Worldwide Assessment of Industry Leak Detection Capabilities for Single & Multiphase Pipelines

by

Dr. Stuart L. Scott, Associate Professor

Dr. Maria A. Barrufet, Associate Professor

Department of Petroleum Engineering

Texas A&M University

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For more information contact:

Offshore Technology Research Center
Texas A&M University
1200 Mariner Drive
College Station, Texas 77845-3400
(979) 845-6000

or

Offshore Technology Research Center
The University of Texas at Austin
1 University Station C3700
Austin, Texas 78712-0318
(512) 471-6989

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Executive Summary

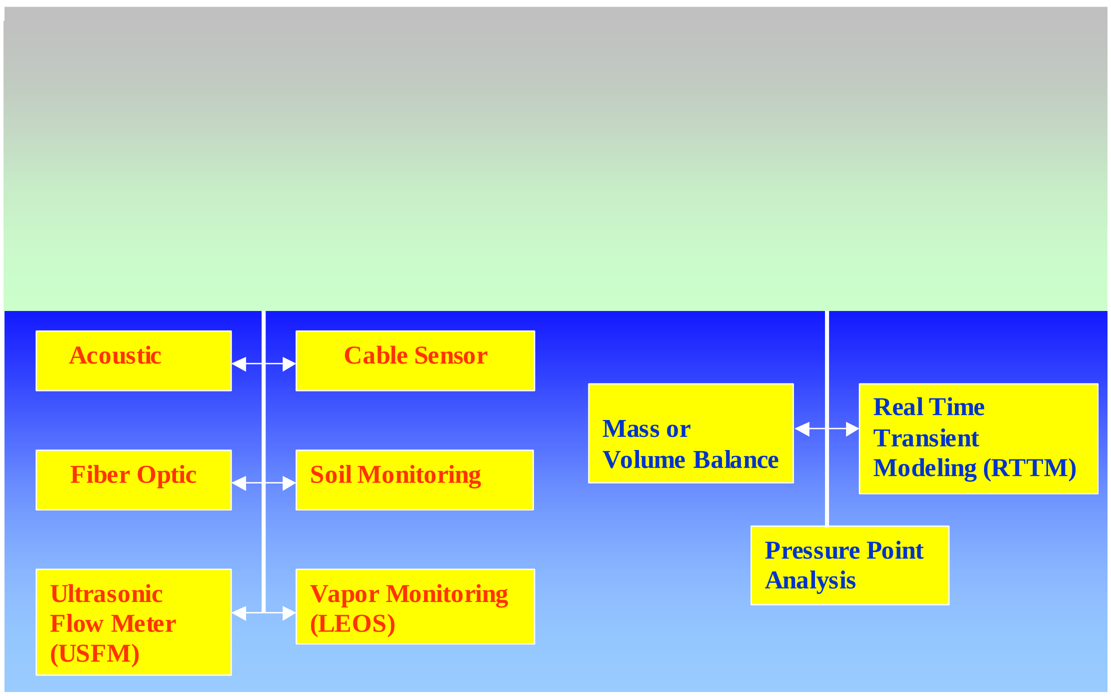
A study has been completed which undertook an examination of the state-of-the-art in pipeline leak detection technology. The advantages and disadvantages of currently available technology have been analyzed with special consideration given to the possible application in deepwater, subsea and arctic developments. These developments represent a significant departure from conventional production operations. Rather than pipelines transporting a processed and single-phase fluid, these developments flow a complex mixture of oil, water, and natural gas. Pipelines transporting an unprocessed, multiphase mixture will be termed flowlines in this study. These flowlines represents a special challenge for leak detection and one that has largely been ignored by both industry and regulators. While historically the number of shallow water releases from pipelines is extremely small, deepwater, subsea and arctic flowlines operate under conditions rarely encountered in previous development schemes. The remoteness of these flowlines, coupled with a number of complex interactions between the released fluids and the deepwater environment makes detection much more difficult. Leak detection using conventional methods is also made difficult by the reduced accuracy or complete lack of flow rate measurements at the flowline inlet. A key focus of the study was to quantify how currently available leak detection methods will function under multiphase flow conditions and what role multiphase metering can play in reducing risks. New methods, such as compositional monitoring and data-driven momentum balance methods were also investigated. The goal of this work has been to provide the information necessary for decision makers to develop strategies for the special testing, inspection and monitoring requirements of deepwater, subsea and arctic pipelines.

The objectives of this study are shown to the right. In pursuit of these objectives a team of Texas A&M graduate and undergraduate students conducted literature surveys, mailings and site-visits. In addition, steady-state pipeline modeling was performed using the PIPESIM program and transient modeling was

1) Identify State-of-the-Art in Leak Detection Technology
2) Assess Leak Detection Techniques
3) Investigate the Role of Multiphase Metering
4) Investigate the Concept of Compositional Monitoring for Leak Detection
5) Investigate the Effectiveness of Pressure Safety Low (PSL) Pilots
6) Investigate Potential of Data Driven Momentum Balance Testing
7) Technology Transfer

performed using the OLGA simulator. These programs were used to examine the response of a pipeline under the condition of a pipeline leak. Analytical methods were also utilized to gain an understanding of how conventional methods would perform under multiphase conditions.

A number of leak detection technologies were investigated during this study. The report lists a summary of each of the methods identified. Leak detection technologies can be categorized based on a variety of criteria. One such criterion used in the past was to classify methods based on where measurements were made. Internal methods examine flow in the pipeline while external methods look to detect fluids that have exited the pipe. Rather than using this criterion, this study has divided leak detection methods based on the methods that use sensors available in normal oil & gas operations (pressure, temperature, rate) and those that require special sensors. The figure below shows the different types of technologies currently being utilized for leak detection.



Classification of Leak Detection Methods Used in Study

In addition to assessing the state-of-the-art in leak detection, this study investigated how current methods might be applied within modern oil & gas development strategies. As mentioned before, modern strategies often utilize multiphase flowlines which are not readily available for inspection due to their remoteness. Several of the major findings of the study are listed below:

- A rapid increase in the number of new leak detection technologies can be observed over the past decade, with many of these new methods employing novel technologies developed in the defense or telecommunication industries.
- More than one leak detection method is employed for special applications such as:
  - where the exterior of the pipe can not be directly inspected
  - environmentally sensitive areas
  - where a release could pose a severe threat to people
- Conventional material balance methods remain the most widely used and are often supplemented with friction/pressure loss (momentum balance) methods.
- Special hardware based methods can mitigate risks of a small leak (<1%) and are complementary to the conventional technologies. These methods are capable of detecting trace amounts of hydrocarbons thereby providing protection against very small leaks that can go undetected for long periods of time.
- For some leak sizes and locations it can be shown that a <u>Pressure Safety Low (PSL) will not detect a leak</u>. The effectiveness of PSL's can be estimated using commercially available software and the length of time to detect a leak can also be determined.
- Multiphase metering currently has limited application for leak detection due to the poor and variable accuracy of these devices. They can, however, provide some value for high pressure and other select applications.
- Detection of a leak by examining compositional changes in the outlet fluid shows promise, but enhancements to the OLGA simulator are needed before this technique can be fully evaluated.
- Published "best case" detection limits have often found their way into regulations, and may not be achievable due to the design/operational constraints on a given system.
- Many software based leak detection systems are marketed as a "black box" in that the methods are kept confidential and are not open to scrutiny. Incredible claims are often made regarding the size of leak that can be detected in multiphase flow conditions. A real need exists for independent verification and demonstration of capabilities.

The modeling results showed that the external pressure applied to pipelines/flowlines in deepwater applications limits concerns for subsea leaks. In most cases examined, sea water will flow into the deepwater pipeline/flowline (flooding) rather than hydrocarbons leaking out into the environment. Cases where a deepwater leak detection system should be employed are shown to the right.

- **High pressure pipelines/flowlines where pressures are not reduced by a wellhead choke**
- **Risers, where at certain depths a gradient is created that will allow a leak from the riser.**
- **Tanker loading buoys**

This study also examined the challenge of leak detection in flowlines that flow a multiphase mixture of oil, water and natural gas. Modeling results indicate that in relation to single-phase transmission pipelines the size of leak detectable by mass balance and pressure drop methods is reduced in multiphase flowline and is highly flow pattern dependent. Some types of hardware based methods, however, are not significantly degraded by multiphase flow and should be utilized <u>in addition to</u> conventional methods for subsea and arctic flowlines.

Based on the analysis performed during this study a number of recommendations can be made. These include the need for large-scale experiment and field demonstration projects in the area of multiphase leak detection. Also of interest is the combination of continuous and batch approaches for hardware based diffusion/dispersion methods. Application of array pressure and temperature sensors also appears promising.

C h a p t e r   1

INTRODUCTION

Pipeline leaks are of major concern to the public. With increasing awareness and concern for the environment, recent pipeline leak incidents have shown that the cost is much more than the associated downtime and clean-up expenses. An effective and appropriately implemented leak detection program will easily pay for itself through reduced spill volume and increased public confidence. Leak detection technology has developed to a sophisticated level of automation for onshore gas and liquid transmission pipelines and this technology is routinely applied for shallow water offshore pipelines. However, deepwater, subsea and arctic flowlines operate under conditions rarely encountered in previous development schemes. These applications are typified by extremely high flowrates of full well-stream, multiphase fluids and flow over lengths that are well beyond our experience, whether onshore or offshore. Figure 1 shows a subsea development from the U.S.A. Gulf of Mexico which illustrates this challenge.   The multiphase mixture entering subsea flowlines is rarely metered due to the expense of placing a meter subsea and concerns regarding the accuracy and rangeability of multiphase flow meters. As a result the flow rates entering the flowline are unknown, a unique situation for leak detection. Even when multiphase meters are utilized, the accuracy of the inlet flow rates will be less than for single-phase meters. This negates the commonly used mass balance techniques that have been applied for many years by the onshore transmission industry. These methods function by monitoring the flow entering and exiting

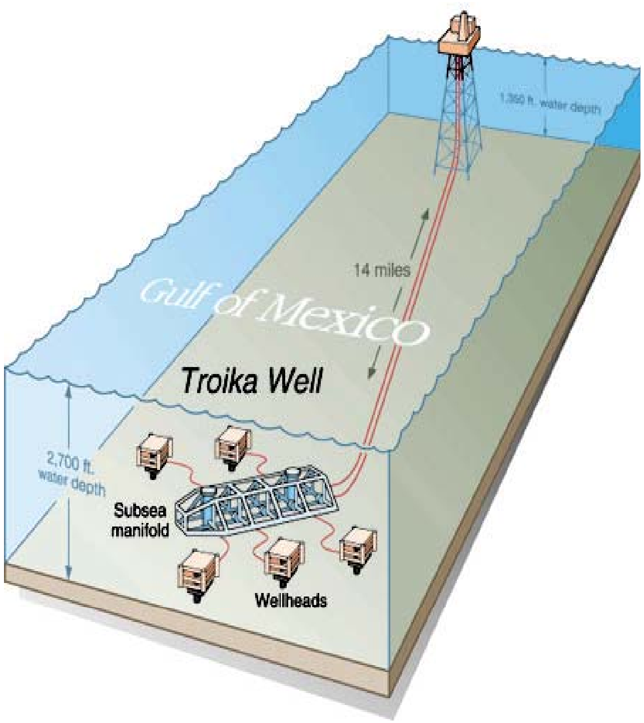
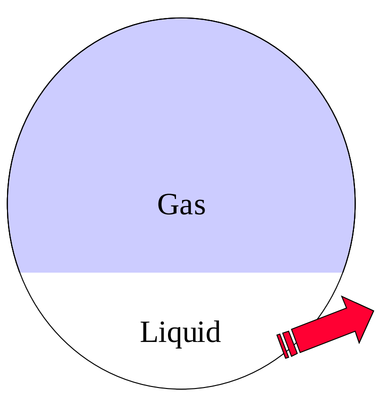


Figure 1.1: Subsea Development U.SA. Gulf of Mexico

the pipeline and looking for increasing discrepancies in the mass balance. This project examined the state-of-the-art for leak detection with the goal of assessing application of the technology to deepwater, subsea and arctic pipelines.

Leak detection methods fall into several categories. The onshore transmission industry has largely employed methods which utilize software to analyze the flow within the pipeline. This approach is still expected to serve as the front-line defense for leak detection and has the most potential for minimizing risks. However, in recent years hardware based methods have been developed that detect the presence of hydrocarbons which have escaped outside the pipe. These hardware based methods are expected to be of value for deepwater, subsea and arctic application where visual observation is difficult. A review of the literature reveals that the subject of multiphase leak detection is in its infancy. While several studies have considered catastrophic leaks, i.e. flowline rupture or blowdown (Norris & Puls, 1993; Norris, 1994; Norris & Hissong, 1994), virtually no experimental work was found for modeling small leaks in multiphase flow.

Several problems are inherent to multiphase flow. The first is the uncertainties associated with multiphase flow. When two or more phases are present in a flowline, the phases can assume differing flow patterns and phase slip characteristics. This greatly increases the uncertainties for the common mass balancing techniques which must now determine the flow characteristic (flow pattern) before a leak can be identified. As shown by Scott et al. (1999), multiphase leak detection is further complicated by the distribution of the phases within the pipe and the location of the leak along the circumference of the pipe. As shown in Figure 1.2, the material released from the flowline depends on the flow pattern and leak location. For stratified flow, liquid would be



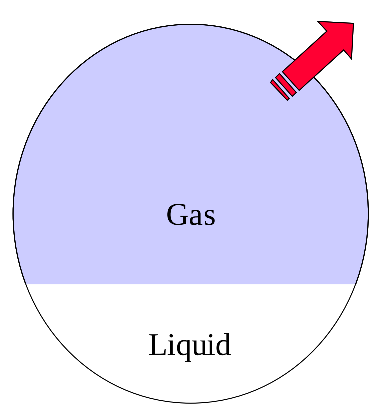


Figure 1.2: a) Liquid Only Leak *b) Gas Only Leak*

expected from a corrosion leak near the bottom of the pipe, while gas would escape from an impact leak at the top of the pipe.

The specific tasks performed in this study are:

1) **Identify State-of-the-Art in Leak Detection Technology** - identify and report on the state-of-the-art in pipeline leak detection worldwide. The leak detection systems will include SCADA, LEOS, PSL's, Fiber Optics and others.

2) **Assessment of Leak Detection Techniques** - provide decision makers with an assessment of the capabilities and advantages/disadvantages of each type of leak detection system. Of particular concern will be how well the currently available methods perform under subsea, arctic and multiphase flow conditions.

3) **Investigation of the Role of Multiphase Metering** - evaluate what role multiphase meters may play in reducing risk.

4) **Compositional Monitoring for Leak Detection** – investigate the use of compositional changes in the fluid produced by a flash at the location of the leak to identify a leak. A loss of methane, ethane and other gas phase components would indicate a substantial gas leak at the top of the pipe while loss of C7+ components or water would indicate a primarily liquid release (either oil or water).

5) **Investigation of the Effectiveness of Pressure Safety Low (PSL) Pilots** - examine the effectiveness of PSL's in detecting leaks for a wellbore-flowline system.

6) **Data Driven Momentum Balance Testing** - evaluate and quantify what reduction in risks would be made possible by mandating special flow tests and/or equipment for full well-stream, subsea flowlines.

7) **Technology Transfer** - Foster interaction between oil and gas operators, suppliers of leak detection technology, regulators and researchers.

A comprehensive review of the leak detection technology has been made based on a search of various databases, an Internet search and site visits to Alaska, California and New Orleans. Extensive discussions were also held with operators, vendors and regulatory agencies. The literature review included published reports by regulatory agencies (MMS, 1992; State of Alaska, 1999). This state-of-the-art technology has been catalogued and evaluated and the advantages/disadvantages of each method have been discussed. To compare the performance of these methods certain key attributes are defined. New emerging technologies in leak detection have also been identified and in each case the area of applicability of the technique is considered.

A list of leak detection systems has been compiled based on the physics of the system. The leak detection systems have then been categorized as hardware-based methods or software based methods (Turner, 1991; Zhang, 1996). In the hardware-based methods, hardware devices are essential to detect and locate the leak. Typical devices used to detect leaks are optical fibers, acoustic sensors, chemical sensors, and electrical sensors. These are then coupled to a SCADA system for detection of leaks. In the software-based methods, software packages are used for detection of discrepancies in flow rate, mass and pressure. Theses techniques are categorized as transient or steady state depending on whether they can account for changes in flow conditions with respect to time. Pressure Point Analysis™ is another software-based technique, which uses statistical methods to detect leaks.

This study utilized the commercial OLGA transient multiphase simulator (licensed by ScandPower) to investigate the minimum leak detectable. Application of OLGA to flow assurance includes pipeline design, pipeline start-up, shutdown, change in rates, process equipment simulation, hydrate formation and safety analysis. OLGA has been used for leak detection since it accommodates transient flow conditions and changes in line packing with pressure, simulates heat transfer and allows specifying the backpressure at the point of leak. It also accommodates both critical and sub-critical leaks.

The leak detection techniques that have been identified have been evaluated to determine their effectiveness. This includes considering their performance under multiphase flow conditions and with respect to deepwater/subsea conditions. A selection criterion was developed to identify the best available technology for subsea, arctic and multiphase flow applications. A special case of flooding of a flowline has been considered for deepwater where the hydrostatic pressure is higher than the internal pressure of the pipeline.

The following sections present the results obtained from this study. Chapters 2 to 4 discuss the currently available and emerging leak detection methods. The role multiphase metering may play in leak detection is discussed in Chapters 5 and 6. In chapter 7 a new compositional leak detection method is analyzed using the OLGA multiphase simulator. Chapter 8 examines leak detection for deepwater flowlines.

IDENTIFICATION OF THE STATE-OF-THE-ART

IN LEAK DETECTION TECHNOLOGY

For this study, leak detection technology has been classified as shown below. Hardware based methods are those that require special sensors while software based methods make use of routine pressure, temperature and flow rate information.

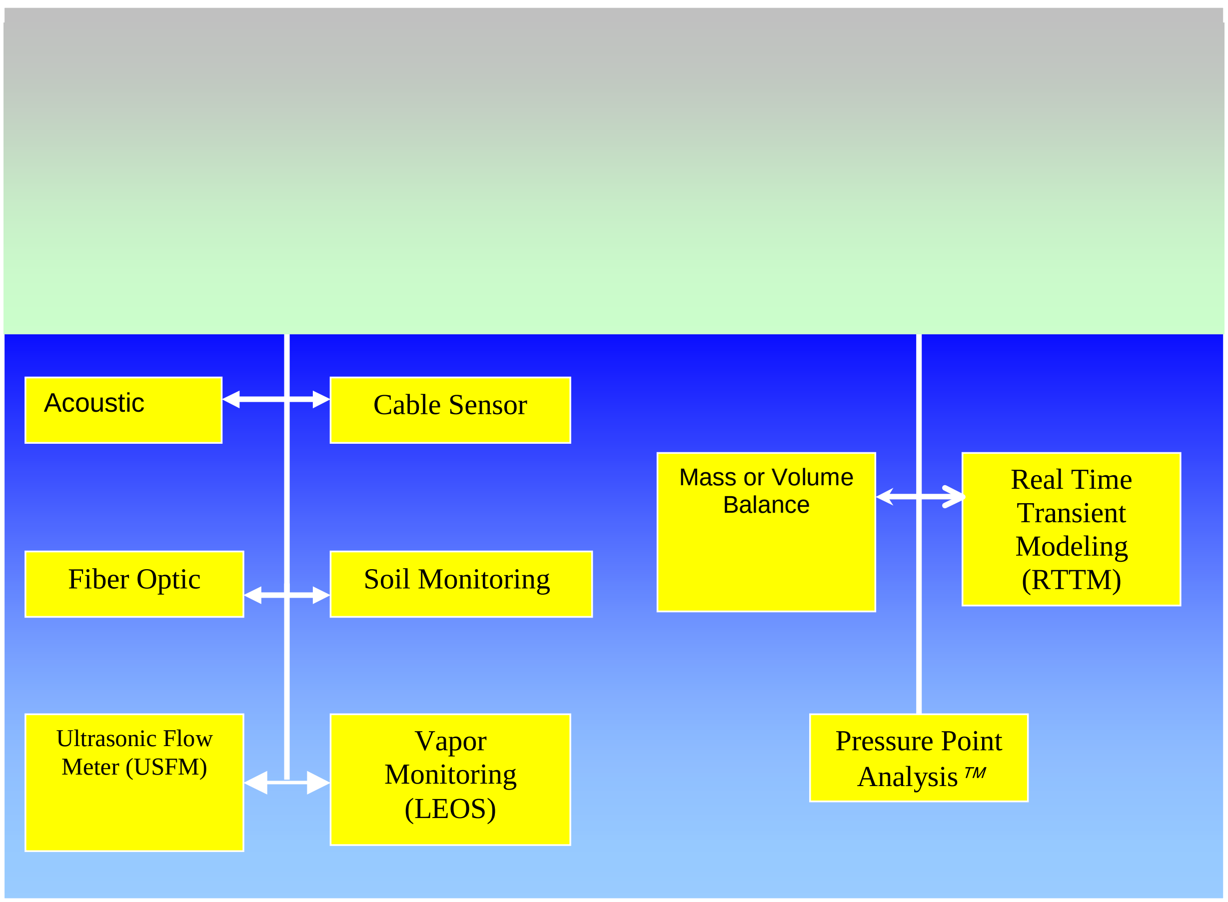


Fig. 2.1: Categorization of Leak Detection Technology Used in this Study

Each of these technologies is defined on the following page and a full description is given in the sections that follow.

A. HARDWARE BASED SYSTEMS

Acoustic Devices: A leak generates noise signal which can be picked up by acoustic sensors installed outside the pipeline.

Cable Sensors These sensors use polymer materials that swell in the presence of hydrocarbon thus changing their electrical properties.

Fiber Optic Sensors: Leaks can be identified through the identification of temperature changes in the immediate surroundings using fiber optic cable or through change in the optical property of the cable itself induced by the presence of a leak.

Soil Monitoring: Leaks are detected by analyzing the concentration of the vapor phase or tracer substances in the soil surrounding the pipeline.

Ultrasonic Flow Meters (USFM): This uses a patented wide beam technology to induce an axial sonic wave in the pipe wall for detection of leaks.

Vapor Monitoring System: If the product inside a pipeline is highly volatile, this system sucks the vapors in a low-density polyethylene (LDPE) sensor tube and run this gas stream past specialized sensors that can detect trace concentrations of specific hydrocarbon compounds.

B. SOFTWARE BASED SYSTEMS

Mass or Volume Balance: This method checks for leak by measuring the mass or volume at two sections of the pipeline.

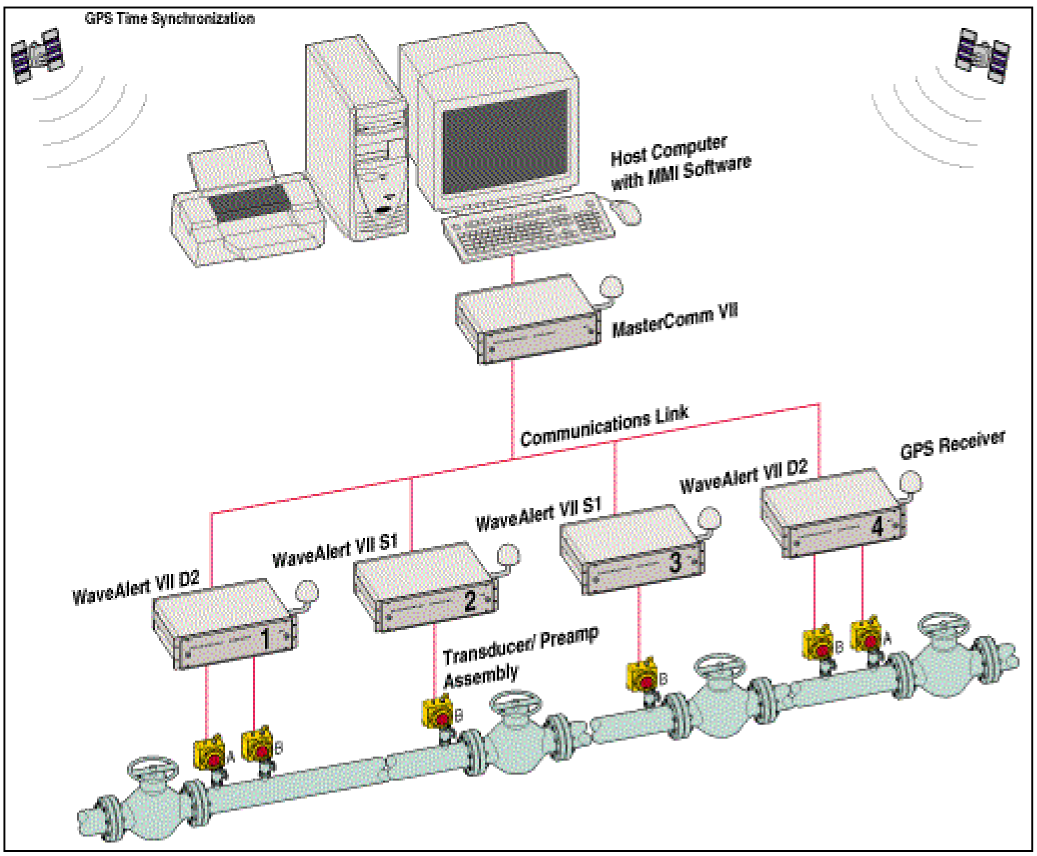
Real Time Transient Modeling (RTTM): This method mathematically models the fluid flow within a pipeline. The equations used to model the flow are conservation of mass, conservation of momentum, and equation of state for the fluid.

Pressure Point Analysis™: This method detects a leak by comparing the current pressure signal with the trend taken over a period of time. The patented software then applies statistical analysis to determine if there is a significant difference between the two signals, thereby indicating a leak.

2.1 HARDWARE BASED METHODS

2.1.1 LEAK DETECTION IN PIPELINES USING ACOUSTIC EMISSION METHOD

This method uses noise (acoustic) sensors installed outside the pipeline. A leak generates a noise signal which can be picked up by these acoustic sensors. This method was used for steam boilers and later for hydro-testing of pipelines. The systems works best for high-pressure, low flow rate pipelines. For accurate leak detection, it is necessary to minimize external noise and identify pipeline operating noises.



Source: Acoustic System Inc.

Fig. 2.1.1: Leak Detection by Acoustic Emission Method

Acoustic Systems Incorporated (ASI)[8] Wavealert[R] is a real time pipeline leak detection system, which detects leak based on acoustic emission system. To detect pipeline leak, the acoustic emission technology uses the signals generated by the sudden pressure drops. The size of the leak can be estimated from the amplitude of the acoustic wave. The acoustic signal increases with the leak size.

Advantages of the Technology

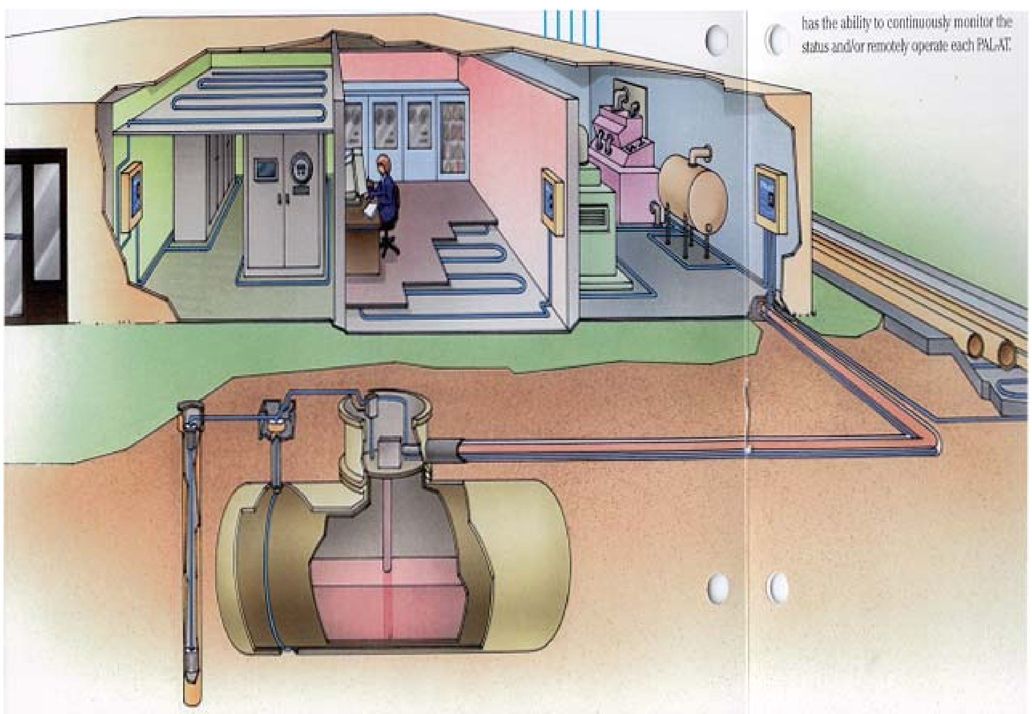
- Leak location in pipeline can be done using Acoustic Emission method by using interrogation techniques.
- Since the sensors are installed outside the pipeline, it does not require shutdown for installation or calibration.

Limitation of the Technology

- For high flow rates, the background noise will mask the sound of a leak.

2.1.2 LEAK DETECTION USING CABLE SENSOR

Electrical sensors that have been used for leak detection generally utilize some polymer materials that react with hydrocarbons. These materials either swell in volume or change their electrical properties. This gives rise to measurable changes in the electrical property of the sensors. The emerging technologies for leak detection are based on changes in resistance property or capacitance property of the cable in presence of hydrocarbon. The best applications of the technology were for short fuel lines in an airport or refinery setting or in highly sensitive areas on longer lines. SensorComm has developed a liquid sensing cable, which is used for leak detection.



Source: SensorComm

Fig. 2.1.2: Leak Detection by Sensor Tubes

Advantage of the Technology

- This technology can be used as a distributed sensor and is non-metallic in nature.
- On development, fiber optic technology can offer advantage for sub-sea leak detection.

Application to Arctic

- This system could be used for Arctic conditions.

Application to Offshore/Deepwater

- Not applicable to deepwater/offshore leak detection.

Application to Multiphase

- Not applicable to multiphase flow leak detection.

Limitation of the Technology

- The maximum burial depth is 20 feet.
- The cable must be air dried after exposure to gasoline and other highly volatile hydrocarbons.
- Sensor may interfere with the working of pipeline's cathodic protection system.

2.1.3 LEAK DETECTION USING FIBER OPTIC TECHNOLOGY

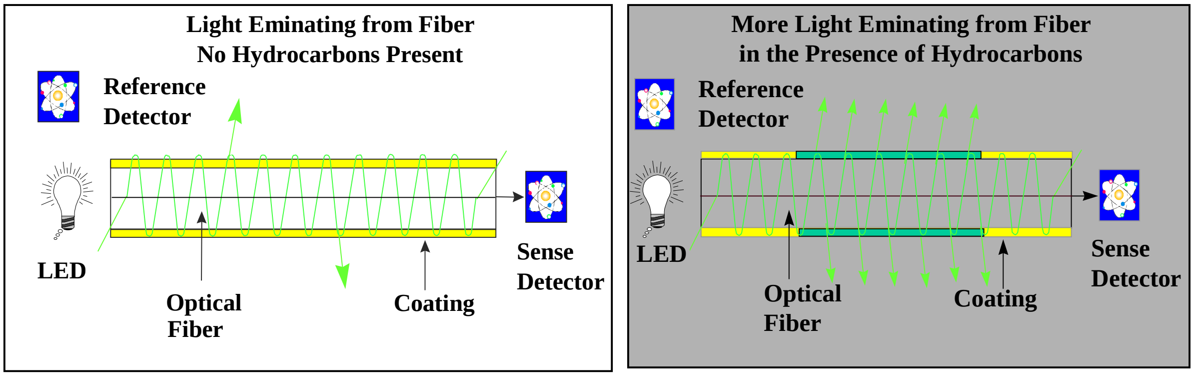
Fiber optic is one of the promising leak detection technologies. Fiber optic sensors can be installed both as point sensors and as distributed sensors. Optical fibers have the ability to detect a wide range of physical and chemical properties (Tapanes) which can help both in leak detection and leak location. Fiber optic technology uses the following for leak detection:

Detection of leak by temperature monitoring: In this method the fiber optic cable is installed parallel to the pipeline for measuring the temperature profile. When leak occurs, gas escapes in the environment and results in cooling of the surrounding environment due to the Joule Thompson effect. This local cooling can be picked up by the fiber optic cable. This technology requires the pipeline to be buried, and was used for gas pipeline.

Detection of leak by developing micro bends: In this method when leak occurs, optical fibers develop micro bends in presence of hydrocarbons. This can be detected and located with an Optical Time Domain Reflectometer (OTDR).

Distributed fiber optic chemical sensors: Optical properties of the sensors change in presence of hydrocarbon. These changes in optical properties can be used for leak detection.

FCI Environmental Inc. has a patented fiber optic chemical sensor technology.



Source: FCI Environmental Inc.

Fig. 2.1.3: Leak Detection by Fiber Optical Sensing

Advantage of the Technology

- This technology can be used as a distributed sensor and is non-metallic in nature.
- On development, fiber optic technology can offer advantage for sub-sea leak detection.

Limitation of the Technology

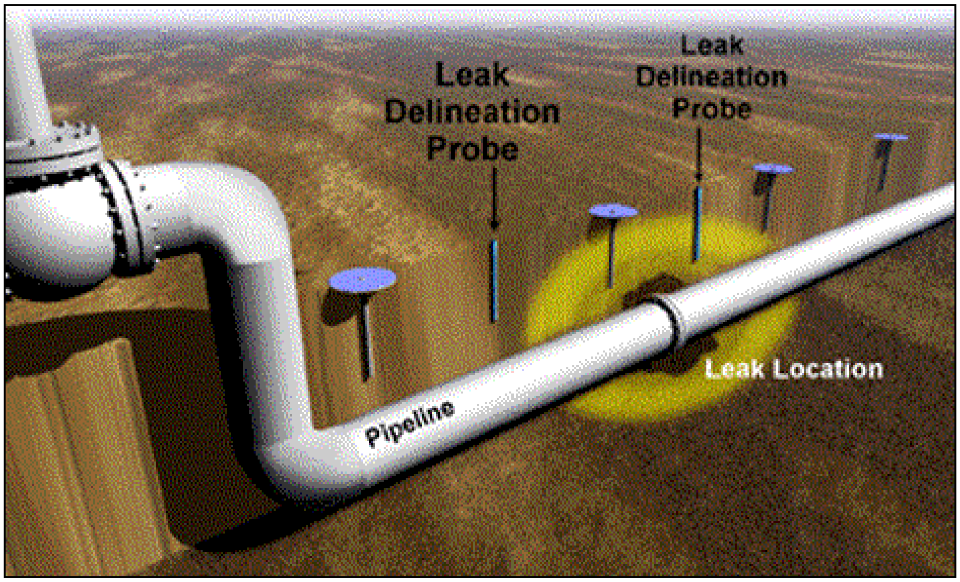
- As of now, there has been limited commercial use of this technology for leak detection.

2.1.4 LEAK DETECTION USING SOIL MONITORING METHOD

This is a vapor monitoring system to analyze concentration of vapor phase hydrocarbons in the soil surrounding the pipeline. Tracer Research has a patented leak detection system based on soil monitoring method.

According to Tracer Research (10):

> This method involves inoculating pipelines with a unique, nontoxic, and highly volatile "tracer" compound. This is an EPA-approved external leak detection technology based on the detection of inert, volatile chemical compounds (the tracer) in shallow, unsaturated soils adjacent to and beneath the pipeline. Tracer is added at a concentration of a few parts per million to pipeline contents and has no measurable impact on their physical properties. Within a few weeks, any tracer that leaks out of pipelines with the fuel disperses, by diffusion, into the surrounding soil air and rapidly volatilizes. Probes are placed in the soil near pipelines. Leak detection hoses are used for long pipelines. Vapor (soil gas) samples are collected from the probes and hoses and are analyzed for tracer with a gas chromatograph. Tracer is detectable in the soil gas at the low parts-per-trillion level. Tracer compound technology can locate leaks in pipelines to within a few feet, regardless of size or length (10).



Source: Tracer Research Corporation

Fig. 2.1.4: Leak Detection by Soil Monitoring

Advantage of the Technology

- It can monitor pipelines operating under multiphase flow.
- Leak detection is unaffected by earlier leaks thus false alarms are minimized.

Application to Offshore/Deepwater

- This is applicable only for short pipelines that are buried. This may limit applicability for subsea installations.

Application to Multiphase Flow

- There are no limitations to multiphase leak detection.

Application to Arctic

- There could be a limitation in terms of use of gas chromatographs in the arctic conditions.

Limitation of the Technology

- Not applicable to above ground or underwater pipelines.
- The tracer technology becomes cost-prohibitive for long pipelines because of the number of sensors and chemicals required.

2.1.5 LEAK DETECTION USING ULTRASONIC FLOW METERS

Controlotron Corporation has developed a leak detection system based on Ultrasonic Flow Meter technology. Ultrasonic Flow Meters (USFM's) leak detection technology offers cost-saving advantages in installation, maintenance and operation. According to the Controlotron Corporation brochure, the details of the leak detection technology are as follows:

> The system operates by separating the pipeline into a series of segments. Two stations bound each segment so that the monitored liquid travels through only one entrance and one exit. Each Site Station consists of a clamp-on flow meter, temperature sensor, and computer. Volumetric flow rate, liquid and ambient air temperature, liquid sonic propagation velocity and site diagnostic conditions are measured or computed at each Site Station. The Master Station collects data from all Site Stations for a volume-balance computation. It accomplishes this by monitoring the volume of the liquid entering a segment, applying software models that reflect the physical and environmental conditions influencing the liquid, then comparing results with the volume leaving the segment. A short integration period will show a large leak quickly. Longer integration periods are needed to detect smaller leaks (11).

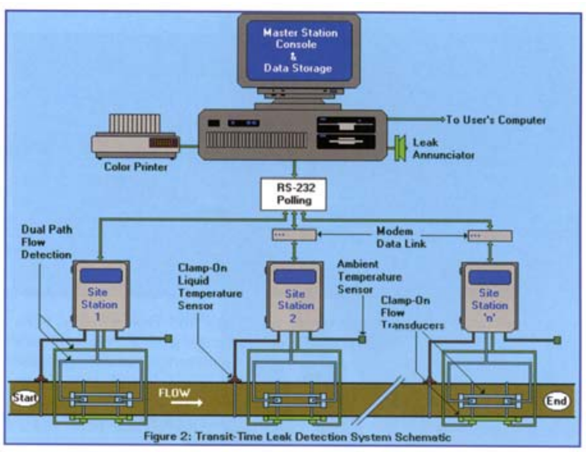


Fig. 2.1.5: Leak Detection by Ultrasonic Flow Meters (USFM)

Advantage of the Technology

- It is a non-intrusive electronic device without moving parts.
- USFMs do not disturb pig passage.
- The technique also provides velocity capabilities along with leak detection.

Application to Offshore/Deepwater

- Ultrasonic flow meters have been successfully installed in underwater environments.

Application to Multiphase Flow

- This system has limitation in detecting leak in higher Gas Volume Fractions (GVFs).

Application to Arctic

- Ultrasonic flow meters have been successfully installed in arctic environments.

Limitation of the Technology

- Limited performance related feedback is available from operators on this new technology.

2.1.6 LEAK DETECTION USING VAPOR-MONITORING SYSTEM

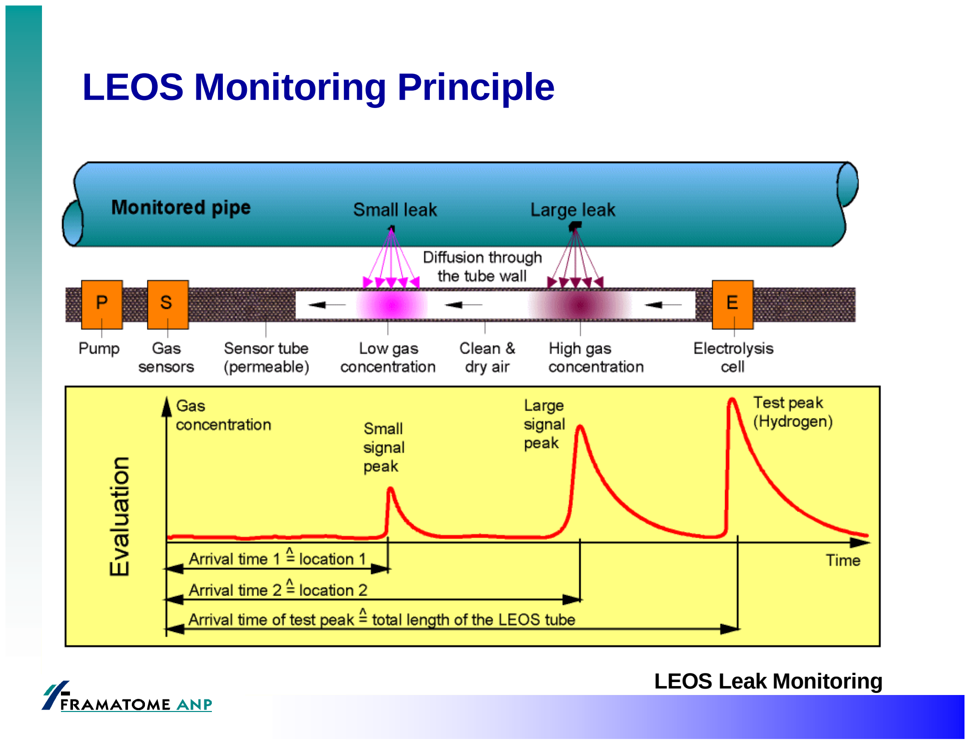
This system detects leak by placing a sensor tube parallel to the pipeline. In the event of leak, the hydrocarbon vapors will diffuse into the sensor tube. The sensor tube is periodically pumped to the base station where the air in the tube passes through a hydrocarbon detector. According to "LASP Leak Alarm System for Pollutants[12]", the location of leak can be located by the peak arrival time at the detector compared with the arrival time of the test gas injected in the sensor tube

The main advantage of the system is that it is a physical method of leak detection and is not dependent on pressure or volume monitoring. This system can detect small leaks which may not be detected by software base methods. Hence this system is ideally suited for leak detection in multiphase flow applications.

This leak detection system needs higher capital investment, however does not require a lot of maintenance. The detection system is installed at the base station. Only the sensor tube needs to be installed along the pipeline, but the detector system can be located in an accessible location. The sensor tube can withstand substantial hydrostatic pressure. These points are a plus for using this system for subsea pipeline leak detection.

One of the drawbacks of this leak detection system is its slow response time for detection. The response time is dependent on the pumping rate through the sensor tube. This system is therefore designed for low level leak detection but not for rapid response. It should be coupled with another leak detection system for faster response of leak detection.

LEOS developed by Siemens is an external vapor monitoring leak detection system. It detects leaks using a low-density polyethylene (LDPE) sensor tube.



Source: Siemens (LEOS)

Fig. 2.1.6: Leak Detection by Vapor Monitoring System

Advantage of the Technology

- This system can detect small leaks, which are not detectable by conventional leak detection methods based on pressure or flow balance.

Application to Offshore/Deepwater

- This system has been used in shallow water depths.

Application to Multiphase Flow

- The vapor monitoring system can detect leaks in multiphase flow.

Application to Arctic

- This system has been in used in Arctic (Northstar Development).

Limitation of the Technology

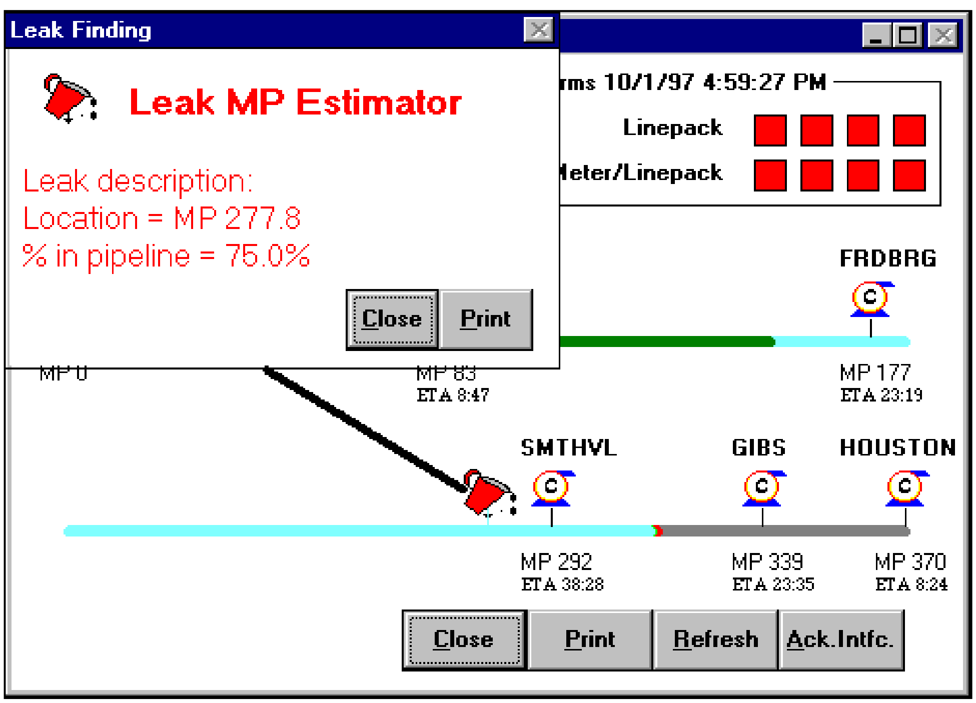
- The time for detection of leaks is dependent on pumping capacity.
- The cost of detection of leaks can be very high.
- The system may not be very effective for deepwater, as the gas can be soluble at that depth.

2.2 SOFTWARE BASED METHODS

2.2.1 LEAK DETECTION USING MASS BALANCE METHOD

The mass balance technique is based on the principle of conservation of mass. For a pipeline the flow entering and leaving the pipe can be measured. The mass of the fluid can be estimated from the dimensions of the pipe and by measuring process variables like volumetric flow rate, pressure and temperature. When the mass of the fluid exiting from the pipe section is less than estimated mass, a leak is determined. The pressure is used for determining the line packing. This is the most widespread technique currently in use. This technique requires high accuracy of the instruments measuring flow, pressure and temperature variables. This software requires the flow variable to be converted into mass flow rate or standard volumetric flow rate.

Enviropipe Applications Inc. has a leak detection system based on the above method.



Source: Enviro Pipe Applications

Fig. 2.2.1: Leak Detection by Volumetric and Mass Measurement Methods

Advantage of the Technology

- It is commercially available and has been used on oil pipelines. Currently this is the most widely used technology for leak detection.
- Mass balance method is a software system relying on the existing pipeline instrumentation and SCADA system. Hence there are no costs associated with data acquisition and extra instrumentation.
- Unlike transient models, it does not rely on detailed pipeline simulation. Hence it does not require long hours of tuning and controller training.

Application to Offshore/Deepwater

- It has been successfully applied in both arctic and underwater environments.

Application to Multiphase Flow

- There is no available multiphase flow leak detection capability with this technology.

Application to Arctic

- This software has been proven in arctic and underwater environments and has been installed on pipelines in Alaska and Canada

Limitation of the Technology

- The Mass Balance system responds to the leak only after the pressure waves corresponding to the leak have traveled to both ends of the line. Depending on the size of the leak this may take a long time.
- It is dependent upon the accuracy of the pipeline instrumentation.

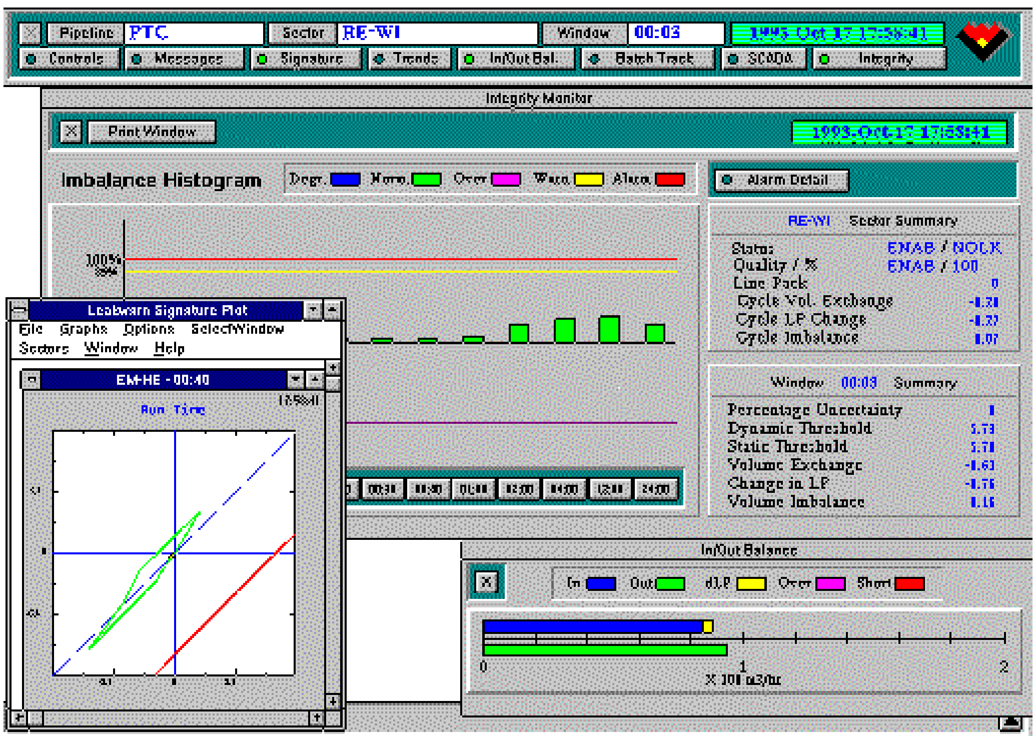
New Developments

- Software incorporating two independent methods such as PPA™ and Mass Balance are being combined to give a more effective leak detection system.

2.2.2 LEAK DETECTION USING REAL TIME TRANSIENT METHOD (RTTM)

The Real Time Transient Method (RTTM) for leak detection uses mass, momentum, energy, and equation of state algorithms for determining the flow rates. The difference between the predicted and measured values of the flow variable is used to determine leak in the pipeline. This technology requires measurement of flow, pressure and temperature variables along with use of above algorithms. RTTM is continuously analyzing noise level and normal transient events to minimize false alarms. Leak thresholds are adjusted based on statistical variations in flow.

Simulutions Inc[14] has a leak detection system based on Real Time Transient Method



Source: Simulations Inc.

Fig. 2.2.2: Leak Detection by Real Time Transient Modeling

Advantage of the Technology

- It can compensate for monitoring during packing and unpacking of the line.
- It can minimize false alarms by adjusting alarm thresholds according to current operating conditions.
- It can detect leaks of less than 1 percent of flow.

Application to Offshore/Deepwater

- It has been successfully applied in underwater environments.

Application to Multiphase Flow

- It reportedly operates sufficiently well under multiphase flow conditions.

Application to Arctic

- It has been successfully applied in cold climate.

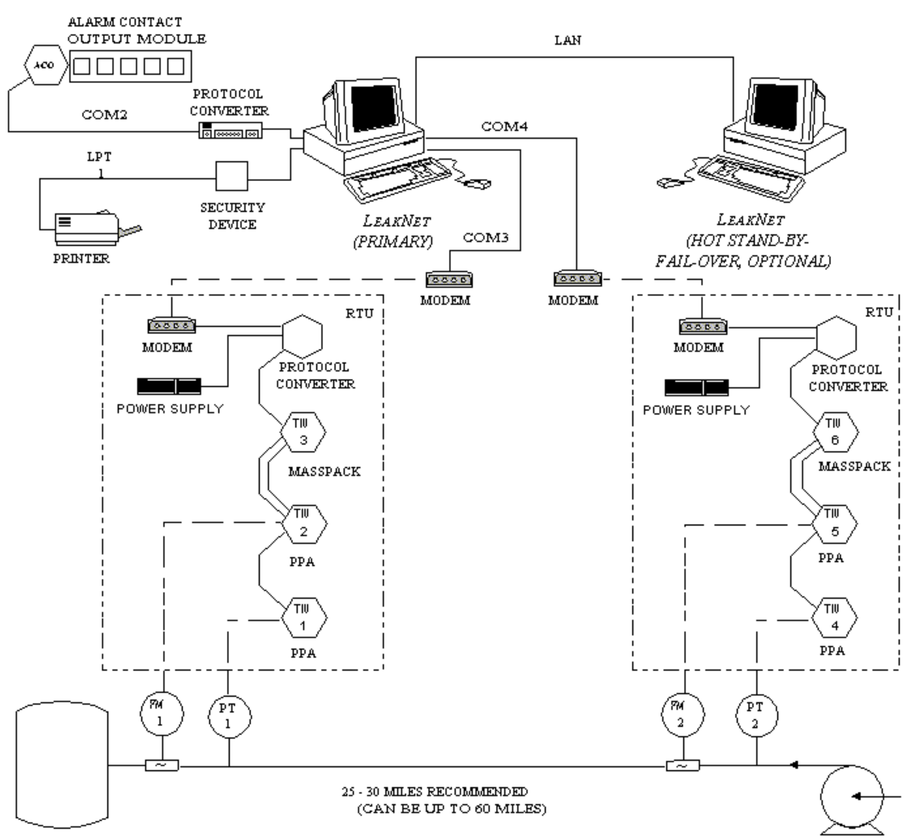
Limitation of the Technology

- Real Time Transient Method is a very expensive technology. It requires extensive instrumentation for real-time data collection.

- Models are complex and require a trained user. Models may require full time SCADA support.

2.2.3 LEAK DETECTION BY PRESSURE POINT ANALYSIS ™

Pressure Point Analysis ™ is an EPA-approved, patented leak detection technology. The Pressure Point Analysis ™ leak detection method (Ed Farmer, 1989 and Farmer et al, 1991) is based on the premise that the statistical property of a series of pressure measurements taken on a pipeline are different before and after a leak occurs. The Pressure Point Analysis ™ leak detection system detects leak by comparing current pressure signals with the trend at a point along the pipeline. Proprietary software determines if the behavior of these two signals contains an evidence of leak.



Source: EFA Technologies Inc.

Fig. 2.2.3: Leak Detection by Pressure Point Analysis™

Advantage of the Technology

- It has been a proven technology for arctic environment, subsea pipelines and multiphase applications.
- Software incorporating two independent methods, Pressure Point Analysis ™ and Mass Balance method are being combined to give a more effective leak detection system.

Application to Offshore/Deepwater

- It has been successfully applied in underwater environments.

Application to Multiphase Flow

- It operates sufficiently well under multiphase flow conditions.

Application to Arctic

- It has been successfully applied in cold climate.

Limitation of the Technology

- Is affected by batch processes where valves are opened and closed and flow are increased. This transient effects may create a time period where leak detection is not possible.
- Multiphase flow will act to dampen the propagation of pressure signals and create considerable background noise due to slugging and other internal flow structures.

Chapter 3

EMERGING NEW TECHNOLOGIES IN LEAK DETECTION

The following new technologies are being introduced into leak detection from other industrial applications:

1. Artificial Neural Network
2. Frequency Response Method
3. Well Logging
4. Air Surveillance
5. Satellite High Resolution Reconnaissance Photography
6. Intelligent Pigs
7. Electrical Resistance Tomography

A brief description of these technologies is given below

A leak detection system for pipelines was developed by using *Artificial Neural Networks* (ANN) (Belsito et. al.; Kikai et. al.) for leak sizing and location. This system can detect and locate leaks down to 1% of flow rates in about 100 sec for pipelines carrying hazardous materials. A reference pipeline was considered for practical implementation of the package. The ability of the package to withstand spurious alarms in the event of operational transients was tested. The compressibility effect, due to 'packing' of the liquid in the pipeline, causes many such spurious alarms. Using a computer code in conjunction with the ANN to compensate for the operational variations and to prevent spurious alarms performed adequate preprocessing of the data. The package detects leaks as small as 1% of the inlet flow rate and correctly predicts the leaking segment of pipeline with a probability of success that is greater than 50% for the smallest leak. In all cases, the timely response of the system was seen as a major advantage.

*The Frequency Response Method (*Mpesha, 2001*)* is used to determine the location and rate of leakage in open loop piping systems. A steady-oscillatory flow, produced by the periodic opening and closing of a valve, is analyzed in the frequency domain by using the transfer matrix method, and a frequency response diagram at the valve is developed. For a system with leaks, this diagram has additional resonant pressure peaks (herein referred to as the secondary pressure amplitude peaks) that are lower than the resonant pressure amplitude peaks (herein called primary amplitude peaks) for the system with no leaks. Several piping systems have been successfully analyzed for all practical values of the friction factor to detect and locate individual leaks of up to 0.5% of the mean discharge. The method, requiring the measurement of pressure and discharge fluctuations at only one location, has the potential to detect leaks in real-life pipe systems conveying different types of fluids, such as water, petroleum, and so on.

The Well Logging Tool (Reservoir Saturation Tool, RST) has been used in the oil industry for more than 10 years. The system measures the ratio of carbon to oxygen (COR) in the soil formation, by sensing the gamma ray emitted from neutron scattering. It has a detection range of 10 inches. The recommended arrangement is a non-PVC tube, which is more than 10 inches from the pipeline. The pigging speed of the logging tool will create a limitation to the minimum amount of leak that can be detected.

Air surveillance (Aminian; Rence) can be through visual observation, or through use of Side looking airborne radar, Ultraviolet (UV) and infrared (IR), forward-looking infrared (FLIR) imaging, or High-resolution Reconnaissance photography. The four airborne sensors listed are not routinely used for surveillance. The sensitivity, resolution and reliability of these combined instrumentation packages have been proven in practice.

Satellite High-resolution Reconnaissance photography has not yet offered adequate reliability (due to cloud cover) nor the desired resolution for detecting small spills.

Intelligent Pigs can use caliper logging, photographic or television logging, magnetic flux logging or ultrasonic logging to detect leaks in the pipelines. These pigs are routinely run more for prevention then detection of leaks. Periodic pigging of sensitive lines should be carried out subsea to identify low wall thickness (badly corroded) pipe sections.

Electrical Resistance Tomography (Josep et. al, 2001) is a non-invasive method for detecting leaks in buried pipes, which uses a surface linear electrode array perpendicular to the axis of the pipe. Two electrodes inject current and the other electrodes detect the drop in voltage on the ground surface using both the dipole-dipole array and a modified Schlumberger array. A single-step reconstruction algorithm based on the sensitivity theorem produces 2-D images of the cross section. A personal computer controls current injection, electrode switching, and voltage detection, which allows various arrays of electrodes to be easily tested and speeds up the measurement process.

Patented Technology in Leak Detection:

More and more patented technologies are emerging for leak detection. Two of the technologies that are promising are:

a. Fiber optics

b. Electrical cable

These technologies have already been discussed in Section 2. A brief summary of patents for these sensor types is shown in the schematics Figure 3.1 and Figure 3.2.

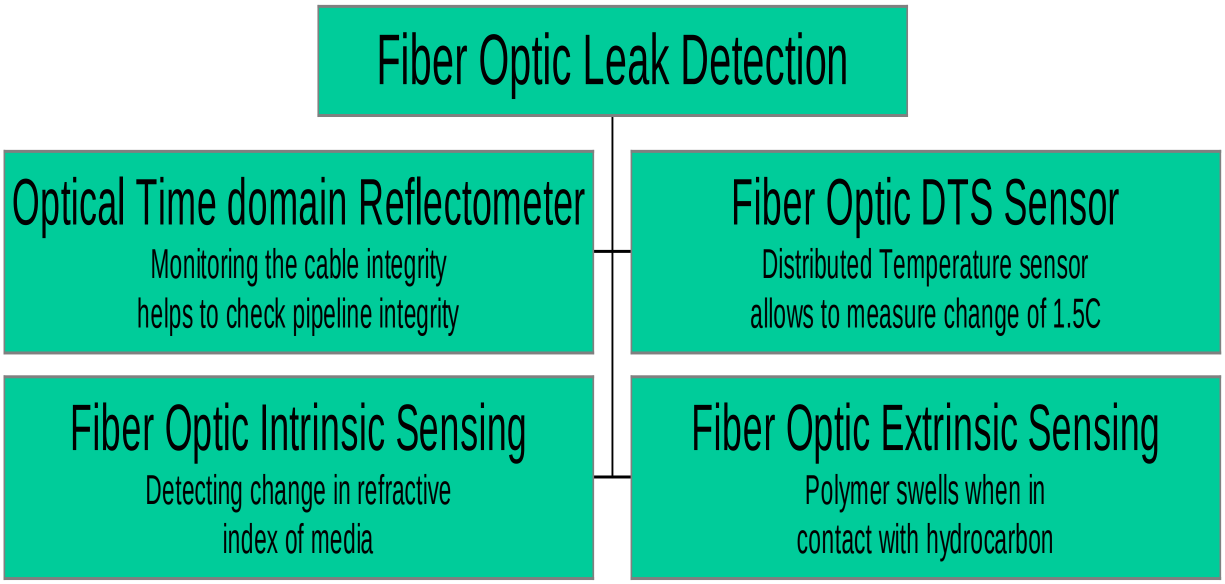


Figure 3.1: Patented Technology in Fiber Optics

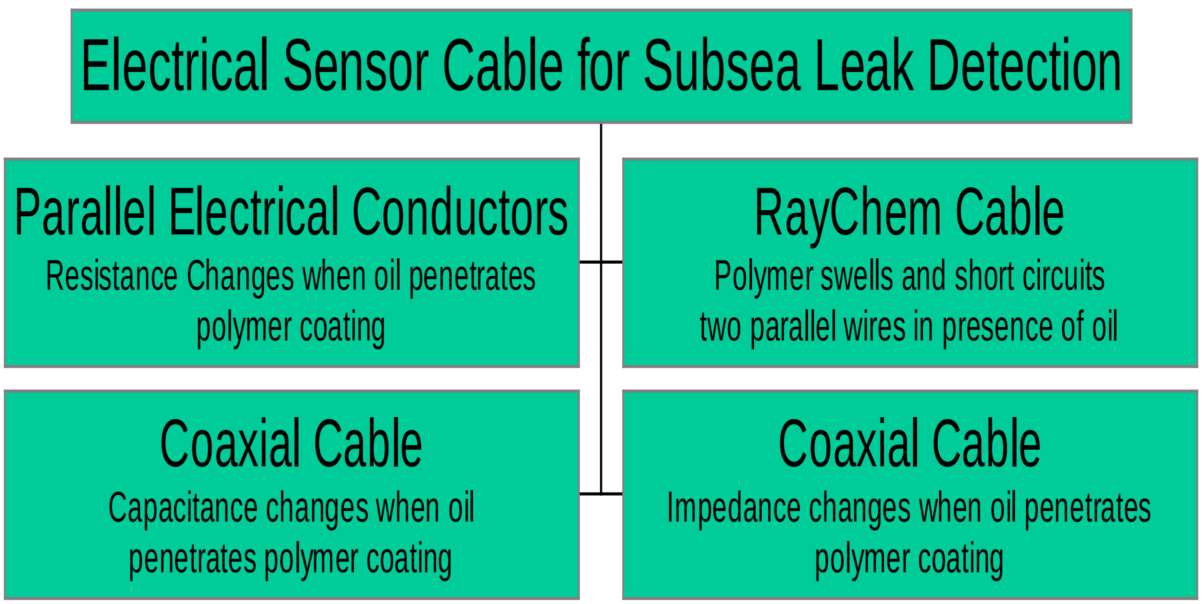


Figure 3.2: Patented Technology in Electrical Sensor Cables

Chapter 4

BEST AVAILABLE TECHNIQUE FOR DETECTION OF LEAK IN SUBSEA, ARCTIC AND MULTIPHASE APPLICATIONS.

The best available technique is evaluated for each of the above applications based on the following criteria

1. Can the system be used in the required application?
2. Each application (subsea/arctic/multiphase) imposes some other physical restriction for detection of leaks. Can the leak detection method work under the physical restrictions?
3. Is the leak detection method a proven technology in these applications? If not the system is still to be proven either because it requires further research & development or it is not implemented due to economics.
4. System provides the best cost-benefit.
5. The system surpasses present regulatory stipulations for leak detection thresholds.
6. The combined system provides low threshold detection capability
7. The combined system provides rapid response in detection and location of leaks.

Steps 1-3 were used to eliminate the leak detection techniques for a particular application. Selecting the Best Available Technique from the proven technology is based on steps 4-5.It is recommended to use alternate methods along with the Best Available Technique. This has been evaluated in steps 6-7.

Some other studies have looked into the following issues from the instrumentation point of view.

- Sensitivity of the leak detection system
- Reliability of the leak detection system
- Robustness of the leak detection system
- Accuracy of the leak detection system

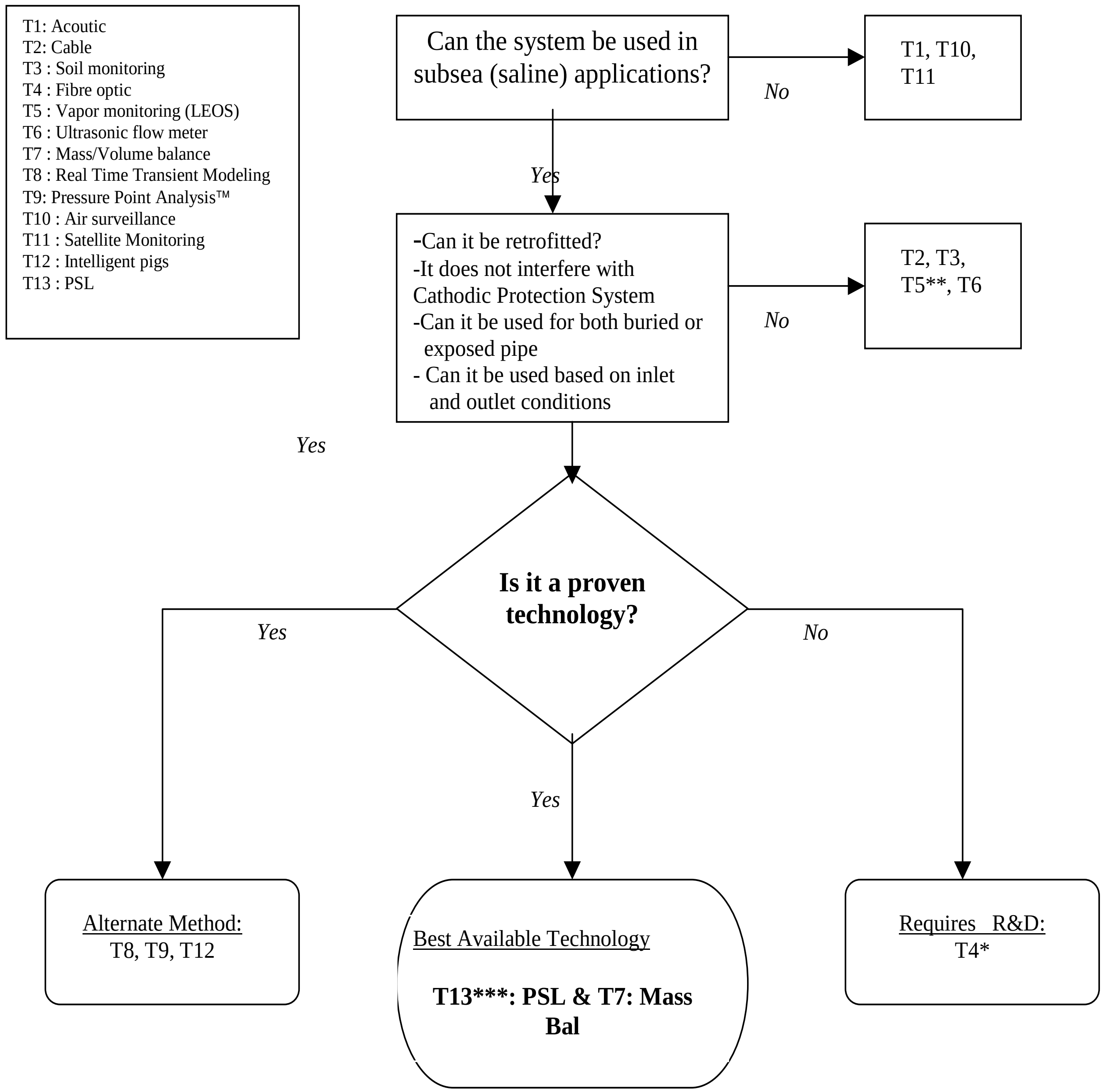
These studies have considered the issue of false alarm at length. Although these aspects are important, they have not been considered explicitly in this evaluation. Once the system has been proven in the field, it has been considered that the leak detection system meets the above criteria.

Leak Detection Techniques for Subsea/Deepwater Applications.

Although the application of leak detection software to offshore pipelines should not pose a problem, there are some significant differences between onshore and offshore pipelines that can affect leak detection system capability. The installation of instrumentation, SCADA and telemetry units is usually limited to surface locations. Another difference is the hydrostatic pressure exerted by the sea on an offshore pipeline. The external pressure might reduce the leakage rate. For the case of hydrostatic pressure a leak results in flow of external water into the pipeline. Since subsea processing may not be a viable option, most of the offshore lines carry multiphase, which makes leak detection even more difficult. The detection capability is further augmented by the solubility of gas in water.

The leak detection system for subsea applications must be sufficiently rugged to endure the extremely harsh environment both during installation and operation. During the life of the project, the leak detection system may experience vertical displacements, thermal cycles, and high saline conditions. The system must not interfere with or compromise the Cathodic Protection (CP) system.

The performance objectives were evaluated for each technique to arrive at the Best Available Technique for leak detection. Based on economics the most commonly used system is Pressure Safety Low (PSL) Pilot/Monitor. However, as will be demonstrated in Chapter 6, PSL's simply cannot detect small leaks. Therefore, PSL's should be combined with other methods. When inlet flowrate are available mass balance and frictional based methods can be utilized. For multiphase flowlines and in cases when inlet flow rates are not available, PSL's should be combined with hardware based methods such as vapor monitoring. Cost is also an issue while selecting the software-based technique of Mass balance vis-à-vis Real Time Transient Modeling. For single-phase fluid it is more economical to use the mass balance technique while Real Time Transient Modeling will give better results for multiphase flow. Fig. 4.1 shows a flow chart for selection of the Best Available Technique for Subsea applications.

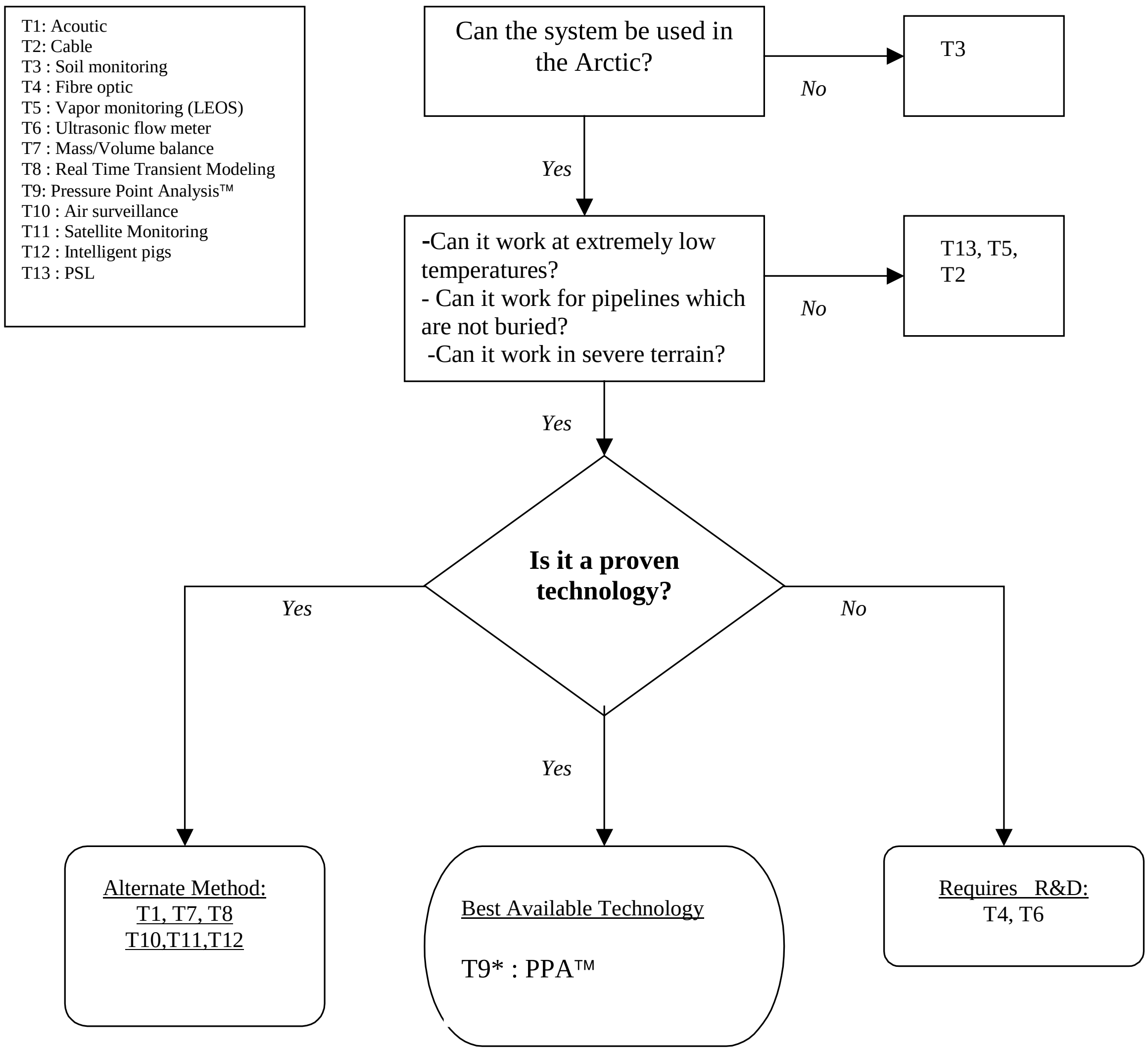


T4*(Fiber Optic): The fiber optic cable needs to be replaced often which could be an issue for subsea application.
T5**(LEOS): This technique can be used for shallow water depths and for small length of pipelines.
T13***(PSL): Flow assurance analysis for the subsea system should be done and various other alternate methods to be used in combination with this technique.

Fig 4.1: Best Available Technology for Leak Detection in Subsea Applications

Leak Detection Techniques for Arctic Applications

The arctic introduces regional considerations in selecting the leak detection system. The arctic environment has very large thermal cycle over a year. The temperature changes are of the order of 100 ^{O}F and above. The system selected must be able to work in these temperature ranges. The surface pipelines are not buried and have significant elevation changes. This eliminates use of leak detection techniques which can be used only for buried pipelines. The elevation change creates pressure differential within the pipe. Since the distances are large, pump stations are required. Pumping itself creates pressure fluctuations in the line. The leak detection system must be able to distinguish between the signatures due to a leak and the pump-induced pressure fluctuations. The Pressure Point Analysis (PPA)™ technique is the preferred methodology considering all the above selection criteria for single-phase pipelines. Fig. 4.2 shows a flow chart for selection of the Best Available Technique for Arctic applications.



T9*(PPA™): This technique should be combined with one hardware based method and one software based method technique for best performance.

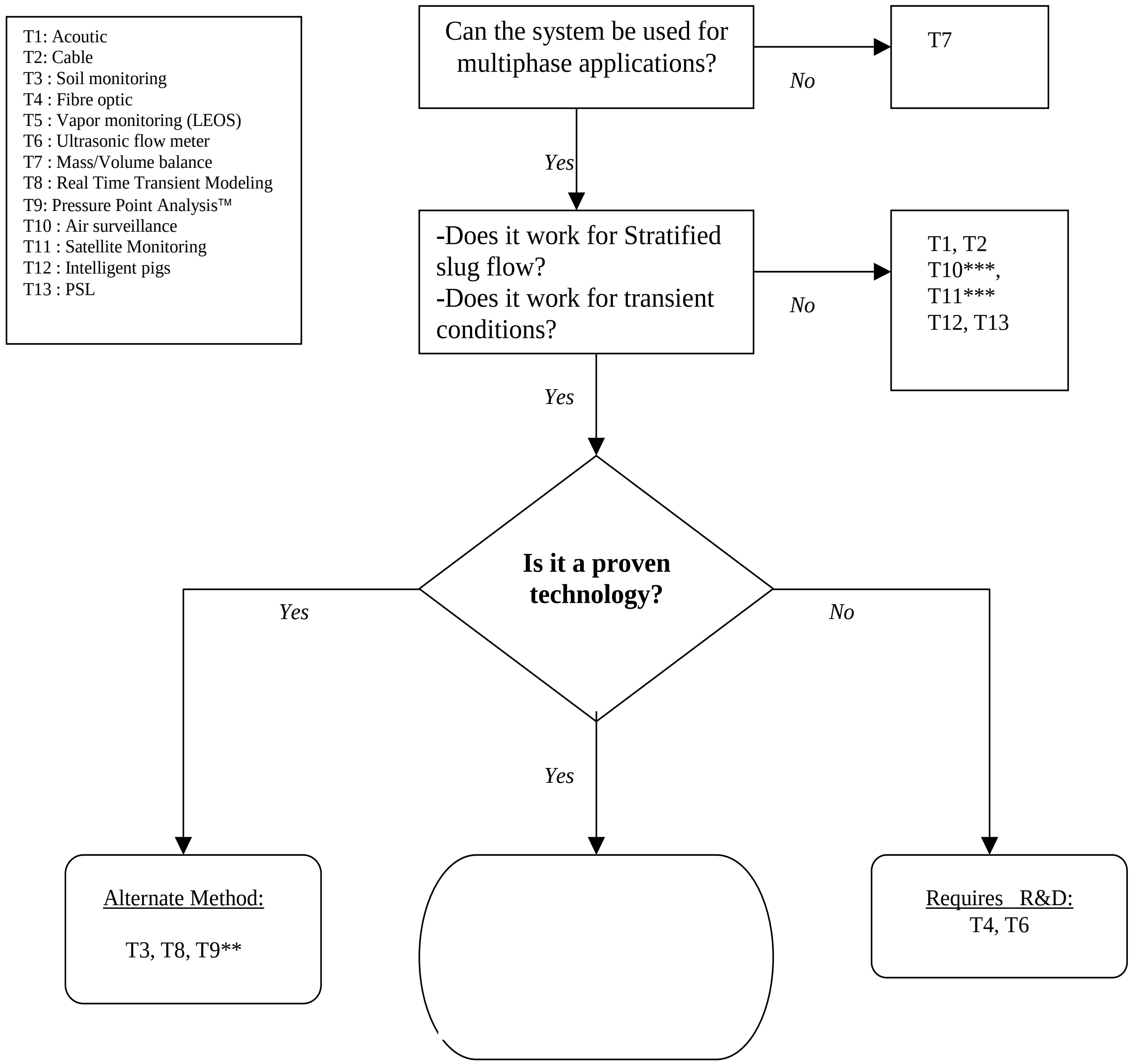
Fig 4.2: Best Available Technology for Leak Detection in Arctic Applications

Leak Detection Techniques for Multiphase Applications

While PSLs are effective in detecting leaks in single-phase transmission transportation pipelines, this approach is not effective for multiphase flow. Only in case of the bubble flow will PSLs be able to effectively detect a leak. The vendor-supplied data of leak detection for 1 % loss of mass flow rate does not apply to multiphase flow. It is very important to perform flow modeling to analyze what can be detected and what cannot be detected.

Based on the above considerations it is concluded that for leak detection in multiphase flow (slug flow, stratified flow) it is mandatory to have a hardware-based method. The software-based method may be able to detect leaks only for certain flow considerations. The detection map for different flow regimes is given in chapter 7.

The recommended technique based on the above criteria is vapor monitoring through tubes. This method can detect even very small leaks. This technique has a restriction in terms of response time and should be complemented with a suitable technique. Fig. 4.3 shows a flow chart for selection of the Best Available Technique for Multiphase applications.



- Multiphase can be in deepwater or arctic applications. The leak detection technique then must use a combination of techniques that are applicable to deepwater/arctic.

T9(PPA™)**: This technique has been used with mixed results.
T10/T12***: These are more dependent on visibility of leak rather then single phase/multiphase.
T5****: Not a very rapid leak detection system hence should be combined either with T8 or T9.

Fig 4.3: Best Available Technology for Leak Detection in Multiphase Applications*

Pipe-in-Pipe Technology

Pipe-In-Pipe (PIP) applications now used extensively in offshore are not for containment but for thermal and carrier (bundle) considerations. There are scenarios especially for oil lines where PIP may provide enhanced safety against containment. There is no effective method of monitoring corrosion of the outer pipe as none of the Non Destructive Testing techniques (MPI, UT) will work.

The best method to monitor leaks is in the annulus of the two concentric pipes. This can be achieved best by vapor monitoring through tubes. Another method is to install packers with bleed-off valves with pressure monitoring at the end of pipe. No such system exists as of today but can be custom designed.

Chapter 5

ROLE OF MULTIPHASE METERING IN LEAK DETECTION

Multiphase metering is a rapidly evolving technology which, in recent years, has experienced significant improvements in accuracy and turndown. This technology has the potential for use in leak detection and may be particularly valuable for obtaining the inlet flow rates. For many deepwater, subsea and arctic flowlines the well is the inlet to the pipelines. The multiphase mixture entering these flowlines is rarely metered due to the expense of separating the phases and metering prior to entering the flowline. Unfortunately, this negates the commonly used mass balance techniques that have been applied for many years by the onshore transmission industry. For these applications the flow into the pipeline is an unknown. In this chapter, multiphase metering, and how it may be used in leak detection is discussed.

5.1 Overview of Multiphase Metering Technology

An overview of multiphase metering technology was given by Scott (2002), Mehdizadeh (2001) and Falcone, et. al (2001). The objective is measurement of oil, water and gas rates without the need for complete separation of the phases. This provides a number of advantages, such as:

- Reduction of stabilization time versus a separator based system
- Reduction in the size and weight of the metering process
- Reduction in cost

In many case the expense of metering the flow entering the pipeline is extremely large or beyond current technology capabilities. For example, consider the Canyon Express development in the

U.S.A. Gulf of Mexico (Figure 5.1). This development utilized subsea flowlines to produce three subsea completed fields back to a shallow water hub platform. Installation of a subsea separator system to separate and meter the flow before entering the pipeline was not practical and has only been attempted in a few isolated pilots. However, use of subsea multiphase meters is a proven technology and can be performed at much less expense. This represents the first use of subsea multiphase meters in the U.S.A. Gulf of Mexico, however, these are only two-phase wet-gas meters.

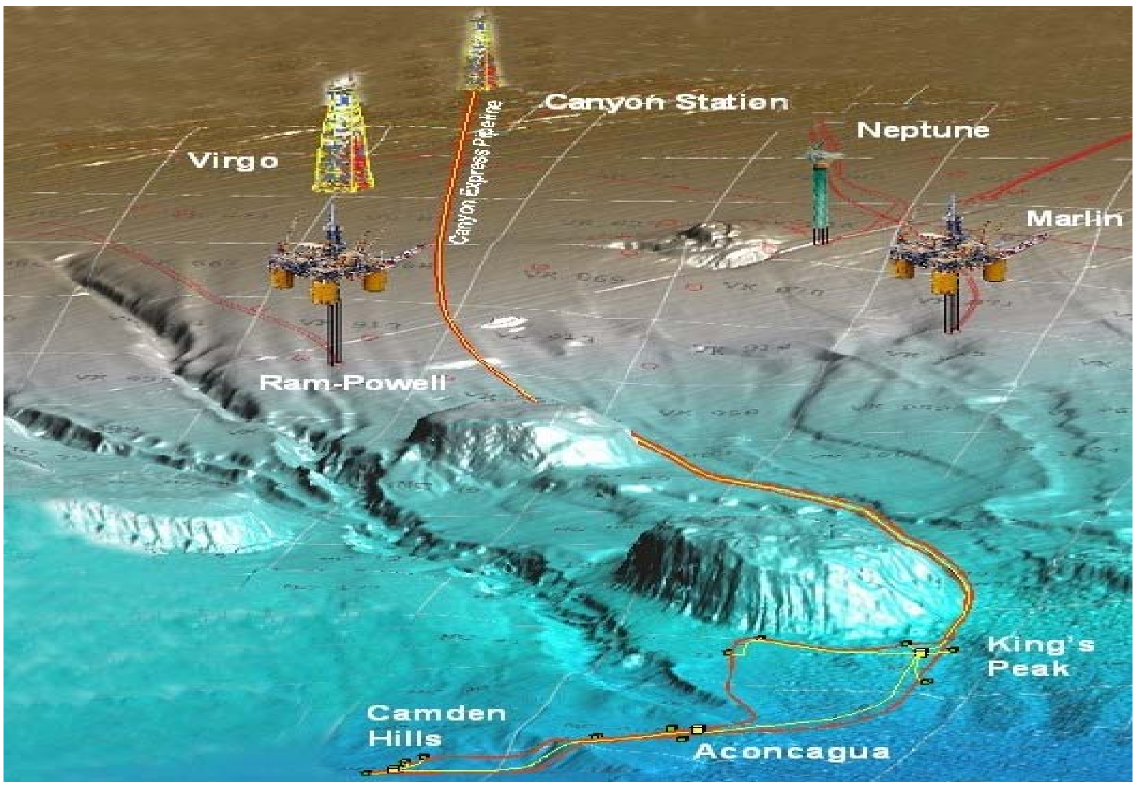


Figure 5.1: Canyon Express Subsea Development – U.S.A. GOM

A number of multiphase meters are commercially available. Figure 5.2 shows a multiphase meter which has been utilized in the Petrozuata Field in Venezuela for several years. Figure 5.3 shows a portable meter used for a variety of applications including extended production testing of new wells. To obtain the flow rates for the individual phases, several measurements are made. Use of a venturi meter is common to almost all multiphase meters. Figure 5.4 shows the internal configuration of a meter by Schlumberger. This meter combines a venturi with dual gamma ray meters to determine the separate oil, water and gas flow rates.

Figure 5.2: Multiphase Meter in Use in Venezuela

Figure 5.3: Portable Multiphase Meter (Schlumberger)

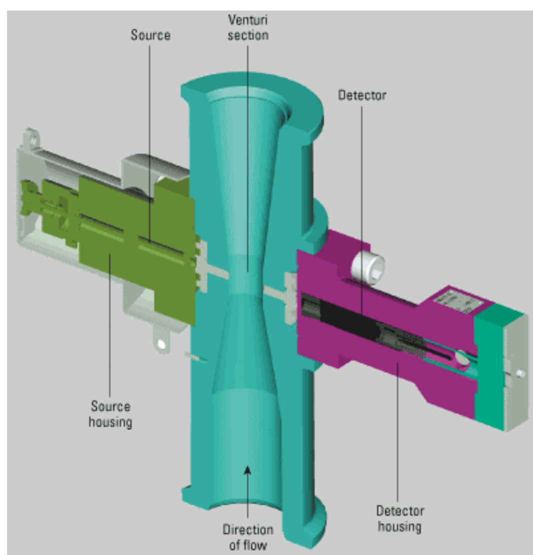


Figure 5.4: Sensor Utilized in Schlumberger Multiphase Meter (Schlumberger)

Other multiphase meters are termed wet-gas meters and focus on measurement under extremely high Gas Volume Fraction (GVF) conditions. Figure 5 shows a wet gas meter that was recently installed in the U.S.A. GOM. This meter also uses a venturi as well as an additional pressure drop device. In general the meter can determine the gas-liquid flow rates, but cannot split the liquid phase into percentages of oil and water.

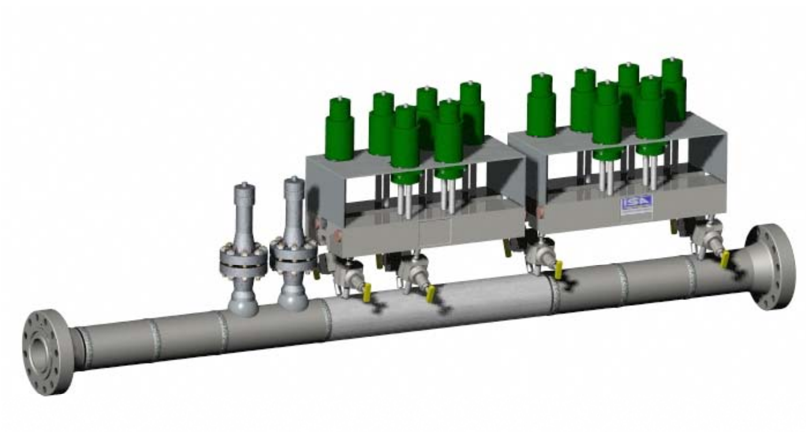


Figure 5.5: Wet-Gas Multiphase Meter (Solartron)

As indicated by Mehdizadeh, approximately 600 multiphase meters have been installed world-wide and 50 have been installed subsea.

5.2 Assessment of Application to Leak Detection

Multiphase metering has the potential to impact pipeline leak detection is several areas:

- Provide Inlet Flow Rates for Difficult Multiphase Applications
- Eliminate “Lag Time” for Rate Data

The “lag time” is a unique problem for multiphase applications. A separator located at the end of the pipeline is the conventional method to obtain the oil, water and gas flow rates. After the fluids are separated, conventional single-phase meters are utilized to provide the oil, water and gas rates required by the leak detection system (Figure 5.6).

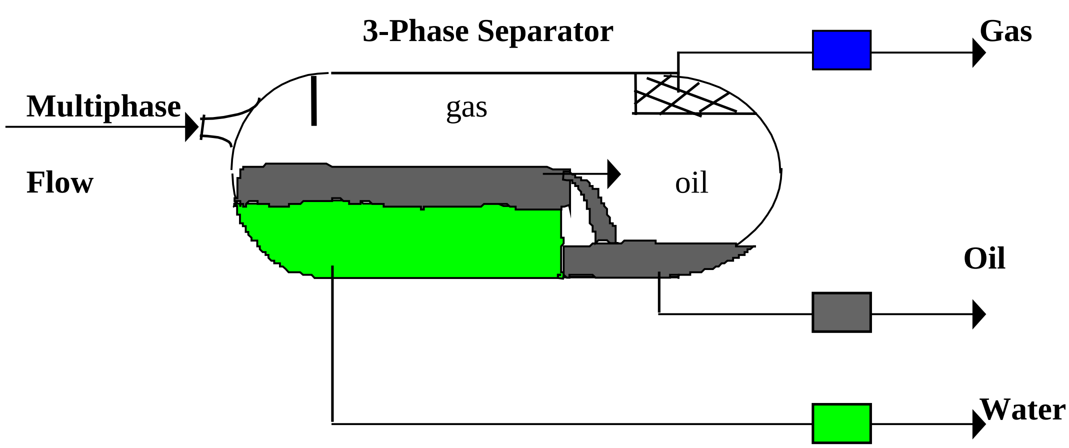


Figure 5.6: Three-Phase Separator Used to Obtain Flow Rate Exiting Pipeline

In some applications these vessels can be very large. Figure 5.7 shows a high pressure separator utilized in the Prudhoe Bay Field off Alaska. The volume of the separator introduces a substantial lag time before changes in rates can be determined. In some fields, a steady-state flow is never obtained due to constant slugging. To obtain reasonable values for flow rates, the rates are averaged over a 4-hour period to perform routine production testing in the U.S.A. federal water. The rates are averaged to remove artificial fluctuations introduced by changing liquid levels in the separator. For leak detection this introduces an enormous time delay in mass balance and pressure loss calculations.

Figure 5.7: High Pressure Separator - Prudhoe Bay Field, Alaska

To date, multiphase meters have only been applied to leak detection in a few isolated applications. Factors limiting wider application of multiphase meters in leak detection are:

- <u>Poor Accuracy of Oil Flow Rate Measurement</u> – As shown by Kouba (1998), the uncertainty of the oil flow rate measurement can be significant. For many oilfield applications the oil-water-gas multiphase mixture is comprised largely of gas and water, with oil representing only a small percentage of the overall flow. To obtain a $\pm$ 20% accuracy in the oil rate measurement, GVF and water cut must both be less than 65%.

This is a significant limitation. For example, for an oil well operating with a GOR of 300 scf/STBO and at a wellhead pressure of 150 psig the GVF at the wellhead would be near 98%. Only applications where multiphase metering is performed at very high pressure will be able to meet this $\pm$ 20% criteria. Another concern is that even under ideal conditions, the accuracy of the flow rate measurement is poor compared with the leak detection accuracy that is desired. For example, if inlet and outlet oil rates can only be measured to an accuracy of $\pm$ 10% what size of leak can be detected? In this case a substantial size leak could continue undetected using conventional mass balancing methods.

- Variable Accuracy – Unlike single-phase metering, the accuracy of multiphase meters is highly dependent on the composition of the oil-water-gas flow. Increases in GVF and water cut result in a dramatic increase in the uncertainty of the oil measurement.

To improve the accuracy of multiphase meters, there has been a trend toward use of partial separation prior to measurement. This approach utilizes a compact separator to remove a large percentage of the gas, thereby concentrating the oil phase and improving the accuracy of the oil rate measurement. These compact separators are on the order of 10-100 times smaller than conventional gravity based separators and utilize centrifugal acceleration to enhance separation based on density differences. Figure 5.8 shows one of these partial separation based multiphase meters. This type of multiphase meter is comprised of a compact gas-liquid separator and a conventional single-phase gas and liquid meter. The oil and water rates are obtained using a microwave based water-cut meter. While being more bulky than the multiphase meters discussed previously it can provide the accuracy needed for leak detection purposes. It has, however, not be adapted for subsea installations.

Figure5.8: Partial Separation Based Multiphase Meter (PhaseDynamics)

The role of multiphase meters in leak detection is limited at this time. Poor accuracy limits their use to only a few applications, such as wells operated with low GVF at the meter (high pressure applications) and low water cuts. In these cases multiphase meters may provide some information to mass balance type methods. But it is likely the meters will not be cost effective for leak detection purposes alone, i.e. other uses must be used to justify the additional cost. For pressure loss methods, the multiphase meters can provide information regarding large to moderate size leaks and would accelerate the detection of these leaks. For wet gas pipelines, the detection of a gas leak would be assisted by the use of wet-gas meters. However, detection of small releases of condensate or produced water from these pipelines would not be possible.

Chapter 6

MULTIPHASE LEAK DETECTION SIMULATION

This chapter examines the performance of a multiphase flowline that has been compromised. The goal is to examine the pressure response to a leak and how this response changes with multiphase flow pattern, leak location and the size of the leak. Extensive review of the literature reveals that the subject of multiphase leak detection is in its infancy stage. Virtually no experimental work was found for modeling of multiphase leaks. However, with the advent of transient multiphase flow simulators, the performance of a flowline experiencing a leak can be approximated. These transient codes can not only predict the ultimate pressure response due to a leak, but can be used to estimate how long it will take for a detectable pressure change to occur at a particular location in the flowline. This allows direct examination of the Pressure Safely Low (PSL) pilots often used in the U.S.A. Federal waters. Given a particular PSL setting and location, these codes can show what sizes of leaks and what leak locations can be detected and those that can never be detected by a PSL. It also allows examination of pressure drop and material balance leak detection methods and a better understanding of their effectiveness for multiphase flowlines.

Several problems are unique to multiphase flow. These include:

- Increased pressure fluctuations – having more than one phase in the pipe tends to increase fluctuations in local pressure.

- Flow patterns - When two or more phases are present in a flowline, the phases can assume different distributions within the pipe due to slip between the phases.

- Leak location along the circumference of the pipe – if the leak location is near the bottom of the pipe, the liquid phase will leak for some flow patterns, while a leak near the top of the pipe will tend to leak the gas phase for some flow patterns.

First analytical modeling of a leak in a multiphase flowline is discussed and then OLGA results for a simultaneous shut-in test are presented. The effect of flow pattern on leak response in a multiphase flowline is then detailed.

Analytical Modeling

The single-phase leak equation for gas flow in terms of inlet and outlet pressure as shown by Scott, S.L. and J.Yi (1998) is given by:

$$q = C\,F_L\ (P_{in}^2 - P_{out}^2)^n \qquad \text{……………………………………………...…….(6.1)}$$

where q is the gas flowrate at the outlet of the flowline, C is a constant for a particular pipe, n is normally 0.5 and F_L is the reduction of efficiency due to a leak. F_L is defined as:

$$F_L = [\,1 + L_{LD}\,(q_{LD}^2 + 2\,q_{LD})\,]^{-n} \text{……………………………………………..…..(6.2)}$$

and the dimensionless leak location and leak rate are given by:

$$L_{LD} = L_L / L_P \quad \text{……………………………………….……………………(6.3)}$$

$$q_{LD} = q_L / q \qquad \text{……………………………………………………..…………(6.4)}$$

Where L_p is the length of the pipeline, L_L is the distance to the leak and q_L is the leak rate from the pipeline. As shown by Scott, S.L et al (1999), the outlet gas flow rate in a multiphase flowline experiencing a leak can be expressed as a function of inlet and outlet pressure in the following form

$$q_{sc} = F_{leak} \ (F_{2\text{-}\phi})_q \ (C \, ZT \, f_{SG} \ L_p \ / \ d^5)^{-0.5} \ (P_{in}^2 \ - P_{out}^2)^{0.5} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(6.5)$$

where C is a constant, Z is the real gas compressibility factor, d is the diameter of the pipe and f is the friction factor. The subscript "SG" denotes superficial single-phase conditions. The additional term ($F_{2\text{-}\phi}$), which is called the two-phase (2-ϕ) efficiency is defined as

$$F_{2\text{-}\phi} = (dP / dx)_{SG} / (dP/ dx)_{2\text{-}\phi} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(6.6)$$

Comparing equations 6.1 and 6.5, the additional two-phase term creates a flow regime dependent term, which separates the single-phase flow leak from the multiphase flow leak. This two-phase term creates a change in the response making it much more difficult to detect a leak in a multiphase flowline. However, this type of analysis makes it possible to examine the performance of momentum (friction) loss leak detection methods to determine what size and location of leaks can be detected. This provide greater confidence and understanding than the "black box" approach taken by most leak detection suppliers. As shown by Scott et al. (1999), these methods provide for rapid detection of leaks but have been shown to be high depended upon the location of the leak. This attribute does not fit well with arbitrary detection limits but can act to reduce detection time and will function even without a measurement of flow rate at the inlet of the pipe.

For flowlines where inlet metering is not practical, such as subsea, special testing requirements may be needed to optimize these data driven momentum balance methods. In particular, periodic testing such as the deliverability testing of gas wells, would provide an accurate and up to date estimate of the $F_{2\text{-}\phi}$ term.

Simultaneous Shut-in Test (SSIT)

To emphasize the difference in single and multiphase flow on leak detection a Simultaneous Shut-in Test has been performed using the transient simulator OLGA. Table 6.1 shows the basic data used for the simulation runs detailed in this chapter. An example OLGA input file is given in Appendix-A. As can be seen three different leak locations were investigated

Table 6.1
Typical Data for Simulation

Parameter	Value
Flowline Size (inches)	8" NB
Flowline Length (m)	4,360 m
Leak Location (Distance from wellhead, m)	Near (875 m) Middle (2,600 m) Far (4,270 m)
Leak Size (inches)	1" – 4"
Backpressure for leak (psia)	15

The first case examined is the shut-in response for a pipeline experiencing a leak. The first step is to shut in the pipeline at both the ends i.e. at the wellhead (done remotely from the platform) and at the separator. The response for single-phase gas and for multiphase (volatile oil) is presented here. For a gas pipeline no leak case the pressure stabilized to an average value with time. In the presence of a leak a drastic pressure drop can be observed at both ends, even for a small leak.

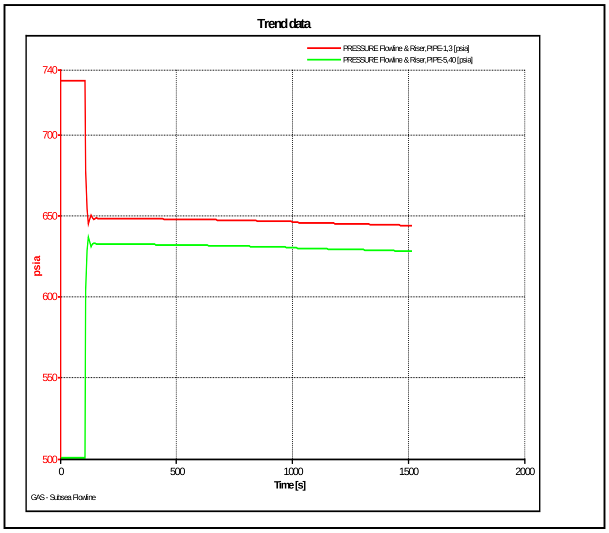


Fig 6.1 (a) Pressure Transient for Pipeline Without Leak (gas)

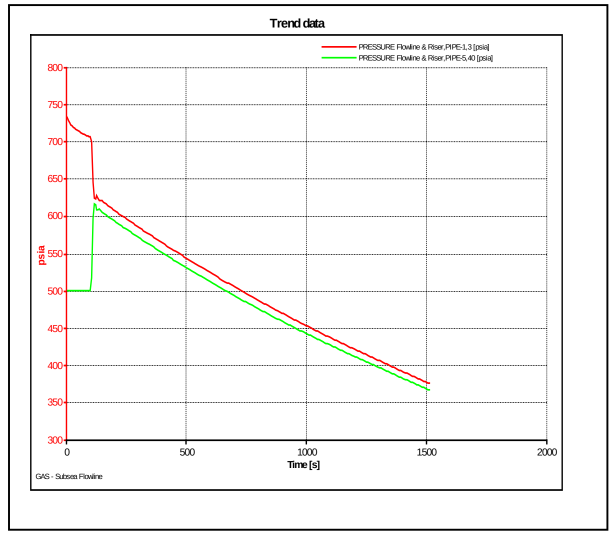
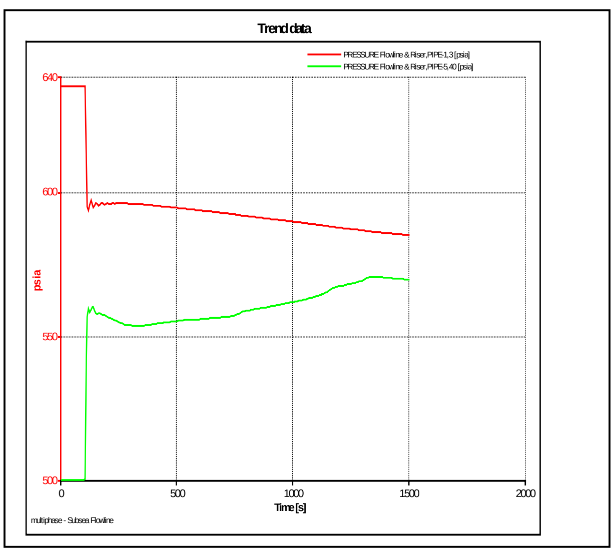
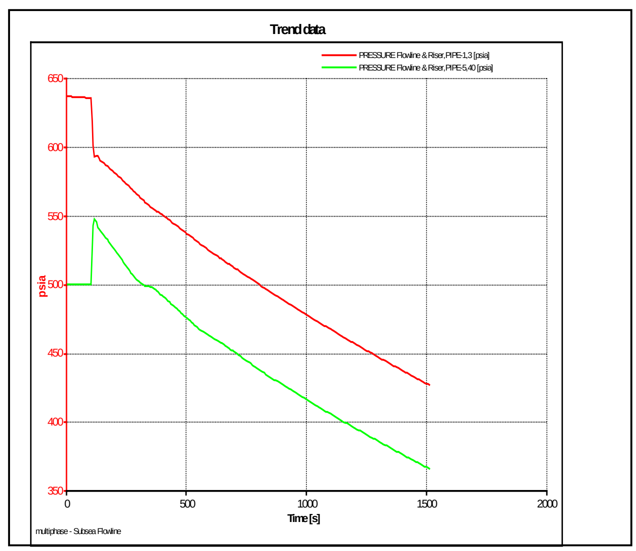


Fig 6.1 (b) Pressure Transient for Pipeline with a Leak (gas)



6.2(a) Pressure Transient for Pipeline without a Leak (Multiphase)



6.2(b) Pressure Transient for Pipeline with a Leak (Multiphase)

For a multiphase pipeline the pressure does not stabilize even for the no-leak case. It is very difficult to determine whether the pressure variation is because of multiphase flow or because of the leak.

Effect of Flow Regime on Detection of Leak

The discontinuities in superficial gas and liquid velocities created at the leak point show very obvious indication of a leak. These changes in superficial gas velocity in gas and liquid also change the liquid holdup and this in turn creates a heavy change in pressure drop.

The multiphase flow can be categorized in the following flow regimes

Distributed flow

- Bubble flow
- Slug flow

Separated flow

- Annular flow regime
- Stratified flow regime

Bubble flow

The Pressure profile for different leak sizes is shown in figure 6.3(a). The leak location is the middle of the flowline for the following plots. The pressure profile changes considerably when there is a change in the flow regime i.e. for extremely high leaks.

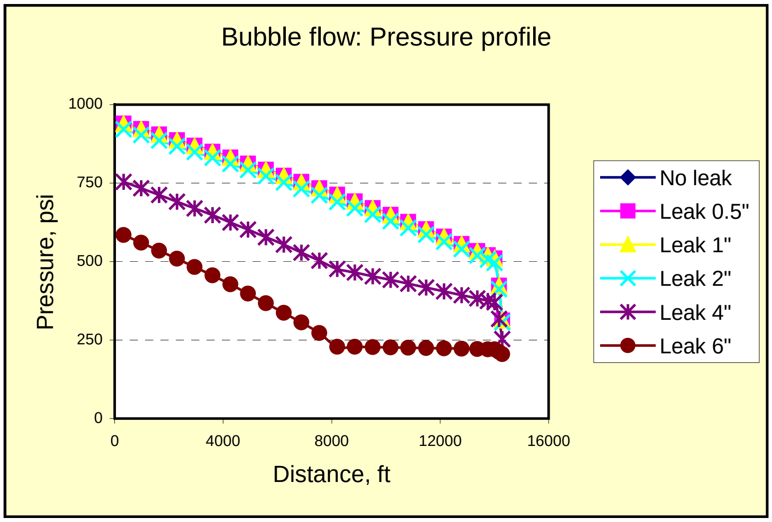


Fig 6.3(a): Pressure Profile for Increasing Leak Size

Figure 6.3(b) shows that the liquid holdup decreases with increase in leak size, where "10" denotes a 1-inch leak size, "20" denotes a 2-inch leak size, etc. For very large size the change in liquid holdup is pronounced. The liquid holdup decreases more before the leak point than after the leak point.

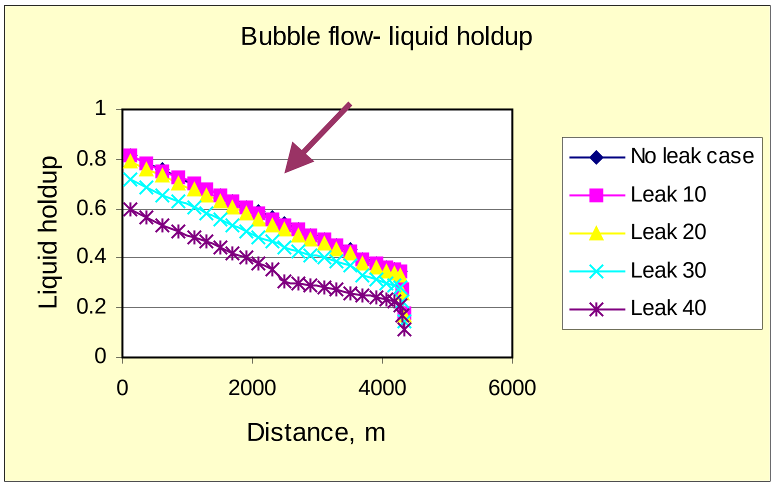


Fig 6.3(b) Liquid Hold Up in Bubble Flow with Increasing Leak Size

Fig. 6.3 (c) shows that the superficial gas velocity for bubble flow increases before the leak point. The larger the leak size the greater is the increase in superficial gas velocity. Figure 6.3(d) shows that the superficial liquid velocity decreases after the leak point.

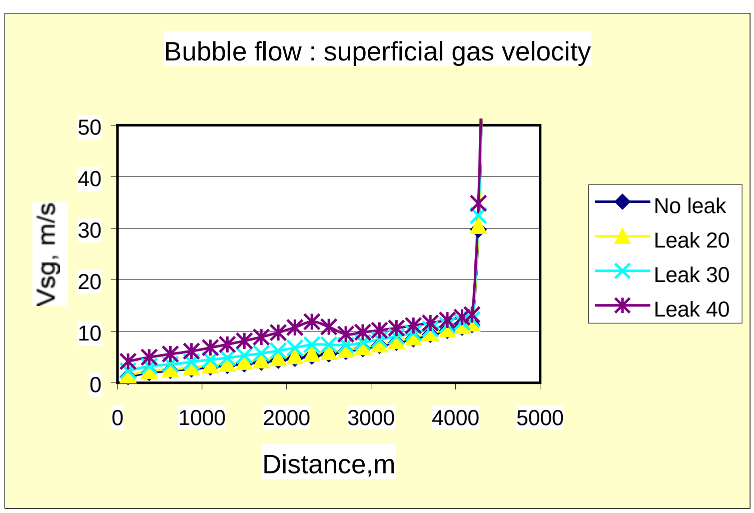


Fig 6.3 (c): Superficial Gas Velocity with Leak Size

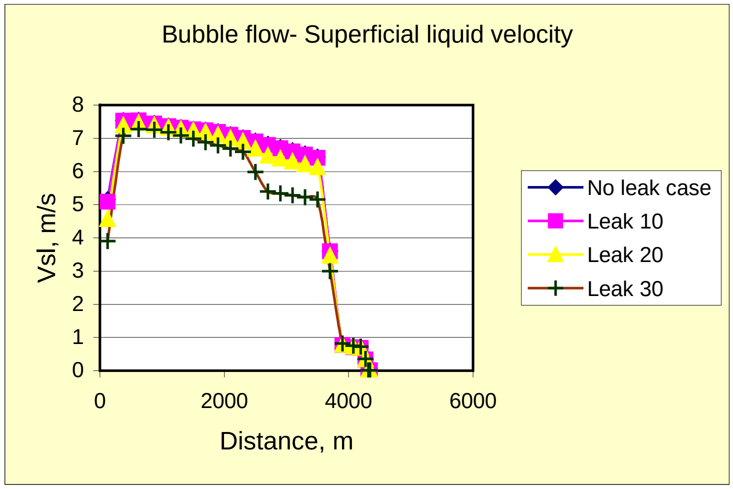


Fig 6.3 (d): Superficial Liquid Velocity Change with Leak Size

The flow regime downstream of the leak changes from bubble to stratified flow. The decrease in superficial liquid velocity downstream of the leak changes the flow from bubble flow (distributed) to stratified flow (separated). The bubble flow behaves more like a single-phase liquid. It is very easy to detect leaks in bubble flow.

Slug flow

Fig 6.4(a) shows that the pressure profile changes due to a leak in a flowline operating in slug flow are only significant when the flow regime changes as a result of the leak.

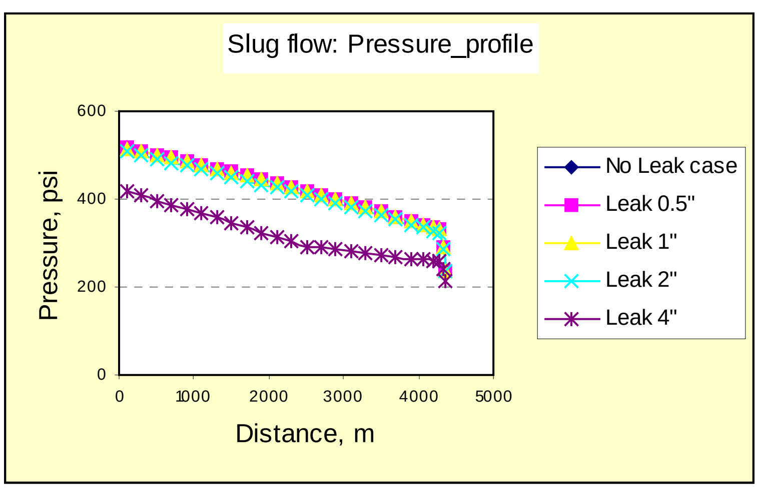


Fig 6.4(a): Pressure Profile with Varying Leak Size

Figure 6.4(b) shows that the holdup decreases only for very large leaks. Unless the liquid holdup decreases drastically, there will not be enough pressure drop that can be detected by PSL. More effective leak detection requires slug tracking, where the number of slugs and slug length play an important role in whether a leak can be detected or not.

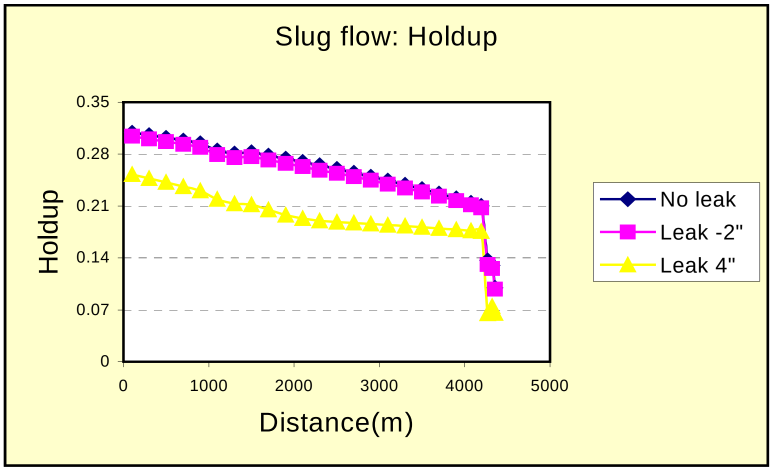


Fig 6.4(b): Holdup for Various Leak Sizes

Figure 6.4 (c) shows that the superficial gas velocity changes only for large leaks, it increases significantly before the leak point and decreases after the leak point. Figure 6.4(d) shows that the superficial liquid velocity decreases after the leak point, however only for very large leaks. This creates a significant pressure drop, which can easily be detected by PSL. The flow regime downstream of the leak point changes after the leak point from slug flow to stratified flow.

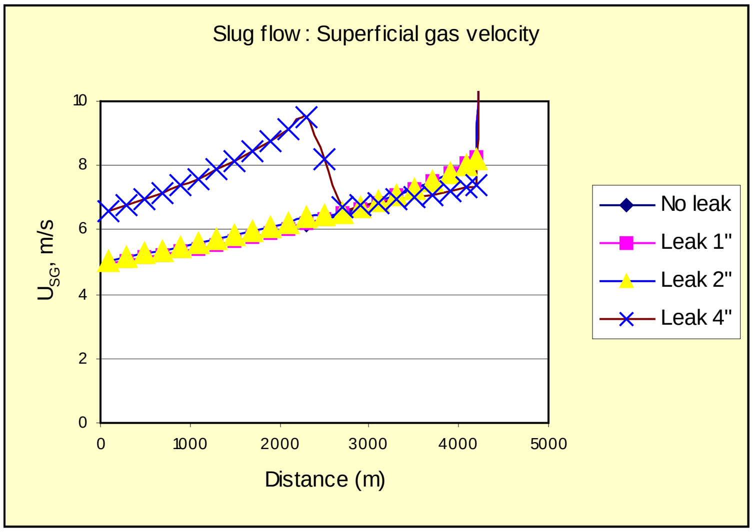


Fig 6.4 (c): Superficial Gas Velocity with Varying Leak Size

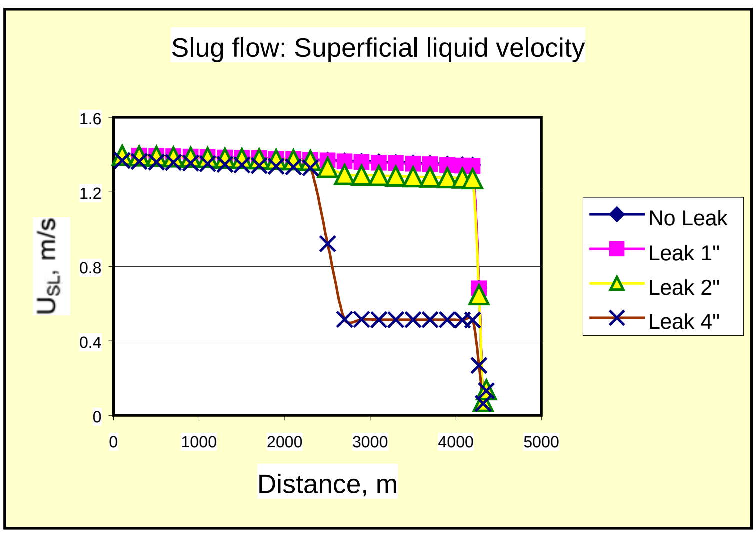


Fig 6.4(d) Superficial Liquid Velocity with Varying Leak Size

Annular flow

Fig 6.5(a) shows that the pressure profile for annular flow changes significantly with varying size of leaks.

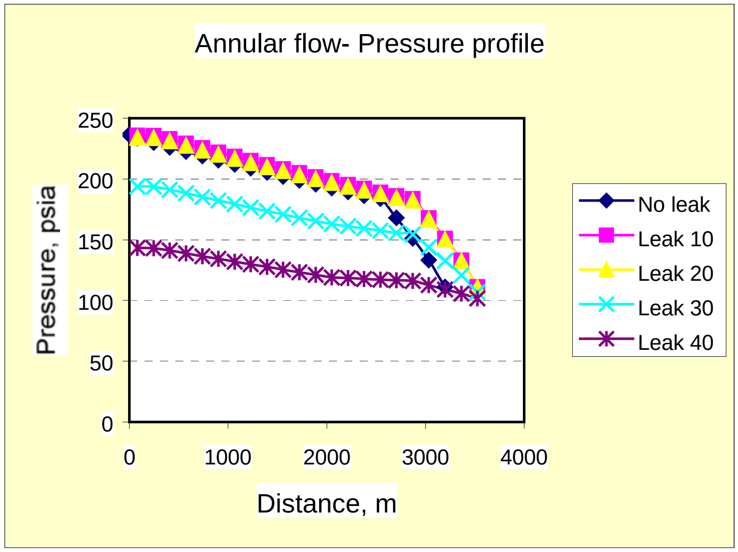


Fig 6.5(a): Pressure Profile with Varying Leak Size

Figure 6.5(b) shows that the holdup decreases dramatically for leaks. This creates a significant change in pressure drop, which can easily be detected by PSL.

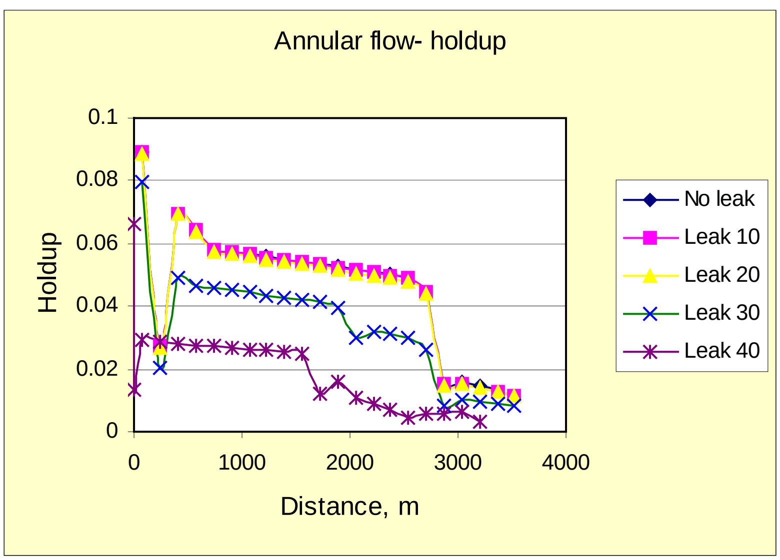


Fig 6.5(b): Liquid Holdup for Varying Leak Size

Figure 6.5 (c) shows that the superficial gas velocity (v_{SG}) does not change much for small leaks and there is a small increase in v_{SG} for large leaks.

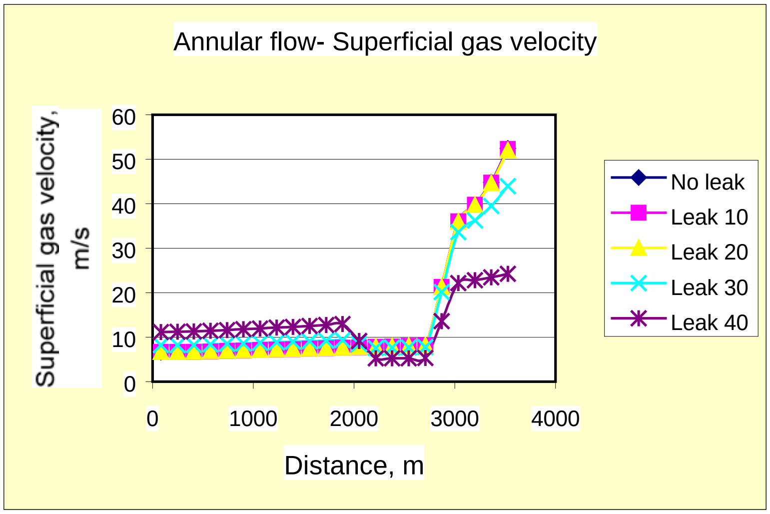


Fig 6.5(c): Superficial Gas Velocity Profile with Varying Leak Size

Figure 6.5(d) shows that the superficial liquid velocity increases before the leak point. This is contrary to the distributed phase. This kind of change in superficial gas and superficial liquid velocity does not create a change in flow regime for annular flow. Even after large leaks the flow remains in the annular flow regime.

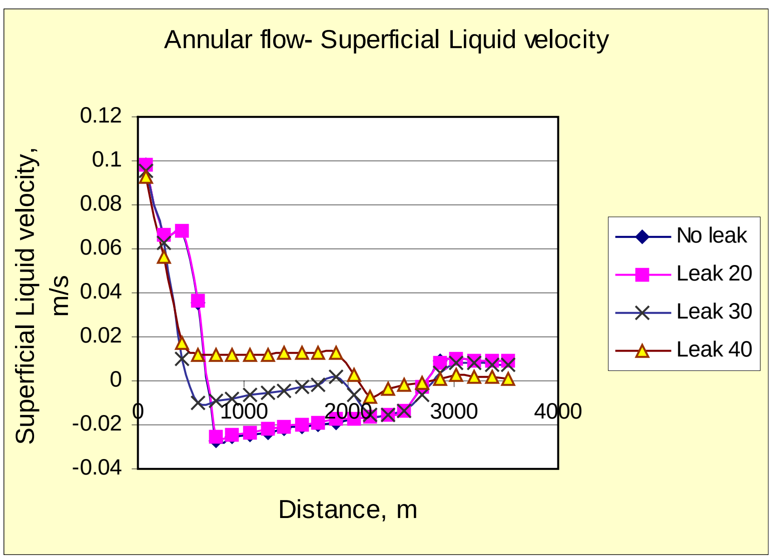


Fig 6.5(d): Superficial Liquid Velocity Profile with Varying Leak Size

Stratified flow

Fig 6.6(a) shows that the pressure profile for stratified flow changes significantly only for large leaks.

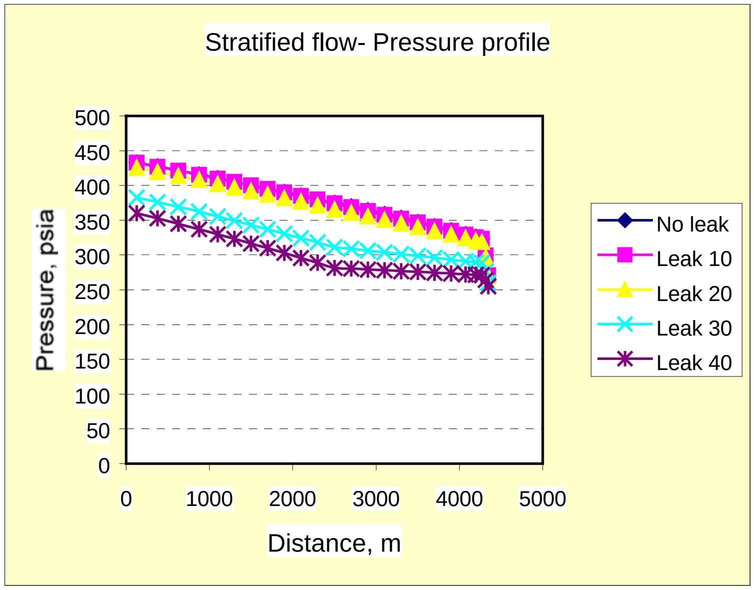


Fig 6.6(a): Pressure Profile with Varying Leak Size

Figure 6.6(b) shows that the holdup decreases for leaks. This creates a change in pressure drop, which can be detected by PSL. For stratified flow the only way to detect a leak is dependent on liquid holdup. A more elaborate analysis with Lockhart Martinelli parameter will help to understand when leaks in stratified flow can be detected.

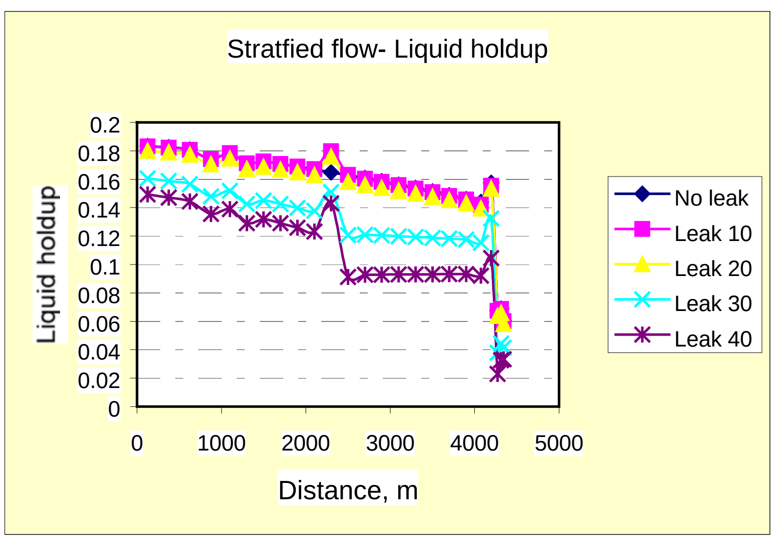


Fig 6.6(b): Liquid Holdup for Varying Leak Size

Figure 6.6 (c) shows that the superficial gas velocity increases before the leak point.

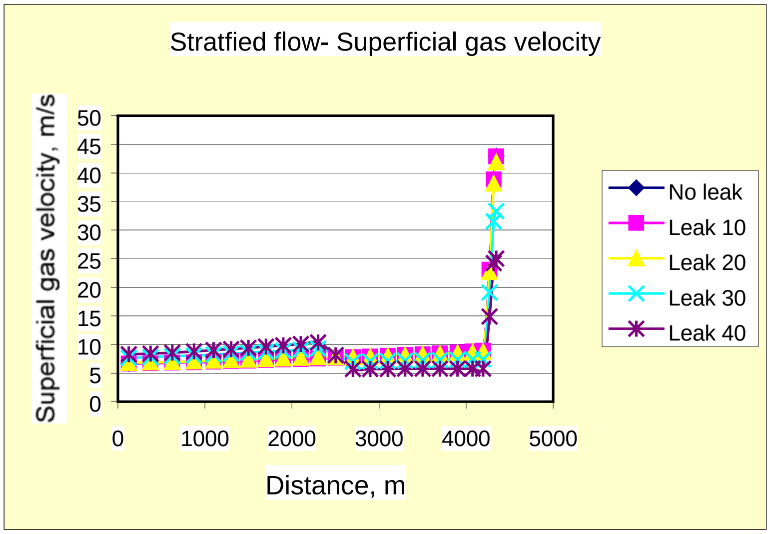


Fig 6.6(c): Superficial Gas Velocity for Varying Leak Size

Figure 6.6(d) shows that the superficial liquid velocity decreases after the leak point. This kind of change in superficial gas and superficial liquid velocity does not create a change in flow regime for Stratified flow. Hence even after large leaks, the flow will remain in the stratified flow regime.

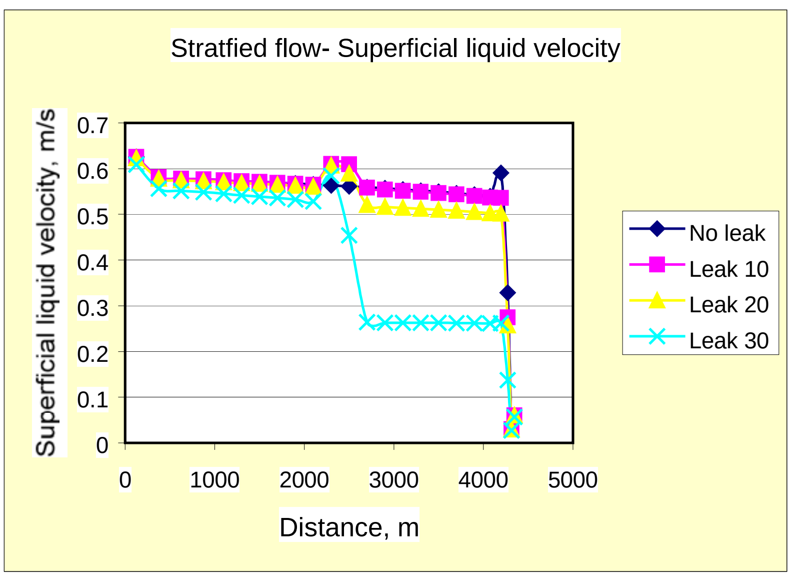
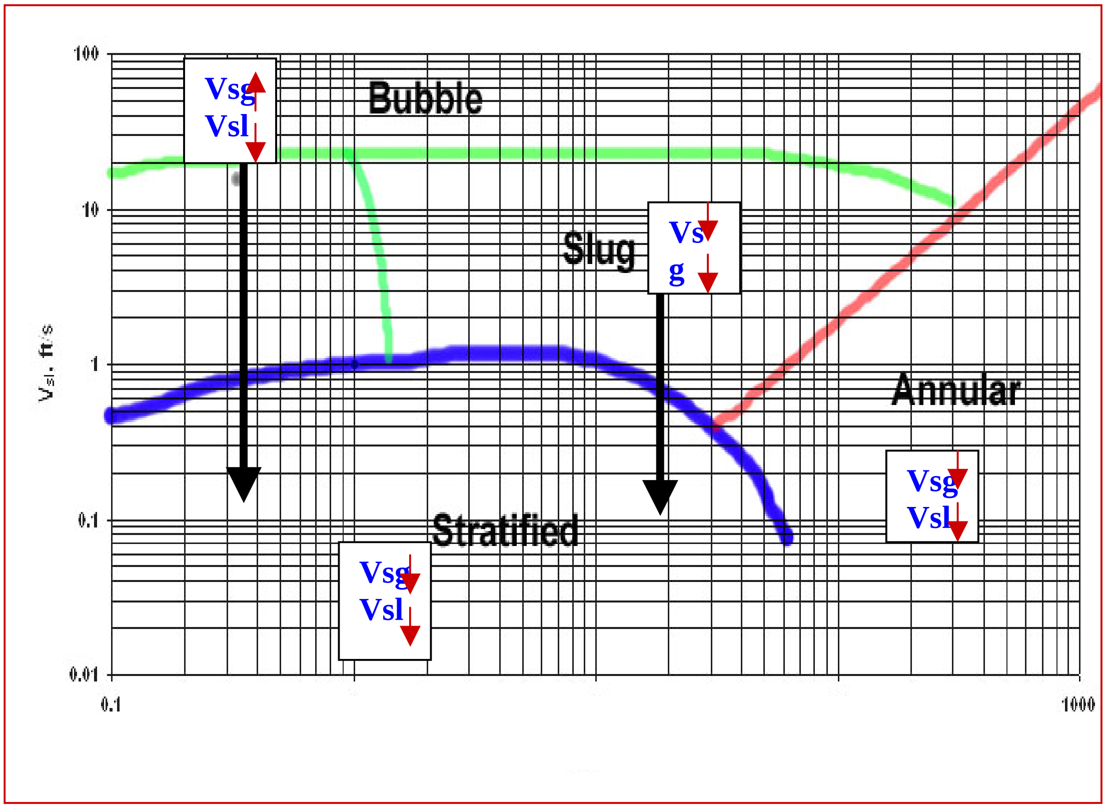


Fig 6.6(d): Superficial Liquid Velocity with Varying Leak Size

Change in Flow Regime Due To Severe Leak

Figure 6.7 shows that for very large leaks with distributed flow (bubble flow, slug flow) there is a change in flow regime downstream of the leak. The drop in superficial liquid velocity (v_{SL}) downstream of the leak is so large that the flow becomes stratified flow. For the case of separated flow (stratified flow, annular flow) the change in v_{SL} cannot create any change in the flow regime. This change in flow regime for the case of bubble flow and slug flow creates a large pressure drop, which can be easily detected by PSL's.



Response Time for Detection of Leak

Figure 6.8 shows the response time for same size of leak to stabilize in the various flow regimes. The response is best for annular flow and worst for slug flow. It is in line with the observation that the response time for detection of leak in gas lines is better than in oil lines.

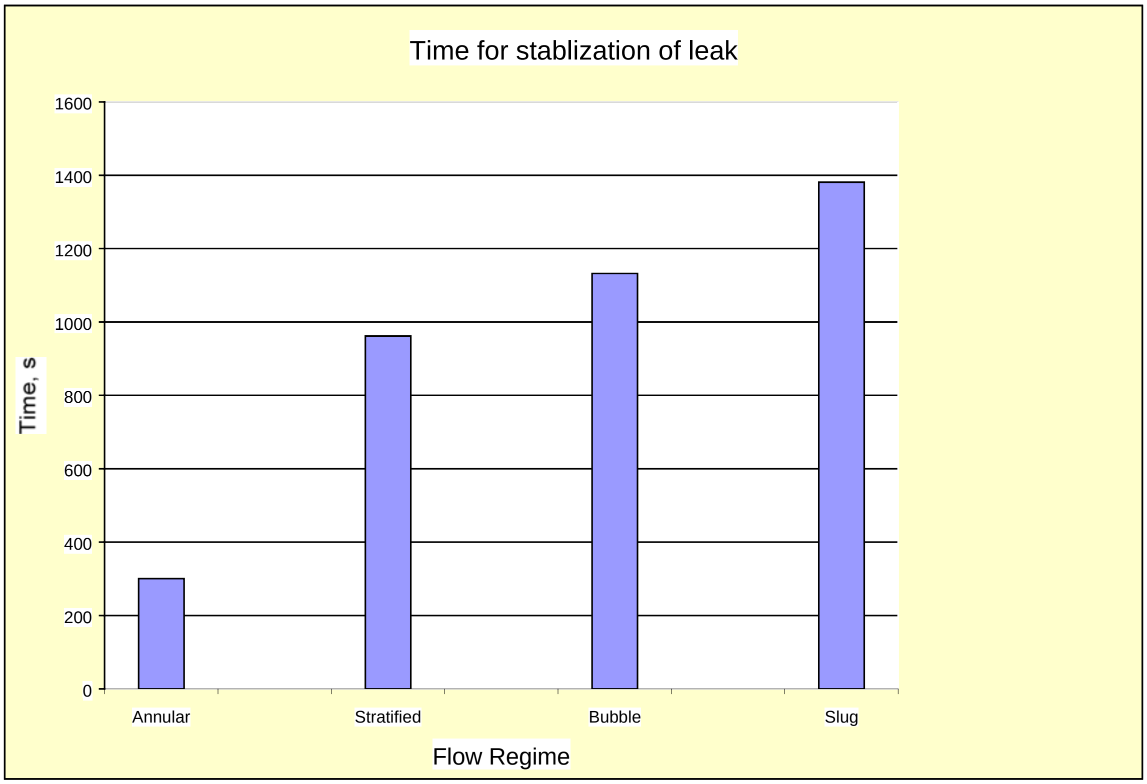


Fig 6.8: Transient Response-time for Stabilization in Various Flow Regimes

The response time for detection of leak in separated flow (Annular flow, Stratified flow) is better than that for distributed flow (Bubble flow, Slug flow).

Conclusion

While PSLs are effective in detecting leaks in single-phase transmission transportation pipelines, this approach is not generally effective for multiphase flow. Only in the case of very large leaks can a leak be detected, with the possible exception of the bubble flow pattern where a PSL would be able to effectively detect a moderate (1-inch) leak. The vendor supplied data specifying a capability for detection of leak for 1% loss of mass flow rate is not correct for multiphase flow for methods that are based on pressure loss. Also, as discussed in Chapter 5, mass balance methods would not be able to achieve a 1% leak detection specification due to metering uncertainties associated with multiphase flow. Modern multiphase flow simulators allow estimate of what can and cannot be detected for a given flowline. Transient simulator can also provide an estimate of the time to detection a leak given a particular PSL location.

The pressure, temperature, v_{SL}, and v_{SG} profiles show changes due to a leak. After the leak point, the pressure gradient becomes less, and the temperature drops faster due to the reduced mass flow rate inside the pipe and due to the Joule-Thomson effect. The v_{SL} and v_{SG} have discontinuities at the leak point.

Leak detection in multiphase flow is dependent on two aspects. First is the change in superficial gas and superficial liquid velocity. For distributed flow like bubble flow and slug flow, significant decrease in the superficial liquid velocity creates a change in flow regime from bubble to stratified and slug to stratified flow downstream of the leak point. This change in flow regime creates a significant pressure drop, which can easily be detected by PSL. However a very large leak is needed to produce this change in superficial liquid velocity and depends on the original condition of the flow.

The second aspect for small leaks is the change in liquid holdup with leak. The larger the change in liquid holdup the larger is the pressure drop. In stratified /slug flow the change in liquid holdup with leak size is low, which makes the leak detection difficult. For stratified flow, the leak detection is dependent on liquid holdup, which can be analyzed using the Lockhart Martinelli parameter. For slug flow, a thorough analysis of the slug characteristics needs to be done to identify what size of leak can be detected with PSL.

Chapter 7

LEAK DETECTION BY COMPOSITIONAL ANALYSIS

A new method is proposed to detect leaks along the flowline in multiphase flow systems by evaluating compositional and phase behavior changes due to flow disturbances caused by leaks. Correlating changes of liquid and vapor composition of the fluid to leak location and size and flow regime provides an idea of how much mass is lost through the leak and its rate of loss.

Compositional analyses with PVTsim, a phase behavior simulator, were done after simulation with OLGA, a multiphase flow simulator, was performed for each case. Different combinations of leak size and location showed that gas/oil ratio and mass reduction rate vary with the presence of a leak along the pipeline. Additionally the methane composition varies significantly since this is the main component of the selected fluid.

Fluid Selection

Initially a PVT file containing fluid properties for a volatile oil, such as density for liquid and vapor phases, enthalpies for phases, molecular weights, and critical properties, was constructed using the expected pressure and temperature ranges along the pipeline. The fluid selected for this study is a typical volatile oil. Volatile oils exhibit pronounced compositional changes during production due to the high amount of methane (C1) and intermediate components that they contain. Therefore C1 can be used as the key component for our analysis, since this is the most sensitive to the changes in pressure that occur when a leak is present. Figure 7.1 presents a typical volatile oil phase diagram.

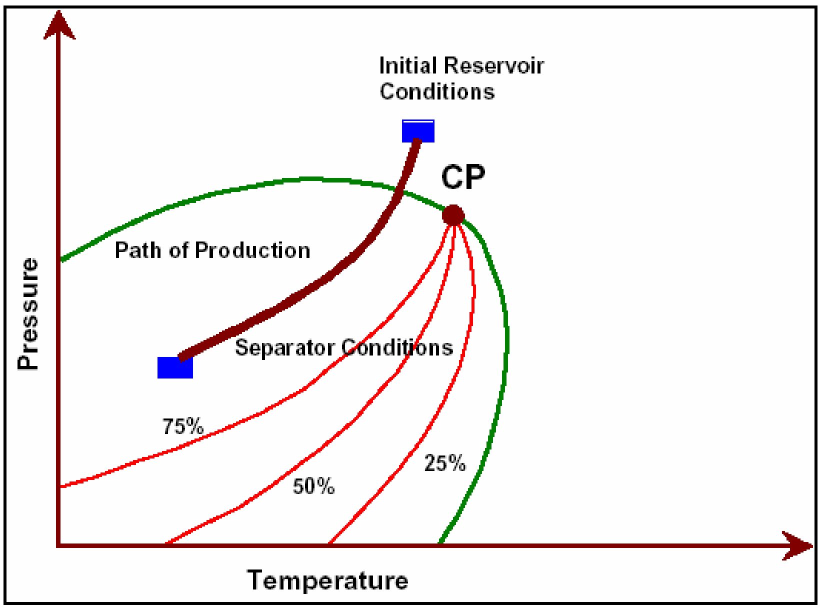


Figure 7.1. Phase Diagram of a Volatile Oil Reservoir

The two-phase region is located inside of the envelope. This is the area where the pipeline will be operating during its production lifetime.

Methodology

Figure 7.2 presents the procedure followed in this study.

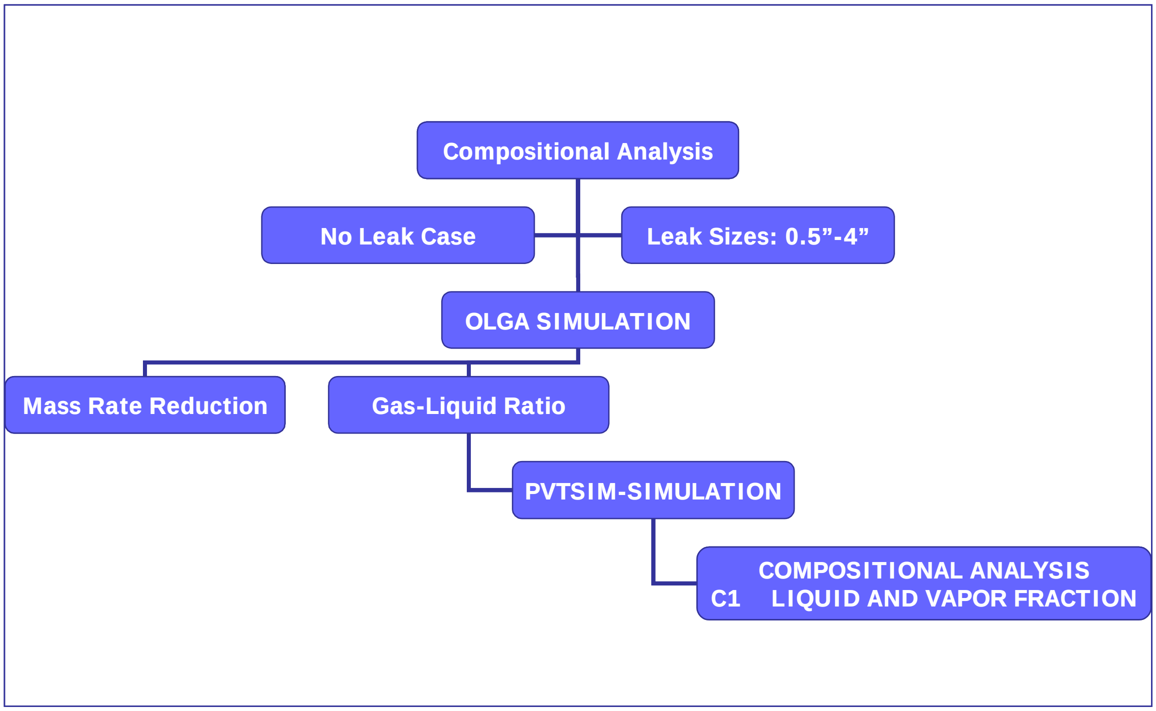


Figure 7.2. Methodology Diagram

Initially we performed a simulation with the OLGA simulator for the no leak case, which is the base case. Later, several runs were done for leak cases with sizes going from 0.5” to 4”. Mass rate reduction and gas/liquid ratio at the separator were recorded for each case. Then we used the PVTSIM simulator to determine phase behavior and fluid properties. Monitoring of the methane liquid and vapor compositions was done for each case and significant differences were found.

The initial composition of the fluid through the pipeline was the input data for PVTSIM, (Figure 7.3a). For all the cases this overall composition remains constant, since the same fluid was used for all the runs performed. However, the gas/liquid ratio is different for all the cases due to the presence of the leak in the system.

Using this fluid composition we performed PT flash calculations at different pressures and temperatures for the ranges expected in the flowline. From these PT flash calculations we obtained several gas / liquid ratios from the vapor and liquid volume fraction reported (figure 7.3b). These ratios were matched with those obtained from the simulations done previously with OLGA. Every gas-liquid ratio has a corresponding liquid and vapor composition that can be obtained from the same PT flash as well. The composition of methane was the one that we recorded for every case. (Figure 7.3c).

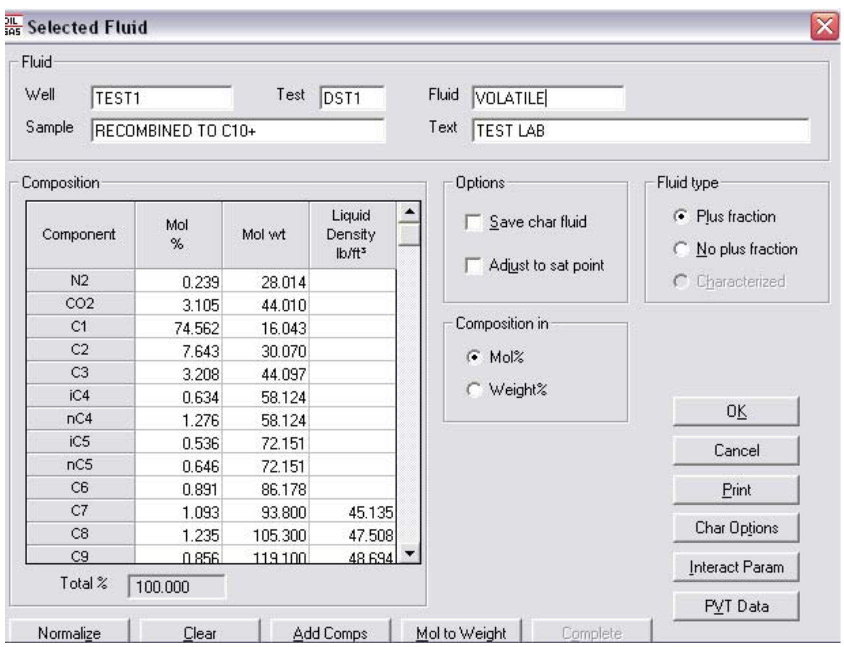


Figure 7.3a. PVTSIM Input Composition Data

TEST1 DST1 GASCOND RECOMBINED TO C10+ EOS = PR

PT Flash at
350.00 psi
80.00 °F

	Total	Vapour	Liquid	
Mole%	100.00	87.78	12.22	
Weight%	100.00	52.28	47.72	
Volume	13.80	15.33	2.83	ft³/lb-mol
Volume%	100.00	97.50	2.50	
Density	2.4214	1.2984	46.1841	lb/ft³
Z Factor	0.8339	0.9261	0.1708	
Molecular Weight	33.41	19.90	130.50	
Enthalpy	-1871.8	183.5	-16639.3	BTU/lb-mol
Entropy	-5.81	-4.40	-15.93	BTU/lb-mol F
Heat Capacity (Cp)	16.72	10.30	62.87	BTU/lb-mol F
Heat Capacity (Cv)	13.57	7.56	56.79	BTU/lb-mol F
Kappa (Cp/Cv)	1.232	1.363	1.107	
J-T Coefficient		0.0737	-0.0064	F/psi
Velocity of Sound		1256.7	3660.3	ft/s
Viscosity		0.0118	0.9689	cP
Thermal Conductivity		0.020	0.103	BTU/hr ft F
Surface Tension		14.816	14.816	mN/m

Figure 7.3b PT FLASH Output - G/L Ratio

Flash

Convert Comp Ext Comp Save Phase

Composition in mole% at
350.00 psi
200.00 °F

	Total	Vapour	Liquid
N2	0.239	0.259	0.009
CO2	3.105	3.331	0.540
C1	74.562	80.519	6.848
C2	7.643	8.113	2.296
C3	3.208	3.295	2.216
iC4	0.634	0.622	0.767
nC4	1.276	1.218	1.935
iC5	0.536	0.462	1.382
nC5	0.646	0.534	1.922
C6	0.891	0.571	4.526
C7	1.093	0.485	8.006
C8	1.235	0.365	11.128
C9	0.856	0.148	8.907
C10+	4.076	0.078	49.517
C10+ Molwt	250.900	148.586	252.743

Composition in mole% at
400.00 psi
100.00 °F

	Total	Vapour	Liquid
N2	0.239	0.270	0.010
CO2	3.105	3.387	0.997

PT Flash

P (psi)	T (°F)
350.00	200.00
400.00	100.00

OK Cancel

Figure 7.3c PT FLASH Output

The first part of the study includes the four common flow regimes that we can find in horizontal multiphase flow systems: stratified, annular, bubble and slug. Significant liquid compositional variation was found for all the cases. The second part is focused on the deepwater vertical flowline case. For this part only slug flow was analyzed since this is the most common in vertical flow lines. The liquid composition is affected as well when a leak is present in these systems. Finally, the last part covers the water ingress case in a vertical flowline. Three different leak locations were tested: near to the separator (identified as "near" in the plots), in the middle section of the pipeline (identified as "middle"), and far from the separator (identified as "far" in all the plots). Compositional analysis was done at separator conditions for all the cases.

Horizontal Flowline

Table 7.1 presents the mass rate reduction percentage for every flow regime. Figures 7.4a through 7.4d illustrate the mass rate reduction percentage vs. leak size for all the four regimes in a horizontal multiphase flow system.

	Leak Size (in)	0.5	1	2	3	4
BUBBLE	Far from Surface	0.021	0.331	4.922	19.515	41.810
	Middle Section	0.015	0.239	3.651	15.787	34.860
	Near to Surface	0.010	0.153	2.379	10.856	27.568
STRATIFIED	Far from Surface	0.028	0.451	6.975	22.850	70.655
	Middle Section	0.026	0.414	6.443	21.455	69.744
	Near to Surface	0.017	0.264	4.172	14.430	34.202
SLUG	Far from Surface	0.045	0.719	11.192	47.988	100.979
	Middle Section	0.043	0.688	10.782	47.551	101.573
	Near to Surface	0.028	0.451	7.143	34.747	102.328
ANNULAR	Far from Surface	0.167	0.790	11.654	43.791	100.000
	Middle Section	0.050	0.711	6.011	41.529	100.000
	Near to Surface	0.024	0.384	2.804	27.966	71.139

Table 7.1. (%) Mass Rate Reduction

The results show that annular and slug flows are the regimes that tend to loose more mass when the leak size increases. Reduction in mass rate is more significant for leaks located far from the separator (closer to the well head), and in the middle section of the flowline than when they are located near the separator (far from the well head).

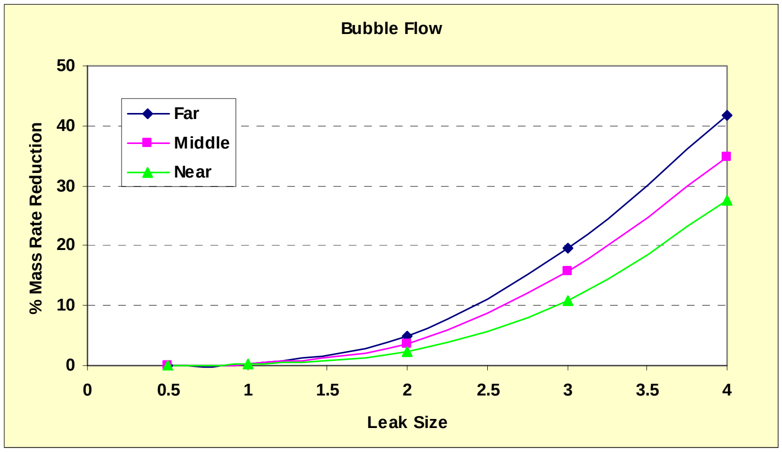


Figure 7.4a Mass Rate Reduction in Bubble Flow

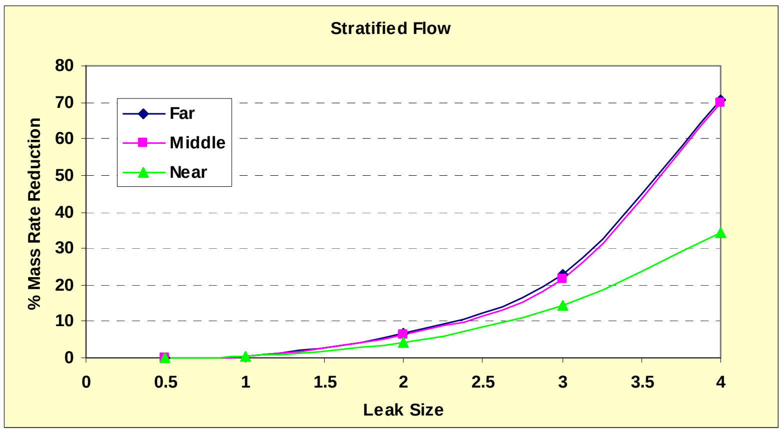


Figure 7.4b Mass Rate Reduction in Stratified Flow

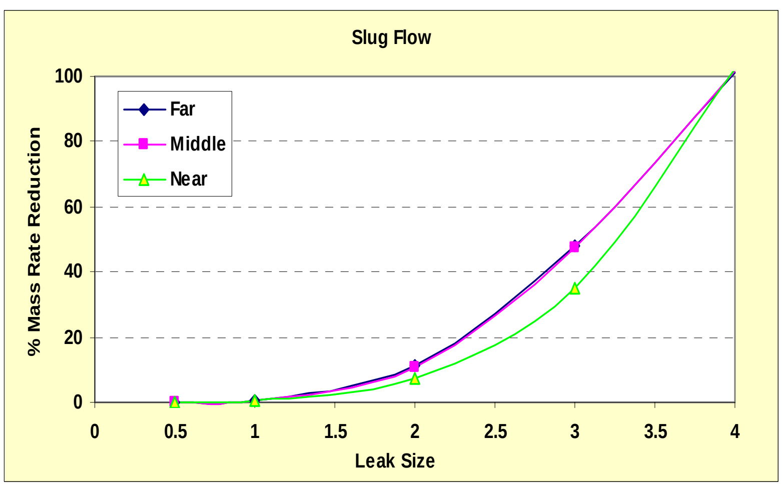


Figure 7.4c Mass Rate Reduction in Slug Flow

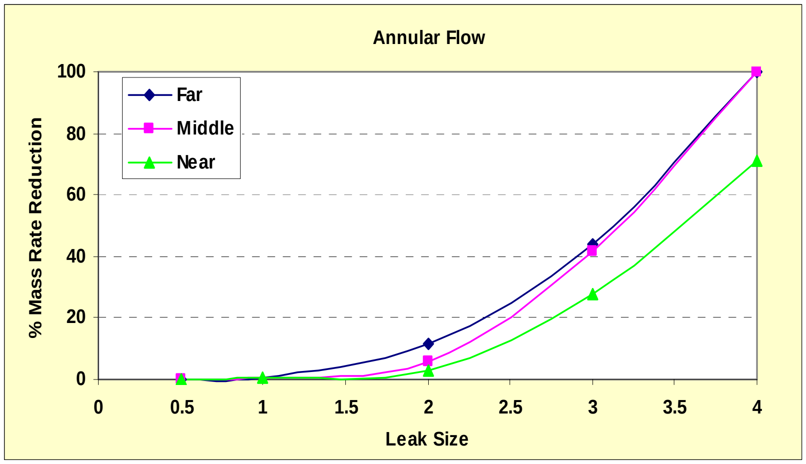


Figure 7.4d Mass Rate Reduction in Annular Flow

The second parameter that we took into account was the gas/liquid ratio. For all the cases the gas/liquid ratio increases as the leak size increases as well. This is due to the additional pressure drop that takes place when a leak is present in the system. In consequence the gas flow rate rises. Table 7.2 presents the gas/liquid ratio increase for each flow regime.

	Leak Size (in)	0.5	1	2	3	4
BUBBLE	Near to Surface	0.033	0.539	8.391	38.597	111.595
	Middle Section	0.024	0.390	6.154	30.781	84.076
	Far from Surface	0.019	0.251	3.982	19.979	59.930
STRATIFIED	Near to Surface	0.020	0.397	6.697	31.420	260.259
	Middle Section	0.020	0.333	5.632	30.345	194.730
	Far from Surface	0.006	0.103	1.776	13.553	27.217
SLUG	Near to Surface	0.035	0.576	10.121	70.833	0.000
	Middle Section	0.035	0.561	9.833	70.755	0.000
	Far from Surface	0.026	0.077	1.233	5.931	0.000
ANNULAR	Near to Surface	0.076	1.235	21.588	171.537	0.000
	Middle Section	0.076	1.114	5.347	151.050	0.000
	Far from Surface	0.018	0.323	4.540	33.400	242.344

Table 7.2 (%) Gas-Liquid Ratio Increase

Values of gas/liquid ratio for 4" leaks were not reported in slug and annular flow because no mass was obtained at the separator. For these cases all the mass was lost through the leak. Figure 7.5a through 7.5d present the results.

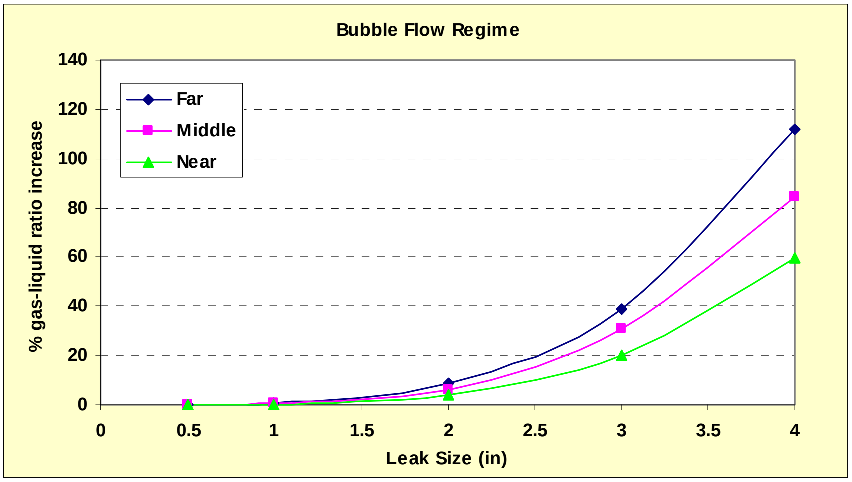


Figure 7.5a Gas-Liquid Ratio Increase in Bubble Flow

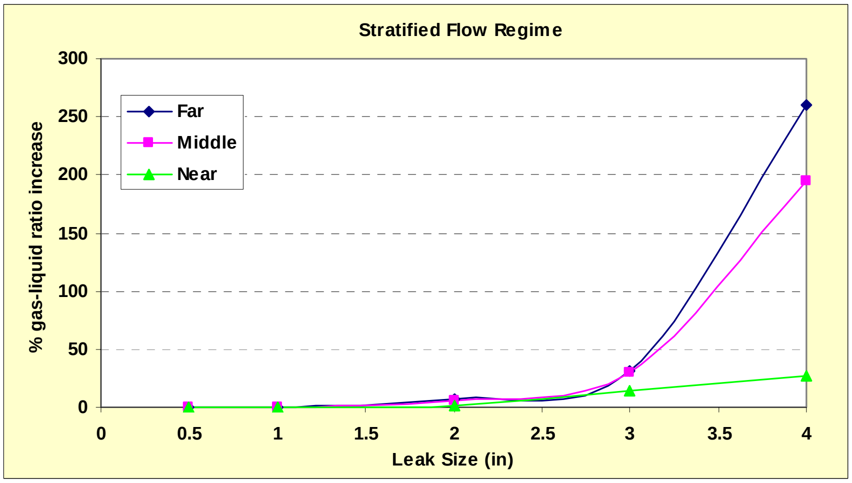


Figure 7.5b Gas-Liquid Ratio Increase in Stratified Flow

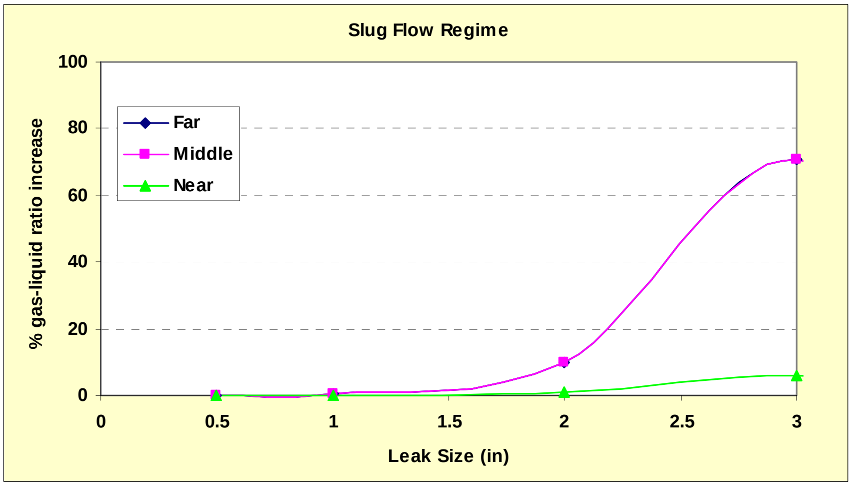


Figure 7.5c Gas-Liquid Ratio Increase in Slug Flow

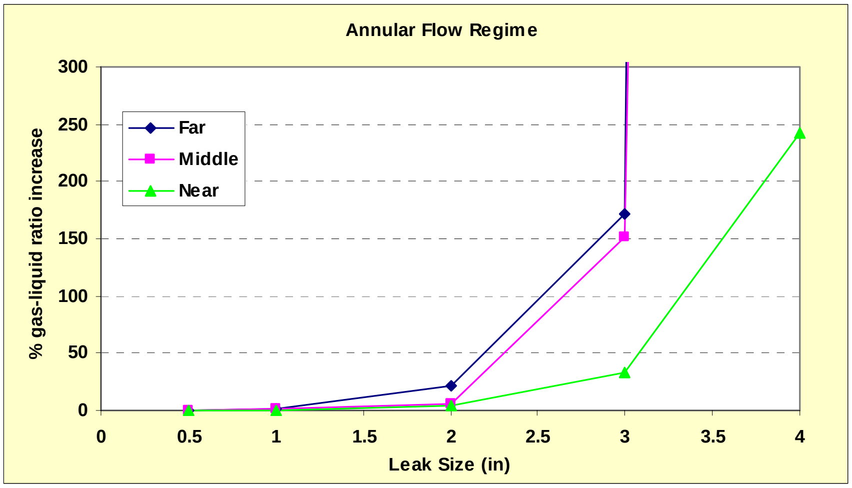


Figure 7.5d Gas-Liquid Ratio Increase in Annular Flow

Gas/liquid ratios from OLGA for each case were used to obtain the corresponding vapor and liquid composition with PVTSIM. Changes in vapor composition were not as significant as changes in the liquid composition. Figures 7.6a through 7.9b show the compositional changes for each regime. These plots present the compositional variation of methane in percentage vs. the leak size. The numbers inside the plots represent the mass reduction rate for that case, for example a leak size of 3 inches located far from the separator has a mass reduction of 20% and a liquid methane composition change of 15%.

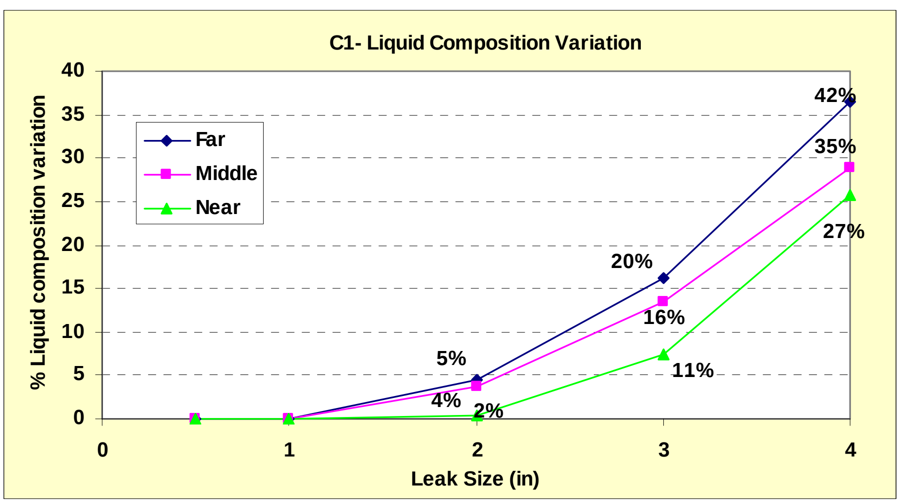


Figure 7.6a Liquid Composition Variation in Bubble Flow

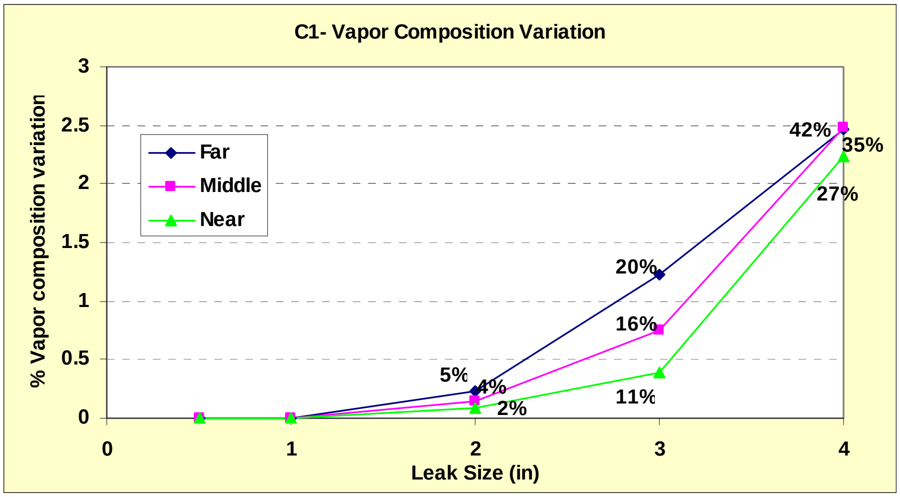


Figure 7.6b Vapor Composition Variation in Bubble Flow

Compositional changes are significant for leaks located far from the separator and so is the reduction in mass rate and increase in gas-liquid ratio.

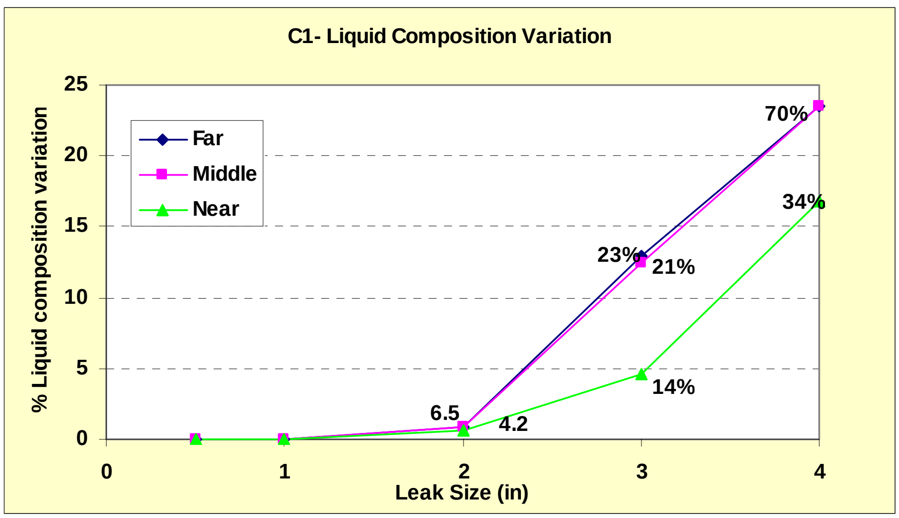


Figure 7.7a Liquid Composition Variation in Stratified Flow

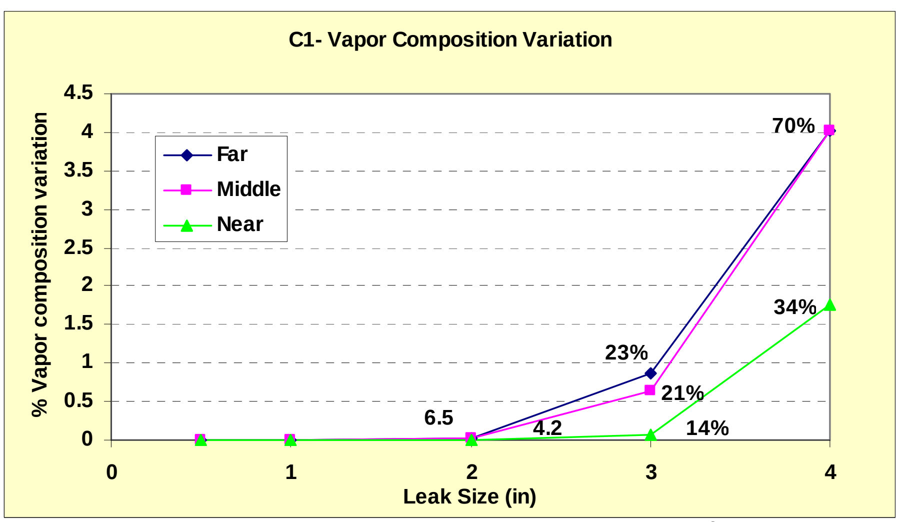


Figure 7.7b Vapor Composition Variation in Stratified Flow

The stratified flow regime presents less variations than the variations in bubble flow for both liquid and vapor compositions. For a leak in stratified flow with 2" diameter, when the mass rate is reduced 6.5% the liquid composition changes only 1.5%. For the same leak size but with a reduction of 5% in mass rate the liquid composition changes 5% in bubble flow. The vapor composition shows insignificant changes for both flow regimes. The same can be illustrated with the 3" leak size where with a 23% mass rate reduction the liquid composition varies 12% in stratified flow while with 20% of mass reduction in bubble flow the composition changes 18%. Changes in vapor composition are less than 1%.

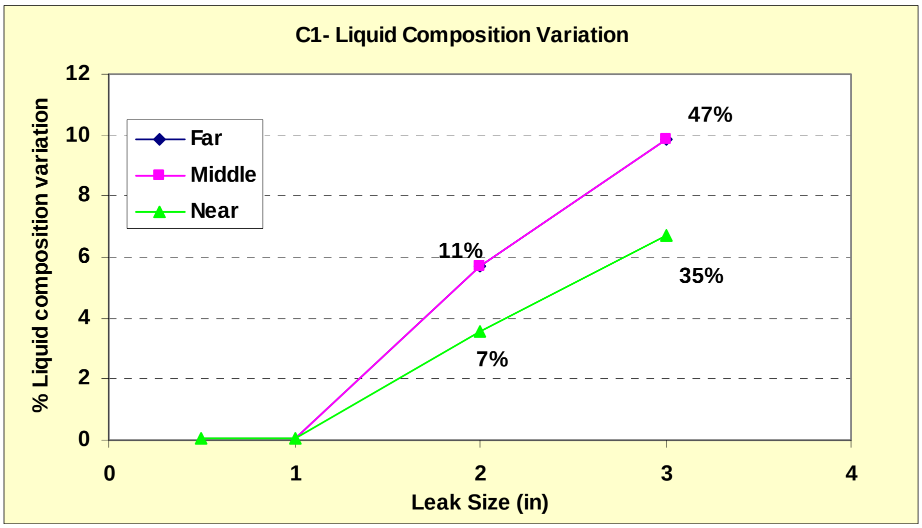


Figure 7.8a Liquid Composition Variation in Slug Flow

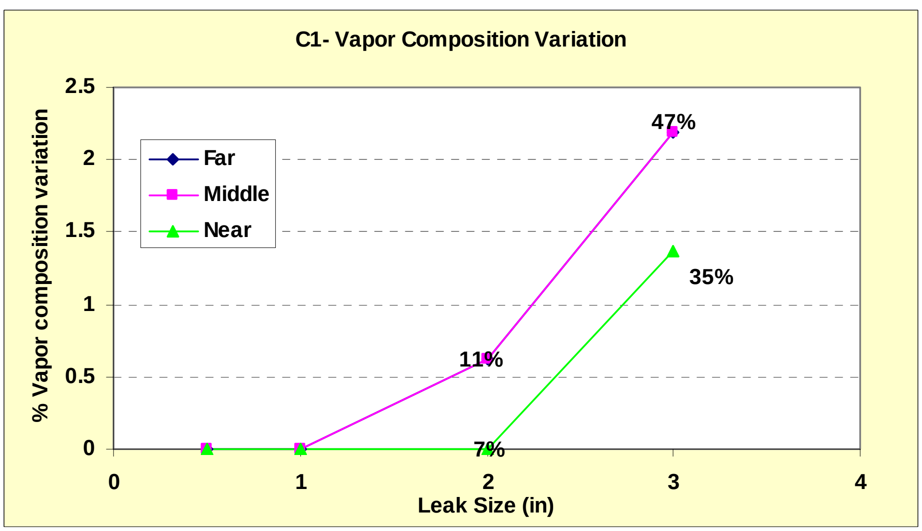


Figure 7.8b Liquid Composition Variation in Slug Flow

Composition changes in slug flow are less than the ones in bubble and stratified flow, although more mass is being lost. Notice the minimum liquid composition variation of 6% when a reduction of mass rate of 35% takes place in the 3” leak size case.

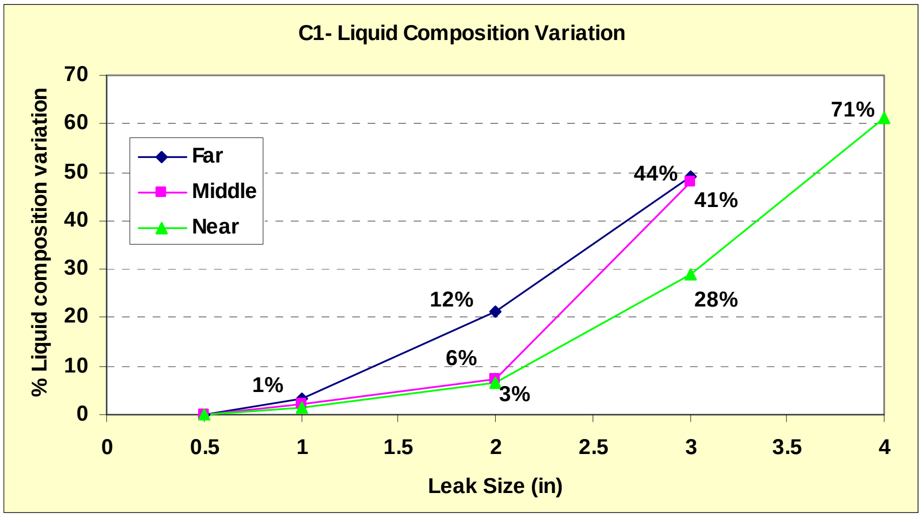


Figure 7.9a Liquid Composition Variation in Annular Flow

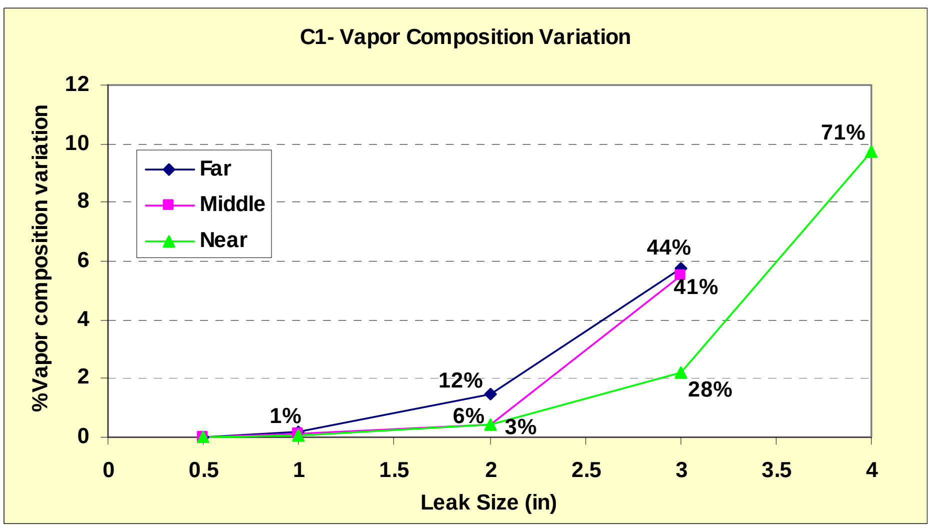


Figure 7.9b Vapor Composition Variation in Annular Flow

Annular flow presents more significant variations in the liquid and vapor composition for all the different leak size cases.

The following charts summarize the compositional changes for all four regimes in the vapor and liquid phase.

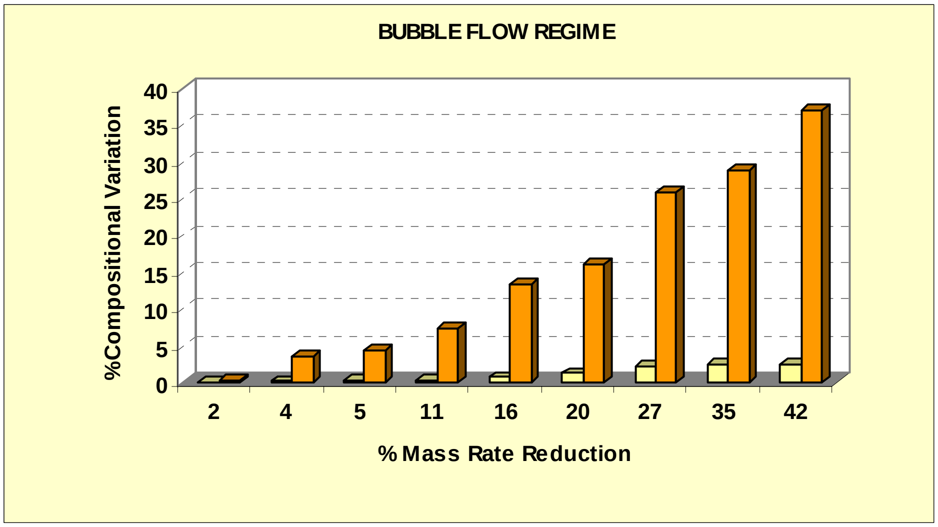


Figure 7.10a Compositional Variation in Bubble Flow

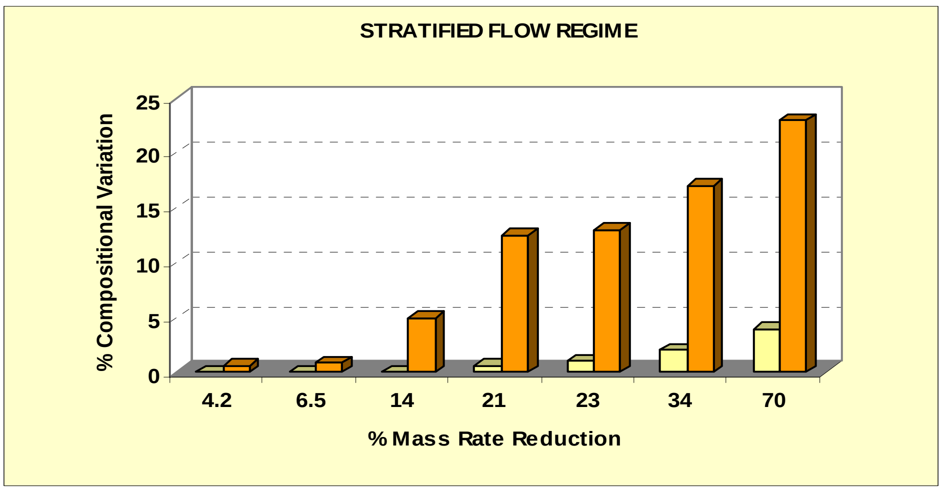


Figure 7.10b Compositional Variation in Stratified Flow

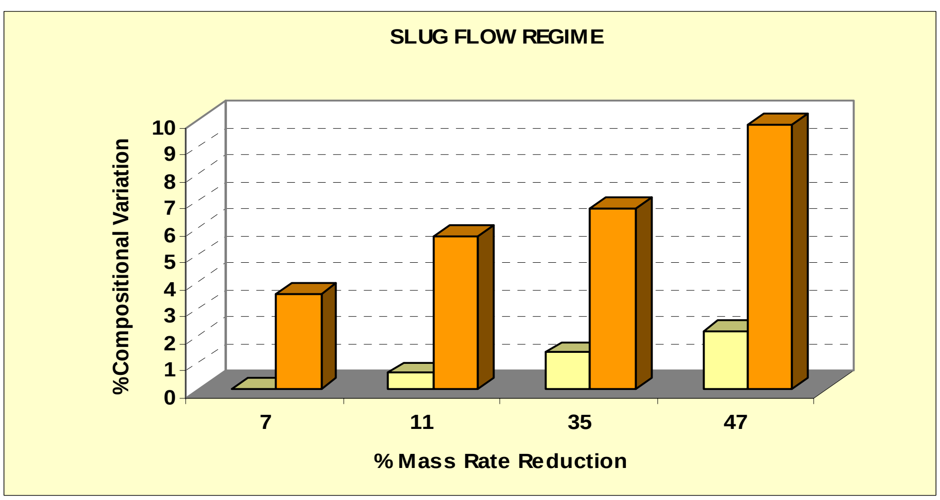


Figure 7.10c Compositional Variation in Slug Flow

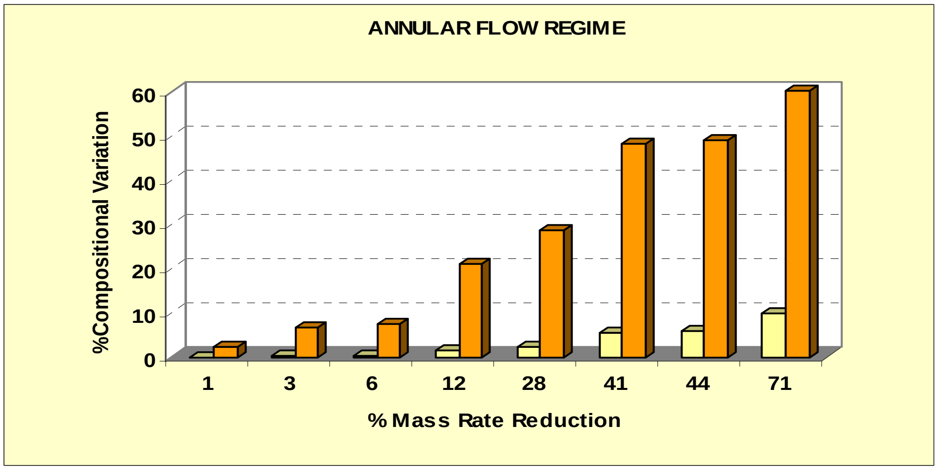


Figure 7.10d Compositional Variation in Annular Flow

The plots above present the percentage in liquid and vapor composition variation vs. the percentage in mass rate reduction. Taking as a guide a 12% mass rate reduction, composition varies more appreciably in annular and bubble flow than in slug and stratified flow regimes.

Vertical Flowline

For the second part of the study the geometry defined in the OLGA simulator is presented in figure 7.11.

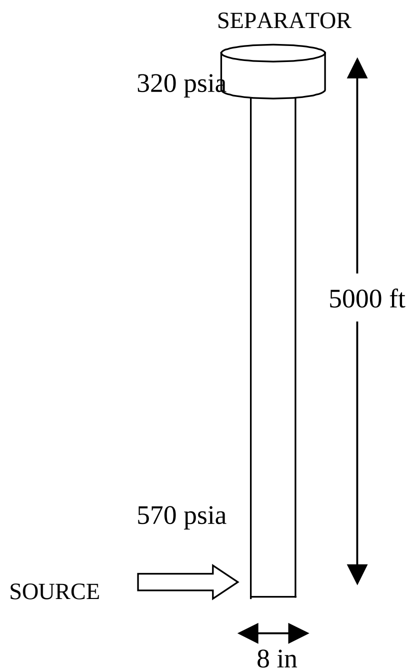


Figure 7.11 Vertical Flow – Riser Section

A vertical pipeline with 5000-ft length and 8" diameter typically used in Gulf of Mexico deepwater operations was used to represent the riser section of the subsea pipeline. This section is the last section that the fluid passes through before arriving at the separator. Therefore this is the section where we have done our compositional analysis. Since the pressure that should arrive to the separators at the surface and the total mass flow rate were suggested based on typical cases in the Gulf of Mexico, a first simulation was performed to determine the input pressure or source pressure that will move the fluid to that point. The value obtained was approx. 600-psia for a total mass flow rate of 22lb/s. At these conditions the fluid exhibits two phases, which is what we were looking for to analyze the variation in the gas-liquid rate when a leak is present along the pipeline.

Once the pressure boundary conditions were established a calculation for the no leak case was executed. The output which contains the pressure, temperature, volume gas rate and liquid gas rate variations with the depth was edited to compare these results with the ones obtained from the leak cases. Leak sizes ranging from 0.5" to 4.0" were simulated.

Hydrostatic pressure represented a limitation for the simulation. As figure 7.12 illustrates after 760' of depth the hydrostatic pressure is higher than the pressure inside of the pipeline. Therefore simulations at deeper points represent the water ingress case that was analyzed in the last part of this study.

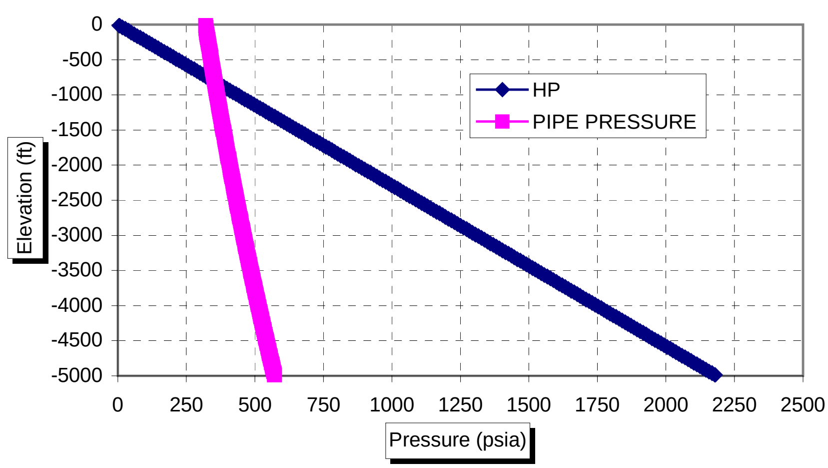


Figure 7.12 Hydrostatic Pressure and Pipeline Pressure Variation

For this part only simulations up to 750’ depth were performed. Leaks located near and far from the surface were tested.

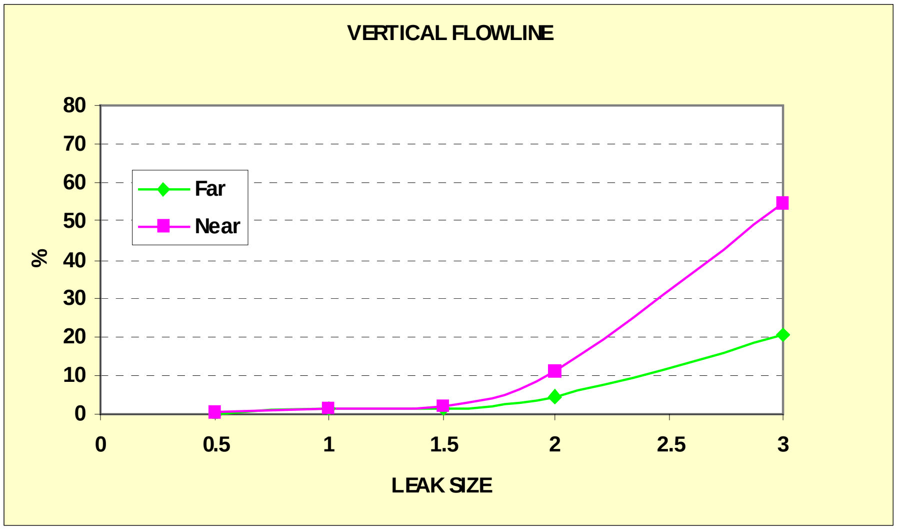


Figure 7.13 Mass Reduction Rate in Vertical Flowline

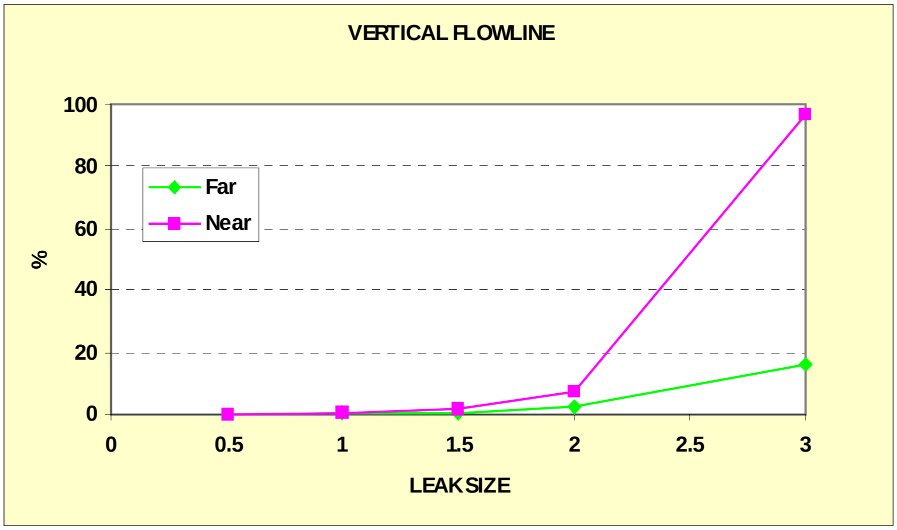


Figure 7.14 Gas-Liquid Ratio Increase in Vertical Flowline

Unlike the horizontal flow the mass reduction rate and gas/liquid ratio have more significant variations for leaks located near the separator (500 ft approximately).

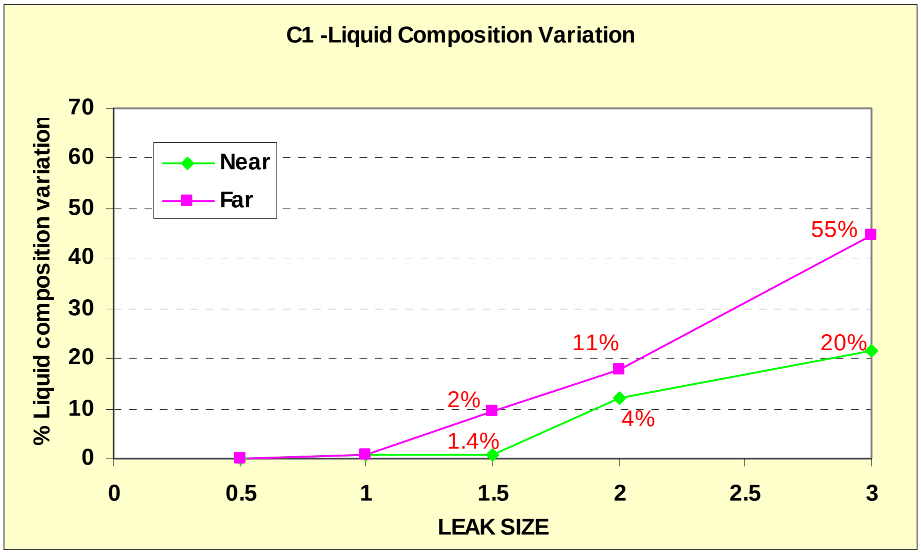


Figure 7.15 Liquid Composition Variation in Vertical Flowline

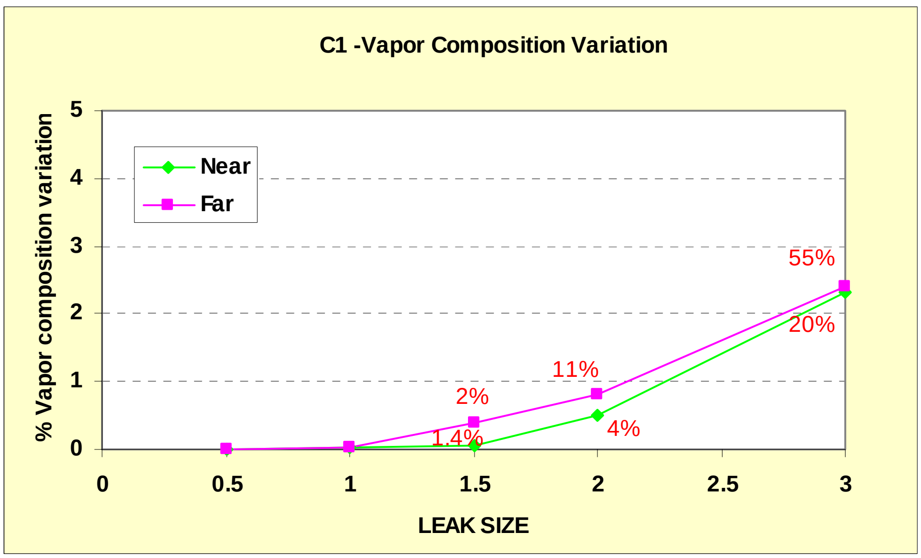


Figure 7.16 Vapor Composition Variation in Vertical Flowline

In vertical multiphase flow systems the variation in liquid composition is more important than in horizontal systems. When the mass reduction rate is as low as 2% there is a significant variation of 10% in the liquid composition according to figures 7.15 and 7.17.

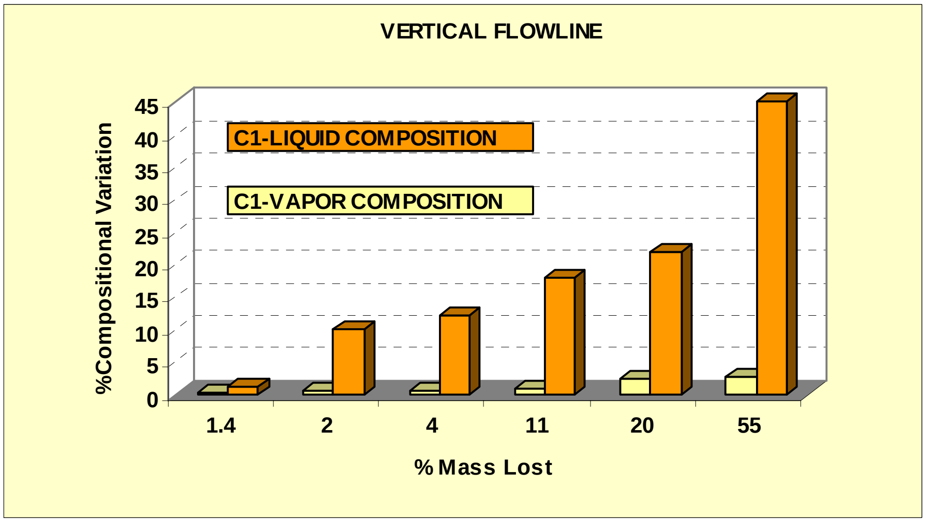


Figure 7.17 Compositional Variation in Vertical Flowline

Finally for the deepwater "water ingress" case at points deeper than 760' along the pipeline, no compositional analysis was done because the water cut increases abruptly when the leak is larger than 1" and only water is obtained at the surface. Compositional changes were appreciable for none of the cases when the leak size is smaller than 1". Figure 7.18 presents the water cut defined as the water rate divided into the total rate.

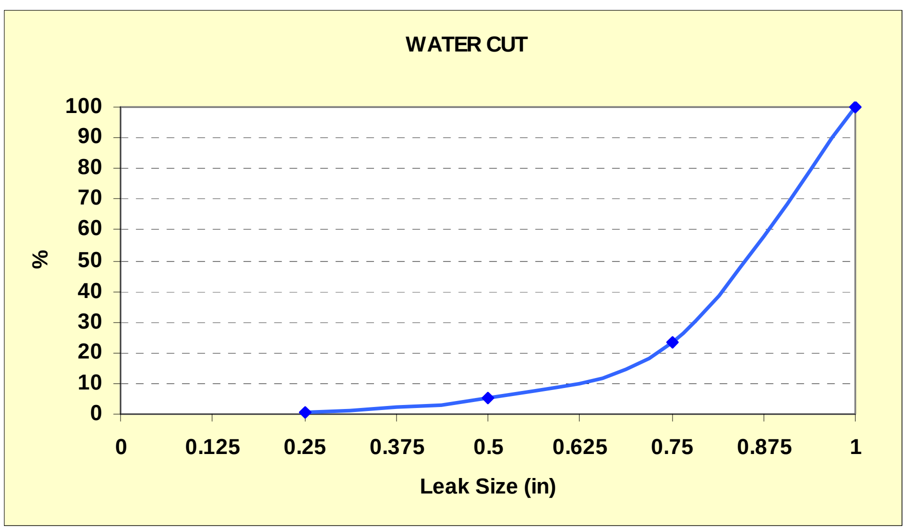


Figure 7.18 Water Cut Increase "Water Ingress Cases"

Initially no water is present in the production stream since only two phases (gas and hydrocarbon) are being produced. When a leak is present the water cut increases up to 100% when no hydrocarbon production is obtained at the surface.

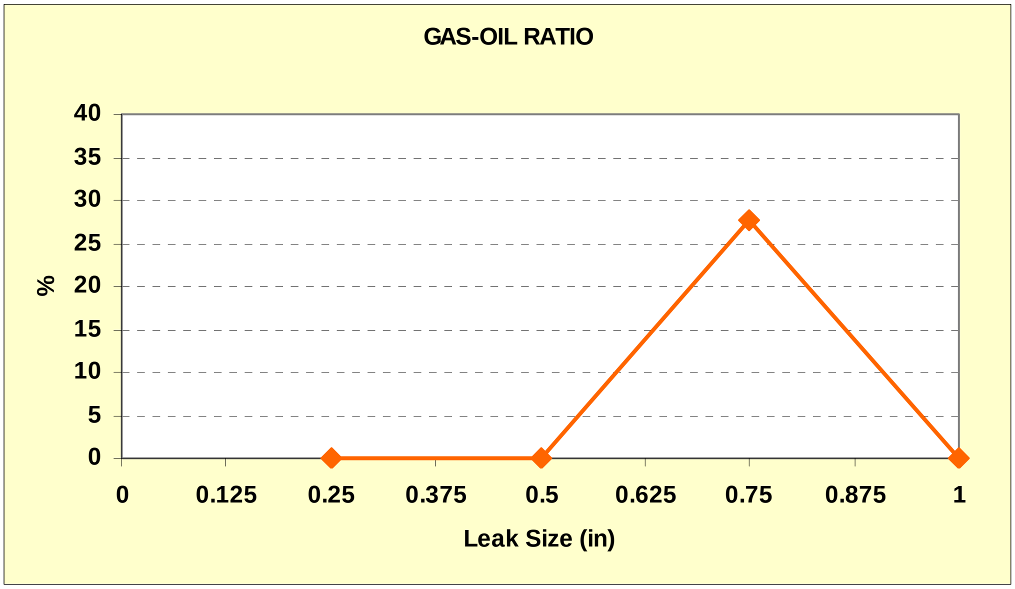


Figure 7.19 Gas-Liquid Ratio Variation “Water Ingress Cases”

The gas-oil ratio variation obtained for leaks between 0.5” and 0.75’ was not enough to affect either liquid or vapor compositional variations.

CONCLUSIONS

It should be noted that software limitations prevented the full evaluation of this method. The composition of the fluid released from the pipeline was the mixture composition. Therefore it was not possible to evaluate a leak comprised of only the gas phase (leak location at the top of the pipe) or a leak comprised of only the liquid phase (leak location at the bottom of the pipe). These cases would be expected to show a much larger compositional change due to the leak.

For Horizontal Flowline

- Liquid molar fractions are significantly affected by leaks larger than 2”.
  - Leaks 1” to 2” can be detected with great difficulty since variations for these cases were very small and require use of a high precision instrument to detect.
  - Leaks smaller than 1” cannot be detected.

- Gas/liquid ratio increases up to 100% or more with increase in size of the leak and its distance from the separator.
- Molar fraction changes depend on the flow regime as shown below. When a leak is present in bubble and annular flow it is easier to detect it than when the flow regime is slug or stratified. This is because the molar fraction change is much large in these cases even though the size of leak (mass reduction) is the same.

Flow Regime	Mass Reduction	x_{C1} change
Annular	11%	20%
Stratified	11%	5%
Bubble	11%	9%
Slug	11%	5%

For Vertical Flowline

- Leaks larger than 1.5" can be easily detected.
- With even as low as 2% mass reduction we can see 10% change in liquid composition of the fluid, hence the leak can be easily detected.
- In case of water ingress, the only way to detect the leak is by monitoring the water cut as there is no change in the composition.
- The vapor molar fraction is not as sensitive as the liquid molar fraction

DEEPWATER FLOWLINE: THE FLOODING REGIME

Identification of a leaking flowline represents a special challenge for many of the deepwater developments planned in the Gulf of Mexico. This chapter focuses on how a leak manifests for the case where the hydrostatic pressure is higher than the internal pressure of the pipeline.

The existence of a hole in a subsea pipeline can lead to two different flows--flooding of the pipeline if the hydrostatic pressure is more then the internal pressure of the pipeline and leaking if the hydrostatic pressure is less than the internal pressure. Fig 8-1 shows that the flooding region represents a large portion of the pressure versus depth range, especially for deepwater flowlines operated at moderate to low pressures. This is expected in the later life of the field when corrosion induced failure would be highest and the internal pressure in the pipeline is the least.

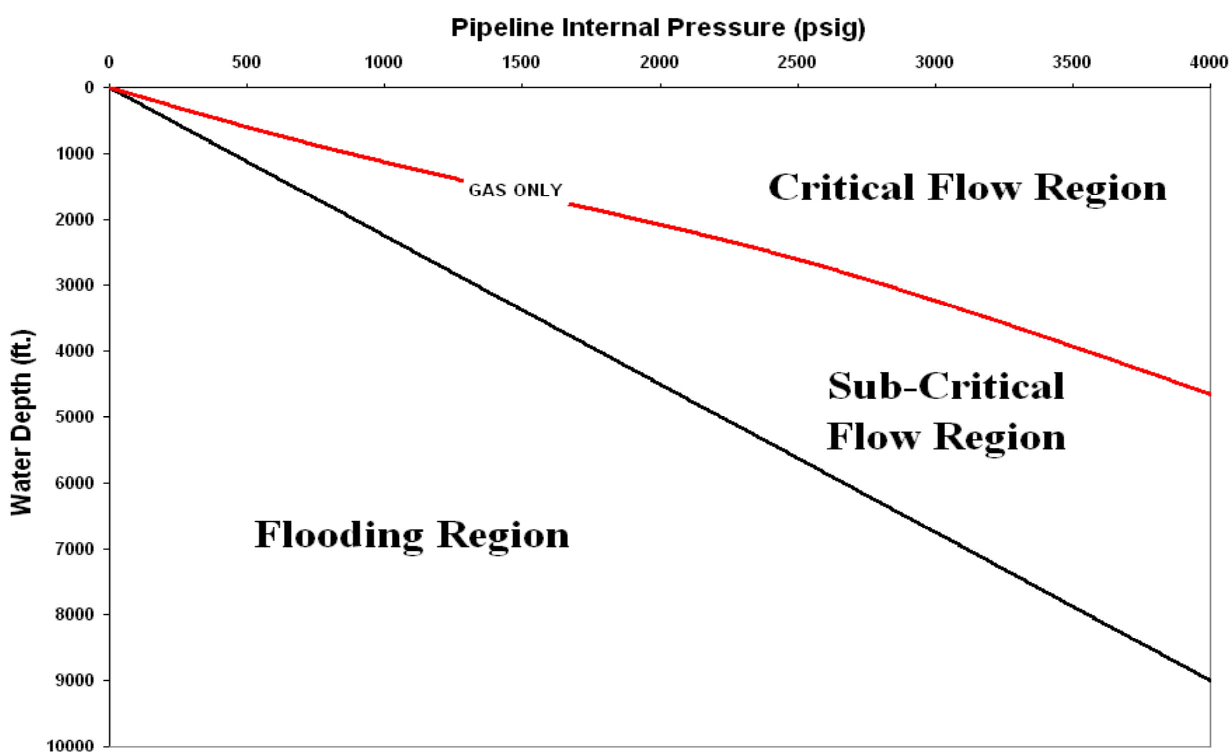


Figure 8-1: Flooding region and leak region for a deepwater pipeline

Figure 8-2 shows a typical case of the flow schematic from the well through tubing, pipeline riser and piping to the separator. Generally the well tubing is encapsulated among other production casings and has less chance of corrosion, thus leaks are unlikely.

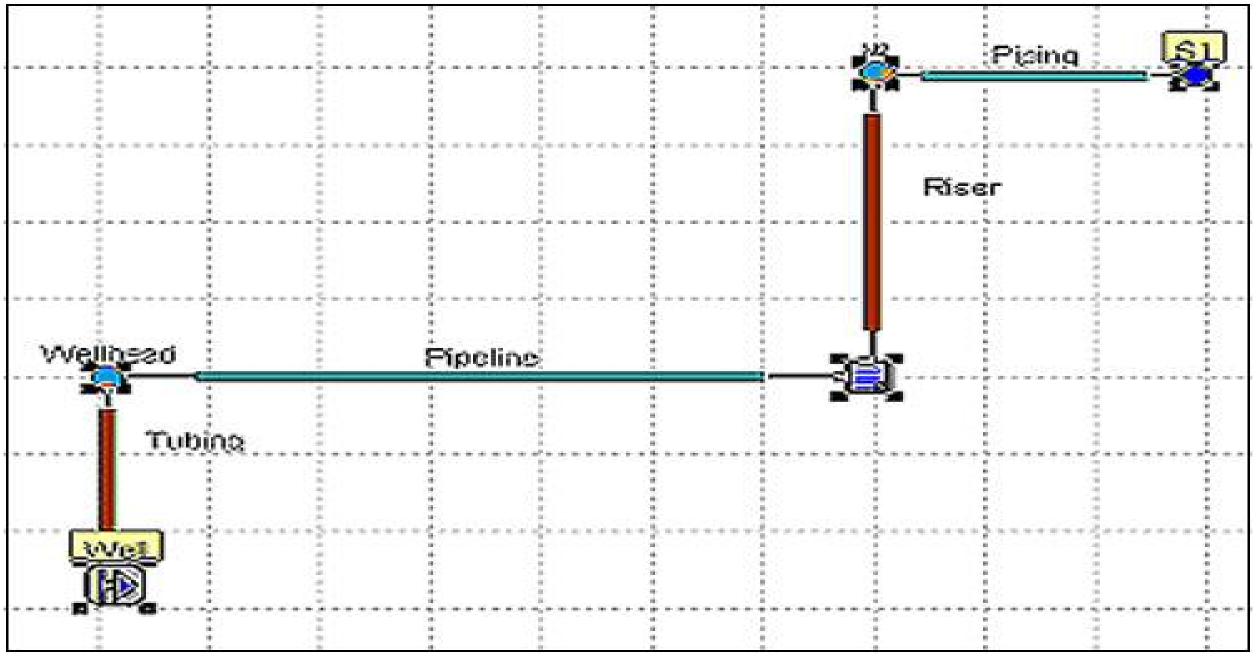


Figure 8-2: Typical flow schematic in an offshore field. The flooding takes place in the pipeline section.

The riser section in deepwater is made of steel pipe and leaks occur mostly in the form of ruptures rather than pinholes, which can be easily detected. Leak detection has been an issue for the case of horizontal pipelines where pockets of static water can create severe corrosion at the bottom of the pipeline. Hence in this case pipeline flooding has been considered only for the horizontal subsea pipeline.

For the case of deepwater, a water depth of 5000 ft has been considered. The reservoir has a pressure of 1500 psi at 135 °C. A multiphase fluid has been selected for this case. This is the most difficult case for leak / flooding detection. Typical pipe diameter, wall thickness, insulation coating has been considered in this application. The detailed input file for the OLGA simulation is given in Appendix-B and summarized in Table 8-1. Initially there is no water cut. The separator pressure has been maintained steady at 200 psi.

Table 8.1
Typical Data for Simulation

Parameter	Value
Water Depth (ft)	5,000
Flowline Size (inches)	4” NB
Flowline Length (m)	4,300
Leak Location (Distance from wellhead, m)	2,500 m
Leak Size (inches)	0.25” – 1”
Backpressure for leak (psia)	2,165

Trend plots and the profile plots have been prepared for varying size of hole in the pipeline. The plots show the effect of hole size on various parameters. The trend plot shows the effect in terms of time at a particular position. Figures 8-3 and 8-4 show the effect of hole size on the pressure inside the pipeline both upstream and downstream of the flooding point. The arrow on the plots indicates how the behavior changes with increasing leak size.

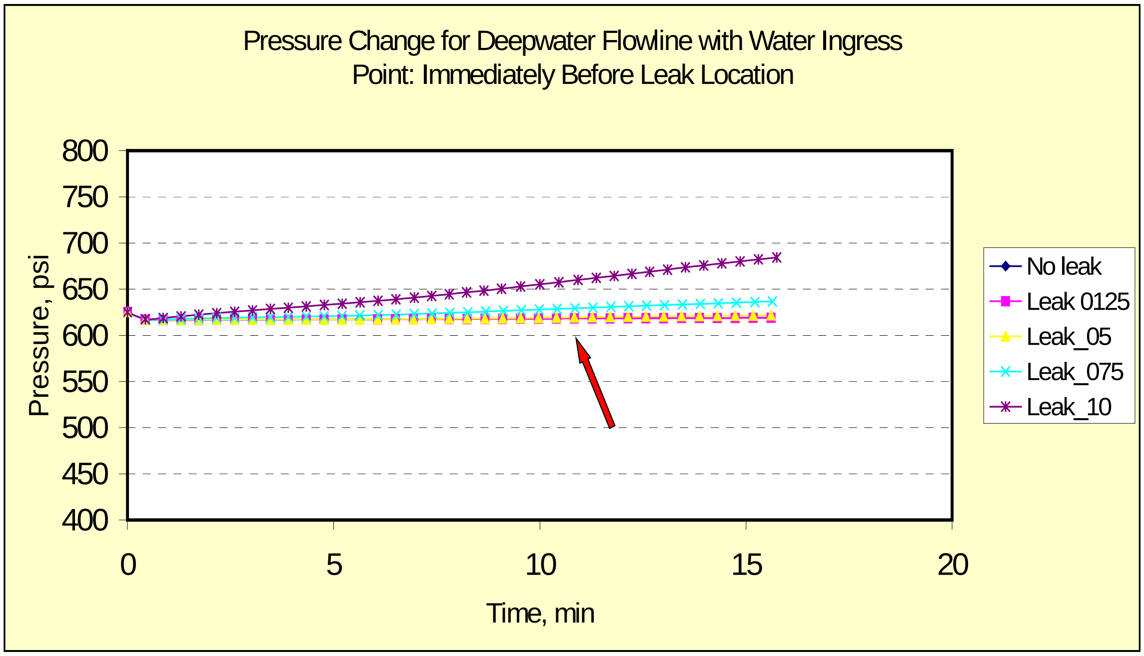


Figure 8-3: Pressure upstream of the hole (leak point) varying with time for various hole size.

The size of the leak is denoted by "0125" for 1/8-inch, "05" for ½-inch, "075" for ¾-inch, "10" for 1-inch, etc.. The location of the leak is approximately in the middle of the flowline. The upstream pressure does not change as significantly as the downstream pressure except for the case of 1" leak size where both upstream and downstream pressures change significantly.

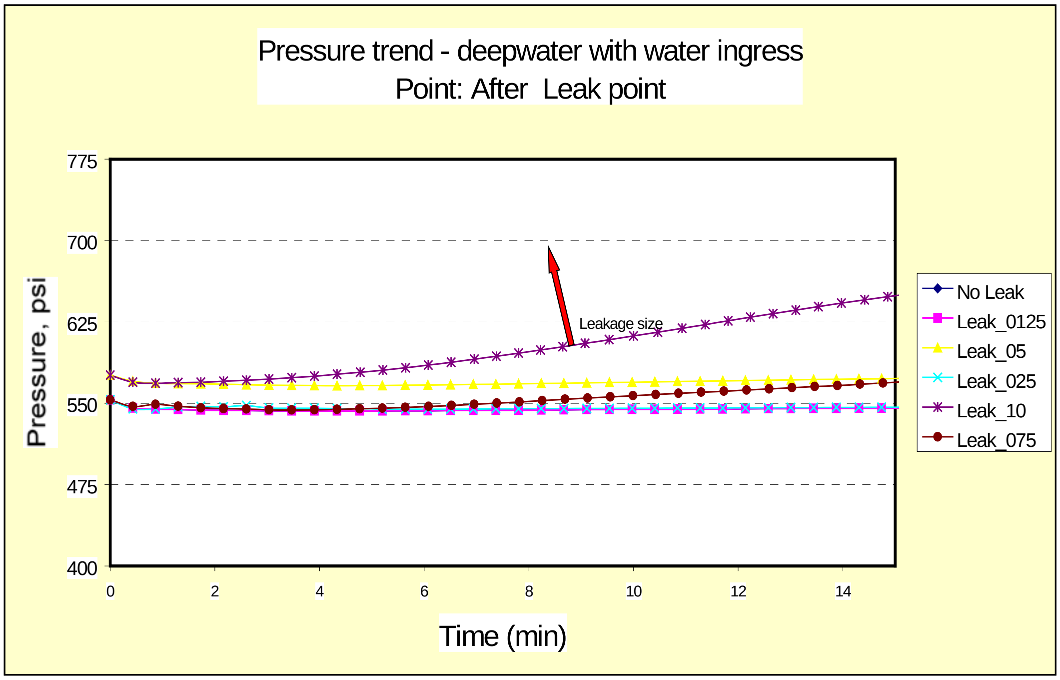


Figure 8-4: Pressure downstream of the hole (leak point) varying with time for various hole size.

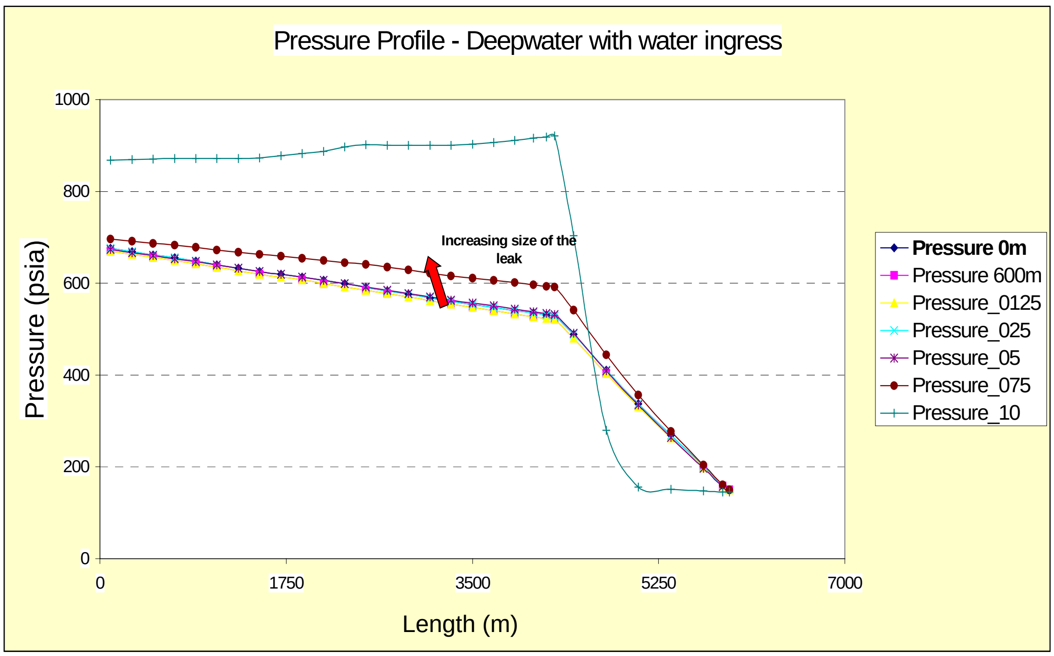


Figure 8-5: Pressure profile in the pipeline with varying size of hole

Figure 8-5 shows the pressure profile from the wellhead to the separator at the host (a total distance of 5,900 m). As hole size increases the pressure profile in the pipeline section becomes flatter. The pressure profiles change suddenly for the case of 1" leak where the internal pressure is greater downstream of the hole than upstream of the hole. This creates a back-flow into the well. If there is no check valve at the wellhead, the flow would go back into the well. This is the case when the pressure downstream of the flooding point becomes larger than in the upstream side. This would start increasing the pressure at the wellhead significantly. Even if a check valve were present this would lead to increase in the pressure at the wellhead.

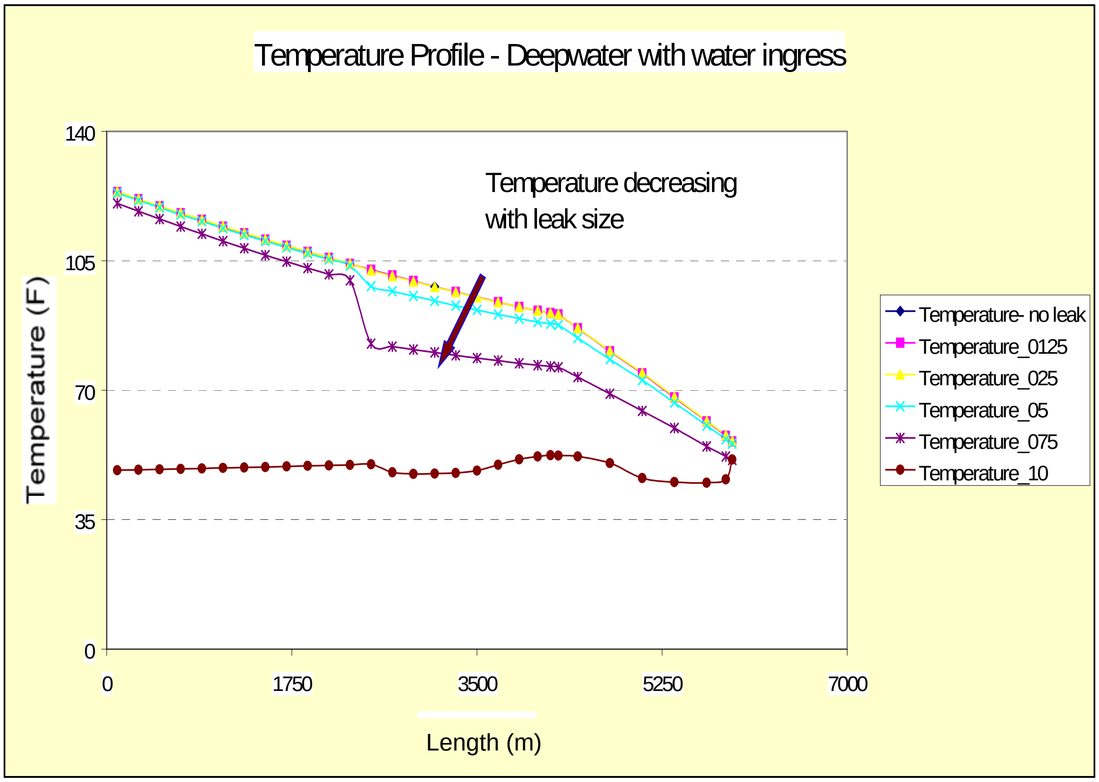


Figure 8-6: Temperature profile in the pipeline with varying size of hole.

One important parameter to be observed is the temperature. The two-phase fluid temperature in the pipeline before leak has to be considerably high so as to prevent gas hydrate formations. The temperature of the seawater coming at 5000 ft is in the range of 5 °C. This water ingress decreases the temperature of the whole fluid drastically. As can be seen from Figure 8-6, initially the temperature falls more drastically downstream of the leak point. As the leak size is increased to such a size where the back flow starts, the temperature on the wellhead also starts decreasing drastically.

In the flooding regime, the temperature goes much below the gas hydrate formation temperatures. Hence it is very important to monitor any kind of leak in the region where hydrostatic pressure exceeds the internal pressure of the pipeline. For small leaks the temperature decreases more downstream than upstream. However a decrease in temperature with increase in pressure is a positive sign of flooding of the pipeline.

Figure 8-7 shows the effect of hole size on water cut at the separator. For a small size hole, the water cut increases to around 200 bbl/d for 0.5” hole, and rises to 450-800 bbl/d for a 0.75” hole. The values of water cut are comparable to those in the reservoir.

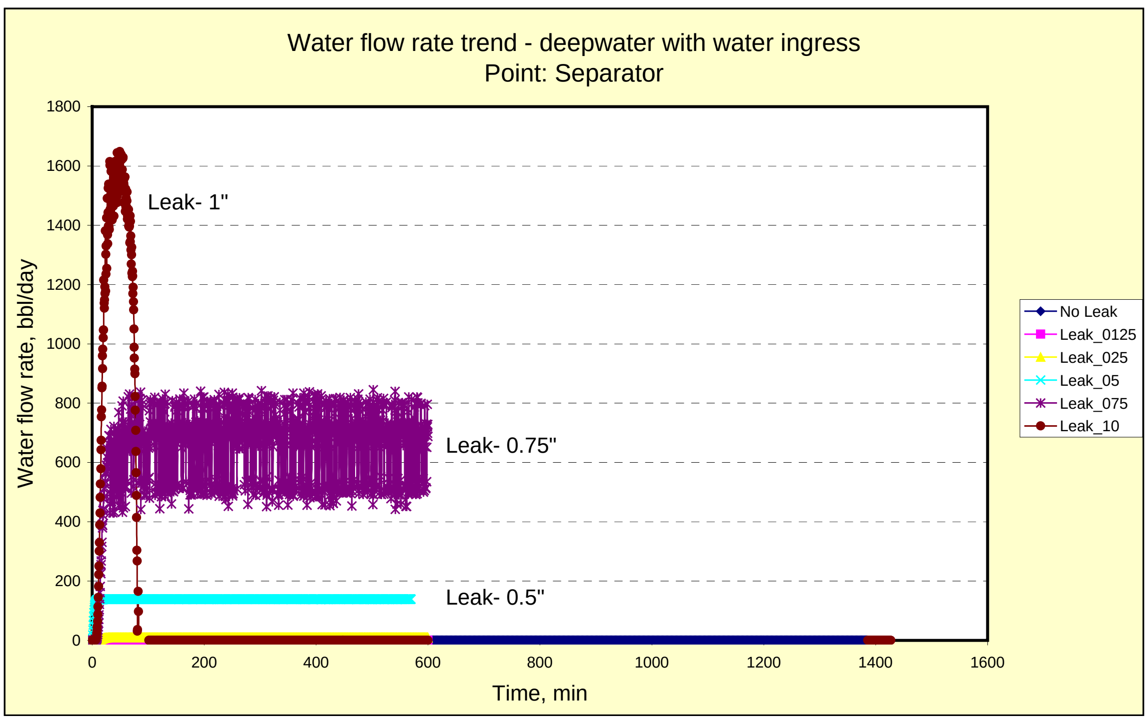


Figure 8-7: Water cut at the separator for flooding region with varying size of hole.

One of the most interesting observations is the moment the internal pressure downstream of the hole is greater than that upstream of the hole, the water cut at the separator jumps to 1600 bbls/day, and drops to zero within a short time. For 1” hole size, because of the pressure profile, back flow starts, hence instead of water coming to the separator it will go towards the wellhead. This is the case when there is no check valve at the wellhead. In case there is a check valve at the wellhead, the line will be full of water.

Figure 8-8 shows the trend of oil production for increasing size of hole in the flowline. The oil production drops from 3000 bbl/day to 2800 bbl/day for hole size of 0.5”. However for the hole size of 1” the production drops from 2800 bbls/day to zero. This sudden pressure drop is the result of the changing pressure profile in the flowline.

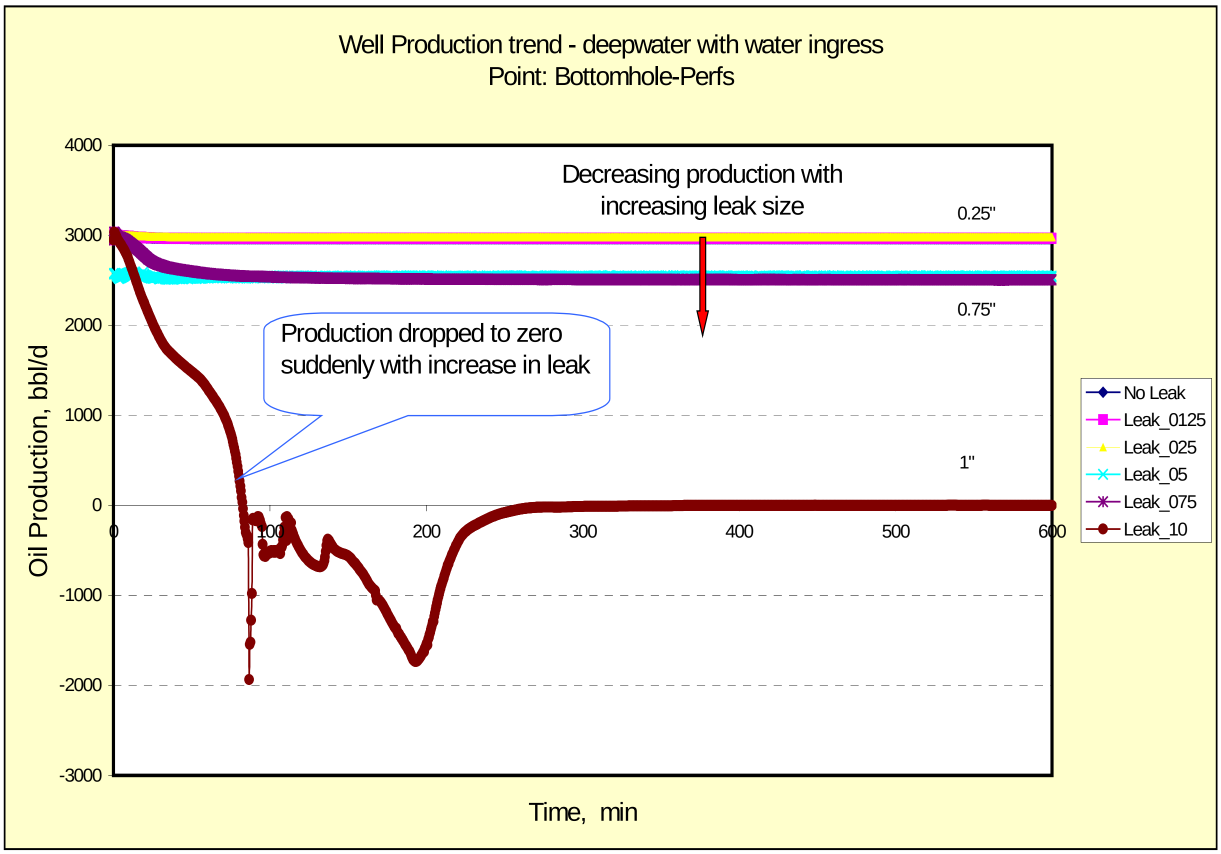


Figure8-8: Oil production at the perforation (bottom hole) for flooding region with varying size of hole.

The case depicted here is for a deepwater pipeline (water depth of 5000 ft) with low internal pressure. It is strongly recommended to do a similar exercise for deepwater pipelines with lower internal pressure to determine what size of leak will be critical to flow. The case where the back flow starts is significant because it may activate the check valve, thus production may drop to zero.

It is very difficult to determine from the decline in production if any flooding of pipeline is taking place. As can be seen for a 0.5” leak the production had dropped by 3-4% and the water cut was in the range of 200-300 bbl/day. These are very normal production figures even with overall decrease in reservoir pressure or water cut from the reservoir itself.

Pressure Monitoring: Surface Vis-A-Vis Subsea

Presently, PSL (Pressure Safety Low) is installed at the surface. The typical response of PSL for a leak into the pipeline is shown in Figure 8.9 below:

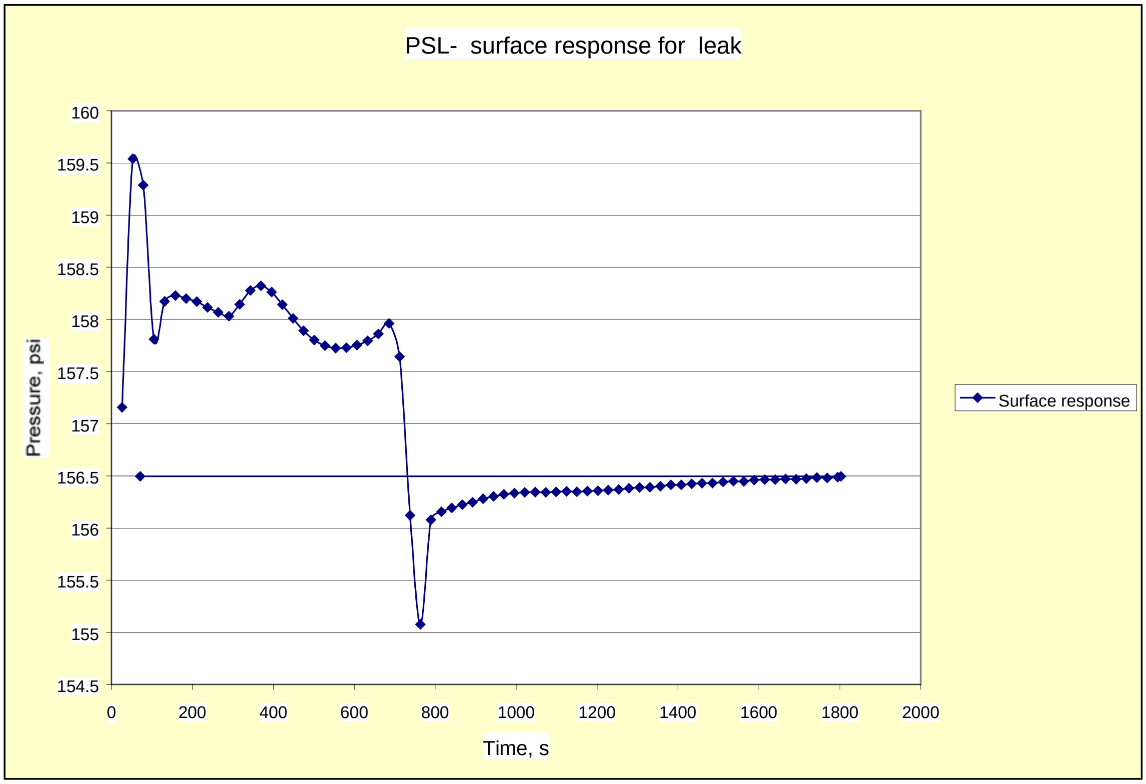


Figure 8-9: Monitoring of pressure at Surface (PSL)

There is a sudden pressure increase followed by an oscillatory change in pressure. The sensor will give an alarm but will be followed by sporadic readings.

The pressure sensor at the wellhead will note a sudden pressure drop followed by an increase in pressure. This change in pressure at the wellhead can be noted even at a longer period of time.

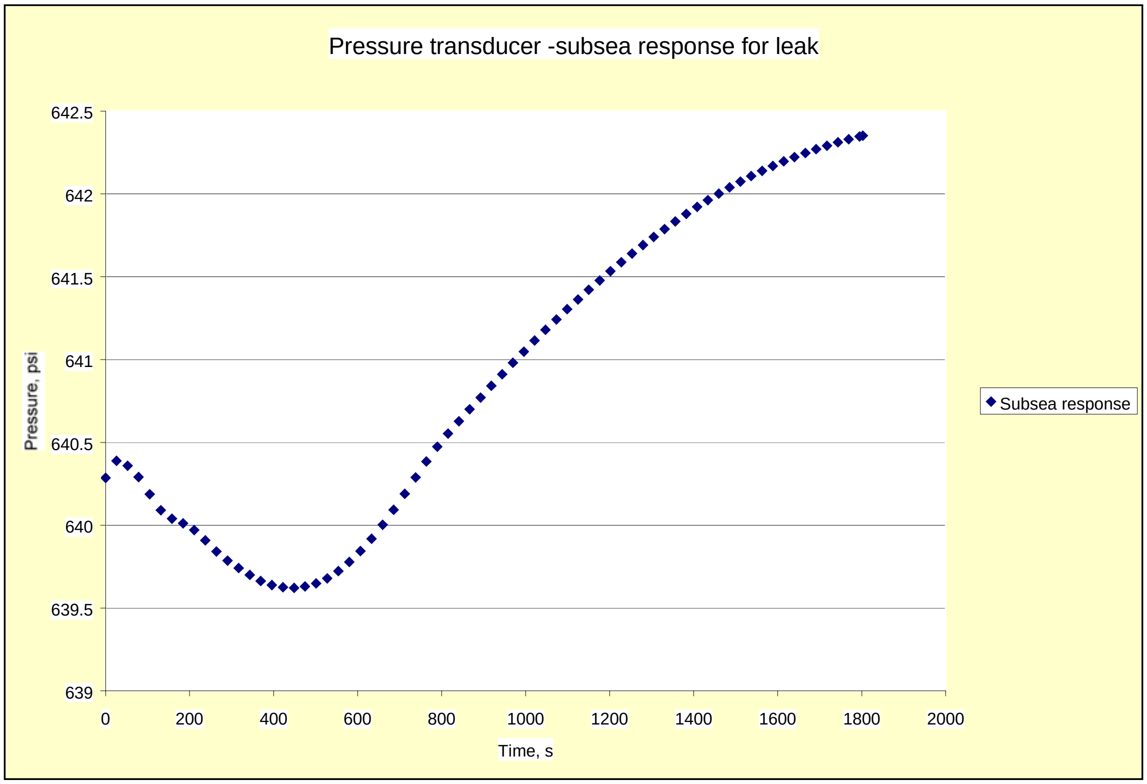


Figure 8-10: Monitoring of pressure subsea

It is better to monitor the pressure subsea than at the surface due to oscillations in pressure at the surface.

Monitoring of Flooding in Deepwater Pipelines

1. It is necessary to do a flow assurance model for the deepwater pipeline to determine what size of leak is critical i.e. when back-flow would start.

2. Since the operator fixes the separator conditions, no significant change can be observed at the separator. However, by monitoring the wellhead we see that as the water cut increases the pressure is increasing and the temperature is decreasing.

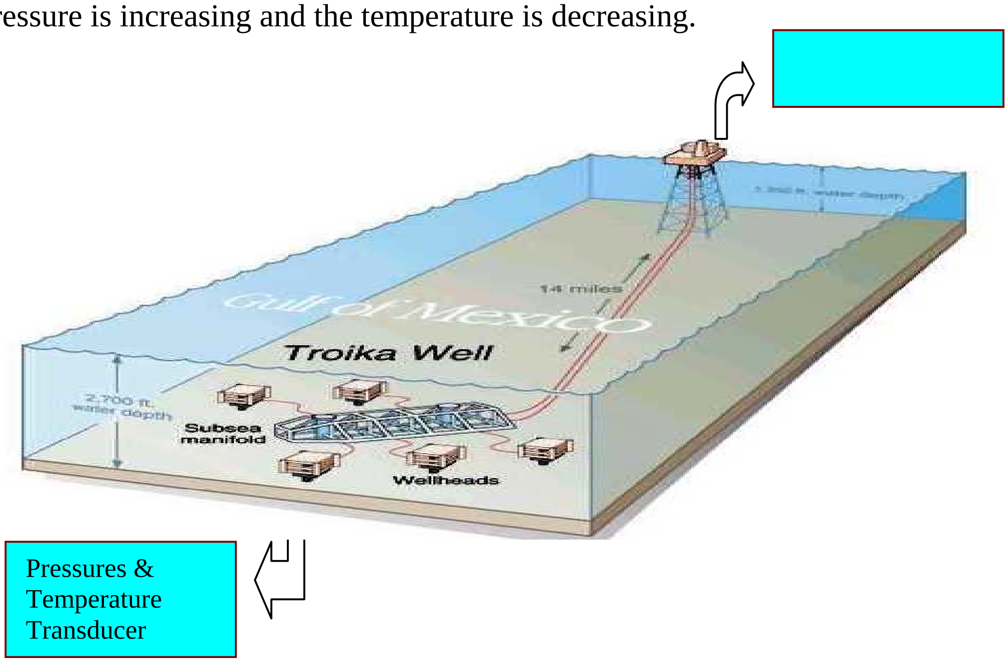


Figure 8-11: Monitoring of flooding in deepwater pipelines.

Installing Pressure Safety High (PSH) & Temperature Safety Low (TSL) at the wellhead can help to identify the flooding of the pipeline. This increase in pressure and decrease in temperature is unique to flooding of the pipeline and can help in easy detection. A very high increase in pressure and severe decrease in temperature indicates a major leak.

3. It is also important to have a water analyzer (chromatograph) after the separator to identify the source of water cut i.e. flowline or reservoir. Even for small holes there are high chances of hydrate formation at the site where flooding takes place.

CONCLUSIONS AND RECOMMENDATIONS

The goal of this study was to provide decision-makers with an insight into the current trends in leak detection and how they might be applied for the many subsea, arctic and multiphase pipelines planned in the future. The study identified many viable leak detection technologies that are commercially available and many more that will be commercialized in the near future. Several of the currently available technologies work in a complementary fashion, greatly expanding the range of leaks that can be detected. As shown in Figure 9.1, each leak detection method covers a specific range of detection times and volumetric leak rates. The external detection methods are able to detect very small leaks, but require a considerable period of time. Pressure monitoring methods are able to very rapidly detect large leaks. Used in combination a wide range of leak conditions can be detected.

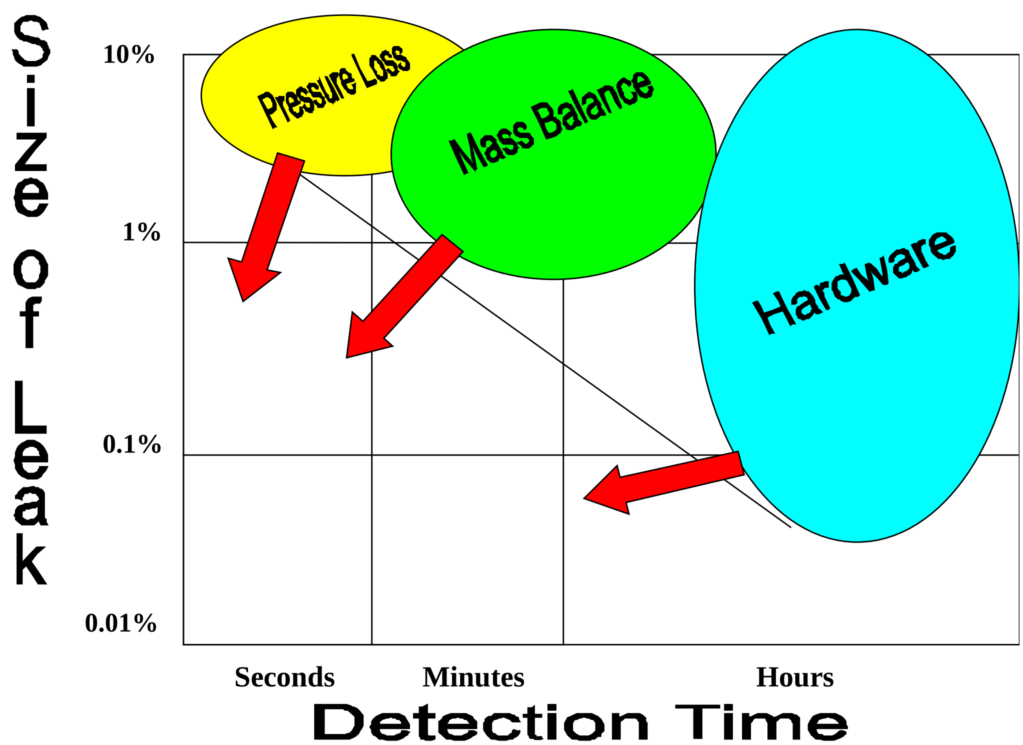


Figure 9.1: Range of Operation for various Leak Detection Options

Several of the major findings of the study are listed below:

- A rapid increase in the number of new leak detection technologies can be observed over the past decade, with many of these new methods employing novel technologies developed in the defense or telecommunication industries.
- More than one leak detection method is employed for special applications such as:
  - where the exterior of the pipe can not be directly inspected
  - environmentally sensitive areas
  - where a release could pose a severe threat to people
- Conventional material balance methods remain the most widely used and are often supplemented with friction/pressure loss (momentum balance) methods.
- Special hardware based methods can mitigate risks of a small leak (<1%) and are complementary to the conventional technologies. These technologies are relatively slow compared with other methods available. However, they do provide a new line of defense against very small leaks that can go undetected for long periods of time. This is especially important when the pipeline/flowline can not be easily inspected.
- For some leak sizes and locations it can be shown that a <u>Pressure Safety Low (PSL) will not detect a leak</u>. While PSL's are effective in detecting leaks in single-phase transmission transportation pipelines, this approach is not effective for multiphase flow. Only in the case of bubble flow are PSL's able to effectively detect leaks. The effectiveness of PSL's can be estimated using commercially available software and the length of time to detect a leak can also be determined.
- Multiphase metering currently has limited application for leak detection due to the poor and variable accuracy of these devices. They can, however, provide some value for high pressure and other select applications.
- Detection of a leak by examining compositional changes in the outlet fluid shows promise, but enhancements to the OLGA simulator are needed before this technique can be fully evaluated.
- Published "best case" detection limits have often found their way into regulations, and may not achievable due to the design/operational constraints on a given system.

- Many software based leak detection systems are marketed as a “black box” in that the methods are kept confidential and are not open to scrutiny. Often incredible claims are made regarding the size of leak that can be detected in multiphase flow conditions. The combined uncertainty of the sensor measurements will be more than the leak detection claims of some vendors. A real need exists for independent verification and demonstration of capabilities.
- For deepwater pipelines, the flow of water into the pipeline (flooding) is expected to be the most common pipeline failure mode. The flooding regime of pipelines in deepwater has been analyzed and it has been shown that even for a small hole there are high chances of hydrate formation at the site where flooding takes place. Installing Pressure Safety High (PSH) & Temperature Safety Low (TSL) sensors at the wellhead can help to identify the flooding of a pipeline.
- External leak detection methods show great promise for providing a vital tool for reducing the risks of small leaks that occur over long periods of time. At present these are not competitive as the primary leak detection system due to the long time needed for sampling.
- Modeling results indicate that relative to single-phase flow transmission, the size of a leak detectable by mass balance and pressure drop methods is reduced in multiphase flow transmission and is highly flow pattern dependent. External methods, however, are not significantly degraded by multiphase flow in the pipeline and can be utilized as a secondary leak detection method for subsea and arctic flowlines.

Based on the analysis performed during this study a number of recommendations can be made:

- It is recommended that large-scale experimental experiments be performed in the area of multiphase leak detection. Field demonstration projects are also suggested as a way of proving vendor claims.
- Distributed pressure and temperature arrays should be investigated as a means to extend the capability of pressure loss detection methods.
- For flowlines where inlet metering is not practical, special testing requirements should be considered to improve the ability of momentum (friction) based methods to detect leaks.

- Combination of continuous sampling and batch sampling should be investigated as a means of reducing the time to detect a leak using LEOS and other diffusion/dispersion based methods.

On September 9-10, 2002 a workshop was held at the George Bush Presidential Library – Conference Center in College Station, Texas. Entitled the ***ASME/Texas A&M Subsea & Arctic Leak Detection Symposium***, this event provided a forum for discussion of the special leak detection issues associated with these developments. At the conclusion of the event, a survey was taken to assess the perceived technology needs. Listed below are the results of the technology survey. As can be seen there exists considerable interest in the area of subsea leak detection. Also of high interest are field demonstration projects, multiphase leak detection and assistance with selection of an appropriate leak detection method for a given application.

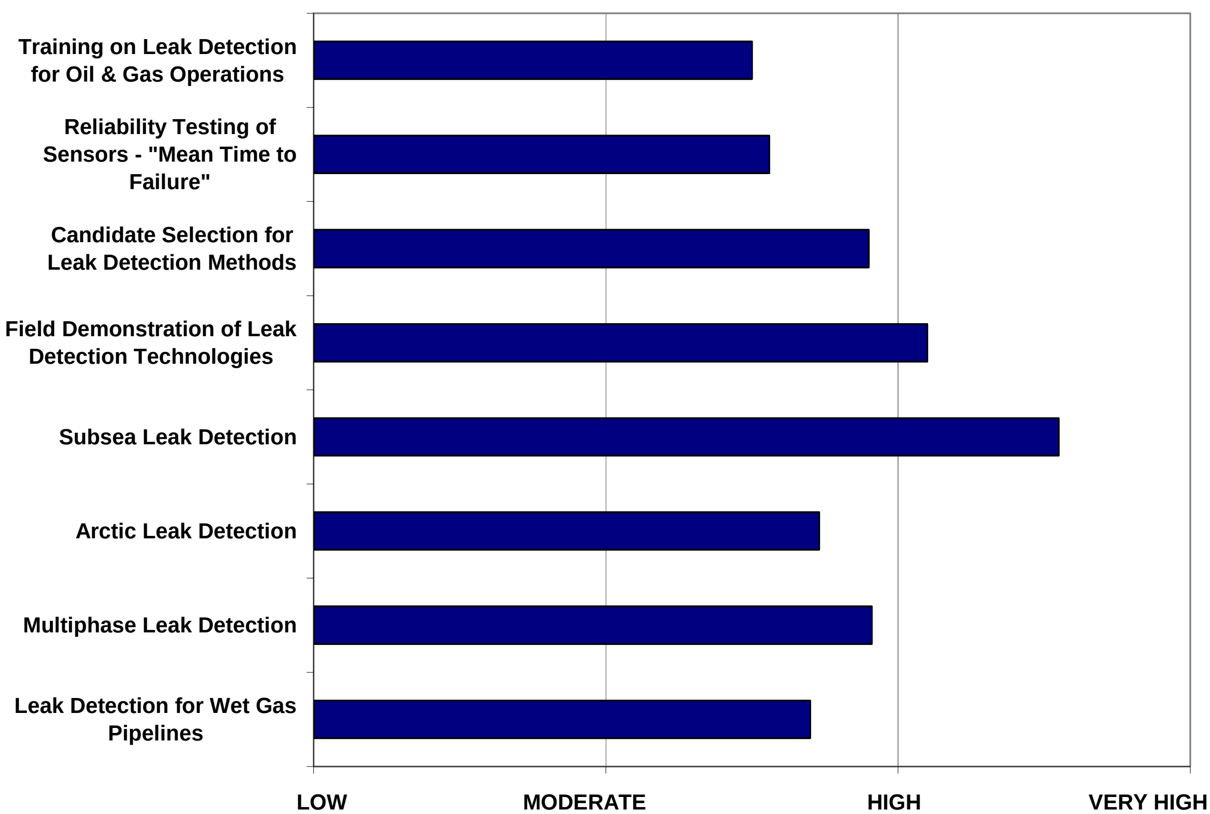


Figure 9.2: Technology Survey Results for Subsea & Artic Leak Detection Symposium

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Appendix- A

OLGA Input File – Simulate Effect of Leak on Different Multiphase Flow Regimes

```
!
!***************************************************************************
!-    CASE Definition
!---------------------------------------------------------------------------
CASE  PROJECT="Exercise 1: Leak Detection", \
    TITLE="Effect of leak on Reservoir/ Wellhead"

!
!***************************************************************************
!-    OPTIONS Definition
!---------------------------------------------------------------------------
OPTIONS  COMPOSITIONAL=OFF, DEBUG=OFF, PHASE=THREE, POSTPROCESSOR=ON,
SLUGVOID=SINTEF, STEADYSTATE=ON, TEMPERATURE=WALL,  \
       WAXDEPOSITION=OFF

!
!***************************************************************************
!-    FILES Definition
!---------------------------------------------------------------------------
FILES  PVTFILE="deep_new.tab"

!
!***************************************************************************
!-    INTEGRATION Definition
!---------------------------------------------------------------------------
INTEGRATION  CPULIMIT=2 h, DTSTART=0.01 s, ENDTIME=0.5 h, MAXDT=5 s, MAXTIME=0
s, MINDT=0.01 s, MINTIME=0 s,  \
           NSIMINFO=10, STARTTIME=0 s

!***************************************************************************
!      WATEROPTIONS Definition
!***************************************************************************
WATEROPTIONS  DISPERSIONVISC=ON, INVERSIONWATERFRAC=0.5  , WATERFLASH=ON,
WATERSLIP=ON

!***************************************************************************
!-    MATERIAL Definition
!---------------------------------------------------------------------------
MATERIAL  LABEL=STEEL, CAPACITY=500 J/kg-C, CONDUCTIVITY=50 W/m-K, DENSITY=7850
kg/m3, TYPE=SOLID
MATERIAL  LABEL=INSULATION, CAPACITY=1500 J/kg-C, CONDUCTIVITY=0.135 W/m-K,
DENSITY=1000 kg/m3, TYPE=SOLID
MATERIAL  LABEL=FORMATION, CAPACITY=1256 J/kg-C, CONDUCTIVITY=1.59 W/m-K,
DENSITY=2243 kg/m3, TYPE=SOLID

!
!***************************************************************************
!-    WALL Definition
!---------------------------------------------------------------------------
WALL  LABEL=WALL-1, ELECTRICHEAT=OFF, MATERIAL=( STEEL, INSULATION, INSULATION
), POWERCONTROL=OFF, THICKNESS=( 0.009,  \
        2:0.0125 ) m
```

```
WALL  LABEL=WALL-2, ELECTRICHEAT=OFF, MATERIAL=( STEEL, INSULATION, INSULATION
), POWERCONTROL=OFF, THICKNESS=( 0.0075,  \
        2:0.0125 ) m
WALL  LABEL=WELL_WALL, ELECTRICHEAT=OFF, MATERIAL=( STEEL, FORMATION, FORMATION,
FORMATION, FORMATION ),  \
    POWERCONTROL=OFF, THICKNESS=( 0.00688, 4:0.15 ) m

GEOMETRY  LABEL=FLOWLINE, XSTART=707 m, YSTART=0 m, ZSTART=0 m

PIPE  LABEL=PIPE_1, DIAMETER=4 in, ELEVATION=0 m, LENGTH=1000 m, NSEGMENTS=5,
ROUGHNESS=2.8e-005 m, WALL=WALL-1
PIPE  LABEL=PIPE_2, ELEVATION=5 m, LENGTH=400 m, NSEGMENTS=2
PIPE  LABEL=PIPE_3, ELEVATION=-5 m, LENGTH=400 m, NSEGMENTS=2
PIPE  LABEL=PIPE_4, ELEVATION=0 m, LENGTH=1600 m, NSEGMENTS=8
PIPE  LABEL=PIPE_5, ELEVATION=-15 m, LENGTH=900 m, LSEGMENT=( 3:200, 150, 90, 60
) m, NSEGMENTS=6
PIPE  LABEL=PIPE_6, DIAMETER=0.1 m, ELEVATION=1524.0045963979 m,
LENGTH=1524.0045963979 m, NSEGMENTS=5, WALL=WALL-2
PIPE  LABEL=PIPE_7, ELEVATION=0 m, LENGTH=120 m, NSEGMENTS=2
GEOMETRY  LABEL=WELLBORE, XSTART=0 m, YSTART=-1507 m, ZSTART=0 m
PIPE  LABEL=WELLBORE-1, DIAMETER=4 in, ELEVATION=707 m, LENGTH=1000 m,
NSEGMENTS=5, ROUGHNESS=2.5e-005 m,  \
    WALL=WELL_WALL
PIPE  LABEL=WELLBORE-2, ELEVATION=800 m, LENGTH=800 m, NSEGMENTS=4

!
!*******************************************************************************
!-    NODE Definition
!-------------------------------------------------------------------------------
NODE  LABEL=PERFS, TYPE=TERMINAL, X=0 m, Y=0 m, Z=0 m
NODE  LABEL=WELLHEAD, TYPE=MERGE, X=0 m, Y=0 m, Z=0 m
NODE  LABEL=PLATFORM, TYPE=TERMINAL, X=0 m, Y=0 m, Z=0 m

BRANCH  LABEL=WELLBORE, FLOAT=ON, FLUID="1", FROM=PERFS, GEOMETRY=WELLBORE,
TO=WELLHEAD
BRANCH  LABEL=FLOWLINE, FLOAT=ON, FLUID="1", FROM=WELLHEAD, GEOMETRY=FLOWLINE,
TO=PLATFORM

!
!*******************************************************************************
!-    BOUNDARY Definition
!-------------------------------------------------------------------------------
BOUNDARY  NODE=PERFS, TYPE=CLOSED
BOUNDARY  GASFRACTION=1 -, NODE=PLATFORM, PRESSURE=145.037 psia, TEMPERATURE=22
C, TIME=0 s, TYPE=PRESSURE,  \
        WATERFRACTION=0 -

!
!*******************************************************************************
!-    HEATTRANSFER Definition
!-------------------------------------------------------------------------------
HEATTRANSFER  BRANCH=WELLBORE, HAMBIENT=6.5 W/m2-C, HMININNERWALL=10 W/m2-C,
HOUTEROPTION=HGIVEN, INTAMBIENT=68 C,  \
            INTERPOLATION=VERTICAL, OUTTAMBIENT=6 C
HEATTRANSFER  BRANCH=FLOWLINE, HAMBIENT=6.5 W/m2-C, HMININNERWALL=10 W/m2-C,
HOUTEROPTION=HGIVEN, INTERPOLATION=SECTIONWISE,  \
            TAMBIENT=6 C
```

```
!*****************************************************************************
!      CONTROLLER Definition
!*****************************************************************************
CONTROLLER  LABEL=CONTROLLER-1, COMBINEVARIABLES=OFF, EXTENDED=OFF,
MAXCHANGE=0.2  , SETPOINT=( 0, 0.015625 )  ,  \
          STROKETIME=33.33 s, TIME=( 0, 1 ) s, TYPE=MANUAL

!*****************************************************************************
!      SOURCE Definition
!*****************************************************************************
SOURCE  LABEL="WATER INGRESS", BRANCH=FLOWLINE, CD=0.84  ,
CONTROLLER=CONTROLLER-1, DIAMETER=0.5 in, CRITFLOWMODEL=FROZEN,  \
      PIPE=PIPE_4, PRESSURE=2165 psia, SECTION=4, TEMPERATURE=8 C,
TOTALWATERFRACTION=1 -

!*****************************************************************************
!      WELL Definition
!*****************************************************************************
WELL  LABEL=WELLS, AINJ=0  , APROD=0  , BINJ=3e-006  , BPROD=3e-006  ,
BRANCH=WELLBORE, GASFRACTION=-1 -,  \
    INJOPTION=LINEAR, ISOTHERMAL=YES, LOCATION=MIDDLE, PIPE=WELLBORE-1,
PRODOPTION=LINEAR, RESPRESSURE=100 bara,  \
    RESTEMPERATURE=100 F, SECTION=1, TIME=0 s, WATERFRACTION=0 -, WAXFRACTION=0
-

!*****************************************************************************
!      VALVE Definition
!*****************************************************************************
VALVE  LABEL=WH-VALVE, BRANCH=WELLBORE, CD=0.84  , CRITFLOWMODEL=FROZEN,
DIAMETER=0.089 m, OPENING=1  , PIPE=WELLBORE-2,  \
     SECTIONBOUNDARY=5, TIME=0 s
VALVE  LABEL=PF-VALVE, BRANCH=FLOWLINE, CD=0.84  , CRITFLOWMODEL=FROZEN,
DIAMETER=0.12 m, OPENING=1  , PIPE=PIPE_7,  \
     SECTIONBOUNDARY=2, TIME=0 s

!
!*****************************************************************************
!-    PRINTINPUT Definition
!-----------------------------------------------------------------------------
PRINTINPUT  KEYWORD=GEOMETRY
PRINTINPUT  KEYWORD=TABLE

!
!*****************************************************************************
!-    OUTPUT Definition
!-----------------------------------------------------------------------------
OUTPUT  COLUMNS=4, DELETEPREVIOUS=OFF, DTOUT=2 h
OUTPUT  BRANCH=WELLBORE, COLUMNS=4, DELETEPREVIOUS=OFF, VARIABLE=( UL, UG, UD,
AL, PT, DPT, BE, GA, ID )
OUTPUT  BRANCH=WELLBORE, COLUMNS=4, DELETEPREVIOUS=OFF, VARIABLE=( RMTOT, BOU,
MG, ML, MD, TM, DTM )
OUTPUT  BRANCH=FLOWLINE, COLUMNS=4, DELETEPREVIOUS=OFF, VARIABLE=( UL, UG, UD,
AL, PT, DPT, BE, GA, ID )
OUTPUT  BRANCH=FLOWLINE, COLUMNS=4, DELETEPREVIOUS=OFF, VARIABLE=( RMTOT, BOU,
MG, ML, MD, TM, DTM )
```

```
!*****************************************************************************
!      TREND Definition
!*****************************************************************************
TREND  BRANCH=WELLBORE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=WELLBORE-1,
SECTION=2, TIME=0 s, VARIABLE=( PT,  \
         TM, QG, QLTHL, QLTWT )
TREND  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=PIPE_1, SECTION=1,
TIME=0 s, VARIABLE=( PT,  \
         TM, ID, USG, USL, QLTWT, QLTHL, QG )
TREND  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=PIPE_3, SECTION=1,
TIME=0 s, VARIABLE=( PT,  \
         TM, ID, USG, USL, QLTWT, QLTHL, QG )
TREND  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=PIPE_3, SECTION=1,
TIME=0 s, VARIABLE=( PT,  \
         TM, ID, USG, USL, QLTWT, QLTHL, QG )
TREND  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=PIPE_4, SECTION=6,
TIME=0 s, VARIABLE=( PT,  \
         TM, ID, USG, USL, QLTWT, QLTHL, QG )
TREND  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=PIPE_5, SECTION=1,
TIME=0 s, VARIABLE=( PT,  \
         TM, ID, USG, USL, QLTWT, QLTHL, QG )
TREND  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=PIPE_4, SECTION=4,
TIME=0 s, VARIABLE=( PT,  \
         TM, ID, USG, USL, QLTWT, QLTHL, QG )
TREND  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=PIPE_7, SECTION=1,
TIME=0 s, VARIABLE=( PT,  \
         TM, ID, USG, USL, QLTWT, QLTHL, QG )

!
!*****************************************************************************
!-    PROFILE Definition
!-----------------------------------------------------------------------------
PROFILE  DELETEPREVIOUS=OFF, DTPLOT=0.25 h, VARIABLE=( HOL, TM, PT, GT, ID )
PROFILE  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=0.25 h, VARIABLE=( USG, USL
)
!
ENDCASE
```

Appendix- B

OLGA Input File - Deepwater Simulation

```
!
!*******************************************************************************
!-    CASE Definition
!-------------------------------------------------------------------------------
CASE  PROJECT="Exercise 1: Leak Detection", \
    TITLE="Effect of leak on Reservoir/ Wellhead"

!
!*******************************************************************************
!-    OPTIONS Definition
!-------------------------------------------------------------------------------
OPTIONS  COMPOSITIONAL=OFF, DEBUG=OFF, PHASE=THREE, POSTPROCESSOR=ON,
SLUGVOID=SINTEF, STEADYSTATE=ON, TEMPERATURE=WALL,  \
       WAXDEPOSITION=OFF

!
!*******************************************************************************
!-    FILES Definition
!-------------------------------------------------------------------------------
FILES  PVTFILE="deep_new.tab"

!
!*******************************************************************************
!-    INTEGRATION Definition
!-------------------------------------------------------------------------------
INTEGRATION  CPULIMIT=2 h, DTSTART=0.01 s, ENDTIME=0.5 h, MAXDT=5 s, MAXTIME=0
s, MINDT=0.01 s, MINTIME=0 s,  \
           NSIMINFO=10, STARTTIME=0 s

!*******************************************************************************
!      WATEROPTIONS Definition
!*******************************************************************************
WATEROPTIONS  DISPERSIONVISC=ON, INVERSIONWATERFRAC=0.5  , WATERFLASH=ON,
WATERSLIP=ON

!*******************************************************************************
!-    MATERIAL Definition
!-------------------------------------------------------------------------------
MATERIAL  LABEL=STEEL, CAPACITY=500 J/kg-C, CONDUCTIVITY=50 W/m-K, DENSITY=7850
kg/m3, TYPE=SOLID
MATERIAL  LABEL=INSULATION, CAPACITY=1500 J/kg-C, CONDUCTIVITY=0.135 W/m-K,
DENSITY=1000 kg/m3, TYPE=SOLID
MATERIAL  LABEL=FORMATION, CAPACITY=1256 J/kg-C, CONDUCTIVITY=1.59 W/m-K,
DENSITY=2243 kg/m3, TYPE=SOLID

!
!*******************************************************************************
!-    WALL Definition
!-------------------------------------------------------------------------------
WALL  LABEL=WALL-1, ELECTRICHEAT=OFF, MATERIAL=( STEEL, INSULATION, INSULATION
), POWERCONTROL=OFF, THICKNESS=( 0.009,  \
        2:0.0125 ) m
WALL  LABEL=WALL-2, ELECTRICHEAT=OFF, MATERIAL=( STEEL, INSULATION, INSULATION
), POWERCONTROL=OFF, THICKNESS=( 0.0075,  \
        2:0.0125 ) m
```

```
WALL  LABEL=WELL_WALL, ELECTRICHEAT=OFF, MATERIAL=( STEEL, FORMATION, FORMATION,
FORMATION, FORMATION ),  \
    POWERCONTROL=OFF, THICKNESS=( 0.00688, 4:0.15 ) m

GEOMETRY  LABEL=FLOWLINE, XSTART=707 m, YSTART=0 m, ZSTART=0 m

PIPE  LABEL=PIPE_1, DIAMETER=4 in, ELEVATION=0 m, LENGTH=1000 m, NSEGMENTS=5,
ROUGHNESS=2.8e-005 m, WALL=WALL-1
PIPE  LABEL=PIPE_2, ELEVATION=5 m, LENGTH=400 m, NSEGMENTS=2
PIPE  LABEL=PIPE_3, ELEVATION=-5 m, LENGTH=400 m, NSEGMENTS=2
PIPE  LABEL=PIPE_4, ELEVATION=0 m, LENGTH=1600 m, NSEGMENTS=8
PIPE  LABEL=PIPE_5, ELEVATION=-15 m, LENGTH=900 m, LSEGMENT=( 3:200, 150, 90, 60
) m, NSEGMENTS=6
PIPE  LABEL=PIPE_6, DIAMETER=0.1 m, ELEVATION=1524.0045963979 m,
LENGTH=1524.0045963979 m, NSEGMENTS=5, WALL=WALL-2
PIPE  LABEL=PIPE_7, ELEVATION=0 m, LENGTH=120 m, NSEGMENTS=2
GEOMETRY  LABEL=WELLBORE, XSTART=0 m, YSTART=-1507 m, ZSTART=0 m
PIPE  LABEL=WELLBORE-1, DIAMETER=4 in, ELEVATION=707 m, LENGTH=1000 m,
NSEGMENTS=5, ROUGHNESS=2.5e-005 m,  \
    WALL=WELL_WALL
PIPE  LABEL=WELLBORE-2, ELEVATION=800 m, LENGTH=800 m, NSEGMENTS=4

!
!*******************************************************************************
!-    NODE Definition
!-------------------------------------------------------------------------------
NODE  LABEL=PERFS, TYPE=TERMINAL, X=0 m, Y=0 m, Z=0 m
NODE  LABEL=WELLHEAD, TYPE=MERGE, X=0 m, Y=0 m, Z=0 m
NODE  LABEL=PLATFORM, TYPE=TERMINAL, X=0 m, Y=0 m, Z=0 m

BRANCH  LABEL=WELLBORE, FLOAT=ON, FLUID="1", FROM=PERFS, GEOMETRY=WELLBORE,
TO=WELLHEAD
BRANCH  LABEL=FLOWLINE, FLOAT=ON, FLUID="1", FROM=WELLHEAD, GEOMETRY=FLOWLINE,
TO=PLATFORM

!
!*******************************************************************************
!-    BOUNDARY Definition
!-------------------------------------------------------------------------------
BOUNDARY  NODE=PERFS, TYPE=CLOSED
BOUNDARY  GASFRACTION=1 -, NODE=PLATFORM, PRESSURE=145.037 psia, TEMPERATURE=22
C, TIME=0 s, TYPE=PRESSURE,  \
        WATERFRACTION=0 -

!
!*******************************************************************************
!-    HEATTRANSFER Definition
!-------------------------------------------------------------------------------
HEATTRANSFER  BRANCH=WELLBORE, HAMBIENT=6.5 W/m2-C, HMININNERWALL=10 W/m2-C,
HOUTEROPTION=HGIVEN, INTAMBIENT=68 C,  \
            INTERPOLATION=VERTICAL, OUTTAMBIENT=6 C
HEATTRANSFER  BRANCH=FLOWLINE, HAMBIENT=6.5 W/m2-C, HMININNERWALL=10 W/m2-C,
HOUTEROPTION=HGIVEN, INTERPOLATION=SECTIONWISE,  \
            TAMBIENT=6 C

!*******************************************************************************
!      CONTROLLER Definition
```

```
!*****************************************************************************
CONTROLLER  LABEL=CONTROLLER-1, COMBINEVARIABLES=OFF, EXTENDED=OFF,
MAXCHANGE=0.2  , SETPOINT=( 0, 0.015625 )  ,  \
          STROKETIME=33.33 s, TIME=( 0, 1 ) s, TYPE=MANUAL

!*****************************************************************************
!      SOURCE Definition
!*****************************************************************************
SOURCE  LABEL="WATER INGRESS", BRANCH=FLOWLINE, CD=0.84  ,
CONTROLLER=CONTROLLER-1, DIAMETER=0.5 in, CRITFLOWMODEL=FROZEN,  \
      PIPE=PIPE_4, PRESSURE=2165 psia, SECTION=4, TEMPERATURE=8 C,
TOTALWATERFRACTION=1 -

!*****************************************************************************
!      WELL Definition
!*****************************************************************************
WELL  LABEL=WELLS, AINJ=0  , APROD=0  , BINJ=3e-006  , BPROD=3e-006  ,
BRANCH=WELLBORE, GASFRACTION=-1 -,  \
    INJOPTION=LINEAR, ISOTHERMAL=YES, LOCATION=MIDDLE, PIPE=WELLBORE-1,
PRODOPTION=LINEAR, RESPRESSURE=100 bara,  \
    RESTEMPERATURE=100 F, SECTION=1, TIME=0 s, WATERFRACTION=0 -, WAXFRACTION=0
-

!*****************************************************************************
!      VALVE Definition
!*****************************************************************************
VALVE  LABEL=WH-VALVE, BRANCH=WELLBORE, CD=0.84  , CRITFLOWMODEL=FROZEN,
DIAMETER=0.089 m, OPENING=1  , PIPE=WELLBORE-2,  \
     SECTIONBOUNDARY=5, TIME=0 s
VALVE  LABEL=PF-VALVE, BRANCH=FLOWLINE, CD=0.84  , CRITFLOWMODEL=FROZEN,
DIAMETER=0.12 m, OPENING=1  , PIPE=PIPE_7,  \
     SECTIONBOUNDARY=2, TIME=0 s

!
!*****************************************************************************
!-    PRINTINPUT Definition
!-----------------------------------------------------------------------------
PRINTINPUT  KEYWORD=GEOMETRY
PRINTINPUT  KEYWORD=TABLE

!
!*****************************************************************************
!-    OUTPUT Definition
!-----------------------------------------------------------------------------
OUTPUT  COLUMNS=4, DELETEPREVIOUS=OFF, DTOUT=2 h
OUTPUT  BRANCH=WELLBORE, COLUMNS=4, DELETEPREVIOUS=OFF, VARIABLE=( UL, UG, UD,
AL, PT, DPT, BE, GA, ID )
OUTPUT  BRANCH=WELLBORE, COLUMNS=4, DELETEPREVIOUS=OFF, VARIABLE=( RMTOT, BOU,
MG, ML, MD, TM, DTM )
OUTPUT  BRANCH=FLOWLINE, COLUMNS=4, DELETEPREVIOUS=OFF, VARIABLE=( UL, UG, UD,
AL, PT, DPT, BE, GA, ID )
OUTPUT  BRANCH=FLOWLINE, COLUMNS=4, DELETEPREVIOUS=OFF, VARIABLE=( RMTOT, BOU,
MG, ML, MD, TM, DTM )

!*****************************************************************************
!      TREND Definition
!*****************************************************************************
```

```
TREND  BRANCH=WELLBORE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=WELLBORE-1,
SECTION=2, TIME=0 s, VARIABLE=( PT,  \
         TM, QG, QLTHL, QLTWT )
TREND  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=PIPE_1, SECTION=1,
TIME=0 s, VARIABLE=( PT,  \
         TM, ID, USG, USL, QLTWT, QLTHL, QG )
TREND  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=PIPE_3, SECTION=1,
TIME=0 s, VARIABLE=( PT,  \
         TM, ID, USG, USL, QLTWT, QLTHL, QG )
TREND  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=PIPE_3, SECTION=1,
TIME=0 s, VARIABLE=( PT,  \
         TM, ID, USG, USL, QLTWT, QLTHL, QG )
TREND  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=PIPE_4, SECTION=6,
TIME=0 s, VARIABLE=( PT,  \
         TM, ID, USG, USL, QLTWT, QLTHL, QG )
TREND  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=PIPE_5, SECTION=1,
TIME=0 s, VARIABLE=( PT,  \
         TM, ID, USG, USL, QLTWT, QLTHL, QG )
TREND  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=PIPE_4, SECTION=4,
TIME=0 s, VARIABLE=( PT,  \
         TM, ID, USG, USL, QLTWT, QLTHL, QG )
TREND  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=25 s, PIPE=PIPE_7, SECTION=1,
TIME=0 s, VARIABLE=( PT,  \
         TM, ID, USG, USL, QLTWT, QLTHL, QG )

!
!*****************************************************************************
!-    PROFILE Definition
!-----------------------------------------------------------------------------
PROFILE  DELETEPREVIOUS=OFF, DTPLOT=0.25 h, VARIABLE=( HOL, TM, PT, GT, ID )
PROFILE  BRANCH=FLOWLINE, DELETEPREVIOUS=OFF, DTPLOT=0.25 h, VARIABLE=( USG, USL
)
!
ENDCASE
```