

Field verification procedures for in-line inspection

Recommended Practice

POF 310

Version December 2012
Amended November 2021



Foreword

This document has been reviewed and approved by the Pipeline Operators Forum (POF) and is based on knowledge and experience available from POF members and others at the date of issue. It is stated however, that neither POF nor its member companies (or their representatives) can be held responsible for the fitness for purpose, completeness, accuracy and/or application of this document.

Comments on this specification and proposals for updates may be submitted to the Administrator at specifications@pipelineoperators.org with the form which is available on the POF website (www.pipelineoperators.org).

The objective of In-Line Inspection (ILI) is to obtain data on the pipeline condition as part of the baseline and/or revalidation process. A key part of the process is verification of the ILI tool performance and analysis process through the use of field verification.

The quality and consistency of data obtained from the field is important for statistical verification of the performance of the ILI processes. In many cases the Operator is only focused on confirmation of a reported feature rather than the performance of the overall inspection process.

This Guidance Note should be read in conjunction with POF 100, *Specifications and requirements for intelligent pig inspection of pipelines* and POF 300, *Guidance on ILI First Run Success*. These documents can be found on the POF website (www.pipelineoperators.org).

Techniques for field inspection have developed over time. As new practices become available it is important that the Operators and ILI Contractors update their practices and procedures to reflect best practices.

This Guidance note will also be useful when referring to performance verification requirements reference in API 1163.

NOTE: Although this Guidance Note is quite extensive, the procedures, information and form included in this document are provided only as guidelines. They are not intended for adoption without review and customizing for all circumstances. Operators or other users choosing to adopt a similar approach should base it on their own organization, structure responsibilities and permitting procedures.

Changes November 2021

The purpose of this revision is to comply with the new POF document numbering system. Changes consist of updated references to other POF documents. In addition, editorial corrections may have been made.

A technical revision of this document is planned in 2022.

Acknowledgement

This guidance document, first developed by BP and their Global ILI Suppliers (BAKER HUGHES, GE-PII, NDT and ROSEN) has been further developed by Members of the Pipeline Operators Forum (POF) and has been made available to share best practices, the objective of which is to improve the quality of field data to support the performance of the ILI process.

Photographs and illustrations used in this Guidance Note have been provided by and are used with permission from a number of sources including BP operations and ILI suppliers listed above.

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Introduction

An ILI project is not complete until the reported features have been verified in the field. The process which is followed in the field to achieve this is important as inappropriate inspection techniques in the field can invalidate an otherwise valid report.

Field verification of reported features has two important aspects as this helps confirm:

- The reported features confirming the condition of the line to operator and helps support any actions that may be taken.
- The tool performance for use on other lines where dig verification is not possible.

It is necessary to determine the performance of the inspection, in order to conduct the required preventative maintenance plans with the certainty of risk required by the Operator. Factors of Safety (FOS) can only be used effectively if the tolerances being used to calculate the FOS actually match those provided in the inspection report, or are more conservative in nature. It is not acceptable to use sizing tolerances that are not conservative, which means the actual measured dimensions are greater than those predicted even with the tool vendors tolerance added.

Most ILI suppliers will provide support for field verification activities. The ILI Suppliers are not just interested in when the ILI tool has not performed to specification. They need good quality field data to help verify the tool performance specifications for a range of feature types.

To achieve consistency with data collection it is necessary to set standards and protocols that must be followed.

This requires trained field personnel to gather the data with the required accuracy and competency so that the results can be relied upon. The techniques and equipment used must be tested and certified in calibration. The calibration and device tolerances must be taken into account when evaluating the results.

Significant problems have occurred where reported feature sizes are incorrectly measured in the field. This has an impact not only on the verification of the reported features but also on determining the tool performance.

Field personnel assigned to dig verification need to be certified and have the right level of competency to use the equipment to measure the reported features. The type of feature and inspection process can include the following

Reported feature	Inspection methods*
External corrosion:	Depth gauge micrometer or <u>laser scanning</u>
Internal Corrosion	UT probes / <u>UT (C) scanning</u> , Radiography
External Crack measurement	Magnetic Particle, Angle UT probes or Phased arrays, ACFM (Alternating Current Field Measurement)
Internal Crack measurement	Angle UT probes or Phased Arrays, ToFD (Time of Flight Diffraction)

* Best methods are underlined.

It is important to have consistent and reliable standards. The anomalies must be accurately measured in length, width and depth. When evaluating anomalies it is important to understand the extent of the anomaly and how its interaction with adjacent anomalies is accounted for in the report.

This Guidance Note provides ILI Field Data Verification and reporting Procedures that can be used to support the ILI process. Guidance is also provided in the “ILI Field verification feedback form” included as appendix A and also available as a separate document (POF 311) on the POF website (www.pipelineoperators.org).

1 Safe working practices

All work on site needs to follow appropriate Safety Procedures and protocols, local regulations and company policies addressing. It is important that each Operator and Contractor evaluate the risks and take appropriate steps to avoid incidents. Factors to consider include:

- Site Access Control
- Right of Way Preparation
- Site Specific Emergency Response and Fire Safety
- Contractor Safety
- Site Security
- Securing permits
- Excavation and Shoring
- Removal Non Asbestos Coatings
- Removal of coatings that may contain asbestos
- Backfilling and Reclamation
- Grinding and Sanding pipeline Anomalies
- Site assessment Questionnaire and safety check list
- Daily Tailgate Safety Meetings

2 References

- API 1163
- ASME B31.4 / ASME B31.8
- ISO 9712, EN 473 or equivalent
- Client Specific Assessment Procedures

3 Personnel

3.1 Responsibilities

The activities and administration performed under this procedure are the responsibility of the nominated Project Manager

3.2 Training and experience

The personnel that are deemed qualified to carry out this location verification procedure shall have, as a minimum, the following:

- Successfully completed a recognised Pipeline Integrity Course (typically a 5-day, 40-hour course outlining the elements that affect pipeline integrity projects)... AND
- A minimum of 3 “Location Verification” assessments performed under the direct supervision of a Senior Pipeline Integrity Technician / Specialist... OR
- Proven their competence and understanding of this procedure during a practical assessment performed by a qualified Senior Pipeline Technician and has had a minimum of 10 digs field experience.

Personnel employed to operate non-destructive equipment (e.g. ultrasonics) for finding and sizing of metal loss defects and/or cracks shall be sufficiently qualified in the relevant technology (e.g. level 2 NDT-UT).

4 Equipment

Finding and sizing features in the field requires information gathered during the ILI run and equipment that can be used in the field to find and size features. A listing of required information and equipment is given below.

Reference Sources:

- ILI Pipeline Listing (Spool count, joint lengths, feature distances).
- AGM Listing (AGM Marker locations, and odometer references).
- GPS Coordinates (GPS survey reports).
- ILI Contractor Dig Sheet(s).
- Client Specific Dig Sheet(s).
- Relevant NDT procedures.

GPS receiver

GPS receiver with horizontal location accuracy better than 1 metre resolution.

Pipeline locator

A pipeline locator device should be available for detection of the pipeline centreline capable of pinpointing pipeline in a multi pipeline corridor.

Measuring devices

- A 30 metre (approx. 100 ft) long (or longer) measuring tape or a 30 m. slack chain for measurement of long distances along the pipeline or Laser range finder for measuring locations that are not typically accessible. The laser range finder must have an accuracy of +/- 30 cm (1 ft). at 300 m (1000-ft) with magnification of 6x.
- A 7.5 metre (24') or longer tape ruler to allow measurements within a joint of anomalies.
- 30 cm (12") long magnetic rulers to attach to the pipeline for measurement of defect lengths and photography reference.
- Clock tape (pipe wrap) for required piping diameter (i.e. 16", 26", 30")
- Curve-O-Mark Centre Punch (TDC)
- Stud-finder (magnetic is preferred)

Anomaly (defect) sizing devices

- Micrometer bar - adequate to measure exterior corrosion to a depth 80% of the pipe wall, with a tip diameter of approximately 1 mm (1/32rd of an inch) and a reach exceeding 60 cm (2 feet).
- Ultrasonic flaw detector with suitable transducers adequate to define internal wall loss, cracks and stress corrosion cracks.

Advised non-destructive equipment for defect sizing:

- Laser scanning unit for mapping and sizing of external corrosion (if applicable).
- Ultrasonic map scan unit with appropriate transducers for mapping and sizing of internal material loss and wall thickness (if applicable).
- Crack measuring equipment: ultrasonic equipment with shear wave transducers, ACFM instrument.

Marking devices

- Grease pencils.
- Black markers.
- Magnet mounted paper to mark indications and measurements for photographs.
- Markal B Paint Stick(s) (white & / or yellow) / Lumber Crayons
- Sharpie Markers (NOT black – blue or red preferred).
- Carpenters Pencil(s).
- 0.9mm Mechanical Pencil(s) with lead refills (optional blue or red lead).
- Spray Paint (orange or red preferably & non-acrylic for light coating).
- Liquid White Out (pen style).

Documentation Devices

- Digital Camera – (8 Mega Pixel Resolution or better).
- Field Data Collection system (digital or paper data reporting).

Calibration

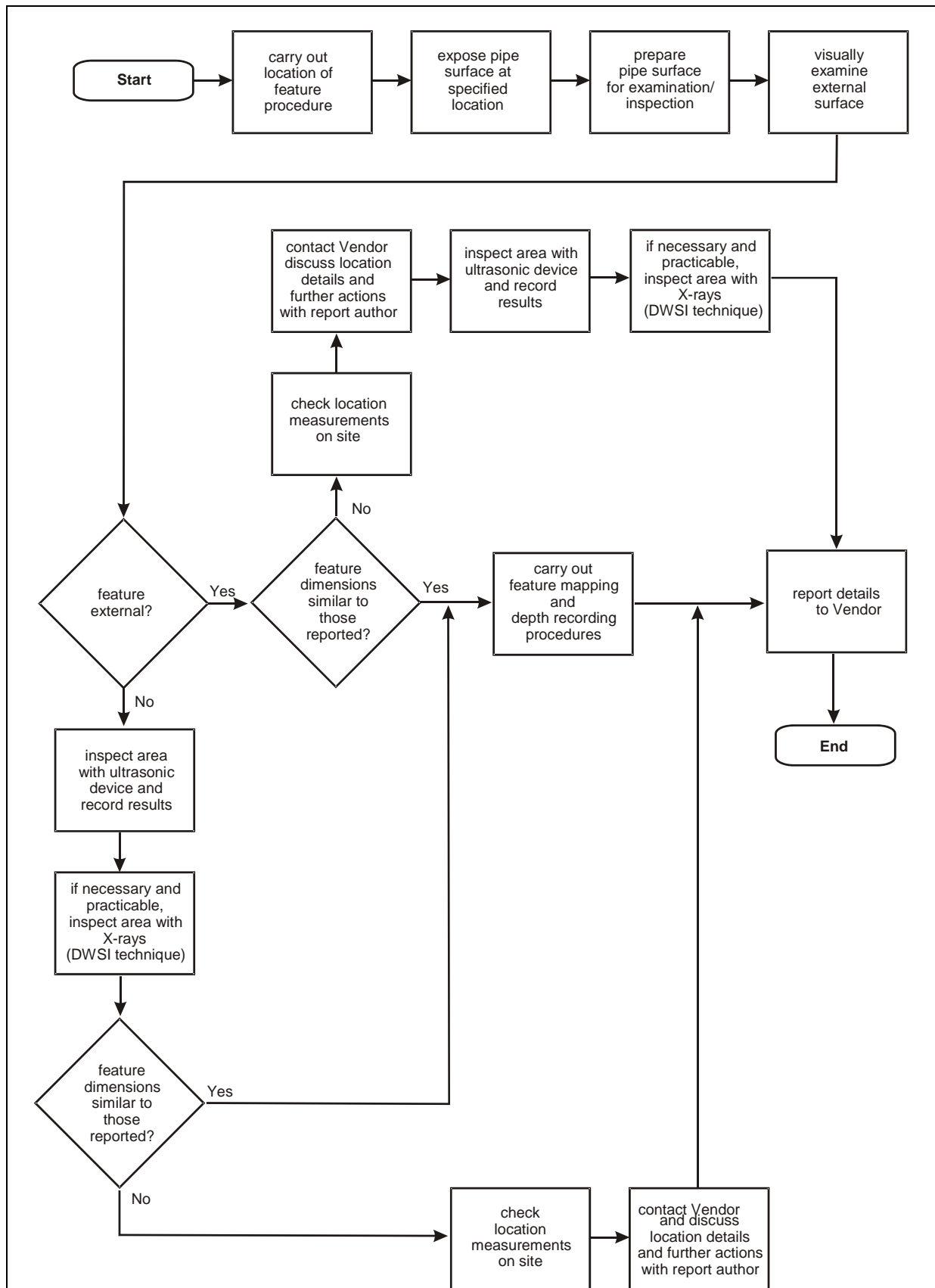
All applicable equipment used in the field requires calibration as stated by the respective manufacturers.

Availability of the equipment

The selected GPS, Ultrasonic equipment, pipe locator equipment and any (portable) other electronic devices shall be fully operative and with batteries in full charge. Follow the check up and maintenance procedures as stated in each equipment's manual. A spare set of fully charged batteries or an alternate power source must be available. Several GPS receivers have skyplot and DOP (satellite geometry) forecasting or they can be consulted online. Plan the GPS data collection around the times of the day when the satellite geometry is best to maximize productivity and accuracy. A minimum of 4 satellites, a maximum PDOP of 6.0, minimum SNR of 4, minimum satellite elevation of 15° and reasonable multipath conditions are required for GPS coordinates of the dig site (check the GPS receiver operator's manual for more detail).

5 General procedure

Verification digs should be carried out according to the following procedure:



6 Locating features in the field

Locating features (e.g. metal losses, dents, mid-wall defects, etc.) is a difficult task, which can cost the pipeline operator valuable time and resources. Therefore, it is important that appropriate techniques are used at each stage in locating these features.

This chapter gives guidelines for locating pipeline features efficiently and effectively.

6.1 Preparatory measures

Before starting any field verification activities, it is advisable to check if the distance information in the Inspection Report of the inline inspection project fits into the client's documentation.

If an operator's pipe tally is available, its pipe sequence should be correlated with the sequence provided in the Inspection Report of the in-line-inspection. The identification of installations can be used as references for the correct numbering of the pipe joint sequences.

Additionally, for proving whether the odometer factor of the ILI tool was appropriately chosen, the pipe lengths of a number of pipe joints within an easy accessible pipeline section (e.g. immediately after the launcher) should be measured and compared with the figures provided in the final report. Thus the general accuracy of the odometer system can be assessed and, if necessary, corrected at an early stage.

6.2 Reference points

Wherever possible, the position of reported features is related to reference points that can be easily identified and located in the field. Reference points are either pipeline fittings, such as mainline valves, off takes or significant bends, or artificial reference points, such as line markers; these will have been placed on or near the pipeline at the time of the inspection.

At least one reference point is provided for each metal loss feature reported on the inspection sheets. If the reference point is more than 500 metres from the metal loss feature then a second reference point will usually be provided, if possible.

This procedure can be applied for onshore, buried pipelines, constructed with ferrous materials and also for areas under a certain depth of water, providing that certain precautions are taken in the measurement for depth of cover (DOC). This chapter describes the procedure to identify the spatial location of a pipeline by locating the pipeline centreline and measuring the DOC. Both operations are completed by use of a pipeline locator.

With reference to pipeline construction, the centreline and DOC are measured for reasons associated with preserving the integrity all along the pipeline as work is performed.

Precise determination of the centreline of a pipeline is critical to identify its spatial position. Furthermore, a precisely obtained centreline is the backbone for spatially based alignment of additional data collected on the right of way. Data corresponding to above ground surveys are all aligned through common spatial coordinates.

The location of the pipeline must be accurately identified and clearly marked at sufficient distances to allow stakes showing location of the pipe to be visible from any location along the pipeline.

The inspection report reference point will identify a starting location and specify the length of pipeline to be measured and marked for centreline location and DOC.

Before attempting to locate the centreline of pipeline, complete a Job Safety Analysis / Risk Assessment of the right of way to determine if any environmental / safety problems may exist (dangerous animals, uneven terrain, hunting season, etc.)

6.3 Pipe location and signalization

Locate the centreline of the pipeline by using a suitable pipe locator.



Figure 1: Locating the centreline with a pipe locator.

In areas where direct soil access is available, identify the located centreline by driving lathe with orange flagging (in the case of natural gas pipelines, or other colours as indicated by the national standard of locating lines) into the ground. In areas covered with hard surfaces, use orange (or the appropriate colour) spray paint to mark centreline location and DOC.

6.4 Marking (Signalizing) the centreline

The centreline of the pipeline should be staked and flagged at intervals no greater than 60 metre (200 feet) apart. In some cases, such as in hilly areas, near Points of Inflection (PIs), or near roads or other crossings of the pipeline right-of-way, the centreline should be staked at closer intervals, normally with 30 metre (100 feet) between markers. Additional activities during marking are:

- Record Location description and Photographs
- Determine starting point for excavation.

6.5 Measuring Depth of Cover

The Depth Of Cover (DOC) is defined as the distance between grade and the top of the pipeline and is measured with a radio-detection pipeline locator.

Measure DOC at each staked location and write this depth on the lathe with a permanent marker.

If the pipeline locator indicates that the DOC is less than 1.5 metre (5 feet), verify the distance to the top of pipe by physically probing the pipe. The probe tool shall be designed such that neither the pipe coating nor the pipe is damaged during the physical probing operation.

7 Pipeline excavation and pipe inspection

7.1 Before starting

Whenever excavating or conducting a detailed inspection of an operating pipeline it should be recognised that a simple data verification exercise can become a full pipeline emergency if either the excavation process goes wrong or the feature is larger than predicted from the inspection!

All parties involved in the excavation / inspection process shall review the risk assessments; ensure that permits to work are in place and are understood; communications are working and that emergency response procedures and systems are in place.

Before excavation begins a Competent Person shall develop an excavation plan. The plan shall include pipeline pressure reduction, type of soil, depth of excavation, type of shoring or sloping required, proximity to structures, traffic issues and communication with other services and utilities such as the “One Call” system. Requirements in each country will vary. Notification to other utilities and services should be done at least 72 hours before excavations commence.

Review all onsite staking marking and ensure the correct information is noted and check for obvious errors. Record any errors.

Determine other facilities (pipelines, utilities, etc) that might impact the excavation activities. Identify and discuss procedure modifications to address these concerns.

7.2 Recording of excavations

To help in answering future queries the pipeline operators should, wherever possible, supply the data shown in the sample Field Verification Feedback Form at the end of this document. This shows feature dimensions and location information.

7.3 Identification of dig site reference / origin

Defining the dig site origin, or reference point (usually the upstream girth weld or Reference girth weld) is required to ensure that ALL subsequent measurements used within each dig site accurately reflects the values that were measured by the ILI equipment.

The bulk of this is covered during the location validation / verification process, but the identification of the Reference girth weld is a critical step to both validating the tool performance and capturing accurate data for comparison with future ILI run results.

The following steps should be followed:

- 1) Identify and document the Reference girth weld both within the report and with the use of digital photography (see figure 2).

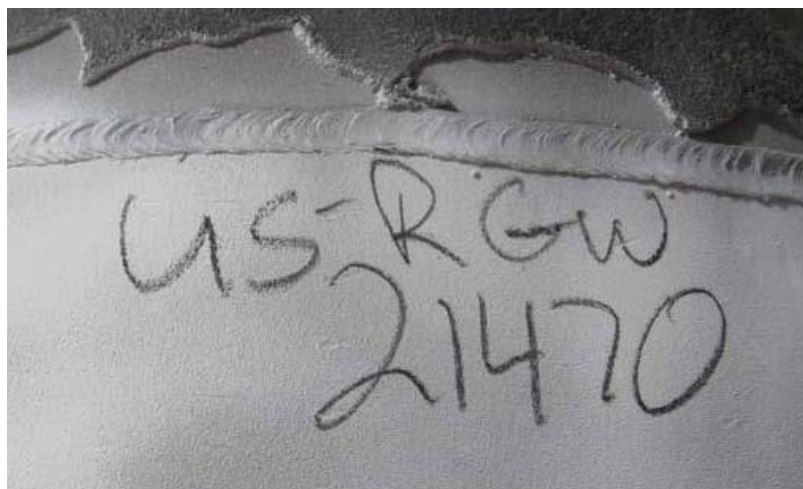


Figure 2: Digital photograph of Reference girth weld with markings

- 2) Measure the length of the pipe joint.
- 3) Identify, measure the position, document the type and location of the long seam present on the feature pipe joint to allow for:
 - Validation of the ILI orientation accuracy (if technology capable)
 - Reference for additional measurements from Top Dead Centre (TDC), see figure 3.

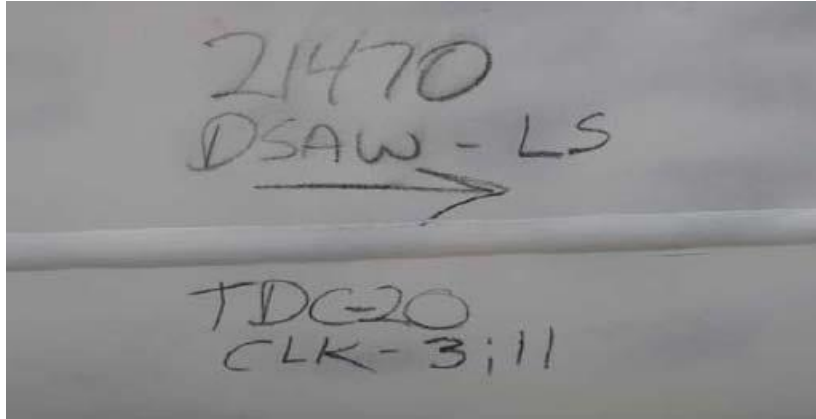


Figure 3: Digital photograph of longitudinal seam weld with clock position.

7.4 Location of features

The location of a feature can be carried out in two stages; locating the pipe joint that contains the feature (see above) and then locating the feature within that joint.

To locate the pipe joint containing the feature, the distance from the reference point to the girth weld at the upstream end of the joint is provided in the inspection sheet. This distance refers to the pipeline route measured with the odometer wheels. The horizontal above ground distance measured between two pipeline locations might be different if the pipeline route deviates from the straight connection line between these points.

To locate the feature within the pipe joint, the distance from the upstream girth weld to the feature and the location of the feature around the circumference of the pipe, as viewed in the direction of flow, are provided in the inspection sheet. Girth weld anomalies will be located within the upstream girth weld.

7.5 Identification of features

Metal loss, dents and girth weld anomalies will require an area of the protective wrap to be removed.

A minimum area of approximately 0.6 m along the pipe axis by 45° of the circumference, centred on the reported feature position, should be cleaned back to bare metal (see next paragraph).

Once this has been done, any external metal loss, dents or the girth weld that contains an anomaly should be easily identified. The position of internal metal loss or mid-wall defect should be marked on the outside of the pipe in preparation for further examination.

Shallow dents can usually be identified by running one's hand along the pipe surface, or by placing a straight edge along the pipe.

7.6 Surface preparation

To achieve satisfactory recording and measurement of the feature it is essential that the specified area of pipe surface is cleaned back to bare bright metal.

There are a number of methods for removing pipe wrap primer including:

- 1) Solvent cleaning.
- 2) Chemical cleaning.
- 3) Wire brushing.
- 4) Grit blasting.

For certain types of corrosion product it is possible to produce a finish resembling bright metal when cleaned using a wire brush. In this instance grit blasting is the preferred method in order to remove the entire corrosion product.

7.7 Definition of ILI feature dimensions

Defining the ILI technology, and its dimensional formatting of the listed features is a critical part of this process. The following information must be determined prior to any ILI feature layout commencing:

- Where is the origin of the ILI feature (distance listed from upstream / downstream girth weld)
- Leading edge (upstream edge) / Centre / Trailing edge of feature “box” (see figure 4).

RGW

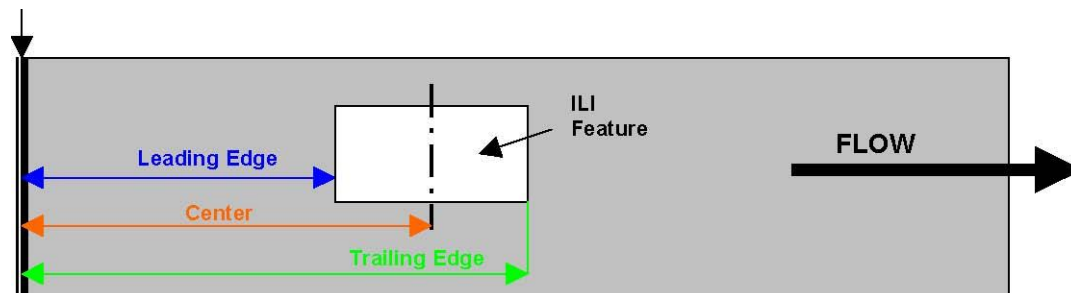


Figure 4: ILI Feature Origin (Distance from U/S Weld. N.B Measurements can also be taken from the downstream weld)

- Where is the listed orientation, clock position or degree position of the ILI feature?
- Once these are established the remaining dimensional information from the dig sheet, pipe tally, or ILI spreadsheet can be referenced and accurately transposed onto the pipe surface (see figure 5).

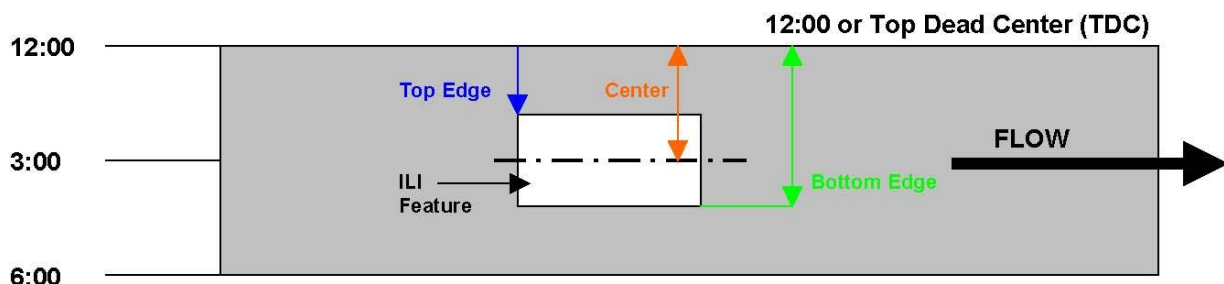


Figure 5: Top / Centre / Bottom of feature “box”

8 The dig verification process

8.1 Overview

The verification of each dig site location is a fundamental requirement of the ILI program. This allows the information collected from the in ditch examination portion of the program to verify the accuracy of the ILI data and ensure that the pipeline has been remediated per Operator specifications and regulatory requirements.

The importance of performing this procedure effectively can be best illustrated by understanding that when an anomaly cannot be identified on the pipeline there is a 90% probability that the investigation is in the wrong location. The 90% figure is applicable in spite of even the improved technologies and processes that are in use today.

Measuring and recording the actual pipe condition is an essential element of the verification process. Only if the measured data has been correlated with the data provided by the ILI tool as per the anomaly can the anomaly be considered to be remediated.

The additional information to be gathered as per this procedure can be used to determine the root cause of the anomaly and used by the analysts and the Client to correct the existing conditions to prevent future problems with the pipeline.

If all of the specified requirements of this dig verification procedure cannot be met, than the Project Manager or his designee shall complete and sign off the "Exception Report" form included in the Dig Site Form

No further excavation or dig site investigation should be carried on until the location is confirmed with the guidance provided by this procedure.

The Excavation Report shall clearly state the location verification procedure that has been utilized for each anomaly dig site location.

8.2 If digging leads to wrong pipe joints

If a feature to be verified cannot be found in an excavated pipe joint, it should be assumed first, that the located pipe joint might be wrong. For verifying this, proceed as follows:

- Measure length of "wrong" pipe joint.
- Measure wall thickness of "wrong" pipe joint as well as of the two adjacent joints.
- Determine position of longitudinal weld for the pipe joint concerned as well as for the two adjacent joints (o'clock position when looking downstream). If the pipes are spirally welded, determine the circumferential start and end positions of the spiral welds directly at the girth welds.
- Provide this information to the Data Analysis Department of Supplier who can normally locate the right pipe joint relative to the "wrong" one.

Note:

Knowing the lengths as well as the wall thicknesses of three subsequent pipe joints, the corresponding sequence may often be identified from the pipe book.

8.3 Contacting Supplier

ILI Suppliers aim to provide their clients with a quality service. If a reported feature cannot be located from the information provided on the inspection sheet or if the feature type is very different from the description given on the inspection sheet, then the project manager at Supplier should be contacted.

Telephone Numbers:

Contact	Telephone	e-Mail	Address

9 Layout of ILI features

The ILI Features shall be laid out on the bare pipe surface after the initial reference layout has been completed, BUT prior to the Metal Loss anomaly assessment beginning.

Once all the reference information can be identified on the pipe surface the ILI feature(s) can be laid out as follows:

- 1) Identify and place a small mark at the “feature origin” (e.g. leading edge) location of the listed ILI feature on the feature pipe joint based on the dig sheet information.
- 2) Identify and place a small mark at the appropriate location of the listed ILI feature orientation (measurement from TDC/clock position/degree) on the feature pipe joint.
- 3) Mark out the ILI feature on the feature pipe joint as per the listed ILI feature dimensions (from the dig sheet OR pipeline listing).
- 4) The following information shall be also written on the coating, and pre-blasted surface for each ILI Feature listed with a marker or pencil (unique colour is preferred):
- 5) Feature ID & Joint ID
- 6) Feature Type
- 7) Max Depth (% / mm or in)
- 8) Odometer / Absolute Distance
- 9) Orientation (o'clock / TDC / degree)
- 10) Relative Distance from RGW (Axial Distance)
- 11) This shall be repeated for ALL listed ILI Features within the exposed piping that exists within the dimensions of the bell hole being inspected (see figure 6).

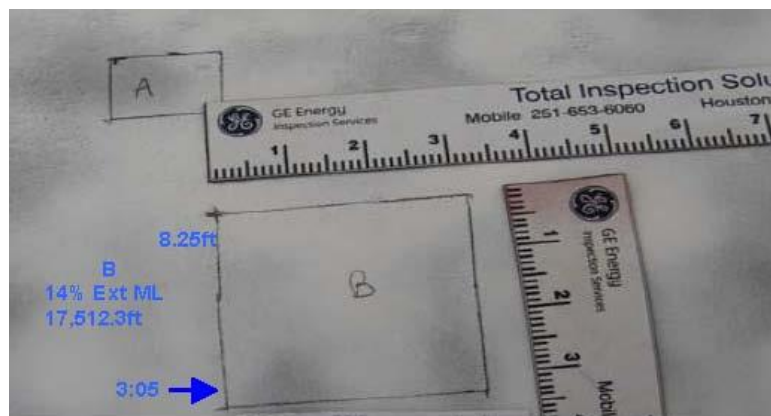


Figure 6: ILI feature dimension layout

- 12) If only the Length is provided for the ILI Features listed on the tool data, or dig sheet than the brackets shall be replaced with the below symbol, but shall contain all the items listed in section 7.3 of this document:
 - Vertical line to represent the listed start distance from the RGW
 - Horizontal line (can be dotted)
 - Vertical line to represent the end of the listed ILI Feature

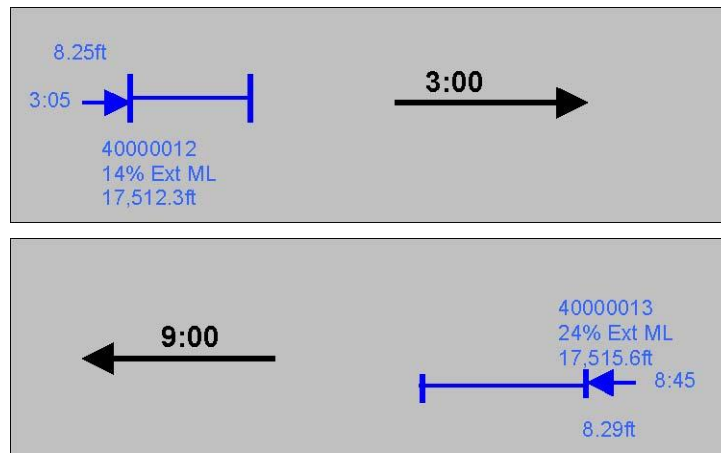


Figure 7: ILI feature dimension layout

10 Correlation of ILI features

The Metal Loss anomalies shall be the last component laid out on the bare pipe surface after all other reference layouts have been completed. As metal loss anomalies might interact, the distance between such anomalies also must be measured.

10.1 Interaction criteria

Identify the interaction criteria that the client requires all the Metal Loss anomaly assessments to be performed to: (t = nominal wall thickness)

- 1) Rstreng method (25 mm axial x 6 t circumferential)
- 2) 3 t Box or 6 t Box
- 3) Length x Width minimum criteria
- 4) Length x Width average criteria
- 5) Other client specific criteria (e.g. 3 t Axial x 6 t Circumferential)

10.2 Grid spacing

Identify the Grid spacing required for all Remaining Strength or burst pressure calculation data collection parameters:

- 1) 12.5mm x 12.5mm ($\frac{1}{2}$ " x $\frac{1}{2}$ ") Grid spacing
- 2) 25mm x 25mm (1" x 1") Grid spacing
- 3) Other

10.3 Lay out of anomalies

Once all the reference information can be identified on the pipe surface the Metal Loss anomalies can be laid out as follows:

- 1) Identify and outline all areas of metal loss greater than the client supplied minimal recordable wall loss depth, or 10% of Nominal Wall Thickness (client criteria supersedes in all cases). OR
- 2) Mark out a grid over the metal loss areas identified to exceed the minimum recordable depth criteria being used (refer to 10.1) with either:
 - a. Pencil / marker, straight edge, ruler, and level (see figure 8)...or

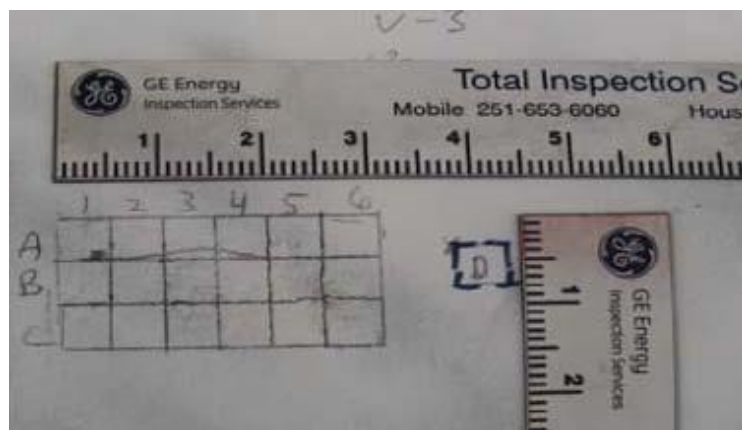


Figure 8: Marked feature lay out with rulers.

- b. Specific grid material that meets section 10.210.2 and spray paint (coloured or WCP-2 if possible, see figure 9).

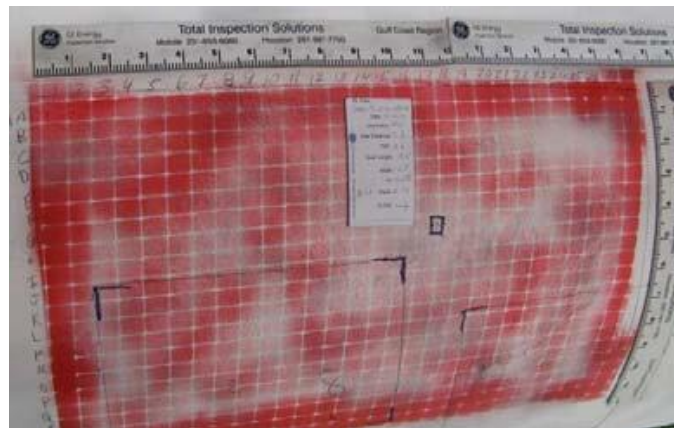


Figure 9: Coloured grid marking.

- 3) Record all required dimensional measurements for all areas that exceed the minimal recordable wall loss depths.
- 4) Correlate the variance from the listed ILI Feature dimensions with the actual Metal Loss anomaly dimensions, and document with digital photography.

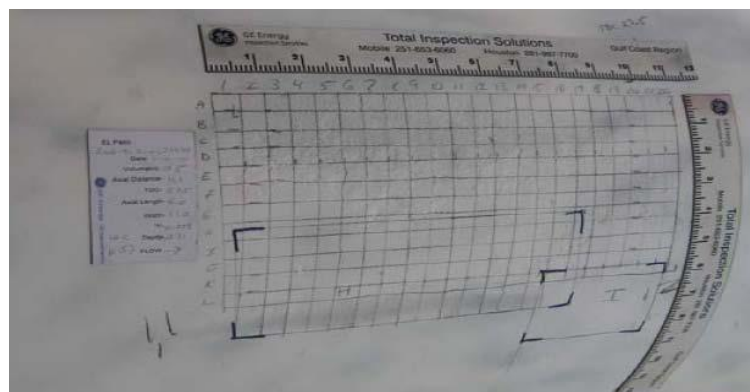


Figure 10: Variance from listed ILI Feature dimensions with actual anomaly dimensions.

- 5) Record all pit depths from the grid itself, and document them in a format that is able to be utilized in further Engineering calculations (i.e. Excel).

MANUAL PIT GAUGE EXAMINATION REPORT (GRID)

Project: Client Metal Loss Correlation

Location:Section Name

Purchase Order No: N/A

Acceptance Standards: As per client request

GEIS Job No: MBPD0053

Procedure: N/A

System: Client Pipeline System

Joint #: 21470 Vol-5

GRID AXIAL DISTANCE (in): 11.1 ft from US GW

GRID TDC (in): 27.5

GRID INCREMENTS (in): 0.50in x 0.50in

MEASURED W.T. (in): 0.250 to 0.260in

GRID LENGTH(in): 11

GRID WIDTH(in): 6

PIT DEPTH (mils) REFERENCE COLOR CHART

2 to 25 mils

26 to 50 mils

51 to 75 mils

76 to 260 mils

LOW

Legend	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38		
A			5																																					
B						24	3			12		21	5	9																										
C		18	15			20	5			9	71	48	13		28	17																								
D		18	5	12	13	15	17	32	14	45	35	46	40	11		35	33																							
E	20	18	50	8	12	8	30	19	18	51	21	12	8	16	11	23	5																							
F	12	5	5				20	19	16	15	14	17	16	38	24		5				24	35																		
G							32	41	20	41		12			11						10																			
H								20		9										39																				
I																			44		28	38	14																	
J					27																																			
K				40																																				
L															37	34	37																							
M															12																									
N																																								
O																																								
P																																								

MAX. PIT INFO:

MAX. PIT AXIAL DISTANCE (in): 11.6

MAX. PIT TDC DISTANCE (in): 26.5

MAX. PIT DEPTH (in): 71

Page 1 of 1

Figure 11: Pit depths recorded in grid.

- 6) Provide all documented details from correlation results, and entire validation process to the client in the agreed upon reporting format.

11 External metal loss mapping

In this chapter technologies are described that can be used to map and size external metal loss. Application of a Non Destructive Technique should be based on a procedure that is approved by a person who is level-3 qualified (ref. ISO 9712, EN 473 or equivalent) for the relevant technology.

11.1 Area mapping and depth measuring by laser scanning

Depth of external corrosion patches can be measured by laser profiling. The resolution of laser measurement is very high but accuracy of depth measurement is determined by the ability of the software to reconstruct the un-corroded surface. Estimated accuracy is 0.1 mm.

11.2 Area mapping by rubbing and photographic methods

An effective and easy method of mapping is by taking a simple rubbing. This is achieved by placing a sheet of paper over the feature, holding the paper firmly in place with, for example, small magnets and rubbing the long edge of a wax crayon over the surface of the paper. The edges of the feature will be delineated and if required, can be highlighted by careful manipulation of the crayon.

The following parameters should be annotated on the paper (see also figure 12):

- 1) Feature identity (e.g. Supplier Report Number and Feature Number).
- 2) Direction of flow.
- 3) Orientation of the feature.
- 4) Distance of the feature from the nearest girth weld.

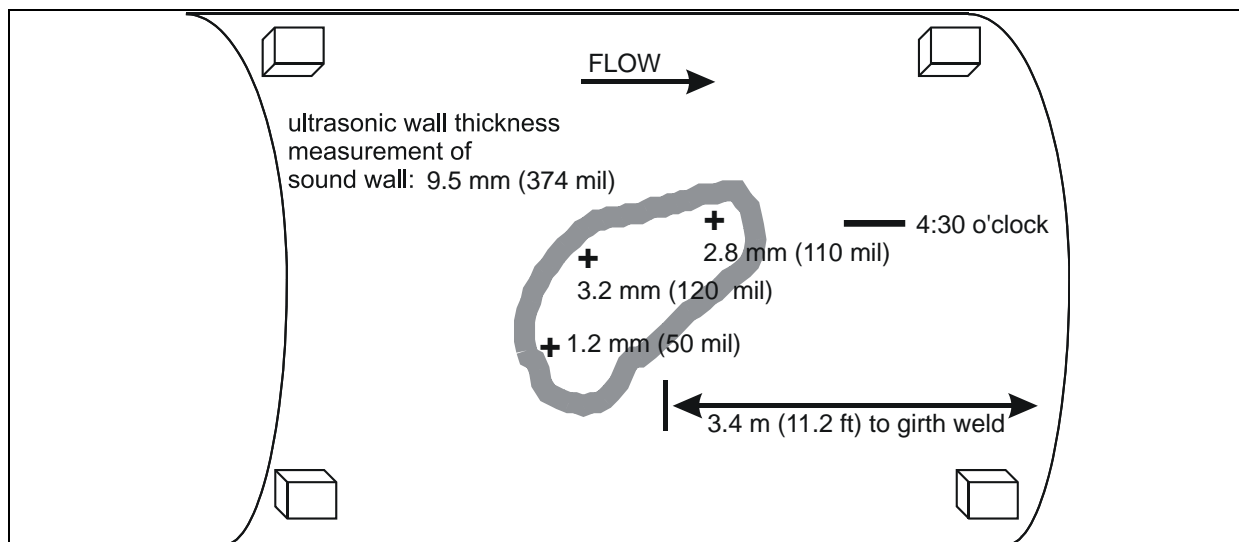


Figure 12: Example of a mapped area using the rubbing technique.

The rubbing technique has a definite advantage over photographic recording methods in that it is possible to record all subsequent measurements directly on the rubbing in the appropriate location e.g. each individual pit depth in multiple pitting.

Photographic recording with digital camera can be used additionally.

11.3 External metal loss depth recording

An effective method for recording external metal loss depth is by using a depth micrometer or micrometer dial gauge in conjunction with a large bridging bar, see figure 13

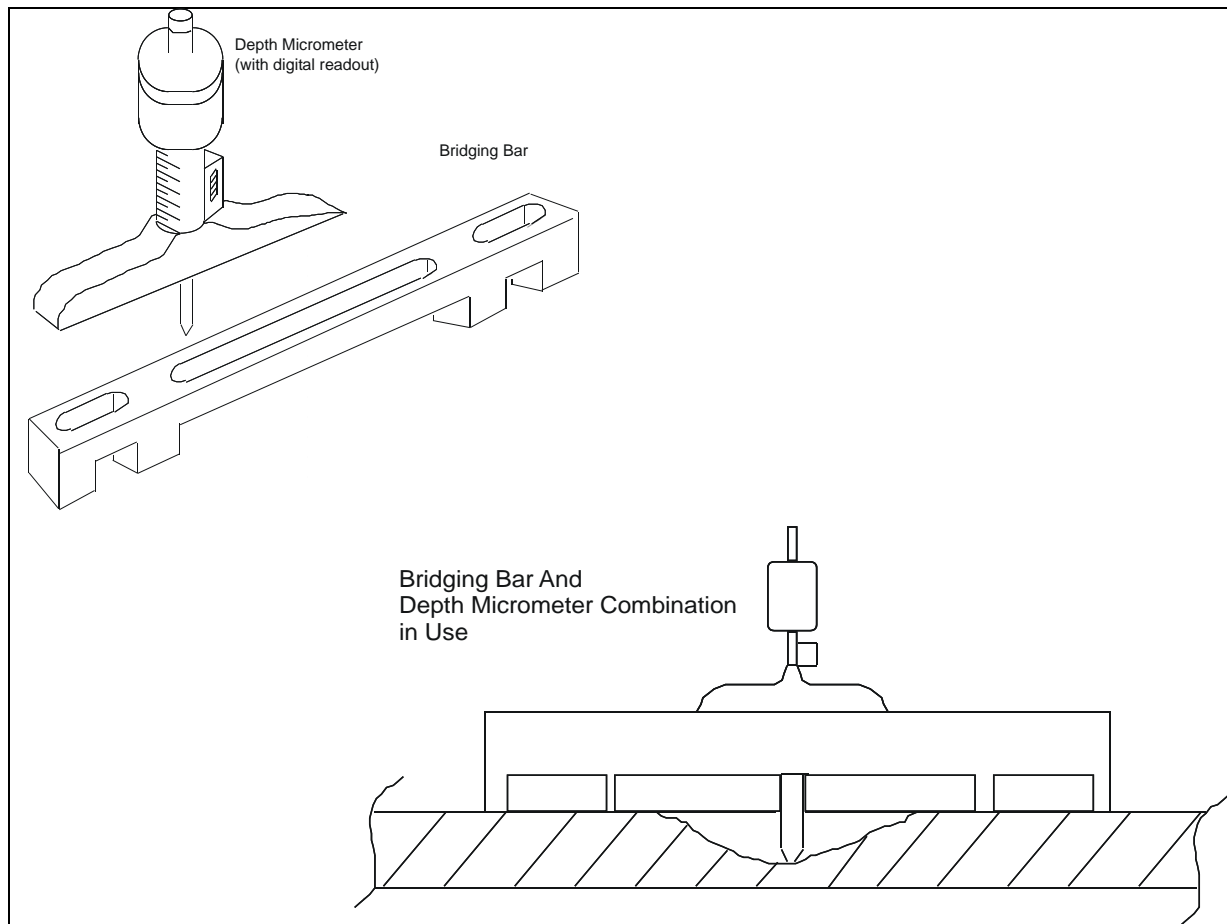


Figure 13: Typical micrometer and bridging bar arrangement

It is recommended that the micrometer anvil be ground to a taper with a tip diameter of approximately 1.0 mm. This will enable entry into the small diameter pitting and concave surfaces found at the bottom of most metal loss features.

A pit gauge is not recommended because of its potential inaccuracy of up to 2.0 mm. A depth micrometer or micrometer dial gauge has a resolution of better than 0.05 mm, resulting in an estimated depth sizing accuracy of 0.15 mm (ref. 1).

11.4 Wall thickness and remaining ligament thickness recording

Pipe wall thicknesses and remaining ligament thicknesses of internal damage can be measured to an accuracy of 0.25 mm using standard ultrasonic wall thickness meters and suitable couplant (ref. 1).

Extreme care should be exercised when attempting to measure remaining ligament thicknesses directly within an area of external damage because there is extra couplant under the transducer when mounted on concave surfaces, which results in an overestimated reading.

Decisions on assessing the significance of the damage are primarily based on the remaining ligament thickness. It is therefore important to obtain a reliable reading. This is best accomplished by obtaining the minimum ultrasonic thickness reading immediately surrounding the damage and subtracting the mechanical depth measurement.

12 Internal metal loss mapping

The preferred method of mapping internal metal loss is by using ultrasonic equipment. The typical training level of the operator is NDT-UT level 2. The estimated accuracy of the reported (remaining) wall thickness is 0.25 mm. (ref. 1). Application of a Non Destructive Technique should be based on a procedure that is approved by a person who is level-3 qualified (ref. ISO 9712, EN 473 or equivalent) for the relevant technology.

12.1 Ultrasonic C-scan mapping equipment

C-scan ultrasonic mapping equipment is the preferred methodology to map and size the (remaining) wall thickness. With the C-scan unit, the marked ILI feature (ref. Chapter 11: Layout of ILI features) can be scanned for the actual wall thickness whereby the X and Y coordinates of the transducer are stored.

12.2 Manually mapping of marked ILI features.

Manual ultrasonic equipment is a basic methodology to measure the (remaining) wall thickness. It is advised to use equipment with a so called A-screen. Depending on the operator's requirements the minimum wall thickness can be found and reported or the minimum wall thickness in each of the grid boxes (ref. Chapter 12.3: Lay out of anomalies) should be reported.

12.3 Ultrasonic transducers for wall thickness measurement

It is advised to use dual element transducers with a focus distance effective for the (remaining) wall thickness. Suitable transducers are:

- For a (remaining) wall thickness of ≤ 2 to 9 mm: Krautkrämer SEB10KF3, Karl Deutsch SE 4.2/4 PB 10 or equivalent.
- For a (remaining) wall thickness of 5 to 30 mm: Krautkrämer MSEB4, Karl Deutsch SE 10/14 PB 4 C or equivalent.

12.4 Radiography.

Radiographic techniques can be used to verify corrosion in gas pipelines. It measures remaining wall thickness but the accuracy is limited. Advantage is that a permanent record of the anomaly can be obtained. Estimated accuracy is 1.0 mm.

13 Recording of cracks

Once a reported crack, crack field or crack-like feature is identified in the field, the following rules regarding the verification of its dimensions should be applied. Application of a Non Destructive Technique should be based on a procedure that is approved by a person who is level-3 qualified (ref. ISO 9712, EN 473 or equivalent) for the relevant technology.

13.1 Determining the location of a crack area

The features list entries describing the location of a crack field area refer to the following ancre points:

Axial position = start position of the feature area (in upstream direction)

Circumferential position = circumferential position of the feature area starting point (clockwise, downstream).

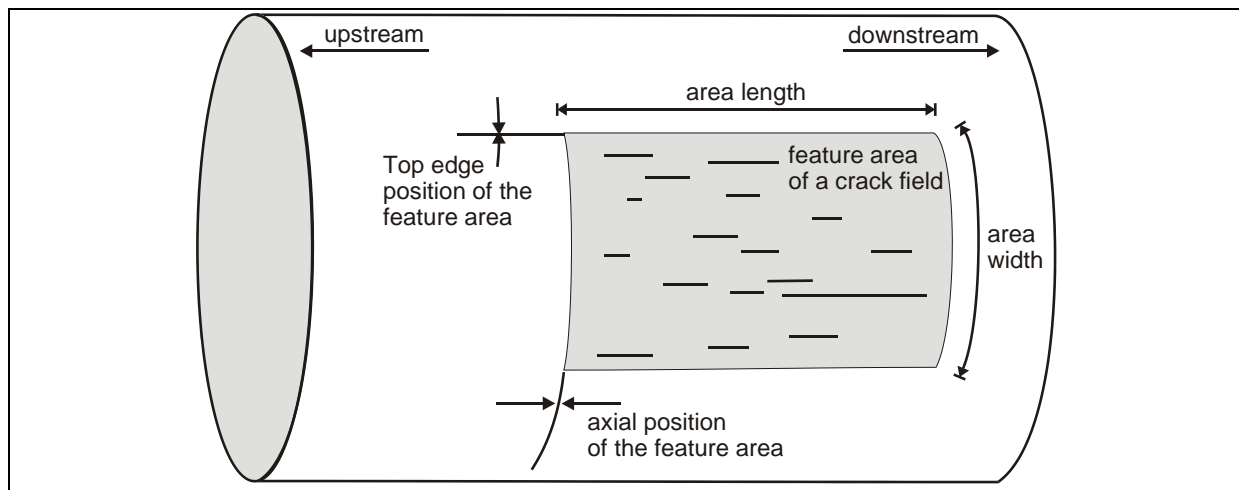


Figure 14: Location of a feature area at the pipeline

Generally, the overall extent of a crack field can be determined by different criteria.

A crack field consisting of different clusters of cracks can be treated as one large field or as several smaller crack fields. Please compare the visual impression of the crack field onsite with the ultrasonic representation of the related feature area.

The deepest single crack of a crack field is not necessarily located in the centre of the related feature area.

13.2 Determining the exact length of a crack

The verification of the length of an individual crack can lead to different results if different measurement methods are used. Common method for the verification of surface-breaking external cracks is the Magnetic Particle Inspection. With this method, the crack length is determined independently from any minimum crack depth.

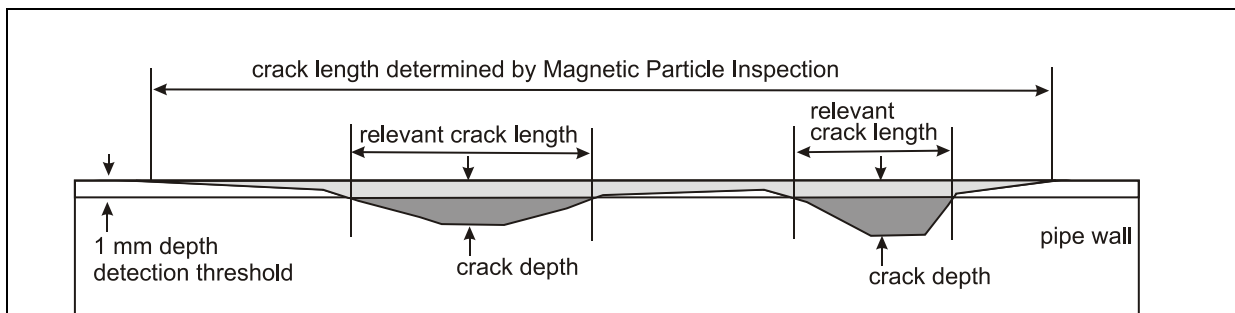


Figure 15: Nomenclature of crack dimensions

The Crack Detection (CD) systems determine the edges at both sides of a crack using a minimum depth detection threshold. Whereas the Magnetic Particle Inspection (MPI) reacts on even smallest crack depths and therefore sometimes lets cracks appear to be much longer than the ILI tool predicted.

To really verify a predicted length it is necessary to grind the crack area down by 1 mm and then repeat the MPI in that case only the "relevant" crack extent should be indicated by the magnetic particles.

13.3 Determining the exact depth of a crack

With ultrasonic ILI systems, the determination of crack depths is carried out by an indirect assessment method with (typically) four depth classes reported. The confidence levels stated in the ultrasonic ILI specifications regarding depth classification only refer to these four depth classes. For the in-field measurement of the depth of cracks which are open to the surface, the following procedures / techniques can be applied:

Reference block method

This is a direct ultrasonic echo comparison method using reference echoes from well defined reflectors contained in a reference block.

DGS (AVG) method

This is an indirect ultrasonic echo comparison method based on "Distance", "Gain" and "Size". The height of an ultrasonic echo is assessed with the "theoretical" echo of an equivalent disc shaped reflector using a suitable DGS diagram (German: Amplitude-Verstärkung-Grösse, AVG). This method can be applied to cracks on both the transducer side of the pipe surface (hence outer pipe surface) via full skip as well as on pipe surface opposite the transducer (hence inner pipe surface) via half skip.

ToFD - Time-of-Flight Diffraction

This technique uses the ultrasonic energy diffraction at corners and tips of cracks and uses certain timing algorithms to determine the depth of a crack. Depending on the location of a crack, its depth and the pipe wall thickness, this technique is less suitable for cracks at the transducers side of the pipe wall (hence outer pipe surface).

Step-wise grinding

This is the most accurate method. With this method, first the crack area is visualised by MPI and the wall thickness within the crack area is measured. Then, the crack area is ground down by a small step and MPI is applied to check whether the crack is still visible. More grinding steps are carried out until the crack cannot be visualized by MPI anymore. Subtracting the wall thickness of the ground area from the wall thickness measured first leads to the maximum crack depth. Grinding should be performed with care to prevent material deformation at the surface whereby the crack can be hidden.

ACFM - Alternating Current Field Measurement

ACFM equipment uses a probe with contact points that can be placed across a surface crack to measure the crack depth. The potential drop of the alternating current across the crack is compared to a reference position where after the crack depth can be measured. The accuracy of the techniques depends on the form and location of the crack and is estimated to be 3 to 15% for ferro-magnetic material. A typical instrument is the RMG 4015 from Karl Deutsch.

13.4 Identification of sloping cracks in weld areas

Cracks open to the surface of the pipe wall normally provide a strong corner reflection when measured with UT. The detection of embedded cracks however, is strongly influenced by its form and angular orientation.

The echoes from parts of the crack which are located deeper within the pipe wall are only received by an ultrasonic probe if the incidence angle fits to the crack angle.

Ultrasonic Pulse-Echo

Detecting a crack within a weld zone using a hand-held ultrasonic device however, is sometimes rather difficult. The reason is the weld cap which doesn't allow to properly place the ultrasonic probe at the pipe wall such that the crack is properly hit with the angular sound beam axis. Two typical examples are depicted in the following figures:

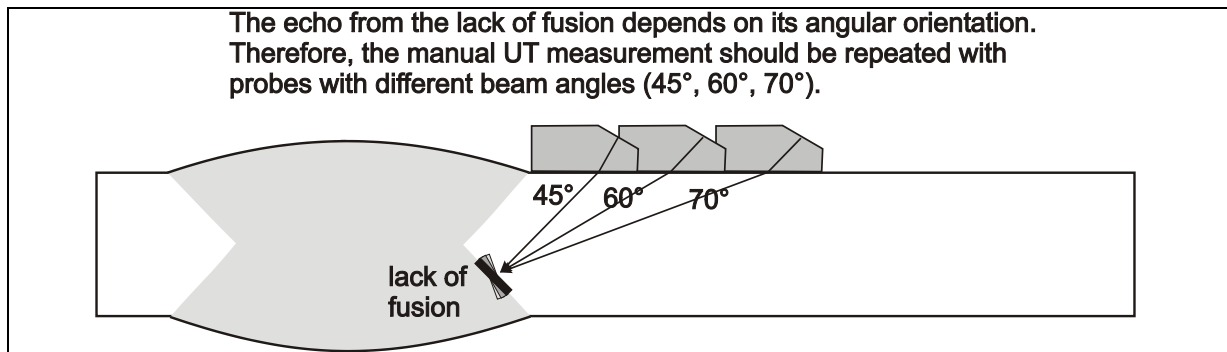


Figure 16: Lack of fusion hit by sound beams of different angles

Figure 16 above shows a lack of fusion hit by 45°, 60° and 70° sound beams. Which of these beams has the strongest echo depends on the angular orientation of the lack of fusion. Best practice is a probe with an angle of $\pm 3^\circ$ perpendicular to the planer of the crack. The 70° probe, for example, is the best solution for 20° sloping mid-wall cracks.

Best practise for the detection of mid-wall cracks is to use at least three angular probes (e.g. 45°, 60°, 70°) and compare the time-of-flight and signal amplitude values of the different probes with each other.

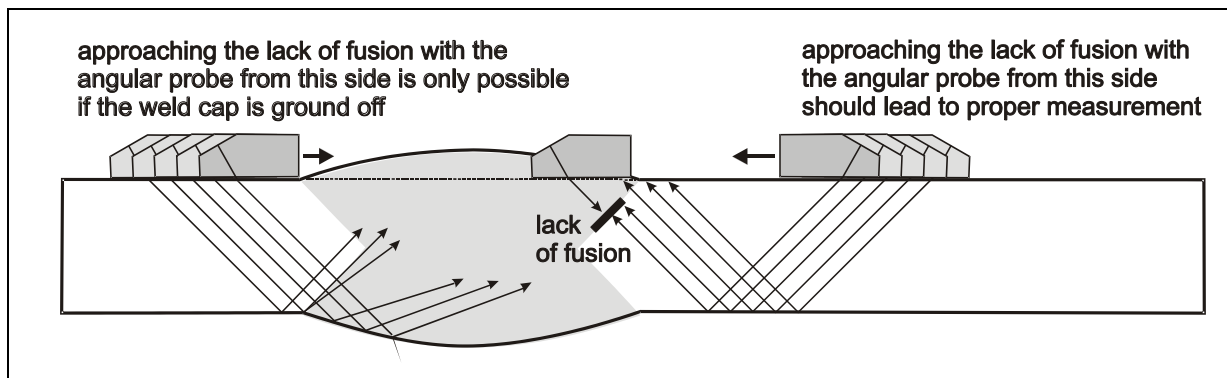


Figure 17: Manual UT detection of a lack of fusion

Figure 17 above shows a lack of fusion which can be detected with an angular probe approaching from the right side via full skip. A detection from the left side via half skip is only possible if the weld cap is ground off. Due to the undefined and curved surface of the weld cap, lack of fusion can only be detected with reasonable confidence if present on the same side of the weld as the transducer. The echo depends on the angular orientation of the lack of fusion relative to the UT beam angle. It is advised to repeat the measurements with probes with different angles (see also fig. 16).

TOFD - Time-of-Flight Diffraction

This technique uses the ultrasonic energy diffraction at corners and tips of cracks and uses certain timing algorithms to determine the length of a crack. Depending on the location of the crack and the pipe wall thickness, this technique is less suitable for cracks near the transducers side of the pipe wall (hence outer pipe surface).

14 References

1. Oil & Gas Journal, *Method proposed for calibrating MLF, UT ILI tools*, F. Caley et al, OGI Sept 13, 2004.

Appendix A: ILI Field verification feedback form

Feedback to ILI suppliers is particularly important as this helps to verify and improve the performance of the tools.

run name:		client:	
pipeline name:		launcher/receiver:	
date of verification:		NDT expert (incl. Qualifications)	

documented feature no:			
pipe no.:		odo distance (m):	
file or area no.:		client's distance (m):	
upstream marker name:		downstream marker name:	
distance to upstr. marker (m):		distance to downstr. marker (m):	

	predicted	verified
feature type:		
distance to upstream girth weld (m):		
distance to downstream girth weld (m):		
wall thickness in feature vicinity (mm):		
depth (mm):		
remaining wall thickness (mm):		
length (mm):		
width (mm):		
orientation (o'clock):		
orientation of long/spiral weld (o'clock):		
pipe joint length (m):		

Comments on the feature verification	
Procedure used:	
probe types/equipment used:	