

**- Observations on Practical -
Leak Detection for Transmission Pipelines
- An Experienced Perspective -**

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“Clear Knowledge in the Over Information Age”

This report, developed from information clearly and readily in the public domain, represents the experience of the author who is solely responsible for its content.

I. Executive Summary

Based on extensive field experience, Accufacts was asked to comment on approaches to leak detection on transmission pipelines.¹ Transmission pipelines are the arteries of the hydrocarbon-based energy network, and there are many misconceptions, even within the industry, as to the technical capabilities of various leak detection approaches to reliably determine releases. This paper will provide a simple perspective on both liquid and gas transmission pipeline release detection, but, given the greater risks of liquid pipeline releases to seriously impact the environment, the majority of this paper will focus on liquid systems. Computer-based leak detection monitoring conditions within the pipeline (also known as internal leak detection) are utilized on most transmission pipeline systems employing leak detection and are the primary focus of this paper. Various computer-supported external leak detection approaches, which monitor for signs of hydrocarbon outside of the pipeline, are also briefly discussed.²

Transmission pipeline leak detection systems should complement appropriate integrity management approaches on a specific pipeline.

This author does not recommend historical approaches utilized in leak detection that focus on lowering alarm thresholds as a percentage of throughput (e.g., set at 1% of throughput) to address all forms of release. Such historical “one-size-fits-all” approaches create an illusion that tighter or lower thresholds are somehow better and this approach does not handle the three types of release (rupture, leaks, and seepage) well.³ In reality, a one-size-fits-all all approach creates a phalanx of false alarms caused by the different natures of releases, and ignores the complexity, system hydraulics, and dynamics of most liquid pipelines. These dynamics set up control room operators with alarm overload such that a real release is not determined, usually missed, or not properly responded to, in the many thousands of false leak alarms, all too many of which occur frequently, even daily. The author would describe the state of false leak detection alarms as epidemic, placing unwarranted and undo burden on, and even setting

up for failure, control room operators, the individuals chartered with monitoring and/or operating the pipeline system.

- “Leak Detection” Regulatory Recommendations**
- 1) Require pipeline leak detection “cover” critical areas.
 - 2) Emphasize reliable rupture determination.
 - 3) Release alarm thresholds should be based on plausible release rate, not on percentage of pipeline throughput.
 - 4) Pipeline operators should set and document the proper alarm thresholds for each type of release.
 - 5) Release alarm records and related documentation should be retained for at least 3 years.
 - 6) Leak detection alarm records should be made public.

This paper proposes computer-based leak detection approaches for liquid pipelines that are based on and tailored to the three different types of transmission pipeline releases. Such approaches are pipeline system or

¹ The author will utilize the general term “leak detection” to mean all forms of release, unless a specific qualifier for the three types of release is applied or inferred in the context.

² Pipeline leak detection is currently not a requirement in U.S. federal pipeline safety regulations, though single phase hazardous liquid pipelines that operate with computational pipeline monitoring must meet the recommendations of API (America Petroleum Institute) publication 1130 as per 49CFR195.444 CPM leak detection.

³ See State of Alaska, AAC Title 18, Chapter 75, Section 55 - Leak detection, monitoring, and operating requirements for crude oil transmission pipelines, which sets among other requirements “(1) if technically feasible, the continuous capability to detect a daily discharge equal to not more than one percent of daily throughput;...”

pipeline segment specific. The “Leak Detection Regulatory Recommendations” defined in the above textbox will improve leak detection performance. Each of the three types of release should have its own method of approach in determination of alarm threshold, as well as separate alarm indication/alert that eliminates or substantially reduces false leak alarms presented to a control room operator. This paper also discusses several of the serious misconceptions related to pipeline leak detection and response. Core pipeline principles concerning system dynamics put to rest the illusion that the lower a stated alarm threshold, or the more complex a leak detection system, the higher the likelihood of identifying an actual release. Given the difficulty in identifying low rate or intermittent seepage leaks, which can be especially insidious to underground sensitive water supplies such as aquifers, a specific approach to more reliably determine such leaks is also presented (see Figure 2 on page 13).

Lastly, natural gas transmission release determination is briefly discussed, highlighting the additional challenges in computer-based leak detection for gas transmission systems moving highly compressible natural gas.

Release determination involving computers is becoming more important in gas transmission pipeline risk management given the greater propensity of many new gas transmission systems upon rupture to release significantly more tonnage of fuel most likely to detonate than past pipeline operations.

II. Liquid Pipeline Leak Detection

General Background

Many reports from the NTSB (National Transportation Safety Board) related to pipeline failures and poor leak detection alarm action/response have raised awareness for badly needed pipeline regulatory improvements in the area of leak detection and control room management.⁴ Congress in the PIPES Act of 2006 included a requirement for PHMSA (Pipeline and Hazardous Materials Safety Administration) to perform a study addressing pipeline leak detection for various types of releases on liquid pipelines.⁵

Leak detection can be subdivided into two major approaches: 1) those based on systems gathering and analyzing data concerning conditions of the fluid within the pipeline, known as internal leak detection, and 2) those leak detection efforts related to monitoring for signs of hydrocarbon outside of the pipeline, known as external leak detection.^{6, 7} Both major approaches are discussed below though the preponderance of liquid pipeline leak detection systems are internal (covering more miles of pipeline), using manual review or computers to assist in leak evaluation and determination of the outputs. This author has little doubt that regulatory improvements in pipeline leak detection as well as control room

⁴ For example, see NTSB Safety Study PB 2005-917005, “Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines,” adopted November 29, 2005.

⁵ PIPES, the Pipeline, Inspection, Performance, Enforcement, and Safety Act of 2006, section 21 defines the requirements for a leak detection technology study.

⁶ See API 1130, “Computational Pipeline Monitoring for Liquid Pipelines – Second Edition,” November 2002.

⁷ Computer based systems do not have to include SCADA as many leak detection systems can be set up on a stand alone leak detection computer that feeds a separate alarm system, though many leak systems either utilize or feed into an existing SCADA computer controlling/monitoring a pipeline.

management are warranted, given the increasing role that computers play in many of today's transmission system operations. Both internal and external leak detection systems have various strengths and weaknesses in effectively identifying the three basic types of releases that can occur on a high-stress transmission pipeline: ruptures, leaks, and seepage discharges.

Ruptures are high-mass-rate releases associated with the failure mechanics of highly stressed pipe, such as transmission systems, where an anomaly in a pipeline fails and catastrophically opens rapidly (in microseconds) well beyond the opening for the original defect. Leaks are much lower-rate releases associated with the hole or opening maintaining its original or fairly near its original size through the pipe wall failure. Leaks can still be quite spectacular, dangerous, and expensive as shown by the photo on the cover of this report.⁸ Both ruptures and higher-rate leaks usually become obvious in areas where visual detection is readily available, as such high-rate releases will frequently break to the surface even in deeply buried pipelines, and they impact areas well beyond the pipeline right-of-way. It is worth noting that there can be a considerable time span between initial release and visual determination even for these higher-rate releases.

Many slow-rate or intermittent seepage leaks cannot be determined with a "pressure squeeze," where the pipeline is shutdown, initially set at some level of liquid hydrocarbon "static" pressure, and the pipeline segment monitored for signs of pressure loss that might suggest a leak.

Seepage leaks are slow, lower-rate releases associated with very small holes or cracks that permit release through the pipe wall or at welds. Seepage failures can be especially troublesome. Their release may not always be continuous since various factors can cause such small holes or cracks to open and close, resulting in intermittent releases that can be very difficult to quickly find. Depending on the location of a slow-rate-leak or seepage release, even a relatively low-rate release can be quite insidious if located in or near a sensitive area such as

population or a critical drinking water aquifer (e.g., Karst aquifer).⁹ Because of their slow rate of release and/or intermittency, a considerable volume of oil can still be released without detection over long periods of time, generating very large underground release plumes. Not all low-rate leaks or seepage releases appear on the surface near a pipeline or on a pipeline right-of-way. As explained below, these slower-rate releases are harder to determine in real time than one might think, as oftentimes the rate of release is much lower than the reliable leak detection threshold rate of determination for a pipeline system or pipeline segment. Fortunately, methods such as that outlined in this paper can assist in capturing such low-rate or intermittent releases, hopefully before the underground plume can become too large or spread too far.

Liquid transmission pipelines move fluid in a liquid state at the operating conditions inside the pipeline. Most liquid transmission pipelines operate liquid full (single phase), but a small number require that one or more segments of their pipeline system operate in slack line condition, or not liquid full (vapor space above the liquid flowing in the line, or two phase). For transmission pipelines, slack line operations are usually connected with very large elevation changes and associated pipeline design limitations. Slack line operation for liquid pipelines introduces another level of noise or magnitude of

⁸ Burnaby, BC Canada 24-inch crude oil pipeline puncture "leak" release with no detonation or ignition, June 24, 2007. Photo courtesy of Mr. Shawn Soucy of Spirit Media, www.spiritmedia.ca.

⁹ A Karst aquifer is a type of aquifer where the enhanced rock porosity acts like a branching network, creating a faster moving underground creek that can rapidly spread underground oil contamination if it occurs.

complication/challenge to a pipeline's leak detection system(s) as flow is non-single liquid phase. Liquids encompass a wide range and mixture of hydrocarbon compounds ranging from the heavier-end asphalts and fuel oils to light hydrocarbons such as ethane and methane). Volatile compounds such as butane and propane are usually liquids in a pipeline but can easily become gases when released. There are many parameters affecting leak detection design/approaches on liquid hydrocarbon pipelines and API 1130 does an excellent job of summarizing some of these variables, underscoring the challenges of leak detection on liquid hydrocarbon pipelines.¹⁰

A critical parameter in the ability of liquid pipelines to remotely identify a release is the determination of the actual bulk modulus of the fluid mixture in the pipeline. The bulk modulus of a mixture is often estimated in various more-complex leak detection programs or compensated for by the use of correction factors that attempt to adjust for the change in actual bulk modulus associated with composition (and temperature) that drives the estimated change in the inventory of the fluid in the pipeline (i.e., the linepack).¹¹ Some of these programs even attempt to compensate for the change in size of the steel pipeline for different pressures and temperatures. Since bulk modulus is not measured (and it changes along a pipeline), a slight deviation in actual conditions from assumed conditions in the pipeline can introduce considerable error in inventory change estimates (i.e., the density changes along a liquid pipeline), raising the threshold requirements for leak detection.¹² It is best to think of a liquid pipeline system as an active compressible spring that never really settles down, even in a mythical steady-state operation. Some transient phases of pipeline operation such as startup and shutdown create more "bounce" or oscillations than normal within the pipeline. Only a rare few hydrocarbon liquid pipeline systems really operate in a true "steady-state" mode, because the liquid is highly compressed and contains considerable stored energy that creates additional noise within the system. Various balance approaches and other internal based leak detection system suppliers utilize different techniques in an attempt to deal with these noises.

A leak detection system is of little or no value if it generates a high number of false leak alarms.

Leak Misconceptions

- 1) Leak tests actually test a leak detection system.
- 2) Lower leak thresholds mean the system can identify larger releases.
- 3) "Closing" the system can be used to stop a release (the old soda straw trick).

Major Misconceptions Concerning Liquid Pipeline Leak Detection

Before describing the various leak detection approaches in further detail, the author believes that additional observations related to several serious technical misconceptions summarized in the text box at left are warranted. It is a common misconception that leak tests, usually performed by opening a small valve off the pipeline, simulate an actual leak. While this test may actually indicate that a particular leak detection

¹⁰ See API 1130, "Computational Pipeline Monitoring for Liquid Pipelines – Second Edition," November 2002, section 1.4 "Transportation Systems," page 2.

¹¹ Bulk Modulus, a fluid property which is usually a range for mixtures of hydrocarbon fluids and also highly dependent on temperature, is the pressure required to produce a specific change in volume. Compressibility for liquids is equal to 1/(Bulk Modulus), the higher the Bulk Modulus the less compressible the liquid.

¹² For example, 50 miles of 16-inch pipeline contains approximately 65,000 barrels (~9000 tons) of liquid, so bulk modulus imprecision can significantly affect gain/loss balances from inventory correction as further discussed below.

approach can indeed identify such an ideal leak at a specific point, this author has observed on too many occasions that such tests don't represent the real operation of the pipeline under its various changing hydraulic conditions. In other words, this test usually evaluates the system usually under very ideal conditions. Such tests also don't determine or indicate the number of false alarms that are generated by a specific leak detection system looking for "small" leaks.

Another common misconception is the illusion that a lower leak detection limit means the approach is capable of identifying larger releases. The three different types of liquid pipeline releases can and do exhibit substantially different indicators of release. These indicators may be different and can be easily masked. Many are complicated by the hydraulics on a specific pipeline system. Transient hydraulic analysis of a leak detection system applied to a particular pipeline is usually warranted to understand these differences as described later in this report.

Complex hydrocarbon liquid mixtures in pipelines are not soda pop!

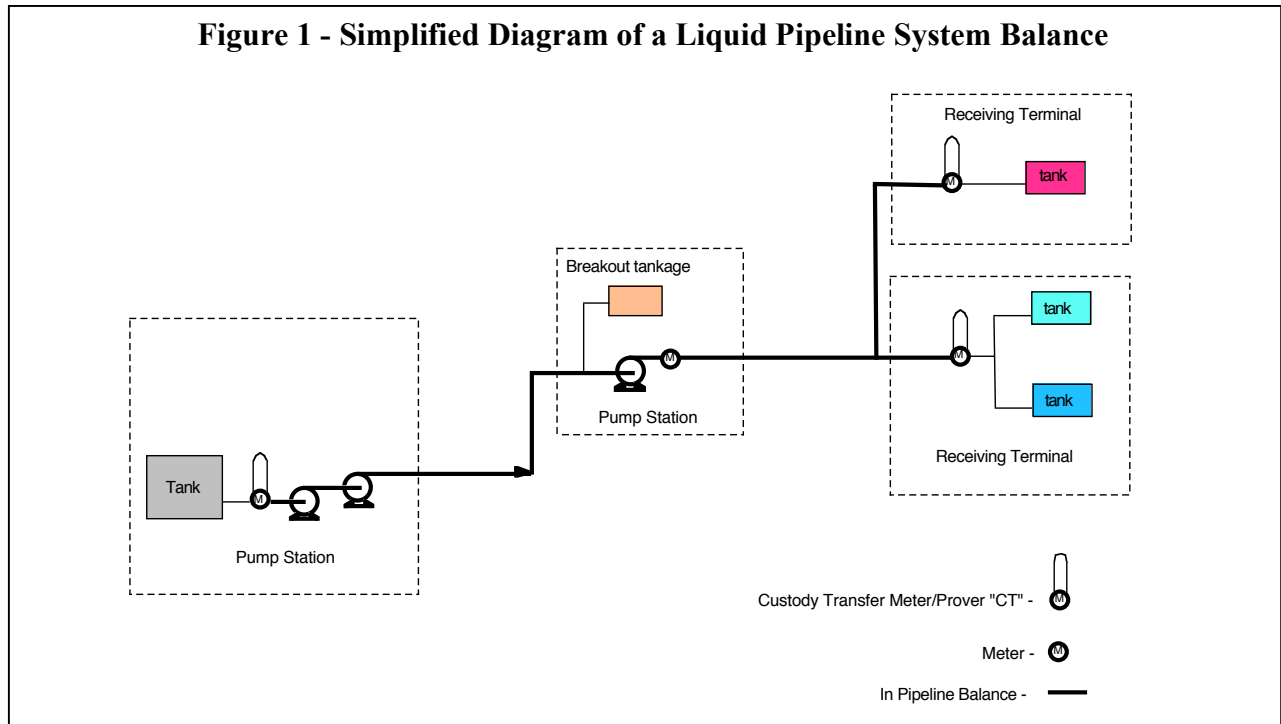
Lastly, this author is continually amazed by the application of very poor engineering approaches, some in often-cited official government reports, demonstrating a clear lack of experience and understanding in the handling of complex hydrocarbon liquid mixtures in pipelines under release conditions. Spill response plans

that recommend uphill valve closure to hold up or reduce downhill drainage of a pipeline into a pipeline break through "suction or siphon lock" (the misapplication of the so-called soda straw effect of holding liquid in a straw by closing your thumb over one end) are going to be in serious trouble as a result of not having sufficient spill response resources on hand. It is a very rare liquid hydrocarbon mixture (most are not that stabilized) that will not separate into gas and liquid under the pull of gravity, breaking any siphon lock that might occur from an uphill valve closure. A yield analysis of any hydrocarbon liquid through refinery crude and vacuum units will demonstrate the ability of even low-pressure hydrocarbon mixtures to easily separate under the pull of gravity. Reid Vapor Pressure and/or Flash Point are very poor indicators of a hydrocarbon liquid's ability to release vapor. Pipelines, especially in hilly conditions, can release out of a break for quite some time, even after pump shutdown and valve closure. Valve closure to limit the pipeline miles that can drain is important, but forget the soda straw effect to reduce possible release volumes.

Internal Leak Detection for Liquid Pipelines

Figure 1 on the next page represents a simplified diagram indicating the system captured (bolded items) in a typical liquid pipeline balance. Pumps are usually used to provide flow along the pipeline and meters of various types are used to measure or account for the volume of liquid into and out of the pipeline system as well as sometimes along the system. Shipping tankage at the front of the system as well as receiving tankage at the end of the system can also be part of a pipeline system, though not always. Additional tankage may be located along the pipeline for various reasons including overpressure protection, breakout, or receipt/delivery. Various monitoring devices such as pressure, temperature, flow, densitometers, etc., may be placed along a pipeline. And, of course, there are additional remotely operating devices that control pump start, stop, flow rate, pressure, horsepower, and in many cases remote operated valves, all of which are not shown in Figure 1 to keep the drawing simple. The status of all these input devices is usually gathered, monitored, and controlled by a central control computer, or SCADA system, whose design varies considerably from pipeline to pipeline, depending on the complexity and field inputs the operators have designed and installed in the field.

Figure 1 - Simplified Diagram of a Liquid Pipeline System Balance



Special attention should be paid to the location and distance between higher precision custody transfer meter/provers (“CT”) usually used for volume measurement into and out of the pipeline system. Because of their higher capacity and greater precision, the higher precision custody transfer meters on liquid transmission pipelines are usually specially conditioned turbine meters, though positive displacement meters are also sometimes used to measure volume. Along with the higher precision meters, certain other additional equipment such as “inline mixers,” samplers, and a remotely operated fixed “certified” meter prover (to periodically prove the meter) will be sited with the meter (or bank of meters). Meter provers are utilized to maintain appropriate volume correction factors, or identify when a meter needs repair/replacement, on special meters requiring the higher precision. The provers are designed to ensure custody transfer meters maintain their intended higher precision which can degrade over time with wear, throughput, or changes in hydrocarbon composition. On occasion, these higher precision rated meters in combination with fixed meter provers may be installed at certain locations along a lengthy pipeline (i.e., at pump stations) to tighten the precision of a “sensitive” pipeline segment balance, though often lower precision meters or tankage are used for measurement down a pipeline. Some lower-volume throughput pipelines sometimes utilize portable meter provers placed on trailers that can be driven from site to site to prove certain meters.

It is worth noting that not all pipelines utilize the higher precision custody transfer meter/prover combination even for in and out volumes. Depending on the complexity and throughput of the system, some pipelines will utilize lower precision meters (e.g. non prover turbine meters, ultrasonic meters), or even tankage to account for some or all “custody transfer” barrels in and out of a pipeline, or measurement along a pipeline.¹³ There are more recently developed flow meters capable of directly measuring mass (e.g., Coriolis meters), but application of mass measurement on transmission systems

¹³ Higher precision custody transfer meters and their associated calibration equipment (i.e., meter provers) are more expensive than conventional flow meters, both in capital and expense dollars, and require greater land footprint for the support equipment.

is of limited use or little added value in most transmission systems (see linepack discussion below). Lower precision meters and/or tankage volume measurement introduces much greater imprecision into pipeline measurement and balancing. For example, changes in daily atmospheric pressure can introduce substantial variation in a tank's liquid measurement, especially for large diameter tanks. The imprecision of these other types of meters, and the even greater imprecision of tank measurement, is well understood in the industry, and is usually captured in greater permitted pipeline loss allowance, or PLA, for a specific pipeline or pipeline segment incorporating such imprecision into its design and operation.¹⁴

Internal Leak Detection - Balancing Approaches for Liquid Pipelines

Most computer-based systems attempt to perform some form of “real-time” pipeline volume balance that may alarm upon a specified deviation. The balances compare barrels in against barrels out while correcting for pipeline volumetric inventory changes within the pipeline or pipeline segments between the in and out measurements (i.e., the linepack). The system/segment balances tend to take some form of the general equation:

$$\text{Gain/(Loss)} = \text{Barrels Out} - \text{Barrels in} + \text{change in pipeline inventory} \quad (\text{Equation 1})$$

A common form of balance is a simple Line Balance, where the inventory change in Equation 1 is set at zero and the in/out measurement differences are tracked either by running manual calculations performed at specified time intervals on a tabular sheet or by a computer that does real-time comparisons. Line Balances may be appropriate for short, simple pipeline systems. Other forms of balance using the basics of Equation 1 are often cited as being a “mass or material balance.” In reality mass-balance measurements are volume measurements corrected to standard volume reference conditions of 60°F and 14.7 psia utilizing industry specified volume measurement correction tables. These tables adjust each volume measurement taken at operating conditions to the standardized conditions required for custody transfer. These correction tables are often incorporated into the leak detection or SCADA computers. Thus these so-called mass or material balances for pipeline systems are actually corrected volume balances in which a mass balance may then be calculated or estimated. Actual mass is never measured and there can be considerable variation in the correction to pipeline-calculated mass or material balances, especially as the change in liquid inventory (linepack) for mass can be considerable with composition, temperature, and pressure variations (i.e., the Bulk Modulus effect). Pipeline balances are based on measured “corrected” volumes resulting in volumetric gains (losses). Mass or material balances derived from such volumetric balances are not true mass balances. Some pipelines actually attempt to measure density in various locations to calculate mass in and out at the measurement point and sometimes along the pipeline, but even these efforts fail to permit a true mass balance (i.e., the inventory change usually negates the accuracy intent of a true mass or material balance). The author discourages the use of the terms “mass” or “material” balances in pipeline operations, as these terms regarding pipelines are serious misnomers that create a false expectation of accuracy in the public's mind (and even in many pipeline operators' minds) that pipelines actually or accurately balance mass.

Pipelines balance volume and this approach creates volumetric gains and losses in every pipeline operation.

¹⁴ PLA is an accepted pipeline tariff condition intended to help compensate the operator for the cost of operating the system including a possible bias volume loss or “shrinkage” that may be associated with a specific pipeline design/operation (e.g., tank venting/flaring). Not all pipelines utilize PLA.

In real-time balances, water in will not usually equal water out in wet systems as water inventory varies considerable even on higher velocity pipelines.

Oftentimes complicating the volume balance is an adjustment for water that may be problematic on some systems. This is because water introduces another variable and more possible noise into the leak detection balancing efforts. Given that water should usually be a small percentage compared to the barrels entering or in a pipeline system, for purposes of computer balance leak detection, we advise clients to perform a gross or wet-barrel “balance” corrected to

volumetric standard conditions (i.e., temperature/pressure correction) for operational real-time leak detection purposes (i.e., SCADA). An accounting balance is also usually performed at least monthly on the dry hydrocarbon basis (net water) for pipeline systems. Note that many such systems include tankage where water can settle, as well as the mainline pipe.¹⁵ The accounting net balance should, however, not be confused with real-time leak detection efforts as two different purposes are being served. Water may sometimes be removed as it proceeds down a pipeline system, though this is not always a certainty, and attempts at water removal should not deactivate a pipeline leak detection system, at least for extended periods of time.¹⁶

There are various different approaches to the basic Equation 1 gain/loss volume balance, and space will not permit me to discuss each in detail. All such approaches attempt to provide a gain/loss volume balance across the system. All attempt to correct for the differences in measurement and/or pipeline inventory to tighten the confidence in a specific volume balance. Various balance detection methods may apply slightly different approaches to compensate, correct, or address each part of Equation 1, as well as how that information is interpolated (using different algorithms), displayed, and/or presented to the pipeline control room operator. Some balancing systems go beyond just providing an alarm, for example, in that a chart or graph (more than a trending graph) is also presented to assist the operator in evaluating the system fluid hydraulics and dynamics. Many of these balancing approaches, depending on the pipeline system, work just fine for certain types of releases. One of the proofs or validation points of each of these approaches is the number of false leak alarms they generate. Balancing approaches do not tell the operator the location of a possible pipeline leak, only that a particular pipeline segment or system between the measurements is not “balancing” to a specified precision limit.

The author has taken more time in explaining the basic approach to pipeline balancing than the average reader may first want to know, but these are important core balancing concepts that many misunderstand, even in the pipeline industry. Misunderstanding of these concepts can create serious misperceptions regarding balancing leak detection capabilities and the challenges that each system may face.

The difficulty in all these balancing approaches is that as leak alarm thresholds are lowered to try to capture smaller releases the number of false alarms increases considerably, especially if the alarms are set below the controlling precision measurement(s). Consequently an operator can and often does lose confidence in a particular leak detection system’s ability to actually alert to a real release (i.e., too many false alarms).

¹⁵ In addition to various operational gross (wet barrel) balances to assist operations in leak detection, the industry usually performs a monthly dry or net water basis “accounting balance” to settle customer accounts.

¹⁶ Dollar transfer between parties is usually based on net corrected dry barrels, and pipeline tariffs will usually state the maximum amount of water permitted before the pipeline will take action on a shipper trying to get rid of or shift a water problem onto a transmission pipeline.

Important Liquid Pipeline Balancing Concepts

- 1) The precision of a volume flow in/out measurement is dictated by the lowest precision measurement device (i.e., higher precision meter with certified prover, regular meter, and/or tankage) utilized in the balance.
- 2) Given the vast amount of volume in a transmission pipeline, inventory change/correction to estimate what is really in the pipeline (i.e., linepack is never actually measured in real time), usually controls or dictates the lower limits of “real time” leak detection thresholds utilizing balancing methods.
- 3) Pipelines do not perform real mass or material balances.

Internal Leak Detection – Non-Balancing Approaches for Liquid Pipelines

Pressure, Flow Changes, and/or Statistical Fingerprint Identification

There are various other non-balancing computer-based leak detection methods tracking fluid hydraulic changes within a pipeline. Such methods usually relate to identifying pressure and/or flow changes or other statistical fingerprints (e.g., acoustic, negative-pressure wave, ultrasonic wave) that are related to signals possibly identifying a pipeline release. Some of these systems attempt to identify the location of the release. Many of these systems require that the operator “tune” a leak detection system to a specific pipeline (reduce certain noise), or require adjustment of statistical algorithms to assure confidence in such approaches. This is because many operating signals are very similar to the “fingerprint(s)” trying to be identified. In the opinion of this author, if the time it takes to tune these systems extends beyond more than a few months, the nature of this leak detection approach may be poor for that specific pipeline because of the changing nature or challenges of that pipeline’s hydraulic dynamics. Serious consideration should be given to changing alarm thresholds or choosing another leak detection approach, especially if too many false leak detection alarms are generated. Depending on the complexity and associated field equipment in a pipeline system, pressure/flow changes may not be the quickest or best method to identify a release, even ruptures, as such changes can take considerable time to show up on a computer system, even with liquid systems.¹⁷ These leak detection approaches can also be very poor at identifying releases during periods of high transients, such as system startup and shutdown, or major flow changes, when hydraulic noise within the system can be significant.

Real Time Transient Modeling

In an attempt to deal with the many transients associated with a pipeline, this approach utilizes computers to calculate transient hydraulic models of a pipeline or pipeline segment and compares these computed values (i.e., pressure-flow gradients) against actual field measurements. Certain deviations between the calculated and measured parameters trigger leak alarms. This leak detection approach tends to be the most complex and most expensive of the various leak detection system efforts. This method is usually highly dependent on the actual field measurement equipment installed along the pipeline (type and number). This field equipment also needs to be properly placed, calibrated, and

¹⁷ A pump trip on low suction pressure with increased flow could signal a possible rupture, but this indicator can also be associated with other system hydraulics, so pipeline hydraulic simulator training can be very helpful.

maintained to keep the leak detection system functioning properly. Real Time Transient Modeling usually attempts to identify the type of release and its general location on the pipeline.

The author needs to be very clear that many internal non-balance leak detection systems work just fine at determining certain releases if they are properly applied to specific and usually less-complex pipeline systems. It is all too easy to blame the leak detection vendor or control room operator when leak detection is poorly chosen, badly incorporated, or unwisely maintained in a pipeline system.

Ironically, leak detection computers and software packages are the “cheap” part of an overall effective leak detection system.

This author recalls one case involving a particularly insidious pipeline release in which the pipeline management punished the control room operator and blamed the leak detection system vendor for the failure to properly detect a major and very expensive rupture release. During the discovery phase of litigation it became very clear (in a highlighted statement on the first page of the vendor’s manual supplied to the pipeline before purchase) that this specific leak detection product did

not work on pipelines operating in slack-line conditions. A large segment of this particular pipeline operated in slack line (well documented in the pipeline’s own operating manual), and this particular leak detection product should never have been installed on this pipeline. Given the many complexities on a pipeline system, installing the cheapest leak detection system, or for that matter the most expensive system, may not be the most technically sound approach or prudent management decision. It is very poor management practice to blame line-operating personnel (e.g. control room operators) for poor management decisions related to equipment selection, installation, operation, and/or maintenance that set up operating personnel for a failure to do their job.

External Leak Detection for Liquid Pipelines

Remote monitoring

External leak detection relies on various approaches such as sound (acoustics) or chemical methods to detect hydrocarbon, once it has left the pipeline. Remote sensors (either fixed or continuous) feed into a computer (e.g., SCADA) to alarm on detection. Many of the external buried systems are limited in the length of pipeline they can monitor, restricting their prudent application. Another difficulty with external leak detection systems is ensuring that the release actually reaches the sensor wherever it is located in proximity to the pipeline. Such contact is not always a certainty given various soil conditions and pipeline release orientation. Murphy’s Law also can work against the buried external leak detection system to divert a release away from the sensor, cable, or pickup. A further problem associated with external sensors is assuring that the sensors don’t generate too many false alarms from background sources not associated with the pipeline. Several types of sensors and approaches can discriminate between a pipeline and background sources (e.g., utilize tracer compounds introduced into the hydrocarbon stream or selective hydrocarbon pickup), reducing the likelihood of false external leak detection alarms.

In the application of external leak detection in highly sensitive areas using buried sensors, it is not unusual for a new pipeline installation to use gunite, or other types of membrane, to coat the pipe trench walls to try and act as a catch basin for a low-rate release. This approach’s intent is to increase the probability that a low-rate release will pool in the soil in the vicinity of an external sensor next to the pipeline, improving the likelihood of sensor detection. There are other forms of external leak detection utilizing some form of annular spacing / gas purging around a new pipeline or vapor pickup

“cable” for an existing pipeline application. In the author’s opinion, these purging or vapor pickup approaches are highly restricted in their field applications. Such restrictions include the inability to be prudently retrofitted to existing pipelines, very limited practicality (especially length) for a specific transmission pipeline/product, or a high likelihood a gas/vapor won’t reach a sensor for various reasons.

Visual

Visual release detection does not fall into the computer alarm leak detection category but visual observation for actual release plays an important role in determinations. One of the disadvantages of visual inspection is that considerable time can occur between the start of a release and discovery, especially for low-rate or intermittent releases. Not all releases reach the surface, so visual discovery is not guaranteed, nor does no indication of a release on a right-of-way (“ROW”) guarantee no release is occurring. A prudent monitor of a pipeline ROW will look for secondary signs of releases such as vegetation discoloration or oil sheens on nearby land and waterways on and off the ROW. There are many efforts underway to apply various new technologies to externally identify certain types of liquid pipeline releases. Such approaches (i.e., FLIR thermal imaging, aerial laser scan) try to improve external leak detection capability while reducing ROW monitoring cost by utilizing aerial or satellite surveillance covering greater areas of the pipeline. To date, these technical applications are still in the very early stages of development, having highly mixed levels of success on transmission pipelines (most generating too many false alarms) to be considered reliable or creditable.

A More Prudent Approach to Computer-Based Liquid Pipeline Leak Detection

Given the complexities of pipeline leak detection and the considerable problems associated with false leak alarms creating a loss in confidence within the control room operation, a more pragmatic and technically sound approach is warranted. This more technically sound approach should properly focus on and be tailored to reliably determining the three different types of liquid pipeline releases where warranted, their much different rates of release, and associated different hydraulic characteristics.

Ruptures

For ruptures, liquid pipeline operators should set their systems to detect high-rate releases, and alarm settings should not be based on a percentage of throughput. A specifically identified “possible rupture” alarm should be clearly indicated for a critical pipeline segment. The alarm rate for rupture release for a pipeline system or critical pipeline segment, such as that spanning a high consequence area, or HCA, should be based on fluid hydraulic determinations based on transient models. Such modeling should be performed by personnel competent and experienced in transient pipeline hydraulic tools and who are sufficiently familiar with a specific pipeline design to properly recommend a prudent rupture release rate alarm value. This value should be reflective of actual field operation using a liquid-pipeline-rupture-appropriate equivalent hole opening (for liquid pipelines the hole is usually not equivalent to a full guillotine break). The alarm values for these very high-rate releases will be substantially higher than the throughput rate of the pipeline. As the pressure loss system curve is reduced, pumps shift out on their pump curves, and the pipeline de-inventories via decompression/gravity out the rupture site. There is considerable margin in these high-rate events to assure a proper alarm set point such that there

Caution is warranted against the temptation to set a rupture alarm level too low under the illusion that lower is better as one of the primary objectives is to avoid false rupture alarms.

is no doubt that a rupture alarm is not a false alarm. Specific checklist actions should be defined for control room personnel for pipeline shutdown and segment isolation in the event of such a rupture alarm (e.g., pump shutdown and valve closure).

It is worth noting that in the U.S., liquid pipeline operators are required to provide spill response plans capable of responding to a worst-case spill.¹⁸ The worst-case scenario calculations must be documented and usually involve some combination of estimated time for leak detection identification, pipeline shutdown response, and other impacts (such as drainage and segment isolation), that are usually developed from a rupture release scenario. There can be great temptation to understate rupture identification, shutdown and isolation (worst-case scenario utilizing optimistic or unrealistic short “reaction” times) if proper transient hydraulic models are not wisely utilized, or field equipment chosen, placed, or maintained poorly. Fifteen minutes can pass very quickly in a centralized control room located many miles from a release during such high intensity adrenalin events.

Leaks

Alarms for liquid leaks should never be developed as a percentage of pipeline throughput, as liquid pipeline leak rates are largely driven by pipeline inventory, pressure, and the size of the “hole” at the release site (see cover photo of a puncture in a pipeline). Leak detection alarms (which should be different than rupture alarms) should be defined based on the minimum rate of release the leak detection system should be reliably able to determine on a specific pipeline. A minimum leak threshold alarm rate (i.e., barrels/hr) for a specific pipeline must be determined that is compatible with the pipeline system and its complexity of operation (i.e., batch product vs. continuous mixture such as crude), including transients. All leak alarm threshold value(s) determinations should be documented and approved by the pipeline management. Any competent engineer can translate a leak alarm rate into an equivalent hole size and pressure. Once established, if the pipeline operator is experiencing frequent false “leak alarms,” the threshold leak alarm value is too low or incompatible with the system dynamics, and management needs to reconsider either changes in the alarm threshold or a different, more appropriate, leak detection approach.

Seepage or Intermittent Releases

In sensitive areas where very slow rate or intermittent seepage leaks can have serious consequences, the following “non real-time” balancing approach is recommended. This determination balances the longer time it takes to identify such a slow rate of release with the much higher probability of actually identifying a true release that may not come to the surface. It must be clearly emphasized that this approach will most likely not determine a slow rate release immediately when it first occurs.

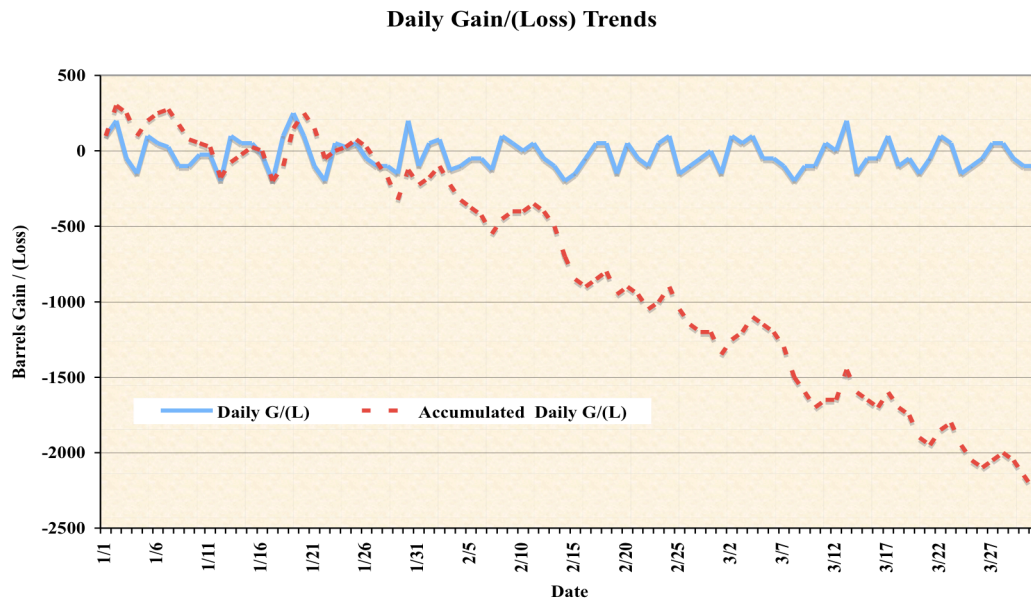
Figure 2 represents a plot of a daily gain/loss (blue solid line) and an accumulated daily gain/(loss) balance (red dashed line) across a sensitive pipeline segment utilizing Equation 1. Each line is plotted for an extended time period (at least month-to-date (M-T-D) and year-to-date (Y-T-D)). The numbers in Figure 2 are for illustrative purposes only, as in all probability the gain/(loss) values and swings will be substantially larger. This graphic presentation is often utilized to assist pipeline operators in identifying possible trouble spots where

Longer historical graphic trend graphs for Daily Accumulated G/(L) can also be very important and of great value in highly sensitive areas.

¹⁸ 49CFR194.105 Worst case discharge.
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slow rate or intermittent leaks such as seepage could be especially problematic (i.e., pipeline passes through a very sensitive area). Note that for leak detection purposes a gross (wet) barrel corrected to standard conditions is utilized in developing the trending graphs. Usually the measurements do not have to be directly at the borders of the sensitive area, but just be located within a pipeline segment that is spanning the area or region of concern.

Figure 2 - Trending Analysis for Slow Rate, Seepage, or Intermittent Releases



Particular attention should be paid to the slope of the accumulated daily gain/loss line, especially if this line stays continually negative over a sustained period. A negative slope indicates a “bias” in the balance segment that needs to be accounted for, reconciled, and corrected, or a loss (possibly associated with a slow rate/intermittent release or a pipeline theft). An alarm value can be set for when the accumulated daily gain/loss goes beyond a certain preset value in a specific critical pipeline segment indicating further evaluation is warranted. Note that a continual positive slope for the accumulated gain/(loss) line is also not good, as either something is inappropriate in the equipment or process utilized in the balance that is introducing bias, or the operator is unduly taking someone else’s barrels.

One of the purposes of the accumulated trend is to remove the noise associated with pipeline inventory changes as the barrels in/out of a pipeline over time will be substantially greater than the pipeline inventory changes. For no-release, tight pipeline systems, both the daily and accumulated daily gain/(loss) trend lines should remain within a specified precision value range for the particular segment. This is indicated in the first month of data in Figure 2 where accumulated daily gain/(loss) for such tight systems trends above and below the zero value. The decay in the accumulated daily gain/loss in Figure 2 indicates an unexplained bias or loss (leak or theft) showing up after the first month.

III. Gas Transmission Releases

Rupture

This paper has mainly focused on liquid pipeline releases. The author would be remiss if he failed to briefly mention some of the differences that make gas transmission release determinations via computer more challenging. Because of the highly compressible nature of natural gas, gas transmission pipeline releases occur at the velocity of the speed of sound within the gas at the bore of the rupture. This velocity is fixed by the laws of thermodynamics but the mass flow rate changes (decays) as gas density immediately upstream of the failure changes. This choked flow phenomenon limiting release velocity is characteristic of all gas releases under high pressure. Because of the fracture mechanics, gas transmission pipeline ruptures will tend to fail as full bore (guillotine) releases venting gas from both the upstream and downstream segments of the pipeline out the failure.

It is difficult for many engineers, even more difficult for the public, to fathom that a rupture on a 48-inch gas pipeline will release gas at the same velocity as a rupture on a 12-inch gas pipeline or even a small hole on a gas transmission pipeline, though the mass release rates will be substantially different. Fifty miles of 36-inch gas pipeline operating at approximately 1000 psig contains roughly 3000 tons of gas. Depending on system factors, a 36-inch gas transmission pipeline will release about 300 to 500 tons of gas within the first few minutes following a rupture.¹⁹ Because of the choked flow, the highly

Given the trend in gas pipelines to increase capacity and pressures to improve pipeline efficiency, and given that many of these pipeline segments are being placed in very sensitive areas, this author advises continuing efforts to improve SCADA recognition and emergency response to gas pipeline ruptures, especially in those areas where detonation of a gas rupture can potentially result in massive casualties.

compressible inventory within the pipeline, and other system factors associated with gas transmission pipelines, even with this high mass rate of release, pressure loss as an indicator of release is very difficult to identify via SCADA. The pressure sensing devices on the pipeline have to be placed very close to the rupture site. Ironically, other transient fluid dynamic indicators that might suggest a gas pipeline rupture via SCADA move upstream (and downstream) of the rupture at the speed of sound in the gas. For example, changes in upstream and downstream compressor operation, not pressure loss, can be one of the first indicators via SCADA that a rupture might have occurred on a gas transmission pipeline. Centrifugal compressor gas fired turbines are sensitive mass flow devices.

Leaks

Because of the high compressibility of natural gas, leaks will not show up as pressure loss in a transmission system as gas inventory within the pipeline will not change substantially with time even though leaks are releasing at the speed of sound. Another way to look at this is that the ratio of mass rate of release for leaks to pipeline inventory mass is very low. A leak will take a very long time to vent the pipeline inventory, even if there are valves to further segment or reduce the line inventory that must be vented. Given the much slower rate of mass release in relation to pipeline inventory, SCADA currently cannot be utilized to reliably identify gas transmission pipeline leaks. Leaks (including

¹⁹ Some of the newer higher capacity gas transmission pipelines are easily capable of releasing much greater tonnage than these figures in a few minutes.

seepage) are usually identified by the performance of visual inspections walking the ROW and special leak surveys along the pipeline with gas detectors that might identify the presence of gas in the event of a leak. In addition, some transmission pipelines inject odorant (such as that utilized in gas distribution systems) into their gas that can indicate a possible gas leak by smell.²⁰ There are many attempts underway to advance or use various technologies (e.g. radar, thermal imaging, multi-spectral imaging) to survey large segments of pipeline for indications of natural gas release (i.e. methane). The author would classify these latest efforts as still in the early stages of development as the success rate in field applications for gas transmission pipelines has been highly mixed for many various complex reasons.

Abbreviations

AAC – Alaska Administrative Code	API – American Petroleum Institute
CFR – Code of Federal Regulation	CPM - Computational Pipeline Monitoring
CT – Custody Transfer	FLIR – Forward Looking Infrared thermal imaging
G/(L) – Volumetric Gain or (Loss)	HCA – High Consequence Area
M-T-D – Month to Date	PHMSA – Pipeline and Hazardous Material Safety Administration
PIPES – Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006	NTSB – National Transportation Safety Board
PLA – Pipeline Loss Allowance	ROW – Right-of-way
SCADA – Supervisory Control and Data Acquisition (Computer)	Y-T-D – Year to Date

²⁰ U.S. federal pipeline safety regulation 49CFR192.625 Odorization of Gas, exempts the use of odorant on certain gas transmission pipelines or segments.