MANUAL

PIPELINE LEAK DETECTION

DEP 31.40.60.11-Gen.

September 1994

DESIGN AND ENGINEERING PRACTICE

USED BY

COMPANIES OF THE ROYAL DUTCH/SHELL GROUP

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1. INTRODUCTION

1.1 SCOPE

This new DEP provides a structured methodology for evaluating the potential consequences of a leak in a pipeline. The methodology is intended to assist pipeline operators in assessing the need to install pipeline leak detection facilities. This DEP also provides an overview of available pipeline leak detection techniques.

1.2 DISTRIBUTION, INTENDED USE AND REGULATORY CONSIDERATIONS

Unless otherwise authorised by SIPM, the distribution of this DEP is confined to companies forming part of the Royal Dutch/Shell Group or managed by a Group company, and to Contractors nominated by them (i.e. the distribution code is "C", as described in DEP 00.00.05.05-Gen.).

This DEP is intended for use by all Functions in the Group that are involved in the design and operation of pipelines.

If national and/or local regulations exist in which some of the requirements may be more stringent than in this DEP, the Contractor shall determine by careful scrutiny which of the requirements are the more stringent and which combination of requirements will be acceptable as regards safety, environmental, economic and legal aspects. In all cases the Contractor shall inform the Principal of any deviation from the requirements of this DEP which is considered to be necessary in order to comply with national and/or local regulations. The Principal may then negotiate with the Authorities concerned with the object of obtaining agreement to follow this DEP as closely as possible.

1.3 DEFINITIONS

1.3.1 General definitions

The **Contractor** is the party which carries out all or part of the design, engineering, procurement, construction, commissioning or management of a project or operation of a facility. The Principal may undertake all or part of the duties of the Contractor.

The **Manufacturer/Supplier** is the party which manufactures or supplies equipment and services to perform the duties specified by the Contractor.

The **Principal** is the party which initiates the project and ultimately pays for its design and construction. The Principal will generally specify the technical requirements. The Principal may also include an agent or consultant authorised to act for, and on behalf of, the Principal.

The word **shall** indicates a requirement.

The word **should** indicates a recommendation.

1.3.2 Specific definitions

Fluid - substances which are transported through a pipeline in liquid and/or gaseous phase.

Hard liquid - a liquid with a vapour pressure below the prevailing atmospheric pressure, e.g. stabilised crude oil.

Leak - an uncontrolled fluid release from a pipeline.

Leak consequences - the result of a pipeline leak in terms of human safety and damage to the environment. Economic loss such as cost of repair and deferred production are not taken into account in the leak consequence evaluation methodology given in this DEP.

Leak expectancy - the probability of occurrence of a leak.

Opco - a Group Operating Company.

Pipeline - a system of pipes and other components used for the transportation of fluids, between (but excluding) plants. A pipeline extends from pig trap to pig trap (including the pig traps and associated pipework and valves), or, if no pig trap is fitted, to the first isolation valve within the plant boundaries or a more inward valve if so nominated.

Pipeline section - the user-selected subdivision of a pipeline.

Soft liquid - a liquid with a vapour pressure above the prevailing atmospheric pressure, e.g. ethylene, NGL, LPG, etc.

Technical integrity - the state of a system which exists when, under specified operating conditions, there is no foreseeable risk of its failure endangering people, the environment or asset value.

1.4 ABBREVIATIONS

ASPIN	-	Assessment of Pipeline Integrity
ECF	-	Environmental Consequence Factor
FRED	-	Fire Release Exposure and Dispersion
KSLA	-	Koninklijke/Shell Laboratorium Amsterdam
LPG	-	Liquefied Petroleum Gas
MAOP	-	Maximum Allowable Operating Pressure
NGL	-	Natural Gas Liquids
PC	-	Personal Computer
ROV	-	Remotely Operated Vehicle
SCF	-	Safety Consequence Factor
SMYS	-	Specified Minimum Yield Strength
SPLD	-	Statistical Pipeline Leak Detection
UT	-	Ultrasonic Testing
USD	-	United States Dollar

NOTE: Further abbreviations and symbols used in leak consequence modelling are defined in Appendix 1.

1.5 CROSS-REFERENCES

Where cross-references to other parts of this DEP are made, the referenced section number is shown in brackets. Other documents referenced in this DEP are listed in (4). Bibliography references are listed in (5).

2. METHODOLOGY FOR PIPELINE LEAK CONSEQUENCE EVALUATION

The methodology given in this DEP only evaluates the potential safety and environmental consequences of a leak, and not the direct economic consequences related to repair and deferred production/transportation. The latter consequences are in general not reduced by the presence of a leak detection system and may be evaluated objectively whereas the safety and environmental consequences are assessed, when necessary, on a more subjective basis.

The potential consequences of a leak are a function of various parameters related to the pipeline, its location and the type of fluid that is transported. By comparing the outcome of the safety and environmental consequence evaluation with a leak consequence classification the pipeline operator is able to determine the pipeline leak detection facilities required for the pipeline. The reduction in leak consequences as a result of a decreased time for leak detection and system shutdown can be demonstrated with the methodology given in this DEP.

The methodology presented in this DEP will not provide an absolute quantitative assessment of the consequences of a potential leak, but intends to rank pipelines on the basis of potential leak consequences.

A pipeline is not expected to leak if it is properly designed, constructed, operated and maintained. Authorities in many countries have no formal requirements for pipeline leak detection. Experience has shown, however, that despite all preventive measures taken pipelines do occasionally leak. Therefore, even when authorities have no requirements for pipeline leak detection systems, the pipeline asset holder should formulate his own requirements based on a structured, quantified approach. In a number of countries there are already formal requirements for integrity monitoring systems capable of detecting leaks in pipelines.

Group and public awareness of safety and environmental issues puts an increasing emphasis on the potential consequences of a pipeline leak regarding human safety and pollution of the environment. Proper pipeline management should ensure technical integrity of a pipeline in order to prevent failures and fluid releases. If a release does occur regardless of the measures taken to safeguard the pipeline integrity and the inspections to verify their effectiveness, e.g. by damage due to third party activity, a leak detection system should make the operator aware of this.

A leak detection system in itself has no effect whatsoever on the leak expectancy of a pipeline and will only make the operator aware of the occurrence of a leak, enabling him to take remedial actions in order to limit the consequences of the release.

Installation of a leak detection system should not be given the first priority when a pipeline has a high leak expectancy; measures shall be taken to reduce the probability of a leak to as low as is reasonably practicable (ALARP principle).

The need for a leak detection system can also be assessed by a failure risk assessment tool. It should, however, be realised that more input data is required for evaluating the probability of failure, in this case a leak, and that the probability itself is not affected by the presence of a leak detection system. The need for a leak detection system should not be related to the risk level itself but should be evaluated by assessing the potential reduction in failure risk due to the reduced safety and environmental consequences in case a leak occurs.

The leak consequence evaluation in this DEP is a simplified version of the leak consequence modelling of ASPIN, pipeline failure risk assessment, EP 94-0101 and EP 94-0102. The leak consequences are assessed by combining:

- factual input data, such as fluid pressure, density, etc.
- assumed input data, such as most likely leak hole size, time to detect a leak and shutdown operation, etc.
- factors such as fluid hazard factor, population density factor, etc.
- calculated parameters, such as fluid release rate, fluid release amount, etc.

The factors used in the assessment are based on expert opinion.

The potential benefit of a leak detection system or an improvement to an existing system can be evaluated by adjusting the "time to detect a leak and shut down" parameter and should be judged on the reduction of leak consequences in absolute terms.

The structure of the methodology and the factors that play a major role in the assessment are shown in Figure 1. The safety consequences are assessed based on the potential leak rate, the possibility of ignition, the population density and the hazardous characteristics of the fluid, and are expressed as a safety consequence factor (SCF). The environmental consequences are assessed on the basis of the potential leak volume, the persistence and/or seepage of the fluid into the environment and the clean-up cost and other costs associated with the environmental consequences of a leak. The persistence and/or seepage of the fluid is adjusted by a climate correction factor. The environmental consequences are expressed as an environmental consequence factor (ECF).

Since the conditions will normally vary along the length of the pipeline, the pipeline is divided into sections and the safety and environmental consequences of a potential leak are evaluated for each section. For example, on offshore pipelines the leak detection requirements are the highest close to the platform with regard to limiting safety consequences, whilst for environmental consequences the requirements are often the highest in the shore approach area. Special leak detection techniques focusing on these different criteria should be used in the respective locations.

Other parameters will also vary along the pipeline, such as internal pressure, most likely hole size, time to detect a leak, water depth, etc. The worst conditions within a particular section are assumed to be valid over the whole section length.

The safety and environmental consequences of a leak are assumed to be pipeline section length dependent, since the potential number of leaks is length dependent.

The requirements for a leak detection system should be judged by classifying the safety and environmental consequence factors as "low", "medium" or "high".

The threshold levels between the "low" and "medium", and the "medium" and "high" categories have been initially defined in a spreadsheet containing the methodology (2.5), but should be verified and confirmed by the Principal.

The need to install a leak detection system on pipelines is evaluated primarily on the basis of the safety and environmental consequences of a leak. The leak expectancy (L_e) is applied in this evaluation as a secondary parameter, see Table 1.

2.1 POTENTIAL LEAK RATE AND LEAK MASS

2.1.1 General

The actual amount of fluid released in case of a leak might range from very small to very large, depending on the leak rate, the presence of a leak detection system, the time to shut down pumps or compressors and the presence and mode of operation of valves.

In the methodology the leak size, i.e. the size of the hole in the pipeline wall, is a variable input parameter. The user can select the most likely hole size on the basis of potential failure modes, for example, a hole of 50 mm caused by the impact of a tooth of a backhoe excavator. The leak rate is then calculated as the fluid mass flow through the hole.

As part of the leak consequence evaluation, the potential leak mass is calculated using a number of assumptions. The calculated leak rate is assumed to continue until the leak is detected and the first remedial actions have been taken, such as closing block valves or shutting down pumps or compressors. The reducing leak rate during the remedial actions after valve closure or pump or compressor shutdown is not incorporated in this methodology, since this would complicate the assessment to a level which would be outside the scope of this leak consequence evaluation methodology.

NOTE: The effect of this assumption is not as large as it seems, since for both gas and liquid lines the consequences of a leak mainly refer to the time period between the onset of the leak and the system shutdown.

The safety consequences of a fluid release are governed by the leak rate, whereas the environmental consequences are related to the leak volume.

2.1.2 Formulae for potential leak rate and leak mass

The cross sectional area of the leak hole, A, is given by:

$$A = \pi \times d^2 / 4 \qquad \text{mm}^2$$

where d = diameter of leak hole (mm)

For liquids the potential leak rate (L_R) is given by the FRED model:

$$L_R = 0.61 \times \rho \frac{A}{10^6} \sqrt{2\left[\frac{(P_{in} - P_{out})10^5}{\rho}\right]} \qquad \text{kg/s}$$

where	0.61	=	the assumed discharge coefficient of the hole (orifice)	
	P_{in}	=	fluid (gauge) pressure in the pipeline, including any static head pressures	bar (ga)
	P_{out}	=	back pressure (gauge) outside the pipeline	bar (ga)
		=	$1025 \times 9.81 \times h / 10^5$	
	h	=	water depth	m
	ρ	=	fluid density	kg/m^3

It is assumed that the leak will occur at the highest P_{in} of a particular section.

The potential leak mass (L_m) is given by:

	L_m	=	L_R 3600 t/1000	m
where	t	=	time to detect a leak and shut down the pumps	kg/m^3

When the calculated liquid release rate is larger than the pipeline liquid flow rate, then the release rate used for calculating the potential leak mass is assumed to decrease gradually towards the pipeline liquid flow rate during the first two hours of the release.

For gases, the flow through a leak hole is either critical or non-critical. If the gas pressure is above the critical pressure, P_c, the flow through the hole is critical, i.e. choked. The critical pressure is given by:

bar (ga)

$$P_c = \left\{ (P_{out} + 1.013) \times \left(\frac{1+k}{2} \right)^{\frac{k}{k-1}} \right\} - 1.013$$

where k = ratio of specific heats for gas (C_p/C_v)

For critical flow the potential leak rate L_R is given by the FRED model:

$$L_R = \frac{A}{10^6} \sqrt{P_{in}\, 10^5\, \rho . \left(\frac{2}{k+1} \right)^{\frac{k+1}{k-1}}}$$

kg/m^3

with

$$\rho = \frac{P_{in} \times 10^5 \times MW}{8314 \times (T_g + 273) \times z}$$

where	MW	=	molecular weight	kg mol/m^3
	8314	=	universal gas constant	J/kg mol °K
	Tg	=	average gas temperature	°C
	z	=	compressibility factor	

2.2 SAFETY CONSEQUENCE FACTOR

Parameters governing the consequences of a leak with regard to safety are:

Potential leak rate (L_R)
Ignition factor (I_g)
Fluid hazard factor (S1)
Population density factor (S2)
Section length (L_s) in metres

The probability of ignition depends on the fluid hazard factor (S1) and population density (S2) and will increase with increasing time to detect a leak and shut down (t in hours).

The ignition factor is given by:

$$I_g = \left(1 - \left(\frac{0.6}{e^{(0.36xt)}}\right)\right) x \sqrt{\frac{S1xS2}{10}}$$

Table 2 gives a list of fluid types, with fluid hazard factors (S1) assigned to each fluid type.

For onshore pipelines the population density around the pipeline is evaluated on the basis of location classes as defined in ANSI/ASME B31.8:

Location class 1: Areas such as waste land, deserts, mountains, grazing land, farmland and sparsely populated areas.

Location class 2: Fringe areas around cities and towns, industrial areas, ranches or country estates.

Location class 3: Suburban housing developments, shopping centres, residential areas, industrial areas, and other populated areas not meeting location class 4 criteria.

Location class 4: Areas where multistorey buildings are prevalent, and where traffic is heavy or dense and where there may be numerous other utilities underground.

For more detailed information about definition of these location classes, refer to ANSI/ASME B31.8.

For the safety consequences assessment for offshore pipelines, a distinction is drawn between the following pipeline locations:

- Open sea
- Shore approach
- Risers and pipeline sections on a platform and in the safety zone around a platform for an unmanned platform or complex
- Similar to the above but for a manned platform or complex.

Table 3 lists the pipeline location classes and gives the population density factors (S2) assigned to the various locations.

The safety consequence factor, (SCF), of a leak is calculated by:

$$SCF = L_R \times L_e \times I_g \times S1 \times S2 \times L_s / 100$$

NOTE: The value 100 merely reduces the result to a number between 1 and 1000.

2.3 ENVIRONMENTAL CONSEQUENCE FACTOR

The environmental consequence factor depends on the following parameters:

Potential leak mass (L_m)
Persistence/seepage factor (E1)
Climate correction factor (E2)
Clean-up and/or other associated costs (E3)

The environmental consequence factor is only applicable to pipelines transporting liquids, i.e. air pollution and potential fire damage is not included in the evaluation.

The environmental consequences of a pipeline leak are expressed and quantified for practical reasons in terms of associated consequential money costs (USD) related to clean-up, compensation, etc. These depend on the volume of fluid released, the type of fluid, the environment category and the type of contingency plans.

The amount of liquid released is adjusted by a factor which reflects the persistence of the liquid in the environment. This factor depends on the fluid type, the climate and whether the leak is offshore or onshore.

It is assumed that the environmental damage is related to the liquid fluid components that remain in the environment after evaporation of the lighter fractions.

For onshore leaks the damage to the environment caused by the persistence of the fluid is affected by the type of crude oil. Light crude will seep into the ground more easily than heavy crude, and it is therefore more harmful and more difficult and costly to remove.

The assessment of clean-up costs is based on costs for light crude. The cost for another fluid is calculated by multiplying the persistence factor for offshore leaks (which depend on the fluid density), or the persistence/seepage factor for onshore leaks.

It is assumed that in an offshore leak of light condensate with a density of 600 kg/m³, or of any other hydrocarbon with a lower density, the total amount of fluid will evaporate under atmospheric conditions, and thus for those offshore leaks the persistence factor is zero.

For denser fluids, the offshore persistence factor E1 may be calculated from the formula:

$$E1 = 0.004 \times \text{density } (15°C, 1 \text{ bar}) - 2.4$$

The onshore persistence/seepage factor E1 may be calculated from the formulae:

Density < 850 kg/m^3 : $E1 = 0.0022 \times \text{density } (15°C, 1 \text{ bar}) - 0.88$
Density ≥ 850 kg/m^3 : $E1 = -0.0013 \times \text{density } (15°C, 1 \text{ bar}) + 2.1$

The factors for onshore leaks are estimated from expert opinion.

These relationships are shown in Figure 2.

The climate correction factor, E2 in Table 4, allows for the relationship between liquid evaporation and the ambient temperature.

Middle East and Far East locations are typical regions for the "Warm" climate category. Europe is typical for "Moderate", whereas Arctic and Northern North Sea will fall into the "Cold" climate category.

The clean-up cost and other associated costs for a liquid spill are expressed per unit volume in Table 5. The environment categories identified and associated clean-up cost and/or other consequential costs for light crude are given in USD/m^3.

The costs, quoted in 1993 money terms, have been estimated by experts using North Sea experience. They are assumed to be applicable worldwide.

Possible fines and other intangible costs related to the possible damage to the environment, e.g. loss of goodwill and credibility, are not included in the above costs. These should either be evaluated as a separate cost in an economic consequence evaluation or incorporated into the methodology by increasing the "clean-up and/or other associated costs" (E3) values. Actual costs are not included since they will be Principal dependent.

The environmental consequence factor (ECF) of a leak is calculated from the formula:

$$ECF = (L_m \times 1000 / R_o) \times L_e \times L_s \times E1 \times E2 \times E3 / 100\,000$$

NOTE: The value 100 000 merely reduces the result to a number between 1 and 1000.

2.4 PIPELINE LEAK CONSEQUENCE CLASSIFICATION

The outcome of the SCF and ECF calculations are not combined and should not be compared with each other, since both calculations have a different origin and the results are not on the same scale.

It is recognised that the basis of the leak consequence calculations is a simplification of the actual potential consequences of a leak when operating a pipeline. The consequence factors should not be considered as an absolute rating of the potential failure consequences. They should only be regarded as an indicator of the potential consequences of a leak in a particular pipeline, regarding safety and environmental aspects, relative to other pipelines.

Despite the fact that the methodology is intended for ranking pipelines on the basis of leak consequences, the calculated safety and environmental leak consequence factors for a particular pipeline can also be classified. This will indicate whether potential safety and/or environmental consequences are "low", "medium" or "high". From the classification of the leak consequences the need for a leak detection system for a particular pipeline should be determined. The threshold levels between "low"/"medium" and "medium"/"high" have been set initially at 200 and 500 respectively for the safety consequence factor and 100 and 400 respectively for the environmental consequence factor. When the leak consequence evaluation methodology has been tested on a large number of pipelines, threshold levels will be reviewed.

The actual risk of a hydrocarbon release from the particular pipeline is affected not only by the leak consequences but also by the leak expectancy (which is included in the evaluation as a secondary parameter only). If it is not possible to limit the consequences of a potential leak, even more attention should be paid to limiting the overall risk by reducing the leak expectancy by accurate condition monitoring. This may be achieved by metal loss intelligent pigging, cathodic protection and coating surveys, pipeline surveillance to detect third party activities/encroachment, etc.

2.5 PC SPREADSHEET

The methodology for pipeline leak consequence evaluation has been incorporated in a PC spreadsheet.

The input parameters are:

Pipeline:	Onshore or offshore Length, split into sections Water depth Population density factor, derived from Table 3, per pipeline section
Fluid:	Liquid or gas Fluid hazard factor, derived from Table 2
Liquids only:	Average ambient temperature Density
Gases only:	Average gas temperature Ratio of specific heats (Cp/Cv) Compressibility factor Gas molecular weight
Operation:	Pressure at pipeline inlet and outlet Fluid flow rate Assumed leak hole size Leak expectancy Time to detect leak and shut down pumps or compressors Liquid clean-up cost and/or other associated costs, derived from Table 5

The spreadsheet contains the equations used in the evaluation in which the pipeline is divided over a maximum of ten sections. The results also show the rating of the two overall consequence factors versus the threshold levels.

Appendices 2 to 5 contain sample printouts for four different cases:

- an onshore natural gas line
- an onshore gasoline line
- an offshore crude oil line
- an onshore HP ethylene line

A diskette with the spreadsheet can be made available by SIPM on request.

3. LEAK DETECTION TECHNIQUES

3.1 GENERAL

Leak detection techniques are based on either continuous or intermittent measurements of specific parameters. Intermittent leak detection methods are often able to detect smaller leak rates compared with continuous leak detection techniques.

Some continuous techniques can only detect transient pipeline conditions during the onset of a leak, and will not be able to identify the presence of a leak at a later time.

For some intermittent techniques fluid transportation through the pipeline needs to be interrupted. Using intermittent techniques, the detection time of a leak will be completely dependent on the frequency of inspection.

Techniques for detection of leaks in liquid lines offer better performance than those for gas pipelines, which in turn are better than those for two-phase pipelines.

The conflicting balance of sensitivity to leaks and false alarms will determine the sensitivity setting of the leak detection system. Large leaks can normally be detected more rapidly than small ones. To maintain the user's confidence in the system, avoiding false alarms should have a higher priority than attempting to shorten the leak detection time or reducing the minimum detectable leak rate.

The performance of pipeline leak detection techniques is dependent on fluid type, operating pressure including fluctuations, batch or continuous operation, pipeline length and size, metering accuracy, etc.

To decide which technique to adopt depends on a detailed case by case evaluation. If the consequences of a leak are considered significant (section 2) then the more sophisticated techniques of leak detection are required. It may be necessary to deploy more than one leak detection technique in order to achieve the overall leak detection performance that is required.

Leak detection systems are categorised into the following groups according to their inherent principle of leak detection:

1. Balancing of pipeline mass input versus output
2. Pressure and/or flow analysis
3. Monitoring of characteristic signals generated by a leak
4. Off-line leak detection

A summary of the capabilities and application of the various leak detection techniques is given in Table 6.

3.2 BALANCING OF MASS INPUT VERSUS OUTPUT

This category of leak detection systems relies on the fact that in a leak-free pipeline the fluid mass flow into the pipeline equals the flow out. Using this mass balance principle the flow-in and flow-out measurements are continuously monitored for any variations over a time interval. Volume flow readings should either be corrected for density or pressure and temperature variations to reference mass flows. To eliminate the effect of flow variations during normal operation, the flow readings should be averaged (totalised) over discrete time periods.

The uncorrected mass balance method can be applied only under steady state operations as it does not allow for changes in the pipeline inventory, i.e. line pack variation. Its accuracy depends largely on the accuracy of the flowmeters and on the steadiness of operations.

In addition to the inlet and outlet flow measurements, the corrected mass balance method uses a correction factor for any changes in the pipeline inventory. Pressure and, if necessary, temperature measurements at intervals along the pipeline are used for calculating the correction factor. The capability for detecting small leaks depends upon the number and accuracy of measurements along the length of the pipeline.

An alternative method is dynamic simulation, which is a model-assisted balance method. A real time computer model calculates the inventory of the pipeline and the line pack variations of the pipeline under steady-state and transient operating conditions. It will correct not only for pressure and temperature effects but also for changes in fluid properties, such as where different batches of fluids are present in the pipeline at the same time. A difference between the mass balance predicted by the model and that actually measured indicates the presence of a leak. Also, unexpected flow and/or pressure trends are used as indicators of the occurrence of a leak.

The dynamic simulation method is similar to the corrected mass balance system. The main difference is that the dynamic simulation method calculates the pipeline inventory whereas the corrected mass balance method interpolates between the measurements along the pipeline. The latter is usually considered to be less accurate because of the inherent accumulation of measurement errors.

The sensitivity of these methods is generally good. Their disadvantage is that they have limited capabilities for locating the leak.

Shell Research (KSLA) have developed a statistical pipeline leak detection (SPLD) system. The system does not need complicated modelling of the pipeline inventory, it continuously calculates the statistical probabilities of a leak based on fluid flow and pressure measured at the inlet and outlet of a pipeline. Depending on the control and operation of a pipeline, the statistical technique is used to identify changes in the relationship between the pipeline pressure and flow which always occur when there is a leak. The SPLD system works as a statistical filter, which is applied to a pipeline input/output balance and which decides between a leak-free and a leak-present hypothesis. Major advantages of this system are its simplicity and robustness compared with other software based techniques. The SPLD system can run on a PC, and is capable of discriminating between fluctuations due to operational variations of the pipeline and the actual occurrence of a leak; it is thus very reliable for leak detection. The SPLD system can only give an indication of the leak location. The SPLD system has been commercialised since October 1991. The statistical filter of the SPLD system can also be combined with a commercially available dynamic simulation method, which makes the latter even more reliable. This combined statistical and dynamic simulation leak detection system is at present the most sophisticated leak detection system available.

3.3 PRESSURE AND/OR FLOW ANALYSIS

The operation of a pipeline can be characterised by the flow of the fluid and the pressure gradient along the pipeline. Pressure drop and flow along a pipeline are related to the flow resistance of the pipeline. A leak will alter the pressure drop profile of a pipeline and therefore affect the 'normal' pressure and flow relationships. Detection of such alterations can be used to indicate the occurrence of a leak.

If a large leak occurs, particularly in the upstream part of a pipeline, the inlet pressure will drop. Observation of a lower than expected inlet pressure indicates the presence of a leak. Detection of low pressure is usually connected to an automatic shut-down system. To avoid false alarms the system is usually set such that only major leaks can be detected.

A leak will result in an increase in flow upstream and a decrease in flow downstream of the leak. As a result of this the pressure gradient will increase upstream and decrease downstream of the leak. The occurrence of a discontinuity in the pressure gradient, which is calculated from the pressure readings along the pipeline, is an indication of a large leak. The rate of change of pressure and flow readings can also be monitored and used to detect sudden changes which indicate the occurrence of a leak.

The combined pressure decrease/flow increase method uses the fact that a leak in an operational pipeline will cause an increase in the flow and a decrease in the pressure upstream of the leak. The simultaneous occurrence of both is an indication of a leak.

3.4 MONITORING OF CHARACTERISTIC SIGNALS GENERATED BY A LEAK

A suddenly occurring leak will cause a sudden pressure drop at the leak location in the pipeline. This sudden pressure drop will create a pressure wave travelling at sonic velocity both upstream and downstream from the leak. Detection of this pressure wave is an indication of the occurrence of a leak. The response time of this negative pressure wave technique is very short because it responds to waves that travel at sonic velocities (in crude oil, approximately 1000 m/s). When the wave is detected both upstream and downstream of the leak, the location of the leak may be calculated from the time difference of detection by the nearest sensors on either side of the leak location. The system will only respond to an instantaneously occurring leak of measurable size. In practice the sensitivity can be poor because the alarm thresholds are often set high to avoid false alarms triggered by pressure transients generated by upstream or downstream processing plant or other noise producing installations, such as pump or compressor stations.

A system which is less sensitive to pipeline noise than the negative pressure wave system uses dual transducers which filter out noise signals. The system is made directional, i.e. it detects signals originating from either the upstream or the downstream direction of the pipeline. This is achieved by installing the two transducers at an appropriate distance from each other and using an electronic signal subtracting system.

Leak detection based on negative pressure wave techniques will only detect the initiation of a leak and not its presence. If the pressure wave created at the moment of leak initiation is not detected, the leak will not be noticed.

Liquid escaping under pressure through a small opening produces supersonic noise. An ultrasonic leak detection pig, which is equipped with hydrophones and data recording, can detect and locate the presence of a leak. A very small leak, down to 10 l/hr, can be detected and fairly accurately located with this technique. Being intermittently operated, the response time will depend on the frequency of running the ultrasonic leak detection pig.

A hydrocarbon-permeable tube (sniffer tube) can be laid in close proximity along the pipeline. Small leaks of hydrocarbons from the pipeline which have permeated into the tube will be detected when the tube is periodically purged into a gas analyser.

Hydrocarbon-sensing cables can be laid along the pipeline. Electrical properties of the cable change when hydrocarbons come in contact with the cable. Contact with water does not affect the properties of the cable.

A prototype system for the measurement of methane in sea water has been developed. The device, which is mounted on a ROV, extracts dissolved gas from a continuous flow of water and determines the methane content using infrared absorption techniques.

Remote sensing of hydrocarbon emissions, e.g. using an infrared technique from an aircraft is becoming commercially available. Particularly for gas and multi-phase pipelines, this offers a powerful alternative to ground based patrolling techniques.

3.5 OFF-LINE LEAK DETECTION

Intelligent pigs have been developed for detection and location of leaks in a pipeline using flow direction recognition in a blocked-in pressurised pipeline. This bi-directional pig has an opening through the body with a sensitive flow meter and a transmitter. By locating the pig at various points along the line and using above-ground interpretation of the flow measurements through the pig, the leak can eventually be located. Locating the leak, however, is time consuming and the line should be equipped with pumping or pressurising facilities at both ends. This system is of interest for pipelines larger than 8 inches in diameter when a small leak has been detected but its location is unknown.

An alternative to the above technique for pipelines smaller than 8 inches is a bi-directional pig equipped with a differential pressure transducer and a transmitter. When located in the pipeline the pig measures the pressure drop on either side. The leak will be on the side at which the pressure drops more rapidly.

The pressure in a blocked-in pressurised pipeline will drop when there is a leak. For a static pressure leak test the pipeline, or a section of it, is pressurised with the transported hydrocarbon fluid to the MAOP. If pressurising to a higher level is required the leak test shall be done with water for safety and environmental reasons. After pressurising, the block valves are closed and the pressure and temperature are monitored for a specified period of time (24 hour minimum). A differential static pressure test can be carried out if block valves are equipped with differential pressure transducers. A difference in the rate of pressure drop in two adjacent sections that cannot be explained by temperature effects, inaccuracy of readings or valve leakage is an indication of a leak.

There are uncertainties about the advantages and disadvantages of pressure testing existing pipelines for condition monitoring purposes at pressures higher than the MAOP. Pressure testing above the MAOP is primarily done for strength testing in order to avoid a pipeline rupture (DEP 31.40.40.38-Gen.). The advantage of pressure testing at high pressures for leak detection is that an existing leak is detected more easily. Also, long defects which have almost broken the surface can be opened, resulting in a leak which is also detected. The disadvantage is the risk that existing defects might be enlarged and/or activated to grow, possibly leading to failures during normal pipeline operations following the pressure test.

A tracer can be added to the pressurising fluid for detection of small leaks. The leak is detected by patrolling the pipeline with a detector which is sensitive to the tracer or by visual observation of a visible tracer.

Sound which is generated when liquid is forced through a small opening during pressure testing can be detected by acoustic monitoring. For pipelines transporting hard liquids, leak detection by an acoustic reflectometry method is feasible. The technique is based on the phenomenon that a pressure wave travelling through a pipeline is reflected at the position of a leak, due to a local change of acoustic properties. For lines which are used intermittently this technique can be used during downtime when the level of disturbing noise is low.

4. REFERENCES

In this DEP, reference is made to the following publications:

NOTE: Unless specifically designated by date, the latest edition of each publication shall be used, together with any amendments/supplements/revisions thereto.

SHELL STANDARDS

Index to DEP publications and standard specifications	DEP 00.00.05.05-Gen.
Hydrostatic pressure testing of new pipelines	DEP 31.40.40.38-Gen.

AMERICAN STANDARDS

Gas transmission and distribution piping systems	ANSI/ASME B31.8 (1992)

Issued by:
The American Society of Mechanical Engineers
345 East 47th Street
New York, NY 10017
USA.

5. BIBLIOGRAPHY

NOTE: The following documents are for information only and do not form an integral part of this DEP:

FRED: Models for Calculating Releases and their Consequences	FRED (version 2.0)
Pipeline Leak Detection Guideline	EP 91-1915
ASPIN - Version 1.1 Pipeline failure risk assessment User manual, worked examples	EP 94-0101
ASPIN - Version 1.1 Reference manual	EP 94-0102

FIGURES

FIGURE 1 PIPELINE LEAK CONSEQUENCE EVALUATION AND CLASSIFICATION METHODOLOGY

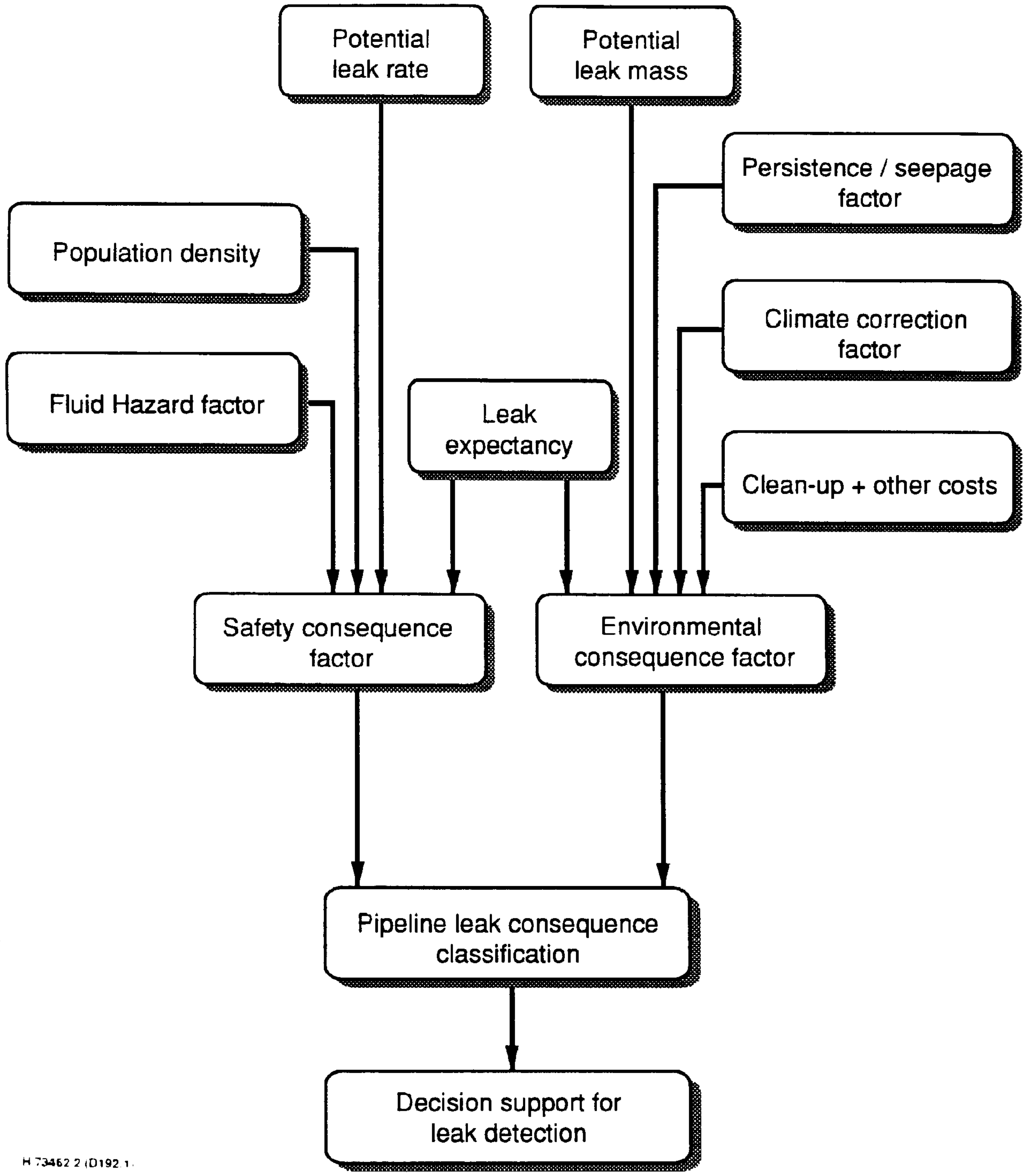
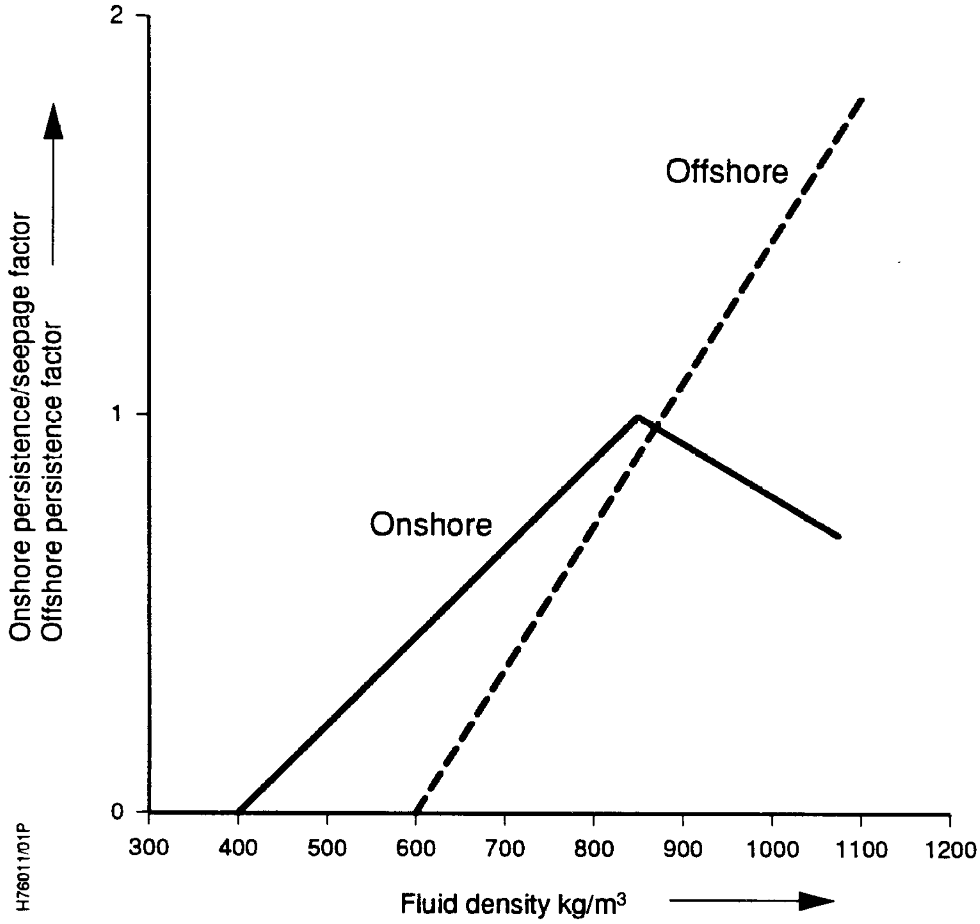


FIGURE 2 PERSISTENCE FACTOR (OFFSHORE) AND PERSISTENCE/SEEPAGE FACTOR (ONSHORE)



TABLES

TABLE 1 LEAK EXPECTANCY; L_E

Leak expectancy		
Input	Meaning	L_e factor
HH	Very high	√3
H	High	√2
N	Neutral	1
L	Low	1/√2
LL	Very low	1/√3

TABLE 2 FLUID HAZARD FACTOR; S1

Fluid	Approx density [kg/m^3] at 15 °C and 1 bar	Approx vapour pressure [bar (abs)] at 0 °C	Fluid hazard factor; S1
Crude oil - heavy	875-1000	0.3	0.5
Fuel oil	920-1000	0.01	1
Gas oil / diesel	850	0.01	1
Crude oil - light	700-875	0.55	1
Kerosene/naptha/gasoline	700-790	0.01-1.2	5
NGL (condensate)	600-700	0.1-1.0	8
LPG	500-600	0.2-1.5	10
LNG	420	4-6	10
Ethylene	1.6		10
Natural gas	1.1		6
Sour natural gas (> 0.5%H_2S)	1.1		10

TABLE 3 POPULATION DENSITY FACTOR; S2

Area classification	Population density factor; S2
Onshore Location Class (as per ANSI/ASME B31.8)	
Class 1	1
Class 2	4
Class 3	8
Class 4	10
Offshore	
Open Sea	1
Shore approach	5
Risers and Safety Zone (unmanned platforms)	6
Risers and Safety Zone (manned platforms)	10

TABLE 4 CLIMATE CORRECTION FACTOR FOR PERSISTENCE(/SEEPAGE) FACTOR; E2

Climate	Average Annual Temperature [°C]	Correction Factor; E2
Warm	≥ 20	0.75
Moderate	>5 - <20	1.0
Cold	≤ 5	1.25

TABLE 5 - CLEAN-UP AND/OR OTHER ASSOCIATED COSTS; E3

Environment		Clean-up costs; E3 [USD/m^3]	Remarks
Offshore	> 40 km from shore	13	a
	5 - 40 km from shore	110 or 240	b
	< 5 km from shore	3500	c
Onshore	Standard terrain	630	
	Water course areas	2200	
	Designated environmentally sensitive areas	2500	

Remarks:

a: Based on surveillance of the released fluid only, whilst allowing self-degradation.

b: Value depend on remedial actions: costs:
Chemical dispersant treatment: 110 USD/m^3
(Dispersant and application)

Containment and recovery: costs:
(Equipment, deployment, recovery, transport and disposal) 240 USD/m^3

c: Including coastal clean-up, fishing and tourism compensation and amenity impact.

TABLE 6 SUMMARY OF THE CAPABILITIES AND APPLICATION OF LEAK DETECTION TECHNIQUES

LEAK DETECTION METHOD	LEAK TYPE	MODE OF OPERATION	RESPONSE TIME	LEAK LOCATION CAPABILITY	REMARKS
low pressure	gas: full bore ruptures liquid: major leaks	any	seconds to minutes	Offshore: None Onshore: Between block valves if pressure readings available	commonly used, high thresholds to avoid false alarms
pressure decrease / flow increase	gas: major leak liquid: large leaks	steady state	seconds to minutes	Offshore: None Onshore: Between block valves if pressure readings available	
pressure gradient along the pipeline	gas: major leaks liquid: large leaks	steady state	minutes	between block valves if pressure readings available	onshore only
negative pressure wave	gas: large leaks liquid: medium leaks	steady state	seconds to minutes	within 1 km	detects only the onset of a leak
wave alert	gas: medium to large leaks liquid: small to medium leaks	steady and transient state	seconds to minutes	within 1 km, depending on transducer spacing	detects only the onset of a leak
mass balance	medium to large leaks	steady state	minutes to hours	none	
corrected mass balance	small to medium leaks	steady and transient state	minutes to hours	Offshore: None Onshore: Between block valves	
dynamic simulation	small leaks	steady and transient state	minutes to hours	at best within 10% of pipeline length	
statistical leak detection	small leaks	steady and transient state	minutes to hours	indication only	low probability of false alarm
ultrasonic leak detection pig	liquids: small leaks (typical 50 l/h)	intermittent	depends on pigging frequency	within 100 m	hard liquids only
acoustic reflectometry	liquids: large leaks (on-line), small to medium leaks (shut-down)	steady state	depends on monitoring frequency	within 1 km	hard liquids only
differential static pressure test	small leaks (hard liquids), medium leaks(soft liquids), large leaks for gas	during shut down	hours to days	none, between block valves	capabilities depends on length and temperature effects
sniffer tube, hydrocarbon sensing-cables	all fluids, including multiphase: small leaks	any	hours	within 100m	short lines only

Leak rate categories used in Table 6:

Full bore rupture:	≥ 100% of flow
Major leak:	50-100% of flow
Large leak:	25-50% of flow
Medium leak:	5-25% of flow
Small leak:	1-5% of flow

APPENDIX 1 LIST OF SYMBOLS (USED IN APPENDICES 2 TO 5)

Symbol	Unit	Description
A	mm^2	area of leak hole
d	mm	diameter of leak hole
D	inch	pipeline nominal diameter
ECF	-	environmental consequence factor
E1	-	fluid persistence/seepage factor
E2	-	climate correction factor for liquids
E3	USD/m^3	clean-up and other associated costs for liquids
h	m	water depth
I_g	-	Ignition factor
k	-	ratio of specific heats for a gas, (C_p/C_v)
L_e	-	Leak expectancy
L_m	tonne	potential leak mass
L_R	kg/s	Leak rate
L_s	km	Section length
MW	kg/kg-mol	molar mass of gases
P_{in}	bar (ga)	fluid pressure in the pipeline (gauge)
P_{out}	bar (ga)	back-pressure outside the pipeline (gauge)
P_c	bar	critical pressure of a gas for choked flow through an orifice
π	-	3.1416
Q	$10^3\ m^3/h$	fluid flow rate (for gases, under standard reference conditions, i.e. 15 °C and 1.013 25 bar)
Ro	kg/m^3	fluid density
SCF	-	safety consequence factor
S1	-	fluid hazard factor
S2	-	population density factor
t	hour	time elapsed between the onset of a leak and shut-down of pumps/compressors
T_g	° C	average gas temperature
T_m	° C	average ambient temperature
z	-	Compressibility factor

APPENDIX 2 CASE: ONSHORE NATURAL GAS LINE

METHOD FOR PIPELINE LEAK CONSEQUENCE EVALUATION

app6dep4.xls

Case: Onshore Natural Gas Line

13/07/94 15:05

PIPELINE / FLUID / OPERATING INPUT DATA (constant)

Liquids only Enter zeros for Tm and Ro			Onshore / Offshore (ON=on, OFF=off)	-	ON
Average ambient temperature [deg C]	Tm	0	Pipeline diameter [inches]	D	24
Density [kg/m3] (15 C, 1 bar)	Ro	0	Pipeline length [km]		180
Gases only			Fluid type (L or G)	-	G
Average gas temperature [deg C]	Tg	9	Fluid flow rate [10^3 m3(st)/h]	Q	625
Ratio of specific heats (Cp/Cv)	k	1.3	Fluid hazard factor	S1	6
Compressibility factor	z	0.85			
Gas molecular weight	MW	20			

VARIABLE INPUT DATA PER SECTION

Section definition		1	2	3	4	5	6	7	8	9	10
Section length [km]	Ls	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
		Lengths match total length									
Safety Consequence											
Population density factor:	S2	4	1	1	1	1	4	1	1	1	4
Environmental Consequence				This section is not relevant for gases							
Liquid clean-up / other costs [$/m3]	E3	0	0	0	0	0	0	0	0	0	0
Other data											
Time to detect leak & shut down [hrs]	t	1	3	3	3	3	2	3	2	2	1
Leak expectancy (HH,H,N,L or LL)	Le	H	N	N	N	N	H	N	N	N	H
Assumed hole size [mm]	d	12.7	50.8	50.8	25.4	50.8	25.4	50.8	50.8	50.8	12.7
Water depth [m] Onshore;not relevant	h	0	0	0	0	0	0	0	0	0	0
Pressure [bar] - input only end values	P	70	65	61	56	51	47	42	37	33	28

CALCULATED VALUES

Fluid Release Data		1	2	3	4	5	6	7	8	9	10
Area of hole [mm2]	A	127	2027	2027	507	2027	507	2027	2027	2027	127
Ignition factor	Ig	0.9	0.6	0.6	0.6	0.6	1.1	0.6	0.5	0.5	0.9
Liquids only											
Persistence factor	E1	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Climate factor	E2	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Potential leak rate [kg/s]	Lr	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Potential leak mass [tonne]	Lm	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Gases only											
Critical flow pressure [bar]	Pc	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Actual gas density [kg/m3]	Ro	70	66	61	56	52	47	42	37	33	28
Potential leak rate [kg/s]	Lr	2	25	23	5	19	4	16	14	12	1
Consequence Factors											
Safety	SCF	9	16	15	4	13	29	11	8	7	4
SCF per km		1	1	1	0	1	2	1	0	0	0
Environment	ECF	0	0	0	0	0	0	0	0	0	0
ECF per km		0	0	0	0	0	0	0	0	0	0

LEAK CONSEQUENCE EVALUATION RESULTS

Overall consequence values			**% consequence value per section**									
			1	2	3	4	5	6	7	8	9	10
Safety	116		8	14	13	3	11	25	9	7	6	3
Environment	0		0	0	0	0	0	0	0	0	0	0

LEAK CONSEQUENCE RATING

Safety	Low	Threshold levels "low"/"medium" and "medium"/"high" initially set at 200 and 500,
Environment	Low	and 100 and 400 for safety and environment consequences respectivily

APPENDIX 3 CASE: ONSHORE GASOLINE LINE

METHOD FOR PIPELINE LEAK CONSEQUENCE EVALUATION

app2dep4.xls

Case: **Onshore Gasoline Line**

13/07/94 15:40

PIPELINE / FLUID / OPERATING INPUT DATA (constant)

Liquids only			Onshore / Offshore (ON=on, OFF=off)	-	ON
Average ambient temperature [deg C]	Tm	15	Pipeline diameter [inches]	D	12
Density [kg/m3] (15 C, 1 bar)	Ro	780	Pipeline length [km]		56
Gases only Enter zeros for Tg, k, z and MW			Fluid type (L or G)	-	L
Average gas temperature [deg C]	Tg	0	Fluid flow rate [10^3 m3(st)/h]	Q	0.4
Ratio of specific heats (Cp/Cv)	k	0	Fluid hazard factor	S1	5
Compressibility factor	z	0			
Gas molecular weight	MW	0			

VARIABLE INPUT DATA PER SECTION

Section definition		1	2	3	4	5	6	7	8	9	10
Section length [km]	Ls	1.0	8.0	8.0	2.0	8.0	4.0	8.0	8.0	8.0	1.0
		Lengths match total length									
Safety Consequence											
Population density factor:	S2	4	1	1	1	1	4	1	1	1	4
Environmental Consequence											
Liquid clean-up / other costs [$/m3]	E3	625	625	625	2180	625	625	625	625	625	625
Other data											
Time to detect leak & shut down [hrs]	t	1	3	3	3	3	2	3	2	2	1
Leak expectancy (HH,H,N,L or LL)	Le	N	N	N	N	N	N	N	N	N	N
Assumed hole size [mm]	d	12.7	50.8	50.8	25.4	50.8	25.4	50.8	50.8	50.8	12.7
Water depth [m] Onshore;not relevant	h	0	0	0	0	0	0	0	0	0	0
Pressure [bar] - input only end values	P	32	29	26	24	21	18	15	13	10	7

CALCULATED VALUES

Fluid Release Data		1	2	3	4	5	6	7	8	9	10
Area of hole [mm2]	A	127	2027	2027	507	2027	507	2027	2027	2027	127
Ignition factor	Ig	0.8	0.6	0.6	0.6	0.6	1.0	0.6	0.5	0.5	0.8
Liquids only											
Persistence factor	E1	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84
Climate factor	E2	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Potential leak rate [kg/s]	Lr	5	83	79	19	71	16	60	55	48	3
Potential leak mass [tonne]	Lm	20	902	858	203	762	118	653	394	348	9
Gases only											
Critical flow pressure [bar]	Pc	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Actual gas density [kg/m3]	Ro	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Potential leak rate [kg/s]	Lr	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Consequence Factors											
Safety	SCF	1	19	18	1	16	13	14	11	10	0
SCF per km		1	2	2	1	2	3	2	1	1	0
Environment	ECF	0	48	46	9	41	3	35	21	19	0
ECF per km		0	6	6	5	5	1	4	3	2	0

LEAK CONSEQUENCE EVALUATION RESULTS

Overall consequence values		**% consequence value per section**									
		1	2	3	4	5	6	7	8	9	10
Safety	102	1	18	17	1	16	13	13	11	9	0
Environment	223	0	22	21	4	18	1	16	9	8	0

LEAK CONSEQUENCE RATING

Safety	Low	Threshold levels "low"/"medium" and "medium"/"high" initially set at 200 and 500,
Environment	Medium	and 100 and 400 for safety and environment consequences respectivily

APPENDIX 4 CASE: OFFSHORE CRUDE OIL LINE

METHOD FOR PIPELINE LEAK CONSEQUENCE EVALUATION

app5dep4.xls

Case: **Offshore Crude Oil Line**

13/07/94 15:44

PIPELINE / FLUID / OPERATING INPUT DATA (constant)

Liquids only			Onshore / Offshore (ON=on, OFF=off)	-	OFF
Average ambient temperature [deg C]	Tm	5	Pipeline diameter [inches]	D	30
Density [kg/m3] (15 C, 1 bar)	Ro	875	Pipeline length [km]		136
Gases only Enter zeros for Tg, k, z and MW			Fluid type (L or G)	-	L
Average gas temperature [deg C]	Tg	0	Fluid flow rate [10^3 m3(st)/h]	Q	2.1
Ratio of specific heats (Cp/Cv)	k	0	Fluid hazard factor	S1	0.5
Compressibility factor	z	0			
Gas molecular weight	MW	0			

VARIABLE INPUT DATA PER SECTION

Section definition		1	2	3	4	5	6	7	8	9	10
Section length [km]	Ls	0.1	0.5	22.0	22.0	22.0	22.0	22.0	22.0	2.3	1.0
		Increase section length by 0									
Safety Consequence											
Population density factor:	S2	10	10	1	1	4	1	1	1	5	4
Environmental Consequence											
Liquid clean-up / other costs [$/m3]	E3	12	12	12	12	12	12	235	3500	3500	625
Other data											
Time to detect leak & shut down [hrs]	t	2	3	5	6	6	6	6	6	4	2
Leak expectancy (HH,H,N,L or LL)	Le	H	H	L	L	N	L	L	L	N	N
Assumed hole size [mm]	d	12.7	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8
Water depth [m]	h	100	200	200	170	135	95	75	35	10	0
Pressure [bar] - input only end values	P	100	92	83	75	67	58	50	42	33	25

CALCULATED VALUES

Fluid Release Data		1	2	3	4	5	6	7	8	9	10
Area of hole [mm2]	A	127	2027	2027	2027	2027	2027	2027	2027	2027	2027
Ignition factor	Ig	0.5	0.6	0.2	0.2	0.4	0.2	0.2	0.2	0.4	0.3
Liquids only											
Persistence factor	E1	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10
Climate factor	E2	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25
Potential leak rate [kg/s]	Lr	10	138	130	124	119	114	107	101	93	82
Potential leak mass [tonne]	Lm	70	1494	2341	2689	2574	2468	2302	2182	1339	589
Gases only											
Critical flow pressure [bar]	Pc	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Actual gas density [kg/m3]	Ro	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Potential leak rate [kg/s]	Lr	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Consequence Factors											
Safety	SCF	0	3	2	2	22	2	2	2	2	1
SCF per km		0	6	0	0	1	0	0	0	1	1
Environment	ECF	0	0	7	8	11	7	132	1867	169	6
ECF per km		0	0	0	0	0	0	6	85	74	6

LEAK CONSEQUENCE EVALUATION RESULTS

Overall consequence values		**% consequence value per section**									
		1	2	3	4	5	6	7	8	9	10
Safety	37	0	8	6	5	59	5	5	4	6	1
Environment	2207	0	0	0	0	0	0	6	85	8	0

LEAK CONSEQUENCE RATING

Safety	Low	Threshold levels "low"/"medium" and "medium"/"high" initially set at 200 and 500,
Environment	High	and 100 and 400 for safety and environment consequences respectivily

APPENDIX 5 CASE: ONSHORE HP ETHYLENE LINE

METHOD FOR PIPELINE LEAK CONSEQUENCE EVALUATION

app4dep4.xls

Case: Onshore HP Ethylene Line

13/07/94 15:49

PIPELINE / FLUID / OPERATING INPUT DATA (constant)

Liquids only			Onshore / Offshore (ON=on, OFF=off)	-	ON
Average ambient temperature [deg C]	Tm	16	Pipeline diameter [inches]	D	10
Density [kg/m3] (15 C, 1 bar)	Ro	470	Pipeline length [km]		83
Gases only Enter zeros for Tg, k, z and MW			Fluid type (L or G)	-	L
Average gas temperature [deg C]	Tg	0	Fluid flow rate [10^3 m3(st)/h]	Q	0.3
Ratio of specific heats (Cp/Cv)	k	0	Fluid hazard factor	S1	10
Compressibility factor	z	0			
Gas molecular weight	MW	0			

VARIABLE INPUT DATA PER SECTION

Section definition		1	2	3	4	5	6	7	8	9	10
Section length [km]	Ls	0.5	12.0	12.0	12.0	3.0	12.5	5.0	12.5	12.5	1.0
		Lengths match total length									
Safety Consequence											
Population density factor:	S2	1	4	1	4	1	1	1	4	1	4
Environmental Consequence											
Liquid clean-up / other costs [$/m3]	E3	100	100	100	100	100	100	100	100	100	100
Other data											
Time to detect leak & shut down [hrs]	t	2	2	2	2	1	2	1	2	2	1
Leak expectancy (HH,H,N,L or LL)	Le	L	N	L	N	L	L	L	N	L	N
Assumed hole size [mm]	d	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4	25.4
Water depth [m] Onshore;not relevant	h	0	0	0	0	0	0	0	0	0	0
Pressure [bar] - input only end values	P	110	105	100	95	90	85	80	75	70	65

CALCULATED VALUES

Fluid Release Data		1	2	3	4	5	6	7	8	9	10
Area of hole [mm2]	A	507	507	507	507	507	507	507	507	507	507
Ignition factor	Ig	0.7	1.4	0.7	1.4	0.6	0.7	0.6	1.4	0.7	1.2
Liquids only											
Persistence factor	E1	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Climate factor	E2	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Potential leak rate [kg/s]	Lr	31	31	30	29	28	28	27	26	25	24
Potential leak mass [tonne]	Lm	226	221	216	210	102	199	97	187	181	87
Gases only											
Critical flow pressure [bar]	Pc	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Actual gas density [kg/m3]	Ro	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Potential leak rate [kg/s]	Lr	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Consequence Factors											
Safety	SCF	1	209	18	199	4	17	6	184	16	11
SCF per km		2	17	2	17	1	1	1	15	1	11
Environment	ECF	0	1	1	1	0	1	0	1	1	0
ECF per km		0	0	0	0	0	0	0	0	0	0

LEAK CONSEQUENCE EVALUATION RESULTS

Overall consequence values			**% consequence value per section**									
			1	2	3	4	5	6	7	8	9	10
Safety	663		0	31	3	30	1	3	1	28	2	2
Environment	4		1	20	14	19	2	13	3	17	12	1

LEAK CONSEQUENCE RATING

Safety	High	Threshold levels "low"/"medium" and "medium"/"high" initially set at 200 and 500,
Environment	Low	and 100 and 400 for safety and environment consequences respectivily