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Buried Pressurized Piping Systems Leak Detection Guide

Regulatory and Scientific Affairs

API PUBLICATION 4716
APRIL 2002

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FOREWORD

This document is intended to provide the reader with a general background in leak detection technologies for the buried pressurized piping in airport hydrant fueling systems and petroleum product terminal systems. This document was developed by Argus Consulting and Ken Wilcox Associates under the guidance of the joint Air Transport Association of America (ATA) and the American Petroleum Institute (API) Leak Detection Committee. The document incorporates information on leak detection technologies including research, laboratory testing, field testing, analysis, and experience. While an attempt has been made to determine the most logical technologies for application in airport hydrant fueling and petroleum product terminal systems, the reader should recognize that there may be other forms of leak detection technologies and concepts not discussed in this publication. The reader is also advised that piping systems, facilities, and site-specific differences can affect technology performance. Therefore, each technology being considered for actual use should be carefully evaluated. Inclusion in this publication of a particular leak detection technology should not be construed as an endorsement of that technology by either API or ATA.

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Buried Pressurized Piping Systems
Leak Detection Guide

I. EXECUTIVE SUMMARY

This Study Documentation Report (the Study) analyzes of the performance of different types of leak detection technologies that were applied to buried pressurized piping systems used in airport hydrant fueling and petroleum product terminals. The Study was conducted by Argus Consulting and Ken Wilcox Associates on behalf of the Air Transport Association of America (ATA) and the American Petroleum Institute (API). This report is intended to provide an overview of the Study methodology and results.

The purpose of the Study, as defined by the joint API and ATA Leak Detection Committee, was to "identify and evaluate reliable leak detection technologies that are currently commercially available and cost-effective for buried piping associated with airport hydrant fueling systems and petroleum product terminals."

The Study was conducted in three phases. In Phase I, the Study consultants collected published data and vendor information regarding the leak detection technologies reported to be applicable to the buried, pressurized piping in airport hydrant fueling systems and petroleum product terminals. During that phase, criteria were identified for evaluating the leak detection technologies in the specified applications. Through application of those criteria, six types of leak detection technologies were determined to have the potential to satisfy the Study purpose. One vendor of each of these technologies was selected and agreed to participate in Phase II of the Study, which consisted of actual testing under conditions intended to represent or approximate conditions at an airport hydrant fueling system or petroleum product terminal.

Testing of the various technologies addressed in Phase II of the Study was conducted at either the Kansas City International Airport (MCI) or a special test facility designed and maintained by Ken Wilcox Associates. The factors considered in evaluating the potential of these technologies included, but were not limited to: applicability to buried piping at airport hydrant fueling systems and petroleum product terminals; compatibility with the operating requirements for such systems and facilities; performance of the technology; installation procedures; operational requirements; reliability, and cost.

Because the Study is not intended to serve as an evaluation or endorsement of particular leak detection technology vendors, rather than identifying the technologies tested by vendor name, the technologies are identified by descriptive categories. While technology categories are used throughout the report, the reader is advised that each of the technologies actually tested have proprietary features that may be unique. The features are described to the extent necessary for accurate reporting purposes consistent with the vendors' proprietary protections.

The six categories of leak detection technologies tested are identified as follows:

- Pressure decay—dual pressure
- Volumetric—dual pressure
- Pressure decay with temperature compensation
- Acoustic emission
- Chemical marker
- Hydrocarbon vapor monitoring

The first three technologies can be classified as pressure-based technologies involving the measurement of fluid within the pipe. The acoustic technology analyzes acoustic signals caused by a leak, which are transmitted through the piping and piping contents. The last two technologies employ external monitoring methods, monitoring the backfill outside of the buried piping for evidence of a leak.

The following is a summary of the information gleaned about the six categories of leak detection technologies:

- Pressure decay—dual pressure. This leak detection technology requires a means to isolate sections of the piping to conduct the test. This is normally accomplished with double block and bleed valves and a pressure transmitter installed in each test section. Application of this technology also requires a means to pressurize and depressurize the piping section being tested. Each leak detection test takes approximately 45 minutes when the piping system is isolated and under static pressure conditions.

The technology appears to be capable of detecting a leak of about 0.01 percent of the line volume per hour with 99 percent probability while operating at a one percent false alarm rate.

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It appears to be viable on both new and existing piping systems.

Previous applications of the technology have used a minimum test pressure of 100 psi, which would limit its applicability for petroleum product terminals. Conversations with the vendor indicate that the technology can be used on lower pressure lines, but there is little experience with that application. The technology requires that any trapped air in the lines be eliminated, and surge suppressors be isolated from the lines, during the test. Elevation differences in the line can affect the results. There is no effect if the leak is at the same elevation as the pressure measurement. The reported result will be biased high if the leak is above the test point, and biased low if the leak is below the test point. The effect would be about 10 percent for a 50-ft elevation change.

Reported rates are standardized to 10 bar (150 psi). Since most of the testing is conducted at night, the effects of exposed pipeline are minimized.

- Volumetric—dual pressure. This technology is designed for permanent installation but can also be employed as a mobile unit where the vendor can conduct a leak detection test on demand. When permanently installed, it is often set up to block in and test the entire line. Unless there is special provision for switching the leak detection unit to different sections of the line by valves, separate fixed units are required for each section. Alternatively, a mobile unit can be utilized to test individual segments of the piping system on a scheduled basis.

  This leak detection technology tests the line in a static condition and controls the pressure to two different levels during the test by adding or removing a volume of liquid product from the line. The test can take two to three hours, depending on the size of the line being tested.

  This technology appears capable of detecting a leak of about 0.006 percent of the capacity of the line with a 99 percent probability of detection and with a false alarm rate of about one percent. This technology appears to be viable on both new and existing airport hydrant fueling systems and petroleum product terminals.

  The technology is affected by elevation differences, with the measured leak rate biased low if the leak is located below the top of the line. The performance estimates are based on testing a line with a 50-ft elevation difference and with the measured rates biased low by about 40 percent. If the same tests were run on a flat line, the system should be able to detect a leak of 0.0037 percent of the line volume based on the 175,000 gallon line tests.

- Pressure decay with temperature compensation. This technology monitors the pressure decay in a static line and sends a pressure pulse through the line at the beginning and end of the test to measure any temperature changes. It requires approximately a 30-minute test period. Testing of this technology during the Study was abbreviated because the vendor determined that further enhancements were needed.

  This technology showed promise, but it appears to require further research and development before being implemented in an operational setting. Its application will depend on improvements by the vendor, but apparently this technology could be designed for either permanent installation or point-in-time testing at both airport hydrant fueling systems and petroleum product terminals.

- Acoustic emission. This technology operates through the placement of microphones (or accelerometers) with radio transmitters on the pipe at intervals of 300 to 500 feet. The acoustic signal generated by liquid flowing out of a defect in the pipe is recorded and analyzed by a computer software program.

  This technology is adversely affected by ambient noise. Thus, given the noise associated with operations at airports, this technology appears to require further development and testing to be viable in actual application at an airport or petroleum product terminal.

  Testing at MCI estimated that it could find a leak of about 89 gallons per hour with one percent PFA and 99 percent PD. With development, this technology could be expected to be capable of detecting a leak rate on the order of 20 gallons per hour. Unlike the pressure-based methods, this technology can also provide an estimate of the location of a leak.

- Chemical marker. The goal in this Study was to assess performance of the technology in cases with high water tables. The technology is well established and appears capable of detecting very small leaks. It also appears capable of locating leaks to within 10 feet or less. However, this technology requires the installation of sampling

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ports approximately every 20 feet, which can be expensive (ports must be closer if the medium is water). Samples must be collected from each of these ports and analyzed periodically.

It also requires the addition of a chemical marker compound to the fuel, which generally requires approval by relevant officials. Testing conducted during the Study demonstrated that this technology can detect leaks as small as 0.05 gal/h even when the pipes are below the water table. However, under these conditions, the time to detection was increased.

This technology appears to be applicable to both airport hydrant fueling systems and petroleum product terminals. However, continuous monitoring could be highly labor intensive. There could also be issues regarding product purity, as it would require continuous injection of the marker compound.

- Hydrocarbon vapor monitoring. This technology monitors hydrocarbon liquid or vapors in the soil and/or dissolved hydrocarbons below the water table. It is designed for permanent installation and continuous monitoring. To properly interpret the data resulting from the monitoring, a representative of the vendor's staff generally must be involved. Testing during the Study found leaks of 0.05 gal/h at 5-feet from the sensor within 15 days. This method requires the installation of probes at 20-foot intervals or less, which can be expensive. The interpretation of results in the presence of existing hydrocarbons is open to question. This technology appears to be viable as applied to either airport hydrant fueling systems or petroleum product terminals. However, the cost of installing probes and paying for a vendor's interpretation of the data must be taken into account.

The following summary tables show how the various leak detection technologies performed during testing and under the particular conditions of the Study. It must be noted that results will vary with application. In selecting a leak detection system, facility owners and operators should consider the configuration and operation of their specific piping systems.

Different technologies have inherently different measures of performance. To make the results as comparable as possible, systems that use pressure as part of the technology are presented as gallons per hour (g/hr) in percent of volume enclosed. A rate in gallons per hour for the size of the system is also presented.

The acoustic system, chemical marker, and hydrocarbon monitoring systems are presented in gallons per hour with the external technologies coupled with the distance from the leak and the time.

Since results were generally different for the airport hydrant systems compared to the API system, two performance tables are reported. The acoustic, chemical marker, and hydrocarbon monitoring methods did not differ for the size of line, so they only appear in the hydrant system table.

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Table I-1 Performance Summary
Airport Hydrant Systems (Results at MCI with 50-foot Elevation Difference)

Technology	Threshold	PFA*	PD*	MDL (99%)	Test Time	Notes
Pressure Decay/Dual Pressure	0.0048% of 175,000 g vol.	1%	99%	0.0095% of 175,000 g vol. (16.6 g/hr)	45 min.	Permanent installation or mobile unit
Volumetric/Dual Pressure	0.0028% of 175,000 g vol.	1%	99%	0.006% of 175,000 g vol. (9.7 g/hr)[3]	2.5 hr.	Permanent installation or mobile unit. Mobile unit can be used for one-time test.
Pressure Decay w/ Temp-Compensation[2]	ND	ND	ND	ND	30 min.	Needs development; could locate leak
Acoustic emission	NA	1%[1]	99%	89 g/hr	2 min.	Needs development; could locate leak
Chemical Marker	NA	ND	99+%	0.05 g/hr (18 g at 10 ft in 15 days)	2-3 weeks	Ports every 20 ft; locates leak to about 10 ft (Results for high water)
Hydrocarbon Vapor Monitoring	NA	ND	ND	0.05 g/hr (18 g at 5 ft in 15 days)	2-3 weeks	Probes every 10 ft; locates leak to 5 ft. (Results for high water)

NA—Not applicable Threshold – Leak Rate PD – Probability of Detection
ND—Not determined PFA – Probability False Alarm MDL – Minimum Detectable Leak

* For quantitative technologies, a threshold for indicating a leak was calculated based on a fixed probability of false alarm (PFA) of 1%. In addition, the minimum leak size that could be detected (MDL) with a probability of 99% was reported. The estimates were based on a normal statistical model. The percentages used (PFA=1% and PD=99%) were selected for purposes of consistent presentation. It was beyond the scope of this study to determine if other percentages were more appropriate. For the qualitative technologies, the threshold was a characteristic of the specific technology and was proprietary. Based on the computed probability of detection curve using a logistic model, a leak rate that was expected to be detected with 99% probability and a corresponding 1% PFA was reported.

[1]The threshold used by the vendor produced a PFA of 35% and a PD of 63%.
[2] The test data after product was circulated gave false alarms and missed detections. The data were not sufficient to provide valid estimates of PD and PFA or MDL.
[3] Performance may be better for lines with no elevation differences.

Table I-2 Performance Summary:
Petroleum Product Terminal System (Based on Tests at MCI, No Elevation Difference)

Technology	Threshold	PFA*	PD*	MDL (99%)*	Test Time	Notes
Pressure Decay Dual Pressure	0.009% of 12,000 g vol.	1%	99%	0.018% of 12,000 g vol. (2.2 g/hr)	45 min.	Permanent installation or mobile unit.
Dual-Pressure Volumetric	0.008% of 12,000 g vol.	1%	99%	0.015% of 12,000 g vol. (1.9 g/hr)	2.5 hr.	Permanent installation or mobile unit. Mobile unit may be used for one-time test.
Pressure Decay w/ Temp-Compensation	ND	ND	ND	ND	30 min.	Needs development; could locate leak

NA—Not applicable Threshold – Leak Rate PD – Probability of Detection
ND—Not determined PFA – Probability False Alarm MDL – Minimum Detectable Leak

- For quantitative technologies, a threshold for indicating a leak was calculated based on a fixed probability of false alarm (PFA) of 1%. In addition, the minimum leak size that could be detected (MDL) with a probability of 99% was reported using a normal model. The percentages used (PFA=1% and PD=99%) were selected for purposes of consistent presentation. It was beyond the scope of this study to determine if other percentages were more appropriate. For the qualitative technologies, the threshold was a characteristic of the specific technology and was proprietary. Based on the computed probability of detection curve using a logistic function, a leak rate that was expected to be detected with 99% probability and a corresponding 1% PFA was reported.

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II. INTRODUCTION

A. Background

Because of the complex physical configuration and unique operational characteristics of buried pressurized piping systems found in petroleum product terminals and airport hydrant fueling systems, proven leak detection technologies have not previously been available. However, within the last few years, several technology vendors and companies have worked to develop and improve leak detection technologies for these unique piping systems. The purpose of this Study was to assess the success of their efforts to date.

In 1997, the American Petroleum Institute (API) and the Air Transport Association of America (ATA) formed a joint Leak Detection Committee to review the new generation of leak detection technologies for potential application to petroleum product terminal piping as well as the hydrant fueling systems at airports. The Leak Detection Committee defined its goals as follows: "Identify and evaluate reliable leak detection technologies that are currently commercially available and cost-effective for buried piping associated with airport hydrant fueling systems and petroleum product terminals."

B. Program Structure

The Leak Detection Committee adopted a three-phased approach to the leak detection Study. In the first phase, the Study consultants collected published data and vendor information regarding the leak detection technologies reported to be applicable to the buried, pressurized piping in airport hydrant fueling systems and petroleum product terminals. In addition, during Phase I, the Committee discussed and identified criteria for evaluating the leak detection technologies in the specified applications. The following twelve evaluation criteria were identified:

- Availability of technology
- Capability of detecting small leaks
- Operational reliability
- Accuracy (defined as the ability of the technology to closely match the actual leak rate)
- Sensitivity
- High probability of detection; low probability of false alarm
- Applicable to new or existing piping systems
- Minimal impact on existing infrastructure
- Minimal maintenance requirements
- Properly operated by site staff
- Procured, installed, and operated at reasonable cost
- Certifiable to comply with the applicable regulations at the installed site

After identifying the evaluation criteria, the Committee applied the criteria to the leak detection technologies that had been identified in the early part of Phase I. Through this process, six existing leak detection technologies were determined to be potentially applicable to airport hydrant fueling systems and petroleum product terminals. The Committee then developed testing protocols for testing these technologies in the field. The following is an outline of the Phase I activities that were undertaken:

■ Phase IA – Gather Data
- Solicitation of Vendors and Data
- Evaluation of Vendors and Technologies
- Discussions with Vendors
- Development of Screening Matrix
- Organization of Data from Vendors
- Analysis of Data
- Selection of Vendors and Technologies

■ Phase IB – Prepare Testing Facilities
- Determine Facility Requirements
- Evaluate Potential Facilities
- Secure Test Facility
- Develop Facility/System Concept
- Design Facility/System Modifications
- Construct Facility/System Modifications
- Conduct Base Line Tests of Systems

Phase II of the Study consisted of actual testing of the technologies under specified conditions. The following is an outline of specific tasks that were undertaken during Phase II of the Study:

■ Phase II – Implement Testing
- Organize and Schedule Testing
- Prepare Written Procedures
- Prepare Written Protocols
- Prepare Vendors for Testing
- Set up Technologies for Testing
- Conduct and Monitor Tests
- Gather and Analyze Testing Data

This document, the Study Documentation Report, is a result of Phase III of the study and

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contains information on the study approach, the conditions under which testing was conducted, and the results of the testing under the specified conditions. The following is an outline of the tasks undertaken in Phase III:

- Phase III – Document Findings
  - Prepare Outline of Final Report
  - Develop Draft Report
  - Review Results and Draft within Committee
  - Solicit Comments from Study Participants
  - Prepare Study Documentation Report

The Study Documentation Report is intended to provide the designers, contractors, operators, owners, and regulators of the buried, pressurized piping in airport hydrant fueling systems and petroleum product terminals with an evaluation guide that may be applied in assessing the leak detection technologies that are currently available. In addition, the testing protocols contained in Volume II of the Study provide a basis for evaluating and comparing the performance of additional leak detection technologies that may be developed or refined in the future for application in the piping systems addressed in the Study.

C. Applications

As noted above, the Study addressed the applicability of currently available leak detection technologies for pressurized piping systems at petroleum product terminals and airport hydrant fueling systems. In general terms, such piping systems contain petroleum hydrocarbon fuels with a specific gravity range between 0.65 and 0.85, and operate within a pressure range of 50 to 200 PSIG at flow rates between 100 and 20,000 gpm. Piping volume ranges from ten thousand to one million gallons.

The petroleum product terminals and airport hydrant fueling systems that were the subject of the Study typically have a combination of aboveground and underground piping systems consisting of pumps, filters, meters, pipes, and fittings. The focus of the Study was to address the application of leak detection technologies to the underground piping within these facilities. In most cases, the underground piping is composed of transfer or distribution lines ranging in size from 6 to 30-inch piping. While slight variations may exist in system materials and methods of construction, the majority of the piping is composed of carbon steel with welded (or bolted flanged) joints meeting ASTM - A53, ASTM - A106 or API-5L specifications. In many cases, the piping is externally coated, cathodically protected, and installed in a selected backfill trench material.

D. Testing Facilities

A significant element of this Study was the testing of technologies on operational buried piping systems under field conditions. The existing airport hydrant fueling system at Kansas City Mid-Continent International Airport (MCI) in Kansas City, Missouri was utilized. The facility at MCI was selected in large part because the piping systems are representative of the buried pressurized piping systems found at both petroleum product terminals and airport hydrant fueling systems. In addition, MCI was chosen because the fueling system has redundant lines that allowed certain lines to be isolated for the Study testing while others were maintained for airport operations.

To create a test facility at MCI, piping manifolds and headers with double block and bleed valves for positive shutoffs were installed at necessary locations. In this manner, the two pipelines dedicated for testing were isolated from the three lines that continued to serve normal airport fueling operations. These modifications to the airport hydrant fueling system at MCI resulted in a test facility that included the following components:

- A 210,000 gallon (5,000 barrel) aboveground jet fuel storage tank;
- 2400 gpm pumping and filtration equipment;
- 14-inch and 16-inch transfer lines, each approximately 10,000 feet in length;
- 2500 feet of 12-inch hydrant system piping, with twenty hydrant pits, around a passenger terminal building; and
- 3000 feet of 8-inch tank return and system recirculation piping.

Following the modifications to the facility, the installation contractor conducted a hydrostatic line test on March 13, 1999. As is generally the case, no temperature compensation was included with this hydrostatic test. The results of the test indicated a loss of 8.6 psi over a 13-hour period. This converts to a volume loss of approximately one gallon per hour. This effect is considered normal with cold weather temperature changes.

An additional test site was constructed at an off-site facility. A series of lined trenches and containment tanks was installed to test specific external monitoring technologies.

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E. Who Should Read This Report

This Study will be useful to owners, managers, operators, designers, vendors, contractors, users, and regulators of aviation and petroleum product terminals. Information within this report includes:

- Identification of the challenges associated with the testing and application of leak detection technologies with respect to complex petroleum piping systems.
- A description of each of the different leak detection technologies that were tested and analyzed as a part of this program.
- A description of the operation and performance of specific leak detection technologies as field tested in a particular operational scenario.
- Information on the operating parameters of high pressure, high volume, buried piping systems with variable flow rates and, hence, the conditions under which leak detection technologies for these systems must operate.
- Discussion of the leak detection rates and performance that might be realistic and attainable within these systems.
- Guidance for interpreting stated performance criteria during the selection of a leak detection technology for a particular installation.
- Discussion of the benefits of conducting moderate large scale tests.

F. Notes Of Caution

Individuals using this report should consider the following cautionary points in applying the information herein. First, there are limitations to each of the leak detection technologies discussed in this report; none of the technologies discussed in this report will detect a small leak rate 100 percent of the time. Further, occasional anomalies in reliability, repeatability, sensitivity, accuracy, and alarms should be expected from most, if not all, of the technologies. This is a consequence of applying leading edge technologies to complex piping systems.

Although the Leak Detection Committee believes the testing that was undertaken during the Study was representative of the buried, pressurized piping likely to be found in petroleum product terminals and airport hydrant fueling systems, it should be recognized that each individual system will vary. Thus, the characteristics of a given system should be considered when a particular leak detection technology is reviewed for actual application.

Similarly, all testing results in this report were obtained using Jet A fuel. Other fuels may have higher or lower coefficients of thermal expansion. This could affect temperature dependent technologies adversely. In addition, use of fuels with different vapor pressures may significantly affect the performance of hydrocarbon vapor monitoring technologies.

Because the Study was not intended to serve as an evaluation or endorsement of particular leak detection technology vendors, the technologies that were tested are identified in the Study by descriptive categories. While the technologies are described in a general manner, the reader is advised that each of the technologies actually tested have proprietary features that may be unique. The features are described to the extent necessary for accurate reporting purposes consistent with the vendors' proprietary protections.

Finally, the technologies tested within this Study were those believed to provide the highest probability of successful application for the buried, pressurized piping under consideration. Leak detection technologies for such applications continue to develop and emerge. As they do so, additional data will be developed. The Committee strongly supports the development of performance data that allows comparisons to be made between leak detection technologies under the conditions present in actual application.

This report should be used as a guideline for understanding the capabilities and limitations of current leak detection technologies as applied to the buried, pressurized piping at petroleum product terminals and airport hydrant fueling systems. This report does not recommend one vendor or technology over another, nor is it intended to do so. Rather, this report is intended to be an unbiased documentation of field application and operational testing at MCI.

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III. FACILITY/SYSTEM CHARACTERISTICS

A. Airport Hydrant Fueling Systems

The construction and use of airport hydrant systems (AHS) date back to the early 1960's with the introduction of jet engine powered aircraft.

Today, most large airports in the world utilize an AHS to serve commercial air carrier operations. Using an AHS to fuel the aircraft generally is the most cost-effective and efficient delivery method. The alternative means of fueling aircraft is through the use of multiple refueling vehicles, which transport fuel from airport storage facilities to aircraft. An AHS uses a piping distribution system that pumps fuel to aircraft from a storage facility. Pressure reducing and filtering carts connect the aircraft to the AHS during fueling operations. Nearly all of the AHS piping is buried underground.

A typical AHS is comprised of thousands of feet of buried piping ranging in size from 4-inches to 30-inches. An AHS maintains constant pressure and is a flow-on-demand system. Normal operating pressures are in the 150-200 psig range with pumping systems from 2000 gallons per minute for small operations and up to 20,000 gallons per minute at large volume airports. Some AHS have hydraulic surge absorbers to mitigate pressure surges within the system that are created by the closure of hydrant valves.

As interest in validating the integrity of AHSs has increased during the past few years, factors that impose testing limitations have been identified. Several operational characteristics were identified that affect the capability of various leak detection technologies. These were the daily usage pattern, nighttime operations, pressure fluctuations as flows are started and stopped, temperature effects, and the relationship between pressure changes and the volume of product in the line.

The following is a list of specific issues that must be considered.

- Most testing must be performed in a static (locked-in pressure) state.
- Due to airport operations, the AHS normally is in an extended static state only during late night and early morning hours (e.g., between the hours of 11:00 p.m. and 5:00 a.m.).
- The AHS may be divided into several sections to serve multiple gates. For testing, each section should be capable of positive shut off with isolation valves.
- Because the volumetric capacity of an AHS can be significant, positive isolation must be provided to facilitate leak detection technologies.
- Surge absorbers and entrapped gases will affect the rate of pressure change for a given leak rate in an isolated system. Accordingly, surge absorbers must be isolated and entrapped gases identified and addressed during the testing process for best performance.
- An AHS is highly susceptible to pressure variations caused by temperature changes of the fuel when shutdown and isolated. Temperature changes can occur due to differences between the fuel and ground temperature and from solar and ambient temperature change effects on the aboveground storage tanks, piping, and equipment.
- Gasses may be trapped in high points of the pipeline and could affect various leak detection systems. Trapped gas would have the effect of reducing the bulk modulus in a way similar to a surge suppressor. Any trapped gas should be bled out of the system before testing to the extent possible.

Figure 3-1 is an illustration of a representative airport hydrant fueling system.

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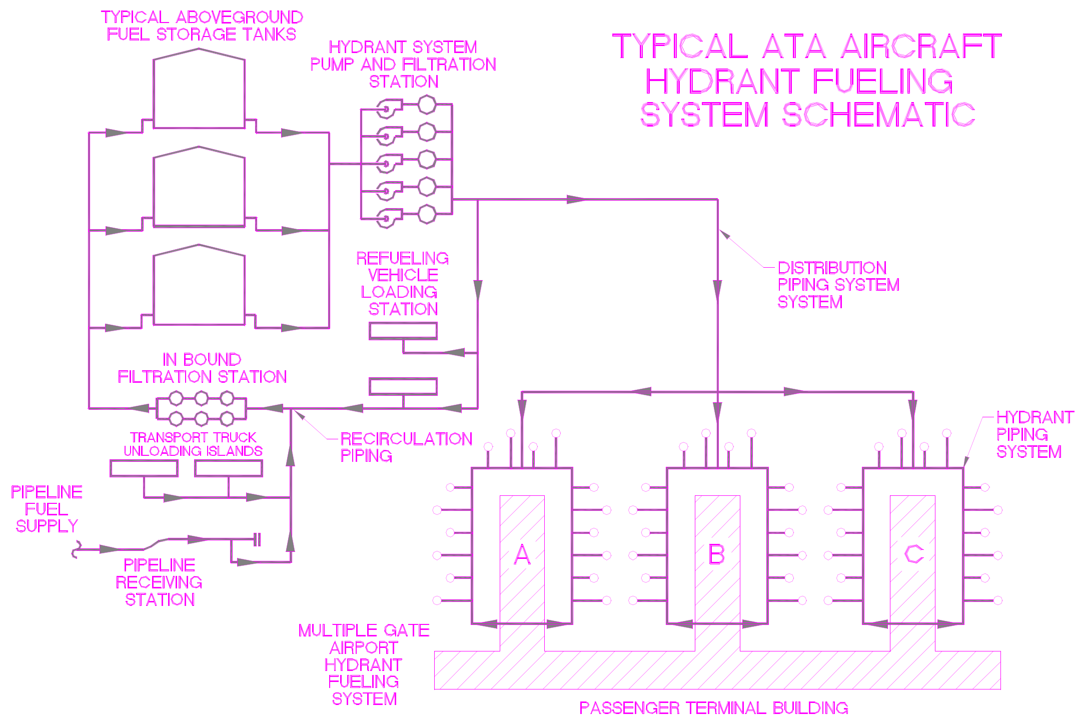

Figure 3-1. Representative Airport Hydrant Fueling System

B. MCI Operating Characteristics

The conclusions supported by the data from the limited monitoring of the operation of the MCI hydrant fueling system are as follows:

1. The pressure within the MCI AHS was seldom stable. Although pressure was relatively stable for short periods during the night, these periods were the exception rather than the rule and were not predictable. Pressure changes almost certainly were the result of temperature changes that could be expected to occur at virtually any AHS. Based on this, leak detection technologies must be able to account for pressure changes not associated with leaks (e.g., due to temperature changes) to have successful application in an AHS.

2. The uninterrupted time without fueling at night at MCI ranged from less than two hours to five or six hours at most. Given the significant effect that fueling can have on leak detection and the operational constraints of testing during the day, it is reasonable to conclude that leak detection technologies that cannot operate within the window of a few night hours will not be suitable for airport use. Larger airports or airports with higher traffic volumes might have even shorter windows for testing.

3. Diurnal pressure changes in out-of-service lines can vary substantially due to ambient temperature and sun conditions. These changes can be large and must be considered.

4. Noise from airport operations was generated at MCI at virtually all times. Although nighttime can be quieter, some noise occurs even then. This can be an obstacle to the effectiveness of acoustical leak detection technologies.

5. At MCI, the time periods during the day when the AHS was not fueling were short, usually between 5 and 15 minutes.

6. Fueling operations occurred at multiple gates simultaneously between the hours of 5 a.m. and 11 p.m. or later. There were few times when the flow was uniform for more than 5 minutes.

C. Petroleum Product Terminal Systems

The typical petroleum product terminal system has less buried pressurized piping than an airport hydrant system. While the materials and methods of

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construction are very similar, petroleum product terminals are usually smaller systems.

The majority of piping found in petroleum storage facilities is used for transferring products between tanks for storage and for distribution from tanks to truck loading racks. Such piping operates within a flow rate range of 100 to 1000 gallons per minute, at pressures between 50 to 100 psi. The piping ranges in size from 3 to 12 inches.

While petroleum product terminals and airport hydrant systems have many shared characteristics, there are significant differences as well. The two most significant differences affecting leak detection are times available for testing and use of surge absorbers. Petroleum product terminals generally have a greater window of opportunity to test the piping systems due to transfer schedules. Secondly, these piping systems operate at a lower pressure, eliminating the need for surge absorbers.

Figure 3-2 is an illustration of a petroleum product terminal system.

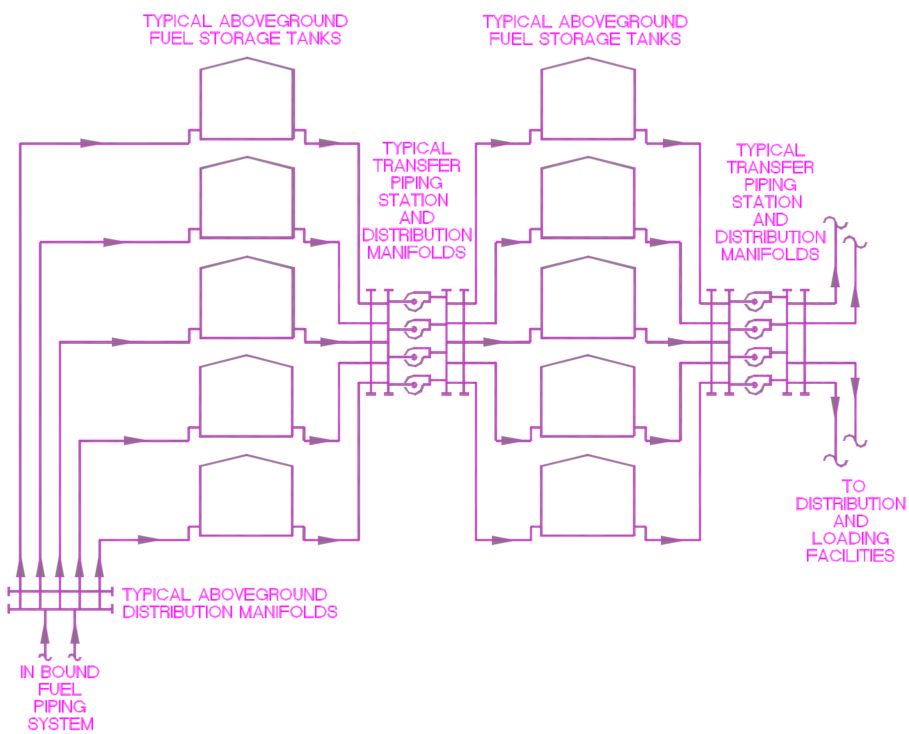

Figure 3-2. Representative Petroleum Product Terminal System

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IV. LEAK DETECTION TECHNOLOGIES

A. Technology Types

As a first step in determining the applicability, characteristics, and performance of various types of leak detection technologies for pressurized petroleum piping systems, the available technologies had to be identified. To do so, an international search for leak detection and leak location vendors and technologies was implemented. Through a series of announcements in trade magazines, industry publications, and Internet Web Sites, thirty-seven vendors of varied leak detection technologies were identified as candidates for evaluation.

The leak detection technologies evaluated in Phase I of the program are listed in below. The concept and methodology of each technology was evaluated to determine applicability and performance.

The following is a listing of the technologies that were identified, accompanied by a brief explanation of the concept behind each technology. For purposes of reporting, short descriptors are used to identify the technologies.

- **Volumetric** – A technology that monitors a pre-determined amount of product in a piping system and searches for a change in that pre-determined quantity to determine if a leak is present. This technology was selected for testing because it is well developed and is in use at a number of airports. Because it is a dual pressure/volumetric method it is able to accommodate trapped vapor better than most methods.

- **Pressure Step** – A technology in which multiple (usually two) pressure states within a piping system are monitored for pressure changes followed by trend line, comparative analysis calculations to determine if a leak is present. Dual Pressure methods are used to compensate for temperature effects. This technology was selected because it is in widespread use at airports around the world.

- **Pressure Decay** – A technology where the static state locked-in system pressure is monitored over a period of time for a change in pressure not related to thermal fluctuations. There are many methods that rely on measurement of pressure decay, both with and without direct temperature compensation. Because of their widespread use and potential simplicity, one of these methods was included in the evaluation.

- **Pressure Wave** – A technology that detects anomalies, i.e., potential leaks, within a piping system by monitoring reflective signals and pressure changes that result from leaks in a dynamic operating state. These methods may be used for either static or dynamic leak detection.

- **Vapor Monitoring** – A technology that continuously monitors hydrocarbon levels using fiber optic or other sensors placed along a buried piping system to detect the presence of hydrocarbon vapors and/or dissolved hydrocarbon. This method is very sensitive, particularly where there is low background contamination. It requires that sampling points be installed along the pipeline at regular intervals. One method was included in the evaluation because of interest in its capability to detect hydrocarbons dissolved in water.

- **Chemical Marker** – A technology wherein a chemical marker compound not found in nature is injected into the fuel at the point of distribution in storage tanks, followed by sampling of well points along the pipe routing to determine if the chemical marker is present, which indicates a leak. This technology has been widely applied to pipeline systems in both manual sampling and automated modes. It was selected primarily because of its widespread use and interest in its performance with a high water table.

- **Acoustics Emission** – A technology whereby energy generated by liquid passing through a hole in a piping system is to be detected by the use of microphones or accelerometers placed along the piping system. Since these methods are generally capable of locating the position of the leak, they are of particular interest to pipeline owners and one method was included for this reason.

- **Ground Penetrating Radar** – A technology designed to look for and detect changes created by a leak as the leak disturbs the trench backfill materials. These methods have not been developed for hydrocarbon

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detection and cannot be permanently installed.

- **Helium Detection** – A chemical marker type of testing technology wherein helium, which has a very small molecular structure, is utilized as a marker chemical. This method was not selected because the line should be emptied prior to the testing. This would be impractical for most systems for which this study was developed.

- **Mass Balance** – A leak detection approach using the mass balance concept; measurements of the amount of fuel entering the piping system are compared to the amount of fuel removed from the system by normal transfer operations. This method was not selected because of its lack of sensitivity to small leaks.

- **Optical Deflection** – A technology that monitors the flow of fuel through a piping system and searches for changes in flow patterns that are indicative of a leak.

- **Product Sensitive Cables** – A technology wherein a series of sensing cables are placed in a trench with the fuel piping or in the interstitial space of a double wall piping system to detect hydrocarbons released from the piping system. Product sensitive cables cannot be installed where there is significant background contamination. Any releases that occur must be completely remediated before the cable can be reinstalled.

- **Product Sensitive Probes** – A technology that employs a conductivity probe usually placed in a leak detection pit or sump of a double wall piping system to detect the presence of fuel. This study did not include sump or valve pit monitoring. Double wall piping was not considered.

- **Inventory Reconciliation** – An operational methodology wherein the physical measurement of fuel volume within the entire system over a pre-determined period of time is compared to the amount of fuel received and dispensed. There are no known reconciliation methods that have been applied to hydrant systems. Inventory reconciliation requires that the amount of product received and dispensed be accurately measured at all points. This is not practical considering the number of hydrant pits and other fueling locations that are present in hydrant systems.

- **Smart Pigs** – A device that is placed within and propelled through a piping system to gather data on pipe material deterioration, such as cracks, holes, and the loss of wall thickness. Hydrant systems consist of too many changes in pipeline diameter and elbows to make this applicable. Pigs work best for long uniform pipelines.

- **In-Situ Containment** – A construction approach where the entire piping system is either encapsulated in the trench with an impervious liner or coated with a covering intended to retain and facilitate detection of product (e.g., through vapor monitoring) released from the piping system. This approach would not easily apply to existing facilities.

- **Double Wall Piping** – A construction approach where a pipe is installed within another pipe; fuel is transferred in the inner pipe, while the outer pipe is intended to serve as a containment device and to facilitate detection (e.g., through product sensitive cables) in the event of a leak. Retrofitting to existing facilities is impractical. The installation of double wall pipelines at new facilities remains controversial.

- **Piping Trenches** – A construction approach where the piping is located in a trench made of concrete or other material intended to contain a leak; the containment has grated openings or removable solid top panels to facilitate leak detection. Cost factors preclude the use of this technology.

B. Selection Criteria

A twelve-point evaluation matrix was developed to assess the applicability of the leak detection technologies and vendors identified in the initial phase of the project to AHS and petroleum product terminals. The evaluation criteria employed are as follows:

- **Sensitivity** – Should be capable of detecting small leaks in piping, joints, welds, and gaskets in a large volume piping system operating at various pressures and flow rates.

- **Reliability** – The technology should identify leaks with a high level of confidence and minimal false alarms.

- **Repeatability** – The technology should be able to reproduce the detection function consistently with acceptable results.

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- **Specificity –** The detection technology's response to a leak should not be affected by piping system conditions under normal operation. For example, the detection technology should not create a false alarm based on signals measured during a change in ambient temperature.

- **Accuracy** – Should be ± 5 percent of actual value for technologies that provide a quantification of the detected leak rate.

- **Alarms** – The technology and its components should be capable of operating within the testing parameters and piping system characteristics. False alarms should be infrequent.

- **Applicability** – The technology should be readily adaptable to the physical and operational characteristics found in typical new and existing AHS and petroleum product terminal piping systems.

- **Compatibility** – Installation of any technology should be consistent with general construction project parameters and local codes without the need for extensive or special installation efforts and/or procedures.

- **Maintainability**– The technology should not require frequent, costl, or complex maintenance procedures. The technology should maintain its calibration for reasonable time periods; replacement components should be readily available, and available personnel should be able to perform periodic component replacement.

- **Operability** – The leak detection technology should be easy to operate by facility staff with normal skills in system controls and the operation of computer hardware and software.

- **Costs** – The cost of procurement, installation, operations, and maintenance should be proportionally in-line with other control and monitoring technologies.

- **Certification** – The technology should possess the performance characteristics that would facilitate certification if regulatory agencies elect to do so.

- **Validation** – The technology should provide for periodic checks to demonstrate that it is functioning correctly and will detect an induced leak of reasonable size.

C. Technologies Selected for Evaluation

Using the screening criteria outlined above, six technologies were identified as those best suited for providing the degree of leak detection performance needed for airport hydrant fueling systems and petroleum product terminals. Additionally, a vendor of each technology was selected to participate in the Phase II or testing segment of this program. The technologies are as follows:

- Pressure decay – dual pressure
- Volumetric – dual pressure
- Pressure decay with temperature compensation
- Acoustic emission
- Chemical marker
- Hydrocarbon vapor monitoring

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V. STATISTICAL NATURE OF THE TESTING PROCESS

Testing a buried pressurized piping system for leaks is an example of the classical statistical problem of finding a signal in a background of noise. At its essence, a leak produces a loss of fuel, a transfer of matter and mass. As such, a leak might be measured, under certain conditions, in terms of pressure change, volume change, or acoustically. Leaks, however, may be difficult to discern from other fluctuations in a piping system during the normal course of operations. The fundamental problem, therefore, is recognizing the transfer of mass and matter that is a leak within the background interference, or "noise," in the system.

In this application, a signal is a discrete and measurable event produced by a leak, while noise is any process or phenomenon not related to a leak that can mask or be mistaken for a leak.

It is important to distinguish between two types of noise. One type is systematic noise and the other type is random noise. Systematic noise is an effect that has a predictable effect of the characteristic being measured by a leak detection technology. An example of systematic noise is the effect on temperature change. In a pipeline that is blocked in, an increase in temperature will cause the pressure in the line to increase due to the thermal expansion of the product in the line. This systematic effect can be predicted with knowledge of the temperature. However, if not properly accounted for, it could mask a leak. Random noise, on the other hand, consists of effects with no predictable size or direction, which nevertheless affect the measurement process. Random noise is inherent in all measurement processes, but can be reduced by careful design of the measurement technology.

A. Signal and Noise

In this report, the concepts of signal and noise are described qualitatively for each technology. It is recognized that not all leak detection technologies for buried pressurized piping systems will have equivalent performance. The outcome of a leak detection test depends on a combination of parameters, including the design of the piping system (size of the pipes, changes in pipe size, valves, etc.), weather, soil or backfill conditions, stored product, and ambient noise. Quantifying the performance of each method with respect to these parameters is beyond the scope of this report. However, the leak detection technologies were tested under realistic conditions that included important noise sources. Thus, the performance of a leak detection technology is an indication of how well it distinguishes the leak signal from the background noise.

There are many sources of noise. First, noise is generated by the measurement technology itself. This type of system noise is generally random, and it defines the accuracy and precision of the measurement technology. In addition, noise is present in the environment in which the measurement is made. This is typically referred to as ambient noise and is generally a systematic effect. It can take many forms, depending on the type of measurement being made. Ambient noise may also include that generated by operational practice (for example the opening and closing of valves or the flow of liquid through the pipe).

Leak detection technologies, regardless of which technology they use, measure a combination of both signal and noise. Reliable leak detection can only be accomplished when the signal can be distinguished from the noise.

In order to evaluate the effectiveness of a leak detection technology, it is necessary to determine the amount of residual noise. The residual noise associated with a leak detection technology for buried pressurized piping is the noise that is measured when there is no leak, after the leak detection technology has removed any systematic effects. To estimate the residual noise requires a large number of tests on one or more non-leaking piping systems, conducted under a wide range of environmental conditions. Alternatively, tests can be run on non-leaking piping systems with known artificial leaks introduced. This procedure will yield a measure of the noise that can be expected in a typical buried pressurized piping system when a given leak detection technology is used and, thus, an estimate of the magnitude of the signal (or leak rate) that can be reliably detected above this level of noise.

In some cases, measures can be taken to reduce the noise; however, reliable detection usually requires a detailed understanding of the sources of noise so that ancillary measurements can be taken to effectively remove some of the (systematic) noise from the data collected during a test. The noise left in the data after this removal can be significantly less than the original ambient noise, depending on the effectiveness of the noise removal techniques. In most cases, the effectiveness of a leak detection

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technology is measured by its effectiveness at removing noise from collected data.

B. Concept of Performance

The concept of performance as a way to measure the effectiveness or reliability of a leak detection technology evolved from research on underground storage tanks (USTs). Although performance requirements for large buried pressurized piping systems have not been defined, many of the general concepts of performance developed for USTs are applicable.

Performance is defined in terms of the probability of a false alarm, PFA, and the probability of detection, PD , of a leak of specified size. The probability of a false alarm is the probability or likelihood that a leak detection test will declare the presence of a leak where none exists. The probability of detection is the probability or likelihood that a leak detection test will detect the presence of a real leak. The probability of detection generally increases with the size of the leak, as large leaks are generally easier to detect than small ones. A related concept is the probability of missed detection, PMD, which is the likelihood that a leak detection test will not find a leak that does exist. Numerically it is equal to one minus PD, and it also depends on the size of the leak. A missed detection, depending on the size of the leak, could result in environmental damage and loss of product.

Table 5-1: Possible Detection Results

	Actual Conditions	
	LEAK	NO LEAK
LEAK	Detection	False Alarm
NO LEAK	Missed Detection	No Detection

The matrix above shows the possible outcomes of a leak detection test. When the test result matches the actual conditions, the outcome is a correct test result – either the detection of an actual leak or the confirmation that no leak exists. If the result does not match the actual condition, the test results in either a missed detection or a false alarm. A reliable leak detection technology generates tests that have a high probability of detection when a leak exists or of non-detection when a leak does not exist and low probabilities of false alarms and missed detections.

C. Declaring a Leak

The basis for declaring a leak is the leak detection threshold. Test results that fall below the threshold are considered noise, while those that exceed the threshold are considered indicative of a leak. The threshold is a function of the measurement used by the leak detection technology. It may be a rate of pressure decay in a blocked-in line, or it may be the amplitude of an acoustical emission signal, or some other measurement, depending on the technology. Even leak detection technologies that are qualitative and report results as a pass or fail rather than a quantified leak rate use a threshold of some sort in their algorithm for processing the measurement data that they use.

The threshold must be set at a value greater than the noise output of the leak detection technology, and less than the size of the leak that the technology will reliably detect. The threshold is thus a value that depends on the amplitudes of the signal and noise, as well as the precision of the measurement technology.

The threshold is closely linked to the performance measure, PFA and PD. If the threshold is too high, the probability of detection (or the size of a leak that can be reliably detected) drops. If it is too low, there will be an excessive number of false alarms. Selection of an appropriate threshold is therefore very important.

Once a threshold has been set, the threshold determines the PFA. Alternatively, the value for PFA can be specified and the appropriate threshold calculated from knowledge of the noise histogram. A related concept is the minimum detectable leak, MDL. This is the smallest leak that can be detected with a high reliability using a given threshold and corresponding PFA. The MDL is stated with the value of PD to indicate the reliability with which the MDL can be detected.

Consider Figure 5-1 below. It represents an ideal situation where there is essentially no overlap between the signal and noise. It is obvious that the threshold should be set between the two histograms.

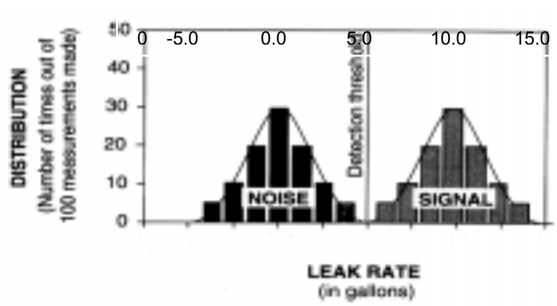

Figure 5-1 Leak Rate Illustration (High Signal to Noise)

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In reality there is generally some degree of overlap between signal and noise, as illustrated in Figure 5-2. In this case, the signal is anything over 0.0 gallons per hour (GPH), representing a leak rate, but any measurement between 0.0 GPH and 10.0 GPH might also be noise. Clearly, the relative size of the signal to the noise increases as the signal increases. If we set the threshold at 0.0 GPH so as to include all of the signal (leak) amplitude, about half of the time what we detect will be a false alarm. On the other hand, if we set the threshold at 10 GPH so as to eliminate essentially all of the false alarms, we will miss approximately half of the signals. One can compromise, opting for the minimum probabilities of both missed detection and false alarm. This is best done, in this instance, by setting the threshold at 5.0 GPH. However, if one type of error is inherently more serious than the other, one might choose a threshold at 7.5 GPH to reduce the probability of false alarm. This would increase the probability of a missed detection of 10.0 GPH, but would still have a good probability of detection of a leak of 15.0 GPH.

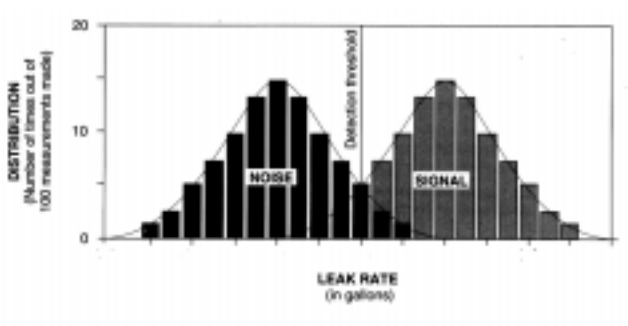

Figure 5-2 Leak Rate Illustration (Low Signal to Noise)

It is beyond the scope of this study to determine the appropriate levels of PD and PFA for leak detection for these lines. Clearly, a considerable amount of thought should be given to selection of the levels of PD and PFA. It should also be recognized that PD, PFA, the threshold, and the minimum detectable leak (MDL) are all inter-related. For a given leak detection system, increasing the threshold will decrease the PFA, but it will also decrease the PD for a given leak size and will increase the MDL. Setting a value for PFA will generally determine the threshold, and consequently the PD, for a given leak size, and the MDL achievable with specified PD.

A leak detection system with a PFA that is too high will produce many false alarms and disrupt operations. In extreme cases, this may cause operators to ignore alarms, eliminating the effectiveness of the leak detection system. As long as the leak detection system produces a false alarm rate that is acceptable, it is desirable to have a small MDL with a reasonably high probability of detection. Thus, one should set the threshold for declaring a leak high enough to produce an acceptable false alarm rate, but not so high that the size of the minimum detectable leak is too large.

Clearly, one needs to balance the chance of disruption of service resulting from a false alarm with the risk of a release that might result if a leak went undetected for a period of time.

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VI. TECHNOLOGIES TESTED

By applying the twelve-point evaluation criteria, six leak detection technologies were found to have potential application in an AHS or petroleum product terminal and were selected for testing under operating conditions. This section presents information on each of the six technologies tested.

A. Pressure Decay—Dual Pressure

One method of leak detection designed for large petroleum lines and AHSs is a pressure decay—dual pressure method. This method was selected for testing in the project, and tests were conducted during March 1999.

The measurement basis for this technology is a suitably precise pressure monitoring technology. Once a pressure is established in the line section being tested, a leak in the line would cause the pressure to drop. The pressure decay—dual pressure method measures the pressure drop over times starting at two different initial pressures, because the leak rate would be different at different pressures. The technology must be capable of distinguishing the pressure drop from a leak from pressure drops caused by other factors.

1. The Nature of the Signal

When a pipeline is leaking, liquid volume escapes from the line. This causes a decrease in pressure over time. This decrease in pressure is the *signal*. The magnitude of the signal is affected by several variables. A large leak rate causes a faster rate of decrease in pressure in the line. As the pressure drops, the leak rate will decrease. The relationship between the leak rate and the pressure is affected by the geometry of the hole in the pipe. The larger the opening, the less pressure is required to force liquid through it. The shape of the opening—smooth or jagged—determines whether the flow is laminar or turbulent, which influences the way that the leak rate varies with pressure.

The bulk modulus of the line also affects the relationship between the volume and pressure. If the bulk modulus is high, a small loss of liquid results in a substantial decrease in pressure. If the bulk modulus is low, a larger volume loss of liquid is required to produce the same pressure loss.

In a pressure decay type of technology, the noise is the sum of the pressure changes resulting from temperature changes that could be confused with the signal. When the liquid is confined under pressure in a pipeline, a temperature increase will result in an increase in the pressure. Similarly, a temperature decrease will result in a decrease in pressure. The amount of pressure increase is related to the compressibility of the liquid product and the flexibility of the pipeline, which together determine the bulk modulus of the system. In order for a pressure decay method to achieve good performance, the method must use a procedure to minimize the noise during the data collection. It must use an algorithm that systematically measures and compensates for those pressure changes that are not related to leak.

The pressure decay—dual pressure test technology distinguishes between pressure changes caused by a leak and those related to the noise by testing at two distinct pressures. Because the leak rate increases with increasing pressure, a higher signal response (leak rate) occurs during the high-pressure portion of the test. Temperature effects should be similar during both the high-pressure and low-pressure parts of the test. Thus, a change in the signal for the high-pressure part of the test indicates that a leak is present, and a similar pressure decay rate at both pressure levels indicates that only a temperature effect is present.

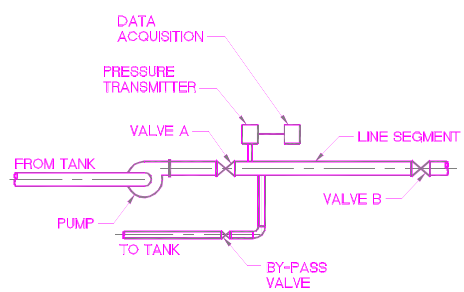

Figure 6-1. Pressure Decay – Dual Pressure

A schematic of a dual pressure decay technology is shown in Figure 6-1. The line segment to be tested is isolated between valve A and valve B. A pressure transmitter is installed into each segment to be tested. The line is pressurized to its normal operating pressure. A bypass line is used to reduce the pressure from the line operating pressure to the low pressure. The bypass fuel is returned to the tank or other reservoir. A data acquisition system collects the data from both pressures and determines if a leak is present and its rate.

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2. Sources of Noise

One of the principal sources of noise for the pressure decay dual pressure test technology is a temperature change of the product in the line. When operating, product is pumped into the line, typically from an aboveground storage tank. Product is dispensed from the line into aircraft or used in other fueling operations. The temperature of the product in the aboveground storage tank fluctuates based on the ambient temperature, the amount of sun heating the tank, the source of the product, and the length of time it has been stored in the tank. In addition, there may be portions of the pipeline that are aboveground and are also subject to diurnal fluctuations in temperature. The ground temperature surrounding the pipeline is generally stable and fluctuates slowly with seasonal changes.

New product that is pumped into the line may have a different temperature from the ground temperature. If the product is warmer than the ground, it will begin to cool, causing thermal contraction. This typically occurs during warm weather months. This contraction would reduce the pressure in the line, which could be mistaken for a leak. On the other hand, if the product introduced into the line is cooler than the ground temperature, as would occur during cold weather when the ambient temperature is cooler than the ground temperature, the product will begin to warm and expand, causing a pressure increase. An increase in pressure could mask the loss of pressure from a leak, causing the technology to miss a leak.

If the line is held under pressure for a substantial period of time, changes in the ambient temperature or solar heating of any aboveground portions of the line may cause the temperature of the product to rise and fall with a corresponding rise and fall in the pressure.

Some lines have a pressure relief system, so that if the product in the line is warming up, the amount of pressure increase is limited. When the pressure reaches a set point, a pressure relief valve opens, allowing some liquid to flow back into the tank or into some other vessel. This represents a loss of product that must be accounted for.

Air or vapor trapped in the line is an important source of noise. Such trapped vapor or air reduces the bulk modulus of the line. This reduces the sensitivity of the test by changing the response of the signal to the size of the leak. If there is trapped air in the system, a larger volume loss is required to cause a decrease in pressure than if no trapped air is present. The amount of trapped air or vapor must be estimated when the technology is installed and reduced as much as practical.

Pressure changes in the pipeline can cause distortions in the line. When the pressure increases, the line may “stretch” a little, slightly increasing the volume. Similarly, when pressure is reduced, the line may “relax,” slightly reducing the volume in the line. These sorts of pipeline distortions in response to pressure changes also can affect results.

The presence of surge suppressors is another potential source of noise. They have the same effect as trapped air or vapor when the line pressure is below the pre-charge pressure of the surge suppressor. If the pre-charge pressure of the surge suppressor is between the high and low pressure settings of the technology, the response will be different during the two portions of the test, not only from the leak, but also from the different pressure to volume relationship. Consequently, any surge suppressors should be isolated from the line during testing in order to achieve optimum results.

In some lines there may be a difference in elevation from one end to the other. If there is a difference in elevation along the line, the difference in elevation between the leak and the point where the pressure sensor is installed affects the test. The technology controls the pressure of the line where the pressure sensor is installed. This will result in somewhat different set pressures at other elevations along the line. If the leak is above the test point, the measured results will overestimate the leak rate; if the leak is below the test point, the measured results will underestimate the leak. There is no bias if the leak is at the same elevation as the test point. With a 50-ft elevation difference the effect could be about 10 percent.

Another source of noise is the valves used to isolate the section of line for testing. Valves should be tight, so that no liquid can flow or seep past them into another portion of the system. Any liquid that leaks past a valve would be interpreted as a leak in the system.

3. Key Features

The technology is designed for permanent installation and point-in-time installation. For evaluation or point-in-time testing, it can be temporarily installed on a section of pipe. The test sections are defined by isolating different parts of the

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line using existing valves installed for that purpose. The valves must be tight for proper calibration when the system is installed. The vendor recommends installation of 100 percent tight valves and prefers double-block-and-bleed valves. After the technology is installed, it must be calibrated separately on each section of line to be tested separately. For most efficient operation, the valves that divide the pipeline into sections for testing should be remotely operated.

The pipeline section to be tested is first isolated and placed under high (typically 10 bar or about 150 psig) pressure. The pressure decay is monitored for about two minutes following a stabilization time of about 10 minutes. Then the pressure is lowered (typically to about four bar or 60 psig) and the pressure decay is again monitored. Finally the pressure is raised again and the pressure decay is monitored.

A leak rate (if there is a leak) is a function of pressure, but temperature effects should be the same at the different pressure levels. If a leak is present, the leak rate is higher at the higher pressure. This allows thermal effects to be separated from the effect of a leak. The pressure decay for the last two minutes or so of each step in the test is used to estimate the leak rate. All measured leak rates are converted and reported at a standard operation pressure, which is normally 10 bar or 150 psi.

Features identified by the test program affecting the installation and operation of this technology are listed below.

- In order to avoid detecting a leak past a valve from one section of the pipeline to another, the valves isolating sections of the pipeline must close tightly. Often double-block-and-bleed valves are recommended so that the seal of the valves can be verified. This requirement has implications for existing systems and also for new installations.
- The pipeline system to be monitored is divided up into convenient sections.
- Each section of the pipeline has a pressure transducer and transmitter installed.
- A means of controlling the pressure in each segment of the pipeline is identified. Typically, the airport's main fuel pumps or a jockey pump are used to pressurize the line.
- Excess air is bled from the lines. (The line must be fully packed and essentially air-free. This implies that any surge suppressers should be isolated from the line for best results.)
- For an actual test the section being tested must be taken out of service for the test duration, which is approximately 45 minutes plus any time needed to isolate the section.
- During initial installation, a series of calibration tests are run. The calibration tests are run with the line in the tight condition and use a series of simulated known leak rates. The calibrations enable the technology to quantify its results based upon the size and compressibility of each pipeline section.
- The line must be known to be tight during the calibration. Any existing leak would either become part of the baseline for the test or would be detected and would have to be corrected in order to complete the calibration.
- Testing should be conducted at night. This will generally fit better with the operation of either an airport hydrant system or an API facility. In addition, it reduces the effect of temperature.
- The minimum volume of any line or segment to be tested should be about 5,000 gallons.
- The technology is designed to test at two pressures that must be substantially different. The standard test pressures are 150 psig and 60 psig. The minimum acceptable test pressure at the high-pressure test is about 110 psig. Thus, the technology is not suitable for lines that cannot be pressurized to this level.
- The technology's computer automatically prints a test report at the conclusion of each test. This report gives an estimated leak rate at 150 psi and determines whether or not the estimated leak rate indicates an actual leak or is within the expected noise level.
- Elevation differences can affect the technology's performance. The effect could be up to ten percent of the leak rate with an elevation difference of 50 feet.
- No location information is available when a leak is found, other than to locate it on the section of line that was tested.

4. Test Results

The technology was evaluated by conducting controlled tests on three different sized lines at MCI. Two of the lines were sections of an AHS. The third line had several components aboveground and was intended to represent lines more typical of petroleum product terminals. Tests were conducted under a tight line or no-leak condition, as well as with induced leaks of various sizes. Twenty-four tests were run, eight on each line. During the tests, the difference between the product temperature

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introduced into the line and the ground temperature varied from –0.9 °F to +6.2 °F, so the ability of the technology to perform when temperature differences exist was checked to some extent.

The test results are expressed as a percent of the line volume per hour. That is, the leak rate that the technology was capable of detecting in the MCI testing is a function of the volume of the line. To present results in a consistent and standard manner, a threshold for indicating a leak has been calculated based on a one percent probability of false alarm. In addition, the minimum leak size that would be detectable with 99 percent probability of detection using the one percent threshold is reported. The quoted results are applicable to AHSs, with the specific results relative to an AHS line of 175,000 gallons. Although the size of the leak in gallons per hour was smaller on the API line, the performance on the API line was not quite as good on a percentage basis. The reason why the detectable leak was larger as a percent of the line volume on the API line is not known. It may be due to an excess amount of air trapped in the system, check valves, or simply the smaller denominator. Based on these tests, in small lines, the leak rate that can be detected is smaller in terms of gallons per hour, but is a larger proportion of the volume of product contained in the line than in large lines. The tests indicated that:

- A threshold of 0.0048 percent of the line volume would be expected to give a one percent probability of false alarm;
- The minimum leak rate detectable with 99 percent probability would be 0.0096 percent of line volume.

This technology has many of the desirable features required for permanent installation at an airport hydrant system. It could be permanently installed at some petroleum product terminals, but the nature of the lines (particularly low pressure operations) and operation might render it less effective. This technology is intended for permanent installation and point-in-time installation.

B. Dual Pressure Volumetric

A dual-pressure volumetric line leak detection method is commercially available. One such method was selected for testing, and tests were conducted during April and May 1999. The vendor's personnel can operate the technology as a one-time test method or it can be installed permanently. When permanently installed, facility personnel initiate testing on a periodic basis.

This technology measures the volume of liquid added to or removed from a pressurized line to maintain a constant pressure. The technology requires a suitably precise means of controlling the pressure in the line to maintain the constant pressure.

1. The Nature of the Signal

When a pipeline is leaking, liquid volume escapes from the line, and this volume change is the signal. The volume loss causes a decrease in pressure over time, which is monitored by the technology. The volume added to or removed from the line to maintain a constant pressure is the signal that is measured by the technology. The magnitude of the signal is affected by several variables. A large leak rate causes a faster rate of decrease in pressure in the line, which in turn requires a greater rate of volume replacement. Since a constant pressure is maintained, the leak rate should remain constant, thus removing the effect of the hole geometry and pressure changes on the signal.

The bulk modulus of the line affects the relationship between the volume and pressure. If the bulk modulus is high, a small loss of liquid results in a substantial decrease in pressure. If the bulk modulus is low, a larger volume loss of liquid is required to produce the same pressure loss. The technology maintains a constant pressure to reduce the effect of the bulk modulus, but the bulk modulus still affects the technology's ability to monitor and maintain the pressure. A low bulk modulus system may require a substantial change in volume before the pressure changes enough to be recognized by the leak detection technology. In pipelines with a high bulk modulus, small volume changes produce substantial pressure changes resulting in more precise readings.

Changes in temperature of the liquid are a source of ambient noise in the pipeline. In an unrestricted space, a temperature increase will result in a volume increase due to thermal expansion. Similarly, a temperature decrease will result in a volume decrease. When the liquid is confined under pressure in a pipeline, a temperature increase will result in an increase in the pressure. The amount of pressure increase is related to the compressibility of the liquid product and the flexibility of the pipeline, which together determine the bulk modulus of the system.

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In a volumetric type of leak detection technology, the noise is the sum of the volume changes needed to maintain constant pressure resulting from effects other than a leak. This includes volume changes resulting from temperature changes that could be confused with the signal. These are measured as pressure changes that are not related to the leak. In order for a constant pressure volumetric method to achieve a good performance, it must use a procedure to minimize the noise during the data collection, or it must use an algorithm that systematically measures and compensates for the noise during the data analysis portion of the test.

The dual pressure volumetric test technology distinguishes between volume changes needed to maintain constant pressure caused by a leak and those related to the noise by testing at two distinct pressures. Since the leak rate increases with increasing pressure, while other effects do not, a higher signal response occurs during the high-pressure portion of the test. Temperature effects should be similar during both the high-pressure and low-pressure parts of the test. Thus, a change in the signal for the high-pressure part of the test indicates that a leak is present, while a similar volume change rate at both pressure levels indicates that only a temperature effect is present.

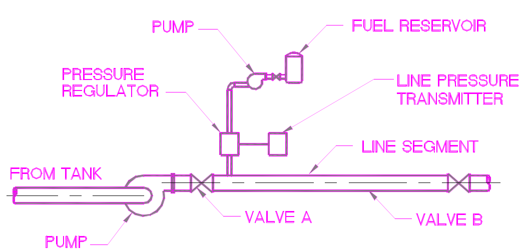

Figure 6-2. Dual Pressure Volumetric

A schematic of a volumetric method based on dual pressure measurements is shown in Figure 6-2. The line segment to be tested is isolated between valve A and valve B. A small, high-pressure pump is used to raise the pressure in the line to the high-pressure level. The fuel for this process is supplied from a reservoir that is part of the leak detection technology. A pressure regulator with a by pass line is used to maintain the pressure at a constant level. The volume of fuel in the reservoir is monitored to determine the volume of fuel added to or removed from the line during testing. Fuel is returned to the reservoir when the pressure is dropped to the low-pressure test level. A data acquisition system monitors the volume of product added to or removed from the reservoir.

2. Sources of Noise

One of the principal sources of noise for the dual pressure volumetric test technology is temperature change of the product in the line. When the line operates, product is pumped into the line, typically from an aboveground storage tank. Product is dispensed from the line into aircraft or used in other fueling operations. The temperature of the product in the aboveground storage tank fluctuates based on the ambient temperature, the amount of sun heating the tank, the source of the product, and the length of time it has been stored in the tank. In addition, there may be portions of the pipeline that are aboveground and are also subject to diurnal fluctuations in temperature. The ground temperature surrounding the pipeline is generally stable, fluctuating only slowly over the seasonal changes during the year.

As new product is pumped into the line, it may be at a different temperature from the ground temperature. If the product is warmer than the ground, it will begin to cool, causing thermal contraction. This typically occurs during warm weather months. This contraction would reduce the volume in the line, thereby reducing the pressure in the line, requiring the leak detection technology to supply volume. This volume loss could be mistaken for a leak. On the other hand, if the product introduced into the line is cooler than the ground temperature, as would occur during cold weather when the ambient temperature is cooler than the ground temperature, the product will begin to warm and expand, causing a pressure increase. This would result in volume being removed from the line to maintain constant pressure. This increase in volume could mask the loss of volume due to a leak, causing the technology to miss a leak. If the line is blocked in under pressure for a substantial period of time, changes in the ambient temperature or solar heating of any aboveground portions of the line may cause a diurnal effect as the temperature of the product rises and falls with a corresponding increase and decrease in volume at constant pressure.

Air or vapor trapped in the line is an important source of noise. Such trapped vapor or air would reduce the bulk modulus of the line. This could reduce the sensitivity of the test by changing the response of the signal to the size of the leak. That is, if there is trapped air in the system, a larger volume loss is required to cause a decrease in pressure than if no trapped air is present. This decrease in pressure must be monitored and the line volume adjusted. While the constant pressure operation of the technology mitigates this source of noise, it does not

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completely eliminate it. For the best performance, the amount of trapped air or vapor should be reduced as much as is practical. The technology was tested with a surge suppresser installed in the line to simulate 40 gallons of trapped vapor. There was no statistically significant difference in the test results with the surge suppresser, although the standard deviation increased by about 25 percent. If this increase is real, it would imply that the detectable leak would also be increased by about 25 percent when trapped vapor was present. A larger volume of trapped vapor or a larger number of tests would be expected to show a more significant effect. Since the difference was not statistically significant, the estimated size of the effect should be viewed with caution. It represents the only quantitative data on the effect of a surge suppressor or trapped vapor.

Pressure changes in the pipeline can cause distortions in the line. When the pressure increases, the line may "stretch" a little, slightly increasing the volume. Similarly, when pressure is reduced, the line may "relax," slightly reducing the volume in the line. These sorts of pipeline distortions in response to pressure changes could affect results.

The technology normally tests at the line operating pressure as the high-pressure set point. It reduces the gauge pressure to zero for the low-pressure set point. In some lines there may be a difference in elevation from one end to the other. If there is a difference in elevation, and the technology is installed at the low end of the line, it is not possible to reduce the low-pressure set point to zero. The minimum pressure at the low point in the line occurs if there is zero pressure at the high point. The minimum pressure then is the hydrostatic head pressure resulting from the product density and the difference in elevation. The sensitivity of the technology is related to the difference in pressure. If there is an elevation difference, and the leak is below the high point in the line, the measured leak rate will be biased downward. The pipeline at MCI had a 50-foot elevation difference from the tank farm to the hydrants, which produced a bias of about 40 percent. The reported rates were adjusted to remove this bias. Normally an adaptation for elevation would be made before the equipment was shipped. This difference in elevation required an adjustment in the interpretation of the measured leak rates. The elevation differences need to be considered on a site-specific basis.

The presence of surge suppressors is another potential source of noise. They have the same sort of effect as trapped air or vapor when the line pressure is above the pre-charge pressure of the surge suppressor. If the pre-charge pressure of the surge suppressor is between the high and low pressure settings of the technology, the response would be different during the two portions of the test, not only from the leak, but also from the different pressure to volume relationship.

Another source of noise is the valves used to isolate the section of line for testing. These valves must be tight, so that no liquid can flow or seep past them into another portion of the system. Any liquid that leaks past a valve would be regarded as a leak in the system. A valve leak signal could not be distinguished from a leak to the environment.

In some lines there may be a difference in elevation from one end to the other. If there is a difference in elevation along the line, the difference in elevation between the leak and the point where the pressure sensor is installed affects the test. The technology controls the pressure of the line where the pressure sensor is installed. This will result in somewhat different set pressures at other elevations along the line. If the leak is above the test point, the measured results will overestimate the leak rate; if the leak is below the test point, the measured results will underestimate the leak. There is no bias if the leak is at the same elevation as the test point.

3. Key Features

The technology is designed for permanent installation. The technology can also be brought in for a point in time test. Because the equipment is somewhat extensive, the Dual Pressure Volumetric Method generally tests the entire piping system. A mobile unit could be transported and installed for testing on sub-sections of the piping system as long as suitable isolation valves are present.

The pipeline section to be tested is first isolated and placed under high (typically the line operating) pressure. The pressure is maintained and any needed volume changes recorded for one hour to one and one-half hours. Then the pressure is lowered (typically to zero gauge pressure if the line is level) and the volume needed to maintain constant pressure is again monitored for the same length of time. The operating principle is that a leak rate (if there is a leak) will depend on the pressure, but the effect of temperature change does not depend on the pressure. Thus, temperature effects should be the same at the different pressure levels, while a leak would only be present at the high pressure. This allows thermal effects to be separated from the effect of a leak. The measured rate reported is at the operational pressure

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at the point of the leak, which is not known if the line is not flat. If the pipeline has elevation differences, the measured leak may be biased low by an amount that depends on the location of the leak. The maximum possible amount of bias can be calculated when the elevation change of the line is known.

Features affecting the installation and operation of this technology are listed below.

- Valves must be tight. In order for this technology to work properly, all of the valves isolating sections of the line must be verified to close tightly. Often double block-and-bleed valves are required so that the seal of the valves can be verified. This requirement has implications for existing systems and also for new installations.
- Each section of the pipeline to be tested must have the equipment installed.
- Excess air is bled from the lines. The technology can test with air or surge suppressors in the line, but to do so degrades the performance of the system.
- The section being tested must be taken out of service for the test duration, which is approximately 3 hours plus any time needed to isolate the section.
- Testing should be conducted at night if there is a significant amount of the line (0.5 percent to one percent or more) aboveground. This will generally fit better with the operation of either an airport hydrant system or an API facility. In addition, it reduces the effect of temperature. Tests can run during the day, but the technology was evaluated during the night. Testing at night is expected to improve system performance; however, no daytime data were collected to assess this assumption quantitatively.
- The technology is designed to test at two pressures. Typically the line operating pressure and zero are used. Thus, the technology is suitable for testing low-pressure lines.
- The technology's computer automatically displays a test report at the conclusion of each test. This report gives an estimated leak rate, which can be compared to a threshold established for that line to determine whether the results indicate a leak.
- The technology can be installed on a new or existing line system. It can be used for point in time tests as well as for permanently installed monitoring. It does not have to be calibrated on a known tight line to function correctly, and so is particularly well suited for finding existing leaks.
- Constant pressure design handles vapor better than pressure decay method.
- No location information is available for a leak other than that it is on the line section that was tested.

4. Test Results

The technology was evaluated by conducting controlled tests on three different sized lines at MCI. Two of the lines were sections of an AHS. The third line had several components aboveground and was intended to represent lines more typical of petroleum product terminals. Tests were conducted under a tight line or no-leak condition, as well as with induced leaks of various sizes. Twenty-four tests were run, eight on each line. During the tests, the difference between the product temperature introduced into the line and the ground temperature varied from +1.5 °F to +7.9 °F, so the ability of the technology to perform when temperature differences exist was demonstrated to some extent.

The test results are expressed as a percent of the line volume per hour. That is, the leak rate that the technology was capable of detecting at MCI is a function of the volume of the line. To present results in a consistent and standard manner, a threshold for indicating a leak has been calculated based on a one percent probability of false alarm. In addition, the minimum leak size that would be detectable with 99 percent probability of detection using the one percent threshold is reported. It should be noted that to calculate the PD and PFA, it was assumed that the differences between the measured and induced leak rates was approximately normal. This assumption of normality could not be adequately checked with the amount of data available. Thus, estimating performance to this level relies on fairly strong statistical distributional assumptions for the errors.

The quoted results are applicable to AHSs. The results are based on testing at MCI with an elevation difference of 50 feet and a line of 175,000 gallons. Theoretical calculations indicated that on a flat line the detectable leak rate would be about 0.0037 percent of the line volume. The performance on the product terminal line was not quite as good on a percentage basis. The product terminal line was about 12,000 gallons in volume and the apparent degradation in performance as a percent of the line volume was due to the small denominator. The vendor has stated that a smaller version of the test equipment is normally used for line volumes less than 12,500 gallons, and this would have improved

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performance for the smaller volume line, but this was not used for this testing.

- Based on these tests, a threshold of 0.0028 percent of the line volume would be expected to give a one percent probability of false alarm.
- Based on these tests, the minimum leak rate detectable with 99 percent probability would be 0.0056 percent of line volume.
- When a surge suppressor (with a volume of 40 gallons) was installed in the line, the performance change was not statistically significant, although the threshold and minimum detectable leak rate were increased by 25 percent.

This leak detection technology appears to have application in either an AHS or petroleum product terminal. It can be permanently installed for periodic testing, or can be used for a single point in time test.

C. Pressure Decay with Temperature Compensation

A pressure decay technology that incorporates temperature compensation was also tested. This technology is based on the fact that when a line is pressurized and sealed, and the temperature is constant, a leak will result in a pressure drop. Temperature changes, however, can also cause the pressure to change. A reduction in temperature will cause the pressure to drop and appear as a leak. An increase in temperature will cause the pressure to rise and potentially mask a leak. This technology explicitly considers the effect of temperature change on the pressure in the line, by measuring both the pressure and temperature change during the test period and adjusting the pressure change to compensate for temperature effects. This technology also includes a measurement of system bulk modulus to identify and compensate for the presence of gases in the lines.

1. The Nature of the Signal

When a pressurized line is leaking, liquid volume is lost from the pressurized portion of the line. This volume loss causes a reduction in pressure. The relationship between volume changes and pressure changes depends on the flexibility of the pipeline and the compressibility of the product and is described by the bulk modulus of the pipeline. Thus, the signal that is measured is the rate of pressure drop.

The ambient noise consists of pressure changes caused by sources other than the leak. One potential source is temperature fluctuations. A reduction in temperature will cause the fluid to contract, resulting in a reduction in pressure that could appear to be a leak. An increase in temperature will cause the fluid to expand, causing a pressure rise that could mask the effect of a leak. For a pressure decay with temperature compensation leak detection technology, the noise is the sum of the apparent changes in the pressure during the course of the test that could be confused with the signal caused by a leak.

A pressure decay technology using a pressure wave temperature compensation process is shown schematically in Figure 6-3. The segment to be tested is isolated between valve A and valve B. The pressure is recorded and monitored continuously during the test period. A small solenoid valve is used to introduce a brief, sudden leak into the line. This sudden loss produces a pressure wave that travels to the end of the pipeline and is reflected back to the pressure transmitter. The velocity of the pressure wave in the pipeline (determined by measuring the time of flight of the wave and the distance traveled) is a strong function of the temperature of the fuel. This measurement is done at the beginning and end of each period of pressure monitoring. The change in pressure wave velocity over the test period is a measure of the change in fuel temperature over this period. The data acquisition system uses this information to adjust the pressure change for the temperature change observed during the test.

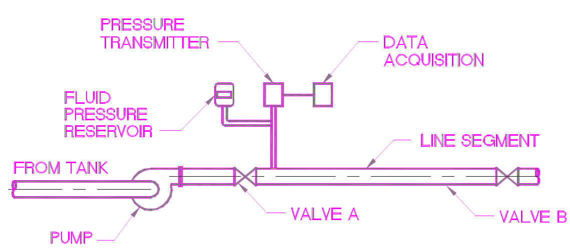

Figure 6-3. Pressure Decay with Pressure Wave Temperature Compensation

After testing at MCI, the vendor states that they have incorporated a measurement of the bulk modulus and a method to adjust for the bulk modulus into the technology. The system used to develop the pressure wave is also used to measure the fuel system compressibility prior to the test. The change in system pressure is measured for a metered amount of fluid withdrawn rapidly from the system. This measurement detects the presence of entrapped gases

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and provides sufficient information to either compensate for the amount of gas present or to initiate necessary action to vent the system if the quantity of entrapped gases is too high to permit a viable test.

2. Sources of Noise

One of the principal sources of noise for the pressure decay with temperature compensation test technology is temperature change of the product in the line. When the line operates, product is pumped into the line, typically from an aboveground storage tank. Product is dispensed from the line into aircraft or used in other fueling operations. The temperature of the product in the aboveground storage tank fluctuates based on the ambient temperature, the amount of sun heating the tank, the source of the product, and the length of time it has been stored in the tank. In addition, there may be portions of the pipeline that are aboveground and are also subject to diurnal fluctuations in temperature. The ground temperature surrounding the pipeline is generally stable, fluctuating only slowly over the seasonal changes during the year.

As new product is pumped into the line, it may be at a different temperature from the ground temperature. If the product is warmer than the ground, it will begin to cool, causing thermal contraction. This typically occurs during warm weather months. This contraction would reduce the pressure in the line, which could be mistaken for a leak. On the other hand, if the product introduced into the line in cooler than the ground temperature, as would occur during cold weather when the ambient temperature is cooler than the ground temperature, the product will begin to warm and expand, causing a pressure increase. This increase in pressure could mask the loss of pressure due to a leak, causing the technology to miss a leak. If the line is blocked in under pressure for a substantial period of time, changes in the ambient temperature or solar heating of any aboveground portions of the line may cause a diurnal effect as the temperature of the product rises and falls with a corresponding rise and fall in the pressure.

Often lines have a pressure relief system, so that if the product in the line is warming up, the amount of pressure increase is limited. When the pressure reaches a set point, a pressure relief valve opens, allowing some liquid to flow back into the tank or into some other vessel. This would represent a loss of product that must be accounted for. However, with the short duration of these tests, this should not be a factor.

Air or vapor trapped in the line is an important source of noise. Such trapped vapor or air would reduce the bulk modulus of the line. This could reduce the sensitivity of the test by changing the response of the signal to the size of the leak. That is, if there is trapped air in the system, a larger volume loss is required to cause a decrease in pressure than if no trapped air is present. The amount of trapped air or vapor must be estimated when the technology is installed and calibrated, and reduced as much as practical.

The presence of surge suppressors is another potential source of noise. They have the same sort of effect as trapped air or vapor when the line pressure is above the pre-charge pressure of the surge suppressor.

Pressure changes in the pipeline can cause distortions in the line. When the pressure increases, the line may "stretch" a little, slightly increasing the volume. Similarly, when pressure is reduced, the line may "relax," slightly reducing the volume in the line. These sorts of pipeline distortions in response to pressure changes could affect results.

Another source of noise is the valves used to isolate the section of line for testing. These valves must be tight, so that no liquid can flow or seep past them into another portion of the system. Any liquid that leaks past a valve would be regarded as a leak in the system. Its signal could not be distinguished from a leak to the environment.

3. Key Features

The technology uses a pressure monitor that is connected to a computer. In addition, a solenoid valve is installed in the line. This valve is operated rapidly to generate a brief pressure pulse. This pressure pulse travels down the line and is reflected back. The pressure sensor detects the return of the pressure pulse and the technology records the time from the generation of the pulse to its return. Since temperature changes in a blocked line produce changes in the density of the product, they also affect the speed of sound in the line. The technology measures the speed of sound from the pressure pulse that it generates. This measurement is conducted at the beginning and end of the test. The difference is used to compute a temperature change, which is used to adjust the pressure decay rate to compensate for temperature changes.

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The same equipment used to generate the pressure pulse is also used to measure the compressibility of the system prior to running the test. A metered amount of fluid is removed rapidly from the system and the resulting pressure change is measured. This measurement can detect the presence of entrapped gases and either compensate for them, if the volume of gas is small, or provide information to the operator that th system must be vented prior to conducting further testing.

Key features include:

- The technology is installed on the line section to be tested.
- The valves isolating the line to be tested must be tight.
- Complicated piping with branches, elbows, etc., can affect the ability of the technology to detect the return of the pressure pulse and correctly compensate for temperature.
- Testing is quite rapid once the technology is installed.

4. Test Results

After installation, only two tests were run. At that point the vendor determined that the technology needed to have additional data analysis algorithms written and incorporated. These algorithms would be expected to provide better temperature compensation during the testing.

- Due to the limited number of tests, no substantial results are available.
- The tests that were performed indicated promise for this technology once it is further developed.
- The two tests that were conducted underestimated the induced leak by 1.2 g/hr and 1.5 g/hr for leaks of 3.74 and 14.74 g/hr, respectively.

This method requires further development and testing before it may be deemed to have application to either an airport hydrant system or a petroleum product terminal.

D. Acoustic Emission

A leak detection technology based on acoustic emission was tested as part of this project. The acoustic emission leak detection technology is based on the fact that liquid under pressure flowing through a hole produces an acoustic signal in a certain frequency range. This is similar to the sound that water makes when flowing through a faucet. The acoustic emission technology uses sensitive microphones connected to the pipeline to pick up the acoustic signal. It is then transmitted to a computer for processing. The computer processing involves several stages of filtering to isolate the relevant frequency range, followed by spectral analysis to estimate the strength of the signal, along with cross-correlation analysis to match the signals from two microphones. This cross-correlation analysis allows the technology to identify a leak signal and, by measuring the difference in times from the two microphones, to estimate the location of the leak.

1. The Nature of the Signal

When there is a leak in a pressurized pipe, liquid will flow out of the hole or orifice. This flow produces a characteristic acoustic signal. In fact, the flow produces two or more distinct signals. One type, the continuous sound, is similar to the hissing noise that might be expected when liquid escapes from a container under pressure. This sound is created by turbulent flow conditions through the leak aperture. Another type of continuous sound is created by the flow causing particulate collisions with the grains in the backfill outside the pipe. An additional type is an intermittent popping sound that extends beyond the audible frequency range. Known as an impulsive sound, it is created by the interaction of the flow field of the leak with air bubbles trapped in the backfill material in the pipe excavation trench. Acoustic emission technologies attempt to isolate these characteristic leak signals.

The strength of the signal could be affected by a number of factors. Clearly, the size of the leak would be expected to affect the strength of the signal. The geometry of the hole would affect the signal. The geometry of the hole coupled with the flow rate would determine whether the flow is turbulent or laminar and would produce different signals. The nature of the backfill would affect the signal. Flow into a backfill with many open spaces with air would be expected to produce a stronger signal than into a more dense backfill. In addition, if the exterior area is saturated with liquid, the signal would probably be reduced. The distance from the leak or signal source to the sensor would affect the signal strength. Pipeline characteristics such as changes in internal diameter, branches, changes in direction, valves, etc., could also affect the transmission of the signal.

The noise background against which the signal must be detected includes many common sounds

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associated with the pipeline. These vary with the type of facility. However, they include sounds inherent from the operation of the pipeline with product flowing, opening and closing valves, etc. In addition, external sources of sound may be important. At operating airports, for example, there is noise from jet aircraft taxiing, taking off, and landing. In addition, traffic from baggage handling contributes to noise, as do generators supplying external power to aircraft during cleaning and preparation operations.

Figure 6-4 is a schematic of an acoustic emission monitoring technology. Sensitive microphones are placed at regular intervals along the pipeline to be monitored. These microphones listen for the sound frequency produced by a leak in the line. This information is transmitted to the data acquisition system that filters and processes the signals. Cross correlation analysis can be used to determine the presence and location of the leak if it is between the two sensors.

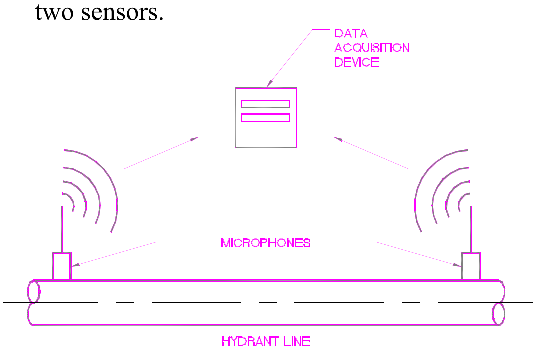

Figure 6-4. Acoustic Emission

2. Sources of Noise

In general, the noise consists of acoustic signals produced by anything other than the leak. One common source of noise is the operation of the facility. Product flow through the pipeline produces a certain level of noise from the interaction of the liquid with the interior of the pipeline, especially elbows, changes in internal diameter, and valves. In addition, sound produced by the pumps may be transmitted through the liquid or metal wall of the pipe. For a given pipeline, testing when there is no flow may reduce this source. However, if there are adjacent pipelines in close proximity, their operation may also produce noise that interferes with the operation of acoustic emission technology.

Other sources of noise include ambient noise caused by traffic or other operations. This source is particularly important at airports. At a busy airport, there may not be any time when this noise is absent. During the day, flight operations produce noise as aircraft arrive and depart and as baggage is loaded and unloaded. Even at night when few flights are scheduled, maintenance of the aircraft may cause a substantial level of noise from portable generators, vacuuming, etc. Thus, to be successful, the acoustic emission technology must be able to isolate the characteristics of the acoustic signal produced by a leak from the background of ambient noise caused by pipeline and other facility operations. This may be possible using sophisticated signal processing to isolate the relevant frequency range, confirm that the signal is being received through the pipe at two or more sensors, and analyze the characteristics of the signal. The distance that the signal must carry affects the performance of the technology. Consequently, sensors need to be placed at frequent intervals along the pipe.

The technology does not seem to be affected by the size or volume of the pipeline. However, sensors must be placed every 300 to 500 feet. The pipe diameter, elbows, branches, or other plumbing features may affect the signal. The nature of the backfill affects the signal.

3. Key Features

The acoustic emission technology used in these tests used microphones placed on two hydrant valves. The microphones were magnetically coupled to the pipe. The signals received by the microphones were transmitted by radio to a receiver connected to the computer used for processing. The vendor stated that better results could be obtained by using hydrophones installed directly in the liquid in the pipe. However, the hydrophones were not physically compatible with the product (Jet A). While this could presumably be overcome by using different materials to construct the hydrophones, development times are expected to be at least 6 to 12 months.

Once the accelerometers were installed, the technology only required about one minute of data for its analysis, so it provided results essentially in real time. The computer provides a graph of the cross-correlation function, which shows a definite peak if a signal was detected. As a separate part of the graph, the location of the signal source is shown as a proportion of the distance between the two sensors. The distances in feet are also displayed. Thus, when the technology detects a leak, it also provides an estimate of the location to the nearest foot from one of the microphone locations.

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An operator from the vendor operated the technology. In principle, it could be permanently installed and could operate automatically.

- Microphones or acoustic sensors must be attached to the pipe at regular intervals. The required interval is estimated to be on the order of 200-300 feet.
- There must be a means of communication between the sensors and the processing computer. This may be through a transmitter, or it could be through permanently installed wiring.
- When a leak signal is detected, the technology also produces an estimate of the location of the leak as measured from one of the sensor locations.
- The computer uses fast processing algorithms to produce a result from about one minute of data collected for each pair of sensors. Thus, it operates almost in real time.
- The technology is qualitative, producing a leak or no-leak result only without any estimate of the size of the leak rate.
- The bulk volume of the pipe only affects the technology through the number of sensors that are needed.
- Pipe diameter, changes in diameter, elbows, branches, valves, and other plumbing features probably affect the technology. Performance is probably better on simpler systems.
- The nature of the backfill affects the performance of the technology.

4. Test Results

The technology was tested at MCI. Two series of tests were run using the technology. The first series of tests considered a variety of factors including the type of backfill, the distance between the sensors, the pressure in the line, and the size of the orifice used to simulate the leak. These tests were conducted during the day with normal flight operations. The results of the first set of tests are summarized below.

- The size of the orifice in the simulator (and hence the leak rate) was an important factor.
- No difference was apparent between leaks with the line pressure at about 150 psig or the line pressure at about 100 psig.
- The backfill was important. It was more difficult for the technology to detect a leak when the leak was into liquid or into liquid-saturated sand than when the leak was into air or into dry sand.
- There was no apparent performance difference between the distance of 260 feet between the sensors and 520 feet between the sensors. (The leak was fixed at about 130 feet from one sensor.)
- Ambient noise from aircraft appeared to affect the results.

Because the ambient noise during the day appeared to affect the ability of the technology to detect leaks, additional testing was conducted later at night. These tests used the largest orifice, corresponding to a leak rate of about 20 gallons per hour (0.01 percent of the line volume) per hour. Tests were conducted with the leak into air or dry sand. The results of testing under these conditions are summarized below.

- The technology produced a false alarm rate of 32 percent.
- The technology had a probability of detection of 63 percent for a leak of about 20 gallons or 0.01 percent of the line volume per hour.

In light of the noise attendant to airport operations (even at night), this technology did not perform well in an airport setting. Facility operators considering this technology should carefully evaluate any advances made since the tests at MCI. The tested configuration appears to require extensive additional development before it can be deemed to have effective application either at an airport hydrant system or a petroleum product terminal.

E. Chemical Marker

A chemical marker technology was selected for testing in this program. This method is a soil-vapor detection technique, monitoring the soil gas for the presence of certain compounds. These compounds are distinct from those normally present in the product or the soil; thus, if there is a hole in the pipe, liquid will leak out and the compounds of interest will vaporize and be detected in the soil gas. The detection of these "target" compounds outside the pipe would indicate a leak.

The performance of the chemical marker leak detection technology has been well established under a variety of actual field conditions. It is known to work well in most conditions other than where an extremely shallow water table exists. Because it has been previously evaluated under dry conditions, the

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focus of this evaluation has been on shallow water table conditions.

If the target substance is already present, the soil monitoring method must be able to measure the concentrations and detect increases in these concentrations and identify these increases as indicating a leak. The key is that changes in the concentration of the marker compound outside the pipeline must be distinguishable from those that occur naturally in the absence of a leak. The entire system to be tested must be exposed to product containing adequate chemical marker concentration.

A chemical marker leak detection technology is shown schematically in Figure 6-5. A series of sample probes are installed at regular intervals along the pipeline. A chemical marker is added to the fuel in the line. If a leak occurs, the chemical marker is released to the environment where it is collected periodically at the sample probe, either manually or automatically. Usually the sampling ports are aspirated with a vacuum to collect the gas sample. The sample is analyzed by a gas chromatograph located either at the site if the technology is automatic, or at a central laboratory if manual sampling is used for sample collection as in this study. The information can be used to determine the presence of a leak and its approximate location.

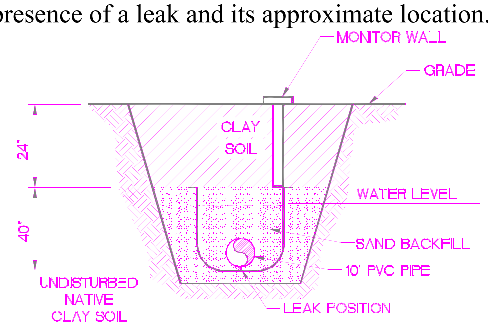

Figure 6-5. Chemical Marker Test Pit

1. The Nature of the Signal

In soil-vapor monitoring the signal is the concentration of the target substance in the vapor collected from the soil at the sampling points. This gas sample may be collected actively through aspiration, or passively, relying on diffusion. Larger leaks will produce large concentrations of the target substance in the backfill around the pipe. The method is generally not designed to quantify the size of the leak, rather, it confirms the presence or absence of the compound above a certain threshold. In fact, the important factor is the concentration of chemical in the soil gas. This concentration can be produced by a slow leak over a relatively long period or by a larger leak over a short period. An extremely slow leak could allow for the chemical marker to dilute to a concentration below detectable levels before it reaches a sampling port.

When a leak occurs, product containing the chemical marker is released into the soil. The chemical marker vaporizes and diffuses through the soil. When soil gas samples are taken at locations near the leak, they would contain the chemical marker at some concentration level, assuming that the marker has diffused far enough to reach the sampling port. The gas samples are analyzed with a gas chromatograph, so the signal is the response of the gas chromatograph showing the presence or absence of the chemical marker as well as its concentration.

One source of noise in this context is any process or phenomenon that affects the diffusion of the marker vapor through the backfill to the sampling ports. A second source of noise results from the presence of other compounds in the soil gas that could interfere with the chemical analysis and affect the sensitivity of the analysis to detect the target compound.

2. Sources of Noise

The mechanisms that produce noise in soil-vapor monitoring technologies are quite different from those that affect pressure monitoring tests, volumetric monitoring tests, or acoustic tests, except for the factors of instrument calibration and calculations.

One source of noise is uneven distribution of the marker compound through the product in the pipelines. Uniform mixing is usually not necessary. It is usually sufficient to add the marker as the product is being pumped through the system. This must be continued until the product with the marker compound has an opportunity to reach all portions of the pipeline system.

Another source of noise is the hydrogeology of the backfill. If there is a high water table above the pipe, the product must leak out of the pipe and float to the top of the water table before the marker can vaporize and diffuse through the backfill to the sampling locations. The degree of water saturation of the backfill material around the pipe will affect the rate at which the chemical vapors migrate. The depth and nature of the soil above the water table may affect the speed and distance that vapors will migrate horizontally. If there is a nearly impervious layer (such as concrete) over the pipeline, the vapor may

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migrate a long distance. However, if there is a very porous covering and the water table is high, the vapor may migrate mostly upward into the atmosphere, and it may be difficult for the vapor to reach the sampling ports. Typically, leak simulations are performed using a chemical marker that is different from the testing marker, released into the soil to verify that adequate vapor transport conditions exist.

Similar chemical substances that may be present also generate noise. This effect would make it difficult for the chemical analysis to detect the marker compound. For this reason, the marker compound must be distinct from the product or other compounds that would be present.

3. Key Features

The chemical marker technology is capable of detecting small leaks from buried pressurized pipelines, provided that tests are properly conducted and certain soil or backfill conditions are satisfied. Below are the key issues affecting this technology.

- Optimum number and location of sampling ports or probes. The backfill conditions and the depth of the pipeline affect how closely the sampling locations must be spaced to ensure that any vapor from the chemical marker will reach one or more sampling ports in the event of a leak.
- Total number of sampling locations needed. The sampling ports must be located along the total length of the buried pipeline. For long pipelines, this can result in a large number of sampling locations required. The position of the sampling locations may vary with the type of soil, groundwater level, and cover material. Typical distances may vary from a few feet to around 20 feet for optimum conditions.
- Water table effects. If a very shallow water table exists under bare soil, there may be reduced ability of the tracer to migrate laterally to the probes because the marker vapors may be lost more easily to the atmosphere aboveground. However, if pavement exists above the soil, as at most airports, the lateral migration of the chemical marker is enhanced. The pavement provides a diffusion barrier that results in a higher concentration of chemical marker migrating laterally. If the water table is very close to the surface of bare soil, the spacing of the probes may be reduced.
- Minimal background levels of the target substance. If the target substance is present in the backfill outside the pipe, the method must be able to detect an increase in the concentration that would indicate a new leak. The actual concentration of chemical marker to declare a leak may depend on a number of factors. In instances where testing has previously taken place, background samples must be collected prior to the current test.
- The method provides leak location as well as leak detection. Since the sampling locations are generally close together, usually the chemical marker is detected at two (or more) adjacent locations. A comparison of the concentrations identifies a peak between two adjacent sampling locations, which indicates the approximate location of the leak. This could locate the leak to at least the spacing of the sampling locations.
- Ground covers, very porous ground cover such as sand combined with a high water table will require much closer spacing of probes.
- Confirmation of a leak. Often the indication of a leak is confirmed by additional analysis of the concentration of the product in the backfill.
- To better define the location of a leak, additional sampling ports may be installed in the suspected vicinity of the leak. The line is then tested again with a different chemical marker to confirm the presence of the leak. The use of additional sampling locations improves the location of the leak.
- The speed of marker transport through the backfill must be established to determine the required waiting time between injecting marker in the product and sample collection.

4. Test Results

The performance of the chemical marker technology has previously been well established under dry, porous backfill conditions. The testing performed as part of this project was intended to determine whether or how well the method would work when the leak was below the water table under bare soil conditions. The testing included water tables of different depths and distances from the surface of the ground. The chemical marker compound was introduced into Jet A. A leak of about 0.05 gallon per hour was introduced below a pipe buried within a secondary container. Testing

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indicated that the technology detected the leak in the water-filled pits after about 20 gallons of product had leaked. This occurred over a period of about two weeks.

In general, the external monitoring methods are more sensitive than the internal systems, which could leak at several gallons per hour for a day or more before they detect a leak. The performance of the chemical marker technology is affected by several factors. Among these are the soil permeability, ground cover, nature of the backfill, and the nature of the leak. This testing was limited to demonstrating that the technology would work in a high water table condition. Flooding the container to various depths set up the different test conditions. Sampling ports were located at distances of 2.5, 5, and 10 feet from the leak location. A dry, porous pit was used as a control, with sampling locations up to 20 feet away. The time needed for the chemical marker to be detected was measured at each location for up to 30 days. The test results are summarized below.

- The higher the water table, the longer it took the method to detect the chemical marker at each location. This is probably due to loss of tracer to the atmosphere where the ground cover is shallow.
- The closer the sampling location was to the leak, the sooner the chemical marker was detected.
- The chemical marker was detected most rapidly in the unsaturated, porous test pit where it was detected within three days at distances of 2.5 feet and 5 feet from the leak.
- Under unsaturated conditions, the chemical marker was detected at a distance of 20 feet within nine days. At one sample position located 20 feet from the leak, chemical marker was detected within 23 days.
- Under the highest water table conditions (where the water table was within 12 inches of the surface; approximately 3 feet above the pipe), the chemical marker took 23 days before it was detected at 5 feet from the leak, while under the lower water table level (where the water table was about 3.5 feet below the surface; about 12 inches above the pipe) it was detected there at 9 days.
- One chemical marker compound has been given an ASTM additive listing for use in jet fuel.

The tests with high water table showed that the chemical marker vapors do rise to the top of the water table and diffuse through the soil. However, this takes considerably longer than under dry conditions and the vapor does not migrate as far when there is no cover over the soil.

F. Vapor Monitoring

A soil-vapor monitoring technique, which monitors the soil gas for the presence of volatile hydrocarbon compounds, also was selected for testing. If there is a hole in the pipe, liquid will leak out and the compounds of interest will vaporize and can be detected in the soil gas. If the backfill is completely clean, there are no hydrocarbon concentrations present. However, some concentration of these compounds may be present in operating sites from small spills or previous leaks. The particular technology tested used a fiber optic sensor that is capable of detecting dissolved hydrocarbons in water, so it can also be used below the water table as well as in the vapor zone.

If the compounds of interest are already present, the soil monitoring method must be able to measure and detect increases in these concentrations, and identify these increases as indicating a leak. The key is that changes in the concentration of the hydrocarbon compound outside the pipeline must be distinguishable from those that occur naturally in the absence of a leak. Accordingly, the sensors must have a large dynamic range.

A hydrocarbon vapor monitoring technology is shown schematically in Figure 6-6. A series of sample wells are installed at regular intervals along the pipeline. If a leak occurs, hydrocarbons are released to the environment where they are detected by hydrocarbon sensitive sensors located in each sample probe. The monitoring is continuous and can be used to determine the approximate location of the leak as well as its presence.

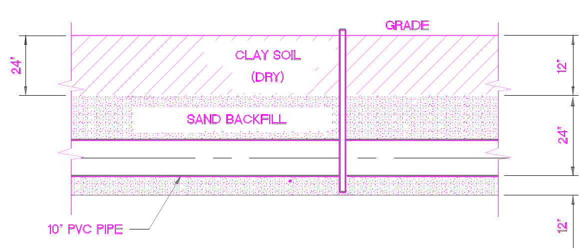

Figure 6-6. Vapor Monitoring Test Pit

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1. The Nature of the Signal

In soil-vapor monitoring the signal is the concentration of the target substance in the vapor measured by the sensor at the sample wells. For permanently installed sensors, the hydrocarbon probes are placed in sample wells and are in equilibrium with the environment. Larger leaks will produce large concentrations of the target substance in the backfill around the pipe. The method is generally not designed to quantify the size of the leak; rather, it confirms the presence or absence of the compound above a certain threshold. In fact, the important factor is the concentration of chemical in the soil gas. This concentration can be produced by a slow leak over a relatively long period or by a larger leak over a short period. An extremely slow leak could allow for the concentration to dissipate before it reaches a sampling port.

When a leak occurs, the liquid product is released into the backfill. The volatile constituents vaporize and diffuse through the soil. When soil gas samples are taken at locations near the leak, they would contain the volatile hydrocarbon compounds at some concentration level, assuming that these compounds have diffused far enough to reach the sampling port. The gas samples are analyzed with a fiber optic sensor, so the signal is the response of that sensor.

2. Sources of Noise

One source of noise in this context is any process or phenomenon that affects the diffusion of the hydrocarbon vapor through the backfill to the sampling ports. A second source of noise results from the presence of other compounds in the soil gas that could interfere with the chemical analysis and affect the sensitivity of the analysis to detect the target compound.

The mechanisms that produce noise in soil-vapor monitoring technologies are quite different from those that affect pressure monitoring tests, volumetric monitoring tests, or acoustic tests, except for the factors of instrument calibration and calculations.

A major source of noise is the hydrogeology of the backfill. If there is a high water table above the pipe, the product must leak out of the pipe and float to the top of the water table before it can vaporize and diffuse through the backfill to the sampling locations. The porosity of the backfill material around the pipe will affect the rate at which the chemical vapors migrate. The depth of the soil above the water table may affect how far the vapors will migrate horizontally. If there is a nearly impervious layer (such as concrete) over the pipeline, the vapor may migrate a long distance. However, if there is a very porous covering and the water table is high, the vapor may migrate mostly up into the atmosphere and it may be difficult for the vapor to reach the sampling ports. Since the conditions of the backfill are specific to each site, they must be well characterized at each site in order for the method to work properly.

Similar chemical substances that may be present at the site also generate noise. This effect would make it difficult for the chemical analysis to distinguish between hydrocarbon concentrations resulting from a leak and those already present. Moreover, there may be seasonal variation in the concentration and volatility of pre-existing contamination. Therefore, the sensors should be selective to a range of petroleum hydrocarbons and must not detect naturally occurring methane and H_2S.

3. Key Features

The soil vapor monitoring technology may be capable of detecting leaks from buried pressurized pipelines, provided that tests are properly conducted and certain soil or backfill conditions are satisfied. Below are the key issues affecting this technology.

- The backfill conditions must be suitable to allow the liquid hydrocarbon to vaporize and diffuse through the backfill to reach the sampling locations.
- Optimum number and location of sampling ports or probes. The backfill conditions and the depth of the pipeline affect how closely the sampling locations must be spaced to ensure that hydrocarbon vapors will reach one or more sampling ports in the event of a leak.
- Total number of sampling locations needed. The sampling ports must be located along the total length of the buried pipeline. For long pipelines and short distances between sampling ports, this can result in a large number of sampling locations. Often the sampling locations must be only 20 feet apart or less. Lower volatility products may require closer sensor spacing than higher volatility products.

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- Seasonal variation in ground and air temperature affects volatility of existing contamination.
- Water table effects. If the water table is near the surface of the ground and above the pipe, this will affect the ability of the hydrocarbon vapor to diffuse through the backfill. This may vary during the year due to seasonal changes.
- Minimal background levels of the hydrocarbons. If the hydrocarbons are present in the backfill outside the pipe, the method must be able to detect an increase in the concentration that would indicate a new leak. This is generally more difficult than simply detecting the presence of hydrocarbon vapors.
- The method provides leak location as well as leak detection. Since the sampling locations are generally close together, usually the hydrocarbon vapor is detected at two (or more) adjacent locations. A comparison of the concentrations identifies a peak between two adjacent sampling locations, which indicates the approximate location of the leak. This could locate the leak to at least the spacing of the sampling locations.
- The sensor is also capable of detecting dissolved hydrocarbons in water, so could also operate when installed below the water table.

4. Test Results

The testing performed as part of this project was intended to determine whether or how well the method would work when the leak was below the water table. The testing included water tables of different depths and distances from the surface of the ground. The product used was Jet A fuel. A leak of about 0.05 gallon per hour was introduced below a pipe buried within a secondary container. Flooding the container to various depths set up the different test conditions. Probes were located at horizontal distances of 2.5, 5, and 10 feet from the leak location. A dry, porous pit was used as a control. Some probes were installed below the water table to test the ability to detect dissolved hydrocarbons. The time needed for the probes to detect hydrocarbon vapors and indicate a leak was measured at each location for up to 30 days. The test results are summarized below.

- In the dry, porous pit, a concentration increase indicating a leak was found at 9 days, 2.5 feet from the leak. No leak was detected in 30 days, 10 feet from the simulated leak.
- Both of the probes in pit one (in the vadose zone of a water table within one foot of the surface; about 3.5 feet above the pipe) detected the leak. The probe located at 2.5 feet from the leak responded within 4 days, while the probe located at 10 feet detected the leak in 13 days.
- In the pit with 2.5 feet of unsaturated space above the water table, a probe at 5 feet detected a leak within 15 days.
- The probes that were fully submerged also detected the leak, but at a slower rate. It was detected within 24 days by the probes at 2.5 feet from the leak due to the solubility of hydrocarbons in water. For hydrocarbons the solubility in water is poor and a concentration gradient develops. The highest concentrations will be close to the leak point.
- The results from these tests indicate that a leak from a pipeline can be detected using the fiber optic probes. A leak was detected by at least one probe in each test pit. The leak was detected faster when the water table was high, and detection was slower when the water table was low or the pit was dry. These probes were also able to detect the leak when they were fully submerged in water.
- A review of the plots of the hydrocarbon concentrations over time led to the conclusion that the interpretation of the data requires trained personnel.

Under high water table conditions, the tests showed that the hydrocarbon liquid rises to the top of the water table and diffuses through the soil. The high water table allowed the leak to be detected faster than in the dry condition. The data from the sensors needs to be interpreted by trained personnel.

G. Facts and Findings

Tables 6-1, 6-2, and 6-3 summarize the characteristics of the technologies tested and some general results of the evaluations. Table 6-1 describes the general characteristics of each of the six methods considered, including the requirements for instrumentation, installation, operation, and maintenance. Although these characteristics are general, there may still be significant differences between methods in a particular category because

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some technologies do a better job of compensating for the various types of interference that may be present during testing. Also, note that some technologies use patented or proprietary methods for analyzing the data.

Tables 6-2 and 6-3 summarize some of the observations and results that were obtained from the testing. It is difficult to obtain specific information since the specifics are very much location related. For example, costs for some technologies vary widely with the site conditions. In addition, to determine an accurate cost for a specific site requires considerable effort for the vendor.

The bottom line for these technologies, however, is their applicability to the types of fueling operations that are practiced at large airports and large petroleum handling facilities. The basis for the conclusions here are somewhat complex, but they are based on both controlled testing and observations of the fueling practices at MCI.

The dual pressure methods appear to work as advertised by the vendors. Although the hardware and measurement principles vary considerably between these methods, both are capable of detecting leaks of a few gallons per hour on lines that are several miles in length with capacities of 100,000 gallons or larger. Both are capable of providing adequate temperature compensation so that variations in test conditions are not a problem.

For the pressure decay method, the amount of data obtained was insufficient to draw reliable conclusions. The limited testing indicates, however, that the method could produce reliable data. Development of the method tested for this project is expected to take at least a year to complete.

The acoustic method tested appears to have considerable potential if the signal filtering can be improved. The technology as it was tested would not be satisfactory for use on airport hydrant systems or at petroleum product terminals. The technology is attractive because it could be operated without regard to isolation of segments of the pipeline, is not temperature sensitive, can be conducted at any time when fueling operations are not actually in progress, and provides location information for any leak detected. Development of this method is also expected to take a year or longer.

External methods such as hydrocarbon and chemical marker leak detection can provide near continuous monitoring. Both are capable of detecting small leaks over a period of a month, but the more volatile materials used for chemical markers seem to work considerably better for small leaks on the order of 0.1 gallons per hour. These technologies depend on the spacing of the sampling points. The line length affects the required number of sampling points but the diameter and total volume of the line are not important. Although the leak rate tested was quite low, the cumulative amount of product leaked before detection at a reasonable distance was about 20 gallons. Larger leaks will be detected much more rapidly by both methods. The primary concern for both of these methods involves installation costs. The installation of probes at 20-foot (or closer for high water table conditions) intervals can be expensive. The costs for manual sampling and analysis are significant and can require the full time services of two people at a large airport.

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Table 6-1. General Characteristics of Pipeline Leak Detection Technologies			
Parameter	**Pressure Decay Dual Pressure[4]**	**Volumetric Dual Pressure[4]**	**Pressure Decay with Temperature Compensation[4]**
Vendor Information			
Number of Installations	Large	Low	None
Third Party Certification[1]	Yes[7]	Yes	No
Technical Performance			
Minimum Detectable Leak (MDL)	16.6 gal/h (0.0095% of 175,000 g pipeline)	9.7 gal/h (0.0055% of 175,000 g pipeline)	Insufficient data to determine
Leak Location Capability	No	No	No
Temperature Compensation	Yes[5]	Yes	Yes
Test Duration	45 minutes	2.5 hours	30 minutes
Service Fluids That Can Be Tested	All	All	All
Kinds of Installation (permanent or point-in-time)	Permanent or point-in-time	Permanent or point-in-time	Permanent
Required Modifications to Piping[2]	By-pass required	None	None
Maximum Capacity of Pipeline[3]	Unlimited	Unlimited	Unlimited
Are threshold/MDL a function of line volume enclosed? Yes/No	Yes	Yes	Yes
Costs			
Permanent	Moderate	Moderate	Unavailable
Point-in-Time	Moderate	Moderate	N/A
Retrofit	Moderate	Moderate	Low
Suitability for Airport or Petroleum Product Facilities			
Airports	Good	Good	Needs additional development
Petroleum Facilities	Not for small lines	Good	Needs additional development

1 As approved by the EPA National Workgroup on Leak Detection Evaluations.
2 The entire pipeline can be tested without additional valves. Isolation valves must be present if the pipeline is to be tested in segments. These costs will depend on the number of isolation valves to be installed.
3 Performance will generally decrease as line size increases.
4 The size of the line affects the performance of these systems. The larger the line, the larger the size of the leak in g/hr that can be detected, but generally the leak as a percentage of the line volume decreases with larger lines.
5. Done by State Technical Supervision Department of the Federal State Hessen, Frankfurt Department, Germany.

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Table 6-1. General Characteristics of Pipeline Leak Detection Technologies (Continued)			
Parameter	**Acoustic Emission**	**Hydrocarbon Vapor Monitoring**	**Chemical Marker**
Vendor Information			
Number of Installations	None	Moderate	Large
Third Party Certification[1]	No	Yes	Yes
Technical Performance			
Minimum Detectable Leak (MDL) - 175,000 gallon line	89 gal/h	<0.1 gal/h[2]	<0.1 gal/h[2]
Leak Location Capability	Yes	Yes	Yes
Temperature Compensation	Not applicable	Not applicable	Not applicable
Test Duration	1 minute	Continuous	Periodic sampling
Service Fluids That Can Be Tested	All	Best with high volatility fuels	All
Kinds of Installation (permanent or point-in-time	Permanent or point-in-time	Permanent	Permanent or point-in-time
Required Modifications to Piping	None	None	None
Maximum Capacity of Pipeline	Unlimited	Unlimited	Unlimited
Costs			
Permanent	Moderate	High	High
Point-in-Time	High	Not applicable	High
Retrofit	High/moderate	High	High
Suitability for Airport or Petroleum Product Facilities			
Airports	Requires further development	Good	Good
Petroleum Facilities	Not Determined	Good	Good

1 As recognized by the EPA National Workgroup on Leak Detection Evaluations.

2 This represents the evaluated leak rate, not the smallest detectable leak rate.

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Table 6-2. General Characteristics for Volumetric and Pressure Decay Technologies

	Pressure Decay Dual Pressure	Volumetric Dual Pressure	Pressure Decay with Temperature Compensation
Measurement Concept	Monitors pressure decay at two pressures to differentiate between leaks and thermal effects	• Maintains constant pressure while monitoring volume change • Monitors at two pressures to differentiate between leaks and thermal effects	• Monitors a continuous pressure trend • Adjusts pressure trend for changes in fuel temperature
Signal	Change in pressure that exceeds that expected for a tight pipeline	Change in volume necessary to maintain pressure that exceeds that expected for a tight pipeline	Temperature compensated pressure decay exceeds the rate equivalent to the required minimum detectable leak rate.
Sources of Noise	• Pipeline distortions • Trapped vapor • Leaking valves • Uncompensated product temperature change	• Pipeline distortions • Trapped vapor • Leaking valves • Uncompensated product temperature change	• Pipeline distortions • Trapped vapor • Leaking valves • Pipeline components obscure temperature compensation signal
Operational Requirements	• Line must be tight at time of installation or system will find leaks continuously • Technology must be calibrated for each pipeline segment • Suspend normal operations for duration of test (45 m) • Blind all valves or check to assure there are no valve leaks in case of leak alarm • Tests conducted at operating pressure of line or higher (150 psig and 60 psig)	• Suspend normal operations for duration of test (2.5 h) • Blind all valves or check to assure there are no valve leaks • Tests conducted at operating pressure of line or higher and at 0 psig	• Suspend normal operations for duration of test (30 m) • Blind all valves or check to assure there are no valve leaks • Tests conducted at operating pressure of line or higher
Minimum Instrumentation	• Pressure transducer in each segment to be tested • Computer and software for data processing • Automated by-pass line to reduce pressure to low level • Computer control of jockey pump to adjust pressure	• Technology hardware for maintaining constant pressure must be installed • Computer and software for data processing • One technology required for each segment or portable technology to be moved to segment	• Pressure transducer in each segment to be tested • Computer and software for data processing • Valving to isolate segments for testing • Solenoid operated valve for producing pressure wave
Installation Requirements	• Install pressure transducer in each segment • Install cable back to data acquisition system	• Technology must be connected to pipeline segment by means of small tubing	• Install pressure transducer • Install pressure wave solenoid mechanism • Install cable back to data acquisition system
Limitations	• Performance deteriorates with trapped vapor • Surge suppressors must be isolated from system during testing or performance degrades • Testing can be conducted whenever operation allows a 45 minute period; testing at night is preferable for best performance • Elevation differences between leak and detector may reduce sensitivity	• May be affected by large vapor pockets • Testing should be conducted at night if possible • Elevation differences between leak and detector may reduce sensitivity • Performance deteriorates somewhat if surge suppressors are not isolated	• This technology is not ready for use at this time • Pressure pulse signal may be obscured by components in pipeline

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Table 6-3. General Characteristics of Acoustic and External Monitoring Technologies

	Acoustic Emission	Hydrocarbon Vapor Monitoring	Chemical Marker
Measurement Concept	Detects signals produced by fuel escaping from the pipeline	Vapors from fuel leaked into the backfill is detected with hydrocarbon sensitive sensors	Chemical markers (tracers) are introduced into the fuel. These are detected by analyzing soil gas samples that are periodically collected.
Signal	Acoustic signal produced by flow through and orifice	Hydrocarbon concentrations in the backfill increase beyond levels expected for a tight pipeline	Chemical markers are detected in the backfill around the pipeline
Sources of Noise	• Operating aircraft and maintenance equipment • Fueling operations through adjacent lines	• Spills not related to leaks	• Spills of labeled product not related to leakage • Impermeable soil conditions • Water tables close to surface
Operational Requirements	• Suspend normal operations for duration of test • Signal must be transmitted to processor via hard wire or radio signal • Pipeline should be at normal operating pressure during tests	• Sensors must be cleaned and calibrated annually.	• Samples must be collected periodically from each sampling port • On-site analyzer must be calibrated and maintained
Minimum Instrumentation	• Sensors must be located at regular intervals along the pipeline • Computer and software for data processing	• Sensors for installation at intervals of 10 – 20 ft. • Cabling or other means of transmitting signals to central data system	• Probe installation equipment • Sample collection equipment • Inoculant • Sample ports must be installed at intervals of approximately 20 feet.
Installation Requirements	• Microphones must be located at periodic intervals.	• Hydrocarbon sensors must be installed at regular calculated intervals along pipeline • Cabling or other means to connect to data acquisition system	• Sample probes at regular intervals
Limitations	• Background noise may preclude successful operation of technology • Access to the line for installation of sensors • Reliability of analysis needs to be improved before technology is commercialized	• Interpretation of the data requires trained personnel or a monitoring service	• Water table close to ground surface • Impermeable soils

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VII. DEVISING THE BEST TESTING STRATEGY FOR A PARTICULAR SITE

This section of the Study presents an overview of the findings and lessons learned regarding the selection of technologies, selection and set-up of the test site, and field-testing of the technologies for this program. While the information is general in nature, it is derived from actual issues and events encountered in the implementation of this program. It should be noted that not all recommendations discussed in this section will apply to all methods. In general, the requirements for external monitors are different from those for internal systems. For example, the line size, the requirements for tight valves, etc., will not apply to chemical marker or hydrocarbon monitoring methods. The intent of this information is not to dictate policies or procedures, but to inform those responsible for setting up and conducting future testing of leak detection technologies for buried pressurized petroleum piping systems.

The previous sections provided information on the key features and the estimated performance of several leak detection technologies. Each technology has its advantages and drawbacks. Each can work well when correctly applied and operated under the appropriate conditions.

With so many options available, how does one choose the best technology for a specific application? Depending on the site-specific conditions, a technology that might work well on one pipeline might not perform adequately on another. Before making a choice, one should be thoroughly familiar with the physical characteristics of the site as well as its operational characteristics. One should also weigh cost considerations and be able to assess the vendor's claims in a realistic way.

A. Site Characteristics

The facility operator, manager, or testing engineer should have a thorough knowledge of a number of site-specific features. First among these are the physical characteristics of the site. This includes knowledge of the source of the product, the number and size of aboveground storage tanks, the amount and size of buried piping, the amount of aboveground piping, line segments, pumps, valves, filters, and other equipment. Other site-specific information includes any changes in elevation of the piping system.

The specific product or products at the site may be important. Certain monitoring methods work better with more volatile products. In addition, leak detection methods that introduce sensors into the pipeline must be compatible with the product.

Knowledge of the ambient weather conditions to be encountered is important. This includes information about the normal range of temperatures and diurnal cycles over the year. The ambient temperatures combined with the ground temperature and the source of the product combine to produce temperature differences between the line and the ground that can influence certain types of testing.

A final consideration is the composition of the backfill material around the pipeline. This includes the nature of the material—sand, pea gravel, or soil, including its porosity. Knowledge of the water table is also important. Is the pipeline in a saturated zone, or is it dry? Does the water table change seasonally or diurnally as in tidal areas? In addition, is there any existing contamination in the pipeline trench?

All of these site-specific characteristics influence the leak detection methods that might be appropriate for the site.

B. Piping System Considerations

A test program is not required but establishing one may be beneficial. If the operator elects to use a test program, factors such as site location, physical configuration, system characteristics, and operational considerations should be considered. The following represents a few of the key factors to keep in mind:

- Periodic checking of the leak detection system is recommended. This can be accomplished by introducing a simulated leak of appropriate size and determining that the leak detection system detects it.
- The facility and associated systems must truly represent a typical application to provide "a real world scenario".
- Drawings of the equipment and piping system configuration, layout, and routing must be secured to determine line lengths, volumetric capacities, and unique system circumstances.
- Specifications on piping materials, protective coatings, components, equipment, and methods of installation must be made available to

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understand how the facility and system was constructed.

- As-Built or As-Constructed documents should be located, if possible, to confirm exact routings of the piping systems.
- Normal and maximum operating flow and pressure ratings should be determined through discussions about the systems operations with the facility staff.
- The volumetric capacity of the piping system to be tested should be calculated and confirmed through a line fill, if practical.
- A determination if the positive shut off of the piping system segments can be accomplished with the existing isolation valves.
- A determination on the availability of field instruments, field instrument connection points, and leak detection technology components connection points should also be performed.
- Based upon the current system configuration, operational requirements, and technology testing issues, determine if temporary headers, manifolds, isolation valve installations and other modifications are required.
- If modifications to the system are required, a detailed schedule of construction and sequence of system shut down is mandatory. Most system shut downs and system modifications will occur between 11 p.m. and 5 a.m. to minimize the impact on normal facility and system operations.
- Consistent with any new construction at a petroleum fueling terminal or airport hydrant system, the piping should be in accordance with applicable codes and industry practices.

C. Operational Characteristics

In addition to the physical aspects of the site, there are a number of operational characteristics of the facility that need to be considered. These include defining periods when the pipeline can be or is normally out of service, the time of day, and the duration periods when the pipeline could be tested in a static condition.

The existence of valves to isolate sections of the pipeline for testing is also a consideration. Some leak detection methods require that the pipeline be tested in sections and that each section must be isolated from the rest of the line with absolutely tight valves. If the valves are not tight, leaks across a valve would be mistaken for leaks from the system. Ensuring a tight seal may require installation of double-block-and-bleed valves if they are not present. In addition, surge suppressors may need to be isolated from the line for testing by some methods.

What are the characteristics of the flow when the pipeline is in use? If the line is under constant, stable flow conditions for long periods of time, a leak detection method that monitors the line during flowing conditions may be appropriate. Operators of pipeline systems that are characterized by frequent changes in flow rate and pressure, such as airport hydrant systems, should not rely on the results reported here for this leak detection method, since all testing was conducted under stable flow conditions. Operators might want to arrange for on-line testing to confirm performance in their application.

The operating pressure of the line and the maximum pressure that can be used for testing affect the choice of leak detection method. Some methods require a minimum test pressure that may exceed what can be used for some lines.

D. Cost Considerations

There are several costs to be considered. The most obvious cost is the price of the leak detection equipment or the leak detection service. This must be obtained directly from each vendor and will probably vary with the site and application. It would also depend on whether the leak detection equipment is permanently installed and is to be operated on demand by facility personnel, or whether the vendor supplies personnel and equipment to conduct test at a particular point in time.

Another cost factor is the interference of the leak detection method with normal operations. If the leak detection method can operate during inactive times in the line, there will be minimal disruption of operations. Some leak detection methods require a long stabilization time before a test can be run. If this stabilization time is much longer than normally available, then the operation of the facility will be disrupted periodically to test for leaks. This could range from a 4-hour period to taking the pipeline out of service for several days.

The implications of the performance of the leak detection method must be considered. A false alarm occurs if a leak detection technology indicates a leak when none exists. This would result in further investigation to determine whether the leak is really there, or to locate the leak. It might result in shutting down operation of the pipeline until the leak can be found or it can be determined to be a false alarm. Clearly, frequent false alarms would seriously disrupt operations and cause unnecessary costs to be incurred. A false alarm rate that is very high would be unacceptable in most applications.

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The possibility that the leak detection technology will miss a leak must be considered. If a leak is missed, product may be lost. This represents a loss of the value of the product or the cost to replace it. In addition, the product may contaminate an area, requiring very expensive clean up or remediation costs. Clearly, it is desirable to detect a leak as soon as practical and when it is relatively small to minimize these costs. Most leak detection methods have a higher chance of finding a large leak than a small one, so most should find large leaks fairly quickly. Typically, one must balance the false alarm rate with the probability of detection. Setting a small false alarm rate is desirable, but it generally means that a leak must be larger to be found, or it may take longer to find.

If a leak is detected, it must be located before it can be corrected. If a leak detection technology also locates the leak, this is an advantage. Otherwise, additional effort will be needed to locate the leak.

The normal operation and maintenance of the leak detection technology must also be considered. For example, some methods may require extensive manual labor to collect and analyze samples. Specially trained personnel may be required to operate the test equipment and interpret the results. Supplies to maintain analytical equipment may be required as well as personnel time to calibrate and operate the equipment.

The ruggedness of the equipment can be a factor when expensive sensors are involved. An estimate of the mean time to failure should be provided where expensive equipment is involved.

Physical cost considerations for a leak detection testing program can be separated into two categories, system modification costs and testing related costs. To prepare a facility for this type of technology testing, system modifications will most likely be required and could include the following:

- A basic or fundamental issue is the need to provide an absolutely pressure-tight piping system for testing. To accomplish this, a combination of line blinds, blind flanges, and double-block-and-bleed valves can be installed.
- The installation of block-and-bleed valves becomes a necessity in isolating segments of the piping system for testing an operational system. The cost of these valves can range from $4,000 for a 6-inch valve to $20,000 for a 20-inch valve. Additionally, if installed below grade the cost of a fiberglass pit or concrete vault must also be included.
- In all probability, certain piping modifications to facilitate the testing of leak detection technologies will be required. This could become a significant cost item dependent upon the extent of modification required. At MCI, for example, this represented an expenditure of more than $100,000.
- A series of miscellaneous items such as flow and/or pressure regulatory control valves to protect existing equipment, a dedicated and uninterruptible electrical power source of various voltages and various instruments, instrument valves, and measurement and monitoring equipment may be required. This could range from $1,000 to $20,000.
- The need to dispose of waste fuel and/or contaminated storm water can result from system modifications prior to testing. In such situations, a cost of $1.50/gallon can be anticipated.

Additionally, if an operator wants to independently evaluate a technology, the costs associated with field-testing of technologies could include the following:

- As the testing of each technology will take between 2-4 hours per night for a 7-10 day period, a field trailer for personnel and electronic equipment is a necessity. This rental cost can range between $100 to $150 per month.
- To facilitate a special one-time testing need, it may be necessary to rent unique instrumentation devices or system components. One such example would be an ultra-sonic flow measuring, monitoring, and recording device at a cost of $100 - $150 per day.
- For the most part, the components associated with this type of leak detection technology are notebook computers, portable printers, software programs, electronic signal integrators, and small instruments. However, certain technologies utilize skid-mounted components, which may require renting a crane, boom truck, and/or high loader to unload, set, and reload the equipment. The cost of this varies widely depending upon the amount, size, and location of equipment.
- In the event the individual or company administering and managing the testing is not a third party independent testing company, test/leak measurement and monitoring equipment must be rented. This cost could range from $1,500 - $2,000 per day, including the cost of an operator.

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E. Operational Considerations

Prior to evaluating the performance of installed technologies, a thorough understanding of the operational characteristics for both the facility system and the technologies must be ascertained. Items of importance are as follows:

- Conduct a baseline test of the system's normal daily performance for several days to document bulk modulus, operating pressures, flow rates, operating cycles, temperature effects, and system anomalies.
- Determine the window of time wherein the technologies can be tested without impacting operations and, conversely, when operations will not impact the testing.
- Enure an adequate supply of fuel to a consistent specification is available for testing.
- The characteristics of fuel within a tank, vessel, or piping system are sensitive to ambient temperature and solar changes; therefore this must be carefully monitored for comparison to test results. Different fuel types may have different performances.
- Small, entrapped pockets of air within a piping system are not unusual in airport hydrant fueling systems; however, reasonable efforts should be made to minimize these conditions. A calculation should be made prior to testing to quantify the amount of air in the system.
- Hydraulic surge absorbers are sometimes installed in airport hydrant fueling systems to minimize surge pressures created by the instantaneous closing of hydrant pit valves. To test some leak detection technologies properly, these must be isolated or removed from the piping system during the test.
- Extraneous noise is an issue when testing acoustical technologies. At airports, where aircraft engine noise is present throughout the day and aircraft auxiliary power units run throughout the night, a window of quiet time, if available, must be identified.
- Operational considerations also include determining the amount of time required to set-up the technology equipment, calibrate the equipment, and perform validation runs. This can range from a few hours to a few days depending upon the circumstances and the technology.
- The amount of information gathered during the test for evaluation and statistical analysis is determined by the procedure and protocol written specifically for each technology as applied to the site and system. These should be developed early in the program and shared with the vendor to help determine the goals and objectives.
- A key element in the operational characteristics of field-testing leak detection technologies is inducing a controlled leak that is defined and documented for comparison later with the technology performance. The leak signal must be consistent for the technology under evaluation.

F. Assessment of Vendors' Claims

An important key to selecting a leak detection method is the ability to assess the credibility of the vendor's claims or advertising. This process can begin by checking that the leak detection method has the required key features for the facility where it is to be used. For the technologies tested in this project, the key features can be reviewed in the tables presented in section VI-G. These tables also provide performance estimates based on the testing conducted during this program.

Other information may be available from the vendor. Some leak detection technologies have had an independent evaluation by a third party. When considering a leak detection method, the facility operator should ask the vendor if there is an evaluation by an independent third party. If so, the vendor should supply a copy of the complete report for the facility operator to review. Such a report should provide information on the conditions when the leak detection technology is applicable and the performance to be expected.

As part of the decision, the facility operator might require a demonstration or validation test of the leak detection equipment. This should be conducted under conditions typical of the facility's operations. Ideally an independent third party, usually hired by the facility, would conduct the demonstration or validation test. The vendor and the facility operator should agree upon the test procedures in advance of testing.

Once the technology is installed, its performance and operation should be periodically checked. This can be done by occasionally simulating a leak of the appropriate size to demonstrate that the leak detection method is functioning and can reliably detect the leak.

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G. Combining Technologies Effectively

Technologies based on different physical principles are subject to different sources of interference. Consequently, they may be combined to produce a more reliable result than a method based on a single principle. For example, a leak detection method based on monitoring pressure might be combined with another based on acoustic principles. The pressure-based technology might detect the leak and the acoustic technology might then be used to find the leak.

A combination that is often employed is to monitor the pipeline with a pressure-based leak detection method. If that method indicates a leak, tests are repeated to confirm the result. If the confirmatory tests still indicate that a leak is present, a chemical marker method may be employed to definitively confirm the existence of the leak and determine the location for excavation and repair.

Since leak detection methods based on different principles are affected by different sources of interference, similar results from two or more different technologies provide strong evidence that the result is correct.

H. Using Multiple Tests

Repeated tests using the same leak detection method are also valuable. A test result that indicates a leak may be confirmed by a subsequent test, particularly if the indicated leak is relatively small. Unusual or severe temperature or other ambient conditions can sometimes produce a false alarm. Repeating the test under better conditions may indicate that the result was a false alarm. Certainly, replicating the test result that indicated a leak is a cost-effective way to guard against false alarms. This should be used with judgment, since a catastrophic failure should not be ignored. However, generally catastrophic failures are easy to detect and confirm. The importance of leak detection is to find small to moderate leaks before they result in a substantial loss of product or contamination. For these types of leaks, requiring a confirmatory test to rule out false alarms is sound practice.

I. Testing Strategy

Just as all leak detection technologies are unique in characteristics, the testing of these technologies is also unique. The following represents a list of items that could be considered in developing a strategy for testing future leak detection technologies for API and ATA piping systems:

- Conduct a thorough desk-top analysis of the technology under consideration to determine the probability of applicability and performance. A screening matrix as presented in Section III of this Guide could be utilized.
- Develop a testing procedure, schedule, and protocol specific to the technology as applied to the system piping.
- To optimize the length of individual tests and to minimize the impact of pressure deviation due to temperature changes, a majority of the technology testing may need to be performed at night. For airport hydrant fueling systems, this is between 11 p.m. and 5 a.m.
- In the event there is a significant change in elevation of the piping between the ends of the system, i.e., the tank farm to terminal apron in the case of MCI, the technology vendor must acknowledge this difference and calibrate the equipment accordingly.
- As stated earlier, the presence of entrapped air and surge absorbers must be taken into account if either or both cannot be removed from the system during the testing period.

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GLOSSARY

Accelerometer: A device that measures the change in velocity or acceleration of an object. As used in this context, the device measures the accelerations produced by liquid flowing through an orifice or leak in a certain frequency range as acoustical energy.

Acoustic: Pertaining to sound; in the context of this booklet, pertaining specifically to the propagation of sound waves caused by pressure fluctuations.

Acoustic Signal: A transient elastic wave generated by a rapid release of energy due to some structural alteration in a solid material; for example, the wave produced in a fluid-filled pipe or tank as liquid escapes through a small hole in the bottom.

Aircraft Fuel Servicing: The transfer of aircraft fuel into an aircraft.

Aircraft Fuel Servicing Hydrant Vehicle: A vehicle, sometimes referred to as a hydrant cart, equipped with the components and devices to facilitate the transfer fuel between a fuel hydrant and an aircraft.

Aircraft Fuel Servicing Ramp or Apron: An area or position at an airport used for the fuel servicing of aircraft.

Airport Fueling System: An arrangement of aviation fuel storage tanks, pumps, piping, and associated equipment, such as filters, water separators, hydrants and station, or aircraft fuel servicing vehicles, installed at an airport and designed to service aircraft at fixed positions.

Algorithm: A set of mathematical steps devised for the solution of a specific problem.

Ambient Noise: The level of noise normally present in the environment (see "noise").

Aspiration Probe: a means of monitoring the soil around and under a tank using tubes that have been installed under the tank. A vacuum system is set up so that air flows through the tubes in a given direction, and samples of this air are taken to determine the presence of specific compounds.

Backfill Material: The material placed around buried tanks and piping systems, usually a sand or granular material that forms a porous boundary between the tank or piping and the surrounding soil.

Bias: The difference between the expected or predicted value of a given parameter and its true or actual value.

Burst Pressure: The pressure at which a component ruptures.

Cathodic Protection: A corrosion protection system installed to protect metallic surfaces in contact with soil or other conductive medium. Cathodic protection systems can either be in the form of a series of sacrificial galvanic anodes or an impressed current rectifier system, which are connected to the buried piping, buried tanks, or aboveground tank bottoms.

Chemical Marker: A compound added to the product in a tank and used as the target substance in a soil-vapor monitoring test (see also "tracer").

Coefficient of Thermal Expansion: A material specific constant used to calculate the dimensional changes of a material due to a change in temperature.

Dead Legs: A section of unused liquid-filled petroleum piping that branches off the main pipe. Dead legs are often the inadvertent result of piping system alterations.

Detection Criterion: A predetermined set of characteristics used to distinguish the leak signal from noise (see also "threshold").

Differential Pressure Sensor: A device for measuring the difference in pressure between two locations or points.

DP Cell: See "differential pressure sensor."

Dry Break Coupler: A device installed in fueling hoses and piping systems to facilitate the coupling and uncoupling of components and to prevent fuel spills in the process. Typically a two piece or mating component installation, the dry break coupler is manufactured with a lever operated – spring loaded poppet to seal off fuel flow.

Emergency Fuel Shutoff: A function performed to stop the flow of fuel in an emergency.

Facility: Refers to the physical property, equipment, buildings, structure, pipelines, or other physical features associated with aboveground storage tanks referred to in this report.

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False Alarm: A term denoting that a leak detection test has indicated a leak when in reality none exists.

Filter Separators: A filter separator is a two stage vessel designed to remove water and dirt from aviation fuels. The filter is the most common fuel quality control device found in aircraft fueling systems. Filter separators are normally installed in the fuel system prior to entering storage tanks, and on refueling vehicles and hydrant carts prior to fueling the aircraft.

Flow and Pressure Control Valves: Flow and pressure control valves maintain and/or limit fuel flow rates and pressure settings to satisfy operational requirements.

Fuel Distribution System: A system or network of piping connecting multiple fuel storage facilities together, or the connection of fuel storage facilities to hydrant systems. A fuel distribution system is normally sized to serve the fuel demand of the entire airport.

Gas Chromatograph: An instrument that detects the presence of volatile compounds. It can be used to determine the distribution of vapor concentrations.

Histogram: A graphical representation of a frequency distribution by means of contiguous vertical rectangles whose widths represent the class intervals of a variable and whose heights are proportional to the corresponding frequencies of this variable.

Hydrant Carts: A non-licensed vehicle designed to be the interface device between the fixed hydrant fueling system and the aircraft. Hydrant carts normally have a _ to one-ton truck chassis with fuel components mounted on the rear. Fuel components include: piping, valves, meters, filter separators, control devices, and hoses. Lift platforms are also provided on some hydrant carts to gain access to the fuel connection on wide body aircraft where the connection point is 15-17 feet above the apron.

Hydrant Pit Assembly: An assembly manufactured for the purpose of serving direct aircraft hydrant fueling operations. The hydrant pit is located in the aircraft apron and is of either steel or fiberglass construction. A cast aluminum cover on top of the pit to provide access to internal components is structurally rated for aircraft wheel loads. The pit assembly includes a hydrant valve to control flow and pressure, a strainer to prevent any debris from entering the hydrant valve and, normally, an under hydrant shut-off valve to isolate the pit assembly for maintenance.

Hydrant System Pumps: Hydrant system pumps are located in the fuel storage facility to provide a direct supply of fuel to the aircraft gate position. Hydrant system pumps operate at a pressure in the range of 150-200 psi.

Hydrant Valve: An outlet of an airport fueling system that includes a deadman-controlled valve and adapter assembly to which a coupler on a hose or other flexible conduit on an aircraft fuel servicing vehicle can be connected.

Hydrophone: A device that, when submerged in liquid, receives sound waves and converts them into electrical impulses.

Hydrostatic Head: The amount of pressure, measured in feet of liquid, exerted by a liquid.

Into-Plane Fueling Servicing: Into-Plane Fuel Servicing is an operation where fuel is pumped into the aircraft while parked at the gate or apron position. In this operation, fuel is transferred from either a hydrant system or refueling vehicle into the aircraft fuel tanks. The into-plane servicing is a physical connection of one or more hoses to the fuel service port on the aircraft.

Inventory Control: A method of monitoring tank integrity by keeping detailed records of all additions and withdrawals of liquid, while at the same time making accurate and regular measurements of the level of liquid in the tank. Over a given period, the change in level should reflect the amount of liquid added or withdrawn. Discrepancies between the two are interpreted as being indicative of a leak.

Jet A: A grade of aviation fuel commonly utilized within the United States as a fuel source for turbine (jet engine) powered aircraft. Jet A is a kerosene-based fuel manufactured under the American Society of Testing Materials (ASTM) Specification D-1655, and is classified by the National Fire Protection Association (NFPA) as a Class II Combustible Fuel, with a flash point between 100-140 degrees Fahrenheit.

Leak: An unplanned or uncontrolled loss of product through a hole, crack, or fissure in a containment structure such as a tank or a pipe.

Leak Detection Method (As opposed to a “leak detection technology”): An approach based on a specific device, usually following a certain protocol, operated by a vendor, to conducting a leak detection test. Different methods can be based on the same technology.

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Leak Rate: The quantification of a leak in terms of the amount of liquid that escapes during a given time; usually expressed in gallons per hour.

Leak Detection Technology: (As opposed to a "leak detection method") A general approach for conducting leak detection tests.

Leak Detection Test: The exercise of a set of steps to determine the integrity of a tank. A test can involve the use of some physical device, or leak detection, which is based on certain operational principles (that is, a leak detection method).

Liquid Release: The abnormal discharge, spill, leak or release of liquid petroleum products outside their primary containment system.

Marker: A chemical compound, not found in nature, used as the target substance in a soil-vapor monitoring test. A marker can be a substance that occurs naturally in the product or one that has been added to it, as long as it is not present in the environment outside the piping system.

Mass Measurement: A method of leak detection based on measurements of the pressure exerted by the liquid in a tank.

Measurement Technology: In the context of this publication, a term used synonymously with "leak detection technology," because the latter relies on some type of measurement in order to detect a leak.

Minimum Detectable Leak (MDL): The smallest leak that can be reliably detected. It depends on the threshold used and the probability of detection desired.

Missed Detection: A term denoting that a leak detection test has failed to identify an existing leak.

Multiple-Test Strategy: An approach in which the declaration of a leak is based on more than one test. For example, if Test #1 indicates a leak, Test #2 must be conducted and must also indicate a leak before a piece of equipment is taken out of service.

Noise: A component of a signal which is typically random in nature and not directly attributed to changes in the variable being measured.

Performance: The reliability of a method or technology in detecting leaks, usually expressed in terms of probability of detection and probability of false alarm at a given leak rate.

Petroleum Product Terminal: A petroleum facility where fuel is stored in aboveground fuel storage tanks and distributed by means of a pressurized piping system. Also, a facility located adjacent to or on airport property where aircraft fuel is stored in large quantities. A fuel reserve of over 3 days consumption is normally stored.

Pressure/Flow Control System: Defined as automatic hydrant and refueler systems controls, the pressure/flow control scheme is an electronic (PC computer-based) logic network to control flow to a hydrant system or refueler loading facility. This is a system where constant pressure is maintained and a loss of pressure is recognized when the deadman control on the hydrant cart or refueler loading valve is opened. The pressure/flow control system responds to a loss of pressure and starts system pumps in the fuel storage facility to satisfy the demand. As the demand is satisfied the control system stops system pumps and the system pressure is stabilized in a no-flow condition.

Probability of Detection: The likelihood that a test will detect an existing leak; expressed as a percentage; inversely related to the probability of false alarm.

Probability of False Alarm: The likelihood that a test will find a leak where none exists; expressed as a percentage; inversely related to the probability of detection.

Probability of Missed Detection: The likelihood that a test will not find a leak even though one exists; expressed as a percentage.

Probe: A means of monitoring the soil around and under a piping system using tubes that have been installed under the tank. Air migrates through the tubes to an outlet point, where samples of this air are taken to determine the presence of specific compounds.

Product: The liquid contents of a piping system; for example, a petroleum product.

Reconciliation Period: When inventory control techniques are used as a means of leak detection, the reconciliation period refers to the period of time during which measurements of inflow and outflow are made. (A leak is suspected when measurements made by a tank gauge do not reconcile with those made by a flow meter.)

Release: In this booklet, a term used synonymously with "leak."

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Residual Noise: Noise that is still present in the data after noise cancellation or compensation algorithms have been applied.

Signal: An identifiable phenomenon that is produced by and is indicative of a leak. The nature of the signal is a function of the leak detection method being used; depending on the method, the signal can be, for example, an acoustic wave, a fluctuation in product level, a concentration of a certain chemical compound, or a number of other phenomena.

Signal-Plus-Noise: A value represented by a linear addition of the amplitude of the signal to the amplitude of the noise.

Soil-Vapor Monitoring: A method of leak detection in which a chemical compound that is not found in the environments, but that is either added to or naturally present in the product, serves as a target for detection; the principle being that any concentrations of this vapor found outside the tank are indicative of a leak (see also “probe” and “aspiration probe”).

Standard Deviation: A statistical parameter used to quantify the precision of a measurement set that obeys a normal distribution (bell shaped curve). As normally applied, it is used to determine the error that can be assigned to a measurement and the corresponding percent of measurements that will fall within this percent of error.

System Noise: The noise produced by a leak detection technology’s instrumentation; for example, level gauges or differential-pressure sensors; usually associated with the accuracy of the measurement technology (see also “threshold”).

Test Pressure: The pressure to which a system or a component of a system is subjected to verify the integrity of the system or component.

Thermal Expansion or Contraction: A temperature-induced change in the volume of product within the piping system.

Threshold: A predetermined value that is the basis for declaring a leak. Data points that fall within the threshold setting are considered noise, whereas those that exceed the threshold are considered indicative of a leak (see also “system noise” and “detection criterion”).

Time Series: A measurement of the amplitude of a signal at regular intervals in time.

Transducer: A device that converts an input signal based on one kind of energy into an output signal based on another kind; in the context of this booklet, a device that converts sound waves into electrical signals.

Volume: The quantity of liquid contained in a piping system, usually expressed in gallons.

Volumetric: A method of leak detection based on measurements of the level of liquid in a tank which are then converted to volume. Measurements that exceed the fluctuation levels considered normal for a non-leaking tank are indicative of a leak.

Working Pressure: The maximum allowable pressure, including momentary surge pressure, to which a system, hose, or other component can be safely subjected while in service.

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