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Review

Roadmap for Recommended Guidelines of Leak Detection of Subsea Pipelines

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Abstract: The leak of hydrocarbon-carrying pipelines represents a serious incident, and if it is in a gas line, the economic exposure would be significant due to the high cost of lost or deferred hydrocarbon production. In addition, the leakage of hydrocarbon could pose risks to human life, have an impact on the environment, and could cause an image loss for the operating company. Pipelines are designed to operate at full capacity under steady-state flow conditions. Normal operations may involve day-to-day transients such as the operations of pumps, valves, and changes in production/delivery rates. The basic leak detection problem is to distinguish between the normal operational transients and the occurrence of non-typical process conditions that would indicate a leak. To date, the industry has concentrated on a single-phase flow, primarily of oil, gas, and ethylene. The application of a leak-monitoring system to a particular pipeline system depends on environmental issues, regulatory imperatives, loss prevention of the operating company, and safety policy rather than pipe size and configuration. This paper provides a review of the recommended guidance for leak detection of subsea pipelines in the context of pipeline integrity management. The paper also presents a review of the capability and application of various leak detection techniques that can be used to offer a roadmap to potential users of the leak detection systems.

Keywords: subsea pipelines; leak detection; asset integrity; pipelines monitoring; loss prevention

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1. Introduction

Subsea pipelines provide economic advantages with a long service life expectancy [1,2]. There is a shift in the industry from having a finite lifespan for subsea pipelines to the idea of keeping them operational for economic reasons [3]. This thinking turn requires some modifications that would have an impact that goes beyond just the maintenance procedure [3]. Such required modifications can extend to financial asset appraisal and environmental planning, as well as a variety of other areas of pipeline operation in an ever-changing world. Decades ago, there was a societal acceptance that the need for oil would require a parallel network of pipelines, which could leak. However, during the last two decades, leaks in pipelines have become unacceptable and as such, the industry standards have provided more guidance on this matter [4–7]. A leak in any hydrocarbon-carrying pipelines would represent a serious incident and if the leak was in a gas line, the economic exposure of the company would be great due to the high cost of lost or deferred gas production. Depending on the leak location, there could be risks to human lives and there would be some impact on the environment. In present times, industry and society do not accommodate leaks, and this is not confined to maintenance only but embraces everything from basic engineering and design philosophy to maintenance concerning inspection and repairs.

Most authorities such as Offshore Petroleum Safety Regulations [8] and Petroleum Submerged Lands and Management of Safety on Offshore Facilities [9] emphasize the potential consequences of subsea pipeline leaks for human safety and environmental pollution. Accordingly, pipeline integrity management frameworks must be in place to ensure the pipeline's mechanical integrity, prevent pipeline failure, avoid the release of fluids or hydrocarbons, and limit the consequences of leak occurrence. The consequences of a pipeline failure comprise economic, safety, environmental, and intangible socio-political concerns. Subsea pipeline leaks can also lead to negative publicity and forfeits, which can be slashed by adopting an appropriate pipeline integrity management and a rapid pipeline emergency response, by utilizing a leak detection system (LDS). Operators should also ensure that other mitigation measures are in place to prevent and monitor pipeline degradation, hence reducing the probability of leaks. Degradation of pipelines could be basically due to corrosion or mechanical damage; however, such degradation is likely to lead to failure and hydrocarbon leaks.

It should be noted that several regulators and authorities do not stipulate LDS for pipelines as an element of pipeline integrity management. However, most countries have legislations and regulations regarding pipeline safety, and utilizing LDS may assist in gaining appropriate regulatory approvals. For instance, LDS may assist pipeline operators to reduce the risk of the loss of containment. LDS is defined under the protective systems element in the pipeline integrity management framework. Pipeline integrity management and life extension require an understanding of two topics. Firstly, the significant threats and risks to integrity over the life cycle of a pipeline. Secondly, the key actions required to effectively manage and mitigate such risks. As a result, it is necessary to confirm that most design conditions are still valid, as changes in operational conditions—or even repurposing—would alter the design parameters. Increased water cuts in crude oil lines, changes in H_2S levels, and increased CO_2 levels internally or externally are examples of such alterations. These modifications may occur gradually without recognition. In terms of material quality, route, or specification, as-built pipelines or pipeline components may differ from the information provided in the design documentation. Also, external influences may increase the stresses in the pipe wall beyond the estimated measurements during the design stage; this occurs around anchors, crosses, and size-on-size trees. In some regions, even minor corrosion may be sufficient to cause a failure. Complex corrosion processes or fatigue cracking might hasten the deterioration of the pipe wall. Hence, routine checks and periodic inspections are important approaches to determine the progress of this deterioration process proportionately (i.e., growth of defects). Hence, there is a need to conduct a complete system integrity check. In principle, integrity means maintaining the asset (e.g., pipeline) wholly in an ever-changing environment, thereby preventing any potential failure. A leak in any of the hydrocarbon-carrying pipeline systems would represent a serious incident. For instance, if the leak is in a gas line, then the economic exposure of the company would be great due to the high cost of lost or deferred gas production. Recently, techniques based on the execution of transient tests were presented, e.g., [10,11]. The results of the transient field tests carried out for fault detection in the Trieste subsea were discussed and in particular, the numerical and analytical models used to analyze the pressure signals acquired during the transient tests.

The leak detection systems are categorized into the following groups according to their inherent principle of leak detection:

- Balancing of pipeline mass or volume input versus output.
- Pressure and/or flow analysis.
- Dynamic models.
- Monitoring of characteristic signals generated by a leak.
- Off-line leak detection.

Others classify leak detection systems in terms of internal and external monitoring methods. The internal methods involve intrusive measurements to monitor the fluid state, whereas the external methods are applied to the environmental condition of the pipeline. Several sources and articles that discussed the leak detection systems and methods including their theoretical aspects are available in the literature, e.g., [12–26].

This paper presents a state-of-the-art review of the policy legislations and guidelines on subsea pipeline leaks in the presence of significant threats that can potentially degrade pipeline conditions over the life of the pipeline asset. The paper presents an example of a gas release from a subsea gas pipeline. The gas releases near the FPSO (Floating Production Storage and Offloading) could result in sea surface fire and consequently, prolonged surface fires can cause structural damage to the FPSO and/or impair or even prevent evacuation of personnel (if the FPSO remains on station).

2. Assessment of Subsea Leak Detection Requirements

The following two regulations require "consideration" of the leak detection systems of some sort: (i) Offshore Petroleum Safety Regulations [8]; and (ii) Petroleum Submerged Lands and Management of Safety on Offshore Facilities [9]. Section 2.17 of [8] states that "The safety case for a facility must consider the incorporation into the facility of both automatic and manual systems for the detection, control and extinguishment of leaks or escapes of petroleum". Section 28 of [9] has similar requirements to [8] and states that "To consider incorporating systems in the offshore facilities that will reduce the risk of hydrocarbon leaks into the environment". Based on these excerpts from the regulations, it is inferred that the incorporation of dedicated subsea leak detection systems (LDS) is not mandatory for offshore facilities.

The following Australian standard is relevant for the assessment of leak detection requirements: AS 2885.4-2016 Pipelines, Gas, and Liquid Petroleum—Part 4: Submarine Pipelines [12]. This design code refers to the international pipeline design code DNV-ST-F101 [27]. The DNV code has no specific mention of LDS and hence it is assumed that the Australian code does not have requirements for the same. The following international industry standard is applicable for the design of subsea pipelines and production systems [11]: DNV-ST-F101-2021 Submarine pipeline systems, offshore standard. This international design code does not mention any mandatory requirements for the inclusion of LDS for subsea pipelines. DNV-RP-F302 industry-recommended practice [28] provides information on the selection and use of subsea LDS. Different types of leak detection techniques have been mentioned; however, the majority of leaks reported, as per statistics obtained by DNV, are either from Remotely Operated Vehicle (ROV) inspections or human observations. This leads to the conclusion that most operators rely on regular inspection programs rather than a dedicated LDS. The statistics also indicate that the largest hydrocarbon leaks occur during transient operations (such as start-up and shutdown) rather than steady-state operations, in which methods such as mass balance could not be relied upon.

3. Key Performance Indicators of Leak Detection System

3.1. System Sensitivity

The sensitivity of the Leak Detection System (LDS) is defined as a composite measure of the minimum size of the leak that a system could detect, and the required time for the system to release an alarm when a leak occurs. The response of the leak detection systems could significantly vary depending on the leak size. The response time could also be relatively independent of the leak size. The leak detection performance is usually defined in terms of detecting a particular leak flow rate within a specified minimum time. It should be noted that any adjustments made to improve the sensitivity of LDS may harm other aspects of performance. For instance, if the minimum leak detectable size is set too small within a specified time, then false alarms would occur more frequently. Furthermore, the system sensitivity is generally insufficient to detect corrosion pinhole leaks. The location and magnitude of the leak are also the output of a detection system, which therefore has a level of performance established by the minimal detectable size of the leak, the required time for detection (response time), the calculated size of the leak, and accuracy of measuring the leak rate. The performance of LDS can be stated in terms of contractual requirements, such as the minimum detectable leak rate, the time to detect the minimum leak rate, and the accuracy of the leak location/leak rate estimates [12–20].

Specific factors such as measurement, operational, data transmission, and model software are presented herewith. The measurement factor is related to instrument accuracy, repeatability and hysteresis, instrument drift, and temperature effects on transducer accuracy. There are numerous operational factors such as fluid type (i.e., gas or liquid), transients or dispatch and terminal points, load changes (i.e., turndown), line pack level, temperature variations, viscosity changes, controller setpoint changes, slackline flow, vapor/liquid phase changes, and multi-product batches. The factors that are related to data transmission include the resolution of A/D converters, noise filtering, and polling rate. Although model software includes the number and location of SCADA (Supervisory Control and Data Acquisition) points, uncertainty exists in fluid property calculations and ground thermal properties, as well as noise discrimination techniques [14–20].

A sensitivity study for leak detection is normally the basis of an acceptance testing procedure within the terms of a supply contract. For model-assisted systems, this is often a reimbursable study carried out by the pipeline leak detection manufacturers in advance of the vendor selection. The objective is to establish, for both the vendor and client, the operating limits of LDS to ensure an acceptable balance between the performance guarantees and any regulatory requirements. The advantage of the sensitivity study based on a specified pipeline configuration is that it provides an opportunity to test increments in the exact configuration of the pipeline and thereby reach an agreement on cost/performance. The sensitivity study is more representative of model-based leak detection than any hardware/electronic or chemical-based system and should be formulated about a range of expected operations for the pipeline. In practice, the sensitivity of LDS depends largely on the filtering techniques used to validate the leak alarms. Reasonable targets to be achieved for leak detection are in the order of the fluid (see Table 1).

Table 1. Leakage targets [12,14].

Service	Leak Size (%)	Time to Detect Leak (min)
Gas	10	120
Liquid	2	20

It should be noted that hardly any gas pipeline leak detection exists and the minimum leak that may be detected can be determined by other methods (e.g., odor or gas presence). For gas, leak detection is therefore questionable. For liquid, performance may be better than the above figures, particularly where the instrumentation maintenance is specially tailored to the leak detection requirements. The values indicated in Table 1 are largely independent of the pipeline length, given constant valve separation. The leak location times to $+/-1$ mile accuracy will in general take much longer (e.g., greater than five times) than the leak detection times [12,14].

3.2. Reliability

Reliability defines the maximum allowable spurious alarms per year. A reasonable target after the initial commissioning phase is four per year for a new LDS system. For existing systems, this may be unachievable, but the spurious alarm rate shall be subject to continuous monitoring and improvement. Any significant increase in spurious alarm levels shall be investigated and rectified.

3.3. Accuracy

Accuracy defines how accurate the leak size estimate and location estimate shall be. A reasonable target for this is +/−1% on leak size error and +/−500 m (1600 ft) on location error, but these values depend on the number of pressure readings along the pipeline [12,14]. As with sensitivity, the location error is dependent on leak size; larger leaks should be located more accurately than small ones.

3.4. Robustness

Robustness defines how the system is affected by the loss of one or more instruments. LDS design shall ensure that the loss of a single instrument does not significantly affect the performance of the system or only affects the smallest possible sections of the pipeline.

3.5. Measured Value Pre-Processing

Any method used for leak detection should apply appropriate signal pre-processing to measured variables to remove or reduce the impact of calibration errors, zero errors, drift, and noise before using them in models or calculations. Repeatability of instrumentation is generally much better than overall accuracy which is why statistical methods are preferred.

3.6. Transients

The LDS shall be designed to cope with normal operational transients without giving spurious alarms. The word "transient" should be clearly defined during the bidding process as some manufacturers only guarantee the performance of their system under steady-state conditions [12,13]. The LDS shall be capable of identifying normal operations such as starting/stopping pumps, opening/closing valves, changing pipeline rates, and receiving/launching pigs without affecting performance and without giving spurious alarms. If surge tanks are part of the system, lifting of surge valves under normal operation shall not be identified as a leak. However, a facility for checking the performance of the leak detection system using this displaced oil shall be provided [16–18].

3.7. Criteria for Selecting Leak Detection and Location Technology

The installation of a leak detection and location (LDL) system is a cost-benefit analysis. When choosing LDL equipment, many factors should be taken into account, as follows [15–23]:

1. **Soil Conditions:** Can affect the performance of LDL technology. Tracer gas, for example, migrates faster in dry, porous soil than in moist soil. Acoustic approaches may be influenced by the type of soil surrounding the pipeline. Salt-water areas impacted by tides give unique corrosion challenges for pipelines. Always keep the soil conditions in mind when looking for leak-detecting equipment.
2. **Water Table:** If the pipeline runs below the water table or the high tide level, several LDL procedures will not function. If the pipeline is beneath the water, tracer approaches are less successful because leaking tracer gas may be washed away before reaching a sensor. Alternatively, the tracer could migrate and be detected by a different sensor, suggesting a leak in the incorrect area.
3. **Pipeline Condition:** When choosing leak detection equipment, the age and condition of a pipeline are key factors to consider. To separate a leaking pipeline from a leaky valve, static pressure testing procedures necessitate contemporary, high-quality valves. Pigging may not be possible in older small-diameter pipes with abrupt bends.
4. **Operations:** Routine operations can have an impact on some LDL approaches. Temperature-compensated pressure tests, for example, must be performed while a pipeline is quiet, which may necessitate a brief halt in operations. Heavy traffic in the nearby region can cause acoustic techniques to be disrupted. Facility activities may obstruct pressure point analysis procedures.
5. **Time Monitoring:** Some LDL systems can identify leaks 24 h a day, seven days a week (continuous monitoring). Other techniques provide a snapshot, or assessment, of the

pipeline's current state. To implement a successful leak control program, regulators may demand that a snapshot technique be used at specific time intervals.

6. **Spatial Resolution:** Different levels of spatial resolution are provided by leak detection and locating systems. Pigging, cables, and acoustic techniques, when used correctly, can precisely find leaks. The accuracy of tracer leak localization, on the other hand, is a function of the spacing between sample points, whereas static pressure testing approaches do not detect leaks at all. Identifying a leak with one approach, such as pressure testing, and then locating it with another technique, such as tracers, is sometimes the best way to tackle leak detection difficulties.
7. **Volumetric Measurement of Leak Rate:** This leak detection technique offers a volumetric measure of the hydrocarbon leak rate. An example of this technique is temperature-compensated pressure testing. There are additional methods, such as product-sensitive cables. These additional methods indicate where the hydrocarbon has been identified but not how much is there.
8. **Ease of Retrofit:** Most piping systems have been in use for a long time. As a result, it is critical to consider whether LDL technology can be implemented into an existing pipeline. Some procedures, such as temperature-compensated pressure testing, can be used on most pipelines, new or old, with little difficulty. The hardware required for these approaches is not built into the pipeline system and can be brought in by the contractor doing the test. These systems, on the other hand, can be integrated into the system if it is proven to be cost-effective.

4. Leak Detection Methods and Current Industry Practice

4.1. External Leak Detection Systems

In the event of a reported incident or pipeline leak that may compromise the integrity of the pipelines, subsequent actions must be taken in a controlled, orderly manner, so that the effects of the incident are mitigated. The prime objective is to minimize the production shutdown time. To this end, this paper discusses and makes recommendations for the immediate response by operations. For instance, if seawater enters a gas export pipeline through a leak, there may be hydrate formation. Hydrate formation may greatly complicate the repair and should be avoided if possible. However, where the leak is sufficiently small, it may be possible to maintain sufficient pipeline pressure to prevent seawater ingress while mobilizing to carry out actions that will prevent hydrate formation. Maintaining pressure while mobilizing equipment will be an acceptable option from a safety point of view when the leak is of a size and location that it presents no hazard to the manned facilities or marine vessels. Unless the leak is extremely small, i.e., a "pinhole" leak, a guard vessel is considered necessary to exclude other vessels from the leak vicinity. Small leaks may grow due to creep or fatigue. If maintaining a certain level of pressure to exclude seawater ingress, the selected pressure should be lower than the pressure that existed when the leak was formed. A leak in any of the hydrocarbon-carrying pipelines would represent a serious incident. There would be potential for significant company image loss. A Crisis Management System that adequately addresses pipeline leaks and other serious incidents is therefore essential. The subsea pipelines can be inspected and leaks can be detected using techniques such as active and passive acoustic sensors, capacitance, fluorometry, and fiber optics, as follows [12–42]:

1. **Active Acoustic Leak Detection:** This technique uses sonar detectors that send out sound pulses, which pass through water and reflect upon contact with mediums such as gas or oil. The sound pulse deflects and returns to the sensor if the acoustic impedance of the medium (or leaking fluid) is different from that of water. The most used sensors are ROV deployable. It should be noted that using acoustic transmitters and receivers is common on a liquid pipeline. The acoustic transmitters and receivers are installed on a liquid pipeline at specific distances. The correlation between the signals transmitted and received is calculated to determine if a leak exists and its possible location. This method is since the acoustic properties will be changed due

to the presence of an opening in the pipeline. The distance between the transmitter and receiver is very short, usually a few hundred meters only. This leak detection system is highly sensitive to gas due to its impedance contrast with water, hence, a gas leak in water can be easily detected. Also, high gas rates and background noise can produce false leak detection.

2. **Passive Acoustic Leak Detection:** This method uses acoustic sensors that are either clamped onto the pipeline or deployed using an ROV. The clamp-on sensors are usually pre-installed on the pipeline at critical points such as joints, valves, flanges etc. or mounted on subsea structures such as manifolds, subsea trees, PTS etc., while the deployable sensors are brought in as part of the pipeline inspection service. The sensors detect the high-frequency sound produced by the leak and transmit signals via cable to the subsea control system (in the case of clamp-on sensors) or a receiver onboard the ROV (in the case of deployable sensors). This system detects leak rates as low as 0.1 L/min; Produces uninterrupted while monitoring for leakage; and Sensors are not affected by current, turbidity or visibility. High gas rates and background noise can mask the high-frequency sound of leaks; Deployable sensors cannot be used for continuous pipeline monitoring.
3. **Capacitance:** The capacitance method involves the use of sensors that can detect and measure changes in an electric property called capacitance in the medium surrounding the sensors. The capacitance varies for different fluids such as water, gas and oil and gives specific values for each of these fluids. In the event of a gas leak into the surrounding water, the sensors will indicate a change in the capacitance value. The sensors can be placed onto subsea structures or critical points on the pipeline such as valves, joints, flanges etc. This system provides high sensitivity when in contact with the leaking medium. It also needs to be in direct contact with the leaking fluid to detect it; the leaking medium can be affected by the surrounding current and move away from the sensor, therefore, a "hat" arrangement next to the sensor may be needed to capture the leaking hydrocarbons; and Positioning of the leak is difficult since the leak could have reached the sensor through drifting currents.
4. **Fluorometry:** Subsea pipeline leaks can be detected by inserting dyes into the hydrocarbon stream and the use of ROV-deployed sensors that use "special" light sources to detect the dyes that come out from the location of a leak. The system provides uninterrupted production during leakage inspection. It is also limited to a detection range of up to 10 m; cannot be used for continuous pipeline monitoring; requires ROV and so poor tidal conditions can make it difficult for ROV operations.
5. **Fiber Optics:** This technology uses a continuous optic fiber cable that runs parallel to the main hydrocarbon pipeline to help detect leaks along the pipeline. The fibers are noise-sensitive and can detect high-frequency noises created by leaks enabling them to locate the position of the leak along the pipeline. The optic fiber, depending on its type, can also detect leaks by comparing the temperature deviation of the surrounding environment against field-verified data. However, this type is considered less suitable for subsea applications since the accuracy of this method will vary with ambient current conditions [22,23]. This system detects leakage rates as low as 0.01 L/min; Identifies the location of the leak within the 1.0 m range; early detection of leaks can help reduce adverse environmental impacts; continuous pipeline monitoring without production interruption; and can be installed on buried pipeline section. It also represents expensive technology and therefore high CAPEX (Capital Expenditures).

4.2. Internal Software-Based Leak Detection Systems

The software-based LDSs mainly work on the principle that the mass or volume flow entering the pipeline should equal the mass or volume flow exiting the pipeline, as follows [12–26]:

1. **Pressure (only) Monitoring:** This is the simplest technique for leak detection. The pressure is monitored at the inlet and outlet of the pipeline using pressure transmitters

and a rate of change of pressure beyond the expected threshold during a steady-state operation indicates a leak in the system. This system does not require any additional instrumentation, hence overall system reliability is not affected; and early detection of large leaks is possible, as it is immediately reflected in the system outlet pressure. It also detects only large leaks; and cannot determine the size of the leak; the accuracy of measurement is heavily reliant on the accuracy of the pressure transmitter; and is not ideal for transient operations and multiphase flow due to large pressure fluctuations. In other words, if the acoustic pressure waves and real-time transient techniques are used for leak location in the leak detection system, the pressure transmitters should be fast-acting in the order of 0.1 s including any time delay for the diaphragm seals. The time stamping of the Integrated Control and Safety Systems (ICSS) controller shall be 0.1 s or faster or the location error will increase. Operators must differentiate between deliberate changes in operating conditions and leaks. The pressure monitoring cannot estimate the leak location. Pressure monitoring is not very good at detecting small leaks, especially in long pipelines that produce only a slow variation in pressure or flow. The pressure monitoring cannot detect steady-state leaks.

2. **Mass or Volume Balance:** This method typically checks the mass balance over various time windows to detect large, medium, and small leaks, respectively. The method may use pressure and temperature measurements to compensate for inventory changes. The main drawback of this method is that long averaging times are needed to indicate leaks without generating false alarms. This technique involves monitoring the fluid flow rate at the inlet and outlet of the pipeline and a leak is evident when the mass rate exiting the pipeline is lower than that at the inlet. The flow rate is measured using flowmeters at either end of the pipeline and the data are transmitted to the Integrated Control and Safety System (ICSS) system on the platform or the onshore plant. This system relies on existing instrumentation such as flowmeters and PT transmitters, therefore, additional instrumentation is not required, and relatively cheaper technology. It also works well only for steady-state operations; the accuracy of measurements is heavily reliant on the accuracy of flowmeters and leaks could be undetected if the quantity of the leak is smaller than the measurement error (i.e., 1% error in the flowmeter measurement will not be able to detect a leak smaller than 1% of the total flow when producing at steady state); and requires sufficient measuring instruments both subsea and topsides to accurately track transient conditions. The minimum requirements for the overall performance of a multiphase flowmeter with respect to accuracy and repeatability of measured/computed flow rates of individual components shall be as below or better:
   - Uncertainty: Liquid flow rate +/−10%, Gas flow rate +/−10%, Water cut +/−10%.
   - Repeatability: Oil flow rate +/−2%, Water flow rate +/−2%, Gas flow rate +/−2%.
3. **Real-Time Transient Modeling:** The real-time transient modelling (RTTM) method uses a dynamic software model to track the transient conditions (mainly pressure and flow rate) of the subsea pipeline. The derivation of the principal equations of fluid dynamics for the dynamical behavior of a fluid is determined by the following conservation laws, namely [29]:
   - Conservation of mass.
   - Conservation of momentum.
   - Conservation of energy.
   - Equation of state for the fluid.

   The above conservation laws can be collected into one system of equations (i.e., conservation of momentum and conservation of energy are not independent) to a better overview of the various terms involved. For instance, a flow field is characterized by balance in mass, momentum, and total energy described by the continuity equation, the Navier-Stokes and Euler equations. The model is tuned with numerous simulated operation scenarios and compares the real-time measured flow conditions against the predicted values for any particular operation. A mismatch between the measured and predicted values indicates a leak in the system. This technique is an advancement of the mass balance method. The dynamic model method uses equations of state to mathematically emulate the fluid flow within the pipeline. The deviation between modelled variables and measured pipeline variables is theoretically indicative of a leak condition. This method, however, has historically proved difficult to successfully implement for online applications. This is due to the complexity of the modelling variables and calculations required. Typically, problems with tuning and high false alarm rates have prevented the successful implementation of a reliable system of this type. The system spans a wide range of applications apart from leak detection, such as hydrate formation risk analysis, pig tracking, slug tracking, pipeline blockage, corrosion rate, etc. It also provides a leak detection rate that varies widely from 1% to 10% of the maximum production throughout depending on:

- Trained personnel required to use and maintain the RTTM software.
- Instrumentation accuracy.
- Accuracy of detecting leak rates, which vary depending on the accuracy of flowmeters and PT transmitters.
- The complexity of the system, which:
  - May not detect very small leaks such as that capable with hardware-based LDS.
  - May not accurately identify the location of the leak.
  - May require extensive additional instrumentation for real-time data tracking.
  - The system is based on driven data that are completely dependent on qualitative and quantitative data available from the pipeline systems.
  - RTTM system makes it difficult to anticipate all possible operating scenarios that might occur during pipeline operations.

4. **Statistical Pipeline Leak Detection System (SPLD):** Dynamic models have proved to be of high initial cost with a high cost of ownership and no great improvement of sensitivity over that of the Statistical Pipeline Leak Detection (SPLD) system. In other words, SPLD requires a high initial cost and is additionally difficult to implement for online applications. This is because the calculation and modelling required are quite complex and this approach is not reliable for implementation due to the high false alarm rate [30]. SPLD applies a mass balance principle; over a small interval of time, the difference between the mass entering and the mass leaving the pipeline should be equal to the change in the inventory. The mass flows in and out of the pipeline are obtained from the flow meter readings and the inventory changes are estimated from the pressure measurements at the ends of the pipeline. At each sample time, t, a mass imbalance, $\tau(t)$, is calculated. In general, $\tau(t)$ is non-zero due to instrument errors. Over a while when there are no leak alarms, the mean (m) and variance (σ^2) of $\tau(t)$ are calculated. Then, at each sample time, the latest series of values of the mass imbalance $\{\tau(1), \tau(2), \ldots, \tau(\mathrm{t})\}$ is subjected to analysis to determine whether or not the fluctuations are statistically significant. The leak-free hypothesis H_0 is that $\tau(t)$ is Gaussian with mean m and variance σ^2. The leak-present hypothesis H_1 is that $\tau(t)$ is Gaussian with a mean ($m + \Delta m$) and variance σ^2. By repeating the statistical significance tests for different values of Δm, checks can be made for the presence or absence of leaks of different sizes. The rules applied for decision-making are developed to give desired values of the false alarm probability and the missed alarm probability. At any sample time, the current decision will be to accept hypothesis H_0 (no leak), to accept hypothesis H_1 (leak), or to accept neither of these hypotheses. SPLD is tuned to interpret a non-zero mass imbalance as an instrument error. A small leak that is growing with time (e.g., a corrosion pinhole) could therefore be misinterpreted as increasing instrument drift. After a leak is detected, its location

can be estimated using the SPLD. The SPLD is claimed to be able to detect leaks of 0.5–2% of the design flow rate and to locate them with a typical accuracy of ±15% of the pipeline length [24]. The accuracy of location could be worse than this for small leaks that are only just detectable or for very large leaks that upset the pipeline dynamics. The performance of the SPLD will be judged mainly on the following system attributes:

- Accuracy of detecting leaks of different sizes.
- False alarm rate.
- Missed alarm rate.

Lesser factors to be considered in selecting a system would be:

- Capital cost.
- Operating cost.
- Reliability, availability, and maintainability under conditions of continuous use.
- Level of technical expertise required to maintain the system.

4.3. Off-Line Leak Detection Methods

Some of the traditional offline leak detection methods are given below. These techniques are generally performed during an inspection and maintenance program and when production is stopped. The pros and cons are not mentioned for these techniques as they generally form part of the operator's regular leak inspection service as required by regulatory bodies, as follows [31–34]:

1. **Aerial/Ground Line Patrol:** The subsea pipelines can be visually inspected for leaks during regular inspection services throughout production life. This is conducted with the help of an aircraft or boat, which goes along the pipeline route inspecting for bubbles on the surface of the sea. If supply vessels travel along the trunkline route, this will allow regular inspection. This method can detect only large leaks of gas, but condensate leaks will be visible.
2. **Static Pressure Test:** It is well known that the pressure in a pressurized pipeline drops if there is a leak in a pipeline. Every pipeline normally undergoes a hydrostatic pressure test to prove the strength of the pipeline materials following construction and before operation. The hydrostatic test pressure and test segments of the pipeline are usually selected to achieve certain stress within the pipe walls during the hydrostatic test that is close to, but not exceeding the specified minimum yield strength of the pipe material as defined by the design code. The test media is usually water, although in some limited cases (e.g., dedicated aviation facilities with no facility for flushing/drying), the product itself might be used as the test media. As a condition of the regulatory process, many liquid pipelines are required to be pressure tested regularly. This may be annually, bi-annually, or at some other specified interval. This pressure test would normally be undertaken with the conveyed fluid, under static conditions at a pressure typically around 110% of the maximum allowable operating pressure. Most pipelines are not subjected to periodic in-service pressure tests. The use of the static pressure test can assist in identifying the location of the leak easily. However, the use of the static pressure test can result in enlarging an existing defect and activating it to grow. During the pressure test, a biodegradable tracer dye may be injected to provide visual evidence of a leak to aid leak location. The environmental impact of such dyes shall be assessed and confirmed as acceptable before use.
3. **Shutdown and Monitor Pressure Decay:** This method is simpler than the previous method and simply monitors for pressure loss in the pipeline once the pipeline is shut at both ends. The pipeline is not pressurized but is generally at the normal operating pressure before a shut-in.
4. **Pipeline Survey by ROV:** A survey of trunkline, flowline, and subsea structures by ROV will be carried out regularly and will detect leaks.

5. **RADAR Detection:** This technique can be used for the detection of oil or condensate on the surface of the sea.
6. **Satellite Detection:** Detection of oil on the surface of the sea can be performed from satellites.
7. **Acoustic Techniques:** The "acoustic pressure waves" or "real-time transient" model technologies can be included in the LDS. Acoustic pressure waves give a quick result but can miss the initial pressure spike that is generated when the leak first occurs (i.e., the spike pressures generated when the liquid flow is suddenly stopped). It requires fast-acting pressure transmitters and a fast scan time on the applicable Integrated control and safety system nodes. To overcome propagation delays, the recommended practice would be to trap the detection "event" within the local controller, exploiting its fast-scanning capability. Each event, together with its accurate time stamp, would then be transmitted to the master leak detection system for analysis. Real-time transient models take longer to determine the leak location and may not reach an accurate conclusion before block valves are closed. If the leak location is of prime importance, both acoustic pressure wave and real-time transient models shall be employed.
8. **Leak Detection by Dye Injection:** If the leak is so large that the pipeline has flooded and the gas emission has stopped before the leak has been located, then it is possible in principle to pump inhibited seawater and dye into the pipeline. During pumping, an ROV fitted with a color camera, ultraviolet light, flow meter, and hydrophone can fly along the pipeline to locate the leak.
9. **Intelligent Pigging:** Leak detection may in principle be carried out with the use of pigs, though only if the line is still piggable. The commonly used pigging methods include:
10. **Acoustic Pig:** This is used in liquid-filled pipelines. Tracked by a surface vessel, the pig is inserted into the pig launcher end and driven down the pipeline. If the isolation valve on the receiver end is closed then the only route of escape for the fluid in the pipeline is through the leak. When the pig reaches the source of the leakage, the liquid ahead of it is incompressible and stops. A diver or ROV may then locate the pig within the pipeline accurately with an acoustic tracker.
11. **Hydrophone Pig:** A hydrophone pig contains a data storage and tracking unit. The sound of escaping fluid at the leak is picked up by the hydrophone and stored electronically together with the instrument running time. After the arrival of the pig at the receiver end, a plot of the noise level or frequency versus the real-time can be obtained. This plot shows the time at which a leak was located. The location of the leak is determined from the accurate record of fluid flow. Alternatively, the pig may be fitted with an acoustic pinger and tracked as it travels down the pipeline by a surface vessel to produce a plot of the pig's position in real-time.
12. **Barrier Pig:** This is designed to provide a high-pressure temporary blockage that can be set at any desired location in the pipeline. Leak detection is carried out by hydrostatic pressurization of the pipeline section between the pump and the barrier pig (which would be a major operation for a long pipeline). If no pressure drop occurs, the pig is pumped further along the pipeline and set. Pressurization and checks for leaks are carried out again. This process is repeated until the pig has moved past the leak; at which time the pressure drop will indicate the presence of the leak. The approximate location of the leak is, therefore, between the latest and the previous pig position.
13. **Constraints on Use of Leak Detection Pigs:** This includes the following:
    - The risk that the inspection pig (or any preceding gauging pig) may become jammed at the damaged section of the pipeline or on hydrates in deepwater sections of the pipeline.
    - The difficulty of controlling a pig in a gas pipeline with great changes of elevation unless an adequate backpressure exists in the pipeline.
    - The availability of suitable pigs.

4.4. Survey, Inspection, and Damage Investigation

A leak would typically come to light or be suspected from a survey report, an incident report or PIMS (Pipeline Integrity Management System) alert. A wide range of survey techniques is available for leak location or damage assessment including [25–34]:

- Helicopter or fixed-wing aircraft.
- Towed fish.
- Remote-operated towed vehicle (ROTV).
- Autonomous underwater vehicle (AUV).
- ROV/diver.
- Pigging.

The selection of a particular method depends on the nature of the reported incident and the anticipated nature of the damage, equipment availability, water depth, and local conditions. The objective of the survey is to locate the leak or confirm its position and to determine the nature of the damage, including the leak size and whether it is associated with any geometrical defect such as denting or buckling or metal loss such as gouging. The following subsections describe the above-listed techniques.

1. **Fixed-wing Aircraft and Helicopters:** Due to their speed and long range, fixed-wing aircraft are the preferred means of confirming the location of a leak and for making estimates of the bubble plume diameter, from which the leak rate and size may be inferred. Helicopters could also be used but have limited flight time due to refueling needs. The average round trip for a helicopter is only about 260 miles so for example, the whole gas export pipeline could not be covered by a single helicopter flight. However, the emergency controller may check the availability of helicopters in the field and may use them if it seems that they might have adequate capabilities for the task at hand. Fixed or rotary-wing aircraft envisaged for use in a leak detection operation should be provided with the pipeline route coordinates as a series of waypoints for navigation. Where an aerial detection of a suspected leak has failed, or where the size of the leak is believed to fall below that suitable for aircraft search and detection, then underwater search techniques must be considered.
2. **Towed Fish:** Towed fish deployed sensors can be mobilized onto standard-sized survey vessels (50–60 m length), supply vessels or other vessels of opportunity, dependent on availability and urgency. The use of towed fish allows a faster rate of pipeline search than an ROV inspection/search and can be conducted without the need for a dynamically positioned support vessel. Tow speeds of up to 6 knots may be achieved, enabling up to 200 km of pipeline to be covered in 24 h.
3. **Remotely Operated Towed Vehicles:** Remotely operated towed vehicles (ROTV) comprise a box-kite construction tow vehicle, with maneuverability achieved via vertical and horizontal flaps on the leading edge of the vehicle, controlled by pilot joystick operation, with any gross position changes being made in conjunction with vessel helm action. The detection of any leak would be enhanced by the ability to control with precision the sensor platform for the pipeline. The use of ROTV deployment combined with Ultra-Short Baseline (USBL) acoustic positioning would enable this level of confidence to be obtained at relatively high speeds of line-kilometer coverage. If the ROTV was fitted with side-scan sonar, then the fish could be maintained at the correct offset to the pipeline, irrespective of USBL quality, sufficient to allow the search to continue.
4. **Autonomous Underwater Vehicle:** The development of autonomous underwater vehicles (AUV) in recent years, if the potential can be fully realized, should lead to survey and inspection applications which would obviate the need for tethered ROV and DP support vessels. The AUV concept involves a mobile, self-propelled instrumentation platform fitted with actuators, sensors, and onboard intelligence designed to complete tasks autonomously. The navigation for an AUV mission entails the vehicle following a pre-programmed route, using a combination of positioning

techniques, appropriate to the task. It is conceivable that an AUV could be stationed at the offshore platform from where it could be deployed for both structure and pipeline inspection, being fitted with acoustic, visual, CP, NDT, and leak detection sensors. Given the known coordinates of the pipeline and the associated terrain model, the AUV would navigate using Doppler velocity-aided DGPS in conjunction with terrain-following techniques and/or pre-installed acoustic reference beacons. This is the case for at least for the early stages of the Malampaya field life; however, it is unlikely that such technology would represent a viable leak location tool [17].

5. **ROV/Diver Operations:** The mobilization of a diving support vessel for diver range survey and investigation would normally include a Remote-Operated Vehicle (ROV) spread for the initial search. The use of ROV can be severely limited by low visibility and high seabed currents. Operational limitations need to be balanced against the inspection data required. Once the leak or damage has been located, a full diver/ROV survey may need to be carried out to detail the actual leak or damage. The type and size of the ROV would be dictated by the actual location of the leak (water depth, current regimeb etc.). The positioning of the leak by other methods is considered a cost-effective solution before the mobilization of an ROV of size and power sufficient to cover the complete range of depth and current scenarios that exist on the pipeline routes.
6. **Leak Detection by Pigging:** Leak detection may in principle be carried out with the use of pigs, though only if the line is still piggable. The risk is that the inspection pig (or any preceding gauging pig) may become jammed at the damaged section of the pipeline or on hydrates in deepwater sections of the pipeline. The difficulty of controlling a pig in a gas pipeline may lead to great changes in elevation unless an adequate backpressure exists in the pipeline. In addition, it is considered that less complex methods (namely PIMS and visual observation) are available for leak detection for the gas export pipeline. Pigging methods include:
    - **Acoustic Pig:** This is used in liquid-filled pipelines. Tracked by a surface vessel, the pig is inserted into the pig launcher end and driven down the pipeline. If the isolation valve on the receiver end is closed then the only route of escape for the fluid in the pipeline is through the leak. When the pig reaches the source of the leakage, the liquid ahead of it being incompressible will stop. A diver or ROV may then locate the pig within the pipeline accurately with an acoustic tracker [35,36].
    - **Hydrophone Pig:** A hydrophone pig contains data storage and a tracking unit. The sound of escaping fluid at the leak is picked up by the hydrophone and stored electronically together with the instrument running time. After the arrival of the pig at the receiver end, a plot of the noise level or frequency versus the real-time can be obtained. This plot shows the time at which a leak was located. The location of the leak is determined from an accurate record of fluid flow. Alternatively, the pig may be fitted with an acoustic pinger and tracked as it travels down the pipeline by a surface vessel to produce a plot of the pig's position in real-time.
    - **Barrier Pig:** A barrier pig is designed to provide a high-pressure temporary blockage that can be set at any desired location in the pipeline. Leak detection is carried out by hydrostatic pressurization of the pipeline section between the pump and the barrier pig (which would be a major operation for a long pipeline). If no pressure drop occurs, the pig is pumped further along the pipeline and set. Pressurization and checks for leaks are carried out again. This process is repeated until the pig has moved to pass the leak, at which time the pressure drop will indicate the presence of the leak. The approximate location of the leak is, therefore, between the latest and the previous pig position. Constraints to the use of leak detection pigs include:

7. **Photography:** Underwater photographs of 35 mm of the damage will be more useful than videotape alone, because of the higher resolution. These photographs should be taken with an underwater scale in each shot. Video can be used to provide supplementary information. This technique applies only to gas leaks.
8. **Impressions and Castings:** Castings and impressions of dents, gouges, scratches, and cracks can be made by diver or ROV, although accessibility in some locations will deny ROV access.
9. **Measurement:** This includes the taut wire measurement of deflections; scale measurement from datum points; and straight edge measurements of dents and deflections.
10. **NDT Methods:** Divers or an ROV can perform non-destructive testing techniques, subject to limits on access by ROV, including:
    - Ultrasonic A scan UT with angle probe, or radiography with localized gamma source, for surface and sub-surface crack detection.
    - Magnetic particle inspection, or eddy current technique, for surface defect detection.
11. **Engineering Assessment:** An engineering assessment of the pipeline damage, together with the relevant as-built data and previous inspection data, is required to determine whether a repair is required. The aim here should be to avoid overreaction and unnecessary repairs. If a repair is required, the important factor will be to plan the repair to minimize production downtime. The repair costs themselves will be a secondary consideration.

4.5. Damage/Leak Classification and Reporting

Completion of a leak or damage data sheet may be assisted by the inclusion of a damage classification table as shown in Table 2.

Table 2. Damage/leak classification [3,27].

Global Damage (GD)	Local Damage (LD)
Deflected Pipeline Buckled Parted Impacted	Dents Abrasions Weld Defects Gouges Scratches
Coating Defects	**Corrosion**
Cracks Impact damage Exposed reinforcement Abrasion Spalling	General Pitting Galvanic Fatigue

The following information about the location and extent of damage is required:

- Water depth and Transverse Mercator (PTM) coordinate the damage.
- Damage assessment.
- The number of the nearest field joint.
- Distance of the damage from the nearest field joint.
- Details of the seabed conditions.
- Burial status of the pipeline.
- Concrete coating.
- Debris in the surrounding area.
- Clock position of the longitudinal seam weld.
- Whether the pipeline remains piggable.

4.6. Machine Learning and Data Acquisitions

The expansion of subsea fields has exceeded some of the leak detection capabilities. It is difficult for example to quantify the actual characteristics of a leak on a long-distance pipeline. Recent work and development utilize machine learning methods with dynamic modelling to overcome the limitations of conventional leak detection systems [41]. Similar methods have growing potential, with reliance on modern data acquisition systems and field data gathering. The actual leakage database will expand this method in the future. However, the weaknesses of these methods are like all machine learning approaches, which are sensitive to data quality. Users should not rely on this method if high-quality data are unavailable.

In recent years, some leak detection methods [37–40] have been developed and involved the use of machine learning (ML), which is a subset of artificial intelligence (AI). ML-AI modelling has the capability of simultaneously detecting the leak size and location, but the modelling effectiveness requires creating a link between the actual data in the fields where quick response and accurate detection are required.

4.7. Underwater Gas Release and Dispersion from Subsea Gas Pipeline Leak

The release of gas from a subsea pipeline can cause a gas cloud close to the sea surface. It should be highlighted that an explosion is likely to take place due to an ignition source (for instance a passing ship in the proximity of the gas cloud) if the gas cloud is close to the sea surface and attains a critical air-to-gas ratio. Therefore, it is imperative to determine the dispersion and consequence of such a gas leakage scenario. The consequences in terms of a gas cloud relate to the events outlined in Figure 1.

- Although, this section and subsections focus only on a gas pipeline leak. In the case of a multiphase (i.e., gas, oil, and water) pipeline leak, the time needed by the oil to reach the surface is longer than the gas. Consequently, a higher spread occurs for the oil and oil slick dimensions are higher than the bubbling area (for the gas). For the multiphase pipeline, the analysis of the vaporization process following the pool/slick formation during the leakage transients should be conducted; this is to determine the following:
- The source term definition for the Pool Fire impact evaluation in case an immediate ignition occurs.
- The potential contribution to the Flash Fire impact evaluation in case of delayed ignition.

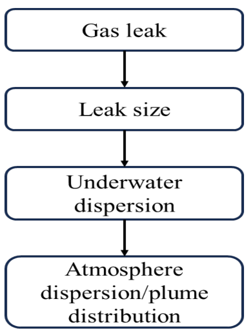

Figure 1. Diagram of the consequence of a gas cloud.

4.7.1. Hazard Description

A release of hydrocarbons from a subsea pipeline could be due to the following reasons [3]:

- External impact from the following sources:
    - objects dropped from the offshore facility.
    - objects dropped from the mobile offshore drilling unit (MODU).
    - shipping including anchor, anchor chain impact and dragged anchors.
    - future construction.

- inspection, monitoring or maintenance, and repair (IMR) campaigns.

- Corrosion (internal and external).
- Natural hazards.
- Structural damages.

Below is an example of a subsea gas release which results in a plume of gas rising to the surface and forming a "boil" area, i.e., an area where gas bubbles from the subsea release break through the surface. If the gas release rate is large enough, a flammable cloud is formed above the area of the release, sometimes extending hundreds of meters [42] (see Figure 2).

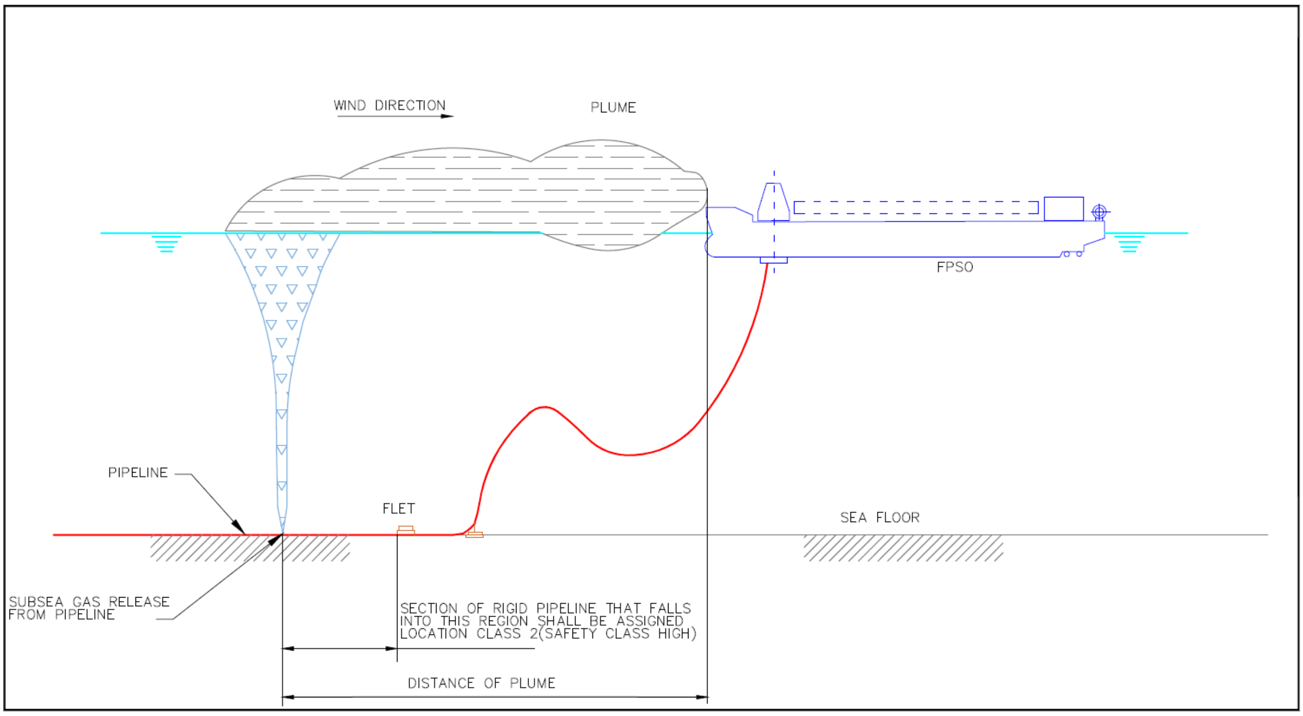

Figure 2. Consequence of subsea gas release.

For releases near the FPSO (Floating Production Storage and Offloading), current studies indicate the prevailing heading of the FPSO aligns with the prevailing wind directions. It is highly unlikely that the FPSO will be aligned opposite to the wind direction. Therefore, it is considered that the worst credible case is a release that is upwind from the FPSO and the cloud and the FPSO are aligned with the wind, as shown in Figure 2. If the gas cloud reaches an ignition source (e.g., on the FPSO), a flash fire or explosion can occur with the potential to result in multiple fatalities i.e., a major accident event (MAE). The release will then burn back to the boil area and continue as a sea surface fire over the release area with the firebase diameter usually taken as approximately equal to the boil area diameter. Sea surface fires, depending upon the release rates, can be several meters or even tens of meters high. Prolonged surface fires can cause structural damage to the FPSO and/or impair or even prevent evacuation of personnel (if the FPSO remains on station). Depending on the quantity released, hydrocarbon liquids from the infield flowlines could result in environmental impacts.

4.7.2. Leak Size

Equations that can be used to provide an understanding of the significance of subsea leaks of different sizes rely on the following items [42–50]:

- Minimum detectable leak size.
- Effect of pipeline pressures and flow rates.

- Bubble plume diameter.
- Flame height for ignited bubble plume.
- Sufficiently small leak size that can be regarded as non-hazardous.

4.7.3. Underwater Dispersion

It can be seen from Figure 3 that the released gas from the damaged subsea pipeline will tend to disperse into the nearby water column in a cone-like shape while heading towards the sea surface. This underwater dispersion can be split into three flow zones:

1. Flow Establishment (ZOFE).
2. Established Flow (ZOEF)
3. Surface Flow (ZOFS).

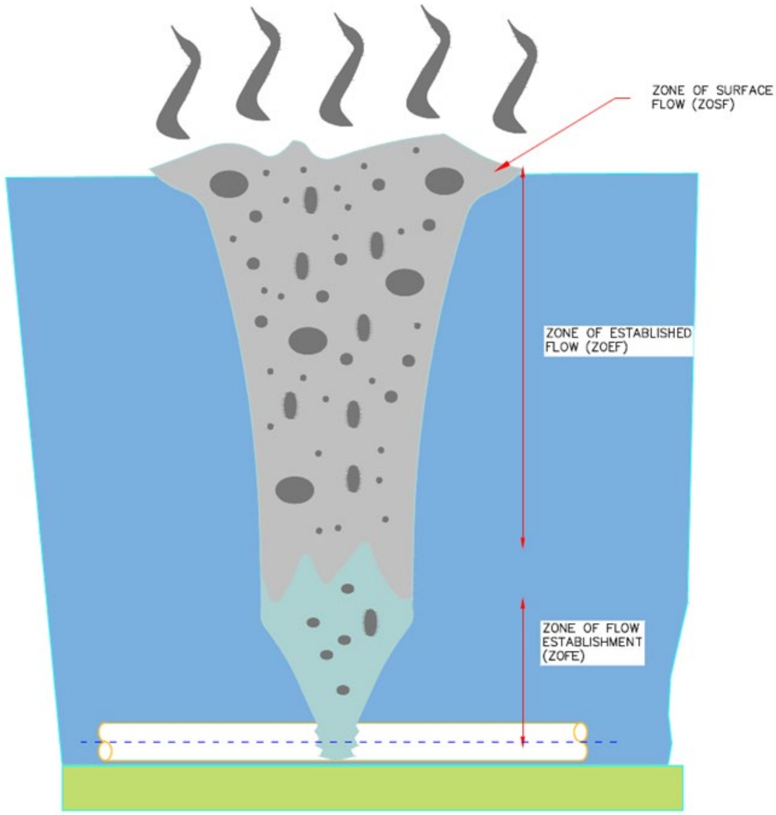

Figure 3. Gas Release from a Rupture Subsea Pipeline [43–46].

Due to the pressure gradient inside and outside the pipeline and the relatively low density of the gas (compared to the water), the gas release will assume a jet-like shape in the ZOFE. Further away from the pipeline, the velocity of the released gas decreases while the buoyancy takes over, and the shape of the gas release turns into a cone-like shape [43–46].

In the ZOEF, the diameter and cone-like shape do not change much towards the surface of the ocean. The diameter widens in the ZOFS region due to the interaction with the stirred surface water creating a gas pool on the surface of the ocean. The pool diameter can then be used to estimate the gas dispersion into the atmosphere.

4.7.4. Atmosphere Dispersion

When the gas reaches the sea surface, an interaction with the atmosphere occurs and the gas begins to disperse into the atmosphere. Depending on the wind speed, people can be affected due to the distribution of the critical distance of the gas cloud. The extent of the critical gas cloud is therefore essential to be assessed. As illustrated in Figure 3 the released gas reaches the surface, and the wind disperses the gas over a critical distance at which passing vessels can ignite [29,49]. To assess the extent of the gas cloud and critical distance, a criterion for the Lower Explosion Limit (LEL) can be applied. The LEL is the lower explosive limit of combustible gases in a mixture. In the example shown in Figure 4, the critical gas concentration concerning possible ignition is assumed to be ½ LEL in compliance with the normal practice for risk analysis implemented in the oil and gas industry. For the natural gases, the LEL is approximately 4.7%; hence, the ½ LEL is approximately 2.35%. The red color in Figure 4 indicates the Upper Explosive Limit (UEL). Concentrations higher than the UEL are "too rich" to burn. The yellow color in Figure 4 indicates the area with the LEL of approximately 4.7% natural gas while the white color marks the area where the ½ LEL of approximately 2.35% natural gas is achieved. To evaluate the plume distribution of the gas dispersion into the atmosphere, wind speed together with gas mass flows and the gas pool diameter should be considered.

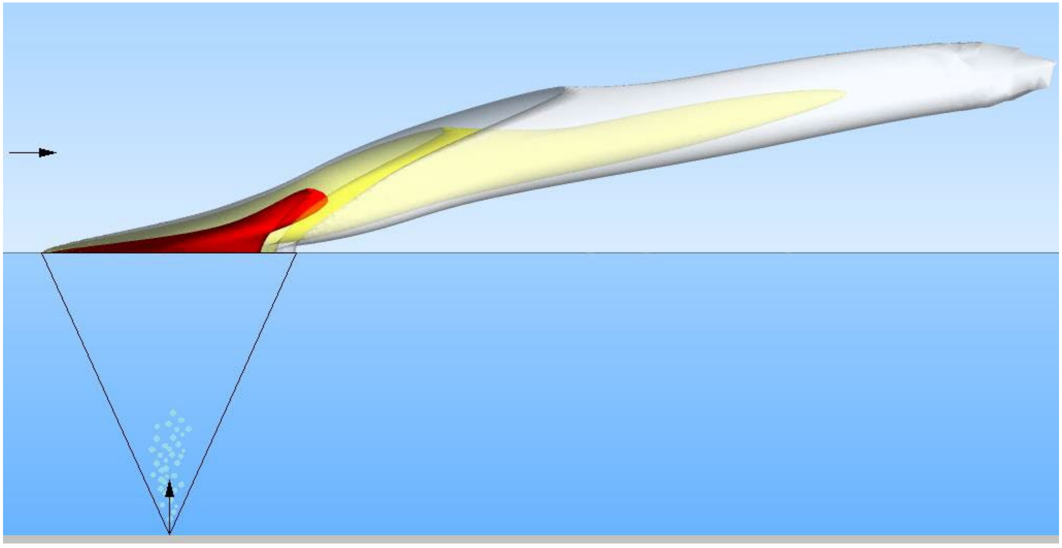

Figure 4. Illustration of gas dispersion into the atmosphere [43–50].

4.7.5. Anti-Hydrate Strategies

When the seawater enters a leaking pipeline, hydrates may form and persist in the flooded sections of the pipeline. The extent of flooding is dependent on the seabed topography and the shape of the location of the leak on the circumference of the pipe. On detection and location of a pipeline leak, it is necessary to estimate the extent of pipeline flooding and possible hydrate formation to allow the most appropriate repair and re-commissioning procedures to be implemented. An estimate of flooding and hydrate formation should therefore be included in the leak response plan to provide input to the subsequent repair and re-commissioning activities. When the internal pipeline pressure approaches the external hydrostatic pressure at the leak site, seawater will start to enter the pipeline. Gas will either escape through the leak or become trapped at high points in the line as shown in Figure 5. The flooding will stop when the hydrostatic pressure at the leak is balanced to each side by the head in the pipeline. Where trapped gas exists at high points in the pipeline, the head in the pipeline will be the sum of the individual hydraulic heads plus the gas pressure at the pipeline end. These principles may be used to make a rough estimate of the extent of flooding.

The following strategies can be considered as avoidance measures for a gas pipeline to avoid hydrate formation inside the pipeline:

1. Purge gas from the pipeline before seawater enters the pipeline: This strategy is to maintain sufficient pressure to prevent seawater ingress while mobilizing for further actions. Then hydrocarbons would be displaced using a flooding pig train, consisting (sequentially) of pig, nitrogen, pig, methanol, pig, and seawater. This approach is feasible for small leaks with no associated denting.

2. Isolate the pipeline on one or both sides of the leak as necessary to prevent water from running down to depths where hydrate can form: This approach could be applied for a small leak with no associated denting near the landfall. Isolation could be made utilizing a high differential pig train (primary isolation) and an inflatable sphere (secondary isolation). This would prevent seawater from reaching depths in the pipeline where hydrates might form, and it would have the added advantage of avoiding flooding of most of the pipeline. The isolations could be removed following repair by pigging them out with gas when the pipeline is repressurized.
3. Maintain as much gas pressure at the pipeline ends as possible to limit flooding: This strategy amounts to simply avoiding unnecessary depressurization at the two ends of the pipeline. This will minimize flooding. This then gives the possibility of (a) sealing the leak in some way and (b) venting the gas trapped at the pipeline ends. In some cases, the venting process may reduce the pipeline pressure sufficiently to dissociate any hydrates that may have formed. This strategy is not an alternative to the others but is considered a generally sensible initial response, for all leak sizes. Other strategies may be applied as well if applicable.
4. Reduce pressure (but not below hydrostatic) if the leak is coming from a flange to see whether the leak stops: If the leak from the flange stops on reduction of pressure, then retighten bolts and repressurize the pipeline. This may in some cases resolve the problem; if not, Strategies (1) or (2) should be applied depending on the flange location. Strategies (1) and (2) involve tolerating the leak while mobilizing for repair. A small leak may be hazardous to a small vessel that enters the bubble plume. However, if an effective guard zone arrangement could be rapidly put into place to prevent vessels from approaching the leak site, then relatively large leaks could be tolerated whilst mobilizing for the repair.

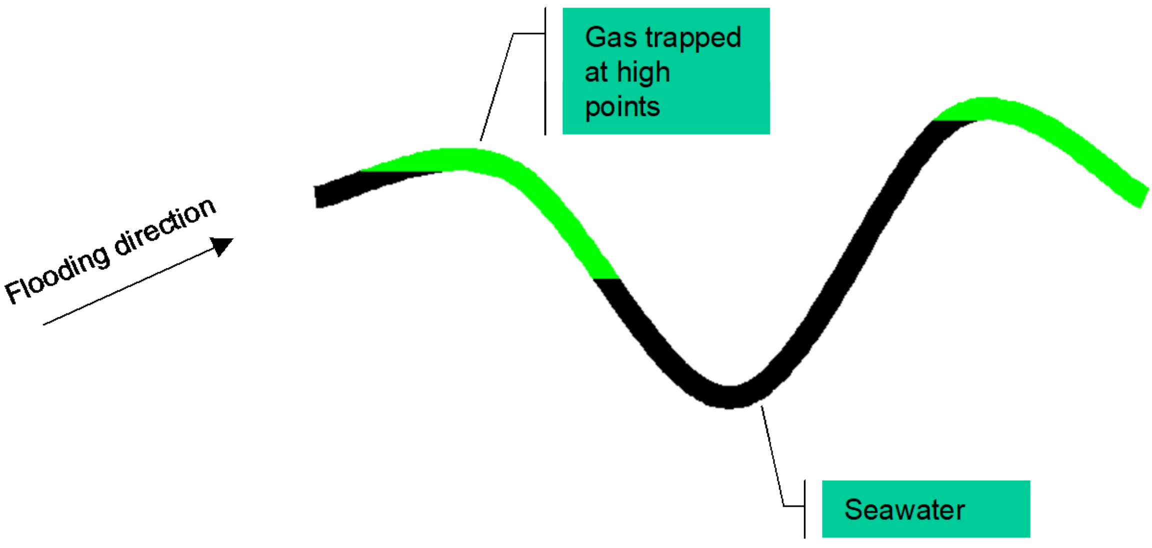

Figure 5. Entrapment of gas at high points in pipeline.

5. Conclusions

Based on the discussion in this article, it was found that the requirements for any type of leak detection and location systems should be derived from an evaluation of the criticality of the pipeline for the ramifications of a leak, depending on the transported product (i.e., oil or gas), the released potential volume, the sensitivity of the environment, and the public safety. Currently, in Australia, there are no legislative requirements for any leak detection system; however, regulatory bodies recommend incorporating appropriate systems that prevent and/or control the escape of hydrocarbons to the environment. Based on the current performance of the leak detection system, it is recommended that a combination of internal and external leak detection methods be considered to improve the leak size detection threshold, reduce the time to detect a leak and/or define the leak location more accurately.

Techniques for offshore pipeline surveillance principally depend on the water depths encountered. For shallow water, surveillance may be feasible using visual or video techniques from a relatively small vessel. For deeper water, the use of high-resolution side-scan sonar, sea-bottom profilers, low-light cameras, and multi-beam echo sounders from AUV/ROV may be required depending on the nature of the subsea environment and perceived threats to pipeline integrity. In all cases, alternative solutions shall be considered before considering the use of driving for routine surveillance. Risks associated with diving shall be fully assessed to ensure that if diving is used the risks are acceptable and diving is approved by a competent authority.

If a leak detection system is required, then the following shall be delivered:

- Definition of the capabilities of the system.
- Operating manuals for the LDS.
- Roles and responsibilities for operating, maintaining, and testing the leak detection system.
- Requirements for maintenance and testing of the LDS including tasks and frequency.
- Requirements for measuring the availability and reliability of the LDS as key performance indicators in line with API RP 1175 [51] and DNV RP F302 [28].

Among the leak detection techniques mentioned in this study, the fiber optic is the most reliable and accurate LDS for pipelines. Also, the acoustic sensors are suitable for monitoring leaks at the subsea trees and manifolds and other critical locations such as valves and connection points. Pipelines are designed to operate at full capacity, under steady-state flow conditions. Normal operations may involve day-to-day transients such as the operations of pumps, valves, and changes in production/delivery rates. The basic leak detection problem is to distinguish between normal operational transients and the occurrence of non-typical process conditions that would indicate a leak. The industry to date has concentrated on single-phase flow, primarily of oil, gas, and ethylene. Therefore, pipelines with a multi-phase flow regime are outside the scope of this review.

In general, an aerial survey is considered the most effective means of locating a leak. The aerial survey can also confirm the leak size from observation of the bubble plume diameter. Where a leak is of such a large size that the gas stops escaping before an aircraft can arrive at the scene, the use of a towed fish, ROTV, AUV, or ROV may be considered to find the leak location. Such a large orifice would be expected to be accompanied by significant damage to the pipeline coatings and there may also be seabed disturbance resulting from the high momentum gas outflow, which may make leak detection easier.

Leak detection methods are normally considered for both onshore and offshore trunk pipelines that have a single dispatch and terminal point. Radial networks or trunk configurations with cross-connections normally contain several branches, which cannot be metered as isolated elements without special provisions. Therefore, unless special provisions have been made these are again outside the scope of this task. The application of a leak monitoring system to a particular pipeline will depend on environmental issues, regulatory imperatives and operating company loss prevention and safety policy rather than pipe size and configuration.

Leak detection is a rapidly evolving technology so all new pipeline projects should carry out a review to determine the leak rate and detection time achievable in practice with the proposed instrumentation including sensitivity analysis to determine what benefits-improved measurements are likely to achieve. This review should be conducted during the Define/FEED stage of the project. On the other hand, for the operating pipelines, it is advised that the LDS performance and design should be reviewed similarly every five years.

There has been previous work that discussed and the reviewed the pipeline detection systems [12–21] but this previous work aimed to find the gaps in technology and analyses. This article aims to define a road map for leak detection system selection based on the asset requirements. As a "roadmap" to potential users of the leak detection systems the first questions to be asked and steps to be considered in sequence are:

- What are the expected operational features of the pipeline?
- What are the safety and environmental requirements?
- What risks apply in the case of leaks and what is the role of the LDS in minimizing the consequences of an unexpected leak?
- What are the physical properties of the pipeline and transported fluids?
- Where is the metering located? (Start and end)
- What is the accuracy and location of instrumentation along the pipeline?
- Which is the most appropriate (cost-efficient) LDS for the pipeline?
- What will then be the responsibilities of the operator/user?
- For the Pipeline Monitoring Systems Criteria, the leak detection system should:
- Have acceptable coverage of the entire pipeline system being monitored. There should be no "dead zones" that are not monitored.
- Allow good localization definition of a failure. The resolution of the system should be sufficient to direct repair crews to the failure site.
- Be essentially an "alarm" type system that activates only when a failure has occurred. The monitoring and support crew should be small.
- Installation and operational costs should be acceptable to undersea pipeline users.

The leak response plan should describe the actions required to detect, locate, assess, and respond to a leak in the pipeline. The leak response plan provides input to the pipeline repair plan. It is envisaged that ultimately the export pipeline leak response plan and repair plan would contribute to the development of specific contingency plans to be used within an overall Crisis Management System developed to handle potential incidents and crises of all kinds.

Finally, a complete risk analysis is required for the different hydrocarbon leaking scenarios. The risk assessment assists in understanding the consequences of the leak and determining the required mitigation actions. Some possible actions aimed at the hydrocarbon inventory reduction can also be identified, as follows:

- Include a subsea interception system at the riser base (i.e., subsea isolation valve, check valve).
- Design Emergency Shut-Down Valve (ESDV) actuation systems accelerating the system isolation.

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