REMOTE CONTROL SPILL REDUCTION TECHNOLOGY:

A SURVEY AND ANALYSIS OF APPLICATIONS FOR LIQUID PIPE-LINE SYSTEMS

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Chapter 1: Introduction

Between 1988 and 1994, the Office of Pipeline Safety (OPS) received 1401 reports of hazardous-liquid spills on U.S. pipelines in which operators claimed a total of 1.2 million barrels of lost product and $220 million in property damage, as well as a number of injuries and fatalities (USDOT/RSPA 1995). This report summarizes a Volpe Center study of the potential for Supervisory Control and Data Acquisition (SCADA) systems to help the operators of hazardous liquid pipelines reduce these losses and damages.

As explained more thoroughly in Chapter 2, a SCADA system can give pipeline dispatchers the ability to effectively monitor pipeline conditions and control a pipeline's operation from a central location. SCADA systems broadly include pipeline sensing devices, a communications network, a centralized or distributed data processing system, and a user interface for the dispatcher. Remotely operated pipeline control devices may be operated through the control room user interface.

Remotely operated devices include pumps, pressure regulators and some *Emergency Flow Restricting Devices* (EFRDs). EFRDs (see Section 3.4) are remotely controlled or automatic valves that are placed along a pipeline. EFRDs partition the pipeline into segments and can be used during an emergency to cut off the flow to any pipeline segments that are damaged. The Pipeline Safety Reauthorization Act of 1988 (Public Law 100-561) required the OPS to examine the need for EFRDs in existing and future hazardous liquids pipelines:

(1) SURVEY AND ASSESSMENT - The Secretary shall, within 2 years after the date of the enactment of this subsection, survey and assess the effectiveness of emergency flow restricting devices (including remotely controlled valves and check valves) and other procedures, systems and equipment used to detect and locate pipeline ruptures and minimize commodity releases from pipeline facilities.

(2) REGULATIONS - Not later than 2 years after the completion of the survey and assessment required by paragraph (1), the Secretary shall issue regulations prescribing the circumstances under which operators of hazardous-liquids pipeline facilities must use emergency flow restricting devices and other procedures, systems and equipment described in paragraph (1) on such facilities.

Given this 1988 directive, the OPS conducted a study on the potential for EFRDs to minimize the volume of pipeline spills. They concluded that *Remote Controlled Valves*

(RCVs) and check valves are the only EFRDs that are effective on hazardous liquids pipelines. They also found that RCVs could not function successfully without a *Supervisory Control and Data Acquisition* (SCADA) system or an independent, software-based *Leak Detection System* (LDS) (USDOT 1991).

SCADA and LDS can improve the dispatchers' ability to detect and locate leaks on pipeline systems, and thus improve their potential to reduce the damages from pipeline accidents. However, many industry experts question the maturity and reliability of this technology. Thus, the imposition of Federal regulations requiring a SCADA or software-based leak detection system was controversial.

This study has three objectives:

- To investigate current SCADA, LDS, and EFRD systems, and to identify their performance measures.
- To investigate the effect of SCADA, LDS, and EFRD performance measures on their potential for reducing the hazard to the public and environment posed by pipeline spills.
- To investigate the feasibility and cost to liquid pipeline operators of SCADA, LDS, EFRDs, and to report on the progress of liquid pipeline operators in adopting and implementing these systems.

To carry out this study, information about SCADA, LDS, and EFRD systems was obtained. Six LDS vendors were contacted for feature, price, and performance information about their systems, and published information on pipeline company experience with vendor and in-house developed systems was collected. Representatives of pipeline companies, including hazardous liquid and natural gas, were interviewed. Seven pipeline companies were visited, allowing on-site examinations of pipeline operations, and discussions with company executives and dispatchers about their field experience with spill reduction technologies. In total, the pipeline companies interviewed for this study operate over 27,000 miles of pipeline, of which approximately 25,400 miles is hazardous liquid pipeline and 1,600 miles is gas pipeline. This represents 16% of the total hazardous liquid pipeline mileage regulated by OPS and 0.6% of gas pipeline miles.

Information about pipeline spills was collected to gain a better understanding of the phenomenon these systems are trying to bring under control. The literature was searched for existing analyses on pipeline spills and spill prevention measures. OPS liquid pipeline accident reports, and pipeline accident reports filed by the *National Transportation Safety Board* (NTSB) were analyzed. This work is summarized in Chapter 4.

Utilization models for EFRDs and LDS/SCADA systems were developed to address the priority of these approaches to spill reduction. When possible, these models were evaluated with data from liquid pipeline accident reports.

Chapter 2: An overview of the liquid pipeline industry

2.0 The liquid pipeline infrastructure

Almost all of the petroleum feed stock and products used in the United States are, at some point, transported through a Federally regulated pipeline. The OPS, part of the Department of Transportation's Research and Special Programs Administration, regulates essentially all of the approximately 155,000 miles of hazardous liquid pipelines in the United States, as well as the approximately 255,000 miles of gas transmissions lines.

Crude petroleum liquids and gasses are transported from the well head by about 250,000 miles of gathering lines that join to larger transmission or trunk lines that carry crude petroleum to the refinery. OPS has jurisdiction over 32,000 miles of gathering lines. Refined liquids and products, such as gasoline, kerosene, fuel oil, and jet fuel are transported thousands of miles throughout the United States in product pipelines. Efficient long distance transport by pipeline requires high operating pressures, typically 500-1200 psi. *Liquefied Petroleum Gasses* (LPGs) such as propane, butane, and their mixtures, are usually liquids under normal line operating pressures, so the pipelines transporting them are classified as liquid lines. Pump stations are needed on liquid lines at intervals of about 50 to 70 miles, depending on pump output pressure, line friction, and elevation changes. Storage structures, such as tank farms for liquids and, increasingly, underground salt caverns for propane, are also used as buffers in transmission network operations and at distribution points of contact.

2.1 The safety record

The Federally regulated pipeline system has consistently improved its safety record over the last 25 years. Our analysis of OPS liquid pipeline incident reports over the last 25 years shows at least a 50% reduction in the accident rate. The rates are presently several times higher for railroad tank cars and trucks (Transportation Research Board 1988). However, there are still about twenty large (1000 barrels or more) spills on the OPS regulated liquids lines each year. Large crude and other viscous product spills are difficult and expensive to clean up. Lighter products, such as gasoline and *Highly Volatile Liquids* (HVL), pose less of a cleanup problem, but the risk of fire and explosion can be significant.

Much of the improvement in the pipeline safety record over the last 25 years has resulted from technical developments outside the scope of this report, such as those in pipeline components, construction, inspection, and corrosion control. Corrosion was replaced by third party damage as the number one cause of pipeline accidents around 1980.

2.2 An overview of SCADA

SCADA systems continuously monitor, transmit, and process pipeline information for the control room dispatcher. Monitoring is conducted using *Remote Terminal Units* (RTUs), which are placed at intervals along the pipeline and at associated facilities, such as pump stations and delivery terminals. RTUs periodically collect data from field instruments, which measure pressure, temperature, flow, and product density. RTUs can also receive information from vapor detectors and tank level gauges in pipeline system routing and storage areas. RTUs process this information to varying degrees and transmit it for analysis to a central computer through a communications network. Information from RTUs may be transmitted by company owned lines, by a commercial telephone service, or by using ground- or satellite-based microwave or radio communication.

Two important performance measures of a communications system are its reliability and the system's *polling rate*. The *polling rate* is the frequency with which updated RTU data is made available to the central computer. More, and more frequently updated, information can improve the performance of any pipeline model for both LDS and non-LDS functions. The *polling rate*, or the time between successive communications between RTU and master station, has been improving steadily over the years. Many companies have reduced their system wide polling rates to below two minutes, and to below two seconds in high priority areas. *Smart RTUs* can preprocess field instrument readings to enhance performance and to reduce communication requirements.

A pipeline's geographic expanse, its local terrain, and the type of information used to model it are important in designing an effective communications network. For instance, some networks are centralized around a *master station* that is linked to a satellite in geostationary orbit that is positioned for direct communication with all the RTUs, even if they are spread across several time zones. Control room computers receive RTU data, further analyze it, and display pipeline conditions for the dispatchers. Dispatchers can, in turn, quickly respond to the pipeline system over the same communications network by remotely controlling valves, manifolds, pressure regulators, and pumps.

The leak detection capabilities of most SCADA systems can be enhanced with additional leak detection software and user interfaces. Field instruments specifically designed for leak detection are also available for SCADA systems, such as acoustic sensors and hydrocarbon sensing cables (see Chapters 3 and 5).

2.3 Industry trends and SCADA

SCADA systems offer pipeline operators many benefits besides leak detection. They enable operators to route product in separate batches through their crude and products lines, allowing them greater flexibility in meeting the needs of their customers. SCADA systems can also measure fluid properties at field sensor locations, which can allow a more responsive control of the pipeline for improved safety and efficiency. Many pipeline company officials interviewed indicated that these factors are driving their investment in SCADA more than the economic benefits of reduced accident rates.

Throughout this century, the pipeline industry has been shaped by the economic advantages of larger diameter lines. A pipe's resistance to flow and the energy costs for moving product a given distance decrease enormously as the pipe's diameter increases. The implications of this principle for the industry are stated in a U.S. Department of Energy policy study (DOE 1980).

> Since significant economies of scale in pipeline services can result if the pipeline is large enough (which depends on a sufficiently large potential throughput of oil), and because the major oil companies are located at both ends of a pipeline (i.e., they produce crude oil and also refine it), it is not surprising that the major oil-producing companies are also the ones which build and operate the pipelines.
>
> Furthermore, because of the potential for great economies of scale, there is a tendency for several companies to engage in joint ventures in constructing pipelines, thereby constructing a larger diameter pipeline and achieving transportation at a lower cost than each of them could by acting separately.

Instead of using many smaller lines, it is common today for some liquid pipelines to carry several batches of different products in succession in a larger diameter pipeline. A sophisticated pipeline monitoring and control capability is required to allow each batch to have different system entry and exit points.

The point on the pipeline where two batches of different products contact each other is known as the batch interface. Sometimes a sphere, or *pig*, is placed in the line between batches to limit mixing, but inserting and removing these devices is often impractical. Often, the products in adjacent batches are allowed to contact each other, and the product in the interface region (sometimes referred to as *transmix*) is diverted for reprocessing. Batched products mix less during transport if they are maintained at a high, steady pressure. This can be done while products are flowing through the system by dynamically adjusting pressure regulators to minimize flow irregularities that cause mixing. Some operators close their RCVs when they halt the line flow to maintain pressure in each segment.

Remotely tracking the batch interface can be done with the same accurate and timely line metering and monitoring techniques that are used for leak detection. Independently routing each batch from the control room requires RCVs and other remotely controlled devices. Thus, operators in competitive markets rely on SCADA systems for remote pipeline monitoring and on remote control devices to enhance dispatcher control. The efficient and flexible transport of multiple batches on modern transmission lines is a primary incentive for operators to acquire state-of-the-art equipment that can serve as the foundation for a remote control spill reduction capability.

Chapter 3: SCADA and leak detection

3.0 Introduction

SCADA systems may be used for leak detection, or they may provide the computational and instrumentation support for a leak detection system (LDS). An LDS also may operate independently of SCADA. The techniques used for leak detection cover a wide range of sensing and computational methods.

3.1 SCADA supported leak detection methods

Leak detection methods may be divided into two categories, direct and inferential. Direct methods detect leaking commodity outside the pipeline. Inferential methods deduce a leak by measuring and comparing the amount of product moving through various points on the line.

Direct leak detection is done the traditional way by line patrols who inspect the pipeline *Right Of Way* (ROW) for pools of leaking product and dead vegetation. Section 195.412 of the Federal pipeline safety regulations requires that hazardous liquid pipelines be patrolled 26 times each year. A new technology used for direct leak detection is chemical sensing cable buried along the pipeline right of way. Cable systems have been developed that can detect the presence and location of hydrocarbon vapors. Other cables locate leaks by absorbing liquids, which results in a loss in the cables' electrical conductivity at an identifiable location. Sensing cables can offer superior detection times, sensitivity, and location accuracy, especially in gathering lines, where the flows can be too irregular for other methods (Sperl 1991). These cables must be buried close to the pipeline to work well, and some liquid sensing cables must be dug up and replaced after every detection. New burying methods are being developed for these cables to lower their total operating cost.

The traditional inferential method of leak detection is called line balance, where one measures the volume of product sent into the pipeline and compares it with the volume that comes out the other end. Enhancements of this method and others are used by SCADA and LDS systems to provide the dispatcher with information that suggests a possible leak. The overlapping capabilities of LDS and SCADA have resulted in the in-house development of integrated SCADA/LDS systems by some of the larger pipeline companies. Independent vendors are also offering leak detection products that can exchange data with existing SCADA systems. The American Petroleum Institute is encouraging these vendors by developing a SCADA-LDS communication standard.

There are dozens of different SCADA-based LDS systems in use today, and new ideas are being implemented in the field every year. It is difficult to divide these products into categories, so instead we list four general methods that they use. Many systems today use a combination of methods to improve their sensitivity and to lower their false alarm rate. *Computational Pipeline Monitoring* (CPM) is a term used frequently in the industry to describe systems that use one or more of the following principles to monitor their operations and to perform leak detection.

1. **Product conservation.** The traditional paper and pencil *line balance* method is in this category, which detects leaks by using flow meters to measure and compare the volume of a batch of product on its way into and out of the pipe. Using line balance, one has to wait until the end of each batch run before a leak can be discovered. On many lines, it is not helpful to compare flow meter readings while the line is running. Even if there was no leak, the meters may not agree, since temperature and pressure differences along the line will cause the product volume to change.

   The automated version of line balance is called *Volume Balance* (VB), *Modified Volume Balance* (MVB), or *Mass Balance* (MB). RTU stations connected to pipeline flow, pressure, temperature and density measuring instruments are placed at several points along the pipeline. They transmit flow data, compensated for variations in product temperature, pressure, and specific gravity (on batched runs), to the master station at the system polling rate. Leaks may be identified during a run, and their location may be narrowed down to within adjacent RTU/field instrument stations. The performance of these systems is degraded by flow irregularities. The next method attempts to correct inaccuracies in the MVB method that are caused by irregular flow.

2. **Hydraulic modeling.** This is the most sophisticated method in use; names for it include *Pressure/Flow Deviation* (P/Q), and *Real Time Transient Modeling* (RTTM). A computer simulation of the flows along the entire pipeline is created from sensor information, using advanced fluid mechanics concepts. These systems send alarms to the dispatcher if the measured flow characteristics deviate from the computer prediction. Remarkably, this technique can also predict the location of leaks between sensors by calculating what might have caused the deviations between predicted and actual sensor values.
3. **Operational boundary checking.** Most systems need to monitor the pipeline during a training period to learn its typical levels and rates of change in pressure and flow. During operation, some systems will notify the dispatcher if they find conditions they did not encounter during their training period.
4. **Leak signal detectors.** Some systems using this method attempt to directly "hear" a leak by listening for sound waves transmitted through the fluid or pipe wall that occur

during rupture initiation. Several sonic detectors must be used for every mile of pipe because of signal attenuation. Other systems look for pressure waves or transients in the fluid caused by the rupture. Leak location can be inferred by using more than one detector and timing the arrival of the sound or pressure wave at different points along the pipeline.

3.2 Flow meters

Current “top of the line” turbine and positive displacement meters are accurate to within 0.02% of flow, although intrusive pipeline modifications are required for their installation. (Controlotron 1991) (Caldon 1992)

Some ultrasonic meters do not require the pipe to be cut during installation, and their performance is improving as the technology matures. They consist of pairs of ultrasound generators and ultrasound sensors that are mounted on the outside of the pipewall. These meters send ultrasonic signals through the pipe perpendicularly and at various angles to the flow. They can infer a number of fluid properties, including pressure and flow rates, by measuring how the speed and other properties of the signal are affected by the pipe. Recent field data on the performance of ultrasonic flow meters, such as the Caldon Leading Edge Flow Meter (LEFM), indicate accuracy comparable with turbine meters. (Smulski 1992).

3.3 Communications

Information from RTUs may be transmitted by company-owned lines, commercial telephone service, or by ground- or satellite-based microwave or radio communication. The polling rate, or time between successive communications between RTUs and the central computer, has been improving steadily over the years. Large companies using satellite communications are capable of system-wide polling rates of once every 20 seconds. Telephone lines and microwave transmissions can poll even faster. Some SCADA systems reduce their transmission requirements by partially processing information in the field with *smart RTUs.* Regardless of the medium, the polling rate can have a dramatic impact on the performance of some LDS systems.

3.4 EFRDs

There are three types of EFRDs: RCVs, *Check Valves* (CVs), and *Automatic Control Valves* (ACVs) .

RCVs can be activated from the control room during an emergency, once the dispatcher has enough information to determine which valves should be closed. CVs and ACVs respond automatically to pipeline conditions. CVs allow the product to flow in one direction only, thus reducing spillage from back-flow. ACVs are a simple LDS and an EFRD in one package: they close automatically when they sense anomalous pressure conditions that may be indicative of a leak. Fluid dynamics limit the ability of an ACV to respond to distant leaks or ruptures. Several ACVs must be strategically placed on each line segment to achieve adequate coverage. They cost several hundred thousand dollars each, even for smaller (diameter < 20 inch) lines, and operators are uncomfortable with relinquishing control of their lines to ACVs.

A valve's response time on liquid lines is limited by the potential of *fluid hammer*. Attempting to stop a twenty mile long column of fluid by suddenly closing a valve, such as an ACV, would create a potentially dangerous surge pressure. The minimum safe closure time can be as long as 30 minutes, depending on the fluid pressure and compressibility, the length of the fluid column, and the ability of the pipe to handle a pressure surge. (University of Texas 1993)

3.5 SCADA performance issues for leak detection

An Oppenhiem Research survey (Oppenhiem Research 1991) of liquid pipeline operators revealed a wide range in their opinions over the reliability and accuracy of SCADA based leak detection systems. The four most frequently reported problems with SCADA/LDS performance concerned:

- False alarms,
- Accuracy problems from poor input information,
- Difficulties with using the system during line startup and shutdown, and
- Program bugs and other startup complications.

1. **False alarms.** False leak alarms are frequent when a SCADA or LDS system is first installed. No system is truly off-the-shelf, and larger pipeline operators often collaborate with independent vendors to redesign their products for use on a company's pipeline system. As long as a year can be required to tune an LDS; that is, to reduce the false alarm rate to an acceptable level. Since the LDS makes new performance demands on field instruments, many faulty or inadequate gauges and sensors cause false alarms and are replaced during this period. False alarms can also be generated by interruptions in the communication system, as well as by small, regular deviations in line flow and pressure that accompany operational changes.

   Many of these problems cannot be entirely eliminated, so either the leak detection software must be sophisticated enough to distinguish them from true leaks, or the alarm threshold/leak detection performance tradeoff must be adjusted to prevent them from generating false alarms.

2. **Component performance.** The performance of a SCADA communications system and its field instruments is evaluated in three fundamental ways: reliability, measurement precision, and measurement frequency. Operators with satellite-based communications networks report high reliability and RTU polling frequencies as high as once every two seconds. RTUs with embedded computers can compensate for a few minutes without communication by storing their field instrument readings and sending them when communication is restored. Some of these *smart* RTUs reduce communication requirements by preprocessing their sensor inputs and sending less, but more informative, data.

   Field instrument accuracy is frequently monitored and usually calibrated semiannually. Field instruments must have high enough sampling rates to capture any brief disturbance in line conditions that may be indicative of a leak. The accuracy and sampling rates of contemporary, correctly operating field instruments do not seem to limit the performance of current SCADA-based leak detection systems. Some meters can detect the minute pressure waves in the fluid caused by outside disturbances such as passing traffic. Using these instruments, operators can distinguish between a truck and a plane passing near the pipeline by reading their outputs. Signal filtering technology can remove such noise from instrument readings, and it is an active area of research.

3. **Uneven flow conditions.** The performance of CPM type LDS is degraded by slack line conditions, or by transients, which are temporary deviations in a pipeline's operating pressure. Each condition results in sensor readings that could easily be interpreted as a leak. Unfortunately, these conditions can be pervasive on pipelines, inhibiting the effectiveness of the LDS.

   Sometimes lines are slack, or not completely filled with product, at the beginning of a run or where flow is going downhill in steep line sections in mountainous areas. Slack lines present a major problem for VB systems, since the pipes unused capacity cannot be accurately estimated with flow meters alone. The pressure waves used by pressure signal analysis leak detection systems are dampened in slack areas, which degrades their performance. At least one LDS vendor is attempting leak detection on alpine lines with slack areas by using hydraulic modeling techniques. However the vendor is aiming for minimum leak sizes and detection times that are several times larger than in non-slack areas (CALDON 1992, 1993), (Smulski 1992).

   Short duration transients are a routine part of pipeline operation. They accompany changes in pump, pressure regulator, and valve use. These transients, lasting seconds or less, may be caused by manifold changes or fluctuations in pump output. Short, severe transients can result from operational errors, such as starting up a line that contains air gaps. Finally, transients are caused by a leak itself, which can be a problem for leak detection when they resemble other system transients.

Under normal operating conditions, surges have limited effects on pipeline integrity. OPS regulations require pipeline controls that constrain positive transients, or surges, to peaks below 110% of the lines maximum operating pressure (lines are hydrostatically tested to at least 125% of their maximum operating pressure). (49 CFR 195.300)

Longer transients are generated during routine changes in line flow rate. The typical duration of a transient of this type could be 20 minutes or more. This is equal to the minimum time required to safely change the flow rate at a typical operating pressure (600 psi), which is about 5 seconds times the line length (in miles) times the change in flow rate (in feet per second). To illustrate, consider starting a pipeline “run” with a filled 40 mile segment at operating pressure, and bringing the flow rate up from 0 to 5 feet per second. This would require 20 minutes. Isolating this segment in the middle of a run with a block valve would also require 20 minutes.

A simple VB or MVB method may not work satisfactorily while a transient is moving through the line, and the performance of hydraulic modeling, operational boundary checking, and leak signal detector methods of LDS will be degraded. More advanced hydraulic modeling systems must accurately model line dynamics during startup and all other operational changes that produce transients before they can attempt to do leak detection while transients are in the system.

Chapter 4: Vendor LDS reviews

4.0 Introduction to LDS descriptions

The pipeline industry is highly diverse in its products, markets, operating environments, and consequently, leak detection system requirements. The leak detection industry has responded to this need with a diverse range of products. The following system descriptions, including vendor-specific information, provides an overview of LDS system techniques and costs. Some of the information on these systems was gathered by Volpe Center staff during on-site visits with vendors; other information was compiled from literature provided by vendors or appearing in trade journals.

4.1 Direct leak detection systems

These systems use sensors to detect hydrocarbon liquid or vapors when they leak from the pipeline. Liquid sensing cables are buried along the pipe and lose their electrical conductive properties when they absorb hydrocarbons. When the cable fails to conduct electric current, an alarm is sent to the dispatcher. Gas detecting systems use a gas permeable hollow tube buried along the pipeline. The air in the tube is periodically pumped through a vapor detector, which will initiate an alarm if it detects hydrocarbon or other vapors associated with a leak. These direct systems are distinguished by their superior sensitivity, as well as their high cost per foot to install and maintain.

These systems must be buried below-ground along the pipeline and are therefore inapplicable to above-ground pipelines. Cable cannot be reused after it has absorbed a hydrocarbon and issued an alarm; it must be excavated and replaced. In addition, these systems are unable to distinguish between the sources of the liquid, as they detect the liquid after it is released. For example, crankcase oil dropped on the ground near a cable could cause an alarm.

Currently, the cost of hydrocarbon sensing cables ranges from about $5 to $12 per foot installed. The accompanying hardware is required for each 1,500 feet of cable, and it costs between $10,000 and $20,000. Costs for a gas diffusion system are about $3 per foot for the sample tube, $20,000 for the vacuum pump and gas detector, and another $10,000 for the computer and additional equipment. A connection to a SCADA system (or independent computer system) is recommended for long-line installations.

4.1.1 PermAlert

Independent performance evaluations conducted by Carnegie Mellon Research Institute (Carnegie Mellon Research Institute 1991) demonstrated that the PermAlert cable sensor, liquid contact, leak detection system can detect leaks of around 100 ml of fluid (diesel fuel, unleaded gasoline, and water) within 6 to 22 minutes. On average, the leak location was accurate to within 0.36% of the test length.

4.1.2 Teledyne

A Teledyne Leak Alarm System for Pollutants (LASP) was installed during the fall and winter of 1989 on 10 miles of the 17-mile on-shore segment of the Chevron Point Arguello natural gas pipeline in California. The total cost for the ten mile LDS reached 5 million dollars, although Chevron officials estimate that half of that money could have been saved had it been installed during pipeline construction. Chevron also developed a gopher resistant casing for the sensor tube and made other design innovations in the system to meet the County of Santa Barbara's requirements that it be able to detect and locate a leak from a ½ inch hole in the line within 30 minutes. Chevron's initial experience with the system suggests that its sensitivity greatly exceeds the county's requirements. Many of the false alarms generated during the first year were traced to very small third party hydrocarbon sources, such as PVC glue used to repair nearby water lines. The false alarms were reduced to a satisfactory level by lowering system sensitivity (Sperl 1991).

4.1.3 Tracer Research Corporation

The Tracer system was tested by Ken Wilcox Associates in September 1991 for compliance with U.S. Environmental Protection Agency (EPA) requirements for evaluating software-based leak detection methods related to "non-volumetric tank tightness." Wilcox Associates' analysis of one application showed one false alarm in 34 tests. The corresponding probability of detection of a 0.005 gallon per hour leak is 97.1%. The detection time required for the tested configuration is at least 14 days, which is equal to the time needed to collect samples from the vapor probes. (Wilcox 1991).

4.2 Pressure signal analysis systems

Acoustic wave and pressure wave detection systems operate on the principle that a rupture—a rapid release of fluid—causes a pressure rarefaction wave that propagates through the fluid in both directions at a fixed speed (equal to the speed of sound in a fluid). When the speed of transmission and propagation is known and very accurate time-measuring devices are used, detection of the exact times of arrival of the pressure waves at measuring points can be used to calculate the volume of the leak and identify its location.

The success of an acoustic wave detection system depends on the frequency of acoustic transmission measurements and the system's ability to determine celerity, which is the true speed of sound in the fluid. Celerity is a function of variable commodity characteristics, such as viscosity, specific gravity, and temperature. Therefore, it must be constantly measured. Under stable conditions, a system can be sensitive to very small leaks associated with ruptures and can identify the location of a leak within a few hundred feet of the actual location. Acoustic wave systems provide very rapid response time and are not limited to single-event detections (as are direct sensing systems). Acoustic wave detection systems can be used on natural gas, gas products, and petroleum lines.

Like wave detection systems, pressure signal analysis systems detect changes in pressure associated with ruptures. Pressure measurements are stored and compared statistically to each other and to an *a priori* distribution to establish a standard against which to measure deviations. These analyses provide deviations from a recent baseline pressure measurement taken by a near-real-time software-based leak detection system. The baseline measurements and deviations are determined by frequent scans at 60-minute intervals; a completely new baseline is established at the end of each interval. The system detects leaks by continually monitoring raw data from pressure transducers on the pipeline.

When a measurement deviates significantly from either the historical series or the assumed distribution, a sequence of leak alarms is issued. Ruptures resulting in large leaks are, therefore, relatively easy to detect instantaneously. Smaller leaks take longer to detect, and some very small, pinhole leaks go undetected.

Pressure signal analysis systems based on single-point measurement do not provide leak location. However, systems are now available that use more than one measuring device that can locate leaks. These systems can be augmented by a metering system, such as a volume balance system, to verify the existence of leaks and to enhance their location capability. Volume balance systems require metering on each segment of pipe.

Wave detection technology may be hampered by the presence of repetitive pressure transients, such as those that occur with "oscillating pressure regulating valves, pumps operating from empty tanks, etc." (Klein undated) This problem might be diminished in some cases by more sophisticated software applications. Additionally, systems using this technology would probably not detect a pinhole-size *seepage* or corrosion leak because the released material would not create a pressure wave large enough to be detected.

One of the major disadvantages of this type of system is its extreme sensitivity to operational changes, such as pump starts and stops and commodity deliveries that create transient pressure waves. Therefore, operation of this type of system is usually suppressed during “potentially” disruptive events. The decision of when to suppress alarms is made during the system installation phase. When the system is carefully calibrated, false alarms are reportedly infrequent.

Depending on size and features, the cost of a basic system ranges from $55,000 to $140,000. To perform only single-point measurements, the system typically requires pressure transmitters for every 20 miles of pipe, as well as a telecommunications link and a personal computer equipped with the vendor’s software. A direct connection to a SCADA system is not required.

4.2.1 Acoustic Systems Incorporated (ASI)

ASI has applications installed on a number of gas and commodities pipelines, including the 42-inch, 900-mile Northern Plains Natural Gas pipeline operated by Enron Gas Transmission Company; the Shell Western E and P pipeline in Brandon, Mississippi; the 14-inch, 2.85-mile Mobil West Coast methane gas pipeline in Torrance, California; and a 4-inch, 23-mile liquid ammonia pipeline owned by Monsanto Chemical Company in Hitchcock, Texas.

The ASI system detected a 0.81-inch-diameter test hole on the Mobil West Coast methane pipeline within 6.6 seconds of its occurrence, and the leak location was determined to within 53 feet. The system has also been tested on larger lines, where the detectors have been spaced at intervals ranging from three to ten miles. Reliable detections are reported for leaks as small as 1% of flow, and they are located with an accuracy of about 1.5% of the distance between adjacent sensors.

4.2.2 Ed Farmer Associates (EFA)

This vendor has developed several types of systems including a pressure wave detector called Pressure Point Analysis (PPA). PPA has been tested by the Chevron Pipeline Company and by Phillips Petroleum for the U.S. Department of the Interior’s Minerals Management Service.

The Chevron tests were performed on the Mesa and West Texas Gulf (WTG) pipelines. The Mesa line, which stretches 80 miles between Midland and Colorado City, Texas, is a 24-inch pipe that transports 240,000 barrels of crude oil daily. There is one side branch in the middle of the line that is used every other day to make a delivery. The WTG pipeline is a more complex 26-inch, 275-mile crude line that stretches between the Mesa's endpoint in Colorado City and Wortham, Texas. Its daily throughput averages 336,000 barrels, with 10 to 15 daily operational changes (such as pump pressures or pipeline configurations).

The performance test assessed PPA's ability to detect a leak as well as the percentage of the time the PPA system would be "suppressed" due to operational changes. It was assumed that the PPA system would be disabled to allow transient conditions to settle for 2 minutes per operational change on the Mesa pipeline, and for 6 minutes on the WTG pipeline. From the field test, Chevron concluded that

PPA could detect a 50 gallon per minute leak (corresponding to less than 1% of flow rate) within 10 minutes. Test leaks of less than 25 gallons per minute were detected on the WTG pipeline within 2 minutes. Chevron Pipeline Company estimated that PPA would be available more than 90 percent of the time on both the Mesa and WTG pipelines, excluding downtime attributable to the existing SCADA or communication system. PPA availability during the 12 day test was 99% on the Mesa pipeline and 93% on the WTG pipeline". (Schlattman 1991)

The Phillips Petroleum offshore commodity pipeline system in the Santa Barbara Channel includes a 10-inch, 7-mile pipeline originating at Platform Houchin, connecting to Platform Hogan, and terminating at the Phillips on-shore facility in La Conchita. With flow rates of 6,000 barrels per day (i.e., 175 gallons per minute), the PPA system detected leaks from a 1/8-inch-diameter hole that produced a leak rate of 1.7% of flow. (Peterson 1990)

4.2.3 Howard Ledeen Associates

A prototype version of the Ledeen system has been installed on a 20-mile segment of a 14-inch mixed products pipeline operated by the CALNEV Pipeline Company, in California. As part of the prototype development, CALNEV installed a ¼-inch hole (tap) in a line segment for use in simulating leaks. During an on-site visit (see Section 5.3.1) by Volpe Center staff, product was allowed to leak from the tap for 15 seconds. The Ledeen system detected the loss of product from the tap within 3 minutes. The difference between the actual tap location and the model's reported location was 126 feet. Three tests conducted that same day were successfully detected by the Ledeen system within 3 minutes of their occurrence.

4.3 VB and RTTM systems

Volume Balance and RTTM systems are described in detail in Chapter 3. These examples of volume balance and RTTM systems illustrate how a variety of vendors have chosen to implement these techniques by combining a variety of field sensors, ultrasonic flow meters, and model-based detection systems to accomplish leak detection.

4.3.1 Caldon

Caldon's "Dual-External Path" system uses clamp-on, non-intrusive meters that transmit ultrasound waves perpendicularly to and at a 45^{o} angle to the flow.

Caldon reports that, on a 100-mile pipeline segment with an inner diameter of 35 inches and a nominal flow rate of 1 million barrels per day, a leak of 0.1% of flow (40 barrels/hr) could be detected in 25 minutes, a leak of 0.40% of flow could be detected in 17 minutes, and a leak of 5% of flow could be detected in 3 minutes.

Caldon systems are currently operating in nuclear power plants, with demonstrated accuracy to within 1% of flow.

4.3.2 Controlotron

The Controlotron 990 LD Pipeline Leak Detection System provides an external clamp-on transit-time ultrasonic flow meter. The system measures flow, commodity temperature, and ambient temperature at each measurement station. It uses these measurements as inputs to a temperature model of each pipeline segment, permitting the measured flow into and out of each segment to be corrected for the expansion or contraction of the liquid computed on the basis of temperature changes between the stations. The system measures liquid conditions every 0.1 second, and it can identify sudden leaks by identifying a pressure wave. Controlotron reports that its high precision, dual-path combination metering system can detect a leak of 1.5% of flow within 1 minute, and a leak of 0.5% of flow in 1 hour. Its basic system can detect a leak of 5% flow leak in 1 minute, and a 1.5% of flow leak in 1 hour. The basic system costs about $33,000 per flow meter, requiring one Master Station control unit (per 32 meter pairs) at a cost of $35,000. Minimum cost for a 20-mile segment is $101,000.

4.3.3 Scientific Software Intercomp (SSI)

SSI reports that its model-based systems can detect leaks of 0.2% of the rated flow on liquid lines. On gas lines, the minimal detectable leak (according to SSI) ranges from 0.8% to 5% of rated flow. Leak location is a function of the spacing of the instrumentation on the pipeline and the size of the leak. In two of the SSI applications (the Alyeska Pipeline Service Company and the Williams Pipeline Company, which are described in Sections 5.2.2 and 5.2.3), leak location can be identified within segment boundaries, but more accurate software-based leak location is a function of instrument accuracy, scan rates, and leak volume. The initial cost (not including instrumentation, power loops, sensors, etc.) of the SSI system used in the Williams application was approximately $900,000. (SSI 1990)

4.3.4 Stoner Associates, Incorporated (SAI)

Like SSI, SAI offers model-based systems that have been implemented on very long, complicated pipelines. An SAI model was installed in 1990 in Calgary, Alberta, Canada, on the 24-inch Trans-Mountain Pipeline, which carries crude oil and refined commodities from Edmonton, Alberta to Vancouver, British Columbia. The performance objectives for this system were to detect (1) a leak flow of 30 cubic meters per hour (m^3/hr) within 6 minutes within 20 km of the leak and (2) a leak flow of 125 m^3/hr within 3 minutes within 5 km of the leak for tight line conditions. In areas of slack line flow, a leak of 100 m^3/hr was to be detected within 6 to 24 minutes within 25 to 50 km depending on the distance of the leak from the section of slack line. (Mountfort et al. 1990) While design specifications were detailed in the available literature, actual performance of the software-based leak detection system was not documented in the currently available literature.

Chapter 5: Pipeline system reviews

5.0 Introduction

This section presents brief reviews of the applications of SCADA systems and the software-based leak detection systems found at the operating companies visited. The systems visited fall into three categories: (1) SCADA systems operating without leak detection systems, (2) integrated SCADA and leak detection systems, and (3) independent leak detection and SCADA.

5.1 SCADA systems with internally developed LDS

A number of pipeline companies have chosen to develop their own SCADA and LDS systems. These systems generally offer great flexibility to the pipeline operator. However, development and maintenance of the SCADA and LDS require a substantial investment on the part of the operator.

5.1.1 AMOCO Pipeline Company

Amoco Pipeline Co. was interviewed due to its size, the variety of products and pipelines managed by the company, and the fact that it has chosen to develop a SCADA system that provides dispatchers with enough data to perform LDS without the implementation of additional independent software.

Amoco Pipeline Co. operates over 14,000 miles of pipeline (10,500 miles of crude oil and 3,500 miles of products lines) in a network that serves 23 states from Texas to Illinois and west into the Rocky Mountains. Amoco's system demands rapidly updated information from the SCADA system to support tracking multiple products ranging from crude oil to gasolines and propane. These products are transmitted from wells offshore near Texas to refineries, and from refineries to distribution centers throughout the US. The pipeline system is extremely complex, with multiple injection and delivery points, many variations in pipeline characteristics, such as diameter, and differing product characteristics. Petroleum products handled by the company range from very low to high viscosity, specific gravity, and vapor pressures. The SCADA system is used to control all pipeline functions from a central dispatching center in Tulsa, Oklahoma.

The complexity of pipeline conditions demand that frequent status updates be provided to the dispatcher. Therefore speed and reliability were critical aspects of the choice of telecommunications hardware to support SCADA.

Amoco's SCADA system is supported by a very sophisticated telecommunications system, involving transponders on the Galaxy 3 satellite in geosynchronous earth orbit over Tulsa, Oklahoma. This communications satellite has provided Amoco with 99.8% communications reliability at less cost than an equivalent leased line network. The satellite system is backed up with a leased-telephone-line system. Leased lines are not routinely used for communication, their only purpose is to provide short-term communications support if there is a failure of the main system.

The SCADA system processes data provided by communication from approximately 450 RTU nodes installed over the last eight years. Amoco is currently redesigning its SCADA system's central facility in Tulsa, and replacing older RTU nodes with new ones that are more compatible with emerging communications standards. RTU nodes are midpoint field stations that act as intermediate repositories of data gathered from RTUs. RTUs gather data from field instruments by scanning the instruments on a frequent basis (sometimes every few seconds).

An RTU node costs roughly $25,000. The RTU nodes poll RTUs, and then communicate that data to the satellite. The Master Earth Station costs $20 to 25 million, but is considered to be quite cost effective when compared with the expected cost of leased lines providing the same communications service. Amoco also maintains a radio system for field communication.

Leak detection is performed primarily by the dispatcher who monitors the information provided by the SCADA system. Dispatchers use several methods to create indicators of anomalous pipeline conditions. In general, all of the methods are based upon trend monitoring. They include:

(1) **Volume balance sheets** - used to conduct hourly flow balance accounting - Dispatchers can set alarms on the volume over/short balance, or on the basis of the frequency and deviation of the over/short balance.

(2) **Absolute levels** - The dispatcher directly defines fixed deviations from a base value, including an error range defined as plus or minus a specified volume to the system. If the system senses drift outside of this range (e.g., commodity changes), an alarm is issued.

(3) **Floating levels** - The dispatcher can initiate a method using a fixed/floating deviation, which allows the base to be defined as a beginning bandwidth value that floats and is updated with each scan, provided it does not exceed the alarm threshold. If the system begins to drift, the bandwidth tracks with the drift instead of remaining at a fixed point.

Employing these techniques, the dispatcher can develop his/her own set of signals to indicate that pipeline conditions are not as expected and to identify the degree of variation.

This system has advantages in that the dispatcher can adjust the monitoring functions to specific pipeline conditions or products. For instance, dispatchers monitoring multiple batches might choose displays that have floating level deviations alarms, since product velocities might increase with decreases in viscosity from one batch to the next. Alternatively, dispatchers working in a terminal area might be interested in very small volume differences to avoid tank overflows or other such mishaps.

Dispatchers are an integral part of the success of the SCADA system for leak detection. Each dispatcher is thoroughly trained in operating the SCADA system, as well as the specific pipeline to which he/she is assigned before being allowed to operate the pipeline independently. Dispatchers are routinely tested to see if they are able to identify anomalous conditions on the pipeline and take corrective action.

Outside reports of damage are funneled through the dispatching center from various one-call systems. This helps to keep dispatchers informed of problems on the pipeline and reinforces their ability to act as the pipeline company's central point of contact for emergency response.

The Amoco system demonstrates that the employment of rapidly reported, reliable data can be successfully interpreted by a trained dispatcher to conduct both pipeline control and leak detection. It is the combination of dispatcher training and SCADA system availability that ensures that pipeline conditions are usually well known, and anomalous conditions are quickly recognized

5.1.2 ENRON Pipeline Company

Enron Gas Transmission Co. operates 1,600 miles of pipeline between Houston, Texas, and Kansas, Iowa, and Illinois. The company delivers natural gas to local distribution companies at the termination points of these lines - therefore, their customers include public utilities and other distribution companies. The major purpose of their SCADA system is to provide pipeline control and monitoring to dispatchers, allowing them to control the large volume of gas they transport daily. Enron uses the data provided from SCADA for a number of functions in addition to pipeline control, including customer billing. Therefore, the company demands high levels of data accuracy and system reliability.

Enron Gas Transmission Co. officials emphasized the importance of the telecommunications system to the success of their SCADA system. Before building their current system they undertook a lengthy study to select a telecommunications network that provided high reliability and expansion capacity at the lowest possible acquisition and operating cost. Much of the focus of their system development effort focused on hardware acquisition and integration of the existing network with newly acquired assets, such as Very Small Aperture Terminal Satellites (VSATS).

Company officials interviewed indicated that most independent software-based leak detection systems would be insufficient for Enron's use. They felt that the properties of natural gas, especially its compressibility, make model-based leak detection methods inapplicable, since those techniques rely so heavily on instantaneous pressure and volume measurements. These measurements are less variable and therefore easier to model with liquids than with gasses. However, the Enron team concluded that their SCADA system, which monitors the gas transmission lines in near real time, provides detailed data at a high enough frequency to allow dispatchers to perform leak detection functions without the assistance of additional LDS software support.

Unlike many SCADA systems that are packaged and distributed by a vendor, Enron's system is an integrated system composed of different operational SCADA systems. It was developed internally, with the assistance of an outside contractor, following the merger (about four years ago) of four companies: Florida Gas Transmission, Houston Pipeline, Northern Natural Gas, and Transwestern Pipeline.

The current SCADA system operates centrally, providing dispatchers with control data to monitor flow rates and pressure at various points along the pipeline. Irregularities in pressure or flow trigger alarms. Alarms may also be triggered by the absence of data, indicating instrument failure, communications failure, or some abnormality on the pipeline. Placement of instrumentation along pipes depends on information requirements and, to some extent, the gas transmission class location level of the surrounding area as defined in the Federal gas pipeline safety regulations (49 CFR 192.5).

Among the telecommunications parameters that most effect the SCADA systems viability, sensitivity, and cost are the rates at which field instruments report their data back to the central computer, and the frequency with which field computers acquire instrument readings. Frequent instrument readings improve the informational basis for monitoring pipeline variations, since transient conditions (such as small pressure deviations associated with minor leaks) can occur and be masked by flow conditions in a short time period. The more rapidly instruments report back to the central computer, the more likely it is that a short-term transient will be detected. The frequency with which field instruments report their data is called the scan rate. In the Enron system, scan rates are quite frequent (for instance once every 5 seconds), and a history of a field instrument's data is maintained by a RTU. At regular intervals, these data are communicated back to the central computer. The frequency with which the central computer (host) calls RTUs to receive their data is referred to as the *polling rate*. This communication process is expensive and therefore polling rates are less frequent than scan rates. The exact frequency of polling rates depends on a number of factors, such as:

Customer information requirements - Enron operates transmission pipelines carrying natural gas for other companies and designs SCADA operations to provide for the information needs of the customers. The dispatchers are able to create their own visual data displays, depending upon these varying information needs; however, these displays may have varying data updating frequency requirements.

Cost - Loading on a circuit may be done to optimize the telecommunications network. The highest cost options are associated with requirements for very frequent RTU polling rates.

The telecommunications method selected for the SCADA system had to be compatible with the other elements of the Enron communication network. Because of the wide geographic distribution of Enron's employees, the SCADA communications system had to serve more than the purposes of the SCADA system alone, to minimize costs and to justify the investment.

After comparing the costs and limitations of several technologies, Enron chose a satellite technology: Very Small Aperture Terminals (VSAT). The satellite dishes cost only $20,000, while microwave technology, for example, can have initial capital costs of as much as $200,000 per tower. Additionally, microwaves provide only limited bandwidths for customer use and may be subject to Federal Communications Commission (FCC) maintenance regulations that hold microwave tenants (i.e., individuals leasing a tower for their equipment) responsible for tower maintenance that they cannot control.

Based upon Enron's experience, development of a cost-effective method of providing reliable telecommunications support was the most critical aspect of maintaining an effective SCADA system capable of supporting pipeline management and control functions, especially those associated with leak detection and SCADA.

Enron's dispatcher interface is also a hallmark of their system. The dispatching center features multiple screens displayed simultaneously to allow each dispatcher to review the status of each pipeline, and specific data on pumps, segments, and delivery points. The control room facilitates oversight of each pipeline's status by any of the three or four dispatchers working at the time, as well as by the managers in the area. This open design promotes information exchange and oversight of each pipeline by both the responsible dispatcher and his colleagues.

Some important aspects of the system are the ability of each dispatcher to choose from among a number of displays, (tabular or graphic) to track pipeline behavior. These displays are rapidly updated (owing to the data acquisition process described above), and the status of all measurement and telecommunications instruments is constantly monitored. This means that a dispatcher is not only made aware of unusual readings from instruments, such as pressure transducers, failures of such instruments are also reported to the dispatcher through the SCADA system and its ability to self-check over the lifespan of the data history of the instrument.

The Enron system is an effective application of SCADA to the process of pipeline control and monitoring that effectively provides LDS functionality without the implementation of additional software.

5.1.3 Seagull Pipeline Company

Seagull Pipeline Company was visited due to its contrastingly smaller size (in comparison to Enron and Amoco). Seagull Energy Systems operates a total of 450 miles of pipeline from their dispatching center in Liberty, Texas. Seagull operates pipelines for three companies: Texaco, Quantum, and Himont. The pipeline dispatching and control systems for the three companies are also different; however, the dispatchers are trained to manage all three.

Seagull handles HVLs, as well as natural gas. These materials are pumped to plants via “feeder lines.” The processing plants turn those materials into products such as ethylene and propylene, and in turn pump them directly into production facilities. Seagull is at times providing real time inventory to plants that are in operation. These plants depend upon continuous product supply, making interruptions of product flow potentially very costly. For this reason, reliability of the SCADA systems is a major concern.

The pipeline control system includes an automatic control valve (ACV) due to the volatility of some of the products handled by Seagull. At the location of the ACV, product is delivered directly from the pipeline for use as fuel for plant equipment. The logic for automatic activation of the valve and shut-down of the line is embedded in an electronic device called a programmable logic controller (PLC) used to actuate the valve at the plant. The PLC uses volume, pressure, and temperature deviations to determine whether dangerous operational conditions exist. If one or more of these conditions are indicated (for instance, excessively high or low pressure), the ACV is activated. The dispatcher has no override capability on this ACV, and the valve can only be reopened by a technician on-site. Due to previous instances of false alarms resulting in unnecessary plant shut-downs, the sensitivity of the PLC is still an issue. Shell, the owner of the plant, continues to want the ACV operational, but Seagull has adjusted the sensitivities to reduce the false alarm rate and minimize costs.

In addition to the ACV, some of Seagull's lines have buried hydrocarbon sensors along the pipeline. These sensors were installed in highly "sensitive" areas due to their ability to provide instant notification of product releases. However, they are currently in use in only a few areas.

Seagull indicated that, while the capital costs of leak detection software could be prohibitively high, the size of the initial investment was less an issue than the reliability and false alarm rate of most commercial LDSs. Representatives of Seagull, like those of Enron, believe that most software-based leak detection applications would be insufficient for their use. The insufficiency owes to the inability of most LDS modeling systems to deal with highly compressible products, such as natural gas and volatiles like ethylene and propylene. Instead, Seagull has developed techniques that integrate real-time data with dispatcher decision-making to accomplish software-based leak detection.

Seagull's operations differ substantially from those of Amoco, which carries crude and petroleum commodities through a relatively older system. Seagull manages and operates three pipeline systems simultaneously. Each pipeline usually carries propylene, ethylene, natural gas, and feedstocks. Although the physical distance covered by the pipelines is relatively small, the three systems used for pipeline management and control are quite complex. Because of the close tie-in of the pipeline systems to plant demand, Seagull has designed SCADA systems that are able to monitor both their input and the output at the delivery points along the pipeline systems. Since the plants, at delivery points, also pump processed material back through the pipeline to other plants, the pipelines have two-way transmission and en-route storage capability.

The Quantum pipeline system operated by Seagull is a good example of the application of SCADA to both management and software-based leak detection functions. It consists of a dedicated natural gas line and a dedicated petrochemicals line, each approximately 17.5 miles long. Each line is monitored by the SCADA system and managed by Seagull's dispatchers. They manage the flow of commodity in the pipeline by attempting to deliver, on a daily basis, the amount of commodity demanded at the plant. Thus, the management of this pipeline system represents the behavior of most systems.

In addition to the automated data collection performed by SCADA, the dispatchers maintain a written history of the requested flow volumes or “nominations” for each day, the actual delivered volumes or “takes,” and the flow rates for the pipeline. Allowable deviations and tolerances around those nominations and flow rates are used to control material movement, while defining a “safe” operational environment. Excessive deviations from these levels alert the dispatcher that a problem exists on the line. Dispatchers review data provided to them via SCADA on pressure (from transducers) and flow (from volume meters).

The Quantum system also has an in-line analyzer, which provides a spectrum of data on the material (including such measures as specific gravity and temperature). These additional data assist in providing management decision information to dispatchers. The data are not included in an elaborate real-time model of the pipeline system. Data are transmitted from field instruments to the Liberty, Texas control station via microwave. They have a scan rate of 1.5 to 2 minutes, and dispatcher displays are updated in one minute.

Quantum is the newest of the three Seagull systems and uses the most sophisticated hardware and software. The Quantum system runs on IBM-compatible model 486 personal computers, and is currently operating in a “user-friendly” Windows environment, which allows the dispatchers to choose interactively the information and the amount of detail to be displayed. The other two systems operated by Seagull are not implemented on newer hardware; however, their other performance characteristics are similar to those of the Quantum system.

In a manner similar to Amoco and Enron, Seagull has developed a pipeline control system that provides dispatchers with enough data to determine whether a loss of product (indicated by a volume balance difference) or a potentially hazardous condition (indicated by a pressure deviation) exists on the pipeline. In this way, Seagull has developed a fundamental LDS, and implemented high level controls (such as ACVs) based upon its SCADA system.

5.2 Integrated SCADA/LDS systems

Three companies that use a hybrid system consisting of an integrated SCADA system and a leak detection system were visited: the All American Pipeline (AAP) Company, the Alyeska Pipeline Service Company, and the Williams Pipeline Company.

5.2.1 All American Pipeline Company (AAP)

AAP's pipeline covers the gamut of topographical variation. The 30-inch, 1,200 mile-long pipeline, which transports crude oil exclusively, travels through the Mojave desert and over a mountain range. Currently, AAP's SCADA system does not have a software-based leak detection component, although the system does run "smart" applications for activities such as batch tracking, which is very similar in character to software-based leak detection. Leak detection software runs separately on a Digital mini- computer. The vendor of that original system was Advance Pipeline Technologies. The original LDS uses data from the SCADA system. AAP has had its current LDS and SCADA system since 1986, and at the time of the interview was in the process of choosing a new SCADA/LDS. The current system was scheduled for replacement due to its obsolescence and high false alarm rate.

AAP was a leader in the acquisition of a SCADA/LDS when these systems first emerged. Due to the rapidly changing technology in the field, however, their hardware system quickly fell behind the data requirements of the SCADA system, and the LDS was unable to keep up with configuration and operational changes on the pipeline.

Application of leak detection systems to the pipeline is a problem for several reasons. Data processing was underfunded, and equipment currently available to AAP is not sufficient to support a sophisticated SCADA and leak detection system, as well as the simulation operation they currently use for operator training. Current instrumentation on the pipeline, such as metering, are not sufficient to provide information for leak detection. The LDS currently in place was designed based upon a 24 hour/ day, 350,000 bbl flow rate at 5 mph or more. The original LDS has not been modified since its design; however, the flow rates are significantly less than the design assumed them to be, and many of the underlying modeling assumptions based upon that flow rate are now missing or inappropriate to the current operation. The physical configuration of the pipeline is not very complex, having about 1,200 miles of trunklines, 35 miles of gathering lines, and 20 pumping stations. Unfortunately, the terrain this pipeline traverses includes dramatic changes in grade, coupled with a major river crossing (the Colorado). The uphill near the Mojave desert requires tremendous pump pressure to keep flow rates at 5 mph. The result on the downhill grade is a slack line, and a requirement for a pressure reduction station. These topographical characteristics also inhibit the use of pressure variation methods of leak detection, and even volume balance methods may be inaccurate due to variations in flow rates on uphill/downhill segments.

Leak detection is, therefore, primarily a function of pipeline operation, where dispatchers monitor conditions and look for anomalies that indicate that problems might exist. For instance, pressure changes due to line punctures will be displayed as SCADA-based threshold alarms to the dispatcher. Dispatchers are trained to respond to excessive pressure changes with specific notification protocols.

There are some limitations to the applicability of the dispatcher notification system. For instance, they would be unable to identify the exact cause of a pressure differential on slack line operations, which exist on some segments of the pipeline (especially where it enters the Mojave desert), making detection of some leaks almost impossible in those areas.

The importance of the dispatcher interface has been a component of the selection and development process of the new SCADA system. AAP personnel indicated that training and improvement of the user interface were the areas where leak detection could really be improved. They felt that the major area of improvement could be in eliminating operator error - often it was not an equipment or leak detection issue. They felt that no amount of software could substitute for a thorough understanding of the information being presented to the dispatcher. As a consequence of this philosophy, dispatcher recommendations on displays will be incorporated into the new SCADA system, including the desirability of graphical (schematic), as well as tabular, displays.

5.2.2 Alyeska Pipeline Service Company

Alyeska Pipeline Service Company operates a crude oil pipeline in Alaska that extends 800 miles, from Prudhoe Bay to Valdez. The software-based leak detection systems in place and in development involve both direct, SCADA-based detection activity and pipeline transient modeling.

Alyeska currently uses a line volume balance method of LDS and depends on threshold alarms and pipeline gradient trend analyses to detect unusual events, such as leaks. (Alyeska 1990) The line volume balance system is based on meter readings that are sufficiently accurate to be used for billing purposes. This data is referred to as *customer transfer quality*. The system calculates only total pipeline system volume balances, adjusting for known variances along the pipeline. The balances are calculated at half-hour intervals.

Leak detection time, based on system tests conducted in 1992, ranged from 5.5 to 8 hours to detect a leak rated at 1,200 to 1,750 barrels per day. (Bose 1992) The current system requires the dispatcher to determine the location of the leak - no software-based leak location was included in its design. The constraints on the system are largely due to the discriminatory ability of the flow meters and the time it takes to detect changes in fluid characteristics under slack conditions.

Pressure deviation alarms are used to signal that a threshold of a predetermined percentage of pressure level has been exceeded (either positively or negatively), thereby indicating a strong transient in the pipeline. These alarms supplement the information provided to dispatchers by the volume balance-based leak detection system. Dispatchers must wait for the iterative volume balance calculations of the LDS to confirm the presence of a leak. However, they can shorten their reaction time to a major rupture by monitoring these pressure deviations. The detection time for pressure disruptions would be a small multiple of the 5-minute scan rate.

Alyeska's telecommunications system uses two microwave channels, coupled with satellite backup. Field communications are conducted from simple RTUs/PLCs, which poll instruments and hold the processed information until it is scanned by the central communications computer. RTUs and PLCs in the field do not perform any special calculations. Threshold settings and alarms are displayed in the operations center in Valdez, enabling controllers to see all alarms and alarm levels. Dispatchers are required to acknowledge and respond to each alarm. A documentation file of alarms and responses is maintained at the dispatching center.

At the time of the interview, Alyeska was in the process of updating its current system and developing a model-based leak detection system with SSI. Since that time, the model has been successfully implemented on the pipeline. A demonstration of the method by the vendor, SSI, illustrated that some of the more important modeling challenges, such as slack line flow, had been addressed in the new LDS. Current performance data on that system is not included in this report.

5.2.3 Williams Pipeline Company

Williams is a very large operator with approximately 8,500 miles of pipeline carrying multiple liquid commodities. The pipeline system is a flexible network with multiple set-off points, origination points, and reversible lines. Leak detection is performed by a SCADA system and a new mathematical model-based leak detection system, which is being developed by SSI.

The SCADA system is an integral part of many functions within the company: administrative tasks, inventory control, and scheduling, as well as the leak detection system. Leak detection could not be accomplished independently of the SCADA system. The system is also very useful in maintaining the quality of instrumentation in the field; that is, it provides diagnostics for assessing the performance of the reporting instruments.

The software-based leak detection system uses two methods: (1) volume balance, and (2) pressure/flow deviation. Using the metered volume balance method, the Williams Company expects to detect leaks as small as 1% of maximum flow during steady state conditions, and as small as 4% of maximum flow during unsteady conditions. Detection of small leaks would require at least 1 hour. (Mears undated) The pressure-flow deviation method provides leak location information based on a given frequency of each data scan from SCADA, requiring 5 to 30 seconds to detect a leak. Leaks of 3% to 5% of flow could be detected within 5 minutes using the pressure-flow deviation method.

The complexity of the Williams pipeline system has made modeling the entire network difficult. Thus, the SSI system is being implemented in phases. The model currently applies to 27 of the 50 applicable segments of the pipeline system.

The new leak detection system has a very sophisticated control room and user interface. The system is designed with a multiple-window environment. Dispatchers can move back and forth between a number of computer systems and information databases without exiting any of the environments. Multiple alarm conditions can be displayed simultaneously, allowing simultaneous identification of and response to communications failures, instrument problems, pressure/flow deviation alarms, and volume balance alarms relating to the same segment.

5.3 Independent leak detection and SCADA

As discussed earlier, some LDS and SCADA systems operate independently. The LDS uses different field instruments and computers for information input than does the SCADA system, and system status displays - such as alarms, appear on separate devices in the dispatching center.

5.3.1 Calnev Pipeline Company

CALNEV'S software-based leak detection system and SCADA system run on separate computers.

CALNEV operates two hazardous liquid interstate pipelines: an 8-inch, 231-mile-long jet-fuel line and a 14-inch, 247-mile-long mixed products line that carries various gasolines and diesel fuels. The CALNEV pipelines, which connect Colton, California, with Las Vegas, Nevada, cross the Mojave Desert and a mountain range. The complexities caused by the topography of these areas and the batching of multiple commodities in the 14-inch line were the company's impetus for investing in a new software-based leak detection system.

Most of CALNEV's leaks have been ruptures caused by other parties (although CALNEV had an "over-pressure" situation in the 1960s), and the soil content in which the lines are buried has never caused a coating failure on and corrosion leak in the pipeline. Therefore, CALNEV's software-based leak detection system has been programmed to accurately locate ruptures and respond to them rapidly, rather than to detect slow leaks caused by corrosion.

Operationally, CALNEV is very similar to most pipeline companies in its use of a SCADA system with a microwave system for telemetry. CALNEV's SCADA system, assembled by VALMET, a SCADA system vendor, was upgraded in 1988. The SCADA system is used to control the daily movement of multiple commodity (batch) shipments, in addition to maintaining MAOP levels and monitoring custody transfer. CALNEV's microwave system for telemetry has a 13-second scan time for reporting back to the dispatching center.

CALNEV does not use the VALMET system for software-based leak detection. Instead, CALNEV has initiated a program to test an experimental software-based leak detection system (vendor: Howard Ledeen Associates), which is currently operating with a dedicated leased line designed specifically for the system. CALNEV's leak detection system specialist indicated that he had been interested in LDSs for many years, and had investigated a number of new LDS technologies. He felt that the field was not improving until he found the Ledeen system. Previously, he felt that constraints on leak detection system performance seemed to stem from limitations of the computer hardware limitations or the specific leak detection technology. In this company official's view, the Ledeen acoustic system was not limited by those constraints and it satisfied one other important criteria - it has a low false alarm rate. CALNEV had attempted to implement systems based upon volume balance calculations in the past, and had been disappointed by their low accuracy and high false alarm rates. The volume balance calculations had usually not compensated for line pack, and therefore, were not as accurate as would be necessary to accomplish leak detection. The performance characteristics of the experimental system were demonstrated in an on-site test. The results of that test are described in Section 4.3.

In addition to the experimental Ledeen system, CALNEV has installed a Gore Tex cable system in the manifold area. The system was chosen for that area because of the system's sensitivity, and because the manifold is a high risk area.

CALNEV has combined the use of independent leak detection systems and the SCADA system to provide dispatchers with leak notifications without integrating the two systems together. However, the systems apparently are successful at providing leak notification.

Table 5-1: Leak Detection Systems Performance Information

A summary of the results of the vendor reviews and interviews presented in this chapter appear in Table 5-1. This is not meant to be a comprehensive list of performance characteristics of all systems, it simply illustrates the possible variation in performance and costs associated with various systems. SCADA costs are not included in the table.

Chapter 6: Spill reduction models

6.0 Introduction

The previous chapters provided descriptions of the function of leak detection systems, the experience of field operators with the systems, and the systems currently available. Leak detection system cost and performance data were gathered to provide a simple basis for comparison among "typical" systems. The list was not exhaustive, and performance data were generally as reported by the vendor or operator. This anecdotal information provides a good general background; however, it has limited decision-making applicability. Ideally, an operator would choose a leak-detection system because it passes a cost/benefit test: the expected cost of a leak in some segment of the pipeline must be great enough to justify the purchase and implementation of a leak detection system that performs at an "acceptable" level. While the cost data for leak detection systems is known, the comprehensive spill incident information needed to assess their performance is not routinely reported.

To facilitate thinking about these tradeoffs, a theoretical method of establishing optimum cost and performance tradeoffs for leak detection systems is offered in this chapter. The "optimum" level in both cases means the point where the combined costs from both spill reduction efforts and spill damages is minimized. This definition of optimum is tangible enough to analyze, it can accommodate industry and environmental concerns, and it reflects a risk management approach to regulating safety in the pipeline industry.

Emergency flow restricting devices (EFRDs) are modeled from an overall operating cost perspective. This framework was designed with the available data in mind. There are, however, some variables whose values are uncertain. These models are not self-contained decision making tools. Hopefully, they provide a framework that pipeline operators can apply to their own unique situations.

LDS and EFRD investments are modeled separately; the model does not determine how a pipeline operator should divide spill reduction dollars between these technologies or any other safety initiative, such as operator training, new equipment, or testing. These simple models do not make heavy demands on the limited public, government, and industry knowledge about pipeline spills. The possible extension of these models to provide better decision information is discussed in Section 6.4, as well as additional data requirements.

The model does not include the national pipeline infrastructure, nor pipeline systems, but only individual pipe segments. All the key parameters in these models, such as failure rates for parts, expected spill volumes, per-barrel spill costs, and false alarm rates depend on the type, size, and condition of the pipe segment, the terrain it crosses, its elevation profile, and the system to which the line is connected. Real pipelines can be handled using these methods by applying the models to individual segments at a time over which these parameters do not vary appreciably.

OPS nationwide pipeline spill data are averaged to get rough estimates of pipeline parameters for illustrative purposes. A sensitivity analysis on many of the model's parameters provides an estimate of their necessary accuracy relative to one another. These models would be most effective in the hands of pipeline operators who have kept detailed information on the line they wish to model and have accumulated performance statistics on the components that comprise it.

Finally, these models apply most readily to new construction. Digging up and modifying existing pipelines may add significant new risks not reflected in these models.

6.1 Model of EFRD placement

The desired level of spill prevention required for any pipeline system depends on the following factors:

- The environment in which the pipeline exists,
- The potential risks to humans and the environment presented by products transported through the pipeline,
- The emergency response capability of the pipeline operator, and
- The probability that a leak will occur.

Some components of the control system for pipelines are variable and can be examined with respect to their ability to enhance leak detection and slow down spillage. Such components include valve placements, leak level sensitivity requirements, user interface performance requirements, and emergency response capability.

Currently, there are few limits as to which type of petroleum product can be transported on a pipeline, and different environments and terrains differ sharply with respect to their sensitivity and potential spill volumes. Therefore, few initial assumptions were made concerning the magnitude of model variables associated with these factors, and the models examined under a diverse group of spill scenarios.

This chapter addresses alternative valve spacing and leak level sensitivity requirements.

6.2 Spill types

Leaks can be placed into three size categories: small, medium, and large. Small leaks will be defined as being below the limits of current CPM-type leak detection capabilities. They can be found with chemical sensing cables or by finding small pools of leaking product or dead vegetation on the pipeline right of way. They result from small, stable fractures or small corrosion holes that result in leak rates usually less than 1% of flow. Many vendor- and company-developed systems can detect leaks as small as 0.1% flow in field tests, but today no pipeline operators are counting on this capability and reducing their right of way inspections. These small leaks can stay small and go unnoticed for weeks.

Medium leaks are detectable with SCADA based leak detection methods, but they are not large enough to cause a loss of working line pressure. Spill rates as high as 100 bbls per hour have gone undetected for up to a day on large lines without SCADA systems. They are caused by fractures that remain narrow, and by worn gaskets and valve stem packings.

Large leaks result in a rapid loss of working line pressure, which will generate an alarm to the dispatcher, even without an LDS. They are caused by third party damage and by unstable fractures that can grow many feet in length. Many high carbon steels used before 1970 are prone to unstable fracture. Hydrogen gas, generated by cathodic protection systems with excessively high voltage, and hydrogen sulfide, found in sour crude oil, can make pipe steel brittle and more prone to such fractures.

6.3 A general accident scenario

In this section, what is referred to in the Report to the California State Fire Marshal (EDM Services 1993) as the four stages of a pipeline spill are described. This breakdown provides a good way to discuss many concepts that influence leak detection and EFRD performance.

Stage 1: Leak initiation to pump shutdown

This stage covers the point from where the leak occurs until it is first discovered and the pumps are shut down. The length of this period can be reduced by an effective leak detection system, and by the ability to quickly shut down the pumps during an emergency. Less volatile products, even crude oil, when escaping through thin pipe cracks under high pressure, produce a fine mist that can explode. The rate of product loss can exceed normal throughput while the pumps are still running, so maintaining effective control over unmanned pump stations is a high priority. Most often, pump shutdown is initiated seconds after leak confirmation, although there have been cases where the pump station was being remotely controlled and the communication lines were disrupted by the incident. ACVs and CVs can reduce losses due to back flow from this stage on.

Stage 2: Pump shutdown to block valve closure

Operators can recover their investment in RCVs by limiting their losses during this stage of the spill, although a small time lag is required between pump shutdown and RCV closure on liquids lines (see Section 3.3). Effective MOV use during this stage requires a network of company employees, local officials, and helpful citizens along the pipeline right of way who can be quickly reached during an emergency. Some of the worst accidents in the NTSB reports involved a poorly maintained response network.

Stage 3: Segment decompression

The losses incurred during this and the last stage can be influenced by closer block valve spacing. Significant pipeline segment loss is typical for natural gas and LPG lines. Incidents on segments carrying heavier products, such as crude and fuel oil, only loose their “line pack”, which is the difference between the segment’s capacity at operating pressure (generally 500-1000 psi on transmission lines) and its capacity at ambient pressure. The line pack results from pipe expansion under pressure (less than 0.2%) and product compression (less than 1%). A 36” line carrying a liquid such as gasoline or crude oil would have a line pack loss of less than 50 barrels per mile of segment.

Stage 4: Segment drain down

The loss rate during this last stage of the spill, before emergency response crews can close off the leak, depends on fluid viscosity and the pipeline elevation profile between the rupture and the nearest block valves. Naturally, a leak at the bottom of a long hill could have high losses. Consequently, the industry considers close valve spacing a high priority in those areas (and in others like them where high losses can occur).

6.4 Valve spacing

Here the authors discuss the effects of Emergency Flow Restricting Devices (EFRDs) on spill reduction by creating a simple model of a pipeline with all the variables listed in the table below.

Table 6-1: Variables used in valve spacing model

Variable	Interpretation	Units
m	length of pipe	miles
v	amortized valve cost	dollars per year
x	valve spacing	miles pervalve
p	pipe capacity	cubic feet per mile
L	product cost (product value + damage and cleanup cost)	dollars
$\mathbf{r_v}$	valve break rate	breaks per year
$\mathbf{r_p}$	pipe break rate	breaks per mile-year
k	average fixed cost for a spill	dollars
n	number of valves in pipeline	none
a	fraction of pipe segment spilled	none

This model is used to derive the optimal utilization of EFRDs based on their cost and the estimated spill volume reductions attributable to the EFRDs. The model does not include a method to account for pipeline elevation change which is a significant parameter in the decision on valve spacing on an operating pipeline. We will construct a manageable operating cost function C for a model pipeline from these variables and assume that the values for all the variables are already known except for (x). We will then calculate the value of x for which this cost function attains its minimum.

Our cost function C(x) will be annual; that is, its units will be dollars per year, and we will begin by breaking it into two parts:

$$C(x) = C_e(x) + C_s(x), \qquad (6.1)$$

where $C_e(x)$ is the annual amortized equipment cost for our pipeline and $C_s(x)$ is the annual cost associated with spills. We assume emergency cut off valves are the only equipment cost relevant to this analysis and that the pipeline operator will receive no significant price breaks in purchasing or using more of them:

$$C_e(x) = nv = \left(\frac{m}{x}+1\right)v \qquad (6.2)$$

The second equality follows from the fact that an m-mile pipeline with a valve at least every x miles requires one valve on each end plus m/x-1 valves in between. We factor the annual spill cost into two components:

$$C_s(x) = R_s(x)\,A_s(x), \qquad (6.3)$$

namely the annual spill rate and the average spill cost. The annual spill rate unfortunately is dependent on the valve spacing, because spills often result from broken valves and failed joints between the valve and the pipeline:

$$R_s(x) = nr_v + mr_p = \left(\frac{m}{x} + 1\right) r_v + mr_p \qquad (6.4)$$

We break the average spill cost into two components; a fixed cost (k) that is independent of the valve spacing and a marginal cost that depends on the volume of product spilled. We express this marginal spill volume as a fraction (?) of the capacity of the damaged pipe segment.

$$A_s(x) = k + Lpx? \qquad (6.5)$$

The independent valve spacing component k can be used to represent the costs resulting from the first barrel spilled until the cut-off valves are used. The component k can also include the costs of setting up a cleanup project. The second term represents the costs due to the spillage that occurs after the block valves isolate the failed segment. This additional spillage results from line decompression and drain down, both of which are related to the capacity of the failed segment (px). The proportionality constant, ? (0 < ? < 1) , is usually close to 1 for natural gas in almost all situations, it is intermediate in segments on a significant grade (depending on the location of the break), and is close to zero for viscous liquids on level segments. Once the first barrels are spilled and a cleanup program must be initiated, the marginal product plus cleanup costs (L) are roughly proportional to the amount of additional product spilled. The following chart, which plots the average damages per barrel spilled by size category, suggests that L remains above $100 per barrel for even the largest spills.

4. Caldon Inc., The Line Watch Group (demonstration/test results from CALNEV, and PEMEX).

5. Ed Farmer Associates DuPont Burnside Plant - On-Line Field test data 1992.

6. Scientific Software Intercomp, Ivor Ellul, “Pipeline Leak Detection,” *The Chemical Engineer*, June 1989.

7. Controlotron, Inc.

8. Stoner Associates, DREM.

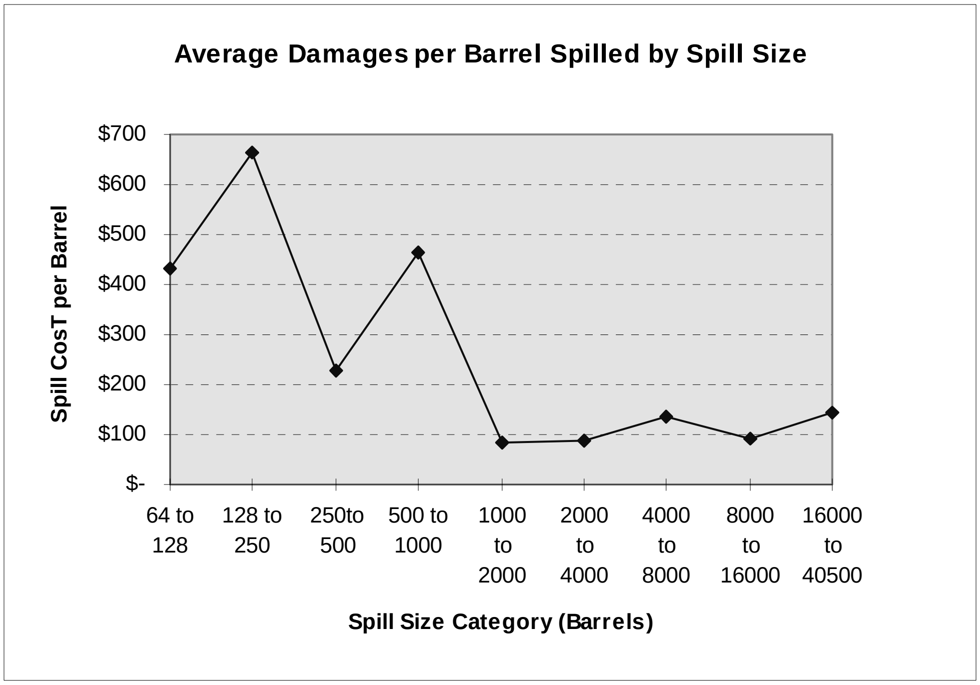


Figure 6-1 Average damage per barrel spilled by spill size

Putting all of these components together:

$$C(x) = \left(\frac{m}{x}+1\right)v + \left(\left(\frac{m}{x}+1\right)r_v + mr_p\right)(k + Lpx\alpha) \quad (6.6)$$

We now seek x*, the valve spacing that will minimize this cost function. Differentiating with respect to x, we obtain:

$$\frac{d}{dx}C(x) = m(v+kr_v) / x^2 + Lp?(r_v + mr_p) \quad (6.7)$$

Setting this equal to zero and solving for x we obtain our minimal solution:

$$x^* = \sqrt{\frac{m(v+kr_v)}{Lp\alpha(r_v + mr_p)}} \quad (6.8)$$

Values for r_p and r_v are obtainable from OPS accident report logs (see next section). This equation certainly does not eliminate the difficulty in optimizing valve spacing, rather, it has consolidated it into the two variables ? and k. The values for these variables fluctuate greatly over the length of most real world pipelines, but perhaps they are stable enough to make this equation applicable to regions of pipeline where their underlying factors such as topography, environmental sensitivity, and accessibility are stable as well.

We now attempt to apply this simplified equation by using it to calculate the most cost effective valve spacing for a 250 mile long, 36 inch diameter pipe over a range of settings. We use 6650 barrels per mile for the variable **p** in the table above. In 1993, the California State Fire Marshal study reports a cost of $25,000 each for manual block valves with a service life of 20 years, and $500 per year for maintenance. This figure is consistent with the responses to recent OPS and API pipeline operator surveys. Based on this information we use $2000/year for **v**, the annual amortized valve cost of a manual block valve. We use $20,000 per year for **v** for a 36-inch Remote Control Valve (RCV), based on a $350,000 installation cost, a $5,000 per year maintenance cost, and a 20-year service life.

The Office of Pipeline Safety received 1435 leak incident reports from pipeline operators from January 1988 to December 1994. Of these, 761 were pipe leaks and 119 were valve leaks. During this time, the total Federally regulated liquid pipeline mileage has remained within 1% of 215,000 miles (Oil and Gas Journal 1991). This gives a value for $\mathbf{r}_p$ = 0.000506 leaks per mile of pipe per year. No block valve specific leak data was found, so we based our estimate for $\mathbf{r}_v$ on OPS data, which is for all valves, and our estimate of 10,000 as the total number of valves under Federal regulation (given an average valve spacing of 20 miles). This gives a value for $\mathbf{r}_v$ = 0.0017 leaks per valve-year. Given the uncertainties in this calculation for $\mathbf{r}_v$, we note that doubling or halving this rate changes the optimum valve spacing in the scenarios below by less than 5%. The effect of **k**, the average fixed cost for a spill, has an even smaller effect on the optimum valve spacing. We use **k** = $100,000 in the figures on the next page, but we note that using a value for k that is ten times higher changes the optimum valve spacing by less than 1% (see Table 6-2).

Table 6-2 : Optimal valve spacing (x*) for various parameter values. (In all cases m = 250 miles, p = 6650 barrels, r_p = 0.000506 leaks/mile.)

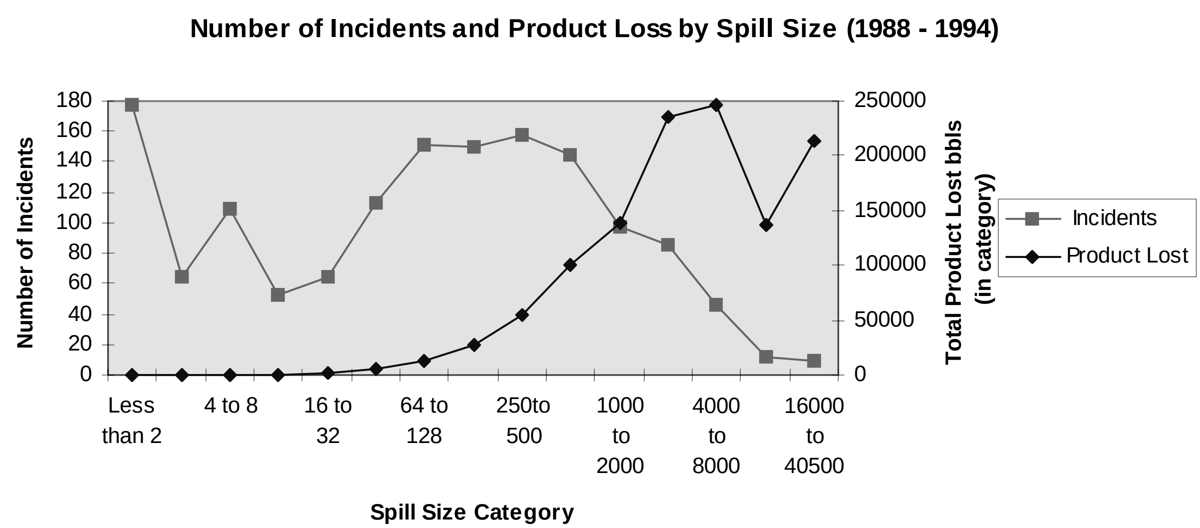
??*L	k	r_v	x*
5 (dollars)	100,000 (dollars)	0.0017 (leaks/year)	34.394 (miles)
5	100,000	0.004	34.283
5	1,000,000	0.0017	35.675
5	1,000,000	0.004	37.186
250	100,000	0.0017	4.864
250	100,000	0.004	4.848
250	1,000,000	0.0017	5.045
250	1,000,000	0.004	5.259

The two figures on the next page plot the optimum valve spacing calculation for various values of L for both manual and remote control block valves. We assume equal performance for both types of valves at this point.

Error! Not a valid link. Figure 6-2 Optimum manual block valve spacing

Error! Not a valid link. Figure 6-3 Optimum remote control valve spacing

6.5 Implications for valve spacing and LDS performance



The California State Fire Marshal's Hazardous Liquid Pipeline Risk Assessment report determined that adding more block valves to all pipelines would not be cost effective, because the average spill size is a very small fraction of the amount of product that could be contained in a pipeline segment of average length. The average spill size on OPS-regulated pipelines is frequently less than the potential volume of product in a segment of average length, but there may be benefits to implementing closer valve spacing on certain pipelines. The following figures and table show that much of the total spill damage is caused by larger spills, which are equivalent to the volumes in pipe lengths near and beyond the average current segment lengths. Numerically, only 5% of the incidents reported to OPS resulted in the loss of the equivalent of more than 10 miles of product, but they represent about 50% of all the operators spill costs. Thus, the incidents that represent about half all the spill damages could be influenced with closer valve spacing. The degree of block valve influence on these large spills depends on the typical fraction of the total segment capacity (?) that is lost after the block valves are closed. This information needs to be collected, and the influence of real world conditions on ? needs to be understood. Once a good estimate for ? can be made for a specific

Figure 6-4 Number of incidents/product loss

pipeline or pipeline section, and the marginal per-barrel cleanup cost (L) is known for a specific area, optimal segment length estimates can be made using Figures 6-2 and 6-3.

Most events result in small spill volumes; however, large volume spills (those in excess of 4000 bbls) result in substantially more total product loss per unit time. In fact, 50% of total volume spilled in the years 1988 -1994 resulted from the 5% of the incidents with the largest spill volumes that occurred during that period.

Table 6-3 Frequency and cumulative percent of spills by volume (1988-1994)

Spill Volume Volume in Size Category Cumulative Percent of Volume Total incidents Size (% **0f Total) Cumulative Percent of Incidents**

Less than 2	112	0.00955	177	12.4	12.36034
2 to 4	156	0.022852	64	4.5	16.82961
4 to 8	584	0.072648	109	7.6	24.44134
8 to 16	623	0.12577	52	3.6	28.07263
16 to 32	1583	0.260749	65	4.5	32.61173
32 to 64	5484	0.728357	113	7.9	40.50279
64 to 128	13583	1.886548	151	10.5	51.04749
128 to 250	26880	4.178544	150	10.5	61.52235
250 to 500	53843	8.769613	158	11.0	72.55587
500 to 1000	99767	17.27652	144	10.1	82.61173
1000 to 2000	138377	29.0756	97	6.7	89.38547
2000 to 4000	235498	49.15598	85	5.9	95.32123
4000 to 8000	246025	70.13396	46	3.2	98.53352
8000 to 16000	136147	81.74291	12	0.8	99.37151
16000 to 40500	214115	100	9	0.6	100
Total	**1172777**		**1432**	**100%**	

Since segment specific data on these spills are unavailable, we created an approximation of a segment length for each spill that would be equivalent to the product volume spilled. The volume of product spilled in each incident, as well as the nominal pipe diameter of the affected pipeline are reported in the OPS data used for this analysis. The reported volume spilled can be represented as a pipeline length by dividing it by the pipe capacity (p in Table 6-1). Pipe capacity can be calculated from pipe diameter using the following equation, assuming the pipe was full and by neglecting product compressibility.

V (volume) = L (length) x (Nominal Diameter)² x ?/4

The resulting length ranges and spill frequencies are shown in the figure below. These indicate that most spill incidents would be unaffected by even extremely close valve spacing. However, the largest spills, which represent most of the total volume, have equivalent segment lengths ranging from 4 to 57 miles.

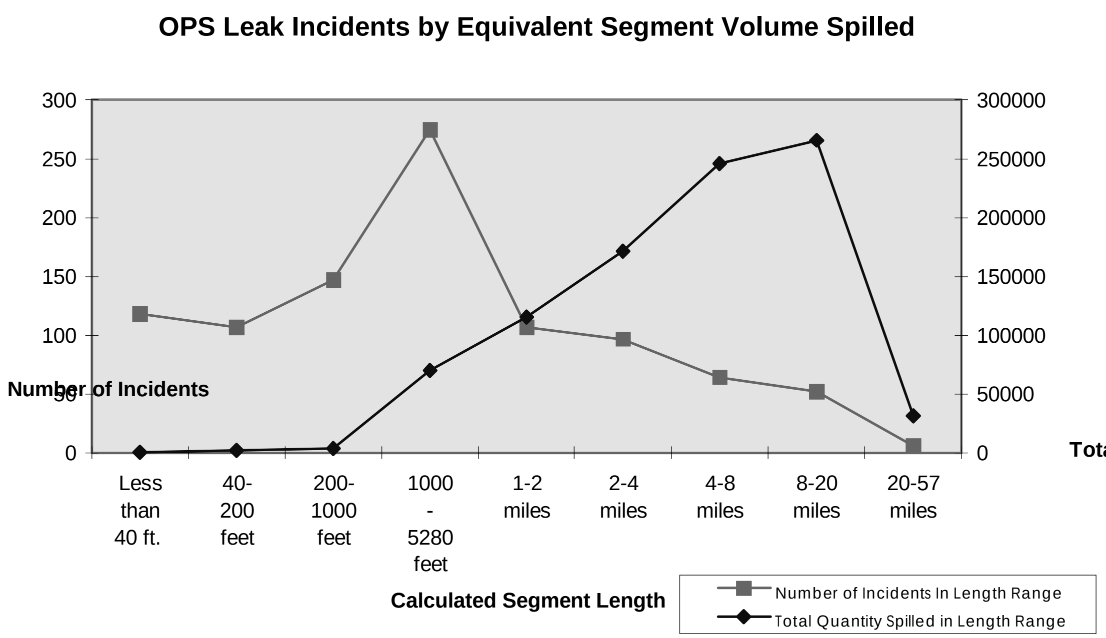


Figure 6-5 OPS leak incidents by equivalent segment volume spilled

This model also offers a perspective to the operator who is deciding between manual and RCV block valves. RCVs cost more but imply a faster response time. Their higher cost has a large impact on the optimum valve spacing, but their faster response time only affects the variable k in our model which was shown to have little impact on spacing. Close valve spacing is advantageous only in situations where a significant fraction (a) of a segment would be lost after it is isolated. Some operators have chosen to use a mixture of manual and remote control valves, which may offer benefits especially in cases where ? decreased with respect to segment length or it increased for longer response times.

Leak detection systems should lower the response time and reduce the portion of the cost that is represented by k in the model above. However, leak detection systems, like valves, have their own benefits and costs. Like the valve-specific leak rate included in the equations used to describe optimal valve spacing, leak detection specific failure rates must be included in an evaluation of their overall benefits. A method of evaluating leak detection system performance characteristics is discussed in the next chapter.

Chapter 7: Model-based LDS performance

7.0 Introduction to LDS models

Leak detection system performance characteristics can be used to choose among alternative systems when operational requirements are well understood. For instance, when pipeline characteristics, such as configuration, grade, and product, are fixed, the cost of alternative leak detection systems can be used comparatively to select a preferred method. However, each method has instrumentation and operational support requirements that vary. In addition, systems that seem to have the same costs may have widely varying leak detection sensitivities and false alarm rates. Therefore, this model is offered as a method to compare among alternative systems when both operational and LDS characteristics are known. Three major attributes of a system's leak-detection performance can be measured and used to compare competing systems:

1. Detection time
2. False alarms
3. Costs

Rather than suggesting a single performance measure that is a function of these three factors, it is proposed that decision-makers and regulators first assess the performance of a particular system by means of an Operating Characteristic (OC): a plot of expected detection time (or equivalent measure) on one axis and the false alarm rate (or equivalent measure) on the other axis. Cost, the third category of measure, can then be used to discriminate among the systems that have already been compared by means of the OC.

Figure 7-1 presents an example plot of an OC for three hypothetical system: A, B, and C. As illustrated by this figure, each system can be represented by a curve showing possible operating capabilities. By adjusting controllable aspects of the system, an operator can sacrifice quick detection for decreasing false alarms and vice versa. On this diagram any two operating points can be compared, with any point "dominating" another that is both above and to the right of it. Thus, it is possible to conclude that system A is always preferred to system B: for any operating point achievable with system B, there is at least one for system A that is better on both measurements or standards. However, the choice between systems A and C cannot be made without further information about where the operator desires to set either false alarm rates or detection times.

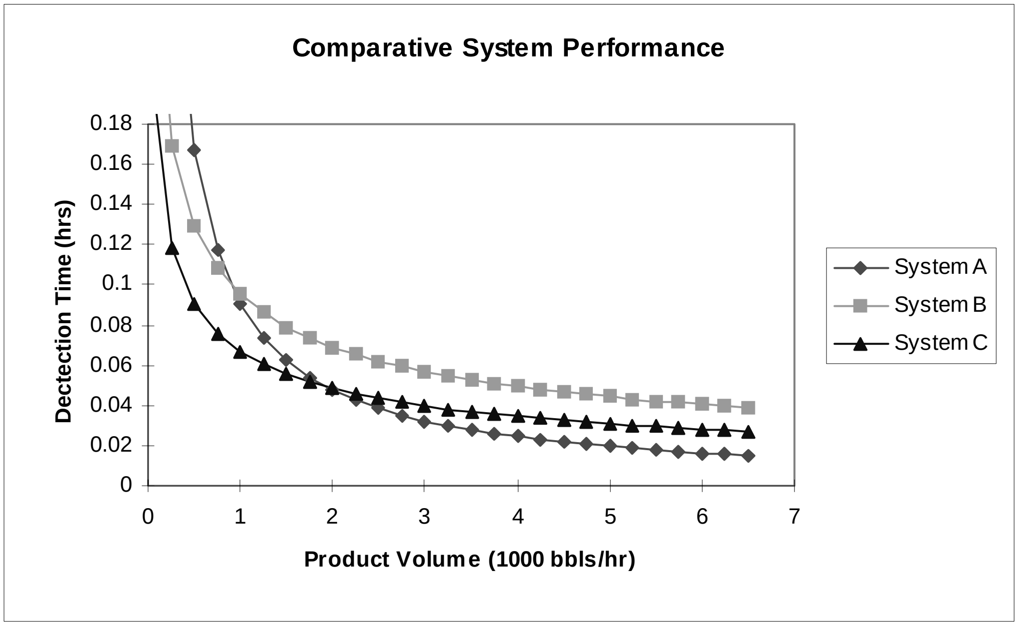


Figure 7-1 Comparative system performance

7.1 Model-based methods using SCADA: A simple example

The essential elements involved in using a model-based method of leak detection system can be best described by the use of a simple "toy" model. This model is not meant to represent any particular pipeline or detection software; in particular, it can readily be seen that most "realities" are left out: valves, branches, pumps, human factors, etc. However, it contains all of the features needed to explicate the nature of most detection algorithms and their impact on performance measures.

The fundamental idea behind most model-based methods is one of conservation of mass; in any given section of pipe, what goes in must eventually come out. By measuring (over a suitable interval of time) the volumes of input and output, any difference must be accounted for as either a leak or some other unexpected event. This idea is well articulated in the Canadian Petroleum Association's recommended practice (see Appendix B), which provides the foundation for the analysis presented below. The notation used here is intended to be generic, and typical dimensions are shown in parentheses for clarity.

Let:

r = rate of leak (ft^3/min)
t = time to detect leak (min)
Q = product volume threshold level for alarm (ft^3)

?Q = "uncertainty" in Q, from model (ft^3)

? = false alarm rate (#/min)

?$_0$ = "assignable cause" false alarm rate (#/min)

w = noise generated effective leak rate (ft^3/min)

V = measured volume differences between endpoints of a pipeline segment

7.2 Detection time

Consider a single section of pipeline in which, by any means, it is determined that a measured V (between selected input and output points) of product is obtained over a pre-specified period of time, t. An alarm is raised if V>Q, where Q is a threshold level set by the operator. The threshold level depends on the nature of the volume difference system, the measuring devices, etc. Since a leak rate r will produce a volume $r \times t$ in time t, simple conservation of volume (ignoring all transient effects) established at the time at which the alarm is raised (hence the "detection time") yields:

$$t = \frac{Q}{r} \qquad (7.1)$$

Note that this is the time it takes to raise an alarm given leak rate r and threshold level Q.

Since all models involve the use of parameter values that will not be known with certainty, various methods for incorporating "uncertainty" into models eventually boil down to ascribing to Q a total uncertainty ?Q , often by means of detailed and complex computations. This factor is used to "hedge" the alarm, by requiring not only that V exceed Q as above, but that V should exceed Q by the amount of this uncertainty. The resulting detection time is thus:

$$t = \frac{(Q + \Delta Q)}{r} \qquad (7.2)$$

An examination of Equation 7.2 makes it immediately obvious that t can be minimized by simply setting Q equal to 0; that is, having the volume threshold equal the total uncertainty in Q. Indeed, this general attitude seems to be prevalent in much of the literature.

7.3 False alarms

Our analysis to this point does not contain any performance measures related to false alarms. The simplest model incorporating false alarm contingencies contains two contributing factors:

1. False alarms due to “assignable” causes, such as unreported valve openings, or unanticipated transients that are well understood after the fact. These can be represented by a rate $?_0$, which will depend upon the operating procedures for the pipeline, operator training, and scheduling uncertainties. In the simple example here, it is assumed $?_0$ is constant. In reality, of course, $?_0$ may vary over time, due to changes in operational procedures, training, weather conditions, product mixes, etc.
2. False alarms due to “noise” in the system; that is, false alarms due to random occurrences of signals received by the instrumentation in such a way that an alarm situation is occasionally created. For example, ambient temperature fluctuations can result in viscosity changes that then are translated into volume discrepancies not attributable to leaks. Also, instrument calibrations can change (especially meters) because the sediment content of a product like crude oil varies depending upon its source and the sediment content fouls the meter. In addition, segments with slack conditions (e.g., downhill slopes) distort pump pressure and volume readings. The effect of these false signals depends on the threshold *Q*. The higher *Q* is set, the less likely it will be that a set of random signals and measurements will exceed this threshold. These can be represented (for the purposes of this model) by assuming there is some (known) noise-generated “effective leak” rate *w*.

The time needed for a false alarm to be generated by this randomness is either *Q/w* or *Q+?Q/w*. Thus results the total false alarm rate, ?, which is equal to the sum of two terms:

$$\Phi = \Phi_0 + \frac{w}{(Q + \Delta Q)} \qquad (7.3)$$

Combining Equations 7.2 and 7.3 creates the OC that serves to represent the most important operating aspects of the system:

$$\Phi = \Phi_0 + \frac{w}{(t \times r)} \qquad (7.4)$$

An illustration of Equation 7.4 for different values of the leak rate r is given in Figure 7-2. The curves are obtained by varying the value of the threshold *Q*: a high value of *Q* produces long detection times but low false alarm rates; a low value of *Q* produces short detection times and higher false alarm rates.

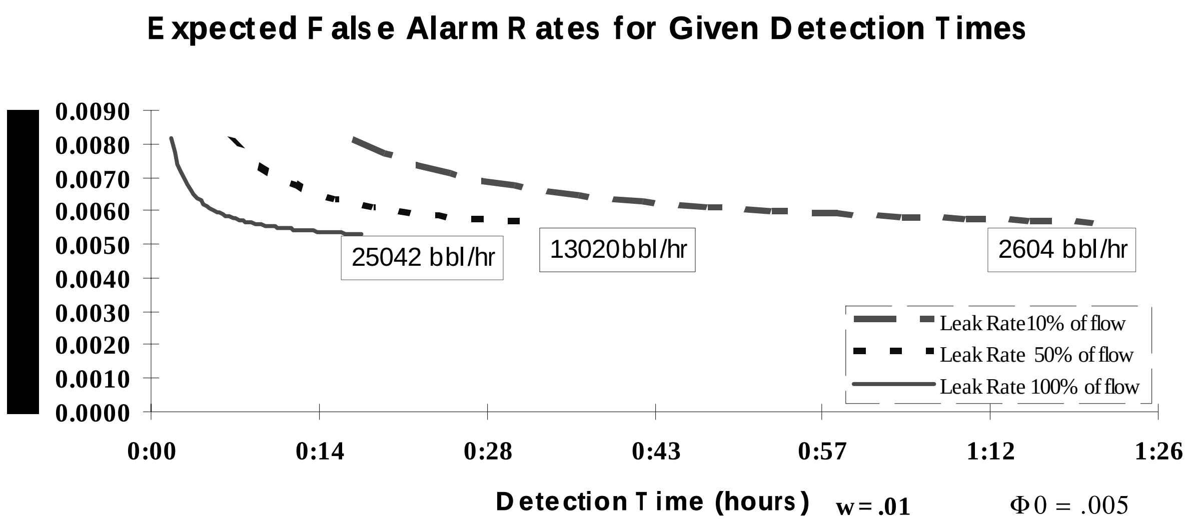


Figure 7-2 Expected false alarm rates for given detection times

Using Equation 7.4 requires the consistent measurement of only two parameters, *w* and $?_0$, to compare the performance of competitive systems. A thorough analysis of the operational performance of a leak detection system is needed to compute the parameters as functions of other factors. If (*Q* +?*Q*) can be measured, or credibly computed from a model, only one of the pair (*w* or $?_0$) need be obtained to characterize the performance of the system.

Note that, according to Equation 7.2, reducing the uncertainty ?*Q* to zero reduces the detection time t. However, according to Equation 7.3, if the detection threshold is decreased so as to be equal to *Q*, the false alarm rate increases.

7.4 System reliability

System reliability is a critical component in the realistic evaluation of overall system performance because of two factors:

· Knowing the reliability of a system is necessary to evaluate and compare alternative proposed systems, given a particular pipeline's configuration.

· False alarms can compromise system reliability and leak detection capability by presenting a nuisance to operators.

To account for system reliability, events such as communication link breakdowns, lapses in operator attention, and power outages in the SCADA system can all be lumped together into a single term "failure." There is thus an overall "failure rate" z (failures/unit time), and there is an associated time *t* needed for the system to recover from such failures. An elementary analysis shows that the resulting expected detection time and the expected false alarm rate ? are given by:

$$\bar{t} = t + \frac{(1-u)\tau}{2}$$
$$= \frac{(Q+\Delta Q)}{r} + \frac{(1-u)\tau}{2} \qquad (7.5)$$

$$\overline{\Phi} = \Phi u = u(\Phi_0 + \frac{w}{(Q+\Delta Q)}) \quad (7.6)$$

where u=[1/(1+zt)] is the fraction of time spent in an operating ("up" or non-failed) condition. The resulting OC is then:

$$\overline{\Phi} = u[\Phi_0 + (\frac{w}{r})(\frac{1}{(\bar{t} - (1-u)\frac{\tau}{2})})] \quad (7.7)$$

If one is interested in operational measures, one must obtain experimental or model-based values of the parameter u, the reliability of the sensor.

Finally, note that these equations have shown that the relationship expressed by Equation 7.2 is more suitably represented by introducing an additional parameter r_0, which can be construed as the minimum leak rate that a particular detection system/ pipeline combination can detect. Experimental results (Liou 1992) show that the relation between r and t is empirically represented by:

$$r = r_0 + \frac{(Q+\Delta Q)}{t} \quad (7.8)$$

Thus, the detection time t of Equation 7.2 can be more generally expressed as:

$$t = \frac{(Q+\Delta Q)}{(r - r_0)} \quad (7.9)$$

In a similar way, the false alarm rate F is now expressed in Equations (7.4) or (7.7) with r replaced by $(r-r_0)$.

Further research is required to specify *u* and *t* for given systems and to specify how increases in the false alarm rate compromise reliability, since false alarms that require system shut downs decrease u and create additional time periods when leak detection cannot occur.

Chapter 8 Summary

The review of the literature on pipeline leak detection and SCADA operations and visits to SCADA and LDS vendors highlights the diversity of the industry and LDS/ SCADA applications. In total, the pipeline companies interviewed in this study operate over 27,000 miles of pipeline, approximately 25,400 miles of HVL and 1,600 miles of gas pipeline. This represents 16% of the total HVL pipeline mileage regulated by OPS and 0.6% of gas pipeline miles. These pipelines included desert and mountainous segments, offshore intakes and industrial in-plant delivery points; and they represented a range of products from crude oil to natural gas.

The diversity of the pipeline industry in turn demands broad requirements for pipeline monitoring and control systems - including LDS. Vendors and pipeline operators have continually attempted to design and tune systems to perform under many specialized conditions. SCADA/LDS vendors have developed numerous techniques and adaptations to products and environments to deliver high sensitivity and reliability.

Commonly, SCADA/LDS systems functionality is dependent upon the sophistication of the host computer system and rapidity with which field data can be provided to it. These two constraints have rapidly relaxed over the last ten years. Advances in computer speed and communications technology have been as critical to the popularization of SCADA systems as have the demands of the industry.

Companies have generally made major investments in SCADA, less in LDS. Companies who buy vendor-provided LDS must invest considerable effort and ingenuity adapting the products to their needs. Some who have made the effort have also advanced LDS technology in the process.

Most companies interviewed as part of this study, and who responded to an industry survey conducted by API, said that they used SCADA or LDS. (Oppenheim Research 1991) SCADA is frequently used by operators for pipeline control and monitoring. Formal LDS are less often acquired than are subroutines built by pipeline operators themselves, using SCADA data as their basis.

Both the site visits and literature reviews have both shown that SCADA and LDS can become an integral part of the dispatcher?s job. However, it is crucial that systems be reliable and have a low false alarm rate. Excessive false alarms may lead dispatchers to ignore the information being presented to them. Likewise, SCADA/LDS must be amenable to rapid understanding and manipulation by their users. Dispatchers must be able to feel comfortable with the systems and understand them well enough to incorporate the system?s diagnostics into their control activity.

Most of the pipeline operators interviewed felt that the critical link in reducing the incidence and volume of pipeline spills lies with dispatcher training. They frequently indicated that there was no substitute for a well-trained dispatcher, most especially not a PLC or other software routine designed to automatically shut down the pipeline. The dispatcher is often the final decision-maker in the process of leak detection and pipeline shutdown. If operators fail to recognize a problematic situation and intervene, unchecked spills are the likely to be large.

Their position may be borne out by existing data - several of the largest spill volumes not attributed to outside force accidents among reportable spills recorded in the OPS data base are attributed to operator error. In 1986, and 1987 for instance, the highest reported spills attributed to corrosion caused the losses of 8,000 and 6,000 barrels, respectively. In those years losses due to operator error were over 14,000 barrels.(USDOT RSPA OPS 1995) More recently, spill volumes to due corrosion have increased to as much as 28,000 barrels in 1991, while, on average, spills due to operator error have been reduced, however in 1993, the highest spill volume attributable to operator error was reportedly 6,200 barrels, compared to a maximum due to corrosion of 700 barrels (USDOT RSPA OPS 1995).

In chapters 4 and 5 the attributes of LDS that enhance (or constrain) their performance in various pipeline environments were discussed. All LDS are not applicable to all environments therefore careful planning is required to determine exactly which system will best suit any particular operator. For instance, hydrocarbon sensing cable is very effective in leak detection but also very expensive. Therefore, its applicability is limited to those locations where the cost of a spill is potentially very high, such as an unusually environmentally sensitive area or near a hospital or school. Pressure deviation techniques may issue too many false alarms if they are used on pipeline segments that have several injection or delivery points. Frequent operational changes such as these may compromise the integrity of the system. Volume balance techniques must be compensated for those deviations in pressure or velocity associated with downhill grades if they are to be effectively applied in topographically varied regions.

Even with these limitations, the field visits and review of existing literature have shown that a SCADA or LDS system can be found to suit most pipeline environments. The most important constraint is that the SCADA or LDS be accompanied by a well-designed dispatcher interface.

The evidence gathered from this study does indicate that any system including standard metering devices and a few pressure transducers would be able to recognize leaks of > 5% of flow within one line-balance recalculation period. Leaks of higher rates (such as 10% of flow per hour) would result in pressure fluctuations or pump pressure changes that would be reported back to the dispatcher at the next data update (the time frequency equal to the scan or polling rate). Therefore, most ruptures could be detected by the dispatcher within 5 seconds to 5 minutes of their occurrence (depending upon the speed of the communications system).

Pipeline rupture detection procedures such as visual inspection, pressure deviation monitoring and volume balance calculations are currently practiced by the pipeline industry, although implementation of automated or formal LDS systems is not as common. Most manual systems of rupture detection can be automated by acquiring relatively simple and commonly available hardware (such as pressure transducers) or developing simple computer programs to display trend analyses of volume balance data. Field instruments coupled with a telephone line and a personal computer can, in most cases, provide the pipeline operator with reliable status information on the pipeline. Implementation of a system including dispatcher training, can allow almost any pipeline operator to conduct effective rupture detection.

As par of this study a trade-off model was developed to help operators evaluate alternative EFRD spacing, and estimate the optimal economic value of an LDS for their pipeline. This model is discussed in chapter 6. Utilization models for LDS and EFRD spacing have were developed as part of this study and applied to simplified situations. Potentially, they provide operators with a methodology for trading-off LDS costs and benefits, but their full implementation will require additional data. EFRD?s can lower the pipeline operators bottom line over the long term, but their value can only be fully realized by rapidly detecting leaks and implementing shut-down procedures that do not cause additional line damage. Consideration of the adverse consequences of major structural changes to existing lines required by installing EFRD?s should be included in the evaluation of their best placement.

The reliability models presented in chapter 7 provide a framework for modeling the trade-off between sensitivity and false alarm rates for an LDS. This model is useful for operators attempting to select systems with varying performance characteristics, and for estimating the economic value of marginal improvements in the leak detection sensitivity or reduction in the expected false alarm rate.

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