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Department of Environment, Land and Infrastructure Engineering

Master of Science in Petroleum Engineering

EFFECT OF SALINITY (KCL) ON ROP AND RHEOLOGICAL PROPERTIES CONCERNING WATER BASE MUD FORMULATIONS

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Thesis submitted in compliance with the requirements for the Master of Science degree

DECLARATION

I declare that this project work is my own work. It is being submitted for the degree of Master of Science in Petroleum Engineering in Politecnico di Torino, Italy. It has not being submitted for any degree or examination in any other University.

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(Signature of candidate)

.........day of..................year...........

ABSTRACT

Despite the numerous challenges associated with drilling through shale formation, Oil and Gas Companies cannot desist from drilling through this troublesome zone because of the increasing depth of wells been drilled, it is almost impossible to reach your targeted zone without having to drill through a shale layer. Due to this, researchers are trying to find a water base mud which will be less costive and environmental friendly as compared to oil base mud. It is this that potassium, sodium and calcium base water muds were introduced to deal with the swelling tendency of a shale layer. However, due to the ability of potassium ion to supress clay swelling as opposed to the other ions, the use of KCl as an additive during the formulation of water base mud is on the rise. But the addition of this ion to the drilling fluid will have an impact on the rheology and drilling parameters of the water base mud been prepared. This research work purposes to identify and evaluate the effect of salinity (KCl) on rate of penetration and rheology properties of water base muds during their formulation. A laboratory prepared treated bentonite mud and Ca^{2+} based polymer mud acquired from the field was used. The fluid loss properties were tested both at LP/LT for both mud and at HP/HT dynamic conditions for the Ca^{2+} based polymer mud. The salinity of this mud was then increased from 0 – 15 % by adding KCl. It was observed that there was a general increase in the mud weight and gel-strength for the two mud samples. Also, the fluid loss to the formation increased and the quality of the filter cake formed reduced as the salinity was increased for all condition tested. Plastic viscosity, yield point and apparent viscosity experienced a reduction as the salinity was increased in the case of the Ca^{2+} polymer mud. For the treated Bentonite mud there was a reduction these properties from 0 -2 % and an increase from 5% - 10 %. This fluctuation trend was due to the instability of Bentonite and some polymers when they reacted with salt causing flocculation and deflocculation depending on the concentration. An application of Beck *et al.*, (1995) correlation, show an increase in ROP as the plastic viscosity reduces and vice versa.

This project is dedicated to late Comfort Nkrumah (Aka Aunty Ekua) for her effort, support, advice and encouragement towards my upbringing

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INTRODUCTION

1.1 Problem Definition

Petroleum being among the world's most essential natural resources since coal was driven away from the world market due to its environmental problems. Petroleum has been the most significant and most traded commodity in the international trade (Iledare, *et al.*, 1999). Although there have been alternates and now researchers are still finding an environmentally friendly fuel that will be less costive and profitable to use, petroleum remains the world's primary source of energy for both industrial and domestic application.

However, drilling for oil and gas comes with its enormous disadvantages. Despite these challenges, wells are still being drilled globally and only experience a slow or no drilling operations in recent times due to the global drop in oil price. Drilling Fluids like the "bathing shampoos" used by humans help to transport cuttings to surface, prevent well-control issues, preserve wellbore stability, minimize formation effects, cooling and lubrication of the drill string, gives vital information about the well drilled and minimise danger to crew, the environment, and drilling rig.

Hence, properly formulating and predicting the behaviour of a drilling fluid remains a core aspect of the drilling operations. Whilst drilling, drilling fluids encounter some contaminates such as drilled solids and salts. These contaminates change the rheological properties and drilling parameters of the mud. Also, drilling fluids have experienced a high reduction in viscosity which reduced its cutting carrying abilities when it encountered formation brine (Das *et al.*, 2014).

There are different types of drilling fluids used in the oil and gas industry. Among these are the oil base mud and water base mud.

Water base mud, which has water as its primary phase and can be prepared using fresh water or salt water depending on the location and its compatibility with the formation been drilled. When these salts are added to slurry, the hydration and dispersion tendency is not promoted but rather enhances the flocculation tendency of the particles and also reduce the quality of the filter cake formed (Rugang et, al., 2014). Salinity reduces the viscosity of the water base mud (Amani et al., 2016), but this consequences lies largely on the polymers used (Das *et al*., 2014).

Ofei and Bendary (2016), in page 13 of their research to investigate the effect of potassium formate in combination with synthetic polymers made the assertion that the rheological properties of water base mud may exhibit a fluctuational trend based on the concentration of potassium formate and types of polymers used in the muds formulation.

KCl gained international recognition in 1960 when mud containing potassium ion improved hole stability by impairing the swelling of clay better as compared to the commonly used calcium or potassium cations to supress clay inflammation or swelling. Potassium ions has significantly reduced hole enlargement in the shale section a result of its inhibitive properties (Joel *et al.,* 2012). Since then the use of KCl as an additive in water base mud to reduce shale swelling has being on a rise till date.

In broad prospective, shale or clay swelling ability has been reduced by increasing salt content in drilling fluids and vice versa (Ichenwo and Okotie,2015), (Awele,2014). However, it is clear from literature that due to ability of KCl to help supress clay swelling, little has been done to assess its effect on ROP and rheological properties during the formulation of water base mud. Hence, the project seeks to evaluate the effect of salinity (KCl) on ROP and rheological properties concerning Water Base Mud formulations.

1.2 Objectives of the Research

The objectives of this project are:

- ❖ To evaluate the change in rheological behaviour of a treated bentonite mud and Ca^{2+} based polymer mud with increasing salinity (KCl) level during formulation;

- Assess the Impact of salinity (KCl) change on rate of penetration.

1.3 Methods Used

The methods employed include:

- Review of relevant literatures;
- Perform relevant experimental work on the rheological properties of the drilling fluid;
- Consult with lecturers; and
- Validate experimental results with mathematical models.

1.4 Organisation of Report

This research is organised in five chapters. The first chapter elaborates on the subject of the research, which includes the statement of the problem, objectives of research, as well as methods used. It is concluded with the organisation of the research. Chapter two, which is the literature review, talks about the review of pertinent literature concerning this research. Chapter three is about experimental procedures used and results obtained. Chapter four focuses on the analysis and interpretation of laboratory data. Chapter five ends and elaborate on the Conclusions and Recommendations of the research.

CHAPTER 2

LITERATURE REVIEW

2.1 Drilling Fluids

Drilling activity is a major operation in the upstream petroleum industry. The use of drilling mud can be dated as far as the 1800s where a few patents mention the use of a drilling fluid in early rotary drilling designs (Barrett, 2011). Drilling fluid may be explained as the combination or mixture of liquid or gaseous fluids and mixtures of fluids and solids (as solid suspensions, mixtures and emulsions of liquids, gases and solids) used in operations to drill wells into the earth (Anon, 2018a). Almost every drilling problem encountered in drilling operations is mostly directly or indirectly related to the fluids being used. The above statement does not mean drilling fluids used in drilling operations cause or is the solution of all drilling related problems, but is a major tool that is often used to alleviate problematic operations in drilling (Annis and Smith 1996). This clearly shows that drilling fluids equates and performs almost the same function as the blood in human body. Therefore, drilling fluid should be seen as a very important drug in the whole drilling operation.

2.2 Functions of Drilling Fluids

For a successful drilling operation, extra care must be implored during the selection and application of the drilling fluid. Hence, many requirements are placed on drilling fluids to ensure it performs its intended function effectively. Dated as early as 1845, the main purpose of drilling fluids was the removal of drilled cuttings from the borehole (Anon, 2000). But the ever-increasing difficulty of holes drilled and depth reached till now has necessitated the modification of drilling fluids to be able to perform different functions. Some of the basic functions performed by the drilling fluid includes:

- Lift formation cuttings to the surface;
- Control subsurface pressures;
- Drill string lubrication;

- Downhole cleaning;
- Aid in wellbore diagnosis ;
- Helps to sustain formation productivity;

2.2.1 Lift Formation Cuttings to the Surface

Cleaning the hole is an essential function of the mud. This benefit is also the most misused and misconstrued (P. L. Moore, 2016). The generated cuttings whilst drilling operations are on-ongoing must be removed from the bottom of the hole and transported to the surface as quickly and efficiently as possible to ensure better penetration rates and prevent wellbore related problems, such as stuck pipes, swab and surge (R. Romagnoli, 2018). Hence, effectively formulating a mud to transport cuttings is very essential in any drilling operations.

2.2.2 Control Subsurface Pressures

The development of pore gradients versus depth determines the density a mud should have and how it has to be changed as a well is deepened. The correct selection of the mud density is the most important parameter a drilling fluid engineer has to define. In fact, until the hydrostatic head assured by the mud column in the well results to be higher than the formation pressure, no fluids can enter the wellbore and no problems take place. But if for any reasons the pressure exerted by the mud in the hole becomes lower than the formation pressure, hole instabilities, kicks or even blowout can occur, which can endanger the safety of the rig, equipment and environment and even the lives of the personnel. Of course, the mud density should not be excessive, otherwise low penetration rates, formation fracturing, circulation losses and, consequently, high drilling costs can be the direct consequence. Therefore, the mud density should be maintained, if possible, 100-150 g/cc above the expected pore pressure gradient and always below the predicted fracture gradient (R. Romagnoli, 2018).

2.2.3 Drill String Lubrication

As compared to any rotating mechanical device, a rotating drill string induces heat which not dissipated will destroy the drill string due to the extravagant heat its produces. As the drilling fluid plies through the bit and exits through the jets/nozzles, this excessive heat is eliminated and carried up the wellbore (Anon, 2018b). It is also important to note that in order to obtain some of the functions the compositions of the drilling fluids are altered based on the specific results needed by the driller.

2.2.4 Bottom-Hole Cleaning

Effectively removing and cleaning drilled and unwanted particles beneath the bit been used seems to require a formulated mud property almost opposite from those required to lift cuttings from the wellbore (Annis and Smith 1996). For this to be achieved, the mud must possess a high suspension capacity to ensure that during moments of non-circulation, the cuttings and commercially added solids such as barite, do not sink to the bottom and the mud circulation rate must be adequate to prevent excessive increase in mud viscosity or density as a result of drilled solids being dispersed into it especially when they become finer (Awele, 2014). Since rate of penetration has been identified to have a direct relation on bottom hole cleaning or cleaning beneath, all other parameters that has a relation with rate of penetration (such as density, hydraulics, etc.) should be looked at concurrently (Annis and Smith 1996).

2.2.5 Provide an Aid to Formation Evaluation

This function of a mud which focuses on discovering and evaluating potential reservoir zones, unfortunately, is not being given so much focus as should be as attentions are being shifted to the drill rates and costs, which often lead to programs being implemented that have a detrimental effect on effective formation evaluation. The drilled cuttings brought to the surface by the drilling fluid in use are diagnosed or analysed for information about the formation being drilled (Awele, 2014).

2.2.6 Provide Protection to Formation Productivity

Formation productivity is of major concern and very often non-commercial hydrocarbon zones are blamed on formation damage introduced through the invasion of mud or filtrate. There is little doubt that it would be desirable to keep the down hole formation in its virgin state with no fluid of any kind entering the zone. In drilling this in general cannot be done. In other to keep liquid out of the formation, some areas are drilled with air, or oil base mud. This practice has been effective in maintaining formation productivity. This practice has also been effective; however, in gas zones it may be more damaging than a salt water fluid. Salt water and high calcium content fluids have also been used to minimize formation damage. Again, to some degree these fluids have also been effective even today, many companies reduce the filtration rate to very low values, below 10 cc API, to minimize filtrate damage in the pay zone (P. L. Moore, 2016).

2.3 Types of Drilling fluids

Selection and application of the drilling fluid are key factors in the success of any drilling operation. The main purpose in designing a mud program is selecting a mud that will help minimise the amount of time lost in the wellbore to be drilled (Annis and Smith, 1996). Based on the complexity of holes drilled nowadays, basic types of drilling fluids have been developed based on the composition to curb against difficulties encountered when drilling. These are:

- Liquid Base (water base and oil base)
- Gaseous base (air and natural gas)
- Gas-Liquid mixture (foam and aerated water)

2.3.1 Water Base Mud (WBMs)

According to the Oilfield Market Report (2014), water-based fluids are used to drill approximately 80% of all wells. The foundation fluid that is the most prevalent phase may be fresh water, seawater, brine, saturated brine, or a formate brine. The type of fluid selected depends on anticipated well conditions or on the specific interval of the well being drilled (Anon, 2018c). The instability of shale, that is, the swelling tendency of clay has been cured by the use Oil base muds. However, developments of water base mud also needed for environmental sensitive areas (Zakaria *et al*, 2012). On the basis of material cost, water is always the first base fluid to be considered because of its inexpensiveness and readily availability. Hence, it applicability is brought to bare mostly when drilling exploration wells (Health and Safety Laboratory, 2000). The ban on oil base mud discharge that will take effect from 2001, will see the use of water base muds to increase until economically viable methods of using oil base muds are being explored and widely used. The main composition of a typical water base mud is highlighted in the figure below.

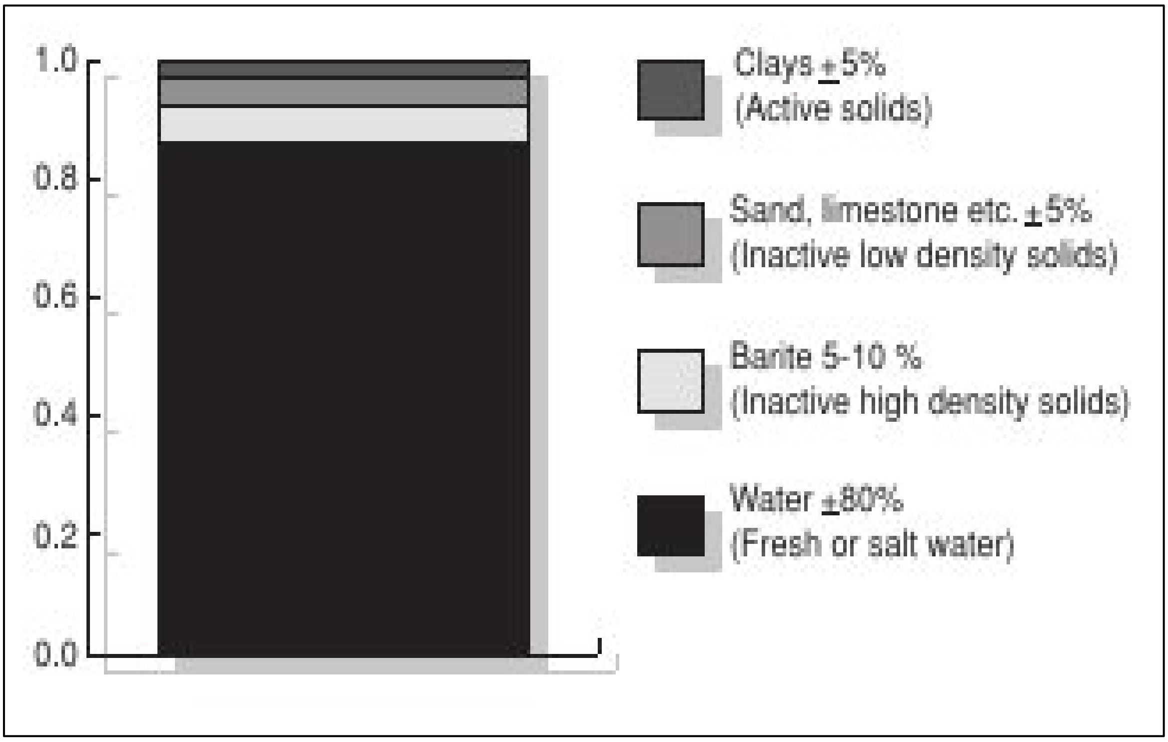

Fig. 2.1 Composition of Water Base Mud (source: Jack, 2015)

2.3.2 Oil Based Muds (OBMs)

In many aspects an oil-based fluid can be described as an ideal fluid because the interactions with the formation are minimal (R. Romagnoli, 2018). Because of the minimal interaction between the base fluid and the formation being drilled, this is the achieved with significantly fewer additives compared with water base systems. Based on wellbore associated problems whilst using Water base fluids such as swelling, sloughing, increasing downhole temperatures, stuck pipe and torque and drag effects Oil-based systems were developed and introduced in the 1960s to help address and curb these wellbore problems (Anon, 2018c).

Temperature stability, lubricity and hole stabilisation attributes of oil base mud makes it the preferred mud over water base mud (Caen and Chillingar, 1996), but tends to have an adverse effect on environment in terms of their tendency to destroy the ecosystem of the biological organism and persist in cuttings piles (Department of Industry and Resources, 2006). Figure 2.2 represents the basic feature of an oil base mud.

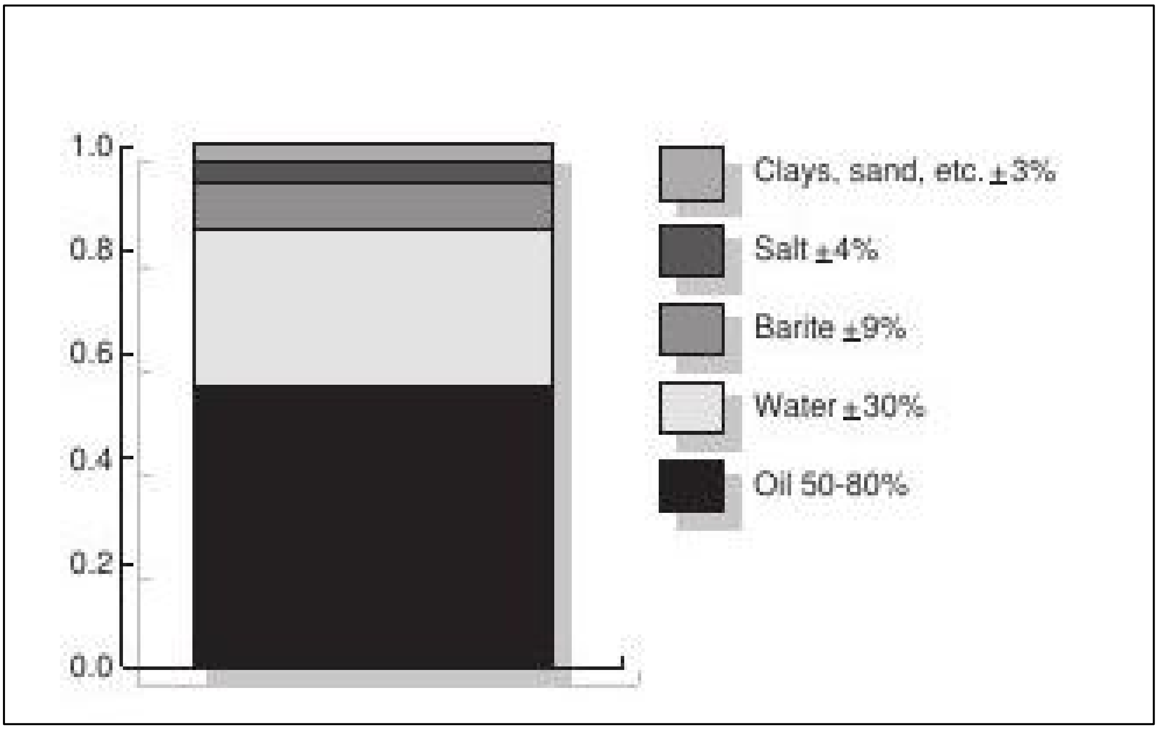

Fig. 2.2 Composition of Oil Base Mud (source: Jack,2015)

2.3.3 Air/ Gaseous Muds

Low density fluids are sometimes called gas-based or reduced pressure drilling fluids. The original purpose of these fluids was either to avoid loss of circulation or reduce the amount of water lost into production zones. Improved rates of penetration and longer bit life soon became well-known secondary benefits (R. Romagnoli, 2018). Compressed air or gas can be used in place of drilling fluid to circulate cuttings out of the wellbore.

The added advantage with the use of pneumatic fluids comes with its added advantages such as little or no formation damage, effective evaluation of cuttings for hydrocarbons presence, prevention of lost circulation and significantly higher penetration rates in hard-rock formations (Anon, 2018c). This technology matured in the late 1950s. The fluids mostly used in gas drilling has evolved as time elapsed, from air, natural gas and nitrogen air. Based on the availability of air or pipeline gas that is mostly flared, many drillers used it in gas drilling requirements in 1980s prior to gas drilling operations. However, the modus operandi of gas drilling makes it naturally expensive and dangerous in its application (Boyun and Deli, 2013).

2.4 Types of Water Base Mud

It will be very prudent to place emphasis on water base mud because the work will focus on formulation of water base mud. Many types of water base mud has been employed in drilling operations since its inception to date. It spans from fresh water to a very complex mixture of water and additives to achieve the desired results. Awele, (2014), in his research to investigate the effect of additives on drilling mud performance stated that, the main types of water base mud are:

- Dispersed Muds;
- Non – Dispersed Muds;
- Salt water Muds;
- Polymer Muds.

2.4.1 Dispersed Mud

These types of muds were introduced to drill greater depths that require the use of higher weighing muds or to drill problematic wellbores where enhanced treatments are required (Awele, 2014). These mud systems are normally treated with chemical dispersants that is mainly purposes to defloculate the clay particles thereby aiding to improve its rheological properties in high density muds. Most of the recognised dispersants used to achieve this purpose are lignosulfonates, lignitic additives, and tannins. Dispersed systems typically require additions of caustic soda (NaOH) to maintain a pH level of 10.0 to 11.0 (Anon, 2018c).

2.4.2 Non-Dispersed Mud

These mud types are basically applied for shallow wells or top hole sections. Usually the main function of this mud is to clean the well from the cuttings. Clear or locally drilled water is used in the formulation of the mud. Some mentioned examples of Non-dispersed muds are spud muds, natural muds and muds that requires slightly treatments. The use of thinning or dispersant additives is not employed in the formulation of this mud type but rather the used water that is the continuous phase is allowed to react with the shale or clay formation so that the mud will form its solid content and density naturally (Awele, 2014).

2.4.3 Salt water Muds

This drilling fluids are being used when it is expected to drill through reactive formations (clays and shales, salt) which could cause hole instability problems by reacting with the continuous phase of the mud. This could be either a saturated salt system or unsaturated depending on the forecast of the drillers on board (Awele, 2014).

2.4.4 Polymer Muds

These are long chain polymers. Mostly, of cellulose and acrylamide that are used in mud formulations to provide shale encapsulation. It protects water sensitive shales from hydrating and sloughing into the wellbore. It also aids in increasing viscosity and minimising fluid loss (Awele, 2014).

2.5 Properties of Water Base Mud

There are so many factors considered when choosing a drilling mud for a particular drilling operation. Apart from cost which is the basic criteria, other factors are the well design, anticipated formation pressure, rock mechanics, chemistry of the formation, mud performance, limit formation damage, temperature, environmental effects economics and logistics. To design and maintain a mud to meet the above-mentioned factors, it is necessary to measure the mud properties which control its ability to perform that function. Once these properties are measured and determined, its control and adjustment lie on the engineer on board. According to R. Romagnoli (2018), these properties possessed by the drilling fluids can be physical or chemical and can be measured on the mud itself or on its filtrate. Some of these properties are density, viscosity, gel strength, cake thickness and pH.

2.5.1 Density

Density is the mass per unit volume of the substance under consideration. The most widely used accepted unit for drilling slurry density measurement is the pounds per gallon (ppg). The approximated density of water used in preparing most drilling fluids slurry is 8.3 ppg. To control pressure in drilling operations, the operator or driller must know how to effectively control the mud weight. Hence, it is the starting point of pressure control. The weight of a column of mud in the hole necessary to balance formation pressure is the reference point from which all pressure control calculations are based. To forecast the specific mud to use in any case, the weight of the mud column must be known without ambiguity (Annis and Smith 1996). Normally, for easier and faster wellbore cleaning, drilling fluids are formulated to have a higher than the cuttings density (Nwaiche, 2015).

Even if too much mud weight does not fracture a formation, it can slow ROP. Hydrostatic pressure that is too high tends to hold cuttings on the bottom so that they cannot easily move up resulting in inefficient hole cleaning. The bit then tends to drill a lot of cuttings instead of fresh formation, which slows ROP. A sudden drop in mud weight, especially when accompanied by a gain in the level of mud in the tanks are two obvious signs that the well may have kicked. Checking mud weight also ensures that it has not gotten too heavy (Dyke, 2000).

2.5.2 Viscosity

It represents the internal resistance offered by the fluid to flow that is to be circulated and maintained in motion. From it, some important performances of drilling fluids depend such as their solids carrying and hole cleaning capacities and wellbore walls stabilization. The viscosity also determines the speed of movement of the drilling slurry (Jaali, 2015).

A viscous mud can transport more and heavier cuttings, so mud often contains a material to increase its viscosity. Viscosity must however be controlled for a mud too viscous puts undue strain on the mud pump and may interfere with other desirable mud properties required to efficiently drill the well (Dyke, 2000).

In fact, the addition of a small amount of substance in suspension or solution can greatly increase the viscosity of the liquid. Apparent viscosity is denoted by the symbol μ, the unit of measurement is in Pa.s or P (poise). The viscosity of liquids are higher than that of gases and this can be attributed to the closely packed molecules of liquids than gases which turns to increase the cohesive force between liquids than gases. But it must be noted that viscosity varies inversely with temperature (Jaali, 2015) and is some cases it is affected by both temperature and pressure. That is to say, as the temperature increases, viscosity decreases and verse versa (Osokogwu *et al, 2014)*.

2.5.3 Gel Strength

This is one of the most important mud property that determines the shear stress necessary to initiate flow of a fluid that has been quiescent. This property is related to its thixotropic characteristics. When drilling fluids circulation ceases during drilling operation, the property of the fluid to suspend drilled cuttings or solids is its Gel Strength. More Pump pressure is needed to move a mud after it gels at higher mud gel strength. In general, high gel strength muds transport cuttings at lower velocities than low gel strength muds (Dyke, 2000). The ability of the drilling fluid to form a gel-like structure after circulation ceases due to its electrostatic interactions with the electrically charged particles of bentonite, native clays, shales and polymers also determines its Gel Strength (R. Romagnoli, 2018). The strength of the structure formed is a function of the amount and type of solids in suspension, time, temperature and chemical environment. Therefore, any occurrence that will cause the particles to flocculate or deflocculate will have an adverse effect on the gelation tendency of a mud (Annis and Smith 1996).

2.5.4 Cake Thickness or Fluid Loss

The filtration process, that is, the partial loss of the water phase of a drilling fluid into a permeable formation, deposits on the walls of the wellbore what is called mud cake or filter cake, formed by the solids which are present in the fluid. The main effect of the filter cake is the protection of the rocks from further filtration (this is particularly important in the case of mineralised formations) and their stabilisation, avoiding problems such as hole caving and sloughing. Obviously, an optimum quality filter cake, in order to be efficient, should be very thin, impermeable and elastic and should be able to self-regenerate very quickly, otherwise problems such as hole tightening with a consequent increase in friction losses, pipe sticking and circulation losses could occur (R. Romagnoli, 2018).

Mud filtrates are lost to the formation which leads to the formation of thick and permeable filter cake at the surface of the wellbore posing wellbore problems as a result of the mud pressure being higher than formation pressure. The problems posed by filtrate invasion are more of formation evaluation and completion problems (Awele, 2014). A good drilling fluid should be able to form a thin and less permeable filter cake which is able to seal the pores between the formation and wellbore. Formation instability, damage, fractured formation and loss of drilling fluid may be due to excessive fluid lost to the formation (West *et al*, 2006). Awele, (2014), again stated that two types of filtration could occur," dynamic and static filtration". Dynamic filtration occurs when the fluid is being circulated and when it is at rest, it is static filtration. Dynamic filtration differs from static filtration in the sense that the flow of mud tends to erode the cake as it is deposited by the filtration process. As the filter cake piles up, it gets to a point where the rate of deposition equals the rate of erosion. At this equilibrium thickness, the rate of filtration becomes constant. This is not the case with static filtration. In static filtration, the cake grows continually with time increasing in thickness and causing a continuous reduction in filtration rate. Static filtration should be controlled to control filter cake thickness and dynamic filtration should be controlled to check invasion of filtrate.

The erosion rate is a function of annular velocity, mud viscosity and flow regime. Consequently, the volume of filtrate lost is not as important as the type of filtrate. From drilling operation prospective, the quality of filter cake formed is of more importance than the volume lost whilst drilling because a poor filter cake can cause wellbore related problems such as differential pipe sticking, torque or drag effects, lost circulation, and poor primary cementing jobs (Osokogwu *et al, 2014)*.

2.5.5 pH

The pH of a solution is a measure of its hydrogen ion concentration. At each hydrogen ion (H^+) concentration, there is an equilibrium concentration of hydroxyl (OH^-) ions. By measuring the hydrogen ion concentration, we are in effect, also measuring the hydroxyl ion concentration. At the neutral point, which is distilled water, having a pH of 7, there is no observable difference between the concentration of H^+ and OH^- . In acidic solution the pH varies from 0 to 7 whilst in a basic solution, is on a scale of 7 to 14 (Osokogwu *et al., 2014)*. Based on the desired condition to have all clay and shale particle negatively charged, maintaining a pH around and above 9 is desired in drilling operations. Furthermore, most of the polymers used solubilise more easily in alkaline environments (R. Romagnoli, 2018). Dyke, 2000 also made the assertion that, usually mud must be alkaline with a pH of between 8 and 13 to allow chemicals in the mud to work well and to minimise corrosion. Acids accelerate corrosion but a pH of 10 and 12 minimises the corrosion rate.

2.6 Additives Used in Drilling Fluids Formulation

Drilling mud is composed of many additives based on the application and required property enhancement. The quantity of modifiers used in the drilling mud will vary based on the drilling conditions. The following section outlines the functionality of the modifiers added to the drilling mud (Vipulanandan and Krishnamoorti, 2013).

- Fluid loss: it is the basic requirement of drilling mud, Bentonite is a clay material used for such applications. The main function of these additives is to reduce the amount of fluid lost to the formation thereby helping to increase hole-cleaning capacity. To ensure good hole stability and reduce excessive fluid loss to the formation, the filter cake formed should be thin and less permeable. The suspension of bentonite clay must be prepared in fresh water, brine can significantly affect its ability to minimise water loss. Its dosage varies with the major purpose of its use.

- Density Control: Barite ($BaSO_4$) is added to increase the density and specific gravity of the mud in order to control formation pressure as unbalanced formation pressures will cause an unexpected influx of formation pressure in the wellbore possibly resulting in a blowout if the influx are not controlled. Also, Hematite (Fe_2O_3) and Gela (PbS) are used as weighting additives to increase the specific gravity to achieve very heavy drilling muds.

- Control Acidity and pH: Caustic soda (NaOH) is used to control the acidity of the mud. Addition of NaOH increases the pH of the mud. But care must be taken while adding it to water since NaOH with water reacts exothermically causing sudden increase in temperature, increase in viscosity of the bentonite mud and decomposition of polymers. Also, caustic potash (KOH) is used to increase pH of those muds which are treated with potassium and also to solubilise lignite.

- Viscosity Modifiers: Sodium Carboxymethyl cellulose (CMC) and other synthetic polymers have been used to increase viscosity and control fluid loss at different fields. Its effectiveness decreases as concentration of the salt in the mud increases. It is also used to thin those muds that are treated with calcium. Also, Mica is added to avoid loss circulation by plugging large gaps in the rock formations. Xanthan Gum is a water soluble polysaccharides, produced by bacterial action on carbohydrates and is often used to enhance the viscosity properties of the mud at low shear rates without affecting the flowability of the mud at high shear rates. This exceptional shear-thinning property is unique to xanthan gums and does not get significantly affected by the presence of salt.

- ❖ Control Swelling of Clay: The swelling tendency of clay has been observed to reduced significantly with the use of calcium, sodium and potassium ions in the formulation of the water base mud.
- ❖ High Temperature Stabilizer: Lignite/Leonardite is used as a mild dispersant and thinner to basically control the flow. It also provides high temperature stability and acts as a deflocculant to reduce attraction between clay particles.

- ❖ Control Biological Activities: Bactericides is added to prevent bio-degradation of natural organic additives added to polymer muds such as the CMC and the Xanthan Gum.

- ❖ Reducing foaming: Anti-foaming agents are added to reduce the foaming action of the mud and therefore prevent the significant transport barrier to muds caused by the foams.

2.7 Rheological Models

Rheology is simply the study of the deformation and flow of matter in this water base mud when is being circulated. Mud engineers are mostly concerned about the relation between flow pressure and flow rate and their influence on the flow characteristics of the fluid (Mitchell and Ravi. 2006). The rheological models which are used by drilling engineers to describe the drilling fluids are:

- ❖ Newtonian model;
- ❖ Non-Newtonian model.

2.7.1 Newtonian Model

This model is the simpliest of all the flow behaviours. The linear constant of proportionality observed between shear stress and rate under constant pressure and temperature is the fluid viscosity. These fluids flow as soon as the shear stress increases as a result of increasing shear rate. Water, oil, gasoline and alcohol are few examples (Faergestad, 2016). It is very important to note that these fluids should be clean from any impurities and the presence of impurities may change its rheology. In practice, Newtonian fluids are real. Also, the shear stress is directly proportional to the shear rate and is mathematically expressed in equation 2.1.

$$\mu = \tau \ / \gamma \tag{2.1}$$

Where:

τ is shear stress

μ is coefficient of viscosity

γ is shear rate

2.7.2 Non-Newtonian Model

These fluids deviates from the newton's law due to the fact that there is no direct proportionality between shear rate and shear stress. The shear stress has been observed to change as the shear rate changes. For this reason, the ratio between shear stress and shear rate is indicated as the "apparent viscosity". Non-Newtonian fluids are classified in four main categories (R. Romagnoli, 2018):

- ❖ Time independent properties;
- ❖ Time dependent properties;
- ❖ Fluids with similar characteristics to solid bodies;
- ❖ Complex fluids.

2.7.2.1 Fluids whose Properties are Time Independent

These fluids are subdivided into three classes:

- ❖ Bingham plastic fluids;
- ❖ Pseudoplastic fluids & Dilatant fluids;
- ❖ Yield pseudoplastic fluids.

Bingham plastic fluids

The relationship between shear stress and shear produces a straight line which does not pass through the origin. A finite shear stress is called the Yield Point is required to initiate flow as shown in Fig. 2.3 below (Anon., 1996). This means that for starting their flow, it is necessary to apply to them a given shear stress, whose value is known as "yield value" and its position on the Y-axis as "yield point". Examples of Bingham plastic fluids are; some aqueous suspensions of rocks and slurries of dirty waters. The behaviour of a Bingham plastic fluid is described by the following equation:

$$\tau = YV + \mu_p \cdot \gamma \qquad \text{being} \quad \tau > YV \qquad (2.2)$$

where:

μ_p = straight line slope, known as "plastic viscosity" PV (while: $YV = \tau_o$)

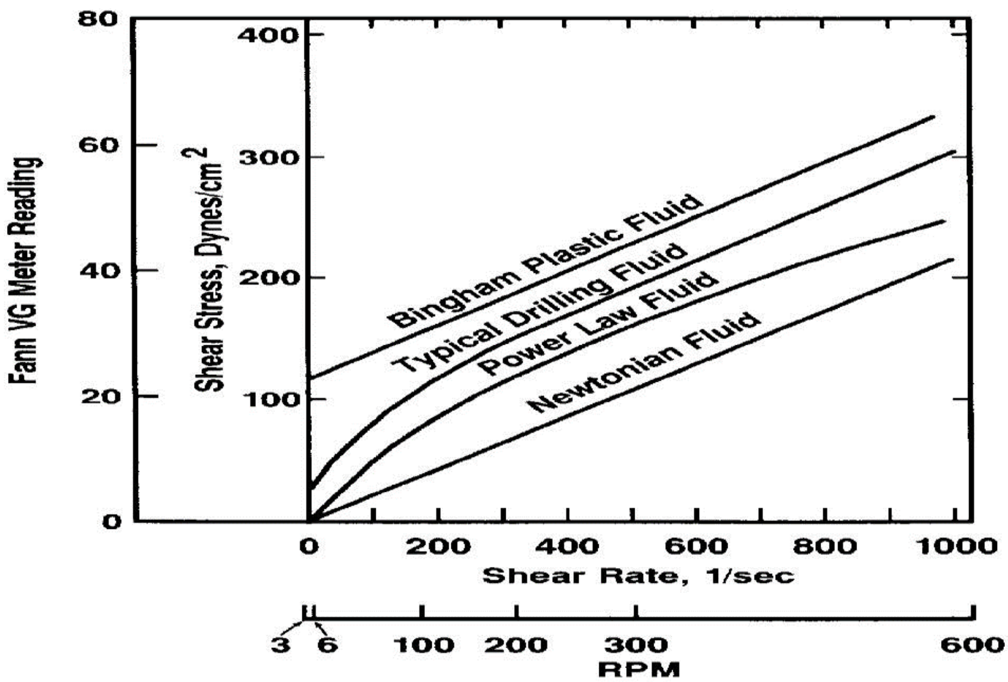

Fig. 2.3 Shear Stress Verses Shear Rate for Various Fluids (Anon., 1996)

Pseudoplastic fluids

The pseudoplastic fluids are characterized by a curve passing through the origin of the Cartesian axes and their behaviour is represented by the following relation, known as "Power Law" or "Ostwald & De Waele model":

$$\tau = K(\gamma)^n \quad \text{being} \quad n < 1 \qquad (2.3)$$

where:

K = flow consistency index

n = flow behaviour index

The term "n" shows of how much the behaviour of the fluid under consideration departs from a Newtonian fluid; in fact:

if n = 1 the fluid is Newtonian and the equation becomes that of a Newtonian fluid with the term K corresponding to the viscosity;

if n ≠ 1, as more n differs from 1 more non-Newtonian is the fluid behaviour; in particular:

when n<1, as in this case, the fluid is called pseudoplastic;

when n>1 the fluid is said to have a dilatant behaviour

The term K is similar to the viscosity, thus higher K indicates higher viscosity of the fluid. The apparent viscosity of a pseudoplastic fluid decreases with increasing shear rates. Examples of pseudoplastic fluids are; solutions or fusions of polymers, paper paste suspensions and pigments.

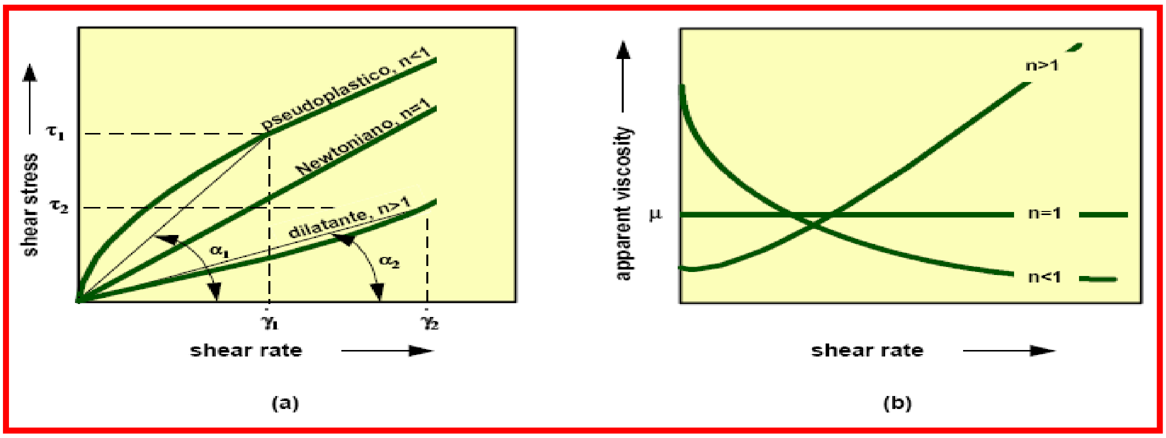

Fig.2.4 Representation of Pseudoplastic and Dilatant Model (R. Romagnoli, 2018)

Dilatant fluids

The behaviour of a dilatant fluid is, in practice, the opposite of that of pseudoplastic fluids. They are described by the same power law with the only difference, that in this case n>1:

$$\tau = K\,(\gamma)^{n} \qquad \text{being} \quad n > 1 \tag{2.4}$$

where:
K = flow consistency index
n = flow behaviour index
In this case, as already pointed out, the apparent viscosity increases with increasing shear. Dilatant fluids includes aqueous suspensions of starch and mica, shifting sands and beach sands.

Yield Pseudoplastic fluids

Yield pseudoplastic fluids have a yield point and an apparent viscosity which have no linear relationship with the shear rate, as already observed for pseudoplastic fluids. In these fluids, the apparent viscosity decreases as the shear rate values increases; the inclination of the flow curve, instead, continually decreases and very often tends to a constant value at high shear rates. The rheological behaviour of a yield dilatant fluid is the opposite to that of a yield pseudoplastic fluid, because its apparent viscosity increases with increasing shear rates.
The theoretical model which represents in the best way the behaviour of these fluids was conceived by Herschel Bulkley, at the beginning of 1900 to simulate the behaviour of rubber and benzene solutions. This model is expressed by this equation

$$\tau = \tau_0 + K\,(\gamma)^{n} \qquad \text{being} \quad n < 1 \tag{2.5}$$

where:
K = flow consistency index
n = flow behaviour index

τ_o = yield point or yield stress

Again, K indicates the degree of fluid viscosity and, at times, is analogous to the apparent viscosity, while n always represents the difference from a Newtonian fluid behaviour.

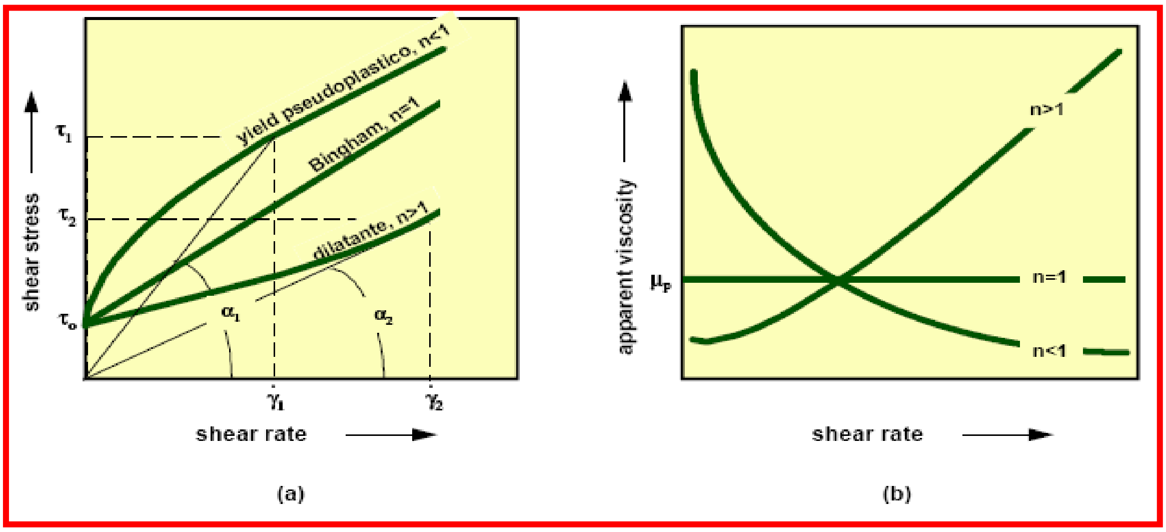

Fig.2.5 Representation of Yield Pseudoplastic Model (R. Romagnoli, 2018)

2.7.2.2 Fluids with Time-Dependent Properties

There are many fluids, whose behaviour cannot be represented by the models seen previously for non-Newtonian time-independent fluids. The apparent viscosity of the non-Newtonian time-dependent fluids is not only a function of shear rates, but also by the time the stress is acting on them. These fluids can be grouped in two categories:

- Thixotropic fluids
- Rheopectic fluids

Thixotropic fluids

The thixotropic fluids possess a structure whose breakage depends on both time and shear rate. Maintaining a constant shear rate, the shear stress decreases as soon as the structure of the fluids starts breaking. The structuration of the fluid restarts when the stress is removed, unless other external forces act on the system. The extent of the DEAFD area is an indication of the thixotropy entity. If we maintain constant the shear rate after Point A, the shear stress decreases along with the AC straight line till the Point C is reached. No other failure of the structure occurs after this Point C for that given shear rate. If the shear rate is decreased, the corresponding shear stress follows the path of the curve CHD, where the Point D is the initial yield point; but to come back again to the Point D, infinite curves can be followed depending on particular circumstances. Examples of these fluids are; drilling muds, paints and inks.

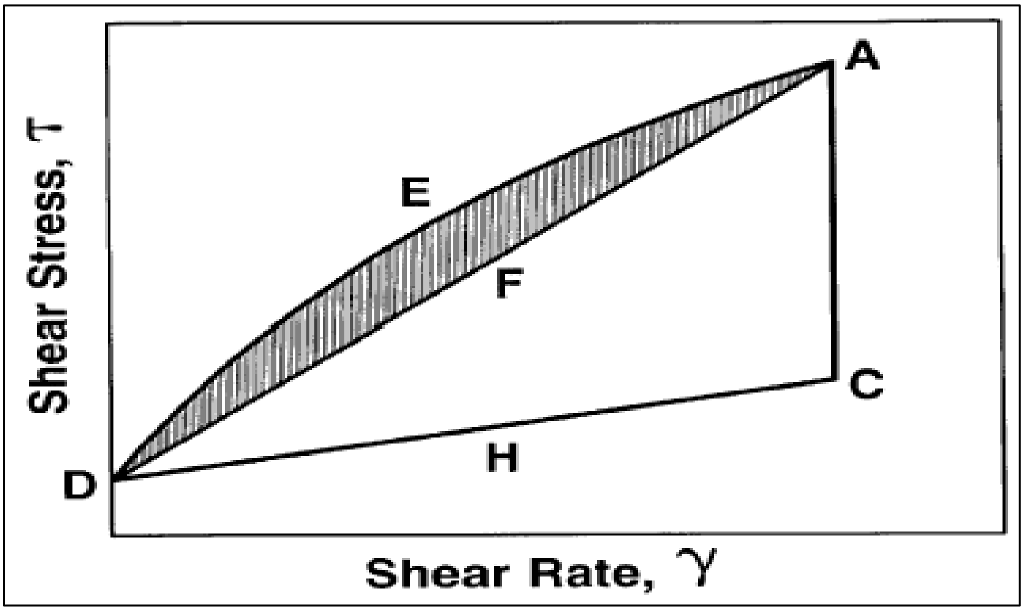

Fig.2.6 Representation of Thixotropic Fluids Model (R. Romagnoli, 2018)

Rheopectic fluids

The fluids of this category tend to build up a structure when they flow at low shear rates; in these conditions, their apparent viscosity increases with increasing shear rates. But when a certain critical shear rate value is surpassed, their structure is destroyed and consequently, their apparent viscosity starts to decrease with increasing shear rates. Rheopectic fluids are: bentonite suspension in sol state and gypsum in water suspensions.

Viscoelastic fluids

The viscoelastic fluids exhibit elastic and viscous characteristics: they, up to a certain extent, are capable to deform elastically. Examples are some liquid polymers, pitch etc.

Complex fluids

There are many fluids which do not belong to any of the categories mentioned up to now, because their shear rate/shear stress relationship cannot be described by a simple mathematical equation. A modern drilling mud, due to its high compositional complexity and the different behaviours it exhibits under varying temperature, time and shear rate regimes can be classified as a typical complex fluid

2.8 Salinity

The sum of all non-carbonate salts that goes into water solution relative to chloride concentration that is only shown by its content is salinity. That is to say, the sum total of all dissolved salts in the mud is its salinity (Amani et al., 2016). Salt water or brine has been used as an alternative to fresh water to increase ROP when drilling through a salt formation or shale. Also, fresh water or salt water with a low salt concentration can dissolve salt formation causing hole enlargement and other difficulties. Brine has been useful in areas where there is normal formation pressure because it can withstand the formation pressure without the need to add barites (Dyke, 2000). The most relied source of calcium and magnesium that is mostly used to control viscosity is salt water. However, undesired salts in the mud can cause a lot of problems in keeping and maintaining the properties of the mud.

2.8.1 Effect of Salinity on Rheological Properties

In a research by Awele, (2014) to investigate additives effects on drilling mud performance. Sodium pyrophosphate decahydrate (SPP) and sodium hexametaphosphate (SHMP) were the salts used in their study. He made the assertion that both salts used reduced viscosity although reduction in the viscosity dial readings after a step increase 0.15 g of salt added was more evident in the case of the sodium pyrophosphate decahydrate (SPP) than it was with sodium hexametaphosphate (SHMP). Sami, (2015) also made the same assertion when he conducted a research to investigate the effect of magnesium salt contamination on the behaviour of drilling fluids. In his research, He made use of two mud samples which was made up of different levels of magnesium chloride salt ($MgCl_2$).The experiment was conducted at the laboratory making use of both ambient and elevated temperature conditions. However, his focus was mainly on the rheological properties of the made under study. As the salt levels were increased, the viscosity, yield point, and gel strength of mud under study. The above observations makes the slurry not a good candidate for cutting suspension because the increasing magnesium salt content affected the dispersion, hydration and flocculation tendencies of the particles. In addition, the amount of filtrate lost to the formation was on the rise as the salinity levels were increased which can cause downhole problems. Again, shear stress and rate curve for NaCl contamination increased as opposed to KCl contamination, which showed a decrease in shear stress and shear rate curves of water-based mud (Hassiba and Amani, 2013). This indication showed that different salts might have different effect on the rheological properties of the drilling slurry under study.

Ali *et al*. (2013), also observed a reduction in plastic viscosity and electrical resistivity in their study to ascertain the effect of salt contamination on the plastic viscosity and electrical resistivity of bentonite drilling mud using sodium chloride (NaCL). Also adding salt whilst formulating a drilling fluid saw the fluid loss to increase by about 30% and the resistivity decreased by 86% as opposed to a drilling slurry with no salt added (Basirat *et al*., 2013).

2.8.2 Effect on Wellbore Stability

Most delays in drilling operations has been attributed to wellbore instability in the past years and in some instance a well being drilled has been out on hold due to wellbore problems. Increasing the salinity of a drilling fluid could help to avoid compressive failure but to some extent may cause tensile failure and may cause chemically induced fracture (Huang *et al*, 2012). However, maintaining constant salt concentration in shale may provide long-term osmotic effect and subsequent long-term wellbore stability. To dehydrate the shale and prevent it from swelling, drilling mud should be designed in such a manner that water activity of the mud should be lower than shale water activity, while the salt concentration of the mud should be higher than the salt concentration of the shale (Bai, 2008). From most published literature, it is clear that, all things being equal, clay-swelling tendency will be reduced or expected to minimise with an increase in salt levels and vice versa. Also, increasing the salt concentration of a drilling fluid increases the fluid loss into the formation (Sami, 2015). Therefore, it can be inferred that if fluid loss increases, then the quality of filter cake formed when increasing the salinity is poor. A better consolidation of the formation being drilled and stabilisation of the wellbore drilled is evident from a good, thin and impermeable mudcake. Also, during drilling, the deposition of thin and impermeable mud forming a cake on the walls of the unconsolidated formation being drilled will prevent the loss of mud being infiltrated into the formation (Charlez 1997). Providing topmost lubrication whilst increasing rate of penetration thereby tending to minimise mechanical vibrations in salt zones has been most significant with the use of synthetic-base-mud (SBM). However, it should be noted that when lost circulation problems are forecasted which can cause wellbore enlargement the use of salt saturated water-base-mud (WBM) has dominated synthetic-base-mud (SBM) (Whitfill *et al*., 2002).

2.8.3 Effect on Cementing

Successfully displacing drilling fluid from the annulus and properly preparing the annular surfaces to respond and accept the bonding with the cement is one of the most well recognised factor in cementing operations (Patel *et al*., 1999). Salts has an adverse effect on the acceleration/retardation properties of cement (Vallejo, 2017).

2.8.4 Effects on Rate of Penetration (ROP)

A study by Beck *et al*, (1995) to determine the effect of rheology on rate of penetration brought to light that most authors have indicated in their research that drilling fluids properties can impact drilling rate. They also continued the assertion that, in laboratory conditions, penetration rates will be affected by altering fluid viscosity. If this claim is true, then is of no doubt that if salinity increase or decrease fluid viscosity, it effects on ROP can also be indirectly correlated.

To John and Eckel (1967), correlating drilling rate to the solids content in the drilling slurry is uncalled for because there is not direct dependency between them but a link can be drawn between the drilling rate and the impact exerted by these solids in the slurry on fluid behaviour. And this can be mostly observed on the fluids viscosity as it exist through the drilling bits nozzles. The above analysis gives a clear clue that says; drilling rates can be related to or correlated with fluid properties which gives indication about the viscosity of the fluid such as the plastic viscosity. Fluid properties that gives indication about the solids content in the fluid can also be used as a means of correlating rate of penetration to viscosity of the fluid (Beck *et al*, 1995).

For Beck et al, (1995), to effectively correlate plastics viscosity to rate of penetration, data were collected from the side-track wells drilled in Prudhoe Bay, Alaska. For easy data collection process and analysis, keeping constant rate of penetration, such as hole size, weight-on-bit, rotary speed, bit type, formation type, bit hydraulic energy, and basic mud type which has a direct link with rate of penetration were all optimised. This was so because they believed that as drilling fluid properties were changed, their impact on drilling rate could be directly ascertained.

Referring from Allen and James (1977) model, Beck *et al.*, (1995) modified their model of equation 2.1

$$\frac{ROP2}{ROP1} = 10^{k\,(FP1-FP2)} \qquad (2.6)$$

Where;
FP1 and FP2 = fluid properties of interest.
k = is a regression constant.

In other to determine the regression constant, a plot of ROP and PV data from the side-track wells drilled in Prudhoe Bay, Alaska was used. Representing FP1 and FP2 by plastic viscosity. Equation 2.7 was the final correlation model from Beck *et al.*, (1995).

$$\frac{ROP2}{ROP1} = 10^{0.0124(PV1-PV2)} \qquad (2.7)$$

Upon thoroughly reviewing literature concerning the correlation between ROP and fluid properties. The most direct link was evident with ROP, where most the review papers concluded in their research that an increase in ROP causes a decrease in plastic viscosity (Cheatham and Nahm, (1985); Beck *et al.*, (1995); Alum *et al.*, (2011); Paiaman *et al.*, (2009)).

CHAPTER 3

MATERIALS AND EXPERIMENTAL METHODS

3.1 Introduction

Sample preparation is a necessary step in almost all research works. Materials to be used for a research work must be carefully and properly selected in order to attain the required results. Performing laboratory study on the mud under consideration made it possible to determine the necessary slurry properties. The properties considered in the project are:

- ❖ Rheological properties (viscosity);
- ❖ Fluid loss;
- ❖ Drilling Parameter (ROP);
- ❖ Density.

The content of this chapter mainly elaborated on the various steps employed in conducting the laboratory investigations. And to make this experimentation possible, the researcher made use of the Drilling laboratory of the University of Miskolc, Hungary through an opportunity offered to him by the Erasmus+ scholarship. Almost all the experiments were conducted under ambient conditions using pressure of 100 psi. However, to test the filtration loss effect at high temperature and pressure conditions the Ca^{2+} polymer based drilling fluid Ca^{2+} polymer based drilling fluid had being already tested at the field and attested to within such conditions.

3.2 Sample Collection

The drilling fluids used in this study are Ca^{2+} based polymer mud collected from the field and a laboratory prepared treated bentonite mud. The fresh water base mud was prepared at the laboratory using water collected at the laboratory. The rheological and basic properties of the water base mud received from the field was already determined and some of the properties listed on the daily mud records sheet

The bentonite and the additives used in preparing the laboratory water base mud was provided by the Miskolc University Drilling Laboratory.

3.3 Sample Preparation

The drilling mud slurry (Water Base Mud) was prepared in accordance with American National Standards Institute/American Petroleum Institute (ANSI/API) specifications. The standard bentonite drilling fluid is described in the API 13A page 15. The standard temperature is 27± ^{0}C and 22.5 g/350 cm3 distilled water. Normally the bentonite is 3-8 % by mass. It consists of 90 percent montmorillonite and 10 percent other minerals, mostly feldspar. The montmorillonite is a crystalline, three phase hydrosilicate. It absorbs five times its own mass and swells about 15 times.

In the study, the water base mud was prepared using bentonite and distilled water, Caustic Soda, Lime, Polythin, Polypac, Polydrill, Duo-vis and Barites being the additives and the salt was being added in time steps to increase its salinity. The Hamilton beach multi-mixture was used in mixing the mud. The mud was prepared by weighing 285 grams of the bentonite using a triple beam balance. The measured sample was transferred in to cup containing 4 litres of distilled water to allow for its mixing. 16 grams of polydrill was then added to ensure fluid loss control at HPHT, 3 grams of Duo-Vis for rheology, 11.4 grams of Polypac -R for general fluid loss control, 12 grams of Polythin as a thinner, 11 grams of caustic soda to increase and maintain pH and alkalinity, 5.7 grams of lime for pH buffer and 411 grams of barites to achieve the desired weight. The mixture was vigorously agitated with the multi-mixer for 10-15 minutes to produce a homogeneous mixture after each additive was added. The mud sample was then aged for 24 hours to allow for adequate hydration after which the properties under investigation was measured. 500ml of the prepared mud was measured and saturated with the salt before every test was conducted.

The Salinity of the both lab and field mud was increased by adding KCL in steps after each measurement. The salts were added from (0-15) % in 5 % step increase.

However, a further (1 and 2) % salinity increase test was conducted using the treated bentonite mud to confirm a trend which was observed during the test.

3.4 Rheological Measurements

The rheological properties of the fluid samples used in this study were measured using Fann 35A Viscometer (see fig. 3.1). Its calibration by industrial experts are in revolutions per minute (RPM) and but the obtained units of measurements are in the centipoises (cp). It measures mud viscosity by use of a coaxial cylinder. A cylinder and a bob assembly are immersed into a sample of mud and the cylinder is rotated with an electric motor. As the cylinder rotates through the mud, a torque arising from the viscous drag of the fluid is exerted on the bob. The torque is balanced by helical spring and the deflection, which is dependent on the mud viscosity, is indicated on a dial. The Fann viscometer with 6 speeds is designed for field and lab use and turns at 600 RPM, 300 RPM, 200 RPM, 100 RPM, 6 RPM and at 3 RPM. The readings obtained by the dial determines the rheological properties although sometimes come computations are needed (Anon, 2018e). The properties of interest studied in this project includes plastic viscosity, yield point and gel strength.

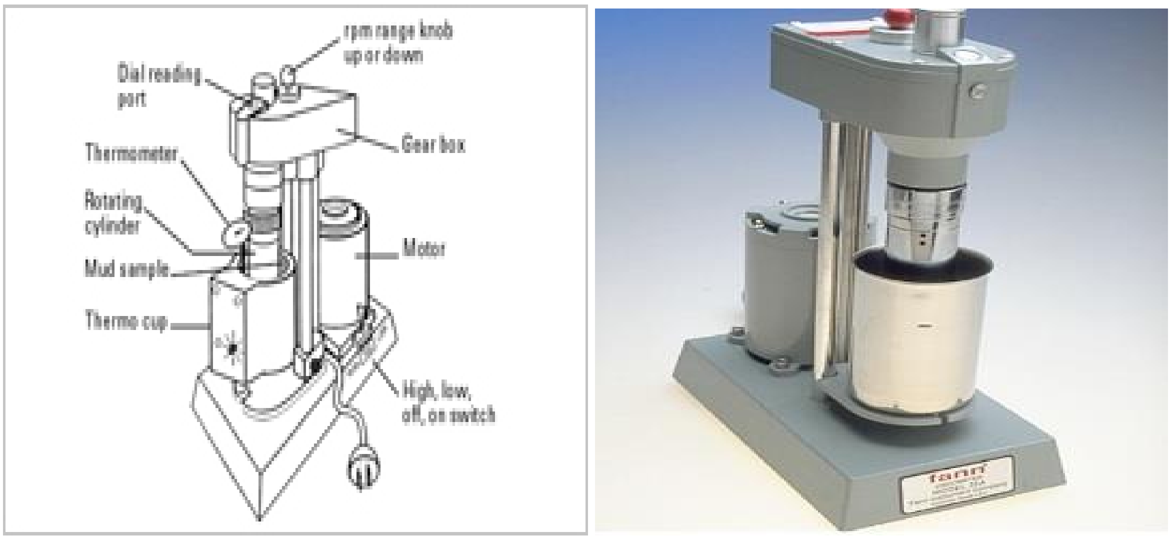

Fig. 3.1 Fan 13A Viscometer (source: Anon, 2018c)

3.4.1 Viscosity Measurement Procedure

The following steps were used:

- Firstly, by making sure the mud is thoroughly agitated, pour it in the study cup to the scribed line and carefully immerse it to the rotor sleeve. After the immersion tight and lock it on the plat form by using tightening nob.
- With the motor running and the motor speed switch in the high position, push the gearshift all the way down to 600 RPM whilst waiting on the dial raeding to stabilise for readings to be taken.
- Using the gear shift and the motor speed switch, switch to lower positions, 300 RPM and so on and record the steady dial readings.

3.4.2 Plastic Viscosity Determination

Plastic viscosity is a measure of the internal resistance to fluid flow attributable to the amount, type and size of solids present in a given fluid (Falode and Ethinola, 2008). Its unit of measurement is centipoises and for all materials following the Bingham's Law of plastic flow, the plastic viscosity is the directly related to the slope of the consistency curve determined by the region of laminar. Plastic viscosity tells us something about the expected behaviour of the mud at the bit. Hence, a corresponding decrease in plastic viscosity will cause a corresponding decrease in viscosity at the bit which may cause an increase in penetration rate if all things are kept constant. Field practices has brought to light that, hole cleaning ability of the mud is retarded if the plastics viscosity is reduced. And this may be due to the fact that an expected increase in plastic viscosity will increase the pressure dissipated down the drill string tending counteract any increase in cutting uplift. Based on the above observed trend in practice, it is worth knowing that plastic viscosity should be maintained as low as reasonably applicable as a higher value is not accepted and if it happens will cause wellbore defects (Osokogwu, 2014).

Obtaining the dial readings at 600 rpm and 300 rpm , The plastic viscosity PV (μ_p) was computed using the equation below:

$$\mu_p = \theta_{600} - \theta_{300} \tag{3.1}$$

Where:

θ_{600} = 600 rpm dial reading.

θ_{300} = 300 rpm dial reading.

3.4.3 Yield Point Determination

The yield point, calculated from the Bingham equation, is not the true yield stress necessary to maintain flow, but a value which is somewhat higher. It is normally close to the value of the shear stress at annular shear rates. Anything that causes changes in the low shear rate viscosities will be reflected in the yield point. For this reason, it is a good indicator of flow behaviour in the annulus and compositional changes that affects the flow behaviour in the annulus (Osokogwu, 2014).

The yield point is the resistance to initial flow and it represents the stress required to start fluid movement. This resistance is believed to be due to electrical charges located on or near the surfaces of the particles. In some cases, the ability of the mud to effectively perform it functions of cuttings uplift is assessed by the use of the yield point (Falode and Ethinola, 2008). Flocculation of the clay particulates or the colloidal particles may cause higher computational yield point values. A lot of factors contributes to the flocculation of clay particles, mentioned few of things includes deflocculant insufficiency and contamination by salt, calcium, carbonates, and bicarbonate. The yield point is needed to better understand the hole cleaning capability and the pressure control characteristic of the mud under study. An increase in yield point will cause an upsurge of the cuttings carrying capacity of the mud thereby increasing the circulating pressure drop in the annulus (Osokogwu, 2014).

The determination of YP (τ_y) was obtained from the dial readings at 300 rpm as the plastic viscosity as follows:

$$\tau_y = \theta_{300} - \mu_p \qquad (3.2)$$

Where:

θ_{300} = 300 rpm dial reading.

μ_p= Plastic Viscosity.

3.4.4 Gel Strength

The gel strength is a measurement of the shear stress necessary to initiate flow of a fluid that has been quiescent for a period of time. It is caused by electrically charged particles that link together to form a rigid structure in the fluid. The strength of the structure formed is a function of the amount and type of solids in suspension, time, temperature and chemical environment. In simply put, any occurrence which will aid in the bonding or breaking of the clay particles will have an adverse effect on the gelation tendency of a mud (Annis and Smith, 1974).

In the determination of the gel strength of any mud under study, two readings are normally required, the first being after mud agitation and the second being after the mud has been allowed to stand and settled for ten minutes. The readings are referred to as the initial gel strength and the ten-minute gel strength respectively. Both gel strength readings so determined will be zero for true fluids no matter how viscous, e.g., distilled honey. However, differences in readings are observed and better appreciated for solutions with suspensions like a drilling muds (Anon, 2018e).

The gel strength of the mud was determined by using the Fann 35A viscometer.
The Procedure used were as follows:

- Stir sample at high speed for about 15 seconds.
- In order to measure the 10-second gel strength at 3-RPM, the gearshift is pulled up to middle position and the motor off switched off. After that the mud is allowed to stand ideal for 10 seconds. After the 10 seconds has elapsed, turn the motor on to the low speed position and measure the maximum dial deflection before the gel breaks.
- To determine the 10-minute gel strength, stir the sample at high speed (600 RPM) before allowing it to remain standing for 10 minutes. Repeat the measurement above and report the maximum dial reading as the 10-minute gel strength.

3.4.5 Apparent Viscosity

Dividing the dial reading at 600 rpm (1022 sec^{-1}) on the viscometer by two (2) is the apparent viscosity of the sample under study. It is a reflection of the plastic viscosity and yield point combined. Since is a reflection of both plastics viscosity and yield point, an increase in apparent viscosity will cause an increase in both plastics viscosity and yield.

$$\mu_a = \frac{\theta\ 600}{2} \qquad (3.3)$$

Where:

θ_{600} = 600 rpm dial reading.

μ_a= Apparent Viscosity

3.5 Filtration Loss and Filter cake

The drilling mud should have the ability to rapidly form a thin filter cake of low permeability on a porous formation. This property of the mud determines to a larger extent the hole stability, freedom of movement of the drill string, and the information and production derived from the hole (Anon, 2018c).

The loss of liquid from a mud due to filtration is controlled by the filter cake formed from the solid constituents in the drilling fluid. The laboratory experiment is done by measuring the amount of filtrate that will pass through filter paper in 30 minutes under given pressure and temperature condition using a standard size cell. The filter cake formation and the filtrate can be determined both at static and dynamic conditions, at high pressure and high temperature, and at low temperature and low pressure. The choice of the test to be employed depends on the researcher and the area of interest in his research. Already published article made the revelation that the amount of filtrate is roughly proportional to the square root of the time (Anon, 2009).

The tendency of the solid particles in a drilling fluid slurry to form a thin and impermeable layer at the face of the formations expresses its filtration property. Therefore, it is clear that when comparing two samples of the same solid concentration, the form that forms thinner and low permeable filter cake will have a good filtration property as opposed to the other mud sample. The ability of the mud to form a good filter cake depends mostly on the colloidal materials in the mud. Field study shows that, when the colloidal content are effectively controlled in mud, drilling difficulties are minimised (Anon, 2009).

Muds with high inert solids and low colloidal particles turns to form a thick filter cake on wellbore walls. A poor or thick filter cake makes the passage of downhole equipments difficult or tedious and turns to contribute to excessive fluid loss into the formation thereby posing a lot of wellbore problems. This thick filter cake formed give defects to the walls of the wellbore. Some of these associated problems are difficulty running casing creating a swabbing effect causing the formation to cave or swab reservoir contents into the wellbore (Anon, 2009). The filtration gives information about the volume of filtration, thickness of filter cake and description of the shape of the filter cake.

This outlined property of the mud was determined at high pressure and high temperature dynamic conditions for the Ca^{2+} base mud using the Ofite HPHT dynamic filter press and at low pressure and low temperature static conditions for both mud under investigation using the baroid multiple unit filter press.

3.5.1 Low Pressure and Low Temperature Static Condition Test

The static filtration test is used to determine and measure static filtration behavior of mud at ambient temperature and a differential pressure of 100 psi. The OFITE's Multi-Unit filter press (see fig 3.2) was the equipment used to measure the filtrate and cake formed in this research. It is perfect for laboratory environments when several tests are run simultaneously. Manifolds, air hoses and bleed-off valves comes with the unit. The test was performed according to specifications set by API, using a static filter press.

Fig. 3.2 Multiple Unit Filter Press (source: Anon 2018d)

The following procedures were employed in the determination of the filtrate and filter cake formed at low pressure and low temperature static conditions:

- With the cell upside down (large open end up) and the index finger over the small hole at the other end, fill the cell with a freshly stirred sample of mud;
- Then, in this order, insert the O-ring, one piece of filter paper and then tighten the base cap;
- Turn the assembled unit upright again and insert it into its pressure assembly;
- Place a clean, dry, graduated cylinder under the exit tube;
- Apply 100 psi of pressure to the cell and collect the filtrate for 30 minutes;
- At the end of 30 minutes, release the pressure and record the volume in cm3 of the filtrate collected as well as the cake thickness in mm;
- Upon dismantling the cell, the remaining filter cake should be examined. look out for the hardness, softness, toughness and firmness by feeling it with your fingers to ascertain the quality of the cake formed. A filter cake thickness less than 1.5 mm is the acceptable standard.

3.5.2 High Pressure and High Temperature Dynamic Filtration Test

This is a test to measure dynamic filtration behaviour of muds at elevated temperature and pressure. The OFITE High-Temperature, High-Pressure (HTHP) Dynamic filter press (see fig 3.3) was used to measures filtration properties under varying dynamic down-hole conditions in this research.

Fig. 3.3 OFITE High-Temperature, High-Pressure (HTHP) Dynamic Filter Press

The operating procedure follows the same steps as the well-known HTHP filtration test. The slight difference is that in this situation, the drilling fluid is simulated to rotate in the test cell whilst taking the filtrate. The results obtained using the dynamic filter press compares well to other laboratories or historical trends. And the reason being that, the manufactured disk used is done to suite field conditions. (Anon, 2012).

The following procedures were the summary of the steps employed in the test:

- ❖ After the test sample has being prepared, place it in the test cell. Allow at least 2.5" of space from the top of the fluid to the o-ring groove to allow for thermal expansion and shaft displacement;
- ❖ Attach the propeller to the end of the shaft and secure it in place;
- ❖ Place the top cap assembly onto the test cell and secure it in place by tightening the locking screws;

- By placing the cell in the heating chamber, adjust the inlet stem valve to face farthest from the motor housing so as to allow easy connection of the pressure manifold;
- Attach the back pressure receiver to the outlet valve stem by securing it in place with the locking pin. Above 212°F (100°C) is when the back pressure receiver is needed;
- By closing the inlet and outlet valves, and apply the needed inlet and and back pressures;
- Start heating the sample to the desired temperature which was 110^{o}c in this research. The sample normally takes 30 to 60 minutes to reach the expected temperature. The heat time should never exceed 60 minutes;
- Set all the belts properly, attach the water lines Run the drain line from the centre of the swivel body to an appropriate drain;
- Set the mixing speed to the desired value. 300 RPM was used in this test. And apply the pressure to the cell; 22 bar was used;
- Set a timer and collect filtrate for 30 minutes by bleeding the back valve to collect the mud filtrate
- Repeat the above stated steps for all the samples left.

After each measurement, the thickness of the cake formed should be determine to the nearest 1/32" (0.8 mm). After the cake formed measured, look out for the hardness, softness, toughness and firmness by feeling it with your fingers to ascertain the quality of the cake formed. To calculate the mud filtrate, make use of the equation below:

Dynamic HTHP Filtration (mL) = 2 × (*mL fluid recovered in 30 minutes) (3.4)

The two added accounts for the initial mud lost before infiltration.

3.6 Density Determination

For safe drilling, high-formation pressures must be controlled. This is achievable by making sure the formation pressure is less than the pressure exerted by the mud. The arithmetic difference between the hydrostatic and formation pressures should be zero if you want to ensure a safe drilling operation. In practice, an overbalance of 10-15 bar is normally used to provide an adequate safeguard against wellkick. The Fann Model 140 Standard Mud Balance and OFITE Pressurized Fluid Density Scale are used to measure density of the mud or cement slurry (see fig. 3.4). In this experiment, the Fann Model 140 Standard Mud Balance was used. This was because it is proven to give an accurate determination of fluid density. It is also the easiest to be used at the filed for density determination. The instrument not depending on the temperature of the sample gives it an added advantage (Anon, 2018d).

The OFITE Pressurized Fluid Density measure instrument is similar in operation to the simple mud balance. The only significant difference is that it is equip with valve on the cap to allow connection of a small piston-type hand pump. This small piston-type hand pump allows pressurisation of the mud so that all the gas or bubbles entrapped in the mud will be removed to allow accurate density determination without the effect of gases or bubbles.

Fig. 3.4 Standard Mud Balance (Red) and Pressurised Mud balance (Grey) (source: Anon 2018d)

The following steps were employed in performing this test/experiment:

- Having removed the lid of the cup and being filled with the mud under study, tap the cup in a controlled way to remove any trapped air bubble if there is any;
- After the above, place the lid back and rotate it till mud starts coming out from the small hole on top of the lid, this is to assure that the mud is full to the brim;
- Carefully wipe off any spilled mud from the cup and place it on fulcrum rest of the whole assembly;
- By moving the rider, observe from the spirit level to ensure that it is in equilibrium;
- Read mud density at the edge of rider nearest fulcrum.

CHAPTER 4

RESULTS AND DISCUSSION

4.1 Laboratory Results

In order to determine the properties of interest in this work, some rheological and filtration test (both at ambient and HPHT dynamic condition) were conducted. The test was conducted on two types of mud. Calcium based polymer mud and treated bentonite mud were the mud used. Below will be the data gathered from the experimental work and will be duly followed by a detailed discussion of the laboratory data.

4.1.1 Mud Density

After measuring the density of both mud types with an increase in salinity content from 0 to 15% in 5% step increase till 15%, there was some inconsistency observed during the measurements with the bentonite mud and further, ascertaining the results gotten, confirmation test using 1 and 2 percentage increase in salinity was conducted which was not part of the original plan. Below were the data was gathered.

Table 4.1 Density Test Values for the Ca^{2+} Based Polymer Mud

SALT CONTENT (%)	**Mud Density Determination Readings**		
	Kg/m^3	**Ib/gal**	**Ib/ft^3**
0	1160	9.68	72.42
5	1210	10.10	75.54
10	1240	10.35	77.41
15	1270	10.60	79.28

Table 4.2 Density Test Values for the Treated Bentonite Mud

SALT CONTENT (%)	Mud Density Determination Readings		
	Kg/m3	Ib/gal	Ib/ft3
0	1100.00	9.81	68.67
1	1110.00	9.18	69.30
2	1112.00	9.28	69.42
5	1115.00	9.31	69.61
10	1150.00	9.60	71.79
15	1200.00	10.01	74.91

4.1.2 Viscosity Readings

Two experiments were performed at ambient temperature with the Ca^{2+} based polymer Mud and the Treated Bentonite Mud. The RPMs and the corresponding dial readings were read and recorded in Tables 4.3 and 4.4.

	Rotation Per Minute (lb/100ft^2)					
SALT CONTENT (%)	**3**	**6**	**100**	**200**	**300**	**600**
	Fann VG meter Reading (centipoise)					
0	7.0	8.0	35.0	53.0	67.5	100.5
5	6.5	7.5	34.5	52.0	66.5	99.0
10	6.0	7.0	33.5	50.5	64.5	96.0
15	5.5	6.0	32.0	49.0	63.0	94.0
	Shear Rate (1/Sec)					
SALT CONTENT (%)	**5.1102**	**10.2204**	**170.34**	**340.68**	**511.02**	**1022.04**
	Shear Stress (Dynes/cm^2)					
0	33.6	38.4	168.0	254.4	324.0	482.4
5	31.2	36.0	165.6	249.6	319.2	475.2
10	28.8	33.6	160.8	242.4	309.6	460.8
15	26.4	28.8	153.6	235.2	302.4	451.2

Table 4.3 Results of Rheology Test for the Ca^{2+} Polymer Mud

Table 4.4 Results of Rheology Test for the Treated Bentonite Mud

Rotation Per Minute ($lb/100ft^2$)						
SALT CONTENT(%)	3	6	100	200	300	600
	Fann VG meter Reading (centipoise)					
0	6.5	9.0	19.0	25.0	30.0	45.0
1	6.0	8.0	17.5	23.0	28.0	41.5
2	5.0	6.5	16.0	21.0	26.0	38.0
5	7.0	10.0	19.5	25.0	31.0	45.5
10	9.5	11.0	20.0	27.0	33.0	49.0
15	11.0	12.0	22.0	30.0	37.0	55.0
Shear Rate(1/Sec)						
SALT CONTENT(%)	5.1102	10.22	170.34	340.68	511.02	1022.04
	Shear Stress (Dynes/cm2)					
0	31.2	43.2	91.2	120.0	144.0	216.0
1	28.8	38.4	84.0	110.4	134.4	199.2
2	24.0	31.2	76.8	100.8	124.8	182.4
5	33.6	48.0	93.6	120.0	148.8	218.4
10	45.6	52.8	96.0	129.6	158.4	235.2
15	52.8	57.6	105.6	144.0	177.6	264.0

4.1.3 Plastic Viscosity

Plastic viscosities were computed from the data obtained from Viscometer readings by using equation 3.1 and the results are as shown in Table 4.5.

Table 4.5 Plastic Viscosities for the Ca^{2+} Based Polymer Mud and Treated Bentonite Mud

SALT CONTENT (%)	plastic Viscosity in Centipoise (Ca^{2+} Mud)
0	33.0
5	32.5
10	31.5
15	31.0

SALT CONTENT (%)	plastic Viscosity in Centipoise (Treated Bentonite Mud)
0	15
1	13.5
2	12.0
5	14.5
10	16.0
15	18

4.1.4 Apparent Viscosity

Apparent Viscosities were computed from the data obtained from Viscometer readings and the results are as shown in Table 4.6.

Table 4.6 Showing Computed Apparent Viscosities

MUD TYPE	SALT CONTENT (%)					
	0	**1**	**2**	**5**	**10**	**15**
	Apparent Viscosity in Centipoise					
Ca^{2+} Based Polymer Mud	50.3			49.5	48.0	47.0
Treated Bentonite Mud	22.5	20.8	19.0	22.8	24.5	27.5

4.1.5 Yield Point

Yield Points were computed from the data obtained from Viscometer readings by using equation 3.2 and the results are as shown in Table 4.7.

Table 4.7 Showing Computed Yield Point

MUD TYPE	SALT CONTENT (%)					
	0	**1**	**2**	**5**	**10**	**15**
	Yield Point in lbf/100ft²					
Ca^{2+} Based Polymer Mud	34.5			34.0	33.0	32.0
Treated Bentonite Mud	15.00	14.5	14.0	16.5	17.0	19.0

4.1.6 Gel Strength

Table 4.8 and 4.9 shows the gel strength readings of both the Ca^{2+} based polymer mud and the treated bentonite mud respectively. The 1 % and 2 % was only conducted as a confirmation test to buttress a trend for the treated bentonite mud.

Table 4.8 Results of Gel Strength Test for Ca^{2+} Based Polymer Mud

SALT CONTENT (%)	10 SECONDS GEL ($lbf/100ft^2$)	10 MINUTES GEL ($lbf/100ft^2$)
0	7.0	8.5
5	6.5	17.0
10	6.0	20.0
15	5.5	22.0

Table 4.9 Results of Gel Strength Test for Treated Bentonite Mud

SALT CONTENT (%)	10 SECONDS GEL ($lbf/100ft^2$)	10 MINUTES GEL ($lbf/100ft^2$)
0	3	7.5
1	4	10
2	5.5	15
5	11	30
10	12	33
15	14	37

4.1.7 Fluid Loss Test

Three experiments were performed with the mud types used. Two at ambient conditions with a pressure of 100 psi and the third one was conducted on the Ca^{2+} based polymer mud at high pressure, high temperature dynamic conditions using a pressure of 21 bar (305 psi), temperature 110°c at 300 RPM (revolutions per minute). The times and the corresponding volumes of filtrate were read and recorded as seen in Tables 4.9 and 4.10 and 4.11.

Table 4.10 Fluid Loss Test for Ca^{2+} Polymer Mud at 100psi and Room Temperature

Time (minute)	Mud Filtrate at Ambient Readings in Millilitre (ml)			
	0%	5%	10%	15%
1	0	0.05	0.1	0.2
2	0.3	0.4	0.5	0.6
4	0.7	0.6	1.1	1.2
6	1.3	1.4	1.7	1.8
9	1.7	1.8	2.1	2.2
10	1.8	2	2.3	2.4
16	2.5	2.9	3.1	3.2
25	3.3	3.8	4	4.1
30	3.7	4.2	4.4	4.6

Table 4.11 Fluid Loss Test for Treated Bentonite Mud at 100psi and Room Temperature

Time (minute)	Mud Filtrate at Ambient Readings in Millilitre (ml)			
	0%	5%	10%	15%
1	0.5	1.6	2.4	3.8
2	1.4	2.4	3.6	5.2
4	2.2	3.5	5.4	7.5
6	3.0	4.6	6.9	9.2
9	3.8	5.8	8.7	12.5
10	4.0	6.2	9.2	13.7
16	5.4	8.0	11.5	16.2
25	6.9	10.2	16.7	20.5
30	7.6	11.0	17.9	22.0

Table 4.12 Fluid Loss Test for Ca^{2+} Polymer Mud at HPHT Dynamic Conditions (110°c, 21 Bar and 300 RPM)

Time (minute)	**Mud Filtrate at HPHT Dynamic Conditions Readings in Millilitre (ml)**			
	0%	**5%**	**10%**	**15%**
1	0	2.4	2.6	3
4	2.6	4.2	6.2	8.4
10	3.6	6.4	8.6	10.4
16	5.6	8.6	10.2	12.8
25	8.4	12.4	13.6	14.4
30	11.6	15.8	16.2	17.2

4.2 Discussion

This section compares and discusses all the results based on the individual results obtained from the laboratory experiments.

4.2.1 Density Test

The starting point of pressure control is the control of mud density. To effectively predict and control pressure during drilling operations, operators monitor closing the exact mud weight need to balance the formation pressure because it is the basis upon which all pressure control predictions are based. For proper estimation of the weight of the mud column, the density of the mud should be known (Annis and Smith 1996). For easier wellbore cleaning and faster cuttings uplift, drilling muds should have higher weights than cuttings being made whilst drilling (Nwaiche, 2015). Hence, a general analysis can be made that if the weight of the mud surpasses the formation and does not fracture it, it can cause other adverse effects, like reducing rate penetration.

Inferring from table 4.1 and 4.2, it is clearly evident that the increase in the salinity of the mud increased the density of both muds under investigation. However, the percentage increase in density from salinity levels of 0 to 15 % for the Ca^{2+} based polymer mud is 8.66 % and that for the treated bentonite mud is 8.33%. This means the density increase of Ca^{2+} is 0.33 % more than the treated bentonite mud. Hence, it is of prime importance for drillers to thoroughly check the density of mud when adding salt to avoid any unexpected density increase that may cause an adverse effect on the borehole being drilled. The increase in mud density as a result of increase in salinity confirms a research done by Amani *et al*., (2016) salinity effects on the viscosity of water-based drilling fluids at high pressures and high temperatures. To Amani *et al*., (2016), when they increased the salinity of the mud by adding NaCl and $CaCl_2$, the density of the mud was observed to increase. Moore, (2016), also made same assertion in his drilling mud paper that he transferred to SPE in 2016. Again, Das et al., (2014), stated in his research on effect of salt concentration on base-gel viscosity of different polymers used in stimulation fluid systems that salt is added to drilling fluid at different concentrations to increase the mud weight. Hence, the trend in mud weight increase observed in this study is in support of the works published by other authors.

4.2.2 Rheological Properties

By going accordingly to the API specifications (1998), the basic rheological properties such as Apparent Viscosity (AV), Plastic Viscosity (PV), Yield Point (YP) and Gel Strength of the treated bentonite mud and the Ca^{2+} based polymer mud were determined by using the Fann Viscometer. A good treated bentonite mud should have its properties as specified in Fig. 4.12 below according to API Specification 13A – 8.1.2 (Anon., 2014). The Ca^{2+} based polymer mud cannot be compared to the API specification because it was a used mud at the field and its initial properties were altered. However, analysis regarding its rheological property change will be purely dealt with in this section.

Requirements	standard
Suspension properties:	
Viscometer dial reading at 600 r/min	Minimum 30
Yield point/plastic viscosity ratio	Maximum 6
Filtrate volume, millilitres	Maximum 15.0

Table 4.13 API Physical Specifications for Treated Bentonite Mud (Source: Anon, 2010)

Data obtained from test on treated bentonite had a Viscometer dial reading at 600 r/min of 45 cp, 41.5 cp, 38 cp, 45.5 cp, 49 cp and 55 cp respectively as the salinity levels were increased from 0 %, 1 %, 2 %, 5 %, 10 % and 15 %. As observed from the data, the 1% and 2% test became possible when the readings deviated from the trend during the experiment. Hence, the researcher conducted that test to confirm the trend being observed. However, the readings at 600 r/min for all the salinity levels conforms to the API specification of a maximum of 30 cp. Yield point and plastic viscosity ratio was 1.2 maximum for various salinity levels which falls within the API range of a maximum 1.5 as shown in Table 4.14.

Table 4.14 Yield Point and Plastic Viscosity ratio at various Salinity Levels

SALT CONTENT (%)	Yield Point /Plastic Viscosity
0	1.00
1	1.07
2	1.17
5	1.14
10	1.06
15	1.06

Closely analysing table 4.5, the plastics viscosity of the treated bentonite mud started reducing as the Salinity levels where increased from 0 – 2 % and increased from 5% to 15 % respectively. Similar behaviour was observed for the yield point and apparent viscosity. However, Gel- strength levels were seen to increase as the salinity levels were increased and no fluctuational trend was observed as seen with the other rheological properties concerning the test conducted with the treated bentonite mud.

This fluctuational trend observed agrees with a research conducted by Olphen, (1963), on the effect of NaCl on rheology of clay suspensions. It also agrees to an assertion made by Ofei and Bendary, (2016) in their research on formulating water base muds for high temperature wellbores using potassium formate brine and synthetic polymers.

Ofei and Bendary, (2016) found out that some of the mud they formulated with synthetic polymer and potassium formate brine caused an increase in plastic viscosity whilst some concentration also caused a reduction in plastic viscosity. However, the reasons for their reduction was not well explained in their research.

Olphen, (1963) also made the revelation that adding a small amount of Nacl, the suspensions start from a flocculation state, the Bingham yield stress reaches a minimum, and thus suspension deflocculates. Upon further addition of NaCl, Bingham yield stress increased again which means the solution flocculates again. Luckham and Rossi (1999), also in their review summarised the same assertion made by Olphen, (1963).

To Luckham and Rossi (1999), Olphen, (1963), the fluctuations observed with the use of bentonite may be due to charged particles of the clay platelets which they assumed that the edges were positively charged whilst the faces were negatively charged. In addition, both authors agreed that the internal mutual flocculation was so because of the initial edge to face bonding due to the opposite attractive forces. Further elaboration on their stand, they attributed the deflocculating to excess salt added which compressed the double clay layers thereby reducing the attractive forces between the edge to edge. This resulted in the breaking down of the bond and reducing the rheological properties as well. However, further compression of the double layers by increasing the salt concentration restores the edge-to-face attraction, which is now greater than the face-to-face repulsion causing the rheological properties to increase again. At extremely high salt levels, there is a face to face bonding again reducing the links between the cay structure and causing thicker particles formations

Oort, (2003), also made similar observations in his research concerning the physical and chemical stability of shales. He deliberated that the success of K+ ions in reducing the pressure of swelling clays is attributed to its low ion repulsion because of its small hydration in water. At low concentration of salt, the swelling tendency of clay was suppressed but the clay was seen to increase in swelling at high concentrations. He went on to say that the addition of more salt resulted in further ion repulsion as a result of the excess hydrated ions introduced into the clay inter layers. The initial small concentration of the potassium salt resulted in a reduction in clay swelling due to K^+ ions substituting the more hydrated ions at the clay surface. But the swelling of clay increased upon more addition of salt because an excessive hydrated ions increase in the clay layers resulting in further spacing. The ions were both positively and negatively charged. But it is worth knowing that in his experiment, the interplatelet clay spacings were filled with only saline water.

From these prior studies, it is then evident that addition of salt (KCl) influences the rheological parameters of bentonite dispersions. But the fluctuation trend observed in this study with different polymers has not been given much attention. Recent authors has all reported a decrease in the rheological properties (Uti and Joel, 2013) and K^+ containing clays show a lower tendency to swell than Na^+. That is why KCl has gained international recognition as the most effective in reducing clay swelling (Hensen and Smit, 2002).

Turning my attention to the Ca^{2+} polymer based drilling mud as illustrated in fig 4.5, viscometer dial readings were observed to reduce upon the addition of the KCl from 0-15 % in 5 % step increase. Yield point, plastic viscosity and gel strength was also observed to reduce. In increasing the salinity by 5 % step, there was an average reduction in plastic viscosity by 2%, yield point by 2.5 % and apparent viscosity by 2.2 %. This means whilst increasing the salt content, the mud will exhibit initial resistance to flow. This trend confirms a lot of work done by different Authors. Sami, (2016), made similar assertion by saying he observed a decrease in yield point, viscosity, and gel strength of his sample due to an increase in magnesium salt concentration. This was also confirmed by (Hosseini et al., 2017, Uti and Joel, 2013). Most authors confirmed a reduction in the properties highlighted above although the salts used vary from author to author.

4.2.3 Shear Stress and Shear Rate

From fig 4.1 and fig 4.2, it is evident that both the drilling mud with and without salt followed the yield pseudoplastic model which was conceived by Herschel and Bulkley. This trend agrees to an earlier research by Hassiba and Amani, (2013) to investigate the salinity effect on the rheological properties of water based mud under elevated pressure and temperature conditions. Their plot fitted well to Herschel and Bulkley model both NaCl and KCl used in their experimentation.

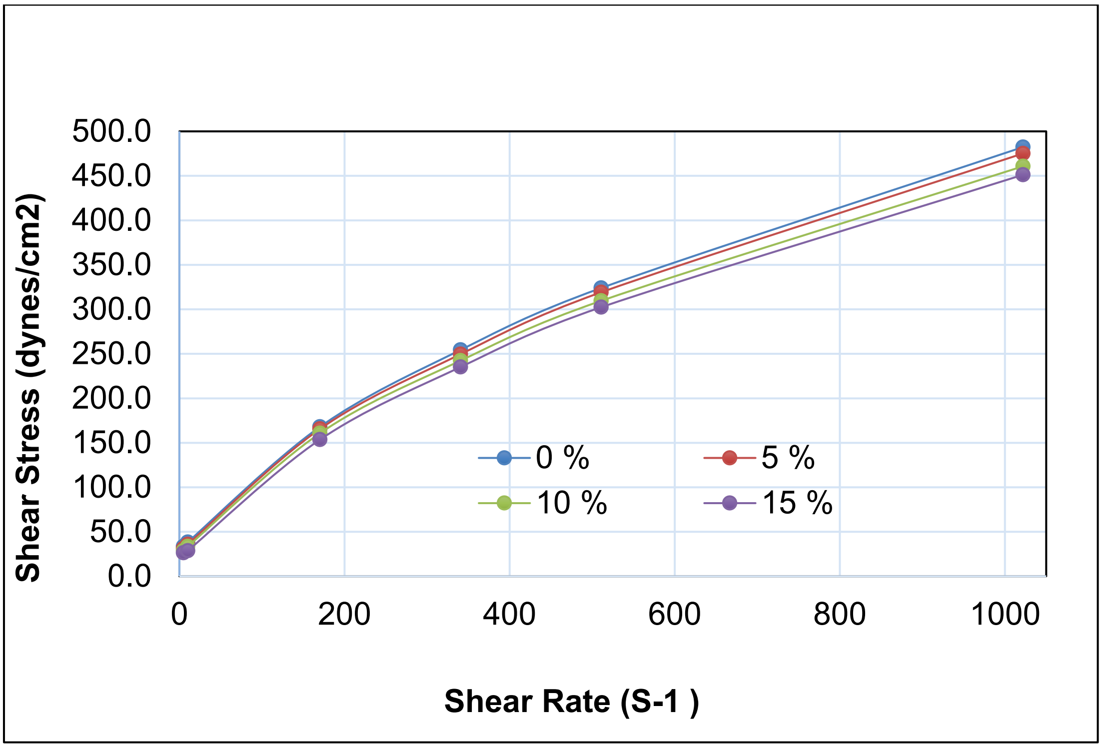

Fig. 4.1 Shear Stress and Shear Rate plot Ca^{2+} based polymer mud

From Fig. 4.1, it is clearly evident that for all the mud samples measured, an increase in shear rate causes a corresponding increase in shear stress. However, for a given shear rate, an increase in salinity causes a reduction in shear stress.

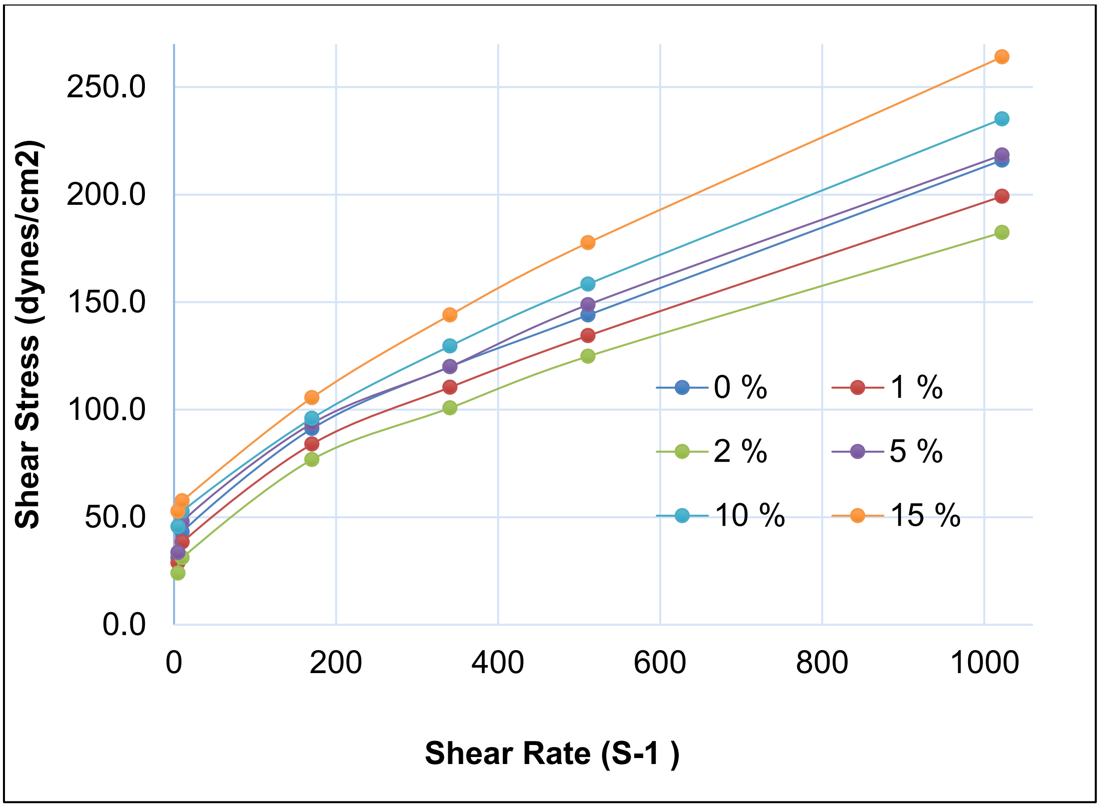

Fig. 4.2 Shear Stress and Shear Rate plot for Treated Bentonite Mud

From Fig. 4.2, it can be deduced that for all the mud samples measured, an increase in shear rate caused a corresponding increase in shear stress. However, for a given shear rate, an increase in salinity level from 0 - 2 % caused a reduction in shear stress whilst an increase from 5 % - 15 % caused an increase in shear stress.

4.2.4 Filtration Test

API fluid loss test was carried out using a filtration apparatus (Filter Press) and according to the specifications of API, a good bentonite drilling fluid should have a fluid loss of a maximum of 15 ml after 30 minutes filtration test which was demonstrated after the filtration loss test.

The Treated bentonite Mud had a fluid loss of 7 ml after 30 minutes of test whilst fluid loss started increasing at each level of salt added till it became unacceptable according to API standards form 10 % - 15 %. The volumes recorded for 10 % and 15 % were 17.9 ml and 22 ml as depicted on fig 4.3. This result confirms the work done by Neshat *et al.,* (2014), on experimental investigation of the effects of a plant-based additive on the rheological properties of bentonite mud contaminated by salt. They demonstrated that the addition of KCl caused the filtration volume to increase by 132% as compared to the original mud.

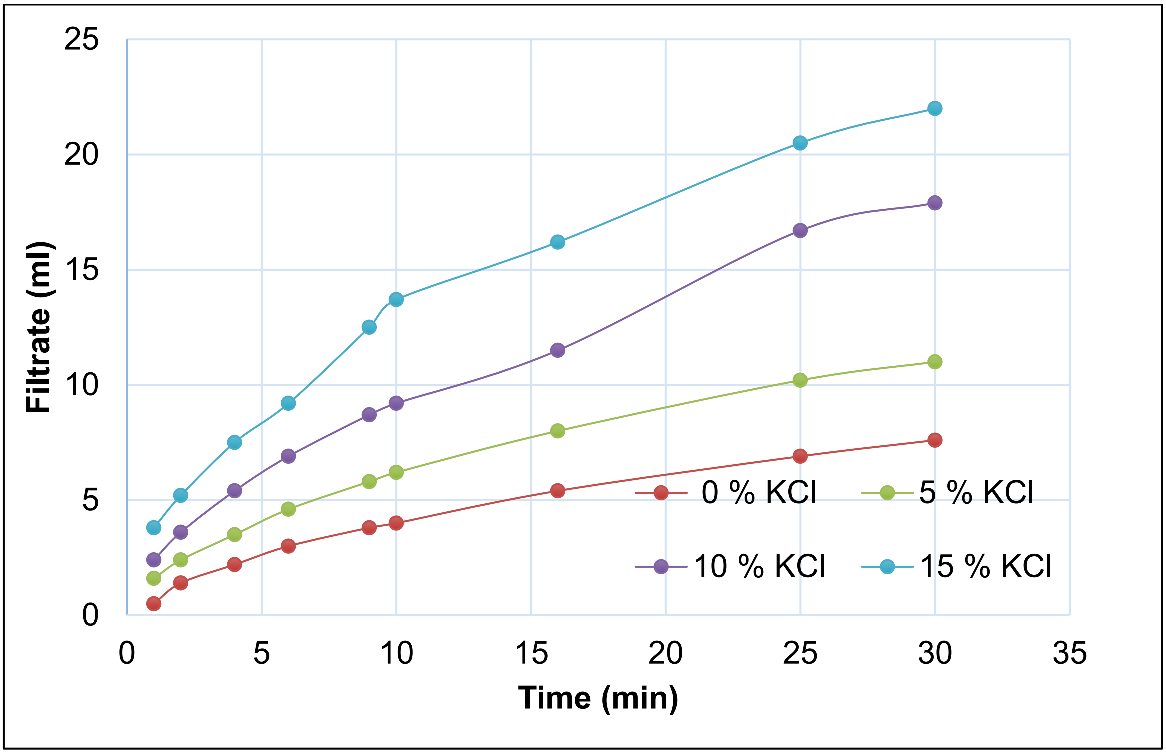

Fig. 4.3 Effects of Salinity on Filtration Loss of the Treated Bentonite Mud

As the filtrate volume increased, the thickness and quality of the filter cake formed was greatly affected (see fig 4.4). The filter cake thickness measured for 0 and 5 % salinity level was 0.5 mm and 0.75 mm which compares very well to API standard of 0.8 mm. However, the thickness formed for the 10 % and 15 % were 4 mm and 5 mm which were far greater than the API standard. The filter cakes formed was very thick and soft. Hence, although is true KCl reduced shale swelling, its concentration in a mud should be controlled as poor filter cake can cause differential pipe sticking as well as increased fluid loss to the formation.

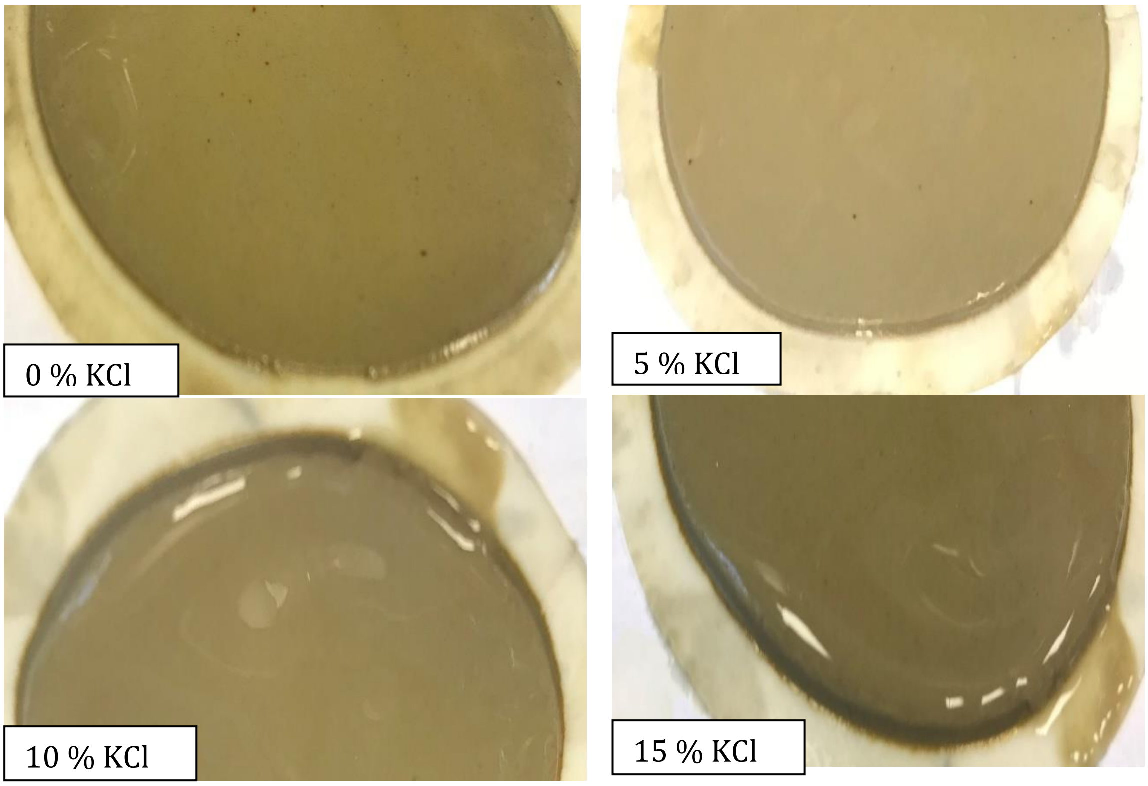

Fig. 4.4 Filter Cake formed for the Treated Bentonite Mud under LT/LP

For the case of the Ca^{2+} based polymer, two filtration tests were performed on the samples. A low pressure and low temperature filtration test and a high pressure and high temperature dynamic filtration test. All test results reveal that the filtration volume increased as the salinity of the mud increased as depicted on fig. 4.5 and fig. 4.6. Also, the quality of the filter cakes formed when the salinity levels were gradually increased was poor as compared to the samples without salt.

The thickness of the filter cake measured at ambient condition and pressure of 100 psi were seen to increase from 1.5 mm, 1.8 mm, 2 mm and 2.5 mm as the salt content was increased from 0- 15 % respectively. Also, the filter cake when touched felt soft as the salinity was increased. The same effect was seen when the mud was tested at HPHT dynamic conditions.

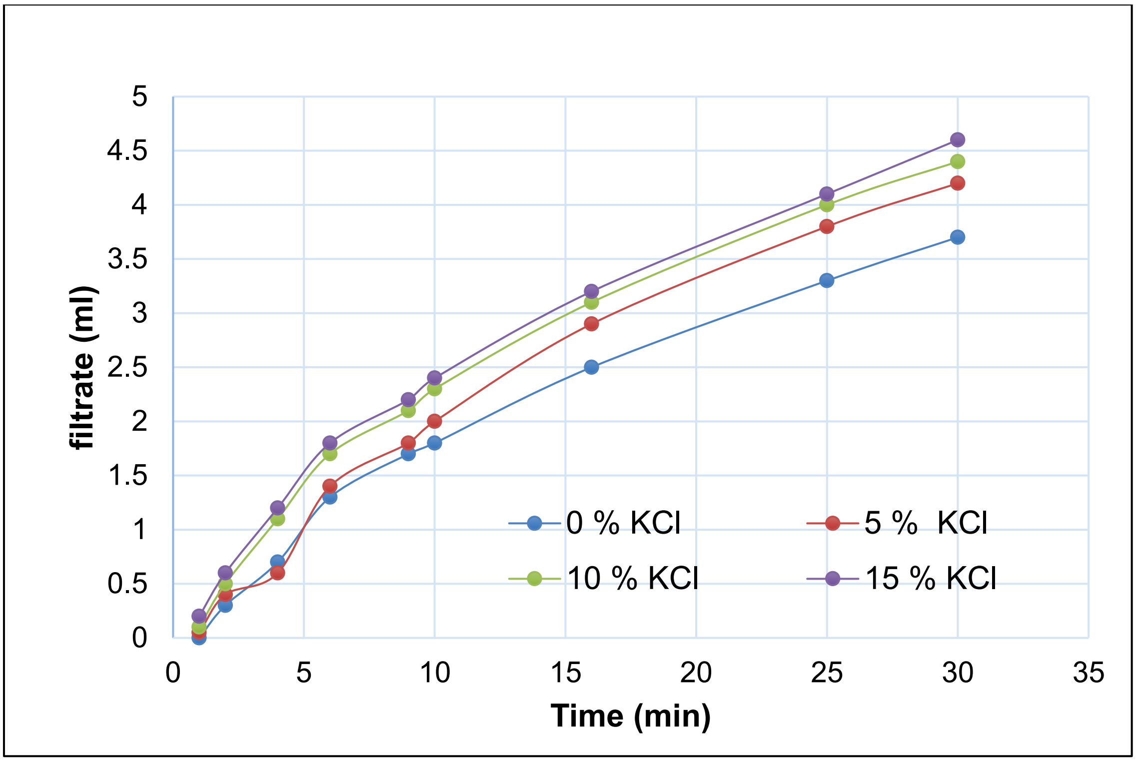

Fig. 4.5 Salinity Effect on Filtration Loss of Ca^{2+} Polymer Base Mud at LP/LT

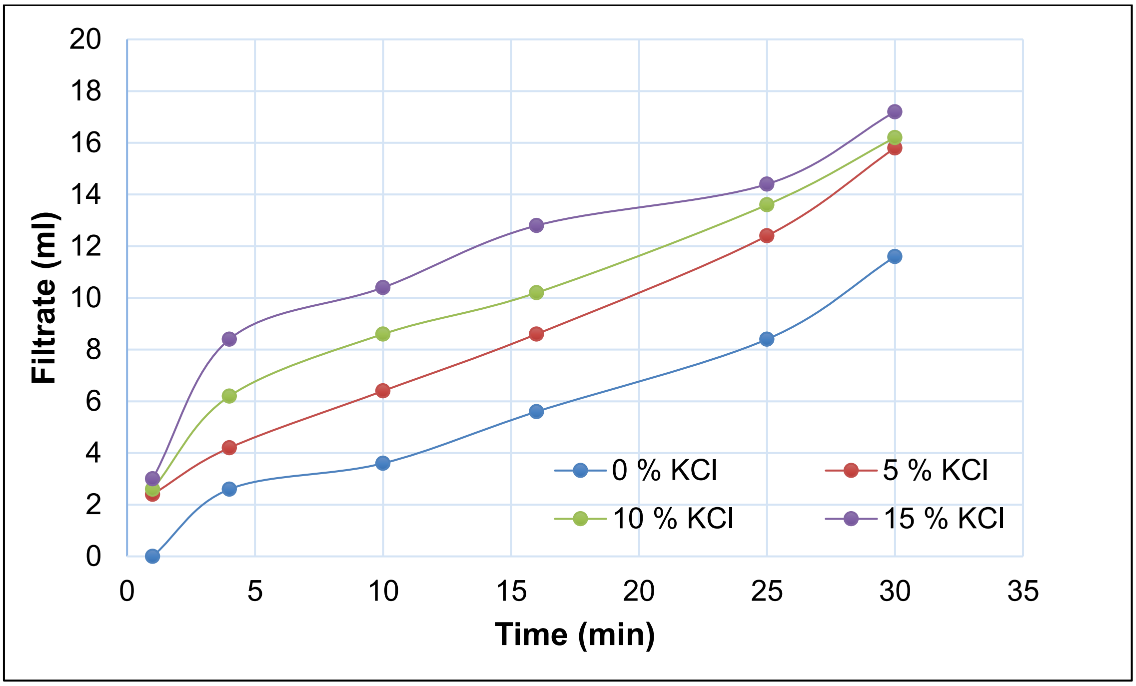

Fig. 4.6 Salinity Effect on Filtration Loss of Ca^{2+} Polymer base Mud at HPHT Dynamic Conditions.

4.2.5 Rate of Penetration

In order to appreciate the effect of salinity on rate of penetration. The modelled equation by Beck *et al.*, (1995) of equation 2.7 was used. This equation relates plastics viscosity to rate of penetration.

The main parameters affecting rate of penetration, such as hole size, weight-on-bit, rotary speed, bit type, formation type, bit hydraulic energy, and basic mud type were all optimized prior to data-collection and were kept constant throughout the data collection process,

In this research, all the assumptions used by Beck *et al.*, (1995) holds, except that the mud type used in this research was assumed to be same as that used to drill side-track wells drilled in Prudhoe Bay, Alaska as described by Beck *et al.*, (1995). This assumption was made so that their correlation can be applied without ambiguity.

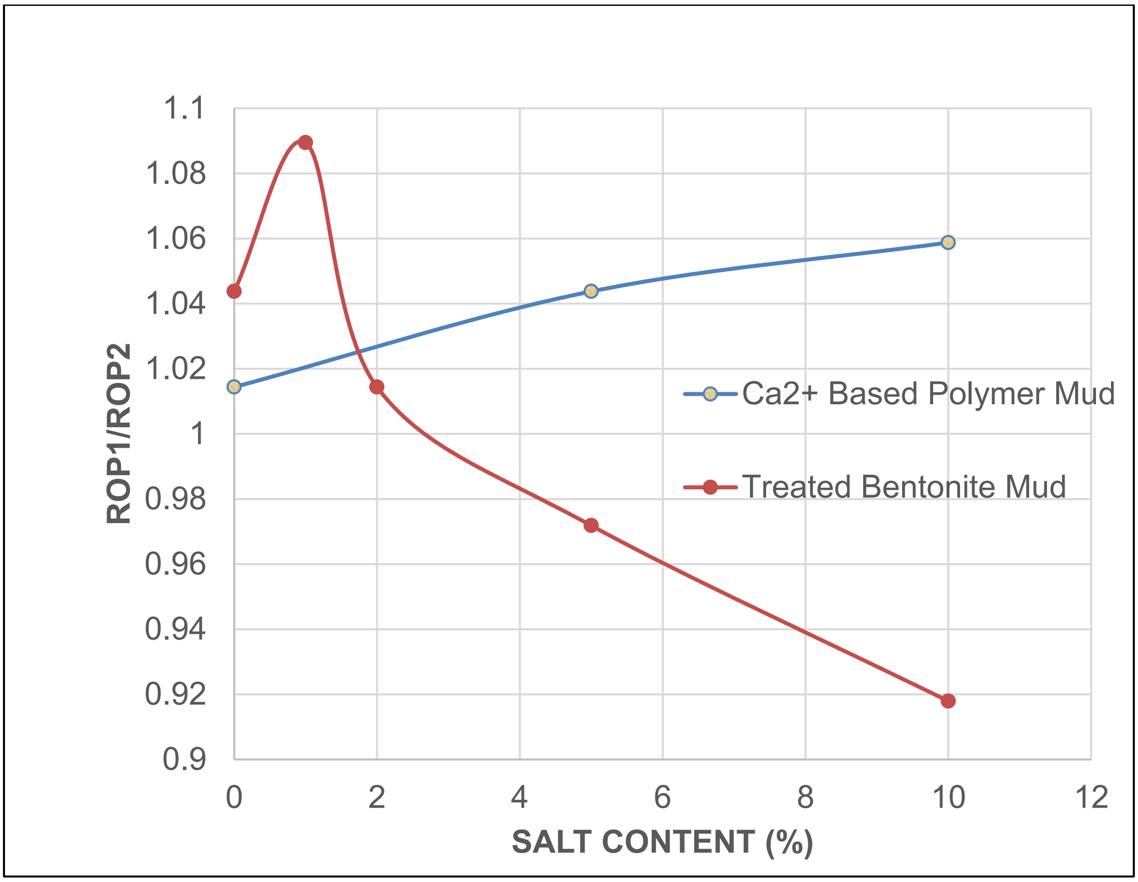

Fig. 4.7 Plot showing how ROP Varies with Salt Content

The results obtained as depicted by fig 4.6, confirms to the same assertion made by Beck *et al.*, (1995) that an increased in plastics viscosity will cause a decrease in rate of penetrations when other parameters affecting rate of penetration are kept constant. The fluctuation trend observed in the case of the treated bentonite mud was due to the same trend observed during the plastic viscosity determination.

CHAPTER 5

OBERVATIONS, CONCLUSIONS AND RECOMMENDATION

5.1 Observation

The general observations are that KCl being the salt used had an influence on the rheological properties and ROP of both Ca^{2+} based polymer mud and treated bentonite mud. As the salinity of the Ca^{2+} based polymer mud was increased, the mud was observed to be shear thinning, thus a reduction in the rheological properties were observed except for gel strength which was increasing as the salinity was increased. For all the two mud types used, an increase in salinity caused an increase in density. Applying the Beck *et al.*, (1995) correlation, it was found that as the salinity increased from 0 – 15 %, the ROP increased because of a reduction in Plastic Viscosity in the case of the Ca^{2+} based polymer mud.

In the case of the treated bentonite mud, a fluctuation trend was observed as the salinity levels were from 0 - 15 %. There was a reduction in Plastic viscosity, Yield Point, Apparent Viscosity from 0 – 2 % and an increase from 5 % to 15 %. This was mainly due to the type of interconnections that occured during the reaction which resulted in either deflocculation or flocculation of the clay particles. The ROP experienced same fluctuation trend because it was linked to plastic viscosity.

5.2 Conclusions

From the research, the following conclusions have been drawn:

- KCl may cause some water base muds to be unstable at higher concentrations;
- The use of KCl in mud formulation will increase the amount of fluid loss to the formation;
- The addition of KCl to a drilling fluid will have an influence on ROP because it will alter the plastic viscosity of the mud under investigation;
- The samples with or without KCl assumed the Herschel Bulkley (yield Power law) model.

5.3 Recommendations

Based on the conclusions it is recommended that the concentration of KCl to be used should be tailored to suite the type of mud that will be used to drill the formation. Also, fluid loss additives should be added to the mud to control the amount of fluid loss due to the addition of KCl.

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The investigation did not include an elemental analysis to determine the type of bonds and interactions that existed when the salinities where been modified to ascertain the actual cause of the fluctuation trend observed with the use of the treated bentonite mud. Therefore, it is recommended that future research should be conducted to investigate in this area. An XRD and XRF coupled with a software that can allow visualisation or arrangements of the bonds could be done.

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