OVERVIEW: REAL-TIME ON-LINE PIPELINE ACCOUNTING AND LEAK DETECTION BY MASS BALANCE, THEORY AND HARDWARE IMPLEMENTATION*

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Abstract

The basic theory, techniques and prerequisites of on-line pipeline leak detection by mass balance are described, specifically including measurement equipment, software model and maintenance requirements.

Key Words: calibration, computational pipeline leak detection, flow measurement, equation of state, mass balance, pipeline inventory, pipeline leak detection, pipeline leak location, pipeline model, pressure measurement, temperature measurement.

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* This paper is available at the Pipeline Safety Trust website, http://www.pstrust.org/docs/massbalance_ld.pdf.

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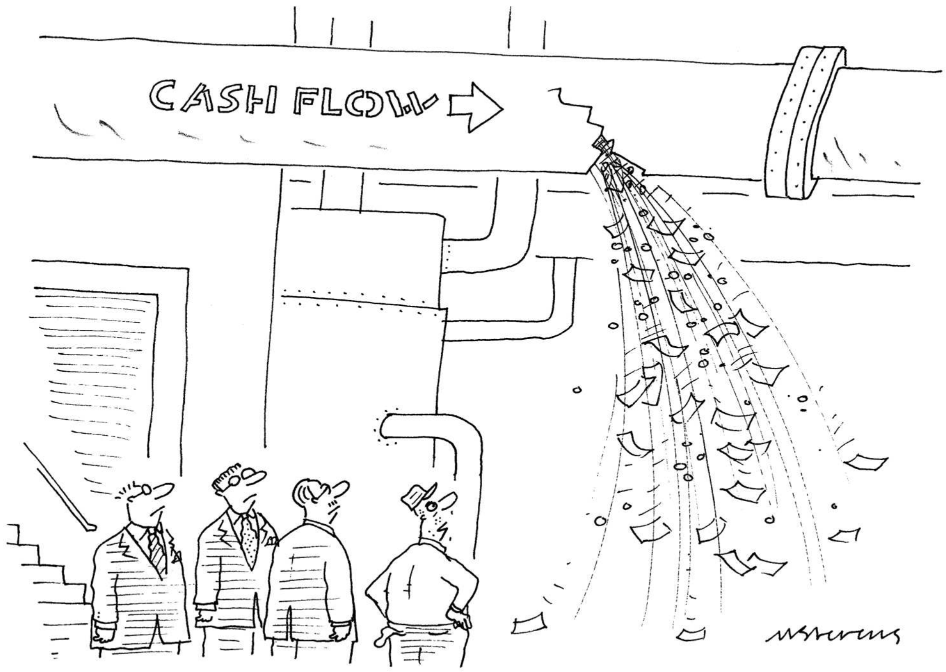

"Well, gentlemen, there's your problem."

0. INTRODUCTION

This paper provides a short introductory discussion of on-line computational pipeline leak detection by mass balance, and its implementation on liquid and gaseous transmission pipelines.

In this paper we deal with primary on-line computational leak detection by mass balance, and ancillary methods such as aerial survey, detection by gas "sniffers", etc., are not considered — although such methods may be used in conjunction with computational leak detection.

0.1 Definition: What Constitutes a Leak?

Leakage from a transmission pipeline is by definition the loss of material / mass being transported by a transmission pipeline. Hence, *the determination of the mass balance of a pipeline is the only truly rigorous method of on-line real-time leak detection.* The problem of determination of the occurrence of *real* leakage is thus closely coupled with the minimization of *apparent* loss of material due to improper flow accounting.

0.2 Why Do We Need Pipeline Measurement and Diagnostic Systems?

Pipeline systems frequently transport billions of dollars per pipeline per annum, often passing through/near heavily populated "high consequence" areas (HCAs). Thus, pipeline measurement systems are required

1. To provide accurate accounting / custody transfer of the oil, gas, or chemical delivered, providing the financial and data basis for all of an energy or pipeline company's operations;
2. As data inputs to pipeline diagnostic / leak detection systems,to insure that:
   a. The pipeline is functioning efficiently;
   b. Leakage of pipeline contents is jeopardizing neither
      i. the pipeline system hardware nor pipeline operation, nor
      ii. personnel, nor
      iii. the environment;[1]
   c. No theft of pipeline contents is occurring along the length of the pipeline;[2]

   and to provide early detection of small leaks so that either

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1. Especially in view of the rapid growth of natural gas consumption, natural gas pipeline Lost and Unaccounted for Gas ("LUGs") may be of particular concern. Methane, the primary component of natural gas, is 21x worse than CO_2 as a greenhouse gas, and is considered by EPA to be a prime candidate for the mitigation of global warming.

2. Nigeria's NNPC has been the victim of ongoing thefts of fuel from its pipeline systems, many of which result in fatalities, e.g. some 150 - 200 people were killed while attempting to collect gasoline from a pipeline near Ilado on May 12, 2006.

   NBC Nightly News (March 25, 2008, 18:30 EST) reported that between 100,000 and 300,000 barrels of oil are stolen from Iraq's pipelines every day, equivalent to some $10 - $30 million/day. This amount is especially significant, since Iraq derives approximately 85% of its national budget — used to finance the war effort and rebuild Iraq — from oil. Thus, pipeline theft and/or sabotage can have staggering national security ramifications. Note that the size of the theft could not even be accurately quantified.

   Real-time detection and location of theft allows prompt dispatch of law enforcement to the specified theft location — and the apprehension of the thieves — before significant quantities of material can be stolen.

   a. Small "pin-hole" defects may be repaired without shutting down the pipeline,[3] *or*
   b. The pipeline can be shut down in a orderly fashion before small defects erode to catastrophic proportions;

3. To minimize operator liabilities for the consequences of pipeline "incidents", as described above, potentially reducing insurance costs;
4. To minimize fiscal liabilities that may result from new state accountability codes, such as Texas H.B. 1920, making operators fiscally liable for Lost and Unaccounted for Gas ("LUGs");[4]
5. To minimize widespread costs to the Nation resulting from panic buying in the wake of major pipeline interruptions;[5]
6. To protect against and/or provide early notification of concerted attacks against a nation's energy infrastructure / delivery system;[6]
7. To comply with government mandates such as NTSB Safety Recommendation P-05-5 (December 23, 2005), to "Require operators to install computer-based leak detection systems on all lines unless engineering analysis determines that such a system is not necessary. (P-05-5)"
8. To assuage the fears of residents and towns adjacent to pipelines that the pipelines pose a threat to their safety and well being. This may be of great importance in countering the fears of the local population with respect to pipelines — and smooth the way for pipeline approvals.

Apart from pipeline specific regulations, there are also significantly tightened requirements for improved pipeline accounting / leak detection for companies wishing to fulfill ISO 9000/9001/9002 and/or Sarbanes-Oxley compliance, e.g. with respect to "planning", "monitoring of routine business activities and key business processes", and "risk assessment".

Petroleum and/or natural gas/petrochemicals are the currency of all major energy companies, and pipeline systems can be viewed as vaults, into which said companies places their valuables via the pipeline packing/loading process. Just as all companies do not tolerate banking inaccuracies, loss, or theft in its financial processes, energy companies cannot afford to neglect the underlying basis of all of their finances, accurate pipeline measurement / accounting nor the auditing thereof via pipeline diagnostic / leak detection systems.[7]

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3. If detected early, small leaks can frequently be (temporarily) repaired using saddle patches or clockspring-type patches without shutting down the pipeline — and incurring the resulting transportation revenue loss.

4. Texas H.B. 1920 originally proposed a "hard cap" of 5% LUGs. The fact that a hard cap was negotiated out of the final version (since enacted as Texas Natural Resources Code 85.065) of the bill may be an indication of the severity of the LUG problem.

5. The EPNG Pipeline 1103 explosion on October 18, 2000 at the Pecos River crossing, NM, not only killed 12 people, but also sent natural gas prices to all time highs in Winter-Spring 2000-2001,

   Similarly, BP's March-April 2006 leakage in its North Slope pipelines resulted in the temporary loss of 8% of the Nation's domestic oil supply, and a large spike in crude oil prices worldwide.

6. See Luft, Gal; "Pipeline Sabotage is Terrorist's Weapon of Choice"; *Pipeline & Gas Journal*, February 2005, pp. 42 - 44.

   For example, Mexico's pipeline system — already plagued by leakage — had further setbacks when its oil and gas pipelines were systematically attacked by leftist guerrillas on July 10, 2007. The *Los Angeles Times* commented on July 11, 2007 (p. A2) that "Oil and gas pipelines around the world have become attractive targets for radical groups seeking to wreak havoc on a nation's economy by disrupting energy supplies."

   Of special concern in developed nations is the possibility that systematic/concerted disruption of natural gas supply to gas-fired electrical generation could result in long-term losses of electrical generation that could not be easily replaced via the electrical grid — which would have significant consequences to national economies.

   Also see Footnote 2.

TABLE 1. The Analogs Between Financial and Petroleum/Petrochemical Accounting

FINANCIAL ACCOUNTING		FLOW ACCOUNTING
Currency	↔	Fluid, e.g. natural gas
Vault	↔	Pipeline
Monetary Accounting	↔	Flow Measurement/Accounting
Fiscal Audits	↔	Pipeline Leak Detection

NOTE

The inability to accurately determine pipeline leakage results in the gradual deterioration of pipeline efficiency, and ultimately the catastrophic failure of the pipeline. Once a major pipeline failure occurs, repairs/remediation may require prolonged periods of time, with high emergency repair costs and the loss of revenue due to the requirement to shut down pipeline operations. Frequently, as was seen in the case of BP's March - April 2006 North Slope leakage problems, there is not enough pipe immediately available for repairs, resulting in prolonged transportation revenue losses for pipeline companies and higher fuel costs as consumers scramble to replace lost supply.

The schematic design of a typical pipeline flow accounting / leak detection system for a contiguous transmission pipeline section under single company management is shown in detail in Figure 1.

The schematic design of a typical pipeline flow accounting / leak detection system for a pipeline section with multiple custody transfer / sales outlets to multiple parties is shown in Figure 2. These graphical depictions focus primarily on natural gas applications — the most complex of pipeline leak detection applications, but are clearly applicable to much simpler liquid flows.

0.3 Pipeline Accounting and Leak Detection Systems

There are six primary elements that are necessary to maintain fiscally sound pipeline systems:

1. Excellent high accuracy, high resolution, high repeatability, high response pipeline instrumentation
2. A rigorous pipeline response / leak detection model
3. Regular maintenance of instrumentation, including referenced calibration
4. Regular maintenance of the software pipeline model, potentially via intelligent self tuning to maximize system sensitivity while simultaneously minimizing false alarms
5. Knowledgeable supervisory personnel
6. Instantaneous high reliability communication

These elements are discussed individually in the following sections.

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7. In the United States, just as the Sarbanes-Oxley Act is imposing much tighter financial reporting on publicly held companies, new pipeline safety recommendations, such as

    - The PHSMA/DOT's Strategic Plan's Program Element 2 (August 2004), and
    - NTSB Safety Recommendation P-05-5 (December 23, 2005), to "Require operators to install computer-based leak detection systems on all lines unless engineering analysis determines that such a system is not necessary. (P-05-5)"

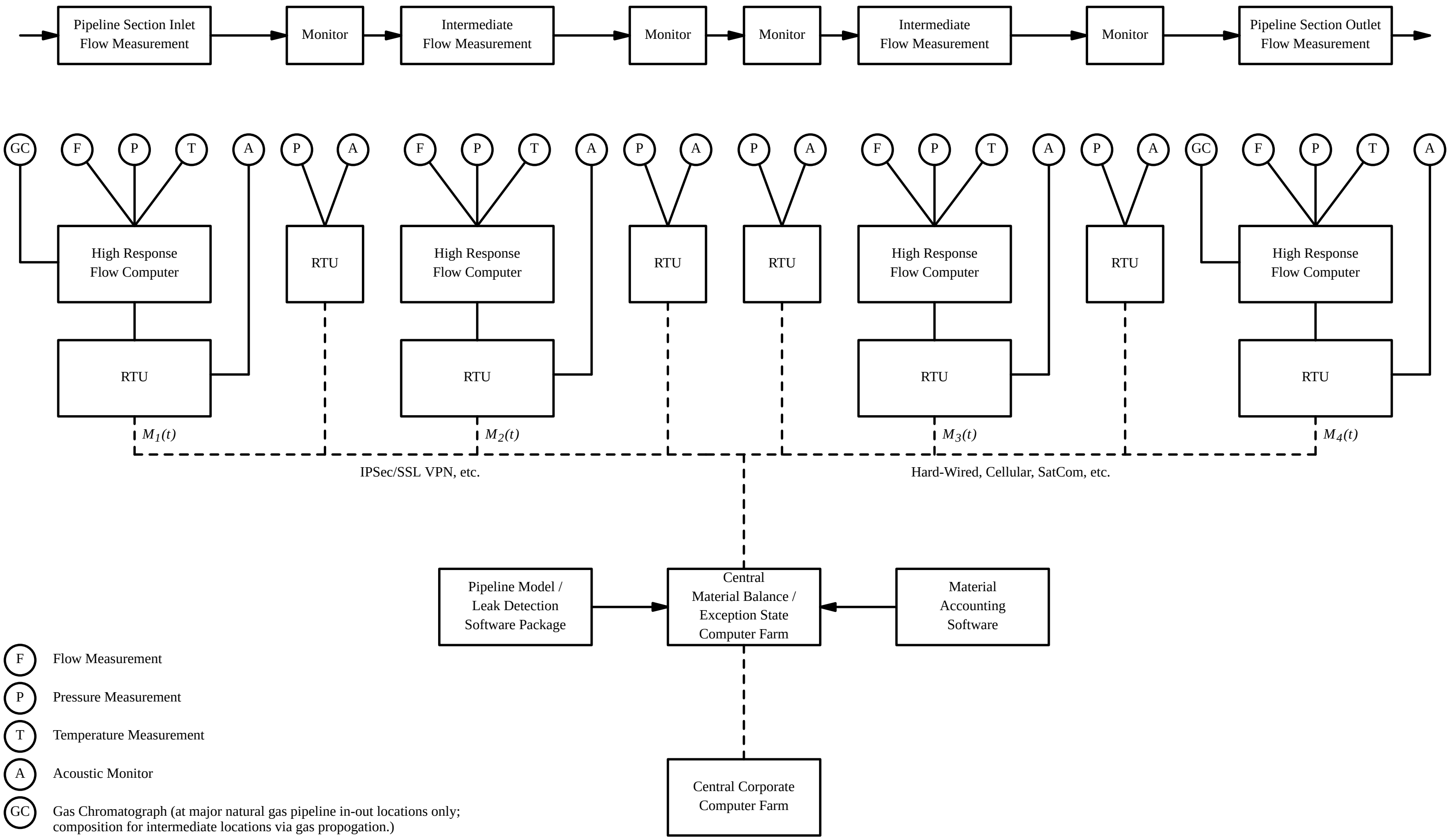
    are imposing greater flow accounting procedures on pipeline companies. Indeed, comprehensive flow accounting and auditing must, in principle, be considered as being required of pipeline companies under Sarbanes-Oxley.

NOTE

This analysis of pipeline measurement and leak detection applies **to both gaseous and liquid pipelines**, whereby the detection of leakage from gaseous pipelines is significantly more difficult than that of the liquid case — but has been successfully performed. In both cases the algorithmic technique is the same, but specific details vary.

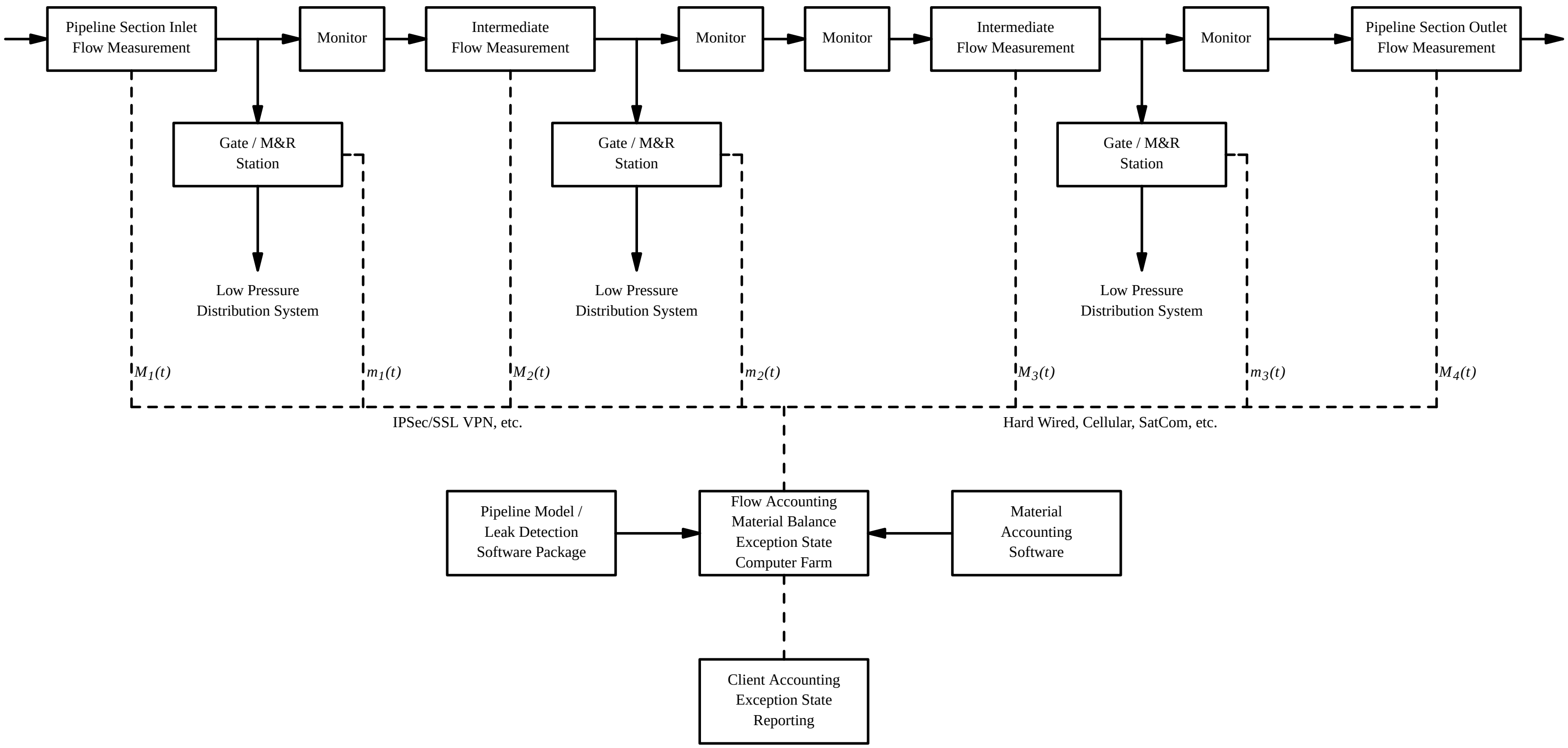
This particular paper tends to stress natural gas pipeline leak detection simply because of the growing importance of natural gas — and because leak detection in natural gas pipelines is the most difficult.

Figure 1: Natural Gas Pipeline Accounting / Leak Detection System Schematic (Typical Transmission Pipeline Section with No Outlets to Distribution)



PROPRIETARY DESIGN OF QUANTUM DYNAMICS / NATURAL GAS ACCESS SYSTEMS

Figure 2: Natural Gas Pipeline Accounting / Leak Detection System Schematic
(Typical Pipeline Transmission Pipeline Section with Outlets to Distribution Systems)



Upper case mass flows $M_1(t)$, $M_2(t)$, $M_3(t)$, $M_4(t)$ are high pressure Tranmission Pipeline Mass Flows. See Figure 1.
Lower case mass flows $m_1(t)$, $m_2(t)$, $m_3(t)$ are Outlet Mass Flows to low pressure Distribution System Pipelines.
Transmission pipeline flow/state is monitored in same manner as in Figure 1.

PROPRIETARY DESIGN OF QUANTUM DYNAMICS / NATURAL GAS ACCESS SYSTEMS

1. PIPELINE INSTRUMENTATION

Pipeline instrumentation measures the quantity of fluids entering, passing through, and leaving the pipeline. Pipelines containing compressible gaseous material can be "packed", hence our analogy (in Table 1) of the pipeline being a vault into which varying amounts of "money" can flow.

1.1 Flow Sensing Systems (Marked ’F’ in Figure 1)

Flow sensing systems determine the flux of material into and out of a pipeline system. Generally speaking, the flow sensors will indicate the volumetric flow.[8] Of the various flow sensor types

> "With regard to flow instrumentation, flowmeters with the highest accuracy are required for mass balance functions. Suitable types include turbine and displacement meters with pulse outputs. Orifice meters are not really suitable."[9]

whereby it is noted that

> "Turbine meters are of special interest because of their accuracy, their sensitivity at very low speed, and their short time of response."[10]

Moreover, the industry standard desk reference for pipelines and leading scientific flow metrology journals mention the utility of specific flow sensors, stating:

> "They have been shown to be outstanding meters for leak detection purposes in gas lines."[11]

Certain aerospace-grade twin-turbine meters have been shown to be of particular utility in leak detection applications, since they provide redundant flow measurement and the ability to detect calibration deterioration.

Flow sensors are designated with an "F" in Figure 1.

The initial calibration and routine follow-on calibration of the flow sensors is of paramount importance in pipeline leak detection applications. See Section 3.1.

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8. While there are inferred mass coriolis meters, etc., these are not generally suitable for high flow high resolution applications, and especially not for low density gaseous applications.

9. *Pipe Line Rules of Thumb Handbook*, Gulf Publishing (Houston), 1998, p. 483.

   Turbine meters may be used in both gaseous and low viscosity liquid applications, while displacement meters are used primarily in viscous (crude oil) applications.

   While ultrasonic meters are being used increasingly in natural gas transmission pipeline operations, "turbine meters exhibit greater repeatability than ultrasonic meters." Source: Kegel, T.M., "Uncertainty Issues Associated with a Very Large Capacity Flow Calibration Facility," Measurement Science Conference, 2000-Jan-01. This must clearly be considered in leak detection applications.

10. Results of the French Atomic Agency’s (CEA/DTA) worldwide study on flow measurement devices, available for review at QUANTUM DYNAMICS.

11. *Pipe Line Rules of Thumb Handbook*, Gulf Publishing (Houston), 1998, pp. 457-458, 481-483.

    Also see Baker, R.C., "Turbine and related flowmeters: I. Industrial practice," *J. Flow Meas. Instr.*, Vol. 2, 1991, pp. 156-157, for a review of several flow sensor types and a discussion of their suitability to custody transfer and leak detection applications.

1.2 Pressure Measurement (Marked 'P' in Figure 1)

In gaseous pipelines, where compressible flow is present, fluid density is strongly dependent on the pressure. Thus, the pressure must be measured with the highest accuracy. Since thermophysical properties are always a function of *absolute pressure*, only the sensors providing direct indication of same should used, and **not** *gauge pressure*. Transducers with the highest possible accuracy ±0.05% to ± 0.1% and reliability should be used.

In liquid flow applications, the fluid density is only weakly dependent on the pressure within moderate pressure ranges.

In both gaseous and liquid applications, accurate pressure measurement plays a role in the detection and determining the location of leakage.

1.3 Temperature Measurement (Marked 'T' in Figure 1)

In both liquid and gaseous pipelines, fluid density is dependent on the fluid temperature, with the density of liquids being particularly dependent on temperature.

The temperature of fluids is best measured with high response sheathed platinum Pt100 RTDs.

1.4 Flow Computers

Local flow computers process flow, pressure, temperature data, together with composition data (from reference GCs or densimeters) to obtain instantaneous mass, standard volumetric, and/or caloric flow. This provides the basis for high accuracy — and hence more equitable — sales / custody transfer and allows central material balance computers to perform more computationally intensive pipeline model calculations.

1.5 Ancillary Measurement Equipment

1.5.1 Gas Chromatographs (for Natural Gas Pipelines)

The compressibility, density, and caloric content of natural gas are functions of its pressure, temperature, and composition. Thus, high accuracy gas chromatographs are required at key flow measurement stations for natural gas pipeline accounting and leak detection.

1.5.2 Viscometers (for Crude Oil / Product Pipelines)

Crude oil and product pipelines will require viscometry instrumentation. Alternately, if the product is well defined, temperature-viscosity correlations may be used. The response of flow sensors under varying viscosity conditions is known.[12]

1.5.3 Densimeters (for Crude Oil/Product Pipelines)

Liquids whose density/composition is not well defined and/or variable will require high accuracy densimetry systems at inlet and outlet measurement points. The density of crude oil and products at intermediate points can be determined via methods defined in the API MPMS.

12. Liu, F.F. and Liu, A.E.; "Trans-Regime Viscosity Effects on Wide-Range Turbine Flowmeter: Comparative Numerical and Conceptual Analyses"; *Proc. 2nd Int'l. Conf. on Flow Measurement* (London), 1988.

1.5.4 Acoustic Monitors (Marked ’A’ in Figure 1)

In some cases, acoustical monitors may be used on high pressure gas pipelines, to detect acoustic anomalies associated with large high pressure leakage. Their range of utility is limited, however.

1.5.5 Other Sensors/Monitors

Other monitors, e.g. seismic monitors, fire monitors, etc., can be interfaced to the RTUs.

2. THE PIPELINE RESPONSE / LEAK DETECTION MODEL

While accurate instrumentation can be used to determine the flow into the pipeline, out of the pipeline, and at specific points along pipelines, a highly accurate pipeline response / leak detection model is required to determine the content / "inventory" of the pipeline and any flow anomalies between specific known locations.

NOTE

> The following discussion of *the pipeline model applies to both liquid and gaseous pipelines*, the latter being the more complicated of the two. The differences in the implementation of the pipeline model software are primarily in the equation of state and representation of viscosity effects.

Pipeline leakage is defined as the loss of material being transported by a pipeline. Hence, ***the only truly rigorous method of on-line pipeline leak detection is "mass balance"***, the determination of the loss of transported material, given in mass units, from a pipeline (or pipeline section):

$$\Delta m(t) = m_{in}(t) - m_{out}(t) - m_i(t)$$

whereby $\Delta m(t)$ is the pipeline leakage as a function of time t,[13] $m_{in}(t)$ is the *measured flow into the pipeline*, $m_{out}(t)$ is the *measured flow out of the pipeline*, and $m_i(t)$ is the *pipeline inventory*, i.e. the amount of fluid determined to be contained in the pipeline.

The pipeline model requires the simultaneous solution of the following four equations,

TABLE 2. Basic Pipeline Modeling Equations and Their Function

EQUATION	FUNCTION
Continuity equation	Enforces conservation of mass
Momentum equation	Unbalanced forces result in fluid acceleration/deceleration
Energy equation	Balances the energy of the fluid into/out of a pipeline section with the energy flux into the pipeline section
Equation of state	Relates the density of the fluid to its composition, pressure and temperature[14]

iterated along the length of the pipeline at as small an interval as computationally tractable from the program execution point of view.[15]

Should an anomalous $\Delta m(t)$ be determined that exceeds combined instrument and pipeline model uncertainties, then the pipeline leak detection software will iterate the pressure drop along the pipeline forward and backward from known points/pressures upstream and downstream of the leak to determine the approximate location of the leakage/loss. In addition to run specific roughness factors, pressure drops due to valves, fitting configurations, etc., must obviously be taken into consideration. (These will already be built into the pipeline model.)

13. $\Delta m(t)$ can also be the amount of fluid stolen from a pipeline via an illegal tap or puncture.

15. If the fluid is of variable composition, the propagation of the fluid must be taken into consideration computationally.

NOTE

Even "tuned" systems will yield spurious "event" notification if the leakage notification threshold is set at very low levels. However, consideration of the monotonicity of $d(\Delta m)/dt$, $d^2(\Delta m)/dt^2$, and advanced adaptive filtering techniques e.g. consideration the autonomous/dynamic systems associated with the above equations) can be used to flag unlikely/random "events" and, if warranted, advise operators that that instruments at specific locations may require checking, or that parameters for specific pipeline sections may require reconsideration.

Using high precision instrumentation and the above modeling techniques in compressible gas pipeline applications, one client reported[16]

> "We use the high repeatability characteristic in a leak detection system being currently commissioned in [location]. The system employs comparative turbine meters, four in all, at regular intervals along a 22-mile pipeline. Any two units calibrated against each other gives a resolution of 0.02 percent of flow volume. By using high accuracy pressure and temperature transducers we are able to measure mass flow to a resolution of 0.05 percent. On our carbon monoxide line, which has a capacity of 6,250 lb/hr, the two meters can track each other to detect leaks of 25 lb/hr. This corresponds to a 1/16-inch size corrosion pit hole in the wall of the pipe.
>
> Our long term experience to date is limited to the hydrogen flow line which runs parallel to the CO line. This line, which has two meters some 12 miles apart, is giving material balances within 0.25 percent per week. Initial tests on the CO line are showing similar trends.
>
> By inducing known sized leaks at known points we can check the effectiveness of the proprietary leak detection software and the performance of the instrumentation. The total system has shown that it can detect leaks of 100 lb/hr in five to fifteen minutes with a location accuracy of ±0.5 mile."

Table 3 demonstrates the accuracies obtained during a typical 10-hour custody transfer run by the pipeline custody transfer / leak detection system, implemented as shown graphically in Figure 1.

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14. Great care must be exercised in the selection of the appropriate equation of state (or volume correction methodology) for pipeline mass balance applications. Only equations of state with the highest accuracy may be used — and the accuracy of the data correlation within specific pressure, temperature and composition ranges must be carefully assessed.

    In the case of natural gas pipelines, the density/compressibility of the natural gas must be calculated via AGA-8 or, preferably, GERG TM15. GERG TM 15, based on the Wagner-Kunz natural gas equation of state, is currently in the process of being ratified/standardized by ISO technical committee TC193. It is tentatively scheduled for release as ISO 20765-2 in late 2010. GERG TM 15 allows the calculation of natural gas compressibility, density, and caloric content within experimental uncertainties (several 1/100-ths of one percent) using the natural gas composition, pressure and temperature. Inasmuch as natural gas pipelines are commonly "packed" / used as large storage vessels, the importance of such equations of state in leak detection applications cannot be ignored.

    In the case of crude oil / product pipelines, the density of the fluid is normally calculated via API 2540 / IP 200, and the fluid viscosity enters into the flow measurement application in a slightly more significant — but still tractable — manner.

    Since the loss of water from underground piping systems is becoming an increasingly important conservation and maintenance issue, we note that the density of ordinary tap water can *normally* be closely approximated by IAPWS-95 up to approximately 60C. In those cases where high mineral content is an issue, the density can be measured using a 0.00001% densimeter.

16. Furness, R.A., "Twin Turbine Meter Experience", *Short Course on Turbine and Vortex Meters*, Cranfield Institute of Technology, 1983.

TABLE 3. Typical System Balances with High Accuracy Metering

Time	Meter 1 Mile 0.0 [MSCF]	Meter 2 Mile 9.4 [MSCF]	Meter 3 Mile 17.0 [MSCF]	Meter 4 Mile 22.9 [MSCF]
00.05	81.56	82.32	82.16	81.79
02.05	246.73	245.99	246.32	246.68
04.05	408.82	408.04	408.13	408.73
06.05	570.54	569.16	569.54	570.40
08.05	731.78	729.89	730.15	731.36
10.05	893.94	891.78	892.05	893.27
Average Flowate [MSCF/H]	81.238	80.946	80.989	81.168
Deviation from Meter 1 in %	0.000	-0.359	-0.307	-0.086

NOTE

All flow accounting / material balance / pipeline leak detection software must, as a minimum, be run on redundant high-reliability computer hardware. Said hardware must be located at secure sites with power back up and inter-computer / inter-site failover capabilities.

The importance of inputs to the pipeline model, both in the form of model parameters/tuning and actual real-time instrumentation inputs cannot be overstressed: Poor definition of pipeline characteristics and/or poor instrumentation will invariably lead to numerous false alarms.

The area of computational pipeline leak detection is of growing importance, driven by increasing environmental and liability concerns, as well as by ever increasing product values — and government mandates such as NTSB Safety Recommendation P-05-5 and Texas H.B. 1920. There are several references of note that that discuss pipeline leak detection.[17]

NOTE

The lowering of the lowest detectable leakage rates to, say, sub-0.1% levels brings with it the reduction of Lost and Unaccounted for Gas ("LUGs") to said levels. When compared with the usual 5% LUGs, 0.1% represents ***a very significant fiscal value, the recovery of gas that would otherwise be unbillable, a significant competitive advantage for suppliers, reduced costs for users, and increase of supply without drilling for new sources of natural gas.*** These, in additional to safety and environmental concerns, are extremely compelling reasons for the implementation of pipeline leak detection.

The implementation is pipeline leak detection systems is thus very profitable and "green."

17. *Hazardous Liquid Leak Detection Techniques and Processes*, NTSB Report DTRS56-02-D-70027-01.

    Furness, R.A., "Twin Turbine Meter Experience", *Short Course on Turbine and Vortex Meters*, Cranfield Institute of Technology, 1983.

    Pipe Line Rules of Thumb Handbook, Gulf Publishing (Houston), 1998, pp. 481-483.

3. MAINTENANCE OF INSTRUMENTATION

In order to maintain an accurate pipeline accounting and leak detection system, the following must be implemented:

- A common calibration facility for liquid and/or gas flows, and
- A program of regular instrument maintenance.

3.1 Calibration Systems

The calibration of fluid flow measurement systems must be regularly maintained, and referenced to a common standard / calibration facility. This not only insures not the accuracy of the flow sensors, but also that they have exactly the same calibration bias for leak detection purposes.

NOTE

In pipeline leak detection applications, all sensors should be calibrated at a single flow calibration facility and/or against a common very high repeatability transfer standard. This insures that the bias of the individual flow calibration facilities does not become an issue. For example, two flow calibration facilities with uncertainties of, say, ±0.1% can yield results that differ by as much as 0.2% for a given data point. On the other hand, if two flow sensors with ±0.02% repeatability are calibrated at the same facility, then the level of leakage detectability can be as low as 0.04% — yielding a five fold lowering of the lowest level of leak detectability.

Alternately, if calibration at a common facility is not possible, all calibration facilities should be intercompared via measurement assurance program (MAP) transfer standards, and each laboratory's relative calibration bias adjusted to the middle of the Gaussian distribution curve.

Similar arguments can be made for the calibration of multiple flow transfer standards at a single calibration facility, each of which is then used to calibrate systems in the field.

Improved methods of density determination and dramatically improved equations of state are leading to the possibility of significant improvements in "first principles / fundamental constants" based flow calibration facilities. Indeed, NIST has commented that a recent proposal for gaseous calibration based on fundamental properties would be[18]

"a significant advance in natural gas flow measurement."

State of the art "first principles / fundamental constants" based designs for calibration systems/facilities for refined products (such as turbo fuels),[19] large gaseous flows (such as natural gas tranmission pipelines), and large water flows are available. Such calibration facilities are capable of achieving calibration uncertainties well below 0.1% of reading.[20]

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18. NIST letter of August 6, 1997 to the author.

19. Aircraft and spacecraft transport limited fuel supplies which are necessary for mission completion, and which must be "lifted." Accordingly, the aerospace industry has always placed a much higher emphasis on high accuracy / high resolution flow measurement and calibration than pipeline industries. For example, engines for entire fleets of aircraft are selected based on differences of less than 0.1% in specific fuel consumption.

NOTE

In situations where it is impossible/impractical to remove the flow sensors from their metering station locations, very high repeatability flow transfer standards (FTS) may be required to transfer the flow calibration from the primary standard to the various field measurement units.

In such cases the design of the metering stations in question is of concern. The metering stations must be designed to accomodate the periodic use of the FTS — and the FTS run/shunt must be designed so that its geometry does not introduce calibration error. This is especially important in the calibration of large flows.

Similarly, calibration requirements for all ancillary instruments relating to the determination of the mass flow cannot be neglected. However, *in situ* flow calibration generally requires the greatest planning.

3.2 Instrumentation Maintenance

The accuracy of instrumentation in the field must be maintained by a continuous and ongoing program of maintenance. The instrumentation must be regularly maintained, inspected, and calibrated. Filters and other consumables, etc., must be regularly replaced.

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20. While detailed design of calibration facilities is not the subject of this paper, the following should be considered in the design of calibration facilities:

    - If the flow sensors are to be used in leak detection applications, calibration runs should be configured to allow multiple flow sensors to be calibrated *in series simultaneously*. This insures that the sensors are calibrated under exactly the same conditions — so that the repeatability of the flow sensors becomes the primary concern in leak detection, rather than the uncertainty of the calibration systems.

    - In some cases, multiple high repeatability flow transfer standards *in parallel* can be used to obtain better calibration resolutions than might be otherwise obtained. For example, when weighing fluids, large scales may be significantly less precise than small scales. In large water distribution systems — notorious for their large leakage losses — four 12" flow transfer standards used in parallel allows the calibrationr of 24" distribution meters with greater resolution for the determination of leakage. Each of the FTS sensors can be calibrated with high resolution.

4. SYSTEM SOFTWARE / PIPELINE MODEL MAINTENANCE

The pipeline leak detection software must be maintained by knowledgeable pipeline and software engineers as new sections of pipeline are added to the pipeline monitoring system. Piping configuration, elevation, roughness factors, etc., must be entered into the model for each pipeline section, and the model "tuned" for the specific sections of pipeline.

Additionally, filtering parameters must be periodically — possibly algorithmically — adjusted to eliminate spurious alarms and/or highlight any events with a higher likelihood of leakage.

5. SYSTEM SUPERVISORY PERSONNEL

In addition to field maintenance personnel, calibration engineers, etc., engineers knowledgeable in pipeline instrumentation, pipeline response, and the pipeline model must be present at the Central Material Balance Computer Farm(s).

These skilled engineers and scientists will be responsible for supervising the system output, resolving alarm issues, and making fine adjustments to the model input parameters to minimize false alarms, but also to optimize system response in the event of actual leakage.

Experienced pipeline engineers from within the pipeline company must be trained, and/or the monitoring, configuring and maintaining the pipeline leak detection outsourced to highly competent organizations. e.g. to the system integrator.

Inasmuch as specialists trained in the overall aspects of pipeline fluid mechanics, instrumentation, pipeline models, equations of state, etc., are rare, it is convenient to monitor system state of multiple pipelines from a single location.[21] Thus, communications / net infrastructure play an important role in pipeline leak detection.

21. The usual precautions regarding mission critical data processing will, of course, apply. These include physical and power security, multiple communication feeds, failover site(s), etc.

6. COMMUNICATIONS

Instantaneous high reliability communications are a key element of accurate pipeline accounting and leak detection.

All system timing can be referenced to the GPS system or to NIST via the ITS or ACTS protocol. The time stamped data from the pipeline monitoring RTUs are then transmitted using SSL and/or IPSec VPN methodologies via hard wired land lines, cellular connection or satellite communications to one or more Central Material Balance Computer Farms for processing.

For optimal response, data should be processed in real time. Otherwise, the time stamped data can be used to reconstruct the state / inventory of the various pipeline sections *ex post facto* in near real time.

7. CONCLUSION / REQUIRED EFFORTS

The movement of petroleum and petrochemical fluids, including natural gas, is the basis of all energy companies' operations and income.

Inasmuch as flow accounting and flow auditing (in the form of pipeline leak detection) form the basis for financial accounting — and the latter form the basis for all corporate decisions — the accuracy of any energy company's flow accounting and auditing cannot be overemphasized.

The following general comments apply to the implementation of pipeline instrumentation system as pertains to the implementation of leak detection systems that are required to insure the accuracy and security of an energy company's flow/revenue stream:

1. A detailed study of the pipeline systems, data, and communications requirements must be undertaken. Simultaneously, the state of the client's calibration facilities/methodologies should be assessed, in order to determine whether they have the accuracy, resolution, and repeatability necessary to support high accuracy measurement and high resolution leak detection.
2. Pipeline accounting / leak detection systems accounting systems shall be implemented on
   a. Major pipelines for high accuracy flow accounting and pipeline leak detection/security.

      This phase requires

      i. Instrumenting the specific pipeline sections with high accuracy, high resolution flow instrumentation, that can be remotely monitored over communication links.

      ii. The establishment of high reliability, redundant Material Balance Computer Farm(s), designed for future expansion, as new pipelines or pipeline sections are added.

      iii. The establishment of high accuracy, high resolution, high repeatability calibration facilities and a transfer standard program to support the pipeline accounting / leak detection instrumentation.

   b. Smaller pipelines having less importance, as time and budget allow.

The above tasks must be performed as a fully coordinated and integrated effort. Based on past experience, it is unlikely that piecemeal attempts at pipeline leak detection will be successful.

We note that

+ The costs for instrumenting high accuracy / high resolution pipeline accounting / leak detection systems are only marginally higher than the usual pipeline "flowmetering systems". Indeed, when such instrumentation is strategically planned and acquired, the acquisition, deployment, and commissioning costs may actually be lower than piecemeal one-at-a-time acquisition of inferior measurement systems.
+ Minimization of product lost through poor accounting or leakage results in more billable product / transportation fees, i.e. increased revenue. In any large scale custody transfer applications, the increased revenue will quickly offset any incremental instrumentation costs for higher accuracy.
+ Any incremental costs for such systems are always significantly less than even a single major pipeline incident that interrupts pipeline flow even for one day: when leakage is determined early, it can frequently be repaired without shutting down the pipeline — and without the corresponding loss of pipeline revenue.
+ Early detection of small leaks and their (temporary) repairs frequently permit the scheduling of major repairs during more convenient / lower demand periods. In the mean time, the leak detection software can provide increased surveillance of adjacent pipeline sections.

+ The cost of clean-up and remediation of land in the wake of a major liquid spillage will always be more significant than the cost of early pipeline leak detection of small leaks — and the operating company may additionally incur resident wrath that will make permission for future projects difficult to obtain.

Thus, superior pipeline measurement/accounting systems and the ability to perform pipeline leak detection by mass balance are not luxury, but rather essential to the safe and fiscally, socially, and environmentally sound operation of any pipeline.