STATE OF ALASKA

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To: Users of the Technical Review of Leak Detection Technologies Report, Volumes I and II, September, 1999

Subject: Disclaimer Statement

The following disclaimer statement applies to the Technical Review of Leak Detection Technologies reports consisting of two volumes: Volume I-Aboveground Bulk Fuel Storage Tanks and Volume II-Crude Oil Transmission Pipelines. These reports were prepared by Oasis Environmental of Anchorage, Alaska.

DISCLAIMER:

The Alaska Department of Environmental Conservation does not endorse, recommend, or approve of any of the materials, methods, illustrations, or concepts for providing leak detection on oil transportation pipelines or at oil storage tank facilities that are represented herein. No warranty regarding suitability or purpose is expressed or implied.

Sincerely,

Ted Moore

Ted Moore
Project Coordinator

Technical Review of Leak Detection Technologies

Volume I

Crude Oil Transmission Pipelines

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ACRONYM DEFINITIONS

ADEC	Alaska Department of Environmental Conservation
API	American Petroleum Institute
BAT	Best Available Technology
CFR	Code of Federal Regulations
CPM	Computational Pipeline Monitoring
DOT-OPS	U.S. Department of Transportation Office of Pipeline Safety
EPA	U.S. Environmental Protection Agency
LDS	Leak Detection System
MTU	Master Terminal Unit
PLC	Programmable Logic Controller
RTTM	Real Time Transient Modeling
RTU	Remote Terminal unit
SCADA	Supervisory Control and Data Acquisition

PREAMBLE

Analysis of recent data from the U.S. Department of Transportation Office of Pipeline Safety (DOT-OPS) indicates that, despite stricter regulations and enforcement, the rate at which pipeline accidents occurs has not significantly changed over the last two decades (Hovey and Farmer, 1999). The statistics suggest that short pipelines will have at least one reportable accident during a 20-year lifetime and longer pipelines (800 or more miles of line pipe) can expect a reportable incident every year.

Research indicates that the best opportunities to mitigate pipeline accidents and subsequent leaks are through prevention measures such as aggressive controller training and strict enforcement of safety and maintenance programs (Hovey and Farmer, 1999; Borener and Patterson, 1995). The next most productive enhancement comes from implementing better pipeline monitoring and leak detection equipment and practices. Early detection of a leak and, if possible, identification of the location using the best available technology allows time for safe shutdown and rapid dispatch of assessment and cleanup crews. An effective and appropriately implemented leak detection program can easily pay for itself through reduced spill volume and an increase in public confidence.

Recognizing the importance of leak detection in the prevention of oil spills and the need for a more thorough understanding of the use and effectiveness of leak detection technologies used by the Alaska oil industry, the Alaska Department of Environmental Conservation (ADEC) developed best available technology (BAT) regulations for inclusion in their spill prevention assessment program. ADEC issued a contract to identify, analyze, and report on technologies and systems that can be used to detect leaks in crude oil transmission pipelines to meet the requirements of 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv). Identifying strengths and weaknesses in leak detection technologies will help the Industry Preparedness and Pipeline Program of ADEC make further improvements in preventing oil spills via strategic implementation of the BAT regulations.

Ideally leak detection vendors could state exactly how their systems would perform on a given pipeline configuration prior to installation. In practice, predicting performance is often difficult due to variability in product characteristics (density, viscosity), pipeline parameters (diameter, length, elevation profile), and process instrumentation variables (flow, temperature, pressure). The focus of this manual is to identify the various types of leak detection systems (LDSs), define a set of criteria for evaluating the performance of these systems that can be adapted to a wide range of operating pipeline systems, and provide a general evaluation of each leak detection technology to facilitate both choosing the appropriate system and evaluating the system according to BAT regulations. This manual should be regarded as a dynamic tool for BAT evaluations and should be updated periodically.

1 INTRODUCTION

1.1 OBJECTIVES

The overall purpose of this project is to identify strengths and weaknesses in industry crude oil pipeline leak detection operations and gain enough information for strategic implementation of the State of Alaska best available technology (BAT) regulations. This manual is to be used as a guidance document by the Alaska Department of Environmental Conservation (ADEC), oil industry representatives, and the public.

Project background information, regulatory framework, and research methodology are discussed in the main body of this document. Also presented are detailed discussions of the various types of leak detection systems available today. Individual evaluations for each leak detection technology are presented by vendor name under the tab "Leak Detection System Evaluations".

1.2 PROJECT BACKGROUND

In response to questions from industry and the regulatory community regarding the BAT regulations, ADEC issued a contract to identify, analyze, and report on technologies and systems that can be used to detect leaks on crude oil transmission pipelines. The technology set reviewed under this scope of work was intended to include any potential candidate technology selected by the oil industry interests in Alaska to meet the requirements of 18 AAC 75.055(a) and 18 AAC 75.425(e)(4)(A)(iv).

Due to recent changes in the regulations, BAT reviews are a required element of Oil Discharge Prevention and Contingency Plan documentation. The Plan must identify and include a written analysis of all available leak detection technologies using the applicable criteria in 18 AAC 75.445(k)(3); and include written justification that the proposed technology is the best available for the applicant's operation. The technical and performance information may be used by ADEC, industry representatives, and the public as a reference aid to determine an individual technology's suitability with respect to the general requirements of 18 AAC 75.055(a), and specific requirements of 18 AAC 75.445(k)(3). In addition, the information in this report may assist pipeline controllers in preparing the written analysis contained in BAT reviews for pipeline leak detection systems (LDSs).

1.3 REGULATORY FRAMEWORK

The U.S. Department of Transportation's Office of Pipeline Safety (DOT-OPS) regulates the transportation of hazardous liquids under the Code of Federal Regulations as legislated through the Pipeline Safety Act and its reauthorizations (49 CFR 195). These regulations were originally adapted from national standards, such as the ASME B31.4, but have evolved over time to address specific concerns of the public and Congress, typically in response to a highly visible pipeline release.

Beginning July 6, 1999, under 49 CFR Part 195, DOT-OPS will require all controllers of hazardous liquids pipelines engaged in pipeline leak detection known as computational pipeline monitoring (CPM) to use, by reference and with other information, American Petroleum Institute (API) document API 1130 *Computational Pipeline Monitoring*. Noteworthy sections of the rule include 195.2 which defines CPM; 195.3 which incorporates API 1130 into Part 195; Subpart C Design Requirements (195.134) which outlines the requirement for a CPM system; and Subpart F Operation and Maintenance (195.444) which outlines compliance with API 1130.

API 1130 defines CPM as an algorithmic, computer-based monitoring tool which allows the pipeline controller to respond to an anomaly that may indicate product release. Controllers who have no such computer-based leak-detection system are not required to install one, but those currently running such a system, or installing one in the future, must consult API 1130 in designing, evaluating, operating, maintaining, and testing their CPM systems.

BAT regulations applicable to Alaskan oil facilities and vessels became effective on April 4, 1997. All oil discharge prevention and contingency plans or plan renewals submitted to ADEC after this date must undergo a BAT review before they are approved. Elements of operations requiring the BAT review are specified in 18 AAC 75.425(e)(4). The pipeline leak detection requirement under 18 AAC 75.055(a) states that a crude oil transmission pipeline must be equipped with an LDS capable of promptly detecting a leak, including:

- If technically feasible, the continuous capability to detect a daily discharge equal to not more than one percent of daily throughput;
- Flow verification through an accounting method, at least once every 24 hours; and
- For a remote pipeline not otherwise directly accessible, weekly aerial surveillance, unless precluded by safety or weather conditions.

Under the leak detection requirement, applicants must identify all available and proven technology alternatives. Each alternative must then be evaluated in relation to the technology in place or proposed based on the criteria provided in 18 AAC 75.445(k)(3) and summarized below:

- Availability;
- Transferability;
- Effectiveness;
- Cost;
- Age and Condition;
- Compatibility;
- Feasibility; and
- Environmental Impacts.

Once this evaluation has been completed, the applicant must then provide written justification for each applicable technology determined to be the best available for the applicant's operation.

2 RESEARCH/DATA COLLECTION

The approach to researching available pipeline leak detection technologies included performing internet and literature searches for viable leak detection vendors and technologies, attending related workshops, and contacting and soliciting information from vendors and industry users. The reference materials obtained during the research phase of this project were cataloged and are available at ADEC Division of Spill Prevention and Response in Anchorage.

2.1 INTERNET SEARCH

An Internet search for leak detection vendors and oil companies using LDSs was performed. The search identified approximately 50 potential vendors and several oil companies, both domestic and foreign. Another 20 to 30 vendors were identified in the literature. Several of these vendors were immediately eliminated because they were no longer “in the business” or they dealt solely with fuel storage tank leak detection measures.

2.2 LITERATURE SEARCH

A great deal of leak detection literature was obtained from a variety of sources including API, the U.S. Environmental Protection Agency (EPA), the Oil and Gas Journal database, and Gulf Publishing. A complete set of references is available for review at ADEC. An alphabetized list of references is presented in Section 5.

2.3 WORKSHOPS AND CONFERENCES

ARCO Alaska Inc. and British Petroleum-Amoco sponsored a one-day leak detection workshop on April 6, 1999. One vendor, EFA Technologies, Inc., and industry representatives from ARCO, BP-Amoco, and Alyeska Pipeline Service Company were present. The workshop included a presentation on leak detection regulatory requirements, an overview of pipeline LDSs, and analyses of operational and proposed LDSs on Alaska crude oil transmission pipelines.

ADEC’s contractor also attended the annual API Pipeline Conference in Dallas, Texas (April 20-21, 1999). A variety of leak detection information was obtained from vendors and oil industry representatives.

2.4 VENDORS

Sixty-seven leak detection vendors were contacted via email, fax, or phone and were sent a detailed questionnaire. Vendors were asked to complete the questionnaire and return it with product literature and a client reference list. Approximately 20 responses were received. Credible references identified by vendors were contacted to determine the veracity of vendor claims. A complete list of viable pipeline LDS vendors identified and evaluated is presented below.

- Acoustic Systems, Inc.
- Controlotron Corporation
- DETEX International
- EFA Technologies, inc.
- EnviroPipe Applications, Inc.
- FCI Environmental, Inc.
- LICEnergy, Inc.
- Løgstør Rør
- National Environmental Services Company (NESCO)
- PermAlert
- Physical Acoustics Corporation

- Raychem Corporation
- Siemens AG
- Simulutions Inc.
- Stoner Associates
- Tracer Research Corporation

2.5 INDUSTRY

Several companies in Alaska, the lower 48, and around the world were contacted, interviewed, and sent questionnaires to assess the effectiveness of pipeline LDSs presently being used in the field. Industry representatives were also interviewed at the annual API Pipeline Conference. A list of industry representatives that directly or indirectly participated in this project is presented below.

- Alyeska Pipeline Services Company
- Amoco Canada Petroleum Company. Ltd.
- ARCO Alaska, Inc.
- Bahrain Petroleum Company
- Boeing Petroleum Services
- British Petroleum-Amoco Alaska
- Buckeye Pipeline Company
- Cenex Pipeline
- Cook Inlet Pipeline Company
- CrossTimbers Operating Company
- Enbridge Pipeline
- Federated Pipelines Ltd.
- Marathon Oil Company
- Mid-Valley Pipeline
- Pennzoil Company
- Phillips Petroleum Company
- Shell Oil Products
- Sun Pipeline Company
- Texaco Company
- TransAlpine Company
- Trans Mountain Pipeline Company
- Unocal Corporation
- U.S. Defense Fuel Supply Command

3 PIPELINE LEAK DETECTION SYSTEMS

Methods used to detect product leaks along a pipeline can be divided into two categories, externally based (direct) or internally based (inferential). Externally based methods detect leaking product outside the pipeline and include traditional procedures such as right-of-way inspection by line patrols, as well as technologies like hydrocarbon sensing via fiber optic or dielectric cables. Internally based methods, also known as computational pipeline monitoring (CPM), use instruments to monitor internal pipeline parameters (i.e., pressure, flow, temperature, etc.), which are inputs for inferring a product release by manual or electronic computation (API, 1995a).

The method of leak detection selected for a pipeline is dependent on a variety of factors including pipeline characteristics, product characteristics, instrumentation and communications capabilities, and economics (Muhlbauer, 1996). Pipeline systems vary widely in their physical characteristics and operational functions, and no one external or internal method is universally applicable or possesses all the features and functionality required for perfect leak detection performance. However, the chosen system should include as many of the following desirable leak detection utilities as possible (API, 1995a):

- Possesses accurate product release alarming;
- Possesses high sensitivity to product release;
- Allows for timely detection of product release;
- Offers efficient field and control center support;
- Requires minimum software configuration and tuning;
- Requires minimum impact from communication outages;
- Accommodates complex operating conditions;
- Is available during transients;
- Is configurable to a complex pipeline network;
- Performs accurate imbalance calculations on flow meters;
- Is redundant;
- Possesses dynamic alarm thresholds;
- Possesses dynamic line pack constant;
- Accommodates product blending;
- Accounts for heat transfer;
- Provides the pipeline system's real time pressure profile;
- Accommodates slack-line and multiphase flow conditions;
- Accommodates all types of liquids;
- Identifies leak location;
- Identifies leak rate;
- Accommodates product measurement and inventory compensation for various corrections (i.e., temperature, pressure, and density); and

- Accounts for effects of drag reducing agent.

The following sections present a detailed discussion of the major components of a typical computer-based pipeline LDS, as well as descriptions of several externally and internally based leak detection technologies. For each technology, a list of evaluated vendor-specific systems is presented.

3.1 MAJOR COMPONENTS OF A COMPUTER-BASED LDS

The utilization of computer systems in pipeline monitoring allows the greatest amount of data to be collected, analyzed, and acted upon in the shortest amount of time. For these reasons, most pipeline systems today employ some form of computer-based monitoring using commercially available or custom-designed software packages to run the system (Furness and van Reet, 1998). Leak detection is just one of many functions that can be performed with computer-based systems, which generally consist of two major elements: instrumentation and a supervisory computer with associated software and communications links.

3.1.1 Instrumentation

Instrumentation includes the flow meters, pressure transducers, sensors, and cables situated along the pipeline (externally or internally) which measure parameters such as line pressure, temperature, flow, product characteristics, and the presence of hydrocarbons. Because the effectiveness of any pipeline LDS is limited primarily by the sensitivity and accuracy of the installed instrumentation, it is critical to select the best performing setup for a given operating scenario. Instrument specifications should be prudently compared to a pipeline's operating design to make the best use of the manufacturer's declared accuracy and linearity (API, 1995a). Additionally, all practical means should be taken to reduce sources of instrument noise[1], which can inhibit the performance of an LDS. Mechanical resonance and electrical interference are primary sources of instrument noise. Mechanical resonance must be considered during the design of process piping and placement of the instrument package. Proper instrument grounding and the use of shielded signal cables will serve to reduce electrical noise. If these measures of noise reduction are not successful, signal conditioning (bandwidth adjustment, digital filters, or data smoothing programs) may be required.

Another means of reducing the impact of mechanical noise on pipeline systems is the use of inline surge or divert tanks. Popular in the lower 48 states and used on at least one North Slope line, surge tanks lessen the impact of pressure wings and system noise on meters that could potentially result in measurement errors, damage, or undue wear. Surge tanks may result in an increase in leak detection sensitivity by allowing the operator to lower alarm thresholds.

McAllister (1998) provides some general guidelines to follow when selecting field instrumentation:

- Choose instrumentation based on performance and not economic grounds. It is better to install fewer high quality pieces of equipment than numerous poor ones.
- Equipment compatibility is important. Use transducers, interface modules, and other hardware that use standard communications protocol.

[1] Noise is that part of a signal that does not represent the quantity being measured (API, 1995a). Fluctuations around a fixed or moving mean are considered noise.

- Where possible, install instruments that are self-checking or self-diagnosing, or install dual systems.
- Seek independent references, user experience, or validation of the instruments chosen. Most equipment performs differently in real applications than under the published ideal conditions.

Pipeline flow meters and pressure transducers are described below. Other sensors, cables, and instruments specific to LDSs are described in Sections 3.2 or 3.3, as appropriate. To supplement this discussion, API Publication 1149, *Pipeline Variable Uncertainties and Their Effects on Leak Detectability*, also documents the importance of field instrumentation to leak detection performance.

3.1.1.1 Flow Meters

Flow measurement is the most important process variable in the operation and control of pipelines; therefore, flow meters are one of the most important instruments installed on a system (McAllister, 1998). Several different types of flow meters are used on pipelines including orifice plates (differential pressure), turbine, positive displacement, mass flow (Coriolis type), and ultrasonic time-of-flight (clamp-on)[2]. This section describes the various types of flow meters, their accuracies, advantages, and disadvantages.

The flow meters most often installed on pipelines are sharp-edged orifice plates, a differential pressure type of meter. Although the use of these types of meters is very common in processes such as the metering of natural gas, their use as accurate instrumentation for pipeline leak detection is questionable. The biggest problem is the measurement uncertainty associated with these instruments. Vendors claim orifice plates are accurate to within 0.5% of flow; however, when all the other variables that can affect uncertainty measurement are considered—fluid composition changes, temperature and pressure variations, conversion and computational errors, etc.—it is unreasonable to assume that accuracies better than 3 to 5% can be achieved (McAllister, 1998).

Turbine meters are flow-measuring devices with rotors that sense the velocity of flowing liquid in a closed conduit. The flowing liquid forces the rotor to move with a tangential velocity proportional to the volumetric flow rate (API, 1995c). Turbine meters are used extensively on pipelines, especially those carrying petroleum hydrocarbons (McAllister, 1998). Among the instruments in this family of flow meters are the custody transfer meters used to bring oil to market. Turbine flow meters tend to be more accurate than other types (i.e., custody transfer meters are reportedly accurate to within 0.05% of throughput), but still suffer from limitations such as calibration shift. Their volumetric accuracy depends on the measured dimensions of the pipeline section, the amount of drag in the turbine's rotor, and the degree of system proving. Fortunately, recent developments have resulted in self-diagnosing twin rotor meter designs, which can detect shifts in calibration caused by bearing wear and blade damage (McAllister, 1998). The microprocessors in these twin rotor meters can also check the integrity of the data generated by the meters and provide alarm output for verified problems. Other variables that may affect turbine meter performance are variations in flow rate, viscosity, temperature, density, and pressure (API, 1995c).

[2] Regardless of how volumetric flow is measured or computed, API standards require that all meters be "proven" or regularly calibrated against a known and accepted standard.

Positive displacement meters measure flow by moving the liquid through a pipe section of known volume. The claimed accuracy of these meters is 0.1 to 0.2% of flow. The accuracy of these meters depends on the accuracy to which the dimensions of the pipe section are known, the extent to which it effectively contains the product, and the temperature and pressure conditions under which the measurements are made (Diane Hovey, EFA Technologies, written commun., 1999).

Another flow meter that is slowly gaining acceptance and being incorporated into the pipeline industry is the Coriolis direct mass meter (McAllister, 1998). The accuracy of these instruments is approximately +/-0.5% of reading or better. The advantage of direct mass measurement over the more common volumetric assessment is that the integration of the instrument signal provides the pipeline fluid inventory directly. Additional measurements of temperature, pressure, and equation of state to determine fluid density are not necessary. The principal disadvantage is the current size range of the meters. Most major pipelines are in the 500 to 2,000 millimeter (mm) bore range, but the largest available direct mass meter is only 150 mm bore. This means that several Coriolis meters would have to be installed in parallel to be effective. Additionally, API does not envision that these meters will be used for custody transfer measurements in the near future.

The ultrasonic transit-time flow meters are installed on the outside of the pipeline. These clamp-on flow meters are reportedly accurate to within 0.001 ft/sec at any flow rate, including zero. However, measurement engineers hold the installed accuracy of these meters to be no better than 2% of flow (McAllister, 1998). Ultrasonic meters have the advantages of negligible headloss and the ability to install additional instrumentation without line shutdown.

3.1.1.2 Pressure Transducers

Pressure-measuring devices may be divided into three groups: those based on measurement of the height of a liquid column; those based on measurement of the distortion of an elastic pressure chamber; and electronic sensing devices. Conventional pressure transducers found on pipelines generally are of the electronic sensing type with various means of discerning pressure (piston, diaphragm, strain gauge, piezoelectric sensors, variable capacitance, and variable element). Pipeline pressure is measured by the displacement of these devices in response to fluid pressure and is converted electronically to an appropriate current, voltage, or digital output signal. The sensors typically are ceramic, silicon, or stainless steel. Ceramic is corrosion and abrasion resistant, has superb electrical isolation, and a high natural frequency. Silicon, an elastic drift-free material, offers low cost and is the most common material used. The accuracy of these transducers is typically +/-0.1% of span.

Recent developments in microprocessing have resulted in the creation of a new generation of “smart” pressure transducers. These intelligent sensors rely on the properties of silicon and microelectronics for optimum performance (McAllister, 1989). The advantages of these transducers are listed below.

- Signal processing is digital and algorithms can be written to cope with any signal/pressure curve, provided it is repeatable;
- Advanced communications capabilities, including remote access and online instrument rearranging;
- On-line temperature compensation;

- Built in diagnostics; and
- Claimed accuracies of better than +/-0.1% of span.

Another type of pressure transducer that has potential pipeline applications is the vibrating wire sensor. This transducer operates on the premise that as pressure changes, the tension on a tungsten wire enclosed in a silicon diaphragm is altered, and the result is a measurable change in the resonating frequency of the wire (McAllister, 1998). The change in frequency is sensed and amplified, and data are provided to the pipeline controller. Pressure and temperature compensation is accomplished within the instrument. While it has shown considerable reduction in size and manufacturing costs from other sensors, this technology is still in the experimental stage and has not been extensively applied in the field.

3.1.2 SCADA/Communications

The Supervisory Control and Data Acquisition (SCADA) system is a computer-based communications system that monitors, processes, transmits, and displays pipeline data for the controller (API, 1995a; Borener and Patterson, 1995). SCADA systems may be used directly for leak detection, they may provide support for an LDS, or an LDS may operate independently of SCADA. Generally, a pipeline LDS will use the data generated by a SCADA system to aid in assessing the potential for a product release.

SCADA systems collect real-time data from field instruments using Remote Terminal Units (RTUs), Programmable Logic Controllers (PLCs), and other electronic measurement devices, which are placed at intervals along the pipeline. Communication with these devices can occur in many ways, including microwave, cellular, satellite, leased line, etc., but the most common media are dedicated phone circuits and terrestrial- and satellite-based radio systems (API, 1995a). An emerging trend is to use multiple methods of communicating based on the concept that each method will have a cost or performance advantage for a given installation (Whaley and Wheeler, 1997).

Data from RTUs or PLCs are gathered into a Master Terminal Unit (MTU) which consists of one or more central computers built around a real-time, memory-resident database. The MTU displays the current operating conditions for the controller, who, in turn, can act on these data if necessary. Messaging between the field devices and the MTU is known as the communications protocol (API, 1995a). The protocol is considered “polled” when the MTU requests data from each device consecutively. When the last device is scanned, the MTU will automatically request information from the first one, creating a ceaseless polling cycle. The SCADA system polling rate, the time between successive communications between the RTU and MTU, has steadily improved over the years and has been reduced to less than 0.25 seconds in high priority areas on some pipelines (Ed Farmer, presentation, April 1999). SCADA communications may also be non-polled. For example, RTUs may report without being polled on a time-scheduled basis or when field conditions change. LDSs that rely on the SCADA system to receive operating data are directly affected by the polling rate. Longer polling cycles typically translate to degraded leak detection sensitivity.

Most modern SCADA systems include quality checking software to assess the validity of the data before any calculations are computed and displayed (McAllister, 1998). Research suggests that this type of continuous quality control greatly improves the sensitivity of the system. In addition, advanced SCADA systems can include predictive modeling to assess “what if” operating scenarios, handle automatic startup and shutdown routines, and evaluate operating strategies for cost-benefit optimization (McAllister, 1998).

For additional discussion of SCADA system design factors and their effects on the quality and timeliness of the data required by an LDS, see API Document 1130, *Computation Pipeline Monitoring* (1995a).

3.2 INTERNAL LEAK DETECTION SYTEMS

Results of the literature search have shown that the main category of inferential leak detection in pipelines is known as computational pipeline monitoring (CPM). CPM refers to algorithmic monitoring tools that are used to enhance the abilities of a pipeline controller to recognize anomalies which may be indicative of a product release (API, 1995a). CPM operates by providing an alarm and displaying other related data to the controller who, in turn, would investigate the reason for the alarm and initiate a response if the anomaly represents a product release. CPM does not include externally based LDSs which operate on the non-algorithmic principle of physical detection of a product leak (API, 1995a). Externally based leak detection methods are presented in Section 3.3.

CPM mainly relies on the data collected from the field instruments, which are continuously input into a computer program that mathematically or statistically analyzes the information. Analysis results are produced in the form of parameter estimates, which in turn are subjected to some probability law or decision criteria to determine if a leak is present (API, 1995b). The degree of complexity in analyzing field data ranges from the comparison of a single element (i.e., pressure) relative to a threshold limit to extensive analyses of multiple elements with dynamic thresholds. Without the computer program and associated algorithms, the data would be difficult if not impossible to interpret in a timely manner. Consequently, the heart of any CPM system is the computer program. The classes of CPM are differentiated by the types of instruments and programs (or algorithms) used. There are three basic types of CPM: volume (or mass) balance, pressure analysis (rarefaction wave monitoring), and real time transient modeling (RTTM). Note that some of the leak detection systems offered by vendors include more than one type of leak detection method (i.e., both volume balance and pressure analysis). Additionally, most of the volume balance and RTTM leak detection systems use some sort of pressure analysis to locate leaks.

3.2.1 Volume Balance

The volume balance method of leak detection, also known as line balance, compensated volume balance, or mass balance, is based on measuring the discrepancy between the incoming (receipt) and outgoing (delivery) product volumes of a particular pipeline segment (API, 1995a). During a unit time interval, the volume of product that enters a pipe may not be equal to the measured volume exiting the pipe. The difference is accounted for by uncertainties in line pack and flow measurement. This relationship is stated below:

$$\left|Q_{in} - Q_{out}\right| \leq dQ_m + \frac{dV_s}{\Delta t}$$

Where,
Q_{in} = Measured Inflow
Q_{out} = Measured Outflow

dQ_m = Bound of uncertainty in flow measurement
dV_s = Bound of uncertainty in line pack change over a time interval Δt

If a leak exists it can only be detected if the following relationship is fulfilled:

$$Q_l = Q_{in} - Q_{out} > dQ_m + \frac{dV_s}{\Delta t}$$

Where,
Q_l = Flow rate of the leak

The principal differences among the various volume balance methods are outlined below.

- Basic line balance does not compensate for changes in line pack due to pressure, temperature, or product composition.
- Volume balance is an enhanced, automated technique, which does account for line pack correction by assessing changes in volume due to temperature and/or pressure variations. A representative bulk modulus is used for line pack calculations.
- Compensated volume balance is an enhanced volume balance technique which accounts for volume change using a dynamic bulk modulus to assess line pack correction.
- Mass balance accounts directly for product density (i.e., with online densitometers).

Ultrasonic systems detect leaks via transient-compensated volume or mass balance; therefore, they are included under this heading. These systems typically operate through accurate tracking of flow rate, computation of pressure, temperature, and product characteristics, and determination of sonic profiles using external clamp-on instruments configured with data processing equipment.

Compared to other leak detection methods, volume balance is particularly useful in identifying small leaks. However, leaks are generally detected more slowly and flow metering at each end of the line or pipeline segment will not identify the location of the leak. Most of the software-based volume-balance systems incorporate additional algorithms for leak location based on pressure analysis.

Volume balance LDSs that were evaluated for this project include EFA Technologies, Inc.'s MassPack™ (part of their LEAKNET™ system) and EnviroPipe Applications, Inc.'s LEAKTRACK 2000. Ultrasonic systems include Controlotron Corporation's System 990LD™ and DETEX International's Series 2000. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.2.2 Pressure Analysis (Rarefaction Wave Monitoring)

The rarefaction wave (also called an acoustic, negative pressure, or expansion wave) method of leak detection is based on the analysis of pipeline pressure variations. When product breaches the pipeline wall there is a sudden drop in pressure at the location of the leak followed by rapid line repressurization a few milliseconds later. The resulting low-pressure expansion wave travels at the speed of sound through the liquid away from the leak in both directions. Instruments placed at intervals along the pipeline respond as the wave passes. If a leak occurs in the middle of a line segment with uniform construction, the rarefaction wave should be seen at opposite ends of the line simultaneously. If the leak is closer to one end, it should be seen first at the close end and later at the far end. The time evidence recorded at each end of the monitored line or segment is used to calculate the location of the leak. Most volume balance and RTTM leak detection systems use pressure analysis to locate leaks. Models also use pressure measurements as boundary conditions.

Since the rarefaction wave travels at significant speeds, on the order of one mile per second, this method of leak detection is particularly useful in identifying large leaks rapidly. Smaller leaks typically take longer to detect and very small, pinhole leaks may go undetected. The success of a rarefaction wave LDS largely depends on the frequency and sensitivity of instrument measurements. Because of the sensitivity of this type of technology to operational changes that result in large transient pressure waves, leak detection performance generally falls off under highly transient, slack-line, and multi-phase flow conditions.

The principal difference among the various rarefaction wave technologies is how the wave is identified and monitored. Some sensors or transducers monitor for the leading edge of the wave while others evaluate the shape of the wave.

Pressure analysis (rarefaction wave monitoring) LDSs that were evaluated for this project include EFA Technologies Inc.'s Pressure Point Analysis (PPA)™ (part of the LEAKNET™ system), Acoustic Systems Inc.'s WaveAlert®, and Tracer Research Corporation's LeakLoc®. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.2.3 Real Time Transient Modeling

The most sensitive, but also the most complex and costly leak detection method in use is real time transient modeling (RTTM). RTTM involves the computer simulation of pipeline conditions using advanced fluid mechanics and hydraulic modeling (Borener and Patterson, 1995). Conservation of momentum calculations, conservation of energy calculations, and numerous flow equations are typically used by the RTTM system. RTTM software can predict the size and location of leaks by comparing the measured data for a segment of pipeline with the predicted modeled conditions. This analysis is done in a three-step process. First, the pressure-flow profile of the pipeline is calculated based on measurements at the pipeline or segment inlet. Next, the pressure-flow profile is calculated based on measurements at the outlet. Third, the two profiles are overlapped and the location of the leak is identified as the point where these two profiles intersect. If the measured characteristics deviate from the computer prediction, the RTTM system sends an alarm to the pipeline controller. The more instruments that are accurately transmitting data into the model, the higher the accuracy of and confidence in the model. Note that models rely on properly operating and calibrated instruments for optimum performance. Calibration errors can result in false alarms or missed leaks, and the loss of a critical instrument could require system shutdown.

The advantage RTTM provides over other methods is its ability to model all of the dynamic fluid characteristics (flow, pressure, temperature) and take into account the extensive configuration of physical pipeline characteristics (length, diameter, thickness, etc.), as well as product characteristics (density, viscosity, etc.) (API, 1995a). Additionally, the model can be tuned to distinguish between instrument errors, normal transients, and leaks. The distinct disadvantages of this LDS are the costs associated with implementing RTTM and the complexity of the system, which requires numerous instruments and extensive controller training and system maintenance.

RTTM LDSs that were evaluated for this project include LICEnergy Inc.'s Pipeline Leak Detection System (PLDS), Simulutions Inc.'s LEAKWARN, and Stoner Associate's SPS/Leakfinder. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.3 EXTERNAL LEAK DETECTION SYSTEMS

3.3.1 Acoustic Emissions

Leak detection in pipelines using acoustic emissions technology is based on the principle that escaping liquid creates an acoustic signal as it passes through a perforation in the pipe. Acoustic sensors affixed to the outside of the pipe monitor internal pipeline noise levels and locations. These data are used to create a baseline "acoustic map" of the line. When a leak occurs, the resulting low frequency acoustic signal is detected and analyzed by system processors. Deviations from the baseline acoustic profile would signal an alarm. The received signal is stronger near the leak site thus enabling leak location.

Acoustic sensing can be applied externally to buried pipelines by using steel rods driven into the ground to conduct the sound to a sensor mounted on the rod. The rods are inserted at intervals along the pipeline.

Physical Acoustic Corporation's Acoustic Emissions LDS was evaluated for this project. The BAT evaluation for this technology is presented under the tab "Leak Detection System Evaluations".

3.3.2 Fiber Optic Sensing

With this technology, fiber optic sensing probes are driven into the soil beneath or adjacent to the pipeline. In the presence of hydrocarbons, the patented covering of the sensor changes its refractive index. This change is registered optically by the sensor and converted to a parts-per-million reading of hydrocarbons.

FCI Environmental, Inc.'s PetroSense® was the only LDS based on fiber optics evaluated for this project. The BAT evaluation for this technology presented under the tab "Leak Detection System Evaluations".

3.3.3 Liquid Sensing

Liquid sensing cables are buried beneath or adjacent to a pipeline and are specifically designed to reflect changes in transmitted energy pulses as a result of impedance differentials induced by contact with hydrocarbon liquids. Safe energy pulses are continuously sent by a microprocessor through the cable. The pulses are reflected and returned to the microprocessor. Based on the specific installation of the cable, a baseline reflection map is stored in the memory of the microprocessor. When a leak occurs, the cable is saturated with fluid. The fluid alters the impedance of the sensing cable, which in turn alters the reflection pattern returning to the microprocessor. The change in signal pattern causes the microprocessor to register a leak alarm at the location of the altered impedance. Controller interface software is available to provide real-time information on leak detection and record keeping. Specific cable types are chosen for each application based on the specific fluid being monitored.

Liquid sensing leak detection is typically marketed as a self-contained leak detection and location system, including all hardware and software. Advantages include relatively high accuracy in determining leak location, no modifications to existing pipeline, and easy software configuration and maintenance. Disadvantages include very high installation costs and extensive power and signal wiring requirements.

Liquid-sensing cable LDSs that were evaluated for this project include PermAlert's PAL-AT®, Raychem Corporation's TraceTek, and Løgstør Rør's LR-Detector. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.3.4 Vapor Sensing

Hydrocarbon gas sensing systems are more frequently used in storage tank systems but can also be applicable to pipelines. Leak detection using vapor-monitoring techniques is a fairly straightforward concept. When a liquid seeps into the soil, vapors migrate from into the surrounding soil pore spaces. Probes are arranged in the soil so that a vacuum may be applied to them. The soil vapors are collected for laboratory or field analysis. Tracers or chemical markers may be added to the product being monitored so that it may be identified from naturally occurring background vapors. When the tracers or markers are encountered during analysis of the vapors, it can be surmised that a leak has occurred.

The vapor sensing tube leak detection method involves the installation of a secondary conduit along the entire length of the pipeline. The conduit may be a small-diameter perforated tube attached to the pipeline or it may completely encompass the pipeline, allowing the annular headspace to be tested. Air gas samples are drawn into the tube and analyzed by hydrocarbon vapor sensors to determine the presence of a leak. Because of the logistical problems associated with any system installed along the entire length of a pipeline, vapor-sensing tubes are usually only employed on short lines.

Vapor-sensing LDSs that were evaluated for this project include National Environmental Services Company's Soil Sentry 12XP, Tracer Research Corporation's Tracer Tight®, and Siemens AG LEOS® system. The BAT evaluations for these technologies are presented under the tab "Leak Detection System Evaluations".

3.4 PERFORMANCE ISSUES

The LDSs discussed in this report are affected by operational factors that may contribute to a deterioration of performance. This section discusses these factors as performance issues limiting the quality of data acquired by the LDS. A more detailed discussion of the limitations of CPM systems may be found in API Publication 1130, *Computational Pipeline Monitoring*.

3.4.1 Multiphase and Slack-Line Effects

Multiphase flow, the simultaneous flow of oil and gas or of oil, gas, and water through one pipe, can occur as a number of different flow patterns (McAllister, 1998):

1. Bubble flow — bubbles of gas flow along the upper part of the pipe at about the same velocity as the product;
2. Plug Flow — the bubbles of gas coalesce into large bubbles which occupy the large part of the cross-sectional area of the pipe;

3. Laminar Flow — the gas-liquid interface is relatively smooth with gas flowing in the upper portion of the pipe;
4. Slug Flow — the tops of some waves on the surface of the liquid reaches the top of the pipe. These slugs move with high velocity;
5. Annular Flow — the liquid flows along the walls of the pipe and the gas moves through the center with high velocity; and
6. Spray Flow — the liquid is dispersed within the gas.

Multiphase flow can occur in a petroleum pipeline for a number of reasons. In the case of crude oil gathering lines, water and gas can be produced with the oil in production wells of mature fields where water flood enhanced oil recovery is used to maintain field pressures, and/or the gas/oil ratio has become elevated following the removal of oil from the reservoir. Multiphase flow may be communicated to a delivery line fed by a production facility in the event its water or gas removal system malfunctions, or cannot keep up with surges of gas and water from gathering lines.

Because water, oil, and natural gas have significantly different physical characteristics, multiphase flow can cause line pressures to change as they pass a point in the line; thus, confounding attempts to gauge internal line pressures on a real-time basis. The erratic pressure swings caused by multiphase flow adversely affect the signal from pressure transducers and may lead to poor-quality input data and/or multiple false alarms.

Slack-line conditions occur where flow is not sufficient to keep the entire volume of the pipe filled with liquid. Under this condition, the pipeline will have “pockets” of volume not occupied by flowing liquid. These regions will be related to line topography and flow rates and, in effect, represent a transient storage term in modeling pipeline flow characteristics. Real time transient modeling is capable of dealing with this transient storage effect, albeit at degraded sensitivities, whereas volume balance methods may misinterpret loss to and gain from the slackline as a leak from or false input to the pipeline. Pressure analysis may also provide erratic results based on slackline volume changes and associated changes in the pressure-volume relationship within the slack-line areas.

3.4.2 Pre-Existing Leaks

Leaks existing during startup of a pressure analysis system will not be detected, rather, the pressure data used to calibrate and run the system will include the perturbation from the leak as the normal baseline condition. Similarly, small leaks that become larger may not be detected until their effect exceeds the rate-of-change boundary condition criteria set for the instruments. However, these situations are rare. Line and volume balance methods will detect such conditions provided the leak rate is greater than the precision limits of the metering devices used.

3.4.3 Variations in Temperature, Pressure, & Flow Conditions

Most RTTM, compensated volume balance, and pressure analysis systems are capable of correcting for pressure/temperature/volume (i.e., line pack) relationships within the pipeline. Line balance or other systems that do not account for these relationships may send false alarm signals because of apparent pressure or volume losses related to temperature changes.

3.4.4 Connected Production Areas

LDSs placed in a pipeline between two or more production areas may respond to flow rate and pressure fluctuations coming from upstream or downstream directions. Thus, operational transients in one production area or pipeline segment may be sensed as a leak by an LDS component assigned to another. Pressure analysis leak detection with leak location software should be capable of isolating the source area of suspect pressure anomalies within a section of pipeline. Sources of pressure change coming from outside the pipe segment being monitored by a given system will be flagged as foreign by the leak detection software. One way to minimize the effects of pressure anomalies on leak detection is to install in-line surge tanks, which reduce pipeline noise and enhance leak detection sensitivity (see Section 3.1.1).

3.4.5 False Alarms

As discussed, many factors contribute to an elevated signal-to-noise ratio with an internal LDS. Some factors are known (i.e., engineered production rate changes, well shut-ins, and diversion to and from tank storage), others are less predictable (slugging, effects from pipeline feed changes in connected production areas). Over time, repetitious false alarms may degrade the quality of response to future alarms irrespective of their cause. If possible, a threshold level of alarms per week or month may be prescribed based on systematic causes. This fine tuning may be achieved through the adjustment of SCADA analog deadband threshold settings or through the use of data filtering programs that eliminate, or at least flag, line perturbations caused by normal system fluctuations. Dangers exist in relying solely on changed settings to reduce the frequency of leak detection alarms. First, the precision required to detect a leak of a desired size may be lost if thresholds or filters attenuate or block the signal significantly. Second, the quality of the response to future alarms may become degraded if controllers become accustomed to long periods of time without reacting to them.

Use of rules-based logic or expert systems within an LDS will be a major enhancement in terms of reducing or eliminating the number of false alarms in the near future (Whaley and Wheeler, 1997). Most LDSs currently include simple rules for alarming when high or low limits are exceeded or when measured values change too rapidly. The problem with these simple limits is that they lead to a proliferation of frequently meaningless alarms and are unable to evaluate situations involving multiple points or sites. Rules-based logic has the potential of reducing the amount of data controllers must review while increasing the amount of meaningful information. Rules do this by automating the analysis performed by a controller to check out the meaning of limit alarms and by allowing more complex checks of multiple sites or values. Drawbacks to the use of these systems include the high cost of purchasing a third-party artificial intelligence package and the high degree of technical expertise required to set up and maintain it.

The number of false leak alarms appropriate for a given system is site and application specific. The frequency of false alarms and the appropriate response to them should be part of the operational program in a facility using any leak detection technology.

3.4.6 Instrumentation

Instrumentation used to detect changes in pressure, temperature, and flow, must be calibrated and checked routinely. API recommends that each pipeline company implement a test and calibration plan as part of a CPM operating and maintenance procedure. The calibration and testing of instrumentation in the LDS should be based on manufacturer recommendations and on historical LDS performance.

Additionally, the devices selected for incorporation into an LDS must afford sensitivity necessary to attain leak detection goals. For example, turbine meters may be selected over orifice meters for greater than one percent accuracy in flow modeling.

The sensitivity of a volume balance LDS is ultimately determined by the combined or aggregate accuracy of the flow meters themselves. Aggregate accuracy typically is evaluated in terms of the standard deviations of the individual meters involved in closing the mass balance, or the "root-sum-squared" method (D. Hovey, written commun., 1999). The basic formula is presented below.

$$\text{Aggregate Meter Accuracy} = \text{Square Root } (a_1^2 + a_2^2 + a_3^2 + ...+ a_n^2)$$

Where a_n is the accuracy of the nth meter.

For example, a system with two meters, each 2 percent accurate, would have an aggregate accuracy of 2.8 percent. If one of these meters is replaced by a meter that is 0.1 percent accurate, the aggregate accuracy would become 2.0 percent. Note that the accuracy of the least accurate meter controls this equation. Ideally, a system should be designed with the fewest number of high-quality sensing devices as practical.

3.4.7 Controller Training

Because of the complexity of LDS technology, the pipeline controller should be trained to recognize the significance of alarms and their potential causes. The significance of the measurement data and credibility of alarms generated by any LDS may be lost if the ability to perform this type of analysis is compromised. API divides alarms into three categories: data failure, transient pipeline operating condition, and possible product release. The pipeline controller must have adequate training to discriminate between the various causes of alarms and respond appropriately. Controller training should include response to a minimum number of false alarms and the use of tests simulating releases.

3.4.8 Redundant Systems

It should be emphasized that in some situations more than one LDS might be appropriate for attaining BAT. Redundant systems may offer faster detection speeds and lower leak volume thresholds than a single system. For example, a combination of mass balance (which can detect small volume leaks) and rarefaction wave analysis (which can detect large leaks very rapidly) would offer a combination of sensitivity, speed, and a leak location ability that might be considered BAT for a particular application.

4 LEAK DETECTION TECHNOLOGY EVALUATION

As noted in Section 1.3, the ADEC BAT evaluation is focused on the performance and suitability criteria listed in 18 AAC 75.445(k)(3). These criteria were combined with related performance and limitation considerations to construct a leak detection technology evaluation strategy. Note that ADEC's Age and Condition[3] criterion will not be used in the evaluation because it is a pipeline-specific parameter. Additionally, due to the variability in pipeline sizes and operating conditions, the leak detection Cost criterion is evaluated only qualitatively for each technology.

The evaluation criteria used in this assessment constitute just one set of general information that a pipeline company can use to determine the best available leak detection technology for their particular pipeline. They must also, on a pipeline-specific basis, be capable of performing the following functions:

- Identify any additional contractual or legal requirements relating to leak detection
- Characterize the pipeline in terms of its possible leak mechanisms and the likelihood that one of them will result in a leak. Factors include, but are not limited to, length and volume of the pipeline; pressure, temperature, and flow rate envelope; terrain; product characteristics; and pipeline operating and maintenance procedures;
- Determine the leak detection potential of the pipeline. A generic spreadsheet prepared by Enbridge Pipelines Inc. and based on principles outlined in API Publication 1149 (*Pipeline Variable Uncertainties and Their Effects on Leak Detectability*) is available on the floppy disc accompanying this manual or at ADEC; and
- Perform an assessment of definite and potential costs associated with incorrectly declaring leak alarms, missed alarms, late alarms, and any other deviation from ideal leak detection system performance (API, 1995b).

4.1.1 Applicability/Availability

The applicability criterion simply serves to ensure that any technology selected for use on a crude oil pipeline system was designed for that intended use. Availability refers to the commercial availability of an LDS and its components.

4.1.2 Effectiveness

Effectiveness deals primarily with the performance related aspects of an LDS and is evaluated in terms of sensitivity, accuracy, reliability, and robustness. Unfortunately, focus on attaining ideal performance in one area, say sensitivity, usually results in some degradation of the other criteria. To exemplify this, consider the following hypothetical leak detection systems (API, 1995b):

System I: This system employs a sensitive leak detection algorithm. The system is normally very reliable, but will frequently generate alarms during normal pipeline operations.

[3] This criterion refers to the age and condition of the leak detection technology in use by the applicant. If the existing leak detection system is being maintained in reliable operating condition, and is shown to have the capability to achieve the same expected results as a new technology, then ADEC may determine that there is no benefit in replacing the existing technology.

System II: This system employs an alternative algorithm which is somewhat less sensitive than that of System I, but generates only a fraction of the alarms.

System III: This system employs the same sensitive leak detection algorithm as System I, but inhibits leak detection during pipeline operations that can cause it to generate alarms.

System IV: This system normally employs the same sensitive leak detection algorithm as System I, but switches to the less sensitive algorithm of System II when it senses conditions that generate alarms.

In order to maintain a high level of sensitivity, the designers of System I have sacrificed a degree of reliability, whereas the designers of System II have decided to sacrifice some degree of sensitivity in order to achieve a high level of reliability. By disabling the leak detection capability under certain conditions, the designers of System III have sacrificed a degree of robustness in order to achieve higher levels of sensitivity and reliability. System IV represents and attempts to achieve a more robust system at the expense of sensitivity and reliability.

Most leak detection technologies attempt to attain a satisfactory tradeoff between sensitivity, accuracy, reliability, and robustness by understanding the specific operating conditions of a pipeline and the controller's expectations. The LDS ultimately selected by a pipeline company will depend upon the performance requirements specific to that company. No one LDS technology is suitable for all pipeline applications.

4.1.2.1 Sensitivity

Sensitivity is defined as the composite measure of the size of leak that a system is capable of detecting, and the time required for the system to issue an alarm in the event that a leak of that size should occur (API, 1995b). The relationship between leak size and the response time is dependent upon the nature of the LDS. Some systems manifest a strong correlation between leak size and response time, while with others, response time is largely independent of leak size. Note that there are no known systems that tend to detect small leaks more quickly than large leaks.

Sensitivity is evaluated according to ADEC regulations specifying that a technology have the continuous capability to detect a leak equal to not more than one percent of daily throughput. In terms of response time, the regulations specify only that a system be capable of detecting leaks "promptly." Response times from field performance data are presented in the evaluation, but it is the pipeline controller's responsibility to establish an appropriate response time for his/her pipeline.

4.1.2.2 Accuracy

Accuracy is a measure of LDS performance related to estimation parameters such as leak flow rate, total volume lost, and leak location (API, 1995b). A system that estimates these parameters within an acceptable degree of tolerance, as defined by the pipeline controller/company, is considered to be accurate. Often times an LDS will use existing pipeline instrumentation such as flow meters and pressure transducers in their processes. The accuracy of these systems is evaluated in terms of the accuracy, repeatability, and precision of the recommended or provided pipeline instruments themselves. Instrument accuracy represents the measurement performance of the instrument relative to that of an ideal device. Repeatability is a measure of the instrument's ability to consistently return the same reading for a given set of conditions.

Precision is a measure of the smallest change that can be seen in the output of the instrument.

For this project, leak location accuracy is discussed in terms of the capability of a technology to locate the leak within a certain percentage of a given pipe segment or within so many feet of an indicating sensor.

4.1.2.3 Reliability

Reliability is a measure of the ability of an LDS to render accurate decisions about the possible existence of a leak on a pipeline (API, 1995b). It is directly related to the probability of detecting a leak, given that a leak does in fact exist, and the probability of incorrectly declaring a leak, given that no leak has occurred. A system which incorrectly declares leaks is considered to be less reliable; however, if the system has the capability to use additional information to disqualify, limit, or inhibit an alarm, a high rate of leak declarations may be considered less significant.

Reliability pertains only to the leak detection hardware and software, not the SCADA system, pipeline instrumentation, communication equipment, or any other factor beyond the control of the vendor. Reliability can be managed through controller response and established procedures; however, unless the LDS automatically adjusts to decision thresholds, these procedures cannot be used to discriminate between systems. For this project, the reliability of a leak detection technology is evaluated in terms of the frequency and cause of reported false alarms on operating pipeline systems, and the ability of the LDS to automatically evaluate line conditions and adjust alarms thresholds.

4.1.2.4 Robustness

Robustness is a measure of an LDS's ability to continue to function and provide useful information, even under changing conditions of pipeline operation (API, 1995b). A system is considered robust if it continues to perform its principle functions under less than ideal conditions. For this project, robustness is evaluated in terms of the capability of the LDS to distinguish between normal transient operating conditions and real leak events, and the ability to automatically make temporary system adjustments or disable certain leak detection functions as needed. Robustness is also evaluated in terms of the ability of an LDS to continue to perform in the event that an instrument is lost or goes off line.

4.1.3 Transferability/Feasibility

This criterion requires a close examination of expected pipeline operating conditions. The performance issues presented in Section 3.4 outline some typical operating conditions that may preclude the installation or limit the effectiveness of certain LDS technologies. Regional considerations should also be used in determining whether a specific LDS technology will be transferable or feasible for use on a specific pipeline. A sound understanding of existing and expected pipeline conditions together with LDS system limitations is necessary for the successful implementation of any LDS technology. Advantages and operational situations that should be avoided are presented for each leak detection technology.

4.1.4 Compatibility/System Requirements

The operating requirements of each LDS, including instrumentation, communications, sampling frequency, and controller training are presented under this criterion to enable the potential user to further evaluate whether the LDS is compatible with a specific pipeline system.

4.1.5 Environmental Impacts

Environmental impacts are assessed under the BAT regulations by determining "whether the environmental impacts of each alternative technology, such as air, land, water, energy, and other requirements, may offset any anticipated environmental benefits." Internally installed LDSs typically do not represent a significant change to the surrounding environment. Externally installed systems may require excavation or other disturbances to the environment surrounding the pipeline system.

4.1.6 Regional Considerations

Regional considerations are key in selecting LDSs for Alaskan pipeline operations. Alaskan operations are characterized by long distances, large and rapid changes in elevation, large changes in throughput due to weather events in production or terminal areas, annual temperature variations of up to 160 °F, and limited ground access along some pipe segments. These regional considerations may be key in the selection of an LDS alternative, its communications system, or both.

Long distance pipelines require multiple pump stations to maintain line pressure. The selected LDS must be capable of highly accurate inventory, or be segmented between pump stations, to compensate for use of surge tanks and operational changes at individual stations.

Elevation changes create pressure differentials within the pipe and, under lower throughput, may cause slack-line conditions to exist in downhill segments. If appropriate, the selected LDS must be able to compensate for large pressure variations (for pressure differential-based systems) or for transient storage terms (for pipeline volume-balance based modeling systems).

Not all pipelines are ground-accessible throughout the year. Therefore, to limit costs, pipelines in such areas should rely on LDSs that do not require frequent maintenance or calibration events.

4.1.7 Field Performance

The evaluation of actual LDS field performance is essential to substantiate vendor claims of system sensitivity, accuracy, reliability, and robustness. Industry references provided by the vendors and ADEC were contacted to verify and comment on the performance of their LDS.

4.1.8 Cost

Vendors were extremely reluctant to provide absolute hardware and software costs for their leak detection systems because there is no way to accurately extrapolate the numbers to a pipeline without knowing its exact configuration. They also indicated that there is a great deal more to the cost of owning an LDS than the bare bones system price (i.e., the relative cost of instruments, maintenance or life cycle costs, and costs associated with adding more lines to the system). For these reasons and unless the vendors provided actual numbers, the costs associated with each technology are discussed only qualitatively. A general LDS pricing discussion is presented in the paragraph below. There are often tradeoffs between the price of an LDS and its performance. Highly effective systems (sensitive, accurate, reliable, and robust) ultimately will cost more to implement and maintain. It is up to the pipeline company to establish pipeline-specific performance standards and weigh the costs and benefits of an LDS.

In general and excluding costs for additional instrumentation and maintenance, installed and tuned software-based volume balance and pressure analysis systems are available for less than $200,000. Ultrasonic volume balance systems typically are more expensive because they require the purchase of vendor-specific clamp-on flow meters at about $35,000 to $40,000 each. Real time transient models run between $200,000 and $1,000,000, depending on pipeline configuration. External liquid-sensing and fiber optics cables are about $5 to $15 per foot installed. Accompanying hardware and software is required for each cable segment at prices between $10,000 and $50,000. Costs for soil gas/tracer sensing technologies are about $15 per probe (a probe needs to be installed about every 20 feet) with additional costs for installing field stations every two miles (approximately $50,000), and a central computer with specialized software ($10,000-$20,000). Acoustic emissions *AE* system can be installed on a single pipeline segment of 200 to 300 feet (i.e., 2 sensor systems with a 2-channel ALM) for $5,000 to $12,000. Each additional segment requires a channel at an added cost of approximately $3,000.

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6 GLOSSARY

Accuracy (Evaluation Criterion): The measure of leak detection system performance related to estimation parameters such as leak flow rate, total volume lost, and leak location. A system that estimates these parameters within an acceptable degree of tolerance, as defined by the pipeline controller/company, is considered to be accurate.

Accuracy (Instrument): The measurement performance of the instrument relative to that of an ideal device.

Alarm: A visual or audible notification to the pipeline operator that an anomaly has been detected that is outside the preset limits.

Algorithm: A mathematical rule or procedure for solving a problem.

Applicability/Availability: A best available technology evaluation criterion. Applicability ensures that any technology selected for use on a crude oil pipeline system was designed for that intended use. Availability refers to the commercial availability of a leak detection system and its components.

Best Available Technology: As defined under 18 AAC 75.990(9), means the best proven technology that satisfies the applicable requirements of 18 AAC 75.425(e)(4) and criteria of 18 AAC 75.445(k).

Bulk Modulus: The bulk modulus of a liquid is the reciprocal of its compressibility.

Compatibility/System Requirements: A best available technology evaluation criterion. The operating requirements of each leak detection system, including instrumentation, communications, sampling frequency, and controller training.

Computational Pipeline Monitoring (CPM): Algorithmic monitoring tools that are used to enhance the abilities of a pipeline controller to recognize anomalies which may be indicative of a product release. Also known as internal leak detection.

Cost: A best available technology evaluation criterion. The hardware and software costs associated with a vendor-specific leak detection system.

Effectiveness: A best available technology evaluation criterion dealing with the performance related aspects of a leak detection system. Effectiveness is evaluated in terms of sensitivity, accuracy, reliability, and robustness.

Environmental Impacts: A best available technology evaluation criterion. As defined in the regulations (18 AAC 75.445(k)), “whether the environmental impacts of each alternative technology, such as air, land, water, energy, and other requirements, may offset any anticipated environmental benefits.”

External Leak Detection System: Externally based methods detect leaking product outside the pipeline and include traditional procedures such as right-of-way inspection by line patrols, as well as technologies like hydrocarbon sensing via fiber optic or dielectric cables.

False Alarms: Transient alarms that are not caused by an actual product release.

Field Performance: A best available technology evaluation criterion. The evaluation of actual field performance to substantiate vendor claims of system sensitivity, accuracy, reliability, and robustness.

Filter: A device or algorithm to remove unwanted components from a process signal.

Flow Meter: Devices installed on pipelines to measure product flow through the line. Several different types of flow meters are used in the industry including orifice plates (differential pressure), turbine, positive displacement, mass flow (Coriolis type), and ultrasonic time-of-flight (clamp-on).

Internal Leak Detection System: Internally based methods use instruments to monitor internal pipeline parameters (i.e., pressure, flow, temperature, etc.), which are inputs for inferring a product release by manual or electronic computation. Also known as computational pipeline monitoring.

Line Pack: The actual volume of product in a pipeline segment. It is a function of pipe diameter, wall thickness and material, the thermal expansion coefficient of the pipe material, the reference density of the product, pressure, and temperature.

Master Terminal Unit (MTU): A component of the SCADA system, usually located in the control room, that gathers and displays process data from the field remote terminal Units (RTUs) and programmable logic controllers (PLCs).

Multiphase: The condition where a pipeline contains liquid product, gas-phase product, and water.

Noise: An unwanted component in a process signal or the part of a signal which does not represent the quantity being measured.

Pig: A device designed to move through a pipeline for purposes of cleaning, product separation, or information gathering.

Pipeline Controller: A person who is responsible for the monitoring and direct control of the pipeline.

Polling: A type of SCADA communications protocol in which sequential requests for process data from field units are issued by the master terminal unit (MTU).

Precision: A measure of the smallest change that can be seen in the output of the instrument.

Pressure Analysis: A leak detection method based on the analysis of pipeline pressure variations and the identification of the rarefaction wave produced when product breaches the pipeline wall. Most internal leak detection systems also use pressure analysis to locate leaks.

Pressure Transducer: Instruments installed on pipelines to measure the pressure of the product within the line. Conventional pressure transducers generally are of the electronic sensing type with various means of discerning pressure (piston, diaphragm, strain gauge, piezoelectric sensors, variable capacitance, and variable element). Pipeline pressure is measured by the displacement of these devices in response to fluid pressure and is converted electronically to an appropriate current, voltage, or digital output signal.

Product characteristics: The physical properties of a product as defined by its density, specific weight, pressure, surface tension, bulk modulus of elasticity, vapor pressure, and viscosity.

Programmable Logic Controller (PLC): A SCADA system component, typically installed at a field site, that gathers process data from instruments for transfer to the MTU.

Protocol: The specifications of the messages between remote terminal units (RTUs) or programmable logic controllers (PLCs) and the master terminal unit (MTU).

Rarefaction Wave: Also called an acoustic, negative pressure, or expansion wave. It is the undulation resulting when product breaches the pipeline wall and there is a sudden drop in pressure at the location of the leak followed by rapid line repressurization a few milliseconds later. The resulting low-pressure wave travels at the speed of sound through the liquid away from the leak in both directions.

Real Time Transient Modeling (RTTM): A leak detection method involving the computer simulation of pipeline conditions using advanced fluid mechanics and hydraulic modeling. RTTM software can predict the size and location of leaks by comparing the measured data for a segment of pipeline with the predicted modeled conditions.

Regional Considerations: A best available technology evaluation criterion assessed in terms of Alaskan pipeline operations (i.e., long pipeline distances, large and rapid changes in elevation, energetic submarine/underwater environments, annual temperature variations of up to 160 °F, and limited ground access along some pipe segments).

Reliability: A measure of the ability of a leak detection system to render accurate decisions about the possible existence of a leak on a pipeline.

Remote Terminal Unit (RTU): A SCADA system component, typically installed at a field site, that gathers process data from instruments for transfer to the MTU.

Repeatability: A measure of an instrument's ability to consistently return the same reading for a given set of conditions.

Robustness: A measure of a leak detection system's ability to continue to function and provide useful information, even under changing operating conditions.

SCADA: An acronym for Supervisory Control and Data Acquisition, the technology that makes it possible to remotely monitor and control pipeline facilities.

Segment (of a Pipeline): A pre-defined portion of pipe that has its own unique indivisible identity and is usually bounded by flow measurement and/or pressure transducer instrumentation.

Sensitivity: The composite measure of the size of leak that a system is capable of detecting, and the time required for the system to issue an alarm in the event that a leak of that size should occur

Slack Line: The condition where a pipeline segment is not entirely filled with product or is partly void.

Transferability/Feasibility: A best available technology evaluation criterion requiring a close examination of expected pipeline operating conditions. Pertains to the advantages and operational situations that should be avoided for each leak detection technology.

Transient: Any unsteady flow or pressure condition in a pipeline. Transients typically arise from operations such as valve changes and pump starts or shutdowns. They are also created when a leak occurs on a pipeline. For non-leak events, transients result in line pack changes that must be accounted for in leak detection.

Volume Balance: A leak detection method based on measuring the discrepancy between the incoming (receipt) and outgoing (delivery) product volumes of a particular pipeline segment.

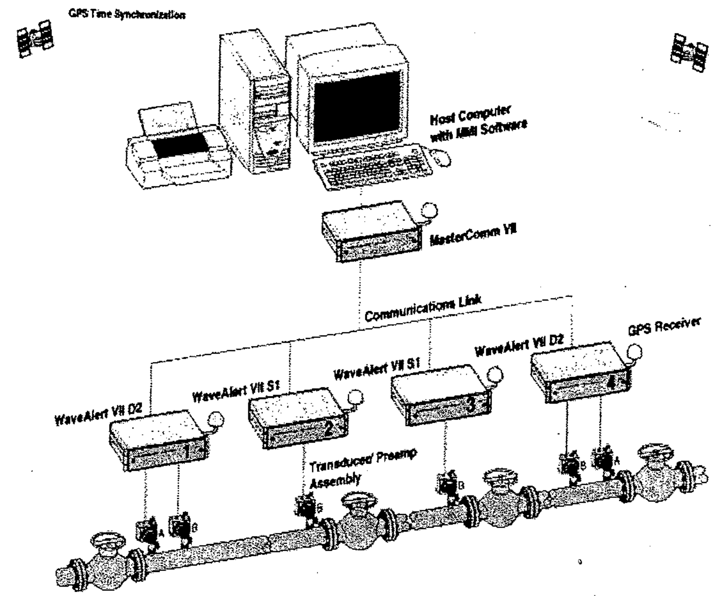
7 VENDOR INDEX

Listed by vendor name in alphabetical order, with leak detection method and system name. Specific product details available on cd-rom from:

mailto:Holly_Hill@envircon.state.ak.us

1. Acoustic Systems, Inc. - Internal Pressure Analysis (Rarefaction Wave Monitoring) - WaveAlert®
2. Controlotron Corporation - Internal Mass Balance Clamp-On Ultrasonic Flow Meters - System 990LD®
3. DETEX International - Internal Mass Balance Clamp-On Ultrasonic Flow Meters - Series 2000™
4. EFA Technologies Mass Pack - Internal Mass Balance - MassPack™ (part of LeakNet™ package)
5. EFA Technologies PPA - Internal Pressure Analysis (Rarefaction Wave Monitoring) - Pressure Point Analysis™ (Part of LeakNet™ package)
6. EnviroPipe Applications, Inc. - Internal Mass Balance - LEAKTRACK 2000
7. FCI Environmental, Inc. - Fiber Optic Chemical Sensor - PetroSense®
8. LICEnergy, Inc. - Internal Real Time Transient Modeling (RTTM) - Pipeline Leak Detection System (PLDS)
9. Løgstør Rør - External Liquid Sensing Cable - LR-Detector
10. National Environmental Services Co. (NESCO) - External Soil Vapor Detection - Soil Sentry Twelve-XP
11. PermAlert - External Acoustics Emissions - Acoustic Emissions (AE)
12. Physical Acoustics Corporation - External Liquid Sensing Cable - PAL-AT®
13. Raychem Corporation - External Liquid Sensing Cable - TraceTek
14. Siemens AG - External Sensing Tube - LEOS®
15. Simulations Inc. - Internal Real Time Transient Modeling (RTTM) - LEAKWARN
16. Stoner Associates - Internal Real Time Transient Modeling (RTTM) - SPS/Leakfinder
17. Tracer Research Corporation - Internal Pressure Analysis (Rarefaction Wave Monitoring) - LeakLoc®
18. Tracer Research Corporation - External Vapor Sensing Leak Detection System - Tracer Tight®

Leak Detection Method: Internal Pressure Analysis (Rarefaction Wave Monitoring)
Vendor: Acoustic Systems, inc.
System: WaveAlert®



Transducer/Preamp Assembly

- Produce a dynamic pressure signal

WaveAlert® VII Site Processor Assembly

- Convert pressure signals from analog to digital;
- Compute correlation of dynamic pressure with leak profile;
- Compare correlation with threshold;
- Perform system tests;
- Set flags indicating acoustic event;
- Uses GPS receiver to synchronize data sampling between processors; and
- Report to MasterComm™VII Node Processor when polled.

MasterComm™ VII Node Processor

- Integrate Information from WaveAlert® VII Site Processors;
- Analyze physical data; and
- Originate updated polling requests for monitor stations.

Host Computer with SCADA Software

- Maintain system databases;
- Provide operator interface;
- Produce displays, alarms, and messages.

Acoustic Systems Incorporated's (ASI) *WaveAlert®* is a real-time pipeline leak detection system operating on the rarefaction wave monitoring principle. The system consists of three major assemblies and their associated communication links including a *WaveAlert®* VII Site Processor (with Transducer/Preamp Assembly), a MasterComm™ VII Node Processor, and a Host Computer with SCADA Software (see figure above). The technology uses the acoustic signals produced by the sudden pressure drop characteristic of a pipeline leak to detect and locate leaks. The size of the leak can also be estimated using the amplitude of the acoustic waves.

Wall failure of a pipeline under pressure is an event that occurs when internal pressure produces a sudden rupture in a weakened pipe wall. When the hole forms, fluid escapes in the form of a high-pressure jet. Fluid loss produces a sudden pressure drop within the pipeline, which propagates in both directions as acoustic signals. These acoustic signals exhibit the following characteristics:

- The pressure loss propagates over large distances within the pipeline due to low signal absorption and because the pipe walls guide the wave fronts.
- Wave fronts propagate with the speed of sound in the fluid.
- Pressure loss is detectable as a low frequency acoustic signal.
- Acoustic signal amplitude increases with leak size.

The *WaveAlert®* Acoustic Leak Detection System makes use of these characteristics to inform the controller of the existence and location of the leak, as well as the estimated size of the leak.

Criteria	Evaluation/Comments
Applicability/Availability	*WaveAlert®* is commercially available and applicable to crude oil transmission

	lines.
Effectiveness	<u>*Sensitivity*</u> The sensitivity of *WaveAlert®* for liquid product lines is reportedly 1 to 3 percent of the nominal flow. The minimum detectable leak size depends upon the operating pressure, distance of the *WaveAlert®* VII from the leak, pipe diameter, and the background noise levels of the pipeline. Detection times are typically 15 seconds to 1 minute depending upon the speed of sound in the pipeline, distance between monitors, data communications scan rate, and computational time. ASI performs an initial sensitivity analysis of the line to determine the minimum detectable theoretical leak size and optimum placement of *WaveAlert®* sensors. <u>*Accuracy*</u> *WaveAlert®* relies largely on pipeline instrumentation to estimate parameters such as leak rate and volume lost; therefore, the accuracy of *WaveAlert®* is largely dependent upon the accuracy of the pipeline instrumentation. ASI recommends using strain-gauge type piezoresistor transducers. The accuracy of these transducers is not as important as the ability of the instrument to measure small changes rapidly. The accuracy of the leak location system depends on the separation distance of the *WaveAlert®* VII Site Processors and the operational pressure of the pipeline. According to the vendor, the system can determine leak location (within 1 minute or less) to within +/-100 feet or better. <u>*Reliability*</u> Reliability of the *WaveAlert®* system is ensured by requiring that more that than one *WaveAlert®* VII Site Processor records an acoustic event. Additionally, the source of the acoustic signal must be found to originate at a location on the protected segment of the pipeline for the system to declare a leak. The vendor guarantees one false alarm per year or less. To lower the incidence of false alarms from events outside a pipeline segment, the *WaveAlert®* system establishes a "muting zone" on each side of a transducer. The length of the muting zone largely depends on the spacing of the transducers and the proximity to pumps, valves, etc. The disadvantage of this feature is that leaks originating within a muting zone cannot be detected. To further reduced false alarms, dual transducer filters are installed at pipeline ends. <u>*Robustness*</u> The *WaveAlert®* system can distinguish between acoustic waves caused by background noise and acoustic waves characteristic of a leak. It does so by comparing the recorded event to a "leak mask", which is based on an actual leak event purposefully initiated during system installation. Note, there is only one chance for the sensors to detect the leak. If the rarefaction wave passes the sensor and it doesn't alarm, the ability of that sensor to detect the leak is lost. When an instrument (i.e., a *WaveAlert®* VII Site Processor) is lost, other online processors will continue to detect leaks, but at lower overall sensitivity. While not commonly done, *WaveAlert®* can be installed with mass balance algorithms for leak detection redundancy.
Transferability/Feasibility	*WaveAlert®* is transferable to crude oil transmission lines and has the following benefits: ▪ It reportedly operates sufficiently under multiphase flow conditions, albeit at reduced sensitivities;

	▪ It has been successfully applied in arctic environments; and ▪ It can consistently detect leaks equal to or less than 1 percent of daily throughput. *WaveAlert®* performs best when: ▪ Transducers are spaced less than 200 feet apart; ▪ Large transient events do not occur frequently; and ▪ There is no slack-line flow.
Compatibility/System Requirements	*Instrumentation* *WaveAlert®* operates using any high-quality electronic pressure transducers normally used in the petroleum industry; however, the vendor indicated that strain-gauge piezoresistors were the instruments best suited for use with their system. The Transducer/Preamp Assembly is mounted directly on the pipeline and is contained in a NEMA-7 (explosion proof) enclosure, suitable for use in Class I, Group D gases, as classified by the National Electrical Code. *Operating System/Communications* The *WaveAlert®* VII Site Processor monitors inputs from one or more Transducer/Preamp Assemblies using a standard 4-20 mA current loop. The processors are enclosed in standard 19-inch rack-mounted electronics cabinets sited either in an equipment shelter or in a NEMA-3R (rain tight) enclosure along the pipeline. The MasterComm™ VII Node Processor serves as the central processing unit for the LDS. It polls *WaveAlert®* VII Site Processors in turn. During each poll cycle, it stores digital and analog values including the time of any acoustic event registered. By comparing arrival times of an acoustic event at two *WaveAlert®* VII Site Processors, it verifies that a leak has occurred. The leak is then located and appropriate messages are issued to the Host Computer. The MasterComm™ VII enclosure is physically identical to the *WaveAlert®* VII enclosure. The communication link between *WaveAlert®* VII Site Processors and the MasterComm™ VII Node Processor is a dedicated two-way half-duplex link, which may include radio, hardwire land line, and/or fiber optic sections. The Host Computer with SCADA software communicates with one or more MasterComm™ VII Node Processors and provides controller interface with the LDS via video displays and audio alarms. The SCADA software residing in the Host computer provides communications management instructions for transfer of data between the Host Computer and MasterComm™ VII Node Processor(s), database management information and instructions, historical operating information, and instructions concerning organization and content of printed reports and graphic displays. *Sampling Frequency* The *WaveAlert®* VII Site Processors sample the pressure transducers every 10 milliseconds. The recommended SCADA polling rate of the MasterComm™ VII Node Processor(s) is ≤15 times per second. *Controller Training* Controller and support training is performed onsite during system installation. The duration of training is about one day.
Environmental Impacts	There are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of *WaveAlert®*.
Regional Considerations	*WaveAlert®* has been proven in arctic environments.

Leak Detection Method: Internal Pressure Analysis (Rarefaction Wave Monitoring)
Vendor: Acoustic Systems, inc.
System: WaveAlert®

	The principal limiting factor in terms of regional considerations is the field instrumentation (i.e., pressure transducers) which needs to be physically rugged to operate in the extreme climactic conditions of Alaska. Oil companies in Alaska generally have already selected the equipment that works the best under these potentially adverse conditions.
Field Performance	The results of tests conducted on *WaveAlert®* systems for two crude oil transmission pipelines are presented in the following table. **Company/Scenario** / **Diameter** / **Length** / **Product** / **Detected Leak** Quiliano Sea Lines / 32 & 36 in. / -- / Crude / 1% of flow* Exxon / -- / 270 mi. / Crude/Mixed / 1% of flow w/in 1 min. (location w/in 300 feet) * Required installation specification; unable to verify actual performance
Cost	The initial cost of the *WaveAlert®* system will depend on the length and diameter of the pipeline and the desired sensitivity of the system. A longer line or larger diameter pipeline will require more points incurring a greater cost. Upgrades range from minor firmware upgrade at a minimal cost to upgrading of the *WaveAlert®* monitors. In the past the *WaveAlert®* monitors have been redesigned every 5 to 7 years. The current version of the *WaveAlert®* monitor was completed in 1998.

Vendor Information

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Leak Detection Method: Internal Mass Balance Clamp-On Ultrasonic Flow Meters
Vendor: Controlotron Corporation
System: System 990LD™

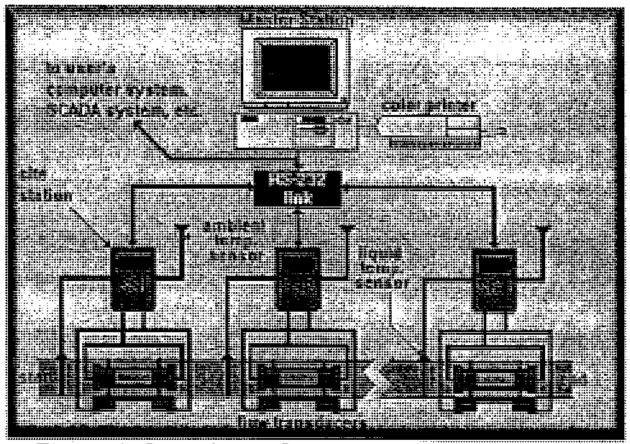

Figure 1. Controlotron Corporation's System 990LD Wide Beam Technology

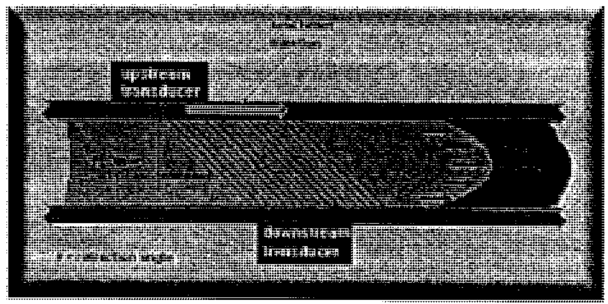

Figure 2. Ultrasonic Flow Meter

Controlotron Corporation's *System 990LD™* detects leaks by means of compensated volume balance. *System 990LD* consists of a PC-based Master Station linked to a series of clamp-on transit-time Site Stations (Figure 1). The system operates by separating the pipeline into a series of segments. Each segment is bounded by two Site Stations so that the monitored liquid theoretically travels through only one entrance and one exit. Each Site Station consists of a clamp-on flow meter, temperature sensor, and computer. A patented thermal model (*CompuTemp™*) computes and corrects for liquid expansion due to pipeline temperature or pressure changes. The following data are measured or computed at each Site Station 10 times per second: volumetric flow rate, liquid and ambient air temperature, liquid sonic propagation velocity ("sonic signature"), and site diagnostic conditions. Every sixty seconds the Master Station collects data from all Site Stations for a volume-balance computation. It accomplishes this by monitoring the volume of the liquid entering a segment, applying software models that reflect the physical and environmental conditions influencing the liquid, then comparing results with the volume leaving the segment. Volume unbalance on any pipeline segment exceeding preset alarm thresholds of any of four integration time periods (1, 5, 15, or 60 minutes) activates audible and visible alarms. A short integration period will show a large leak quickly. The longer integration periods detect smaller leaks.

Calculation of the segment volume balance allows *System 990LD* to locate a possible leak to a specific segment. The *SoniLocator™* option further pinpoints a possible leak location to an area within the specific segment. This feature is based on the detection of the relative arrival time of a leak-induced pressure drop at each Site Station.

Positive product identification is a critical factor for successful volume balance leak detection. *System 990LD's LiquIdent™* uses the sonic propagation velocity of the liquid and the measured liquid temperature to compute a unique "sonic signature" for that product. The Site Station monitoring the entrance to each pipe segment reports the product's sonic signature to the Master Station, so the system is always aware of the liquid type flowing through a segment.

The basis for the benefits of the *990LD* leak detection system lie in the performance and operating parameters of the ultrasonic flow meter itself. System 990 Clamp-On Transit-Time Ultrasonic Flow Meters use patented wide beam technology to induce an axial sonic wave in the pipe wall (Figure 2). As the wave travels along the pipe a collimated beam of sonic energy "rains" across the liquid. This beam arrives at the far wall and travels toward the receiving transducer. The wide beam completely covers the receiving transducer assuring continuous operation of the system regardless of bubbles or changes in the refraction angle of the liquid. System 990 transmits alternately upstream and downstream. Proportional to the actual flow velocity, the upstream transit time takes slightly longer than the downstream. Thus the meter's ability to measure flow is based on measurement of this time difference. Since there is no energy taken from the stream, flow is rangeable (0 to +/-40 ft/sec), sensitive (0.001 ft/sec), and bi-directional.

System 990LD's clamp-on design allows it to service practically any pipeline architecture. A single Master Station can monitor as many as 32 Site Stations. Optional system configurations can increase this capacity. Controlotron supplies *System 990LD* on a turnkey basis only.

<table>
<tr><th>Criteria</th><th>Evaluation/Comments</th></tr>
<tr><td>Applicability/Availability</td><td>System 990LD is commercially available and has been successfully applied to crude oil transmission pipelines.</td></tr>
<tr><td>Effectiveness</td><td><u>Sensitivity</u>

The sensitivity of the 990LD system depends largely on the sensitivity of the clamp-on flow meters providing data to the system. Controlotron provided the following chart depicting the estimated best leak detection performance achievable on a pipeline. Current fielded systems generally support these values (see Field Performance criteria).

THRESHOLD SETTING AS A PERCENTAGE OF NORMAL FLOW RATE
<table><tr><th><u>Description</u></th><th><u>1Min.</u></th><th><u>5 Min.</u></th><th><u>15 Min.</u></th><th><u>60 Min.</u></th></tr><tr><td>High Precision Dual Path</td><td>3</td><td>2</td><td>1.5</td><td>1</td></tr><tr><td>Std. Precision Dual Path</td><td>4</td><td>3</td><td>2</td><td>1.5</td></tr><tr><td>High Precision Single Path</td><td>5</td><td>4</td><td>3</td><td>2</td></tr><tr><td>Std. Precision Single Path</td><td>7</td><td>5</td><td>4</td><td>3</td></tr></table>
<u>Accuracy</u>

System 990LD relies on the clamp-on meters to estimate parameters such as leak flow rate and volume lost; therefore, the accuracy of 990LD is only as good as the accuracy of the instrumentation. The System 990 clamp-on transit-time flow meters are reportedly accurate to within 0.001 ft/sec at any flow rate, including zero.

Controlotron claims that SoniLocator is capable of placing the source of leaks to within meters of their actual location. Field data were not available to substantiate this claim.

<u>Reliability</u>

Newly installed 990LD systems undergo an “optimization” process whereby calibration is normalized and sources of both short term and long term data variation due to the particular characteristics of the pipeline are identified and minimized. This results in the ability to set the leak detection threshold at the lowest value consistent with pipeline conditions and minimize false alarms.

In order to avoid false alarms, Controlotron recommends including an automated application control function (AppCon™). System 990LD's AppCon™ dynamically adjusts leak detection thresholds to avoid false leak alarms due to deteriorated or other operating conditions. However, such a condition will also trigger the leak warning system which alerts the controller of the potential of an as yet undeclared leak. A ReaLeak™ scatter plot screen shows the controller a graphical correlation of reported leak data with current operational conditions to help confirm leak reality.

System 990LD reliability is also enhanced by its ability to detect and compensate for line packing and unpacking. This is because compression of the liquid (i.e., line pack) increases the liquid's density and its sonic propagation velocity. By correlating the increase in flow rate with the increase in velocity, 990LD can confirm that the current segment volume imbalance is due to line pack and not a leak, thus preventing the declaration of a false leak alarm. Note that during the optimization process, a determination is made as to the amount of liquid normally packed in each pipeline segment under various flow conditions. Using this data, 990LD can determine if the actual liquid imbalance during line pack events is within historical limits. If it exceeds these limits, the system will declare a leak alarm.

<u>Robustness</u>

System 990LD is a non-intrusive electronic device without moving parts; therefore, it has no liquid induced wear or calibration-change mechanism as found in conventional intrusive turbine or positive displacement flow meters.</td></tr>
</table>

	However, as with any computer-based system it is not immune to failure and is dependent upon data communication links, power supply, proper installation, and periodic maintenance. The clamp-on transit-time flow meter automatically detects both line pack and, for pipelines in which temperature gradients are expected, it also determines the effect of liquid and pipeline expansion or contraction, so as to preclude either false alarms or failure to detect a leak. *System 990LD* is intended as a source of flow data so that the controller, with information from other sources, can make the decision as to the existence of a leak. Confidence factors determined by current pipeline conditions are displayed to assist the controller in evaluation of the data obtained from the *990LD* system. A key to the performance of *System 990LD* is its ability to continuously identify the type and condition of the product in the pipeline, and thereby assure correct system calibration at all times (*System 990LD* takes approximately 1000 measurements per second and identifies the product once per minute). This is important because the characteristics of crude oils can vary substantially. Additionally, the "wide beam" technology used in the flow meters assures that no matter what liquid is in the pipe, the beam will cover the receiving transducer and permit continuous operation of the system.
Transferability/Feasibility	*System 990LD* is transferable to crude oil transmission lines and has the following benefits: ▪ It can compensate for monitoring during line packing and unpacking; ▪ It can monitor bi-directional pipelines; ▪ It is capable of monitoring relatively long pipeline segments (30 miles or more); ▪ It has been applied in arctic environments; ▪ It does not require shutdown of operations for installation, calibration, or maintenance; ▪ The non-intrusive clamp-on feature insures against the system itself being the cause of a future pipeline leak; ▪ It permits application to pipelines which are "pigged"; and ▪ It can detect leaks on crude oil transmission lines of less than 1 percent of flow. *System 990LD* performs best when: ▪ Product characteristics are consistent. Despite the vendor's claim that *System 990LD* is its capable of continuously identifying the type and condition of the liquid in the pipeline, one reference indicated that system did not recognize or respond to batch changes in the line. ▪ The flow rate is not highly variable; ▪ The clamp-on meters are not installed in an environment conducive to corrosion (i.e., offshore platforms); ▪ There is no multiphase flow or slugging of water; ▪ There is no slack-line flow; and ▪ Large transients do not occur frequently. Although *System 990LD* is capable of detecting and compensating for normal operating noise and transient events, highly dynamic pipelines tend to desensitize the system.
Compatibility/System	Controlotron markets *System 990LD* as a completely self-contained leak detection system including all hardware, software, and services. *System 990LD*

<table>
<tr><td>Requirements</td><td>can accommodate pipes from 1.25 to 240 inches in diameter, and of any wall thickness of sonically conductive pipe material. Individual clamp-on site stations can be installed in less than 2 hours.

<u>Instrumentation</u>

System 990 clamp-on transit-time ultrasonic flow meters are designed for precision flow measurement. Basic System 990 functions and parameters, as <u>reported</u> by Controlotron, are summarized in the list presented below.
• Flow range from zero to +/-40 ft/sec flow velocity, bi-directional;
• Flow sensitivity of 0.001 ft/sec, even under zero flow conditions;
• Calibration stability of 0.05 to 0.1 percent;
• Accurate operation for Reynolds number from 1 to 10^9;
• 10 Hz flow detection response rate;
• Temperature-compensated mass/volumetric flow measurement;
• Built-in datalogger with site identification and time stamp;
• Incorporates 9600 baud, RS-232 I/O serial data communication;
• Meters operate on only 12 watts of power;
• Meters are rated for pipeline temperatures ranging from –80 to 500 °F;
• Built-in diagnostics alert user to liquid/system conditions (LiquIdent product identification, liquid interface detection, empty pipe detection, free gas and water detection); and
• Built-in pig detection.

<u>Operating System/Communications</u>

All leak detection algorithms are built into the Master Station with alarm and data storage and printout facility. Data communication from the site stations to the master station is provided independently either through the existing communication system (i.e., dedicated phone lines, radio, satellite, optical cable, direct wire, or SCADA system) or as a freestanding communications system provided by Controlotron. The Master Station console provides audio/visual warnings and alarms to signal a possible leak event. Its user interface includes instant hot-key access to a host of graphic and numerical data screens. Using these screens, controllers can locate, view, and analyze the data to decide quickly if a leak alert represents a real emergency.

<u>Sampling Frequency</u>

The following data are measured or computed at each Site Station 10 times per second: volumetric flow rate, liquid and ambient air temperature, liquid sonic propagation velocity (sonic signature), and site diagnostic conditions. Every sixty seconds the Master Station collects data from all Site Stations for a volume-balance computation.

<u>Controller Training</u>

Controller training is provided by Controlotron at their training center in Hauppauge, NY or at the user's facility. Personnel familiar with standard computer-based pipeline operation controls are ordinarily qualified for training in System 990LD operation.</td></tr>
<tr><td>Environmental Impacts</td><td>There are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of System 990LD.</td></tr>
<tr><td>Regional Considerations</td><td>System 990LD has been installed on pipelines in arctic environments. Relevant clients include the U.S. Defense Fuel Supply Command (Alaska) and Transalpine Pipeline (Italy, Germany, and Austria).</td></tr>
<tr><td>Field Performance</td><td>The results of tests conducted on System 990LD for various crude oil transmission pipelines (and a single jet fuel line in Alaska) are presented in the following table.</td></tr>
</table>

Leak Detection Method: Internal Mass Balance Clamp-On Ultrasonic Flow Meters
Vendor: Controlotron Corporation
System: System 990LD™

	Company/Scenario / **Diam.** / **Length** / **Product** / **Detected Leak** Sun Pipeline Co. / 30 in. / 1 mi. / Crude / 1% flow in 1 hour DFSC (Elmendorf AFB, AK) / 8 in. / 67 mi. / Jet Fuel / 0.75% within 1 hour* Mid-Valley Pipeline / 22 in. / 1000 mi. / Crude / 0.1-0.5% in <1 hour Transalpine Pipeline / 40 in. / 832 mi. / Crude / 1% of flow** Shell Offshore Pipelines / Various / Various / Crude / 3% in 2 hours*** SNAM (Italy) / 32 in. / 120 mi. / Crude / 1% of flow in <1 hour* Petroleos Mexicanos / 12-20 in. / 345 mi. / Crude/Mixed / 1% in <1 hour* Equilon (Texaco Co.) / 6-30 in. / 2-4mi. / Crude/Mixed / 1-2% in <1 hr* Esso (France) / 26 in. / 24 mi. / Crude/Mixed / 1% in <1 hour* Chevron (Louisiana) / 12 in. / -- / Crude / 1% in <1 hour* *Best performance estimates based on pipeline operating conditions. ** Sensitivity depends on flow profile predictability. ***According to the user, this sensitivity is achieved only if the meters have been properly maintained, flow rates are consistent, and slugging of water is not an issue.
Cost	*System 990LD* is available in a variety of configurations so that the appropriate combination of performance versus cost is available for any pipeline. Systems can be provided for applications involving as few as 2 site stations, monitoring only 1 pipeline segment, or as many as 64 site stations, monitoring 63 segment, or between 1 and 32 different pipelines. In addition, *System 990LD* offers options of standard and high precision transducers in single, dual, or triple beam configuration. This gives the user the ability to provide enhanced performance for any pipeline segment which lies in a particularly sensitive region, while saving costs in regions of lower sensitivity. Based on information from users of the *990LD* system, the clamp-on ultrasonic flow meters require considerable maintenance.

Vendor Information

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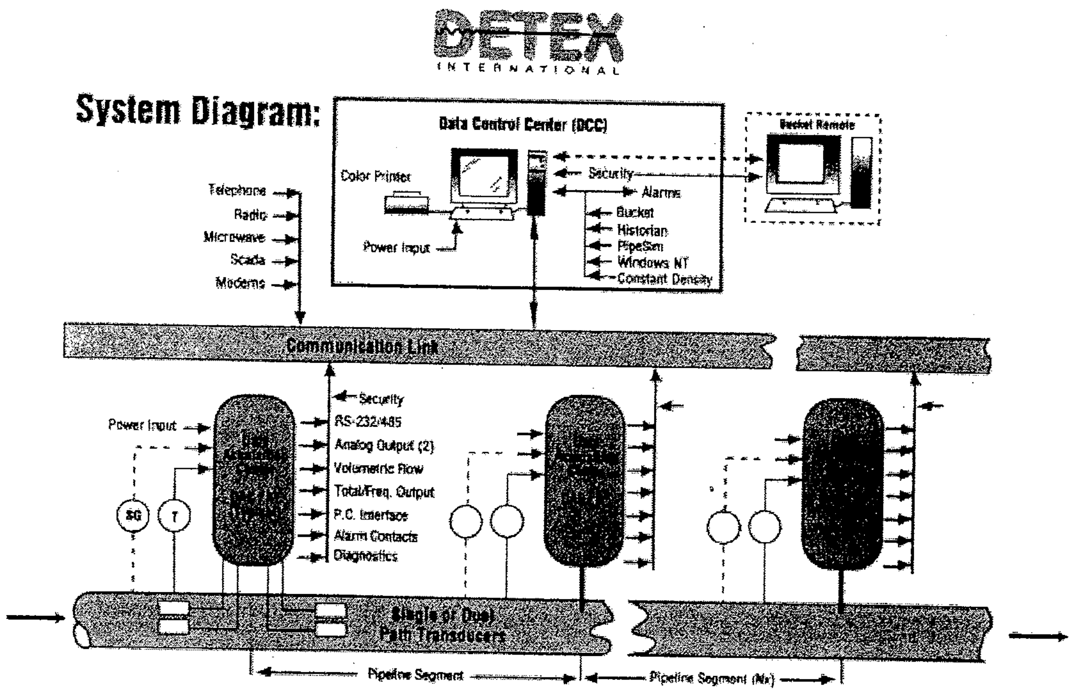
Phone: (516) 231-3600
Fax: (516) 231-3334

Leak Detection Method: Internal Mass Balance Clamp-On Ultrasonic Flow Meters
Vendor: DETEX International
System: Series 2000™



DETEX *Series 2000™* detects leaks by means of compensated volume balance. *Series 2000* consists of a number of Data Acquisition Centers (DACs) placed at intervals along the pipeline, where two DACs create a pipeline section (Figure 1). Each DAC consists of an ultrasonic clamp-on flow meter, temperature sensor, densitometer (optional), and flow computer. The clamp-on flow meters are positioned so that the upstream and downstream signal transit times are compared to produce flow measurement. The time differential is related to the sonic propagation velocity of the liquid and other conditional data (temperature, product characteristics, pipeline expansion/contraction, etc.). These data are reported by the DAC to the Data Control Center (DCC), usually at 30-second intervals through the SCADA or other communication system. The data are processed and analyzed at the DCC for a volume-balance computation. This is accomplished by monitoring the volume of the liquid entering a section, applying algorithms (*Bucket™* software) that reflect the physical and environmental conditions influencing the liquid, then comparing results with the volume leaving the segment. Volume unbalance on any pipeline segment activates alarms. *Series 2000 Continuos Integration* program sets alarm thresholds automatically based on normal, historical pipeline operating conditions.

Positive product identification is a critical factor for successful volume balance leak detection. *Series 2000* uses the sonic propagation velocity of the product and the measured liquid temperature (densitometer is optional) to accurately identify the liquid. The DAC monitoring the entrance to each section reports this information to the DCC, so the system is always aware of the liquid type flowing through a section.

Calculation of the section volume balance between two DACs allows *Series 2000* to pinpoint a possible leak location to a specific section. DETEX also offers a leak location option which further pinpoints a possible leak location to an area within the specific section. This feature is based on the detection of the relative arrival time of a leak-induced pressure wave at each DAC.

Criteria	**Evaluation/Comments**
Applicability/Availability	*Series 2000* is commercially available and the technology is applicable to crude oil transmission lines. However, to date, only the transit-time ultrasonic flow meters (not the leak detection software) have been successfully installed on crude lines. The *Series 2000* package in its entirety has only been installed on one 10-inch, 2-mile long gas line.

Leak Detection Method: Internal Mass Balance Clamp-On Ultrasonic Flow Meters
Vendor: DETEX International
System: Series 2000™

<table>
<tr><td>Effectiveness</td><td>

<u>Sensitivity</u>

The sensitivity of the Series 2000 system depends largely on the sensitivity of the clamp-on flow meters providing data to the system. DETEX provided the following estimated best leak detection performance achievable on a pipeline with Series 2000:

Catastrophic leak within 30 seconds
5% of flow within 1 minute
2% of flow within 2 minutes
1% of flow within 5 minutes
0.5% of flow within 8 minutes
0.25% of flow within 15 minutes

<u>Accuracy</u>

Series 2000 relies on the clamp-on meters to estimate parameters such as leak flow rate and volume lost; therefore, the accuracy of the LDS is largely dependent upon the accuracy of the instrumentation. The Series 2000 clamp-on transit-time flow meters are reportedly accurate to within 0.001 ft/sec at any flow rate, including zero.

DETEX claims that the optional leak location system is capable of pinpointing the source of a leak to within 60 feet of its actual location on a 35-mile pipeline segment. However, this claim has never been substantiated in the field. Leak location software is not installed on the single pipeline presently monitored by Series 2000.

<u>Reliability</u>

With its Continuous Integration software (part of Bucket package), newly installed Series 2000 systems undergo an initial tuning process where the system "learns" all of the normal operating characteristics of the pipeline and its products including flow rate changes and pump output. This feature combined with the MiniThresh program results in the ability to automatically set the leak detection threshold at the lowest value consistent with pipeline conditions, thereby minimizing false alarms.

DETEX guarantees that Series 2000 will not false alarm more than twice a month.

Series 2000 can also minimize false alarms by detecting line packing and unpacking. In essence, liquid compression or line pack increases the density and sonic propagation velocity of the liquid. By correlating the increase in flow rate with the increase in velocity, Series 2000 can confirm that the current volume imbalance is due to line pack and not a leak, thus preventing the declaration of a false leak alarm.

<u>Robustness</u>

Series 2000 is a non-intrusive electronic device without moving parts; therefore, it has no liquid-induced wear or calibration-change mechanism as found in conventional intrusive flow meters. However, as with any computer-based system it is not immune to failure and consistent operation and performance is dependent upon data communication links, power supply, proper installation, and periodic maintenance.

A key to the robustness of Series 2000 is its ability to continuously identify the product in the pipeline (Series 2000 takes approximately 1000 measurements per second and identifies the product once every 30 seconds). This is important because the liquid characteristics of crude oils can vary substantially.

</td></tr>
<tr><td>Transferability/Feasibility</td><td>

Series 2000 is <u>reportedly</u> transferable to crude oil transmission lines and has the following benefits:

It can compensate for line packing and unpacking;
It can monitor bi-directional pipelines;
It can detect the presence of free gas and "slugs" of water (but performance

</td></tr>
</table>

	deteriorates under true multiphase conditions); ▪ DACs can be used on any size pipeline and are not dedicated to one pipeline; ▪ It is capable of monitoring relatively long pipeline segments (25 miles or more); ▪ *Series 2000* flow meters have been successfully installed in both arctic and underwater environments; ▪ It does not require shutdown of operations for installation, calibration, or maintenance; ▪ The non-intrusive clamp-on feature insures against the system itself being the cause of a future pipeline leak; ▪ It is resistant to corrosive or abrasive liquids; ▪ It permits application to pipelines which are "pigged"; and ▪ It can reportedly detect leaks on crude oil transmission lines of less than 1% of flow. Factors which may result in an increase in the detection threshold of *Series 2000* include: ▪ Aeration or slack line; ▪ Multiphase flow; ▪ Low Reynolds number; ▪ Different liquids at adjacent DACs; ▪ Very low flow rates (<0.5 ft/sec); ▪ Sudden high flow rate changes (i.e., presumptive line packing) within a 30-second integration period; and ▪ Passage of a product interface.
Compatibility/System Requirements	DETEX markets *Series 2000* as a completely self-contained leak detection system including all hardware, software, and services. *Series 2000* clamp-on design allows it to service practically any pipeline configuration. It can accommodate pipes from 2 to 200 inches in diameter, with wall thickness up to 3 inches. Individual clamp-on site stations can be installed in about 2 hours. A single DCC can monitor as many as 128 pipeline sections simultaneously. <u>Instrumentation</u> *Series 2000* clamp-on transit-time ultrasonic flow meters are designed for precision flow measurement. Flow meters can be of single or dual path configuration depending on the flow profile and accuracy required. Two analog inputs are available for densitometer and temperature data. DAC flow meters have the following characteristics/output data: • Accurate to within 1% of flow in most applications; • Flow range from zero to +/-40 ft/sec flow velocity, bi-directional; • Flow sensitivity of 0.001 ft/sec, even under zero flow conditions; • Repeatability of +/-2%; • Determination of liquid sonic propagation velocity; • Reynolds number • Low operating power; • Pig detection; • Empty pipe alarm; • Built-in 43,000 point datalogger; and • Built-in diagnostics (*Automatic Tracking Window*) to alert user to liquid and system conditions (i.e., product identification, line packing/unpacking, and empty pipe detection). <u>Operating System/Communications</u> The DCC receives the required data from the DACs and performs leak detection analysis using the *Bucket* software program. The DCC comes standard with an Intel Pentium Pro Processor, 32 megabytes RAM, 16550a UARTS, high-resolution PCI video, 17-inch monitor, sound card, color printer, and uninterruptible power

<table>
<tr><td></td><td>supply.

Data communication from the DACs to the DCC is provided independently either through the existing communication system (i.e., dedicated phone lines, radio, satellite, optical cable, direct wire, or SCADA system) or as a freestanding communications system provided by DETEX. Communications methods are interfaced to Series 2000 through RS-232 serial ports.

Series 2000 Bucket software provides the leak detection algorithms. Bucket is a 32bit multithreaded application capable of running on all platforms supported by Widows NT, including multiprocessor systems. Using Graphical User Interface (GUI), Bucket can monitor up to 128 individual pipeline sections depending on the selected polling frequency and communications throughput. Additional software includes:
▪ Bucket Remote™, an application designed to monitor/control Bucket from a remote location;
▪ PipeSim™, a simulation program designed for controller training; and
▪ Historian™, a program which allows full replay of archived data enabling review of leaks, warnings, noted events, and trending.

<u>Sampling Frequency</u>

The following data are measured or computed at each DAC 1000 times per second: volumetric flow rate, temperature, liquid sonic propagation velocity, and site diagnostic conditions. Every 30 seconds, the DCC collects data from all DACs for a volume-balance computation.

<u>Controller Training</u>

Series 2000 training is provided by DETEX at their training center in Kings Park, NY or at the user's facility. Training typically requires two 8-hour days. Additionally, DETEX engineers can dial into any pipeline's DCC and operate Series 2000 remotely from Kings Park; thereby enabling direct consultation and troubleshooting.</td></tr>
<tr><td>Environmental Impacts</td><td>There are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of Series 2000.</td></tr>
<tr><td>Regional Considerations</td><td>Series 2000 transit-time ultrasonic flow meters have been installed in arctic and underwater environments; however, the full LDS, including Bucket software, has not.</td></tr>
<tr><td>Field Performance</td><td>The results of a test conducted on a pipeline equipped with the Series 2000 LDS is presented in the following table.

<table><tr><th><u>Scenario</u></th><th><u>Diameter</u></th><th><u>Length</u></th><th><u>Product</u></th><th><u>Detected Leak</u></th></tr><tr><td>Refinery to Tank Farm</td><td>10 inch</td><td>2 miles</td><td>Gasoline</td><td>0.2% of flow in 2 minutes</td></tr></table></td></tr>
<tr><td>Cost</td><td>Series 2000 is available in a multitude of configurations so that the appropriate combination of performance versus cost is available for any pipeline. A single DCC is capable of monitoring as few as 2 DACs (1 pipeline section) or as many as 64 DACs (63 sections), and any number of different pipelines.</td></tr>
</table>

<u>Vendor Information</u>

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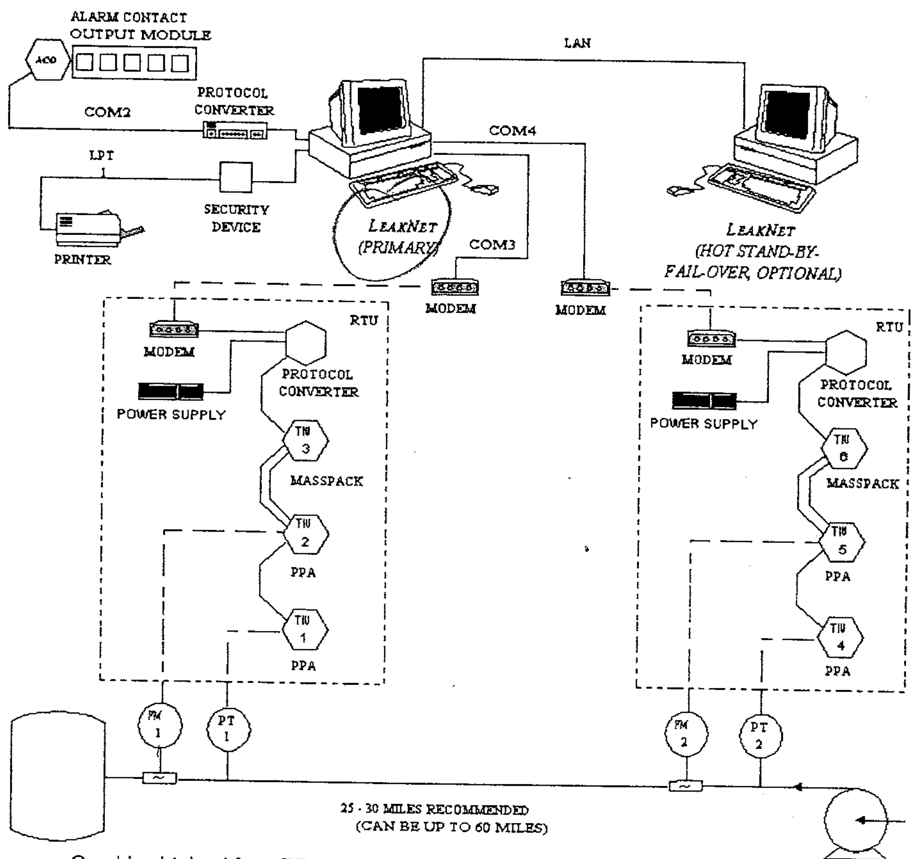
Leak Detection Method: Internal Mass Balance
Vendor: EFA Technologies
System: MassPack™ (part of LeakNet™ package)



Graphic obtained from EFA Technologies, Inc. (May 1999)

MassPack™ is part of EFA's *LeakNet*™ package, which also includes *Pressure Point Analysis*™ (a pressure analysis system described separately) and *Locator*™ (a leak location option). *MassPack* is a line-pack compensated volume balance leak detection system based on flow into and out of a pipeline segment. Once each minute, the mass flow balance and the change in the fluid packed within the line are computed and accumulated in four accumulators operating over different time periods. The first accumulator looks at the line-pack-corrected mass balance over a user-selected interval of 1 to 99 minutes. The second accumulator monitors the previous hour. The third accumulator watches the previous 24 hours. The fourth accumulator can be user-set to watch either the entire proceeding month, or it can total the inflow volume until manually reset. When the accumulated mass flow balance indicates fluid is being lost, and when the amount lost exceeds a warning or alarm setting, the controller is alerted. All warning and alarm limits are user configurable.

Criteria	Evaluation/Comments
Applicability/Availability	*MassPack* is commercially available and has been used on crude oil transmission pipelines.
Effectiveness	<u>Sensitivity</u> The sensitivity of the *MassPack* system depends directly on the sensitivity of the flow meters and other instruments providing data to the system. Depending on the type of metering, *MassPack* can detect leaks equal to or less than 1 percent of daily oil throughput. Note: *MassPack* responds to the leak only after the event has traveled to both ends of the line (or line segment) and the measurable difference exceeds the

	alarm threshold. Depending on the size of the leak this may take minutes to hours. *Accuracy* *MassPack* relies on pipeline instrumentation to estimate parameters such as leak flow rate and volume lost; therefore, the accuracy of *MassPack* is largely dependent upon the accuracy of the pipeline instrumentation. Leaks cannot be located using *MassPack* exclusively. *Reliability* *SmartPoint* is an intelligent alarm-processing feature which is configured by the user to alarm only when all specified conditions are met, potentially providing 100 percent nuisance alarm free operation. *SmartPoint* recognizes a leak on a pipeline segment by the characteristic decrease in pressure and increase in flow on the upstream segment (inlet) and a decrease in both pressure and flow on the downstream segment (outlet). *MassPack* includes an optional line pack correction feature which can be turned on by the customer if the line has packing/unpacking issues associated with it. Pressure at each end of the pipeline segment is monitored and used to compute the corresponding changes in line pack. These changes are used to adjust the mass balance errors so warnings and alarms are issued only as a result of an actual loss of fluid. *Robustness* All mass balance systems, including *MassPack* are limited by the performance of the meters. Some meters deal with transients better than others. Positive displacement meters are probably the most immune to transients. Pressure sensing flow meters such as orifice meters are probably the most affected. Also like any other mass balance system, *MassPack* is vulnerable to poor meter maintenance or improper proving. Note that by incorporating two independent methods of leak detection that use completely different ways of evaluating the line (pressure analysis and mass balance), *LEAKNET* will detect leaks by one or both methods regardless of the transient conditions.
Transferability/Feasibility	*MassPack* is transferable to crude oil transmission lines and has the following benefits: ▪ It can compensate for monitoring during steady packing and unpacking of the line; ▪ It can monitor bi-directional pipelines; ▪ It has been successfully applied in both arctic and underwater environments; ▪ For leak detection redundancy, it is readily compatible with a pressure analysis method (*PPA*); and ▪ It can consistently detect leaks of less than 1 percent of flow, thereby meeting ADEC criteria. *MassPack* performs best when: ▪ Transient events do not occur frequently; ▪ There is no slack line flow; and ▪ There is no multiphase flow.
Compatibility/System Requirements	*Instrumentation* *MassPack* operates using any high-quality metering system normally used in the

	petroleum industry. These instruments share a similar range of accuracy and repeatability that is suitable for leak detection. For maximum performance, flow should be measured to custody transfer accuracy and presented to *MassPack* as either mass flow rate or standard volumetric flow rate. Pressure also should be measured to custody transfer accuracy (i.e., to the nearest 0.1 psi) using industrial quality pressure transducers. If *MassPack* is being used, the meters will require standard calibration and proving indicated by API metering practices. *Operating System/Communications* The basic *LEAKNET* package consists of an industrial grade, rack mountable CPU, monitor, mouse and keyboard. If the link is via SCADA an appropriate cable and card are included. If the system collects its own information, the package can include the modems, analog to digital converter modules, power supplies, etc. Standard *LEAKNET* includes one Ethernet board with connectors for both 5BaseT (coaxial cable) and 10BaseT (modular telephone jack). It supports the TCP/IP and NetBEUI protocols. Other networks and protocols can be included at additional cost. The underlying Windows NT™ operating system includes support for simultaneous operation on multiple LANs using multiple protocols on each LAN. Communication needs to be at least 9,600 baud with 16-bit resolution. The data interface is bi-directional and implemented using formatted ASCII files. The interface point is typically a network-accessible RAMdrive but any network-accessible drive can be used. Raw data are provided by the host DCS or SCADA system for *LEAKNET*'s use in a simple format. *LEAKNET* provides files containing a user-selectable collection of the processed data which may be used by the host computer for display or other purposes. Data interchange can also be implemented over an RS-232 link operating at 9,600 baud. The following systems have been interfaced to *LEAKNET*: Honeywell SCAN 3000; Whessoe Coggings Fuels Automation System (FAS); Mass Technologies, Inc.; ULSI Startrack; Valmet-Sentrol; Baker CAC Realflex; Control Systems International; Bailey System 90; and Heuristics On-Spec. *Sampling Frequency* The optimal data instrument sampling frequency for *MassPack* is once per minute. EFA found no significant improvement in sensitivity with updates faster than one minute. Additionally, placing instruments closer together than 25-35 miles does not improve sensitivity, although more instruments do provide a certain level of redundancy which may be advantageous in remote areas. Longer pipeline segments (over 100 miles) can be monitored when reduced sensitivity is acceptable. *Controller Training* The *LEAKNET* system can be installed and operational the day it arrives on site. Controller training takes one 8-hour day. Training for support personnel working with the SCADA system takes two to three days.
Environmental Impacts	There are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of *MassPack*.
Regional Considerations	*MassPack* has been proven in arctic and underwater environments and has been installed on pipelines in Alaska and Canada. The principal limiting factor in terms of regional considerations is the field instrumentation, which needs to be physically rugged to operate in the extreme climactic conditions of Alaska. Oil companies in Alaska generally have already selected the equipment that works the best under these potentially adverse conditions.

Leak Detection Method: Internal Mass Balance
Vendor: EFA Technologies
System: MassPack™ (part of LeakNet™ package)

Field Performance

Few field test results are available for mass balance systems since performance is directly related to the accuracy of the instrumentation (i.e., the better the instrumentation, the better the leak detection performance). BP Alaska and ARCO Alaska were contacted to discuss the performance of *MassPack* leak detection on two crude oil transmission pipelines operating in Alaska. The following data represent best performance estimates:

Company	Diam.	Length	Meter Acc.	Detected Leak
ARCO Alaska (Kuparuk)	8-18 in.	50 mi.	0.1-1%	<5% in 1 min; <1% in 1 hr; <0.5% in 24 hr
BPXA (Endicott/Badami)	12-16 in.	50 mi.	0.25%	≤0.05% in 3 to 5 min

Performance of other mass balance systems (non-*MassPack*) on crude oil lines is presented in the following table:

Company	Diam.	Length	Meter Acc.	Detected Leak
Alberta Energy Co.	22 in.	350 mi.	0.1%	<1% in 1 hr; <0.5% in 24 hr
Pembina Pipeline	--	1200 mi.	0.25%	<5% in 5 min; <1% in 24 hr
Pennzoil Company	14 in.	82 mi.	0.5%	<2% in 24 hr

Cost

Different *MassPack* applications will have different initial costs. A short pipeline might only require monitoring of four field instruments or measurement points. A longer line might require forty points or even 75 points. Because of this variability, LEAKNET is available in standard sizes of 10 points, 25 points, 50 points, 75 points, and 100 points. Larger size systems cost more than the smaller one. Depending on the individual needs on a particular pipeline the owner may elect to purchase optional features such as leak *Locator* which will add to the price. Beyond that, a system collecting its own field data via modems and RTU boxes will cost more than one receiving data directly from SCADA because of the extra hardware costs. A feature in the EFA pricing structure is the full availability of all points within the system for no additional licensing fees as they are brought on line. The price initially paid for the system is the actual cost.

LEAKNET does not result in additional maintenance costs for the owner. The software does not require the maintenance normally associated with custom transient model systems. The PC only needs the routine care given to any PC.

Vendor Information

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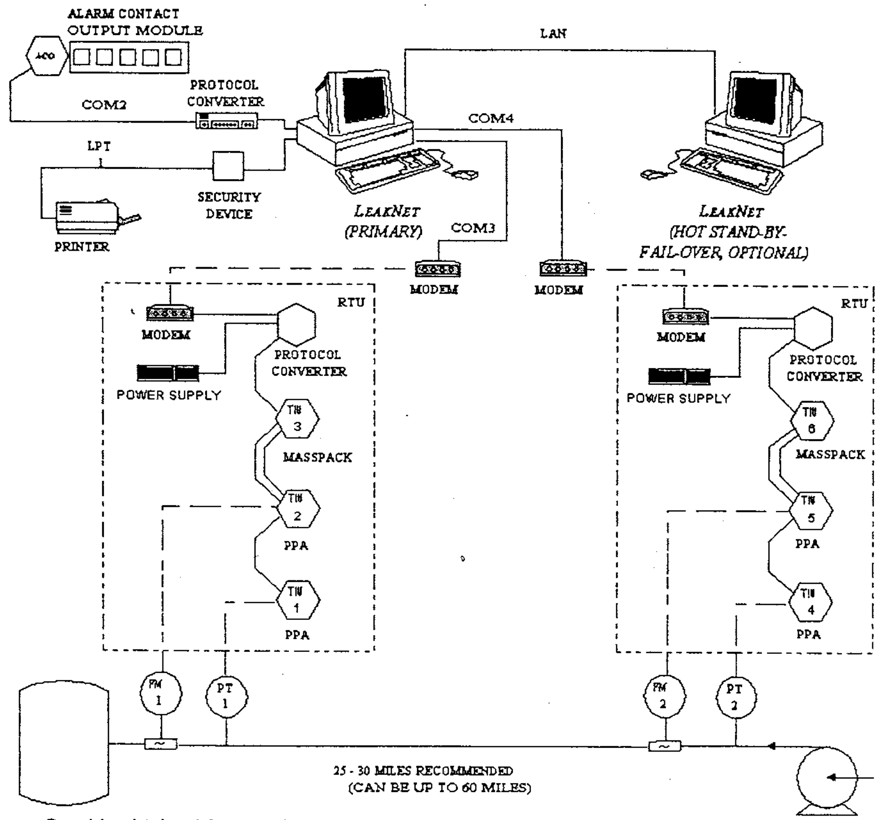
Leak Detection Method: Internal Pressure Analysis (Rarefaction Wave Monitoring)
Vendor: EFA Technologies
System: Pressure Point Analysis™ (part of LeakNet™ package)



Graphic obtained from EFA Technologies, Inc. (May 1999)

Pressure Point Analysis (*PPA*™) is part of EFA Technologies Inc.'s *LEAKNET*™ package, which also includes *MassPack*™ (a mass balance system described separately) and *Locator*™ (optional). *PPA* is an EPA-approved, patented leak detection technology operating on the rarefaction wave monitoring principle. Either pressure or flow measurements can be used with *PPA*, which relies on analyzing data at a single or multiple measurement points. Additional points improve intelligence, but are not essential to the technique. The additional points can be used to configure a *SmartPoint*™, an intelligent alarm-processing feature which is configured by the user to alarm only when all specified conditions are met, thereby reducing the number and frequency of false alarms. An instrument configuration as shown above would provide 100% nuisance alarm free operation for the pipeline segment between the meters.

PAA detects leaks by (Farmer, 1989):

- Extracting signals from data taken at measurement points along the pipeline that are representative of current operations and recent trends.
- Determining if the behavior of these signals contains evidence of a leak and if the evidence is the result of events on the line known to *PPA* to produce leak-like signatures. Patented and proprietary algorithms evaluate the manner in which each individual pressure and flow reading changes. Pattern recognition algorithms determine whether these specific changes show a significant movement away from recent, normal operation. The algorithms are designed to filter out background hydraulic noise thereby making the expansion wave associated with a leak visible.
- Reporting the results of this procedure to the controller.

After the detection and identification of the leak, *LEAKNET* determines the location at which the leak occurred by invoking *Locator*, a statistically based leak location algorithm. *Locator* determines the location of leaks using the same pressure measurements used by *PPA* and the actual speed of sound in the pipeline. With *Locator*, a measurement is required at each end of a monitored line segment; therefore, a single measurement point is not practical. *Locator* contains a heuristic learning module which accounts for pipeline geometry through real world results from controlled test leaks.

Leak Detection Method: Internal Pressure Analysis (Rarefaction Wave Monitoring)
Vendor: EFA Technologies
System: Pressure Point Analysis™ (part of LeakNet™ package)

Criteria	Evaluation/Comments
Applicability/Availability	*PPA* with *Locator* is commercially available and has been used successfully on crude oil transmission pipelines.
Effectiveness	<u>*Sensitivity*</u> The sensitivity of the *PPA* system depends largely on the amount of hydraulic noise at the measurement points and where the pump or compressor is operating on its curve. Essentially, the more smoothly the line runs, the greater the sensitivity. A well designed application with the equipment running at high efficiency and instruments located in hydraulically quiet locations may be sensitive to 0.15 percent of flow or less. For a typical crude oil application, sensitivities are in the range of 0.5 to 1.0 percent of flow (see Field Performance criterion). Detection time for *PPA* depends on the distance between the leak and the instruments. The leak signature travels at the speed of sound in the product. *PPA* typically will detect the leak within five minutes of the event's arrival at the instruments. If the leak signature is above the "noise floor" (the normal peak-to-peak variation in pressure or flow) the time will be under three minutes. <u>*Accuracy*</u> *PPA* relies on pipeline instrumentation to evaluate how the current data differs from operation over the past five minutes. Because the algorithms used by *PPA* are relational and there are no direct comparisons of data, instrument accuracy, unlike sensitivity and repeatability, is not a major concern. Infrequent maintenance of pressure transmitters and flow meters will not result in degraded leak detection or location performance by *PPA*. *Locator* accuracy depends upon the data update rate. EFA recommends sampling every 0.25 seconds. An update rate slower than recommended will result in degradation of location accuracy. <u>*Reliability*</u> *SmartPoint* is an intelligent alarm-processing feature which is configured by the user to alarm only when all specified conditions are met, potentially providing 100 percent nuisance alarm free operation. *SmartPoint* recognizes a leak on a pipeline segment by the characteristic decrease in pressure and increase in flow on the upstream segment (inlet) and a decrease in both pressure and flow on the downstream segment (outlet). <u>*Robustness*</u> *PPA* is tuned to detect leaks approaching the noise floor. Depending on the physical characteristics of the pipeline and how it is operated, normal peak-to-peak values may vary widely. *PPA* has detected leaks under conditions where normal operating transients ranged from 0.2 psig to >150 psig. To initiate an alarm, a leak must generate a pressure or flow signature that creates an excursion into a pipeline's peak-to-peak noise floor by 1/4. Once *PPA* is initiated, the system will "look" for a pattern in the excursion. If *LeakNet* can separate the pattern from random events, it will alarm, if not, it will rest itself and reestablish the system's sensitivity. A disadvantage inherent to this process is that a leak cannot be detected by *PPA* during the time it takes for the system to reestablish itself. The ability to detect a leak while the line is reestablishing itself was part of the ATA/API 3rd party testing protocol. *LeakNet* reliably detected leaks under these conditions that were sufficiently above the noise floor to be visible. In this case a change equivalent to 1/3 of the peak-to-peak range was detected. Note that by incorporating two independent methods of leak detection that use completely different ways of evaluating the line (pressure analysis and mass balance), *LeakNet* will detect leaks by one or both methods regardless of the

	transient conditions.
Transferability/Feasibility	*PPA* is transferable to crude oil transmission lines and has the following benefits: ▪ As documented in the field, *PPA* operates sufficiently under multiphase flow conditions; ▪ It can monitor bi-directional pipelines; ▪ It has been successfully applied in both arctic and underwater environments; ▪ For leak detection redundancy, it is readily compatible with a mass balance method (*MassPack*); and ▪ It can consistently detect leaks of less than 1 percent of daily throughput, thereby meeting ADEC criteria. *PPA* performs best when: ▪ Large transient events do not occur frequently. Although *PPA* is capable of detecting leaks under a wide range of normal peak-to-peak operating conditions (0.2 to >150 psig), highly dynamic pipelines tend to desensitize the system because *PPA* is constantly attempting to reestablish its sensitivity level following large normal transient events. Additionally, *PPA* is not capable of detecting leaks during the reestablishment process. ▪ There is no air present during slack line flow. One study indicated that *PPA* performed well under slack-line conditions (0.1 percent of flow) when the line was pulling a vacuum. This is because the effect of the expansion wave can travel through the vacuum and be detected. However, the system did not detect the expansion wave when air was present in the line.
Compatibility/System Requirements	<u>*Instrumentation*</u> LEAKNET operates using any high-quality electronic pressure transmitters or flow meters normally used in the petroleum industry. These instruments share a similar range of accuracy and repeatability that is suitable for leak detection. Pneumatic instruments with a P/I transducer will not work. Instrument evaluation for *PPA* leak detection is identical to that for normal process control. Per API-550, instruments are checked for calibration every six months. The leads are usually packed with a light product to prevent the crude from freezing the capsule. Modern instruments also have an internal diagnostic that can be run in under sixty seconds. If the instrument passes normal maintenance checks, it is working correctly. With *PPA*, the accuracy of the instrument is less important than repeatability and absolute sensitivity. The instruments must be able to respond to small changes and they must be able to repeatedly respond to the same small change in the same way. Whether the absolute value is correct is not critical to the analysis. <u>*Operating System/Communications*</u> The basic LEAKNET package consists of an industrial grade, rack mountable CPU, monitor, mouse and keyboard. If the link is via SCADA an appropriate cable and card are included. If the system collects its own information, the package can include the modems, analog to digital converter modules, power supplies, etc. Standard LEAKNET includes one Ethernet board with connectors for both 5BaseT (coaxial cable) and 10BaseT (modular telephone jack). It supports the TCP/IP and NetBEUI protocols. Other networks and protocols can be included at additional cost. The underlying Windows NT™ operating system includes support for simultaneous operation on multiple LANs using multiple protocols on each LAN. Communication needs to be at least 9,600 baud with 16-bit resolution. The data

interface is bi-directional and implemented using formatted ASCII files. The interface point is typically a network-accessible RAMdrive but any network-accessible drive can be used. Raw data are provided by the host DCS or SCADA system for LEAKNET's use in a simple format. LEAKNET provides files containing a user-selectable collection of the processed data which may be used by the host computer for display or other purposes.

Data interchange can also be implemented over an RS-232 link operating at 9,600 baud. The following systems have been interfaced to LEAKNET: Honeywell SCAN 3000; Whessoe Coggings Fuels Automation System (FAS); Mass Technologies, Inc.; ULSI Startrack; Valmet-Sentrol; Baker CAC Realflex; Control Systems International; Bailey System 90; Wunderware, Allen/Bradley and Heuristics On-Spec.

<u>*Sampling Frequency*</u>

The optimal data instrument sampling frequency for *PPA* is once every 6 to 10 seconds. Performance begins to degrade at 15 seconds. EFA found no significant improvement in sensitivity with updates faster than 6 seconds. Additionally, placing instruments closer together than 25-35 miles does not improve sensitivity, although more instruments do provide a level of redundancy which may be advantageous in remote areas. Longer sections (over 100 miles) can be monitored when reduced sensitivity is acceptable.

Leak location (*Locator*) requires an update rate of 0.25 seconds in liquids. *Locator* analyzes the data to find the data point representing the first evidence of the leak at each transmitter and uses those time stamps to make the location calculation. If the update rate is slower, there is a larger error forced into the system due to the physical speed of the event. The update rate used by *Locator* was selected to be the most compatible with the largest number of SCADA and PC-based data collection system.

<u>*Controller Training*</u>

The LEAKNET system can be installed and operational the day it arrives on site. Controller training takes one 8-hour day. Training for support personnel working with SCADA takes two to three days.

Environmental Impacts

There are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of *PPA*.

Regional Considerations

PPA has been proven in arctic and underwater environments, and has been installed on pipelines throughout Alaska and Canada. Relevant clients include ARCO Alaska, Inc., British Petroleum (Alaska), Esso Petroleum Canada, and Shell Products Canada Limited.

The principal limiting factor in terms of regional considerations is the field instrumentation, which needs to be physically rugged to operate in the extreme climactic conditions of Alaska. Oil companies in Alaska generally have already selected the equipment that works the best under these potentially adverse conditions.

Field Performance

The results of tests conducted on *PPA* systems for various crude oil transmission pipelines are presented in the following table.

Company/Scenario	Diam.	Length	Product	Detected Leak
Boeing Petroleum Services	36 in.	37 mi.	Crude	0.16% of flow in 240 seconds
Bahrain Petroleum Company	-	39 mi.	Crude	0.1% of flow in 35 seconds
Chevron (Mesa Line)	24 in.	80 mi.	Crude	1% in 10 minutes
Phillips Petroleum Company	10 in.	7 mi.	Multiphase	1.7% of flow in 66 seconds
Offshore Pipeline	8 in.	6 mi.	Multiphase	≈1% of flow in 60 seconds
ARCO Alaska (Kuparuk)	8-18 in.	50 mi.	Crude	≈1% of flow in 45 seconds
BPXA (Endicott/Badami)	12-16 in.	50 mi.	Crude	Failed to alarm at ≈100% loss of fluid*

**PPA* went into warning mode but never alarmed. Fortunately, *MassPack* did alarm. This

	emphasizes the importance of redundancy in leak detection.
Cost	Different *PPA* applications will have different initial costs. A short pipeline might only require monitoring of four field instruments or measurement points. A longer line might require forty points or even 75 points. Because of this variability, *LEAKNET* is available in standard sizes of 10 points, 25 points, 50 points, 75 points, and 100 points. Larger size systems cost more than the smaller one. Depending on the individual needs on a particular pipeline the owner may elect to purchase optional features such as leak *Locator* which will add to the price. Beyond that, a system collecting its own field data via modems and RTU boxes will cost more than one receiving data directly from SCADA because of the extra hardware costs. An important feature in the EFA pricing structure is the full availability of all points within the system for no additional licensing fees as they are brought on line. The price initially paid for the system is the actual cost. *LEAKNET* does not result in additional maintenance costs for the owner. The software does not require the maintenance and the PC only needs the routine care given to any PC. The field instruments used by *PPA* do not need to be recalibrated even as frequently as recommended by the API Standard Practices.

<u>Vendor Information</u>

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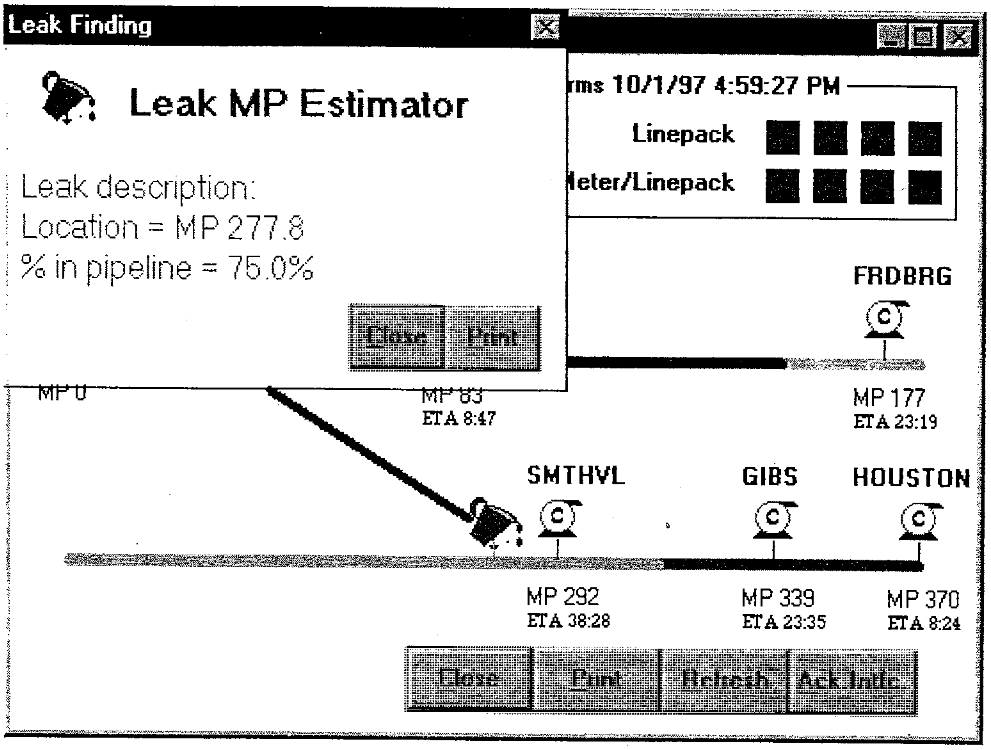
Fax: (916) 443-3759

Leak Detection Method: Internal Mass Balance
Vendor: EnviroPipe Applications
System: LEAKTRACK 2000



EnviroPipe Application's (EnviroPipe) *LEAKTRACK 2000* is a pipeline leak detection technology operating on the line-pack compensated volume balance approach. The basic premise of this technology is the metering in and out of product while the pressure along the pipeline is used to compute an accurate line pack. *LEAKTRACK 2000* is also capable of locating leaks through pressure drop analysis.

LEAKTRACK 2000 performs volume balance on a pipeline segment by measuring the discrepancy between the incoming and outgoing product volumes. Leak detection thresholds are set for four different alarm intervals (instantaneous, 15 minute, 1 hour, and 24 hours). The instantaneous volume balance calculation does not compensate for line pack; however, the 15-minute, 1-hour, and 24-hour imbalance measurements do. Line pack is calculated for each line segment every time the data is received from the SCADA system. The line pack for all segments is summed and compared to the alarm limits for processing. *LEAKTRACK 2000* performs volume correction on each segment by either accounting for temperature and pressure, or through interface detection/batch arrival functions. EnviroPipe prefers the latter because it is not sensitive to poor instrument readings. Actual volume displacements within a line segment is constantly being recalculated using interface detection (manually or automatically) to realign product interfaces to actual positions in the pipeline. This is done by modifying the volume between segments to accommodate more product or reducing the volume to push the interface further up the pipeline.

When a leak has been detected, *LEAKTRACK 2000* automatically runs its location algorithm. The pressure measurements from each transducer along the pipeline are saved during each SCADA scan. Following alarm initialization, the pressure measurements are analyzed to find the location of the first, second, and third pressure drops. Elapsed time among pressure drops is used to triangulate the location of the leak.

Criteria	**Evaluation/Comments**
Applicability/Availability	*LEAKTRACK 2000* is commercially available. The system has been installed on one crude oil transmission pipeline and is presently being installed on seven more.
Effectiveness	<u>Sensitivity</u> Leak detection sensitivity is directly affected by the data sampling capability of the SCADA system. Performance also depends on instrument quality and

	controller proficiency. The sensitivity of *LEAKTRACK 2000* as reported by the vendor is as follows: ▪ 1 percent of flow within 15 minutes ▪ 0.5 percent of flow within 1 hour ▪ 0.3 percent of flow within 24 hours These values correlate well with the actual performance of fielded systems (see Field Performance Criteria). <u>*Accuracy*</u> *LEAKTRACK 2000* largely relies on the accuracy of pipeline instrumentation to estimate parameters such as leak flow rate and volume lost. Leak location accuracy depends upon the spacing of the pressure transducers. *LEAKTRACK 2000* was able to locate a leak to within 75 miles of a transducer on a 295-mile pipeline equipped with only 3 transducers. <u>*Reliability*</u> To minimize false alarms, *LEAKTRACK 2000* can automatically adjust leak detection thresholds for a period of time while it determines if the source of the alarm is due to a leak or normal operating transients. It does so by the process described below. When an operating change occurs (i.e., pump start/stop), *LEAKTRACK 2000* automatically raises the alarm limits with an upset timer algorithm. This "new" alarm limit is used for leak detection for a period of time to allow the system to return to normal. After the upset timer has been active for 2 minutes, the existing line pack and meter over/short calculation is compared to see if these values are less than 25% of the unadjusted alarm limits. If they are, the reset timer is turned off and the limits are returned to normal. Additionally, limits are returned to normal if the upset timer has been active for 5 minutes and the line pack and meter over/short values have not exceeded 75% of the unadjusted alarm limits. In a 2-week field test at Colonial Pipeline, *LEAKTRACK 2000* experienced no false alarms. <u>*Robustness*</u> All mass balance systems, including *LEAKTRACK 2000* are limited by the performance of the meters. Some meters deal with transients better than others. Positive displacement meters are probably the most immune to transients. Pressure sensing flow meters, such as orifice meters, are probably the most affected. Also like any other mass balance system, *LEAKTRACK 2000* is vulnerable to poor meter maintenance or improper proving. *LEAKTRACK 2000* continues to operate during the loss of an instrument, or when missing values are encountered. The calculation for line pack and milepost extrapolation are minimally affected if the remaining transducers are fairly close (within 50-80 miles). At longer distances, the amplitude of the pressure wave can flatten and reduce the exactness of the calculations. Distance form pressure points and size of pressure drop are factors which affect the detectability in any configuration on any leak detection system.
Transferability/Feasibility	*LEAKTRACK 2000* is transferable to crude oil transmission lines and has the following benefits: ▪ It can compensate for line pack; ▪ It can monitor bi-directional pipelines; ▪ It can continually analyze operating noise and normal transient events to automatically adjust alarm thresholds; and

	▪ It can consistently detect leaks of less than 1 percent of flow. *LEAKTRACK 2000* performs best when: ▪ There is no multiphase flow; ▪ There is no slack-line flow; ▪ Large transient events do not occur frequently. Highly dynamic pipelines tend to desensitize *LEAKTRACK 2000* because the system is constantly adjusting alarm thresholds.
Compatibility/System Requirements	*Instrumentation* *LEAKTRACK 2000* operates using any high-quality electronic pressure transmitter, flow meter, or temperature sensor normally used in the petroleum industry. These instruments share a similar range of accuracy and repeatability that is suitable for leak detection. *Operating System/Communications* *LEAKTRACK 2000* relies solely on the data collected by the pipeline's SCADA system; therefore, it is imperative that the system is properly instrumented, calibrated, serviced, and maintained. The *LEAKTRACK 2000* software installation is usually confined to a dedicated workstation that only communicates with the computer handling the SCADA data. *LEAKTRACK 2000* is fully compatible with Windows NT and for optimal performance should be run on this platform. System hardware requirements include a standard computer with Pentium 300 or faster, 1 gig disk, 48 megabytes of RAM, CD-ROM, VGA monitor, LAN card, and 56K baud modem. *Sampling Frequency* Instruments should be sampled at the field level several times in a millisecond interval. The vendor recommends that the SCADA system have the ability to scan or poll every second to ensure accurate leak location. *Controller Training* EnviroPipe indicated that the *LEAKTRACK 2000* system can be installed and tuned in approximately one week. An additional couple of days is required to train engineering personnel and pipeline controllers.
Environmental Impacts	There are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of the *LEAKTRACK 2000* system.
Regional Considerations	*LEAKTRACK 2000* is a software-based LDS that works in conjunction with instrumentation and a SCADA system supplied by vendors other than EnviroPipe. It is installed on a computer in the control room; therefore, *LEAKTRACK 2000* can be applied to systems in any environment. The principal limiting factor in terms of regional considerations is the field instrumentation, which needs to be physically rugged to operate in the extreme climactic conditions of Alaska. Oil companies in Alaska generally have already selected the equipment that works the best under these potentially adverse conditions.
Field Performance	To date, the *LEAKTRACK 2000* system has been installed on one crude oil pipeline (Cenex) and is scheduled to be installed on seven more (Diamond Shamrock). The results of tests conducted on *LEAKTRACK 2000* systems for the Cenex crude line and other mixed-product pipelines are presented in the following table.

Company/Scenario	Diam.	Length	Product	Detected Leak (as % of flow)
Cenex Pipeline	16 in.	295 mi.	Crude	0.4% in 5 min*
Colonial Pipeline Co.	12 in.	254 mi.	Lt.-end	4% w/in 15 min; 1.5% in 1 hr; 0.2% in 24 hr**
GATX Pipeline	16 in.	108 mi.	Lt.-end	1.5% w/in 15 min; 0.3% w/in 24 hr.

Leak Detection Method: Internal Mass Balance
Vendor: EnviroPipe Applications
System: LEAKTRACK 2000

	GATX Pipeline 10 in. 87 mi. Lt.-end 1.6% w/in 15 min; 1% in 1 hr; 0.17% in 24 hr * The most conservative test results are presented. Other results were 0.06% in 5 min.; 0.12% in 8 min. ** Test results only. *LEAKTRACK 2000* is not installed on this pipeline. Lt.-end = Light-end (refined petroleum products)
Cost	Similar to transient models, *LEAKTRACK 2000* is a software-only system relying on the existing pipeline instrumentation and SCADA system for operating data (i.e., no costs associated with remote data acquisition and extra instrumentation). Unlike models, *LEAKTRACK 2000* does not rely on detailed pipeline simulation which typically requires numerous hours of tuning and extensive controller training. *LEAKTRACK 2000* typically can be installed for less than $100,000.

Vendor Information

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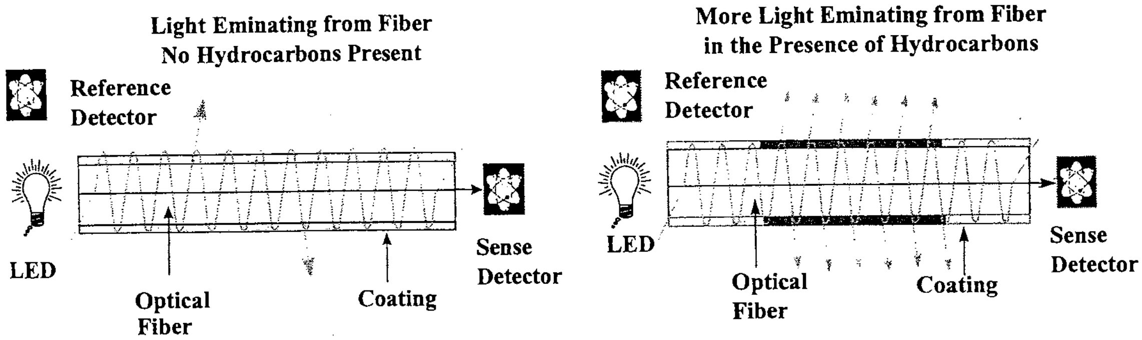
Leak Detection Method: Fiber Optic Chemical Sensor
Vendor: FCI Environmental Inc.
System: PetroSense®



FCI Environmental Inc.'s *PetroSense®* is a continuous-monitoring leak detection system incorporating patented fiber optic chemical sensor technology with digital electronics and a microprocessor. The chemical coating on the fiber optic sensor has a specific affinity for hydrocarbons which makes the *PetroSense* system accurate for total petroleum hydrocarbon (TPH) measurements. The *PetroSense* technology is based on the principle of a fiber optic chemical sensor and the modulation of light guided along an optical fiber (see figure above). A light emitting diode (LED) sends light thought the chemical coated strand of optical fiber. As the outside of the fiber comes in contact with hydrocarbons, some of the light traveling through the optical fiber escapes. A reference detector at one end and a sense detector (PD) at the other end of the fiber measure that loss of light. This change in the refractive index (loss of light) correlates to the concentration of hydrocarbons present. Data from the fiber optic sensors can be communicated to the controller via the pipeline's SCADA system.

Criteria	Evaluation/Comments
Applicability/Availability	*PetroSense* is a commercially available technology and reportedly applicable to crude oil lines; however, the technology has never been installed on a crude oil line and a recent API draft report indicates that the practical limit of the sensor is along the lines of a light heating oil (API, 1999). The vendor indicated that the best applications of the technology were for short fuel lines in an airport hydrant or refinery setting.
Effectiveness	*Sensitivity* *PetroSense* has a reported sensitivity to crude of <10 ppm in the vapor phase and 0.1 ppm in water. The reported probability of detecting a leak of 0.2 gallons/hr is 98% with a 2% false detection rate. The reported probability of detecting a leak of 0.1 gal/hr leak is 95% with a 5% false alarm rate. Response time to vapor is < 1 minute and water is <5 minutes. *Accuracy* The fiber optic sensor will only respond in the direct presence of hydrocarbons; therefore, the detection time is entirely dependent upon the spacing of the sensors, the hydrogeologic setting, and the physical and chemical characteristics of the product. In the direct presence of hydrocarbons, *PetroSense* is reported to have a 15-second initial response time, with an accuracy of ±15% of reading for vapor and ±10% of reading in water. *Reliability* The reported average probability of false alarming for any given application is ≤5%. Alarm thresholds are established during system calibration and are set above background contamination and noise levels. *Robustness* If a fiber optic sensor fails, the ability to continue to detect leaks at that sensor is lost. Following a leak event, all affected sensors must be excavated, cleaned,

	and reinstalled.
Transferability/Feasibility	*PetroSense* is reportedly transferable to crude oil transmission lines and has the following benefits: ▪ It can monitor pipelines operating under almost any scenario (slack line, multiphase flow, bi-directional); ▪ It does not require shutdown of operations for installation, calibration, or maintenance; ▪ It is unaffected by a high water table; and ▪ It is a continuous system that can consistently detect small leaks (typically less than what would be 1 percent of flow on a crude oil transmission line). *PetroSense* performs best when: ▪ The pipeline is buried. This technology is not really applicable to above ground pipelines; ▪ Pipelines are relatively short. The vendor indicated that the best applications of the technology were for short fuel lines (<10 miles) in an airport or refinery setting.
Compatibility/System Requirements	<u>*System Requirements*</u> Basic instrumentation for the continuous-monitoring *PetroSense* system includes the fiber optic sensors, data loggers, an AC power source, and a communications system (typically SCADA or telephone line). A pipeline SCADA system, if available, will also function in place of the data loggers. <u>*Testing Frequency*</u> The sampling time for each sensor is approximately 12 seconds; sensors may be polled continuously. <u>*Operator Training*</u> FCI will train individuals to interpret field data and operate/maintain the *PetroSense* equipment. Controller training is conducted in one day and may be done at FCI headquarters in Nevada for free or at the site at a cost of $750 per person per day. FCI also offers a remote-monitoring program at $25 per day per probe. Monitoring of the system is conducted by FCI at their headquarters in Nevada. The information from the sensors is transmitted to the data logger, which is downloaded monthly by FCI. The data are interpreted, compiled into a report, and sent to the client.
Environmental Impacts	Other than minimal excavation to place the fiber optic sensors (usually within the pipeline right-of-way), there are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of *PetroSense*.
Regional Considerations	The *PetroSense* leak detection system has been installed on a short fuel pipeline in northern Canada.
Field Performance	The *PetroSense* leak detection system has never been installed on a crude oil transmission pipeline.
Cost	The initial cost of the system depends on the application. Each site is unique, requiring a certain number of sensors and a specific system layout. System maintenance consists of annual inspection and calibration. The system has remote diagnostics to determine if any unscheduled maintenance is required. Upgrades are on a priority driven basis and the associated costs are relatively small.

Leak Detection Method: Fiber Optic Chemical Sensor
Vendor: FCI Environmental Inc.
System: PetroSense®

Vendor Information

Corporate:
FCI Environmental, Inc.
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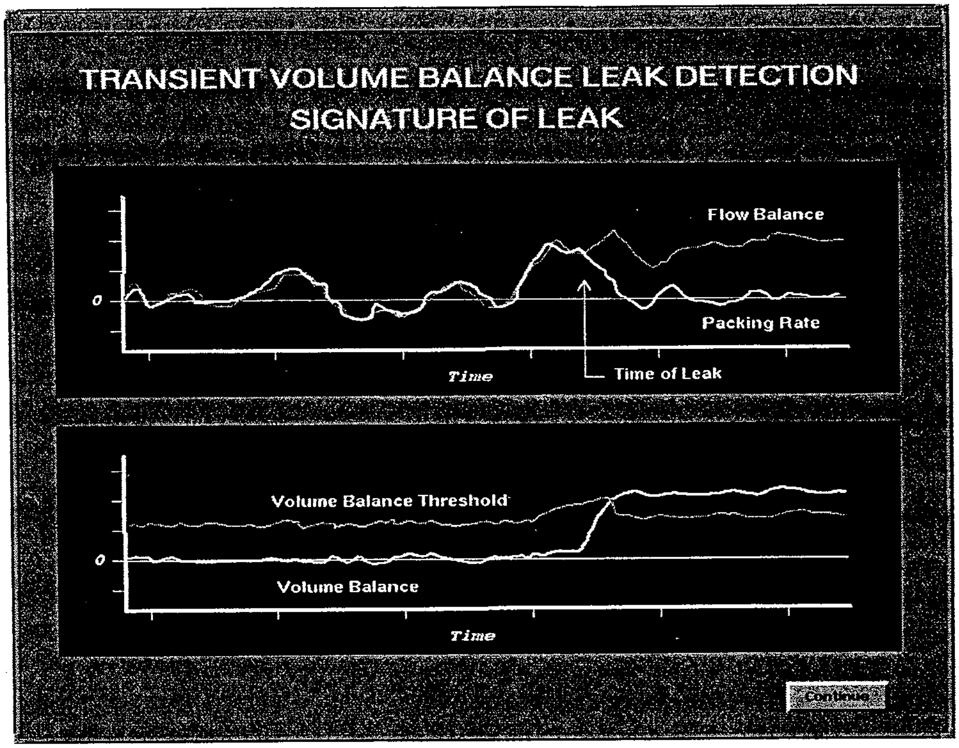
1181 Grier Drive, Building B
Las Vegas, Nevada 89119
Phone: (800) 510-3627
Fax: (702) 361-7921

Leak Detection Method: Internal Real Time Transient Modeling (RTTM)
Vendor: LICEnergy Inc.
System: Pipeline Leak Detection System (PLDS)



LICEnergy's *Pipeline Leak Detection System* (*PLDS*) is a leak detection technology operating on the model-compensated volume balance approach. *PLDS* is based on the real time simulation of flow in the pipeline with a rigorous transient computer model driven by SCADA data. The flow model uses mass, momentum, energy, and equation of state algorithms to continually and accurately determine volume balance on a defined pipeline segment by measuring flow balance and packing rate. The flow balance of a pipeline segment is the difference between input and output flow as measured by meters. The packing rate is the change in line pack (mass, or fluid inventory) within a segment due to changing conditions within the pipe (i.e., temperature and pressure). Accurate volume balance measurement is a function of the quality of the instrumentation, as well as current operational conditions. *PLDS* automatically and dynamically adjusts leak alarm thresholds for the noise level of volume balance fluctuations. A leak is alarmed if the positive volume balance on a given segment is sufficiently and persistently above the normal operating noise level.

PLDS consists of user-defined volume balance sections (VBSs) each with its own set of leak alarm thresholds and persistence criteria. The *PLDS* software analyzes flow in each VBS and computes volume using pressure-pressure boundary conditions. To enhance system, performance, *PLDS* allows the configuration of multiple VBSs (i.e., a section within a section) and leak detection averaging periods (LDAPs). By defining internal VBSs (bounded by intermediate pressure measurements) within an overall VBS, the time to detect a leak will decrease and the accuracy of determining leak size and location will increase. At the same time, robustness is maintained when a loss of intermediate measurements occurs since leak detection remains enabled in the overall VBS. A range of LDAPs, designed to reduce noise and increase sensitivity, are defined for each VBS to ensure a rapid response to large leaks, while maintaining sensitivity in longer time periods for small leaks.

The *PLDS* model has the following features:

- Cold start initialization using steady state solution;
- Warm start initialization using profiles from previous runs;
- Navier-Stokes equations of motion with Darcy/Moody/Weisbach friction force term;
- Rigorous energy equation;
- Local friction factor continuously recalculated from Reynolds number and roughness;
- Composition or batch tracking;
- Real-fluid equation of state which is continually recalculated based on local temperature, pressure, and composition;
- Viscosities calculated from Andrade equation at every point on the pipeline;

Leak Detection Method: Internal Real Time Transient Modeling (RTTM)
Vendor: LICEnergy Inc.
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- Reduction of frictional pressure loss due to drag reducing agents 9DRAs) and modeling of DRA concentration as a function of distance traveled and equipment traversed;
- Simultaneous solution of momentum, mass, and energy equations using numerical integration algorithm for accuracy and stability;
- Offline analysis of pipeline using archived data sets;
- Pipe expansion calculated from local temperature and pressure model;
- Detection of slack-line flow;
- Alarm criteria based on a combination of leak thresholds and persistence;
- Automatic adjustment of alarm thresholds for instrument noise and transient events;
- Pipeline network configuration and automatic reconfiguration;
- Analysis of tuning resulting in alarm when instrument calibration drifts beyond specified limits; and
- Real time calculation of pipeline state based on data input from the SCADA system.

Criteria	Evaluation/Comments
Applicability/Availability	*PLDS* is commercially available and has been installed on crude oil transmission pipelines.
Effectiveness	The *PLDS* model is entirely dependent on SCADA polling and input; therefore, the performance of the technology is dependent upon the performance of the SCADA system. For example, transient events occurring faster than the SCADA's scan cycle are only imperfectly tracked by the model. *<u>Sensitivity</u>* Leak detection sensitivity is directly affected by the data sampling capability of the SCADA system. The response time of the *PLDS* system is about 5 SCADA scans for large leaks (<5 percent of the rated flow), and about 100 SCADA scans for small leaks (≤1 percent of the rated flow). Leaks of less than 1 percent of flow typically are detected within 15 minutes. The actual performance depends on instrument quality and controller proficiency. Some installed systems have sensitivities of about 0.2 percent of the rated flow (see Field Performance criterion). *<u>Accuracy</u>* The *PLDS* model requires a large number of instruments placed at various points along the length of the line. Calculations are made for each point, comparing the real values against the calculated values. The more nodes a system has the more accurate it becomes. *PLDS* can locate leaks to within 5 to 10 percent of the distance between pressure transducers. *<u>Reliability</u>* As a result of establishing multiple VBSs and LDAPs, multiple leak detection thresholds are established and false alarms are minimized. Usually, a persistence criterion is added to the alarm logic on a VBS so that alarms are not triggered by temporary data fluctuations or by large transients on the pipeline. Reliability is also enhanced when PLDS automatically adjusts the volume balance thresholds according to local hydraulic conditions. This dynamic adjustment screens out false alarms during times of large or rapid transients. The adjustments are a function of several parameters including statistical variations in flow balance, packing rate, and mass balance, and pipeline operating parameters such as flow rate. *<u>Robustness</u>* Loss of communication with an instrument for a significant amount of time can disable modeling on that portion of the pipeline until communication is restored. The type and duration of the failure determines the degradation in system performance. Typically, loss of boundary condition measurements, which are those used to drive the hydraulic model, have the greatest effect. In this

	instance, *PLDS* would automatically disable leak detection for the VBS until the measurements are restored. At non-boundary measurement points, *PLDS* has an automatic reconfiguration feature that allows continued leak detection operation regardless of partial loss of data due to a lost sensor. Noise appears in the leak detection system as random fluctuations in the discrepancies between the calculated packing rate and flow balance. Typically, the SCADA scan period is sufficient to track normal transients such as compressor starts and stops, but high frequency fluctuations caused by chattering valves or instruments with poorly chosen feedback constants are more challenging. To deal with noise, the *PLDS* uses a high frequency filtering method based on seventh-order Bessel functions to improve the quality of the input SCADA data. *PLDS* also automatically adjusts alarm thresholds for instrument noise and transient events based on LDAPs.
Transferability/Feasibility	*PLDS* is transferable to crude oil transmission lines and has the following benefits: ▪ It can compensate for monitoring during packing and unpacking of the line; ▪ It reportedly operates sufficiently under multiphase flow conditions; ▪ It reportedly operates sufficiently under slack-line flow conditions; ▪ It can monitor bi-directional pipelines; ▪ It can monitor and compensate for the effects of DRA in the line; ▪ It can continually analyze operating noise and normal transient events to dynamically adjust alarm thresholds, minimize false alarms, and assure accurate leak identification; ▪ It has been successfully applied in both arctic and underwater environments; and ▪ It can consistently detect leaks of less than 1 percent of flow, thereby meeting ADEC criteria. *PLDS* performs best when: ▪ Large transient events do not occur frequently. Highly dynamic pipelines tend to desensitize the system because *PLDS* is constantly attempting to reestablish sensitivity and alarm thresholds.
Compatibility/System Requirements	LICEnergy does not provide or install any of the instrumentation or communication hardware associated with *PLDS*. They do provide the leak detection software, as well as the following services: configuration, interfacing, installation, initial tuning, testing, and training. *<u>Instrumentation</u>* *PLDS* operates using any high-quality electronic pressure transmitter, flow meter, or temperature sensor normally used in the petroleum industry. *PLDS* requires the placement of flow, pressure, and temperature sensors at all supply and delivery points, and pressure and temperature sensors at upstream and downstream ends of pump stations and pressure control valves. Additional pressure sensors are recommended at intermediate points to increase leak detection sensitivity. *PLDS* also requires instruments capable of measuring product density and viscosity. <u>Operating System/Communications</u> The *PLDS* model relies solely on the data collected by the pipeline's SCADA system; therefore, it is imperative that the system is properly instrumented, calibrated, serviced, and maintained. *PLDS* software installation is usually confined to a dedicated workstation that communicates with the computer handling the SCADA data. *PLDS* is configurable using text files, binary files,

Leak Detection Method: Internal Real Time Transient Modeling (RTTM)
Vendor: LICEnergy Inc.
System: Pipeline Leak Detection System (PLDS)

<table>
<tr><td></td><td>and the OMEGA graphical user interface.

<u>Sampling Frequency</u>

Analog measurements should be taken at the field level several times in a millisecond interval. For maximum performance, the vendor recommends that the SCADA system have the ability to scan or poll every 5 seconds.

<u>Controller Training</u>

Models are inherently complex and require a sophisticated user; therefore, controller training is extensive. Models may require a full time SCADA engineer to keep them up and running, and vendor participation to modify them.</td></tr>
<tr><td>Environmental Impacts</td><td>There are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of the PLDS system.</td></tr>
<tr><td>Regional Considerations</td><td>PLDS is a software-based LDS that works in conjunction with pipeline instrumentation and a SCADA system supplied by vendors other than LICEnergy. It is installed on a computer in the control room; therefore, PLDS can be applied to systems in any environment.

The principal limiting factor in terms of regional considerations is the field instrumentation, which needs to be physically rugged to operate in the extreme climactic conditions of Alaska. Oil companies in Alaska generally have already selected the equipment that works the best under these potentially adverse conditions.</td></tr>
<tr><td>Field Performance</td><td>The PLDS system has been installed on pipelines in arctic and underwater environments. Relevant clients include Alyeska Pipeline Services Company (Alaska) and Amoco Canada Petroleum Company, Ltd (Canada). The results of tests conducted on PLDS systems for various crude oil transmission pipelines are presented in the following table.

<table>
<tr><th>Company/Scenario</th><th>Diam.</th><th>Length</th><th>Product</th><th>Detected Leak</th></tr>
<tr><td>Alyeska Pipeline (TAPS)</td><td>48 in.</td><td>800 mi.</td><td>Crude</td><td>0.12% of flow tight-line; 0.21% in slack-line*</td></tr>
<tr><td>Amoco Canada</td><td>12 in.</td><td>1900 mi.</td><td>Light-end</td><td>4% in 20 min; 1% in 30 min.**</td></tr>
<tr><td>Koch Industries</td><td colspan="4">Would not give details, but indicated they were satisfied with the system.</td></tr>
<tr><td>Texaco Trading & Trans.</td><td colspan="4">Would not give details.</td></tr>
</table>

*Original design by SSI (Houston), which was acquired by LICEnergy.
**Since testing the detection times have been reduced 40%. Location error ranged from 3 to 70 miles.</td></tr>
<tr><td>Cost</td><td>The biggest disadvantage of the LICEnergy PLDS system is the expense associated with its implementation and maintenance. Models require extensive instrumentation for real-time data collection and pipelines often have to retrofitted with additional pressure transducers and flow meters. Additionally, models are custom software which means they take some time to prepare and bring on line, often a year or more.</td></tr>
</table>

<u>Vendor Information</u>

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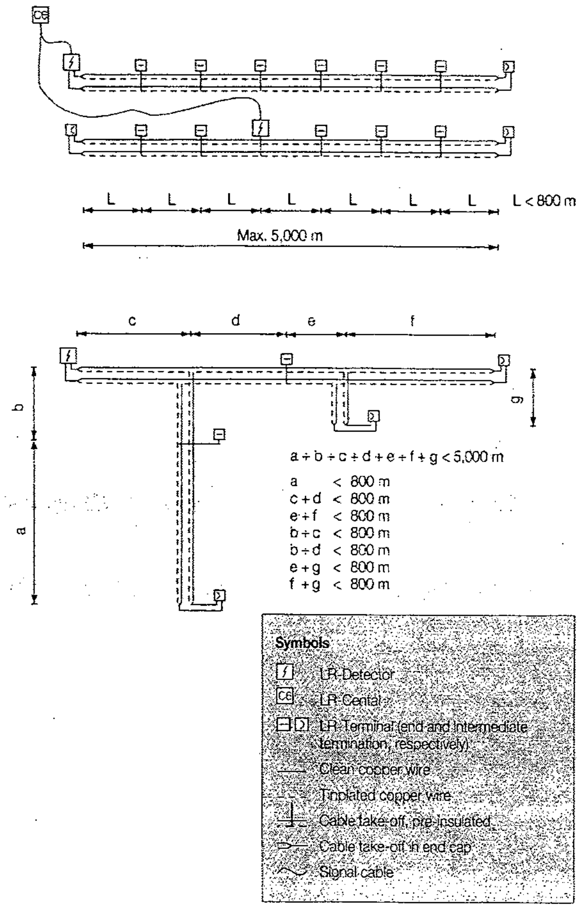
Leak Detection Method: External Liquid Sensing Cable
Vendor: Løgstør Rør
System: LR-Detector



Løgstør Rør uses polyurethane foam as part of the sandwich construction for their bonded (double-walled) pipe systems. The concept of bonded pipe elements is that the thermal expansion of the hot inner pipe is constrained by the outer pipe. Løgstør Rør's *LR Detection System* is designed to work in conjunction with their bonded pre-insulated piping. The *LR Detection System* uses a pulse reflectometer and copper sensor wires embedded within the polyurethane insulating layer to detect and locate leaks. The *LR-Detector* records the electric conductivity of the insulation on an ongoing basis. When a leak occurs, product enters the insulation, conductivity increases, and a signal is transmitted to the reflectometer. To locate the leak, the instrument measures the reflection time from the measuring point to the leak position. The reflection time is a function of the propagation velocity of the liquid in the surrounding material and the distance to the leak position. The pulse reflectometer shows the condition of the insulation and the wire in graphical form as a function of length. If the instrument is adjusted to the correct propagation velocity for the insulation, the distance can be read directly from the instrument display.

A single Løgstør Rør *LR-Detector* can monitor approximately 6 miles of pipe; however, signals can be transmitted via the sensor wires from one *LR-Detector* to the next, so longer pipelines may also be monitored. Up to six *LR-Detectors* can be monitored from a central location (*LR-Central*). Additionally, both the *LR-Detector* and *LR-Central* can be connected via SCADA or some other form of communication to the pipeline's control room. Positions along the pipeline known as *LR-Terminals* are the measuring points for leak location. To maximize accuracy, the distance between measuring points should not exceed 2600 feet or approximately 0.5 miles.

Criteria	Evaluation/Comments
Applicability/Availability	Løgstør Rør's *LR Detection System* is commercially available and is reportedly applicable to crude oil transmission lines; however, to date, the system has only been installed on water pipelines. Note that existing crude lines cannot be retrofitted with this technology. It is applicable to new installations only and the pipe itself must be supplied by the vendor.
Effectiveness	<u>*Sensitivity*</u> The *LR Detection System* sensitivity has been optimized for use in district heating applications. Leak detection is based on a measurement of the electrical resistance between the wire and the carrier pipe. The choice of alarm level is based on the conductivity of the actual media. In district heating, the chosen level corresponds to water contacting the wire and propagating 4 inches through the pipe. In the case of crude oil, the alarm level will be chosen based on experiment and the size of the leak to be detected. <u>*Accuracy*</u> Leak location by means of a pulse reflectometer can be carried out accurately, provided the wiring is known and measuring points are accessible at suitable

	intervals. The shorter the distance between the measuring point and the leak, the greater the accuracy and the smaller the risk of faulty measuring. Using a pulse reflectometer the accuracy is approximately 0.1 percent of the distance between measuring points. _Reliability_ The system is not sensitive to high magnetic fields or any electrical noise from the surrounding environment. _Robustness_ The *LR Detection System* has an integrated function to ensure that the detection system is intact at all times. This means any system errors (i.e., a broken wire) will be reported. The *LR Detection System* is designed to detect leaks of products at temperatures ranging from -328°F to 302°F. However, the existing casings of the detection boxes can only withstand temperatures as low as -4°F, so they would require modifications to meet the arctic conditions.
Transferability/Feasibility	The *LR Detection System* is reportedly transferable to Løgstør Rør-installed crude oil transmission lines and has the following benefits: ▪ It is a built-in leak detection system; ▪ It can monitor pipelines operating under almost any scenario (slack line, multiphase flow, bi-directional); ▪ The pipe jacket is 100% watertight and salt resistant; therefore, it can be applied to submarine/underwater piping; ▪ The system can be modified to handle low temperatures, so it is may be applied to pipelines operating in the arctic; ▪ Because it has a chemical-resistant outer jacket, leaks can be contained within the pipeline; and ▪ It is a continuous system that can consistently detect small leaks on water lines. Actual performance with crude oil has yet to be verified. The *LR Detection System* performs best when: ▪ The pipeline can be readily divided into segments less than 6 miles long for leak detection and less than 0.5 miles long for leak location.
Compatibility/System Requirements	_Instrumentation_ *LR Detection System* instrumentation generally includes the sensor wires, *LR-Detector(s)* with pulse reflectometer(s), *LR-Central*, and *LR-Terminal(s)*. Wire and pipe connections are established for *LR-Detectors* and *LR-Terminals* by means of pre-insulated cable take-offs. The *LR-Detector* and *LR-Central* can be powered by battery or connection to a main system. The *LR-Terminal* does not require a power supply. _Operating System/Communications_ Field data from the *LR-Detector(s)* and/or *LR-Central* may be communicated to the pipeline controller in a number of different ways, including modem, SCADA, radio, and/or satellite. _Testing Frequency_ The system continually monitors for leaks along the entire length of pipeline equipped with sensing wires and *LD-Detector(s)*. _Controller Training_ Løgstrør Rør's training program features a course which explains the use and installation of the components used in the *LR Detection system*. The training

	course is 5 days long and can be conducted in Løgstør, Denmark or on-site, which ever is more cost effective
Environmental Impacts	Because the *LR Detection System* is installed with new piping, there are excavation considerations. However, there aren't any additional air, land, water, energy, or other system requirements specific to the leak detection component that may offset the anticipated environmental benefits of system.
Regional Considerations	The product has been manufactured to withstand a wide range of temperatures, climates, and environments, including arctic and submarine conditions.
Field Performance	The system has not been applied to any oil and gas projects, but has extensive application in district heating pipelines. In 1999 and 2000, the City of Fairbanks will be installing approximately 12 miles of Løgstør Rør district water heating pipeline with the *LR Detection System.*
Cost	Pricing information is available from the vendor.

Vendor Information

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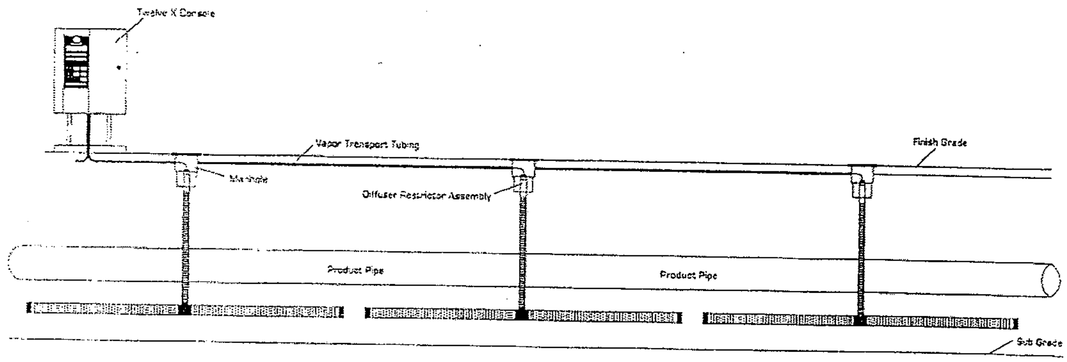
Leak Detection Method: External Soil Vapor Detection
Vendor: NESCO Technology Division (formerly Arizona Instruments)
System: Soil Sentry Twelve-XP



NESCO's *Soil Sentry Twelve-XP* is an aspirated vapor monitoring system designed to analyze concentrations of vapor-phase hydrocarbons in soil surrounding a pipeline. Air samples are extracted from monitoring wells/points along the pipeline and vapors are analyzed using a metal oxide sensor (MOS). Results are based on measured differences in resistivity. Monitoring wells typically are positioned horizontally along the line, as depicted in the figure above. For remote monitoring of long pipelines, multiple *Soil Sentry Twelve-X* consoles can be connected via a communications link to a personal computer at the site, or in a separate location. One console is capable of continuously monitoring twelve horizontal wells, or about 1500 feet of line pipe (pictured above). Soil Sentry communications software provides access to all data and allows complete operation of the *Twelve-XP* system through standard phone lines. If there is a system alarm, the console will provide the user with analytical and leak location information. The user may remotely acknowledge and, if necessary, reset the alarm, trouble shoot the sensor, and/or reconfigure the system.

Criteria	Evaluation/Comments
Applicability/Availability	NESCO's *Soil Sentry Twelve-XP* is commercially available and is reportedly applicable to crude oil transmission lines; however, the system has only been installed on small fuel hydrant lines.
Effectiveness	<u>Sensitivity</u> The system is capable of detecting leaks as small as 0.003 gallons per hour (gph) within 12 hours. Strategic placement of the sampling points, in addition to soil porosity dictates the speed with which the system will detect vapor. The system does not provide true analytical results; rather, the MOS is a hydrocarbon screening tool designed to detect between 50 and 3500 ppm of hydrocarbon vapor. <u>Accuracy</u> The capability of locating leaks with *Soil Sentry Twelve-XP* is directly dependent upon the spacing of the horizontal wells. Each of the twelve monitoring wells is sampled in sequence, so the location of a leak can be isolated to between two well points. <u>Reliability</u> The occurrence of false alarms depends on the presence of existing hydrocarbons (i.e., from previous spills/leaks or naturally occurring). Typically, the *Twelve-XP* system is installed and operated for 7 to 14 days to determine background hydrocarbon concentrations. The alarm levels are then set at a point above background. <u>Robustness</u> The *Twelve-XP* system has automatic shutdown capabilities. Once an alarm condition is achieved the relay is immediately triggered.

Transferability/Feasibility	*LEAKWARN* is reportedly transferable to crude oil transmission lines and has the following benefits: ▪ It can monitor pipelines operating under almost any scenario (slack line, multiphase flow, bi-directional); ▪ It does not require shutdown of operations for installation, calibration, or maintenance; and ▪ It can consistently detect leaks of what would typically be less than 1 percent of flow on a crude oil transmission line. *LEAKWARN* performs best when: ▪ The pipeline is buried. This technology is not applicable to above ground or underwater pipelines; ▪ The vadose zone is greater than 18". There must be sufficient space to facilitate vapor migration to each monitoring point; ▪ Soil type allows 1.5 liters/minute of air to be drawn from the sampling point; and ▪ Pipelines are relatively short. One *Twelve-XP* console is capable of monitoring twelve horizontal wells or about 1500 feet of pipe.
Compatibility/System Requirements	*Instrumentation* The major components of the *Soil Sentry Twelve-XP* system include an MOS sensor, sixteen solenoid valves, a single-directional internal air pump, power supply, and internal modem (optional). HDPE tubing is used to transport the air samples from the horizontal monitoring wells to the console. The console is installed inside a building or weather-proof enclosure and powered by 115 VAC. The transport tubing can be installed in a conduit or directly in the ground. The *Twelve-XP* sensor typically is changed every 12 to 24 months depending on the level of fuel in the ground at the site. Other individual parts such as solenoid valves are replaced occasionally. *Operating System/Communications* The *Twelve-XP* typically operates with its own personal computer, communicating directly via modem with the remote field consoles. The vendor indicated that a pipeline's SCADA system may be used for communication; however, this has never been done on an installed system. *Testing Frequency* One *Twelve-XP* console continuously samples the 12 vapor monitoring wells/points. *Controller Training* Pipeline controllers can be trained to read and interpret the *Twelve-XP* results, but NESCO indicated they would probably stay involved with equipment maintenance and some of data interpretation.
Environmental Impacts	Other than excavation to place the horizontal monitoring wells (usually within the pipeline right-of-way), there are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of *Soil Sentry Twelve-XP*.
Regional Considerations	*Soil Sentry Twelve-XP* has never been installed on pipelines in Alaska. However, the system has been installed on small fuel lines in South Dakota and on fuel storage tanks in Alaska, northern Canada, and Minnesota.
Field Performance	*Soil Sentry Twelve-XP* has never been installed on a crude oil transmission line. It has been successfully installed on small fuel hydrant lines at a U.S. Air Force base in South Dakota. The reported sensitivity of the system on these lines is

	0.01 gph.
Cost	The *Soil Sentry Twelve-XP* console system with remote communications software and modem (which can monitor approximately 1500 feet of pipe) is $7200. This does not include the cost of installing and connecting the horizontal monitoring wells. NESCO recommends annual calibration of the metal oxide sensor, which can be accomplished in the field with a calibration kit that sells for $595.

Vendor Information

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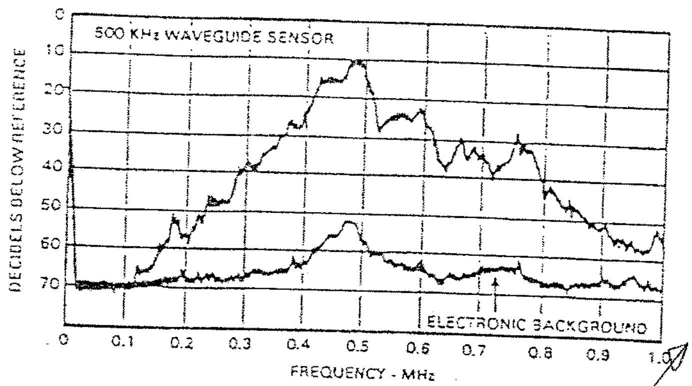
Leak Detection Method: External Acoustics Emissions
Vendor: Physical Acoustics Corporation
System: Acoustics Emissions (AE)



Just like Sonar

Physical Acoustics Corporation (PAC)'s Acoustic Emissions (*AE*) leak detection system uses non-invasive acoustic sensing technology to identify and locate pipeline leaks. Acoustic emissions are stress waves produced by the high differential pressure at the leak orifice. The waves radiate from the source through the pipeline and are detected by piezoelectric transducers placed at intervals along the pipeline. The transducers convert the energy from a sound wave into an electrical (RMS) signal, which is then amplified and processed by standard acoustic emission instrumentation. Deviations from the pipeline's baseline acoustic profile (i.e., electronic background), which is created during system calibration, would signal an alarm (see figure above). Once a leak is detected, the arrival times of each acoustic event are fed into an algorithm that predicts the most likely origin of the event.

Acoustic sensing can be applied externally to buried pipelines by using steel rods driven into the ground to conduct the sound to a sensor mounted on the rod. The rods are inserted at intervals along the pipeline.

Criteria	Evaluation/Comments
Applicability/Availability	*AE* is a commercially available technology and is reportedly applicable to crude oil; however, the technology has never been installed on a crude oil transmission line.
Effectiveness	<u>*Sensitivity*</u> The sensitivity of the *AE* system for most applications is 1 to 10 gallons per hour, which typically is less than 1 percent of daily throughput for a crude oil transmission line. <u>*Accuracy*</u> On the recommended pipeline segment length of 200 feet (with sensors at either end), the *AE* system can locate leaks to within 2 feet. <u>*Reliability*</u> The *AE* system reportedly has no false alarms because it uses built-in alarm logic to differentiate a leak from other sources of noise. The signal data from a potential leak are allowed to build over time (approximately one hour) and are analyzed to determine if the acoustic pattern matches that of a leak (i.e., the signal remains consistently high over a given time period). The vendor indicated that the *AE* system can easily differentiate between a leak and a one time transient event. Of more concern than false alarms are the reporting of false locations by the *AE* system. The presence of elbows and T's in a pipeline's geometric configuration can alter the acoustic signals emitted during a leak event and affect the system's ability to accurately place the origin of the leak. <u>*Robustness*</u> Identification and elimination of external ambient and pipeline operating noise is essential for an accurate acoustic assessment. External noise sources can be effectively avoided through careful choice of measurement period and sensor

	location or minimized through robust data collection and signal processing. In the event that an acoustic sensor is lost or is malfunctioning, the *AE* system will send a low-level alarm to the controller. If the failed instrument is not an end unit (i.e., there are additional sensors further down the line), the *AE* system will continue to detect and locate leaks, albeit at reduced sensitivity and location accuracy.
Transferability/Feasibility	*AE* leak detection is <u>reportedly</u> transferable to crude oil transmission lines and has the following benefits: ▪ It is non-invasive and non-destructive; ▪ It has been applied in arctic environments (successful application depends on the skin temperature of the pipeline; the *AE* sensors are rated to –40°F); ▪ Testing indicated that it can potentially be applied to underwater/offshore applications where maximum water depth is 100 feet; ▪ It has the capability of detecting corrosion prior to breakthrough; ▪ It does not require shutdown of operations for installation, calibration, or maintenance; ▪ The non-intrusive nature insures against the system itself being the cause of a future pipeline leak; ▪ It permits application to pipelines which are "pigged"; and ▪ It can reportedly detect leaks of 1 to 10 gallons per hour. *AE* leak detection performs best when: ▪ There is no multiphase or slack-line flow (the presence of gas in the pipeline interrupts the ability of the system to transport acoustic waves); ▪ Transducers are spaced along the pipeline at intervals less than 300 feet; ▪ The signal velocity of the product within the pipe is known; ▪ Background noise is minimized or filtered; and ▪ Large pressure transients do not occur frequently.
Compatibility/System Requirements	<u>*Instrumentation*</u> PAC's acoustic emissions piezoelectric sensors are designed for high-sensitivity/low-noise measurement. The sensor assembly, which consists of an *AE* sensor, preamplifier, and connecting cables, is mounted to the outside surface of the pipe at an optimal interval of one every 200 to 300 feet. Coaxial cables are used to conduct the acoustic emissions signals from the sensor assembly to the Acoustic Leak Monitor (ALM). <u>*Operating System/Communications*</u> For permanent and continuous monitoring of liquid transmission pipelines, the vendor recommends using a multi-channel *AE* leak detection system. These computer-based systems are based around the ALM, which has the following characteristics: ▪ Modular Design; ▪ 1 to 8 Channel Expandability (a channel is required for each *AE* sensor system; recommended pipeline segment length is 200 to 300 feet); ▪ Continuous Monitoring; ▪ User Variable Sensitivity; ▪ 19-Inch Rack-Mount Chassis; and ▪ Three Alarm Levels The ALM uses specific software for tracking long-term monitoring conditions while simultaneously reflecting instantaneous results and alarm status. Data communication from the ALM to the master computer (a stand alone PC or part of the control room rack) is provided either through an RG58 system (limited by

	cable length) or a newer application whereby the RMS signal from the ALM is sent to the master computer via twisted cable pairs. The master computer console provides audio/visual alarms to signal a possible leak event. _Sampling Frequency_ The AE sensors continually transmit electrical signals indicative of the present "noise" level on the pipeline. Data are analyzed by the ALM and can be sent to the master computer either on an alarm or polling basis. _Controller Training_ Controllers can be trained in the operation and maintenance of the *AE* leak detection system in about 40 hours at approximately $900 per person.
Environmental Impacts	There are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of *AE* leak detection.
Regional Considerations	The *AE* system has been proven in arctic environments and has been installed in Siberia. In cold-climate conditions, the technology is limited by the skin temperature of the pipeline. The acoustic sensors are rated to –40°F.
Field Performance	The *AE* leak detection system has never been installed on a crude oil transmission pipeline.
Cost	For continuous leak detection, the *AE* system can be installed on a single pipeline segment of 200 to 300 feet (i.e., 2 sensor systems with a 2-channel ALM) for $5,000 to $12,000. Each additional segment requires a channel at an added cost of approximately $3,000.

Vendor Information

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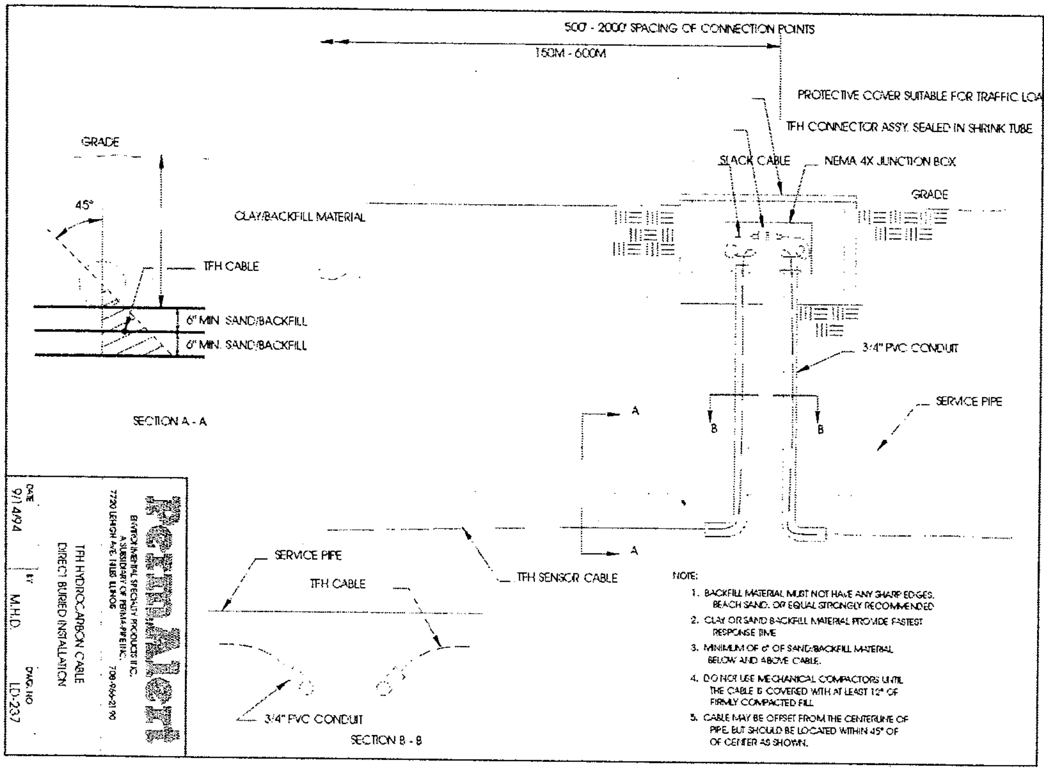
Leak Detection Method: External Liquid Sensing Cable
Vendor: PermAlert
System: PAL-AT®



PermAlert's *PAL-AT®* is an external leak detection system based on the hydrocarbon liquid-sensing principle. It is a cable-type leak detection and location system consisting of a microprocessor based monitoring unit, jumper and hydrocarbon (TFH) sensor cables, system layout map, and auxiliary equipment. PAL-AT operates similar to radar by sending out safe energy pulses (two thousand times a second) on the sensor cable. The reflection generated by these energy pulses is specific to the condition of the installed sensor cable. The cable reflections are measured, digitized, and stored in memory as a reference map. The alarm unit continuously measures the cable reflections and compares them with the referenced values. Liquids in sufficient quantities to "wet" the sensor cable will alter the cable's impedance at the leak location. This alteration will change the amplitude of the energy reflected from the cable. The monitoring unit's microprocessor recognizes the change and provides audio and visual alarms to the controller, including a digital output of the distance to the leak origin. After proper acknowledgement of a leak, *PAL-AT* is capable of monitoring the entire sensing cable for additional leaks even if they are smaller than the leaks previously acknowledged.

PAL-AT units can monitor eight separate hydrocarbon-sensing cables each having up to 10,000 feet of cable length. The cables can be buried underground (typical installation pictured above) or affixed to the bottom of an aboveground line at the 6 o'clock position. Network software known as PALCOM® runs the *PAL-AT* leak detection system. The software has the ability to continuously monitor the status and/or remotely operate each *PAL-AT* unit. PALCOM® is available in Windows® 3.X/95/98/NT and can simultaneously monitor up to 254 *PAL-AT* units (approximately 3,800 miles of sensing cable).

Criteria	Evaluation/Comments
Applicability/Availability	PermAlert's *PAL-AT* is commercially available and is applicable to crude oil transmission lines; however, to date, the system has only been installed on small segments of crude pipelines, typically in highly sensitive areas such as

	river crossings.
Effectiveness	*Sensitivity* The system will not detect incidental liquid contact. On a 10,000-foot cable segment, a leak generally must be sufficient to wet 20 feet of cable. The sensitivity of the system is field adjustable to increase or decrease the amount of wetted cable needed to cause an alarm from several inches to feet. In the presence of a sufficient amount of hydrocarbon liquid, the response time of the *PAL-AT* system is less than 5 minutes, regardless of temperature. *Accuracy* The *PAL-AT* system will identify the presence of a liquid at any point along its sensing string and indicate its location within +/-1% of the distance from the last calibration point or +/- five feet, whichever is greater. *Reliability* The false alarm rate of external leak detection systems is generally much lower than that of statistically based internal systems. The vendor indicated that false alarms on the *PAL-AT* system typically are the result of improper installation of the cable connections. No false alarms were reported during EPA third-party testing. When liquid is detected, *PAL-AT* sounds an alarm and displays the location of the leak. The unit then continues to monitor the cable and will re-alarm if there are any major changes. The system is capable of monitoring (detecting and locating) multiple leaks or additional liquid on the sensor cable. *Robustness* Because the *PAL-AT* system uses reflected energy data specific to the condition of the installed sensor cable, the reference map can include energy reflections from wet cable. This allows the sensor cable to be installed in environments that are not "bone dry". With certain types of cables the system's software can use wet cable segments, from an acknowledged leak, in a reference map. This allows the monitoring unit to continue providing leak surveillance while remedial efforts are undertaken. Note that the TFH cable can not be reused after exposure to crude oil. In the event of a power failure, system conditions and parameters shall be stored in nonvolatile memory allowing the unit(s) to automatically resume monitoring, without resetting, upon restoration of power. An improperly installed connector can limit the ability of the system to see beyond the connector. Additionally, when a cable is pinched, cut, or broken, a break alarm is sent to the controller, the *PAL-AT* system is disabled, and the cable must be replaced prior to system restart. The *PAL-AT* unit is designed to be located inside a temperature-controlled building. The operating temperature range is 0°F to 120°F.
Transferability/Feasibility	*PAL-AT* is reportedly transferable to crude oil transmission lines and has the following benefits: ▪ It can monitor pipelines operating under almost any scenario (slack line, multiphase flow, bi-directional); ▪ It does not require shutdown of operations for installation or maintenance; ▪ Other than developing an initial reference map (depicting cable location and response patterns), the system does not require calibration; ▪ It has been installed in Alaska; and ▪ It is a continuous system that can consistently detect small leaks (typically less than what would be 1 percent of flow on a crude oil transmission line).

	PAL-AT performs best when: ▪ Sensor cables and jumper cables are not installed in locations that are subject to frequent moisture intrusion or wetness; and ▪ The burial depth of the hydrocarbon (TFH) sensing cable is less than 20 feet.
Compatibility/System Requirements	<u>*Instrumentation*</u> The *PAL-AT* unit consists of a solid state electronic alarm/location panel connected by jumper cable to a sensor cable. There are five models of the *PAL-AT* leak detection/location system available. The most applicable to crude transmission lines is the *PAL-AT AT20K*. If a *PAL-AT* unit is direct wired, a short haul modem (PermAlert Model SHS-1 or compatible) is provided along with the necessary cables, power supply, and accessories to allow connection and communication to the computer system. A phone modem (Model PM-1) is also provided for remotely located *PAL-AT* units. In addition to the above referenced material, the contractor will provide a dedicated phone line, communications cable, power supply, and other materials as may be required to ensure the proper operation of the computer. <u>*Operating System/Communications*</u> PALCOM® is the central point monitoring system for a single or multiple *PAL-AT* leak detection and location units. PALCOM® is interactive with each *PAL-AT* providing bi-directional communications. It receives status information (i.e. leak, break, short, location, etc.) from each *PAL-AT* and also allows remote operation of each *PAL-AT*. The minimum hardware requirements for PALCOM® for Windows are a personal computer 386SX 100% compatible system (486 recommended), 2M available RAM memory, one 3 ½" or one 5¼" high density disk drive, one hard disk drive with a minimum of 2MB available memory, one RS-232 serial port, one Parallel printer port, one Graphics adapter and monitor (VGA or CGA), Microsoft Windows operating system, version 3.1 or higher, and a mouse. <u>*Testing Frequency*</u> *PAL-AT* continually monitors and tests for leaks, breaks, or errors within the system. <u>*Controller Training*</u> PermAlert will provide a factory-trained representative at on-site meetings for the pre-construction and sensor/electronics installation. The installing contractor will be responsible for coordinating training by PermAlert for the PALCOM® controllers. Training will consist of a factory-authorized person performing a minimum of four hours training on the system.
Environmental Impacts	Other than excavation to place the liquid-sensing cable beneath buried piping (usually within the pipeline right-of-way), there are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of *PAL-AT*.
Regional Considerations	The *PAL-AT* system is reportedly designed for all climates (desert, arctic, underwater, etc.), and has been installed on tanks and pipelines throughout Alaska.
Field Performance	The *PAL-AT* leak detection system has only been installed on small segments of crude oil transmission pipelines. The installations typically are in highly sensitive environments such as river crossings. There are no field test results because there is no way to simulate a real leak event without exposing the environment to hydrocarbons. Additionally, the cable must be excavated and replaced following contact with liquid hydrocarbons.

Leak Detection Method: External Liquid Sensing Cable
Vendor: PermAlert
System: PAL-AT®

Cost	The approximate costs of the *PAL-AT* system are $10 per foot of cable plus panel and PALCOM® software costs.

Vendor Information

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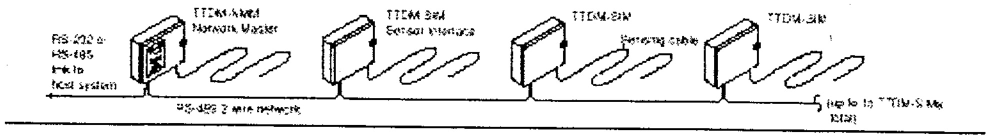
Leak Detection Method: External Liquid Sensing Cable
Vendor: Raychem Corporation
System: TraceTek



Raychem Corporation's *TraceTek Leak Detection and Location Module (TTDM)* is an external leak detection system based on the hydrocarbon liquid-sensing principle. *TraceTek's* basic Sensor Interface Module (SIM), part of the *TTDM*, consists of an alarm system, a leak locating system, leader/jumper cable (nonsensing cable between module and areas monitored), sensing cable, end termination, and accessories. Each SIM can monitor up to 5000 feet of *TraceTek* liquid-sensing cable. When liquid is detected, the SIM communicates with a centralized Network Master Module (NMM) to report the alarm condition, leak location, time, and date. Each NMM can monitor up to 15 SIMs.

TraceTek's TT5000 sensing cables are designed to detect the presence of liquid hydrocarbons at any point along their length. The core of the cable is constructed of two sensing wires, an alarm signal wire, and a continuity wire. The core is encased in a conductive polymer jacket and surrounded with a fluoropolymer braid. A small DC voltage is applied to the sensing cable and internal resistors limit the current flow through the sensor cable loops to approximately 75 microamps. The actual amount of flowing current is monitored by measuring the voltage drop across an internal reference resistor. If a spill occurs, additional current will seek the path of least resistance and flow across the leak. The resultant increased voltage drop across the reference resistor signals the module to alarm.

After a leak has been detected, the circuitry in the *TraceTek* leak detection module is automatically reconfigured into the locating mode. The digital location readout is generated by measuring the voltage drop along the sensing cable between the leak and the SIM. The voltage drop is linear and proportional to the leak location. A different scaling factor is applied for feet, meters, or zones.

Criteria	**Evaluation/Comments**
Applicability/Availability	Raychem's *TraceTek* is commercially available and is applicable to crude oil transmission lines; however, to date, the system has only been installed on small fuel pipelines and crude oil storage tanks. The vendor indicated that the best applications of the technology were for short fuel lines in an airport or refinery setting or in highly sensitive areas on longer lines.
Effectiveness	<u>*Sensitivity*</u> Raychem ran a bench-top sensitivity test on Alaska North Slope Crude Oil supplied by ARCO Alaska. The results indicated that when the oil was in direct contact with the liquid sensing cable, it took 40 minutes to alarm at 104°F, 3 hours to alarm at 68°F, and 200 hours to alarm at -40°F. <u>*Accuracy*</u> The *TraceTek* locating system reportedly pinpoints where liquid contacted the sensing cable to within 0.1% of total cable length. <u>*Reliability*</u> The false alarm rate of external leak detection systems is generally much lower than that of statistically based internal systems. False alarms on the *TraceTek* system typically are a result of background contamination or water infiltrating the cable's jacket. When liquid is detected, *TraceTek* sounds an alarm and displays the location of the leak. The unit then continues to monitor the cable and will re-alarm if there are any major changes. Once the alarm condition has been cleared, the module can be reset with a single keystroke. <u>*Robustness*</u> If the cable is broken, the current will cease to flow. The voltage across the reference resistor decreases to zero and the internal circuitry recognizes this as

	a continuity fault. Any loss of system integrity, whether caused by an interruption in power or damage to a cable are indicated by the module panel display and relay output. An internal test feature allows the user to check system operations. The liquid-sensing cable must be replaced after exposure to hydrocarbons. The operating temperature range for the TT5000 Fuel-Sensing Cable is –4°F to 140°F. The operating temperature range for the leak detection and location module is 32°F to 122°F.
Transferability/Feasibility	*TraceTek* is reportedly transferable to crude oil transmission lines and has the following benefits: ▪ It can monitor pipelines operating under almost any scenario (slack line, multiphase flow, bi-directional); ▪ It does not require shutdown of operations for installation or maintenance; ▪ Other than developing an initial plot plan of the site (depicting cable location and response patterns), the system does not require calibration; and ▪ It is a continuous system that can consistently detect small leaks (typically less than what would be 1 percent of flow on a crude oil transmission line). *TraceTek* performs best when: ▪ Pipelines are relatively short. The vendor indicated that the system is best suited for pipelines or pipeline segments less than 7 miles long.
Compatibility/System Requirements	*Instrumentation* Every *TraceTek* SIM has the following basic parts: an alarm module, a locator module, leader and/ or jumper cables (nonsensing cable between module and areas monitored), sensing cable, end termination, and accessories such as tags, hold-down clips, and installation tools. *Operating System/Communications* Each SIM monitors up to 5000 feet of sensing cable. When the cable detects a liquid, the SIM communicates with an NMM to report the alarm condition, leak location, time, and date. Field data from the NMM, if it is remotely located (i.e., not in the control room), may be communicated to the pipeline controller in a number of different ways, including modem, SCADA, radio, and/or satellite. *Testing Frequency* The *TraceTek* system continually monitors for leaks along the entire length of the liquid-sensing cable. *Controller Training* Raychem will train individuals to interpret field data and operate/maintain the *TraceTek* equipment. Controller training may be done at a Raychem office or onsite.
Environmental Impacts	Other than excavation to place the liquid-sensing cable (usually within the pipeline right-of-way), there are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of *TraceTek*.
Regional Considerations	The *TraceTek* system is reportedly designed for all climates (desert, arctic, underwater, etc.); however, the system's response time is degraded under extreme cold temperatures (see Applicability/Availability criterion).
Field Performance	The *TraceTek* leak detection system has never been installed on a crude oil transmission pipeline.
Cost	The cost of the *TraceTek* leak detection system depends on the customer's

	needs and pipeline configuration. In general, *TraceTek* can be installed on pipelines less than 1000-feet long for about $15-16 per linear foot. On longer lines, the price drops to about $8-9 per foot.

Vendor Information

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Leak Detection Method: External Sensing Tube
Vendor: Siemens AG
System: LEOS®

Siemens LEOS® is an external leak detection system which detects leaks by means of a low-density polyethylene (LDPE) sensor tube. The tube is highly permeable to the substances to be detected, which must come into contact with the tube in the form of vapor, gas, or dissolved in water. In accordance with the Water Resources Act, LEOS® is capable of detecting several different hydrocarbons and is ideally suited for pipeline sections that cross highly sensitive water environments.

In the event of a leak, a portion of the leaking product diffuses into the sensor tube due to the concentration gradient (i.e., product moving from areas of high concentration to areas of low concentration). Following a given time period, the detector unit within the tube produces an accurate image of the detected product, regardless of whether the tube was installed in air, water, or in the ground.

The detector unit consists of semi-conductor gas sensors which measure the concentration of the product and produce a corresponding "leak peak". The height of the peak is proportional to the concentration of the substance, which in turn is an indication of the size of the leak. The concentration distribution present within the sensor tube is analyzed by forcing a column of air past a detection unit at a constant speed and measuring the concentration as a function of the pumping time. The concentration profile is not affected by the pumping action.

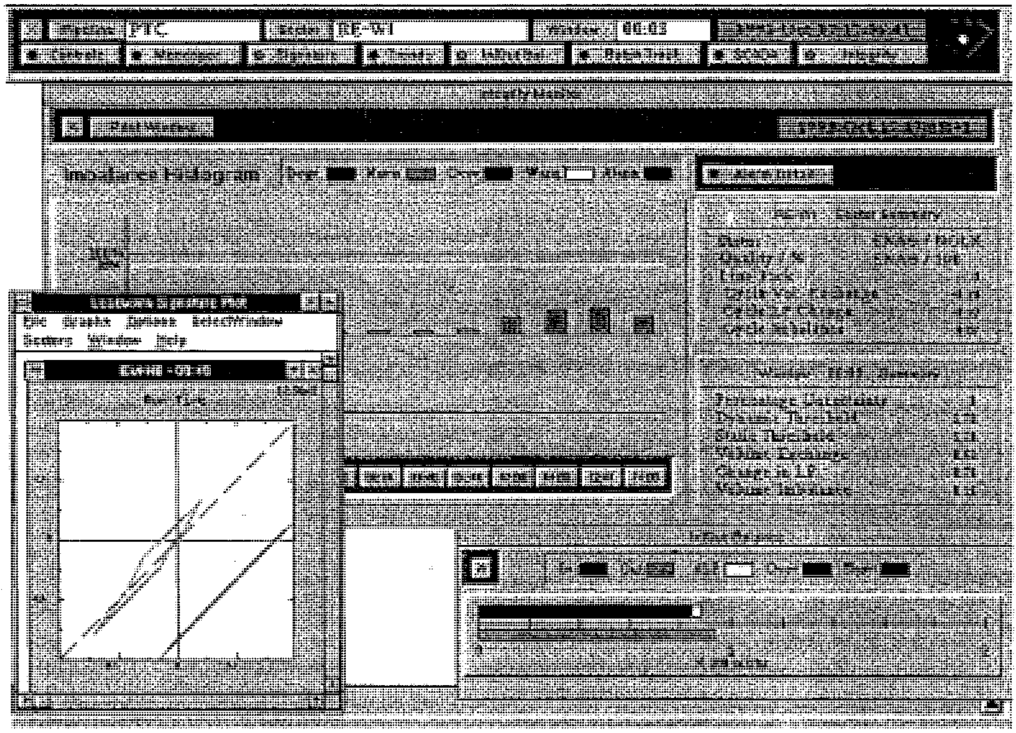
Prior to each pumping action, an electrolytic cell at the end of the tube injects a specific volume of test gas into the tube. When the test gas passes the detector unit it generates a marking or end peak, which serves as a control marker indicating that the entire air column contained in the tube has passed through the detector unit. Based on the ratio of the travel time of the leak peak to that of the end peak, the leak location can be calculated.

Two different LEOS® systems are available — LEOS® Detection System and LEOS® PC System. The LEOS® Detection System consists of an analog component, which performs the analyses, and a microprocessor, which processes the signals and issues alarms when necessary. This system is strictly an alarm system and does not include and extensive analysis feature. In the event of a leak alarm, analysis is performed using a mobile testing system which connects to the sensor tubes. The LEOS® PC System is a multi-channel, PC-controlled leak analysis and location system, which is used for more complex monitoring. The PC System has the following advantages:

- The last 100 measurements are stored in data memory and can be called up as a pre-event history in the event of an alarm (trend analysis).
- Leak data are automatically logged and output in the event of an alarm.
- Each measurement result for the concentration profile of LEOS® can be displayed on the monitor as a function of the tube length.

ADDITIONAL INFORMATION FOR THE SIEMENS LEOS SYSTEM IS FORTHCOMING.

Leak Detection Method: Internal Real Time Transient Modeling (RTTM)
Vendor: Simulutions Inc.
System: LEAKWARN



Simulutions Inc.'s *LEAKWARN* is a pipeline leak detection technology operating on the model-compensated volume balance approach. *LEAKWARN* is based on the real time simulation of flow in the pipeline with a rigorous transient computer model driven by SCADA data. The flow model continually and accurately determines volume balance on a defined section by measuring volume exchange and packing rate. The volume exchange of a pipeline segment is the difference between input and output flow as measured by meters. The packing rate is the change in line pack within a segment as measured by pressure boundary conditions. Unique to the *LEAKWARN* model is the use of actual (vs. modeled) pressure measurements to calculate line pack. The relationship between change in line pack and volume exchange is graphically represented by *LEAKWARN* as a Signature Plot. For added leak detection performance, *LEAKWARN* is also capable of continually characterizing and recording the composition of the product in the line.

Accurate volume balance measurement through *LEAKWARN* is a function of the quality of the instrumentation, as well as current operational conditions. Volumes through each meter and change in line pack on each segment are integrated over various time intervals called Windows. Imbalance is computed from the appropriate set of accumulated meter and pipe segment volumes and displayed on a Signature Plot (pictured above). These imbalances are constantly monitored and compared against Window thresholds. Short time-frame thresholds are established to detect rupture size leaks while avoiding false alarms due to operating transients and instrument repeatability error. Longer-term thresholds are sized to detect small leaks while avoiding false alarms due to flow measurement bias. When accumulated imbalance in any Window exceeds its threshold, a warning or alarm is issued by *LEAKWARN*. The controller can then use the Signature Plot for that window to confirm the leak alarm.

Criteria	Evaluation/Comments
Applicability/Availability	*LEAKWARN* is commercially available and has been installed on crude oil transmission pipelines.
Effectiveness	The *LEAKWARN* model is entirely dependent on SCADA polling and input; therefore, the performance of the technology is limited by the performance of the SCADA system. For example, transient events occurring faster than the SCADA's scan cycle are only imperfectly tracked by the model.

Leak Detection Method: Internal Real Time Transient Modeling (RTTM)
Vendor: Simulutions Inc.
System: LEAKWARN

<table>
<tr><td></td><td><u>Sensitivity</u>

Leak detection sensitivity is directly affected by the data sampling capability of the SCADA system. It also depends on instrument quality and controller proficiency. Based on field performance, LEAKWARN can detect leaks of less than 1 percent of flow.

<u>Accuracy</u>

The LEAKWARN model requires a large number of instruments placed at various points along the length of the line. Calculations are made for each point, comparing the real values against the calculated values. The more nodes a system has the more accurate it becomes.

LEAKWARN can typically locate leaks to within 10% of the pipe length between pressure transducers.

<u>Reliability</u>

For a given pipeline segment, LEAKWARN establishes leak detection thresholds for a variety of time frames (windows). This allows leaks to be detected while minimizing false alarms due to operating transients, instrument repeatability error, and flow measurement bias. Additionally, in the event of a potential leak warning, the Signature Plot feature provides the controller with a tool to determine the exact cause of a pipeline anomaly (leak or other) relatively quickly. The references contacted to verify the performance of the LEAKWARN system were especially pleased with this feature.

Reliability is enhanced by LEAKWARN's ability to automatically adjust the leak detection thresholds according to local hydraulic conditions. This dynamic adjustment screens out false alarms during times of large or rapid transients by peak shaving or clipping.

<u>Robustness</u>

In the event of a loss of communication with an instrument, LEAKWARN will tag the instrument and, rather than disarm leak detection for that pipeline segment, will add an uncertainty value to the line pack calculation and continue to operate in "degraded" leak detection mode. When the instrument comes back online LEAKWARN immediately starts operating at former sensitivity levels (the model does not have to be restarted).

To compensate for normal operating noise, LEAKWARN undergoes an initial adjustment to "tune out" long-term fixed errors associated with product and pipeline characteristics, and instrument noise. LEAKWARN is also capable of automatically adjusting alarm thresholds to compensate for pipeline transients.</td></tr>
<tr><td>Transferability/Feasibility</td><td>LEAKWARN is transferable to crude oil transmission lines and has the following benefits:

▪ It can compensate for monitoring during packing and unpacking of the line;
▪ It operates sufficiently under slack-line flow conditions;
▪ It can monitor bi-directional pipelines;
▪ It can monitor and compensate for the effects of DRA in the line;
▪ It can continually analyze pipeline noise to dynamically adjust alarm thresholds, minimize false alarms, and assure accurate leak identification;
▪ It has been successfully applied in both arctic and underwater environments; and
▪ It can consistently detect leaks of less than 1 percent of flow.

LEAKWARN performs best when:</td></tr>
</table>

<table>
<tr><td></td><td>

There is no multiphase flow;
Large transient events do not occur frequently. Highly dynamic pipelines tend to desensitize the system because LEAKWARN is constantly adjusting alarm thresholds.

</td></tr>
<tr><td>Compatibility/System Requirements</td><td>
Simulutions does not provide or install any of the instrumentation or communication hardware associated with LEAKWARN. They do provide the leak detection software, as well as the following services: configuration, interfacing, installation, initial tuning, testing, and training.
<u>Instrumentation</u>
LEAKWARN operates using any high-quality electronic pressure transmitter, flow meter, or temperature sensor normally used in the petroleum industry. LEAKWARN requires the placement of flow, pressure, and temperature sensors at all supply and delivery points, and pressure and temperature sensors at upstream and downstream ends of pump stations and pressure control valves.
<u>Operating System/Communications</u>
The LEAKWARN model relies solely on data collected by the pipeline's SCADA system for model inputs; therefore, it is imperative that the SCADA system is properly instrumented, calibrated, serviced, and maintained. The LEAKWARN software installation is usually confined to a dedicated workstation that communicates with the computer handling the SCADA data.
<u>Sampling Frequency</u>
Field instruments should be sampled several times in a millisecond interval. The vendor recommends that the SCADA system have the ability to scan or poll at least every 30 seconds.
<u>Controller Training</u>
Models are inherently complex and require a sophisticated user; therefore, controller training is relatively extensive. Simulutions indicates they can tune their model and provide controller training within two weeks; however, most model users indicated that it takes significantly longer (months to years) to optimize the system.
</td></tr>
<tr><td>Environmental Impacts</td><td>There are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of the LEAKWARN system.</td></tr>
<tr><td>Regional Considerations</td><td>
LEAKWARN is a software-based LDS that works in conjunction with instrumentation and a SCADA system supplied by vendors other than Simulutions. It is installed on a computer in the control room; therefore, LEAKWARN can be applied to systems in any environment.
The principal limiting factor in terms of regional considerations is the field instrumentation, which needs to be physically rugged to operate in the extreme climactic conditions of Alaska. Oil companies in Alaska generally have already selected the equipment that works the best under these potentially adverse conditions.
</td></tr>
<tr><td>Field Performance</td><td>
The LEAKWARN system has been installed on pipelines in arctic and underwater environments. Relevant clients include Federated Pipelines Ltd. (Canada). The results of tests conducted on LEAKWARN systems for various crude oil transmission pipelines are presented in the following table.
<table>
<tr><th><u>Company/Scenario</u></th><th><u>Diam.</u></th><th><u>Length</u></th><th><u>Product</u></th><th><u>Detected Leak (% of flow)</u></th></tr>
<tr><td>Pennzoil Company (Bonito)</td><td>14 in.</td><td>87 mi.</td><td>Crude</td><td>Cat. in <3 min; 4% in 30 min; 1% in 4 hr*</td></tr>
<tr><td>Buckeye Pipeline Co.</td><td>--</td><td>120 mi.</td><td>Mixed</td><td><10% in 6 min; <1% in 24**</td></tr>
<tr><td>Exxon Pipeline Co.</td><td colspan="4">Presently only using for line pack calcs; will be upgrading to full system soon.</td></tr>
</table>
*Based on simulated pipeline leaks.
</td></tr>
</table>

	**Buckeye is very satisfied with the *LEAKWARN* system. They are especially pleased with the Signature Plot feature, which allows the controller to easily and accurately evaluate the cause of an anomaly. In one instance, the controller could see a 12 bbl change on the Signature Plot.
Cost	The biggest disadvantage of the *LEAKWARN* system is the expense associated with its implementation and maintenance. Models require extensive instrumentation for real-time data collection and pipelines often have to retrofitted with additional pressure transducers and flow meters. Additionally, models are custom software which means they take some time to prepare and bring on line, often a year or more.

Vendor Information

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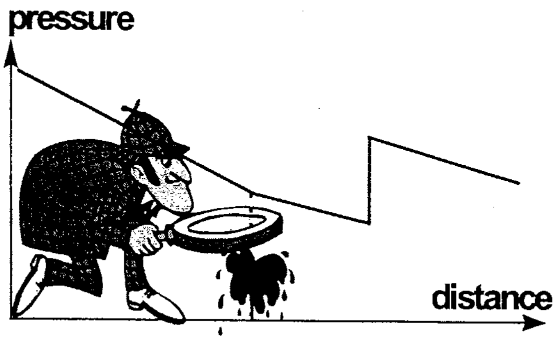
Leak Detection Method: Internal Real Time Transient Modeling (RTTM)
Vendor: Stoner Associates, Inc.
System: SPS/Leakfinder



LeakFinder Status by ...	LF.STATUS[0]	LEAK
LeakFinder Status by ...	LF.STATUS[1]	LEAK
LeakFinder Status by ...	LF.STATUS[2]	LEAK
LeakFinder Status by ...	LF.STATUS[3]	LEAK
Alarm Confidence Level	LF.CONF[0]	HIGH
Alarm Confidence Level	LF.CONF[1]	HIGH
Alarm Confidence Level	LF.CONF[2]	HIGH
Alarm Confidence Level	LF.CONF[3]	MEDIUM
Location of the i-th Leak	LF.LOC[0]	15.698 MI

Stoner Associates, Inc. (Stoner) supplies software with two independent leak detection algorithms; a model-compensated volume balance system (*VBS*) and a pressure-based leak analysis system (*LAS*). Stoner calls its leak detection software *SPS/Leakfinder*. The *VBS* uses mass, momentum, energy, and equation of state algorithms to determine the flow rates into and out of a pipeline segment with line pack corrections. A leak is alarmed when the corrected difference exceeds an established threshold. By comparison, the *LAS* is a more sophisticated software tool that operates in close cooperation with *SPS/Statefinder*. When a release occurs on the "real" pipeline, its effects will be shown by the real-time SCADA data being presented to *SPS/Statefinder*, which has no equivalent release in the model. In order to match the SCADA data, *SPS/Statefinder* allows fluid to enter or leave the model at key locations. The *LAS* constantly analyzes the magnitude of these artificially induced injections or deliveries looking for a leak signature in the pressure profile. SPS/Leakfinder also provides an estimate of the leak size and location milepost.

SPS/Leakfinder continually analyzes the calculated state of the pipeline searching for anomalies which suggest a leak. The system filters reported data from the SCADA system addressing known sources of uncertainty including instrument repeatability, deadband filtering, timestamp error, fluid properties, and the physical characteristics of the pipeline itself. The combined effects of data uncertainties define a threshold between detectable and undetectable leaks. *SPS/Leakfinder* constantly compares the filtered pipeline data to known hydraulic principles. When a hydraulic anomaly is present which exceeds the leak detection threshold (LDT), a potential leak is signaled (as pictured above). *SPS/Leakfinder* uses multiple LDTs for each pipeline segment and thresholds are adjusted every timestep, usually every few seconds, to minimize the number of false alarms.

Criteria	Evaluation/Comments
Applicability/Availability	*SPS/Leakfinder* is commercially available and has been installed on crude oil transmission pipelines.
Effectiveness	<u>*Sensitivity*</u> Leak detection sensitivity is directly affected by the data sampling capability of the SCADA system, the quality of the pipeline's instrumentation, and the operating conditions. The *SPS/Leakfinder* system is capable of detecting leaks equal to or less than 1 percent of flow. <u>*Accuracy*</u> *SPS/Leakfinder* relies largely on pipeline instrumentation to estimate parameters such as leak flow rate and volume lost. The model requires a large number of instruments placed at various points along the length of the line. Calculations are made for each point, comparing the real values against the calculated values. The more points a system has the more accurate it becomes. <u>*Reliability*</u> *SPS/Leakfinder* applies multiple leak detection thresholds to each pipeline segment. Thresholds are dynamically adjusted every timestep to minimize the number of false alarms. The adjustments are a function of several parameters including statistical variations in flow balance, packing rate, and mass balance,

	and pipeline operating parameters such as flow rate. _Robustness_ In the event of a loss of communication with an instrument, *SPS/Leakfinder* will tag the instrument and, rather than disarm leak detection for that pipeline segment, will estimate the measurement for continued leak detection performance. Extended instrument loss will eventually result in degraded system sensitivity. Additionally, *SPS/Leakfinder* is continually analyzing noise, normal transient events, and other operating parameters, and dynamically adjusting alarm thresholds to minimize false alarms and assure accurate leak identification.
Transferability/Feasibility	*SPS/Leakfinder* is transferable to crude oil transmission lines and has the following benefits: ▪ It can compensate for monitoring during packing and unpacking of the line; ▪ It operates sufficiently under slack-line flow conditions; ▪ It can monitor bi-directional pipelines; ▪ It can monitor and compensate for the effects of DRA in the line; ▪ It can minimize false alarms by adjusting alarm thresholds according to current operating conditions; ▪ It has been successfully applied in both cold climate and underwater environments; ▪ For leak detection redundancy, it has two readily compatible methods of leak detection (*VBS* and *LAS*); and ▪ It can detect leaks of less than 1 percent of flow. *SPS/Leakfinder* performs best when: ▪ There is no multiphase flow; and ▪ Large transient events do not occur frequently. Highly dynamic pipelines tend to desensitize the *SPS/Leakfinder* system because it is constantly attempting to account for transients by reestablishing alarm thresholds.
Compatibility/System Requirements	Stoner does not provide or install any of the instrumentation or communication hardware associated with *SPS/Leakfinder*. They do provide the leak detection software, as well as the following services: configuration, interfacing, installation, initial tuning, testing, and training. _Instrumentation_ *SPS/Leakfinder* operates using any high-quality electronic pressure transmitter, flow meter, or temperature sensor normally used in the petroleum industry. *SPS/Leakfinder* requires the placement of flow, pressure, and temperature sensors at all supply and delivery points, and composition information at all supplies. Pressure and temperature sensors are required at upstream and downstream ends of pump stations and pressure control valves. Additional pressure sensors are recommended at intermediate points to increase leak detection sensitivity. _Operating System/Communications_ The *SPS/Leakfinder* model relies solely on the data collected by the pipeline's SCADA system; therefore, it is imperative that the system is properly instrumented, calibrated, serviced, and maintained. The *SPS/Leakfinder* software installation is usually confined to a dedicated workstation that communicates with the computer handling the SCADA data.

Leak Detection Method: Internal Real Time Transient Modeling (RTTM)
Vendor: Stoner Associates, Inc.
System: SPS/Leakfinder

	Sampling Frequency Field instruments should be sampled several times in a millisecond interval. For maximum performance, the vendor recommends that the SCADA system have the ability to scan or poll every 5 seconds. *Controller Training* Models are inherently complex and require a sophisticated user; therefore, controller training is relatively extensive. Models may require a full time SCADA engineer to keep them up and running, and vendor participation to modify them.
Environmental Impacts	There are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of the *SPS/Leakfinder* system.
Regional Considerations	*SPS/Leakfinder* is a software-based LDS that works in conjunction with pipeline instrumentation and a SCADA system supplied by vendors other than Stoner. The software is installed on a computer in the control room; therefore, *SPS/Leakfinder* can be applied to systems in any environment. The principal limiting factor in terms of regional considerations is the field instrumentation, which needs to be physically rugged to operate in the extreme climactic conditions of Alaska. Oil companies in Alaska generally have already selected the equipment that works the best under these potentially adverse conditions.
Field Performance	*SPS/Leakfinder* has been installed on pipelines in cold climate and underwater environments. The results of tests conducted on *SPS/Leakfinder* systems for various crude oil transmission pipelines are presented in the following table. **Company/Scenario** / **Diam.** / **Length** / **Product** / **Detected Leak** Trans Mountain Pipeline / 24 in. / ≈700 mi. / Crude/Mixed / 10% of flow within 15 minutes* Enbridge Pipeline (operates 15 crude lines; all with Stoner SPS/Leakfinder) / 12-48 in. / ≤1100 mi. / Crude / 1-9% within 1 hr** *The user indicated that the slightly degraded performance is a result of the dated instrumentation installed on the pipeline (i.e., lower accuracy/sensitivity) and the complex operating conditions (i.e., slack line and multiple products including crude batches with greatly varying characteristics). Overall they were very satisfied with their leak detection system. **Sensitivity depends upon pipeline operating conditions. Shorter, quieter lines have lower thresholds; longer, more transient pipelines tend to have higher thresholds. Enbridge is very satisfied with the performance of SPS/Leakfinder and Stoner's customer service.
Cost	The biggest disadvantage of the *LEAKWARN* system is the expense associated with its implementation and maintenance. Models require extensive instrumentation for real-time data collection and pipelines often have to retrofitted with additional pressure transducers and flow meters. Additionally, models are custom software which means they take some time to prepare and bring on line, often a year or more.

Vendor Information

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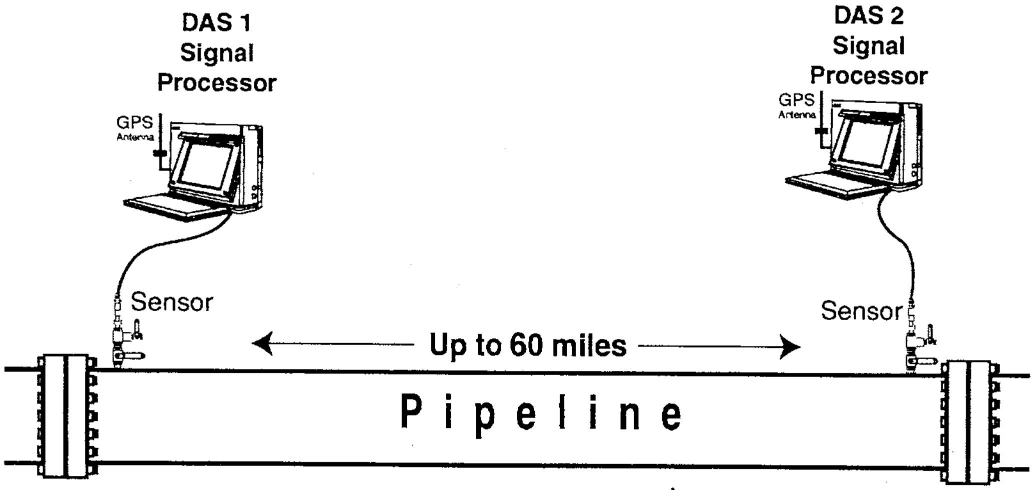
Leak Detection Method: Internal Pressure Analysis (Rarefaction Wave Monitoring)
Vendor: Tracer Research Corporation
System: LeakLoc®



LeakLoc® is a self-contained leak detection and location system operating on the rarefaction wave monitoring principle. A single segment installation can reportedly monitor up to 60 miles of pipeline. Existing pipeline access points can be utilized for sensor installation thereby minimizing excavation. *LeakLoc* uses computer technology combined with signal processing and acoustical modeling to locate a leak. *LeakLoc* systems are reportedly capable of detecting and locating leaks within 3 minutes of the initiation of the leak. *LeakLoc* detects leaks by the methodology presented below.

> When a leak occurs the resulting drop in pressure will cause a rarefaction wave to travel both upstream and downstream of the leak location at the acoustic velocity of the fluid constrained within the pipeline. The wave will travel past downstream and upstream pressure sensors, which will detect the wave. A *LEAKLOC* data acquisition system (DAS) located at each sensor location continually searches the data stream from the sensors for events exceeding a predetermined threshold. The exact time that the wave passes the sensor is also recorded. Based on the calculated time difference between sensors and the acoustic velocity (wave speed) of the fluid, the location of the leak may be determined. Once an event is detected and located, the results, which include rise times, maximum wave amplitude, onset times, and noise levels, are communicated to the central data system (CDS) in the control room for comparison with data from other sites. If this *coincidence analysis* meets leak criteria, an alarm is declared.

LeakLoc uses the following equation to calculate the location of the leak:

$$L_1 = \left(\frac{D}{2}\right) - \left((T_1 - T_2) \times \frac{\lambda}{2}\right)$$

Where:
L_1 = Location of Leak from Sensor 1 (feet)
D = Length of Pipeline Segment
T_1 = Time of Wave Detection at Sensor 1
T_2 = Time of Wave Detection at Sensor 2
λ = Wave Speed (feet per second)

Criteria	**Evaluation/Comments**
Applicability/Availability	Although it is still in the test phase, *LEAKLOC* is commercially available and according to Tracer is applicable to most liquid pipelines, including crude oil. However, to date, *LEAKLOC* has not been installed on a crude oil transmission line. Additionally, the system is only recommended for use on static (vs. flowing) lines; therefore, it does not meet the ADEC criteria of "continuous" leak

	detection.
Effectiveness	*Sensitivity* Tracer claims LEAKLOC can achieve a leak detection threshold of 10 to 15 gallons per hour (gph) regardless of pressure, flow, or pipeline geometry. However, these performance figures are based on short fuel lines operating under low pressures and flow rates, and tested under static flow conditions (see Field Performance criteria for details). These conditions are not typically found on crude oil transmission lines. The leak detection capability of LEAKLOC for oil pipelines is unknown, but is expected to be greater than 4 percent of daily throughput, which exceeds ADEC criteria of 1 percent of flow. The sensitivity of the LEAKLOC system is a function of the amount of normal hydraulic noise on the pipeline, pipeline pressure, and the distance between the leak and the sensor. The opening and closing of valves and normal pump operation produces either compression or rarefaction waves which may trigger the LEAKLOC sensors. In particular, positive displacement pumps with check valves that operate at a frequency near 1Hz produce noise that is difficult to eliminate. LEAKLOC compensates for these normal excursions by zeroing them out. In the process, system sensitivity is reduced. Detection time for LEAKLOC depends on the distance between the leak and the instruments. The leak signature travels at the speed of sound in the product. The vendor claims LEAKLOC typically will detect the leak within 3 minutes of the event's arrival at the instruments. *Accuracy* LEAKLOC relies on pipeline instrumentation to estimate parameters such as leak rate and volume lost; therefore, the accuracy of LEAKLOC is largely dependent upon the accuracy of the instrumentation. Tracer recommends using their proprietary dynamic pressure sensors, which can reportedly detect a 0.001-psi (pounds per square inch) change over an operating pressure from 10 to 2,000 psi. On the two static fuel lines where LEAKLOC has been commissioned, it was capable of locating a leak to within 0.05 percent of the total pipeline length or +/- 40 feet of actual location. Keep in mind that these lines are only about 3,000-feet long. Performance on longer dynamic pipelines would depend on the spacing of instruments along the line and the frequency of data uptake. *Reliability* Under static-line conditions, LEAKLOC'S false alarm rate is relatively low (1 per week or less). The false alarm rate for flowing/dynamic pipelines is unknown. *Robustness* LEAKLOC'S dynamic pressure sensor allows slow pressure changes (i.e., a 20-psi change over a 24-hour period) to be zeroed out, so that the sensor does not respond to pressure changes caused by normal pipeline operations. However, it is not expected to perform well under dynamic flow conditions. Note that LEAKLOC employs only one method of leak detection; therefore, there is no system redundancy. Additionally, there is only one chance for the sensors to detect the leak. If the rarefaction wave passes the sensor and it doesn't alarm, the ability of that sensor to detect the leak is lost.
Transferability/Feasibility	LEAKLOC is reportedly transferable to crude oil transmission lines and performs best when: ▪ The pipeline is static or operates in steady state mode (Note that the system has never been installed on a flowing line). Additionally, LEAKLOC cannot account for normal transient events where peak-to-peak operating conditions exceed approximately 20 psi in a 24-hour period;

	▪ There is no multiphase flow. *LeakLoc* has never been used on pipelines operating under multiphase flow conditions. Performance is expected to be compromised under these conditions because the rarefaction wave cannot propagate through vapor-phase product; ▪ There is no slack-line flow. *LeakLoc* has never been used on slack-line segments. However, the Tracer representative felt the system would continue to operate under slack-line conditions because the rarefaction wave could still travel through the pipe; and ▪ The characteristics of the product (viscosity, density) are consistent. This is critical because the wave speed of the product, a parameter which is used in both the leak detection and location calculations, is calculated only once during initial system calibration. Any change in the characteristics of the product during normal pipeline operations is not accounted for by the leak detection system and performance may be compromised.
Compatibility/System Requirements	With *LeakLoc*, a data acquisition station (DAS) is placed at each end of the pipeline segment to be monitored. Each DAS consists of a pressure sensor, a global positioning system (GPS)-based clock, a power supply, and a computer with analog to digital converter, modem communications, and data acquisition software. Data from each DAS are transmitted to RTUs to the control center via cable, FM, satellite, or existing SCADA system. *Instrumentation* Tracer does not recommend using conventional pressure transducers with *LeakLoc*. It is their position that conventional equipment cannot be sampled at the same rate as the *LeakLoc* sensor (1000 times per second); therefore, it is not capable of detecting a leak event which typically lasts a fraction of a second. *LeakLoc's* dynamic pressure sensor is a solid-state, piezoelectric transducer producing an output proportional to the pressure change. The pressure change is continually differentiated so that the output is the total pressure change over the time constant (decay time) of the sensor. Its sensitivity is independent of the operating pressure over a large range, with a sensitivity of 0.001-psi change over an operating pressure range of 0 to 2,000 psi. *Operating System/Communications* The DAS consists of a high-capacity industrial personal computer (PC), data acquisition board, GPS clock, and communications system. The data acquisition board performs the analog-to-digital (A/D) conversion of the sensor signal and is mounted in an expansion slot on the DAS computer. The board includes a programmable sampling system with the ability to write directly to the computer's memory. The time clock is a separate GPS-based system consisting of a plug-in card located in the computer and a small antenna. The GPS system allows the multiple computers used for data acquisition to be synchronized to within less than a millisecond. There are several communications options: telephone modem, the pipeline's SCADA system, or a custom communications system. *Sampling Frequency* The dynamic pressure sensors are sampled at a minimum rate of one thousand times per second. Tracer contends that sampling at greater intervals could potentially result in missing the leak event, which occurs within a fraction of a second. *Controller Training* The *LeakLoc* system can be installed and operational the day it arrives at the site. Controller training takes a couple of days and can be done at the user's

	facility.
Environmental Impacts	There are no air, land, water, energy, or other system requirements that may offset the anticipated environmental benefits of *LEAKLOC*.
Regional Considerations	*LEAKLOC* has not been used or proven on pipelines in either arctic or underwater environments. It is not known how the *LEAKLOC* system would operate in these conditions.
Field Performance	The *LEAKLOC* system has been installed and tested on two small jet-fuel transmission pipelines. These lines, located at Kelly Air Force Base in Texas and Moffet Field in Califomia, are 8 to 10 inches in diameter, approximately 3,000-feet long, and operate at low pressures and flow rates. Under static line conditions, *LeakLoc* was able to detect leaks on the order of 5 gph in less than 10 seconds, and report the location of the leak to within 10 feet. *LEAKLOC* has never been installed or tested on flowing, dynamic transmission pipelines.
Cost	Different *LEAKLOC* applications will have different initial costs. A short pipeline might only require monitoring of two data acquisition stations, longer lines will require more. Additional costs may be incurred because Tracer recommends using their dynamic pressure sensors instead of conventional transducers which may already be installed on the pipeline.

<u>Vendor Information</u>

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