Development of an Impact Monitoring System for Petroleum Pipelines

Oluwafemi Ayodeji Olugboji

School of Mechanical and Systems Engineering, Newcastle University
Newcastle upon Tyne, Tyne and Wear, United Kingdom
E-mail: <olufem000@yahoo.com>

Abstract

Third party damage to petroleum pipelines can be catastrophic if undetected. This damage results in financial losses, environmental pollution and frequent loss of life as a result of explosion. Therefore the timely detection and location of damages along petroleum pipelines will play a key role in the overall integrity management of a pipeline system.

This paper presents the development and testing of mathematical techniques for locating an impulsive event on a pipeline using the pressure pulse caused by it from measurements made remotely. An impulsive event occurring along a pipeline generates pressure pulses which propagate in both directions and this can be detected and measured by sensors located at different positions along the pipeline. From these measurements the location of the event can be determined.

The theoretical work was validated by experiments using a simulated pipeline.

The experimental work was carried out using an experimental test rig comprising a flexible hose pipe 23 m long and 19 mm diameter with four pressure sensors distributed along the pipe and connected to a data acquisition system.

The experiments were tested using static air in the pipe, and were found to give good results.

Keywords*: Petroleum pipeline, third party damage, impact, event location, pulse propagation.*

Introduction

Pipelines are regarded as one of the surest and safest means of transporting petroleum products (USDOT 2003). Unfortunately, these pipelines are occasionally subjected to natural damages (earthquakes, erosion, etc), or third party mechanical damages (terrorist attacks, vandalisation, heavy duty equipment, etc) of which, mechanical damage has been singled out as one of the largest cause of pipeline failure from history (Posakony and Hill 1992, NTSB 1995). Vandalisation here refers to illegal or unauthorised activities that involve the destruction of petroleum pipelines to disrupt supply or the damaging of petroleum pipelines to appropriate crude oil or its refined products for personal use or for sale in the black market (Akintola 2006). This damage, which occurs mostly in remote areas, is of great concern in developing countries of the world, where third party damages are rampant causing the supply of petroleum products to be disrupted. Even in situations where it had been known that damage has occurred along the pipelines, it has actually been difficult to pin-point the exact location of the damage.

Most of this damage caused by impulsive events generates a pressure pulse that propagates in both directions through the fluid in the pipe. This can be detected and measured at points remote from the event and the measured pulses which contain information about the event can potentially be used to locate and characterize what must have caused it. This information might then be used to assess the damage.

Pipeline Damage Detection

It is quite oblivious that pipelines dangers and damage exist from the building of them to their use. They traverse large distances, which makes them vulnerable to damage and their complexity makes it difficult to detect and locate faults. Moreover, this medium of transportation is usually attributed to very sensitive products such as crude oil, natural gas, industrial chemicals, in which an unintended pause in their operation result in the loss of millions of dollars. Thus, it is of great importance to set up reliable mechanisms or systems in keeping a close watch at every inch of their length, in order to sustain normal operation and to prevent losing significant amount of those products. The design and application of pipeline detectors is made around the properties of the product that is being transported and expected nature of damage to the system. There are several methods in use that can detect and locate pipeline damage, ranging from simple visual inspection to complicated satellite based hyper-spectral imaging (Bray 1989, Carlson 1993, Doctor and Dunker 1995, Hosokawa *et al*. 2000, Nakamachi *et al*. 1992, Leis 2003, Jolly *et al*. 1992, Kulp *et al*. 1998, Huebler 2002, Francini *et al*. 1997), each with its own advantages and disadvantages.

Event Location

Locating an event on a pipeline requires the use of two sensors on opposite sides of the event. This paper looks at the location of an event on a pipeline considering a situation without gas flowing through the pipe. With gas not flowing through the pipe, the calculations are quite straight forward. But with flowing gas, it becomes a bit more complex and requires the pulse propagation velocity to be calculated in both directions of the propagating pulse.

Location of an Event on a Pipeline

The location of an event such as impact or explosion along pipelines can be determined from knowledge of the pulse arrival times and sensor positions. Figure 1 shows schematically a pipeline with three pressure sensors denoted by 1, 2 and 3 at distances x_1, x_2 and x_3 from some datum. An impulsive event occurs at some unknown location and the pulse generated is recorded by the three sensors, arriving at times t_1 , t_2 and t_3 , respectively. Clearly, if the sensors are spaced at approximately equal intervals the event will be located between the first two arrivals; between sensors 1 and 2 in this case.

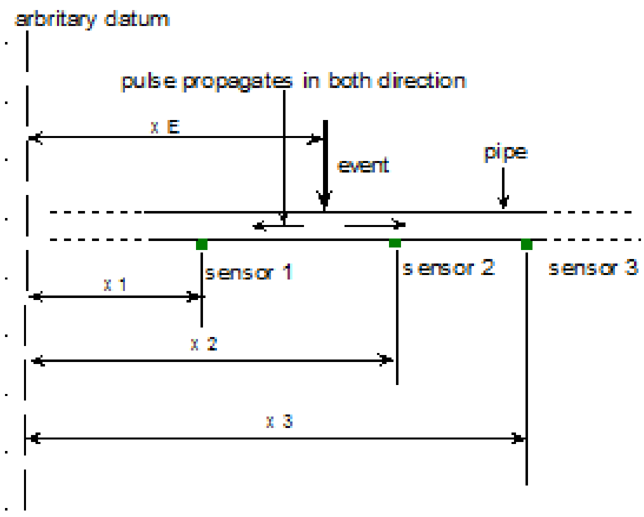

Fig. 1. Schematic representation of sensors on a pipeline.

The location of an event on the pipe shown in Fig. 1 maybe determined with respect to either sensor 1 or sensor 2. The pulse propagation velocity can easily be measured from the arrivals at the sensors on the same side of the event, sensor 2 and 3 in this case. If we neglect the effect of gas flow rate which is normally small compared to the pulse propagation velocity, c_p , the exact event location from sensor 1 is calculated by:

$$x_{E1} = \frac{(t_{12}c_p + x_{21})}{2} , \qquad (1)$$

or from senor 2,

$$x_{E2} = \frac{(x_{21} - c_p t_{12})}{2} . \qquad (2)$$

Unfortunately, this calculation as simple as it may look is made difficult due to the uncertainties in measurement of the arrival time of the pulses at the sensors. Olugboji (2011) Investigated this and recommended the use of the cross correlation technique for measurement of this arrival times, as this technique was found to give the best estimate in estimating the delay in pulse arrival times irrespective of the signal to noise ratio.

Experimental Test Rig

Figure 2 shows the test rig that was developed to validate the theory of event location as discussed earlier. It consists of an air filled pipe along which pressure pulses propagate, a pressure pulse generator and an instrumentation system to capture and record the propagation of the pressure pulses.

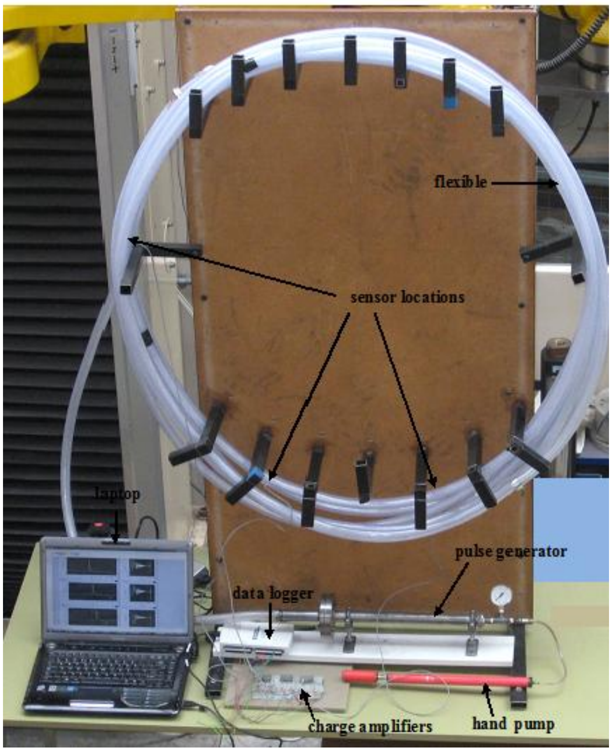

Fig. 2. Experimental test rig showing the various components of the rig.

The air filled pipe is a smooth bore flexible hose pipe of internal diameter of 19 mm coiled on a circular framework at a diameter approximately 1.5 m, having established that at this curvature the pressure pulses would propagate through it unimpeded, as a waveguide (http://www.pulsation-ampeners.com). That is, the radius of curvature should be greater than ten times the diameter of pipe ($R > 10 \times D$) . An advantage in this arrangement is that even though the pressure measurement sensors attached to the pipe of the test rig are located at long distances along the hose pipe they are still physically close together for convenience of monitoring using a single data logger without the need for long cables. Three piezoelectric pressure sensors were located at different positions along the hose pipe and connected to a single NI 6215 USB data logging device via three DU 3226 charge amplifiers.

The total length of the hose pipe is approximately 23 m and the distances of the sensors from one end of the pipe are 9.77 m for sensor 1, 13.59 m for sensor 2 and 15.45 m for sensor 3.

Experimental Results

The experiments were done using the test rig illustrated in Fig. 2 and Fig. 3 shows schematically a representation of the pressure pulses captured at each of the sensors located along the pipeline. The pulse signals at the four sensors were measured and recorded at a sampling rate of 60 kHz.

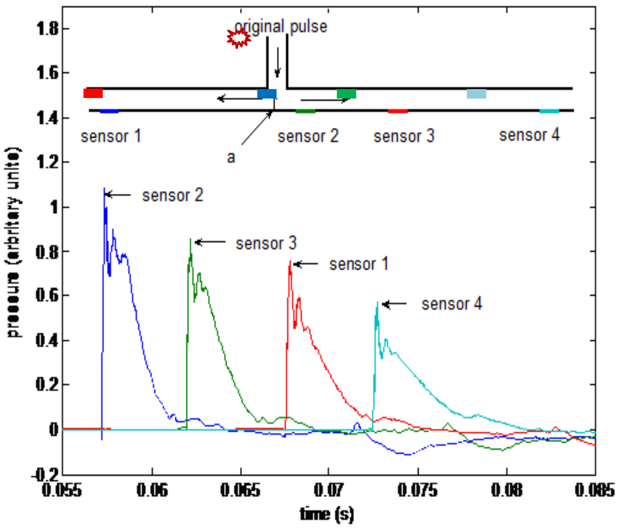

Fig. 3. Typical pressure pulse measured at all four sensors of experimental rig.

Figure 3 shows a typical pressure pulse from one of the test results obtained at the four sensors located along the pipe of the rig. Sensor 2 was located as close as possible to the tee connection, and hence to the point of arrival of the pulse in the main pipe which defines the event location because this is the place where the pulse enters the main pipe and sets off in both directions, arriving first at sensor 2, followed by sensor 3, then sensor 1 and finally sensor 4. These times of arrival are associated with the distances of the sensors from the position where the generated pressure pulse enters the pipe.

Sensor 2 is the best possible independent measurement of the event (the pulse as it enters the main pipe) because it is close to it and there will be little distortion/attenuation before the pulse propagating from the tee reaches it. The other three sensors are spread out along the pipe to locate the event.

The position ‘a’ shown is the region in the pipe wall where the originally generated pressure pulse reflects back to the source (the pulse generator) and on reaching the end wall of the source, is again reflected back into the pipe. This can be seen as the negative pressure unloading pulse appearing at sensor 2 at approximately the same time as the original pulse arrives at sensor 4. This unloading pulse is not used in any of the experimental calculations; neither did it affect any of the results of this work.

Velocity of Pressure Pulse Propagation in Static Air

Referring to Fig. 3, the velocity at which the pressure pulse propagates through the pipe of the rig was determined based on the measured pressure pulses at sensors 3 and 4. These were cross-correlated in Matlab® to estimate the delay between arrival times ($t_{delay,34}$). The velocity of propagation of the pressure pulse was computed as

$$c_p = \frac{x_{3,4}}{t_{delay,34}}, \tag{3}$$

where $x_{3,4}$ is the known distance between sensors 3 and 4. The smallest pressure pulse was generated with 0.2 bar in the pulse generator, and the highest 1.0 bar. A total of 75 measurements (15 each at each pressure in the pulse generator) were taken between these limits and the results are shown in Fig. 4.

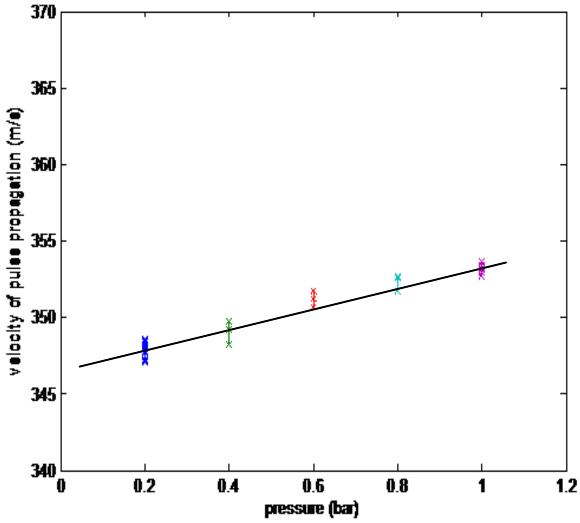

Fig. 4. Computed velocities of pulse propagation (the pressure quoted is the pressure in the pulse generator).

Considering the results obtained in Fig. 4, the velocity of pulse can be seen to be proportional to the pressure in the pulse generator. It is reasonable to suppose that this pressure in the pulse generator is proportional to the pulse pressure and so the computed pulse velocity may be said to be proportional to the pulse pressure. The nominal velocity of sound propagation in air at normal temperature and pressure is 343 m/s (Kaye *et al*. 1918). The reason for the discrepancy was not obvious, but it was clearly systematic and repeatable and so it was investigated.

Pressure Related Pulse Velocity

Sonic velocity in a perfect gas such as air is related to temperature through the equation:

$$c^2 = \gamma RT\,. \tag{4}$$

It was suggested that the rise in pressure within the pulse might have caused a localised temperature rise to account for the increased velocity. To investigate this hypothesis the necessary rise in temperature was calculated:

$$\left(\frac{c_n}{c_p}\right)^2 = \frac{T_n}{T_p}, \tag{5}$$

$$T_p = T_n\left(\frac{c_n}{c_p}\right)^2, \tag{6}$$

where T_p = air temperature within the pressure pulse; T_n = ambient temperature; c_p =

measured pulse propagation velocity; c_n = nominal sound propagation velocity.

Considering a measured pulse propagation velocity of 349 m/s and the speed of sound 343 m/s at 20°C, the value of T_p was obtained using Eq. (6),

$$T_p = \left(\frac{349}{343}\right)^2 \times 293 = 303\text{K},$$

that is, a rise of 10°C. This raised the question: is that quite substantial temperature rise possible?

The compression and subsequent expansion of the air as the pulse passes through it is very rapid, and so it is reasonable to assume it is an adiabatic process. So we may apply the ideal gas law:

$$\frac{P_p V_p}{T_p} = \frac{P_n V_n}{T_n}, \qquad (7)$$

where the subscripts p and n refer to the state within the pulse and standard values, respectively, as before.

Furthermore, one may assume constant volume compression/expansion since the air is constrained within a pipe, and so

$$\frac{P_p}{P_n} = \frac{T_p}{T_n} = \left(\frac{c_p}{c_n}\right)^2, \qquad (8)$$

$$\therefore P_p = P_n\left(\frac{T_p}{T_n}\right) = P_n\left(\frac{c_p}{c_n}\right)^2. \qquad (9)$$

Taking normal atmospheric pressure as 1.0 bar, this gives a pressure of 1.034 bar within the pulse, or a rise of 34 mbar above ambient. This seems quite feasible since the atmospheric pressure can vary by more than 90 mbar due to natural weather conditions (-80 mbar for hurricanes and +15 mbar for anticyclones). It is therefore proposed that the high measured pulse velocities are indeed accounted by change in temperature within the pulses as proposed.

Event Location in Static Air

The calculation of the location of the event on the pipe of the test rig was performed using a program written in the Matlab® m-code language. The estimate of the location of the real event, that is, the point where the original pressure pulse enters the main pipe was determined from the measured data at sensors 1 and 3 in Fig. 3, and later compensated for the small offset to sensor 2.

This compensation is necessary because the true source of the pulses is the tee joint and this should have formed the basis of all the calculations about the location of the event. The position of the ‘effective event’ (that is, the event apparently occurring at sensor 2) is calculated according to Eq. (2), minus the distance x_{offset}, where x_{offset} is the known distance between sensor 2 and the tee connector. This calculation makes use of the measured value of pulse propagation velocity c_p as given in Eq. (3), and $t_{delay,13}$, the measured delay between arrivals at sensors 1 and 3, computed using the cross correlation technique. Figure 5 shows the spread of the location calculations against the pressure in the pulse generator for the seventy-five tests carried out.

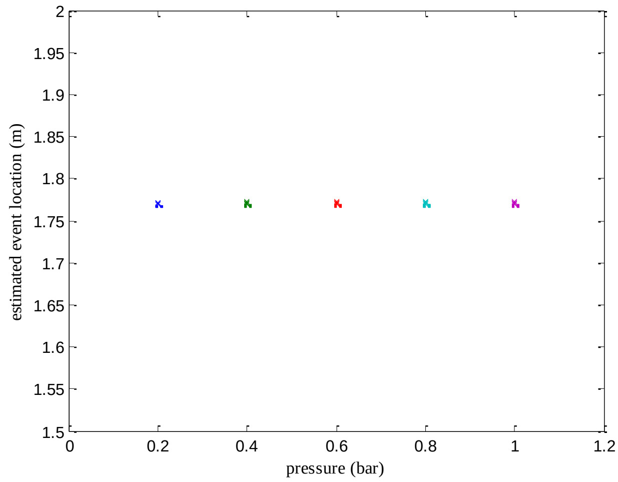

Fig. 5. Event location: Computed estimates in event location.

Figure 5 showed consistency in the computed estimates in the location of the event within the limits of the pulse pressure measurements used. The computed estimates in the location of the event for the 75 measurements taken ranged between 1.770 m and 1.772 m, a scatter of just 2 mm, as against the actual measured event location of 1.760 m. The small discrepancy may be accounted for by the assumption of uniform velocity between the sensors in the calculation.

Conclusion

An accurate method of locating the position of an impulsive event on a pipeline was developed, based on time delay between pulse arrivals at two sensors, measured using cross correlation. The results obtained for event location using this technique showed that it can be applied to real pipeline applications. With the use of static air there was a difference of only 12 mm between the computed and actual locations.

References

Akintola, T. (tomakint). 2004. Pipeline vandalization and oil scooping in the Niger's Delta and others. 22 December 2004. Available: <http://activism.greenpeace.org/cybercentre/gpi/Community/1103715096/1103715096.html>; <http://gg.tigweb.org/tomakint>.

Bray, D.E.; and Stanley, R.K. 1989. Non-destructive evaluation: A tool for design, manufacturing, and service. McGraw-Hill Series in Mechanical Engineering, New York, NY, USA.

Carlson B.N. 1993. Selection and use of pipe-line leak detection methods for liability management into the 21st century. Pipeline Infrastructure II, Proc. Int. Conf. Amer. Soc. Chem. Engineers, ASCE.

Doctor, R.H.; and Dunker, N.A. 1995. Field evaluation of a fiber optic intrusion detection system - FOIDS. GRI Final Report GRI-95/0077, December 1995.

Francini, R.B.; Leis, B.N.; Narendran, V.K.; and Stulen, F.B. 1997. Real-time monitoring to detect third-party damage: Phase II. GRI Final Report GRI-97/0141, April 1997.

Hosokawa, Y.; Masuda, T.; Ohira, H.; and Sasaki, N. 2000. On-line monitoring system for detecting third-party damage on cathodically protected pipelines. Pipeline Technology 2: 193.

Huebler, J.E. 2002. Detection of unauthorized construction equipment in pipeline right of ways. Presentation given at U. S. Department of Energy, National Energy Technology Center Natural Gas Infrastructure Reliability Industry Forums, Morgantown, WV, USA.

Jolly, W.D.; Morrrow, T.B.; O'Brien, F.F.; Spence, H.F.; and Svedeman, S.J. 1992. New methods for rapid leak detection in Offshore pipelines. Final Report for U.S. Department of the Interior Minerals Management Service, April 1992, pp. 1-84.

Kaye, G.W.C.; and Laby, H. 1918. Tables of physical and chemical constants and some mathematical functions. Kessinger Publishing, Whitefish, MT, USA (September 2010).

Kulp, T.J.; Powers, P.E.; and Kennedy, R. 1998. Remote imaging of controlled gas releases using active and passive infrared imaging systems. Proc. Infrared Technology and Applications XXIII, SPIE Vol. 3061, pp. 269-78.

Leis, B. 2003. Real-time monitoring to detect contact, product loss, and encroachment on transmission pipelines. 54th API Pipeline Conference, April.

Nakamachi, K.; Uchida, Y.; Hosohara, Y.; Okada, M.; and Nagashim, S. 1992. Damage detection system by monitoring audible sound in pipeline and its application. Proc. Int. Conf. on Pipeline Reliability, Calgary, Alberta, Canada.

NTSB. 1995. Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey March 23, 1994. National Transportation Safety Board (NTSB), Washington, DC, USA. Available: <http://www.ntsb.gov/doclib/reports/1995/PAR9501.pdf>.

Olugboji, O.A. 2011. Development of a monitoring system for detection, location and assessment of impact events in petroleum pipelines. Ph.D. Thesis (Unpublished), Newcastle University, Newcastle upon Tyne, Tyne and Wear, United Kingdom.

Posakony, G.J.; and Hill, V.L. 1992. Assuring the integrity of natural gas transmission pipelines. Tropical Report, Gas Research Institute, GRI-91/0366, November.

USDOT. 2003. Pipeline integrity management in high consequence areas (Gas transmission pipelines). Research and Special Programs Administration, United States Department of Transportation (USDOT), Washington, DC, USA.