SENT TO COMPLIANCE REGISTRY
Hardcopy___ Electronically ✓
# of Copies 1 / Date 8-22-08

08-22-08A11:38 RCVD

TESORO

Refining and Marketing Company

Pipeline, Terminal, & Trucking
300 Concord Plaza
San Antonio, TX 78216-6999

August 21, 2008

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration
12300 W. Dakota Ave., Suite 100
Lakewood, CO 80228

Dear Mr. Hoidal:

SUBJECT: RESPONSE TO CPF NO. 5-2008-0006M – NOTICE OF AMENDMENT

This letter is in response to the above-referenced NOA, dated March 13, 2008. The finding from the NOA is repeated in shaded italics, and Tesoro Refining and Marketing Co.'s (Tesoro's) response follows. *All referenced documents are attached.*

Tesoro has completed a revision of its Integrity Management Program. This program, which previously covered only hazardous liquid pipelines, now includes both gas and hazardous liquid pipelines. The information and procedures for integrity management of Tesoro's only gas pipeline, the subject of this Notice of Amendment, are now interwoven into the newest revision of Tesoro's Integrity Management Program

1 – HCA Identification
1A: 192.905(a)

Tesoro's High Consequence Area (HCA) identification process does not document the method used to identify HCAs.

Tesoro's revised Procedure IM001, Volume Release and HCA Impact, describes the different methods used to identify HCAs. Method 2 is used for this determination; this is identified on page 2-3 of the Tesoro Integrity Management Program.

1B: 192.903

The calculations performed by Tesoro's consultant, SECOR, to determine the potential impact radius (PIR) appear to use a value for the pipe Diameter of 10.52 inches, while the Tesoro IMP states that the pipe outside diameter is 10.75 inches. This results in a lower PIR.

Tesoro calculated the PIR based on the nominal diameter of the pipe, 10-inches, as discussed in the description of the variable "D" in FAQ 16 (part of which is included below).

FAQ 16: Determining if Pipeline is in an HCA

Question: How will an operator determine if a pipeline is in an H CA?

Answer: The potential impact radius must be calculated along the pipeline using the following formula:

$PIR = .69 * (p * d^2)^{0.5}$

Where:

PIR = Potential Impact Radius (in feet)

P = maximum allowable operating pressure (in pounds per square inch)

D= nominal pipeline diameter (in inches)

0.69 is a constant applicable to natural gas (constants for other gases must be determined in accordance with Section 3.2 of ASME B31.8S-2001)

...

1C: 192.905(b)(1)

The Tesoro HCA identification results do not indicate whether high consequence areas that were identified include the area extending axially along the length of the pipeline from the outermost edge of the first potential impact circle to the outermost edge of the last contiguous potential impact circle.

Tesoro has re-evaluated the pipeline's PIR; the entire pipeline is evaluated with a PIR of 253 feet that extends axially along the length of the pipeline, as demonstrated in Procedure IM001, Volume Release and HCA Impact.

1D: 192.905(a) and 192.905(b)(1) & (2)

The Tesoro HCA identification does not include a systematic identification of potential identified sites in the vicinity of the pipeline. The HCA identification did not include consideration of the "Coke Barn" facility as an identified site, even though the site occupancy may meet the criteria for an identified site.

Tesoro has re-evaluated the HCA and now accounts for all buildings and the occupancy of the buildings. The pipeline, identified to be in a Class 3 area, is now designated as a 100% HCA segment due to the extended buffer and the counting of the identified sites. This is stated on page 2-4 of Tesoro's Integrity Management Program.

2: 192.917 Risk Assessment

The Tesoro IMP does not document the risk assessment process that will be used in future risk assessments. A risk assessment is needed to set priorities for integrity assessments and it is required to support evaluation of preventive and mitigative measures. Current documentation is from a Shell risk assessment process was last implemented in 2004. Potential errors were found in the risk scorecard evaluation that was part of the risk assessment at that time. IMP Section 3 does not indicate what risk assessment process will be conducted in the future.

Tesoro's revised Procedure IM003, Risk Assessment, describes the risk assessment process that will be used in future risk assessments (the same process that is currently used for Tesoro's hazardous liquid pipelines). This risk assessment process, performed annually, uses an algorithm based on the risk scoring presented by Kent Muhlbauer (Pipeline Risk Management Manual).The data gathering process for the risk assessment analysis is described in Procedure IM002, Information Analysis.

3: 192.937 Reassessment Intervals

The assumed corrosion growth rate used to obtain the seven-year reassessment interval is not conservative. The corrosion growth analysis assumes a corrosion half-life of 39 years. This is not consistent with NACE defaults and predicts slower corrosion growth than would be obtained using these default figures. Tesoro does not offer a basis for making these more optimistic assumptions..

Tesoro's revised Procedure IM010, Pipe Repairs, discusses appropriate techniques to address corrosion growth and reflects NACE processes.

4: Preventive and Mitigative Measures
4A: 192.935(a)

The Tesoro IMP process for evaluation of preventive and mitigative measures is not defined adequately. A risk assessment was conducted in 2004, but this was performed using Shell Pipeline's approach that is not the approach that is intended to be used in the future. .

Tesoro's Procedure IM011, Preventive and Mitigative Measures, defines the measures to implement on an HCA pipeline segment. This procedure defines the areas to review and mitigate should a concern or threat be identified. Tesoro's Procedure IM012, Leak Detection and EFRD Analysis, gives further guidance on determining the need for leak detection and EFRD.

4B: 192.935(b)(1)

The Tesoro IMP does not require the preventive and mitigative evaluation to consider the alternatives specified in 192.935(a). It is not clear what alternatives were considered in the risk assessment completed in 2004.

Tesoro's Procedure IM011, Preventive and Mitigative Measures, defines the measures to implement on an HCA pipeline segment and includes consideration of the alternatives specified in 192.935(a). A review of pipeline segments and preventive and mitigative activities for a covered segment in an HCA is conducted on an annual basis.

4C: 192.935(a)

The Tesoro IMP does not document a systematic decision-making process to decide which measures are to be implemented, considering both the likelihood and consequences for pipeline failures.

Tesoro utilizes Procedure IM003, Risk Assessment, to perform risk evaluations on covered pipeline segments and IM011, Preventive and Mitigative Measures, to enhance protection of a covered segment. The data generated from the assessment is then reviewed, in addition to other accumulated data for the covered pipeline segment, including, but not limited to, pipeline characteristics, operating history, environment, corrosion activities, leak detection, third-party activity, and threats for further preventive and mitigative actions. An action plan, as described in IM011, is developed to document the findings and, if necessary, provide recommended actions.

Should you have any questions or concerns regarding this letter or any other matters, please do not hesitate to me at 210-626-6465 or bfrieh@tsocorp.com .

Sincerely

Bernie Frieh

Bernadette Frieh, P.E.
Manager Environmental, Compliance, and Training

CC: Mike McCann

Attachments:

- Procedure IM001, Volume Release and HCA Impact
- Tesoro Integrity Management Program – Section 2
- Procedure IM003, Risk Assessment
- Procedure IM002, Information Analysis
- Procedure IM010, Pipe Repairs
- Procedure IM011, Preventive and Mitigative Measures
- Procedure IM012, Leak Detection and EFRD Analysis

Integrity Management Plan

Integrity Management Plan Overview

The *Integrity Management Plan* (IMP) uses Tesoro's regional operating and maintenance procedures together with data collection and integration to evaluate pipeline integrity on pipeline segments that could affect High Consequence Areas (HCAs). The results are analyzed through several techniques to quantify the amount of risk associated with identified integrity threats. From that analysis, the appropriate tool or tools are selected for integrity assessment (in-line inspection, hydrostatic test, or other technology). Prevention and mitigation measures are performed based on assessment results and analysis. Pipeline segment integrity is confirmed annually.

The following figure displays the IMP process graphically, and provides the name of contributing elements to each process step:

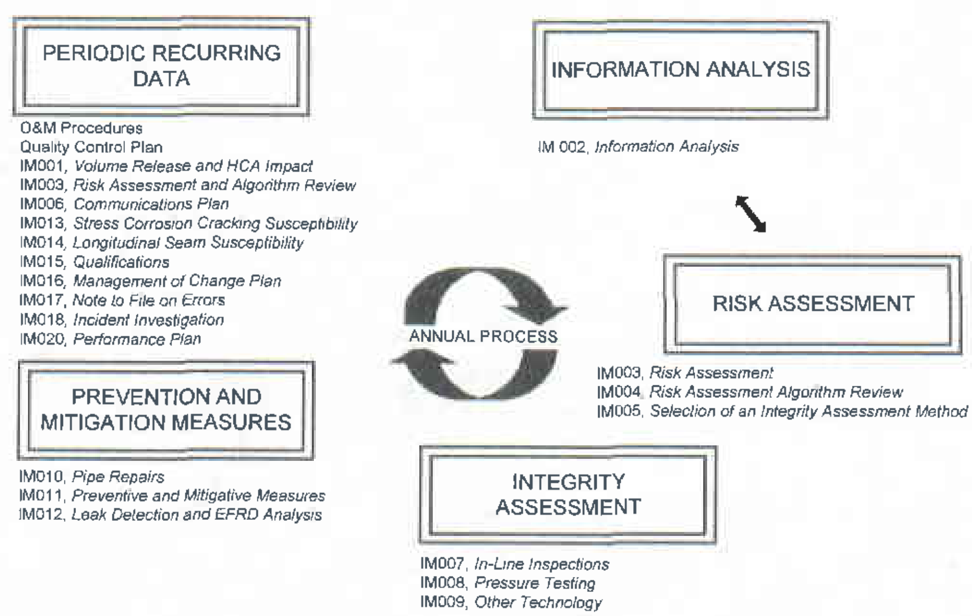


Figure 2: IMP Annual Process

Note: The "IM number" indicates the IM Program Procedure number.

The Gas IMP sections of this program are structured according to the Protocols which were issued by PHMSA in January 2006. The latest January 2008 Gas IMP Protocol revision is within the PT&T IMP files for guidance during operator audits.

The Liquid IMP sections of this program are structured according to the Protocols which were issued by PHMSA in January, 2003. These protocols are filed within the PT&T IMP files, to use as guidance during operator audits.

A detailed description of the process is located in the Integrity Procedure(s) referenced within the section.

Records produced due to implementation of the IMP are retained for the life of the system in the IM Program files.

Integrity Management Procedures

Tesoro has designed the IM Program such that it can be readily implemented through the issuance and implementation of Integrity Procedures. These procedures ensure that required integrity tasks and functions are completed according to regulation, code, standard and best practice. These procedures include:

- IM001, *Volume Release and HCA Impact*
- IM002, *Information Analysis*
- IM003, *Risk Assessment*
- IM004, *Risk Assessment Algorithm Review*
- IM005, *Selection of an Integrity Assessment Method*
- IM006, *Communications Plan*
- IM007, *In-line Inspection*
- IM008, *Pressure Testing*
- IM009, *Other Pipeline Assessment Technology*
- IM010, *Pipe Repairs*
- IM011, *Preventive and Mitigative Measures*
- M012, *Leak Detection and EFRD Analysis*
- IM013, *Stress Corrosion Cracking and Susceptibility*
- IM014, *Longitudinal Seam Susceptibility*
- IM015, *Qualifications*
- IM016, *Management of Change*

- IM017, *Note to File on Errors*

- IM018, *Incident Investigation*

- IM020, *Performance Plan*

These IM Procedures are located within Appendix B.

1 Liquid Pipeline: Identification of High Consequence Area (HCA) Pipe Segments

APPROACH

Tesoro operates 348 miles of *49 CFR § 195* regulated pipeline. Of the 348 miles, 187 miles is classified as pipe segment that could affect an HCA based on the National Pipeline Mapping System (NPMS) dataset and HCA impact analysis.

The Rule defines timeline requirements for HCA Segment Identification based on the category type of the pipelines.

- Identification of all Category 1 pipeline must be completed by December 31, 2001.

- Identification of all Category 2 pipeline must be completed by November 18, 2003.

The results of previous HCA analyses including completion dates will be archived upon completion of a more recent analysis. Subsequent analyses will be maintained in the PT&T files.

Tesoro does not operate Highly Volatile Liquid (HVL) pipe segments, and therefore has not made allowances for HCA impact analysis on these types of systems.

The roles and responsibilities of everyone involved in the completion of this task are identified in the Quality Control Plan. This plan also ensures the quality and accuracy of the segment identification results.

Any revisions to the analysis results or the methodology requires following the procedures in the *Management of Change Procedure (see IM016).*

The Communications Plan provides the procedures to incorporate segment identification results into other IM Program elements.

2 Gas Pipeline: Identification of High Consequence Area (HCA) Pipe Segments

A pipeline segment that could affect a HCA falls under the requirements of The Rule. This performance based program satisfies the requirements within *49CFR192 Subpart O* (Pipeline Integrity Management in High Consequence Areas - Gas Transmission Pipelines).

This section addresses the identification of pipeline segments that could affect one or more HCAs. This includes all of the steps to perform the segment identification, including identification/verification of HCAs, correlation of HCAs to pipeline locations, buffer zones, and justification for excluding segments physically located within an HCA.

The results of previous HCA analyses are archived upon completion of a more recent analysis. The most current analyses are located in the PT&T file room.

Gas HCA segment identification is performed in accordance with *IM001 Volume Release and HCA Impact (Appendix B).*

The company must periodically evaluate the pipeline route to determine if any land use attributes changes have occurred that that would alter the defined HCAs.

The LAR pipeline is currently identified as one HCA Segment. Potential identified site information was included in the HCA identification process. Public Officials were not contacted as the pipeline is located in an industrial area, and qualifies for HCA status independently. Therefore, the entire pipeline has qualified as an HCA segment (See FAQ #192 below).

> **PHMSA Gas IMP Website, FAQ #192: Whole line as HCA:**
>
> Question: If an operator has a short line and wants to declare it as an HCA, and assess it respectively, does the operator have to count houses, buildings, and identified sites?
>
> Answer: No. An operator with only a limited amount of pipeline can elect to treat its entire pipeline as an HCA and need not determine if potential impact circles contain 20 houses nor locate identified sites.

Calculated Impact Circle Radius for Tesoro Gas Pipeline

System	Diameter – outside/nominal (inches)	MAOP (psig)	Impact Radius (ft)	PIR Calculation Method
Southern CA	10.75 / 10	220	253*	2

*Includes a 150-foot buffer for spatial uncertainty.

APPLICABLE PROCEDURES

- *IM001 Volume Release and HCA Impact*

3 Baseline Assessment Plan

This section addresses the development of the Baseline Assessment Plan (BAP) for liquid and gas pipelines. This Plan identifies the integrity assessment method(s) for *each pipeline* segment that can affect a High Consequence Area, and provides the schedule when the assessments will be performed. This Protocol addresses the selection of assessment methods and the development of an integrated, risk-based prioritized assessment schedule.

The latest *Baseline Assessment Plan* is located in *Appendix F.*

APPROACH

The baseline assessment is the first integrity assessment performed on a pipe segment that could affect an HCA as required by the Rule. Tesoro has developed a Baseline Assessment Plan (BAP) using the following information:

- Pipe segments that could affect an HCA

- *Results from the Tesoro Risk Algorithm*

- Other considerations including:

    - Results from previous integrity assessments, defect types and sizes found in the previous assessment method and defect growth rate
    - Pipe size, material, manufacturing information, coating type and condition, seam type
    - Leak history, repair history, Cathodic Protection history
    - Product transported
    - Operating pressure and % SMYS
    - Existing or anticipated activities in the pipeline ROW and impact zone
    - Environmental factors
    - Geo-technical hazards
    - Safety Risks

The following elements are included in the BAP:

- Identification of the potential threats and supporting information
- The methods selected to assess the integrity of the pipeline and an explanation as to why each method was selected
- The risk-based assessment schedule for completing the integrity assessment of all covered segments
- A procedure to ensure the baseline assessment is conducted in a manner that minimizes environmental and safety risks
- A procedure to incorporate prior assessments
- A procedure to update and revise the BAP

BASELINE ASSESSMENT PLAN:

Communications Plan

The Communications Plan details the requirements for using Other Technology or for variations from the required test interval due to engineering basis or unavailable technology.

Identification of Potential Threats

Tesoro uses IM002 Information Analysis and IM003 Risk Assessment to identify integrity threats to its pipelines. Detailed Data Integration and Risk Assessment results are within the PT&T file room.

Integrity Assessment Methods

Integrity assessment method(s) are selected in accordance with IM005 Selection of an Integrity Assessment Method.

Risk-Based Assessment Schedule

Tesoro develops a prioritized schedule for completing baseline assessment activities based on results from Data Integration and Risk Assessment.

Qualified Prior Assessments
The company may use qualified prior integrity assessments conducted by acquired assets, provided the assessment(s) complies with the requirements of The Rule. Data collected from prior integrity assessments is used in the information analysis and risk assessment process. (see *IM002 Information Analysis* and *IM003 Risk Assessment*).

Minimizing Risk to People and Environment
Precautions are taken when performing integrity assessments and related field activities to minimize risks to people and the environment. The requirements of this section are in addition to those in other company programs and manuals (e.g., Operations and Maintenance Manual).

The Pipeline Integrity Management Program is designed to maintain the continued safe operation of its pipeline systems through the use of the following integrity assessment methods:

- Pressure Testing
- In-line Inspection
- Other technologies

Written procedures, where applicable, for performing each integrity assessment are designed to obtain specific information about the pipeline in a safe and effective manner that minimizes risk to personnel performing the assessment, the general public, and the environment. The written procedure provides the necessary detail to ensure that required tasks are performed and implemented by trained and qualified personnel, in a safe manner.

The safety of personnel, contractors, general public, and environment are also guarded by the procedures established in Operations and Maintenance Manuals, Operator Qualification Program, and various safety manuals in effect within Tesoro. The policies established within each of the documents must be adhered to while performing the aforementioned integrity assessment methods.

Prior to integrity assessment, Tesoro will ensure the following:

- Instructions for performing activities in the field are fully and properly documented and reviewed by the field personnel prior to conducting the activity.
- All work is performed in accordance with all applicable safety rules and regulations.
- Each person performing an activity is suitably trained and qualified, understands the potential risks and how the risks can be mitigated or avoided.

In-line Inspection
During the actual process of performing an in-line inspection, Tesoro will use appropriate caution and restrict access during the loading and unloading of pigs or in-line inspection tools to minimize risks associated with high pressure and possible accidental ignition of fuel gas or hazardous liquids. See IM007 In-Line Inspection.

Pressure Testing
During pressure tests, company will restrict access to aboveground pressure tested pipe using barricades or other sufficient means. In addition, spill control measures for will be followed in the event of a leak or rupture. New construction will include a pre-commissioning hydrostatic test of the entire pipe segment (See *IM008 Pressure Testing*).

Excavations (Direct Examinations)

Safety procedures as defined by the O&M Manual and Safety Manuals will be followed at all times during direct examinations. Excavation safety measures, including proper shoring techniques and markings, will be used and maintained as work is conducted. All applicable state and/or local regulations will be followed.

Pipeline coatings containing asbestos shall be handled according to the O&M Manual and the standard operating procedures of the Safety and Industrial Hygiene Policies.

Where the stability of adjoining buildings, walls, sidewalks, pavement or other structures is endangered by the excavation operations, support systems such as shoring, bracing, or underpinning shall be provided to ensure the stability of such structures for the protection of personnel.

For any excavation, Tesoro will maintain supervisory personnel at the site when digging is underway and when workers are in the ditch performing any activity (e.g., measuring anomaly dimensions, effecting repairs).

Incorporating Previous Integrity Assessment Results
As integrity assessments are conducted, the ECM or designee will promptly evaluate the results to determine if changes are warranted in the BAP.

Newly Identified and Acquired HCA Pipeline Segments
Newly identified HCA segments will be included in the BAP within one-year from the date the segment is identified. A baseline assessment will be completed within 5 years for liquid pipelines and within 10 years for gas pipelines, of the date a new gas HCA is identified &/or new pipe segment installation.

Newly acquired pipe segments are incorporated into the Pipeline Integrity Management Program and BAP as soon as practical, not to exceed one-year after the assumption of operation. The regulatory deadlines associated with the previous operator for testing and repairing the acquired segments continue to apply. Acquired pipe segments will be scheduled for assessment using the minimum interval determined in accordance with the Data Integration and Risk Assessment processes (*IM003 Risk Assessment*), or by the previous operator (e.g. If the Risk Assessment process determines that the segment should be tested in two years, but the previous operator scheduled the segment for testing this year, it must be tested this year).

Implementing the Baseline Assessment Plan
The BAP is implemented according to the risk-based schedule. As assessments are completed, re-assessments are scheduled as discussed this program. Re-assessments may be required before all baseline assessments are completed.

Updates and Revisions
Changes to the BAP are made through the *Management of Change Procedure (see IM016 and FM016-01 Management of Change)*. Some changes to the BAP may require notifications to PHMSA or state or local authorities (See *IM006 Communications Plan*). Notifications are required for substantial and significant changes. No notification is required for minor and editorial changes or anticipated changes to occur to the baseline assessment schedules due to foreseeable circumstances such as weather, permitting delays, or re-ranking schedule priorities due to updated risk assessment information. It is not necessary to apply for a waiver to change the BAP for these reasons.

The company promptly updates the BAP when newly arising information and/or information on applicable threats and consequences that may lead to changes to the segment prioritization or assessment method are identified.

The BAP is modified if knowledge from the initial (baseline) assessments or from newer data integration and/or risk assessments leads to a change in inspection priorities, assessment methods, or other improvements to its program.

LIQUID PIPELINE BAP:

In accordance with the Liquid IMP Rule, the Tesoro BAP complies with the following time periods for the liquid pipelines:

Table 3: Baseline Assessment Deadlines

Pipeline Category	Complete baseline assessment not later than the following:	Assess at least 50% of the line pipe by:
1	March 31, 2008	September 30, 2004
2	February 17, 2009	August 16, 2005
3	Date the pipeline begins operations	Not applicable

Tesoro may use qualified prior integrity assessments conducted after the date indicated in *Table 4: Prior Assessments*, if the assessment complies with the requirements of the Rule.

Table 4: Prior Assessments

Pipeline Category	Pipeline Name	Date
2	Tesoro Alaska Pipeline Company	February 15, 1997
2	Tesoro Hawaii Corporation – Honolulu Pipeline	February 15, 1997
1	TR&MC* – Salt Lake City Pipelines	January 1, 1996
1	TR&MC* – High Plains Pipeline	January 1, 1996
1	TR&MC* – Golden Eagle Pipelines (Northern CA)	January 1, 1996
1	TRMC* – Southern California Pipelines	Jan. - Aug. 1995

* TR&MC – Tesoro Refining and Marketing Company

GAS PIPELINE BAP:

In accordance with the Gas IMP Rule, the Tesoro BAP complies with the following time periods for the Southern California gas pipeline:

Table 5: Baseline Assessment Time Period

Complete baseline assessment not later than the following:	Assess at least 50% of the line pipe by:
December 17, 2012	December 17, 2007

Shell Oil Products US d.b.a Equilon Enterprises LLC elected to use a qualified prior integrity assessment for baseline assessment purposes. A hydrostatic test conducted on 08/14/2003 was the 10-inch fuel gas pipeline's baseline assessment for the Gas IMP.

APPLICABLE PROCEDURES

- IM001, *Volume Release and HCA Impact*
- IM002, *Information Analysis*
- IM005, *Selection of an Integrity Assessment Method*
- IM006, *Communications Plan*
- IM007, *In-line Inspection*
- IM008, *Pressure Testing for IM*
- IM010, *Pipe Repairs*

4 Identify Risks, Data Integration and Risk Assessments

This section addresses the integration of data and identification of threats and risk. This includes review, validation, and evaluation of results from integrity assessments. In addition, this section discusses the overall Risk Analysis/Data Integration process employed by the company to support various integrity management program elements, including Baseline Assessment Plan development, continuing evaluation and assessment of pipeline integrity, and identification of preventive and mitigative measures.

APPROACH

Integrity Assessment Results

Integrity assessment results are used to determine the condition of a pipeline, prioritize repairs, and determine preventive and mitigation measures needed to address relevant integrity threats. To ensure diligence, the Tesoro integrity assessment vendor specifications require receipt of results in a timely manner.

Tesoro requires that qualified individuals perform the review, validation, and evaluation of these results in accordance with the *Quality Control Plan.*

The results of all integrity assessments are distributed to the Project Manager, the ECM, and the regional Operations Manager in accordance with the applicable Integrity Assessment procedure and the *Communications Plan.* This plan also provides guidance for interaction with external and internal stakeholders.

Data Integration

Data Integration is performed in accordance with *IM002 Information Analysis.*

Data Integration is a systematic process used to collect and effectively utilize data elements that are needed to identify integrity threats, perform Risk Assessment, select the appropriate method(s) for integrity assessment, and determine what Preventive and Mitigative Measures are required to ensure pipeline integrity. Such information can include, but is not limited to: risk assessment results, historical data, O&M information and data, maps and drawings, and pipe data.

Threat Identification

Integrity threats are identified and quantified during the Information Analysis, Risk Assessment, and Preventive and Mitigative Measures processes (*IM002 Information Analysis, IM-003 Risk Assessment* and *IM-011 Preventive and Mitigative Measures*).

Risk Assessment

Risk assessment results are located in the PT&T files.

The company utilizes the Tesoro risk algorithm to assign risk to its pipeline segments. The algorithm is used to determine a relative risk score and/or a threat categorization. A risk score profile for each pipe segment is also generated.

The risk algorithm, which includes both integrity threats and consequences of a pipeline failure, has been customized to reflect knowledge of pipeline attributes as well as current and historical operations. It is expected that Subject Matter Experts will improve and evolve the algorithm over time as additional information and data is collected during O&M activities and integrity assessments.

Risk results are used to:

- Rank pipe segments based on relative risk; the highest scoring covered segment having the highest relative risk.
- Use the risk ranking to schedule an integrity assessment in the BAP.
- Identify preventive and mitigative measures appropriate to each pipe segment.
- Define a benchmark risk assessment by which all subsequent risk assessments will be compared.

APPLICABLE PROCEDURES

- IM002, *Information Analysis*
- IM003, *Risk Assessment*
- IM011, *Preventive and Mitigative Measures*

5 Remedial Action

APPROACH

This section describes procedures and criteria for addressing anomalous conditions identified during or after an integrity assessment.

The Rule requires that the company:

- Take prompt action to address all anomalous conditions discovered through an integrity assessment. Such conditions will be responded to in accordance with IM Procedure *IM010, Pipe Repairs.* The *Communications Plan, IM006,* provides the notification procedures in the event that the response times cannot be met and safety cannot be provided through a reduction in operating pressure.
-
- Evaluate all conditions and remediate those that could negatively impact pipeline integrity.
- Be able to demonstrate that the remediation of an anomalous condition will ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next scheduled re-assessment of the pipe segment.

The company must evaluate all anomalous conditions discovered regardless of whether they are identified during or after an integrity assessment or through other means.

The process of assessing the severity of anomalies consists of the following activities:

- Define and document the "discovery" date for the anomaly. At the same time, determine whether the anomaly meets the definition of an immediate, scheduled or monitored condition.
- Schedule and complete a detailed assessment and repair, if appropriate. If the anomaly is an immediate repair condition, reduce pressure or shut down the line and perform a repair.

- Consider the potential for other locations in the system where similar conditions may exist.
- Determine if other remedial or preventive and mitigative actions should be implemented.

APPLICABLE PROCEDURES

- *IM007 In-line Inspection*
- *IM010 Pipe Repairs*

6 Preventive and Mitigative Measures

APPROACH

Preventive and Mitigative (P&M) Measures are considered, evaluated, and implemented in accordance with *IM011 Preventive and Mitigative Measures* and *IM012 Leak Detection* and *EFRD Analysis.*

APPLICABLE PROCEDURES

- IM011, *Preventive and Mitigative Measures*
- IM012, *Leak Detection and EFRD Analysis*

7 Continual Process of Evaluation and Assessment

APPROACH

This section describes how the company continually evaluates, maintains and improves the integrity of its pipe segments. The Rule requires that the IMP include a process for continual evaluation and assessment.

The company follows the processes described in this section to periodically re-evaluate its entire pipeline system, as well as its planning, Data Integration, Risk Assessment, Selection of an Integrity Assessment Method, and re-assessment practices.

The requirements of this section are in addition to those described in the Performance Plan (see IM020). The continual evaluations described here concentrate on the pipeline system, the results of integrity assessments, and modifications needed to address new or changing conditions. The Performance Plan concentrates on the how well the company implements the Pipeline Integrity Management Program.

Continual Evaluation

The continual evaluation program consists of two components:

- Yearly reviews of the effectiveness of the IMP, including but not limited to integrity assessment results, performance measures, and confirmation (or change) of criteria, decision practices, and reassessment intervals.
- Ongoing activities to identify areas for improvement and to incorporate "lessons learned" from completed integrity assessments.

Ongoing evaluations are coordinated by the Pipeline Integrity Engineer and/or ECM, and performed by qualified personnel.

Yearly Program Review
The company will conduct an annual review on all aspects of its Pipeline Integrity Management Program (not to exceed 15 months between reviews). The information to be reviewed will include information on the effectiveness and implementation of all parts of the program. The ECM, or designee, initiates the reviews.

The Review Team consists of people qualified to audit the integrity management processes, the results of related processes and performance measures. <u>The annual review covers all aspects of the program, as described below:</u>

<u>Decision Making Criteria</u>

- Method for establishing risk criteria
- Selection of integrity assessment methods and practices
- Criteria for repairing, re-rating, replacing, or re-routing pipelines, stations, and associated piping
- Area for improvements

<u>Organizational Effectiveness (Personnel, Training, Qualification, Supervision)</u>

- Management and analytical processes
- Assignment of responsibility for each subject area
- Training/Experience of supervisory personnel
- Qualification of personnel performing integrity management tasks
- Qualification of personnel involved in changes that affect pipeline integrity and the program

<u>Documentation Effectiveness (Internal and External)</u>

- Required reporting and notifications
- Documentation included in the quality program
- Documentation of personnel qualification process
- *Documentation of the quality of processes performed by outside resources*
- Documentation of all required activities
- Documentation and monitoring of corrective action items
- Deficiencies in record keeping

<u>Preventive and mitigative measures</u>

- Compliance with activities outlined in the program
- Root cause analysis of failures and near misses
- Identification and implementation of preventive and mitigative measures
- Tracking benefits of preventative and mitigative measures

Performance measures

- Compliance with DOT regulations
- Evaluation of assessments and assessment results
- Performance measures.
- Corrective Actions Implemented

The review will identify areas where changes could or should be made to improve the program. Based on the evaluation, the Review Team should construct a list of proposed changes to address any deficiencies found. The list should be subdivided into essential and desirable actions. Each action should identify an individual or department responsible for implementing the change and any requirements on schedule. The list of actions should be reviewed and implemented in accordance with the *Management of Change Procedure (see IM016)*.

Yearly Pipeline System Review

On a yearly basis, the company will review its entire DOT jurisdictional pipeline system to identify and address changes that can impact the Pipeline Integrity Management Program. The review will explicitly consider:

- Changes in physical or operating conditions, including but not limited to operating pressures, cathodic protection, etc.
- Changes in known characteristics or conditions along a pipeline (e.g. discovery of SCC on a pipe segment previous thought to have no SCC).
- Changes to HCAs, including but not limited to new HCAs, changes in boundaries of existing HCAs, changes in the nature of existing HCAs (e.g. as a result of encroachment), etc.
- Changes to the risk profile in HCA pipe segments and any action(s) required because of the changes. Included here could be an increase in importance of one type of threat (e.g. third party damage) over another.
- Changes to integrity assessment methods or scheduling of the integrity assessments, and justification why the changes are required.
- Additions and other changes to the baseline assessment plan.

As part of the yearly evaluation, the company will evaluate the results and effectiveness of its integrity assessments. The company will evaluate past results, data integration and risk assessment information, decisions about remediation, and additional preventive and mitigative measures. The review should consider the following:

- Changes to The Rule that affect the program and the proposed action to maintain compliance with the regulations.
- Changes made or proposed to the integrity management program manual.
- Trends in and changes to the Program Performance Measures.
- Changes in reassessment intervals.
- Completed integrity assessments.
- Results from assessments of facility integrity.

- Investigations, repairs, and remediation work carried out in the last year on all DOT-jurisdictional segments.
- Additional preventative and mitigative actions and justification why the actions are required.
- The status of record keeping, including updates of appropriate databases.

The company will assess the methodology used to establish reassessment intervals and, if changes are indicated, revise the methodology. If the evaluation concludes that the reassessment of an HCA pipe segment should occur prior to the scheduled program review, the reassessment is to be performed without waiting for the annual review.

Ongoing Evaluations
The company will continually assess new data on pipeline operations, conditions, and the environment around pipe segments in a complete and thorough manner and incorporate results into its risk assessment process and baseline assessment plan. This information is used to determine if additional integrity assessments should be performed and if the reassessment intervals are valid for identified threats.

As part of the ongoing evaluations, the company will:

- Identify the need to repeat or improve the risk assessment process.
- Update the pipeline system database and risk algorithm as new data become available.
- Ensure that data is collected for Performance Measures (*IM020 Performance Plan*).
- Ensure remedial action is implemented in accordance with regulations and remedial criteria (*IM010 Pipe Repairs*).
- Reassess the integrity threats based on available data to ensure that:
  a) The appropriate integrity assessment method(s) has/have been used.
  b) The integrity assessment interval identified is still appropriate.
  c) The remediation priority and schedule is appropriate.
- Obtain data to enable the reassessment interval to be substantiated or adjusted based on the data obtained.
- Ensure records are up to date.

Re-assessment Intervals
Continually evaluating the integrity of pipe segments includes periodic re-assessments of pipeline integrity. Re-assessments are conducted as required by The Rule and the requirements of this section. The company will assign re-assessment intervals in accordance with *IM003 Risk Assessment,* after each integrity assessment is successfully completed.

The maximum re-assessment interval cannot be greater than 5 years for liquid pipelines, or 7 years for gas pipelines. The interval will not be automatically set as specified above but will be based an analysis of the results of the last integrity assessment, data integration and risk assessment. The re-assessment interval chosen for each identified threat on each covered segment must be supported by appropriate documentation.

Deviations from Prescribed Intervals
Deviations from the prescribed maximum re-assessment interval are performed in accordance with the Communications Plan.

APPLICABLE PROCEDURES

- IM002, *Information Analysis*
- IM005, *Selection of an Integrity Assessment Method*
- IM007, *In-Line Inspection*
- IM008, *Pressure Testing*
- IM010, *Pipe Repairs*
- IM011, *Preventive and Mitigative Measures*
- IM012, *Leak Detection and EFRD Analysis*

8 Program Evaluation

APPROACH

The company measures the effectiveness of the Pipeline Integrity Management Program through the Performance Plan (see IM020) and Quality Control Plan.

The company performs an annual review, not to exceed 15 months, and audit of the Pipeline Integrity Management Program.

APPLICABLE PROCEDURES

N/A

Integrity Management Plan Revision Control

Revision Control is documented and maintained within Pipeline Integrity Management Program *Review and Revision Tracking Table* located in *Appendix E*.

SCOPE	This procedure provides specific requirements and guidance for determining if a pipe segment could affect a High Consequence Area (HCA). This procedure details requirements for liquid and gas pipe segments and associated facilities.
HCA PIPE SEGMENT IDENTIFICATION (LIQUIDS)	In order to develop a Baseline Assessment Plan (BAP) that complies with 49 CFR 195, the location of all jurisdictional pipe segments that could affect an HCA must be identified. There are four types of HCAs for a liquids pipeline: ♦ Commercially navigable waterway HCA – A waterway where a substantial likelihood of commercial navigation exists ♦ Population HCA – ▪ High Population Area: An urbanized area that contains 50,000 or more people and has a population density of at least 1,000 people per square mile or ▪ Other Populated Area: A place that contains a concentrated population such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area ♦ Drinking Water HCA – An Unusually Sensitive Area (USA) drinking water resource as defined in 49 CFR 195.6 ♦ Ecologically Sensitive HCA – A USA ecological resource as defined in 49 CFR 195.6 (b) HCA data are available to pipeline operators through the *National Pipeline Mapping System (NPMS)* in a format which allows each HCA to be located based on its coordinates. Note: The methods described in this procedure were effective December 30, 2004. Prior analysis methodologies are not described within this procedure.
RESPONSIBILITY	♦ ECM ♦ Regional Managers
FREQUENCY	Annually
HCA IDENTIFICATION (LIQUIDS)	Tesoro transports liquids through its pipeline system, none of which are highly volatile liquids (HVLs). The following factors are qualitatively considered when determining if a pipe segment could affect an HCA: ♦ Potential physical pathways between the pipeline and the HCA (e.g., elevation contours, valleys, or ditches) ♦ Terrain surrounding the pipeline, including the contour of the land profile which may allow liquid from a release to impact an HCA ♦ Drainage systems, such as small streams and other small waterways, that could serve as a conduit to an HCA ♦ Crossing of farm tile fields ♦ Crossing of roadways with ditches along the side ♦ Potential natural forces inherent in the area ♦ The nature and characteristics of the liquid being transported once

	released to atmosphere ◆ Stress indicators on the pipeline (e.g., overhead crossings or pipe supports) ◆ Operating pressure and the potential to exceed MOP ◆ The hydraulic gradient of the pipeline ◆ The diameter, potential release volume, and the distance between the isolation points ◆ Response capability Tesoro uses three levels of impact analysis to determine if a pipe segment could impact an HCA, including: ◆ Direct Impact Analysis ◆ Indirect Impact Analysis ◆ Potential Impact Analysis A summary of HCA information can be collected as a table of HCA Analysis Results or on *FM001-01, Volume Release and HCA Impact Worksheet*. A summary of HCA information can also be plotted on HCA Analysis System Maps.
Direct Impact Analysis (LIQUIDS)	Direct impact analysis is the simplest of the three processes. Pipeline segments that pass directly through an HCA could have an obvious and definite impact. Station measures are derived where the pipeline and HCA Geographic Information System (GIS) layers intersect.
Indirect Impact Analysis (LIQUIDS)	Indirect analysis creates a conservative shield around the HCA GIS layer. It incorporates HCAs that may extend further than the mapped areas portray or HCAs that may have increased in size since they were mapped. The size of the conservative shield is at Tesoro's discretion and takes into account several factors such as product viscosity, soil type and conditions, and field personnel validation of HCAs. Station measures are derived to indicate the intersection of the pipeline GIS layer with the extended HCA GIS layer.
Potential Impact Analysis (LIQUIDS)	Direct and Indirect Impact Analysis will identify much of the pipeline that could affect an HCA. The exceptions are where product from a release is transported away from the pipeline. Potential Impact Analysis offers an improved prediction of the potential spill impact by accounting for many external effects that could be overlooked by more straightforward analysis. The analysis includes: ◆ *Worst Case Release Volume* – calculates worst case release volume on a discrete basis (i.e., at specified intervals) considering pipeline elevation profiles; placement of valves; and time to detect a rupture, isolate the system, and close isolation valves. ◆ *Buffer Zone* – enlarges the HCA boundary of rivers, lakes, streams, and other water features to account for variations dataset.

Worst-Case Release Volume (LIQUIDS)	A worst-case release volume is calculated at least every 100 ft using the *attributes listed below.* ♦ Pipe diameter and wall thickness ♦ Viscosity, specific gravity, and vapor pressure of liquid ♦ Terrain elevation profile ♦ Valve location, valve type, and closure mechanism ♦ Maximum flowrate (historic or calculated based on MOP) ♦ Time to confirm leak and shutdown
FACILITIES ANALYSIS (LIQUIDS)	Terminals, pumps, stations, and breakout tanks are assessed as having the same potential to impact an HCA as the incoming and outgoing pipelines to the facility. Tesoro breakout tanks have spill containment per SPCC regulations. Therefore, releases from tanks will not be transported off facility properties.
HCA PIPE SEGMENT IDENTIFICATION (GAS)	For gas transmission pipelines, PHMSA has defined two methods by which an operator can identify select an HCA, Method 1 or Method 2 (49 CFR Appendix E to Part 192). HCA means an area established by one of the methods below: 1. An area defined as either: a. A Class 3 or Class 4 location b. Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters) and the area within a potential impact circle contains 20 or more buildings intended for human occupancy c. The area in a Class 1 or Class 2 location where the potential impact circle contains an identified site (see below) 2. The area within a potential impact circle containing either: a. Twenty or more buildings intended for human occupancy unless the exception below applies b. An identified site (see below) An HCA will be identified by using either method. One method can be used for the entire system or to identify individual portions of the pipeline system. Each HCA will have a description of the method used to identify it and the potential impact radius when used to establish the area. Class location information can be located in the Pipeline Operations and Maintenance Manual, Tesoro Los Angeles Refinery. Potential Impact Circle To determine if an area along the pipeline is an HCA, consider all structures within the PIC of the pipeline. Determine the radius of the PIC by the following calculation:

$R = 0.69\ (P \times D^2)^{1/2}$
Where: R = potential impact radius (feet)
P = MAOP (psi)
D = nominal pipe diameter (inches)

0.69 is the factor for natural gas.

Other gases or rich natural gas shall use different factors.

Equation 1 is derived from:

$R= [(115{,}920/8)*\mu*x_g* \text{ч} *C_d*H_c*(Q/a_o)*(pd^2/I_{th})$

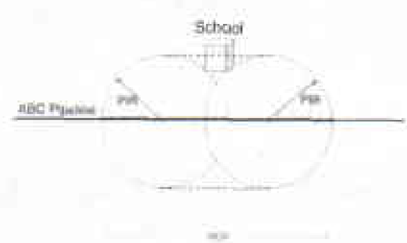
Where:
C_d= discharge coefficient
H_c=heat of combustion
I_{th}= threshold heat flux

Q= flow factor = $\lambda(2/(\lambda+1)^{\wedge(\lambda+1)/2(\lambda-1)}$
R= Gas constant
T= gas temperature
a_o= sonic velocity of gas = $(\lambda RT/m)^{\wedge 1/2}$
d= line diameter
m= gas molecular weight
p = live pressure
r = reformed radios of impact
λ= specific heat ratio of gas
ч= release rate of decay factor
μ=combustion efficiency factor
x_g=emissivity factor

Where a PIC is calculated under either method to establish an HCA, the length of the HCA extends axially along the length of the pipeline from the outermost edge of the first PIC to the last contiguous PIC that contains either an identified site or 20 or more buildings intended for human occupancy.

If the PIC contains an identified site (see below), the circle will move down the pipeline in both directions until the outside corner of each structure or outdoor area is just touching the edge of the PIC. The HCA is defined as the area between where the outside of each of the two circles intersects the pipeline.

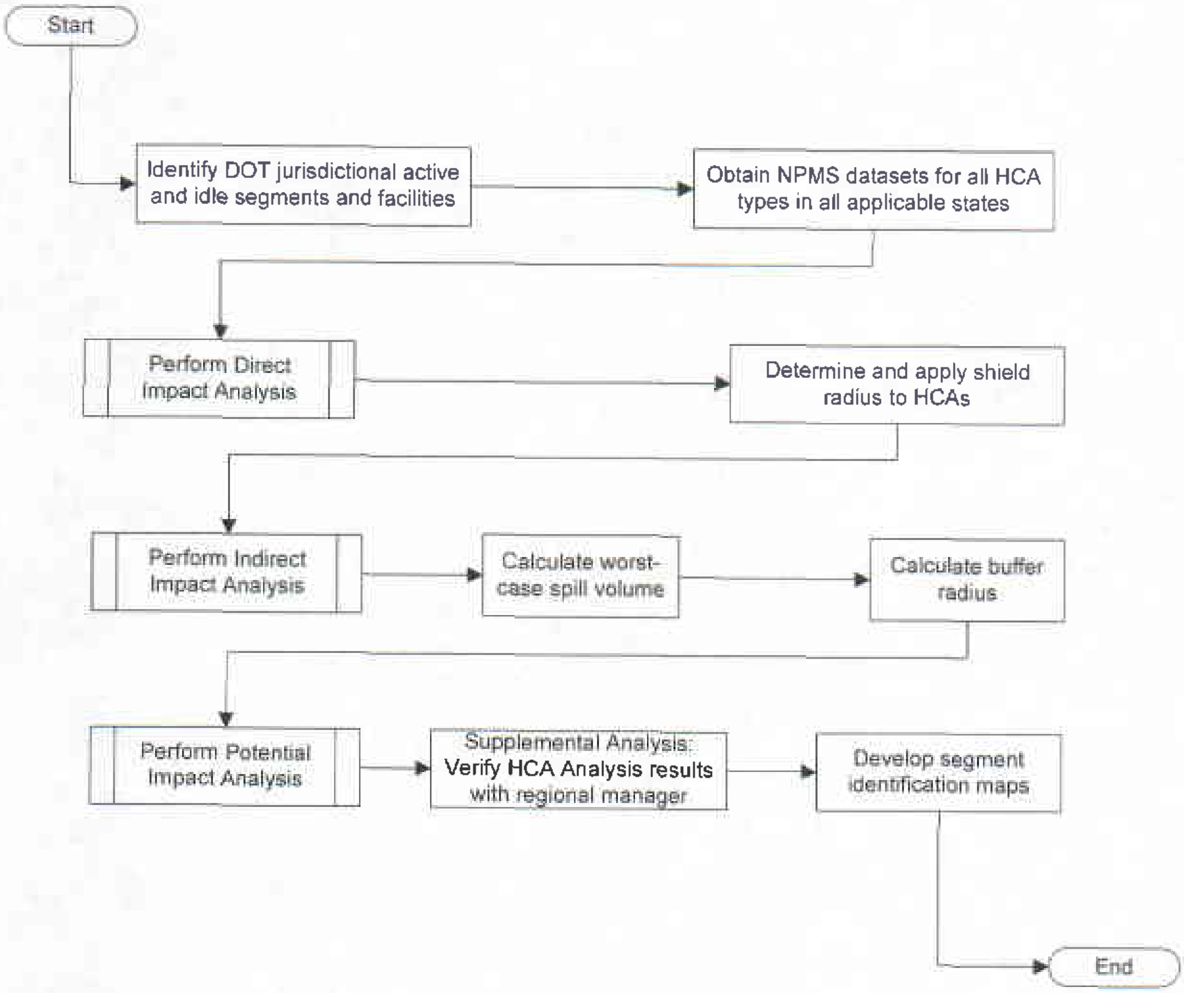
Determining High Consequence Area



	<u>An "Identified Site" is defined as:</u> An identified site must be located from information obtained by routine operations and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate that they know of locations meeting the identified site criteria (such as emergency planning). If a public official with safety or emergency response or planning responsibilities informs a Tesoro representative that he or she does not have the information to determine an identified site or cannot be contacted, Field Operations will use one of the following sources, as appropriate, to identify these sites: • Visible Marking • The site is licensed or registered by a federal, state or local government agency. • The site is on a list (including an intenet web site list) or map maintained by or available from a federal, state or local government agency and available to the general public. Document the meeting/interview with the Public Official. If HCA information is identified, forward a copy of the form to the ECM. An identified site means: • Outside areas or open structures occupied by 20 or more people on at least 50 days in any 12 month period (days need not be consecutive), • Buildings occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12 month period (days and weeks need not be consecutive), and • Facilities occupied by persons who are confined, have impaired mobility, or would be difficult to evacuate. The company must periodically evaluate the pipeline route to determine if any land use attributes changes have occurred that that would alter the defined HCAs. HCA results/maps are located in Appendix D of the Pipeline Integrity Management Program.

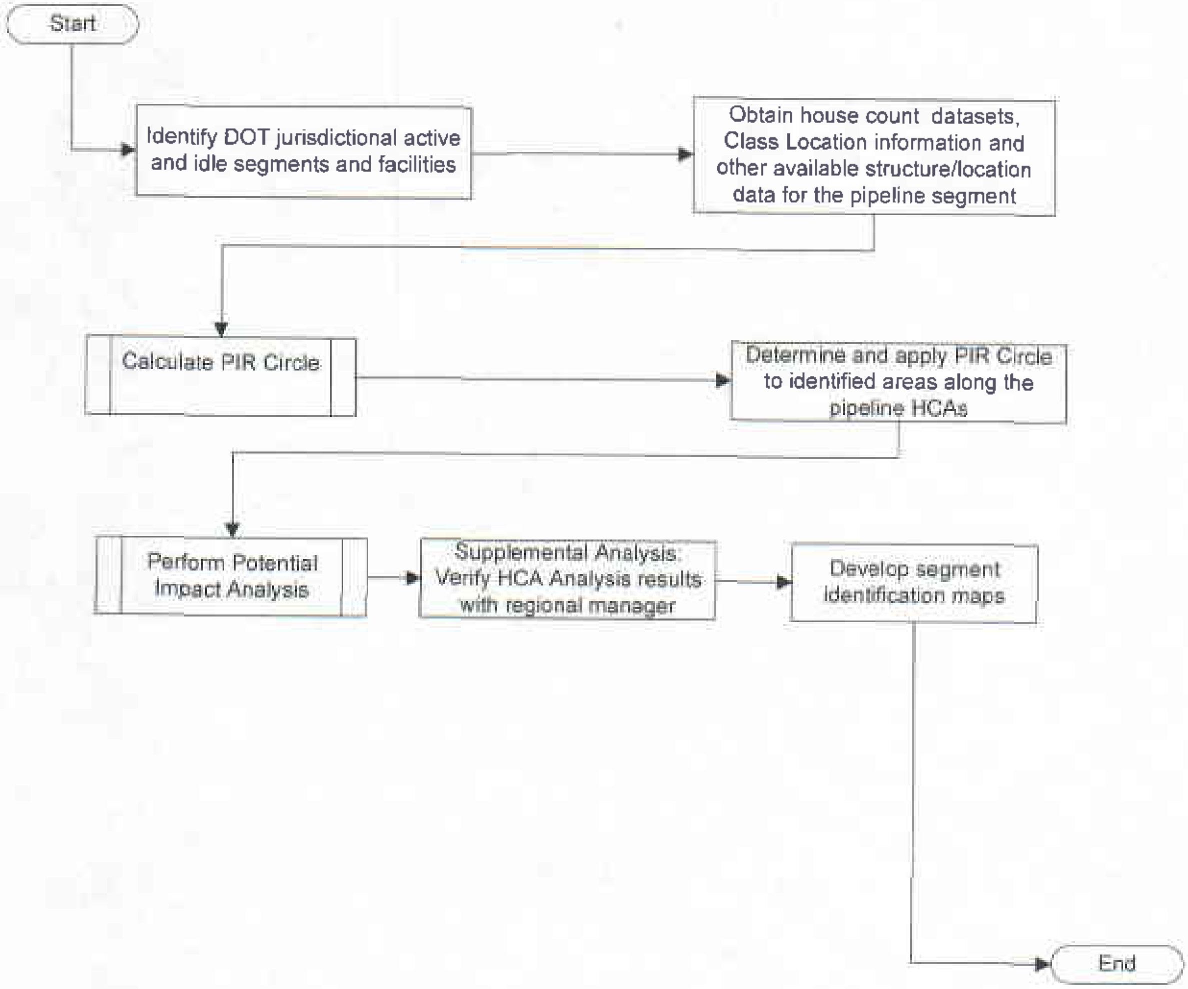
SUPPLEMENTAL ANALYSIS	The accuracy of the NPMS data and HCA Analysis Results are verified by Regional Operations Managers. Operations Managers will review HCA Analysis System Maps, surveys, encroachments, and HCA types/locations after the annual review to ensure all HCAs have been included and are appropriately addressed.
ANALYSIS UPDATES	The ECM will review the NMPS data file annually to determine if the datasets have been updated. Additionally, changes in existing HCAs will be examined by Regional Managers. If new or changed HCAs exist, the ECM will incorporate these into the IM Program within one year of identification.
NEWLY IDENTIFIED OR ACQUIRED HCA SEGMENTS	Newly acquired or identified pipe segments are incorporated into the Pipeline Integrity Management Program and BAP as soon as practical, not to exceed one-year after the assumption of operation or identification.
DOCUMENTATION	The ECM maintains the records and documentation resulting from implementation of this procedure for the life of the facility at the PT&T main office. The following records directly result from implementation of this procedure. ♦ *NPMS data file* ♦ Worst Case Volume Release Calculation ♦ HCA PIR Calculations and related documentation ♦ HCA Surveys identifying affected sites ♦ *HCA Analysis Results* ♦ HCA Analysis System Maps ♦ FM001-01, Volume Release and HCA Impact Worksheet (equivalent format may be used)
REFERENCES	♦ *National Pipeline Mapping System (NPMS)* ♦ *Pipeline Operations and Maintenance Manual, Tesoro Los Angeles Refinery* ♦ *ASME B31.S-2004 Managing System Integrity of Gas Pipelines* ♦ *49CFR195.452 & 49CFR192*
APPLICABLE PROTOCOLS	This procedure applies to the following Integrity Management Inspection Protocols: ♦ Liquids Protocol 1: Identification of Pipeline Segments that Could Affect High Consequence Areas ♦ Gas Protocol Area A: Identify HCAs (High Consequence Areas)

REVISION CONTROL	DATE	DESCRIPTION OF CHANGES
	12/30/04	Rev. 0: Procedure creation
	12/30/06	Rev. 1: Change in calculation of buffer zone (previously assumed to be a circular disk with 1-in thickness); made *FM001-01* optional; added three sections: Responsibility, Frequency, and References
	07/01/08	Rev. 2: Added process to identify HCAs for gas pipelines



Unless otherwise noted all tasks are the responsibility of the ECM.
Liquids Process Flow

Figure 1-1: Liquid Volume Release and HCA Impact Flowchart



Unless otherwise noted all tasks are the responsibility of the ECM.
Gas Process Flow

Figure 1-2: Gas Release and HCA Impact Flowchart

SCOPE	This procedure provides a systematic process for Tesoro to collect and effectively utilize data elements needed in the risk assessment process.
INTRODUCTION	Comprehensive pipeline and facility knowledge is essential to a successful Pipeline Integrity Management Program. A major strength of an effective integrity management program is the ability to merge and utilize multiple data elements obtained from several sources to provide an improved confidence in the assessment of an integrity threat to a pipeline segment. Information Analysis is the process for determining data considerations, data requirements, and required analysis to effectively support the Risk Assessment, Integrity Assessment, and Preventive and Mitigative Measures processes.
RESPONSIBILITY	♦ ECM ♦ Regional Managers ♦ Subject Matter Experts
FREQUENCY	Annually, preceding *IM003 Risk Assessment*
INFORMATION ANALYSIS	Information Analysis is the process of collecting, reviewing and analyzing data elements to enhance results of the risk assessment database as well as determine preventive and mitigative measures. The collected information is used with the Risk Assessment (see *IM003, Risk Assessment*) results to determine the risk drivers on a pipe segment and the action necessary to ensure pipeline integrity. Newly generated information from the Information Analysis and Risk Assessment processes will be updated and reflected in the BAP.
Data	The data needed for information analysis is obtained from both internal and external sources – design or construction documentation and current O&M records. A detailed listing of data elements which can be used in the Information Analysis process can be found within the Risk Assessment Questionnaire Process (see *FM003-01 & FM003-02, Offshore & Onshore Risk Assessment Questionnaires*), which provide a framework to determine the necessary data types and data sources
Assignment of Tasks	The ECM or designee initiates data collection activities with the Regional Managers, who then may contact the appropriate Subject Matter Expert (SME) for analysis or review. A summary of findings is documented and communicated (via *FM003-01 & FM003-02, Offshore & Onshore Risk Assessment Questionnaires*) to the ECM so that the issues can be considered in subsequent integrity management processes.

Recommended action	Recommended action for each data element or combination of data elements is considered in: ♦ Risk Assessment - to ensure risk is accurately reflected ♦ Integrity Assessment - to ensure the appropriate tool(s) are selected ♦ Preventive and Mitigative Measures - to ensure threats that will not be mitigated by integrity assessment are addressed accordingly
DOCUMENTATION	The ECM maintains the records and documentation resulting from implementation of this procedure for the life of the facility at the PT&T Main office. The following record(s) directly result from implementation of this procedure. ♦ *FM003-01, Offshore Risk Assessment Questionnaire* ♦ *FM003-02, Onshore Risk Assessment Questionnaire*
REFERENCES	♦ *IM003, Risk Assessment* ♦ *Baseline Assessment Plan* ♦ *49CFR195.452(g) Pipeline integrity management in high consequence areas* ♦ *49CFR192.911 What are the elements of an integrity management program* ♦ *ASME B31.S-2004 Managing System Integrity of Gas Pipelines*
APPLICABLE PROTOCOLS	This procedure applies to the following Integrity Management Inspection Protocols: ♦ Protocol 2 (Liquid): Baseline Assessment Plan ♦ Protocol 2; Area B (Gas): Baseline Assessment Plan ♦ Protocol 5; Area C (Gas): Risk Analysis ♦ Protocol 5 (Liquid): Risk Analysis

REVISION CONTROL

DATE	DESCRIPTION OF CHANGES
12/30/04	Rev. 0: Procedure creation
11/13/06	Rev. 1: Added three sections: Responsibility, Frequency, References
07/01/08	Rev. 2: Added statement to reflect the BAP upon generation of new data; Added Protocol review area for Gas Integrity Management Program

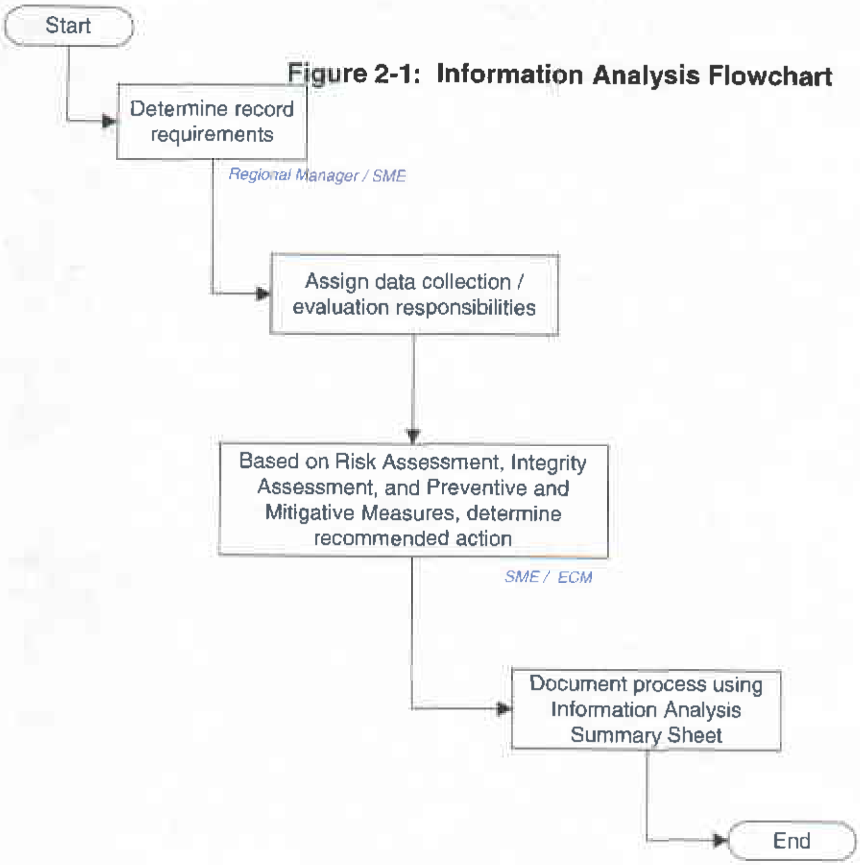


Figure 2-1: Information Analysis Flowchart

Unless otherwise noted all tasks are the responsibility of the ECM.

SCOPE	This procedure provides specific requirements and guidance for performing risk assessments on gas and liquid pipeline segments that could affect a High Consequence Area.
INTRODUCTION	Risk assessments achieve the following objectives: ◆ Prioritization of pipeline segments for scheduling integrity assessments and mitigating action (e.g. Baseline Assessment Plan) ◆ Assessment of the benefits of mitigative action (e.g. risk reduction) ◆ Determination of the most effective mitigative measures for the identified threat (e.g. integrity assessment method(s) selection) ◆ Assessment of the risk impact of modified inspection intervals ◆ Assessment of the use of or need for alternative inspection methodologies Tesoro's intention of a risk assessment is to provide a thorough and integrated evaluation of threats and consequences to the pipeline and establish a relative ranking of HCA segments. Once a risk assessment is completed and risk drivers are identified on a given pipe segment, the appropriate integrity assessment method(s) is selected using *IM005, Selection of an Integrity Assessment Method.*
RESPONSIBILITY	◆ ECM ◆ Operations Manager ◆ Project Manager
FREQUENCY	Annually (subsequent to *IM002, Information Analysis*)
RULE REQUIREMENTS (LIQUID)	◆ The Rule requires risk assessment the following factors for a liquid pipeline *(49 CFR 195.452 (e)(1))*: ◆ Results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate; ◆ Pipe size, material, manufacturing information, coating type and condition, and seam type; ◆ Leak history, repair history and cathodic protection history; ◆ Product transported; ◆ Operating stress level; ◆ Existing or projected activities in the area; ◆ Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic); ◆ Geo-technical hazards; and ◆ Physical support of the segment such as by a cable suspension bridge. ◆ Additional information on risk factors is provided *in 49 CFR 195, Appendix C.*

RULE REQUIREMENTS (GAS)	The Rule requires risk assessment to be based on ASME.ANSI B31.8S, section 5 and at a minimum consider the identified threats for each segment for a gas pipeline (49 CFR 192.917(c). ◆ Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking ◆ Static or resident threats, such as fabrication or construction defects ◆ Time independent threats such as third party damage and outside force damage; and ◆ Human error ◆ Additional information on risk factors is provided *in 49 CFR 192 and ASME B31.8S-2004.*
RISK ALGORITHM	Risk Assessment is determined using an algorithm based on the risk scoring presented by Kent Muhlbauer[1].
Algorithm Summary	Relative risk of a pipeline failure can be calculated; four indexes are used to score the probability and importance of all factors that increase or decrease the risk of a failure. The *Index Sum* is then adjusted by the *Leak Impact Factor*, a consequence factor that measures the relative impact of a pipeline failure on nearby populations. The final relative risk score then ranges from a high of about 300 – 2000 (safest) to a low of 0 (riskiest). The Index Sum Factors are: ◆ Third Party ◆ Corrosion (Atmospheric, Internal, and External) ◆ Design ◆ Operations (Design, Construction, Operation, and Maintenance) The above *Index Sum Factors* are scored on 0-100 point scales, each, based on a combination of statistical failure data and operator experience. The *Leak Impact Factors* and the scales upon which they are scored are: ◆ Product Hazard (0 – 22 point scale) ◆ Dispersion Factor (0 – 6 point scale) Risk is evaluated for both the *Index Sum* and *Leak Impact Factors* based on weighted data concerning pipeline design, operations, maintenance, and environment. Both the *Index Sum* and *Leak Impact Factor* are adjusted to account for the potential of sabotage. A low *Index Sum* score corresponds to a relatively high risk condition. Whereas, a low *Leak Impact Factor* score corresponds to a relatively

[1] Muhlbauer, Pipeline Risk Management Manual.

low risk condition (see figure below).

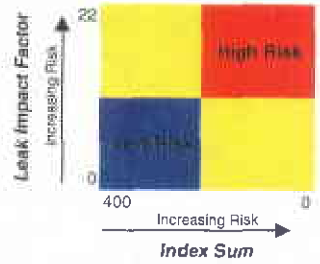


Figure 3-1: Risk Ranking

Leak History[2]

Pipeline sections that have experienced previous leaks are more likely to have additional leaks; conditions that promote one leak will most likely promote additional leaks. Many of these conditions and considerations have been included in the *Index Sum Factors* of the algorithm, as they are evidence of problems with conditions such as coating, soil corrosivity, welding quality, and potential for earth movements.

However, an adjustment to the scoring of the individual risk items can supplement the impact of leak history which is already being considered in scoring individual *Index Sum Factors* (third party, corrosion design, and operation). This component is time-factored in order to credit mitigating actions in the assessment. The evaluator may adjust the *Index Sum* if he/she believes that leak history is better captured as an additional indication of leak probability.

First, the "root cause" of the leaks, attributable to one of the four *Index Sum Factors*, must be determined. Where more than one failure mechanism is involved, the leak history can be proportioned to more than one index. The leak frequency is then assessed on a qualitative scale by making a determination, on a relative basis, for each segment in Tesoro's IMP. The evaluator must consider that, when conditions change or corrective actions are applied, the event probability changes.

The following adjustment factors can now be applied to each category of the *Index Sum Factors*, thereby assigning a higher risk probability.

High – 10% reduction

Medium – 5% reduction

Low – no change

[2] Muhlbauer, Pipeline Risk Management, pps. 213-214.

Algorithm Assumptions	The Tesoro Risk algorithm includes the following assumptions to maintain the conservative nature of the risk assessment process: 1. Where information is unknown, unable to be determined, or unavailable, the worst-case condition is assigned to the section. 2. Hazards are assumed to be independent. In other words, each item that influences the risk picture is considered separately from all other items. 3. The algorithm is subjective to the interpretations of Tesoro personnel. 4. The model considers consequences to the public and not the effects on Tesoro's business. 5. The model does not explicitly consider stress corrosion cracking, manufacturing, and equipment threats. Throughout the Risk Assessment process, these assumptions will be considered, and if necessary, algorithm or other IM Program modifications will be implemented to address concerns.
RISK ASSESSMENT	Tesoro performs the following four activities annually to facilitate the risk assessment process: 1. Sectioning – ECM and field Operations to divide pipeline into individual segments based on physical characteristics 2. Data Collection and Input – field Operations to complete questionnaire(s) *(FM003-01, Offshore Risk Assessment Questionnaire* and *FM003-02, Onshore Risk Assessment Questionnaire*) and ECM to input the information into the database 3. Calculating Risk – ECM to use the Tesoro risk algorithm to determine relative risk 4. Algorithm Maintenance – ECM to identify if, when, and how changes to the Tesoro risk algorithm and database should occur
Sectioning	Sectioning is the process of dividing a pipeline into individual segments based on physical characteristics. When sectioning a pipeline, the ECM and field Operations first analyze the pipeline attributes and operating conditions. The ECM then considers pipeline attributes and conditions that impact risk. The attributes and conditions are prioritized based on the impact of change and the frequency of change. Pipeline conditions that significantly impact risk and change frequently are considered first. Beginning at the upstream end of a pipeline, break points are inserted each time a change in the prioritized conditions occurs. The following figure illustrates an example sectioning of pipeline:

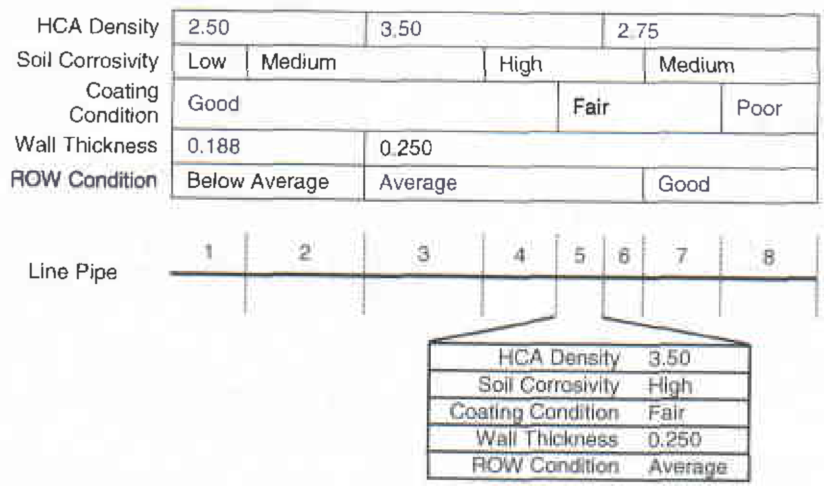


Figure 3-2: Risk Ranking

The above example results in 8 sections. The pipeline conditions of Section 5 are identified.

If the sectioning results in too many sections, the lowest priority condition is eliminated and the pipeline is re-sectioned. If the sectioning results in too few sections, the list of conditions is expanded, reprioritized, and the pipeline re-sectioned. Sectioning is a continual improvement process.

Currently, the Tesoro pipeline systems are sectioned according to isolation sections (i.e., block valve to block valve) due to spill/release volume being the highest impact and most frequently-changing pipeline condition.

Data Collection and Input	Data Input is the process of populating the Tesoro Risk Assessment database by completing a questionnaire (*FM003-01, Offshore Risk Assessment Questionnaire* and *FM003-02, Onshore Risk Assessment Questionnaire*) and inputting the values into the database. The ECM is responsible for facilitating the completion of the Questionnaires. The questionnaires and instructions will be sent to the operating sites annually to be completed by the Operations Manager. The following guidelines should be considered when completing a questionnaire: ♦ Complete one questionnaire for each sectioned segment. ♦ Questionnaires are specific to onshore and offshore locations. Therefore the appropriate questionnaire must be completed. ♦ Worst-case attributes should be assigned to a pipeline segment where more than one condition applies. For example, a pipeline segment with 3 miles of adequate CP and 5 miles of inadequate CP should be identified as having inadequate CP for all 8 miles. ♦ Questions should be answered consistently across the entire pipeline system. ♦ Comment fields are provided for any additional information or clarifications. ♦ Questionnaires must be filled out completely. The ECM is responsible for populating the database with information from the completed questionnaires.
Calculating Risk	Risk is calculated and reported using the algorithm, and the ECM examines and validates the results of the calculations to ensure the results are logical and consistent with Tesoro's operating conditions and industry experience. The algorithm output, the *Segment Ranking Report*, provides a prioritized list of segments based on their **relative** risk score. The report also identifies the following for each segment: ♦ Index Sum score ♦ Leak Impact Factor score ♦ Relative Risk score The *Baseline Assessment Plan* is developed and maintained from the prioritized list.
Algorithm Maintenance	Maintenance is the process of identifying if, when, and how changes to the Tesoro Risk Algorithm and database should occur. Tesoro performs maintenance activities to continuously improve the risk assessment process. The re-evaluation of the algorithm is described in *IM004, Risk Algorithm Review*.

HCA DENSITY & RE-INSPECTION INTERVAL

Tesoro uses the algorithm results and HCA density to determine a maximum allowable re-inspection interval for integrity assessment.

HCA density is calculated as the ratio of the cumulative length of all HCAs contained within the segment to the length of the segment (see equation below). This method of calculating HCA Density weights all HCA types [high population (HPA), other population (OPA), ecologically sensitive (ESA), navigable waterway (NW), and drinking waters (DW)] equally.

Gas Pipelines: HCA density for a gas pipeline is calculated in the same manner as the liquids pipeline. Currently, Tesoro has only one gas pipeline and the entire segment is in a HCA. The maximum reassessment period for a gas pipeline is 7 years.

$$\text{HCA Density} = \frac{(\text{HPA} + \text{OPA} + \text{ESA} + \text{NW} + \text{DW})}{\text{Segment Length}}$$

Liquid Pipelines: The results of the risk assessment are combined with the HCA Density score to determine a maximum allowable re-inspection interval for integrity assessment.

Figure 3-3: Integrity Re-Assessment Interval Matrix (Liquid& Gas):

HCA Density				
4.00 – 3.01	5	4	4	3 Highest Risk
3.00 – 2.01	5	5	4	4
2.00 – 1.01	5	5	5	4
1.00 – 0.01	5 Lowest Risk	5	5	5
Risk Assessment Score	> 60	41 – 60	21 - 40	0 - 20

Tesoro uses the above matrix to determine the maximum allowable re-inspection intervals for a given liquid or gas pipeline segment. Although, the findings of an integrity assessment may warrant a re-inspection prior to the time specified by the matrix.

After a baseline in-line assessment has been completed and data on the condition of the pipe has been obtained, the following data is used by the Project Engineer to either validate or modify the subsequent re-assessment interval derived from the table in Figure 3-3.

Results of previous integrity assessments

Defect type and size (that the assessment method can detect)

Corrosion growth rates of the deepest anomalies

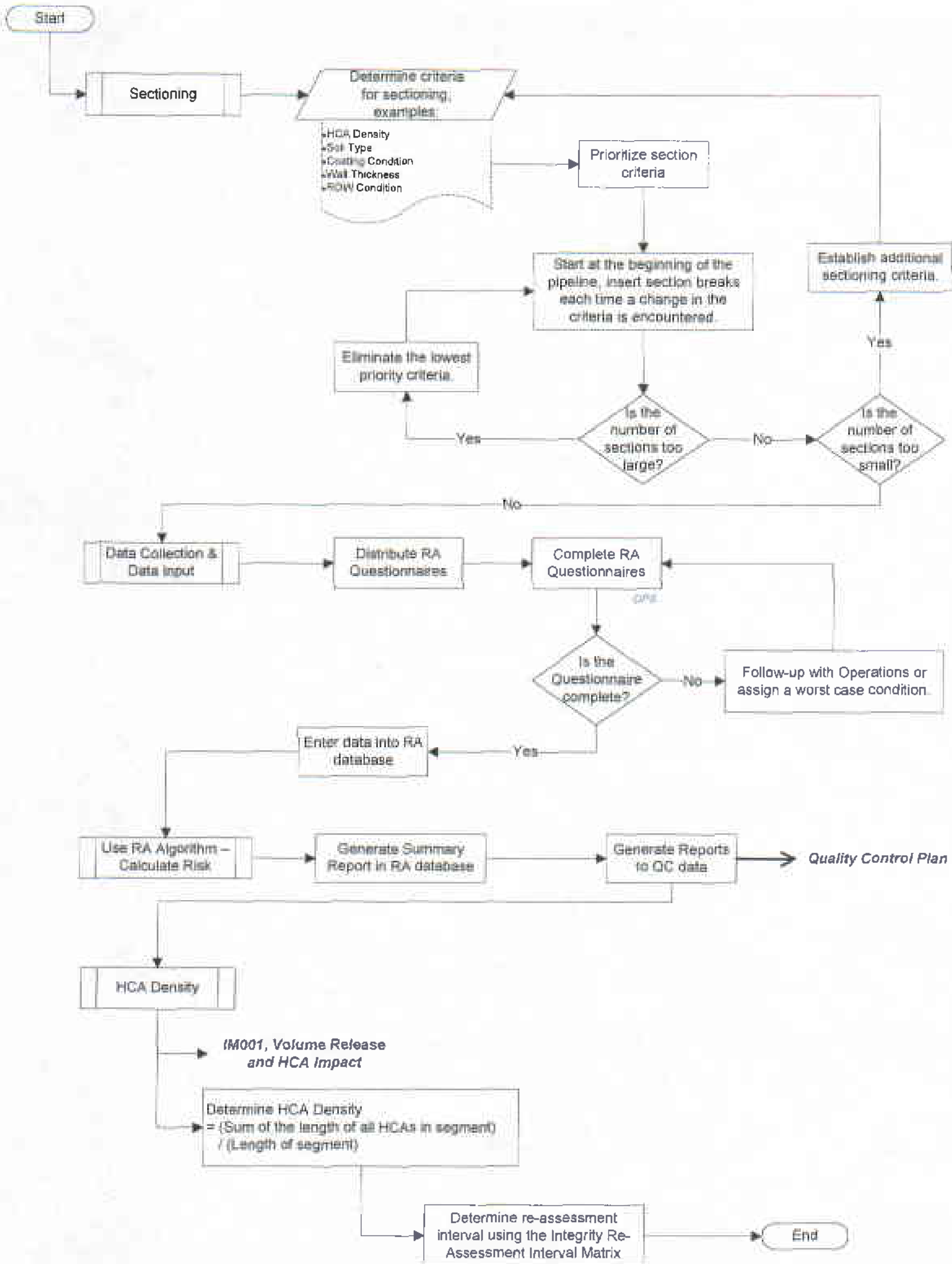
Remaining strength calculation

	Such validation/modification will be documented in the ILI results in the *Closure Report* (refer to *IM007, In-Line Inspection*) as well as on the *Baseline Assessment Plan.*
WHAT-IF SCENARIO MODELING (OPTIONAL)	What-if scenario modeling allows Tesoro to predict the potential risk benefit(s) of performing integrity management activities. Tesoro may perform What-if scenario modeling using the Risk Assessment database to compare the original risk score with the scenario risk score (since this is a relative risk database). Based on the risk drivers, the ECM first determines potential integrity management activities to model. Activities to consider: ◆ Leak Detection and EFRD Analysis ◆ In-line Inspection ◆ Pressure Testing ◆ Close Interval Survey ◆ Adequate Cathodic Protection ◆ Valve Spacing ◆ Other preventive and mitigative measures (see *IM011, Preventive and Mitigative Measures)* The ECM then creates one scenario segment for each scenario integrity management activity to be modeled. It is important to maintain the original segment data in order to make benchmark comparisons. The input data is then modified to include the integrity management activity. For example, to model in-line inspection, the ECM would modify the year of the last inspection as the current year. Once all scenarios have been input, the ECM generates reports to examine the potential benefits. The ECM and Project Manager review current and planned integrity management activities, compare these to the results of scenario modeling, and determine if modifications to plans are necessary.
FACILITIES RISK ASSESSMENT	Tesoro's DOT breakout tanks are monitored by pipeline personnel in the field, and many are monitored by SCADA. All applicable tanks are scheduled for *API 653* inspections at API-recommended frequencies. Facility risk assessment will be conducted based on *IM001, Volume Release and HCA Impact.*
DOCUMENTATION	The ECM maintains the records and documentation resulting from implementation of this procedure for the life of the facility at the PT&T Main office. The following records directly result from implementation of this procedure. ◆ *FM003-01, Offshore Risk Assessment Questionnaire* ◆ *FM003-02, Onshore Risk Assessment Questionnaire*

	♦ *Risk Assessment Algorithm outputs: Risk Driver Analysis Report and Segment Ranking Report* ♦ *Results of What-if Scenario Modeling (optional)* ♦ *Updated Engineering Records, Maps, Facility data and etc.* ♦ *Baseline Assessment Plan*
REFERENCES	♦ *API 653, Tank Inspection, Repair, Alteration, and Reconstruction* ♦ *49 CFR 195.452 (e)(1) What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments?* ♦ *49 CFR 195, Appendix C Guidance for Implementation of Integrity Management Program* ♦ *49CFR192.939, What are the required reassessment intervals* ♦ *ASME B31.8S–2004 "Supplement to B31.8 on Managing System Integrity of Gas Pipelines."* ♦ *IM001, Volume Release and HCA Impact* ♦ *IM002, Information Analysis* ♦ *IM004, Risk Algorithm Review* ♦ *IM005, Selection of an Integrity Assessment Method* ♦ *IM007, In-Line Inspection* ♦ *IM011, Preventive and Mitigative Measures* ♦ *Kent Muhlbauer, Pipeline Risk Management Manual, Second Edition: Butterworth-Heinemann, 1999.*
APPLICABLE PROTOCOLS	This procedure applies to the following Integrity Management Inspection Protocols: ♦ Protocol 2 (Liquids); Area B (Gas): Baseline Assessment Plan ♦ Protocol 3 (Liquids): Integrity Assessment Results Review ♦ Protocol Area C (Gas): Risk Assessment ♦ Protocol 5 (Liquids): Risk Analysis ♦ Protocol 7 (Liquids); Area F (Gas): Continual Process of Evaluation and Assessment
REVISION CONTROL	

DATE	DESCRIPTION OF CHANGES
12/30/04	Rev. 0: Procedure creation
11/13/06	Rev. 1: Added three sections: Responsibility, Frequency, References; specified that What-if Scenario modeling is optional
05/25/07	Rev. 2: Added paragraph on p. 6 directing the consideration of other factors (besides the Risk Assessment Score) in the determination of re-inspection interval.

	10/31/07	Rev. 3: Added "Leak History" section on p. 3.
	07/01/08	Rev. 4: Added references to the Gas Pipeline Integrity Management Rule; included the use of ASME B31.8S–2004 "Supplement to B31.8 on Managing System Integrity of Gas Pipelines."



Unless otherwise noted all tasks are the responsibility of the ECM.

Figure 3-1: Risk Assessment Flowchart

SCOPE	This procedure provides specific requirements and guidance for pipeline repairs.
INTRODUCTION	Pipeline repairs shall be in accordance with this procedure, *49 CFR 192.309 or 195.422,* and *ANSI/ASME B31.4, API 1104, API 1107, API 1111, API 1160,* and *API 2200.* A Repair Plan (resulting from implementation of one of the following appropriate procedures: *IM007, In-Line Inspection, IM008, Pressure Testing for IM,* or *IM009, Other Pipeline Assessment Technology*) will be developed such that each segment of pipe that contains defects requiring repair, as defined in this procedure, will be repaired, removed from service, replaced, or de-rated to a lower operating pressure. Repairs shall be made in a reasonable time and prioritized according to *Table 10-2: HCA Response Table.*
RESPONSIBILITY	Project Manager
FREQUENCY	Subsequent to integrity inspection, as required
GENERAL REQUIREMENTS AND GUIDANCE	The Project Manager is responsible for coordinating pipeline repairs and ensuring they are completed within the allotted time. The appropriate welding procedure must be selected based on the repair type. Consult the Project Manager for precautions that apply to unusual situations. *NOTE: Repair methods and procedures outlined in this procedure are for use only on weldable, proven pipe materials. For repairs to pipe with unknown metallurgy, manufacturing process, or weldability, consult the engineering department to determine the appropriate repair procedure.*
Gouges and Grooves	Gouges and grooves having a depth greater than 50% of nominal wall thickness shall be removed or repaired. Those having a depth less than or equal to 50% should be reviewed with Engineering.
Dents	Dents meeting any of the following conditions shall be removed or repaired: ♦ Dents located in the pipe seam or girth weld ♦ Dents containing a scratch, gouge, groove, or corrosion ♦ Dents greater than ¼ inch in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12 ♦ Dents with a depth greater than 6% of pipeline's diameter for NPS > 4 ♦ Dents with a depth of >2% should be evaluated by the ECM
Arc Burns	Arc burns sustained while making pipe repairs shall be removed or repaired.
Cracks	Cracks shall be removed or repaired.
Weld Defects	Weld defects exceeding the acceptability standards of *API 1104* or *API 1107* shall be removed or repaired.

General Corrosion	General corrosion proceeds more or less uniformly over the exposed surface without appreciable localization of attack. This leads to relatively uniform thinning of the metal, with the corrosion proceeding inward at essentially a uniform rate. General corrosion is measured in terms of penetration rates per unit time in millimeters (or mils) per year. Loss of thickness can be measured directly using a micrometer-caliper or ultrasonic thickness measurement instrument. Steel structures buried in higher resistant, well-aerated soils may be affected by general corrosion. General corrosion that has reduced the wall thickness to less than the specified nominal wall thickness, decreased by an amount equal to the manufacturing tolerance of pipe or component, requires replacement of the pipe or component or repairing the corroded area, if small (reference *API 5L*). Alternatively, the decision to repair general corrosion may be made based on the calculated design thickness (refer to *ASME B31.4 Section 404*) needed to support the MOP/MAOP (existing and future, if appropriate) of the pipeline at the location of the corrosion. In this case, general corrosion that has reduced the wall thickness to less than the calculated safe operating pressure requires replacement of pipe or component, repairing the corroded area if small, or operating at a reduced MOP/MAOP (see *ASME B31.4 Section 451.7*). The impact of external loading, e.g. at railroad and road crossings, must be considered. If internal general corrosion is found on pipe that is adjacent to a removed segment of pipe, the general corrosion on that pipe cannot be repaired. That pipe must be removed, or the operating pressure must be reduced.
Localized Corrosion	Localized corrosion pitting, the most common type of corrosion, occurs at discrete sites on a metal surface. While corrosion activity at these sites may start and stop with changes in the environment and new sites may start corroding, corrosion is concentrated at these sites. The areas surrounding the sites where localized corrosion occurs are corroded to a lesser extent or may be essentially unattacked. The steel structure's surrounding environment usually promotes this selective corrosion. Steel structures buried in low resistant, moist soils are often affected by pitting type corrosion. Localized corrosion pitting that has reduced the wall thickness to less than the specified nominal wall thickness decreased by an amount equal to manufacturing tolerance of pipe or component requires replacement of pipe or component or repairing the corroded area. This applies if the axial length of the pitted area is greater than permitted by the following equation from *ASME B31.4 Section 451.6.2*: $L = 1.12B\sqrt{Dt_n}$ Where, $B = \sqrt{\left[\frac{c/t_n}{1.1c/t_n - 0.15}\right]^2 - 1}$ L = maximum allowable longitudinal extent of corroded area, as shown in the sketch which follows.

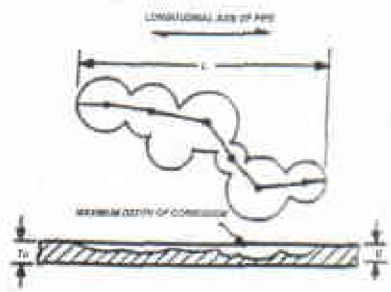


Figure 10-1: Maximum Allowable Longitudinal Defect Length

B = a value determined from the above equation or Figure 451.6.2(a)(7) of ASME B31.4 which does not exceed 4.0.

D = nominal outside diameter of the pipe, in.

t_n = nominal wall thickness of the pipe, in.

c = maximum depth of the corroded area (measured on corroded area cleaned to bare metal), in.

Alternatively, the decision to repair localized corrosion may be made based on the calculated thickness needed to support the MOP/MAOP (existing and future, if appropriate) of the pipeline at the location of the corrosion. (Consult the Engineering Department for calculations to make this determination using *RSTRENG*[1] and *ASME Modified B.31G*.)

Localized corrosion pitting that has reduced the wall thickness to less than the calculated thickness to support the MOP/MAOP requires replacement of pipe or component, repairing the corroded area, or operating at a reduced MOP/MAOP. This applies if the axial length of the pitted area is greater than permitted by the above equation, where:

t_n = calculated design wall thickness of pipe needed for MOP/MAOP

The above method for evaluating localized corrosion pitting only applies when the corrosion pit depth is less than 80% of the nominal pipe wall thickness. Pipe with corrosion pit depth of 80% or greater of the nominal wall thickness of the pipe must be replaced or repaired.

The above method shall not be used to evaluate corrosion concentrated in electric resistance welded (ERW), electric induction welded, or electric flash-welded seams; nor shall it be used to evaluate corrosion-caused metal loss which is circumferentially oriented along or in a girth weld or its related heat-affected zone (heat-affected zones usually extend less than 1/4 inch laterally on both sides of the weld). Pipe with corrosion in these areas must be replaced or repaired. This method may be used however, to evaluate the longitudinal profile of corrosion-caused metal loss which crosses a girth weld or impinges on a submerged arc-welded seam.

Wall Thickness Reduced by Grinding	Grinding that has reduced the wall thickness may be analyzed in the same manner as localized corrosion pitting to determine if the ground areas require any of the following:

[1] Kiefner, J. F., and Vieth, P. H, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe", Project PR-3-805, Pipeline Research Committee, American Gas Association, Catalog No. L51609 (1989).

	♦ Replacement of pipe or component ♦ Repair ♦ Reduction in operating pressure
Releases	All leaking pipe or welds shall be removed or repaired.
Ovalities	Ovalities that reduce the cross-sectional area by more than 2.5% at any point shall be removed or repaired.
ALLOWABLE REPAIR METHODS	The Project Manager is responsible for ensuring that the appropriate repair method is used on a case by case basis. All welding shall be in accordance with the appropriate *Tesoro Welding Procedure.* If practical, the pipeline should be taken out of service and the defect removed. If taking the pipe out of service is not practical, take the following precautions before repairing pipe containing liquid or gas: ♦ Inspect the pipe to assure the pipe is sound and has adequate wall thickness in the areas to be ground, welded, cut or hot-tapped. (Refer to *API 1104*, *2200*, or *2201* for guidance.) Ultrasonic thickness testers shall be used to assure adequate wall thickness and pipe integrity in these areas. ♦ Reduce the operating pressure of the line segment involved on in-service pipelines during repair operations. Consult the Engineering Department for restrictions on flow, pressure and temperature during welding. When repairing the pipe, remove the defect by cutting out a cylindrical piece of pipe having a length not less than 1/2 pipe diameter. Replace the removed cylinder with pipe meeting the material requirements given in the *Repair Materials* section. Replacement pipe shall be pressure tested and the test documented in accordance with *IM008, Pressure Testing.* Consider having the removed pipe analyzed for further defect assessment. Consult the Engineering Department for guidance on analysis of removed pipe. The removed pipe should be inspected for corrosion per *49 CFR 192.459 or 195.569* (external corrosion) and *49 CFR 192.475 or 195.579* (internal corrosion). Refer to corrosion control procedures and appropriate forms in regional O&M manuals. The following table, *Table 10-1: Repair Options Based on Defect Type*, summarizes allowable repair methods.

Table 10-1: Repair Options Based on Defect Type

	Type B Full Encirclement Sleeve	Type A Full Encirclement Sleeve	Grinding[2]	Mechanical Clamp[3]	Welding Fitting[4]	Hot Tapping[5]	Composite Material Wrap
Gouges and Grooves	Yes	Yes[6]	Yes	Yes	Yes[7]	Yes	Yes
Dents	Yes[8]	Yes[9]	No	Yes[10]	No	No	Yes
Arc Burns[11]	Yes	No	Yes[12]	Yes	Yes[13]	Yes	No
Non-Leaking Cracks	Yes[14]	Yes	Yes	Yes[15]	No	Yes	No
Leaking Cracks	No	No	No	Yes[16]	No	Yes	No
Weld Defects	Yes	No	No	Yes	No	No	No
General Corrosion	Yes	Yes[17]	No	Yes	No	No	No
Localized Corrosion	Yes	Yes[18]	No	Yes	Yes	Yes	Yes
Ovalities	Yes[19]	Yes[20]	No	Yes[21]	No	No	No

---

[2] Ground areas must be smoothly contoured.

[3] Mechanical clamps used for permanent repair of onshore lines should be welded up, including seal welding of bolts and nuts. Mechanical clamps used for permanent repair of offshore lines need not be welded provided clamps are equipped with circumferential seals that are activated independently from the clamping mechanism.

[4] Shall not be used for offshore pipeline repairs.

[5] Portion of pipe containing the defect must be contained within the extracted coupon.

[6] Using Type A full encirclement sleeves are the preferred repair method for gouges and grooves caused by grinding. However, gouge or groove depth cannot exceed 50% of nominal wall thickness when using Type A sleeves.

[7] Only if the defect is removed by grinding.

[8] A hardenable filler material, such as metal putty, shall be used to fill the void between the sleeve/clamp and the pipe restoring the contour of the pipe or the pipe shall be tapped through the sleeve/clamp to equalize the internal pressures of the pipe and sleeve.

[9] May be used if a hardenable filler material, such as metal putty, fills the void between the pipe and the sleeve/clamp.

[10] A hardenable filler material, such as metal putty, shall be used to fill the void between the sleeve/clamp and the pipe restoring the contour of the pipe or the pipe shall be tapped through the sleeve/clamp to equalize the internal pressures of the pipe and sleeve.

[11] Applies only to arc burns on existing pipe that is not being replaced.

[12] See Welding Standard.

[13] Only if the defect is removed by grinding.

[14] Non-leaking crack repair requires equalizing the internal pressures of the pipe and the sleeve/clamp by tapping through the pressure containing sleeve/clamp.

[15] Non-leaking crack repair requires equalizing the internal pressures of the pipe and the sleeve/clamp by tapping through the pressure containing sleeve/clamp.

[16] For cracks that leak only at elevated pressures, drilling a hole through the pipe wall at the crack ends will result in pressure equalization. The drilled holes will prevent crack growth during pressure cycling. Using a Type B full encirclement sleeve to repair a crack with drilled holes at the crack ends will require controlling the liquid flow through the drilled holes to allow welding the sleeve to the pipeline.

[17] Using Type A full encirclement sleeves are the preferred repair method for corrosion. However, corrosion depth cannot exceed 80% of nominal wall thickness when using Type A sleeves.

[18] Using Type A full encirclement sleeves are the preferred repair method for corrosion. However, corrosion depth cannot exceed 80% of nominal wall thickness when using Type A sleeves.

[19] A hardenable filler material, such as metal putty, shall be used to fill the void between the sleeve/clamp and the pipe restoring the contour of the pipe or the pipe shall be tapped through the sleeve/clamp to equalize the internal pressures of the pipe and sleeve.

[20] May be used if a hardenable filler material, such as metal putty, fills the void between the pipe and the sleeve/clamp.

[21] A hardenable filler material, such as metal putty, shall be used to fill the void between the sleeve/clamp and the pipe restoring the contour of the pipe or the pipe shall be tapped through the sleeve/clamp to equalize the internal pressures of the pipe and sleeve.

Temporary repairs	Continued operations may require temporary repairs. Temporary repairs should be made permanent as soon as practical, generally within 30 days. If the temporary repair cannot be made permanent within 30 days, an engineering review should be performed to confirm longer-term acceptability of the temporary repair. ♦ Minor defects – Steel-bolted clamping devices and suitable gasket material, cone plugs or mechanically-applied split sleeves may be used to repair minor releases. ♦ Major defects – Parted pipe or deformed pipe that cannot be repaired using a mechanically applied split sleeve may be repaired using a "Weld+Ends" coupling or equivalent joining of replacement pipe. Using this coupling requires limiting the longitudinal force on the coupling. The set screws alone will not withstand the longitudinal force of moderately high operating pressures or of appreciable temperature changes. Longitudinal forces can be limited by providing additional axial restraint or by reducing operating pressure.
Replacing Pipe	Tie-ins of replacement pipe may be by circumferential butt-welding or by using "Weld+Ends" couplings (straight pipe only). When "Weld+Ends" couplings are used on permanent repairs, they must be attached to the pipe by circumferential fillet welds. Replacement pipe shall meet the following requirements: ♦ Pipe with equal or greater internal design pressure as the pipe being replaced shall be used. It is preferred to use pipe of similar nominal wall thickness to minimize tie-in problems. ♦ Full penetration groove welds shall be used for tie-ins and girth welds joining pipe sections. Couplings shall meet the following requirements: ♦ Thickness shall be equal to or greater than the pipe nominal wall thickness to maintain the internal design pressure of the pipe. ♦ Circumferential fillet welds attaching the couplings to the pipe shall be continuous with minimum size equal to the pipe nominal wall thickness and maximum size equal to 1.4 times the pipe nominal wall thickness when repair is permanent. ♦ Bolts and set screws shall be cut flush with outside surface and seal welded when repair is permanent. ♦ A ¼- inch nominal pipe thickness opening at each end will be used to permit pneumatic testing. ♦ All new "Weld+Ends" welds shall be soap tested after installation by injecting nitrogen into the annulus between the pipe OD and the coupling through the ¼-inch nominal pipe thickness openings. Nitrogen pressure shall not exceed the line pressure. Existing "Weld+Ends" welds can be soap tested by adding ¼-inch, 3000# half-couplings and drilling a hole through the coupling bodies for injecting nitrogen. Do not drill into the pipe body. Drilling shall be done using hot-tap equipment if there is any possibility that the elastomer seal is leaking. Nitrogen pressure shall not exceed the line pressure.

Type B split sleeves (pressure containing)	Type B full-encirclement sleeves are split sleeves designed to withstand the internal design pressure of the pipeline. They are welded directly to the pipeline at each end of the sleeve to provide pressure containment. Welded full encirclement split sleeves shall meet the following requirements: ◆ Axial length shall be 4 inches, minimum, but long enough to completely cover the defective area with an allowance for installation misalignment ◆ Thickness shall be equal to or greater than the pipe nominal wall thickness in order to maintain the internal design pressure of the pipe ◆ Sleeves shall be attached using continuous, full-fillet welds with minimum size equal to pipe nominal wall thickness ◆ Circumferential fillet welds shall not be located within 2 inches of a girth weld ◆ Longitudinal welds shall be full penetration groove welds with backing bars ◆ Longitudinal welds shall not penetrate into the pipe wall. Mild steel or tape backing bars may be used to prevent this penetration ◆ Ends of sleeves that are more than 1.5 times the nominal pipe wall thickness shall be chamfered (at approximately 45°) down to the pipe wall thickness.
Type A split sleeves (not pressure containing)	Type A full encirclement sleeves are welded split sleeves that provide reinforcement to the damaged area but are not designed to withstand the internal design pressure of the pipeline. Therefore, they are not welded directly to the pipeline. Type A full-encirclement split sleeves shall meet the following requirements: ◆ Axial length shall be 4 inches, minimum, but long enough to completely cover the defective area with an allowance for installation misalignment ◆ Type A full encirclement sleeves require intimate contact between the sleeve and the flaw in order to resist radial movement of the pipe. A non-shrinkable, hardenable filler material in the annulus between the sleeve and pipe provides this intimate contact. Placement of the hardenable filler into the annular space may be by troweling onto the defective area or pumping into the annulus. ◆ The longitudinal seams of the sleeve may be joined by fillet welding overlapping weldable steel bars to the sides. Or, the longitudinal seams may be joined using full-penetration "V" groove welds. ◆ Full-penetration longitudinal welds shall not penetrate into the pipe wall. Mild steel or tape backing may be used to prevent this penetration ◆ Since cathodic protection is not effective under a sleeve, suitable coating of both the sleeve and adjacent pipe is very important. The sleeve / pipe junctions should be protected to prevent water and dirt from entering the annulus. Epoxy filler built up to form a fillet between the sleeve and pipe provides this protection. Also, layered heat shrink sleeves at the full encirclement sleeve / pipe

	junctions may be used. Consult the Engineering Department for other protective coating options.
Mechanically-applied split sleeves (mechanical clamps)	Mechanically-applied full encirclement split sleeves shall meet the following requirements: ◆ Axial length shall be 4 inches, minimum, but long enough to completely cover the defective area with an allowance for installation misalignment ◆ Thickness shall be equal to or greater than the pipe nominal wall thickness in order to maintain the internal design pressure of the pipe ◆ Sleeves shall be attached using continuous, full-fillet welds with minimum thickness equal to pipe nominal wall thickness when repair is permanent ◆ Circumferential fillet welds shall not be located within 2 inches of a girth weld ◆ Longitudinal joints shall be seal welded when repair is permanent ◆ Nuts shall be seal welded to the bolts and to the sleeve when repair is permanent ◆ Ends of sleeves that are more than 1.5 times the nominal pipe wall thickness shall be chamfered (at approximately 45°) down to the pipe wall thickness ◆ Distance from the weld to the gasket must be adequate to prevent welding from heat damaging the gasket ◆ Plidco's® Split+Sleeve can only tolerate 1/32 inches, or less, surface irregularities at the sealing gasket ◆ Plidco's® Split+Sleeve can tolerate maximum out-of-roundness of 5% of the nominal pipe diameter if positioned so that the split line is parallel to the minor diameter ◆ Pipe surface must be clean at gasket-sealing location ◆ No welding is required on bolted sleeves for permanent repair for submerged offshore pipelines and submerged pipelines in inland navigable waters ◆ Follow split sleeve manufacturer's recommended installation instructions
Special Sleeve Configurations	<u>Multiple Sleeve Repair (Longer Repair)</u> Multiple sleeves can be circumferentially welded together prior to installation. Or, if multiple sleeves are welded together on the in-service pipeline, a circumferential backing strip can be placed on the carrier pipe at the location of the circumferential butt weld which will connect the two sleeves. Backing strips for this situation will not be crimped and can be rolled to match the OD of the carrier pipe. <u>Repair to Curved (Field-Bent) Pipe ("Armadillo")</u>[22] A conventional Type A or Type B sleeve can be installed on a curved piece of pipe. In the case of a Type A sleeve, the annular space created by curvature can be filled with a hardenable filler to provide the necessary contact with the carrier pipe. In the case of a Type B sleeve,

[22] Kiefner and Associated, Inc. Catalog No. L51716e, p. 34

	the so-called "armadillo" sleeve, comprised of two or more short segments connected by bridging sleeves, can be used. The sleeve can be a Type A if the final two ends are left un-welded or a Type B if they are welded. Alternately, mitered segments can be butt welded to each other to make a continuous sleeve. Sleeve-On-Sleeve Repair (Defects at Fillet Welds at end of Type B Sleeve)[23] Cracking at the toes of fillet welds around the ends of conventional Type B sleeves can be repaired with a sleeve-on-sleeve repair. This configuration consists of two rings installed outboard to the ends of the defective sleeve. Each ring is fillet welded to the carrier pipe on the side facing the defective sleeve. Thus, if a toe crack forms at one or both rings, it will be contained within the space between the rings and the sleeve. The final step involves installing two outer sleeves to bridge the gaps between the rings and the defective sleeve. These sleeves are fillet welded to the rings and the defective sleeve making a leak-tight repair in the event the toe crack grows through the wall of the carrier pipe.
Welding fittings	Maximum size welding fitting is NPS 3 when used to cover pipeline defects. Welding fittings shall have a design pressure equal to or greater than the pipe.
Composite Material Wrap	Composite repair technology, e.g. Clock Spring®, is approved for the permanent repair of defects, including corrosion and mechanical damage, when there is less than 80% metal loss. Criteria for using the composite repair is that it should permanently restore the serviceability of the pipe as shown by reliable engineering testing and analyses.
REPAIR MATERIALS	All repair materials must meet the specifications or standards listed in *ASME B31.4, Table 423.1*, or as otherwise required by *ASME B31.4*. ♦ Pipe – Replacement pipe, both new and used, must be constructed to standards consistent with requirements *49 CFR 195*. Pipe conforming to *API 5L* is preferred. Pre-tested pipe must be positively identified, allowing it to be linked to hydrostatic test records. ♦ "Weld+Ends" couplings – Steel for welded couplings shall be made in accordance with a specification that has chemical requirements and mechanical properties testing. Steel weldability and chemical and mechanical properties for couplings should be equivalent to those of the pipe. Either pipe or plate may be used. In addition, bolts and screws shall be of weldable material. ♦ Mechanical split sleeves – Mechanically applied split sleeves, including the nuts and bolts, shall be of weldable material. ♦ Elastomers – Gasket material and cone plugs (for temporary repair of leaks) may be neoprene, Hycar™, Viton™ or Buna-N™. Other materials that are non-combustible, chemically resistant to the fluid, and not subject to "cold flow" may be used for gaskets and cone plugs. ♦ Weld filler materials – Weld filler materials shall meet the welding

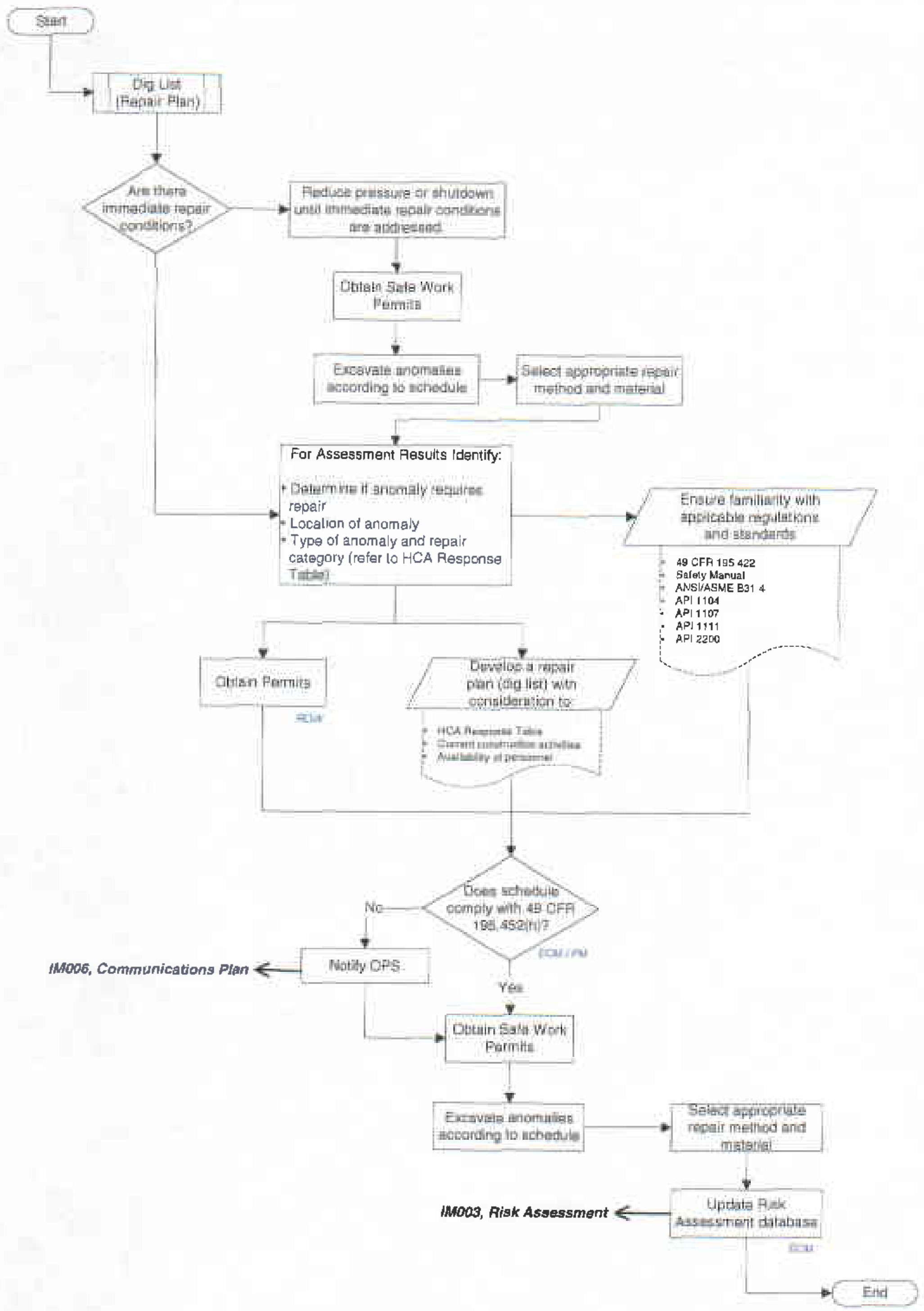
[23] Kiefner and Associated, Inc. Catalog No. L51716e; p. 34.

	procedure requirements. Low hydrogen electrodes shall be used for shielded metal arc welding (SMAW) of Grade X-52 and higher pipe and fittings under pressure or containing product. In addition, these electrodes shall be used for SMAW on all DOT-jurisdictional pipelines. ♦ Type B welded split sleeves – Steel for welded full-encirclement split sleeves shall be made in accordance with a specification that has chemical requirements and mechanical properties testing. Steel weldability and chemical and mechanical properties should be equivalent to those of the pipe. Either pipe or plate may be used. ♦ Type A split sleeves – Steel for Type A full-encirclement split sleeves shall be weldable. Either pipe or plate may be used. ♦ Non-shrinkable, hardenable filler materials – Troweled on epoxies, such as Belzona 1341, Interline 102, Denso Kop-Coat A-788, or pumpable epoxy, such as Interline 983SF or Denso Sea Shield 530, may be used in the annulus between sleeve and pipe. For subsea repairs, Belzona 1341, Denso Sea Shield 530 or Shell Epon 828 may be used. ♦ Welding fittings – Steel for welding fittings shall be made in accordance with a specification that has chemical requirements and mechanical properties testing. Steel weldability and chemical and mechanical properties should be equivalent to those of the pipe.
DOCUMENTATION	Documentation on Pipe Repairs is specified in the appropriate procedure: *IM007, In-Line Inspection, IM008, Pressure Testing for IM,* or *IM009, Other Pipeline Assessment Technology.*
REFERENCES	♦ *49 CFR 192.309 Repair of Steel pipe* ♦ *49 CFR 192.459 External Corrosion Control: Examination of buried pipeline when exposed* ♦ *49 CFR 192.475 Internal Corrosion control: General* ♦ *49 CFR 195.422 Pipeline Repairs* ♦ *49 CFR 195.569 Do I have to examine exposed portions of buried pipelines?* ♦ *49 CFR 195.579 What must I do to mitigate internal corrosion?* ♦ *IM007, In-Line Inspection* ♦ *IM008 Pressure Testing* ♦ *IM009, Other Pipeline Assessment Technology* ♦ *Tesoro Welding Procedure Manual* ♦ *AGA PR-3-805 A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe* ♦ *ANSI/ASME B31.4; Pipeline Transportation Systems for Liquid Hydrocarbon and Other Liquids* ♦ *ASME/ANSI B31G Manual for Determining the Remaining Strength of Corroded Pipelines*

	• *API 5L: Specification for Line Pipe* • *API 1104 / API 1107: Welding of Pipelines and Related Facilities* • *API 1111: Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines* • *API 1160: Managing System Integrity for Hazardous Liquid Pipelines* • *API 2200: Repairing Crude Oil, LPG, and Product Pipelines* • *API 2201: Safe Hot Tapping Practices in the Petroleum and Petrochemical Industries* • *Kiefner and Associated, Inc.; Edison Welding institute; Battelle Memorial Institute; Pipeline Repair Manual from Technology for Energy Pipelines, Catalog No. L51716e.* • *Kiefner, J.F., and Vieth, P.H., "A modified Criterion for Evaluating the Remaining Strength of Corroded Pipe", Project PR-3-805, Pipeline Research Committee, American Gas Association, Catalog No. L51609 (1989).*
APPLICABLE PROTOCOLS	This procedure applies to the following Integrity Management Inspection Protocols: • Protocol 2 (Liquid); Area B (Gas): Baseline Assessment Plan • Protocol 3 (Liquid); Area C (Gas): Integrity Assessment Results Review • Protocol 4,(Liquid); Area E (Gas): Remedial Action
REVISION CONTROL	(see table below)

DATE	DESCRIPTION OF CHANGES
12/30/04	Rev. 0: Procedure creation
11/08/06	Rev. 1: Added Clock Spring® as acceptable permanent repair method; added three sections: Responsibility, Frequency, References other minor formatting changes
05/21/07	Rev. 2: Added provision to apply abutted split sleeves; added reference to IM007, In-Line Inspection, to clarify calculation of P (now relocated to IM007 In-Line Inspection, see REV No. 3)

	07/01/08	Rev No. 4: Updated repairs to reflect guidance in 49 CFR 192, Updated Protocol section to reflect Gas Integrity Protocols.



Unless otherwise noted all tasks are the responsibility of the PM.

Figure 2: Pipe Repairs Flowchart

SCOPE	This procedure applies to preventive and mitigative measures that are used to protect a gas and liquid pipeline high consequence areas (HCA), in accordance with *49CFRξ195.452* and *49CFRξ192.935.*
RESPONSIBILITY	ECM Project Manager Tesoro's Corrosion Control Specialist Regional Manager
FREQUENCY	Annually
INTRODUCTION	Tesoro evaluates the benefit of and implements measures to prevent and mitigate the consequences of a pipeline failure that could affect an HCA. These measures are identified after conducting an Information Analysis and Risk Assessment (refer to *IM002, Information Analysis* and *IM003, Risk Assessment*) and are implemented in accordance with the *IMP Section 5, Management of Change Plan*. Measures include the following: ♦ Operational Changes ♦ Pipe replacement and/or repair ♦ Recoating ♦ Additional Cathodic protection enhancements ♦ Cathodic protection monitoring and maintenance ♦ Retirement, de-activation, or abandonment ♦ MOP/MAOP or pressure reduction ♦ Maintenance pigging and/or cleaning ♦ Increasing or protection of depth of cover ♦ Leak detection and Emergency Flow Restricting Device improvements ♦ Additional training to personnel on response procedures ♦ Additional signage ♦ Corrosion inhibitors ♦ Public Awareness Program ♦ Site-specific procedure implementation ♦ Observation/monitoring ♦ Feedback to/from One-call systems (Third Party Damage Prevention ♦ ROW maintenance and inspections (Third Party Damage Review) ♦ Additional pipe wall thickness ♦ Purchase of additional or wider ROW easement ♦ Shorter integrity assessment inspection intervals ♦ Conducting drills with emergency response responders According to *49CFRξ195.452(i)(2) and 49CFRξ192.935,* each of these actions will be evaluated using at least the following risk criteria where applicable: ♦ Terrain surrounding the pipe segment, including drainage systems that act as a conduit to an HCA (e.g. streams, smaller waterways, ditches, drain tiles etc.)

	◆ Elevation profile ◆ Product characteristics ◆ Worst-case volume release ◆ Physical support of the pipe segment such as by cable suspension bridge ◆ Exposure of the pipe segment to pressure which exceeds the established MOP/MAOP (surge and abnormal operations) ◆ Pipe length and size ◆ Proximity to an HCA ◆ Potential for ignition
Operational Changes	Changes to pipeline operations, equipment, or personnel are considered if risk is reduced by such action.
Pipe Replacement and/or Repair	Pipe is replaced when a determination is made that the existing pipe is no longer suitable for service. New pipe is installed in accordance with O&M Procedures. Pipe is repaired in accordance with *IM010, Pipe Repairs.*
Cathodic Protection Enhancements	The *PT&T Technical Specifications Manual* contains cathodic protection requirements for new facilities. Field personnel make every effort to balance the demand for current with the capability of existing cathodic protection facilities. However, if demand is greater than existing cathodic protection capability, Tesoro will evaluate and implement the optimal solution.
Cathodic Protection Monitoring and Maintenance	Tesoro closely monitors cathodic protection systems in accordance with *49 CFRξ195 & ξ192,* and *NACE RP0169* standards. Tesoro may also perform additional monitoring by performing cathodic protection or coating surveys to ensure integrity of a pipe segment, as recommended by Tesoro's Corrosion Control Specialist.
Retirement, De-Activation, or Abandonment	A pipe segment is considered for retirement, de-activation or abandonment for any of the following reasons: ◆ The asset poses a risk that cannot be effectively addressed by the Pipeline Integrity Management Program ◆ The operating and maintenance costs associated with an asset exceed revenue with no foreseeable change ◆ The asset has an unacceptable operating risk
MOP/MAOP or Pressure Reduction	Pressure in the pipeline can be reduced to ensure pipeline integrity. This is considered a temporary measure, not to exceed 365 days, which may be implemented before further remedial action is taken to ensure the safety of the pipeline. This option is used in select cases where Tesoro is further evaluating a defect or until the defect can be repaired. Criteria and conditions for implementing a pressure reduction are included in *Table 2: HCA Response Table in IM Procedure IM010, Pipe Repairs.*

Maintenance Pigging and/or Cleaning	Dewatering, cleaning, batching, maintenance, and drying pigs are used to eliminate, reduce, or displace internal corrosion-causing agents in a pipeline. A site-specific internal corrosion control plan should be developed that identifies the number, frequency, and type of pigs to be used.
Increasing or Protection of Depth of Cover	In some cases, Tesoro may need to increase the depth of cover over portions of its pipeline to meet the cover requirements in *49 CFR ξ195.248 and ξ192.917,* or to provide additional protection in areas of third party activity, encroachment, or in highly populated areas. In-service pipelines are lowered in accordance with *API RP-1117, Movement of In-Service Pipelines.*
Leak Detection and EFRD Improvements	Tesoro uses *IM012, Leak Detection and EFRD Analysis,* to determine the appropriateness of its leak detection means and EFRD capabilities. The installation of computerized monitoring and leak detection systems may be evaluated based on site-specific conditions.
Automatic Shut-Off or Remote Control Valves	In high risk situations, Tesoro may install Automatic Shut-Off or Remote Control Valves.
Additional Signage	In addition to the signage requirements in *49 CFRξ195.410 & ξ192.917,* Tesoro may elect to install signage to further mitigate the risk of third party damage. This is particularly true in areas where third party damage has previously occurred, where encroachment and/or construction activity is identified, and in populated and industrial areas.
Corrosion Inhibitors	Corrosion inhibitors may be used in conjunction with other methods to impede internal corrosion. The type and amount of inhibitor will be selected based on the severity of the problem and the focus of the site-specific internal corrosion control plan. The use of corrosion inhibitors will be recommended and authorized by Tesoro's Corrosion Specialist.
Public Awareness Programs	Public Awareness is provided through the *Tesoro Public Awareness Program* and *IM006, Communications Plan*. These plans educate the public about pipeline location, operations, safety, dangers, and emergency response issues.
Site-Specific Procedure Implementation	Site-specific procedures are developed when a risk reduction measure is needed at a particular location. Personnel are trained on new procedures, such as emergency response, drills, and inspection & maintenance programs.
Observation / Monitoring	In some cases, an identified integrity threat that does not pose an immediate safety or environmental hazard or violate Tesoro O&M Procedures can be best mitigated through observation. Engineering and field personnel should perform a risk assessment to validate this option (see *IM003, Risk Assessment*).
Feedback to/from One-Call Systems	One-Call systems are used so that a single telephone call can be made to determine if buried underground line is located in a particular area of interest. Tesoro participates in One-Call Systems for all jurisdictional pipeline segments. In addition, Tesoro works to ensure pipeline mapping information is accurate and that personnel are available to accurately locate and mark the pipeline.

Damage Prevention Program	Tesoro has enhanced its Damage Prevention Program with respect to gas and liquid covered pipeline segments, to prevent and minimize the consequences of a release due to third party damage (see *49CFRξ192.935(b) and 49CFRξ195.452(f)(8))*.
	
	Enhanced Damage Prevention Program measures include the following:
	• Use of qualified personnel for all jurisdictional pipelines (see *IM015 Qualification*)
	• Collection of excavation damage information in a central database:
	  ◦ For covered and non-covered gas transmission pipeline segments.
	  ◦ Including the root-cause analysis to support identification of additional preventative and mitigative measures for HCAs.
	  ◦ Data must include recognized damage that is not required to be reported as an incident per *49CFRξ191*.
	• When a third party is digging in the vicinity of Tesoro's gas pipeline, regional O&M procedures will be followed which include the following:
	  ◦ Excavations with uncovered pipelines are monitored by Qualified Tesoro personnel (see *IM015 Qualification*)
	  ◦ If personnel find physical evidence of encroachment involving an unmonitored excavation near a covered pipeline segment, Tesoro personnel must do one of the following:
	    ▪ Excavate the area near the encroachment or
	    ▪ Conduct an above ground survey using methods defined in *NACE-RP-0502-2002*.
	    ▪ If any indication of coating holidays or discontinuity warranting direct examination are found, then the pipeline must be excavated and issues remediated in accordance with *ANSI/ASME B31.8S* and *49CFR192.933*.

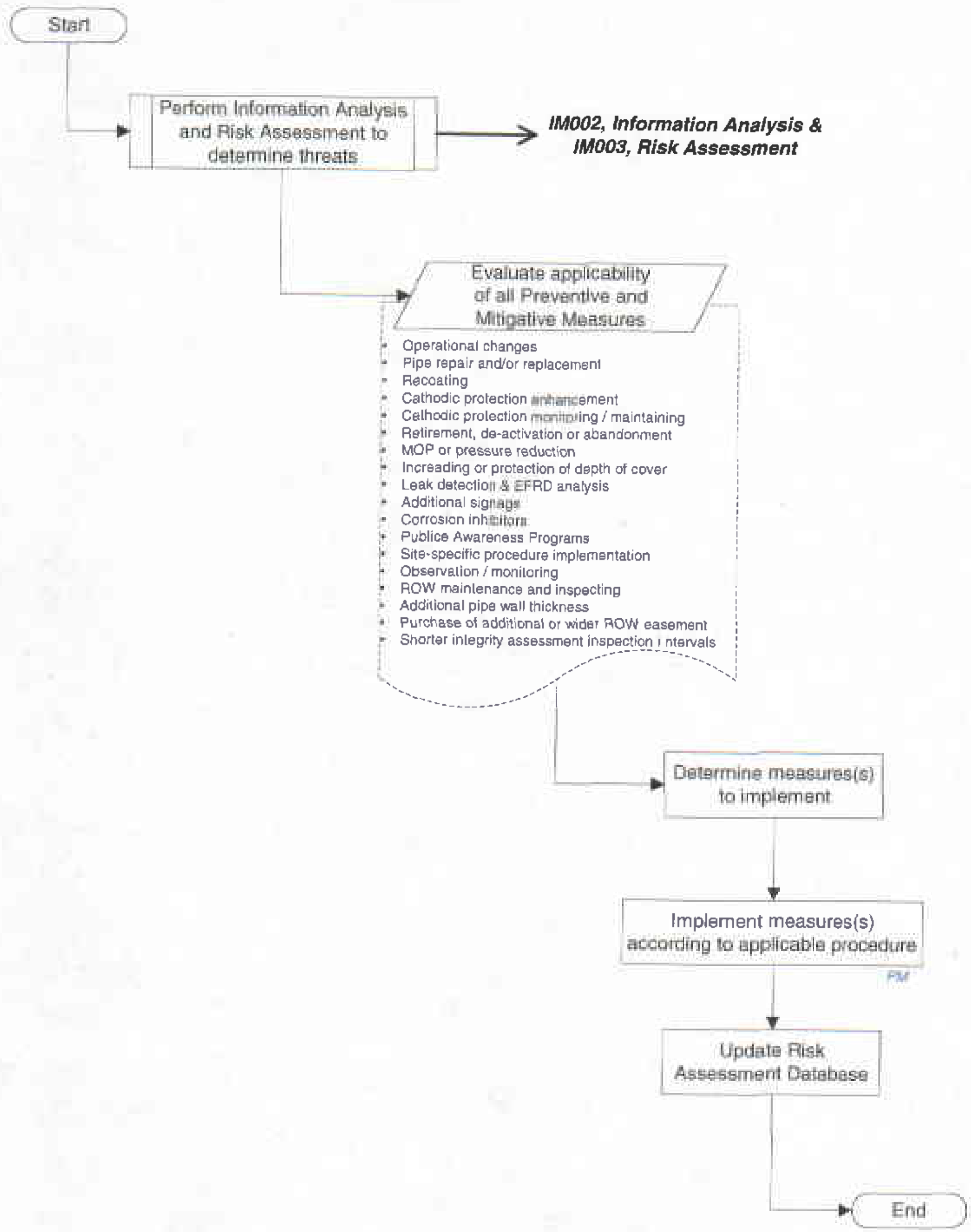
ROW Maintenance and Inspections	Right-of-Way (ROW) must be maintained in order to reduce the possibility of third-party damage and to provide pipeline access. Maintenance will include: • Control of vegetation such that the pipeline corridor is visible by air patrol or ground personnel • Removal of trash and debris • Erosion and sediment control devices • Removal of any structures on ROW ROW is inspected in accordance with regional O&M Procedures. Additional inspection activities may be implemented to further reduce the risk of third party damage.
Additional Pipe Wall Thickness	Tesoro will consider installing pipe of greater wall thickness if warranted. Justification includes, but is not limited to, additional strength, decreased possibility of puncture from a third party, and increased corrosion allowance.

Purchase of Additional or Wider ROW Easement	In some cases, the purchase of additional or a wider ROW easement will be considered to provide a larger buffer against population or construction encroachment.
Shorter Integrity Assessment Inspection Intervals	The frequency of the inspection interval is determined during the information analysis and/or risk assessment process (see *IM002, Information Analysis* and *IM003, Risk Assessment*). Integrity assessment intervals are shortened when evidence is present to suggest that a threat will not be mitgated by the scheduled integrity assessment. Such evidence can include: ♦ Data from O&M activities or inspections that suggest a threat is not mitigated or is progressing at a greater rate than originally anticipated ♦ Identification of a previously unidentified threat ♦ Failure or near miss
PROCEDURE	For each measure identified above, the ECM is responsible for identifying and documenting existing mitigation measures, as well as assigning reviewing responsibility to the Regional Operators. The Regional Managers will review operation and maintenance records for each HCA segment, document their findings, and if necessary provide recommend actions. *FM011-01 Preventive and Mitigative Measures Worksheet* (Sections 1 & 2) is used to document this process. The Regional Manager is then to submit the documentation on *FM011-01* to the ECM. After receiving the Regional Manager's review documented on *FM011-01, Preventive and Mitigative Measures Worksheet*, the ECM compiles all documents and submits an *Action Plan* (included in *FM011-01* Section 3) to the Project Manager. The *Action Plan* prioritizes activities according to severity and impact to operations. The Project Manager will complete the *Closure Report* (included in *FM011-01* Section 4) within 90 working days after the *Action Plan* has been submitted. The report will document what actions are scheduled or were implemented as a result of the Action Plan. Scheduled actions are tracked by the ECM, and the completion status is documented in the next annual P&M Measures review.
DOCUMENTATION	The ECM maintains the records and documentation resulting from implementation of this procedure for the life of the facility at the PT&T main office. The following records directly result from implementation of this procedure. ♦ *FM011-01, Preventive and Mitigative Measures Worksheet* ♦ *Action Plan* ♦ *Closure Report*

REFERENCES	♦ *49 CFR ξ195.248 Cover over buried pipeline* ♦ *49 CFR ξ195.410 Line markers* ♦ *49CFR ξ195.452 Pipeline integrity management in high consequence areas* ♦ *49CFR ξ195.452 (i)(2)* ♦ *NACE RP0169 Control of External Corrosion on Underground or Submerged Metallic Piping Systems* ♦ *API RP-1117 Movement of In-Service Pipelines* ♦ *49 CFR ξ192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program* ♦ *49 CFR ξ192.935 What additional preventative and mitigative measures must an operator take* ♦ *49CFRξ192.933 What actions must an operator take to address integrity issues* ♦ *NACE-RP-0502-2002 Pipeline External Corrosion Direct Assessment Methodology* ♦ *49CFRξ191Transportation of Natural and Other Gas by Pipeline; Annual Reports, Incident Reports, and Safety-Related Condition Reports* ♦ *ASME B31.S-2004 Managing System Integrity of Gas Pipelines* ♦ *Tesoro Public Awareness Program* ♦ *PT&T Technical Specifications Manual* ♦ *IM002, Information Analysis* ♦ *IM003, Risk Assessment* ♦ *IM006, Communications Plan* ♦ *IM010, Pipe Repairs* ♦ *IM012, Leak Detection and EFRD Analysis* ♦ *IMP Section 5, Management of Change Plan* ♦ *IM019 Determination Process*
APPLICABLE PROTOCOLS	This procedure applies to the following Integrity Management Inspection Protocols: ♦ Protocol 5 (Liquid): Risk Analysis ♦ Protocol 6 (Liquid): Preventive and Mitigative Measures ♦ Protocol 7 (Liquid): Continual Process of Evaluation and Assessment ♦ Protocol C.01 (Gas): Threat Identification ♦ Protocol H.01 (Gas): General Requirements (Identification of Additional Measures)
REVISION CONTROL	(see table below)

DATE	DESCRIPTION OF CHANGES
12/30/04	Rev. 0: Procedure creation

	12/30/06	Rev. 1: Changed *Closure Report* timing requirement from 60 to 90 days after Action Plan, Added three sections: Responsibility, Frequency, References; other minor misc. revisions
	7/01/08	Rev. 2: Added Gas IMP information.



Unless otherwise noted all tasks are the responsibility of ECM.

Figure 1: Preventive and Mitigative Measures Flowchart

SCOPE	This procedure applies to performing analysis to determine the need for Leak Detection and Emergency Flow Restricting Devices (EFRD) in accordance with *49 CFR 192.935 (a)-(d)* and *49 CFR 195.452(i)(3)-(4)*. It focuses on the data and analysis requirements and describes procedures for reporting and recommending action based on analysis results.
INTRODUCTION	Leak Detection and EFRD Analysis involve determining the probable extent of a liquid or gas release and the potential cost/benefit of implementing proposed changes. Tesoro will take action to protect an HCA if leak detection or EFRD analysis indicate that an HCA is not appropriately protected in the event of a release. Such action can include: ♦ Addition of an EFRD ♦ Modification to an existing EFRD ♦ Operational changes ♦ Equipment changes ♦ Software changes and/or additions
RESPONSIBILITY	♦ ECM ♦ Project Manager
FREQUENCY	Leak Detection and EFRD Analysis will be conducted initially after completing the Risk Assessment (refer to *IM003, Risk Assessment*) and subsequently based on the criteria in the *Subsequent Analysis* section.
LEAK DETECTION	The Project Manager will complete the Leak Detection Assessment within 1 month of conducting Risk Assessment per *IM003, Risk Assessment.* If a computational pipeline monitoring (CPM) technique is determined necessary for leak detection, the design, maintenance, controller training, and record-keeping aspects of *API 1130* will be addressed in system design and maintenance practices.

Leak Detection Assessment	Tesoro determines if modifications to leak detection systems are needed to improve the ability to respond to a pipeline failure and protect HCAs. Leak detection capability is assessed through a systematic evaluation of the following factors (ref *49 CFR 195.452(i)(3)*): ◆ Pipe segment characteristics (length and size of the pipeline, type of product carried, current throughputs, pipe segment hydraulics-steady state and transient) ◆ HCA Impact ◆ Swiftness of leak detection and shutdown capabilities ◆ Location of nearest response personnel ◆ Leak history ◆ Risk assessment results ◆ False alarm history ◆ SCADA ◆ Thresholds for leak detection ◆ Flow and product measurement ◆ Specific procedures for lines that are idle but still under pressure ◆ Testing
PIPELINE CHARACTERISTICS	A complete understanding of pipeline segment characteristics is required in order to give consideration to the following criteria in determining the appropriate means of detecting leakage for that segment. ◆ Length and diameter of the pipeline ◆ Type of product ◆ Historical and current throughputs ◆ Scheduling (batch sizes and type) ◆ Pipe segment hydraulics (steady-state and transient) ◆ Existing leak detection and SCADA capabilities
PROXIMITY TO AN HCA	The results of the HCA impact analysis, performed in accordance with *IM001, Volume Release and HCA Impact*, are used to prioritize leak detection activities.
SWIFTNESS OF LEAK DETECTION	See section on *EFRD Analysis - Swiftness of Leak Detection*, below.
LOCATION OF NEAREST RESPONSE PERSONNEL	Tesoro considers the location of personnel to determine how quickly it could respond to a hazardous liquid or gas release.
LEAK HISTORY	Tesoro uses leak history to determine the level of operational risk for a pipe segment. This information is used when evaluating the likelihood of a pipeline release and its affect on HCAs.

RISK ASSESSMENT RESULTS	Tesoro uses a Risk Assessment Database and algorithm based on W. Kent Muhlbauer's methodology (see *IM Procedure IM003, Risk Assessment*) to prioritize relative risk for consideration in the leak detection decision-making process.
FALSE ALARM HISTORY	It is essential that the methods Tesoro uses as a means of detecting leaks be sensitive enough to detect small leaks, yet not overly sensitive to the point that excessive false alarms occur. Tesoro considers false alarm history to include: ♦ Issues related to the ability of the control center and operations to detect potential leaks or releases ♦ Failure to detect and respond to a potential release incident ♦ Surge events and other normal operating conditions False alarm events are documented and given special consideration when developing What-If Scenarios (refer to *What-If Scenario* section of this procedure*)* to identify potential improvement opportunities.
SCADA	Potential SCADA capabilities with respect to leak detection include the use of volume balance data, standard SCADA trend displays to indicate over/ shorts as a function of time, and detection of major pressure drops resulting from catastrophic failures.
THRESHOLDS FOR LEAK DETECTION	Leak Detection thresholds are based on pipeline operating characteristics or other jurisdictional requirements.
FLOW AND PRODUCT MEASUREMENT	Tesoro utilizes a variety of electronic flow measurement devices depending on service requirements. The following flow measurement characteristics are reviewed and documented during the Leak Detection System site acceptance test: ♦ Metering regime ♦ Metering accuracies ♦ Metering practices and policies ♦ SCADA availability and reliability ♦ Current severity of service ♦ Potential growth in service ♦ Adequacy/appropriateness of existing instrumentation ♦ Operational history ♦ Scheduled test intervals
Idle Lines	Idle pipelines are segments that contain a hazardous liquid or gas, but are currently static or unused. Idle pipelines will be assessed per this procedure after being placed back into active operation in accordance with the requirements of the Integrity Management Program Manual.
Testing	Tesoro tests leak detection systems by physical removal of product from the pipeline or other methods, as deemed appropriate.

Capabilities and Improvements	What-if Scenarios, described below, may be used to model improvements or changes in leak detection.
Potential Costs and Benefits	If changes to the leak detection system are recommended for further consideration, the Leak Detection Analysis *(FM012-01, Leak Detection and EFRD Analysis Reporting)* will also document the cost and anticipated benefit of the change. What-if Scenarios, described below, may be used to determine potential benefits of the change.
EFRD ANALYSIS	The Project Manager will complete the EFRD Assessment within 1 month of conducting Risk Assessment per *IM003,Risk Assessment*). Tesoro determines, on a segment-by-segment basis, if additional EFRDs are needed to protect an HCA. In making this determination, Tesoro will perform a systematic evaluation of the following factors (ref *49 CFR 195.452(i)(4)*): ♦ Swiftness of leak detection and pipeline shutdown capabilities ♦ Type of commodity carried ♦ Operating Pressure ♦ Rate of potential leakage ♦ Volume that can be released ♦ Topography or pipeline profile ♦ Potential for ignition ♦ Proximity to power sources ♦ Location of nearest response personnel ♦ Specific terrain between the pipeline segment and the high consequence area ♦ Benefits expected by reducing the spill size The following sections describe each of these factors in detail.
SWIFTNESS OF LEAK DETECTION	Swiftness of leak detection and pipeline shutdown capabilities (response time) are determined on a site-specific basis with consideration given to the following factors: ♦ System detection times ♦ Operator response times ♦ Remotely controlled valve response characteristics ♦ System isolation time assessments
TYPE OF COMMODITY CARRIED	The physical properties of the type of commodity carried contribute to the flow/release pattern within the pipeline as well as the leak or rupture flow pattern. Tesoro models the worst-case product type when completing EFRD analysis and What-if Scenario Modeling. Physical properties are available from *Material Safety Datasheets (MSDS)* (refer to the *Safety Department* link within the Tesoro intranet website).

VOLUME RELEASED AND RATE OF POTENTIAL LEAKAGE	Tesoro determines the worse case release volume of a given pipeline segment as described in *IM001, Volume Release and HCA Impact*. The calculated worse case release volume is the sum of the volume that initially escapes before shutdown and isolation plus the amount of product that could escape during "drain-up" or "drain-down" while stabilizing to atmospheric conditions. The worse case release volume formula is as follows: Release Volume = Max Initial Loss + Max Stabilization Loss Where: Max Initial Loss = Pipeline throughput x Shutdown time Stabilization Loss = Volume between EFRDs at standard conditions that will be released after isolation occurs. (Essentially, the sum of the pipe volumes for upstream and downstream sections that are above the elevation of the release point, to an isolation point or a point of maximum elevation.)
POTENTIAL FOR IGNITION AND PROXIMITY TO POWER SOURCES	Ignition and power sources that could potentially introduce a fire and/or explosion hazard are identified and incorporated into the Release Profile (refer to section below).
LOCATION OF RESPONSE PERSONNEL	Tesoro considers the location of personnel to determine the speed of response to a hazardous liquid or gas release site.
BENEFITS OF REDUCING SPILL VOLUME	The benefits of reducing the potential spill volume are examined by overlaying release profiles and performing What-if Scenarios as described below.
WHAT-IF SCENARIOS	What-If Scenario modeling identifies if an existing EFRD is adequate for protecting an HCA. Refer to *IM Procedure IM003, Risk Assessment: What-if Scenario Modeling*. Specifically, What-if Scenarios facilitate the identification of opportunities to: • Minimize potential risk to HCAs • Reduce release volumes What-If Scenarios are developed on a case-by-case basis to specifically answer the following questions: • Can an EFRD be added on the pipeline to minimize the potential spill impact to HCA(s)? • Can the type of EFRD be changed to avoid the potential spill impact to HCA(s)? • Can the leak detection and response time be feasibly reduced such that the risk posed to an HCA(s) is reduced?

Data Elements	Tesoro requires that the following data elements be considered in EFRD analysis: ♦ Release Profile (reference *IM001 , Volume Release & HCA Impact)* ♦ Leak detection capability (contained in release profile) ♦ Leak and false alarm history ♦ Location of response personnel ♦ Risk as determined by Risk Assessment ♦ HCA impact
Release Profile	Tesoro develops release profiles by gathering and coordinating the following information: ♦ Elevation profile ♦ EFRD placement and type ♦ HCA location and type (direct intersection only) ♦ Pipeline station numbering ♦ Release volume ♦ Proximity of power or ignition sources ♦ HCA segments The Release Profile scenario is compared to the worst-case release volume. Opportunities for improvement, if any, are identified and the benefits of implementation are documented.
Other	Tesoro qualitatively considers leak and false alarm history. Opportunities for improvement, if any, are identified, and the benefits of implementation are documented.
Risk	Tesoro determines the amount of relative operating risk associated with a given pipeline segment by using the Tesoro Risk Algorithm (see *IM003, Risk Assessment*). The Tesoro Risk Algorithm is capable of evaluating both the Index Factors and the Leak Impact Factors, as shown in the following table. Pipeline design information (diameter, wall thickness, length, etc.) and elevation data for the entire Tesoro system are input into a spreadsheet so that worst-case release volume calculations can be performed.

INDEX FACTORS	LEAK IMPACT FACTORS
Third Party	Product Hazard
Corrosion	Dispersion Factor
Design	
Incorrect Operations	

BENEFIT ANALYSIS

Tesoro evaluates the benefit of changes defined by What-If Scenarios by reviewing reduction in risk and the potential release volume. This allows Tesoro to efficiently and optimally allocate resources to protect HCAs.

Risk Reduction

Tesoro determines a risk associated with each What-If Scenario. The existing risk is then compared to each scenario risk to identify the amount and percent of risk reduction.

HCA Impact

Tesoro will determine the benefit of a What-If Scenario by performing indirect and potential HCA impact analysis (see *IM001, Volume Release and HCA Impact*). The existing HCA segment length is compared to the HCA segment length for each scenario to identify the amount and percent of HCA segment length reduction.

Benefit Matrix

The relative merits of each scenario are evaluated using a benefit matrix similar to the example below. If the change(s) associated with a scenario proves to reduce risk or HCA segment length in an amount that exceeds the minimum criteria in the benefit matrix, the change(s) is recommended for further consideration.

The following table provides an example benefit matrix.

% REDUCTION				
		>60%	Scenario A	>50%
		40-60%		
	Scenario B	20-40%		25-50%
	Scenario A	<20%		15-25%
			Scenario B	<15%
	RISK		HCA SEGMENT LENGTH	

Figure 12-1: Example Benefit Matrix

In the matrix above, Scenario A is recommended for further consideration, because it meets the criteria for % Reduction of HCA segment length, whereas Scenario B does not meet the criteria for Risk or HCA segment length.

Note: The criteria (as indicated by a bold line in the matrix above) are determined based on Company philosophy.

ACTION PLAN / CLOSURE REPORT	*FM 012-01 Leak Detection and EFRD Analysis Reporting* outlines the following Leak Detection and EFRD Analysis activities: ◆ Scenarios modeled ◆ Findings ◆ Benefits ◆ Recommended action (if any) ◆ Schedule to implement ◆ Cost estimate to implement actions The Project Manager will complete *FM012-01, Leak Detection and EFRD Analysis Reporting;* the *Action Plan* Section is to be completed within 30 working days of completing the Leak Detection Analysis, the *Closure* Section to be completed within 60 working days after changes recommended in *Action Plan* are implemented.
SUBSEQUENT ANALYSIS	Upon completion of the Leak Detection and EFRD Analysis, future analysis is not required unless one of the following changes to a pipeline segment is proposed or made: ◆ Newly identified HCA segment ◆ MOP/MAOP or normal operating pressure increase ◆ Throughput increase ◆ Change in leak detection response time ◆ Change in product type ◆ New or modified EFRD ◆ Integrity assessment completed ◆ Change that warrants analysis in the judgment of Tesoro operations or integrity management personnel Tesoro will perform Leak Detection and EFRD Analysis within 18 months of any of the above changes.
DOCUMENTATION	The records and documentation resulting from implementation of this procedure are retained for the life of the facility at the PT&T Main office. The following records directly result from implementation of this procedure. ◆ *FM 012-01 – Leak Detection & EFRD Analysis Reporting* ◆ *What-If Scenarios (optional)* ◆ *Benefit Matrix (optional)*
REFERENCES	◆ *API 1130, Computational Pipeline Monitoring for Liquid Pipelines; 2nd edition; 11/2002* ◆ *49 CFR 192.935 (a)-(d) What additional preventative and mitigative measures must an operator take* ◆ *49 CFR 195.452(i)(3)-(4), Pipeline integrity management in high consequence areas* ◆ *ASME B31.S-2004 Managing System Integrity of Gas Pipelines*

	• *Risk Assessment Database (refer to IM003, Risk Assessment)* • *IM001, Volume Release & HCA Impact* • *IM003, Risk Assessment*
APPLICABLE PROTOCOLS	This procedure applies to the following Integrity Management Inspection Protocols: • Protocol 5 (Liquds); Area C(Gas): Risk Analysis • Protocol 6(Liquids); Area H(Gas): Preventive and Mitigative Measures • Protocol 7(Liquids); Area F(Gas): Continual Process of Evaluation and Assessment
REVISION CONTROL	

DATE	DESCRIPTION OF CHANGES
12/30/04	Rev. 0 - Procedure creation
09/23/2006	Rev. 1: Added three sections: Responsibility, Frequency, Documentation; clarification of responsibilities; renumbered form FM012-02 to FM012-01 – totally revised form, renumbered form FM012-01 to FM012-02 evisions.
07/01/08	Rev. 2: Added references to Gas Integrity Management program, Updated Protocol references to reflect Gas Integrity Management Protocols.

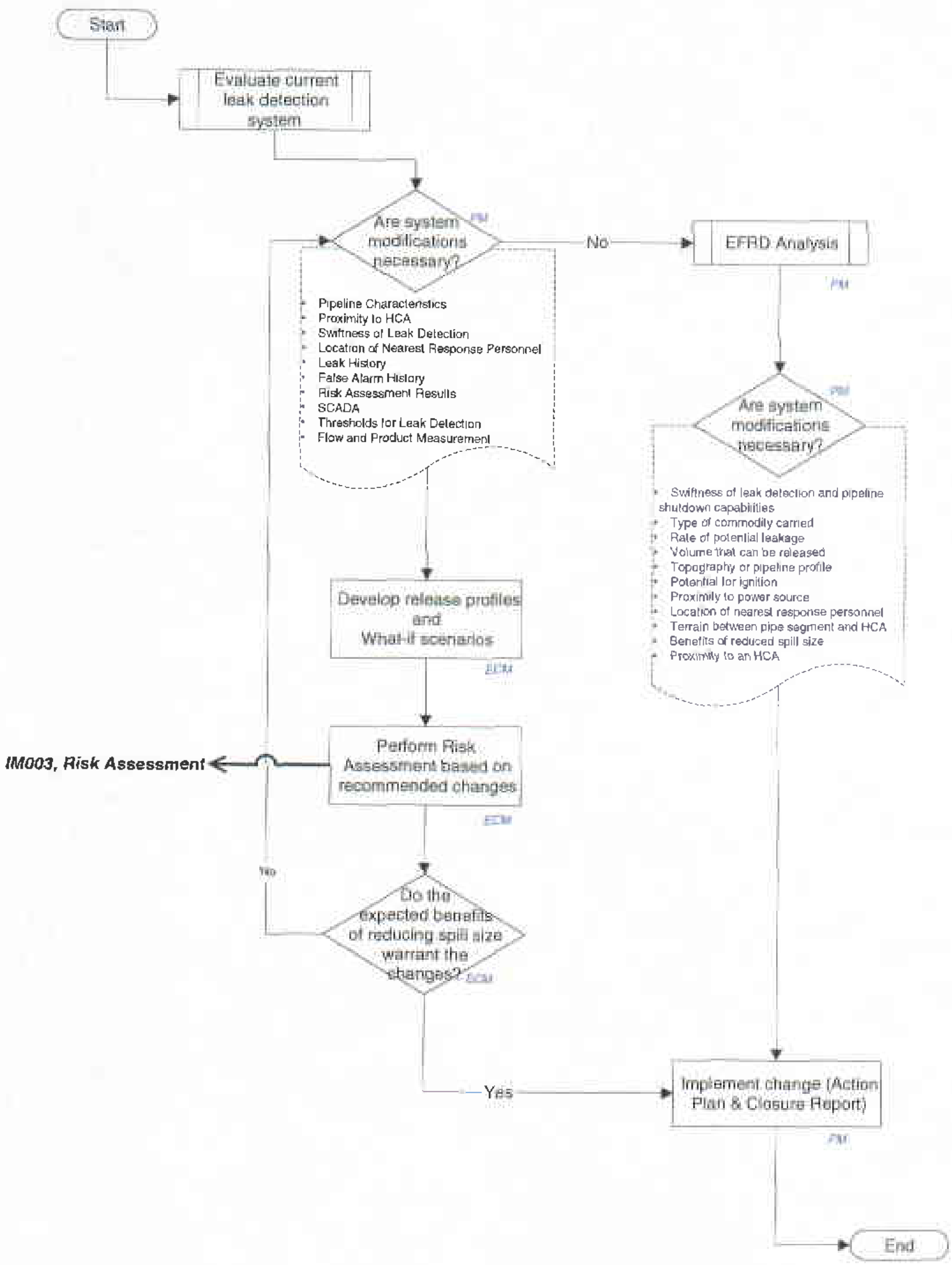


Figure 12-1: Leak Detection and EFRD Analysis Flowchart