Economic Comparison of a Simulator-Based GLR Method for Pipeline Leak Detection with Other Methods

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Abstract

In this paper, we show a simulator-based implementation of the Generalized Likelihood Ratio method to detect leaks and locate biases in pipelines. We compare its leak detection ability, costs, and levels of tuning required to those of other software and hardware leak detection methods. The economic comparison includes computing the losses for not detecting the leaks. It was found that GLR is the most economic leak detection method available. Simulations were run with varying pipe diameters, price of oil, and cost of leak clean up.

Introduction

Pipelines are the most commonly used method to deliver petroleum products, natural gas, liquid hydrocarbons, and water to consumers. The petroleum pipeline network in the United States transports over 600 billion ton-miles of freight each year. It accomplishes this job in an exceptionally effective manner. In fact, oil pipelines transport 17% of all US freight but cost only 2% of the freight bill. They do so in a cost effective and safe manner; however, safety and losses due to leaks are the number one concern in pipeline operation. The largest challenge is discovering economic leak detection methods capable of accurately detecting leaks in a timely fashion.

There are three different pipeline systems: gathering systems, distribution systems, and single pipelines that go from one point to another. Gathering systems and distribution systems are very similar. A gathering system has many pipes that gather the product from different areas and funnel it into one larger pipe. A distribution system takes the product from one large pipeline and delivers it to different areas via smaller pipes. The basic idea of the two systems is the same; the flow is simply reversed. Figure 1 illustrates the gathering and distribution network system.
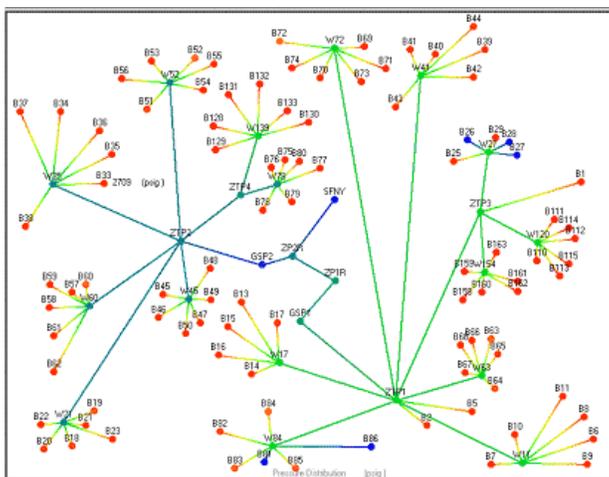

Figure 1: Gathering/Distribution Systems

Significant incidents for pipelines operated within the United States are tracked by the US Department of Transportation Pipeline and Hazardous Materials Safety Administration, commonly known as the PHMSA. The number of significant incidents, including the number of injuries and fatalities that resulted from those incidents, has been recorded over the past twenty years. Figure 2 provides a graphical representation of this data. A significant incident, as defined by the PHMSA, is a pipeline incident that meets any of the following conditions:

1. A fatality or injury requiring hospitalization
2. $50,000 or more in total costs, measured in 1984 dollars
3. Highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more
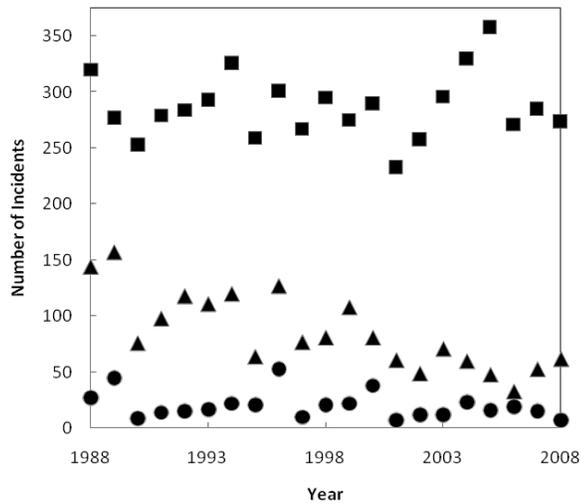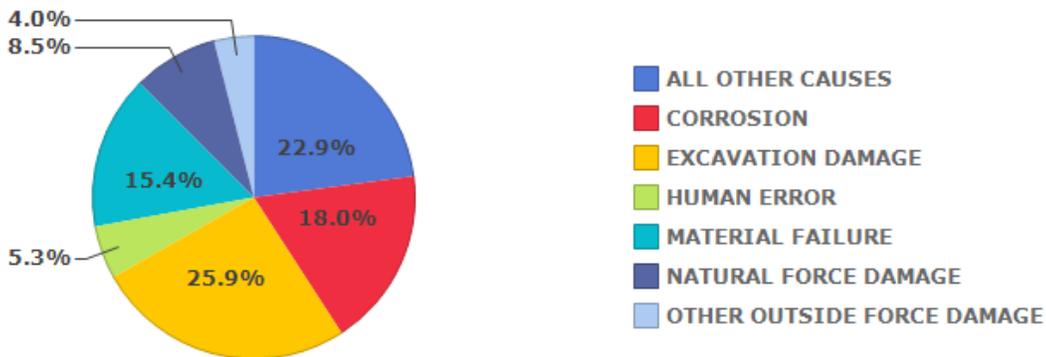4. Liquid releases resulting in an unintentional fire or explosion

Figure 2. Significant Incidents Summary 1988-2008. (■) Significant Incidents,(▲) Injuries,(●) Fatalities

The causes of significant incidents and other pipeline leaks are fairly well understood thanks to careful record keeping. The PHMSA has maintained these records for pipelines operated in the US. The pie chart representation in Figure 2 shows the causes of significant incidents over the past twenty years. Excavation damage is clearly the primary cause but corrosion and material failure are close behind.

Significant Incident Cause Breakdown
National, All Pipeline Systems, 1988-2008

4.0%
8.5%
15.4%
5.3%
22.9%
18.0%
25.9%

■ ALL OTHER CAUSES
■ CORROSION
■ EXCAVATION DAMAGE
■ HUMAN ERROR
■ MATERIAL FAILURE
■ NATURAL FORCE DAMAGE
□ OTHER OUTSIDE FORCE DAMAGE

Source: PHMSA Significant Incidents Files January 14, 2009

Figure 3: Significant Incident Cause Breakdown

Pipeline spills are still small in relation to the amount of product transported. In fact, they amount to only 1 gallon per million barrel-mile, where a barrel-mile equals one barrel traveling one mile. However, leaks are expensive, both in economic and human terms. The significant incident data clearly indicates that leaks do indeed injure and kill people. The economic reasons for not wanting leaks can be made clear by examining the BP Alaska pipeline

incident that occurred in March 2006. In this case, roughly 4,800 barrels of oil were lost over a five day period and the Prudhoe Bay field later underwent a phased shut down due to the leak (BP HSE). On top of the expenses incurred from pipeline repairs and the phased shut down, the Environmental Protection Agency leveled a $20 million fine against the company (Loy).

The paper is organized as follows: we first review the different leak detection methods, then we focus on describing our implementation of GLR and finally, we present the economic comparison.

Hardware Leak Detection

Hardware leak detection methods are in general sensitive to small leak sizes and quite accurate regarding location. Typically, instrumentation is run along the entire length of the pipeline which helps with the detection of both large and small leaks in a timely fashion and allows for the detection of a leak anywhere along the pipeline. The instrumentation used in these schemes also allows for an estimation of a leak's location. This information helps to minimize both the economic and environmental impact in the event of a leak.

Although significant instrumentation provides many of the advantages associated with hardware leak detection, it also provides disadvantages. The high level of instrumentation results in installation and maintenance costs that are significant. Installation is complex, requiring a considerable amount of below surface work since many pipelines are buried. Consequently, hardware methods are commonly used for pipelines traveling through high risk areas.

Acoustic Emission

The **acoustic emissions** method of leak detection relies on escaping fluids giving off a low frequency acoustic signal. Acoustic sensors are placed around the entire length of pipeline to monitor the noise levels of the interior of the pipeline. A baseline or "acoustic map" of the pipeline's acceptable noises is created. Future measurements are compared to this baseline with any deviations outside a specified range triggering the alarm system. Once the detection system has been fine tuned, false alarms are uncommon and have reportedly been as low as once per year. The acoustic signal will be strongest near the leak, thus making it possible to locate the leak. Typical leak detection times are 15 seconds to 1 minute, with the detection time being limited by the speed of sound, the distance between monitors, the data communication time, and the necessary computational time. The sensitivity for this type of detection method is 1 to 3 percent of the nominal flow for a liquid pipeline. For a pipeline carrying gas, a hole with a diameter 2 to 10 percent that of the pipeline diameter can be detected. The location of the leak can be estimated within ±30 meters. While this method of leak detection works well for detecting leaks large and small, it does not provide a way to estimate the size of the leak (Wavealert).
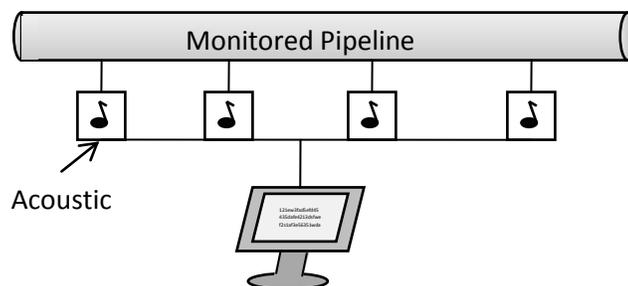
Figure 4: Acoustic Emissions Method

Fiber Optic Sensing

The **fiber optic sensing** method of leak detection utilizes fiber optic sensing probes to detect leaks. The fiber optics are placed in the soil along the pipeline and monitor the temperature, usually recording the temperature every 0.5 meters. This temperature information is achieved by analysis of scattered light using either the Raman or Brillouin scattering process as the foundation. The Raman scattering process is strictly intensity based and was the first method proposed in the 1980's when this technology was first used. However, in the 1990's the Brillouin scattering process, which relies on frequency measurements and has been shown to be more accurate, began to replace the Raman process and remains the top preference to date. In the event of a leak, the escaping hydrocarbon would cause a temperature change. Gas leaks would result in a cooling of the surroundings based on the Joule Thompson effect, whereas liquid leaks typically increase the temperature of the surrounding area. A baseline profile of acceptable temperatures along the pipeline must first be obtained, but if done properly, there should be no false alarms with this method. The best sensitivity attained with this method has been 50 ml/min and leaks can be isolated based on information from surrounding fiber optic probes (Nikles). If the sensors are spaced every 0.5 meters, as is typical, the location of the leak can be estimated to within a one meter range. The magnitude and speed of the change in temperature is indicative of the fluid being transported as well as the size of the leak (Omnisens). Although the leaks magnitude is indicated by the temperature change, it is still difficult to accurately predict any leaks size within a certain range. It proves to be more an indicator of large, medium, or small. The time required to obtain a complete profile of the pipeline is dependent on the pipeline length, but typically varies between 30 seconds and 5 minutes (Nikles). The price tag for this method is steep though. For a 1200 km pipeline, which is roughly equivalent to the distance between Houston and El Paso, the material costs for this method can run upwards of $18 million. This does not include installation costs. So although fiber optics provide a very accurate method for leak detection, the initial upfront investment is considerable (Sensortran).
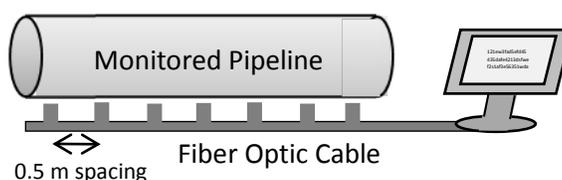

Figure 5: Fiber Optic Sensing Method

Vapor Sensing Method

With the **vapor sensing method** a tube, highly permeable to the material being transported, is placed alongside the pipeline. A test gas is pumped through this vapor sensing tube and analyzed for vapors of the pipeline fluid. If there is a leak, the pipeline material will diffuse through this vapor sensing tube and become apparent upon analysis. The size of the leak can be estimated based on the analysis of the gas. The larger the leak is, the higher the expected magnitude of vapor in the tube. The mixture is transported at a flow controlled rate, making it possible to estimate the location of the leak. If done properly, the leak location can be narrowed down to 0.5% of the monitored area. For example, if a pipeline being monitored in this manner were 10,000 meters long, the vapor sensor method could narrow down the leak location to a 50 meter length range of pipeline. The sensitivity of this method is 1 l/hr for liquids and 100 l/hr for gases. Additionally, the response time usually varies from 2 to 24 hours, although this is highly dependent on pump capacity (Areva).
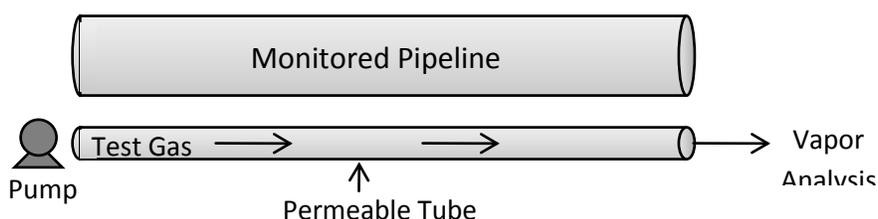
Figure 6: Vapor Sensor Method

Ultrasonic Flow Meters

Ultrasonic flow meters provide another alternative hardware leak detection method. With this method, ultrasonic flow meters are attached to the outside of the pipeline and generate an axial sonic wave in the pipe wall. A computer measures the time differences for the wave to travel upstream and downstream and computes the flow rate from this information. This method essentially relies on a mass flow balance which, simply stated, means the mass flow rate that goes in must equal that which comes out or there is a leak (Bloom). The smallest leak that can be detected with this method is 0.5% that of the nominal flow (Controlotron). Since this operates on a mass balance, a corresponding estimate can be made regarding the size of the leak. The leak location can only be narrowed down based on how far apart the measurement devices are installed. For instance, if the ultrasonic flow meters are placed 50 meters apart then the leak location can be narrowed down to a 50 meter range.
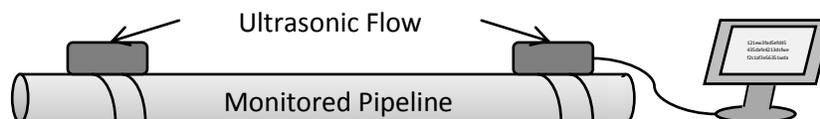
Figure 7: Ultrasonic Flow Meter Method

Software Leak Detection

Volume Balance

The first type of software leak detection considered was balancing systems. The main types of balancing systems are the volume balance and the compensated balance.   In the **volume balance**, only the flow into and out of the system are considered. The volume balance assumes the flow in a pipeline is *always* at steady state, which is not necessarily true if two liquids with different densities are mixed.   Since only the inlet and outlet flow are being considered in the volume balance, and third term is needed in order to compensate for changes in the line pack. Multiplying the volume balance through by the fluid's density and adding the additional term to account for change in the amount of fluid in the system give the following equation:

$$\dot{M}_I(t) - \dot{M}_O(t) = \frac{dM_L}{dt} \approx 0 \qquad\qquad (1)$$

where: $\dot{M}_I$ = inlet mass flow rate

M_O = outlet mass flow rate

M_L = line pack

This equation is called the **compensated balance**.   The mass flow rate entering the system can be estimated from pressure and temperature readings. A leak is detected when the mass of the fluid exiting the pipeline is less than the estimated mass entering the pipeline. To account for the line pack, a simulation model of the pipeline has to be run. Adding the term for the change in line pack significantly reduces the error in the volume balance. A Supervisory Control and Data Acquisition (SCADA) system is used to control and monitor the process. Errors will still be seen from faulty instrumentation as well as from errors in the line pack calculation (Whaley).

The main problem with the volume balance method and all similar software leak detection method is its susceptibility to false alarms in non-steady state situations. A mass balance system responds to the leak only after the pressure waves generated by the leak have traveled to both ends of the pipeline. If there is a leak whose magnitude is less than 5% of the total flow, therefore, it can take on the order of few hours before the leak is detected. This technique only applies to single pipelines, so complex networks like gas distribution systems in urban areas do not apply. The volume balance does not help in detecting the location of leaks, and it also cannot distinguish between biases and leaks (Reddy).

Pressure Analysis

The next major type of software leak detection considered was **pressure analysis**. Since a leak in a pipeline corresponds to a depressurization, abnormally low pressure readings can be used to identify possible leaks. Pressure and flow waves caused by a leak propagate to the end of the pipeline and imprint the leak signal on measured data. The measured data is then

compared with data calculated from SCADA, and discrepancies show where leaks are present. This method was found to detect leaks that were at least 5% of flow within 5 meters. When implementing this method, one must be careful to account for anything else that might cause a pressure drop in the pipeline; otherwise false alarms will arise frequently. Since pressure decline is not unique to leaks, this is one of the difficulties with the pressure analysis method. Longer pipelines would present the most trouble since more transients would occur, causing more false alarms. As with the volume balance method, pressure analysis methods cannot distinguish between biases and leaks. The method is, however, very simple to implement, so little extra instrumentation is required (Whaley).

One specific type of pressure analysis is the **gradient intersection method**. Deviations between measured and calculated values at the endpoints of a pipeline are indicative of a leak in the system. First a pressure profile is constructed as a model for how the simulation predicts pressure will change over the length of the pipe. Next a pressure profile is constructed for the real data. When there is a leak, the real data profile will show a greater pressure drop upstream of the leak in comparison to the model, and then downstream of the leak the pressure drop will converge with the model. This is due to the boundary conditions put into the simulation.

The **reflected wave method** takes advantage of the fact that changes in flow conditions create transients in pressure. Pressure waves, therefore, propagate through the system and are reflected by changes in geometric or hydraulic properties. When a leak is present in a pipeline, a reflected wave will be generated at the location of the leak. Recorded time series of pressure make it possible to trace these locations, and the magnitude of the leak will directly relate to the size of the reflected wave. The main difficulty with this method deals with determining the source of a reflected wave. Junction, nodes, and bends all affect the reflected waves, so this makes it challenging to determine where the leak actually came from. Another limitation of the reflected wave method is that it can only be used in series pipelines (Reddy).
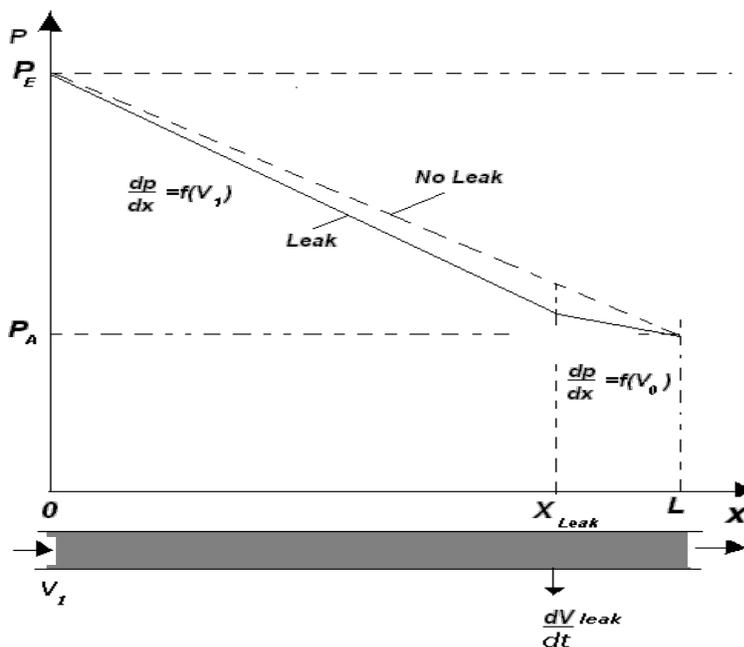

Figure 8: Pressure Profiles

The size of the pressure deviation depends on the size of the leak and its location in the pipeline. The size of flow deviation is directly related to the size of the leak in the system. The simplest way to determine the location of a leak in this method is by using geometric calculations using a plot like the one shown above. Threshold values must be set in the gradient intersection method since normal pressure drop fluctuations will occur. Many false alarms will be the result of not setting these values. Since this method is dependent on the tuning of the model, measurement errors along with uncertain fluid properties can cause difficulties.

Transient Models

The next type of software considered was **transient model based methods**. This method attempts to distinguish the effects of a leak from all other phenomena in a pipeline. While the pressure analysis method cannot distinguish between a leak and anything else that causes a pressure drop, transient models simulate transients in a system in real time. This method is a numerical integration of three different equations: the momentum, continuity, and the energy equation. Generally an implicit matrix based solution is used with all three of these equations. One downside to this approach is that many parameters are needed to work the method accurately. Some of these pipeline parameters can be difficult to obtain, such as the inside pipe roughness, the current drift, and calibration of the instruments. In order to do calculations in real time, adaptive modeling must be used. This implies that certain parameters in the system will be adjusted when compared to simulation or measured values.

In transient models, pipeline data must first be acquired, and then measured values will be used as the limits for the aforementioned momentum, continuity, and energy equations. Calculated values are compared with measured values, and then leak calculations are performed. A leak is detected if the discrepancy between the actual data and the model data is greater than the determined limits. If no leak is found, the differences between the measured and calculated values are used to adjust parameters. Billmann and Isermann (1987) showed that detectable leaks were greater than 2% for liquid and 10% for gas.

Frequency Analysis Methods

Frequency analysis methods can also be used in leak detection. In frequency domain analysis, a steady oscillatory flow is produced by periodically opening and closing a valve. Pressure amplitude peaks are developed from this oscillatory flow for a system with leaks, and then the peaks are compared with a system where no leaks are present. This allows for identification of leak location and magnitude in a given system. Frequency analysis methods have been implemented on both parallel and branched pipe systems. A downside to these methods is the fact that they are only valid for well defined boundary conditions. These methods can be very complex, and normal pipeline operations must be suspended for frequency analysis methods to be implemented (Whaley).

Generalized Likelihood Ratio

The final method considered is the **Generalized Likelihood Ratio** (GLR). The GLR is a statistical method modeled after the flow conditions in a pipeline. A mathematical model is derived with GLR, which is used to find leaks in pipeline networks. Given a process network, associated constraints, and a covariance matrix of measurement errors, measurements are simulated using random numbers from the standard normal distribution. When a leak is present in the system, the simulation computes the balance residuals, since leaks are viewed as additional output streams. The balance residuals are used by the GLR method to detect and identify gross errors. This can be done for different types, locations, and magnitudes of gross errors. Simulations are run consisting of 10,000 simulation trials, where in each simulation different sets of randomly generated measurements are used.

The accuracy of the generalized likelihood ratio in identifying gross errors will now be evaluated. In order to use this approach, a mathematical model that describes the effects of a leak and / or bias on the process is needed. The biases include both measurement bias and process leaks in steady state processes. The model of the generalized likelihood ratio can be seen as follows.

Process Model

First a steady state model without leak is developed:

$$\underline{z} = \underline{x} + \underline{v} \tag{2}$$

Where: z is a measurement vector
x is the true value of state variables
v is the vector of random error

We then set up a constraint matrix on the true values:

$$\underline{A}x = 0 \tag{3}$$

Where A = constraint matrix

Measurement Bias Model

Next, a model is developed for measurement biases:

$$\underline{z} = \underline{x} + \underline{v} + b\underline{e}_i \tag{4}$$

Where: b is the bias of unknown magnitude in instrument *i*
e is a vector with unity in position i

Process Leak Model

A mass flow leak in process unit (node) j of unknown magnitude b can be modeled by;

$$\underline{A}x - b\underline{m}_j = 0 \tag{5}$$

The elements of vector *m* correspond to the total mass flow constraint associated with node j.

<u>Procedure for single gross error</u>
We then define *r* as a linearization of *z:*

$$\underline{r} = \underline{A}\underline{z}$$ (6)

When there is no gross error;

$$E[\underline{r}] = 0$$ (7)

$$Cov[\underline{r}] = \underline{V} = \underline{A}\underline{Q}\underline{A}'$$ (8)

If a gross error due to a bias of magnitude b is present in measurement I, then;

$$E[\underline{r}] = b\underline{A}\underline{e}_i$$ (9)

If a gross error due to process leak in magnitude b is present in node j, then;

$$E[\underline{r}] = b\underline{m}_i$$ (10)

When a gross error due to a bias or process leak is present;

$$E[\underline{r}] = b\underline{f}_i$$ (11)

where

$$f_i \begin{cases} \underline{A}\underline{e}_i & \text{for a bias in measurement i} \\ \underline{m}_j & \text{for a process leak in node j} \end{cases}$$

Next, we move to hypothesis testing. Let μ be the unknown expected value of r, we can formulate the hypotheses for gross error detection as

$$H_0 : \mu = \underline{0}$$
$$H_1 : \mu = b\underline{f}_i$$ (12)

Ho: is the null hypothesis that no gross errors are present and
H1: is the alternative hypothesis that either a leak or a measurement bias is present.

Here, b and fi are unknown parameters. B can be any real number and fi will be referred to as a gross error vectors from the set F:

$$F = \{\underline{A}\underline{e}_i, \underline{m}_j : i = 1...n, j = 1...m\}$$ (13)

We will use the likelihood ratio test statistics to test the hypothesis by:

$$\lambda = \sup \frac{\Pr\{r|H_1\}}{\Pr\{r|H_0\}} \tag{14}$$

$$= \sup_{b_i,\underline{f}_i} \frac{\exp\{-0.5(\underline{r}-b\underline{f}_i)'\underline{V}^{-1}(\underline{r}-b\underline{f}_i)\}}{\exp\{-0.5\underline{r}'\underline{V}^{-1}\underline{r}\}}$$

The expression on the right hand side is always positive. The calculation can be simplified by the calculation by the test statistics, T as:

$$T = 2\ln\lambda = \sup_{b,\underline{f}_j} \underline{r}'\underline{V}^{-1}\underline{r} - (\underline{r}-b\underline{f}_i)'\underline{V}^{-1}(\underline{r}-b\underline{f}_i) \tag{15}$$

The maximum likelihood estimate is shown here:

$$\bar{b} = (\underline{f}_i\underline{V}^{-1}\underline{f}_i)^{-1}(\underline{f}_i\underline{V}^{-1}\underline{r}) \tag{16}$$

Substituting b in the test statistics equation and denoting T by Ti:

$$T_i = \frac{d_i^2}{C_i} \tag{17}$$

Where:
$$d_i = \underline{f}_i'\underline{V}^{-1}\underline{r}$$
$$C_i = \underline{f}_i'\underline{V}^{-1}\underline{f}_i$$

This calculation is performed for every vector $\underline{fi}$ in set F and the test statistics T is:

$$T = \sup_i T_i \tag{18}$$

Our Procedure for Generalized Likelihood Ratio

For a given pipeline configuration and covariance matrix of errors Q, the measured values are simulated within ±5% error in the steady state true values using the RANDBETWEEN function in excel. Biases were introduced in a measurement by picking a random number outside the given range of measured values. If a leak is being simulated, it is looked at as an extra outflow and the new mass balance of the network is computed. Measured values are subsequently introduced as earlier stated. Different runs are performed for each type of bias introduced, and a different set of measurements is generated in each run. Methods proposed by Rosenberg (1985) were used to evaluate the performance of the generalized likelihood ratio in each simulation trial. The overall power of the method in identifying gross errors is given by:

$$overall\, power = \frac{number\ of\ gross\,errors\,correctly\,identified}{number\,of\ gross\,errors\,simulated}$$

RESULTS AND DISCUSSION

SIMULATION PROCEDURE

The generalized likelihood ratio for bias detection was implemented and evaluated using only simulations in Simsci Esscor's PRO/II. Pressure measurements were introduced along with the flow measurements not to only identify and estimate the leak, but also to provide an estimate of its location. As earlier mentioned, flow meters alone are insufficient for error location as different number of scenarios may arise. Take the case of the simple pipeline seen in figure 9, with the flow in and out only assumed to be measured.

Figure 9

Three possible scenarios could arise as seen in the table 1.

	Sensor 1	Leak	Sensor 2
Case 1	0.4	0	0
Case 2	0	0.4	0
Case 3	0	0	-0.4

Table 1

A bias of 0.4 may be present in the first sensor, a leak of 0.4 may be present in the pipeline and lastly, or a bias of -0.4 may be present in the second sensor. With flow measurements only, these three scenarios cannot be differentiated; therefore, pressure measurements have to be introduced for analysis of the pipeline.
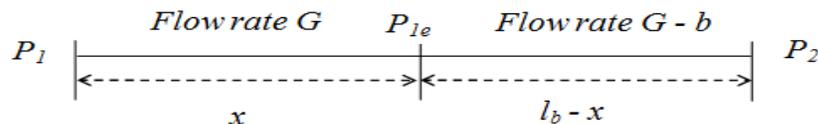
Problem Formulation

Energy balance without leak is as follows:

(19)

$$P_1 - P_2 = f(G)$$

Where: P1 and P2 = inlet and outlet pressures respectively
        G= flow rate

In the presence of leak of magnitude b and location x from the head of the branch, the energy balance becomes:

$$P_1 - P_2 = (P_1 - P_{1e}) + (P_{1e} - P_2) \tag{20}$$

The pressure drop becomes:

$$P_1 - P_2 = f(G, b, l_b) \tag{21}$$

Where: $b = leak\ magnitude$

$x = leak\ location$

In the case where no gross error is present, the following data reconciliation problem is solved:

$$Min \sum_i (\tilde{G}_i - G_i)^2 * S_{G_i}^{-1} + (\tilde{P}_i - P_i)^2 * S_{P_i}^{-1} \tag{22}$$

$where\ \tilde{G}_i = var\ iable\ flow, \tilde{P}_i = var\ iable\ pressure,$

$\quad S_{G_i}^{-1} = var\ iance\ of\ flowmeasurement, S_{P_i}^{-1} = var\ iance\ of\ pressuremeasurement$

Where Equation 22 is subject to the following constraints:

$$G_{i,in} - G_{i,out} = 0 \tag{23}$$

$$P_{i,in} - P_{i,out} = f(G) \tag{24}$$

In the case of an error of magnitude b and location x, the model becomes:

$$Min \sum_i (\tilde{G}_i - G_i)^2 * S_{G_i}^{-1} + (\tilde{P}_i - P_i)^2 * S_{P_i}^{-1} \tag{25}$$

Where Equation 25 is subject to:

$$G_{i,in} - G_{i,out} - b = 0 \tag{26}$$

$$P_{i,in} - P_{i,out} = f(G, b, l_b, x) \tag{27}$$

The leak detection procedure is as follows:
1. Hypothesize leak in every branch and solve data reconciliation problem
2. Obtain GLR test statistic for each branch obj(no_leak) – obj(with_leak_k)
3. Determine the maximum test statistic obj(no_leak) – obj(with_leak_k)
4. We compare the max test statistic with the chosen threshold value: Max{obj(no_leak) – obj(with_leak_k)}> threshold value: leak is identified and located in the branch corresponding to the maximum test statistic

The pipeline network and measurements taken from Bagajewicz et al was used in our simulations. Figure 10 is a depiction of the same pipeline network in the simulator. A leak is being simulated in pipe 1 and the calculator is used to solve the data reconciliation problem, while the optimizer minimizes the result from the calculator by varying the parameters where measurements are assumed to be taken. This corresponds in this case to all inlet and outlet streams.
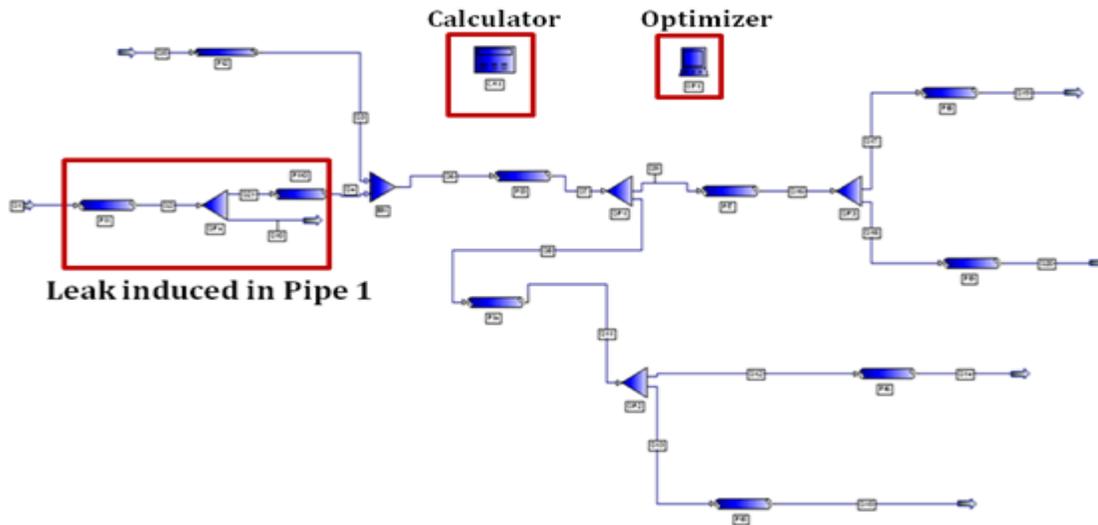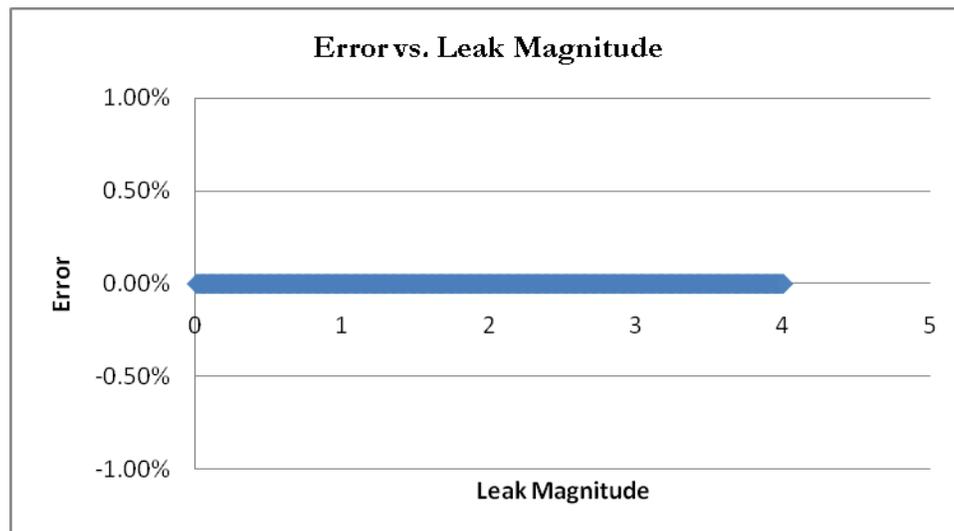

Figure 10: Pipeline Network

The procedure was tested first under perfect measurement conditions, meaning no random variance or noise in the pipeline sensors, graph 1.
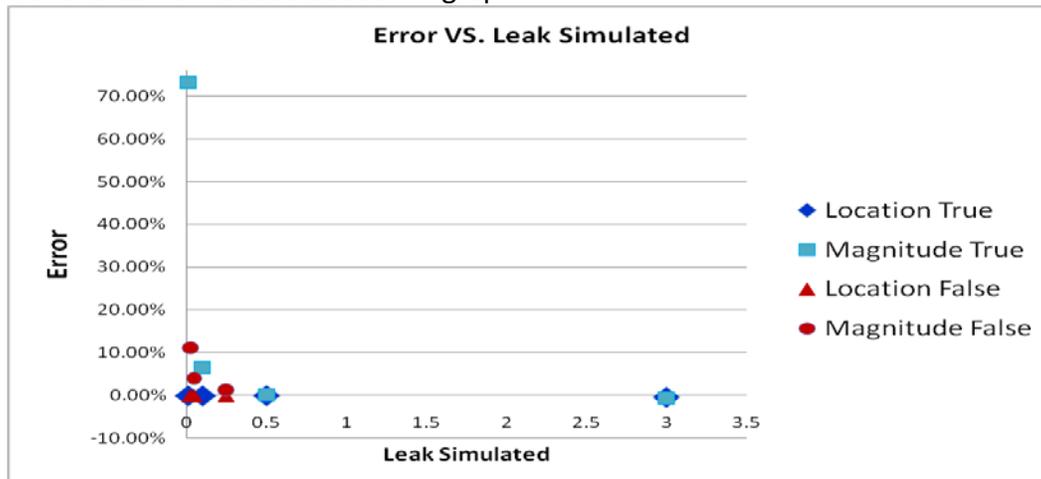

Graph 1. Error vs. Leak Magnitude

A leak of varying size was introduced into the system to test the theory behind the procedure. As expected, the procedure is able to correctly identify both the location and

magnitude of the leak for even very small leaks. This case is highly unlikely as meter variance or noise is always present in measurements.

To further test the ability of the procedure to correctly identify both the magnitude and location of a leak, a random variable generator was introduced into the system in the form of a code in calculator. The random variable generator caused the measured variables in the system to vary by 2.5%. The error in both the location and magnitude of the leak is plotted verse the true size of the leak simulated as seen in graph 2.

Graph 2. Error vs. Leak Simulated

There is an apparent trend of decreasing error in the calculated magnitude with increasing leak size. This trend is the same as was found in the GLR method, however, there is insufficient data to conclude this trend is accurate. The error in the leak location is always small with no apparent trend.

The overall power is also found and plotted verse the magnitude of the simulated leak, graph 3.
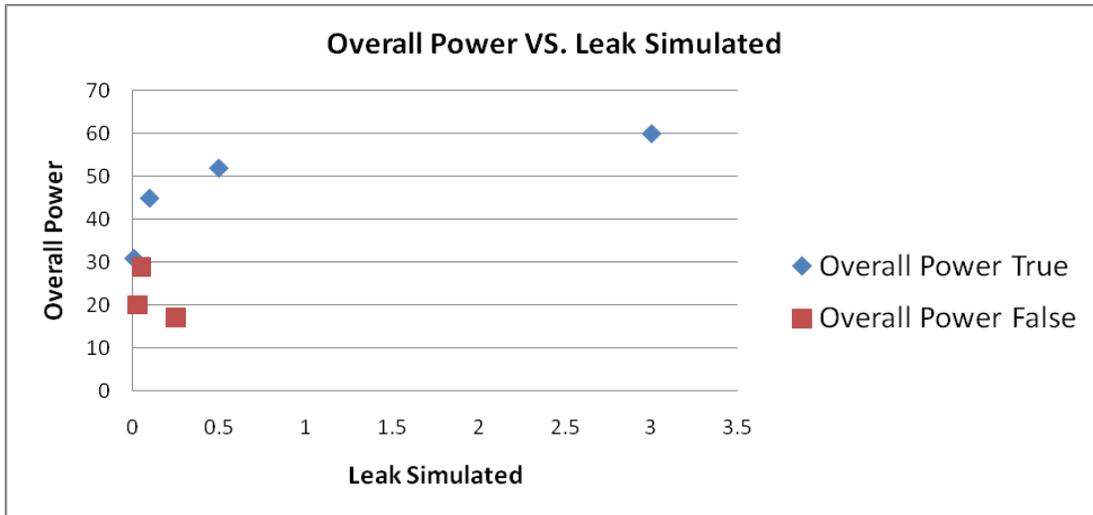
Graph 3. Overall Power vs. Leak Simulated

As the magnitude of the simulated leak increases the overall power increases, which is also what happened with the earlier mentioned GLR method. However, there is insufficient data to conclude this trend is accurate. More case studies need to be run to correctly evaluate the simulation procedure.

The procedure is a viable method since it is able to always identify the size and location of a leak when there are perfect measurements available. It also shows similar trends when compared to the GLR method used by Narasimhan and Mah, in that larger leaks are more accurately identified in both location and magnitude. The generalized likelihood ratio method provides an outline for identification of all gross errors that can be modeled in a pipeline network. It is especially useful as it can differentiate between sensor biases and leaks, which is an essential tool for risk assessment in pipeline networks. The simulations in this paper showed that with the proper constraints, the GLR method can successfully detect and locate gross errors in various pipeline systems

The following table gives a comparison of the aforementioned leak detection methods:

Method	Power	Size Estimate of Leak	Location	Smallest Leak (gas)	Smallest Leak (liquid)	Response Time
Acoustic Emmisons	1 false alarm / year	Not provided	+/- 30 m	Hole 2-10% of pipeline dia.	1-3% nominal flow of pipeline	15 seconds to 1 minute
Fiber Optic Sensing	Reportedly no false alarms	Indicates whether leak is large, medium, or small	1 m	50 ml/min		30 seconds to 5 minutes
Vapor Sensing	Reportedly no false alarms	Indicates whether leak is large, medium, or small	0.5% of monitored area	100 l/hr	1 l/hr	2-24 hours
Ultrasonic Flow Meters	Reportedly no false alarms	Indicated by difference in mass flow measurements (0.15% nominal flow smallest)	100 m range for 10 km pipeline	0.15% of nominal flow		Near real time
Volume Balance	Many false alarms	Indicated by difference in mass flow measurements	Not provided	Greater than 5% of flow		Directly related to size of leak. (bigger leak = faster response)
Reflected Wave	Many false alarms	Related to size of propagated wave	Difficult to locate if near the measuring section	Not provided		Not provided
Pressure Analysis	Many false alarms	No estimate provided	Identifies the transducers involved	50 ml/min		Delayed
Transient (Inverse)	Sensitive to initial estimates	Can be localized	Not provided	Greater than 10% of flow	Greater than 2% of flow	Real time
Frequency Analysis	Not provided	Found from pressure amplitude peaks	Found from pressure amplitude peaks	Greater than 5% of flow		Delayed, pipeline operations must be suspended
GLR	Less than 80% detection ability for leak sizes up to 10%	Indicated by difference in mass flow measurements	Can be found for even very small leaks	Not provided		Not provided

Table 2: *Leak Detection Methods*

Economic Analysis

The next step was to determine if GLR was the most economic leak detection method for the each of the pipeline systems. The ultrasonic method, the volume balance method, and the pressure analysis method were each compared with GLR. The aforementioned different types of pressure analysis methods were grouped together since no significant change in cost or implementation was found. In order to do this comparison, an excel database was set up.

The cost of each method was computed using the following equation:

$$Cost = L + P + M + F \tag{28}$$

Where L is the value of the product lost due to a leak, P is the value of the product that could have been shipped if the pipeline was not shut down for repair, M is the maintenance and installation cost of the leak detection method, and F is the value of fines levied.

To calculate L, PHMSA data for leaks occurring in the US was consulted to get an average leak size. The average leak size changes for each detection method based on its sensitivity to leaks. Consequently, an adjusted average leak size was used for each method corresponding to that method's particular detection abilities. For example, a method that could detect a leak 5% of the nominal flow would have a larger average leak size than a method that could detect 3% of the nominal flow. The total number of leaks detected would also change based on the method's sensitivity. The method that detects leaks as low as 3% of the nominal flow would detect more leaks than the method that detects leaks of 5% of nominal flow. The tabular data obtained from the PHMSA allowed for this to be taken into account for each method. New averages were taken and, similarly, the number of instances of leaks was adjusted for each method based on the smallest leak that method could detect.

Once the adjusted average leak size was known, it was then multiplied by the value of the product. This gave the value of the product lost due to a leak. The value of the product was difficult to project, so multiple scenarios were looked at over a range of values. For oil, the prices used ranged from $40 to $80 per bbl and the natural gas prices used ranged from $4 to $12 per mcf.

There was also an additional component to this L term beyond the value of the product lost due to the leak and that was clean up costs associated with the leak. Clean up costs vary greatly but generally are between $700 to $5,000 per bbl (Kristiansen). This range was then used with the adjusted average leak size to determine the total clean up costs for multiple scenarios.

P was the value of the product that could have been shipped if the pipeline was not shut down due to leak repairs. Already having a range of values for the product value, the only other piece of information needed was the daily amount of product transported through the pipeline. The flow through a particular pipeline was estimated based on the API Recommended Practice 14 E for piping systems. 14 E gives the following equation:

$$Q = \frac{v \times d^2}{0.012} \tag{29}$$

Where Q is the flow through the pipe (bpd), d is the diameter of the pipeline, and v is a given value. To calculate Q_{min}, a v_{min} value of 3 ft/sec was used. To calculate Q_{max}, a v_{max} value of 12 ft/min was used. Both v_{min} and v_{max} were values suggested for use in API Recommended Practice 14 E. Q_{min} gave the lower limit for the flow so that it was sufficiently high to minimize corrosion while Q_{max} gave the upper limit of flow so that erosion was not an issue. The middle point between these two limits was used as the flow for the pipe.

To calculate M, estimates were gathered for the initial installation costs of each of the different methods by contacting vendors. Maintenance was assumed to be 5% of the installation cost.

Calculating the fines, or F, for the equation required research into current US laws and past fines levied against companies. It was seen that fines levied by the EPA were by far the most dramatic and costly. To get an idea of what the EPA might fine a company for a leak on a per barrel basis, past spills were scrutinized. Additionally, the Clean Air Act and the Clean Water Act were reviewed. From this, an estimated fine on a per barrel basis was found. This was kept constant for all calculations and was multiplied by the adjusted average leak size for each method to determine the fine.

Different types of instrumentation were accounted for, as were the different levels of tuning required for each method. The cost of engineers and technicians needed to monitor the pipeline was also factored into the calculations.

Simulations were run for varying nominal pipe diameters of 2 to 8 inches for gathering/distribution networks and 12 to 24 inches for the single pipeline. Multiple scenarios were tested for each, with a range of values used for the price of oil as well as for the price of leak clean up. Additionally, the overall length of each of the pipeline systems was varied from very short at one tenth of a mile, to very long at 10,000 miles.

Once the simulations were run, the results were plotted with cost per mile on the y-axis and pipeline length on the x-axis. As expected, economies of scale reduced the overall cost for each method as the length increased. Graphs 4 and 5 indicate the economics for the different detection methods for a six inch gathering/distribution network. Slight separation can be seen between the ultrasonic and pressure methods, but GLR provides the most separation and is thus the most economic. GLR is clearly the best option for both cases.
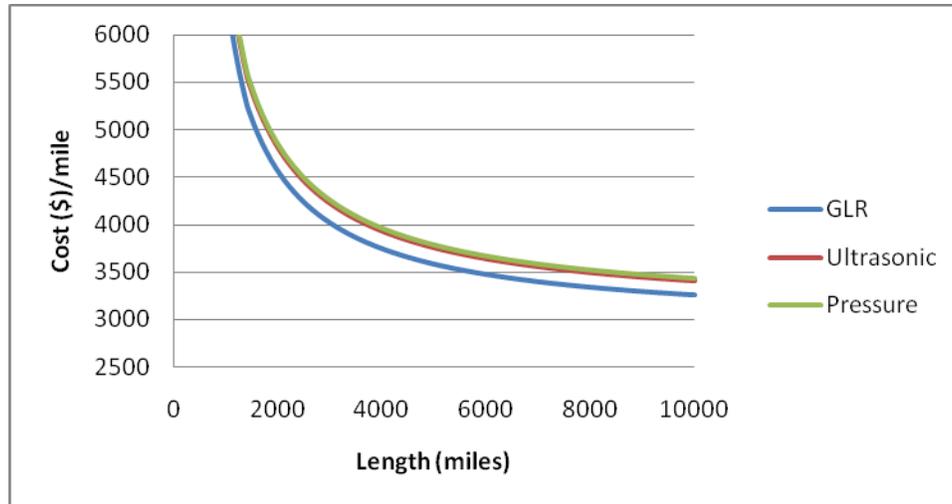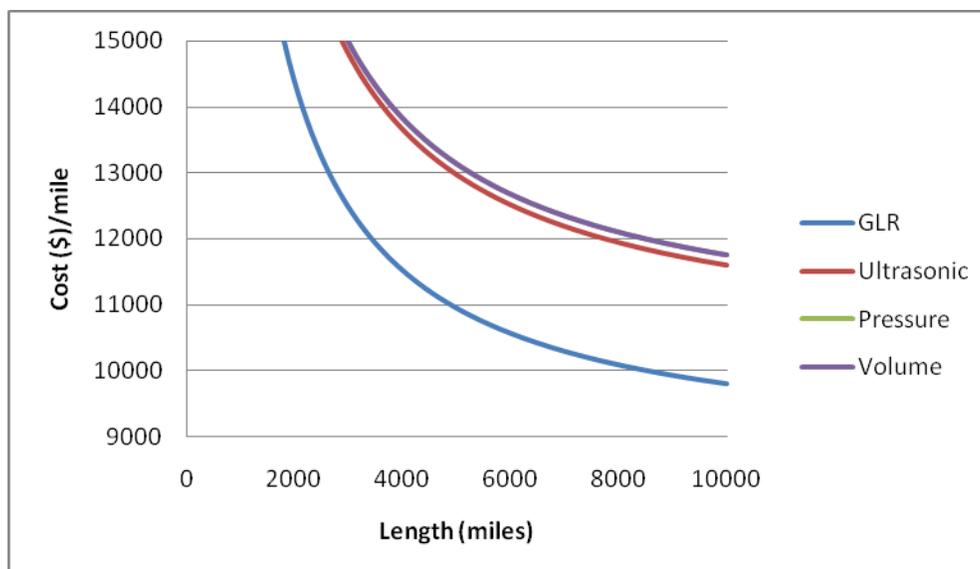
**Graph 4.** 6" Gathering/Distribution Network: Oil=$40 and Clean Up=$1,000
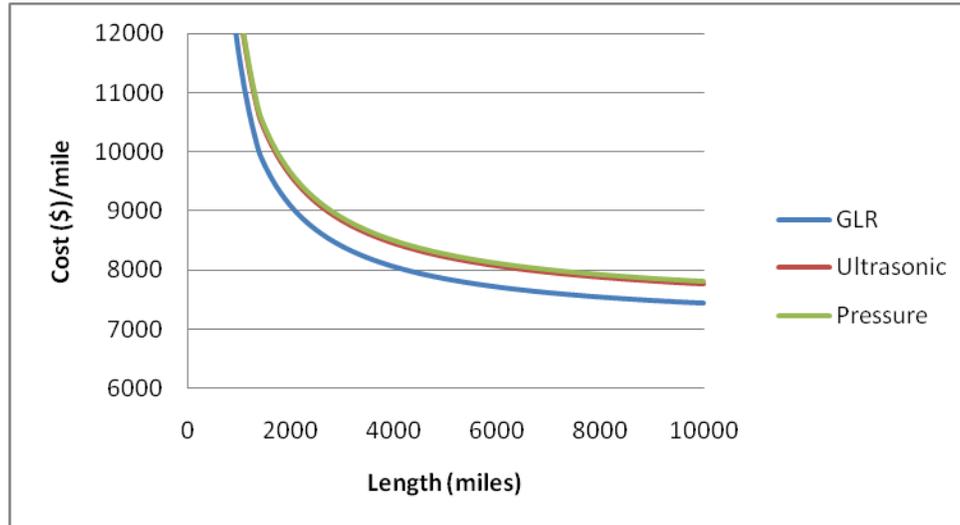
Graph 5. 6" Gathering/Distribution Network: Oil=$80 and Clean Up=$5,000

A single pipeline transporting oil showed much the same performance as the gathering/distribution network. Graphs 6 and 7 clearly indicate that the GLR method is the most economic choice for this instance as well.
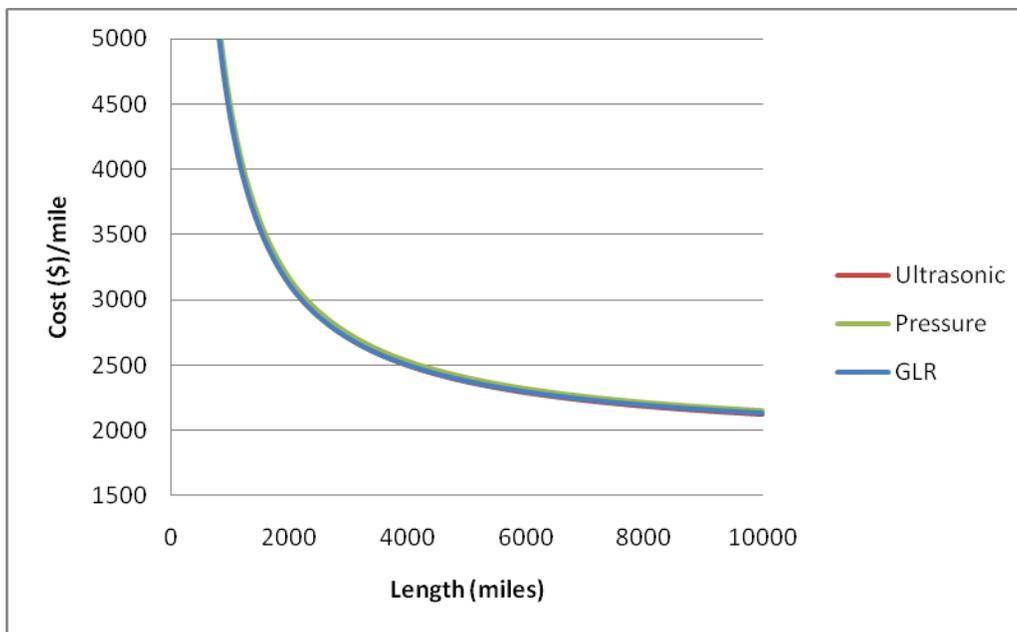
**Graph 6.** 20" Single Pipeline: Oil=$40 and Clean Up=$1,000
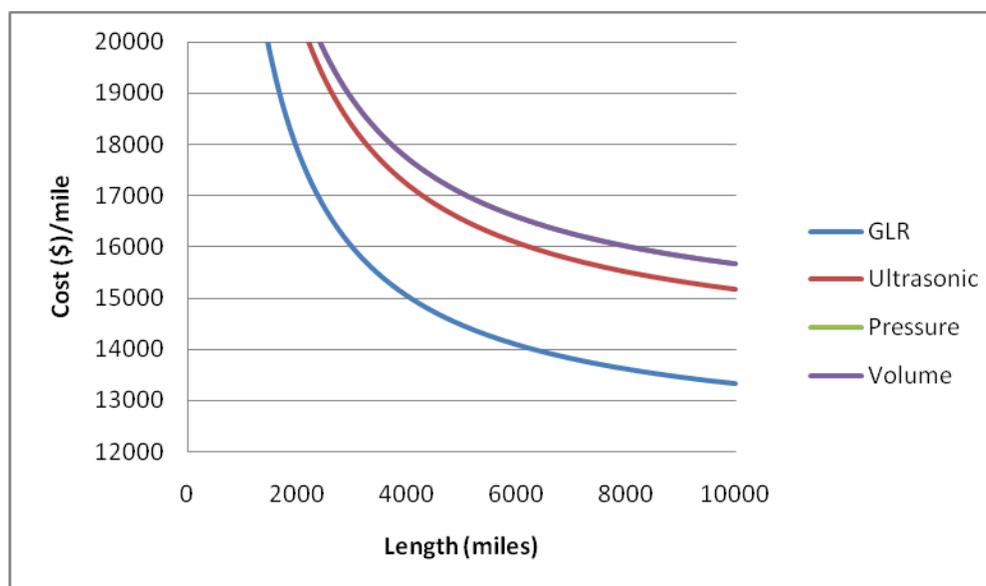
Graph 7. 20" Single Pipeline: Oil=$80 and Clean Up=$5,000

Natural gas pipeline systems showed generally the same characteristics for economic performance as oil pipeline systems. However, the separation between the methods from an economic standpoint was less pronounced. This is attributable to the lower cost of natural gas in relation to the cost of oil. The economics for a six inch natural gas gathering/distribution network is shown in graphs 8 and 9. Very little separation is seen for any of the methods at the lowest natural gas price and clean up cost in graph 8. Slightly more separation can be seen in graph 9 when the natural gas price and clean up costs are higher.

Graph 8. 6" Gathering/Distribution Network: Natural Gas=$4 and Clean Up=$1,000
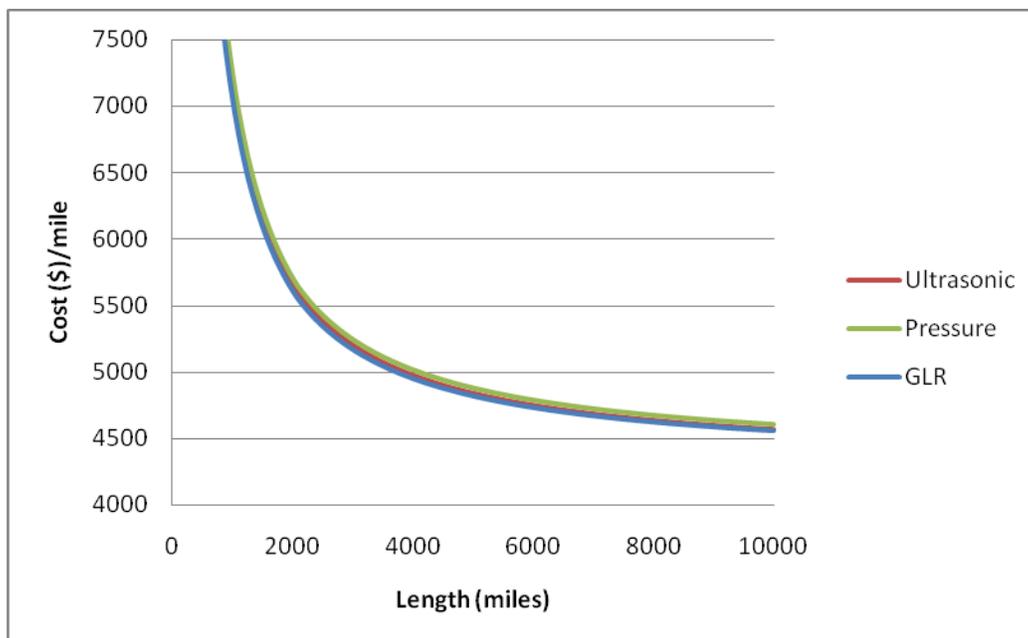

Graph 9. " Gathering/Distribution Network: Natural Gas=$12 and Clean Up=$5,000

Similar to the previous results, GLR is the most economic choice for a single pipeline transporting natural gas as well. Graphs 10 and 11 make this point. As seen before, the scenario with increased commodity price and clean up costs has better GLR economics in relation to the other detection methods. GLR is the economic choice for the single pipeline transporting natural gas.
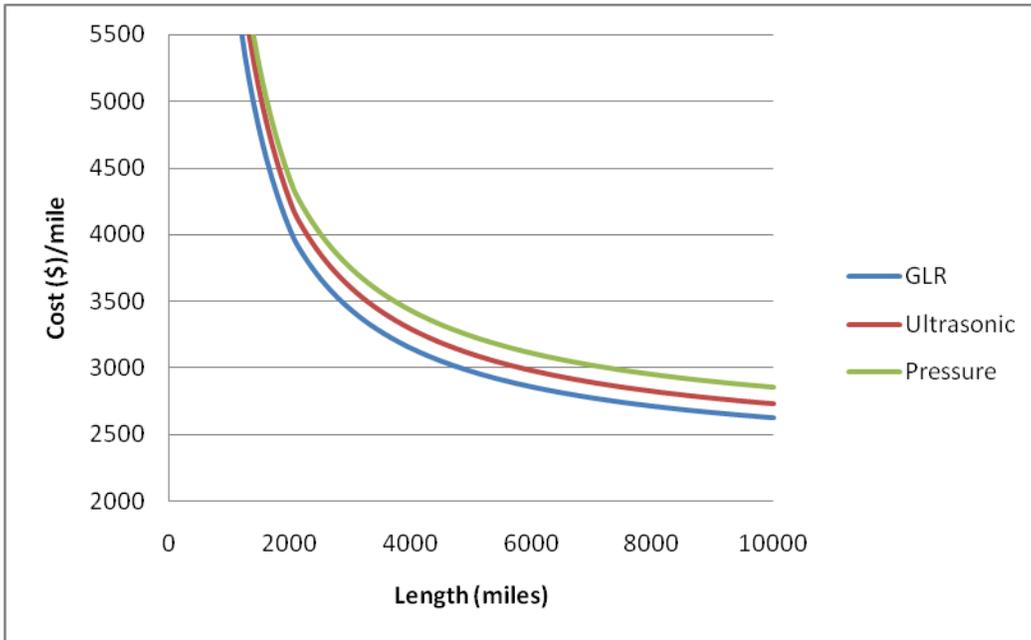
Graph 10. 20" Single Pipeline: Natural Gas=$4 and Clean Up=$1,000
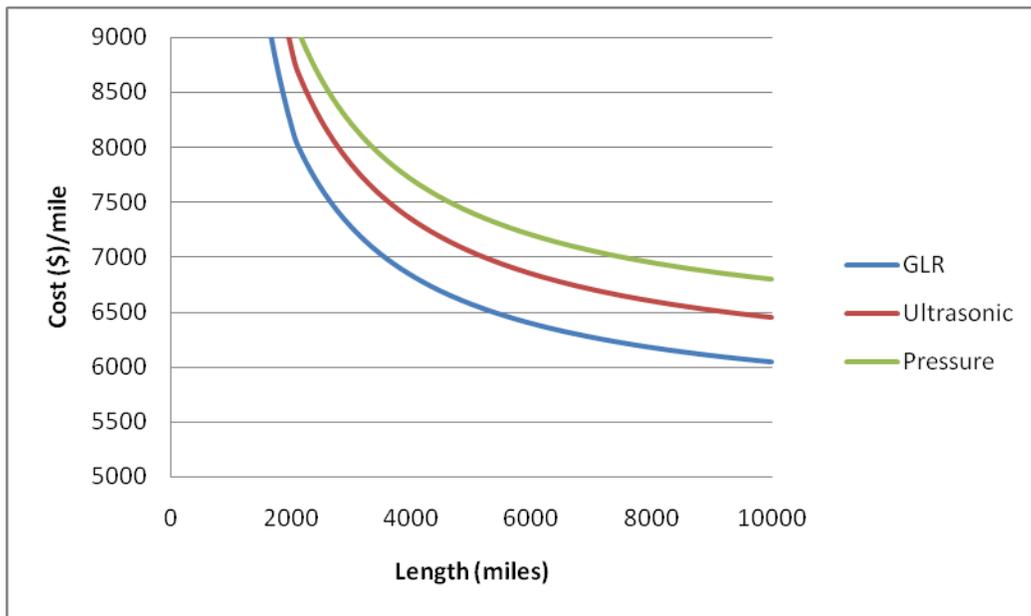
Graph 11. 20" Single Pipeline: Natural Gas=$12 and Clean Up=$5,000

All of the different simulations produced the same conclusion: GLR is the most economic leak detection method. Both software and hardware methods were researched and compared based on leak detection ability, base cost, cost of implementation, levels of tuning

required, and cost of crew required. The economic comparison included computing the losses for not detecting the leaks. GLR finds smaller leaks in the pipeline, which prevents larger leaks from occurring later on. This results in fewer fines for leaks and also less lost production. Simulations were run with varying pipe diameters, price of oil, and cost of leak clean up. Simulations were run for a single pipeline as well as for a gathering/distribution network.   In both cases GLR showed to be the best method.

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