ENGINEERING ASSESSMENT FOR LINE 9 REVERSAL PHASE 1

Submitted to:

NATIONAL ENERGY BOARD

CANADA

Prepared by:

Enbridge Pipelines Inc. Pipeline Integrity Department

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1. EXECUTIVE SUMMARY

This engineering assessment ("EA") completed by the Enbridge Pipelines Inc. ("Enbridge") demonstrates that the Line 9 Reversal Phase I ("Project") can proceed as proposed and the subject pipeline from the Enbridge North Westover Pump Station ("NW") to the Enbridge Sarnia Terminal ("SA") can continue to operate in a safe and reliable condition irrespective of flow direction.

Corrosion

The established programs that manage corrosion on the Enbridge pipeline system are aligned to meet or exceed the current licensed maximum operating pressure ("MOP") all along the length of the pipeline and since the Project does not involve a change to the licensed MOP, the proposed flow reversal does not present a condition that would require a modification to the corrosion management program of the subject pipeline. The results of the EA presented herein support this assessment.

Cracking Threat

The established programs that manage fatigue cracking and stress corrosion cracking ("SCC") on the Enbridge pipeline system are aligned to meet or exceed the current MOP along the length of the pipeline and since the Project does not involve a change to the licensed MOP, the proposed flow reversal does not present a condition that would require a modification to the crack management program of the subject pipeline. Line reversal does result in a revision to the crack risk profile and additional crack mitigation activities including investigative excavations west of SA will be completed to reduce the overall crack risk profile. The results of the EA presented herein support this assessment.

Mechanical Damage

The established programs that manage the risk associated with mechanical damage including third party damage will not be affected by the Project and the mechanical damage threat on Line 9 is not considered to increase due to the proposed flow reversal on this pipeline. The results of the EA presented herein support this assessment.

Planned Activities Prior to Flow Reversal

In addition to the EA presented herein, which reassures that this pipeline can be operated in a safe and reliable condition irrespective of flow direction, Enbridge plans to complete the following integrity work prior to the flow reversal in the fall of 2012:

- Conduct assessment of select geometry features in 2011 recognizing that the risk associated with existing features is not considered to increase due to the line reversal.
- Conduct investigative crack excavations in 2012 with particular focus west of SA where the cracking risk profile is expected to change due to the line reversal.
- Install two new remote-controlled sectionalizing valves at Milepost ("MP") 1837.99 near the Black Creek water crossing, MP 1843.5 near the Nith River and automate valve at MP 1750.01.
- Enhance the cathodic protection ("CP") monitoring system by installing remote monitoring equipment on all Eastern Region rectifiers by the end of 2011.

2. PROJECT INFORMATION

2.1 Project Background

The Project proposes to reverse a section of the Enbridge Line 9 between SA and NW to accommodate Enbridge customers' request for greater capacity and access to the Ontario market. The scope of the Project also includes a plan to maintain bi-directional capability of the pipeline to facilitate any future requirements to transport crude oil from NW to SA in westward flow.

This NPS 30 pipeline, as shown in the schematic in Figure 1.1, was originally constructed in 1975 and commissioned in June 1976 to operate in eastward flow direction as part of the Enbridge Line 9 pipeline from SA to Montreal ("ML"). The pipeline was then reversed in 1999 as part of the "Line 9 Reversal Project (OH-2-97)" and pursuant to NEB Order X0-JI-34-97.

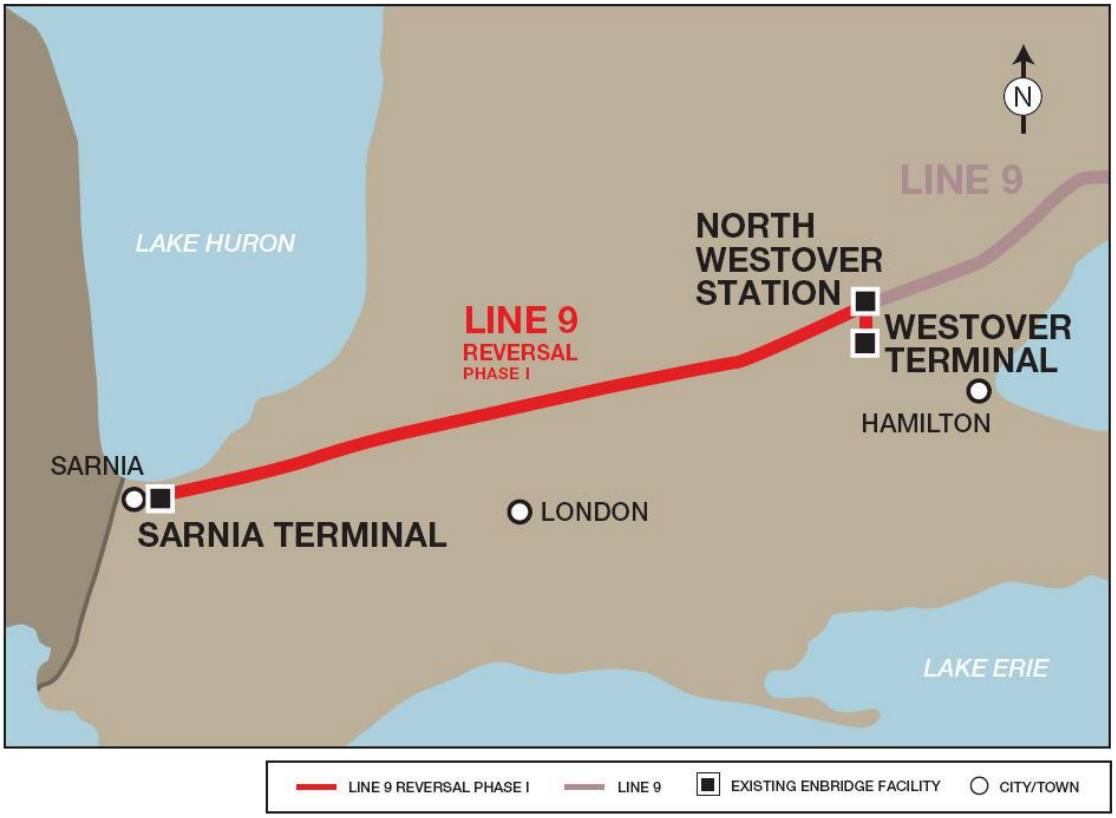


Figure 1.1 –The Project System Map

2.2 Engineering Assessment

This EA was prepared in accordance with section 10.14.6 of CSA Z662-07 "Oil and Gas Pipeline Systems" and consists of the following:

- review of historical and pipeline integrity management records;
- threat identification; and
- fitness for service ("FFS") assessment and effect of the line reversal on the identified threats.

The review of historical records included consideration of the design, materials, construction, pressure testing, operations, inspection and maintenance histories. The review of pipeline integrity management records included:

- an evaluation of the findings from the metal loss inspection conducted in 2007;
- an evaluation of the findings from the geometry inspection conducted in 2007; and

- an evaluation of the findings from the crack inspections conducted in 2008.

3. PIPELINE RECORDS

Enbridge has reviewed records that describe the condition of Line 9 from NW to SA including design, materials, construction, pressure testing, operations, inspection and maintenance histories in order to identify any areas of potential concern associated with the proposed reversal in flow.

3.1 Pipeline Specifications

Table 3.1 provides a summary of the pipe properties for this pipeline, which is constructed with Grade X52 pipe having a wall thickness varying between 6.35 and 12.7mm. The MOP of the pipeline varies between 3856 and 5375 kPa (559 - 779 psi), which corresponds to equivalent stress levels between 59 and 80 percent of specified minimum yield strength ("SMYS"). Table 3.1 also provides the range of pressures for the last hydrostatic test completed in 1997 between SA and NW.

Table 3.1 - Pipe Properties and Test Pressures

Pipe Properties	NW to SA
Diameter	NPS 30 (762 mm)
Wall Thickness	6.35 mm x 140.808 km 7.14 mm x 43.644 km 7.92 mm x 4.279 km 8.74 mm x 0.042 km 12.7 mm x 4.27km
*** Grade**	API 5L X52 (359MPa)
Construction Date	1975
Long Seam Weld Type	Double Submerged Arc Weld ("DSAW")
Manufacturer	Stelco
Pipeline Length	194.12 km
Coating	Single Layer Polyethylene Tape ("PE Tape")
Range of MOP	3856 – 5375 kPa (559 – 779 psi)
Range for 1997 Hydrostatic Test Pressures	4821 – 6737 kPa (699 – 977 psi)
Range of SMYS	5977 – 7459 kPa (867 – 1082 psi)

* Manufactured in accordance with CSA Z245.1-1971 and CSA Z245.2-1971

3.1.1 Mechanical Properties

Toughness requirements are not specified in CSA Z245.1-93 for Category 1 line pipe, but for the purpose of the fracture assessment, and in the absence of actual material toughness properties, Enbridge conservatively assumed a material toughness of 20 Joules (15 ft-lb) for both the pipe body and long weld seam.

3.2 Operating Information

3.2.1 Operational Background

Line 9 NW to SA was constructed in 1975 and placed into service in 1976 as part of the Enbridge Line 9 pipeline system design and built to transport Western Canadian crude oil from SA to ML. The pipeline was hydrostatically tested in 1976 to satisfy the initial construction hydrostatic test requirements and to achieve the maximum hydrostatic test profile accepted for service by the National Energy Board ("NEB") to operate at or below 80 percent of the proven test pressure.

Line 9 was deactivated in July 1991 and reactivated two years later in July 1993. The line remained purged with nitrogen at a constant pressure of 200 kPa (29 psi) and was protected externally with CP during this time.

A second hydrotest was conducted on Line 9 in 1997 as part of the Line 9 Reversal Project ("OH-2-97") and pursuant to **Order X0-JI-34-97.** Line 9 was tested to a minimum test pressure of 4821 kPa (699 psi) as shown in Table 3.1. Following the reversal, Line 9 has operated in westward flow into SA transporting condensate, sweet and sour crude oil. Despite the 1999 approved reset in MOP, this pipeline has experienced operating pressures well below MOP and minimal pressure cycling as describe in detail in Section 4.3 of this analysis due to the relatively low throughput requirements. Appendix A shows a system schematic of Line 9 from NW to SA in the current westbound service configuration.

3.2.2 Planned Operating Mode

This pipeline from NW to SA will transport between 50,000 and 90,000 bpd upon reversal in 2011; however, the pipeline would be able to transport beyond 150,000 bpd to accommodate additional volumes to offset any significant downtime on Line 7, which also serves this market.

3.2.3 Future Operating Pressures

Upon flow reversal, the licensed MOP between NW to SA will not change. Table 3.2 gives a summary of past versus future typical operating pressures experienced on this pipeline segment.

Table 3.2 - Summary of Pressure Information: Line 9 (NW – SA)

Operation Summary	Pressure		% SMYS[1]
	(kPa)	(psi)	
Proposed Maximum Discharge Pressure at SA	3393	492	51
Typical NW Discharge Pressures 1999 – 2010	2414	350	40
1997 Maximum Hydrotest Pressure	6737	977	110
Licensed MOP at NW	4781	693	80

1 Calculated based on the predominant line pipe for each pipe segment.

3.3 Crossing Records

Line 9 from NW to SA does not cross navigable waters (as defined by the federal *Navigable Waters Protection Act*). Detailed as-built records for all other crossings, including a total of thirty-nine (39) cased crossings, are contained within the Enbridge alignment drawings.

3.4 Welding Inspection Construction Records

Circumferential welds were completed and inspected at the time of construction to the existing CSA Z662-71 code requirements.

3.5 Operating and Maintenance Records

3.5.1 Hydrotest Failures

There were no leaks or ruptures on Line 9 during the last hydrostatic test conducted in 1997.

3.5.2 In-Service Leaks and Ruptures

The mainline segment of Line 9 from NW to SA has not experienced mainline leaks or ruptures.

3.5.3 In-Line Inspection History

A summary of the In-Line Inspection ("ILI") history is provided in Table 3.3 which includes magnetic flux leakage ("MFL") and ultrasonic ("UT") for metal loss ILI and Ultrasound Crack Detection ("USCD") for crack ILI.

Table 3.3 – ILI History: Line 9 (NW – SA)

Date	Vendor	Tool
1975	TDW	Caliper
	IPEL	Geometry
1976	IPEL	Geometry Re-run
1978	TDW	Caliper
1979	IPEL	Metal Loss (MFL)
1986	TDW	Caliper
1988	Tuboscope	Metal Loss (MFL)
1990	Nowsco	Geopig
1994	Nowsco	Geopig
1995	British Gas	Metal Loss (MFL)
2002	Ctool	Caliper
	BJ	Geopig
	GE-PII	Metal Loss (UT)
2007	GE-PII	Metal Loss (MFL)
	GE-PII	Metal Loss (UT)
	TDW	Caliper
2008	GE-PII	USCD

3.5.4 Excavation and Repairs

Within Enbridge, all ILI programs include repair and correlation excavations based on the most recent defect assessment criteria being utilized. Table 3.4 lists the number and types of features from the most recent ILIs, which met excavation criteria from NW to SA.

Table 3.4 - Recent Excavation and Repairs: Line 9 (NW – SA)

Targeted Feature Type	Total	Sleeve Repairs	Recoats	Line Cut-outs
Corrosion	4	2	2	0
Dent	21	20	1	0
Crack	7	0	7	0
Total	**30**	**21**	**9**	**0**

3.5.5 Operating Risk Management

The Operational Risk Management liquid mainline risk assessment model integrates the data related to corrosion, cracking, mechanical damage, third party damage, ground movement, natural forces, human factors, incorrect operations, appurtenances and consequences (including impacts on population, environment and business).

The integration of this data yields a relative comparison of the risk for the pipeline (using 300 m segmentation). These results are reviewed annually to determine the need for mitigation activities in addition to those that are already in place for individual threats driving the identified risk.

In preparation for the Project, the risk model was modified to account for the proposed conditions in reversed flow and bidirectional capability.

The likelihood scores anticipated for the Project in reversed operation are not expected to change substantially from those generated in its current service. The existing risk prevention and mitigation activities and tasks performed to assess, prevent, and mitigate crack, corrosion, and denting threats as described in this EA are adequate. The threats resulting from the remaining hazards including natural forces, system operations, appurtenances, third-party damage and ground movement do not change with the reversal.

An Intelligent Valve Placement analysis has been performed on this pipeline in reverse flow. This analysis has identified that two additional remote controlled valve placements are required at MPs 1837.99 and 1843.50 to protect water crossings. A complete valve conversion is also required east of SA at MP 1750.01 to provide additional protection to an area with an increased density of population and environmentally sensitive locations. These locations are also informally categorized by Enbridge Pipeline Integrity as High Consequence Areas (“HCA”). The valve placement near SA is in addition to that required by existing regulations and standards.

An overview of the liquid mainline risk assessment and a review of the Project risk assessment results are provided in Appendix B.

4. FFS ASSESSMENTS

4.1 Threat Identification

Reversing the flow direction and operating pressure profile of this pipeline does not require a change to the existing MOP. However, the flow reversal will result in segments of the pipeline being operated at higher pressures than the previous operating levels. As a result, a threat identification assessment has been conducted to identify and assess any features and failure mechanisms that may become more susceptible due to the change in pressure profile. Using the terminology in CSA Z662-07 Annex H, the effect of the line reversal was evaluated on the six primary causes of pipelines failures identified below:

- metal loss;

- cracking;
- external interference;
- dents and mechanical damage;
- material, manufacturing or construction; and
- geotechnical threats

Potential threats identified were evaluated for their suitability for service under reverse flow and the details of the validation of the individual features and threat mechanisms are described herein.

4.2 Metal Loss

Pipeline metal loss is managed by Enbridge through a series of comprehensive prevention, monitoring and mitigation programs. The external corrosion prevention measures include:

- protective external coating;
- a CP system installed and maintained to Enbridge standards;
- routine ILI using high resolution MFL and UT ILI technology; and
- excavation and repair programs.

The internal corrosion prevention and mitigation measures include:

- tariff limits on sediment and water ("S&W") content;
- routine monitoring, line cleaning and chemical inhibition (if required);
- oil batch testing;
- routine ILI using high resolution MFL and UT ILI technology; and
- excavation and repair programs.

The above programs have been designed to maintain reliable operation up to the MOP along the entire NW to SA pipeline segment regardless of actual operating pressure at each particular line segment. As such, the proposed reversal of flow does not require any changes to the metal loss management programs. Based upon the metal loss related analysis and assessments summarized herein, it is concluded that the metal loss threat on the line is adequately managed and will continue to be managed at an acceptably low risk level regardless of flow direction.

4.2.1 External Corrosion Control

External corrosion on Line 9 between NW to SA is prevented through the (original) application of an external single layer PE Tape coating and a CP system operated and maintained to industry and Enbridge standards. An annual pipe-to-soil survey is performed to determine the state of the CP system and to evaluate the overall protection level(s). Any areas that exhibit low potential measurements would typically be investigated further utilizing a close interval survey ("CIS"). Rectifier parameters are inspected monthly by Enbridge personnel to comply with CSA Z662-07 and CGA OCC-1-2005 (Control of External Corrosion on Buried Submerged Metallic Piping Systems).

4.2.1.1 Rectifier Replacement and System Upgrades

On the basis of the annual CP performance and monthly rectifier inspections between NW to SA, Enbridge undertakes capital projects to improve protection levels and/or to make the CP infrastructure more reliable and easier to maintain. Any operational issues that arise throughout the year are dealt with immediately to ensure that protection is maintained. Currently a remote monitoring program is being implemented, which will allow for weekly recordings of all rectifiers via satellite communications. Enbridge plans to install remote monitoring equipment on all Eastern Region CP Rectifiers by the end of 2011 and prior to the proposed reversal between NW to SA.

4.2.1.2 CP Protection System Status

The annual CP inspections along the Eastern Region mainline corridor are typically performed in the late summer and fall seasons. Polarized and 'Instant Off' potentials are obtained utilizing current interrupters and hand held pipe-to-soil waveform analyzers. All data is collected by National Association of Corrosion Engineers ("NACE") certified technicians.

Enbridge evaluates the protection levels of the CP systems utilizing one of two NACE CP protection criteria as per SP-0169-2007 (Control of External Corrosion on Underground or Submerged Metallic Piping Systems). The first evaluation is based on the -850mV OFF polarized potential criterion. Instant off polarized potentials measured with respect to a $Cu/CuSO_4$ reference electrode that are more electronegative than the -850mV threshold indicate that protection is achieved. The second evaluation is based on the 100mV polarization decay criterion. In areas where the -850mV instant off criterion is not achieved, the rectifiers are turned off to allow monitoring of polarization decay. Polarization decay of more than 100mV also indicates that protection is achieved. To obtain proper measurements of polarization decay, extensive areas of the CP system require shutdown for upwards of several weeks; therefore, Enbridge minimizes the usage of this criterion to avoid prolonged system outages that may have an effect on the overall protection levels of the pipeline.

Enbridge has implemented a program of utilizing CP monitoring to allow for the recording of IR free potentials in the areas of foreign CP system influence (eliminating the need to interrupt foreign owned CP systems) and the measurement of 100 mV decay of the coupon rather than the pipeline.

The most recent CP information available to date is in the 2009 annual adjustive survey, in which pipe-to-soil potentials were determined at 99 separate locations along the right-of-way between SA and NW. The majority of the readings (97/99 or 98%) achieved the -850mV threshold, while the remaining two readings satisfied the 100mV decay criterion, of which one was located immediately upstream of MLV #5 (M.P. 1805.656/K.P. 2905.922). This MLV is remotely controlled and electrically grounded and suspected to be poorly coated below grade. Additional testing was conducted and the lower potentials immediately improve upstream and downstream of this location. Plans are in place to install a CP coupon at test stations located at MPs 1805.624 and 1806.483 (K.P. 2905.87 and 2907.253) to aid in future CP system evaluations.

The following four locations could not be assessed during the 2009 annual adjusted CP survey due to inaccessibility from construction or agricultural activity (crops).

- MP 1746.127 CNR Carrier & Casing
- MP 1750.010 Mainline Valve #1
- MP 1842.397 CPR CARR. & CAS. (N&S)
- MP 1844.361 AYR Paris Rd. Carrier (W)

These locations have been addressed to ensure every effort will be made to acquire information pertaining to these sites in the 2010 assessment.

4.2.1.3 Cased Crossing Management

This pipeline has a total of thirty-nine (39) cased crossings between SA and NW that are part of Enbridge ongoing CP monitoring program. These casings were originally installed to provide mechanical protection from road and railway crossings and incorporate electrically isolating spacers and end seals that separate the carrier pipe from the casing. Over time, the integrity of the end seals can degrade allowing for the ingress of potentially corrosive groundwater. Pipe movement due to settling and degradation of the isolating spacers may also allow for potential contact of the casing to the carrier pipe resulting in an electrical short. Failed end seals and electrical shorts can present an elevated risk of external corrosion of the section of piping located within the cased crossing.

During the annual CP survey, potential measurements are taken on all casings. These readings are then compared with the pipeline potentials at the same locations. A potential difference of 10mV or more is an indication that the carrier pipe is electrically isolated minimizing the risk of external corrosion within the casing. All casing potential readings recorded on this pipeline from NW to SA indicated a minimum potential difference of 150mV indicating that the casings are still isolated from the carrier pipe throughout this section.

This pipeline contains additional casings that were originally installed and subsequently removed, or filled with dielectric gel as part of a casing rehabilitation program. These are no longer part of the CP monitoring program and are managed through Enbridge ILI and excavation programs.

4.2.2 Corrosion Management Approach

4.2.2.1 Monitoring

Detailed information regarding the integrity condition of the pipeline can be obtained through high resolution metal loss ILIs. Table 4.1 provides a list of metal loss inspections completed to date.

Table 4.1 - Metal Loss ILI History: Line 9 (NW - SA)

Date	Vendor	Tool
1979	IPEL	Metal Loss (MFL)
1988	Tuboscope	Metal Loss (MFL)
1995	British Gas	Metal Loss (MFL)
2002	GE-PII	Metal Loss (UT)
2007	GE-PII	Metal Loss (MFL)
	GE-PII	Metal Loss (UT)

4.2.2.2 Defect Severity Target Level for Reassessment

To incorporate a safety margin within the monitoring programs Enbridge has set the re-assessment intervals for this line such that corrosion features are identified for repair before they grow past a **target level** equivalent to a rupture pressure ratio (“RPR”) of 0.9 and a depth of 75%. The RPR is defined as the predicted failure pressure of an anomaly divided by the pressure necessary to achieve stress in the pipe wall equivalent to 100% of the pipe’s SMYS or briefly stated, an RPR value of 1.0 equates to 100% of SMYS.

4.2.2.3 Excavation and Repair Criteria

Metal Loss features identified by the metal loss ILIs that equal or fall below an RPR value of 1.0 or a depth equal to or greater than 50% of the pipe wall thickness are selected for excavation and assessment. Metal loss features meeting the repair criteria, as described in Table 4.2 are repaired with full encirclement sleeves.

Table 4.2 – Enbridge Metal Loss Repair Criteria

Metal Loss	RPR and %WT Depth	Remedial Action
External	RPR≤1.0 Depth ≥ 80%	Repair
	RPR>1.0 Depth < 80%	Recoat
Internal	RPR≤1.0 Depth ≥ 50%	Repair

All features identified by the 2007 metal loss inspection and excavation programs that met the required repair criteria have been excavated, assessed and repaired.

4.2.3 Metal Loss Incidence Charts

In order to provide a qualitative description of the metal loss distribution along this pipe segment, the location and severity of metal loss anomalies as reported from the 2007 ILI have been plotted. The charts are useful in identifying any locations along the pipeline that have unusual patterns of metal loss density or severity and can lead to further investigation and analyses. They are also useful to review as the pipe section is re-inspected and the charts compared against different times in the pipe section's operational life. Along with other analysis outputs these charts can support investigation into CP adequacy, the reassessment interval planning process, the internal corrosion program, and the excavation/repair program.

4.2.3.1 Metal Loss Orientation Charts

Metal loss depth severity is plotted as circumferential orientation versus their axial location. Figures 4.1 and 4.2 describe the external and internal corrosion feature distributions respectively. The metal loss severity, taken from the overlaid 2007 Ultrasound Wall Metal ("USWM") and MFL data, has been delineated by the use of different colours as identified in the chart legends. The bands of external corrosion all occurred at areas of significant elevation change, while there are no apparent trends of internal corrosion along the pipeline suggesting the internal mitigation program is adequate.

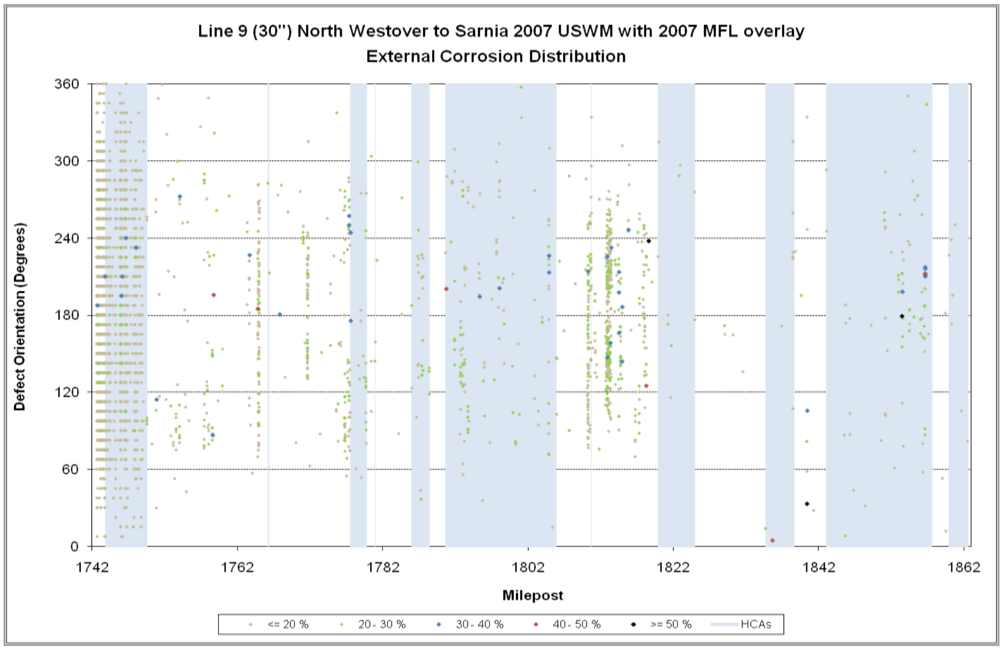


Figure 4.1 - Distribution of External Metal Loss

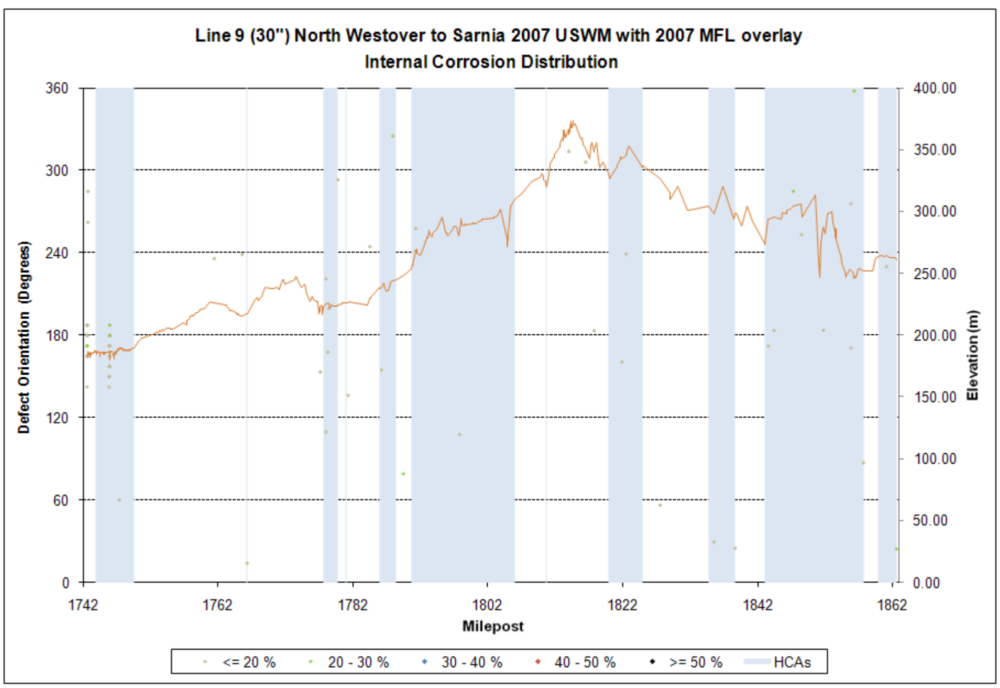
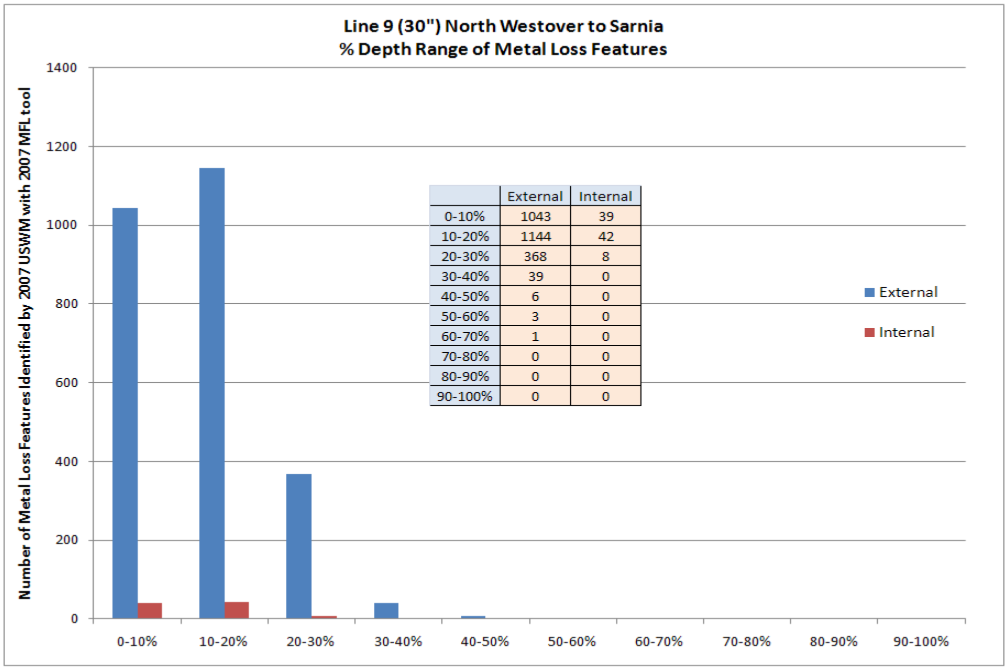


Figure 4.2 - Distribution of Internal Metal Loss

4.2.3.2 Metal Loss Histograms

Figure 4.3 shows number of metal loss ILI anomalies grouped into depth ranges of 10%.



	External	Internal
0-10%	1043	39
10-20%	1144	42
20-30%	368	8
30-40%	39	0
40-50%	6	0
50-60%	3	0
60-70%	1	0
70-80%	0	0
80-90%	0	0
90-100%	0	0

Figure 4.3 – Percent Depth Range of Metal Loss

As can be seen in Figures 4.1 through 4.3 the majority of the metal loss anomalies detected have a low depth severity and do not pose a threat to the integrity of the pipeline. Four features identified in Figure 4.3, with greater than or equal to 50% depth, were excavated and two required a sleeve repair while the other two only required a recoat.

4.2.3.3 Rupture Pressure Charts

Metal loss anomalies with ILI tool reported RPR values have been plotted by MP in Figure 4.4. Features are excavated, assessed and repaired when their predicted failure pressure falls to, or below, 1.0 RPR criteria or 100% of the SMYS. As can be seen from Figure 4.4 below, there are no metal loss features requiring excavation based on the 1.0-RPR criteria.

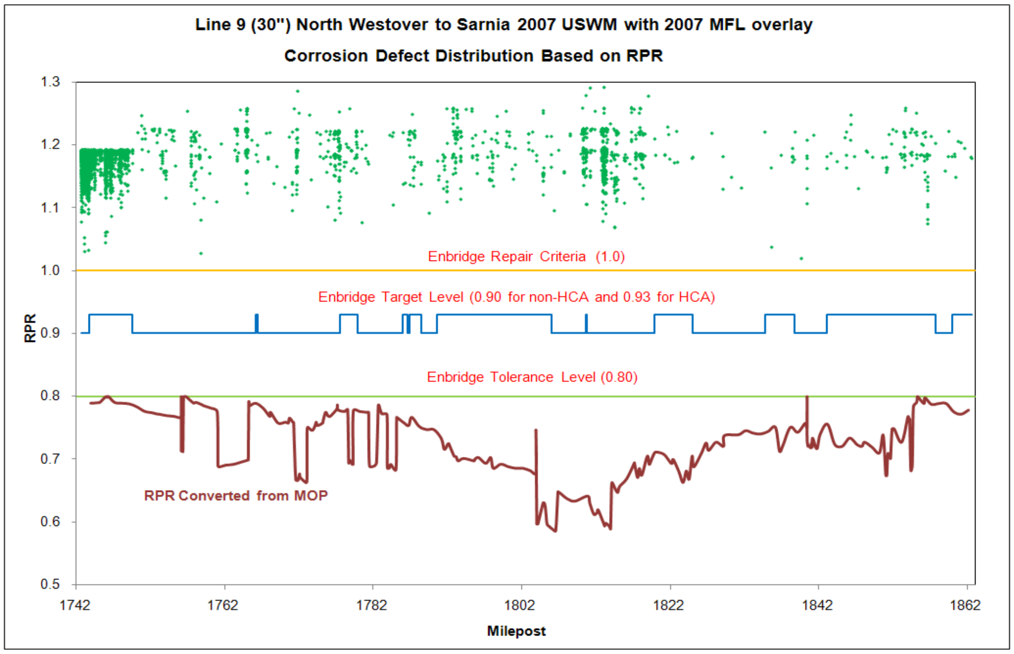


Figure 4.4 – Line 9 (NW – SA) – Predicted Metal Loss Failure Pressure

4.2.3.4 Metal Loss Depths

The depths of all metal loss anomalies identified by the 2007 ILI runs are plotted in Figure 4.5 along with the Enbridge standard excavation criteria, target level and tolerance level.

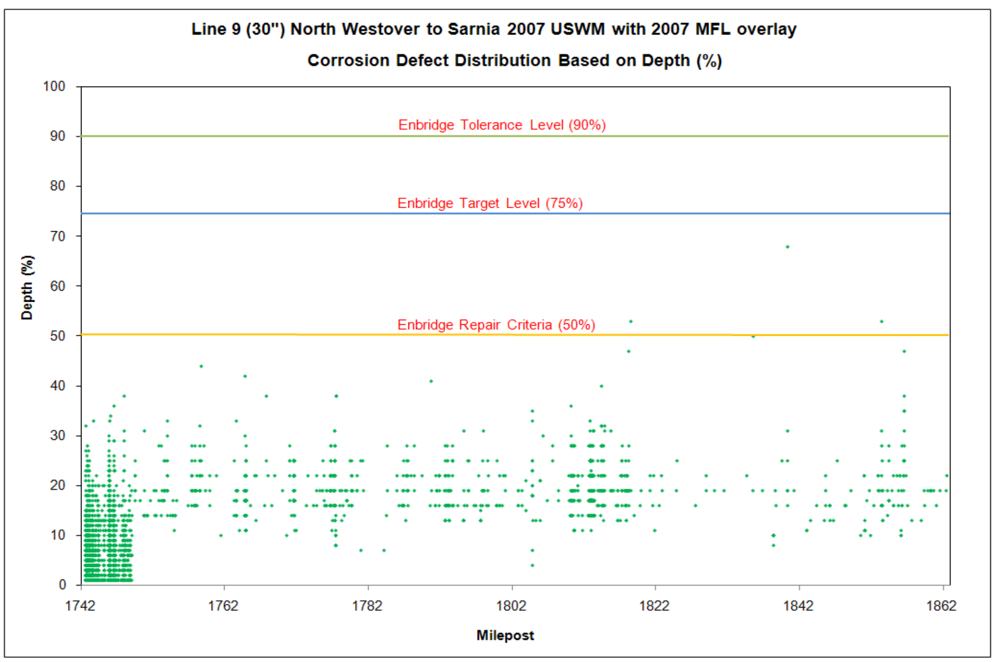


Figure 4.5 - Line 9 (NW – SA) – Metal Loss Depth Distribution

Features are excavated, assessed and repaired when their % depth rises to, or above, 50%. The four features that met the criteria in Figure 4.5 above were excavated and repaired.

4.2.4 ILI Metrics

The metal loss metrics including total number and per kilometre frequency are summarized in Table 4.3 below.

Table 4.3 – ILI Metrics

		Metal Loss RPR		**Metal Loss Depth**	
		1.0<RPR <1.1	**1.1<RPR<1.2**	**D<20%**	**20%<D<50%**
External	# Features	22	2171	2187	414
	Feature Density (per km)	0.11	11.25	11.36	2.15
Internal	# Features	3	77	81	8
	Feature Density (per km)	0.02	0.40	0.42	0.04

Table 4.3 shows a low feature density per kilometre for both external and internal corrosion demonstrating that the threat from internal metal loss is being managed to acceptable levels and in the ground conditions that this section of Line 9 traverses, PE Tape has performed well.

4.2.5 Corrosion Growth Rates

Corrosion growth rates (“CGRs”) are calculated in order to provide insight in the integrity condition of the pipeline and to support the monitoring and mitigation planning. Historical CGRs have been calculated by dividing the defects depth by the calculated time of growth multiplied by a safety factor of two. Industry standards offer guidelines regarding maximum expected external CGRs. Table 4.4 shown below includes the average CGRs experienced on this pipeline from NW to SA.

Table 4.4 –Average CGRs

DESCRIPTION		**CGRs (2007)**
Historical CGRs	External Corrosion	0.058 mm/year
	Internal Corrosion	0.046 mm/year

Table 4.5 below contains a summary of CGRs found in industry guidelines and/or standards. The industry rates are higher than the 95th percentile rates for external corrosion seen on this pipeline, which indicates that the CGRs are low.

Table 4.5 - Industry Guidelines for External CGRs versus CGRs on Line 9 (NW – SA)

Standard/Guideline	Recommendations
NACE RP0102 (Ext)	0.3mm/yr: 80% confidence max rate with 'good' CP
ASME B31.8S (Ext)	0.31mm/yr max rate for active corrosion in low resistivity soils
GRI-00/0230 (Ext)	0.56mm/yr for pitting; 0.3mm/yr for general corrosion
Line 9(NW-SA) Ext. Historical 95th Percentile	0.109 mm/yr
Line 9(NW-SA) Int. Historical 95th Percentile	0.067 mm/yr

The growth rates used for ILI re-assessment interval determination take all these values into account and a judgement is made regarding the most appropriate CGR values that balance out the Enbridge CGRs experience with industry experience. Specific rates used in these analyses are included within the Deterministic Growth Analysis in Section 4.2.8.1.

4.2.6 Internal Corrosion Program

4.2.6.1 Overview

Enbridge transports crude oils that contain trace amounts of water, suspended solids and bacteria. The proposed products to be shipped from NW to SA are expected to contain such potential corrodents. Under certain operating conditions (such as low flow rates / low turbulence) this can lead to the development of local corrosive conditions.

Enbridge's internal corrosion program is designed to collect and integrate data relevant to the internal corrosion threat. Enbridge regularly conducts evaluations that include periodic testing to ensure that the S&W content does not exceed tariff quality limits as well as routine analysis of operating conditions to ensure corrosive conditions do not develop. Line 9 is also monitored for internal corrosion through regular ILI. For Enbridge pipelines considered to have an elevated susceptibility to internal corrosion, additional monitoring and prevention programs are implemented. Additional monitoring programs include coupons, Electric Resistance Matrices ("ERMs"), or Field Signature Method – Inspection Tools ("FSM-Its"). Additional preventative programs include regular cleaning and/or inhibition treatments.

4.2.6.2 Product Characteristics and Operating Temperature

Mixed sour blend ("SO") and light sour blend ("LSB") crude oils are specified as the two main commodity types to be shipped following the flow reversal. Properties for these two main commodities are listed in Table 4.6 below. Table 4.7 provides the estimates on injection temperatures at SA Terminal.

Table 4.6 – Proposed Batch Properties

Fluid	Density (kg/m^3)	Viscosity at 10°C (cSt)	Viscosity at 30°C (cSt)	RVP (kPa)
SO	887	39.5	16.60	83.5
LSB	847	14.0	5.31	67.0

Table 4.7 – Batch Injection Temperatures

Injection Location	Annual Average (°C)	Q1 (°C)	Q2 (°C)	Q3 (°C)	Q4 (°C)
SA	13.1	5	14	21	13

4.2.6.3 Internal Corrosion Susceptibility Analysis

A key component of the Enbridge Internal Corrosion Control Program is the performance of periodic Internal Pipe Corrosion ("IPC") susceptibility analyses. These analyses are completed for all pipelines in the Enbridge system and are regularly updated as operating conditions change and new data (such as ILI data) becomes available.

This analysis uses several leading and lagging indicators to evaluate the potential internal corrosion threat based on Enbridge historical experience. Key factors include the monitoring of the product shipped; roughness of the pipelines interior surface as reported through inspection data – which affects the accumulation of corrosive sediments; and the pipeline flow conditions – which determines the ability of pipeline product flow to flush corrodents out of the system. These factors are assessed and related to determine the IPC threat on all Enbridge mainlines.

Lighter commodities such as LSB are typically cleaner (lower S&W than heavier commodities). The reduced concentration of corrosive contaminants contained in this product decrease the overall corrosion threat under all flow conditions.

4.2.6.4 Year 2011 Flow Rates

The proposed annual rates in reversed service are between 248 and 447m^3/h (50,000 and 90,000 bpd). In the rare event of a Line 7 outage, the flow rates on this pipeline from NW to SA could rise beyond 992m^3/h (150,000 bpd). Table 4.8 shows the average discharge pressures based on the normal operating limits being designed for this line in reverse light-sour service. Higher limits may be achievable under additional modifications to existing equipment.

Table 4.8 - Proposed Operating Limits with SO and LSB

Line Rate		SA Average Discharge Pressure	Minimum Reynolds Number
(bpd)	(m^3/h)	(psi)	(commodity SO)
50,000	330	295	3840
75,000	496	321	5760
100,000	661	335	7670
150,000	992	364	25000

As shown in Figures 4.6 and 4.7, proposed lower annual rates are not expected to achieve the critical Froude number at which free water will be entrained in the light or sour crude oils. As such, a prevention program has been planned to displace corrodents on a regular basis through routine maintenance (cleaning) pigging.

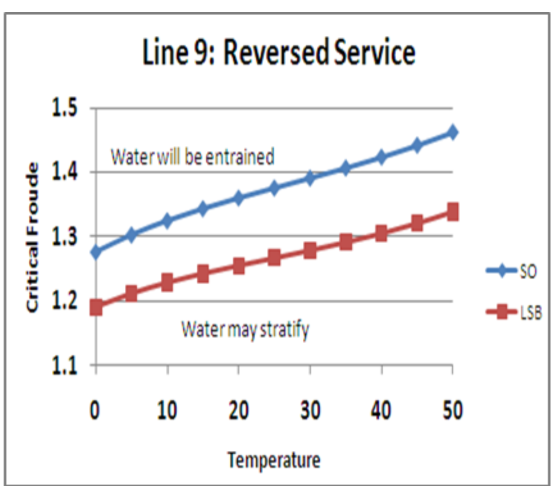


Figure 4.6 - Critical Froude

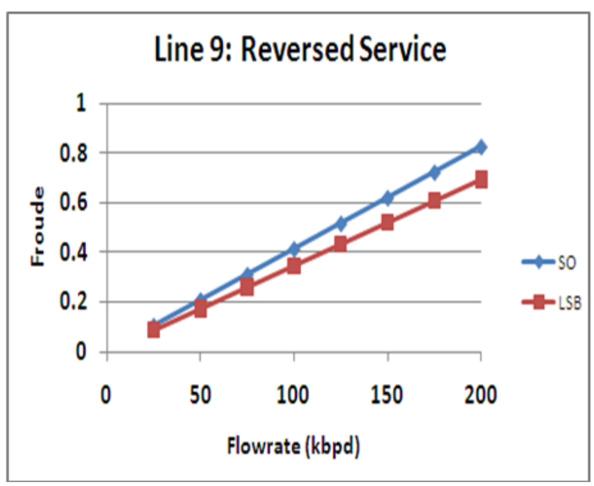


Figure 4.7 - Froude Number vs Flowrate

4.2.7 Metal ILI Data Accuracy

4.2.7.1 ILI Tool Accuracy Specification

The most recent metal loss inspections on this pipeline were conducted using USWM and MFL high resolution technology provided by General Electric in 2007. The ILI tools are capable of identifying low level non-injurious features up to critical sized defects. The uncertainty and variability in tool accuracy is concentrated at the ILI tool reporting thresholds and accuracy variability is anticipated for low level and/or non-critical features. The Probability of Detection ("POD") increases with increasing feature severity and therefore there is a low likelihood of the ILI tool missing a near critical defect. This relationship for three different POD specifications is shown in Figure 4.8 below.

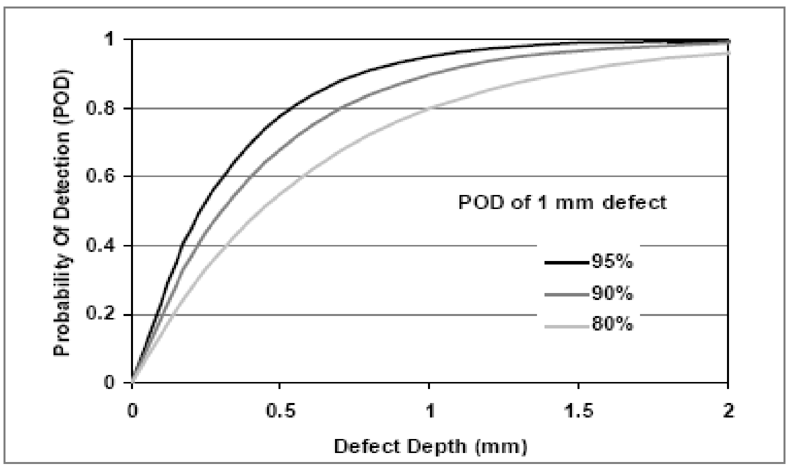


Figure 4.8 - POD vs. Metal Loss Defect Depth

As can be seen from Figure 4.8, the POD rapidly increases as the metal loss depth increases. The ILI tool used on the line has a specified POD of 90% for metal loss depth of 10% for general corrosion and 12% for pitting corrosion. This provides a high level of certainty that metal loss with depths exceeding the Enbridge repair criteria of 50% will be detected.

4.2.7.2 Metal ILI Data / Field Data Verification

The dig and repair program based on the 2007 metal loss inspection has been completed. The data and field verification results evaluated to date have been incorporated into this line's unity plot as shown in Figure 4.9.

It should be noted that the 2007 inspection program incorporated results from two different inspection technologies; USWM and MFL. The MFL inspection was performed to offset the limitations of UT inspection technology in detecting small diameter corrosion pits and as such, the vendor was only requested to report on deep pitting (>40% through wall). The limitation of the UT technology to see small diameter corrosion pits can be seen by the number of false negatives on the y-axis of the unity plot.

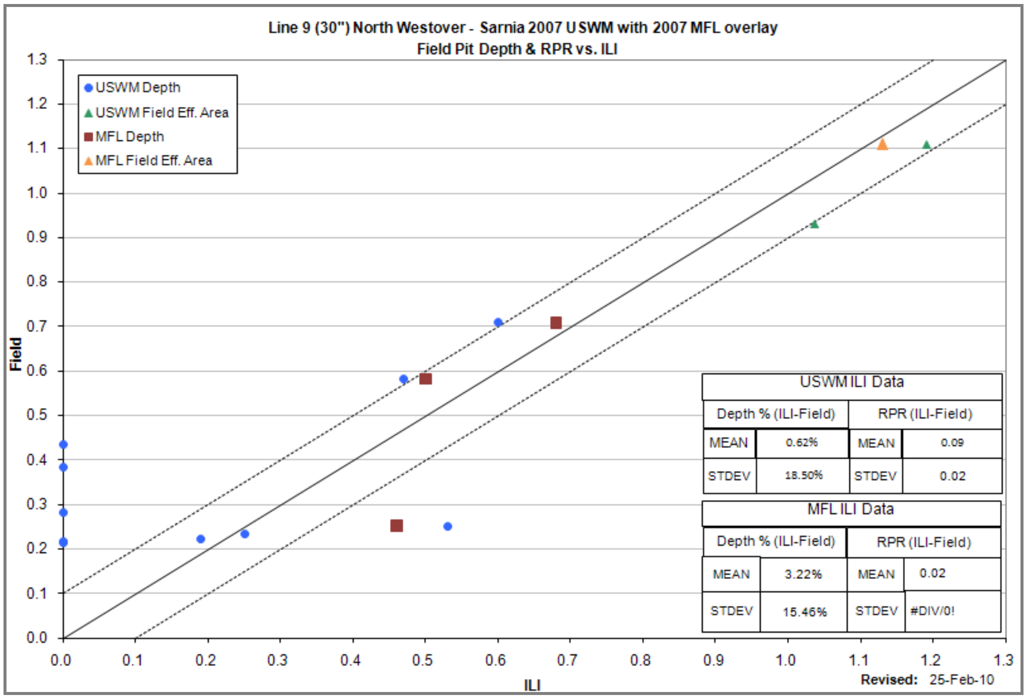


Figure 4.9 –Unity Plot: Line 9 (NW – SA)

4.2.8 Re-Assessment Interval Planning Experience

4.2.8.1 Deterministic Growth Analysis

To provide additional insight into the corrosion condition of the pipeline the anomaly population can be grown out over time utilizing appropriate CGRs.

Each metal loss anomaly is plotted relative to the Enbridge target and tolerance levels along a trap to trap section. The severity of each feature is increased by an offset value to address an ILI tool bias and accuracy variability determined through analysis of the ILI data to field data comparisons. The features are then grown out over time using a reasonably conservative corrosion growth rate. The year that a feature grows to a severity equivalent to the target severity level on the pipeline sets the reassessment interval up to a maximum of ten years.

For this pipeline the depth target level is 75% and the RPR target level are 0.90 for non-HCA areas and 0.93 for HCA areas. Conservative tool offsets and growth rates are applied to the analysis to account for tool variability.

Figures 4.10 and 4.11 investigate the growth of general corrosion features (i.e. RPR values) and the depth of metal loss features over time based on the 2007 USWM ILI result.

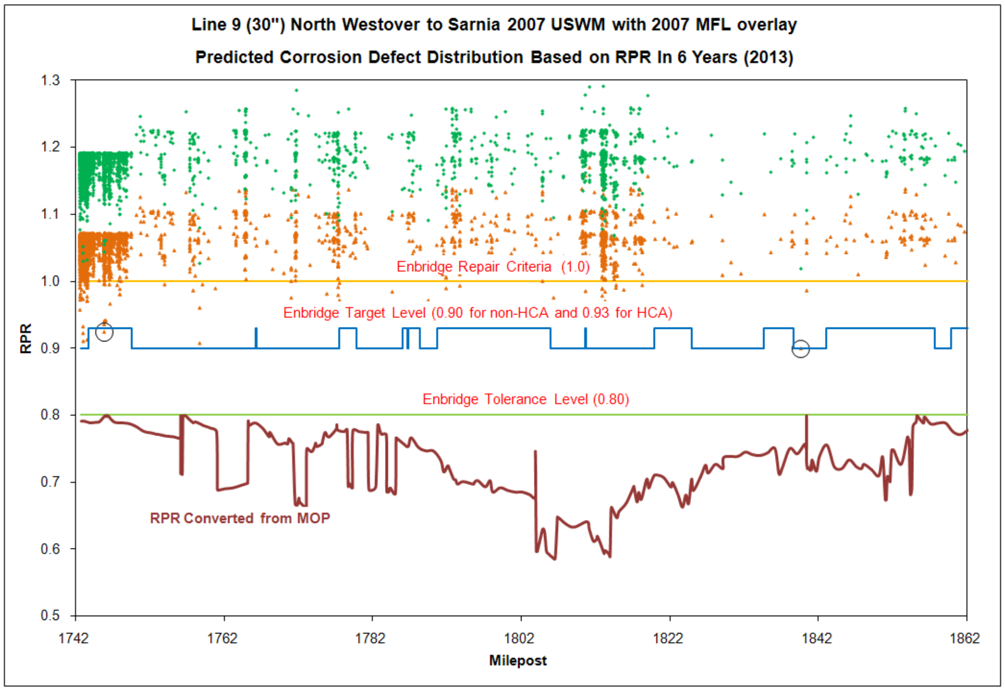


Figure 4.10 - Predicted RPR Severity in 2013 based on USWM and MFL

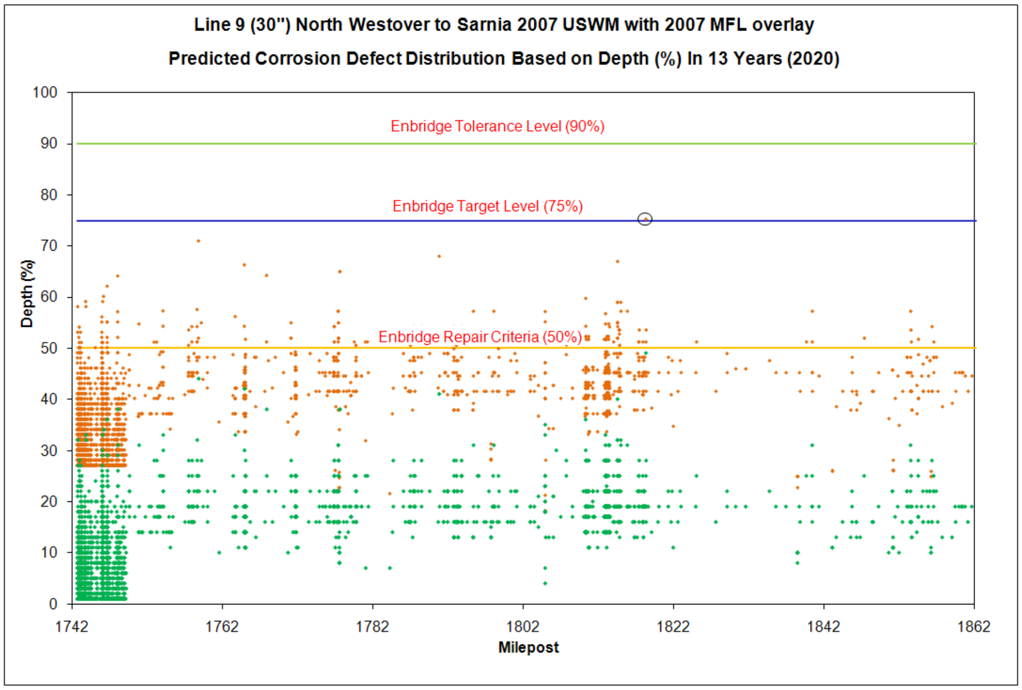


Figure 4.11 - Predicted Depth Severity in 2022 based on USWM and MFL

The deterministic analysis, as summarized in Table 4.9, presents an RPR reassessment interval of 6 years and depth reassessment interval of 13 years. These generally large reassessment intervals illustrate that features on this pipeline segment are low in severity and none will pose a threat to the integrity of the pipeline prior to the next planned inspection, which is scheduled for 2013 in order to meet the most conservative defect RPR severity evaluation.

Table 4.9 – RPR and Depth Reassessment Intervals

2007 Metal Loss Technology	Predicted Defect RPR Severity	Predicted Defect %Depth Severity
USWM and MFL	6 years / re-inspection in 2013	13 years / re-inspection in 2020

4.2.8.2 Final Reassessment Interval

Based on the most conservative defect RPR evaluation completed on the 2007 metal loss inspection, the next ILI for metal loss on this segment of Line 9 is planned for 2013.

4.2.9 Metal Loss Summary and Conclusions

- Enbridge metal loss ILI and mitigation programs meet or exceed the current licensed MOP. As a result, operating the pipeline system in reverse service will not affect the existing programs.
- There are no metal loss features on Line 9 NW to SA that require excavation or repair prior to the proposed flow reversal based on Enbridge excavation criteria in consideration of the 2007 USWM and MFL inspection.
- Proposed lower annual rates are not expected to achieve the critical Froude number at which free water will be entrained in the light or sour crude oils. As such, a prevention program has been planned to displace corrodents through routine maintenance (cleaning) pigging.
- Based upon the analyses completed and summarized in this document the metal loss threat is being adequately addressed and should not prohibit the proposed flow reversal.
- The next MFL is planned to be conducted in 2013 (post reversal).

4.3 Cracking

4.3.1 Crack Management Program

As previously indicated in Section 3.0 of this report, the section of pipeline between SA and NW has not experienced any in-service incidents due to cracking related mechanisms nor other threats. There were also no leaks or ruptures of any kind during the 1997 hydrostatic test of this section of pipe to a pressure equal to 125% of the pipe's MOP.

Enbridge has an established Crack Management Program to manage the threat associated with crack-related defects on its entire pipeline system. Details of Enbridge's Crack Management Program were described in the Integrity Status Report submitted to the NEB on February 23, 2011.

The Crack Management Program for Line 9 consists of the following activities:

- Condition monitoring using an UT crack detection ILI tool.
- Engineering analysis to assess current FFS (i.e. immediately following the ILI).
- Excavation and repair programs to validate crack inspection data and mitigate critical anomalies. In addition to specific excavation programs based on the UT crack detection ILI tool, Enbridge also examines the pipe for crack-related features during its excavation programs based on other ILI technologies.
- Engineering analysis to assess continued FFS (i.e. takes into consideration subsequent growth from fatigue and/or environmental cracking).

Enbridge's excavation and repair programs associated with crack management are based in part on a safety factor approach where the reference level is the maximum allowed operating pressure as determined from the original commissioning hydrostatic test; there is no consideration for actual "at-site" operating pressures below the maximum allowed operating pressures. Thus, as illustrated in Figure 4.12, although the proposed post reversal normal discharge pressure at SA will be higher than the current normal discharge pressures at NW, all pressures are lower than the range of maximum allowed operating pressures (559 to 779 psi). As such, flow reversal will not result in a change to the excavation and repair programs that were previously developed or will be developed in the future.

It is anticipated that flow reversal will result in changes to the magnitude of the pressure cycling due to the proposed post reversal normal discharge pressure (364-492 psi) at SA being higher than the current normal discharge pressures (350 psi) at NW. The pressure cycling spectrum at SA post reversal was modeled based on pressure data collected from the most aggressive loading conditions observed at NW (third quarter of 2003), then scaling the magnitude of pressures (and hence pressure cycles) to reflect the proposed increase in normal operating pressures. A graphical depiction of this pressure spectrum is provided in Figure 4.13. The conclusion that the third quarter of 2003 exhibited the most aggressive loading conditions is illustrated by the fact that during the third quarter of 2003 operating pressures exceeded 340 psi approximately 7% of the time; whereas, for the period between 2007 and 2011 operating pressures exceeded 340 psi only in 2007 and for only approximately 1.1% of the time (refer to Figure 4.14)

For fatigue and SCC growth modeling purposes, the maximum anticipated operating pressures at SA (post-reversal) were derived by scaling the operating pressures at NW by the ratio of 492 psi/350 psi. As illustrated in Figure 4.15, this resulted in generating a pressure cycling spectrum that included a number of high amplitude cycle (> 400 psi). The actual operating pressure cycling will be further evaluated through pressure cycle monitoring and associated remaining life assessments once the flow has actually been reversed.

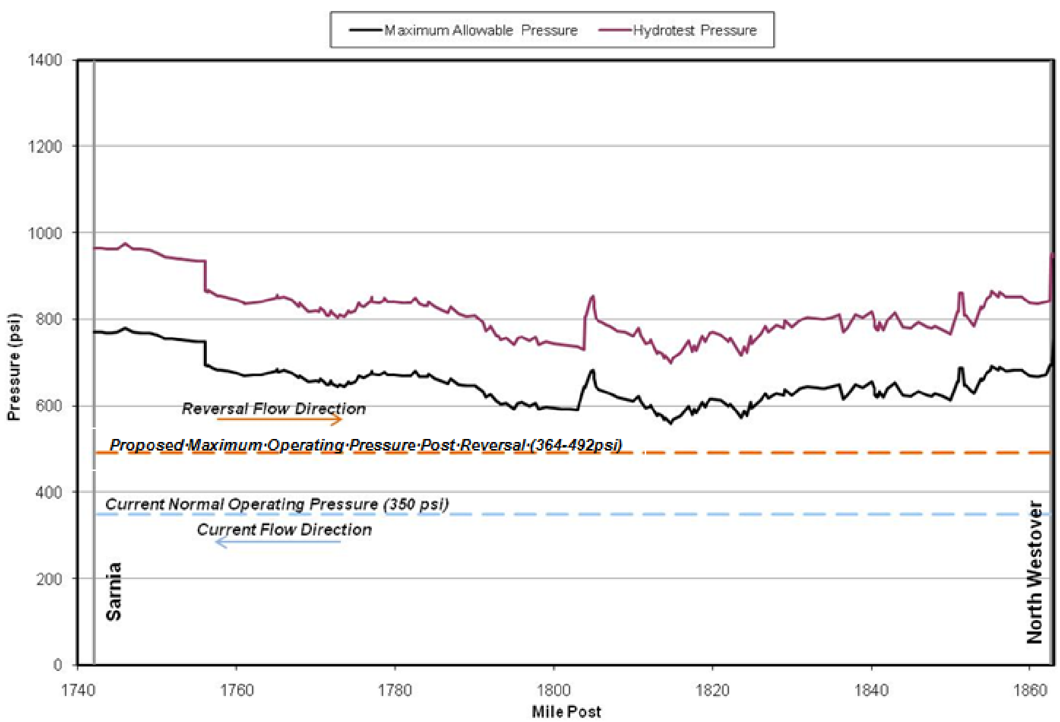


Figure 4.12 - Maximum Allowable Pressure Profiles vs. Mile Post

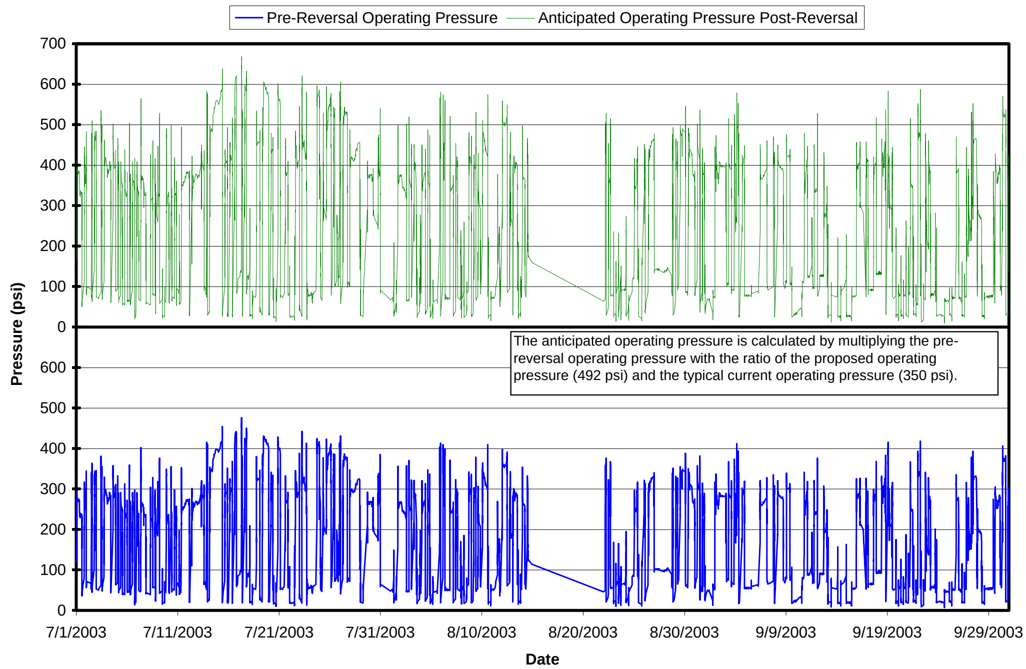


Figure 4.13 - Development of a Post Flow Reversal Pressure Spectrum from 2003 Q3 Operating Pressures

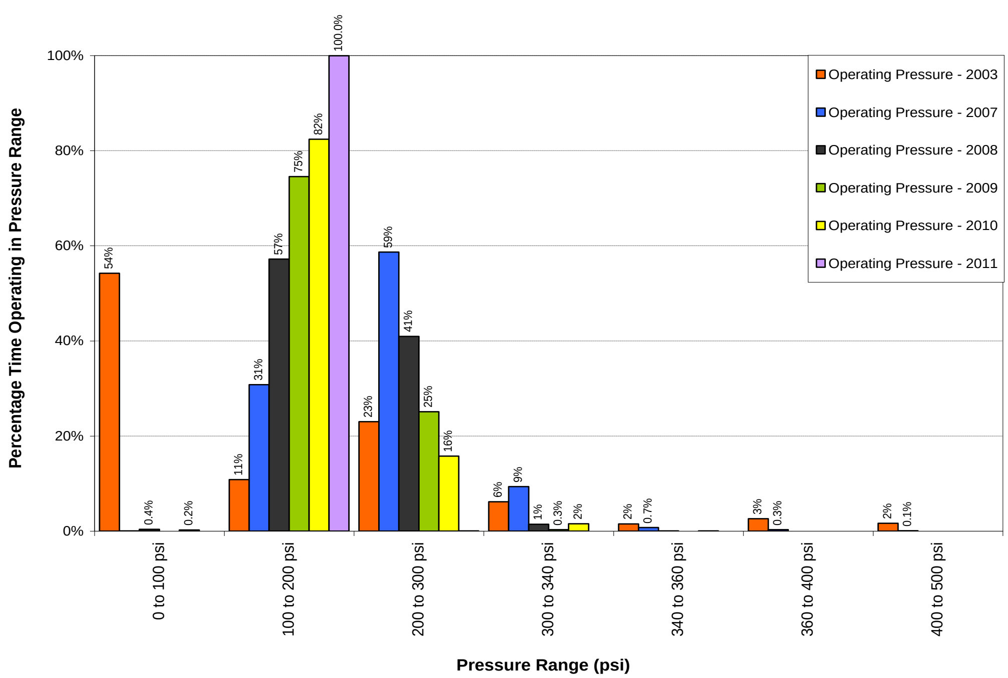
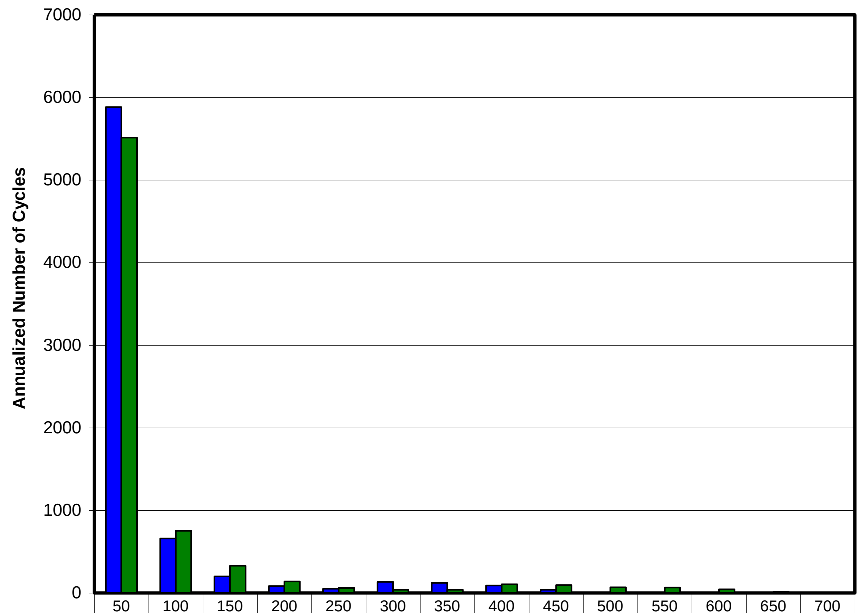


Figure 4.14 - Percentage Time Operating in Pressure Range



	50	100	150	200	250	300	350	400	450	500	550	600	650	700
Pre-Reversal Operating Pressure	5883.5	660.5	199.9	82.6	52.1	134.7	121.7	91.3	39.1	4.4	0.0	0.0	0.0	0.0
Anticipated Operating Pressure Post-Reversal	5514.1	751.7	330.2	139.1	60.8	39.1	39.1	104.3	95.6	69.5	65.2	43.5	13.0	4.4

Pressure Bins (psi)

Figure 4.15 - Rainflow Cycle Counting for Pre and Post Flow Reversal

4.3.2 UT Crack Management Program – 2008 Results

The portion of Line 9 between NW and SA was inspected in 2008 using the high resolution GE UltraScan™ crack detection ("USCD") tool (owned and operated by GE Oil & Gas, PII Pipeline Solutions) in order to identify any axially orientated crack-related features including those located in the longitudinal seam weld.

In GE's final report to Enbridge, GE indicated that there were no data quality related issues (i.e. missing data, lack of sensor coverage, areas of speed excursions, etc.) associated with the inspection run.

Enbridge identified for excavation 6 of the 18 deepest tool reported features (i.e. depths between 1 and 2 mm) to assess the tool's performance. In addition to the 6 excavations selected specifically for the deeper crack-like features, there were also 2 excavations conducted for deformation related features which included 2 crack-like features with depths less than 1 mm. The aim of this initial excavation program was to assess whether: a) the tool was performing as expected in which case additional excavations, as needed, could be identified and undertaken or b) the tool's performance was less than expected in which case GE and Enbridge would need to work together to correct the problem.

As illustrated in Table 4.10, only 2 of the 8 tool reported features identified for excavation corresponded to a field confirmed flaw, both being crack-like features (refer Table 4.11). Based on these observations, GE completed a re-analysis of the USCD data associated with all crack-like features having a reported depth between 1 and 2 mm and identified that a classification error, albeit conservative in nature, had occurred for many of these UT reflectors. As such, GE reclassified 10 similar features previously identified within the 1 to 2 mm depth bin as *irrelevant*, thus only 8 crack-like features were reported in that depth bin as opposed to the previous number of 18. In addition, there were also 3 features previously identified within the <1 mm depth bin that were re-classified as *irrelevant*. The revised feature listing was provided to Enbridge in May of 2011 and was subsequently used in the EA discussed below in Section 4.3.4.

The deepest field measurement of the 2 tool reported features was 1.4 mm (21% of the pipe wall thickness) which is within the tool reported depth range of 1 to 2 mm (15 to 31% of the pipe wall thickness). Figure 4.16 provides a graphical depiction of the depth based field-tool trending.

The lowest field predicted burst of the 2 tool reported features was 1020 psi (157% of the maximum allowable operating pressure ("MAOP") and 207% of the proposed normal operating pressure post reversal (492 psi) which is significantly greater than the tool predicted burst pressure of 814 psi (125% of the MAOP and 165% of the planned maximum discharge pressure (492 psi). Figure 4.17 provides a graphical depiction of the predicted burst pressure based field-tool trending.

Table 4.10 - Field Excavation Data for Line 9

Girth Weld	ILI Reported Information								Field information						
	ILI Feature	WT	Length	Est. Depth	Type	Predicted Burst Pressure			WT	Length	Depth	Type	Predicted Burst Pressure		
		mm	mm	mm		psi	% MOP	% of 492	mm	mm	mm		psi	% MOP	% of 492
18440	015 - 00403	6.50	167.00	1 - 2 mm	Crack Like	807.58	130.98%	164.14%	Not Found						
25680	020 - 05223	7.29	210.82	<1 mm	Crack Like	926.18	148.43%	188.25%	Not Found						
28060	022 - 03235	6.50	145.00	1 - 2 mm	Crack Like	813.92	125.44%	165.43%	6.48	57.91	1.10	Crack-Like	1020.74	157.28%	207.47%
65420	051 - 00683	6.50	82.00	1 - 2 mm	Crack Like	895.84	153.36%	182.08%	6.60	29.97	1.40	Crack-Like	1063.78	182.15%	216.22%
65420	051 - 00734	6.50	120.00	1 - 2 mm	Crack Like	846.71	144.96%	172.10%	Not Found						
88390	068 - 05255	6.81	426.72	<1 mm	Crack Like	900.39	151.32%	183.01%	Not Found						
131520	101 - 07249	6.50	54.00	1 - 2 mm	Crack Like	938.16	143.05%	190.68%	Not Found						
149080	115 - 01682	6.50	84.00	1 - 2 mm	Weld Anomaly	892.79	129.63%	181.46%	Not Found						

Table 4.11 - Field Observations by USCD Reported Feature Type

Observed Defect	Feature Type as Reported by the USCD Tool			
	Crack-Field	Crack-Like	Notch-Like	Weld Anomaly
SCC				
Crack-Like		2 (25%)		
Lack of Fusion				
Lamination				
Gouge				
Feather Burn				
Mill Weld Trim				
Notch				
Mill Grind				
Stringer				
Roller Mark				
Mill Defect				
Arc Strike with Cracking				
Not Found		6 (75%)		
Corrosion				
Total	**0**	**8**	**0**	**0**
Probability of Detection (POD)	**N/A**	**100%**	**N/A**	**N/A**
Probability of Identification (POI)	**N/A**	**100%**	**N/A**	**N/A**

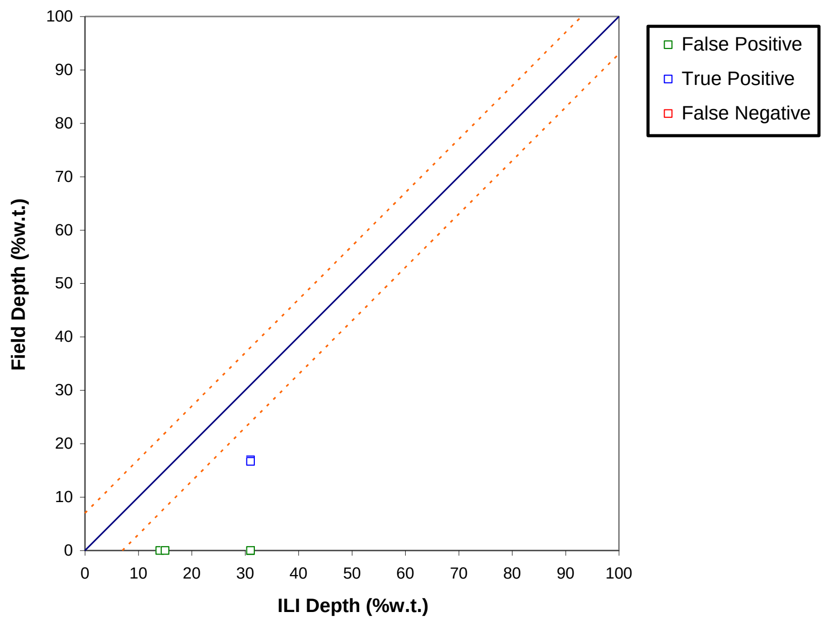


Figure 4.16 - Depth Unity Plot based on USCD 2008

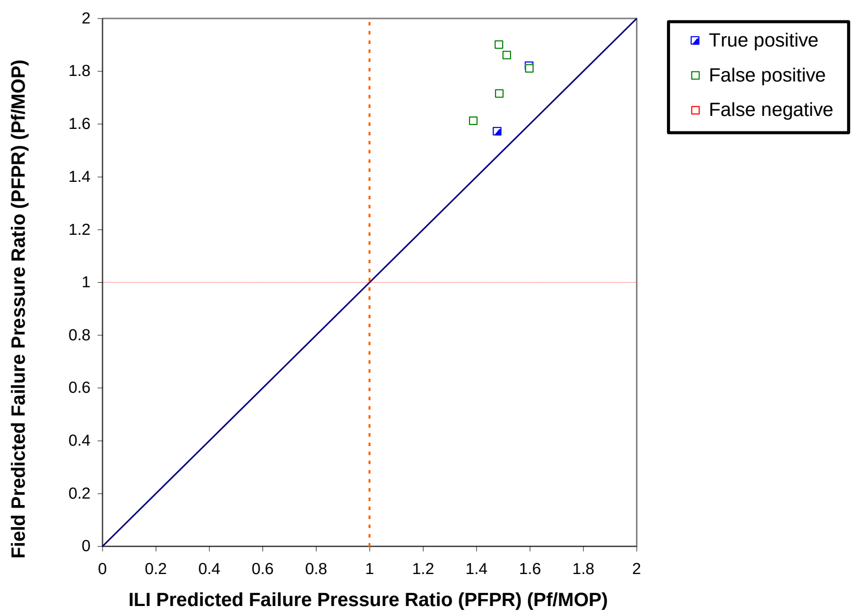


Figure 4.17. Fitness-for-Purpose Unity Plot based on USCD 2008

* for plotting purposes, false positive flaws are plotted with a field Pf/MOP value equal to the flow stress of the pipe.

As illustrated in Table 4.12, there were a total of 357 crack-like features within the final USCD report, all of which were identified by GE as being adjacent to the long seam weld. Approximately 79% (281) of those features were reported as being external features while the remaining 21% (76) features were identified as being internal features. There were no other crack feature types identified by this inspection.

The reported features are spread throughout the length of line between SA and NW; although the frequency of features varies along the length of the line there is no discernible trend (refer to Figure 4.18).

Approximately 98% (349) of the features had reported depths <1 mm while only 2% (8) features had reported depths between 1 and 2 mm (refer to Figure 4.19). There were no features with reported depths >2 mm.

The lowest predicted burst pressure of the reported features, as determined using the CorLAS™ software, was 814 psi which equates to 125% of the MAOP and 165% of the proposed normal operating discharge pressure (492 psi) following the planned flow reversal (refer to Figure 4.20). This particular feature was excavated in 2009. The lowest predicted burst pressure of a reported feature, that hasn't yet been excavated nor is planned for excavation in 2011, is 870 psi which equates to 128% of the MAOP and 177% of the planned maximum discharge pressure (492 psi) following the planned flow reversal. As illustrated in Figure 4.21, there were no features with predicted burst pressures less than 125% of the MAOP while the vast majority (80%) of the features had a predicted burst pressure >140% of the MAOP. The following assumptions were used as input into the CorLAS™ software to calculate the predicted burst pressures of the reported features:

- Flaw profile: rectangular profile
- Wall thickness: the lesser of the nominal wall thickness or the wall thickness as measured by the UT wall measurement ILI tool
- Nominal yield strength for grade 359 MPa: 359 MPa
- Nominal tensile strength for grade 359 MPa: 455 MPa
- Flow strength: yield strength + 68.9 MPa
- Charpy V-notch impact toughness: 15 ft-lb

Table 4.12 - Summary of Tool Reported Features

Feature Type	Relative Position	Radial Position	Number of Features	Percentage of Total
Crack-Like	Base Metal	External	0	0.00%
Crack-Like	Base Metal	Internal	0	0.00%
Crack-Like	Adjacent to Weld	External	281	78.71%
Crack-Like	Adjacent to Weld	Internal	76	21.29%

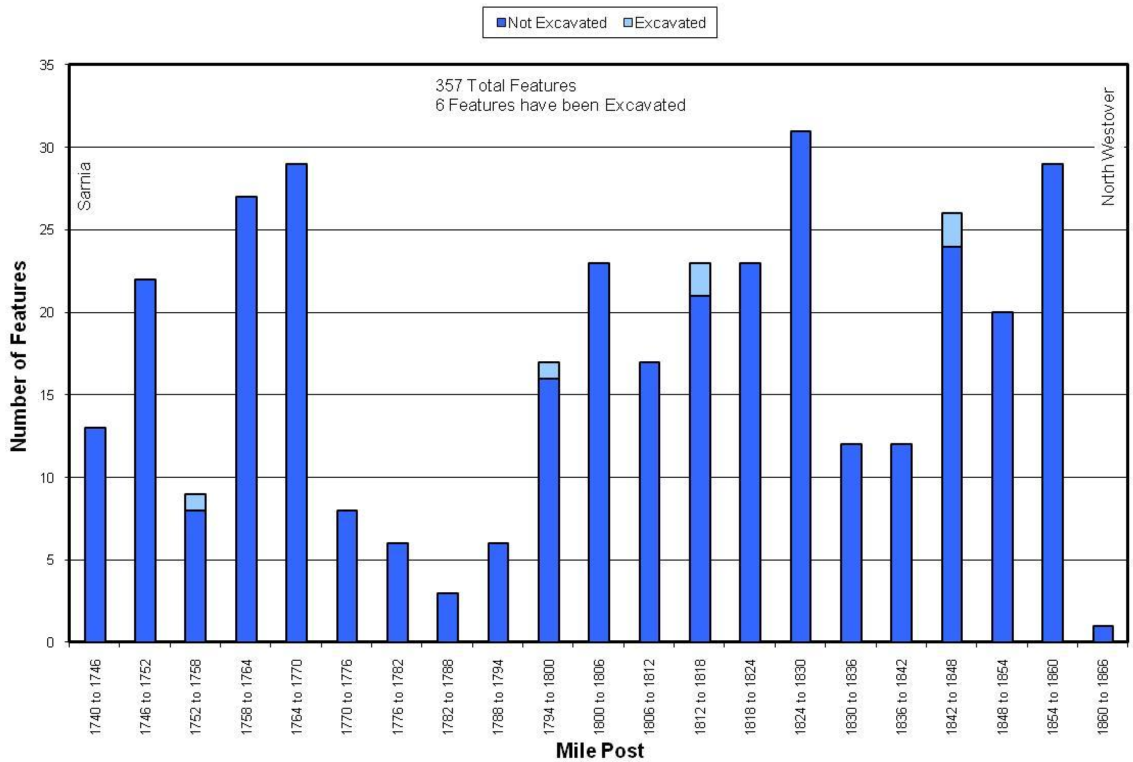


Figure 4.18 - Number of Features versus Chainage

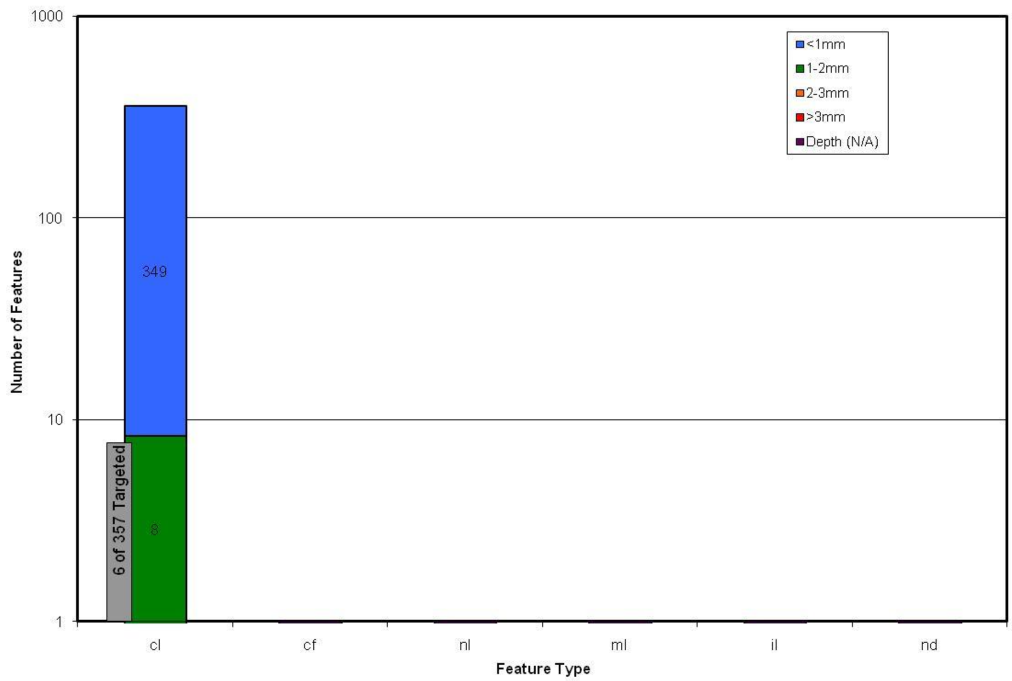


Figure 4.19 - Line 9 SA to NW Feature Depth Bins.

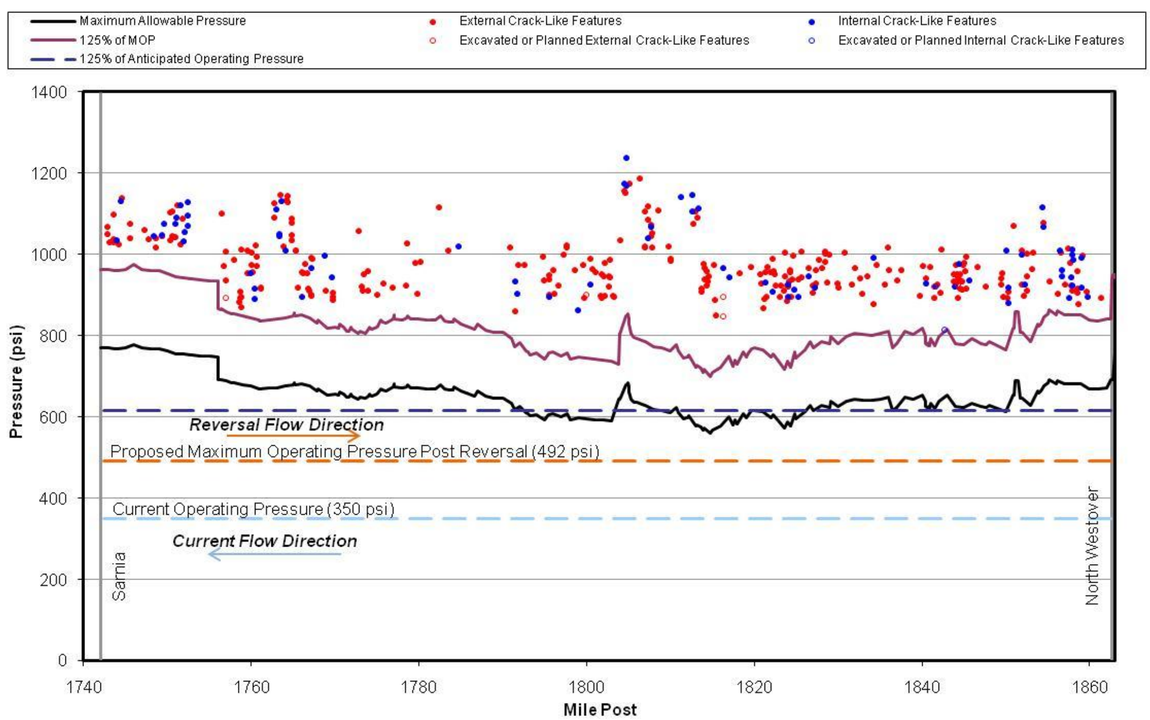


Figure 4.20 - Line 9 SA to NW Predicted Burst Pressures.

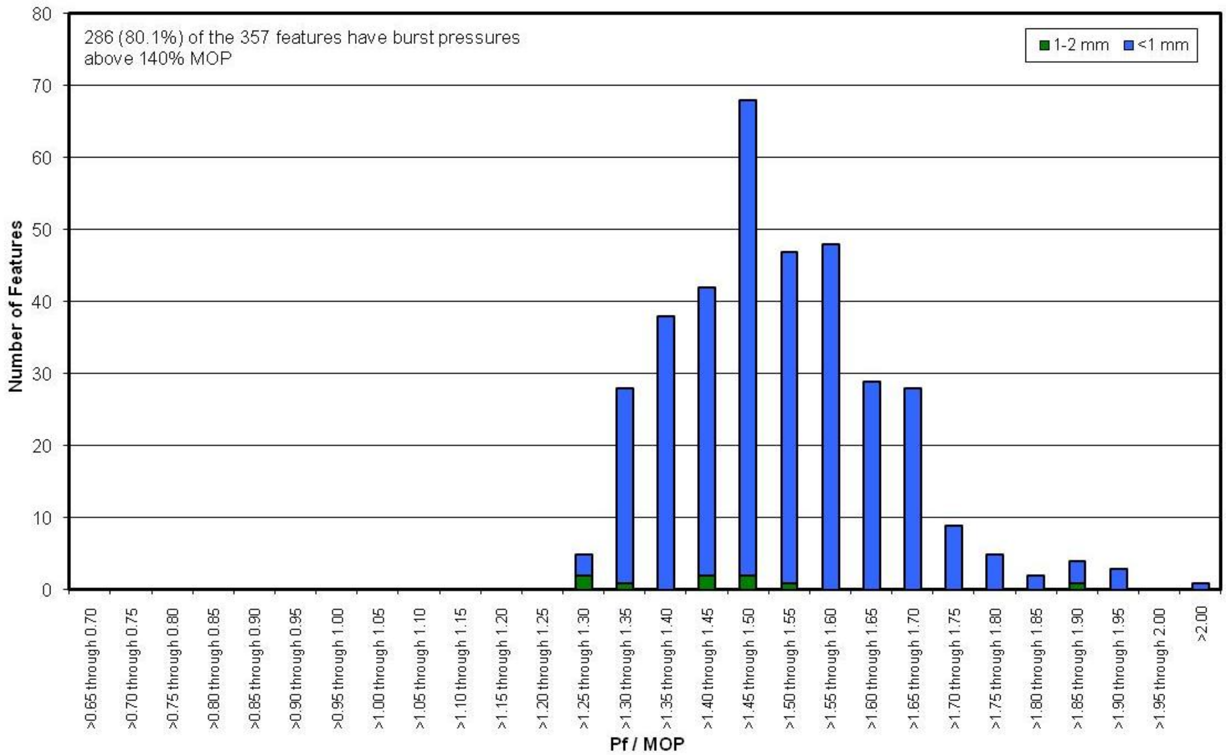


Figure 4.21 - Histogram Showing Predicted Burst Pressures for Tool Reported Crack ILI Features

4.3.3 UT Crack Detection ILI Program – Engineering Assessments

Enbridge contracted Det Norske Veritas (Canada) LTD. ("DNV") to undertake an EA of the 351 unexcavated tool reported features not planned to be excavated in 2011 to determine their respective remaining lives. The remaining life assessment considered growth from both a fatigue and SCC perspective. In order to compare the affect of the flow reversal on the predicted remaining lives of the features an assessment was done based on pre and post flow reversal operating conditions.

Provided below is the approach used by DNV to undertake that remaining life assessment, the assumptions used in the assessment, and the subsequent results.

4.3.3.1 Initial and Final Dimensions of Unexcavated Tool Reported Features

Since there is currently limited field-tool trending data available with which to assess the accuracy of the 2008 crack detection tool data the reported dimensions of the features were adjusted by +2 tool tolerances (i.e. 0.040" in depth and 20% in length) to account for any potential under sizing of the reported features. These adjusted feature dimensions were used as the initial feature dimensions.

The final critical dimensions of each adjusted tool reported feature were subsequently calculated using the CorLAS™ software. The following assumptions were used as input into those calculations:

- Flaw profile: semi-elliptical profile based on the adjusted tool reported total length and maximum depth
- Operating Pressure (Scenario 1): 350 psi (typical maximum discharge pressures at NW pre-flow reversal)
- Operating Pressure (Scenario 2): 492 psi (expected maximum discharge pressure at SA post-flow reversal)
- Wall thickness: the lesser of the nominal wall thickness or the wall thickness as measured by the UT wall measurement ILI tool
- Nominal yield strength for grade 359 MPa: 359 MPa
- Nominal tensile strength for grade 359 MPa: 455 MPa
- Flow strength: yield strength + 68.9 MPa
- Charpy V-notch impact toughness: 15 ft-lb

4.3.3.2 Pressure Cycle Analysis

A loading spectrum is required for the fatigue and SCC remaining life calculations which is obtained by performing a pressure cycle analysis on representative pressure data. Provided below are the operating histories that were used to assess the remaining lives of reported features pre and post flow reversal:

- **Pre-Flow Reversal Operating Pressure History**

  The pressure data recorded in the third quarter of 2003 at NW was used to represent the pre-flow reversal operating pressure. This pressure data was selected because it has been deemed to be the most aggressive loading conditions that this section of Line 9 has experienced since 2003 (refer to Section 4.3.1).

- **Post-Flow Reversal Operating Pressure History**

  In order to simulate the post-flow operating pressure history the pressure data recorded in the third quarter of 2003 at NW was multiplied by the ratio of expected maximum discharge pressure at SA post-flow reversal/typical maximum discharge pressures at NW pre-flow reversal (492 psi/350 psi).

The two pressure histories discussed above were evaluated by the rainflow cycle counting method to establish the number and magnitude of the various pressure cycles contained within the pressure data. This method of cycle counting is described in ASTM E1049, Standard Practices for Cycle Counting in Fatigue Analysis.[1]

Rainflow counting historically was developed to relate variable amplitude strain histories to constant amplitude fatigue data. Under nominally elastic conditions, the strain amplitude can be directly related to the stress amplitude. The technique is now widely used to relate variable amplitude fatigue loading to constant amplitude fatigue data. In typical pipeline applications, rainflow counting is applied to a representative pressure fluctuation history to produce cycle counts for a series of pressure ranges. The pressure ranges are then converted to stress ranges using the Barlow formula.

The results of the cycle counting were then used to perform the SCC and fatigue crack growth assessments discussed below.

4.3.3.3 SCC Growth Rate Analysis

The cycle counting program described above is capable of determining the frequency and loading rate associated with each pressure cycle that is counted. This calculation is required for SCC growth analysis. The fatigue growth analysis calculates the damage per cycle, which is independent of the frequency of the cycle. The SCC growth analysis calculates the amount of SCC growth based on the crack tip strain rate, which is frequency and loading rate dependent.

To calculate the SCC growth rate, the cyclic frequency (*f*) is used in conjunction with the R-ratio (*R*), maximum stress intensity factor (K_{MAX}), a constant (*C*) and yield strength (σ_y) to calculate the average crack tip displacement rate ($\dot{\delta}$), as demonstrated in previous SCC research by Beavers[2] (see Equation 1).

$$\dot{\delta} = \frac{C}{\sigma_y}\left(f\, K_{MAX}{}^{2}\,(1 - R)\right) \qquad (1)$$

The K_{MAX} is computed using fracture mechanics principles utilizing the maximum pressure, nominal pipe dimensions and an assumed crack length. The crack lengths and depths used for these calculations were the adjusted dimensions of the tool reported features discussed above. For each of the adjusted reported features, the starting K_{MAX} value based on an operating pressure of 350 psi (pre-flow reversal) or 492 psi (post-flow reversal) was chosen for the SCC growth rate calculation.

Beavers also demonstrated a relationship between crack tip displacement rate and crack velocity (*v*), which is:

$$\nu = 0.0049 \cdot \left(\dot{\delta} \right)^{0.5478} \quad (2)$$

By knowing the crack tip displacement rate, the amount of crack growth is computed from the crack velocity and duration of each cycle. The damage for all cycles is then summed and divided by the time period for the pressure history to calculate the SCC growth rate.

4.3.3.4 Fatigue and SCC Remaining Life Calculations

There are three fatigue crack growth regimes, as shown in Figure 4.22, where the cyclic crack growth rate (da/dN) is a function of the range of stress intensity factor (ΔK).

The range of stress intensity factor, ΔK, is a parameter relating to the cyclic stress and crack size and is the driving force for crack growth. This figure shows that crack initiation, propagation (growth), and final failure are exhibited in Region A, B, and C, respectively. The Paris region corresponds to Region B, where the cyclic crack growth rate is directly proportional to the range of stress intensity factor. The Paris Law[3,4] was used to describe this relationship:

$$\frac{da}{dN} = C(\Delta K)^n \quad (3)$$

where *C* and *n* are constants that depend on material and environment. Values for *ΔK* were calculated assuming a semi-elliptical surface crack[5,6]. Thus, the remaining fatigue life is calculated by integrating the Paris Law crack growth from the initial flaw size (adjusted tool reported dimensions) to the final flaw size (critical dimensions of adjusted tool reported at pre and post flow reversal pressures (350 psi and 492 psi) using the pressure cycles calculated above for the pre and post flow reversal operating pressure histories. These calculations were conducted at the upper-bound fatigue crack growth rates from API 579-1/ASME FFS-1[7]. Using the upper-bound fatigue crack growth should provide a lower bound (conservative) remaining life.

For a cyclic crack growth rate (da/dN) in terms of inches per cycle and ΔK in terms of ksi-in$^{0.5}$, these upper bound rates correspond to the following Paris Law parameters:

- A coefficient of 8.61×10^{-10} and exponent of 3.00 for weld material

The SCC remaining life for each adjusted tool reported feature was calculated by dividing the amount of crack growth required for failure (i.e. the difference between the initial flaw size (adjusted tool reported dimensions) and the final flaw size (critical dimensions of adjusted tool reported at pre and post flow reversal pressures (350 psi and 492 psi)) by the SCC growth rate calculated for each feature using the approach discussed above.

To ensure conservatism in establishing the actual remaining life for each adjusted tool reported feature the lesser of the calculated fatigue or SCC remaining life was assumed.

4.3.3.5 Summary of Assessment

Based on the analysis discussed above, there are no adjusted tool reported features expected to fail at either the pre-flow reversal pressure (350 psi) or the post-pressure reversal pressure (492 psi) during the next 3 years (refer to Figures 4.23 and 4.24). Enbridge presently plans to re-inspect this portion of Line 9 in 2 years time.

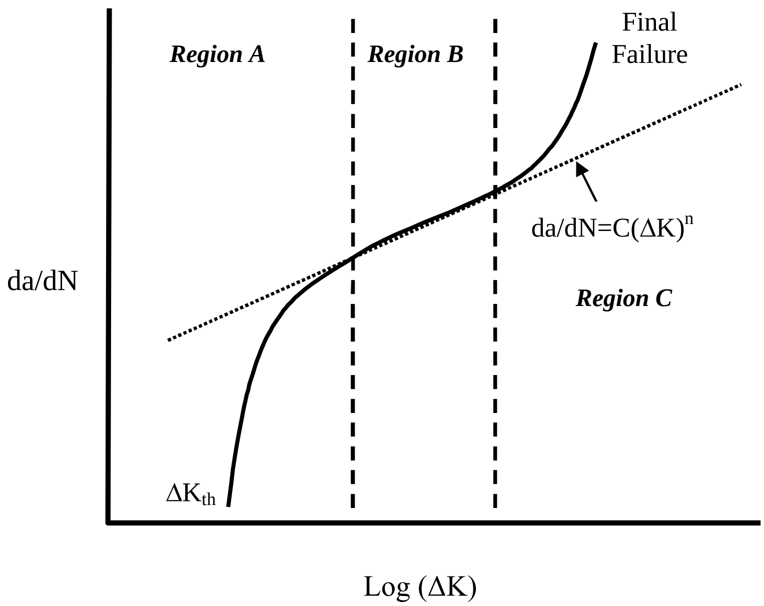


Figure 4.22 - Fatigue crack growth regimes represented as the cyclic crack growth rate (da/dN) as a function of the range in stress intensity factor (ΔK)

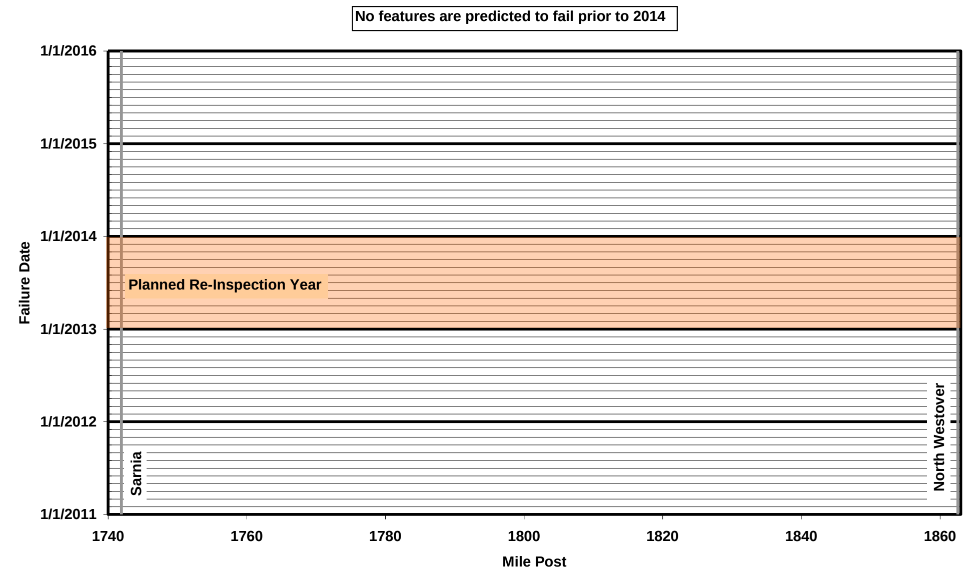


Figure 4.23 - Line 9 SA to NW Deterministic Assessment – Growth to 350 psi using Pre-Reversal Operating Pressure with +2 Tolerances added to their Flaw Dimensions

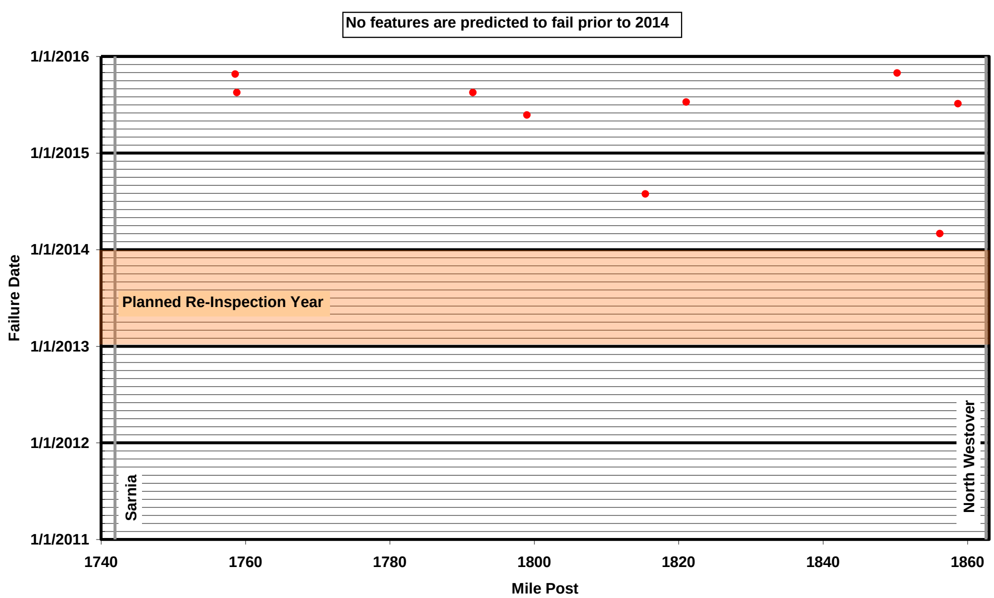


Figure 4.24 - Line 9 SA to NW Deterministic Assessment – Growth to 492 psi using Anticipated operating Pressure Post-Reversal with +2 Tolerances added to their Flaw Dimensions

4.3.4 SCC

Enbridge considers that the external coating applied to a pipeline is the predominate factor determining the susceptibility of a given pipeline to SCC. The section of Line 9 between SA and NW is coated with a single layer PE Tape; it has been well documented that other PE Tape coated pipelines with the industry have exhibited moderate to high susceptibility to SCC. Consequently, Enbridge considers the section of Line 9 between SA and NW to be potentially susceptible to SCC.

As mentioned previously in Section 4.3.2, during the 2008 ILI with the GE USCD tool there were no crack-field features reported by the tool. Although field observed SCC has been associated with tool reported crack-like features it’s predominately associated with tool reported crack-like features. Despite the fact that only 2 of the reported crack-like features excavated had associated crack-field features both of those crack-field features were in fact crack-like and not SCC. Thus the implication of the 2008 USCD data is that there are potentially no SCC colonies present in the section of Line 9 between SA and NW with dimensions greater than the tool’s reporting threshold (60 mm deep and 1 mm long).

In addition to the excavations that were undertaken based solely on the findings of the USCD tool, Enbridge has also undertaken 44 other excavations, since 2003, to address features reported by other ILI technologies (refer to Table 4.13). During those excavations, in which 169 m of pipeline was inspected for cracking using Magnetic Particle Inspection (“MPI”), a total of 10 SCC colonies were detected at4 different locations. Field assessment of the SCC colonies determined that none of the SCC met the definition of significant SCC. Thus although shallow SCC has been detected on the portion of Line 9 between SA and NW the excavation data, collected to date, suggests that it doesn’t currently present an immediate threat to the integrity of this portion of Line 9.

Enbridge will continue to monitor the portion of Line 9 between SA and NW for SCC and other cracking related mechanisms using crack detection ILI technologies. In addition, Enbridge will also continue to undertake MPI during its excavation programs based on other ILI technologies.

Table 4.13 - Listing of Historical Excavations Performed on Line 9 – SA to NW

GW	Excavation Year	Reason for Excavation	NDE Length (m)	Comments
12800	2009	Dent	5.45	No crack found in the field
12850	2009	Corrosion	4.86	7 SCC colonies found. Maximum crack depth was 35%
13360	2009	Dent	5.00	No crack found in the field
17840	2009	Dent	5.00	No crack found in the field
23260	2009	Dent	6.00	1 SCC colony found. Maximum crack depth was 10%
24980	2009	Dent	5.15	No crack found in the field
25680	2009	Dent	3.68	No crack found in the field
28920	2009	Dent	5.00	No crack found in the field
31280	2009	Corrosion	7.25	No crack found in the field
37950	2010	Corrosion	3.29	No crack found in the field
39700	2009	Dent	3.96	No crack found in the field
4700	2003	Dent	2.54	8% SCC found in the field
50620	2009	Dent	5.90	No crack found in the field
54070	2009	Dent	5.85	No crack found in the field
55820	2009	Dent	5.50	No crack found in the field
62110	2009	Corrosion	3.75	No crack found in the field
62470	2009	Dent	3.60	No crack found in the field
62990	2009	Dent	5.00	No crack found in the field
63260	2009	Dent	3.58	No crack found in the field
6530	2003	Dent	1.88	20% deep LI, no SCC found
7580	2003	Dent	1.94	No crack found in the field
7660	2003	Dent	2.25	No crack found in the field
8940	2003	Dent	1.69	No crack found in the field
9070	2003	Dent	3.05	No crack found in the field
10370	2003	Dent	3.30	No crack found in the field
11770	2003	Dent	3.9	No crack found in the field
12750	2003	Dent	2.60	No crack found in the field
13100	2003	Dent	5.20	No crack found in the field
14200	2003	Dent	1.75	No crack found in the field
16880	2003	Dent	4.00	No crack found in the field
16960	2003	Dent	4.09	No crack found in the field
17890	2003	Dent	1.65	No crack found in the field
60170	2003	Dent	2.45	No crack found in the field
60910	2003	Dent	2.10	No crack found in the field
66350	2003	Corrosion	1.32	No crack found in the field
84930	2009	Dent	2.98	No crack found in the field
86210	2009	Dent	5.29	No crack found in the field
88390	2009	Dent	4.20	No crack found in the field
88480	2003	Dent	1.97	No crack found in the field
94960	2009	Dent	7.54	No crack found in the field
97910	2009	Dent	2.27	No crack found in the field
106940	2009	Dent	2.68	No crack found in the field
146470	2003	Corrosion	3.95	No crack found in the field
164230	2003	Dent	4.32	No crack found in the field

Note that field assessment of these flaws determined that none of the observed SCC met the definition of “Significant SCC”.

4.3.5 Cracking Risk Profile Pre and Post Flow Reversal

The cracking risk profile associated with the portion of Line 9 between SA and NW, pre and post flow reversal, is depicted graphically in Figure 4.25. The risk profile was determined by Enbridge's Operational Risk Management group. The cracking risk profile pre and post flow reversal is essentially identical except for the first 5 miles downstream of SA and the last 5 miles upstream of NW. As would be expected, the cracking risk profile is calculated to be higher post-flow reversal immediately downstream of SA because this section will now see higher operating pressures than it typically has seen in the past; conversely, the cracking risk profile is calculated to be lower post-flow reversal immediately upstream of NW because this section will now see lower operating pressures than it typically has seen in the past.

To better understand the implications of a higher cracking risk profile immediately downstream of SA, post flow reversal, the results of the EA for this section of pipe were collected and are summarized below:

- There are only 14 reported crack-like features in the 5 mile section immediately downstream of SA
    - All of those features have depth <0.040"
    - The lowest predicted burst pressure of those features is 209% of the MAOP
    - The shortest calculated remaining life of those features is approximately 53 years

Thus although the cracking risk profile is theoretically higher post-flow reversal immediately downstream of SA the 2008 crack detection data and subsequent EA would suggest that this section of line is not at an immediate threat from cracking related mechanisms. Notwithstanding, investigative crack excavations will be conducted in 2012 on crack ILI reported defects with particular focus on the area west of SA.

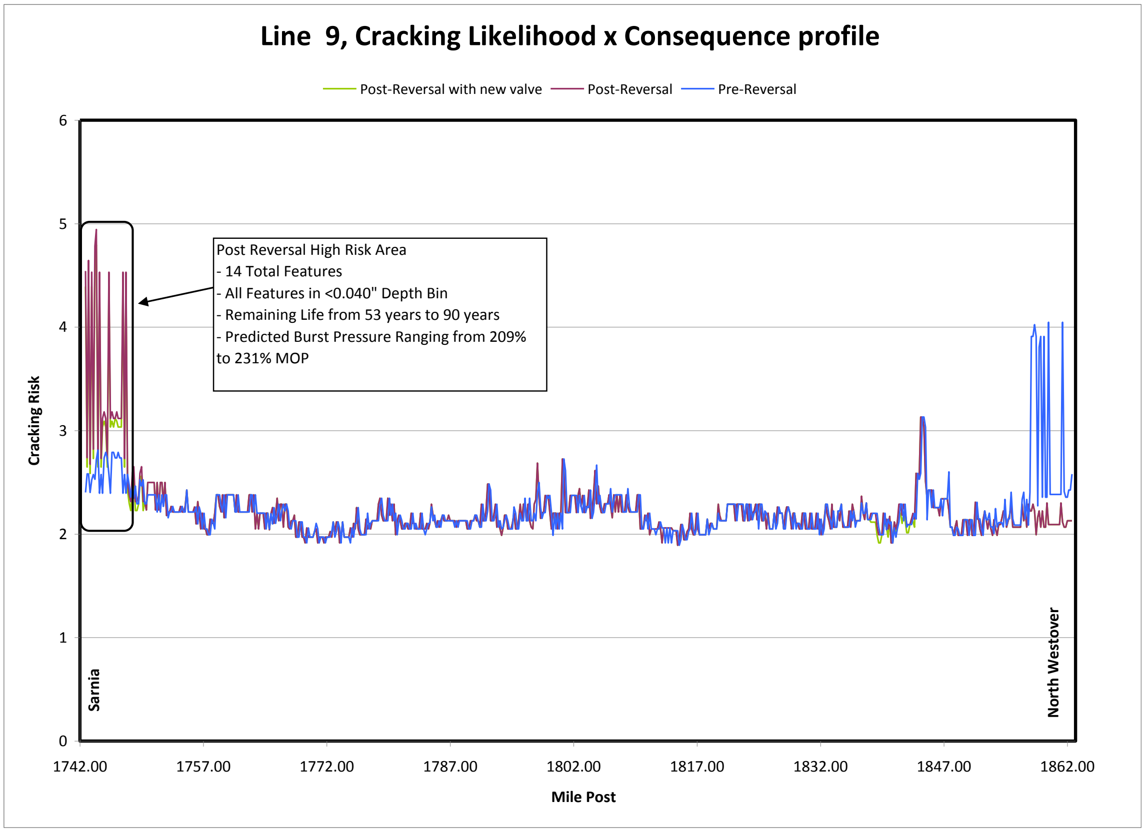


Figure 4.25 - Risk Assessment of Line 9 between SA and NW

4.3.6 Cracking Summary and Conclusions

- Flow reversal will not require any modifications to the manner in which the existing crack management program is developed or implemented; however, investigative crack excavations will be conducted in 2012 on crack ILI reported defects west of SA.

- Based on an EA, there are presently no features reported by the 2008 crack detection inspection that are predicted to fail in the next 3 years under either pre or post-flow reversal operating conditions.

- A crack ILI is not required prior to flow reversal but will be conducted in 2013 following reversal as part of the existing crack management program.

4.4 Mechanical Damage

Enbridge has a mechanical damage management plant (“MDMP”) to address the threat of damage in the form of dents, gouges, etc. from a variety of sources including strikes from excavating equipment and pipe settlement onto rock. Enbridge refers to damage of this type as mechanical damage. Damage that may result in a failure some time after the initial impairment (e.g. months or years after the damage occurs) is the focus of Enbridge MDMP. The application of the MDMP to assess the condition of the pipeline consist primary of utilizing ILI technologies, coupled with field excavation programs.

4.4.1 Third Party Damage Prevention

Prevention is a key component to Enbridge's approach to mitigating the potential for mechanical damage to occur as a result of third party damage. The Enbridge Lands & Right of Way Department uses a comprehensive right of way ("RoW") monitoring and stakeholder awareness program to prevent third parties from gaining access and damaging the pipeline system. Components of the program include public (landowner and local contractor) awareness, RoW patrols, signage and participation in local One Call organizations and investigation and follow up on unauthorized activities. Enbridge has succeeded in minimizing third party damage on its pipeline system through this approach to damage prevention. Where required, depth-of-cover surveys are initiated and results are reviewed to determine if additional monitoring activities are necessary.

4.4.2 Susceptibility to Mechanical Damage

Pipelines are susceptible to mechanical damage during construction or as a result of changing RoW conditions or damage resulting from third party contact during the operating life of the pipeline.

For mechanical damage that is sustained to the pipeline, whether it is residual from construction, experienced due to pipe or soil settlement post construction or created by undetected third party contact, detection is made by ILI. Pipelines with a high diameter over thicknesss ("D/t") ratio (typically > 100) are relatively more susceptible to mechanical damage. With a D/t ratio of 120, this pipeline is no exception, which is evidenced by the dent population reported by ILI technologies as described in the sections that follow. Despite the relatively high susceptibility to mechanical damage and a relatively high population of reported dent features, integrity management systems can successfully manage the mechanical damage threat on in service pipelines. As indicated earlier in this report, Enbridge has never experienced a leak or rupture on this pipeline from NW to SA due to mechanical damage or otherwise.

4.4.3 Mechanical Damage Identification and Characterization

ILI tools that are utilized to detect deformation and potential mechanical damage include both geometry tools and metal loss tools. The primary technology used to detect and identify mechanical damage is geometry (caliper), which physically measures variances in the internal diameter of the pipeline to identify geometry features indicative of mechanical damage. In additional to identifying features in the pipeline, modern technologies have the ability to characterize those features in shape (plain, smooth, symmetrical, sharp, multi-apex), circumferential orientation (top side vs. bottom side and proximity to long seam welds), axial position (distance from nearest girth weld) and depth.

Enbridge uses only high resolution caliper inspection tools for the purpose of completing mechanical damage inspections throughout the pipeline system. Prior to use, caliper ILI vendors and their accompanying technologies are required to complete a qualification process to ensure that the tool will meet the required performance and reporting standards adopted by Enbridge. All caliper ILI tools utilized by Enbridge are proven to repeatedly detect dents that are 2% or greater in depth, as well as dents less than 2% in depth; however, tool specifications generally indicate that sizing of dents less than 1% in depth can be unreliable. Enbridge requires all dents equal to or greater than 2% that are detected by the caliper tools to be reported by the ILI Vendor in the ILI report.

Caliper technology can be supplemented with data from metal loss technology such as MFL or USWM to provide additional characterization of mechanical damage features with respect to stress concentrators (corrosion features, gouging, etc.) that may provide an initiation point for cracking to occur. Because of the limited ability of metal loss technologies to accurately measure dent depths, typically all geometry features identified are reported, and those that are associated with secondary features such as metal loss, gouging or welds are flagged. This data can then be integrated with caliper data to determine actual dent depths to assist in determining the need for additional assessment or field investigation for individual features.

To mitigate features identified as potential threats, Enbridge has developed criteria for selection of features for potential field assessment. Selection of geometry features for field assessment is supported by the additional levels of characterization provided by integrating data from multiple ILI technologies. The excavation and field assessment criteria are based on Enbridge and industry experience and regulatory requirements.

The Enbridge excavation criteria applicable to mechanical damage programs on this pipeline are:

- Dents >=6.0%
- Dents >=2.0% between the 8:00 and 4:00 radial positions (top-side)
- Dents >=2.0% on welds (weld position per metal loss tool)
- Dents >=2.0% associated with metal loss, or other stress risers
- Dents >=2.0% identified as having multiple apexes

4.4.4 Recent Mechanical Damage Program Results

The mechanical damage inspection and repair results for the ILI runs completed in 2007 are shown in Table 4.14. These include the results from the 2007 TDW Magpie Kaliper and the 2007 GE MFL inspection, which reported a total of 812 geometry features, including dent features <2%. Figures 4.26 and 4.27 illustrate the distribution of the reported dent features on this pipeline.

Table 4.14 – Mechanical Damage Reported by 2007 ILI

Inspection	Number of Dents
2007 TDW Magpie Kaliper	462 (>2%)
2007 GE HR MFL	812 (all geometry features)

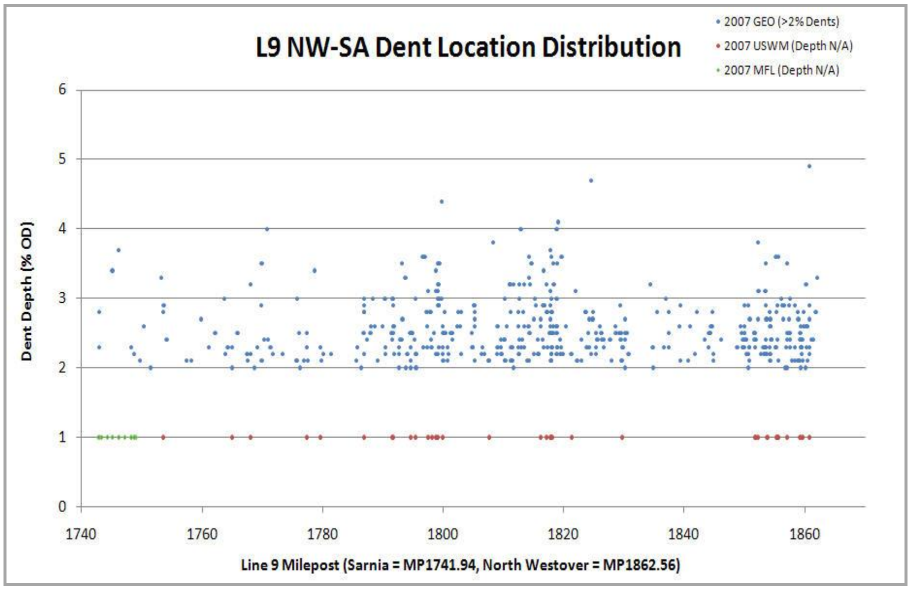


Figure 4.26 - Line 9 (NW – SA) Dent Location Distribution

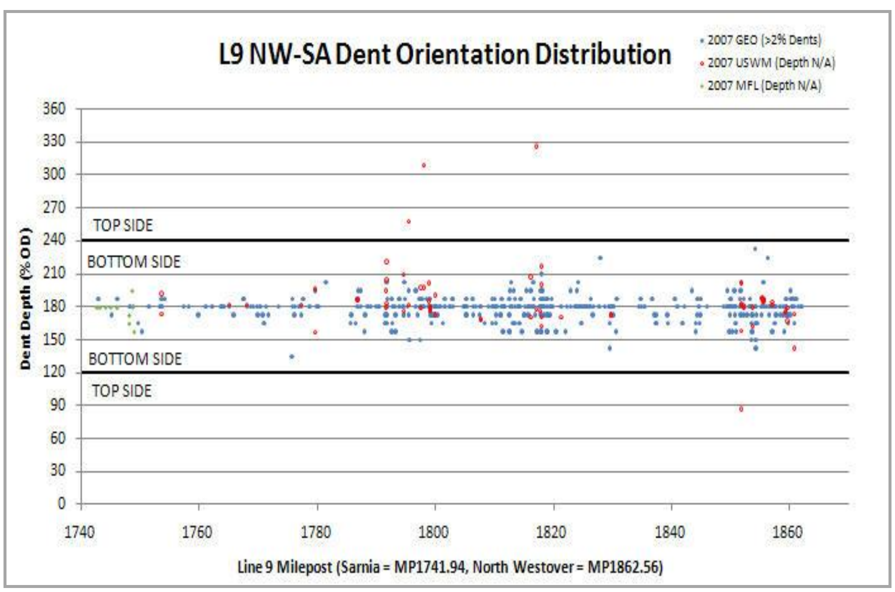


Figure 4.27 - Line 9 (NW – SA) Dent Orientation Distribution

Based on the 2007 ILI reports, a total of 21 features were identified as meeting field assessment criteria and issued for excavation. Twenty (20) were identified as dents >2% interacting with girth welds and one (1) feature identified for excavation was reported in the USWM ILI report with the comment "geometry multiple" indicating a feature containing multiple apexes.

All 21 features were excavated and assessed in the field. The field assessment of all 20 dents interacting with girth welds indicated that they were plain, smooth dents. All 20 dents did interact with girth welds and have been repaired in accordance with Enbridge repair criteria. No other stress risers were identified as being associated with these dents. Field non-destructive examination ("NDE") assessments indicated that the dents did not affect the integrity of the welds (i.e., no cracking or linear indications had initiated at the welds due to the deformation of the pipeline. The additional dent reported as "geometry multiple" was confirmed to contain multiple apexes. However, the dent was smooth and contained no stress risers and did not require further mitigation.

There are no additional outstanding dents with depths >2% that meet repair criteria or were considered to require excavation.

The next planned geometry inspection will occur coincident with the next planned Metal Loss or Crack Inspection in 2012-2013.

4.4.5 Additional Mechanical Damage Assessment

The Enbridge MDMP processes have been revised recently to include an increased focus on shallow dents that are located in close proximity ("DICP") and/or contain multiple apexes including dents that meet those criteria with depths <2%. The revisions were made in response to lessons learnt from recent mechanical damage failures experienced on other Enbridge pipelines, and to address preventative actions identified in the NEB Safety Advisory 2010-01, dated June 18, 2010.

The increased focus on DICP and MAD features was implemented following completion of the recent mechanical damage programs on this pipeline. As part of the implementation of the revisions to the MDMP, Enbridge has reviewed the 2007 ILI data to identify whether or not there are features that meet these criteria that would require further assessment or field excavation. At total of 46 occurrences of DICP were identified in the caliper ILI data, coincident with dents depths of 2% of outside diameter or greater. An additional 29 occurrences were identified in the metal loss ILI data, and none in the caliper data, indicating that they are coincident with dent depths of less than 2%.

Additional assessment of these features will be completed in 2011. Assessment will include additional analysis of ILI data to rank and prioritize features for field excavation and assessment to mitigate any potential risk identified with these features. Although additional assessment will be undertaken, the reversal of the pipeline is not considered to increase the risk associated with the DICP or MAD features.

4.4.6 Impact of Line Reversal on Mechanical Damage Features

Despite the presence of mechanical damage features on the pipeline, the reversal of the pipeline is not considered to influence the threat due to existing mechanical damage features. Features that meet repair criteria specified in Canadian regulations have been mitigated. The vast majority of the remaining mechanical damage features present on the line are most likely a result of the influence of settlement following construction due to the Line 9 high D/t ratio and have been present over most of the life of the pipeline. These features would have experienced previous operating conditions when the pipeline flowed in its original eastward configuration, prior to the reversal in 1999.

Review of the location of historic mechanical damage failures experienced by Enbridge on pipelines with similar diameter and D/t ratios as Line 9 show a random distribution of location along a pipe segment between discharge and suction pump stations. This distribution suggests that the risk of failure of a dent feature due to fatigue cracking is not influenced primarily by the pressure profile along the pipeline segment, but rather the result of pressure cycling, which has been deemed to be non-significant in the proposed reversed flow conditions.

4.4.7 Geotechnical Issues

Enbridge has not identified any areas of existing slope instability that are of concern with respect to their potential effect on integrity on this pipeline from NW to SA. However, routine RoW inspections will continue in an effort to detect any area where slope instability might exist. In the event that slope instability is identified on or near this Enbridge pipeline corridor, the slopes would be monitored to assess the risk that future ground movements might affect the pipeline. The scope of such monitoring programs would depend on the site-specific conditions, but can include instrumentation, regular visual monitoring, pipe assessments or a combination of these methods. Remediation, reconstruction projects or both may be implemented as required to ensure the ongoing integrity of the affected pipeline.

4.4.8 Mechanical Damage Summary and Conclusions

- Currently there are no dents, buckles or gouges on this pipeline from NW to SA that require excavation or repair based on regulatory requirements or standard industry practices.
- Additional assessment of select features will be conducted in 2011, however, risk associated with existing features on the pipeline is not considered to increase due to flow reversal.
- Third party damage will continue to be managed in the same manner as other pipelines within the Enbridge system.

- The next caliper inspection is planned for 2012-2013.
- There are no known areas of geotechnical instability along the pipeline RoW.

5. PLANNED ACTIVITIES PRIOR TO FLOW REVERSAL

The following activities will be conducted on Line 9 from NW to SA prior to the flow reversal.

- Conduct investigative crack excavations in 2012 with particular focus west of SA where the cracking risk profile is expected to change due to the line reversal.
- Additional assessment of select geometry features will be conducted in 2011; however, risk associated with existing features on the pipeline is not considered to increase due to the flow reversal.
- Install two new remote-controlled sectionalizing valves at MP 1837.99 to protect the Black Creek water crossing and MP 1843.5 to protect the Nith River and complete a valve conversion at MP 1750.01.
- Install remote monitoring equipment on all Eastern Region CP rectifiers by the end of 2011 and prior to the propose pipeline reversal.

6. CONCLUSION

The EA completed on Line 9 between NW and SA to evaluate corrosion, cracking, and mechanical damage threats indicates the following:

1. There are no metal loss features in the line section that require repair prior to the next MFL inspection planned for 2013.
2. The fatigue cracking threat will continue to be managed at an acceptable level and based on the results of the fatigue analysis, the crack threat will not be aggravated by the proposed line reversal.
3. Although susceptibility to SCC has been low on this NW to SA segment of Line 9, Enbridge will continue to manage the SCC threat.
4. There are no mechanical damage features that require excavation prior to the proposed line reversal.

The overall results of this EA thereby demonstrate that the line reversal can proceed in 2011 in a safe and reliable operating condition.

7. REFERENCES

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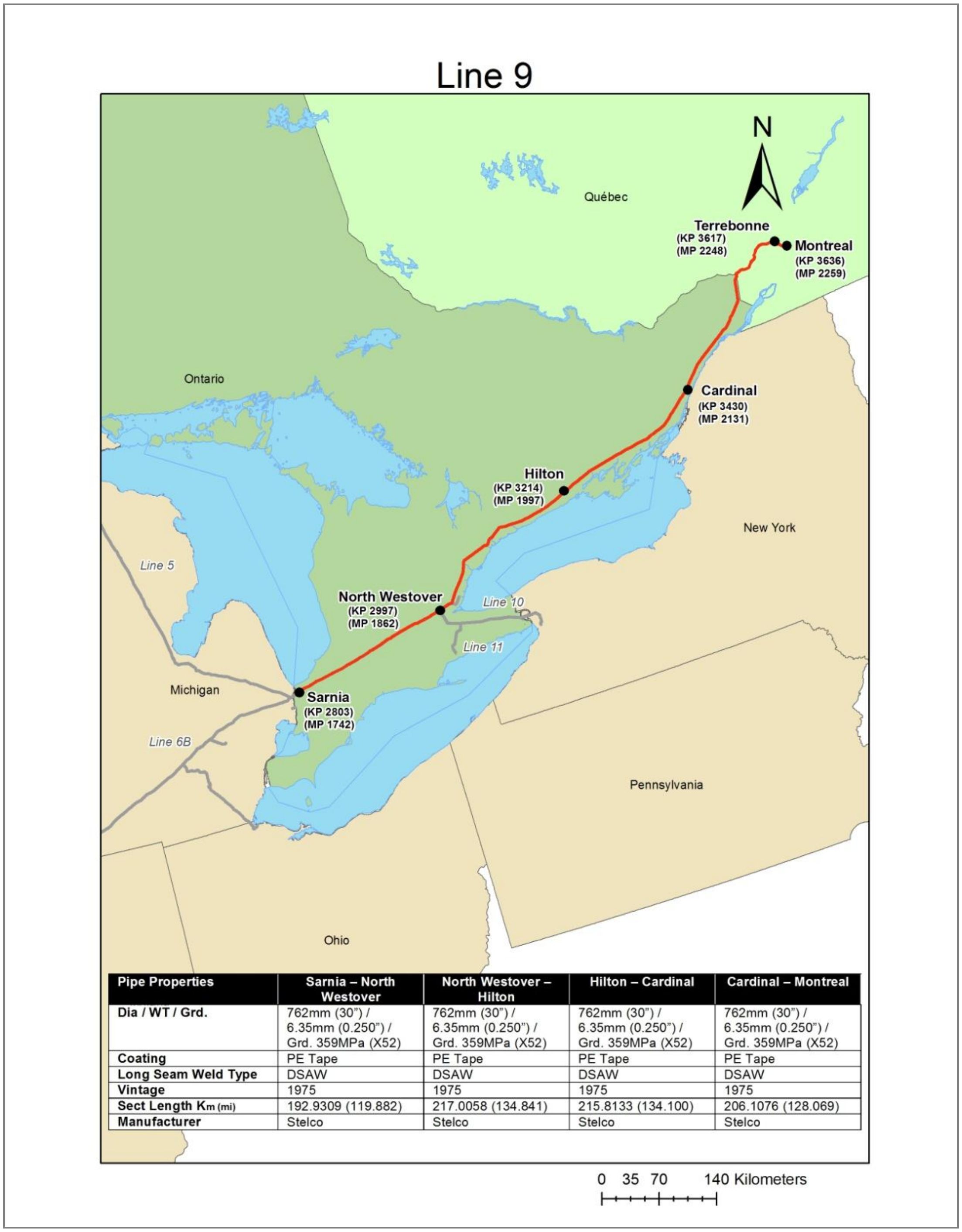
7. API 579-1/ASME FFS-1, Fitness-for-Service, American Petroleum Institute, Washington, D.C., Appendix F, June 5, 2007.

APPENDIX A – Line 9 System



Pipe Properties	Sarnia – North Westover	North Westover – Hilton	Hilton – Cardinal	Cardinal – Montreal
Dia / WT / Grd.	762mm (30") / 6.35mm (0.250") / Grd. 359MPa (X52)	762mm (30") / 6.35mm (0.250") / Grd. 359MPa (X52)	762mm (30") / 6.35mm (0.250") / Grd. 359MPa (X52)	762mm (30") / 6.35mm (0.250") / Grd. 359MPa (X52)
Coating	PE Tape	PE Tape	PE Tape	PE Tape
Long Seam Weld Type	DSAW	DSAW	DSAW	DSAW
Vintage	1975	1975	1975	1975
Sect Length Km (mi)	192.9309 (119.882)	217.0058 (134.841)	215.8133 (134.100)	206.1076 (128.069)
Manufacturer	Stelco	Stelco	Stelco	Stelco

APPENDIX B – Pipeline Compliance and Risk Management (Mainline Risk Assessment)

APPENDIX C – Proceedings of ASME 8th International Pipeline Conference 2010, "Pressure Cycling Monitoring Helps Ensure the Integrity of Energy Pipelines"