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HAZARDOUS LIQUID LEAK DETECTION TECHNIQUES AND PROCESSES

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1.0 INTRODUCTION

1.1 Purpose

The purpose of this report is to identify the range of practical methods used to detect leaks in hazardous liquid pipelines including both internal and external techniques. The report presents a brief description of each method, its limitations, relative precision, practicality, and swiftness characteristics. The information presented in this report is based on a literature search performed to identify proven technologies used by pipeline companies to detect leaks. This report is intended to be used by pipeline inspectors as an aid in assessing leak detections systems that may be installed to comply with the integrity management rule (49 CFR 195.452).

1.2 Background

The US Department of Transportation, RSPA, Office of Pipeline Safety (OPS) has undertaken an integrity management initiative to improve pipeline safety and environmental protection, as well as, to provide assurance to the public concerning the safety of our nation's pipelines. The initiative is based on OPS' experience gained from pipeline inspections, accident investigations, and the risk management program. As part of this initiative, the Office of Pipeline Safety published the Final Rule on Pipeline Integrity Management in High Consequence Areas for Hazardous Liquid Operators on November 2, 2000 (see 65 FR 75378). The rule applies to operators who own or operate 500 or more miles of hazardous liquid or carbon dioxide pipelines (large liquid operators) and went in to effect on May 29, 2001. The rule establishes requirements for pipelines that can affect High Consequence Areas (HCA), which include populated areas defined by the Census Bureau as urbanized areas or places, unusually sensitive environmental areas, and commercially navigable waterways. Included in this rule is a requirement for operators to have a means to detect leaks on their pipeline systems.

The Office of Pipeline Safety has extended the regulations requiring hazardous liquid pipeline operators with 500 or more miles to establish an integrity management program for pipelines that could affect a high consequence area, to operators with less than 500 miles. This rule "Pipeline Integrity Management in High Consequence Areas for Hazardous Liquid Operators with Less Than 500 Miles of Pipeline" was published on January 16, 2002, and went in to effect on February 15, 2002 (see 67 FR 2136).

2.0 OVERVIEW OF LEAK DETECTION

2.1 Introduction

The methodologies used for leak detection cover a wide spectrum of technologies and processes and are based on a number of different detection principles. They vary from intermittent aerial inspections to hydrocarbon sensors to sophisticated real-time monitoring. Each approach has its strengths and weaknesses. These strengths and weaknesses are dependent on the application and the complexity of the pipeline system to which the leak detection is applied. In combination with processes and procedures, applying the appropriate technology (or technologies) is the key to an effective leak detection system. See reference 40.

2.2 Classification of Leak Detection Technologies

Leak detection technologies can be classified according to the physical principles involved in the leak detection. Using this type of classification, leak detection systems can be divided into the following four groups:

2.2.1 Physical Inspection - This type of leak detection involves either direct or remote visual inspection to detect a leak.

2.2.2 Manual Tabulation - This type of leak detection includes direct monitoring of pipeline flow and/or pressure for evidence of a leak. This may also involve manual calculations to identify lost product.

2.2.3 Discrete Sensor-Based Technologies - Sensor-based technologies rely on the use of an external sensor to detect the escaping hydrocarbon liquid. These systems include, but are not limited to:

- Liquid Sensing
- Vapor Sensing
- Acoustic emissions

2.2.4 Computational Pipeline Monitoring - Computational Pipeline Monitoring (CPM) systems are distinguished from other leak detection systems by the use of an algorithm that uses input from field sensors that monitor the internal pipeline parameters (e.g. pressure, flow, temperature, frictional pressure drop, density, batch interfaces) to determine when a leak has occurred. These systems include, but are not limited to:

- Over and short comparison
- Mass balance with line pack correction:
  - line pack correction based on pressure and temperature sensors
  - line pack correction based on transient flow modeling
- Pattern of discrepancy in pressure/flow between model and measurement
- Rate of pressure/flow change
- Statistical methods that are not model-based
- System identification methods based on digital signal analysis

The operational principle, data and equipment requirements, the strength, the weakness, and the realistic performance limits (size, response time, location, false alarm) for leak detection methods listed above are addressed in the subsequent sections of this report.

2.3 Evaluation of Leak Detection Systems

Each leak detection system is unique based on the pipeline on which it is used. As such, the capabilities of the system and the degree to which it mitigates risk to high consequence areas (HCAs) must be evaluated for each pipeline system. More sophisticated systems will have more unique capabilities. The criteria used to evaluate the capability of an installed leak detection technology may include, but are not limited to, the following:

2.3.1 Leak Size or Leak Flow Rate - What is the minimum leak size that the system is capable of detecting? A leak is detectable only when its' effect rises above uncertainties in the variables being monitored (see Response Time below). The size of a leak is usually expressed as a percentage of the throughput of the pipeline. Leak size is a function of the size and shape of the opening (leak area) and the pipeline pressure. A leak can be either constant in size, such as a pre-existing small leak, or variable over time, such as a sizable leak that diminishes as the pipeline is depressurized.

2.3.2 Response Time - What is the time needed to detect a leak of a given size? Depending on the leak detection methodology used, the response time can vary over a wide range.

For algorithms based on volumetric balance, the response time is related to the leak size. This is because of the uncertainties in the variables involved. Uncertainties, or noise in the variables used for leak detection, are always present. A leak can be detected only when its effect, herein called leak signal, is discernable amongst noise. Since noise is random in nature while a leak signal is not, over time, the accumulated noise remains at a noise level while the accumulated leak signal grows in size. Eventually, the accumulated leak signal rises above the noise and becomes detectable in a probabilistic sense (see False Alarms and Misses below). A minimum time period exists for each minimum detectable leak. A curve that relates minimum detectable leak size to response time is a leak threshold curve for this leak detection methodology. Two such leak threshold curves are shown in figure 2-1 to illustrate the general trend. Given an uncertainty level, larger minimum detectable leaks have a shorter response time. A smaller uncertainty in the variable results in a tighter threshold. It takes less time to detect for a given size leak if the uncertainty is reduced. Small leaks with size approaching the combined non-repeatability of instrumentation have a very long response time. Such leaks can only be determined by physical observations.

For leak detection methods based on discrepancy patterns generated from a real-time transient flow model, the response time is not a function of leak size. Instead, it is a function of the propagation speed (about 3000 to 4000 ft/s) of a pressure disturbance and the distance between the leak and the nearest pressure or flow sensors.

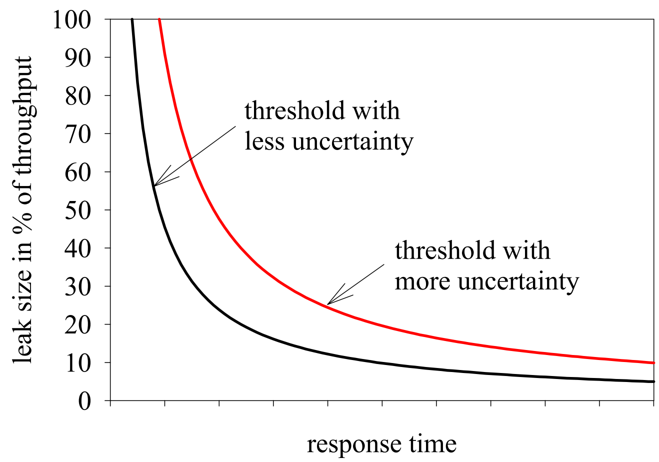

Figure 2-1 Detectable Leak Size Versus Response Time

2.3.3 Leak Location Estimation - Can the system locate a leak and what is the accuracy of the location estimate? The relevance of this criterion is to aid pipeline operator response to a leak in leak mitigation. Location can be estimated based on the time of arrival of a leak disturbance at a pair of sensors. Figure 2-2 indicates a leak occurring at time t0. This leak generates a local pressure drop, which then propagates both upstream and downstream. If this signal is picked up by pressure transducer A at time t1 and by pressure transducer B at time t2, then the leak can be located. This approach requires either a fast data scan rate or the time of arrival at the transducers is registered by data collectors and later transmitted to the control center.

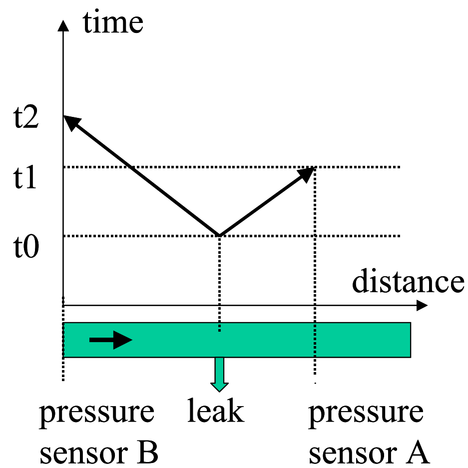

Figure 2-2 Locating a Leak by the Time of Arrival of a Leak Signal

Alternatively, a leak can be located by the profile of the piezometric head, also known as the hydraulic grade line. Figure 2-3 shows a pipeline with its inlet and outlet pressures held constant. The dotted profile is associated with the steady state flow prior to a leak. The solid profile is the hydraulic grade line after the transients caused by the leak have damped out and a new steady state is established. The leak steepens the upstream hydraulic grade and flattens the downstream hydraulic grade. The effectiveness of this approach relies on multiple pressure sensors along the pipeline so that segments of the hydraulic grade line can be defined after a leak has occurred.

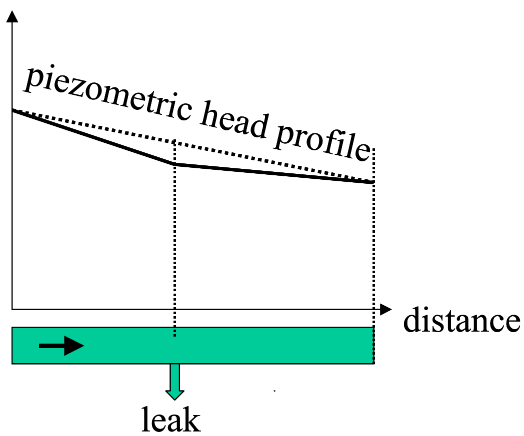

Figure 2-3 Locating a Leak by the Piezometric Head Profile

2.3.4 Release Volume Estimation - Does the system have the ability to determine the volume of liquid released? Reasonably accurate release volume estimation is possible for CPM methods where a mathematical model for transient flows is used. By using the measured pressure and flow from each end of a pipeline segment, the leak flow rate as a function of time can be calculated.

Less accurate release volume can be estimated if a CPM method tracks the mean volume or mass imbalance (linefill change minus the difference between inflow and outflow). When a leak is detected, the volume or mass imbalance prior to and after the leak can be used to estimate the release volume over time.

2.3.5 Detecting Pre-existing Leaks - Does the system have the ability to detect between pre-existing leaks, as well as, the onset of a new leak? Some CPM approaches depend on a change in one or several parameters to detect the onset of a leak. Such approaches will not be able to detect a leak (usually small) that is in existence before the CPM is activated.

2.3.6 Detecting a Leak in Shut-in Pipeline Segments - Does the system have the ability to detect the onset of a leak in a shut-in pipeline segment? The detection of a leak under such a situation is a matter of monitoring linefill change and discerning variations due to environmental temperature variations and/or due to a leak. CPM methods based only on metered inflow-outflow comparison will not be able to detect a leak in a shut-in pipeline segment.

2.3.7 Detecting a Leak in Pipelines in a Slack Condition During Transients - Does the system have the ability to detect a leak in pipelines under a slack condition during transients? Liquid vaporizes when its pressure is sufficiently low. A pipeline is slack if vaporization occurs.

A pipeline can be slack under both steady state and transient flow conditions. Leak detection on a slack line under transient conditions is difficult because the uncertainty in line pack change due to vaporization is large.

2.3.8 Rate of False Alarms and Misses - What is the false alarm rate for the system? There are many sources of uncertainty in the data that drive the CPM algorithm. These sources include hydraulic noise, non-repeatability of field sensors, uncertainties introduced by the data collection and communication system (analog-to-digital conversions, data timing), uncertainties in batch positions for product lines, and the state of flow (steady, drifting, or transient). As a result, the output from the algorithm is also uncertain. This uncertainty can be a significant issue facing the CPM technologies.

To illustrate this issue, consider the volume imbalance as the algorithm output. In terms of standardized volumes, subtract the change of linefill over a time period from the difference between inflow volume and outflow volume over the same period. The result is the volume imbalance. A positive imbalance means a leak. Refer to Figure 2-4 where the estimated imbalance is plotted against the true imbalance. Had the estimations been perfect, all points should fall on the 45-degree (diagonal) line. However, because of uncertainties, the points will be scattered around the diagonal line. Points above the diagonal represent under-estimation of the imbalances, while points below the diagonal represent over-estimated imbalances.

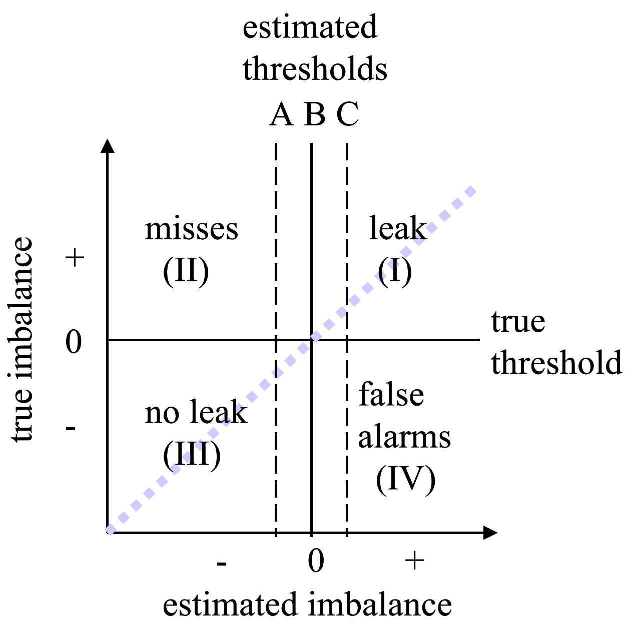

Figure 2-4 False Alarms, misses, and leak thresholds

The estimated imbalance versus true imbalance plot in Figure 2-4 is divided into four quadrants by the horizontal line labeled “true threshold” and the vertical line B which is the “perfectly estimated threshold.” In reality, the true threshold is unknowable and the estimated threshold is determined empirically (by tuning, for example). Scatter of the points near the center of the plot gives rise to false alarms (for those points falling into quadrant IV) and misses (for those points falling into quadrant II). Notice that false alarms and misses occur even when the estimated threshold is perfect. For this reason, and given the fact that variable uncertainties are unavoidable, CPM is not the appropriate technology for detecting very small leaks. However, given the practical limitations of various other technologies, CPMs may be applied as long as the their performance limitations are understood and acceptable to the pipeline operator.

Given the scatter in the estimates, the frequency of false alarms can be reduced by raising the estimated threshold (vertical line C). In so doing, the chances of misses (leaks not detected) increases. Lowering the threshold (vertical line A) reduces the chances of misses at the expense of increasing the frequency of false alarms.

Periods of greater linefill uncertainty occur when the pipeline is undergoing transients due to planned pipeline operations, such as pump startup and valve swings. To reduce the occurrence of false alarms, the leak threshold may be raised temporarily during such periods. Having the flexibility to raise the leak threshold can be an advantage, provided the operator understands that this is done at the expense of increased chances for misses (see Availability below).

2.3.9 Sensitivity to Flow Conditions - Will operational transients (such as those caused by pump startups or valve swings) degrade the ability to detect a leak? A pipeline seldom operates at a true steady state. This is especially true for long lines with numerous booster pump stations and delivery terminals. The linefill changes as a result of transients. Volume balance methods that do not compensate for linefill change accurately will be excessively sensitive to the flow conditions. The uncertainty in linefill induced by even mild transients can routinely exceed the combined non-repeatability of flow measurements in short time intervals.

Transients generated by pump startups, shutdowns, and valve swings also put extra demands on the data collection system since data polling frequency and timing skew can become issues of concern. Shorter data sampling periods help to discern leaks in such a situation.

2.3.10 Robustness - Will degradation or malfunction of a system component cause catastrophic loss of leak detection ability? This criterion measures how gracefully the leak detection capability degrades when system components malfunction. It also measures a system’s ability to function in complex pipeline configurations (see paragraph 2.3.12) when not all the needed information is available. Pipeline operators should be alerted at the first sign of degradation so that restoration efforts can be initiated, and catastrophic loss of leak detection ability can be avoided.

2.3.11 System Self Check - Will the leak detection system have the capability to automatically check and possibly rectify parameters that affect leak detection performance? Will it have the capability to detect and locate non-functional or degrading field sensors and alert pipeline operators?

2.3.12 Ability to Handle Complex Pipeline Configurations - What is the ability of the system to handle complex pipeline configurations as well as complex operations? Complex systems may include multiple injection and delivery points, or multiple modes of operation. These may complicate CPM due to needed model (i.e. algorithm) refinements, increased data requirements, and increased uncertainty when the needed data is not available.

2.3.13 Availability - Is the leak detection algorithm active around the clock? To avoid false alarms, some CPM systems that can not handle transient flow conditions usually increase the detection threshold until the operational transients have passed. Since a leak is equally likely (or even more likely) to occur when a pipeline is experiencing transients, the leak detection function is considered unavailable during periods of raised leak threshold. The percentage of time during which operational transients exist is an important factor in selecting the appropriate CPM method.

2.3.14 Retrofit Feasibility - What is required to install a new leak detection system and/or methodology on an existing pipeline? An upgrade requiring modification to, or addition of, field sensors may be less feasible than one that only requires software modifications. Algorithms that require a prolonged period of on-line parameter tuning are more difficult to retrofit.

2.3.15 Ease of Testing - API 1130 “Computational Pipeline Monitoring” recommends that a leak detection system be tested during commissioning and every 5 years thereafter. As a result, ease of testing to affirm leak detection capability is a relevant criterion. Can the system be tested with pre-existing leak test data, as well as, by actual withdrawal?

2.3.16 Cost - What is the cost of the system including capital and operational expenses, as well as, data and equipment requirements?

2.3.17 Ease of Personnel Training - How are personnel trained on the operation and maintenance of the system? Is the system easy to operate? Complex systems requiring a high level of training may not afford the same level of leak detection capability when the human interface is considered.

2.3.18 Ease of Maintenance - What are the maintenance requirements for the system? Will the system degrade with improper or missed maintenance tasks?

2.4 Standards for Leak Detection Systems

Several industry consensus standards have been developed to address the selection, design, operation, maintenance of leak detection systems. These standards include:

Table 2-1 Industry Leak Detection Standards

Standard	Revision	Title
API 1130	Second Edition November 2002	Computational Pipeline Monitoring
API 1149	November 1993	Pipeline Variable Uncertainties and Their Effects on Leak Detectability
API 1155	First Edition February 1995	Evaluation Methodology for Software Based Leak Detection Systems
API 1160	First Edition November 2001	Managing System Integrity for Hazardous Liquid Pipelines

Of the consensus standards, API 1130 has been incorporated by reference into 49 CFR 195. Specifically, section 195.134, "CPM leak detection" under Subpart C - Design Requirements, states:

> "This section applies to each hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid). On such systems, each new computational pipeline monitoring (CPM) leak detection system and each replaced component of an existing CPM system must comply with section 4.2 of API 1130 in its design and with any other design criteria addressed in API 1130 for components of the CPM leak detection system."

Section 195.444, "CPM leak detection" under Subpart F - Operation and Maintenance Requirements, states:

> "Each computational pipeline monitoring (CPM) leak detection system installed on a hazardous liquid pipeline transporting liquid in single phase (without gas in the liquid) must comply with API 1130 in operating, maintaining, testing, record keeping, and dispatcher training of the system."

For the purpose of the regulations 49 CFR 195.2, "Definitions" defines CPM as follows:

> "Computation Pipeline Monitoring (CPM) means a software-based monitoring tool that alerts the pipeline dispatcher of a possible pipeline operating anomaly that may be indicative of a commodity release."

3.0 VISUAL LEAK DETECTION

3.1 Introduction

Visual leak detection is the oldest and most widely used method of leak detection. All operators of hazardous liquid pipelines within the United States that are regulated by the US Department of Transportation are required to perform visual inspection of their system. One reason for this inspection is to detect leaks. Specifically, 49 CFR 195.412 requires that:

> "Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Methods of inspection include walking, driving, flying or other appropriate means of traversing the right-of-way."

The purpose of performing these right-of-way inspections is to:

- aid in the detection of unauthorized releases (leaks)
- visually inspect for naturally occurring damage
- identify right-of-way encroachments and potential third-party damage before it occurs

3.2 Visual Inspection Procedures

Most pipeline companies have developed procedures and/or forms for conducting right-of-way inspections. These procedures and/or forms are typically included in the Pipeline Operation and Maintenance Manual or in the Pipeline Right-of-Way Manual. These procedures and/or forms generally require that the employee inspect the right-of-way and nearby area for the following:

- Stains or other evidence of leaks
- Oil on the surface of water
- Excavation, ditching, grading, etc.
- Large fires
- Blasting or drilling
- Boring, tunneling, etc.
- Vandalism
- Washouts/exposed pipeline
- Debris in the right-of-way
- Road improvements
- Condition of waterway banks
- Dead vegetation
- Trees and debris collecting on lines crossing creeks and rivers
- Dead or incapacitated livestock
- Abandoned vehicles
- Damaged signs, vents, markers
- Ditching for new pipelines or utilities
- Construction
- Settling of backfill
- Suspicious activities

These inspections not only look for evidence of leaks, but also look for conditions that could lead to a pipeline failure. These inspections may be performed by walking, driving, or flying over the right-of-way. The method employed for the inspection is the preference of the pipeline company but depends in large degree on the accessibility and length of the pipeline. Pipelines in urban or flat terrain with vehicular access via improved roads may be driven. Long pipelines and pipelines traversing hills or mountains, as well as, lines through remote wilderness or wetlands are often inspected from small fixed wing aircraft or helicopters.

3.3 Visual Leak Detection Capability

The capability of visual leak detection is dependent on the size of the leak, the frequency of inspection, the type of inspection performed, soil conditions, and the ability of the inspector. The following describes influence of each of these variables in visual leak detection.

3.3.1 Leak Size - Larger leaks are easier to detect. The larger the leak the greater the probability that the product will reach the surface where it can be detected. How quickly the product reaches the surface is also dependent on the local terrain and the ground water level. Highly permeable soil and low ground water can delay detection.

3.3.2 Inspection Frequency - By regulation, hazardous liquid pipeline companies must visually inspect pipeline right-of-ways 26 times each year at an interval not to exceed three weeks. To comply with these requirements, most companies inspect at least once every two weeks. Shortening this inspection interval on average will decrease the interval from when the leak becomes visually detectable and when it is actually visually detected thereby reducing spill quantities.

3.3.3 Inspection Type - Inspection types include direct visual (walking or driving the right-of-way) and remote visual (flying over the right-of-way). Direct visual is the more sensitive leak detection method due to the proximity of the inspector to the surface of the right-of-way.

3.3.4 Soil Conditions - The local soil conditions where the leak occurs can affect the ability to detect the leak by visual means. Oil can collect in porous soils, increasing the time for the oil to reach the soil surface where it can be detected by visual inspection. In contrast, leaks which occur in pipelines under waterways or wetlands, where the oil will rise to the surface, may be detected sooner.

3.3.5 Inspector Ability - Persons performing visual inspections should have a corrected vision of at least 20/20 in each eye. Inspector tasks can also have an influence on the ability of the inspector to detect a leak. Inspectors that are also piloting an aircraft or driving a vehicle cannot give full attention to the inspection activity.

4.0 MANUAL TABULATION

4.1 Introduction

Manual tabulation methods of leak detection include manual over/short calculations and pressure monitoring. The following sections describe these methods.

4.2 Manual Over/Short Calculation

Many pipeline operators perform a manual over/short calculation to identify lost product. These calculations compare the volume of the product that is injected into the pipeline with the volume of the product that is removed from the pipeline. A leak may be suspected if there is a shortage (calculation indicates less product was removed than injected). The manual over/short calculation can be an effective means to identify a leak, especially in smaller pipeline systems of simple configuration.

The accuracy of manual over/short calculation is highly dependent on how the volume measurements are performed. The volumes are generally measured either directly using meters or indirectly based on a change in tank level. Using tank level measurements in lieu of flow meters can introduce large errors into the manual over/short calculation. This is due to the large tank diameter where a very small change in level can result in a large volume change. For example, a level change of 1/16 of an inch[1] in a 150 ft diameter tank would correspond to a volume change of approximately 16 barrels.

Temperature measurements may also be used to correct the measured volume and improve the accuracy of the manual over/short calculation method. Volume measurement can be corrected to standard conditions for temperature based on calculation or a lookup table. Custody meter readings are generally corrected for both temperature and pressure to standard conditions as part of the accounting for the custody transfer.

Manual over/short calculation is typically performed either periodically (e.g. daily, once per shift, hourly) or on a batch basis. Smaller pipelines may operate on an infrequent basis where the line is used to transfer a batch and is then shutdown until another batch transfer is required. On these lines operators often perform the manual calculations at the completion of the transfer. The accuracy of the over/short method is based in part on the time between the measurements used in the calculations. The longer the time period, the smaller the leak that can be detected. When calculations are made on a frequent basis (shorter time period), trending multiple calculations over time can aid in identifying small leaks. However, more frequent over/short calculations may have a diminishing value if too much of the individual's attention is diverted from other critical operational tasks.

[1] Stated accuracy of several tank gauging systems.

4.3 Pressure Monitoring

Operators may also monitor pressure to identify pipeline leaks in smaller pipeline systems of simple configuration. This is particularly effective in those pipelines that are operated at a constant pressure or shutdown for long periods with pressure shut-in. Pressure monitoring is typically performed on a periodic basis (e.g. daily, once per shift, hourly). Similar to the manual over/short calculation, the accuracy of the pressure monitoring method is also based, in part, on the time between readings in the absence of any operating transients. The longer the time period, the smaller the leak that can be detected. When readings are taken on a frequent basis, looking at the trend of multiple readings can aid in identifying small leaks.

5.0 DISCRETE SENSOR BASED TECHNOLOGIES

5.1 Introduction

There are several types of external methods used to detect leaks from liquid pipelines. The technology used is similar to the technology used to detect leaks in Underground Storage Tanks (UST) that are regulated by the Environmental Protection Agency. Cable methods rely on liquid sensing using a cable and fiber optic or electro-chemical detection. “Sniffing” methods rely on vapor sensing through hoses. Acoustic methods rely on detecting the noise or sound produced by turbulent flow through a leak.

5.2 Liquid Sensing

Liquid sensing techniques used for detecting leaks from liquid pipelines rely on specialized cables buried adjacent to or beneath the pipeline. The cables can rely on electro-chemical technology or fiber optics. In the case of electro-chemical, the cables are designed to either degrade or reflect changes in the electrical properties, specifically impedance, when in contact with hydrocarbons.

There are a number of different electro-chemical cable arrangements in use. The simplest cables undergo a physical change upon contact with hydrocarbons. Contact is made in some cables by a conductive fluid which carries current from one circuit to an other, or through direct contact. An example of direct contact is a hydrocarbon detecting cable, which uses conductive polymers. The core is comprised of two sensing wires, an alarm signal wire and a continuity wire. The core is encased in a conductive polymer jacket and surrounded by a containment braid. The conductive polymer jacket swells when exposed to hydrocarbons and the containment braid forces the polymer to expand inward forcing the two sensing wires together. When electrical contact between the two sensing wire occurs, the alarm is tripped. This type of cable is used with a locating module to determine leak location. This type of cable requires double containment and, depending on the type of cable used, may require replacement after hydrocarbon detection has occurred. (See Reference 15)

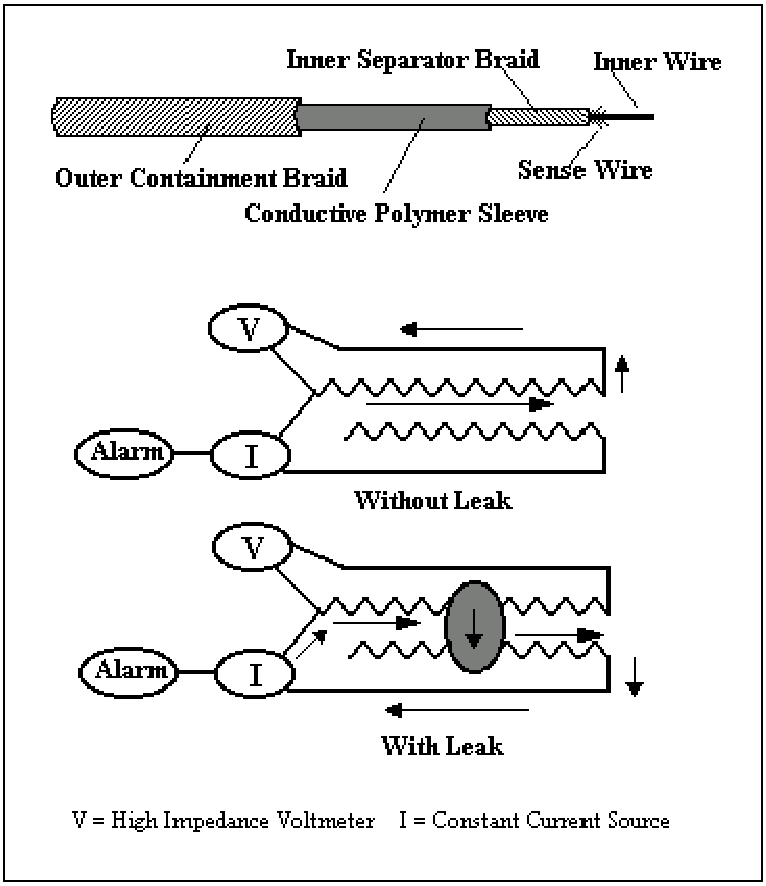

Figure 5-1 Hydrocarbon Sensing Wire Schematic (from Reference 27)

In a more sophisticated cable arrangement, “safe” energy pulses are continuously transmitted by a microprocessor through the sensor cable. Pulse reflections, or echoes, are generated which are specific to the actual installation of the sensor cable. The echoes are processed and stored by a microprocessor to create a baseline reference map. In the event of a leak, the hydrocarbons penetrate the cable and alter the impedance of the cable at the leak site. The change in impedance alters the echoes returning to the microprocessor and triggers an alarm. The change in signal is used to detect the location of the impedance change and thus the leak location. The advantage of this type of system is that, once a leak occurs, the reference map can be stored and the system can continue to be used to detect liquids. (See Reference 14)

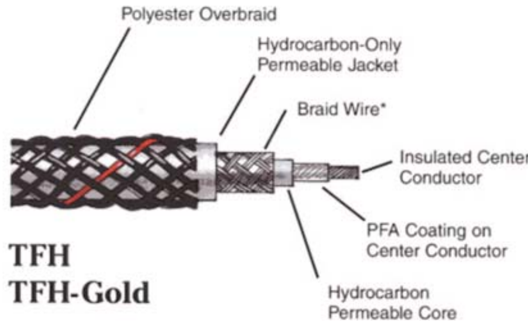

Figure 5-2 Hydrocarbon Sensing Wire (from Reference 36)

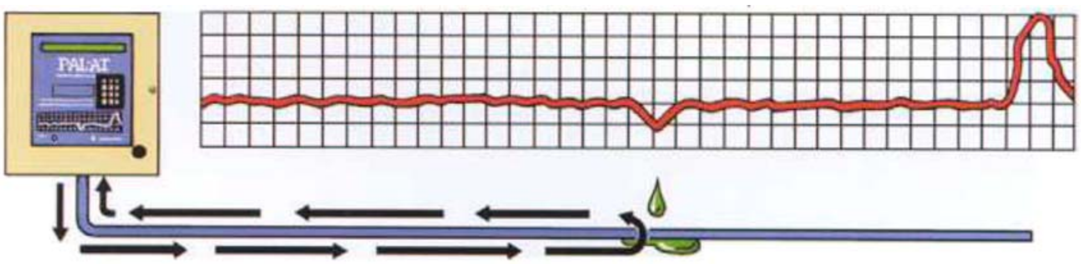

Figure 5-3 Typical Pulse-Echo Sensor (from Reference 36)

Fiber optics are also used to detect the presence of hydrocarbons. An optical fiber core is surrounded by a coating or cladding that is reactive to hydrocarbons. When the coating or cladding contacts hydrocarbon, the refractive index is altered and affects the transmission of light through the optical fiber. The transmission of light must be measured and compared with the emitting source to determine the loss of light.

In a typical optical sensor system, a light-emitting diode transmits light through a chemically-coated optical fiber cable. When the cable comes in contact with hydrocarbons, the chemical coating is altered and allows some of the light to escape. A reference detector used in conjunction with a sensor at the other end of the cable measures the loss of light. The loss of light and the inferred change in refractive index is used to estimate the concentration of hydrocarbons. The fiber optic sensing probes are placed along the pipeline, either adjacent to or beneath the pipeline.

Based on the application of the fiber optics, the location of the leak can be determined. A disadvantage of the fiber optics that has been reported is the stability of the reactive coating.

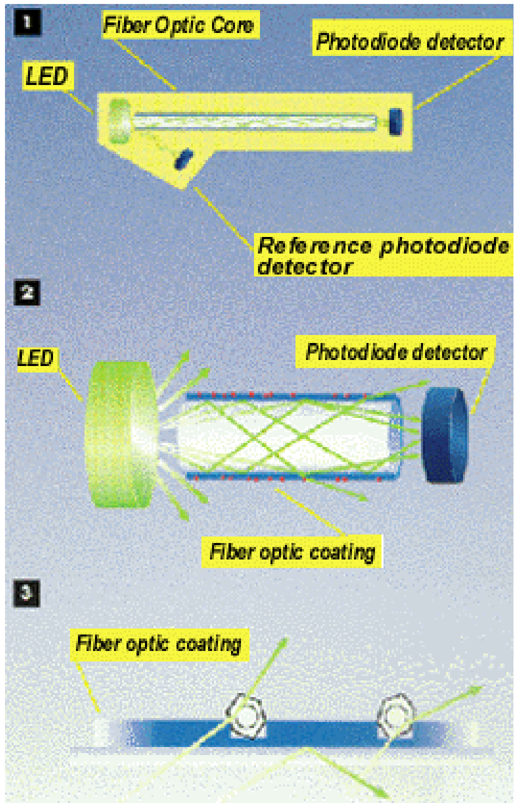

Figure 5-4 Fiber Optic Hydrocarbon Sensor (from Reference 27)

5.3 Vapor Sensing

Vapor sensing systems consist of a network of vapor-permeable tubes installed along the length of the pipeline. In the event of a liquid hydrocarbon leak, vapors from the liquid migrate into the surrounding soil pore spaces. The tubes may be small diameter perforated tubes attached to the pipeline, or may completely encompass the pipeline. The automatic leak detection system collects and analyzes the gas from the individual tubes by pumping it through a detector which analyzes the vapor for the presence of hydrocarbons or a tracer chemical (if one is used). The vapor sensing method relies on the leaking hydrocarbon to produce sufficient vapors to be detected. Once a leak is detected, additional samples can be taken to determine the location of the leak using the concentrations detected.

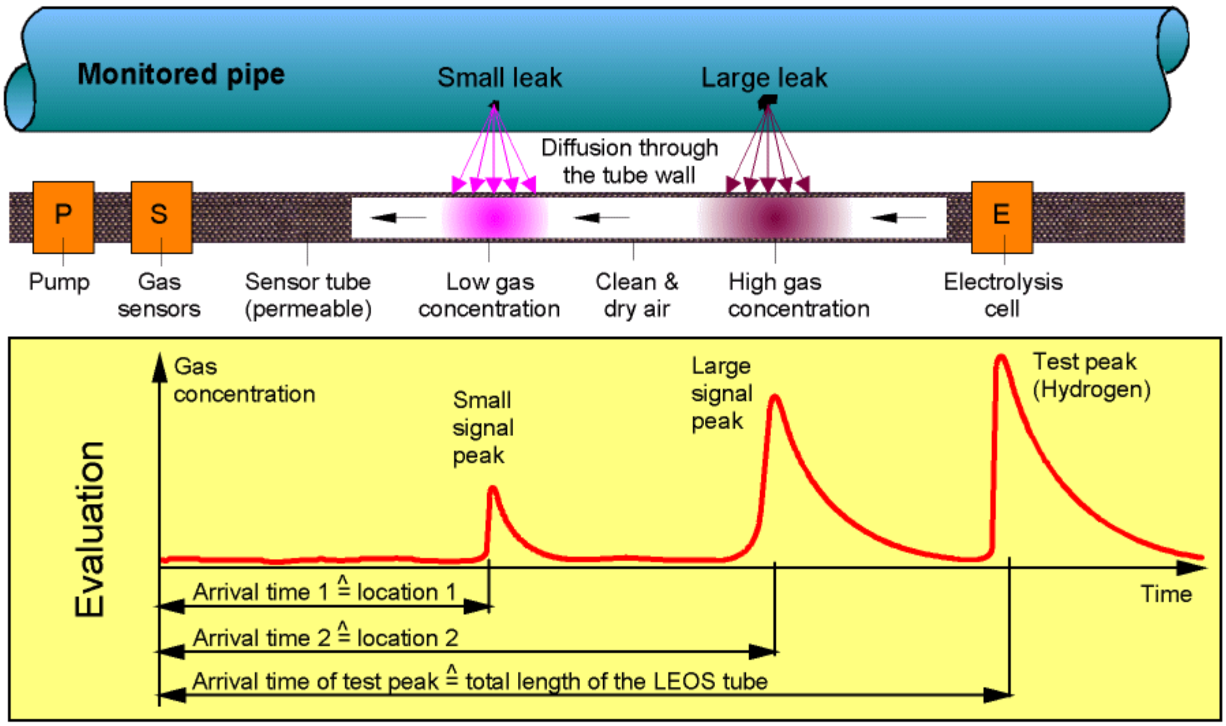

Figure 5-5 Vapor Sensing System (from Reference 37)

5.4 Acoustic Emissions

Acoustic emissions (AE) technology can provide continuous leak detection in pipelines. AE is based on the principle that the leaking liquids are in turbulent flow and create a detectable acoustic signal. Acoustic sensors are located on the outside of the pipe to monitor internal pipeline noise. The acoustic sensor is a transducer that converts the sound waves associated with leaks in the pipe to an electrical signal. The acoustical sensor is the most important component of detection and must have sufficient sensitivity and low intrinsic noise. Once the acoustical sensors are attached to the pipeline, a baseline acoustic map of the pipeline is developed. This map serves as a reference. Deviations from the acoustic profile result in an alarm. The acoustic signals can be used to determine the location of the leak. Several case studies have been performed by Physical Acoustics Corporation in both Russia and the United States (documented in the report *Detection and Location of Cracks and Leaks in Buried Pipelines Using Acoustic Emission*). These have demonstrated that Acoustic Emission is feasible to detect and locate leaks in buried pipelines. The ideal sensor is a resonant device operating between 10 kHz and 40 kHz. Location of the leak requires special algorithms to achieve accuracy.

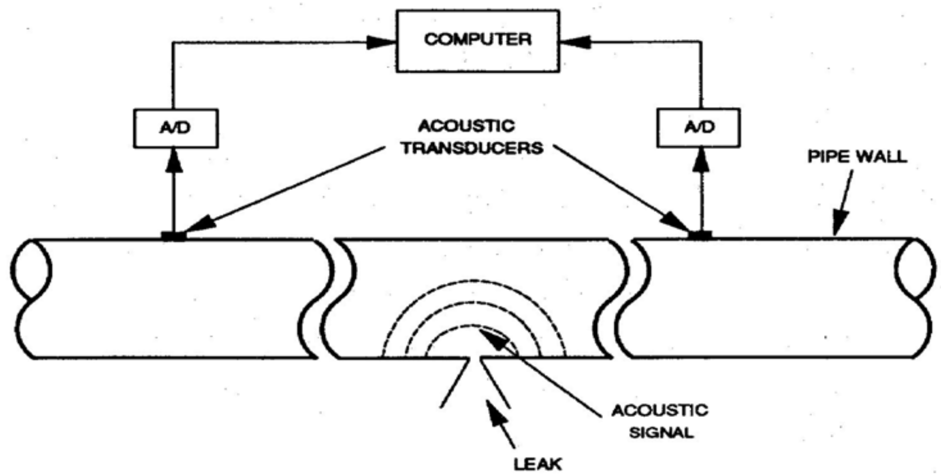

Figure 5-6 Acoustic Emission Leak Detector (from Reference 7)

5.5 Factors that can Affect External Methods

There are many factors that affect the performance of external leak detection methods and should be considered as part of the selection process. A User Guide developed by the Naval Facilities Engineering Service Center, UG-2028-ENV, details selection criteria for the different methods as summarized below:

5.5.1 Soil Conditions - Soil conditions can affect the performance of leak detection technology. Specifically, tracer gases or hydrocarbon vapors will migrate faster in dry, porous soil than wet soil. Acoustic emission techniques may also be affected by the type of soil around the pipe because the soil loading affects the leak signal.

5.5.2 Water Table - If the pipeline runs below the water table or high tide level, tracers and vapor collection systems may suffer from water interference resulting in either not detecting a leak, or detecting one in the wrong location.

5.5.3 Condition of Pipeline - The age and condition of the pipeline are important considerations. The ease of retrofitting a method to the pipeline is based on the location of the pipeline and access to the pipeline for installation and monitoring.

5.5.4 Time Monitoring - Each of the external methods describe can be used for either “snap shot” assessment or continuous monitoring based on the equipment and the application. Continuous monitoring provides the greatest assurance of pipeline integrity.

5.5.5 Spatial Resolution - When properly applied, all the external techniques can both identify and locate leaks. The response time and accuracy of each method can be affected by the spacing of sensors and sampling points.

5.5.6 Leak Rate Resolution - In the event of a leak, not all of the external techniques can provide information on how much liquid has been lost.

Table 5-1 that follows presents a comparison of the sensor-based leak detection technologies.

Table 5-1 Comparison of Sensor Based Technologies

Parameter	Electro-Chemical Cable	Fiber Optic Cable	Vapor Sensing	Acoustic Emission
Response Time	seconds to minutes	seconds to minutes	minutes	real time
Location Estimate	capable	capable	capable	capable
Released Volume	limited	limited	estimate	estimate
Existing Leak	yes	yes	yes	yes
Shut-in Condition	yes	yes	yes	yes
Slack Condition	yes	yes	yes	yes
False Alarms	less frequent	less frequent	less frequent	frequent
Ease of Retrofit	difficult	difficult	difficult	moderate

6.0 COMPUTATIONAL METHODS

6.1 Introduction

Computational Pipeline Monitoring (CPM) is a tool for leak detection. It uses real-time pipeline operational data to drive a set of algorithms that provide the basis for detection should a leak occur or exist. Geographically-distant field sensors on the pipeline are polled 24/7 and data is transmitted to a control center that monitors the pipeline. In the control center, the field data provides the input to a real-time leak detection algorithm. The quality of the data has a major impact on a CPM's ability to detect a leak.

The design, implementation, testing, and operation of CPM’s are addressed by API 1130 - Computational Pipeline Monitoring. Based on the nature of the algorithms used, CPM can be categorized below. The instrumentation requirements for CPM methods are discussed in Section 6.10.

6.2 Over/Short Comparison

The volume of products entering and leaving a pipeline are measured over a specified time period. The measurement results are expressed in terms of standardized volumes (volume at 60EF or 15EC and 0 psig). The outgoing volume is subtracted from the incoming volume over the time period. A leak is suspected if the difference exceeds a threshold. This algorithm is simple and gives credible results when the flow in the pipeline is at, or close to, a steady state (i.e. the pressure, temperature, and flow along the pipeline do not change rapidly over time), or when the time period is sufficiently long. The leak threshold depends on the accuracy of the volume measurements, the length of the time period, the pipeline volume, and the state of flow in the pipeline. This approach is more effective for pipelines with a smaller volume since the linefill is less affected by the state of flow. This approach cannot detect a leak in a shut-in pipeline since both the inflow and outflow at the ends of a pipeline segment are zero at all times and yield no useful information.

The ability to detect a leak in a slack pipeline (one where low pressures cause localized vaporization) depends on the state of flow. If the flow is at a steady state, a leak can be detected by this method. However, when the flow is in a transient state, the vapor volume changes appreciably and cannot be modeled with accuracy. Consequently, the ability to detect even a significant leak is greatly diminished.

The ability of this approach to detect a small leak is highly dependent on the combined nonrepeatability of flow meters at the ends of a pipeline segment. When flow (or volume) metering is not accurate or not available, data on level changes over time in the supply and receiving storage tanks may be used to estimate the volumes. However, due to the limited resolution in tank level readings, the estimated volume changes over short time periods is much less accurate than flow metering.

6.3 Volume Balance with Line Pack Correction

The shortcoming of the over/short comparison is that changes in the standardized volume of the pipeline over a time period are not accounted for. Two methods can be used to correct this:

- **Use of Additional Sensors** - By placing additional pressure and temperature sensors along the pipeline, real-time pressure and temperature are measured at a set of selected locations along the pipeline. The change in the standardized volume over the line balancing period can be estimated using volume correction factors for pressure and for temperature. The accuracy of this correction improves as the spacing between adjacent sensors is reduced. An example of this approach is given by Liou, 1996.

- **Use of a Transient Flow Model** - A valid transient flow model computes changes in linefill from measured pressure and flow at the ends of a pipeline segment. When appropriate, the effects of temperature can be included in the model. This approach is more complicated and the data requirements can be significant. However, it may be the only choice when it is not feasible to obtain pressure and temperature data at a sufficient number of the interior points of a pipeline segment.

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

Both approaches can detect a leak in a shut-in pipeline. Data noise is the main limitation for this approach to leak detection.

6.4 Pattern of Discrepancy Between Modeled and Measured Pressure and/or Flow

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

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

The advantage of this approach is that a leak occurring during all flow conditions (including operational transients) can potentially be detected. Figures 6-1 and 6-2 show laboratory verification of one version of this approach. The measured head and flow at the inlet of a pipeline are used to drive a transient flow model that computes the head and flow at the outlet. At the same time, the measured head and flow at the outlet are used to compute the head and the flow at the inlet. A 6.5% leak was imposed while the pipeline was experiencing transients caused by a sudden 37% flow reduction due to a partial valve closure at the outlet.

For this example, the discrepancy patterns are: (1) immediate and simultaneous rise in the discrepancy (measured minus calculated) in inlet head and inlet flow, (2) immediate rise in the discrepancy of the outlet head; and immediate and simultaneous fall in the discrepancy of the outlet flow, (3) the sum of the number of consecutive time steps with discrepancies at the pipe ends equals the number of computational reaches used in the model, and (4) the difference in the timing of the sudden changes indicates the location of the leak (Liou, 1993).

Depending on how the transient model is driven by the measured data, the discrepancy patterns may vary (Liou and Tian, 1995). In each case, the discrepancy patterns are specific to a leak. Consequently, false alarms are rare.

This approach is data intensive and the SCADA's data scan rate needs to be fast. The model parameters must also be in tune with reality, thus requiring higher maintenance. Successful implementation of this approach was reported as early as 1980 (Stewart, 1980).

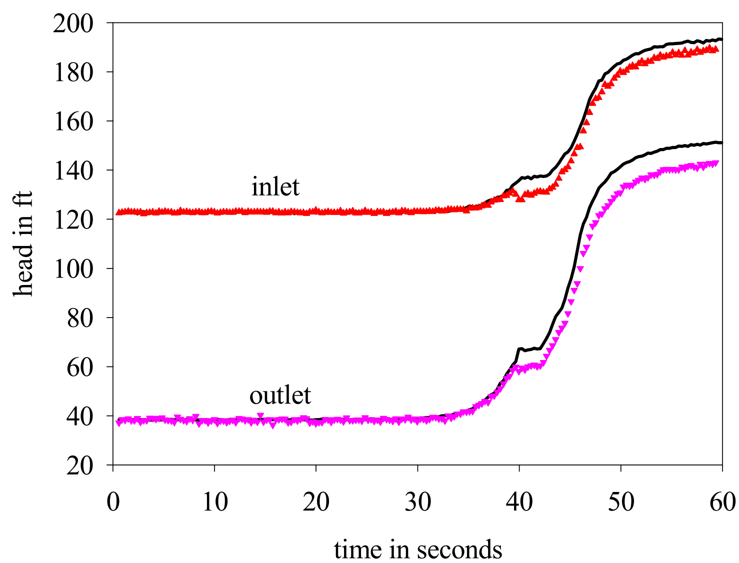

Figure 6-1 Discrepancy Pattern Between Measured (Solid Lines) and Calculated (Symbols) Heads

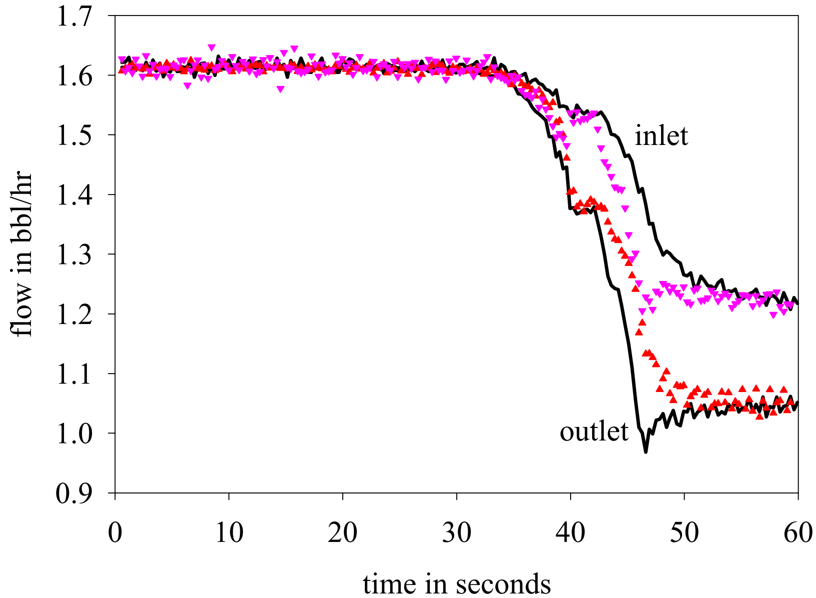

Figure 6-2 Discrepancy Pattern Between the Measured (Solid Lines) and Calculated (Symbols) Flows (Source: Liou 1990)

6.5 Rate of Pressure/Flow Change

The rationale for this approach is that rapid depressurization, rapid inflow increase, rapid outflow decrease, and rapid increase in the difference between inflow and outflow are associated with the onset of a leak. Each criterion, or several in combination, can be used for leak detection. Since pipeline operation transients can also cause rapid changes, alarms need to be inhibited for a time period following an operation, such as a pump startup or a change in the set point of a control valve (Bose, et. al., 1993). This approach is effective for large leaks only.

6.6 Statistical Methods

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

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

Hypotheses testing for the presence or absence of a leak needs to be performed. Leak thresholds are established only after a prolonged period of tuning to establish the underlying probabilistic distribution, the mean, and the variance of the parameter(s) to be tested under different states of no-leak flow (i.e. steady, drifting, or transients). The tuning process reduces the occurrence of false alarms (Zhang and Di Mauro, 1998).

6.7 System Identification with Digital Signal Analysis

System identification using real-time data is a rapidly developing discipline. When applied to leak detection, it relies on the occurrence of a leak changing the pipeline-fluid system in some characteristic way. For example, a leak will alter the impulse response of a pipeline. This response can be extracted by digital signal processing techniques in real time. A change of the impulse response in a leak-specific way generates an alarm (Liou, 1998).

This approach, like the statistical methods, does not use a mathematical model for the transient pipeline hydraulics. Dealing with data noise and extracting information from noisy data is the main focus of this approach.

6.8 Rupture Detection

When a leak potentially impacts a high consequence area (HCA), such as a community, it may be desirable or even necessary to have a completely independent and redundant system to detect a large leak associated with pipeline rupture. For such a situation, the estimated imbalance versus true imbalance point lies in the upper right corner of Figure 2-4 and false alarm is not an issue.

Since false alarm is unlikely and prompt leak isolation is of primary concern, automatic leak isolation and system shutdown without operator involvement can be justified provided the transients resulting from rapid leak isolation and system shutdown do not cause over pressure in the pipeline system. System-wide transients resulting from automatic leak isolation and system shutdown must be analyzed for such systems.

6.9 Comparison of Computational Methods

The implementation of the various algorithms can vary considerably. As a result, the performance of a particular method may be significantly different from another one in the same category. Furthermore, the boundary between categories can be blurred by hybrid approaches. For example, statistical analysis can be applied to volume balance, with pressure sensor-based linefill correction.

Table 6-1 represents a comparison of the general characteristics of the various forms of CPM. Since the over/short comparison is the most widely used and has the longest history, it is used as a basis for the comparisons.

Table 6-1 Comparison of CPM Leak Detection Methods

	Over/short Comparison	**Volume Balance W/ Pressure Sensors**	**Volume Balance W/ Dynamic Model**	**Discrepancy Patterns W/ Dynamic Model**	**Rate of Change**	**Statistical Analysis**	**System ID with Digital Signal Analysis**
Leak Size/Response Time (§2.3.1, §2.3.2)	5% to 1%/minutes to hours	1%/minutes	1%/minutes	1%/seconds	5%/minutes	1%/seconds to minutes	1%/seconds to minutes
Location Estimate (§2.3.3)	unable	unable	unable	capable	capable	capable	capable
Released Volume (§2.3.4)	rough estimation for long term average	improved estimation for long term average	improved estimation for long term average	can provide leak flow rate as a function of time	can estimate the volume for large leaks	unable to estimate	unable to estimate
Existing Leaks (§2.3.5)	yes	yes	yes	no	no	no	no
Shut-in Condition (§2.3.6)	no	yes	yes	yes	yes	yes	yes
Slack Condition (§2.3.7)	no	no	possible	possible	no	no	no
False Alarms (§2.3.8)	frequent	less frequent	less frequent	more frequent	frequent	less frequent	less frequent
System Transients (§2.3.9)	no tolerance	better tolerance	better tolerance	best tolerance	some tolerance	best tolerance	best tolerance
Robustness (§2.3.10)	average	average	less	less	less	better	better
Availability (§2.3.9, §2.3.12,§2.3.13)	part time	yes	yes	yes	part time	yes	yes
Ease of Retrofit (§2.3.14)	easy	not easy	easy	easy	easy	easy	not easy
Complex Configuration (§2.3.12)	adaptable	adaptable	less adaptable	less adaptable	not adaptable	easily adaptable	easily adaptable
Simplicity (§2.3.14, §2.3.17)	simple	more complex	more complex	most complex	complex	complex	complex
Ease of Testing (§2.3.15)	easy	easy	difficult	more difficult	more difficult	difficult	difficult
Ease of Training (§2.3.17)	easy	easy	difficult	more difficult	difficult	easy	easy
Ease to Maintain (§2.3.18)	easy	difficult	difficult	difficult	easy	easy	easy
Cost (§2.3.16)	average	higher	higher	highest	higher	higher	higher

Each approach has its strength and weakness. Effective leak detection requires applying appropriate and complementary technologies.

6.10 Field Instrumentation Requirements

Four types of field instrumentation are commonly used in CPM: pressure, temperature, volumetric flow, and specific gravity (or degrees API). The required instrumentation for each CPM method is indicated in Table 6-2. API-1130 discusses many aspects of field instrumentation in the context of CPM. Additional comments are given below.

Among the four variables, pressure has the greatest range of variation and the fastest time rate of change, and should be measured with pressure transducers with sufficient range and dynamic response. Calibration of the transducers (gain and zero) should be a part of CPM system maintenance. Volumetric flow measurements are often performed by accurate custody transfer meters (turbine and/ or positive displacement meters). In cases where volumetric flow rate is not directly measured, tankage may be used as a substitute, but the accuracy for flow rate estimates is greatly reduced. Aside from the passage of hot or cold product batches, the range of temperature change at a fixed location is small. This is attributed to the large thermal capacity of the petroleum liquids. The specific gravity needs to be accurately measured at custody transfer meters so that the meter factors (volume correction factors for pressure and for temperature, API 1984 and ASTM, API, and IP 1980) can be accurately determined. Measurements of specific gravity or density for the purpose of determining batch positions in the interior of a pipeline segment do not require high accuracy.

The accuracy of the field instrumentation is usually a function of the measurement range. Consequently, the range of a field instrumentation should not be too much wider than the range of variations of the variable being measured. For pressure measurements, the range of variations should include variations due to accidental transients.

The accuracy found in instrument specifications usually includes effects of linearity, hysteresis, and non-repeatability. For CPM purposes, effects of linearity and hysteresis can be regarded as bias errors and can be compensated for. Non-repeatability, on the other hand, is a random error and cannot be corrected. The non-repeatability should be quantified separately from linearity and hysteresis since it is the non-repeatability that influences the ability of CPM to detect a leak.

The non-repeatability requirements for pressure and temperature vary. In general, longer and/or larger diameter pipelines require measurements with lower non-repeatability. Because of the large pipeline volume, a small uncertainty in these measurements will result in a large uncertainty in linefill.

The placement of pressure and temperature sensors must be such that they are in contact with the throughput. Situations exist where pressure transducers are connected to the pipeline through long sensing lines resulting in a time delay and erroneous measurements during transients. Situations also exist where a temperature sensor is on a line branched off from the mainline in a delivery terminal. The temperature sensor will not yield the correct temperature of the through flow if the terminal is closed.

Spacing between field sensors impacts leak detectability. For volume balance with line pack correction, closer spacing of instrumentation results in better leak detectability.

Field sensor non-repeatability is only one component of the total picture. Because of rounding or truncation (of numbers) involved in analog-to-digital conversion of signals, in binary data communications, and in converting the received data in the control center into physical units, additional non-repeatabilities are generated. The root-sum-square procedure (API-1149) to combine the non-repeatabilities from independent sources should be used.

Depending on the CPM approach and the size of leak to be detected, the requirement of accuracy for each field instrument may be different. For example in volume balance with line pack correction, the non-repeatability of flow meters plays no role in detecting a large leak, but becomes crucial in detecting small leaks. The relative importance of the process variables (pressure, temperature, and flow) to leak detectability is discussed in API-1149. Instrument accuracy should be consistent with the relative importance of the variables involved.

Finally, it needs to be pointed out that flow turbulence and flow unsteadiness generate random fluctuations in pressure and flow. These fluctuations cannot be accounted for and cannot be modeled by the CPM algorithms. Consequently, such fluctuations are regarded as noise. Noise reduces CPM's ability to detect a leak. The magnitude of noise should be determined by analyzing the signal received at the control center so that all contributing factors (instrumentation, A/D conversion, data transmission, etc) are included. Through experimentation, the noise can be reduced to enhance the leak signal to noise ratio, but it cannot be eliminated entirely. For some pipelines, the noise level in the filtered data can be significantly greater than the combined non-repeatability of instrumentation and data communication. For such systems, it will be fruitless to pursue excessive instrumentation accuracy.

Table 6-2 Data Sensors Required for CPM Leak Detection Methods

	Over/short Comparison	Volume Balance W/ Pressure Sensors	Volume Balance W/ Dynamic Model	Discrepancy Patterns W/ Dynamic Model	Rate of Change	Statistical Analysis	System ID with Digital Signal Analysis
Inlet Pressure	yes	yes	yes	yes	yes	yes	yes
Inlet Temperature	yes	yes	yes	yes	no	no	no
Inlet Flow	yes	yes	yes	yes	yes	optional	no
Inlet sp. gr.	yes	yes	yes	yes	yes	optional	no
Outlet Pressure	yes	yes	yes	yes	yes	yes	yes
Outlet Temperature	yes	yes	yes	yes	yes	no	no
Outlet Flow	yes	yes	yes	yes	yes	optional	no
Outlet sp. gr.	yes	yes	yes	yes	yes	optional	no
Interior Pressure	no	yes	no	no	optional	optional	yes
Interior Temperature (2)	no	yes	no	no	no	no	no
Interior Flows	no	no	no	optional	no	no	no
Interior sp. gr. (or a Batch Tracking Algorithm)	no	yes	yes	yes	no	optional	no

Note:
(1) the pressure, temperature and specific gravity data at flow meter locations are required to obtain products' corrected volume at the standard condition.
(2) temperature and pressure interaction (the Joule-Thompson effect) is negligible for crude oil and petroleum products. Temperature does not change rapidly as pressure and flow do during transients. Therefore, temperature is a secondary variable in CPM based on a dynamic model. In principle, temperatures in the interior of a pipeline segment can be estimated from a quasi, steady-state temperature model instead of direct measurements.

7.0 PROCEDURAL CONSIDERATIONS

7.1 Introduction

How operators implement their leak detection program is as important as the capabilities of the method. The best leak detection system is useless unless the operator carries out the appropriate actions in response to an indication of a leak. The following sections describe some of the procedural considerations with respect to leak detection.

7.2 Immediate Actions

Procedures for response to indication of a leak should mandate the immediate actions to be taken by pipeline personnel. These actions may include, but are not limited to:

- **Actions to Verify the Existence of a Leak** - This may include direction to check certain operating parameters that can corroborate the initial indication. This could include a review of pressure, flow, and tank levels for evidence of abnormal indication, as well as, physical inspection of the line. Review of parameter trends may also assist in identifying the leak and/or its location. In small lines, it could include a line shutdown and shut-in while monitoring for pressure decay.

- **Actions to Mitigate the Consequences of a Leak -** This may include pipeline shutdown, isolation of pipeline segments, dispatching emergency response personnel, and operation of the line in a manner that removes oil from the pipeline minimizing the oil that is leaked.

- **Notification -** This includes both notification of emergency response personnel, authorities (local, state, and federal), and company management. This is often addressed in the company's emergency response plan.

7.3 Data Analysis

Data analysis of pipeline and leak detection system parameters is an important aspect of the use of a leak detection system. Trending and comparing periods of identical operation can be useful in identifying small leaks that are below the leak detection system threshold. This is particularly useful in both the manual over/short and CPM over/short methods.

7.4 Authority

The lack of clearly defined authority for the pipeline controllers and technicians has been a contributing factor in a number of documented accidents. Although pipeline companies may state that an operator has the authority to shutdown a line when there is an indication of a leak, a corporate culture exists that penalizes the operator for shutting down a system when it turns out that there is no leak. This negative consequence has resulted in operators failing to shut down pipelines even though there is clear indication of a leak or in attempting to restart a pipeline after a rupture. Procedures should clearly identify the authority of the pipeline technicians and controllers for leak detection system operation and response. Additionally, if pipeline procedures require a controller to obtain prior approval to shut a line down or take other actions, those procedures should provide latitude for the technicians and controllers to take independent action if the individual whose approval is required cannot be contacted.

8.0 ENHANCEMENTS TO PROTECT HIGH CONSEQUENCE AREAS

8.1 Introduction

Several options exist for an operator to enhance their leak detection system to protect High Consequence Areas (HCAs). Enhancements can include improvements to enhance the capability and use of existing leak detection methods employed by the operator, as well as, the installation of new systems. Both of these options are discussed in the following section.

8.2 Enhancing Existing Systems

There are a number of actions that an operator can take to enhance the effectiveness of the leak detection systems employed by the operator. These enhancements include physical changes to the detection systems, changes to how the system is operated, and how the operator responds to indication of a leak. Examples of leak detection system enhancements include, but are not limited to, the following:

8.2.1 Improving Measurement Accuracy - Improving the accuracy of the measurement inputs can reduce the detection threshold for a leak detection method. An example of accuracy measurement improvement is where operators use tank gauging to provide a flow measurement input for a volume balance manual over/short or a CPM. The operator could install flow meters to replace the tank gauges for the leak detection input or could install new tank gauges that provide a higher resolution (e.g replace mechanical tape gauges with radar gauges).

8.2.2 Installation of Additional Sensors - Operators may install additional sensors to enhance leak detection capability. These include sensors that are used for Manual Tabulation (Section 4.0), Discrete Sensor Based Systems (Section 5.0), and Computational Methods (Section 6.0). Additional sensors could include, but are not limited to:

- Pressure (Manual Tabulation and Computational Methods)
- Temperature (Computational Methods)
- Flow meters (Manual Tabulation and Computational Methods)
- API Gravity (Computational Methods)
- Hydrocarbon detection (Discrete Sensor Based Systems)

8.2.3 Changing Operating Modes - Where the operating mode of the pipeline impacts the performance of the leak detection method employed, the operator can change the operating mode to reduce that impact. For example, a CPM based volume balance method may not be effective during transients. An operator may chose to switch mainline pumps daily to equalize pump wear. Alternating pumps introduces transients into the system that may degrade the ability of the leak detection system until the transient has passed. The operator could change this operation to reduce the number of transients the line is subjected to, thereby increasing the availability of the leak detection system and the protection it provides.

8.2.4 Revising Leak Procedures - Operators may revise or enhance the procedures used by the technicians and controllers in detecting and responding to a leak. Enhancements may include changing action thresholds, increasing technician and controller authority to declare a leak and take appropriate immediate actions, adding job aids such as flowcharts to assist the technician and controller. The use of procedures and job aids can aid the technicians and controllers by working through a logical sequence to verify the existence of a leak, determine the probable location of a leak, and estimate the quantity of the product lost.

8.2.5 Improving Operator Training - Training of the pipeline technicians and controllers in detecting and responding to a leak can enhance the protection of an HCA. The ability of the operator to detect and respond to an indication of a leak is a key element of most leak detection systems.[2] A comprehensive training program can provide operators with the necessary skills to aid the operator in identifying leaks, determining possible leak locations, and taking appropriate actions in response to a leak. Operator training can also be enhanced by the use of simulators and/or emergency drills. Simulators and/or emergency drills allow the operator to practice and reinforce skills and knowledge. Additionally, simulators and/or emergency drills can be used by operators to assess the performance of their technicians and controllers. Performance assessment is required by 49 CFR 195, Subpart G, "Qualification of Pipeline Personnel."

8.2.6 Increasing Frequency of Manual Methods - Operators may increase the frequency of performance of manual leak detection methods. These methods include Visual Inspection (Section 3.0), Manual Over/Short Calculation (Section 4.2), and Pressure Monitoring (Section 4.2). Increasing the frequency of performance for any of these methods would possibly shorten the time that a leak would go undetected and enhance the leak detection ability of the pipeline.

8.3 Use of Multiple Systems

It is often desirable to employ more than one leak detection method for a pipeline. Two types of leaks require detection: pre-existing leaks and newly-occurring leaks. The former refers to a leak already in progress before a leak detection system is activated. A small leak that has gone undetected for a long time is an example. The latter refers to a leak that occurs when a pipeline is already under leak detection surveillance. A typical example is a leak caused by third-party damage to a pipeline monitored by a leak detection system. To detect a pre-existing leak (usually small), a technology that is highly sensitive to leak size should be used. On the other hand, to detect the onset of a leak due to third party damage, greater emphasis should be placed on the responsiveness of the method than on its sensitivity to leak size. Consequently, multiple complementary methods are useful in addressing the wide variety of leak scenarios that can exist.

[2]Rupture detection systems that automatically shutdown the pipeline or pipeline segment on indication of a rupture do not require operator action.

9.0 CONCLUSIONS

External leak detection methods are better suited for shorter pipeline segments due to the installation costs associated with installing either cables or vapor sensing tubes adjacent to the pipeline for the length of the pipeline to be instrumented. These types of sensors are standardized and have proven results for underground storage tank applications. As they are used more widely on liquid pipelines, case study data is becoming available to document their performance.

The single most important aspect of CPM leak detection is that each system is unique to the pipeline on which it is installed. The same CPM system installed on two different pipelines will not have the same performance. The performance of the system is highly dependent on the pipeline on which it is installed. Evaluating the capability of a leak detection system must consider the pipeline design and operation. Validation of a leak detection system is best accomplished by testing the installed system. This testing should follow the requirements of API 1130.

The leak detection techniques described herein are applicable to both short (less than 500 miles), as well as, long (greater than 500 miles) pipelines. In fact, most leak detection systems are applied on pipeline segments that represent a short line with the sensor based systems often being installed on very short segments. The effectiveness of these systems is dependent on the application and the complexity of the system.

APPENDIX A

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REFERENCES

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APPENDIX B

GLOSSARY

Glossary of Terms

Accuracy -The degree to which the measured leak rate agrees with the induced leak rate on the average. If a system is accurate, it has a very small or zero bias.

Bias - An indication of whether the device's measured leak rate consistently overestimates (positive bias) or underestimates (negative bias) the actual induced leak rate.

Bulk Modulus (of Elasticity) -The ratio of hydrostatic pressure to the relative change it produces in volume.

Continuous Detector - Detectors that operate continuously, are always present, and are never turned off.

False alarm - Indication of a leak when none exists.

Groundwater - Water table.

Induced Leak Rate - The actual leak rate used during the evaluation against which the results from a given test device will be compared.

Intermittent Detector - Detectors that monitor on a regular basis. An intermittent detector may be a hand held device that is portable or a permanently installed device that is used to periodically test for the presence of product.

Lag Time - The elapsed time from the detector's first contact with test product to the first detectable signal.

Leak Detectability - The ability to detect a leak measured in terms of leak size, response time, and quality of leak location and release volume estimates.

Leak Threshold - The demarcation between a detectable and undetectable leak. Usually, leak threshold is expressible as a curve on a leak size versus response plot (see Fig. 2-1).

Linefill - The amount of mass stored in a pipeline. This mass is usually expressed as a volume at the standard condition of 15 EC and 0 psig.

Measured Leak Rate - A positive number measured by a test device that indicates the amount of product leaking out of the tank system. A negative number would indicate that something was being added to the tank. The performance of a system is based on how well the measured leak rate compares to the actual induced leak rate.

Nominal Leak Rate - The set or target leak rate to be achieved as closely as possible during the evaluation of a leak detection system. It is a positive number expressed in barrels per hour.

Non-repeatability - The random error or imprecision in a measurement. In general, this random error is different for every reading. Non-repeatability can not be removed by calibration.

Precision - The degree of agreement of repeated measurements of the same parameter. Precision estimates reflect random error and are not affected by bias.

Probability of Detection (PD) - The probability of detecting a leak of a given size, usually expressed as a percentage.

Probability of False Alarm (PFA) - The probability of declaring a leak when none is present, usually expressed as a percentage.

Probe - A component of a detection system that must come into contact with product before product can be declared or measured.

Qualitative Responses - The type of detector response that indicates only the presence or absence of product without determining the specific product concentration or thickness.

Quantitative Response - A type of detector response that quantifies the concentration or thickness of product present.

Relative Accuracy - A function of systematic error, or bias, and random error, or precision. Smaller values indicate better accuracy. See entry for "Accuracy."

Resolution - The smallest change in the quantity being measured which the measurement system is capable of detecting.

Response Time - The time needed to detect a given size leak with a reasonable confidence level.

Specificity - Specificity applies to vapor and liquid sensors and lists products or components of products that these sensors can detect. Specificity for quantitative sensors is the ratio of sensor output, or measured concentration, to the actual concentration of hydrocarbon test gas expressed as a percentage. Specificity for qualitative sensors is reported as activated if the sensor responds within 24 hours. Otherwise, specificity is reported as inactivated.

Standardized Volume - The volume of a given mass of liquid at 15 EC and 1 atm.

Transients - A state of flow in a pipeline where pressure and velocity vary rapidly over time and distance.