MONITORING OF DEPOSITS IN PIPELINES USING PRESSURE PULSE TECHNOLOGY

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ABSTRACT

The basis of pressure pulse technology is presented in terms of the water hammer equation, the pipeline pressure drop equation and the equation for speed of sound in multiphase mixtures. The technology can be used for a range of applications, from on-line monitoring of flowing conditions to on-demand measurements and analysis to locate and quantify deposits in wells and pipelines. While pressure pulse measurements are low-cost and easy to implement, the commercial use of pressure pulse technology has resulted from extensive field experience and substantial in-house software development. Simulation tools were used to illustrate the effect of a 2 mm thick deposit, 500 m long and located 375 m from a quick-acting valve. The simulation conditions used are typical for multiphase gas-oil flow along a horizontal 2 km long pipeline from wellhead to manifold.

Keywords: Deposits, pipelines, flowrate, pressure pulse

INTRODUCTION

The pressure profile in a flowing pipeline can be used to detect and monitor solid deposits. The pressure profile is obtained from pressure measurements at one location, immediately up-stream of a valve. When the valve is activated, the up-stream pressure is measured, resulting in a pressure-time log. The pressure-time log is then converted into a pressure-distance log. The pressure-distance log gives the location and extent of deposits in a pipeline. Pressure pulse technology can also be used in non-flowing pipelines. In this case the pressure pulse must be generated by forcing a pressure change by some external mechanism, for example by opening a pipeline valve to a higher/lower pressure.

PRESSURE PULSE

When a valve in a multiphase pipeline is activated, a pressure pulse will be generated. The pressure pulse will propagate both up-stream and down-stream of the valve. The magnitude of the pressure pulse will be governed by the water-hammer equation:

$$\Delta p_a = \rho u a$$

where ρ (kg/m3) represents the fluid density, *u* (m/s) the fluid flowing velocity change and *a* (m/s) the speed of sound in the fluid. The speed of sound in the fluid is equivalent to the propagation speed of the pressure pulse generated. The subscript M is usually added to the variable *ρ*, *u* and *a* when the flowing fluid is a multiphase mixture.

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A typical pressure pulse technology set-up is shown in Figure 1a. It shows a valve and two pressure transducers, A and B, up-stream of the valve. The pressure transients generated at locations A and B are shown in Figure 1b. The valve generates a rapid increase in the pipeline pressure at locations A and B. The initial rapid pressure increase is the water-hammer. The pressure pulse will arrive at location A before it arrives at location B. The time difference is the time-of-flight Δt (s) which can be used to determine the speed of sound in the flowing gas-liquid mixture:

$$a = \Delta L_{AB}/\Delta t$$

Other configurations and methods can be used to measure the speed of sound. A pressure pulse travelling up-stream a pipeline, will arrest (stop) the flow. The pressure pulse will travel up-stream the pipeline at the in-situ speed of sound. In principle, when the pressure pulse has reached the end of the pipeline, the fluid velocity throughout the pipeline will be reduced to practically zero.

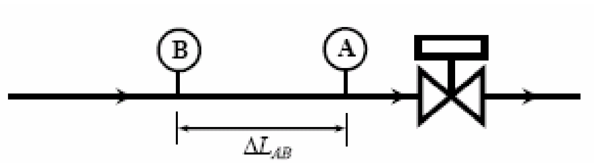

Figure 1a: Pressure pulse set-up for pipeline showing aquick-acting valve and pressure transducers.

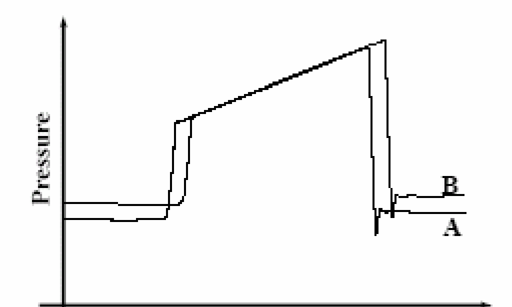

Figure 1b: Pressure pulse at locations A and B up-stream of quick-acting valve.

MASS FLOWRATE

The mass flowrate in a pipe of constant cross-sectional area A (m^2) can be obtained directly from the water-hammer equation, when the sound speed is also measured. The mass flux G (kg/s.m^2) can be expressed as

$$G = \rho \times u$$

where ρ (kg/m^3) is the gas-liquid mixture density and u (m/s) the mixture average velocity. The mass flowrate m (kg/s) is given by the expression

$$m = G \times A$$

Therefore, provided the sound speed a (m/s) and the water-hammer pressure increase are known, the mass flowrate can be found directly from the relationship

$$m = (\Delta p_a)\frac{A}{a}$$

The continuity principle dictates that the mass flow rate at the valve is the same as the mass flow rate at other locations, including: downhole, flowline, separator and stock-tank. Extensive field testing has demonstrated that water-hammer theory can be applied to most multiphase flow situations in the offshore industry.

LINE PACKING

In pressure pulse measurements, as the flow is brought to rest, the pressure loss due to wall friction will be made available. That is, the pressure drop due to gas-liquid mixture flow in a pipeline will be released. This frictional pressure drop will propagate continuously to the valve location and can be measured and is often called line-packing. The gradual pressure increase (pressure gradient) after the initial water-hammer in Figure 1b is the line-packing.

Frictional pressure drop in pipes is governed by the equation:

$$\Delta p_f = (f/2)(\Delta L/d)\,\rho u^2$$

where f (dimensionless) is the friction factor, ΔL (m) pipe length, d (m) pipe diameter, ρ (kg/m3) fluid density and u (m/s) fluid velocity. The ΔL is not the same distance as the ΔL_{AB} used to determine the speed of sound in Figure 1a. The pressure drop equation holds for single-phase laminar and turbulent flow and multiphase flow. The pressure drop equation can be written in terms of the pressure gradient:

$$(\Delta p_f)/\Delta L = (f/2)(1/d)\,\rho u^2$$

which is the measured line packing gradient in Figure 1b. The friction factor f (-) in single-phase and multiphase flows can be obtained from semi-empirical relationships available in the literature and from field experience.

MULTIPHASE MIXTURES

The density of a gas-liquid mixture is given by the relationship:

$$\rho_M = \alpha\rho_G + (1-\alpha)\rho_L$$

where α (dimensionless) is the void fraction and the subscripts stand for *M* (mixture), *G* (gas) and *L* (liquid). In hydrocarbon production the liquid-phase will often consist of oil and water.

The propagation of pressure pulses in homogeneous gas-liquid mixtures a_M is given by the well established speed of sound equation:

$$a_M = (IJ)^{-1}$$

where

$$I = [\alpha\,\rho_G + (1-\alpha)\rho_L]^{0.5}$$

and

$$J = \left(\frac{\alpha}{\rho_G\, a_G^2} + \frac{1-\alpha}{\rho_L\, a_L^2}\right)^{0.5}$$

and a_G and a_L the speed of sound in gas and liquid phases, respectively.

Using the above equation, the speed of sound was calculated for a gas-oil mixture flowing at 60 bar and 90 bar in a typical offshore well in the North Sea. The results of the speed of sound calculations are shown in Figure 2 with void fraction from 0 to 1. The speed of sound in pure liquid is high and decreases dramatically with small amounts of gas bubbles. In the void fraction range 0.2-0.8 the sound speed remains relatively constant. As the void fraction increases from 0.8 to pure gas, the sound speed increases. As the pressure increases, the sound speed in gas-liquid mixtures also increases. The observation that the sound speed in gas-liquid mixtures is lower than the sound speed in either liquid-only or gas-only is noteworthy.

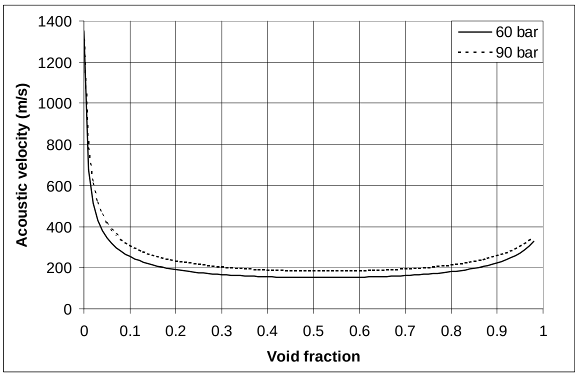

Figure 2: Speed of sound (acoustic velocity) in a gas-oil mixture at 60 bar and 90 bar.

MULTIPHASE METERING

The primary objective in multiphase metering is to know the flowrate of each of the flowing phases (oil, water, gas). Considering oil and water as one flowing phase, pressure pulse technology can be used to measure the gas-liquid mixture density. The water-hammer equation has four variables, two of which are readily measured; that is, pressure increase Δp_a (Pa) and sound speed a (m/s). The two parameters not measured are mixture flowing velocity u_M (m/s) and mixture density ρ_M (kg/m^3).

The mixture flowing velocity and mixture density appear also in the pipeline pressure drop equation. The line packing pressure gradient given by the ratio of Δp_f (Pa) and ΔL (m). The pipeline diameter d (m) is known and the friction factor f (-) can be estimated from established correlation (and field experience), knowing the mixture mass flowrate. The two parameters not measured are mixture flowing velocity u_M (m/s) and mixture density ρ_M (kg/m^3), the same as in the water-hammer equation above. Therefore, having two equations and two unknowns means that the mixture density can be calculated directly. Assuming the pressure and temperature are known, and the PVT-properties of the gas phase are known, the density of the liquid phase can be calculated.

An alternative to using line packing information, to determine the flowing mixture density, other pressure drop data can be used. For example, the mass flowrate through a venturi nozzle is given by the equation:

$$m = C\sqrt{2\rho \times \Delta p}$$

where C is a nozzle specific constant (includes the discharge coefficient). A venturi nozzle calibrated for homogeneous multiphase flow can therefore be used in pressure pulse technology.

PIPELINE SITUATIONS

Multiphase flow in land-based and offshore wellbores and pipelines depends on many factors, including the pressure, volume and temperature (PVT) behaviour of the fluid mixtures involved. It is convenient to illustrate the use of pressure pulse technology in multiphase flow by assuming several of the main factors as constant. Later, in practical situations, such assumption can be relaxed and the various effects can be taken into consideration. For illustration purposes the following assumptions were made:

- Single-phase flow in a pipeline.
- Constant pipeline diameter.
- Constant friction factor.
- Constant flowrate.
- Constant in-situ speed of sound.
- Constant fluid density and viscosity.

Given the above assumptions, the line-packing measured at a valve after full/complete closing, will increase linearly with time. Furthermore, assuming that the valve closes instantaneously, the pressure increase with time for such conditions is illustrated in Figure 3a. For any point A (not the same A as illustrated in Figure 1) the pressure measured represents the pipeline line-packing the distance ΔL up-stream:

$$\Delta L = \frac{1}{2} a\,\Delta t$$

where Δt (s) is the time. The factor ½ is applied because the pressure pulse must first travel the distance A and then back to the closing valve.

The assumption of a constant pipeline diameter can be relaxed to illustrate the situation where the pipeline diameter has been reduced in a certain interval. The diameter reduction is an abrupt and significant and exists for some distance, until the diameter expands abruptly and significantly. The pressure increase with time for such a condition is illustrated in Figure 3b. The point C represents the distance from the valve to the reduction in pipeline diameter, and the point D represents the distance from the valve to the resumption of full pipeline diameter. Such a reduction in pipeline diameter the distance CD may result from the deposition of solids in a particular interval.

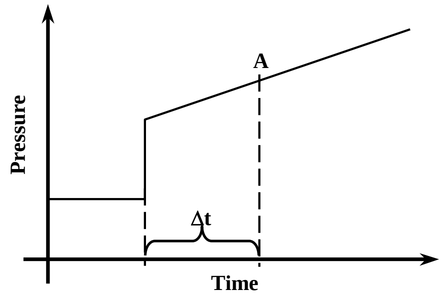

Figure 3a: Line packing increases linearly with time.

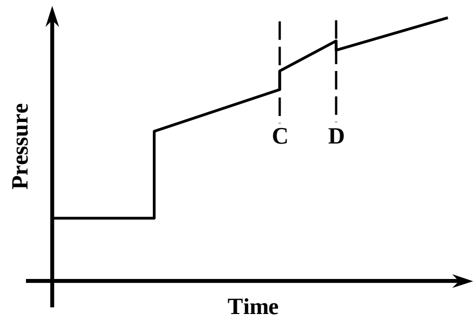

Figure 3b: Pipeline diameter reduced in interval C-D.

Figures 3a-3b illustrate the water-hammer pressure when a valve is closed and the subsequent gradual increase in line-packing pressure with time. The figures illustrate simplified situations, and the points A, C and D represent for each situation a particular distance ΔL. To calculate this particular distance, fluid flow equations and fluid properties need to be known. In single-phase flow of fluids with constant PVT properties, the calculations are simple and explicit. In multiphase flow of fluids with variable PVT properties, however, the calculations are more involved.

The following steps describe how the distance ΔL might be calculated for the particular situation illustrated in Figure 3b where the point C represents the distance to the start of solids deposition in a pipeline:

1. A pressure pulse test is made and the mass flowrate of the gas-liquid mixture flowing at the valve is calculated from the water-hammer equation, and the temperature is measured.
2. The pressure-volume-temperature properties of the gas-liquid mixture flowing immediately up-stream the valve are assumed known from standard oilfield practices, based on measurements and/or established correlations.
3. A commercial or in-house pipeline flow simulator is then used to calculate the pipeline pressure and temperature from the valve and up-stream, including fluid densities and void fraction.
4. The speed of sound in the flowing gas-liquid mixture is then calculated piecewise from the valve and up-stream, using fundamental relationships and the pipeline flow simulation results.
5. The time-scale in Figure 3b is converted to distance in a piecewise manner using the relationship $\Delta L = (1/2)a\Delta t$.

The above calculations can be carried out using data and models that range from simple to comprehensive - the more accurate the data and models, the more accurate the results. The accuracy of the calculations can also be improved by additional measurements. For example, pressure measurements from somewhere up-stream can be matched to the arrival of the pressure pulse. And the known locations of changes in pipeline diameter and other features can be matched to their appearance in the line-packing signal measured.

SOLIDS DEPOSITION

Practical pressure pulse tests/measurements have been made in multiphase wells in the North Sea. The tests have shown that the theories expressed by the water hammer equation, the pressure drop (line-packing) and the speed of sound equation (pressure pulse propagation), are applicable in wellbore and pipeline situations.

Computer codes have been developed in-house to simulate the propagation of transient pressure in pipelines and wellbores. Such codes can be used to illustrate the use of pressure pulse technology to detect and monitor deposits in pipelines and other flow channels. One such example concerns a horizontal on-land pipeline flowing a multiphase gas-liquid mixture. The water-hammer and line-packing were calculated for a horizontal pipeline flowing a multiphase gas-liquid mixture, where solids deposition restricts the flow in a particular interval. The following conditions were assumed:

- Pipeline length, 2 km.
- Internal diameter, 0.1024 m.
- Oil density, 850 kg/m3.
- Gas specific gravity, 0.8 (-).
- Average speed-of-sound in mixture, 250 m/s.
- Inlet pressure, 35 bar (outlet pressure, 30 bar)
- Friction factor, 0.023 (-).
- Average temperature, 40 C.
- Gas-oil-ratio, 400 scf/STB.
- Total flowrate 8 kg/s.

The pipeline flows a multiphase mixture 2 km (from wellhead to gathering station) with inlet pressure of 35 bar and outlet pressure of 30 bar. The valve is at the gathering station and closes in 1 s (from 5 to 6 s). The deposition starts at about 9 s, 3 s after full closing. For a sound speed of 250 m/s this corresponds to one-half of 250 m/s × 3 s, namely 375 m. The point of closing is used for illustration purposes because most of the pressure drop over valves in the offshore industry occurs from 80% to 100% of closing. The thickness of the deposits increases the first 100 m (diameter reduces from 10.24 cm to 9.84 cm) and then remains 2 mm thick for 300 m (diameter 9.84 cm) and then decreases in thickness the last 100 m (diameter increases from 9.84 cm to 10.24 cm).

The simulated water-hammer and line-packing pressures for the pipeline are shown in Figure 4. The initial pressure increase from 30 bar to about 32.5 bar is the water-hammer pressure and the more gradual pressure increase is the line-packing pressure. Experience from field tests has shown that the water-hammer and line-packing pressures can easily be measured using off-the-shelf pressure transducers.

Analysis of the line-packing pressure shown in Figure 4 makes it possible to locate the solids deposit, to estimate the thickness of the deposit, and its total length. Such analysis will include the measurement of mass flowrate by pressure pulse testing.

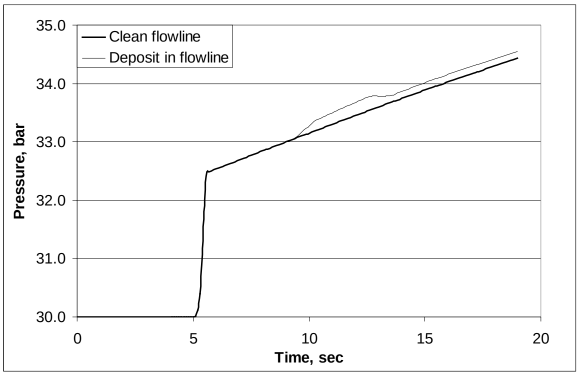

Figure 4 - Deposition in a pipeline.

If solids are deposited immediately up-stream of a closing valve used in pressure pulse measurements, and the mass flowrate is known from separator measurements for example, the thickness of the deposited material can readily be calculated from the water-hammer equation. The measured water-hammer pressure increase is proportional to the fluid velocity which in turn depends on the pipe diameter squared. A reduction in flow diameter from 8 inch to 4inch gives a quadrupling in measured water-hammer pressure compared to a clean pipe.

CONCLUSIONS

1. Pressure pulse technology is based on high-speed measurements of the pressure transient that arise when a valve is actuated and closed for a few seconds. The technology is based on the physics of pressure propagation in fluids, single phase and multiphase.
2. Pressure pulse technology can readily be used to locate and quantify deposits in pipelines. The technology can be used for routine monitoring and on-demand measurements. The equipment used to make pressure pulse measurements is low cost and robust.
3. Pressure pulse technology is field proven and is currently in use offshore Norway to measure gas-liquid flowrate in production wells and to locate and quantify deposits in a pipeline between platforms. Extensive field experience and substantial in-house software development make commercial pressure pulse technology services to the oil industry possible.