Index

Paper 3.1

A Review of Pipeline Integrity Systems

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1 INTRODUCTION

The visible evidence of a leak is often the first sign that the integrity of a pipeline has been breached. In an ideal world, one in which cost did not matter, pipelines would be designed to have guaranteed integrity, but in the real world it is inevitable that leaks will occur. Whether carrying water, gas or oil, there are financial, political, regulatory, safety and environmental issues which must be addressed when designing and operating pipelines. Pipeline integrity monitoring and leakage detection systems therefore have a key role to play in minimizing the occurrence of leaks and their impact.

The requirement to monitor the integrity of extensive and inaccessible pipelines is clearly widespread and there is a belief that some of these issues can be addressed by sharing experiences and practices across sectoral boundaries. As part of the 2002-2005 Flow Programme, NEL undertook a project to review the state of the art in monitoring systems for pipeline integrity across all relevant industrial sectors.

The overall review covered pipeline integrity in general, with a focus on documenting leakage detection methodologies. Although such techniques are used across a range of industries, the different operational and safety requirements have led to a variety of implementations.

It is clear that practices differ from sector to sector and the very different operational regimes of, and potential hazards from, oil, gas and water pipelines, mean that transferring best practice from one sector to another is not simply a matter of implementing an identical solution. The key recommendation with regard to the selection of any leak detection system therefore is that it must be made within the context of an overall pipeline integrity management plan. This paper provides a summary of the report, including an overview of the issues and a review of potential techniques. The project report [1] and associated Guidance Note [2] (available from the Flow Programme website) provide background information and a basic framework on which leakage-detection-based systems selection can be based.

2 BACKGROUND

Pipeline integrity can be assured by appropriate design, construction and operation; the use of a pipe-in-pipe system with annular-space leak sensing would, for example, significantly reduce or entirely eliminate the possibility of fluid release to the general environment. Whilst this approach can be applied to new pipelines, it is much more difficult to "retrofit" to an existing pipeline to ensure inherent integrity. Most integrity systems are therefore based on specific instrumentation and methodologies to reduce the likelihood of pipeline failure and minimize the consequences of such an event.

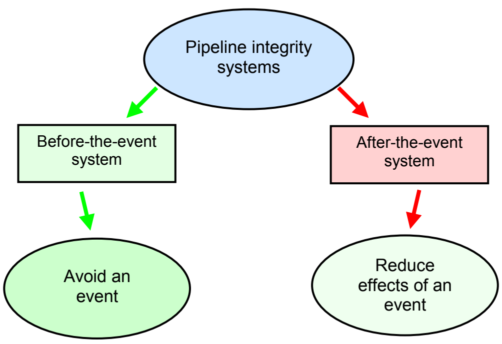


Fig. 1 – Pipeline integrity systems

Pipeline integrity systems can therefore be divided into 'Before-the-event' and 'After-the-event' systems, as summarized in Table 1 and Figure 1. Before-the-event systems are aimed at ensuring the integrity of a pipeline and use a combination of operational procedures, maintenance procedures, and dedicated hardware and software as part of an overall pipeline integrity management system (PIMS) to provide advance warning of any events or changes in the physical state of the pipeline which may lead to a loss of integrity. After-the-event systems are aimed at detecting and locating leaks caused by a loss of integrity and can be based on dedicated sensors or a combination of existing sensors and modelling techniques.

Table 1 - Pipeline Integrity Systems

System	Before-the-event	After-the-event
Aim	ensure integrity	detect leaks
Approach	appropriate design and operation hardware and / or software-based monitoring systems	hardware and / or software-based detection systems

Operational considerations and safety requirements differ from sector to sector, with key differences summarized in Table 2. For product value and safety reasons, oil and gas pipelines make more use of before-the-event systems than water pipelines. For instance, gas distribution, oil and chemical pipelines are subject to observational surveys made by air, road vehicle and by foot in order to detect the presence of excavating activities close to the pipeline; this helps prevent failure due to impact.

Table 2 - Sector Intercomparison

Sector	Pipeline pressure	Issues
Gas transmission	up to 70 bar	High value product Leakage unacceptable on safety grounds
Oil and petrochemicals	up to 100 bar	High value product Leakage unacceptable on safety and environmental grounds
Water	up to 10 bar	Low value product Non-hazardous product but gross leakage unacceptable on political grounds

Pipelines may also be inspected in-line using a range of inspection tools to detect the presence of metal loss defects, such as those caused by corrosion and external impact. Pressure cycling can be monitored and controlled to prevent the growth of construction defects due to fatigue. In principle, these survey techniques [1, 3] can be applied to pipelines carrying any fluid but many of the techniques require access over the whole length of the pipeline and thus would not be suitable for offshore applications or buried onshore pipelines. The remainder of this paper is therefore concerned with after-the-event, leakage detection, systems, in particular software-based methods.

3 LEAK DETECTION SYSTEMS

Leak detection systems can be categorized based on where the measurements are made [4] or the methods used [5]. In terms of where the measurements are made, this classification differentiates between internal measurements, which examine flow in the pipeline in an attempt to infer leakage, and external measurements, which look to detect fluids that have exited the pipe.

Classification based on the methods used differentiates between systems that use sensors available in normal pipeline operations (pressure, temperature, flow rate) and those that require special sensors. Systems that use special sensors can be regarded as hardware-based; although software will be involved, it is dedicated to processing the data from these sensors. Systems that use existing sensors can be regarded as software-based since they depend on additional software to process data from different types of sensors and extract extra information from which leaks can be inferred. Table 3 summarizes this classification scheme.

Table 3 - Categorization of Leak Detection Systems by Detection Method

Hardware-based	Software-based
Acoustic emission	Mass or volume balance
Cable sensors	Real-time transient modelling
Fibre-optic sensors	Rate of change
Soil monitoring	Statistical analysis
Vapour monitoring	System identification with digital signal analysis

3.1 Evaluation of Leak Detection Systems

The key criteria for assessing any leak detection system are:

- What is the minimum leak size that the system is capable of detecting?
- What is the time needed to detect a leak of a given size?

A leak is detectable only when its effect rises above uncertainties in the variables being monitored. The size of a leak is usually expressed as a percentage of the throughput of the pipeline. Leak size is a function of the size and shape of the opening (leak area) and the pipeline pressure. A leak can be either constant in size, such as a pre-existing small leak, or variable over time, such as a sizable leak that diminishes as the pipeline is depressurized.

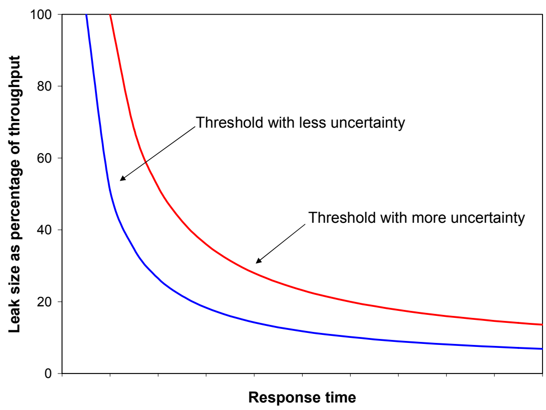


Fig. 2 - Detectable leak size versus response time for mass balance detection

Depending on the leak detection methodology used, the response time can vary over a wide range. For algorithms based on volumetric or mass balance, the response time is related to the leak size because of the uncertainties in the variables involved. Reducing the uncertainty on the measurements improves the detection threshold [6], as illustrated in Figure 2. For leak detection methods based on discrepancy patterns generated from a real-time transient flow model, the response time is not a function of leak size. Instead, it is a function of the propagation speed of a pressure disturbance and the distance between the leak and the nearest pressure or flow sensors.

Depending on the location of the pipeline and the fluid it is carrying, the rate of leakage or the total volume lost over a given period may be more significant. For example, a very slow leak from an oil pipeline may go undetected for a long period. Whilst this is unlikely to have a major financial impact on the operation of the pipeline, the environmental impact may be significant. On the other hand, the environmental impact of a long-term, slow leak from a gas pipeline would probably be insignificant but the safety implications huge; in the case of an underground gas main, the gas could remain trapped around the pipe, building to a volume which, if ignited, could cause very serious damage.

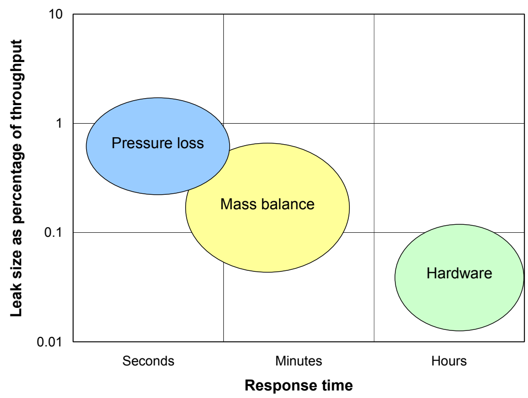


Fig. 3 - Detectable leak size versus response time for various detection methods

For comparable pipeline conditions, the response time is also, broadly, a function of the detection method used, as illustrated in Figure 3.

Whilst the key criteria are minimum leak size and response time, there are a number of other criteria that should be considered when assessing a leak detection system [6], as summarized in Table 4.

Table 4 - Assessment Criteria

Criterion		Description
1	Leak size / leak flow rate	What is the minimum leak size that the system is capable of detecting?
2	Response time	What is the time needed to detect a leak of a given size?
3	Location estimation	Can the system locate a leak and what is the accuracy of the location estimate?
4	Release volume estimation	Does the system have the ability to determine the volume of liquid released?
5	Pre-existing leaks	Does the system have the ability to detect pre-existing leaks, as well as the onset of a new leak?
6	Shut-in condition	Does the system have the ability to detect the onset of a leak in a shut-in pipeline segment?
7	Slack condition	Does the system have the ability to detect a leak in pipelines under a slack condition during transients?
8	False alarms	What is the rate of false alarms and misses for the system?
9	Sensitivity to flow conditions	How sensitive is the system to operational transients (such as those caused by pump startups or valve swings)?
10	Robustness	Will degradation or malfunction of a system component cause catastrophic loss of leak detection ability?
11	System self-checks	Does the system have the capability to automatically check and possibly rectify parameters that affect leak detection performance?
12	Complex configurations	Can the system handle complex pipeline configurations (e.g. multiple injection and delivery points) as well as complex operations (e.g. multiple modes of operation, bi-directional operation)?
13	Availability	Is the system available full-time or only during steady-state operation?
14	Ease of retrofitting	What is required to install a new leak detection system and/or methodology on an existing pipeline?
15	Ease of testing	How easy is it to test the system during commissioning and at regular intervals thereafter?
16	Cost	What is the cost of the system including capital and operational expenses, as well as, data and equipment requirements? What is the cost of tuning the system to match current operation of the pipeline?
17	Ease of use	Is the system easy to use? How much operator training is required?
18	Ease of maintenance	What are the maintenance requirements for the system? Will the system degrade with improper or missed maintenance tasks? How frequently does it need to be tuned?

The remainder of this section reviews a range of leak detection techniques, summarizing their advantages and limitations. Table 5 provides an overview of the techniques, following the classification scheme given in Table 3.

Table 5 - Leak Detection Systems

Hardware-based		Software-based	
Acoustic emission	A leak generates noise which can be picked up by acoustic sensors installed outside the pipeline.	Mass or volume balance	This method checks for leak by measuring the mass or volume at two sections of the pipeline.
Cable sensors	These sensors use polymer materials that swell in the presence of hydrocarbon thus changing their electrical properties.	Real-time transient modelling	This method mathematically models the fluid flow within a pipeline. The equations used to model the flow are conservation of mass, conservation of momentum, and an equation of state for the fluid.
Fibre-optic sensors	Leaks can be identified through the identification of temperature changes in the immediate surroundings using fibre optic cable or through change in the optical property of the cable itself induced by the presence of a leak.	Rate of change	Rapid depressurization, rapid inflow increase, rapid outflow decrease, and rapid increase in the difference between inflow and outflow are associated with the onset of a leak.
Soil monitoring	Leaks are detected by analyzing the concentration of the vapour phase or tracer substances in the soil surrounding the pipeline.	Statistical analysis	This method detects a leak by undertaking statistical analysis of pressure and/or flow at multiple locations. Leak alarm generation is based on a set of consistent patterns of relative changes of the mean data at different locations.
Vapour monitoring	If the product inside a pipeline is highly volatile, this system sucks the vapours in to a low-density polyethylene (LDPE) sensor tube and runs this gas stream past specialized sensors that can detect trace concentrations of specific hydrocarbon compounds.	System identification with digital signal analysis	This method relies on the occurrence of a leak changing the pipeline-fluid system in some characteristic way but does not use a mathematical model for the transient pipeline hydraulics.

3.2 Hardware-Based Systems

There are many factors that affect the performance of external leak detection methods and these should be considered as part of the selection process. Table 6 provides a comparison of the systems listed in Table 5 in terms of key criteria given in Table 4. Full details of these systems are given in [1].

With the exception of the acoustic emission-based approach, most hardware-based systems are relatively difficult to retrofit even for on-shore pipelines, as they generally require access over most of the length of the pipeline; this would clearly limit their potential application to off-shore pipelines. However, developments in cable-based systems, in particular fibre-optic systems, may make retrofitting easier.

Although the response times given in Table 6 range down to seconds, in practice many of these systems require much longer when detecting very small (less than 0.1%) leaks.

However, as they are capable of detecting existing leaks and dealing with pipelines in shut-in or slack conditions, they are potentially very useful. Their use should therefore be considered as part of an overall pipeline integrity strategy when even low-level leaks are unacceptable.

Table 6 - Comparison of Hardware-Based Technologies

Criterion \ System		Acoustic emission	Electro-chemical cable	Fibre-optic cable	Soil monitoring	Vapour monitoring
2	Response time	real time	seconds to minutes	seconds to minutes	minutes to hours	minutes
3	Location estimate	✓	✓	✓	✓	✓
4	Released volume	estimate	limited	limited	estimate	estimate
5	Existing leak	✓	✓	✓	✓	✓
6	Shut-in condition	✓	✓	✓	✓	✓
7	Slack condition	✓	✓	✓	✓	✓
8	False alarms	frequent	less frequent	less frequent	less frequent	less frequent
14	Ease of retrofit	moderate	difficult	difficult	difficult	difficult

3.3 Software-Based Systems

3.3.1 Mass or Volume Balance

Mass or volume balance relies on the principle of conservation of mass. For each pipe section the mass of fluid entering the section either remains in the pipe section or leaves it. A leak is identified when less fluid leaves the pipeline section than is expected from the measurements of the input flow and estimates of the pipeline section contents.

At its most basic, the technique is implemented by measuring the volume of products entering and leaving a pipeline section over a specified time period and expressing the results in terms of standardized volumes (volume at 60°F or 15°C and 0 psig). Although simple, this method gives credible results when the flow in the pipeline is at, or close to, a steady state (i.e. the pressure, temperature, and flow along the pipeline do not change rapidly over time), or when the time period is sufficiently long. The leak threshold depends on the accuracy of the volume measurements, the length of the time period, the pipeline volume, and the state of flow in the pipeline.

This approach is more effective for pipelines with a smaller volume (since the linepack is less affected by the state of flow) but obviously it cannot detect a leak in a shut-in pipeline since both the inflow and outflow at the ends of a pipeline segment are zero at all times and yield no useful information. The ability to detect a leak in a slack pipeline (one where low pressures cause localized vaporization) depends on the state of flow. If the flow is at a steady state, a leak can be detected by this method. However, when the flow is in a transient state, the vapour volume changes appreciably and cannot be modelled with accuracy. Consequently, the ability to detect even a significant leak is greatly diminished. The ability of this approach to detect a small leak is highly dependent on the combined nonrepeatability of flow meters at the ends of a pipeline segment.

Whilst the simple volume-based approach can give reasonable results under certain conditions, it must be borne in mind that the physical basis of the technique is conservation of mass. However, most flowmeters are volumetric devices and so, strictly, it is necessary to know the density of the fluid throughout the section of the pipeline being monitored. For gas, the temperature and pressure in the pipeline will have a significant effect on the density. Furthermore, the composition of the gas (and hence the effect of temperature and pressure on its density) between two flowmeters within any section of pipe can change significantly over comparatively short periods of time, as gas from alternative sources is introduced into the distribution system. Although the effects of temperature and pressure on the density of oils are lower than for gases, they must still be taken into account. On oil pipelines, flowmeters for fiscal and custody transfer applications generally have an uncertainty of 0.25% (see Table 7) and, depending on the operational regime of the pipeline, it may be possible to resolve imbalances (and hence leaks) of the order of 0.1%.

Table 7 - Flowmeter Accuracy

Metering type	**Accuracy (mass)**	**Comments**
Fiscal	±0.25 – 0.5%	Single phase, well known conditions
Wet gas (>90% by volume gas phase)	±0.4 – 1.5%	When test separation is regularly used to establish gas and liquid phase fractions
	±3 – 5% for gas ±10 – 20% for liquids	With no test separation
Multiphase metering (<90% by volume gas)	±5 – 10% for each phase	Accuracy deteriorates markedly if one phase is less than 5% by volume of total flow
Inference metering	±5 – 10% for gas ±20% for liquids	

The limitations of the basic volume balance can be overcome by the use of additional sensors. By placing additional pressure and temperature sensors along the pipeline, real-time pressure and temperature can be measured at a set of selected locations along the pipeline. The change in the standardized volume over the line balancing period can be estimated using volume correction factors for pressure and for temperature, rather than using an assumed linepack. The accuracy of this correction improves as the spacing between adjacent sensors is reduced [7].

An extension of this approach is to use a valid transient flow model to compute changes in linepack from measured pressure and flow at the ends of a pipeline segment. When appropriate, the effects of temperature can be included in the model. Although this approach is more complicated and the data requirements can be significant, it may be the only choice when it is not feasible to obtain pressure and temperature data at a sufficient number of the interior points of a pipeline segment.

For either of these extensions to the basic approach, the pressure-temperature-specific volume relationship of the liquid must be known, to enable linepack changes to be calculated from pressure and temperature. Hence, the type of liquid in the pipeline needs to be identified, usually by its specific gravity or degree-API. For products pipelines, the position and the specific gravity for each product needs to be tracked. The accuracy of batch tracking may be verified or enhanced by densitometers along the pipeline.

For multiphase systems, the uncertainty in flowrate measurement for each phase is such that leaks above about 10% of the pipeline throughput can be detected [3]. Figure 4 shows the results of a simulation of a multiphase pipeline with wet gas metering offshore and fiscal metering onshore. A leak of 10% of the pipeline throughput can be clearly identified (Figure 4a) but the flowrate difference seen for a 2.5% of throughput leak is far smaller than the possible meter errors (Figure 4b).

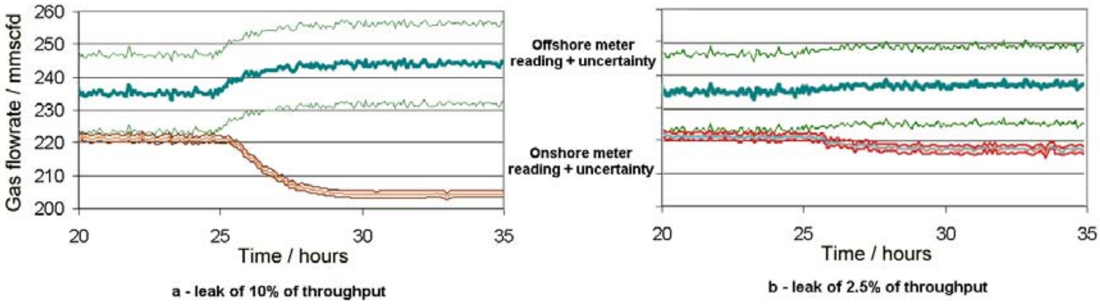


Fig. 4 - Simulation of the effect of a leak on flowrates in a multiphase pipeline

3.3.2 Rate of Change

Rapid depressurization, rapid inflow increase, rapid outflow decrease, and rapid increase in the difference between inflow and outflow are associated with the onset of a leak. In principle, each of these criterion, or several in combination, can be used for leak detection. However, since pipeline operation transients can also cause rapid changes, alarms need to be inhibited for a time period following an operation, such as a pump start-up or a change in the set point of a control valve, limiting the limits the usefulness of this method. In addition, this approach is effective for large leaks only.

3.3.3 Real-Time Transient Modelling

A volume or mass flow-based model with additional sensors pressure and temperature sensors along the pipeline can be extended by the use of a transient flow model or a simulation model.

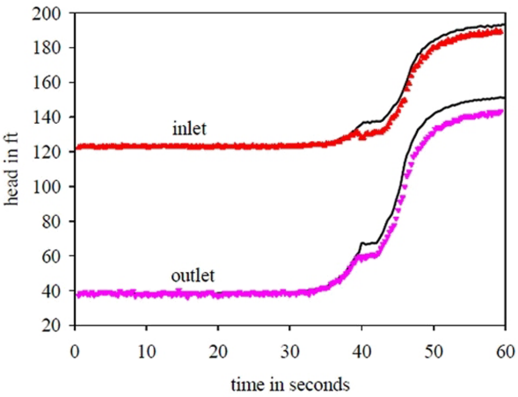
In this approach, a subset of the measured pressure and flow data recorded by the SCADA system is used to drive a simulation model. The model results are then compared with the remaining measured data. Since the measured data are affected by leaks while the model assumes the pipeline to be intact, leak-specific discrepancy patterns between the measured and the calculated parameters will develop. These discrepancy patterns provide the basis for leak detection, leak location, and release volume estimation.

A model simulates transient flows in the pipeline based on the conservation principles of mass and momentum. An energy equation is not involved when the liquid temperature along the pipeline is known. When the temperature is not known, a separate temperature model based on the energy equation may be necessary. For products pipelines, a separate batch tracking model can be used to provide the transient flow model with valid batch positions.

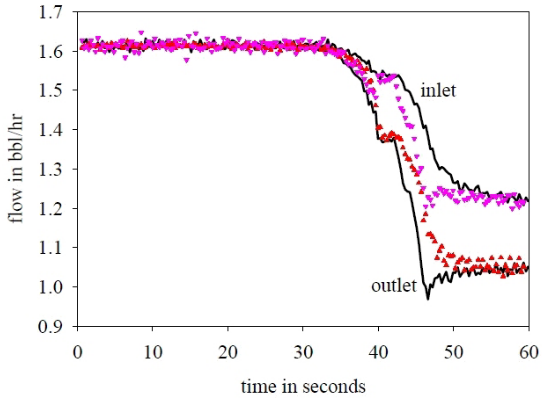
The advantage of this approach is that a leak occurring during all flow conditions (including operational transients) can potentially be detected. Figure 5 shows laboratory verification of one version of this approach [8]. The measured head and flow at the inlet of a pipeline were used to drive a transient flow model that computed the head and flow at the outlet. At the same time, the measured head and flow at the outlet were used to compute the head and the flow at the inlet. A 6.5% leak was imposed while the pipeline was experiencing transients caused by a sudden 37% flow reduction due to a partial valve closure at the outlet. For this example, this gave rise to:

- immediate and simultaneous increases in the discrepancy (measured minus calculated) in inlet head and inlet flow, and
- an immediate increase in the discrepancy of the outlet head and an immediate and simultaneous decrease in the discrepancy of the outlet flow.

Depending on how the transient model is driven by the measured data, the discrepancy patterns may vary but for each case they are specific to a leak and false alarms are claimed to be rare [9]. In addition, the difference in the timing of the sudden changes can be used to indicate the location of the leak [10].



a - discrepancy between measured (solid lines) and calculated (symbols) heads



b - discrepancy between measured (solid lines) and calculated (symbols) flows

Fig. 5 - Effect of a leak in a system with real-time transient modelling

This approach is data intensive and the SCADA system's data scan rate needs to be fast. Thus, although this approach is classified as software-based, it requires extensive hardware. The model parameters must also be tuned regularly, to ensure that the model accurately reflects reality, thus requiring higher maintenance than for a simple mass or volume balance model approach.

3.3.4 Statistical Analysis

In the simplest form of this approach, statistical analysis is performed on a measured pressure to discern a decrease in the mean value over a threshold. However, simple statistical methods are prone to false alarms; to reduce the frequency of false alarms, more sophisticated statistical analysis methods use pressure and/or flow at multiple locations. Leak alarm generation is based on a set of consistent patterns of relative changes of the mean data at different locations. For example, a leak alarm is generated only if the mean inlet pressure drops and the mean inlet flow exceeds the mean outlet flow.

Statistical methods rely on trends consistent with the principle of mass conservation for corroborating mean data values at multiple locations. In this sense statistical methods are physically-based but they do not use a mathematical model for the transient hydraulics in the pipeline to compute pressure and flow. Consequently, the data requirement is not as demanding as for model-based approaches.

The basic principle used for the probability calculations is mass conservation and hypothesis testing: leak against no-leak. Although the flow and pressure measurements in a pipeline fluctuate due to operational changes, statistically the total mass entering and leaving a network must be balanced by the inventory variation inside the network. Such a balance cannot be maintained if a leak occurs in a network. The deviation from the established balance is then detected by an optimal statistical test method [11]. Leak thresholds are established only after a prolonged period of tuning to establish the underlying probabilistic distribution, the mean, and the variance of the parameter(s) to be tested under different states of no-leak flow (i.e. steady, drifting, or transients). The tuning process is necessary to reduce the occurrence of false alarms.

3.3.5 System Identification with Digital Signal Analysis

System identification with digital signal analysis relies on the occurrence of a leak changing the pipeline-fluid system in some characteristic way. For example, a leak will alter the impulse response of a pipeline. This response can be extracted by digital signal processing techniques in real time. An alarm can then be generated when the impulse response changes in a leak-specific way [12].

Table 8 - Comparison of Computational Pipeline Monitoring Leak Detection Methods

	Criterion \ System	Basic volume balance	Volume balance with pressure sensors	Volume balance with dynamic model	Real-time transient modelling	Rate of change	Statistical analysis	System ID with digital signal analysis
1, 2	Leak size / response time	1-5% / minutes to hours	1% / minutes	1% / minutes	1% / seconds	5% / minutes	1% / seconds to minutes	1% / seconds to minutes
3	Location estimation	×	×	×	✓	✓	✓	✓
4	Released volume	rough estimation for long-term average	improved estimation for long-term average	improved estimation for long-term average	can provide leak flowrate as a function of time	can estimate the volume for large leaks	×	×
5	Existing leaks	✓	✓	✓	×	×	×	×
6	Shut-in condition	×	✓	✓	✓	✓	✓	✓
7	Slack condition	×	×	✓	✓	×	×	×
8	False alarms	frequent	less frequent	less frequent	more frequent	frequent	less frequent	less frequent
9	System transients	no tolerance	better tolerance	better tolerance	best tolerance	some tolerance	best tolerance	best tolerance
10	Robustness	average	average	poorer	poorer	poorer	better	better
9, 12, 13	Availability	part time	full time	full time	full time	part time	full time	full time
14	Ease of retrofit	easy	not easy	easy	easy	easy	easy	not easy
12	Complex configuration	adaptable	adaptable	less adaptable	less adaptable	not adaptable	easily adaptable	easily adaptable
14, 17	Simplicity	simple	more complex	more complex	most complex	complex	complex	complex
15	Ease of testing	easy	easy	difficult	more difficult	more difficult	difficult *	difficult
17	Ease of training	easy	easy	difficult	more difficult	difficult	easy	easy
18	Ease of maintenance	easy	difficult	difficult	difficult	easy	easy	easy
16	Cost	moderate	higher	higher	highest	higher	higher	higher

* Recent work has allowed the injection of "standard" data to statistical systems, simplifying testing

This approach, like the statistical methods, does not use a mathematical model for the transient pipeline hydraulics. Dealing with data noise and extracting information from noisy data is the main focus of this approach and it can, in principle, be used with other software-based techniques.

3.3.6 Summary of Software-Based Systems

For each of the categories listed previously, the implementation of the various algorithms can vary considerably. As a result, the performance of a particular method may be significantly different from another one in the same category. Furthermore, the boundary between categories can be blurred by hybrid approaches. For example, statistical analysis can be applied to volume balance, with pressure sensor-based linepack correction. Table 8 provides a summary of the categories in terms of key criteria given in Table 4, using the basic volume balance approach as the basis for the comparison. More detailed information on the design, implementation, testing and operation of software-based systems are covered in the relevant API document [13].

From Table 8 it can be seen that none of the methods is perfect. However, unlike the hardware-based approaches, most of the software-based systems are relatively easy to retrofit and in general do not require access to the pipeline over its full length, thus making them suitable for off-shore applications. In practice, to obtain the best performance in terms of response time and leak size detection, it may be necessary to upgrade existing sensors (flowmeters, pressure transducers etc) or add new ones (additional pressure transducers, temperature sensors, densitometers etc). In terms of the most important criteria (response time, leak size and ability to handle transient conditions), real-time transient modelling and statistical analysis appear to be the most successful but this must be balanced against their data requirements, complexity and cost.

3.4 System Selection

The selection of one or more leak detection systems must be made within the context of an overall pipeline integrity management plan [3]. This should contain full details of the pipeline, including associated facilities and their operations. The plan should contain (or reference) a full description of the technical methods and analyses of the threats to the integrity of the pipeline and the risks to the surrounding population and environment. Details of existing and any proposed new prevention, detection and mitigation practices should also be included, along with a justification for any scheduling applied, demonstrating that pipeline segments with the highest risk are prioritized accordingly. For example, ASME B31.8S standard [14] is specifically designed to provide the pipeline operator with the information necessary to develop and implement an effective integrity management programme for on-shore pipeline systems constructed with ferrous materials and transporting gas. Whilst this standard applies specifically to gas pipelines, the principles and processes embodied in its integrity management approach are applicable to all pipeline systems.

The plan should also address the responses to information collected during assessments, mitigation activities and other integrity-related activities. This will ensure that the plan is dynamic rather than static and so can be updated periodically to reflect any new information that may affect the pipeline integrity systems. This includes damage incidents or pipeline leaks, improved understanding of integrity threats, any changes in the operation of the pipelines or changes in the environment of the pipeline such as new mining/quarrying activity in the vicinity of the pipelines or changes to population density that may result in new pipeline segments covered by regulation.

At the detail level of selecting one or more leak detection systems, the first stage of the process is to address the questions given in Table 9. The answers to these questions will help to define the weighting to apply to the criteria listed in Table 4 and allow a decision-tree approach to be used for selecting the best available technique. Figure 6 illustrates this approach for single-phase sub-sea applications. The depth of the decision-tree can be extended to address more of the criteria in Table 4.

Table 9 - System Selection Issues

1 What are the expected operational features of the pipeline?	• steady state / frequent transients • single product / batch mode • single phase / multi-phase • shut in (no-flow) conditions • slack (localized flashing) conditions • variable pressure operation
2 What are the regulatory requirements?	• safety case • environmental impact assessment
3 What risks apply in the case of a leak?	• explosion / fire - release of explosive or flammable product • poisoning - rapid release of poisonous (to man / other species) substance • poisoning - slow release of bio-accumulating toxins • environmental damage • structural damage – rapid release of large volume of fluid
4 What is the role of leak detection in minimizing the consequences of a leak?	• detection of low-level leaks • rapid detection and location of large-scale leaks • estimation of release volumes
5 Where is metering located and what type is it?	• basic meter / smart meter • process / fiscal accuracy
6 What other instrumentation is available?	• temperature sensors • pressure transducers • densitometers • composition analysis
7 What will be the responsibilities of the operator / user?	• operator training • system optimization • system maintenance / testing

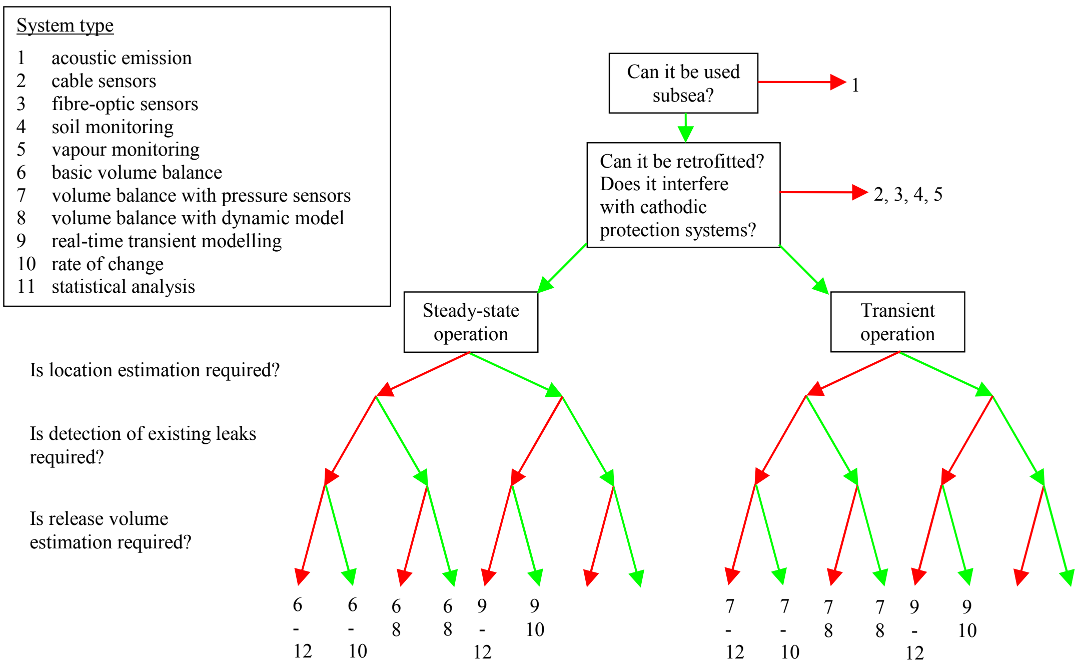


Fig. 6 – Best available technology for leak detection in subsea applications

4 CONCLUSIONS

Systems aimed at ensuring the integrity of a pipeline use a combination of operational procedures, maintenance procedures, and dedicated hardware and software as part of an overall pipeline integrity management system (PIMS) to provide advance warning of any events or changes in the physical state of the pipeline which may lead to a loss of integrity.

However, it is inevitable that leaks will occur. Leakage detection therefore forms a key part of the total strategy and the selection of one or more leak detection systems must be made within the context of an overall PIMS.

Although there is no single ideal approach, several of the currently available technologies can work in a complementary fashion, greatly expanding the range of leaks that can be detected.

In terms of the most important criteria (response time, leak size and ability to handle transient conditions), real-time transient modelling and statistical analysis appear to be the most successful but this must be balanced against their data requirements, complexity and cost.

It is clear that practices differ from sector to sector and the very different operational regimes of, and potential hazards from, oil, gas and water pipelines, mean that transferring best practice from one sector to another is not simply a matter of implementing an identical solution. The key recommendation with regard to the selection of any leak detection system therefore is that it must be made within the context of an overall pipeline integrity management plan [3,14]. This will ensure that, as far as possible, the system or systems chosen address the specific requirements of the pipeline and its interactions with its environment.

Even within each sector, there is considerable variation in best practice, both in terms of implementation by pipeline operators and the solutions offered by leakage detection system providers. Whilst the decision-tree-based approach can provide an indication of systems that meet the technical criteria, it is important to speak to other pipeline operators, in other sectors if appropriate, but certainly within the sector.

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