Sunoco Logistics

Sunoco Pipeline L.P.
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Sugar Land, TX 77478

VIA: Overnight Mail

April 27, 2007

Mr. R. M. Seeley
Director, Southwest Region
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
8701 S. Gessner, Suite 1110
Houston, TX 77074

Re: NOA / CPF No. 4-2007-5007M / Comprehensive IMP Audit - 2006

Dear Mr. Seeley:

This will acknowledge the receipt of your Notice of Amendment letter on March 14, 2007 regarding the enforcement findings of the 2006 PHMSA audit of our Integrity Management Program.

Sunoco's responses to these issues are set forth below:

1. § 195.452 (f)(1) A process for identifying which pipeline segments could affect a high consequence area;

A. *SPLP must modify IM procedures for the Western Area to include substantiation of the operator and system response times used in their HCA analysis spill volume calculations. Because an adequate spill volume analysis (for HCA identification) may require consideration of various scenarios and assumptions regarding operator and system response times, release estimate analysis is expected to include identification and evaluation of a sufficient spectrum of leak scenarios, including consideration of various size ruptures, to adequately determine the overall effectiveness of leak detection capability,*

RESPONSE: Section 2 of SPLP's Integrity Management Plan has been reviewed and revised as of 12-27-06. This section addresses segment identification, specifically HCA Impact Identification in subsection 2.3.1. These procedures describe how "potential impact determination was designed to be a consistently reproducible analysis that adequately simulates the transport of a hypothetical release overland and in waterways." Dynamic volume is defined as "the volume in the pipeline that is added to the release due to the continuation of running the pipeline for a short period of time between the occurrence of the leak and the shutdown of the pipeline. ....the time to detect, confirm, and continue response to a leak was determined for each segment based on the unique operation characteristics of the line segment, leak detection capabilities and interviews with Control Center and operations personnel." In order for the Western Area to better substantiate operator and system response times used in HCA analysis spill volume calculations, and to better consider various scenarios, the following activities are being conducted to improve our analysis of potential spills and their ability to impact an HCA. The Western Area is currently collecting leak detection data and response times for different scenarios from all field districts and controllers. The data collection and evaluation will be completed by September 30, 2007. A sensitivity analysis will follow to be completed by December 31, 2007.

B. *SPLP must modify IM procedures such that the HCA segment identification process considers tank volumes at storage sites as part of the calculated drain down volume for pipeline ruptures where leaks cannot be quickly isolated by remote shutdown valves or check valves. Consideration of these volumes could expand the "spill plumes" for pipelines located near facilities and result in more HCA affecting pipeline mileage. Where EFRDs are in place to prevent tankage from adding to the volume of a pipeline rupture, this justification should be included in the spill model documentation.*

RESPONSE: SPLP will perform a tank manifold design study for its facilities with DOT breakout tanks. This study will identify which facilities could have additional volumes from the tankage impacting pipeline spill volumes, in the event of a release along the pipeline that cannot be isolated by remote shutdowns or check valves. Once this study is completed, SPLP will then forward these volumes to Geofields to rerun the HCA impact analysis and produce revised spill plume mapping and HCA impact mileage. This analysis will be completed by September 30, 2007.

2. § 195.452 (c)(1)(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.

A. SPLP must modify IM procedures to require clear explanation of the treatment of line segments which are deemed susceptible to seam defects with regard to their inclusion in the baseline assessment plan. SPLP's analysis of (pre-1970) LF ERW and lap-welded pipe concluded that, in part, two lines in the eastern region (11035 and 13002) required a seam assessment be performed as part of their baseline assessment. However, the baseline assessment plan reviewed by the PHMSA team recorded these lines as having completed baseline assessments and no seam assessment tools were used. Additionally, several lines were identified as susceptible to seam defects in the Western Area and some of these segments were not scheduled for seam assessments in the baseline assessment plan.

RESPONSE: In response to PHMSA's observations during the audit, SPLP modified its IMP to clarify its process for the evaluation of manufacturing and construction related defects (specifically detailing the evaluation to the long-seam defect) and lists the appropriate assessment methods for long-seam susceptible line segments. SPLP's IMP, Section 4.1.1, references the criteria to be reviewed and evaluated prior to the assessment method being selected. The Eastern Area baseline assessment plan was updated to specifically document the evaluation of seam threats for the susceptible line segments (11035 and 13002). Line segment 11035 was assessed in 2006, with an ILI technology capable of assessing the longitudinal seam weld. Line segment 13002 is scheduled for seam inspection in 2007. These actions were acknowledged during the exit interview notes shared with SPLP upon the conclusion of the audit. Western Area seam susceptible line segments were identified in the 2003-2004 Long Seam Study and were installed in the Western Area Baseline Assessment Plan.

B. SPLP must modify IM procedures to require the assessment method selection process to provide requirements or guidance regarding how the analysis is to be performed to determine pipe segment susceptibility to manufacturing seam threats or stress corrosion cracking.

RESPONSE: In response to PHMSA's observations during the audit, SPLP modified its IMP Section 4.1.1 to clarify its evaluation process and assessment requirements for manufacturing related defects and environmentally assisted cracking. SPLP's IMP, Section 4.1.1, references the SCC Management Plan and the assessment requirements. These modifications were shown in draft form to the auditors during the audit, and were acknowledged during the exit interview notes shared with SPLP upon the conclusion of the audit.

Since the 2006 IMP audit, SPLP drafted and implemented an SCC Management Program to formalize the existing practices regarding SCC. The SCC Management Program is referenced in the IMP and includes the following topics: SPLP's experience with SCC, SCC susceptibility criteria and evaluation of line segments, SCC training requirements, and SPLP's assessment & investigation requirements.

The IMP Section 4.1.1 and the SCC Management Program are attached to this document.

C. SPLP must modify IM procedures by formalizing treatment of the inspection, examination, and evaluation of those segments that are considered susceptible to stress corrosion cracking (SCC). SPLP has identified near-neutral SCC as a potential threat to several of its HCA segments in both Eastern and Western Regions. SPLP has developed a training package and draft excavation procedure for field personnel regarding inspections for SCC. However, SPLP has not developed a formal program to manage the inspection, examination, and evaluation of those segments that are considered susceptible to SCC.

RESPONSE: As previously discussed, SPLP has formalized an SCC Management Program. Please see the following attachments: IMP Section 4.1.1 and the SCC Management Program.

3. § 195.452 (h)(2) & (4) Special requirements for scheduling remediation.

(i) Immediate repair conditions. An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction In operating pressure using the formula in section 451.7 of ASME/ANSI B31.4 (incorporated by reference, see Sec. 195.3). An operator must treat the following conditions as immediate repair conditions:

A. SPLP must modify IM procedures to require discovery for immediate repair conditions when adequate information is available and ensure that sufficient information about a condition is promptly obtained. PHMSA interpreted discovery in the Final Order for CPF 4-2004-5006 in the following: "discovery of a condition occurs "when an operator has adequate information about the condition to determine that the condition represents a potential threat" to the integrity of the pipeline. In this case, the integrity assessment was conducted by internal inspection, meaning that information such as the percentage of metal loss from corrosion and the magnitude of dent-type deformations sufficient to enable a determination that the potential exists for an integrity threat at the corresponding location was available to Respondent in the internal inspection results." The PHMSA inspection team noted that for the completed assessment reports reviewed during the inspection the discovery times were typically within a week (for immediate repairs) of the receipt of the vendor's final report. However, SPLP's process regarding review of assessment results allowed the declaration of discovery to be delayed for three weeks after receipt of the final vendor report for immediate repair anomalies.

RESPONSE: During review of the PHMSA's audit team observations, SPLP developed draft changes to SPLP Technical Procedure PR-11-0036, *ILI Evaluation, Investigation & Documentation,* Section 4.2.1 stating that reviews for immediate repair anomalies will be done *expeditiously*, but in no case will discovery occur later than 3 weeks after receiving applicable vendor reports. This was noted in the exit interview notes by PHMSA. As PHMSA indicated above, SPLP's practice has positively demonstrated to determine 'discovery' within one week of the receipt of the vendor's report. SPLP does not agree with the observations above, that 'SPLP's process ... allowed the declaration of discovery to be [*delayed*]...', but more prudently, it is a mandated 'discovery' *deadline*.

SPLP's Technical Procedure PR-11-0036, *ILI Evaluation, Investigation, & Documentation*, documents the process of assessing ILI data. Two critical steps in this process are quality control of the ILI data and data integration. Both steps are time consuming, but have been proven necessary to differentiate and prioritize true integrity threats from flawed information and previously repaired anomalies.

SPLP continues to seek methods that would allow more automated and prompt comparisons of new assessment results with past results and repairs. Tools that are being considered are Geofields' Risk Frame Analyst and Data Loading software and New Century's iAlign software. These software packages are still under development by their respective companies. SPLP is assessing the functionality of these tools and their compatibility with SPLP's existing GIS program. Until such technology is available, SPLP will continue to evaluate all assessment reports as expeditiously as possible and mandates that it will take no longer than 15 business days, or three weeks, to properly evaluate assessment results and declare discovery.

B. SPLP must modify IM procedures to clarify Procedure PR-11-0010 in requiring a 20% pressure reduction based on the operating pressure immediately prior to discovery of an anomaly instead of a 20% reduction from the current operating limit (COL).

RESPONSE: SPLP modified PR-11-0010 during the audit, in response to the observations noted by PHMSA. The exit interview notes specifically detailed this modification, under Specific Observation, #1A and #1B. PR-11-0010 now has clear verbiage that details the requirement for the pressure reduction to be taken from the operating pressure experienced within the previous 60 days. See attached PR-11-0010, page 8 of 11, Section VII.2.B.2., which states, '...a 20% reduction from the highest operating pressure actually experienced at the location of the defect within the two months preceding the inspection...' This section also requires a printout or electronic copy of the two month pressure history shall be included as part of the MOC file.

Should you have any questions or require further information please contact K. David Born of our Houston office at 281-637-6497.

Sincerely,

David A. Justin
Vice President, Operations
Sunoco Pipeline L.P.

Enclosures: IMP Section 2
IMP Section 4
SCC Management Program
SPLP EA Baseline Assessment Schedule
SPLP WA Baseline Assessment Schedule

Bcc: Ron Russo - Montello
Kim Legge – Icedale
Barbara Palmer - Sugarland
Kenneth D. Born – Sugarland
Dave Meadows – Icedale
Chris Ruggiero - Mellon
Bruce D. Davis – Mellon

Subject: DETERMINATION OF THE MAXIMUM OPERATING PRESSURE (MOP), MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP), OR CURRENT OPERATING LIMIT (COL) FOR A PIPELINE SYSTEM

Prepared By: R. Todd	Revision: 4	Page: 1 of 11	Code: ENGR	Number: PR-11-0010
Approved: R. Russo	Date: 7-17-06	Replaces: PR-11-0010 (8/10/04)		

THIS PROCUDURE IS TO BE UTILIZED IN CONJUNCTION WITH APPLICALBLE REFERENCES TO ESTABLISH THE MAXIMUM OPERATING PRESSURE, MAXIMUM ALLOWABLE OPERATING PRESSURE OR CURRENT OPERATING LIMIT FOR A LIQUID, NATURAL GAS, OR OTHER GAS PIPELINE TRANSPORTATION SYSTEM. THE PROCEDURE IS NOT APPLICABLE TO GAS DISTRIBUTION SYSTEMS, PLASTIC, COPPER, CAST IRON, OR OFFSHORE PIPELINE SYSTEMS.

I. OBJECTIVE

This specification covers the various methods used to establish the:

1. Maximum Operating Pressure (MOP) of Liquid Pipelines as defined by 49 CFR Part 195.406 of the Code of Federal Regulations, Title 49, Transportation of Hazardous Liquids by Pipeline.
2. Maximum Allowable Operating Pressure (MAOP) of Gas Pipelines as defined by 49 CFR Part 192.619 of the Code of Federal Regulations, Title 49, Transportation of Natural or Other Gas by Pipeline.
3. The Current Operating Limits (COL) of Liquid or Gas Transmission Systems as conditions warrant based upon ILI data, field investigations, and/or Company inferred limitations which may limit the pressure a segment may be operated to as compared to the officially established MOP or MAOP.
4. **Changes to the MOP, MAOP, or COL of a pipeline must be documented through the Management of Change (MOC) process.**

II. REFERENCES:

1. ASME/ANSI B31.4, Liquid Transportation Systems for Hydrocarbons, LPG, Anhydrous Ammonia and Alcohol
2. ASME/ANSI B31.8, Gas Transmission & Distribution Piping Systems
3. ASME/ANSI B31G, Manual for Determining the Remaining Strength of Corroded Pipelines
4. AGA PR-3-805, A Modified Criteria for Evaluating the Remaining Strength of Corroded Pipelines (RSTRENG program) (December 1989)
5. 49 CFR Part 191, Transportation of Natural and other Gas by Pipeline; Annual Reports, Incident Reports, and Safety Related Condition Reports.
6. 49 CFR Part 192, Transportation of Natural and other Gas by Pipeline

7. 49 CFR Part 195, Transportation of Hazardous Liquids by Pipeline
8. Sunoco Logistics, L.P., Procedure PR-11-0006, Pipeline Repair Procedures
9. Sunoco Logistics, L.P., Procedure PR-11-0036, ILI Evaluation, Investigation, & Documentation.
10. Sunoco Logistics, L.P., Procedure PR-11-0037, Activating and Deactivating Pipelines
11. Sunoco Logistics, L.P., Procedure PR-11-0039, Management of Change (MOC).

III. DEFINIITIONS:

1. MOP - The maximum pressure at which a LIQUID pipeline or segment of pipeline may be normally operated under 49 CFR Part 195.
2. MAOP – The maximum allowable operating pressure at which a GAS pipeline or segment of pipeline may be operated under 49 CFR Part 192.
3. COL – Current Operating Limit, defined as the established Company pressure limit that a pipeline segment may be operated, by taking into account business or technical decisions.

IV. PROCEDURE

The **Maximum Operating Pressure (Liquid) OR Maximum Allowable Operating Pressure (Gas)**, excluding surge pressures and other variations from normal operations for a pipeline is determined per applicable regulations and represents the maximum pressure that a particular pipeline segment is permitted to operate under normal flow conditions and is established by the following methods.

LIQUID:

1. No pipeline may operate at a pressure that exceeds any of the following:
   A. The internal design pressure of the pipe in accordance with 49CFR Part 195.106, as determined by the following equation.
   P = (2* S * t / D) * E * F
   P = Internal design pressure

S = Yield Strength, if unknown follow requirements of 49CFR 195.106(b).
t = Nominal wall thickness, if unknown follow requirements of 49CFR 195.106(c).
D = Nominal outside diameter, inches
E = Seam joint factor;
Furnace butt welded – 0.60
Furnace lap welded – 0.80
All others – 1.00
F = Design factor, 0.72, unless a riser on an offshore or navigable waterway then 0.60. If pipe was subjected to cold expansion meeting certain criteria a design factor of 0.54 should be utilized.

B. If any of the design factors are unknown, then the design pressure shall be either:
   i. Eighty percent of the first test pressure that produces yield, when testing in accordance with ASME B31.8 Appendix N, reduced by the appropriate factors located in 49CFR Part 195.106 (a), and (e).
      OR
   ii. For pipe diameter of 12 ¾" or less, which is not tested to yield a design pressure of 200 psi should be used.

C. The design pressure of the lowest rated component of the pipeline.

D. Eighty percent of the test pressure, for any part of the pipeline, which has been pressure tested in accordance with 49CFR Part 195 Subpart E

E. Individually installed components in the pipeline segment - [Part 195.406 (a)(4)] The MOP is established as 80% of the factory test pressure of an individual component or prototype component installed and exempted from testing as defined under 195.305.
   i. The manufacturer certifies that the component was hydro-statically tested at the factory, or

ii. The component was manufactured under a quality control program that ensures it is of equal strength as a prototype that was hydrostatically tested.

2. Except as noted below all lines require a test of record in order to determine the appropriate MOP, as established in Part 195, Subpart E:

A. Pipelines that have not been pressure tested in accordance with Part 195 Subpart E and meet the requirements of 195.302 (b)(1) and (b)(2)(i), permit that 80% of the test pressure or highest operating pressure demonstrated by logs or pressure charts for a continuous 4 hour period or longer, may be used as the design pressure, Contact Engineering for assistance in establishing an MOP under this criteria.

B. Additionally Pipelines that meet the requirements of any of the following, additionally maybe exempt from requiring a test of record
   i. The pipeline has a maximum operating pressure established under 195.406(a)(5) and it is
      a) An interstate pipeline constructed before January 8, 1971;
      b) An interstate offshore gathering line constructed before August 1, 1977;
      c) An intrastate pipeline constructed before October 21, 1985;
   or
      d) Low-stress pipeline constructed before August 11, 1994, that transports HVL

   ii. Low-stress pipeline constructed before August 11, 1994, that does not transport HVL

   iii. Portions of older hazardous liquid and carbon dioxide pipeline systems, for which an operator has elected the risk based alternative under Part 195.303 and which are not required to be tested based on the risk based criteria.

NATURAL GAS OR OTHER GAS

Note – This Procedure is not applicable for pipelines being converted under 49CFR Part 192.14 or proposed to be uprated in accordance with 49CFR Part 192 Subpart K, Engineering and Integrity Management shall be contacted in order to determine applicability and appropriate procedures.

3. No pipeline may operate at a pressure that exceeds the lowest of the following:

   A. The design pressure of the weakest element in the segment where the design limitations of the pipe shall be calculated as follows:

   P = (2*S*t/D) * F * E * T

   P = Design pressure in pounds per square inch gage
   S = Yield strength in pounds per square inch, if unknown or pipe is of unknown manufacturing process contact Engineering.
   t = Nominal wall thickness of the pipe in inches. If wall thickness is unknown refer to 49CFR Part 192.109
   D = Nominal outside diameter of the pipe in inches
   F = Design factor

Location Class	Factor
1	0.72
2	0.60
3	0.50
4	0.40

   - For pipelines in a Class 1 or Class 2 location refer to additional limitations noted in 49CFR 192.111(b),(c), and (d) to determine whether additional restrictions are applicable.

   E = Longitudinal joint factor shall be 1.00, except for:

Pipe Type	Factor
API 5L Furnace butt welded	0.60
Other/Unknown seam type for Pipe over 4 inches	0.80
Other/Unknown seam type for Pipe 4" or less	0.60

   T = Temperature derating factor shall be 1.00 for all pipelines operating at 250 F or less. Contact Engineering for operations exceeding 250 F.

B. The design or pressure limiting component of the segment. Each component must be able to withstand the operating pressures and other anticipated loadings without impairment to serviceability. The design may be based upon the pressure rating established by the manufacturer by pressure testing of the component or a prototype of the component. All fittings and valves shall be in accordance to 49CFR Part 192 Subpart D.

C. If any of the design factors are unknown, in sections (A) or (B) above, then the design pressure shall be either:
   i. Eighty percent of the first test pressure that produces yield, when testing in accordance with ASME B31.8 Appendix N, reduced by the appropriate factors located in 49CFR Part 192.619(a)(2)(ii), as shown in (D) below.
      OR
   ii. For pipe diameter of 12 ¾" or less, which is not tested to yield a design pressure of 200 psi should be used.

D. The test pressure of the segment after construction divided by the following factors:

Class Location	Installed Before 11/12/1970	Installed After 11/11/1970
1	1.1	1.1
2	1.25	1.25
3	1.4	1.5
4	1.4	1.5

E. The highest operating pressure to which the segment was subjected during the 5 years preceding 7/1/70, unless the segment was uprated in accordance with 49CFR Part 192 Subpart K or pressure tested after July 1st, 1965 and derated by the appropriate factors in (D) above.

F. The pressure determined to be by the maximum safe pressure after considering the history of the segment, known corrosion, and the actual operating pressure.

G. Each segment shall be protected to prevent the MAOP from being exceeded in accordance with 49CFR Part 192.195.

V. CONVERSION OF SERVICE

Due to limited changes of service regarding Sunoco Logistics, LP pipeline systems, Engineering and Integrity Management shall review and thoroughly evaluate proposed changes and the implications or impact on the design, construction, operating, maintenance history, integrity requirements, etc., in order to prepare appropriate recommendations. Pipelines being converted from one service to another, ex.: liquid to gas, the establishment of the Maximum Operating Pressure or Maximum Allowable Operating Pressure shall follow either 49CFR Part 195.5 or 49CFR Part 192.14. The conversion of service pipeline shall also be reviewed per the requirements of PR-11-0037 Activating and Deactivating Pipelines, to ensure appropriate reviews, notifications, and documentation updates are made.

VI. ATTACHMENTS

1. The MOP, MOAP, or COL for Eastern Area pipelines including determination basis and corresponding calculations are located in the MOP application of the SPLINT database.

2. The Manager of Engineering & BD Support, Western Area, should be contacted in regards to the current MOP, MOAP, or COL's for pipeline segments within the Western Area Operations.

VII. CHANGES TO THE MOP, MAOP, OR COL

1. CHANGES TO THE MOP, MAOP, or COL OF A PIPELINE MUST BE DOCUMENTED THROUGH THE MANAGEMENT OF CHANGE (MOC) PROCESS.

2. Procedure for reducing the COL, MOP, or MAOP for a pipeline system.

A. OBJECTIVE

The objective of this procedure is to standardize the method for calculating and implementing the temporary or permanent reduction in current operating limit (COL), maximum operating pressure (MOP), or maximum allowable operating pressure (MAOP), as appropriate, of a pipeline system based on in-line inspection reported or field discovered anomalies, regulatory requirements and the defects remaining strength calculations referenced in industry specifications listed below.

B. PROCEDURE

1. Review in-line inspection data (preliminary or final) or field investigated anomaly. PR-11-0006 identifies the anomalies that require immediate shutdown or temporary pressure reduction.

2. Calculate the temporary (i.e. – new COL) or permanent pressure reduction (i.e. – new MOP) by using Section 451.7 of ASME/ANSI B31.4 (B31G).

   NOTE: If these formulas are not applicable (for example, dents and dents with metal loss), a 20% reduction below the highest operating pressure actually experienced at the location of the defect within the two months preceding the inspection may provide the necessary additional safety margin until the defect can be remediated. Pressures that exceed 110% of the established MOP or MAOP shall not be included as accepted data during this period. A printout or electronic copy of the two month pressure history shall be included as part of the MOC file.

3. After reviewing in-line inspection data, the Pipeline Integrity Group will verbally notify Oil Movements (Product Movement) and the associated District (Regional) Headquarters of the impeding reduction in pressure as appropriate.

4. When the pressure reduction and the resultant rate prediction calculations have been completed, the Pipeline Integrity Group or Operations Engineering will complete a Management of Change (MOC) and utilize the MOC application to send an electronic mail to the following distribution list:

Sunoco Pipeline L.P. Eastern Area Personnel	Sunoco Pipeline L.P. Western Area Personnel
Manager, Product Movement	Manager, Engineering & BD Support
Manager, Operations Engineering	Manager, Product Movement
Eastern Area Operations Coordinator	District Supervisor
Regional Superintendent	Technical Supervisor
Manager, Capital Projects / Engineering / CM	Operations Supervisor (for manned facilities)
Technical Supervisor	
Operations Supervisor (for manned facilities)	

5. The electronic mail will include the following information:

- Existing operating pressure (psig) (MOP, MAOP, or COL)
- Proposed pressure reduction operating level (psig)
- Derated pressure control set point and trip settings (psig)
  Note: The difference between the line pressure control and new operating pressure shall be either a percentage of the proposed operating limit or a fixed pressure differential and shall be determined by the same method in which the original setting was established for the line segment.
- Derated predicted flow rates from Operations Engineering (SPLPEA) or Engineering (SPLPWA)

6. Upon receipt of this notice, changes will be made within the SCADA system to protect the pipeline and equipment. If it is determined that immediate repairs can not be completed or that the new reduced operating pressure will remain in effect for more than 10 days the Technical Supervisor will instruct the Technicians to reset the control and trip set points at the affected pump stations, in conjunction with main line relief set points and other equipment as necessary in order to protect the line at the reduced pressure.

7. The MOC originator shall follow up within 10 days to verify whether changes in field settings are necessary. Note: For changes in operating pressure limits in effect for less than 10 days, field changes will not be implemented, unless the line segment is not overseen by the Control Center and monitored by SCADA.

8. The EAOC (SPLPEA) or Supervisor of Control Center and Scheduling (SPLPWA), including Operations Supervisors for manned facilities, will revise the Operations Manual accordingly and issue a notice to the Control Center Supervisors of the new set points

9. The pressure reduction shall remain in place until the Pipeline Integrity Group advises that the pressure may be raised. The MOC procedure will be used to raise the operating pressure back to the level not to exceed the initial COL or MOP or MAOP prior to the reductions.

   Note:

   - Pressure reductions associated with an assessment under 49CFR Part195.452, the reduction in operating pressure cannot exceed 365 days without taking further remedial action to ensure the safety of the pipeline. For pressure reductions associated with an assessment under 49CFR Part 192.933(a), the reduction in operating pressure cannot exceed 365 days without the operator providing a technical justification that continued pressure restriction will not jeopardize the integrity of the pipeline. For pressure reductions exceeding 365 days, a safety-related condition report will be initiated by the Pipeline Integrity Group or Operations Engineering and filed with the U.S. DOT Office of

Pipeline Safety via the DOT Compliance Coordinator in accordance with the Hazardous Liquid Code 49CFR Parts 195.55 and 195.56 or 49CFR Part 191.23 and 49CFR Part 192.949 for Gas Pipeline requirements. .

- If a COL, MOP, or MAOP pressure reduction, based on a field confirmed anomaly, is greater than or equal to 20% and the condition will not be repaired in five days, a safety-related condition report will be initiated by the Pipeline Integrity Group or Operations Engineering and filed with the U.S. DOT Office of Pipeline Safety via the DOT Compliance Coordinator in accordance with the Hazardous Liquid Code 49CFR Parts 195.55 and 195.56 or 49CFR Part 191.23 and 49CFR Part 192.949 for Gas Pipeline requirements.

4 INTEGRITY ASSESSMENT

4.1 Integrity Assessment Selection

The integrity of each pipeline segment shall be periodically assessed to ensure its continued safe operation. The integrity assessment method selected to assess the integrity of a pipeline system must be chosen based on the segment-specific characteristics and perceived threats discussed in Section 4.1.1 and the best available integrity assessment method (or combination of methods) discussed in Section 4.1.2.

The selection of the integrity assessment method for each line segment shall be documented along with the appropriate justification. This documentation shall be stored on the Integrity Network.

4.1.1 Segment Characteristics & Perceived Threats

Each pipeline segment that could affect an HCA shall be evaluated by the Integrity Engineers to determine the pipeline's characteristics and the integrity threats associated with that segment. These include time dependent threats, static threats, time independent threats, and human error. The identified threats shall be documented in the IAP and the evaluation shall be summarized in the Integrity Close-Out Summary as discussed in Section 8.3.

The evaluation should consider the following eight (8) major risk categories and their corresponding risk factors, which are incorporated into the Risk Management System:

1. Third Party Damage (TPD)
2. Internal Corrosion
3. External Corrosion
4. Manufacturing Related Defects (e.g. Seam Assesment, pipe body anomalies, etc)
5. Construction Related Defects (e.g. girth weld, field bend, repairs)
6. Environmentally Assisted Cracking (e.g. SCC, fatigue)
7. Operations (e.g. human error, equipment failure)
8. Natural Forces (e.g. earthquake, weather)

The potential of these threats impacting integrity of the pipeline can be determined using the sources listed below:

- Historical information and events, such as construction practices and previous failures, identified through documentation & discussions with field and engineering personnel as necessary,
- Operational history of the pipeline,
- Results of the *Risk Management System* (Section 6),
- Results of previous integrity assessments and remedial actions, and
- The *Close-Out Integrity Summaries*, as available.

The leading causes of pipeline failures throughout the industry are TPD and corrosion. Therefore, these threats must be considered for each pipeline segment.

The potential for manufacturing and construction related defects is primarily a function of the age and manufacturing process of the pipe, and the contruction practices used during the pipeline's construction. The presence of such threats is most evident by assessing the history of the specific line segment and similar line segments within SPLP and throughout the industry. A specific manufacturing threat that must be evaluated is the integrity of the longitudinal seam weld (LSW). The LSW evaluation shall be performed using the criteria presented in *Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation*[*]. Pipelines identified as being susceptible to LSW concerns will be assessed using hydrostatic testing or an ILI capable of assessing the longitudinal seam weld.

Environmentally Assisted Cracking includes the threat of fatigue induced cracking (cyclic fatigue) and stress corrosion cracking (SCC). The maximum operating pressures should be monitored along with significant changes to the number and magnitude of the operational cycles to determine if cyclic fatigue should be a concern. In addition, all pipelines shall be evaluated to determine their susceptibility to SCC per the SCC Management Plan located on the SPLP Document Repository. The integrity of pipeline segments identified with SCC anomalies will be further assessed with hydrostatic testing or an ILI technology capable of detecting SCC-type cracking. Pipelines susceptible to SCC, but with no confirmed SCC anomalies, will be continually monitored during maintenance and excavation activities to inspect for SCC.

Integrity concerns arising from incorrect operations includes equipment related errors and human related errors. These issues are typically addressed through day-to-day operational procedures, training, and safety precautions. However, an appropriate integrity assessment shall be considered if an event occurs that could impact the integrity of a pipeline.

Natural forces that could impact the integrity of a pipeline segment include events, such as seismic activity, land slides, subsidence, etc. These events

[*] Michael Baker Jr., Inc. Report, *Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation*, TTO Number 5, Final Report, Integrity Management Program Delivery Order DTRS56-02-D-70036, April 2004.

occur randomly and have the potential to exert stress on the pipeline, which could result in a number of integrity concerns. Integrity concerns from natural forces will be assessed as necessary.

Additional considerations should be evaluated for other identified threats as necessary, including new industry concerns and advisories from PHMSA.

4.1.2 Integrity Assessment Methods

The assessment method selected to assess the integrity of the pipeline should be based on the characteristic and integrity threats associated with that line segment. The integrity assessment methods that may be considered include in-line inspection technologies, pressure testing, external corrosion direct assessment (ECDA), and other technologies as approved by the Manager of Engineering and PHMSA. Each integrity assessment method is discussed briefly below.

As technology and research advance and new integrity assessment methods develop, appropriate changes will be incorporated into this plan and communicated using the established MOC procedure.

<u>In-Line Inspection</u>
A wide range of ILI technologies and vendors are available for identifying various integrity concerns. However, these technologies and vendors differ widely in their experience, detection capabilities, and reliability. Each of these factors should be taken into account when selecting an ILI technology.

Deformation and High Resolution magnetic flux leakage (MFL) technologies are the primary inspection method for reliably identifying and characterizing pipe deformations and corrosion caused metal loss* for its baseline assessment and reassessment programs. These technologies should be used together, as appropriate, and the data should be integrated to obtain the most use of the data.

The use of developing ILI technologies may be considered as necessary to inspect pipelines for injurious integrity threats that have been identified on the pipeline segment. The reliability of these developing technologies is still being examined. Therefore, the data from these technologies will be used as supplemental information to evaluate and enhance the Integrity Management Program. The Pipeline Integrity Department will establish the appropriate response requirements based on the pipeline's characteristics, the vendor's reported performance specifications, and the industry's experience with the developing ILI technology. Such technologies and threats include ultrasonic crack detection and transverse magnetic field inspection technologies to inspect pipelines for longitudinal seam weld concerns or crack-like anomalies.

* Under certain circumstances, ultrasonic wall measurement (UTWM) technology may be used in place of MFL technology.

Hydrostatic Testing

Hydrostatic testing (in accordance with 49 CFR 195, Sub-Part E for Hazardous Liquid Pipelines and 49 CFR 192, Sub-part J for Gas Pipelines) may be considered, as appropriate, for any piggable or non-piggable line segment. A spike-test will also be considered for inspecting pipeline segments for critical, crack-like defects.

All integrity assessments using hydrostatic testing must be performed in conjunction with a review of the line segment's history and the effectiveness of its corrosion control program.

Direct Assessment

The pipeline industry has developed direct assessment (DA) processes for three threats:

1. External Corrosion
2. Internal Corrosion
3. Stress Corrosion Cracking

The external corrosion direct assessment (ECDA) process may be utilized for liquid and gas pipelines to identify locations of possible external corrosion. The ECDA process has not been utilized by SPLP as an integrity assessment method to date. Procedures consistent with §192.925 and the ANSI/NACE Standard Recommended Practice RP0502-2002 will be developed and implemented under the direction of the Corrosion Control Supervisor if the need for ECDA is established.

The internal corrosion direct assessment (ICDA) process may be utilized to identify locations of possible internal corrosion in gas pipelines. The ICDA process has not been utilized by SPLP as an integrity assessment method to date. Procedures consistent with §192.927 will be developed and implemented under the direction of the Corrosion Control Supervisor if the need for ICDA is established.

The stress corrosion cracking corrosion direct assessment (SCCDA) process may be utilized for gas pipelines to identify locations of possible stress corrosion cracking. The SCCDA process has not been utilized SPLP as an integrity assessment method to date. Procedures consistent with §192.929 and the ANSI/NACE Standard RP0204-2004 will be developed and executed under the direction of the Corrosion Control Supervisor if the need for SCCDA is established.

Other Assessment Methods/Technologies

Other new and/or developing integrity assessment methods/technologies may be considered as appropriate based on the pipeline's unique characteristics and identified threats following the approval of the Manager of Engineering and notification to PHMSA. The notification to PHMSA must be made 90 days prior to the assessment.

4.2 Integrity Assessment Results

The integrity assessments shall be performed according to SPLP Technical Procedures and Industry Standards. The results of an integrity assessment shall then be evaluated by an Integrity Engineer or qualified representative to determine the validity of the assessment results, identify potential integrity threats that may impact the integrity of the pipeline, and develop an appropriate Response Program.

The evaluation for each integrity assessment method is discussed in the following subsections. Necessary remedial activities identified in the review shall then be approved and carried out in a Response Program as discussed in Section 5.

4.2.1 In-Line Inspection

ILI surveys shall be performed in accordance with SPLP's ILI vendor requirements. The results of ILI surveys shall then be evaluated in accordance with SPLP Technical Procedure, PR-11-0036, *ILI Evaluation, Investigation, & Documentation*, which includes the quality control of the data, the integration and development of an ILI response program, and validation of the ILI data.

The ILI results, validation of those ILI data, and the ILI Response Program shall be well documented. The ILI results and any required excavations shall be documented electronically on the Integrity Network in SPLP's standard ILI format. At a minimum, the following information shall be maintained:

1. ILI Details
    a. ILI vendor, technology used, and details of the ILI survey, such as the dates the ILI was performed, difficulties that were encountered (failed inspections, inoperable sensors, etc), and the ILI vendor's contact information.
    b. Dates the preliminary notification of potential Immediate Conditions were received and the response to those notifications.
    c. Dates the draft ILI report was received from the ILI vendor and any major issues associated with that report.
    d. Dates the Final ILI Report was received.
    e. Comments regarding the ILI data that are pertinent to the integrity of the pipeline.

2. ILI Results
    a. ILI Anomalies
    b. Calculated stationing of the ILI data
    c. Integrated HCA data
    d. Immediate, 60-Day, 180-Day, and Other Conditions identified within the ILI data with associated Discovery Dates (Liquid Pipelines regulated by 195.452)

e. Immediate Repair Conditions, One-Year Conditions, and Monitored Conditions
   (Gas Pipelines regulated by 192, Subpart O)
f. ILI Anomalies that require investigation as part of the subsequent ILI Response Program

Comments and supporting evidence regarding the validity of the ILI data and planned Preventative & Mitigative Actions shall be documented in the Integrity Close-Out Summary discussed in Section 8.

4.2.2 Pressure Testing

All integrity assessment pressure tests are to be performed in accordance with 49 CFR Part 195 Subpart E and SPLP Technical Procedure PR-11-0004, "Pressure Testing of Pipelines." This includes the evaluation of any pressure test failures to determine the cause of the failure and a documented review of the corrosion control program using the Corrosion Review Checklist.

The results of the pressure test, the cause of any failures that occurred, and the Corrosion Review Checklist will be documented in Pipeline Integrity Department's files. The test pressure should be evaluated by an Integrity Engineer, the Corrosion Control Supervisor, and the Pipeline Integrity Manager to determine if additional preventative & mitigative activities are necessary.

4.2.3 Direct Assessment

Integrity assessments performed using DA will be done with prior approval from Manager of Engineering and in accordance with industry Recommended Practices and Government Regulations.

2 SEGMENT IDENTIFICATION

The following topics are discussed throughout Section 2:

- Identification and updates of line segments and facilities;
- Identification and updates of HCAs based on government data and field knowledge;
- Analytical identification pipelines and facilities that could impact an HCA
    - Liquid Pipeline HCA Impact,
    - HVL Pipeline HCA Impact,
    - Gas Pipeline HCA Impact,
    - Facility HCA Impact, and
    - Quality control of the HCA process; and
- Education and distribution of HCA impact information.

2.1 Pipeline System Identification and Updates

Many aspects of the IMP depend both on the identification and accuracy of the line segments and facilities, as well as managing updates to that information when changes of service or new acquisitions occur.

2.1.1 Pipeline and Facility Identification

In order to manage and maintain information about the DOT regulated pipeline segments, SPLP has worked with GeoFields to establish the ALIGN database. ALIGN is a Pipeline Open Database Standard (PODS) based model. It is a centralized repository for information, from line segment IDs and basic information to maintaining "events" on the pipeline, such as appurtenances (valves, tees, casings, etc) and coating data.

The ALIGN database is the repository for active jurisdictional line segments in accordance with SPLP's Technical Manual PR-11-0037, which defines active, idle, out of service, and abandoned lines. Other line segments, such as non DOT-jurisdictional lines, are also included in the database as part of the company's regular pipeline maintenance. Lists of active, DOT jurisdictional pipelines are maintained on the SPLP Document Repository. Each pipeline has an ID number and descriptive name assigned to it.

Information about pipeline facilities, which include pump stations, tank farms, junctions, wharfs/docks, and delivery facilities, are maintained on the SPLP Document Repository and used in the facility risk model database. Each facility also has a unique ID and descriptive name assigned to it.

2.1.2 Pipeline and Facility Updates

Any new acquisitions and changes of service must be incorporated into the IMP within one year from the acquisition or change of service. All new acquisitions and activation of out-of-service line segments require that the following tasks be performed:

- Add the pipeline/facility to the ALIGN database and/or Facility ID list
- Perform an HCA analysis on the pipeline/facility
- Add the pipeline/facility to the Baseline/Continual Assessment Plan
- Add the pipeline/facility to the risk model, and
- Establish a Re-assessment interval.

DOT CFR 195.452 defines Category 3 pipelines as pipelines constructed or converted after May 29, 2001. Any line segment of new construction, or any new acquisitions and change of service meeting the below definitions must be added to the ALIGN database and have an HCA analysis completed prior to the date the pipeline begins operation.

New Acquisitions: New acquisitions may include new construction or acquiring assets from another company. Both must be rolled into the IMP as discussed above. However, due diligence of existing assets acquired from another company must be performed to determine the integrity of the asset and how it will be rolled into the IMP. This should include a review of the line segment's HCA impact, risk model information, integrity assessment and repair history.

Change of Service: If a pipeline changes status from idle or out of service to active or vice versa, the information in the IMP needs to be updated. The existing company technical procedure, PR-11-0039, *Management of Change (MOC)*, and PR-11-0037, *Activating and Deactivating Pipelines*, provide methods and processes to communicate and track updates to existing segments and facilities. In addition, a Return-to-Services Plan will also be generated that satisfy the two procedures.

If the update is due to a pipeline or facility going out-of-service, the asset should be removed from the locations listed above and tracked through the revision history for that item.

2.2 SPLP HCA Identification and Updates

In addition to identifying and maintaining pipeline and facility information, it is also necessary to ensure that the HCAs used for the HCA analysis are current and updated.

HCA information is established through two sources:

- The National Pipeline Mapping System (NPMS) - NPMS is updated and maintained by the government. It is described in more detail in Section 2.2.1. This dataset contains both federal and state information to produce the five types of HCAs.
- Field Information - Information from SPLP's field organization is used to enhance the data provided by the government. Field-identified HCAs are collected each year through the HCA Update Process described in Section 2.2.2.

New HCAs identified through NPMS and the field identification process are incorporated into electronic maps and the HCA analysis within one year of being identified.

2.2.1 NPMS

The National Pipeline Mapping System provides shapefiles for each of the five types of HCAs. Their definitions are summarized here:

- High Population Area (HPA): HPAs are created from census data and are an urbanized area that contains 50,000 or more people and has a population density of at least 1,000 people per square mile;
- Other Populated Area (OPA): OPAs are also created from census data. They capture places outside of HPAs that contain a concentrated population, such as an incorporated or unincorporated city, town, village, or other residential or commercial area;
- Drinking Water (DW): A DW is categorized as an Unusually Sensitive Area (USA), an area that is unusually sensitive to damage from a hazardous liquid pipeline release. Drinking water HCAs capture locations that provide drinking water such as public water systems, source water protection areas, wellhead protection areas, and sole-source aquifers. The information is provided by each state.
- Ecological Area (ECO): An ECO is also considered a USA. The shapes were created to identify areas where there are endangered or imperiled species and can include migratory and marine habitats. They are also defined by individual states.
- Commercially Navigable Waterway (CNW): A CNW is made up of waterways that allow commercial traffic. The information comes from the Bureau of Transportation Statistics National Waterways Network database.

NOTE: Pennsylvania has not yet supplied ecological HCA information to DOT. In order to adequately capture that information, Resource Control Corporation (RCC) was contracted to identify the PA ECO HCAs. The analysis is presented in Attachment E-2.

More information about the specific sources of this information can be found on the NPMS website (http://www.npms.rspa.dot.gov).

The Pipeline Integrity Group monitors the data provided by federal, state, and local authorities to identify information that may be used to identify new HCAs or enhance the identification of existing HCAs.

Information provided by government authorities will be assessed and incorporated into the Risk Management System in the first quarter of the year. This effort will be done in conjunction with the in-house HCA Update Process discussed in Section 2.2.2.

2.2.2 HCA Update Process

SPLP uses the knowledge of field personnel to supplement the NPMS data and update HCAs. The existing High Consequence Areas (HCAs) are continually assessed in an annual process to determine if additional HCAs should be incorporated based on input from the regions/districts and the ROW department.

The HCA maps and design one calls are collected from the Region/District and the ROW Department by the end of the 4th quarter. Any other information from relevant groups, whether through the Risk Management System or other means, is also integrated at this time.

The new HCA information is reviewed and validated by the Integrity group to verify that it meets the HCA requirements of 192 Subpart O or 195.452. Once validated the new HCA information is incorporated into the HCA analysis (Section 2.3), the Pipeline Risk Model (Section 6.2.2), and the Facility Risk Model (Section 6.2.3). All newly identified HCAs are maintained independently from the areas provided from NPMS. They are designated "Field Identified Population HCA," "Field Identified Ecological HCA," and "Field Identified Drinking Water HCA."

Once the new HCA locations have been updated, revised HCA maps are then distributed to the Regions/Districts by the end of the 1st quarter so the process can repeat. If no new HCA were identified, the Region/District may maintain the original maps to repeat the process.

2.2.2.1 HCA Reporting within SPLP: Region/District

Each Region/District collects information to help identify new HCAs using the following four (4) resources: Aerial Patrols, One-Call, ROW, and Local Field Observation.

Each resource is used to identify new or previously unidentified HCAs that fall into the following categories:

- Population Areas* – these are areas of concentration of population. The collection of two types of population areas will occur:
  - Housing Developments
  - Congregated areas: Structures that could contain approximately 20 or more people on a regular basis. Examples are:
    - Hospitals
    - Nursing Homes
    - Assisted Living Complexes,
    - Schools,
    - Churches,
    - Apartment buildings/complexes
    - Businesses,
    - Shopping centers, and
    - Areas of outside congregation, such as parks.
- Ecologically Sensitive Areas – Examples: locations of endangered plant or animal species or designated wetlands encountered in pipeline maintenance or permitting activity.
- Sources of Drinking Water – Examples: water treatment facilities and wells for larger public use.

NOTE: Commercially Navigable Waterways (CNW) are not currently a component of this Region/District HCA Update due to the high infrequency of newly used/discovered commercial traffic waterways. These updates will occur as NPMS revises their identification of CNWs.

To facilitate the Region/District efforts, the Pipeline Integrity Group distributes maps of each line segment that defines the location and type of all currently identified HCAs. These maps are then used by the Regions/Districts to track new information identified by the available resources, such as the location of newly identified ecological areas and locations of construction along the pipeline right-of-way that result in a new HCA. An example of the maps provided to the Regions/Districts is presented in Attachment C-4.

The information provided to the Regions/Districts includes the following:

- One official set of maps (all line segments) will be provided to each maintenance supervisor for tracking all HCA Updates
- Two loose sets of maps, split by line segment for field personnel
- Informational Instruction Sheets

The official set of maps is used to track all HCA updates from each source (aerial patrol, field observation, etc.) and serve as the master copy, which is collected at the end of the 4th quarter. Each maintenance supervisor is provided with two additional loose sets of maps for distribution to the Pipeliners. These maps can then be divided between the Pipeliners according to their specific areas of responsibility. All sets of HCA maps have

* Changes in populated areas may occur as a result of new construction or renovation (change of the use) of an existing structure.

a table at the bottom of each page with the necessary fields to be filled in as listed below. At the beginning of each line segment's map, there is a definition of the criteria for HCA updates as well as potential examples.

Data collected by the Regions/Districts for new potential HCA locations includes the following:

- HCA Identification Number
- Pipeline ID
- Date identified by the field
- Type of HCA
- Description of the HCA
- Source (Field Observation, Aerial Patrol, etc.)
- Location and extent of the HCA (if available, start and stop stationing of the pipeline relative to the HCA and the area covering or is near to the pipeline)
- GPS coordinates, if available
- Newly identified area drawn on the map

2.2.2.2 HCA Reporting within SPLP: ROW Department

The Right of Way Department (ROW) is responsible for notifying the Pipeline Integrity Group of relevant Design One Calls. The proper notification is to forward a copy of the final letter produced for each Design One Call to the Pipeline Integrity Group.

Design One Calls, which require more extensive reviews by engineering or ROW, are often provided early in the planning process for a new development or business. Occasionally the projects can take years to commence construction or may not occur at all. Therefore, the letters will be reviewed by Integrity personnel annually with the HCA update maps from the Regions/Districts for any additional areas that need to be added.

Note: As necessary, the integrity group will review available integrity information for the area that will be affected by a Design One-Call to determine if additional preventative and mitigative activities are required. These integrity reviews will be performed at the request of the ROW department.

2.3 SPLP HCA Impact Analysis

Once a pipeline or facility has been identified as described in Section 2.1 and the surrounding HCAs have been identified as described in Section 2.2, an HCA impact identification is performed. The following sections contain detailed information on the Liquid Pipeline HCA impact identification, Highly Volatile Liquids (HVL) Pipeline HCA impact identification, Gas Pipeline HCA Impact Identification, and Facility HCA impact identification and the associated quality control processes.

2.3.1 Liquid Pipeline HCA Impact Identification

Pipelines can clearly impact High Consequence Areas that they are physically located within. But pipeline release history shows that the direct environment is sometimes not the only area to get impacted by a release.

Therefore to model the hypothetical impact of a release on a pipeline that does not transport HVLs, SPLP performs a three-part analysis to determine HCA impact.

1. **Direct Impact:** The intersection of the pipeline and the HCAs is performed to determine the areas of direct impact.

2. **Indirect Impact:** A ¼ mile buffer is applied to all HCAs before intersecting the pipeline with the resulting shapes. (The ¼ mile buffer was determined by a leak history review of both the Eastern and Western areas of the pipeline. See Attachments E-3 and W-3).

3. **Potential Impact:** Hypothetical releases of product are applied at 500 foot or smaller intervals along the pipeline. The resulting 'plumes' are transported over land and waterway. The intersection of these plumes with the HCAs determines the sections of pipe that can impact an HCA. More description on potential impact determination is provided below.

These three analyses were chosen to perform a conservative determination of SPLP's HCA impact and to account for different possible release scenarios. If a pinhole release were to occur, SPLP's experience indicates that the ground around the leak site generally absorbs most of the product, effectively reducing the spread of the release. This scenario would be covered by the direct and indirect analyses. If the product is not absorbed (i.e. if the leak occurs near a waterway) then the overland spread and water transport models take the travel of the product into account. For larger releases, with more potential product escaping, the potential impact analysis helps to better determine the impact. As described below, the potential impact analysis assumes catastrophic failure of the pipeline - a leak that assumes the pipeline is sheared and a maximum flow rate release occurs through the full bore of the pipe. Therefore as the product movement is modeled with overland spread and water transport methods, it assures that a worst-case volume of product is considered. In addition, the buffer for the indirect analysis accounts for mapping inaccuracies, the possibility that product sprays from the release and does not follow the logical topographical path from the line segment, and that there may be another method for the environment to transport product (sewers, drain tiles, etc).

Of the three HCA impact analyses, the potential impact is the most complex. Potential impact determination was designed to be a consistently reproducible analysis that adequately simulates the transport of a hypothetical release over land and in waterways. SPLP uses GeoFields to perform this analysis. The specifics of their methodology are described in Attachment C-5.

As stated in the attachment, there are several inputs to be provided by the operator:

Basic Pipeline Information: GeoFields performs the analysis on active jurisdictional pipeline segments on SPLP's system. In addition, SPLP provides nominal diameter and wall thicknesses.

Use of Valves: The potential spill volume at each hypothetical release point is determined as the sum of static and dynamic spill volumes. The static volume captures the amount of product that would drain out of a line due to elevation differences at a specific spill point. This volume can be reduced by either check valves or Motor-Operated Valves (MOVs) in the pipeline. Check valves located downstream from a spill point prevent product from flowing upstream towards a leak. MOVs can be operated remotely to block product flow in both directions in the case of a release. Manually operated valves were not considered in order to ensure a conservative analysis. SPLP cannot assume a specific time for personnel to reach manually operated valve sites.

Dynamic Volume: The dynamic volume is the volume in the pipeline that is added to the release due to the continuation of running the pipeline for a short period of time between the occurrence of a release and the shutdown of the pipeline. To determine a conservative value for the dynamic volume, the time to detect, confirm, and continue response to a leak was determined for each segment based on the unique operating characteristics of the line segment, leak detection capabilities and interviews with Control Center and Operational personnel. A catastrophic, full-bore release at the maximum flow rate for the pipeline is assumed to be the worst-case scenario because it produces the highest volumes.

Waterway Response Time: The time it would take a release to impact a hydrological feature was determined based on the individual detection, confirmation and response times discussed above, information from the Oil Spill Response Organizations (OSROs), and interviews with field crews. A three hour period was determined to be a conservative estimate. This time was then doubled to six hours to include a factor of safety and account for unforeseen circumstances.

Residual Thickness: SPLP uses a 0.25-inch residual thickness to take into account product left behind or absorbed for the overland spread model.

Hydrological Feature Buffers: Once product enters a waterway, it can impact more area than is captured by the borders of the hydrological shape. Therefore, for SPLPEA, the water transport model applies a 300 feet buffer distance to rivers and water bodies to account for the possibilities of vapors and product on the shores. For SPLPWA, the water transport model applies a 100 feet buffer distance to rivers and water bodies because crude oil can potentially impact less area around a waterway.

Release Point Interval: The HCA analysis creates potential release points along each pipeline segment to ensure a conservative HCA impact. These release points are created every 500 feet along the pipeline and at major waterways to capture the worst-case scenario for water transport.

All of the inputs listed above are used to perform the three types of HCA Impact analyses; direct, indirect and potential. The results of these analyses are then combined to produce HCA Impact Segments. The HCA Impact Reports for the EA and WA are maintained on the SPLP Document Repository.

2.3.2 HVL Pipeline HCA Impact Identification

A small portion of SPLP pipelines (<5% of all pipeline miles) transport Highly Volatile Liquids, such as propane and butanes. For specific details on HVL properties, consult the product specific Material Safety Data Sheet (MSDS).

SPLP contracted a third-party consultant, TRC, to provide guidance and model the behavior of HVLs in a release scenario. To determine the HCA impact from a release, TRC performed a sensitivity analysis to evaluate the potential impact of environmental factors (temperature, humidity, surface roughness) during a release and then used the "average" and "worst-case" environmental factors in their HVL release model, CHARM. The details TRC's study are presented in Attachment C-6.

As stated in the attachment, hypothetical releases are modeled periodically along the length of the pipelines. The release points are applied every mile for the first five miles, then one point every five miles after that. The results provide vapor cloud dispersion distances from the pipeline where the concentration reaches the Lower Explosive Limit (LEL). The distances are greatest near the pressure sources for the pipeline.

The maximum distances to LEL assuming worst-case weather conditions are then used to determine HCA impact. The distances are applied as a dynamically changing buffer to the pipeline (every change in the maximum distance changes the width of the buffer up to the next point the maximum distance changes). The buffer is then intersected with all types of HCAs except for drinking water, since the contamination of drinking water is not a concern with these products. Then the HCAs that touch the buffer have that particular buffer distance applied around them. The point where the HCA buffer intersects the pipeline is the beginning or end of an HCA impact segment.

Each of the pipelines that transport HVLs also transport conventional liquid products. Therefore, the HVL HCA analysis was incorporated with the conventional product analysis described in Section 2.3.1 to identify a HCA impact independent of the product being transported.

2.3.3 Gas Pipeline HCA Impact Identification

Gaseous products act differently in a release scenario than liquid and HVL products. Therefore these pipelines require a separate HCA analysis consistent with the requirements of DOT Part 192, Subpart O.

Currently SPLP only operates one pipeline segment that transports hydrogen gas and is regulated by the Gas IMP regulations. A separate HCA analysis has been performed for this line segment. The details of the analysis are presented in Attachment C-7.

2.3.4 Facility HCA Impact Identification

Facility HCA Impact Identification is performed utilizing the analysis discussed in Section 2.3.1. Pump stations and other types of facilities without storage tanks are considered to have the same impact as the pipeline going in and out of the facilities. This means that every facility uses the direct, indirect, and potential impact to determine its impact. For facilities with storage tanks, the potential exists for additional volume to be available from the tanks during a release. In the cases where check valves or motor-operated valves are able to isolate the tank and are located inside the containment dikes, no additional volume is assumed to enter a hypothetical facility release. In the cases of facilities where the possible methods for tank volume isolation are outside the dikes, a ½ mile buffer was applied around each facility border. In addition, each facility will be evaluated to determine whether or not additional release modeling needs to occur to adequately reflect the possible impact a facility could have. This modeling will be performed similarly to the pipeline spill modeling, with spill points placed at the location(s) of tanks. The Facility HCA Impact Report is maintained on the SPLP Document Repository.

2.3.5 Quality Control

GeoFields has performed an extensive QA/QC process, which is described in Attachment C-5.

SPLP also performs an in-house quality control check. To check the accuracy of the HCA analysis and resulting impact determinations, a random sampling of geographical areas are reviewed. The Attachment C-8 is being used to perform and document these checks and outlines in more detail the areas of focus. Currently Facility Explorer, the company's internet based mapping system that displays ALIGN information, is used as a tool to perform the checks.

2.4 HCA Education & Distribution

HCA Impact information is a key element in the decision making process throughout SPLP. Understanding HCA impact is critical for a number of activities including understanding the risk management system (Section 6) and the results of the pipeline and facility risk models (Sections 6.2.2 and 6.2.3), prioritizing the appropriate preventative and mitigative activities (Section 7), planning for and responding to emergency situations, and updating the locations of HCAs as they develop around the SPLP pipeline system.

Numerous efforts continue to be performed to educate all levels of SPLP's personnel on the five types of HCAs and how our pipeline may impact those HCAs. These efforts include numerous one-on-one interactions (such as new employee orientation) and the formalized group training events listed below. These events are performed as needed.

- HES Company Training,
- Roll-Out of Facility Explorer (FE),
- HCA Update Process,
- Line Specific Risk Analysis Meetings,
- Integrity Training Workshop held in conjunction with Welding School, and
- Region/District Office Staff Meetings and periodic Safety Sessions.

The locations of HCAs and sections of SPLP pipeline system that could potentially impact HCAs have been distributed and area accessible to SPLP personnel through the following initiatives:

- Facility Explorer (FE) – A web-based mapping application populated with data from ALIGN that has the ability to view HCAs and the potential HCA impact.
- HCA Update Maps – Hard copy maps of the pipeline and associated HCAs that are distributed to the field through the HCA Update Process (Section 2.2.2)
- Data Sheets from the Risk Analysis Meetings (Section 6.3) – Data sheets that contain HCA impact, pipe material information, and ILI data are maintained on the Integrity Network for easy access to all SPLP employees.
- Alignment Sheets – Detailed pipeline drawings that identify the HCA locations and the pipeline's attributes (ROW information, pipe material, elevation profile, and coating data, etc.) on an aerial background photograph.

SPLP EASTERN AREA BASELINE ASSESSMENT SCHEDULE	2006

Pipe ID	Designation	Description	Length Miles	2006 HCA Miles	Last Assessment Type	Last Assessment Year	Current Assessment Type	Current Assessment Completed Date	Current Assessment Basis	Current Assessment Comment	Re-assessment Interval Years	Re-assessment Target Date
		SPLPEA Line Segments										
11019	MACD-SWAR-8	8" Philadelphia Spur	2.06	2.06	n/a	n/a	Hydrotest	2/8/2006	ML/Dent Baseline		5	2/8/2011
11026	PHWB-PTBR-12A	12" APL 4 Line	0.95	0.95	Hydrotest	1999	Hydrotest	11/16/2006	ML/Dent Baseline/MOP Δ	Note#4	5	11/16/2011
11027	PHWB-PTBR-12B	12" APL 5 Line	0.95	0.95	Hydrotest	1999	Hydrotest	11/9/2006	ML/Dent Baseline/MOP Δ	Note#4	5	11/9/2011
12114	TAMQ-KING-6-8	6"/8" Tamaqua - Kingston (Note #1)	46.20	37.36	Hydro;Hires	1965;1998	Hires MFL	10/29/04G, 7/29/05G, 8/10/05, 10/10/05, 2/17/06G, 2/24/06, 6/21/06	ML/Dent Baseline		3	10/29/2007
13020	ALLE-INJT-6	6" Pitt Spur (11/11/05 G)	3.70	3.70	Hydrotest	1979	Hires MFL	3/29/2006	ML/Dent Baseline		4 pend	2009
13021	INJT-INDI-8	8" Pitt Spur (11/11/05 G)	2.07	2.07	Hydrotest	1979	Hires MFL	3/29/2006	ML/Dent Baseline		4 pend	2009
13125	CTOL-CTV8-16	16" Crude to BP Valve 8 - by Capital Proj	0.67	0.67	n/a	n/a	Hydrotest	8/14/2006	ML/Dent Baseline			
		Total Baseline Assessment Miles	56.60	47.76								

Pipe ID	Designation	Description	Length Miles	2006 HCA Miles	Last Assessment Type	Last Assessment Year	Current Assessment Type	Current Assessment Completed Date	Current Assessment Basis	Current Assessment Comment	Re-assessment Interval Years	Re-assessment Target Date
		SPLPEA Reassessments										
11003	TWIN-ICED-8	8" Twin Oaks - Icedale	32.97	32.97	Hires MFL	7/25/2001	Hires MFL	4/18/2006	ML/Dent Reassess			
11109	PHSP-PHBW-12B	5 Line River Crossing	0.13	0.13	Hydrotest	11/1/2004	Hydrotest	11/9/2006	ML/Dent Baseline/MOP Δ	Note#4	5	11/9/2011
11112	PHSP-PHBW-8E	4 Line River Crossing	0.13	0.13	Hydrotest	10/18/2004	Hydrotest	11/16/2006	ML/Dent Baseline/MOP Δ	Note#4	5	11/16/2011
11010	TWIN-NWRK-14	14" Twin Oaks - Newark	110.91	110.57	Hires MFL	12/16/2003	USWM/TFI	12/19/2006	ML/Dent Reassess	See Note #3	3 pend	2009
11023	FTMN-PH4T-30A	30" FM-3 (GP-38)	3.06	3.06	Hires MFL	12/12/2001	Hires MFL	11/17/2006	ML/Dent Reassess			
11035	WOOD-LIN3-16	16" Harbor Line	80.33	77.09	Ultrasonic	8/3/2001G, 1/16/2002	MFL/TFI	5/26/06 G, 6/22/06 TFI, 8/01/06 MFL	ML/Dent/Seam Reassess	See Note #2		
11047	HIWF-DCTF-24A	24" Hog Island - DCTF (North Ship Line)	3.04	3.04	Hires MFL	2/1/2001	Hires MFL	1/24/2006	ML/Dent Reassess		5	1/24/2011
11048	HIWF-DCTF-24B	24" Hog Island - DCTF (South Ship Line)	3.05	3.05	Hires MFL	3/1/2001	Hires MFL	3/2/2006	ML/Dent Reassess		5	3/2/2011
12000	MNTL-BLUE-8	8" Montello - Blue Mountain	79.66	68.37	Hires MFL	2/18/2001	Hires MFL	1/26/2006	ML/Dent Reassess			
12008	MNTL-BEJT-8	8" Montello - Berne Jct.	16.70	13.43	Hires MFL	4/12/2005	Hydrotest	9/18/2006	ML/Dent Reassess/Seam Baseline		5 years	2011
12113	BEJT-TAMQ-6	6" Berne Jct. - Tamaqua	21.65	14.89	Hires MFL	9/9/2001	Hires MFL	5/31/2006 G	ML/Dent Reassess			
13008	MLJT-INKS-6	6" Millard Junction - Inkster (DSPL)	47.16	43.77	Hires MFL	11/14/2001	Hires MFL	6/6/6 G	ML/Dent Reassess		3 pend	2009
13024	TOLE-MLJT-6/8	6"/8" Toledo - Millard Junction (DSPL)	4.58	4.58	Hydrotest	12/3/2004	Hires MFL	6/6/6 G	ML/Dent Reassess			
13014	FOST-FOS2-8	8" Fostoria Jct. - Inland PS	4.20	2.06	Hires MFL	7/11/2001	Hires MFL	5/24/2006	ML/Dent Reassess			
13019	BOAR-ALLE-10	10" Boardman - Allegheny	63.38	55.89	Hires MFL	11/13/2001	Hires MFL	10/21/2006	ML/Dent Reassess			
13019	HUDS-BOAR-10&8	8"/10" Hudson - Boardman	51.00	46.67	Hires MFL	7/20/2001	Hires MFL	10/2/2006	ML/Dent Reassess			
		Total Reassessment Miles	521.95	479.70								

Total Miles for Plan Year	578.55	527.46

Revised 1/9/07

Note #1: Tamaqua - Kingston shows all runs completed to get 100% coverage for entire line segment
Note #2: Harbor Line is being reassessed for Dent and ML. Seam Assessment is baseline per Kiefner's Study showing susceptibility. Seam reassess to be determined
Note #3: Assessment Methods/Tools under evaluation, to be determined (TBD)
Note #4: 11109 and 11112 were reassessed along with 11026 and 11027, due to requirement to raise MOP

SPLP EASTERN AREA
BASELINE ASSESSMENT SCHEDULE

2007

Pipe ID	Designation	Description	Length Miles	2003 HCA Miles	Last Assessment Type	Last Assessment Year	Current Assessment Type	Current Assessment Completed Date	Current Assessment Basis	Current Assessment Comment	Re-assessment Interval Years	Re-assessment Target Date
		SPLPEA Line Segments										
11007	MHTF-PH4T-6B	IRPL 5N	18.64	18.50	Hires MFL	7/21/2004	TBD		Seam Baseline	See Note#1		
11011	PIJT-PISC-6	6" Piscataway Spur	0.07	0.07	Hydrotest	1987	Hydrotest		ML/Dent Baseline			
11012	LIND-LID1-12	12" B.P. Linden Spur	0.78	0.78	Hydrotest	1980	Hydrotest		ML/Dent Baseline			
11013	LIND-LIN2-12	12" Buckeye Spur	1.09	1.09	Hydrotest	1981	Hydrotest		ML/Dent Baseline			
11018	TWIN-CHEL-16	16" BP Chelsea Spur	2.30	2.30	Hydrotest	1980	Hires MFL		ML/Dent Baseline			
11020	HIWF-FTMN-30	30" Hog Island Crude Line	0.78	0.78	Hydrotest	1994	Hires MFL		ML/Dent Baseline			
11024	FTMN-PH4T-30B	30" FM-4	3.06	3.06	n/a	n/a	Hires MFL		ML/Dent Baseline			
11036	LIN3-LIN2-12	12" Harbor Linden Connection	0.23	0.23	Hydrotest	1997	Hydrotest		ML/Dent Baseline			
11125	SRTF-PTBR-10	10" Keystone FM-8 (GP-09)	1.20	1.20	Hydrotest	1988	Hydrotest		ML/Dent Baseline			
12100	MTJT-MTVL-6	6" Montour Broad Street Spur	0.13	0.13	Hydrotest	1986	Hydrotest		ML/Dent Baseline			
13002	CMAR-CTOL-16	16" Marysville - Toledo Crude	122.42	103.20	Hires MFL	6/1/2003	TBD		Seam Baseline	See Note#1		
13003	DELM-EPJT-12	12" Delmont/Export Spur (Salem Spur)	2.47	2.47	Hydrotest	1967	Hires MFL		ML/Dent Baseline			
13010	CSJT-CSAM-14	14" Samaria Spur	1.28	0.00	Hydrotest	1995	Hydrotest		ML/Dent Baseline			
13017	ALJT-ALLE-6	6" Allegheny Spur	1.66	1.66	Hydrotest	1953	Hydrotest		ML/Dent Baseline			
13018	BOAR-YOUN-3	3" Youngstown Spur	2.22	2.22	Hydrotest	1992	Hydrotest		ML/Dent Baseline			
13022	VAJT-VANP-6	6" Vanport Spur	1.20	1.20	Hydrotest	1989	Hydrotest		ML/Dent Baseline			
13126	RMJT-RMJ2-8	8" Romulous Jct - Amoco Spur	0.61	0.61	Hydrotest	1985	Hydrotest		ML/Dent Baseline			
		Total Baseline Assessment Miles	160.14	139.50								

Pipe ID	Designation	Description	Length Miles	2003 HCA Miles	Last Assessment Type	Last Assessment Year	Current Assessment Type	Current Assessment Completed Date	Current Assessment Basis	Current Assessment Comment	Re-assessment Interval Years	Re-assessment Target Date
		SPLPEA Reassessments										
11001	PTBR-BOOT-12	12" Pt. Breeze - Boot	26.94	26.94	Hires MFL	2/16/2004	Hires MFL		ML/Dent Reassess		3	
11001	BOOT-MNTL-12	12" Boot - Montello	32.98	32.03	Hires MFL	2/16/2004	Hires MFL		ML/Dent Reassess		3	
11124	DCTF-GPRF-16	16" Crude Line (GP-07)	3.00	3.00	Hires MFL	11/17/2003	Hires MFL		ML/Dent Reassess			
12002	CORN-CALE-8	8" Corning - Caledonia	72.53	22.38	Hires MFL	12/11/2002	Hires MFL		ML/Dent Reassess			
12002	CALE-BUF2-8	8" Caledonia - Buffalo	57.35	20.48	Hires MFL	6/17/2002	Hires MFL		ML/Dent Reassess			
12003	CALE-ROCH-8	8" Caledonia - Rochester	19.17	8.67	Hires MFL	12/12/2002	Hires MFL		ML/Dent Reassess			
12114	TAMQ-KING-6-8	6"/8" Tamaqua - Kingston (10/29/04 G)	46.38	27.47	Hires MFL	6/13/2006	Hydrotest		ML/Dent Reassess	See Note #2		
13013	TOLE-FOST-8	8" Toledo - Fostoria	31.22	17.95	Hires MFL	3/13/2002	Hires MFL		ML/Dent Reassess			
13015	FOST-HUDS-8	8" Fostoria - Hudson	107.62	65.01	Hires MFL	3/11/2002	Hires MFL		ML/Dent Reassess			
		Total Reassessment Miles	397.19	223.93								

Total Miles for Plan Year	557.33	363.43

Revised 8/8/2006

Note #1: Kiefner Study requires baseline for seam assessment, assessment method/tools under evaluation, to be determined (TBD)

Note #2: Pending shift of assessment into 2009 if closure summary reveals a 5 year reassessment schedule. Need to hydro Rt 309 Crossing.

SPLP WESTERN AREA
BASELINE ASSESSMENT SCHEDULE
2007

BASELINE

DISTRICT	COMPANY	MAINLINE SEGMENT	Gathering or Mainline	STATUS	COUNT TOWARD RISKIEST 50%?	JURISDICTION	PLAN YEAR	REASSESSMENT YEAR	2nd REASSESSMENT YEAR	PREVIOUS INSPECTION	REASSESSMENT INTERVAL	LINE SIZE	INSPECTION METHOD	TYPE OF LONG SEAM	LONG SEAM SUSCEPTIBLE TO FAILURE?	DATE OF INSTALL	4/13/04 RISK FACTOR	RISK RANK	4/30/04 HCA MILES	TOTAL ASSESSED MILES
WTX	SPLP	Truscott to Childress	Mainline	No BL	No	RRC	[redacted]	2012	2017	MFL/DEF - 02	5	10	Hyd.	LW	YES	1927	6.3	231	0.00	44.100
MVPL LON	MVPL	Delhi to Delhi MS Trap	Mainline	No BL	No	OPS	[redacted]	2012	2017	MFL - 7/21/99	5	12	ILI	EFW	No	UNK	18.5	62	16.84	44.150
MVPL LON	MVPL	Haynesville to Magnolia	Mainline	No BL	No	OPS	[redacted]	2011	2015	Hyd. 1991	4	8	ILI	ERW	No	UNK	15.5	77	1.15	20.000
LON	SPLP	ET10 - Thomas Station to Mid-Valley Station	Mainline	No BL	No	OPS	[redacted]	2012	2017	Hyd. - 5/99	5	10	ILI	ERW/UNK	NO	1931/UNK	9.8	96	1.61	1.989
LON	SPLP	30-6"-D	Gathering	No BL	No	RRC	[redacted]	2012	2017	Unknown	5	6	Hyd.	UNK	NO	UNK		103	0.15	0.150
LON	SPLP	48-4"-C	Gathering	No BL	No	RRC	[redacted]	2012	2017	Unknown	5	4	Hyd.	UNK	NO	UNK		103	0.08	0.520
CTX	SPLP	Breckenridge to Ranger WTG	Mainline	No BL	No	RRC	[redacted]	2012	2017	Hyd. - 12/86	5	8	ILI	ERW	NO	1986	8.4	99	0.81	23.100
WTX	SPLP	Merten to Dixon	Mainline	No BL	No	RRC	[redacted]	2012	2017	Hyd. - 1978	5	10	ILI	ERW	NO	1978	7.7	101	3.28	28.790
CTX	SPLP	Pendell Station to Comyn Station 8in Trunk	Mainline	No BL	No	RRC	[redacted]	2012	2017	Hyd.	5	8	ILI	LW	NO	1925	9.6	97	3.06	60.520
WTX	WTG	Abilene to Ranger 26"	Mainline	No BL	No	RRC	[redacted]	2012	2017	ILI - 1995	5	26	ILI	ERW	NO	1952			41.74	64.500

SCC Management Program

Outline

Introduction 1
Background Information 1
Industry's Experience & Considerations with SCC 1
SPLP's Experience with SCC 2
SCC Management Process 3
SCC Susceptibility Evaluation 3
Criteria 3
Evaluation of SPLP's System 4
SCC Training 5
Assessment & Investigation Requirements 5

Introduction

Stress corrosion cracking (SCC) is an integrity concern throughout the pipeline industry. As such, the following program has been created to manage the threat of SCC in SPLP's system through continuous training evaluation, monitoring.

Background Information

Industry's Experience & Considerations with SCC

In recent years, an increased number of pipeline failures have been attributed to SCC and numerous papers have been published throughout the industry. The rise in SCC related pipeline failures is likely attributed to a higher level of failure investigation, increased awareness of SCC, and an aging infrastructure. Several notable industry papers that summarize the threat of SCC are referenced below:

- Stress Corrosion Cracking Recommended Practices[1], 1997.
- Advisory Bulletin ADB-03-05, *Pipeline Safety: Stress Corrosion Cracking (SCC) Threat to Gas and Hazardous Liquid Pipelines*[2], 2003.
- *Stress Corrosion Cracking Study*[3], January 2005.
- *Stress Corrosion Cracking (SCC) Direct Assessment Methodology*[4], 2004.
- *OPS Review Addresses SCC Threat to Pipeline Integrity*[5], April 18, 2005.

The mechanisms of SCC include a susceptible material, a corrosive environment, and a stress on the pipe. These mechanisms are generally understood; but many practical issues associated with SCC are not understood. Examples of these issues include the following:

- Industry criteria to determine if a pipeline is susceptible to SCC are too broad.

  - Experience has shown that a very small percent of pipe locations that exhibit the SCC characteristics actually contain cracking.
  - Much less than 1% of SCC colonies found within the industry are of a size to be a threat to the integrity of a pipeline.
- There are no well-established models to predict locations or magnitude of existing SCC colonies.
  - Predictive SCC data models throughout the industry are not well validated by experience and are often not applicable across pipeline systems.
  - No particular soil chemistry has been identified with SCC.
- Several ILI technologies have been marketed for identifying SCC, but the following concerns exist:
  - More experience and validation is required to document the technologies' capabilities to detect and size SCC colonies, especially as ILI technologies continue to evolve.
  - The marketing of an ILI technology's capability isn't always in alignment with the technology/data analysis capabilities*.
  - The ILI technologies are cost prohibitive for SCC-susceptible pipelines that have no evidence of containing SCC.
- Hydrostatic testing a pipeline that is susceptible to SCC will only identify critical SCC colonies that fail within the pressure limits of the hydrotest. Hydrostatic testing will not identify sub-critical SCC colonies that remain in service after the hydrostatic test.

Despite these issues, SPLP acknowledges that SCC is an integrity concern that must be considered. SPLP's experiences and SCC Management Program are described throughout this document.

SPLP's Experience with SCC

SPLP has experienced only one failure that was attributed to SCC. The failure occurred on the Haynesville-Spearsville segment of the Mid-Valley Pipeline in November 2000 and was characterized as near-neutral pH SCC (NN-pH SCC). As a result of the failure, SPLP contracted with several industry experts, including Marr & Associates and CC Technologies to perform numerous assessments of the affected segment. These assessments included soil modeling, ILI using transverse field inspection (TFI) and traditional MFL technology, hydrostatic testing with a spike test, and numerous field investigations. No additional locations of SCC were identified.

SPLP also contracted with Kiefner & Associates (Kiefner) to assess the characteristics of the pipeline system, develop SCC susceptibility criteria and

* For example, PII's TFI tool was originally marketed as a technology capable of identifying SCC. However, years of experience have proven that identifying SCC with the TFI tool is very difficult, such that the ILI analyst shy away from that claim. However, PII's marketing literature still states the tool can identify large, established colonies of stress corrosion cracking.

make recommendations for excavation activities to assess for SCC when the pipeline is exposed. Kiefner's assessment concluded that SCC is not a significant integrity threat to SPLP's system. The SCC susceptibility criteria and recommendations for excavation have been incorporated into the SCC Management Process discussed throughout this document and are used to train field crews.

SCC Management Process

The SCC Management Process includes the following steps, which are discussed below.

- SCC Susceptibility Evaluation
- SCC Training
- Assessment & Investigation Requirements

SCC Susceptibility Evaluation

Criteria

All pipelines shall be evaluated annually to determine their susceptibility to stress corrosion cracking (SCC). Pipelines that meet all of the following criteria* will be classified as susceptible to SCC:

- Operating Stress > 60% SMYS
- Age > 10 years
- Coating is not FBE
- Wet/dry soil conditions
- Operating temp > 100 degrees F (High pH SCC only)
- Distance < 20 miles from upstream pump station (for High-pH SCC)

In addition, all pipelines that have been identified with an SCC anomaly will be classified as susceptible. Identification of SCC may occur through: an in-service failure, hydrostatic testing failure, and inspection of an exposed pipeline.

The SCC evaluation shall be performed annually with the Risk Assessment Model. The results will be documented on the Integrity Network Drive, incorporated into the Integrity Assessment Plan, and communicated to the Regions/Districts during the Continual Assessment Meetings.

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* These criteria were derived from two studies: *Stress Corrosion Cracking Study* performed by Michael Baker Jr., Inc.[3] and the Draft Report, *Development of an Integrity Management Plan to Address the Threat of SCC in Sunoco Logistics Pipelines*, Draft Report, August 31, 2005.

Evaluation of SPLP's System

Kiefner's assessment[6] concluded that the parameters characterizing SPLP's system suggests that SCC is not a significant integrity threat to SPLP's pipeline system. Kiefner also concluded that while neither form of SCC (NN-pH SCC and high-pH SCC) poses a significant threat, the most likely form of SCC on SPLP's system would be NN-pH SCC. These conclusions were based on the following key points:

- High-pH SCC is most commonly associated with gas pipelines, high operating stresses, and temperatures >100°F. High-pH SCC has only been identified in rare instances on liquid product pipelines.

  SPLP's system is almost entirely composed of liquid lines (~18.5 miles of a hydrogen gas line) with typical characteristics of low stress (<60% SMYS) and low operating temperatures (<90°F).

- NN-pH SCC is most common in liquid product pipelines constructed with higher strength steel that operated at levels >60% SMYS. NN-pH SCC is primarily found in locations of localized residual stresses with ineffective cathodic protection. Examples of localized residual stresses include field bends, deformations, hard spots, seam welds, and girth welds. Many reasons exist for ineffective CP, but one of the most significant factors includes the use of coatings that shield CP current, such as polyethylene tape. Much fewer instances of NN-pH SC have been associated with non-shielding coatings, which include coal tar, asphalt, and somastic. Pipe coated with FBE is not considered to be at risk for NN-pH SCC. Pipe coated with extruded polyethylene is also not considered to be at risk for NN-pH SCC because of extruded polyethylene's resistance to damage and disbondment.

  SPLP's system is primarily comprised of liquid pipelines constructed with API Grade B and X42 line pipe with operating stress levels less than 60% SMYS. The predominant coating types used through the SPLP's system are extruded polyethylene, coal tar, and somastic.

SPLP characterized each pipeline segment according to the SCC susceptibility criteria identified in this document. The results indicated several line segments in the EA and WA are potentially susceptible to SCC. These line segments are identified in the Integrity Network Drive and will be monitored as discussed in this document.

SCC Training

One training session for SCC shall be performed each year, at a minimum, by the Eastern and Western Areas. The training session(s) should be provided to field crews that excavate and inspect a pipeline.

The training should include the following topics:

- Industry & SPLP Experiences with SCC;
- Types of SCC (Classical/High-pH SCC, NN-pH SCC);
- Characteristics of SCC (with photographs);
- Causes of SCC; and
- Non-Destructive Examination (NDE) methods to detect SCC when the pipeline exposed.

Field crews that inspect pipe for SCC must be qualified to perform magnetic particle inspection (MPI). If field crews are not qualified, then a qualified contractor may be required to perform NDE.

Assessment & Investigation Requirements

Pipeline segments that are susceptible to SCC shall be classified into two categories:

1. Pipeline segments with confirmed SCC anomalies, and
2. Susceptible pipeline segments with no identified SCC anomalies.

Pipeline Segments with Confirmed SCC Anomalies

The following actions will be performed for all pipeline segments in which SCC has been identified:

- Review of the type, magnitude, and environment of the SCC identified:
  - Type – Was it High-pH SCC or NN-pH SCC?
  - Magnitude – Was the SCC severe enough to have an impact on the integrity of the pipeline? (i.e. Was it *Significant SCC*, as defined by CEPA?)
  - Environment – What were the conditions surrounding the SCC and likely causes for its presence.

- Review of pipeline and operational characteristics relative to industry experience and SPLP susceptibility criteria to identify the following:
  - Pipeline and operational characteristics that may be changed to minimize the growth of new or existing SCC anomalies, and
  - Changes to SPLP's SCC susceptibility criteria.

- Inspection with an integrity assessment capable of detecting SCC, such as hydrostatic testing or an ILI technology capable of detecting SCC-type cracking.

The results of the reviews and assessment will establish the extent of the SCC threat and dictate future efforts, which may include additional integrity assessments and excavations with increased testing and data collection requirements.

<u>Susceptible Pipeline Segments with No Identified SCC Anomalies</u>
Pipelines determined to be susceptible to SCC, but without any confirmed SCC anomalies, will be continuously monitored by trained field crews to look for SCC during routine maintenance and anomaly excavations.

The anomaly excavations will include NDE (MPI at a minimum) of high stress areas, such as deformations and field bends in the pipeline. The results of these inspections (disbonded coating, identification of cracking, etc) will be documented in the Maintenance Records. Any discovery of SCC or other questionable anomaly in the field will require an immediate notification to the Pipeline Integrity Department for additional actions that may be necessary.

The Pipeline Integrity Department will further evaluate all anomalies identified with SCC characteristics to determine the appropriate course of action. The specific location will be evaluated to identify necessary safety precautions, additional data collection requirements, required documentation, and the appropriate repair method. Further consideration will include the anomaly characteristics (if a metallurgical examination is required), the characteristics of the surrounding environment, as well as, further assessment of the pipeline and its operating characteristics.

References

1 *Stress Corrosion Cracking Recommended Practices*, Canadian Energy Pipeline Association (CEPA), 1997.
2 Advisory Bulletin ADB-03-05, *Pipeline Safety: Stress Corrosion Cracking (SCC) Threat to Gas and Hazardous Liquid Pipelines*, Pipeline and Hazardous Materials Safety Administration (PHMSA), 2005.
3 Michael Baker Jr., Inc. Report, *Stress Corrosion Cracking Study*, Final Report, TTO Number 8, Integrity Management Program Delivery Order DTRS56-02-D-70036, January 2005.
4 *Stress Corrosion Cracking (SCC) Direct Assessment Methodology*, ANSI/NACE Standard RP0204-2004.
5 Carson, P. A., B. E. Hansen, J. H. McHaney, *OPS Review Addresses SCC Threat to Pipeline Integrity*, Oil & Gas Journal Online, April 18, 2005.
6 Mackenzie, J., et. al., "Development of an Integrity Management Plan to Addres the Threat of SCC in Sunoco Logistics Pipelines", Draft Document, Kiefner & associates, Inc., August 31, 2005.