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Steel pipelines - state of the art for internal condition monitoring and inspection technologies

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Steel pipelines - state of the art for internal condition monitoring and inspection technologies

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ABSTRACT

The aim of this project is to sum up the state-of-the-art technology and experiences with corrosion and erosion monitoring and internal inspection of steel pipelines, both in the North Sea and worldwide. The following items are included:

1. Review of methods for corrosion and erosion monitoring – evaluation of efficiency for different types of pipelines.
2. Review of internal inspection methods applied to different types of pipelines (Carbon steel, 13%Cr-steel, a.o.) – evaluation of quality and reliability.
3. Evaluation of internal baseline inspection as part of a philosophy for follow-up of internal condition of pipeline.
4. Historical and future development of technology and tools for internal inspection of pipelines.

The work has been performed as a combination of interviews with operators and suppliers, technology and literature survey.

It is suggested that a framework for risk based internal inspection of pipelines should be established. It is also important to establish a recognized method for comparison of inspection results.

KEYWORDS	ENGLISH	NORWEGIAN
GROUP 1	Maintenance technology	Vedlikeholdsteknologi
GROUP 2	Condition monitoring	Tilstandskontroll
SELECTED BY AUTHOR	Inspection	Inspeksjon
	Pipelines	Rørledninger
	Corrosion	Korrosjon

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1. Executive summary and conclusions

The Norwegian Petroleum Safety Authority (PSA) issued a tender within the area of "Pipeline and riser technology", ref. 09/52. Reference is made to Framework Agreement - Consultancy services within safety, emergency and working environment in the petroleum activities on the Norwegian continental shelf and on land 2009 – 2011.

The assignment called for a report describing state-of-the-art for internal condition monitoring and internal inspection technology for steel pipelines.

1.1 Purpose of report

The aim of this project is to sum up the state-of-the-art technology and experiences with corrosion and erosion monitoring and internal inspection of steel pipelines, both in the North Sea and worldwide. The following items are included:

1. Review of methods for corrosion and erosion monitoring – evaluation of efficiency for different types of pipelines.
2. Review of internal inspection methods applied to different types of pipelines (Carbon steel, 13%Cr-steel, a.o.) – evaluation of quality and reliability.
3. Evaluation of internal baseline inspection as part of a philosophy for follow-up of internal condition of pipeline.
4. Historical and future development of technology and tools for internal inspection of pipelines.

The work has been performed as a combination of interviews with operators and suppliers, technology and literature survey.

Corrosion monitoring

Measuring the corrosivity of the internal fluid in the pipeline is the most widespread application of corrosion monitoring equipment, i.e. through weight-loss coupons or electrical resistance probes. The equipment is most often installed topside or onshore for practical reasons. Subsea monitoring with FSM or Ceion requires special considerations regarding underwater packing and necessary adjustments for enabling stable conditions for communication and power supply. However, promising new non-intrusive monitoring equipments, based on ultrasound techniques, have been developed for subsea usage measuring the local metal loss from the pipeline wall.

In-line inspection

In-line inspection (ILI) methods are, in general, capable of providing a good overview of the integrity condition of a pipeline. The technologies have evolved to a point where it is expected that inspections performed today (and the past 5 years) yield results of sufficient quality to enable comparison with future inspections. There does not exist any industry best practice or recognized method on how to perform such a comparison of

different inspections. Evolution of technologies further enhance ILI to provide possibilities for detecting smaller anomalies such as cracks, although some development is needed with regard to issues of accuracy vs. inspection speed.
The electromagnetic transducer (EMAT) pig and ultrasonic angle-beam crack detection (TOFD-UT) have been used for crack detection. However, the experiences so far are that crack detection still is difficult, even with the new technologies. For inspection of CRA pipelines, which primarily are subject to environmentally assisted cracking, the currently available technologies are not considered satisfactory.

First inspection

The requirements in the Activities Regulation section 47 on inspection and maintenance of pipelines is unclear and to some extent self-contradictory. It is said that risk assessment should be the basis for a maintenance program, and then state, as an imperative requirement, that the first inspection should be performed within the two first years of operation. Whether to perform first inspection within the two first years of operation or not shall be decided based on a risk assessment, but this is not intuitively understood from the current wording of section 47.
Based on the findings reported here we suggest that a new framework or regulation is prepared that clearly states that all pipelines shall be subject to a risk assessment. DNV-RP-F116 includes one example of such risk assessment procedures. The result of such assessment shall be used to decide when first inspection is to be performed and the frequency of subsequent inspections. The first inspection is essentially an as-built inspection, however it should also be designed as a baseline inspection. The risk assessment shall be updated after each inspection.

Development within inspection and monitoring technology

New technology that is expected to be available in near future include the acoustic resonance technology (ART), remote field eddy current (RFEC) and guided wave. ART is in particular expected to improve inspection of gas pipelines. The RFEC technology is more of a specialized tool to be mounted on crawlers for inspection of unpigable pipelines. Guided wave sensors for corrosion monitoring have been available on the marked for some time, but pigging tools based on guided wave are also under development. Smartpipe, which is a concept for distributed monitoring on pipelines, is still in the R&D stage and market introduction can first be expected in a few years.

1.2 Abbreviations

ART	Acoustic Resonance Technology
CEM	Corrosion Erosion Monitoring
CM	Corrosion Monitoring
CoF	Consequence of Failure
CRA	Corrosion Resistant Alloys

CS	Carbon Steel
DFI	Design, Fabrication and Installation
EC	Eddy Current
EFM	Electric Field Method
EMAT	Electromagnetic Acoustic Transducer
ER	Electrical Resistance
FSM	Field Signature Method
GW	Guided Wave
ICT	Information and Communication Technology
ID	Inner Diameter
ILI	In-Line Inspection
JIP	Joint Industry Project
LPR	Linear Polarization Resistance
MFL	Magnetic Flux Leakage
MTBF	Mean Time Between Failures
NCS	Norwegian Continental Shelf
NDT	Non Destructive Testing
OD	Outer Diameter
PoF	Probability of Failure
PSA	Petroleum Safety Authority
RBI	Risk Based Inspection
RFEC	Remote Field Eddy Current
ROV	Remotely Operated Vehicle
TOFD	Time of Flight Diffraction
UT	Ultrasound transducer
WT	Wall Thickness
ZRA	Zero Resistance Ammeter

2. Condition monitoring overview

2.1 Introduction – PSA requirement

According to ”REGULATIONS RELATING TO CONDUCT OF ACTIVITIES IN THE PETROLEUM ACTIVITIES (THE ACTIVITIES REGULATIONS) – § 47 Specific requirements to condition monitoring of structures and pipeline systems” the following requirement is given by the PSA:

Condition monitoring shall be carried out in respect of new structures during their first year of service.

With regard to loadbearing structures of a new type, data shall be collected from two winter seasons in order to compare them with the design calculations, cf. the Facilities Regulations Section 16 on instrumentation for monitoring and recording.

With regard to pipeline systems where fault modes may constitute an environment or safety risk, cf. Section 43 on classification, inspections shall be carried out to map possible corrosion of the pipe wall. Parts of the pipeline system where the lay condition or other factors may cause high loads, shall also be checked.

The first inspection shall be carried out in accordance with the maintenance programme as mentioned in Section 44 on maintenance programme, however at the latest two years after the system has been put into operation.

Within the industry, there is a mix of terms where “baseline inspection” and “initial inspection” are interpreted as “first inspection”. The regulations use the term “first inspection”. From the text of the regulations it is not understood intuitively that risk assessment is an option to decide whether or not to perform an inspection within the two first years.

The term “first inspection” will be discussed and a new procedure using risk assessment as basis for the decision on when to perform the first inspection will be proposed in this report.

In this report the following definition of a pipeline inspection is used: Running an intelligent pig through the pipeline to examine the internal and external condition of the pipeline. This is also called In-Line Inspection (ILI).

2.2 Pipeline condition monitoring, modeling and prediction

Condition monitoring of pipelines is primarily focused on metal loss and material defects in pipe walls. This report is concerned with various technologies and methods for internal condition monitoring of pipelines made from carbon steel or corrosion resistant alloys (CRA).

Measuring technologies provide the opportunity for accurate local measurement of wall thickness and pipe wall defects (e.g. cracks, dents) in pipelines, or for less accurate measurements of the overall pipe condition. None of the technologies in use provide both types of measurement (i.e. accuracy in local defects and overall condition), but both types of measurements are valuable as input to condition assessment procedures.

Traditionally, local measures of metal loss (e.g. coupons, ER probes) have been used to measure the effect of corrosion inhibitors or change in process conditions (e.g. change in oxygen content) as they do provide accurate and immediate response to local conditions that are affected by injection of such chemicals. Such spot-measures of metal loss has to a lesser degree been used as a direct value for assessment of remaining wall thickness. The reason is that corrosion attacks are seldom uniform in area extent and depth, even in non-alloyed carbon steels. Corrosion attacks in CRA are typically very local phenomena and it is difficult to predict where such attacks will occur (although welds are normally more exposed to attack than the base material).

For CRA use of process parameters to define safe operational windows for operating conditions has been employed in risk based inspection (RBI) analysis to determine the likelihood of corrosion attacks in different parts of a pipeline. Such use of process data has to a lesser extent been employed as operational measures to avoid corrosion.

2.2.1 Corrosion models

There are several models available for corrosion prediction. IFE has performed a study on such models and provided a guideline for CO_2-corrosion in oil and gas production systems (IFE 2009).

Prediction models may be categorized as either being mechanistic or empirical.
A mechanistic model takes the chemical, electrochemical and transport processes into account, whereas an empirical model starts with some simple empirical correlations. However, both types use data from laboratory testing and field data for calibration.
The results of the corrosion rates calculated by the studied models do not depend significantly on whether the model is mechanistic or empirical. The main differences between the models are attributed to how the protectivity of the corrosion films and the effect of oil wetting is included in the prediction. Two such models are described briefly in the following. (IFE 2009)

- Hydrocor is a mechanistic model, developed by Shell to combine corrosion and fluid flow modeling (9, 10). Hydrocor is now Shell's preferred tool for corrosion prediction. A relatively weak protection from corrosion product films is assumed for condensed water cases. No protection from corrosion product films is assumed when formation water is present, due to risk for localized attack. Oil wetting effects are included for crude oil systems, but not for gas condensate systems where water separation is likely to occur. (IFE 2009)

- Corpos is a tool developed by CorrOcean / Force Technology. The model is based on using input from an external fluid flow model combined with calculation of a probability of water wetting and calculation of pH. The NORSOK corrosion model is then used to calculate the corrosion rate in several points along the pipeline. (IFE 2009)

Such models are typically used as guidelines for the expected maximum rate of metal loss in a pipeline at several locations. This is useful both for planning of the expected amount of corrosion inhibitor that will be necessary and for planning of inspections on the locations where corrosion is expected.

Models can also be used in the operational phase of the life of the pipeline, and fairly good predictions can be made by correcting modeled results through the use of actual observations. This is somewhat similar to the exercise of model validation described earlier. Actual process parameters (including flow composition) should also be used in this assessment. By utilizing inspection results and actual process parameters for correction of modeled results it should be possible to predict the rates of metal loss at defined locations on the pipeline and thus take appropriate action to mitigate such effects.

3. Review of internal corrosion monitoring

3.1 General

Corrosion monitoring is used in a subsea pipeline system to detect, predict, and prevent corrosion failure with its consequent safety, financial and environmental implications. In addition to local corrosion detection monitoring provides the assurance that the corrosion-mitigation systems, such as inhibitors are doing their job. The general philosophy of corrosion monitoring is that multiple techniques can be used to both complement and check each other.

Internal corrosion monitoring equipment is often placed at the landfall, in the topsides facility, and/or in the onshore facility. The most vulnerable places or hot spots for corrosion in the pipeline are often located at the seabed at places difficult to reach without diving or remote operating vehicles. Thus, installation of local corrosion monitoring devices at subsea locations requires special adjustments and packing of the equipment for effective application.

In the absence of subsea monitoring, monitoring equipment mounted topside or at landfall may provide the only data for monitoring corrosion and corrosion-control programs. These locations allow the use of both intrusive and nonintrusive techniques.

Common intrusive monitoring methods include weight-loss coupons, electrical resistance (ER) probes, linear polarization resistance (LPR) probes and Zero resistance ammeter (ZRA). Non-intrusive monitoring methods include techniques based on electric field mapping, ultrasonic and acoustic sensors. Electrochemical methods, as LPR and ZRA, are more rarely used and have not been discussed further in the report, even if LPR probes sometimes are used to control injected water lines. The electrodes need to be fully submerged in water to give reliable measurements. Thus, oil fouling and deposits can impede the successful operation of these probes.

The variety of techniques and methods for internal corrosion monitoring described more thoroughly in two NACE articles; NACE Publication 3T199 and NACE Publication 1D199.

3.2 Weight-Loss Coupons

3.2.1 Principle

Weight-loss coupons are small test specimens of metal that are exposed to an environment of interest for a period of time to determine the reaction of the metal to the environment. The coupon is removed at the end of the test time and the average corrosion rate is determined from the mass loss of metal of the period of exposure. They are installed topside or onshore at one or both ends of the pipeline. Weight-loss coupons can be applied to any type of pipelines, regardless of materials (carbon steel, CRA) or process environment.

3.2.2 Suppliers

Weight-loss coupons are one of the most used corrosion monitoring tool, supplied by a range of corrosion monitoring companies.

3.2.3 Benefits

- Easily understood technique.
- The coupons are generally low in cost.
- Wide applications can be used in virtually any types of pipelines and process environment.
- Both uniform and pitting corrosion can be seen.

3.2.4 Limitations

- Only average corrosion rate can be determined after removal of the coupons from the system
- Unrepresentative rates of metal loss may be achieved after short exposure periods
- Timing or magnitude of corrosion upsets is not possible to determine

3.3 Electrical Resistance Probes

3.3.1 Principle

The Electrical Resistance (ER) method is one of the most widely used techniques for corrosion monitoring of pipelines. The principle consists of determining the change in resistance of a metal element as a result of corrosion, erosion, or a combination of both. Corrosion on the element decreases the cross sectional area, thereby increasing the electrical resistance. The element is usually in the form of a wire, strip or tube, and if the corrosion is roughly uniform, a change in resistance is proportional to an increment of corrosion.

Estimates of the total corrosion over a period may be obtained from successive readings. A simple formula converts readings to an average corrosion rate. The technique can be made online and provide real-time measurements when sufficiently sensitive probes are used. Measurement resolution is typically 1/1000 parts of the total measuring range of the probe, which is typically from 0.05 to 0.64 mm (size of the element).

3.3.2 Suppliers

Most of the probes have been installed topside or at the landfall / terminal. Even though subsea ER probes have been on the marked for about a decade, the number of installed subsea ER probes are not more than about 100, normally mounted close to manifold, wellhead or riser base. ER probes for permanent subsea installations are available from mainly two suppliers:

Roxar (CorrOcean)	SenCorr CM sensor ER probe (Figure 3.1)
Teledyne Cormon	Ceion™ technology (RPCM™ spool and PTEC™ ER probe, **Figure 3.2**)

In addition to the "normal" ER-probe (PTEC™) configuration, the Ceion technology is also featured in a flow-through spool with a 360° ring element. The supplier claims that the Ceion™ technology can provide a higher resolution and shorter response time compared to conventional ER-probes.

Figure 3.1 Roxars SenCorr CM probe. (www.roxar.no).

Figure 3.2 Cormons Ring Pair Corrosion Monitoring (RPCM™) Spool (left), and Pressure Temperature Corrosion & Erosion (PTEC™) probe (right) for subsea corrosion monitoring, (www.cormon.com).

3.3.3 Experiences

Electrical resistance probes are rugged and well adapted to any corrosive environment; liquid, gas or particle streams. The ER technique is well proven in practice and is simple to use and interpret. ER monitoring permits periodic or continuous monitoring to be established for one or a multiple number of probes. Corrosion can thus be related to process variables, and the method is one of the primary on-line monitoring tools.

However, feedbacks from users indicate that there can be some uncertainty related with the measured corrosion values from ER-probes. It is said that the absolute values measured by the corrosion monitoring equipment might differ from the real corrosion rate in the pipeline by an order of magnitude, so the corrosion monitoring equipment should only be used for monitoring indications of changes. Thus, in practice the probes are normally installed to reveal changes in the corrosion regime and catch any step changes that may take place. This may be due to changing inhibitor demand, process upsets, changing process or production conditions.

The experience with the Ceion RPCM spool is more limited. Only three systems has been installed in the Norwegian Continental Shelf[1], according to feedback from operators.

3.3.4 Benefits

- Continuous monitoring with real-time measurements
- High sensitivity
- Known ratio metric principle
- Ceion™ technology has a larger area coverage applied in a spool

3.3.5 Limitations

- Limited surface monitoring area. Results can depend on placement and data interpretation.
- It is challenging to find the locations that are representative for the corrosiveness of the pipeline that is monitored (inlet, outlet, midline corrosion, top of pipe, bottom of pipe, distance from bends, representative diameters, etc.)
- Limited lifetime at corrosive environments as the thickness of the element decides the sensitivity. Thin elements give high sensitivity.
- A penetration of the pipeline is required.
- Ceion™ technology applied as a spool requires special considerations at installation.

3.4 Electric Field Mapping Sensors

3.4.1 Principle

The electrical field mapping technique is based on feeding a current through a selected section of the structure to be monitored and sensing the electric field pattern by measuring small potential differences set up on the surface of the monitored object. Local voltage measurements are obtained between the pins attached to the outside of the pipe. The voltage measurements, when compared with the original measurements, reflect wall thickness loss, resulting in a corrosion “map” of the monitored area. The first measurement in time (signature) is unique to the geometry of the object, and later measurements are compared to this first reading. When general or local corrosion takes place, the pattern of electric field will change and can be compared to the signature. By

[1] For Statoil on the Snøhvit Field

proper interpretation of the changes in the potential differences, conclusions can be drawn, e.g. regarding general wall thickness reduction or localized corrosion.

The commercial rights to the technology for internal corrosion monitoring were acquired by CorrOcean, which started product development on the field signature method (FSM), a concept that was originally developed as a method for crack monitoring in the mid eighties. The first offshore installation was made in 1991, and the first subsea installation was made in 1994 (K.Wold). The field signature method is non-intrusive and allows for monitoring of the internal condition of piping and vessels from the outside. Normally the FSM systems are positioned on the pipeline to monitor both field welds and base material.

The accuracy and resolution of the field signature method depends on factors like (K.Wold, 2007):

- Wall thickness of monitored object
    - Thinner walls give better absolute resolution
- Distance between sensing electrodes at the monitored object
    - Longer distance gives better resolution for general corrosion
    - Shorter distance gives better resolution for localized attacks.
- Measurement frequency
- Available power

A resolution between 0.03% and 0.5% of the monitored object’s wall thickness is claimed for general corrosion (K.Wold).

3.4.2 Suppliers

The field signature inspection technique is available from two suppliers, see figure 2:

Roxar (CorrOcean)	FSM™
Fox-Tek	Pin-Point EFM (Electrical Field Mapping)

The FSM™ technology by Roxar (CorrOcean) is a non-intrusive technology that uses externally brazed and wired pins in an array over a pipe section. FSM™ instrumentation can be made interchangeable and autonomous, only the current feeder clamps and sensing pins are permanently installed. About 50 subsea FSM™ systems have been installed since 1994 (Roxar).

The EFM from Fox-Tek is a two-piece assembly that carries an array of electrodes, thermocouples and current input points. Electrical contact of the electrodes is made using cup-point set screws that are positioned through special inserts in the fiberglass sleeve. The removable sleeve design allows for pre-calibration of the probe array to establish a baseline electrical field for un-corroded pipe thicknesses. The sleeve can be installed as a permanent fixture or relocated to various, same diameter monitoring locations if required. Subsea installation of the EFM has not been reported yet.

Figure 3.3 Roxar FSM™ above (www.roxar.no) and Fox-Teks PinPoint EFM sleeve below (www.fox-tek.com).

3.4.3 Experience

Of the 50 FSM systems installed since 1994, about 20 systems are not operating today. Challenges with communication, signal and power have been the main problems with the installed FSM systems. Some of the pipelines, where the FSM's have been installed are also taken out of service. Batteries and hydro acoustic frequently caused problems to first versions of subsea FSM systems. Battery technology and hydro acoustic systems is not the preferred solutions for signal and power transferring today, according to the supplier. Cable lengths of 20 km are possible and acceptable today.

3.4.4 Benefits

- Non intrusive technology.
- Long mean time before failure (MTBF) for permanently installed parts.
- Larger area (0,5 m2) covered vs. ER probe principle.
- Direct measurement of the pipe wall.
- Supplier claims high sensitivity.

3.4.5 Limitations

- Do not distinguish between internal flaws, external flaws, or material loss.
- Compensation is applied for the change of resistivity of the alloy due to the effect of temperature.
- Baseline data on original wall thickness and results of previous inspection measurements are required.
- Output is relative change in wall thickness (not absolute wall thickness).
- Data interpretation is sometimes impaired by conductive scales and depositions.
- Communication with the units can be a challenge.

3.5 Ultrasonic sensor technologies

3.5.1 Principle

Ultrasonic array sensors are simply piezoelectric ultrasonic thickness gauges that are permanently placed in an array to give wall thickness readings over a pipe section. Sensors can be are arranged in an array around the circumference or axial in the 6 o-clock position of the pipeline in order to detect local corrosion.

3.5.2 Suppliers

3.5.2.1 Rightrax – GE Inspection

The basic components of the Rightrax monitoring system are the M2 sensor and the DL1 data logger, as seen in Figure 3.4. The M2 sensor is a multi-element, flexible, self-adhesive ultrasonic transducer array, measuring wall thickness by pulse echo technique. The sensors are permanently bonded to the plant or pipe to be monitored, at critical locations where corrosive / erosive activity has historically taken place or is anticipated. Supplier of this technology is GE Inspection Technologies. Wall thickness measurement accuracy is reported to be 0.2 mm.

Application of Rightrax subsea has not been reported yet.

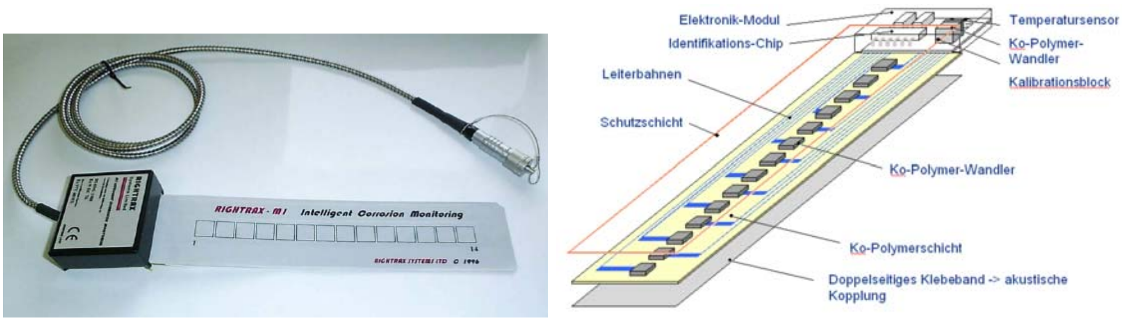


Figure 3.4 Picture and construction of the sensor M2 in the Rightrax tool, (W.Roye)

3.5.2.2 Ultramonit - Sensorlink

The Ultramonit™ system is a newly developed, non-intrusive technique that is able to monitor the corrosion and erosion rates of pipelines. (Feedback from Baltzersen, Sensorlink)

Ultramonit™ is developed in a JIP with Statoil since 2003, initially with focus on resolution and inspired by the Roxar (then CorrOcean) FSM™. Resolution under favorable conditions is 1/100 mm or better. The system is based on using multiple ultrasound sensors to ensure good circumferential measurements of wall thickness with very high accuracy and resolution. The Ultramonit™ tool for subsea pipelines is an instrumented clamp- on device, as shown in Figure 3.5, with multiple transmitters and receivers which can be installed on new or existing pipelines by an ROV. The tool can be retrofitted at any time, and can be moved between different locations. Data is stored in the onboard data logger, and is also transmitted via a subsea acoustic communication unit or via cable.

The Ultramonit™ system for wall thickness monitoring is based on the well-established ultrasonic pulse-echo method (A-scan).

The Ultramonit™ tool can be used for verification and calibration of inspection pig data at selected locations, and to provide information in critical areas between inspection surveys. A prototype was installed in 2003 *onshore* at Kårstø, and the first of two commercial systems was installed in 2008, both at fixed locations. (/7/, Baltzersen, 2009).

Figure 3.5 Ultramonit™ tool (Courtesy Sensorlink)

Primary development is directed towards increased robustness for communication and power, increased mobility of device to make it possible to use on different locations, and not so much on increased resolution.

Benefits

Key advantages (from www.Sensorlink.no):

- Non-intrusive method
- Predicts wall thickness reduction rate with an accuracy of 0.1 mm per year
- Easy installation on new and existing pipelines without interference of flow
- Retrofitable at any time during the life cycle of the pipeline
- On-line and remote operation
- The Ultramonit™ system gives rapid feedback on the efficiency of the corrosion inhibitors, offering the operators a potential for great savings

Limitations

- Limited field experiences, with unexpected "first-version-problems" with communication.

- Weight coating has to be removed before installation on existing pipelines

3.5.2.3 Corrosion Erosion Monitoring (CEM) - ClampOn

The working principle of the ClampOn CEM (Figure 3.6) is based on transmitting ultrasonic signals that propagate through the pipe-wall, (Instanes, ClampOn). The dispersive characteristics of a group of guided acoustic waves, called Lamb modes, are exploited to indicate a mean change in wall thickness relative to reference values acquired during the installation of the CEM system. This is done by clamping up to eight transducers to the pipe wall, which will work in a pitch-catch mode of operation, making it possible to monitor as much as 65% of the area in stretches up to 2 meters. The signal path follows the metal structure between the transducers in operation, which in turn generates a matrix of all the measurements. The CEM does not measure the minimum wall thickness, but the average. Changes in average wall thickness of 1% can be measured in real time.

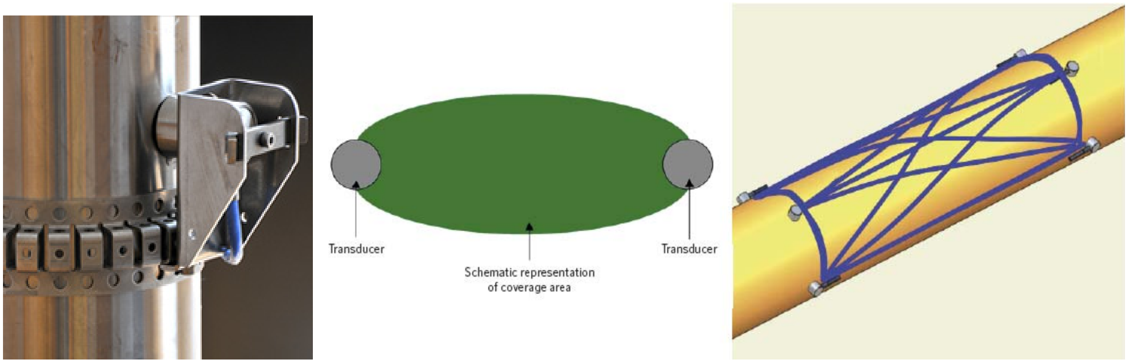


Figure 3.6 ClampOn CEM with transduser. To the right: CEM coverage area on an 8" OD pipe, with a total separation of 700 mm and a six-transducer set-up, giving a total coverage of approximately 60%. (courtesy ClampOn)

As can be seen from Figure 3.7 below, it will not be equally sensitive to different types of corrosion/erosion as they do not affect the average wall thickness to the same degree. Localized pitting can be hard to detect due to the small change in average thickness.

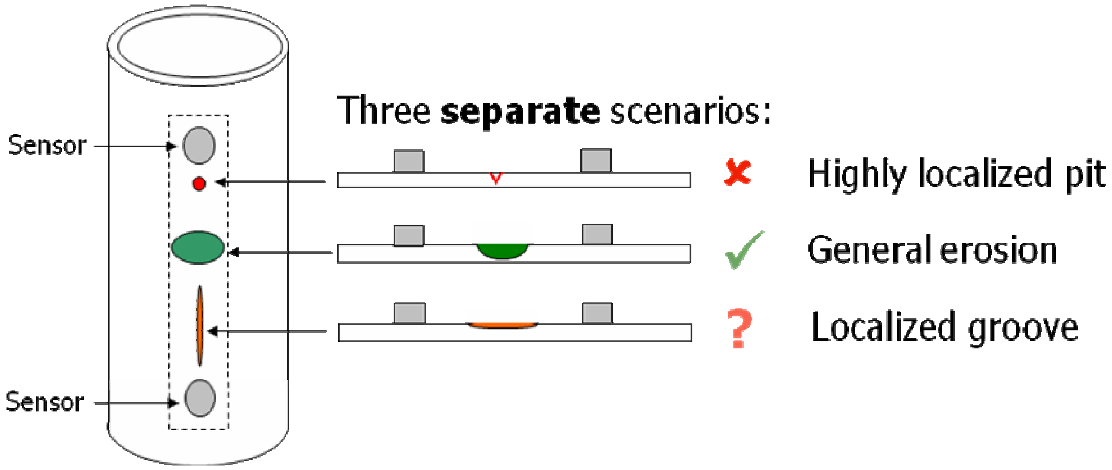


Figure 3.7 CEM's sensitivity to different types of corrosion. (Instanes)

__Experience__

ClampOn currently only supply a topside Corrosion-Erosion Monitor (CEM), according to the supplier. Development of a subsea version is ongoing. This will be based on the same technology as the topside version, with some adjustments to fit the subsea environment.

The CEM system is installed and used by several operators, for instance BP, BG, Saudi Aramco, ConocoPhillips, Chevron, Premier Oil andENI. The CEM has been installed on straight pipes and bends of various dimensions, reducers and welds (to monitor wear in the weld). Flow conditions has not been a problem, e.g. gas, water, oil, multiphase, (Instanes).

A future development of the ClampOn monitor is to utilize electromagnetic-acoustic transducers (EMAT)

3.6 Erosion and Sand Detection methods

Sand production in oil and gas producing wells can cause rapid erosion and wear of top side equipment such as chokes, valves, and flowlines. Rapid detection and remediation of sand producing/erosion episodes is necessary to prevent short-term failure.

There are several methods available for sand detection and erosion monitoring. For erosion monitoring intrusive probes via access fittings are most effective, while detection of sand may be achieved through non-intrusive techniques based on acoustic sensors.

The sensing elements in probes for erosion measurement can be made from almost any commercially available alloy. Less corrosion resistant materials, such as carbon steel, will show the combined effects of corrosion, and erosion, whereas more resistant alloys, such as duplex stainless steel or Hastelloy, will show erosion effects exclusively. The probes are compact and rugged, and may be mounted directly on the Christmas tree in order to detect sand production at an early stage, thus minimizing damage to the chokes and valves.

Generally, the experiences from the users of sand and erosion monitors are good.

In Table 3.1below is shown some common sand and erosion monitoring methods.

Table 3.1 Sand detection and erosion monitoring methods

Instrument	Supplier	Measurement Technique	Installation	Characteristics
Acoustic Sand Detector	Roxar	Acoustic – detects solids	Non Intrusive, clamp on type	Single instrument. Listens for solids impacting on internal surface of flowline. Can be calibrated to measure quantity of sand if flow conditions remain relatively constant.
	ClampOn	Passive acoustics sensor technology		The sensor is installed two pipe diameters after a bend, where the particles/solids impact the inside of the pipe wall, generating an ultrasonic pulse. The ultrasonic signal is transmitted through the pipe wall and picked up by the acoustic subsea sensor. (Figure 3.8).
High Sensitivity ER Probe	Teledyne Cormon Limited	ER (Electric Resistance) principle with Ceion technology - Measures metal loss rate	Intrusive via access fitting	Angled head type installed directly in flow stream. Element metal loss relative to reference element causes change in electrical resistance.
	Roxar	ER (Electric Resistance) principle - Measures metal loss rate		Four independent sensing elements measure increased element resistance as they are exposed to sand erosion. (Figure 3.9)
	Rohrback Cosasco			Angled head or cylindrical type installed directly in flow stream. Element metal loss relative to reference element causes change in electrical resistance. (Figure 3.10)

Figure 3.8 Compact acoustic ClampOn particle detector and funnel on pipe (courtesy ClampOn).

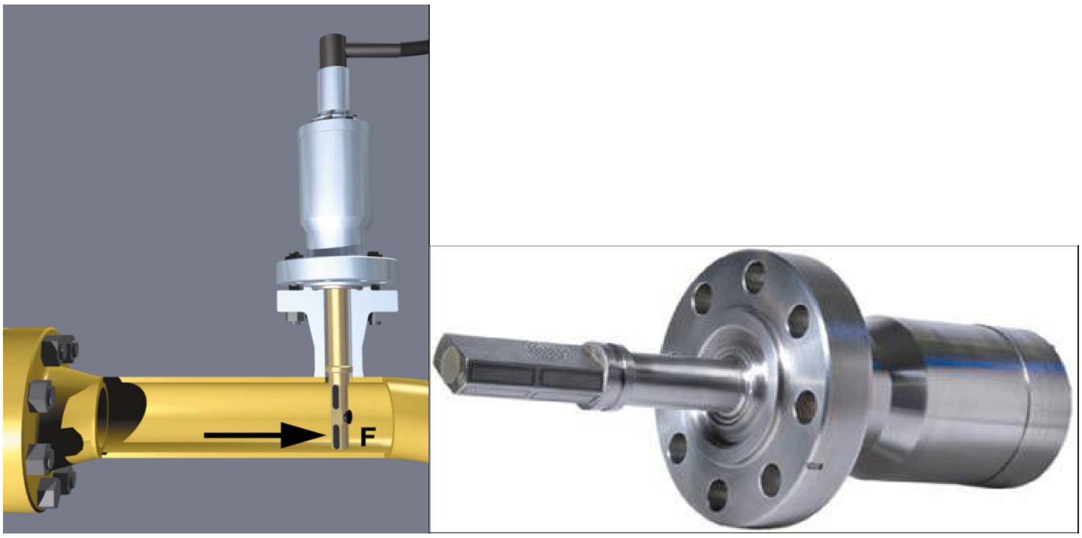


Figure 3.9 Roxar subsea sand & erosion sensor (courtesy Roxar).

Figure 3.10 Rohrback Cosasco's Quicksand™Erosion Detection System (courtesy Rohrback Cosasco).

3.7 Summary

In general, all of the corrosion monitoring techniques reviewed above are local range surveillance methods measuring either the corrosivity of the fluid or local wall thicknesses in the pipeline. The overall integrity of the pipeline cannot be controlled by a single corrosion monitoring equipment alone. Other internal inspection techniques, as reviewed in the next section of this report, are also required.

The two most common corrosion monitoring techniques in use today are undoubtedly the weight-loss coupons and the electrical resistance probes. Both methods are intrusive techniques which require fittings to be mounted on the pipeline of interest. Retro-fitting of ER-probes subsea on existing pipelines is therefore seldom an alternative. While the coupons are a slow and non-sensitive technique, the ER-probes provide high sensitivity and ability to monitor in real-time instant changes of the corrosivity of the fluid. Thus, it is possible to adjust the process condition and optimize the inhibitor concentration at relatively short notice.

Techniques for monitoring the wall thickness locally in a pipeline include both ultrasonic based techniques (Ultramonit, ClampOn or Rightrax), and electric field mapping (FSM). All these tools are non-intrusive, making them more applicable and easy to install subsea, also as retro-fitting on existing pipelines. Subsea installation is often desired to be able to monitor the most vulnerable places or hot spots for corrosion in the pipeline.

However, adjustment and packing of tools for subsea monitoring has been and still is a challenge, most of all with communication of data signals and power supply. Thus, topside mounting of monitoring equipment is currently the primary location for retrieving pipeline integrity data. The potential of the various corrosion monitoring techniques is very much dependent on the development and improvement of existing communication and power equipment.

4. Review of internal inspection methods

Internal inspection in pipelines is carried out using so-called pigs. The early forms of such equipment used straw as a cleaning agent and the noise generated while travelling through the pipe resembled the squealing of a pig, hence the name. Usually, pigs are built to match the diameter of a pipeline and they may use the normal production fluid to transport them along the pipe. Pigs have been used in pipelines for many years and have many uses. Some separate one product from another, some clean and some inspect. The latter category is the subject of this chapter.

In 1961, the first intelligent pig was run by Shell Development. It demonstrated that a self contained electronic instrument could traverse a pipeline while measuring and recording wall thickness. The instrument used electromagnetic fields to sense wall integrity.

Pigs are now used for internal surface inspection to inspect the internal pipe wall surface for anomalies and record the actual pipe geometry (dents, partial collapse, large surface cracks, weld corrosion, deposits, etc). A different type of pig is used to determine wall thickness and material defects. The first type of inspection is based on optical pigs using cameras and laser or fitted with calipers. The latter type of inspection has utilized known robust methods for detection of material defects. Such pigs are known as "intelligent" or "smart" inspection pigs because they contain electronics and can thus collect and even process data real-time while travelling through the pipeline. Sophisticated electronics on board allow such tools to accurately detect very small features.

This chapter deals with the following type of pigs:

- MFL – magnetic flux leakage
- US – Ultrasonic (piezoelectric and EMAT)
- Optical (video, laser)
- Physical (caliper)

4.1 Magnetic flux leakage

Magnetic flux leakage (MFL) is the oldest and most commonly used in-line inspection method for finding metal-loss regions in gas-transmission pipelines. MFL can reliably detect metal loss due to corrosion and, sometimes, gouging. In addition, while not designed for this purpose, MFL can sometimes find other metallurgical and geometric conditions /Nestleroth 1999/.

Typically, an MFL tool consists of two or more bodies. One body is the magnetizer with the magnets and sensors and the other bodies contain the electronics and batteries. The magnetizer body houses the sensors that are located between powerful "rare-earth" magnets. An MFL tool can take sensor readings based on either the distance the tool travels or on increments of time. The choice depends on many factors such as the length of the run, the speed that the tool intends to travel, and the number of stops or outages that the tool may experience.

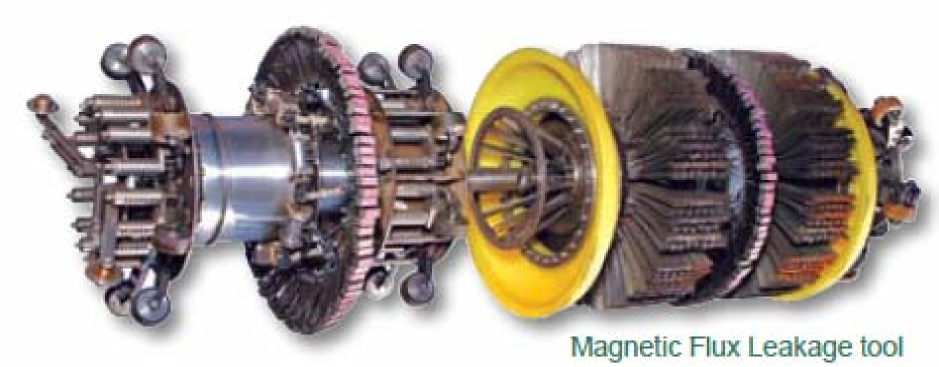


Figure 4.1 MFL tool (courtesy Weatherford)

The second body is called an electronics can. This section can be split into a number of bodies depending on the size of the tool and contains the electronics of the smart pig. The can also contains the batteries and is some cases an inertial navigation unit to enable accurate positioning of the found defects. On the very rear of the tool are odometer wheels that travel along the inside of the pipeline to measure the distance and speed of the tool. Some pigs make use of inertial navigation units as well to record the geometrical location of defects.

4.1.1 MFL principle

As an MFL tool navigates the pipeline a magnetic circuit is created between the pipe wall and the tool. Brushes typically act as a transmitter of magnetic flux from the tool into the pipe wall and a flow of flux is created. High Field MFL tools saturate the pipe wall with magnetic flux. Saturation is dependent on the type of material and wall thickness. The more wall thickness, the higher the magnetic field power needed for saturation. If metal is lost or a crack occurs, the material can not accommodate the magnetic flux and this starts to “leak”, i.e. it takes other paths than through the metal. By using Hall effect sensors it is possible to detect such leakage. It should be noted that the magnetic flux can leak both to the outside and the inside of the pipe, with quite large differences in quantity. The pig is always on the inside of the pipe and can thus only record what leaks to the inside.

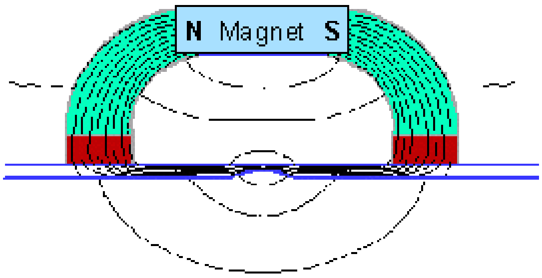


Figure 4.2 Principle of magnet providing flux in a pipe wall with defect, showing flux lines and leakage around the defect (courtesy Battelle Memorial Institute)

Given the fact that magnetic flux leakage is a vector quantity and that a hall sensor can only measure in one direction, three sensors must be oriented within a sensor head to accurately measure the axial, radial and circumferential components of an MFL signal. The axial component of the vector signal is measured by a sensor mounted orthogonal to the axis of the pipe, and the radial sensor is mounted to measure the strength of the flux that leaks out of the pipe. The circumferential component of the vector signal can be measured by mounting a sensor perpendicular to this field. Earlier MFL tools recorded only the axial component but high-resolution tools typically measure all three components. To determine if metal loss is occurring on the internal or external surface of a pipe, a separate eddy current sensor is utilized to indicate wall surface location of the anomaly. The unit of measure when sensing an MFL signal is the gauss or the tesla and generally speaking, the larger the change in the detected magnetic field, the larger the anomaly.

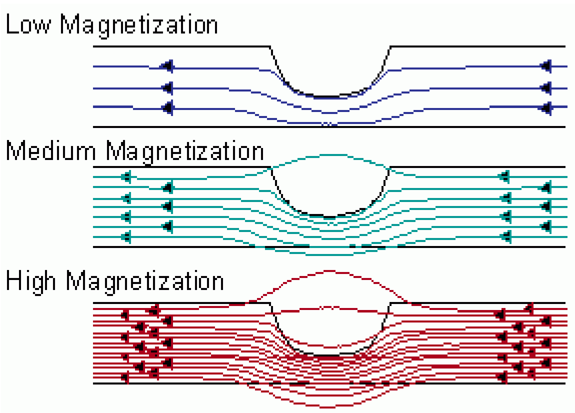


Figure 4.3 Flux level at different levels of flux saturation (courtesy Batelle Memorial Institute)

4.1.2 Signal analysis

The primary purpose of an MFL tool is to detect corrosion in a pipeline. To more accurately predict the dimensions (length, width and depth) of a corrosion feature,

extensive testing is performed before the tool enters an operational pipeline. Using a known collection of measured defects, tools can be trained and tested to accurately interpret MFL signals. Defects can be simulated using a variety of methods.
Creating and therefore knowing the actual dimensions of a feature make it possible to correlate signals to actual anomalies found in a pipeline. When signals in an actual pipeline inspection have similar characteristics to the signals found during testing it is logical to assume that the features would be similar. The algorithms used for calculating the dimensions of a corrosion feature are proprietary. An anomaly is often reported in a simplified fashion with an estimated length, width and depth. In this way, the effective area of metal loss can be calculated and used in acknowledged formulas to predict the estimated burst pressure of the pipe due to the detected anomaly.

4.1.3 Estimating rate of metal loss

High-resolution MFL tools collect data approximately every 2 mm along the axis of a pipe and this allows for a comprehensive analysis of collected signals. Pipeline Integrity Management programs have specific intervals for inspecting pipeline segments and by employing high-resolution MFL tool a corrosion growth analysis can be conducted. This type of analysis is useful in forecasting the inspection intervals.

Although primarily used to detect corrosion, MFL tools can also be used to detect features that they were not originally designed to identify. When an MFL tool encounters a geometric deformity such as a dent, wrinkle or buckle, a very distinct signal is created due to the plastic deformation of the pipe wall.

There are cases where large non-axial oriented cracks have been found in a pipeline that was inspected by a magnetic flux leakage tool. To an experienced MFL data analyst, a dent is easily recognizable by trademark "horseshoe" signal in the radial component of the vector field. What is not easily identifiable to an MFL tool is the signature that a crack leaves.

MFL tools can provide a range of sensitivities, generally categorized as follows:

- Low-Res or Standard tools
  - Sizing; Anomaly grading to a minimum 20% wall loss, with 15 – 20% accuracy
- High-Res tools
  - Sizing; Anomaly grading to within 10% of wall loss, with 10 – 15% accuracy
- Extra High-Resolution (XHR) tools
  - ID/OD discrimination
  - Sizing; accuracy levels for low-level corrosion detection of <10% Wall Thickness and sizing accuracy of ~5- 10% Wall Thickness

- Long inspection ranges

4.1.3.1 Types of flaws detected, advantages and disadvantages

What can be detected:

- Metal loss
- Plastic deformations

Advantages:

- Varying levels of testing can be chosen according to needs
  - Low resolution
  - High resolution
  - Extra high resolution (high number of sensors)

Disadvantages:

- Residual magnetization of pipe

4.1.4 Eddy current testing /ref. Sandia National Laboratories/

Eddy current Testing (ET) is an electromagnetic NDT technique that can only be used on conductive materials. It can be used for crack detection and sorting of flaws, size variations, or material variation. ET is commonly used in the aerospace, automotive, marine, and manufacturing industries.

When an energized coil is brought near the surface of a conductive component, electromagnetic eddy currents are induced in the component. The impedance of the coil is affected by the presence of the induced eddy currents in the component.
When the eddy currents in the component are distorted by the presence of flaws or material variations, the impedance in the coil is also altered. This change is measured and interpreted in a manner that indicates the type of flaw or material condition.

4.1.4.1 Types of flaws detected, advantages and disadvantages

What can be detected:

- Cracks
- Delaminations
- Wall thickness

Advantages:

- Non-contact
- No residual effects
- MFL induced currents can be detected by ET sensors

Disadvantages:

- May limit speed of inspection tool
- Sensitive to lift-off distance and coupling variations

4.2 Ultrasonic transducer technology (UT)

Pigs utilizing UT technology can be divided into two main categories. The use of piezoelectric transducers has the longest operational history. This technology is used for liquid filled pipes and requires contact between the transducer and the pipe wall. The EMAT technology provides the possibility for ultrasonic scanning without direct contact on the pipe wall. This technology can be used in gas filled pipes as well.

Ultrasonics is the frequency range above 20 kHz and this technology has been in use for detecting anomalies in metallic materials in a wide range of applications. The technology is recognized as having a potential for detecting quite small anomalies and defects, although being sensitive to the competence of the operator and interpreter of the signals.

4.2.1 Piezoelectric UT, pulse-echo

In ultrasonic testing, an ultrasound transducer connected to a diagnostic machine is passed over the object being inspected. The transducer is typically separated from the test object by a couplant (such as oil) or by water, as in immersion testing.

There are two methods of receiving the ultrasound waveform, reflection and attenuation. Reflection is the technology used by intelligent pigs. In reflection (or pulse-echo) mode, the transducer performs both the sending and the receiving of the pulsed waves as the "sound" is reflected back to the device. Reflected ultrasound comes from an interface, such as the back wall of the object or from an imperfection within the object. The diagnostic machine displays these results in the form of a signal with amplitude representing the intensity of the reflection and the distance, representing the arrival time of the reflection.

4.2.1.1 Types of flaws detected, advantages and disadvantages

What can be detected:

- Internal/External metal loss
- Longitudinal channeling
- Blisters/Inclusions
- Deformations
- Flanges
- Laminations (sloping & hydrogen induced)

- Cracking
- Weld characteristics
- Wall thickness variations
- Usable on bends, tees, and valves

Advantages:

- Direct and linear wall thickness measurement method, and reliable defect depth sizing and good repeatability
- No upper limit to pipe-wall thickness, relative to inspection
- Sensitive to a larger number of features than MFL

Disadvantages:

- Difficulty in coupling to the pipe wall with a fast moving pig

4.2.1.2 Time of flight diffraction (TOFD)

Time of Flight Diffraction (TOFD) is different from conventional pulse-echo (PE) ultrasonic examination in that it detects low-amplitude diffracted pulses from flaw edges or tips. Most P-E UT techniques detect high-amplitude reflected pulses from flaws.
Two separate probes, a transmitter and a receiver, are used in a tandem configuration. The probes are placed on either side of a weld with UT beams directed into the weld. A lateral wave travels along the contact surface in between the two probes. The longitudinal wave of the angle beam is reflected from the back wall surface. Flaws generate diffracted pulses that appear in between the lateral wave and back wall signals. All of the R-F A-scan data are recorded and stored in memory for later recall and analysis. The A-scans can then be stacked together to create B-scan or D-scan images that show a cross-sectional view in proportion to the weld thickness and scan position. Additionally, R-F and D-scan images can be viewed in real time as scanning is performed. Because this technique does not rely on detection of reflected pulses, it is not amplitude dependent for flaw detection or measurement.

Advantages:

- Weld inspection with usually one scan only.
- No interruption of the operation of the inspected object needed.
- Permanent record of the inspection data.
- Inspection repeatability. Suitable method for monitoring the propagation of discontinuities.
- The length, the depth and the height of the discontinuity are recorded in only one scan.
- Ideal for the detection of cracks on the interface between wall and internal cladding.

- No protection against radiation required, neither interruption of other peoples work.
- Continuous control of probe-surface contact through the back wall echo signals and the surface wave.

4.2.2 Electromagnetic Acoustic Transducer technology (EMAT)

An electromagnetic acoustic transducer (EMAT) is a non-contact inspection device that generates an ultrasonic pulse in the pipe wall. The waves reflected from the pipe wall induce a varying electric current in the receiver. This current signal is interpreted by software to provide clues about the internal structure of material in the pipe wall.

Any faults or cracks constitute a boundary resulting in partial reflection of the incident ultrasonic pulse. Knowing the speed of ultrasound in the sample means that the depth of each crack can be calculated. This is done by halving the time taken between the generation of the pulse and the reception of the reflected signal, and multiplying by the speed of ultrasound in the sample. Thus, using an EMAT, it is possible to build up a profile of the interior of a sample without having to damage or deform it in any way.
As well as cracks in the interior, ultrasound will be reflected off the exterior boundaries of samples, meaning that the technique can also be used to calculate the thickness of samples. This is particularly useful when calculating the thickness of metal pipes, as the pipe does not have to be opened up or even empty for it to be tested. Blockages, corrosion and other problems can be tested for and located without stopping the flow.

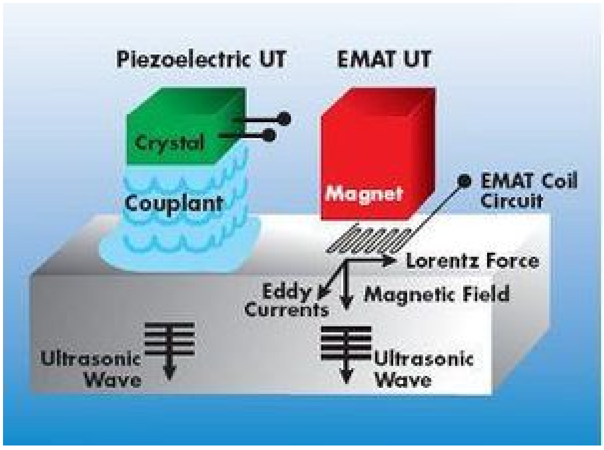


Figure 4.4 Sketch of the principles for piezoelectric and EMAT UT technologies

4.2.2.1 Types of flaws detected, advantages and disadvantages

What can be detected:

- Internal/External metal loss
- Longitudinal channeling

- Blisters/Inclusions
- Deformations
- Laminations (sloping & hydrogen induced)
- Cracking
- Weld characteristics
- Wall thickness variations
- Applicable to flanges, valves, bends, and
- tees

Advantages:

- Dry coupling, readily applicable in gas pipelines
- Improved capability of horizontally polarized shear waves for inspection on areas such as welds
- Improved scanning process reliability, due to the absence of couplant, reducing the risk of overlooking defects where coupling has been lost

Disadvantages:

- EMAT needs to be located ~1mm from the test object
- Relatively low transmitted ultrasonic energy. Because of this, the dynamic range is determined (in many cases) by electronic noise
- High frequencies cannot be applied

4.3 Optical inspection

Visual inspection of pipelines is possible through the use of optical pigs. Different approaches have been used for such applications, with the simplest being a forward mounted camera with lighting. Such systems provide direct visual inspection possibilities but they are fairly limited in that it is difficult to assess the geometry in the pipe. The reason is that video lighting optically flattens the pipe wall surface (i.e. reduces contrasts in the image). Deformities, anomalies and defects need to be quite large to be seen.

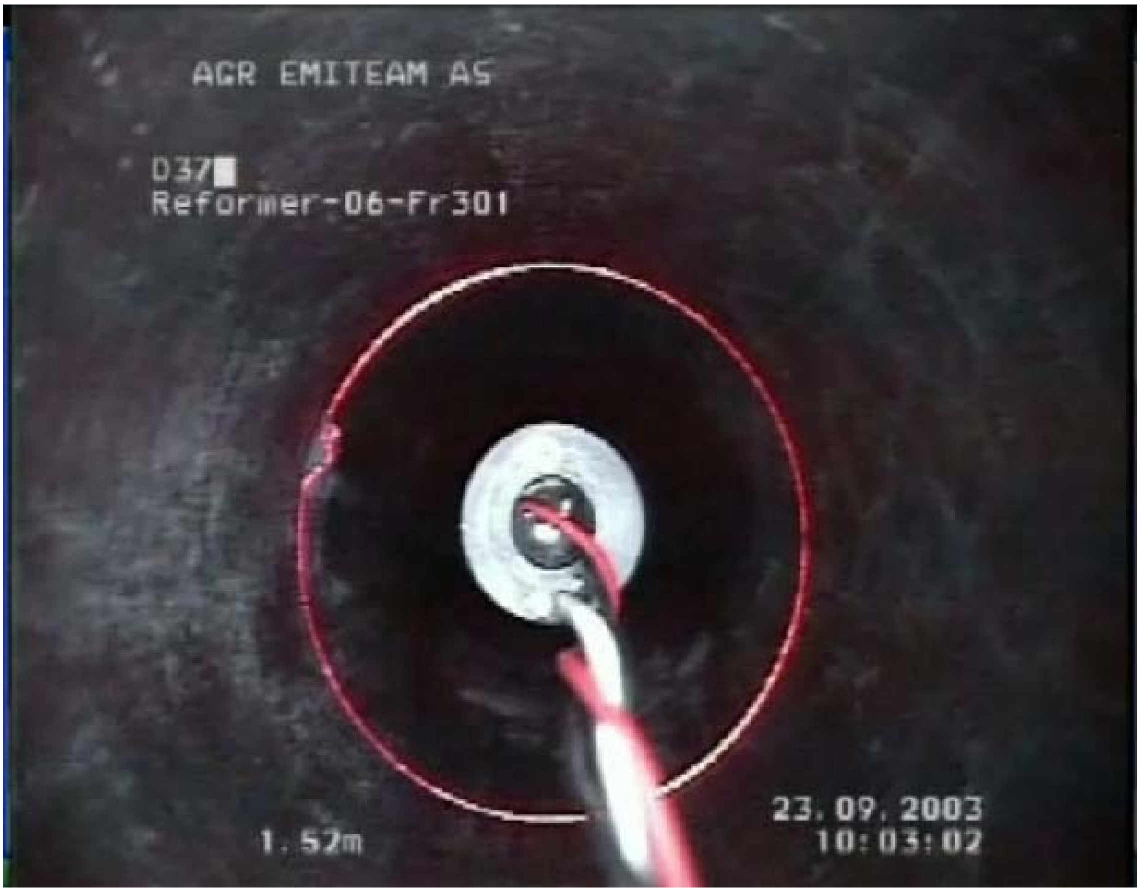


Figure 4.5 Screen capture from AGR promotional video on laser enhanced visual inspection. To the left an anomaly is clearly seen by the distortion of the laser ring (courtesy AGR Group)

Some manufacturers have met this challenge by providing visual assistance in the form of a video generated reference circumference to which the actual pipe circumference can be compared. A further development of this technology /AGR/ makes use of a laser mounted in front of the camera which generates light perpendicular to the pipe centerline thus generating an actual outline of the pipe quite clearly. In this way it is possible to see e.g. elliptical form of the pipe, dents and other geometrical features.

As the name implies, visual inspection requires the fluid in the pipe to be transparent. Video inspection is often used as pipeline restriction inspection prior to running larger and more sophisticated tools.

4.4 Caliper ILI tools

Caliper ILI tools employ tools to measure the circumferential geometry (bore) of the pipe. Different tools are in use, such as physical calipers (i.e. metal plates in contact with the pipe wall), laser or acoustic sounding equipment. The simplest calliper tools deflect metal sheets on the pig to establish the absolute minimum pipe diameter. Caliper ILI tools are normally used only when large deformities are suspected in the pipeline that may compromise the pipe integrity. Caliper tools are often found in combined use on other ILI tools. Caliper inspection is often used as pipeline restriction inspection prior to running larger and more sophisticated tools.

4.5 Experience in use

Several operators have been interviewed with regard to their experiences with use of intelligent pigs for internal inspection of pipelines. Interviews were based on a written form provided by email and a follow-up interview by telephone. The feedback from operators is summarized in the following.

The input is gathered from Statoil, Gassco, Total, BP, Shell and ConocoPhillips.

What kind of intelligent pig is used by your company today?
Different kind of pigs (MFL, UT, combo tools, geometrical etc.) are used depending on the inspection requirement, the type of fluid carried in the pipeline. The choice is based on an assessment that is being done case by case. Both free swimming and cable operated pigs are used; the trend seems to be more UT pigs.

What are the limitations on the equipment?
One limitation is metal loss measurements on extra thick pipe walls for gas pipelines (MFL inspections). Other limitations are related to HTHP in some pipelines. The need for high resolution/high accuracy requires use of a UT tool; if the activity is less demanding on resolution/accuracy the MFL will be used. Also in a pipeline with a huge amount of low level corrosion - the MFL will normally be the best equipment

What is the field experience in practice?
The experience varies and depends on the tool(s) used, the vendor and the analyst. Relatively good experience with UT. MFL technology do have a problem with heavy wall thickness. In the 90-ties a qualification test run was performed with a 300-400 m long test pipe where they run different pigs up to 23 km to examine the repeatability of the pig. The result was that sensitivity requirements had to be reduced.
Intelligent pigging operations are not looked upon as an extraordinary In-line inspection operation. Little or no problems with equipment, or operational impact. In terms of data obtained, UT is recognized as the most accurate for individual features, but MFL is considered a better screening tool.

How are the data utilized?
The data is utilized as an external report from the ILI vendor with data evaluation of pipeline integrity and internal review of the results.

Can you elaborate on experiences vs expectations?
There are uncertainties and risk related to internal inspection.
Risk for the pipeline or equipment (e.g. stuck or lost pig, damage to valves).

Quality of inspection is not always according to specification (i.e. less sensitive than claimed)

What will be your future needs in this field?

- Obtaining information about external and internal metal loss in gas pipes with thick walls, e.g. land fall.
- More accurate results in girth welds and /or longitudinal welds.

4.6 Summary

In-line inspection (ILI) methods are, in general, capable of providing a good overview of the integrity condition of a pipeline.

The most common ILI methods in use are the MFL and UT as they are used for gas and liquid pipelines, respectively. The technologies have evolved to a point where it is expected that inspections performed today (and the past 5 years) yield results of sufficient quality to enable comparison with future inspections.

Introduction of EMAT and eddy current technologies further enhance ILI to provide possibilities for detecting smaller anomalies such as cracks, although some development is needed with regard to issues of accuracy vs. inspection speed.

Optical and calliper ILI tools can be used in conjunction with MFL, UT, EMAT and eddy current to enhance the results of internal inspection. Optical tools are suited to detect geometrical anomalies in pipelines (e.g. dents, collapse etc.)

5. Evaluation of internal baseline inspection as part of a philosophy for follow-up of internal condition of pipelines

5.1 Input from selected operating companies on the Norwegian Continental Shelf

As part of the evaluation contact has been established with several companies operating on the Norwegian Continental Shelf (NCS). In the following is given a brief summary of the feedback from these companies.

Company A

- They have only old carbon steel (CS) pipelines (commissioned in the 80/90-ties). They have not done any baseline inspection on these CS pipelines
- For new CS pipelines they are planning to do baseline inspection as part of the commissioning phase max. 1 year after start up of the operation. They want to do baseline inspection to find anomalies from the fabrication, installation and commissioning phase and to measure accurate wall thickness (WT).
- For new lines they plan to use UT, but they have also used MFL recently (on an existing pipeline).
- For corrosion resistant alloys (CRA) Company A have not decided upon any philosophy yet. They have internal discussions about the need, what can they get from an ILI and which method(s) to be used.

Company B

- They will do inspection for carbon steel pipelines with wet service according to the PSA requirement.
- Internal company specifications describe first inspection within 5 years after start of operation. This is based on the fact that a lot of inspection is done during fabrication. This information can be used to establish a "baseline" status.
- For CRA and flexible pipelines - they apply for deviation from the regulations, based on their view of no need for internal inspection.

Company C

- They follow the PSA requirement for inspection. All their pipelines except one or two have been pigged within 2 years after commissioning.
- They have used the MFL tool for baseline inspection.
- Their strategy is to inspect the pipelines every 10th year if no indications from measuring dew point, CO_2 / H_2S and oxygen content indicate more frequent inspection due to internal corrosion.

Company D

- They have only done intelligent pigging (baseline or in-service) on one of their newest subsea pipelines on the NCS.
- They base their decision on
    - Criticality (Risk) Assessment
    - Inspection data from the fabrication phase

- One reason for not doing any baseline inspection was the fact that no intelligent pig run was planned for any of the lines and that a possible internal inspection would be done several years after commissioning of the pipeline. In the meantime the quality of the intelligent pig would have been highly improved and it would be difficult or impossible to compare the two sets of inspection data.

Company E

- They do not have any specification for baseline inspection but use the requirement from PSA.
- They plan to initiate an internal activity to establish a procedure for <u>baseline</u> and <u>initial</u> inspection
    - <u>Baseline</u>: To look for anomalies from the fabrication, installation and commissioning phase
        - They have seen under-documentation of installation flaws (ovality, saxing, ..) during pipe welding -> fabrication reports do not always give "the right picture"
    - <u>First inspection</u> (2-3 years): To see the effect of water filling during commissioning, dew point control, pH stabilizing, inhibitor on corrosion shortly after start-up
        - Wet gas lines: Can use UT pig for initial inspection if used during water filling to get accurate WT, even if MFL is used later (due to no contact fluid)
    - Will also include strategy for inspection of CRA
- They have limited experience with baseline inspection of CRA – have tried to use UT on SMSS

Company F

They have not done any baseline inspection so far. For one of their pipelines Company F got acceptance from PSA not to perform any baseline inspection based on criticality assessment and risk (including CorPos AD[2] modeling).

Company G

- Baseline inspection is normally done 2-3 years after commissioning. Baseline inspection is important to find installation/production damages even if they already have 100% UT of the pipes (from fabrication) and the welds (during welding).
- For reeled pipes they want to do the baseline inspection on shore before the pipes are installed subsea.
- They did a baseline survey with MFL on their newest gas pipeline last year (5 years after installation).

5.2 Input from published papers

In the following is shortly summarized information from published papers in the open domain dealing with baseline inspection.

[2] CorPos service supplied by Force Technology, Trondheim

H.Vestre: ***Norwegian regulatory requirements related to the utilization of intelligent pigs in pipeline integrity monitoring. Paper no. 47, NACE Corrosion'96, Denver Colorado (USA).***

- Baseline inspection is very important for establishing the condition of the pipeline as soon as it has been put into operation in order to disclose possible damage or failures originated from the fabrication, transportation, installation and commissioning phase.
- The purpose of baseline inspection:
  1. To establish a survey of possible defects and damage from fabrication and installation.
  2. To quantify possible corrosion caused by the waterfilling/commissioning phase.
  3. To establish reference values for the operation of the transport system within the design assumptions
- Baseline inspection can only be omitted if the design, construction or material makes internal inspection impossible or for pipeline systems which have no particular significance when it comes to safety or economical factors.
- In order to establish necessary reference values, the first inspection should be carried out as soon as practically feasible, subsequent to the pipeline system being put in operation.
- Planning of the baseline inspection shall be based on:
  - Economical and safety aspect of the pipeline system
  - Technical fabrication and installation aspects
  - Duration of the water filled/commissioning phase as well as any specific problem linked to the drying process for dried gas lines

M.Roche et.al.: ***Intelligent pigging: Policy, recent experience and needs of a petroleum operator, Paper no. 49, NACE Corrosion'96, Denver Colorado (USA).***

- Intelligent pigging is the main method for inspecting pipelines for internal corrosion/erosion, but can also detect external damages
- <u>Baseline inspection</u>: Survey run prior to start-up, or immediately after when the produced fluid is needed for driving the pig. The objective is to detect and measure fabrication and laying defects, in order to later differentiate them from corrosion defects observed during in-service inspection.
- <u>Early inspection</u>: Survey which is planned after a very short production period, because the corrosion risk of the pipeline is estimated to be high due to a) corrosion prevention efficiency is questionable b) corrosion failure may occur within a short time. The objective is to verify the applied corrosion mitigation system.
- Need for baseline inspection:
  - Only to be used if available tools are not able to differentiate operation metal loss from installation defects.
  - To demonstrate/verify the feasibility of running an intelligent pig

P.Hopkins, M.Lamb: ***Incorporating intelligent pigging into your pipeline integrity management system. Onshore Pipelines Conference, Berlin, Germany, 8-9th December 1997***

Benefits of a baseline survey:

1. The baseline (or 'fingerprint') inspection allows an operator to perform a final check on the construction quality of the pipeline, and can be used as the basis for poor construction practice claims by the operator under any pipeline warranty.
2. The baseline is certainly a good quality assurance tool, as it will provide a searching inspection for a variety of possible defects.
3. It also allows an operator to log defects reported during the inspection. These defects can be assessed, but as they have passed the pre-service hydrotest they are not significant, and are likely to be pipeline material defects, or minor damage. On subsequent in-service inspections these defects can be ignored (provided they have not grown during the interim period), and the operator is in no doubt that any other defect reported has been caused in-service. This can prevent extensive excavations of defects that are innocuous.
4. A limitation of the hydrotest is that it will only impose a pressure load on the pipeline; it will not be a searching test for circumferentially orientated defects (that may cause problems under external loads at spans). A pig can detect a variety of different defects in different orientations.
5. Another limitation of the hydrotest is that there can be a long delay between testing and commissioning. This increases the risk of corrosion being present in the pipeline at the start of operation. A baseline survey, conducted soon after commissioning, would detect any serious corrosion.
6. Information about the initial condition of the pipeline as 'very important', as it provides 'absolute necessary reference values for future condition control'. Knowledge of defects at the start of a pipeline's life will 'disclose possible damage or failures originated from the fabrication, transportation, installation and commissioning phase'

Arguments against a baseline survey:

1. It should always be remembered that no intelligent pig is 100% reliable (i.e. it will not detect all defects), or 100% accurate. A pig can miss defects, or incorrectly size them. Similarly, the idea of 'comparing' the results of a baseline survey with emphasized that a pig does not report a defect, it reports an electronic signal of some description. Later pig runs (say, 15 years in the future) will not use the same pig, and even if the same pig supplier is used, it is highly unlikely that they will be using the same technology. Hence, comparisons will not be between identical signals. However, the more sophisticated intelligent pig operators are understood to be able to make these comparisons, providing the two runs use their pigs on both occasions.
2. Certainly, a baseline survey would allow an operator to log defects that have been detected, but these defects would still require assessment, and an explanation of their origins. Later inspections of the line would allow these defects to be dismissed as (e.g.) fabrication defects. However, it is difficult to quantify such a benefit; all that can be said is that these defects have survived the pre-service hydrotest, and are unlikely to pose an integrity threat to the line.
3. A limitation of the hydrotest is that it will only impose a pressure load on the pipeline; it will not be a searching test for circumferentially-orientated defects (that may cause problems under external loads at spans). A pig can detect a variety of

different defects in different orientations. However, the probability of these defects, and resulting failures, occurring are difficult to quantify, and hence any benefit is difficult to quantify.

4. The only practical way (and the only impartial way) that the value of a baseline inspection can be quantified is to assess its effect on the integrity of the pipeline. This can be done by assessing precisely what the baseline inspection will and will not detect, and also comparing the defects that the baseline would detect, to those that would be detected (i.e. failed) by the pre-service hydrotest.

S. Westwood, A.Bhatia: ***Inline Inspection Decision and Results using an Integrated Technology for a Baseline Inspection Program on a Large Diameter High Pressure Transmission and Interconnect System. Paper no. IPC04-0100, International Pipeline Conference, October 2004, Calgary, Canada.***

Developing a Baseline Inline Inspection Program with Design and Operational Decisions on the use of a High Resolution Magnetic Flux Leakage Tool, Paper no. 03172, NACE Corrosion 2003

- Baseline inspection with a MFL tool was performed in the period 2-4 years after commissioning of the pipeline in 2000
- The information from this inspection showed the real physical condition of the pipeline and the data will serve as baseline measurements for further integrity assessment programs
- The baseline inspection was a *feasibility study/test of the inspection system* and the learning was that several improvements (operational and for the tool itself) were necessary for the following planned in-service inspections to come.

K.Reber, M. Beller: ***In-line Inspection of new pipelines. Pigging Products and Services Association 2004.***

- Baseline inspection is a verification/quality control of the fabrication process and the outcome is important for review of in-service inspection data
- The fabrication process of a pipeline is thoroughly documented since
  - All components have been tested individually
  - The steel plates have been tested for flaws and lamellations
  - All welds have been tested with UT or radiography
  - The pipeline has been hydrotested as part of the commissioning phase
- Which inspection tool to be used
  - Existing UT tools give extremely accurate wall thickness (WT) values ➔ baseline inspection gives the real wall thickness of the entire pipeline.
  - MFL gives a quantitative value of metal loss but gives inaccurate WT values

DNV-RP-116: ***Integrity Management of Submarine Pipeline Systems. October 2009***

This is a new Recommended Practice that has been developed in close cooperation with the industry. This document does not mention baseline inspection. However:

- in Section 3.4.5 it is said that *"following commissioning of the system, it shall be verified that the operational limits are within design conditions"*
- in Section 4.1 it is said that *"Inspection plans shall be established in the design phase and implemented in the organization prior to production start up (Initial inspection plan)"*
- in Appendix G is shown an example of Risk Assessment and planning for a 10" oil flowline. Through the Risk assessment process including Probability of Failure (PoF) and Consequence of Failure (CoF) modeling for the actual pipeline, the result turned out to require the first inspection within 1 year after start up. This is mainly due to uncertainty in the actual status of the system after construction and commissioning ➔ an inspection needs to be done to reduce the uncertainty (increase the confidence level).

5.2.1 Discussion

5.2.2 Introduction

It is common opinion among the operators today that first inspection (often called baseline inspection) is performed to look for anomalies from the fabrication, installation and commissioning phase. Even if baseline inspection primarily is performed to look for internal anomalies, also external anomalies can be detected especially when using the MFL technology. However, even if this is a common opinion some of the operators try to avoid to perform the first inspection immediately after commissioning based on risk assessment..

The majority of the companies also state that they prefer not to perform baseline inspection of pipelines made from CRA or flexible pipes. This statement is based on:

- Lack of reliable inspection methods
- Low risk level (low PoF) for the pipelines

The pipeline suppliers do intensive inspection during the fabrication process. This includes inspection for flaws, lamellation, weld inspection and wall thickness measurements of individual pipes. During construction in the field girth welds are 100% inspected. All these information is made available for the operator as part of the DFI-resume. Assuming that this information is correct the need for baseline inspection to look for fabrication defects and anomalies could be reduced or eliminated. However, experience has shown that the DFI-resume not always describe the real situation (ref. is made to Statoil). In addition anomalies from the installation and the commissioning phase can not be observed and quantified if a baseline inspection is not executed.

The newly developed DNV-RP-F116 "Integrity Management of Submarine pipeline systems" describes a structured way to execute a Risk Assessment for pipelines. This is one systematic approach that can be used to document the need and to prioritize which pipelines to be included in a baseline inspection program.

When to perform the first inspection? There are two different opinions about what should be included in the first inspection:

1. Should only include fabrication and installation anomalies – commissioning anomalies not included ➔ inspection to be performed before or during the commissioning phase i.e. when the pipeline is water filled for hydrotesting.
2. Fabrication, installation and commissioning anomalies to be included ➔ inspection to be performed after the pipeline has been emptied after hydrotesting.

The advantages with the first alternative are that the inspection can be based on the UT-technology due to water coupling even for gas pipelines. For the second alternative the real status after commissioning will be established. This is important since water from hydrotesting can be corrosive and can on some occasions remain in the pipeline in e.g. low spots and cause local corrosion. In this case gas pipelines need to be inspected with the MFL technology. It is well accepted that UT gives accurate wall thickness values, while MFL are able to quantify volume loss with a certain accuracy.

For some pipelines implementation of a corrosion mitigation program is necessary to maintain the integrity of the pipeline. The effect of this mitigation program can be followed up by e.g. locally installed ER probes, weight loss coupons (WLC), subsea CM-device (FSM, CEION) or measuring pH, iron counting,…However, the only way to really see the effect of the mitigation method(s) is to perform an internal inspection. For some pipelines – with High Risk according to the Risk Assessment evaluation – an initial inspection shortly after start up of the operation (1-3 years) should be implemented.

Earlier version of UT and MFL type inspection tools had weaknesses and gave in many cases not reliable (poor) data compared with actual pipeline conditions. One important argument against running a baseline inspection was that the quality of the technology was under continuous improvement and that it would be impossible to compare two datasets measured with year's interval. However, the tool quality has been continuously improved during the years, and the In-line inspection operators claim that the tools today give very accurate WT (UT-tools) and metal loss (MFL) values. It is not expected the big improvements in tool quality in the coming years.

5.2.3 Future procedure – proposal for discussion

The Activity reg. §47:

"With regard to pipeline systems where fault modes may constitute an environment or safety risk, cf. Section 43 on classification, inspections shall be carried out to map possible corrosion of the pipe wall. Parts of the pipeline system where the lay condition or other factors may cause high loads, shall also be checked."

We propose to introduce a Risk Assessment process as planning basis for the first inspection. The process described in DNV-RP-F116 “Integrity Management of Submarine Pipelines” can be one alternative way to perform the Risk Assessment analysis. This document should have been updated with a section dealing with first inspection. In this section special focus should be put on the fabrication, installation and commissioning phases in addition to the operating phase when the PoF evaluations are performed. However, it is reason to believe that the operating companies will establish their own internal detailed Risk Assessment (by some companies called Criticality Assessment) procedure based on the DNV document.

The DFI-resume is important input to the Risk Assessment process especially during the initial evaluation. This means that special focus needs to be put on the data quality and the confidence level of the inspection during fabrication and installation in the evaluation process. The operators need to put special focus on documentation of all anomalies occurred during fabrication and installation of a pipeline system. They also need an internal system to review and store such information for later use.

The Risk level for operating the pipeline will be the outcome of the Risk Assessment through defining the actual PoF-level and CoF-level for the pipeline under evaluation. Time for first inspection needs to be linked to the Risk level. This connection needs to be described in the company specification. Appendix G in DNV-RP-F116 gives one example for the link between Risk level, adjustment factors for data quality and confidence level for elements influence PoF and inspection interval.

Does the first inspection need to be performed within a max. number of years? It is proposed that the first inspection should be performed within 5 years after the pipeline has been commissioned.

What about pipelines made from CRA? These pipelines will also be evaluated through a Risk Assessment process that results in a time for initial inspection. Due to the fact that CRA is selected to reduce the probability of internal corrosion, it is reason to believe that the initial inspection will be after more than 5 years in operation. As long as the PoF is low and the probability of failure detection (pitting, crack ..) in CRA for existing tools is low, the requirement for initial inspection of CRA within 5 years is questionable.

The results from the first inspection should be used to update the initial risk assessment with the aim to establish when to perform the next inspection of the pipeline. It is important that all pipeline inspections are planned for performing comparisons with earlier inspections, i.e. the first inspection must also encompass the basis of a baseline inspection. A framework for risk based inspection of pipelines should be established.

Earlier arguments about the poor quality of the inspection tools and the expected future improvements of the tools and the data quality, is not valid any longer. Both UT and MFL technology has greatly improved during the last years. Some improvements will take place, but inspection data from today (both WT and metal loss) can easily be compared with corresponding data from inspections performed e.g. 10 years in the future. New inspection technologies will be developed in the future (e.g. Acoustic Resonance Technology – ART). The output from these new techniques will also be WT and/or volume loss. However, due to the today quality of the existing UT and MFL tools, similar data from the old and the new technology can be compared and used in the status evaluation.

The ability to perform comparisons with earlier inspection results depends on several issues. The quality of previous inspections, the ILI technology used, the analysis software and not least the competence of personnel performing analyses are among the more important issues. There does not exist any industry best practice or recognized method on how to perform such a comparison of different inspections. A recognized method would form a foundation for defining the scope of comparative inspections and the format for reporting of results.

6. Historical and future development of technology and tools for internal inspection of pipelines

6.1 Delimitations and outline

This section of the report focuses on future development of technology and tools for internal inspection pipelines. Some surveillance technology is also included since the development within corrosion monitoring may decrease or eliminate the need for internal inspection in some pipelines. Current stat of the art is covered by the previous sections and will not be repeated here. A brief summary of the historical development within in-line inspection technology is given. The main part of this section deals with current research and development on specific technologies for in-line inspection and corrosion monitoring of pipelines.

6.2 Historical development

6.2.1 Principles of inspection

Mainly four different principles of measurement are used in pipeline inspection technology:

- Magnetism: Magnetic flux leakage
- Acoustics: Ultrasound
- Electrical induction: Eddy current (EC)
- Physical: Caliper
- Optics: Video

Ongoing research is still focusing on the same principles of measurement, but equipment with more sophisticated use of the physical measurement principles are under development.

6.2.2 Brief historical development

- 1964: Pig with capabilities for measuring wall thickness by magnetic flux leakage
- 1978: First high resolution MFL pig
- 1986: First ultrasonic pig
- 1996: Transverse Field MFL inspection
- 1997: Ultrasonic angle-beam crack detection pig (TOFD-UT)
- 2005: Guided wave
- 2006: The electromagnetic acoustic transducer (EMAT) was introduced, enabling acoustic measurements without liquid between the transducer and pipe wall
- 2006: Introduction of combined MFL and eddy current pig

6.2.3 Signal processing and data treatment

During the past 20 years or so, the development of inspection technology has been driven by the development in information and communication technology (ICT). Hence, the inspection technology has improved with respect to capacity and sensitivity, rather than introduction of new sensor technology. The development has mainly been within signal processing and data storage capacity. The development in computer technology has increased clock frequency of microprocessors and data storage capacity by many orders of magnitudes. This has paved the way for high resolution inline inspection technology by digital signal processing technology. The current tools have a higher number of channels than the earlier versions and are able to collect more information. The sensor systems have also evolved, but it is the processing and data storage revolution that enables us to take advantage of these developments.

6.3 Objectives with ongoing research

The motivation for further development of inspection technology mainly falls within one or more of these issues:

- Access to “unpigable” pipelines
- Detection of small defects: cracks and/or pits
- Increased accuracy and resolution
- Maintain regular production during inspection

We can therefore expect two development trends within in-line inspection technology:

- Specialized pigs to be used in currently unpigable pipelines and for detection of small defects, e.g. in CRA/clad pipelines.
- “More, better and faster” data from the technology currently on the market

The main limitation to inline inspection technology world wide is access for the pig. Physical obstacles like pipe bends, valves and large changes in pipe diameter make many pipelines unpiggable. In addition some pipelines are installed without a pig launcher. Approximately 60 % of the world’s gas, oil and product pipelines can be inspected with off-the-shelf inspection tools. The remaining 40 % of pipelines have often been classified as ‘unpiggable’ (Beugen 2008). A large proportion of these unpiggable pipelines are offshore multi-diameter lines with large diameter ratios, or with challenging flow conditions. However, on the Norwegian continental shelf a larger percentage of pipelines are piggable.

6.4 Acoustic resonance technology (ART)

The information given in this section is based on text and images received from DNV and a conference presentation (Eide 2009).

6.4.1 Principle of measurement

When sound waves are emitted from an acoustic transducer through a medium and then hit a part of a pipe wall or plate, parts of the acoustic energy is reflected from the surface and parts of it are transmitted into the plate/pipe wall. Some frequencies are more easily transmitted into the plate/pipe wall than others, and create resonances. Resonances occur when an acoustic wave returns from a round trip across the plate or pipe wall and back (after partial reflections at each face), in phase with itself. Waves that have completed one or more round trips will then combine with each other, and the original wave, to produce particularly large amplitude vibrations. The particular resonance that gives the greatest amplitude of vibration for a plate or pipe wall is called the half wave resonance, since it occurs when the round trip distance equals one wavelength, i.e. the wall thickness is half a wavelength. Also multiple integers of this half wave resonance (called harmonics of the fundamental half wave resonance frequency) create local amplitude maxima.

The fundamental frequency f_0 of the plate is given by:

$$f_0 = \frac{c}{2d}$$

Where c is the sound velocity of the plate and d is the plate thickness. f_n is the n^{th} harmonic of this frequency:

$$f_n = n \cdot f_0$$

This phenomenon is the basis of ART.

By transmitting a broad banded acoustic signal containing one or more of the harmonic frequencies a 'build up' of resonances will occur, and these resonances will then leak out from both sides of the plate. An illustration is given in Figure 6.1.

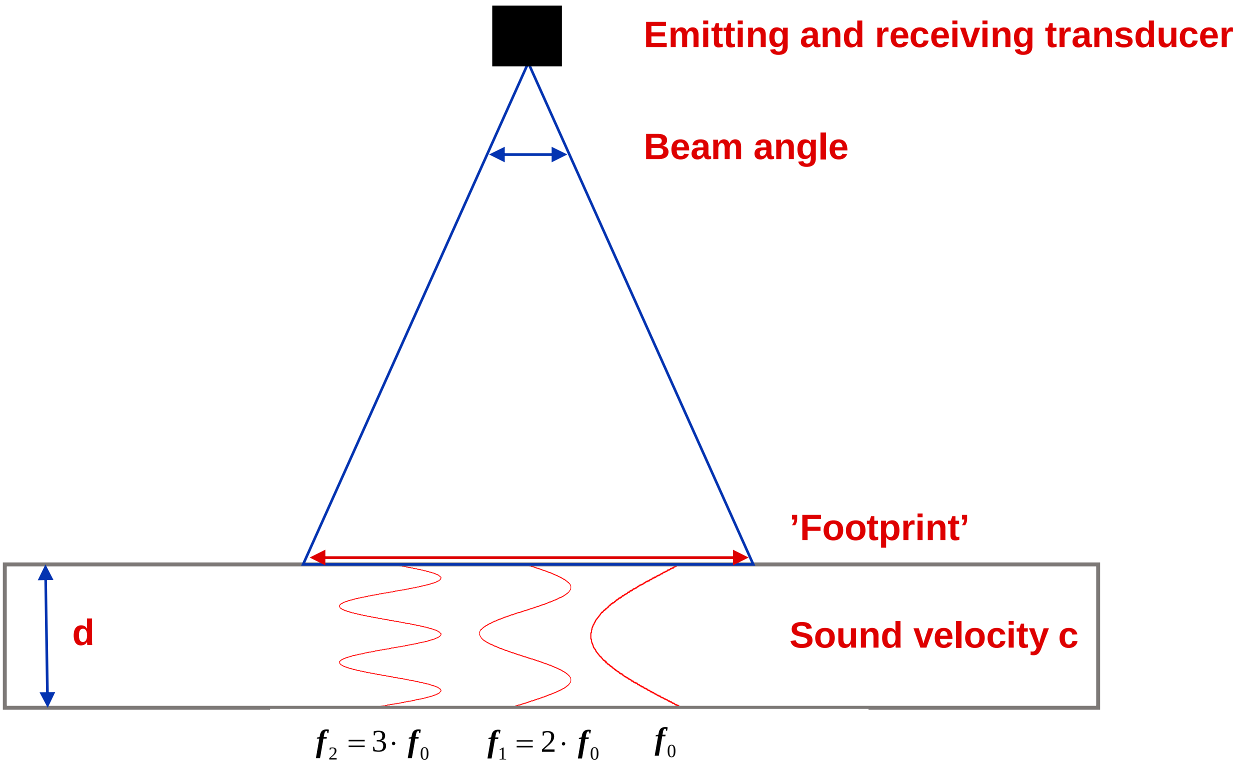
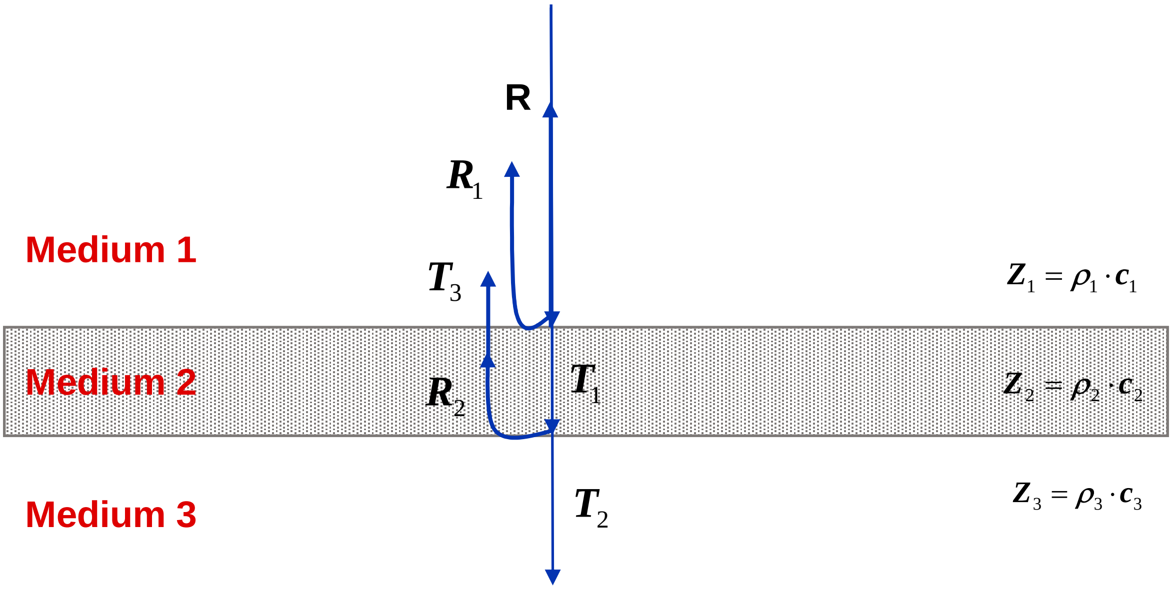


Figure 6.1. Half wave resonances in a plate with thickness d and sound velocity c. The fundamental frequency plus the first and second harmonic are shown.

The frequency content of these resonances is determined by the velocity of sound in the material and the thickness of the plate. If one of them is altered, the resonance frequency is altered. In addition the relative energy content of the resonances will be related to the difference in specific acoustic impedance of the plate and its surrounding media. Hence, half wave resonances may be utilized for thickness measurements by analyzing the frequency content, and analyzing the energy content may provide information about the medium.

The theoretical basis for characterization of the medium is shown in Figure 7



$$R = \frac{Z_2 - Z_1}{Z_2 + Z_1} + \frac{4 \cdot Z_1 \cdot Z_2 (Z_3 - Z_2)}{(Z_2 + Z_1)^2 \cdot (Z_3 + Z_2)}$$

Figure 6.2. A plate surrounded by to different media with different acoustic. R is the reflection coefficient and T is the transmission coefficient.

R is the energy fraction reflected from the plate. As can be seen from the formula, this fraction depends on the sound velocity, density of the plate and density of the surrounding media. As an example, measurements of reflection coefficients can be used to detect hydrate plugs or wax build up in pipelines from the outside, or for detection of water ingress.

Even though a complex system is needed for ART measurements, the benefit is a robust and flexible system capable of doing measurements in varying environment, and at different distances from the object to be measured. The ART system is also robust regarding the angle of inclination, since it will tolerate deviation from the ideal 90 degrees angle of incidence. How much it will tolerate is a matter of transducer design, the transducers can easily be designed to tolerate the deviations which could occur during pigging operations offshore.

ART is a low frequency method, which makes it less sensitive to surface roughness, enables penetration of coating materials such as marine growth, concrete, sediments, corrosion products, coating etc.

6.4.2 Inline inspection with ART

ART can be used both in pigging and permanently installed monitoring equipment, but so far the development has been focused on pigging. Compared to traditional ultrasound pigging technology, ART is supposed to have some advantages:

- There is no need for liquid or physical contact between the transducer and pipe wall, which makes pigging of gas lines much easier.
- The acoustic source can be located at some distance from the pipe wall, as shown in Figure 6.1 and Figure 6.2. This gives some flexibility that can be utilized in pipelines with variations in pipe diameter. Current inspection tools have a limited ability to pass changes in pipe diameter. An ART tool may have some advantages in such pipelines.
- The high accuracy of the measurement enables wall thickness measurement at higher pig velocities than current state-of-art pigging. The measurements can also handle variations in the pipe flow. Pigging can then be performed during regular production in the pipeline. This means that normal flow rates can be maintained during the pigging operation.

Compared to UT technology, eliminating the need for liquid or physical contact between the sensor and the pipe wall is an important improvement, which enables inspection of gas pipelines. Today MFL is the most frequently used inspection technology in gas pipelines. If ART gives higher accuracy in the measurements and full production rate can be maintained during inspection, significant improvements to inspectin of gas pipelines is achieved.

6.4.3 Current development status for ART

ART has been qualified for a range of application areas, such as thickness measurements through coating, graphite or wax deposits. A commercial Pipescanner for in line inspection of water pipelines has been in commercial for about 2 years through the company Breivoll Inspection Technology who has the license for this application. The latest achievement has been the qualification of the technology for use in gas from 1 bar and upwards. In cooperation with Gassco a three channel Pipescanner has been developed for demonstration and qualification of this capability. Seven test runs were conducted in February and March 2009 in the 20 km pipeline from Kårstø to Kallstø. These test runs demonstrated the capability of measuring wall thickness in gas also through a liquid layer. It was also shown that it was possible to extract information about welds and the medium outside the pipe. The developers claim that water ingress in the coating and delamination also can be detected.

A full version with 192 channels for 28” to 44” pipes is now in production. DNV and Gassco are setting up a joint venture for commercialization of the technology.

6.5 Remote Field Eddy Current

6.5.1 Principle of measurement

The remote field eddy current (RFEC) technique was originally developed for the in-situ detection of external corrosion in oil well casings. Later the application has been expanded to a wide variety of steel tubulars, e.g. heat exchanger tubes and pipelines.

The RFEC tool uses an internal solenoid exciter coil. A circumferentially distributed array of detector coils is placed near the inside of the pipe wall. The detector coils are placed at some distance from the exciter coil, corresponding to about two pipe diameters. Two distinct coupling paths exist between the exciter and the detector coils. The direct path, inside the tube, is attenuated rapidly by circumferential eddy currents induced in the tube's wall. The indirect coupling path originates in the exciter fields which diffuse radially outward through the wall. At the outer wall, the field spreads rapidly along the tube with little further attenuation. These fields re-diffuse back through the pipe wall and are the dominant field inside the tube at remote field spacing. Anomalies anywhere in the indirect path cause changes in the magnitude and phase of the received signal, and can therefore be used to detect defects (Nestleroth 2007).

Conventional eddy current inspection techniques are limited to inspection of only the surface nearest to the probe. The remote field technique is capable of inspecting the entire wall thickness without the need to use ultra low frequency. Like conventional eddy current techniques, RFEC respond well to cracks because these interact strongly with eddy currents. Although RFEC probes have been used for well casing inspection for many years, it is a rather complex phenomenon. The interaction with defects is now well understood, thanks to development of defect models and computer animations.

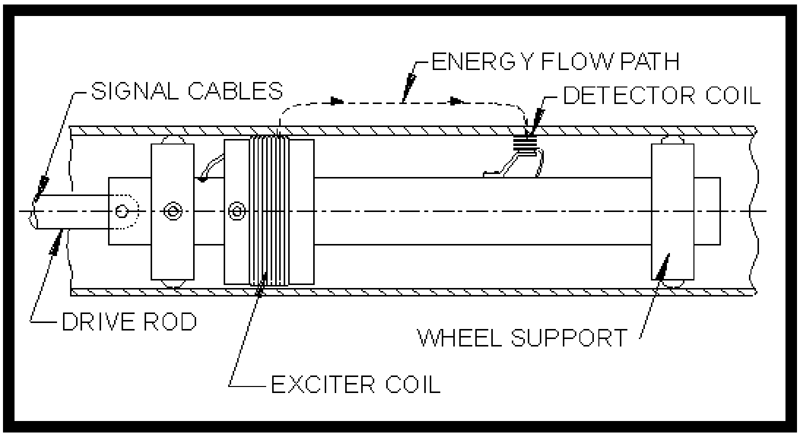


Figure 6.3. Remote field eddy current pig (Nestleroth 2007).

6.5.2 RFEC with permanent magnets

Battelle is developing a rotating permanent magnet inspection system where pairs of permanent magnets are rotated around the central axis. This alternative to the more common concentric coil method can be used to induce high current densities in the pipe. Along the pipe away from the magnets in either direction, the currents flow in the circumferential direction. Anomalies and wall thickness variations are detected with an array of sensors that measure local changes in the magnetic field produced by the current flowing in the pipe. The inspection methodology can be configured to pass tight restrictions and narrow openings such as plug valves. The separation between the magnets and the pipe wall is on the order of 25 mm. The strength of circumferential current produces signals on the order of a few gauss, which can be detected by hall effect sensors positioned between 10 and 100 cm away from the rotating magnets. Battelle's technology is depicted in Figure 5.

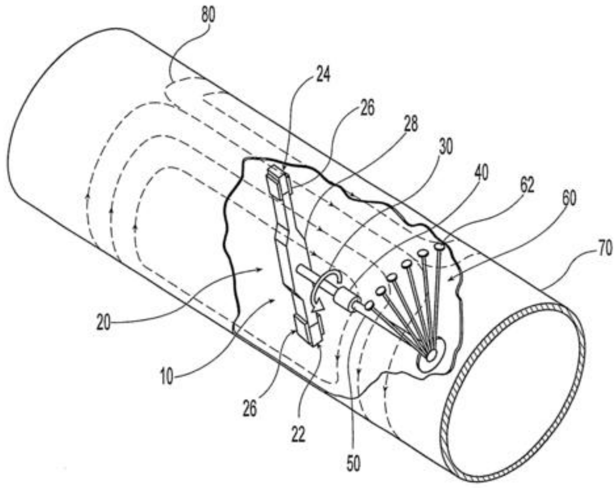


Figure 6.4. Remote field eddy current measurement with permanent magnets. The illustration is taken from world patent WO/2007/089224.

6.5.3 In-line inspection with RFEC

The main advantages with RFEC are:

- Ability to operate with some liftoff from pipe wall
- Reasonably high accuracy in the measurement
- Relatively small sensor unit
- Able to detect both corrosion and cracks

The main disadvantages are:

- High current consumption
- Rather weak signal

The development of an in-line inspection tool based on RFEC has focused on a small tool to be mounted on a crawler for inspection of otherwise unpigable pipelines.

6.5.4 Current development status

A prototype RFEC device that will travel through the types of obstructions found in unpiggable pipelines has been prepared (Laursen 2009). An untethered, modular, remotely controllable, self-powered inspection robot equipped with a RFEC unit has been used for the visual and non-destructive inspection of 6- and 8-inch natural gas tranmission and distribution system pipelines. Two additional deployments under live conditions are planned for early 2010. Full commercial inspection of pipelines will begin in mid-2010

Figure 6.5. Pipeline crawler robot with RFEC inspection unit (Laursen 2009).

6.6 SmartPipe

6.6.1 General description of the system

SmartPipe is a research project and not commercially available yet. The principal objective with the R&D project is to develop a concept for online monitoring of the technical condition and for flow assurance of offshore pipelines and risers. The SmartPipe system will consist of three main parts:

- Packages of sensors, communication and power supply, distributed along the pipeline or riser
- Data analysis tools that converts the sensor data into meaningful degradation parameters and failure risks.

- A graphical user interface presenting the results to the operator and a database for storing of sensor data and analysis results.

The idea has been to develop a system with sensors located inside the pipeline coating, with locally produced power and wireless communication. The hardware is mounted in pipeline field joints during production of the pipeline and covered by the field joint coating. Hence, the hardware is hidden in the coating and is not exposed to the surroundings. The sensor belt can contain ultrasound transducers for wall thickness measurement, strain gauges (both hoop and axial direction), thermo elements and accelerometers, depending on which parameters the operator wants to monitor. The sensor belts are mounted in every field joint, together with a local micro controller, a communication antenna and a power supply (node).

Communication between the nodes take place by electromagnetic signals transmitted in the pipeline coating. The data are transmitted in a multihop topology, where data are sent from node to node along the pipeline. Each node is able to communicate with three nodes up or down the pipeline, which means that two nodes next to each other can fall out without breaking the communication line. At the end node the data are picked up by an external node and fed into a powerline modem and to topside by conventional technology.

The system is powered by a battery package at each sensor/communication node. The battery package will have a finite lifetime, so one of the major challenges has been to decrease the power consumption of the system. This is mainly achieved by:

- Use components with low power consumption
- Let the system sleep much of the time, i.e. low duty cycle
- Local processing of data and optimization of the communication protocol

Characteristics of the system:

Length of monitoring section	Unlimited
Density between measurement points	12 or 24 m
Sensitivity	0.1 mm
Mounting	Under coating
Max hydrostatic pressure	Not determined yet
Power	Batteries
Durability of system	> 20 years
Calibration	Self calibrating
Retrofitting	No

6.6.2 Corrosion monitoring

Corrosion monitoring is achieved by a number of UT sensors mounted on each sensor belt. The sensor belts are distributed along the pipeline, which perhaps is the main advantage of SmartPipe compared to other corrosion monitoring systems. Still, the UT sensors will only measure corrosion in an area of ca 1 cm^2 beneath the sensor, so SmartPipe will not be able to measure all corrosion attacks in the pipeline. However, corrosion in a pipeline follows a certain statistical distribution (Weibull distribution), and from a number of UT measurements it is possible to estimate the statistical distribution of corrosion in the pipeline, i.e. average corrosion and maximum depth of attack. The corrosion modeling is done by the CorPos AD tool (Force Technology).

So far simple pulse-echo UT sensors have been implemented, with a resolution of about 0.1 mm. This is a minimum resolution required for detection of corrosion inhibitor failure within reasonable time. A somewhat higher resolution is desired. More advanced UT sensors may be applied, but this will increase the costs and energy consumption of the system. Increasing the number of UT sensors is also considered, in order to increase the number of input data points for the statistical analysis.

6.6.3 Current status

A 24 m demonstrator pipeline with four nodes were built and tested during the summer 2009. All hardware survived molding into the poly propylene field joint coating. A subsequent reeling test was also successful, and did not affect the performance of the system. The communication principle was successfully demonstrated, and a patent application has been submitted.

The consortium is now applying for a pilot project, which according to the plan will end up with installation of the system on an offshore pipeline in 2012.

6.7 Guided wave monitoring and pigging technology

Corrosion monitoring of guided wave (GW) have been commercially available for some years now. The reason why this technology is listed in this section of the report and not section 3 is that there are few installations of GW subsea. An in-line inspection tool based on GW is also under development, which is described below.

This section is mainly based on information received from Guided Ultrasonic Ltd (Evans 2007).

6.7.1 Principle of measurement

The guided wave technology has been developed for the rapid survey of pipes, for the detection of both internal and external corrosion. The principal advantage is that long lengths, up to ca 50 m in each direction, may be examined from a single test point. The benefits are:

- Reduction in the costs of gaining access to the pipes for inspection,
- The ability to inspect inaccessible areas, such as buried and sleeved pipes, at clamps,
- Avoidance of removal and reinstallation of insulation or coatings (where present), except for the area on which the transducers are mounted,
- The whole pipe wall is tested in accessed range, thereby achieving a 100% examination.

Long-range ultrasonic methods use so-called guided ultrasonic waves. Much lower frequency is used compared to normal ultrasonic tests. Frequencies usually between 30 and 75 kHz are used compared with about 5MHz for conventional UT thickness measurement. The low frequency waves have the property that they can travel many meters with minimal attenuation and therefore offer the potential of testing long distances from a single point. A pulse-echo transducer bracelet is wrapped around the pipe, which both sends and receives the echoed signal. Transmission of a circular wave along the pipe wall interacts with the annular cross-section at each point. Any changes in the thickness of the pipe, either on the inside or the outside, cause reflections of the sound wave that are detected by the transducer. Hence metal loss defects from inside or on the outside of the pipe can be detected. The detection of additional mode converted signals from defects aids discrimination between pipe features and metal loss.

6.7.2 Corrosion monitoring with guided wave technology

The guided wave equipment currently available are screening tools and do not provide the same kind of resolution as local thickness measurements. The aim with the method is to provide a rapid screening at a limited number of access points so that more appropriate test methods may be directed at areas requiring further attention. Long range UT does not provide a direct measurement of wall thickness, but is sensitive to metal loss where depth, circumferential extent and the axial length to a lesser degree produce signal responses.

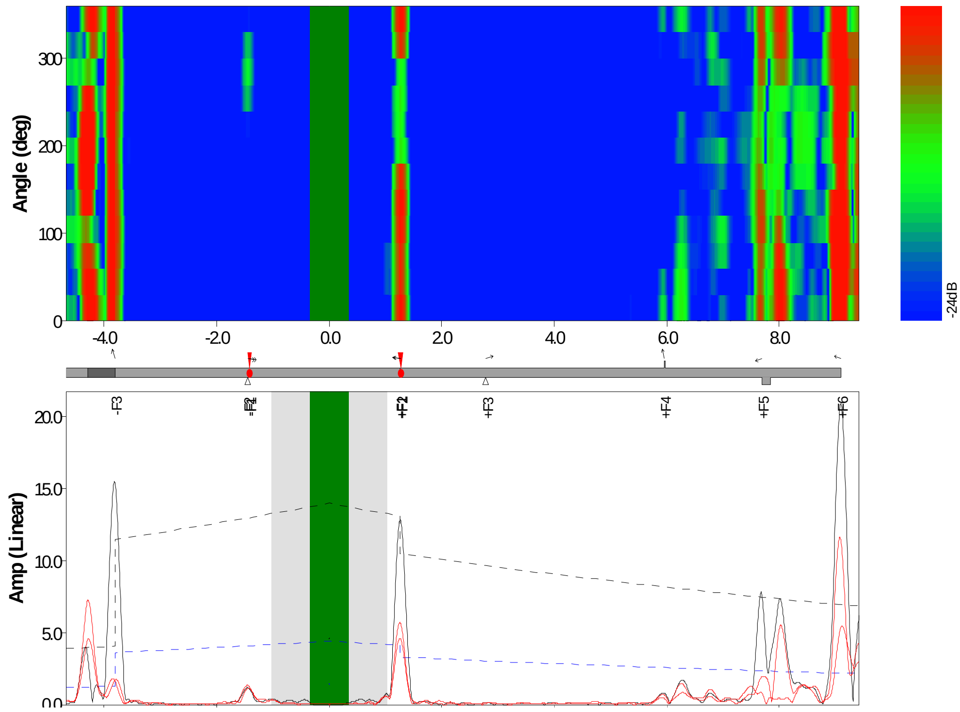


Figure 6.6: Example of signal reflections from corrosion features along the pipeline on both sides of the sensor (Evans 2007).

6.7.3 Current status

Guided Ultrasonic Ltd. in UK has a commercially available called “Permanently Installed Monitoring System” (PIMS). PIMS have already been installed on around 100 buried pipes. The system can be pre-installed on pipe and then installed subsea and cabled back to platform. Retrofit installation by diver or ROV is also possible. So far offshore installations have mainly been above splash zone on risers in the North Sea and offshore in South America.

At present the guided wave technology has a detection limit of about 1% reduction in pipe wall cross sectional area. Between measurements detection of down to 0.1% change in cross sectional area has been achieved. The location of a defect around the circumference of the pipe is accurate within ± 22°, see the upper diagram in Figure 6.6.

Figure 6.7: Guided wave sensor installed on pipeline (Evans 2007).

Characteristics of the system:

Length of monitoring section	50 - 100 m in both directions from the sensor
Sensitivity	About 1% of steel cross sectional area. Can detect 0.1% changes between measurements
Mounting	Can be mounted both directly on the steel and outside coating
Max hydrostatic pressure	Can be installed down to 500 m by ROV
Power	Battery or powerline
Durability of system	> 20 years
Calibration	?
Retrofitting	Yes

6.7.4 Guided wave in-line inspection tool

A pigging tool for in-line inspection based on guided wave measurements has also been developed. A bristle traction system enables the pig to travel up or down-stream to specific areas of interest. The pig can also run down the pipeline and stop at regular intervals to make a measurement in order to map the entire pipeline.

Figure 6.8. Illustration of guided wave inspection pig (Evans 2007).

7. Summary

Corrosion monitoring technologies

Technology	Installation	Retro-fitting on existing pipelines	What is measured?	Sensitivity	Subsea maturity	Type of defect*	Limitations
UT	Non-intrusive	Yes	Wall thickness	<0.1 mm	Prototypes installed	Uniform	Pipe coating may prevent signal transmission Need for physical contact with pipe Local measurement directly under sensor
Guided wave	Non-intrusive	Yes	Cross-sectional area (CSA)	1% CSA	Prototypes installed	Uniform, local, crack	50-100 meters in both directions from sensor
ER	Intrusive	Yes (topside) No(subsea)	Corrosivity of fluid	<0.1 mm/year	Mature	NA	Finite lifetime
Electric field mapping	Non-intrusive	No	Wall thickness	0.1 mm	Mature	Uniform	
Weight loss	Intrusive	Yes	Corrosivity of fluid	0.1 mm/year	No	NA	Provides average corrosivity only after removal of coupon

*: Uniform corrosion, local corrosion, crack

In-line inspection technologies

Technology	Type of fluid	Material	Maturity	What is measured?	Sensitivity	Type of defect	Limitations
MFL	Gas, liquid	CS, Magnetic materials	Mature	Volume loss	Low	Uniform, local	Maximum wall thickness (~40 mm) depending on force of magnetic field
UT piezo	Liquid	All	Mature	Wall thickness	Medium to high depending on velocity	Uniform, local	Needs physical contact with pipe wall (liquid as contact medium) Special requirements for cleaning prior to inspection
EMAT	Gas, Liquid	All	New	Uniformity of pipe wall material	Uncertain, highest for near-surface defects	Local, crack	
Eddy current	Gas, liquid	All	New	Surface cracks and pitting	Uncertain, claimed as high	Local, crack	Not for uniform metal loss
UT TOFD	Gas, liquid	All	New	Cracks	Uncertain, claimed as high	Crack	Only for inspection of specific areas (e.g. welds) Requires production shut-down
Optical	Optically clear	All	Mature	Surface appearance (geometry, precipitation)	Low	Geometry, large surface anomalies	Oil carrying pipelines must be flushed and cleaned prior to inspection.
Caliper	Gas, liquid	All	Mature	Surface appearance (geometry, precipitation)	Low to medium	Geometry	
ART	Gas, liquid	All	R&D	Wall thickness	Uncertain, claimed as high	Uniform, local	
Guided wave	Gas, liquid	All	R&D	Cross-sectional area (CSA)	Uncertain, claimed 1% CSA	Uniform, local, circumferential cracks	ILI device needs to be stopped at location for measurement Production shut-down required
RFEC	Gas, liquid	All	R&D	Wall thickness (claimed), surface cracks, pitting	Uncertain	Local, crack	

8. Conclusions

Corrosion monitoring

Measuring the corrosivity of the internal fluid in the pipeline is the most widespread application of corrosion monitoring equipment, i.e. through weight-loss coupons or electrical resistance probes. The equipment is most often installed topside or onshore for practical reasons. Subsea monitoring with FSM or Ceion requires special considerations regarding underwater packing and necessary adjustments for enabling stable conditions for communication and power supply. However, promising new non-intrusive monitoring equipments, based on ultrasound techniques, have been developed for subsea usage measuring the local metal loss from the pipeline wall.

In-line inspection

In-line inspection (ILI) methods are, in general, capable of providing a good overview of the integrity condition of a pipeline. The technologies have evolved to a point where it is expected that inspections performed today (and the past 5 years) yield results of sufficient quality to enable comparison with future inspections. Evolution of technologies further enhance ILI to provide possibilities for detecting smaller anomalies such as cracks, although some development is needed with regard to issues of accuracy vs. inspection speed.

The electromagnetic transducer (EMAT) pig and ultrasonic angle-beam crack detection (TOFD-UT) have been used for crack detection. However, the experiences so far are that crack detection still is difficult, even with the new technologies. For inspection of CRA pipelines, which primarily are subject to environmentally assisted cracking, the currently available technologies are not considered satisfactory.

First inspection

The requirements in the Activities Regulation section 47 on inspection and maintenance of pipelines is unclear and to some extent self-contradictory. It is said that risk assessment should be the basis for a maintenance program, and then state, as an imperative requirement, that the first inspection should be performed within the two first years of operation. Whether to perform first inspection within the two first years of operation or not shall be decided based on a risk assessment, but this is not intuitively understood from the current wording of section 47.

Based on the findings reported here we suggest that a new framework or regulation is prepared that clearly states that all pipelines shall be subject to a risk assessment. DNV-RP-F116 includes one example of such risk assessment procedures. The result of such assessment shall be used to decide when first inspection is to be performed and the frequency of subsequent inspections. The first inspection is essentially an as-built inspection, however it should also be designed as a baseline inspection. The risk assessment shall be updated after each inspection.

Development within inspection and monitoring technology

New technology that is expected to be available in near future include the acoustic resonance technology (ART), remote field eddy current (RFEC) and guided wave. ART is in particular expected to improve inspection of gas pipelines. The RFEC technology is more of a specialized tool to be mounted on crawlers for inspection of unpigable pipelines. Guided wave sensors for corrosion monitoring have been available on the marked for some time, but pigging tools based on guided wave are also under development. Smartpipe, which is a concept for distributed monitoring on pipelines, is still in the R&D stage and market introduction can first be expected in a few years.

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