

**High Consequence Area (HCA)
Identification
Procedure # P-192.901a**

Appendix A



Description: This procedure is used to identify High Consequence Areas (HCAs) for pipeline integrity management.

Applies To: All regulated gas pipelines.

Frequency:

Responsibility Integrity Management Team (IMT)

Reference: 49 CFR Part 192.903
49 CFR Part 192.905
49 CFR Part 192.907
49 CFR Part 192.9011

Prerequisites: All covered tasks identified in this procedure must be performed by qualified individuals or under the direct supervision of someone who is qualified according to BP's OQ program.

Forms:

Revision Date/Number 03/31/2008 / 4



A. HCA Program Requirements

1. High Consequence Area Identification Process: (192.905(a))

The Integrity Management Team (IMT) is responsible for executing and maintaining HCA identification for the pipelines operated by BP. The process described below is performed by the IMT and applicable to all program mileage. **(NOA #1)**

HCA identification is executed through computer analysis performed within ESRI's ArcMap application. The IMT maintains the master elements utilized for HCA identification: geodatabase (Gas_HCA_Data); reference platform (ortho-rectified aerial photography); dwelling and identified site locations (ArcMap shapefiles); and computer application (New Century Software, Inc., Gas HCA Analyst). Gas_HCA_Data contains pipe spatial centerline, diameter, and MAOP information. This information is maintained current using the data sources described below. The reference platform consists of an ortho-rectified, aerial photographic background that is no greater than three (3) years of age. Aerial photography can be purchased commercially, downloaded from government sites, and/or accessed through commercial websites (ex: Google earth). The dwelling and identified site shapefiles contain the spatial location and description information for each. (See "Gas HCA Analyst" document)

The Bass-Trigon, "HCA Impact Zone Identification Final Report" (Dated September 2004) identified potential HCA impact zones using three (3) methods:

2. Class Location Analysis (Method 1B) – Identifies class 3 or 4 locations that intersect the buffer zone around the pipeline using building count and land use/land cover data.
3. Building Count HCA Analysis (method 2B) – Identifies areas where the potential impact circle contains 20 or more buildings intended for human occupancy.
4. Gas Corridor Analysis (Identified Site) – Captures identified sites that fall within the potential impact circle, using the above noted programs and databases.

BP's pipeline system was analyzed utilizing the above described methods of identification. Although three (3) methods were used for the initial evaluation, BP will decide to use either the Class Location Analysis (Method 1B) or the Building Count HCA Analysis (Method 2B) in conjunction with the Identified Site analysis. The more conservative of the two HCA identification methods will always be utilized.

1. Class Location Analysis (Method 1B):
 2. Receive correct spatial centerline
 3. Create 660' buffer zone
 4. Assemble aerial imagery and digitized buildings
 5. QC analysis (See P-192.901 I (Quality Assurance))
 6. Class determination (Is it a Class 3 or 4?)
 7. If "No" – Not an HCA; If "Yes" it is an HCA
 8. Import results into database
 9. Analyze results
10. Building Count HCA Analysis (Method 2B):
 11. Receive correct spatial centerline



12. Create Potential Impact Radius (PIR)
13. Assemble aerial imagery
14. Digitize buildings (See Page 6; Note 1)
15. QC analysis (See P-192.901 I (Quality Assurance))
16. If <20 buildings – NOT an HCA; if >20 buildings IS an HCA so,
17. Import results into database
18. Analyze threats

B. Data Gathering

The following data (sources) is required for HCA identification:

1. Pipe centerline (GIS, PODS database)
2. Pipe diameter (GIS, PODS database)
3. Pipe MAOP (OMER, Book II)
4. Dwellings and identified sites surrounding the pipeline (IMT maintained data file)

Per Omer Book 1 (Gas), Section 4, Procedure 192.613. (Continuing Surveillance for Class Locations and HCA Procedure, prior to execution of HCA identification the sources, as well as, the completed and submitted forms as noted in Procedure 192.613 shall be reviewed to assure the most current information is utilized.

The pipe centerline and diameter is maintained in the GIS, PODS database and kept current by the Technical Information & Maintenance Team (TIM). Pipeline reroutes are captured into pipe centerline updates after execution of relocation projects and submission of Repair & Inspection (R&I) reports.

The TIM team shall notify the IMT after receipt of the R&I report for either of the following events:

1. Relocation that extends beyond current rights-of-way easements
2. Relocation that involves an increase in pipe diameter

The IMT shall incorporate the new information into the HCA identification process and incorporate any newly defined HCA pipe segments into the Baseline Assessment Plan no later than one (1) year from the discovery date.

Pipe MAOP is maintained in the BP OMER Book II manual and kept current by the Technical Services Team (TS). MAOP changes are captured through the MOC process (Section K). The IMT shall be an approving reviewer of all MAOP changes. The IMT shall incorporate the new information into the HCA identification process and incorporate any newly defined HCA pipe segments into the Baseline Assessment Plan no later than one (1) year from the approval date of a pressure increasing MOC.

Dwelling and identified site data is defined below (Section A.03). Collection of this information can be performed by any of the following:

1. IMT personnel



2. Operations personnel (Operations & Maintenance and/or Damage Prevention)
3. Contract land survey providers

Data collection procedures are defined in Section A.6. Data is forwarded to the IMT for analysis. Location, format, and information of the data shall follow:

1. Dwellings – markup of most recent HCA Map or GPS coordinate taken from the side of the dwelling nearest the pipeline
2. Building type
3. Unit count information
4. Identified sites - markup of the most recent HCA Map (perimeter outline that depicts identified site limits)
5. GPS coordinates that accurately define the limits of the identified site
6. Identified site type
7. Contact information (where available).

The IMT shall approve the scope of work for any land surveyor provider contracted to collect dwelling or identified site data prior to the formal sanction of the contract agreement. The IMT shall incorporate the new information into the HCA identification process and incorporate any newly defined HCA pipe segments into the Baseline Assessment Plan no later than one (1) year from the occupation date of the dwelling or identified site that establishes the HCA.

C. HCA Identification Methodology (192.905(a))

The IMT identifies high consequence areas (HCA) utilizing both Method 1 (Section A.04) and Method 2 (Section A.05). Pipeline segments located within HCA limits are subject to Gas HCA Rule requirements.

Each TRA that is conducted will specify which of the two previously noted methods was utilized for analyzing the pipeline.

Method 2 is the primary methodology used and is based on the radius of the potential impact circle (PIC) (Section A.02). Under this method, a HCA is defined as PIC areas that contain 20 or more buildings intended for human occupancy or an identified site (Section A.03).

Method 1 is the secondary (optional) methodology used and is based on Class location, as defined per CFR 49 Part 192.5. Under this method, a HCA is defined as Class 3 and 4 locations and Class 1 and 2 locations where the PIC area contains an identified site. This methodology shall only be used for pipelines operating such that the PIC radius is ≤ 660 feet. The length of the pipeline segment located in a HCA extends the full diameter of the PIC (Method 1 and 2) and the full extent of Class 3 and 4 locations (Method 1). HCA identification can utilize both methodologies interchangeably.

The methodology used shall be documented in the reporting of HCA identification results. Results produced from the Gas Analyst software are documented in the "Segment Identification" spreadsheet.

NOTE: see HCA Identification Results – "Segment Identification" spreadsheet. **(NOA #1)**



1. HCA Identification Analysis

The computer application (New Century Software, Inc., Gas HCA Analyst) is capable of performing HCA identification using either method described above. After completion of data updates, Gas HCA Analyst is launched. The setup and execution of Gas HCA Analyst is contained in the Gas HCA Analyst for ARCGIS9, Installation and User Guide.

The previous HCA identification analysis project is opened and saved under a new file name to archive the current analysis. New aerial photography is loaded (if available) along with the pipe centerline from GIS, PODS. Prior to pipe centerline download from PODS, the TIM team is consulted to determine if any relocations are pending update into PODS. The pipe centerline from the geodatabase Gas_HCA_Data is overlaid to allow comparison and adjustment. The detail of the aerial photographic background allows identification of the pipeline route through rights-of-way clearing and ground discoloration. The IMT reviews as-built survey linesheet information and edits the Gas_HCA_Data pipe centerline to mimic the PODS centerline and position it true to the photographic reference background. Major discrepancies shall be reviewed with the TIM team and resolved to assure centerline accuracy. While in the pipe centerline edit session, MAOP and pipe diameter are reviewed for correctness and updated if necessary.

The dwelling and identified site information is added to the analysis project. Each file is edited to achieve rectification to the photographic background. New information shall be added per the guidelines contained in the Gas Class Location HCA def.xls document. Dwellings shall be digitized as point objects and identified sites shall be digitized as polygon objects.

The user selects the identification methodology and establishes analysis parameters per the user guide. The execute command is initiated and upon completion of the analysis, a statistical report is displayed that indicates successful completion of the analysis. The output from the analysis is a new geodatabase with the results information loaded into the analysis project for QA/QC (See P-192.901 | (Quality assurance)). The IMT reviews the results for accuracy and reasonableness before publication. **(NOA #1)**

2. HCA Identification Results: (192.905(a))

HCA identification results are documented in both tabular and map format. Tabular format is used for summary information purposes and is typically reported as percentage of or gross mileage of a pipeline section that contains pipe that meets the HCA criteria. The HCA methodology shall be documented in the Gas Transmission Pipelines HCA (Excel) which contains the current record of HCA identification results. Map format is used to identify the specific boundaries of pipe segments that meet the HCA criteria. Map format shall depict the pipe centerline, the pipe segments that meet the HCA criteria, and the buildings/identified sites used in the analysis. HCA Maps are accessible through the website links located at the end of this section.

NOTE: Both formats shall indicate the PIC radius dimension applied and the Methodology used:

3. Gas Transmission Pipelines HCA: PIC radius & HCA Segment ID Method (fields).

4. HCA Map: Title Block or text located above title block.

5. Completion Requirements of Identified Pipelines: (192.907 and 192.911(a))

Bass Trigon completed a report for BP dated September 14, 2004, the "HCA Impact Zone Identification Final Report." This report addresses documentation of the RiskCAT HCA Impact Identification Process utilizing both Method 1 and Method 2. It also addresses:

6. HCA Impact Zone Summary



7. Identified Site HCA Impact Zones
8. Method 1B - Population Class Identification
9. Method 2B – Building Count HCA Impact Zones
10. Potential Impact Radius (PIR) Calculations

NOTE: See the BP IMP "Segment Identification" spreadsheet.

The IM Team shall establish the Gas Baseline Assessment Plan schedule to accomplish the following: complete assessments on 50% of the HCA pipe segments by December 17, 2007 and complete the remaining assessments by December 17, 2012. The HCA pipe completed prior to the December 17, 2007 deadline shall be from the highest risk pipe segments.

D. Potential Impact Radius/Circle (PIR or PIC)

1. Verification of PIR Formula: (192.903)

The Potential Impact Circle (PIC) radius (r , feet) is determined from the pipe nominal diameter (d , inch) and the current pipeline maximum allowable operating pressure (MAOP, psi) using the formula:

$$r = 0.69 \times \sqrt{(\text{MAOP} \times d^2)}$$

r = the radius of a circular area in feet surrounding the point of failure

MAOP = maximum allowable operating pressure

d = nominal diameter of the pipeline (in inches)

The multiplier 0.69 is used for natural gas. For pipelines carrying gas other than natural gas, the 0.69 multiplier is adjustable according to the formula contained in section 3.2 of ASME/ANSI B31.8S-2001 (Supplement to ASME B31.8). Use of multipliers other than 0.69 shall have supporting calculations documented. Pipelines that carry non-flammable gas shall be considered 100% HCA unless a waiver (from PHMSA) has defined it otherwise.

As noted in the Bass Trigon HCA Impact Zone Identification Report, the Bayer line, which is not in natural gas but in hydrogen chloride, the appropriate multiplier is 0.106, however, the .69 was utilized in order to be conservative.

2. Potential Impact Circles Conditions: (192.903(3))

In order for the analysis to be carried out, the Potential Impact Radius (PIR) buffer needs to be determined. BP shall apply a buffer of +/- fifty (50) feet to the applied to the PIR to account for any inaccuracies in the pipe centerline location. BP has determined that this buffer is sufficient based on a thorough study and evaluation of BP's pipeline line sheets and GIS data. The appropriate documentation regarding the selection of the buffer area being utilized will be submitted to NPMS.

High Consequence Areas extend axially along the length of the pipe. Beginning at the farthest upstream edge of the first PIC that contains either an identified site or twenty (20) or more buildings intended for human occupancy. Ending at the farthest downstream edge of the last PIC that contains either an identified site or twenty (20) or more buildings intended for human occupancy.

E. Identified Sites

1. Buildings Intended for Human Occupancy and Identified Sites: (192.903 and 192.905(b))

A building intended for human occupancy shall include any of the following:



- a. Single family dwelling (count 1);
 - b. Building that contains multiple single family dwellings (each dwelling unit counts as 1);
 - c. Building that that doesn't meet the definition of identified site and contains a single unit (business, office, or industrial) (count 1);
 - d. Building that that doesn't meet the definition of identified site and contains multiple units (business, office, or industrial) (each unit counts as 1).
2. An identified site shall include any of the following:
- a. Outside area or open structure that is occupied by twenty (20) or more persons on at least fifty (50) days in any twelve (12) month period;
 - b. Building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12) month period (for buildings that don't meet this criteria, the building intended for human occupancy definition shall apply);
 - c. Facility occupied by persons who are confined, are of *impaired mobility*, or would be difficult to evacuate. (Occupancy limits need not be consecutive.)
3. Sources of Information Utilized to Identify Sites: (192.905(b))

Buildings and identified sites are identified using one or more of the following outside sources:

- a. U.S. Census Bureau (Tiger dataset)
- b. USGS (Geographic Names Information System (GNIS))
- c. Aerial imagery
- d. Local Emergency Manager network (LEM)
- e. VRisk (identified site information from Visual Risk Technologies), and/or field survey review
- f. Visual markings (i.e. signs and line posts) **(NOA #2)**

The operator's employees shall be considered when determining both buildings intended for human occupancy and identified sites.

Buildings and identified sites are identified using one or more of the following BP sources, discussed in Sections F - I of this procedure.

The Damage Prevention Team issues an EMR (Emergency Responder Program) packet tri-fold brochure to local emergency management officials and the public once every three (3) years to address pipeline concerns, emergency procedures, pipeline safety, and BP business philosophy. The purpose is also to make the public and public officials aware of updated contact information and recommended practices if an issue would occur.

F. Routine Compliance Requirements

Please refer to BP OMER Book I – Gas, Section 3 – Specifics, Table 3-1 for this information. The IMT shall receive copies of all specified documents from the appropriate personnel. The specified procedure of how the IM Team shall receive the documentation and the specified list of documentation is in Section 4, Procedure 192.613. **(NOA #2)**



Through review and evaluation of the above noted data reports that the IMT will receive, changes to existing identified sites and newly identified sites can be determined. This will also allow for the HCA's to be updated on a yearly basis by the IMT.

G. Ground and Aerial Patrols

Ground and aerial patrols are discussed and documented in P-192.705AP, F-192.705AP, P-192.705GP, F-192.705GP. Documentation of meeting with public officials and land owners is achieved through form F-192.615(c) (Conduct Liaison with Public Officials). **(NOA #2)**

Through review and evaluation of the above noted data reports that the IMT will receive as outlined in OMER Book 1, Section 4, Procedure 192.613, changes to existing identified sites and newly identified sites can be determined. This will also allow for the HCA's to be updated on a yearly basis by the IMT.

H. Routine and If/Then Compliance Requirements

Please refer to BP OMER Book 1 – Gas, Section 3 – Specifics, Table 3-1 for the "Routine Compliance Requirements and Table 3-2 for the "If/Then compliance Requirements" that take place on the pipeline. The IMT shall receive copies of all specified documents from the appropriate personnel.

Through review and evaluation of the above noted data reports that the IMT will receive changes to existing identified sites and newly identified sites can be determined. This will also allow for the HCA's to be updated on a yearly basis by the IMT, as outlined in the BP OMER Book 1, Section 4, Procedure 192.613.

I. Necessary Compliance Records

Please refer to BP OMER Book 1 – Gas, Section 3 – Specifics, Table 3-3 for the "Necessary Compliance Records" required to be maintained. The IMT shall receive copies of all specified documents from the appropriate personnel, as outlined in OMER Book, Section 4, Procedure 192.613.

Through review and evaluation of the above noted data reports that the IMT will receive changes to existing identified sites and newly identified sites can be determined. This will also allow for the HCA's to be updated on a yearly basis by the IMT.

J. HCA Identification Using Class Location (Method 1)

1. Class 3 and 4 Piping: (192.5(b)(3), (b)(4), (c))

Method 1 HCA identification shall only be used on pipelines where the calculated PIC radius is ≤ 660 feet. It begins with PIC determination as described in Section K. Method 1 HCA determination begins with a pipeline route demarked with the results from a class study performed in accordance with 49 CFR Part 192.5. The sections of pipeline that fall within the limits of Class 3 or 4 locations are designated as HCA pipe and are subject to Gas HCA Rule requirements.

2. Class 1 and 2 Piping: (192.903(1)(iii))

This option was not utilized.

3. High Consequence Areas in Class 1 and 2: (192.903 (1)(iv))

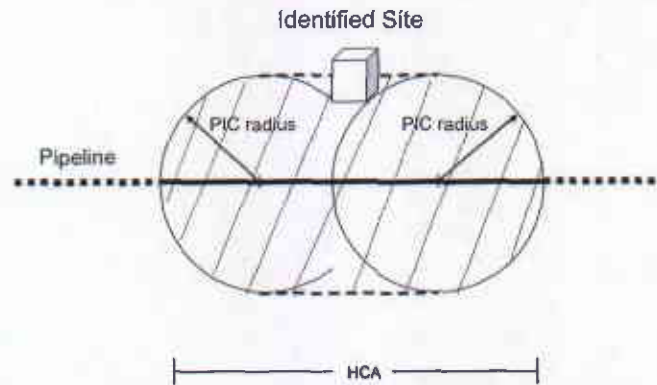
If the PIC radius is > 300 feet, Class 1 and 2 locations must be further analyzed for additional HCA identification. The Method 2 HCA identification procedure, as described in Section K, is performed within Class 1 and 2 locations and considers only identified sites (Section E). The predetermined PIC is centered on and slid along the pipeline. Sections of pipeline where



identified sites intersect the PIC are designated as HCA pipe and are subject to Gas HCA Rule. HCA pipe limits are determined according to the following figure.



Determining HCA Pipe Limits

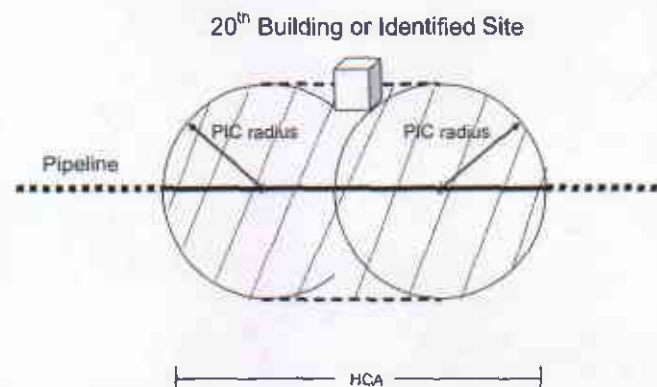


K. HCA Identification Using Potential Impact Radius/Circle (Method 2)

1. Locations of High Consequence where Potential Impact Circle Contains > 20 Buildings:
(192.903(2)(i))

Method 2 HCA identification can be used on all pipelines and shall be used on pipelines where the calculated PIC radius is > 660 feet. It begins with PIC determination as described in Section D. The predetermined PIC is centered on and slid along the pipeline. Locations where the PIC intersects the 20th building intended for human occupancy (Section E) are designated as HCA pipe and are subject to Gas HCA Rule. HCA pipe limits are determined according to the following figure.

Determining HCA Pipe Limits





2. Locations of High Consequence within the Potential Impact Circle Containing an Identified Site: (192.903(2)(ii))

Method 2 HCA identification can be used on all pipelines and shall be used on pipelines where the calculated PIC radius is > 660 feet. It begins with PIC determination as described section A.02. The predetermined PIC is centered on and slid along the pipeline. Locations where the PIC intersects an identified site (Section J) are designated as HCA pipe and are subject to Gas HCA Rule. HCA pipe limits are determined according to the following figure.

L. Newly Identified High Consequence Areas

1. Process for New Information Gathering and Integration: (192.905(c))

Field operations shall annually review in the first quarter, not to exceed 15 months, the population footprint surrounding the pipeline through the execution of the Class Location/HCA Survey and Determination Procedure (P-192.5 and P-192.613). They shall monitor the areas surrounding the pipeline (out to the 660 foot or PIC boundary limits, whichever is greater) and capture the information of any buildings and/or identified sites that are newly created (constructed, designated, etc.) or removed. Information gathered from this effort shall be communicated to the IM Team for review and validation. The IM Team shall evaluate the significance of all changes and determine the need to adjust HCA limits using the methodologies described above. Newly identified areas shall be incorporated into the Gas Baseline Assessment Plan within one year from the date it was identified.

BP Pipelines builds new pipelines, acquires existing pipelines, divests existing pipelines, assumes operatorship of joint venture pipelines, temporarily idles pipelines, and abandons pipelines.

Newly installed pipelines shall utilize Method 1 for HCA identification based on the Class Location design basis for construction until completion of a Method 2 analysis. Newly installed segments of pipe shall have the HCA Identification process completed per the timing requirements described in Section A.

Acquired pipelines or operatorships shall have the HCA Identification process completed as necessary to allow incorporation into the Baseline Assessment Plan within 1 year of the date that BP Pipelines assumes operation.

Divested pipelines shall have its Gas IMP data transferred to the new owner in a timely manner.

Idle pipelines shall have the HCA Identification process completed prior to re-activation.

Changes to the following essential variables might result in the addition or reduction of HCA on existing pipelines:

2. Maximum allowable operating pressure (MAOP)
3. Pipeline diameter
4. Commodity transported
5. Building utilization
6. Class location changes
7. Pipeline reroutes; and/or Pipeline centerline corrections

Changes to any of these variables shall be communicated to the IM Team for review and validation. The IM Team shall evaluate the significance of all changes and determine the need to adjust HCA limits using the methodologies described in section A.1. Newly identified areas



shall be incorporated into the Gas Baseline Assessment Plan within one year from the date it was identified. Changes shall be determined through the review of the below noted data to be received by the IMT:

Please refer to Sections F – I of this procedure for records and documentation to be reviewed.

Through review and evaluation of the above noted data reports that the IMT will receive, as outlined in OMER Book 1, Section 4, Procedure 192.613, changes to existing identified sites and newly identified sites can be determined. This will also allow for the HCA's to be updated on a yearly basis by the IMT.

The completion date of these activities shall be entered into the Gas IMP Implementation Log to serve as the record of compliance.

8. Facility Identification

All facilities attached to the pipeline carry the same HCA designation as that of the coincident pipe and are subject to the Gas HCA Rule requirements. HCA facilities are identified on the HCA Maps.

M. Records

The IM Team and Pipeline Inspection Team maintain the records for the Gas IMP. Unless otherwise noted, these records are archived for the life of the facility. The listing below outlines the addresses for official IMP documentation. Please contact the IM Team for inquiries about current Gas IMP documentation.

1. Gas_HCA_Data geodatabase - I:\APL\ENGR\Integrity\Gas IMP (Data - Results)\Gas_HCA_Data.mdb
2. Gas_Class_Location_HCA_def - I:\APL\ENGR\Integrity\Gas IMP (Data - Results)\Gas_Class_Location_HCA_def.xls
3. Gas HCA Analyst for ARCGIS9, Installation and User Guide - I:\APL\ENGR\Integrity\Gas IMP (Data - Results)\Gas HCA Analyst User Guide.pdf
4. Gas Transmission Pipelines HCA - I:\APL\ENGR\Integrity\Gas IMP (Data - Results)\Gas_Transmission_Pipelines_HCA.xls
5. HCA Maps – (https://wss2.bo.com/RM3/FRA_Team/default.aspx) - HCA OPID Maps
6. Class Location/HCA Survey and Determination Procedure # P-192.5 – BP Pipelines NA Intranet
7. Bass Trigon, “HCA Impact Zone Identification Final Report”, dated September 2004

**Baseline Assessment Plan
Procedure # P-192.901b**

Appendix B



Description: This procedure is used to develop the Baseline Assessment.

Applies To: All regulated gas pipelines.

Frequency:

Responsibility Integrity Management Team (IMT)

Reference: 49 CFR Part 192.921
ASME B31.8S

Prerequisites: All covered tasks identified in this procedure must be performed by qualified individuals or under the direct supervision of someone who is qualified according to BP's OQ program.

Forms:

Revision Date/Number 03/31/2008 / 5



A. Assessment Methods

1. Baseline Assessment Methodology: (192.919(b), 192.921(a), 192.921(c), and 192.921(h))

BP Pipelines shall select Baseline Assessment methodology to address the threats identified from the Prescriptive Threat Analysis and/or the Threat Risk Analysis. Methods can include but are not limited to:

- a. External/internal corrosion threat:
 - i. In-line inspection (ILI) using standard or high resolution magnetic flux leakage tool,
 - ii. ILI using transverse magnetic flux leakage tool,
 - iii. ILI using *ultrasonic compression wave tool*,
 - iv. ILI using ultrasonic shear wave tool, and/or
 - v. Hydrostatic test.
- b. Stress Corrosion Cracking (SCC) threat:
 - i. ILI using ultrasonic shear wave tool and/or
 - ii. Hydrostatic test.
- c. Fabrication/Construction/Outside Force threat:
 - i. ILI using deformation/geometry tools including gage tool,
 - ii. Multiple channel caliper tools, and/or
 - iii. Higher resolution caliper tools that provide x/y/z transition mapping.
- d. Third Party threat:
 - i. ILI using deformation/geometry tools including gage tool,
 - ii. Multiple channel caliper tools. In addition,
 - iii. ILI using standard or high resolution magnetic flux leakage tool,
 - iv. ILI using transverse magnetic flux leakage tool,
 - v. *ILI using ultrasonic compression wave tool*,
 - vi. ILI using ultrasonic shear wave tool, and/or
 - vii. Hydrostatic test.



B. Internal Inspection Tools (192.921(a)(1))

The following table lists the various internal inspection tools available for use by BP.

ILI Tool	Uses
Magnetic Flux Leakage (MFL)	<ul style="list-style-type: none">• Use for metal loss indications such as corrosion and gouges.• Limited sizing accuracy for irregular geometries such as dents. Sizing accuracy is limited by sensor size.• High resolution MFL tools can also be used to detect circumferential cracking.• Limited detection capabilities for mill defects such as laminations or inclusions.• Detect previous repairs if steel sleeves or ferrous markers were used.
Transverse Flux Inspection (TFI) Tool	<ul style="list-style-type: none">• Identifies and measures metal loss.• Used to determine the location and extent of longitudinally oriented corrosion.• Useful for detecting seam related corrosion.• Cracks and other defects can be detected, though not with the same level of reliability as other tools.• Detection and sizing of cracks and crack like defects.• May be able to detect axial pipe wall defects – such as, cracks, lack of fusion in the longitudinal weld seam, and stress corrosion cracking (SCC) – that are not detectible with conventional MFL and ultrasonic tools.• Lower probability of detection for tight cracks.• Limited detection capabilities for mill defects, such as, laminations or inclusions.• Detect previous repairs if steel sleeves or ferrous markers were used.



ILI Tool	Uses
Ultrasonic Compression Wave Tool	<ul style="list-style-type: none">Measures pipe wall thickness and metal loss.The successful deployment of the UT tool is pipeline cleanliness. Tool is sensitive to debris and deposit on the inside of the pipe wall. Recommend using a cleaning pig prior to use of UT tool.Detection and sizing of metal loss, including narrow axial external corrosion.Detection and sizing of laminations and inclusions; detection of other mill anomalies.UT tools are liquid coupled tools. May be run either in a liquid slug or by completely filling the line with liquid.
Ultrasonic Shear Wave Tool	<ul style="list-style-type: none">Most reliably detects longitudinal cracks, longitudinal weld defects, and crack-like defects (such as stress corrosion cracking (SCC)).UT Shear Wave is categorized as a liquid coupled tool.Utilizes shear waves generated in the pipe wall by the angular transmission of UT pulses, through a liquid coupling medium (oil, water, etc.). The angle of incidence is adjusted such that a propagation angle of 45 degrees is obtained in pipeline steel. Appropriate for longitudinal crack inspection.
Caliper/Geometry	<ul style="list-style-type: none">Used for ovality and dent detection/sizing due to construction flaws, soil movement, and third party damage.Used for detecting damage to the line involving deformation of the pipe cross-section.Tools range from single-channel gaging pigs to multi-channel caliper pigs.Use prior to an ILI tool to verify pipeline bore and bend radii to ensure safe passage of the ILI.

Note: For pipe containing longitudinal seams manufactured using either the low frequency ERW or lap-welded process:

- ILI using transverse magnetic flux leakage tool, ILI using ultrasonic shear wave tool, and/or hydrostatic test.
- BP Pipelines shall establish a historical operating pressure (highest pressure recorded in past 5 years) and take one of the following actions:
 - Option 1: Freeze MAOP at the historical operating pressure.
 - Option 2: Monitor operating pressure annually to assure that the initial historical operating pressure is not exceeded by greater than 10%.



If operating pressure exceeds the initial historical operating by greater than 10%, the affected pipe shall be subjected to the hydrotest option, described below, within 1 year from the date of occurrence.

BP Pipelines shall give priority to the ILI methodologies for Baseline Assessments (to obtain the most tangible information concerning the integrity condition of the pipeline) and follow B31.8S-2004, Section 6.2.5 when selecting the appropriate ILI tool. Specification **BPPL-STP 32-211** (Requirements for In-Line Inspection Projects – Gas) outlines the requirements for ILI tool selection. Considerations taken into account when utilizing ILI methodology shall include the following:

1. Detection sensitivity (minimum defect detectable).
2. Defect classification differentiation.
3. Defect sizing accuracy.
4. Defect location accuracy.
5. Defect assessment requirements.

C. Pressure Test Assessment Method: (192.921(a)(2) and ASME B31.8S)

If the hydrotest option is used, the test shall follow 49 CFR Part 192 Subpart J requirements per Engineering specification STP-115 (PLNA Specifications for Hydrostatic Testing (or Liquid Pressure Testing)).

Hydrotesting may be applicable and utilized for addressing Time Dependent Threats (i.e. external corrosion, internal corrosion, and stress corrosion cracking) and manufacturing related defects. Hydrotests will not be utilized to address other identified threats.

D. "Other Technology" Methods: (192.921(a)(4), 949)

If BP Pipelines chooses other technology that it feels can provide an equivalent understanding of the integrity condition of the pipeline, notification shall be made to PHMSA 180 days prior to implementation. If the pipeline segment in question falls under Intrastate jurisdiction or is located in a State where PHMSA has an Interstate agent agreement, notification shall also be sent to the State or local pipeline safety authority.

E. Low Frequency Electric Resistance Welded Pipe (ERW): (192.917(e)(4) and ASME B31.8S, Appendix A (Section 4.3))

If the hydrotest section contains any pipe with low frequency ERW or lap welded longitudinal seam construction, testing plans shall consider the information contained in the PHMSA evaluation report (TTO Number 5; Integrity Management Program Delivery Order DTRS56-02-D-70036; Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation; Final Report).

If a Covered Segment contains low frequency electric resistance welded pipe, lap welded pipe or other pipe described in ASME/ANSI B31.8S Appendices A4.3 and A4.4 and any Covered or Non-covered Segment in the pipeline system with such pipe has experienced a seam failure or an increase in operating pressure over the maximum operating pressure in the last five years, then a manufacturing threat will be considered present. The operating pressure data is acquired through BP's Tulsa Control Center. The data is evaluated and seam analysis will be completed utilizing "Pipelife" by Kiefner and Associates.



Pressure (hydrotesting) testing will be performed to at least 1.25 times the MAOP. Seam analysis data will be run utilizing "Pipelife" by Kiefner and Associates.

F. Plastic Transmission Pipe: (192.921(h))

At this time BP does not own or operate any plastic gas transmission pipelines. Therefore, only steel main has been addressed in the procedure. *If BP installs or acquires plastic transmission pipeline, appropriate procedures will be developed at that time.*

G. Prioritized Schedule

1. Baseline Assessment Plan Development Process: (192.921(a, b and c))

BP Pipelines utilizes the results from the Prescriptive Threat Analysis (Section C) to develop the Baseline Assessment Plan (BAP). (Note: See "Prescriptive Threat Analysis" spreadsheet in BP IMP) The analysis shall identify the threats to the pipeline, allow selection of proper assessment methodology(s), and provide basis to support the prioritization schedule. The Baseline Assessment Plan shall:

- a. Contain all pipelines requiring assessments per the requirements of the Gas HCA Rule;
- b. Identify the assessment method(s) selected;
- c. Identify the threat(s) addressed; and
- d. Outline a time schedule for completing the assessments.

Note: Pipe segments containing longitudinal seams manufactured using either the low frequency ERW or lap-welded process or having SCC threat potential shall be classified as a high risk segment for BAP purposes.

2. Baseline Assessment Schedule: (192.921(d))

The IM Team shall establish the Gas Baseline Assessment Plan (BAP) schedule to accomplish the following: complete assessments on 50% of the HCA pipe segments by December 17, 2007 and complete the remaining assessments by December 17, 2012. The HCA pipe completed prior to the December 17, 2007 deadline shall be from the highest risk pipe segments.

The IM Team shall facilitate a BAP review meeting with the Pipeline Inspection Team to review the methodology selection and prioritization schedule for reasonableness. The Pipeline Inspection Team leads discussions with field operations personnel, service providers, and third party customers to develop a project timeline for assessment(s) execution.

The BAP must:

- a. Meet the requirements of the Gas HCA Rule
- b. Be achievable by both the service providers and field operations
- c. Have commitment by all parties involved

It is important to note that because of these requirements, the BAP may not precisely follow the ranking order established in the plan spreadsheet. Assessment dates are defined by the calendar year that the assessment will occur with an actual execution date entered upon assessment completion. BAP timing is also included in the Integrity Management Plan Overview (Located in rear tabs of IMP).



H. Use of Prior Assessments

BP does not plan to utilize prior integrity assessments as Baseline Assessments.

I. New HCAs/Newly Installed Pipe

1. New Pipelines and HCA: (192.905(c))

BP Pipelines occasionally builds new pipelines, acquires existing pipelines, assumes operatorship of joint venture pipelines, divests existing pipelines, temporarily idles pipelines, and/or abandons pipelines.

Newly installed pipelines or segments of pipe and newly identified HCA pipe shall be incorporated into BP's baseline assessment plan within one (1) year from the date the area or pipe is identified.

2. Baseline Assessments for New HCA's: (192.921(f))

Newly identified HCA pipe shall have a TRA completed within one year of discovery in order to identify threats and determine the risk ranking. The Baseline Assessment will be scheduled in accordance with the risk ranking and completed within ten (10) years of discovery. The assessment method will be selected per Section B.01 to address the threats identified during the TRA process.

3. Newly Installed Pipe with Impacts on HCA Areas: (192.921(g))

Newly installed pipelines or segments of pipe with impacts on HCAs shall have TRA completed within one year of discovery in order to identify threats and determine the risk ranking. The Baseline Assessment will be scheduled in accordance with the risk ranking and completed within ten (10) years of discovery. The assessment method will be selected per Section B.01 to address the threats identified during the TRA process.

Acquired pipelines or new operatorships shall keep the BAP schedule and assessment methodology established by the previous operator until they are integrated into the BP IMP. This integration will occur with one (1) year from the final date of acquisition. In any case, the Baseline Assessment deadline shall be no later December 17, 2012..

Divested pipelines shall have its BAP schedule date and Gas IMP data transferred to the new owner in a timely manner. Idled and abandoned pipelines are not tracked in the BAP. Idled pipelines shall have an integrity verification review, presented to the IMP Committee to determine assessment requirements prior to reactivation.

4. Identify Threats to Newly Installed Pipe/New HCA's: (192.921(b))

a. External/internal corrosion threat:

- i. In-line inspection (ILI) using standard or high resolution magnetic flux leakage tool,
- ii. ILI using transverse magnetic flux leakage tool,
- iii. ILI using ultrasonic compression wave tool,
- iv. ILI using ultrasonic shear wave tool, and/or
- v. Hydrostatic test.

b. Stress Corrosion Cracking (SCC) threat:

- i. ILI using ultrasonic shear wave tool and/or
- ii. Hydrostatic test.



- c. Fabrication/Construction/Outside Force threat:
 - i. ILI using deformation/geometry tools including gage tool,
 - ii. Multiple channel caliper tools, and/or
 - iii. Higher resolution caliper tools that provide x/y/z transition mapping.
- d. Third Party threat:
 - i. ILI using deformation/geometry tools including gage tool,
 - ii. Multiple channel caliper tools. In addition,
 - iii. ILI using standard or high resolution magnetic flux leakage tool,
 - iv. ILI using transverse magnetic flux leakage tool,
 - v. ILI using ultrasonic compression wave tool,
 - vi. ILI using ultrasonic shear wave tool, and/or
 - vii. Hydrostatic test.

5. Assessment Methods Used for Identified Threats: (192.919(b & d))

For pipeline segments containing Low frequency ERW or lap welded pipe that satisfy the conditions specified in ASME B31.8S-2004, an ILI using transverse magnetic flux leakage tool, ILI using ultrasonic shear wave tool, and/or hydrostatic test will be performed in order to address that threat.

BP Pipelines shall establish a historical operating pressure (highest pressure recorded in past 5 years) and take one of the following actions:

- a. Option 1: Freeze the MAOP at the historical operating pressure in order to minimize the seam threat. A hydrotest can be performed to re-establish the previously documented MAOP and address the seam threat.
- b. Option 2: Monitor the operating pressure annually to assure that the initial historical operating pressure is not exceeded by greater than 10%.

If the operating pressure ever exceeds the initial historical operating pressure by greater than 10%, the affected pipe shall be subjected to the hydrotest option, described below, within 1 year from the date of occurrence.

BP Pipelines shall give priority to the ILI methodologies for Baseline Assessments (to obtain the most tangible information concerning the integrity condition of the pipeline) and follow B31.8S-2004, Section 6.2.5 when selecting the appropriate ILI tool. Specification BPPL-STP 32-211 (Requirements for In-Line Inspection Projects – Gas) outlines the requirements for ILI tool selection. Considerations taken into account when utilizing ILI methodology shall include the following:

- a. Detection sensitivity (minimum defect detectable).
- b. Defect classification differentiation.
- c. Defect sizing accuracy.
- d. Defect location accuracy.
- e. Defect assessment requirements.

Comment [MB1]: This is in reference to Protocol B.01.e in order to address seam threats.



If the hydrotest option is used, the test shall follow 49 CFR Part 192 Subpart J requirements per Engineering specification STP-115 (PLNA Specifications for Hydrostatic Testing (or Liquid Pressure Testing)).

If BP Pipelines chooses other technology that it feels can provide an equivalent understanding of the integrity condition of the pipeline, notification shall be made to PHMSA 180 days prior to implementation. If the pipeline segment in question falls under Intrastate jurisdiction or is located in a State where PHMSA has an Interstate agent agreement, notification shall also be sent to the State or local pipeline safety authority.

J. Environmental and Safety Risks During Assessments

1. Verification of Precautions: (192.919(e) and 192.911(o))

BP Pipelines will utilize either the ILI or hydrotest methodology for all baseline assessments. Since BP gas pipelines route through the public domain activities associated with the execution of baseline assessment have the potential to impact the public. BP shall, during the planning and execution of all baseline assessments, engage the appropriate Health, Safety, Security, and Environment (HSSE) personnel to assure that potential threats to company, contractor, and public are identified and addressed.

The Safety Manual (Pipelines) outlines procedures to control potential threats including but not limited to the following, located at:

<http://pl.bpweb.bp.com/ehns/safety/2007%20Safety%20Manual/Safety%20Manual%20Main07.htm>

a. Unintentional release of pipeline contents.

- i. Hydrotest failure.
- ii. ILI pig trap operations.
- iii. Defect excavation.

b. Unintentional access to worksites.

- i. ILI pig traps.
- ii. Valve sites.
- iii. Hydrotest equipment.
- iv. Open excavations.

The BP ISO 14001 Document, Section 4.2.1: Pipelines Environmental Policy outlines procedures such as, BP's commitment to Health, Safety and Environmental performance. The policy references:

- a. ISO 14001 – 4.2 Policy
- b. NEIC 12 Key Elements of an EMS – Key Element 1 Management Policies and Procedures

This document describes the process by which the US Pipelines & Logistics BU communicates the BP U.S. Health, Safety, and Environmental Policy and expectations to their employees and contractors, and the process by which the Policy is maintained.

The HSE Policy affirms the US Pipelines & Logistics organizational commitment to compliance, prevention of pollution and continual improvement, and supports the BP Group Health, Safety,



Security and Environmental (HSSE) policies. The BU develops and implements practices and procedures to comply with legal obligations, HSSE Policy, and other internal HSSE requirements.

This document applies to US Pipelines & Logistics operations and activities, onshore and offshore, providing transportation and storage of crude oil, refined products, petrochemicals, natural gas and natural gas liquids by pipelines, trucking and marine terminals where BP is the Pipeline Operator.

The HSSE Policy is communicated to employees and contractors via several means. Examples include: EMS training, staff meetings, team briefings, contractor safety forms, safety and toolbox meetings, posters, and the Intranet. The policy is made available to the public through periodic Environmental Statements and meetings with community representatives. Communication of the policy statement is an ongoing process.

BP U.S. Health, Safety and Environmental Policy (On Pipeline Website: <http://pl.bpweb.bp.com/ehns/Environmental/EMS/New%20EMS%20Pages%202006/4.0/4.2.2%20USHHealthSafetyandEnvironmentalPolicy.pdf>) (NOA #3)

K. Changes to the Baseline Assessment Plan

1. BAP Update Process and Change Modifications: (192.911(k) and ASME B31.8S (Section 11))

Changes to the Baseline Assessment Plan can be caused by but not limited to the following:

- a. Threat or prioritization changes.
 - i. New information discovered through execution of the BAP.
 - ii. New information discovered through continuous evaluation (section F).
 - iii. New information discovered through execution of remediation (section E).
- b. Operational changes.
 - i. Inadequate flow to propel ILI tool.
 - ii. Asset availability due to supply issues.
- c. Project Execution
 - i. Major modification requirements.

During the current calendar year, the IM Team will use the BAP to track the execution of Baseline Assessments and progress towards meeting HCA Rule requirements. Assessment completion is indicated on the BAP by changing the Section's Baseline Assessment Year value to the actual date of assessment execution. Changes to the BAP will be documented in the **Gas IMP Implementation Log** with supporting explanation and revised Baseline Assessment schedule.

Baseline Assessment Plan status is reported out as follows: **Semi-annual Gas IMP Report** to PHMSA and the **Gas IMP Annual Summary Report** to BP Pipelines Leadership (section I).

L. Records

The IM Team and Pipeline Inspection Team maintain the records for the Gas IMP. Unless otherwise noted, these records are archived for the life of the facility. The listing below outlines the addresses for



official IMP documentation. Please contact the IM Team for inquiries about current Gas IMP documentation.

1. Gas Baseline Assessment Plan - I:\APL\ENGR\Integrity\Gas IMP (Data-Results)\Gas_Transmission_Pipelines_BAP.xls
2. Integrity Management Plan Overview - I:\APL\ENGR\Integrity\Gas IMP (Data-Results)\Integrity_Management_Plan_Overview.xls
3. Engineering specification STP-115 (PLNA Specifications for Hydrostatic Testing (or Liquid Pressure Testing) – BP Pipelines NA Intranet
4. Engineering Specification BPPL-STP 32-211 - BP Pipelines Intranet
5. Safety Manual (Pipelines) - BP Pipelines Intranet
6. BP ISO 14001 Document – BP Pipelines Intranet (Section 4.2.1: Pipelines Environmental Policy)

**Threat Identification and Risk
Analysis
Procedure # P-192.901c**

Appendix C



Description: This procedure is used to perform threat identification and risk analysis as part of the Integrity Management Plan.

Applies To: All regulated gas pipelines.

Frequency:

Responsibility Integrity Management Team (IMT)

Reference: 49 CFR Part 192.917
ASME B31.8S

Prerequisites: All covered tasks identified in this procedure must be performed by qualified individuals or under the direct supervision of someone who is qualified according to BP's OQ program.

Forms:

Revision Date/Number 03/31/2008 / 5



A. Threat Identification (NOA #4)

1. Potential Threats: (All 9 categories in spreadsheet and are per ASME B31.8S (Sect. 2.2) and 192.917)

Threats are categorized into three (3) main categories:

- a. Time dependent threats:
 - i. External Corrosion
 - ii. Internal Corrosion
 - iii. Stress Corrosion Cracking
- b. Static or resistant threats:
 - i. Manufacturing (Seam Threat)
 - ii. Construction defects
 - iii. Equipment Threat
- c. *Time independent threats*:
 - i. Third party damage
 - ii. Outside force damage
 - iii. Incorrect Operations Threat

2. Theory/Basis for Risk Assessment Process

If data used for threat identification and categorization is insufficient or suspect:

- a. Each threat covered by the missing or insufficient data is assumed to apply to the entire segment being evaluated.
- b. Unavailable information is not justification for exclusion of a threat.
- c. Conservative assumptions are used in the risk assessment or the segment is given a higher priority.

3. Identify Time-Dependent Threats:

- a. Identify the High Consequence Areas (HCA's) to be evaluated.
- b. Consider External Corrosion a threat for each HCA, evaluating:
 - i. Diameter of pipe
 - ii. Year constructed/installed
 - iii. Years since construction
 - iv. Pipe wall thickness
 - v. Operating stress (% SMYS)
 - vi. Past hydrotest pressure
 - vii. Past hydrotest year
 - viii. Time since past HT
 - ix. Coating type



- x. Years with no CP (Cathodic Protection)
 - xi. Coating condition
 - xii. Years with questionable CP
 - xiii. Years with good CP
 - xiv. Soil characteristics
 - xv. MIC detected
 - xvi. R&I reports (Pipe/coating condition visual observations)
 - xvii. Leak history
- c. Consider Internal Corrosion a threat for each HCA, evaluating:
- i. Diameter of pipe
 - ii. Year constructed/installed
 - iii. Utilization percentage (%)
 - iv. Pipe wall thickness
 - v. Operating stress (% SMYS)
 - vi. Past hydrotest pressure
 - vii. Past hydrotest year
 - viii. Time since past HT
 - ix. Flowrate (MMSCFD)
 - x. Operating velocity
 - xi. Internal Corrosion det.
 - xii. Gas, Liquids, solid testing
 - xiii. Bacteria testing
 - xiv. R&I reports (Pipe/coating condition visual observations)
 - xv. Leak history
 - xvi. Corrosion Detection Devices (i.e. coupons, probes, etc.)
- d. Determine if Stress Corrosion Cracking (SCC) is a threat for each HCA, evaluating:
- i. Coating type
 - ii. Year constructed/installed
 - iii. Operation temperature
 - iv. Operation stress (% SMYS)
 - v. Past hydrotest pressure
 - vi. Past hydrotest year
 - vii. Time since past HT
 - viii. R&I reports (Pipe/coating condition visual observations)
 - ix. Leak history



- x. Distance of segment to compressor station
- e. Identify the near-neutral SCC threat if all three (3) of the following conditions are met:
 - i. Operating stress level (MAOP) greater than 60% of SMYS
 - ii. Coating other than Fusion Bonded Epoxy (FBE)
 - iii. Age of pipe greater than ten (10) years
- f. Identify the high-pH SCC threat if all five (5) of the following conditions are met:
 - i. Operating stress level (MAOP) greater than 60% of SMYS
 - ii. Coating other than Fusion Bonded Epoxy (FBE)
 - iii. Age of pipe greater than ten (10) years
 - iv. Operating temperature greater than 100 degrees F
 - v. Less than twenty (20) miles of downstream from the nearest compressor station

NOTE:

If evidence of SCC has been found anywhere on the line, identify SCC as a threat for the HCA.

If a leak or failure due to SCC has occurred anywhere on the line, identify SCC as a threat for the HCA.

4. Identify Static or Resistant Threats:

- a. Identify the High Consequence Areas (HCA's) to be evaluated.
- b. Determine if the Manufacturing (Seam) threat exists for each HCA, evaluating:
 - i. Year constructed/installed
 - ii. NOP (Normal Operating Pressure)
 - iii. Operating stress (% SMYS)
 - iv. R & I reports (Pipe/coating condition visual observations)
 - v. Leak history
 - vi. Seam type
 - vii. Joint factor
 - viii. Pipe material
- c. Determine if the Construction threat exists for each HCA, evaluating:
 - i. NOP (Normal Operating Pressure)
 - ii. Operating stress (% SMYS)
 - iii. R & I Reports (Pipe/coating condition visual observations)
 - iv. Leak history
 - v. Pipe material
 - vi. Wrinkle bends
 - vii. Wrinkle bends bend radius



- viii. Wrinkle bend depth
 - ix. Wrinkle bend OP temperature
 - x. Welding procedure
 - xi. Post weld reinforcement
 - xii. Girth weld inspection %
 - xiii. Land slide potential
 - xiv. Seismic potential
 - xv. Past hydrostatic test pressure
 - xvi. Past hydrostatic test year
 - xvii. Soil characteristics
 - xviii. Depth of cover
- d. Determine if the Equipment threat exists for each HCA, evaluating:
- i. R & I Reports (Pipe/coating condition visual observations)
 - ii. Leak history
 - iii. Equipment failure
 - iv. Equipment failure date
5. Identify Time Independent Threats:
- a. Identify the High Consequence Areas (HCA's) to be evaluated
 - b. Determine if Third Party Damage is a threat for each HCA, evaluating:
 - i. R & I Reports (Pipe/coating condition visual observations)
 - ii. Leak history
 - iii. Vandalism incidents
 - iv. Encroachments
 - v. One-call rating
 - vi. Discovery of dent/gouges
 - vii. Incident with prior damage
 - viii. Evidence of pipe hit
 - c. Determine if Outside Force is a threat for each HCA, evaluating:
 - i. Diameter of pipe
 - ii. Year constructed/installed
 - iii. Pipe weight
 - iv. Pipe SMYS
 - v. R & I Reports (Pipe/coating condition visual observations)
 - vi. Leak history
 - vii. Welding procedure



- viii. Land slide potential
- ix. Flood potential
- x. Seismic potential
- xi. Frost line depth
- d. Determine if Incorrect Operations is a threat for each HCS, evaluating:
 - i. R & I Reports (Pipe/coating condition visual observations)
 - ii. Leak history
 - iii. Procedure review timing
 - iv. Audit discoveries
- 6. Performance Bases Approach: (192.917(a) and ASME B31.8S, Section 2.2)

At this time BP is not following the "Performance" Based criteria, a Prescriptive based method was utilized for the BP IMP and threats were addressed the Prescriptive based criteria.

7. Interactive Threats: (ASME B31.8S, Section 2.2)

The interactive nature of threats (i.e. more than one threat occurring on a section of pipeline at the same time). shall also be considered. (See Interactive Threat Table)

Consider the following interactive threats:

a. External Corrosion and Third Party Damage

- i. Prior wall loss due to external corrosion reduces the pipeline's ability to withstand Third Party Damage.
- ii. Third Party Damage to the pipe or coating creates a likely spot for accelerated External Corrosion.

b. External Corrosion and Outside Force Damage

- i. Prior wall loss due to external corrosion reduces the pipeline's ability to withstand Outside Force Damage.
- ii. Outside Force Damage to the pipe (due to seismic forces, etc.) or damage to the coating based on the outside forces creates a likely scenario for accelerated External Corrosion.

As part of the Annual Integrity Evaluation, the IMT will evaluate the potential for interactive threats in a Covered Segment. The IMT will use new information from the most recent information update, the most recently completed risk analysis, routine maintenance results, most recent integrity assessment results and repair data. The IMT will apply reasonable technical judgment in making this evaluation.

Results of the evaluation will be documented through OM&ER P-192.613 (Continuing Surveillance for Class location for HCA) process. (F-192.613) In conjunction with the corridor review a data collection questionnaire will be issued to collect updated risk data on the pipelines. (NOA #4)

If an instance of interactive threats is suspected to be occurring, the IMT will identify appropriate further measures to be taken. These measures will be specific to the identified interactive threats. Examples of measures that might be taken include the following.

1. Field investigation to validate the existence of the interactive threats.
2. Engineering analysis to identify the seriousness of the interactive threats.



3. Increased surveillance such as more frequent cathodic protection readings.
4. Temporary pressure reductions until the threats are validated and mitigated.
5. Identification of other locations where similar interactive conditions may exist.
6. Other repair or remediation action as appropriate.
7. Elimination of Specific Threats: (ASME B31.8S Section 5.10; Non-mandatory Appendix A)

NOTE: For prescriptive threat based integrity management program ASME B31.8S; Appendix A specifies the minimum data requirements and criteria for risk assessment in order to eliminate a threat from further consideration.

a. External Corrosion:

Per A.4.b., this is the minimal data required to be collected and reviewed per Appendix A (ASME B31.8S). If any of the required conditions that make External Corrosion a threat as listed are not evident or present; the threat can then be eliminated.

For External Corrosion all data required per Appendix A will be collected and evaluated. This data is mainly for prioritization of integrity assessment.

b. Internal Corrosion:

Per A.4.c., this is the minimal data required to be collected and reviewed per Appendix A (ASME B31.8S). If any of the required conditions that make Internal Corrosion

For Internal Corrosion all data required per Appendix A will be collected and evaluated. The required data shall assist in making the necessary calculations to determine what specific, if any, threats occur in this category. (i.e. Hydrotest required wall thickness, NOP required wall thickness, corrosion allowance, etc.)

c. Stress Corrosion Cracking (SCC)

Per A.4.d., this is the minimal data required to be collected and reviewed per Appendix A (ASME B31.8S).

Per Appendix A (ASME B31.8S) all of the following criteria are required to be present for SCC to be considered a threat:

- i. Operating stress > 60% SMYS
- ii. Operating temperature > 100 degrees F
- iii. Distance from compressor station < or = 20 miles
- iv. Age > or = 10 years
- v. All corrosion coating systems other than fusion bonded epoxy (FBE)

NOTE: In addition to the above noted criteria, if any segment has one or more service incidents, hydrostatic test breaks, or leaks associated with SCC then SCC will be identified as a threat for that segment.

d. Manufacturing (Seam) Threat:

Per A.4.b., this is the minimal data required to be collected and reviewed per Appendix A (ASME B31.8S).

All of the following criteria must be present for Manufacturing (Seam) to be considered a threat:

- i. Cast iron or steel pipe > 50 years old



- ii. Pre-70 ERW pipe
- iii. Seam type
- iv. Joint factor
- v. Land movement
- e. Construction Threat:
Per A.5.c., this is the minimal data required to be collected and reviewed per Appendix A (ASME B31.8S).
All of the following criteria must be present for Construction to be considered a threat:
 - i. Outside force potential
 - ii. Potential defective welds
- f. Equipment Threat:
Per A.5.d., this is the minimal data required to be collected and reviewed per Appendix A (ASME B31.8S). If any of the required conditions that make Internal Corrosion a threat as listed are not evident or present; the threat can then be eliminated.
- g. Third Party Threat:
Per A.6.b., this is the minimal data required to be collected and reviewed per Appendix A (ASME B31.8S). Due to the fact that Third Party damages is a time independent threat, *even with the absence of the noted indicators these instances can occur at any time.* Strong prevention measures are necessary and this is not a threat to be eliminated. It is also necessary to account for specific land use when determining susceptibility for this threat.
- h. Outside Force Threat:
Per A.6.c., this is the minimal data required to be collected and reviewed per Appendix A (ASME B31.8S). At locations where the pipeline meets the following criteria this threat classification shall be evaluated:
 - i. Seismic potential
 - ii. Hurricane potential
 - iii. Landslide potential
 - iv. Frost line location
 - v. Buckling potential
 - vi. Flooding Potential (Based on Federal documented flood areas/locations noted on HCA maps)
- i. Incorrect Operations Threat:
Per A.6.d., this is the minimal data required to be collected and reviewed per Appendix A (ASME B31.8S). If the data collected illustrates that the operation and maintenance are performed in accordance with BP company policy and by adequately qualified personnel then no additional assessment of this threat is required.

B. Data Gathering And Integration

The IMT works with the SME to identify and collect all of the data necessary to perform a prescriptive threat analysis. The IMT reviews the collection of data and captures the pertinent information into the



Prescriptive Threat Analysis spreadsheet. The data collected addresses the following threats: (See [Prescriptive Threat Analysis Spreadsheet](#))

- External Corrosion
- Internal Corrosion
- Stress Corrosion Cracking
- Seam Analysis
- Construction
- Equipment
- Third Party Damage
- Incorrect Operations
- Outside Force

1. Plan for Collecting, Reviewing, and Analyzing Data: (ASME B31.8S, Section 4.2 and 4.4)

a. Data Categories:

- i. *Attribute Data* (i.e. Pipe wall thickness, diameter, seam type and joint factor, manufacturer, manufacturing date, material properties, equipment properties):

Attribute data represents specification information. This information can be found at: 1) TIM storage location, 2) Pipeline control centers, 3) Subject matter experts, 4) Prescriptive Threat Analysis Data Requirement Table, 5) Engineering and Maintenance inspection team, 6) Corrosion team, 7) Pipeline inspection team. Review of each of these is required to assure that the most current information is incorporated into the analysis.

- ii. *Construction Data* (i.e. Year of installation, bending method, joining method (process & inspection results), depth of cover, crossings/casings, pressure test, field coating methods, soil backfill, inspection reports, cathodic protection installed coating type):

Construction data is archived by the Technical Information & Maintenance Team (TIM). The TIM receives construction data upon project completion, catalogs the data, and sends it to offsite storage. The cataloging process includes a search engine so that specific files can be recalled from storage. The IMT/SME provides the TIM key search criteria to pull the necessary files for review.

- iii. *Operational Data* (i.e. Gas quality, flow rate, normal maximum operating pressures, leak/failure history, coating condition, cathodic protection system performance, pipe wall temperatures, pipe inspection reports, OD/ID corrosion monitoring, pressure fluctuations, regulator/relief performance, encroachments, repairs, vandalism, external forces)

Operational data is provided by the respective pipeline control centers. Each control center archives data pertinent to pipeline operations. A request is made to database administrator for the parameter required and the time duration of the requirement. The administrator downloads the data and formats for viewing and analysis.

- iv. *Inspection Data* (i.e. Pressure tests, in-line inspections, geometry tool inspections, bell hole inspections, CP inspections (CIS), coating condition inspections, audits and reviews)



Inspection data is archived by the Engineering and Maintenance Inspection Team. Cathodic protection data is maintained by the Corrosion Team and in-line (ILI) inspection data is maintained by the Pipeline Inspection Team. A request is made for the data required and the time stamp of the requirement. The appropriate team downloads the data and formats for viewing and analysis.

b. Data Sets for Threat Identification and Risk Assessment: (192.917(b) and ASME B31.8S)

i. Prescriptive Threat Analysis Data Spreadsheet:

Each threat contained in ASME/ANSI B31.8S (Non-mandatory Appendix A) is reviewed to determine the data necessary to perform the prescriptive analysis. The Prescriptive Threat Analysis Data Requirement Table outlines the data requirements for each applicable threat analysis and the source of the data. The Operations & Maintenance Team Lead for each applicable pipeline is consulted to assign a subject matter expert (SME) to assist with the data collection.

c. Verification of Utilized Data Sources for Initiation of IM Program: (ASME B31.8S Table 2)

Data Sources Utilized	Data Source Location
Process and instrumentation drawings	Documentum
Pipeline alignment drawings	ArcGIS
Original construction inspector notes/records	Project Files
Pipeline aerial photography	Commercial Suppliers
Facility drawings/maps	Documentum
As-built drawings	Documentum
Material certifications	Project Files
Survey reports/drawings	Project Files
Safety related condition reports	DOT Files
Operator standards/specifications	OM&ER (BP Pipelines Intranet)
Industry standards/specifications	Commercial Suppliers
O & M procedures	BP Pipelines Intranet
Emergency response plans	BP Pipelines Intranet
Inspection records	Field Office
Test reports/records	Technical Information Management Group
Incident reports	DOT Files
Compliance records	DOT Files
Design/engineering reports	Project Files
Technical evaluations	Project Files
Manufacturer equipment data	Project Files & Field Office

d. Verification of Data Accuracy: (ASME B31.8S Section 4)

- i. As noted in the Prescriptive Threat Identification Table for all threats, as identified in Appendix A (ASME B31.8S), data has been collected and evaluated to determine a ranking of the gas pipeline segments identified as BP's responsibility.



At the time of the initial baseline assessment evaluation no threats have been eliminated based on exclusion of existence.

If there would be an occurrence of missing or suspect data then all applicable threats identified would be assessed for the pipeline.

- ii. Conservative assumptions: The most conservative assumptions were made in the data evaluation process for the BP IMP. (i.e. highest temperature on line assumed across line, thinnest wall pipe on line assumed for entire line, etc.)

Where invalid or unavailable data was encountered the worst case or most conservative scenario data was used to assess the pipeline after all reasonable efforts were made to identify the missing data.

- iii. What type of records are maintained that identify how unsubstantiated data is used?
 - iv. Once the initial data collection efforts are complete, if it is deemed necessary, additional data will be collected from subject matter experts (SME) from within BP or external sources (i.e. industry wide data).
- e. Collection Procedure for New Data (Management of Change (MOC)): (ASME B31.8S (Section 11); API RP 750; 192.911(k))
- i. Ensure management personnel (main office and regional/field offices) responsible for data storage are aware of the data collection effort. This includes, but is not limited to:
 - a) Timeframe (Integration of new data will occur no later than ninety (90) days from identification of new data)
 - b) Scope
 - c) Personnel
 - d) Requested support
 - ii. New data collection required when any of the following changes occur, but not limited to (Integration of new data will occur no later than ninety (90) days from identification of new data):
 - a) Work order (i.e. pipe replacement, repairs, etc.)
 - b) Percent SMYS
 - c) MAOP
 - d) Corrosion protection adjustments/changes
 - e) Temporary changes
 - f) Emergency changes
 - iii. New data collection is typically obtained through the following sources, but not limited to:
 - a) As-built drawings received from field personnel
 - b) Work orders
 - c) Technical Information & Maintenance (TIM) team
 - d) Subject Matter Experts (SME)



- e) Pipeline Control Centers (Database administrator)
 - f) Engineering and Maintenance Inspection Team
 - g) Corrosion Team
 - h) Pipeline Inspection Team
- iv. *Roles and Responsibility of those involved in Management of Change:*
- a) *Originator: The individual or group of individuals who identified the need for the change.*
 - b) *MOC Process Leader: Individual assigned responsibility for the change which follows the MOC process from pre- to post-change assignment.*
 - c) *MOC Approver: Individual responsible for the final authorization of change and serves as the gatekeeper throughout the entire MOC process.*
 - d) *Reviewer: Reviewers must be knowledgeable, trained, and experienced with the equipment, practices, or process changes under consideration and have a thorough understanding of the MOC process.*
 - e) *Employee: Employees must understand the definition of change and identify such changes as they are proposed so the change can be managed to prevent incidents.*

NOTE: Please reference "Management of Change Policy", P-192.901k.

f. **Integration of Data: (ASME B31.8S, Section 4.5)**

The TRA will be evaluated in a program that will allow a common point for all data to be collected and integrated in order to evaluate and determine the risk ranking and assessment of the pipeline. The software to be used will be the Lloyd's Register RBMI program. Reference the RBMI User's Manual (Chapter 20 for a detailed process for the database set-up and organization procedure.

Such data as listed below will be input in order to evaluate the pipeline as required.

- i. ILI Results
- ii. CIS Results
- iii. Hydrotest Results
- iv. CPDM Data

g. **Data Analysis:**

The IMT assembles the Prescriptive Threat Analysis spreadsheet to allow comparison of data variability and preparation of the specific threat analysis. The data table is underscored by data assumption and source information and the data field requirements for each prescriptive threat analysis. A separate tab is created for each threat and the data described above is copied to each sheet. Reference IM 14: Threat Risk Assessment (TRA) RBMI Software Process document.

For conditional threats (SCC, Seam, Construction, Equipment, Operations), the data is reviewed per the requirements outlined in the respective section of ASME/ANSI B31.8S (Nonmandatory Appendix A) to determine if the threat exists. For the non conditional threats (External Corrosion, Internal Corrosion, Third-Party, and Outside Force), the IMT



reviews the data variability presented and formulates a risk model that will force a threat risk prioritization result. The approach for each threat model shall be described in sufficient non formula terminology to describe logic and determine reasonableness. Algebraic equations are utilized for risk modeling on the basis that increasing model value indicates increasing risk. The model results for each pipeline are then compared to establish a ranking order for each threat with the highest model score is ranked #1, the 2nd highest score is ranked #2, etc. Pipelines with identical model scores receive identical rank score.

The ranking order for each threat is tabulated and summed together to establish an overall rank for each segment. The final ranking order is incorporated into the Gas Baseline Assessment Plan to establish the prioritized schedule (section B.2). (LINK to BAP Spreadsheet) (NOA #4)

h. Prescriptive Threat Analysis Maintenance:

The Prescriptive Threat Analysis spreadsheet shall be maintained by the IMT until the Baseline Assessment Plan meets the deadline requirement to complete assessments on 50% of the HCA pipe segments by December 17, 2007. Assessments in the BAP are prioritized based on risk ranking, the TRA assessments will begin with the higher risk segments. Remaining pipeline sections are tracked to assure that the Baseline Assessment Plan is completed by the December 17, 2012 deadline. The IMT shall incorporate new data upon discovery, rerun the models, and determine if a new prioritization results. This re-evaluation process is not intended to make changes to the current years budgeted baseline assessment plan and is completed in time to facilitate the succeeding year's budgeting process.

C. Risk Assessment (ASME 31B.8S; Section 5)

1. Risk Assessment Objectives: (ASME B31.8S, Section 5.3 and 5.4)

Prioritization of pipeline/segments for scheduling integrity assessments and mitigation:

Section A.4. of this plan outlines and specifies the threats that are considered and the data required to be evaluated for each threat. Based on the data collected for each threat the identified pipelines/segments are ranked in each threat classification. (Reference the Prescriptive Threat Identification Spreadsheet)

The rankings for each threat are then compiled into the Segment identification Baseline Assessment Plan Risk Rank Summary spreadsheet which allows for an overall ranking of the identified pipeline segments based on a compilation of the data for all nine (9) threat categories.

The IM Team shall conduct an information analysis (Threat Risk Assessment) on all pipelines containing HCA pipe segments, two (2) years prior to the scheduled reassessment. This analysis incorporates all existing data and information about the entire pipeline. It will follow the requirements of ASME/ANSI B31.8S (section 4 and 5) and consider the prescriptive pipeline integrity program data elements.

The IM Team develops a threat based risk model to:

- a. Identify the required data inputs
- b. Identify the repository and related data authorities
- c. Collect and codify risk data into the model
- d. Execute the risk algorithm



The threats and potential mitigative actions include but are not limited to: (Reference RBMI Pipeline Module Document, LR RBMI User's Manual Document, and [IM14: Threat Risk Assessment \(TRA\) RBMI Software Process document.](#))

- a. External Corrosion Threats
 - i. Perform enhanced CP surveys (CIS, DCVG, etc.).
 - ii. Track EC condition from Inspection & Repair reports.
 - iii. Upgrade CP systems.
 - iv. Reduce re-assessment cycle.
 - v. Recoat pipeline.
- b. Internal Corrosion Threats
 - i. Protocol NDT examination for IC at excavation sites.
 - ii. Monitor IC condition from Inspection & Repair reports.
 - iii. Increase frequency of corrosion coupon monitoring.
 - iv. Alter operations and/or maintenance activities (flow rate, cleaning pig frequency, etc.)
 - v. Reduce re-assessment cycle.
 - vi. Replace pipe.
- c. Stress Corrosion Cracking Threat
 - i. Protocol NDT examination for SCC at excavation sites.
 - ii. Develop SCC intervention program.
 - iii. Recoat and/or grind-out cracking and recoat.
 - iv. Alter operations and/or maintenance activities (maximum pressure, pressure cycling, etc.).
 - v. Perform additional alternate assessment.
 - vi. Determine appropriate re-assessment cycle.
 - vii. Replace pipe.
- d. Manufacturing (Seam) Threat
 - i. Lower operating pressure.
 - ii. Reduce cycle frequency.
 - iii. Perform cyclic fatigue analysis.
 - iv. Perform additional alternate assessment.
 - v. Calculate re-assessment timing requirements.
 - vi. Protocol seam NTD examination at excavation sites.
 - vii. Replace pipe.
- e. Manufacturing (Fabrication/Construction) Threat
 - i. Lower operating pressure.



- ii. Protocol NDT examination at excavation sites.
 - iii. Protocol excavation procedures to prevent pipe movement.
 - iv. Replace pipe.
 - v. Install additional support to reduce loading stresses.
- f. Third Party Damage Threat
- i. Additional line markers.
 - ii. Increased patrol frequency.
 - iii. Protocol to monitor excavations occurring within ROW.
 - iv. Physical investigation of unmonitored excavations occurring within ROW.
- g. Incorrect Operations Threat
- i. Enhance operator qualification and training requirements.
 - ii. More frequent procedure reviews.
 - iii. More frequent internal audits (procedure enforcement).
- h. Outside Force Damage Threat
- i. Increased aerial patrols.
 - ii. Increased surface patrols.
 - iii. Removal of overburden.
 - iv. Surface runoff control measures.
 - v. Perform additional assessment.
2. Risk Assessment Approaches: (ASME B31.8S, Section 5.5)
- a. Subject Matter Experts: The BP IMP plan TRA process will utilize SME's for each pipeline segment location. Questionnaires will be issued to the SME's requesting required information to assist in Risk Assessment scoring.
 - b. Relative Assessment Models: The BP IMP will utilize a relative assessment model system that will utilize an algorithm based on the specified threats and their criteria as noted in BP IMP Section P-192.901c.
 - c. Scenario-Based Models: Not utilized
 - d. Probabilistic Models: Not utilized
3. Risk Assessment Approach – Threat Risk Analysis (TRA): (ASME B31.8S, Section 3 and 5)
- a. The Threat Risk Analysis (TRA) is a report that through the use of an analytical risk ranking program (Lloyd's Register RBMI software), with an appropriated weighted algorithm helps to identify high risk pipe segments and their associated drivers. The results are then utilized to develop a mitigation/inspection plan that controls the risks, and as a result, protects High Consequence Areas (HCA's). The TRA will be completed by a member of the HSSE IM Team.
 - b. Analytical Risk Ranking Program Structure and Outputs: Risk scores calculated by the analytical risk ranking program are based on two components – a comprehensive database and a risk assessment algorithm developed by the S & I Team and Subject Matter Experts (SME's).



c. Database Design: The database is a collection of data about the pipeline that includes information on design, operation, maintenance, location specific characteristics and features, environmental conditions, inspections, leak history and testing results. Sources of this data included but are not limited to:

- i. Alignment sheets
- ii. Repair and Inspection Reports (R & I Reports)
- iii. In-line Inspections Results
- iv. CPDM imports
- v. Interviews with company personnel and SME's
- vi. Close Interval Survey results
- vii. Main line valve reports
- viii. Leak reports
- ix. Hydrotest results
- x. Seismic or Landslide study results
- xi. Other database information
- xii. Diagrams of change
- xiii. RiskCat evaluations
- xiv. Depth of Cover Surveys
- xv. One Call Analysis
- xvi. HCA Analysis

(Reference Lloyd's Register RBMI Pipeline Module document) Algorithm Design: The algorithm determines a relative risk by taking into account the Likelihood (Probability) of Failure (LoF) and Consequence of Failure (CoF) factor types. Likelihood of Failure is a function of the Threats to a pipeline's integrity. Threats to a pipeline's integrity are listed in ten categories. BP may add additional threat categories if conditions warrant such addition.

1. External corrosion.
2. Internal corrosion.
3. Stress corrosion cracking.
4. Manufacturing.
5. Construction including consideration of pressure cycling and fatigue.
6. Equipment.
7. Third party damage.
8. Incorrect operations.
9. Weather Related and Outside Force.
10. Other as identified by BP.

Consequence of Failure is a function of the severity of a release. Ten factors listed below are evaluated to determine the consequence of a release.



1. Proximity to populated areas - method 2
2. Damage impact from release
3. Public awareness
4. Properties of product transported
5. Class location
6. Potential release quantity
7. Proximity to populated areas - method 1
8. PIC size
9. Relationship with local authorities
10. Leak detection system

- a. When the algorithm is applied to the database, results are generated which identify areas on the selected pipeline system(s) that are a higher risk relative to other areas. See Section 192.901c (3.1.2) of the BP IMP plan for further detail on the algorithm break down.

The TRA utilizes all available information about the pipeline section. A majority of the data needed or required has been collected over the years and collected for each pipeline, but *requires verification to assure accuracy (Reference P-192.901j)*. Much of the information requires detailed knowledge of the pipeline section; this resides in the domain of Field Operations, and is obtained through the interview process. The S & I Team utilizes a questionnaire to collect additional data, as needed from the field.

The algorithm will determine the relative risk by taking into account the Likelihood (Probability)of Failure (LoF) and Consequence of Failure (CoF) factor types. The Comparison Criteria is a benchmark reference to be used for evaluating acceptable risk levels within the software (Reference Lloyd's Register RBMI Pipeline Module Document). All the calculated risk scores will be compared to this value. The Comparison Criteria represents the 90 percentile. In other words, for a given factor type, 10% of the scores will be above the Comparison Criteria and 90% will be at or below the Comparison Criteria.

Where quantitative data is not available, qualitative data will be used and justified accordingly. The model shall help identify any threat(s) to the pipeline and provide a basis to the planned preventive and mitigative measures. The IM Team compiles the results of the TRA into a report and then facilitates a meeting with pipeline stakeholders and pertinent subject mater experts to review/validate results, validate planned and identify any additional assessment requirements, and identify additional preventive mitigative actions if necessary.

If mitigating actions are necessary, they will be prioritized and included in a Mitigation Plan complete with responsible parties and timing deadlines. The IM Team will track the execution of the Mitigation Plan. The Mitigation Plan will be included in the TRA Report and the report archived for future reference.

Every threat concern, discovered during the TRA, shall be addressed in a reasonable ,or as specified based on the risk ranking status of the identified threat, amount of time through Mitigation review.

The review process includes:

- i. Threat risk driver identification
- ii. Risk exposure determination



iii. Preventive and mitigative measure alternatives

iv. *Action plan development and implementation*

The measures executed shall be based on Engineering analysis and operating experience and can include the activities outlined below. Recurring preventive and mitigative measures shall be formally developed and placed in a mitigation toolbox to be applied elsewhere in the system as needed. Data from non covered segments shall be considered in this process.

The office of record for the completed TRA Report will be the Cantera 1, 5th floor, S & I Team archives. It will be archived in hard copy with an electronic version stored on the I: drive.

11. Threat Risk Analysis (TRA) model variables: (Reference [IM14: Threat Risk Assessment \(TRA\) RBMI Software Process Document](#))

a. External Corrosion:

i. *Deficient Coating*

ii. Unknown pipe design

iii. Coating design

a) Uncoated

b) Asphalt or TGF (Tar Glass Felt)

c) Tape wrap (Cold applied pre 1990)

d) Extruded (shrink sleeve)

e) Coal tar enamel

f) Composites

g) Concrete

h) Other (Coated, but type unknown)

i) Tape wrap (Hot applied)

j) Tape wrap (Cold applied post 1990)

iv. NOP vs. Pipe Strength

a) > 65%

b) 55 to 65%

c) 40 to 55%

d) 30 to 40%

v. Cathodic Protection Criteria

a) No test stations

b) Does not meet EC Cathodic criteria

c) No survey within 15 months

vi. Close interval criteria

vii. External corrosion leak rate



- viii. In-line or visual inspection results
 - a) >70% wall loss
 - b) >50-70% wall loss
 - c) >35-50% wall loss
- ix. In-line or visual inspection anomaly PRF
 - a) >0.9499
 - b) 0.90 to 0.9499
- x. Close interval survey
 - a) No survey performed
 - b) Inspection > 8 years old
 - c) Inspection 5 to 8 years old
 - d) Inspection 2 to < 5 years old
- b. Internal Corrosion:
 - i. Product type
 - ii. NOP vs. pipe strength
 - a) > 65%
 - b) 55 to 65%
 - c) 40 to < 55%
 - d) 30 to < 40%
 - iii. Flow rate
 - a) Reynolds number ≤ 0
 - b) Reynolds number >0 to 2000
 - c) Reynolds number >2000 to 4000
 - iv. Internal corrosion leak rate
 - a) > 1 leaks per leak age
 - b) > 0.5 to 1 leaks per leak age
 - c) > 0 to 0.5 leaks per leak age
 - v. In-line or visual inspection results
 - a) > -70% wall loss
 - b) > -50 to -70% wall loss
 - c) > -35 to -50% wall loss
 - vi. In-line or visual inspection anomaly PRF
 - a) > 0.9499
 - b) 0.9 to 0.9499
 - vii. Low spots in pipeline



- c. Stress Corrosion Cracking:
 - i. Material flaws
 - ii. Pressure cycling
 - iii. Pipe visual inspection
 - iv. SCC In-line inspection
 - v. Test pressure vs. pipe strength
 - vi. Pressure testing
 - vii. Repair – SCC Inspection
 - viii. Repair – crack detection inspection
- d. Manufacturing (Seam):
 - i. Material flaws
 - ii. Pressure cycling
 - iii. Pipe visual inspection
 - iv. In-line inspection
 - v. Test pressure vs. pipe strength
 - vi. Pressure testing
 - vii. Repair - crack detection inspection
- e. Construction Threats:
 - i. One call effectiveness
 - ii. Patrol frequency
 - iii. Public education
 - iv. Ground cover protection
 - a) > 3 to 6 feet
 - b) > 2 to 3 feet
 - c) > 0 to 2 feet
 - d) <= 0 feet
 - e) Unknown
 - v. Wall thickness
 - vi. Line marking
 - vii. ROW condition
 - viii. Diameter/Wall thickness
 - ix. NOP vs. Pipe strength
 - a) > 65%
 - b) 55 to 65%
 - c) 40 to < 55%



- d) 30 to < 40%
- e) 20 to < 30%
- x. Third party leak rate
 - a) > 2 leaks per leak age
 - b) 1 to 2 leaks per leak age
 - c) > 0 to < 1 leaks per leak age
- xi. Anomaly type
 - a) Dent with metal loss
 - b) Dent without metal loss
 - c) ID anomaly < 2% with metal loss
 - d) ID anomaly < 2% without metal loss
 - e) Mechanical damage
- xii. Toughness
- f. Equipment Threats:
 - i. Engineered pipe spans
 - ii. Pipe seam design
 - iii. Girth weld condition
 - iv. Pipe temperature
 - v. Toughness
 - vi. Material flaws
 - vii. Pipe age
 - viii. NOP vs. pipe strength
 - ix. Pressure testing
- g. Third Party:
 - i. Construction activity
 - ii. Farm activity
 - a) Active tilling/oyster leases
 - b) Livestock
 - iii. One call effectiveness
 - iv. Patrol frequency
 - v. Public education
 - vi. Ground cover protection
 - a) > 3 to 6 feet
 - b) > 2 to 3 feet
 - c) > 0 to 2 feet



- d) ≤ 0 feet
- e) Unknown
- vii. Wall thickness
- viii. Line marking
- ix. ROW condition
- x. Diameter/Wall thickness
- xi. NOP vs. Pipe strength
 - a) $> 65\%$
 - b) 55 to 65%
 - c) 40 to $< 55\%$
 - d) 30 to $< 40\%$
 - e) 20 to $< 30\%$
- xii. Third party leak rate
 - a) > 2 leaks per leak age
 - b) 1 to 2 leaks per leak age
 - c) > 0 to < 1 leaks per leak age
- xiii. Anomaly type
 - a) Dent with metal loss
 - b) Dent without metal loss
 - c) ID anomaly $< 2\%$ with metal loss
 - d) ID anomaly $< 2\%$ without metal loss
 - e) Mechanical damage
- xiv. Toughness
- h. Outside Force:
 - i. Ground movement
 - a) *Landslide potential*
 - b) *Flooding potential*
 - c) *Seismic potential*
 - ii. Ground movement leak rate
 - iii. Diameter/wall thickness
 - iv. Patrol frequency
 - v. Repairs
- i. Incorrect Operations:
 - i. *High number of line situations (6+)*
 - ii. *Medium number of line situations (1 to 5)*



- iii. Surge pressure exceeds MAOP
- iv. NOP vs. Pipe strength
 - a) > 65%
 - b) 55 to 65%
 - c) 40 to < 55%
 - d) 30 to < 40%
- j. System operations leak rate
 - i. > 1 leaks per leak age
 - ii. > 0.5 to 1 leaks per leak age
 - iii. > 0 to 0.5 leaks per leak age

D. Revision Process for Risk Assessment: (ASME B31.8S and 192.917)

1. Upon completion of the TRA the finding will be shared and discussed with the appropriate field personnel and mitigative actions will be issued through the BP Work Tracking System. The Work Tracking System will also be a mean for tracking the progress and completion of the required mitigative actions.

Once the mitigative actions are completed the information will be updated in the database and the risk assessment/ranking will be re-calculated.

2. As identified in P-192.901b the IMT shall receive copies of the following reports (Per OMER Book 1 – Gas (Section 3 – Specifics) to integrate the risk assessment process into field reporting, engineering, and facility operations:
 - a. Patrolling (Class 1 & 2 at highway and railroad crossings, Class 3 (other crossings)) – Semi-Annually
F-192.705(a) AP & GP
 - b. Patrolling (Class 3 at highway and railroad crossings, Class 4 everywhere) – Quarterly
F-192.705(a) AP & GP
 - c. Annual Report
PHMSA F-7100.0-1
 - d. Conduct Liaison with Public Officials – Annually
F-192.615(c)
 - e. Patrolling (Class 1 & 2) – Annually
F-192.705(a) AP & GP
 - f. Abnormal Operating Conditions
F-192.605(c)
F-192.605(c)(4)
 - g. Pipeline being converted from liquid to gas
F-192.14



- h. Pipeline repairs to be done or the pipeline extended
 - F-192.141
 - F-192.241/43
 - F-192.305DL
 - F-192.305PR
 - F-192.617
 - F-192.709(b)
 - i. Pipeline is abandoned
 - F-192.727
 - j. New encroachment on the pipeline
 - F-192.614(b)(2)
 - k. Pipeline is exposed
 - R & I report
3. BP West Coast Products LLC Repair and Inspection report
- a. Line locate request from One Call System
 - F-192.614(c)(5)
 - b. Excavation on the pipeline right-of-way
 - F-192.614(b)(2)
 - c. Increase in population
 - F-192.5
 - d. New Construction in the State of Texas
 - TxRRC 7.70(f)(4)
 - e. Pipeline system sold in the State of Texas
 - TxRRC 3.65 T4b
 - f. Change to pipeline system in the State of Texas
 - TxRRC T4
 - g. Class Location
 - F-192.5
 - h. Conversion of Service
 - F-192.14
 - i. Monthly Third Party Damage reports
 - F-192.614(b)(1)
 - F-192.614(b)(2)
 - j. Right-of-Way inspection during excavation
 - F-192.614(c)(6)



k. Steel pipe MAOP determination

Engineering Specification SP202 Exhibit #2

4. As per 192.917 and ASME B31.8S (Section 5.12) revisions to the documented TRA risk assessment process will be completed as the above noted documents are received from the field operations personnel and the data is reviewed and integrated into the risk model.
5. The TRA risk assessment model is a living document, it is constantly improving and evolving based on collected data, field information, and renewed calculations.
6. Staff Responsible for Risk Assessment: (ASME B31.8S, Section 5)

The TRA for each identified pipeline segment will be completed by a member of the BP Integrity Management Team (IMT) – HSSE - IMT members will complete the data collection and run the evaluation for risk assessment. (Reference 192.901c (Section C); IM14: Threat Risk Assessment (TRA) RBMI Software Process Document).

The data collection process will involve field personnel and SME's.

E. Validation Of The Risk Assessment

1. Validation Process of Risk Results: (192.917(c) and ASME B31.8S, Section 5)

Validation will be completed by:

- a. Examination of the pipe (R & I Reports) when it is exposed for maintenance or repair.
- b. Review and evaluation of R & I Reports for other pipeline locations that are determined to have the same risk ranking and characteristics to determine if meaningful results are being generated in the TRA process.

F. Plastic Transmission Lines:

At this time BP does not own or operate any plastic gas transmission pipelines. Therefore, only steel main has been addressed in the procedure. If BP installs or acquires plastic transmission pipeline, appropriate procedures will be developed at that time.

G. Records

The IM Team and Pipeline Inspection Team maintain the records for the Gas IMP. Unless otherwise noted, these records are archived for the life of the facility. The listing below outlines the addresses for official Gas IMP documentation. Please contact the IM Team for inquiries about current Gas IMP documentation.

1. Prescriptive Threat Analysis Data Requirement Table - [I:\APL\ENGR\Integrity\Gas IMP \(Data-Results\)\Prescriptive Threat Analysis Data Requirement Table.xls](I:\APL\ENGR\Integrity\Gas IMP (Data-Results)\Prescriptive Threat Analysis Data Requirement Table.xls)
2. Prescriptive Threat Analysis - [I:\APL\ENGR\Integrity\Gas IMP \(Data-Results\)\Prescriptive Threat Analysis.xls](I:\APL\ENGR\Integrity\Gas IMP (Data-Results)\Prescriptive Threat Analysis.xls)
3. Threat Risk Analysis Procedure - BP Pipelines 1st TRA is scheduled to occur during calendar year 2009. The TRA procedure will be developed and integrated into the integrity management plan, through management of change (section K), prior to its implementation.

**Discovery Evaluation &
Remediation Scheduling
Procedure # P-192.901e**

Appendix D



Description: This procedure is used in the scheduling, execution, and assessment of remediation and its results. In addition, it is used to develop repair plans used to identify ILI anomalies requiring remedial actions and to compile the related documentation.

Applies To: All regulated gas pipelines.

Frequency:

Responsibility: Integrity Management Team (IMT)

Reference: 49 CFR Part 192.933

Prerequisites: All covered tasks identified in this procedure must be performed by qualified individuals or under the direct supervision of someone who is qualified according to BP's OQ program.

Forms:

Revision Date/Number 03/31/2008 / #3



A. Discovery Evaluation & Remediation Scheduling (NOA #6 & #7)

1. Integrity Assessment Results Remediation Actions

The Pipeline Inspection Team, which is part of the Engineering & Maintenance (E&M) Department, is responsible for:

- a. Scheduling the in-line inspection (ILI) assessments;
- b. Coordinating the execution of hydrotest assessments;
- c. Managing the contractual relationships between BP Pipelines and its ILI vendors;
- d. Executing the ILI assessment projects;
- e. Analyzing the ILI assessment results;
- f. Developing Repair Plans to identify ILI anomalies requiring remedial actions; and
- g. Compiling remedial actions documentation.

BP Pipelines and its primary ILI vendor, H. Rosen USA, have developed and maintained a long-term relationship for the mutual benefit of both parties. The principles of this relationship are defined in this extract of the **Rosen Charter**, a document referenced herein as the Charter.

The Pipeline Inspection Team interfaces with other E&M teams, BP field operations personnel, and contractors to ensure a smooth execution of the assessment program.

2. Assessment Scheduling

The Assessment Scheduling process begins with the completion of the Gas Baseline Assessment Plan prepared by the IM Team. The ILI Project Coordinator receives the BAP and develops a preliminary, and later completes a final assessment schedule after soliciting and receiving input from all Stakeholders.

3. Field Assessment Execution

Once the Assessment Schedule has been completed, the Pipeline Inspection Team Leader assigns individual ILI projects to the ILI Project Managers (PM). The ILI PMs are responsible for planning, estimating, requesting approval, developing, and coordinating the execution of each individual tool run project using BP's project management guidelines. After the execution of the ILI field assessment, the ILI vendor verifies that the assessment data quality is within acceptable parameters and prepares it for evaluation. The guidelines used to assure the quality of the ILI data are listed in STP 32-211.

4. Evaluation of Assessment Results

The Evaluation phase begins with the ILI vendor. The raw data from the tool run is converted to a format suitable for evaluation, or otherwise known as log grading. The ILI vendor analysts' qualifications to evaluate these data are summarized in the Charter. The Charter and STP 32-211 include BP Pipeline's requirements for vendor reporting of conditions representing imminent threats to pipeline safety. The Evaluation Phase ends when the ILI vendor completes the log grading and issues a Final Report. The reporting requirements for the Final Report are also listed in the Charter.

5. Analysis of Assessment Results and Implementation of Remedial Actions

The Pipeline Inspection Team receives the reports from the ILI vendor, screens for HCA conditions that could impact pipeline integrity, and schedules remedial actions. These HCA conditions are anomalies discovered on HCA pipe and are defined by the Gas HCA Rule. They are categorized into 4 classifications (immediate; scheduled; 1 - year; and monitored), which



designate the deadline for remedial action. Condition descriptions and remedial action implementation guidelines are outlined in the following documents:

- a. OMER, P-192.711 Repairs Replacements Relocations of BP Pipelines Operations, Maintenance and Emergency Response Manual, Book 1.
- b. OMER, P-191.23 Safety-Related Conditions of BP Pipelines Operations, Maintenance and Emergency Response Manual, Book 1.
- c. Engineering Specification STP 32-210, "Evaluation and Inspection Procedures for In-Line Inspection Projects."
- d. Engineering Specification STP 32-211, "Requirements for In-line Inspection Projects - Gas."

The above documents specify:

- a. The criteria by which the conditions identified in the assessments are to be evaluated.
 - b. How the conditions identified are to be categorized.
 - c. The actions required once the conditions have been evaluated and categorized.
 - d. The acceptable repair and/or remedial methods needed to address identified conditions.
 - e. How the results from the remedial actions are to be documented and distributed.
6. Repair Plan Development

The Pipeline Inspection Team will utilize this information and create a Repair Plan document that summarizes:

Remedial Actions Execution, Tracking, and Maintenance

The Pipeline Inspection Team will track each HCA condition that is discovered either through ILI assessment or the normal course of pipeline operations to assure timely remedial action implementation. The Gas IMP Tracking Tool spreadsheet maintained by the ILI Coordinator serves as both the tracking mechanism and the record of compliance.

B. Records

The IM Team and Pipeline Inspection Team maintain the records for the IMP. Unless otherwise noted, these records are archived for the life of the facility. The listing below outlines the location for official IMP documentation. Please contact the IM Team for inquiries about current IMP documentation.

1. Rosen Charter – Hardcopy review by request only. Contact Pipeline Inspection Team.
2. OMER, P-192.711 Repairs Replacements Relocations - BP Pipelines Intranet
3. OMER, P-191.23 Safety-Related Conditions - BP Pipelines Intranet
4. Engineering Specification BPPL-STP 32-210 - BP Pipelines Intranet
5. Engineering Specification BPPL-STP 32-211 - BP Pipelines Intranet
6. Gas IMP Tracking Tool - BP Pipelines Intranet
7. Repair plans & appropriate field documentation – Hardcopy review by request only. Contact Pipeline Inspection Team.

**Continuous Evaluation and
Assessment
Procedure # P-192.901f**

Appendix E



Description: This procedure is used for the purpose of monitoring pipeline operations, maintenance activities, and the surrounding the pipeline. This procedure is intended to cover the period of time between assessments.

Applies To: All regulated gas pipelines.

Frequency:

Responsibility Integrity Management Team (IMT)

Reference: 49 CFR Part 192.937

Prerequisites: All covered tasks identified in this procedure must be performed by qualified individuals or under the direct supervision of someone who is qualified according to BP's OQ program.

Forms:

Revision Date/Number 03/31/2008 / #4



A. Periodic Evaluations

BP Pipeline shall monitor, during the period of time between assessments, pipeline operations, maintenance activities, and the areas surrounding the pipeline (out to the 660 foot or PIC boundary limits (with buffer area), whichever is greater. Activity monitoring occurs through the execution of:

1. OMER Book 1 (Gas), P-192.613 (Continuing Surveillance for Class Location & HCA Procedure).
2. Yearly review (to be completed in the 1st quarter, not to exceed 15 months) by the IMT of the Repair & Inspection reports.
3. Management of Change reporting for changes to operations, control settings, and organization.
4. OPS Summary Report for weekly field activities along the pipeline rights-of-way.
5. Traction reports for major incidents and releases.

The review of the above listed documentation shall provide the IM Team the data required to re-evaluate the pipelines status periodically, such as, HCA and Class locations status. This information shall be updated and re-evaluated on a yearly basis, but at intervals not to exceed 15 months. If the data received changes the status of the pipeline, the necessary measure shall be taken as specified by 192.917, and 192.937, and the IMP shall be updated. Initially, the IM Team evaluated all above noted documents, as well as, additional data collected for the pipelines, for past assessment results. This data was evaluated and integrated into the initial baseline study.

Integrity related information from any of these activities is routed to members of the **IMP Technical Committee**. This committee meets monthly to review and monitor emerging integrity issues. All release events undergo a root cause analysis (RCA) to determine the exact failure mechanism. RCA results and any information that might indicate a change to the integrity of the pipeline shall be reviewed by the IMP Committee to determine if new threats have materialized or existing threats escalated, and the appropriate assessment and mitigative actions required. The IMP Committee shall determine if any of the following actions are necessary:

1. Acceleration of current assessment timing.
2. Addition of alternate assessment methodology.
3. Follow up testing and/or mitigative actions. **(NOA #6)**

A. Analysis of Assessment Results and Implementation of Remedial Actions

The Pipeline Inspection Team receives the reports from the ILI vendor, reviews the reports to ensure validity and completeness, screens for HCA conditions that could impact pipeline integrity, and schedules remedial actions. These HCA conditions are anomalies discovered on an HCA 'could affect' pipe and are defined by the HCA Rule. They are categorized into 4 classifications (immediate; 60 day; 180 day; and other), which designate the deadline for remedial action. Condition descriptions and remedial action implementation guidelines are outlined in the following documents:

1. OMER, P# 192.711 Repairs Replacements Relocations of BP Pipelines Operations, Maintenance and Emergency Response Manual, Book 1 (Gas).



2. OMER, P# 192.23 Safety-Related Conditions of BP Pipelines Operations, Maintenance and Emergency Response Manual, Book 1 (Gas).
3. Engineering Specification BPPL-SP-200, "Evaluation and Inspection Procedures for In-Line Inspection Projects".
4. Engineering Specification BPPL-SP-211, "Diagramming Procedures".

The above documents specify:

1. The criteria by which the conditions identified in the assessments are to be evaluated.
2. How the conditions identified are to be categorized.
3. The actions required once the conditions have been evaluated and categorized.
4. The acceptable repair and/or remedial methods needed to address identified conditions.
5. How the results from the remedial actions are to be documented and distributed.

B. Remedial Actions Tracking and Maintenance

The Pipeline Inspection Team will track each HCA condition that is discovered either through ILI assessment or the normal course of pipeline operations to assure timely remedial action implementation. Remedial Actions that are discovered through the TRA (Threat Risk Assessment) are issued to the field for "actions to be taken" in Maximo and are tracked by the IM Team through the TRA process. The Data Master spreadsheet serves as both the tracking mechanism and the record of compliance.

Actions triggered by the IMP Committee shall be captured in the Gas IMP Implementation Log. Data from non-covered segments shall be considered in this process.

Observations and/or events that have potential to increase the risk of a covered segment or non-covered segment include but are not limited to:

1. External Corrosion:

- a. In service release caused by external corrosion.
- b. Discovery of external corrosion not identified from prior assessment.
- c. Discovery of external accelerated corrosion from prior assessment.
- d. Increase in operating pressure.
- e. Discovery of bad coating.

2. Internal Corrosion:

- a. In service release caused by internal corrosion.
- b. Discovery of internal corrosion not identified from prior assessment.
- c. Discovery of internal accelerated corrosion from prior assessment.
- d. Reduction in throughput (flowrate).
- e. Change in stream composition.
- f. Increase in operating pressure.

3. Stress Corrosion Cracking:



- a. In service release caused by SCC.
- b. Discovery of SCC.
- c. Increase in operating temperature.
- d. Increase in operating pressure.
- e. Increase in pressure cycling.

4. Manufacturing:

- a. In service release caused by manufacturing defect.
- b. Discovery of low frequency ERW or lap-welded pipe.
- c. Increase in operating pressure.
- d. Increase in pressure cycling.

5. Construction:

- a. In service release caused by manufacturing defect.
- b. Discovery of girth weld reinforcement.
- c. Discovery of wrinkle bend.

6. Equipment:

- a. In service release caused by equipment failure.
- b. Discovery of equipment recall.

7. Third Party Damage:

- a. In service release caused by third party damage.
- b. Discovery of third party damage not identified from prior assessment.

8. Incorrect Operations:

- a. In service release caused by incorrect operations.
- b. Operating pressure exceeding 110% allowable.
- c. Unscheduled valve closure.
- d. Unscheduled shut down.

9. Weather or Outside Force:

- a. In service release caused by weather or outside force.
- b. Hurricane event.
- c. Seismic event. **(NOA #6)**

C. Reassessment Methods

C.1. Threat Risk Analysis

The IM Team shall conduct an information analysis (Threat Risk Assessment) on all pipelines containing HCA pipe segments, two (2) years prior to the scheduled reassessment. In the case that an incident occurs, BP (IM Team) will conduct the reassessment at the time of the incident. This analysis incorporates all existing data and information about the entire pipeline. It will follow the requirements of



ASME/ANSI B31.8S (Section 4) and consider the prescriptive pipeline integrity program data elements. The IM Team develops a threat based risk model to identify the required data inputs; identifies the repository and related data authorities; collects and codifies risk data into the model; executes the risk algorithm. Where quantitative data isn't available, qualitative data will be used and justified accordingly. The model shall help identify any threat(s) to the pipeline and provide a basis to the planned re-assessment methodology. The IM Team compiles the results of the TRA into a report and then facilitates a meeting with pipeline stakeholders and pertinent subject matter experts to review/validate results, validate planned and identify any additional assessment requirements, and identify preventative mitigative actions if necessary. (NOA #6)

C.2. Assessment Methodology

BP Pipelines shall select re-assessment methodology to address the threats identified from the Threat Risk Analysis Methods can include, but are not limited to:

1. External/internal corrosion threat:
 - a. In-line inspection (ILI) using standard or high resolution magnetic flux leakage tool,
 - b. ILI using transverse magnetic flux leakage tool,
 - c. ILI using ultrasonic compression wave tool,
 - d. ILI using ultrasonic shear wave tool, and/or
 - e. Hydrostatic test.
2. Stress Corrosion Cracking (SCC) threat:
 - a. ILI using ultrasonic shear wave tool,
 - b. ILI using ultrasonic E-Mat tool and/or
 - c. Hydrostatic test.
3. Fabrication/Construction/Outside Force threat:
 - a. ILI using deformation/geometry tools including gage tool,
 - b. Multiple channel caliper tools, and/or
 - c. Higher resolution caliper tools that provide x/y/z transition mapping.

Note: For pipe containing longitudinal seams manufactured using either the low frequency ERW or lap-welded process: ILI using transverse magnetic flux leakage tool, ILI using ultrasonic shear wave tool, and/or hydrostatic test will be used to address the seam threat.

4. Third Party threat:
 - a. ILI using deformation/geometry tools including gage tool,
 - b. Multiple channel caliper tools. In addition,
 - c. ILI using standard or high resolution magnetic flux leakage tool,
 - d. ILI using transverse magnetic flux leakage tool,
 - e. ILI using ultrasonic compression wave tool,
 - f. ILI using ultrasonic shear wave tool, and/or



g. Hydrostatic test

BP Pipelines shall give priority to the ILI methodologies for reassessments (to obtain the most tangible information concerning the integrity condition of the pipeline) and follow B31.8S-2004, Section 6.2.5 when selecting the appropriate ILI tool. Specification BPPL-STP 32-211 (Requirements for In-Line Inspection Projects – Gas) outlines the requirements for ILI tool selection. Considerations taken into account when utilizing ILI methodology shall include the following:

1. Detection sensitivity (minimum defect detectable)
2. Defect classification differentiation
3. Defect sizing accuracy
4. Defect location accuracy
5. Defect assessment requirements

If the hydrotest option is used, the test shall follow 49 CFR Part 192 Subpart J requirements per Engineering specification STP-115 PLNA Specifications for Hydrostatic Testing (or Liquid Pressure Testing). If the hydrotest section contains any pipe with low frequency ERW or lap-welded longitudinal seam construction, testing plans shall consider the information contained in the PHMSA evaluation report (TTO Number 5; Integrity Management Program Delivery Order DTRS56-02-D-70036; Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation; Final Report).

If BP Pipelines chooses other technology that it feels can provide an equivalent understanding of the integrity condition of the pipeline, notification shall be made to PHMSA 180 days prior to implementation. If the pipeline segment in question falls under Intrastate jurisdiction or is located in a State where PHMSA has an Interstate agent agreement, notification shall also be sent to the State or local pipeline safety authority.

C.3. Preventative and Mitigative Actions

Upon completion of the Threat Risk Assessment (TRA) process mitigative measures are noted and assigned and scheduled through the use of Maximo. The Maximo software is BP's means of communicating to the field required field activities to be completed. Maximo also serves as a tracking device for scheduled projects. The mitigative actions are tracked and monitored by the IM team to assure completion. Funds are set-up and controlled or allocated also through the IM Team for the mitigation projects. (NOA #6)

D. Low Stress Reassessment

BP Pipelines currently has no plans to develop and use the low stress reassessment methodology. If, at a future date, BP Pipelines decides to utilize low stress reassessment, it shall be developed and integrated into the integrity management plan, through management of change (Section K), prior to its implementation. The low stress reassessment process shall meet the requirements of 49 CFR Part 192 (Subpart O) Section: §192.941.

E. Re-assessment Timing, Waiver, and Deviation

BP Pipelines determines 'Primary' re-assessment intervals based on ASME B31.8S, Section 5, Table 3. 'Secondary' determination is completed by the IM Team through the execution of the Threat Risk Analysis (Section F.2). 'Event Driven' determination is completed by the IMP Committee through root cause



analysis (RCA) results and through the process of periodic evaluations (section F.1). The maximum re-assessment interval shall not exceed 7 years. The Gas IMP Tracking Tool spreadsheet serves as both the tracking mechanism and the record of compliance for reassessment interval.

Inability to complete the re-assessment within the deadline established above can be caused by but not limited to the following:

1. Lack of internal inspection tool
 - a. Limited ILI tool availability.
 - b. ILI tool technology not yet developed.
2. Operational changes
 - a. Inadequate flow to propel ILI tool.
 - b. Asset availability due to supply issues.

If BP Pipelines is unable to meet a re-assessment deadline, it shall seek a waiver in accordance with 49 U.S.C. 60119(c) within 180 days before the required re-assessment deadline. If the waiver request is based on supply issues, it shall be submitted as soon as the need arises.

BP Pipelines currently has no plans to deviate from reassessment plan described above. If, at a future date, BP Pipelines decides to deviate from this plan, it shall have completed at least 2 assessment/repair cycles. All plan deviations shall be developed and integrated into the integrity management plan, through management of change (Section 192.901k), prior to implementation. The deviation plan shall meet the requirements of 49 CFR Part 192 (Subpart O) Section: §192.913.

F. Environmental/Safety Risks during Re-Assessments

BP will utilize either the ILI or hydrotest methodology for all re-assessments. Since BP gas pipelines route through the public domain activities associated with the execution of baseline assessment have the potential to impact the public. BP shall, during the planning and execution of all baseline assessments, engage the appropriate Health, Safety, Security, and Environment (HSSE) personnel to assure that potential threats to company, contractor, and public are identified and addressed. The Safety Manual (Pipelines) outlines procedures to control potential threats including but not limited to the following:

1. Unintentional release of pipeline contents.
 - a. Hydrotest failure.
 - b. ILI pig trap operations.
 - c. Defect excavation.
2. Unintentional access to worksites.
 - a. ILI pig traps.
 - b. Valve sites.
 - c. Hydrotest equipment.
 - d. Open excavations.



G. Records

The IM Team and Pipeline Inspection Team maintain the records for the Gas IMP. Unless otherwise noted, these records are archived for the life of the facility. The listing below outlines the addresses for official IMP documentation. Please contact the IM Team for inquiries about current Gas IMP documentation.

There are no new records attached to this section.

**Preventative and Mitigative
Measures
Procedure # P-192.901h**

Appendix F



Description: This procedure describes and defines the preventative and mitigative measures used on BP pipelines.

Applies To: All regulated gas pipelines.

Frequency:

Responsibility: Integrity Management Team (IMT)

Reference: 49 CFR Part 192.935

Prerequisites: All covered tasks identified in this procedure must be performed by qualified individuals or under the direct supervision of someone who is qualified according to BP's OQ program.

Forms:

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A. Identification of Additional Measures (NOA #7)

1. Using the Baseline Assessment Plan, Risk Assessment database or other sources of threat data, review the identified threats for each HCA.
2. The BP IM team takes responsibility to assure that the required additional measures are taken.
3. Using "Preventative and Mitigative Measures by Threat Type" spreadsheet as a guide, review applicable additional P&M measures for each threat identified. (NOA #7)
4. Consider both the likelihood and consequences of a pipeline failure in regards to the P&M Measure(s). (NOA #7)
5. Additional measures may include, at a minimum:
 - a. Performing additional patrols.
 - b. Implementing additional training programs.
 - c. Installing additional line markers.
6. The data that is considered/evaluated during the TRA process is collected, reviewed, and entered into the risk assessment database for the appropriate pipeline segment. This data, once integrated, is what the software utilizes in the evaluation and calculation to determine the status of risk for the pipeline segment. (NOA #5 & #6)
7. Solicit the input of Subject Matter Experts to determine the effectiveness of potential P&M Measures. SME's may include, but are not limited to personnel from: (NOA #7)
 - a. Corrosion
 - b. Operations
 - c. Maintenance
 - d. Engineering
8. Determine which P&M measure(s) should be implemented. (NOA #7)
9. Schedule the additional P&M measure(s) as required. (NOA #7)

B. Third Party Damage

B.1. Damage Prevention Program

BP is committed to "No Accidents, No Harm to People and No Damage to the Environment". A key factor in obtaining this company goal is through a proactive Damage Prevention Program. Pipeline damage can result in injury and death, as well as severe property damage and loss of product.

The Damage Prevention Program includes several elements:

1. Use of Qualified personnel:
2. Operator Qualification Program (OQ).

The operator qualification program assures that all work performed on the physical pipeline system is conducted by qualified personnel. It defines work tasks that fall under OQ requirements and defines the training and testing requirements necessary to gain qualification. Identification and tracking procedures



are in place to assure that any person performing work on the pipeline system meets the requirements of OQ. This program is applicable and enforced on contractors working for BP Pipelines. This program also applies to pipelines operating below 30% SMYS which are located in HCA and Class 3 or 4 areas. **(NOA #7)**

B.2. State One Call Participation (F-192.614 (c)(5) – Line Locate Request: Used if No One-Calls or Excavator Written Request is available)

BP Pipelines is a member of qualified One-Call programs in states where BP owns and operates pipelines. The following activities listed below will be performed either through the State One-Call Centers or by BP to minimize the likelihood of damage due to excavation activities.

1. Receive and record notifications of pending excavations.
2. Identify persons involved in excavating activities through the State One-Call Centers, contractor associations, or Standard Industrial Classification (SIC).
3. Communicate marking information and method of marking to the excavator who gave notice to dig. Markings shall be in accordance with the APWA Uniform Color Code (Exhibit A). Flagging shall be yellow in color per the uniform color code for oil and gas facilities.

Excavation activities planned or unplanned performed by BP Field Representatives or approved company contractors will follow the State One Call Laws. Proposed excavation by a Field Representative or an approved company contractor should be marked in accordance with the APWA Uniform Color Code. Flagging should be white in color per the uniform color code for proposed excavation.

The BP One Call program maintains a database called "Dig Track" for all One Call data collected. This allows for the data integration of One Call information in order to ensure that comprehensive measures are implemented for the threat of third party damage. This site is accessible through the BP Pipelines NA Intranet.

Damage Prevention Specialists manage the field verification of all One Call activations. Third Party Damage information for the risk assessments is acquired through the Damage Prevention Specialist who monitor/manage the "Dig Track" One Call system. **(NOA #5 & #6)**

B.3. Pipeline Right-of-Way Patrol (See OMER Book 1 (Gas) P-192.705)

B.4. Aerial and Ground Patrol (See OMER Book 1 (Gas) F-192.705 (a) AP & GP)

B.5. Receiving Notification of Unplanned and Planned Excavation

Upon receipt of notification from the State One-Call Center, the Control Center (CC) One-Call Dispatchers or a Field Representative reviews the information for proximity to the Pipeline. Excavation activities taking place near the Pipeline are transmitted to the appropriate Field Representative. The Field Representative will determine if the Pipeline needs to be located and marked. Direct notification of excavations should be discouraged. Calls received directly from excavators will be advised to call the appropriate State One-Call Center. Excavators refusing to use the State One-Call Centers or excavators identified working without having called the State One-Call Center will be documented and recorded to the Contractor Data Base.



Follow-up letters may be sent to excavators explaining current state laws and notification requirements to State One-Call Centers prior to excavation.

B.6. Pipeline Security

Regulations require that pipeline facilities be secure from vandalism and unauthorized entry. Appropriate levels of protection will be provided according to location of the facility and level of risk. Protection may include fencing, signs, chains, locks, etc.

BP Pipelines (N.A.) Security Alert State actions are aligned with industry established security levels, designed to be controlled by BP Pipelines (N.A.), and be flexible in application. These Security Alert States are located in Pipeline Alert States section of the BP Pipelines (N.A.) Security Manual.

Smoking and open flames are prohibited where there is a possibility of the leakage of flammable liquid, vapor, or gas or the presence of flammable vapors. Employees and visitors are to smoke in approved smoking areas only. "No Smoking" signs are conspicuously placed in areas where smoking is prohibited. If in doubt as to whether or not an area is a No Smoking area, ASK. Smoking is prohibited in these areas:

1. Bellhole areas
2. Flammable or combustible storage areas
3. Leak sites
4. Marine Terminals
5. Meter run areas
6. Near vented batteries.
7. Pipeline excavations
8. Refueling areas
9. Truck loading/unloading racks

B.7. Damage Prevention Activities (See OMER Book 1 (Gas) P-192.614; Section IV. Damage Prevention Activities)

B.8. Pipeline Markers: (See OMER Book 1 (Gas) P-192.614; Section IV. Damage Prevention Activities; B)

Pipeline rights-of-way and crossings shall be marked in accordance with DOT requirements to indicate the presence of the Pipelines to the public, contractors, other outside agencies; facilitate aerial patrol; and guide its personnel engaged in maintenance operating activities.

B.9. Leak Survey (See OMER Book 1 (Gas) P-192.706)

B.10. Monitoring of Excavations/Inspections of the Pipeline

A Field Representative will be dispatched to the location whenever there is likelihood that the Pipeline may be involved in an excavation. The purpose of the Field Representative is to assist in identifying the location of the Pipeline during excavation, to inspect the Pipeline when it is exposed, to determine what measures may be needed to protect and support the Pipeline during construction and to promptly begin emergency response actions if the Pipeline is damaged.



The Field Representative will provide continuous monitoring of excavation activities whenever excavation of the Pipeline and foreign line crossings are taking place.

1. Any ongoing excavation project which does not have to be monitored (based on the excavation of the Pipeline and foreign line crossing requirement) will be re-evaluated no less frequently than weekly, or as frequently as necessary if there is reason to believe the Pipeline could be damaged by the excavation activity. This inspection, at a minimum, shall consist of a visual inspection of the Pipeline and/or right-of-way. Documentation of each inspection will be maintained on the Excavator/Locator Orientation Form (form F-192.614(c)(3) Excavator-Locator Orientation Form).
2. In the case of blasting near BP Pipelines, Engineering Specification BPPL-SP-206 will be followed when establishing or reviewing the criteria for safe blasting around the Pipelines. A leak survey must be performed to verify the integrity of the Pipeline. This inspection is: <http://pl.bpweb.bp.com/Training/OQ/OQGAS09W.doc> for gas pipelines.
3. Whenever the Pipeline is involved in a foreign line or utility crossing, a Field Representative must complete a Repair and Inspection Report (for West Coast operations use BP West Coast Products LLC Repair and Inspection Report). Refer to Engineering Specification BPPL-SP-211 for detailed instruction on completing the form.

In the event that BP finds evidence of an encroachment involving excavation that was not monitored near a covered segment, then BP shall conduct above ground surveys in accordance with NACE RP-0502-2002. If the results of the above ground survey dictate, then a direct examination of the pipeline will be completed and remedial actions taken, as necessary.

In addition to promptly recording all relevant information regarding unauthorized excavation activity or unreported damage, efforts should be made to photograph the scene of the excavation as well as any visible damage to the pipeline as soon as possible following notification. Where there has been damage to the pipeline, documentation of the labor and material costs involved in repairing the line should be maintained. Even where there is no damage to the line, but inspection of the line is necessary to verify that the line is not damaged, photos of the exposed line segment and a record of the hours expended and costs incurred by BP Pipelines' employees or contractors verifying the condition of the line should be maintained. Photos and other documentation of expenses incurred on repairs should be appended to the F-192.614(b)2 Report of Investigation of Third Party Excavation Activity form.

B.11. Program Evaluation and Effectiveness

The program strives to improve communications with excavators and property owners through participation in the various State One-Call Centers, mailing education materials to contractors (P-192.616), emergency responders, utilities, elected officials and landowners, conducting face to face meetings, providing an emergency toll free contact number, marking pipeline routes with visible signs, accurate and timely line locate marking and providing visual inspections of the pipeline rights-of-way, and presence whenever excavation is occurring within 25 feet of the pipe centerline. This program also applies to pipelines operating below 30% SMYS which are located in HCA and Class 3 or 4 areas. (See OMER Book 1 (Gas) P-192.614)



C. Pipelines Operating Below 30% SMYS

C.1. This section applies to Pipelines Operating Below 30% SMYS (in High Consequence Areas) and Pipelines Operating Below 30% SMYS (in Class 3 and 4 area but not HCA)

C.1.1. Operator Qualification Program

The operator qualification program assures that all work performed on the physical pipeline system is conducted by qualified personnel. It defines work tasks that fall under OQ requirements and defines the training and testing requirements necessary to gain qualification. Identification and tracking procedures are in place to assure that any person performing work on the pipeline system meets the requirements of OQ. This program is applicable and enforced on contractors working for BP Pipelines. This program also applies to pipelines operating below 30% SMYS which are located in HCA and Class 3 or 4 areas.

C.1.2. Damage Prevention Program: (Participation in One-Call System)

See B.1.1 (Damage Prevention Program) above; also refer to OMER Book 1 (Gas) P-192.614 and P-192.614(b).

C.1.3. Public Awareness Program

The public awareness program includes three subparts: Public Awareness Mass Mailing; Public/Private School Program; and Emergency Manager Program. The public awareness program attempts to communicate pipeline safety information to each dwelling within 660 feet (urban/developed) [3 miles (rural)] of the pipeline, on a two year rotation. The school program attempts to communicate pipeline safety information to each school located within 660 feet of the pipeline, on a three year rotation. The emergency manager program attempts to communicate pipeline safety information to every emergency planning manager whose jurisdiction encompasses our pipeline, on a three year rotation. This program also applies to pipelines operating below 30% SMYS which are located in HCA and Class 3 or 4 areas.

C.1.4. Pipeline Monitoring

See B.1.1 (Damage Prevention Program) above; also refer to OMER Book 1 (Gas) P-192.614 and P-192.614(b).

D. Plastic Transmission Pipelines

BP currently has no plastic transmission pipelines.

E. Outside Force Damage

BP has several procedures in place to address outside force damage that includes, but are not limited to, the following plans.

E.1. Gulf Coast Business District Hurricane Contingency Plan

The purpose of this document is to provide the Gulf Coast Business District with a Hurricane Contingency plan to prepare BP pipeline owned, leased, or operated assets for the eventual landfall of a hurricane. These preparations are intended to mitigate or minimize property damage and to provide operational integrity of the assets to the extent possible without field personnel intervention during the hurricane. After the hurricane has moved inland, this document will provide a recovery process.



E.2. West Coast Regions – Southern California Emergency Response Zone Plan

Section 4.2.4 of the Emergency Response Core Plan states, "All reports of natural disasters occurring along the pipeline are investigated to determine the effect on the operation of the pipeline."

E.3. West Coast Regions – Emergency Response Core Plan

Section 4.2.4 of the Emergency Response Core Plan states, "All reports of natural disasters occurring along the pipeline are investigated to determine the effect on the operation of the pipeline."

E.4. Olympic Pipeline Response Plan

Section 2.1.6 of the response plan states, "Facility personnel shall investigate Olympic Pipeline Company Facilities following reports of natural disasters, such as, floods or earthquakes, to determine any effect that the disaster may have had on the pipeline operations. For earthquake investigations, the Pipeline Geotechnical Inspection and Structural Mechanical Inspection checklists in the OM&ER Book shall be utilized."

E.5. Strudel Scour (Alaska)

Alaska has an ongoing monitoring program in place that utilizes side scan sonar to assist in the detection of Strudel Scour occurrences. (NOA #7)

F. Corrosion

F.1. Electrical Survey Program

The electrical survey program assures that pipeline has adequate cathodic protection and helps identify coating and interference problems. The primary methodology utilized in the electrical survey program is the close interval survey (CIS). If CIS results indicate potential problems, additional follow up testing can be performed (direct current voltage gradient [DCVG], pipeline current mapping [PCM], etc.). This program also applies to pipelines operating below 30% SMYS which are located in HCA and Class 3 or 4 areas and shall be performed on a seven year cycle. (See Close Interval Survey (CIS))

G. Automatic Shut-Off Valves or Remote Control Valves

G.1. Risk Analysis/Evaluation

Perform a risk analysis of each line segment containing HCAs to determine if an Automatic Shut-Off Valve (ASV) or Remote Control Valve (RCV) would be an effective means of adding protection to a HCA in the event of an unintentional gas release. The analysis will be completed using IAP software to determine the rupture volume calculations. Individual databases will be created for each BP gas line which the software (IAP) will utilize for the calculations.

During the risk determination, consider the following factors:

1. Swiftness of leak detection and shut-down capabilities.
2. Type of gas being transported.
3. Operating pressure and %SMYS.
4. Rate of potential release.
5. Pipeline profile.



6. Potential for ignition.
7. Location of nearest response personnel.
8. Pipe diameter.

Evaluate the results of the analysis and determine if automating existing valves or installing new valves would be effective. If it is determined that automating existing valves or installing new valves would not be an effective means of adding protection to the HCA, no further action is necessary. If it is determined that an ASV or RCV would be effective, work with Gas Control and Field Operations to determine the locations for the valves. A timeline will be developed for installing the ASV / RCV valves. **(NOA #8)**

G.2. Documentation

Maintain documentation in the IMP Project File. Documentation should include, but is not limited to:

1. Risk Analysis (BP will maintain IAP databases for each gas line segment noted in the IMP so that the IM team can utilize the IAP software to run "Rupture Volume" calculations as part of the evaluation to calculate risk for each line segment based on the factors noted in Section G.1., above, and pipeline design data).
2. Recommendation on whether or not valves would be effective.
3. If applicable, locations where valves will be installed.
4. Timeline for installing valves.

H. Implementation of Additional Measures

H.1. Threat Risk Analysis

The IM Team shall conduct an information analysis (Threat Risk Assessment) on all pipelines containing HCA pipe segments, 2 years prior to the scheduled reassessment. In the case that an incident should occur, the IM Team would conduct the reassessment at the time of the incident. (Refer to 192.901(c))

On a yearly basis, during the budget planning process, the TRA's required and/or scheduled to be completed in the specified year are assigned to an IM Team member. Upon completion of the TRA the IM Team member creates a list of mitigative measures to be completed on the evaluated pipeline. The mitigative measures are entered into Maximo for completion by BP field personnel. The mitigative measures are then tracked by the IM Team and funds set up through the budgeting process are utilized to complete the project work. Upon completion of the mitigative actions, the project is closed in Maximo and the appropriate documentation supplied for record maintenance purposes. This is submitted to the IM Team and other appropriate BP personnel.

I. Records

The IM Team and Pipeline Inspection Team maintain the records for the Gas IMP. Unless otherwise noted, these records are archived for the life of the facility. The listing below outlines the addresses for official IMP documentation. Please contact the IM Team for inquiries about current Gas IMP documentation.

1. Public Awareness Program – BP Pipelines Intranet
2. Damage Prevention Program – BP Pipelines Intranet



3. Operator Qualification Program – BP Pipelines Intranet
4. Close Interval Survey Procedure – I:\APL\ENGR\Integrity\IMP (Documentation)\Procedures\IM6(CIS)\CIS Procedure.doc
5. Gulf Coast Business District Hurricane Contingency Plan – BP Pipelines Intranet
6. West Coast Regions – Southern California Emergency Response Zone Plan – BP Pipelines Intranet
7. BP Severe Weather Contingency Plan – BP Pipelines Intranet
8. Olympic Pipeline Response Plan – BP Pipelines Intranet
9. Contractor Selection Tool (CST) – BP Pipelines Intranet
10. OMER Book 1 (Gas) – BP Pipelines NA Intranet

Management of Change Procedure #P-192.901k

Appendix G



Description: This procedure is used to address temporary and permanent changes in operations, maintenance, products, chemicals, procedures, facilities and personnel.

Applies To: All regulated gas pipelines.

Frequency:

Responsibility: Integrity Management Team (IMT)

Reference: 49 CFR Part 192.909

Prerequisites: All covered tasks identified in this procedure must be performed by qualified individuals or under the direct supervision of someone who is qualified according to BP's OQ program.

Forms:

Revision Date/Number: 03/31/2008 / #4



A. Documentation and Notification of Changes to the Integrity Management Program

BP currently follows a Management of Change (MOC) process to address temporary and permanent changes in operations, maintenance, products, chemicals, procedures, facilities, and personnel. This process ensures that the impact of changes which affect the health and safety of personnel or impact the environment are recognized, reviewed, approved, communicated, and documented. Substantial change to program implementation or significant change to schedule for carrying out elements shall be communicated to PHMSA within 30 days of adoption.

These changes may include but are not limited to:

1. Development and implementation of new procedures.
2. Delay baseline assessment of high risk HCA beyond the December 17, 2007 deadline.
3. Delay baseline assessment of any segment beyond the December 17, 2012 deadline.
4. Delay of any reassessment beyond the reassessment deadline.
5. Deviation from reassessment process. (NOA #9)

The MOC Policy document was created to address the management of change process for the US Pipelines & Logistics business unit (PLBU). The pipeline facilities are not subject to the Occupational Safety and Health Administration (OSHA) Process Safety Management regulations, but they are subject to OSHA Management of Change requirements. The American Petroleum Institute (API) RP 750 document was used as a guide in developing the management of change process.

This management of change (MOC) plan addresses temporary and permanent changes in operations, maintenance, products, chemicals, procedures, facilities, and personnel that may impact the performance of the business unit.

The purpose of this MOC plan is to identify and control the impact and potential hazards associated with change. MOC ensures that the impact of changes which affect the health and safety of personnel or impact the environment are recognized, reviewed, approved, communicated, and documented. All projects require a MOC evaluation and MOC has been incorporated into the Capital Value Process (CVP). The Capital Value Process is a gated process that is used to frame in business decisions. It is a structured and integrated approach to project selection, development, and execution, resulting in enhanced Capital Productivity.

Applications requiring proper MOC vary widely, not only in hazard potential but also with respect to organizational and technical factors. While no single procedure is recommended for universal application, the process to manage each change should address:

1. Reason for change.
2. Authority for approving changes.
3. Analysis of implications.
4. Acquisition of required permits.
5. Documentation (reviews and post-implementation).
6. Communication of change to affected parties.
7. Time limitations, especially for temporary changes.



8. Training. (NOA #9)

B. Attributes of the Change Process

See BP "Management of Change Policy, US Pipelines & Logistics" located in IMP.

C. Records

The IM Team and Pipeline Inspection Team maintain the records for the Gas IMP. Unless otherwise noted, these records are archived for the life of the facility. The listing below outlines the addresses for official Gas IMP documentation. Please contact the IM Team for inquiries about current Gas IMP documentation.

1. Management of Change Procedure - BP Pipelines Intranet

**Quality Assurance
Procedure # P-192.901I**

Appendix H



Description: This procedure is used to evaluate the IMP to ensure that the program is effectively assessing pipeline integrity, and to provide documentation towards that end.

Applies To: All regulated gas pipelines.

Frequency:

Responsibility: Integrity Management Team (IMT)

Reference: 49 CFR Part 192.911(l)

Prerequisites: All covered tasks identified in this procedure must be performed by qualified individuals or under the direct supervision of someone who is qualified according to BP's OQ program.

Forms:

Revision Date/Number: 03/31/2008 / #4



A. Program Requirements for the Quality Assurance Process

A.1. Responsibilities and Authorities for the Integrity Management Program

BP personnel involved in the Integrity Management Program include, but are not limited to:

1. Team Lead(s)
2. Subject Matter Expert(s) (SME)
3. IM Team
4. IM Program Committee
5. Pipeline Inspection Team
6. Third party Service Providers (i.e. ILI, Corrosion testing, etc.)
7. E & M and Field Operations Personnel

See Section B, below, for specific responsibilities of the above noted personnel in the Integrity Management Program.

A.2. Integrity Management and Quality Assurance Program Reviews and Corrective Action Procedures

1. Annually, review applicable laws and regulations related to Integrity Management for revisions. Documents to review include, but are not limited to:
 - a. 49 CFR Part 192 Subpart O and incorporated by reference documents
 - b. PHMSA Frequently Asked Questions
 - c. PHMSA Protocol documents
 - d. B31.8S Section 12
2. Compare the changes to applicable laws and procedures against the written BP Integrity Management Plan. As appropriate or needed, secure the assistance of third-party resources. See Section A.3 below for Third Party requirements.
3. Evaluate new and emerging technologies to determine the effect on the IMP.
4. P-192.901(c): Defines the process and software used for the determination of the HCA locations/sites. This section also outlines the procedure on how the Threat Risk Assessments (TRAs) are completed and defines the software used.
5. Evaluate any recommendations or feedback received from feedback loops.
6. Determine if changes are required to the written IMP.
7. Provide a summary of proposed changes to the IMP to the Manager, Gas Asset Strategies and the IM Team.
8. At a minimum, communicate changes resulting from:
 - a. Key regulation changes
 - b. Emerging technologies



9. Upon completion of the annual review, as applicable, develop a Corrective Action Plan for completing the required updates.
10. Assign accountability and a timeline to each action item.
11. Complete required updates as directed.
12. Document changes per P-192.901k (Management of Change (MOC)).
13. Issue updated Integrity Management and Quality Assurance Program information to the designated personnel and contractors. **(NOA #9 & #10)**

A.3. Third Party Resources

1. Secure Third-Party Resources that meet the requirements of the specific integrity assessment procedure and are approved through the BP Contractor Selection process.
2. Ensure third-party Resources used to implement Preventive and Mitigative measures meet the requirements of the BP Operator Qualification Plan and are qualified for the applicable Covered Tasks.
3. Obtain and review qualifications for Third-Party Resources involved in all aspects of the Integrity Management Program. **(NOA #10)**

B. Personnel Qualifications and Training Requirements (192.915)

B.1. Supervisory Personnel

B.1.1. Team Leads

1. Ensure Team Leads received the appropriate training and/or has the appropriate experience to fulfill Integrity Management related duties.
2. Verify Team Lead has at least ten (10) years of pipeline or integrity management or related engineering experience.
3. Encourage Team Lead to attend at least one (1) industry recognized event a year with Integrity Management content.
4. Examples include, but are not limited to:
 - a. Public meetings sponsored by the Office of Pipeline and Hazardous Materials Safety Administration (PHMSA).
 - b. American Gas Association (AGA) meetings and/or conferences.
 - c. NACE classes.
5. Recommend additional training for the Team Lead and other supervisory personnel as necessary.
6. Ensure management personnel with Integrity Management supervisory duties have an updated PDP on file.

B.1.2. Subject Matter Expert(s) (SME)

1. Designate key personnel as Subject Matter Experts (SME) as appropriate.
2. SMEs are personnel that possess extensive knowledge of any of the following:



- a. BP operating assets.
- b. Condition of the BP operating assets.
- c. Past history of the BP operating assets.
- d. Specific technical subject matter.

B.1.3. Integrity Management Program Committee

Gas IMP implementation, quality control, and revision oversight is provided through the IMP Committee which is composed of:

1. Manager, HSSE & Integrity;
2. Team Leader, Pipeline Inspection Team;
3. Team Leader, Integrity Management Team;
4. Team Leader, E&M Technical Services; and
5. Representatives from the Pipeline Inspection and HSSE & Integrity teams.

This committee reviews and monitors emerging integrity issues and monitors implementation/execution and the subsequent quality assurance of the Gas IMP. It develops and implements changes where necessary to maintain assurance and oversees preparation of the annual report to management.

B.2. Personnel That Conduct Integrity Assessments, Evaluate Assessment Results, and Participate in Implementing Preventative & Mitigative Measures

B.2.1. IM Team

The Integrity Management Team is responsible for HCA Identification, Threat Risk Analyses, Baseline Ranking, Preventative and Mitigative Review, and Continual Evaluation.

Members of the team shall have demonstrable knowledge of the processes, procedures, and tools utilized. This skill-set can be established through related background experience, related training, or a formal engineering degree. Each individual will participate in a Continuous Improvement process by completing task related training programs, attending industry workshops/conferences, or participating in vendor sponsored user's meetings. Each person will catalog all Continuous Improvement activities in a personalized training record. The Continuous Improvement and training log for each member of the IM Team is carried in the Virtual Training Assistant (VTA) database.

B.2.2. Pipeline Inspection Team

The Pipeline Inspection Team is responsible for Baseline Assessment, Assessment Results the following tasks:

1. Executing ILI Assessments;
2. Analyzing Assessment Results;
3. Determining Remedial Actions;
4. Over-seeing implementation of Remedial Actions; and
5. Compiling Remedial Actions documentation.



Team members shall have demonstrable knowledge of the process, procedure, and tools utilized to implement the team's roles and responsibilities. The skill-set needed to be part of the team can be established through related experience, training, or with a formal engineering degree. Each individual will participate in a Continuous Improvement process by completing related training, attending industry workshop and conferences, or participating in vendor sponsored presentations. The Continuous Improvement and training log for each member of the Pipeline Inspection Team is carried in the Virtual Training Assistant (VTA) database.

B.3. Personnel Who Execute Activities Within the Integrity Management Program

B.3.1. ILI Service Providers

Written practices for qualification and certification of ILI Analysts as well as a Personnel Qualification Statement for each analyst performing data analysis for BP Pipelines shall be maintained by BP Pipelines. These documents are maintained in the Rosen Charter and the Rosen Technical Reference.

B.3.2. E&M and Field Operations Personnel & Contractors

E&M (Project Managers and Construction Coordinators) and field operations personnel are responsible for assisting with or in some cases leading the execution of ILI and/or hydrotest assessments, investigating and/or correcting remedial actions, preventive and/or mitigative maintenance activities, and routine maintenance activities. In some cases, these work activities are performed by 3rd party contractors under the oversight and direction of field operations personnel or the Engineering & Maintenance Construction Coordinators. All field activities conducted on BP Pipeline assets are executed according to the requirements of BP Pipeline's Operator Qualification (OQ) Program. This program is a written qualification program that evaluates the ability of employees and contractors to perform "covered tasks" and to recognize and respond to abnormal operating conditions that may be encountered while performing these activities. The program defines a Covered Task as an activity by an individual or group of individuals that (a) is performed on a pipeline facility and; (b) is an Operations or Maintenance task and; (c) is required by Part 192 or Part 195; and (d) affects the operation or integrity of the pipeline. The OQ training log for each field operations personnel is carried in the Virtual Training Assistant (VTA) database.

C. INVOKING NON-MANDATORY STATEMENTS IN STANDARDS

Incorporate and implement non-mandatory statements (i.e. "should" statements) from industry standards or other documents invoked by Subpart O into the Integrity Management Program. If it is determined that the non-mandatory statements will not be incorporated into the Integrity Management Program, utilize one of the following approaches:

1. Incorporate and implement an equivalent alternative method for accomplishing the same objective.
 - a. Document the alternative method in a "white paper" and include:
 - i. Rationale for using an alternative method
 - ii. Explanation of why the alternative method will accomplish the same objective as the nonmandatory statement



2. Incorporate a documented justification in the Integrity Management Plan that demonstrates the technical basis for not implementing recommendations from standards or other documents.
 - a. As an alternative, document the technical justification in a "white paper".
3. Maintain "white papers" in the IMP Project **(NOA #11)**

**Communications Plan
Procedure # P-192.901(m)**

Appendix I



Description: This procedure describes the responsibilities associated with external and internal communications.

Applies To: All regulated gas pipelines.

Frequency:

Responsibility: Integrity Management Team (IMT)

Reference: 49 CFR Part 192.911

Prerequisites: All covered tasks identified in this procedure must be performed by qualified individuals or under the direct supervision of someone who is qualified according to BP's OQ program.

Forms:

Revision Date/Number 03/31/2008 / #4



A. External and Internal Communication Requirements

A.1. External Communications

A.1.1. Public Awareness Program

The public awareness program includes three subparts: Public Awareness Mass Mailing, Public/Private School Program, and Emergency Manager Program. The Public Awareness Program attempts to communicate pipeline safety information to each dwelling within 660 feet (urban/developed, and/or 3 miles (rural)) of the pipeline, on a two year rotation. The School Program attempts to communicate pipeline safety information to each school located within 660 feet of the pipeline, on a three year rotation. The Emergency Manager Program attempts to communicate pipeline safety information to every emergency planning manager whose jurisdiction encompasses our pipeline, on an annual basis. This program also applies to pipelines operating below 30% SMYS which are located in HCA and Class 3 or 4 areas.

A.1.2. Damage Prevention Program

The Damage Prevention Program includes several related programs: State One Call Participation, Pipeline Right-of-Way Patrol, Aerial and Ground Patrol, Receiving Notification of Unplanned and Planned Excavation, Pipeline Security, Damage Prevention Activities, Pipeline Markers, and Program Evaluation and Effectiveness. The program strives to improve communications with excavators and property owners through participation in the various State One-Call Centers, mailing education materials to contractors, emergency responders, utilities, elected officials and landowners, conducting face to face meetings, providing an emergency toll free contact number, marking pipeline routes with visible signs, accurate and timely line locate marking and providing visual inspections of the pipeline rights-of-way, and presence whenever excavation is occurring within 25 feet of the pipe centerline. This program also applies to pipelines operating below 30% SMYS which are located in HCA and Class 3 or 4 areas.

A.2. Internal Communications (NOA #12)

A.2.1. BP Integrity Management Group Standards

The BP Group Standard for Integrity Management requires conformance with the following ten elements:

1. Accountabilities
2. Competence
3. Hazard Evaluation and Risk Management
4. Facilities and Process Integrity
5. Protective Systems
6. Practices and Procedures
7. Management of Change
8. Emergency Response
9. Incident Investigation and Learning
10. Performance Management and Learning



This Standard reflects the balanced judgment of the BP Group and is based on experience and input from a variety of sources.

This Standard has two main intents:

1. To ensure a formal approach to the management of the integrity of BP Operations throughout the lifecycle from design and construction, through operation and maintenance, to decommissioning.
2. To promote the adoption of the Standard by companies working on behalf of BP. BP shall seek to hire contractors with IM programs that are just as encompassing as this Standard – if not more so – and to encourage those who do not have such a program to adopt one.

Document origination and distribution will be made per the following table:

DOCUMENT	ORIGINATOR	DOCUMENT RECIPIENT	ACTION REQUIRED	DUE DATE
F-192.705(a) <u>AP & GP</u> (Aerial and Ground Patrols of Pipeline)	Field Personnel	Control Center, District Office, Patrol Pilot, Affected Department(s)	As needed	Quarterly
F-192.706 <u>ROW</u> (ROW Survey)	Field Personnel	Field Supervisor, Area Manager, Patrol Pilot, Affected Department(s)	As needed	Quarterly
PHMSA F-7100.0-1 (Annual Integrity Management Report)	DOT Pipeline Compliance Files	Affected Department(s), DOT	Review and approval	Annually
IM Team TRA Results with Repair/Remediation Plan	IM Team	Field Operations Personnel Other affected departments (i.e. corrosion, ILI, etc.)	Annual IMP update and Risk Analysis update, enter mitigation items in Maximo for field completion	Results within 180 days of completing assessment, remediation per Repair Plan
Approved Management of Change	US Pipelines & Logistics Business Unit	Affected Department(s)	As specified in the approved MOC	As needed
F-192.614(b)(2) (Encroachment on the Pipeline)	Field Personnel	Affected Department(s)	As specified in the ROW specifications	As needed
F-192.615(c) (Conduct Liaison with Public Officials)	DOT Pipeline Compliance Files	Affected Department(s)	As needed	Annually



DOCUMENT	ORIGINATOR	DOCUMENT RECIPIENT	ACTION REQUIRED	DUE DATE
F-192.5 (Increase in Population – Class Location)	Field Personnel	Engineering Department	Review data, revise IMP as necessary	Annually
F-192.616 (Public Education)	DOT Pipeline Compliance Files	Affected Department(s)	As needed	Annually
F-192.613(a) (Repair & Inspection report)	Field Personnel	District Office Corrosion Specialist	Review data, if mitigation required schedule in Maximo	As needed

A.2.2. The Group IM Standard

1. Sets out the IM requirements necessary to satisfy the Group Values, particularly those relating to Risk, Health and Safety and Environmentally Sound Operations.
2. Requires the controlled application of hazard evaluation including major accident risk assessment, process safety and engineering management, combined with internationally recognized industry standards and engineering, maintenance and operating practices developed by BP.
3. Aims to reduce the number and severity of uncontrolled releases of hydrocarbons, chemicals, hazardous materials and other high-energy sources (including catastrophic and chronic releases) to the atmosphere, water or ground, and to prevent the failure of equipment and infrastructure in order to avoid serious harm to people, the environment and BP assets.
4. Will help BP to benefit from greater operational integrity; better Health, Safety, Security and Environmental (HSSE) performance; increased lifecycle value of BP assets; and greater engineering standardization and productivity.
5. Will help sustain BP's License to Operate, improve its operational reputation, reduce future *environmental liabilities* and achieve internal targets as defined in BP's Management Framework.

A.2.3. Annual Project/Budget Planning

BP's commitment to the operating philosophy of no harm to people, no harm to the environment, no accidents, and compliance with all laws and regulations gives high priority to IM related projects. Current year integrity management projects begin development during the third quarter of the previous year. During the development period the IM Team and the Pipeline Inspection Team communicate with the Asset Managers about the integrity projects planned for the following year. The Asset Managers incorporate these project costs into their local budgets and secure the necessary funds. The Engineering & Maintenance Team assigns Project Managers who begin development of a project execution plan. Field representatives participate in the development and execution of the projects.

B. Addressing Safety Concerns

OMER Book 1 (Gas) P-192.23 (Safety Related Conditions) addresses reporting criteria based on; Criteria I: Reportable Pipeline, Criteria II: Reportable Items, and Criteria III: Reportable Locations. Once a determination that a reportable safety related condition exists, that cannot be repaired within 5 working



days, or is a condition that must be reported, a Safety Related Condition Report (Form F-191.23 Safety-Related Condition Report) must be filed in writing within that 5 working day period, and should be filed by the Coordinator-Regulations.

The Safety Related Condition Report shall be filed with the Office of Pipeline Safety and submitted concurrently to the appropriate State agency. Appropriate State agencies are agencies, which act as an agent of the Secretary with respect to interstate pipelines and/or intrastate pipelines.

OMER Book 1 (Gas) P-191.15 (Reporting Accidents) procedure is used to report accidents and safety-related conditions to the Federal DOT and state. An accident report is required for each failure in a pipeline system subject to this part in which there is a release of natural gas transported resulting in any of the events listed in the "Events Table" of this procedure.

The DOT Team will continually monitor the DOT/PHMSA website for rule changes, new information and recommended practices.

The DOT Team will review annually Regional Compliance Actions including Orders, Notices, Extensions, Letters, Amendments and Agreements from the Office of Pipeline Safety, evaluate the postings with BP's IMP and other policies and programs and make changes to BP's IMP and other policies and programs as appropriate.

The DOT Team will review annually National Transportation Safety Board Pipeline Accident reports, evaluate findings and recommendations in those reports with BP's policies and programs and include appropriate changes to BP's IMP and other policies and programs as appropriate. **(NOA #3 & 12)**

C. Records

The Damage Prevention Team maintains the records for the Gas IMP Communications Plan. Unless otherwise noted, these records are archived for the life of the facility. The listing below outlines the location for official IMP documentation. Please contact the IM Team for inquiries about current Gas IMP documentation.

1. Public Awareness Program – BP Pipelines Intranet
2. Damage Prevention Program – BP Pipelines Intranet
3. BP Group Standards Integrity Management – BP Pipelines Intranet
4. OMER Book 1 (Gas) – BP Pipelines Intranet

**Continuing Surveillance for Class
Location and HCA
Procedure # P-192.613**

Appendix J



Description: To establish the procedures for continuing surveillance of the pipeline.

Applies To: All regulated gas pipelines.

Frequency: At least once each calendar year or when an increase in population density potentially indicates a change in class location.

Responsibility: Integrity Management Team (IMT)

Reference: 49 CFR Part 192.613 *"Continuing Surveillance"*
http://www.access.gpo.gov/nara/cfr/waisidx_03/49cfr192_03.html

Prerequisites: All covered tasks identified in this procedure must be performed by qualified individuals or under the direct supervision of someone who is qualified according to BP's OQ program.

Forms: Repair & Inspection Report
BP West Coast Products LLC Repair and Inspection Report
F-191.23 "Safety Related Condition Report"
F-192.5 "Class Location Determination"
F-192.465(a) "Cathodic Protection Survey"
F-192.465(b) "Cathodic Protection Unit Report"
F-192.465(e) "Reevaluation of Unprotected Pipelines"
F-192.467 "Pipeline Crossing of Foreign Lines"
F-192.467 B "Bond Site Report"
F-192.467(d) S "Shorted Casing Monitor Report"
F-192.477 "Coupon Inspection"
F-192.481A "Exposed Pipe Inspection Report"
F-192.481B "Station Exposed Pipe Inspection Report"
F-192.605(c)(4) "Abnormal Operation: Procedure Review"
F-192.613(a) "Continuing Surveillance for Class Location and HCA (Using GSP)"
F-192.613(b) "Continuing Surveillance for Class Location and HCA (No GPS)"
F-192.615(b)(3) "Review of Operator Personnel During Emergencies"
F-192.705(a) AP "Aerial Patrol"
F-192.705(a) GP "Ground Patrol"
F-192.706 ROW "Aerial Leak & Right-of-Way Report"
F-192.706 "Leakage Surveys"
F-192.731 "Compressor Station Relief Device"
F-192.739 "Pressure Limiting and Regulating Stations: Inspection & Testing"
F-192.743 "Pressure Limiting and Regulating Stations Inspection"



F-192.745 "Valve Inspection & Maintenance"
F-192.749 "Vault Maintenance"

Revision Date/Number 04-01-2008 / #3



A. Visual Facility Inspection

It is important the pipeline route and all associated facilities have periodic visual inspections. By routinely surveying the line potential problems may be alleviated. A continuing surveillance program must be established to identify abnormal, unusual or changing conditions which may affect operation and maintenance of the facility. Changes in population in the area surrounding the pipeline should be checked regularly as increases or decreases may affect the pipeline area class location designation. The Facilities Supervisor shall be responsible for reporting any new structures, including but not limited to subdivisions, businesses, shopping centers, schools, playgrounds, recreation areas or any other commercial or residential development which may affect the existing class location designation.

The pipeline route and associated facilities shall also be inspected for vandalism or tampering of any components. By frequent inspection damage may be prevented. If vandalism occurs regularly or frequently, action will be taken to protect the pipeline and its components.

Any earth movement, such as a landslide or subsidence, which may have affected the pipeline's integrity, should be investigated. Any damages shall be recorded for repair.

The integrity of the pipeline should be reviewed following the installation of other pipelines or facilities in the immediate area. Typically a new pipeline will be installed underneath the existing pipeline; this may affect the stability of the ground surrounding the existing line. During and following any additional pipeline installation, the area surrounding the pipeline shall be inspected to ensure its integrity and remedial action taken. If necessary the MAOP will be reduced if reconditioning is not an immediate option.

At any time when the pipeline is exposed or possibly moved, the after effects on the facilities shall be investigated. Any damage due to movement or exposure will be recorded. All repairs resulting from such activities shall be documented in accordance with procedure P-192.711 Repairs, Replacements & Relocations.

B. Field Procedure For Corridor Inspection

1. The IM Team will issue, to the designated field personnel, on a yearly basis (typically in the First Quarter), two (2) copies of all required line sheets for the designated field personnel's responsibility area. (One (1) copy to mark-up and return to IM Team; one (1) copy to mark-up and retain in field for reference). Yearly, an updated "Final" version of the line sheets will be issued to the field.
2. The designated field personnel will then complete a pipeline corridor assessment that will include:



NOTE: (Pertains ONLY to LA Basin)

- Due to the extent of the population encountered in the Los Angeles area Line 211A is deemed 100% HCA therefore the corridor surveillance for class location and HCA process will apply as follows:
 - 1) HCA maps for Line 211A will be issued to the appropriate field personnel on a yearly basis, these HCA maps will note the pipe centerline, HCA "could affect" pipe and the PIR buffer zone. They will also note buildings with symbols to indicate the population status, and identified sites. The sites of largest concern are buildings with four (4) or more stories above ground.
 - 2) Field personnel are requested to evaluate the corridor based on the issued HCA maps and verify all existing noted four (4) story buildings and document any new four (4) story buildings directly on the line sheets provided. If the status of a location has changed, mark changes directly on the issued line sheets, as well as, noting the change on the forms provided. (F192.613 (A & B)) GPS data and/or perpendicular measurements from the pipe centerline will no be required.
- a. Verification of existing identified dwellings and/or sites
 - i. If an existing dwelling/identified site is verified this should be noted directly on the line sheet.
 - ii. If an existing dwelling is NOT shown correctly on the line sheets, issued to the field, cross out incorrect location and indicate on line sheets correct location of dwelling. Note corrected information on F-192.613(a) or (b). , as applicable.
 - b. Identification of newly identified dwellings and/or sites
 - i. Newly identified dwellings/identified site data should be entered on F-192.613
 - c. Data collection on newly identified areas/buildings: (Data collected utilizing GPS Unit) (Data to be recorded using: F-192.613(a))
 - i. If the newly identified area/building is classified as a "Dwelling" (See "Definitions" table) then field personnel will be required to collect the following data:
 - a) A MINIMUM of three (3) GPS points on side of the dwelling closest to the pipeline. (For accuracy assurance)
 - b) Building count (Ex: Single family residence = 1; Duplex = 2, etc.)
 - c) If field personnel believe "Dwelling" to be an identified site, but received conflicting information from source at the site, document sources name, address, and phone number. Otherwise this data does NOT need to be collected for "Dwellings."
 - ii. If the newly identified area/building is classified as an "Identified Site" (See "Definitions" table) then field personnel will be required to collect the following data:
 - a) GPS readings at each outside corner of the structure
 - b) Building/site type
 - c) Contact and/or business name
 - d) Address



- e) Phone number
- d. Data collection on newly identified areas/buildings: (Data collected NOT utilizing GPS unit) (Data to be recorded using: F-192.613(b))
 - i. If the newly identified area/building is classified as a "Dwelling" (See "Definitions" table) then field personnel will be required to collect the following data:
 - a) Dwelling location:
 - (i) Perpendicular measurement from the pipeline centerline. (As reasonably as possible, state distance and assumed accuracy of measured distance)
 - (ii) Mark directly on line sheets location of dwelling. Place the uniquely assigned reference number, that corresponds with entry on F-192.613(a) or (b), by mark on line sheets and assure information noted correctly on F-192.613(a) or (b), as appropriate.
 - b) Building count (Ex: Single family residence = 1; Duplex = 2, etc.)
 - c) If field personnel believe "Dwelling" to be an identified site, but received conflicting information from source at the site, document sources name, address, and phone number. Otherwise this data does NOT need to be collected for "Dwellings."
 - ii. If the newly identified area/building is classified as an "Identified Site" (per the definitions listed below) then field personnel will be required to collect the following data:
 - a) Measurement from the pipeline centerline. (As reasonably as possible, state distance and assumed accuracy of measured distance)
 - b) Building/site type
 - c) Contact and/or business name
 - d) Address
 - e) Phone number
- e. Encroachment evaluation and identification
 - i. Identify any structures that lie with in the pipeline Right-of-Way (ROW)
- f. Identification of proposed building sites (Ex: New construction, etc.)
- g. If site no longer exists (i.e. shows on line sheets, but is non-existent) cross out non-existent site on line sheet and place the unique reference number that corresponds to F-192.613(a) or (b) next to mark on line sheet. Assure information is also noted on F-192.613(a) or (b), as appropriate.

NOTE:

For each "mark" placed on the line sheets there is to be a corresponding entry in Form F-192.613 (a) or (b), as appropriate, with a unique reference number assigned.



Per 192.5 the following definitions apply:

DEFINITIONS TABLE:

Class 1 Location Unit	<ul style="list-style-type: none"> i) An offshore area; or ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.
Class 2 Location Unit	<ul style="list-style-type: none"> i) Any class location that has more than 10 but fewer than 6 buildings intended for human occupancy
Class 3 Location Unit	<ul style="list-style-type: none"> i) Any class location unit that has 46 or more buildings intended for human occupancy; or ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well defined outside area (such as a playground, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 1 weeks in any 12 month period. (The days and weeks need NOT be consecutive)
Class 4 Location Unit	<ul style="list-style-type: none"> i) Any class location unit where buildings with four (4) or more stories above ground are prevalent.
Identified Site	<ul style="list-style-type: none"> i) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any 12 month period. (These days need NOT be consecutive) (Examples include, but are not limited to: playgrounds, recreational facilities, beaches, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, religious facilities, commercial business, etc.) NOTE: Parking lots are not to be included, UNLESS, there are sanctioned events that occur on a periodic basis at that location) ii) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any 12 month period. (The days and weeks need NOT be consecutive) (Examples include, but are not limited to: Religious facilities, office buildings, community centers, general stores, 4-H facilities, commercial business, roller skating rinks, etc.)
Dwelling	<ul style="list-style-type: none"> i) Dwellings are considered living establishments (Examples include, but are not limited to: house, duplex, town home, condominium, house trailer, etc.) ii) Each dwelling is assumed to house three (3)



persons, therefore, multi-unit dwellings containing seven (7) or more units are considered to meet the definition of an "Identified Site"

See Note, below.

- A "Class location unit" is an onshore area that extends 220 yards (200 meters) on either side of the centerline of a continuous 1 mile length of pipe.
- Each separate "Dwelling Unit" in a multiple dwelling unit building is counted as a separate building intended for human occupancy.
- All GPS coordinates will be submitted as decimal units.

C. Record Review

The records of specific activities shall be periodically reviewed. This process shall include reviewing the reports of all patrols made of the pipeline facilities. *Any leakage surveys performed shall be examined.*

Appurtenances, such as valves, or equipment which regulates, relieves and limits pressure require regular inspection. Periodic review of these inspections shall be performed regularly. All corrosion control and facility failure investigation reports shall be regularly examined. Gradual changes shall be noted and monitored as required.

Each survey shall be documented on form F-192.5 Class Location Determination. Should this survey show any deviation to the existing class location designations, action shall be taken to confirm or revise the maximum allowable operating pressure of each affected segment.

Continuing Surveillance for Class
Location and HCA Field Survey
(Using GPS)
Form # F-192.613a

Appendix J

**Continuing Surveillance for Class
Location and HCA Field Survey
(No GPS)
Form # F-192.613b**

Appendix J

