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UNDERGROUND PIPELINE LEAK DETECTION AND LOCATION TECHNOLOGY APPLICATION GUIDE

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This Technology Application Guide is designed to help the user select and apply leak detection and location equipment for pressurized, high-capacity, underground, fuel-pipelines typical of hydrant systems at Navy bases.

Many variables must be considered when researching, selecting, and purchasing underground pipeline leak detection equipment. These variables include regulations, technology type, climate, soil type, groundwater, funding, and site logistics. At this time, there is no available leak detection and location technology that meets all of the Navy's needs. Different leak detection and location problems can be solved with different technologies, including tracers, temperature-compensated pressure testing, and smart-pigging.

This Technology Application Guide provides the user with the tools required for solving this problem. Specifically, the Guide explains:

- How to determine the applicable pipeline leak detection regulations
- How the different leak detection and location technologies work
- Which technologies are best suited to solve different problems
- Which technologies are evolving for future applications
- Who are the points of contacts for pipe leak detection (PLD) within the Department of Defense (DOD) and in private industry.

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EXECUTIVE SUMMARY

This Technology Application Guide is designed to help the user select and apply leak detection and location equipment for pressurized, high-capacity, underground, fuel-pipelines typical of hydrant systems at Navy bases. The Technology Application process is graphically outlined in Figure 1.

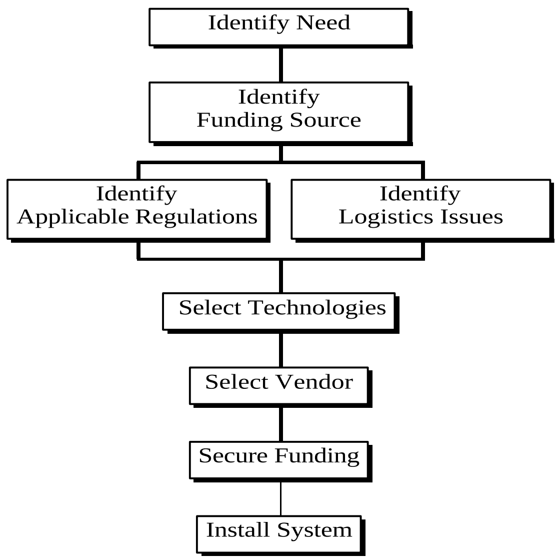

Figure 1. Underground pipeline leak detection and location technology application steps.

Many variables must be considered when researching, selecting, and purchasing underground pipeline leak detection equipment. These variables include regulations, technology type, climate, soil type, groundwater, funding, and site logistics. At this time, there is no available leak detection and location technology that meets all of the Navy's needs. Different leak detection and location problems can be solved with different technologies, including tracers, temperature-compensated pressure testing, and smart-pigging.

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DISCLAIMER

This report has been subject to NFESC's peer and administrative review, and has been approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

FOREWORD

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LIST OF ABBREVIATIONS

TAG -	Technology Application Guide
LDL -	Leak Detection and Location
KWA -	Ken Wilcox Associates, Inc.
UST -	Underground Storage Tank
CP -	Cathodic Protection
CFR -	Code of Federal Regulations
SERDP -	Strategic Environmental Research and Development Program
Army CERL -	Army Construction Engineering Research Laboratory

LIST OF RELATED WEB SITES

NFESC Home Page:	http://www.nfesc.navy.mil/
NFESC Environmental Home Page:	http://energy.nfesc.navy.mil/environm/environm.htm/
SERDP Home Page:	http://www.hgl.com/SERDP/
SERDP Program:	http://clean.rti.org/SERDP/comp1K.htm/
Ken Wilcox Associates Page:	http://www.kwaleak.com/
EPA Contacts for Pipelines and UST:	hhtp//www.epa.gov/OUST/states/statcon1.htm

CHAPTER 1. INTRODUCTION

1.1 SCOPE

This Technology Application Guide (TAG) is a resource for understanding, procuring, and applying one or more of the commercially available Leak Detection and Location (LDL) technologies to pressurized underground fuel pipelines typical of those found at a Naval Air Station.

1.2 BACKGROUND

The Navy has extensive underground pipelines for bulk fuel transfers and aircraft refueling. The typical profile for these pipelines is summarized in Table 1.

Table 1. Characteristics of Typical Underground Pipelines at Navy Bases

Pipe Diameter	12 to 20 inches
Pipe Material	Stainless Steel, Aluminum, Fiber-Reinforced Plastic
Pipeline Length	500 feet to 18 miles
Operating Pressure	100 psig
Fuel Type	JP5
Flow Rate	600 to 10,000 gph

Undetected fuel leaks from Navy pipelines can cause gross soil and groundwater contamination. These leaks can be caused by faulty (or absent) corrosion protection, failed mechanical joints, ambient vibrations, or accidental impact.

Inspecting pipelines for leaks and installing leak detection and location equipment can help you avoid this gross contamination and the associated cleanup costs. Remediation expenses for leaking fuel lines can range from one hundred thousand dollars to millions of dollars, depending on the size and location of the spill, and timeliness of finding the leak.

CHAPTER 2. REGULATIONS

2.1 FEDERAL ENVIRONMENTAL PROTECTION AGENCY REGULATIONS

Federal regulations (Ref. 1) require "release detection" for underground storage tanks (USTs) and their associated piping[1]. Federal regulations also defer the release detection requirement indefinitely (Section 280.10 c and 280.10 d of Ref. 1) for field-constructed USTs, emergency power generator fuel tanks, and airport hydrant fuel distribution systems (typically found at Naval Air Stations). Release detection methods that satisfy the Federal requirement for existing UST systems are discussed at Sections 280.41 and 280.43 (for tanks), and Section 280.44 (for piping) (Ref. 1). The options for release detection for pressurized piping are:

(1) Automatic line leak detection
(2) Annual line tightness testing
(3) Monthly monitoring of soil vapor, groundwater, or the interstitial space of a double walled pipeline.

Automatic line leak detectors must be able to detect leaks of 3 gallons per hour at a pressure of 10 psig within an hour. The annual tightness test must be able to detect a leak rate of 0.1-gallon per hour. Other methods are also allowed if they can detect a 0.2-gallon per hour leak rate, a release of 150 gallons in a month, or are approved by the implementing agency (Ref. 1 Section 280.43(h)).

Section 280.42 of Reference (1) requires that release detection at existing UST systems (except those types that are deferred) be upgraded by December 1998 to meet the requirements of Section 280.42(b) (Ref. 1) (i.e., secondary containment or double walls for tanks).

This situation is not at long term equilibrium. While many airport hydrant systems do not have leak detection systems that meet existing requirements, regulators generally recognize the technical difficulties and expense associated with meeting these requirements. Instead of being used to punish those out of compliance, existing regulations are being used to "drive" the evolution of leak detection technologies. As technologies evolve and become less expensive, implementation will be required. Until then, facilities that operate without leak detection risk large-scale contamination and the associated clean up expense.

The US Environmental Protection Agency (EPA) publishes several reports that clarify the applicable Federal regulations for pipeline, UST, and AST (aboveground storage tanks) leak detection (References 2 through 6).

2.2 STATE REGULATIONS

Contacts at the State (or Territorial) regulating offices are available to answer leak detection questions. A list of contacts can be found at http://www.epa.gov/OUST/states/statcon1.htm.

[1] The federal definition of "underground storage tank" includes associated underground piping, but not "pipelines regulated under the Hazardous Liquid Pipeline Safety Act." In practice, this means that piping within facility boundaries is regulated along with tanks by the underground tank regulations, when 10 percent or more of the volume of the total system is underground.

California, Florida, and Texas have special leak detection requirements. Table 2 provides a summary of the regulatory requirements for airport hydrant systems, USTs, ASTs, and their associated piping.

2.2.1 California

California UST regulations do not defer release detection requirements for field constructed or other classes of underground tanks, and as discussed earlier, the definition of a UST includes its associated piping. Also, California regulations do not defer release detection requirements for hydrant fuel distribution systems at airports. Reference (7), Section 2641(f) requires "non-visual monitoring" (i.e., release detection) for pressurized underground piping in accordance with Section 2643(c)(1) of Reference (7) that states "monitoring shall be conducted at least hourly at any pressure" (when the piping is in pressurized use). "The (hourly) monitoring method shall be capable of detecting a release equivalent to 3.0 gallons per hour defined at 10 psig, within one hour of its occurrence with at least a 95 percent probability of detection." Additionally, either monthly monitoring (capable of detecting 0.2-gallon per hour) or annual monitoring (capable of detecting 0.1-gallon per hour defined at 150 percent of operating pressure) shall be conducted.

Section 2644(e) of Reference (7) states the annual tightness test requirement for underground pressurized piping (of the California Health and Safety Code, Section 25292(e)) is satisfied by monthly monitoring using non-visual qualitative release detection method.

California Statutes (California Health and Safety Code Section 25270) requires AST leak detection by groundwater monitoring or tank foundation design (containment walls). The AST tank facility includes piping up to the first isolation valve outside the containment.

2.2.2 Florida

Florida Administrative Code, Rule 62-762, Sections 62-762.520 and 62-762.600 (Ref. 8) currently require annual pressure testing for existing hydrant piping and bulk product piping not having secondary containment. As presently written, this requirement would step up, by December 31, 1999, to either having an installed release detection system or performing quarterly testing at 1½times the maximum working pressure. However, proposed revisions would allow annual tightness testing to fulfill the release detection requirement indefinitely, with a "monthly release detection system" (based on groundwater or vapor monitoring) or another approved system being an alternative. Check with your local regulating office for more information about current regulatory requirements.

2.2.3 Texas

Since 1990, Texas has not deferred release detection requirements for field constructed USTs or for airport fuel hydrant distribution systems (Ref. 9). Tanks (both USTs and ASTs) include their associated underground piping. No distinction is made between bulk fuel piping and smaller piping. Pressurized piping is required to have automatic line leak detection (0.2-gallon per hour standard), and to undergo annual tightness testing (0.1-gallon per hour at 150 percent of normal operating pressure). Tanks require either automatic tank gauging (0.2-gallon per hour) or annual tank tightness testing combined with inventory control.

Table 2. Pipeline Leak Detection Regulations

		Airport Hydrant Systems	**UST and Associated Pressurized Piping**	**AST And Associated Pressurized Piping**
Federal		(Deferred)	Same as tank (deferred for field constructed USTs); After 22 December 1998, secondary containment (for piping), *AND* Automatic Line Leak Detector required (3 gal/hr at 10 psig). Option for approval of alternate release detection methods.	No requirement, unless piping is >10 percent of total volume, which makes the entire system a UST.
California		Same as UST>>	Hourly (3.0 gal/hr) when pressurized *AND* Monthly (0.2-gal/hr) or Annual (0.1-gal/hr at 150 percent operating pressure)	No requirement, unless piping is >10 percent of total volume, which makes the entire system a UST.
Texas		Same as UST>>	Hourly (0.2-gal/hr) *AND* Annual Tightness Test (0.1-gal/hr at 150 percent of operating pressure)	<< Same as UST.
Florida (Current reg's)	Thru 1999	Same as UST >>	Annual Tightness Test	<< Same as UST.
	After 1999	Same as UST >>	In-Line Leak Detector (0.3-gal @ 10 psig) *OR* Quarterly Pressure Test	Hydrant & bulk product piping (3-inch+ diameter.): << same as USTs; Other piping upgrade with secondary containment.
Florida (Proposed)		Same as UST >>	Annual Tightness Test *OR* Monthly Release Detection system	Hydrant & bulk product piping: Annual tightness test.

2.3 REGIONAL REGULATIONS

Certain localities may impose regulations that differ from Federal and State requirements. Consult your local EPA office for more information on regional requirements.

CHAPTER 3. LEAK DETECTION AND LOCATION TECHNOLOGIES

3.1 TEMPERATURE COMPENSATED VOLUMETRIC TESTS

3.1.1 Background

A volumetric test measures the changes in the volume of fuel in a pipeline. A volumetric test takes a continuous measurement of the volume of fuel that must be added or removed from the line in order to maintain a constant pressure. There are two equipment options. The first uses a pump system to add or remove fuel. The second lets fuel move freely between the line and a measurement cylinder in which constant pressure is maintained by a gas blanket. The equipment can be attached to the line at any location, either permanently for continuous online monitoring or temporarily for a tightness test. Volumetric tests can detect and measure the flow rate of a leak in gallons per hour, the quantity of regulatory interest.

Although volumetric tests have been used successfully over the last ten years to detect small leaks on USTs and pressurized piping at retail service stations, standard volumetric leak detection systems and pressure-based systems do not work well on the longer and larger-diameter bulk transfer and hydrant lines found at military facilities. However, the last several years, have seen the development of new volumetric systems for these larger lines. Such a volumetric system was recently demonstrated and evaluated, according to EPA and American Society of Testing Materials (ASTM) performance evaluation procedures (References. 10 through 13), under the Naval Environmental Leadership Program (NELP).

A volumetric test meets all the standards required of a conventional pressure test (sometimes called a hydrostatic test) in terms of both detecting a leak and assuring the structural integrity of the line (Ref. 14). However, it does so with the enhanced attributes that are necessary for operational efficiency, environmental protection, and regulatory compliance. The test results are more accurate than those of a pressure test and require no interpretation. This is why volumetric tests have replaced pressure tests at retail service stations, and why the same trend is occurring at bulk storage facilities.

3.1.2 Characteristics of a Pressurized Line

In order to understand how a volumetric test (or pressure test) works, it is necessary to understand how and why the pressure in a line changes. Changes in pressure occur whenever the volume of fuel in the line increases or decreases. The volume of the fuel in the line will also change with the temperature. Both real and apparent volume changes will produce pressure changes. Physically adding or removing liquid from the line is an example of a real volume change, while thermally induced volume changes is an example of an apparent volume change. There are two types of volume changes that can produce pressure changes in a piping system. One type of volume change occurs whenever fuel is physically added or removed from the line. The other type of volume change occurs whenever the temperature of the fuel in the line changes. Thermal expansion of the fuel will produce a pressure increase, and thermal contraction of the fuel will produce a pressure decrease. The magnitude of the thermally induced volume changes depends on the volume of fuel in the line, the coefficient of thermal expansion of the fuel, and the magnitude of the temperature changes.

The volume of fuel that must be added or removed from the line to attain or maintain a specified pressure depends on the compressibility characteristics

(1) Fuel in the line
(2) Volume of trapped vapor in the line
(3) The piping system itself

The more compressible the system, the more fuel that needs to be added or removed from the line to change the pressure. Thus, it requires a larger volume of fuel to change the pressure in a line containing trapped vapor than a line without trapped vapor. Similarly, it takes a larger volume of fuel to change the pressure in a line constructed of a flexible material (i.e., fiberglass) or containing segments of flexible pipe than one constructed solely of a more rigid material such as steel. Finally, it takes a larger volume of a liquid, such as jet fuel, to change the pressure in the line, than a liquid such as water.

Historically, a static or conventional pressure test has been the most common method of detecting leaks from underground pressurized piping containing petroleum fuels. When the fuel in the line is removed and replaced by water, it is known as a hydrostatic pressure test. However, the procedure is the same, regardless of the type of liquid. The line is pressurized, if the pressure drops below a predetermined threshold, a leak is declared. In order for the test result to be accurate, the decrease in pressure must be large enough that it can be detected by the sensors, and it must also be larger than the sources of noise that may mask a leak or falsely indicate that one is present.

Even if the change in temperature during a pressure-based test happens to be negligible, it is not possible to interpret the results in terms of flow rate, unless the relationship between volume and pressure is known. Unfortunately, this relationship is different for each pipeline and may also be different during each test due to the presence of trapped vapor. Thus, the relationship must be established not only for each line being tested but each time the line is tested. The relationship can be established by a simple calibration procedure (Ref. 15). Unless the line is free of leaks, the relationship will include the effect of the leak itself. If this relationship is not known, it will be impossible to properly interpret the results of a pressure test or to assess the performance of the pressure-based method in a meaningful way. For example, does a 10 psi drop in pressure during a test represent the volume change due to a 0.1-, 1.0-, or 10- gallon per hour leak?

Volumetric methods do not have this type of calibration problem because they make a direct measurement of the volume of liquid that must be added or removed from the line in order to maintain a constant pressure. Also, there are no drops in pressure that could impact the operational conduct of the test or the accuracy of the results.

3.1.3 Thermally Induced Volume Changes

The volume changes that occur in a pressurized line can originate from one of two sources. One type of volume change is a result of the thermal expansion or contraction of the fuel within the line. This occurs whenever the fuel changes temperature. The other type, is a result of a leak. The magnitude of these volume changes depends on the volume of fuel in the line, the coefficient of thermal expansion of the fuel, and the size of the temperature changes. A volumetric test must compensate for these thermally induced volume changes to achieve accurate results. Accuracy depends on the magnitude of the uncompensated, thermally induced volume changes, that either mask a small leak (causing a missed detection) or are mistaken for a small leak (causing a false alarm). A volumetric test achieves high performance only when thermally induced volume changes are adequately compensated for.

Figure 2 illustrates a typical time history of fuel temperature immediately after a transfer through an underground line (beginning at the point when the fuel in the line is static). The rate of change of temperature, which can be high, is nonlinear. It is produced by the difference between the temperature of the liquid in the line (or the liquid brought into a line in order to pressurize it for a test) and the temperature of the surrounding backfill and native soil. The highest rate of change occurs immediately after a transfer. To conduct an accurate test of a line under the conditions shown in Figure 2 would require either: (a) A pre-test waiting period long enough to ensure that thermally induced pressure or volume changes have sufficient time to decay, so they are significantly smaller than the leaks to be detected (e.g., passive temperature compensation in the sense that the liquid and the ground have nearly come into thermal equilibrium) or (b) active temperature compensation. It is desirable to conduct a leak detection any time the line is static (i.e., without a waiting period and at any time between transfers), even when the rate of change of temperature is high. For this to be accomplished, active temperature compensation is required.

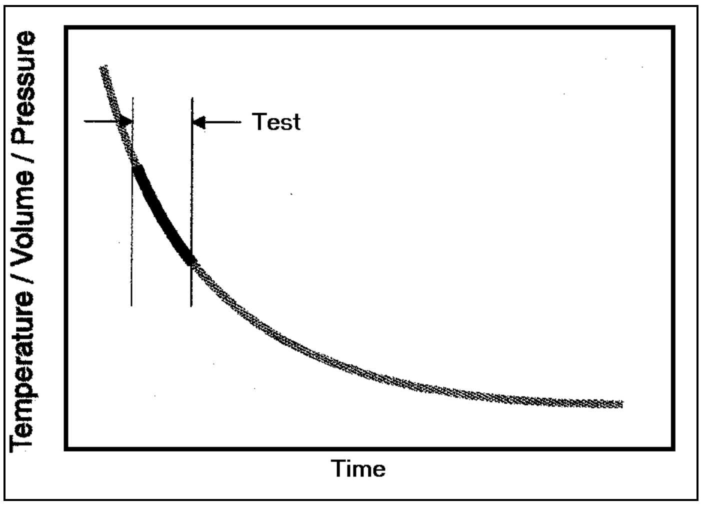

Figure 2. Rate of temperature change of fuel in a pipeline due to the difference in temperature between the fuel and the surrounding backfill and soil.

3.1.4 Temperature Compensation

There are three basic approaches to temperature compensation:

(1) Wait until temperature changes dissipate
(2) Use thermistors to measure the temperature changes in the line. Calculate the temperature induced volume change and adjust the measured change in volume
(3) Measure temperature induced volume changes directly as part of the test.

The first approach uses a waiting period, a quiescent time between the end of the last transfer and the beginning of a test, to allow temperature changes to dissipate. This passive approach is commonly used for volumetric and pressure testing. When such tests are conducted on the large diameter piping found at bulk AST and bulk UST storage facilities, an adequate waiting period may run for hours, even days. In the case of an airport/airfield and marine hydrant lines, the waiting period may have to be even longer.

The second approach is an active form of temperature compensation whereby fuel temperature is measured at one or more locations along the line by sensors inserted into the line. The data from these sensors are used to estimate the magnitude of the thermally induced volume changes during a test. This estimate, when subtracted from the measured volume changes, leads to the determination if a leak is present or not. This approach has been successfully used in underground tanks, but is not practical for underground piping. Precision sensors would have to be installed at frequent intervals along the entire length of the line, a physical impracticality, and complex algorithms would have to be developed to address the thermal contribution from exposed sections of line and trapped vapor. Operationally, calibration and maintenance of the temperature sensors would be difficult. As a consequence, this approach has not been used on underground lines.

The third and final approach, which is described in detail below, is another active form of temperature compensation whereby thermally induced volume changes are measured during the test and are subtracted from the total volume changes. This approach was successfully evaluated as part of the aforementioned NELP demonstration program (References 1 through 4). It offers short, reliable tests. There are no waiting periods or installed temperature sensors. It can be easily implemented as either a portable system for tightness testing or as a permanently mounted online system for continuous monitoring. In either case, tests can be conducted in 2 hours or less.

Unlike conventional pressure tests, volumetric tests are not affected by the presence of trapped vapor. While the thermal expansion or contraction of the vapor must be compensated for (like that of the fuel), the total volume of trapped vapor does not change or prevent the conduct of a test nor does it interfere with the interpretation of the test result.

3.1.5 Innovative Technology

An innovative volumetric technology for the detection of small leaks in underground piping found at bulk fuel storage facilities, hydrant fuel distribution systems, and marine terminal transfer lines, has been developed and operationally demonstrated by Vista Research. Two leak detection systems based on this technology, the LT-100 and the HT-100, achieve a high level of performance against small leaks due to the temperature compensation that is achieved as part of the test (see section 3.1.6). Moreover, compensation is accomplished without a pre-test waiting period or line temperature measurement. A leak detection test can be completed in 2 hours. Since accuracy of the temperature compensation is also measured during each test, high reliability is assured. Thus, the technology overcomes the major operational and performance problems associated with conventional pressure and volumetric tests. If a leak is detected, both systems give a direct measurement of the flow rate of the leak in gallons per hour and the quantity of regulatory interest.

LT-100. The LT-100 tests underground bulk piping used to transfer fuel in and out of USTs or ASTs. The LT-100 is a self-contained leak detection system that uses a battery-operated notebook computer to power the sensors and the data acquisition system. The LT-100 is usually used at remote sites or areas where electrical power is not available, or where safety considerations preclude the use of electrical outlets. The LT-100 is intrinsically safe, incorporating a standard ASTM pressure vessel with fireproof valves and fittings.

The LT-100 volumetric sensor unit looks very similar to a surge suppressor and consists of:

(1) A 16-inch diameter pressure cylinder.
(2) A 2-1/2-inch diameter measurement cylinder.

(3) means of measuring level changes in the measurement cylinder visually (with a sight glass) and electronically (with a differential pressure sensor).
(4) Three valves that are opened or closed to operate the unit, connect/isolate the unit from the line, and adjust the line pressure.

The cylinders are approximately 48 inches in height. The system includes a pressure relief valve and a check valve to ensure safe operation of the device. Minute changes in volume can be measured. For example, a liquid-level change of 1/16 of an inch in the measurement cylinder (and sight glass) is equivalent to a volume change of 0.0012-gallon (4.5 ml) in the line.

The LT-100 data acquisition unit makes a permanent record of all test operations. In addition to reporting the test results, the electronic record is used for quality control, quality assurance, and test auditing.

HT-100. The HT-100 is used to test long, large-diameter, underground lines found in military hydrant fuel distribution systems, marine terminal transfer lines, feeder lines, and bulk fuel farm piping. It is typically used to test lines up to several miles in length. The HT-100 is a fully automatic, computer-controlled system. This system can be fully integrated into both existing and new aviation fueling lines and SCADA systems.

The HT-100 consists of two storage reservoirs, two differential pressure sensors (one for each reservoir), and a pressure management system comprised of the pump, pressure regulating valves, pressure gauge, solenoid valves, and a computer and electronics control unit. The storage reservoirs are used for changing or maintaining pressure during a leak detection test. These containers are 24 inches in diameter and over 60 inches in height. Unlike the LT-100, these containers are not pressurized and serve only to store sufficient fuel to complete a test. (When the HT-100 is used on smaller lines or is integrated directly into the fueling system, one of the storage containers can be eliminated and the other can be made smaller.) The HT-100 is connected to the line by a valve. When open, the valve allows the exchange of fuel between one of the reservoirs (the measurement cylinder) and the line. A differential pressure sensor measures the volume of fuel that must be removed or added to the measurement cylinder to maintain constant pressure. The other reservoir stores the excess fuel used in attaining the two specified pressures. Pressure in the line is increased, decreased, or maintained constant by the pressure management system.

Some of the attributes of the LT-100 and the HT-100 are summarized below.

- The output of a leak detection test (i.e., the test result) is easy to interpret, because it is a direct measurement of the leak rate in gallons per hour at the test pressure, and is the quantity of regulatory and operational interest.

- The LT-100 and HT-100 compensate for the thermal expansion or contraction of the fuel in the line during a test. This means that accurate tests can be conducted without long, pre-test waiting periods to assure thermal stabilization.

- The output of a leak detection test includes a measure of the test error, which establishes the credibility of each test result and minimizes the chance of a false alarm or a missed detection. The test error is a direct estimate of the accuracy of temperature compensation achieved during the test.

- The compressibility characteristics of the pipeline system do not need to be known in order to conduct a test or interpret the results. Thus, the LT-100 and HT-100 can be used to test existing lines or newly constructed ones.

- The HT-100 can be used to test pipelines containing surge suppressors, which are commonly found in many hydrant fuel distribution systems.

- Both systems can be used to conduct a test even when vapor is trapped in the line.

- The LT-100 and HT-100 can be used to measure the volume of trapped vapor in the line.

- During a test, both systems can be used to measure the average temperature and the average thermally induced volume changes that occur.

- Both systems can be used to measure the compressibility of the line, with or without the effects of trapped vapor included in the compressibility estimate.

- Both systems can be permanently installed for online monitoring or can be moved from line to line to conduct tightness tests. They can be integrated into the design of new lines or retrofitted to existing ones. Retrofitting these systems is easy because they only require a single hose connection to the line, at any location along the line. Online calibration of the equipment is not necessary. While the LT-100 and HT-100 can be used to measure the onset of a leak, their principal use is for testing lines whose integrity is unknown. Determining the onset of a leak is accomplished with a difference measurement approach. Determining line integrity is accomplished with the following absolute measurement approach:

A static leak detection test is performed with the existing fuel in the line. The line is first isolated from the tank(s) and other lines it is associated with. During a test the LT-100 or HT-100 measures the volume of fuel in the line at two different pressures, each that are maintained constant while the measurement is taken. Since the LT-100 and HT-100 are volumetric systems, a leak detection test can be conducted even with surge suppressors and trapped vapor in the line. Both systems are capable of measuring the volume of trapped vapor; although this is not required as part of the test, it is another unique feature of the technology and a useful measurement tool during normal pipeline operations (i.e., during line packing).

3.1.6 Innovative Test Methodology

Vista's technology uses a data collection and analysis algorithm to compensate for changes in the temperature of the product. The systems based on this technology measure volume changes in the pipeline at two different pressures; each one being constant. This approach makes use of the fact that the leak rate changes depend on line pressure and the rate of thermally induced volume change is not affected by line pressure.

Typically, the two pressures selected for a test are the normal operating pressure of the line (test pressure) and, in most cases, atmospheric pressure (0 psig). However, any two pressures can be used. The order of the two pressures is not critical. The LT-100 (as well as the HT-100) generates a test result, which estimates the leak expressed in gallons-per-hour, and a test error, which estimates the accuracy of the temperature compensation achieved. There are a number of ways to analyze the volume data used in computing the test result and test error. One way, illustrated in Figure 3, is to divide the 2-hour test into a minimum of three equally spaced segments, all with the same duration, so that one of the segments is taken at a different pressure than the other two. Changes in the volume of liquid in the line are measured during each segment.

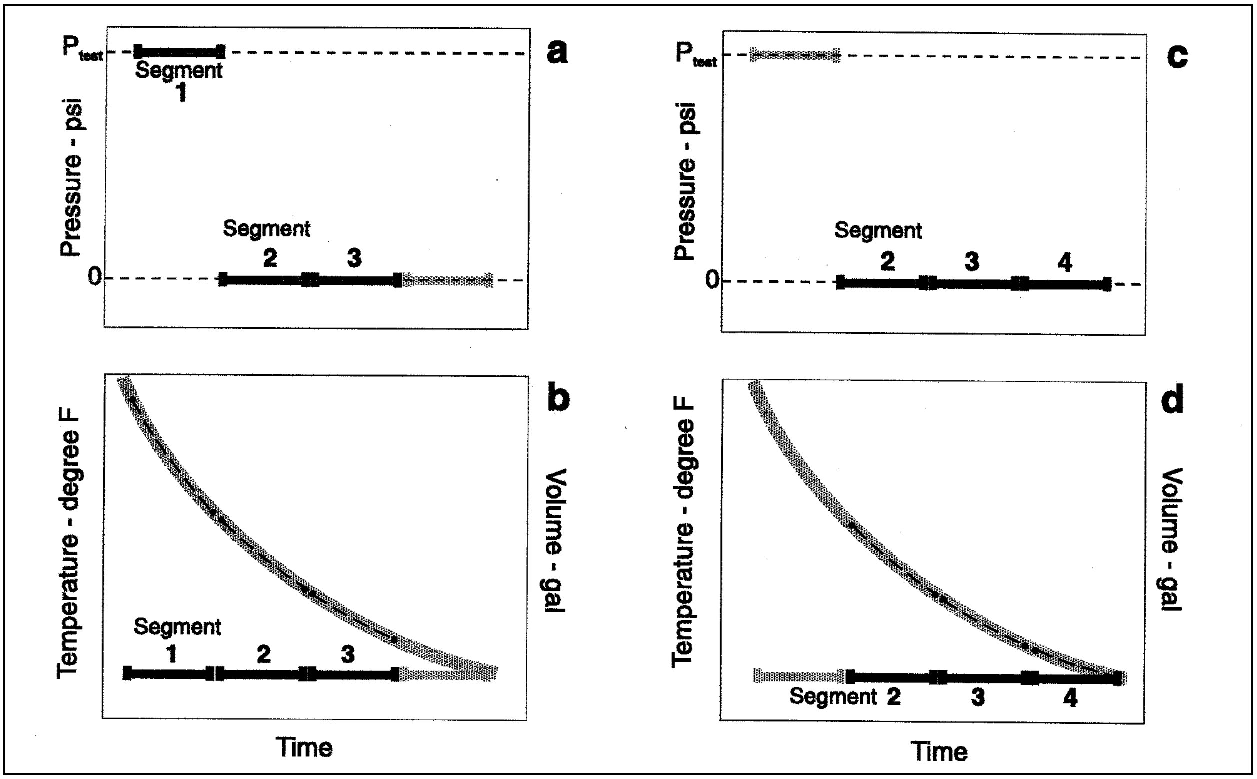

Figure 3. Volumetric test method.

Plots “a” and “b” illustrate how the test result is obtained, and plots “c” and “d” illustrate how the test error is obtained. Plots “a” and “c” show the pressure at which the volume measurements are made, while “b” and “d” illustrate the volume changes induced by the temperature changes. The test result ,“TR”, which is equal to the leak rate, if one exists, is estimated by averaging the data collected during the first three segments in Figure 3 and is computed by:

$$TR = [(V_1 + V_3)*0.5 - V_2]/ t$$

where V_i is the measured volume change during each segment of duration “t”; subscript i denotes the segment number. A nonzero estimated test result, “TR”, does not mean that the piping is not tight. For example, a nonzero flow rate may be produced by residual fluctuations in temperature remaining after compensation.

If the pressure during three of the segments is the same, then an estimate of the error in temperature compensation can also be made; this is a test error. The test error, “TE”, is estimated by averaging the data from the last three segments in Figure 3 and is computed by:

$$TE = [(V_2 + V_4)*0.5 - V_3]/ t$$

3.1.7 Demonstrations and Certifications

This technology has been successfully demonstrated numerous times at operational facilities. The LT-100 was demonstrated on four occasions as part of the NELP at Naval Air Station, North Island, Coronado, California (References 10 through 13). The HT-100 was demonstrated on a 2-mile fuel distribution line (hydrant system) at Miami International Airport (References 11 and 16). It has been demonstrated on several high-pressure, oil-filled underground cable transmission lines, 4 to 8 miles in length, owned and operated by Public Service Electric & Gas (New Jersey) and Boston Edison (Ref. 17), and on bulk underground piping at a variety of military and commercial AST facilities (Ref. 18). The system has been included in the design of a major metropolitan airport. In addition to these demonstrations, both the LT-100 and HT-100 are being used to tightness test lines for military and commercial clients. Finally, both the LT-100 and HT-100 were recently evaluated by the American Petroleum Institute (API) in controlled operational field tests at the international airport in Nassau, Bahamas.

Many of the bulk lines at military fuel farms are regulated as part of the UST regulations. KWA performed a third-party evaluation of the LT-100. The performance of the LT-100 was determined to be experimental and was reported in accordance with the procedures for evaluating leak detection methods set forth in ASTM Standard Practice E 1596-93 (Ref. 19) and EPA Standard Test Procedure EPA/530/UST-90/010 (Ref. 20). The LT-100 meets regulatory performance standards established by the EPA for both tightness tests and monthly monitoring tests (i.e., 0.1-gallon per hour and 0.2-gallon per hour, respectively, with a $P_{D,}$ Probability of Detection, of 95 percent and a P_{FA}, Probability of False Alarm, of 5 percent) on pressurized lines associated with underground storage tanks (Ref. 21). When the LT-100 is used as a monthly monitoring system, the probability of false alarm is less than 1 percent. This third-party evaluation has been reviewed and approved by the National Review Board.

The California State Water Resources Control Board (SWRCB) has certified the LT-100 for testing lines associated with bulk fuel USTs. Both the LT-100 and HT-100 systems are approved by the Florida Department of Environmental Protection (FDEP) and satisfies the annual testing requirement for bulk storage and airport hydrant fueling system piping. Both systems are also acceptable substitutes for the pressure tests required by the California State Fire Marshal and the California State Lands Commission.

3.2 TRACERS

3.2.1 Background

The concept of tracer based leak detection is simple. A unique tracer compound is placed inside the system to be tested. If that tracer compound is detected outside of the system, there is a leak. This concept allows tracer leak detection to be applied to any system geometry including buried piping, underground tanks, and aboveground tanks.

Tracer leak detection can be applied to any pipeline configuration. This method is not dependent on or impacted by variables such as pipe material, dimension, pressure, or coatings.

There is also no impact on the sensitivity from background hydrocarbon contamination. Tracer leak detection has been Third-Party Certified by KWA and is approved for testing and monitoring in all 50 states.

3.2.2 Test Methods

The most commonly applied tracer leak detection method is “inoculation”, that is, the addition of a tracer chemical directly into the product being circulated or pumped through the pipe. This practice allows the piping system to stay in service during testing, while the normal operating turbulence helps distribute the tracer labeled product evenly. After the tracer has circulated throughout the system, a waiting period, ranging between 1 and 30 days, allows tracer labeled fuel to escape and diffuse away from the leak location (Figure 4).

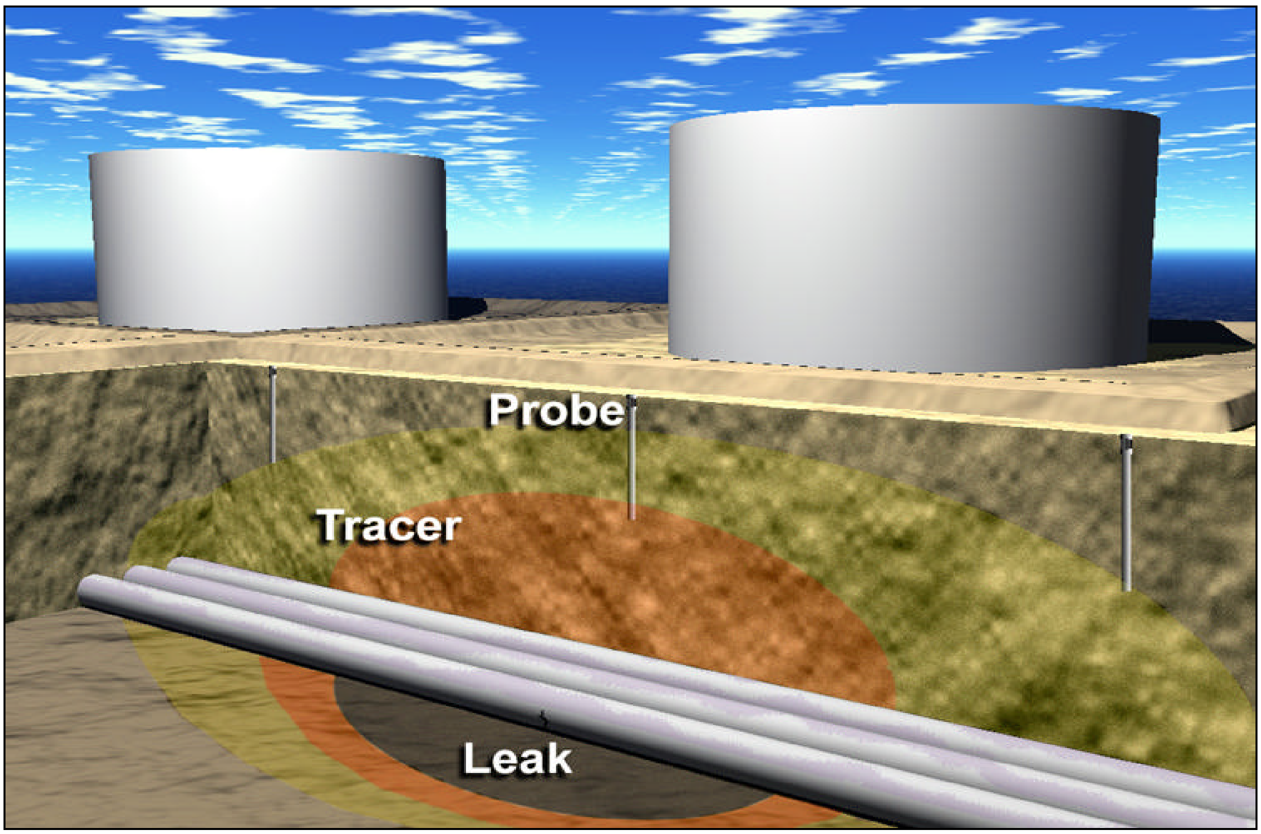

Figure 4. Tracer diffusing away from leak location.

Soil gas samples are collected after the waiting period. This is accomplished by driving a series of hollow probes, typically on 20-foot centers, into the soil above the pipeline and then evacuating the probes (Figure 5). The soil gas sample is then analyzed for the presence of tracer. Samples can be collected in areas where there is a soil, asphalt, or concrete cover. For asphalt and concrete covered pipelines, a small diameter hole (1.5 inches or less) is drilled through the cover to the soil before the probe is installed. Sensitive analyses with detection levels in the low parts per trillion range allow for the detection of leaks as small as 0.05-gallon per hour. The detection limit is not affected by the size or the geometry of the system.

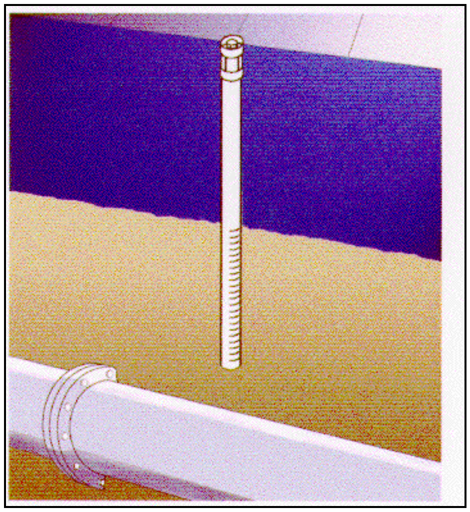

Figure 5. Tracer probe installation.

Effective tracer testing has been demonstrated in soil types ranging from clay to gravel and generally relies an area of unsaturated soil above the pipeline to allow the tracer to diffuse away from the leak location. When a pipeline is under water, different restrictions apply. If the product is less dense than water and leaks from a pipe that is under water, the product will rise to the water table and tracer will be released into the unsaturated zone. However, if the product is heavier than water, there is no mechanism to bring the tracer to the unsaturated zone and the line cannot be tested with the same reliability.

Soil gas samples can also be analyzed for the presence of hydrocarbon product vapors. The hydrocarbon levels can be used as an assessment of the severity of contamination due to current or past leakage or spills. The analysis can be conducted on-site with a mobile analytical laboratory or in a remote lab.

3.2.3 Leak Detection

Tracers can be applied for annual testing, monthly testing, or automated continuous monitoring. For automated continuous monitoring, a horizontal vapor collection system, a bundle of tubes with individual tubes that terminate at the desired sampling intervals, can be installed in the soil adjacent to or above the pipeline to be monitored. This automatic leak detection system collects and analyzes soil gas through each individual tube. When a leak occurs, tracer vapors migrate through the soil to one of the tubes in the vapor collection system. The system detects the presence of tracer and prompts an alarm, that is visual, audible, or an alternative method. An industry standard, personal computer, holds a database engine that collects and stores all the data generated by the monitoring system. The system can also be configured for off-site monitoring or third party monitoring.

During new construction, the horizontal vapor collection system for continuous monitoring can be installed directly in the trench or "roughed-in." Roughed-in consists of slotted PVC pipe and pull boxes, which allow easy changes and replacement of the horizontal vapor collection system. However, during a retrofit, horizontal drilling or trenching must be performed. This process can be more intrusive than simply probing the pipeline and there is a greater possibility that above ground and below ground features will limit the ability to install the system.

3.2.4 Leak Location

Tracers can also be effective at locating leaks. If a leak is detected, additional samples can be collected to “zero in” on the leak location. The sample with the highest concentration of tracer is nearest the leak location. Leaks are typically located in this fashion, to within a few feet.

Rapid leak location can be accomplished with the tracer method for lines that are suspected or known to be leaking. Rapid testing requires that the line be emptied of product and then pressurized with an air and tracer mixture. A short time, usually 12 hours or less, is allowed for the air and tracer mixture to leak into the soil. Samples are then collected. Samples are usually analyzed on site, which allows adjusting of the sampling interval with real time results.

3.2.5 Training

The application of tracer leak detection requires specialized equipment and personnel trained to interpret the data. For this reason, tracer based leak detection and monitoring are currently offered as a service. Consequently, there is no requirement for specialized training or manpower to the owner or operator of the system being tested or monitored.

3.2.6 Costs

Tracer testing costs (January 1997) can be estimated using Table 3.

Table 3. Costs for Tracer Testing per Linear Foot of Pipeline

INITIAL TESTING	
1 to 2,000 feet	**$5.45**
2,001 to 4,999 feet	**$4.95**
5,000 feet and up	**$4.65**
ANNUAL RETEST	
1 to 2,000 feet	**$4.45**
2,001 to 4,999 feet	**$3.95**
5,000 feet and up	**$3.65**
Add: $2,400 per site mobilization/demob and $67.20 per 1,000 bbl of product for tracer inoculant for each test.	
MONTHLY MONITORING (Price per Foot per Month)	
1 foot to 2,000 feet	**$1.25**
2,001 feet to 4,999 feet	**$1.00**
5,000 feet and above	**$0.85**
Add: $1,200 per month per site mob/demob and $67.20 per 1000 bbl of product for tracer inoculant. (Frequency of inoculation depends on throughput and usage of the system.)	
CONTINUOUS MONITORING (Price per Foot)	
System Installation (per foot)	**$35 to $45**
Monitoring Service	**Consult Tracer**
Add: System rough in costs where applicable	

3.3 PIGGING

A Magnetic Leak Detector, also know as a "pig," is an instrument that identifies and records information about pipeline anomalies such as corrosion pits, mechanical damage, dents, mill defects, wrinkle bends, hard spots, and hydrogen blisters. While configurations vary, a pig generally consists of three major elements:

(1) Drive section
(2) Combined magnetizing and transducer section
(3) Electron amplifier and recording system section (Figure 6).

The drive section, which is centered by polyurethane cups, houses the pig's power supply. The transducer section contains several transducer shoes mounted on two offset rings so that close contact with the inner surface of the pipeline is maintained throughout the inspection run. The electronics and data storage unit are housed in the third section.

A pig must be launched with the pipeline completely evacuated and requires special launch and recovery stations. As the pig passes through a pipeline, it sends a magnetic flux into the pipe. Pipeline anomalies, both internal and external, cause a leakage of magnetic flux. This flux leakage is detected by the leading edge and trailing group of sensors and is recorded on magnetic tape. Discontinuities can be located with an accuracy of +/- 0.1 percent of the distance measured. In most plate pipe, the minimum detectable pit will range from 5 to 10 percent penetration of the pipe thickness.

NFESC has expertise in implementing pigging operations. Assessment begins with an inspection of the physical characteristics and operating conditions of the pipeline. Important considerations for pigging hydrant systems include pipeline diameter, bend radius, and availability of launch and recovery sites. For the operation to be effective, a long pipeline is required. The point of contact for the Navy's Pipeline Integrity Assessment program may be contacted at (202) 433-5196, DSN 288-5196. Additional review of leak detection technology is reported in a report entitled "Leak Detection Systems Report," which was prepared for the Pipeline Integrity Assessment Program (Ref. 22).

3.4 PRODUCT-SENSITIVE CABLE

Product-sensitive cables are constructed with materials that will degrade or change electrical properties as they come in contact with certain fluids. Various cables have been developed to detect fuels, solvents, and aqueous chemicals. Generally, the cables are composed of a signal wire conductor, a continuity monitoring wire conductor, and semi-conductive jacketed sensors enclosed with a flouropolymer braid (Figure 7). The conductive-polymer layer swells when exposed to most hydrocarbon-based solvents and fuels. The surrounding braid restrains outward swelling. When the solvent or fuel come in contact with the cable, the conductive-polymer swells inward and makes electrical contact with the two sensor wires. The cable must be replaced in the section that has contacted a solvent or fuel. The cables must also be rugged, yet flexible, so they can be easily pulled through double containment enclosures (Figure 8). The conductive polymer layer should be continuous and act as a water barrier to prevent the sensor from triggering a false alarm.

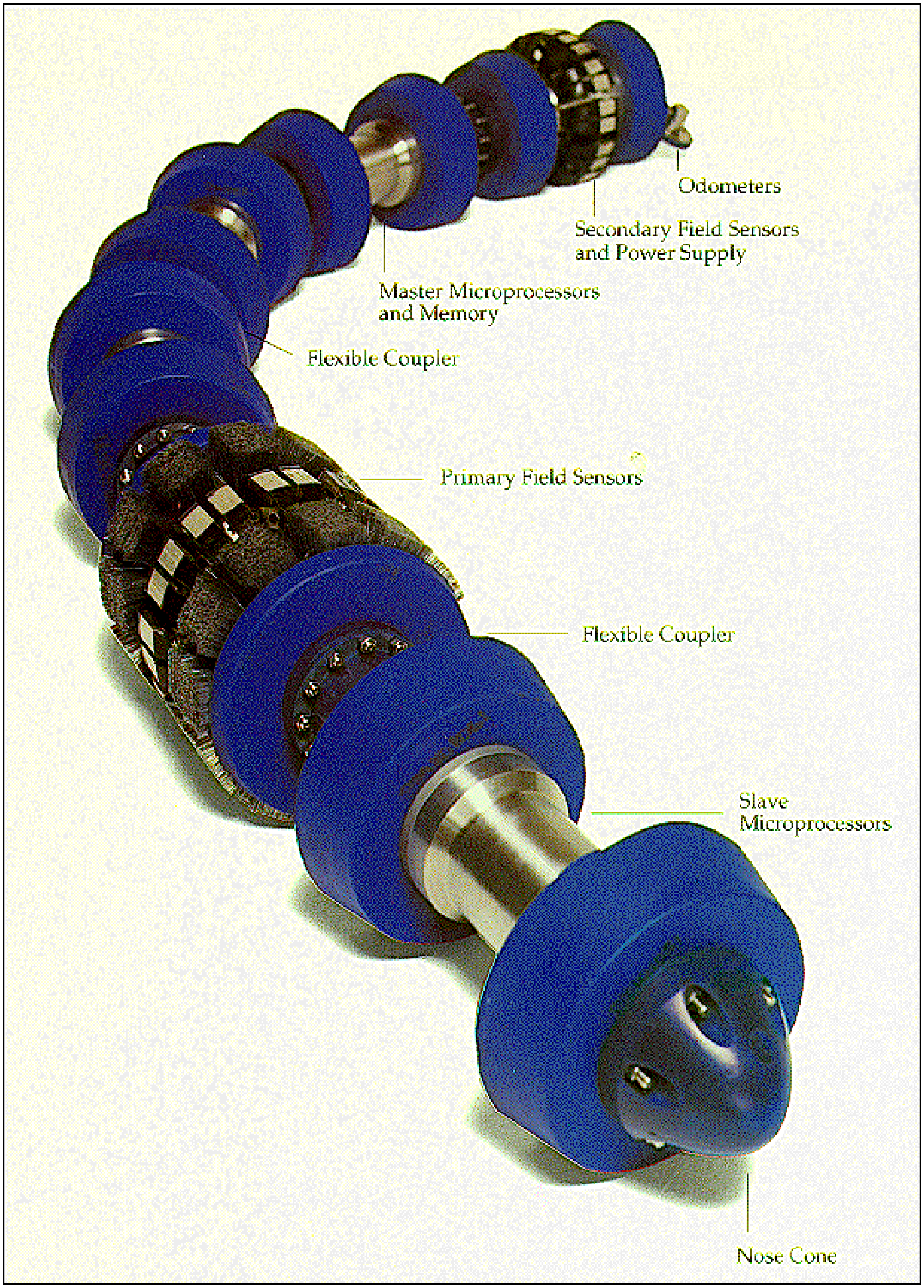

Figure 6. Magnetic leak detector.

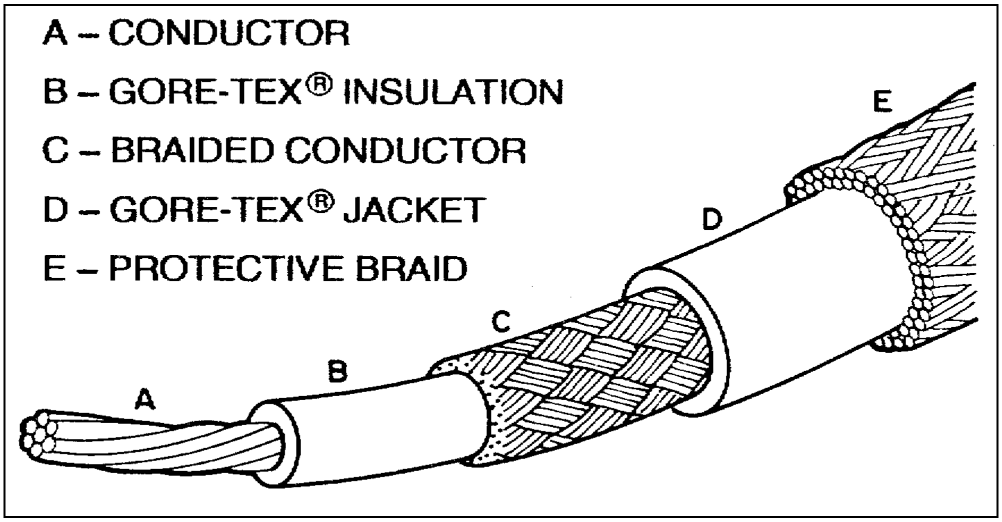

Figure 7. Product sensitive cable – typical detail.

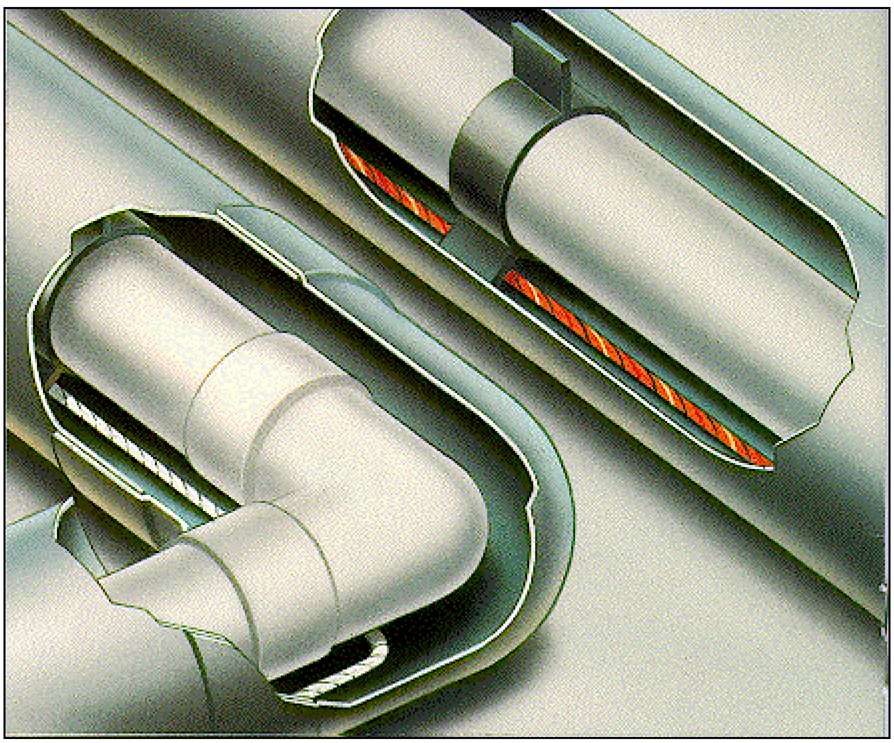

Figure 8. Product sensitive cable in interstitial spaces.

3.5 FIBER OPTICS

Chemical or physical reactions that perturb the light transmission through an optical fiber can be used as leak detection mechanisms. Technologies based on the properties of fiber optic chemical sensors have been developed for environmental monitoring.

A fiber optic sensor usually consists of a core, two coatings, cladding, and a jacket. The optical fiber is made of glass or plastic and the cladding is made of doped silica or polymers. Most of the fiber optic leak detection methods use reactive coatings on large or small sections of fiber that chemically or physically interact with a given contaminant. In the presence of these contaminants, a change in the coating's refractive properties moderates light throughput through the fiber optic strand, resulting in a change in intensity of the light signal propagating through the fiber, thus providing a means of detecting the local presence of the contaminant.

There are two categories of fiber optic sensors, intrinsic and extrinsic. The intrinsic fiber acts as a sensor itself. This can be accomplished by modifying the chemistry of the core glass or by replacing the cladding with special materials. These special materials include electric or magneto-restrictive jackets, biological receptors, selective chemical reagent-doped polymers, or reactive metal coatings that enhance the modulation of optical radiation when exposed to specific measurement phenomena. They can be used to measure temperature, pressure, or magnetic and electric field strengths.

The extrinsic fiber optic is used to transmit light between measuring devices and external transducers. The sensing materials or reagents can be localized at the sensing region by direct deposition on the fiber or by encapsulation with a polymeric membrane.

Fiber optic sensors can have problems with the stability of their reactive coating system. Fiber optic systems on the market today can be very expensive to implement. Systems based on long strands of reactive fiber have to use optical time domain reflectometry (OTDR) techniques (cost is proportional to sensitivity) to pinpoint the location of contaminant releases. Some distributed systems based on chemically reactive fibers are available at a reasonable cost considering the liability associated with an undetected leak.

3.6 ACOUSTIC EMISSION

Acoustic leak detection methods (Ref. 23) (Figure 9), which are applied primarily to commercial service station pipelines, are based on the phenomenon of a rapid, localized release of energy from material discontinuities in a structure when it is placed in a state of stress. Loose components, growing cracks, corrosion product fracture, and rubbing surfaces emit energy in the form of high-frequency sound when they undergo a load large enough to cause a very small movement. Sound waves propagate from these energy sources in all directions through the structure. When the waves reach a sensor, the motion is converted to an electric signal, usually by a piezometric crystal. The degree of attenuation (loss of the signal with increased distance from the source) determines the maximum distance possible between sensors.

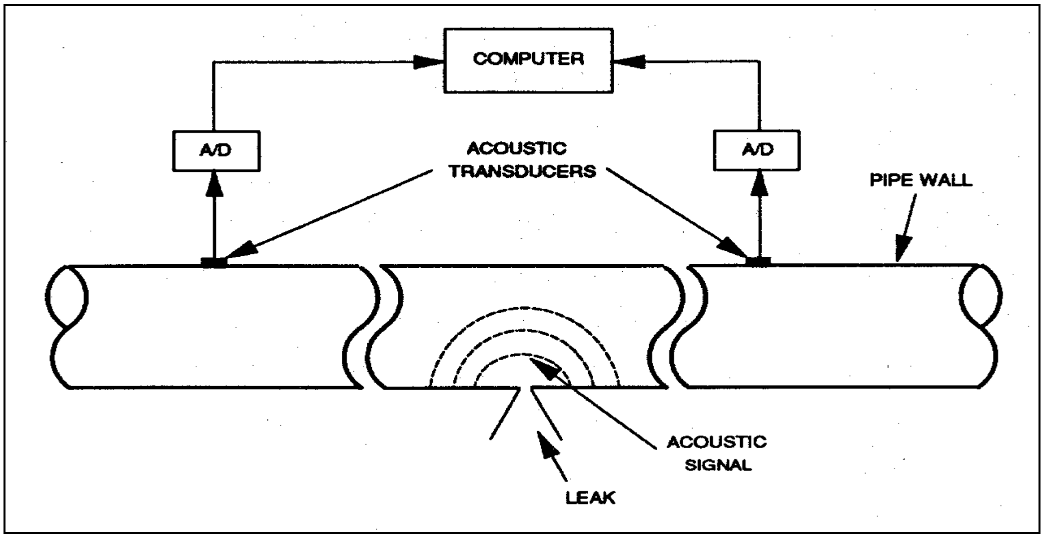

Figure 9. Acoustic emission leak detector.

Acoustic sensors must be properly spaced and set to the correct frequency. Otherwise, the sensors may cause the computer to signal a leak that does not exist or mask a real defect. This phenomenon is called "ghost chasing." A significant investment in computers and software is needed to filter out interference caused by noise in the lines.

Acoustic methods have been used to test ASTs. Good results have been achieved by eliminating or reducing noise from or near the tanks. One cause of disturbances found in these tests is the difference in temperature between the inside and outside of the tank. This temperature difference can cause condensation to form on the inside of the tank. The condensation drips from the roof into the product, creating excessive background noise levels.

Portable ultrasound equipment for detecting leaks in pipelines and tanks has been widely used in the industry. As a permanent acoustic method, ultrasound airborne technology is based on detecting specific sound patterns of leaks in pipelines. Unlike standard ultrasonic sensing, that uses some form of pulse-echo technique and usually operates within the megahertz spectrum to measure thickness or detect flaws, airborne ultrasonic instrumentation is almost exclusively receptive in nature and is sensitive to a limited range of ultrasound within the low end of the spectrum (usually 1 to 4 kHz).

3.7 PRESSURE POINT ANALYSIS AND MASS BALANCE

3.7.1 Background

Pressure Point Analysis (PPA) and mass balance types of leak detection monitor the fluid within the pipeline rather than the environment outside the pipeline. Sensors mounted on the pipeline respond to the changes that occur at the inception of a leak, providing a “window” for observation. Since this technology is focused on internal pipeline behavior, external conditions such as ground water, previous contamination, and location of the pipeline (above or below ground) have no effect on performance.

The changes the system responds to result from a loss in mass as product escapes from the pipeline. This loss in mass causes a drop in pressure at the leak site, which in turn causes the higher pressure regions next to the leak to move into the lower pressure zone at the leak. This effect, called an “expansion wave,” continues up and down the pipeline creating a low pressure wave, that moves at the speed of sound, in the fluid. Depending on the method used to detect the changes, these effects can be masked by line noise, or imitated by other conditions in the pipeline.

3.7.2 Application

One application of this technology, LEAKNET PPA™ by EFA Technologies, includes both expansion wave monitoring and an optional mass balance feature.

PPA monitors the expansion wave created by a leak through either pressure or flow inputs, or both.

To accomplish the mass balance, flow meters are located at the ends of the pipeline. Line pack compensation is available in the package for use on longer pipelines that tend to alarm when the line is being packed or unpacked.

A leak location option, LOCATOR, is also available from EFA Technologies. It locates any leak that can be detected by the two transmitters on either side of it. LOCATOR is triggered by the PPA alarms and uses the same data collected for leak detection.

Cost for this type of system varies with the number of nodes and amount of peripheral hardware needed. Training takes about one day and is not complicated.

3.7.3 Performance

PPA can operate on pipelines ranging in diameter from 3 to 42 inches. The larger the volume within the pipeline, the more difficult it is to detect small leaks during static conditions. Operating pressures of 20 psig down to 10 psig, require a specially calibrated transmitter. Pressure transmitters connect directly to the fluid in the line, while flow meters may or may not be surface mounted. Hourly testing requirements can be met on lines containing 58,000 to 116,000 gallons. If annual testing parameters are required on a line with this capacity, intermediate block valves or cold plugs are required to reduce the volume.

Background noise, background contamination, groundwater levels, and soil moisture have no effect on this methodology. If tidal influence affects the internal pressure of the pipeline and results in an expansion wave, the system must be tuned to accept these tidal variations as "normal".

The size of the leak detected, depends on the pipeline and its operating conditions. Small leaks are easy to detect when the line is blocked-in and left in a static condition (no background noise). The lower limit of detection under static conditions depends on the volume being monitored. Leaks as small as 0.05-gallon per hour can be detected on lines containing 5,000 gallons, leaks at 0.1-gallon per hour can be detected on lines containing 17,000 gallons and 2.2 to 3.0 gallons per hour on lines containing 58,000 to 116,000 gallons.

Hydraulic noise is generated when the line is flowing. This noise and the hydraulic characteristics of the pumps then determines the size of leak detected. A case-by-case performance estimate must be obtained from the manufacturer. Depending on operating conditions, detection can be expected to fall within a band of 0.5 to 2 percent of flow.

3.7.4 Equipment

Pressure is monitored by standard industrial quality pressure transmitters, such as those manufactured by Rosemount, Honeywell, or Stathem. These instruments come in direct contact with the product in the pipeline. They "mount-off" root valves welded to the line and do not present any obstruction to pigs or other in-line inspection tools. Flow is monitored by standard industrial instruments such as differential pressure transmitters, custody transfer meters, and ultrasonic strap-on flow meters. The instruments, which can be existing or newly installed, must be sensitive and repeatable (e.g., provide a consistent response to the same conditions, regardless as to whether the value is truly correct).

The instruments can be spaced miles apart, unless a unique condition exists, such as a pipeline that runs over a steep hill. Pressure at the top of the hill may be much lower than at the start and end of the line (perhaps 15 psig versus 500 psig). An additional transmitter at the top of the hill calibrated for the local pressure would provide leak detection across the entire line. In addition to a dedicated personal computer, pressure sensors, and flow meters, PPA system configurations may require other peripheral equipment, including communications devices (i.e., radio, modems, telephone lines) a printer, a signal processor, to name a few.

3.8 Certifications and Third party Evaluations

An independent testing organization uses EPA or other standard leak detection protocols to evaluate the performance of leak detection equipment. This is known as a Third Party Evaluation. Ken Wilcox Associates, Inc. (KWA), is an independent testing organization that specializes in providing third party evaluations of leak detection equipment.

KWA operates an advanced test facility for leak detection equipment and is a leader in developing methods and techniques to assist leak detection manufacturers in meeting regulatory requirements. KWA has an international reputation among regulators, manufacturers, and users of leak detection equipment as a reliable source of third-party certifications for underground pipeline and bulk storage tank leak detection methods.

KWA produces a website that is dedicated to providing regulatory and other information affecting the leak detection community. The site is a convenient source of on-line certifications, standard industry protocols, current industry regulatory information and other helpful information for users, and potential users, of leak detection equipment.

Another resource is the KWA Leaklist E-Mail Forum, which is an informal discussion group that addresses questions and provides information affecting the leak detection industry. To participate, send the e-mail message 'subscribe' to leaklist@kwaleak.com. Your e-mail address will be automatically added to the list. Any questions or topics that are e-mailed to leaklist@kwaleak.com will be automatically sent to everyone on the leaklist.

Contact Ken Wilcox Associates, Inc. at:

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1125 Valley Ridge Drive
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E-mail: info@kwaleak.com
Web: http://www.kwaleak.com

As with all leak detection systems and vendors, certifications can change with time. It is recommended to regularly contact vendors and local regulating offices for current information.

CHAPTER 4. LEAK DETECTION AND LOCATION TECHNOLOGY SELECTION

4.1 TECHNOLOGY SELECTION CRITERIA

Implementation of LDL is a tradeoff between cost and performance. Many variables should be considered when selecting leak detection and location (LDL) equipment. These considerations are listed in Table 4 and are discussed in this section. Further information on these LDL methods is contained in the previous chapters.

4.1.1 Soil Conditions

Soil conditions can affect LDL technology performance. For example, tracer gas migrates more quickly in dry, porous soil than in wet soil. Acoustic emission techniques may also be affected by the type of soil around the pipeline. Tidally influenced, salt-water environments pose special corrosion problems for pipelines. When researching leak detection equipment, always consider the soil conditions.

4.1.2 Water Table

Some LDL techniques don't work well if the pipeline runs below the water table or the high tide level. Tracer techniques are less effective if the pipeline is under water because leaking tracer gas may be washed away before it reaches a sensor. Or, the tracer may migrate and be detected by another sensor, thus indicating a leak in the wrong location.

4.1.3 Condition of Pipeline

The age and condition of a pipeline are important considerations when selecting leak detection equipment. Static pressure testing techniques require modern, high-quality valves so that a leaky pipeline can be distinguished from a leaky valve. Older, small diameter pipelines containing sharp bends may be unsuitable for pigging.

4.1.4 Operations

Certain LDL techniques can be affected by routine operations. For example, temperature compensated pressure tests must be conducted when a pipeline is 'quiet', which may require temporary suspension of operations. Acoustic emission techniques can be disturbed by vibrations generated from heavy traffic in the surrounding area. Pressure point analysis techniques may be hampered by fuel facility operations.

4.1.5 Time Monitoring

Some LDL methods provide leak detection 24 hours a day (continuous monitoring). Other methods provide a 'snap shot', or assessment of the pipeline condition at that moment. Regulators may require that a snap shot technique be employed at specified time intervals to implement an effective leak control program.

4.1.6 Spatial Resolution

Leak detection and location techniques provide different levels of spatial resolution. When properly applied, pigging, cables, and acoustic emission techniques can accurately locate leaks. However, the accuracy of tracer leak location is a function of the spacing between sampling points. Static pressure testing techniques don't locate leaks at all. Sometimes, the best way to solve leak detection problems, is to first identify a leak with one technique, such as pressure testing, and then locate it with another technique, such as tracers.

4.1.7 Leak Rate Resolution

Some leak detection techniques, such as temperature compensated pressure testing, provide a volumetric measure of the leak rate. Other techniques, such as product sensitive cables, indicate where fuel has been detected, but not how much fuel is present.

4.1.8 Ease of Retrofit

Most hydrant systems at Navy facilities have been in service for many years. It is therefore important to address whether a LDL technology can be applied to an existing pipeline. Some techniques, such as temperature compensated pressure testing, can be easily applied on most pipelines, new or old. The hardware associated with these techniques is not an integral part of the pipeline system and can brought to the pipeline by a contractor who performs the test. However, these systems can be made a part of the fueling system if it is determined to be cost effective.

Table 4. Performance Characteristics of LDL Technologies

	LDL Technologies						
Parameter	Temperature Compensated Pressure Test	Tracers	Pigging	Sensitive Cable	Fiber Optic Cable	Acoustic Emission	Pressure Point Analysis
Soil Conditions	No Effect on LDL Performance	Works Best in Highly Permeable Soils	No Effect on LDL Performance	No Effect on LDL Performance	No Effect on LDL Performance	Sensitive to the Acoustic Properties of the Surrounding Soil	No Effect on LDL Performance
Water Table	No Effect on LDL Performance	High Water Table and Saturated Soils Reduce Effectiveness	No Effect on LDL Performance	Sensitive to Water Intrusion to Cable	Sensitive to Water Intrusion to Cable	Sensitive Soil Moisture Content	No Effect on LDL Performance
Condition of Pipeline	Leaking Valves Prevent Accurate Testing	No Effect on LDL Performance	No Effect on LDL Performance	No Effect on LDL Performance	No Effect on LDL Performance	No Effect on LDL Performance	Leaks Present at Installation Will Not Be Detected.
Operations	Sensitive to Fueling Operations	Tracer Gas Must Be Dissolved in Fuel Throughout Pipeline	No Effect on LDL Performance	No Effect on LDL Performance	No Effect on LDL Performance	Sensitive to Noise Generated by Facility Operations	Sensitive to Vibrations and Fuel Operations at the Facility
Time Monitoring	Snap Shot	Snap Shot	Snap Shot	Continuous	Continuous	Snap Shot	Continuous
Spatial Resolution	Poor	Dependent Upon Sample Spacing	Good	Good	Good	Good	Good
Leak Rate Resolution	Good	Low	Low	Low	Low	Low	Good
Ease of Retrofit	Easy	Moderate	Depends on Configuration of Pipeline	Difficult	Difficult	Moderate	Easy

CHAPTER 5. CORROSION PROTECTION

5.1 Background

Corrosion leads to numerous environmental, operational, and safety problems. Mission readiness, the environment, materials conservation, and operations and maintenance costs are all compromised when corrosion is allowed to proceed unrestrained. Corrosion related problems cost the Navy millions of dollars per year, yet they can be minimized through the use of properly designed and installed anti-corrosion cathodic protection (CP) systems. CFR Title 49, Chapter 1, part 192 “Transportation of Natural Gas by Pipeline” along with CFR Title 40, Part 20, “Technical Standards and Corrective Action for Owners and Operators of Underground Storage Tanks” requires the installation of CP systems on buried or submerged pipelines and storage facilities used in the distribution or storage of gas, fuel, and other hazardous materials. There are clearly both utilitarian and statutory requirements for an aggressive Navy-wide CP program, yet in some cases, CP requirements have been overlooked. Corrosion protection in conjunction with leak detection systems provide the safest method of preventing large scale environmental contamination from underground pipeline fuel leaks. The following sections provide a summary of the types of corrosion protection that can be applied to fuel lines.

5.2 The Corrosion Process

Corrosion is the deterioration of a metal through a reaction with its environment. The deterioration can be in the form of a uniform “wasting away”of the metal, a localized attack (such as the pitting of the metal in isolated areas), or a reduction in strength and ductility through stress corrosion cracking. Corrosion occurs through the action of a electrochemical cell (Figure 10). The electrochemical cell is made up of four components:

(1) An anode where corrosion occurs.
(2) A metallic or conductive path for the exchange of electrons.
3) A cathode for the consumption of electrons.
4) An electrolyte for the supply and exchange of ions.

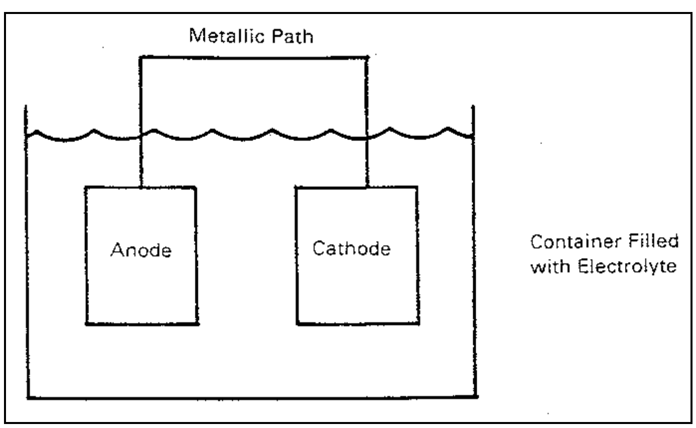

Figure 10. The electrochemical cell.

At the anode, metal atoms give up one or more electrons and become metal ions. The general formula for this corrosion reaction is:

$$\mathbf{M^0 \rightarrow M^+ + e^-}$$

The symbol, M^0, represents a metal atom such as iron or copper in a metallic structure. The arrow represents the direction in which the chemical reaction occurs. The symbol, M^+, represents a metal ion. Metal ions formed in the corrosion reaction leave the metal structure and enter the environment. The symbol, e^-, represents the negatively charged electron released by the formation of the metal ion. The free electron that is formed in the corrosion reaction remains within the metal structure. The anodic reaction that occurs in the corrosion of a copper pipe is written:

$$\mathbf{Cu^0 \rightarrow Cu^{++} + 2e^-}$$

This represents the reaction of one copper atom to form one copper ion with a charge of +2 and two electrons. Note that there is no change in total charge (0 = +2 plus –2). All metals can react to form metal ions and electrons. Anodic reactions characteristically produce metal ions and free electrons.

There are a variety of possible reactions at the cathode. One common reaction is the reaction between hydrogen ions, present in water solutions, and electrons to form hydrogen gas. This reaction is written:

$$\mathbf{2H^+ + 2e^- \rightarrow H_2}$$

This represents the reaction of two hydrogen ions ($2H^+$) with two electrons ($2e^-$) to form one diatomic atom of hydrogen gas (H_2) that contains 2 hydrogen atoms. There is no net change in charge in this reaction ($2 + {}^-2 = 0$). In other cathodic reactions, different ions react with electrons. However, the important characteristic of every cathodic reaction is the consumption of electrons. Note that there is no direct reaction of the metal in the cathodic reaction. Although the cathodic reaction must occur for the corrosion reaction to proceed, there is no corrosion occurring at the cathode.

The electrons formed at the anode flow through the metallic electron path and are consumed at the cathode. Metal loss occurs where the current is discharged from the anode into the electrolyte. The most common electrolytes involved with pipeline corrosion and most other common corrosion problems are soil, sea water and fresh water, lakes, and streams .

The corrosion reaction can be considered a cyclic phenomenon during which, each part of the electrochemical cell must occur for the overall corrosion reaction to proceed. If any one of the components is removed, or if the individual reactions at either the anode or cathode are interrupted, the entire corrosion process will be interrupted. Corrosion mitigation techniques are based on this principle.

5.3 Cathodic Protection

There are many cathodic and anodic areas present on a corroding pipe. Metal loss and corrosion occur at the anodic areas, where, the current is flowing from the steel into the surrounding electrolyte (soil or water). No corrosion occurs at cathodic areas where the current flows from the electrolyte onto the pipe. Therefore, if the entire surface of the pipe is made to collect current, it will not corrode, since it will be cathodic. Direct current is forced to flow from an external source to the pipeline, onto the surface of the pipeline. In the proper amount, current flowing onto the pipe will overpower the corrosion current discharging from the anodic areas, and there will be a net current flow onto the pipe surface. The entire pipe surface will then be a cathode, and corrosion is significantly relieved (Figure 11).

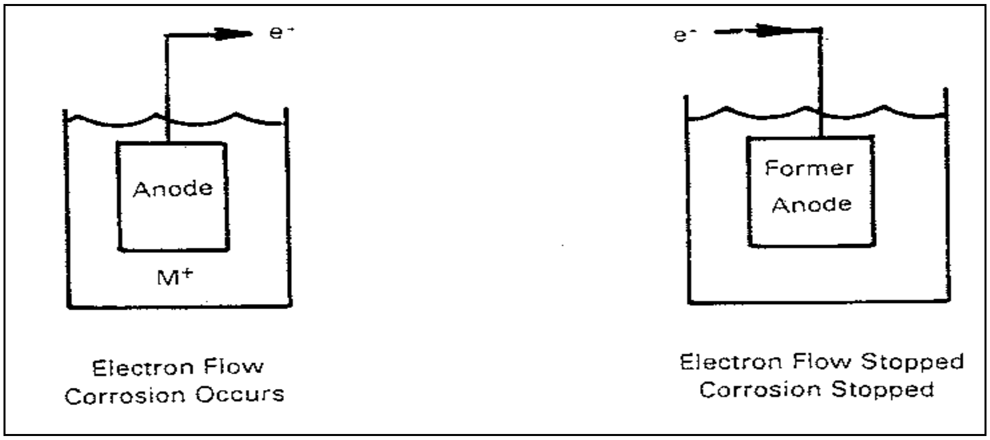

Figure 11. Prevention of Corrosion by using Applied Potential.

Current flowing onto the pipeline will polarize the pipe to a more negative potential versus a copper/copper sulfate reference electrode. This polarized potential of the pipe will give an indication of the effectiveness of the CP being applied. The potential that indicates that adequate levels of CP are achieved, depends on the metal being protected and the environment or electrolyte surrounding the material. For example, the basic criterion for the protection of steel pipe in soil and water (as determined using NAVFAC MO-306, Maintenance and Operation of Cathodic Protection Systems) is –850 millivolts (850 millivolts more negative) with respect to a standard copper/copper sulfate reference cell. The criterion can change based upon different conditions. To fully understand how potentials are determined for various combinations of metals, soils, and water, consult NAVFAC MO-306.

To provide the protective potential difference (for example, –850 millivolts), current must flow from the system anode to the structure being protected. The amount of current required to protect a given structure is proportional to the surface area that is exposed to the electrolyte (moist soil is the electrolyte for buried pipelines). Therefore, current requirements are usually given as current densities (in milliamps per square foot of exposed surface). To reduce the exposed surface area, pipelines are typically provided with a fusion-bonded epoxy exterior coating. As long as the coating remains intact, it prevents the surrounding soil (the electrolyte) from contacting the metal, the electrochemical circuit is broken and no corrosion occurs. The amount of current required for coated structures is much less than that for bare structures since only those areas with damaged coating, will require or receive current. Coatings can reduce current requirements by over 90 percent compared to bare metal. Current densities required for

CP depend on the metal being protected and typically range from 0.5-milliamperes per square foot (bare steel encased in concrete) to 40.0 milliamperes per square foot (bare steel buried in a highly aggressive soil containing anaerobic bacteria).

The method used to create the required driving potential and supply the required current to the structure of pipeline being protected depends on the type of CP being used; sacrificial anode or impressed current.

5.4 Sacrificial Anode Protection Systems

Cathodic protection with sacrificial anodes (Figure 12) establishes a dissimilar metal corrosion cell which has a strong driving potential to counteract corrosion cells normally existing on the pipeline. This is done using a strongly anodic metal electrically connected to the pipeline. The anodic metal will corrode and discharge current into the electrolyte. The current then flows onto the pipeline and protects it. Usually, current available from sacrificial anodes is limited to relatively small amounts. For this reason, cathodic protection with sacrificial anodes is used in applications where the required current for protection is low. Magnesium is typically used as a sacrificial anode material for protecting buried structures. Zinc and aluminum are typically used as sacrificial anodes for marine applications. The anodes in any sacrificial anode CP system must be periodically tested and replaced.

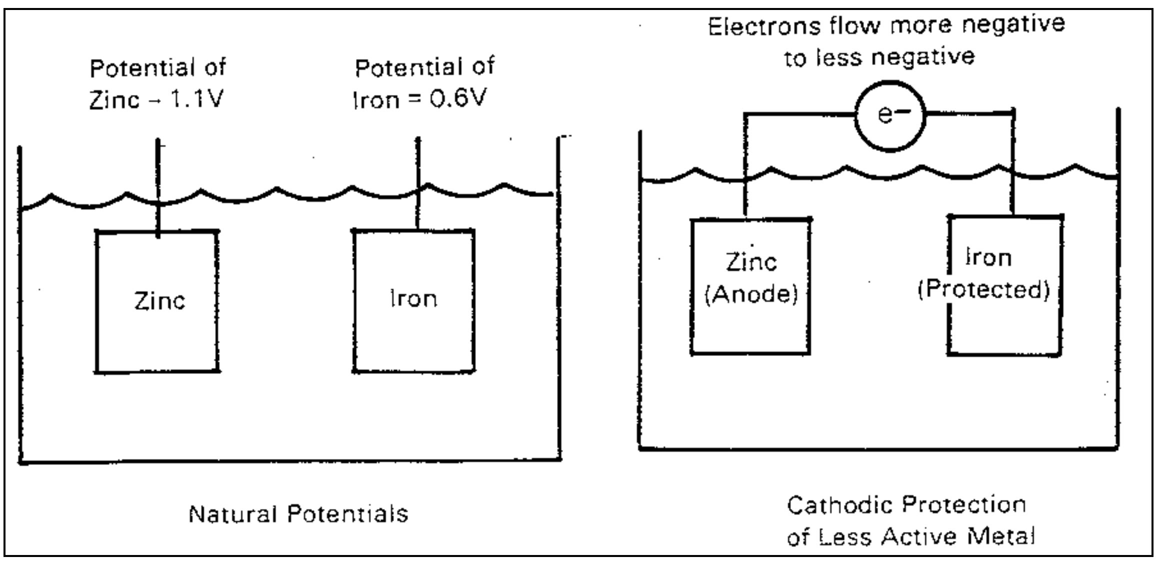

Figure 12. Sacrificial anode cathodic protection.

5.5 Impressed Current System

When current requirements are too high for a sacrificial anode CP system to adequately protect a pipeline, an impressed current CP system is utilized. With an impressed current system the anodes are not depended on as a source of electrical energy. Instead, an external source of direct current power is connected between the structure to be protected, and the impressed current anodes. The positive terminal of the power source is connected to the anode bed, which is then forced to discharge the desired amount of CP current into the electrolyte and onto the pipeline (Figure 13). If the positive terminal is erroneously connected to the structure, the structure will become the anode and will corrode at an accelerated rate. Care must be taken to ensure the system is installed correctly.

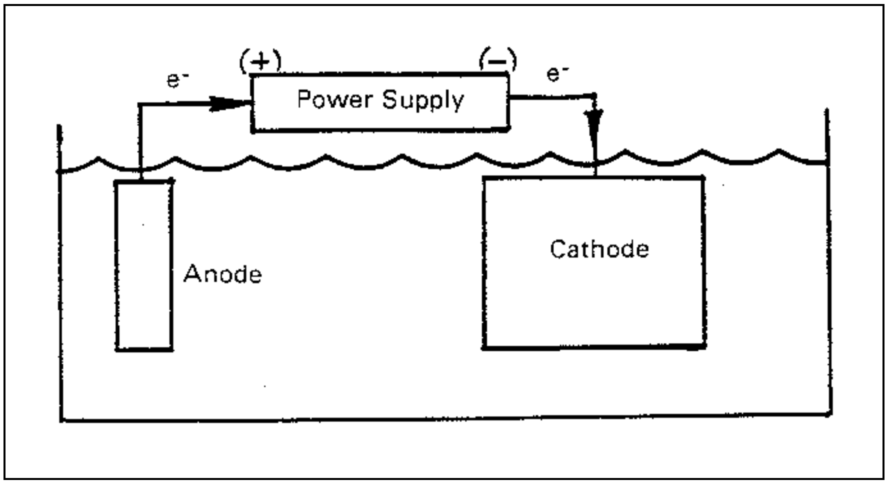

Figure 13. Impressed Current Cathodic Protection.

The most common power source used for impressed current cathodic protection is a rectifier. The energy for the rectifier is provided by an ordinary, alternating current power source. The rectifier converts the alternating current to a lower voltage, direct current using a transformer and rectifying device. Impressed current anodes are made of materials which corrode at a slower rate, while still discharging the required amount of CP current. For buried structures, graphite and high silicon cast iron are the most commonly used impressed current anodes. Lead-silver alloys and platinum coated titanium are commonly used impressed current anodes for marine applications. Anodes are available in various sizes and shapes. In impressed current systems, anodes must be periodically inspected and replaced if consumed or damaged. Rectifiers used for impressed current CP systems also require routine preventative maintenance to ensure proper operation.

CHAPTER 6. PIPELINE LEAK DETECTION ACTIVITY WITHIN THE DOD

The Department of Defense (DOD) interprets Section 40 of CFR, subsection 80, as exempting Air Force Bases (AFB), Army fueling depots, and Navy fuel supply systems from the requirement for continuous leak detection monitoring. However, in efforts to comply with environmental concerns of the EPA and the nation, the DOD has installed leak detection systems at many DOD fuel supply facilities. These systems are typically installed with MILCON funds and are operated by the facility maintenance staff.

A review of DOD pipeline leak detection activities (summarized in Table 5) and a discussion of EPA involvement in leak detection development are presented in the following sections. Current practices for new fuel distribution system installation and leak detection are also discussed.

6.1 DOD FUELS PANEL

Tri-service efforts in continuous leak detection monitoring have explored the use of marker chemical techniques, hydrocarbon sensing, volumetric monitoring and pressure decay techniques. These activities, as well as current DOD fueling operations and practice, are monitored by the "DOD Fuel Facilities Engineering Panel." This panel meets periodically to discuss technical issues about system design concepts, new vendor products, best practice for new installations and Research, Development, Testing and Evaluation (RDT&E). Current panel members are:

Navy	(202) 433-8767
Army	(202) 761-8621
Air Force	DSN 523-6357

6.2 NAVY

The Navy installs new fuel delivery systems in accordance with local regulations. In California, Florida, and Texas, the Navy installs double-wall pipe with interstitial sensing for hydrocarbons. The Navy also installs stainless steel pipe in concrete trenches or directly in the soil. The Navy installs block and bleed valves that permit static pressure testing of sections of line and line valves, in accordance with local regulations, for periodic leak detection.

6.3 AIR FORCE

Current Air Force policy for installation of new fuel lines is to rigorously comply with local regulations. The preferred installation method is to use direct buried stainless steel pipe. The Air Force also places stainless steel lines in concrete trenches that may either be open or covered. When required by regulators, double-walled pipelines with interstitial sensing are installed. Existing fuel supply systems are pressure tested for leaks at intervals required by local regulators.

In an effort to develop workable continuous monitoring leak detection systems for underground pipelines, the Air Force has investigated technologies and systems from four vendors:

(1) Tracer Research - marker gas
(2) Argus Technologies - hydrocarbon vapor sensing

(3) Permalert - interstitial sensing
(4) Controlotron - ultra sonic transit time flow meter

The marker gas system by Tracer Research has been installed at Dover Air Force Base (AFB) in Delaware, Travis AFB in California, and Whiteman AFB in Missouri. This approach to leak detection provides an intermittent check on pipeline integrity since monitoring occurs as leak tests are performed. Approximately one week before the test, the fuel is inoculated with trace levels of an inert marker gas, usually a chloroflurohydrocarbon (CFC) like one of the freons. During the test, technicians take a soil gas sample at each of the monitoring wells spaced at 20-foot intervals along the length of the underground pipe. The sample is analyzed using a portable gas chromatograph to detect the presence of the marker gas, the presence of the marker gas indicates that a leak has occurred. This method can locate a leak with a resolution approximately that of the well spacing. The system installed at Travis AFB was found to be expensive to install due to the number of monitoring wells. Operational costs are high because each well has to be sampled manually. Although expensive, this approach was found to be more reliable than other methods evaluated by the Air Force. However, the method is sensitive to groundwater and rainwater intrusion to the sensors which can cause false alarms.

Direct hydrocarbon sensing by Argus Technologies was also used as a leak detection method at Travis AFB. This method draws atmospheric air into an underground conduit installed along the length of the pipeline. Hydrocarbon vapors from a leak along the evacuated length of conduit will be swept into the air stream, which is analyzed by a sensor sensitive to hydrocarbons. The instrument will “alarm” if hydrocarbon vapors are present. The distance to the leak site can be inferred from the length of time the sample was in transit from the leak site to the detector. The Air Force believes this method to be based on sound principals, but the system did not perform as specified. The Air Force does not recommend the use of this method.

The Permalert system for sensing hydrocarbons in the interstitial space between double-wall pipes was used at Elmendorf AFB in Alaska. The presence of hydrocarbons on the sensor will cause the impedance of the sensor cables to change, which creates a standing electromagnetic wave in the cable that can be electronically analyzed to determine the location of the leak. The system has performed as specified, but a major disadvantage is that the cable continually “alarms” to one leak event until the hydrocarbon from that leak dissipates, or the cable is cleaned or replaced.

Charleston AFB installed a mass balancing system (Controlotron) that senses the fuel fluid velocities in the pipeline using externally mounted (non-invasive) ultrasonic transit time flow meters. Accurate flow velocities permit accurate calculation fuel mass flow rates entering and leaving sections of the pipeline. If the flow rates at two successive points differ, a leak is suspected at some point between the two points. Controlotron claims that fuel leaks of 1.5 gallons per hour can be detected by this system. Controlotron products are used extensively in European chemical industries, nuclear industry, and aboard nuclear submarines, primarily for volumetric flow-metering. Applying this technology to leak detection, while not unprecedented, is a new application for the Air Force.

6.4 ARMY

As required by local regulators, the Army installs double-wall or single-wall stainless steel pipe for new fuel lines. The Army also installs a 4-inch perforated PVC conduit along the length of newly installed lines. New sensors for fuel leak detection may be placed in this conduit as new technologies become available. The current leak detection practice for underground fuel lines is to install local monitoring wells adjacent to the line. The wells are sampled periodically for the presence of hydrocarbon vapors.

At Fort McCoy in Wisconsin, the Army has installed a continuous leak detection system on three fuel lines, all contained in one conduit. A Raychem TraceTek sensor cable, capable of sensing hydrocarbons, is installed in the conduit along the fuel lines. The system is capable of locating the site of a leak by impedance sensing as with the Permalert system. It has performed as specified, however, the sensor cable system has some disadvantages associated with its operation. Once a portion of the cable is “alarmed” by the presence of hydrocarbon, the sensor will continue to monitor an alarm until the cable is cleaned or replaced which is not economical. The sensor cable is also sensitive to water intrusion causing troublesome false alarms.

The U. S. Army Construction Engineering Research Laboratory (CERL) has conducted a survey of leak detection technologies used at eight DOD facilities. The results of this survey are presented in a report entitled “Summary of Findings and Survey Results for Leak Detection Sensors for Water, Fuel, and Energy Pipe Systems” 30 September 1996 (Ref. 24). To learn more about Army CERL and underground pipeline leak detection, visit the following web site:

Army CERL Home Page: http://www.cecer.army.mil/homepage.html.

6.5 SERDP PROGRAM

The EPA believes acoustic methods lend themselves more easily than other technologies to retrofitting existing pipeline systems. In 1994, the EPA’s Risk Reduction Engineering Laboratory initiated an interagency Strategic Environmental Research and Development Program (SERDP) project to develop acoustic emission leak detection and location technology to test single and double wall pipelines of various sizes and content (i.e., gasoline, diesel, jet fuel, potable water, low level radioactive wastes, etc.).

To accomplish this goal, the EPA partnered with the Department of Energy’s (DOE) Oak Ridge National Laboratory, NFESC, Army CERL, New Jersey Insitutue of Technology (NJTI), and Iowa State University (ISU) to address the leak detection needs of the various partners. A leak detection test bed was built at the EPA facility in Edison, New Jersey. It will serve as a research platform for further development of acoustic emission technology as applied to pipeline leak detection.

To learn more about this leak detection project, call the SERDP Information Line at (703) 525-5300, Extension 546, or, visit the following SERDP web sites:

SERDP Home Page: http://www.hgl.com/SERDP/
SERDP Acoustic Emission Leak Location: http://clean.rti.org/SERDP/comp1K.htm/

6.6 PETROLEUM INDUSTRY

The API pursues the development of a number of leak detection technologies including volumetric inventory monitoring, pressure decay techniques, marker chemical techniques, and acoustic emission monitoring. The API in cooperation with the EPA is developing acoustic techniques at the NJIT test facility.

The Petroleum Equipment Institute (PEI) has applied several technologies to meet the leak detection requirements, including acoustic monitoring, marker chemical detection, hydrocarbon vapor detection, pressure decay monitoring, and volumetric monitoring of fuels. Most successful vendors of these technologies apply their systems to small fuel distribution systems such as gas stations.

Table 5. Tri-Service LDL Installations

FACILITY	TECHNOLOGY	VENDOR
Air Force		
Dover AFB	Marker gas detection system	Tracer Research
Ellsworth AFB	Remote sensing for hydrocarbon vapors	Arizona Instruments, Inc.
Elmendorf AFB	Direct sensing hydrocarbons in double-wall interstitial space	Permalert
Travis AFB	Marker gas detection system	Tracer Research
Travis AFB	Hydrocarbon vapor sensing	Argus Technologies
Whiteman AFB	Marker gas detection system	Tracer Research
Army		
Fort McCoy	Direct sensing for hydrocarbons in conduit	Raychem
Navy		
NAS North Island	Temperature compensated pressurized “tank tightness” testing	Vista Research
NAS Pensacola	Remote sensing for hydrocarbon vapors	Arizona Instruments, Inc.

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POINTS OF CONTACT

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	Air Force	DSN 523-6357	
Independent Leak Detection Evaluations		Ken Wilcox & Associates	(816) 433-2494
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