\Transportation\tech_ser\Internal Inspections\0 Calculators.
   iii) Issue Past Due Repair Pressure Deration email to the following distribution list.
      (1) Senior Pipeline Controller – Recipient, others are on the .cc list
      (2) Manager of Engineer and Projects
      (3) Pipeline Integrity Manager
      (4) Pipeline Integrity Manager
      (5) Technical Services Engineer
      (6) Pipeline Division Manager
      (7) Major Maintenance Supervisor
      (8) Logistics Manager
      (9) Scheduling Director
      (10) Pipeline Scheduler
      (11) Controller Center Manager
      (12) Regulatory Compliance Manager
      (13) DOT Coordinator
      (14) DOT SRC Coordinator
      (15) Pipeline Integrity Analyst
      (16) Integrity Engineer Lead
      (17) Environmental Coordinator

   iv) Update the BAP with the Past Due Derate Date. Add a comment identifying the deration pressure and your initials in the Analysis Comments field.
   v) Update EDMS with the pressure deration email.
   vi) Update EDMS with the pressure deration calculations.

F36) If the line cannot be derated or operated under a pressure deration on the line, notification to PHMSA must be made and further controls must be implemented to ensure public safety and environmental protection. The IE is to email (include an automatic reminder that a response is required back to the initiator within 24 hours of the email) Manager of Pipeline Integrity, Manager of Asset Integrity, and Manager of Regulatory Compliance of the PHMSA notification requirement. The Manager of Asset Integrity must submit a notification to PHMSA based upon information gathered in the following step.

F37) Complete the required information for the PHMSA notification form. An editable copy of the form is located at:

PHMSA Notification Form

F38) Upon submission of the information to the PHMSA website, post a copy of the submission to EDMS under the appropriate line ID.

F39) Upon notification of status from PHMSA, post a copy to EDMS under the appropriate line ID.

F40) Upon completion of all Immediate, *Priority and/or overdue repairs*, issue rescinded deration email.
   a) Update BAP for date of rescinded deration and remove deration from the deration log.
   b) Update EDMS with rescinded pressure deration email.
F41) Upon Completion of project, close ILI WO.
F42) Upon receipt from the field, the Pipeline Integrity Analyst (PIA) loads the ILI worklist to S:\Transportation\tech_ser\Internal Inspections\0 ILI Worklist Review. The IE will review the worklist within one week after it is posted to the S:drive, following the steps outlined in **the ILI Worklist Review Procedure** in the back of this appendix.
F43) Each time a worklist is returned with new completions, the IE will review it for compliance with API 1163 as outlined in the **API 1163 Compliance Review Procedure** located near the bottom of this procedure.

ACD Load Procedure

A1) Review and confirm the System, Section and Run ID in CPL-AID. If not already setup, **see CPL-AID Procedure 1.0 – Initial Setup of a New Pipeline Segment in CPL-AID.**

A2) Using the "Anomaly Import Query – From CPL-AID V5_5 ILI Worklist Export" query, search for any anomalies which were input after the Preliminary Report Worklist Development. If anomalies are found, confirm that those anomalies are on the current final worklist and after loading the new worklist to the ACD, delete these duplicate entries.

A3) To load the anomalies in the ACD, do the following:

a) Temporarily change Immediate Due Dates to match the Discovery Date in the ILI Integrity Worklist exported from CPL-AID, if applicable.
b) Temporarily change Priority Due Dates to one year from the Discovery Dates in the ILI Integrity Worklist exported from CPL-AID, if applicable.
c) Temporarily change the engineering station format to remove the "+" sign by setting the appropriate column format as numbers, if applicable.
d) Check the far right columns of the ILI Integrity Worksheet to ensure that the worklist has the Section ID and Run ID fields completed. If the worklist was exported from CPL-AID, these two columns should be populated. If the worklist was generated manually, determine the Section ID and Run ID from the appropriate tables in CPL-AID and add the Run ID and Section ID to the ILI Integrity Worklist.

A4) Load the anomaly features information to the Anomaly Counting Database (ACD).

A5) Copy and paste all of the anomalies from the ILI Integrity Worklist including the Run ID and Section ID added above and after completing the temporary modifications above to the worklist, into the "Anomaly Import Query – From CPL-AID V5_5 ILI Worklist Export" query of the Anomaly Counting Database (ACD).

A6) Before leaving the ACD, make sure that there are no duplicate entries for any given anomaly.

ILI Worklist Review Procedure

B1) Upon receipt of a worklist with completed excavations, the PIR Analyst uploads the worklist to the S:\Transportation\tech_ser\Internal Inspections\0 ILI Worklist Review folder. The IE will be responsible for review of the list, loading to EDMS and forwarding the approved worklist back to the Maintenance Supervisor. The IE is also responsible for updating the ACD with all dig completion details. In addition, the IE forwards the worklist to the tool vendor's Sr. Data Analyst.

i) ***Repeat this process on a weekly basis until the field evaluation is completed for all Immediate, Priority and 60 Day features. (A final copy of the worklist will be forwarded to the tool vendor upon completion of the dig program as part of the System Results Verification Process. (Process to be developed))***

B2) Open the Excel file. On the Worklist tab, check Actual Field Evaluation and Repair Information columns (columns T through AE) for completeness and accuracy.

i) Verify Field Determined Priority Code (column AC) is consistent with other reported information.
ii) Verify data has been entered correctly, e.g., Metal Loss Actual Depth (%) (Column W) should be entered as a percent; Dent Actual Depth (inches) (Column X) should be entered in inches.
iii) Verify that all required fields have been entered. If not, return the worklist to the field and notify them that the data is required prior to updating of the worklist.
iv) Verify cell formats are correct as stated in the comment fields in row one.

v) Make changes as required.

B3) Upload the reviewed list to the ACD using the above procedure.

B4) Return the due dates and engineering stationing fields to the original formats.

B5) Upload the completed ILI worklist as a new version on the appropriate EDMS site.

B6) Email an EDMS link of the updated work list to the appropriate field personnel.

B7) Then, using the email template called Vendor Review, email the worklist, unity graph(s), and Summary Report from the ACD to the vendor.

B8) Place email sent and any responses from the vendor in the Dig Verification Program folder.

Administrative Controls Extensions

For Administrative Controls Extensions, See Appendix 05T Anomaly Evaluations and Deration Tracking Procedures.

API 1163 Compliance Review

For API 1163 Compliance Review Procedures, Appendix 05Q, Procedure 15.0 Dig Program Verification Procedures.

Field Procedures for updating the ILI Integrity Worklist

For future updates to the ILI Worklists please follow the steps below. If you have any questions please contact Betty Hendricks at 580/767-7450 or email to:
Betty.J.Hendricks@conocophillips .com.

Thanks for your help in keeping our data consistent for quicker processing time.

For reference we use the following process when updates come in. Betty Hendricks receives the updated worklist and double checks the "Date of Revision" with the date in EDMS making sure the most recent version was used to make updates. She will then send the worklist to a folder where the ILI Engineer will review making sure you have entered the correct data. If corrections need to be made they will return the worklist to the person responsible and ask them fix. Once the worklist has been corrected they will update EDMS and enter changes into the Anomaly Counting Database (ACD).

Steps:

1. Field downloads the most recent worklist from EDMS and updates "Actual Field Evaluation and Repair Information." If you cannot get into EDMS contact Betty Hendricks.

2. When editing the worklist make all your changes in a Red Font.

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	NA	[illegible]	[illegible]	NO	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]												
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible] 08-09-076	[illegible]	[illegible]		[illegible]	[illegible]	[illegible]	NA	[illegible]	[illegible]	NO	[illegible]

A few things to remember when entering data:

The following fields are numeric fields and ONLY numbers should be input, (do NOT include % or " in any of these fields):
- Actual Wall Thickness
- Metal Loss Actual Depth (%), (Input as a decimal number, i.e.. 0.25 will be displayed as 25%).
- Dent Actual Depth (inches)
- Length (inches)

If a field of data does not apply to the anomaly you are recording, (such as Metal Loss Depth (%) for a plain dent), just leave the cell blank. Do not put in "0" or "n/a".
The cells are formatted to automatically wrap text. Please do not insert spaces to get information displayed on the next line.

Please keep in mind that the same anomaly may have a different Priority Code depending on whether it affects an HCA or not.

1. Once the ILI Engineer updates from this end they will change back to a **Black Font** and highlights the entire row in Yellow (indicating anomaly is complete) *Example below.*

Note:

The Integrity Engineer may make changes to the data that you submit so that the data format is correct and that the Field Priority Codes are correct. For this reason, it is important that you use the most current Worklist in EDMS when submitting future revisions. The Integrity Engineer will send an email to you letting you know that EDMS has been updated and if any you need to make any revisions to the data what was submitted.

1. DO NOT change the "Date of last revision" the top of the worklist. We will do this when we update your worklist in EDMS.

If you are unsure about how to create a PMLR number please see attached "how to."

http://livelink.conocophillips.net/livelink.exe/MPR_%2D_2809_%2D_Instructions_for_Completing_Form_3933_%2D_Pipeline_Maintenance_and_Leak_Report_%28PMLR%29.doc?func=doc.Fetch&nodeId=34362255&docTitle=MPR+%2D+2809+%2D+Instructions+for+Completing+Form+3933+%2D+Pipeline+Maintenance+and+Leak+Report+%28PMLR%29&viewType=1

PMLR #s.doc (90 B)

Also attached is a copy of the Priority Codes (GPL-513) when determining "Field Determined Priority Codes."

http://livelink.conocophillips.net/livelink.exe/GPL_513_%2D_PI_Form_%2D_Inline_Inspection_Analysis_Checklist_.xls?func=doc.Fetch&nodeId=36529832&docTitle=GPL+513+%2D+PI+Form+%2D+Inline+Inspection+Analysis+Checklist+&viewType=1

Inline_Inspection_Analysis_Che...

Stress Corrosion Cracking Dig Procedure

C.1. Procedures as identified in this section shall be reviewed and applied to all UT Crack tool ILI runs

C.2. Once the standard ILI anomaly dig list has been prepared, review the HCA and SCC Susceptibility Assessment.

C.3. Notify the Corrosion Control Engineers that a UT crack tool has identified crack fields which require a close interval survey (CIS).

C.3 . Insert a note in the IE's comment field to perform magnetic particle/dye penetrant testing of all dents in HCAs being excavated as part of the IMP.

C.4. For each crack field identified on the ILI worklist, determine whether it is in an area which has been identified as "Very High" or "High" susceptibility. For all such identified digs, put a note in the IE's comment field requiring the following additional tests:

- C.4.a Document the dig site with the following photos: (place a ruler or other device in the field of view for reference
  - i. The undisturbed site
  - ii. The coating condition (show sagging coating if found)
  - iii. Any identified cracks from magnetic particle/dye penetrant testing
- C.4.b pH of liquid under coating
- C.4.c pH of soil
- C.4.d Magnetic particle/dye penetrant testing (360 degrees around pipe required for SCC crack field digs only)
- C.4.e If crack fields are confirmed in the field, perform phased array TOFD UT or grind out the crack field to determine type and size

C.5 If more than three crack fields are on the list, but less than three crack fields have been identified as existing in a "Very High" or "High" susceptibility area, identify up to the minimum of three crack fields that represent the longest/deepest crack fields and put a note in the IE's comment field requiring the additional tests as listed in C.4.a-C.4.e above.

C.6 If no crack fields have been identified from a UT Crack tool ILI run, a minimum of three external metal loss features shall be identified for complete SCC documentation by putting a note in the IE's comment field requiring the additional tests as listed in C.4.a – C.4.e above.

Revision Log:

No.	Date	Initials	Description
0	06/27/2005	DMW	Added more description on how to load features into the Anomaly Counting Database after the Preliminary and Final Immediate transmittals.
1.0	07/12/2005	DMS	Added more description to some of the preliminary and final step to clarify if there are applicable or not when immediate features were not present in the preliminary or final reports.
1.1	07/22/2005	DMS	Added a few more clarifications to EDMS documents and folders in the final report section.
1.2	09/12/2005	DMW	Revised several sections to address the email distribution of transmittal letters and other documents.
1.3	09/12/2005	DMW	Revised procedures to cross check CPL-AID Dig Lists with the Checklist and the Worklists. Revised Anomaly Counting Database loading procedure to match CPL-AID export changes.
1.4	09/13/2005	DMW	Removed Integrity Analyst from email distributions and changed distribution of Integrity Projects Director, Regulatory Director, and DOT Coordinator to as necessary rather than only if there are

			features to be addressed.
1.5	09/14/2005	DMW	Added steps to the Preliminary Report and Final Immediate sections to remind the Integrity Engineer to release the SAP WO for repairs, if needed
1.6	09/14/2005	DMW	Added steps to *Final Report Immediate/60-Day* Evaluation on applying tool tolerance to features that could affect HCAs. Added 60-Day evaluation criteria.
1.7	09/26/2005	DMW	Added comment to include DOT Coordinator on all transmittals that include an ILI worklist so that the CSFM can be informed.
1.8	09/27/2005	DMW	Removed requirement to indicate Immediate Due Dates as Jan 1st of the current year when putting features into the Anomaly Counting Database.
1.9	11/02/2005	DMW	Added tolerance requirements to Step F8.
1.10	11/03/2005	DMW	Added Pipeline Integrity Analyst to email distributions only if ILI Integrity Worklists are issued
1.11	11/20/2005	DMW	Revised distributions to include everyone from the District Directors down to the person responsible for making the repairs.
1.12	12/04/2005	DMW	Moved Step F39 about updating SAP with hours worked to come after making the Repair Estimate step.
1.13	12/22/2005	DMW	Revised Final Transmittal section regarding issuing of dig sheets rather than Inspection Notebooks. Removed requirements to put certain jewelry items into SAP as notifications
1.14	1/10/06	DMS	Move steps F27 and F28 to New procedure "CPL-AID Modified Procedure" and renumbered this document. Also changed all references in this document, from "CPPL-AID" to CPL-AID" as the database name has recently been changed back to its original name.
1.15	01/17/2006	DMW	Revised ACD loading steps to change Immediate to Discovery Date and Priority to 1 year after the Discovery Date.
1.16	02/01/2006	DMW	Revised process to include Corrosion Control Team Leads to all Final Transmittal Reports and removed Corrosion Director and Corrosion Specialist from the distribution.
1.17	02/03/2006	DMW	02/03/2006Removed requirement to update EDMS with MOP Determination Spreadsheets, OD Sheets and HCA data.
2	02/03/2006	DMS	Rev 2. Remove the following statement from step P1, as it is understood (**If no Immediate or Priority features are present, also issue email of notification as such, for documentation.)** and does not need to be stated. Added checklists to document and modified title into the header strip.
3	02/15/2005	DMS	Rev 3. Revised page format by added headers and footers. Added notes in red below Final Report – All Remaining Feature Selections. Changed some of the section headers. Removed requirements for emails on Areas of Suspect Cathodic Protection and requirements to create and issue histograms. Changed all references from CPPL-AID to CPL-AID. Changed all references

			from Control Points to Reference Points.
4	02/22/2006	DMS	Rev 4. Revised distribution to include Pipeline Integrity Analyst on all distributions. Re-organized procedure to segregate responsibilities of Pipeline Integrity Analyst. Revised procedure to make the Pipeline Projects Integrity Engineer responsible for preparing the repair estimates. Added Step F10 to send vendor corrosion histograms to Corrosion Control Group. DMW. Corrected numbering some of the items, corrected the checklist to make changes above, and modified wording of items # F28. Also correct the date and revision of this report
5	03/24/2006	DMS	Rev 5. Removed Corrosion Engineer and the Corrosion Technician from the Preliminary Report distribution. Removed the "(Only if ILI Worklist is included)" from the distribution of Transmittals for the Integrity Analyst. Added Step F25 to remind IE to send Corrosion Histograms for MFL tools if it wasn't previously done in the Immediate/60-Day Transmittal.
6	05/09/2006	DMW	Rev 6. Modified distribution lists to add Corrosion Leads to any distribution that contains a Worklist.
7	05/12/2006	DMW	Rev 7. Modified Step F25 to send Corrosion Histograms for <u>all</u> MFL assessments to the Corrosion Leads.
8	07/12/2006	DMS	Rev 8. Revised step P3 to say District Engineer (SCD) instead of Operations Services Supervisor. Also under step P3, add link for email transmittal templates. Revised step P5 and added second sentence about the District Engineer (SCD) and the Technical Service Engineer participation in MOP and pressure uration determination, where applicable. Revised step P7 by adding the location information for the ILI Integrity Worklist template. Step P9 was changed to an Integrity Engineer's requirement and no longer the Analyst requirement. Step P9b was revised by adding notes 1 and 2 and modifying note 3. Step P9C was almost completely revised to include System, Section, and Run IDs setup in CPL-AID and Anomaly Counting Database (ACD) before added features to the ACD. Steps P10 and P11 were changed to Integrity Project Engineer's requirement instead of Integrity Engineer's requirement. Step F4b was revised. Step F7b (i) was revised to include Vendor's Orientation Tolerance. Step F9b was revised to include use vendor orientation tolerance. Step F11 was revised by adding requirement for notes on # features being report as well as revisions to me it read better and more specific. F11b was revised by adding notes 1 and 2 and modifying note 3. Steps F11 and F12 were changed to Integrity Project Engineer's requirement instead of Integrity Engineer's requirement. Step F21 as added to obtain GPS Lat, Lat and Elevation data from mapping group to be loaded into CPL-AID. Step F23 was revised to better describe the issuing of histograms. Step F24 was revised to exclude Appx 05P CPPL-AID Analysis Procedure as that procedure is not being used. When Appx 05P is reinstated as an active procedure it will again be added back into this procedure. F11b was revised by adding notes 1 and 2 and

			modifying note 3. Also revised F11b to include all of the EDMS File Naming Convention Documents listed in that document. The Checklist we removed from this document, as it was no longer current. The document owner was changed to Kelly Lee.
9	7/14/2006	DMS	Rev-9 Steps F21 and F22 including exports of Master Joint and Sublog to Terry Moore to obtain GPS data for CPL-AID and obtaining Landowner track numbers have been removed from this procedure and included in the Appendix 05Q – CPL-AID Modified Analysis Procedure.
10	7/25/06	KAL	Rev – 10. Clarified sequence of steps in *Preliminary and Final* Immediate pressure uration and transmittal emails. Steps P3 and F8 – Clarified immediate derate pressures with respect to data sources. – Step P8 – Added reference to HCA database for determining Immediate versus Priority features. Step P7, F10 and F24 – Added Project Integrity Engineer to all transmittals. Step P10 – Clarified BAP data entry process. Step F25 – Added "Tool run validation emails from vendors" and "Administrative Controls Extension emails" to EDMS stored information. Step F26 – Clarified original documentation files for records and clarified entries into Anomaly Counting Database (ACD). Steps P11, P12, F12, F13, *F27 and F28 – Changed to Notes: since* work is performed outside the of this document.
11	8/3/06	KAL	Rev 11. Renamed Appendix 05Q to reflect new title and scope of 05Q document. New Appendix is "05Q CPL-AID Procedures Manual – Procedure 7 – Dig List Creations"
12	9/11/06	KAL	Rev 12. Removed reference to loading System ID, Section ID and Run ID to Anomaly Counting Database. Minor format changes
13	11/21/06	KAL	Rev 13 Added Bottom side dents with 1) metal loss, 2) crack or 3) stress riser to section F9 (b) as these are 60 day features.
14	12/4/06	KAL	Changed transmittal letters to an email with appropriate links to final documents stored on EDMS.
15	1/19/07	KAL	Minor updates of distribution lists to include Pipeline Financial Analyst. Added instructions on pipeline repair date extensions and past due repair derations beginning at step F25
16	2/5/07	KAL	Remove development of corrosion histograms from 05M procedure. New procedures exist in CPL-AID for this work. Removed procedures for setup of System, Section and Run ID. New procedures exist in CPL-AID for this work. Modified procedure for adding anomalies to Anomaly Counting Database.
17	4/12/07	KAL	Added information on writing work orders *to cover excavations* and repairs. Added information on steps to take to document extension of time to perform repairs and required PHMSA notifications.
18	5/14/07	KAL	Renumbered steps for consistency. Removed requirement for checklist on transmittal letters.
19	6/29/07	KAL	Changed PHMSA notification form to Live link editable form. Added section ACD Load. Added crack tool references. Rewrite of sections to reduce redundancy.

20	2/28/08	KAL	Minor cleanup of verbiage. Changed link for spreadsheet process from S: drive to EDMS link. Added ILI Worklist review and RIA documentation requirements. Added AP History update process.
21	3/10/08	KAL	Added Administrative Controls Extension Procedure details. Moved routine tasks to minor procedure area attend of document. Removed MOP Determination Spreadsheets, OD Sheets and mechanical Data Sheets from file to load to EDMS. Mechanical Data Sheet load requirement sent to Terry Red Leaf to inclusion in Appendix 05A. Cleaned up formatting.
22	3/25/08	KAL	Added crack tool anomalies for excavation and evaluation.
23	3/27/08	KAL	Added Environmental Coordinators to the cc: list for all transmittals that include an ILI Integrity Worklist.
24	4/15/08	KAL	Added Pipeline Controller Shift Superintendent and Supervisor Engineering Services to derate emails. Clarified storage areas on EDMS for Corrosion Items.
25	4/16/2008	MRN	F29 c) iii – Removed this requirement to print dig sheets for basement filing system.
26	5/8/08	DMS	Added cover page header and revised footers. Also put the revision log in a table.
27	5/13/08	DMS	Updated Text of API 1163 Compliance Review Procedure to be consistence with today's requirements.
28	5/14/08	DMS	Relocated Administrative Controls Extensions from this document to Appendix 05T Anomaly Evaluations and Deration Tracking Procedures.
29	5/20/08	DMS	Relocated API 1163 Compliance Procedure to Appendix 05N Dig Program Verification Procedure.
30	5/27/2008	BJH	Added Field Procedure for Updating the ILI Integrity Worklist
31	10/3/2008	MRN	F7 c) iii) (1) Corrected the link for Crack calculator.
32	10/3/2008	MRN	F37 Updated the PHMSA link with the correct URL.
33	10/6/2008	MRN	Replaced F25 & F26 with new procedures for evaluating crack tools.
34	10/6/2008	MRN	P11 & F30 – Added corrosion engineers to distribution list
35	10/27/2008	MRN	P14 – Change responsibility of developing cost estimates from IE to field personnel.
36	12/11/2008	MRN	P8 – Added a statement that tool tolerance is only applied to anomalies <u>not</u> located in HCAs.
37	3/18/2008	MRN	B6 & B8 – Added two new steps for emailing updates to field personnel and unity graphs, etc to the vendor.
38	3/18/2009	MRN	F36 – Added distribution list for PHMSA notification.

39	3/18/2009	MRN	F31b- Added Dig Verification Category.
40	4/14/2009	MRN	P4, F8, F35 – Updated distribution list due to re-organization
41	4/15/2009	MRN	F36 – Added statement about automatic reminder within 24 hours P4 & F8e – Added statement about Area Supervisor being a recipient of SRC portion of duration emails.
42	4/15/2009	MRN	P3, P5, P9, P11ii, P11iii, P11iv, F8e, F10), F10b (3) (4) (7), F29, F30, F30c) d), F35)ii) – Updated these section with correct business titles per the organization chart. Integrity Projects Director and Integrity Projects Engineer were deleted as recipients of any transmittals.
43	4/24/2009	MRN	Removed Supervisor Engineering Services from all distribution lists.
44	6/5/2009	MRN	Change reference Appendix in API 1163 Compliance Review section from O5N to O5Q.
45	7/27/2009	MRN	Added notes about creating and updating a deration log (P7, P19, F11c, F18, F34).
46	8/11/2009	KAL	Add SCC dig documentation requirement procedure. Added requirement to notify Corrosion Engineers of crack fields so CIS can be scheduled. Added statement that 360 degree magnetic particle/dye penetrant is required for all dents.

CPPL

ConocoPhillips Pipe Line Company

CPPL-TSD-8000

Line Pipe External Stress Corrosion Cracking Threat Assessment

Rev. 0 – Effective Date: 2009-08-24

2009-08-24 SUPERSEDES CPPL-MPR-7011 Effective Date: 2005-08-03

Document Summary

This document outlines the standard practice for assessing the susceptibility of line pipe to external stress corrosion cracking.

Disclaimer

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Table of Contents

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1. Scope, Purpose, and Application

1.1. Scope

This program addresses two types of external stress corrosion cracking; identified in industry as classical (or high-pH) stress corrosion cracking and near-neutral pH stress corrosion cracking. Other types of stress corrosion cracking (i.e., ethanol stress corrosion cracking) are outside the scope of this program.

1.2. Purpose

The purpose of this performance standard is to specify the requirements of the ConocoPhillips Pipe Line Company (CPPL) program to identify, prioritize, manage, and mitigate risks associated with pipeline external stress corrosion cracking.

1.3. Application

The program governed by this document applies to carbon steel pipeline (line pipe) used for the purpose of transporting hydrocarbons in pipelines controlled or maintained by CPPL.

2. Reference Publications

The following documents are referenced in this standard. Users are encouraged to apply the most recent editions of the references indicated below:

2.1. International, National and Industry Standards and Publications

DOT Advisory Bulletin ADB-03-05, *Stress Corrosion Cracking (SCC) Threat to Gas and Hazardous Liquid Pipelines*
DOT TTO Number 8, *Integrity Management Program Delivery Order DTRS56-02-D-70036-Stress Corrosion Cracking Study* - January 2005
CEPA Stress Corrosion Cracking Recommended Practices, 2nd Edition, December 2007
NACE International Publication 35103, *External Stress Corrosion Cracking of Underground Pipelines*, October 2003
ANSI/NACE Standard RP0204-2004, *Stress Corrosion Cracking (SCC) Direct Assessment Methodology*
NACE SP0502-2008, *Pipeline External Corrosion Direct Assessment Methodology*

ASME B31.8S, *Managing System Integrity of Gas Pipelines*

2.2. ConocoPhillips Corporate Standards

TPO-7001, *Corrosion Control Policy*
Form 3933, *Pipeline Maintenance and Leak Report*
MPR-2809, *Instructions for Completing Form 3933 – Pipeline Maintenance and Leak Report*
MPR-4103, *General Line and Equipment Maintenance Evaluation/Repair of External/Internal Pipeline Defects and Anomalies*
MPR-4105, *General Line and Equipment Maintenance – Cleaning and Coating of Buried Pipe*
MPR 4406, *Welding-Repair or Removal of Defects by Grinding or Welding*
MPR-7012, *Field Determination of Soil pH*
MPR-7013, *Field Determination of pH Under Coatings*
IMP Appendix 05M

3. Definitions

3.1. Classical (High-pH, or Carbonate/Bicarbonate) Stress Corrosion Cracking

A form of stress corrosion cracking found propagating from the exterior (OD) of line pipe steels. It is characterized by tight, branched, intergranular cracks and is typically associated with the presence of a high pH electrolyte (pH > 9.3) containing carbonate/bicarbonate compounds.

3.2. Near-Neutral pH Stress Corrosion Cracking

A form of stress corrosion cracking found propagating from the exterior (OD) of line pipe steels. It is characterized by transgranular cracks with limited branching and is typically associated with the presence of a near-neutral electrolyte (pH range 6-8). Typically there is also corrosion of the crack walls and pipe surface.

3.3. Stress Corrosion Cracking

The cracking of a material due to the combined action of stress and a corrosive environment. The cracking may be intergranular (between grains) or transgranular (across grains), with or without significant branching. There are many types of stress corrosion cracking affecting many types of materials, each requiring the combination of mechanical stresses with very specific environmental (chemical exposure and temperature) conditions.

3.4. Hydrogen Potential (pH)

The negative logarithm of the hydrogen ion activity written as:

$$pH = -\log_{10} (a_H^+)$$

Where a_H^+ = hydrogen ion activity = the molar concentration of hydrogen ions multiplied by the mean ion-activity coefficient.

3.5. Pipeline Segment

The portion of a pipeline from station to station or from pig launcher to receiver.

3.6. Pipeline Sub-Segment

The portion of a pipeline segment defined by changes in pipe properties such as pipe grade, diameter, thickness, coating type, HCA boundaries, etc. Pipeline properties data as extracted from PODS is used to determine pipeline sub-segments.

4. Mechanisms of Cracking

Stress Corrosion Cracking (SCC) mechanisms require ALL of the following conditions in order to occur:

- Susceptible material
- Stress
- Corrosive Environment

If any one of these conditions are removed or eliminated, cracking will not occur.

4.1. Susceptible Material

Line pipe steels are susceptible to various corrosive environments which can occur at the pipe surface. Since it is not cost-effective to use metals which are resistant to the environments the pipe may experience, pipelines are covered with a non-metallic coating to protect it from the environment. If there are holidays or failures of the coating, the corrosive environment may reach the steel.

Adequate cathodic protection of the steel can prevent the steel from corroding in areas of coating damage, but only if the coating is not shielding the cathodic protection current from reaching the pipe.

4.2. Stress

Stress in the line pipe steel comes from many sources and is nearly impossible to eliminate. Increasing stress results in increasing probability of cracking. Some areas on the pipe, such as bends, defects and mechanical damage (i.e., dents) are even more susceptible to cracking due to the increased localized stresses.

4.3. Corrosive Environment

Various corrosive environments can form at the surface of the pipe if the coating is compromised. Water trapped under the coating will contain varying corrosive species, depending on the type of soil and soil contaminants present. Different environments can be created depending on how well the soil drains. Repeated wet/dry cycles may lead to more corrosive conditions than areas that are constantly wet.

5. Program Requirements

The Line Pipe External Stress Corrosion Cracking Threat Assessment and Mitigation Program consists of three primary parts:

- Identification of pipeline segments susceptible to high-pH or near-neutral pH stress corrosion cracking.
- Management of pipeline segments susceptible to high-pH or near-neutral pH stress corrosion cracking.
- Management of pipeline segments containing high-pH or near-neutral pH stress corrosion cracking damage.

5.1. Identification of Pipeline Segments Susceptible to High-pH or Near-Neutral pH Stress Corrosion Cracking

All pipelines shall be subject to a series of screening processes to determine susceptibility to stress corrosion cracking (SCC). The first screening process, Tier 1, occurs at the pipeline or pipeline segment level. The Tier 2 screening process is used to examine sub-segments of pipelines or pipeline segments found to have a "High" or "Medium" susceptibility by the Tier 1 screening process.

5.1.1. Tier 1 Screening Process

Each pipeline shall be screened for susceptibility to SCC according to the criteria outlined below. Pipelines found NOT susceptible in the Tier 1 process will be reviewed every 5 years to re-evaluate susceptibility.

Any pipeline segments which have had external SCC confirmed are automatically moved to the Tier 2 screening process.

In the Tier 1 assessment, the pipeline major segments (i.e., station to station) are evaluated for susceptibility based on operating stress and coating type.

Operating stress is calculated based on the MOP (maximum operating pressure) of the line segment and the diameter and thickness of the pipe. That stress is compared to the specified minimum yield stress (SMYS) of the pipe, resulting in a percentage.

All Pipelines with the potential to operate above 50% SMYS are further evaluated based on coating type, as shown in the table below. The ≥50% SMYS limit may be raised to 60% SMYS upon verification of pipe properties.

Table 5.1.1.1 Tier 1 Coating Type Screening

Coating Type	CP Shielding	Examples	SCC Susceptibility
Shielding	Significant	Polyethylene tape, shrink sleeves, fiberglass wraps	High
Non-Shielding	Low	coal tar wraps and asphaltic mastic type coatings, geotextile backed tapes, and fabric-backed wax tapes	Medium
High Performance	None	Fusion Bonded Epoxy (FBE), field-applied epoxy, epoxy urethane, and extruded polyethylene.	Low

Susceptibility due to operating stress (%SMYS) and coating type are combined to perform the Tier 1 SCC Susceptibility ranking as shown in the table below.

Table 5.1.1.2 Tier 1 SCC Susceptibility Screening

Known SCC Present	Operating Stress Rank	Coating Type Rank	Tier 1 SCC Susceptibility Rank	Action
Yes	Any	Any	High	Tier 2 Screening (Within 6 months)
No	≥50% SMYS*	High	High	Tier 2 Screening (Within 6 months)
No	≥50% SMYS*	Medium	Medium	Tier 2 Screening (within one year)
No	≥50% SMYS*	Low	Low	Reassess every 5 years
No	<50% SMYS	N/A	Low	Reassess every 5 years

* The ≥50% SMYS limit may be raised to 60% SMYS upon verification of pipe properties.

5.1.2. Tier 2 SCC Susceptibility Screening Process

Only pipelines with a Tier 1 SCC Susceptibility Rank (see Table 5.1.1.2) of Medium or High shall be subject to the Tier 2 Level Screening Process.

Prior to undergoing the Tier 2 Screening Process, all pipelines shall be broken into sub-segments according to pipe attributes.

According to B31.8S, Appendix A, "Each segment should be assessed for risk for the possible threat of SCC if all of the following criteria are present:

a) Operating stress >60% SMYS
b) Operating temperature >100F
c) Distance from compressor station ≤20 miles
d) Age ≥10 years
e) All corrosion coating systems other than fusion-bonded epoxy (FBE)"

The process used in this analysis is more conservative than the B31.8 criteria outlined above:

- Operating stress >50% SMYS rather than >60% SMYS

- Rather than requiring ALL criteria to be present, several levels of susceptibility are considered, with the highest level comprising all of the above criteria.

The following series of tables is used to determine the relative Tier 2 SCC Susceptibility based on the above factors, and the presence of HCA's.

Table 5.1.2.1 SCC Susceptibility
MOP >50%* SMYS, Shielding Coatings, in HCA

Distance D/S of Pump Station	Coating Age	Operating Temp	HCA	Tier 2 SCC Susceptibility Ranking	Recommended Action
<20 mi	>10 yr	>100F	Yes	Very High	Perform Close Interval Survey over identified sub-segment. Notify ILI team to provisionally budget for ILI Crack Tool pending results of Engineering Analysis.**
<20 mi	<10 yr	>100F	Yes	High	Schedule Close Interval Survey over identified sub-segment. Perform Engineering Analysis.***
<20 mi	>10 yr	<100F	Yes	High	Schedule Close Interval Survey over identified sub-segment. Perform Engineering Analysis.***
>20 mi	>10 yr	>100F	Yes	High	Schedule Close Interval Survey over identified sub-segment. Perform Engineering Analysis.***
<20 mi	<10 yr	<100F	Yes	Medium High	Schedule for Corrosion Engineering review.
>20 mi	<10 yr	>100F	Yes	Medium High	Schedule for Corrosion Engineering review.
>20 mi	>10 yr	<100F	Yes	Medium High	Schedule for Corrosion Engineering review.
>20 mi	<10 yr	<100F	Yes	Medium	Reassess every 5 years or as conditions change

*The ≥50% SMYS limit may be raised to 60% SMYS upon verification of pipe properties.

** Engineering Analysis consists of a joint review by Corrosion and Pipeline Integrity Engineers to evaluate the need to run a UT crack detection ILI tool. A decision not to run an ILI with a UT crack detection tool on a segment with a Tier 2 SCC Susceptibility

Ranking of Very High requires the approval of the Manager, Asset Integrity.

***Engineering Analysis consists of a joint review by Corrosion and Pipeline Integrity Engineers to evaluate the need to run a UT crack detection ILI tool. If the Engineering Analysis determines that a UT crack tool run is required, the ILI team will budget for the tool run.

Table 5.1.2.2 SCC Susceptibility
MOP >50%* SMYS, Shielding Coatings, NOT in HCA

Distance D/S of Pump Station	Coating Age	Operating Temp	HCA	Tier 2 SCC Susceptibility Ranking	Recommended Action
<20 mi	>10 yr	>100F	No	High	Schedule Close Interval Survey over identified sub-segment. Perform Engineering Analysis.**
<20 mi	<10 yr	>100F	No	Medium High	Schedule for Corrosion Engineering review.
<20 mi	>10 yr	<100F	No	Medium High	Schedule for Corrosion Engineering review.
>20 mi	>10 yr	>100F	No	Medium High	Schedule for Corrosion Engineering review.
<20 mi	<10 yr	<100F	No	Medium	Reassess every 5 years or as conditions change
>20 mi	<10 yr	>100F	No	Medium	Reassess every 5 years or as conditions change
>20 mi	>10 yr	<100F	No	Medium	Reassess every 5 years or as conditions change
>20 mi	<10 yr	<100F	No	Low	Reassess every 5 years or as conditions change

*The ≥50% SMYS limit may be raised to 60% SMYS upon verification of pipe properties.

**Engineering Analysis consists of a joint review by Corrosion and Pipeline Integrity Engineers to evaluate the need to run a UT crack detection ILI tool. If the Engineering Analysis determines that a UT crack tool run is required, the ILI team will budget for the tool run.

Table 5.1.2.3 SCC Susceptibility
MOP >50%* SMYS, Non-Shielding Coatings, in HCA

Distance D/S of Pump Station	Coating Age	Operating Temp	HCA	Tier 2 SCC Susceptibility Ranking	Recommended Action
<20 mi	>10 yr	>100F	Yes	High	Schedule Close Interval Survey over identified sub-segment. Perform Engineering Analysis.**
<20 mi	<10 yr	>100F	Yes	Medium High	Schedule for Corrosion Engineering review.
<20 mi	>10 yr	<100F	Yes	Medium High	Schedule for Corrosion Engineering review.
>20 mi	>10 yr	>100F	Yes	Medium High	Schedule for Corrosion Engineering review.
<20 mi	<10 yr	<100F	Yes	Medium	Reassess every 5 years or as conditions change
>20 mi	<10 yr	>100F	Yes	Medium	Reassess every 5 years or as conditions change
>20 mi	>10 yr	<100F	Yes	Medium	Reassess every 5 years or as conditions change
>20 mi	<10 yr	<100F	Yes	Low	Reassess every 5 years or as conditions change

* The ≥50% SMYS limit may be raised to 60% SMYS upon verification of pipe properties.

**Engineering Analysis consists of a joint review by Corrosion and Pipeline Integrity Engineers to evaluate the need to run a UT crack detection ILI tool. If the Engineering Analysis determines that a UT crack tool run is required, the ILI team will budget for the tool run.

Table 5.1.2.4 SCC Susceptibility
MOP >50%* SMYS, Non-Shielding Coatings, NOT in HCA

Distance D/S of Pump Station	Coating Age	Operating Temp	HCA	Tier 2 SCC Susceptibility Ranking	Recommended Action
<20 mi	>10 yr	>100F	No	Medium High	Schedule for Corrosion Engineering review.
<20 mi	<10 yr	>100F	No	Medium	Reassess every 5 years or as conditions change
<20 mi	>10 yr	<100F	No	Medium	Reassess every 5 years or as conditions change
>20 mi	>10 yr	>100F	No	Medium	Reassess every 5 years or as conditions change
<20 mi	<10 yr	<100F	No	Low	Reassess every 5 years or as conditions change
>20 mi	<10 yr	>100F	No	Low	Reassess every 5 years or as conditions change
>20 mi	>10 yr	<100F	No	Low	Reassess every 5 years or as conditions change
>20 mi	<10 yr	<100F	No	Very Low	Reassess every 5 years or as conditions change

* The ≥50% SMYS limit may be raised to 60% SMYS upon verification of pipe properties.

5.2. Management of Pipeline Segments Susceptible to High-pH or Near-Neutral pH Stress Corrosion Cracking

5.2.1. Engineering Analysis

An Engineering Analysis shall be performed on all segments with a Tier 2 Susceptibility Ranking of Very High or High. Engineering Analysis consists of a joint review by Corrosion and Pipeline Integrity Engineers to evaluate the need to run a UT crack detection ILI tool. A decision not to run an ILI with a UT crack detection tool on a segment with a Tier 2 SCC Susceptibility Ranking of Very High requires the approval of the Manager, Asset Integrity.

5.2.2. Inline Inspection

When the need for inline inspection has been determined through Engineering Analysis, inspection tools utilizing transverse shear wave ultrasonic crack detection technology, or equivalent, shall be used. Transverse magnetic flux technology has not been proven to be able to detect stress corrosion cracks and shall not be considered equivalent to the transverse shear wave ultrasonic technology. This is the preferred method of inspecting large amounts of susceptible pipe that is also susceptible to seam defect growth by pressure cycle fatigue mechanisms.

5.2.3. Anomaly Digs

Evaluation and repair digs already scheduled for metal loss, dents, and seam features shall be utilized for evaluating pipeline segments susceptible to stress corrosion cracking. MPR-4103 shall be used for evaluation and repair of anomalies.

5.3. Management of Pipeline Segments Containing High-pH or Near-Neutral pH Stress Corrosion Cracking

5.3.1. Evaluation of Crack Fields

Once a crack field has been identified and sized, it must be evaluated. Crack fields shall be evaluated as if it were a metal loss anomaly of the same dimensions and as if it were a seam defect susceptible to pressure cycle fatigue. The pressure cycle evaluation shall consider the longest and deepest crack found via phased array UT, taking into account potential interactions of nearby cracks as a single crack.

5.3.2. Repair of Crack Fields

All crack fields shall be repaired per the requirements of MPR-4103.

5.3.2.1. Coating of Repairs

The pipe shall be cleaned and recoated in accordance with MPR-4105, "General Line and Equipment Maintenance – Cleaning and Coating of Buried Pipe." In all cases, use of shielding coatings (i.e., polyethylene tapes, glass/fiberglass wraps, and shrink sleeves) in areas where Stress Corrosion Cracking has been identified shall be prohibited.

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6. Program Continuous Improvement

This program shall be modified as more data and experience is developed relative to detecting and managing line pipe external stress corrosion cracking.

6.1. Evergreen Document

This document may be modified at any time, by the controlling organization, as needed for process improvement purposes. It may also be modified if there are outstanding regulatory requirement changes that affect this process.

6.2. Required Updates

This document shall be reviewed and updated by the controlling organization at least annually. This update shall include, in addition to process improvements, any changes required by regulatory changes as well as any change editorial in nature.

(End of Document)

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7. Revision/Approval Log

Revision/Approval Log			
Rev. No.	Date	Action	By
0	08/24/2009	Initial issuance.	Kelly Lee

Asset Naming Convention: ________________ **Pipeline Segment:** ____________________

Conclusion **Corrosion Susceptibility:**	*Based on completed evaluation* ☐ **High** ☐ **Moderate** ☐ **Low**

Overview

The following considerations should be used as a checklist to help determine the effectiveness of internal and external corrosion protection plans for the pipeline segment being considered. These considerations will be evaluated by the Corrosion Engineer to assist in making key decisions in the type of reassessment method(s) to be implemented as well as defining any other potential preventive and mitigative activities.

The process for determining the reassessment type requires the susceptibility to corrosion for each line segment be categorized into high, moderate, or low susceptibility. After evaluating the considerations listed in this document, the Corrosion Engineer will determine a corrosion susceptibility category based on the criteria listed at the end of this Appendix (see section titled, "Corrosion Susceptibility Categorizing Criteria").

In this document, the term line segment *refers to* "a length of pipe that can be identified from block valve to block valve (i.e. process flow isolation), pig trap to pig trap (i.e. smart pig run), or isolating flange to isolating flange (i.e. cathodic protection). The segments that will be evaluated using this evaluation are consistent with the segments identified in the assessment plan.

Prior to completing this Corrosion Protection Effectiveness Survey, obtain engineering data for HCA stationing. This data will be used to correlate any areas of concern to HCA position.

Section Completed by ILI Engineers

Questions Related to Internal and/or External Corrosion

Completed By: ______________________________ **Date Completed:** ____________________

1. Has the line segment been internally inspected (smart pig)?					
ILI Pig (MFL)	**Run Date**	**Anomalies**		**Number of Digs Identified that Failed Pressure Calculations**	**Number of Corrosion Related Anomalies Requiring Repair**
		External	**Internal**		
Most Recent:					
Prior (Last):					
Comments:	An internal inspection provides data to assess if there has been any metal loss or thinning in the pipe walls (internal or external). Multiple ILI runs can be evaluated for increasing number of anomalies or increasing damage.				

2. For the completed ILI digs, what was the condition of the coating?	☐ **Good** ☐ **Fair** ☐ **Poor** ☐ **Essentially Bare**
Comments:	Consider whether the coating is protecting the pipe from corrosion or is its condition such that the pipe should be considered bare.

Questions Related to External Corrosion

3a. For areas that had greater than 5% (normalized) of the cumulative damage with an identified step change, was a CIS performed over the suspect area?	☐ No ☐ Yes
3b. Did the CIS indicate areas of concern with respect to adequacy of CP?	☐ No ☐ Yes
3c. How were areas of CP concern mitigated?	☐ Coating Remediation: ______
	☐ Increased CP Date Completed: ______ Date Effectiveness Confirmed: ______
	☐ Other: ______

3d. List all areas of concern in the table below:

Eng Start	Eng Stop	P/S Reading (Average)	Concern	Recommendation

4. Does the line segment have effective CP as defined by NACE criteria (6.2 and 6.3 of NACE Standard RP0169-96)?	☐ No ☐ Yes
Comments:	Effective cathodic protection provides for mitigation of pipeline corrosion.

5a. What is the rectifier spacing in miles?	______
5b. Based upon the current rectifier settings, what is the current density in mA/ft^2?	______ *Note: Report the highest current density along line segment.*

6a. Has a CIS been performed on the line segment within the last 2 years?	☐ No ☐ Yes
Comments:	A CIS will identify areas for additional corrosion control investigation. CIS can be run on all or part of the line segment.

6b. Did the CIS identify any areas of concern?	☐ No ☐ Yes
Comments:	Identified anomalies could be the result of poor coating, ineffective CP, or active corrosion.

6c. If areas of concern were identified, were they investigated and/or mitigated?	☐ No ☐ Yes
Comments:	Evaluation of anomalies assists in identifying poor coating, ineffective CP, or active corrosion.

List all HCAs identified during this evaluation that have not been cleared of issues with remedial measures:

Anomaly Type (Int / Ext)	HCA Number	Eng Start	Eng Stop	PIRAMID Risk Ranking	Comments

Corrosion Susceptibility Categorizing Criteria

High The pipe segment susceptibility to corrosion should be categorized as High if any of the following conditions are met.

- In-service corrosion failure(s) since the last assessment, or
- Ineffective corrosion mitigation program
  - Surveys have been consistently below criteria over portions of the pipe segment, or
  - Significant increase in corrosion features is identified by the latest ILI assessment or corrosion related failures occurred, if the latest assessment was a hydro test, or
  - Internal corrosion rate has been consistently in excess of 1 mil/year.

Moderate The pipe segment susceptibility to corrosion should be categorized as Moderate if the following condition is met.

- The line segment has an effective corrosion mitigation program (both external and internal), and any of the following conditions are met.
  - Only 1 (or no) ILI corrosion detection tool assessment has been run during the history of the pipe segment, or if it has been 10 years since the last tool run, or
  - There is an increasing number of corrosion features since the last ILI corrosion detection assessment (as identified with cumulative damage analysis).

Low The pipe segment susceptibility to corrosion should be categorized as Low if the following conditions are met.

- The line segment has an effective corrosion mitigation program, with no indication of a significant amount of increased cumulative damage, and
- There have been 2 or more compatible high resolution ILI corrosion detection tools which are 5 – 10 years apart, and
- No in-service corrosion failures have occurred since the last ILI corrosion detection tool assessment.