U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

SEP 17 2008

1200 New Jersey Avenue, SE
Washington, D.C. 20590

The Honorable Mark V. Rosenker
Acting Chairman
National Transportation Safety Board
490 L'Enfant Plaza East, SW
Washington, DC 20594

Dear Chairman Rosenker:

This letter provides an updated response and requests the National Transportation Safety Board (NTSB) close Safety Recommendation P-05-5. Safety Recommendation P-05-5 recommends Pipeline and Hazardous Materials Safety Administration (PHMSA) require operators to install computer-based leak detection systems on all lines unless engineering analysis determines that such a system is not necessary.

Section 21 of the Pipeline Inspection, Protection, Enforcement, and Safety Act required PHMSA to submit a report on leak detection systems with discussion about what can be done to foster development of more effective technologies. A draft version of this report was posted for public comment in January 2008 before the final report was sent to the Congress on June 23, 2008. A copy of this report is enclosed for your records.

PHMSA requires operators to deploy an interconnected set of required layers of protection to detect and repair hazardous liquid pipeline leaks at the soonest possible time to mitigate any damages appropriately. Pipeline operators are continuously improving the cumulative performance of these interlinked protections in leak detection. These protections include but are not limited to: customized leak detection technology deployment, periodic risk-based assessment and defect repair prioritized by environmental consequence, corrosion management, pipeline rights-of-way surveillance, public awareness leading to citizen identifications of leaks, emergency preparedness and response - including ongoing liaison with emergency responders, and lessons learned and applied from accident analyses and investigations.

Requirements in our regulations emphasize prompt and remote detection of leaks through monitoring operational parameters and engineered leak detection systems for areas identified as having the greatest consequence in the event of a pipeline failure. Under the Integrity Management (IM) rule, PHMSA addresses existing leak detection system inadequacies with each operator by analyzing and evaluating each operator's leak detection capabilities for individual pipeline systems. PHMSA encourages, and in some cases requires, more timely and comprehensive adoption and application of currently available technology commensurate with the system-specific needs of each operator. PHMSA has also funded Research and Development projects designed to improve leak detection effectiveness and efficiency through development of new technology, new national consensus leak detection standards, and operational best practices. Over the past few years, PHMSA and the industry have invested over $5 million in research and development for six leak detection technology projects. These projects focused on providing cost effective means of external leak detection using land-based systems, airborne technology and underwater technology. We have continued to work with our stakeholders on improving sensitivity of technologies to detect small pipeline leaks.

We are developing and refining technology currently proven by other industries in order to apply it to leak detection for hazardous liquid, gas transmission and distribution pipelines. The Airborne Light Detection and Ranging (LIDAR) Pipeline Inspection System (ALPIS) is an example of collaborative technology development PHMSA is conducting to improve the industry's capability to detect leaks. The ALPIS is an airborne remote sensing system for detecting natural gas and hazardous liquid pipeline leaks. It will be capable of working with helicopters, fixed wing aircraft, or unmanned aircraft. The system uses differential LIDAR to detect the presence of hydrocarbons in the atmosphere. The data collected with ALPIS can be incorporated into Geographic Information Systems to map leak detection information.

PHMSA is collaborating with other Federal agencies and stakeholders on the Sensor Enabled Nextgen Technology to develop an enhance surveillance system to detect leaks and prevent infrastructure damage in an aerial surveillance environment. This initiative will apply technology developed for space exploration and military defense to further enhance the safety of the general public and our pipeline infrastructure. The objective is to utilize advance sensor technology on manned aircraft with a view towards use of an Unmanned Aerial Vehicle or satellite to survey pipeline rights-of-way once that technology becomes cost-effective.

As stated in the enclosed report, our analyses indicate that hazardous liquid pipeline spills are trending downward. We believe this is due in part to the number of pipeline repairs performed on anomalies prior to failure that are discovered as a result of the internal inspections required by our IM rule, the many layers of protection described in this report as well as the many efforts of our stakeholders. PHMSA has provided strong leadership for this effort through our IM regulatory program and research to assure the safety and reliability of the Nation's pipeline system.

PHMSA requests the NTSB classify Safety Recommendation P-05-5 as "Closed-Acceptable Action." If you have questions, please feel free to contact me at 202-366-4433.

Respecfully,

R. Kowalewski

Rick Kowalewski
Acting Assistant Administrator/
Chief Safety Officer

Enclosure: Leak Detection Technology Study

Leak Detection Technology Study

For PIPES Act

H.R. 5782

The U.S. Department of Transportation

December 31, 2007

Leak Detection Study

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EXECUTIVE SUMMARY

In enacting the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES), the U.S. Congress directed the U.S. Department of Transportation's (DOT's) Pipeline and Hazardous Materials Safety Administration (PHMSA) to prepare a report on leak detection systems utilized by operators of hazardous liquid pipelines. Specifically, Congress asked for a discussion of the inadequacies of current leak detection systems, including their ability to detect ruptures, small leaks that are ongoing or intermittent, and what can be done to foster development of better technologies as well as address existing technological inadequacies.

In short, while no single solution exists to effectively detect all hazardous liquid pipeline leaks and few exist that reliably detect small leaks, available evidence indicates that many layers of protection and renewed focus of both operators and PHMSA are driving down both the frequency and overall consequence of those leaks that do occur. Over a 10-year period (1997-2007), during which PHMSA implemented the integrity management (IM) program, the median volume lost from hazardous liquid pipeline accidents dropped by more than half, from 200 to less than 100 barrels. At the same time, the number of accidents declined by over a third.

Operators' choices about methods of leak detection will be as varied as the types of pipeline construction, operation, and the environments in which they operate. The Nation's pipeline infrastructure is comprised of a wide variety of materials installed over many decades in environments as widely diverse as Florida and Alaska. Environmental factors, many of which can fluctuate over the course of a day, a month, or a year, affect the performance of these leak detection systems. These include soil type, moisture, temperature, topography, and seismicity. Operational factors also fluctuate widely due to seasonal or demand factors. These operational factors include flow volumes, product transported from crude oil to jet fuel and potentially ethanol, leaks caused by corrosion to excavation to equipment failure and more, and time of day. Technical capabilities to detect leaks vary in terms of sensitivity, accuracy and responsiveness.

Economics of pipeline operation pose a varied set of factors which influence decisions about leak detection. Additionally, operators must consider the cost of the initial purchase, potential retrofitting, operator training, and maintenance prior to upgrading their leak detection technology. Often the ability to recover the costs of the implementation of new technology is rate constrained. Lastly, the economic viability of individual pipeline systems that provide critical energy supplies throughout our country daily varies widely.

PHMSA and pipeline operators place particular emphasis on preventing pipeline leaks from occurring in the first place. For this reason, PHMSA relies on an interconnected set of required layers of protection to detect and repair hazardous liquid pipeline leaks at the soonest possible time to mitigate any damages appropriately. Operators are continuously improving the cumulative performance of these interlinked protections in leak detection. Accommodating the wide variations noted above, these protections include: customized leak detection technology deployment, periodic risk-based assessment and defect repair prioritized by environmental consequence, corrosion management, pipeline rights-of-way (ROW) surveillance, public awareness leading to citizen identifications of leaks, emergency preparedness and response - including ongoing liaison with emergency responders, and lessons learned and applied from accident analyses and investigations. In addition to these many layers of regulatory protections, PHMSA will soon propose additional measures designed to enhance the ability of control rooms and controllers to effectively detect and mitigate the consequences of a leak.

Requirements in our regulations, particularly those imposed about 7 years ago in PHMSA's IM rules, emphasize prompt and remote detection of leaks through monitoring operational parameters and engineered leak detection systems for areas identified as having the greatest consequence in the event of a pipeline failure. Under the IM rule, PHMSA addresses existing leak detection system inadequacies with each operator by analyzing and evaluating each operator's leak detection capabilities for individual pipeline systems. PHMSA encourages, and in some cases requires, more timely and comprehensive adoption and application of currently available technology commensurate with the system-specific needs of each operator.

For example, PHMSA through its hazardous liquid IM program requires operators to more rigorously evaluate the capability of their leak detection systems and to make improvements if needed. Using the IM inspection protocols, PHMSA inspectors have identified a number of issues related to the operator's evaluation of its leak detection capabilities. Most issues fall into one of two procedural categories:

1. The operator did not perform an evaluation of its leak detection capability and its IM program did not adequately require or specify that such an evaluation be conducted, or
2. The operator's process or procedures for evaluating its leak detection system capability were inadequate or technically deficient in some respect.

PHMSA has completed inspections on all of the hazardous liquid pipeline operator's integrity programs. In response to the leak detection issues, PHMSA has initiated enforcement actions, or formally documented its concerns, for approximately 40 percent of hazardous liquid pipeline operators to date. In response to the enforcement actions, operators are required to submit revised procedures to correct inadequacies related to leak detection evaluations. Operators must then evaluate (or reevaluate) their leak detection capabilities in accordance with these corrected procedures. Before a case is closed, PHMSA reviews the revised procedures, and determines that the revisions satisfactorily address identified issues. PHMSA's requirements for IM programs, other hazardous liquid safety controls, and risk-based oversight in a holistic approach are designed to get the best performance from each pipeline system. PHMSA and its many State partners actively monitor pipeline operator compliance with these many requirements and compel improvements to be made. The system of checks and balances appears to be working well and continuously getting better.

While getting good results with the control systems described above, PHMSA funded Research and Development projects designed to improve leak detection effectiveness and efficiency through development of new national consensus leak detection standards, new technology, and operational best practices. Over the past few years, PHMSA and the industry have invested over $5 million in research and development for six leak detection technology projects. These projects focused on providing cost effective means of external leak detection using land-based systems, airborne technology and underwater technology. We have continued to work with our stakeholders on improving sensitivity of technologies to detect small pipeline leaks. We are developing and refining technology currently proven by other industries in order to apply it to leak detection for hazardous liquid, gas transmission and distribution pipelines. The Airborne

Light Detection and Ranging (LIDAR) Pipeline Inspection System (ALPIS) is an example of collaborative technology development PHMSA is conducting to improve the industry's capability to detect leaks. The ALPIS is an airborne remote sensing system for detecting natural gas and hazardous liquid pipeline leaks. It will be capable of working with helicopters, fixed wing aircraft, or unmanned aircraft. The system uses differential LIDAR to detect the presence of hydrocarbons in the atmosphere. The data collected with ALPIS can be incorporated into Geographic Information Systems to map leak detection information.

As PHMSA concludes this report, we believe our holistic approach to managing pipeline leak detection through a set of protections is yielding good results while we and the pipeline industry pursue more sensitive leak detection technologies.

1 Introduction

Every day, millions of Americans depend on the safe and reliable transportation of oil and gas through pipelines. The energy transportation pipeline network of the United States consists of over two million miles of pipelines. Pipelines are historically a very safe means of transporting large quantities of oil, natural gas, fuels, and other hazardous materials. However, since 2002, there has been an average of two serious pipeline incidents per year and 123 significant pipeline incidents per year. A dependable leak detection system is important to promptly identify when a leak is occurring in order to shutdown the line, isolate the leak, initiate response actions, reduce the volume of the spill, and mitigate safety, environmental, and economic consequences of the release.

This report describes the capabilities and limitations of leak detection systems used by operators of hazardous liquid pipelines as required by Section 21 of PIPES. Topics discussed include:

- The capabilities and limitations of current leak detection systems;
- The results of the IM program as it relates to pipeline leak detection systems;
- Inspection findings and enforcement actions;
- Regulatory requirements for pipeline leak detection; and,
- Advancements in leak detection technology.

2 Current Leak Detection Capabilities and Technology

2.1 Introduction

The methods used for leak detection cover a wide spectrum of technologies and are based on a number of different detection principles. They vary from intermittent aerial inspections to hydrocarbon sensors to Supervisory Control and Data Acquisition (SCADA) based, real-time monitoring. Each approach has its strengths and weaknesses. The operational principle, data and equipment requirements, strengths, weaknesses, and the realistic performance limits (size, response time, location, false alarm, etc.) for the leak detection methods listed above are addressed in sections 2.4, 2.5 and 2.6 of this report. Please note the system performance information provided in this report has been obtained from vendor literature and is not always reproducible during actual conditions due to system-specific factors or environmental variables.

2.2 Current Leak Detection Technologies

Leak detection systems are varied and uniquely designed for each pipeline application. However, for discussion purposes, leak detection technologies can be classified according to the physical principles involved in the leak detection. Using this type of classification, general categories of leak detection technologies can be divided into the following three groups: visual inspection/observation, instrumented monitoring of internal pipeline system conditions, and external instrumentation for detecting spilled hydrocarbons.

2.2.1 Visual Inspection/Observation

Simple visual observation is reliable and is part of every pipeline ROW patrolling and monitoring program, as mandated by Federal regulations. However, it cannot assure timely detection of leaks. Section 2.4 addresses this approach.

2.2.2 Instrumented Monitoring of Internal Pipeline System Conditions

Internal monitoring of the operational and hydraulic conditions of the system can detect possible leaks when measurements deviate from normal parameters. This is the most common and most practical approach for promptly and reliably identifying significant leaks from a remote location. There are a number of different approaches for establishing the normal parameters and selecting the variables to monitor. Some approaches are relatively simple and are analyzed manually by pipeline controllers. Others are more sophisticated and rely on sophisticated computer algorithms and hydraulic models, which require very frequent polling of data sources to analyze operational parameters in nearly real time. Each solution presents the operator with choices in tradeoffs between cost, reliability, sensitivity, speed of detection, operational flexibility, and ease of operation. The following sections address the most commonly used approaches:

1) Regular or Periodic Monitoring of Operational Data
    a) Volume balance (over/short comparison) (Refer to section 2.5.1.1)
    b) Rate of pressure/flow change (Refer to section 2.5.1.2)
    c) Pressure point analysis (Refer to section 2.5.1.3)
    d) Negative pressure wave method (Refer to section 2.5.1.4)
2) Computational Pipeline Monitoring (CPM)
    a) Mass balance with line pack correction (Refer to section 2.5.2.1)
    b) Real time transient modeling (Refer to section 2.5.2.2)
3) Data Analysis Methods
    a) Statistical methods (Refer to section 2.5.3.1)
    b) Digital signal analysis (Refer to section 2.5.3.2)

2.2.3 External Instrumentation for Detecting Spilled Hydrocarbons

External monitoring seeks to detect the presence of fluid that has escaped from the pressure boundary of the piping system. There are several types of external methods used to detect leaks from liquid pipelines. Some of the technology is similar to the technology used to detect leaks in Underground Storage Tanks (UST) that are regulated by the Environmental Protection Agency. Impedance 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. These methods are typically used only in selected sensitive or problem locations, due to the high cost of installing and maintaining sensors and communication equipment for the entire length of the pipeline.

The following sections address each of these approaches:

1) Liquid Sensing Cables (Refer to section 2.6.1)
2) Fiber Optic Cables (Refer to section 2.6.2)
3) Vapor Sensing Tubes (Refer to section 2.6.3)
4) Acoustic Emissions (Refer to section 2.6.4)

2.3 Key Considerations for Evaluating Adequacy 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 must be evaluated for each pipeline system. Pipeline size, length, operating parameters and instrumentation design will affect the detection time. Key considerations that should be taken into account include, but are not limited to, the following: (Note that much of the following discussion includes comments on the internal instrumented leak detection method, since it is by far the most widely used technology in the pipeline industry.)

Rate of False Alarms and Misses - This is the most critical aspect of implementing computational leak detection systems. Systems that are tuned to trigger alarms at very sensitive (low) threshold limits will produce more false alarms. Experience has shown that numerous false alarms can result in real alarms subsequently being acknowledged without appropriate intervention. The key is to select detection thresholds that balance the engineering trade-off between detecting the smallest leak possible while minimizing false alarms. The current state of internal instrumented leak detection technology allows for the reliable detection of leaks sizes of approximately one to five percent of throughput without excessive false alarms (depending on system specific variables), although this level of performance is not guaranteed. The response time to detect small leaks varies with the technology being used and ranges from seconds (in the case of real time transient modeling) to hours (in the case of volume balance).

There are many sources of uncertainty in the data that drive computational algorithms. These sources include hydraulic noise, non-repeatability of field sensors, uncertainties introduced by the SCADA system (analog-to-digital conversions, data timing), data communication errors, and the state of flow (steady, drifting, or transient). As a result, the output from the algorithm is also uncertain. This uncertainty is the central issue facing the computational techniques for detecting leaks.

To illustrate this issue, consider the volume imbalance as the algorithm output. In terms of standardized volumes, subtracting the change of line fill (over a time period) from the difference between inflow volume and outflow volume (over the same period) gives the volume imbalance. A positive imbalance means a leak. Refer to figure 2-1 where the estimated imbalance is plotted against the true imbalance. Had the estimations been perfect, all points would fall on the

45-degree (diagonal) line. Because of uncertainties, the points will be scattered around the diagonal line. The points above the diagonal represent under-estimation of the imbalances, while the points below the diagonal represent over-estimated imbalances.

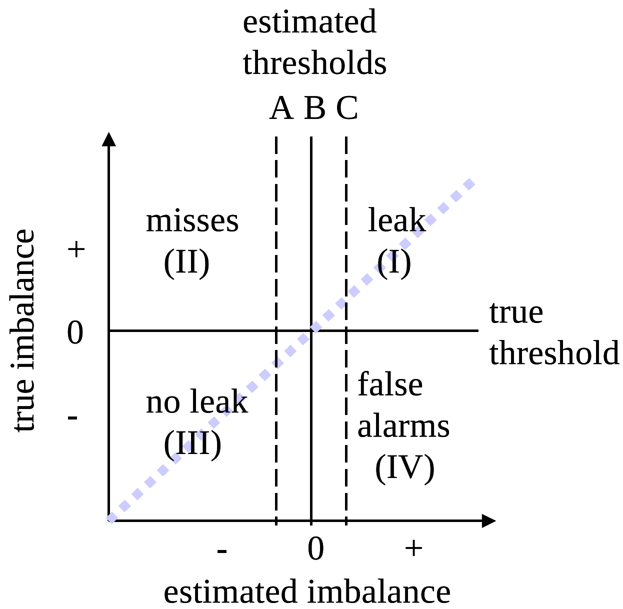

Figure 2-1 False Alarms, misses, and leak thresholds

The estimated imbalance versus true imbalance plot in figure 2-1 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 unknown 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 III). 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, computational techniques have limited ability to detect very small leaks.

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. A low threshold (vertical line A) reduces the chances of misses at the expense of increasing the frequency of false alarms.

In addition, during transients, detectable leak limits are generally higher than when operating under steady state conditions. Therefore, thresholds may need to be raised to avoid false alarms during transient conditions.

Instrument Accuracy - A system that receives inaccurate data will produce inaccurate results, resulting in false alarms or missed leak indications. Instrument accuracy most affects computational methods due to non-repeatability or calibration drift.

Personnel Training and Qualification - Complex systems requiring a high level of training or skill level to interpret data or signals may not afford the same level of leak detection capability when the human interface is considered, due to the potentially higher rate of human error.

System Size and Complexity (Including Batch Line Factors) - Large systems have greater variability in environmental factors (such as temperature), pipe parameters (such as diameter), topography (more complex elevation profile), etc. Complex systems may include multiple injection and delivery points, variable commodity properties (as in a batch line), or multiple modes of operation. These may complicate the design of computational algorithms due to needed model (i.e. algorithm) refinements and increase the likelihood of modeling errors. In addition, these factors result in increased data requirements and uncertainty when all the needed data is not available (such as could occur due to data communication errors or communication system unavailability).

Leak Size or Leak Flow Rate - The size of a leak is usually expressed as a percentage of the throughput of the pipeline. Leak size is a function of the opening (leak area) and the pipeline pressure. The leak size can be constant, such as a pre-existing small leak. It can also be variable over time, such as a sizable leak that diminishes as the pipeline is depressurized. Detectable thresholds are usually much lower with external detection systems. With computational detection methods, the detectable leak size is inter-related to the response time required to detect the leak. In general, computational methods are able to detect leaks in the range of one to two percent of throughput.

Response Time - Depending on the technique, system, or algorithm used, the response time may or may not vary with leak size. For computational methods based on volume or mass balance, the detectable leak size and the response time are related as shown in Figure 2-2. A large leak can be detected quickly and have a short response time. A smaller leak will take a longer time to be detected and the corresponding response time is long. Leaks smaller than the combined non-repeatability of flow meters are not detectable. Such leaks have a response time of infinity.

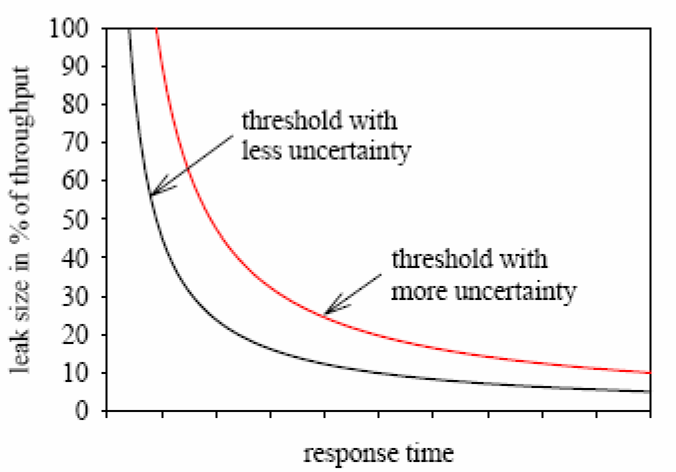

Figure 2-2 Detectable leak size versus response time

For methods based on discrepancy patterns using a transient flow model, the response time is not a function of leak size. Instead, it is a function of the propagation speed (about 3,000 to 4,000 feet per second (ft/s)) of a disturbance and the distance between the leak and the nearest pressure or flow sensor.

Leak Location Estimation - Location can be estimated based on the time of arrival of a leak disturbance at a pair of sensors. Figure 2-3 indicates a leak occurring at time t_0. This leak generates a local pressure drop, which then propagates both upstream and downstream. If this signal is picked up by pressure sensor A at time t_1 and by pressure sensor B at time t_2, then the leak can be located. This approach requires either a fast data scan rate or recording the time of arrival at the sensors which is later transmitted to the control center.

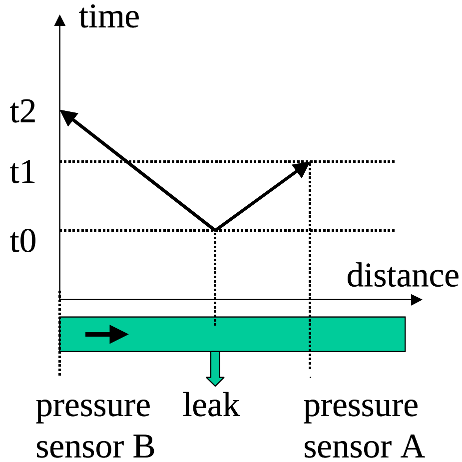

Figure 2-3 Locating a leak by the time of arrival of a leak signal

Alternatively, a leak can be located by the profile of the piezometric head, also known as the hydraulic grade line. Figure 2-4 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 leak and after the transients caused by the leak have damped out. 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.

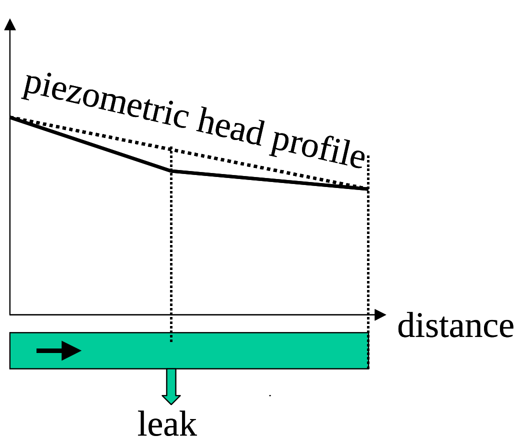

Figure 2-4 Locating a leak by the piezometric head profile

Release Volume Estimation - Release volume estimation is possible for computational 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 computed.

The release volume can also be estimated if a computational method tracks the mean mass imbalance (line fill change minus the difference between inflow and outflow). When a leak is detected, the difference between the mean mass imbalance prior to and after the leak can be used to estimate the release volume over time.

Detecting Pre-existing Leaks - Some computational 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 system is activated.

Detecting a Leak in Shut-in Pipeline Segments - The detection of a leak under such a situation is a matter of monitoring line pack change due to environmental temperature variations and/or due to a leak. Computational methods based only on inflow-outflow comparison will not be able to detect a leak in a shut-in pipeline segment.

Detecting a Leak in Pipelines under a Slack Condition During Transients - Liquid hydrocarbons vaporize when 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.

Sensitivity to Flow Conditions - A pipeline seldom operates at a true steady state. Consequently, line fill always changes. Volume balance methods that do not compensate for line fill change will be excessively sensitive to the flow conditions. The uncertainty in line fill induced by even mildly unsteady flows can easily exceed the combined non-repeatability of flow measurements.

Pump startups, shutdowns, and valve swings all generate transients. Such transients can be so rapid that the SCADA data polling frequency and timing skew become issues. For such situations, data quality is often the central issue.

Multiphase Flow - Multiphase flow, the flow with a mixture of gas, oil, and/or water (and in some locations sand), complicates measurement of flow rate and leak detection immensely. Various flow regimes can occur in the piping system depending on flow rates of the individual phases, pipe diameter, and pipe orientation. Flow regimes that commonly occur are bubbly flow, plug flow, stratified flow, slug flow, annular flow, and mist flow. A flow meter designed for single-phase flow (liquid or gas only) will not perform well in multiphase flow and may even fail. Uncertainties of 50 to 100 percent or more can result. Volume or mass balance methods are challenging to produce meaningful results in multiphase flow conditions. Additionally, significant pressure fluctuations occur which makes pressure change or transient leak detection methods very suspect. False alarms or leaks that are not detected can easily arise when multiphase conditions are occurring in the pipeline.

In the case of air being introduced into the liquid in the pipeline (perhaps through a reservoir emptying), single phase flow meters will be affected. If the amount of air is not large, then the flow regime will probably be bubbly flow or plug flow. Typically a flow meter will measure a higher flow rate than is actually flowing. The volume taken up by the air will increase as the pressure drops along the pipeline which can change the measured flow and significantly increase the pressure drop over the liquid-only case. All of these cases increase the uncertainly in the CPM techniques, which would lead to a higher threshold for leak detection (the leak must be larger than the single phase case to accurately detect) or in the worst case, numerous false alarms would occur or an actual leak would be missed.

Robustness - This criterion measures error handling capabilities when system components malfunction. It also measures a system's ability to function in complex pipeline configurations 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 complete loss of leak detection ability can be avoided.

Availability - To avoid false alarms, computational systems that can not handle transient flow conditions usually increase the detection threshold until the operational transients has 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 computational method.

Retrofit Feasibility - 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.

Testing - American Petroleum Institute (API) Publication 1130 *Computational Pipeline Monitoring* (API 1130) recommends that a leak detection system be tested during commissioning and every five years thereafter.

Cost - The cost of the system including capital and operational expenses (including data, communications, and equipment requirements).

Maintenance - Maintenance requirements for the system.

2.4 Visual Leak Detection

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 DOT are required to perform visual inspection of their system for 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 ROW. Methods of inspection include walking, driving, flying or other appropriate means of traversing the ROW.

The purpose of performing these ROW inspections is to:

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

Most pipeline companies have developed procedures and/or forms for conducting the ROW inspection. These procedures and/or forms are typically included in the Pipeline Operation and Maintenance Manual or in the Pipeline ROW Manual. These procedures and/or forms generally require that the employee inspects the ROW 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 ROW
- Road improvements
- Condition of waterway banks
- Dead vegetation
- Dead or incapacitated livestock
- Abandoned vehicles
- Damaged signs, vents, markers
- Ditching for new pipelines or utilities
- Construction
- Settling of backfill
- Suspicious activities
- Trees and debris collecting on lines crossing creeks and rivers

These inspections look for evidence of leaks and conditions that could lead to a pipeline failure. These inspections may be performed by walking, driving, or flying over the ROW. 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 can easily 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, as long as canopy cover allows an unobstructed view of the ROW from the air.

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

Table 2-1 Capabilities and Limitations of Visual Leak Detection

Capabilities	**Limitations**
Requires no tools or equipment	Up to three-week detection time

Location of leak is immediately known in most cases	Small leaks may not be readily apparent at ground level
	Dependent on the diligence of personnel inspecting the ROW
	Aerial inspection might miss some evidence of small leaks

2.5 Capabilities of Internally Instrumented Leak Monitoring Systems

Internally based leak monitoring systems use pipeline operational data to calculate predicted operational parameters under normal conditions. The predictions are compared to measured parameters to identify differences that could indicate a leak. Geographically-distant field sensors on the pipeline are constantly polled and data is transmitted to a control center through a SCADA system. In the control center, the SCADA system then provides the needed data to a monitoring computer running the leak detection algorithm. (In some simple applications of volume balance method, the controller manually reads the instruments and performs the calculations, sometimes locally.) The quality of the data affects the system's ability to detect a leak and the pipeline size, length and operating parameters affect leak detection time.

The design, implementation, testing, and operation of these systems are addressed by API 1130.

Based on the nature of the algorithms used, these methods can be categorized below:

2.5.1 Regular or Periodic Monitoring of Operational Data by Controllers

2.5.1.1 Volume Balance (Over/Short Comparison)

This meter-based method identifies an imbalance between the incoming (receipt) and outgoing (delivery) volumes. The volumes of product entering and leaving a pipeline are measured over a specified time period. The measurement results are expressed in terms of standardized volumes (volume at 15 °C and 0 pounds per square inch gage (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 can be implemented manually by pipeline controllers. It gives credible results when the flow in the pipeline is at a steady state (i.e. the pressure, temperature, and flow along the pipeline do not change over time) or when the time period over which change could occur is sufficiently long. Often, there is no compensation for changes in pipeline inventory due to changes in temperature, pressure, or composition. It is difficult to manually compensate for such changes.

The 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 line fill 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.

The ability to detect a leak in a slack pipeline (one where low local pressure causes 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 unsteady, the vapor void volume changes and the ability to detect even a significant leak is lost.

The ability of this approach to detect a small leak is dependent on meter accuracy and meter repeatability. When volume metering is not accurate or available, level changes in the tanks in pump stations and delivery terminals may be used to estimate the volumes.

The capability of the volume balance method is dependent on the size of the leak, the frequency of calculating the volume balance, the repeatability of instrumentation, and the operating conditions at the time of the leak. The following describes influence of each of these variables in visual leak detection:

Table 2-2 Capabilities and Limitations of the Volume Balance

Capabilities	**Limitations**
Implementation or retrofitting on any pipeline configuration is easy	Leaks cannot be detected during shut in and slack line conditions
This method is easy to learn and use	Leaks cannot be detected during transient conditions
Testing and maintenance are easy	Small leaks may have very long detection times
Costs are relatively low	The location of a leak cannot be determined
Detect less than 5 percent leak in minutes to hours	Long-term average of leak volume can only be roughly estimated
	False alarms are frequent unless thresholds are softened during transient states

2.5.1.2 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. This approach is effective for large leaks only.

The capability of the rate of pressure/flow change method is dependent on the size of the leak, the skill and diligence of the pipeline controller, the repeatability of instrumentation, the operating conditions, and the selection of alarm set points. The following describes the influence of each of these variables in visual leak detection:

Table 2-3 Capabilities and Limitations of the Rate of Pressure/Flow Change

Capabilities	**Limitations**
Leaks can be detected in shut in conditions	Small leaks, existing leaks, and leaks during slack line conditions can not be detected
This method can estimate the volume and location of large leaks	Implementation and testing are not easy
Retrofitting and maintenance are easy	The method is not easy to learn and use
Able to detect 5 percent leak in minutes	False alarms are frequent during transient conditions
	The method is less robust

2.5.2 Computational Pipeline Monitoring (CPM)

2.5.2.1 Mass Balance with Line Pack Compensation

The shortcoming of the traditional over/short comparison is that changes are not accounted for in the standardized volume of the pipeline over the time period. The rate of change in line pack is measured using pressure and temperature sensors and/or densitometers at several locations between the inlet and outlet flow meters. The pipeline is subdivided into a pre-determined number of segments based on the location of instruments, elevation profile, and desired level of accuracy. This measured rate of change in line pack is included in the mass balance to adjust for fluid composition changes and transient flow conditions. In this method, leak flow equals inlet flow minus the outlet flow minus the rate of change in line pack. When the leak flow exceeds a specified threshold, a warning is displayed and an alarm sounds. Volume imbalance is typically monitored over a number of time periods to detect commodity releases of different sizes.

In some implementations of this approach, the rate of change in line pack is not measured directly using pressure and temperature sensors. Instead, it is predicted using a transient flow model with inlet boundary conditions regularly adjusted by inlet pressure and temperature sensors and/or densitometers. This predicted rate of change in line pack is included in the mass balance to adjust for anticipated fluid composition changes and transient flow conditions. Although easier to retrofit because additional sensors at intermediate pipeline locations are not needed, it has some disadvantages compared to actually measuring line pack parameters, such as being less robust, and less adaptable to complex pipeline configurations.

The capability of the mass balance with line pack compensation method is dependent on the size of the leak, skill and diligence of the pipeline controller, repeatability of instrumentation, number of instrumented locations on the pipeline, operating conditions, and selection of alarm set points. The following describes the influence of each of these variables in visual leak detection.

Table 2-4 Capabilities and Limitations of the Volume Balance with Line Pack Correction

Capabilities	Limitations
Existing leaks and leaks for shut in and transient conditions can be detected	Leaks can not be detected during slack line conditions
Able to detect 1 percent leaks in minutes	Implementation, retrofitting, and maintenance are not easy
Leak detection can be used during transient conditions with less frequent false alarms	The location of a leak cannot be determined.
The method is easy to learn and use	Cost is high
Testing is easy	
The method is adaptable to any pipeline configuration	

2.5.2.2 Real Time Transient Model (RTTM)

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 model assumes the pipeline to be intact, and since the measured data is affected by leaks, leak-specific discrepancy patterns between the measured and the calculated parameters will develop. These discrepancy patterns provide the basis for leak detection, location, and release volume estimation.

The model simulates transient flows in the pipeline. The application software generates a real-time transient hydraulic model using field inputs from meters at strategic receipt and delivery locations, referred to as software boundary conditions. Fluid dynamic characteristic values will be modeled throughout the pipeline, even during system transients. The RTTM software compares the measured data for a segment of pipeline with its corresponding predicted values. Extensive data inputs are required, including:

Physical pipeline parameters:	• Length • Diameter • Thickness • Pipe composition • Route topography • Internal pipe wall roughness • Pump status • Valve status • Equipment location
Commodity characteristics:	• Accurate bulk modulus value • Viscosity
Local station logic:	• Pressure controllers • Flow controllers
Valid batch positions (for products pipelines):	• Batch tracking software interface

The advantage of this approach is that a leak occurring during all flow conditions (including operational transients) can be detected. Because this approach is data intensive, the SCADA's data scan rate needs to be fast. The model parameters also require higher maintenance.

The RTTM method is the most accurate and sophisticated leak detection technology in practical widespread use today. It can both identify and locate small leaks in seconds. However, it is cost prohibitive for many smaller operators. It also requires more training and technical expertise to operate and maintain.

Table 2-5 Capabilities and Limitations of RTTM

Capabilities	Limitations
Able to detect 1 percent leaks in seconds	Existing leaks cannot be detected
Leak flow rate and leak location can be estimated	The method is difficult to learn and use
Leaks can be detected for shut in, slack line and transient conditions	The model must be customized and tuned to each unique pipeline configuration
	Implementation, testing, and maintenance are difficult
	Costs are very high

2.5.3 Data Analysis Methods

2.5.3.1 Statistical Analysis

In the simplest form of this approach, statistical analysis is performed on a measured pressure to discern a decrease in the mean value over a threshold. 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.

The statistical analysis methods still use the principle of mass conservation for corroborating mean data values at multiple locations and 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).

Statistical analysis requires a long time to set up and establish the baseline parameter distribution. If there is a leak on the system when the system is set up, the leak itself is part of the statistical baseline and would never be detected, unless it grew to a significantly larger leak. It becomes more difficult to discern leaks as operating conditions drift from established norms.

Table 2-6 Capabilities and Limitations of the Statistical Analysis Methods

Capabilities	Limitations
Able to detect 1 percent leaks in seconds to minutes	Existing leaks and leaks in slack line conditions cannot be detected
Leaks can be detected for shut in and transient conditions	Leak volume difficult to estimate
False alarms are less frequent	Implementation and testing are difficult
Leak location can be estimated	Costs are high
The method is easy to use	
Retrofitting and maintenance are easy	
The method is easily adaptable to any pipeline configuration	
The method is more robust	

2.5.3.2 Digital Signal Processing

Digital signal processing is used on the flow, pressure and other measurements of the pipeline parameters to detect leaks. The response of the pressure, flow and other sensors to a known impulse change in flow is measured and digital signal processing on these normal operation responses is used to recognize the changes in the responses of these sensors when a leak occurs. The digital signal processing makes it possible to extract the leak response of these sensors from noisy data even when the signal to noise ratio is small. In this method, leaks produce identifiable patterns when digital signal processing is used on the inlet, outlet, and interior pressure and flow sensors. The measured pressure and/or flow data produced by the statistical analyses are used for leak/no leak hypothesis testing. An alarm sounds if a leak pattern is found by the digital signal processing.

This approach, like the statistical analysis methods, does not use a mathematical model for the transient pipeline hydraulics. Extracting information from noisy data is the main focus of this approach.

While this method has several advantages, it is difficult to set up and test. Like the statistical analysis, if there is a leak on the system when the system is set up, the leak itself is part of the statistical baseline and would never be detected, unless or until it grew to a significantly larger leak. It also does not work well under any but normal operating conditions.

Table 2-7 Capabilities and Limitations of the Digital Signal Processing Technique

Capabilities	Limitations
Able to detect 1 percent leaks in seconds to minutes	Existing leaks and leaks in slack line conditions cannot be detected
Leaks can be detected for shut in and transient conditions	Leak volume cannot be estimated
False alarms are less frequent	Implementation, retrofitting, and testing are difficult
Leak location can be estimated	Costs are high
The method is easy to learn and use	
Maintenance is easy	
The method is easily adaptable to any pipeline configuration	
The method is more robust	

2.5.4 Uniqueness of Internally Instrumented Detection Methods

The single most important aspect of internally instrumented leak detection is each system is unique to the pipeline on which it is installed. The same 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. When evaluating the capability of a leak detection system one must consider the pipeline design and operation. Validation of leak detection systems is best accomplished by testing the installed system. This testing should follow the requirements of API 1130.

2.5.5 Comparison of Internally Instrumented Leak Detection Methods

The implementation of the various algorithms within this category varies considerably. As a result, the performance of a particular method may be significantly different from a similar system deployed on a different pipeline. Further compromising the boundary between categories are the many hybrid approaches that have been developed. For example, statistical analysis can be applied to volume balance, with pressure sensor-based line pack correction.

Table 2-8 represents a comparison of the general characteristics of the various forms of internally instrumented leak detection. 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 2-8 Comparison of Internally Instrumented Leak Detection Methods

	Volume Balance (Over/short Comparison)	Rate of Pressure/Flow Change	Volume Balance W/ Line Pack Compensation Using Actual Pressure Measurements	Volume Balance W/ Line Pack Compensation Using Dynamic Computational Model	Real Time Transient Model (RTTM)	Statistical Analysis	Digital Signal Analysis
Leak Size (approaching % of throughput in ideal conditions)	5% to 1%	5%	1%	1%	1%	1%	1%
Response Time	minutes to hours	minutes	minutes	Minutes	seconds	seconds to minutes	seconds to minutes
Location Estimate	no	yes	no	No	yes	yes	yes
Released Volume Estimate	no	yes-for large leak only	no	No	yes	no	no
Existing Leaks	yes	no	yes	Yes	no	no	no
Shut-in Condition	no	yes	yes	yes	yes	yes	Yes
Slack Condition	no	no	no	possible	possible	no	No
False Alarms	frequent	frequent	less frequent	less frequent	more frequent	less frequent	less frequent
System Transients	no tolerance	some tolerance	better tolerance	better tolerance	best tolerance	best tolerance	best tolerance
Robustness	average	less	average	average	less	better	Better
Availability	part time	part time	yes	yes	yes	yes	Yes
Ease of Retrofit	easy	easy	not easy	easy	easy	easy	not easy
Complex Configuration	no	no	no	no	no	yes	Yes
Simplicity	simple	complex	less simple	less simple	most complex	complex	Complex
Ease of Testing	easy	more difficult	easy	difficult	more difficult	difficult	Difficult
Ease of Training	easy	difficult	easy	difficult	more difficult	easy	Easy
Ease to Maintain	easy	easy	difficult	easy	difficult	easy	Easy
Cost	average	higher	higher	higher	highest	higher	High

Table 2-9 Data Sensors Required for Computational Leak Detection Methods

	Over/short Comparison	Rate of Pressure/ Flow Change	Volume Balance W/ Pressure sensors	Volume Balance W/ Dynamic Computational Model	RTTM	Statistical Analysis	Digital Signal Analysis
Inlet Pressure	yes	yes	yes	yes	yes	yes	yes
Inlet Temperature	yes	no	yes	yes	yes	no	no
Inlet Flow	yes	yes	yes	yes	yes	optional	no
Inlet specific gravity	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 specific gravity	yes	yes	yes	yes	yes	optional	no
Interior Pressure	no	optional	yes	no	yes	optional	yes
Interior Temperature (2)	no	no	yes	no	optional	no	no
Interior Flows	no	no	no	no	optional	no	no
Interior sp. gr. (Or a Batch Tracking Algorithm)	no	no	yes	yes	yes	optional	no

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

2.6 Capabilities of Current External Leak Detection Technologies

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 have proven results for underground storage tank applications. There are several factors that affect the performance of external leak detection systems (other than visual inspection) and should be considered as part of the selection process. A user guide developed by the Naval Facilities Engineering Service Center (UG-2028-ENV) describes selection criteria for the different methods, summarized as follows:

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.

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.

Continuous Monitoring
Each of the external methods described can be used for either snap shot assessment or continuous monitoring based on the equipment and the application. The former is labor intensive, as personnel must physically insert monitoring instrumentation at intervals along the ROW to detect the presence of hydrocarbons in the soil. This can be significant for long pipelines. Continuous monitoring provides the greatest assurance of prompt leak detection, but can also be cost prohibitive since a continuous detection cable, tubing, or other hardware must be installed along the entire length of the pipeline.

Spacing of Sensors
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.

Leak Rate
In the event of a leak, not all of the external techniques can provide information on how much liquid has been lost, only that a leak of some unknown magnitude has been detected.

2.6.1 Liquid Sensing Cables

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 electrochemical technology or fiber optics. In the case of electrochemical, 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 electrochemical 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 another, or through direct contact. An example of direct contact is the TraceTek 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. The alarm is tripped when electrical contact between the two sensing wire occurs. 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 (www.tycothermal.com).

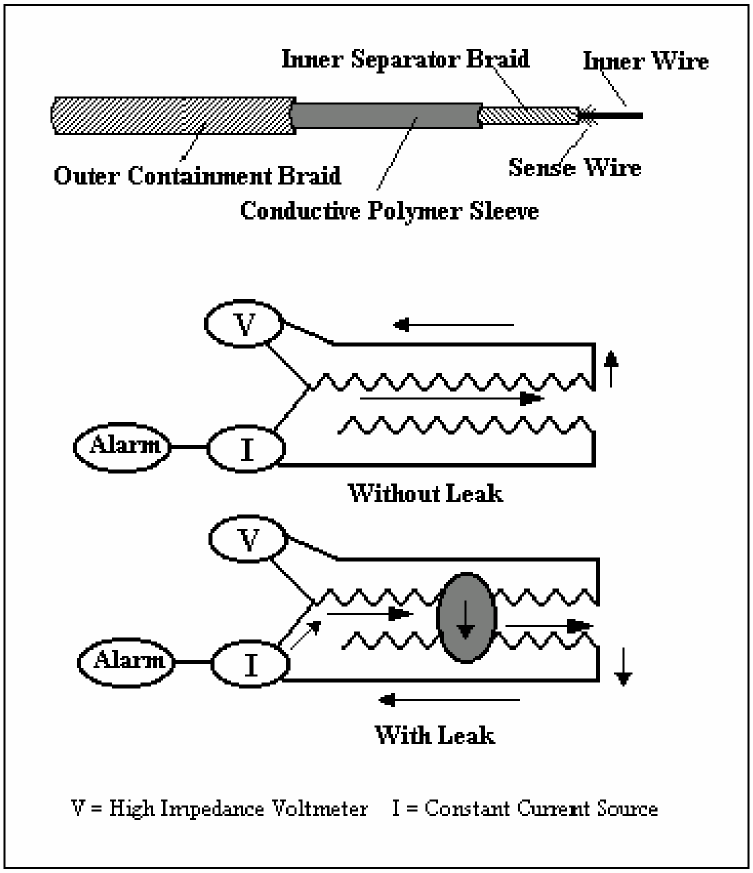

Figure 2-5 Hydrocarbon Sensing Wire Schematic (from www.clu-in.org)

In a more sophisticated cable arrangement such as PermAlert PAL-AT®, 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 (www.permapipe.com).

Figure 2-6 Hydrocarbon Sensing Wire (from Permalert Brochure)

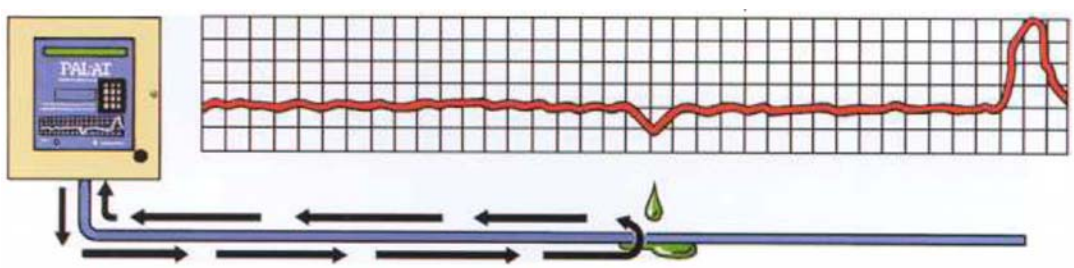

Figure 2-7 Operation of the Pal-AT Sensor (from Permalert Brochure)

Table 2-10 Capabilities and Limitations of Liquid Sensing Cable

Capabilities	Limitations
Operated in a continuous mode and may be automated	Cannot estimate the size of a leak
Method can determine leak location	Retrofitting to existing pipelines would be very difficult
A reasonably fast time response	Multiphase flow leak may not be detected if only gas escaped
Minimally affected by multi-component flow conditions	Costs are extremely high
More sensitive than computational methods and responds in seconds to minutes	

2.6.2 Fiber Optic Cables

Fiber optic cables 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 the Petrosense 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 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 or long-term integrity of the reactive coating.

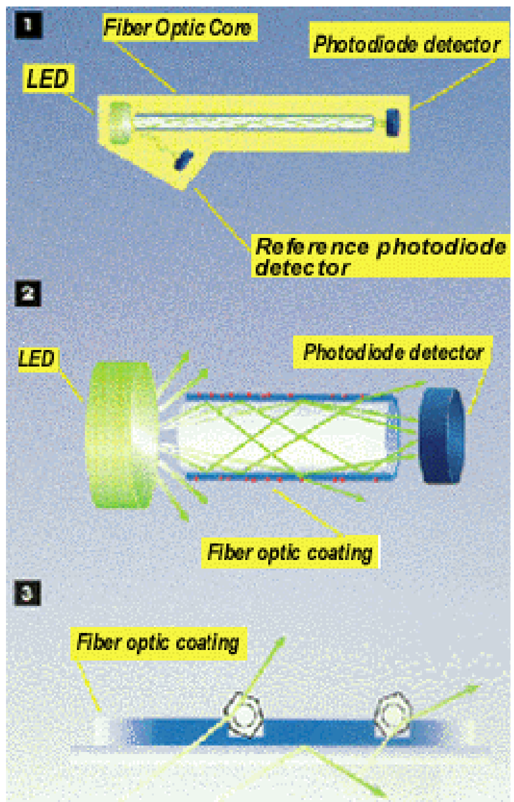

Figure 2-8 Fiberoptic Hydrocarbon Sensor (from http//.fate.clu-in.org)

Table 2-11 Capabilities and Limitations of Fiber Optic Cables

Capabilities	**Limitations**
Operated in a continuous mode and may be automated	Retrofitting to existing piping system is difficult
Method can determine leak location	Multiphase flow is problematic for this technique
Method can estimate the concentration of the hydrocarbon and maybe the size of the leak	Stability of the chemical coating is an issue which could lead to missed leaks
Fiber optic is immune to electromagnetic interference (noise)	Costs are extremely high
Response time to a leak is reasonable	
Minimally affected by multi-component flow conditions	
More sensitive than computational methods and responds in seconds to minutes	

2.6.3 Vapor Sensing

There are two methods of vapor sensing. One method includes the injection of a tracer compound into the liquid being transported by the pipeline. A pipeline leak releases this tracer into the environment where it is detected by a monitoring system. The second method involves detecting the vapors given off by the leaking volatile hydrocarbon liquid that migrates into surrounding soil pockets or pores. With either method, probes can be inserted into the soil surrounding the pipeline at pre-determined intervals to actively sense for hydrocarbon vapors or the tracer compound. The probes can also serve as vapor collectors that are routinely removed and taken to a laboratory for analysis.

For continuous measurements, 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 vapors from the individual tubes by pumping them through a detector which analyzes the vapors 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.

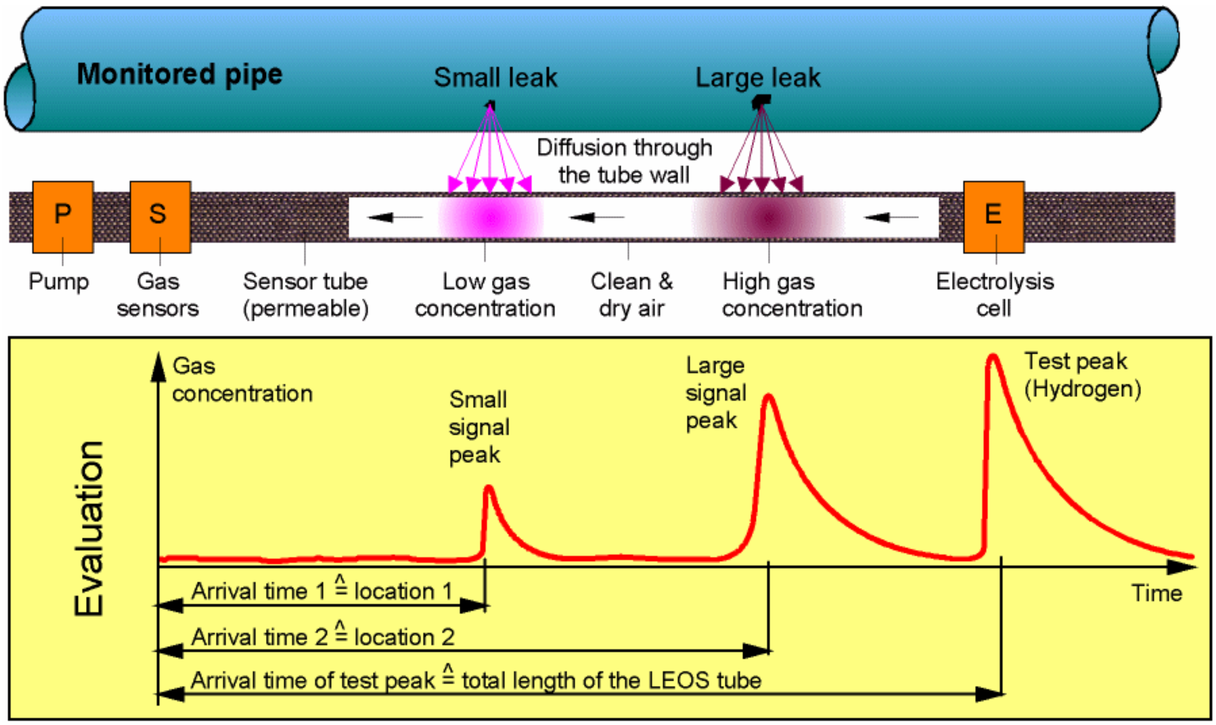

Figure 2-9 Vapor Sensing LEOS System (from Siemens LEOS Brochure)

Table 2-12 Capabilities and Limitations of Vapor Sensing

Capabilities	**Limitations**
Operated in a continuous mode and may be automated	Response time is slower than most other continuous external measurement types
Location of the leak can be estimated	Typically used for short piping runs
The size of the leak can be estimated by concentration measurements	This method is not effective for above ground pipelines
Minimally affected by multi-component or multiphase flow conditions	Costs are extremely high
More sensitive than computational methods and responds in minutes	

2.6.4 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.

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 studies have demonstrated that AE is feasible to detect and locate leaks in buried pipelines. The ideal sensor is a resonant device operating between 10 kilohertz (kHz) and 40 kHz. Location of the leak requires special algorithms to achieve better location accuracy than computational methods.

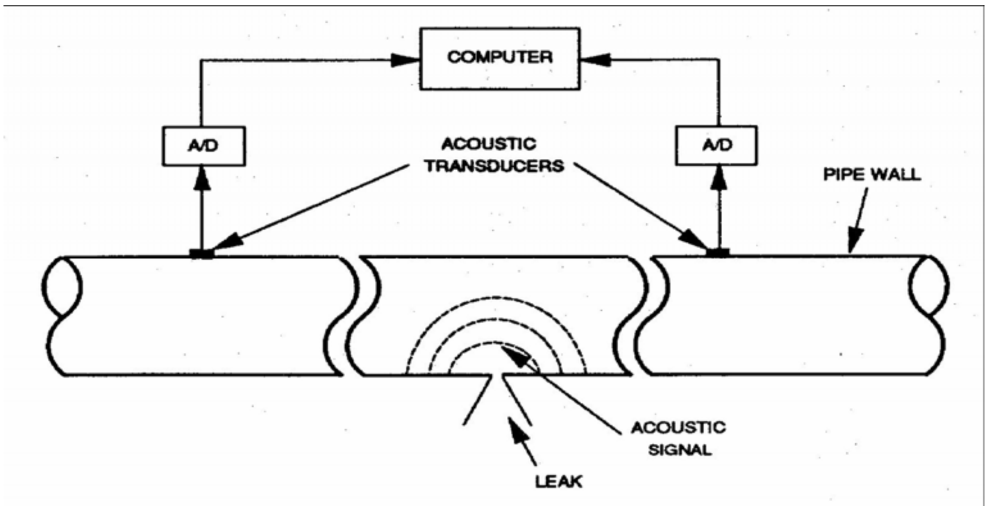

Figure 2-10 Acoustic Emission Leak Detector (from NAVFAC UG-2028-ENV)

Table 2-13 Capabilities and Limitations of Acoustic Emissions

Capabilities	**Limitations**
Operated in a continuous mode and may be automated	High flow noise conditions may mask the leak signal (valve or pump noise, multiphase flow)
Method can determine the location of the leak	Numerous sensors may be needed to monitor long pipelines
Size of leak can be estimated	Costs are extremely high
Minimally affected by multi-component flow	
The acoustic emission method can be used on new or retrofitted to existing pipelines	
More sensitive than computational methods and responds in essentially real-time	

2.6.5 Comparison of Sensor Based External Leak Detection Methods

Table 2-14 that follows presents a comparison of the external sensor-based leak detection technologies.

Table 2-14 Comparison of Sensor Based Technologies

	Parameter	Liquid Sensing	Fiber Optic Cable	Vapor Sensing	Acoustic Emission
Sensitivity	**Response Time**	Seconds to minutes	Seconds to minutes	Minutes	Near real time
	Leak Sensitivity	More sensitive than computational methods	More sensitive than computational methods	More sensitive than computational methods	More sensitive than computational methods
Accuracy	**Location Estimate**	Capable	Capable	Capable	Capable
	Released Volume Estimate	No	Yes	Yes	Yes
Reliability	**Existing Leak**	No	No	Yes	No
	False Alarms	Less frequent	Less frequent	Less frequent	Frequent
Robustness	**Continuous Monitoring**	Yes	Yes	Yes	Yes
	Stability or Robustness	High	Med	High	High
	Complexity	Low	Low	Low	Low
	Ease of Use (Training, Testing, etc.)	Med	Med	Med	Med
	Maintenance Requirement	Low	Med	Low	Low
Adaptability	**Affected by Multiphase or Multi-Component Flow**	No	No	No	Yes
	Retrofit	No	No	Yes	Yes
	Noise Susceptibility	Low	Low	Low	Med
	Availability various piping configurations or throughputs	Yes	Yes	No	Yes
	Shut-in Condition	Yes	Yes	Yes	Yes
	Slack Condition	Yes	Yes	Yes	Yes
	Ease of Retrofit	Difficult	Difficult	Difficult	Moderate

3 Integrity Management (IM) Program

3.1 Overview

PHMSA regulations require that hazardous liquid pipeline and natural gas pipeline operators develop and implement an IM program to provide enhanced protection to designated pipeline segments that could affect high consequence areas (HCAs) in the event of failure. HCAs are populated areas (that meet certain census bureau definitions), unusually sensitive environmental areas, sole source drinking water supplies, and commercially navigable waterways. These enhanced protections take the form of measures to prevent leaks, failures, and incidents, and measures to mitigate the effects of leaks, failures, and incidents.

Pipeline integrity is assured by means of controls and programs that prevent or minimize the likelihood of a leak, failure, incident, rupture, or accident. Many of these programs are embodied in regulations that pre-date the IM rule. These include such fundamental programs as damage prevention, corrosion control practices (such as coating systems and cathodic protection), and overpressure controls.

Timely leak detection is a critical part of prompt leak mitigation, since the operator's response to leaks does not begin until the leak is detected. Operators are required, by the IM rule, to have a means to detect leaks. Operators must also perform a critical, investigative, risk-based evaluation of their leak detection capabilities. The operator's evaluation of its leak detection capabilities must consider, at a minimum, the following factors:

1. Length and size of the pipeline:
2. Type of product carried:
3. The pipeline's proximity to the high consequence area:
4. The swiftness of leak detection:
5. Location of nearest response personnel:
6. Leak history; and,
7. Risk assessment results.

Operators must modify and improve means of detecting leaks, as necessary, to protect HCAs if modifications are indicated by the evaluation.

While the IM rule focuses on additional protections for HCAs, operators also have an obligation to detect and respond to leaks in non-HCAs. Typically, the same leak detection systems and procedures are used to detect leaks on both HCAs and non-HCAs on the same pipeline.

3.2 PHMSA Oversight

PHMSA's oversight program for IM includes specific inspection protocols that guide inspectors to examine the operator's leak detection capabilities and periodic evaluations, including the basis for any decision to modify (or not modify) the means of leak detection currently employed on a pipeline. PHMSA inspectors are trained and instructed to inspect the following characteristics of an operator's program for evaluating leak detection capabilities:

1. Inclusion of all seven of the required system risk evaluation factors identified above. If all required factors are not considered, a basis for excluding the evaluation factor(s) must be documented.
2. Inclusion of all seven factors specifically pertaining to the leak detection evaluation, including risk assessment results. If all required factors are not considered, a basis for excluding the evaluation factor(s) must be documented.
3. Identification and evaluation of a sufficient spectrum of leak scenarios to adequately determine the overall effectiveness of leak detection capability (e.g., "most likely" in addition to "maximum possible").
4. Consideration of additional important evaluation factors such as:
   - current leak detection method for the HCAs;
   - use of SCADA systems;
   - thresholds for leak detection;
   - flow and pressure measurement;
   - specific procedures for lines that are idle but still under pressure;
   - additional leak detection means for areas in close proximity to sole source water supplies; and,
   - leak detection testing (such as physical withdrawal of product from the pipeline).
5. Evaluation of all modes of line operations including slack line, idled line, static conditions, and the impact of special or unique operating modes.
6. If a CPM technique is part of the leak detection system, design, maintenance, controller training, and record keeping aspects of API 1130 must be addressed in system design and maintenance practices.
7. Evaluation of leak detection performance during transient conditions, and a strategy to manage any related short-term reduced or inhibited performance.
8. Evaluation of the operational availability and reliability of the leak detection systems, and the operator's process to manage system failures.
9. Consideration of enhancements to existing leak detection capability.
10. Consistent application of a risk-based decision making process for leak detection.
11. A documented basis for all operator reactions credited in the leak detection evaluation (e.g. operational procedures and/or training materials).
12. Measures applied to assure that required actions are accomplished and prudently restored if varying modes of pipeline operations require controllers or other personnel to engage/activate or mute/disable certain attributes of the overall leak detection capabilities.

13. Integration of emergency response procedures and incident mitigation plans with associated leak detection indications.
14. Adequate guidance in documented work processes to assure that operating personnel have the authority and responsibility to initiate response actions, up to and including shutdown the pipeline if warranted.
15. Assurance that supervision is always promptly available for contact if procedures require that operating personnel contact supervision prior to initiating response actions and/or shutting down the pipeline.

PHMSA’s inspectors review operator plans and procedures for conducting the evaluation and check if the considerations itemized above have been considered by the operator. If the operator’s leak detection evaluation has been completed, PHMSA’s inspectors critically review the technical basis for the evaluations, including the conclusions and recommendations. PHMSA inspectors emphasize that operators should:

- have leak detection systems fully developed and deployed;
- complete a thorough analysis of leak detection capabilities; and,
- identify and make plans to implement enhancements to leak detection capabilities over time, if indicated by the evaluation.

3.3 Inspection Findings and Enforcement Actions

Most hazardous liquid operators have some form of instrumented leak detection capability in place. However, PHMSA inspections identified a number of issues related to the operator’s evaluation of its leak detection capabilities. Most issues fall into one of the following two categories:

- The operator’s IM procedures did not adequately require or specify that a leak detection evaluation be conducted.
- The operator’s IM procedures required that a leak detection evaluation be conducted, but the procedure or process by which the evaluation would be conducted was inadequate in some respect.

In response to these leak detection issues, PHMSA has initiated enforcement action, or formally documented its concerns, for approximately 40 percent of inspections conducted to date.

In response to the enforcement actions, operators are required to submit revised procedures to correct inadequacies related to leak detection evaluations. Operators must then evaluate (or reevaluate) leak detection capabilities in accordance with these corrected procedures. Before a case is closed, PHMSA reviews the revised procedures and determines if the revisions satisfactorily address the identified issue.

A key component of the IM rule is continual improvement. Each operator’s IM program is expected to mature and improve over time. PHMSA’s oversight program includes periodic IM inspections of hazardous liquid operators to monitor and inspect ongoing IM activities. As operators complete their evaluation of leak detection capabilities, PHMSA inspectors will be performing a more detailed technical review of the operator evaluations in subsequent rounds of inspections to judge the circumstances under which improvements in operator leak detection capabilities are indicated. Operators will be expected to identify and implement upgrades and improvements to its leak detection capabilities when indicated by the results of their own evaluation. This could include the development and application of new and better technology as it become available.

4 Other Pipeline Safety Regulations

There is no guarantee that a pipeline system, equipped with a state-of-the-art leak detection system, will detect every leak. The best way to detect a pipeline leak is to prevent the leak from occurring. However, multiple processes must be in place with trained personnel to achieve optimum pipeline system performance and safety. The high performing pipeline system operators have a leak detection system in place, a preventative maintenance program, well trained personnel, conduct internal audits, perform emergency response drills as well as multiple other best practices, and adhere to regulatory requirements.

The DOT pipeline safety regulations provide areas of overlap for pipeline leak detection beyond the actual leak detection system. Pipeline ROW inspection, cathodic protection inspection, public awareness, and damage prevention programs are the primary means of detecting small leaks along the pipeline ROW. These methods are required by PHMSA and used by operators in addition to the remote leak detection capabilities currently employed on most hazardous liquid pipeline systems. PHMSA's pipeline IM program provides an additional layer of regulatory oversight and is covered in Section 3 of this report.

4.1 Leak Detection

Pipeline safety regulations require operators of pipelines that could affect a HCA to have a means to detect leaks. The leak detection systems and their capabilities and limitations are discussed in detail in Section 2 of this report. When a CPM system is used, PHMSA requires that it conform to the requirements of the national consensus standard published by the API 1130.

4.2 Pipeline ROW Inspection

Regular ROW inspection is essential to the early detection of small leaks undetectable to leak detection systems. Pipeline safety regulations require hazardous liquid pipeline operators in the United States to perform periodic visual inspections of their pipeline ROW at least 26 times per calendar year. The inspection can be performed by walking the pipeline, driving, flying, or other appropriate means of traversing the ROW. Small leaks that are below the detection threshold of remote leak detection systems or operational instrumentation can be detected in this manner. This type of inspection is called a visual or external inspection and is discussed further in Section 2.4 of this report.

4.3 Corrosion Control

Preventative maintenance for pipeline corrosion decreases the likelihood of a pipeline leak. These regular inspections also result in an increased presence of operator employees on the ROW and increase the likelihood that leaks will be discovered. Regular monitoring, testing, and inspection of pipeline corrosion is required under pipeline safety regulations. The intervals between activities are based on the design, condition, and environment surrounding each pipeline system. Pipeline operators must monitor, test, and inspect their pipeline systems for external, internal, and atmospheric corrosion. Leading indicators found early through regular monitoring, testing, and inspection can prevent or minimize pipeline failures and leaks.

4.4 Public Awareness

In order to train the public to recognize and report pipeline leaks quickly, Federal pipeline regulations require that pipeline operators develop and implement a public education program in accordance with API Recommended Practice 1162, which is unique to the characteristics and attributes of each operator's pipeline system. Each public awareness program must provide education to the public, government organizations, and excavators on the following:

1. One call notification system;
2. Hazards associated with unintended pipeline releases;
3. Description of physical indicators that a pipeline release may have occurred;
4. Steps for public safety should an unintended pipeline release occur; and,
5. Reporting procedures.

The public awareness program must include activities that educate and advise potentially affected municipalities, school districts, businesses, and residents. Educating the public and the stakeholders improves the likelihood that leaks will be detected and reported by others.

4.5 Damage Prevention Program

Third party impact due to excavation activities is the leading cause of pipeline accidents resulting in product releases. Effective damage prevention programs reduce the risk of leaks due to pipeline failure caused by outside sources. Pipeline operators are required to have a damage prevention program to prevent pipeline damage caused by excavation activities. The damage prevention program should include the following:

- Participation in State damage prevention programs (i.e. State one call);
- Identify persons who normally engage in excavation activities in the area of the pipeline;
- Provide notification to the public in the vicinity of the pipeline and excavators on the damage prevention program;
- Establish a means of receiving and recording notification of planned excavation activities;
- Provide temporary pipeline location marking once an excavation notice is received and prior to excavation activity; and,
- Plan for inspection of pipelines at locations where an operator believes damage could have occurred due to excavation.

An effective damage prevention program results in an increased presence of operator personnel on the ROW and increases the likelihood leaks will be detected visually and reported.

4.6 Procedures for Investigating Abnormal Operating Conditions

Federal pipeline regulations require that operators have procedures to investigate abnormal conditions. Operators must respond, investigate, and correct the cause of any malfunction of a component, deviation from normal operation, or personnel error that could be hazardous to persons or property. Therefore, any abnormal condition that could be indicative of a leak must, by rule, be investigated sufficiently to confirm either the pipeline integrity is intact or a leak is occurring.

5 PHMSA Research and Development

PHMSA places a high priority on the further advancement of leak detection technology and continues to collaborate with industry to sponsor research aimed at improving technologies for detecting pipeline leaks. Since 2002, PHMSA has awarded over $3.8 million on pipeline research and development, and has solicited an additional $1.4 million of co-share funding from industry for six leak detection technology development projects. The focus of the projects is to provide cost effective means of external leak detection. Two projects are focused on land based systems, three are focused on airborne technologies, and one is focused on underwater technology for use with offshore pipeline systems. The research is being applied both for hazardous liquid and natural gas transmission and distribution pipelines.

Three of the projects resulted from Broad Agency Announcements, one congressional request, and two from PHMSA participation in the DOT's Small Business and Innovative Research program. All six projects seek to develop and refine technology currently proven for other applications by other industries in order to apply it to pipeline leak detection applications.

One of the program goals is to develop airborne leak detection with the use of LIDAR technology attached to a helicopter, fixed wing or unmanned aerial vehicle platforms. The following two of the projects supported by PHMSA are well advanced and are currently being commercialized:

- DTRS56-04-T-0012 - *Hazardous Liquids Airborne LIDAR Observation Study (HALOS)*
- DTRS56-01-X-0023 - *Airborne LIDAR Pipeline Inspection System (ALPIS) Mapping Tests*

A complete list of PHMSA research projects related to pipeline leak detection is provided in Appendix A. Information on PHMSA's research and development program and projects is found at http://primis.phmsa.dot.gov/rd/.

6 Conclusion

The United States energy transportation system requires safe and reliable pipelines. One component needed to maintain the safety and reliability of a pipeline system is the ability to detect leaks so they can be promptly identified and repaired. A variety of leak detection systems are available and pipeline operators must select which application is appropriate for their pipeline system by carefully evaluating pipeline system and environmental variables.

PHMSA's IM program is a holistic strategy aimed at improving operator performance and ensuring pipeline safety. Best practices for pipeline maintenance and performance are carefully reviewed including pipeline inspection, anomaly identification and repair, corrosion prevention, public awareness, emergency response, and leak detection. These tools improve pipeline safety, reliability, and performance when augmented together. Through the IM program, PHMSA assures that people and processes are in place to successfully manage the pipeline system to achieve the best performance and results.

As part of the IM, pipeline operators are required to perform an analysis to determine if inadequacies on the leak detection system exist and prepare plans to implement system enhancements. PHMSA recognizes that leak detection systems and system enhancements will vary since they are pipeline system specific but works to assure operators are diligent in their review.

PHMSA fosters ongoing technological improvement and development through its research and development initiatives. PHMSA has invested over $5 million on projects to develop promising technologies with its stakeholders. These initiatives focus on technologies that have been proven in other applications and can be adapted for use on pipelines. These projects address both the threshold for detecting leaks and the time that leaks can reliably be detected.

Our analyses indicate that hazardous liquid pipeline spills are trending downward. This is due in part to the number of pipeline repairs performed on anomalies prior to failure that are discovered as a result of the internal inspections required by our IM rule, the many layers of protection described in this report, as well as the many efforts of our stakeholders. PHMSA will continue to provide leadership for this effort through our IM regulatory program and research to assure the safety and reliability of the Nation’s pipeline system.

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Appendix A

PHMSA Pipeline Safety Research

(Leak Detection Projects since 2002)

No.	Goal	Type	Location	Project ID	Contractor	Project Title	PHMSA	Co-Share	Pct Cmpl
1.	Safety	HazLiq GasTrans Dist-Steel Dist-Non-Metal	Onshore Alaska	DTPH56-05-T-0004	Electricore, Inc., Pipeline Research Council International, Inc.	*"Use of Unmanned Air Vehicle (UAV) for Pipeline Surveillance to Improve Safety and Lower Cost"*	$457,361	$625,416	100
2.	Environmental Stewardship	HazLiq GasTrans	Offshore	DTPH56-05-T-0004	Electricore, Inc., Pipeline Research Council International, Inc.	*"Use of Unmanned Underwater Vehicle (UUAV) for Pipeline Surveillance to Improve Safety and Lower Cost"*	$405,358	$285,000	100
3.	Environmental Stewardship	HazLiq GasTrans Dist-Steel Dist-Non-Metal	Onshore Offshore Alaska	DTRS56-04-T-0012	ITT Industries Space Systems, LLC	*"Hazardous Liquids Airborne LIDAR Observation Study (HALOS)"*	$553,114	$555,115	100
4.	Environmental Stewardship	GasTrans Dist-Steel Dist-Non-Metal	Onshore Alaska	DTRS56-01-X-0023	LaSen and U.S. Air Force Research Laboratory	*"Airborne LIDAR Pipeline Inspection System (ALPIS) Mapping Tests"*	$2,245,204		100
5.	Environmental Stewardship	HazLiq GasTrans Dist-Steel Dist-Non-Metal	Onshore	DTRS57-04-C-10012	Prime Research	*"Intrinsic Distributed Fiber Optic Leak Detection"*	$99,706		100
6.	Environmental Stewardship	GasTrans Dist-Steel Dist-Non-Metal	Onshore Alaska	DTRS57-04-C-10016	Midé Technology Corporation	*"Piezo Structural Acoustic Pipeline Leak Detection System"*	$100,000		100
						Total:	$3,860,743	$1,465,531	

(2) by redesignating subsections (d) and (e) as subsections (b) and (c), respectively.

(c) EMERGENCY RESPONSE GRANTS.—Section 60125(b) (as redesignated by subsection (b)(2) of this section) is amended—

(1) in paragraph (1) by adding at the end the following: "To the extent that such grants are used to train emergency responders, such training shall ensure that emergency responders have the ability to protect nearby persons, property, and the environment from the effects of accidents or incidents involving gas or hazardous liquid pipelines, in accordance with existing regulations."; and

(2) in paragraph (2)—

(A) by striking "$6,000,000" and inserting "$10,000,000"; and

(B) by striking "2003 through 2006" and inserting "2007 through 2010".

(d) ONE-CALL NOTIFICATION PROGRAMS.—Section 6107 is amended—

(1) in subsection (a) by striking "fiscal years 2003 through 2006" and inserting "fiscal years 2007 through 2010"; and

(2) in subsection (b) by striking "for fiscal years 2003 through 2006" and inserting "for fiscal years 2007 through 2010".

(e) INSPECTOR STAFFING.—The Secretary shall ensure that the number of positions for pipeline inspection and enforcement personnel at the Pipeline and Hazardous Materials Safety Administration does not fall below 100 for fiscal year 2007, 111 for fiscal year 2008, 123 for fiscal year 2009, and 135 for fiscal year 2010.

49 USC 60102 note. Deadline.

SEC. 19. STANDARDS TO IMPLEMENT NTSB RECOMMENDATIONS.

Not later than June 1, 2008, the Secretary of Transportation shall issue standards that implement the following recommendations contained in the National Transportation Safety Board's report entitled "Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines" and adopted November 29, 2005:

(1) Implementation of the American Petroleum Institute's Recommended Practice 165 for the use of graphics on the supervisory control and data acquisition screens.

(2) Implementation of a standard for pipeline companies to review and audit alarms on monitoring equipment.

(3) Implementation of standards for pipeline controller training that include simulator or noncomputerized simulations for controller recognition of abnormal pipeline operating conditions, in particular, leak events.

49 USC 60117 note.

SEC. 20. ACCIDENT REPORTING FORM.

Not later than December 31, 2007, the Secretary of Transportation shall amend accident reporting forms to require operators of gas and hazardous liquid pipelines to provide data related to controller fatigue.

SEC. 21. LEAK DETECTION TECHNOLOGY STUDY.

Reports.

Not later than December 31, 2007, the Secretary of Transportation shall submit to Congress a report on leak detection systems utilized by operators of hazardous liquid pipelines. The report shall include a discussion of the inadequacies of current leak detection systems, including their ability to detect ruptures and small leaks that are ongoing or intermittent, and what can be done to foster development of better technologies as well as address existing technological inadequacies.

SEC. 22. CORROSION CONTROL REGULATIONS.

(a) REVIEW.—The Secretary of Transportation, in consultation with the Technical Hazardous Liquid Pipeline Safety Standards Committee and other appropriate entities, shall review the internal corrosion control regulations set forth in subpart H of part 195 of title 49 of the Code of Federal Regulations to determine if such regulations are currently adequate to ensure that the pipeline facilities subject to such regulations will not present a hazard to public safety or the environment.

(b) REPORT.—Not later than December 31, 2007, the Secretary shall submit to Congress a report containing the results of the review and may modify the regulations referred to in subsection (a) if necessary and appropriate.

SEC. 23. INSPECTOR GENERAL REPORT.

(a) ASSESSMENT.—Not later than December 31, 2007, the Inspector General of the Department of Transportation shall conduct an assessment of the actions the Department has taken in implementing the annex to the memorandum of understanding between the Secretary of Transportation and the Secretary of Homeland Security, dated September 28, 2004, relating to pipeline security.

(b) SPECIFIED DUTIES OF INSPECTOR GENERAL.—In carrying out the assessment, the Inspector General shall—

(1) provide a status report on implementation of the program elements outlined and developed in the annex;

(2) describe the roles, responsibilities, and authority of the Department of Transportation relating to pipeline security;

(3) assess the adequacy and effectiveness of the process by which the Department of Transportation has communicated and coordinated with the Department of Homeland Security on matters relating to pipeline security;

(4) address the adequacy of security standards for gas and oil pipelines in coordination, as necessary, with the Inspector General of the Department of Homeland Security; and

(5) consider any other issues determined to be appropriate by the Inspector General of the Department of Transportation or the Secretary of Transportation.

(c) ASSESSMENT REPORT AND PERIODIC STATUS UPDATES.—

(1) ASSESSMENT REPORT.—Not later than December 31, 2007, the Inspector General of the Department of Transportation shall transmit a report on the results of the assessment, together with any recommendations (including legislative options for Congress to consider), to the Committees on Transportation and Infrastructure and Energy and Commerce of the House of Representatives and the Committee on Commerce, Science, and Transportation of the Senate.

(2) PERIODIC STATUS REPORTS.—The Inspector General shall transmit periodically to the Committees as referred to in paragraph (1), as necessary and appropriate, reports on matters pertaining to the implementation by the Department of Transportation of any recommendations contained in the report transmitted pursuant to paragraph (1).

(d) FORMAT.—The report, or portions of the report, under subsection (c)(1) may be submitted in a classified format if the Inspector General determines that such action is necessary.

49 USC 60101 note.

SEC. 24. TECHNICAL ASSISTANCE PROGRAM.

(a) IN GENERAL.—The Secretary of Transportation may award, through a competitive process, grants to universities with expertise in pipeline safety and security to establish jointly a collaborative program to conduct pipeline safety and technical assistance programs.

(b) DUTIES.—In cooperation with the Pipeline and Hazardous Materials Safety Administration and representatives from States and boards of public utilities, the participants in the collaborative program established under subsection (a) shall be responsible for development of workforce training and technical assistance programs through statewide and regional partnerships that provide for—

(1) communication of national, State, and local safety information to pipeline operators;

(2) distribution of technical resources and training to support current and future Federal mandates; and

(3) evaluation of program outcomes.

(c) TRAINING AND EDUCATIONAL MATERIALS.—The collaborative program established under subsection (a) may include courses in recent developments, techniques, and procedures related to—

(1) safety and security of pipeline systems;

(2) incident and risk management for such systems;

(3) integrity management for such systems;

(4) consequence modeling for such systems;

(5) detection of encroachments and monitoring of rights-of-way for such systems; and

(6) vulnerability assessment of such systems at both project and national levels.

(d) REPORTS.—

(1) UNIVERSITY.—Not later than March 31, 2009, the universities awarded grants under subsection (a) shall submit to the Secretary a report on the results of the collaborative program.

(2) SECRETARY.—Not later than October 1, 2009, the Secretary shall transmit the reports submitted to the Secretary under paragraph (1), along with any findings, recommendations, or legislative options for Congress to consider, to the Committees on Transportation and Infrastructure and Energy and Commerce of the House of Representatives and the Committee on Commerce, Science, and Transportation of the Senate.

(e) AUTHORIZATION OF APPROPRIATIONS.—There are authorized to be appropriated such sums as may be necessary to carry out this section for each of fiscal years 2007 through 2010.

SEC. 25. NATURAL GAS PIPELINES.

Deadline. Recommendations.

The Secretary of Transportation shall review and comment on the Comptroller General report issued under section 14(d)(1) of the Pipeline Safety Improvement Act of 2002 (49 U.S.C. 60109 note; 116 Stat. 3005), and not later than 60 days after the date of enactment of this Act, transmit to Congress any legislative recommendations the Secretary considers necessary and appropriate to implement the conclusions of that report.