Exit Interview Items - KinderMorgan
Week 1 Integrity Management Inspection

## General Comments

1. OPS appreciates KM's hospitality, the open discussion, and KM's willingness to share information during this inspection and also the positive attitude exhibited this week during the inspection. We realize this inspection approach is new – both for KM and for OPS. We appreciate your willingness to work with us to gain an understanding of your integrity management program.

2. OPS recognizes the challenge involved in developing and implementing a formalized, robust integrity management program in a large organization with significant diverse and distributed pipeline assets and people. KM has laid out an ambitious program for implementation as reflected during this inspection's discussions and in the IM Program documents. We believe that the work activities in this plan, along with the issues identified in this exit interview, are important to the further development of a fully mature program. Based on feedback received during this inspection, OPS anticipates that KM management supports the program with necessary resources to meet the currently documented program and assessment schedule.

3. Segment identification performed at 30 foot intervals is a comprehensive approach to identifying pipeline segments that could affect high consequence areas.

4. The IAP risk analysis tool being utilized appears to have many capabilities and the potential to be a useful integrity management tool. In particular, the ability to extract the most important risk "trigger" factors is considered to be a strength.

5. The Inspection team noted a need for improved cross referencing of appendices/procedures with the main body of the IMP.

6. Lack of overall guidelines for SME tasks and responsibilities to ensure company wide consistency.

7. Inspection team unable to confirm adequacy of change control process given the recent implementation of this procedure.

> [§452 (l) *What records must be kept?* (1) An operator must maintain for review during an inspection … (ii) Documents to support the decisions and analyses, including any modifications, justifications, variances, deviations and determinations made, and actions taken, to implement and evaluate each element of the integrity management program listed in paragraph (f) of this section.]

**Section-Specific Comments**

1.0 Segment Identification

1. Local field knowledge has been collected but has not been applied to HCA changes.

> §195.452(d)(3) *Newly-identified areas*. (i) When information is available from the information analysis (see paragraph (g) of this section), or from Census Bureau maps, that the population density around a pipeline segment has changed so as to fall within the definition in §195.450 of a high population area or other populated area, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified.] [1.01]

2. Facilities:

- The IMP list of could affect facilities did not include Plantation (analysis stated as not yet being completed) [1.01]
- Could affect analysis was based on proximity to pipeline rather than facility characteristics [1.02]
- No documentation of position that potential facility release volumes into associated line pipe could not impact line release volumes [1.04]

3. Rupture volumes were based, in part, on a two minute detection time for leak events response time (SCADA). There appeared to be insufficient documentation to support this assumption. [1.05]

4. Could Affect Release Transport Analysis [1.06]

- Assumptions for product pool depths in the indirect spread (1") and terrain analysis (1.9") were not consistent
- Assumptions for product pool depths in the indirect spread and terrain analysis did not appear to be substantiated by release history or physical commodity characteristics
- Termination criteria for terrain analysis does not account for release volumes at flat locations
- Spread distance predictions/results did not appear to be benchmarked against leak history (documented or SME knowledge)

5. Consideration of pool fires did not appear to be considered or justified for exclusion as a potential "could affect" consideration for releases. [1.08]

2.0 Baseline Assessment Plan

1. Lack of a documented technical basis for the position that pre-'70 low frequency ERW piping is not susceptible to seam failures. [2.01]

2. No documentation as yet to support the removal of idle lines from the BAP. [2.02] [*Specific data to be provided by KM.*]

3. Current IMP process does not appear to provide for flexibility to rerank BAP segments if updated information indicates a different risk than previously estimated. [2.02]

4. Decision to exclude previous hydro/ILI tests as "Qualified Prior Assessment" into the original BAP development. *This may be inappropriate as consideration of the existing assessment would have ranked a particular segment lower; ranking a system artificially higher and then taking credit for the existing assessment does not meet the intent of performing the highest risk 50% of could affect piping prior to the lower ranked line segments.* [2.02, 2.04]

5.0 Risk Analysis

The risk analysis process that has been presented includes a solid framework for effective risk analysis and risk-based decision making. OPS acknowledges that the risk analysis process undergoes an annual review and update as KM's IM program matures and the risk analysis output is needed for purposes beyond ranking segments for the Baseline Assessment Plan.

1. KM did not consider some risk factors which are required by rule to be addressed in the basis for the baseline assessment plan. These features are able to be analyzed in IAP, but were "turned off" in IAP due to reasons such as lack of quality data or consistent data across KM's diverse systems.

> [§452 (e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?* ... An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The factors an operator must consider include, but are not limited to:" ...including:

- Results of previous integrity assessments (not just the fact that an assessment was performed), including previously identified defect type and predicted defect growth rate,
- Repair history,
- Local environmental factors such as soil corrosivity, subsidence, and climatic conditions,
- Geo-technical hazards,
- Physical support of a segment such as a cable suspension bridge [2.03, 5.01]

Other risk factors are listed in the rule when evaluating additional preventive and mitigative actions. In addition, the risk factors that must be considered (as required by the rule) are not limited to those risk factors listed in the rule.

2. The basis for some decisions on risk factor weighting and scoring are not documented. Some of the weights and decisions dramatically affect the risk analysis results and should be justified and documented. Examples include:

- Heavy weighting of both the LOF and COF risk scores based on product type,
- The weighted averaging of risk scores appears to skew the results toward short lines
- Consequence scoring based on HCA type inflate the scores when different HCA types overlap reduces the relative impact of large amounts of line that impact a single type of HCA. OPS acknowledges the convenience associated with the scoring scheme.
  *Nevertheless, the scoring scheme should be designed based on actual estimates of relative risk, and not on convenience of discerning the HCA types impacted when reviewing the results. If necessary, additional data fields should be added to provide for a meaningful consequence risk score*
- ILI and pressure test history received the same score, regardless of the age of the previous assessment. Although under consideration for future use, this issue is an important issue when risk ranking the BAP. OPS acknowledges that lines without a prior assessment correctly are assigned the highest relative risk score. However, the scoring scheme should differentiate lines based on the age of previous assessments that have been performed. [5.02]

3. No documented criteria for excluding data when a full complement of data was not available. [5.05]

4. KM has not performed any confirmatory analysis to validate risk model results with actual operating history. [5.05]

5. The IM program does not address risk analysis of facilities that could affect HCAs. It appears that some ongoing activities may address some aspects of facility risk, for example identification of facilities that could affect HCAs. [5.06]

Exit Interview Items - Kinder Morgan
Week 2 Integrity Management Inspection

## General Comments

1. As in week 1, OPS appreciates KM's hospitality, the open discussion, willingness to share information during this inspection, and the positive attitude exhibited during the inspection.

2. OPS recognizes the challenge involved in developing and implementing a formalized, robust integrity management program in a large organization with significant diverse and distributed pipeline assets and people.

3. Inclusion of specific reporting time constraints in ILI vendor contracts with disincentives for delayed reporting is considered to be a strength.

4. BAP risk model weighting factors do not appear to reflect KM operating experience. It appears that this masks the relative importance of other significant risk contributors such as external corrosion factors, third party factors, design materials factors, etc.

- The LOF internal corrosion weighting does not compare well with KM historical experience.
- The COF HCA scoring appears to have the appropriate order of priority, but a disproportionately wide range of assigned values has the effect of masking contributions from other factors.

5. The weighted averaging risk scoring methodology for BAP segments appears to reduce the relative scoring of segments that affect multiple types of HCAs.

6. Full complement of currently available risk information has not been utilized in the risk analysis applications to-date.

7. Given the above risk analysis considerations, the BAP prioritization may not be reflective of the relative importance of KM's integrity threats.

8. As discussed previously, changes to the BAP from 3/31/02 to the current BAP did not appear to be documented as required.

- *§195.452(c)(2) - An operator must document, prior to implementing any changes to the plan, any modification to the plan, and reasons for the modification.*

9. Personnel training requirements in the IMPM are very general, and do not provide specific technical capabilities. HR type of job description are not considered to be sufficient for this purpose.

- Example: IMPM Section 11.2.2 - "Subject matter expert personnel are fully qualified in their respective areas of expertise by a combination of pipeline experience, formal education, and other training."
- *§452 (f) An operator must include, at minimum, each of the following elements in its*

*written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information*]

10. IMPM documentation requirements are very general and do not detail specific records for retention and the target locations of these records.

11. The inspection team again noted the need for improved cross referencing of appendices/ procedures with the main body of the IMP.

- One way linkage of IMPM Section 8.2 and associated Appendix H5.3.

Section-Specific Comments

3.0 Integrity Assessment Results Review

1. Vendor ILI preliminary report conditions do not include requirements to report geometry features. If current generation geometry tools have the capability to generate this information, KM should be cautious in waiting for the assessment final reports prior to responding to anomaly indications from these tools. [3.02]

2. Although geometry/MFL tool runs are normally run close together, the IMPM process could be enhanced to address the discovery date for instances of widely separated tool runs. [3.02]

3. No consideration of ILI tool tolerances when evaluating assessment data. [3.03]

- "*Tool tolerances should be considered as part of the data integration process ... This does not necessarily mean simply adding the vendor-supplied tolerance value to reported depth of indications ... Defect characterization should consider all relevant uncertainties to assure that defects posing a potential integrity threat, including those meeting the criteria in 452(h)(4), are promptly identified.*"

4. A criteria for the need for, or the number of, verification digs to validate ILI results was not included in the IMPM. [3.03]

5. Appendix H4.1 (Receive and Analyze Assessment Data - Formulate Repair Schedule) flow chart (pp. 9/9) contains an action to "Review other non-ILI related data from IMP." There appears to be no supporting process steps to implement this item. [3.04]

6. Process guidance should be expanded to include the determination and documentation of whether or not anomaly locations are in "could affect" locations. [3.05]

7. Lack of criteria for comparing vendor and field definitions of anomaly categories to IM rule definitions (i.e., "ovalities," "dents,""flat spots"). [3.05]

8. Lack of documentation of current practice of contacting ILI vendor when field calls do not

match ILI vendor reports. [3.05]

9. OPS Western Region may conduct further follow up regarding LS-14 assessment results.

10. In the "Pipeline Repair/Modification Report" forms, provisions should be provided to record as found conditions and other pertinent IM information (e.g., pipe to soil readings, anomaly field calls).

11. Inspection team noted a repair using a grade B type B sleeve on X42 pipe (KM Southeastern Region example Underground Inspection/Report; 3/11-12/02). OPS Southern Region may follow up.

## 4.0 Remedial Action

1. IMPM Section 7.4.1 discusses application of ASME/ANSI B31.4 formula to determine temporary operating pressure reductions. Process does not address determination of reduced operating pressure for anomalies for which this formula does not apply. Also, language in Appendix E1.2 regarding the use of $P_d$ or $P_h$ could be clarified to avoid any misapplication of reduced pressure levels. [4.01]

2. Consideration for establishing timeliness guidance for those items requiring immediate action. No deficiencies noted to-date, but may become more important as assessment activities accelerate. [4.02]

3. Dig lists were not prioritized by risk rank. KM stated that few anomalies had been identified to-date under the IM Rule, and that there had been no need to do actual ranking of anomalies. [4.02]

4. Upcoming review of Plantation data may generate additional items.

## 6.0 Preventive and Mitigative Measures

1. Overall P&M process is currently at a framework status. Examples of areas that may benefit from further development include the following:

- IMPM Section 9.2.1 refers to a "scenario" evaluation process, but detailed procedure Appendix H6.1 has no reference to the utilization of scenarios. [6.04]
- Appendix H6.1 does not specifically focus P&M evaluation on the higher risk locations. [6.03]
- Appendix H6.1 Section 4 does not specify the documentation of evaluated, but non-implemented/suspended projects. [6.03]
- IMPM 9.2.2 does not specify the "broadness" of the SME team that analyzes proposed P&M measures. [6.04]

· P&M process refers to the receipt of ILI data versus "assessment" data. [6.04]

2. Evaluation of facilities is not included in the P&M process. The IMPM Section 4.3 referenced "additional analysis of facilities" should be extended to the P&M process. [6.01]

3. §452(i)(2) required evaluation factor (viii), Exposure of the pipeline to operating pressure exceeding established maximum operating pressure, does not appear to have been considered in the risk analysis identified to-date. No justification for this exclusion could be located, although KM noted ongoing surge analysis project. [6.02]

4. KM leak history indicates several events due to operator error. Operating experience can be an important consideration for the evaluation of P&M measures. As such, consideration of the degree of operator experience may be appropriate in the risk analysis. [6.02]

5. Lack of a defined evaluation criteria for determining which P&M measures will be recommended for implementation and a process to assure that recommended measures are actually implemented. [6.03]

6. IMPM Section 9.2.2, 9.2.4 refers to performance of the P&M review within 18 months after receiving ILI data or other triggering events. OPS expects that the evaluation of preventive and mitigative measures should occur within one year after assessments have been performed. [6.04]

7. The evaluation of leak detection and EFRD systems and processes is presently in a rudimentary state of development. The following is noted regarding the eventual LD/EFRD process: [6.06, 6.07, 6.08]

· As noted in §452(i)(3), the leak detection evaluation process must include an evaluation of the adequacy of the current LD capabilities, as well as the need for improvements.
· §452(i)(4)-required evaluation factors require consideration of the potential for ignition, and the proximity to power sources. These factors do not appear to be included in the risk analysis process developed to-date.

7.0 Continual Process of Assessment and Evaluation

1. The program appears to have largely pre-determined that assessment intervals will default to 5 years, and that any other assessment interval would be determined by exception only. The IM Program does not explicitly require a segment-specific analysis in order to make a positive determination of reassessment interval for each segment. [7.01]

2. In Appendix H5.1, § 3.6.1.7, the note about notification refers to H5.2, "Conduct of Direct Assessment." It appears as if this should refer to H5.3, "DOT Notifications and Variances." [7.03]

3. Certain prior assessments credited as baseline assessments were conducted as early as 2000. To date, the analysis (e.g., corrosion rate analysis, crack growth analysis, fatigue cycle analysis) to determine re-assessment intervals for these segments has not been initiated. Kinder Morgan may not be able to comply with the risk-based assessment schedule results if there are further significant delays in making this determination. [7.05]

## 8.0 Program Evaluation

1. The program does not appear to provide for independent oversight such as audits, internal quality reviews, etc. [8.01]

2. The program evaluation procedures do not appear to provide for adequate accountability to assure communication of program performance results to management. Specific program elements should include oversight and follow-up of program evaluation results, findings, and recommendations by appropriate company managers. [8.01]

3. The program does not establish any performance goals, targets, or objectives for the selected performance metrics. [8.02]

4. The program evaluation metrics selected do not include threat specific metrics. [8.02]

5. The root cause analysis process and specific root cause results (for both releases and near-miss events) are not currently integrated with the IM program. This is another example of the type of data integration that is expected, in addition to populating the IAP database. [8.05]

**Integrity Management Inspection**
**Inspection Summary Report**

**Report Issue Date:** January 10, 2004

Operator: Kinder Morgan Energy Partners, L.P.

**Corporate Address:** 500 Dallas
Suite 1000
Houston, Texas 77002

**Operator ID Number(s):** 26125, 18092, 2190, 15674, 31555, 31452, 26041, 4472

**Dates of Inspection:** April 7-11 & April 21-25, 2003
June 23, 2003 (Plantation Pipeline and Central Florida Pipeline Supplemental Assessment Inspection)

**Location of Inspection:** 1100 Town & Country Road
Orange, CA 92868

**Primary Contact:** Buzz Fant
Director - Pipeline Safety
Phone: (713) 369-9454 Fax: (713) 495-2713

**Persons In Attendance:**

**Operator Representatives:**

Buzz Fant, Director - Pipeline Safety
Stephen Biagiotti, Manager Pipeline Risk Analysis
Thomas Bickel, Senior Engineer (Plantation/Central Florida)
Edward Bott, Operational Superintendent - Petroleum
Scott Davis, Manager - Pipeline Integrity and Facility Engineering
F. Bryant Dicks, Manager - Pipeline Engineering (Plantation/Central Florida)
Olen Foreman, Manager - Engineering Standards and SCADA Support
Ken Havens, Source and Transportation Director
Jaime Hernandez, Manager, Pipeline Safety
Brad Lewis, Area Manager
Carlos Munguia, Manager of Engineering, Maintenance and Technology
Anita Smith, Manager, Risk Engineering
Eric Coyle, Senior Engineer - Project Manager (BassTrigon)
Elaine Hendren, Senior Engineer - Project Manager (BassTrigon)

**OPS Inspection Team:**

Byron Coy (Lead) (OPS Eastern Region)
Terri Binns (OPS Southwest Region)
Gregory Hindman (OPS Southern Region)
Jeffery Gilliam (OPS Central Region)
Hossein Monfared (April 21-25 only) (OPS Western Region)
Donald Moore (OPS Central Region)
Bruce Kain (State Corporation Commission of Virginia)
Charles MacDonald (California State Fire Marshal)
Robert Miller (Arizona Corporation Commission)
David Kuhtenia (Cycla Corporation)
Steve Stout (Cycla Corporation)

June 24-25, 2003 Plantation Pipeline and Central Florida Pipeline Supplemental Assessment Inspection:

Byron Coy (Lead) (OPS Eastern Region)
Greg Hindman (OPS Southern Region)
Steve Stout (Cycla Corporation)
Bruce Kain (State Corporation Commission of Virginia)

## Inspection Objectives

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

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

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

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

## Integrity Management Program Overview

KM operates a number of pipeline systems across the United States, including the Plantation Pipeline. Given the ownership arrangements for Plantation Pipeline, the list of "could affect" segments/facilities and baseline assessment plan are maintained separately from the remainder of the KM system. In addition, the assessment records for both the Plantation Pipeline and the Central Florida Pipeline are maintained in Doraville Geogia. As such, the inspection team conducted a supplemental review of integrity management and assessment records for the Plantation and Central Florida systems in Doraville, GA, subsequent to the main integrity management inspection of KM in Orange County, CA.

In general, the inspection team noted that there was a general lack of specificity with respect to tying together the various appendices to the main body of the Integrity Management Program Manual (IMPM). While a large variety of supporting procedures were located in the supporting appendices, it was not clear that there were specific pointers in the main procedure to invoke all of these procedures.

In addition, while the IMPM utilized a variety of subject matter expert opinion and input, there was a lack of overall guidelines for SME tasks and responsibilities to ensure company wide consistency. The IMPM also did not include any personnel qualifications for integrity management-specific tasks.

**1. Segment Identification** - The KM process to identify high consequence areas (HCAs) utilized NPMS data to identify HCAs and KM pipeline locations, including updated NPMS data incorporating 2000 census bureau data. To verify the correct application of NPMS data, the inspection team reviewed seventeen locations, with no deficiencies noted. Non-NPMS field information had not been used in the identification of "could affect" segments, although it had been incorporated into the risk model database.

The KM process to identify could affect segments of pipeline analyzed releases at 30 foot intervals along each pipeline and involved five basic categories of potential impact - direct intersect, indirect analysis, terrain analysis, water transport analysis, and HVL transport:

- "Direct intersect" identified portions of the pipeline that directly intersect HCAs;
- "Indirect analysis" considered the spread of a one-inch flat pool of liquid around the release location;
- "Terrain analysis" considered the potential flow of a liquid release along physical pathways in the vicinity of the release location;
- "Water transport analysis" considered "direct waterway" transport (pipeline intersections with waterways) and "indirect waterway" transport (either indirect or terrain overland transport to a waterway); and
- "HVL transport" considered the dispersion of HVLs.

Nominal rupture volumes were based on full drain down of the line at the point of release plus short-term pumped flow. There was no justification for the assumption that release volumes for small leaks were bounded by large ruptures when considering which pipeline segments could affect an HCA.

Based on the resolution of available geospatial maps, terrain surrounding pipeline release points was divided into 30 $m^2$ grids. If a >2% grade was present at the initial point of release, a 1.95

inch thick flow was assumed to occur until either the release volume was exhausted by "filling up" each 30 $m^2$ area (approximately 275 bbl per "pixel"), or the surrounding area was <2% elevation difference.

KM noted that benchmarking of overland spread modeling with actual leak events had not been done due to limitations of large leak history data. Instead, reliance was placed on the overland spread model contractor (BTS) to compare models with actual events.

Where a pipeline location intersected with a National Hydrographic Dataset (NHD) waterway, a release was assumed to occur and be transported 35 miles downstream, independent of any volume considerations (based on the average NHD stream velocity of (4 mph)* (8 hour assumed response time) = 32 miles, rounded to 35 miles). Where the indirect or terrain analyses indicate that release volumes may migrate overland to a waterway, the KM methodology assumed the release migrated 35 miles downstream. No consideration had been taken for flooding conditions or subsurface water transport.

The KM process for HVL releases consisted of evaluating flame jet impact zones and overpressure blast distances. Both analyses utilized the DOT-distributed ARCHIE (Automated Resource for Chemical Hazard Incident Evaluation) model. In addition, a toxicity analysis (asphyxiation) was conducted for $CO_2$ lines. Results indicated flame "safe separation distances" on the order of 2600 ft., overpressure blast distances on the order of 7000 ft., and toxic cloud buffer distances on the order of 70,000 ft. for $CO_2$ lines. Pool fires had not been considered in could affect analysis.

No exceptions were taken for direct intersect or other potential HCA impacts; KM stated that this was under consideration as a future enhancement to the program (e.g., for $CO_2$/drinking water interactions).

Facility-specific release locations had not been identified. Instead, examination of line 1000 ft. upstream and downstream of each facility had been examined. If any could affect segments were found in this 1000 ft. "zone," the facility was assumed to be a could affect facility. There was no consideration of potential facility volumes (e.g., tank volumes) in the could affect analysis.

The change control/revision process for the KM segment identification process did not appear to be well established as segment identification revisions appeared to be ongoing without documentation of the changes.

**2. Baseline Assessment Plan** - The inspection team reviewed the KM BAP for assessment methods and noted that 1.) no specific assessment methods appeared to address piping susceptible to seam failures (e.g., low frequency ERW piping), 2.) no consideration was given for selecting tools capable of assessing stress corrosion cracking (SCC) risks, and 3.) portions of the $CO_2$ system had direct assessment shown as the assessment methodology. KM responded to these issues as follows:

- Susceptible piping - KM noted that while some portions of their system contained low frequency ERW piping, these lines were not considered to be susceptible to seam failures. The primary basis for this assertion was that in 30+ years of service, there had been no history of seam-related failures observed in any currently active lines. The inspection team noted that this position needs to be well documented in the IMPM and that OPS generally considers all low frequency ERW to be susceptible unless a sound technical justification proving otherwise is provided.
- SCC - KM stated that they did not consider SCC to be a risk on their lines and did not consider tools capable of detecting tight cracks such as shear wave UT.
- The recent pipeline accident in Arizona has caused KM to undertake a re-evaluation of the potential for SCC.
- Direct Assessment - The main KM BAP indicated that direct assessment (DA) would be the technique utilized to assess the $CO_2$ lines. Although listed as the type of assessment for the $CO_2$ lines, KM stated that this was not yet a final determination, and that pilot projects with three vendors were being planned to try out and evaluate different DA techniques (likely conducted in Summer, 2003). If DA was decided upon as the assessment technique of choice, the IMPM contained requirements to notify OPS.

With respect to hydrostatic testing, the risk analysis was stated as being the place of integrating additional information such as the evaluation of corrosion issues. KM noted that the hydro would satisfy the assessment requirement, and that they intended the risk evaluation to cover additional relevant assessment issues such as corrosion.

The main KM BAP indicated that 52% of could affect mileage, representing approximately 1345 miles of pipe would be completed by the 3rd quarter of 2004. The Plantation BAP indicated that 51% of could affect mileage, representing approximately 885 miles of pipe would be completed by the 3rd quarter of 2004. In general, the higher risk sections of pipe were scheduled to be assessed as part of the first 50%. However, the Plantation follow-up identified that 9 out of the 10 highest rank segments were being assessed up to two years after segments that ranked 11 - 27. When asked, KM indicated that they were doing their long lines first in order to make more progress toward meeting the 50% milestone deadline. However, this approach appears to negate the value to be obtained from establishing a risk ranking.

While the risk analysis tool was capable of applying all of the §195.452(e)-required risk factors, the following factors were noted as not being considered, or having a documented basis for their exclusion:

- Results of previous integrity assessments (not just the fact that an assessment was performed), including previously identified defect type and predicted defect growth rate
- Repair history
- Local environmental factors such as soil corrosivity, subsidence, and climatic conditions
- Geo-technical hazards
- Physical support of a segment such as a cable suspension bridge

KM noted that by design, credit was not taken for previous ILI/pressure testing, whether potentially useful for baseline assessments or not, when doing the original "raw" risk ranking. This was stated as being the only risk analysis parameter that this approach was taken for.

An apparent inconsistency was noted of not reflecting past assessments in the risk scoring of BAP sections, but in some cases then crediting these past assessments as the baseline assessment. Subsequent to considerable discussion, KM noted that this was due to a misunderstanding of OPS expectations for crediting past assessments for line segments that did not fall within the upper 50% of risk ranked segments. The inspection team noted that past assessments could be credited for IM purposes as long as they met all qualifying criteria, regardless of where they fell within the overall risk ranking. BAP sections should be risk ranked based on all available data, without regard to any eventual impact on BAP assessment activities.

A variety of changes to the original March 31, 2002 BAP had been discussed, but the change history/basis required by 195.452(c)(2) was not included in the IMPM. KM provided a copy of the "Integrity Management Program Change Log" but actual BAP revisions were not reflected in this change log (IMPM revisions also did not appear to be directly documented in the IMPM).

**3. Integrity Assessment Results Review:** Qualifications of assessment personnel were discussed in a general way, but a description of requirements defining when an individual was considered to be a "person qualified to evaluate the results and information" as noted in the IM Rule was not contained in the IMPM.

Overall, KM ILI contractors are required to have a final assessment report completed within 60 days of tool runs being verified as being "good," with financial disincentives for each subsequent week of delay.

Requirements for ILI conditions that constitute immediate reporting were not included in the IMPM. In practice, KM noted that a >70% wall loss is used as an immediate condition for the vendor's preliminary report. Dents were not included in the vendor's immediate reporting conditions.

Vendor ILI preliminary report conditions do not include requirements to report geometry features. The inspection team noted that if current generation geometry tools have the capability to generate this information, KM should be cautious in waiting for the assessment final reports prior to responding to anomaly indications from these tools. The Plantation follow up identified a circumstance in which a dent was successfully identified and located with a current generation geometry tool prior to the integration with the MFL data. This demonstrates that it is possible to act on geometry tool results for urgent conditions. KM and its tool vendors therefore appear to have enough information to discover and remediate dents that meet immediate repair criteria prior to the integration with MFL tool data.

With respect to validation of the ILI tool results, the IMPM stated that after the vendor preliminary report is received, reported data is to be analyzed to determine if verification digs are needed. The specific criteria for whether or not digs are performed is not defined, but is left to the judgement of technical personnel. KM further clarified that in practice, a dig list is prepared for each ILI run and actual anomaly digs are used to verify the accuracy of ILI data; KM does not normally do digs solely to check pig accuracy results.

KM had not quantified reported anomaly vs. as-found anomaly data via scatter plots or unity graphs, but asserted that vendor call outs are generally more conservative than as-found conditions. The degree to which this is true, however, had not been quantified.

In addition, no specific consideration is made for tool tolerances when evaluating ILI results. Vendor data is used and engineering judgement applied for evaluating "close" anomalies. The inspection team noted that previous OPS guidance has been that tool tolerance is an important consideration and should be addressed in an appropriate manner.

To determine if anomaly locations are in HCA could affect locations, KM used the list of could affect sections in the IMPM to manually compare anomaly locations and could affect locations. The inspection team noted that the IMPM did not contain any guidance/procedure for comparing/documenting HCA locations to anomaly locations, and that this was a likely enhancement to the KM IM process.

Regarding comparison between vendor anomaly descriptions such as "ovalities," "dents," "buckles," and "flat spots" and IM Rule repair categories. KM stated that "ovality" is defined by

the vendor for specific id x id discrepancies, and noted that the determination of how dimensional anomalies are treated that are not identified as "dents" by the ILI vendor is left to the judgement of the technical analyst, given the number of possibilities.

All hydrostatic tests credited in the IM program are "subpart E" tests. KM further noted that hydro spike tests may be conducted on an as-needed basis but are not counted as "assessments."

**4. Remedial Action**: From a programmatic standpoint, repair techniques that meet IM requirements are implemented for all line piping, regardless of its status as a segment that could affect an HCA.

With respect to the pressure reduction to take upon discovery of an immediate repair condition, the amount of pressure reduction was specified as being based on the formula in Section 451.7 of ASME/ANSI B31.4. The inspection team noted that the IMPM did not address anomalies that are not addressed by the B31.4 calculations.

In the dig lists examined, there did not appear to be any type of risk-based priority. KM stated that to-date, they had identified very few anomalies under the IM Rule, and that there had been no need to do any actual rankings of anomalies. The inspection team noted that this was a requirement of the IM rule and therefore needed to be performed. Note: This issue was brought up at the Plantation exit. No changes to this writeup are needed as a result of the Plantation issue.

The declaration of discovery is not adequately addressed in Kinder Morgan procedures/manuals, thereby resulting in the inconsistent declaration of discovery dates from one district to another.

The inspection team noted that some anomalies were defined as "ovalities" by the ILI vendor. KM noted that the IM repair criteria does not address ovalities, and that the anomaly in question was dug and simply recoated. If anomalies are identified as an ovality and then discovered to be a dent, the discovery date would be declared upon the determination that a dent existed.

**5. Risk Analysis Process**: KM uses the BassTrigon (BTS) Integrity Assessment Program (IAP) with a custom "front end" prepared for KM as the basic tool for evaluating risk. IAP is basically an index model that calculates the relative risk of different pipelines. While the IAP system has the capability to model a wide variety of risk factors, KM had selected a subset of those available to perform risk analyses. No Business Impact factors had been used as part of the KM risk process.

Regarding the likelihood of failure (LOF) factors, the inspection team noted the following:

- No IAP variables had turned on for ground movement. KM stated that this was due to not having comparable data across their systems to enable a consistent treatment of this risk. KM noted that, in general, this type of "partial" information is collected and stored in the IAP database as additional information. When sufficient data is collected to do a meaningful analysis, application to the risk analysis process can be considered.
- Withing the Design Material category, the "Pipe Seam Design" factor (i.e., high or low frequency seams) could only contribute a maximum of 1.6% of the overall LOF.
- Product type was the sole factor for internal corrosion, which contributed a maximum of 24% of the overall LOF.
- SCC or cracking in general was not considered in the LOF risk factors. KM stated that they did not consider SCC to be risk on its lines due to having no operational history of cracking.
- The recent pipeline accident in Arizona has caused KM to undertake a re-evaluation of the potential for SCC.
- Although KM had historical ILI anomaly data, this information had not been used in the risk analyses conducted to-date for the IM program.

In the consequence of failure (COF) factors, only one dependency (product type) had been used for the Impact on Population factor. No dependency that considered the release volume was included in the Impact on Population factor. Overall, product type contributed a maximum of 68% to the COF value.

Overall, the risk rankings appeared to be heavily weighted toward product type. KM noted that overall risk of failure (ROF) was weighted toward the COF component, and that the COF scoring was heavily weighted toward product type. The inspection team also noted that the LOF score was also weighted up to 24% for the internal corrosion risk (as noted above, product type was the only factor considered for internal corrosion). Given this weighting arrangement, lines that transport higher risk products such as gasoline were generally calculated as higher risk lines.

To further understand algorithm weightings, the inspection team contrasted the scoring of a hypothetical new line carrying gasoline compared with an old diesel carrying line, and asked if the gasoline line would be risk ranked higher. KM stated that this would be the likely outcome, although several other variables could influence specific results.

Consequence risk factors related to HCA type (i.e., population, ecological, drinking water) appeared to reduce the risk score for lines that go through extensive HCA mileage of a single type as compared to short sections that could affect multiple types of HCAs.

Results of the risk analysis process were expressed in terms of the risk ranking of BAP sections. KM stated no formal comparison of results to leak history had been performed, but that part of the SME review considerations when reviewing results of the BAP risk ranking was their knowledge of leak history.

With respect to a past leak event on a KM $CO_2$ line, KM stated that inadvertent relief valve actuations leading to releases would not currently be captured, as this was not thought to represent a pipeline integrity issue. The inspection team noted that all losses of commodity from a pipeline were considered to be integrity issues.

KM also noted that nothing specific had been done to attempt to quantify uncertainty in results or identify any specific areas to reduce the uncertainty in estimates of risk.

Although facilities had been included in the segment identification process, KM had not performed an evaluation of risk from pipeline facilities.

With respect to plans to update IAP results, KM noted that the IAP algorithm would be reviewed annually to expand and improve, and that it is not intended to wait until the baseline assessments are complete. Regarding the impact of any risk algorithm changes on the finalized BAP, KM stated that the BAP will be reviewed on an annual basis to determine if any new information indicates the need for changes.

**6. Preventive & Mitigative Measures:** At the time of inspection, the preventive and mitigative (P&M) process had not yet been performed by KM, and limited detail of actions to be considered by the intended process had been developed in the IMPM.

The IMPM provided a high level overview of the P&M process, noting that "Integrity Management Personnel" would annually generate "a listing of potential preventative and mitigative measures in the form of scenarios that could be taken to reduce total risk in these higher risk segments."

Overall, KM noted that risk models would be reviewed and enhanced as necessary prior to exercising the P&M process, and described that the IAP structure is a hierarchical structure and algorithm pages are designed with SME input. These SME meetings have not yet been held and these models had not yet been designed.

The evaluation of P&M measures for facilities was not included in the IMPM; KM noted that the approach for analyzing the risk of facilities was expected to be different than for line pipe.

The inspection team examined the risk analysis performed to-date, to determine if all risk factors required by 195.452(i)(2) had been taken into consideration, and noted the following:

- Risk factor (viii), exposure of the pipeline to operating pressure exceeding established maximum operating pressure, did not appear to be included in the risk analyses conducted. The inspection team noted that the absence of required factors must be documented and justified.
- Regarding risk factors (v), possibility of a spillage in a farm field following the drain tile into a waterway, and (vi), ditches along side a roadway the pipeline crosses, KM noted that data had been requested from SMEs, but that no specific information had been provided due to the difficulty of acquiring accurate data
- Regarding considering risk from small leaks below detection limits that have the potential to result in large undetected releases, KM noted that the RiskCAT model does not distinguish between release rates, and that large ruptures had been used as the bounding release volume. The inspection team reiterated the concern that a broad spectrum of releases be considered to assure that all appropriate risk factors were being considered.

Operator error was not an active element in the utilized IAP model. The inspection team noted that the KM leak history indicated several events due to operator error, and that consideration of the degree of operator experience may be appropriate in the risk analysis.

There was no defined basis for P&M measure implementation decision making. Formal cost-benefit studies for making P&M decisions was not to be done in part due to the perceived difficulty of establishing benefit values (e.g., assigning value to human life).

The evaluation of leak detection systems and processes was in a rudimentary state of development, with the IMPM noting that this element of the program was still under development.

KM does not have true CPM leak detection systems, but does have “algorithmic” systems. As such, adherence to API 1130 and performing withdrawal tests are not required, but some withdrawal tests had been electively performed. It was further stated that the KM lines are normally operated in batch type of operations, and that the systems are rarely, if ever, in steady state.

KM presented example Operations procedures delineating the authority of controllers to shutdown a line without explicit approval authorization of management. It was also noted that controllers are not empowered or have the capability to change any alarm setpoints that could affect safety.

With respect to the evaluation of the need for additional EFRDs, the inspection team noted that 195.452(i)(4)-required evaluation factors require consideration of the potential for ignition, and the proximity to power sources. These factors did not appear to be included in the risk analysis process developed at the time of inspection.

**7. Continual Process of Evaluation and Assessment**. The IMPM stated that a five year assessment frequency would be applied unless analysis indicates longer or shorter periods (longer periods were noted as requiring a variance from OPS). It was also stated that the reassessment frequency analysis would consider five specific types of data to consider when making the interval determination. At the time of inspection, no reassessment interval determinations had been conducted. The inspection team noted that 5 years is not a default reassessment value, but needed to be determined for each assessment section.

Pre-70 ERW assessments were noted as using methods capable of assessing seam integrity. In addition, a supporting appendix contained a procedure for tool selection for dents and other deformations, metal loss corrosion, cracks, and long seam defects, and had a guidance form to assist in making the tool selection.

With respect to risk factors required by 195.452(e) to be considered in determining reassessment intervals, the inspection team noted that the physical support such as cable suspension bridge did not appear to be present or justified for exclusion.

Regarding the capture of new information that may cause an assessment interval to be modified, the KM process relied on the general risk analysis process to provide any required information analyses.

The IMPM contained a discussion of the limitations of pressure testing, and emphasized the use of the corrosion control program in conjunction with hydrostatic assessments. KM also noted their preference for ILI methods to perform assessments.

The inspection team noted that certain prior assessments credited as baseline assessments were conducted as early as 2000. To date, analyses to determine re-assessment intervals for these segments had not been initiated. As such, it may be difficult to comply with the risk-based assessment schedule results if there are further significant delays in making this determination.

**8. IM Program Performance Monitoring and Evaluation**: At the time of inspection, the program evaluation portion of the IMPM had not yet been implemented.

With respect to performance measures, KM noted that they prefer leading metrics (proactive) instead of lagging (reactive) metrics. Defined numerical performance goals had not been established; alternately, a defined direction (e.g., reduction in operational risk) had been identified for each metric. Trending of equipment, material failures, or near misses was not included in the defined set of metrics.

The inspection team noted that periodic self assessments, internal/external audits, management reviews, or other self critical evaluations to assess program effectiveness were not contained in the program evaluation process. It was also noted that the IMPM did not appear to provide for adequate accountability to assure communication of program performance results to management.

The TapROOT process or a Process Hazards Analysis (PHA) were referenced to perform root cause analyses. It was also noted that not all employees are trained in these processes, but specific groups such as regulatory compliance and environmental, health, and safety are trained. KM also noted that they consider these processes as folding into the IM program, but no references had been added to the IMPM. The inspection team noted the need to integrate the root cause process with the IM process, and indicated that this is another example of the type of data integration that is expected, in addition to populating the IAP database.

**OPS Feedback**:

The following summarizes OPS Inspection Team feedback to Kinder Morgan as a result of the Integrity Management inspection:

**General Comments**

1. OPS recognizes the challenge involved in developing and implementing a formalized, robust integrity management program in a large organization with significant diverse and distributed pipeline assets and people. KM has laid out an ambitious program for implementation as reflected during this inspection's discussions and in the IM Program documents. We believe that the work activities in this plan, along with the issues identified in this exit interview, are important to the further development of a fully mature program. Based on feedback received during this inspection, OPS anticipates that KM management supports the program with necessary resources to meet the currently documented program and assessment schedule.

2. Segment identification performed at 30 foot intervals is a comprehensive approach to identifying pipeline segments that could affect high consequence areas.

3. Inclusion of specific reporting time constraints in ILI vendor contracts with disincentives for delayed reporting is considered to be a strength.

4. The IAP risk analysis tool being utilized appears to have many capabilities and the potential to be a useful integrity management tool. In particular, the ability to extract the most important risk "trigger" factors is considered to be a strength.

5. BAP risk model weighting factors do not appear to reflect KM operating experience. It appears that this masks the relative importance of other significant risk contributors such as external corrosion factors, third party factors, design materials factors, etc. [2.03]

- The LOF internal corrosion weighting does not compare well with historical experience.
- The consequence of failure HCA scoring appears to have the appropriate order of priority, but a disproportionately wide range of assigned values has the effect of masking contributions from other factors.

6. The weighted averaging risk scoring methodology for BAP segments appears to reduce the relative scoring of segments that affect multiple types of HCAs. [2.03]

7. Full complement of currently available risk information has not been utilized in the risk analysis applications to-date. [2.03]

8. Given the above risk analysis considerations, the BAP prioritization may not be reflective of the relative importance of KM's integrity threats. [2.03]

9. The inspection team noted a need for improved cross referencing of appendices/ procedures with the main body of the IMP. [1.11]

10. Lack of overall guidelines for SME tasks and responsibilities to ensure company wide consistency. [1.11]

11. Personnel training requirements in the IMPM are very general, and do not provide specific technical capabilities. HR type of job description are not considered to be sufficient for this purpose. [3.01]

12. IMPM documentation requirements are very general and do not detail specific records for retention and the target locations of these records. [1.11]

13. Inspection team unable to confirm adequacy of change control process given the recent implementation of this procedure. [1.10]

**Section-Specific Comments**

<u>1.0 Segment Identification</u>

1. Local field knowledge has been collected but has not been applied to HCA changes. [1.01]

2. Facilities: Could affect analysis was based on proximity to pipeline rather than facility characteristics. Also, there was no documentation of position that potential facility release volumes into associated line pipe could not impact line release volumes. [1.04]

3. Rupture volumes were based, in part, on a two minute detection time for leak events response time (SCADA). There appeared to be insufficient documentation to support this assumption. [1.05]

4. Could Affect Release Transport Analysis [1.06]

- Assumptions for product pool depths in the indirect spread (1") and terrain analysis (1.9") were not consistent
- Assumptions for product pool depths in the indirect spread and terrain analysis did not appear to be substantiated by release history or physical commodity characteristics
- Termination criteria for terrain analysis does not account for release volumes at flat locations
- Spread distance predictions/results did not appear to be benchmarked against leak history

5. Consideration of pool fires did not appear to be considered or justified for exclusion as a potential "could affect" consideration for releases. [1.08]

6. Plantation Pipeline facilities were not included in the IMPM that was reviewed during Week 1 of the inspection. However, the list of Plantation facilities was added to the IMPM prior to Week 2 of the inspection. The inspection team reviewed the Plantation list of facilities that could affect HCAs during Week 2 and had no further issues. This potential issue is considered to be resolved. [1.02]

2.0 Baseline Assessment Plan

1. Lack of a documented technical basis for the position that pre-'70 low frequency ERW piping is not susceptible to seam failures and that KM lines are not susceptible to SCC failure. [2.01]

2. No documentation as yet to support the removal of idle lines from the BAP. [2.02]

3. IMP process did not appear to provide for flexibility to rerank BAP segments if updated information indicates a different risk than previously estimated. [2.03]

4. Decision to exclude previous hydro/ILI tests as "Qualified Prior Assessment" into the original BAP development. [2.03]

5. Changes to the BAP from 3/31/02 to the current BAP did not appear to be documented as required. [2.05]

3.0 Integrity Assessment Results Review

1. Vendor ILI preliminary report conditions do not include requirements to report geometry features. If current generation geometry tools have the capability to generate this information,

KM should be cautious in waiting for the assessment final reports prior to responding to anomaly indications from these tools. [3.02]

2. Although geometry/MFL tool runs are normally run close together, the IMPM process could be enhanced to address the discovery date for instances of widely separated tool runs. [3.05]

3. No consideration of ILI tool tolerances when evaluating assessment data. [3.03]

4. A criteria for the need for, or the number of, verification digs to validate ILI results was not included in the IMPM. [3.03]

5. Appendix H4.1 (Receive and Analyze Assessment Data - Formulate Repair Schedule) flow chart (pp. 9/9) contains an action to "Review other non-ILI related data from IMP." There appears to be no supporting process steps to implement this item. [3.04]

6. Process guidance should be expanded to include the determination and documentation of whether or not anomaly locations are in "could affect" locations. [3.05]

7. Lack of criteria for comparing vendor and field definitions of anomaly categories to IM rule definitions (i.e., "ovalities," "dents,""flat spots"). [3.05]

8. Lack of documentation of current practice of contacting ILI vendor when field calls do not match ILI vendor reports. [3.05]

9. In the "Pipeline Repair/Modification Report" forms, provisions should be provided to record as found conditions and other pertinent IM information (e.g., pipe to soil readings, anomaly field calls). [3.05]

10. KM does not adequately document the date of discovery of anomalies. [3.05]

## 4.0 Remedial Action

1. IMPM Section 7.4.1 discusses application of ASME/ANSI B31.4 formula to determine temporary operating pressure reductions. Process does not address determination of reduced operating pressure for anomalies for which this formula does not apply. Also, language in Appendix E1.2 regarding the use of $P_d$ or $P_h$ could be clarified to avoid any misapplication of reduced pressure levels. [4.01]

2. Consideration for establishing timeliness guidance for those items requiring immediate action. No deficiencies noted to-date, but may become more important as assessment activities accelerate. [4.02]

3. Dig lists were not prioritized by risk rank. KM stated that few anomalies had been identified to-date under the IM Rule, and that there had been no need to do actual ranking of anomalies. A generic implication of some of the documentation and prioritization issues observed is the management of the sequence of events associated with remediating defects. Discovery dates, shutdown dates, repair deadlines, etc., could be useful management tools to measure performance and managing resources to achieve compliance (as long as management did not push the edge of "just-in-time" compliance operations and create vulnerabilities to miss deadlines when unexpected

circumstances arise, i.e., if one manages completion of tasks to always occur just prior to the expiration of the deadline, sooner or later unexpected circumstances could cause a missed deadline). [4.02]

4. A Plantation excavation list was not implemented (i.e., all excavations were not completed as planned) nor was the list revised to document the basis for this change in remediation plan. [4.02]

5. OPS Western Region may conduct further follow up regarding LS-14 assessment results. [4.02]

6. Inspection team noted a repair using a grade B type B sleeve on X42 pipe (KM Southeastern Region example Underground Inspection/Report; 3/11-12/02). OPS Southern Region may follow up. Based on further investigation by the Southern Region and additional information provided by KM prior to the Plantation followup inspection, the repair method used was appropriate and this issue is **resolved**. [4.02]

## 5.0 Risk Analysis

The risk analysis process that has been presented includes a solid framework for effective risk analysis and risk-based decision making. OPS acknowledges that the risk analysis process undergoes an annual review and update as KM's IM program matures and the risk analysis output is needed for purposes beyond ranking segments for the Baseline Assessment Plan.

1. KM did not consider some risk factors which are required by rule to be addressed in the basis for the baseline assessment plan. These features are able to be analyzed in IAP, but were "turned off" in IAP due to reasons such as lack of quality data or consistent data across KM's diverse systems. [2.03]

- Results of previous integrity assessments (not just the fact that an assessment was performed), including previously identified defect type and predicted defect growth rate,
- Repair history,
- Local environmental factors such as soil corrosivity, subsidence, and climatic conditions,
- Geo-technical hazards,
- Physical support of a segment such as a cable suspension bridge

Other required risk factors are listed in the rule when evaluating additional preventive and mitigative actions that have not yet been incorporated into the KM risk analysis algorithms. [6.02]

2. The basis for some decisions on risk factor weighting and scoring are not documented. Some of the weights and decisions dramatically affect the risk analysis results and should be justified and documented. Examples include:

- Heavy weighting of both the LOF and COF risk scores based on product type, [5.02]
- The weighted averaging of risk scores appears to skew the results toward short lines [5.04]
- Consequence risk factors related to HCA type (i.e., population, ecological, drinking water) appear to reduce the risk score for lines that go through extensive HCA mileage of a single type (compared to short sections that could affect multiple types of HCAs) [5.02]
- ILI and pressure test history received the same score, regardless of the age of the previous assessment. Although under consideration for future use, this issue is an important issue when risk ranking the BAP. OPS acknowledges that lines without a prior assessment correctly are assigned the highest relative risk score. However, the scoring scheme could differentiate lines based on the age of previous assessments that have been performed. [5.02]

3. No documented criteria for excluding data when a full complement of data was not available. [5.03]

4. KM has not performed any confirmatory analysis to validate risk model results with actual operating history. [5.05]

5. The IM program does not address risk analysis of facilities that could affect HCAs. [5.06]

6.0 Preventive and Mitigative Measures

1. Overall P&M process is currently at a framework status. Examples of areas that may benefit from further development include the following: [6.04]

- IMPM Section 9.2.1 refers to a "scenario" evaluation process, but detailed procedure Appendix H6.1 has no reference to the utilization of scenarios.
- Appendix H6.1 does not specifically focus P&M evaluation on the higher risk locations.
- Appendix H6.1 Section 4 does not specify the documentation of evaluated, but non-implemented/suspended projects.
- IMPM 9.2.2 does not specify the "broadness" of the SME team that analyzes proposed P&M measures.
- P&M process refers to the receipt of ILI data versus "assessment" data.

2. Evaluation of facilities is not included in the P&M process. The IMPM Section 4.3 referenced "additional analysis of facilities" should be extended to the P&M process. [6.01]

3. §452(i)(2) required evaluation factor (viii), Exposure of the pipeline to operating pressure exceeding established maximum operating pressure, does not appear to have been considered in the risk analysis identified to-date. No justification for this exclusion could be located, although KM noted an ongoing surge analysis project. [6.02]

4. KM leak history indicates several events due to operator error. Operating experience can be an important consideration for the evaluation of P&M measures. As such, consideration of the degree of operator experience may be appropriate in the risk analysis. [6.02]

5. Lack of a defined evaluation criteria for determining which P&M measures will be recommended for implementation and a process to assure that recommended measures are actually implemented. [6.03]

6. IMPM Section 9.2.2, 9.2.4 refers to performance of the P&M review within 18 months after receiving ILI data or other triggering events. OPS expects that the evaluation of preventive and mitigative measures should occur within one year after assessments have been performed. [6.04]

7. The evaluation of leak detection and EFRD systems and processes is presently in a rudimentary state of development. The following is noted regarding the eventual LD/EFRD process: [6.06, 6.08]

- As noted in §452(i)(3), the leak detection evaluation process must include an evaluation of the adequacy of the current LD capabilities, as well as the need for improvements. [6.06]
- §452(i)(4)-required evaluation factors require consideration of the potential for ignition, and the proximity to power sources. These factors do not appear to be included in the risk analysis process developed to-date. [6.08]

## 7.0 Continual Process of Assessment and Evaluation

1. The program appears to have largely pre-determined that assessment intervals will default to 5 years, and that any other assessment interval would be determined by exception only. The IM Program does not explicitly require a segment-specific analysis in order to make a positive determination of reassessment interval for each segment. [7.01]

2. In Appendix H5.1, § 3.6.1.7, the note about notification refers to H5.2, "Conduct of Direct Assessment." It appears as if this should refer to H5.3, "DOT Notifications and Variances." [7.03]

3. Certain prior assessments credited as baseline assessments were conducted as early as 2000. To date, the analysis (e.g., corrosion rate analysis, crack growth analysis, fatigue cycle analysis) to determine re-assessment intervals for these segments has not been initiated. Kinder Morgan may not be able to comply with the risk-based assessment schedule results if there are further significant delays in making this determination. [7.05]

## 8.0 Program Evaluation

1. The program does not appear to provide for independent oversight such as audits, internal quality reviews, etc. [8.01]

2. The program evaluation procedures do not appear to provide for adequate accountability to assure communication of program performance results to management. Specific program elements should include oversight and follow-up of program evaluation results, findings, and recommendations by appropriate company managers. [8.01]

3. The program does not establish any performance goals, targets, or objectives for the selected performance metrics. [8.02]

4. The program evaluation metrics selected do not include threat specific metrics. [8.02]

5. The root cause analysis process and specific root cause results (for both releases and near-miss events) are not currently integrated with the IM program. This is another example of the type of data integration that is expected, in addition to populating the IAP database. [8.04]

# Kinder Morgan Integrity Management Inspection
# Executive Summary

| | |
|---|---|
| Inspection Date(s): | April 07 – 11, April 21 – 25, and June 24 – 25, 2003 |
| Location: | Orange Co., CA and Doraville, GA |
| Lead Inspector: | Byron Coy (Eastern Region) |
| Operator Representative: | Buzz Fant, Integrity Management |
| Executive Contact: | Tom Jensen, VP, Engineering |

## System Overview

1. Kinder Morgan operates a number of refined products, LNG, and $CO_2$ systems (including systems acquired in mergers/acquisitions), including CalNev, Santa Fe Pacific, Plantation, MidCon, LQT, KMI (Texas Pipelines), Central Florida Pipelines, and KM $CO_2$ Pipelines.
2. KM operates approximately 8443 miles of interstate lines and 1065 miles of intrastate lines.
3. KM has a separate baseline assessment plan for its Plantation and Central Florida Systems due to shared ownership issues.

## Integrity Management Program - Summary Conclusions

Program Strengths

1. Kinder Morgan's contract with ILI vendors includes specific time deadlines for submitting final reports with financial disincentives for untimely submittal of final reports. This approach to assuring timely discovery of conditions that require remediation is considered to be a strength.
2. Kinder Morgan has taken a thorough approach to determining if releases could affect HCAs by analyzing postulated leak scenarios at 30-meter intervals along the pipeline.

Most Significant IM Program Concerns/Issues

1. Kinder Morgan's Risk Model uses weighting factors and risk scoring methods that do not appear to reflect actual experience nor do they appear to reflect the true risks associated with the pipelines. As a result, the risk ranking and the Baseline Assessment prioritization may not be reflective of the risk conditions of Kinder Morgan's pipelines. For example:
   - 1.1. Product type, which is the sole internal corrosion risk factor, is weighted 15 times heavier (i.e., is evaluated as 15 times riskier) than most other significant risk factors, including stress corrosion cracking (SCC), longitudinal seam type, construction activity, wall thickness, coating age, soil type, etc. Kinder Morgan has never experienced an internal corrosion release in its history and has no particular indicator that internal corrosion is such a significant risk.
   - 1.2. The full complement of available risk-related information has not been used in the risk analysis conducted to date. For example, Kinder Morgan uses only two consequence-related risk factors, the type of HCA and the type of product. Other significant consequence factors (e.g., spill volumes) are not used.
   - 1.3. Consequence risk factors related to HCA type (i.e., population, ecological, drinking water) appeared to reduce the risk score for lines that go through extensive HCA mileage of a single type as compared to short sections that could affect multiple types of HCAs.
   - 1.4. The method used to develop a weighted average risk score on an "average risk per mile" basis appears to mask lines with significant risk and tends to rank long lines that affect many HCAs inappropriately low.
2. Portions of Kinder Morgan's system contain low frequency ERW piping, but these lines were not considered to be susceptible to seam failures. Kinder Morgan did not have an adequate justification for this position and further review may be necessary to determine if Kinder Morgan's position is technically justified.

## Significant Pipeline Integrity Issues and Insights

1. The inspection team noted that little data on pipeline integrity issues was available due to the relatively low number of assessments that had been completed to-date.
2. On four occasions, Plantation system has shutdown lines due to immediate repair conditions. (12" line in MS due to corrosion; a 6" line in VA due to top-side dents; a 12" line in Atlanta due to top side dents; and a 26" line in SC due to mechanical damage.) Kinder Morgan shut these lines down instead of taking a pressure reduction.

**Kinder Morgan Energy Partners**
**Integrity Management Program Inspection**
**Executive Summary**

| | |
|---|---|
| Inspection Date(s): | September 25 – 29, October 10 – 12, and October 30 – November 2, 2006 |
| Location: | Houston, TX, Alpharetta, GA, and Orange, CA |
| Lead Inspector: | Chris McLaren |
| Operator Representative: | Mike Outlaw, Director of Pipeline Integrity |
| Executive Contact: | Ron McClain, Vice President Operations and Engineering |

## System Overview

Kinder Morgan Energy Partners (KMEP) is divided into ten (10) operating systems and four (4) operating regions (Pacific; Central; Eastern; and West Texas Crude & $CO_2$). The systems and summary mileage associated with each system is summarized in the following table.

| OP ID | System Name | System Mileage | HCA Mileage | Baseline HCA Miles Assessed |
|---|---|---|---|---|
| 2190 | Central Florida Pipeline | 201 | 164 | 155 |
| 4472 | Kinder Morgan Energy Partners LP | 1681.22 | 901 | 561.7 |
| 15674 | Plantation Pipeline Co. | 3140 | 2139 | 1652 |
| 18092 | Santa Fe Pacific Pipeline | 2756.48 | 1729.3 | 1372 |
| 26041 | Kinder Morgan Liquids Terminals | 78.87 | 75.88 | 64.24 |
| 26125 | CalNev Pipeline Co. | 557.39 | 377.8 | 375.06 |
| 31344 | Heartland Pipeline Co. | 51.6 | 9.3 | 9 |
| 31451 | Kinder Morgan Texas Pipeline | idled & purged | 0 | 0 |
| 31555 | Kinder Morgan $CO_2$ | 1196 | 139 | 167 |
| 31957 | Kinder Morgan Wink Pipeline | 459 | 44 | 42 |
| | Total Mileage | 10121.56 | 5579.28 | 4258 |

## Integrity Management Program - Summary Conclusions

Program Strengths

1. KMEP has taken ownership of their IMP as shown through the significant program improvement that has been accomplished since the first Integrity Management Inspection.
2. Through December 2005 KMEP has assessed a total of 4258 miles of the 5579 miles that can affect an HCA. This is approximately 76% of their total could affect an HCA segment miles.

Most Significant IM Program Concerns/Issues

1. KMEP's discovery process requires that a minimum of one validation dig be conducted for each ILI tool run within 60 days of receiving the final report. A consumption of 60 days for validating the results of the ILI report and conducting validation dig delays declaration of discovery of anomalous conditions and potentially delays the repair of anomalies meeting 60-day criteria beyond the required timeframe.
2. KMEP's hydrostatic pressure test re-assessment interval evaluation does not specify what standards are used for threats to justify the establishment of reassessment intervals.

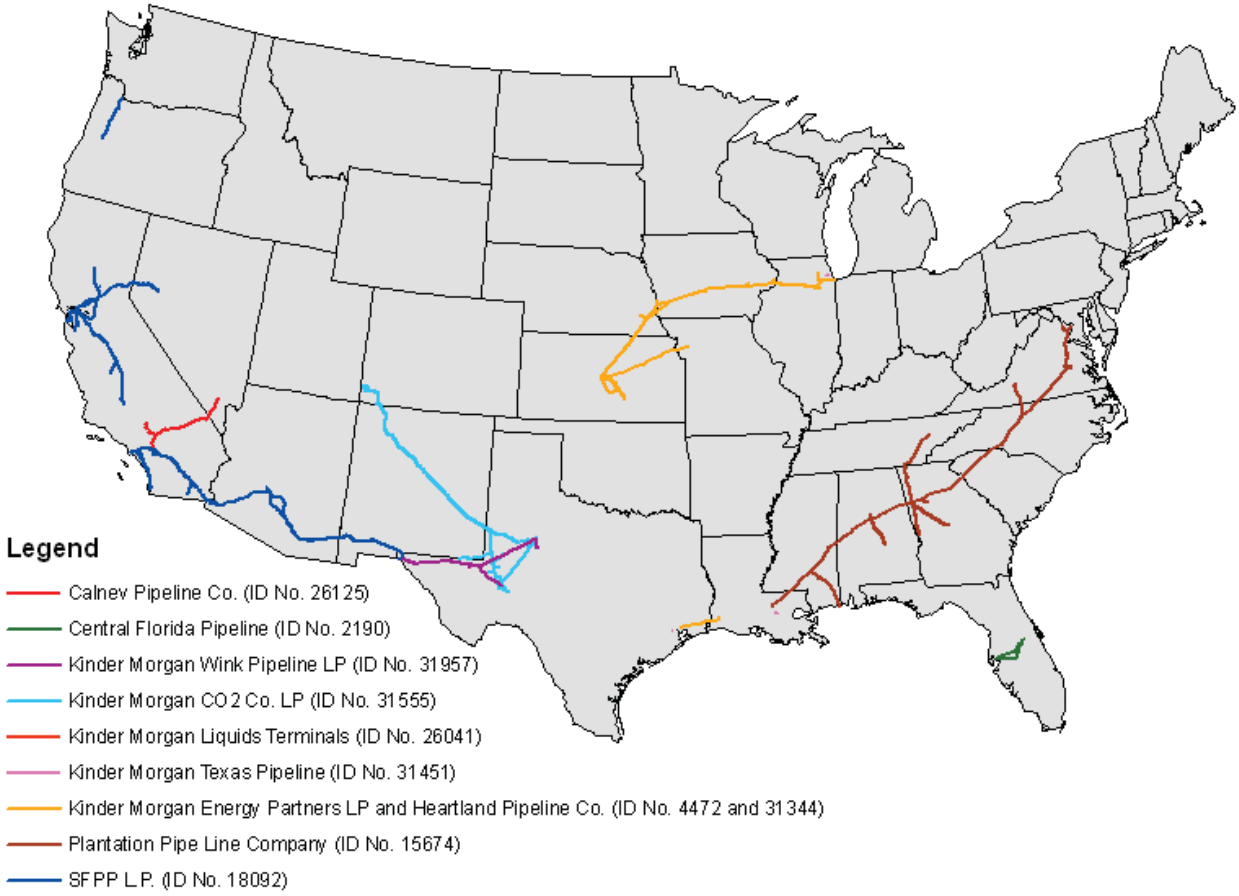
November 7, 2006

3. Seven pipeline segments have not been re-assessed within the maximum 5-year re-assessment interval required by §195.452(j)(3) with the appropriate notification, and those segments are: LS-64, LS-14, LS-122, GX64A 14", GX64B 14", GX32 10"/12", and PL-119.
4. An anomaly classified as a 60-day repair on PL-107, Morris to Lemont, IL was not discovered or remediated within required timeframes.
5. The ECDA program requires revision to add additional program formality to meet the requirements of §195.588 and NACE RP 0502. IMP Appendix H8.2 provides the broad requirements for a DA plan; however, the DA procedure must contain the detail necessary to specify the requirements of the IM rule and associated NACE RP 0502 standard.

**Significant Pipeline Integrity Issues and Insights**

1. CPF No. 1-2004-5004 item 1 noted that KM excluded LFERW and SCC threats from risk analysis without adequate technical justification. As part of the effort to remedy this deficiency, KMEP has determined that they will be unable to complete assessments for these threats prior to the compliance deadline of March 31, 2008. An alternative proposal was provided to PHMSA-HQ by KMEP on October 25, 2006. This proposal suggested that the assessments be completed by 2010.

The following is the KMEP company-wide system map for those assets covered by the current IMP (i.e. excludes KM Canada which is comprised of the acquired Terasen assets):



# US Department of Transportation
# Pipelines and Hazardous Materials Safety Administration
# Pipeline Safety

# Integrity Management Program
# 49 CFR 195.452

# Kinder Morgan Energy Partners
## Hazardous Liquid Integrity Management Program Inspection
## September 25 – 29, October 10 – 13, and October 30 – November 2, 2006

# Integrity Management
# Inspection Protocols

**October 2006**

# Table of Contents

## Explanation of Inspection Form Format

The next two pages provide a brief description of each item in the Integrity Management Inspection Form.

| | |
|---|---|
| **Protocol #** | *Keywords reflecting the subject area of the Protocol Question are entered here. Each question has a unique number, as indicated to the left.* |
| **Protocol Question** | *Question to be answered in reviewing an operator's Integrity Management Program or the implementation of its Program.*<br><br>*Questions in the Integrity Management Inspection Protocols generally cover two main aspects of an operator's Program: One part deals with the inspection of a particular aspect or feature of the operator's Integrity Management processes, procedures, technical methods, etc. The second part addresses how effectively the operator has implemented that process and the results that have been obtained.* |

*This section contains additional guidance and items for consideration by the inspector in reviewing operator response to the protocol question. This guidance presents characteristics typically expected in an effective Integrity Management Program consistent with the intent of the Rule. Some, all, or none of these characteristics may be appropriate depending on factors unique to each protocol, and the operator's Integrity Management Program and its pipeline assets. Operators should be able to demonstrate that their programs address each of these characteristics or should be able to describe how their program will be effective in their absence.*

*For some protocol questions, this portion of the inspection form is also used to articulate specific prescriptive requirements in the Rule. These requirements are mandatory for all Integrity Management Programs.*

| | |
|---|---|
| **Rule Requirement** | *Reference to related rule requirement(s)* |

| | |
|---|---|
| **Inspection Issues Summary** | *This space is provided to record any issues or concerns the inspector identifies in reviewing the operator's response to the protocol question.* |

| **Inspection Results** *The boxes to the right are checked based on the information supplied in the Summary.* | | **No Issues Identified** |
|---|---|---|
| | | **Potential Issues Identified (explain in summary)** |
| | | **Not Applicable (explain in summary)** |

**Documents Reviewed:** *Documents reviewed in answering the Protocol Question are listed below.*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | | |
| | | | |
| | | | |

**Inspection Notes:**

*This section is provided to record more detailed information about the operator's program obtained during the review of the operator's response to the protocol question. For protocol questions dealing with the implementation of a particular facet of an operator program, a summary of the records review is entered at this location.*

| **Issue Categorization** | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|
| *For each potential issue, type an "X" in the first column for the one "best fit" Issue Category. A risk category (A-E) can then be assigned for each checked issue, based on guidance provided in the Area Finding / Risk Factor Reference Table (http://primis.phmsa.dot.gov/imdb/Library.imd). The "Area Finding" column provides a cross-reference to the applicable Area Finding in the Area Finding / Risk Factor Reference Table.*<br><br>*Note: The Risk Category need NOT be filled in for State inspections. If the Risk Categories are not filled-in, select the option that imports Issue Categories but not risk categories, when "importing" the protocols to IMDB.* | | |

# Integrity Management

## Inspection Form

**Name of Operator: Kinder Morgan Energy Partners (KMEP)**

**Headquarters Address:** 500 Dallas St. Suite 100, Houston, TX 77002

**Company Official:** Ron McClain, Vice President Operations and Engineering

**Phone Number:** 713-369-9356

**Fax Number:** 713-495-7432

**Operator ID:** 2190, 4472, 15674, 18092, 26041, 26125, 31344, 31451, 31555, 31957

**Activity ID:**

| Persons Interviewed | Title | Phone No. | E-Mail |
|---|---|---|---|
| **Primary Contact:** Mike Outlaw | Director, Pipeline Integrity | 713-369-9433 | mike_outlaw@kindermorgan.com |
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| Scott Davis | Director Pipeline Engineering | 714-560-4822 | daviss@kindermorgan.com |
| F. Bryant Dicks | Manager Pipeline Engineering, Southeast Region | | bryant_dicks@kindermorgan.com |
| Noel Duckworth | Director SP Integrity Management | 713-369-8025 | noel_duckworth@kindermorgan.com |
| David Edwards | Corrosion Process Manager | | edwardsd@kindermorgan.com |
| Buzz Fant | Director Codes & Standards | | buzz_fant@kindermorgan.com |
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| | | | |
|---|---|---|---|
| Carlos Munguia | Director Engineering and Maintenance | | carlos_munguia@kindermorgan.com |
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| Ron Sherstan | Senior Risk Engineer | 713-369-8041 | ron_sherstan@kindermorgan.com |
| Dave Tammen | Director MidCon System | | tammend@kindermorgan.com |
| Joe Woodford | Senior Engineer | | joe_woodford@kindermorgan.com |

**Dates: September 25 – 29, October 10 – 12, and October 30 – November 2, 2006**

**PHMSA/State Representatives:**

| | | | |
|---|---|---|---|
| Chris McLaren | Inspection Team Lead Southwest Region | 713-272-2847 | chris.mclaren@dot.gov |
| Theresa Bell | Dept of Interior, MMS | 805-389-7554 | therese.bell@mms.gov |
| Huy Van Nguyen | Staff Engineer, Western Region | 720-963-3174 | huy.v.nguyen@dot.gov |
| Corky Hanson | Senior Pipeline Engineer, AZ | 602-262-5601 | chanson@azcc.gov |
| Tin Tran | Senior Deputy State Fire Marshall, California | 916-445-8357 | tin.tran@fire.ca.gov |
| Derick Turner | Project Manager / Senior Engineer, Southern Region | 404-832-1156 | derick.turner@dot.gov |
| Byron Coy | Project Manager | 609-989.2180 | byron.coy@dot.gov |
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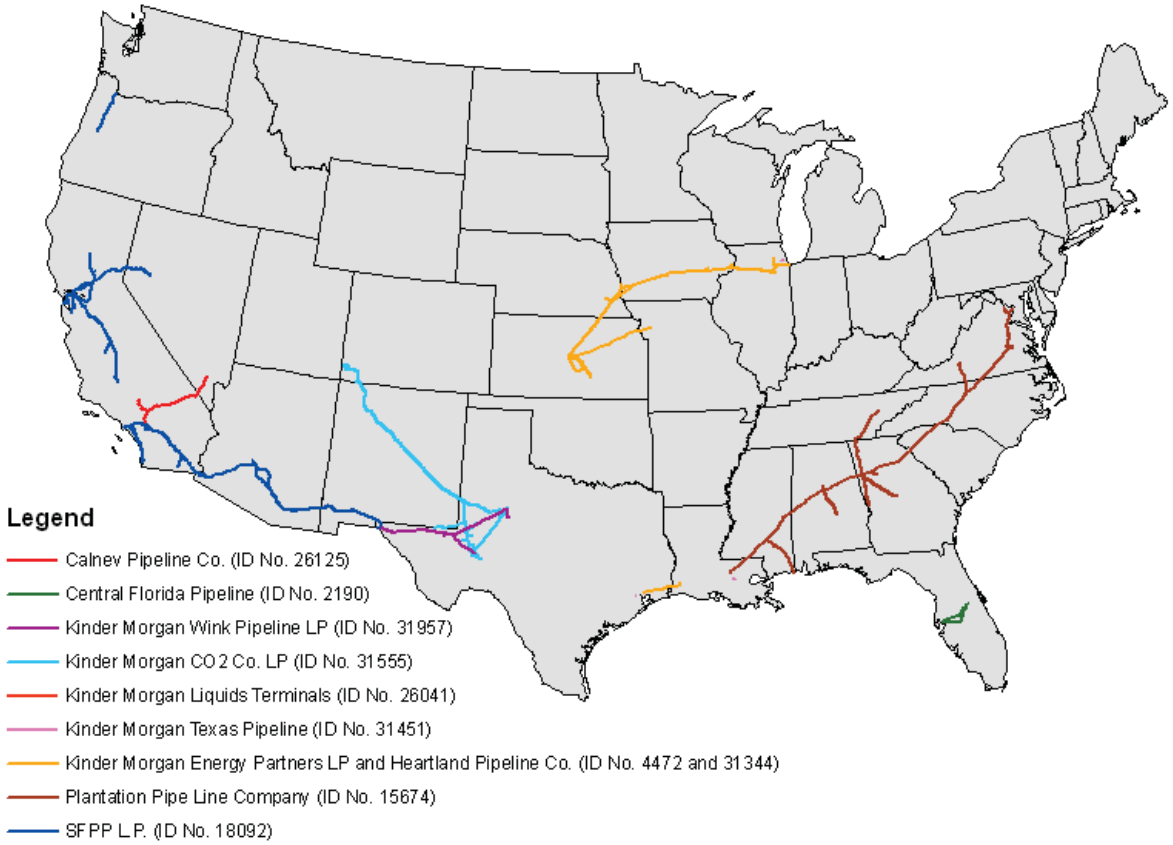
| Doug Allen | State Fire Marshal Pipeline Safety Engineer | 916-455-8345 | doug.allen@fire.ca.gov |
| Tim Floyd | Consultant, Cycla | 865-803-3296 | timf@cycla.com |
| David Kuhtenia | Consultant, Cycla | 740-548-4930 | davidk@cycla.com |

**System Description:**

Kinder Morgan Energy Partners (KMEP) is divided into ten operating systems. The systems and summary mileage (as reported in PHMSA F 7000-1.1 and the Continuing Assessment Plan as of December 2005) associated with each system is summarized in the following:

| OP ID | System Name | System Mileage | HCA Mileage | Baseline HCA Miles Assessed |
|---|---|---|---|---|
| 2190 | Central Florida Pipeline | 201 | 164 | 155 |
| 4472 | Kinder Morgan Energy Partners LP | 1681.22 | 901 | 561.7 |
| 15674 | Plantation Pipeline Co. | 3140 | 2139 | 1652 |
| 18092 | Santa Fe Pacific Pipeline | 2756.48 | 1729.3 | 1372 |
| 26041 | Kinder Morgan Liquids Terminals | 78.87 | 75.88 | 64.24 |
| 26125 | CalNev Pipeline Co. | 557.39 | 377.8 | 375.06 |
| 31344 | Heartland Pipeline Co. | 51.6 | 9.3 | 9 |
| 31451 | Kinder Morgan Texas Pipeline | idled & purged | 0 | 0 |
| 31555 | Kinder Morgan $CO_2$ | 1196 | 139 | 167 |
| 31957 | Kinder Morgan Wink Pipeline | 459 | 44 | 42 |
| | Total Mileage | 10121.56 | 5579.28 | 4258 |

The following is the company-wide system map:



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# Integrity Management
# Inspection Protocol 1

# Identification of Pipeline Segments
# That Could Affect High Consequence Areas

**Scope:**

This Protocol addresses the identification of pipeline segments that could affect one or more HCAs. This Protocol addresses all of the steps to perform the segment identification, including identification of HCAs, correlation of HCAs to pipeline locations, commodity transport to HCAs from spills located outside of HCA boundaries, buffer zones, and justification for excluding segments physically located within a HCA. This Protocol does not address how the segment identification results are further used in other Integrity Management (IM) Program elements.

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| Protocol # 1.01 | Segment Identification: HCA Identification |
|---|---|
| **Protocol Question** | Does the process to identify segments that could affect HCAs include steps to identify, document, and maintain up-to-date geographic locations and boundaries of HCAs using the NPMS and other information sources as necessary?<br>———————<br>Verify that the operator correctly identifies and maintains up-to-date locations and boundaries of HCAs using NPMS and other information sources as appropriate for all states/regions in which it operates. |

An operator's process to identify pipeline segments that could affect HCAs must identify the location of HCAs that could be affected by pipeline failures. To accomplish this step, the operator's documented IM process would be expected to include the following elements:

1. The use of NPMS (or equivalent sources) to identify HCAs.
2. Adequate measures to identify drinking water USAs in New York State and ecological USAs in Pennsylvania, if applicable.
3. Adequate provisions to assure that local knowledge, information obtained from routine field activities (e.g., ROW surveillance, aerial surveys), and other information sources are used as required to supplement NPMS data in order to accurately reflect current conditions in the vicinity of the pipeline.
4. Provisions for periodic review and update of HCA boundaries, including timely use of revised NPMS data and local information in the update (e.g., per the requirements of §195.452 (d)(3)).

| | |
|---|---|
| **Rule Requirement** | §195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (1) A process for identifying which pipeline segments could affect a high consequence area. |
| | §195.450 Definitions. A high consequence area means: (1) A commercially navigable waterway, which means a waterway where a substantial likelihood of commercial navigation exists; (2) A high population area, which means an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile; (3) An other populated area, which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area; (4) An unusually sensitive area, as defined in §195.6. |
| | §195.6 Unusually Sensitive Areas (USAs). As used in this part, a USA means a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release… |

| 1.01 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**1.01 Inspection Issues Summary**

**1.01 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| Appendix H4.2 | 6 | 8/21/06 | Identify HCAs (Annual/New/Acquired) |
| Appendix H4.3 | 5 | 10/28/05 | Calculate Volume Release Data |
| | | 8/28/06 | Integrity Management Program Manual |

**1.01 Inspection Notes**

IMPM 4.4.1 notes that all KMEP operated pipelines have been digitized and have been submitted to the NPMS in accordance with the requirements of the Pipeline Safety Act of 2002. Updates to the pipeline centerline shapefiles are incorporated into the program on an annual basis following the completion of the annual HCA verification process described in IMPM Section 4.4.7. These pipeline centerline shapefiles are used for determining the potential impact to HCAs. On an annual basis, KMEP incorporates additional HCA information mapped by the NPMS, as it becomes available. The KMEP plan includes an annual reanalysis of the potential impact of HCAs by KMEP pipeline segments.

KMEP procedure H4.2 Section 4.1.1 requires that the KMEP Risk Management Team collect updated KMEP pipeline data and HCA data available from the National Pipeline Mapping System (NPMS). Section 4.1.2 requires that for KMEP pipelines not defined in the NPMS new shapefiles are to be generated as required. Copies of new shape files are distributed to the Drafting Department for their use in NPMS notification process. Under the supervision of the KMEP Manager, Pipeline Risk Analysis, the KMEP Business Unit Integrity Management Teams validates the population HCA data reported by NPMS by direct comparison of HCA data and field conditions. The following information is to be reviewed and documented on Form H4.2-01, High Consequence Area Map Checklist.

- Ensure pipeline segments for each local operation area are included and complete.
- Identify recently Idled pipelines.
- Identify pipeline routing irregularities not shown in the information.
- Ensure DOT regulated facilities (breakout terminals, boosters, meter stations, etc.) associated with each pipeline segment are included and complete.
- Identify population sensitive areas along the pipeline right-of-way or adjacent to breakout facilities that have changed significantly from those shown in the data.
- Identify areas where, due to extraordinary circumstances, population sensitivity may be extra high. Pipelines close to schools, hospitals, or other areas of high-density population, or areas with previous known problems might pose special issues.
- Determine additional information on population centers, areas of high population concentration, and other high consequence areas known to local field personnel that are not shown in the data.
- Collect field maps and other review material and report results to the KMEP Risk Management Team.

IMPM 4.4.5: Facilities include DOT jurisdictional terminals, pump stations and meter stations. DOT regulated facilities are identified by the KMEP Business Unit Integrity Management Teams and are listed in Appendix B2.1 (HCA Segments Method) and Appendix B2.2 (Screening Analysis Method) The DOT regulated facilities in Appendix B2.2 are digitized by KMEP and are included on the HCA Maps described in Section 4.4.10. Updates to the facility shapefiles are incorporated into the program on an annual basis following the completion of the annual HCA verification process described in Section 4.4.9. The facility shapefiles are used for determining the potential impact to HCAs.

IMPM 4.4.6: Newly constructed facilities or facilities converted for service are included in the IMP within one year of being placed in service and will include notifications through the Management of Change process. Facilities that could affect HCAs will be identified before the facility is placed in service. Facilities obtained through acquisition will be reviewed and incorporated into this IMP program within one year of assumption of operational responsibility.
Appendix H4.2 Section 4.2.2: see above

The annual update is conducted in the July – December timeframe each year. New Century Sheet Cutter software is used to overlay the pipeline on the maps. KMEP has identified HCAs other than those identified by NPMS. Imperial County near El Cento, CA is an HCA identified by field personnel that is not included in NPMS. The Mid-Con – Minooka segment was identified as a new HCA that was not identified by NPMS (PL-316 8" Morris to Exxon Mobile).

HCA Map Checklist Form sent to the field to identify new HCAs (Form H4.2-01). This form documents changes to population density. Line riders and ROW technicians are used in the process. Pipeline pilots provide information to the areas on regular basis. This aerial information is considered by the field personnel.

| **1.01 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **1.01.01** | HCAs were not adequately identified and located | AF 1.1 | |
| | **1.01.02** | Periodic re-examining and updating of the list and boundaries of HCAs was not adequately required | AF 1.2 | |
| | **1.01.03** | Analysis of updated HCA location information to determine if changes to the segment identification results are necessary was not adequately required | AF 1.2 | |
| | **1.01.04** | Use of local knowledge, field personnel input, and other sources to update HCA location information was not adequately required | AF 1.3 | |
| | **1.01.05** | Requirements to update the segment identification were not adequately implemented | AF 1.2 | |
| | **1.01.06** | HCA identification for new or acquired pipe was not adequately required | AF 1.5 | |
| | **1.01.07** | Segment identification analysis were revised following the receipt of assessment results in order to avoid remediation of anomalies | AF 1.2 | |
| | **Other:** | | | |

| Protocol # 1.02 | Segment Identification: Direct Intersect Method and Direct Intersect Exceptions |
|---|---|
| **Protocol Question** | Does the operator have an adequate process to determine all locations where its pipeline system is located in an HCA? If applicable, has the operator developed and documented an adequate and convincing technical justification for concluding that any segments located in an HCA could not affect the HCA in the event of a release?<br><br>Verify that the operator determined all locations where its pipeline system is located in an HCA (i.e., determine if the operator correlated its complete pipeline system(s) maps with the HCA maps, and identified areas where the pipeline system intersects an HCA). Determine if the operator has taken exception to any segments that directly intersect an HCA. If so, verify that the operator has provided an adequate and convincing technical justification for that conclusion. |

The purpose of this question is to review the operator's identification of intersections between the operator's pipeline and HCAs and the operator's technical justification for excluding any segments that directly intersect an HCA. An effective operator process for identification of these intersections would be expected to have the following characteristics:

1. The process requires that segments that are physically located within HCAs are identified and defined by specific locations that represent the place where the pipeline actually intersects that HCA boundary. (The entire segment that could affect the HCA could be much larger based on transport analysis.)
2. The process requires that pipeline facilities that are located in HCAs are identified (not just line pipe).
3. Any GIS or other mapping software used by operators employs a valid analysis algorithm or methodology to identify segments that intersect HCAs.
4. Any manual analysis techniques used by operators employ a valid analysis technique or methodology to identify segments that intersect HCAs.

§195.452 (a) presumes that a pipeline segment within a HCA could affect that HCA. If the operator concludes that some segments within HCAs could not affect the HCAs, then a technical justification for this conclusion is required. If the operator intends to maintain any segment intersecting a HCA could not affect that HCA, then an effective operator process would be expected to include provisions for such a technical justification with the following characteristics:

1. Guidance for performing an analysis to substantiate the conclusion that a pipeline segment located within an HCA could not affect the HCA.
2. An adequate level of rigor specified for any analysis that is used to justify the conclusion that a segment located in an HCA could not affect the HCA.
3. A valid analysis to justify the conclusion that a pipeline segment located within an HCA could not affect the HCA. The operator's analysis should consider the following factors:
    - HVL properties.
    - Topographical considerations.
    - HCA properties.

| | |
|---|---|
| **Rule Requirement** | §195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program:<br>(1) A process for identifying which pipeline segments could affect a high consequence area. |
| | §452 (a) *What pipelines are covered by this section?* The section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. |

| 1.02 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**1.02 Inspection Issues Summary**

**1.02 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix B1.1 | | 8/3/06 | RiskCAT Identification Process |
| Appendix H4.2 | 6 | 8/21/06 | Identify HCAs (Annual/New/Acquired) |

**1.02 Inspection Notes**

IMPM 4.4.4 notes that KMEP used the BTS [RiskCAT] software to identify three potential impact zones to an HCA. A more detailed discussion of the HCA identification process is contained in Appendix B1.1, RiskCAT Identification Process. Direct Impact Zones are locations at which the pipeline exists within (intersects with) an HCA. This analysis identifies points at which a pipeline enters and exits an HCA. Indirect Impact Zones are locations at which the pipeline is in proximity to an HCA. This analysis involves calculating the rupture volume for each pipeline segment and then assumes a pipeline rupture on 30-foot increments along the segment. Potentially impacted HCAs are then identified when impacted by this expanded area of potential influence. The rupture volume assumes 15 minutes of full flow before the pipeline is shut down plus the pipeline volume of drain down based on elevation, limited by applicable EFRDs. Pipeline shut down may occur more rapidly than 15 minutes after rupture; however as a conservative measure, 15 minutes is applied to KMEP pipelines. The transport analysis techniques used to identify HCA impacts, which are performed independent of the volume of fluid released, would also identify potential HCA impacts in the event that the small release traveled downhill or along a water conduit. Thus, the assumption to only consider the impact associated with a full volume rupture in the HCA impact identification process is conservative and will result in equal to or larger areas of impact along KMEP pipelines.

Appendix H4.2 Section 4.2.2: Under the supervision of the KMEP Manager, Pipeline Risk Analysis, the KMEP Business Unit Integrity Management Teams validate the population HCA data reported by NPMS by direct comparison of HCA data and field conditions. The following information shall be reviewed and documented on Form H4.2-01, High Consequence Area Map Checklist.

- Ensure pipeline segments for each local operation area are included and complete.
- Identify recently Idled pipelines.
- Identify pipeline routing irregularities not shown in the information.
- Ensure DOT regulated facilities (breakout terminals, boosters, meter stations, etc.) associated with each pipeline segment are included and complete.
- Identify population sensitive areas along the pipeline right-of-way or adjacent to breakout facilities that have changed significantly from those shown in the data.
- Identify areas where, due to extraordinary circumstances, population sensitivity may be extra high. Pipelines close to schools, hospitals, or other areas of high-density population, or areas with previous known problems might pose special issues.

- Determine additional information on population centers, areas of high population concentration, and other high consequence areas known to local field personnel that are not shown in the data.
- Collect field maps and other review material and report results to the KMEP Risk Management Team.

IMPM Appendix B1.1 Section 1.2.1: For the Direct analysis, the RiskCAT software is used to perform a spatial analysis between the HCA and pipeline location data. This process determines the location of pipelines within HCAs. In RiskCAT, the pipeline is shown as a black line and the Drinking Water shape files are shown as blue polygons. The RiskCAT Direct Analysis designates the region of pipeline inside the DW HCA as the solid blue portion of the line. The supporting details associated with the HCA are listed in an accompanying database table.

IMPM 4.4.7: The HCA analysis methods typically result in line pipe inside facilities being classified as having the same potential to impact HCAs, as the incoming and outgoing pipelines to the facility. Buffer zones are also included in the above analysis due to the increased pressures associated with pump stations. Where this may not apply, for example at large breakout facilities, KMEP also employs a "could affect" screening process to identify HCA Facilities. HCA Segment Method KMEP utilizes the HCA analysis results of the first 1,000 feet of previously identified incoming or outgoing HCA Segments to DOT regulated facilities to determine HCA Facilities. The HCA Facilities identified by this method are listed in Appendix B2.1. KMEP also utilizes a screening analysis to identify HCA impacts for DOT regulated facilities that are not identified by the HCA Segment Method. The screening process consists of evaluating each facility using GIS and HCA data (see Appendix B2.2, Screening Analysis Method) to determine if the facility directly intersects an HCA or is within a 35¬mile radius of an HCA. Breakout Tank Volumes Breakout facilities have the potential of adding additional spill volume to the incoming and outgoing pipelines to the facility. This information will be documented for each HCA Facility listed in Appendix B2.2 as described in Procedure H9.4, Facilities Risk Analysis and Prevention and Mitigative Measures Evaluation. Facility breakout tanks with the potential to back feed spill volumes into HCA Segments will be identified and the calculated worst case spill volume will be added to the HCA Segment(s) during the annual HCA Identification process described in Section 4.4.4.

IMPM 4.4.10 - Detailed maps with Pipeline Facility and HCA information for each local area are available within each area and can be accessed from the KMEP internal website. Drawings are reviewed annually by Business Unit Integrity Management Teams, and updates are sent to the KMEP Manager, Pipeline Risk Analysis. The KMEP Risk Management Team updates maps as necessary, and current master copies are maintained on the website. For more detail, consult Procedure H4.2, Identify HCAs (Annual/New/Acquired).

IMPM 4.4.10.1 – KMEP practices prescribe that pipeline segments are identified as HCA segments if they are determined to have direct, indirect, or potential transport impact zones during RiskCAT analysis. If it is decided to remove identified HCA segments from consideration, procedures for analyzing HCA impacts and justifying the basis for removal will be developed.

| **1.02 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **1.02.01** | Pipeline segments located within HCAs were not adequately considered or included in the segment identification analysis or results | AF 1.4 | |
| | **1.02.02** | An analytical method or software was used whose algorithm does not correctly identify the boundaries of segments that are within, or could affect, HCAs | AF 1.1 | |
| | **1.02.03** | Idle lines were not included in segment identification analysis or results | AF 1.4 | |
| | **1.02.04** | Adequate justification was not provided for the categorical exclusion of the potential effect of HVL release on drinking water or ecological USAs | AF 1.1 | |
| | **1.02.05** | The exclusion of segments intersecting an HCA was not | AF 1.1 | |

| | | | | |
|---|---|---|---|---|
| | | adequately justified | | |
| | **1.02.06** | Facilities located within HCAs were not adequately considered or included in the segment identification results. | AF 1.7 | |
| | **Other:** | | | |

| Protocol # 1.03 | Segment Identification: Release Locations and Spill Volumes |
|---|---|
| **Protocol Question** | Does the operator's segment identification analysis process include a technically adequate method to determine the locations/scenarios and volume of potential commodity releases?<br>Verify that the operator's identified release locations and spill volumes are appropriate, technically adequate, and determined consistent with its documented process. |

The operator's approach for analyzing the potential effects of pipeline failures that could affect HCAs must define potential locations on the pipeline where releases could occur. An effective operator program would be expected to consider the following elements:

1. Proximity to water crossings;
2. Variations in topography near the line;
3. Variations in distance between the pipeline and the HCA (for HCAs that do not intersect the pipeline);
4. Adequate choice of release locations, if fixed spacing along the pipeline is used in the definition of locations;
5. Consideration of spills involving pipeline facilities (e.g., breakout tanks).

Analyzing the potential effects of pipeline failures that could affect HCAs involves estimating the volume of commodity that could be released in the event of a failure. An effective operator program would be expected to include appropriate treatment of the following factors that affect estimation of spill volume:

1. Failure hole size (see note);
2. Operating conditions (e.g., flow rate, operating pressure);
3. Leak detection and response time;
4. Calculations of drain down following leak or rupture;
5. Release rate estimates, if air dispersion of vapor clouds is a transport mechanism that is applicable to the operator's system; and
6. Pipeline system design factors (e.g., pipe diameter, distance between isolation valves, location of tanks and other facilities).

If the operator's approach to identify segments that could affect HCAs involves the definition of a spill buffer zone, then the basis for the defined buffer distance would be expected to include appropriate treatment of the above factors.

Note: Because an adequate spill volume analysis may require consideration of various scenarios and combinations of assumptions regarding different variables, the operator's release estimate analysis would be expected to include a sensitivity analysis to variations in assumptions, including consideration of both catastrophic failure and leaks below detection limits.

| | |
|---|---|
| **Rule Requirement** | §452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program:<br>(1) A process for identifying which pipeline segments could affect a high consequence area. |

| 1.03 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**1.03 Inspection Issues Summary**

The Inspection Team had concerns that the HCA "could affect" analysis had not adequately considered situations where a pipeline release is due to a slow pipeline leak condition (seeper) vs. the KMEP analyzed rapid full volume release assumptions. A basis for assumptions (e.g.; comparisons with industry and operator specific data) that the full guillotine release bounds a potential slow release should be included as part of the IMP documentation. The Inspection Team reviewed information provided by KMEP that included historical information to substantiate their position that full rupture volumes bound seeper leak volumes.

*Materials were received from Mike Outlaw of KMEP following the inspection on December 1, 2006 concerning this issue, and the revisions were reviewed and deemed adequate: The basis for the assumption that the potential impact associated with a pipeline "seeper" type leak versus a pipeline rupture has been documented in KMEP's IMP Manual, Section 4.4.4.2. The information used to document the basis for this assumption was compiled by KM in September 2006 and analyzed during October and November prior to being presented to PHMSA during Week 3 of the IMP Inspection.*

**1.03 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix B1.1 | | 8/3/06 | RiskCAT Identification Process |

**1.03 Inspection Notes**

IMPM 4.4.4: KMEP used the American Innovations (formerly Bass-Trigon) RiskCAT software to identify three potential impact zones to an HCA. A more detailed discussion of the HCA identification process is contained in Appendix B1.1, RiskCAT Identification Process. Direct Impact Zones are locations at which the pipeline exists within (intersects with) an HCA. This analysis identifies points at which a pipeline enters and exits an HCA. Indirect Impact Zones are locations at which the pipeline is in proximity to an HCA. This analysis involves calculating the rupture volume for each pipeline segment and then assumes a pipeline rupture on 30-foot increments along the segment. Potentially impacted HCAs are then identified when impacted by this expanded area of potential influence. The rupture volume assumes 15 minutes of full flow before the pipeline is shut down plus the pipeline volume of drain down based on elevation, limited by applicable EFRDs (only automatic or check valves considered in analysis). Pipeline shut down may occur more rapidly than 15 minutes after rupture; however as a conservative measure, 15 minutes is applied to KMEP pipelines. This is a starting point that will be refined on a line segment by line segment basis during Leak Detection and EFRD or worst case discharge studies. The potential impact associated with a pipeline leak versus a pipeline rupture was initially considered by the Subject Matter Experts and the KMEP Risk Management Team. It was determined that in the event of a slow leak, the area of impact would be confined to an area in relative proximity to the pipeline and move downward in the soil. After reviewing the buffer size developed in the Indirect HCA analysis process, KMEP believes that either the Direct or Indirect HCA analysis processes (described in Appendix B1.1, RiskCAT Identification Process) would identify this region of pipe as having the potential to impact an HCA. Furthermore, the transport analysis techniques used to identify HCA impacts, which are performed independent of the volume of fluid released, would also identify potential HCA impacts in the event that the small release traveled downhill or along a water conduit. Thus, the assumption to only consider the impact associated with a full volume rupture in the HCA impact identification process is conservative and will result in equal to or larger areas of impact along our pipelines. Potential Transport Zones are locations at which large amounts of liquid pipeline product could migrate or be transported by stream, river, drainage or other means to affect a distant HCA. An analysis was conducted that integrated terrain conditions for each line to develop variable proximity

distances from the pipeline to determine transport impact zones. Overland terrain transport vectors were evaluated at lengths up to 5 miles or up to the first contact with an HCA (by HCA type), whichever occurred first. The Watershed analyses proceed for up to 35 miles – the distance was derived based on an average stream velocity of 4 mph and a maximum response time of 8 hours (4 x 8 = 32, rounded to 35 miles)

IMPM Appendix B1.1 Section 1.2: Five levels of analysis are conducted to determine if a given segment could impact an HCA in accordance with the HCA definitions in 49 CFR 195.450.1 The levels of analyses are: Direct, Indirect, Terrain, Direct Watershed, and Indirect Watershed. For each of the five analyses, the RiskCAT software is used to conduct a spatial analysis between the HCA and pipeline location data. This RiskCAT process involves several key steps:

1. Join fragments of a company's digital pipeline centerline data into a single length consistent with the operator's definition of the pipeline segment, such as trap-to-trap, or pump-to-pump lengths.
2. Identify the pipeline engineering station range over which the pipeline interacts with the HCA shape file.
3. Capture the name of the impacted HCA.
4. Merge overlapping HCAs by type and by pipeline, in order to report accurate percentages of impacted pipeline length.

The date of each RiskCAT Analyses is imbedded in the shape file .dbf as the last column in the table

IMPM Appendix B1.1 Section 1.2.2: The primary distinction between the Direct and Indirect Analysis is that the Indirect Analysis considers the impact of a pipeline release at a distance away from the pipeline along the entire pipeline system. The impact zone calculates a moving circle traveling along the length of the pipeline. The circle size varies based on buffer size. This buffer distance is based on a one-inch deep pool of product spreading out from the centerline of the pipeline until the maximum release volume is consumed in the volume calculation of the resulting one-inch thick cylinder. The radius of this circle is used as the dispersion distance. The net result is a buffer zone encompassing the pipeline. The indirect buffers are determined based on dispersion distance calculations associated with the maximum anticipated release volume. This release volume is calculated by adding the maximum initial volume loss and the maximum stabilization loss. The initial volume loss is the time to isolate the valve-to-valve section being analyzed, multiplied by the maximum flow rate of product for the section. The maximum stabilization loss uses the pipe design information (diameter, wall thickness, and isolation valve location or section length) along with the elevation profile of the pipeline. The dispersion distance has the potential to change at every location in the database where the above referenced information changes, the buffer circle moves along the pipeline at 30-foot intervals.

Appendix B1.1 Section 1.2.3: An additional analysis is conducted for liquid pipeline segments that did not have the potential to impact an HCA under the Direct or Indirect Analyses. Each pipeline segment is evaluated to determine if the contents from a pipeline release have the potential to migrate to an HCA. A spatial comparison is conducted between the pipeline location and USGS National Elevation Dataset (NED) to determine the potential flow path in the event of a release. The maximum transport distance used in the analysis was based on set distance specified by the client or maximum volume release. The maximum perpendicular flow vector length calculation is limited by the accuracy of the NEDs. The elevation values within the NEDs are reported to the nearest 0.1 meters (~3.9 inches). This resolution sensitivity creates the potential for two adjacent pixels to appear equivalent, even if the actual terrain slightly varies. As in the case shown below, a 30m by 30m area of land with less than one decimeter in elevation change will yield equivalent elevation results (i.e., the terrain appears flat). Therefore, it can be concluded that the data source is unable to distinguish resolution variances of (±1.95 inches 0.05 meters). The most accurate volume estimates possible using the NED is a box with dimensions 30m x 30m x 0.05m (97½ft x 97½ft x 1.95inches). As shown in Table 6, this equates to a volume of approximately 275 barrels per pixel. For example, to reach a distance of five miles, over 72,500 bbls of product would need to be released in an uncontrolled manner.

IMPM 4.4.7: The HCA analysis methods typically result in line pipe inside facilities being classified as having the same potential to impact HCAs, as the incoming and outgoing pipelines to the facility. Buffer zones are also included in the above analysis due to the increased pressures associated with pump stations. Where this may not apply, for example at large breakout facilities, KMEP also employs a "could affect" screening process to identify HCA Facilities. Both these analysis methods are described below. HCA Segment Method KMEP utilizes the

HCA analysis results of the first 1,000 feet of previously identified incoming or outgoing HCA Segments to DOT regulated facilities to determine HCA Facilities. The HCA Facilities identified by this method are listed in Appendix B2.1. Screening Analysis for Breakout Facilities KMEP also utilizes a screening analysis to identify HCA impacts for DOT regulated facilities that are not identified by the HCA Segment Method. The screening process consists of evaluating each facility using GIS and HCA data (see Appendix B2.2, Screening Analysis Method) to determine if the facility directly intersects an HCA or is within a 35¬mile radius of an HCA. The evaluations will be completed by KMEP's Risk Management Team or qualified subcontractors. In this analysis, each facility will be placed in one of the two categories below and documented on the Facility HCA "Could Affect" Screening Checklist: 1) HCA Facility HCA Facilities directly impact an HCA and/or have the potential to impact an HCA. These facilities will be located in an HCA and/or within a 35 mile radius of an HCA. 2) Non-HCA Facility A DOT Regulated Facility that does not have the potential to impact a HCA. Facilities included in this category are not in an HCA and are not within 35 miles of an HCA. Breakout Tank Volumes Breakout facilities have the potential of adding additional spill volume to the incoming and outgoing pipelines to the facility. This information will be documented for each HCA Facility listed in Appendix B2.2 as described in Procedure H9.4, Facilities Risk Analysis and Prevention and Mitigative Measures Evaluation. Facility breakout tanks with the potential to back feed spill volumes into HCA Segments will be identified and the calculated worst case spill volume will be added to the HCA Segment(s) during the annual HCA Identification process described in Section 4.4.4.

| **1.03 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **1.03.01** | The process did not adequately consider potential spills occurring at waterway crossings in segment identification | AF 1.1 | |
| | **1.03.02** | Facilities were not adequately analyzed for potential impact to HCAs | AF 1.7 | |
| | **1.03.03** | Release locations that could affect an HCA were not adequately defined | AF 1.1 | |
| | **1.03.04** | The use of release volume assumptions that are less than historical release volumes was not adequately justified | AF 1.1 | |
| **X** | **1.03.05** | Release volumes for a range of possible leak sizes that could result in a larger release than assumed, including slow leaks below SCADA detection thresholds, leaking for long time periods were not adequately considered | AF 1.1 | E |
| | **1.03.06** | Assumptions used in release volume calculations, including hole size, pressure, equipment and operator response times, and drain down volume were not technically justified | AF 1.1 | |
| | **1.03.07** | Nearby tank volumes were not adequately considered in spill volume calculations | AF 1.7 | |
| | **Other:** | | | |

| Protocol # 1.04 | Segment Identification: Overland Spread of Liquid Pool |
|---|---|
| **Protocol Question** | Does the operator's process include an adequate analysis of overland flow of liquids to determine the extent of commodity spread and its effects on HCAs?<br>Verify that the operator produced an overland spread analysis (if applicable) that is technically adequate and consistent with its program requirements. |

Analyzing the potential effects of pipeline failures that could affect HCAs involves estimating the distance and direction of the commodity spilled from a potential failure at a location on the pipeline and determining if the identified direction and extent of the spill could result in adverse consequences to a HCA. Commodity spilled from hazardous liquid pipelines may spread by land, water, or air to impact HCAs. This protocol considers the operator's analysis of overland spill transport. An effective operator process would be expected to include the following characteristics in analyzing overland spread of spills:

1. The assumptions used in the overland spread analysis are valid for all applications of the assumption (e.g., assumptions used to conduct overland spread analysis used as a basis for buffer zone size should be valid for all systems and locations to which the buffer zone is applied).
2. The overland spread analysis technique adequately and accurately evaluates the effects of topography on overland spread consequences.
3. Assumptions on operator spill response actions used to determine the pool spread limits are valid.
4. The overland spread analysis process identifies and adequately analyzes local factors such as ditches, sewers, farm tile, drains, etc.
5. Any computer modeling of overland transport mechanisms that is used produces valid overland spread consequence results.

If the operator's approach to identify segments that could affect HCAs involves the definition of a spill buffer zone, then the basis for the defined buffer distance would be expected to bound the overland spread distances estimated for each location to which the buffer is applied. The analysis used to define the buffer zone would be expected to include the above characteristics.

| | |
|---|---|
| **Rule Requirement** | §452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program:<br>(1) A process for identifying which pipeline segments could affect a high consequence area. |

| 1.04 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**1.04 Inspection Issues Summary**

**1.04 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix B1.1 | | 8/3/06 | RiskCAT Identification Process |
| Appendix H6.10 | | 8/31/06 | Field Data SME Validation |

**1.04 Inspection Notes**

IMPM 4.4.4: KMEP used the American Innovation (formerly Bass-Trigon) RiskCAT software to identify three potential impact zones to an HCA. A more detailed discussion of the HCA identification process is contained in Appendix B1.1, RiskCAT Identification Process. Indirect Impact Zone Indirect Impact Zones are locations at which the pipeline is in proximity to an HCA. This analysis involves calculating the rupture volume for each pipeline segment and then assumes a pipeline rupture on 30-foot increments along the segment. Potentially impacted HCAs are then identified when impacted by this expanded area of potential influence. The rupture volume assumes 15 minutes of full flow before the pipeline is shut down plus the pipeline volume of drain down based on elevation, limited by applicable EFRDs. Pipeline shut down may occur more rapidly than 15 minutes after rupture; however as a conservative measure, 15 minutes is applied to KMEP pipelines. This is a starting point that will be refined on a line segment by line segment basis during Leak Detection and EFRD or worst case discharge studies. The potential impact associated with a pipeline leak versus a pipeline rupture was initially considered by the Subject Matter Experts and the KMEP Risk Management Team. It was determined that in the event of a slow leak, the area of impact would be confined to an area in relative proximity to the pipeline and move downward in the soil. After reviewing the buffer size developed in the Indirect HCA analysis process, KMEP believes that either the Direct or Indirect HCA analysis processes (described in Appendix B1.1, RiskCAT Identification Process) would identify this region of pipe as having the potential to impact an HCA. Furthermore, the transport analysis techniques used to identify HCA impacts, which are performed independent of the volume of fluid released, would also identify potential HCA impacts in the event that the small release traveled downhill or along a water conduit. Thus, the assumption to only consider the impact associated with a full volume rupture in the HCA impact identification process is conservative and will result in equal to or larger areas of impact along our pipelines. Potential Transport Zones Potential Transport Zones are locations at which large amounts of liquid pipeline product could migrate or be transported by stream, river, drainage or other means to affect a distant HCA. An analysis was conducted that integrated terrain conditions for each line to develop variable proximity distances from the pipeline to determine transport impact zones. Overland terrain transport vectors were evaluated at lengths up to 5 miles or up to the first contact with an HCA (by HCA type), whichever occurred first. The Watershed analyses proceed for up to 35 miles – the distance was derived based on an average stream velocity of 4 mph and a maximum response time of 8 hours (4 x 8 = 32, rounded to 35 miles)

IMPM Appendix B1.1 Section 1.1 - The Terrain Analysis method removes any assumptions regarding potential spill volumes and allows the operator to consider the movement of product in the event that the product quantity was infinite or as if a minimal amount of product was released and allowed to move on a frictionless surface. The Terrain Analysis follows ground contours, as well as areas where water features can be found, until the terrain

rises, a calculated or fixed length is reached, or a buffer distance from the pipeline is reached.

Section 1.2.3: An additional analysis is conducted for liquid pipeline segments that did not have the potential to impact an HCA under the Direct or Indirect Analyses. Each pipeline segment is evaluated to determine if the contents from a pipeline release have the potential to migrate to an HCA. A spatial comparison is conducted between the pipeline location and USGS National Elevation Dataset (NED) to determine the potential flow path in the event of a release. The maximum transport distance used in the analysis was based on set distance specified by the client or maximum volume release. The maximum perpendicular flow vector length calculation is limited by the accuracy of the NEDs. The elevation values within the NEDs are reported to the nearest 0.1 meters (~3.9 inches). This resolution sensitivity creates the potential for two adjacent pixels to appear equivalent, even if the actual terrain slightly varies. As in the case shown below, a 30 meter by 30 meter area of land with less than one decimeter in elevation change will yield equivalent elevation results (i.e., the terrain appears flat). Therefore, it can be concluded that the data source is unable to distinguish resolution variances of (±1.95 inches 0.05 meters). The most accurate volume estimates possible using the NED is a box with dimensions 30 meter x 30 meter x 0.05 meters (97½ ft x 97½ ft x 1.95 inches). As shown in Table 6, this equates to a volume of approximately 275 barrels per pixel. For example, to reach a distance of five miles, over 72,500 bbls of product would need to be released in an uncontrolled manner.

Appendix H6.10, Section 4.4.1: No Activity = No regular farming or ranching land usage. Pasture (Low Activity) = Pastureland or other low use ranching activities. Medium Activity = Periodic farming and other ranching activities. Cultivated (High Activity) = Regular farming activities with tilled soil typical (including some years fallow) Drain Tiled = Farmed fields with drainage tiles typical.

| **1.04 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **1.04.01** | Overland spread analysis was not adequately performed | AF 1.1 | |
| | **1.04.02** | The overland spill spread analysis did not adequately consider valid, consistent, substantiated, and conservative assumptions and techniques | AF 1.1 | |
| | **1.04.03** | The process did not adequately consider topography for overland spread analysis | AF 1.1 | |
| | **1.04.04** | The process did not adequately consider overland transport of liquids and liquid pool fires for HVL lines without adequate justification | AF 1.1 | |
| | **Other:** | | | |

| Protocol # 1.05 | Segment Identification: Water Transport Analysis |
|---|---|
| **Protocol Question** | Does the operator's process include a technically adequate analysis of water transport of liquids to determine the extent of commodity spread and its effects on HCAs?<br>Verify that the operator produced a water transport analysis (if applicable) that is technically adequate and consistent with its program requirements. |

This protocol considers the operator's analysis of spill transport through waterways. An effective operator process would be expected to include the following characteristics in analyzing the transport of spills by water:

1. The analysis adequately evaluates the effects of all applicable factors, including stream conditions, flow characteristics, and water properties on water transport consequences.
2. The assumptions used in the analysis are valid for all systems and locations to which the assumptions are applied (e.g., assumptions used to conduct water transport analysis as a basis for buffer zone size are valid for all systems and locations to which the buffer zone is applied).
3. Pool spread limits based on assumptions of operator spill response actions are defensible.

Additional factors that may be important to understanding water transport of spilled commodity include:

1. Changes in commodity properties due to interaction with the environment (such as dissolved MTBE transport and change in buoyancy and density due to evaporation).
2. Commodity solubility.
3. Abnormal stream conditions such as flood or storm conditions, etc.
4. Subsurface water transport as well as surface water transport.
5. Indirect introduction into water due to overland pool spread that reaches waterways.
6. Introduction into water from spray releases.

If the operator's approach to identify segments that could affect HCAs involves the definition of a spill buffer zone, then the basis for the defined buffer distance would be expected to bound the spill water transport distances estimated for each location to which the buffer is applied. The analysis used to define the buffer zone would be expected to include the above characteristics.

| | |
|---|---|
| **Rule Requirement** | §452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program:<br>(1) A process for identifying which pipeline segments could affect a high consequence area. |

| 1.05 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**1.05 Inspection Issues Summary**

**1.05 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix B1.1 | | 8/3/06 | RiskCAT Identification Process |

**1.05 Inspection Notes**

IMPM 4.4.4: KMEP used the BTS [RiskCAT] software to identify three potential impact zones to an HCA. A more detailed discussion of the HCA identification process is contained in Appendix B1.1, RiskCAT Identification Process. Direct Impact Zone Direct Impact Zones are locations at which the pipeline exists within (intersects with) an HCA. This analysis identifies points at which a pipeline enters and exits an HCA. Indirect Impact Zone Indirect Impact Zones are locations at which the pipeline is in proximity to an HCA. This analysis involves calculating the rupture volume for each pipeline segment and then assumes a pipeline rupture on 30-foot increments along the segment. Potentially impacted HCAs are then identified when impacted by this expanded area of potential influence. The rupture volume assumes 15 minutes of full flow before the pipeline is shut down plus the pipeline volume of drain down based on elevation, limited by applicable EFRDs. Pipeline shut down may occur more rapidly than 15 minutes after rupture; however as a conservative measure, 15 minutes is applied to KMEP pipelines. This is a starting point that will be refined on a line segment by line segment basis during Leak Detection and EFRD or worst case discharge studies. The potential impact associated with a pipeline leak versus a pipeline rupture was initially considered by the Subject Matter Experts and the KMEP Risk Management Team. It was determined that in the event of a slow leak, the area of impact would be confined to an area in relative proximity to the pipeline and move downward in the soil. After reviewing the buffer size developed in the Indirect HCA analysis process, KMEP believes that either the Direct or Indirect HCA analysis processes (described in Appendix B1.1, RiskCAT Identification Process) would identify this region of pipe as having the potential to impact an HCA. Furthermore, the transport analysis techniques used to identify HCA impacts, which are performed independent of the volume of fluid released, would also identify potential HCA impacts in the event that the small release traveled downhill or along a water conduit. Thus, the assumption to only consider the impact associated with a full volume rupture in the HCA impact identification process is conservative and will result in equal to or larger areas of impact along our pipelines. Potential Transport Zones Potential Transport Zones are locations at which large amounts of liquid pipeline product could migrate or be transported by stream, river, drainage or other means to affect a distant HCA. The Watershed analyses proceed for up to 35 miles – the distance was derived based on an average stream velocity of 4 mph and a maximum response time of 8 hours (4 x 8 = 32, rounded to 35 miles)

Appendix B1.1 Section 1.2.4: The Direct Watershed Analysis is very similar to the Terrain Analysis. Unlike the Terrain Analysis in which NED flow vectors are used, the Direct Watershed Analysis follows the downstream direction of the National Hydrographic Dataset (NHD) RiskCAT identifies the intersection of NHD features with the pipeline. The application captures the name and length of each downstream adjoining NHD feature (see table 7) for a total distance of thirty-five miles (see Section 1.1). Once the water flow path is built, the path is applied against the HCA datasets. The result is the name of the HCA, distance to that HCA, and flow path information

(water names and distances). The USGS website that provides the NHD datasets has listed a series of problems with many of the datasets due to NHD production process oversights. These known problems can be reviewed at http://nhd.usgs.gov/problems html. Line lengths of topologically corrupt features are immeasurable and discarded. NHD datasets are being updated in an irregular manner by the USGS in conjunction with the NHD user community. Updated datasets are downloaded on a quarterly basis.

Appendix B1.1 Section 1.2.4: The Direct Watershed Analysis is very similar to the Terrain Analysis. Unlike the Terrain Analysis in which NED flow vectors are used, the Direct Watershed Analysis follows the downstream direction of the National Hydrographic Dataset (NHD)

Appendix B1.1 Section 1.2.5: The Indirect Watershed method integrates the Terrain Analysis results with water features to yield the transport flow path associated with a release that flows overland, spills into a watershed feature, and then moves downstream toward an HCA. The overland vector stopped at the river (green arrow) and the Indirect Watershed Analysis in RiskCAT will detect this intersection and will follow the watershed feature for 35 miles. Once the Indirect watershed vector is known (red arrow), RiskCAT identifies the first intersection with each HCA type.

Water transport analysis is based on a response time to stop transport (assuming the release would continue infinitely). Individual factors are not included in the calculation as the infinite release/infinite spread is the worst case. Eight hour response time encompassed with 4 mph average is considered to be conservative. Leak detection response time analysis has shown a worst case much less than 8 hours.

| **1.05 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **1.05.01** | Water transport analysis was not adequately performed | AF 1.1 | |
| | **1.05.02** | Invalid or non-conservative assumptions were used in water transport analysis | AF 1.1 | |
| | **1.05.03** | Stream flow characteristics, including potential stream flow velocity, were not adequately considered | AF 1.1 | |
| | **1.05.04** | All possible means by which spills could be introduced to water transport mechanisms, including overland spills reaching water bodies, were not adequately considered | AF 1.1 | |
| | **Other:** | | | |

| Protocol # 1.06 | Segment Identification: Air Dispersion Analysis |
|---|---|
| **Protocol Question** | Does the operator's documented consequence analysis process include a technically adequate analysis of the air dispersion of vapors from the release of highly volatile liquids and volatile liquids to determine the extent of harmful commodity vapor spread and its effects on HCAs?<br>_____<br>Verify that the operator produced an analysis of the air dispersion of vapors (if applicable) that is technically adequate and consistent with its program requirements. |

This protocol considers the operator's analysis of spill transport through air dispersion. An effective operator process would be expected to have the following characteristics in analyzing the dispersion of spills through air:

1. The process includes air dispersion analysis where appropriate for the operator's system and release scenarios.
2. The operator's selection of analysis model and software tool is appropriate for the operator's system and release scenario.
3. The analysis correctly models the physical properties of the commodity that could be released.
4. The air dispersion analysis inputs and assumptions used to determine if the release could affect a HCA are adequate.
5. If the air dispersion analysis involves consideration of threshold levels of concern for the adverse effects of releases, then the thresholds that are used are based on valid criteria to determine if releases could affect a HCA.
6. For completeness, the air dispersion analysis considers the potential for any additional significant release effects (e.g., chemical byproducts of combustion) to adversely affect a HCA.

If the operator's approach to identify segments that could affect HCAs involves the definition of a spill buffer zone, then the basis for the defined buffer distance would be expected to bound the vapor dispersion distances estimated for each location to which the buffer is applied. The analysis used to define the buffer zone would be expected to include the above characteristics.

| | |
|---|---|
| **Rule Requirement** | §452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program:<br>(1) A process for identifying which pipeline segments could affect a high consequence area. |

| 1.06 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**1.06 Inspection Issues Summary**

**1.06 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| Appendix B1.1 | | 8/3/06 | RiskCAT Identification Process |
| | | | |

**1.06 Inspection Notes**

The Inspection Team discussed the potential HCA consequence impact of $H_2S$ releases and air dispersion. Following the discussion, the Inspection Team had no objection to the data presented that the KMEP systems would not present an adverse impact from release of H2S. However, the technical basis for this conclusion should be documented and maintained as part of KMEP's IMP documentation.

IMP Appendix B1.1 Section 1.2.2.1: KMEP uses the toxic vapor dispersion hazards model. This model predicts (based on atmospheric conditions such as temperature, wind speed, and amount of solar radiation) the distance from the release that the chemical concentration in the air drops below the user defined level. Typically these concentration levels are based on the Occupational Safety and Health Administration's (OSHA) defined Threshold Limit Value (TLV), which is the concentration that OSHA deems acceptable for long term and repeated exposure (usually no longer than 8-hours), or the Immediately Dangerous to Life and Health (IDLH) level for short-term exposures (no longer than 30-minutes). Based on sample cases, these values range from 1000 feet to 20 miles and are very dependent upon the atmospheric conditions at the time of release. Using the worst-case scenario could cause an operator to grossly overstate the amount of their pipeline that could affect an HCA and it is recommended that an analysis of regional weather conditions be considered for determining these dispersion distances.

The Flame Jet Hazards model produces two outputs; the flame jet distance and the safe separation distance from the jet flame. ARCHIE describes the model as follows:

> "Transportation or storage tanks or pipelines containing gases under pressure (i.e., compressed gasses) or normally gaseous substances that have been pressurized to the point they become liquids (i.e., compressed liquefied gases) may discharge gases at a high speed if somehow punctured or broken during an accident. The gas discharging or venting from the hole will form a gas jet that blows into the atmosphere in the direction the hole is facing, while entraining and mixing with air. If the gas is flammable and encounters an ignition source, a flame jet of considerable length may form (possibly hundreds of feet in length) from a hole less than one foot in diameter. Such jets pose a thermal radiation hazard to nearby people and property, and are particularly hazardous if they impinge upon the exterior of a nearby intact tank containing a flammable, volatile, and/or self-reactive hazardous material."

By examining many liquid ethane pipeline scenarios it was determined that the flame jet distance and safe separation distance is independent of flow, pipeline pressure, pipeline length, and hydrostatic head pressure present in the pipeline. Scenarios were examined on pipe ranging in diameter from 2" to 16," pressures from 275

psia to 2160 psia, and flows from 800 bbl/day to 315,000 bbl/day. Based on all the scenarios using the same pipeline contents (ethane), a linear relationship exists between the flame jet safe separation distance and the diameter of the pipeline.

An example HVL line was reviewed during the inspection – Mid-Con line leading to Port Arthur. The segment map shows the flow lines for indirect transport. The entire line is an HCA due to flame jet analysis

HVL ARCHIE analysis creates a much larger buffer than the liquid spill buffer. PL-106W 8" Williams to Lemont is a multi-product system that has a liquid dispersion range of 105 to 199.2 feet. The vapor HVL dispersion distance is 7672 feet.

Morris to Lemont 107 10" Vapor HVL dispersion distance is 7672 feet. Mount Belvieu HVL dispersion distance is 7672 feet

KMI provided the following basis documenting why dispersion of $H_2S$ gases from the Wink system is not a concern:

*The term sour oil has different meanings to different parts of the oil business. From an oil field production point of view, sour oil commonly refers to oil that has $H_2S$ in the produced associated gas. $H_2S$, being quite poisonous at concentrations above 500 ppm, is a concern to the oil field workers and many safeguards are taken to make sure there are no releases of this associated gas and plans are made for the safety of local populations in case of a release. The amount of sulfur in the oil may or may not be indicative of the presence of $H_2S$. There are examples of crude oil that production people call sweet, because there is no appreciable $H_2S$ that have a high sulfur content. Conversely there are examples of oils that production people call sour, due to the presence of $H_2S$ in the associated gas, that have ultra-low sulfur content*

*From an oil refiner's point of view, sour oil has to do with its sulfur content. Sulfur content of the oil arriving at the refinery consists of various chemical compounds that incorporate the sulfur molecule. One such compound might be ethyl mercaptan, the odorant used to give natural gas its characteristic odor in order to detect gas leaks. Certainly mercaptans smell very bad, but are not particularly poisonous. Ethyl mercaptan is only one of the many sulfur compounds dissolved in sour oil that make up its sulfur content. $H_2S$ is a negligible component of sour oil when it arrives at the refinery.*

*The reason the oil arriving at the refinery doesn't contain significant amounts of $H_2S$ is that this poisonous gas is almost entirely separated from the oil before it enters the pipeline. This is not to say that the amount of $H_2S$ in the pipeline oil is zero, but $H_2S$ is present in insignificant amounts. This separation occurs at many points along the way to the LACT (Lease Active Custody Transfer) meter and once more after.*

*When the oil is produced from the well head the oil goes to a gas oil separator. Here most of the H2S goes with the rest of the gas components for further processing so that the associated natural gas can be sold. The oil is then pumped to a storage tank where it is flashed to atmospheric pressure and this gas is collected with a VRU (Vapor Recovery Unit) to be cycled to the gas plant for treatment and eventual sales. This flash to atmospheric pressure in this storage tank reduces the amount of $H_2S$ to an insignificant amount. The oil then passes through the LACT to another storage tank at the head of the pipeline to be flashed one more time at atmospheric pressure.*

*This last flash to atmospheric pressure is into a floating roof tank. The vapor from this oil is so insignificant that the Texas Natural Resources Conservation Commission does not require a VRU to capture volatiles released. This oil is what goes into the pipeline. This very dead, low vapor pressure oil has insignificant amounts of $H_2S$ present. Any release of oil from the pipeline would have a very bad, rotten egg, smell characteristic of $H_2S$, but since the lower limit of olfactory detection of $H_2S$ is 10 parts per billion this is very far away from the 10 parts per million OSHA 8 hour exposure limit and not worthy of a plume study.*

| **1.06 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **1.06.01** | Non-conservative inputs or assumptions were used in the air dispersion analysis | AF 1.1 | |
| | **1.06.02** | Air dispersion analysis of hazardous vapors resulting from spill was not adequately performed or documented | AF 1.1 | |
| | **1.06.03** | Exclusion of effects of HVL releases on HCAs was not adequately justified | AF 1.1 | |
| | **Other:** | | | |

| Protocol # 1.07 | Segment Identification: Identification of Segments that Could Indirectly Affect an HCA |
|---|---|
| **Protocol Question** | Does the operator's analysis process adequately identify all locations of segments that do not intersect, but could indirectly affect, an HCA?<br>Review the operator's analysis and determine if there is reasonable assurance that the operator has correctly identified the endpoints of segments that could affect an HCA. |

This protocol addresses the results of the operator's process for segments that do not intersect, but could affect, HCAs. An effective operator process would be expected to have the following characteristics:

1. The process requires that segments that could affect HCAs (according to the analysis reviewed under protocols 1.04 through 1.06) are identified and defined by specific beginning and ending endpoints.
2. If the operator used a buffer zone approach to identify segments that could affect HCAs, an approach that is reasonable, technically justified, and identifies the endpoints of segments that could affect an HCA.
3. If any segments intersect a buffer zone, but were declared to not affect the HCA, a documented and adequate technical justification for this assertion.
4. Identification of pipeline facilities that could affect HCAs.

| | |
|---|---|
| **Rule Requirement** | §452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program:<br>(1) A process for identifying which pipeline segments could affect a high consequence area. |

| 1.07 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**1.07 Inspection Issues Summary**

The inspection Team noted that on LS-52, a 306 foot section was identified as "not affecting an HCA". Review of aerial photographs raised questions with this exclusion. PHMSA looks forward to receiving additional information from KMEP providing an explanation for exclusion or inclusion in the IMP of this segment based on field verification.

*Materials were received from Mike Outlaw of KMEP following the inspection on December 1, 2006 concerning this issue, and the revisions were reviewed and deemed adequate: The 306 foot section that was excluded from HCA impact pipeline is being corrected in December 2006 by KMEP's Risk Engineering Team. The 306 foot section that was identified as not affecting an HCA was not identified in the field review update process because the map scale/color coding used does not adequately bring to the attention of the reviewer small sections of non-HCA pipeline.*

*To prevent this problem in our annual HCA map review process, KMEP's Risk Engineering Team will distribute the HCA maps with additional highlighting of non-HCA segments 500 feet in length or less. The process for this map highlighting has been added to the annual map review process as outlined in Procedure H4.2, Identify HCAs – Annual/New/Acquired.*

**1.07 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix B1.1 | | 8/3/06 | RiskCAT Identification Process |

**1.07 Inspection Notes**

IMPM 4.4.4: KMEP used the American Innovations (formerly Bass-Trigon) RiskCAT software to identify three potential impact zones to an HCA. A more detailed discussion of the HCA identification process is contained in Appendix B1.1, RiskCAT Identification Process. Direct Impact Zones are locations at which the pipeline exists within (intersects with) an HCA. This analysis identifies points at which a pipeline enters and exits an HCA. Indirect Impact Zones are locations at which the pipeline is in proximity to an HCA. This analysis involves calculating the rupture volume for each pipeline segment and then assumes a pipeline rupture on 30-foot increments along the segment. Potentially impacted HCAs are then identified when impacted by this expanded area of potential influence. The rupture volume assumes 15 minutes of full flow before the pipeline is shut down plus the pipeline volume of drain down based on elevation, limited by applicable EFRDs. Pipeline shut down may occur more rapidly than 15 minutes after rupture; however as a conservative measure, 15 minutes is applied to KMEP pipelines. This is a starting point that will be refined on a line segment by line segment basis during Leak Detection and EFRD or worst case discharge studies. The potential impact associated with a pipeline leak versus a pipeline rupture was initially considered by the Subject Matter Experts and the KMEP Risk Management Team. It was determined that in the event of a slow leak, the area of impact would be confined to an area in relative proximity to the pipeline and move downward in the soil. After reviewing the buffer size developed in the Indirect HCA analysis process, KMEP believes that either the Direct or Indirect HCA analysis processes (described in Appendix B1.1, RiskCAT Identification Process) would identify this region of pipe as having the potential to impact an HCA. Furthermore, the transport analysis techniques used to identify HCA impacts, which are performed independent of the volume of fluid released, would also identify potential HCA impacts in the event that the small release traveled downhill or along a water conduit. Thus, the assumption to only consider the impact associated with a full volume rupture in the HCA impact identification process is conservative and will result in equal to or larger areas of impact along our pipelines. Potential Transport Zones

are locations at which large amounts of liquid pipeline product could migrate or be transported by stream, river, drainage or other means to affect a distant HCA. An analysis was conducted that integrated terrain conditions for each line to develop variable proximity distances from the pipeline to determine transport impact zones. Overland terrain transport vectors were evaluated at lengths up to 5 miles or up to the first contact with an HCA (by HCA type), whichever occurred first. The Watershed analyses proceed for up to 35 miles – the distance was derived based on an average stream velocity of 4 mph and a maximum response time of 8 hours (4 x 8 = 32, rounded to 35 miles) HVL liquid pipelines operated in cold climates could produce a liquid release that would not immediately vaporize. HVL liquids could be trapped under an ice cap or remain a liquid due to other temperature/pressure conditions for some period of time. Additionally, for segments transporting HVL products, the Resource for Chemical Hazard Incident Evaluation (ARCHIE) evaluation model has been utilized. This model is intended for use by emergency response personnel and has been approved for distribution by the Federal Emergency Management Agency (FEMA), the US Environmental Protection Agency (EPA), and the U.S. Department of Transportation (DOT). Where HVL releases occur with resulting vaporization of the released product, two scenarios have been included in the analysis as follows; a) The ARCHIE Toxic Vapor Dispersion Hazard model has been utilized to determine the potential impact of a vapor cloud of released product that is not subject to immediate ignition. b) The ARCHIE Flame Jet Hazard model has been utilized to determine the potential impact of the release of product with immediate ignition. Identification of potential impact to HCAs for each segment is reported based on the worst case condition. In 2003 the continuing HCA analysis for CO2 Segments utilized the Process Hazards Analysis Software Tool (PHAST). A detailed description of the PHAST calculations and assumptions are included in Appendix B1.2. Upon completion of these analyses, the worst case impact is determined for each pipeline segment. Identification of potential impact to HCAs for each segment is then reported based on the worst case condition.

IMPM Appendix B1.1 Section 1.2: Five levels of analysis are conducted to determine if a given segment could impact an HCA in accordance with the HCA definitions in 49 CFR 195.450.1 The levels of analyses are: Direct, Indirect, Terrain, Direct Watershed, and Indirect Watershed. For each of the five analyses, the RiskCAT software is used to conduct a spatial analysis between the HCA and pipeline location data. This RiskCAT process involves several key steps:

1. Join fragments of a company's digital pipeline centerline data into a single length consistent with the operator's definition of the pipeline segment, such as trap-to-trap, or pump-to-pump lengths.
2. Identify the pipeline engineering station range over which the pipeline interacts with the HCA shape file.
3. Capture the name of the impacted HCA.
4. Merge overlapping HCAs by type and by pipeline, in order to report accurate percentages of impacted pipeline length.

The date of each RiskCAT Analyses is imbedded in the shape file .dbf as the last column in the table

Appendix B1.3: This appendix includes a listing of HCA segments. The listing includes segment name, HCA length, and identification of start / stop locations.

IMPM 4.4.10: Current KMEP practices prescribe that facilities are identified as HCA segments if they are determined to have direct, indirect or potential transport impact zones during RiskCAT analysis. If KMEP decides to allow SME teams to remove identified HCA segments from consideration, a procedure for analyzing HCA impacts and justifying the basis for removal during field validation process will be developed. KMEP Risk Management Team and Core Team approval would be required for elimination of a segment.

IMPM 4.4.7: The HCA analysis methods typically result in line pipe inside facilities being classified as having the same potential to impact HCAs, as the incoming and outgoing pipelines to the facility. Buffer zones are also included in the analysis due to the increased pressures associated with pump stations. Where this may not apply, for example at large breakout facilities, KMEP also employs a "could affect" screening process to identify HCA Facilities.

| **1.07 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| **X** | **1.07.01** | All segments that could affect HCAs in the buffer zone | AF 1.1 | E |

| | | | | |
|---|---|---|---|---|
| | | intersection analysis methodology were not adequately identified | | |
| | **1.07.02** | An incorrect or deficient algorithm was used in buffer zone analysis | AF 1.1 | |
| | **1.07.03** | Segments were not adequately identified by specific and unique endpoints in buffer analysis | AF 1.1 | |
| | **1.07.04** | Facilities that could affect HCAs were not adequately included in the buffer analysis | AF 1.7 | |
| | **1.07.05** | The buffer size used to identify segments or facilities that could affect HCAs was not adequately justified | AF 1.1 | |
| | **Other:** | | | |

| Protocol # 1.08 | Segment Identification: Timely Completion of Segment Identification |
|---|---|
| **Protocol Question** | Did the operator complete segment identification by the dates prescribed in 452(b)(2)? |

The operator must identify all segments that could affect HCAs by the prescribed dates:

1. 12/31/2001 for Category 1 pipelines
2. 11/18/2002 for Category 2 pipelines
3. Beginning of operation for Category 3 pipelines

| | |
|---|---|
| **Rule Requirement** | §452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must:<br>(2) Include in the program an identification of each pipeline or pipeline segment in the first column of the following table not later than the date in the second column:<br><br>Pipeline — Date<br>Category 1 — December 31, 2001<br>Category 2 — November 18, 2002.<br>Category 3 — Date the pipeline begins operation. |

| **1.08 Inspection Results** | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**1.08 Inspection Issues Summary**

**1.08 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix H4.2 | 6 | 8/21/06 | Identify HCAs (Annual/New/Acquired) |

**1.08 Inspection Notes**

Segment identification was completed by 12/31/01

IMPM 4.4.2: Newly constructed pipelines or pipelines converted for service are included in this IMP program within one year of being placed in service and include notifications through the Management of Change process. Segments that could affect HCAs are identified prior to the pipeline being placed into service. Pipelines obtained through acquisition are reviewed and incorporated into this program within one year of assumption of operational responsibility. Kinder Morgan's due diligence checklist assures adequate understanding and documentation of integrity management program related information prior to the acquisition. IMPM 4.4.6: requires that newly constructed facilities or facilities converted for service be included in this IMP within one year of being placed in service and will include notifications through the Management of Change process. Facilities that could affect HCAs will be identified before the facility is placed in service. Facilities obtained through acquisition will be reviewed and incorporated into this IMP program within one year of assumption of operational responsibility.

| **1.08 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **1.08.01** | The segment identification process was not completed by the required date | AF 1.1 | |
| | **1.08.02** | Segments that could affect HCAs were not adequately identified prior to placing new or newly converted pipe (i.e., Category 3 pipe) into service | AF 1.5 | |
| | **1.08.03** | The process did not adequately address segment identification requirements when bringing idle lines back into service | AF 1.4 | |
| | **1.08.04** | Segment identification process requirements were not adequately documented | AF 1.6 | |
| | **1.08.05** | A segment identification process requirement was not adequately implemented | AF 1.1 | |
| | **Other:** | | | |

# Integrity Management Inspection Protocol 2

# Baseline Assessment Plan

**Scope:**

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

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| Protocol # 2.01 | Baseline Assessment Plan: Assessment Methods |
|---|---|
| **Protocol Question** | Are the assessment methods shown in the Baseline Assessment Plan appropriate for the pipeline specific conditions and risk factors identified for each segment? |

The rule requires that the selected assessment method allow the operator to adequately assess the integrity of the pipeline. The operator's assessment method selection process must exhibit the following characteristics:

1. The assessment methods selected for each segment are effective and appropriate for identifying anomalies associated with the specific risk factors identified for the segment. Specific risk factors can include fatigue cracks, stress corrosion cracking (SCC), internal corrosion, general external corrosion, corrosion along seam or girth welds, construction defects such as wrinkle bends, dents, etc. The operator should utilize industry information when evaluating previously unidentified risk factors.
2. If ILI tools are used, they are used in combinations that assure the capability to detect corrosion anomalies and deformation anomalies including dents, gouges and grooves.
3. All of the assessment methods and tools documented in the Baseline Assessment Plan comply with the acceptable methods specified in 195.452 (c) (1).
4. The assessment methods selected for all low-frequency ERW pipe or lap-welded pipe susceptible to longitudinal seam failure are capable of assessing seam integrity and of detecting corrosion and deformation anomalies.
5. Indication/documentation that, if other technology is planned for use, the operator submitted a 90-day notification to PHMSA regarding the use of other technologies.

[For review of external corrosion direct assessment (ECDA) refer to protocols 7.03 and 7.05-7.08.]

| | |
|---|---|
| **Rule Requirement** | §195.452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must:<br>(3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section. |
| | §195.452 (c) *What must be in the baseline assessment plan?* (1) An operator must include each of the following elements in its written baseline assessment plan:<br>(i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.<br>(A) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;<br>(B) Pressure test conducted in accordance with subpart E of this part;<br>(C) External corrosion direct assessment in accordance with §195.588; or<br>(D)Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section ... ( iii) An explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule. |

| 2.01 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**2.01 Inspection Issues Summary**

**2.01 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix C1.1 | 4 | 7/31/2005 | Baseline Assessment Plan |
| Appendix F | 6 | 8/31/06 | Pipeline Integrity Assessment Procedures |
| Appendix H8.1 | 6 | 8/31/06 | Select The Appropriate Assessment Tool And Vendor |
| Appendix H8.5 | 6 | 8/31/06 | Weld Seam Evaluation and Remediation |

**2.01 Inspection Notes**

Possible pipeline naming convention changes were discussed for various KMLT pipelines that could result in less confusion between the BAP and the description in the integrity assessments. Pipeline nomenclature used for the KMLT and Pacific Region systems is confusing for both operator and inspectors.

IMPM 5.4.4: Assessment methodology is selected based on specific risk drivers for each pipeline segment. Assessment methodology is further discussed in IMPM Section 8, Continuing Assessment and Analysis, and Appendix F, Pipeline Integrity Assessment Procedures.

Appendix C.2 - Prior to conducting an assessment on a pipeline segment, KMEP examines risk information to predict the types of integrity threats that should be anticipated. The assessment method for a particular pipeline segment is based on the threats associated with that segment. While a more detailed discussion of threats as they relate to assessment methodology is presented in Appendix F, Pipeline Integrity Assessment Procedures, the general categories of threats addressed in this section are as follows:

- Outside force damage (OFD).
- Corrosion (internal and external) and/or other metal loss features.
- Low frequency electric resistance weld (ERW) and lap weld pipe susceptibility to longitudinal seam failure.
- Stress Corrosion Cracking (SCC).

Appendix F Section 4: Prior to running a baseline assessment on a pipeline segment, KMEP will examine the history of the segment and consider the root cause of failures, if any. KMEP will also consider other factors, such as the type and age of pipe and coating, seam type, operating pressure, performance of cathodic protection systems and environmental issues before selecting an internal inspection tool or a combination of tools for an assessment. An internal in-line inspection is one method to assess the integrity of a pipeline. Different in-line-inspection technologies exist for different kinds of anomalies. When in-line inspection is selected to verify the integrity of a pipeline segment, the inspection will be conducted using the appropriate technology to detect anomalies that KMEP has reason to believe may exist on a given pipeline. Multiple inspection runs using different tools should prove to be more beneficial than running any single tool to detect defects and anomalies. KMEP will utilize ILI tools capable of detecting metal loss or deformation and where low frequency ERW pipe

or lap-welded pipe exists, run a TFI or other type of crack detection tool. In-line inspection tools are only available in certain sizes and some line segments cannot accommodate them. In that case, alternate inspection techniques will be considered. In conducting an in-line-inspection program, KMEP will evaluate the capabilities of the available inspection tools for the intended application and formulate a plan to validate the results. Sufficient verification excavations will be made to show that the tool is accurate and reliable. Table F1-1 lists the different tools that can be used to address the various threats of concern.

Appendix H8.1 Section 4notes that types of threats identified along pipeline segments dictate the type of inspection methods that are employed. Pipeline segments with multiple threats may require the use of multiple inspection techniques. In accordance with 49 CFR 195.452 (j)(5), only the following methods of integrity assessment are employed:

- In-Line Inspection (ILI) Smart Pigs: It is KMEP's policy to employ ILI for long-line pipeline segments when possible (Appendix F, Pipeline Integrity Assessment Procedures).
- Caliper/geometry Tool
- High Resolution Magnetic Flux Leakage (HR-MFL) Corrosion Tool
- Crack Detection (ultrasonic shear wave, transverse MFL)
- Mapping Tools
- Pressure Testing (Appendix F, Pipeline Integrity Assessment Procedures).
- Other Technology that KMEP and OPS deem appropriate for use. Other Technology may include Direct Assessment (Procedure H8.2, Conduct Direct Assessment).

Appendix H8.1 Section 4.3 requires that prior to selection of an assessment technique, the KMEP Business Unit Integrity Management Teams consider specific threats of the segment in need of evaluation, as assessment methodology selections must be threat based. For the selection of assessment methodology, KMEP Business Unit Integrity Management Teams refer to the guidance provided in Table 8.1-1, Assessment Method Selection Matrix. Table T8.1-1 is to be updated to reflect Consent Agreement #12A.

IMPM Appendix F Section 7 addresses hydrostatic testing which is conduced in accordance with 49 CFR 195 Subpart E has long been accepted as a method of integrity testing of pipelines. Hydrostatic testing lines that have been in service is complicated due to interruption of service and difficulty in acquiring permits to acquire, treat, and dispose of water that will be contaminated by the product being transported. However, hydrostatic testing remains a viable alternative considered by KMEP for integrity testing if the pipeline cannot accommodate passage of an in-line inspection tool, the segment history shows anomalies that are not detectable by internal inspection tools, or the segment is very short. Pressure testing validates integrity at the time of the test by demonstrating the integrity of a pipeline with respect to the established MOP and the leak tightness of a pipeline. Within limits, the greater the ratio of test pressure to operating pressure, the more effective the test. ASME B31.4 and 49 CFR Part 195 currently requires a test pressure 1.25 times MOP at four hours when the pipe can be visually inspected and an additional four hours at 1.1 times the MOP when the pipe cannot be visually inspected. Another test, commonly called a "spike test " is conducted at 1.39 times MOP for approximately 30 minutes to detect linear type defects associated with longitudinal seams.

Appendix F Section 8 addresses Direct Assessment (DA) methodology. DA in accordance with 49 CFR 195.588 may be used to evaluate the integrity of a pipeline system where internal inspection and assessment methods are impractical. Data, including verification dig site data, will be collected, compared and analyzed to further validate each testing procedure and technology, in order to develop a KMEP direct assessment examination standard (see Procedure H8.2, Conduct Direct Assessment).

IMPM Appendix H8.1 Section 4.6.3 requires a review of the type of longitudinal seams, if present, to determine if the use of a crack tool is necessary. Consider the following three areas:

- History of seam failure problems: If there is no history of seam failure, no further tests may be needed.
- Operating pressure: The operating pressure of the pipeline may be low enough that it makes the risk of seam failure negligible.
- Kind of pipe materials used: Pipelines built with pre-1970 low-frequency ERW or lap welded pipe may have the potential for seam

Appendix H8.5: Provide a systematic method for distinguishing and assessing the integrity of low-frequency ERW and lap-welded pipeline segments with the potential to be susceptible to longitudinal seam failure in a High Consequence Area (HCA). These segments will then be evaluated for testing and remediation as outlined in IMP Procedures H7.1 and H8.1. Review the pipeline system to identify those segments containing:

- Low-frequency ERW pipe
- Flash-welded pipe
- Lap-welded pipe
- Unknown seam-type pipe

| **2.01 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **2.01.01** | Assessment method(s) were not adequately specified for all segments in the BAP | AF 2.5 | |
| | **2.01.02** | Assessment method(s) were not technically justified | AF 2.5 | |
| | **2.01.03** | Assessment method(s) appropriate for the segment-specific threats were not adequately selected | AF 2.5 | |
| | **2.01.04** | Assessment method(s) appropriate for pre-70 LF ERW, lap-welded, or flash welded pipe were not adequately selected | AF 2.5 | |
| | **2.01.05** | Adequate technical justification was not provided that pre-70 LF ERW or lap-welded pipe is not susceptible to seam integrity issues | AF 2.5 | |
| | **2.01.06** | A deformation tool was not run and the operator does not intend to excavate all dent indications for MFL tool runs | AF 2.5 | |
| | **2.01.07** | The process did not require PHMSA notification when using "other technology" | AF 2.7 | |
| | **2.01.08** | PHMSA was not notified when using "other technology" | AF 3.6 | |
| | **2.01.09** | The operator did not have a documented BAP | AF 2.7 | |
| | **Other:** | | | |

| Protocol # 2.02 | Baseline Assessment Plan: Prioritized Assessment Schedule |
|---|---|
| **Protocol Question** | Does the Baseline Assessment Plan include a prioritized schedule in accordance with §195.452 (d) that is based on the risk factors required by §195.452 (e)? |

The rule requires that the operator develop a prioritized schedule for assessment of pipeline segments. The operator's Baseline Assessment Plan must exhibit the following characteristics:

1. Identification that all pipeline segments that could affect HCAs are included in the Baseline Assessment Plan. (If the plan identifies line pipe by piggable/testable sections, the documentation should identify a cross reference or other means by which the applicable segments that could affect HCAs can be identified.)
2. Incorporation of newly identified segments that could affect HCAs into the Baseline Assessment Plan within one year from the date the segment is identified as required by §195.452 (d) (3).
3. A prioritization process that considers risk factors that reflect the risk conditions for each pipeline segment, including, at a minimum, consideration of the risk factors contained in §195.452 (e).
4. Revision as appropriate to reflect the insights gained from completed assessments as well as other information that might impact the priority or assessment method of future integrity assessments.

An effective baseline assessment schedule should exhibit the following additional characteristics:

1. The schedule appears to be reasonable and achievable.
2. If the Baseline Assessment Plan prioritizes piggable or assessment sections of pipes where the assessment sections include multiple segments that can affect HCAs, the process for determining the relative priority of assessment sections is carefully explained. Furthermore, the methodology assures the highest risk segments that can affect HCAs are scheduled for assessment early in the period allotted for completing baseline assessments.

Inspection of Baseline Assessment Plan implementation should include a check of the following characteristics:

1. Assessments scheduled for completion were, in fact, completed.
2. Beginning with the highest risk pipe, at least 50% of the line pipe that can affect HCAs are scheduled to be assessed prior to the segments compliance deadline (September 30, 2004 for Category 1 and August 16, 2005 for Category 2). All baseline assessments of the line pipe that can affect HCAs are scheduled to be completed prior to the compliance deadline (March 31, 2008 for Category 1 pipe, February 17, 2009 for Category 2 pipe). Category 3 pipe must have a completed assessment prior to beginning operation.
3. Assessment methods were used as described in the plan.
4. The date on which assessment field activities are completed is recorded.
5. The total pipeline mileage for which assessments have been completed, and the total mileage that can affect HCAs for which assessments have been completed should be available.
6. Based on assessment results information reviewed during the inspection, the data in Part K (Mileage of Baseline Assessments Completed) of the most recent Form PHMSA F 7000-1.1 appear valid and completed per Instructions for Completing Form PHMSA F 7000-1.1.

| | |
|---|---|
| **Rule Requirement** | §195.452 (f) *What are the elements of an integrity management program?* (2) A baseline assessment plan meeting the requirements of paragraph (c) of this section |
| | §195.452 (b) *What program and practices must operators use to manage pipeline integrity?* Each operator of a pipeline covered by this section must: (3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section. |

| | | | |
|---|---|---|---|
| | §195.452 (c) *What must be in the baseline assessment plan?* (1) An operator must include each of the following elements in its written baseline assessment plan ... (ii) A schedule for completing the integrity assessment; | | |
| | §195.452 (d) *When must operators complete baseline assessments?* Operators must complete baseline assessments as follows: (1) *Time periods*. Complete assessments before the following deadlines: | | |
| | If the pipeline is: | Then complete baseline assessments not later than the following date according to a schedule that prioritizes assessments: | And assess at least 50 percent of the line pipe on an expedited basis, beginning with the highest risk pipe, not later than: |
| | Category 1 | March 31, 2008 | September 30, 2004 |
| | Category 2 | February 17, 2009 | August 16, 2005 |
| | Category 3 | Date the pipeline begins operation | Not applicable |
| | §195.452(d)(3) Newly-identified areas. When information is available from the information analysis (see paragraph (g) of this section), or from Census Bureau maps, that the population density around a pipeline segment has changed so as to fall within the definition in Sec. 195.450 of a high population area or other populated area, the operator must incorporate the area into its baseline assessment plan as a high consequence area within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified. | | |
| | §195.452(e) What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)? (1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment. An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. | | |

| **2.02 Inspection Results** | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

| **2.02 Additional Data** | *(Type an X in the applicable box to verify task completion.)* |
|---|---|
| X | **Annual Report Part K Data of the Most Recent Form PHMSA F 7000.1-1 Reviewed** |

**2.02 Inspection Issues Summary**

Assessed mileage reported on the PHMSA Form 7000-1.1 Annual Report for the Wink System (OP ID 31957) for the years 2003 and 2004 was incorrect. It was reported that for 2003 there were 196 miles assessed and for 2004 229 miles were assessed. Review of the Continuing Assessment Plan show that actual mileage assessed is 28 miles for 2003 and 15 miles for 2004. [2.02]

*Note that a Supplemental Annual Report has been submitted by KMEP on December 14, 2006 to correct this concern.*

| 2.02 Documents Reviewed | *(Tab from bottom-right cell to add additional rows.)* | | |
|---|---|---|---|
| **Document Number** | **Rev.** | **Date** | **Document Title** |
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix C1.1 | 4 | 7/31/06 | Baseline Assessment Plan |
| Appendix H4.2 | 6 | 8/21/06 | Identify HCAs (Annual/New/Acquired) |

**2.02 Inspection Notes**

During the course of the inspection efforts were made to confirm the accuracy of the KMEP 2005 PHMSA Form 7000-1.1 Annual Report. Assessed mileage reported on the PHMSA Form 7000-1.1 Annual Report for the Wink System (OP ID 31957) for the years 2003 and 2004 was incorrect. It was reported that for 2003 there were 196 miles assessed and for 2004 229 miles were assessed. Review of the Continuing Assessment Plan show that actual mileage assessed is 28 miles for 2003 and 15 miles for 2004. The following summary reflects reported mileage with the totals for the Wink System corrected:

**KMEP OP ID Mileage**

| | | | Assessed Mileage | | | |
|---|---|---|---|---|---|---|
| OP ID | Mileage | HCA Mileage | Prior | 2003 | 2004 | 2005 |
| 2190<br>Central Florida Pipeline | 201 | 164 | 155 | 0 | 0 | 0 |
| 4472<br>KM Energy Partners | 1681.22 | 901 | 59.8 | 150.9 | 184.9 | 166.1 |
| 15674<br>Plantation Pipeline | 3140 | 2139 | 526 | 508 | 317 | 301 |
| 18092<br>Santa Fe Pacific Pipeline | 2756.48 | 1729.3 | 477 | 197 | 522 | 176 |
| 26041<br>KM Liquids Terminals | 78.87 | 75.88 | 20.87 | 12.15 | 16.84 | 14.38 |
| 26125<br>CalNev Pipeline | 557.39 | 377.8 | 64.2 | 147.2 | 161.7 | 1.96 |
| 31344<br>Heartland Pipeline | 51.6 | 9.3 | 8.5 | 0 | 0.5 | 0 |
| 31451<br>KM Texas Pipeline | Idled & purged | 0 | - | - | - | - |
| 31555<br>KM CO2 | 1196 | 139 | 0 | 128 | 0 | 39 |
| 31957<br>Wink Pipeline | 459 | 44 | 0 | 28 | 15 | 0 |

IMPM Appendix B.1 contains a listing of all HCAs. Appendix C1.1, Baseline Assessment Plan Segment Summary Ranking is the listing of pipelines recommended for inspection in the first 3½ years, and those to be inspected in the second half of the inspection program based on the risk model algorithm. This list has been merged with state and federal requirements and lists the current plan for past and future assessment. Appendix C2 is the Continuing Assessment Plan (CAP).

IMPM 4.4.1 notes that all KMEP operated pipelines have been digitized and have been submitted to the NPMS in accordance with the requirements of the Pipeline Safety Act of 2002. Updates to the pipeline centerline shapefiles are incorporated into the program on an annual basis following the completion of the annual HCA verification process Appendix H4.2 Section 4.3 requires that the KMEP Risk Management Team enters HCA data collected into the KMEP risk analysis database. New shape files are generated from local field interview information on population centers, areas of high population concentration and other high consequence areas for use as additional data sources to define pipe segments that could affect HCAs.

IMPM 5.4.1 addresses the prioritized ranking of KMEP pipeline segments. This ranking is based on risk factors that reflect risk conditions of each pipeline segment. Categories of factors that were considered for the ranking processes include, but were not limited to, the following: HCA information; Historical assessment data; Pipe physical characteristics (e.g. pipe size, material, manufacture, coating, condition, seam type, susceptibility to SCC, etc.); Leak history, repair history, and cathodic repair history; Products transported; Operational parameters (i.e. operating stress level); Existing or projected activities in the area; Local environmental factors (i.e. corrosivity of soil, climate); Geo-technical hazard; Physical support of segments The KMEP risk assessment model was populated with pipeline risk considerations, and a ranking of pipelines organized in order of decreasing weighted average Risk of Failure (ROF) was generated. In 2006, the KMEP risk assessment model ranking of pipelines was organized in order of decreasing Maximum Risk of Failure (Max ROF) in order to highlight the worst case risk scores for each pipeline segment included in the Analysis (the ROF score calculation is simply the LOF score x COF score per calculation section). Appendix C1.1, Baseline Assessment Plan, contains the ranking of pipeline segments and details ROF, LOF, COF, and HCA information.

IMPM 5.4.5 notes that the Baseline Assessment Plan shown in Appendix C1.1, Baseline Assessment Plan, has been reviewed by Subject Matter Expert (SME) teams for validation purposes. Additionally, the SME teams integrated state and other requirements as necessary. KMEP's Baseline Assessment Plan Validation Process is presented in Procedure H8.4, Baseline Assessment Plan Validation. The plan reflects KMEP's most current information of its system at the time of publication. The initial Baseline Assessment Plan published on March 31, 2002 was considered a dynamic document that was intended to be updated as new information became available. The final Baseline Assessment Plan was published on January 29, 2003. IMPM 5.4.7 requires that in the event that new lines are acquired or constructed, they are to be added to the CAP. The CAP process is presented in IMPM Section 8, Continuing Assessment and Analysis. IMPM Appendix H8.7 Section 4.5 also requires that CAP reports be reviewed by Business Unit subject matter experts who are to verify that the CAP is reasonable from their experiential beliefs for the risk of the listed pipeline segments.

| **2.02 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **2.02.01** | A BAP was not issued by the required deadline | AF 2.7 | |
| | **2.02.02** | Idle lines were removed from the BAP without adequate justification | AF 2.7 | |
| | **2.02.03** | 100% of the segment assessments were not scheduled prior to the compliance deadline for completion | AF 2.1 | |
| | **2.02.04** | At least half of the segment assessments that affect HCAs (by mileage) were not scheduled prior to the compliance deadline for the 50% progress milestone | AF 2.2 | |
| | **2.02.05** | Schedules contained inadequate detail, were unrealistic or exhibited evidence of lack of realistic planning such as using the same September 30, 2004 schedule date for 50% of the segments | AF 2.7 | |
| | **2.02.06** | High risk segments were not included in the first 50% without adequate justification | AF 2.4 | |
| | **2.02.07** | The process did not adequately include all of the relevant risk factors required by the rule in performing a risk analysis for BAP scheduling | AF 2.4 | |
| | **2.02.08** | A risk evaluation that was not up-to-date was used for BAP scheduling | AF 2.4 | |
| | **2.02.09** | The BAP schedule did not adequately reflect the relative risk of the HCA affecting segments | AF 2.4 | |
| | **2.02.10** | Baseline assessments were not completed for 50% of the HCA mileage by the required date | AF 2.2 | |
| | **2.02.11** | Baseline assessments were not completed for 100% of the HCA mileage by the required date | AF 2.1 | |
| | **2.02.12** | Assessments were not performed as scheduled in the first | AF 2.2 | |

| | | | | |
|---|---|---|---|---|
| | | half of the BAP | | |
| | **2.02.13** | Assessments were not performed as scheduled in the second half of the BAP | AF 2.1 | |
| | **2.02.14** | Completion of baseline assessments was not adequately documented | AF 2.7 | |
| **X** | **2.02.15** | Annual Report Part K Data of the most recent Form PHMSA F 7000-1.1 incomplete and/or invalid | NA | E |
| | **Other:** | | | |

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| Protocol # 2.03 | Baseline Assessment Plan: Prior Assessments |
|---|---|
| **Protocol Question** | Does the Baseline Assessment Plan make use of prior assessments as baseline assessments? |

Assessments performed prior to the effective date of the rule may be used as baseline assessments provided they are consistent with rule requirements for baseline assessments. The operator's Baseline Assessment Plan must exhibit the following characteristics:

1. Evidence that baseline assessments performed after January 1, 1996 but before March 31, 2002, for Category 1 pipelines have been performed using the methods prescribed in §195.452 (c) (1) and that repairs have been categorized and completed in accordance with the requirements of the IM rule if the line has been in service after March 31, 2002.
2. Evidence that baseline assessments performed after February 15, 1997 but before February 18, 2003, for Category 2 pipelines have been performed using the methods prescribed in §195.452 (c) (1) and that repairs have been categorized and completed in accordance with the requirements of the IM rule if the line has been in service after February 18, 2003.

| **Rule Requirement** | §195.452 (d) (2) *Prior assessment*. To satisfy the requirements of paragraph (c)(1)(i) of this section for pipelines in the first column of the following table, operators may use integrity assessments conducted after the date in the second column, if the integrity assessment method complies with this section. However, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe according to paragraph (j)(3) of this section. The table follows: |
|---|---|

| Pipeline | Date |
|---|---|
| Category 1 | January 1, 1996 |
| Category 2 | February 15,1997 |

| **2.03 Inspection Results** | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

| **2.03 Inspection Issues Summary** |
|---|
| |

**2.03 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix C1.1 | | 8/31/06 | Baseline Assessment Plan |
| Appendix H5.2 | 5 | 10/28/05 | Select And Use Prior Assessment For Baseline Assessment |

**2.03 Inspection Notes**

Appendix C1.1 is the Baseline Assessment Plan Segment Summary Ranking

IMPM 5.4.6 notes that KMEP has determined that pipelines inspected after calendar year 2000 are eligible for use as a baseline assessment. However, KMEP only considered in-line inspections and pressure testing in its consideration of prior assessments. See Procedure H5.2, Select and Use Prior Assessments for Baseline Assessments.

Appendix H 5.2 Section 1notes that prior integrity assessment tests may be selected for use as the baseline assessment of the KMEP IMP. Selection is to occur prior to March 31, 2002. Section 2 requires the analysis of completed integrity assessments of selected pipe segments to ensure the data gathered as a part of those assessments and resulting repairs made to the segment comply with the requirements of the KMEP IMP and can be used as a part of the BAP. Section 4.1.1notes that integrity assessments performed after January 1, 1996 may be used to validate segment integrity if the assessment approach and documentation are consistent with the provisions of the IMP. KMEP has chosen to consider only in-line inspections or pressure testing conducted after January 1, 2000 in its consideration of prior assessments. In evaluating the results of the integrity assessments, Business Unit assessment personnel must integrate information from other relevant sources with the inspection or testing results to assure that the assessment fully identified and characterized any potential threats to pipeline integrity. Section 4.1.3 specifies that to be considered for use as the baseline assessment, an assessment must be reviewed to determine the presence of any unremediated anomalies. If any immediate, 60-day, or 180-day unremediated anomalies are present, they must be repaired in the timeframe as described in Procedure H7.1, Collect, Receive, and Analyze IMP Assessment Data – Formulate Repair Schedule, and no greater than 180 days after the assessment has been declared to be the baseline assessment. Section 4.1.4 notes that the risk ranking of the pipe segment on the KMEP Baseline Assessment Plan may be used in making a determination whether or not to use a prior assessment. Section 4.4 specifies that assessments that are to be utilized as baseline assessments must be conducted by tools capable of assessing risk factors identified in the BAP.

2.03 #2 - N/A

| **2.03 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **2.03.01** | BAP has prior assessments that were conducted before the date allowed by the rule | AF 2.3 | |
| | **2.03.02** | A prior assessment method did not adequately meet rule requirements for assessment method | AF 2.3 | |
| | **2.03.03** | All anomalies discovered in prior assessment were not adequately evaluated in accordance with remediation criteria in the rule | AF 2.3 | |
| | **2.03.04** | A prior assessment was used that precludes compliance with the 5 year re-assessment requirement for prior assessments | AF 2.3 | |
| | **Other:** | | | |

# Integrity Management
# Inspection Protocol 3

## Integrity Assessment Results Review

**Scope:**

This Protocol addresses the review, validation, and evaluation of results from integrity assessments (i.e., in-line inspection, pressure testing, or other technologies). In addressing this program element, this protocol covers verification of information accuracy, the integration of other information about the pipeline with the assessment results to help identify and characterize defects, and obtain an improved understanding about the condition of the pipe.

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| Protocol # 3.01 | Integrity Assessment Results Review: Qualifications of Individuals that Review and Evaluate Assessment Results |
|---|---|
| **Protocol Question** | Does the operator have a formal, documented process to ensure that individuals who review and evaluate integrity assessment results are qualified to perform this work?<br>_____<br>Review records such as job descriptions, resumes, training records, etc., to verify that individuals that review assessment results are qualified to do so. |

The rule requires that individuals who review assessment results and information analysis be qualified to do so. An effective operator program would be expected to require that appropriate means be taken to ensure the requisite level of qualification, and contain the following characteristics:

1. Job description, task analysis, or other means to identify the qualification requirements for performing reviews of assessment results and information analysis, that address education, experience, skills, and training requirements, as appropriate.
2. Documentation of existing personnel skills, education, training, and experience that (1) demonstrates the individual's qualification and proficiency, and (2) identifies additional qualification needs for those individuals that do not meet all qualification requirements.
3. Plan and schedule to provide additional training or skills acquisition to achieve and maintain qualification requirements, as applicable.

[For review of individual qualifications for external corrosion direct assessment (ECDA) refer to protocol 7.03.]

| | |
|---|---|
| **Rule Requirement** | §452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program:<br>(8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section). |

| 3.01 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**3.01 Inspection Issues Summary**

KMEP has received written commitment from two of their ILI vendors to implement the qualification requirements of API 1163 (ASNT-ILI-PQ-2005) for those personnel who review and evaluate integrity assessment results. The Inspection Team reviewed the process in Appendix H8.1, Section 4.8.2.2 in which KMEP details the process of ensuring that ILI vendor personnel are qualified to perform the analysis through interviews with the lead ILI vendor personnel at a minimum. While it appears that KMEP meets the intent of §195.452(f)(8) for a process for review of integrity assessment results by a person qualified to evaluate the results, the entire process should have additional structure detailed in the IMPM. KMEP updated the Client Analysis Profile during the inspection to require that any analysts working on grading of an ILI tool run meet the requirements specified in API 1163 and ANST ILI-PQ-2005. [Protocol 3.01]

*Materials were received from Mike Outlaw of KMEP following the inspection on December 1, 2006 concerning this issue, and the revisions were reviewed and deemed adequate: KM has modified IMPM Appendix H8.1, Select Best Assessment Tool and Vendor, section 4.8.2 to address this issue. The revised Appendix H8.1 procedure now has additional structure detailed that includes the interview process with vendor personnel and details to show compliance with API 1163.*

**3.01 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| | | | |

**3.01 Inspection Notes**

IMPM 7.4.2 and Appendix H7.1 Section 3.4: Only qualified individuals review and analyze information generated from integrity assessments. Persons evaluating integrity assessment results have specific training and/or experience to qualify them for their specific work tasks. KMEP personnel involved in the review and evaluation of integrity assessment results (evaluation is a validation of the report data vs. the field evaluations) possess at least, or work under the direct supervision of someone who has, a Bachelor of Science Degree in an engineering discipline, or a related field and knowledge by formal training and/or experience of applicable pipeline regulations and industry standards. The Inspection Team reviewed the job descriptions for the 4 KMEP individuals who perform information analysis.

IMPM 1.2.1: The KMEP Director, Pipeline Integrity is responsible for oversight of the entire integrity management program and insuring that KMEP has the necessary resources to implement and comply with the policies and procedures contained in the IMP manual.

Requirements for vendor – vendor presents process and methodology prior to the use of them by KMEP. Vendors required to work under the bounds of API 1163. Expectation is included in the tool contract and the Customer Profile Checklist. Vendors are audited by KMEP.

IMPM Appendix H8.1 Section 4.8.1 and 4.8.2 provide requirements for the evaluation of vendor capabilities. The GE-PII and Magpie commitment to API 1163 requirements was reviewed. Client Profiles are developed for each ILI vendor. The profile spells out KMEP expectations and is consistent with requirements from API 1163. KMEP updated the Client Analysis Profile during the inspection to require that any analysts working on grading of an ILI tool run meet the requirements specified in API 1163 and ANST ILI-PQ-2005.

Appendix H7.3, Section 3.2.5 requires that KEMP NDE processes being performed are documented with a procedure and that employees have received comprehensive and documented training.

| **3.01 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| X | **3.01.01** | A process was not adequately developed to qualify personnel reviewing assessment results | AF 3.1 | E |
| | **3.01.02** | Qualified personnel were not used to review assessment results | AF 3.1 | |
| | **Other:** | | | |

| Protocol # 3.02 | Integrity Assessment Results Review: ILI Vendor Specifications |
|---|---|
| **Protocol Question** | Do the requirements established by the operator for the In-Line Inspection (ILI) assessment process (such as ILI technical specifications, scope of work statements, etc.) assure that those responsible for conducting in-line integrity assessments (i.e., ILI tool vendors) understand their responsibilities in performing integrity assessments that comply with this rule? |

ILI tool vendors perform an important role in pipeline integrity. However, the operator is ultimately responsible for the quality of assessments and the validity of tool data analysis. An effective operator program would be expected to demonstrate that the ILI vendor has met all of the requirements of the rule. This includes:

1. The final vendor report is provided within 180 days of completion of the assessment.
2. The vendor uses the tool(s) specified by the operator.
3. The vendor reports immediate conditions or other conditions indicating a serious threat to line integrity in a timely fashion.
4. The vendor report identifies and categorizes all anomalies.

[For review of vendor specifications for external corrosion direct assessment (ECDA) refer to protocol 7.03.]

| | |
|---|---|
| **Rule Requirement** | §452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program:<br>(4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section); |
| | §452 (h) *What actions must an operator take to address integrity issues?*<br>(2) *Discovery of a condition*. Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable. |

| 3.02 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**3.02 Inspection Issues Summary**

The KMEP Client Analysis Profile fails to specify that ILI vendors must contact KMEP promptly upon the identification of an immediate condition. The Client Analysis Profile (step 15) defines an ILI vendor expectation for the ILI vendor to contact KMEP lead personnel regarding immediate conditions prior to submitting a final report rather than promptly following identification of the condition. The Client Analysis Profile was updated during the inspection to ensure ILI vendors promptly contact KMEP upon identification of any immediate conditions.

**3.02 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix H8.1 | 6 | 8/28/06 | Select The Appropriate Assessment Tool And Vendor |
| Appendix H7.3 | 3 | 8/18/06 | ILI Metal Loss Tool Grading And Validation |

**3.02 Inspection Notes**

Appendix H8.1 Section 4.2 notes that the types of threats identified along pipeline segments dictate the type of inspection methods that are employed. Pipeline segments with multiple threats may require the use of multiple inspection techniques. In accordance with 49 CFR 195.452 (j)(5), only the following methods of integrity assessment are employed:

- In-Line Inspection (ILI) Smart Pigs
- Caliper/geometry Tool
- High Resolution Magnetic Flux Leakage (HR-MFL) Corrosion Tool
- Crack Detection (ultrasonic shear wave, transverse MFL)
- Mapping Tools
- Pressure Testing (Appendix F, Pipeline Integrity Assessment Procedures).
- Other Technology that KMEP and OPS deem appropriate for use. Other Technology may include Direct Assessment

Appendix H8.1 Section 4.8 addresses ILI vendor selection. KMEP develops bid sheets and customer profiles for vendors. Bid sheets and customer profiles include tool performance specifications, report requirements, project timing, and other considerations identified by the project team. Appendix H7.3 Section 3.2 requires that the ILI 'Customer Profiles' for each ILI metal loss tool vendor, incorporate an ILI results process that accounts for the tool tolerances, interaction lengths and corrosion growth rates in the pre-validation grading of the dimensions of metal loss anomalies listed in the ILI Final Report.

IMPM 7.4.3 and Appendix H7.1, Section 4.1.2 define discovery of a condition. Discovery of a condition occurs when adequate information is obtained about the condition to determine if it represents a potential threat to the integrity of the pipeline. Depending on circumstances, adequate information may be obtained when KMEP receives the preliminary internal inspection report, gathers and integrates information from other inspections or the periodic evaluation, excavates the anomaly, or when the final internal inspection report is analyzed. For instances in which geometry/metal loss tool runs are not run simultaneously, data analysis shall start within three months of completion of any individual tool run. This is based on 60 days to complete vendor analysis and 30 days for Business Unit analysis to achieve "discovery" prior to 180-day regulatory requirement. Discovery shall occur when KMEP has sufficient data from each individual tool run to indicate a potential threat to the integrity of the asset. Procedure H7.1, Collect, Receive, and Analyze IMP Assessment Data – Formulate Repair Schedule,

is the procedure for reviewing data received from vendors and procedure H7.3, ILI Metal Loss Tool Grading and Validation is the procedure for documenting validation. Sufficient information about a condition to make that determination must be obtained promptly, but no later than 180 days after an integrity assessment, unless KMEP can demonstrate that the 180-day period is impracticable. Inline inspection data is reviewed on the next business day after receiving the final vendor report. For data completeness per the requirements of the Customer Profile, the final vendor report is forwarded on to the Business Unit Integrity Management Team for response per 195.452(h) timelines. The information about the tool run is captured on a "Data Summary" form in which the HCA related anomalies are identified as a function of the required remediation time. A copy of this form is included in Procedure H7.1, Collect, Receive, and Analyze IMP Assessment Data – Formulate Repair Schedule.

Crack tools require a substantial amount of time to grade the data results and will often exceed 180 days. To facilitate the grading, validation digs will begin prior to completion of the report. These early digs are to provide the analyst with data to calibrate" the data grading.

IMP 7.4.4 addresses validation of ILI assessment results. Anomalies reported by the inline tool vendors are used as presented. KMEP recognizes that the reported tool tolerances are ±10% accurate 80% of the time. An ILI tool Action Plan is developed with each ILI tool run and managed as outlined in Procedure H7.3, ILI Metal Loss Tool Grading and Validation. In order to continually assess the performance of the ILI vendor, KMEP will track the correlation between reported and measured anomalies using Procedure H7.1, Collect, Receive, and Analyze IMP Assessment Data – Formulate Repair Schedule.

Appendix H7.1 Section 4.4 addresses ILI preliminary reports. The ILI vendor provides a preliminary report within the contract defined time period after running the tool and verifying survey data quality. The purpose of this report is to identify conditions that require an immediate response. Appropriate SMEs use reasonable efforts to evaluate the report data for 49 CFR 195.452(h)(4) related conditions by the next business day after receiving the report from the ILI vendor. If Immediate Repair Conditions, are noted in the Preliminary Report, immediately reduce pressure to safe limits or shut down the pipeline. Immediately contact the KMEP Director of Pipeline Safety and appropriate Business Unit personnel as outlined in governing Business Unit operating and emergency procedures. The Director of Pipeline Safety provides guidance regarding any Safety Related Condition Reports and/or State requirements governing pipeline segments within the work area. Initiate pipeline repair procedures and/or pressure reduction procedures in accordance with the KMEP Integrity Management Manual and governing Business Unit operations/maintenance procedures. Adhere to environmental, local or state "one call", and other requirements outlined in the KMEP Integrity Management Manual and the Business Unit procedures.

| **3.02 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **3.02.01** | The tool vendor was not required to use, or did not use, the assessment method specified in the BAP | AF 3.5 | |
| **X** | **3.02.02** | Vendor specifications did not require timely discovery and reporting of rule required repair conditions to the operator (particularly timely reporting of immediate repair conditions) | AF 3.2 | E |
| | **3.02.03** | Vendor specifications did not contain important requirements (e.g., tool tolerances and timeframes for ILI reports) | AF 3.3 | |
| | **3.02.04** | Vendor specifications did not provide for appropriate categorization of anomalies | AF 3.3 | |
| | **Other:** | | | |

| Protocol # 3.03 | Integrity Assessment Results Review: Validation of Assessment Results |
|---|---|
| **Protocol Question** | Does the operator's integrity assessment results review process provide sufficient assurance that all activities required to verify the accuracy of the in-line inspection data are identified and implemented?<br>_____<br>Review selected dig records to verify that physical pipeline data obtained from field excavations was appropriately used to validate ILI results. |

After ILI tool runs are completed, an operator may implement a process by which called anomalies are excavated so that tool results may be validated using actual, measured defect characteristics, in order to have confidence in the assessment results. An effective operator program would be expected to have the following characteristics:

1. Determination of the appropriate number (representative sample) and type of defects (representative of the different types of anomalies called such as internal corrosion, external corrosion, and dents) for which validation digs are required.
2. Identification, collection, and documentation of all pertinent information during the validation dig process, and dissemination to the individuals reviewing assessment results.
3. Field validation digs that assure that the locations of all anomalies are verified, and that collect all information needed to compare the actual anomaly characteristics to the vendor report.

If an operator chooses not to validate tool results, an effective operator program would be expected to have documented justification to demonstrate that validation activities are not necessary for its circumstances.

| | |
|---|---|
| **Rule Requirement** | §452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section) |
| | §452 (h) (2) *Discovery of a condition*. Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable. |

| 3.03 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**3.03 Inspection Issues Summary**

**3.03 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| Appendix H7.1 | 6 | 8/31/06 | Collect, Receive And Analyze IMP Assessment Data - Formulate Repair Schedule |
| | | 8/28/06 | Integrity Management Program Manual |

**3.03 Inspection Notes**

Appendix H7.1 Section 4.4.2.2 notes that the Project Manager is responsible for preparing an Action Plan based on the final report and consistent with the procedures outlined in H7.2, Uniform Girth Weld Positioning and H7.3, ILI Metal Loss Tool Grading and Analysis. Published defects must be responded to in accordance with the HCA Response Table provided in Attachment 1 of this procedure. Section 4.4.2.3 requires that following an Action Plan, pressure reductions are to be taken in response to immediate repair conditions as noted in Section 4.4.1.5. A minimum of one validation dig is to be conducted for each ILI tool run within 60 days of receiving the final report. Validation digs shall be selected to include a representative sample of anomaly types and depths. Anomalies shall be evaluated and documented in order to validate the ILI tool run results. When the accuracy of the data is determined, by analysis and or validation digs, KMEP is to determine if the anomalies can affect an HCA. IMPM 7.4.5.6 also specifies that KMEP performs validation digs in accordance with H7.1 and documents findings and results in the Action Plan.

Appendix H7.1 Section 4.4.2.2 notes that all noted requirements identified in the procedure that are associated with the preliminary report are also required for the final report. In addition, the Project Manager is responsible for preparing an Action Plan based on the final report and consistent with the procedures outlined in H7.2, Uniform Girth Weld Positioning and H7.3, ILI Metal Loss Tool Grading and Analysis. Published defects must be responded to in accordance with the HCA Response Table.

Appendix H7.1 Section 4.4.4: Evaluation of anomaly accuracy activities run in parallel to those identified in the preliminary and final ILI reports. KMEP is required to evaluate ILI anomaly accuracy by assessing the performance of the vendor and tool. By tracking with a "unity" chart, the correlation between reported (before excavation) and measured (after excavation) features and anomalies, KMEP ensures that the severities of reported anomalies are accurate and that the tools are performing within tolerance. Discrepancies for items that cannot be resolved internally by KMEP must be submitted to the ILI vendor for further analysis/ re-grading.

Appendix H7.1 Section 4.4.5 notes that KMEP assesses ILI tool performance by comparing the indicated anomalies to the actual field findings as outlined in Procedure H7.3, ILI Metal Loss Tool Grading and Analysis and the Action Plan process. By assessing ILI tool performance, the error associated with ILI tools can be better quantified and the results are calibrated accordingly. The "Unity Charts" on tool performance are developed at the validation and Closure steps of the Action Plans and are forwarded on to the ILI vendor. Upon receiving a completed completion report from the field, the Manager, Pipeline Integrity incorporates the dig and the ILI results into the ILI Data Validation and Results Review Form or equivalent.

| **3.03 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **3.03.01** | Assessment results were not provided that were of adequate quality and consistent with specified tool tolerances | AF 3.3 | |
| | **3.03.02** | Adequate assurance was not provided through calibration/verification digs, or other means, that tool data are valid and suitable for integrity-related analysis | AF 3.3 | |
| | **3.03.03** | Known field information was not adequately considered to correct invalid assessment data | AF 3.3 | |
| | **3.03.04** | Tool tolerance was not adequately considered in evaluating ILI results | AF 3.3 | |
| | **3.03.05** | Assessment results were not adequately correlated when field calls did not match vendor results | AF 3.3 | |
| | **3.03.06** | The review of assessment results was not adequately documented | AF 3.3 | |
| | **Other:** | | | |

| Protocol # 3.04 | Integrity Assessment Results Review: Integration of Other Information with Assessment Results |
|---|---|
| **Protocol Question** | Does the operator's integrity management process documentation require the integration of additional sources of pertinent risk-factor data with the assessment results (either ILI, pressure testing, or "other technology") to support evaluation of the condition of the pipeline, or to make decisions related to the repair or remediation of pipeline defects?<br>_____<br>Review records documenting the operator's review of assessment results to determine if the operator integrates and analyzes all appropriate sources of other information with the assessment data. |

The rule requires that operators integrate assessment results with other pertinent information about the risk-conditions of the pipeline to uncover integrity issues that might not be evident from the assessment data alone. An effective operator program would be expected to have the following characteristics:

1. A process to ensure that the analyst is aware of and uses other sources of data in order to make the best integrity decisions (e.g., corrosion control data such as rectifier readings, close interval surveys, or corrosion coupon results).
2. A documented process by which data is collected and disseminated to persons evaluating assessment results.
3. A process that integrates the following types of information, as appropriate:
    - Previous assessment results;
    - Surveillance, testing, and other monitoring data (e.g., internal corrosion coupon monitoring);
    - Historical maintenance and repair information;
    - Uncertainty of assessment results including tool tolerances;
    - Any other information related to pipeline integrity; and
    - Information about how a failure would affect the high consequence area.
4. Consideration of new information such as industry reports on new technology, incident reports, etc.
5. Documentation of the overall results of integrated data analysis and conclusions regarding the integrity of the segment, including the nature of the integrity threats identified, and a reliable characterization of anomalies such as type of anomaly (e.g., internal corrosion, external corrosion, and dents), size (amount of metal loss, depth of dent) and location (e.g., axial location and circumferential orientation).
6. Identification and documentation of integrity issues and potential trends in the integrity of the pipeline.

| | |
|---|---|
| **Rule Requirement** | §452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section) |
| | 452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. This information includes: (1) Information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline segment; (2) Data gathered through the integrity assessment required under this section; (3) Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys; and (4) Information about how a failure would affect the high consequence area, such as location of the water intake. |

| 3.04 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**3.04 Inspection Issues Summary**

**3.04 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/26/2006 | Integrity Management Program Manual |
| Appendix F | 7 | 10/6/2006 | Pipeline Integrity Assessment Procedures |

**3.04 Inspection Notes**

IMPM 7.4.6 addresses the integration of other data. In order to ensure that remediation decisions are made based upon the best available information, KMEP integrates other pipeline data with the assessment results. The following categories of data are considered:

- ILI Results
- Cathodic Protection
- Historical Information
- Local Knowledge
- Other (i.e. program performance and lessons learned) The Business Unit Integrity Management Teams review other data to ensure all anomalous conditions are identified.

Appendix F Section 7.1 notes that when KMEP chooses to employ pressure testing as its integrity assessment tool, the quality and effectiveness of the pipeline corrosion control program will be reviewed. This includes data such as release history, cathodic protection annual survey results, pipeline current demand, results of cathodic protection close interval survey data, coating integrity and results of open hole (open assessment) reports and, if available, previous ILI results.

Action Plan Templates and Integrity Alignment Sheet also provide a means for analysts to review integrated pipeline data.

IMPM 7.4.4 addresses validation of ILI assessment results. Anomalies reported by the inline tool vendors are used as presented. KMEP recognizes that the reported tool tolerances are ±10% accurate 80% of the time. A rigorous and engineered ILI tool Action Plan is developed with each ILI tool run and managed as outlined in Procedure H7.3, ILI Metal Loss Tool Grading and Validation. In order to continually assess the performance of the ILI vendor, KMEP will track the correlation between reported and measured anomalies using Procedure H7.1, Collect, Receive, and Analyze IMP Assessment Data – Formulate Repair Schedule.

Appendix F Section 11 includes the Assessment Interval Form. This form is used to record key integrity data:

- In-service failures
- Previous tool run data
- Most recent tool run data
- Hydrostatic test data
- Other surveys, inspections, and corrosion protection information
- Repairs completed

- Preventive and mitigative measures taken
- Risk analysis and risk factors
- Segment reassessment interval

| **3.04 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **3.04.01** | The data integration process was not adequately used to identify integrity threats (e.g., external corrosion problem identified from CP data) | AF 3.3 | |
| | **3.04.02** | The process did not adequately require the integration of other pertinent data in a timely manner, when evaluating assessment results | AF 3.3 | |
| | **3.04.03** | Other pertinent data was not adequately integrated in a timely manner, when evaluating assessment results | AF 3.3 | |
| | **3.04.04** | As-found excavation data was not adequately captured or used in other aspects of the IM program | AF 3.3 | |
| | **Other:** | | | |

| Protocol # 3.05 | Integrity Assessment Results Review: Identifying and Categorizing Defects |
|---|---|
| **Protocol Question** | Does the operator's process documentation provide adequate guidance to assure the appropriate categorization (and scheduling for repair) of all identified anomalies in accordance with the criteria contained in the rule?<br>_____<br>Review assessment records to verify that defects have been discovered within 180 days of completion of the assessment and that defects have been categorized in accordance with the special requirements for scheduling remediation contained in §452 (h) (4). |

Upon discovery of a condition, the operator is required to determine if the condition meets any of the rule's special requirements for scheduling remediation. If so, repair or remediation must be scheduled for completion within the time frames established by the rule. An effective operator program would be expected to have the following characteristics:

1. Provisions to ensure that all repair conditions are discovered within 180 days of completion of the assessment.
2. Procedures to ensure that all anomalies are correctly categorized in accordance with the repair provisions of the rule ("immediate repair," 60-day, 180-day, and "other" conditions).
3. Procedures that define the time at which the discovery of an anomaly occurs.
4. Procedures that define actions to be taken if the review cannot be completed within 180 days of assessment completion. (The rule specifically requires that the operator demonstrate that discovery within 180 days is not practical and document this justification.)

| | |
|---|---|
| **Rule Requirement** | §452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section); |
| | 452 (h) (2) *Discovery of a condition.* Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable. |
| | 452 (h) (4) *Special requirements for scheduling remediation* (i) *Immediate repair conditions* ... (ii) *60-day conditions* ... (iii) *180-day conditions* ... (iv) *Other conditions*.... |

| 3.05 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**3.05 Inspection Issues Summary**

1) The KMEP Action Plan Template does not require that the date final ILI reports are received and also the date they are accepted be recorded by KMEP. The previous version of the template required that the date the final report is forwarded to the field be recorded. Without acknowledging all three dates, actions to ensure discovery of anomalous conditions may not occur in a timely manner. In Appendix H7.3, Section 4.4.2.1 certain steps are outlined but are not captured in the chronological data table: these steps being when the report is received by KMEP and when it is accepted. The Inspection Team notes that KMEP has made the necessary changes to the Action Plan Template to resolve this concern.

2) Appendix H7.1, Section 4.4.2.3 requires that a minimum of one validation dig be conducted for each ILI tool run within 60 days of receiving the final report. A consumption of 60 days for validating the results of the ILI report and conducting validation dig delays declaration of discovery of anomalous conditions and potentially delays the repair of anomalies meeting 60-day criteria beyond the required timeframe. Appendix H7.3 details the process and procedures used during the ILI Metal Loss Tool Grading and Validation. The Inspection Team reviewed proposed changes and detail to the discovery process for specific tools (and threats), and we continue to review how this process for discovery timeframes align with rule requirements and PHMSA expectations. The process to declare discovery must be sufficiently detailed to ensure consistent application within typical applications.

*Materials were received from Mike Outlaw of KMEP following the inspection on December 1, 2006 concerning this issue, and the revisions were reviewed and deemed adequate: KM has modified IMPM, section 7.4.3 and Appendix H7.1, section 4.1.2, and Appendix H7.3, section 4.4 to address this issue.*

**3.05 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| Appendix H7.1 | 6 | 8/31/06 | Collect, Receive And Analyze IMP Assessment Data - Formulate Repair Schedule |
| | | 8/26/2006 | Integrity Management Program Manual |

**3.05 Inspection Notes**

IMPM 7.4.3 addresses discovery of condition. Discovery of a condition occurs when adequate information is obtained about the condition to determine if it represents a potential threat to the integrity of the pipeline. Depending on circumstances, adequate information may be obtained when KMEP receives the preliminary internal inspection report, gathers and integrates information from other inspections or the periodic evaluation, excavates the anomaly, or when the final internal inspection report is analyzed. For instances in which geometry/metal loss tool runs are not run simultaneously, data analysis shall start within three months of completion of any individual tool run. This is based on 60 days to complete vendor analysis and 30 days for Business Unit analysis to achieve "discovery" prior to 180-day regulatory requirement. Discovery shall occur when KMEP has sufficient data from each individual tool run to indicate a potential threat to the integrity of the asset. Procedure H7.1, Collect, Receive, and Analyze IMP Assessment Data – Formulate Repair Schedule, is the procedure for reviewing data received from vendors and procedure H7.3, ILI Metal Loss Tool Grading and Validation is the procedure for documenting validation. Sufficient information about a condition to make that determination must be obtained promptly, but no later than 180 days after an integrity assessment, unless KMEP can demonstrate that the 180-day period is impracticable. Inline inspection data is reviewed on the next business day after receiving the final vendor report. For data completeness per the requirements of the Customer Profile, the final vendor report is forwarded on to the Business Unit Integrity Management Team for response per

195.452(h) timelines. The information about the tool run is captured on a "Data Summary" form in which the HCA related anomalies are identified as a function of the required remediation time. A copy of this form is included in Procedure H7.1, Collect, Receive, and Analyze IMP Assessment Data – Formulate Repair Schedule.

IMPM 7.4.5 defines the following conditions as immediate repair conditions:

- Metal loss greater than 80% of nominal wall regardless of dimensions.
- Predicted burst pressure less than the established maximum operating pressure at the location of the anomaly. Dents on the top of the pipeline (above 4 and 8 o'clock position) with any indicated metal loss, cracking or a stress riser.
- A dent located on the top of the pipeline (above the 4 and 8 o'clock position) greater than 6 % of the nominal diameter.
- An anomaly that in the judgment of the person designated by KMEP to evaluate the assessment results requires immediate action.
- IMPM 7.4.5.3 defines 60-day conditions as the following:
- A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 3 % of the pipeline diameter (greater than 0.250 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12)
- A dent located on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser.

IMPM 7.4.5.3 defines 60-Day Conditions as follows:

- A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld
- A dent located on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser.

IMPM 7.4.5.4 defines 180-Day Conditions as follows:

- A dent located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12).
- A dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline's diameter.
- A calculation of the remaining strength of the pipe shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (''Manual for Determining the Remaining Strength of Corroded Pipelines'' (1991)) or AGA Pipeline Research Committee Project PR–3–805 (''A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe'' (December 1989)).
- An area of general corrosion with a predicted metal loss greater than 50% of nominal wall.
- Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.
- A potential crack indication that when excavated is determined to be a crack.
- Corrosion of or along a longitudinal seam weld.
- A gouge or groove greater than 12.5% of nominal wall.

Appendix H 7.1 Section 4.1.2 notes that discovery is considered to have been made when adequate assessment and validation data is available for qualified personnel to determine that a condition is a potential threat to the integrity of the pipeline. This determination occurs no more than 180 days from the date an inline inspection, hydrostatic test, or other IMP assessment is complete unless it is demonstrated that the 180-day period is impracticable. Refer to Procedure H8.3, DOT Notifications and Variances, for notification requirements. This time frame includes the time needed to evaluate data received from the assessment vendor. Upon discovery of anomalies in areas where a pipeline segment can affect an HCA, the repairs must be coordinated and completed in accordance with the KMEP Integrity Management Program Manual and Attachment 1 of this procedure.

| **3.05 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|

| | | | | |
|---|---|---|---|---|
| X | **3.05.01** | Anomalous conditions were not discovered within 180 days of the assessment or when sufficient information was available | AF 3.2 | E |
| | **3.05.02** | The process did not adequately specify what constitutes "completion" of an assessment | AF 3.2 | |
| | **3.05.03** | The process did not adequately specify actions when discovery cannot be made within 180 days | AF 3.2 | |
| X | **3.05.04** | The process did not adequately require discovery date declaration within 180 days of an assessment or when sufficient information is identified | AF 3.2 | E |
| | **3.05.05** | The appropriate operating pressure reduction was not correctly determined when a reduction was required | AF 4.2 | |
| | **3.05.06** | Discovered anomalies were not properly classified per 195.452(h)(4) | AF 3.3 | |
| | **3.05.07** | Dents with unknown orientation were not conservatively classified | AF 3.3 | |
| | **3.05.08** | The process did not adequately address integrity assessment results review requirements in the IM program | AF 3.3 | |
| | **3.05.09** | The process did not incorporate adequate review or other mechanisms to assure assessment results quality | AF 3.3 | |
| | **Other:** | | | |

| Protocol # 3.06 | Integrity Assessment Results Review: Hydrostatic Pressure Testing |
|---|---|
| **Protocol Question** | For integrity assessments using hydrostatic pressure testing, has the operator reviewed the test results to determine whether the failures experienced imply that additional assessment activities are needed?<br>_____<br>Review hydrostatic pressure test records to verify that the test complied with Subpart E requirements, that the test results were valid, and that the causes of all test failures were determined. |

An effective operator program would be expected to have the following characteristics:

1. Documentation of test records sufficient to allow compliance with Subpart E requirements to be verified.
2. Test procedures and records that document the basis for test acceptance and test validity.
3. Documentation and evaluation of hydrostatic pressure test failures to understand the cause of the failure (e.g., was the failure due to hook cracks, selective seam corrosion, internal corrosion, etc?).
4. Metallurgical evaluation of test failures, as required, to assure a full understanding of test failures.
5. Documented evidence that the operator has an effective corrosion control program and that corrosion control is being effectively applied to the assessed pipeline.
6. Identification, documentation, and analysis of pressure reversals to determine the cause of pressure reversals and identify any integrity threats indicated by the pressure reversals.

| | |
|---|---|
| **Rule Requirement** | §452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section) |
| | 452 (j) (5) *Assessment methods*. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.... (ii) Pressure test conducted in accordance with subpart E of this part; |

| 3.06 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**3.06 Inspection Issues Summary**

**3.06 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| Appendix H7.1 | 7 | 9/18/06 | Collect, Receive And Analyze IMP Assessment Data - Formulate Repair Schedule |
| Appendix H8.1 | 6 | 8/28/06 | Select the Appropriate Assessment Tool and Vendor |
| Appendix F | 7 | 10/6/2006 | Pipeline Integrity Assessment Procedures |

**3.06 Inspection Notes**

Widely varying temperature values on the charts supporting the 16-inch Exxon Lateral hydrostatic pressure test indicate that appropriate locations for placing the temperature probe were not established. The Facility specific hydrostatic pressure testing procedure was reviewed for this assessment to determine if the procedures appropriately addressed test medium temperature consideration, and it appeared to not adequately address temperature probe placement. Also, it is recommended that hydrostatic pressure tests include a diagram or map of the assessed pipe segments so that it is clear what sections of pipe have been tested. The KMEP O&M consolidation program is expected to be completed in the 4Q/2006, and the unified hydrostatic pressure testing procedure will be inspected during the PHMSA O&M Inspection. The KMEP Standard 8101 for hydrostatic pressure testing was reviewed (Section 6.1), and it appeared to adequately address temperature probe placement. An additional concern with the hydrostatic pressure testing process was noted during the review of tests conducted on the SFPP system. Paper charts with a high range of 3000 psi were inappropriately used in performance of tests that used 500 pound dead weights.

IMPM Appendix H 7.1 Section 4.5 requires that assessments utilizing pressure testing are to be conducted in accordance with Appendix F of the KMEP Integrity Management Program Manual and governing federal, state, and local regulations. Section 4.5.1 notes that a pressure test is considered satisfactory if it meets the minimum requirements of 49 CFR 195, Subpart E and meets the minimum requirements of governing state and/or local pressure test requirements. Section 4.5.2.6 requires that repairs be made on the pipeline due to external leakage following governing Business Unit procedures. Information is to be gathered at the failure site to aid in locating other sites that should be excavated and inspected. Additional inspections and repairs are to be scheduled as appropriate.

Appendix H8.1, Section 4.7.1 addresses considerations and requirements for pressure testing. This section in part requires that pressure testing be done in accordance with 49 CFR 195, Subpart E. If there is a history or the potential for ERW seam problems, consideration is to be given to supplementing these tests with a spike test.

Appendix H 7.1, Section 4.5.2.6 addresses investigation and repair of hydrostatic test failures. If there is an external leakage failure of the pipe not associated with a flange gasket or other type of non-welded fitting, the Project manager is top identify any and all specimens to be collected for further metallurgical investigation. During the inspection documentation of a hydrostatic pressure test failure was reviewed. Failure occurred on the 16" CRC $CO_2$ Pipeline. The report was dated November 20, 2003 and it documented the cause of the failure.

The cause was due to a mid-wall lamination and gouge that occurred possibly during installation or due to 3rd party damage. Corrosion pitting developed inside the internal ligament of the lamination.

IMPM Appendix F, Section 7.1 requires that when KMEP chooses to employ pressure testing as its integrity assessment tool, the quality and effectiveness of the pipeline corrosion control program will be reviewed as required by IMPM Appendix F. This includes data such as release history, cathodic protection annual survey results, pipeline current demand, results of cathodic protection close interval survey data, coating integrity and results of open hole (open assessment) reports and, if available, previous ILI results.

| **3.06 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **3.06.01** | Hydrostatic pressure test was not conducted in accordance with Subpart E | AF 3.4 | |
| | **3.06.02** | The process did not adequately require determination of root cause of hydrostatic test failures | AF 3.4 | |
| | **3.06.03** | Root cause analysis of hydrostatic test failures was not adequately determined | AF 3.4 | |
| | **Other:** | | | |

| Protocol # 3.07 | Integrity Assessment Results Review: Results from the Application of Other Assessment Technologies |
|---|---|
| **Protocol Question** | For assessments using "other assessment technology," is the operator's process for evaluation of the results adequate to identify integrity threats?<br>_____<br>Review selected assessment records for assessments conducted using "other technology" to verify that all anomalous conditions or potential defects (including the cause) were analyzed and documented, and that appropriate, timely corrective action was taken. |

An operator that chooses to use "other technology" for its integrity assessments is expected to have a documented process to assure that the chosen technology will result in a level of understanding of a pipeline's condition, equivalent to that obtained through the use of accepted ILI tools or a hydrostatic pressure test. An effective operator program would be expected to have the following characteristics:

1. Criteria for the selection of other technology that support major integrity decisions, such as (a) identification of minimum data analysis required, (b) data integration requirements prior to the assessment, (c) assignment of priority to excavations, (d) number of excavation digs required, (e) basis for assessing applicability (e.g., some direct assessment techniques may detect external corrosion but not internal corrosion), and (f) validity of assessment results.
2. Procedures that adequately implement industry accepted practices for the successful use of the technology, including conformance to applicable consensus industry standards.
3. Procedures that address the method by which validation of the results of assessments using alternative technology is conducted.
4. Provisions for identification of excavations required to validate other technology results.
5. Provisions for conducting excavation digs that support the applicability and validity of the assessment technology (as a result, additional information may need to be collected beyond the information that the operator typically collects during an excavation, depending on the specifics of the "other technology" selected).
6. Procedures must address reporting requirements and timing of discovery (180 days from completion of the assessment) and repair conditions (per paragraph 452(h)).

[For review of external corrosion direct assessment (ECDA) refer to protocols 7.03, and 7.05-7.08.]

| | |
|---|---|
| **Rule Requirement** | §452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section) |
| | 452 (j) (5) *Assessment methods*. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.... (iv) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify OPS 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section. |

| 3.07 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**3.07 Inspection Issues Summary**

| 3.07 Documents Reviewed | *(Tab from bottom-right cell to add additional rows.)* | | |
|---|---|---|---|
| **Document Number** | **Rev.** | **Date** | **Document Title** |
| Appendix H8.1 | 6 | 8/28/06 | Select the Appropriate Assessment Tool and Vendor |
| Appendix H8.3 | 5 | 8/23/2006 | DOT Notifications and Variances |

**3.07 Inspection Notes**

IMPM Appendix H8.1, Section 4.2.4 addresses the use of Other Technology that KMEP and OPS deem appropriate for use. Other Technology may include Direct Assessment (IMPM Appendix H8.2, Conduct Direct Assessment).

IMPM Appendix H8.1, Section 4.7.2.3 addresses requirements for notification of the intent to use Direct Assessment. Notifications must be made in accordance with Appendix H8.3, DOT Notifications and Variances. Other technology that KMEP demonstrates can provide an equivalent understanding of the condition of the line pipe may be employed on a case by case basis. Industry standards and procedures will be reviewed as available and adopted as appropriate.

IMPM Appendix H8.3, Section 4.1.2 also addresses notification requirements for the use of "other technology." Notifications must be made 90 days prior to assessment. Notifications must include a description of "other technology", the basis for concluding equivalent understanding of pipe condition, the procedure for performing assessment, and the schedule for assessment.

| **3.07 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category** (A – E) |
|---|---|---|---|---|
| | **3.07.01** | Anomalous conditions were not identified in a timely manner | AF 3.2 | |
| | **3.07.02** | Assessment results were not reviewed | AF 3.3 | |
| | **3.07.03** | PHMSA was not notified 90 days in advance of using other technology | AF 3.6 | |
| | **Other:** | | | |

# Integrity Management
# Inspection Protocol 4

# Remedial Action

**Scope:**

This Protocol addresses the operator's remediation of conditions identified through integrity assessments and information analysis that could affect the integrity of a pipeline segment. This includes the process to repair or remediate these conditions in such a manner to assure they will not jeopardize public safety or environmental protection, and to determine if the operator has implemented this remediation process effectively.

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| Protocol # 4.01 | Remedial Action: Process |
|---|---|
| **Protocol Question** | Does the operator's Integrity Management Program include a documented process to assure prompt action to address all anomalous conditions that could reduce a pipeline's integrity that are discovered through the integrity assessment or information analysis? |

The rule requires the operator must take prompt action to address all anomalous conditions that the operator discovers through the integrity assessment or information analysis. An effective operator program would be expected to contain the following characteristics:

1. A requirement to develop a prioritized schedule for remediation of all identified repair conditions consistent with the repair criteria and time frames found in §195.452(h).
2. A requirement to document justification for changes to the repair/remediation schedule including demonstration that such changes will not jeopardize public safety or environmental protection.
3. A requirement to notify PHMSA if the operator cannot meet the remediation schedule and cannot provide safety through a temporary reduction in operating pressure.
4. A requirement that if an immediate repair condition is identified, the operating pressure of the affected pipeline be temporarily reduced in accordance with the formula in Section 451.7 of ASME/ANSI B31.4 or the pipeline be shutdown until the condition is repaired. Where pressure reduction cannot be calculated using the method of Section 451.7, the process should identify alternative methods of calculating a safe operating pressure.
5. A requirement that any temporary reduction in operating pressure taken until repair or remediation can be completed cannot exceed 365 days without the operator taking additional remedial actions to assure the safety of the pipeline.
6. A requirement that the operator comply with §195.422 when making a repair.
7. Specification of the records to be generated during the remediation process.

| | |
|---|---|
| **Rule Requirement** | §195.452 (h) (1) *General requirements*. An operator must take prompt action to address all anomalous conditions that the operator discovers through integrity assessment or information analysis ... evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity ... demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the long-term integrity of the pipeline. A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action to ensure the safety of the pipeline. An operator must comply with § 195.422 when making a repair. |
| | §195.452 (h) (3) *Schedule for evaluation and remediation*. An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation.... the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety or environmental protection. An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure. |
| | §195.452 (h) (4) *Special requirements for scheduling remediation. Immediate repair conditions*.... To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline ... calculate the temporary reduction in operating pressure using the formula in section 451.7 of ASME/ANSI B31.4.... |

| 4.01 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**4.01 Inspection Issues Summary**

IMPM Sections 7.4.5.3 and 7.4.5.4 indicate repairs must be "scheduled" for evaluation and remediation within 60 days for 60-Day anomalies or 180 days for 180-Day anomalies rather than "completed" within the required 60 and 180 day timeframe. These IMP sections were updated during the inspection to require that 60-day and 180-day repairs be evaluated and remediated within the required timeframes.

*Materials were received from Mike Outlaw of KMEP following the inspection on December 1, 2006 concerning this issue, and the revisions were reviewed and deemed adequate: This issue is already addressed by KMEP's IMPM procedures which references IMPM Section 7.4.3, Discovery of a Condition. Additional clarification and communication of KMEP expectations to ILI tool vendors has been included in the ILI Customer Profiles.*

**4.01 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix E | 5 | 8/31/2006 | Repair Criteria |
| Appendix H7.1 | 6 | 8/31/06 | Collect, Receive And Analyze IMP Assessment Data - Formulate Repair Schedule |
| Appendix H8.3 | 5 | 8/23/2006 | DOT Notifications And Variances |
| Appendix H11.3 | 1 | 8/31/2006 | Records And Document Retention |

**4.01 Inspection Notes**

CPF No. 1-2004-5005-M 8(a) notes that although geometry/MFL tool runs are normally run close together, the IMPM process could be enhanced to address the discovery date for instances of widely separated tool runs. FAQ 4.13 also states that evaluation of the assessment results, integration of other information, and repair of anomalies must still be performed in accordance with the requirements established for these activities in the rule. This means that, in the event a series of ILI tool runs is used to complete an assessment, the 180 day discovery period for each individual tool run begins when that specific tool reaches the receiver if the tool provides sufficient information to determine if a particular repair criteria condition exists. These activities are considered to occur after the completion of the "assessment". Review of completed assessment results for the CalNev 14" Barstow – Las Vegas showed that the geometry tool run was completed on March 24, 2004 but the report was not provided by the vendor until more than 180 days on October 12, 2004 when the ILI report was final and included metal loss information. While there were no dents reported for the geometry tool run in this case, there is potential that long delays in the receipt of ILI reports could allow for immediate action anomalies to remain un-remediated.

IMPM 7.4.1 requires that prompt action be taken to address pipeline anomalous conditions that are discovered through the integrity assessment and/or information analysis. All anomalous conditions must be evaluated. Those anomalous conditions that could be considered defects and reduce a pipeline's integrity must be remediated in accordance with these requirements. KMEP shall be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. Alternatively, the maximum operating pressure of that segment shall be reduced to a pressure level that will insure system integrity. A reduction in operating pressure cannot exceed 365 days without KMEP taking further remedial action to ensure the safety of the pipeline.

IMPM Section 7.4.5.1 requires that repairs must be completed according to a schedule that prioritizes the conditions for evaluation and remediation. If KMEP cannot meet the schedule for any of the conditions, KMEP

will justify the reasons why the schedule cannot be met and that the changed schedule will not jeopardize public safety or environmental protection. KMEP will notify PHMSA if it cannot meet the regulatory mandated schedule and cannot provide safety through a temporary reduction in operating pressure until a permanent repair is made.

IMPM Appendix H8.3, Section 4.1.1 establishes requirements for notification in the event KMEP is unable to meet repair deadlines and unable to reduce pressure. When KMEP determines schedules cannot be met, the notification is to include the description of defects/repairs needed, the reason for delay, why pressure cannot be reduced, the basis for concluding delay will not jeopardize health or environment, the schedule for repair, and other preventive and mitigative actions planned.

IMPM Section 7.4.5.2 addresses KMEP's evaluation and repair schedule process for immediate repair conditions. Immediate means a response that is initiated within 24 hours of discovery based on the review and interpretation of sufficient integrated data by the Business Unit Integrity Management Team. To maintain safety, KMEP Operations may need to temporarily reduce operating pressure or shut down the pipeline until the repair of these conditions is completed. The temporary operating pressure reduction for corrosion metal loss anomalies is to be based on the formula in Section 451.7 of ASME/ANSI B31.4 remaining wall thickness. For all other anomalies operating pressure reduction shall be based on sound engineering analysis performed on a case-by-case basis. Pressure reduction calculations or analysis will be documented in the Action Plan.

Appendix E, Section E.1.2 addresses safe pressures. Whenever a known pipeline defect or a pipeline anomaly which may be approaching failure is to be examined for evaluation and possible repair, the possibility of sudden failure of the defect or anomaly must be recognized. To minimize the risks to personnel and facilities, the internal pressure level in the pipeline is to be reduced to a level that would be expected to prevent a near-failure defect from failing while the repair is in progress.

Appendix H7.1, Section 4.4.1.4 requires the calculation of safe operating pressure and burst pressure for pipelines at anomaly sites:

- Utilize B31G calculations to determine safe operating pressure (Psafe) and burst pressure (Pburst) for the segment containing the defect. Note: After validating tool performance in the Action Plan there may be the opportunity to utilize KAPA, LAPA or RSTRENG for Psafe and Pburst.
- Determine the shut-off head pressure produced by pumping units on the segment. Calculate the hydraulics of the pipeline, including elevation at the anomaly, to determine the maximum pressure to which the pipe could be subjected at the anomaly site.

Appendix H7.1, Attachment 1, HCA RESPONSE TABLE also addresses pressure reductions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of the following conditions. The operator must calculate the temporary reduction in operating pressure using ASME/ANSI B31.4 section 451.7.

IMPM 7.4.8.1 notes that Appendix E of the IMP Manual outlines the acceptable repair methods for pipeline anomalies. The details of the specified repair methods are covered in the individual Business Unit's maintenance manual, engineering standards, or other procedures, and are performed under qualified supervision by trained personnel aware of and familiar with the hazards to public safety, utilizing strategically located equipment and repair materials. The maintenance plan considers the appropriate information contained in ASME B31.4, ASME Sections IX, API Publication 2200, API Publication 2201, API Standard 1104, API 1107 and API RP 1111. Personnel working on repairs to pipelines are informed on the specific properties, characteristics, and potential hazards associated with those liquids, precautions to be taken following detection of a leak, and safety repair procedures. Repair personnel also meet the "operator qualification" requirements set forth in Part 195. Approvals, procedures, and special considerations are observed for welding, as well as making hot taps on pipelines, vessels, or tanks that are under pressure. All repairs are made in accordance with 49 CFR 195.422.

IMPM 7.5 requires that remediation reports and records be maintained in accordance with Appendix H11.3, Records and Document Retention. Appendix H6.6, Section 4.2 requires that the KMEP Business Unit Integrity Management Team ensure that:

- Assessment data (ILI, Pressure Test and Other Technology) is collected and complete for all segments in

accordance with procedure H7.1, Collect, Receive and Analyze IMP Assessment Data – Formulate Repair Schedule,

- Pipeline Repair/Modification Reports and other repair data are submitted and complete for all assessed segments.

Appendix H11.3: Section 5, Record Retention Table includes:

- ILI Survey Review for 452(h)(4)
- Required Digs form (in Appendix H7.1)
- Assessment Interval Evaluation Form
- Approval for assessment interval extension
- ILI Survey Review for 452(h)(4) Required Digs
- ILI Vendor Final Report
- Remediation Completion Report
- Corrosion Detection Survey and Electronic Geometry Survey: Technical Questionnaire
- ILI Data Review and Validation Form
- DOT notifications, variances, reports, permits

This table indicates the retention schedule for records. Repair records are maintained for the life of the pipeline.

| **4.01 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **4.01.01** | Repair procedures did not adequately incorporate the IM rule's remediation requirements | AF 4.1 | |
| **X** | **4.01.02** | Repair procedures did not adequately include the IM rule's response time requirements | AF 4.1 | E |
| | **4.01.03** | The process did not adequately require pressure reductions for immediate repairs | AF 4.2 | |
| | **4.01.04** | The process did not adequately define response timeframes for immediate repair conditions | AF 4.1 | |
| | **4.01.05** | The process did not adequately require use of the ASME B31.4 Section 451.7 to determine appropriate pressure reduction, or document other acceptable method when this code section is not applicable | AF 4.2 | |
| | **Other:** | | | |

| Protocol # 4.02 | Remedial Action: Implementation |
|---|---|
| **Protocol Question** | Has the operator adequately implemented its remediation process and procedures to effectively remediate conditions identified through integrity assessments or information analysis? |

The rule requires that an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline. The inspection should ensure that:

1. A prioritized schedule was prepared by the operator for remediation of anomalous conditions.
2. Repairs were made in accordance with the operator's prioritized schedule and within the time frames allowed in §195.452(h).
3. Changes to the schedule were justified by the operator and the schedule changes were demonstrated not to jeopardize public safety or environmental protection.
4. PHMSA was notified in those cases where the schedule could not be met and safety could not be provided through a reduction in operating pressure.
5. For an immediate repair condition, operating pressure was reduced or the pipeline was shutdown.
6. For an immediate repair condition, temporary operating pressure was determined in accordance with the formula in Section 451.7 of ASME/ANSI B31.4 or, if not applicable, the operator should provide an engineering basis justifying the amount of pressure reduction.
7. Operating pressure was not reduced for more than 365 days without the operator taking further remedial action to ensure the safety of the pipeline.
8. Repairs were performed in accordance with §195.422 and applicable industry standards.
9. Based on remediation information reviewed during the inspection, the data in Part J (Integrity Inspections Conducted and Actions Taken Based on Inspection) of the most recent Form PHMSA F 7000-1.1 appear valid and completed per Instructions for Completing Form PHMSA F 7000-1.1.

| | |
|---|---|
| **Rule Requirement** | §195.452 (h) (1) *General requirements*. An operator must take prompt action to address all anomalous conditions that the operator discovers through integrity assessment or information analysis ... evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity ... demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the long-term integrity of the pipeline. A reduction in operating pressure cannot exceed 365 days without an operator taking further remedial action to ensure the safety of the pipeline. An operator must comply with §195.422 when making a repair. |
| | §195.452 (h) (3) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation ... the operator must justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety or environmental protection.... An operator must notify OPS if the operator cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure. |
| | §195.452 (h) (4) *Special requirements for scheduling remediation Immediate repair conditions*.... To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline ... calculate the temporary reduction in operating pressure using the formula in section 451.7 of ASME/ANSI B31.4. |

| 4.02 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

| 4.02 Additional Data | *(Type an X in the applicable box to verify task completion.)* |
|---|---|
| X | **Annual Report Part J Data of the Most Recent Form PHMSA F 7000-1.1 Reviewed** |

**4.02 Inspection Issues Summary**

An anomaly classified as a 60-day repair on PL-107, Morris to Lemont, was not discovered or remediated within required timeframes. The preliminary ILI report was received 12/2/2005 and the final ILI report was received 1/3/2006. Discovery of condition was established as 6/23/2006 which exceeded the required 180 day timeframe for discovery. The repair was completed on 9/6/2006 which exceeded the 60-day repair timeframe criteria.

**4.02 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix E | 5 | 8/31/2006 | Repair Criteria |
| Appendix H7.1 | 6 | 8/31/06 | Collect, Receive And Analyze IMP Assessment Data - Formulate Repair Schedule |
| Appendix H8.3 | 5 | 8/23/2006 | DOT Notifications And Variances |

**4.02 Inspection Notes**

IMPM 7.4.5 addresses anomaly evaluation and remediation. Repairs must be completed according to a schedule that prioritizes the conditions for evaluation and remediation. If KMEP cannot meet the schedule for any of the conditions, KMEP will justify the reasons why the schedule cannot be met and that the changed schedule will not jeopardize public safety or environmental protection. KMEP will notify PHMSA if it cannot meet the regulatory mandated schedule and cannot provide safety through a temporary reduction in operating pressure until a permanent repair is made. KMEP's evaluation and repair schedule provides for immediate repair conditions. Immediate means a response that is initiated within 24 hours of discovery based on the review and interpretation of sufficient integrated data by the Business Unit Integrity Management Team. To maintain safety, Operations may need to temporarily reduce operating pressure or shut down the pipeline until the repair of these conditions is completed. The temporary operating pressure reduction for corrosion metal loss anomalies will be based on the formula in Section 451.7 of ASME/ANSI B31.4 remaining wall thickness. For all other anomalies operating pressure reduction shall be based on sound engineering analysis performed on a case-by-case basis. Pressure reduction calculations or analysis will be documented in the Action Plan.

The Rosen June 1, 2004 ILI assessment of the 14" BRF Spartanburg to Gastonia segment identified an anomaly cluster at a log location of 83,797.91 feet which corresponded to an HCA location. The detailed explanation of the 2004 ILI results, in comparison to previous 2001 ILI data show that the anomaly is an internal mill orientated indication with no growth.

During the course of the inspection efforts were made to confirm the accuracy of the KMEP 2005 PHMSA Form 7000-1.1 Annual Report. Assessed mileage reported on the PHMSA Form 7000-1.1 Annual Report for the Wink System (OP ID 31957) for the years 2003 and 2004 was incorrect. It was reported that for 2003 there were 196 miles assessed and for 2004 229 miles were assessed. Review of the Continuing Assessment Plan show that actual mileage assessed is 28 miles for 2003 and 15 miles for 2004 (this potential issue is tracked under Protocol 2). The following summary reflects reported mileage with the totals for the Wink System corrected:

| KMEP OP ID Mileage | | | | | | |
|---|---|---|---|---|---|---|
| | | | Assessed Mileage | | | |
| OP ID | Mileage | HCA Mileage | Prior | 2003 | 2004 | 2005 |
| 2190 | 201 | 164 | 155 | 0 | 0 | 0 |
| 4472 | 1681.22 | 901 | 59.8 | 150.9 | 184.9 | 166.1 |
| 15674 | 3140 | 2139 | 526 | 508 | 317 | 301 |
| 18092 | 2756.48 | 1729.3 | 477 | 197 | 522 | 176 |
| 26041 | 78.87 | 75.88 | 20.87 | 12.15 | 16.84 | 14.38 |
| 26125 | 557.39 | 377.8 | 64.2 | 147.2 | 161.7 | 1.96 |
| 31344 | 51.6 | 9.3 | 8.5 | 0 | 0.5 | 0 |
| 31451 | Idled & purged | 0 | - | - | - | - |
| 31555 | 1196 | 139 | 0 | 128 | 0 | 39 |
| 31957 | 459 | 44 | 0 | 196 | 229 | 0 |

The following CO2, Wink, KMLT, Mid-Continent and Heartland assessments were reviewed the week of September 25, 2006 in Houston, TX

CO2 and Wink Pipeline

1. L304: El Paso - Wink 20", 195.5 miles, 11/23/2005 GE Pii Caliper and 12/7/2005 GE Pii HR-MFL, Report Date 2/26/2004, Discovery Date not specified, pipe removed from service for pipe replacement, 65 180-day anomalies identified (2 checked and repaired 10/14/2004 and 10/28/2—4). 6 immediate anomalies identified. 194 feet of pipe replaced 8/25/2004, 10/14/2004 repair by sleeving, and 1/31/2005 552 feet of pipe replaced.
2. L302: McCamey - Wink 10", 75.09 miles, 6/29/2004 GE Pii Caliper and 8/3/2004 GE Pii HR-MFL, Report Date 9/23/2004, Discovery Date 9/23/2004, 10 180-day anomalies identified and 3 60-day anomalies (non-HCA) identified.
3. L310: Sharon Ridge 8", 3.67 miles, 7/19/2005 hydrostatic test by Ferguson Construction Co., Report Date 7/25/2005, no failures, CP records appropriate.
4. Canyon Reef Carriers, 138.7 miles. Hydrostatic pressure test conducted for 6 testable segments. An 8-hour test was performed by Milbar Hydro-Test Inc on the following dates: 5/26/2003, 5/27/2003, 5/28/2003, 5/31/2003, 6/3/2003, 6/5/2003, and 6/7/2003. One segment had a test failure. Report dated 11/20/2003 provided an analysis of the failure.

KMLT

5. CNJ-1601-1, 16" Buckeye Pipeline, 0.18 miles, 9/14/2004 hydrostatic test by Brayco Brothers, no failures, CP records appropriate.
6. CNJ-1201-2, 12" PSE&G (leased), 1.90 miles, 9/14/2004 hydrostatic test by Brayco Brothers, no failures, CP records appropriate.
7. 16" 16L Cross-Channel-TX, 1.92 miles, 12/19/2003 hydrostatic test, no failures, CP records appropriate.
8. CNJ-0801-1/2, 8" Buckeye Pipeline, 2.3 miles, 8/31/04 Rosen Deformation tool and 9/1/2004 Rosen HR-MFL, Report Date 11/2/2004, Report Received Date 11/2/2004, no rule categorized anomalies identified.
9. 20" Cross Channel -TX, 1.34 miles, 12/4/2003 hydrostatic test, no failures, CP records appropriate.
10. 16" Chevron Pipeline -TX, 1.62 miles, 1/23/2004 hydrostatic test by Greene's Pipeline Services, Report Date 1/28/2004, no failures, CP records appropriate.
11. 16" LCRC Cross-Channel-TX, 0.31 miles, 2/12/2004 hydrostatic test, no failures, CP records appropriate.
12. 16" 16G Cross-Channel-TX, 1.29 miles, 12/10/2003 hydrostatic test, no failures, CP records appropriate.
13. 16" 16N Cross Channel, 1.3 miles, Hydrostatic test performed by Greene's Energy Group, Report Date 4/26/2005. No failures and CP records judged appropriate.

14. 8" TEPPCO – TX, 0.44miles, 4/27/2004 hydrostatic test, no failures, and CP records appropriate.
15. 16" Exxon Lateral, 0.16 miles, 5/3/2004 hydrostatic test by Shamrock Farrel, no failures, CP records appropriate. Widely varying temperature values on the charts supporting the 16-inch Exxon Lateral hydrostatic pressure test indicate that appropriate locations for placing the temperature probe were not established.
16. 12" Truck Rack South-TX, 1.79 miles, 9/15/2004 hydrostatic test, no failures, CP records appropriate.
17. PANJ-1201, 12" Buckeye – Motiva, 2.2 miles, 9/21/04 Rosen Deformation tool and 9/22/2004 Rosen HR-MFL, Report Date 11/30/2004, Report Received Date 12/2/2004, no rule categorized anomalies identified.
18. 28" Explorer –TX, 2.1 miles, 6/9/2005 hydrostatic test, no failures, and CP records appropriate.
19. 4" Transmix-TX, 1.74 miles, 4/20/2004 hydrostatic test, no failures, CP records appropriate.
20. 12" LCR Oil Inbound-TX, 2.05 miles, 10/11/2005 hydrostatic test, no failures, CP records appropriate.
21. 12" Phillips Return-TX, 2.1 miles, 4/24/2006 hydrostatic test by Greene's Pipeline Services, Report Date 5/4/2006, no failures, CP records appropriate.
22. 12" Truck Rack North-TX, 1.79 miles, 9/21/2004 hydrostatic test, no failures, CP records appropriate.
23. CNJ-1601-2, 16" Buckeye Pipeline, 0.17 miles, 8/27/2003 hydrostatic test by UEI, Report Date 8/27/2003, no failures, CP records appropriate.
24. CNJ-1201-1, 12" PSE&G (Sun, Mobil), 1.78 miles, 8/27/2003 hydrostatic test by UEI, Report Date 8/27/2003, no failures, CP records appropriate.
25. Sanders PL - Jet fuel to Midway, 2.32 miles, 4/20/2004 hydrostatic test, no failures, CP records appropriate.
26. ICPT 6" St. Gabriel, 10.5 miles, 3/22/2005 Rosen Deformation tool and 3/23/2005 Rosen HR-MFL, Report Date 5/23/2005, Report Received Date 5/23/2005, no rule categorized anomalies identified.
27. 16" Colex-TX, 5/4/2006 hydrostatic test, no failures, initial service, not listed in BAP as of the time of the inspection (1 year timeframe still in process)..

Mid-Continent

28. PL-100; 6" Conway – Bushton, 29.55 miles, 8/11/04 Rosen Deformation tool and 10/10/2004 Rosen HR-MFL, Report Date 12/10/2004, Report Received Date 12/11/2004, Discovery Date 12/11/2003, no rule categorized anomalies identified (1 60-Day condition was initially identified but was later determined to not be an actionable anomaly).
29. PL-100; 6" Wichita – Conway, 53.10 miles, 9/9/2003 Rosen Deformation tool and 9/27/2003 Rosen HR-MFL, Report Date 11/26/2003, Report Received Date 12/1/2003, no rule categorized anomalies identified. SCC was found on ID anomaly – dent (log distance 66872.58). Two ID anomaly – dents identified with no metal loss. Repaired by sleeving.
30. PL-101; 8" Holmesville – Plattsmout, 72.65 miles, 11/22/2003 Rosen Deformation tool and 1/13/2004 Rosen HR-MFL, Report Date 3/12/2004, Report Received Date 3/15/2004, no rule categorized anomalies identified.
31. PL-101; 8" Massena - Des Moines, 70.53 miles, 12/6/2003 Rosen Deformation tool and 12/20/2003 Rosen HR-MFL, Report Date 3/12/2004, Report Received Date 3/15/2004, no rule categorized anomalies identified.
32. PL-101; 8" Miltonvale – Holmesville, 71.41 miles, 11/18/2003 Rosen Deformation tool and 11/20/2003 Rosen HR-MFL, Report Date 2/18/2004, Report Received Date 2/23/2004, no rule categorized anomalies identified.
33. PL-101; 8" Plattsmouth – Massena, 65.3 miles, 4/26/04 Rosen Deformation tool and 5/10/2004 Rosen HR-MFL, Report Date 7/14/2004, Report Received Date 7/19/2004, Discovery Date 7/20/2004, no rule categorized anomalies identified.
34. PL-102 8" Bushton – Miltonvale 76.55 miles, 6/23/2003 Rosen Deformation tool and 9/16/2003 Rosen HR-MFL, Report Date 11/14/2003, Discovery Date 11/17/2003, no anomalies requiring repair were identified – maximum depth identified was 28%.
35. PL-102 8" Holmesville - Tabor, 75.31 miles, 2/28/2005 Rosen Deformation tool and 8/17/2005 Rosen HR-

MFL, Report Date 10/21/2005, no rule categorized anomalies identified – maximum depth identified was 25%. HR-MFL required 4 attempts to get a successful run.

36. PL-102 8" Miltonvale – Holmesville 72.22 miles, 5/13/2005 Rosen Deformation tool and 6/237/2005 Rosen HR-MFL, Report Date 9/28/2005, no rule categorized anomalies identified – maximum depth identified was 33%.
37. PL-102 8" Tabor – Massena, 58.62 miles, 3/7/2005 Rosen Deformation tool and 7/18/2005 Rosen HR-MFL, Report Date 10/6/2005, no rule categorized anomalies identified – maximum depth identified was 39%
38. PL-103; 8" Bushton – Conway, 29.75 miles, 4/29/04 Rosen Deformation tool and 6/16/2004 Rosen HR-MFL, Report Date 9/17/2004, Report Received Date 9/20/2004, no rule categorized anomalies identified – maximum depth identified was 29%.
39. PL-104AB; 6" Halstead to Reno, 26.33 miles, 8/4/2003 Rosen Deformation tool and 8/7/2003 Rosen HR-MFL, Report Date 9/30/2003, Report Received Date 10/13/2003, Discovery Date 9/17/2003 for 4 immediate anomalies, 10/13/2003 for 2 immediate anomalies. Line was out-of-service from before 9/17/2003 until after 10/20/2003. Repairs completed 9/29 – 10/20/2003.
40. PL-105; 10" Des Moines – Ewart, 49.4 miles, 11/15/2005 GE Pii Caliper and 12/7/2005 GE Pii HR-MFL, Report Date 12/22/2005, no rule categorized anomalies identified – maximum depth identified was 62% (actual was 64%).
41. PL-105; 10" Eldridge – Walnut, 51.76 miles, 11/9/2005 GE Pii Caliper and 11/14/2005 GE Pii HR-MFL, Report Date 12/22/2005, no rule categorized anomalies identified – maximum depth identified was 45%.
42. PL-105; 10" Ewart - Iowa City, 55.6 miles, 11/16/2005 GE Pii Caliper and 12/9/2005 GE Pii HR-MFL, Report Date 12/28/2005, no rule categorized anomalies identified – maximum depth identified was 68% (not in an HCA). 14 dents with metal loss were identified on 1 joint not in an HCA.
43. PL-105; 10" Iowa City – Eldridge, 55.6 miles, 11/5/2005 GE Pii Caliper and 11/9/2005 GE Pii HR-MFL, Report Date 12/22/2005, no rule categorized anomalies identified – maximum depth identified was 58% (actual was 46%).
44. PL-105; 10" Walnut – Morris, 69.21 miles, 11/5/2005 GE Pii Caliper and 12/1/2005 GE Pii HR-MFL, Report Date 12/28/2005, Report Received Date 12/16/2005, Discovery Date 12/16/2005, Pressure reduction 12/16/2005 and released 12/21/2005. Repairs completed 12/19 – 21/2005.
45. PL-107; 10" Morris to Lemont", 27.71 miles, 11/13/2005 GE Pii Caliper and 11/16/2005 GE Pii HR-MFL, Report Date 12/22/2005, Received Date 12/2/2005 (preliminary) and 1/3/2006 (final), Discovery Date 12/2/2005 and 6/23/2006, 1 60-day condition repaired 9/6/2006, 1 180-day condition repaired 5/23/2006, 1 immediate repair condition completed 12/7/2005. Pressure reduction 12/5/2005 to 12/8/2005.
46. PL-115; 8" Mt. Belvieu - SP, 8/18/04 Rosen Deformation tool and 8/13/2004 Rosen HR-MFL, Report Date 11/22/2004, Report Received Date 11/23/2004, no rule categorized anomalies identified – maximum depth identified was 23%.
47. PL-115; 8" SP - West Lake, 8/13/04 Rosen Deformation tool and 8/19/2004 Rosen HR-MFL, Report Date 10/27/2004, Report Received Date and Discovery Date not noted, 1 180-day repair condition.
48. PL-204; 6" Des Moines - Williams, 0.31 miles, 9/22/2004 hydrostatic, no failures, CP records appropriate.
49. PL-315; 6" PL-106E T/O to BP, 0.42 miles, Hydrostatic test conducted in 2 segments on 10/15/2004 and 11/3/2004. No failures and CP records judged appropriate (high at foreign crossings).
50. PL-317; 8" Conway to Williams (WESC) , 1.04 miles, 4/13/2004 hydrostatic test, no failures, CP records appropriate. Segment dropped from 2006 CAP since it no longer has HCA impacts.

Heartland Pipeline

51. PL-112; 8" McPherson – Conway, 10.9 miles, 4/13/2004 hydrostatic test, no failures, CP records appropriate.
52. PL-114; 8" Des Moines-Heartland, 0.23 miles, 10/10/2004 hydrostatic test, no failures, CP records appropriate.

The following Plantation and Central Florida assessments were reviewed 10/11 – 12/2006 in Alpharetta GA.

53. 14" 14W: Greensboro, NC to Richmond Jct., VA, 164.8 miles, Assessment Date(s): 10/20/2003, Baseline

Assessment, HR-MFL - Rosen, Rosen CDP Caliper Tool – Report date 1/6/2004, Report Received date 1/8/2004, no rule categorized repair conditions. ILI Summary Review Sheet (Appendix H7.1) has been added subsequent to the initial review of the report by KMEP. The newly added manager review date (2006) needs to include an annotated comment about why the additional review occurred so long after the actual report date. Additionally the Summary Sheet provides for the MAOP to be recorded. This segment has multiple MAOPs and rather than recording each MAOP or the maximum MAOP, the pipeline design pressure was recorded. It is also noted that the ILI Summary Review Sheet for the 8" 8RK Greensboro to Roanoke segment did not reflect completion of the management review.

54. 8" 8RK: Greensboro, NC to Roanoke, VA, 87.0 miles, Assessment Date(s): 11/6/2003 Rosen Deformation tool and 11/7/2003 Rosen HR-MFL, Baseline Assessment, Report Date 1/9/2004, Report Received Date 1/12/2004, no rule categorized anomalies identified. It is also noted that the ILI Summary Review Sheet for the 8" 8RK Greensboro to Roanoke segment did not reflect completion of the management review.
55. 12" PJF - DEL: Pebblebrook Jct. to Chattahoochee, GA, 2.3 miles, Assessment Date(s): 4/6/2004 Rosen HR-MFL and Caliper, Baseline Assessment, Report Date 5/28/2004, Report Received Date 5/31/2004, no rule categorized anomalies identified.
56. 12" PJG - DEL: Pebblebrook Jct. to Chattahoochee, GA, 2.3 miles, Assessment Date(s): 4/8/2004 Rosen HR-MFL and 3/31/2004 Caliper Tool, Baseline Assessment, Report Date 6/7/2005 and Received date 6/7/2005 (probably not correct), no rule categorized anomalies identified.
57. 18" MDF: Baton Rouge, LA to Collins, MS, 125.8 miles, January 2004 Rosen Deformation tool and May 2004 Rosen HR-MFL, Report Date 9/17/2004, Report Received Date 9/20/2004, no rule categorized anomalies identified.
58. 14" BRF: Bremen to Doraville GA, 54.7 miles, Assessment Date(s): 6/13/2003 Rosen Deformation tool and 7/23-24, 2003 Rosen HR-MFL, Baseline Assessment, Report Date 11/14/2003, Report Received Date 11/14/2003, Discovery Date 11/14/2003, no rule categorized anomalies identified.
59. 14" BRF: Doraville to Center, GA, 55.9 miles, Assessment Date(s): 6/19-20/2003 Rosen Deformation tool and 7/224-25/2003 Rosen HR-MFL, Baseline Assessment, Report Date 11/14/2003, Report Received Date 11/17/2003, Discovery Date 11/17/2003, no rule categorized anomalies identified.
60. 14" BRF: Center, GA to Anderson, SC, 52.7 miles, Assessment Date(s): 6/25-26/2003 Rosen Deformation tool and 7/25-26/2003 Rosen HR-MFL, Baseline Assessment, Report Date 11/13/2003, Report Received Date 11/17/2003, Discovery Date 11/17/2003, no rule categorized anomalies identified.
61. 14" BRF: Anderson to Spartanburg, SC, 52.8 miles, Assessment Date(s): 6/16-17/2003 Rosen Deformation tool and 7/28/2003 Rosen HR-MFL, Baseline Assessment, Report Date 11/24/2003, Report Received Date 11/24/2003, Discovery Date 11/24/2003, no rule categorized anomalies identified.
62. 14" BRF: Spartanburg, SC to Gastonia, NC, 49.1 miles, Assessment Date(s): 3/14/2004 Rosen Deformation tool and 6/1/2004 Rosen HR-MFL, Baseline Assessment, Report Date 10/6/2004, Report Received Date 10/11/2004, Discovery Date 10/11/2004, no rule categorized anomalies identified.
63. 14" BRF: Gastonia to Salisbury, NC, 48.9 miles, Assessment Date(s): 6/2-3/2004 Rosen Deformation tool and 7/1/2004 Rosen HR-MFL, Baseline Assessment, Report Date 11/10/2004, Report Received Date 11/15/2004, Discovery Date 11/15/2004, no rule categorized anomalies identified.
64. 14" BRF: Salisbury to Greensboro, NC, 44.3 miles, Assessment Date(s): 3/15-16/2004 Rosen Deformation tool and 4/28-29/2004 Rosen HR-MFL, Baseline Assessment, Report Date 9/13/2004, Report Received Date 9/15/2004, Discovery Date 9/15/2004, no rule categorized anomalies identified.
65. 18" MDG: Baton Rouge, LA to Collins, MS, 125.8 miles, April 2004 Rosen Deformation tool and 8/25/2004 Rosen HR-MFL, Report Date 1/10/2005, Report Received Date 1/18/2005, no rule categorized anomalies identified.
66. 12" BM-SEG-DEL: Birmingham to SE Terminal, AL, 2.1 miles, Assessment Date(s): 7/15/2004, Baseline Assessment, Pressure Test, 2003 and 2004 CP records reviewed and found to be appropriate.
67. 18" CNA: Collins, MS to Akron, AL and Akron, AL to Helena, AL, 201.9 miles, 5/19/2004 Rosen Deformation tool and Rosen HR-MFL, Baseline Assessment, Report Date 9/15/2004, Report Received Date 9/21/2004, no rule categorized anomalies identified.
68. 10" BM-SEF-DEL: Birmingham to SE Terminal, AL, 2.1 miles, Assessment Date(s): 7/21/2004, Baseline

Assessment, Pressure Test by E&M Construction, 2003 and 2004 CP records reviewed and found to be appropriate.

69. 6" CN-CV-DEL: Collins to Chevron Terminal, MS, 1.3 miles, 7/28/2004 Rosen Deformation tool and 7/28/2004 Rosen HR-MFL, Baseline Assessment, Report Date 11/3/2004, Report Received Date 11/4/2004, Discovery date 11/4/2004, no rule categorized anomalies identified.
70. 14" RM-CV-DEL: Richmond to Transmontaigne, VA, 4.2 miles, Assessment Date(s): 8/4/2004 Rosen Deformation tool and 8/16/2004 Rosen HR-MFL, Baseline Assessment, Report Date 11/4/2004, Report Received Date 11/8/2004, no rule categorized anomalies identified.
71. 8" RM-PR-DEL: Richmond to Transmix Deepwater, VA, 1.8 miles, Assessment Date(s): 9/10/2004, Baseline Assessment, Pressure Test conducted by Bradford Brothers, Inc., 2003 and 2004 CP records reviewed and found to be appropriate.
72. 6" RM-KI-DEL: Richmond to KMST #2, VA, 1.2 miles, Assessment Date(s): 9/14/2004, Baseline Assessment, Pressure Test conducted by Bradford Brothers, Inc., 2003 and 2004 CP records reviewed and found to be appropriate.
73. 8" RK-EX-DEL: Roanoke to Kinder Morgan Terminal, VA, 8.3 miles, Assessment Date(s): 9/16/2004, Baseline Assessment, Rosen HR-MFL, Caliper Tool – Report date 12/1/2004, Received Date 12/6/2004, 1 60-day condition repaired 10/5/2006 due to new validation threshold criteria 2 years after initial report review in 2004. Topside dent reported as less than 2% found as 3.13 %. Repaired by ClockSpring. 1 remaining dig after new validation thresholds @ 156+41 for 2% dent @ 10:18.
74. 8" 8MG: Helena to Pure, AL and Pure to Montgomery, AL, 72.8 miles, Assessment Date(s): 2/8-9/2005, 2/14/2005,and 3/1-2/2005, Baseline Assessment, Rosen HR-MFL, Caliper Tool – Report Date 4/11/2005 and 5/5/2005, Report Received Date 4/14/2005 and 5/9/2005, Discovery Date 4/14/2005 and 5/9/2005, no rule categorized repair conditions identified in either of the 2 segments (runs), 3 digs in HCAs repaired by ClockSpring
75. 12" MRA: Meridian Spur to Meridian, MS, 2.5 miles, Assessment Date(s): 3/7/2005 Rosen Deformation tool and 3/72005 Rosen HR-MFL, Baseline Assessment, Report Date 5/3/2005 and Received Date 5/5/2005, Discovery Date 5/5/2005, no rule categorized anomalies identified.
76. 12" 14W: Richmond Jct to Washington, VA, 101.5 miles, Assessment Date(s): 3/21/2005 Rosen Deformation tool and 3/21/2005 Rosen HR-MFL, Report Date 9/30/2005, Report Received Date 10/3/2005, 1 60-Day condition repaired 11/8/2005 and 1 180-Day condition repaired 1/7/2006.
77. 18" CNB: Collins, MS to Akron, AL and Akron, AL to Helena, AL, 201.9 miles, Assessment Date(s): 8/6/2005 & 3/3/2005 and 12/5/2005 & 1/29/2005, Baseline Assessment, Rosen EGP HR-MFL, CDP Caliper Tool – Collins to Akron Report Date 10/7/2005, Received date 10/11/2005, Discovery Date 10/11/2005. Akron to Helena Report Date 3/24/2005, Received date 3/31/2005, Discovery Date NA. 1 180-day condition found on Collins to Akron which was repaired 12/16/2005.
78. 14" 14R: Richmond Jct to Richmond, VA, 13.5 miles, Assessment Date(s): 3/18/2005 Rosen Deformation tool and 12/2/2005 Rosen HR-MFL, Baseline Assessment, Caliper Report Date 9/2/2005 and Received Date 9/6/2005, MFL Report Date 12/28/2005 and Received Date 1/4/2006, no rule categorized anomalies identified.
79. 26 CNG: Bremen, GA to Spartanburg, SC and Spartanburg, SC to Greensboro, NC, 358.5 miles, Bremen to Spartanburg Assessment Date(s): 11/3/2005 GE Pii HR-MFL and 1/26/2006 Caliper, Reassessment, Report date 3/16/2006, Report Received Date 3/16/2006, Discovery Date 1/10/2006 for preliminary report, 3/16/2006 for final report, 2 topside dents with metal loss (in ESA and HPA) immediate repairs completed 1/10 – 11/2006 based on preliminary report, 9 60-day conditions based on the final report had repairs completed 3/30 – 4/20/2006. Spartanburg to Greensboro Assessment Dates: 11/3/2005 GE Pii HR-MFL and 10/14/2005 Caliper, Report Date 12/29/2005, Received Date 1/4/2006, Discovery Date 1/4/2006, 3 immediate repair conditions repaired 1/7 – 8/2006, pressure reduction date 1/6/2006, pressure restoration date 1/9/2006. MOC on pressure reduction was reviewed.
80. 06 CMF: Charlotte to Charlotte Airport, NC, 4.4 miles, Assessment Date(s): 3/2/2006 GE Pii HR-MFL and Caliper Tool, Reassessment, Report date 3/17/2006, Report Received Date 3/20/2006, no rule categorized anomalies identified.
81. 12" MAF: MA3 Terminal to MA2 Terminal, GA, 1.2 miles, Assessment Date(s): 3/2/2006, Baseline

Assessment, Rosen HR-MFL and Deformation Tool, Report Date 3/8/2006 and Report Received Date 3/13/2006. No anomalies reported for HCAs.

82. 18" CNF: Helena to Silver Run, AL and Silver Run, AL to Bremen, GA, 104.9 miles, Helena to Silver Run Assessment Date(s): 3/28/2006 & 3/24/2006. Silver Run to Bremen Assessment Date(s): 3/21/2006 and 2/25/2006, Baseline Assessment, GE Pii HR-MFL, Caliper Tool – Both Report Dates 3/31/2006, Both Received Dates 4/3/2006, Both Discovery Dates 4/3/2006. Helena to Silver Run had 2 60-day conditions and 5 180-day conditions. Repairs completed appropriately 4/25 to 6/5/2006. Silver Run to Bremen had 1 immediate repair condition and 1 180-day condition. Pressure reduction date 4/3/2006, immediate repair completed 4/4/2006, pressure restored on 4/4/2006, MOC reviewed to verify pressure reduction. 180-day condition repaired on 4/23/2006.

83. 8" 8CO: Bremen to Columbus, GA, 85.0 miles, Assessment Date(s): 4/20/2006 for MFL and 4/11/2006 for Caliper, Baseline Assessment, GE Pii HR-MFL, Caliper Tool – Report Date 5/17/2006, Report Received date 5/22/2006, Discovery Date 5/22/2006, 1 immediate condition only required a recoat following the excavation and evaluation, recoat completed 5/23/2006, pressure reduction taken 5/22/2006 and pressure restored 5/23/2006

84. 8" 8MC: Bremen to Macon, GA, 11.7 miles, Assessment Date(s): 5/12/2006 and 6/7/2006, Baseline Assessment, GE Pii HR-MFL, Caliper Tool – Report date 7/31/2006, Report received Date 5/12/2006 Caliper, 7/31/2006 MFL, no rule categorized anomalies identified (6 180-day repairs made as if in an HCA but were later determined to not be in an HCA).

85. 08 BMF: Helena to Birmingham, AL, 12.3 miles, Assessment Date(s): 6/29/2006 GE Pii Caliper and 7/17/2006 GE Pii HR-MFL, Reassessment, Report date 8/7/2006, no rule categorized anomalies identified.

86. 10 BMG: Helena to Birmingham, AL, 12.3 miles, Assessment Date(s): 6/15/2006 GE Pii Caliper and 6/29/2006 GE Pii HR-MFL, Reassessment, Report Date 7/24/2006, Report Received Date 7/24/2006, Discovery Date 7/24/2006, 1 60-Day condition repaired 8/10/2006 and 3 180-Day conditions repaired in 8/2006.

87. 10" CFPL: Hemlock to Taft, FL, 84.8 miles, Assessment Date(s) 9/14/2005, Reassessment, GE-Pii HR-MFL, CDP Caliper Tool – Report Received Date 10/6/2005, Discovery Date 10/6/2005, 5 immediate conditions repaired 10/10-13/2005 by Type B Sleeves over dents, 1 60-day condition dug on 11/18/2005, 1 180-day condition repaired on 3/18/2006, pressure reduction taken 10/6/2005, pressure restored on 10/14/2005.

88. 16" CFPL: Tampa to Taft, FL, 109.4 miles, Assessment Date(s) 8/25/2006, Reassessment, HR-MFL, Caliper. A report has not been provided to KMEP as of the date of the inspection.

89. 6" 60 A, Newington to Dulles, Assessment Date July 2002, Rosen EGP HR-MFL, CDP Caliper Tool, Report Date 1/15/2003. No rule categorized anomalies; however older anomalies repaired April to May 2003.

The following KMLQT, CalNev and SFPP assessments were reviewed 11/1 – 11/2/2006 in Orange, CA.

KMLQT

90. GX32 10"/12"; Carson Term. - Arco Mfld, 0.06 miles, Re- Assessment, 11/18/2005, Hydrostatic Pressure Test. 732 psi MOP and 915 psi test pressure for 8 hours. No failures. CP records were appropriate.

91. GX64A 14"; Carson Term. - Arco Mfld, 0.61 miles, Re-Assessment, 11/10/2005, Hydrostatic Pressure Test. 721 psi MOP and 901 psi test pressure for 8 hours. No failures. Pressure chart recorder showed dramatic pressure impulses with explanation aligned with water draws. CP records were appropriate.

92. GX64B 14"; Carson Term. - Arco Mfld, 0.65 miles, Re-Assessment, 11/10/2005, Hydrostatic Pressure Test. 721 psi MOP and 901 psi test pressure for 8 hours. No failures. CP records were appropriate.

93. GX130 8"; Berth 172 - B St. & Neptune Mfld, 0.99 miles, Baseline Assessment, 5/28/2003, Hydrostatic Pressure Test. 504 psi MOP and 630 psi test pressure for 8 hours. No failures. CP records were appropriate.

94. GX140 10"; Berth 172 - Carson Term., 4.01 miles, Baseline Assessment, 5/28/2003, Hydrostatic Pressure Test. 504 psi MOP and 630 psi test pressure for 8 hours. No failures. CP records were appropriate.

95. GX150 12"; Berth 172 - Avalon & Broad Mfld, 0.68 miles, Baseline Assessment, 5/28/2003, Hydrostatic Pressure Test. 504 psi MOP and 630 psi test pressure for 8 hours. No failures. CP records were appropriate.

96. GX180 8"; Berth 118 - Carson Term., 3.06 miles, Baseline Assessment, 6/2/2003, Hydrostatic Pressure

Test. 625 psi MOP and 781 psi test pressure for 8 hours. No failures. CP records were appropriate.

97. GX-190 Carson Term. - Torrance Meter Sta. 8"/10", 8.27 miles, Baseline Assessment, 10/19/2005 GE HR-MFL and 9/16/2005 GE Caliper. Report date 12/29/2005, received date 1/3/2006, and discovery date 11/22/2005. 1 immediate anomaly was reported but reclassified as a 60-day condition when it was exposed and repaired on 11/28/2005. Another 60-day anomaly was repaired on 11/29/2005. Pipeline was shutdown on 11/22/2005 and pressure was restored on 11/28/2005.

98. GX200 10"/12"; Chemoil Term. - Arco Mfld, 0.20 miles, Baseline Assessment, 4/1/2004, Hydrostatic Pressure Test. 730 psi MOP and 900 psi test pressure for 8 hours. No failures. CP records were appropriate.

99. GX205 12"/14"; Chemoil Term. - Arco Mfld, 0.61 miles, Baseline Assessment, 4/1/2004, Hydrostatic Pressure Test by A. H. Construction Corp. No failures. CP records were appropriate.

100. GX-210 Carson Term - Willow Mfld, 12", 0.58 miles, Baseline Assessment, 11/18/2005, Hydrostatic Pressure Test y A. H. Construction Corp. No failures. CP records were appropriate.

CalNev

101. 8" ML Colton - Barstow, 86.61 miles, Baseline Assessment, 10/3/2003 Rosen HR-MFL and 8/19/2003 Rosen Caliper. Report date 11/26/2003, received date 12/1/2003, and discovery date 12/1/2003. 2 60-day anomalies with repairs completed 1/20/2004 and 2/5/2004. Rosen AFD was run 3/6/2005 and Rosen Deformation tool run on 3/13/2005. Report date 7/15/2005, received date 7/20/2005, and discovery date 7/21/2005. 1 immediate repair condition repaired on 4/8/2005. Pressure was reduced on 4/8/2005 based on the preliminary report.

102. 8" ML Barstow - Bracken Jct, 144.33 miles, Baseline Assessment, 10/3/2003 Rosen HR-MFL and Rosen Caliper. Report date 12/1/2003, received date 12/2/2003, and discovery date 12/2/2003. 3 60-day anomalies with repairs completed 1/14/2004, 1/22/2004, and 1/28/2004. Rosen AFD was run 4/5-7/2005 and Rosen Deformation tool run on 3/15-17/2005. Report date 7/29/2005, received date 8/2/2005, and discovery date 8/29/2005. 3 180-day anomalies with repairs completed 5/11/2005, 1/2006, and 2/23/2006.

103. 14" ML Colton - Barstow, 87.12 miles, Baseline Assessment, 6/15/2004 Rosen HR-MFL and 5/10/2005 Rosen Caliper. Report date 8/19/2005 and received date 8/25/2005. No rule categorized anomalies identified.

104. 14" ML Barstow - Las Vegas, 161.04 miles, Baseline Assessment, 3/24/2004 Rosen Deformation tool and 3/17/2004 and 6/16/2004 Rosen HR-MFL. 2 HR-MFL tool runs were conducted. The first one had approximately 2 miles with no data. The second run to capture the missing data was completed approximately 3 months later. The caliper final report was not completed within 180 days but there were no rule categorized anomalies identified. Report date 10/12/2004, received date 10/12/2004, and discovery date 10/12/2004. No anomalies were initially identified when the RSRENG criteria was used. 2 180-day anomalies identified once B31G criteria was applied and repaired 5/4/2005 and 5/5/2005. Rosen EGP run on 3/15/2004 and Rosen CDP on 6/14/2004. Report dated 9/27/2004, received date 9/30/2007, and discovery date 9/30/2004. 1 60-day anomaly identified that was repaired 11/17/2004.

105. 6"/4" Adelanto - George Terminal, 1.96 miles, Baseline Assessment, 7/12/2005, Hydrostatic Pressure Test. 1432 psi MOP. 4 hours of the test was at 1770 and 4 hours at 1785. The MOP was adjusted to allow the test to fulfill the test acceptance. No failures. CP records were appropriate.

106. 20" Unleaded Receiving, 0.54 miles, Baseline Assessment, 12/17/2003, Hydrostatic Pressure Test. 366 psi test pressure. No failures. CP records were appropriate.

107. 20" Diesel Receiving, 0.54 miles, Baseline Assessment, 5/7/2003 and 5/14/2003, Hydrostatic Pressure Test. 5/7/2003 was at 2220 psi for 6 hours on the 16”. 5/14/2003 was at 351 psi for 8 hours on the 20”.

108. 16" Jet Fuel Receiving B, 0.38 miles, Baseline Assessment, 11/15/2004, Hydrostatic Pressure Test. 248 psi MOP and 356 psi test pressure for 8 hours. No failures. CP records were appropriate.

Santa Fe Pacific Pipeline (SFPP)

109. LS-4/5; El Paso - Lordsburg 8", 164.52 miles, Baseline Assessment, 7/30/2004 Rosen HR-MFL and 5/24/2004 Rosen Caliper. Report date 11/9/2004, received date 11/11/2004, and discovery date 11/12/2004. 1 180-day anomaly which was repaired 3/10/2005. Re-evaluated 6/22/2005 using B31G criteria and 5 additional 180-day anomalies were identified. These were repaired 3/10/2005, 3/10/2005, 7/27/2005,

7/27/2005, and 8/22/2005. Magpie deformation caliper on 2/22/2006, Report date 3/30/2006, received date 4/4/2006, and discovery date 4/5/2006. 2 60 day dents greater than 3 percent were identified, one of which was re-classified as an immediate condition following verification digs. Repairs were completed 7/11/2006 and 7/24/2006.

110. LS-5/6; Lordsburg - Tucson 8" -NIS, 139.22 miles, Baseline Assessment, 8/26/2004 Rosen HR-MFL and 6/24/2004 Rosen Caliper. Report date 12/30/2004, received date 1/4/2005, and discovery date 1/4/2005. No rule categorized anomalies identified. Dig #5 was 20 feet outside of an HCA and had a cluster with 49% depth. This anomaly was identified from a prior ILI run and repaired with a Clock Spring.

111. LS-7; Bon - LS-117 8" -NIS, 36.74 miles, Baseline Assessment, 8/19/2004 Rosen HR-MFL and 8/12/2004 Rosen Caliper. Report date 12/1/2004, received date 12/3/2004. No rule categorized anomalies identified. 2 digs were made before use of 452(h) criteria. Line pressure was already reduced due to previously identified SCC. The line is now out of service.

112. LS-8; Richmond - Concord 8", 23.05 miles, Baseline Assessment, 10/23/2003 Rosen HR-MFL and Rosen Caliper. Report date 12/23/2003, received date 12/29/2003. No rule categorized anomalies identified. Report was re-evaluated using B31G criteria on 4/26/2005.

113. LS-9; Concord - Bradshaw 10", 92.45 miles, Baseline Assessment, 3/22/2005 Rosen HR-MFL and 3/16/2005 Rosen Caliper. Report date 5/20/2005, received date 5/23/2005, and discovery date 5/24/2005. 5 180-day anomalies were identified and repaired.

114. LS-11; Rocklin - Newcastle 10", 9.68 miles, Re-Assessment, 8/18/2005 Magpie Caliper. Report date 10/26/2005, received date 5/23/2005. No rule categorized anomalies identified.

115. LS-11; Newcastle - Clipper Gap 6", 11.67 miles, Re-Assessment, 8/19/2005, Magpie Caliper. Report date 11/3/2005, received date 11/7/2005. No rule categorized anomalies identified.

116. LS-11; Clipper Gap - Colfax 10", 12.32 miles, Re-Assessment, 9/19/2005, Magpie Caliper. Report date 10/26/2005, received date 10/31/2005. No rule categorized anomalies identified.

117. LS-12; Colfax - Woodchopper Spgs 8", 56.83 miles, Re-Assessment, 8/20/2005, Magpie Caliper. Report date 10/27/2005, received date 11/03/2005 and discovery date of 9/29/2005 based on the preliminary report. 2 immediate condition anomalies and 11 60-day anomalies identified. 2 repairs exceeded the 60-day timeframe but had pressure reductions and notifications submitted to PHMSA.

118. LS-12/13; Woodchopper -10x6 Red 10", 23.04 miles, Re-Assessment, 11/2/2005, Magpie Caliper. Report date 12/8/2005, received date 12/15/2005. No rule categorized anomalies identified.

119. LS-13; 10x6 Reducer - Reno 6", 7.38 miles, Re-Assessment, 11/2/2005, Magpie Caliper. Report date 12/8/2005, received date 12/141/2005 and discovery date of 12/15/2005. 1 immediate repair condition identified – dent with a gouge. A 20% pressure reduction taken on 12/20/2005. Repair was completed on 12/21/2005.

120. LS-14; Portland - Eugene 8", 114.60 miles, Re-Assessment, 10/28/2005 GE Pii Caliper and 10/28/2005 GE Pii HR-MFL. Report date 12/30/2005, received date 1/3/2006, and 1/13/2006 discovery date. 2 60-day anomalies identified and repairs completed on 2/15/2006 and 3/1/2006.

121. LS-15; Bakersfield - Fresno 8", 97.85 miles, Baseline Assessment, 7/10/2004 Rosen Deformation tool and 7/17/2004 Rosen HR-MFL. Report date 10/20/2004, received date 10/21/2004, and discovery date 7/29/2005 (based on re-evaluation using B31G criteria). 1 180-day condition identified (based on re-evaluation) that was repaired 12/19/2005.

122. LS-16; Concord - San Jose 10", 51.41 miles, Re-Assessment, Rosen Deformation tool and 11/15/2004 Rosen HR-MFL. Report date 12/22/2004, received date 1/6/2005, and discovery date 1/11/2005. 1 180-day condition identified. Run was re-evaluated 1/6/2005 with a new discovery date of 4/28/2005 that identified 21 180-day anomaly conditions. All anomalies were repaired within required timeframes.

123. LS-17/18; El Paso - Afton 12", 51.82 miles, Baseline Assessment, GE Pii Caliper and 12/9/2005 GE Pii HR-MFL. Report date 1/3/2006, received date 1/4/2006, and 1/4/2006 discovery date. 6 180-day anomalies identified and repairs completed between12/28/2005 and 2/16/2005.

124. LS-18/19/21; Afton - Lordsburg 12", 112.03 miles, Baseline Assessment, GE Pii Caliper and 12/17/2005 GE Pii HR-MFL. Report date 1/30/2006 and 1/24/2006 discovery date (based on the preliminary report). 1 immediate condition anomaly and 8 180-day condition anomalies identified. Pressure reduction taken on

1/24/2006. Immediate condition repair completed 2/2/2006. Other repairs completed within required timeframes.

125. LS-21/22; Lordsburg - Tucson 12", 139.37 miles, Baseline Assessment, - assessment combined with the LS-18/19/21; Afton - Lordsburg 12" segment.

126. LS-20; Sacramento - Rocklin 12", 23.50 miles, Baseline Assessment, Rosen Deformation tool and 10/29/2003 Rosen HR-MFL. Report date 1/26/2004 and received date 1/28/2004. No rule categorized anomalies identified.

127. LS-27; Martinez - Concord 12", 5.33 miles, Baseline Assessment, Rosen Deformation tool and 10/20/2003 Rosen HR-MFL. Report date 12/11/2003, received date 12/12/2003, and discovery date 12/12/2003. 2 180-day condition anomalies identified. All anomalies were repaired within required timeframes.

128. LS-33; Mococo - Concord 12", 4.58 miles, Baseline Assessment, 10/22/2003 Rosen Deformation tool and 10/22/2003 Rosen HR-MFL. Report date 12/15/2003 and received date 12/18/2003. No rule categorized anomalies identified.

129. LS-36; Richmond - Oakland 12", 12.65 miles, Baseline Assessment, 6/14/2004 Rosen Deformation tool and 7/22/2004 Rosen HR-MFL. Report date 10/11/2004 and received date 10/12/2004. 1 180-day condition identified. The 180-day anomaly condition was repaired 11/4/2004. Data was re-evaluated per B31G criteria on 6/20/2005.

130. LS-38; Brisbane - S.F. Airport 12", 5.39 miles, Re-Assessment, 5/17/2006 Magpie Deformation and 6/14/2006 GE Pii HR-MFL. Report date 6/23/2006 for the corrosion tool and 7/6/2006 for the deformation tool, received date 6/29/2006, and 6/30/2006 discovery date. 4 180-day anomalies identified and repairs have not been completed as of the time of the inspection (still within required timeframes).

131. LS-42; Oakland - Brisbane 12", 24.93 miles, Re-Assessment, 2/14/2005 Rosen AFD (TFI). Report date 4/5/2005, received date 4/8/2005, and discovery date 4/6/2005 (based on the preliminary report). 2 “other” conditions identified and repaired 2/25/2005 and 3/5/2005.

132. LS-43; Stockton-British Petroleum W, 0.21 miles, Baseline Assessment, 4/21/2004, Hydrostatic Pressure Test. MOP 286 psi and 358 psi test pressure. No failures. CP records were appropriate.

133. LS-46; Richmond - Oakland 10/8", 12.65 miles, Baseline Assessment, Rosen Deformation tool and 9/24/2004 Rosen HR-MFL. Report date 10/26/2004 (preliminary) and received and discovery date 6/20/2005 (re-evaluated). 8 180-day conditions identified based on the report re-evaluation. All anomalies were repaired within required timeframes.

134. LS-47; Concord - Carquinez Strait 8", 4.74 miles, Baseline Assessment, 11/30/2005 GE Pii Caliper and 12/1/2005 GE Pii HR-MFL. Report date 12/28/2005, received date 1/3/2006, and discovery date 1/4/2006. No rule categorized anomalies identified.

135. LS-47; Carquinez Strait Bridge – Suisan Jct, Baseline Assessment, 12/1/2005 GE Pii Caliper and 12/7/2005 GE Pii HR-MFL. Report date 12/28/2005, received date 1/3/2006, and discovery date 1/4/2006. No rule categorized anomalies identified.

136. LS-47; Concord - Carquinez Strait 8" - Hydrostatic Pressure Test on 11/17/2005. No failures. Above grade section of piping.

137. LS-49; Western - UPRR 4", 5.54 miles, Baseline Assessment, 9/20/2005, Hydrostatic Pressure Test. 903 psi test pressure for 8 hours. No failures. CP records were appropriate.

138. LS-52 Phoenix - Luke AFB 6", 18.20 miles, Baseline Assessment, 12/18/2003 Rosen Deformation tool and 3/15/2004 Rosen HR-MFL. Report date 5/18/2004 and received date 5/24/2004. No rule categorized anomalies identified.

139. LS-54; Tucson - Davis Monthan AFB, 6.36 miles, Baseline Assessment, 12/16/2003 Rosen Deformation tool and 12/16/2003 Rosen HR-MFL. Report date 1/21/2004 and received date 2/9/2004. No rule categorized anomalies identified.

140. LS-58; LS-133 - Imperial, 25.22 miles, Re-Assessment, 6/6/2005 Rosen Deformation tool and 6/6/2005 Rosen HR-MFL. Report date 7/5/2005 and received date 8/8/2005. No rule categorized anomalies identified.

141. LS-61; Yuma - Yuma MCAS 6", 9.10 miles, Baseline Assessment, 12/8/2003 Rosen Deformation tool and 12/8/2003 Rosen HR-MFL. Report date 1/30/2004, received date 2/3/2004 and discovery date 2/3/2004. 1

immediate repair condition repaired on 2/6/2004. Upon review of report KMEP treated anomaly as immediate because of dent with metal loss.

142. LS-62; Jct-Stockton - Stockton 8", 4.16 miles, Baseline Assessment, 6/21/2004 Rosen Deformation tool and 7/21/2004 Rosen HR-MFL. Report date 9/22/2004 and received date 9/23/2004. No rule categorized anomalies identified.

143. LS-64; Rocklin - Chico 8 ", 77.31 miles, Re-Assessment, 11/2/2005 Rosen Deformation tool and 11/9/2005 Rosen HR-MFL. Report date 12/22/2005, received date 1/3/2006 and discovery date 1/5/2006. 1 180-day condition identified and repaired 1/24/2006 with an A-sleeve. Pressure was reduced to 1255 psi on 1/5/2006 and was restored on 7/14/2006.

144. LS-65; Erle Jct - Beale AFB 6", 5.74 miles, Baseline Assessment, 1/13/2004 Rosen Deformation tool and 1/13/2004 Rosen HR-MFL. Report date 2/13/2004, received date 2/23/2004 and discovery date 4/27/2005 after re-evaluation of the data. 1 “other” condition identified and repaired 9/14/2005. Pressure was reduced to 1148 psi from 1428 psi on 4/27/2005 and was restored on 9/14/2005.

145. LS-68/88; Martinez - Amorco Jct 10, 1.15 miles, Baseline Assessment, 5/28/2004, Hydrostatic Pressure Test. MOP 1445 psi and 1807 psi test pressure for 8 hours. No failures. CP records were appropriate.

146. LS-69; Chevron #1 - Richmond 8", 1.28 miles, Baseline Assessment, 11/7/2005, Hydrostatic Pressure Test. MOP 364 psi test pressure for 8 hours. No failures. CP records were appropriate.

147. LS-71; LS-89 - Richmond 8", 2.09 miles, Baseline Assessment, 9/14/2004, Hydrostatic Pressure Test. 1173 psi test pressure for 8 hours. No failures. CP records were appropriate.

148. LS-72; Rodeo - Concord 8", 13.09 miles, Baseline Assessment, 10/28/2003 Rosen Deformation tool and 10/28/2003 Rosen HR-MFL. Report date 1/21/2004 and received date 1/29/2004. No rule categorized anomalies identified. Data re-analyzed per B31G criteria on 6/15/2005.

149. LS-73; Tesoro - Concord 8" - Not Owned/Oper, 0.01 miles, Baseline Assessment, 9/15/2005, Hydrostatic Pressure Test. Assessment not reviewed. System was sold 12/6/2005.

150. LS-75; IMTT - Richmond 8", 1.76 miles, Baseline Assessment, 9/14/2004, Hydrostatic Pressure Test. No failures. CP records were appropriate.

151. LS-76; ST Services - LS-75, 0.41 miles, Baseline Assessment, 9/14/2004, Hydrostatic Pressure Test. 902 psi test pressure for 8 hours. No failures. CP records were appropriate.

152. LS-77; Shell - Portland 8", 1.89 miles, Baseline Assessment, 6/9/2004, Hydrostatic Pressure Test. MOP 282 psi and 353 psi test pressure for 8 hours. No failures. CP records were appropriate.

153. LS-78; Conoco/Phillips-Portland 8", 1.20 miles, Baseline Assessment, 6/12/2004, Hydrostatic Pressure Test. MOP 284 psi and 355 psi test pressure for 8 hours. No failures. CP records were appropriate.

154. LS-79; Chevron - Portland 8", 1.25 miles, Baseline Assessment, 6/15/2004, Hydrostatic Pressure Test. MOP 282 psi and 353 psi test pressure for 8 hours. No failures. CP records were appropriate.

155. LS-81; Willbridge - Portland 8", 0.97 miles, Baseline Assessment, 6/24/2004, Hydrostatic Pressure Test. MOP 360 psi. No failures. CP records were appropriate.

156. LS-82; Arco - Portland 8", 2.23 miles, Baseline Assessment, 6/18/2004, Hydrostatic Pressure Test. MOP 282 psi. No failures. CP records were appropriate.

157. LS-82/83/84; Linnton - Portland 8", 2.96 miles, Baseline Assessment, 6/8/2004, Hydrostatic Pressure Test. MOP 2882 psi. No failures. CP records were appropriate.

158. LS-84/83; Mobile - Portland 8", 2.01 miles, Baseline Assessment, 6/13/2004, Hydrostatic Pressure Test. MOP 365 psi. No failures. CP records were appropriate. One CP reading was low. Pipe is to be relocated in 2006.

159. LS-86; LS-4 - Alamogordo Jct, 0.04 miles, Baseline Assessment, 7/15/2004, Hydrostatic Pressure Test. MOP 1440 psi and test pressure 1800 psi. No failures. CP records were appropriate.

160. LS-89; Arco - Richmond 8", 0.37 miles, Baseline Assessment, 9/14/2004, Hydrostatic Pressure Test. 1173 psi test pressure for 8 hours. No failures. CP records were appropriate.

161. LS-90/50/60; Concord - Fresno 12", 171.20 miles, Baseline Assessment, 12/19/2003 Rosen Deformation tool and 1/22/2004 Rosen HR-MFL. Report date 3/22/2004 and received date 3/23/2004. No rule categorized anomalies identified. Data re-analyzed per B31G criteria.

162. LS-95; Valero - Amorco 10", 2.73 miles, Baseline Assessment, 11/2003 Rosen Deformation tool and 11/18/2003 Rosen HR-MFL. Report date 2/6/2004 and received date 2/9/2004. No rule categorized anomalies identified. Data re-analyzed per B31G criteria 6/21/2005.
163. LS-99; Chevron - Richmond 10", 1.22 miles, Baseline Assessment, 11/17/2005, Hydrostatic Pressure Test. 363 psi test pressure for 8 hours. No failures. CP records were appropriate.
164. LS-102; Ontario - Ontario Airport 6", 1.65 miles, Baseline Assessment, 7/15/2004, Hydrostatic Pressure Test. 275 MOP and 350 psi test pressure for 8 hours. No failures. CP records were appropriate.
165. LS-103; Exxon - Mococo 10", 3.16 miles, Baseline Assessment, 11/6/2003 Rosen Deformation tool and 11/7/2003 Rosen HR-MFL. Report date 12/17/2003, 12/9/2003, and 12/16/2003. Received date 12/15/2003, 12/18/2003 and 12/19/2003. No rule categorized anomalies identified. Data re-analyzed per B31G criteria.
166. LS-104; Chevron - Richmond 10", 1.22 miles, Baseline Assessment, 11/9/2005, Hydrostatic Pressure Test. 275 MOP and 360 psi test pressure for 8 hours. No failures. CP records were appropriate.
167. LS-105/108; Watson - Nogales BV 24", 30.83 miles, Baseline Assessment, 6/30/2004 Rosen Deformation tool and 7/12 & 23/2004 Rosen HR-MFL. Report date 10/20/2004 and received date 10/21/2004. No rule categorized anomalies identified. Data re-analyzed per B31G criteria 9/26/2005.
168. LS-108; Nogales BV - Colton 20", 32.07 miles, Baseline Assessment, 7/14/2004 Rosen Deformation tool and Rosen HR-MFL. Report date 1/27/2004 and received date 2/2/2004. No rule categorized anomalies identified. Data re-analyzed per B31G criteria 6/22/2005.
169. LS-109; Sepulveda Jct. - Watson 16", 3.96 miles, Baseline Assessment, 12/3/2003 Rosen Deformation tool and Rosen HR-MFL. Report date 2/6/2004 and received date 2/9/2004. No rule categorized anomalies identified. Data re-analyzed per B31G criteria 6/21/2005.
170. LS-110; McMillian Vault - Watson St, 2.89 miles, Baseline Assessment, 6/17/2004 Rosen Deformation tool and Rosen HR-MFL. Report date 9/8/2004 and received date 9/13/2004. No rule categorized anomalies identified. Data re-analyzed per B31G criteria 6/22/2005.
171. LS-116/117; Tucson - Naviska 12", 32.01 miles, Baseline Assessment, 3/18/2003 Rosen Deformation tool and 3/22/2004 Rosen HR-MFL. Report date 5/6/2004 and received date 5/20/2004. No rule categorized anomalies identified.
172. LS-117; Naviska - Toltec 12" -ELX, New line tested as part of installation requirements. Assessment not reviewed.
173. LS-117 Toltec - Bon 12", 19.99 miles, Baseline Assessment, 3/18/2004 Rosen Deformation tool and 3/23/2004 Rosen HR-MFL. Report date 5/21/2004 and received date 5/24/2004. No rule categorized anomalies identified.
174. LS-117; Bon - Salt River 12" -ELX, New line tested as part of installation requirements. Assessment not reviewed.
175. LS-117; Salt River - Phoenix Term, 3.98 miles, Baseline Assessment, 8/19/2004 Rosen Deformation tool and 8/16/2004 Rosen HR-MFL. Report date 11/8/2004 and received date 11/9/2004. No rule categorized anomalies identified.
176. LS-119 A; Fresno - Fresno Military, 0.45 miles, Baseline Assessment, 7/27/2004, Hydrostatic Pressure Test
177. LS-120/1; Watson - Colton 16", 64.07 miles, Baseline Assessment, 4/1/2004 Rosen Deformation tool and 6/2/2004 Rosen HR-MFL. Report date 9/9/2004 and received date 9/13/2004. No rule categorized anomalies identified in initial evaluation. 1 180-day anomaly identified using B31G criteria. This anomaly was repaired 10/27/2005.
178. LS-122; Hwy 52 - Mission Valley 10", 6.04 miles, Re-Assessment, 6/28/2005 Rosen Deformation tool and Rosen HR-MFL. Report date 8/24/2005, received date 9/12/2005 and 11/11/2005 discovery date. 1 60-day anomaly identified and repaired 11/30/2005.
179. LS-128/129/131; Afton - Apache 16" -ELX, 161.20 miles, Baseline Assessment, Hydrostatic Pressure Test - LS-128 on 10/24/2005, LS-128 #3 on 11/3/2005, LS-128 #4 on 11/21/2005, LS=128, LS-129, LS-131 on 11/28/2005, and LS-131 on 12/5/2005. No failures noted.

180. LS-130A; Concord-Waterfront Rd 20", 3.51 miles, Baseline Assessment, 2/23/2005 Rosen Deformation tool and 2/21/2005 Rosen HR-MFL. Report date 4/19/2005 and received date 4/20/2005. No rule categorized anomalies identified.

181. LS-130B; Waterfront Rd-N Carquinez 14", 2.96 miles, Baseline Assessment, 2/23/2005 Rosen Deformation tool and 2/21/2005 Rosen HR-MFL. Report date 2/23/2005 and received date 4/21/2005. No rule categorized anomalies identified.

182. LS-130C; N Carquinez-Sacramento 20", 63.58 miles, Baseline Assessment, 2/23/2005 Rosen Deformation tool and 3/3/20054 Rosen HR-MFL. Report date 8/5/2005 and received date 8/9/2005. No rule categorized anomalies identified.

183. LS-132; Diamond Jct - Breakout 16" -ELX, 6.03 miles, Baseline Assessment, 9/30/2005, Hydrostatic Pressure Test – test pressure 1830 psi

184. LS-133; Niland - LS-58, 4.26 miles, Baseline Assessment, 8/26/2004 Rosen Deformation tool and Rosen HR-MFL. Report date 11/17/2004 and received date 11/22/2004. No rule categorized anomalies identified. Data was re-analyzed per B31G criteria.

| **4.02 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| X | **4.02.01** | The required remediation criteria timeframes were not met | AF 4.1 | D |
| | **4.02.02** | Anomalies were not adequately prioritized for repair | AF 4.1 | |
| | **4.02.03** | Operating pressure was not immediately reduced when required | AF 4.2 | |
| | **4.02.04** | An anomaly was not repaired using an acceptable repair method | AF 4.1 | |
| | **4.02.05** | Further remedial action was not adequately implemented when a pressure reduction exceeded 365 days | AF 4.1 | |
| | **4.02.06** | PHMSA was not required to be notified when repair deadlines were not met and pressure is not reduced | AF 4.3 | |
| | **4.02.07** | Remediation activities and results were not adequately documented | AF 4.4 | |
| | **4.02.08** | Necessary pressure reductions were not based on actual recent operating pressures rather than the pipeline maximum operating pressure (MOP) | AF 4.2 | |
| | **4.02.09** | Adequate controls were not required such as the resetting of relief valve actuation pressures to assure that pressure reduction limits are not violated | AF 4.2 | |
| | **4.02.10** | Annual Report Part J Data of the most recent Form PHMSA F 7000-1.1 incomplete and/or invalid | NA | |
| | **Other:** | | | |

# Integrity Management
# Inspection Protocol 5

# Risk Analysis

**Scope:**

This Protocol addresses the overall risk analysis/information analysis process employed by operators to support various integrity management program elements, including Baseline Assessment Plan development, continuing evaluation and assessment of pipeline integrity, and identification of preventive and mitigative measures. The Protocol addresses the comprehensiveness of the risk analysis process, the methods of combining/integrating risk information, input information, the subdividing of pipelines for risk analysis, results, the risk analysis of facilities, and implementation of the risk analysis process. Evaluations of application-specific risk analyses are performed in the respective Protocol area in which they are utilized.

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| Protocol # 5.01 | Risk Analysis: Comprehensiveness of Approach |
|---|---|
| **Protocol Question** | Does the operator's process for evaluating risk require consideration of all relevant risk categories and operating conditions when evaluating pipeline segments? |

At the onset of examining the operator's process for evaluating risk, it is important to establish the general categories of risk factors that the operator has included in their process. To that end, this protocol question addresses the overall comprehensiveness of the risk evaluation process. An effective operator program would be expected to have the following characteristics:

1. Inclusion of all relevant important factors that might constitute a threat to pipeline integrity, such as:
    - external and internal corrosion
    - stress corrosion cracking
    - materials problems
    - third party damage
    - operator or procedures errors
    - equipment failures
    - natural forces damage
    - construction errors
2. Inclusion of all important relevant factors that affect the consequences of pipeline failures, such as
    - health and safety impact
    - environmental damage
    - property damage
3. Integration of results from the analysis of how pipeline failures could affect high-consequence areas from the segment identification process.
4. Consideration of the risks associated with alternate modes of operation of their pipelines (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.).

Note: The Protocols are organized such that verification of the use of specific required risk factors in various parts of the rule (e.g., risk factors required for assessment scheduling) is done as part of the protocols for each respective part of the rule, as follows:

Baseline Assessment Plan Factors: Protocol Question 2.02
Continual Assessment Plan Factors: Protocol Question 7.01 and 7.02
Preventive & Mitigative Risk Analysis: Protocol Question 6.02
Leak Detection Evaluation Factors: Protocol Question 6.04
EFRD Evaluation Factors: Protocol Question 6.06

| | |
|---|---|
| **Rule Requirement** | §195.452(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)? ....* |
| | §195.452(i)(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: .... |

| 5.01 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**5.01 Inspection Issues Summary**

**5.01 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix B | B | 8/3/2006 | HCA Identification Process |
| Appendix H4.2 | 6 | 8/21/2006 | Identify HCAs (Annual/New/Acquired) |
| Appendix H6.2 | 5 | 8/21/2006 | Review Risk Algorithm - Annual |
| Appendix H6.11 | 1 | 8/22/2006 | Risk Assessment Results Validation |
| Appendix D3 | 5 | 8/23/2006 | Integrity Assessment Program (IAP) Algorithm Sheets – Current |

**5.01 Inspection Notes**

IMPM 6.4.2 describes the data collection requirements. The KMEP Risk Management Team is responsible for the collection of integrity assessment and risk related data. These personnel are qualified by training and experience and work with KMEP Business Unit Integrity Teams to insure that the appropriate information and data is entered into the database. Data sources for utilization in the integrity assessment process will typically include the following: Results of previous assessments; internal inspections (defect type, size, and growth), pressure testing (cathodic protection data is gathered in accordance with Procedure H6.4, Collect Corrosion Data) or other technology (see Procedure H8.2, Direct Assessment); Pipe size, material, manufacture, coating, condition, seam type; Leak history, repair history; Product transported, product characteristics; Operating stress level; Existing or projected activities in area; Local environmental factors (e.g. corrosivity, subsidence); Geo-technical hazards; Physical supports/spans ; Elevation and terrain; Volume that could be released; Potential spillage following drain tiles or ditches; Exposure to pressure > MOP; HCA data changes and growth; Operator Error; Incident investigation results. In order to ensure that input into the Risk Model represents the most current and accurate information available and to facilitate a risk analysis that best reflects the current conditions associated with pipeline segments, KMEP Business Unit Integrity Management Teams validate HCA and field interview data in accordance with Procedures H4.2, Identify HCAs (Annual/New/Acquired) and H6.10, Field Data SME Validation. Additionally, KMEP Risk Management Team reviews and validates input information to ensure that input data represents the most accurate and current data available in accordance with Procedure 6.3, Quality Control Data Checks. IAP risk model demonstrates integration of the data. Online data from the IAP was reviewed for LS-14 risk scoring data, Portland-Eugene 8"

IMPM 6.4.3 discusses the KMEP risk model. In accordance with API Standard 1160, Section 7.5, an electronic database is employed for data storage, analysis, and decision-making assistance. The software database is also utilized to store integrity assessment related information and perform the annual risk assessment analysis. The KMEP risk algorithm is capable of evaluating both the likelihood of failure (LOF) and the consequences of failure (COF), as shown in Table 6.1, Risk Factors. Each risk factor shown in the table can be further sub-divided into additional detailed variables (such as coating design, age, type, cathodic protection data, etc.). Table 6.1, Risk Factors. Likelihood of Failure (LOF) Consequence of Failure (COF) External Corrosion Impact

on Population Third Party Damage (Outside Force Damage) Impact on Environment Ground Movement (Outside Force Damage) Impact on Business Design/Material System Operations Other Factors KMEP populated the software database with selected variable information from the above listed variables for those pipeline segments that could affect an HCA. For a more detailed description of risk variables utilized, see Procedure H8.7, Develop Continuing Assessment Plan. Pipeline design information (size, wall thickness, etc.) and elevation data for the entire KMEP system has been entered into the database to facilitate pipeline rupture volume calculations. During the initial risk assessment process, complete and detailed information was not available for some data fields. In these instances, one of two actions was taken; A reasonable engineering assumption was made to populate the data and these assumptions are noted in the comment field. Or, the factor weighting was set to zero so that the factor had no affect in the analysis conducted using the algorithm. KMEP's current practice prescribes that all appropriate available pipeline integrity data will be incorporated in the risk database even though similar data may not be uniformly available for all line segments. The model allows for drilling down to understand what factors are driving the risk. All pipelines have been evaluated using the IAP risk model. Risk analysis is segmented on the HCA length. Analysis uses the worst case variable in the segment if attributes vary.

Appendix D3 includes the latest version of the risk analysis algorithm used to establish the current year Assessment Plan. This appendix has the algorithm sheets and includes consideration of pressure cycling. On the consequence side, pipeline throughput provides consideration of operational modes.

| **5.01 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **5.01.01** | A comprehensive risk analysis process was not adequately developed | AF 5.2 | |
| | **5.01.02** | All portions of pipelines were not included in the risk analysis without justification | AF 5.5 | |
| | **5.01.03** | The process did not adequately consider unique risk factors when using a "standard" risk model | AF 5.1 | |
| | **5.01.04** | The process did not adequately consider risk to HCAs in the risk analysis | AF 5.1 | |
| | **5.01.05** | Susceptibility to failure due to use of low-frequency ERW piping was not adequately considered | AF 5.1 | |
| | **5.01.06** | Susceptibility to SCC to not appropriately considered | AF 5.1 | |
| | **5.01.07** | The process did not adequately require training and qualification for personnel involved with performing risk analysis | AF 5.2 | |
| | **5.01.08** | The risk analysis process was not adequately documented | AF 5.8 | |
| | **5.01.09** | The risk analysis process did not adequately consider all required risk factors. | AF 5.1 | |
| | **Other:** | | | |

| Protocol # 5.02 | Risk Analysis: Integration of Risk Information |
|---|---|
| **Protocol Question** | Does the process for evaluating risk appropriately integrate the various risk factors and other information utilized to characterize the risk of pipeline segments? |

Methods to evaluate risk utilize a variety of input data to characterize the physical condition of pipelines and the surrounding population/environment for which consequences are estimated. This information, including "risk factors," is typically combined in some fashion (e.g., input into an algorithm or mathematical model, evaluated by subject matter experts, etc.) to produce an estimate of the risk for a particular section of pipe. In some methods used to combine risk information, numerical "weights" are applied to risk factors when calculating or estimating risk. An effective operator program would be expected to have the following characteristics:

1. Inclusion of the appropriate variables needed to adequately determine the relevant risk ranking of a pipeline segment (e.g., variables to determine the potential for area-specific external and internal corrosion, mechanical damage, construction defects, etc.).
2. A technically justifiable basis for the analytical structure of any tools, models, or algorithms utilized to integrate risk information, and recognition of any limitations of these analytical structures.
3. Logical, structured, and documented processes and guidelines for any subject matter expert evaluations that are used to perform or influence the integration of risk information.
4. Justification for the relative magnitude of any numerical weights used to estimate measures of risk.
5. A risk integration/combination process that emphasizes the potential risk to human health and the environment as compared to "non-safety" risk factors such as those principally associated with business and economic risks.
6. In cases where a risk model is utilized, a method that integrates the risk model output with any important risk factors that were not included in the model to provide a more complete evaluation of the risk.

| | |
|---|---|
| **Rule Requirement** | §195.452(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)? ....* |
| | §195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section); |
| | §452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure .... |
| | §195.452(i)(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: .... |

| 5.02 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**5.02 Inspection Issues Summary**

Further explanation of the use of the weighted average risk score should be provided in the IMP to ensure consistent application. With one primary risk engineer using the weighted average risk score, consistent application did not appear to be a problem at this time, but personnel changes could highlight the need for the additional process detail discussed during the inspection as a process improvement. Segmentation for risk analysis is based on HCAs with the worst case risk factor found in the HCA length applied to the entire segment. The Inspection Team reviewed how this analysis is applied in the preventive and mitigative measures (P&MM) process. The Inspection Team discussed with KMEP its transition to "newer" risk models and how the other models support the evaluation of additional P&MM and application of models, such as the current IAP, that use a dynamic segmentation process in the IMP.

**5.02 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix D1 | 5 | 8/23/2006 | IAP Manual Ch1 - Introduction |
| Appendix D3 | 5 | 8/23/2006 | Integrity Assessment Program (IAP) Algorithm Sheets – Current |
| Appendix H5.1 | 6 | 8/31/2006 | Develop Baseline Assessment Plan |
| Appendix H6.1 | 6 | 8/31/2006 | Develop Initial Risk Algorithm |
| Appendix H6.2 | 5 | 8/31/2006 | Review Risk Algorithm - Annual |
| Appendix H6.11 | 1 | 8/22/2006 | Risk Assessment Results Validation |

**5.02 Inspection Notes**

Further explanation of the use of the weighted average risk score should be provided in the IMP. Segmentation for risk analysis is based on HCAs with the worst case risk factor found in the HCA length applied to the entire segment. The Inspection Team reviewed how this analysis is applied in the preventive and mitigative measures (P&MM) process. The Inspection Team discussed with KMEP its transition to "newer" risk models and how the other models may support the evaluation of additional P&MM and application of models, such as the current IAP, that use a dynamic segmentation process in the IMP.

IMPM Section 6 establishes a process by which KMEP evaluates pipeline and facility risk. In order to determine risk, KMEP evaluates both the likelihood of an event or condition that leads to a release and the consequences of that release. The KMEP risk evaluation process includes, but is not limited to, the following components: Data acquisition and validation Risk Evaluation Risk Results Evaluation

Appendix H6.1Section 4 discusses the development of the risk analysis. The KMEP Risk Management Team begins development with the initial IAP program using the default risk algorithm. Appendix H6.2 Section 4 discusses how to calculate the IAP model risk factors and generate report(s) on current algorithm values.

IMPM 6.4.3 discusses the KMEP risk model. In accordance with API Standard 1160, Section 7.5, an electronic database is employed for data storage, analysis, and decision-making assistance. The software database is also utilized to store integrity assessment related information and perform the annual risk assessment analysis. The KMEP risk algorithm is capable of evaluating both the likelihood of failure (LOF) and the consequences of failure (COF), as shown in Table 6.1, Risk Factors. Each risk factor shown in the table can be further sub-divided

into additional detailed variables (such as coating design, age, type, cathodic protection data, etc.). Table 6.1, Risk Factors. Likelihood of Failure (LOF) Consequence of Failure (COF) External Corrosion Impact on Population Third Party Damage (Outside Force Damage) Impact on Environment Ground Movement (Outside Force Damage) Impact on Business Design/Material System Operations Other Factors KMEP populated the software database with selected variable information from the above listed variables for those pipeline segments that could affect an HCA. For a more detailed description of risk variables utilized, see Procedure H8.7, Develop Continuing Assessment Plan. Pipeline design information (size, wall thickness, etc.) and elevation data for the entire KMEP system has been entered into the database to facilitate pipeline rupture volume calculations. During the initial risk assessment process, complete and detailed information was not available for some data fields. In these instances, one of two actions was taken; A reasonable engineering assumption was made to populate the data and these assumptions are noted in the comment field. Or, the factor weighting was set to zero so that the factor had no affect in the analysis conducted using the algorithm. KMEP's current practice prescribes that all appropriate available pipeline integrity data will be incorporated in the risk database even though similar data may not be uniformly available for all line segments. The model allows for drilling down to understand what factors are driving the risk. All pipelines have been evaluated using the IAP risk model. Risk analysis is segmented on the HCA length. Analysis uses the worst case variable in the segment if attributes vary. KMEP's current practice prescribes that all appropriate available pipeline integrity data will be incorporated in the risk database even though similar data may not be uniformly available for all line segments.

Appendix D1describes the IAP Version 5.80 software. The KMEP Integrity Management Team maintains complete copies of the IAP User's Manual, most recent version. The IAP User Manual can be accessed from the Orange network

In accordance with IMPM Section 6.4.2, the KMEP Risk Management Team is responsible for the collection of integrity assessment and risk related data. These personnel are qualified by training and experience and work with KMEP Business Unit Integrity Teams to insure that the appropriate information and data is entered into the database. Data sources for utilization in the integrity assessment process will typically include the following: Results of previous assessments; internal inspections (defect type, size, and growth), pressure testing (cathodic protection data is gathered in accordance with Procedure H6.4, Collect Corrosion Data) or other technology (see Procedure H8.2, Direct Assessment); Pipe size, material, manufacture, coating, condition, seam type; Leak history, repair history; Product transported, product characteristics; Operating stress level; Existing or projected activities in area; Local environmental factors (e.g. corrosivity, subsidence); Geo-technical hazards; Physical supports/spans ; Elevation and terrain; Volume that could be released; Potential spillage following drain tiles or ditches; Exposure to pressure > MOP; HCA data changes and growth; Operator Error; Incident investigation results. In order to ensure that input into the Risk Model represents the most current and accurate information available and to facilitate a risk analysis that best reflects the current conditions associated with pipeline segments, KMEP Business Unit Integrity Management Teams validate HCA and field interview data in accordance with Procedures H4.2, Identify HCAs (Annual/New/Acquired) and H6.10, Field Data SME Validation. Additionally, KMEP Risk Management Team reviews and validates input information to ensure that input data represents the most accurate and current data available in accordance with Procedure 6.3, Quality Control Data Checks.

IMPM 6.4.5 requires that the KMEP Manager, Pipeline Risk Analysis and the KMEP Algorithm Enhancement Team annually conduct an algorithm review in accordance with Procedure H6.2, Review Risk Algorithm – Annual. The intent of the review is to insure that the risk algorithm includes appropriate risks/threats to the pipeline operation and reflects KMEP most current views and philosophies. Upon reviewing the Risk Model, the KMEP Integrity Management Core Team reviews KMEP Algorithm Enhancement Team findings, and provides final approval and/or recommendations. Business impact is not a considered factor. Consequence is a 60/40 split among population and environment.

Appendix D3 includes the Integrity Assessment Program (IAP) Algorithm Sheets. This algorithm is the latest version used to establish the current year Assessment Plan.

An annual review of the risk model is conducted by SMEs. Feedback may result in modifications to the output of the model. The variance process is provided in IMPM Section 5.4.5. Through the variance process adjustments to risk rank can be documented. LS-14 Portland to Eugene original rank was 153. It was moved up in priority

without impacting the top 50% priority of other lines. (Appendix C.1.2). The priority was moved up because the 1997 inspection had many anomalies.

Appendix H6.11, Section 4 requires review of risk assessment reports for correctness and completeness and to document the review on the KMEP Risk Assessment Data Output Review Checklist Form. Results are determined to be valid if SME knowledge and historical data concurs with IAP generated risk driver information. Discrepancies are reported to the KMEP Manager, Pipeline Risk Analysis. In the event that results appear to be inaccurate, outdated, or incomplete, the KMEP Manager, Pipeline Risk Analysis coordinates resolution with the KMEP Integrity Risk Management Team and the appropriate KMEP Business Unit Integrity Management Teams.

| **5.02 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| **X** | **5.02.01** | Risk weighting factors were not adequately validated or justified | AF 5.4 | E |
| | **5.02.02** | Health and safety factors were not adequately weighed relative to other consequence factors in the risk analysis process | AF 5.4 | |
| | **5.02.03** | Likelihood of pipeline failures was not adequately considered in the risk analysis | AF 5.4 | |
| | **5.02.04** | Explicit guidelines and process formality were not provided to support use of SMEs in risk analysis | AF 5.2 | |
| | **Other:** | | | |

| Protocol # 5.03 | Risk Analysis: Input Information |
|---|---|
| **Protocol Question** | Are adequate and appropriate data and information input into the risk analysis process? |

The overall quality and usefulness of a risk evaluation processes are highly dependent on the validity and quality of input data and information. An effective operator program would be expected to have the following characteristics:

1. Use of the most accurate available data to represent pipeline characteristics in the analysis of different segments, including the results of integrity assessments.
2. Controls to provide assurance of the completeness and quality of input information.
3. Guidance to minimize the use of input information that is unnecessarily or excessively conservative (to avoid masking best-estimate risk insights).
4. Use of sources best suited to provide whatever subjective information is used (e.g., from operator personnel, including field units).
5. Use of a sufficiently structured process for obtaining subjective information (e.g., using forms, surveys, interviews, quality checks, etc.) to ensure that consistent information is provided for different segments.
6. Use of the operator's and industry's collective operating experience data where applicable.

| | |
|---|---|
| **Rule Requirement** | §195.452(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)? ....* |
| | §195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section); |
| | §452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure .... |
| | §195.452(i)(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: .... |

| 5.03 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**5.03 Inspection Issues Summary**

**5.03 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix H6.2 | 5 | 8/21/2006 | Review Risk Algorithm - Annual |
| Appendix H6.10 | 6 | 8/31/2006 | Field Data SME Validation |
| Appendix H9.4 | 2 | 8/3/2006 | Facility Risk Analysis And Preventive And Mitigative Measures Evaluation |

**5.03 Inspection Notes**

IMPM 6.4.2 addresses data collection processes. The KMEP Risk Management Team is responsible for the collection of integrity assessment and risk related data. These personnel are qualified by training and experience and work with KMEP Business Unit Integrity Teams to insure that the appropriate information and data is entered into the database. Data sources for utilization in the integrity assessment process will typically include the following: Results of previous assessments; internal inspections (defect type, size, and growth), pressure testing (cathodic protection data is gathered in accordance with Procedure H6.4, Collect Corrosion Data) or other technology (see Procedure H8.2, Direct Assessment); Pipe size, material, manufacture, coating, condition, seam type; Leak history, repair history; Product transported, product characteristics; Operating stress level; Existing or projected activities in area; Local environmental factors (e.g. corrosivity, subsidence); Geo-technical hazards; Physical supports/spans ; Elevation and terrain; Volume that could be released; Potential spillage following drain tiles or ditches; Exposure to pressure > MOP; HCA data changes and growth; Operator Error; Incident investigation results. In order to ensure that input into the Risk Model represents the most current and accurate information available and to facilitate a risk analysis that best reflects the current conditions associated with pipeline segments, KMEP Business Unit Integrity Management Teams validate HCA and field interview data in accordance with Procedures H4.2, Identify HCAs (Annual/New/Acquired) and H6.10, Field Data SME Validation. Additionally, KMEP Risk Management Team reviews and validates input information to ensure that input data represents the most accurate and current data available in accordance with Procedure 6.3, Quality Control Data Checks.

IMPM 6.4.3 discusses the KMEP risk model. In accordance with API Standard 1160, Section 7.5, an electronic database is employed for data storage, analysis, and decision-making assistance. The software database is also utilized to store integrity assessment related information and perform the annual risk assessment analysis. Pipeline design information (size, wall thickness, etc.) and elevation data for the entire KMEP system has been entered into the database to facilitate pipeline rupture volume calculations. During the initial risk assessment process, complete and detailed information was not available for some data fields. In these instances, one of two actions was taken; A reasonable engineering assumption was made to populate the data and these assumptions are noted in the comment field. Or, the factor weighting was set to zero so that the factor had no affect in the analysis conducted using the algorithm. KMEP's current practice prescribes that all appropriate available pipeline integrity data will be incorporated in the risk database even though similar data may not be uniformly available for all line segments. The model allows for drilling down to understand what factors are driving the

risk. All pipelines have been evaluated using the IAP risk model. Risk analysis is segmented on the HCA length. Analysis uses the worst case variable in the segment if attributes vary. KMEP's current practice prescribes that all appropriate available pipeline integrity data will be incorporated in the risk database even though similar data may not be uniformly available for all line segments.

Appendix H6.10 Section 4.3 requires that the KMEP Risk Management Team transmit integrity management and integrity analysis information to the KMEP Business Integrity Management Teams for review and validation. Reviews include verification of the diameter, installation date, wall thickness, grade (SMYS), external coating design, redundancy (looped line), presence of casings and overhead spans, and other key operational, maintenance, and material condition attributes.

Data related to facilities is collected and verified in accordance with Appendix H9.4. Facility documentation for break out terminals, pump stations and other pipeline facilities is compiled using KMEP's *Facilities Risk Analysis and Preventive and Mitigative Measures Evaluation Form*. KMEP will compile available facility documentation including, but not limited to, the following:

- Current facility P&MMs.
- Facility Release Reports for all DOT regulated equipment
- Applicable inspection reports (e.g. exposed pipe inspection reports, storage tank inspection reports/summaries)
- Incident data for the facility
- Facility Response plans (Contingency Plans, Spill Plans, etc.)
- Company-wide release related lessons learned and histories
- KMEP *Facilities Risk Analysis and Preventive and Mitigative Measures Evaluation Form*

Appendix H6.2 addresses development and review of the risk algorithm. Under the oversight of the KMEP Manager, Pipeline Risk Analysis, the KMEP Risk Management Team calculates the IAP model risk factors and generates report(s) on current algorithm values. Industry spill history data is considered as is performance against industry metrics. SME experience contribution is in annual review of risk model.

| **5.03 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **5.03.01** | Operator-specific and industry leak/failure history and other operating experience were not adequately considered in the in risk analysis | AF 5.3 | |
| | **5.03.02** | Field input was not adequately incorporated in the risk analysis | AF 5.3 | |
| | **5.03.03** | General or default values were inappropriately used where data has not been collected | AF 5.3 | |
| | **5.03.04** | Poor quality data was used in the risk analysis | AF 5.3 | |
| | **5.03.05** | The basis for risk model scores was not adequately documented | AF 5.4 | |
| | **5.03.06** | Reliability / accuracy / age of data was not adequately considered | AF 5.3 | |
| | **Other:** | | | |

| Protocol # 5.04 | Risk Analysis: Risk Analysis of Segments that Could Affect HCAs |
|---|---|
| **Protocol Question** | Does the operator's risk analysis approach adequately represent and consider the variation in risk factors along the line such that segment-specific risk results and insights are obtained? |

The manner in which a pipeline is subdivided for the evaluation of risk is an important factor when considering the results of the analysis. An effective operator program would be expected to have the following characteristics:

1. The ability to clearly differentiate the relative risks of different pipeline segments. [Note: The manner in which a pipeline is divided up for the purposes of risk analysis may sometimes differ from "sections" established for segment identification and/or assessment schedules.]
2. An approach for applying risk factors to a pipeline subdivision unit when the factors differ across the unit.
3. A method for relating the subdivision of the pipeline used in risk analysis to: (1) the sectioning of the pipeline defined for the operator's integrity assessments and (2) the segments that can affect high consequence areas.

| | |
|---|---|
| **Rule Requirement** | §195.452(e) *What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)? ....* |
| | §195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section); |
| | §452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure .... |
| | §195.452(i)(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: .... |

| 5.04 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**5.04 Inspection Issues Summary**

**5.04 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix C1.1 | 4 | 7/31/2005 | Baseline Assessment Plan |
| Appendix H5.1 | 6 | 8/31/2006 | Develop Baseline Assessment Plan |

**5.04 Inspection Notes**

IMPM 6.4.2 addresses data collection processes. The KMEP Risk Management Team is responsible for the collection of integrity assessment and risk related data. These personnel are qualified by training and experience and work with KMEP Business Unit Integrity Teams to insure that the appropriate information and data is entered into the database. Data sources for utilization in the integrity assessment process will typically include the following: Results of previous assessments; internal inspections (defect type, size, and growth), pressure testing or other technology; Pipe size, material, manufacture, coating, condition, seam type; Leak history, repair history; Product transported, product characteristics; Operating stress level; Existing or projected activities in area; Local environmental factors (e.g. corrosivity, subsidence); Geo-technical hazards; Physical supports/spans ; Elevation and terrain; Volume that could be released; Potential spillage following drain tiles or ditches; Exposure to pressure > MOP; HCA data changes and growth; Operator Error; Incident investigation results. In order to ensure that input into the Risk Model represents the most current and accurate information available and to facilitate a risk analysis that best reflects the current conditions associated with pipeline segments, KMEP Business Unit Integrity Management Teams validate HCA and field interview data in accordance with Procedures H4.2, Identify HCAs (Annual/New/Acquired) and H6.10, Field Data SME Validation. Additionally, KMEP Risk Management Team reviews and validates input information to ensure that input data represents the most accurate and current data available in accordance with Procedure 6.3, Quality Control Data Checks. Appendix C.2 is the annual risk ranking document based on the risk analysis algorithm. There are 266 testable segments in the current assessment list.

Appendix H5.1 is used to risk rank pipeline segments that could affect an HCA based on KMEP risk beliefs and threat assessment. This procedures requires that KMEP assess those pipeline segments first that are operating at the highest level of risk based on KMEP risk beliefs.

IMPM 5.4.1 addresses segment prioritization. For the purpose of scheduling and prioritizing its Baseline Assessment Plan, KMEP developed a prioritized ranking of its pipeline segments. This ranking is based on risk factors that reflect risk conditions of each pipeline segment. Categories of factors that were considered for the ranking processes include, but were not limited to, the following: HCA information; Historical assessment data; Pipe physical characteristics (e.g. pipe size, material, manufacture, coating, condition, seam type, susceptibility to SCC, etc.); Leak history, repair history, and cathodic repair history; Products transported; Operational parameters (i.e. operating stress level); Existing or projected activities in the area; Local environmental factors (i.e. corrosivity of soil, climate); Geo-technical hazard; Physical support of segments. The KMEP risk assessment model was populated with pipeline risk considerations, and a ranking of pipelines organized in order

of decreasing weighted average Risk of Failure (ROF) was generated. In 2006, the KMEP risk assessment model ranking of pipelines was organized in order of decreasing Maximum Risk of Failure (Max ROF) in order to highlight the worst case risk scores for each pipeline segment included in the Analysis (the ROF score calculation is simply the LOF score x COF score per calculation section). Appendix C, Baseline Assessment Plan, contains the ranking of pipeline segments and details ROF, LOF, COF, and HCA information. Segmentation for risk analysis is based on HCAs. The worst case risk factor found in the HCA length is applied to the entire segment. The highest risk HCA drives the priority of the testable segments in the BAP.

| **5.04 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **5.04.01** | The risk ranking did not give adequate priority to the highest-risk pipeline segments that can affect an HCA | AF 5.4 | |
| | **5.04.02** | The process did not adequately risk-rank based on segments that can affect HCAs or other appropriate subdivisions of the pipeline | AF 5.4 | |
| | **5.04.03** | A risk analysis method that produces inappropriately skewed results was used | AF 5.4 | |
| | **5.04.04** | Consequences to multiple HCAs were not adequately considered when more than one HCA could be affected | AF 5.4 | |
| | **Other:** | | | |

| Protocol # 5.05 | Risk Analysis: Results |
|---|---|
| **Protocol Question** | Are results of the process to evaluate risk useful for drawing conclusions and insights in the operator's Integrity Management Program decision making? |

Examination of the application of risk analysis results to specific areas is covered separately in the protocol questions for each applicable Integrity Management program element (e.g., assessment scheduling, preventive and mitigative measures). Overall characteristics of risk results, however, can be examined on a general basis. An effective operator program would be expected to have the following characteristics:

1. Identification of the pipeline locations having the highest estimated risk.
2. Identification of the most important risk drivers for the highest risk locations (e.g., third party damage, internal corrosion, etc.) and the underlying causes (e.g., what conditions are elevating the risk of internal corrosion).
3. A means to evaluate and reduce major sources of uncertainties in the process of evaluating risk. [Examples of areas of uncertainty include data and information limitations, subject matter expert opinions, risk model assumptions, and analytical techniques.]

| | |
|---|---|
| **Rule Requirement** | §195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section); |
| | §452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure .... |
| | §195.452(i)(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to: .... |

| **5.05 Inspection Results** | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**5.05 Inspection Issues Summary**

**5.05 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| Appendix C1.1 | 4 | 7/31/2005 | Baseline Assessment Plan |
| Appendix H6.3 | 6 | 8/21/2006 | Quality Control Data Checks |
| Appendix H6.10 | 3 | 8/31/2006 | Field Data SME Validation |

**5.05 Inspection Notes**

IMPM Appendix C addresses the Baseline Assessment Plan and Continuing Assessment Plan which include a "Predicted Assessment Threat" e.g., outside force damage, LFERW, corrosion. Appendix H6.3, Section 2 addresses the results to the risk assessment. In order to ensure that input data represents the most accurate and current data available, the data is reviewed during data importing tasks performed by a qualified contractor and the KMEP Field Data SME Validation process prior to being entered into the KMEP Risk Model. Section 4.3 requires that the KMEP Risk Management Team transmit integrity management and integrity analysis information to the KMEP Business Integrity Management Teams for review and validation. IMPM Appendix H6.10 provides processes to ensure integrity data for all appropriate pipeline segments is identified by local area SMEs and validated in the IMP risk database. SMEs are to capture local information that may not be shown in other files or records.

| **5.05 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **5.05.01** | Risks in all operating modes were not adequately considered | AF 5.4 | |
| | **5.05.02** | Risk analysis results did not adequately identify dominant risk factors | AF 5.4 | |
| | **5.05.03** | Risk analysis results were not adequately aggregated such that segment-specific risk measures were obscured | AF 5.4 | |
| | **5.05.04** | The impact of uncertainties on the results were not adequately considered | AF 5.3 | |
| | **5.05.05** | Risk model results were not adequately used in the preventive and mitigative IM program | AF 6.2 | |
| | **5.05.06** | Risk model results were not adequately used in the periodic evaluation IM program | AF 7.1 | |
| | **5.05.07** | Risk model results were not adequately used in the re-assessment interval determination process | AF 7.2 | |
| | **5.05.08** | Risk model results were not adequately integrated with other information to develop a complete and integrated understanding of risk when the risk model does not consider all risks | AF 5.2 | |

| | | | | |
|---|---|---|---|---|
| | **5.05.09** | The risk analysis was not adequately performed | AF 5.2 | |
| | **5.05.10** | The risk analysis process was not adequately followed | AF 5.2 | |
| | **Other:** | | | |

| Protocol # 5.06 | Risk Analysis: Facilities |
|---|---|
| **Protocol Question** | Are technically adequate approaches used to identify and evaluate the risks of facilities that can affect HCAs? |

In addition to line pipe, associated facilities that can affect HCAs are also included in the scope of the Integrity Management rule. While the integrity assessment provisions of the rule apply only to the line pipe, the other provisions of the rule apply to pump stations, break-out tanks, and other equipment if a failure at these locations could affect a high consequence area. Thus, an operator's integrity management program should include processes for addressing these facilities, including the integration of all available information affecting the likelihood and the consequences of equipment or facility failures (i.e., a risk analysis). An effective operator program would be expected to have the following characteristics:

1. Clear documentation of the operator's approach for evaluating the risk of facilities that can affect HCAs.
2. Results that facilitate the determination of measures to reduce facility risks.

| | |
|---|---|
| **Rule Requirement** | §195.452(f) An operator must include, at minimum, each of the following elements in its written integrity management program: (3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section); |
| | §195.452(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. |

| 5.06 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**5.06 Inspection Issues Summary**

**5.06 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| Appendix H4.2 | 6 | 8/21/2006 | Identify HCAs (Annual/New/Acquired) |
| Appendix H9.4 | 2 | 8/3/2006 | Facility Risk Analysis And Preventive And Mitigative Measures Evaluation |

**5.06 Inspection Notes**

The HCA analysis process for facilities is described in IMPM Section 4.4.7. The HCA analysis methods typically result in line pipe inside facilities being classified as having the same potential to impact HCAs, as the incoming and outgoing pipelines to the facility. Buffer zones are also included in the above analysis due to the increased pressures associated with pump stations. Where this may not apply, for example at large breakout facilities, KMEP also employs a "could affect" screening process to identify HCA Facilities. KMEP utilizes the HCA analysis results of the first 1,000 feet of previously identified incoming or outgoing HCA Segments to DOT regulated facilities to determine HCA Facilities. The HCA Facilities identified by this method are listed in Appendix B2.1. KMEP also utilizes a screening analysis to identify HCA impacts for DOT regulated facilities that are not identified by the HCA Segment Method. The screening process consists of evaluating each facility using GIS and HCA data to determine if the facility directly intersects an HCA or is within a 35¬mile radius of an HCA. The evaluations will be completed by KMEP's Risk Management Team or qualified subcontractors. In this analysis, each facility will be placed in one of two categories and documented on the Facility HCA "Could Affect" Screening Checklist: 1) HCA Facility HCA Facilities directly impact an HCA and/or have the potential to impact an HCA. These facilities will be located in an HCA and/or within a 35 mile radius of an HCA. 2) Non-HCA Facility A DOT Regulated Facility that does not have the potential to impact a HCA. Facilities included in this category are not in an HCA and are not within 35 miles of an HCA. Breakout Tank Volumes Breakout facilities have the potential of adding additional spill volume to the incoming and outgoing pipelines to the facility. This information will be documented for each HCA Facility listed in Appendix B2.2 as described in Procedure H9.4, Facilities Risk Analysis and Prevention and Mitigative Measures Evaluation. Facility breakout tanks with the potential to back feed spill volumes into HCA Segments will be identified and the calculated worst case spill volume will be added to the HCA Segment(s) during the annual HCA Identification.

Appendix H9.4, Section 4 addresses facility documentation for break out terminals, pump stations and other pipeline facilities is compiled using KMEP's *Facilities Risk Analysis and Preventive and Mitigative Measures Evaluation Form*. Typically, break out terminals will be evaluated on one form; pump stations and other pipeline facilities can be grouped together and evaluated on one form provided that the facility documentation is similar (e.g. similar equipment, facility response plans, etc.); otherwise one form must be completed for each pump station or other facility. The Facility Manager will make the determination whether to use one or more forms. KMEP will verify facility documentation for completeness and accuracy. In the event that facility documentation does not accurately represent actual operations or equipment, update facility documentation accordingly. The evaluation of available facility integrity related documentation will be conducted by a team of Subject Matter Experts (SME) with specific knowledge of, and responsibility for, the operations and

maintenance of the subject facility. The facility specific SME team is responsible for reviewing the available documentation in an effort to identify Risk Factor Categories and to consider additional P&MMs not listed in the current KMEP P&MMs.

| **5.06 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **5.06.01** | Facilities (e.g., tanks) were not adequately considered in risk analysis | AF 5.6 | |
| | **5.06.02** | A technically sound process was not used for analysis of facilities risk | AF 5.6 | |
| | **5.06.03** | Facilities risk analysis results could not be applied to evaluation of risk reducing measures | AF 5.6 | |
| | **Other:** | | | |

# Integrity Management
# Inspection Protocol 6

# Preventive and Mitigative Measures

**Scope:**

This Protocol addresses the evaluation of preventive and mitigative measures, and is divided into three parts:

1. Questions applicable to all areas of the preventive and mitigative measures evaluation, including risk analysis requirements (§194.452(i)(1)-(i)(4));

2. Questions specific to the evaluation of leak detection system capabilities and the need for upgrades (§194.452(i)(3));

3. Questions specific to the evaluation of the need for installation of additional EFRDs (§194.452(i)(4)).

Note: While this Protocol addresses the specific requirements for application of risk analysis to the evaluation of preventive and mitigative measures, the overall adequacy of the operator's risk analysis process is separately covered in Protocol Area 5, Risk Analysis.

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| Protocol # 6.01 | Preventive & Mitigative Measures: Actions Considered |
|---|---|
| **Protocol Question** | Does the process to identify additional preventive and mitigative actions include consideration of risk and cover a spectrum of alternatives? [Note: Leak detection and EFRDs are covered in more detail in subsequent questions within this protocol.]<br>Do operator records provide documentation of the preventive and mitigative actions that have been considered? |

The integrity management rule requires operators to "take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area." An effective operator program would be expected to have the following characteristics:

1. Identification of the most significant causes/drivers of segment-specific risk (e.g., third party damage, internal corrosion, etc.) when evaluating additional preventive and mitigative actions.
2. Identification of potential preventive and mitigative actions that address the most significant segment-specific risks, including consideration of preventive and mitigative actions listed in §195.452(i)(1).
3. Review of the effectiveness of current preventive and mitigative actions and the potential for enhancements and upgrades.
4. Consideration of a spectrum of modifications, ranging from incremental improvements to major changes.
5. Consideration of changes to both documented work processes (e.g., procedures, response plans) and physical changes.
6. Consideration of additional preventive and mitigative actions for non-pipe facilities that can affect an HCA.
7. Consideration of alternate modes of operation i.e., startup, shutdown, pressure cycling, etc.
8. Evaluation of additional preventive and mitigative measures in a timely manner (e.g., within one year) after integrity assessments are conducted on a segment or other events occur that indicate a need for re-evaluation (e.g., unsatisfactory detection or mitigation of an actual leak).

| | |
|---|---|
| **Rule Requirement** | §195.452 (f) *What are the elements of an integrity management program?* (6) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph of this section) |
| | §195.452(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?*(1) *General requirements.* An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing EFRDs on the pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls. |

| 6.01 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**6.01 Inspection Issues Summary**

The Inspection Team reviewed the KMEP PM&M process. It is expected that line-specific "local" knowledge would be used in the evaluations to identify threats to pipeline segments that might not have been identified otherwise. An exposed section of the Lordsburg line east of Tucson was identified by an Arizona State inspection in December 2005. The steep terrain present in the location of the exposure would be an example of local knowledge applied in the P&MM process that could be considered and appropriate mitigative measures established, when appropriate. IMP Appendix H9.1, Attachment 1, Section 1(b) requires consideration of depth of cover protection.

*Materials were received from Mike Outlaw of KMEP following the inspection on December 1, 2006 concerning this issue, and the revisions were reviewed and deemed adequate: KMEP has modified IMPM Appendix H9.1, Identify Preventive and Mitigative Measures to address this issue.*

**6.01 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix H9.1 | 6 | 10/28/2006 | Identify Line Pipe Preventive And Mitigative Measures |
| Appendix H9.4 | 2 | 8/3/2006 | Facility Risk Analysis And Preventive And Mitigative Measures Evaluation |

**6.01 Inspection Notes**

IMPM Section 9.4.2 discusses the preventive and mitigative measures (P&MM) process. Upon having obtained and validated information from the risk process (IMPM Section 6, Analysis of Integrated Information), P&MMs are evaluated by the KMEP Business Unit Integrity Management Teams for their sufficiency and effectiveness by means of a risk based review process. This process includes the following steps: current P&MM review; additional P&MM consideration (EFRDs, Leak Detection, and Other P&MMs); and documentation and justification. Pipeline segments that are found to have sufficient P&MMs require no additional P&MMs be recommended for consideration by the KMEP Business Unit Integrity Management Teams. The basis for P&MM sufficiency is documented by the appropriate KMEP Business Unit Integrity Management Team and findings are submitted to the KMEP Manager, Pipeline Risk Analysis for review and approval. KMEP Business Unit Integrity Management Teams are responsible for maintaining associated records in appropriate segment files. Segments found to be candidates for additional P&MMs are further evaluated by the KMEP Business Unit Integrity Management Teams. The teams consider each of the three P&MM categories (EFRDs, Leak Detection, and Other P&MMs) by employing a risk-based analysis. The KMEP risk assessment model integrates segment specific information and has the ability to generate P&MM strategies into "scenarios." These scenarios are utilized to evaluate the benefits (in reduced risk) for given P&MMs. Subsequently, the most appropriate P&MMs are selected for the particular risk drivers. New P&MMs are tracked to completion by Business Unit Integrity Management Teams, and the KMEP Manager, Pipeline Risk Analysis is updated on P&MM implementation progress. More P&MM detail is provided in Procedure H9.1, Continuing Risk Analysis to Identify Preventive and Mitigative Measures and H9.3, Leak Detection, H9.5, EFRD Analysis. Mitigative measures deemed effective and efficient are given consideration during the budget development process, which begins in June of each year. Planned budget projects, process changes, or procedural changes are valued (in reduced risk) and ranked against other actions that could be taken to reduce risk. Beginning in calendar year 2006, P&MM evaluations will occur at intervals not to exceed 12 months.

Appendix H9.1 Section 4.5 requires that Business Unit Integrity Management Teams and the Manager, Risk Engineering conduct P&MM conference calls. This includes utilizing the potential risk reduction possibilities listed in Attachment 1 of Appendix H9.1 as a guide. Potential risk reduction scenarios that are recommended for implementation are communicated to the Pipeline Risk Analysis Group for modeling and feedback reports on the impacts of the proposed risk reduction actions.

Appendix H9.4 Section 4.1 addresses P&MM evaluations for non-pipe facilities. Facility documentation for break out terminals, pump stations and other pipeline facilities is compiled using KMEP's Facilities Risk Analysis and Preventive and Mitigative Measures Evaluation Form. Typically, break out terminals will be evaluated on one form; pump stations and other pipeline facilities can be grouped together and evaluated on one form provided that the facility documentation is similar (e.g. similar equipment, facility response plans, etc.); otherwise one form must be completed for each pump station or other facility. The Facility Manager will make the determination whether to use one or more forms. The evaluation of available facility integrity related documentation will be conducted by a team of Subject Matter Experts (SME) with specific knowledge of, and responsibility for, the operations and maintenance of the subject facility. Individual participants should include, but not be limited to, the following disciplines: Facility Management Team; Control Room personnel; Maintenance Team; Corrosion personnel; Engineering personnel; Above Ground Tank Inspection staff; and Instrumentation and Metering personnel. The facility specific SME team is responsible for reviewing the available documentation in an effort to identify the release related items.

| **6.01 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **6.01.01** | An adequate technical basis was not adequately documented for concluding that existing measures to protect HCAs are adequate | AF 6.8 | |
| | **6.01.02** | The process did not adequately require consideration of additional measures for significant integrity threats | AF 6.1 | |
| | **6.01.03** | The process did not adequately require consideration of additional measures to protect HCAs from non-pipeline facilities | AF 6.3 | |
| **X** | **6.01.04** | The process did not adequately require integration of applicable operational and maintenance data into the preventive and mitigative decision process | AF 6.1 | E |
| | **6.01.05** | A systematic, documented process was not in place to evaluate additional measures to protect HCAs | AF 6.1 | |
| | **6.01.06** | Timely evaluation of preventive and mitigative measures was not adequately performed | AF 6.5 | |
| | **6.01.07** | Approved preventive and mitigative measures were not adequately implemented | AF 6.5 | |
| | **Other:** | | | |

| Protocol # 6.02 | Preventive & Mitigative Measures: Risk Analysis Application |
|---|---|
| **Protocol Question** | Does the process effectively evaluate the effects of potential actions on reducing the likelihood and consequences of pipeline releases?<br>_____<br>Verify that the operator has used the risk analysis process to evaluate preventive and mitigative measures. |

Operators must conduct a risk analysis as part of the evaluation of preventive and mitigative measures, including a number of specific risk factors. In addition to the required set of factors, there are other factors that are relevant to the preventive and mitigative measures evaluation. An effective operator program would be expected to have the following characteristics:

1. Consideration of all risk factors required by §195.452(i)(2) in the risk analysis applied to the preventive and mitigative measures evaluation. If all required factors are not considered, a documented basis provided for the exclusion of certain listed factors.
2. Risk analysis variables are defined such that the impact of preventive and mitigative measures on risk to pipeline segments can be evaluated.
3. Measures to assure that the analysis is up to date prior to use (e.g., pipeline data and configuration assumptions verified to be current prior to evaluating the relative impact of a proposed preventive or mitigative measure).

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|---|---|
| **Rule Requirement** | §195.452(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?*<br>(1) *General requirements.* An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection ...<br>(2) *Risk analysis criteria.* In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to:<br>(i) Terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area; (ii) Elevation profile; (iii) Characteristics of the product transported; (iv) Amount of product that could be released; (v) Possibility of a spillage in a farm field following the drain tile into a waterway; (vi) Ditches along side a roadway the pipeline crosses; (vii) Physical support of the pipeline segment such as by a cable suspension bridge; (viii) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure. |

| 6.02 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**6.02 Inspection Issues Summary**

**6.02 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix H9.1 | 6 | 8/28/2006 | Identify Line Pipe Preventive And Mitigative Measures |

**6.02 Inspection Notes**

IMPM Section 9.4.2 provides an overview of the preventive and mitigative measures (P&MM) process. Upon having obtained and validated information from the risk process (IMPM Section 6, Analysis of Integrated Information), P&MMs are evaluated by the KMEP Business Unit Integrity Management Teams for their sufficiency and effectiveness by means of a risk based review process. This process includes the following steps: current P&MM review; additional P&MM consideration (EFRDs, Leak Detection, and Other P&MMs); and documentation and justification. Pipeline segments that are found to have sufficient P&MMs require no additional P&MMs be recommended for consideration by the KMEP Business Unit Integrity Management Teams. The basis for P&MM sufficiency is documented by the appropriate KMEP Business Unit Integrity Management Team and findings are submitted to the KMEP Manager, Pipeline Risk Analysis for review and approval. KMEP Business Unit Integrity Management Teams are responsible for maintaining associated records in appropriate segment files. Segments found to be candidates for additional P&MMs are further evaluated by the KMEP Business Unit Integrity Management Teams. The teams consider each of the three P&MM categories (EFRDs, Leak Detection, and Other P&MMs) by employing a risk-based analysis. The KMEP risk assessment model integrates segment specific information and has the ability to generate P&MM strategies into "scenarios." These scenarios are utilized to evaluate the benefits (in reduced risk) for given P&MMs. Subsequently, the most appropriate P&MMs are selected for the particular risk drivers. New P&MMs are tracked to completion by Business Unit Integrity Management Teams, and the KMEP Manager, Pipeline Risk Analysis is updated on P&MM implementation progress. More P&MM detail is provided in Procedure H9.1, Continuing Risk Analysis to Identify Preventive and Mitigative Measures and H9.3, Leak Detection, H9.5, EFRD Analysis. Mitigative measures deemed effective and efficient are given consideration during the budget development process, which begins in June of each year. Planned budget projects, process changes, or procedural changes are valued (in reduced risk) and ranked against other actions that could be taken to reduce risk. Beginning in calendar year 2006, P&MM evaluations will occur at intervals not to exceed 12 months.

Appendix H9.1 includes process requirements for risk analysis supporting identification of P&MM. The Business Unit Integrity Management Team verifies that the pipeline risk analysis information accurately reflects local operating experience and risk history. Any changes or additions will be noted on Attachment 2 which is the P&MM Work Sheet. Business Unit Integrity Management Teams and the Manager, Risk Engineering conduct the P&MM-CC utilizing the potential risk reduction possibilities listed in Attachment 1 of Appendix H9.1as a guide. Potential risk reduction scenarios that are recommended for implementation are communicated to the Pipeline Risk Analysis Group for modeling and feedback reports on the impacts of the proposed risk reduction

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| actions. |

| **6.02 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **6.02.01** | Risk analysis was not adequately considered in making preventive and mitigative decisions | AF 6.2 | |
| | **6.02.02** | All required risk factors were not adequately considered in the preventive and mitigative evaluation process | AF 6.2 | |
| | **6.02.03** | The impact of preventive or mitigative actions on risk was not adequately evaluated | AF 6.2 | |
| | **Other:** | | | |

| Protocol # 6.03 | Preventive & Mitigative Measures: Decision Basis |
|---|---|
| **Protocol Question** | Does the process provide an adequate basis for deciding which candidate preventive and mitigative actions are implemented?<br>———————<br>Do operator records indicate that the decision making process has been applied as described? |

The process and decision criteria used by an operator to decide if potential actions are to be implemented or rejected are a critical part of the preventive and mitigative measure process. An effective operator program would be expected to have the following characteristics:

1. A systematic decision-making process involving input from relevant parts of the organization such as operations, maintenance, engineering, corrosion control, etc., that considers the results of the risk analysis along with other information in making decisions about which preventive and mitigative actions to implement.
2. Priority in schedule and scope for additional actions on the highest risk lines and facilities.
3. A defined basis for decision making that includes the benefit (e.g., risk reduction, reduction in threat to integrity, etc.) preventive and mitigative measures are expected to produce.
4. Integration of approved preventive and mitigative actions with the operator's work processes responsible for scheduling and implementing the approved actions (e.g., budgeting, project management, maintenance).
5. Documentation of candidate preventive and mitigative measures that have been considered, including those that have not been implemented.
6. Implementation of approved additional actions as previously planned and scheduled.

| | |
|---|---|
| **Rule Requirement** | §195.452(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?*<br>(1) *General requirements.* An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection .... |

| 6.03 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**6.03 Inspection Issues Summary**

**6.03 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix H9.1 | 6 | 10/28/2006 | Identify Line Pipe Preventive And Mitigative Measures |

**6.03 Inspection Notes**

IMPM Section 9.4.2 provides an overview of the preventive and mitigative measures (P&MM) process. Upon having obtained and validated information from the risk process (IMPM Section 6, Analysis of Integrated Information), P&MMs are evaluated by the KMEP Business Unit Integrity Management Teams for their sufficiency and effectiveness by means of a risk based review process. This process includes the following steps: current P&MM review; additional P&MM consideration (EFRDs, Leak Detection, and Other P&MMs); and documentation and justification. Pipeline segments that are found to have sufficient P&MMs require no additional P&MMs be recommended for consideration by the KMEP Business Unit Integrity Management Teams. The basis for P&MM sufficiency is documented by the appropriate KMEP Business Unit Integrity Management Team and findings are submitted to the KMEP Manager, Pipeline Risk Analysis for review and approval. KMEP Business Unit Integrity Management Teams are responsible for maintaining associated records in appropriate segment files. Segments found to be candidates for additional P&MMs are further evaluated by the KMEP Business Unit Integrity Management Teams. The teams consider each of the three P&MM categories (EFRDs, Leak Detection, and Other P&MMs) by employing a risk-based analysis. The KMEP risk assessment model integrates segment specific information and has the ability to generate P&MM strategies into "scenarios." These scenarios are utilized to evaluate the benefits (in reduced risk) for given P&MMs. Subsequently, the most appropriate P&MMs are selected for the particular risk drivers. New P&MMs are tracked to completion by Business Unit Integrity Management Teams, and the KMEP Manager, Pipeline Risk Analysis is updated on P&MM implementation progress. More P&MM detail is provided in Procedure H9.1, Continuing Risk Analysis to Identify Preventive and Mitigative Measures and H9.3, Leak Detection, H9.5, EFRD Analysis. Mitigative measures deemed effective and efficient are given consideration during the budget development process, which begins in June of each year. Planned budget projects, process changes, or procedural changes are valued (in reduced risk) and ranked against other actions that could be taken to reduce risk. Beginning in calendar year 2006, P&MM evaluations will occur at intervals not to exceed 12 months.

Appendix H9.1 includes process requirements for risk analysis supporting identification of P&MM. The Business Unit Integrity Management Team verifies that the pipeline risk analysis information accurately reflects local operating experience and risk history. Any changes or additions will be noted on Attachment 2 which is the P&MM Work Sheet. Business Unit Integrity Management Teams and the Manager, Risk Engineering conduct the P&MM-CC utilizing the potential risk reduction possibilities listed in Attachment 1 of Appendix H9.1as a guide. Potential risk reduction scenarios that are recommended for implementation are communicated to the Pipeline Risk Analysis Group for modeling and feedback reports on the impacts of the proposed risk reduction

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| actions. |

| 6.03 Issue Categorization *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | Area Finding | Risk Category (A – E) |
|---|---|---|---|---|
| | **6.03.01** | The process did not adequately require a documented justification for decisions regarding additional preventive and mitigative measures | AF 6.8 | |
| | **6.03.02** | Excessive reduction in risk was required for implementing additional preventive and mitigative measures | AF 6.4 | |
| | **6.03.03** | The process for evaluating additional preventive and mitigative measures was inadequate | AF 6.1 | |
| | **Other:** | | | |

| Protocol # 6.04 | Leak Detection Capability Evaluation: Evaluation Factors |
|---|---|
| **Protocol Question** | Does the process for evaluating leak detection capability adequately consider all of the §195.452(i)(3)-required factors and other relevant factors?<br>Do operator records indicate that all required and other relevant factors have been evaluated? |

As part of the leak detection-specific portion of the preventive and mitigative section of the integrity management rule, a number of factors are required to be part of the operator's evaluation. In addition to the required set of factors, there are other factors that are relevant to the evaluation of the operator's leak detection capability. An effective operator program would be expected to have the following characteristics:

1. Inclusion of all eight of the required §195.452(i)(3) evaluation factors, including risk assessment results. If all required factors are not considered, a documented basis for the exclusion of certain listed factors. [Note: Risk analysis details are covered in protocol question 6.02.]
2. Identification and evaluation of a sufficient spectrum of leak scenarios to adequately determine the overall effectiveness of leak detection capability (e.g., "most likely" in addition to "maximum possible").
3. Consideration of additional evaluation factors such as:
   - current leak detection method for the HCA areas,
   - use of SCADA,
   - thresholds for leak detection,
   - flow and pressure measurement,
   - specific procedures for lines that are idle but still under pressure,
   - additional leak detection means for areas in close proximity to sole source water supplies, and
   - leak detection testing (such as physical removal of product from the pipeline).
4. Evaluation of all modes of line operations including slack line, idled line, and static conditions.
5. If a computational pipeline monitoring technique is part of the leak detection systems, design, maintenance, controller training, and record-keeping aspects of API 1130 are addressed in system design and maintenance practices.
6. Evaluation of leak detection performance during transient conditions, and a strategy to manage any short-term reduced performance.
7. Evaluation of the operational availability and reliability of the leak detection systems, and the operator's process to manage system failures.
8. Consideration of enhancements to existing leak detection capability (e.g., increasing the monitoring frequency of existing techniques).
9. Consistent application of a risk-based decision-making process for leak detection, as described in protocol question 6.03.

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|---|---|
| **Rule Requirement** | §195.452 *What preventive and mitigative measures must an operator take to protect the high consequence area?* (3) *Leak detection.* An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider the following factors-length and size of the pipeline, type of product carried, the pipeline's proximity to high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results. |

| 6.04 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**6.04 Inspection Issues Summary**

**6.04 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | INTEGRITY MANAGEMENT PROGRAM MANUAL |
| Appendix H9.3 | 4 | 10/28/2006 | LEAK DETECTION ANALYSIS |

**6.04 Inspection Notes**

IMPM Section 9.4.3.1 addresses EFRD and leak detection reviews. KMEP Risk Management Team and KMEP Business Unit Integrity Management Teams review the required factors listed in 49 CF4 195.452 (i)(3) to determine the necessity of improved leak detection. A more detailed discussion of the leak detection evaluation process is presented in Procedure H9.3, Leak Detection Analysis. Appendix H9.3 requires that KMEP take action to protect an HCA if leak detection analysis indicates that an HCA is not appropriately protected in the event of a hazardous liquid release. Leak detection analysis will be conducted within 30 days of receiving an integrity assessment Action Plan or as part of the response to a MOC for pipeline construction project. The Manager, Pipeline Risk Analysis is responsible for initiating the leak detection analysis and providing the Manger SCADA/IT Technology with details on each pipeline HCA area and the current risk model release response times.

KMEP uses a combination of the following leak detection methods on active pipeline systems:

- Visual observation – Line rider, ROW Coordinator, O&M Technician, etc.
- Aerial observation – Line flyer aerial observations, where they are performed, are done on a biweekly basis (26 times per year not to exceed 3 week intervals).
- External gas/vapor detection sensors at pipeline facilities
- External $CO_2$ vapor detection sensors for $CO_2$ pipelines
- Over/ Short reports
- SCADA system monitoring
- Computational Pipeline Monitoring
- Internal tracer gas injection and monitoring
- KMEP Public Awareness Program

KMEP Risk Engineering uses BTS [*IAP* and *RiskCAT*] software to develop data on a pipeline segment to be reviewed in a Leak Detection Analysis. KMEP Risk Engineering group summarizes the data to be reviewed in the Leak Detection in a summary table that will include the HCA's and their corresponding leak detection capabilities assumptions. For the leak detection response basis, KMEP reviewed leak detection capabilities system-wide and determined that in the event of a rupture it should take no more than 15-minutes to detect, isolate and shutdown a pipeline. For Leak Detection System Analysis, any HCA area with a leak detection and response greater than 15 minutes requires a detailed investigation and recommendation. The results of the Leak

Detection Analysis Sheet are provided to the Manager Risk Analysis to verify risk reduction potentials are valid for any proposal being made. If the current response time for an HCA segment is determined to be greater than 15 minutes, HCA impact analysis is performed in accordance with Integrity Management Program Manual Section 4.4.4, *Defining HCA Segments*. The Leak Detection Analysis is to include any proposals and estimates for applicable scenarios determined by the analysis. The recommendation and risk reduction elements of the Leak Detection Analysis are to be documented and maintained by the Manager Risk Engineering. This analysis must be concluded no later than 1 year from the date of the ILI assessment or before the MOC on new pipe construction is closed. Projects shown to reduce risk will then be submitted for business unit review and implementation as part of the annual budget cycle.

| **6.04 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **6.04.01** | An evaluation of leak detection capability to protect HCAs was not adequately performed or documented | AF 6.6 | |
| | **6.04.02** | The process did not adequately consider required evaluation factors in the leak detection evaluation process | AF 6.6 | |
| | **6.04.03** | A basis was not adequately developed for making decisions about enhancing leak detection capability to protect HCAs | AF 6.6 | |
| | **Other:** | | | |

| Protocol # 6.05 | Leak Detection Capability Evaluation: Operator Actions/Reactions |
|---|---|
| **Protocol Question** | Does the process adequately consider and document operator actions and reactions associated with leak detection systems? |

The role of operations personnel is critical in responding to leak detection indications as well as making certain that leak detection systems are operating correctly. An effective operator program would be expected to have the following characteristics:

1. A documented basis for all operator reactions credited in the leak detection evaluation (e.g., operational procedures and/or training materials). [Note: This does not imply that integrity management-specific operator procedures and/or training are anticipated. Operator responses assumed in the leak detection evaluation, however, should be based on verifiable operational expectations versus arbitrary assumptions.]
2. Measures applied to assure that required actions are accomplished and prudently restored if varying modes of pipeline operations require controllers or other personnel to engage/activate or mute/disable certain attributes of the overall leak detection capabilities.
3. Integration of emergency response procedures and incident mitigation plans with associated leak detection indications.
4. Adequate guidance in documented work processes to assure that operating personnel have the authority and responsibility to initiate reaction measures and to shutdown the pipeline if warranted.
5. Assurance that supervision is always promptly available for contact if procedures require that operating personnel contact supervision prior to initiating response actions and/or shutting down the pipeline.

| | |
|---|---|
| **Rule Requirement** | §195.452(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?* (3) *Leak detection.* An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider the following factors-length and size of the pipeline, type of product carried, the pipeline's proximity to high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results. |

| 6.05 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**6.05 Inspection Issues Summary**

KMEP is required to consider and document operator actions and reactions associated with leak detection systems. In support of this requirement, a basis for assuming operator response within 15 minutes of a release should be documented. Measures that KMEP may consider include operating history; coordinated product withdrawal tests; or disconnection of sensor hardware to evaluate actual response actions and times.

*Materials were received from Mike Outlaw of KMEP following the inspection on December 1, 2006 concerning this issue, and the revisions were reviewed and deemed adequate: KMEP has modified its IMP Manual, Appendix H9.3 to incorporate the basis for the assumption that the rupture volume assumes 15 minutes of full flow before the pipeline is shut down.*

**6.05 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| Appendix H9.3 | 4 | 10/28/2006 | Leak Detection Analysis |
| | | | |

**6.05 Inspection Notes**

Operator actions are considered in the leak detection analysis required by Appendix H.9.3. For the leak detection response basis, KMEP reviewed leak detection capabilities system-wide and determined that in the event of a rupture it should take no more than 15-minutes to detect, isolate and shutdown a pipeline. For leak detection system analyses, any HCA area with a leak detection and response greater than 15 minutes requires a detailed investigation and recommendation. Guidance has been provided to controllers to document near-miss consistently. As part of the consent agreement, KMEP is in the process of developing a training program for implementation of the near-miss program. All operators / field personnel have the authority to shut the system down. The shutdown requirement is included in their training. A January 10, 2001 company letter acknowledges this company policy.

| **6.05 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| X | 6.05.01 | An adequate basis was not provided for assumed operator actions/reactions in evaluating leak detection capability | AF 6.6 | E |
| | **Other:** | | | |

| Protocol # 6.06 | EFRD Need Evaluation: Factors |
|---|---|
| **Protocol Question** | Does the process for evaluating the need for additional EFRDs adequately consider all of the 195.452(i)(4)-required factors and other relevant factors?<br>Do operator records indicate that all required and other relevant factors have been evaluated? |

As part of the EFRD-specific portion of the preventive and mitigative section of the integrity management rule, a number of factors are required to be part of the operator's evaluation. In addition to the required set of factors, there may be other factors that are relevant to the evaluation of the need for additional EFRDs. An effective operator program would be expected to have the following characteristics:

1. Inclusion of all ten of the required 195.452(i)(4) evaluation factors, including consideration of the benefits of reduced consequences expected due to reducing spill size. If all required factors are not considered, a documented basis provided for the exclusion of certain listed factors.
2. Consideration of any additional relevant line-specific factors beyond those listed in 195.452(i)(4) (e.g., the relative reliability of existing or proposed EFRDs, any relevant operating modes beyond nominal full flow conditions, etc.).
3. Consideration of risk analysis results, including identification of highest risk segments. [Note: Risk analysis details are covered in protocol question 6.02.]
4. As part of the "swiftness of leak detection and pipeline shutdown capabilities" factor, consideration of system detection times, operator response times, remotely controlled valve response characteristics, and system isolation time assessments, as applicable.
5. Evaluation of the need for additional EFRDs to respond to releases during transient conditions.
6. Consideration of the potential effects of additional EFRDs, including a) conducting proper valve sequencing during intended EFRD activations, b) the operator's ability to promptly detect and react to inadvertent EFRD activations, and c) possible elevated pressures caused by transient conditions during EFRD activations.
7. Consistent application of a risk-based decision-making process for additional EFRDs, as described in protocol question 6.03.

| | |
|---|---|
| **Rule Requirement** | §195.452(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?* (4) *Emergency Flow Restricting Devices (EFRD).* If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors - the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of the nearest response personnel, specific terrain between the pipeline segment and the high consequence area, and benefits expected by reducing the spill size. |

| 6.06 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**6.06 Inspection Issues Summary**

IMP Appendix H9.5, Attachment 1, Section 2 does not provide for the documentation of the basis supporting the consideration of the "what if analysis" elements listed. Conclusions documented in the Section 2 and 3 summary table using the "Yes/No" check boxes should provide a linkage to the "what if analysis" elements and provide an understanding of why decisions are made.

*Materials were received from Mike Outlaw of KMEP following the inspection on December 1, 2006 concerning this issue, and the revisions were reviewed and deemed adequate: KMEP has modified IMPM Appendix H9.5, EFRD Engineering Analysis to address this issue. The revised Appendix H9.5 procedure provides improved documentation forms that include documentation of the basis supporting consideration of the "what if analysis" elements used.*

**6.06 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| Appendix H9.3 | 4 | 10/28/2006 | Leak Detection Analysis |
| Appendix H9.5 | 3 | 10/28/2006 | EFRD Engineering Analysis |

**6.06 Inspection Notes**

An example EFRD process was reviewed for the LS-12; Colfax – Woodchopper Springs 8" pipeline. Information provided to the team was shown. Scenarios, maps, HCA info and release profiles, risk data, Data is evaluated by team conference call, what-if scenarios reviewed, decisions on need for EFRDs are documented for review by the business units.

Appendix H9.5 describes thee EFRD analysis process. KMEP Risk Engineering uses BTS [IAP and RiskCAT] software to develop data on a pipeline segment to be reviewed. The KMEP Risk Engineering group summarizes the data to be reviewed in a summary table that includes the following present operating information:

- Swiftness of leak detection and pipeline shutdown capabilities and current EFRD capabilities (response time)
- Type of commodity carried (product type)
- The rate of potential leakage (flow rate, initial rupture volume)
- The volume that can be released at each HCA location
- Topography or pipeline profile (elevation)
- Proximity of Power or Ignition Sources. NOTE: KMEP considers all petroleum products pipelines susceptible to being in the proximity of ignition sources.
- Location of nearest response personnel (emergency response time). NOTE: KMEP considers the location of on-duty or emergency response personnel to determine how quickly they could respond to a hazardous liquid release.
- Specific terrain between the pipeline segment and the HCA (terrain analysis).
- Benefits expected by reducing the spill size.

Appendix H9.5 Section 4.3 describes the KMEP "What if" scenario analysis. 'What if' scenarios are used to determine if EFRD Engineering Analysis is required. The KMEP Risk Management Team develops what-if scenarios based to determine if the EFRDs are appropriate for protecting an HCA. Specifically, what-if scenarios

| |
|---|
| allow the identification areas for more detailed EFRD Engineering Analysis. |

| **6.06 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **6.06.01** | A documented EFRD needs analysis was not adequately documented | AF 6.7 | |
| | **6.06.02** | Required evaluation factors were not adequately considered | AF 6.7 | |
| | **6.06.03** | Operator-specific risk factors were not adequately considered | AF 6.7 | |
| **X** | **6.06.04** | An adequate basis was not developed for making decisions about additional EFRDs to protect HCAs | AF 6.7 | E |
| | **Other:** | | | |

# Integrity Management
# Inspection Protocol 7

# Continual Process of Evaluation and Assessment

**Scope:**

This Protocol covers the requirements for conducting periodic integrity assessments based on the results of operator evaluations of pipeline integrity. This Protocol addresses the adequacy of re-assessment methods and intervals, compliance with the 5-year maximum re-assessment interval, and adequacy of any notifications for variance from the 5-year interval.

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| Protocol # 7.01 | Continual Process of Evaluation and Assessment: Periodic Evaluation |
|---|---|
| **Protocol Question** | Does the operator have an adequate process for performing periodic evaluations of pipeline integrity?<br>_____<br>Verify that the operator is performing periodic evaluations of pipeline integrity on a technically justified frequency. |

An operator must have an approach to periodically evaluate pipeline integrity. The periodic evaluation process must include the following provisions:

1. An evaluation of pipeline integrity that is performed periodically to update the operator's understanding of pipeline condition and the segment-specific integrity threats for segments that can affect HCAs.
2. Periodic evaluation intervals that are based on risk factors associated with the pipeline, including those specified in §195.452 (e).
3. Consideration of the results of baseline and re-assessments.
4. Consideration of the information analysis (risk analysis) required by paragraph §195.452 (g).
5. Consideration of remediation actions taken; and
6. Consideration of prior and pending decisions about preventive and mitigative actions.

| | |
|---|---|
| **Rule Requirement** | §195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section); |
| | §195.452 (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?* (1) *General.* After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area. (2*) Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and of this section). |

| 7.01 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**7.01 Inspection Issues Summary**

**7.01 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| Appendix F | 6 | 8/30/2006 | Pipeline Integrity Assessment Procedures |

**7.01 Inspection Notes**

IMPM 8.4.1 addresses Periodic Evaluations. KMEP conducts periodic evaluations as frequently as necessary to ensure pipeline integrity. Integrity evaluation frequency is based on risk factors specific to each pipeline segment and the following minimum factors as specified in 49 CFR 195.452 (e):

- Results of the previous integrity assessments, defect types and sizes found in the previous assessment method and defect growth rate
- Pipe size, material, manufacturing information, coating type and condition, and seam type
- Leak history, repair history and cathodic protection history
- Product transported
- Operating stress level
- Existing or projected activities in the area
- Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic)
- Geo-technical hazards
- Physical support of each segment

Evaluations include consideration of any baseline and periodic integrity assessment data, information analysis, and decisions regarding remediation and preventive and mitigative actions.

As a minimum standard, KMEP reassesses each pipeline segment that could affect an HCA on intervals not to exceed 5-years from the previous assessment. The interval benchmark is the date on which the final field activities related to that integrity assessment is performed, not including repair activities. In making the determination for the reassessment intervals, the KMEP Risk Management Team considers pipeline segment data in accordance with the *Assessment Interval Evaluation Form* on a segment by segment basis. This form is presented in Appendix F, *Pipeline Integrity Assessment Procedures*, and considers the following categories:

- In service failures
- Past and present integrity assessment results.
- Analysis of information from other surveys and inspections.
- Repairs and other preventive and mitigative measures implemented.
- Specific risk factors.
- The risk analysis results.

Appendix F Section 6 includes requirements for setting reinspection intervals. On-going modes of deterioration

such as external and internal corrosion and the growth of defects as the result of pressure-cycle-induced fatigue or environmental cracking will necessitate repeated inspection. Examples of factors for determining reinspection intervals follow. Other factors for setting reinspection intervals may be appropriate. In making the determination for the reassessment frequency, at the completion of the integrity assessment and associated remediation program the KMEP Integrity and Risk Management Team will consider risk factors in accordance with the Assessment Interval Evaluation Form on a segment by segment basis.

| **7.01 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **7.01.01** | An adequate periodic evaluation process that meets rule requirements was not adequately developed or documented | AF 7.1 | |
| | **7.01.02** | The process did not adequately specify appropriate intervals to periodically evaluate the pipeline risks | AF 7.1 | |
| | **7.01.03** | The process did not adequately require non-routine evaluations and reassessments when pipeline risk information (e.g., degrading performance) is available that indicates one should be performed | AF 7.1 | |
| | **7.01.04** | Plan requirements or procedures for implementing periodic evaluations were not adequately followed and/or results were not adequately documented | AF 7.6 | |
| | **7.01.05** | Periodic evaluation was not adequately performed when pipeline risk information was available that indicated an evaluation should have been performed | AF 7.1 | |
| | **Other:** | | | |

| Protocol # 7.02 | Continual Process of Evaluation and Assessment: Re-assessment Intervals |
|---|---|
| **Protocol Question** | Does the operator have an adequate process for determining re-assessment intervals for pipeline segments that could affect HCAs?<br>_____<br>Verify that re-assessment intervals are consistent with the risks identified for the pipeline and the results of previous assessments. |

An operator must have an approach to determine future integrity assessment plans. The re-assessment process must include the following provisions:

1. Re-assessment intervals that are based on all risk factors associated with the pipeline and adequately consider the risk factors listed in §195.452 (e).
2. Re-assessment intervals that consider analysis of results from the last integrity assessment.
3. Re-assessment intervals that are determined using all information obtained on the condition of the pipeline as required by §195.452 (g).
4. Segments that are to be re-assessed on a schedule not to exceed five years unless a variance has been submitted and approved by PHMSA (see 7.04).

[For review of reassessment intervals for external corrosion direct assessment (ECDA), refer to Protocol 7.08.]

| | |
|---|---|
| **Rule Requirement** | §195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);<br>§195.452 (g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. |
| | §195.452 (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?* (1) *General.* After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area. (3) *Assessment Intervals.* An operator must establish intervals not to exceed five (5) years for continually assessing the line pipe's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section. |

| 7.02 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**7.02 Inspection Issues Summary**

1) Seven pipeline segments have not been re-assessed within the maximum 5-year re-assessment interval required by §195.452(j)(3) with the appropriate notification. Segments that exceeded the 5-year timeframe are: LS-64, LS-14, LS-122, GX64A 14", GX64B 14", GX32 10"/12", PL-119. The Inspection Team notes the organization changes and process improvements KMEP has implemented to address this issue.

2) IMP Appendix F hydrostatic pressure test re-assessment interval evaluation does not specify what standards are used for defect growth rates to justify the establishment of reassessment intervals.

*Materials were received from Mike Outlaw of KMEP following the inspection on December 1, 2006 concerning this issue, and the revisions were reviewed and deemed adequate: KMEP has modified IMPM Appendix F, Section 7.2.2, Retesting Frequency; Section 10.1, Assessment Interval Form to address this issue. The revised Appendix F procedure specifies standards that shall be used for defect growth rates to justify the establishment of reassessment intervals.*

**7.02 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/06 | Integrity Management Program Manual |
| | | | |

**7.02 Inspection Notes**

IMPM 8.4.1 addresses Periodic Evaluations. KMEP conducts periodic evaluations as frequently as necessary to ensure pipeline integrity. Integrity evaluation frequency is based on risk factors specific to each pipeline segment and the following minimum factors as specified in 49 CFR 195.452 (e):

- Results of the previous integrity assessments, defect types and sizes found in the previous assessment method and defect growth rate
- Pipe size, material, manufacturing information, coating type and condition, and seam type
- Leak history, repair history and cathodic protection history
- Product transported
- Operating stress level
- Existing or projected activities in the area
- Local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic)
- Geo-technical hazards
- Physical support of each segment

Evaluations include consideration of any baseline and periodic integrity assessment data, information analysis, and decisions regarding remediation and preventive and mitigative actions.

As a minimum standard, KMEP reassesses each pipeline segment that could affect an HCA on intervals not to exceed 5-years from the previous assessment. The interval benchmark is the date on which the final field activities related to that integrity assessment is performed, not including repair activities. In making the determination for the reassessment intervals, the KMEP Risk Management Team considers pipeline segment data in accordance with the *Assessment Interval Evaluation Form* on a segment by segment basis. This form is presented in Appendix F, *Pipeline Integrity Assessment Procedures*, and considers the following categories:

- In service failures

- Past and present integrity assessment results.
- Analysis of information from other surveys and inspections.
- Repairs and other preventive and mitigative measures implemented.
- Specific risk factors.
- The risk analysis results.

IMPM Section 8.4.3 addresses assessment schedule modifications. In order to ensure that KMEP proactively identifies issues that could adversely impact compliance with the Continuing Assessment schedule, KMEP Managers, Pipeline Risk Analysis and KMEP Business Unit Integrity Management Teams monitor for potential issues that could result in schedule deviations. Upon becoming aware of potential deviations from the assessment schedule, the appropriate KMEP Business Unit Integrity Management Team notifies the KMEP Manager, Pipeline Risk Analysis. When practicable, the Manager, Pipeline Risk Analysis and the Business Unit Integrity Management Team attempt to correct conflicts and maintain compliance with the assessment schedule. In the event a change in assessment intervals is warranted, the Risk Management Team updates the inspection schedule in accordance with the procedures established in the MOC process. Variances from the 5-year assessment interval minimum are permitted only in circumstances where an engineering basis for a variance is established or the technology required is unavailable.

| **7.02 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **7.02.01** | All relevant information was not adequately considered or adequate justifications were not developed for reassessment intervals | AF 7.3 | |
| | **7.02.02** | The process did not adequately require notification to PHMSA when reassessment intervals exceed five years | AF 7.5 | |
| | **7.02.03** | Reassessments were not performed when pipeline risk information was available that indicated a reassessment should have been performed | AF 7.3 | |
| **X** | **7.02.04** | Re-assessments were not conducted when scheduled | AF 7.2 | C |
| **X** | **7.02.05** | A process was not adequately developed or documented for determining re-assessment intervals | AF 7.3 | E |
| | **7.02.06** | A schedule for reassessment of pipeline segments that could affect HCAs was not adequately prepared | AF 7.3 | |
| | **Other:** | | | |

| Protocol # 7.03 | Continual Process of Evaluation and Assessment: Assessment Methods |
|---|---|
| **Protocol Question** | Are the assessment methods shown in the continual assessment plan appropriate for the pipeline specific integrity threats? |

The rule requires that the selected assessment method allow the operator to adequately assess the integrity of the pipeline. The operator's assessment method selection process should exhibit the following characteristics:

1. The assessment methods selected for each segment are appropriate for the specific integrity threats identified for the segment through the updated risk analysis, periodic evaluations, previous assessments, and industry experience.
2. The process for assessment method selection includes consideration of completed assessment results.
3. If ILI tools are used, they are capable of detecting corrosion and deformation anomalies including dents, gouges and grooves.
4. The assessment methods selected for all low-frequency ERW pipe or lap-welded pipe susceptible to longitudinal seam failure are capable of assessing seam integrity and of detecting corrosion and deformation anomalies.
5. If external corrosion direct assessment (ECDA) is the selected method, the operator must have a complete ECDA Plan that addresses the requirements of NACE RP0502-2002. [Note that review of specific ECDA plan details are covered under Protocols 7.05-7.08.] In addition, the operator is expected to address:
    a. A formal, documented process to ensure that individuals who implement and evaluate ECDA assessments are qualified to perform that work. Characteristics of an effective process include:
        i. A means to identify qualification requirements for the various ECDA steps,
        ii. Documentation that demonstrates the individual's qualifications and proficiency, and
        iii. Plan and schedule to provide additional training or skills acquisition to achieve and maintain qualification requirements, as applicable.
    b. Requirements established by the operator for any vendors conducting ECDA assessment activities (e.g., indirect inspection) to assure that the vendors understand their responsibilities in performing integrity assessments that comply with this rule.
6. If technology other than pressure testing, external corrosion direct assessment, or in-line inspection is planned for use, the operator submits a notification to PHMSA at least 90 days before conducting the assessment.

An effective operator program would be expected to have the following characteristics:

1. For line segments that are being hydrostatically tested, the operator performs a comprehensive review of corrosion control program effectiveness for these locations.
2. If the operator has reason to suspect a pipeline segment is susceptible to cracks or has exhibited crack-like features, the re-assessment method selection process should address assessment of cracks.
3. If the operator has reason to suspect a pipeline segment is susceptible to internal corrosion, the re-assessment method selection and subsequent data integration should address this threat.
4. The methods used to conduct re-assessments are periodically reviewed and modified if necessary based on new insights from baseline assessments, the results of information integration and risk analysis, and to allow use of new, improved assessment technologies.

| | |
|---|---|
| **Rule Requirement** | §195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section); (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section). |

| | |
|---|---|
| | §195.452 (j) (5) *Assessment methods.* An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.<br>(i) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;<br>(ii) Pressure test conducted in accordance with subpart E of this part;<br>(iii) External corrosion direct assessment in accordance with §195.588; or<br>(iv) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify OPS 90 days before conduction the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section. |

| **7.03 Inspection Results** | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**7.03 Inspection Issues Summary**

The Cortez CO2 DA procedure, which served as the KMEP ECDA Plan, lacked sufficient detail to meet the requirements of §195.588 and NACE RP 0502, and was not consistent in some cases. IMP Appendix H8.2 provided the broad requirements for a DA plan; however, the DA procedure must contain the detail necessary to specify the requirements of the IM rule and associated NACE RP 0502 standard. As an example of Plan inconsistencies, the DA procedure contained 3 flow charts that did not match the processes described in the text of the procedure:

a. "Kinder Morgan Protocol for Third Party Damage" referenced a step to "Perform CDA"

b. "Kinder Morgan Protocol for Paved Roads Bored w/ No Casing referenced C-Scan, GW UT, CICOS

c. "Kinder Morgan Protocol for Paved Roads Bored w/ Cased Crossings" referenced C-Scan, GW UT

*The inspection team notes that KMEP has made changes such that above referenced flow charts (b) & (c) have been revised to now only refer to CIS, DCVG, PCM, and ACVG. Flow chart (a), however, still states "Perform CDA." "CDA" is not defined anywhere in the body of the procedure. An acronym should be defined prior to its use.*

**7.03 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| Appendix F | 7 | 10/6/2006 | Pipeline Integrity Assessment Procedures |
| | | 8/28/2006 | IMP Section 8, Continuing Assessment and Analysis |
| | 6 | 8/30/2006 | IMP Appendix H8.2, Conduct Direct Assessment |
| | | October 2004 | ECDA Pre-Assessment Report, Cortez CO2 Line (TechCorr Inspection & Engineering) |
| | | | Cortez CO2 Line Process and Procedure – Direct Assessment – Cortez CO2 Liquid Pipeline |

**7.03 Inspection Notes**

IMPM Section 8.4.4 requires consideration of applicable threats when selected assessment methods. Prior to conducting an assessment on a pipeline segment, KMEP examines risk information to predict the types of integrity threats that should be anticipated. The assessment method for a particular pipeline segment is based on the threats associated with that segment.

The types of threats identified along pipeline segments dictate the type of inspection methods that are employed. Pipeline segments with multiple threats may require the use of multiple inspection techniques. In accordance with 49 CFR 195.452 (j)(5), only the following methods of integrity assessment are employed:

- Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves,
- Pressure test conducted in accordance with 49 CFR 195 Subpart E, or
- External corrosion direct assessment in accordance with 49 CFR 195.588; or.
- Other technology that KMEP and OPS deem appropriate for use.

Other technology that KMEP demonstrates can provide an equivalent understanding of the condition of the line pipe may be employed on a case by case basis. Industry standards and procedures will be reviewed as available and adopted as appropriate. KMEP will notify OPS 90 days before conducting this assessment.

Appendix F provides process requirements for selection of assessment methods. The appropriate assessment method is selected to address the potential threats of:

- Outside force damage
- Corrosion and other metal loss anomalies
- Low frequency ERW pipe
- Stress corrosion piping

ECDA Plan:
At the time of inspection, the Cortez CO2 line was in the middle of an ECDA baseline assessment. Indirect assessments were completed in 2005 on HCA-affecting segments in the "Northern" region around Albuquerque, NM and were scheduled for completion in 2006 for the "Southern" region. [Note: Preparations for utilizing ECDA were initiated via the IM notification process as "other technology" prior to the addition of ECDA to the integrity management rule.]

The ECDA plan was stated by KMEP as being document "Cortez CO2 Line Process and Procedure – Direct Assessment – Cortez CO2 Liquid Pipeline." The inspection team noted that this procedure lacked sufficient detail to meet the requirements of §195.588 and NACE RP 0502. IMP Appendix H8.2 provides the broad requirements for a DA plan; however, the DA procedure must contain the detail necessary to specify the requirements of the IM rule and associated NACE RP 0502 standard.

With respect to the qualifications and skills of ECDA personnel, pre-assessment report section "Service Provider Requirements" stated that the DA vendor must follow a specific procedure to ensure the DA technology is applied consistently and provides consistent quality data. This section also contained a "Training" subsection indicating that "All Indirect Inspection personnel must at a minimum have completed the following training courses… and that "All Indirect Inspection personnel must at a minimum have reviewed the following industry standards…"

This section also stated that "All Indirect Inspection personnel must prove competency in the following OEM training…" and that "All Indirect Inspection personnel must meet or exceed the KM Operator Qualification (OQ) requirements that apply to the specific task to be undertaken before the task is attempted including those listed in the following table…"

ECDA procedure Section 3.3, Contractor Selection, stated "The contractor's personnel will also be Operator Qualified based on the requirements set forth in 49 CFR Part 195 for any applicable covered tasks that may be

required on the job site. A NACE Certified technician or an equivalent who meets all Operator Qualified (OQ) requirements per part 195 will be present while all field crews are performing indirect inspections and examinations on the pipeline right-of-way."

Vendor specifications were provided that indicated training/qualification requirements.

| **7.03 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **7.03.01** | The appropriate reassessment method(s) were not selected for the segment-specific risks | AF 7.4 | |
| | **7.03.02** | The reassessment method(s) were not technically justified | AF 7.4 | |
| | **7.03.03** | The appropriate reassessment method(s) were not selected for pre-1970 LF ERW, lap-welded, or flash welded pipe | AF 7.4 | |
| | **7.03.04** | Technical justification was not adequately provided to show that pre-70 LF ERW or lap welded pipe is not susceptible to seam integrity issues for reassessments | AF 7.4 | |
| | **7.03.05** | A deformation tool was not run and the operator does not intend to excavate all dent indications for MFL tool runs | AF 7.4 | |
| | **7.03.06** | The reassessment process did not require PHMSA notification when using "other technology" | AF 3.6 | |
| | **7.03.07** | PHMSA was not notified when using "other technology" for reassessments | AF 3.6 | |
| **X** | **7.03.08** | ECDA was a selected assessment method but an adequate ECDA Plan was not developed. | AF 7.7 | E |
| | **7.03.09** | Qualified individuals and/or vendors were not required or were not used to perform ECDA or review ECDA results. | AF 3.1 | |
| | **7.03.10** | Adequate requirements were not established and/or applied to vendors performing ECDA activities. | AF 3.1 | |
| | **Other:** | | | |

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| Protocol # 7.04 | Continual Process of Evaluation and Assessment: Assessment Interval Variance |
|---|---|
| **Protocol Question** | Does the operator's IM Program include provisions for submitting variance notifications to PHMSA for assessment intervals longer than the 5-year maximum assessment interval? |

The Rule contains provisions for exceeding a 5 year re-assessment interval under certain circumstances. If an operator desires a variance from the 5 year interval, it must notify PHMSA of its intentions. The variance must be based upon an engineering analysis or the unavailability of the technology to be used for the assessment. The operator's notification to PHMSA must contain the following characteristics:

1. Engineering Justification Requirements
   - Notification time frame - 270 days before the end of the five year re-assessment deadline;
   - Describe use of other technology such as external monitoring to provide equivalent understanding of the condition of the line pipe; and,
   - Propose an alternate interval.
2. Unavailable Technology Requirements
   - Notification time frame - 180 days before the end of the five year re-assessment deadline;
   - Demonstrate interim actions to evaluate integrity of pipeline segment; and
   - Provide an estimate of when assessment can be completed.

An effective operator program would be expected to have the following characteristics:

1. The operator's IM Program contains requirements for technically rigorous and documented engineering justifications for extending assessment intervals.
2. Evaluation of historical and current integrity information is performed to determine a new assessment interval period.
3. The operator pro-actively identifies and addresses issues that could adversely impact meeting assessment schedules.
4. The operator's IM Program adequately documents justifications for extending assessment intervals due to unavailable technology.

| | |
|---|---|
| **Rule Requirement** | §195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section); |
| | §195.452 (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?* (4) *Variance from the 5-year intervals in limited situations - Engineering basis.* An operator may be able to justify an engineering basis for a longer assessment interval on a segment of line pipe. The justification must be supported by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technology, that provides an understanding of the condition of the line pipe equivalent to that which can be obtained from the assessment methods allowed in paragraph (j) (5) of this section. An operator must notify OPS 270 days before the end of the five-year (or less) interval of the justification for a longer interval and propose an alternative interval. An operator must send the notice to the address specified in paragraph (m) of this section. (ii) *Unavailable technology.* An operator may require a longer assessment period for a segment of line pipe (for example, because sophisticated internal inspection technology is not available). An operator must justify the reasons why it cannot comply with the required assessment period and must also demonstrate the actions it is taking to evaluate the integrity of the pipeline segment in the interim. An operator must notify OPS 180 days before the end of the five-year (or less) interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed. An operator must send a notice to the address… |

| 7.04 Inspection Results | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| X | **No Issues Identified** |
| | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**7.04 Inspection Issues Summary**

**7.04 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/2006 | Integrity Management Program Manual |
| Appendix H8.3 | 5 | 8/23/2006 | Select The Appropriate Assessment Tool And Vendor |

**7.04 Inspection Notes**

Appendix H8.3 Section 4 addresses variance requests. The KMEP Integrity Management Program includes a maximum five (5) year reassessment interval. Business Unit Integrity Management Teams seeking to extend reassessment intervals are expected to exercise and document their due diligence well in advance of the deadline if they expect to obtain OPS acceptance of a variance from the rule's requirement. A Business Unit Integrity Management Team seeking to extend an inspection interval beyond maximum interval of 5 years due to the unavailability of assessment technology must provide technical justification for the intended assessment tool. Additionally, the Business Unit Integrity Management Team shall explain why this technology will not be available in time, and provide an estimate of when the assessment can be completed. The Business Unit the integrity of the pipe as an interim measure. Notices of this kind of extension must be submitted to OPS no less than 180 days before the end of the 5-year interval. Business Unit Integrity Management Teams seeking to use an 'engineering basis' to justify a re-assessment interval in excess of five years must provide a description of the engineering basis for the extended interval. The justification must also include use of other technology, such as external monitoring technology, to provide an understanding of the condition of the line pipe. Business Unit Integrity Management Teams need not submit detailed engineering evaluations; these evaluations will be examined during OPS inspections. Business Unit Integrity Management Teams must submit a notification of this kind of extension no less than 270 days before the end of the 5-year interval.

IMPM 8.4.3.1 also addresses variance from the 5-year interval. KMEP may attempt to obtain an OPS variance by justifying an engineering basis for a longer assessment interval on a segment of line pipe. The justification made to the OPS must include, at a minimum, the following:

- Date and method of last assessment
- Proposed new retest interval
- Actions that will provide equivalent understanding of pipe condition
- A summary of the engineering basis

Justifications must be supported by a reliable engineering evaluation combined with the use of other technology, such as external monitoring technology (Direct Assessment). Technology must provide KMEP with an understanding of the condition of the line pipe equivalent to that which can be obtained from the assessment methods established in 49 CFR 195.452 (j)(5). In order to receive approval for a variance, KMEP must notify OPS 270 days before the end of the five year period (or less) interval of the justification for a longer interval, and propose an alternative interval.

In the event that technology required for assessment is not available, KMEP may attempt to obtain an OPS variance by justifying a longer assessment period. At a minimum, justifications to the OPS must include the following:

- Date and method of last assessment
- Justification for why required interval cannot be met
- Actions that will provide equivalent understanding of pipe condition
- A schedule for assessment

KMEP must justify the reasons why it cannot comply with the required assessment period. Additionally, KMEP must demonstrate the actions being taking to evaluate the integrity of the pipeline segment in the interim. KMEP must notify OPS 180 days before the end of the five-year (or less) interval that the operator may require a longer assessment interval, and provide an estimate of when the assessment can be completed.

IMPM 8.4.3 addresses assessment schedule modifications. In order to ensure that KMEP proactively identifies issues that could adversely impact compliance with the Continuing Assessment schedule, KMEP Managers, Pipeline Risk Analysis and KMEP Business Unit Integrity Management Teams monitor for potential issues that could result in schedule deviations. Upon becoming aware of potential deviations from the assessment schedule, the appropriate KMEP Business Unit Integrity Management Team notifies the KMEP Manager, Pipeline Risk Analysis. When practicable, the Manager, Pipeline Risk Analysis and the Business Unit Integrity Management Team attempt to correct conflicts and maintain compliance with the assessment schedule.
In the event a change in assessment intervals is warranted, the Risk Management Team updates the inspection schedule in accordance with the procedures established in the MOC process and justifications for changes to assessment schedules are documented.

In October 2006, KMEP met with PHMSA to discuss the path forward for resolving Compliance Order Item 1. This item required the inclusion of LF-ERW pipe in the risk model and assessment of the piping long seams. KMEP presented the case that due to the scope of work there are limits to how fast KMEP and ILI vendors can accelerate the evaluation of LF-ERW pipe. KMEP proposed completion of the ILI tool runs by 2010 and completion of any associated remediation by 2011.

| **7.04 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **7.04.01** | PHMSA was not notified within 270 days of reassessment interval exceeding five years | AF 7.5 | |
| | **7.04.02** | PHMSA was not notified within 180 days of the end of the assessment interval of unavailable technology | AF 7.4 | |
| | **7.04.03** | Adequate technical justification was not provided for engineering-based assessment intervals that exceed five years | AF 7.5 | |
| | **7.04.04** | The reasons for unavailable technology were not adequately justified and adequate actions were not taken to evaluate integrity in the interim | AF 7.4 | |
| | **Other:** | | | |

| Protocol # 7.05 | **Continual Process of Evaluation and Assessment: External Corrosion Direct Assessment (ECDA) – Pre-Assessment** |
|---|---|
| **Protocol Question** | Verify that the ECDA pre-assessment process complies with NACE RP0502-2002 Section 3 and §195.588 to (1) determine if ECDA is feasible for the pipeline to be evaluated, (2) select indirect inspection tools, and (3) identify ECDA regions. |

The ECDA process includes four basic steps; pre-assessment is the first of these steps. By incorporating portions of NACE RP0502-2002, §195.588 specifies a variety of requirements for the pre-assessment process, including:

1. The Plan requires adequate data to be identified and collected to support the ECDA pre-assessment, and the identification and collection of data is adequate
2. An ECDA feasibility assessment is conducted by integrating and analyzing the data collected
3. Appropriate requirements for selecting indirect inspection tools are established:
    a. Minimum of 2 complementary tools must be selected such that the strength of one tool compensates for the limitations of the other tool. (Note: The operator must consider whether more than two indirect inspection tools are needed to reliably detect corrosion activity.)
    b. Tools are able to assess and reliably detect corrosion activity and/or coating holidays.
    c. The basis on which at least two different, but complementary, indirect assessment tools are selected is documented.
    d. For selected tools that are not listed in NACE RP0502-2002 Appendix A, justification and documentation of the method's applicability, validation basis, equipment used, application procedures, and utilization data.
4. ECDA Regions are identified based on the use of data integration results applied to specific criteria.
5. More restrictive criteria are applied when conducting ECDA pre-assessment for the first time on a pipeline segment.

| **Rule Requirement** | §195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section); |
|---|---|
| | §195.452 (j) (5) *Assessment methods.* An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies<br>(iii) External corrosion direct assessment in accordance with §195.588; |

| | |
|---|---|
| | §195.588 What standards apply to direct assessment?<br>(b) The requirements for performing external corrosion direct assessment are as follows:<br>(1) General. You must follow the requirements of NACE Standard RP0502-2002 (incorporated by reference, see §195.3). Also, you must develop and implement an ECDA plan that includes procedures addressing pre-assessment, indirect examination, direct assessment, and post-assessment.<br>(2) Pre-assessment. In addition to the requirements in Section 3 of NACE Standard RP0502-2002, the ECDA plan procedures for pre-assessment must include –<br>(i) Provisions for applying more restrictive criteria when conducting ECA for the first time on a pipeline segment;<br>(ii) The basis on which you select at least two different, but complementary, indirect assessment tools to assess each ECDA region; and<br>(iii) If you utilize an indirect inspection method not described in Appendix A of NACE Standard RP0502-2002, you must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method. |

| **7.05 Inspection Results** | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| **X** | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

**7.05 Inspection Issues Summary**

1. ECDA Pre-Assessment Report regions do not match the regions being applied in practice.
   a. The ECDA procedure indicates the need to define regions, but does not list the specific regions for the Cortez line. The ECDA procedure is a living document and should be revised, as appropriate.
   b. ECDA Procedure section 3.2.2, Feasibility, stated that due to limitations of ECDA to detect third party damage, "…areas that are prone to third party damage or activity will be identified and considered separate ECDA regions." However, no "third party damage" ECDA regions were defined.

2. The pre-assessment report indicated that "long range guided wave" would be used for casings (both not-shorted and shorted). However, KMEP indicated that CIS and DCVG were selected for field use except for the Casings "region" which used PCM along with inferred information from upstream and downstream CIS data.

3. "More restrictive criteria" were not specified for the pre-assessment step of the Cortez line baseline assessment, as required by §195.588 and NACE RP0502.

*The inspection team reviewed changes that KMEP made to the Cortez ECDA Plan and deemed them adequate to address these issues. The ECDA integrity assessment should be reviewed for the incorporation of these changes to address these comments into practice when the completed results are presented for inspection. .*

**7.05 Documents Reviewed** *(Tab from bottom-right cell to add additional rows.)*

| Document Number | Rev. | Date | Document Title |
|---|---|---|---|
| | | 8/28/2006 | IMP Section 8, Continuing Assessment and Analysis |
| | 6 | 8/30/2006 | IMP Appendix F, Pipeline Integrity Assessment Procedures |
| | 6 | 8/30/2006 | IMP Appendix H8.2, Conduct Direct Assessment |

| | | | |
|---|---|---|---|
| | | October 2004 | ECDA Pre-Assessment Report, Cortez CO2 Line (TechCorr Inspection & Engineering) |
| | | | Cortez CO2 Line Process and Procedure – Direct Assessment – Cortez CO2 Liquid Pipeline |

**7.05 Inspection Notes**

The ECDA Pre-Assessment Report described pre-assessment process. In this report, the "ECDA Feasibility Assessment" section described pre-assessment data collection, including Form A: Data Element Check Sheet. Also included in the pre-assessment report were Indirect Inspection Survey Feasibility, Special Survey Consideration, and Direct Examination Feasibility, and Post-Assessment Feasibility. A Region Analysis was also included, which defined five regions – Rocky Soils, Sandy Soils, Loamy Clay Soils, Cased Crossings, and Pasture.

The pre-assessment regions did not match the five regions in the data sheet given to the inspection team (file "DA-SummaryDataCollection-KinderMorganCO2.xls") – Wetlands, Sandy, River Crossing, Rocky, and Pasture. KMEP also indicated a 6th "casing" region for three road crossings (I-45, I-20, and SR-318) and one railroad crossing. It was also noted that non-cased road crossings were not considered to be a separate region, given that the DCVG and CIS data were adequate to characterize these portions of pipe.

With respect to a third party region being defined, ECDA Procedure section 3.2.2, Feasibility, stated that due to limitations of ECDA to detect third party damage, "…areas that are prone to third party damage or activity will be identified and considered separate ECDA regions. Data collected within these regions during the Indirect Examination surveys will be more closely examined during the Direct Examination process. Areas that would not normally be of concern in other ECDA regions will be considered in these." At the time of inspection, however, no TPD region had been defined by KMEP.

Pre-assessment report discussion of ECDA tool selection indicated CIS, DCVG, and PCM as being used for all regions except casings, which would use PCM and GWUT. The pre-assessment report also indicated that "long range guided wave" would be used for casings (both not shorted and shorted) KMEP indicated, however, that CIS and DCVG were selected for field use, except the casings region which used PCM along with inferred information from upstream and downstream CIS data.

The pre-assessment report and ECDA procedure did not explicitly specify more restrictive criteria to be applied during the pre-assessment phase of the baseline ECDA baseline assessment.

| **7.05 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **7.05.01** | The identification and collection of data to support ECDA pre-assessment was not adequately required and/or implemented | AF 7.8 | |
| | **7.05.02** | Performance of an adequate ECDA feasibility assessment was not required and/or conducted | AF 7.8 | |
| | **7.05.03** | Indirect inspection tools were not adequately selected | AF 7.8 | |
| **X** | **7.05.04** | The basis for ECDA tool selection was not adequately documented | AF 7.8 | E |
| | **7.05.05** | The selection of a tool not listed in Appendix A of NACE RP0502 was not adequately documented and/or justified | AF 7.8 | |
| **X** | **7.05.06** | ECDA Regions were not adequately identified | AF 7.8 | E |
| **X** | **7.05.07** | More restrictive criteria were not specified and/or not applied when conducting ECDA pre-assessment for the first time on a pipeline segment | AF 7.14 | E |
| | **7.05.08** | Procedures did not adequately document requirements for ECDA pre-assessment | AF 7.8 | |
| | **7.05.09** | No process/procedures existed that described the ECDA pre-assessment process | AF 7.8 | |
| | **Other:** | | | |

| Protocol # 7.06 | Continual Process of Evaluation and Assessment: External Corrosion Direct Assessment (ECDA) – Indirect Inspection |
|---|---|
| **Protocol Question** | Verify that the ECDA indirect inspection process complies with NACE RP0502-2002 Section 4 and §195.588 to identify and characterize the severity of coating fault indications, other anomalies, and areas at which corrosion activity may have occurred or may be occurring, and establish priorities for excavation. |

The ECDA process includes four basic steps; indirect examination is the second of these steps. By incorporating portions of NACE RP0502-2002, §195.588 specifies a variety of requirements for the indirect assessment process, including:

1. The indirect inspection measurements are conducted in accordance with NACE RP0502-2002, Section 4.2:
    a. Identifying and clearly marking the boundaries of each ECDA region.
    b. Performing indirect inspections over entire length of each ECDA region and the inspections conform to generally accepted industry practices.
    c. Specifying and following generally accepted industry practices for conducting ECDA indirect inspections and analyzing results.
    d. Specifying physical spacing of readings (and practices for changing the spacing as needed) such that suspected corrosion activity on the segment can be detected and located.
2. Indications are properly aligned and compared with the data from each indirect inspection to characterize both the severity of indications and urgency for direct examination in accordance with NACE RP0502-2002, Sections 4.3 and 5.2.
    a. Criteria are specified for identifying and documenting those indications that must be considered for excavation and direct examination, including at least the following:
        i. The known sensitivities of assessment tools
        ii. The procedures for using each tool
        iii. The approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected
    b. Criteria are specified and applied for classification of the severity of each indication.
        i. Impacts of spatial errors considered when aligning indirect inspection results
        ii. Results from the indirect inspections compared and consistency of indirect inspection results determined to resolve conflicting or differing indications by the primary and secondary tools.
        iii. Comparison of indirect inspection results with pre-assessment results to confirm or reassess ECDA feasibility and ECDA region definitions.
    c. For each indication identified during indirect examination, criteria specified and applied for:
        i. Defining the urgency level of excavation and direct examination of indications based on the likelihood of current corrosion activity plus the extent and severity of prior corrosion.
        ii. Defining the excavation urgency as immediate, scheduled, or monitored.
    d. Criteria specified and applied for scheduling excavations of indication in each urgency level.
3. More restrictive criteria are applied when conducting ECDA indirect inspection for the first time on a pipeline segment.

| | |
|---|---|
| **Rule Requirement** | §195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section); |

| | |
|---|---|
| | §195.452 (j) (5) *Assessment methods.* An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies<br>(iii) External corrosion direct assessment in accordance with §195.588; |
| | §195.588 What standards apply to direct assessment?<br>(b) The requirements for performing external corrosion direct assessment are as follows:<br>(1) General. You must follow the requirements of NACE Standard RP0502-2002 (incorporated by reference, see §195.3). Also, you must develop and implement an ECDA plan that includes procedures addressing pre-assessment, indirect examination, direct assessment, and post-assessment.<br>(3) Indirect examination. In addition to the requirements in Section 4 of NACE Standard RP0502-2002, the procedures for indirect examination of the ECDA regions must include –<br>(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment;<br>(ii) Criteria for identifying and documenting those indications that must be considered for excavation, including at least the following:<br>(A) The known sensitivities of assessment tools;<br>(B) The procedures for using each tool; and<br>(C) The approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;<br>(iii) For each indication identified during the indirect examination, criteria for –<br>(A) Defining the urgency of excavation and direct examination of the indication; and<br>(B) Defining the excavation urgency as immediate, scheduled, or monitored<br>(iv) Criteria for scheduling excavations of indications in each urgency level. |

| **7.06 Inspection Results** | *(Type an X in the applicable box below. Select only one.)* |
|---|---|
| | **No Issues Identified** |
| X | **Potential Issues Identified** *(explain in summary)* |
| | **Not Applicable** *(explain in summary)* |

| 7.06 Inspection Issues Summary |
| --- |
| 1. The ECDA procedure and IMP Appendix H8.2 largely mixed the implementing details of the indirect examination and direct examination steps and discuss repair/remediation. This approach is inconsistent with §195.588 and RP0502, which separate the indirect examination and direct examination steps. In addition, multiple uses of terminology, such as "immediate," without clear definitions causes confusion with IM §195.452(h)(4)-required repair criteria (e.g., "immediate repair conditions").<br>*Materials were received from Mike Outlaw of KMEP following the inspection on December 1, 2006 concerning this issue. A new procedure H8.2, ECDA replaces the original procedure, which has been broken out into two additional procedures in as part of KMEP's O&M consolidation process. When the Liquid O&M procedures are rolled out in 2007, all three direct assessment procedures (ECDA, ICDA and SCCDA) will be included in the Liquid O&M procedures as separate documents. The Inspection Team notes that KMEP has made changes to IMP Appendix H8.2 to resolve this concern. With respect to the ECDA procedure, KMEP provided a revision with additional detail and improved definitions with respect to the direct examination step, but that continued to use the term "immediate repair" in the context of prioritizing direct examinations (Section 3.5.5, Classification Grading of combined CIS and DCVG survey indications). This terminology is not consistent with NACE RP0502 and remains confusing with respect to the IM rule §195.452(h)(4) immediate repair criteria. In addition, the procedure does not yet address the tie-in of conditions discovered during the direct examination step to the rule repair criteria. The site specific ECDA integrity assessment should be reviewed for changes to address this comment when the completed results are presented for inspection.*<br><br>2. NACE RP0502 requires that direct examination indications be prioritized based on the likelihood of current corrosion activity plus the extent and severity of prior corrosion, and are to be separated into three categories – immediate, scheduled, and monitored. ECDA procedure section 3.5.4 contained classifications A-D that combine complementary indirect tool readings. The procedure is not clear as to how these classifications correlate to the NACE RP0502 direct examination categories.<br>*Materials were received from Mike Outlaw of KMEP following the inspection on December 1, 2006 concerning this issue. The Inspection Team notes that KMEP has made the changes to the ECDA procedure to resolve this concern.*<br><br>3. "More restrictive criteria" were not specified for the indirect inspection step of the Cortez line baseline assessment, as required by §195.588 and NACE RP0502.<br>*The inspection team reviewed changes that KMEP made to the Cortez ECDA Plan and deemed them adequate to address this issue. The ECDA integrity assessment should be reviewed for the incorporation of this change to address this comment in practice when the completed results are presented for inspection..* |

| 7.06 Documents Reviewed | *(Tab from bottom-right cell to add additional rows.)* | | |
|---|---|---|---|
| **Document Number** | **Rev.** | **Date** | **Document Title** |
| | | 8/28/2006 | IMP Section 8, Continuing Assessment and Analysis |
| | 6 | 8/30/2006 | IMP Appendix F, Pipeline Integrity Assessment Procedures |
| | 6 | 8/30/2006 | IMP Appendix H8.2, Conduct Direct Assessment |
| | | October 2004 | ECDA Pre-Assessment Report, Cortez CO2 Line (TechCorr Inspection & Engineering) |
| | | | Cortez CO2 Line Process and Procedure – Direct Assessment – Cortez CO2 Liquid Pipeline |

**7.06 Inspection Notes**

ECDA procedure Section 3.5.1, Indirect Inspection Data, stated that "Indirect Inspection results will be reviewed by Company personnel within 5 business days. Indications will be graded and prioritized for excavation, inspection and repair with consideration given to the type of indirect inspection method used and the inspection results." The procedure then went on to discuss response times for excavation, inspection and repair of indications identified by indirect inspection are addressed in the ECDA plan…Immediate (Severe)…, Scheduled (Moderate)…, Monitored (Minor)…" This approach is inconsistent with RP0502, which separates the indirect examination and direct examination steps. This arrangement and use of terms such as "immediate repair" may cause confusion with rule-required repair criteria. Similar text was also contained in IMP Appendix H8.2 Section 4.3.3, Indirect Examination Data.

KMEP indicated that Appendix H8.2 would be broken out into two procedures – one dealing with ECDA per §195.588 and one dealing with ICDA and SCCDA.

ECDA procedure Section 3.5.2, Close Interval Survey (CIS), contained Type I, II, III criteria (decreasing severity) for classifying CIS results. Procedure Section 3.5.4, Direct Current Voltage Gradient (DCVG), contained Category 1, 2, 3, 4 criteria (increasing severity) for classifying DCVG results. In both cases, the procedure did not specify more restrictive criteria for the baseline assessment.

Cortez indirect examination were reviewed by the inspection team, with the following items of interest noted:

1. Indication in field – 15.9% IR (Category 2)
2. Indication in field – 32% IR (Category 2)
3. #7 at SR318 – Test station, minor DCVG indication
4. #8 at Interstate 25 – Test station, 76.8% IR
5. #9 at Interstate 25 – Test station 62.7% IR
6. Small indication close to Interstate 41 – Test station
7. No indication close to Interstate 41 (crack arrestor) – counted as validation dig
8. East of Interstate 41 – 7.6% IR barbed wire
9. Valves – 100% IR

| **7.06 Issue Categorization** *For each potential issue, type an "X" in the first column for one "best fit" Issue Category and then enter the appropriate Risk Category (A-E) from the Enforcement Guidance.* | | | **Area Finding** | **Risk Category (A – E)** |
|---|---|---|---|---|
| | **7.06.01** | The boundaries of the ECDA regions were not clearly defined and/or identified | AF 7.9 | |

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| | **7.06.02** | Indirect inspections were not adequately performed over the entire length of each ECDA region | AF 7.9 | |
| | **7.06.03** | Indirect inspections that conform to generally accepted industry practices were not adequately specified and/or performed | AF 7.9 | |
| | **7.06.04** | Physical spacing of readings and/or the criteria for changing the spacing if and when needed were not adequately specified | AF 7.9 | |
| **X** | **7.06.05** | Criteria for identifying and documenting those indications that must be considered for excavation and direct examination were not adequately specified | AF 7.9 | E |
| | **7.06.06** | Criteria for classification of the severity of each indication were not adequately specified | AF 7.9 | |
| | **7.06.07** | Conflicting results from indirect inspection tools were not adequately addressed | AF 7.9 | |
| **X** | **7.06.08** | Criteria for defining the urgency level with which excavation and direct examination of indications will be conducted were not adequately specified | AF 7.9 | E |
| | **7.06.09** | Pre-assessment data (such as third party damage) were not adequately factored into the criteria for defining the urgency with which excavation and direct examination of indications will be conducted | AF 7.9 | |
| **X** | **7.06.10** | More restrictive criteria were not specified and/or applied when conducting ECDA indirect inspection for the first time on an HCA-affecting segment | AF 7.14 | E |
| | **7.06.11** | Procedures did not adequately document requirements for ECDA indirect inspection | AF 7.9 | |
| | **7.06.12** | No process/procedures existed that described the ECDA indirect inspection | AF 7.9 | |
| | **Other:** | | | |

| Protocol # 7.07 | Continual Process of Evaluation and Assessment: External Corrosion Direct Assessment (ECDA) – Direct Examination |
|---|---|
| **Protocol Question** | Verify that the ECDA direct examination process complies with NACE RP0502-2002 Section 5 and §195.588 to determine which indications from the indirect inspections are most severe, collect data to assess corrosion activity, and remediate defects discovered. |

The ECDA process includes four basic steps; direct examination is the third of these steps. By incorporating portions of NACE RP0502-2002, §195.588 specifies a variety of requirements for the direct assessment process, including:

1. Excavations and data collection are performed in accordance with NACE RP0502-2002, Sections 5.3, 5.4, 5.10, and 6.4.2:
    a. Excavations based on priority categories described in NACE Section 5.2.
    b. Minimum requirements identified and implemented for data collection, measurements, and recordkeeping to evaluate coating condition and significant corrosion defects at each excavation location.
    c. The number and location of direct examinations complies with NACE RP0502-2002, Sections 5.10 and 6.4.2.
2. Criteria are developed and applied for deciding what action should be taken if corrosion defects are discovered that exceed allowable limits (Section 5.5 of NACE RP0502-2002):
    a. Determination of the remaining strength at locations where corrosion defects are found.
    b. All anomalies are correctly categorized and remediated in accordance with the repair provisions of §195.452 (h) (4) ("immediate repair," 60-day, 180-day, and "other" conditions).
3. Root cause is identified for all significant corrosion activity and identifies and reevaluates all other indications that occur in the pipeline where similar root-cause conditions exist.
    a. Criteria are developed and applied if root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE RP0502-2002 provides guidance for criteria) and alternative methods of assessing the integrity of the pipeline segment are necessary.
4. Mitigation or preclusion of future external corrosion resulting from significant root causes.
5. Evaluation of indirect inspection data, results from the remaining strength evaluation, and root cause analysis to evaluate the criteria and assumptions used to:
    a. Categorize the need for repairs
    b. Classify the severity of individual indications
6. Criteria are developed and applied that describe how and on what basis indications are reclassified and reprioritized in accordance with the provisions specified in NACE RP0502-2002, Section 5.9.
7. Criteria are established and implemented for internal notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications.
8. Processes are in place to consider the use of assessment methods other than ECDA (e.g., ILI or Subpart E pressure test) to assess the impact of defects other than external corrosion (e.g., mechanical damage, stress corrosion cracking) discovered during direct examination.
9. More restrictive criteria are applied when conducting ECDA direct examinations for the first time on a pipeline segment.

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| **Rule Requirement** | §195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section); |
| | §195.452 (h) (4) *Special requirements for scheduling remediation* (i) *Immediate repair conditions* ... (ii) *60-day conditions* ... (iii) *180-day conditions* ... (iv) *Other conditions*.... |