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REPORT ON THE USE OF IN-LINE INSPECTION TOOLS FOR THE ASSESSMENT OF PIPELINE INTEGRITY

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Table of Contents

Section:	Page
1.0 INTRODUCTION	1
1.1 Purpose.....	1
1.2 Background.....	1
2.0 PLATTE PIPE LINE	2
2.1 Background.....	2
2.2 Description of Integrity Issue.....	2
2.3 Inspection Tool Selection	3
2.3.1 Field Verification.....	3
2.3.2 TFI Tool Validation Program	4
2.3.3 Implementation	4
2.4 Summary	5
3.0 TEXAS EASTERN SOUTH LINE	6
3.1 Background.....	6
3.2 Description of Integrity Issue.....	7
3.3 Inspection Tool Selection	7
3.3.1 Tool Performance Specifications.....	8
3.3.2 Tool Validation Program	8
3.3.3 Inspection and Assessment	9
3.3.4 Hydrostatic Strength Test and Leak Survey	9
3.4 Summary	9
4.0 CMS PANHANDLE HAVEN 400 LINE.....	11
4.1 Background.....	11
4.2 Description of Integrity Issue.....	12
4.3 Inspection Tool Selection	12
4.3.1 Tool Performance Specifications.....	13
4.3.2 Inspection and Assessment	13
4.4 Summary	14
5.0 TRANS ALASKA PIPELINE SYSTEM.....	15
5.1 Background.....	15
5.2 Description of Integrity Issue.....	16
5.3 Inspection Tool Selection	16
5.3.1 Inspection and Assessment	17
5.3.2 Data Analysis and Integration.....	18
5.4 Summary	22

6.0	OWENSBORO-CATLETTSBURG PIPELINE	23
6.1	Background	23
6.2	Description of Integrity Issue.....	23
6.3	Inspection Tool Selection	26
6.3.1	Tuboscope Slope Deformation Tool Performance	26
6.3.2	PII Transverse Flux Induction Tool Performance	26
6.4	Inspection and Assessment	27
6.5	Summary	28
7.0	OLYMPIC PIPELINE	29
7.1	Background	29
7.2	Description of Integrity Issue.....	31
7.3	Inspection Tool Selection	31
7.3.1	Inspection and Assessment	31
7.3.2	Validation Program	34
7.4	Summary	34
8.0	COLUMBIA GAS	35
8.1	Background	35
8.2	Description of Integrity Issue.....	35
8.3	Inspection Tool Selection	35
8.3.1	Tool Performance Specifications	36
8.3.2	Inspection and Assessment	36
8.4	Summary	37
9.0	CONCLUSIONS AND RECOMMENDATIONS	38
9.1	Conclusions	38
9.2	Recommendation	39
	Appendix A – In-line Inspection Tools	A1
1.0	Magnetic Flux Leakage (MFL) Inspection Tools	A2
1.1	Standard MFL Tool	A3
1.2	High Resolution MFL Tool	A3
1.3	TFI Tool	A3
1.4	Comparison of MFL Technologies	A4
2.0	Ultrasonic Inspection Tools	A5
2.1	Standard UT Tools	A5
2.2	Shear Wave UT Tools	A6

3.0	Geometry Tools	A7
	Appendix B – Case Study Quick Reference Guide	B1

Figures:

Figure 5.1 Example of Integrated Monitoring Overlay	21
Figure A-1 Magnetic Flux Defect Detection	A2
Figure A-2 TranScan TFI Tool	A4
Figure A-3 Ultrasonic Inspection.....	A5
Figure A-4 Standard UT Tool.....	A6
Figure A-5 Elastic Wave UT Tool.....	A6
Figure A-6 Geometry Inspection Tool.....	A7

Tables:

Table 2-1 Platte Pipeline Parameters	2
Table 3-1 South Line Segment Parameters.....	7
Table 4-1 Haven 400 Line Parameters.....	12
Table 5-1 TAPS Line Parameters	15
Table 5-2 TAPS MAOP	16
Table 5-3 In Line Inspection Tools Used on Taps.....	16
Table 5.4 Assessment of Integrity Threats for the Entire Length of the TAPS.....	18
Table 6-1 Owensboro to Catlettsburg Line Parameters	23
Table 6-2 TFI Tool Run Results	27
Table 7-1 Olympic Pipeline System Parameters	30
Table 7-2 Olympic Pipeline System Inspection Summary	33
Table 8-1 Columbia Gas Pipeline Parameters	35
Table 8-2 Tool Performance Specifications	36
Table B-1 Case Study Quick Reference Guide.....	B2

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- EnCana Pipelines Limited (Platte Pipeline)
- Duke Energy (Texas Eastern South Line)
- CMS Energy (Panhandle Haven 400 Line)
- Alyeska Pipeline Service Company (Trans Alaska Pipeline System)
- Marathon Ashland LLC (Owensboro-Catlettsburg Pipeline)
- BP Pipelines (Olympic Pipeline)
- Columbia Gas Transmission Corporation (Richmond, VA to Petersburg, VA Line)

1.0 INTRODUCTION

1.1 Purpose

The purpose of this report is to document the results of various in-line inspections that pipeline Operators have performed. The purpose of these in-line inspections was to locate anomalies in pipe that could fail in the future. OPS has allowed the use of newly developed in-line inspection tools, the integration of data from different inspection tool runs, and the reinterpretation of raw data from previous inspections to assess the integrity of pipelines.

The report contains a series of case studies that illustrate the application of state of the art in-line inspections tools and analysis of data. The case studies document how in-line inspection tools have been used to detect a number of common pipeline defects including: Longitudinal Seam Cracks, Stress Corrosion Cracking, Internal Corrosion, External Corrosion, Top-Side Anomalies, Dents, and Gouges. For each case study, the report includes a discussion of the in-line inspection technology (Appendix A) and integrity assessment methodology used to evaluate the integrity of the pipeline.

The case studies presented in this report were selected because of their innovative use of state of the art inspection technologies and because these programs represent best practices in the use of in-line inspection techniques.

1.2 Background

In response to significant integrity concerns, OPS has required Operators to perform in-line inspection of pipeline segments where a systemic problem with pipeline integrity have been identified. These inspections have been used to identify and locate defects and in-service damage that, if not repaired, could result in a pipeline failure. In many cases an in-line inspection was performed in lieu of hydrostatic testing. On occasion, pipeline Operators have reanalyzed data from previous in-line inspections to locate/identify defect types not identified in the original assessment. The results of a select group of these in-line inspections and data analysis are documented in this report.

2.0 PLATTE PIPE LINE

The Platte Pipe Line, currently operated by AEC Pipelines (USA) Inc. conducted an inspection program using Transverse Field Inspection (TFI) to identify seam weld defects in their 932 mile system. This inspection method was determined to have less impact on pipeline operations and offered greater reliability assurance than hydrostatic testing.

2.1 Background

The Platte Pipe Line System experienced a failure in July 1997 due to a longitudinal seam split initiated by the fatigue growth of hook crack, resulting in a spill of more than 7,000 barrels of crude oil with an estimated incident cost of \$325,000.¹ The failure occurred in a segment manufactured by A. O. Smith that was flash welded.

In response to this accident, the Office of Pipeline Safety (OPS) issued a Corrective Action Order (CAO) that required Marathon Pipe Line (operator at the time of the accident) to verify the integrity of the pipeline through hydrostatic testing or in-line inspection.

Table 2-1: Platte Pipe Line Parameters

Platte Pipeline Parameters	
Commodity	Crude Oil
Total Length	932 miles
Size	20 inches OD
Wall Thickness	0.312 and 0.344 inches
Manufacturer	A. O. Smith
	Miles – 550 miles
	Seam – ERW (flash welded)
	Youngstown
	Miles – 255 miles
	Seam – ERW
	Kaiser
	Miles – 127 miles
	Seam – SAW

2.2 Description of Integrity Issue

The pipe segment that failed in 1997 was manufactured by A. O. Smith Corporation from plate and used a flash welding process to produce the longitudinal seam. The flash welding process is an application of electric resistance welding (ERW) where the joint is heated above its melting point by its resistance to the flow of the electric current. A force is then applied immediately following the heating that causes an expulsion of metal and the formation of a flash. The weld is made simultaneously over the entire area of abutting surfaces by the application of pressure after

¹ As reported to OPS in the Hazardous Liquid Pipeline Accident Report.

the heating. The strength of the joint is affected by the tolerances on the edges of the joint and the cleanliness of the surfaces to be joined.

In the late 1960's and early 1970's, the pipeline industry experienced a number of failures of longitudinal seam welds in ERW pipe. Metallurgical testing of these failures showed that the failures resulted from cracks that grew from defects² in the ERW seams.³

2.3 Inspection Tool Selection

Marathon Pipe Line was required to perform either a hydrostatic test or an in-line inspection, as part of a Corrective Action Order (CAO). There were a number of disadvantages to performing a hydrostatic test, including cost, removal of the pipeline from service, and disposal of the test water. Ultrasonic inspection could have been used but a tool appropriate for the 20-inch line was not available. Recent advances in inspection technology indicated that Transverse Field Inspection (TFI) might be a viable method for detecting defects in ERW seams. Marathon Pipe Line contacted Pipeline Integrity International (PII) to work together to develop a 20-inch Transverse Field Inspection (TFI) in-line inspection tool.

For Platte Pipe Line to establish pipeline integrity based on TFI technology, three items needed to be established:

- The ability of the tool to detect the suspected anomalies on the line.
- Data analysis techniques to sort and discriminate the data collected by the tool.
- The ability to evaluate the suspected anomalies against the established criteria to determine if they required excavation.

Detailed descriptions of the TFI technology, the application of TFI technology, and the development of the TFI in-line inspection tool are included in Appendix A to this report.

2.3.1 Field Verification

To validate the TFI in-line inspection tool in the field, suspected anomalies needed to be confirmed through non-destructive examination (NDE). It was determined that shear wave would be inadequate due to sensitivity issues, so the Flaw Assessment and Sizing Technique (FAST) was selected based on the technique's ability to detect crack-like anomalies. Use of FAST was then proposed to OPS. The FAST technique is a multimodal ultrasonic sensor probe. To validate the FAST technique, a field trial run was conducted. The TFI in-line inspection tool was directed through a section of pipe and suspected anomalies identified. Anomalies detected by the TFI tool and characterized by the FAST method were validated based on destructive examination. Platte initially ran the TFI in-line inspection tool through a 50-mile section of pipe. From the data, 50 TFI signals were selected within 10 excavation sites that represented a variety of signal characteristics. At each site, a section of the pipe was removed to perform destructive

² Defects in ERW seams included misalignment, lack of fusion, hook cracks, hard spot microcracks, and laminations.

³ The Office of Pipeline Safety issued Technical Report – OPS 89-1 “Electric Resistance Weld Pipe Failures on Hazardous Liquid and Gas Transmission Pipelines” in August 1989 to document the problems with ERW pipe.

examination. The destructive examination confirmed the NDE findings and validated the ability of the TFI in-line inspection tool to identify these longitudinal-type anomalies.

2.3.2 TFI Tool Validation Program

The Validation Program was conducted on a 73-mile section of pipe and included the following steps:

- Perform a TFI in-line inspection run
- Analyze the data to select suspected seam weld anomalies
- Excavate all selected sites
- Perform NDE at excavated sites
- Perform pipe replacement based on NDE findings for seam-weld cracks greater than 10% of wall thickness

A total of 262 excavations were performed as part of the Validation Program. From these excavations, 63 anomalies were removed by pipe replacement. Several of the pipe sections were then hydrostatically tested to failure. Of the defects that were hydrostatically tested to failure, only one defect failed at a pressure less than 100% of specified minimum yield strength (SMYS). This defect failed at 1550 psi or 95.9% SMYS. If the pipeline integrity had been validated solely on hydrostatic testing, this defect could have gone undetected due to its size, and would probably have failed at a future date while in-service. The ability to detect smaller defects than can be detected by hydrotest is a major advantage of in-process inspection.

After all the identified defects had been repaired through pipe replacement, the 73-mile section of pipe was hydrotested to within 90% - 95% SMYS with no failures. Because the section passed the hydrotest, there was a high degree of confidence that no critical defects remained in the section following the TFI inspection. This, combined with the detection of numerous defects that failed at greater than SMYS, led the TFI in-line inspection tool methodology to be considered an acceptable alternative to hydrotesting for the entire line.

2.3.3 Implementation

Inspection on the entire line began in late summer of 1998 and continued through March 1999. Inspecting the entire line required 12 cleaning tool runs, 12 geometry tool runs, and 22 TFI tool runs. Each section, approximately 100 miles in length, required 25-30 days of preparation work and was removed from service for approximately 10 days for repairs. Once the data from the TFI in-line tool was received, the data was analyzed to identify excavation sites. After the pipeline was excavated, the external surface was cleaned to perform FAST NDE. The NDE was performed to confirm the presence of a rejectable defect. These defects were then repaired through pipe replacement. A total of 1,262 excavations were made and 381 crack-like defects were removed. The ratio of excavations to defects was 3.3:1. This is high, but the number should improve as the TFI data analysis techniques are refined through additional inspections.

2.4 Summary

The use of the TFI in-line inspection tool on the Platte Pipe Line to detect longitudinal cracks was proven to be at least as effective as hydrostatic testing. It offered the additional benefit of detecting many defects that may “just survive” a hydrostatic test and possibly fail in the future. The TFI in-line inspection tool can be used in-service and reduces pipeline outages. Due to its ability to perform the inspection in-service, with modest cleaning requirements, the costs associated with the TFI in-line inspection tool are less than a hydrostatic test. As TFI in-line inspection runs increase, the accuracy of data assessments should improve to reduce the number of excavations required.

3.0 TEXAS EASTERN SOUTH LINE

A natural gas pipeline in Pennsylvania currently operated by Texas Eastern Transmission Corporation (a division of Duke Energy) conducted an inspection program using Transverse Field Inspection (TFI) to identify seam weld defects in a 22.75 mile segment of the pipeline known as the South Line. This inspection method was selected for its ability to identify ERW seam-weld defects in natural gas pipelines.

3.1 Background

The South Line System was constructed in 1943 as a War Emergency Pipeline (WEP) by the US Government to transport crude oil from the gulf coast to the refineries in the northeast United States. In 1947, the pipeline was sold to Texas Eastern. Texas Eastern converted the pipeline to natural gas service and operated the pipeline at an MAOP of 400 psi. In the 1950's, cathodic protection was added to the line. In 1972, the pipeline was placed in idle service with 50 psi pressure. While in idle service the cathodic protection and other required maintenance was continued. In 1997 and 1998, Texas Eastern implemented the following actions to return the line to service:

- Conducted an Enduro dent tool run to make sure the line was free of obstructions so that an in-line inspection tool could be run safely.
- Conducted a Tuboscope MFL corrosion tool run to evaluate the line integrity.
- Repaired anomalies identified by the Tuboscope MFL corrosion tool.
- Performed a hydrostatic test of the line in accordance 49 CFR 192.505 based on an MAOP of 400 psi. During this strength test one failure occurred (seam split) near Eagle Station. This section was repaired.

Following these actions, the line was returned to service at an MAOP of 400 psi, where it was successfully operated into the year 2000.

In 2000, as part of a project to supply natural gas to a new electric generation station being constructed in Eddystone, PA (also known as the Liberty project) there was a need to raise the MAOP for a segment of the line to the full Class 3 pressure permitted by 49 CFR 192 (656 psi). The segment of the line for which the MAOP was to be raised was the segment from Eagle Station in Eagle, PA to Chester Junction in Brookhaven, PA. Table 3-1 details the design parameters for this segment of the South Line

Table 3-1: South Line Segment Parameters

South Line Parameters, Eagle Station to Chester Junction	
Commodity	Natural Gas
Total Length	22.75 miles
Size	20 inches OD
Material	X42 Grade B
Wall Thickness	0.375 inches
Manufacturer	Youngstown
Seam Type	ERW
Coating	Coal Tar Enamel

3.2 Description of Integrity Issue

During the 1960's, Texas Eastern up-rated a similar pipeline segment that runs from Eagle, PA to Lambertville, NJ based on a hydrostatic test. The MAOP of this line was also increased from 400 psi to 656 psi. The MAOP of this line was up-rated based on a hydrostatic test. During the hydrostatic test, this line experienced a significant number of failures due to splits in the weld seam. The pipes that failed had been manufactured by Youngstown Sheet and Tube using an Electric Resistance Weld (ERW) process to produce the longitudinal seam.

The weld joint in the ERW process is made by heating the plate material above its melting point by using its resistance to the flow of the electric current. A force is then applied following the heating that causes the metal to fuse. The weld is made continuously as the plate is forced through a roller to form a cylinder and the longitudinal-weld seam. The strength of the joint is affected by the tolerances on the edges of the joint and the cleanliness of the surfaces to be joined. Natural gas transmission pipeline companies have experienced numerous failures of pre-1970 ERW pipe manufactured by Youngstown Sheet and Tube.⁴

The segment of the South Line that Texas Eastern wanted to up-rate runs through a highly developed area. As a result of the failures experienced during the strength test of the Eagle, PA to Lambertville, NJ line in the 1960's, Texas Eastern made the decision to perform an in-line inspection of the pipeline for ERW seam defects before conducting the hydrostatic strength test. By identifying and repairing defects prior to conducting the hydrostatic test, Texas Eastern hoped to avoid some of the repair and restoration costs associated with hydrostatic test failures.

3.3 Inspection Tool Selection

Texas Eastern needed an in-line inspection tool that was sensitive to ERW seam defects that could fail during the hydrostatic strength test. Two types of in-line inspection tools have been successfully used to detect defects in a longitudinal weld seam. These include ultrasonic and magnetic flux leakage based tools. The magnetic flux leakage based tools use the Transverse

⁴ Office of Pipeline Safety, Technical Report – OPS 89-1 “Electric Resistance Weld Pipe Failures on Hazardous Liquid and Gas Transmission Pipelines,” August 1989.

Field Inspection (TFI) technology to detect longitudinal defects. Texas Eastern selected the TFI tool since it does not require a couplant and is therefore easily run in natural gas pipelines. Texas Eastern was also interested in gaining experience with this new tool for possible use elsewhere in its system.

The tool selected by Texas Eastern is the same type selected by Marathon Pipeline for the inspection of the Platte Pipe Line. Detailed descriptions of the TFI technology, the application of TFI technology, and the development of the TFI in-line inspection tool are included in Appendix A to this report.

3.3.1 Tool Performance Specifications

Pipeline Integrity International (PII), the company contracted to supply the TFI tool and evaluate the inspection results, made the following statements concerning the detection ability of the tool:

“The system will detect defects in the longitudinal seam weld within a zone extending 2 inches either side of the weld fusion line. Defects propagating from either internal or external will be detected, although the system will not discriminate between internal and external defects. Defects aligned within 30 degrees of the pipe axis will be identified.

Within the seam weld region defined above, defects exceeding 2 inches long and 25% wall penetration will be detected and reported. Defects exceeding 1 inch long and 50% wall penetration will also be detected and reported. Additionally, all reasonable endeavours will be made to detect those defects that lie below these thresholds but above the 100% SMYS failure curve.”

PII also made the following statements with respect to the accuracy of the tool:

“The sizing accuracy is expected to be better than 20% wall thickness for depth and 1 inch for length for 80% of defects.

Features will be located to an accuracy of 4 inches of the distance to the upstream girth weld; this weld will generally be located to within 1% of the distance from the nearest reference point.”

3.3.2 Tool Validation Program

The inspection program conducted by Texas Eastern did not include any independent validation of the tool performance. A validation program was not necessary since the up-rating of the pipeline was to be based on the successful completion of a hydrostatic strength test in accordance with 49 CFR 192.505.

3.3.3 Inspection and Assessment

Inspection on the entire line segment was conducted in June 1999. Inspecting the entire 22.75 mile line segment was accomplished in one run. Once the data from the TFI in-line tool was received, the data was analyzed to identify anomalies for further evaluation. A total of 34 anomalies were identified for excavation. After the pipeline was excavated, the external surface was cleaned to perform ultrasonic shear wave NDE. The external NDE was performed to confirm the presence of a rejectable defect. Texas Eastern identified and repaired 29 rejectable defects through pipe replacement. Two of the 34 anomalies were found to be minor defects that were repaired by grinding and recoated. The remaining three anomalies were found to be minor and were recoated.

Of the 29 defects repaired through pipe replacements, 12 were weld seam defects. Texas Eastern is currently conducting metallurgical studies on the 12 sections of pipe that were removed. These studies are being conducted to determine the types of weld defects that exist and to establish if the defects would have failed during the hydrostatic test.

3.3.4 Hydrostatic Strength Test and Leak Survey

Following the assessment and repair of the anomalies identified by the TFI tool, Texas Eastern conducted a hydrostatic strength test of the line in accordance with 49 CFR192.505. This hydrostatic test provided the basis for raising the MAOP to 656 psi. During the hydrostatic strength test, seven failures occurred in the line. Of these seven failures, six were identified as weld seam defects and the other defect was identified as a line defect. All of the failed sections were replaced.

Texas Eastern reviewed the inspection data to determine if the TFI tool had identified any indications at the locations of the hydrostatic test failures. The TFI tool had identified an anomaly at only one of the failure locations. During the data analysis, this anomaly was classified as a non-critical weld seam anomaly and was not investigated. No anomalies were identified at the remaining six failure locations.

Following the return to service at the higher MAOP, Texas Eastern conducted a leak survey. Two weld seam defects were identified during this leak survey. Neither of these defects were identified by the TFI tool. The defects were described as very small, through wall defects that only permitted gas flow at high pressure. Both of these defects were repaired and the line was then placed in service at the full Class 3 MAOP of 656 psi.

3.4 Summary

The use of the TFI in-line inspection tool on the South Line to detect longitudinal cracks was successful in identifying seam weld defects that could have failed during a hydrostatic strength test. The TFI tool did however fail to identify nine seam defects that failed during the subsequent hydrostatic strength and leak survey. Considering that 12 seam weld defects that were identified by the TFI tool were subsequently selected to be replaced, the success rate for

identifying defects that would fail during a hydrostatic test is, at best, 63%.⁵ Texas Eastern did consider the use of the TFI tool to be a benefit based on the number of failures avoided during the hydrostatic test. It is clear however, that the TFI tool would not have been an adequate substitute for the hydrostatic strength test.

⁵ This is based on the assumption that all of the defects repaired by Texas Eastern would have failed during the hydrostatic test. Texas Eastern is currently conducting an assessment of the replaced sections of pipe to determine if the defect would have failed during the hydrostatic test. This work is not yet complete.

4.0 CMS PANHANDLE HAVEN 400 LINE

The Panhandle Haven 400 line, a natural gas pipeline currently operated by CMS Panhandle, conducted an inspection program using a high resolution Magnetic Flux Leakage (MFL) internal inspection tool to find anomalies associated with the pipe seam, indications located on the top half of the pipe and minor surface corrosion that has been associated with the selective seam corrosion of the past incidents. The In-line Inspection (ILI) tool was used as part of an overall Integrity Assessment Plan for the line.

4.1 Background

The Panhandle Haven 400 line experienced a failure on December 9, 2000 due to a longitudinal seam split along the flash-welded seam of the pipe due to external surface corrosion extending across the weld seam. The pipe rupture extended for a length of approximately 63 feet along the longitudinal seam until it arrested on each end of the upstream and downstream adjacent pipe joints. The weld seam preferential corrosion resulted in an axially oriented, V-shaped groove flaw within the seam. The fracture propagated in a brittle mode and arrested in the two adjacent joints in a ductile mode. There had been a previous incident on this line in 1996.

In response to this accident, the Office of Pipeline Safety (OPS) issued a Corrective Action Order (CAO) that required CMS Panhandle to perform the following actions to verify the integrity of the pipeline:

- A detailed metallurgical analysis of the pipe that failed on December 9, 2000 to determine the cause and contributing factors.
- Running a high resolution MFL, internal inspection tool with emphasis on identifying and evaluating the following: 1) anomalies associated with the pipe seam, 2) indications located on the top half of the pipe, and 3) minor surface corrosion that has been associated with the selective seam corrosion of the past incidents.
- A detailed description of the repair criteria used in the field evaluation of the anomalies that are excavated.
- An evaluation of the line for areas of disbonded coating, including but not limited to, a close internal survey, current interrupted, pipe to soil survey.
- Integration of all available data from internal inspection, including cathodic protection surveys, metallurgical analysis, soil conditions, and historical data.
- Pressure testing of the line segment. In lieu of pressure testing, Panhandle may use an alternative technology capable of identifying cracks and other defects in the longitudinal seam weld, subject to OPS approval.

Table 4-1 details the design parameters for this segment.

Table 4-1: Haven 400 Line Parameters

Haven 400 Line Parameters	
Commodity	Natural Gas
Total Length Analyzed	19 miles
Size	30 inches OD
Material	API 5L Grade X60
Wall Thickness	0.312 inches
Manufacturer	A.O. Smith
Seam Type	ERW (flash welded)
Coating	Coal Tar Enamel

4.2 Description of Integrity Issue

Due to previous issues in the industry with ERW seam splits, the failure mechanism needed to be determined and the integrity verified. The failure mechanism was determined to be general corrosion that intersected and preferentially corroded the longitudinal seam weld. The Integrity Assessment Plan was developed for the line which examined a number of different factors:

- Soil Surveys and Analysis
- In-Line Inspection
- Over the Line Corrosion Control Surveys
- Pipeline Defect Assessment and Repair Development
- Data Integration
- Identification of Locations with Potentially Hazardous Conditions
- Pipeline Excavations, Inspections, and Necessary Repairs
- Develop Plan to Address Sub-Critical Anomalies Over an Elapsed Timeline

The In-Line Inspection was only one of several actions used to verify the integrity of the line. The metallurgical analysis concluded that specific environmental factors must be present for general corrosion to occur that can lead to the preferential attack of the seam. Therefore, the Integrity Assessment Plan was used to determine where the necessary environmental factors were present along the pipeline.

4.3 Inspection Tool Selection

CMS Panhandle selected a high resolution MFL internal inspection tool. Prior to the tool run, historical data from a past standard resolution MFL tool run was integrated with past close interval survey (CIS) data along with environmental and pipeline data to identify six (6) locations for investigation. Three of the sites were remaining anomalies which had been identified by the standard resolution ILI vendor. The three additional sites were selected based on the analysis of the raw data as indications of possible corrosion in the area of the weld seam. The three additional sites were un-graded. None of the six sites selected for investigation occurred in areas with low potentials as identified by the CIS data although all six were investigated. The high resolution MFL ILI tool was selected as the best tool for detecting corrosion that may lead to preferential attack of the Electric Flash Welded (EFW) seam.

Detailed descriptions of MFL technology and the standard and high-resolution MFL in-line inspection tools are included in Appendix A to this report.

4.3.1 Tool Performance Specifications

CMS Panhandle conducted the in-line inspections using the Tuboscope High Resolution MFL in-line inspection tool. Specific performance specifications were not available. However, Tuboscope states the following about their High Resolution MFL tools:

“They incorporate leading-edge technologies to run efficiently, detect anomalies accurately and retain comprehensive, high-resolution data.

- Advanced, permanent neodymium magnetic materials, with the power and efficiency to achieve extended run times
- Hall element sensor devices, for accurate measurement of the absolute magnetic field from low to normal flow velocities
- Optimized sensor spacing, creating the ideal configuration for data accuracy and survey efficiency
- High linear sampling rates, with intervals of one-tenth of an inch (2.5 mm)
- Sophisticated digital recording techniques, allowing 100% data storage, and reconstruction of a complete magnetic signature
- Solid-state recording capabilities, providing virtually unlimited data storage and eliminating the need to filter data due to memory limitations
- High-accuracy distance measuring, using Tuboscope's industry-leading methodology to pinpoint areas of interest
- Time-based above ground marking system, which provides essential and extremely accurate referencing for reliable location of anomalies

Complete integrated sensing capabilities, providing ID and OD metal loss identification, as well as the ability to log information on product temperature, pressure, tool orientation, and other parameters as needed.⁶”

4.3.2 Inspection and Assessment

The high resolution MFL ILI tool was run in the Panhandle Haven 400 line in December 2000. The data was analyzed to identify and size anomalies down to 3% metal loss and to identify the EFW seam orientation. Panhandle reports that standard analysis techniques only identify and size anomalies greater than 15-20% of the pipe wall thickness in depth.

Excavation of the six additional sites identified by the high resolution MFL tool confirmed the presence of anomalies of a size and orientation predicted by the data analysis. Based on engineering analysis, Panhandle determined that all of the investigated anomalies were not significant enough to affect the pipeline integrity and repairs were not made. Panhandle installed

⁶ Information from the Tuboscope web site, <http://www.tuboscope.com/pipeline/Tools/HR/hr.html>

full encirclement sleeves at two locations for future removal and research. These two sites were selected based on corrosion being near or intersecting the seam.

4.4 Summary

Panhandle stated the following conclusions based on the investigations:

- “In-line inspection, combined with data integration of environmental conditions, close interval survey data, and pipeline data, was confirmed as the best technique for identifying both hazardous conditions, as well as, locations where hazardous conditions may evolve during future operations.”
- “The high resolution circumferential MFL tool successfully detected and measured low grade anomalies (down to 3% metal loss), reliably identified the location of the seam, and indicated where metal loss indications coincided with the seam.”
- “One site in soil identified as conducive to preferential attack of the EFW seam (near the incident locations, confirmed by the soil survey) had evidence of the initiation of crevice-like corrosion in the seam.”
- “Two other investigations discovered corrosion near and across the seam with no evidence of crevice initiation. These sites were in areas outside of the soil identified as conducive to preferential attack of the EFW seam.”
- “The remaining nine inspections did not detect corrosion in the seam, and, in each case upon site investigation, the findings confirmed the information predicted by the in-line inspection and data integration.”

An Integrity Assessment Plan was developed in order to verify and ensure the integrity of the line in lieu of a pressure test. The Plan relied on performing inspections and analysis to identify conditions that lead to corrosion and subsequent preferential corrosion in the seam.

Based on published reports written in 1991 and 1993 by Battelle and SWRI respectively, Panhandle has concluded that a “crack identifying” tool would not be an effective tool in improving system integrity. Therefore, the Plan relied on investigating areas where a corrosive environment could exist at the weld zone.

The high resolution MFL in-line inspection tool combined with the data analysis technique was successful in identifying and grading anomalies down to 3% metal loss. This is an improvement over the typical threshold of 15-20% metal loss. The orientation of the seam was also identified by the tool to find the locations where the metal loss coincided with the seam.

5.0 TRANS ALASKA PIPELINE SYSTEM

The Trans Alaska Pipeline System (TAPS), currently operated by Alyeska Pipeline Service Company (Alyeska), initially began their inspection program to identify differential settlement due to melting permafrost that had resulted in two leaks in 1979. Alyeska has also identified a problem with external corrosion. Alyeska has conducted 58 separate inspection runs using eight different tool designs between 1978 and 2001. As part of their inspection program, Alyeska has integrated inspection data from multiple inspections to develop an Integrity Management System.

5.1 Background

The TAPS consists of an 800-mile (1287 km), 48-inch (122 cm) diameter pipeline extending from Prudhoe Bay to Valdez, Alaska. A majority of the pipeline route is underlain by permafrost, which when thawed may subject pipeline structures to subsidence. Therefore 420 miles (676 km) of the pipeline was constructed aboveground to avoid the adverse effects of thaw-settlement. Conventional buried pipeline construction is used for 376 miles (605 km) in thawed or thaw-stable ground, with the remaining 4 miles (6.4 km) refrigerated, insulated and buried in thaw-unstable ground.

The TAPS began operation in June of 1977, following three years of construction. Table 5-1 details the design parameters for this system. Table 5-2 details the MOP based on the pipe grade and wall thickness.

Table 5-1: TAPS Line Parameters

TAPS Line Parameters	
Commodity	Crude Oil
Total Length Analyzed	800 miles
Size	48 inches OD
Material	API 5L Grade X60, X65, and X70
Wall Thickness	0.562 and 0.462 inches
Manufacturer	NKK, Nippon, Sumitomo, Ilva
Seam Type	DSAW, includes 100 miles of spiral welded pipe
Coating	Fusion Bonded Epoxy, tape overcoat

Table 5-2: TAPS MOP

Pipe Wall Thickness (in)	Pipe Grade	MOP (psig)
0.462	X60	832
0.462	X65	901
0.462	X70	970
0.562	X60	1012
0.562	X65	1096
0.562	X70	970 (Atigun Reroute)
0.562	X70	1180

5.2 Description of Integrity Issue

In 1979, TAPS experienced two leaks that were related to differential settlement due to melting permafrost. Following these failures, Alyeska routinely ran internal inspection tools of various types to monitor locations of known problems and to identify new occurrences. In 1987, external corrosion was also identified as an integrity issue based on a run of an improved MFL corrosion tool.

5.3 Inspection Tool Selection

Since Alyeska began their Integrity Management Program in 1978, they have conducted 58 separate in-line inspection runs using eight different tool designs. Each tool was selected to provide the best possible results based on the available tools at the time of the inspection for the suspected problem. Table 5-3 lists the eight tools and the year(s) they were used on TAPS.

Table 5-3: In-Line Inspection Tools Used on TAPS

Tool	Year(s) Used
TDW Kaliper	1979, 1981
Vetco MFL Corrosion	1978, 1987
Vetco Corrosion/Deformation	1981, 1987
Vetco Deformation	1987, 1998
IPEL (Pipetronix) MFL Corrosion	1987, 1988
IPEL (Pipetronix) HRMFL Corrosion	1992
NKK Ultrasonic Corrosion	1989, 2001
BJ Inertial Navigation Curvature	1992, 2000

Detailed descriptions of the MFL technology and the standard and high-resolution MFL in-line inspection tools are included in Appendix A to this report. Appendix A also includes information on standard slope deformation in-line inspection tools.

5.3.1 Inspection and Assessment

Alyeska has performed over 800 excavations and physical examinations of the pipeline in response to ILI results and as part of other maintenance activities. The in-line inspections and excavations have provided significant knowledge about the types of defects that can occur on the TAPS. Alyeska has performed a critical review of this information to identify potential integrity issues and evaluate the risk associated with each.

Table 5.4 provides a listing of integrity issues observed over the operating life of the pipeline, along with an estimate of the numerical magnitude of the occurrence of these defects.

In addition to excavations and in-line inspection tool indications, Alyeska has conducted screening risk assessments or informational analysis to systematically assess integrity-related threats. Corrosion, mechanical defects, washout settlement, and excavation damage are the primary integrity-related issues mitigated by integrity testing and account for approximately 44 percent of the total perceived risk on the pipeline. The use of ILI identifies these potentially threatening defects, so they can be assessed, inspected, and repaired if necessary.

Table 5.4: Assessment of Integrity Issues for the Entire Length of the TAPS⁷

Observation	Number of Observations/Locations
External corrosion	25,000 joints with indications > 50 mils
Internal corrosion	250-300 bottom of pipe indications
Microbiologically-influenced corrosion	5-10 external indications
Girth-weld corrosion	<10 significant locations
Seam-weld corrosion	2 observed in heat affected zone at animal crossings
Narrow axial external corrosion	2
Dents	100 (>2%) constrained rock dents on bottom of pipe
Mechanical damage	10-100 repaired, includes dents with metal loss
Fatigue	None known
Corrosion fatigue	None known
Stress corrosion cracking	1 (sleeved), unique circumstances
H ₂ S (hydrogen-induced cracking/ stress oriented, hydrogen-induced cracking)	None known
Curvature	24 (>85% critical curvature)
Insulated animal crossing	2 of 23 non-refrigerated crossings had significant base metal corrosion; 4 had undercutting of double submerged arc weld
Monitoring rods	~ 2,200 monitoring rods, potential for corrosion at cadweld
River weights	~ 7,000 locations, potential for longitudinal corrosion
Casings	32 locations – potential for shorted casing corrosion
Sleeves	100 locations – potential for under sleeve corrosion
Structural overfill	150 locations – potential for elevated curvature
Vandalism/ bullet strikes	10 – 50 locations observed during line-walk

5.3.2 Data Analysis and Integration

Alyeska has developed and implemented a comprehensive Integrity Management Program (IMP). The IMP is based on the requirements of 49 CFR 195.452 and API Standard 1160. Key parts of this program are the data management and risk management systems. These systems are designed to support the gathering, review, and integration of pipeline integrity data and perform a line-wide risk assessment. The overall objectives of the IMP is to:

- Integrate critical integrity-related data
- Support integrity maintenance decisions in a timely, accurate, secure, and readily accessible manner
- Assess operational and environmental risks on the TAPS

⁷ Data as of March 2002

- Prioritize maintenance resources in high consequence and other areas commensurate with the risks perceived

The data management and risk management systems are based on, and contain “all available information” associated with Alyeska’s operating history, the regulations, and industry practice. This body of knowledge includes but is not limited to the following:

- Pipeline configuration data contained in the as-built engineering database
- Screening risk assessments completed on 5-year intervals (1991, 1995, and 2001)
- ILI experience with 58 ILI runs as of March 31, 2002
- Direct examination of the pipeline in excavations at over 800 locations as of March 31, 2002
- Leak experience, based on eight pipeline leaks over 50 bbls as of March 31, 2002
- RCM analysis of the TAPS mainline
- Defects defined by 49 CFR 195.452 (h)
- Defects defined by industry practice, ASME B31.4, and API Standard 1160

Alyeska’s risk management system encompasses all aspects of the company’s day-to-day business, such as pipeline and facility integrity, operations and maintenance, safety, and environment. The system:

- Identifies hazards and risks
- Evaluates and assesses the risks
- Recommends remedial or mitigating actions to reduce the risks to an acceptable level
- Complies with appropriate regulations and standards

5.3.2.1 Data Management System Description

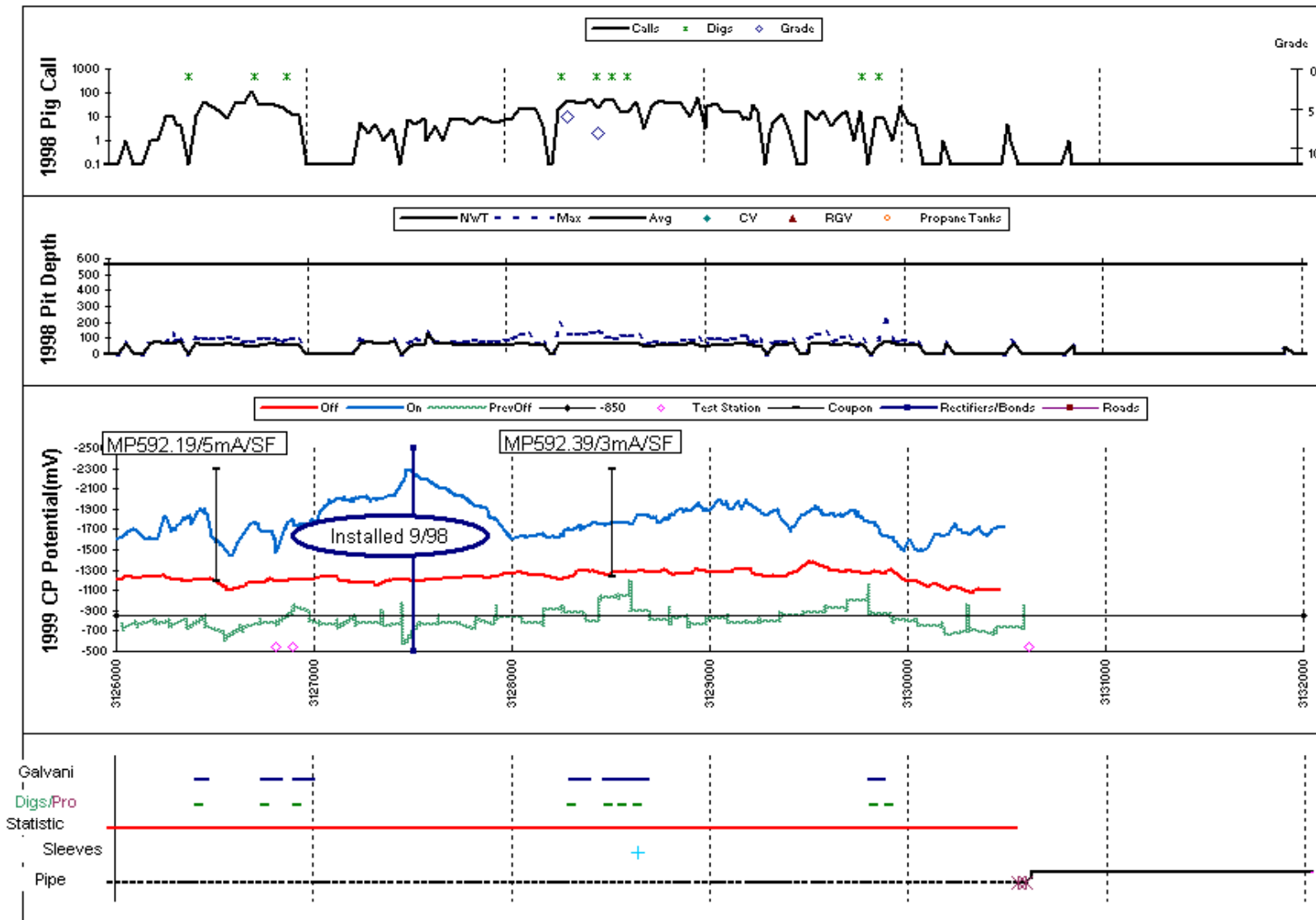
Alyeska’s data management system is designed to support all required integrity-related maintenance decisions in a timely, accurate, secure, and readily accessible manner. Operating experience is supplemented by risk assessments in order to define pipeline failure modes and required maintenance decisions. The data management system is capable of maintaining records of decisions. The following methods, processes, and procedures describe Alyeska’s data management system.

Alyeska has developed an Oracle[™]-based, central database repository to store the large volume of data gathered over its operating history and provide a secure environment to maintain historical data. In addition to the central repository, two customized portals (entry points into the data system) have been developed to provide data entry, query, and analysis capabilities. These portals, referred to as Engineering Data Management/Corrosion Data Management (EDM/CDM), provide secure data entry and allow Alyeska engineers easy access to information needed to make decisions from their desktop or portable computers. The following is the key information contained in the data management system:

- Location of High Consequence Areas and could-affect pipe segments

- As-built survey information for significant features found along the pipe
- Pipe design and construction information by joint, including the location of all welds, seam type, coating type and wall thickness, yield strength, maximum operating pressure, and manufacturer
- Monitoring history of the above-ground system, including the vertical support members (VSMs) and heat pipes
- Monitoring history of the below-ground pipe, including thermistor readings and monitoring rod data
- Cathodic protection (CP) system and monitoring history, including test station and CP coupon readings, rectifier readings, and close interval survey data
- Corrosion pig data
- Dent and curvature pig data
- Pipe investigation history and results, including wall thickness found in the field, sleeve locations, and derates in operating pressure
- Corrosion inhibitor program and associated internal coupon monitoring results
- Significant features that may increase risk such as river weights, floodplains, etc.
- Graphic representation of integrated data – The integrated monitoring overlays (Figure 5.1) is one example of Alyeska's ability to stack (integrate) and graphically display data for improved analysis and planning. The overlays provide graphical representation of corrosion pigging data, CP system and monitoring data, and significant features overlaid to the same scale for every mile of below-ground pipe. Other data sets are routinely stacked on an ad hoc basis for analysis purposes without the graphic component. As part of continual improvement further data stacking may be implemented.

Figure 5.1 Example of Integrated Monitoring Overlay



The engineering portal (EDM) provides access to two major classifications of data, reference data and pipe monitoring data. Reference data includes configuration data gathered during pipeline construction and subsequent maintenance activities. Monitoring data includes data gathered on the above-ground support assemblies, elevation surveys, and thermistor readings.

The corrosion portal (CDM) provides access for tracking and analyzing corrosion-related monitoring, including test stations and CP coupon monitoring, bi-monthly rectifier performance, corrosion pig calls, and the corrosion investigation program. Additional monitoring data includes tank inspection results, the internal coupon monitoring program, and inhibitor injection.

5.3.2.2 Data Analysis

Alyeska's data management system is designed to support all integrity-related maintenance decisions required by Alyeska's IMP. The analysis of all data collected is in accordance with Alyeska MP 166 "System Integrity Monitoring Program Procedures." The results of the analysis are used to reach one of three decisions described below:

- **Remediation required** - Two conditions must occur to determine that repair/mitigation is required: (1) the anomaly does not meet the minimum standard as set forth by Alyeska procedures and (2) adequate information is available to make a decision.
- **Engineering evaluation required** - If (1) the anomaly has not yet reached the level requiring immediate action but has reached a level requiring further analysis, or (2) adequate information is not yet available to determine that remedial action is required, then further engineering analysis or data acquisition is required.
- **No remediation required** – If an anomaly does not meet the criteria cited above, repair/mitigation or further engineering analysis is not needed

The locations of anomalies requiring either remediation or engineering evaluation are maintained in EDM/CDM. Locations requiring remedial action are additionally tracked in Alyeska's maintenance management system (Passport), in accordance with procedures outlined in Alyeska MP-167, "Maintenance System Manual." At the end of each year, Alyeska reviews the status of recommended maintenance and overall success of the program and updates the procedures to reflect changes, if any.

5.4 Summary

The Integrity Management Program developed by Alyeska is unique in its integration of in-line inspection data from multiple inspections, engineering data, cathodic protection data, and other inspection data. The data management system is a key feature of Alyeska's comprehensive risk management approach to maintaining line integrity.

6.0 OWENSBORO-CATLETTSBURG PIPELINE

A crude oil pipeline in Kentucky, currently operated by Marathon Ashland LLC, established an in-line inspection program using Slope Deformation and Transverse Field Induction (TFI) tools to identify dents and cracks in dents respectively. This inspection program was initiated after a failure occurred due to near neutral stress corrosion cracking in a shallow dent.

6.1 Background

In January of 2000, Marathon Ashland's Owensboro to Catlettsburg 24 inch crude oil pipeline failed and released crude oil in the Winchester, Kentucky area. The point of failure occurred in a deformation located in the 6:00 position on the pipeline. Analysis of the failure indicated that it occurred as a result of near neutral stress corrosion cracking in a shallow dent. Because of the existence of other shallow dents⁸ in similar environmental conditions, the MOP was reduced and an inspection program was implemented under OPS Corrective Action Order, CPF No. 220005011-H.

The Owensboro to Catlettsburg 24 inch crude oil pipeline was constructed in 1973. Table 6-1 details the design parameters for this segment.

Table 6-1: Owensboro to Catlettsburg Line Parameters

Owensboro to Catlettsburg Line Parameters	
Commodity	Crude Oil
Total Length	265 miles
Size	24 inches OD
Material	API 5L X-52
Wall Thickness	0.250 inches
Manufacturer	Stupp, Republic, Stelco
Seam Type	ERW and DSAW
Coating	Asphalt Enamel

6.2 Description of Integrity Issue

The failure that occurred on the Owensboro to Catlettsburg 24 inch crude oil pipeline was due to near neutral stress corrosion cracking (SCC) in a shallow dent. Stress corrosion cracking is a type of environmentally-assisted cracking failure mechanism. Environmentally-assisted cracking occurs when the environmental conditions surrounding a component or structure assist in the formation of cracks. These cracks can ultimately lead to the failure of the component or structure.

Corrosion is generally a chemical or electrochemical reaction that results in the removal of sound base metal. In SCC, stress assists the corrosion process and, if sufficiently high, propagates

⁸ Marathon Ashland LLC has defined a shallow dent as be less than 1/2 inch deep.

cracks through the base material. Stress corrosion cracking has been observed in a number of different materials and environmental conditions.

There are three conditions necessary for stress corrosion cracking to occur:

- Potent Environment
- Tensile Stress
- Susceptible Material

All three conditions must exist simultaneously for stress corrosion cracking to occur. If any one of the three conditions can be eliminated, stress corrosion cracking can be prevented.

Potent Environment

A potent environment at the pipe surface is necessary for both stress corrosion cracking and other types of corrosion. There are four primary factors that contribute to a potent environment for stress corrosion cracking: pipe coating, cathodic protection, soil conditions, and pipe temperature.

Pipeline operators have long coated pipelines to prevent corrosion. These coatings will protect the pipe from stress corrosion cracking as long as they remain intact and isolate the pipe from the environment. It is also common practice to cathodically protect pipelines to prevent corrosion. Cathodic protection can, in the absence of a coating or in the case of a damaged coating, prevent stress corrosion cracking. However, disbonded coatings can act as barriers to cathodic protection allowing stress corrosion cracking to occur beneath the coating.

The soil condition around the pipe is an important factor in developing a potent environment. Some soil types can damage coatings and expose the steel to the ground water. Soil drainage is also important, since moisture aids the development of stress corrosion cracking. Alternating wet/dry soils are typically the worst soil condition for stress corrosion cracking. An additional factor in establishing a potent environment for SCC is the soil chemistry. The pH of the soil and the presence of certain chemicals in the soil also influence SCC.

Tensile Stress

The second factor necessary for stress corrosion cracking to occur is an applied tensile stress. The tensile stresses necessary for stress corrosion cracking can be created by a number of sources. Tensile stresses in pipes can be classified as residual (resulting from the fabrication and installation of the pipeline) or applied (resulting from applied internal and external loads). Research has demonstrated that stress corrosion cracking is more likely to occur at higher tensile stress levels, although there is no threshold stress below which cracking will not occur. Sources of tensile stress include:

Residual

- Contraction of weldments
- Bending or formation during fabrication
- Installation induced strain

Applied

- External mechanical loading
- Internal operating pressure
- Cyclic loading
- Strain rate
- Thermal expansion

Tensile stresses can be either circumferential or longitudinal based on the direction of the stress.

Circumferential

- Internal operating pressure (hoop stress)
- Residual stress created during fabrication
- Bending stresses in out-of-round pipes from internal pressure
- Localized stresses from weld joints, mechanical gouges, corrosion pits, dents, and other stress concentrations
- Secondary stresses from soil movement
- Thermal differential stresses

Longitudinal

- Internal operating pressure (one third to one half the circumferential stress)
- Mechanical loads that bend the pipe and introduce high longitudinal stresses; includes soil settlement and other soil movement
- Stresses due to temperature changes along the axis of the pipeline

Susceptible Material

A number of research studies have been conducted to determine the susceptibility of various pipeline materials to stress corrosion cracking. Through this research and operating experience, it has been shown that all of the commonly used pipeline steels are susceptible to stress corrosion cracking. A number of material characteristics have been studied to determine if they influence the susceptibility of the pipeline material to stress corrosion cracking. The characteristics studied include the following:

- Type of steel
- Grade of steel
- Steel composition
- Cleanliness of steel
- Surface condition

The type and grade of steel do not significantly change the susceptibility of the pipeline to stress corrosion cracking. The problem of stress corrosion cracking can be more significant in the higher strength steels due to the smaller critical crack size that will result in a failure. The susceptibility of steel can be reduced with the addition of chromium, nickel and molybdenum.

The addition of these elements in quantities sufficient to reduce the susceptibility of the steel to stress corrosion cracking is generally cost prohibitive.

Cleanliness and surface condition can also influence the susceptibility of a pipeline steel to stress corrosion cracking. Non-metallic inclusions and the presence of mill scale on the surface of the pipe have both been shown to increase the susceptibility of the pipeline steel to stress corrosion cracking.

6.3 Inspection Tool Selection

Marathon Ashland initially selected a Tuboscope Slope Deformation in-line inspection tool based on its ability to detect dents. Using this tool, 601 anomalies were identified in the entire 265 mile segment. Due to the large number of anomalies found using the Slope Deformation tool, Marathon Ashland chose to reinspect the line using an alternate inspection technology to identify geometric anomalies that contained another type of anomaly. The Transverse Field Induction (TFI) was selected because of its ability to detect axially oriented cracks within dents.

The TFI tool selected by Marathon Ashland is the same type of tool selected by Marathon Pipeline for the inspection of the Platte Pipe Line. A detailed descriptions of the TFI technology, the application of TFI technology, and the development of the TFI in-line inspection tool are included in Appendix A.

6.3.1 Tuboscope Slope Deformation Tool Performance

Based on performance claims by the manufacturer, the Tuboscope Slope Deformation tool used by MAPL should be able to detect all deformations with a depth greater than $\frac{1}{4}$ inch. The manufacturer's performance claims are generally accepted in the industry and were not independently verified by MAPL for this inspection. Appendix A includes information on standard slope deformation in-line inspection tools.

6.3.2 PII Transverse Flux Induction Tool Performance

In June of 2000, pull-through testing of the Transverse Flux Induction⁹ tool was conducted by Battelle. This testing was jointly funded by MAPL and other interested parties. The goal was to determine if the TFI technology could locate features in dents, specifically cracks.

The results of the pull-through tests were favorable. The tool produced spiked signals from the cracks and gouges in the deformations contained in the test spool. The tool was able to distinguish between plain dents and dents containing cracks. Simulated cracks were 1.5 inches long and 0.125 inches deep. Features were located with an accuracy of 4 inches of the distance to the upstream girth weld; this weld is generally located to within 1% of the distance from the nearest reference point. The test spool also included actual defects previously removed from the pipe.

⁹ Also know as Transcan Wave Tool technology from PII

6.4 Inspection and Assessment

MAPL decided to run the TFI tool to inspect the entire 265 mile system. The tool collected data in 40-mile segments of the 24 inch pipeline. The data is composed of seven (7) segments for the 265 mile length. The anomalies identified by TFI inspection were categorized as follows:

- Deformations
- Deformations with Linear Indications
- Deformations with Corrosion
- Deformations with Mechanical Metal Loss
- Deformations associated with a Girth Weld
- Deformations associated with a Seam Weld
- Deformations Large
- Linear Indications

Table 6-2 documents the results of each run.

Table 6-2: TFI Tool Run Results

Run	Starting Mile Post	Ending Mile Post	Total Deformations	Total Deformations Containing Anomalies
1	0	40	279	14
2	40	80	479	12
3	80	120	875	23
4	120	160	536	23
5	160	200	1023	65
6	200	240	557	50
7	240	265	473	23
System Totals			4222	210

The 23 deformations containing anomalies from Run 4 (Mile Post 120 to Mile Post 160) were investigated first. They were excavated, analyzed and repaired. Several of the items were cut out of the line and sent to a lab for a more detailed analysis. Based on the analysis, the TFI tool signals appeared similar for laminations, corrosion, cracks or sharp dents. This made it difficult to determine an exact identity for indications detected by the tool. The signals are apparent in both deformations and normal pipe. The tool did not provide any information on the deformation depth. The items identified by TFI had to be excavated and analyzed using visual and ultrasonic testing to characterize them. Excavation showed that the TFI tool found items with features and the majority of these features required a sleeve. Based on the results obtained in Run 4, the items identified in the remaining 6 runs were excavated and assessed to determine the required repair.

6.5 Summary

Use of the Tuboscope Slope Deformation in-line inspection tool alone was not sufficient to identify geometric anomalies of concern due to the large number of geometric anomalies that existed within the system. The PII Transverse Flux Induction tool was able to identify other anomalies within geometric anomalies, however the analysis could not discriminate between types of other anomalies. Use of the PII Transverse Flux Induction tool significantly reduced the number of anomalies to be investigated from 4222 to 210.

7.0 OLYMPIC PIPELINE

Olympic Pipeline Company conducted in-line inspections using Geometry In-Line Inspection and High Resolution Magnetic Flux Leakage Tools. Following the inspections, Olympic Pipeline Company conducted a test program to determine a reasonable size dent that could safely remain in the system without compromising line integrity. This case study describes the pipeline inspections and the test program implemented by Olympic Pipeline Company.

7.1 Background

On June 10, 1999, a failure occurred in a 16-inch petroleum products pipeline that was part of the Olympic Pipeline system operated by Equilon. The failure occurred in the Ferndale to Allen segment of the Olympic system at Mile Post 16, in the city of Bellingham, Washington. The point of failure was in a dent located in the 12:00 position on the pipeline. Analysis of the failure indicated that it occurred as a result of fatigue cracking in a dent from third party damage. As a result of the failure, OPS issued a Corrective Action Order (CAO) requiring Olympic Pipeline Company to reduce the MOP of the Ferndale to Allen segment and to implement an inspection program on the Olympic Pipeline system¹⁰.

The Olympic Pipeline system is comprised of pipeline segments ranging in size from 6 to 20-inches in diameter. The total length of the Olympic system is 397.6 miles. The system transports refined petroleum products from four refineries near Ferndale, Washington and Anacortes, Washington to the Seattle, Washington and Portland, Oregon areas. The Olympic pipeline system was constructed between 1965 and 1973. With the exception of a seamless 6-inch pipeline segment, the system was constructed of ERW pipe manufactured by US Steel, Lone Star, and Kaiser. The line is cathodically protected and coated with coal tar enamel. Table 7-1 summarizes design information for the 11 segments of the Olympic pipeline system.

¹⁰ OPS issued Corrective Action Order CPF No. 59505-h on June 18, 1999.

Table 7-1: Olympic Pipeline System Parameters

Segment	NPS (inches)	Length (miles)	Year Built	Pipe Specification	Wall Thickness	MAOP ¹ (psi)	Longitudinal Weld	Manufacturer	Coating
Cherry Point to Ferndale	16	5.0	1971	5LX-52	0.312	718.0	High Frequency ERW Low Frequency ERW Low Frequency ERW	US Steel Lone Star Kaiser	Coal Tar
Ferndale to Allen	16	41.1	1965	5LX-52	0.312	1370.0	High Frequency ERW Low Frequency ERW Low Frequency ERW	US Steel Lone Star Kaiser	Coal Tar
Anacortes to Allen	16	10.3	1971	5LX-52	0.312	1428.0	High Frequency ERW Low Frequency ERW Low Frequency ERW	US Steel Lone Star Kaiser	Coal Tar
Allen to Renton	16	75.6	1965	5LX-52	0.312	1298.0	High Frequency ERW Low Frequency ERW Low Frequency ERW	US Steel Lone Star Kaiser	Coal Tar
Allen to Renton	20	76.2	1973	5LX-52	0.250	928.0	High Frequency ERW	US Steel	Coal Tar
Renton to Portland	14	147.6	1965	5LX-52	0.281	1426.0	High Frequency ERW	US Steel	Coal Tar
Renton to Seattle	12	12.4	1965	5LX-52	0.281	1440.0	High Frequency ERW	US Steel	Coal Tar
Renton to SeaTac	12	5.5	1970	5LX-52	0.281	1440.0	High Frequency ERW	US Steel	Coal Tar
Tacoma Junction to Tacoma DF	8	3.9	1965	5LX-52	0.188	1440.0	High Frequency ERW	US Steel	Coal Tar
Olympia Station to Olympia DF	6	15.5	1965	5LX-52	0.188	1440.0	Seamless	US Steel	Coal Tar
Vancouver Junction to Vancouver DF	12	4.5	1967	5LX-52	0.281	1440.0	High Frequency ERW	US Steel	Coal Tar

¹ MAOP is the lesser of the MOP of the line pipe, the MOP of the line pipe fittings and flanges, or the maximum operating pressure based on system hydraulic limitations.

7.2 Description of Integrity Issue

The failure that occurred on the 16-inch Ferndale to Allen segment at Mile Post 16 was the result of third party damage and subsequent degradation in service. As a result of the failure, and the high population density areas through which the portions of the pipeline are routed, concerns were raised about the integrity of the Olympic Pipeline system¹¹. The increased development and construction activity along the pipeline right-of-way increased the risk of additional third party damage that could fail inservice. The inspection program implemented by Olympic Pipeline Company was specifically developed to identify and assess third party damage that may have occurred along the Olympic system.

7.3 Inspection Tool Selection

The Office of Pipeline Safety (OPS), in the CAO, required Olympic Pipeline Company to conduct internal inspection tool surveys using the best available technology to detect defects of the type that led to the June 10, 1999 failure. In accordance with the CAO, Olympic Pipeline Company prepared a plan to conduct internal inspections of the Olympic Pipeline system and submitted the plan to OPS for approval.

In the approved plan, Olympic proposed to conduct inspections using both a Geometry ILI tool and a High Resolution Magnetic Flux Leakage (MFL) ILI tool. The Geometry ILI tool was selected to identify changes in the roundness of a pipeline that could be caused by dents and other external force damage. The High Resolution Magnetic Flux Leakage (MFL) ILI tool was selected to identify potential pipe manufacturing defects, metal loss caused by external forces, and internal and external pipeline corrosion.

The results of the inspections with both tools were to be combined to identify defects of the type that led to the June 10, 1999 failure. Detailed descriptions of the MFL technology and the high-resolution MFL in-line inspection tool are included in Appendix A to this report. Appendix A also includes information on standard geometry in-line inspection tools.

7.3.1 Inspection and Assessment

The Olympic Pipeline Company conducted internal inspections using the Geometry and MFL ILI tools during the period May through July 2000. Both the Geometry and MFL ILI tools used by Olympic Pipeline Company were manufactured by Pipeline Integrity International (PII). The analysis of the inspection data was conducted by PII and reviewed by Olympic Pipeline Company.

The inspection plan developed by Olympic Pipeline Company included the establishment of a depth criterion for evaluation and repair of dents. At the time of the development of the Olympic

¹¹ Additionally, integrity concerns were raised because portions of the Olympic system are constructed of pre-1970 ERW pipe manufactured by Lone Star. This piping has been shown to be susceptible to seam splits. These concerns were also addressed by Olympic's inspection program but are not the subject of this case study.

inspection plan, an industry standard for an acceptable depth of a dent did not exist.¹² The Olympic plan, approved by OPS, required that dents and defects greater than 0.6% (0.10 inch for the 16-inch line) be excavated and evaluated. Table 7-2 includes a summary of all defects identified and the disposition of the defects.

¹² Subsequent to the inspection program undertaken by Olympic, API Standard 1160, "Managing System Integrity for Hazardous Liquid Pipelines" established a maximum dent depth of 2% for pipe diameters greater than or equal to NPS 12 and 0.25 inches for pipes less than NPS 12.

Table 7-2: Olympic Pipeline System Inspection Summary

Segment	Defects Identified by ILI ¹	Cut Out	Sleeve (Clock Spring)	Recoat	Incomplete ³	Temporary Sleeve	Eliminated ⁴	No Action ⁵
Cherry Point to Ferndale	3	3	0	0	0	0	0	0
Ferndale to Allen	38	19	6	9	0	4	0	0
Anacortes to Allen	3	0	1	2	0	0	0	0
Allen to Renton	86	54 ²	17	5	2	0	8	0
Allen to Renton	34	8	3	17	2	4	0	0
Renton to Portland	27	2	2	16	0	4	3	0
Renton to Seattle	2	0	0	2	0	0	0	0
Renton to SeaTac	1	0	0	0	1	0	0	0
Tacoma Junction to Tacoma DF	3	2	0	1	0	0	0	0
Olympia Station to Olympia DF	12	2	0	8	0	0	0	2
Vancouver Junction to Vancouver DF	6	0	0	6	0	0	0	0
Totals	215	90	29	66	5	12	11	2

¹ Includes all defects meeting the 0.6% depth criterion established in the inspection plan.

² Since this line was shutdown, more defects were cutout than would have been if the line had remained in service.

³ Action on these defects has not yet been completed.

⁴ Upon reanalysis of the data, these defects were found not to meet the criterion for follow-up evaluation and were eliminated from corrective action.

⁵ These defects were located in above ground piping that was inspected w/o coating removal. Because the defects were determined to be acceptable and the coating was not removed, no action was required.

7.3.2 Validation Program

Following the inspections, excavations and removal of defects, Olympic Pipeline Company conducted a test program to verify the adequacy of the inspection program. Three test articles were created from 21 cutouts containing defects with each article comprised of seven cutouts. The seven cutouts were welded together with end caps. The defects contained in the test articles ranged in size from 0.63% OD (0.10 inches) to 2.38% OD (0.38 inches). The defects included dents with gouges, dents with minor cracks, and one 0.69% OD smooth dent.

Each of the three test articles was subjected to cyclic pressure testing. The pressure ranged from 640 psi to 1460 psi. A minimum of 50,000 cycles was conducted on each test article to correspond to a service life of thirty years. No failures occurred during the cyclic pressure test.

Following the cyclic pressure test, the three test articles were welded together and subjected to a hydrostatic pressure test at 100% SYMS (2020 psi). Again no failures occurred. Following the hydrostatic pressure test, the pressure was raised in 50 psi increments until a failure occurred. The pipe failed at 2150 psi or 106% SMYS.

Since the test included defects with depths in excess of 1.6% OD (0.25 inches) and no failures of these defects occurred, Olympic has requested OPS approval to raise acceptance criterion for dents from 0.625 % (0.10 inches) to 1.6% (0.25 inches) for defects not yet repaired and for future inspections of the Olympic system.

7.4 Summary

The Olympic Pipeline Company inspection program demonstrated the ability to detect and assess dents as small as 0.625% (0.10 inches in a 16 inch line). Additionally the post-inspection test program demonstrated that dents less than 1.6% (0.25 inches in a 16-inch line) may not compromise pipeline integrity. This program has provided a technical basis for the establishment of an acceptance criterion for dent type defects.

8.0 COLUMBIA GAS

Columbia Gas, operator of a natural gas pipeline, conducted an inspection of a 39-mile segment of the line in Virginia using an in-line inspection tool to identify corrosion. The in-line inspection was accomplished using a high resolution Magnetic Flux Leakage (MFL) tool. The high resolution MFL tool was selected for its ability to detect both internal and external wall loss in natural gas pipelines without the use of a liquid couplant.

8.1 Background

The Richmond, VA to Petersburg, VA natural gas line was constructed in 1957 of electric resistance welded pipe. The manufacturer of the pipe is not known. Both Polychem Tape and Semastic Asphalt were used to coat the pipe. Cathodic protection is used to protect against external corrosion, however the date on installation of the cathodic protection is unknown. The MAOP for this line segment is 639 psi. Table 8-1 details the design parameters for this system.

Table 8-1: Columbia Gas Pipeline Parameters

Pipeline Parameters	
Commodity	Natural Gas
Total Length	39 miles
Size	18 inches OD
Material	X52
Wall Thickness	0.250 inches
Manufacturer	Unknown
Seam Type	ERW
Coating	Polychem Tape and Semastic Asphalt

8.2 Description of Integrity Issue

During bell-hole inspections, Columbia Gas found evidence of disbonded coating. This combined with low close interval survey (CIS) readings and anodic to anodic DCVG, led pipeline personnel to believe that the line may be susceptible to external corrosion. Since similar bell-hole inspection findings, cathodic protection readings, and soil composition were observed along this line segment, the potential for external corrosion was identified as a possible systemic problem that could affect the entire segment.

8.3 Inspection Tool Selection

Columbia Gas selected a high resolution MFL tool because of its ability to accurately locate and detail both internal and external wall loss anomalies. The MFL tool was selected over the ultrasonic tool because it does not require the use of a liquid couplant. A detailed description of the MFL technology and its application is included in Appendix A to this report.

8.3.1 Tool Performance Specifications

Pipeline Integrity International (PII), the company contracted to supply the high resolution MFL tool and evaluate the inspection results, made the following performance specifications for the tool:

Table 8-2: Tool Performance Specifications

Parameter	Specification
Smallest bend radius for passage	1.5 D ¹³
Minimum metal loss size	10% wall loss for 2t x 2t anomaly ¹⁴
Accuracy of metal loss measurement (for 3t x 3t anomaly)	±10% of nominal wall thickness
Location accuracy of detected anomalies (linear measurement)	±0.5 m, (1.6 ft)
Tool speed	0.1 to 2.25m/sec (1.3 to 7.4ft/sec)
Maximum wall thickness	1 inch
Maximum pressure	1750 psi

8.3.2 Inspection and Assessment

Columbia Gas conducted two inspections of the Richmond, VA to Petersburg, VA natural gas line. The first inspection, conducted in June 2001, was made using the Enduro DDL digital tool. This inspection was conducted to obtain geometry data for the line. A second inspection using the PII High Resolution MFL tool was conducted in November 2001. The data from each of the inspections was analyzed by the tool vendor. Columbia Gas performed an independent analysis of a majority of the anomalies.

Using the MFL tool, 2151 corrosion anomalies were identified based on the measured wall loss of greater than 10%. Of the 2151 anomalies, 1989 were observed to have a measured wall loss between 10 and 20%, and 162 anomalies had a wall loss greater than 20%. Of the 162 anomalies, 10 have been identified for follow-up this year. An additional 17 have been selected for follow-up in 2003. To date none of the anomalies have been excavated for follow-up examination.

Based on current planning, Columbia Gas anticipates that the follow-up investigations will include an excavation and direct local inspection of the pipe. The direct local inspection of the pipe will include measurement of the defect size and shape and the use of ultrasonic thickness measurement to determine the pipe wall thickness. Additionally, Columbia Gas will use Magnetic Particle inspection techniques if dents or cracks are evident or suspected.

¹³ Where D = Pipe Diameter

¹⁴ Where t = Nominal Wall Thickness

Columbia Gas has adopted the following criteria to establish when an anomaly is considered significant and follow-up action is required:

- Anomalies with a measured wall loss greater than 80%
- Anomalies that could potentially lower operating pressures
- Large groups of anomalies with a 10% or greater wall loss that may be indicative of a problem (coating or cathodic protection failure)

Columbia gas is also planning to compare the results of the direct local inspection back to the in-line inspection tool data to assess the accuracy and quality of the in-line inspection tool data. Additionally, significant defects may be removed for further analysis.

8.4 Summary

The use of the MFL inspection tool on the Richmond, VA to Petersburg, VA natural gas line has identified a significant number of anomalies for follow-up analysis. When the follow-up investigations are conducted, this inspection program should provide valuable insight to the capabilities of the High Resolution MFL tool and its usefulness as a part of an integrity management program.

9.0 CONCLUSIONS AND RECOMMENDATIONS

9.1 Conclusions

This report documents a series of case studies that illustrate the application of state of the art in-line inspections tools and analysis of data and industry best practices for inspection tool programs. The case studies document both the advantages and disadvantages of the in-line inspection technologies. The case studies also present a number of elements (best practices) that comprise a successful in-line inspection program. These elements include:

- ***Comparison of actual findings to in-line inspection data*** Comparing an actual measured defect back to the in-line inspection data enables pipeline companies to assess the quality of the inspection.
- ***Performing post inspection testing of removed defects*** Performing destructive fatigue, hydrostatic, and or metallurgical testing of the defect found by in-line inspection and removed from the pipeline can aid pipeline Operators in determining if those anomalies left in the line are deleterious to the line integrity.
- ***Performance of a validation program*** A validation program is used to assess the quality of the inspection results and ensure that critical defects are not missed. Validation programs can include running the inspection tools through a calibration standard¹⁵ installed in the pipeline or performing a hydrostatic test of a portion of the line after running an in-line inspection tool to verify the absence of critical defects.
- ***Integration of data from multiple sources*** Using data from multiple sources provides Operators with a comprehensive assessment of the line integrity. Sources may include, but are not limited to, multiple inspection tool runs using different technologies, or the same technology performed at different times, cathodic protection system data, environmental conditions, and visual inspections.

The state of the art in ILI is not yet advanced enough to solely rely on data interpretation to identify critical defects. As shown in the case studies in this report, it is essential that some means of data validation be performed. Differences in material properties, pipeline age and construction techniques, and pipeline commodity can all influence the performance of the in-line inspection tool and the results of the inspection.

ILI can offer economic and performance benefits compared with hydrostatic testing. As in-process techniques, they require substantially less downtime during examination, reducing revenue loss. By reliably detecting flaws smaller than those that will fail during a hydrostatic test, they potentially can justify higher operating pressures and extended intervals between inspections.

¹⁵ A calibration standard would consist of a pipe segment with a known defect at a known location that can be used to check the accuracy and detection ability of the in-line inspection tool.

9.2 Recommendation

Currently there are no consensus standards governing the interpretation and validation of in-line inspection tool data. GP recommends that OPS encourage and participate in the development of a consensus standard for interpretation and validation of in-line inspection tool data.

Appendix A – In-line Inspection Tools

1.0 Magnetic Flux Leakage (MFL) Inspection Tools

Magnetic Flux Leakage (MFL) is a well-established in-process method of non-destructive examination (NDE). In standard MFL, a powerful, axially oriented, magnetic field is created in the pipeline walls by magnets mounted on the MFL in-line inspection tool. Loss of wall metal due to corrosion or to circumferential gouging can be readily detected, as can many problem features in the circumferential (girth) welds. All of these features have substantial components that are perpendicular to the magnetic field lines. By forcing the magnetic field in the pipe wall to pass through an area of reduced wall metal, they cause “leakage” of the field into the interior of the pipeline, where the increase in magnetic flux can be detected by sensors mounted on the in-line inspection tool. Data from the sensors is stored and analyzed off-line after the in-line inspection tool is recovered. Combined with the orientation and axial position data also logged by the in-line inspection tool, a comprehensive survey of the pipeline can be obtained with minimal disruption of operations.¹⁶

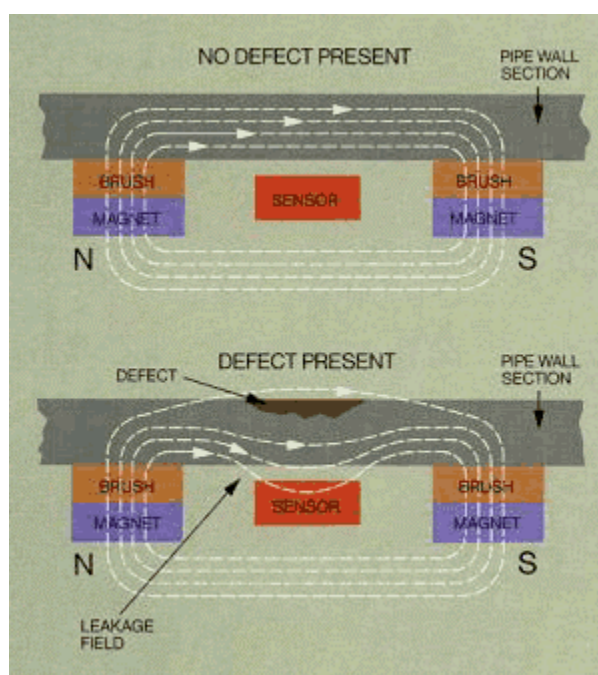


Figure A-1 Magnetic Flux Defect Detection¹⁷

Three different types of MFL tools have been developed for the in-line inspection of pipelines. These included the Standard MFL Tool, the High Resolution MFL Tool, and the Transverse Field Inspection or Circumferential MFL Tool. The following sections describe each of these tools.

¹⁶ Nestleroth and Bubenik, “MFL Technology for Natural Gas Pipeline Inspection,” The Gas Research Institute, 1999, p. 5.

¹⁷ Graphic courtesy of PII.

1.1 Standard MFL Tool

The Standard MFL Tool was the first MFL tool developed. Generally, the corrosion anomalies detected are reported as light (10% to 30% wall loss), moderate (30% to 50% wall loss), or severe (greater than 50% wall loss)¹⁸. There is significant industry experience with the use of the Standard MFL Tool for detecting corrosion.

Standard MFL Tools have limited ability to detect and characterize narrow, axially oriented, features, such as longitudinal gouges and cracks. This makes many of the features associated with ERW pipe problems, such as hook cracks and preferential corrosion, nearly “invisible” to standard MFL. The magnetic field in the pipe wall “sees” only a slight restriction in the cross sectional area of metal available to carry field lines. As a result, very little field leakage occurs and the signals generated by these features do not identify them as significant anomalies.

1.2 High Resolution MFL Tool

The High Resolution MFL Tool uses the same technology as the Standard MFL Tool. The major difference between the High Resolution MFL and Standard MFL Tools is that the High Resolution MFL Tool uses a larger number of closely spaced sensors. With the higher number of closely spaced sensors, the High Resolution MFL Tool can more precisely measure the length, width and depth of corrosion anomalies than the Standard MFL Tool. These measurements are sufficiently accurate for performing remaining strength calculations. High Resolution MFL Tools have been used to measure wall loss as low as 3% and have also been successful in detecting axial defects (selective seam corrosion of ERW pipe).¹⁹

1.3 TFI Tool

In TFI, the direction of the magnetic field is rotated 90° with respect to standard MFL so that the field lines are circumferentially oriented, forming a magnetic “hoop” around the pipeline. In this orientation, axially oriented features such as hook cracks cause a significant restriction in the metal area available to the magnetic field lines, causing significant flux leakage and easy detection by the sensors on the in-line inspection tool. This makes TFI much more effective in locating ERW pipe seam problems than standard MFL.

TFI’s field orientation makes it insensitive to circumferentially oriented features, such as girth weld anomalies and circumferential gouging. The two methods are thus complimentary in many respects.

¹⁸ API Standard 1160, “Managing System Integrity for Hazardous Liquid Pipelines,” First Edition, November 2001

¹⁹ Reported by CMS Energy in their Supplemental Report to OPS dated February 22, 2001.

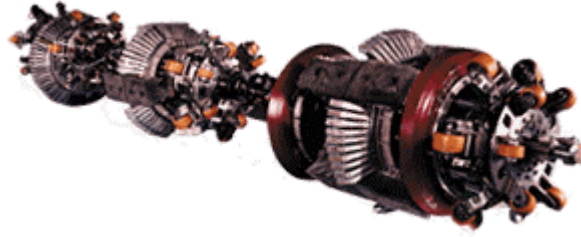


Figure A-2 TranScan TFI Tool²⁰

A modified form of MFL, known as Transverse Field Inspection or Circumferential MFL, addresses many of these limitations. Pipeline Integrity International (PII) introduced the first commercial TFI system in 1996 specifically to detect Narrow Axial External Corrosion (NAEC) in a 34 inch pipeline in Canada. PPI developed a 20-inch TFI in-line inspection tool in early 1998 for the inspection of the Platte Pipeline. To establish the ability of the TFI in-line inspection tool to detect the specific types of anomalies, PPI conducted laboratory tests and pull tests in their facilities in April, 1998. The tests confirmed the ability of the tool to detect longitudinal cracks.

Standard and transverse technologies both have comparable abilities to detect metal loss due to general or pitting corrosion. Standard MFL is easier to implement in practice than TFI, as more space is available in the tool for the necessary equipment.

1.4 Comparison of MFL Technologies

Both standard and transverse MFL have limited abilities to characterize the dimensions of pipe wall anomalies, although the greater operating experience with standard MFL has allowed refinement of the software used to process the data generated. All forms of MFL are sensitive to background noise in the pipe metal, and can suffer from degraded performance at high operating speeds due to eddy current formation in the pipe.²¹

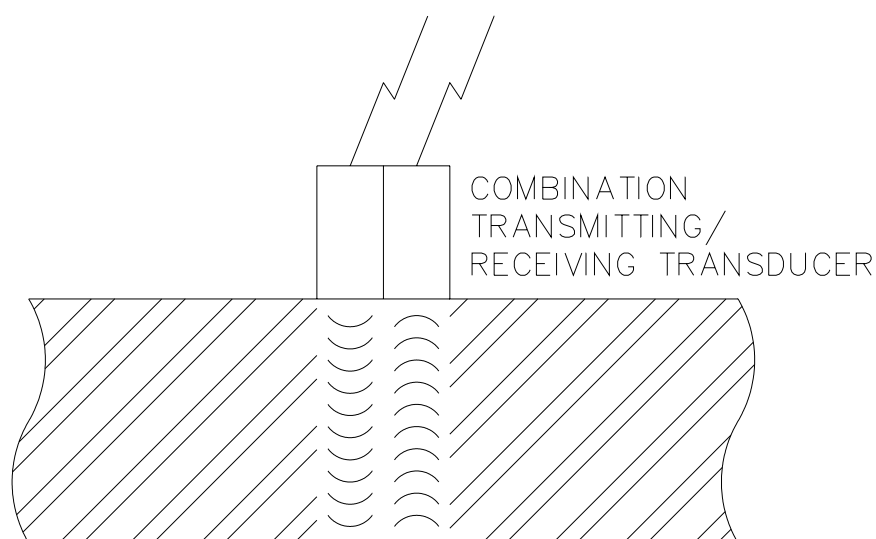
The MFL methods are also effective in non-liquid service, making them suitable for gas pipeline examination. TFI appears to have particular value in the examination of ERW pipe, due to its ability to detect features such as hook cracks that have the potential to grow through fatigue mechanisms, at sizes below those detectable under normal hydrostatic test conditions.

²⁰ Picture courtesy of Pipeline Integrity International.

²¹ Nestleroth and Bubenik, pp 26-32.

2.0 Ultrasonic Inspection Tools

The basic function of a ultrasonic inspection instrument is of the pulse-echo principle, similar to sonar. A short ultrasonic pulse is transmitted into the object by a probe (transducer). The pulse travels through the material until it encounters an interface. An interface is a material with substantially different physical characteristics, such as crack or the back surface of the object being inspected. At the interface, the pulse is reflected back to the probe where it is detected. The time needed for the pulse to make this round trip is divided by two and multiplied by the velocity of sound in the material by the ultrasonic inspection instrument. The result is the thickness of the material between the surface and the interference. Figure A-3 shows a graphic representation of an ultrasonic instrument.



DOT025

Figure A-3 Ultrasonic

Ultrasonic Testing (UT) is most sensitive to defects and material boundaries that are 90° to the incident sound wave. For this reason two basic applications of UT have been used in in-line inspection tools; Standard UT and Shear Wave UT. In Standard UT the ultrasonic sound wave is transmitted through the pipe wall at 90° to the surface. Standard UT is used to detect corrosion (metal loss) and lamination in the pipe wall. In Shear Wave UT, the ultrasonic sound wave is transmitted through the pipe wall at an angle less than 90° to the surface. Shear Wave UT is used to detect cracks that are 90° to the surface of the pipe.

2.1 Standard UT Tools

Standard UT tools are principally used to measure wall loss. The tools consist of a large number of sensors mounted at 90° to the surface. The applications of standard UT in an in-line inspection tool requires a clean internal surface. Standard UT also must be performed in a liquid medium. The liquid is necessary to couple the transducers to the surface permitting the ultrasonic sound waves to travel from the transducer through the liquid and into the pipe wall.

Standard UT can be performed in natural gas pipelines if the in-line inspection tool is run in a liquid batch. The inspection data obtained from a Standard UT is sufficiently detailed and accurate to assess the remaining pipe strength. Figure A-4 is a photograph of a typical Standard UT in-line inspection tool.



Figure A-4 Standard UT Tool²²

2.2 Shear Wave UT Tools

Shear Wave UT tools are principally used to detect cracks. The tools consist of a large number of sensors mounted at an angle to the surface (typically 45°). Like Standard UT the application of Shear Wave UT in an in-line inspection tool requires a clean internal surface and must be performed in a liquid media. Shear wave UT is generally used in pipelines to inspect for seam weld defects that could compromise integrity (e.g. hook cracks in ERW pipe) and for stress corrosion cracking.

To overcome the need to run a Shear Wave UT tool in a liquid medium, the Elastic Wave Tool was developed. In the elastic wave tool the UT sensors are mounted in wheels that are maintained in tight contact with the pipe wall. The Elastic Wave Tool is not as accurate as the Standard Shear Wave Tool but can be used without the need for a liquid batch. Elastic Wave Tools have also been shown to be effective in detecting disbonding of certain types of coatings. Figure A-5 is a photograph of an elastic wave in-line inspection tool.



Figure A-5 Elastic Wave UT Tool²³

²² Picture courtesy of Pipeline Integrity International.

²³ Picture courtesy of Pipeline Integrity International.

3.0 Geometry Tools

Geometry Inspection Tools are used to detect and measure mechanical deformation of the pipe. Sources of mechanical deformation can include third part damage, construction damage, and movement of the pipeline from natural causes (frost heave, floods, subsidence and land slides).

Geometry Inspection Tools use a series of lever arms to follow the pipe wall and measure changes in the pipe wall geometry as the tools moves through the pipeline. The lever arms are connected to a potentiometers to create a position signal that is recorded. The tool is also equipped with an odometer to measure the distance traveled by the tool. Geometry tools can detect and accurately locate circumferential welds, valves and tees.

Pipeline anomalies that are detected and characterized using Geometry Inspection Tools generally include dents, wrinkles, buckles, and pipe ovality. Some Geometry Inspection Tools have been equipped to measure changes in slope that occur with movement of the pipe and/or measure bend radius. A photograph of a typical geometry inspection tools is included as figure A-6.



Figure A-6 Geometry Inspection Tool²⁴

²⁴ Picture courtesy of Pipeline Integrity International.

Appendix B – Case Study Quick Reference Guide

Case Study Quick Reference Guide

Case Study	Pipeline	Operating Company	Commodity	Integrity Concern	In-Line Inspection Tool
2.0	Platte Pipeline	EnCana Pipelines Ltd.	Crude Oil	ERW Seam Splits	Transverse Field Inspection
3.0	Texas Eastern South Line	Duke Energy	Natural Gas	ERW Seam Splits	Transverse Field Inspection
4.0	Panhandle Haven 400 Line	CMS Energy	Natural Gas	ERW Seam Corrosion	High Resolution Magnetic Flux Leakage
5.0	Trans Alaska Pipeline System	Alyeska Pipeline Service Company	Crude Oil	Differential Settlement and External Corrosion	Slope Deformation, Magnetic Flux Leakage, High Resolution Magnetic Flux Leakage, Ultrasonic
6.0	Owensboro-Catlettsburg	Marathon Ashland LLC	Crude Oil	Stress Corrosion Cracking	Slope Deformation, Transverse Field Inspection
7.0	Olympic Pipeline	BP Pipelines	Refined Petroleum Products	Third Party Damage / Top Side Anomalies	Slope Deformation, High Resolution Magnetic Flux Leakage
8.0	Richmond, VA to Petersburg, VA	Columbia Gas	Natural Gas	External Corrosion	High Resolution Magnetic Flux Leakage