PII pipeline Solutions a GE Oil & Gas and Al Shaheen joint venture.

1 Cracks in Corrosion

The Crack detection tool cannot detect or size corrosion features. The angular projection of its sensors are designed to reflect off perpendicular axial orientated fissures in the pipe wall as shown in red and indicated by the arrows in Fig 1 below. The tool assumes only cracks are present during the inspection.

For significant perpendicular cracks (above detection threshold) in shallow, smooth corrosion, detection and identification would be distinctive and based on the reflected echo – see figure below red arrows. The estimated depth would relate to the cracking indications only, not to the depth of the metal loss. It is therefore important to note the metal loss depth must be added to the crack estimated depth in order to establish the true extent of the crack. An exception is when cracks occur at the edge of steep sided corrosion. The Corrosion depth will not come into effect, as the sound will reflect from the corner effect from a singular vertical surface in the axial plain from the external surface – see figure below blue arrow.

Shallow crack fields (below detection threshold) and corrosion could diffuse the ultrasonic signal and therefore reflect more or less identical signals with low amplitude and cannot be discriminated.

In order to ensure consistency in the analysis, these features are classified as crack fields; the previously used 'Metal Loss' classification in USCD data has been discontinued.

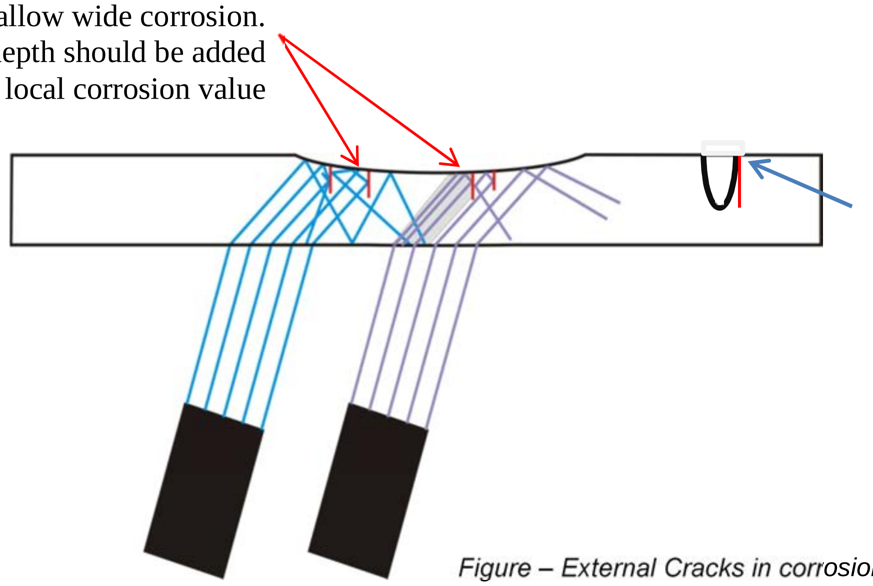


Figure – External Cracks in corrosion

Impact on performance

- POD – Signals reflected by corrosion could be diffused and overlaid on the signals of shallow cracks.

- POI – Weak signals could be identified as rough surface and therefore not sized and reported.

- Depth Estimation – The sizing performance could be affected by diffused and overlaid signals of the corrosion.

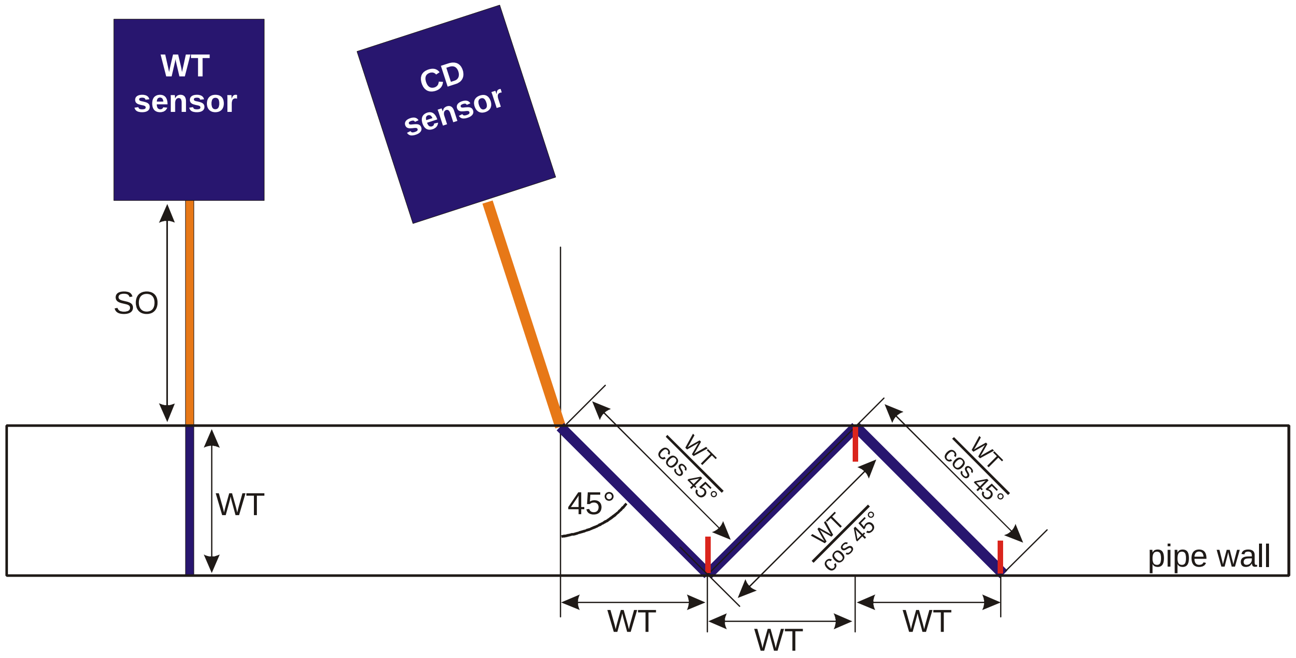
- Integrity assessments – When evaluation a crack in shallow external corrosion without any excavation results, and only utilizing ILI data, then the respective tolerances of both the ILI tools, wall loss and cracking must be taken into account.

Cracks in corrosion with regard to depth.

		Technology			
Hypothetical case		Magnetic Flux Leakage Tool MFL	Utlasonic Wall Measurement Tool USWM	Ultrasonic Crack detection tool USCD	
Nominal Wall thickness in inches		0.256	0.256	0.256	
Corrosion measurement of wall loss		% wt	Inches	NA	
		25%	0.192		
Tolerence of depth in inches		+/- 10% WT	+/- 0.5 mm (0.0197")		
	+/-	0.0256	0.0197		
Boundaries of remaining wall thickness in inches	Upper	0.2176	0.2117		
	Lower	0.1664	0.1723		
Crack depth 0-12.5% 12.5 - 25% 25%-40% >40%				% wt	
				40.00%	
Tolerence of depth in inches				+/- 0.5 mm (0.197)	
				0.0197	+/-
Crack depth tolerence boundaries in inches +/- 0.0197" of Nom WT				0.1221	Upper
				0.0827	Lower
Boundaries of remaining wall thickness in inches corrosion + crack		0.1349	0.1290		Upper
		0.0443	0.0502		Lower

Function of WT Sensors for the Detection of Cracks with UltraScan CD

Crack detection with UltraScan CD is carried out with angularly oriented ultrasonic sensors. For practical reasons, an incident angle of 45° in the steel plate is used in most cases. To achieve this 45° incident angle in steel, the CD sensors are mounted in the sensor carrier to maintain an incident angle of approximately 18° within the coupling liquid (the exact incident angle of the sensor depends on the sound speed of the coupling liquid used during the inline inspection).



Sound paths of perpendicular WT sensor and 45° angular CD sensor

An UltraScan CD sensor carrier is equipped with a limited number of perpendicularly oriented WT sensors. The number of WT sensors is just as big as it is necessary to provide a reasonable reference wall thickness figure of each inspected pipe spool. The wall thickness is determined with time-of-flight measurement, by subtracting the time-of-flight of the entry echo (=SO reading) from the time-of-flight of the rear wall echo. The determination of the WT figure is carried out by multiplying the time-of-flight within the pipe wall with the sound speed in steel – therefore, apart from the amplifier adjustment of the ultrasound unit, no transducer calibration is necessary.

The wall thickness readings are used by the UltraScan CD system to determine the axial location of potential crack readings at the internal and external surfaces of the pipe wall (see picture above). Even if the CD sensor is angularly oriented, it receives an echo from the ultrasonic wave reflected at the internal surface – this echo is used to identify the internal surface of the pipe wall.

If a crack is present in the pipe wall, a number of CD sensors on the sensor carrier should pass this crack and record a sufficient number of readings caused by corner echoes from the crack. Depending on the time-of-flight within the steel plate, the location of the crack can be interpreted as follows:

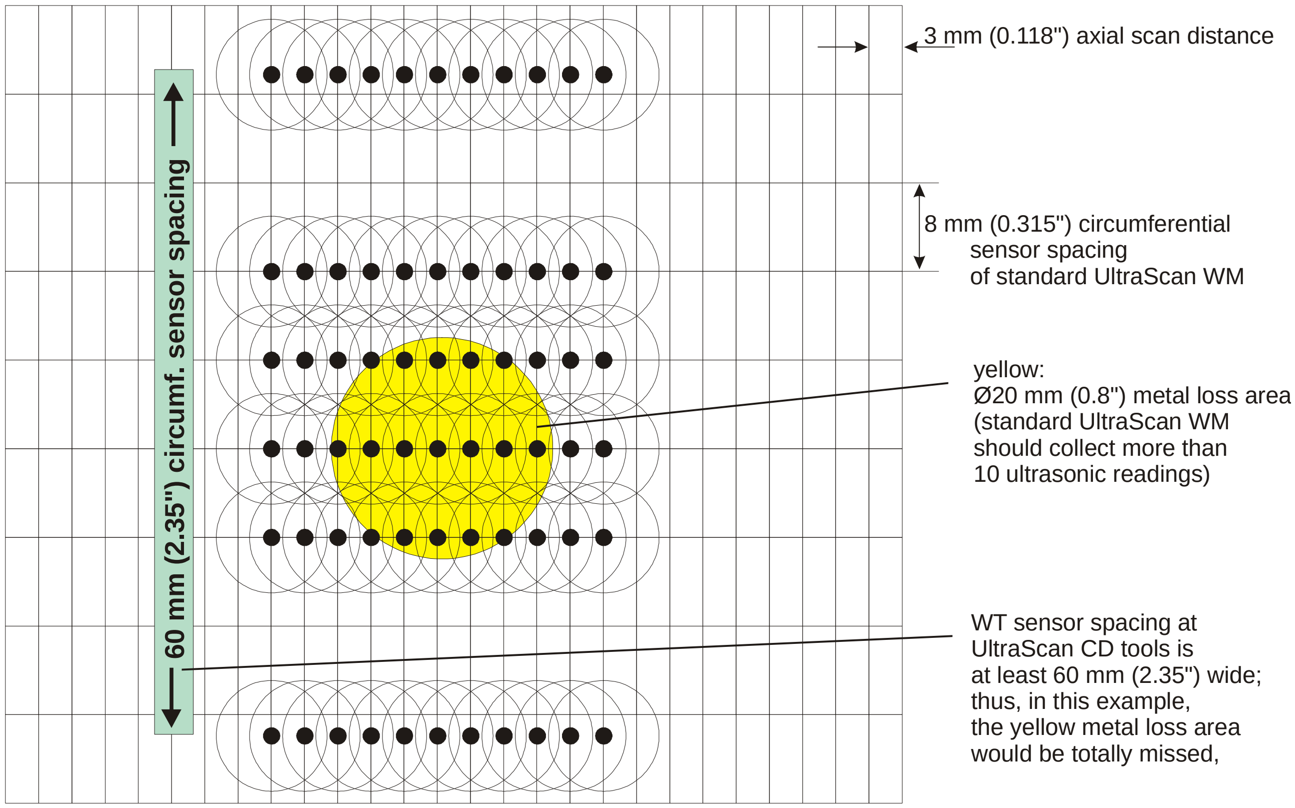
ToF = 1 x WT x cos 45°: external crack (at 1/2 skip)
ToF = 2 x WT x cos 45°: internal crack (at 1 skip)
ToF = 3 x WT x cos 45°: external crack (at 1+1/2 skip)

Note: For CD sensors with incident angles other than 45° (e.g. alpha = 55° or 60°) the calculation of the sound path is similar (just replace cos 45° by cos alpha).

As the picture above shows, the WT readings of the WT sensors are used to determine the axial location of detected cracks by time-of-flight measurement. However, this geometrical algorithm is not appropriate for determining the crack depth. This is rather been done by assessing the amplitudes of the individual signal echoes received from a crack indication

The WT sensors in the UltraScan CD system provide a reliable figure for the reference wall thickness of a pipe spool – this figure can be used for determining the axial crack location and for the statement of the reference wall thickness in the pipebook. However, the WT readings are not sufficient to establish a proper metal loss detection.

The number of WT sensors mounted at an UltraScan CD sensor carrier only provide a circumferential sensor spacing between approx. 60 mm and 115 mm (2.35" and 4.53"), depending on the pipeline diameter. Compared to the regular circumferential sensor spacing of approx. 8 mm (0.315") at the standard UltraScan WM sensor carrier, the circumferential scan resolution of the UltraScan CD is 7 to 14 times worse than the related resolution of the standard UltraScan WM.



Ø20 mm metal loss area covered In the UltraScan by UltraScan WM and UltraScan CD WT sensors

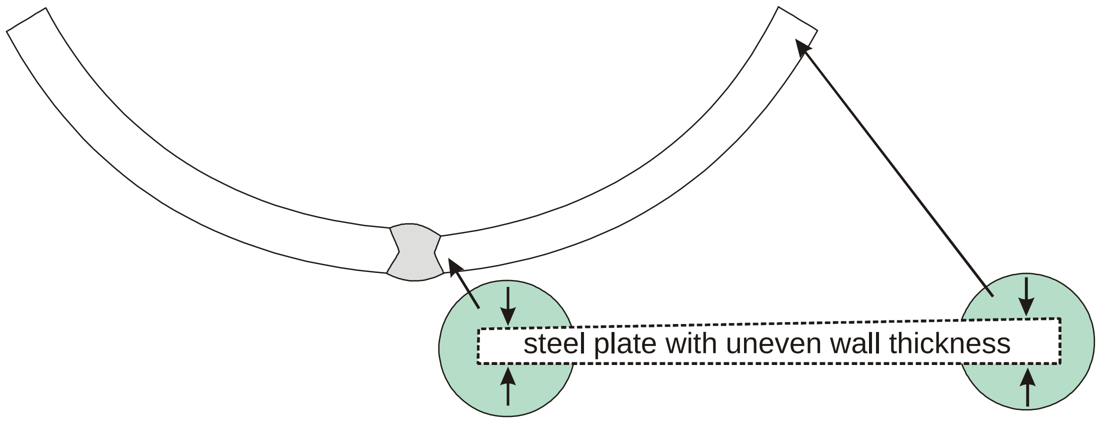
The yellow circle in the picture above indicates a metal loss area with 20 mm (0.8") diameter. The overlaying grid represents the 3 mm x 8 mm (0.118" x 0.315", axial x circumferential) scan resolution. Each black dot represents an UltraScan WM measurement shot at the pipe wall.

Depending on the circumferential location of the metal loss area relative to the rotational position of the sensor carrier, the yellow metal loss area might be touched by two or three UltraScan WM sensor tracks – but because of the axial scan frequency, at least 10 WT sensor readings of this metal loss area should be recorded.

In contrast to the UltraScan WM sensor arrangement, the WT sensors at the UltraScan CD sensor carrier have a circumferential sensor spacing of at least 60 mm (2.35"). In the situation shown by the sketch above, the metal loss area would be totally missed by the UltraScan CD WT sensors. Only in the case that an WT sensor track accidentially passes the center of the metal loss, the UltraScan CD tool would record a more or less representative depth contour of the metal loss area.

From the physical point of view, the ultrasonic wall thickness measurement is a direct measurement based on the time-of-flight of the ultrasonic signals. The determination of the reference wall thickness of a pipe spool assumes that the most often measured wall thickness value (not the mean value) represents the reference wall thickness of the whole pipe spool.

In cases where the steel plate was rolled into a non-parallel shape before it was bent to a tube, the wall thickness at both sides of the longitudinal weld can be significantly different (see following sketch). As a consequence, the computed reference wall thickness of the pipe spool might be either closer to the thinner part of the steel plate or closer to the thicker part.



Example with different wall thicknesses at both sides of a longitudinal weld

Because the UltraScan CD tool has only a relatively small number of WT sensors, the statistics used for the determination of the pipe spool's reference wall thickness might lead to a value which significantly differs from the reference wall thickness in the vicinity of a detected crack.

Example: WT sensors' performance in failure joint GW 217720

The 30“ UltraScan CD tool is equipped with 30 WT sensors, firing every 3 mm (0.118") along the 12 m (40 ft) pipe length. Over the full joint length, the following number of WT measurements is taken:

12,000/3 = 4,000 spots x 30 sensors = 120,000 = total number of measurements

In the present case, the value mostly seen was 7.239 mm (0.285”) over the entire pipe joint and recorded on the UltraScan CD tool software as such.

However, over a given length of 2.155 m (85“) PII reported two crack-like (CL) features at the same orientation:

a 647 mm (25.45“) long x 0% to 12.5% CL indication,
and, after a ligament of 197 mm (7.75“) of no indications,
a 1311 mm (51.6)“ long x 12.5% to 25% CL indication

The actual WT in the vicinity of these features was measured by the phoreniscs lab was between 5.08 mm and 6.604 mm (0.20” and 0.26”). The feature width would straddle no more than 4 sensors in tota over 2 sensor carriers.

Thus, the USCD reference WT in the vicinity of these two features is covered by the following number of WT measurements:

2155/3 = 718 spots x 4 sensors = 2,872 measurements

The measured WT by the phorensics lab at the failure edges represents approximately 2.4% of the total number of WT measurements taken by the USCD in this pipe joint.

The USCD tool actually uses the *Mostly Seen value out of the total 120,000 measurements taken in the pipe joint.* Which may explain the difference in WT values in the vicinity of the failure site.

Changes to USCD Feature Classification Since 2005

As part of PII's commitment to continuous improvement, numerous changes to analysis procedures have been implemented based on feedback from customers including Enbridge. GE PII continues to monitor its performance within API 1163 based upon client feedback to ensure it inspection performance remains or exceeds specifications.

Re-Classification of Metal loss
Based on feedback received between 2004 and 2007, it was observed that reported metal loss features were being found as low level crack fields. Subsequently, PII adjusted the classification analysis criteria regarding metal loss features as metal loss reporting is not the true mission or nature of the configuration of USCD tool. Since 2008, Crack inspection reports do not include metal loss classification and features previously reported as metal loss are now classified as crack field or crack-like. This classification criteria change was validated with over 250 field verifications. Such features are still detected by the inspection tool but are not included in standard reporting (also known as "non-reportable" features)

Improved sizing algorithm for crack fields
An improved sizing approach uses amplitudes without length restrictions and revised weighting on amplitude reflections to gain performance improvements in the depth accuracy of crack fields. This improved sizing algorithm for crack fields was developed from the logic and experience of recognizing that the characteristics of small multiple cracks are what constitutes the crack fields. This depth estimation algorithm for crack fields was introduced in 2008 and is based upon feedback from > 600 field excavations. As such, there are two distinct sizing models for crack-like and crack fields, respectively.

Notch-Like features at the long seam
Notch like features located at the long seam previously had the comment "possibly weld defect". Based upon field excavation feedback and for fundamental reporting consistency reasons, the classification of notch-like features adjacent to the long seam was discontinued in 2008. These features are classified as crack-like features in the current inspection reports.

Indications below specification
Prior to 2009, all detected features were included in the feature listings which includes significant populations with depths <1mm or <12.5%WT. In the inspection reports issued after June 2010, only features with a minimum depth of 0.5 mm are included in the inspection report. This criteria change was implemented based on excavation feedback and within the context of the similar timing of the introduction of absolute depth profiling and reporting framework that enables it allowing better quantification and insightful reporting for relative sizes of relevant features.

Information features
Information features are features that have been reported in the previous inspection but identified as non-reportable in the current inspection. These are features that have been repaired or are not visible in the current inspection when compared to the previous. They appear in the listings of the current inspections as “information” with comments from the previous inspection and will not be included in the feature counts in the reports.

Updates to Analysis Process

The USCD analysis Process, since 2007, has undergone 2 revisions (May 2008 and June 2009). The changes are a general revision to standardize the document and align with other processes and the inclusion of the re-inspection reporting process. A recent revision in 2011 (outside of this reporting period), further defines an expert panel to be used as an internal audit review of the reports to ensure consistency for all analysis.

Independent of formal procedural changes, analysis technical alerts are issued to share learning’s and best practices across all analysis personnel.

Signal recognition and selection (feature classification) have changed within the process and are documented with technical alerts

Aside from the regular training and certification processes for analysts, there were several additional consistency tests performed by all analysts since 2006.

Re-inspection Processes and Review

The re-inspection process, implemented in May 2008, takes into account previous inspection data and was introduced as a result of the number of re-inspections taking place with the same technology.

When historical data exists, all of the reportable features above the tool specification from the previous inspection are imported into the current inspection database and compared with current signals. Any new reportable features are cross referenced against location in the previous data set for comparison purposes (i.e. growth, non-existence).

The re-inspection is done after the initial QA process of the most recent data set. In the event of a discrepancy, a direct signal comparison is completed. The re-inspection process provides the analyst with more information to support or change the feature classification. For example; no change in amplitude or feature dimensions indicates an inert feature. It therefore allows the analyst to refine the classification on a feature by feature basis.

Any changes in classification that are a result of process changes between inspections are flagged in the inspection report with comments

PoD, PoI

imagination at work

API 1163
What must ILI vendors supply?

- Can we detect it? – PoD
- Can we classify it correctly? – PoI
- Can we size it accurately? – Sizing Performance
  - > Is the other information accurate?
- Can you prove it? – Client Feedback
  – Dig Verification

Probability of Detection - PoD

API 1163 defines PoD as:

"the probability of a feature being detected by an in-line inspection tool"

What does ***detected*** really mean?

In practice, a defect is detected if:

The inspection tool records a resolvable signal (wrt to the signal noise level) at the defect location

One could go further and say that:

A defect is only detected if that signal has been boxed (or recorded in some way) by either an automatic algorithm or by the analyst

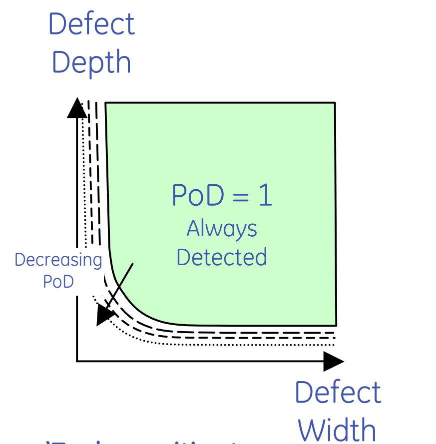
Probability of Detection – PoD

The signal amplitude,
and consequently the PoD,
is dependent on defect size

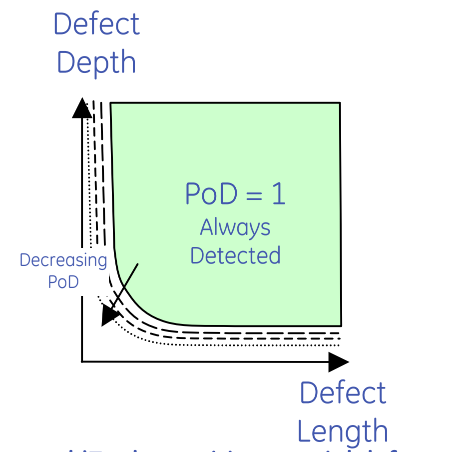
The PoD of an inspection system can only be determined from a set of defects whose dimensions have been measured and are known

The PoD is usually derived from pull throughs in spools containing a range of known defects of different sizes

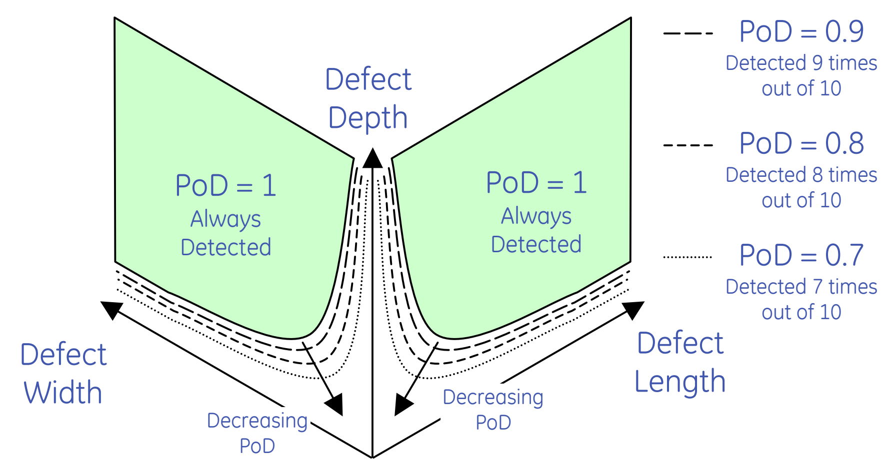
It is expected that the PoD performance achieved by the tool in a pull through will be replicated during each inspection run



a)Tools sensitive to circumferential defects (MFL 2.0, MFL3.0, SmartScan, etc)



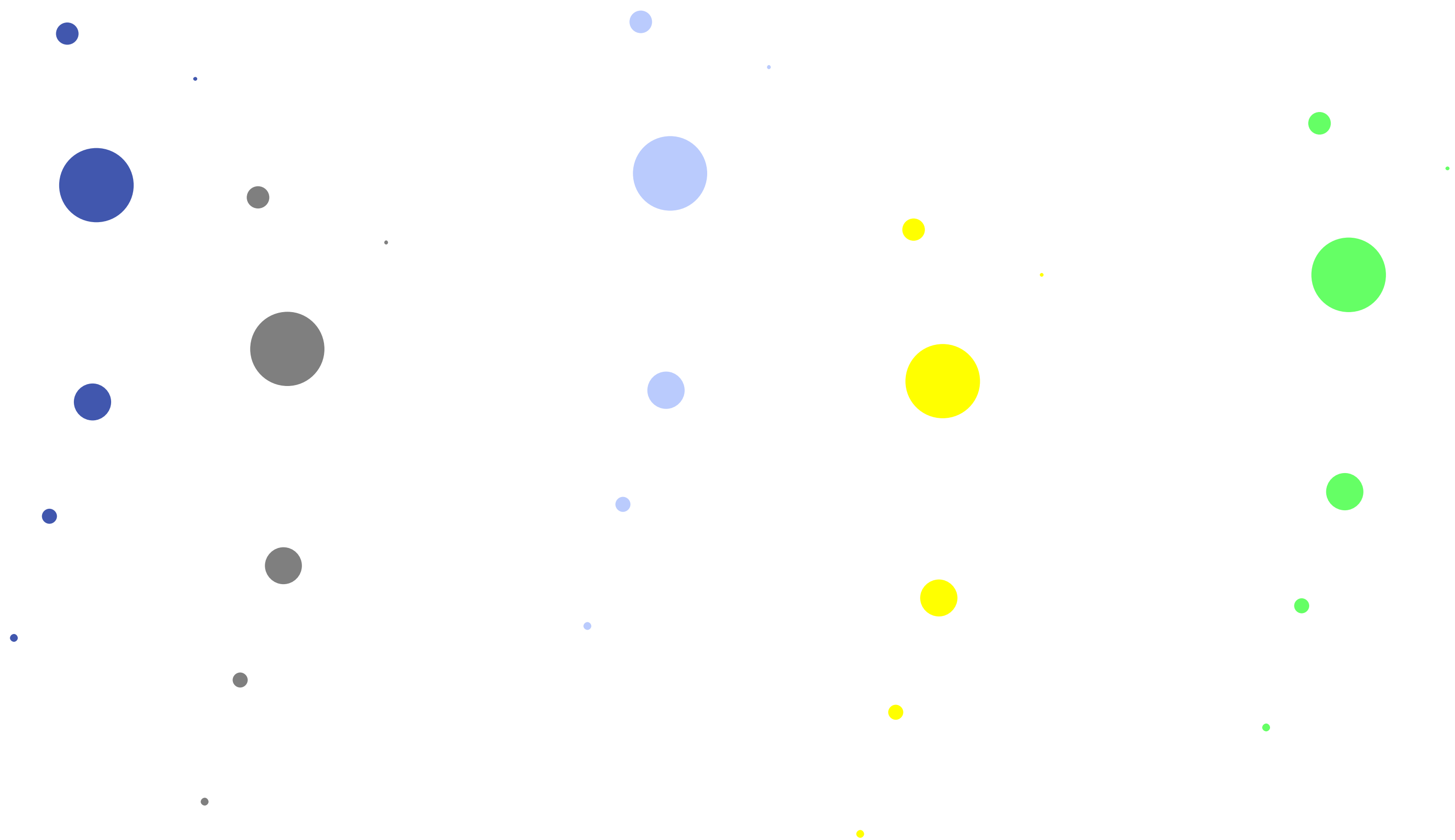
b)Tools sensitive to axial defects (USCD, EMATScan, Elastic Wave, TransScan, etc)



c)Tools sensitive to defect volume (Triax, USWM, USDUO, etc)

Probability of Detection – PoD

6 dots – 5 colours



The PoD of large dots is 1. The PoD of the smallest dots is <1

PoD depends on size of and shape of defect

Probability of Detection – PoD

How should we calculate PoD?

From the pull through results:

- Known defects that have been detected are ***true positives***
- Known defects that have not been detected are ***false negatives***

	Defect Detected	
	Yes	No
Known and measured defect of a specific type and size	True Positive (TP)	False Negative (FN)

$$PoD_{\text{specific defect type and size}} = \frac{\text{No. of times a defect of that type and size has been detected}}{\text{No. of opportunities to detect a defect of that type and size}}$$

$$= \frac{TPs}{(TPs + FNs)}$$

imagination at work

Probability of Detection – PoD

How should we calculate PoD?

Example:

- Pull Through Data recorded from
  - > 5 identical defects
  - > Over 10 pull through runs
  - > Signal detected = 48 times - ***TP***
  - > Signal not detected = 2 times - ***FN***

	Defect Detected	
	Yes	No
Known and measured defect of a specific type and size	True Positive (TP)	False Negative (FN)

$$PoD_{\text{specific defect type and size}} = \frac{TPs}{(TPs + FNs)}$$

$$= \frac{48}{48+2} = 0.96$$

If there is only one defect of each size in the pull through then from a single run the PoD for each defect can only be calculated to be either 1 or 0

So a number of repeat runs and/or duplicate defects are needed to enable a more meaningful PoD value to be calculated

Probability of Identification - PoI

API 1163 defines PoI as:

"the probability that the type of anomaly or other feature, once detected, will be correctly identified (e.g. as metal loss, dent, etc.)"

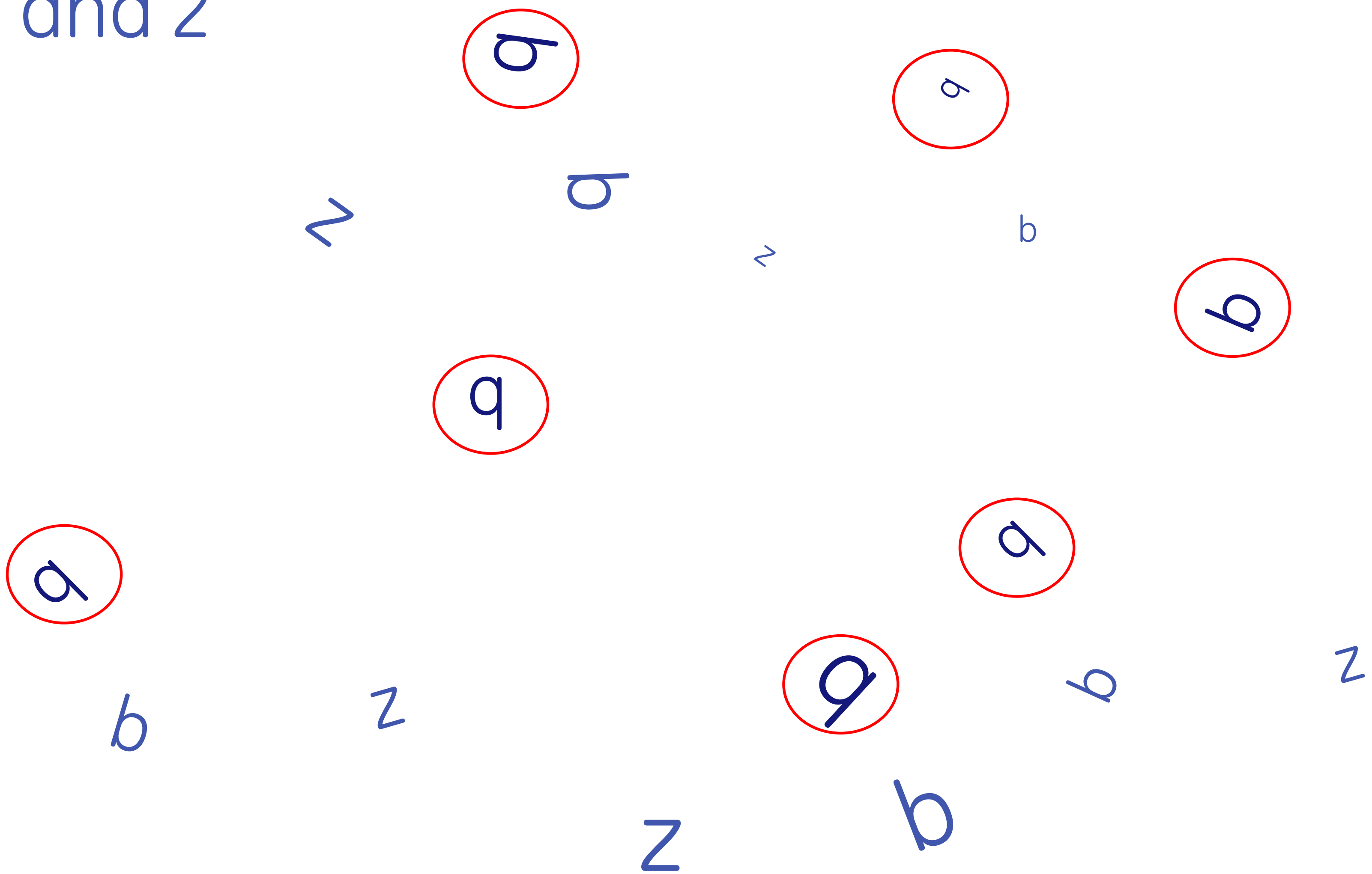
The PoI of an inspection system can only be determined from a set of defects where we have **both**

the analyst's classification

AND

the in-the-ditch classification made by a competent NDE/NDT operator

Probability of Identification – PoI
b, q and z



Our ability to classify z prevents p & q being misclassified as z

PoI on a particular pipeline depends on mix of defect types

Probability of Identification – PoI

How should we calculate PoI?

From the analysis results and the excavation data:

- Defects reported as Defect Type X (such as crack) and assessed in-the-ditch as of Defect Type X are ***true positives***
- Defects reported as Defect Type X but assessed in-the-ditch as **not** of Defect Type X are ***false positives - (False Digs)***
- Defects reported as **not** Defect Type X but assessed in-the-ditch as of Defect Type X are ***false negatives - (Missed Threats)***
- Defects reported as **not** Defect Type X and assessed in-the-ditch as **not** of Defect Type X are ***true negatives***

		Excavated: Crack	Excavated: Not a Crack
Reported	Crack	TP	FP
	Not a Crack	FN	TN

$$PoI_{\text{specific defect type}} = \frac{\text{No. of correct identifications}}{\text{No. of opportunities to classify a defect}}$$

$$= \frac{TPs + TNs}{(TPs + FNs + FPs + TNs)}$$

Probability of Identification – PoI

How should we calculate PoI?

Example:

- 50 features were reported and excavated
- 15 of these were reported as Cracks
  - 10 were found to be cracks – ***TP for Cracks***
  - 5 were classified in-the–ditch as metal loss - ***FP***
- 35 of these were reported as Notch-like
  - 33 were classified in-the–ditch as notch-like - ***TN***
  - 2 were found to be cracks – ***FN***

		Excavated: Crack	Excavated: Not a Crack
Reported	Crack	TP	FP
	Not a Crack	FN	TN

$$PoI_{\text{Cracks}} = \frac{TPs + TNs}{(TPs + FNs + FPs + TNs)}$$

$$= \frac{10+33}{10+2+5+33} = 43/50 = 0.86$$

$$PoI_{\text{Notch-like}} = \frac{33+15}{33+0+2+15} = \frac{48}{50} = 0.96$$

POD - Statistical examples for the USCD tool specification

Probability of Detection - POD means the Statistical probability of a specific inspection tool detecting a reportable anomaly in a pipeline. A reportable anomaly is defined as a specific type of pipeline feature (Crack, Crack field etc.) the tool has a written specification to find. The POD is based upon the smallest anomaly the tool can contractually find with a repeatability stated with a confidence level. Larger anomalies will have a much greater probability of being detected within a greater confidence level, which in fact will be trending to unity. The minimum anomaly detection specified for the USCD tool is a crack which is both longer than 1” and deeper than 0.04” along its entire length. This is not the actual minimum size of anomaly this tool can and has detected, but it is the size that contractually the ILI vender is confident can meet the required level of repeatability of 95%. For this example we have taken this minimum contractual specification and one close to unity (99.9%) to explain the meaning of POD using a statistical approach.

POD for a 1” long x 0.04” deep crack = 95%

PoD** **specific defect type and size **= True Positive / (True Positive + False Negative)**

Example: - 10 identical cracks of minimum detection level have a tool passed over it 100 times, what is the probability of detecting such cracks?

In the example of 10 identical cracks of the minimum detection dimensions of 1” long and 0.04” deep being present and the tool is passed over them 100 times, then a total of 10 X 100 = 1000 possible occurrences.

95% = 950 / (950 + 50)

0.95 x 1000 = A probability of 950 True positives or 50 False Negatives

A **True positive** means the tool identifies the anomaly and it is proven to exist on the pipeline.

A **False positive** means the tool has identified an anomaly and it is not proven to exist in the pipeline.

A **False Negative** means the tool did not identify an anomaly and it does exist in the pipeline.

If there were only a single 1” x 0.04” crack present, it would require up to 20 passes of the tool before the probability of having a single False Negative (or missed call) occurring, or 1 in 20 chance of missing one 1” x 0.04” deep crack.

If there were 10 identical larger cracks, they could theoretically be at a, (for example purposes only), 99.9% POD and had a tool pass over them 100 times?

0.999 x 1000 = A probability of 999 True Positives or 1 False Negative

99.9% = 999 / (999 + 1)

If there were only 1 large crack present, it would require up to 1,000 passes of the tool before having a probability of a single False Negative (or missed call) occurring, or statistically a 1 in 1000 chance of missing this larger crack in a single run of the tool.

POI – Definition

Probability of Identification - POI is the statistical probability of having detected an anomaly, it is characterized correctly (Crack-like, Crack field, Notch-like etc.). In the case for the USCD tool it is 80%, or there is a contractual probability of characterizing more than 8 out of every 10 anomalies correctly. This again is not the actual performance capability of the tool/analysis, but is what contractually, the ILI vender is confident can be met with the required level of repeatability.

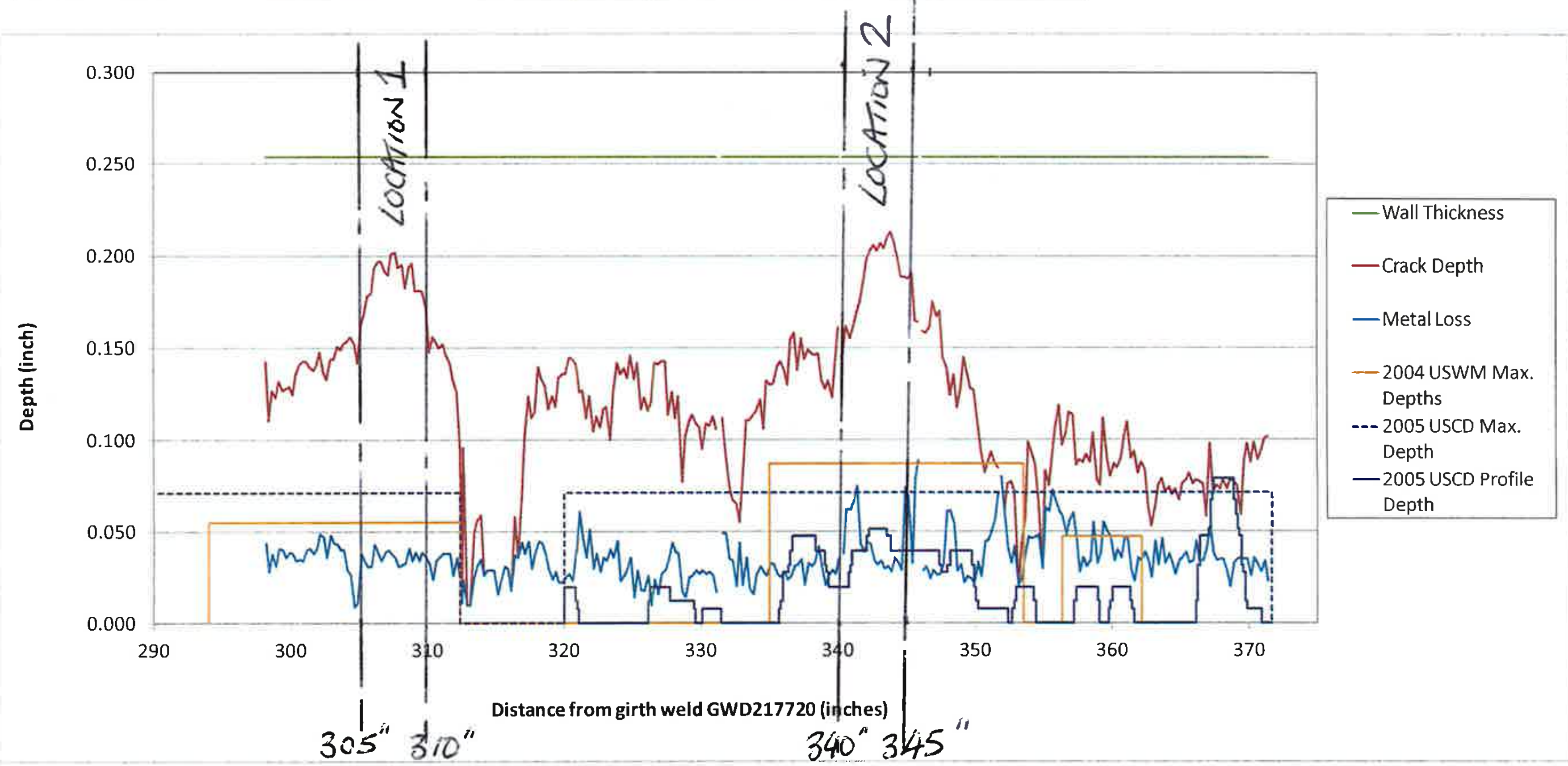
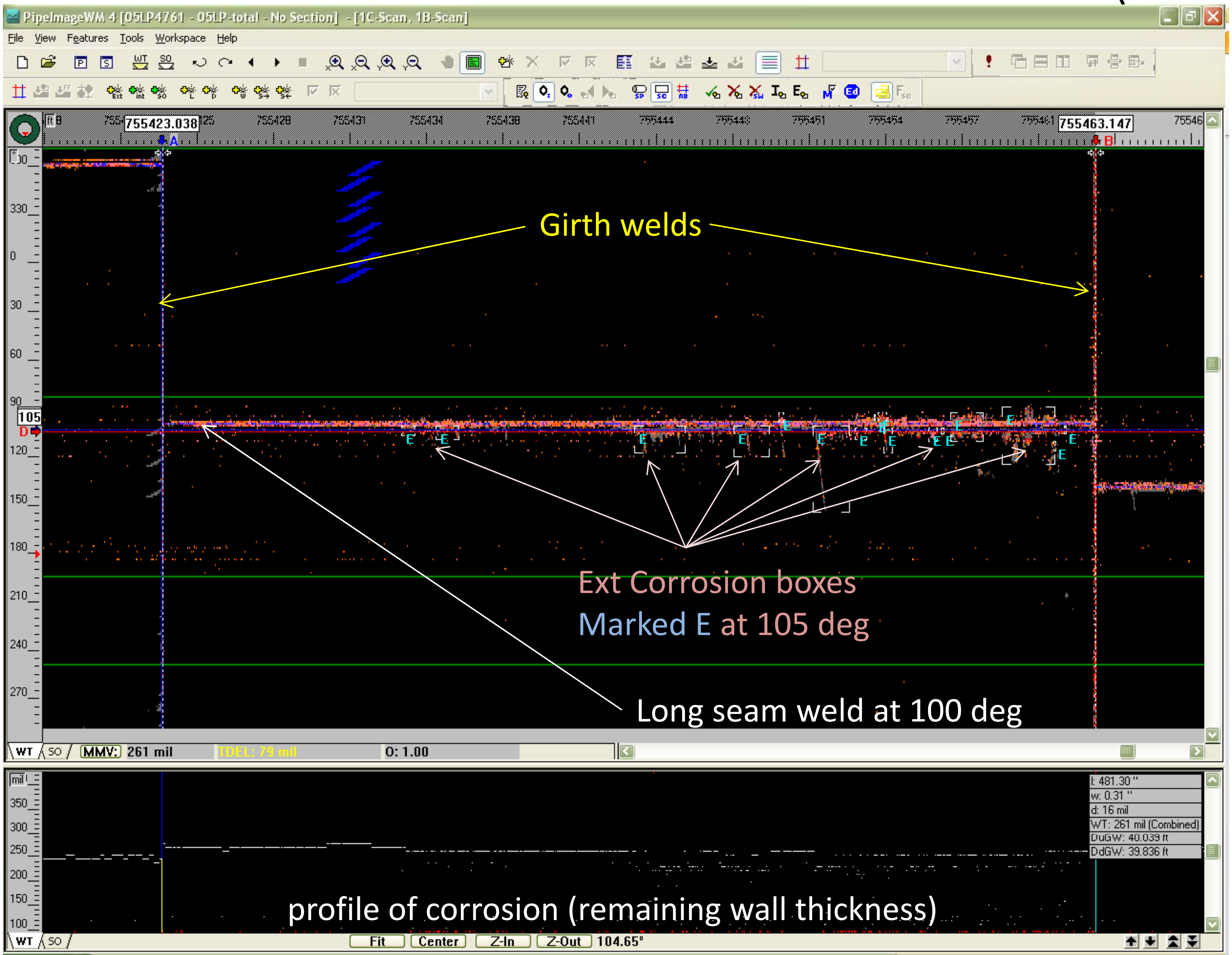


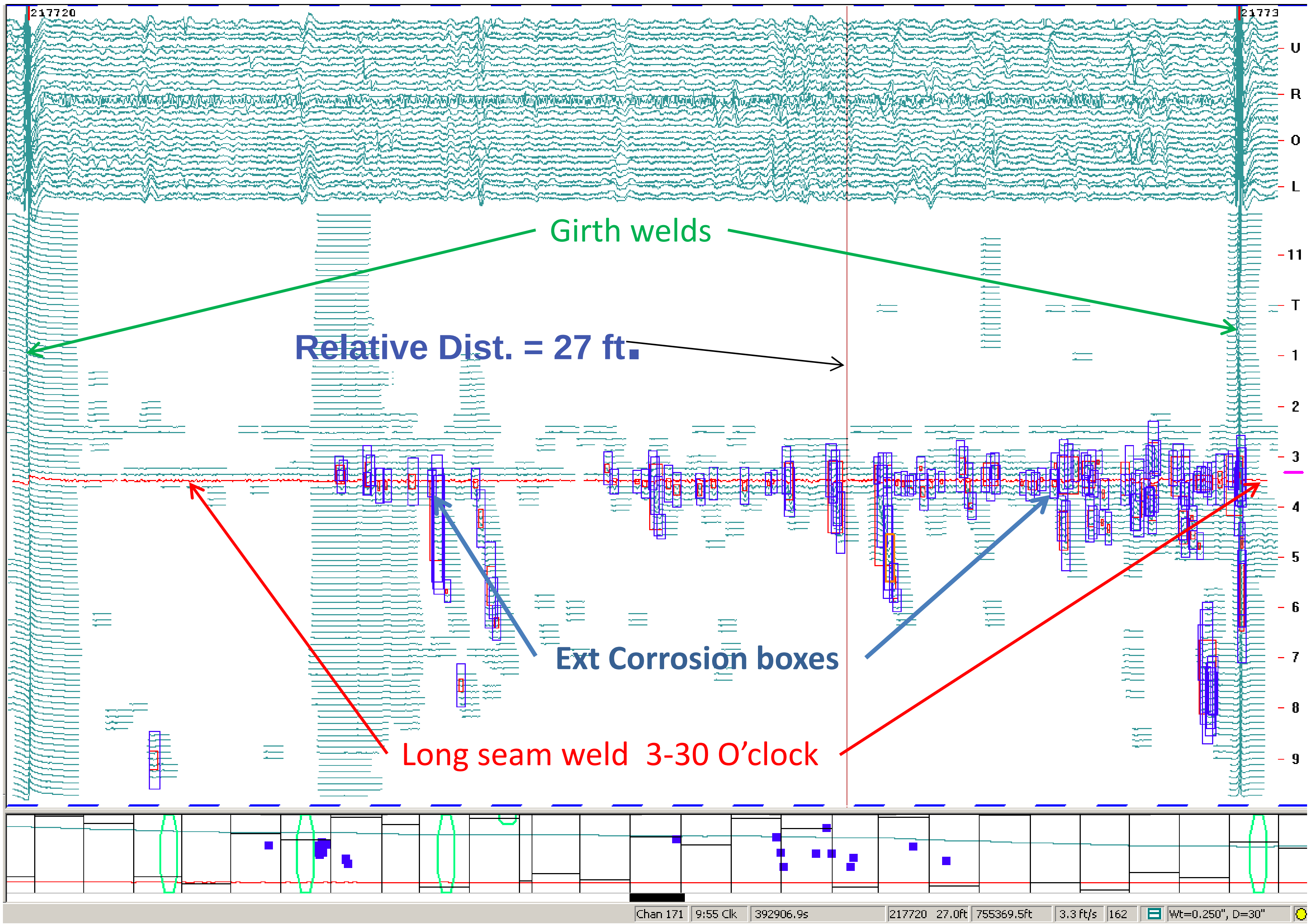
Figure 27. Crack profile data for the rupture at the area of deepest crack penetration showing metal loss depth and crack penetration depth along the length of the rupture at ¼-inch increments. Breaks in the data indicate locations where cuts were made. Metal loss depth and crack penetration depth are referenced to the estimated original wall exterior surface as determined using an average of micrometer measurements in adjacent areas that appeared free from corrosion features. The wall thickness in this plot represents the wall thickness determined from the micrometer measurements. The solid yellow line and the dashed purple line indicated results from the 2004 ultrasound wall measurement (USWM) and the 2005 ultrasound crack detection (USCD) in-line inspection (ILI) tool inspection reports showing locations and maxiumum depths for features reported in this area. In addition, the solid purple line shows the post-accident depth profile of the 51.6-inch long feature determined from the 2005 USCD ILI data. (Additional details of the ILI inspections are included in Section D.15 of this report.)

Enbridge Line 6B GW 217720
PII ILI 2004, 2007 & 2009 Metal loss
Full joints + zoom into failure area

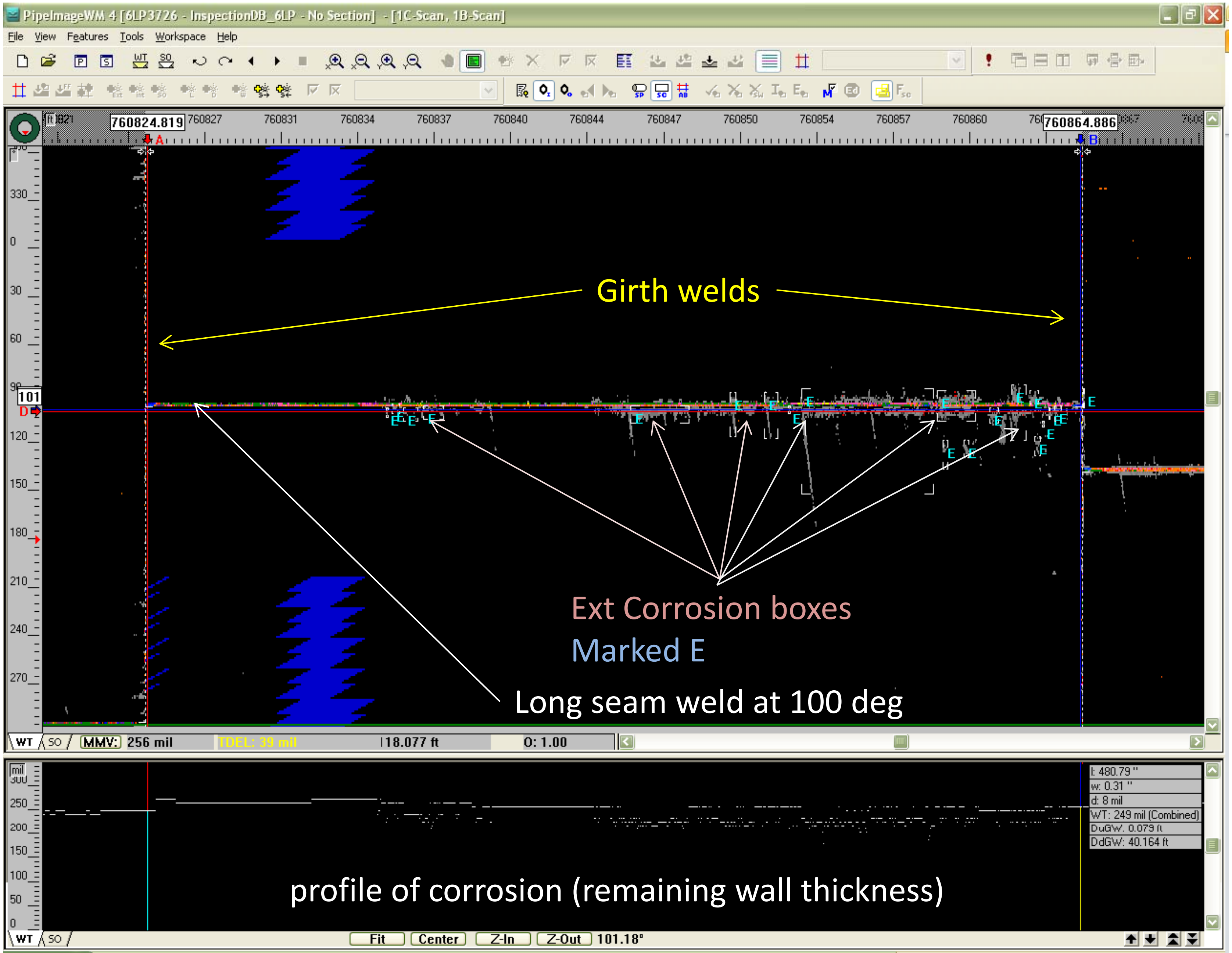
Line 6B GW 217720 2004 Ulta-sound wall measurement (USWM)



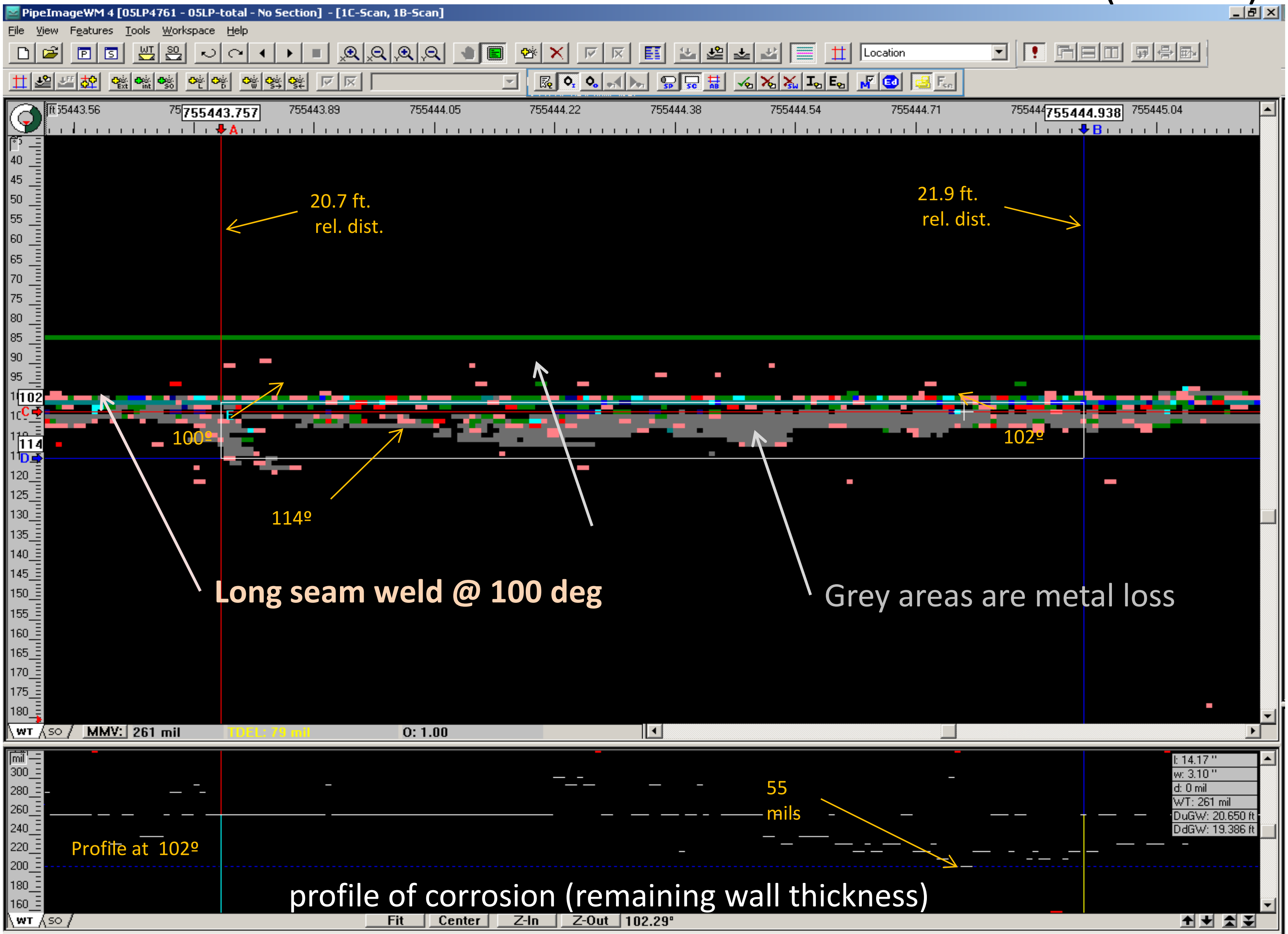
2007 (MFL) magnetic flux metal loss GW 217720 – Entire pipe joint



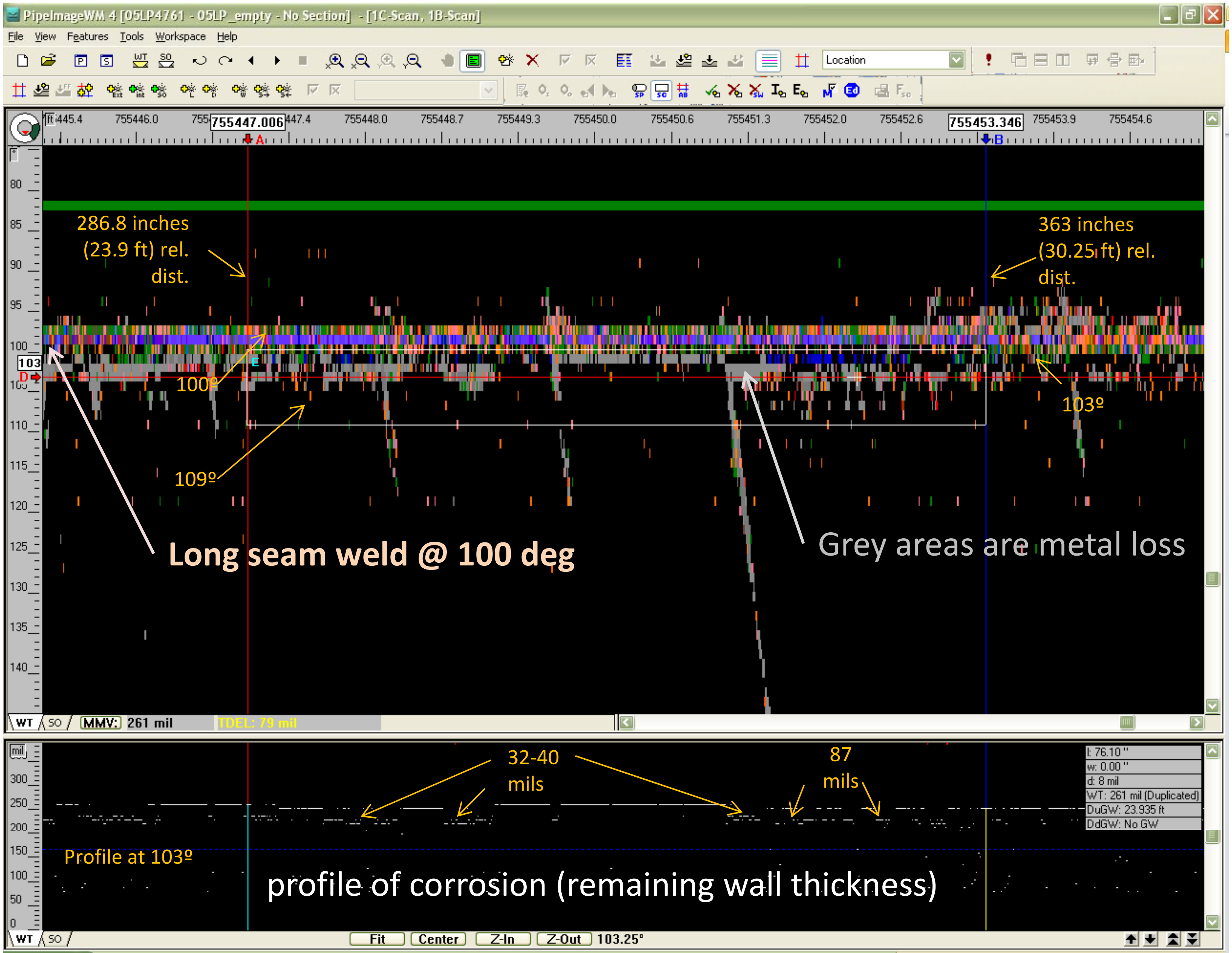
Line 6B GW 217720 2009 Ulta-sound wall measurement (USWM)



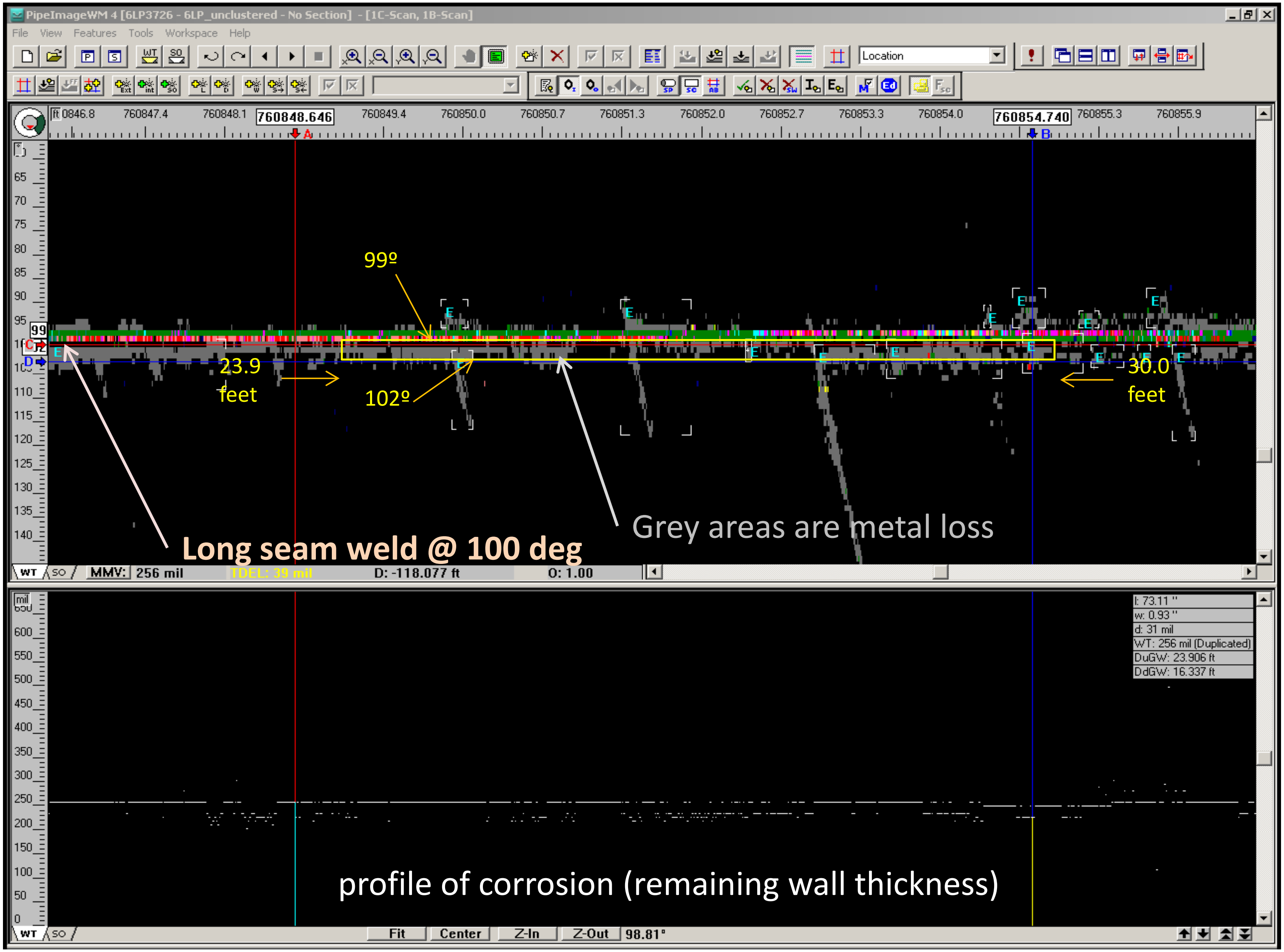
Line 6B GW 217720 2004 Ulta-sound wall measurement (USWM)



Line 6B GW 217720 2004 Ulta-sound wall measurement (USWM)



Line 6B GW 217720 2009 Ulta-sound wall measurement (USWM)



2. Description of the UltraScan™ CD Tool

2.1 General Information on the UltraScan™ CD

In order to continue safe operation, pipeline operators in many countries have to prove the integrity of their lines. Increasing the lifetime of a pipeline might severely impact its operational safety due to the presence of various undetected damage mechanisms. Corrosion, for example, in the course of time can cause wall thinning or may even lead to crack generation and growth when combined with tensile stresses (SCC - stress corrosion cracking). Fatigue loading can also lead to crack generation especially in the heat-affected zone of the longitudinal weld.

In order to avoid catastrophic pipeline failures due to such defects, it is necessary to periodically inspect pipelines – in particular older pipelines – by non-destructive inspection techniques. Normally, such inspections are performed "in-line" using intelligent pigs. While the detection of metal loss (corrosion) with ultrasonic tools or MFL (Magnetic Flux Leakage) tools has been state of-the-art for some years, there were no tools available in the past for the much more difficult task of crack detection.

In an effort to meet this important industry demand, PII Pipeline Solutions developed an ultrasonic pig for the detection and sizing of axially oriented crack-like anomalies (fatigue cracks, SCC, etc.) – the UltraScan™ CD Tool. The tool has been commercially available since autumn 1994.
I
n contrast to the ultrasonic corrosion inspection, which uses longitudinal sound waves propagating perpendicularly (90°) into the pipe wall, the crack detection tool is based on a transverse sound wave inspection. This is accomplished by angling the incident longitudinal ultrasonic pulses through the liquid coupling medium (e.g. crude oil), resulting in a 45° refracted transverse sound path being generated in the pipe wall.
To date, more than 15,000 kilometers (9,320 miles) of oil and gas pipeline have been inspected worldwide using PII's proven ultrasonic technology. The experience gained so far has resulted in the UltraScan™ CD Tool being officially recognized by the German TÜV authority, as a government-approved substitute for in-service hydrostatic testing1.

4.4 Notes on the Features List

The results of the interpretation work done by the PII Pipeline Solutions Data Analysis Departments are compiled in the Features Lists (see Appendix 6A).
During the off-line data preparation, the ultrasonic indications coming from the same locations (ideally from the same reflector) are combined to form Feature Areas. These areas are indicated in the C-scans by rectangular, coloured boxes. Such an area is usually related to one individual reflector. In the case of a crack-field, for example, with many defects located close together usually one area is generated for the whole field. For each area several parameters like area length, width, overlap, amplitude etc. are derived and stored in a database. These steps are performed automatically using special computer software. The subsequent data interpretation is presently performed in such a way, that from the whole set of areas only those complying with certain criteria are selected from the database. These areas are then looked at and classified by PII's skilled Data Analysts. Finally, the result of data interpretation is summarised in the features list.

The features list normally consists of several sections. One section typically corresponds to a length of approx. 1.5 km (0.93 miles) depending on the actual amount of data.

Besides its coordinates (distance and circumferential position) each feature is identified by a special ID number.

The features list contains the following types of indications:

- indications caused by crack fields
- indications caused by crack-like defects
- indications caused by metal loss
- indications caused by geometries (conspicuous indications at the longitudinal weld near to the girth weld are classified with geometry; weld ihg; striking)
- indications caused by installations (useful as 'natural' markers)
- notch-like indications (notch-like indications with the comment *weak* are not included)
- indications of unknown or ambiguous origin (not decidable)
- indications with the comment strong or striking
- dents, deformations (if detected)
- verified (v), fully documented (d) and examined indications

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Pipeline In Line Inspection – Evolution and Future direction

Author: **Geoff Foreman,** Growth and Strategy Leader

PII Pipeline Solutions, a GE Oil & Gas and Al Shaheen joint venture

Today, a wide variety of In Line Inspection (ILI) tools is available to hydrocarbon pipeline operators, designed to identify and measure various types of pipeline anomalies. The need to keep a growing global pipeline infrastructure safe has driven the development and widespread use of these devices for over 40 years.

Evolution of ILI tools

The first system in the 1960's was a 'geometry' or caliper tool, which used a clockwork mechanism to take movement from the drive elements (or cups) and write it on a circular trace, in order to record dents and wall thickness changes (internal pipe-wall measurements) on a single channel system. By 1965 in the USA, the very first pig to measure metal loss was successfully run through a pipeline. Imperfections in the carbon steel pipe were identified using magnetic fields disturbance or Magnetic Flux Leakage (MFL), where missing ferrous material would cause the magnetic field to leak out of the pipe. The inspecting devices induced a magnetic field using magnets and a coil sensor could detect the leakage between the two poles it generated. This application worked in both liquid and gas pipelines.

In 1970, The British Gas Corporation (BG) decided to use ILI as the preferred method of keeping its recently constructed 80,000 kms of high pressure gas transmission pipeline network safe in the UK. After testing the MFL device, the British operator saw some promise in the results. The tool detected larger areas of metal loss well, though struggled to size these accurately. BG decided to launch a R&D project to produce a "high resolution" tool using the same principles, with 10 times the number of sensors. By 1975, the first high resolution MFL ILI tool was introduced into the British Gas Network.

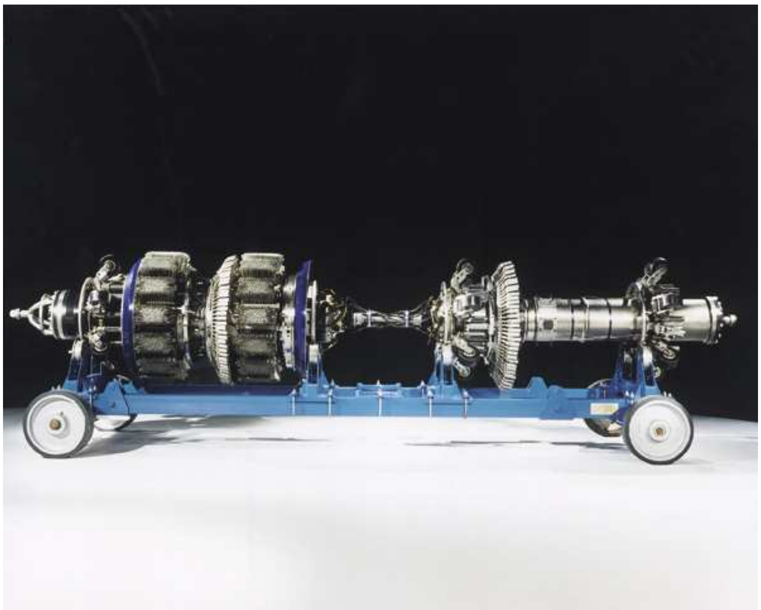


Fig 1- MagneScan™ pipeline inspection technology, using MFL principle

The Industry became concerned following gas pipeline failures in Canada and Australia, caused by Stress Corrosion Cracking (SCC) upon investigation. In 1982, BG launched the Elastic Wave tool in 36" diameter. This technology used long wave ultrasound, which bounced around the pipe wall in a circumferential direction. Anomalies lying in the axial plane would be reflected back to the sensor producing the sound. The challenges were two-fold: 1-to get the sound into the pipe in a gas environment, when ultrasonic probes required a liquid coupling to transmit sound, and 2-to do this in a none-static mode. A unique oil filled wheel, housing Ultrasonic Transducer (UT) probes was used to overcome these challenges.

Unlike MFL, which requires a sizing model to predict the shape and size of metal loss from a magnetic signature, ultrasound can make very accurate direct measurements using "a time of flight" method. It measures how long the sound takes to reflect back to the sensors, from the surfaces of the pipe, or any metal loss in-between. As mentioned above, this technology requires a liquid coupling. A device ideally suited for liquid pipelines was introduced in 1985 called the Ultrasound Wall Measurement (USWM) tool. Its accuracy can help detect and measure erosion or wall thinning, laminations, blisters and inclusions that elude the physics of the MFL tool. This technology requires a clean pipeline surface, liquid product and steady low speed, in order to get the echoes required to produce a very accurate measurement.

In 1986, an ILI tool was introduced to "map" the center line of a pipeline. This mapping pig used a series of accelerometers and gyroscopes, in an Inertial Mapping Unit (IMU). Globally, pipeline construction was expanding further offshore and into more mountainous or unstable environments, so engineers became concerned with buckling or severe denting on the pipes, which could cause a pipeline breach. It was necessary to measure pipe movement, in order to predict a problem before it happened. In later years, these devices were used to measure the strain induced by possible “out-of-straightness” caused by movement. With the onset of digitized maps, a precise x,y,z GPS center line location to align database information was also provided.

As sensing technology advanced, alternatives to the original coil sensors emerged and the first tri-axial Hall Effect sensors were mounted on an MFL tool in 1988. Improved sensitivity and accuracy was being sought out by measuring the 3 active magnetic fields as 3 separate vectors, compared to the single axis devices.

In 1994, the ultrasonic principle was adapted to look for axial aligned cracking in liquid pipelines. The new USCD tool (Ultra-Sound Crack Detection) worked by angling sound from two sets of conventional USWM probes clockwise and counter clockwise at 45 degrees to the pipeline axis. It could detect cracks larger than 1” (25mm) long and 0.04” (1mm) deep. This was an order of magnitude better than Elastic Wave detection and sizing capability >25% +/- 25% wt (Wall Thickness). Not only for SCC, which tends to be found in one form in colonies, but also single fine fatigue cracks and shrinkage (hook) cracks along the long seam weld could be detected. This tool was successful in finding ‘lack of fusion’ defects in ERW (Electric Resistance Welds). USCD replaced the Elastic Wave technology for crack detection in liquid pipelines globally. The requirement for a liquid coupling meant crack detection in gas pipelines was still reliant on Elastic Wave technology, unless a liquid slug was introduced and contained to surround the USCD tool propelled through the pipeline.

In 1997, a liquid pipeline failed soon after an MFL inspection. The cause was determined to be Narrow Axial External Corrosion (NAEC) along the long seam weld. Due to the aspect ratio (length vs. width) of this new type of pipeline defect, the physics of the MFL technique could not determine its dimensions. In order to overcome the physics effect, the Transverse Field Inspection (TFI) tool was built, by turning the magnetic poles 90 degrees to the MFL. The magnetic field is therefore running around the circumference of the pipe, rather than along the axis (per MFL). Although this tool is very good at detecting axial aligned defects, it is challenged by speed effects, and has a lesser specification than MFL for detection and sizing of corrosion defects. It met some success with detecting large hook cracks in seam welds.

A decade of Innovation

In 2002, the first alternative technology to Elastic Wave for gas pipeline crack detection was introduced by PII. This alternative technology, based on EMAT (Electro Magnetic Acoustic Transducer) sensors, uses a number of guided ultrasonic wave forms around the pipe, without the need for a liquid coupling. This innovative solution, with ongoing improvements and variations, continues to be verified by the industry today.

Fig 2- EmatSan™ pipeline inspection tool with Electro Magnetic Acoustic Transducer sensors

In 2004, PII introduced another new technology for crack detection and sizing in liquid pipelines. Using phased array ultrasound, a smart matrix of finite element sound emitters can be programmed to form sound waves of infinite angles and high resolution. The success of this technology in the NDE industry over conventional Ultrasonic Transducer (UT) probes, makes it a leading technology for the next generation of CD tools.

Fig 3- UltraScan™ Duo pipeline inspection tool with phased array ultrasound

From 2006 to the present day, variations utilizing multi-technology tools or 'combos' have become prevalent, especially in the USA. Combining MFL, caliper and IMU is most common, to reduce the number of individual pig runs. Some specialty niche tools and robots, developed to take Cathodic Protection (CP) readings and detect coating disbondment have also become available.

What the Future holds

Leak detection and mechanical damage assessments are now emerging developments, as failures due to corrosion or cracking in the pipeline become less common. "Unpiggable" pipelines require inspection equal to ILI, therefore multi-diameter tools utilizing both MFL and UT technologies, and capable of 'hot tap' insertion, have been developed.

Pipelines are built in increasingly extreme settings, such as arctic regions, deserts or in deep water, where temperatures and pressures are beyond normal operation. ILI tools and sensing systems will have to be continually enhanced to deal with changing operating conditions and help mitigate the risks to pipeline safety. Developments in the past 40 years have shown that in a relatively short time, technology continues to emerge, to keep the pace with more challenging pipeline inspection requirements.

PII Pipeline Solutions
a GE Oil & Gas and
Al Shaheen joint venture

Enbridge Pipelines: Line 6B: Griffith to Sarnia (294 miles)

Inspection tools – Mission and minimum defect specifications

Magnetic Flux Leakage (MFL)

This is a high resolution metal loss inspection tool that works in both a liquid and Gas product pipeline. It will detect, locate and size, both internal and external corrosion. It can examine girth welds and can locate valves, bends and metal objects touching or in close proximity to the pipe, and therefore is often used to create a pipe tally or listing of all pipeline fittings and repairs, as well as the metal loss contained in the pipeline. A typical high resolution MFL tool can detect anything any metal loss feature that has a depth greater than 10% of the pipeline wall thickness (WT) and minimum length and width 0.276" x 0.276". There are 2 main types of external corrosion features, pitting and general corrosion. Metal loss can also be caused by mechanical damage which results in a "gouge" damage

Pitting corrosion – Minimum surface area of 0.276" x 0.276".

- Minimum depth detected 20% WT
- Sizing +/- 10% WT (at 80% confidence level)
- Length accuracy +/- 0.393"

General Corrosion – Surface area > 4 times WT x 4 times WT.

- Minimum depth detected 10% WT
- Sizing +/- 10% WT (at 80% confidence level)
- Length accuracy +/- 0.787"

Gouging damage – Minimum surface width of 0.276"

- Minimum depth detected 20% WT
- Sizing +/- 10% WT (at 80% confidence level)
- Length accuracy +/- 0.787"

Maximum WT for full specification is 0.82"

Maximum speed limit is 13 ft/sec.

Ultrasonic Wall Measurement (USWM)

This is a metal loss inspection tool that works in a liquid pipeline only as it requires a liquid coupling of the ultrasound sensors and the inner pipe wall to allow sound waves to pass between the tool and the pipeline. The speed of the sound returning allows a measurement of both internal and external corrosion. It also has the added benefit of being able to detect and measure any mid pipe wall defects such as inclusions and laminations in the steel itself. A USWM tool can detect anything any metal loss feature that has a depth greater than (1mm) 0.039" and minimum length and width of (20mm) 0.787". The main types of external corrosion features are, pitting, general and channelling corrosion.

Pitting and channelling corrosion – Minimum surface area of 0.787" dia.

- Minimum depth detected 0.0393"
- Sizing +/- (0.5mm) 0.0197" (at 80% confidence level)
- Length accuracy +/- 0.393"

General Corrosion – Surface area > 4 times WT x 4 times WT".

- Minimum depth detected 0.0393"
- Sizing +/- (0.5mm) 0.0197" (at 80% confidence level)
- Length accuracy +/- 0.393"

Maximum WT for full specification is 0.866"

Maximum speed limit is 3 ft./sec.

Ultrasonic Crack Detection tool (USCD)

This is a tool designed to detect, locate and size, axially aligned cracks in liquid pipelines, as it requires a liquid coupling between the ultrasound sensors and the inner pipe wall to allow sound waves to pass between the tool and the pipeline. The amplitude of the sound returning at 45 degrees allows a measurement of the depth of a crack (cl) or cracks (crack field) in the pipeline. A crack must be both greater than 1.18" long and deeper than 0.0393" (30 mm x 1 mm) to be detected by the tool and included in inspection report. The tool reports single and multiple cracks (crack fields) that are axial aligned; both in the body of the pipe and the seam weld area. The sizing was supplied in 2005 in depth range buckets as follows:

0% - 12.5%, 12.5% - 25%, 25% - 40%, >40% Wall thickness (WT) Tolerance of Sizing +/- (0.5mm) 0.0197", for each of these buckets.

The following are reportable feature types in 2005

Indications caused by crack like defects- single individual cracks in a given orientation

indications caused by crack-field defects – multiple cracks in a given orientation

Indications caused by metal loss – Similar reflectors to SCC caused by surface roughness from corrosion or low level SCC (below reporting spec.)

Indications caused by geometries (Non- linear indications at the longitudinal weld, which are near to the girth weld are classified with geometry; weld ihg; striking) – seam weld anomaly with dimensions and characteristics that do not exceed acceptable limits.

Indications caused by Pipeline Fittings (useful as 'natural' markers) - Any physical part of the pipeline, other than line pipe, including but not limited to valves, tees, flanges, fittings, taps, branch connections, outlets, supports and anchors.

Notch-like indications (notch-like indications with the comment weak are not included) – manufactured or construction damage

Indications with the comment strong – The feature area contains indications which clearly lie above the normal amplitude level of the corresponding feature type

Indications with the comment striking – The feature area contains indications which clearly differ from "normal" indications of the corresponding feature type

Dents, deformations (if detected) - A local change in surface contour caused by an external force such as mechanical impact or rock impact.

Indications of unknown or ambiguous origin (not decidable) – reflectors that do not fall in any of the above categories

verified (v) indications – features, verified in the field, are marked by “v”

fully documented (d) indications – features, documented in detail (dig sheet), are marked by “d”

Maximum WT for full specification is 0.866”

Maximum speed limit for full specification is 3 ft./sec

Previous Inspection history:

1993 Pre GE project (Pipetronix) Magnetic Flux Leakage HR metal loss inspection, run date November 1993, Report issue date unknown.

1994: GE Project # C7209_30A, Magnetic Flux Leakage, Metal loss Inspection date November 1994, Report issue April 1995.

1999/2000: GE Project # 50127, Ulrtrasonic wall measurement Inspection 1st Pass through the pipeline: October 1999 - Data collected from 0 miles to 234 miles. 2nd Pass through the pipeline: November 2000 – The remaining 60 miles of data was collected, Report Issue Date: Unknown, Revision 1 Issue Data: July 29, 2003. Correct for internal metal loss characterization discrepancies between internal and external metal loss. External metal loss features on (GW 217720) the failure pipe joint did not change as a result.

2004: GE Project # 103437_30A, Triaxial Magnetic Flux Leakage metal loss, inspection run Date: January 2004. Report Issue Date: August 2004, Specific areas of inspection data was collected from 2296.5 ft. to 6.2 miles and from 143.5 miles to 180.2 miles, (GW 217720) This was not a regular inspection run (i.e. as part of the Enbridge Integrity program), it was a full scale test run of the PII prototype of the next generation of magnetic inspection sensors and was run as part of the GE PII/Enbridge R&D continuous improvement partnership. The failure pipe joint was outside of the targeted area and therefore any previously reported features were not influenced by this test.

2004: GE Project #103437_30A, Ultrasonic Wall Measurement Inspection run date: February 2004, Report Issue 1 Date: May 26, 2004, Report Issue 2 Date: June 7, 2004: A correction to the above ground reference “Location Marker listing” was made, no changes to the metal loss features and therefore no impact to the features on the failure pipe joint (GW 217720). It was decided to

make a magnetic flux leakage metal loss inspection run in 2007, as magnetic tools can detect metal containment sleeves more consistently than an ultrasonic tool.
2007: Magnetic Flux Leakage Inspection data was used to confirm or correct the containment sleeved repairs in Issues 1 and 2 of the USWM report.
Report Issue 2 incorporates results from both the 2004 Ultrasonic wall measurement and the 2007 Magnetic Flux Leakage inspection
Report Issue 3 date : May 30, 2008. This revision was requested by Enbridge due to changes to the number and location of the metallic, full circumferential containment shell repairs, made by Enbridge – features that had already been repaired were removed from the integrity evaluation (RPR) listing and these repair locations were included in the pipeline listing (listing in distance order, of the location of all the pipeline fittings and attachments) for accuracy of historical pipeline reference data.
No changes to the feature listing for the failure pipe joint resulted (GW 217720).
Report Issue 4 Date: September 15, 2008. This issue contains corrections to the nominal wall thickness values. There was no changes to the remaining wall values of the reported features in the failure joint (GW 217720).

Inspections since 2005:

2005 Ultrasonic Crack Detection Inspection 1st run: launch date 30-Sep-run name: EGS105 – fail (incorrect tool parameter programming) 2nd run: launch date 24-Oct, run name: EGS205 – pass (re-run of EGS105) 3rd run: launch date 07-Dec, run name: EGS305 – pass
The recorded data was analysed, a report prepared including the crack features list and submitted to Enbridge Pipelines in March 2006.

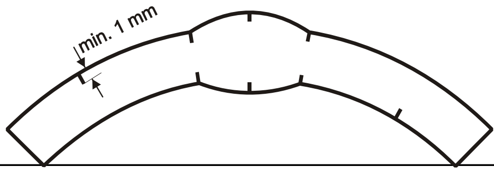
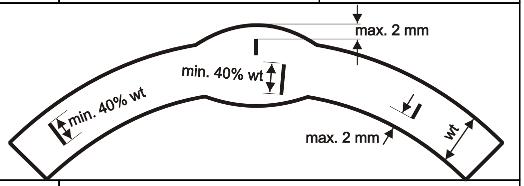
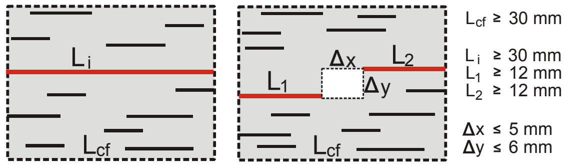
2007: GE Project # 108504_30A, MFL, Inspection Date: October 2007.
This inspection run was initially used as a supplementary technology run to complete the 2004 USWM inspection, where there were areas of Echo loss, specifically peak depths of pitting corrosion.
29th July 2008: Enbridge instructed PII to treat this inspection as a complete stand alone inspection and to generate the usual MFL inspection report from the run data. Report issue 1 date November 2008.
May 2009: Issue 2 When comparing the Above Ground Marker (AGM) distance to the inspection tool odometer distance, it was found the second half of the ILI run was reporting consistently and significantly shorter inline distance measured by the tool (odometer wheel slippage) than the actual distance between the (AGM's) above ground monitoring equipment. Issue 2 contained corrections to the length of the features after GW 235350 This did not affect the reported features in the failure pipe joint GW 217720, as this is located in the first half of the pipeline, and was inspected prior to the odometer wheel slippage problems occurring.

2009: GE Project # 109866_30A, USWM, Inspection Date: June 19, 2009.
Report Issue 1 Date: November 23, 2009
Report Issue 2 Date: May 14, 2010 Issue 2 of the report contained corrections to the river bottom profiles following the debugging of the "river bottom profile software". This program generates the shape of the metal loss in

terms of its remaining wall thickness along the axial length of a metal loss feature. The Rupture Pressure Ratio (RPR) of the corrosion feature on GW 217720 associated with long seam at relative distance 28.2 ft. downstream of the reference girth weld 217720, changed from 1.067 to 1.056. The maximum depth remained at 27% and the axial length remained at 68.03 inches.

2010: GE Project # 109866_30A, USCD+, Inspection Date: July 24, 2010. Tool stopped in the pipeline. The tool did not advance past the failure pipe joint before it failed and therefore it was not inspected.

General Inspection on Longitudinal Cracks in 24" to 34" Pipelines

	Crack fields (like SCC)	**Isolated radial cracks with longitudinal orientation**			**Longitudinal gouging**
		In base material	**In longit. weld area**	**Non surface breaking**	
	Minimum length 30 mm				
Minimum depth extension at POD = 90%	1 mm			40 % of wt (max. 2 mm from surface)	1 mm
					
Depth grouping in 3 classes **at 80% certainty with ±0.4 mm tolerance or at 90 % certainty with ±0.5 mm tolerance**	alternative classes available: 12.5 - 25 % of wt — 1 - 2 mm 25 - 40 % of wt — 2 - 3 mm above 40 % of wt — > 3 mm			n/a	
Length sizing accuracy at 80% certainty **Length sizing accuracy at 90% certainty**	±7.5 mm or ±7.5% of length ±10 mm or ±10% of length				
Acceptable tolerances for crack orientation	Maximum deviation from longitudinal orientation: ±10° Maximum deviation from radial orientation: ±10°				
Internal/external discrimination	yes			n/a	yes
Types of crack-like features	The ILI tool will detect (and identify as crack-like with 90% POI) all types of **radial, longitudinal cracks** which terminate in the internal or external wall surface, including the weld bead, as indicated in the sketch above left. Typical crack types are single, isolated cracks like toe cracks or fatigue cracks, crack fields like SCC colonies, or crack-like defects in the weld bead like lack of fusion, undercuts and welding defects. **Non surface breaking cracks** will be found when their depth extension is at least 40 % of wall thickness and the distance between the crack tip and either surface is less than 2 mm, as indicated in the sketch above right. In most cases, a distinction between midwall cracks and surface breaking cracks is not made.				
Crack fields (like SCC)	A crack field is detected and sized when the cracks cluster is ≥30 mm long and contains at least one crack indication with ≥1 mm depth over ≥30 mm interlinked length. This crack can be a single, continuous crack or consecutive cracks (at least two) of ≥12mm lengths each, but with a max. gap of 5 mm axial and 6 mm circumferential between them. 				
Laminations	Only surface breaking laminations are reported.				
ERW welds	The sizing accuracy of cracks related to ERW can be deteriorated by overlaying echoes from planing marks.				
Seam welds with roof topping	Crack detection at seam welds with roof topping (pipe out-of-roundness, with peak at seam weld position) is carried out with same PODs and certainties as in regular inspections, if the following conditions are fulfilled: **(1)** this particular defect is known to be present, **(2)** the necessary tool modifications are applied, **(3)** the pipeline operator supports the PII Data Analysis with supplying the dimensions of representative cracks within the roof topping area for calibration purposes.				
Nominal tool speed range	The Defect Detection Capabilities refer to the nominal tool speed range stated in the Tool Data Sheet. If the speed increases beyond this nominal tool speed range the minimum detectable crack length increases linearly with speed, i. e. increases to double the length if the actual tool speed is twice as high as the max. nominal speed.				
Nominal wt range	The Defect Detection Capabilities refer to the nominal wall thickness range stated in the Tool Data Sheet.				
Wall thickness measurement	The ILI tool features a number of perpendicular sensors to measure wall thickness. They provide information on the actual wall thickness of the pipe joint. But they are not designed to determine corrosion.				
Other features	The following features are identified by the UltraScan CD, with 90% POI: - welds (longitudinal, spiral, girth welds), longit. weld anomalies (the same depth grouping as with crack features applied) - fittings (with 50 mm minimum diameter)				
Defects associated with deformations	Reduced detection and sizing capabilites.				
Liquefied gas	For crack detection in liquefied gas pipelines (propane), a separate Defect Detection Capabilities sheet is available.				

This specification is generally valid for clean pipeline without internal coating and can be impacted by the attenuation of the media the ILI tool will be run in. For the determination of the required line cleanliness and the assessment of how the ILI tool's inspection capabilities are affected by the attenuation of the media or the presence of internal coating or a rough surface, please refer to the responsible project manager.

Note: POD = Probability of detection; POI = Probability of identification; all accuracies are only valid for nominal tool speeds.

PII Pipeline Solutions reserves the right to introduce technical changes and modifications without prior notice.

An explanation of POD, POI and 80% confidence intervals in sizing of ILI Tools.

POD Probability of detection

The probability of a feature being detected by an in-line inspection tool. This is based upon the minimum detection level defect dimensions and type detailed in the tool reporting specification. The probability of detecting larger defects increases in relation to the dimensions of the defect. As this then an infinite number of larger features, the specification is determined on the smallest detectable feature dimension, which is based upon the physics of the tool technology and pipeline parameters.

POI Probability of Identification

Once a feature has been detected as per the POD description above. The probability that the type of an anomaly or other feature, once detected, will be correctly identified (e.g. as metal loss, dent, crack field etc.).

Sizing accuracy % confidence level

The accuracy with which an anomaly dimension or characteristic is reported. Typically, accuracy is expressed by a tolerance and a certainty. Each technology tool will have specific tolerances related to the type of feature described in the report. As an example, depth sizing accuracy for MFL metal loss is commonly expressed as +/- 10% of the wall thickness (the tolerance), 80% of the time (the certainty or confidence level).

API 1163 and POF (pipeline operators forum) give detailed explanations and examples of POD, POI and % confidence levels. Whereas API is more general POF is more metal loss orientated and detailed in the various types of metal loss defects and how they are described and seen differently by the various technologies. In Europe POF require vendors to publish yje % confidence their tools have in seeing 7 different categories of metal loss (See attached example of a typical MFL POF spec)

ILI tool limitations:-

There is a variety of ILI tools designed for specific missions. The specifications detail the minimum size and determination of a feature, for which a specific tool can detect (POD, POI) and the accuracy in which it can estimate the size at the given confidence level. Each ILI tool will have physical limitations relating to the minimum diameter, bend configurations, internal fittings dimensions, pressure, product being transported and its speed.

Geometry tools :- Are designed to detect and size, internal diameters and changes, dents, ovalities, expansions and gouges in a pipeline. They cannot detect cracking or external metal loss and cannot size accurately, if detected, internal metal loss or wall thinning.

Metal loss :- Magnetic Flux Leakage (MFL) These tools are designed to detect and measure volumetric metal loss, both situated on the internal and external surface of the pipeline. The minimum dimensions of specific defects are available from the vendors specification sheet. Each ILI tool will have physical limitations relating to the minimum diameter, bend configurations, internal fittings dimensions, pressure, product being transported and its speed. Wall thickness, along with tool speed dictates the level of magnetism in the pipe wall and therefore is a limitation on the detection and sizing ability of magnetic tools. Each tool will have a max/min wall thickness value in its published specifications.

These tools are good at detecting and sizing metal loss that crosses the lines of magnetic field produced by the permanent magnets (i.e. MFL is good for circumferentially orientated features and Transverse Field magnetic tools are good for axially aligned features). They cannot detect SCC cracking, mid wall laminations or general wall thinning (erosion).

Ultrasonic Wall Measurement USWM) tool:- These tools are designed to measure the remaining wall thickness, mid wall laminations and wall thinning of pipelines transporting liquids (as the technology requires a liquid medium to transfer the sound waves into the pipe wall and back to the tool sensors. Each ILI tool will have physical limitations relating to the minimum diameter, bend configurations, internal fittings dimensions, pressure, product being transported and its speed. With Ultrasound it is also important to have a clean environment, therefore loose debris and adhered wax or salt deposits can prevent a good ultrasound coupling and result in degraded or failed runs.

Ultrasonic Crack Detection (USCD) tools;- These tools are designed to detect various types of axially aligned cracks. Each ILI tool will have physical limitations relating to the minimum diameter, bend configurations, internal fittings dimensions, pressure, product being transported and its speed. The minimum dimensions of axial (within +/- 5 degrees perpendicular to the central axis of the pipe) features and with minimum length and depth, depending upon speed and wall thickness of the pipeline, will be supplied by the tool vendor.

Metal loss, sharp dents and general wall thinning cannot be detected and sized by this technology.

2005 Description of USCD Feature Types

Crack Field

Crack fields mainly occur in colonies consisting of many small axially-oriented cracks. The colonies have a spatial extension and can be of considerable length (several meters). As a rule, stress corrosion cracks occur at the external pipe surface. The following indication characteristics can be expected:

- Many individual indications with amplitude variation between the indications and fewer within the indications
    - are allowed to be significantly shorter than 30 mm
    - provided a couple of neighboring cracks form a chain of at least 30 mm length and the distance between any neighboring, individual cracks are shorter than 5 mm.
- Gaps in axial and circumferential direction
    - if the gaps between individual crack indications are < approx. 10 mm in axial direction or < approx. 2 mm in circumferential direction respectively, a total length (interlinked crack length) can be given.
- If the defect depth is larger than approx. 2 - 3 mm, shading effects occur sometimes, i.e. with a suitable amplitude adjustment in the B-Scan, considerably fewer signal vectors are visible in the region after the indication than to the right and to the left of the indication. The shading effect is an *essential characteristic* of a large defect depth.
- Additional metal loss indications.

Stress corrosion cracking particularly occurs in the base material and strongly depends on the structure and chemical composition of the pipe steel used as well as on the ambient conditions such as the composition of the ground.

Note: In the case of crack fields with corrosion, the classification crack field with the comment 'with metal loss' is used.

Cause of crack fields:

- Stress corrosion cracking (SCC)

Possible source for confusion:

- Metal Loss
- Surface-breaking laminations

Crack-Like

An indication is classified as crack-like when in the case of a fatigue crack it has a notch-like character, but differs with respect to the following characteristics:

- The indication characteristics are rather irregular (not straight).
- The amplitude characteristics show a rather irregular pattern.
- The beginning and the end of the signal show a rather gradual amplitude increase and decrease (not abrupt).
- If the defect depth is larger than approx. 2 - 3 mm, shading effects occur sometimes, i.e. with a suitable amplitude adjustment in the B-Scan, considerably fewer signal vectors are visible in the region after the indication than to the right and to the left of the indication. The shading effect is an essential characteristic of crack-like defects with a large defect depth.

Due to the local stress and structural conditions, fatigue cracks are mainly to be expected in the heat-affected zone of the longitudinal weld. Cracks lying directly at the weld line are referred to as toe cracks. They can often occur together with form indications, but have significantly different amplitudes, and in the case of a large distance to the probe, they show the multiple indications typical of crack-like defects.

Jeopardized regions are sectional transitions or heavily deformed locations such as deep dents. The crack detection tool can recognize crack-like defects even under these conditions (shown is a test notch of 40 mm length and 1 mm depth, external).

Further crack-like indications can be caused by crack-like defects related to the manufacturing process such as relief cracks or shrinkage cracks in the weld.

Cause of crack-like indications:

- Fatigue cracks
- Weld defects (shrinkage cracks, hook cracks, lack of fusion)
- Relief cracks
- Laminations with contact to the surface, shells

Note: Rolling defects such as laps or shells as well as weld defects such as undercuts often have notch-like and/or inclusion-like characteristics in addition to crack-like characteristics.

Possible sources of confusion:

- weld inhomogeneities
- attachments (see above)
- laminations near the surface

Notch-Like

An indication is classified as notch-like when a correlation with respect to position, length and shape of the indication recorded by different sensors and lying within the same area can be detected and when the indication pattern has the following characteristics:

- With an optimal distance between sensor and reflector, the indication amplitude is relatively high. The optimum distance for external defects is half or 1 1/2 skips, for internal defects one or two skips.
- The sensor neighboring the optimally positioned sensor generally provides significantly weaker amplitudes or, depending on the distance between sensor and reflector, no indication at all (signal failure).
- In the B-Scan, the shape of the indication shows a straight characteristic in parallel to or slightly inclined to the axial direction.
- The amplitude characteristic is generally rather regular with usually skipping amplitude changes at the beginning and end of the indication. One or more sensors often supply multiple indications, i.e. two or more parallel indications with distances dependent on wall thickness and sound velocity. Multiple indications occur particularly with sensors which have a larger distance to the reflector.
- The evaluation of notch-like indications is dependent on the project. But generally all areas, which are marked with 'strong', should stand out by their amplitudes from the mass of the notch-like indications in the actual project. Areas, which are classified as 'weak', are not included in the features list. It is possible to use 'weak' specifically to avoid areas that are added to the features list.

Example for Internal Notch-like Indications:
For evaluation purposes the following guidelines are used for the red, wide indications at the inner surface which results from the direct reflection:

red in 1st skip	-> strong
brown or yellow in 1st skip	-> no comment
blue or green in 1st skip	-> weak

Example for External Notch-like Indications:
For evaluation purposes the following guidelines are used for indications at the outer surface:

red in 0.5 skip	-> strong
brown or yellow in 0.5 skip	-> no comment
blue or green in 0.5 skip	-> weak

Remark:
Multiple indications may be caused by both, mode conversion during reflection at a crack-like reflector, and by different sound paths. For a wall thickness of 8 mm, the typical distance between two multiple indications is approx. 3 µs, i.e. it is considerably larger than with double indications. In the case of wider, notch-like indications, double indications may also occur; they can be distinguished from inclusion-like double indications by their rather straight characteristic.
Apart from that, the amplitude of relevant notch-like indications (depth > 1 mm) is considerably higher than that of inclusions or laminations.
If the reflector lies close to a weld edge, an indication is often given from one side only by sensors which are on the same side of the weld as the reflector.

Cause of notch-like indications:
Notch-like indications are generally caused by grooves or gouges brought into the material during pipe manufacturing or pipeline construction (e.g. drawing groove). Due to the notch effect as well as the cold forming occurring when the notches are brought into the material and the connected reduction of toughness these locations are potential areas for cracking.
Note: Rolling defects such as laps or shells as well as weld defects such as undercuts often have notch-like indication patterns as well. These characteristics are sometimes mixed with crack-like characteristics.

Possible sources of confusion:

- weld inhomogeneities
- notch-like defects with a low depth (< 0.5 mm) may be confused with inclusions

In 2005, the features list contains the following types of indications:

- Indications caused by crack like defects- single individual cracks in a given orientation
- indications caused by crack-field defects – multiple cracks in a given orientation
- Indications caused by metal loss – Similar reflectors to SCC caused by surface roughness from corrosion or low level SCC (below reporting spec.)
- Indications caused by geometries (Non- linear indications at the longitudinal weld, which are near to the girth weld are classified with geometry; weld ihg; striking) – seam weld anomaly with dimensions and characteristics that do not exceed acceptable limits.
- Indications caused by Pipeline Fittings (useful as 'natural' markers) - Any physical part of the pipeline, other than line pipe, including but not limited to valves, tees, flanges, fittings, taps, branch connections, outlets, supports and anchors.
- Notch-like indications (notch-like indications with the comment *weak* are not included) – manufactured or construction damage
- Indications with the comment strong – The feature area contains indications which clearly lie above the normal amplitude level of the corresponding feature type
- Indications with the comment striking – The feature area contains indications which clearly differ from "normal" indications of the corresponding feature type
- Dents, deformations (if detected) - A local change in surface contour caused by an external force such as mechanical impact or rock impact.
- Indications of unknown or ambiguous origin (not decidable) – reflectors that do not fall in any of the above categories
- verified (v) indications – features, verified in the field, are marked by "v"
- fully documented (d) indications – features, documented in detail (dig sheet), are marked by "d"

Treatment of Cracks in Corrosion

The USCD tool is specifically designed to detect and estimate the depth of axially aligned cracking to the inner and/or outer surfaces of a pipeline. The physics of this tool relies upon a corner effect causing a reflation of the ultrasonic sound wave back at 45 degrees to the tool sensors. This sound dynamic does not allow the tool to measure corrosion or wall loss, only the crack depth estimation is captured, and as such must be treated independently of any other defects at a particular location on the pipe (i.e. Metal loss, gouges etc.) However, due to the uneven surface of the corrosion, it is possible that some ultrasound is dispersed away from the 45 degree retuning path and therefore a possibility to receive less amplitude than from a corner effect, produced from the same crack in a smooth surface. As the crack depth estimation relies heavily on the returning amplitude of the sound, it is possible to under call crack depths if the corrosion surface has caused such a reduction in amplitude.