TECHNICAL UNIVERSITY OF CRETE

SCHOOL OF MINERAL RESOURCES ENGINEERING

PETROLEUM ENGINEERING MASTER COURSE

In – Line Measurements of Oil/Gas Production Fluids

Master Thesis

Dimitris Lianos

Supervisor: Professor Nikos Pasadakis and Scientific Advisor: Dr. Dimitris Marinakis

MARCH 2021

CHANIA, CRETE

A thesis submitted in fulfillment of the requirements for the

Master degree of Petroleum Engineering in the

School of Mineral Resources Engineering

Technical University of Crete

The MSc Program in Petroleum Engineering of the Technical University of Crete,

was attended and completed by Mr. Dimitris Lianos, in the context of

the Hellenic Petroleum Group Scholarship award.

ACKNOWLEDGEMENTS

The present Master Thesis was prepared at the School of Mineral Resources Engineering of the Technical University of Crete under the supervision of Professor Nikos Pasadakis and Dr. Dimitris Marinakis. The current Master Thesis constitutes the completion of my studies in the field of Petroleum Engineering and hence, I would like to thank the group of people who supported me in this endeavor. Specifically, I would like to express my thanks to my supervisor, Professor Nikos Pasadakis, Petroleum Engineering MSc Course coordinator, for the opportunity he gave me to participate in this specific postgraduate programme as well as my scientific advisor Dr. Dimitris Marinakis, Laboratory Teaching Staff, who supported me during my postgraduate studies and completion of the Master Thesis. Finally, I would like to thank my family and my friends for their support, understanding and encouragement during my postgraduate studies and completion of the present Master Thesis.

ABSTRACT

In the current Master Thesis, the in – line measurements of oil/gas production fluids as well as the existing technologies and techniques are presented. Initially, the flow regimes, which define the operation principles of multiphase flow meters (MPFMs), are analyzed and then the in – line MPFMs, separation type meters, wet gas flow meters and other categories of MPFMs are described in detail. Afterwards, the performance of MPFMs is described, which defines the application of the multiphase flow measurement technologies and the selection the most suitable one. Furthermore, guidelines for designing MPFM installations are presented as well as the main characteristics of the operation of MPFMs such as cost, maintenance, footprint, radioactive source and calibration. Last but not least, MPFMs which are being sold in the market from different companies such as Agar Corporation, are presented as well as some very useful conclusions as far as the perspectives and the new trends of MPFM technologies are concerned.

ΠΕΡΙΛΗΨΗ

Στα πλαίσια της παρούσας Μεταπτυχιακής Εργασίας, παρουσιάζονται οι εντός ροής μετρήσεις των πολυφασικών ρευστών κατά την παραγωγή πετρελαίου και φυσικού αερίου καθώς και οι υπάρχουσες τεχνολογίες και τεχνικές. Αρχικά, αναλύονται τα είδη των καταστάσεων ροής, τα οποία καθορίζουν τις αρχές λειτουργίας των μετρητών πολυφασικής ροής (MPFMs), και στη συνέχεια περιγράφονται λεπτομερώς οι εντός ροής μετρητές πολυφασικής ροής, οι τρόποι μέτρησης της πολυφασικής ροής οι οποίοι βασίζονται στο διαχωρισμό, οι μετρητές ροής συμπυκνωμάτων φυσικού αερίου (wet gas) κι άλλες κατηγορίες μετρητών πολυφασικής ροής. Κατόπιν, περιγράφεται η απόδοση των μετρητών πολυφασικής ροής, η οποία καθορίζει την εφαρμογή αυτών των τεχνολογιών καθώς και την επιλογή της πιο κατάλληλης. Επιπλέον, παρουσιάζονται οδηγίες για το σχεδιασμό των αντίστοιχων εγκαταστάσεων καθώς και τα κύρια χαρακτηριστικά της λειτουργίας των μετρητών πολυφασικής ροής όπως το κόστος, η συντήρηση, ο όγκος του αντίστοιχου εξοπλισμού, οι ραδιενεργές πηγές που χρησιμοποιούνται κατά τη μέτρηση και η βαθμονόμηση. Τέλος, παρουσιάζονται κάποιοι μετρητές πολυφασικής ροής, οι οποίοι πωλούνται στην αγορά από διάφορες εταιρείες όπως η Agar, καθώς και μερικά πολύ χρήσιμα συμπεράσματα σχετικά με τις προοπτικές και τις νέες τεχνολογίες των μετρητών πολυφασικής ροής.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

INTRODUCTION

The aim of the present Master Thesis is the presentation of the in – line measurements of oil/gas production fluids and extent analysis of the existing technologies and techniques. In the hydrocarbon industry, it is essential that reliable and accurate measurements of the amount of oil, gas and water being produced by individual wells be carried out. Multiphase flow measurements are accomplished in the flowstreams of individual wells by the use of the respective meters. Nonetheless, their use is not always reliable or economical and hence, as an alternative technique to monitoring individual well performance in real – time, the Virtual Flow Metering (VFM) is proposed.

Initially, the individual stages of exploration and production of hydrocarbon reservoirs are analyzed very briefly and then the flow regimes, that may prevail within the production pipes depending on their liquid and gas phase content, are described. These flow regimes define the operation principles of the multiphase flow meters (MPFMs). MPFMs are implemented for single well monitoring, production optimization, flow assurance, well testing, production allocation metering and fiscal or custody transfer measurements. MPFMs are categorized in in – line meters, separation type meters, wet gas flow meters and other categories. In – line MPFMs, which are the main object of the present Master Thesis, are consisted of the electromagnetic meters (capacitance, conductance and microwave technology), gamma – ray densitometry or spectroscopy, neutron interrogation, differential pressure using orifice plate, Venturi meter and V – cone meter, positive displacement, Coriolis mass flow meter, cross – correlation flow meter, ultrasonic meters, turbine flow meter, tracer techniques and thermal mass flow meters.

In the next section, the separation type meters (full two – phase gas/liquid separation, partial separation and separation in sample line), wet gas flow meters and other categories of MPFMs are described briefly as well as VFMs, which are the new trend in multiphase flow metering. Afterwards, the performance of MPFMs is described because it is a key element in the assessment of whether multiphase flow measurement technologies can be applied in a specific application and it is also a basis for selecting the most suitable technology. Furthermore, guidelines for designing MPFM installations are presented as well as the main characteristics of the operation of MPFMs.

Finally, MPFMs, which are being sold in the market from different companies, are presented as well as some very useful conclusions regarding with the perspectives and new trends of MPFM technologies.

CHAPTER 1

1.1 The History of Hydrocarbons

Hydrocarbons have been used in a variety of ways for hundreds of years. Firstly, there were areas where hydrocarbons were found in shallow reservoirs and as a result they were naturally developed, fact that made their collection easy. According to Herodotus and Diodorus Siculus, asphalt was used in the construction of Babylon buildings and there are also written sources which describe that ancient Persians and Chinese used oil and natural gas for medicine, lighting and boiling water. At 1859 A.D., Edwin Drake managed to achieve his main goal which was to drill the first successful well in order to find oil. Since then, the hydrocarbon industry has been continuously developing and contributing to global growth. [1]

Figure 1: A Pennsylvania oil field in 1862
Source: https://en.wikipedia.org/wiki/Pennsylvania_oil_rush#/media/File:Earlyoilfield.jpg

1.2 The Main Sectors of the Hydrocarbon Industry

The main sectors of hydrocarbon industry are defined, according to their use during the production process:

- **Exploration**, which refers to the prospecting, seismic and drilling activities which are carried out in order the existence and the possibility of exploitation of the hydrocarbon reservoir to be determined.
- **Upstream**, which refers to the process through which oil and natural gas are produced. This sector consists of the drilling of producing wells and more exploratory wells which bring the reservoir fluids to the surface and contribute to the even more exploration of the hydrocarbon field respectively. [1]

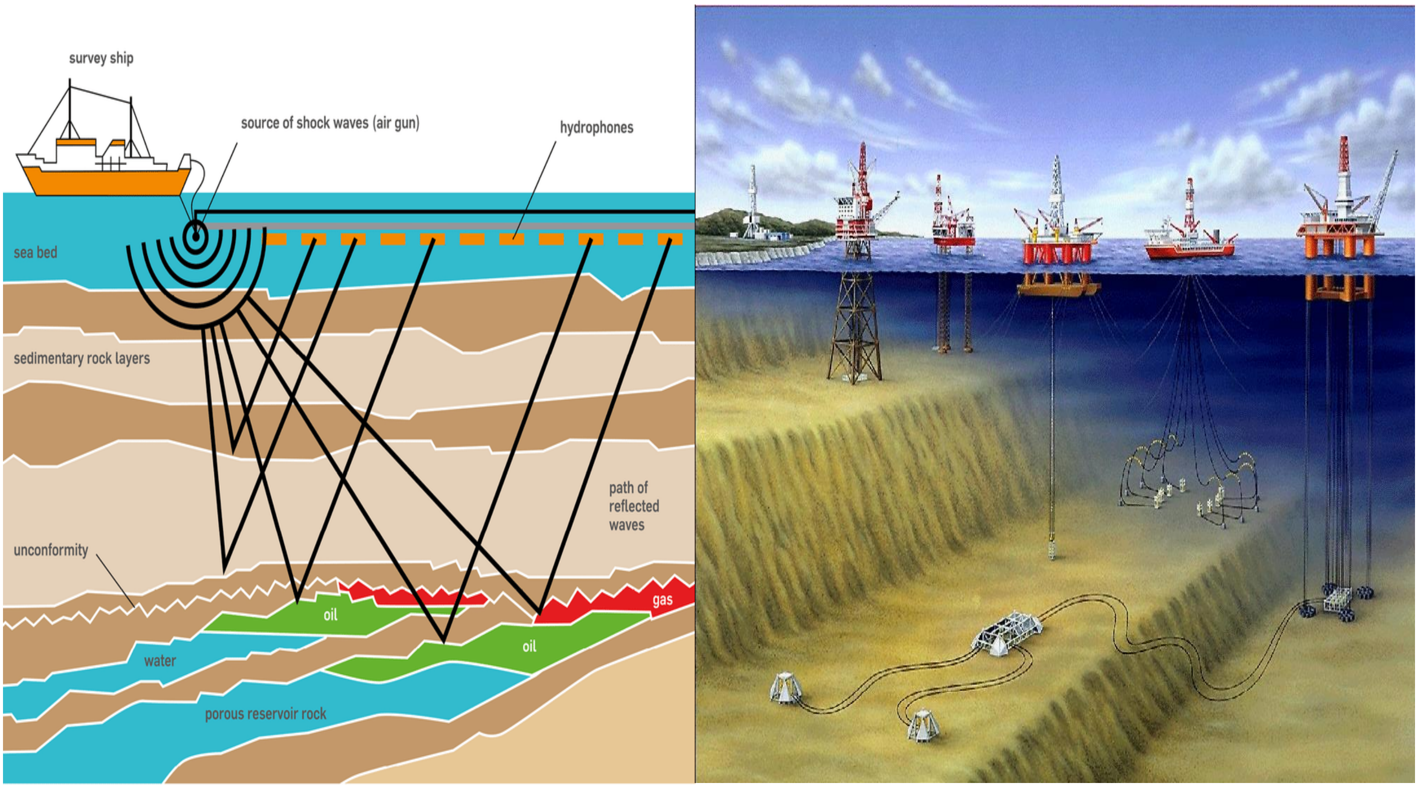


Figure 2: The Exploration and Upstream Processes
Sources: https://www.researchgate.net/figure/Offshore-seismic-survey_fig1_320561682
https://gr.pinterest.com/pin/289285976035456966/

❖ **Midstream**, which refers to the intermediate process at which the produced hydrocarbons are transported to the refineries. This sector mainly consists of storage, transportation by pipelines or tanker vessels and trading. [1]

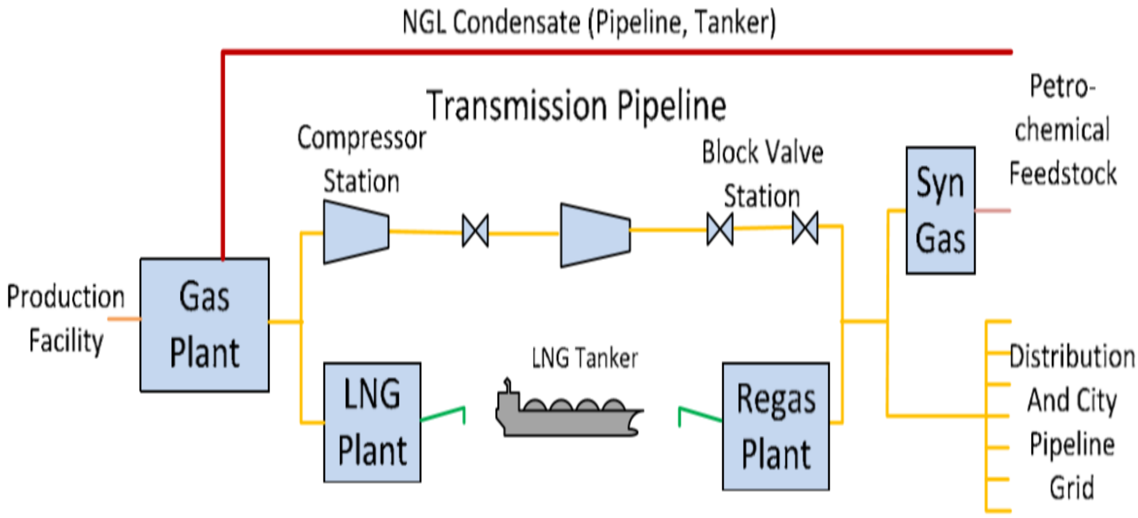


Figure 3: The Midstream Process [1]

❖ **Downstream**, which refers to the process at which the processed oil and natural gas reach the final consumers either directly or indirectly through the abundance of processed products. [1]

Figure 4: The Downstream Process
Source: https://www.financebrokerage.com/refineries-in-japan-will-resume-operations-after-typhoon-hagibis/

1.3 The Hydrocarbon Reservoir

The reservoir is defined as the concentration of hydrocarbons in porous, permeable and sedimentary rocks. It is surrounded by impenetrable rock, the cap – rock, and usually from an aquifer. An oil field can consist of several reservoirs, which are either in different pressure conditions or in different stratigraphic horizons. The geological environment for the accumulation of hydrocarbons is called sedimentary basin which provides the conditions for the creation of oil and gas concentration, in particular:

- the source of hydrocarbons
- the formation and migration of hydrocarbons
- the hydrocarbon trapping mechanism, i.e. the existence of geological structures in porous sedimentary rocks in time but also in its path of hydrocarbon migration

The hydrocarbons come from the anaerobic degradation of lipids, proteins and carbohydrates, which are coming from marine and terrestrial plants and animals, as well as from plankton and algae. This process requires rapid sedimentation in water with organic material, which leads to the accumulation of clay, rich in organic matter in anaerobic environment. However, the formation of oil and gas presupposes the "maturation" of this clay in the effect of pressure and temperature. A temperature ranges from 140^{o}F to 300^{o}F, which can be related to depth and time, seems to be optimum for the formation of the hydrocarbon mixture which is classified as "oils". Extensive exposure to high temperatures or shorter exposure to very high temperatures can progressively lead to the formation of gas condensates, wet gas or dry gas. The first stage of migration, from source rock to one more porous neighboring environment, is called primary migration. The next stage, in the porous environment at higher topographic points, via faults, until trapped, is called secondary migration. [1]

There are two main types of geological structures, the so called traps, where hydrocarbons can be trapped and create a concentration of interest, which are the tectonic one, which is most often encountered, and the stratigraphic one. The tectonics traps are mainly classified into anticlines, faults and salt domes. The stratigraphic traps are divided into the primary one, which are created by the deposition of lenticular permeable layers in impermeable sediments, and into the diagenetic one, which are arising during the diagenesis stage from the lateral change of permeability within the same sedimentary horizon. [2]

Impermeable rocks provide a cap rock above and below the permeable reservoir rock. The density difference between water, oil and gas creates, in equilibrium conditions, boundary contact areas of fluids known as contacts, for instance gas – oil and oil – water contact. [2]

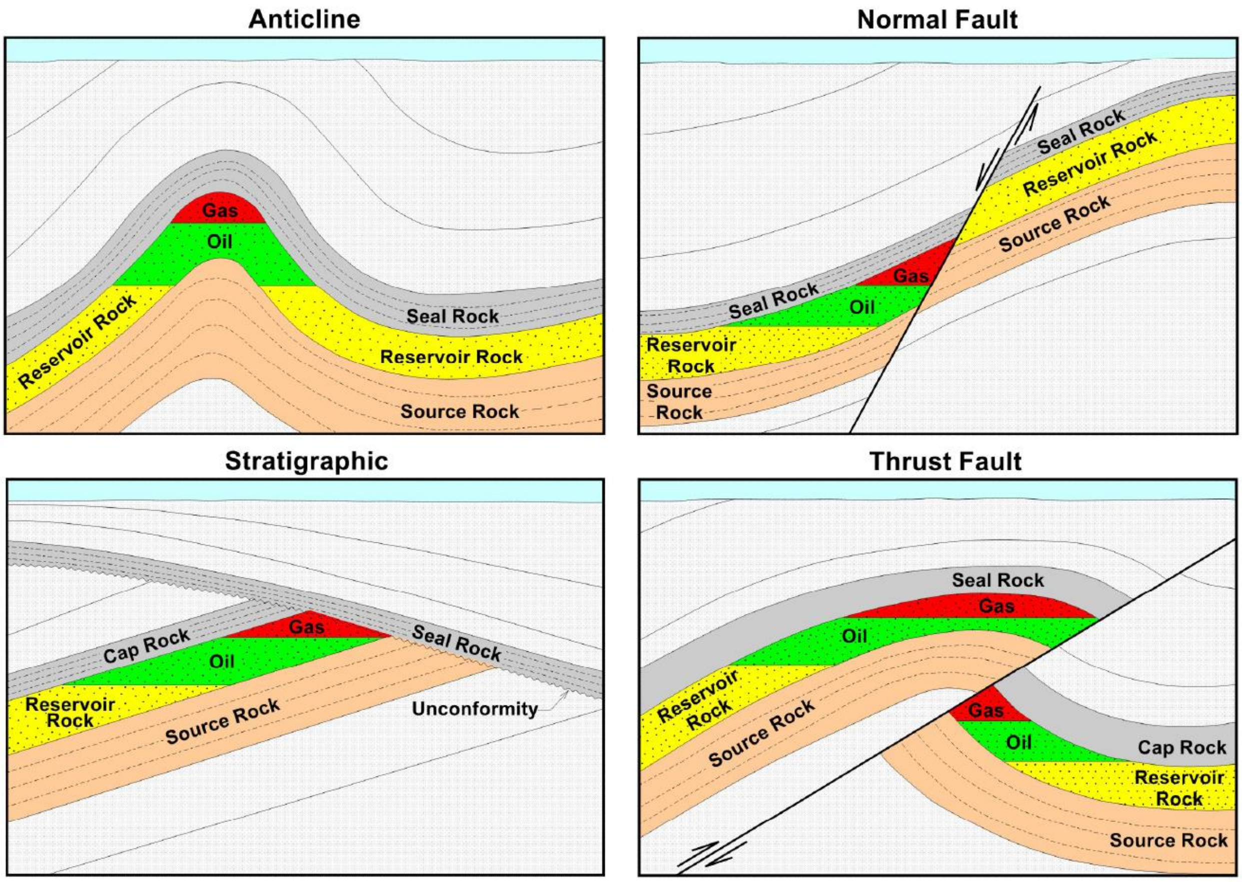


Figure 5: Common Types of Hydrocarbon Traps
Source: http://energy-alaska.wikidot.com/natural-gas-as-a-resource

1.4 Drilling and Production of the Hydrocarbon Reservoir

The historic period of the hydrocarbon industry began in 1859 in the Titusville area of Pennsylvania, when oil first came out of a 69.5 feet deep well (~ 21 meters) in the shape of a jet. The drilling of the wells was based on a simple percussion system, which included a massive blade similar to a sculptural chisel which, through a heavy rod, was attached to the surface with a beam moving in the vertical direction. The break of the rock was made by the abrupt fall of the blade. The removal of the cuttings, which had to be done at regular intervals, followed approximately the following procedure, the well was filled with water and a muddy mixture which came from the water and the cuttings. A cylindrical tool, which was carrying a substandard valve to the one edge, was descending to the bottomhole and then it was filling the bottomhole with muddy mixture, the valve was closing and the tool was lifting to the surface. [2]

In 1900 Antony Lucas demonstrated the effectiveness of rotary drilling when he discovered the Spindeltop deposit in Texas. He was the first who combined the use of rotary drilling with the continuous mud injection. Since then the rotary drilling technology has gained enormous application worldwide and has incorporated significant technological advances. In rotary drilling, a cone bit is used to dig into the rock. Different cones are used for different types of rock and at different stages of the well. Very characteristic types of such cones are the roller cones with inserts and the Polycrystalline Diamond Compacts (PDC). The piercing of the rocks is carried out by the rotating of the cutters and the simultaneous applying pressure on them. A main advantage is the continuous circulation of the muddy fluid which is injected through the drill string and the cutters and as a result it brings the cuttings to the surface in order the cutting front (cutters – rock contact) to be continuously free from them. The fluid, which returns to the surface, follows a process of cleaning and reuse. [2]

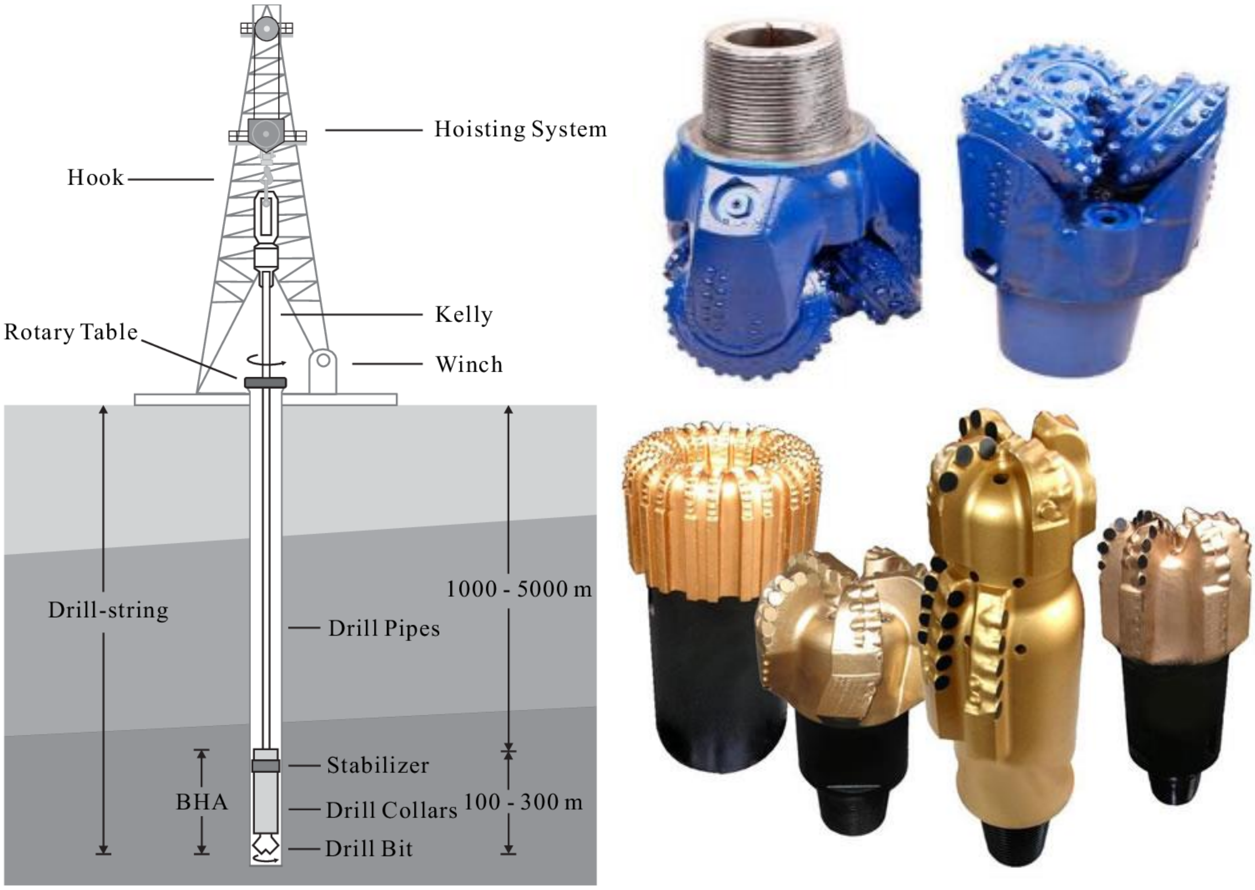


Figure 6: A Main Drilling Activity, Roller Cones and PDC
Sources: https://www.vippng.com/maxp/hTJmwbo/, http://www. geocoredrill.com/Polycrystalline-Diamond-Compact-Bits-products.html, https://www.indiamart.com/proddetail/tricone-rock-bit- 14919550488.html

After the drilling of the well, it must be completed. This process consists of a number of stages, such as:

- **Well Casing**, which consists of a series of metal tubes installed in the drilled hole and their purpose is to strengthen the sides of the well, ensure that no hydrocarbons will be seeping out during production, and keep other fluids from seeping into the formation through the well. There are five different types of well casing:
  - **Conductor Casing**, which is installed before main drilling to prevent the top of the well from caving in and to help in the circulation of the drilling fluids up from the bottom of the well. [1]

- **Surface Casing**, which is a conduit through which drilling fluids return to the surface and also protects the hole from damages which can be caused during drilling.
- **Intermediate Casing**, which is the longest section of casing found in a well and its main goal is to minimize the hazards associated with subsurface formations which can affect the well.
- **Production Casing**, which is the last and the deepest section of casing in a well. It provides a conduit from the surface of the well to the reservoir rock. Its size depends on some parameters such as the lifting equipment, the number of completions and the possibility of deepening the well at a later date. [1]

When the casing process is completed, tubing is inserted inside the casing, from the opening well at the top to the reservoir at the bottom. The hydrocarbons, which flow from the porous media of the reservoir rock to the wellbore, run up this tubing to the surface. At last two packers are placed between casing and tubing at the bottomhole in order the hydrocarbon fluids to flow to the surface only through the tubing. [1]

- **Completion**, which is the process of finishing the well in order to be ready to produce hydrocarbons. The six types of completions are the following:
  - **Open Hole Completions**
  - **Conventional Perforated Completions**
  - **Sand Exclusion Completions**
  - **Permanent Completions**
  - **Multiple Zone Completion**
  - **Drainhole Completions** [1]

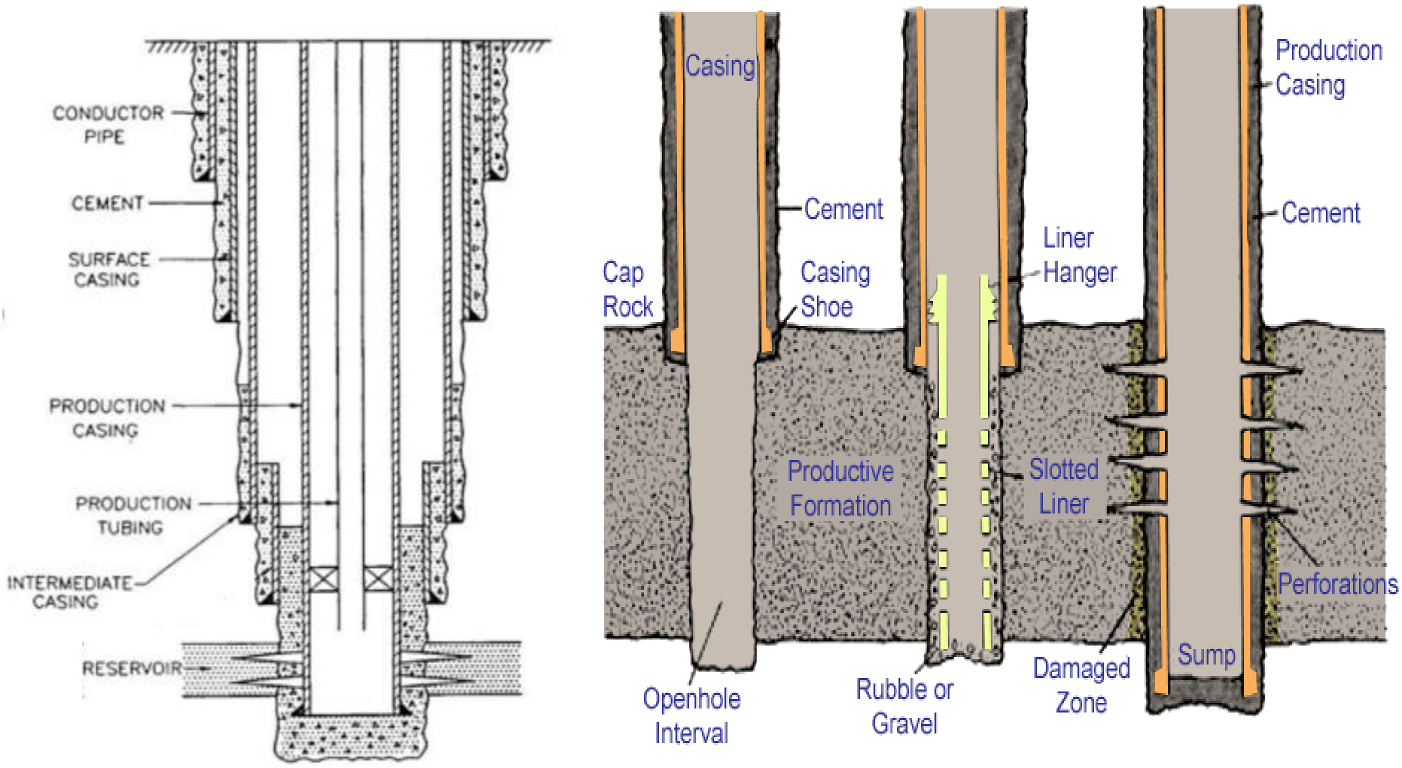


Figure 7: Well Casing and Three Types of Well Completions
Sources: https://www.slideshare.net/akincraig/petroleum-engineering-drilling-engineering-casing-design, http://hmf.enseeiht.fr/ travaux/ CD0910/ bei/beiep/4/html/index.html

- **Wellhead**, which can have dry or subsea completion. Dry completion can be found at the onshore wells or on the topside structure on an offshore installation. Subsea wellhead is located underwater on a special seabed template. The purpose of the wellhead equipment is to regulate and monitor the production of hydrocarbons from the reservoir. It also prevents hydrocarbons leaking out of the well and also the blowouts due to high pressure formations. The wellhead consists of, the casing head, the tubing head and the "Christmas Tree". [1]

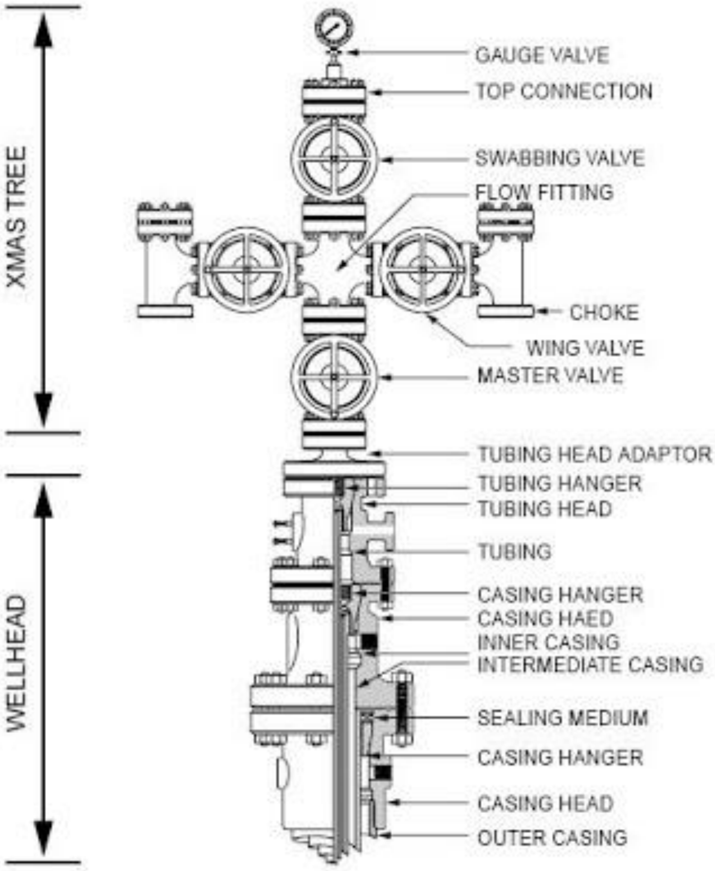


Figure 8: Wellhead and Christmas Tree
Source: http://www.ingenieriadepetroleo.com/christmas-tree-oil-wellhead/

- **Lifting Equipment**, is used when the production starts. When there is a big difference between the downhole and the reservoir pressure then the hydrocarbon fluids begin to flow from the porous media of the reservoir rock to the wellbore. Then the engineers should regulate the pressure at the wellhead in order to exist also a difference between the bottomhole and the wellhead pressure and as a result the hydrocarbon fluids, due to these two pressure differences, flow from the reservoir to the surface. If the formation pressure is too low and the aforementioned pressure differences cannot be achieved, then the well must be artificially lifted. Some types of artificial lift methods are:
  - **Rod Pumps**, are the most common artificial lift method used in onshore operations.
  - **Electrical Submersible Pumps**, are downhole pumps which insert the whole pumping mechanism into the well. [1]
  - **Gas Lift**, is a method at which gas is injected into the tubing in order to reduce the hydrostatic pressure of the fluid column. This bottomhole pressure reduction allows the reservoir fluids to flow in the wellbore with higher rate. [39]

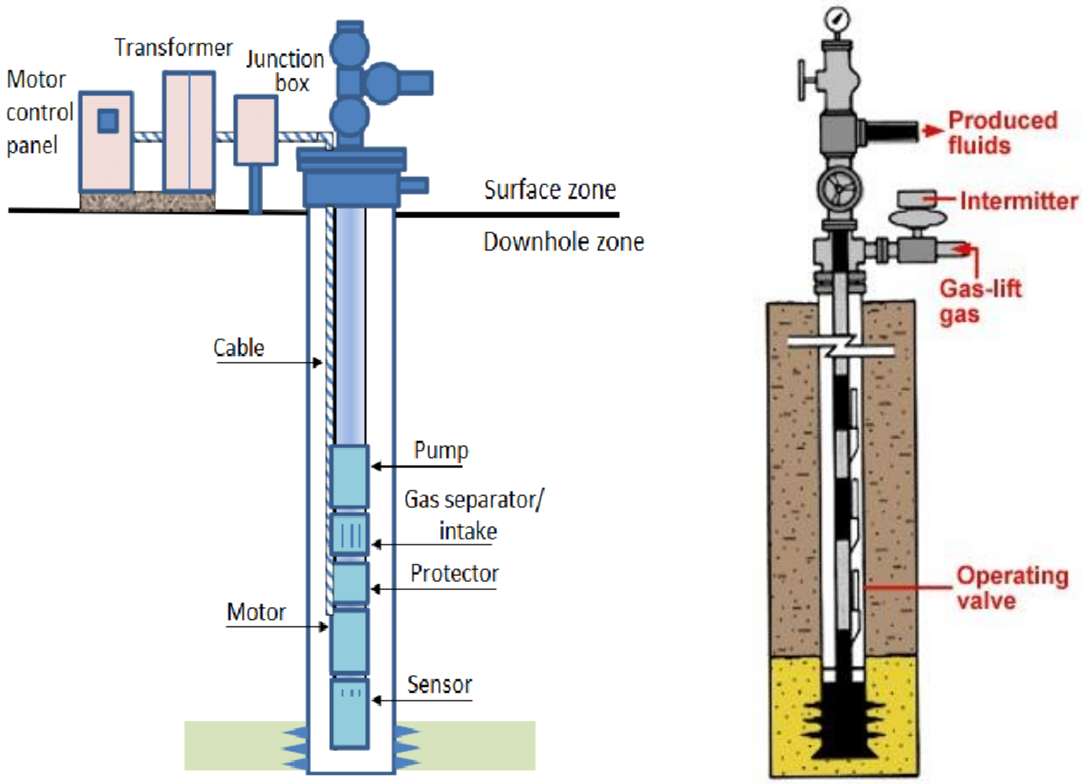
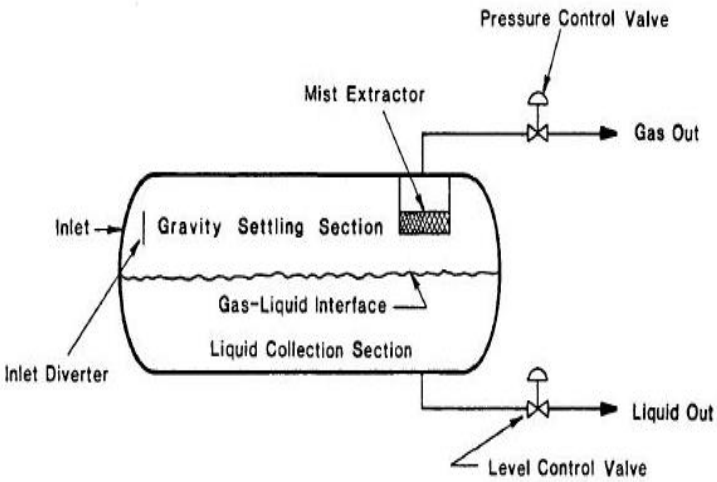


Figure 9: The Methods of Electrical Submersible Pump and Gas Lift
Sources: https://pet-oil.blogspot.com/2012_08_25_archive.html, https://www.researchgate.net/figure/Typical-Electrical-Submersible-Pump-system-and-main-components_fig1_336221251

- **Well Workover**, which purpose is to carry out a maintenance on the production well. This maintenance may include actions such as the replacement of the tubing, the installation of new completions and new perforations, the installation of gas lift mandrels and new packers.
- **Well Intervention**, is the process through which well maintenance and workover without killing the well are carried out and is time – saving. Wireline operations take place by lowering instruments or tools on a wire into the well.
- **Reservoir Stimulation**, consists of the processes of chemical injection, acid treatment and heating. These actions are carried out in order to correct various forms of structure damage and improve the hydrocarbon fluids flow. [1]
- **Separation**, is the final stage of the production process and is carried out through big vessels on the surface almost near the well which called separators. Separators have cylindrical or spherical shape and separate oil, gas and water from the total produced fluid stream. They can be either horizontal or vertical and are classified into two – phase (oil and gas) and three – phase (oil, gas and water) separators. [40]



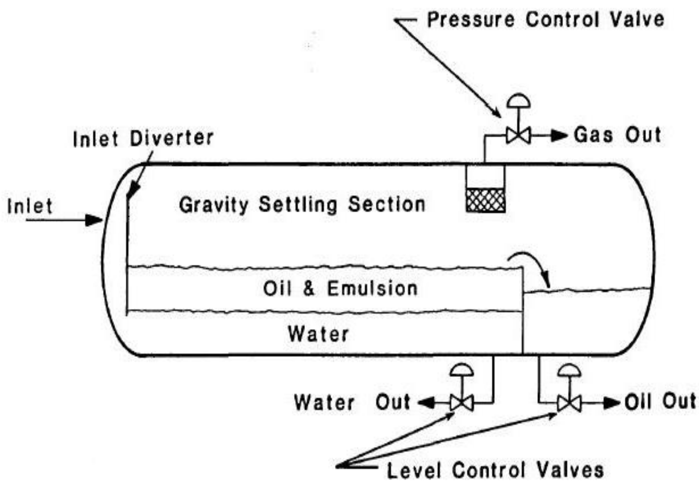


Figure 10: Two – Phase and Tree – Phase Separators
Sources: http://www.oilngasprocess.com/oil-handling-surfacefacilities/horizontal-two-phase-separator.html, http://www.oilngasprocess.com/oil-handling-surfacefacilities/horizontal-three-phase-separator-part-1.html

1.5 Hydrocarbon Flows in the Reservoir

The hydrocarbon flow in the reservoir porous media is a complex phenomenon and it is not the same with the fluid flow through pipes or conduits. Regarding pipes, when their length and diameter are measured then the capacity as a function of pressure can be computed in contrast with the reservoir porous media where there are no clear – cut flow paths which lend themselves to measurement. Through the time passing, the analysis of fluid flow in the porous media can be carried out into two ways, the experimental and the analytical one. A variety of correlations have been discovered which can be used in order to make analytical predictions. These mathematical correlations depend on the reservoir characteristics such as:

- Types of fluids in the reservoir
- Flow regimes
- Reservoir geometry
- Number of flowing fluids in the reservoir [3]

1.5.1 Types of Reservoir Fluids

There are three main types of reservoir fluids:

- **Incompressible Fluids**, whose volume and density do not change with pressure. There are not incompressible fluids but we assume that they exist in order the derivation and the final form of many flow equations in some cases to be simplified.
- **Slightly Compressible Fluids**, which exhibit small changes in volume and density, with changes in pressure. Crude oil and water systems fit into this category.
- **Compressible fluids**, which exhibit large changes in volume as a function of pressure. All gases are considered as compressible fluids. [3]

Compressibility is defined as the relative rate of change of volume as a function of pressure or temperature change. It is considered that isothermal pressure changes occur, so the compressibility is generally defined by the following correlation:

$$c = -\frac{1}{V} \cdot \left(\frac{\partial V}{\partial P} \right)_T$$

According to the following table we can distinguish that the compressibility of the gas is significantly higher than that of liquid hydrocarbons which in turn are more compressible than water of the reservoirs. [2]

Table 1: Typical Compressibilities of Various Systems [2]

System	Symbol	psi^{-1}
Reservoir Water Salinity	c_w	$3 * 10^{-6}$
Saturated Black Oils	c_o	$17 * 10^{-6}$
Natural Gas at 1500 psi	c_g	$689 * 10^{-6}$
Natural Gas at 5800 psi	c_g	$172 * 10^{-6}$

1.5.2 Flow Regimes in the Reservoir

There are basically three types of flow regimes which identify the fluid flow behavior and reservoir pressure distribution as a function of time and these are:

- **Steady – State Flow**, which means that the pressure at every location in the reservoir does not change with time. Mathematically, this condition is expressed as:

$$\left(\frac{\partial p}{\partial t} \right)_i = 0$$

  In hydrocarbon reservoirs, the steady – state flow conditions can only occur when the reservoir is completely recharged and supported by strong aquifer or pressure maintenance operations. [3]
- **Pseudosteady – State or Semisteady – State Flow**, prevails in the reservoir when the pressure at different locations is declining with a constant rate. Mathematically, this condition is expressed as: [3]

$$\left(\frac{\partial p}{\partial t} \right)_i = \text{constant}$$

- **Unsteady – State or Transient Flow**, which means that the rate of change of pressure with respect to time at any position in the reservoir is not zero or constant. So, the rate of pressure change with respect to time is a function of position (i) and time (t). Mathematically, this condition is expressed as: [3]

$$\left(\frac{\partial p}{\partial t}\right) = f(i,t)$$

1.5.3 The Geometry of the Reservoir

The geometry of the reservoir affects its flow behavior. The most reservoirs have irregular boundaries and a rigorous mathematical description of their geometry is carried out only by numerical simulators. For practical reasons, it is accepted that the actual flow geometry may be represented by the following flow geometries:

- ❖ **Radial Flow**, is prevailed when there is a severe heterogeneous reservoir and the fluids flow into or away from the wellbore follows radial flow lines from a substantial distance from the wellbore. [3]

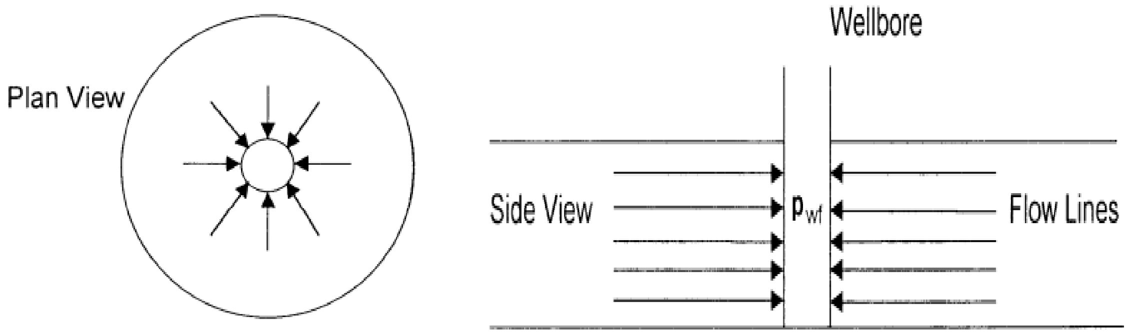


Figure 11: Radial Flow into the Wellbore [3]

- ❖ **Linear Flow**, happens when the flow paths are parallel and the fluids flow in a single direction. An application of the linear flow is the fluid flow into vertical hydraulic fractures. [3]

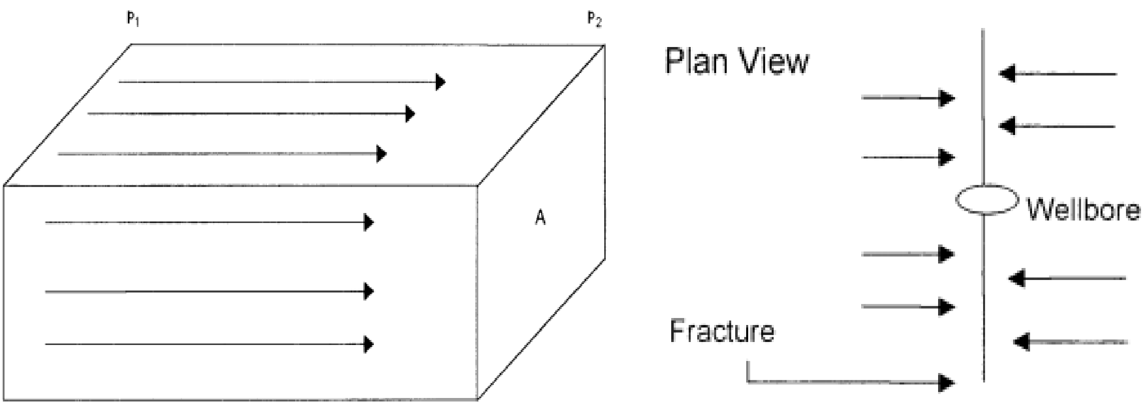


Figure 12: The Linear Flow and Linear Flow into Vertical Fracture [3]

- ❖ **Spherical and Hemispherical Flow**, which is possible to occur depending upon the type of wellbore completion configuration. This type of flow can also be occurred where coning of bottom water is important. [3]

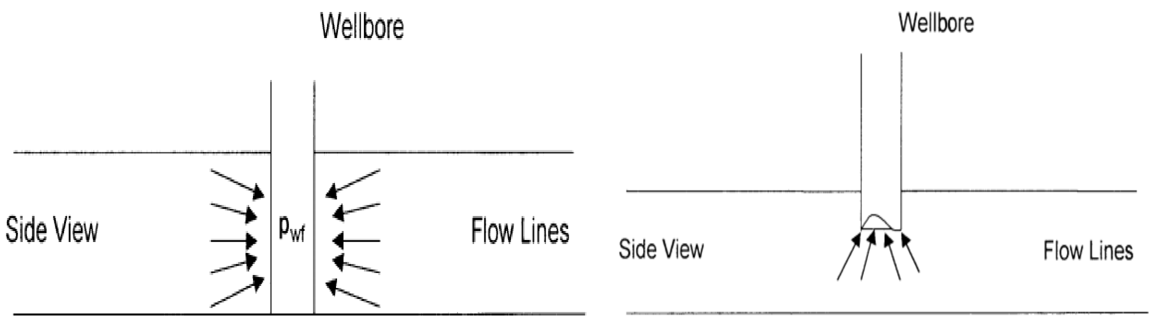


Figure 13: Spherical Flow due to Limited Entry and Hemispherical Flow in a Partially Penetrating Well [3]

1.5.4 Darcy's Law

The fluid flow equations which describe the flow behavior in a reservoir can take many forms depending upon the combination of variables such as, the type of flow and the types of fluids. By combining the conservation of mass equation with the Darcy's equation and various equations of state then the flow equations can be developed. The fundamental law of fluid flow in the reservoir porous media is Darcy's Law. This mathematical equation was developed by Henry Darcy in 1856 and states that the velocity of a homogeneous fluid in a porous medium is proportional to the pressure gradient and inversely proportional to the fluid viscosity. [3]

The general form of this equation is:

$$v = \frac{q}{A} = -\frac{k}{\mu}\frac{dp}{dx}$$

where: v the apparent velocity in cm/s

q the volumetric flow rate in cm^3/s

A total cross – sectional area of the rock in cm^2

μ the fluid viscosity in cP

dp/dx the pressure gradient in atm/cm

k the permeability of the rock in Darcy units

Darcy's Law is implemented when the following conditions are prevailed:

- Laminar or Viscous Flow
- Steady – State Flow
- Incompressible Fluids
- Homogeneous Formation

At higher velocities, turbulent flow is occurred and the pressure gradient is increased at a greater rate than does the flow rate, so a special modification of Darcy's equation is needed. Darcy's Law takes different forms depending on the type of flow and the properties of the reservoir fluids, an analysis which goes beyond the objectives of the present master thesis. [3]

1.5.5 Multiphase Flow

Multiphase flow is a complex phenomenon which is difficult to predict and model. The description of characteristics such as velocity profile, turbulence and boundary layer, is more difficult in multiphase flow than in single – phase flow. The fluid phases' distribution in the space and time is different for the various flow regimes and is usually not under the control of the engineers. [4]

The types of flow regimes depend on fluid properties, flow rates, operating conditions and the geometry of the pipe through which the fluids flow. The transition between different flow regimes may be a gradual process. The main mechanisms, which involve in the forming of the different flow regimes, are:

- **Transient Effects**, which occur due to changes in system boundary conditions. Operations such as opening and closing of valves cause transient conditions.
- **Geometry and Terrain Effects**, which occur due to changes in pipeline geometry or inclination. These effects can be important in and downstream of sea – lines and as a result the flow regimes, which are generated by this way, can prevail for several kilometers.
- **Hydrodynamic Effects**, which occur due to the absence of transient and geometry – terrain effects, the determination of the steady state flow regime by the flow rates, the fluid properties and the pipe diameter and inclination. These flow regimes are encountered at the horizontal straight pipes and at the wellhead location. [4]

As aforementioned the flow of a gas – liquid mixture could be more complex than for single phase flow. Each of the phases have individual properties such as density and viscosity which are a function of pressure and temperature and hence position in the well. Some types of multiphase flows are:

- Gas – Liquid Flow
- Liquid – Liquid Flow
- Gas – Liquid – Liquid Flow
- Gas – Liquid – Solid Flow
- Gas – Liquid – Liquid – Solid Flow [5]

1.5.5.1 Vertical Pipe Flow Regimes

In the production of a reservoir containing oil and gas in solution, it is preferable to maintain the flowing bottomhole pressure above the bubble point so that single – phase oil flows through the reservoir pore space. As the liquid moves up the production tubing, the pressure drops and gas bubbles begin to be formed. This flow regime where gas bubbles are dispersed in a continuous liquid medium is called **Bubble Flow**. As the fluid moves further up the tubing, the gas bubbles grow and become more numerous. The larger bubbles slip upward at a higher velocity than the smaller ones, because of the buoyancy effect. A stage is reached where these large bubbles extend across almost the entire diameter of the tubing. As a result, slugs of oil containing small bubbles are separated from each other by gas pockets that occupy the entire tubbing cross – section except for a film of oil moving relatively slowly along the tubing wall. This is called **Slug** or **Plug Flow**. [5]

Afterwards, the larger gas flowrates, which prevail, cause a more chaotic flow. The slug bubbles are distorted by forming longer narrow structures and hence, the flow adopts a random oscillatory nature. The liquid flow occurs mainly at the tubing wall but a significant proportion is vigorously mixed with the gaseous core. This is called **Churn Flow**. Still higher in the tubing, the gas pockets may have grown and expanded to such as extent that they are able to break through the more viscous oil slug. Gas forms a continuous phase near the center of the tubing carrying droplets of the oil up with it. Along the walls of the tubing there is an upward moving oil film. This is called **Annular Flow**. Continued decrease in pressure with resultant increase in gas volume results in a thinner and thinner oil film, until finally the film disappears and the flow regime becomes a continuous gas phase in which oil droplets are carried along with the gas. This is called **Mist Flow**. All these flow regimes will not occur simultaneously in a single tubing string, but frequently two or possibly three flow regimes may be present. [5], [6]

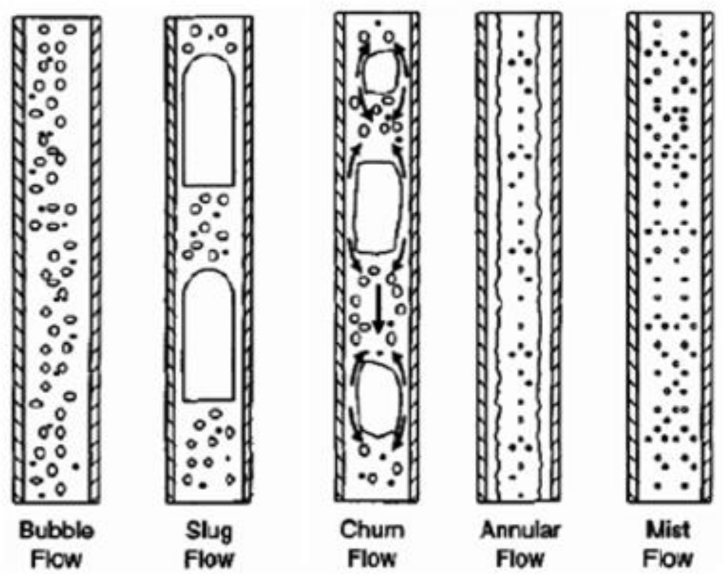


Figure 14: The Flow Regimes in a Vertical Pipe
Source: https://www.researchgate.net/figure/Two-phase-flow-regimes-in-vertical-pipe-9_fig9_254533540

The aforementioned flow regimes can be grouped into the following three types of flows:

- **Dispersed Flow**, which occurs when there is a uniform phase distribution in both the radial and axial directions. Such flows are the bubble and the mist flows.
- **Separated Flow**, which occurs when there is a non – continuous phase distribution in the radial direction and a continuous one in the axial direction. Such flow is the annular flow.
- **Intermittent Flow**, which occurs when there is a non – continuous phase distribution in the axial direction and therefore exhibits locally unsteady behavior. Such flows are the bubble, churn and slug flows. [4]

1.5.5.2 Horizontal Pipe Flow Regimes

Flow regime transitions take place also in horizontal tubing and are functions of parameters such as conduit diameter, interfacial tension and flowing phases' densities. The flow regimes, which are formed in horizontal pipes, are more complex than their vertical counterparts due to gravity induced asymmetries. The heavier phase (liquid) will be accumulated at the bottom of the conduit. The horizontal flow regimes are divided into six main categories:

- The **Bubbly Flow**, at which the gas phase exists as discrete bubbles within the liquid flowstream, which are tend to flow in the upper section of the conduit. Nonetheless, with larger gas flowrates, a uniform bubble distribution across the conduit cross – sectional area may be witnessed.
- The **Plug Flow**, at which the liquid flowrate reduction enables the gas bubbles to coalesce into larger bubbles or plugs, which will occupy the upper section of the pipe.
- The **Stratified Flow**, at which the further reductions to both the gas and liquid flowrates will result in phase stratification whereby the two phases flow separately with a relatively smooth interface. The liquid phase will occupy the conduit lower section due to gravity.
- The **Wavy Flow**, at which the increasing gas flowrate of a stratified system produces a less stable phase interface, fact that is caused by the increased turbulence. The interface between the liquid and gas phases will have irregular and wavy form, despite the fact that the good separation between the flowing phases is maintained.
- The **Slug Flow**, at which the increasing liquid flowrate produces waves of a much larger magnitude until the liquid is increased to such a point where the wave occupies the whole conduit cross – section. This facilitates the propagation of a high velocity fluid slug down the conduit.
- The **Annular** and **Mist Flow**, at which very high gas flowrates take place, so the liquid phase is forced to flow up the conduit wall as a liquid film while the gas flow in the center. The liquid film is thicker at the bottom of the conduit due to gravitational effects. [6]

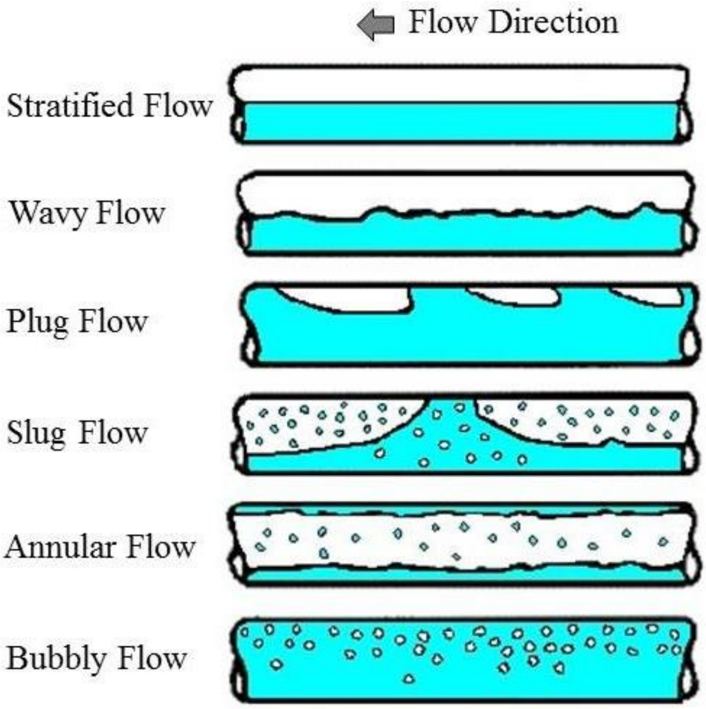


Figure 15: The Flow Regimes in a Horizontal Pipe
Source: https://www.researchgate.net/figure/REPRESENTATIVE-TWO-PHASE-FLOW-PATTERNS-IN-A-HORIZONTAL-PIPE_fig1_322395593

1.5.6 Multiphase Flow Regime Maps

As aforementioned the flow regimes are affected by physical parameters, such as the density of the fluids, viscosity and surface tension, and by the diameter of the flow line. The multiphase flow regimes do not have sharp boundaries, therefor they change smoothly from one regime to another. Despite the fact that the bottomhole pressure may reach the bubble point pressure, the gradual pressure drop, as the reservoir fluids flow from the bottomhole through the tubing up to the surface, results in an increasing amount of gas escaping from the oil. The following graphs depict how flow regime transitions depend on superficial gas and liquid velocities in vertical multiphase flow. Superficial velocities of liquid and gas are used on the axes of flow regime maps. For instance, the superficial gas velocity ($v_{s,\,gas}$) is the gas velocity as if the gas was flowing in the tubing without liquids or the total gas flowrate (Q) in m^3/s divided by the total cross – sectional area of the tubing (A). The case of liquid is the same with the previous one. [4]

$$v_{s,gas} = \frac{Q_{gas}}{A} \quad and \quad v_{s,liquid} = \frac{Q_{liquid}}{A}$$

The sum of these two velocities gives the multiphase mixture velocity, which is:

$$v_m = v_{s,gas} + v_{s,liquid}$$

Nonetheless, the latter equation gives a derived velocity whose value is meaningful if the multiphase flow is homogeneous and slip free. When there is a vertical flow, then the superficial gas velocity will increase and the multiphase flow will change between all flow regimes such as bubble, slug, churn, annular and mist. [4]

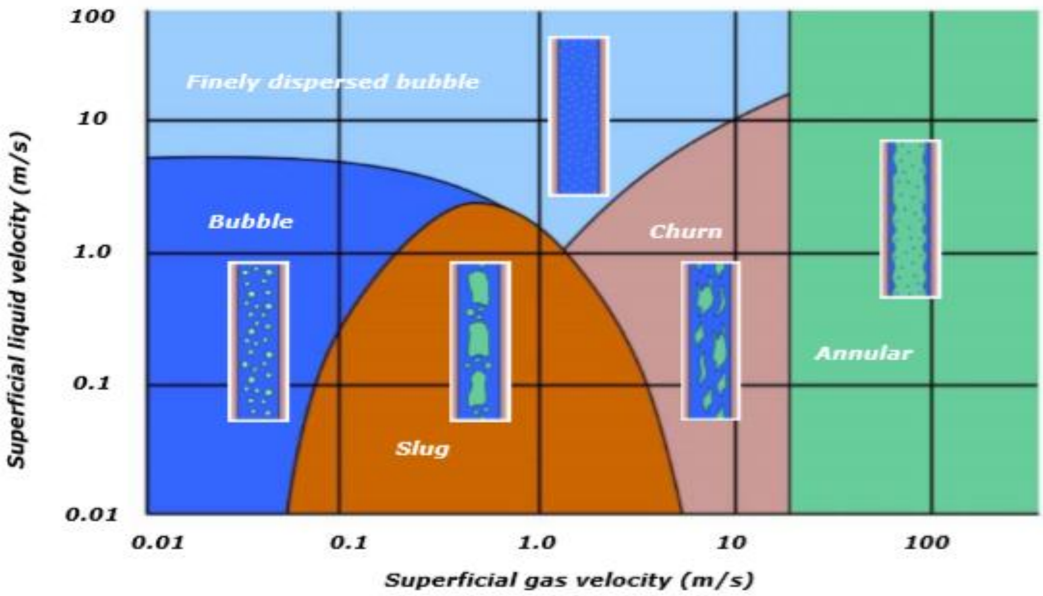


Figure 16: A Two – Phase Vertical Flow Map [4]

When there is a horizontal flow the phase transitions are functions of factors such as pipe diameter, interfacial tension and density. The following graph depicts how flow regime transitions depend on superficial gas and liquid velocities in horizontal multiphase flow. [4]

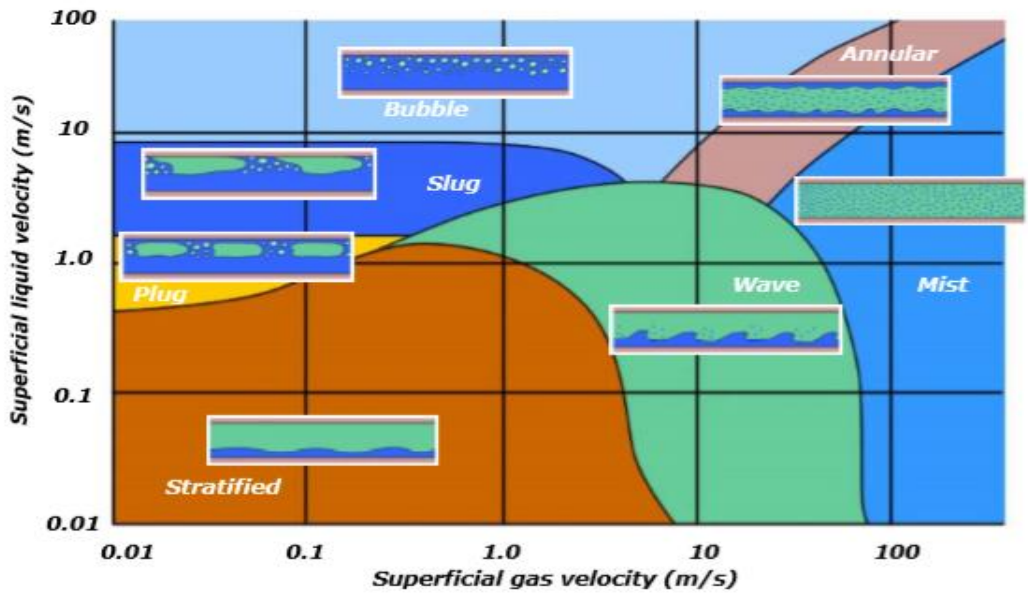


Figure 17: A Two – Phase Horizontal Flow Map [4]

1.5.7 Slip Effects during the Flow

When the fluids flow through the production tubing, the cross sectional area, which is covered by the liquid phase, will be greater than under non – flowing conditions. This occurs due to the effect of slip between liquid and gas. The gas phase, which is lighter than the liquid one, will move faster than the liquid phase, so the liquid will accumulate in horizontal and inclined tubing segments. The liquid and gas fraction, α_{liquid} and α_{gas}, of the tubing cross – sectional area (A), which are measured under two – phase flow conditions are called liquid hold – up and gas void fraction, λ_{liquid} and λ_{gas}. Due to slip effects, the liquid hold – up will be larger than the liquid volume fraction. Liquid hold – up is equal to the liquid volume fraction only under slip free conditions, when the homogeneous flow is prevailed and the liquid and gas phases travel at equal velocities.

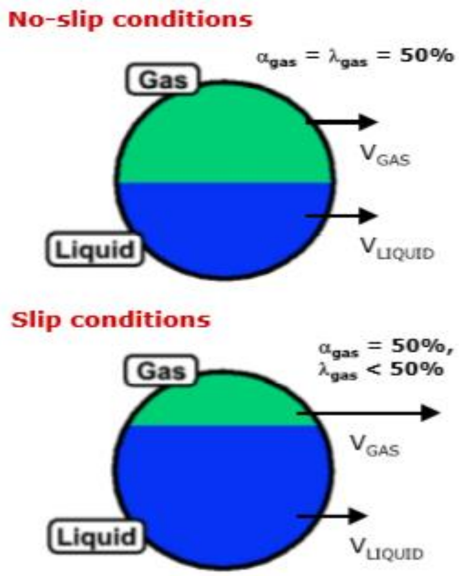
$$\lambda_{liquid} = \frac{A_{liquid}}{A_{pipe}}, Liquid\ Hold - up$$

$$\lambda_{gas} = \frac{A_{gas}}{A_{pipe}}, Gas\ void\ fraction$$

$$\lambda_{liquid} + \lambda_{gas} = 1$$

$$\alpha_{liquid} + \alpha_{gas} = 1$$

The gas void fraction is equal to the gas volume fraction and the liquid hold – up is equal to the liquid volume fraction only in no – slip conditions. Moreover, in the majority of flow regimes the liquid hold – up will be larger than the liquid volume fraction and the gas void fraction will be smaller than the gas volume fraction. Even more, the superficial gas and liquid velocities can be estimated from the liquid hold – up and the actual velocities. [4]



$$\lambda_{liquid} \geq \alpha_{liquid}\ and\ \lambda_{gas} \leq \alpha_{gas}$$

$$v_{s,gas} = \frac{Q_{gas}}{A_{pipe}} = \frac{Q_{gas}}{A_{gas}} \cdot \frac{A_{gas}}{A_{pipe}} = v_{gas} \cdot \lambda_{gas}$$

$$v_{s,liquid} = \frac{Q_{liquid}}{A_{pipe}} = \frac{Q_{liquid}}{A_{liquid}} \cdot \frac{A_{liquid}}{A_{pipe}} = v_{liquid} \cdot \lambda_{liquid}$$

Figure 18: Difference between Gas Void Fraction and Gas Volume Fraction [4]

1.5.8 Another Kind of Multiphase Flow Classification

Apart from the classification according to the flow pattern, multiphase flow can also be classified according to the Gas – Volume Fraction (GVF) of the flow. This classification method is described as the following:

- **Low GVF (0% - 25%)**, which is called 'gassy liquid'. In the lower end of this range traditional single – phase meters may in many cases provide the sufficient measurement performance. Moreover, as the GVF is increased, then the measurement uncertainty and malfunctioning risk are expected to be increased.
- **Moderate GVF (25% - 85%)**, which can be considered as the 'sweet spot' of multiphase meters, i.e. the range where they have their optimum performance and where at the same time traditional single – phase meters are not a viable option.
- **High GVF (85% - 95%)**, at which the multiphase meters' uncertainty starts to be increased, with a rapid increase towards the upper end of the range. This increase in uncertainty is not only linked to more complex flow patterns at high gas fraction, but also because the measurement uncertainty will increase as the relative proportion of the fraction of the component of highest value, in this case the oil, is decreased. Therefore, in some cases partial separation is utilized in order the GVF to be moved back into the Moderate range.
- **Very High GVF (95% - 100%)**, which is called 'wet gas' range. In the lower end of this range the measurement performance of in – line multiphase meters may still be sufficient for well testing, production optimization and flow assurance. For allocation metering, in particular at the high end of this range, often gas is the main 'value' component, and a wet gas meter would be the preferred option. This corresponds to a Lockhart – Martinelli value in the range from 0 to approximately 0.3. [4]

CHAPTER 2

2.1 Multiphase Flow Metering

The metering of a single – phase system requires the well stream phases to be fully separated upstream of the measurement point. Regarding the production metering the aforementioned requirement is automatically implemented at the outlet of the conventional process plant. This kind of plant receive all the well streams in the one end and delivers the stabilized single phases, which are ready for transport and measurement, in the other end. The metering of single – phase systems usually provide us with high – performance measurements of hydrocarbon production. The multiphase flow metering (MPFM) is essential to be carried out when the engineers want to meter the well stream upstream of inlet separation. The MPFM technology can be an alternative way, because it enables the measurement of unprocessed well streams very close to the production well. Such measurements can decrease the initial cost of the installation. Nevertheless, such measurements have a significant uncertainty, so it is necessary a cost – benefit analysis to be carried out over the project life cycle in order its application to be justified. The MPFMs give to the engineers the opportunity to monitor continuously the well performance and increase the hydrocarbon production. Nonetheless, this technology is complex, which means that there are limitations when it is to be implemented. [4], [7]

A limitation of the MPFM technology is the measurement uncertainty. The main reason, why the MPFM uncertainties are higher than the single – phase ones, is the fact that they measure unprocessed and far more complex flows. A second limitation is the possibility to extract representative samples of the reservoir fluids. Although the fluid samples are easily collected from the single – phase outlets of a test separator, there is no simple method for multiphase fluid sampling available yet. The most MPFMs need a priori information about the properties being measured, such as density, oil permittivity, conductivity and salinity of water. This information must be available and updated on a regular basis. [4]

There are many different MPFMs on the market, which employ a great diversity of measurement principles and solutions. Hence, a careful comparison and selection process is required in order the optimal MPFM installation for each specific application to be worked out. In order for the optimal MPFM technology to be selected for a specific application, one must first define the expected flow regimes and the phase envelope of the production fluid from the wells. Afterwards, the type of MPFMs, which corresponds to such envelope, should be investigated. The next stage in the selection of a MPFM, is the required uncertainties of the fluid flows. The well stream flowrate varies over time and hence, it should be ensured that the MPFM will measure within the required uncertainty at all times. Alternatively, the MPFM may have to be replaced at some later stage in the production life. The MPFM installation is also an important factor which must include adequate auxiliary test facilities, which allow calibration and verification during measurement process in order the measurement confidence to be ensured. [4]

Main MPFM applications are categorized in the following general types:

- Single well surveillance or monitoring
    - Production optimization
    - Flow assurance
- Well testing
- Production allocation metering
- Fiscal or custody transfer measurements

2.1.1 Single Well Surveillance or Monitoring

When a MPFM is utilized for continuous monitoring, then the time resolution of the information is higher compared with random well testing with a test separator. Hence, the total uncertainty in well data may be reduced, even if the instantaneous flowrates of the flowing phases are measured with increased uncertainty, while changes in performance between tests are not recorded by separators. Moreover, access to continuous high – resolution data from a MPFM may be a valuable resource in various decision processes, such as in connection with well overhauls. The installation a new MPFM can save space, weight and cost compared to the installation of a new test separator, fact that can reduce the time occupation of existing test separators. [4]

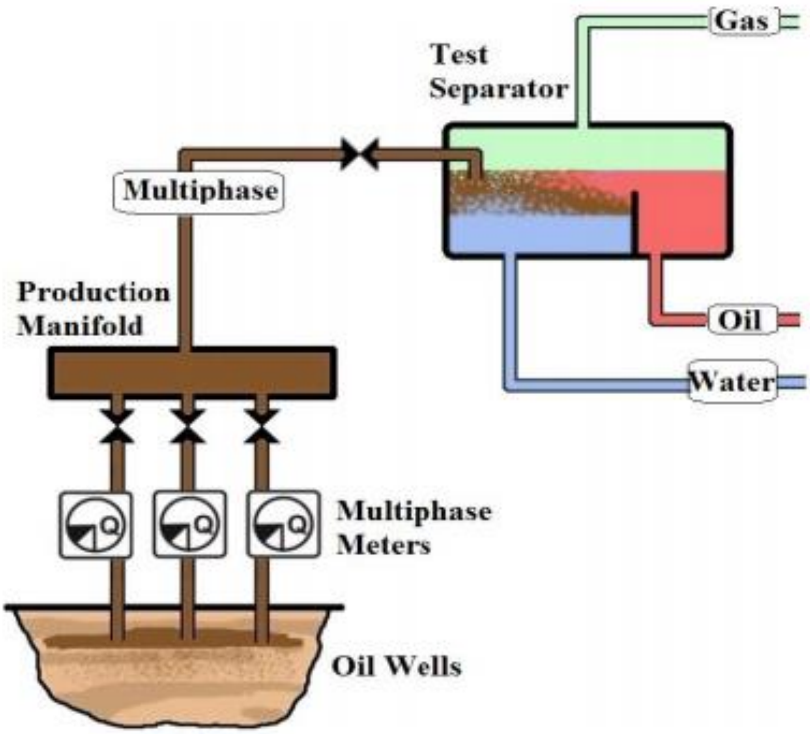


Figure 19: Multiphase Flow Meters on the Flow Line of Each Well [4]

Well instability is a well – known problem during decline of production and in many cases it is not acceptable that the well is connected to the production installation before some degree of control has been achieved. Flowrate variations may be difficult to be detected from unstable wells by utilizing conventional separators and as a result, MPFMs are a useful tool in such cases. MPFMs may be considered as a useful or even an integral part of subsea installations. When there are subsea commingling and/or long flow lines, MPFM technology can be utilized for flowrate monitoring from individual wells or flow lines. Nevertheless, the retrieval of a MPFM for maintenance or repair may be expensive, difficult or impossible. Reliability and stability of subsea MPFMs is of paramount importance and needs to be addressed by the MPFM manufacturer, the subsea system integrator and the operator. [4]

2.1.1.1 Production Optimization

Oil production may be assisted by gas lift. Once gas lifting has been implemented, then the optimization of this process is required due to the fact that gas lift is economical and there is also a clear optimum for the amount of gas to be utilized in order the oil production to be maximized. MPFMs can help in finding the optimum gas injection rate, as they are also capable of instantaneously showing the oil flowrate as function of injection gas flowrate. In contrast with the conventional test separators, which need more time in order to provide the same information. Nonetheless, most gas lift operations are relatively high GVF applications, due to the continuously add even more gas into the system, and it should be taken into consideration if the MPFM technology is capable of handling high GVF operation. Therefore, a wet gas meter might also be utilized. Other similar optimization considerations can be made for chemical injection, gas coning detection and water breakthrough detection. [4]

2.1.1.2 Flow Assurance

Flow assurance is consisted of all aspects that guarantee the hydrocarbon flow from reservoir to the sales or custody transfer point. At these processes, engineers and operation staff are working to evaluate and study the hydraulic, chemical and thermal behavior of produced multiphase fluids. When MPFMs carry out frequent measurements, then potential blockages in the production system may be identified quickly. Furthermore, the repeatability for an application of a flow assurance type is often more important than the absolute accuracy. [4]

2.1.2 Well Testing

In order the hydrocarbon production and field lifetime to be optimized, it is important the performance of each single well to be monitored. For instance, for most large North Sea's hydrocarbon fields important decisions are received depending on well – test results, which are received by the use of conventional test separators. Standard well testing is carried out by use of a test separator. A MPFM may be applied as a replacement for, or a supplement to, a test separator if:

a) it is decided not to install a test separator in the processing plant,
b) there is a need to increase the capacity for well testing, or
c) the test separator is occupied with other use.

Furthermore, the response time of a MPFM is significantly less (minutes) than that of a separator (hours) and more well tests may be carried out by utilizing a MPFM. [4]

2.1.2.1 Conventional Well Testing

Conventional well testing is usually performed by means of an extra separator dedicated for well test or special purposes. The well streams are measured by directing one well stream at the time through the test separator. The well stream being tested is then separated into three phases, oil, gas and water, which are then measured by means of single – phase instrumentation at the outlets of the separator. [4]

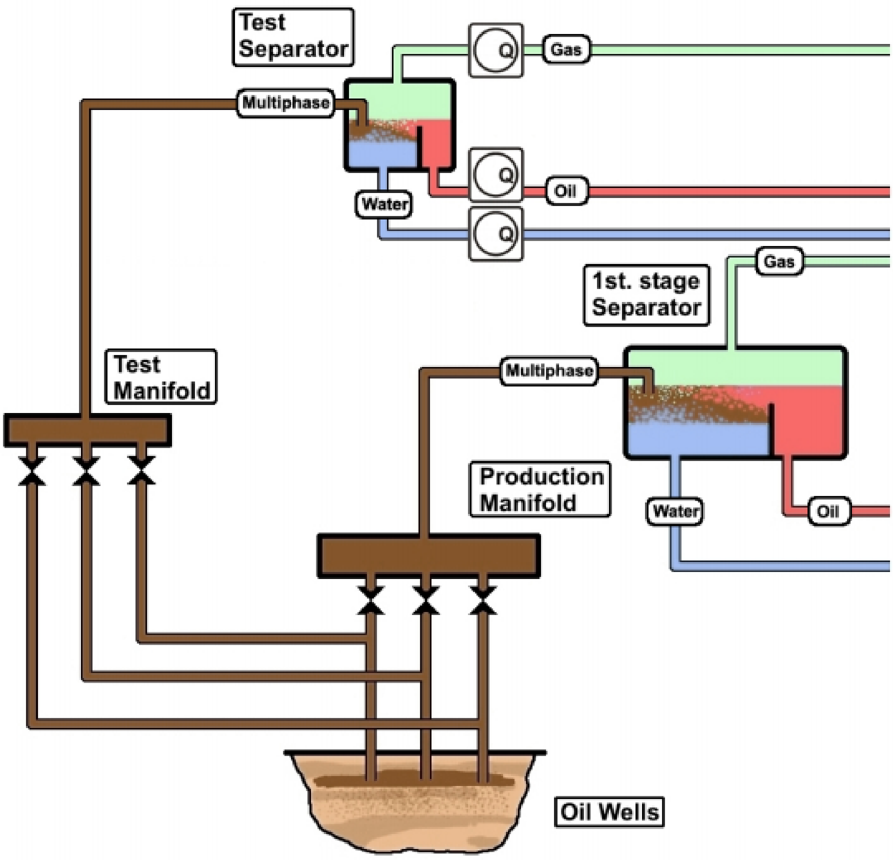


Figure 20: 1st – Stage Production Separator and Test Separator [4]

2.1.2.2 Well Testing by MPFMs

MPFMs may be installed and used in the same way as the test separator. When a MPFM and a test separator are both installed in a production system, they can provide an increased flexibility. Either test separator and MPFM can both be utilized for well testing in order the overall testing capacity to be increased, or only the MPFM, which means that the test separator will be utilized as a normal production separator, fact that will increase the total production capacity of the processing facility. The main advantage of the MPFM over the test separator is that it reduces the receiving time of a measurement. Moreover, separator must be allowed to fill and stabilize when changing wells for test, in contrast with MPFM which responds more quickly to changes in the well fluids and needs less time to stabilize. MPFM might also replace the test separator completely, fact that can be a solution for fields in the decline phase, where the production from the well does not match the size of the test separator any more. [4]

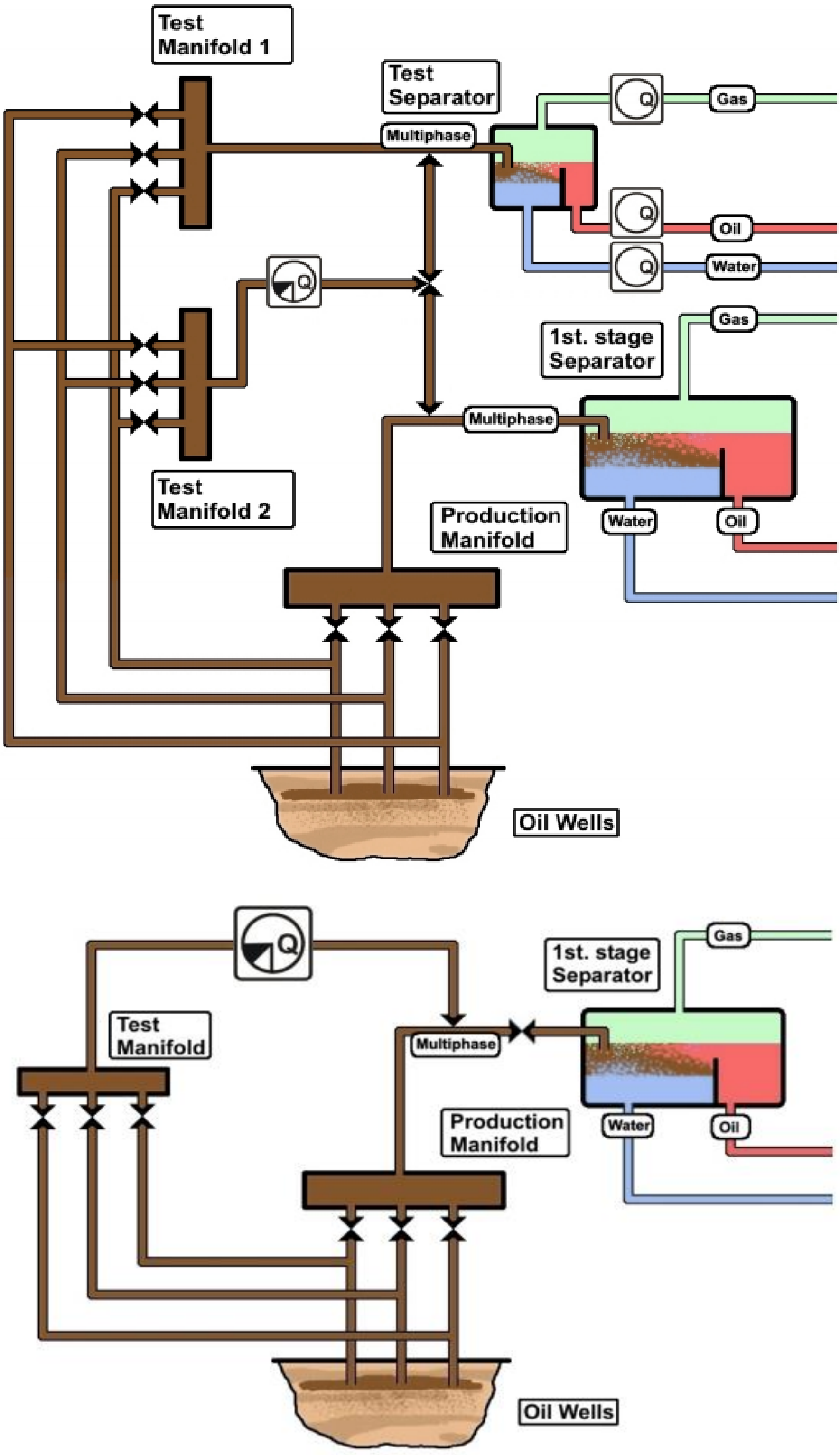


Figure 21: MPFM and Test Separator in Operation and only MPFM in Operation [4]

2.1.3 Production Allocation Metering

In the case of production allocation measurements, stricter requirements are usually imposed in terms of measurement uncertainty, calibration of instruments and representative fluid sampling than what is required for well testing. At this type of measurement, an unmanned wellhead platform can have MPFMs on each individual well for well surveillance and the main tie – in stream, into a manned installation, be measured by a MPFM that is frequently "proved" to provide k – factors by a test separator equipped with measurement equipment to a fiscal standard. Long proving periods should be utilized in order the uncertainties to be minimized, when accumulated oil, gas and water flowrates measured by the MPFM are compared to the separator measurements and in some cases proving should last for days. At this process the measurement of each well stream by means of MPFMs are replacing the conventional well testing and when the test separator is not used as a "prover" it can be used for other purposes or to "prove" other tie – in streams. Well testing and production metering from the wells in a satellite field can be done by means of MPFMs and this removes the need for a separate test line and manifold system for the satellite field. Assuming that a dedicated inlet separator would still be needed on the production platform, a typical multiphase production metering concept could be as it is depicted at the following figure. [4]

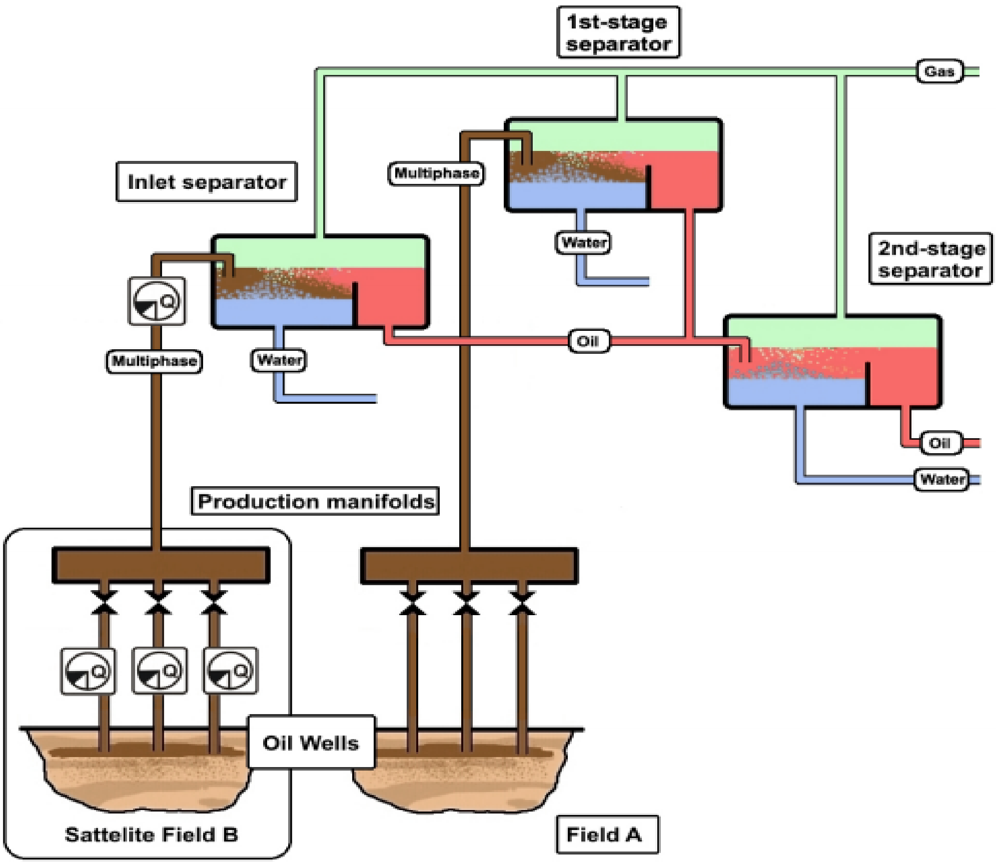


Figure 22: Satellite Field "B" with MPFMs for Well Testing and Production Metering [4]

2.1.4 Fiscal or Custody Transfer Measurement

When well streams from different production licenses are commingled into one single processing facility or flow line, it is normally necessary to meter the production from each license area separately before it enters the common processing facility or flow line. The production metering from each license area is used to allocate each field owner's ownership to the well streams at the outlet of the common processing facility. Consequently, national regulations or guidance notes for hydrocarbon measurements govern this production metering. Other optimization considerations can be made for chemical injection, gas lift optimization, gas coning detection, and water breakthrough detection. Fiscal or custody transfer measurements are the basis for money transfer, either between company and government or between two companies. Any systematic error in the measurement will result in a systematic error in the money flow. Hence, it is of paramount importance that sufficient verification processes are included. Furthermore, the classification fiscal or custody transfer does not specify any uncertainty requirement, but it just describes the purpose of the meter. The uncertainty needs to be further negotiated. For fiscal MPFMs it is required to follow the regulations and guidelines as set forward by the government authorities. [4]

2.1.5 Advantages and Disadvantages of MPFMs

The advantages of MPFMs are:

- ❖ Continuous monitoring or metering is possible.
- ❖ Installation and operating costs are low compared to those of a conventional system.
- ❖ Test separator, test lines, manifolds and valve systems are eliminated.
- ❖ Given the possibility of continuous metering, the total uncertainty will be lower than in a conventional system. [4]

The disadvantages of MPFMs are:

- ❖ MPFMs are complex instrument systems that require awareness of the personnel operating the meters in order to operate according to specifications.
- ❖ MPFMs may not be stable over time.
- ❖ MPFMs are sensitive to the physical properties of the phases to be measured.
- ❖ Verification is strongly recommended. For allocation metering systems periodic verification is normally required.
- ❖ There is no standard for multiphase fluid sampling. It is difficult, if at all possible in practice. [4]

2.2 Fundamentals of Multiphase Flow Measurements

When the engineers want to carry out multiphase flow measurements then they should know the flow rates of the three existing phases, oil, gas and water. A practical way to extract such data would be if a multiphase flow meter could carry out direct and independent flow rate measurements of the three existing fluid phases. However, such method has not been discovered yet. As a result, the development of the MPFM technology use inferential techniques, which, in order to implement such measurements, utilize the instantaneous velocity and cross sectional fraction of each phase. [8]

When a single – phase fluid flows through a pipe, with a cross – sectional area (A) and an average velocity (V), then the volumetric flow rate (Q) can be estimated by the following equation:

$$Q = A*V$$

When multiphase flow is prevailed in the same pipe then the situation is more complicated. When oil and gas travel simultaneously through the pipe, then they can be distributed to the aforementioned flow regimes which depend on the flow rates of the fluids and their properties and on the diameter of the pipe. An easy method to calculate the volumetric flow rate of each phase is the establishment of each phase distribution by accepting the assumption that each of the three phases is covering a fraction of the total cross – sectional area at any moment of the flow, which can be estimated by the following equations:

$$f_o = A_o/A_{tot},\ f_w=A_w/A_{tot},\ f_g = A_g/A_{tot} \Rightarrow f_o+f_w+f_g = 1$$

So, each phase and the total volumetric flow rate can be estimated by the following equations:

$$Q_o = A*f_o*V_o,\ Q_w = A*f_w*V_w,\ Q_g = A*f_g*V_g \Rightarrow Q_t = Q_o+Q_w+Q_g$$

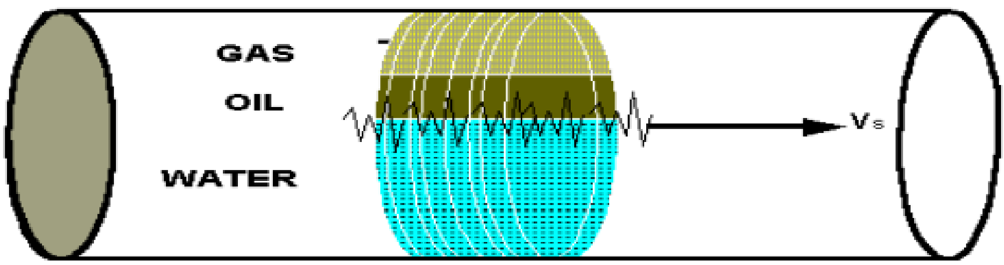


Figure 23: The Approximate Model of the Multiphase Flow in a Pipe [8]

The available MPFM systems use conventional three – phase separators to in – line multiphase meters which have a spool piece without separation. The main target of these systems is to accurate estimate the flowrates of the three phases. The fluid flow stream is scanned by the MPFM system at high frequencies and its purpose is to process the instantaneous each phase flow rate, and to sum up each phase data in order to estimate each phase flow rate within the multiphase stream. The following graph depicts the distribution of the three phases at a wellhead as a function of time, which has been recorded by a multiphase meter. [8], [9]

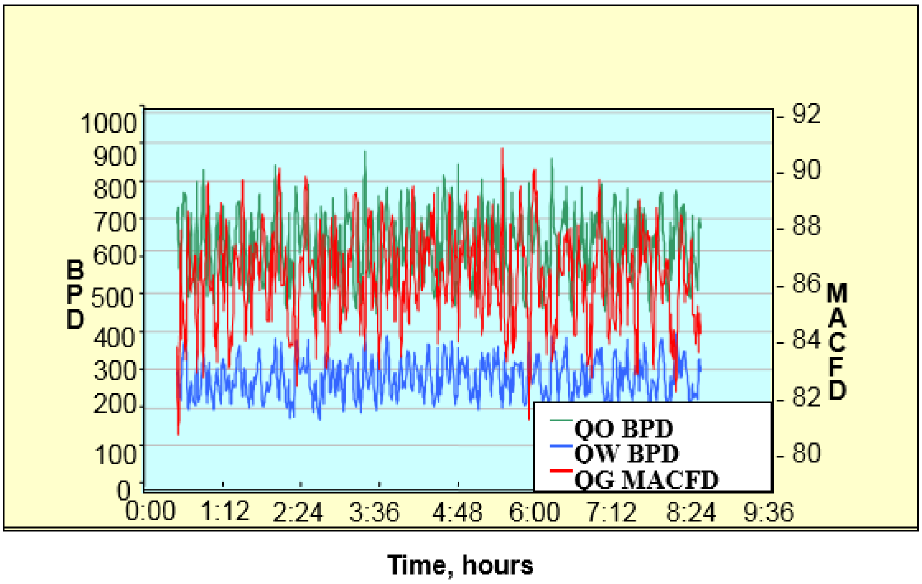


Figure 24: The Distribution of Oil (Green), Water (Blue) and Gas (Red) Flow Rates in Real Time [8]

Nowadays the multiphase meters are not classified into groups, but Parviz Mehdizadeh on behalf of Alaska Oil and Gas Conservation Commission proposed a temporary classification method. According to this method, the multiphase meters are grouped depending on the methods by which the phases are measured.

- **Group I**, at which the single – phase or the multiphase flows are measured when they are completely separated with each other. It is not necessary the aforementioned separated streams to be recombined in order the original stream to be formed. This group consists of gravity and centrifugal based separation methods.
- **Group II**, at which the flowstream is distinguished into "liquid and gas rich" streams, by utilizing centrifugal based separation method. Afterwards, multiphase measurements are applied to each of the aforementioned streams and when this process is completed then these streams are recombined in order the original stream to be formed.
- **Group III**, at which the three phases flow through a pipe and simultaneously multiphase measurements are carried out. This group consists of all these kinds of meters which are called inline meters. [8]

2.3 In – Line Multiphase Flow Measurements

When the multiphase measurements of the individual phase fractions and total or individual phase flow rates are carried out directly in the multiphase flow line, then this process is called in – line multiphase flow measurements. As a result, there is no need for separation and collection of fluids samples. When the area fraction is multiplied by each phase velocity then it is possible each phase flow rate to be estimated. For this estimation, at least six parameters should be determined. There are MPFMs, which assume that the two or totally the three phases flow with the same velocity, fact that leads to the reduce of the required measurements number. Therefore, a mixer ought to be utilized or a calibration factors set should be established.

In the context of the present Master Thesis, the types of in – line multiphase flow meters are categorized depending on the flowing mixture's properties and parameters, which are being measured during their operation. This categorization is presented below:

- **Measurement of Fraction of each Phase and Density of the Mixture or of each Phase**, which are carried out by the following techniques:
  - **Electromagnetic Meters** (**Conductance, Capacitance and Microwave Technology**)
  - **Gamma Ray Densitometry or Spectroscopy**
  - **Neutron Interrogation**
- **Measurement of Volumetric and Mass Flowrates of the Mixture or of each Phase**, which are carried out by the following techniques:
  - **Differential Pressure using Orifice Plate, Venturi Meter and V – Cone Meter**
  - **Positive Displacement**
  - **Coriolis Mass Flow Meter**
  - **Tracer Techniques**
  - **Thermal Mass Flowmeters**
- **Measurement of Velocity of the Mixture or of each Phase**, which is carried out by the following techniques:
  - **Cross – Correlation Flow Meter**
  - **Ultrasonic Meters**
  - **Turbine Flow Meter**

2.3.1 Measurement of Fraction of each Phase and Density of the Mixture or of each Phase

2.3.1.1 Electromagnetic Meters

When the engineers carry out electrical impedance methods in order to measure the phases fractions, then the flowing fluids at the pipe's measurement section are considered as an electrical conductor. When the electrical impedance across the pipe diameter is measured, by using for example contact or non – contact electrodes, then properties of the flowing fluids, such as conductance and capacitance, are able to be determined. Afterwards, the measured electrical quantity of the flowing mixture depends on the conductivity and permittivity of the flowing three phases, respectively. [4]

The property of permittivity differs for each of the three phases (oil, gas and water) and as a result the permittivity of the flowing fluid is resulting from the measurement of the phases fractions. Moreover, the aforementioned property is also known as dielectric constant. Permittivity can be determined by utilizing a capacitance sensor. This sensor is working when an electrode is placed on each side of the flowstream, inside of the spool but separated from the tubing by an electrical insulator. The aforementioned electrodes behave as capacitance detectors and the capacitance, which results from this detection, may be measured between the electrodes. As it is understood, the aforementioned capacitance will vary with the change of permittivity and more specifically depending on the amount of each of the three phases in the flowing mixture. The aforementioned capacitance measurement process is successful as long as there is an oil continuous flow, which means that water phase is dispersed in the oil phase and as a result a continuous water path between the electrodes cannot be formed. The flow remains oil continuous as long as the water cut percentage is less than 70% and for higher water cut percentages the flow turns into water continuous. Under these conditions the capacitance measurement is replaced by the conductivity measurement. [4], [11]

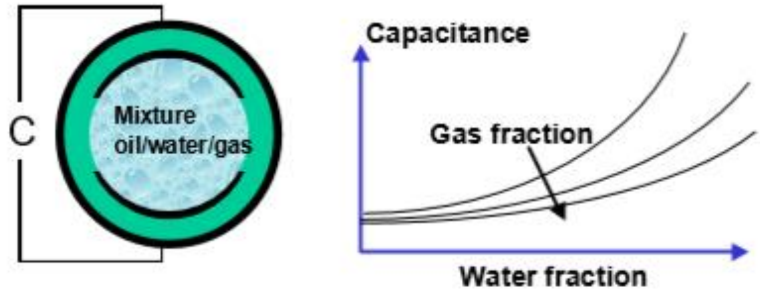


Figure 25: Capacitance Measurement Graphs [4]

Conductivity measurement method is carried out by the injection of a controlled electrical current into the flowstream and afterwards the voltage reduction between to electrodes along an insulated section of the tubing is measured. The electrical current can be injected into the flowstream by contact electrodes or by coils, which is a non – contacting mode, the so called inductive mode. When the electrical current and the voltage reduction are known, then the resistance is estimated by Ohm's Law. The distance between the detector electrodes is also known, so the resulting resistance may be converted into a conductivity measurement. [4]

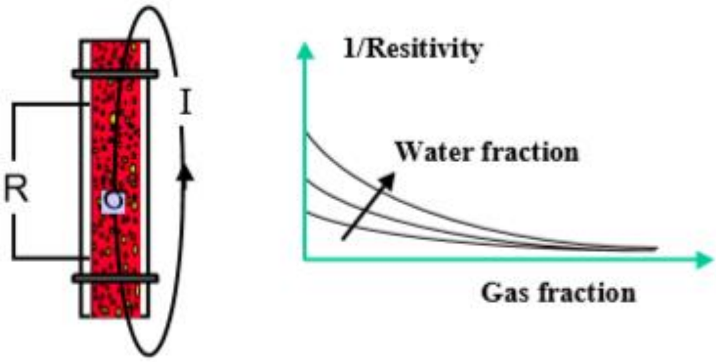


Figure 26: Conductance Measurement Graphs [4]

2.3.1.1.1 Fundamentals of Capacitance Transducers for Two - Phase Measurements

Capacitance sensors are utilized in order to determine the concentration ratios and flows of the two phases if they have different electrical permittivity. The main principle of this method is that the permittivity difference of the two phases, which flow between the two electrodes, i.e. the capacitance plates, leads to the dependence of the capacitance between these two plates from the flow ratio of each phase. Nevertheless, the relation between the concentration ratios, the flowing mixture's permittivity and the sensor capacitance, is depended on the flow regimes' distribution. Moreover, if the flowing phases are homogeneously mixed, then the capacitance technique may be utilized for concentration measurements even if it is depended on flow regimes. A simple capacitance sensor structure is illustrated by the following figure: [11]

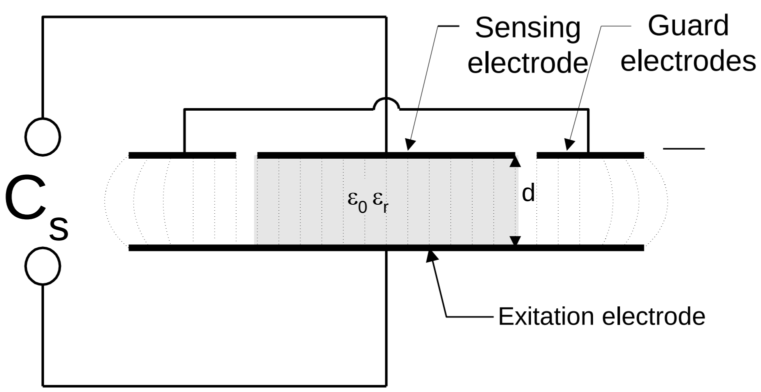


Figure 27: A Capacitance Sensor [11]

When the guard electrodes, which provide a uniform electric field in the adjacent ends of the measuring electrode, remain at the same potential as the sensing electrode and simultaneously they are electrically insulated from it in order the fringe field influence and the electrodes edge effect to be eliminated, then the capacitance is estimated by the following equation:

$$C_s = \frac{\varepsilon_r \varepsilon_0 A}{d}$$

where: A the area of the sensing electrode in m^2

d the distance between the electrodes in m

ε_r the relative permittivity of the material between the electrode plates

ε_o the permittivity of free space which is $8.854 * 10^{-12}$ F/m

When there is a flow of two phases between the electrodes with their different permittivity, then the volume of each phase may be estimated if it is known with which way the permittivity is depended on the phases' distribution. For this kind of sensors, the formed electric field between the electrode plates is not homogeneous and as a result it is more sensitive when there are concentration variations in the surroundings of the gaps between the plates. Nonetheless, the guard arrangement, which is depicted at the Figure 28 (a), eliminates the effect of the strongest inhomogeneous field at the electrodes edges and as a result the sensor will be less sensitive for inhomogeneities in the flowstream. According to the Figure 28 (b), the electrode plates are placed inside the liner, so they come directly in contact with the flowstream and for this reason they have a very high electrode capacitance, fact that increases the technique sensitivity. [12]

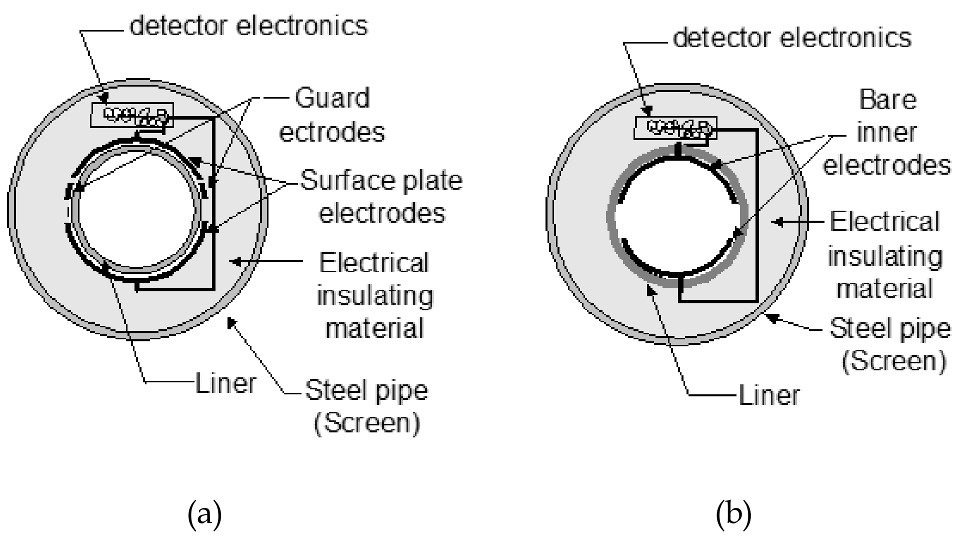


Figure 28: Surface Plate Electrodes (a) and Inside Naked Electrodes (b) [11]

Another kind of capacitance sensor is the coaxial electrode sensor, which has an inner electrode supported in the pipe center as it is depicted at the following figure:

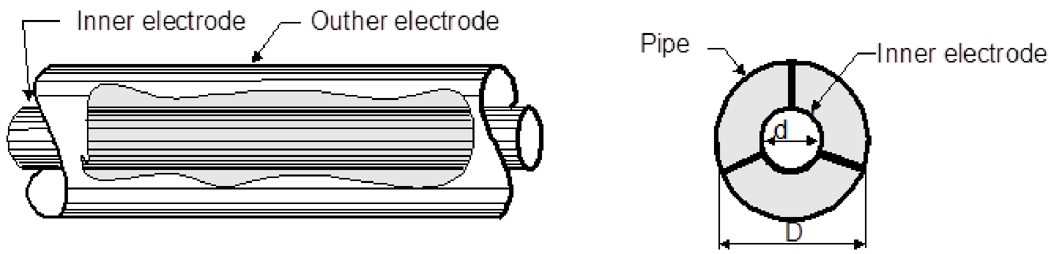


Figure 29: Coaxial Electrode Sensor [11]

The electric field, which is formed by this sensor, is strongly inhomogeneous but symmetric around the pipe axis. The sensitivity to variation in concentration of the liquid will be highest close to the inner electrode. The sensor's capacitance per unit length can be estimated by the following equation:

$$C_s = \frac{2\pi\varepsilon_m\varepsilon_0}{\ln\frac{D}{d}}$$

where: ε_m the relative permittivity of the flowstream through the sensor head [12]

The operation of capacitance sensors depends on the different phases distribution in the flowstream. For this reason, reliable measurements may be collected only if a constant flow regime is prevailed in the tubing which means that the flow is homogeneous i.e. the two phases are well mixed. Scientists such as Maxwell in 1873, Bruggeman in 1935 and others have developed equations for the permittivity and conductivity of homogeneous mixtures of two different materials. Ramu and Rao in 1973, based on the model of van Beek (1967), developed equations, which are also valid if one of the components in the mixture has a high conductivity. If $\sigma_1 << \sigma_2$ and $\varepsilon_1 << \varepsilon_2$ then the flowstream permittivity and conductivity can be estimated by the following equations of Ramu and Rao:

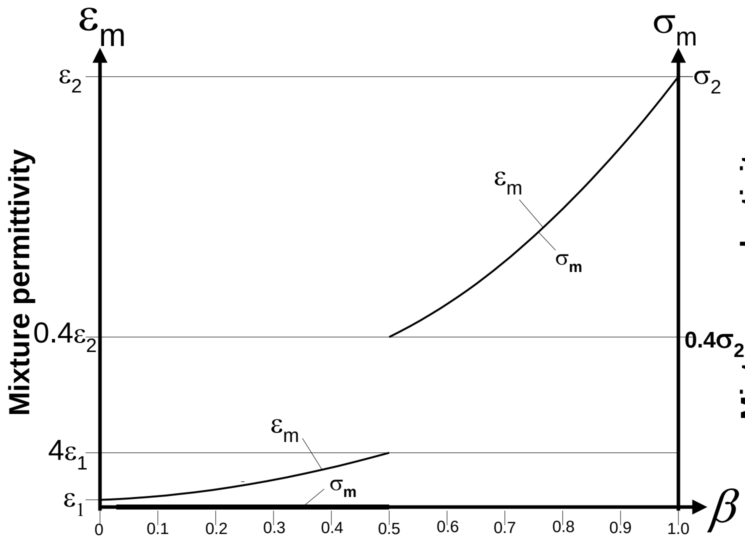
$$\varepsilon_m = \varepsilon_1 \frac{1+2\beta}{1-\beta} \qquad \varepsilon_m^{'} = \varepsilon_2 \frac{2\beta}{3-\beta}$$

$$\sigma_m = \sigma_1 \frac{1+2\beta}{1-\beta} \qquad \sigma_m^{'} = \sigma_2 \frac{2\beta}{3-\beta}$$

where:

ε_m the mixture relative permittivity when component 1 is the continuous phase
ε'_m the mixture relative permittivity when component 2 is the continuous phase
σ_m the mixture conductivity when component 1 is the continuous phase
σ'_m the mixture conductivity when component 2 is the continuous phase
ε_1 the component 1 relative permittivity
ε_2 the component 2 relative permittivity
σ_1 the component 1 conductivity
σ_2 the component 2 conductivity
β the component 2 volume fraction [12]

At this point is given a characteristic example. It is assumed that the conductivity of component 1 is zero and is the continuous phase when $\beta < 0.5$ and that component 2 is conductive ($\sigma_2 > 0$) and is the continuous phase when $\beta > 0.5$. As a result, the permittivity and conductivity versus the volume fraction of component 2 of a homogeneous mixture is illustrated at the following graph. [12]



In order the capacitance sensor reaction, when the mixture's permittivity is changing, to be understood, it is useful to work out an equivalent diagram for the respective sensor. Such a diagram is depicted at the following figure. [12]

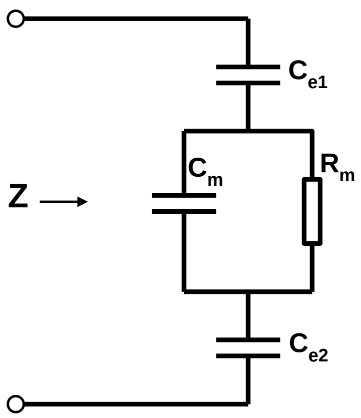


Figure 30: Equivalent Diagram of a Capacitance Sensor when all the spread capacitances are eliminated. [11]

In Figure 30, C_m and R_m are the capacitance and the resistance between imaginary electrodes, placed at the mixture – liner interface, and with the same area as the sensor electrodes. C_{e1} and C_{e2} are resultant capacitances between the sensor electrodes and the mixture with the electrode insulating material as dielectric. If component 1 is non – conducting as well as the continuous phase in the flow, $R_m = \infty$, then the measured capacitance can be estimated by the following equation:

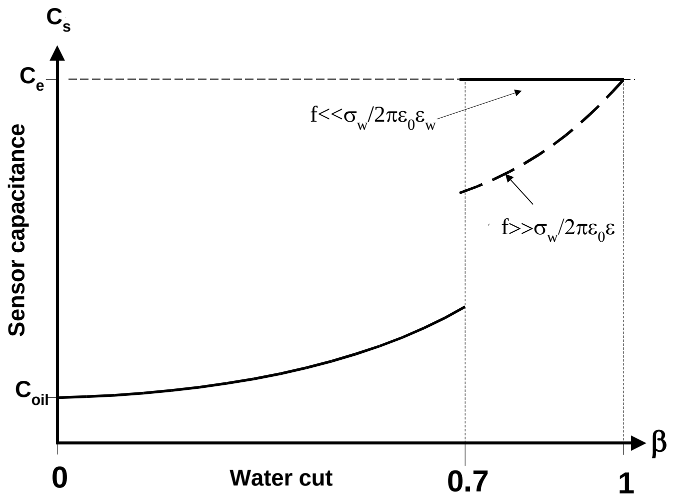
$$C_s = \frac{C_e C_m}{C_e + C_m}$$

where $C_e = 1/2C_1 = 1/2C_2$

If component 2 is conducting as well as the continuous phase, then the current through C_m will be by-passed by R_m. It can be shown that the current through C_m is equal to the current through R_m if:

$$f_e = \frac{\sigma_2}{2\pi\varepsilon_0\varepsilon_2}$$

Such an example can be the measured capacitance of a capacitance sensor, which is utilized for measuring the water content in a mixture of oil and saline water. The transition point is equal to β_C= 0.7. [13]



According to the graph, the measured capacitance of a capacitance sensor is presented as a function of the water fraction of a homogeneous mixture of oil and water. The upper horizontal line represents the excitation frequency $f << \sigma_{water} / 2\pi\varepsilon_0\varepsilon_{water}$ and the dotted line indicates the characteristic if $f >> \sigma_{water} / 2\pi\varepsilon_0\varepsilon_{water}$. It is obvious that the water content in oil is accurately estimated, if the water distribution is known, which means that only homogeneous two – phase flowing mixtures can reliably be measured. When the water concentration fluctuates from 20% to 40%, then the continuous component in a two – phase flowstream changes from oil to water. Moreover, the transition point in a mixture of oil and water occurs somewhere between 60% and 80% water fraction, depending on the oil type, temperature and content of emulsion breaker. Whether the water concentration is detectable or not above the transition point is dependent on the water conductivity and sensor excitation frequency. The sensor capacitance is increased with increasing water fraction, even above the transition point ($\beta > \beta_C$), if the sensor excitation frequency is:

$$f > \frac{1}{2\pi}\frac{\sigma_w}{\varepsilon_0\varepsilon_w} = f_e$$

A very characteristic example is the case of North Sea oilfields, where the water conductivity in the flowstream is approximately 5 S/m and the relative permittivity is approximately 70, with a critical excitation frequency of $f_e = 1.3 \cdot 10^9$ Hz. Nevertheless, for $f > f_e$ this method cannot be implemented because the effect of parasitic capacitances for frequencies higher than 1 MHz cannot be eliminated by the capacitance detector. For this reason, the water concentration of North Sea oilfields cannot be measured with such sensors, if the flowing mixture is water continuous ($\beta > \beta_C$). [12], [13]

2.3.1.1.2 Microwave Methods

The methods of microwave measurements are also a type of dielectric measurements and are utilized in order the oil and water phases to be distinguished in the liquid flowstream. Water and oil have distinctly different dielectric constants and conductivities and it is this difference that allows a microwave sensor to determine the water content of an oil – water mixture. A microwave sensor consists of a source that generates the microwave signals, a detection part that detects and measures the microwaves, a routing part that converts the signals into multi – views (images) of the flow and microwave transmitting and receiving antennas. Nonetheless, microwave measurements differ from the capacitive measurements because their frequencies are higher and the operation way of these devices is significantly different. There are many types of microwave measurements, which are:

- The **Transmission Sensor**, which carries out measurements on **a single frequency**. This type of sensor utilizes two probes (antennas), from which the first one is used for the transmission of a signal and the second one for the receiving of the signal after its transmission through the medium. It is essential, the reflections in the pipe – sensor system to be avoided. An alternative way could be the use of a guided wave transmission sensor. The sensor operation consists of the attenuation measurement and the changes of flowing phases. [14]
- The **Transmission Sensor**, which carries out measurements on **a variable frequency**. When there are high frequencies, the attenuation in water – continuous fluids is high and as a result the change of the measurement frequency with the fluid permittivity would be an advantage. A particularly useful concept is to measure the change of phase such that the meter detects the frequency, where the change of phase is constant, i.e. the meter looks for the frequency, where the change of phase is equal to a fixed value.
- The **Resonator Sensor**, at which the dielectric properties of the mixture are measured by the use of resonant cavity method. A resonant cavity is comprised of a metal structure which confines an electric field, causing it to reflect back and forth within the cavity. By matching one of the dimensions of the cavity to the wavelength of the electromagnetic radiation, a standing wave is produced. When this cavity is filled with a specific fluid, the resonant frequency of the cavity will shift in direct proportion to the dielectric constant of the fluid present. By measuring the resonant frequency and peak width, the dielectric properties of the fluid can be determined and the system can be calibrated to give the water cut. [6]

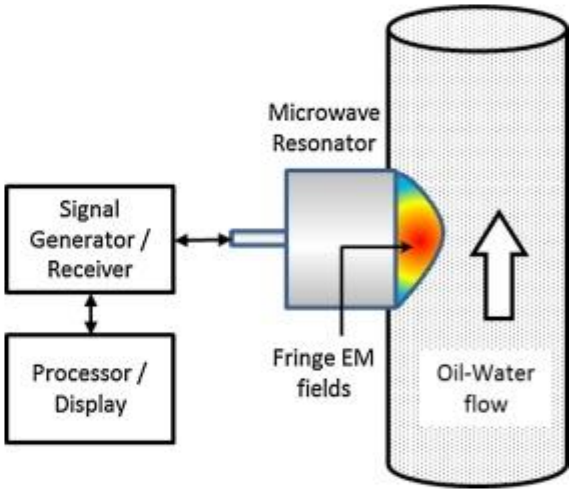


Figure 31: Resonator Sensor
Source: https://www.sciencedirect.com/science/article/abs/pii/S0925400518302351

In practice, microwave sensors use a combination of techniques, using the resonating cavity principle for oil – continuous flows and the variable transmission frequency for water – continuous flows. It also known that, the microwave MPFMs contain a gamma densitometer, which detects the differences between liquids and gas. On the other hand, the microwave sensors detect the differences between water and hydrocarbons because the water permittivity is highly compared to that of hydrocarbons. [4]

2.3.1.1.3 Selection of Electrical Impedance and Microwave Sensors Technology

The methods of electrical impedance, which measure the capacitance, are appropriate only for oil – continuous flowing mixtures, whereas for the case of water – continuous flowing mixtures, where conductivity measurement methods are utilized. The choice between the different aforementioned methods occurs whenever the flowing mixture is changing between oil and water continuous flows, fact that increases the uncertainty if the sensor operates for a long time in the transition region, i.e. where the flow is more or less rapidly changing between oil and water – continuous flow inside the measurement volume of the meter. [4]

The electrical impedance sensors should be robust against erosion, which can cause damages on the sensor, that affect the reliability of the measurements. The structure of microwave MPFM technology consists of special microwave cables and transceivers, which may be replaced without removing the entire flow meter from the installation. [4], [14]

2.3.1.2 Gamma – Ray Densitometry or Spectroscopy

The method of gamma densitometry utilizes a radioactive source in order multiphase flow measurements to be carried out. Gamma – ray technique is appropriate for multiphase flow metering because it can measure the distribution of a material based on its atomic number and density. When gamma – rays are radiated from the source to the detector, the ray will attenuate depending on the absorption of radiation of the flow within the pipe. Depending on the detected gamma quanta at the detector, the sensor is able to measure even small changes in the density differences of the flowing mixture and hence, can obtain accurate measurements of the fraction of each phase. There are many different gamma – ray methods which are implemented in multiphase flow metering. The gamma ray attenuation measurement methods are implemented to two – phase and three – phase flows or to combination of them. These measurement types are applied in a range from 0% to 100% water cut and also have few limitations during their implementation. [33]

2.3.1.2.1 Single Energy Gamma – Ray Attenuation Measurement

The first type is called single energy gamma – ray attenuation measurement which is based on the attenuation of a narrow beam of gamma – rays of energy E. It is essential to mention that, when the single energy gamma – ray attenuation method is implemented as a stand – alone measurement then it is applicable only in two – phase flows. When there is a two – phase flow through a pipe, with inner diameter equal to d, then the gamma – ray attenuation caused by the flowing mixture is estimated by the following correlation:

$$I_m(e) = I_v(e).\exp[-\sum_{i=1}^{2} \alpha_i.\mu_i(e).\mathrm{d}]$$

where: $\mathbf{I_m(e)}$ the measured count rate, i.e. the number of gamma – photons passing through the flowing mixture

$\mathbf{I_v(e)}$ the count rate when the pipe is evacuated, i.e. the number of unattenuated gamma – photons

$\boldsymbol{\mu_i}$ the linear attenuation coefficients for the two – phase flow, i.e. the quantity that characterizes how easily electromagnetic radiation penetrates a material

$\boldsymbol{\alpha_i}$ the phases' fractions

Apart from the phases' fractions (α_i), the attenuation coefficients (μ_i) are also initially unknown. Nonetheless, the attenuation coefficients may be found by calibration in two ways, first when the meter is subsequently filled with the individual fluids and second when they can be entered in the software after they have been determined offline by taken a sample from the flowing mixture. According to the all the aforementioned, the following equations can be utilized in order the phases’ fractions to be estimated:

$$I_{Water} = I_v.\exp[-\alpha_{Water}.\mu_{Water}.d]$$

$$I_{Oil} = I_v.\exp[-\alpha_{Oil}.\mu_{Oil}.d]$$

There is a possibility these two calibration points with the equation, $\alpha_{water} + \alpha_{oil} = 1$, to be rewritten as a correlation of the water fraction in a two – phase liquid – liquid flowstream as it is depicted at the following correlation:

$$\alpha_{Water} = \frac{\ln(I_{Oil}) - \ln(I_m)}{\ln(I_{Oil}) - \ln(I_{Water})}$$

The method of single energy gamma ray attenuation is utilized in liquid – liquid system and in liquid – gas systems. If Single energy gamma – ray attenuation meters are used in multiphase meters where three phases are present, often algorithms or correlations based on the output from the other measurements in the multiphase flow meter are implemented in the software to correct the expression in the previous correlation. [4], [15]

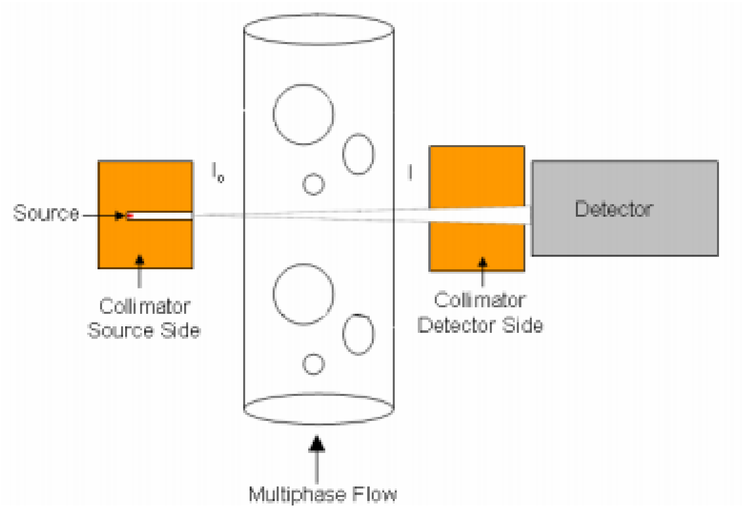


Figure 32: Gamma Attenuation Measurement [6]

2.3.1.2.2 Dual Energy Gamma – Ray Absorption Measurement

The method of the Dual Energy Gamma – Ray Absorption measurement (DEGRA) is almost similar to the previous method, but in this case two gamma – rays of energies e_1 and e_2 respectively are utilized. When there is a pipe, with inner diameter equal to d, through which a three – phase mixture with fractions α_{oil}, α_{water} and α_{gas} flows, then the measured count rate $I_m(e)$ is estimated by the following equation:

$$I_m(e) = I_v(e).\exp[-\sum_{i=1}^{3} \alpha_i . \mu_i(e).\mathrm{d}]$$

where $I_v(e)$ the count rate when the pipe is evacuated

$\mu_{i,\, o,\, g,\, w}$ the linear attenuation coefficients for the three phases

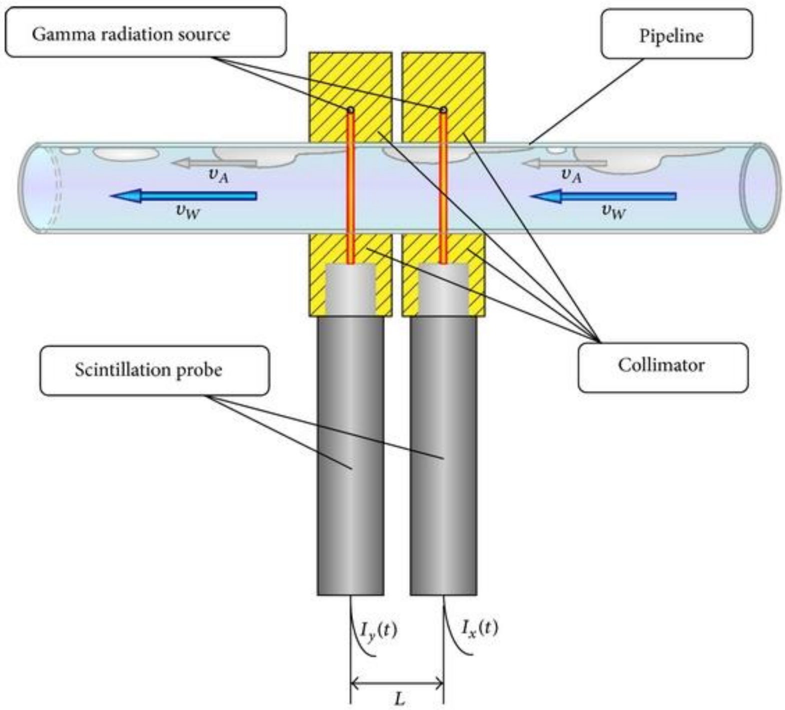


Figure 33: Dual Energy Gamma Ray Absorption Measurement
Source: https://www.researchgate.net/figure/The-principle-of-gamma-absorption-measurement-of-two-phase-flow_fig10_268576416

When there are two energy levels, with e_1 and e_2 respectively, and provided that the linear attenuation coefficients of the three phases are different with each other, then two independent equations are utilized. Moreover, the third equation identifies that the fractions sum of the three – phases in a closed tubing ought to be equal to 1. The following set of linear equations represents all the aforementioned. R_o, R_w, R_g and Rm are the count rates logarithms for the three phases and the flowing mixture respectively, at the energies 1 and 2. The aforementioned elements of the matrix are determined by a calibration process which consist of the instrument filling with 100% oil, gas and water respectively or alternatively by calculations which are dependent on the properties of the flowing fluids. When the count rates of a multiphase flowing mixture at the two energy levels are measured, then the unknown phases fractions can be estimated. [4]

$$\begin{bmatrix} R_w(e_1) & R_o(e_1) & R_g(e_1) \\ R_w(e_2) & R_o(e_2) & R_g(e_2) \\ 1 & 1 & 1 \end{bmatrix} \cdot \begin{bmatrix} \alpha_w \\ \alpha_o \\ \alpha_g \end{bmatrix} = \begin{bmatrix} R_m(e_1) \\ R_m(e_2) \\ 1 \end{bmatrix}$$

All the aforementioned are depicted at the following graph, where the logarithm of the count rates at the two energy levels are plotted along the axis. The triangle corners are the phases calibrations and every point inside the triangle represents a particular phase fraction of the flowing mixture. Regarding the single energy gamma – ray attenuation method, the phases contrast ought to be significant, which means that the aforementioned triangle will have a large cross – sectional area. The triangle shape is mainly based on the utilized energy levels, conduit diameter, flowing mixture properties and detector characteristics. In the case of which the energy levels are too close to each other, then the triangle will turn into a line and as a result it is impossible to be utilized for three – phase measurements. [4], [15]

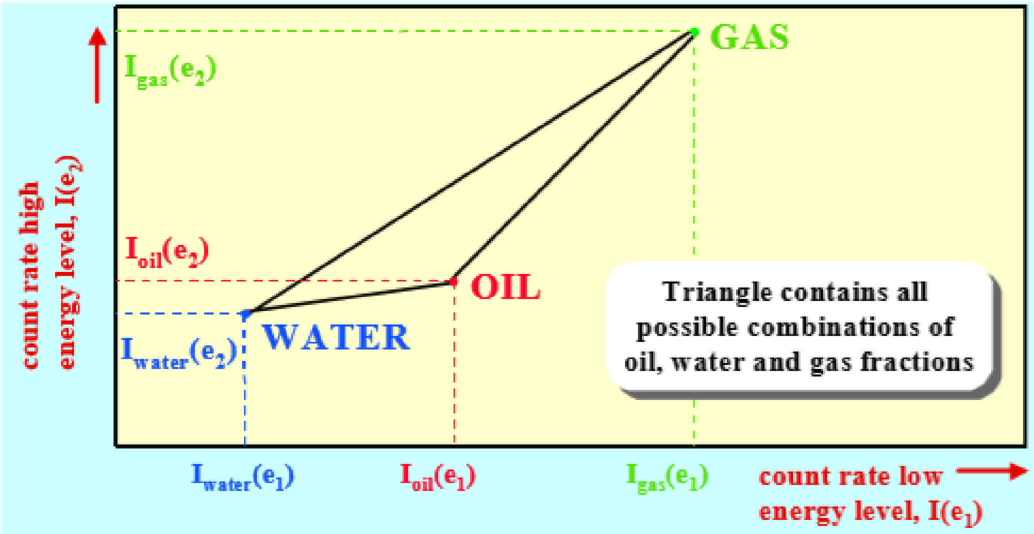


Figure 34: The Composition Triangle [4]

2.3.1.2.3 The MGB and DMD Methods

2.3.1.2.3.1 Multiple Gamma – Ray Beams for Flow Regime Identification

The method of Multiple Gamma – Ray Beams (MGB) is widely utilized in order the flow regime type to be identified. There is one gamma source, with principal emission at 60 keV. The first detector is positioned diametrically opposite to the source, whereas the second and third detectors are placed to the sides in order the beams to be close to the wall of the conduit. The operation principle of the method is based on the comparison of the measured intensities of the aforementioned detectors, through which the instantaneous gas – liquid distribution in the pipe can be identified. [16]

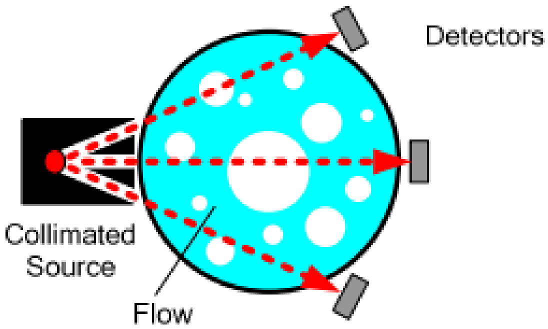


Figure 35: Multibeam Gamma – Ray Measurement Geometry [16]

The operation of multiphase flow meters is based on the combination of the instantaneous velocity and measured cross – sectional fractions of the mixture's phases. The main reason, where the flow regimes induce errors during the measurement process, is the temporal variations in the distribution of the flowing phases (liquid and gas) in the cross – section of the conduit. Nonetheless, the distribution of the phases of oil and water is less critical because the aforementioned flowing components have small difference in density, fact that means that these components are less possible to be separated. The measurement of flow velocity can be influenced by the temporal variations in the distribution of the flowing phases (liquid and gas), however, the main challenge is the component volume fraction measurement. Therefore, the Gas Volume Fraction (GVF) measurements are more susceptible, because the gas fraction of the measurement cross – section might be different compared to the GVF of the flow. The GVF is defined as the gas volume flowrate relative to the multiphase volume fraction flowrate. If the gas has higher velocity compared to the liquid, then the gas fraction over the measurement cross – section will be lower than the GVF. Nevertheless, errors can also occur during the measurement of Water in Liquid Ratio (WLR), which is also called water cut. This occurs due to the inhomogeneity of the single measurements sensitivity over the conduit cross – section. The reduction of such errors can be achieved by the identification of temporal variations in the flow regime and making the essential corrections. According to the aforementioned, MGB technique provides gas fraction measurements and flow regime information. [15], [16]

The main goal of the multiphase flow metering is to achieve an appropriate degree of homogeneity of the flowing mixture through the cross – section of the pipe and hence, they are installed with the T – bend vertical way. Nevertheless, when there are moderate values of GVF and slug and annular flow type are quickly prevailed, then the gamma – ray densitometers overestimate the GVF. The aforementioned problem is coped with by utilizing models, which take into account the difference of GVF inside the beam from that, which corresponds to the whole conduit cross – section. Nonetheless, the prevailing flow regime in the production tubing is based on many factors, so it is not easy for the general models, which correct the GVF, to be utilized. [16]

In the Christian Michelsen's flow loop facility took place a very characteristic experiment, at which it was utilized one fan – beam collimated gamma – source and nine detectors in order the whole conduit cross section to be covered. The experiment's apparatus was placed in a tilt section and many measurement series were carried out with horizontal, 45° tilted and vertical flows. In Figure 36 are depicted the results for a typical series. The nine detectors counting time is 30ms, fact that means that one hundred individual measurements constitute each of the presented 3s long sequences. Slug flow is prevailed in all tree cases, which means that it is not easy to be carried out an accurate measurement of the GVF by utilizing one beam densitometer and model compensation. However, when the flow is divided into short segments, then the continuous identification of the instant cross sectional flow pattern is possible. For the horizontal case it can be seen that this typically varies between what would be stratified and bubble type of regime if it was continuous. The same applies also for the vertical case, which is consisted of bubble and annular flow. Regarding the case of tilted flow, it is identified a combination of all flow patterns. It probably occurs due to the fact that the position of the measurement is almost 2 meters above the floor level, where the flowstream enters into the tilt section. Maybe, if the tilted flowstream was further developed, then it would look different. Nevertheless, it is observed that in all cases the bubble flow is detected as a homogenously mixed flow from the detectors due to the limited spatial measurement resolution. [16]

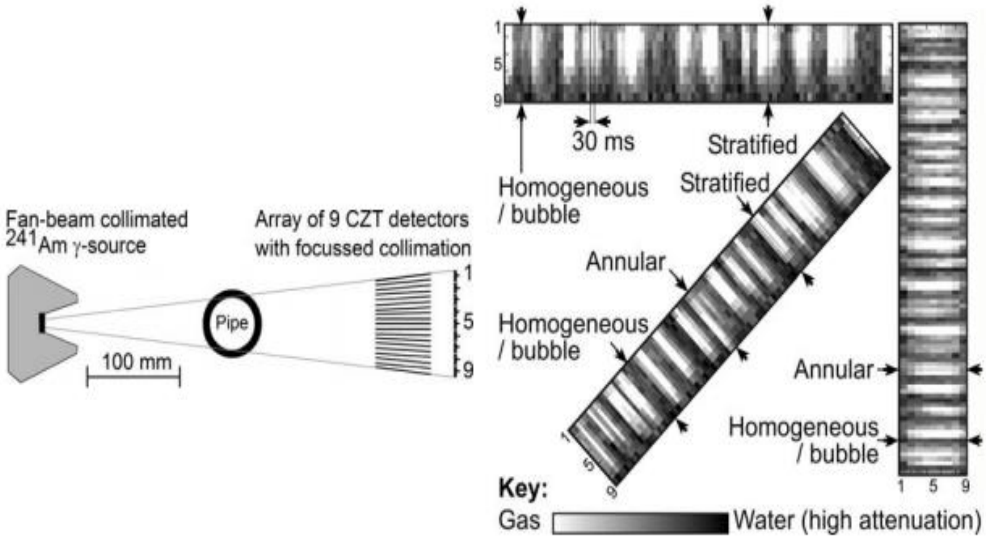


Figure 36: Experiment's Structure and Measurement of Three – Phase Flowing Mixture with Q_{oil}= 5m^3/h, Q_{water}= 25m^3/h, Q_{gas}= 20m^3/h, WLR= 83% and GVF= 67% [16]

The conclusion of the aforementioned process was that the method of multiple gamma – ray beams gives the opportunity to the instantaneous flow regime's type, which is prevailed in the conduit's multiphase flowing mixture, to be identified at any time. Moreover, it may be utilized in order the GVF to be estimated with more accuracy and also to correct other measurements. Nevertheless, in practice the MGB method requires to be more simple and compact than the structure of the Figure 36. A practical structure consists of the source and detectors which are partially embedded in the conduit's wall. It utilizes only two transmission detectors for the identification of the flow regime. [19]

2.3.1.2.3.2 Dual Modality Densitometry for Salinity Measurements

The main principle of the Dual Modality Densitometry (DMD) method is based on the fact that the Compton scattering, i.e. the scattering of a photon by a charged particle, usually an electron, is roughly proportional to the flowing mixture's density, i.e. $\mu_\sigma \sim \rho$, and furthermore the photoelectric absorption coefficient depends significantly on mixture's atomic composition, i.e. $\mu_\tau \sim Z^4$ to Z^5, which means that is very sensitive to salts due to their high atomic numbers (Z). In order to be carried out measurements of these two components, two detectors are utilized as it is depicted at the following figure. [18]

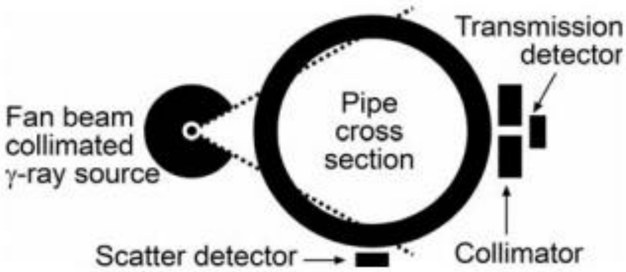


Figure 37: The DMD Measurement Structure [16]

Photoelectric absorption and Compton scatter significantly contribute to the total attenuation which is measured by the transmission detector. In order the forward scatter contribution to be avoided, a fairly strict detector collimation is implemented, according to the exponential decay law of Lambert – Beer. The scatter detector is placed outside the direct view from the source and as a result, it is impossible for it to detect directly transmitted radiation. This detector will solely measure the radiation, which comes from Compton scatter in the conduit cross – section. Hence, the transmission detector provides measurements of the Compton scatter and photoelectric coefficient respectively, in contrast with the scatter detector, which mainly provides measurements for the Compton coefficient. For the estimation of the response in the scatter detector many empirical models have been discovered. All these models utilize the proportionality between the scatter response and the scatter events number, which is generated over the conduit diameter or its active volume:

$$I_s \sim \frac{\mu_\sigma}{\mu}\left[1-\exp(-\mu(1-GVF)d)\right]$$

where μ and μ_σ the total and Compton linear attenuation coefficients of the flowing fluids, respectively. Moreover, the attenuation of the incident beam should to be corrected before it reaches the active volume, and for the respective scattered radiation. If the scatter emission is isotropic and the scatter detector's geometrical factor is small, then there will be an advantage if the Compton dominant attenuation in the flowing mixture takes place, however, the photoelectric absorption contribution is also essential in order the salinity to be monitored. The latter can be fulfilled at 60 keV. [16]

Accurate semi-empirical models of the scatter response are just the first step in calculating the water salinity in addition to the GVF. It turns out that that it is more efficient to correct for changes in the water salinity directly by using a simple empirical relationship between the measured transmitted (I_T) and scattered (I_S) intensities:

$$R = \frac{I_S}{I_T^n}$$

Several experiments with different geometries confirm that this ratio varies with the GVF, but not with the water salinity, i.e. it provides salinity independent GVF calculation. The exponent n is often equal to 0.55, but in some cases depends on the geometry of the measurement. The calibration measurements are the main source from which the value of the aforementioned exponent can be estimated. It is also proved that the salinity is independent of the previous equation except from the case of the annular flow. So it is confirmed that the multiphase flow measurements depend on the flow regime. [16]

As it is understood, the variation of water salinity can be another problem for the smooth operation of the multiphase flow meters because it has a significant influence on the volume fraction estimations, which results from the implementation of the various multiphase flow measurement methods. There are some ways, which help the engineers to solve this problem. One of them uses the difference in the composition of the gamma – ray attenuation coefficient at different energies. The method, which is presented in the context of this Master Thesis, uses the same effect, through simultaneous measurements of transmitted and scattered gamma – rays from a $^{241-}$Am source. According to this method, it was proved that the water salinity changes cannot affect the gas volume fraction determination. The main challenge is again the minimization of the effects of flow regime changes. [17]

The most common radioisotope, which is utilized for GVF measurements in flowing mixtures in the production tubing, is the ^{137}Cs with 662 keV gamma – ray emission. This radioisotope has a 30 year half – life and a pure emission spectrum with sufficiently high energy to enable clamp – on installation on the conduits. Nevertheless, the latter is not so essential for the operation of the multiphase flow meters which will be installed in – line. [18]

2.3.1.2.4 Implementations of Gamma – Ray Technology

It is known that when the flowing mixture properties change, then the systems of single energy gamma – ray attenuation may need recalibration. For instance, if the density of oil or water changes, then the new linear attenuation coefficients should be entered into the flow computer and a recalibration should be carried out. The update of the linear attenuation coefficients depends on the hydrocarbon compositional analysis. The respective water coefficient can be determined from the water analysis. [4]

It would be an advantage if the changes of fluid properties and their influence on the measurements uncertainty are identified at an early stage. If the mixture properties are known, then the manufacturer's advice will be necessary in order the effect on the primary and derived measurements to be determined. For instance, if the oil density is increased from ρ_1 to ρ_2 kg/m^3, then this increase will lead to a systematic error in water cut. The attenuation measurements, which are carried out during the implementation of the single and multiple energy gamma – ray attenuation methods, involve a certain counting time. For a specific time period, the gamma – ray detector's measurements are registered and the total measurements during that time period are utilized in the estimations. Nonetheless, as the gamma – ray's attenuation is an exponential phenomenon, it will be considered correct only if the flowing mixture's composition remains constant during the time period of measurement. [4]

When the single, dual or multiple energy gamma – ray attenuation methods are implemented, the water reference count rate depends significantly on the salinity of the produced water, because salt has higher attenuation coefficient than water. When the salinity of the produced water changes and hence, the water reference count rate does not represent the actual water salinity, then systematic errors in the measured fractions of three – phases will be revealed. It is known that during the implementation of multiphase flow metering, the salinity of the produced water can be changed continuously during production time or it may differ for each well which produces from the same reservoir. In reservoirs, where the waterflooding method is implemented, the water salinity varies between that of formation's water and that of injection water. [4]

Furthermore, the kind of radioactive source is an important parameter and requires the proper consideration with respect to the national and international regulations. Generally, when a multiphase flow meter is modified, then the flow meter's primary variables should be verified. It is essential a static calibration and a PVT data update should be carried out after a time period. In the case of which the results will remain the same, then the time interval between the tests should be extended. [4]

2.3.1.3 Neutron Interrogation

From all the aforementioned, it is obvious that the hydrocarbon production monitoring is very important for its control and optimization. The 70% of worldwide oil resources are consisted of heavy oil (Alboudwarej et al., 2006). Countries such as United States of America, Russia, Saudi Arabia, Venezuela, Iran, Mexico, Iraq, Kuwait and others have large oil reserves, which consist of heavy oil, extra heavy oil and bitumen. Therefore, the scientists and engineers still try to find an appropriate technology, which will successfully meter and control the heavy oil. The majority of multiphase flowmeters is utilized in production wells with oil viscosity lower than 500cP, whereas the heavy oil, extra heavy oil and bitumen metering during production causes many problems, which cannot be coped with by the conventional methods. An appropriate measurement technology for the monitoring of heavy oil production should operate at a wide temperature range, in low pressures and to carry out accurate measurements at the flowing mixture's high viscous components. It also ought to be operate at high water – cuts, to be resistant to erosion and plugging, not to be influenced by entrained gaseous and solid particles, to be not so sensitive to emulsion properties and velocity profile's changes respectively. Hence, the measurement should be carried out inline, right on site which can provide measurements in real time. According to all the aforementioned, the best choice which can cope with these problems is the multiphase flow metering which is based on the neutron activation analysis.

Relevant researches have shown that various neutron activation analysis techniques, with the appropriate adaptation, can carry out measurements of the chlorine's and sulphur's concentrations and the speed of oxygen and other chemical elements in the flowstream and as a result they can provide accurate information about the water – cut level, the content of the flowing three – phases, water fraction velocity and other properties, which are crucial for the production process. [20]

The main problems of heavy oil production are its high viscosity and low reservoir pressure. Therefore, this oil rarely flows with natural way from the reservoir porous media to the wellbore and as a result, specific oil recovery techniques should be implemented. These techniques are separated into the cold one, which consist of oil production with sand, waterflooding and vapor assisted extraction, and the thermal one such as the steam assisted stimulation. Due to the kind of recovery technique and heavy oil's properties such as composition, density and viscosity, the heavy oil metering faces severe problems. As aforementioned, the majority of the multiphase flowmeters can operate only in conventional oils, which have viscosity less than 500cP. [20]

So the question is, why this occurs. There are two reasons:

- There are very little or not at all gravity differences between oil and water and hence any multiphase metering system, which is based on phase separation, cannot operate in such environment.
- Thermal and cold techniques are implemented for the heavy oil production and hence, the multiphase flowmeters should cope with many properties of the flowing fluids, such as:
    - Fluids emulsification
    - Foaming
    - High temperature
    - Entrapped gas, sand and water
    - High water – cut

The method of Neutron Interrogation is a non – destructive analysis which is utilized at the bulk material analysis. Neutrons have neutral charge and hence, they do not interact with charged particles. Nonetheless, they usually interact with the nucleus, and as a result, a secondary radiation is created. The neutron interactions depend on energy. When the nuclear reactions, which are initiated by neutrons, are utilized for elemental analysis, then they are consisted of elastic and inelastic neutron scattering and thermal neutron capture. So, when nuclear reactions with the material inside the object take place, then gamma rays with characteristic energies are emitted. The method of gamma spectroscopy is utilized in order the gamma ray spectra to be measured. When the number of gamma rays, which is emitted with a specific energy, is counted, then the sample's elemental composition can be identified. The specific gamma peak energies are utilized in order the chemical elements to be determined and moreover, the area underneath the peaks identifies the relative amount of each element. So, when the concentration of specific atoms is known, then the respective phases' content may be identified. [20]

The implementation of neutron interrogation method for multiphase flow metering requires some work to be done. For instance, the monitoring of hydrogen and carbon per volume concentration, by implementing the aforementioned method with the proper calibration, can determine directly the content of flowing oil and water. When the produced gamma photons with energies of 2.2 and 4.43 MeV respectively are counted, then the hydrogen and carbon atoms' concentrations can be estimated. The aforementioned monitoring method is small, needs little set – up time and provides data in – line. The system's calibration may be carried out away from the site by using suitable samples. Moreover, this monitoring system is accurate over the whole range of possible combinations of the three – phases' fractions and as a non – intrusive method is not influenced by pressure, temperature and flow regime into the tubing. [20]

Another method was proposed by Arnold and Smith in 1980. According to this technique the measured reservoir fluid is bombarded with fast neutrons, which are thermalized by interaction with matter, and afterwards are subjected to thermal neutron – capture reactions with fluid's nuclear and hence, prompt neutron capture gamma – ray is produced. When the obtained gamma spectrum is monitored, then the relative concentration of sulfur and chlorine can be measured. Furthermore, if the fluid's salinity is determined, then the relative concentration of salty water can be identified. Neutron interrogation method can be utilized in order the flowrate to be measured. The interaction between neutrons and nuclides produces radioactive isotopes, which decay depending on their respective half – lives. The flowing mixture in the pipe is bombarded with neutron pulses from pulsed neutron sources, which activate some fluid's species. Afterwards, these activated species flow across the flowstream and gamma rays from the activity are detected from the activation point. [20]

The implementation of Pulsed Neutron Activation technique, P.N.A., which is based on the measurement of liquid sodium flowrate was investigated by Kehler in 1976. According to this technique, the reaction ^{23}Na (n, a) ^{20}F takes place. Moreover, according to the following figure, this method is based on the activation of sodium, which is flowing through the tubing, by a burst of 14 MeV neutrons and the resulting radioactivity measurement is taken by a system of scintillation detectors, which is installed downstream of the neutron source. The neutron source and detectors are installed external to the conduits, so the whole equipment may be installed and the flow velocity measurement may be carried out without interruption of the normal operation process, fact that consists of the main advantage of this technique. [20]

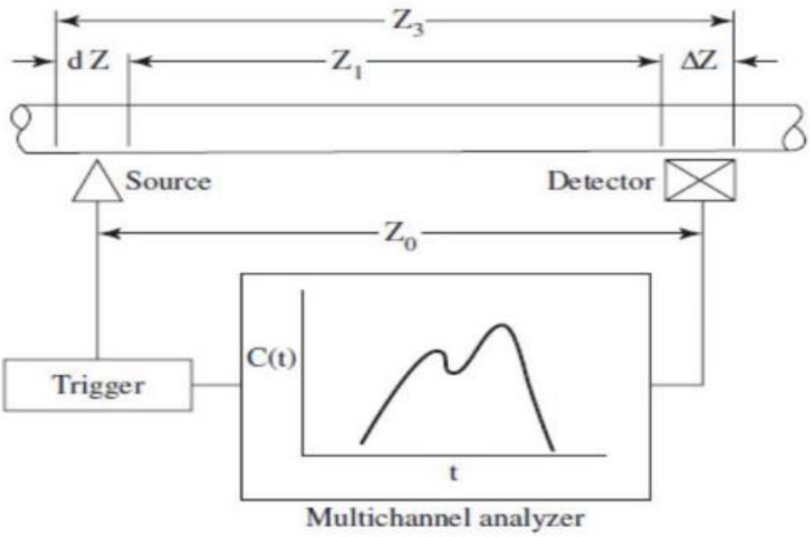


Figure 38: The Pulsed Neutron Activation Technique [20]

This technique is also suitable for liquids and slurries, which contain ^{16}O. Its operation is based on irradiation of the flowing water in a tubing with 14 MeV neutrons, which will produce the radioactive nuclide ^{16}N through the ^{16}O (n, p)^{16}N reaction. Hence, from the detection and analysis of the emitted gamma radiation from ^{16}N information about the water velocity can be provided. Another implementation of the PNA technique is the measurement of density variations or void fraction, which is possible because it depends on density. [20]

Neutron interrogation methods are more appropriate for multiphase measurements during the production of heavy oil. Regarding such complicate mixtures, the three – phases' fractions can be determined from the measurement of oxygen, carbon and hydrogen concentrations. Moreover, with the measurement of chlorine and sulfur concentrations and the knowledge of water's salinity, an accurate determination of watercut and oil content may be carried out. This method can provide the oxygen flowrate and density of the flowing mixture's components in the tubing. The detection of specific elements of the particular reservoir fluids, by utilizing the aforementioned method, can provide the determination of a parameters' combination and in combination with the cross checking results, more accuracy can be provided for such multiphase flow measurements. Because of the neutrons' good penetration capability, the measurement can be carried out through the conduit's walls. Hence, the device installation can be carried out easy and fast without production's interruption and also without any change in pipes' system. Neutron interrogation technique operates reliably at the heavy oil production. This method is not affected by temperature's changes, low pressure, changes in emulsions' properties and flow regimes, whereas operates well at fluids with high viscosity and at high watercuts. Such technique can also be combined with other devices in integrated instrument package. [20]

2.3.2 Measurement of Volumetric and Mass Flowrates of the Mixture or of each Phase

2.3.2.1 Differential Pressure using Orifice Plate, Venturi Meter and V – Cone Meter

The Differential Pressure transmitters are utilized by many multiphase flow meters in order the pressure difference between two given points inside the tubing to be measured. The transmitters, which are usually utilized in the offshore production platforms, are consisted of an orifice plate or a Venturi meter, which provide accurate in – line measurements. According to Bernoulli's principle, when the fluid velocity is increased, then its pressure will be decreased. Hence, the mixture's flowrate can be estimated, if the differential pressure is obtained. The aforementioned methods cause a disturbance to the fluid flow, which enables the differential pressure transmitters to measure the pressure difference between two given points in the tubing. According to the latter and in combination with the respective software, which is based on empirical algorithms, many differential pressure meters can provide accurate measurements. Such multiphase flow meters are called Virtual Flow Meters and in combination with their simple equipment, may be a cheaper option for the offshore production process. However, the fact that the flowing mixture's composition must be constant, consists the main limitation of these meters' operation. This limitation can be coped with by combining the virtual flow meters with void fraction sensors and gamma densitometers during the measurement process. [21], [22], [23]

2.3.2.1.1 Orifice Plate

Orifice plates are utilized in order the mixture's volumetric flowrate within a conduit to be measured. This method is based on the applying of a thin plate with a small opening inside the tubing, as it is depicted at the following figure.

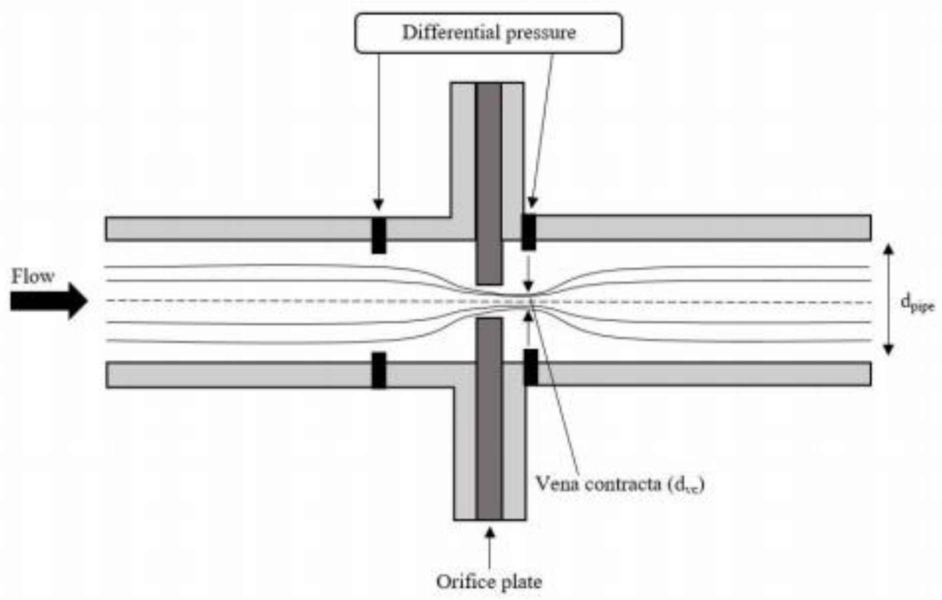


Figure 39: Orifice Plate's Method [24]

As it is shown, the mixture's flow is interrupted by an orifice plate inside the conduit. Afterwards, transmitters are measuring the pressure difference at a point before and after the orifice plate and hence, the flowing mixture's velocity is estimated by Bernoulli's correlation. Vena contracta is the point where the mixture's flow is experiencing the maximum convergence. As it is depicted at the previous figure, vena contracta is occurring just after the orifice plate and its diameter is symbolized with d_{vc}. The transmitters measure the pressure in the regular diameter of the conduit and at vena contracta and hence, the pressure difference is estimated, which leads to the estimation of the flowing mixture's velocity by utilizing Bernoulli's correlation. [24]

The following equation estimates the volumetric flowrate for vertical orifice plates regarding pressure difference:

$$Q = C_d A_{ori} Y \sqrt{\frac{2(\Delta P + \rho g \Delta z)}{\rho(1-\beta_d^4)}} l$$

where: β_d the ratio between the tubing and the orifice plate diameter

z the change in elevation

C_d the discharge coefficient

A_{ori} the orifice plate area

ρ the flowing mixture's density

g the gravity

The orifice plate discharge coefficient fluctuates around 0.61. Y is the expansion coefficient, which is determined by the following equation:

$$Y = \frac{C_{d,c}}{C_{d,i}}$$

The expansion coefficient depends on the discharge coefficient for compressible $C_{d,c}$ and incompressible $C_{d,i}$ flows. For incompressible fluids Y is equal to one and for compressible fluids is defined by the discharge coefficients. The technique of the orifice plate is usually utilized in combination with other measurement instrument in order to estimate the mass flowrate of the multiphase flow. [24]

The advantages of orifice plates' technique are:

- simple construction
- inexpensive
- robust
- easily fitted
- no moving parts
- large range of sizes and opening ratios
- suitable for liquids and gas

- ❖ price does not increase dramatically with size [27]

The disadvantages of orifice plates’ technique are:

- ❖ permanent pressure loss of head is quite high
- ❖ inaccuracy, typically 2 to 3%
- ❖ accuracy is affected by density, pressure and viscosity fluctuations
- ❖ erosion and physical damage to the restriction affects measurement accuracy
- ❖ viscosity limits measuring range
- ❖ requires straight pipe runs to ensure accuracy is maintained
- ❖ pipe must be full
- ❖ output is not linearly related to flowrate [27]

2.3.2.1.2 Venturi Meter

The effectiveness of the multiphase flow measurements by utilizing a Venturi meter has been presented by many studies. Venturi meter's operation principle is almost the same with the orifice plate's one. It was observed that venturi meter has the lowest pressure loss compared to other differential pressure transmitters. In order the volumetric flowrate by utilizing a venturi meter to be estimated, the same equation as the orifice plate is utilized. The only difference is that the discharge coefficient is higher in venturi meter's case and fluctuates between 0.984 and 0.995. This measurement method is widely utilized for multiphase flow measurements in the offshore production process. [24]

When there is a single phase flow, the flowing fluid's density can be known and hence, only the differential pressure should be measured in order the flowrate to be estimated. Nonetheless, the flowing multiphase mixture's density is unknown, although the individual phases densities are known. Hence, it is important the flowing mixture's density, which enters the Venturi meter, to be measured. It can be realized by utilizing a gamma densitometer containing a ^{137}Cs gamma source, clamped onto the conduit upstream of the Venturi meter. [25]

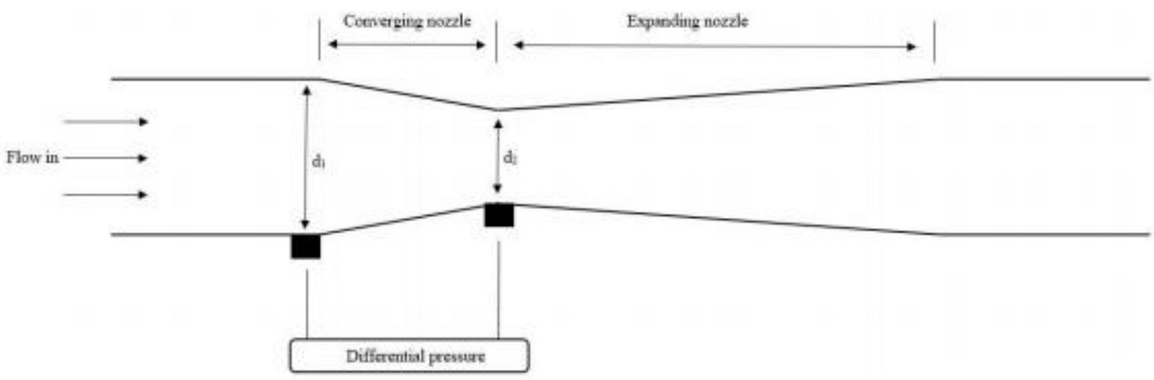


Figure 40: Venturi Metering Method [24]

The Venturi meter's operation can be combined with an ECT sensor in two – phase flow measurements. This sensor is measuring the void fraction information while the flow's velocity is being measured by the Venturi meter. Venturi meter can also operate with an ERT sensor. This sensor measures the flow pattern in real time, while the void fraction and mass quality is determined by the aforementioned method. Depending on the mass quality and the differential pressure across the Venturi meter, the mass flowrates can be estimated. [24]

The advantages of Venturi meter's technique are:

- Permanent pressure loss lower than that for an orifice plate.
- Less unrecoverable pressure loss.
- It is widely accepted for high pressure and temperature flow.
- Requires less straight pipe up and downstream.

The disadvantages of Venturi meter's technique are:

- Cost is higher than orifice plate.
- It is limited to moderate pipe sizes.
- It requires more maintenance. It is necessary to remove a section of pipe to inspect or install it. [37]

2.3.2.1.3 V – Cone Meter

It is known that if the engineers want to collect flowrate information from a production well, which produces two – phase fluid, then the method, they utilize, is based on the pressure drop of the flowing mixture's flow. This measurement method is usually summarized as one measurement model, the pressure drop model. The latter consists of the stratified flow and homogeneous flow model. The separated model's principle is to treat the two phases separately as a single fluid. It is assumed that each flowing phase flow alone in the tubing with its own flow parameters and properties. At the homogeneous flow model, it is considered that the two flowing phases, i.e. oil and water, are mixed so well that the flowing mixture may be considered as one single phase approximately. In contrast with the two – phase flow of gas and water, each phase of the two – phase flow of oil and water has the similar flow characteristics. Hence, the aforementioned measurement model cannot be utilized in the case of the two – phase flow of gas and water.

At 1961 researcher Charles, whose researches were based on the two – phase flow regimes of oil and water, established some foundations for the aforementioned type of two – phase flow. At 1989 Arirachakaran carried out some experiments about stratified flow, mixed flow, annular flow, intermittent flow and homogeneous flow and the conclusion was that if the oil phase is considered as one kind of high density gas phase, then the flow regime is much similar. Some years later, in 1997 Hewitt studied and compared the flow regimes of oil – water flow and gas – water flow, and observed that stratified flow was formed in both of the two aforementioned types of two – phase flows. Slug flow is very rare in oil – water two – phase flow, in contrast with gas –

water two – phase flow where is very common. If the gaseous phase is less than 30%, then it could disperse into the water phase in contrast with water phase which cannot disperse into gaseous phase. Nevertheless, in the case of oil – water two – phase flow, each phase can disperse into the other, independently of each phase percentage. Moreover, annular flow prevails very commonly in gas – water two – phase flow, in contrast with oil – water two – phase flow where is hard to be appeared. Furthermore, in 1995 Nadler presented also some similar results. Finally, in 1996 Trallero presented the technique about the oil – water two – phase flow regime, which is widely utilized until our days. [26]

One of the primary elements, which is utilized in the flowrate measurement by differential pressure method, is the throttling set. The fluid cross section area is decreased when it flows inside the throttling set and hence, the fluid velocity is increased. As a result, from the pressure difference between the upstream and downstream of the throttling set the flowing mixture's flowrate can be estimated. This technique is characterized by reliability, accuracy, simple structure and easy installation, fact that makes the throttling set widely applicable in single – phase flow measurements and in researches on two – phase flowrate measurements. Nonetheless, in the middle of 1980 decay, a new type of flow meter was found, the V – cone flow meter, which is depicted at the following figure. The streamlined structure of the V – cone meter overcomes the disoperations of other throttling sets, which may be caused by the high oil viscosity. Furthermore, the noise signal, which is created when the flowstream passes through the V – cone, is much lower than that generated by other throttling sets. When the flowstream passes through the V – cone meter, a pressure difference is generated from the shrinking cross – section area. V – cone meter is widely utilized for two – phase flow measurements because with a wider measurement scale it provides more accuracy and effectiveness in flowrate measurements. [26]

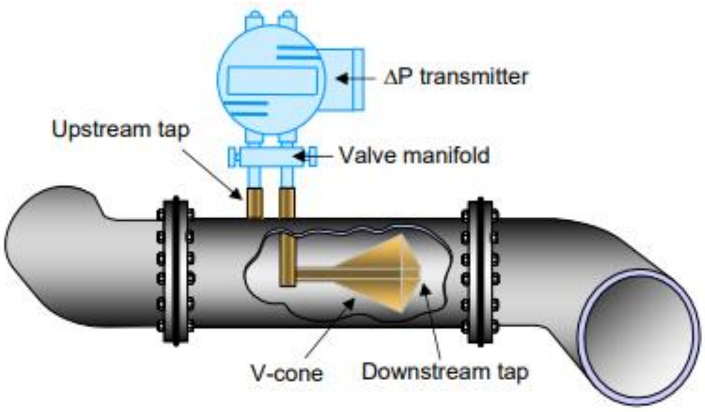


Figure 41: V – Cone Flow Meter [27]

When the oil – water mixture passes the V – cone meter, according to the Bernoulli equation and fluid continuity equation:

$$\frac{p_1^{'}}{\rho_1}+\frac{u_1^{2}}{2}=\frac{p_2^{'}}{\rho_2}+\frac{u_2^{'2}}{2} \quad \text{and} \quad A_1u_1=A_2u_2^{'}$$

p_1', p_2', u_1, u_2', ρ_1, ρ_2, A_1, A_2 represent the upstream pressure of V – cone, the downstream pressure of V – cone, upstream flowrate, downstream flowrate, upstream fluid density, downstream fluid density, upstream circulation area, downstream circulation area respectively. If the fluid is incompressible, then $\rho_1 = \rho_2 = \rho$, $A_2 = \mu A_0$, where A_0 is the circulation area of the V – cone, thus:

$$u_2^{'}=\frac{1}{\sqrt{1-\mu^2}}\sqrt{\frac{2}{\rho}(p_1^{'}-p_2^{'})}$$

and $\mu^2 = \beta^4$, β is the equivalent diameter ratio. Because p_1' and $p_2'$are average pressures, the modified formula $\sqrt{p_1^{'}-p_2^{'}}=\sqrt{\psi}\sqrt{p_1-p_2}$ is necessary, where $\sqrt{\psi}$ is called pressure tapping coefficient which changes as the mode of the pressure tapping changes. Moreover, an error (ε) is introduced in order the u_2', considering the loss due to fluid viscosity, to be modified, so:

$$u_2=\varepsilon u_2^{'}=\frac{\varepsilon\sqrt{\psi}}{\sqrt{1-\beta^4}}\sqrt{\frac{2}{\rho}(p_1-p_2)}$$

The flowing mixture's volume flowrate is: $q_v=u_2\mu A_0=\frac{\mu\varepsilon\sqrt{\psi}}{\sqrt{1-\beta^4}}A_0\sqrt{\frac{2}{\rho}\Delta p}$

Discharge coefficient is defined: $C=\mu\varepsilon\sqrt{\psi}$, then: $q_v=\frac{C\varepsilon}{\sqrt{1-\beta^4}}A_0\sqrt{2\Delta p\rho}$

For $A_0=\frac{\pi}{4}(D^2-d^2)$, D is the diameter of pipe, d is the largest cross – section area of V – cone, so the mass flowrate is determined by: [26]

$$q_m=\frac{C\varepsilon}{\sqrt{1-\beta^4}}\frac{\pi}{4}(D^2-d^2)\sqrt{2\Delta p\rho}$$

2.3.2.2 Positive Displacement Meter

The operation principle of such meter is based on the multiphase flow's segregation into small incremental packages, which is a kind of partial separation, in order in their transit through the device the flowing phases to be temporarily confined without relative slip. When the densities in packages are measured, then it is possible the flowing mixture's mass flowrate to be determined by multiplying the package volume flowrate by the density. Furthermore, through a pulse generating and detection system monitoring rotor revolutions, the volumetric flowrates can be estimated. The individual phases' mass flowrates can be determined from flowing mixture's properties such as hydrocarbon densities and watercut. Representative fluid samples can be collected from the meter central chamber. The measurement error of positive displacement meters fluctuates between 10% and 20% for volumetric and mass flowrates, respectively. Nevertheless, the positive displacement meters' intrusive nature and the fact that their mechanical parts need continuous maintenance can lead to their disoperation under severe flow conditions. [27]

Positive displacement meters split the fluid flow into separate known volumes, which depend on the meter physical dimensions, and they count and totalize them. The fact that in that one or more moving parts, which are placed in the flowstream, are mechanical meters, then it gives the opportunity to the fluid to be physically separated into increments. The needed energy, which moves these parts, is given by the flowstream and comes up as pressure loss between the inlet and outlet of the meter. The positive displacement meters' accuracy depends on minimizing clearances between the moving and stationary parts and maximizing the length of the flowing path. Therefore, their accuracy is increased as the meter size is increased. [37]

Positive displacement meters are divided into following categories:

- ❖ **Nutating Disk**, in which the displacement element is a disc pivoted in the center of a circular measuring chamber. [27]

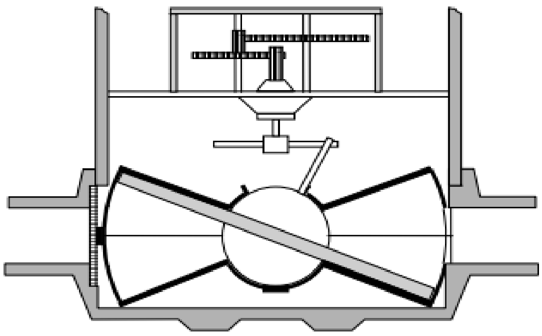


Figure 42: Nutating Disk [27]

- ❖ **Reciprocating Piston Meter**, in which passes the fluid alternately through each end of the cylinder from the inlet to the outlet and also the slide valve which controls the inlet and outlet ports and operates the counter. [27]

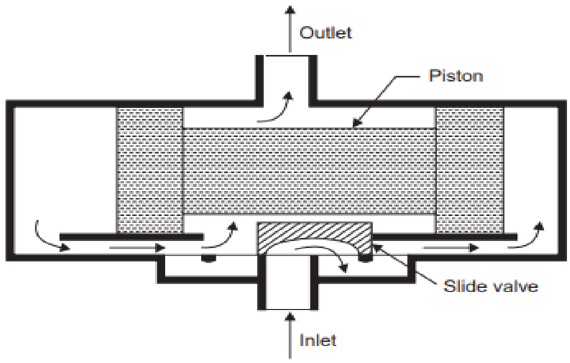


Figure 43: Reciprocating Piston Meter [37]

❖ **Oval – Gear Flow Meters**, at which the main characteristics are the oval – geared metering elements. These kind of meters are utilized on very viscous fluids, which are difficult to be measured by other flow meters. [27]

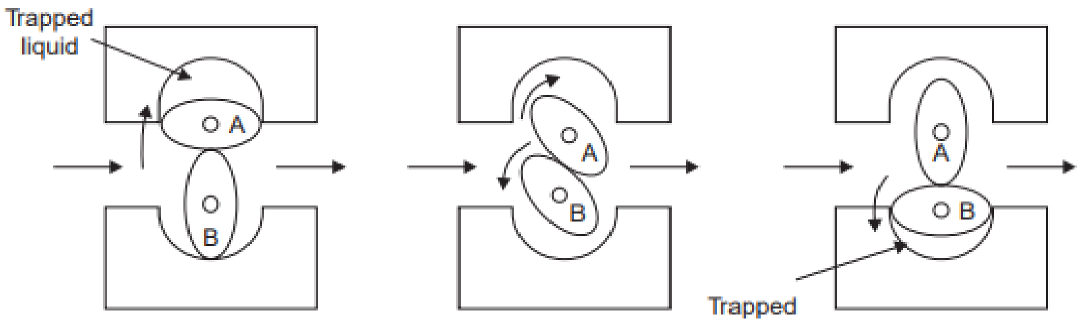


Figure 44: Oval – Gear Flow Meter Operation Principle [37]

❖ **Helix Flow Meters**, which is a positive displacement device utilizing two uniquely nested, radically pitched helical rotors as the measuring elements. Close machining tolerances ensure minimum slippage and thus high accuracy. [37]

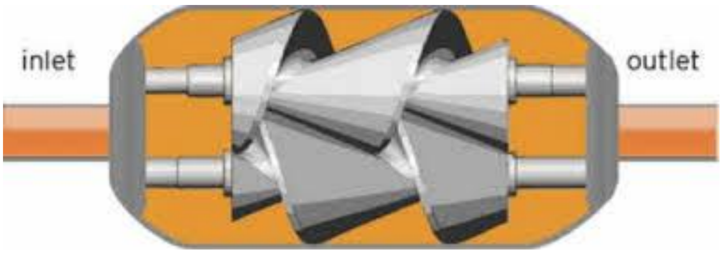


Figure 45: Helix Flow Meter
Source: https://automationforum.co/helix-flowmeter/

❖ **Sliding Vane**, which consists of a rotor assembly fitted with four spring – loaded sliding vanes so that they make constant contact with the cylinder wall. The rotor is mounted on a shaft that is eccentric to the center of the meter chamber. [27]

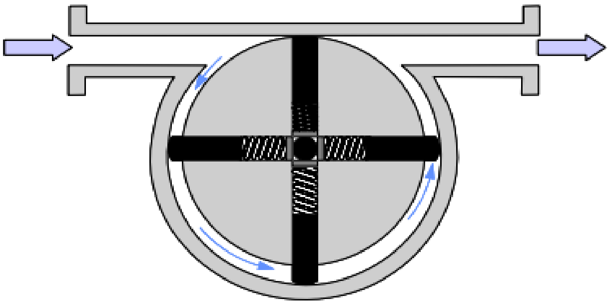


Figure 46: Sliding Vane [27]

- **Fluted Rotor Meters**, which utilize two aluminum spiral fluted rotors working within the same measuring chamber, with the rotors maintained in a properly timed relationship with one another by helical gears. [27]

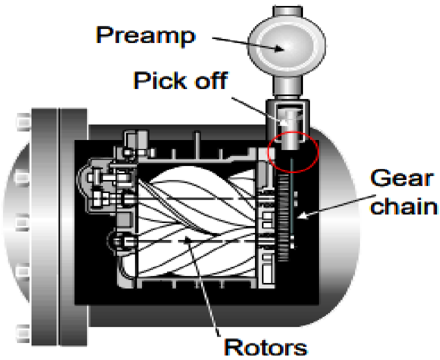


Figure 47: Fluted Rotor Meter [27]

- **Wet Gas Meters**, which consist of a gas – tight casing containing a measuring drum, with four separate compartments, mounted on a spindle that is free to revolve. The casing is filled to approximately 60% of its volume with water or light oil. Under normal operation the gas passes through the measuring drum, so that each compartment of the drum must be emptied of water and filled with gas, thus forcing the drum to rotate. In the case of another arrangement the gas is introduced into the space above the water in the outer casing and then passes through the drum to the outlet of the meter. Such meters are available in capacities ranging in size from 0.25 to 100 dm^3 with an accuracy down to ±0.25%. [27]

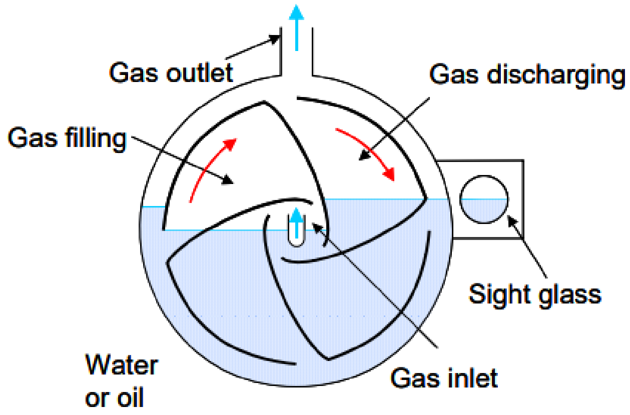


Figure 48: Wet Gas Meter [27]

2.3.2.3 Coriolis Mass Flowmeter

The Coriolis mass flowmeter is a multivariable device, which measures directly the flowing mixture's mass. It can also indirectly measure the liquid density and temperature of the conduit. The measurements of mass flow and density are utilized in order the liquids' gross volume to be estimated. Moreover, the measurement of temperature may be utilized in order the flowing mixture's temperature to be approximated. Such flowmeter is bidirectional. Coriolis mass flowmeter took its name from the French mathematician, Gaspar Gustave de Coriolis, who described the apparent forces on a mass moving through a rotational plane. Its operation principle is based on the Coriolis Effect. The direct mass flowrate determination is the first independent measurement, which can be carried out by a such flowmeter. Coriolis flow sensor structure consists of one or two intrinsically balanced metal tubes fixed at each end. The tube system is oscillated by utilizing a center mounted electromechanical system that imparts a force to set the tubes in motion, depending on the applied excitation signal. A variable gain feedback circuit maintains the amplitude of the tube oscillation at the minimum applied excitation current to set the tubes in motion. When the flowing mixture's mass is subjected to an oscillation, which is perpendicular to the flow direction, then a Coriolis force occurs in the measurement system, which depends on the mass flow. When the flowing mixture passes through the flow sensor, then Coriolis force is created by the oscillatory motion and transferred to the measurement tubes which causes a motion change. The aforementioned change, i.e. the tubes' twisting, is detected by two electrodynamic motion sensors. From the phase offset or difference between the inlet and outlet measurement signals, which are derived at the electrodynamic sensors, the mass flowrate can be identified. As the mass flowrate is increased or decreased, then the phase offset, which is measured by the electrodynamic sensors, is proportionally increased or decreased, respectively. When flow stops, then there is no phase offset. Afterwards, a calibration factor is determined and retained in the flowmeter memory. [29]

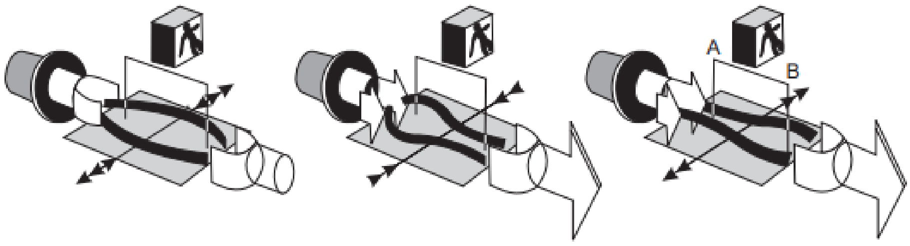


Figure 49: Coriolis Mass Flowmeter [37]

A Resistance Temperature Device (RTD) is placed on the conduit and its purpose is to compensate for the increased or decreased flexibility of the conduit due to the changes of the flowing mixture's temperature. Furthermore, a second RTD can be installed on the sensor housing in order the environmental temperature impact on the sensor to be compensated. In contrast with volumetric metering systems, no additional correction of temperature or density is needed in order a direct mass flowrate measurement by a Coriolis flowmeter to be carried out. [29]

As aforementioned, Coriolis flowmeter is also utilized in order the liquids' density to be estimated. This process includes the vibration of flow tubes at a resonant frequency which corresponds to the sensing tubes material and the density of the flowing mixture which flow in the tubes. Feedback from the electrodynamic sensors to the excitation current circuit permits the drive frequency to migrate to the resonant frequency. Moreover, when the fluid density changes, then the resonant frequency changes too. Hence, the resonant frequency corresponds directly to the liquid density in the sensor. [29]

Nonetheless, Coriolis flowmeter is not so accurate regarding the measurement of gas density. It is known that Coriolis mass flowmeters are more accurate than volume – based devices due to the fact that when gas is present in the flowing mixture, then it adds very little mass but large volume. Hence, when there is multiphase flow in the tubing, then many problems may be caused, although Coriolis mass flowmeter has inherent advantages in such flow conditions. The high liquid viscosity may trap gas within the liquid and hence, it brings gas downstream to places, where it is assumed that the flow is single – phase. Many researches have shown that density and mass flowrate measurements deviate from the true values, when there is two – phase flow. Even single – phase flows, with small amounts of another phase, for instance liquid flow with entrained gas, decrease the measurement accuracy of Coriolis flowmeter. As a result, the flowing mixture no longer vibrates in sync with the flow tubes, fact that leads to measurement errors. [28]

Effects, which affect Coriolis mass flow and density measurements, are the decoupling, which is also known as particle or bubble effect, and compressibility, which is also known as the resonator effect or velocity of sound effect. Errors may also be caused by asymmetry in bubble distribution and suboptimal installation. Such errors usually occur at low flowrates. Coriolis flowmeters estimate the mass flowrate based on phase difference between inlet and outlet ends of the measuring tube. However, if content differences are caused between the inlet and outlet, then it could cause measurement errors. Depending on installation orientation gas may accumulate on either inlet or outlet end of the measuring tube. Hence, it may give rise to altered damping, which is caused by decoupling. This problem can be coped with higher flowrates, which prevent gas to be accumulated, and with giving of a more homogeneous mixture. [28]

On the other hand, at low flowrates errors may be caused by installation, i.e. by the uneven distribution between the two measuring tubes of the Coriolis flowmeter. As a result, uneven distribution of different densities' components may be caused due to gravitational forces. This uneven distribution of mass may cause unbalanced vibration. Hence, it will make the flowmeter more sensitive to external vibrations, which may lead to errors regarding the measurements of mass flowrate and density. Nevertheless, it can be prevented by high flowrates, homogeneous mixtures and well planned flowmeter installation. [28]

Very briefly, the Coriolis mass flowmeters have the following features:

- Balanced dual – type system for universal use in a wide range of process conditions
- High vibration immunity
- Compact design, occupying very little space
- Hygienic design in accordance with the latest requirement
- Guaranteed product quality
- Robust field housing from aluminium or stainless steel
- Direct, in – line and accurate mass flow measurement of both liquids and gases
- Accuracies as high as 0.1% for liquids and 0.5% for gases
- Mass flow measurement ranges cover from less than 5 g/m to more than 350 tons/hr
- Measurement independent of temperature, pressure, viscosity, conductivity and density of the flowing mixture
- Mass flow, density and temperature can be accessed from the one sensor

Their advantages are the following:

- They are insensitive to viscosity, pressure and temperature.
- They can handle clean liquids, multiphase fluids, foams and slurries.
- They may be utilized for fluctuating flows.

Their disadvantages are the following:

- They are expensive
- Many models are affected by vibration
- Current technology limits the upper pipeline diameter to 150 mm
- Secondary containment can be an area of concern. [27], [37]

2.3.2.4 Tracer Techniques

The properties of a chemical compound in the flowing mixture can be utilized as a chemical tracer and characteristics such as temperature are physical tracers. Tracers may be artificially introduced, like dye tracers, or they may be naturally occurring such as radioactive materials. Tracer methods are typically utilized where flow measurement or removal of flow measurement equipment for calibration is not possible due to, for instance, the size, time or a complex or inaccessible environment. Owing to typical uncertainty levels involved, tracer methods would normally be utilized to verify that a meter is operating within an acceptable tolerance rather than providing a traditional calibration. There are two main methods which are:

- Tracer Dilution Method
- Tracer Transit Time or Pulse Method [34]

Tracer is added either in a small batch or continuously and its concentration or presence is monitored downstream. Although, in principle, any soluble material can be utilized as a tracer, in practice the main types of tracers are the following:

- Radioactive Isotopes
- Fluorescent Chemicals
- Fluorobenzoic Acids
- Other types of chemicals, which are utilized depending on the specific fluid to be measured. Some of these types are the following:
    - Inorganic Solutes
    - Inert Volatiles and Gases
    - Metal Complexes
    - Bacteriophages and Microspheres [34]

2.3.2.4.1 Tracer Dilution Method

The tracer solution with a concentration of c is injected at a constant rate q into the flow to be measured. At a point downstream, where the tracer is completely mixed with the flow the concentration is measured to c_m. The flow at the injection site Q is thus calculated from a tracer balance as:

$$Q = \frac{q \cdot c}{c_m}$$

For the measurement of more than one flowing phase the same principle can be applied using individual tracers for each phase. Said tracers must be in a form that only distributes into one phase and remains there. Furthermore, they must show such differences in the emitting gamma – radiation energy spectra that they can be simultaneously detected by on line gamma – spectrometry. [34]

Preferred candidate tracers for oil, gas and water are presented in following table:

Table 2: Candidate Tracers for Oil, Gas and Water [34]

Phase	Isotope	Half – Life	Gamma – Radiation of Interest (MeV)	Chemical Form
Oil	^{82}Br	36 hours	0.55 – 1.32	Bromobenzene
Gas	^{85}Kr	10.6 years	0.51	Noble Gas
Water	^{24}Na	15 hours	1.37 – 2.75	EDTA – Complex
	^{140}La	40 hours	0.33 – 2.54	

The tracers are injected simultaneously at a constant rate into the flow in the pressurized pipe and the concentration is detected as series of instantaneous measurements taken downstream after complete mixing. The phases' flows at the injection position as functions of time are calculated according to the following equations:

$$Q_o(t) = \frac{q_o \cdot c_o}{c_{mo}(t)}, \quad Q_g(t) = \frac{q_g \cdot c_g}{c_{mg}(t)} \quad \text{and} \quad Q_w(t) = \frac{q_w \cdot c_w}{c_{mw}(t)}$$

The average flow of a flowing phase is calculated from a number, n, of discrete measurements as:

$$\bar{Q}_p = \frac{\sum Q_p(t)}{n}$$

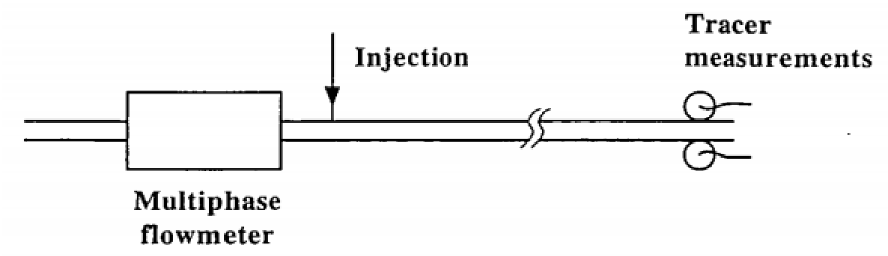


Figure 50: Tracer Technique [34]

These basic equations are valid under certain assumptions about the flow, such as limited axial dispersion along the pipe in relation to the variations in flowrate during measurements. We assume that these conditions are fulfilled to a satisfactory degree. In situ measurement of the concentration of radioactive tracers in the different phases requires that the phases are separated and arranged according to density difference over the measurement cross – section in a horizontal pipe. At the measuring point the tracer method thus covers stratified, wavy and slug flow, whereas bubble and annular flow cannot be measured. The potential appearance of said flow regimes, however, can be observed from the current measurements. [34]

One very characteristic way in order the tracer concentrations to be determined is the gammaspectrometric measurements with 2 detectors. According to this technique, the measurements are performed with two spectral gamma – detectors placed on top and bottom of the pipe respectively. In the case of three – phase flow, the detector measurements reveal the amounts of tracers in each phase as seen over a unit length of the pipe by the detectors (a_g, a_o, and a_w) and the position of the boundaries between the phases (b_{go} and b_{ow}). The cross – section area of each phase is calculated from the latter the inner radius (r) of the pipe using trigonometric formulas. From this the tracer concentrations (c_{mg}, c_{mo} and c_{mw}) and hence, the volume flows of the flowing phases are calculated. [34]

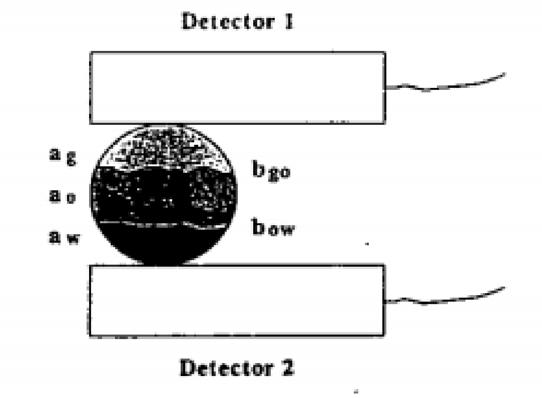


Figure 51: Detector Set – Up for Tracer Measurement in Three – Phase Flow [34]

2.3.2.4.2 Tracer Transit Time or Pulse Method

This method is similar to the previous one but instead of using concentration as a method to determine overall flowrate, the actual presence of the tracer is monitored instead. The tracer transit time technique involves a pulse of tracer fluid being injected into the main line and the time taken for tracer to pass between two detectors of known separation length measured. Thus, a velocity is determined from the length and time. If the cross – sectional area of the pipe between the two detectors is known, the volumetric flowrate of the target fluid can be estimated. In this technique, radioactive isotopes with short half – lives have primarily been utilized owing to their relative effectiveness to be detected and having reduced health and environmental risks due to being below normal contamination limits. A tracer is injected into the flowstream using an injection point. Two detectors are positioned sufficiently downstream of the injection point and as the tracer pulse passes the detectors, they respond to the presence of the tracer material and their output signals are sent to a data acquisition system. The time between the peaks of the response curves is the mean transit time of the tracer between the detectors, where the flow velocity is calculated. The linear velocity can be converted to volume flowrate by multiplying it with the mean cross – sectional area of the pipe. [35]

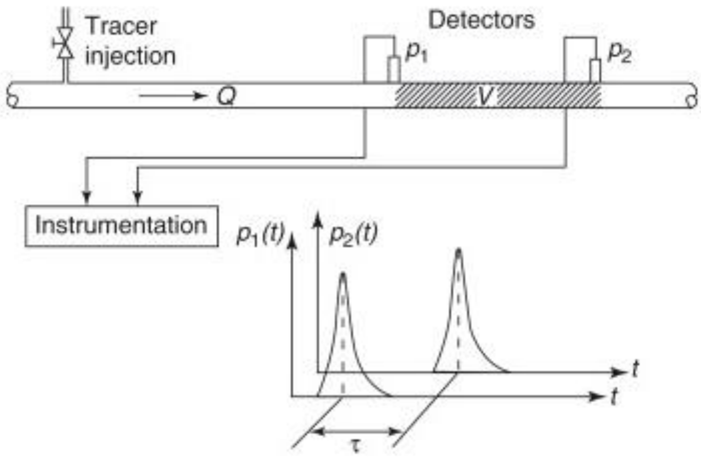


Figure 52: Tracer Transit Time Technique
Source: https://www.sciencedirect.com/topics/earth-and-planetary-sciences/flowmeters

This technique can be affected by the flow regimes and flow profiles. The application of tracers to multiphase flows indicates a number of potential issues with the methodology and subsequent measurements. For instance, intermittent flow regimes such as slug flow are generally un suitable for this method as the procedure assumes that a constant flow of each phase has passed during the time when the tracer is between both detectors. In addition, the velocity profile of each phase will not be uniform, this method essentially estimates a single velocity for all phases. Another source of error comes from the uncertainty associated with the internal cross – sectional area of the pipe between the two detectors. It is unlikely that this will be constant across the detectors and as such any deviations from the nominal pipe diameter will result in errors in the calculation of the volumetric flowrate. In addition, the flow conditions can influence the pipe geometry over time. If this is not accounted for the calculation errors will incur. [35]

Some of the difficulties associated with the application of tracer techniques to flow metering are:

- the achievement of a uniform distribution of the tracer throughout the flowing fluid
- the interphase mass transfer and mixing gives rise to a non – uniform modulation of the tracer
- the changes in flow pattern and velocity between the point where the tracer was added and the point of detection
- the tracer must be of a suitable density and must be clearly visible within the fluid. [4], [10]

Other potential applications for using tracers in the oilfield are the following:

- Drilling Muds
- Reservoir Management
- Production Logging
- Flare Gas/ Emissions Monitoring
- Corrosion/Wear Detection
- Leak Detection
- Facility Operations [35]

2.3.2.5 Thermal Mass Flow Meters

Thermal mass flow measurement is an almost direct method, suited for measuring gas flow. The measurements of such mass flowmeters are based on the thermal properties of the flowing fluid, such as specific heat and thermal conductivity, and hence, are capable of providing measurements which are proportional to the flowing fluid mass. Thermal flow meters can be divided into two categories:

- Flow meters that measure the rise in temperature of the fluid after a known amount of heat has been added to it. They can be called heat transfer flow meters.
- Flow meters that measure the effect of the flowing fluid on a hot body. These instruments are sometimes called hot wire probes or heated – thermopile flow meters. [27], [37]

2.3.2.5.1 Heat Transfer Flow Meter

The equations of this technique are the following:

$$Q = W\,C_P\,(T_2 - T_1) \qquad W = \frac{Q}{C_P\,(T_2 - T_1)}$$

where: Q the heat transferred (cal/hr)

W the mass flowrate of fluid (kg m/hr)

C_P the specific heat of fluid (cal/kg m °C)

T_1 the fluid temperature before heat is transformed to it (°C)

T_2 the fluid temperature after heat has been transferred to it (°C)

Heat is added to the flowstream with an electric immersion heater. The power to the heater equals the heat transferred to the fluid and is measured by a Watt meter. T_1 and T_2 are thermocouples or resistance thermometers. By measuring Q, T_1 and T_2, the flowrate can be calculated as specific heat of the fluid is known. T_1 and T_2 do not have to be separately detected; they can be connected together so that the temperature difference is measured directly. [37]

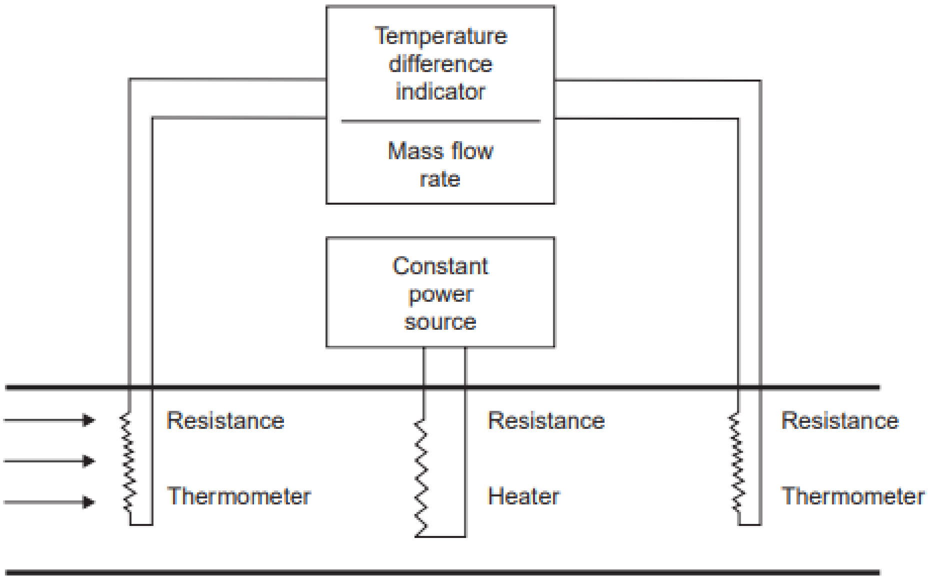


Figure 53: Heat Transfer Flow Meter [37]

2.3.2.5.2 Hot Wire Probes or Heated – Thermopile Flow Meter

In this design two thermocouples (A and B) are connected in series forming a thermopile. This thermopile is heated by passing an alternating current through it. A third thermocouple (C) is placed in the direct current output circuit of the thermopile. Alternating current does not pass through this thermocouple, and it is therefore not electrically heated. This assembly is inserted into the flowstream, which is usually gas. The gas cools the heated thermopile by convection. Since the AC input power to the thermopile is held constant, the thermopile will attain an equilibrium temperature and produce an electromagnetic flow meter, that is a function of the gas temperature, velocity, density, specific heat and thermal conductivity. The third, unheated thermocouple (C) generates an electromagnetic flow meter that is proportional to the gas temperature. This cancels the effect of the ambient gas temperature on the output signal of the heated thermopile. The output signal of this instrument is given by the following equation:

$$e = \frac{C}{2\,(\pi\, KC_P\, \rho\, dv)^{1/2} + K}$$

where: e the generated voltage

C the instrument constant

K the fluid thermal conductivity

C_P the fluid specific heat

d the diameter of heated thermocouple wire

v the fluid velocity

ρ the fluid density

Since K is very small, and since the term $(KC_P \rho)^{1/2}$ remains constant over a wide range of temperatures, this type of instrument can be used to measure the gas mass flowrate. [37]

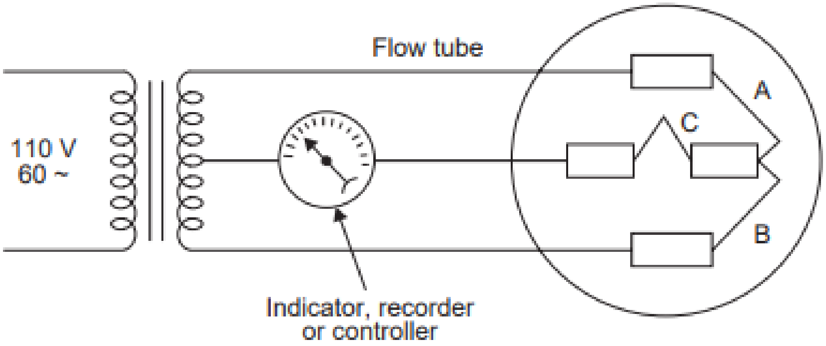


Figure 54: Hot Wire Probes or Heated – Thermopile Flow Meter [37]

2.3.3 Measurement of Velocity of the Mixture or of each Phase

2.3.3.1 Cross – Correlation Flow Meter

The cross correlation measurement theory has been found since 1930, but until 1960 it was not utilized practically by the industries. Cross – Correlation measurement method is widely utilized in order the rate of flow change in the tubing to be measured by deriving the transit time of a tagging signal in the flowstream through a pair of parallel mounted sensors on the target conduit. When a two – phase flow is prevailed in a tubing, then it causes a random disturbance signals, which can be identified by several transducer types. Moreover, the cross correlator measures also the signal transit time. The two waveforms' resemblance is measured as an assignment of a time log applied to one of them. The main goal of this technique is to measure the time taken by a disturbance to pass between two points spaced along the flow direction. [30]

The cross – correlation method is a standard signal processing method, which determines the flow velocity. Its operation principle is based on the measurement of some flow property by two identical sensors at two different locations in the meter, separated by a known distance. When the flowing mixture passes the two sensors, the signal pattern measured by the first sensor will be repeated at the downstream sensor after a short period of time, dt, corresponding to the time it takes the flow to travel from the first to the second sensor. The signals from the two sensors can be input to a cross – correlation routine, which moves the signal trace of the second sensor over the signal trace of the first sensor in time. The time – shift that gives the best match between the two signals corresponds to the time it takes the flow to travel between the sensors. Thus, after the distance between the sensors is known, then is possible the flow velocity to be estimated. [4]

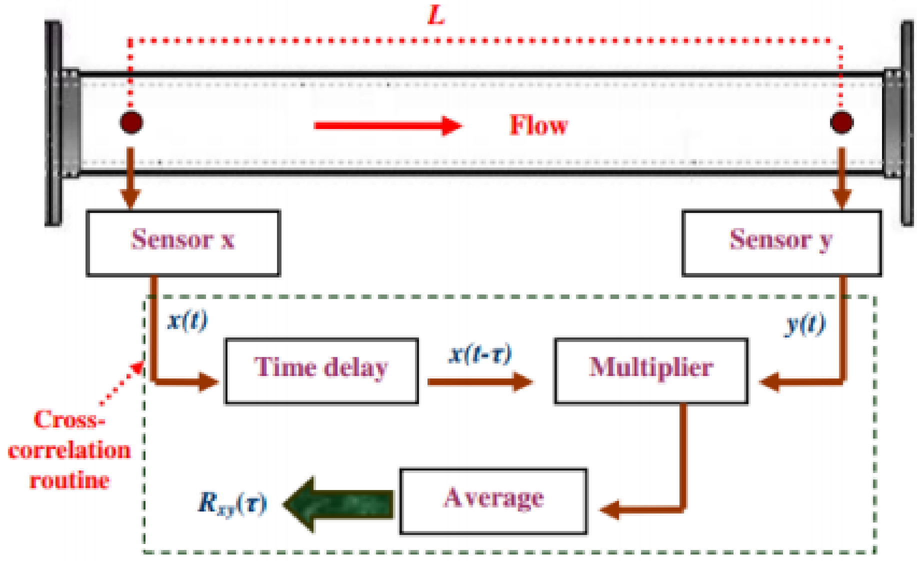
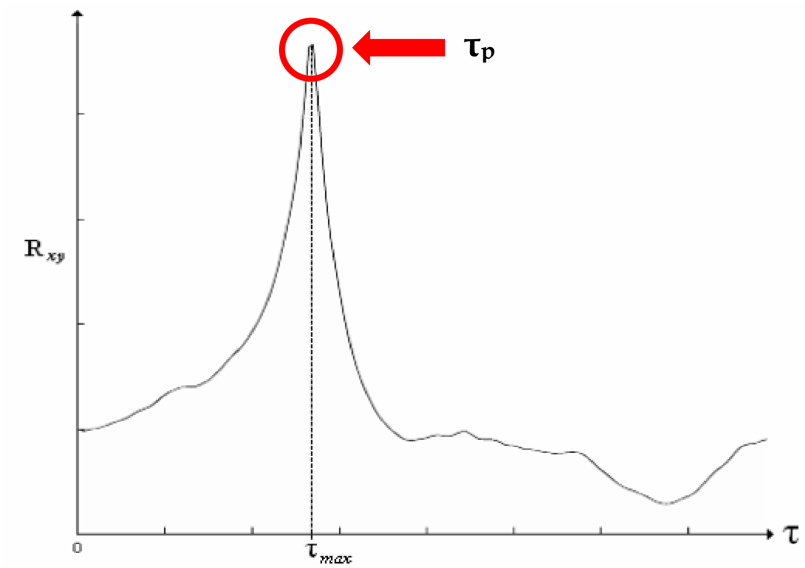


Figure 55: Cross – Correlation Measurement Technique
Source: Hasan, PhD Thesis, University of Huddersfield, 2010

The cross – correlation function, $R_{xy}(\tau)$ of two random signals, x(t) and y(t) can be mathematically expressed as:

$$R_{xy}(\tau) = \lim_{T \to \infty} \frac{1}{T} \int_{0}^{T} x(t-\tau).y(t)\,dt$$

where τ is variable time delay of signal output x(t) and T is time period over which the signals x(t) and y(t) are sampled. The cross – correlation function, $R_{xy}(\tau)$ is plotted as a function of τ, as it is shown in the following diagram. The maximum value (peak) of $R_{xy}(\tau)$ will occur at $\tau = \tau_p$, where τ_p is the time shift between the maximum similarities in the two measurement signals. Thus τ_p can be measured by obtaining the value of τ which gives a maximum value of $R_{xy}(\tau)$. [30]



Since the distance between two sensors, L is known, the average fluid velocity, $\overline{U}$ can be expressed as:

$$\overline{U} = \frac{L}{\tau_p}$$

The flow measurements by cross – correlation method is similar with the tagging or tracing techniques due to the detection of transit time. Any measurable process variable which is noisy may be utilized in order a correlating flowmeter to be built. The noisy pattern must persist long enough to be seen by both detectors as the flowstream travels down the conduit. The flow velocity is determined by dividing the distance between the two detectors with the transit time. The sensing method is classified into three main categories, the measurement of electrical and thermal properties of the flowing mixture, the radiation emission of the flowing mixture and the radiation modulation by flowing mixture. There are a plenty of methods, which could be utilized in order whatever measuring problem to be overcome. The reliability and cost of the aforementioned sensing devices are the major factors of their choice in industrial process. In the case of cross – correlation measurements, time delay of the signals between the sensors do not depend on the gain. Hence, the sensor gain and stability is not essential in this case. Some types of such sensors are mentioned below:

- Electro conductive sensors
- Thermal sensors to correlated injected heat pulses
- Electrostatic sensors
- Cross – correlation measurement capacitance sensors [30], [37]

2.3.3.2 Ultrasonic Flow Meters

Ultrasonic waves are sound waves which have frequencies higher than those to which the human ear can respond. These waves are very applicable in engineering processes and are divided into two categories, the low – amplitude vibrations and high energies. In the first category, the effect of the medium on the incident waves is important, but in the second one the changes brought about on the medium by the waves is important. Therefore, during the measurement process only low – amplitude ultrasonic waves are being utilized. The main principle of its method is based on the fact that the reflection, absorption, and scattering effects of the medium on the incident ultrasonic waves are utilized in order the wanted information about the measured medium to be determined. The ultrasonic meters were first utilized almost 60 years ago and nowadays their manufacturers are producing fifth generation products which can carry out measurements in both single – phase and two – phase flows. [10]

When ultrasonic flow measurements are carried out, ultrasonic signals ought to be transmitted and received by ultrasonic transducers, which are the most essential parts of any ultrasonic sensor. The aforementioned transducers convert an electrical signal, such as a voltage pulse, into an acoustic signal, such as a sound pressure pulse, and vice versa. The temporal and spatial radiation characteristics of these components are the prime determinants of sensor performance. Furthermore, in order zero drift problems to be avoided, it is important the characteristics of any pair of sensors to be matched when they are utilized in an ultrasonic flow measurement. The transducers must have a finite size in order to generate ultrasonic beams at adequate sound levels. The generated ultrasonic beam will have a definite directionality and the beam shape and width and the number of side lobes will be determined by the ratio of the acoustic wavelength to the transducer effective size. So, the smaller this ratio is, the more directional the transducer will be and hence, the narrower the ultrasound beam will be. It is known that all acoustic beams spread and as a result, the sound pressure level is gradually decreased along the beam. [10]

In the case of gas ultrasonic flow meters, the transducers are usually directly exposed to the inside of the conduit, which means that they are exposed to corrosive gases, traces of liquids and particles and to large variations of pressure, temperature and humidity without compromising their acoustic performance to any significant degree. Therefore, in real measurement conditions many of the ultrasonic transducers' operation aspects should be taken into consideration in order to be ensured that an accurate, operationally safe and reliable ultrasonic flow measurement will be carried out. Piezoelectric transducers, whose surface is usually a plane circle, are utilized in such metering processes. Nonetheless, the piezoelectric element's acoustic impedance is much higher than that of the flowing mixture and hence, a matching layer of suitable materials may be utilized between the flowstream and the transducer in order the acoustic efficiency to be maximized. Moreover, the matching layer's acoustic impedance will be between that of the flowing mixture and that of the piezoelectric crystal. Such ultrasonic flow meters with piezoelectric transducers are usually utilized for measurements of single - phase liquids. Nevertheless, disoperations arise when it is tried to be carried out gas flow measurements due to the big difference in acoustic impedance between the transducer and the gas. Ultrasonic flow measurement methods for multiphase flows have been introduced by several researchers, who concluded that the ultrasonic three – phase flow measurements are possible to be carried out. [10]

However, there are strict limits on the applicability of ultrasonic flow meters to multiphase fluids. Ultrasonic flow meters are usually selected for the following reasons:

- ultrasonic equipment provides measurements independently from the type of flow phase
- the equipment is relatively easy to use
- the flow regime can be laminar, transitional or turbulent
- transducers are minimally invasive
- there is no extra pressure drop
- the instrument has a fast response
- the instrument is generally reliable except at extreme temperatures
- the capital and running costs are reasonable

Ultrasonic flow meters with quadrature or other special – path or multi – path configurations are the most accurate and have laboratory calibration accuracies typically around 0.5% of reading, or better, over most of the meter’s flow range. Flow conditioners and straight tubing contribute to this accuracy achievement, even if the flow disturbances are taken place in the upstream tubing. The manufacturers of ultrasonic meters, when they are ideally installed, claim a meter uncertainty around ±0.5% for the dry gas flow and moreover, when the meter carries out a velocity measurement, it does not have the restrictions at high Reynolds number, which apply to differential pressure meters. The ultrasonic flow meters' main principles allow flexibility in design and therefore, a wide range of them is available in the market. The modern ultrasonic flow meters utilize contra – propagating transmission, single and multiple transducers, single and multiple paths, passive and active principles for liquid level sensing, for determination of flowrates in open channels or partially or full conduits and other interactions. Ultrasonic meters measure the gas velocity through the meter body. Hence, after the velocity and the cross – section area are known, the uncorrected volume flowrates can be estimated. [10]

After researches, it seems that ultrasonic meters give accurate results for dry gas flow, provided they are installed in the tubing and work independently from any flow disturbance. The measurement system does not consist of moving parts, does not create an additional pressure drop and is insensitive to gas composition fluctuations. Their fast response allows measurements in transient or pulsating flows and also provide bidirectional flow measurements. Furthermore, this measurement system can significantly reduce installation and maintenance cost. Nevertheless, the aforementioned ultrasonic meters' advantages for the case of dry gas are offset by some significant problems, which are cased when these meters are being utilized for dry gas metering during production. The wrong meter location in the metering system affects negatively the measurement process. More specifically, if the meter is too close to bends, valves or other obstructions, the resulting swirl can seriously affect the velocity profile and hence, the flowrate's measurement accuracy. Moreover, the bonding material utilized in the ultrasonic transducers' manufacture tends to fail at temperatures in excess of 150°C and when there is a sudden pressure fluctuation. [10]

The ultrasonic flow meters are divided into two types:

- **Transit Time Flow Meter**, whose operation principle is based on sending an ultrasonic beam diagonally through the tubing, such that the beam crosses the tubing in the radial direction, but also travels along or against the flow direction, that is along the axial direction as well. The difference in travel time between the two diagonal paths can be utilized in order the flow velocity to be estimated. Hence, by knowing this time difference and the sound speed, then with simple geometric calculations the average flow velocity along the ultrasonic beam's direction can be determined. Moreover, by knowing the velocity distribution in the conduit, then the measured velocity can be corrected in order the cross – section area average velocity and also the volumetric flowrate to be determined. [31]

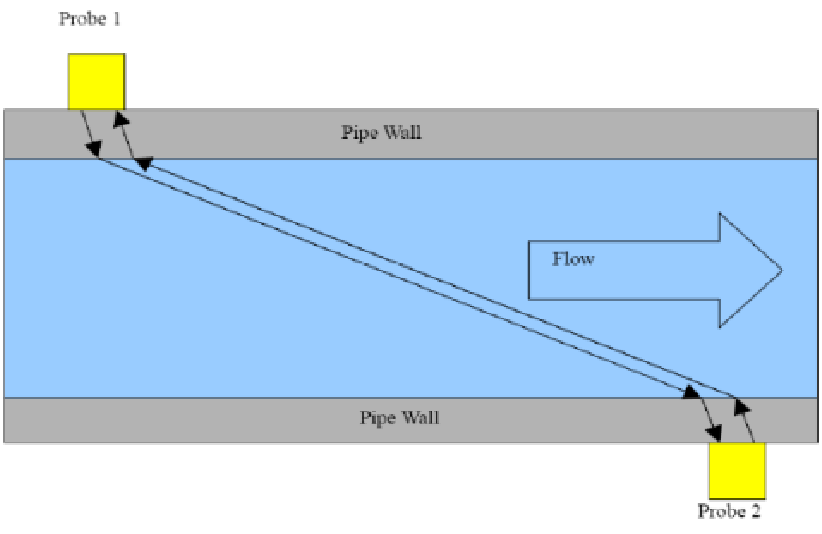


Figure 56: Transit Time Flow Measurement Technique [31]

The meter comprises two transducers (A and B) mounted at an angle to the flow and having a path length L, as it is depicted in the following figure, with each acting alternately as the receiver and transmitter. The transit time of an ultrasonic pulse, from the upstream to the downstream transducer, is first measured and then compared with the transit time in the reverse direction. [27]

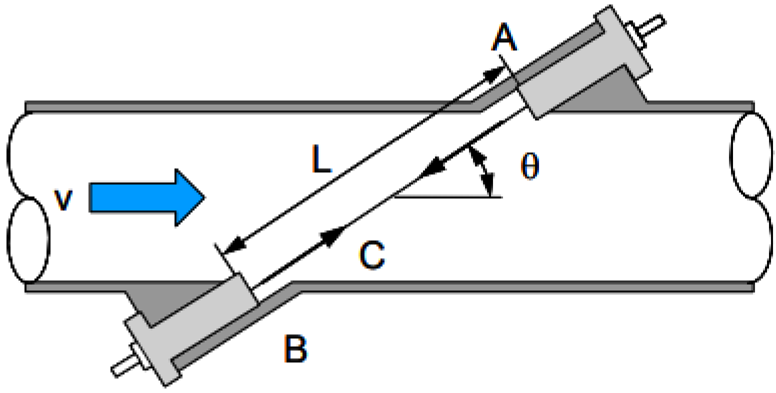


Figure 57: Transit Time Flow Measurement Technique with Two Transducers A and B [27]

Mathematically:

$$T_{AB} = \frac{L}{(C \quad v\cos\theta)} \quad \text{and} \quad T_{BA} = \frac{L}{(C + v\cos\theta)}$$

where:
T_{AB} = upstream travel time
T_{BA} = downstream travel time
L = path length through the fluid
C = velocity of sound in medium
v = velocity of medium

The difference in transit time ΔT is:

$$\Delta T = T_{AB} - T_{BA} \longrightarrow \Delta T = \frac{2Lv\cos\theta}{(C^2 \quad v^2\cos^2\theta)}$$

Since the velocity of the medium is likely to be much less than the velocity of sound in the medium itself, the term $v^2 \cos^2\theta$ will be very small compared with C^2 and may thus be ignored for all practical flow velocities. Thus:

$$\Delta T = \frac{2Lv\cos\theta}{(C^2)} \longrightarrow v = \frac{\Delta T C^2}{2L\cos\theta}$$

This shows that the flow velocity v is directly proportional to the transit time difference ΔT. This also illustrates that v is directly proportional to C^2 (the square of the speed of sound) which will vary with temperature, viscosity, and material composition. [27]

- **Doppler Flow Meter**, whose operation principle is based on reflecting ultrasonic beams off of particles (dirt, gas bubbles or strong eddies) moving with the flow. However, this technique has limited application and accuracy. Since moving particles within the flowstream do not necessarily move at the velocity of the cross – section average flow velocity, the accurate Doppler measurement method needs the knowledge of the relationship between particle velocity and average flow velocity, which is not always available. Furthermore, by carrying out Doppler flow measurements may require inserting the meter into the flowstream, making it no longer non – intrusive, which means that it loses the ultrasonic flow meters' advantages. [31]

As aforementioned, in the Doppler ultrasonic flowmeter, an ultrasonic beam, usually of the order of 1 to 5 MHz, is transmitted, at an angle, into the flowstream, as it is depicted in the following figure. Assuming the presence of reflective particles in the flowstream, some of the transmitted energy will be reflected back to the receiver. Because the reflective particles are moving towards the sensor, the frequency of the received energy will differ from that of the transmitted frequency, which is the so called the Doppler effect. This frequency difference, the Doppler shift, is directly proportional to the velocity of the particles. [27]

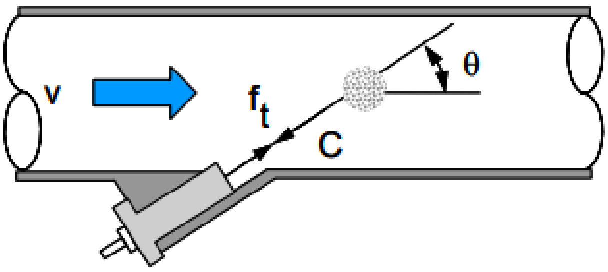


Figure 58: Doppler Flow Measurement Technique [27]

Assuming that the media velocity (v) is considerably less than the velocity of sound in the media (C), the Doppler frequency shift (Δf) is given by:

$$\Delta f = \frac{2 f_t \, v \cos\theta}{C}$$

where f_t is the transmitted frequency.

From this it can be seen that the Doppler frequency, Δf, is directly proportional to flowrate. The main disadvantage of this technology is that in multiphase flows, the particle velocity may bear little relationship to the media velocity. Even in single phase flows, because the velocity of the particles is determined by their location within the pipe, there may be several different frequency shifts, each originating at different positions in the pipe. As a result, the Doppler method often involves a measurement error of 10% or even more. [27]

2.3.3.3 Turbine Flow Meter

The turbine flow meter is essentially a turbine rotor which rotates as the fluid passes through its blades. The turbine output, registering a pulse for each passing blade, can be used in order the velocity and the volumetric flowrate of the flowing mixture to be estimated. The turbine meter is available in sizes from 5 to 600 mm and usually comprises an axially mounted bladed rotor assembly, which runs on bearings and mounted concentrically within the flowstream by means of upstream and downstream support struts. The support assembly also often incorporates upstream and downstream straightening sections to condition the flowstream. The rotor is driven by the medium (flowing fluid) impinging on the blades. The easiest way in order the rotor speed to be measured is by means of a magnet, which is fitted within the rotor assembly and induces a single pulse per revolution in an externally mounted pick – up coil. In order the resolution to be improved, the externally mounted pick – up coil is integrated with a permanent magnet and the rotor blades are made of a magnetically permeable ferrous material. As each blade passes the pick – up coil, it cuts the magnetic field produced by the magnet and induces a voltage pulse in the coil. In order the resolution to be improved even more, especially in large turbine meters 200 mm and above, where the rotor operates at much lower angular velocities, small magnetic bars are inserted in a non – magnetic rim that is fitted around the blades. This modification can improve the pulse resolution by as much as ten times. [27]

The flowing fluid impinges on the blades of turbine (rotor), imparting a force to the blade surface which causes the rotor rotation. At a steady rotational speed, the rotor speed is directly proportional to the fluid velocity, and hence, to the volumetric flowrate. The rotation speed is monitored in most of the meters by a magnetic pick – up coil, which is fitted to the outside of the meter housing. The magnetic pick – up coil consists of a permanent magnet with coil windings which is mounted in close proximity to the rotor but external to the fluid channel. As each rotor blade passes the magnetic pick – up coil, it generates a voltage pulse which is a flowrate measurement and the total pulses' number give a total flow measurement. By using digital techniques, it is possible the electrical voltage pulses to be totaled, differenced and manipulated so that a zero error characteristic of digital handling is provided from the electrical pulse generator to the fluid readout. [37]

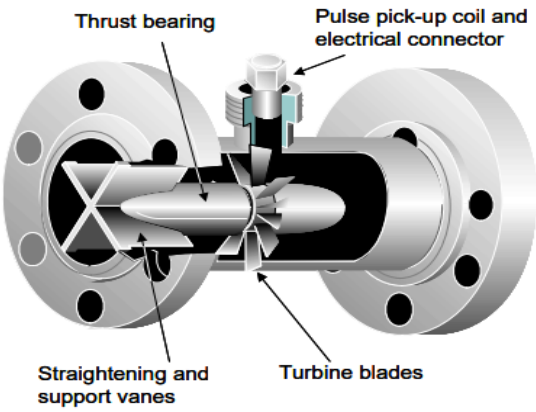


Figure 59: Turbine Flow Meter [37]

The main factor, which influences the turbine meter's operation, is fluid viscosity. It has been observed that larger meters are less affected by fluid viscosity than smaller meters. Therefore, someone may think that larger meters would be preferred, but in fact the opposite is true. When a smaller meter is utilized, the operation is more likely to occur towards the maximum permitted flowrate and away from the non – linear 'hump' response at low flows. Turbine meters are specified with minimum and maximum linear flowrates that ensure the response is linear and the other specifications are met. For good rangeability, it is recommended that the meter be sized such that the maximum flowrate of the application be about 70 to 80% of that of the meter. In the case of liquid flows, the maximum flowrate is usually limited by the cavitation effect, which occurs when the system pressure drops to a point at which the liquid and the dissolved gas in it 'boil off' at critical points in the meter where hydrodynamic forces cause a low pressure region. Cavitation can be avoided by retaining a sufficiently high back pressure and by keeping the pressure loss through the meter at a minimum. [27]

The advantages of turbine meters are:

- It has better accuracy from ± 0.25% to ± 0.5%.
- It provides excellent repeatability and rangeability.
- It has fairly low pressure drop.
- It is easy to install and maintain.
- It has good temperature and pressure ratings.
- It can be compensated for viscosity variation. [37]

The disadvantages of turbine meters are:

- High cost.
- They cannot maintain its original calibration over a very long period and therefore periodical recalibration is necessary.
- They are sensitive to changes in the viscosity of the fluid passing through the meters.
- They are sensitive to flow disturbances.
- Due to high bearing friction is possible in small meters, they are not preferred well for low flowrates. [37]

3.1 Separation Type Multiphase Flow Meters

Separation type multiphase flow measurements are carried out by performing a complete or partial separation of the multiphase flowstream and afterwards, in – line measurements of each of the three flowing phases are carried out. Test separator is basically a two – phase or three – phase separation type meter and it takes place on nearly every production platform. In the context of the present Master Thesis, the main types of separation multiphase flow measurements will be presented without extensive analysis. [4]

3.1.1 Full Two – Phase Gas/Liquid Separation

This meter's operation principle is based on the multiphase flow's separation, which is usually a full separation to gas and liquid phase. The gas flowrate is then measured by a single – phase flowmeter with good tolerance to liquid carry over, and the liquid flowrate is also measured by a liquid flowrate meter. Furthermore, there is also an on – line water fraction meter, through which the water in liquid ratio can be estimated. [4]

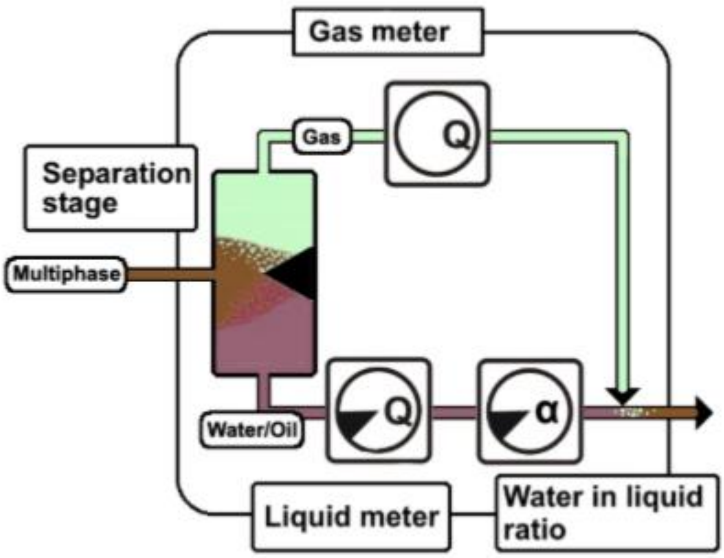


Figure 60: A Full Two – Phase Gas/Liquid Separation Type Multiphase Flow Meter [4]

3.1.2 Partial Separation

This meter's operation principle is based on the separation of only a part of the gas into a secondary measurement loop around the main loop through the multiphase flowmeter. Nonetheless, since the separation is only partial, it is expected some liquid to travel with the gas through the secondary measurement loop and hence, the process is called wet gas measurement. The remaining multiphase flowing mixture will have a reduced GVF and thereby operate within the designed envelope of the flowmeter. [4]

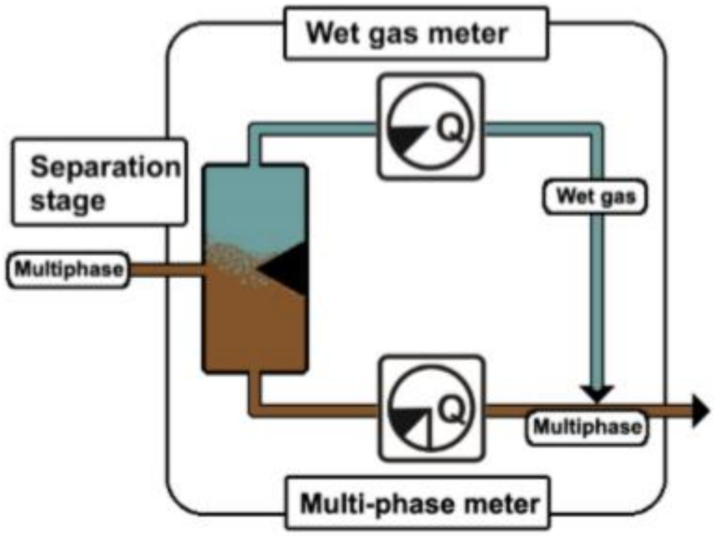


Figure 61: A Partial Separation Type Multiphase Flow Meter [4]

3.1.3 Separation in Sample Line

This meter's operation principle is based on the fact that separation is not performed on the total multiphase flow, but on a bypassed sample flow. This sample flow is typically separated into a gas and liquid flow, where after the water in liquid ratio of the liquid sample flowstream can be determined by utilizing an on – line water fraction meter. Total gas – liquid flowrate and ratio must be measured in the main flow line and by assuming the bypassed sample flow is representative of the main flow, the water in liquid ratio is based on the bypass measurement of this parameter. [4]

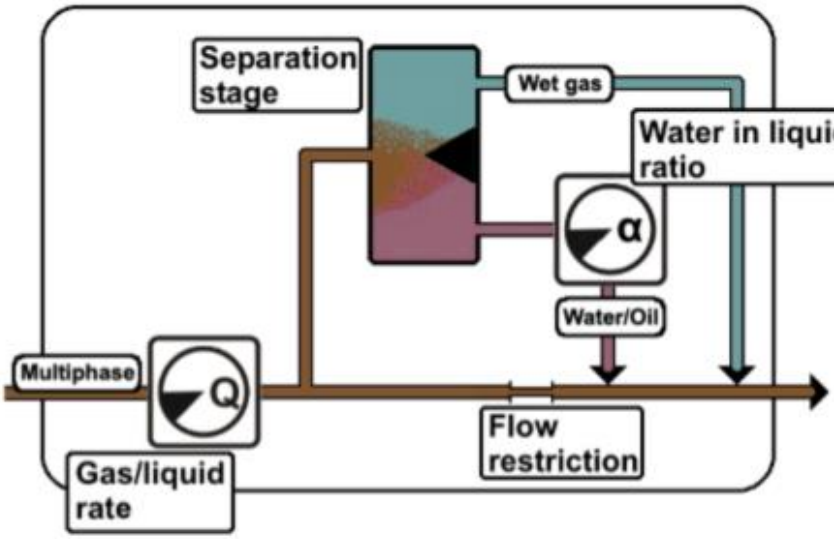


Figure 62: A Separation in Sample Line Type Multiphase Flow Meter [4]

3.2 Wet Gas Flow Meters

There are several types of applications for wet gas meters, some of which are distinctly different:

- ❖ As aforementioned, gas measurements are carried out with some entrained liquid, which has no value and causes problems during the gas measurements. The main goal is the correction, which should to be made in order a correct gas measurement to be achieved. A single – phase meter is usually utilized, corrected for liquid fraction.
- ❖ Measurement of hydrocarbon fluids and water. Moreover, the liquid needs to be measured but the WLR is unknown or unimportant.
- ❖ Measurement of hydrocarbon fluids and water, where the hydrocarbon fluids are measured.
- ❖ Water measurement and water fraction's small changes. This application can take place as flow assurance in order the hydrate mitigation and corrosion inhabitation to be overcome. This is a difficult task because the water fraction may be very low and the changes in water fraction even lower. Water is of primary interest, but is normally available only as a fraction. Hence, gas flow must be measured accurately in order the water flowrate to be determined.
- ❖ Measurement of water salinity or changes in water salinity. The purpose is to be able to monitor wells for water breakthrough. [4]

A wet gas flow meter can be installed as a stand – alone system or in conjunction with a partial separation system. It can be operated as a combination of the aforementioned measurement methods. For instance, wet gas can be measured by single – phase flow meters such as Venturi or V – Cone meters. Nevertheless, when single – phase meters are utilized for wet gas flow measurements, then the standard single – phase measurement models must be corrected by utilizing various models and correction factors in order the presence of liquid in the gas to be compensated. Other wet gas flow meters measure two phases, hydrocarbons and condensate with content water.

Furthermore, there are in – line three – phase wet gas flow meters. Some wet gas meters can even discriminate between produced water, condensate water and formation water by measuring the water salinity. Gas density may be calculated by means of PVT from gas composition, pressure and temperature. Water content may be calculated from the assumption that the gas is saturated in the reservoir. [4]

A wet gas flow can be defined by Lockhart – Martinelli parameter, which is a dimensionless number ranging from 0 to 0.3. Zero is representing a completely dry gas. The Lockhart – Martinelli parameter can be determined by the following equation:

$$X_{LM} = \sqrt{\frac{SuperficialLiquidInertia}{SuperficialGasInertia}} = \frac{m_l}{m_g}\sqrt{\frac{\rho_g}{\rho_l}}$$

where m_l, m_g, ρ_l and ρ_g are the mass flowrate and density of the liquid and gas respectively. In order the wet gas flow pattern to be predicted, the Lockhart – Martinelli parameter is utilized in combination with the gas and liquid densimetric Froude number. The gas and liquid densimetric Froude number can be determined by the following equations:

$$Fr_g = \frac{U_{sg}}{\sqrt{gD}}\sqrt{\frac{\rho_g}{\rho_l - \rho_g}}$$

$$Fr_l = \frac{U_{sl}}{\sqrt{gD}}\sqrt{\frac{\rho_l}{\rho_l - \rho_g}}$$

where D is the conduit internal diameter, g is the gravitational constant, ρ_g and ρ_l are the densities of gas and liquid, and U_{sg} and U_{sl} are the superficial gas and liquid velocities calculated by the following equations:

$$U_{sg} = \frac{m_g}{\rho_g A}$$

$$U_{sl} = \frac{m_l}{\rho_l A}$$

where m_g and m_l are the mass flow of gas and liquid. [24]

3.3 Other Types of Multiphase Flow Meters

Other types of multiphase flow meters consist of advanced signal processing systems, the "virtual" measurement systems, which estimate phase fractions and flowrates from analysis of the time – variant signals from whatever sensors are available in the multiphase flowstream. Such sensors may be acoustic, pressure or other types. The signal processing may be a neural network or other pattern – recognition or statistical signal – processing system. [4]

The determination of how much the wells are producing for effective production optimization and reservoir management, is very important to engineers. All the aforementioned can be achieved by the use of multiphase flow meters, which can provide continuous flowrate measurements. Nevertheless, the installation of multiphase flow meters may not be possible for all wells due to high costs and difficult access for maintenance, calibration or replacement in case of malfunction. Hence, a real – time software application, which is called Virtual Flow Meter, may provide a continuous determination of oil, gas and water flowrates for all wells. This software is built based on the hydraulic models from the reservoir to the surface facilities. Several studies have been carried out during the last decade on virtual flow measurement technology. They present encouraging results, which prove that a virtual flow measurement model can be applied as a multiphase flow measurement, as a metering backup or a malfunction monitoring tool and also for production allocation applications. Although the virtual flow measurement technology is accepted as an alternative solution for multiphase flow measurement, especially in subsea systems, there are still severe limitations on its technology application. Nonetheless, the last decade's research show that virtual flow measurement technology has acceptable accuracy for several different virtual flow measurement models and for wide range of field conditions. [32]

There are also multiphase metering systems that have been developed on the basis of process simulation programs combined with techniques for parameter estimation. Instead of predicting the state of the flow in a pipeline at the point of arrival, its pressure and temperature can be measured at the arrival point and put into the simulation program. In addition, the pressure and temperature of an upstream or downstream location must also be measured. When the pipeline configuration is known along with properties of the fluids, it is then possible to make estimates of phase fractions and flowrates. [4]

CHAPTER 4

4.1 Performance Specification of Multiphase Flow Meters

The performance of MPFMs is a main element which determines if the measurement techniques may be implemented in a specific application and which of them are most suitable in order to be selected. Nonetheless, there is a need for more standardized performance specification of MPFMs, both for comparison of measuring ranges and measurement uncertainties but also for more efficient selection of technology and operation of the systems. More standardized performance specifications can help engineers compare MPFMs proposed from different manufacturers for specific applications. Furthermore, a performance specification includes also other equally important properties such as, rated operating conditions, limiting conditions, measuring ranges, component performances, sensitivities, influence factors, stability and repeatability, which should also be described and specified in order the correct overall performance and systems' use to be ensured. [4]

4.1.1 Technical Description

Manufacturers of MPFMs, due to the complexity of multiphase flow metering systems, ought to provide clear technical descriptions of their products as part of the performance specification. This is an essential prerequisite in order the engineers to evaluate the suitability and expected performance of an MPFM for a specific application. The technical description should include:

- general overview of the MPFM and its operation principle
- descriptions and specifications for all sub – systems/ primary measurement devices such as sensors, transmitters, software, computers, that can affect the meter performance
- general outline of the basic measurement principles and models that can help the user in assessing and predicting the meter behavior
- description of configuration parameters and required input data. [4]

4.1.2 Specification of Individual Sensors and Primary Devices

A MPFM system is based on a number of individual sensors and transmitters that each directly influence the overall quality of the measurements. Detailed descriptions of the individual sensors and primary devices and their measuring ranges, limiting conditions of use and measurement uncertainties should therefore, be included in the performance specification. This applies to for example:

- Pressure and temperature measurement devices
- Differential pressure measurement devices
- Gamma – ray instruments
- Electrical sensors such as capacitance, conductance and microwave systems
- Densitometers [4]

4.1.3 Specification of Output Data and Formats

All measurements output from the MPFM to the user should be clearly described and documented with corresponding output formats and units. It should be clearly stated whether data are reported at actual or reference conditions. If data are converted to reference conditions, the method and models used in these calculations should be specified, including specification of uncertainties and validity ranges.

A three – phase MPFM normally provides the following outputs:

- Oil, gas and water flowrates
- Phase volume fractions
- Pressure and temperature

Instruments that have been developed specially for measurement in wet gas typically provide the following outputs:

- Gas and liquid flowrates
- Gas and water flowrates
- Gas, oil and water flowrates
- Pressure and temperature [4]

4.1.4 Measuring Range, Rated Operating Conditions and Limiting Conditions

The performance specification should include information about:

- **Measuring Range**, which is the range within which the MPFM operates according to its specification.
- **Rated Operating Conditions**, which is the range within which specified metrological characteristics of a measuring instrument are intended to lie within given limits.
- **Limiting Conditions** for which the MPFM and its components can be used without failure or irreversible change in performance. [4]

4.1.5 Measurement Uncertainty

If engineers want to utilize a MPFM in a specific application, then the meter has to be evaluated with respect to combined expanded measurement uncertainty for the various measurements, which will be performed. Such an uncertainty evaluation must include the uncertainties of the quantities input to the MPFM and the functional relationships used. This evaluation should also include the implementation of the models and measurement procedures in the MPFM, in order to consider the meter as it really operates. Uncertainty calculations should be performed according to the principles of the ISO Guide to the expression of uncertainty in measurement. [4]

4.1.5.1 Measurement Uncertainty Evaluation of MPFMs

MPFMs are complex and extensive systems, which are consisted of a number of subsystems and primary devices that are closely integrated, and hence, a complete quantitative uncertainty evaluation may not be possible. Furthermore, a complete quantitative uncertainty evaluation is most certainly not sufficient, since the major sources of uncertainty in these meters are related to less quantifiable multiphase flow regimes. Therefore, uncertainty evaluation should also include results from independent laboratory tests and field tests to document the meter measurement uncertainty for various relevant flow regimes. The confidence level of the specified measurement uncertainties of MPFMs should be clearly stated, and 95% (k=2) should be the default confidence level. Measurement uncertainties can be specified both as absolute or relative uncertainties and for MPFMs flowrates are normally specified with relative uncertainties and phase fractions are normally specified with absolute uncertainties. Generally, as the MPFMs' development is being progressed, the minimum achievable uncertainty went from approximately ± 20% in each phase down to ± 5% – 10% of reading and water cut at ± 2% absolute. [4]

4.1.5.2 Influence Quantities and Sensitivity Coefficients

Except from the aforementioned quantitative evaluations, a qualitative evaluation is also performed in order the influence quantities to be considered. Influence quantities are quantities that are not the measured, but that still affect the result of measurement. Examples of influence quantities to MPFMs are:

- flow regimes
- salinity variations
- additives such as emulsifiers, wax inhibitors and corrosion inhibitors
- scale, wax and hydrates
- pressure loss
- vibrations
- viscosity variations
- fluid properties such as water salinity and conductivity, oil permittivity and fluid densities
- ambient temperature and pressure variations
- sand
- installation effects, upstream straight lengths and bends

The effect of influence quantities on the measurements can be estimated by sensitivity coefficients. Sensitivity coefficients describe how the output estimate varies with changes in the value of an input estimate or quantity and should be given to quantify the effect of these factors on the combined expanded uncertainty of the MPFM measurements. For instance, the sensitivity coefficient for salinity influences on the WLR measurement can be given as a % variation of WLR per % change in salt content. [4]

4.1.5.3 Reproducibility and Repeatability

The reproducibility of a meter is a quantitative expression of the closeness of the agreement between the results of measurements of the same value of the same quantity, where the individual measurements are made under different conditions. One significant difference between MPFMs and single - phase meters is that most of the uncertainty of a multiphase meter is caused by variations in process conditions and fluid properties, rather than the uncertainty of the primary measurement devices. Therefore, the meter’s ability to reproduce its performance under different process conditions, installation set – ups and flow regimes becomes a very important factor. The reproducibility of a MPFM for a set of flowrates may be established by recording the deviation between values measured by the meter and reference values obtained from different test facilities. The repeatability of a MPFM should also be specified. It is a quantitative expression of the closeness of the agreement between the results of successive measurements of the same measuring instrument carried out under the same measurement conditions, i.e. by the same measurement procedure, by the same observer, with the same measuring instrument, at the same location at appropriately short intervals. Generally, repeatability values fluctuate from ±0.02% to ±0.1%. [4]

4.1.5.4 Stability and Time Response

MPFMs can be utilized to continuously follow rapid variations in flow regimes or for unattended applications, so it would be important if the time related performances are specified. Examples of such performance specifications can be:

- response time for variations in flow regimes and conditions
- response time for variations in fluid properties
- measurement duration
- drift in readings with time [4]

4.2 Design Guidelines of MPFM Installations

In this part of the present Master Thesis new guidelines for designing MPFM installations are proposed. The two – phase flow map and composition map are a significant aid in designing MPFM installations. Regarding the two – phase flow map, liquid flowrate is plotted against gas flowrate, in contrast with the composition map where the GVF is plotted against WLR. These two maps provide convenient ways of first plotting the predicted well production, the production envelope, which is due to be measured in a specific application. The measuring range of a MPFM, the measuring envelope, may then be plotted on the same maps, overlying the production envelope. [4]

4.2.1 Production Envelope

4.2.1.1 Plotting the Production Envelope in the Two – Phase Flow Map

The two - phase flow regime maps are very general and use the diameter dependent superficial gas velocity along the X – axis and the superficial liquid velocity along the Y – axis. A more practical presentation is where the superficial velocity together with the conduit diameter is converted in to actual flow rates, i.e. along the X and Y – axis the actual gas and liquid flowrates in m^3/day are plotted, respectively. The use of logarithmic scales can provide more convenience. Compared to linear scales this has the advantage that measuring envelopes of different size MPFMs have equal cross sectional areas in the two – phase flow map and that uncertainty bands in the low flowrates are equal in size throughout the two – phase flow map. According to the following graph, three decades along each axis are often covered in most applications. The actual boundaries between flow regimes are not as sharp as is indicated in the following graph. These boundaries also depend on density, viscosity, surface tension, pressure and geometry, apart from the conduit diameter which is utilized. [4]

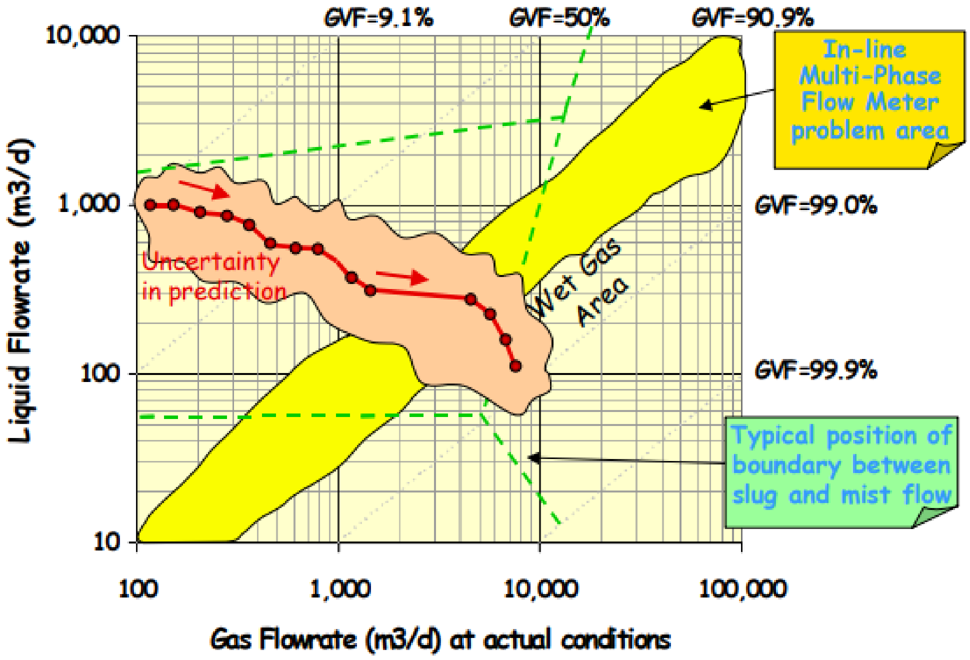


Figure 63: Two – Phase Flow Map which is used for Plotting the Production Envelope and Measurement Envelope of a MPFM [4]

Gas and liquid flowrates can be plotted in this flow map and over time the wells will follow a certain trajectory, i.e. both the liquid and gas flowrates will change over time. One or more of these trajectories can be defined as the production envelope of an oil field. Often this production envelope is also indicated as an area between minimum and maximum liquid and gas flowrates. Furthermore, the units, which are utilized along the X and Y – axis is Am^3, i.e. the volumetric flowrate at the pressure and temperature of which the meter will operate. As these trajectories are often based on very preliminary information from reservoir engineers, there is uncertainty attached to these trajectories and it is recommended that these uncertainty ranges are also shown in the two – phase flow maps. For instance, a 10% and 25% uncertainty production envelope can be used. This uncertainty can either be plotted as an area or uncertainty crosses can be used for each point. It is known that, MPFMs have measuring envelopes and hence, the production envelope and measuring envelopes ought to be overlapped. This is the first step in the selection of a suitable multiphase meter for a particular application. [4]

4.2.1.2 Plotting the Production Envelope in the Composition Map

Another useful tool in the selection of MPFMs is the composition map, with WLR, in % or fraction, on the X – axis and GVF, in % or fraction, on the Y – axis. The top line, where GVF=100%, represents the gas phase, the left bottom corner, where GVF=WC=0%, and the right bottom corner, where GVF=0% and WC=100%, represent the oil and water phase, respectively. Moreover, the scale can be adjusted to increase visibility in a certain region. As WLR and GVF generally are increased over time also a well trajectory in the composition map can be plotted, similar to the well trajectory in the two – phase flow map. One or more of these well trajectories will represent the production envelope in the composition map. MPFMs can also have their measuring envelope plotted in the composition map and obviously the two envelopes should overlap. [4]

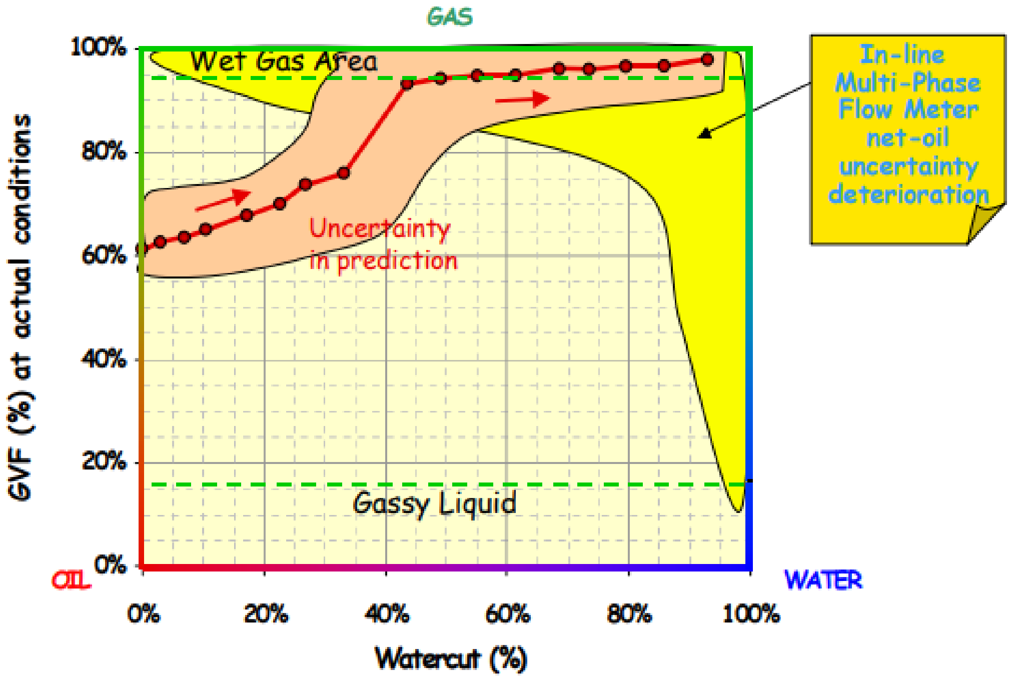


Figure 64: Well Trajectory in the Composition Map. The Largest Uncertainties in Liquid and Oil Flowrate occur at the High GVF Applications. [4]

In this example a strong increase in GVF from 75% to 95% is noticed which is due to the introduction of gas lift during later field life. Again also the uncertainty in the reservoir engineering data should be taken into account and if possible also plotted in the composition map. This can be done either as an uncertainty area or with uncertainty crosses per year. [4]

4.2.2 MPFM Measuring Envelope

4.2.2.1 Plotting the MPFM Measuring Envelope in the Two – Phase Flow Map

MPFMs have measuring envelopes that are specified by the vendor. Often the minimum and maximum gas and liquid flowrates are given and uncertainties in liquid flowrate, gas flowrate and WLR are specified as a function of GVF. Like the production envelopes, the MPFM measuring envelopes can be plotted in the two – phase flow map and if various uncertainties are quoted it is possible to plot various measuring envelopes, one for each set of uncertainties. In the following graph an example is presented where the 5% and 10% uncertainty measuring envelopes are plotted. This allows the user to assess what the consequences in the measurement uncertainty are over the field lifetime, and whether different measurement ranges need to be used over the field lifetime, with different measurement uncertainties. [4]

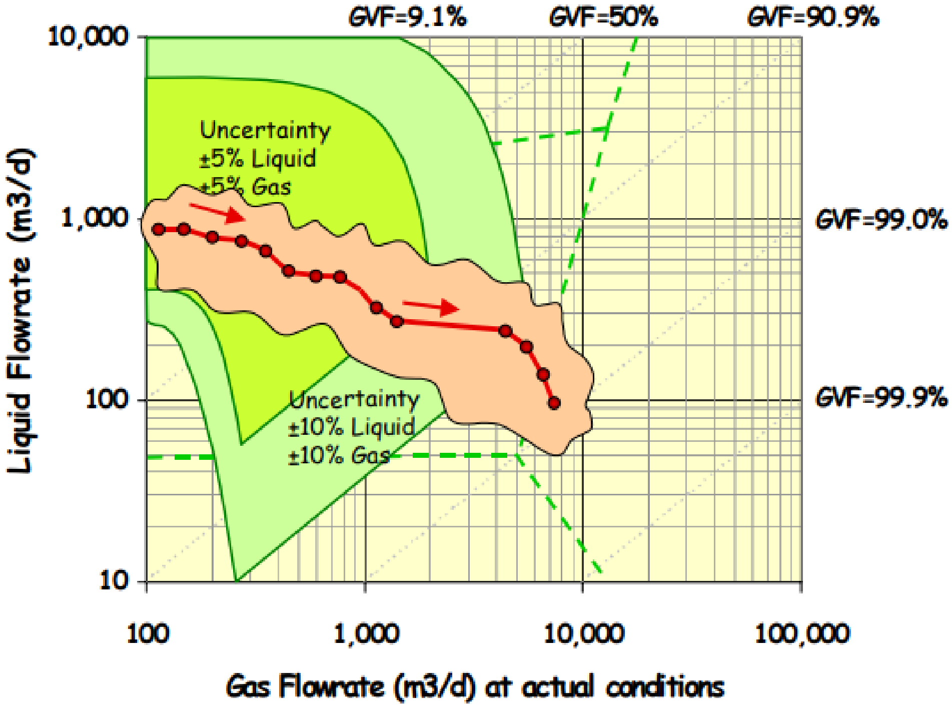


Figure 65: A MPFM Measuring Envelope Plotted Together with a Well Trajectory or a Production Envelope in the Two – Phase Flow Map [4]

The diagonal lines in this two – phase flow map are lines of constant GVF. Generally, oil fields operate in a GVF region between 40%, which are high pressure operations, and 90% - 95%, which are low pressure and gas lifted operations. Oil field operations at the high flowrates, top right corner of the flow map, means high productivity wells but also calls for high maintenance costs due to the mechanical vibrations and erosion of production facilities. Operating at the lower flowrates, the lower left corner of the two – phase flow map means less than expected production rates and thus oversized flow lines. Both these corners of the flow map should be avoided. The most commonly encountered flow regime in oil field operations is the slug flow regime in the middle of the flow map. Gas field operations generally are situated on the right bottom side of the flow map, i.e. the wet gas region. [4]

4.2.2.2 Plotting the MPFM Measuring Envelope in the Composition Map

In a similar manner to plotting the measuring envelope in the two – phase flow map, one can plot a measuring envelope in the composition map as well. Generally, MPFMs cover the entire range of 0 – 100% WLR and 0 – 100% GVF, but the uncertainty specifications are often given as a function of the WLR and GVF. In particular, at the high GVF the uncertainties in the liquid flowrates will deteriorate. [4]

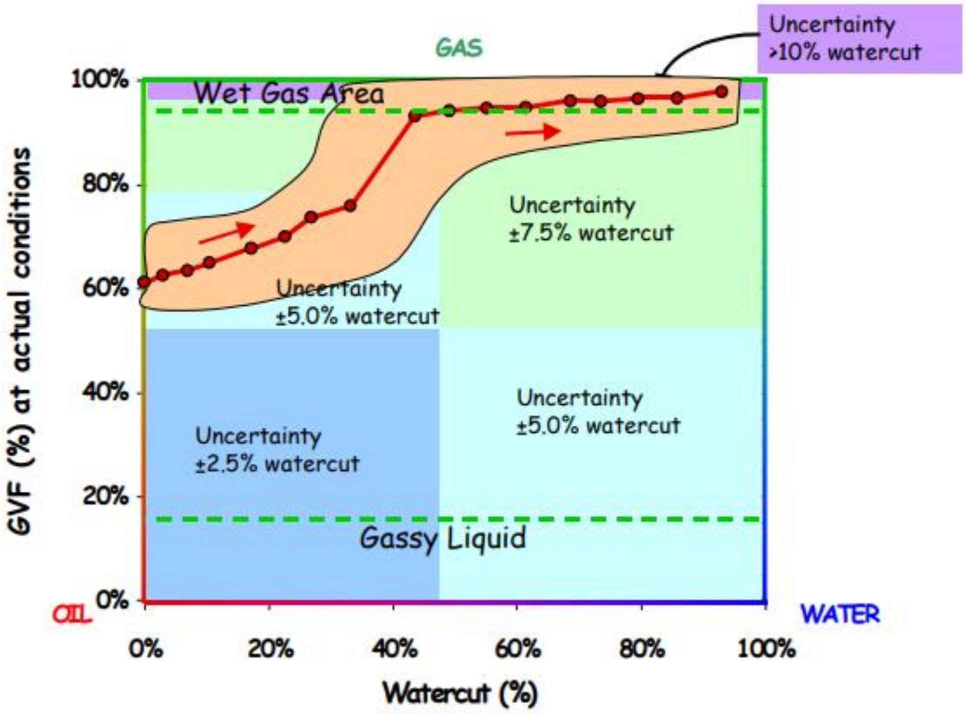


Figure 66: A MPFM Measuring Envelope Plotted Together with the Production Envelope in the Two – Phase Flow Map [4]

4.2.3 Using the Flow Maps During Testing

The previous two – phase flow map and the composition map are very convenient, when test programs run in order the performance of MPFMs to be verified. Both the reference measurements and the MPFM measurements can be plotted in the two – phase flow map and the composition map and by connecting these two points with a single line the test point is represented. The directions of the lines indicate whether deviations are in the liquid flowrates, mostly vertical lines, or whether they are in the gas flowrates, mostly horizontal lines. The length of the line indicates the magnitude of the deviation and again a logarithmic flow map gives same length for a certain relative deviation in the entire map. [4]

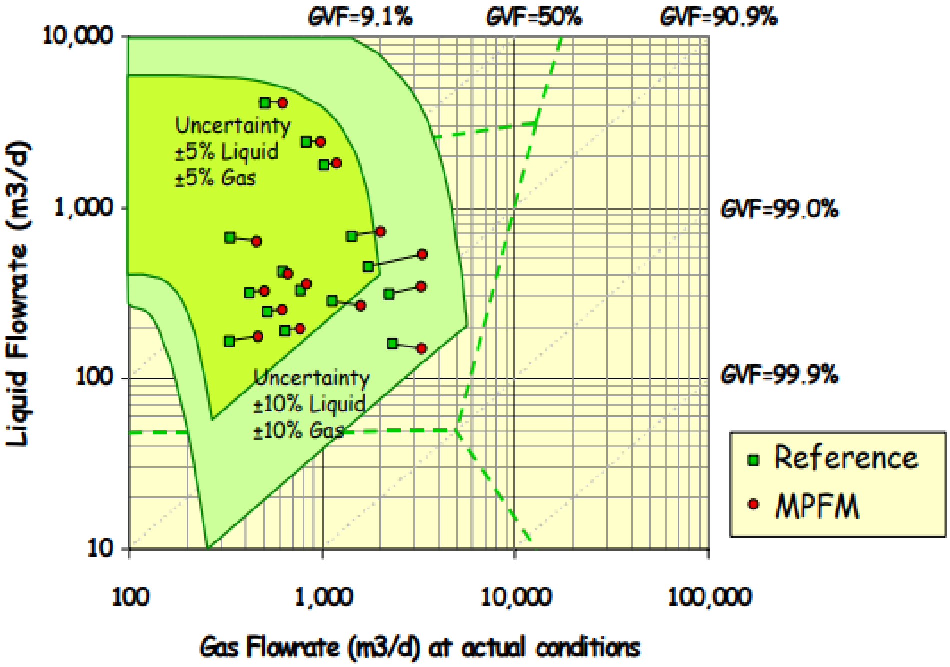


Figure 67: Test Results for a MPFM Plotted in the Two – Phase Flow Map [4]

According to the graph, the MPFM shows some systematic errors in the gas flowrates, due to overreading, whereas the liquid flowrates are ok. Measurement deviations in MPFMs are often systematic due to partially optimized flow models or differences between the used and actual fluid properties. The same test points can also be plotted in the composition map. Again deviation in WLR and GVF can be presented and it is often easy to spot where the largest deviations occur. The length of the lines between the reference measurement and MPFM measurement point indicates an absolute deviation between the reference and MPFM. According to the following graph, the MPFM shows larger deviations in the water continuous emulsions than in the oil continuous emulsions. [4]

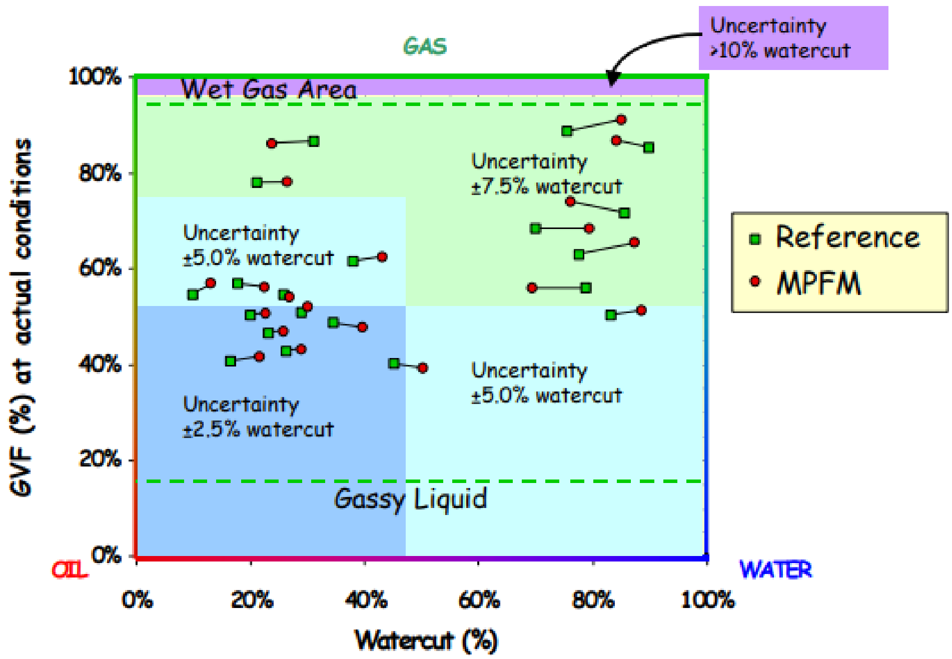


Figure 68: Test Results for a MPFM Plotted in the Composition Map [4]

4.2.4 The Cumulative Performance Plot

With sufficient test points in an evaluation program it is possible to make cumulative performance plots, which can be conveniently utilized in order the performance of various MPFMs to be compared. A characteristic example is illustrated in the following graph, where the X – axis represents the deviation between reference and MPFM measurement and the Y – axis indicates the percentage of test points that fulfil certain deviation criteria. The meter used shows that approximately 70% of all test points show deviations of 10% or less in liquid flowrate, approximately 80% of the test points show deviations of 10% absolute or less in WLR and only 10% of all test points show a deviation of less than 10% in gas flowrate. The test points to be used in the cumulative plots are obviously only test points that fall within the measuring envelope of the MPFM. If the measuring envelope is specified with various GVF ranges, it is recommended to construct cumulative deviation plots for each GVF range, i.e. one plot for 0 < GVF < 30%, one for 30% < GVF < 90%, one for 90% < GVF < 96% and one for GVF > 96%. [4]

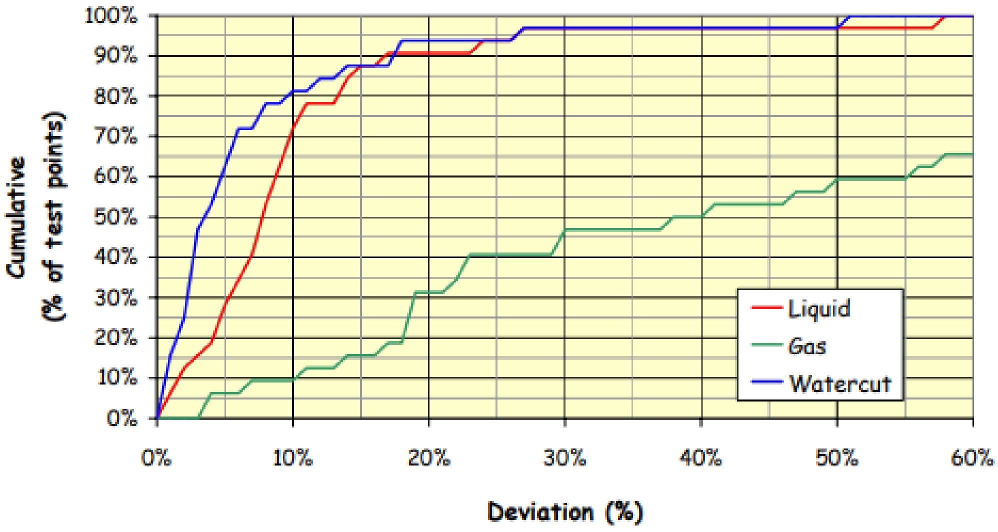


Figure 69: A Cumulative Performance Plot [4]

4.2.5 Other Considerations during the Designing of a MPFM Installation

A number of other considerations should also be included in when designing a MPFM installation such as:

- **High or low ambient temperatures**, because the operation of a MPFM in high or low ambient temperatures may require extra shielding of the pressure lines and temperature transmitters and sometimes the whole meter needs to be insulated and heat traced.
- **H_2S and chemicals**, because MPFMs must be resistant to H_2S and chemicals, which are utilized for hydrate prevention and scale inhibition. Moreover, it should be clear, if concentration and physical properties of these chemicals affect the measurement of phase fractions.
- **Instantaneous vs average flowrates**, because depending on the flow conditions at the installation, there may be significant differences between instantaneous and average flowrates.
- **Changes in fluid properties**, because they call for sampling of the fluids for laboratory analysis and a subsequent update of the fluid data in the MPFM flow computer. Hence, sensitivity for expected fluid property changes at the specific installation must be considered and facilities for measuring and tracking fluid properties with time must be included in the design.
- **Pressure drop**, because some MPFMs introduce pressure drops that can be significant in some installations.
- **Hydrate, wax or scale deposits**, because the MPFMs' ability to tolerate forming of hydrate, wax or scale should be evaluated and also susceptibility to the chemicals that might be used to prevent forming of these on a regular basis, or as part of a program to clean the pipelines and meter internals for such deposits.

- **Method of verification during operation**, which should be considered already in the design stage, because it ought to be ensured that any special facilities, such as bypass, isolation valves, sampling points or others required for the selected method of verification, will be in place.
- **Test or acceptance program**, because if a new type of MPFM is to be utilized, the user may decide that tests are carried out to establish or verify performance – suitability of the meter.
- **Maintenance requirements**, which should be clarified. Frequent maintenance requiring manufacturers assistance at remote or offshore sites may be expensive and disrupt MPFM operation.
- **Nucleonic gauge requirements**, because the installation and use of nucleonic devices in industrial plants is subject to rigorous regulations, requiring conscious and consistent handling.
- **Spare parts**, because the issue is if the vendor has spare parts on the shelf, or must spare parts be purpose made.
- **Support, service on site or remote service**, because it is important if service – support is locally available.
- **Verification and calibration options**, because may vary considerably from one installation to another. Reference measurements may be expensive or unavailable. The usefulness of a MPFM and credibility of absolute numbers depend on calibration and verification methods.
- **Solids impact**, because the issues are if the MPFM can take some wear and tear from abrasive particles in the flow, if there are aspects of technical safety and how MPFM performance is affected.
- **Remote access**, because the issues are if MPFM can be accessed remotely, if there are sufficient communication ports available to serve communication to plant control system (SAS), information system (IMS), metering control system and local PC, simultaneously, if communication software runs on remote PC or on local server and the way of which the manufacturer can access the MPFM from outside company network.
- **Test media**, because the representativity, suitability and availability of MPFMs must be considered before their delivery and regular operation. [4]

4.3 Perspectives of MPFMs

In the next sections, the instrumental perspectives of MPFMs are analyzed, which are based on the cost, maintenance, footprint, radioactive source and calibration, and which can also contribute to the conclusions and the future predictions for the MPFMs. [24]

4.3.1 Cost

The prices of MPFMs fluctuate from 100,000 to 500,000 US dollars, depending on their operation requirements. The prices vary depending on whether the MPFM is installed onshore or offshore or if the location is topside or subsea. The operational cost for a MPFM fluctuates from 10,000 to 40,000 US dollars per year. So it is obvious, that MPFMs are more economical than conventional test separators, which has an operational cost around 350,000 US dollars per year. Moreover, VFMs are much cheaper compared to other MPFMs, as they only consist of measurements based on simple conventional field instruments and empirical algorithms. [24]

4.3.2 Maintenance

When MPFMs are consisted of, for instance, pressure and temperature sensors or gamma - ray source, then the instrument maintenance can be affected. Maintenance is a cumbersome procedure when it is performed offshore. If maintenance is performed on an unmanned platform, the procedure can be challenging and expensive due to shipping of the right personnel to the platform. Another contributing factor to the expenses of maintenance is whether the equipment is located subsea or above sea level. If the equipment is located subsea, the maintenance is assigned by specially educated divers and consultants, which is a cumbersome and expensive procedure. Pressure and temperature sensors are installed with such a way in order to be easy to be adjusted or replaced by new sensors, fact that makes their maintenance more doable. According to the following figure, a sensor is measuring either the pressure or temperature on a flowing mixture inside a conduit. The valve can easily be shut down without any interruption of the flowstream and the sensor can be replaced without a complete shutdown of the fluids' production. If the MPFM receives the mass flow and density distribution from a Coriolis device, the maintenance and replacement can cause more difficulties. Even though the Coriolis mass flow meter is supposed to have lower maintenance due to no moving parts, it can still cause problems. It is installed in – line of the conduit and its maintenance and replacement requires a complete shutdown of the production. Furthermore, maintenance of a gamma source is not required often. The radiation of the source is decay over time with respect to the half – life time of the radioactive source. If a gamma source is to be maintained or replaced, the procedure is expensive as specialized and certificated personnel is shipped to the concerned platform. [24]

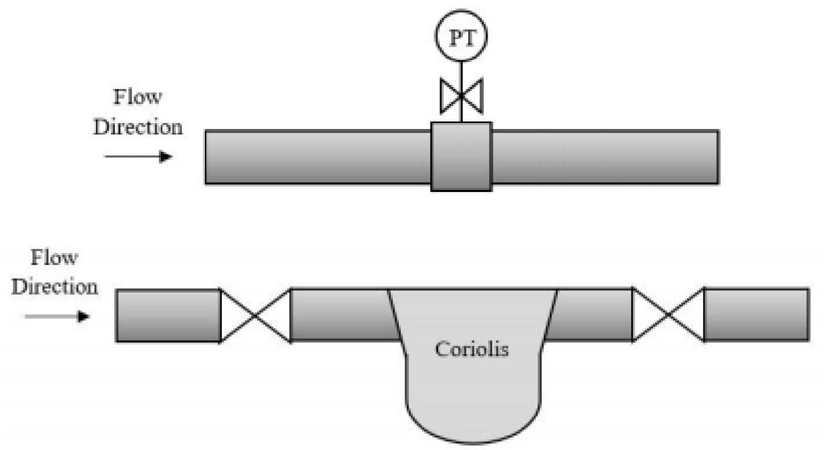


Figure 70: A P.T. Sensor placed on a Conduit and A Coriolis Meter placed In – Line of the Conduit. [24]

4.3.3 Footprint

The footprint of the equipment is essential at offshore installations. A compact platform makes huge constructions and equipment impossible and the footprint of a MPFM should be as small as possible. Therefore, a solution with an inline MPFM is preferred instead of the huge test separator. [24]

4.3.4 Radioactive Source

Radioactive materials require careful supervision during execution, operation and disposal. Handling radioactive materials requires permission and experts to meet the given law, which means that a MPFM consisting of a radioactive source requires special educated employees, when handling the meter. This is contributing to a higher operating expenses (OPEX) and capital expenditures (CAPEX) due to external employees shipped to the offshore platform for implementing, operating and disposal of the radioactive material. [24]

4.3.5 Calibration

For the right operation of the MPFM, calibration in the form of input data from time to time is needed. Especially VFMs need much calibration before start – up to estimate and produce the empirical equations for the software. However, other MPFMs need calibration only when the accuracy of the data is drifting over time. PT – sensors have a long – term stability and are calibrated with respect to the electric signal from the sensor. Over the time a PT – sensor will drift from the initial zero point offset, so by calibration, the zero point offset can be readjusted increasing the accuracy. Pressure calibration is carried out by venting the sensor with ambient air and hereby trimming the offset, so that the zero point is again matching. Gamma – ray source requires special educated personnel and strictly permissions and hence, there is a more comprehensive technology for the calibration process. The aforementioned process depends on the half – life time of the source, so for a given period stated by the manufacturer, the radioactive source must be calibrated to take account for the loss of the source intensity. If the half – life time is short, the calibration needs to be performed more frequently compared to a radioactive source with a longer half – life time. The calibration is carried out by measuring the count rates of the radiation with respect to each single phase. [24]

4.4 Commercial Description of In – Line MPFMs

As aforementioned, the operation of in - line multiphase flow meters is based on the complete measurement of fraction and flow of each phase, oil, gas and water, in the tubing, which carry out without any separation or sampling. The following description of the main multiphase flow meters, in alphabetical order, follow the strategies adopted in order the oil, gas and water fractions and flowrates to be measured. [24]

- **Agar Corporation**

This meter combines a positive displacement device, a dual momentum meter, two venturi devices in series, in a vertically upward flow and a microwave monitor. The total flowrate of liquid and gas is determined by the positive displacement device. The momentum meter measures the aforementioned flowrates by utilizing the fundamentals of fluid flow through a venturi device. The water cut is derived from the energy absorbed by the multiphase mixture from the microwave monitor. AGAR MPFM combines all the aforementioned flow measurement methods in order to achieve superior accuracy in the entire GVF range from 0% to 100%, including the wet gas regime from 95% to 100%. Moreover, AGAR oil – water monitor is capable of measuring water cuts from 0% to 100% and is not affected by salinity changes. AGAR MPFM eliminates the need for expensive, secondary equipment such as phase separators, valves, and pumps for flow measurement. It is fully self – contained and compact for use in rugged field conditions and can easily be trailer – mounted for portable service. [33], [36]

Figure 71: Agar Corporation MPFM
Source: www.agarcorp.com

The general specifications of Agar MPFM are presented in the following table.

Table 3: General Specifications of Agar MPFM [36]

GVF	0% – 100%
Water Cut	0% – 100%
Flow Regimes	All (Bubbly, Wavy, Slug, Annular)
Pressure	Standard: Up to ANSI 1500
Ambient Temperature	-20°C to 60°C Optional Low Temperature: -40°C to 60°C
Process Temperature	Standard Model: 0°C to 100°C High Temperature Model: 0°C to 232°C Extreme High Temperature Model: 0°C to 300°C
Liquid Viscosity	Low Viscosity Model: 0.1 – 100cP High Viscosity Model: 0.1 – 2000cP
Salinity	0% – 30% w/w NaCl
Sand – Particulate	Up to 2% by volume and less than 1mm particle size
Maximum Pressure Drop	Less than 15 psi

❖ **DUET (Kvaerner Oilfield Products)**

This meter combines two gamma – ray densitometers separated by a known distance along of the conduit and pressure and temperature sensors. The first one is a single energy gamma – ray densitometer that measures the density of the flowing mixture. The second is a dual energy gamma – ray densitometer that measures mass fraction of oil and water in the liquid flow. The gas fraction is determined from the combined thickness of oil and water in the gamma – ray beam. Velocity measurement is performed by cross – correlation of two gamma – ray densitometer signals. [33]

Figure 72: DUET MPFM
Source: https://flevy.com/browse/business-document/liquid-and-gas-flow--suppliers-of-multiphase-flowmeters-3527&language=sp

❖ **ESMER (Petroleum Software Limited)**

This meter's operation principle is based on measuring the flowrates of individual phases in the flowstream by utilizing standard differential pressure, pressure, temperature and impedance (capacitance and conductance) sensors. The ESMER technology is founded on random signal analysis and pattern recognition in order to take a fingerprint of the signals and relate them to the flowrates of the individual phases. A version using an extra orifice plate is also available. [33]

Figure 73: ESMER MPFM
Source: https://psluk.wordpress.com/esmer/

❖ **Fluenta AS**

This meter utilizes several different sensors, arranged in combination. A single gamma densitometer measures the average density of the flowing mixture. Capacitance and inductive sensors are utilized in order the flowing mixture's electrical properties in oil and water continuous flow to be measured, respectively and hence, the phase fractions can then be determined from this information. Velocity measurements are performed by cross – correlation of capacitance signals in case of oil continuous regime and by differential pressure across a Venturi device in case of water continuous regime. [33]

Figure 74: Fluenta MPFM
Source: https://www.fluenta.com/

- **Framo Engineering AS**

At this technique, there is a special static mixer upstream of the measurement section. The measurement section is composed of a Venturi device and a dual energy gamma – ray densitometer, which is mounted at the throat of the Venturi device and is utilized in order the phase fractions to be determined. The flowing mixture's velocity is determined by the Venturi device. [33]

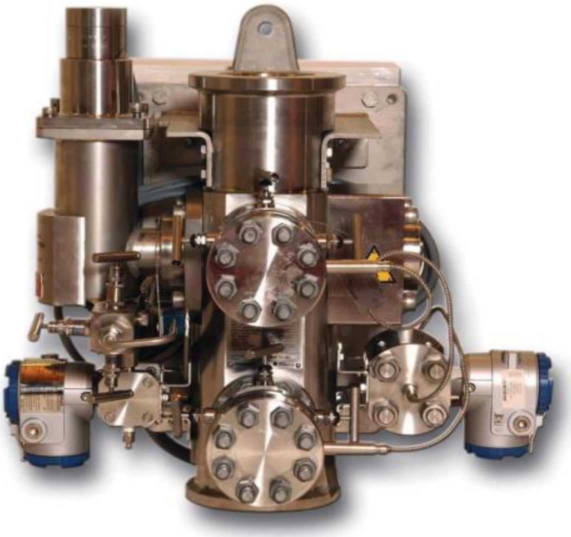


Figure 75: Framo MPFM
Source: https://imistorage.blob.core.windows.net/

Table 4: General Specifications of Framo MPFM [41]

Venturi Throat Diameter	87.5mm, 52mm and 29.25mm
Working Pressure	0psi – 5000psi
Temperature Rating Process	-40°C to 150°C
Ambient Temperature	-20°C to 85°C
WLR	0% – 100%
Liquid Viscosity	0.1cP – 2000cP at line condition

❖ **MFI (Roxar Limited)**

The operation principle of this meter is based on the use of an electromagnetic resonant cavity and a single energy gamma – ray densitometer. The resonant frequency of the cavity is a function of the shape, geometry and dielectric constant of the multiphase flowing mixture. The gamma – ray densitometer is used to measure the total mixture density and the resonant cavity measures the dielectric constant of the medium. The phase fractions are determined by combining the dielectric constant and the total mixture density. The mixture velocity is determined by cross correlation between two microwave sensors located at a known axial distance from each other. [33]

Figure 76: MFI MPFM
Source: https://nfogm.no/wp-content/uploads/2019/02/1999-01-Multiphase-Flow-Measurement-System

❖ **MIXMETER (Jiskoot)**

This meter uses a static mixer with a dual energy gamma – ray densitometer. The function of the mixer is to homogenize the mixture before it reaches the dual energy gamma – ray densitometer and to measure the mixture velocity by differential pressure measurement across the mixer. The phase fractions are determined by taking radiation attenuation measurements. [33]

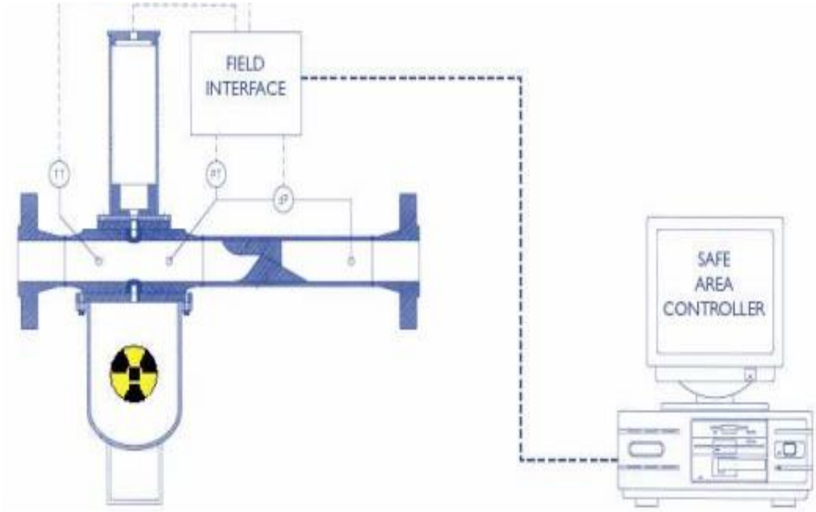
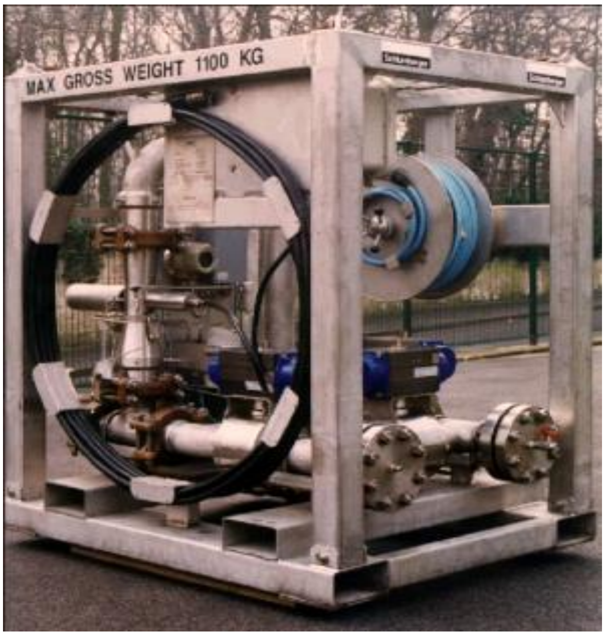


Figure 77: MIXMETER (Jiskoot) MPFM
Source: https://www.scribd.com/document/264017983/Mixmeter-brochure-Rev2-pdf

❖ **VenturiX, 3 – Phase Measurements AS**

This meter combines a Venturi device and a dual energy meter located at the Venturi throat. There are two versions available, one for periodic testing services and other for permanent monitoring. [33]



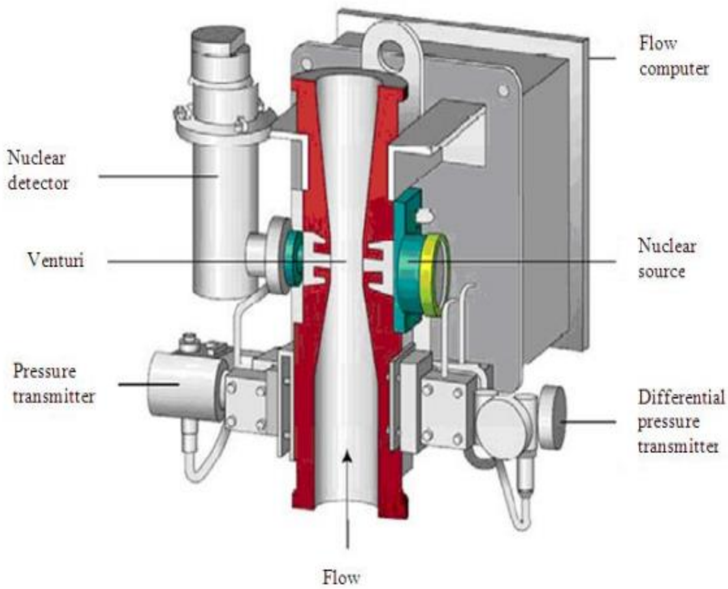


Figure 78: VenturiX MPFM
Source: Schlumberger and Framo Engineering AS

4.5 Future Scenarios for Multiphase Flow Metering

Future scenarios for multiphase flow metering application include the wet christmas tree and downhole site. These scenarios will enable the entire production system to be simplified, including subsea manifolds and even elimination of some production components. As a consequence, the follow – up of the reservoir depletion, the performance of each well, the production shut down and the optimization of production by gas lift shall be effected in real time. Even though the technological maturity stage has already started, there is still work to be done regarding standard modification in the operating culture, from the one based on test separator to well testing. Although several tests have already shown that the uncertainties of a MPFM are comparable to those of a typical test separator, users still assume that test separators work satisfactorily, even when they do not consider the defects of such equipment, as for instance the low separation efficiency, which leads to efficiency loss from 5% up to 20%. So, the acceptance of MPFMs will have to be based on a change in the culture of production system operation. [33]

Nowadays MPFMs have already been accepted for subsea applications and in those cases of unmanned systems, solely because such systems require a total automation level, associated with a reasonable degree of reliability. Some meters have the advantage of not including movable parts or devices which may suffer wear and tear. The natural path for MPFMs is to be installed in wet christmas trees and even on well bottom or downhole environments. In these cases, measurements shall be effected under conditions closer to the oilfield reality, allowing on – line monitoring to be performed. Some companies projecting subsea systems have already concepts of meters on the trees, integrated to the controlling systems of the latter. Once each well is provided with its own multiphase meter, on – line management of the reservoir will become feasible, with immediate action on its production adjustment. [33]

A possible concept of an on – line oilfield management system is the one called Optimizing Module of Field Flow. According to this concept, each Christmas tree is smart and provided with a MPFM, gas – lift gas meter, oil/gas – lift chokes provided with remote adjustment devices, and integrated subsea control system, connected to the communications network. The communications network carries every information on the tree's variables, such as oil, gas and water flows, pressure, temperature, gas – lift flow, and the set points for the correct positioning of the chokes of oil and gas lift. The same applies to water and gas injection wells of the same field. At the Offshore Production Unit, the communications network is integrated to the supervisory system, where the Optimizing Module will have the following functions:

- Well Simulator
- Reservoir Simulator
- Control Module and Set Point Generator
- Efficiency Calculator, which estimates efficiency of each well, efficiency of the oilfield, operating cost of oil per well and total operating cost of oil.

In order to assess efficiency, the Optimizing Module must also receive the data concerning internal consumption of the plant, such as kWh, exportation figures, gas burning, injection and chemical products, and generate basic commands to the gas compressing systems, water injection pumps and oil exportation pumps. [33]

CONCLUSION

The aim of the present Master Thesis was the presentation of the in – line multiphase flow measurements, which are carried out during the hydrocarbon production. As it is aforementioned, the accuracy and reliability of multiphase flow measurements are essential for allocated production data and model prediction. MPFMs play an important role over the entire lifetime of production. Hence, it is essential to monitor production and stage of each well, as this can estimate the lifetime and future development of the field. In the latter years of the production life of a well, the focus of production is increasing rather than the exploration of the well. For mature wells, it is extremely important the multiphase flow to be accurately measured, due to the fact that as the water cut is increased, the reservoir pressure is decreased.

Multiphase flow meters' uncertainties fluctuate from ±5% to ±10% over a large operation range, which is considered a satisfactory performance, equal to or better than that of a test separator. Nonetheless, their use still depends on cost – benefit analyses, operating impact, legal and cultural implications due to the fact that the use of some devices is based on radioactive attenuation and there is also lack of knowledge of the functioning and reliability of MPFMs and doubts concerning the need of recalibration. In the subsea environment, as in the case of subsea manifolds, wet christmas trees and downhole sites, the implementation of multiphase flow metering has been improved because such technology reduces the cost, needs simplified facilities and reduces the functions, which are performed in the topside environment. After two decades of development, the technological route of multiphase flow metering reached a better understanding of the behavior of different physical principles, such as capacitance, microwave and radioactive attenuation, of the conventional flow meters, such as Venturi and positive displacement, of the signal processing and of the development of new correlations in multiphase flow, fact that led to the development of more compact and lower cost meters.

The number of MPFMs and investigations of accurate and intelligent technologies of multiphase flow measurement will be continuously increased and expand in the coming years because of maturing fields and the focus upon the continuous hydrocarbon production. The overall issue is to design a commercial solution, which can accurately measure the entire GVF and provide accurate measurements in real time. This should be without compromising safety and the footprint on the respective platform. Other essential qualities for future MPFMs are low maintenance, availability and easy operation. Therefore, a possible option might be the further investigation of VFMs, as they can carry out accurate and reliable multiphase flow measurements.

BIBLIOGRAPHY

[1] Oil and gas production handbook, An introduction to oil and gas production, transport, refining and petrochemical industry, Håvard Devold, ABB Oil and Gas

[2] Sofia Stamataki, Petroleum Engineering, Academic Handbook, NTUA Publications, 2004

[3] Reservoir Engineering Handbook, Second Edition, Tarek Ahmed, Gulf Professional Publishing

[4] Handbook of Multiphase Flow Metering, Revision 2, March 2005, Norwegian Society for Oil and Gas Measurement

[5] Production Engineering, Academic Notes, Professor Bahman Tohidi, Technical University of Crete

[6] Gamma Radiation Methods for Clamp-On Multiphase Flow Metering, S. Blaney, PhD Thesis, School of Engineering Department of Process and Systems Engineering, Cranfield University, 2008

[7] Impedance Sensors for Fast Multiphase Flow Measurement and Imaging, Technische Universität Dresden, Dipl.-Ing. Marco Jose da Silva

[8] Principles of Multiphase Measurements, 2004, Alaska Oil and Gas Conservation Commission, Parviz Mehdizadeh

[9] Falcone, G., et al, "Multiphase Flow Metering – Current Trends and Future Applications," SPE 71474, New Orleans, 2001

[10] Al - Yarubi Qahtan, Phase flow rate measurements of annular flows, Doctoral thesis 2010, University of Huddersfield

[11] Hammer, E.A., Three – Component Flow Measurement in Oil/Gas/Water Mixtures using Capacitance Transducers, Ph.D. thesis, University of Manchester, 1983

[12] Hammer, E.A., Chapter 14.1.1 Capacitance transducers – Basic Principles, Multiphase Flow Handbook, Crowe C (editor), Taylor and Francis Group, 2003

[13] Ramu, T.S. and Narayana Rao, Y., On the Evaluation of Conductivity of Mixtures of Liquid Dielectrics, IEEE Transactions on Electrical Insulation. Vol. E1-8, No. 2, 1973

[14] Nyfors E, Vainikainen P (1989): "Industrial microwave sensors", Artech House

[15] S. Corneliussen, J.-P. Couput, E. Dahl, E. Dykesteen, K.-E. Frøysa, E. Malde, H. Moestue, P.O. Moksnes, L. Scheers and H. Tunheim Handbook of Multiphase Flow Metering, Rev. 2, 2005

[16] Fluid Composition Analysis by Multiple Gamma – Ray Beam and Modality Measurements, Geir Anton Johansen and Stein – Arild Tjugum, University of Bergen, Department of Physics and Technology, Roxar Flow Measurement, Michelsen Centre for Industrial Measurement Science and Technology, Bergen, Norway

[17] G. A. Johansen and P. Jackson "Salinity independent measurement of gas volume fraction in oil/gas/water pipe flows", 2000

[18] G. A. Johansen and P. Jackson Radioisotope gauges for industrial process measurements John Wiley & Sons, Ltd., 2004

[19] S.-A. Tjugum, J. Frieling and G. A. Johansen "A compact low-energy multibeam gammaray densitometer for pipe-flow measurements" Nucl. Instr. & Meth. B197, 2002

[20] Application of Neutron Activation Analysis for Heavy Oil Production Control, Valeria Kornienko and Petr Avtonomov, RatecLab, St. Petersburg, Russia, World Conference on Technology, Innovation and Entrepreneurship, published by Elsevier, 2015

[21] Oosterbroek, R.; Lammerink, T.S.; Berenschot, J.W.; Krijnen, G.J.; Elwenspoek, M.C.; van den Berg, A. A micromachined pressure/flow-sensor. Sens. Actuators A Phys., 1999

[22] Xu, L.; Xu, J.; Dong, F.; Zhang, T. On fluctuation of the dynamic differential pressure signal of Venturi meter for wet gas metering. Flow Meas. Instrum., 2003

[23] Campos, S.R.V.; Baliño, J.L.; Slobodcicov, I.; Paz, E. Orifice plate meter field performance: Formulation and validation in multiphase flow conditions. Exp. Therm. Fluid Sci., 2014

[24] Multi-Phase Flow Metering in Offshore Oil and Gas Transportation Pipelines: Trends and Perspectives, Lærke Skov Hansen, Simon Pedersen and Petar Durdevic, Department of Energy Technology, Aalborg University, Denmark, 2019

[25] Use of Venturi Meters in Multiphase Flow Measurement, A R W Hall and M J Reader-Harris, Flow Measurement Centre, National Engineering Laboratory, Glasgow, UK

[26] Flow rate measurement of oil-water two-phase flow based on V-cone flow meter, Journal of Physics: Conference Series, F Dong et al 2009 J. Phys.: Conf. Ser. 147 012059

[27] Industrial flow measurement, Master thesis, Michael Anthony Crabtree, University of Huddersfield, 2009

[28] A study of the Coriolis flowmeter as a reference instrument in multiphase flow, Master thesis, Sigve Naustdal, Department of Physics and Technology, University of Bergen, 2015

[29] Coriolis Mass Flow Meters for Gas and Liquid Measurement, Michael Keilty, Endress + Hauser Flowtec AG, Greenwood, Indiana USA

[30] Cross – Correlation Velocity Measurement of Multiphase Flow, Muhammad Waqas Munir, Bushra Anam Khalil, International Journal of Science and Research, University of Auckland, New Zealand, 2015

[31] Modeling of Cross Correlation Flow Measurement Systems, Alexander Gurevich, Faculty of Technology, De Montfort University, 2013

[32] Performance Evaluation of Virtual Flow Metering Models and Its Application to Metering Backup and Production Allocation, Kahila Mokhtari Jadid, Louisiana State University and Agricultural and Mechanical College, 2017

[33] Multiphase Flow Metering Technology Updated, Claudio Barreiros da Costa e Silva, Jose Alberto Pinheiro da Silva Filho, Miguel Joao Borges Filho, Josaphat Dias da Mata, Flomeko 2000 - IMEKO TC9 Conference Salvador, Bahia, Brazil, 2000

[34] Development of an in - situ calibration method for multiphase flow meters using a radioactive tracer technique, Torben Sevel, Niels Hald Pedersen, Claus Erik Wei nell and Birger Lind – Nielsen FORCE Institute, Brandby, Denmark, North Sea Flow Measurement Workshop 1995

[35] http://www.tuv-sud.cn/uploads/images/1549626287932323140970/ 2018-302-final-tracer.pdf

[36] https://www.agarcorp.com/wp-content/uploads/2018/12/MPFM-50-11-26-18.pdf

[37] https://www.idc-online.com/technical_references/pdfs/ instrumentation/Industrial _ Instrumentation% 20-%20Flow.pdf

[38] https://patentimages.storage.googleapis.com/52/b7/84/f129ff9a8ef568/US8322228.pdf

[39] https://www.glossary.oilfield.slb.com/en/Terms/g/gas_lift.aspx

[40] https://www.glossary.oilfield.slb.com/Terms/s/separator.aspx

[41] https://imistorage.blob.core.windows.net/imidocs/99123p001%20framo %20multiphase%20flowmeters %20-%20phasewatcher%20vx.pdf