EVALUATION OF THE FLOW REGIME IDENTIFICATION CAPABILITY OF GAMMA-BASED MULTIPHASE FLOWMETERS

BY

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CERTIFICATION

This is to certify that this research work entitled **"Evaluation of the Flow Regime Identification Capability of Gamma-based Multiphase Flowmeters"** was carried out by **Gbaden, Eric Tersoo (20154989728)** in partial fulfillment of the requirements for the award of the degree of M.Eng in Petroleum Engineering of the Federal University of Technology, Owerri, Imo State, Nigeria.

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DEDICATION

This work is dedicated in loving memory of my beloved little sister Gloria Iwuese Gbaden.

ACKNOWLEDGEMENT

First and foremost, I wish to acknowledge the Almighty God for granting me the grace to go through the programme in sound mind and good health.

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ABSTRACT

The application of a single beam, dual energy gamma densitometer unit in determining the flow patterns of vertically upward multiphase flow was investigated. A fast-sampling (250Hz) gamma densitometer was installed on a 3" schedule 160, 11.1mm wt inlet manifold riser in an onshore production facility, Delta-X, in the Niger Delta. Gamma radiation attenuation data for the caesium-137 radioisotope-based densitometer was collected for Well-X effluent of oil, water and gas mixture. Classification of the multiphase mixture's flow regimes was investigated through the analysis of the probability mass function (PMF) chart obtained from the soft gamma count data. The prevalent flow regimes identified during the trial period were bubbly, slug, churn, annular and transition (bubbly-slug and churn-annular) flows. The result showed consistency with similar test facility studies conducted using air, diesel oil and portable water. An economic model was proposed for evaluating the economic viability of replacing existing test separators with multiphase flowmeters. Results from the economic analysis showed that given the current cost of multiphase flowmeters, it is not viable to replace existing test separators with multiphase flowmeters on a per well basis. The valuation, however, favoured replacing an existing test separator with a single multiphase flowmeter. Sensitivity study indicated that installing multiphase flowmeters on a per well basis will be economically viable with over 60% reduction in multiphase flowmeter present CAPEX for an 8-well production facility.

Keyword(s): Gamma Densitometer; Multiphase Flow; Test Separator; Flow Regime; Net Present Value; Sensitivity.

CHAPTER ONE

INTRODUCTION

1.1 BACKGROUND OF STUDY

Multiphase flow is prevalent in many industries. The term 'multiphase flow' refers to scenarios where two or more phases flow simultaneously in a conduit. In the oil and gas industry, multiphase flow refers to flow of oil-water-gas or a combination of any two of the aforementioned substances either in conduits or porous media. The term in this work focuses on flows comprising oil, water and natural gas as found in the upstream sector of the petroleum industry.

It is important to measure the individual flowrates of each producing well in order to facilitate reservoir management, field development, operational control, flow assurance, production allocation and custody transfer. Conventionally, fluid flow metering in multiphase scenario requires the use of test separators with their attendant drawbacks. They are expensive and cumbersome, require field personnel intervention and high maintenance cost; and do not lend themselves to continuous metering.

In order to enhance economic viability of exploiting hydrocarbon accumulations, deep sea wells are completed subsea and crude oil from several wells are commingled and sent to a common production facility via a marine riser. The resulting economic constraints on such developments do not favour the deployment of three-phase test separators as the primary measurement device. Consequently, viable alternatives to three-phase separators became essential. The industry, in the early 1980s, responded to this challenge through the development of the multiphase flowmeter (MPFM).

A number of novel multiphase metering techniques, employing a variety of technologies, have been developed which eliminate the need for three-phase separator deployment. These MPFMs offer substantial economic and operating advantages over their three-phase separator predecessors. Nevertheless, it is still widely recognized that no single MPFM in the market can meet all multiphase metering needs.

In spite of the advances in multiphase flow metering, industrial deployment of this technology remains expensive for meters that offer an acceptable performance. Thus, there is a clear need for further development of multiphase flow monitoring devices within the petroleum industry.

Gamma-densitometry is a suitable technique for facilitating non-intrusive multiphase flow metering as it does not require breaking into the pipeline for installation. As a result, meter units could be installed and decommissioned without production deferment. The reduced hardware and installation costs associated with deploying such units of MPFMs, with the prospect of increasing oil prices, could facilitate economic justification for a per well installation.

Low intensity gamma radiation sources, usually Caesium-137 deployed in gamma densitometer units, do not present significant technical or health problems for installation as they are properly shielded in lead before deployment in oilfields. However, in some countries, administrative and logistical issues in deploying radioactive sources in the field are virtually insuperable. Consequently, gamma densitometer units cannot be readily deployed in such countries as MPFMs; nevertheless, a sizeable market remains in the countries (including Nigeria) where radiation-based instrumentation is permissible. Indeed, many commercially available multiphase flowmeters employ gamma-densitometry techniques either wholly or as part of their measurement systems.

1.2 PROBLEM STATEMENT

Flow regime identification capability is one of the advantages most multiphase flowmeters have over test separators. However, studies on the flow regime identification capability of multiphase flowmeters are based on laboratory and test facility data which are a mere approximation of the oilfield scenario. Thus, in spite of their excellent laboratory and test facility performance, some multiphase flow metering devices, when deployed to oilfields are susceptible to transient-induced metering errors. While laboratory and test facility performance of gamma-based multiphase flowmeters is well documented, there is a growing lack of literature on oilfield trial experience.

1.3 OBJECTIVE OF STUDY

This research work aims at evaluating the flow regime identification capability of non-intrusive gamma-based multiphase flowmeters in oilfield scenario. The following specific objectives shall be pursued in achieving this research objective.

i. To analyse gamma attenuation signals in a view to identifying the prevailing flow regimes.
ii. To appraise the economic viability of replacing an existing multiphase test separator with a single gamma-based multiphase flowmeter.
iii. To determine the economic viability of replacing an existing multiphase test separator with gamma-based multiphase flowmeters on a per well basis.

1.4 JUSTIFICATION OF STUDY

i. The result from this work will be used in the industry to enhance the acceptability of gamma-based multiphase flowmeters to both operators and regulators.
ii. The result from this study would aid managers in the oil and gas industry in deciding on eliminating test separators in oilfield production especially in offshore operations where space is at a premium and weight savings is much desired.
iii. The result of this work will serve as a bridge to the yawning gap between laboratory-based study and field-based experience on the performance of gamma-based multiphase flow metering.

1.5 SCOPE OF STUDY

This research work covers the following:

i. Identification of multiphase flow regimes through analysis of gamma densitometer signals.

ii. Economic analysis of the viability of replacing existing test separators with a single multiphase flowmeter.

iii. Economic analysis of the viability of replacing an existing test separator with multiphase flowmeters on a per well basis.

CHAPTER TWO

LITERATURE REVIEW

2.1 MULTIPHASE FLOW FUNDAMENTALS

A mixture of two or more phases is known as Multiphase. A phase can be defined as a distinct and homogeneous state of matter in a system without visible (and/or immiscible) boundary that separates it into different parts. Multiphase flow is the simultaneous passage of two or more phases through conduits and pipes. This type of flow is unavoidably encountered in the oil and gas production where liquid (oil and/or water) and natural gas flows together in oil wells and pipelines. Multiphase flow is also a common phenomenon in all process, nuclear, chemical industries etc. (Crowe, 2006 and Brennen, 2006). Multiphase flow, as encountered in oil and gas production, can be two-phase (e.g. gas-oil, gas-water, oil-water etc.), three-phase (e.g. gas-oil-water etc.), four-phase (e.g gas-oil-water-sand etc.). Handling (understanding, predicting, measuring and modeling) multiphase flow is much more challenging than handling single phase flow (Brennen, 2006). Properties like: density, velocity, flowrate (mass and volumetric), viscosity etc., of multiphase flow are functions of properties of the flow constituent phases. Figure 2.1 shows a typical multiphase flow and distribution of phases in a pipe cross section.

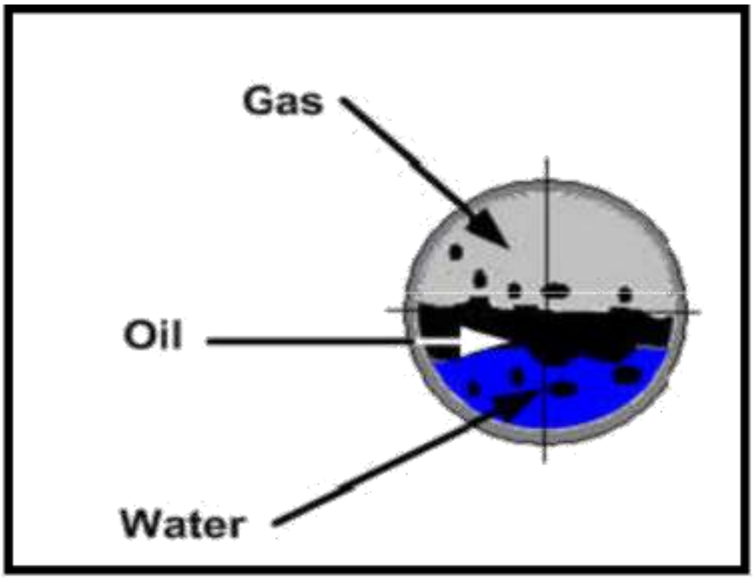


Figure 2.1: A typical Multiphase Flow in a Pipe Cross-Section (Brennen, 2006)

Phases as shown is Figure 2.1 are distributed in the pipe by gravity. Water being the heaviest, is lying at the bottom of the pipe followed by oil and gas remains at the top of the pipe, being the lightest. This distribution is possible when the flow rate is low and of horizontal pipe orientation and this type of flow pattern is called stratified flow (Douglas *et al*, 1993). There are several other multiphase flow patterns which will be discussed later in this chapter. Jamieson (1999) used multiphase composition triangle to explain the intricacy and complexity of multiphase flow. As shown in Figure 2.2, the vertices of the triangle represent the regions of single-phase gas, oil and water flows, the two phase gas-oil, gas-water and oil-water flows are found along the sides of the triangle while inside the triangle represents the region of three-phase flow. More so, the composition of the multiphase flow along the triangle sides and inside the triangle differs with respect to position. There exists a region inside the triangle called transition region where phase inversion between the liquid part of the multiphase flows occurs (oil-in-water to water -in-oil). This makes metering difficult for meters that use electrical properties like Electrical Resistance Tomography, ERT, Electrical Capacitance Tomography, ECT etc.

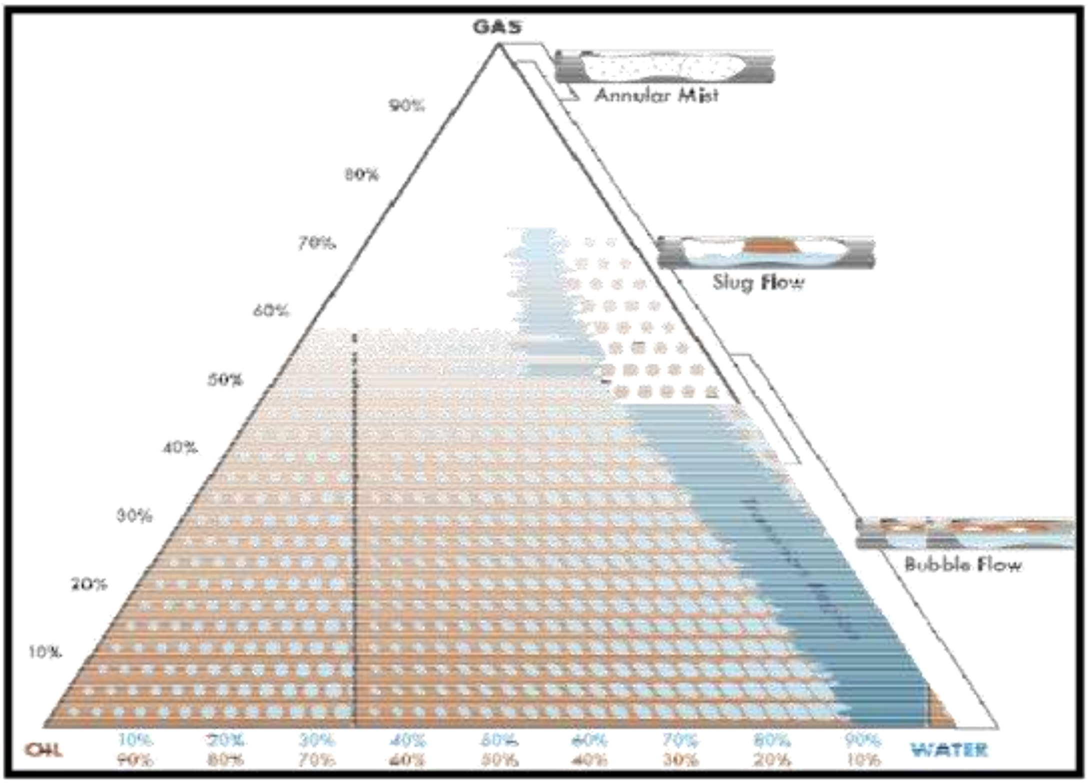


Figure 2.2: Multiphase Composition Triangle (Jamieson, 1999)

2.1.1 Multiphase Flow Terminologies

Volume Fraction: Volume fraction is the portion of the pipe occupied by individual phase. Mathematical, volume fraction is the ratio of an individual phase volume or volume fraction to total volume or volume flow rate of the fluid flowing through the pipe.

Gas Volume Fraction (GVF): Gas volume fraction is the portion of the pipe or conduit occupied by gas or the ratio of gas volume flowrate, Q_g to the total mixture volume flowrate, Q_T. It could be the same as Gas Void Fraction, α_g.

Equation 2.1 expresses it mathematically.

$$GVF = \alpha_g = \frac{Q_g}{Q_T} = \frac{A_g}{A_p} \qquad 2.1$$

Liquid Volume Fraction (LVF)/Liquid Hold-Up (α_l): This is the ratio of liquid volume flowrate, Q_l (oil volume, Q_o or water volume, Q_w) to the total mixture volume flowrate, Q_T. Mathematically,

$$LVF = \alpha_l = \frac{Q_l}{Q_T} = \frac{V_l A_l}{V_m A_p} = \alpha_{o,w} = \frac{Q_{o,w}}{Q_T} = \frac{V_{o,w} A_{o,w}}{V_T A_p} \qquad 2.2a$$

For homogenous flow where phase velocities are equal, Equation 2.2a becomes:

$$LVF = \alpha_l = \frac{A_l}{A_P} = \alpha_{o,w} = \frac{A_{o,w}}{A_P} \qquad 2.2b$$

Where, α_o and α_w are oil and water volume (phase) fractions respectively. More so, summation of all phase fractions is unity (1).

$$A_g + \alpha_o + \alpha_w = 1 \qquad 2.3$$

Note: When there is phase slip, liquid hold-up is greater than liquid volume fraction and gas void fraction is less than gas volume fraction.

Gas-Oil Ratio (GOR): Gas-oil ratio compares the amount of gas, Q_g in relation to that of oil, Q_o. In a gas-oil flow, GOR is the same as the GVF. But for gas-oil-water flow, GOR and GVF are not equal.

$$GOR = \frac{Q_g}{Q_o} \qquad 2.4$$

Water Cut (WC): Water cut is the ratio of amount of water (water volume flowrate, Q_w) to that of total liquid (total volume flowrate, Q_L) present in the flow. It is given as:

$$WC = \frac{Q_w}{Q_l} \qquad 2.5$$

Water Cut is equal to LVF if only oil and water are the multiphase flow components. WC is sometimes expressed as the percentage (%) of amount of water to total amount of liquid.

Superficial Gas Velocity (V_{sg}): Superficial gas velocity is the velocity the gas would have if the whole pipe cross sectional area were filled with it. It is ratio of gas volume flowrate, Q_g to the pipe area, A_p. V_{sg} is given as:

$$V_{sg} = \frac{Q_g}{A_p} \qquad 2.6$$

Superficial Oil Velocity (V_{so}): Superficial oil velocity is the velocity the oil would have if the whole pipe cross sectional area were filled with it. It is the ratio of oil volume flowrate, Q_o to the pipe area, Ap. V_{so} is given as:

$$V_{so} = \frac{Q_o}{A_p} \qquad 2.7$$

Superficial Water Velocity (V_{sw}): Superficial water velocity is the velocity the water would have if the whole pipe cross sectional area were filled with it. It is the ratio of water volume flowrate, Q_w to the pipe area, Ap. V_{sw} is given as:

$$V_{sw} = \frac{Q_w}{A_p} \qquad 2.8$$

Phase Velocity: It is the actual velocity of each phase (gas, oil or water) flowing through the pipe or conduit. It can be expressed mathematically as the ratio of individual phase superficial velocity to its phase fraction. It can be expressed mathematically as:

$$V_{g,o,w} = \frac{V_{sg,so,sw}}{\propto_{g,o,w}} \qquad 2.9$$

Mixture Velocity (V_m): Is the summation of superficial velocities of phase compositions of the flow in the pipe.

$$Vm = V_{sg} + V_{so} + V_{sl} \qquad 2.10$$

Mixture Density (ρ_m): Is the addition of the product of each phase density and phase fraction.

$$\rho_m = \rho_g\alpha_g + \rho_o\alpha_o + \rho_w\alpha_w \qquad 2.11$$

Where, ρ_m, ρ_g, ρ_o, and ρ_w are mixture, gas, oil and water densities respectively.

Total Volume Flowrate: Is the total volumetric flowrate of the flow through pipe or conduit. It can be expressed as the summation of all volumetric flowrates of all phases involves.

$$Q_T = Q_g + Q_o + Q_l \qquad 2.12$$

2.2 Multiphase Flow Regimes

When a particular composition of multiphase mixture flows through a pipe or conduit, the phases involved interact with one another and assume different configuration or patterns. The spatial arrangement of phases in multiphase mixture which describes their relative distribution in the pipe they flow is called flow regime or pattern. Multiphase flow regime is a function of the relative phase velocities and fractions, phase properties like viscosity, density etc; pipe orientation (i.e. horizontal, vertical or inclined) and pipe size (McQuillan and Whalley, 1985; Crowe, 2006 and Brennen, 2006).

2.2.1 Vertical Pipe Flow Regimes

Multiphase flow is fairly common in oil well flowlines despite the fact that the well pressure at the bottom can exceed the bubble point of the oil. The pressure drop experienced by the oil as it is transported from the seabed to the surface can result in gas liberation from the liquid oil phase. The flow regimes witnessed in vertical risers are usually fully developed and essentially axial-symmetrical. Generally, the multiphase flow features present vary with well age with older wells exhibiting a larger gas vapour fraction.

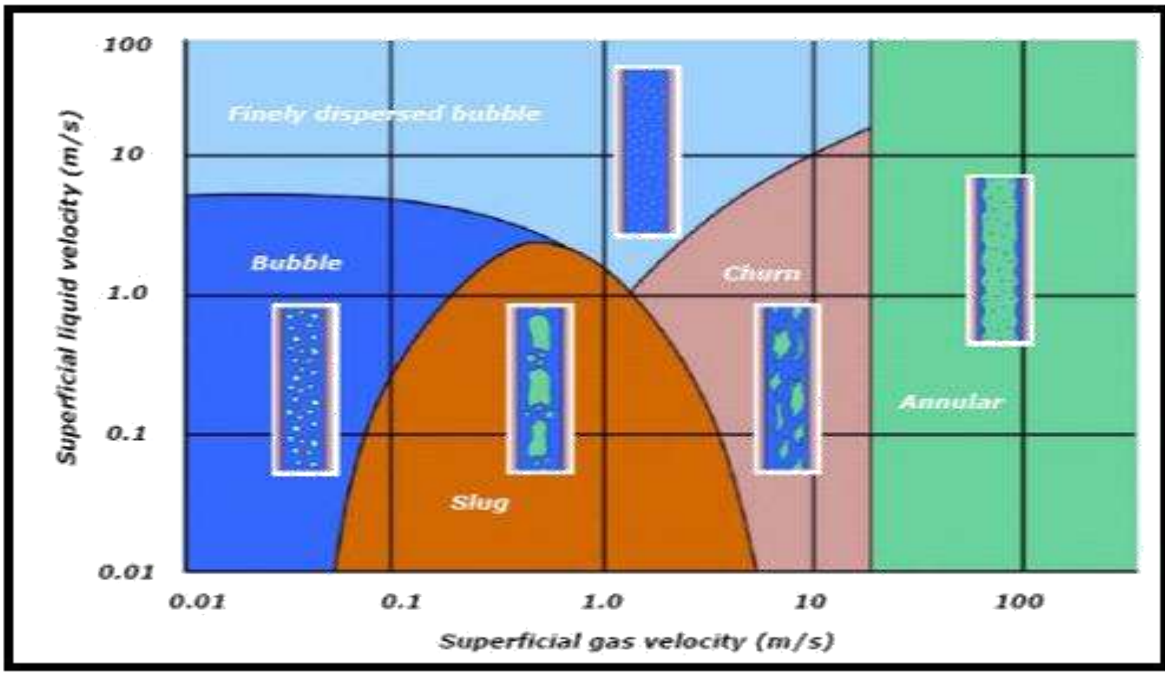


Figure 2.3: Flow Regime Map for Vertical Pipes (Dykesteen, 2005)

The vertical flow regimes (refer to Figure 2.3) are commonly categorised into four main classifications:

Bubble (including finely dispersed bubble): At low gas flow rates, a continuous liquid phase is formed with the gas phase producing discrete bubbles within the continuum. The gas bubbles may coalesce to form larger bubbles or slugs.

Slug: Increased gas flow rates increase bubble coalescence until the bubble diameter eventually approaches that of the pipe diameter. The resulting flow alternates between high-liquid and high-gas composition.

Churn: Somewhat similar to slug flow, but more chaotic in nature owing to the larger gas flow rates. The slug bubbles have become distorted to form longer, narrow structures and the flow adopts a random oscillatory nature. The liquid flow occurs mainly at the pipe wall but a significant proportion is vigorously mixed with the gaseous core.

Annular: At very high gas flow rates, the liquid phase is forced to flow up the pipe wall as a liquid film while the gas flow in the centre. The interface betweenthe phases is typically wavy. The wavy interface enables liquid entrainment in the gaseous core. When the quantity of entrained liquid becomes significant, the flow is described as having an annular mist regime.

2.2.2 Horizontal Pipe Flow Regimes

As with vertical flow, flow regime transitions in horizontal pipes are functions of parameters such as pipe diameter, interfacial tension, and phase densities. However, the flow patterns exhibited in horizontal regimes are not axially symmetrical and a pipe length equivalent to at least 100 pipe diameters is required to establish fully developed flow. Multiphase flow maps based on superficial phase velocities are also readily available for horizontal flows.

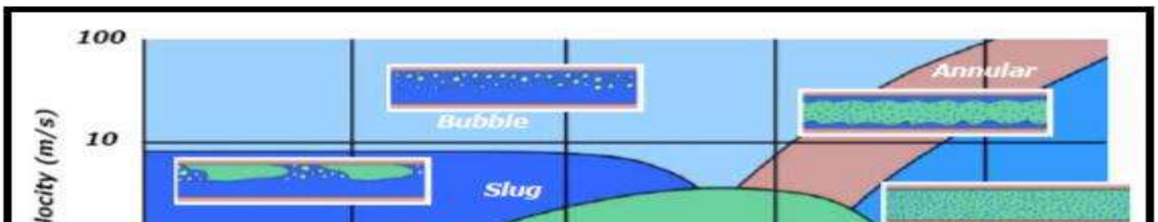


Figure 2.4: Flow Regime Map for Horizontal Pipes (Dykesteen, 2005)

The flow patterns obtainable in horizontal pipe configuration (refer to Figure 2.4) are a bit different from those in vertical pipes – stratified flow regime is not possible in vertical pipes configuration.

The flow regimes observed for horizontal flows will tend to be more complex than their vertical counterparts due to gravity induced asymmetries. The heavier phase will be inclined to accumulate at the bottom of the pipe. The horizontal flow regimes are commonly categorised into six main classifications:

Bubble: The gas phase exists as discrete bubbles within a liquid continuum. The gas bubbles will tend to flow in the upper section of the pipe. However, with larger gas flow rates, a uniform bubble distribution across the pipe cross-sectional area may be witnessed.

Plug: Reducing the liquid flow rate will enable the gas bubbles to coalesce into larger bubbles or plugs which will occupy the upper section of the conduit.

Stratified: Further reductions to both the gas and liquid flow rates will result in phase stratification whereby the two phases flow separately with a relatively smooth interface. The liquid phase will occupy the lower section of the pipe due to gravity.

Wave: Increasing the gas flow rate of a stratified system will produce a less stable phase interface as a result of the increased turbulence. The interface between the liquid and gas phases will be irregular and wavy in nature although good separation between phases will be maintained.

Slug: Increasing the liquid flow will produce waves of a much larger magnitude until the liquid is increased to such a point where the wave occupies the whole of the pipe cross-section. This facilitates the propagation of a high velocity fluid slug down the pipe.

Annular/Mist: At very high gas flow rates, the liquid phase is forced to flow up the pipe wall as a liquid film while the gas flow in the centre. The liquid film will be thicker at the bottom of the pipe owing to gravitational effects.

2.2.3 Operational Flow Regime

Under real oil and gas production, the flow conditions (flowrates and pressure) change with time and this consequently causes changes in the prevailing flow regimes and hence flow transient. Dynamic nature of multiphase flow regime is largely caused by change in the relative velocities of the phases – gas and liquid. The main flow regime that affects the performance of multiphase flow meters in operations is slug flow regime – MPFMs are flow regime specific. Slug flow is the intermittent flow of liquid column and gas pocket – a column of liquid followed by a gas pocket called Taylor bubble. The liquid column called liquid slug ma y occupy a large section of the pipe or the entire pipe section. Hydrodynamic slug and severe slug are examples of operational slug flow regimes. Operationally, this flow condition is mostly caused by well startup, well slugging, gas lifting operations and/or valve actions.

Figure 2.5 shows the dynamics of flow regimes in a gas lifted well. This technique boosts oil production, however, gas injection causes fluctuations of the prevailing flow regime in the tubing or riser and hence flow dynamic (Boyun *et al.*, 2007).

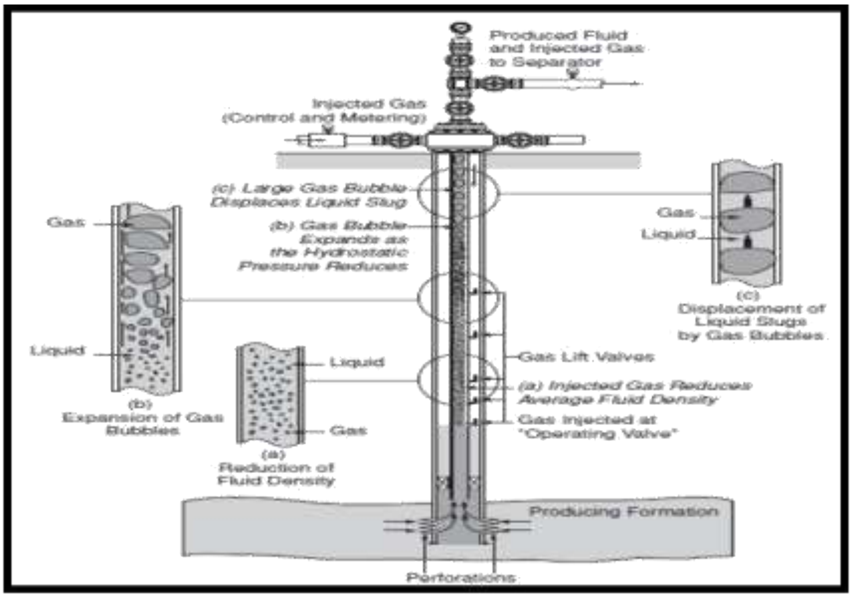


Figure 2.5: Flow Regime Dynamics in Tubing of Gas-Lifted Well (Al-burtamani, 2009)

2.2.3.1 Hydrodynamic (Normal) Slug Flow

According to Danielson (2011), hydrodynamic slug is the prevailing flow regime in oil and gas production. Hydrodynamic slug flow is caused by instabilities in the flows through the conduit or pipe (Schoppa, *et al.,* 2002). As the velocity of the gaseous phase increases, waves are created on the surface of the liquid which later grow in height to the pipe internal diameter thus forming a slug. Hydrodynamic slug is much shorter compared to severe slug. The mechanics of hydrodynamic slug flow in pipes is shown in Figure 2.6.

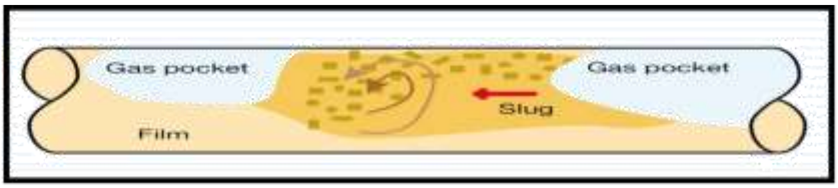


Figure 2.6: Hydrodynamic (Normal) Slug Flow Formation Mechanisms (Havre et al., 2000)

2.2.3.2 Severe Slug Flow

Severe slug flow is more problematic than hydrodynamic slug flow because the liquid slug is equal or more than the riser length. It is terrain induced type of slug flow. Severe slug formation mechanism is shown in Figure 2.7. Liquid slug accumulation is encouraged by the lower part of the pipeline-riser system or deep in the pipeline (Havre *et al.*, 2000).

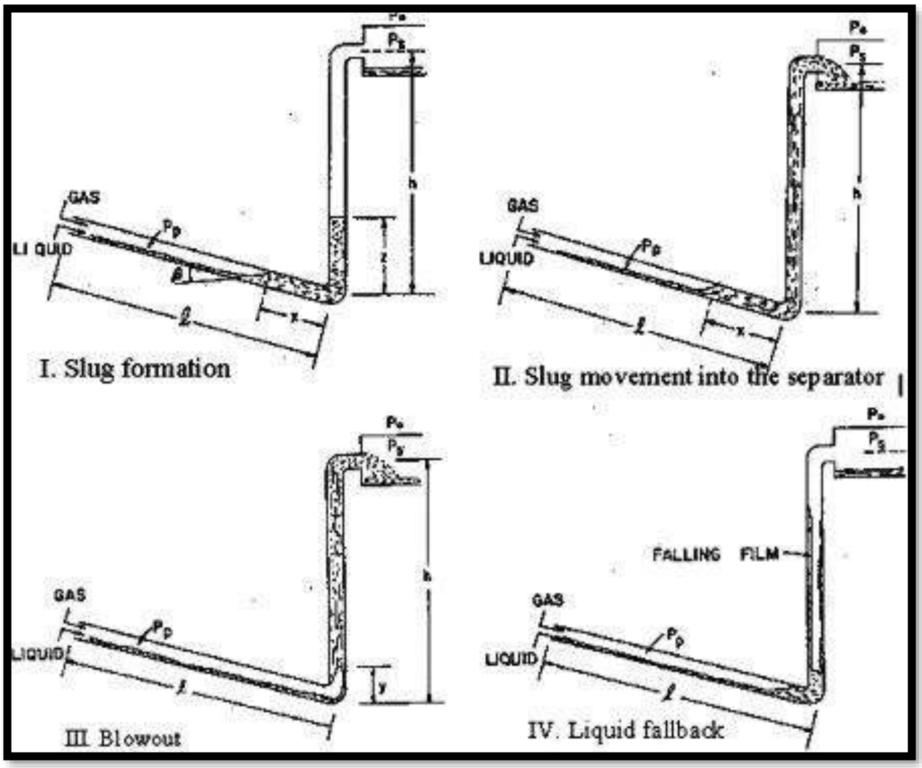


Figure 2.7: Severe Slug Flow Formation Mechanisms (Havre et al, 2000)

2.3 MULTIPHASE FLOW MEASUREMENT

Conventionally, multiphase flow measurement is done by using test separator which separates the multiphase mixture into its constituent phases and then using well established single phase meters to determine each phase flow rate. Multiphase flow metering with the aid of test separator is carried out downstream of the separator. However, measure upstream is very important forcontinuous flow monitoring. Hence, there is a need to develop and establish an accurate multiphase metering without flow conditioning (homogenization) and phase separation.

2.3.1 Development of Multiphase Measurement

Multiphase flow measurement is undoubtedly one of the most important and/or crucial technologies that affect the development of oil and gas industry in future (Lingya *et al.,* 2011). Using conventional technique (test separator) to measure multiphase flow cannot meet the demand of many of the world's oilfields today. This therefore led to a need for multiphase flow measurement in the oil and gas industry. Hence, the research and development of multiphase flow measurement kicked off in the early eighties (Al Araimi, 2005). Accurate downhole multiphase measurement (for production logging) and development of multiphase flow meters were achieved throughout the nineties (Al Araimi, 2005). This technology is capable of handling multiphase flow directly without separating each component of the flow and measuring each component flowrate (gas, oil and water) and hence capable of replacing the traditional technique (Lingya *et al.*, 2011).

Multiphase flow metering is a promising and attractive measurement alternative to the conventional technique for the fact that it makes measurement of unprocessed well streams upstream of the well possible (Corneliussen *et al.*, 2005). With MPFMs, well performance can be continuously monitored and thereby makes reservoir exploitation and/or drainage better (Corneliussen *et al.*, 2005).

2.3.2 Inferential Measurement Strategies

Mass flowrates of the multiphase flow components – gas, oil and water are the primary information requirement in oil and gas production (Thorn *et al.*, 1997 and Mehdizadeh and Williamson, 2004). It is required of an ideal multiphase flow meter to meter independently this flow parameter of each component. However, direct measurement of two-phase mass flowrates is rarely obtainable and impossible for three-phase flow (Mehdizadeh and Williamson, 2004). Three-phase mass flowrate measurement can be achieved by using an "**Inferential Method**" (Sidsel, 2005; Mehdizadeh and Williamson, 2004). An inferential method (see Figure 2.8) for measuring multiphase components mass flowrate involves measuring instantaneous velocities and fractional cross section of each component. Therefore, the individual mass and total mass flowrates can then be calculated by using measured instantaneous velocities and cross section fractions with their densities which are readily available. The phase velocities and fractions can be measured by some techniques which will be discussed later in this chapter. Equation 2.13 gives the gas-oil-water mixture total mass flowrate as the summation of individual flowrates.

$$M_T = \alpha_g v_g \rho_g + \alpha_o v_o \rho_o + \alpha_w v_w \rho_w \qquad 2.13$$

Where, M_T is the total mixture mass flowrate, and are gas, oil and water fractions respectively, and are gas, oil and water velocities respectively and , and are gas, oil and water densities respectively. The first (m_g), second (m_o) and third (m_w) terms in Equation 2.13 are gas, oil and water mass flow rate respectively. If only two of the component fractions are known (say gas void fraction and water fraction), then Equation 2.13 becomes,

$$M_T = \alpha_g v_g \rho_g + \alpha_o v_o \rho_o + [1 - (\alpha_g + \alpha_o)\, v_w \rho_w] \qquad 2.14$$

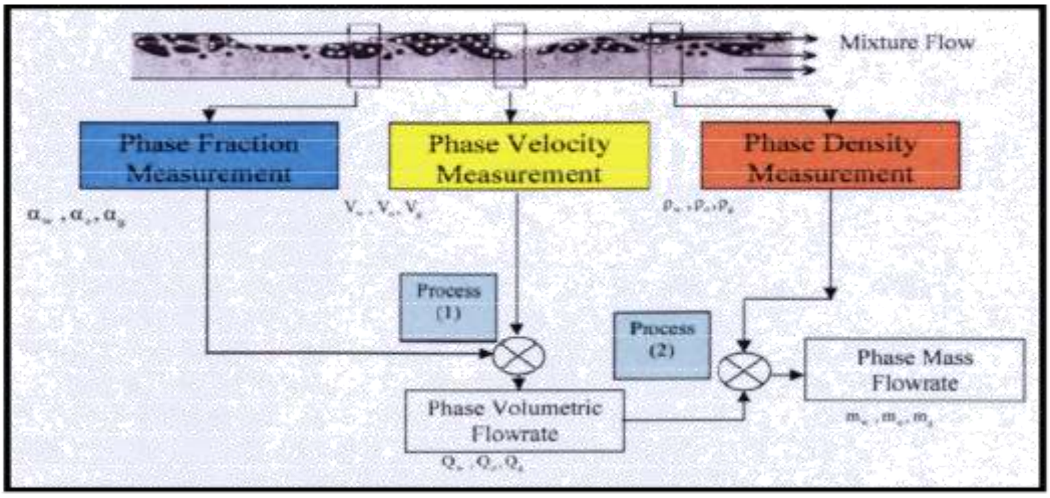


Figure 2.8: Inferential Method for Three-Phase Flow Metering (Liu, 1995)

2.3.3 Test Separator

Test separator method is the most common technique to measure multiphase flow whereby it is separated into its constituent phases and single phase flowrates are therefore metered (Liu, 1995 and Lingya *et al.*, 2011). The schematic of the multiphase flow measurement with three-phase separator is shown in Figure 2.9. Test separator is a well-known piece of equipment with well proven technology. Gas being the lightest phase is evacuated out through the top part of the separator and metered using an orifice plate. While oil and water go through the bottom of the separator and are measured using suitable meters e.g. Turbine meters.

Partial separation method can also be used where the three-phase flow are separate into gas and liquid (mixture of oil and water) as shown in Figure 2.10 (Corneliussen *et al.*, 2005). Gas, liquid and water-liquid ratio and measured by appropriate flow meters.

Measurement of multiphase flow with test separator is associated with some errors due to inability to achieve perfect separation. The set-up of test separator is usually large, heavy and expensive this therefore, limits it application for multiphase flow metering.

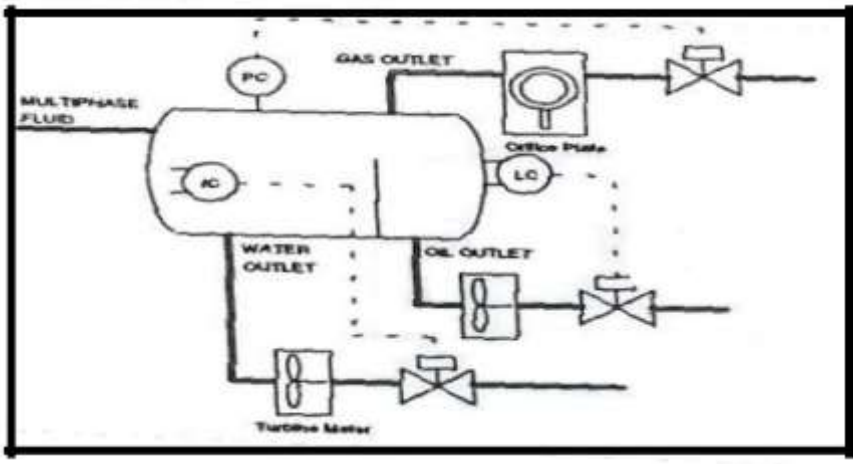


Figure 2.9: Conventional Multiphase Flow Measurement by 3Phase Separator (Liu, 1995)

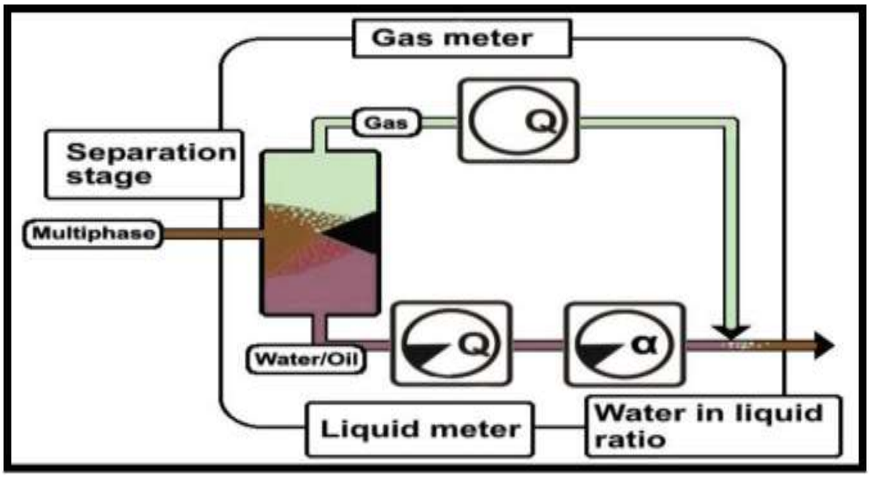


Figure 2.10: Multiphase Flow Measurement by Partial Phase Separation (Liu, 1995)

2.3.4 Multiphase Flow Meters (MPFMs)

Multiphase flowmeters (MPFMs) measure the individual phase flowrates directly without separating the flow into their constituent phases (Corneliussen *et al.*, 2005; Al Araimi, 2005 and Lingya *et al.*, 2011) – these are therefore called "In-line multiphase flowmeters". To achieve this, a number of old and new techniques are employed. Some of the techniques are discussed in the sections below. Using multiphase flowmeter is advantageous over using test separators. Better accuracy, significantly reduced footprint and continuous flow well flow measurement are some of the advantages of MPFMs over the conventional multiphase flow measurement. More so, with MPFMs, dynamic response of the flow and/or the well can be clearly seen which is impossible with test separator (Al Araimi, 2005).

2.3.5 Fraction Measurement

The fractions of a multiphase fluid can be measured by several methods e.g. inferential method as discussed in section 2.2.2 above. Gamma ray attenuation and electrical impedance techniques are the commonest methods for measuring gas and water fractions in multiphase flows (Thorn *et al.*, 1997).

2.3.5.1 Gamma Ray Absorption

The principle of a gamma ray densitometer is based on the fact that the absorption of gamma rays depends on the density of the material it penetrates and on the energy level of the gamma rays. Gamma ray densitometers are used in several multiphase meters. Some flow meters use one densitometer but different energy levels to measure not only the density of the fluid but also the fractions (Al Araimi, 2005). Gamma ray attenuation is capable of determining two-phase flow compositions (single energy) while dual energy can be used to measure three-phase fractions (Corneliussen *et al.*, 2005). Multiphase flow measurement using gamma densitometer is discussed in a later section.

2.3.5.2 Microwave Fraction Meter

The microwave fraction meter uses microwaves – electromagnetic waves in the high MHz and low GHz range. The velocity of electromagnetic waves through a fluid is determined by the dielectric constant of the fluid. The flow composition is calculated from the propagation velocity calculated by measuring the phase shift between receivers and emitters of microwaves (Corneliussen *et al.*, 2005).

2.3.5.3 Capacitance and Conductance

Capacitance and conductance are electrical impedance techniques. Capacitance meter, similar to microwave technology, uses dielectric constant of the fluid to calculate its fraction. Two metal plates are positioned on either side of the fluid. The capacitance of the two plates is dependent on the dielectric constant of the fluid. However, it application is limited by the fact that it only works in oil-continuous flows because water-continuous multiphase flows are conductors rather than insulators. Measurement of conductance is rather used for water-continuous multiphase flows (Thorn *et al.*, 1997 and Corneliussen *et al.*, 2005).

2.3.6 Volumetric Flowrate Measurement

Some methods are available to measure multiphase components volumetric flowrates such as using venturi meter, cross correlation, positive displacement meter etc. Inferential method can be used to obtain volumetric flowrates (see Figure 2-8 and Equations 2.13 and 2.14).

2.3.6.1 Venturi Meter

Venturi meter is commonly employed in multiphase flow metering (Al Araimi, 2005 Corneliussen *et al.*, 2005). Venturi meter is used in the Schlumberger novel Vx multiphase flowmeter technology. A venturi tube is a simple, static device, which provides a gradual restriction to the fluid flow. The pressure across the restriction or throat of the venturi is a measure of the volumetric flowrate through it.

2.3.6.2 Cross Correlation

Cross correlation technique uses two identical measurements a small distance apart. These measurements are compared with each other to determine the time difference between the two signals. The distance between the two meters are fixed hence, flow velocity can be determined. This technique can be used with capacitance sensors, microwaves probes and gamma ray densitometer.

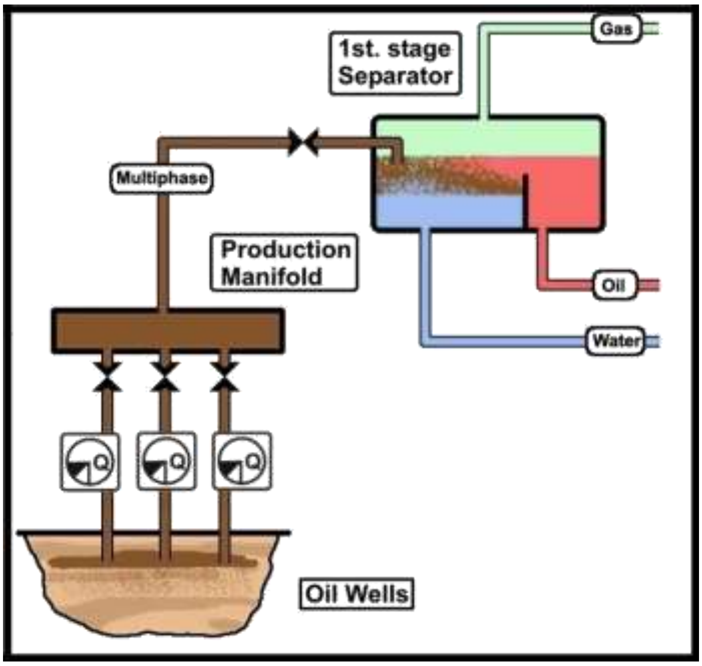
2.3.6.3 Positive Displacement Meter

Positive displacement meters are less common volumetric flowrate. It is an intrusive meter meaning it has moving parts. Its application is limited by its mechanical parts being eroded by sand and fluid and blockage.

2.4 APPLICATIONS OF MULTIPHASE FLOW METERS

New installation or well surveillance, production optimization, flow assurance, well testing, production allocation and custody transfer metering are the major application of MPFMs.

Direct or continuous monitoring of well performance is vital and using a MPFM helps in gathering information that is used in trending well performance and scheduling for overhauls (see Figure 2.12). Using this meter reduces uncertainty in



well testing as compared to a test separator.

Figure 2.11: MPFMs Installation on a New Oil Well (Corneliussen et al., 2005)

It is important to install a MPFM in a new oil and gas facility especially in subsea or offshore field locations where space is limited; installing a MPFM gives more advantage because of its light weight, compactness, reduced cost when compared to test separator and easy accessibility of continuous high resolution oil well data (Corneliussen *et al.*, 2005).

2.4.1 Replacement of Test Separator

One of the most important uses of MPFMs on new installations is to replace the test separator with a MPFM especially for a satellite development where pipelines are needed to convey fluid separately to the main processing facility for separation (Lingya *et al.*, 2011). This is illustrated in Figure 2.12 through 2.13. This schemes as shown brings about more cost saving on subsea pipes required to transport the fluids to host facilities where separation of individual phases will be done.

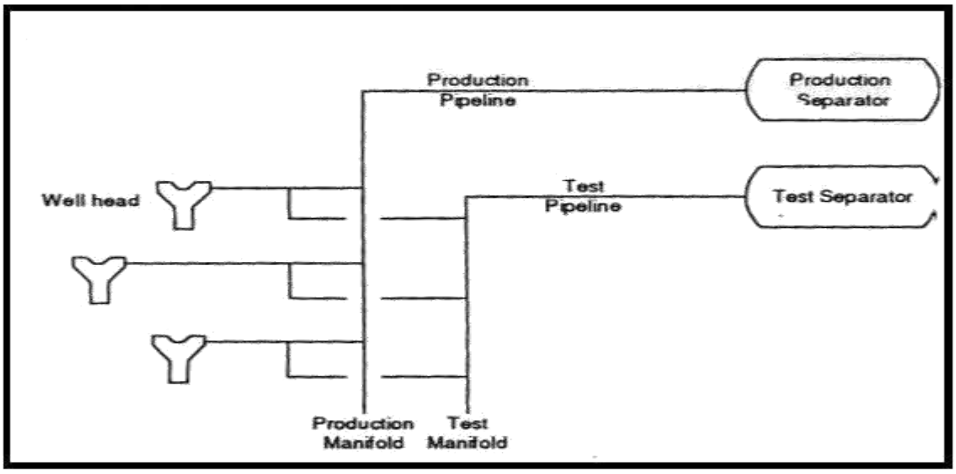


Figure 2.12: Standard Satellite Development with Test Separator (Liu, 1995)

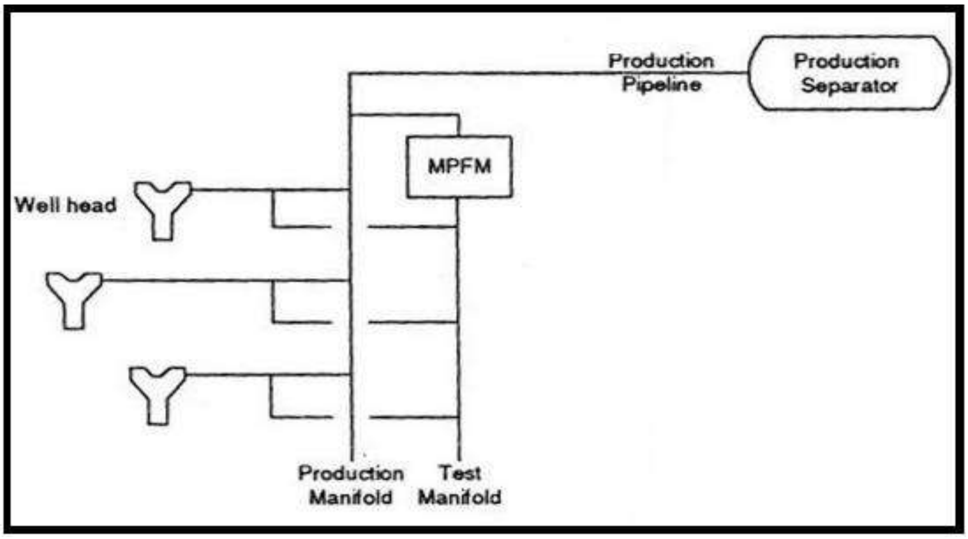


Figure 2.13: Satellite Development with Manifold Installed MPFM (Liu, 1995)

2.4.2 Allocation Metering

The use of MPFM as shown in Figure 2.14 below to facilities where different reservoirs are produced and commingled through the same processing plant is vital because it is necessary for accounting purposes in order to measure the output from the two reservoirs.

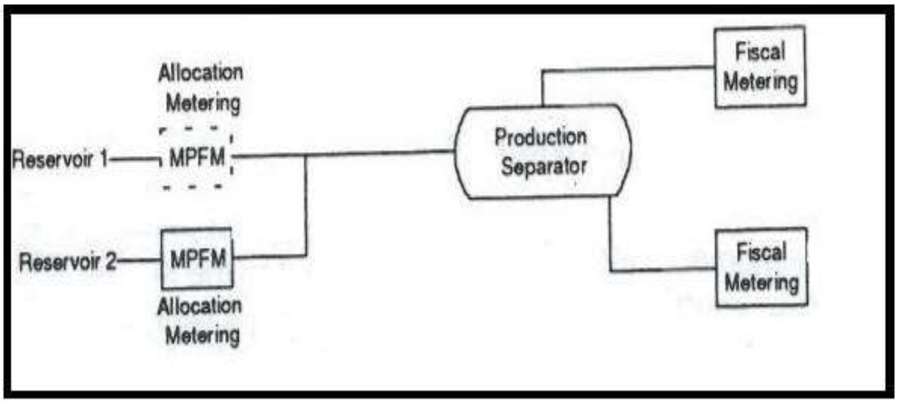


Figure 2.14: MPFM Used for Allocation Metering (Liu, 1995)

2.4.3 Production Optimization

In case of depleting oil wells where artificial gaslift or water injection is needed to flow wells, it is of great importance to optimize the rate of injection because too big or little gas or water injected is of no economic value to the operator hence there should be an exact amount of lift gas or water to be injected to maximize oil production (Corneliussen *et al.*, 2005). Since a MPFM can display instantaneous oil flowrate as a function of gas or water injection rate, this can be a resourceful instrument in determining the optimum gaslift or water injection rate because conventional test separator needs more time to give such data (Lingya *et al.*, 2011).

2.4.4 Flow Assurance

Multiphase flowmeters offer continuous monitoring of oil well performance. With this feature, it is easy for the flow assurance engineers, facility engineers and operators to quickly identify the show stoppers (sands, wax, hydrates, scale formation, sabotage, and leakages in flow line) in the production of the oil well. Hence this will enhance efficiency in the delivery of hydrocarbon from the oil reservoir to the point of sale.

2.4.5 Well Testing

In order to optimize the production of an oil well, continuous monitoring is encouraged. In large field locations like the North sea, Bonga in south west

Nigeria, vital decisions are made based on well test results. Conventional test separators can be used which involves operations like closing in some wells for "workover", drilling new well and reduced production rate from reservoir.

Since a test separator can be used as a bulk separator, it takes more time for it to stabilize during well testing hence makes it impossible to test many wells as required especially when there is only one test separator or when it is used for other purposes. MPFM is desirable in well testing operations because it's quick response, data availability and stability when compared to the former (Lingya *et al.*, 2011).

Often during well testing, some parameters such as choke opening, flowing tubing head pressure, closed-in tubing head pressure, separator temperature and pressure are recorded with fluid sample which are done for individual wells. The data obtained are often used until another scheduled well test which is not economical for flow assurance especially where daily control of wells are needed to optimize the full potential of a production facility hence a MPFM is used because these data are readily available (Falcone *et al.*, 2002).

2.4.6 Satellite Development/Custody Transfer Measurement

Multiphase flow meters are normally used when well streams belonging to different companies are commingled into a single processing manifold or when small fields are developed near existing facility. This is done to ensure proper accountability of production from individual company which is the basis for money transfer between the company and governmental agencies.

2.4.7 Subsea Applications of Multiphase Flowmeters

Framo MPFM used in East Spar development offshore West Australia was the first commercial subsea multiphase flowmeter which combines Framo fluid mixer and venturi with a multiple gamma ray absorption measurement techniques to estimate oil, gas and water flowrates (Winser *et al.*, 1997). In subsea and downhole separation technology where processing of hydrocarbons on topside facilities are minimal with few or simpler flowline networks, flow assurance issues will be eased by the introduction of MPFM in order to optimize field recovery and ensure economic delivery of fluids to sales point. Also in subsea and downhole multiphase metering, MPFMs are best suited for intelligent well monitoring where stream with different producing interval needs monitoring (Falcone *et al.*, 2002) hence continuous optimisation of artificial gaslift systems such as electrical submersible pumps are achieved.

2.5 SELECTION OF A MULTIPHASE FLOWMETER

It is good before selecting a multiphase flow meter to have a realistic idea or data of what the meter will be used for because there is no multiphase flow meter currently that can measure all the phases with high accuracy throughout the entire operating envelope. Some inputs are required by the designer of the meter from the instrument, process and petroleum engineers which includes; density of fluid, viscosity, accuracy and at what level of repeatability, flow regime identification, phase and volume measurements. It is when all the list of priorities are established can a correct meter be selected.

2.5.1 Flow Regime Identification

The most important thing to be considered in selecting a MPFM is to identify the flow regimes expected from wells so as to determine the production envelope as compared to the other MPFMs with similar properties (Corneliussen *et al.,* 2005). Dynamics of process conditions e.g. flow regime as a function of change in the flow compositions and fluid properties affect the performance (accuracy) of MPFMs. For meters using differential pressure, DP for flowrate estimation, flow regime consideration is very important as the accuracy of the meters are affected by the flow fluctuations and consequently differential pressure measurement (Ruiz, 2004 and

Lingya, 2010). Differential pressure fluctuation is more erratic in chaotic flows like slug, churn flow etc.

2.5.2 Phase and Volume Measurement

This is important to be considered when considering a suitable MPFM for a particular application such that the meter will be capable of metering the represented phases and volumes within the estimated uncertainties. Nevertheless, it is important during this selection stage to include adequate auxiliary test facilities that will enable it to be verified or adjusted because failure to provide this will lead to prompt measurement uncertainties because these meters needs verification during operation (Falcone *et al.*, 2002; Ruiz, 2004 and Lingya, 2010).

2.6 LIMITATIONS OF MULTIPHASE FLOWMETERS

The following are the limitations of a typical MPFM; Flow regime dependency, Phase volume fraction, salinity effects, emulsion, difficulties in maintenance, inability to extract fluid sample, density variations and sensor dependency.

2.6.1 Flow Regime and Flow Conditioning

Flow regimes, a function of flow transients, such as slug flows cause large pressure and liquid flowrate fluctuations in the flowline. Also the geometry of the pipe, fluid density and viscosity can affect the accuracy of the MPFM.

Since it is not under the control of the MPFM manufacture to detect a flow regime that the meter will encounter in normal operations because the distribution of fluid phases in space and time differs for flow regimes (Corneliussen, *et al.*, 2005), it is advisable to look at flow conditioning because each meter has a restricted operating envelop when compared to others. This can vary from bend or blanked off T-joint and for some meters a homogenization mixer or a mini separator should be incorporated. Hence, it important to recognize and incorporate a flow conditioning requirements when designing or installing some MPFMs while some meter multiphase flow without flow conditioning or separation. However, some MPFMs like Schlumberger VX can withstand all flow regimes.

2.6.2 Phase Volume Fraction

Most multiphase flow meters have restricted operating envelopes and within that envelope, the accuracy of the measurement can vary significantly because every meter will measure most accurately the most dominant phase. For example, this means that at high Gas Volume Fraction (>80%), the gas phase is the dominant phase and it will be measured with the highest accuracy and invariable at Low Gas Volume Fraction (<20%), the liquid phase will be the most dominant and depending on the water cut, the oil or water will be metered accurately.

Also oil wells deplete during their life time. This will make the fluid composition to vary. Oil wells normally start with almost 0% water cut and gradually increase up to 90% towards the end of their life time. A change like this occurs for Gas Volume Fraction. This means that the accuracy of the MPFM becomes questionable, since the composition of the fluid changes over the life time of the well (Falcone *et al.*, 2002; Ruiz, 2004 and Lingya, 2010).

2.6.3 Salinity

Varying water salinity is one of the major challenges for most MPFMs because it affects the volume fractions calculation (Tjugum *et al.*, 2002) and the accuracy of the meter. A MPFM can be used to tests wells of different salinity and injection of sea water can affect them. More so, some oil wells can cut more injected water than others hence causing salinity variations. This variations cause has effect on meters using gamma ray absorption principles like gamma densitometer because this changes the mass attenuation factor and conductivity of the fluid.

In some cases in order to prevent the effects of this salinity on meters, an in-line salinity measurement which detects the salt water emanating from the reservoir breaking through and flowing into the well (Arnstein and Oyetein, 2009). This measurement is geared towards enhancing well performance and optimization of chemical inhibitor injection rates into the wells in order to avoid corrosion or hydrate formation in pipes. Also it is good to install a MPFM with correct water conductivity in case of a well whose Water Liquid Ratio is projected to increase during the life time of the well because the flow will become water continuous.

2.6.4 Density Variations

It is important to keep record of density measurements from a well through sampling because MPFM suffers from the changes in oil and gas densities especially when one meter is been used in testing different wells.

2.6.5 Emulsion

Some electromagnetic sensors are severely affected by emulsion formation along the well stream especially when making a transition from oil continuous to water continuous flow pattern or verse versa (Winsor *et al.*, 1997).

2.6.6 Sensor Dependency

Some MPFM that applies electromagnetic principles their sensors are strongly dependent on the relative physical distribution of the oil, gas and water phases in the pipe than others (Winsor *et al.*, 1997).

2.6.7 Difficulties in Maintenance

Retrieval of MPFM for maintenance or repair is considered to be expensive or impossible because in-situ calibration is not available hence direct verification methods are applied which includes base line monitoring, use of mobile test unit (skid or truck mounted MPFM), use of two meters in series or use of permanently installed or portable test separator (Corneliussen *et al.*, 2005).

2.6.8 Inability to Extract Fluid Sample

At the moment, there is no standard for multiphase fluid sampling because it is impossible to extract fluid sample using a MPFM especially non-intrusive types like gamma densitometer.

2.6.9 Inability to Meter Hot Fluids

In heavy oil transportation, like the case of steam assisted gravity (SAGD) oil sand development in Athabasca Alberta Canada SGDA pilot where hot steam between 250^{o}C to 350^{o}C is injected into the reservoir to drive oil. Arendo *et al*. (2005) stated that the electrical insulation of MPFMs based on gamma ray (density), venture and dielectric measurements exposed above 80^{o}C will degrade hence affects meter accuracy. Also at a temperature above 150^{o}C, MPFM using gamma dual energy technology needs to be stabilized in order to focus the gamma ray.

2.7 GAMMA-BASED MULTIPHASE FLOW MEASUREMENT TECHNIQUES

Gamma densitometer can be used for phase measurement and void fraction which is one of the key parameters in a gas-liquid flow condition and it can be measured by applying different methods which includes, volumetric, electrical, optical, ultrasonic and radiation methods (Hyun and Chang, 2007). Among these listed methods, radiation techniques are commonly used in multiphase flow metering. Examples of these includes; Neutron scattering, gamma and X-ray attenuation techniques. Gamma ray absorption technique is gaining ground among all other radiation methods mentioned because gamma rays of different energy can be chosen depending on the application (Hyun and Chang, 2007). Examples are single beam, dual beam and multiple beam gamma ray system.

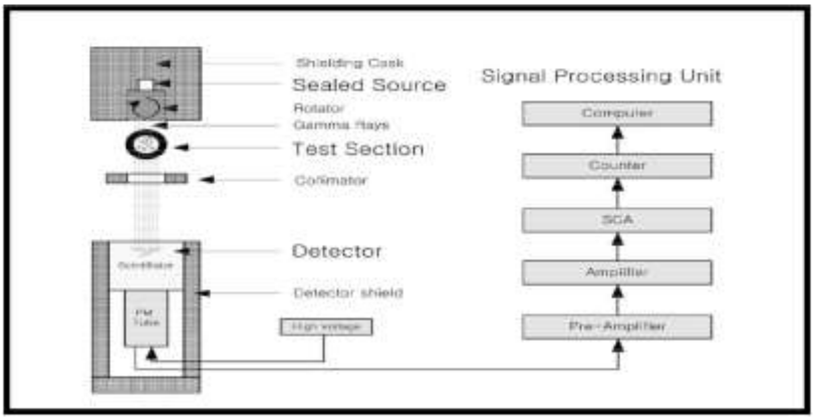


Figure 2.15: Vertical Installation of a Single beam gamma densitometer (Hyun and Chang, 2007)

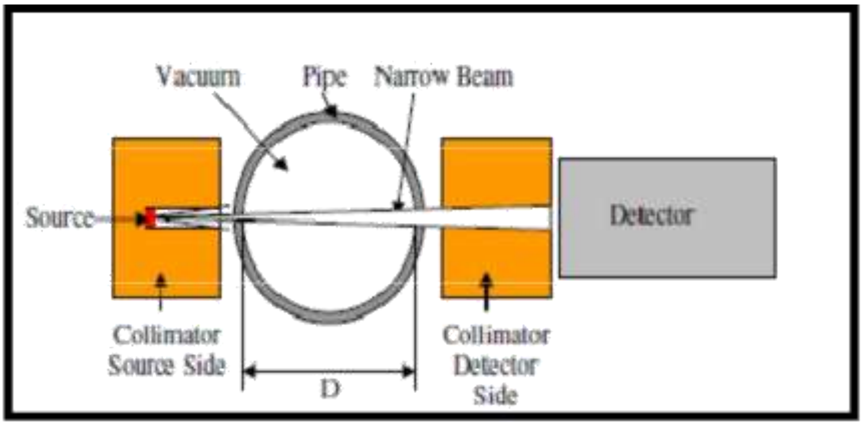


Figure 2.16: Horizontally Installed Single Beam Gamma Densitometer (Hyun and Chang, 2007)

2.7.1 Single Energy Gamma Densitometer

The single gamma energy densitometer in Figure 2.15 below comprises of a sealed gamma ray source, shielding material, a radiation detector, a signal processing unit and a traverse system. The selections of these components are based on the geometry and pipe material over which the void fraction measurement is taken (Ruiz, 2004 and Lingya, 2010).

2.7.2 Gamma Densitometer Design Principles

Gamma ray works on the principles that the intensity of gamma beam decreases exponentially as it passes through a matter (Hyun and Chang, 2007). Single energy gamma ray attenuation can be used in two phase flow condition which can be oil/water or liquid/gas. Consider a two phase flow in pipe with diameter d as shown in Figure 2.16 comprising a pipe wall and the process fluid. Assuming the existence of a vacuum in the pipe, let Io be the intensity gamma radiation measured by the detector. There when the pipe of internal diameter, d, is filled with air the intensity of radiation will be given as (Ibrahim, 2009).

$$I_a = I_o e^{-\gamma a d} \qquad 2.15$$

In this scenario, there will be very small attenuation of gamma radiation hence, (I_a) tends to be very close to I_0 because of relatively low density of air. This will make the linear attenuation of air (γ_a) to be zero in spite of the photon energy. Thus during the two phase flow measurement, (I_a) will be assumed to be the maximum photon count that will be detected. Hence when the pipe is filled with liquid, the intensity of radiation (I_l) will be given as:

$$I_l = I_o e^{-\gamma a d} = I_a e^{-(\gamma l - \gamma a) d} \qquad 2.16$$

When the pipe is filled with liquid, the intensity of (I_l) describes the lower count limit for the two phase flow. The degree of attenuation when the pipe is filled with liquid will be higher because of large liquid density hence I_l will be smaller than (I_a). From this the linear attenuation coefficients of liquid and air can be derived as (Ibrahim, 2009).

$$\gamma_l - \gamma_a = \frac{1}{d} \ln \frac{I_a}{I_l} \qquad 2.17$$

Let the absorbance thickness of the liquid be h_l and the air thickness be $d - h_l$ for the two phase flow condition under consideration. Therefore, the detected radiation intensity will be given as:

$$I = I_a e^{-\gamma a (D - hl)} e^{-\gamma l h 1} \qquad 2.18$$

$$I = I_o e^{-\gamma a d} e^{-(\gamma l - \gamma a) h} \qquad 2.19$$

$$I = I_a e^{-(\gamma l - \gamma a) h} \qquad 2.20$$

Assuming I_a and I_l are given from calibration measurements, the liquid thickness (h_l) along the path of gamma beam can be derived from the measured intensity, I.

$$\ln\left(\frac{I}{Ia}\right) = -(\gamma_l - \gamma_a) h_l = \frac{hl}{d} \ln\left(\frac{Il}{Ia}\right) \qquad 2.21$$

Hence, the liquid hold-up (ε_l) will be given as

$$\varepsilon_l = \frac{hl}{d} = \frac{\ln(\frac{I}{Ia})}{\ln(\frac{Il}{Ia})} \qquad 2.22$$

Hence the degree of the measured intensity I will be between the calibration values I_a and I_l. This will generate a liquid hold up that will lie between 0 ($I=I_a$) and 1 ($I=I_l$).

$$I = I_o e^{-\gamma aha} e^{-\gamma whw} e^{-\gamma oho} \qquad 2.23$$

2.8 MULTIPHASE FLOWMETER CALIBRATION

According to the National Engineering Laboratory (NEL), Scotland, United Kingdom calibration is the set of operations that establish, under specified conditions, the relationship between values of quantities depicted by a measuring instrument or measuring system and the corresponding values realized by standards. Calibration is aimed at boosting the confidence in readings obtained from a flowmeter in operation. Mass or volume can be the basis for the standards which is applicable to the calibration conditions. Based on the application and output of the flowmeter, the standards can be static or dynamic. The flow calibration standards should be close replicates/match as practicable as possible of the conditions (PVT, Viscosity and installation effects) of operation of the flowmeter.

Calibration of flowmeters can be carried out in three alternative ways;

i. Factory Calibration: This is usually done by the flow meter manufacture in the factory where it is made.

ii. Test Facility Calibration: This type of calibration is done in a standard and dedicated laboratory like NEL in the United Kingdom. The flows of gas, oil and water are separately measured. These individual single-phases are then combined upstream the multiphase flowmeter. The readings from the multiphase flow meter are therefore compared with the single-phase measurements.

iii. In Situ Calibration: It is carried out on-line, where the flow meter is being used (in operation). The multiphase flowmeter measurements are compared with the test separator output single-phase measurements.

Factory and In situ calibrations are more important than test facility calibration (Corneliussen *et al.*, 2005).

The modes of calibrations alternatives can be;

i. Static Calibration: Involves taking static measurements.

ii. Dynamic Calibration: This is carried out by allowing fluid flow in the system.

To obtain the desired accuracy, the multiphase flow meter readings are curve-fitted onto the test separator.

2.9 APPLICATION OF GAMMA DENSITOMETER IN MULTIPHASE FLOWMETERING

Earlier studies on the application of gamma radiation techniques in multiphase flow measurement concentrated on exploitation of gamma attenuation for determining component ratio in two-phase flow systems (Spight, *et al.*,1964) and in the development of the radiation detector units (Price, 1964). An encompassing review of gamma attenuation measurement system design and implementation for multiphase flow hold-up measurement are contained in the works of Mareuge (2000) and; Chan and Banarjee (1981).

Jiang and Rezkallah (1993) furthered research works undertaken in the determination of two-phase flow void fraction by analyzing the sensitivity of gamma attenuation measurement method to pipe diameter. Experiments on upward and downward co-current gas liquid flows in a 9.525mm diameter pipe was carried out using a single beam gamma densitometer system comprising a Caesium-137 (662keV) source and a sodium iodide (NaI) detector crystal. Void fraction measurements were obtained to within ±5% relative agreement with the reference values yielded from a quick closing valve system. The data was then compared to data obtained for larger diameter pipes and it was noted that pipe diameter had no significant effect on the accuracy of the gamma attenuation based void fraction measurement.

The use of multi-energy gamma attenuation techniqueto resolve three-phase mixture component ratios was first proposed by Abouelwafa and Kendall (1980) . They examined various static mixtures of oil, water and gas in a 0.1m diameter pipe section using Cobalt-57 (122keV) and Barium-133 (365keV) radioisotopes and a Lithium-drifted Germanium based detector. Gas fraction measurements were detected to within ±1%; oil fractions to within ±10% and the water fraction within ±10%.

Static oil, water and gas mixtures were analysed by Li *et al.,* (2005) using a gamma densitometer system comprising two radioactive isotopes, Americium-241 (59.5 keV) and Caesium-137 (662keV), a Sodium Iodide detector crystal, and a 600mm long square (100mm × 100mm) Plexiglas conduit. A modification algorithm was employed to adjust readings for error. They reported that small errors in the intensity measurements can be transferred to large errors in liquid phase component resolution owing to the similarities in the magnitude of the water and oil attenuation coefficients. Onapplication of the modification algorithm, phase fraction readings were reported at within ±6% of their true values.

Scheers and Slijkerman (1996) in their study, reported on a triple-energy gamma ray multiphase composition measurement that facilitated the determination of the oil, water and gas phase fractions and the water salinity. However, the gamma measurement system was intrusive with an Americium-241 gamma source occupying the centre of the pipe in a concentric set up. Operating the meter in a standard dual energy mode to determine the individual phase compositions yielded measurements with errors of ±2%. Utilising a third energy level (26.3keV) facilitated simultaneous water salinity measurement given that the dynamics of the salinity variation could be assumed to have a one-hour time span. The corresponding phase fractions measurements were defined acceptable but not quantified.

Abro and Johansen (1999) investigated a multi-beam configuration for void fraction measurement using gamma ray attenuation and compared the results against those obtained from a single-beam gamma densitometer. The measurement apparatus comprised an Americium-241 (59.5keV) gamma source, a single CdZnTe semiconductor detector and a pipe with an inner diameter of 80mm and an outer diameter of 90mm. A series of static multiphase combinations were presented to the gamma measurement system. For each test, a complete measurement consisted of determine the gamma attenuation at 17 different positions around the pipe, from 180° (diametrical position) to 52°. It was reported that the multi-beam arrangement yielded results to within ±10% when measurements from four of the detector positions were combined and that the system was less sensitive to flow regime than the conventional single beam technique.

Tjugum, *et al.* (2002) extended on the work undertaken by Abro and Johansen (1999) and assembled a multi-beam instrument with an Americium-241 (59.5 keV) source using three detectors all of which were collimated and embedded in the pipe wall. Two of the three detectors detected the gamma ray attenuation across the pipe flow while one detector was installed at a 90° angle for the purpose of monitoring the scattered radiation. They reported that the multi-beam design with 3 detectors gave more accurate results than the conventional single beam and that the multi-beam geometry and dual modality of the gamma system enabled data on the flow regime water fraction salinity to be obtained.

Tjugum *et al.* (2002) proposed a multi-beam gamma-ray densitometry system to facilitatevoid fraction measurement. A 9-beam fan collimated measurement geometry was employed using an Americium-241 (59.5keV) source and a row of nine (9)CdZnTe semiconductor radiation detectors on the other side of a 2-inch pipe. A number of oil, water and gas flow combinations were tested for pipe section tilt angles of 0°, 45° and 90° (with respect to the horizontal). Improved GVF measurements on non-homogeneous flows, with respect to those obtained using a conventional single beam configuration, were reported, typically to within ±10%. Significant errors were obtained for test points at high GVFs and at separated flows, typically deviations greater than 25%. The source of these errors was attributed to possible backflow (for vertical tests), slip and unstable flow regimes.

Stahl and von Rohr (2004) examined the accuracy of void fractions measurements in a horizontal pipe using a single-beam gamma densitometer. A theoretical model to determine the measurement accuracy for a number of idealised flow regimes was presented. The model described the measurement accuracy as a dimensionless function of the pipe radius and liquid absorption coefficient. Experimental verification of the model was conducted using air and water in a 21mm pipe. A single beam gamma densitometer comprising an Iodine-125 (35.5 keV) source and a sodium iodide (NaI) scintillator detector crystal was employed as the measuring device. It was found that a linear approximation correction was best suited to flow regimes where the phase interfaces are mainly orientated parallel to the radiation beam; while, logarithmic corrections gave better results for flow profiles with a perpendicular orientation or dispersed flow pattern. The maximum absolute deviation owing to inaccuracy in the two-phase mixture void fraction, as determined by the application of the correction models was defined to be one tenth of the product of the pipe internal diameter and the liquid attenuation coefficient.

Froystein *et al*. (2005) reported results on a dual-gamma tomography system for high pressure multiphase flows. A Barium-133 (31keV and 81keV) source was coupled with a CdZnTe detector and a digital spectrum analyser was employed to monitor gamma ray attenuation for different chordal positions of the pipe cross-section.

Results indicated that the tomography system was able to reconstruct different fluid zones for different flow regimes.

More recently, Blaney and Yeung (2007) investigated the development of a cost-effective multiphase flowmeter to determine the individual phase flowrates of constituents using a single fast-sampling clamp-on densitometer and signal processing techniques. Gamma radiation attenuation data was collected for dual energy ranges of a Caesium-137 radio-isotope. Air, portable water and lubricating oil were used as the multiphase mixture. Initial results yielded individual phase flowrate predictions to within ±10% accuracy.

CHAPTER THREE

MATERIALS AND METHODS

3.1 MATERIALS

Materials used in this study include:

i. Gamma Attenuation Signal Data (Gamma counts).
ii. MATLAB Package Version 9.0 (Probability Mass Function tool) for assigning probabilities to Gamma counts.
iii. Microsoft Excel package for presentation of results.

3.2 METHODS

The methods used in this study include:

i. Test Facility Description and Equipment Set-up
ii. Data gathering (Gamma Counts data)
iii. Signal Analysis
iv. Economic Analysis of the viability of replacing existing test separators with multiphase flowmeters.
v. Discussion of Results

3.2.1 Test Facility

The pilot run of gamma-based multiphase flowmetering was carried out on an oil and gas production facility, code named Delta-X for the purpose of this research. Delta-X is an onshore oilfield in the Niger Delta operated by an indigenous oil and gas company. Hydrocarbon production on the facility commenced in October, 2005 with field reserves initially estimated at 5MM barrels later upgraded to over 20MM barrels. Delta-X has developed into a fully integrated oil and gas production asset with a 20,000bbl/d oil processing capacity, a 100MMSCF/d gas producing capacity and a 1,000bbl/d mini refinery currently being upgraded to 11,000bbl/d capacity.

Including the discovery well, eight (8) producing wells currently flow into the facility with more planned for the future.

3.2.1.1 Test Section

The test section is a 3” schedule 160, 11.1mm wt inlet manifold riser. The riser makes an angle of 90° with the horizontal. It connects the inlet manifold to a 1,000m long flowline running from Well-X on natural drive.

The gamma densitometer was installed on the 3” riser at 4ft above ground level.

3.2.1.2 Gamma Densitometer Installation

The gamma densitometer supplied by Neftemer Ltd consists of a lead-filled source housing, a detector unit, and a data processing box. The gamma source housing and the detector are mounted directly opposite each other across the pipe with the aid of a mounting bracket (See Figure 3.1 below). The densitometer was installed in an enclosed area visibly delineated as containing radioactive material with access restricted to only trained personnel. Operation of a mechanical shutter at the side of the source block (marked “ON” and “OFF”) enabled the gamma source to be moved between its safe “OFF” and active “ON” positions. At all times, a large colour coded panel located in the enclosed area indicated whether the gamma source was in its “active” open (RED) or “dormant“ closed (GREEN) position.

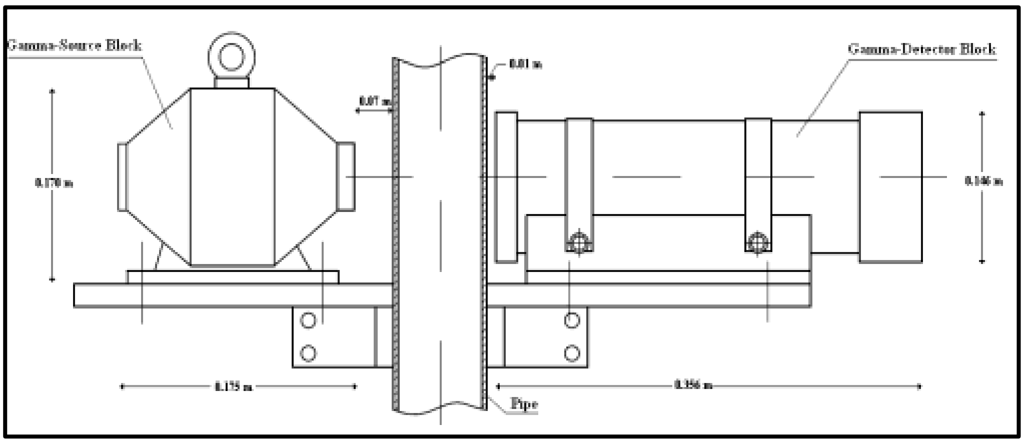


Figure 3.1: Gamma-based Multiphase Flowmeter Installation (Cheng et al, 1998)

3.2.1.3 Gamma Source and Housing

The gamma-source housing consists of an outer casing fabricated from stainless steel. This casing adds mechanical strength and rigidity to the lead-filled internals that contains a gamma radionuclide source capsule surrounded by a lead body to prevent the gamma radiation emitted by the source from escaping into the surrounding environment. A collimator designed to limit the size and angle of spread of the gamma rays, is built into the housing to provide an outlet that produces a cone of beam having uniform physical properties in all directions with an angle of 6 degree to be directed across the diameter of the pipeline. Brass discs of various thicknesses is inserted in the collimated beam path to control the intensity of the gamma radiation that is passing through, taking into account the size and thickness of the installation pipe and the strength of the source.

The radioactive source used was caesium-137 which has a half-life of about 30years. The nucleus of the 6.6GBq caesium-137 radionuclide undergoes radioactive decay through the mechanism depicted in Figure 3.2 below.

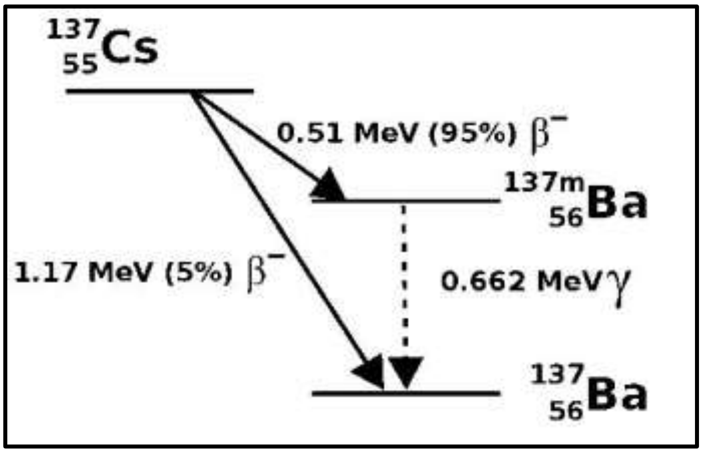


Figure 3.2: Caesium-137 Decay

It emits an electron (β) and a neutrino. As a result, its nuclear charge increases from 55 to 56 by changing a neutron into a proton. From Figure 3.2 above, 95% of the decays result in only 0.5MeV being transferred to the electron and neutrino, leaving the barium-137 in a metastable, excited state. This will further decay by either emitting a 0.662MeV gamma or by "internally converting" the gamma before it leaves the barium atom and ejecting a K-shell electron instead.

3.2.1.4 Meter Calibration

Figure 3.3 is the caesium-137 spectrum plot obtained during calibration of the Neftemer gamma densitometer unit when clamped on to an empty pipeline. The x-axis of the spectrum plot represents the channels from the multiple channel analyser used to classify the gamma photon energy distribution, where the channel number is directly proportional to the gamma photon energy. The y-axis represents the number of counts per second. From the plot, it is noted that the caesium-137 source emits a wide range of photon energies. The Neftemer unit exploits the direct high-energy 0.55 – 0.94MeV photons (subsequently referred to as the hard spectrum) and the lower energy 0.1 – 0.55MeV Compton scattered range (subsequently referred to as the soft spectrum) for multiphase flow measurement.

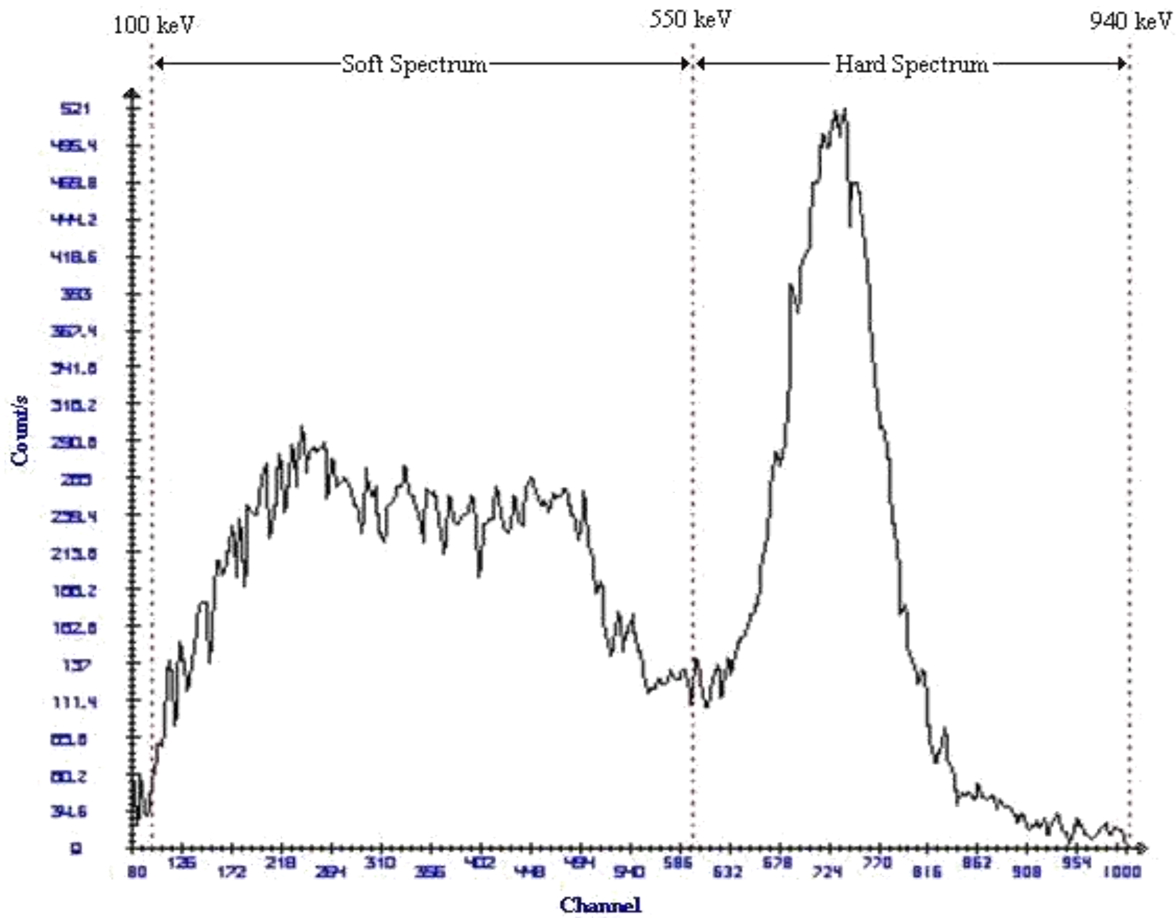


Figure 3.3: Measured Caesium-137 Spectrum (Cheng et al., 1998)

Calibration gamma count values for the different test fluids (air, oil and produced water) were obtained in static conditions at the test facility before the commencement of the field trial campaign in line with API RP 86 (2005). The densitometer measurement is initiated and gamma count collected for one hour when the dummy test section is completely filled with each fluid (produced water and crude oil) in static conditions. The densitometer has a high sampling rate of 250Hz. Thus, every four milliseconds, a gamma count value is registered. The average gamma count for the two energy levels and the corresponding mass attenuation coefficients of the test fluids are summarised in Table 3.1 below.

Table 3.1: Average Gamma Count and Attenuation Coefficients for Test Fluids

	Average Gamma Count			**Linear Attenuation Coefficient (m^{-1})**		
Spectrum	**Air**	**Water**	**Oil**	**Air**	**Water**	**Oil**
Hard	290	180	191	0	0.4770	0.4176
Soft	678	393	414	0	0.5453	0.4933

Source: Field Data (2019)

3.2.1.5 Radiation Safety

In order to comply with Health and Safety legislation, the radioactivity levels around the installation were measured on daily basis throughout the test period. The unit of effective radiation dose is the Sievert (Sv). The maximum effective dose for radiological workers is set at 20mSv per year (whole body dose). This figure is averaged over a 5-year period and no single year is expected to exceed 50mSv. The gamma dosage measurements taken 1.5metres radius around the source was 0.3µSv/hr. Thus installation radiation levels met the Environment Agency and Health Protection Agency criteria.

3.2.2 Data Acquisition

The gamma densitometer detection unit was connected via a RS-485 serial interface to a Programmable Logical Controller (PLC) where the raw densitometer signal was processed into a gamma count signal and passed to a local PC workstation through an RS-232 serial connection. During data collection, gamma count measurements were made at a rate of 250Hz and passed from the PLC to the local PC through the RS-232 serial connection and stored in a text file for offline data processing. For each measurement, two text files were created: one to record the hard-energy count and the other to record that of the soft-energy gamma count.

Data for economic analysis were obtained through telephone interviews and email correspondence with multiphase flowmeter manufacturers and field engineers.

3.2.3 Data Analysis for Flow Regime Identification

Raw data text files obtain as stated in section 3.2 above were imported into MATLAB and transformed into workspaces for further processing. Probability Mass Function (PMF) was used in analysing the raw data for the purpose of characterising flow behaviour. Probability Mass Function (PMF) estimation is a powerful tool for characterizing the behaviour of multiphase flow. It describes the probability that at a given time the signal will have the value within some defined range.

Probability Mass Function, PMF, is a statistical function that assigns a unique probability value for a discrete random variable. PMF is used to define a discrete probability distribution for only discrete distribution of data. For a discrete random variable X, probability mass function can be expressed mathematically as in equation 3.1 below.

$f(x) = P(X = x)$ 3.1

for all values of x. PMFs were obtained for each trial data as a whole and its divisions into one-hour and ten-minute sampling periods.

Probability mass function (PMF) of gamma count data has been long established to be characteristic of the prevailing flow regime (Cheng *et al.*, 1998; Blaney and Yeung, 2007).

3.2.4 Economic Analysis

An economic model based on the Incremental Net Present Value (NPV_i) was proposed to aid management of operating companies in the oil and gas industry in evaluating the economic viability of multiphase flowmeter installation over the test separator.

The incremental net present value is obtained by subtracting the discounted Test Separator (TS) Total Cost (TC) from the discounted Multiphase Flowmeter (MPFM) Total Cost (TC). Total cost is the cash flow of respective equipment comprising its capital expenditure (CAPEX) and operating expenditure (OPEX).

TC = CAPEX + OPEX 3.2

$NPV_{\mathrm{i}} = \sum_{i=0}^{n} \left[\frac{\mathrm{TC_{MPFM}} - \mathrm{TC_{TS}}}{(1+r)^n}\right]$ 3.3

Decision Rule:

i. If NPV_i is positive, continue use of test separator.

ii. If NPV_i is negative, replace existing test separator with multiphase flowmeter

iii. If NPV_i is zero, further investment analysis is needed for decision making.

The following are the assumptions made in this analysis:

i. The equipments have a 15-year service life with no salvage value.
ii. There is no tax implication to the investment.
iii. Base case of 15% discount rate is considered.
iv. A field with eight (8) producing wells within the same operating envelope is considered.
v. Maintenance contract of four-year cycle is considered with 10% variation.

Two cases were considered:

Case A: Replacing an existing test separator with a single multiphase flowmeter on the test line.

Case B: Replacing an existing test separator with multiphase flowmeters on per well basis.

CHAPTER FOUR

RESULTS AND DISCUSSION

4.1 FLOW REGIME IDENTIFICATION

The main flow regimes observed in the course of this study were bubbly, slug, churn and annular with bubbly-slug and slug-churn transition flow regimes.

4.1.1 Bubbly Flow

Bubbly flow is the spatial distribution of phases when gas bubble is well distributed in liquid with relatively higher flow rate. This type of flow regime is synonymous to homogeneous flow. The degree of homogeneity depends on the gas and liquid flow rates and how evenly the phases are distributed with respect to one another.

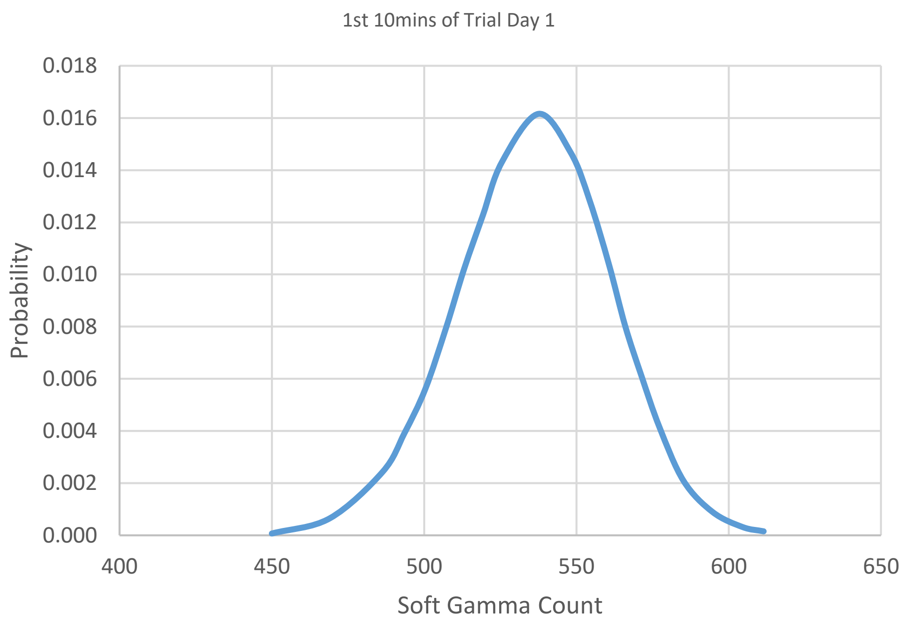


Figure 4.1: PMF Chart Indicating Bubbly Flow

4.1.2 Slug Flow

Slug flow is a multiphase flow intermittent flow regime where liquid slug and large gas bubble (Taylor bubble) flow intermittently in pipelines or conduits. This usually occurs when gas flow rate increases considerably to promote huge coalescence of smaller gas bubbles into large Taylor bubbles which are about the diameter of the pipe or conduit. The liquid slug length might be equal or longer than the pipeline length (in case of severe slugging) or much shorter but more frequent (in case of hydrodynamic slugging). However, this work does not focus on the slug length determination.

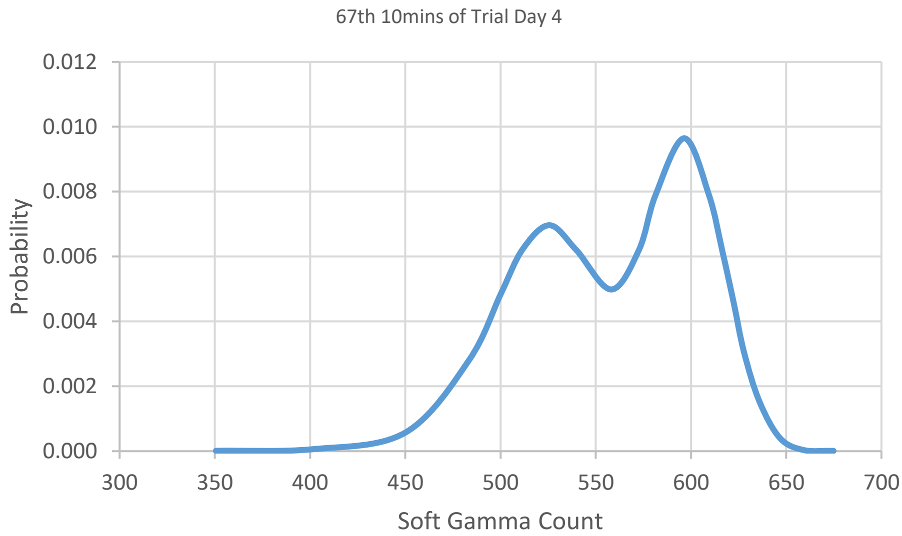


Figure 4.2: PMF Chart Indicating Slug Flow

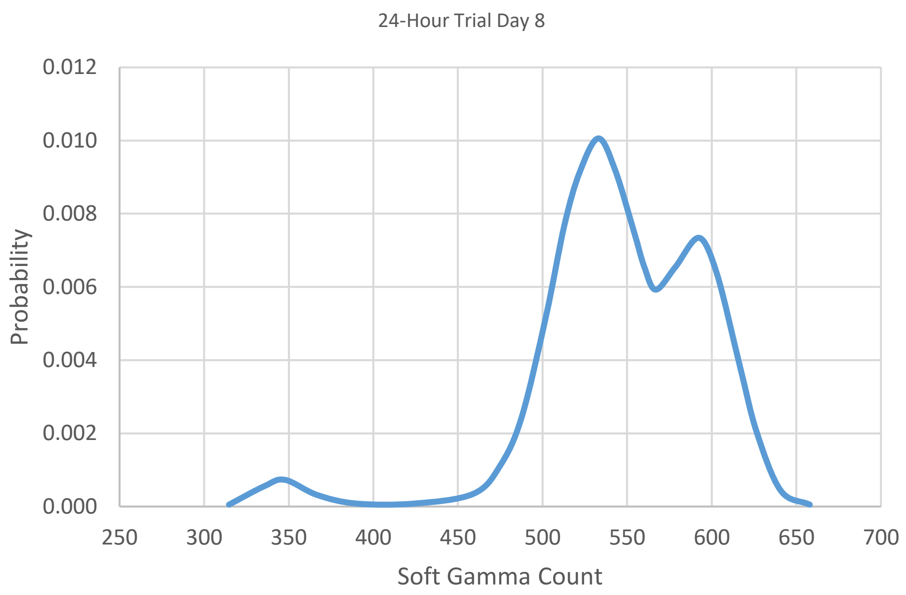


Figure 4.3: Slug Flow PMF with Three Peaks

4.1.3 Churn Flow

Slug flow changes to churn flow when there is a further increase in inflow of gas which causes an increase in Taylor bubbles and consequently causes huge entrainment of gas bubble into liquid slug body. Hence, liquid slug and gas Taylor bubbles break down and result into oscillating and chaotic churn flow regime.

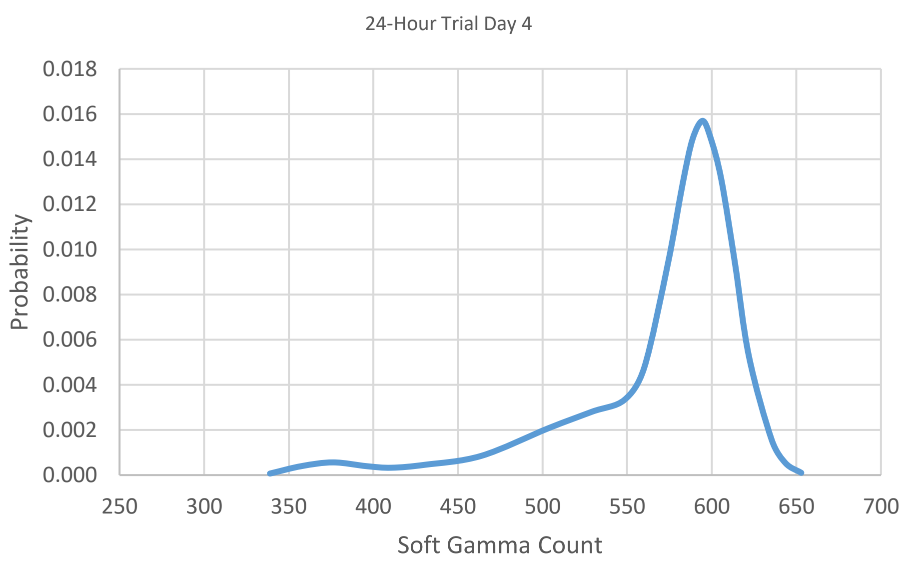


Figure 4.4: PMF Chart Indicating Churn Flow

4.1.4 Annular Flow

Annular flow is an extreme flow regime that occurs when there is a very high gas rate. It can be thought of as a transition from churn flow where gas flow rate is high enough to break through the oscillating churn flow. Hence, continuous gas bubble body occupies the core of the pipe while liquid is found clinging to the pipe walls.

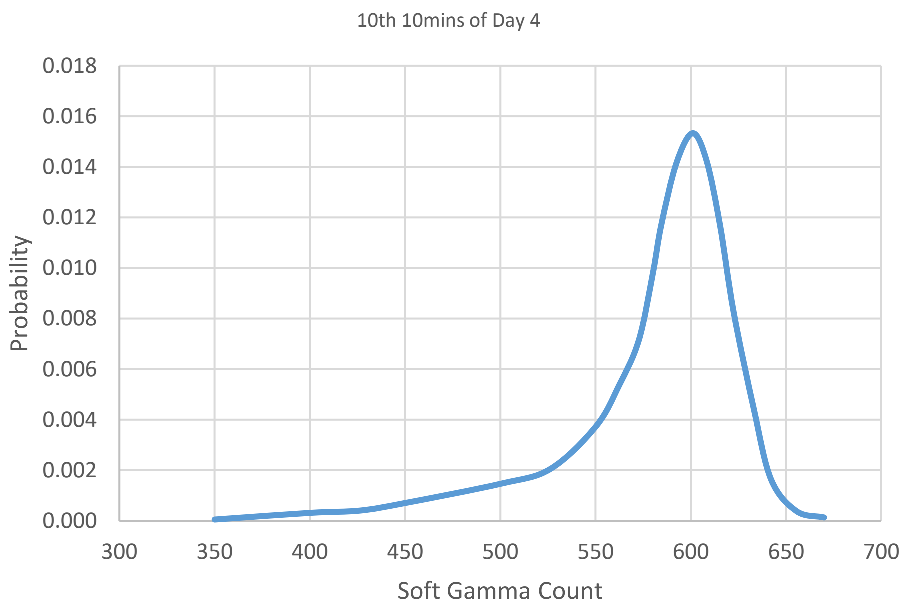


Figure 4.5: PMF Chart Indicating Annular Flow

4.1.5 Transition Flow Regimes

Two transition flow regimes were identified in this study, which are bubbly-slug and slug-churn transitions.

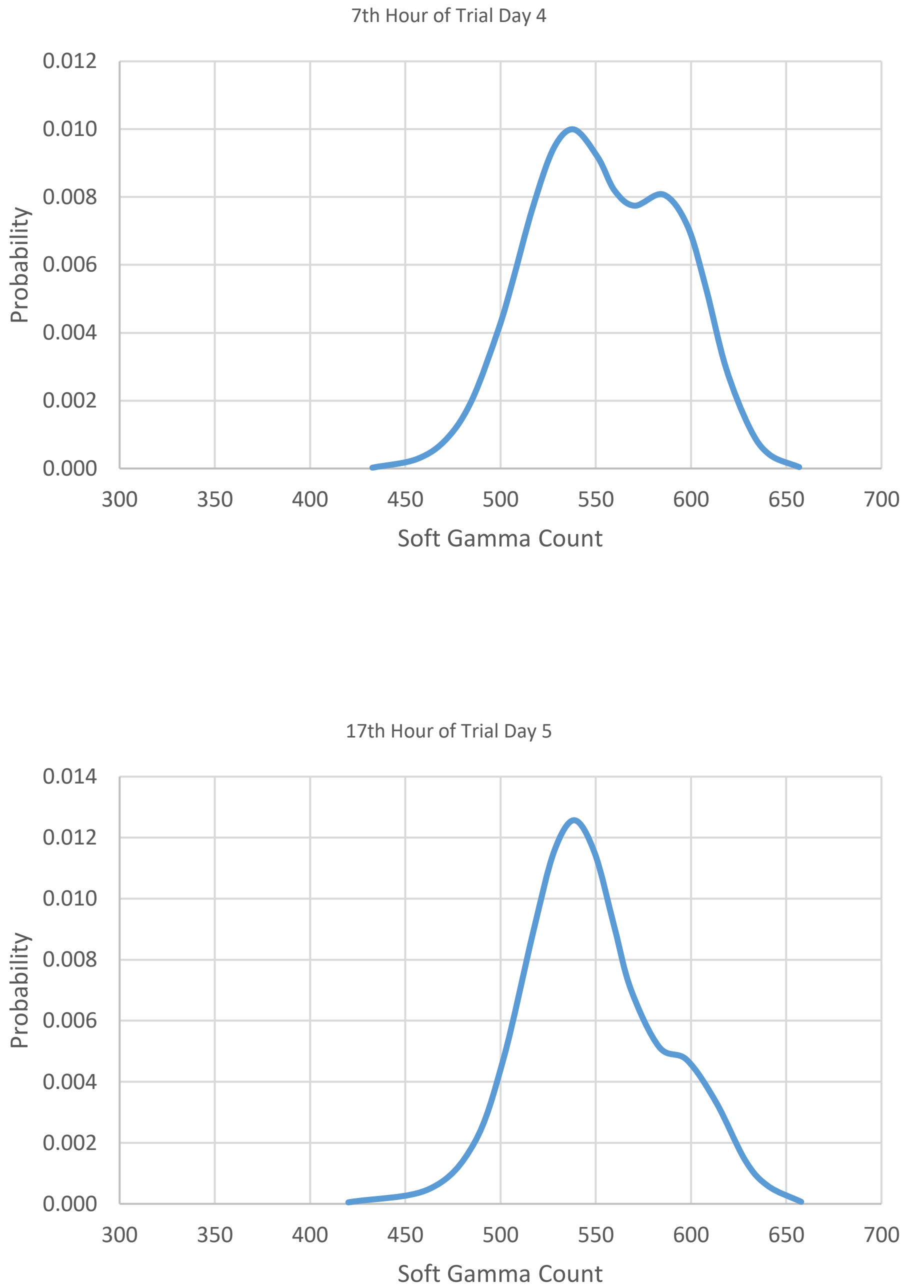


Figure 4.6a/b: PMF Chart Indicating Bubbly-Slug Transition

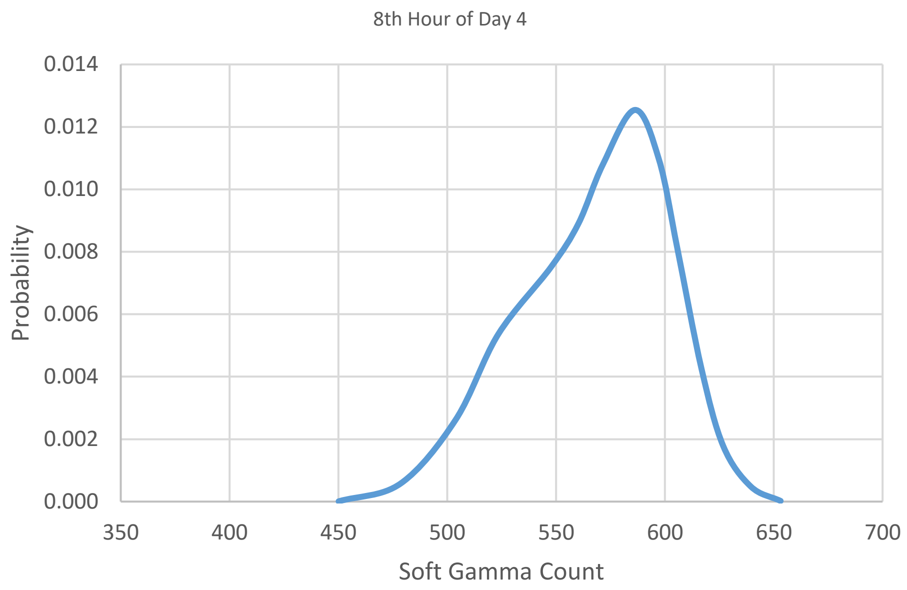


Figure 4.7: PMF Chart Indicating Slug-Churn Transition

4.2 DISCUSSION OF FINDINGS

Probability mass function, PMF with single peak as shown in Figure 4.1 above is characteristic of bubbly flow. The single peak in bubbly flow PMFs falls at the center or almost the center of the gamma counts scale. This is chart is in agreement with Cheng et al (1998); Blaney and Yeung (2007) that the deviation of the single peak from the center depends on the relative gas flow rate. An increase in gas flow makes the peak shift right (higher gamma count region). Also, for a decrease in gas rate, the peak shifts left (lower gamma count region). Higher gamma count is an indication of lower fluid density (majorly gas) flowing through the meter while lower gamma count is an indication of higher mixture density (mostly liquid). Unlike bubbly flow, PMFs with two major peaks as shown in Figure 4.2 above are characteristic of slug flow. The first peak is located at the lower count region representing liquid (or gas-liquid mixture) slug while the other peak represents larger gas bubbles. Two peaks mean there are two separate phases with two different mean values. In some cases, there might be a third peak but with smaller amplitude (probability of occurrence) as shown in Figure 4.3.

The PMF in Figure 4.5 has a long bandwidth with a long tail at lower gamma counts region representing low concentration liquid body in conformity with Cheng *etal* (1998); Blaney and Yeung (2007). Unlike slug flow where the liquid slug and gas Taylor bubble are parallel to each other, liquid and gas bubble distribution are erratic. That is the reason while other peaks in liquid region of the PMF are not fully developed. But in the gas region there exists a prominent peak with higher amplitude (however, smaller bandwidth). The smaller peak in the range of 300-400 gamma counts might be a region of pure liquid while the next peak (500-550counts) to it might be a feature of liquid with some gas bubbles.

The annual flow PMF (See Figure 4.5) looks like a churn flow PMF but with no tendency of second or more peaks formation. It has a long tail with lower amplitude than that of churn flow PMF at the liquid region (lower counts) agreeing with the result from laboratory work reported by Cheng et al (1998); Blaney and Yeung (2007). The amplitude of the liquid tail is thought to be proportional to the thickness of liquid around the pipe wall.

Bubbly-slug transition flow has both features of bubbly and slug flow as shown in Figure 4.6. The second peak is not fully developed in both flow transitions. Figure 4.6b has a second peak at the gas region (higher gamma counts) that is more developed than that in Figure 4.6(a). Slug-churn transition has its developing peak at liquid region (lower gamma counts) as shown in Figure 4.7. These shapes agree with the laboratory works by Cheng et al (1998); Blaney and Yeung (2007).

4.3 ECONOMIC VIABILITY OF REPLACING EXISTING TEST SEPARATORS WITH MULTIPHASE FLOWMETERS

An economic analysis to ascertain the viability of replacing existing test separators with multiphase flowmeters on a per well basis was undertaken in the course of the study. Data obtained from meter manufacturers and inputs from industry experts formed the basis for the analysis as earlier stated in section 3.2 of this research work.

4.3.1 Replacing an Existing Test Separator with a Single Multiphase Flowmeter (CASE A)

This section considers the economic viability of replacing an already existing test separator with a multiphase flowmeter. Tables 4.7 and 4.8 show the costs outlay and undiscounted total cost respectively for both multiphase flowmeter and test separator in terms of capital expenditure (CAPEX) and operating expenditure (OPEX).

Table 4.7: Cash Outlay for Multiphase Flowmeter and Test Separator (Case A)

Year	Multiphase Flowmeter		Test Separator	
	CAPEX ($)	OPEX ($)	CAPEX ($)	OPEX ($)
0	122000	0	0	0
1	0	5000	0	77120
2	0	5000	0	77120
3	0	5000	0	77120
4	0	5000	0	77120
5	0	5500	0	84832
6	0	5500	0	84832
7	0	5500	0	84832
8	0	5500	0	84832
9	0	6050	0	93315
10	0	6050	0	93315
11	0	6050	0	93315
12	0	6050	0	93315
13	0	6655	0	102647
14	0	6655	0	102647
15	0	6655	0	102647

Source: Field Data 2019

Table 4.8: Undiscounted Total Cost for Multiphase Flowmeter and Test Separator (Case A)

Year	MPFM Total Cost ($)	TS Total Cost ($)
0	122000	0
1	5000	77120
2	5000	77120
3	5000	77120
4	5000	77120
5	5500	84832
6	5500	84832
7	5500	84832
8	5500	84832
9	6050	93315
10	6050	93315
11	6050	93315
12	6050	93315
13	6655	102647
14	6655	102647
15	6655	102647

Source: Field Data (2019)

Table 4.9: Discounted Total Cost for Multiphase Flowmeter and Test Separator (Case A)

	Multiphase Flowmeter		Test Separator	
Year	Total Cost ($)	15%PV ($)	Total Cost ($)	15%PV ($)
0	122000	122000.00	0	0
1	5000	4347.83	77120	67060.87
2	5000	3780.72	77120	58313.80
3	5000	3287.58	77120	50707.65
4	5000	2858.77	77120	44093.61
5	5500	2734.47	84832	42176.50
6	5500	2377.80	84832	36675.21
7	5500	2067.65	84832	31891.49
8	5500	1797.96	84832	27731.73
9	6050	1719.79	93315	26525.95
10	6050	1495.47	93315	23066.04
11	6050	1300.41	93315	20057.43
12	6050	1130.79	93315	17441.24
13	6655	1081.62	102647	16683.01
14	6655	940.54	102647	14506.96
15	6655	817.86	102647	12614.75
		153739.26		**489546.241**

Source: Field Data (2019)

From Table 4.9, NPV*i* calculated using equation 3.2 yielded $(-335806.98), a negative value. This implies that the discounted total cost for test separator is greater than that of the multiphase flowmeter by $335806.98. Thus, going by the decision rule, this evaluation favours replacing an existing test separator with a multiphase flowmeter since a decision to replace existing test separator with a multiphase flowmeter would result to $335806.98 in cost savings.

A graphical cost comparison between the multiphase flowmeter and test separator at varying discount rates is shown in Figure 4.9 below.

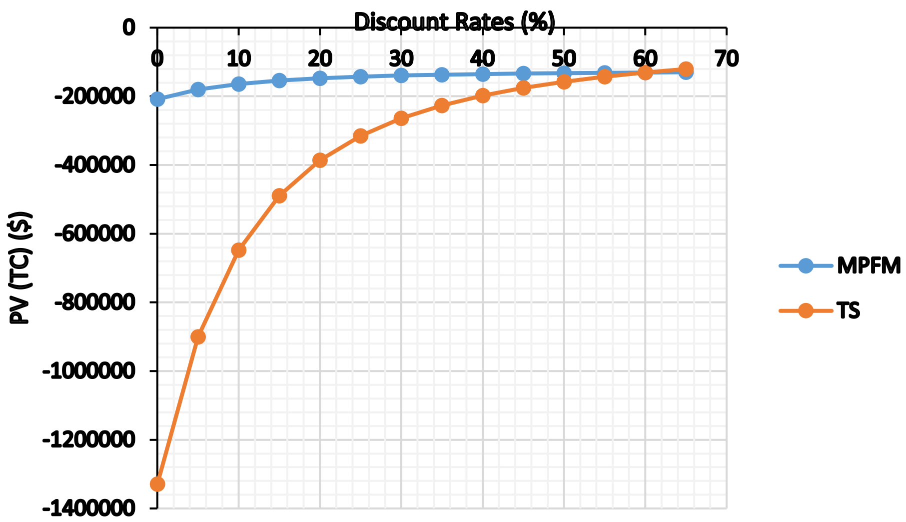


Figure 4.8: Total Cost Present Value for MPFM and TS vs Discount Rates (Case A)

It can be seen from Figure 4.8 that the total cost for both multiphase flowmeter and test separator will even out at 62% discount rate. The multiphase flowmeter gives a better investment proposal below the 62% rate. Meanwhile, beyond this point, the test separator gives a better investment proposal than the multiphase flowmeter.

The expenditure curves in Figure 4.10 shows the relationship between CAPEX and OPEX for both MPFM and the Test Separator.

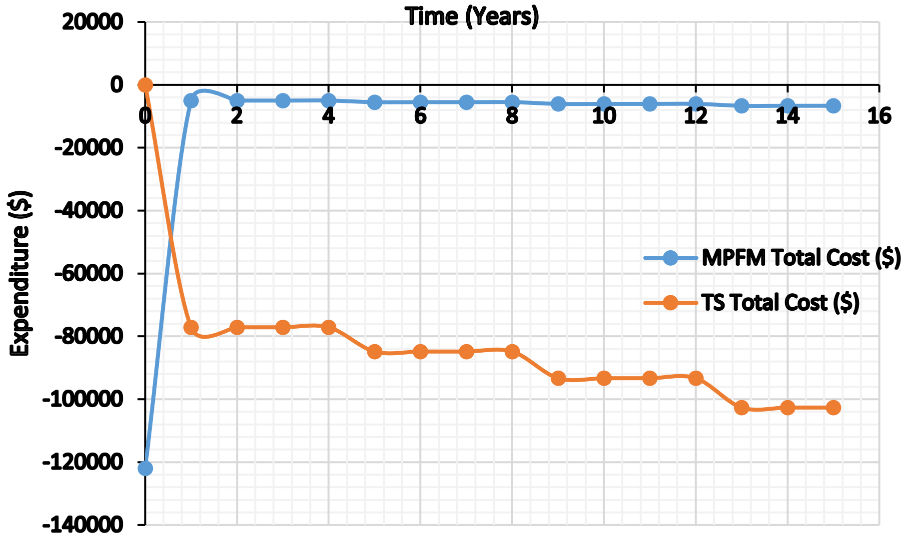


Figure 4.9: Expenditure curves for MPFM and Test Separator (Case A)

From Figure 4.19, it can be seen that the test separator OPEX increases rapidly over the life of the equipment while MPFM OPEX increased marginally over the same period. This is more so as aging test separators in the field are prone to leaking ligament valves and increased cost of desanding.

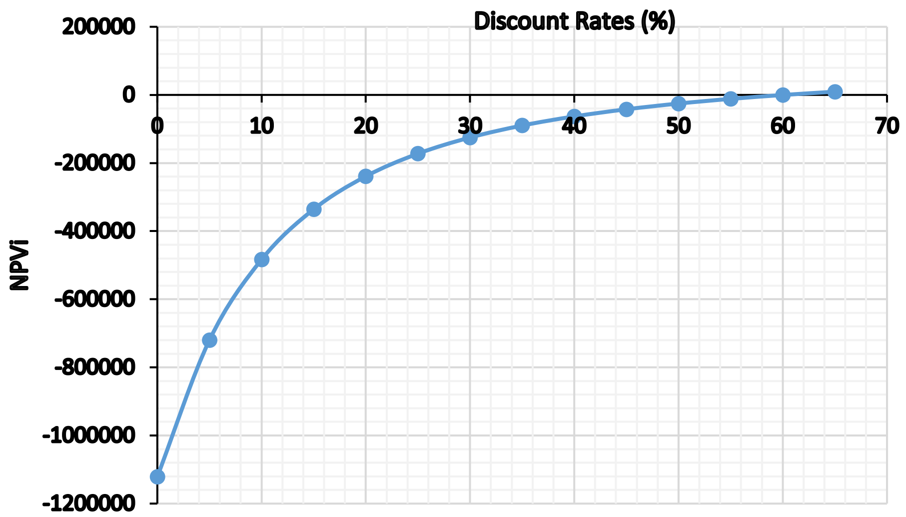


Figure 4.10: Incremental PV Profile for Case A

The incremental present value shown in Figure 4.10 was obtained using Equation 3.2 by calculating the differential present value total cost between MPFM and TS. The negative incremental present value decreases exponentially with increasing discount rate thus gradually turning to favour a continued use of the existing test separator at increasing discount rate over multiphase flowmeter installation. The incremental present value profile intersects the discount axis at 62% implying that both alternatives have a compelling argument at that discount rate.

Sensitivity analysis was carried out to analyze risks associated with changes in input parameters. Figure 4.11 gives a sensitivity plot for replacing existing test separator with a multiphase flowmeter.

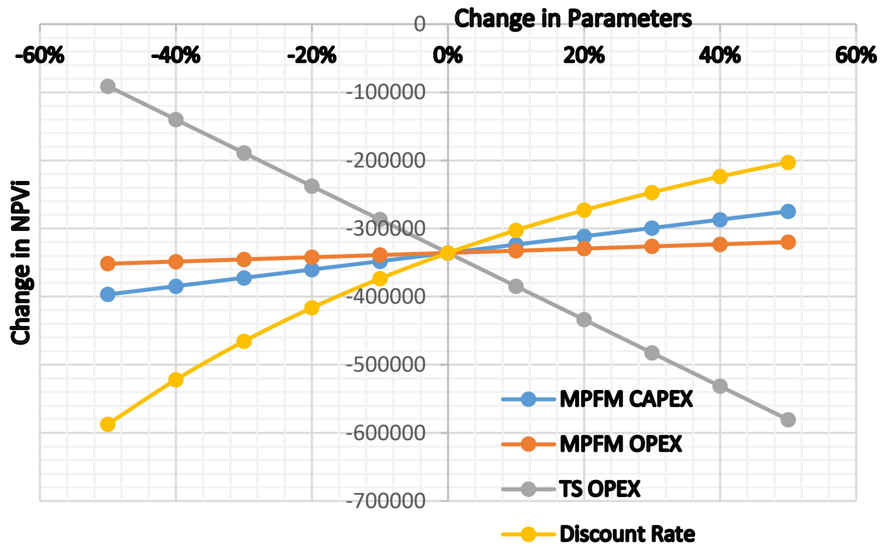


Figure 4.11: Sensitivity Plot for Case A

From the sensitivity study shown in Figure 4.12, economic viability of replacing an existing test separator with a multiphase flowmeter is highly sensitive to test separator OPEX. A decrease in test separator OPEX drastically reduces the viability of this investment decision of replacing existing test separator with a single multiphase flowmeter. Conversely, a reduction in MPFM capital expenditure (CAPEX) greatly enhances the viability of the proposed investment decision. Changes in MPFM have, by far, less impact on the valuation.

4.2.2Replacing an Existing Test Separator with Multiphase Flowmeters on per Well Basis (Case B)

This section considers the economic viability of replacing an already existing test separator with multiphase flowmeters on a per well basis. Tables 4.10 and 4.11 show the costs outlay and undiscounted total cost respectively for both multiphase flowmeter and test separator in terms of capital expenditure (CAPEX) and operating expenditure (OPEX).

Table 4.10: Cash Outlay for Multiphase Flowmeter and Test Separator (Case B)

	MPFM		TS	
Year	**CAPEX($)**	**OPEX($)**	**CAPEX($)**	**OPEX($)**
0	976000	0	0	0
1	0	40000	0	77120
2	0	40000	0	77120
3	0	40000	0	77120
4	0	40000	0	77120
5	0	44000	0	84832
6	0	44000	0	84832
7	0	44000	0	84832
8	0	44000	0	84832
9	0	48400	0	93315
10	0	48400	0	93315
11	0	48400	0	93315
12	0	48400	0	93315
13	0	53240	0	102647
14	0	53240	0	102647
15	0	53240	0	102647

Source: Field Data (2019)

Table 4.11: Undiscounted Total Cost for Multiphase Flowmeter and Test Separator in Case B

Year	MPFM Total Cost ($)	TS Total Cost ($)
0	976000	0
1	40000	77120
2	40000	77120
3	40000	77120
4	40000	77120
5	44000	84832
6	44000	84832
7	44000	84832
8	44000	84832
9	48400	93315
10	48400	93315
11	48400	93315
12	48400	93315
13	53240	102647
14	53240	102647
15	53240	102647

Source: Field Data (2019)

Table 4.12: Discounted Total Cost for Multiphase Flowmeter and Test Separator (CaseB)

	Multiphase Flowmeter		Test Separator	
Year	Total Cost ($)	15%PV ($)	Total Cost ($)	15%PV ($)
0	976000	976000	0	0
1	40000	34782.61	77120	67060.87
2	40000	30245.75	77120	58313.80
3	40000	26300.65	77120	50707.65
4	40000	22870.13	77120	44093.61
5	44000	21875.78	84832	42176.50
6	44000	19022.41	84832	36675.21
7	44000	16541.23	84832	31891.49
8	44000	14383.68	84832	27731.73
9	48400	13758.30	93315	26525.95
10	48400	11963.74	93315	23066.04
11	48400	10403.25	93315	20057.43
12	48400	9046.31	93315	17441.24
13	53240	8652.99	102647	16683.01
14	53240	7524.34	102647	14506.96
15	53240	6542.90	102647	12614.75
		1229914.06		**489546.241**

Source: Field Data (2019)

From Table 4.12, NPV*i* calculated using equation 3-2 yielded $740367.82, a positive value. This implies that the discounted total cost for test separator is less than that of the multiphase flowmeter by $740367.82. Thus, going by the decision rule, this evaluation does not favour replacing an existing test separator with multiphase flowmeters on a per well basis since a decision to replace existing test separator with multiphase flowmeters would result to further incurring $740367.82 in cost.

A graphical cost comparison between the multiphase flowmeter and test separator at varying discount rates for Case B is shown in Figure 4-12.

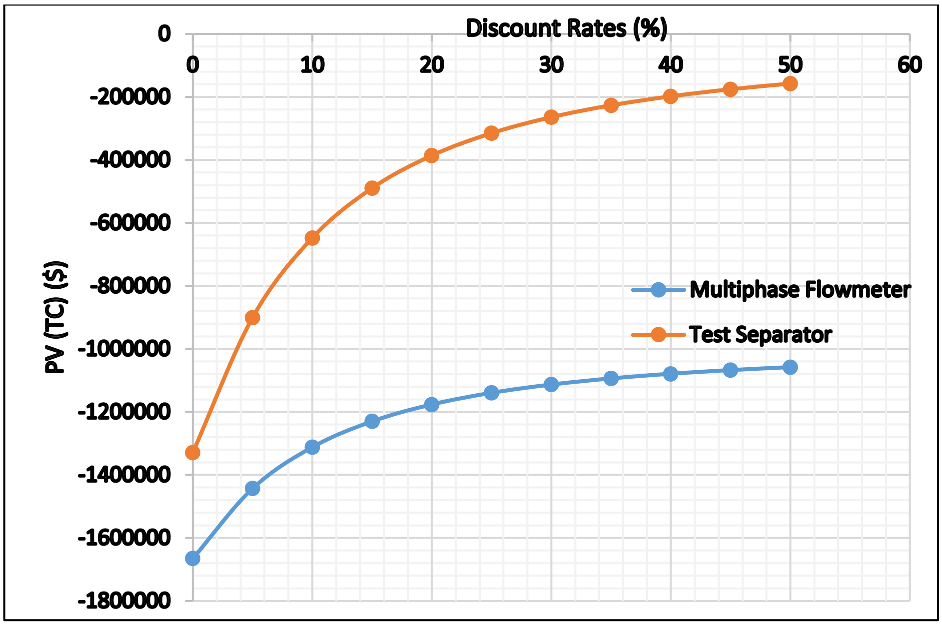


Figure 4.12: Total Cost Present Value for MPFM and TS against Discount Rates (Case B)

From Figure 4.12, test separator exhibited a low cost profile compared to the multiphase flowmeter. Thus the graph is in agreement with the incremental present value that replacing an existing test separator with multiphase flowmeters on per well basis is not economically viable with the present cost outlay.

The expenditure curves in Figure 4.13 shows the relationship between CAPEX and OPEX for both MPFM and the Test Separator.

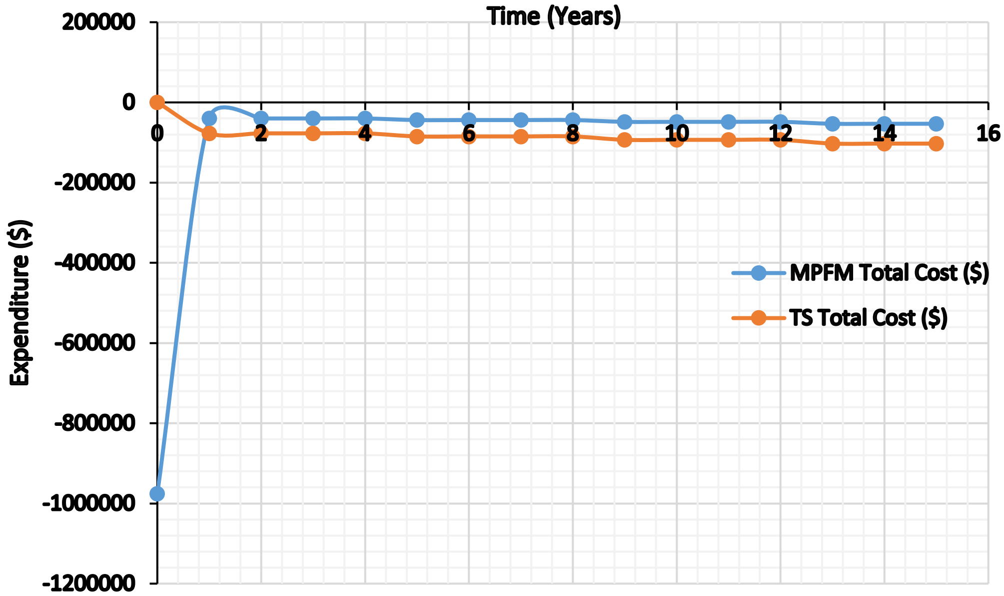


Figure 4.13: Expenditure curves for MPFM and Test Separator (Case B)

From Figure 4.14, it can be seen that the major contributor the MPFM total cost is its CAPEX. However, test separator OPEX over the life of the equipment is higher than MPFM OPEX over the same period.

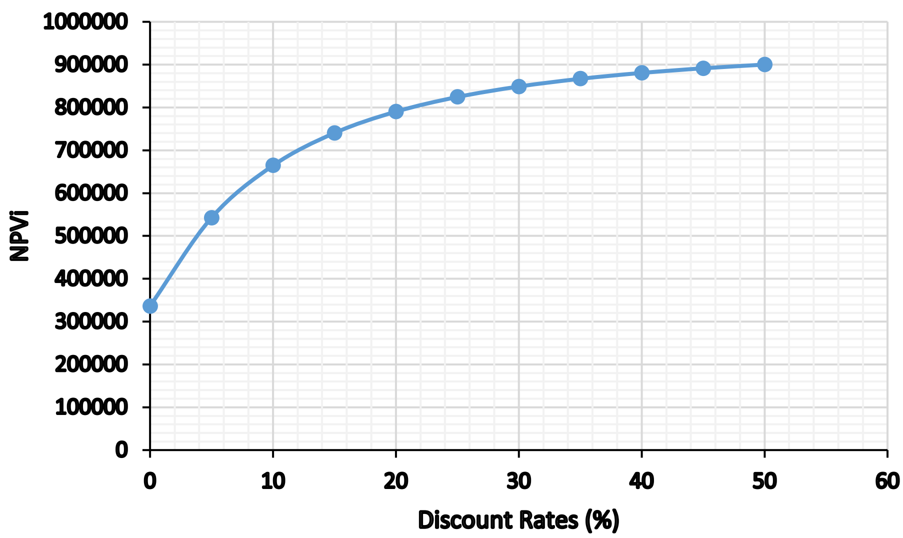


Figure 4.14: Incremental PV Profile for Case B

The incremental present value shown in Figure 4.14 was obtained using Equation 3.2 by calculating the differential present value total cost between MPFM and TS. The positive incremental present value increased exponentially with increasing discount rate. This implies that the economic viability of replacing existing test separator with multiphase flowmeters on per well basis becomes even increasingly unattractive with increasing discount rate. The incremental present value curve cuts the zero discount rate at $336311 differential cost which means that even at zero discount rate; it is not economically viable to replace an existing test separator with multiphase flowmeters on per well basis.

Sensitivity analysis was carried out to analyze risks associated with changes in input parameters. Figure 4.15 gives a sensitivity plot for replacing existing test separator with multiphase flowmeters on per well basis.

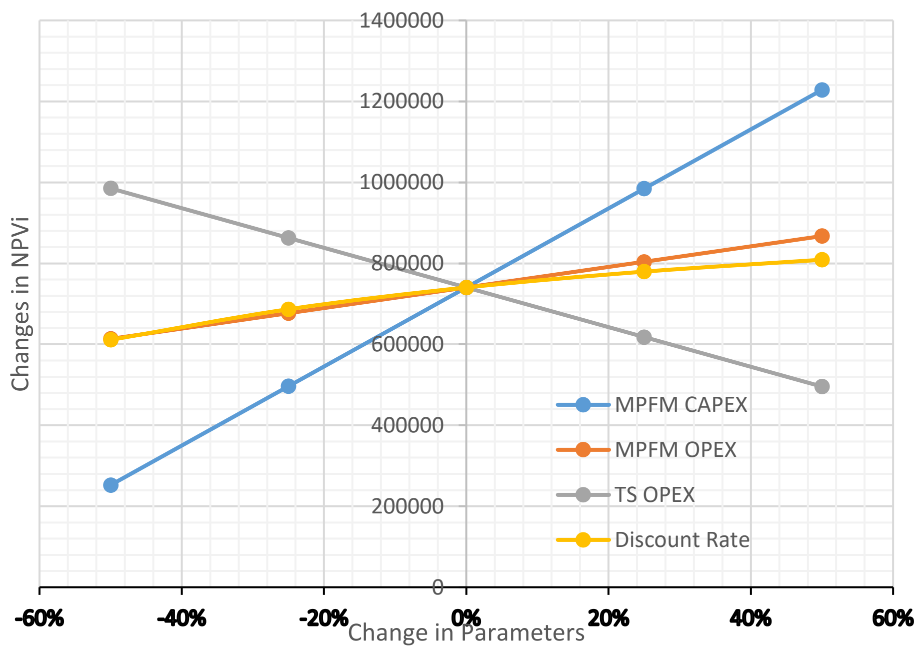


Figure 4.15: Sensitivity Plot for Case B

From the sensitivity study shown in Figure 4.15, economic viability of replacing an existing test separator with multiphase flowmeters on per well basis is highly sensitive to multiphase flowmeter CAPEX. An increase in multiphase flowmeter CAPEX drastically reduces the economic viability of this investment decision of replacing existing test separator with multiphase flowmeters on a per well basis and vice versa. Conversely, a reduction in test separator operating expenditure (OPEX) greatly enhances the unattractiveness of the proposed investment decision. Changes in MPFM operating cost and the discount rate showed have, by far, less impact on the valuation.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATIONS

5.1 CONCLUSION

The flow regime identification capability of Gamma-based multiphase flowmeters was studied using the Neftemer well monitor at an onshore oilfield in the Niger Delta. The flow regimes observed during the trial operation were identified from raw gamma counts with the aid of Probability Mass Function charts to be bubbly, slug, churn, annular and transition (bubbly-slug and churn-annular) flows. Economic analysis was conducted based on feedback from multiphase flowmeter manufacturers and industry experts.

From the results and analysis performed in this work, the following conclusions are made:

1. Signal analysis of Gamma-based multiphase flowmeters give a good estimation of multiphase flow regimes in vertical conduits.
2. Soft gamma counts present a clearer means of flow regime identification than hard gamma counts.
3. Though hydrocarbon flow through risers is mostly steady (giving consistent PMF shapes denoting same flow regime), it becomes intermittently chaotic (giving different PMF shapes denoting different flow regimes).
4. Flow regime identification using laboratory data does not differ significantly from field data experience.
5. Replacing an existing test separator with a single multiphase flowmeter is economically viable.
6. The current capital expenditure for multiphase flowmeters does not economically support installation on a per well basis.

5.2 RECOMMENDATIONS

The following recommendations are made for further research studies.

1. Field assessment of the flow regime identification capability of Gamma Ray multiphase flowmeters on horizontal flow.
2. Assessment of the impact of bean size on gamma ray multiphase flowmeter performance.
3. Evaluation of the economic viability of per well multiphase flowmeter installation at the development stage of an oil field.

5.3 CONTRIBUTIONS TO KNOWLEDGE

The following are possible contributions of this study to knowledge:

1. The result from this work can be used in the industry to enhance the acceptability of gamma-based multiphase flowmeters to both operators and regulators.
2. The result from this study would aid managers in the oil and gas industry in deciding on eliminating test separators in oilfield production especially in offshore operations where space is at a premium and weight savings is much desired.
3. The result of this work can serve as a bridge to the yawning gap between laboratory-based study and field-based experience on the performance of gamma-based multiphase flow metering.

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NOMENCLATURE

API – American Petroleum Institute

CAPEX – Capital Expenditure

GOR – Gas Oil Ratio

GUM – Guide for expressing Uncertainty Measurement

GVF – Gas Volume Fraction

LVF – Liquid Volume Fraction (Liquid Holdup)

MPFM – Multiphase Flowmeter

NaI – Sodium Iodide

NEL – National Engineering Laboratory, Scotland, UK.

NPV – Net Present Value

OPEX – Operating Expenditure

PLC – Programmable Logical Controller

PMF – Probability Mass Function

TC – Total Cost

TS – Test Separator

WC – Water Cut

Wt – Wall thickness

APPENDICES

APPENDIX A

Table 4.1: Gamma Count and Probability for Bubbly Flow

Soft Gamma Count	Probability
450	0.000068
469	0.000652
486	0.002432
494	0.003921
500	0.005616
507	0.007972
513	0.010204
519	0.012270
525	0.014296
538	0.016157
548	0.014674
554	0.012817
561	0.010382
566	0.008030
571	0.006131
577	0.004151
585	0.002088
595	0.000893
605	0.000317
611	0.000154

Source: Field Data (2019)

APPENDIX B

Table 4.2: Gamma Count and Probability for Slug Flow

Soft Gamma Count	**Probability**
351	0.000012
401	0.000061
450	0.000572
484	0.002811
500	0.004864
512	0.006225
526	0.006964
540	0.006204
558	0.004984
573	0.006207
581	0.007891
596	0.009644
609	0.007893
616	0.006164
622	0.004574
628	0.003053
636	0.001532
647	0.000403
659	0.000035
675	0.000010

Source: Field Data (2019)

APPENDIX C

Table 4.3: Gamma Count and Probability for Churn Flow

Soft Gamma Count	Probability
339	0.000068
358	0.000399
376	0.000563
396	0.000395
411	0.000326
431	0.000457
464	0.000852
504	0.002078
529	0.002806
548	0.003336
560	0.004764
574	0.009383
583	0.012939
589	0.014900
595	0.015697
599	0.014965
606	0.013103
614	0.009345
622	0.005256
635	0.001565
644	0.000533
653	0.000100

Source: Field Data (2019)

APPENDIX D

Table 4.4: Gamma Count and Probability for Annular Flow

Soft Gamma Count	Probability
350	0.000053
400	0.000317
426	0.000408
450	0.000706
500	0.001470
526	0.002061
550	0.003734
562	0.005362
573	0.007157
580	0.009826
585	0.011702
593	0.014162
601	0.015331
608	0.014250
615	0.011669
623	0.008254
633	0.004382
642	0.001634
655	0.000388
670	0.000134

Source: Field Data (2019)

APPENDIX E

Table 4.5: Gamma Count and Probability for Bubbly-Slug Transition

Soft Gamma Count	Probability
433	0.000023
456	0.000283
472	0.000894
485	0.002043
499	0.004107
506	0.005513
517	0.007694
528	0.009453
539	0.009992
551	0.009173
560	0.008189
570	0.007745
586	0.008074
598	0.007161
608	0.005310
618	0.002991
631	0.001211
641	0.000415
657	0.000041

Source: Field Data (2019)

APPENDIX F

Table 4.6: Gamma Count and Probability for Slug-Churn Transition

Soft Gamma Count	**Probability**
450	0.000008
479	0.000580
504	0.002626
523	0.005357
548	0.007512
560	0.008913
571	0.010782
586	0.012543
597	0.010958
606	0.008115
617	0.004265
627	0.001781
639	0.000485
653	0.000021

Source: Field Data (2019)