Faculty of Science and Technology

MASTER'S THESIS

Study program/ Specialization: Petroleum Engineering/Drilling Technology	Spring semester, 2015 Open
Writer: Mona Fosseli Ågotnes	……………………………………… (Writer's signature)
Faculty supervisor: Mesfin Belayneh and Bernt S. Aadnøy	
Thesis title: **Effect of Nano silica and Salts on CMC/PAC polymer –Bentonite fluid system**	
Credits (ECTS): 30	
Key words: WBM, Nano Silica, Rheology, Hydraulics	Pages: 100 + enclosure: 15 Stavanger, 15.06.2015 Date/year

Acknowledgements

First and foremost I would like to thank my supervisor Mesfin Belayneh for his engagement throughout the learning process of this master thesis, - for his comments, his knowledge and his humour which kept me sane enough to finish the thesis. I would also like to thank Professor Bernt S. Aadnøy for providing me the project.

Furthermore I would like to express my gratitude towards my friends who supports me and comes to my aid whenever I am in need of it.

Finally I would like to thank my family for the endless support and encouragement I have received throughout the entire process.

Stavanger, June 2015

Abstract

Drilling fluids are an integral part of drilling operations. The quality of the fluid system determines the success of drilling operations. Recently the application of nanotechnology shows positive results in cement, drilling fluid and enhanced oil recovery. However the application of nano technology is not yet fully investigated. This thesis presents the effect of nano silica on CMC based water based bentonite fluid system. The objective was to formulate an optimized nano-additive system, which improves the rheology and filtrate performances of a conventional water based fluid system. Several combinations of brine treated and polymer (CMC and PAC) treated systems were tested. From the overall tests,

- The result shows that the mixture of 0,3g Nano silica + 0,5g CMC + 2,5g NaCl +2,5g KCl in bentonite/H_2O (25g/500g) was found to be the best fluid system with respect to the desired rheology and fluid loss.
- The hydraulics and cutting transport efficiency of the best optimized system was simulated and the result shows improved performance compared with nano free, fluid system.
- The viscoelasticity and flow in porous media of the optimal fluid system were also evaluated.

Table of Contents

List of figures

List of tables

1 Introduction

This thesis presents the performance of conventional (nano-free) and nano silica systems in polymer (carboxymethyl cellulose (CMC) and polyanionic cellulose (PAC)) based bentonite fluid systems. The main objective was to investigate how nanoparticles add value in improving the conventional system. Several experiments were carried out in order to investigate the effect of nanoparticles in various concentrations of polymer, KCl and NaCl salts. The rheology and the filtrate volume were measured.

After testing several fluid formulations an optimized nano-based system in polymer and salt system was obtained. Using this system further study was conducted. These are performance simulations (hydraulics and hole cleaning), flow in porous media and viscoelasticity studies.

1.1 Background

To produce hydrocarbons wells need to be drilled. The main objective when drilling a well is to drill a hole as fast as possible without accidents. Drilling is an important part when producing hydrocarbons and drilling fluids represent one fifth (15 to 18%) of the total cost of well drilling [1]. Therefore it is of interest to develop better solutions for a less costly operation. Better techniques have been made to improve the production, such as horizontal wells, directional drilling and managed pressure drilling.

Drilling fluid, sometimes referred to as drilling mud, is used in drilling operations. It is circulated down the drillstring, through the bit and back to the surface through the annulus.

The primary source of hydrostatic pressure in a well is the mud weight (or density). While circulating, the mud contributes with a pressure expressed as equivalent circulating density (ECD). ECD contributes to the hydrostatic pressure in the wellbore, helping it to be greater than the pore pressure of the formation. If the fluids density is insufficient, the hydrostatic pressure may become lower than the pore pressure. This may lead to an influx of formation fluids into the wellbore, known as a kick. An uncontrolled kick can result in a blowout which can result in a major accident, damage the equipment and potentially lead to rig personnel injuries. If well pressure is larger than fracture pressure, there is a risk of loss of drilling fluid into the formation, known as lost circulation. If the density of the drilling fluid is insufficient it may result in wellbore instability, and in worst case, wellbore collapse (see figure 1.1).

Therefor to avoid wellbore instability or lost circulation, ECD must be within the mud weight window (see figure 1.2) [2].

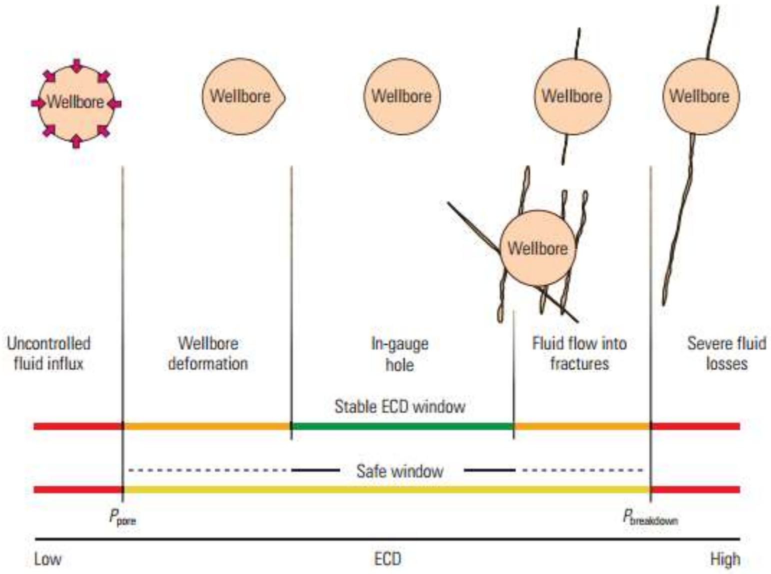


Figure 1.1: Description of the ECD window [2]

Equivalent circulating density is determined by [3]:

$$ECD = \rho_{st} + \frac{\Delta P_{annulus}}{0.052.TVD} \tag{1.1}$$

Where:

ρ_{st} - Static mud weight [ppg]

$\Delta P_{annulus}$ - Pressure loss in the annulus [psi]

TVD - True vertical depth [ft]

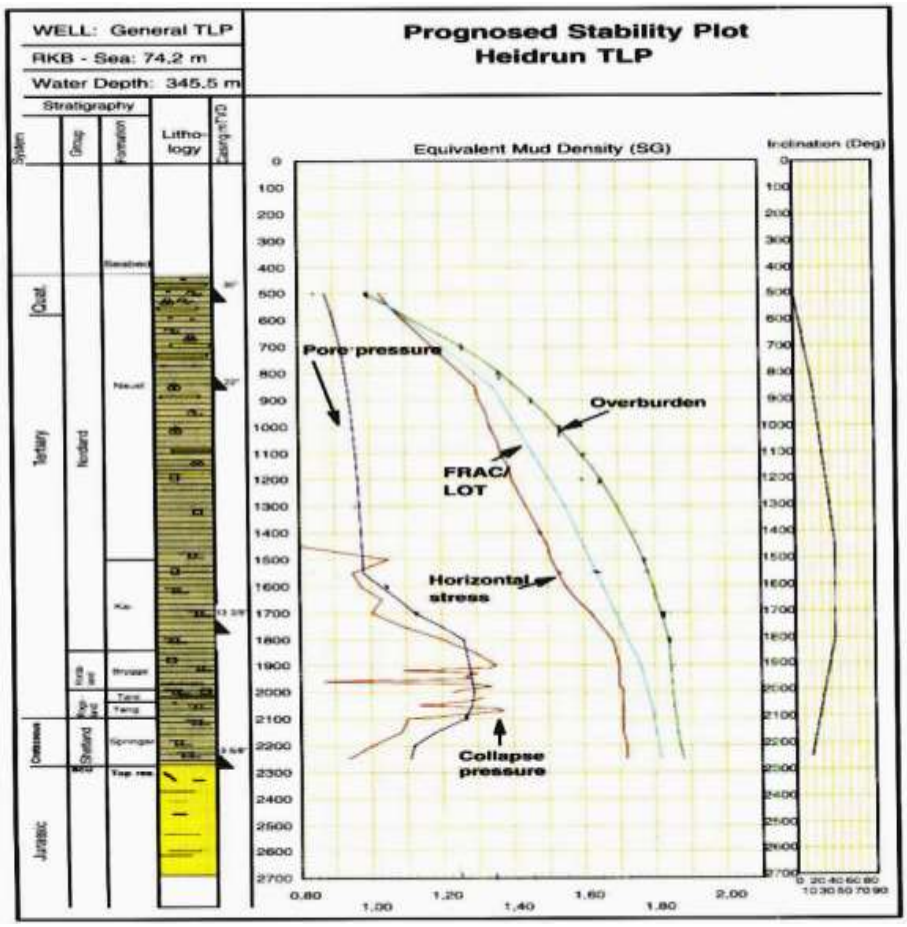


Figure 1.2: Prognosis stability plot for a typical Heidrun TLP well [4]

1.2 Problem definition

The positive effects of using nano silica in cement are documented in literature section [5]. The particle improves the mechanical strength and reduces the filtrate loss. This thesis evaluates the effect of nano silica in polymer based bentonite drilling fluid, as well as combined with salt. The issues to be addressed are:

- Effect of polymers; CMC and PAC
- Effect of salts; KCl and NaCl
- Effect of nano particles; nano silica
- Effect of temperature
- Effect of in situ and ex-situ systems

Screen test was performed in order to find the most suitable water based fluid for drilling a well. Afterwards the best fluid system was used for performance simulation studies.

1.3 Objective

The objective of this thesis is to perform experimental and simulation studies. The activities are:

- Literature study of different rheology and hydraulics models
- Literature review on water based drilling fluid components
- Experimental study on the effect of nano silica and salt on polymer based bentonite fluid system.
- Simulation studies of the best formulated nano silica treated drilling fluid in terms of hydraulics and cutting transport performance

1.4 Methodology

The effect of nanoparticles and salt in bentonite will be investigated based on the following four systems shown in figure 1.3. The goal is to develop a fluid system with low filtrate loss and improved rheology properties by using nano silica as additive. In order to achieve this, the system should be dispersed and flocculated. Figure 1.3 is used to interpret the fluid systems under which conditions they are, whether they are flocculated or deflocculated based on the plastic viscosity (PV), yield strength (YS) and filtration result.

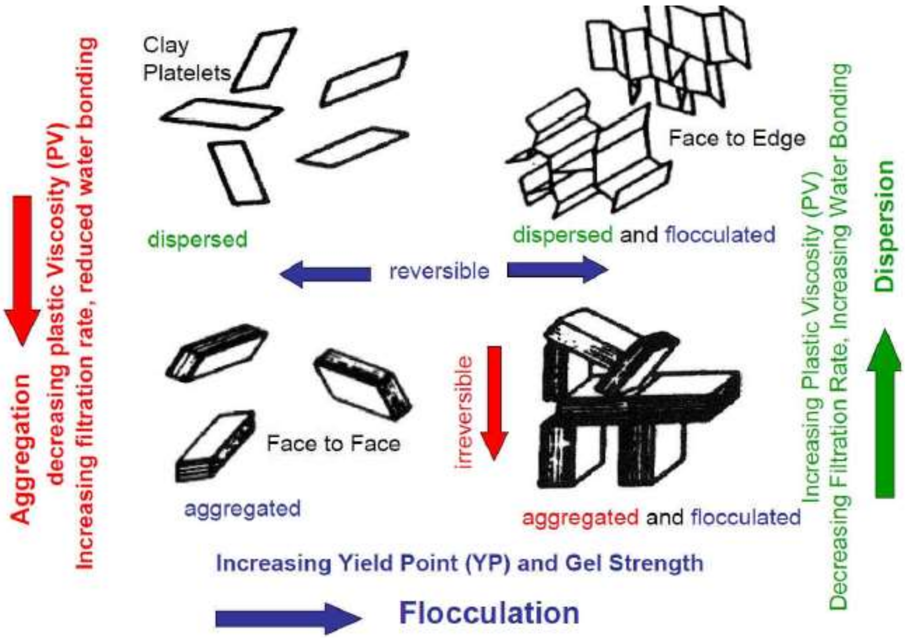


Figure 1.3: Description of four different fluid systems

This thesis consists of two parts (see figure 1.4);

1. Part 1 deals with experimental measurements of the formulated fluid systems which include rheology, filtrate and viscoelasticity measures.
2. Part 2 deals with performance simulations studies. The best fluid system obtained in part 1 will be evaluated by cutting transport and hydraulics.

Different rheology models were also analyzed to find the most suitable for the drilling fluid.

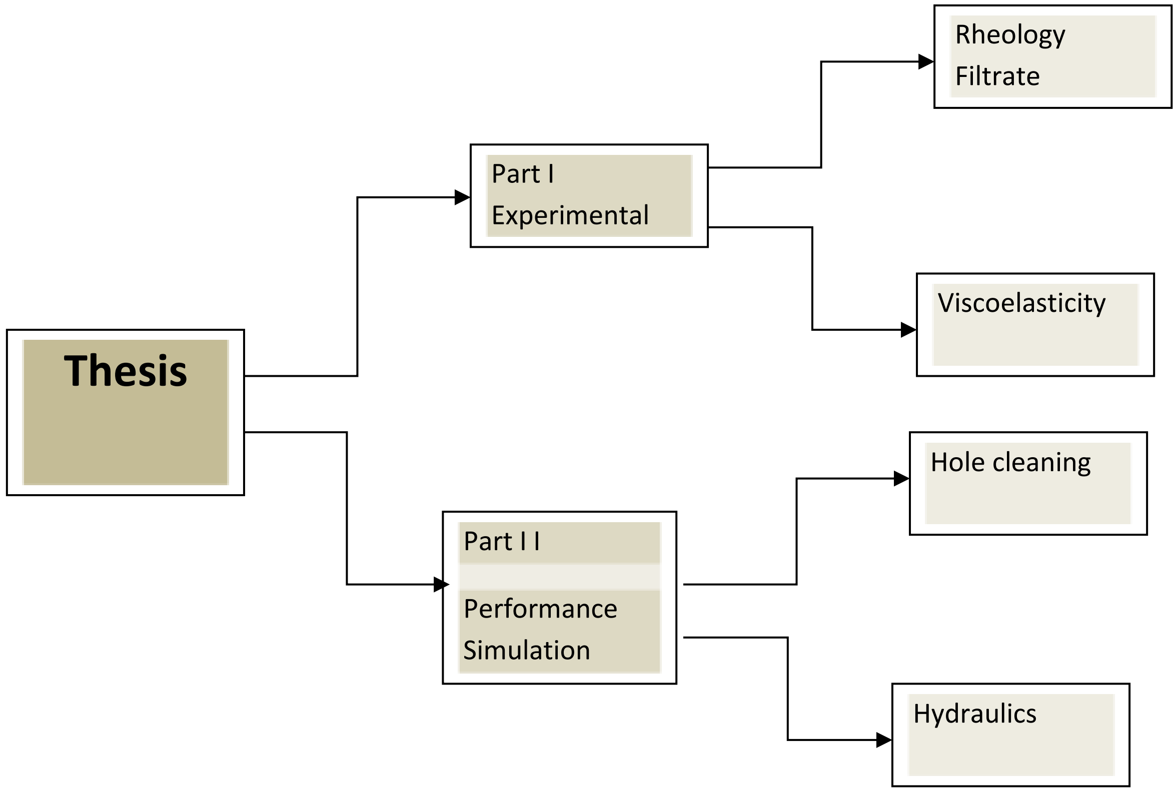


Figure 1.4: Overview of thesis methodology

2 Literature study

This section present literature associated with drilling fluid, such as rheology and viscoelasticity which determine the performance of drilling operations, hole cleaning and well stability. It also presents different additives which are used to prepare the fluids in this thesis work.

2.1 Rock mechanics

Since drilling fluid is associated with rock mechanics, this section present wellbore stability models such as well fracture and collapse.

2.1.1 Fracture model

The primary functions of drilling fluid amongst others are to transport cuttings and to maintain well pressure. When the well pressure exceeds the strength of the formation, it results in well fracturing. Depending on the boundary conditions, there are two types of well fracture models; Non-penetrating fracture model and penetrating fracture model.

2.1.2 Non-penetrating fracture model

For formations with non-penetrating or impermeable well boundary conditions it is assumed that there is little communication between the formation and the well.

In rocks with low permeability, mud cakes with extremely low fluid loss are required.

Figure 2.1 shows a non-penetrating boundary condition between the formation and the borehole [6].

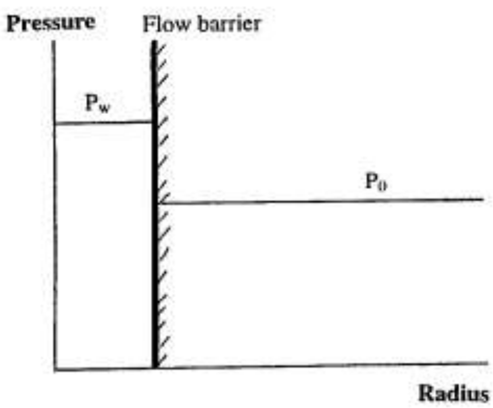


Figure 2.1: Non-penetrating case [6]

Aadnoy and Chenvert (1987) [6] derived elastic solutions for the fracture model. The model links the hydraulic fracturing initiation pressure, $P_{wf,}$ and the two principal horizontal stresses σ_h and σ_H. It is assumed that the deformation is linear elastics, isotropic, and a continuous medium. The model is based on the Kirsch solution and the formation breakdown is given by [6]:

$$P_{wf} = 3\sigma_h - \sigma_H - P_o + \sigma_t \tag{2.1}$$

Where:

P_{wf} - Fracturing pressure [psi]

σ_h, σ_H - Minimum and maximum in-situ horizontal stresses [psi]

P - Pore pressure [psi]

σ_t - Tensile strength of the rock [psi]

The equation is a function of reservoir parameters and the in-situ rock. Experimental work show that the fracturing pressure also depends on the type of drilling fluids [7].
This indicates that mud cake contributes to the fracturing resistance in the case of a permeable rock, suggesting that it is needed to characterize the fluid behaviour in order to properly evaluate the performance on well strengthening.

2.1.3 Penetrating fracture model

In permeable rocks the particle bridge does not need to be perfect due to the fact that the passing fluid will leak away from within the fracture into the rock matrix. Because of this there will be no pressure build up in the fracture and the fracture will not propagate [8]. If a mud cake forms on the walls of the fracture, the fracture may grow and expose new surface and relieve the pressure. Then the pressure will decline behind the bridge when fracture occurs. The effective stress across the fracture will increase and cause a closure behind the bridge, making the bridge stable.

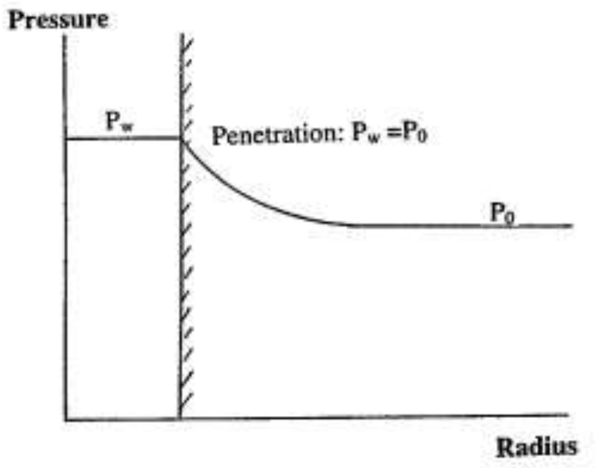


Figure 2.2: Penetrating case [6]

The formations porosity, permeability and micro fracture allows the differential pressure to cause fluid and filtrate to flow into the formation. The flow adds to the stress field around the wellbore and results in formation pressure build up. Figure 2.2 illustrates the fluid flow and pressure communication between the formation and the borehole. Aadnøy [6] assumed that the wellbore pressure and the formation pressure are equal at the wellbore. By using eq 2.1, the penetrating equation can be derived as:

$$P_{wf} = \frac{1}{2}(3\sigma_h - \sigma_H + \sigma_t) \tag{2.2}$$

Where:

P_{wf} - Breakdown pressure [psi]

σ_t - Tensile strength of the rock [psi]

σ'_h - Minimum effective stress [psi]

σ'_H - Maximum effective stress [psi]

2.1.4 Collapse model

Shear failure is the main cause of borehole collapse. The collapse results in a near –wellbore breakout zone that causes sloughing, spalling, and hole enlargement, and occurs when the pressure in the wellbore is low [7, 9].

With low pressure, the hoop stress increases while the radial stress decreases at the same rate as the pressure. This cause a significant difference between the hoop stress and radial stress, thus a large shear stress will occur.

Well collapse pressure can be determined by a number of failure criteria, and the most commonly used failure criterion is Mohr-Coulomb. The criterion considers a vertical hole with an impermeable wall which is drilled in an anisotropic horizontal stress ($\sigma_H > \sigma_h$) field. Then the minimum mud weight required in order to prevent shear failure by hoop stress can be found using the equation [10, 11]:

$$\rho_{\min} gH = \frac{3\sigma_H - \sigma_h - C_o + \alpha P_o(\tan^2\beta - 1)}{1 + \tan^2\beta} \tag{2.3}$$

Where:

Co	- Uniaxial compressive strength [1/psi]
β	- Failure angle [Degrees]
α	- Biot coefficient []
Po	- Pore pressure [psi]
g	- Acceleration due to gravity [ft/s^2]
H	- Vertical depth [ft]

For deviated boreholes the stability is reduced with increasing hole angle. From field experiences it is known that drilling fluid composition also has an effect on hole stability, and the use of oil based fluid largely improves the stability. Experiments have shown that adding polymers have given a positive effect on the stability [11].

2.2 Lost circulation

Lost circulation causes several negative effects. The US Department of Energy reports that on average 10-20% of the cost of drilling HPHT (high pressure-high temperature) wells is expended on losses [2]

Lost circulation may occur when there are [12]:

1. Unconsolidated or highly permeable formations (such as loose gravels)
2. Natural fractures
3. Drilling induced fractures
4. Cavernous formations (crevices and channels)

The gas and oil industry has made great progress in developing new techniques to avoid lost circulation. However, as new hydrocarbon sources are found in remote and complex reservoirs, the industry is bound to continue the development to meet the wellbore integrity challenges present. In the Gulf of Mexico, stuck pipe, wellbore collapse, sloughing shales and lost circulation are the reasons for 44% of the nonproductive time (NPT). Lost circulation is when drilling fluid flows into the formation through thief zones, affecting the hydrostatic pressure in the annulus that prevents the formation fluids from entering the well during drilling.

To prevent lost circulation to occur, several approaches can be assessed depending on the severity. One type of method is the four-tiered strategy consisting of both prevention and remediation measures (figure 2.3). The prevention tiers are: best drilling practices, drilling fluid selection and wellbore strengthening materials. Drilling fluid selection includes the selection of the best suited fluid with the proper rheological properties. The remediation tier (lost circulating materials), is devoted to reduce the lost circulation with materials such as cure or stop-loss pills. Experience has proved that it is more sufficient to prevent the occurrence of losses rather than to stop or reduce them when they have started, thus it is of importance to develop suitable drilling fluids [2].

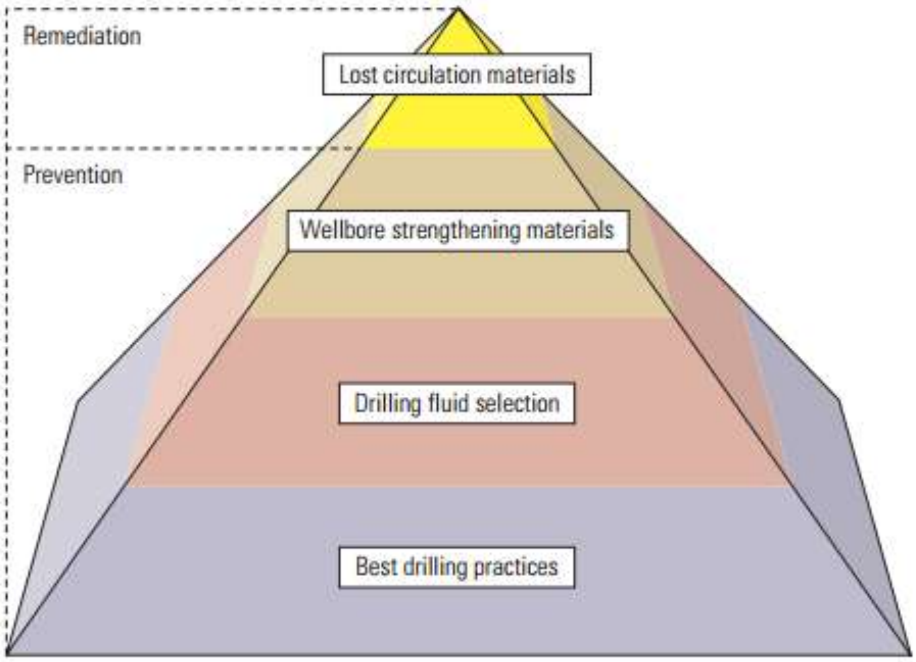


Figure 2.3: Four-tiered strategy consisting of both prevention and remediation measures for lost circulation [2]

2.3 Drilling fluids and function

Drilling fluid was first introduced in 1913 for subsurface pressure control. In the following decades US companies specialized in distribution, development and engineering of drilling fluids, leading to a significant improvement in drilling efficiency and well productivity.

Drilling fluids has many functions, and plays an important part of all drilling operations. Drilling fluids main tasks are [13]:

- **Hole cleaning.** Transport the crushed material out from the well.
- **Controlling formation pressure** (barrier).
- **Buoyancy**. Keeping the drillstring submersed reduces the effective weight of the drill string on the hook load.
- **Lubrication**. Smoothening operation for the bit and also the drillstring in long deviated/horizontal wells.
- **Cooling**. Keeping the drill bit cool, in order to keep change the mechanical properties of the bit.
- **Provide power to the bit**. Hydraulic power is transmitted so that the can cones rotate. Only valid for roller-cone bits. For polycrystalline diamond compact (PDC) bits the hydraulic power is used for jetting the crushed rock away from the bit teeth.

- **Keeping the wellbore stable** with regards to chemical reactions. Shale can be a problem.
- **Signal transfer**. For real time measurements and logging, the drilling fluid itself is used as the transfer medium for pressure waves.
- **Costs**. Drilling fluids are an expensive part of the operations, and should be handled with care to avoid excessive spending.
- **Environmental**. Drilling fluid shall not cause danger for the staff or the environment.

There are three drilling fluid functions that are systematically controlled:

1. Sufficient density to prevent formation influx
2. Sufficient viscosity to transport the cuttings
3. Filter loss control

Figure 2.4 shows the circulating system for the drilling fluid.

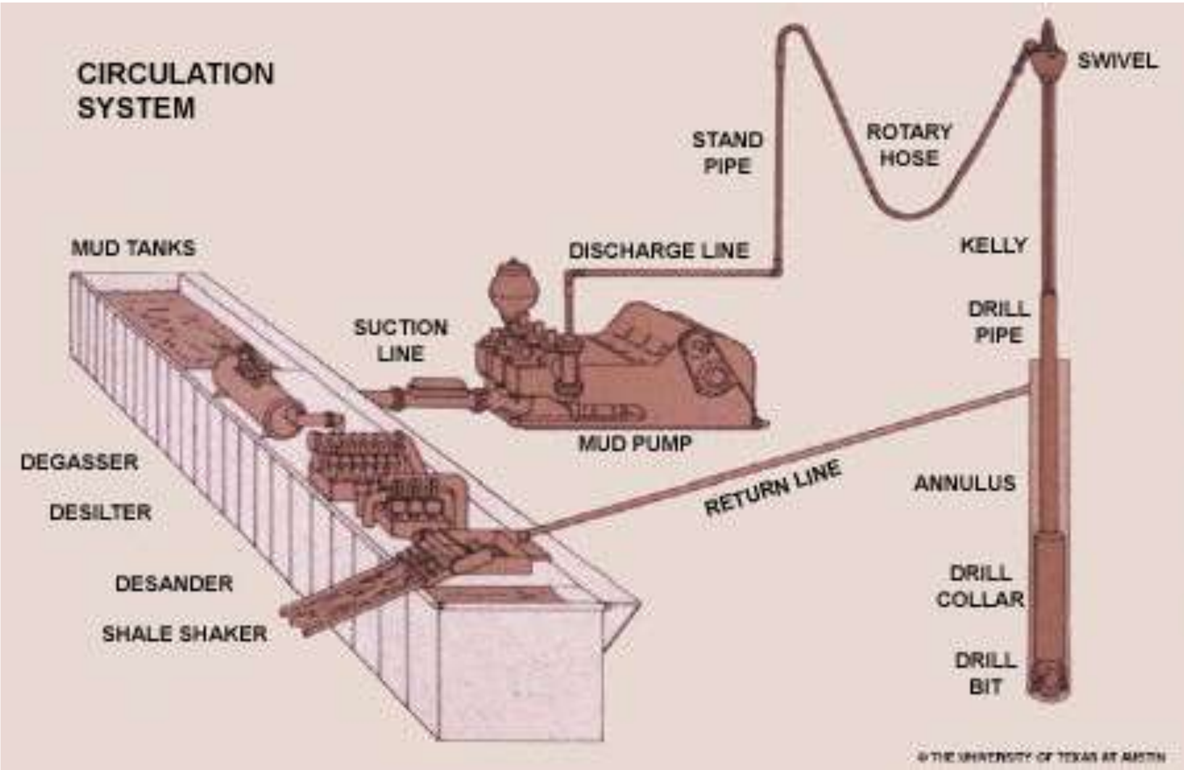


Figure 2.4: Circulation system for drilling fluid [14]

2.3.1 Drilling Fluid Types

Changes in temperature and pressure in a well causes the properties of the drilling fluid to change as well. Hence it influences the performance of the drilling fluid. There is no standard drilling fluid that can be used in all types of drilling conditions.

There are four types of drilling fluids available in the industry [15]:

- Water-based fluids
- Oil-based fluids
- Synthetic-based fluids
- Pneumatic drilling fluids

The earliest drilling fluids/muds were water based (WBM). Since they didn't perform well under all types of drilling conditions, they were modified by adding chemicals. Refined oil was added to lubricate the drill string or to help free stuck pipe. It was noticed that the use of oil in WBM helped stabilize the wellbore wall, leading to the development of oil based fluids/muds (OBM) to drill in difficult shale formations [16].

This thesis is based on the use of water based drilling fluids.

2.3.1.1 Water based drilling fluid/mud (WBM)

WBM consist of salt or fresh water containing a weighting agent (usually barite), clay or organic polymers and various inorganic salts. Different additives are used to modify the physical properties of the fluid for optimal functions. The ingredients of WBM can be divided into 18 functional categories (National Research Council, 1983; World Oil, 1999) [16].

Table 2.1: Functional Categories for Water Based Fluid Ingredients

Functional Categories for Water Based Fluid Ingredients		
Weighting materials	Flocculants	Alkalinity, pH-control additives
Filtrate reducers	Thinners, dispersants	Lost circulation materials
Viscosifiers	Foaming agents	Bactericides
Corrosion inhibitors	Surface-active agents	Defoamers
Pipe-freeing agents	Calcium reducers	Shale control inhibitors
Temperature stability agents	Emulsifiers	Lubricants

Each of the group of additives contains several alternative materials, and more than 1000 generic additives are available for drilling fluids. However, most WBMs do not contain more than 20 additives, added to solve specific down-hole problems.

One of the biggest advantages for using WBMs is environmental; WBMs are non-toxic, or practically non-toxic. Some WBMs are added petroleum hydrocarbons (for lubrication etc.), but usually the amount is sufficiently low so cutting piles do not harm bottom-living communities on the sea floor. WBMs are also less expensive than OBMs, as they are generally less complex [16].

2.4 Nano technology and application

Over the last decade nanotechnology has contributed to technical advances in various industrial biomaterials and renewable energy productions. It involves using particles which are of 1-100nm in size. An interest has increased in the petroleum industry such as exploration, drilling and production. This renewed interest has been expanded by the increasing worldwide oil demand and the maturation of oil fields worldwide. The main benefit of adding nanoparticles to injection fluids is enhanced oil recovery. This is done by changing the properties of the fluid, improving the wettability alternation of rocks, increasing the drag reduction, strengthening the sand consolidation, reducing the interfacial tension and increasing the mobility of the capillary-trapped oil [17].

Amanullah and Al-Tahini classified in 2009 nano fluids as “simple or advanced nano fluids based on the nano-particles concentration in the drilling fluid”. Nano-particles have a high surface area to volume ratio, thus increasing the reactivity of the nanoparticles. The amount of nanoparticles required are therefore much less, which reduces the cost to a great extent [18]. The high surface area of nanoparticles enables them to be used in oil well cementing to accelerate the cement hydration process. Nano silica has been used in cement to develop high early strength, enhance final compressive strength and control fluid loss [5].

There are many other positive factors when using nanoparticles in drilling fluid. During overbalanced drilling the presence of weighted solid content in the drilling mud contribute to the creation of micro and macro fractures. By using nanoparticles it reduces the solid content and the density of the drilling fluid which increases the ROP. The dispersion and sagging of solid content are also eliminated. Shale swelling, spurt loss and fluid loss caused by lost circulation can be prevented by using nanoparticles to form a thin layer of non-erodible and impermeable nanoparticles. This process eliminates the addition of fluid loss additives, rheology modifiers, formation strengthening materials, shale inhibitors etc. [18].

For this thesis nano silica is used to modify the drilling fluid, with the aim of better sealing properties, to avoid formation damage.

2.5 Bentonite

Bentonite is defined as "any clay whose physical properties are dominated by the presence of a smectite". It is formed by the weathering of volcanic ash. In WBMs, bentonite works as viscosifiers and filtrate reducer, and it is usually the second most abundant ingredient in most WBMs [16].

Clay provides the colloidal base of almost all aqueous muds, and is used in oil based drilling fluids. Colloids are particles of any substance which size lies between that of the smallest particles that can be seen with an optical microscope and that of true molecules. Geologists have defined the upper limit of clays particle size as 2 microns, meaning that virtually all clay particles is within the colloidal size range.

Clay minerals are of a crystalline nature, with their atomic structure of its crystals being the prime factor to determine their properties. Most clays have a mica-type structure, with flakes composed of tiny crystal platelets. A single platelet, called a unit layer, consists of an octahedral sheet and one or two silica tetrahedral sheets. Oxygen atoms tie the sheets together by covalent bonds as shown in figure 2.5. The unit layers form what is called crystal lattice meaning that the layers are stacked together face-to-face. C-spacing is the distance between a plane in one layer and the corresponding plane in the next layer [19].

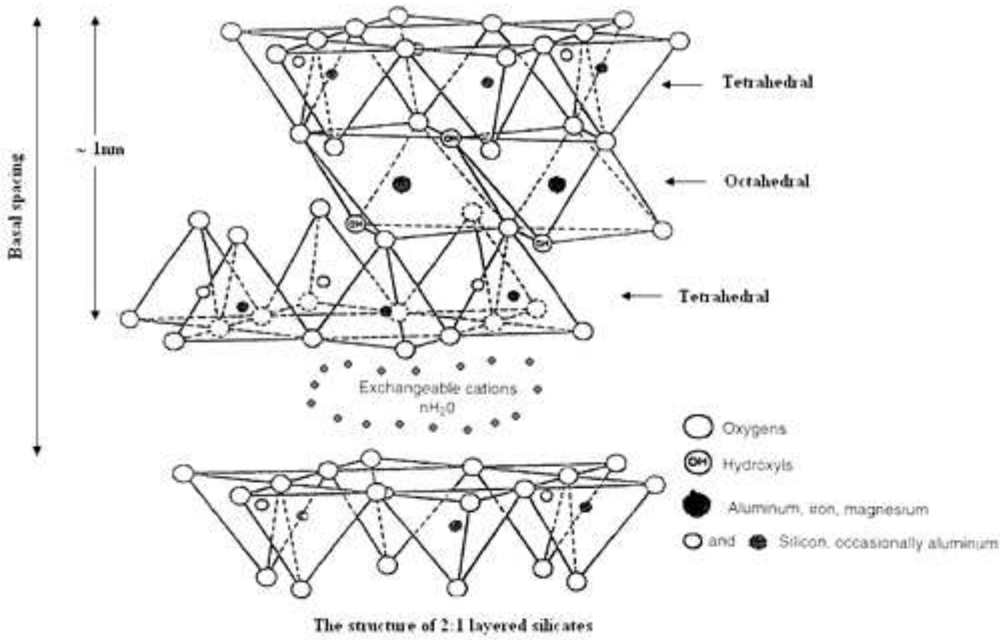


Figure 2.5: Idealized structure of a montmorillonite layer showing two tetrahedral-site sheets fused to an octahedral-site sheet (2:1 type) [20]

Smectites

Pyrophyllite and talc are the two prototype minerals for the smectite group. Their tetrahedral sheet of one layer is adjacent to the tetrahedral sheet of the next, meaning that the bonding between the layers are weak and cleavage is easy. Thus water can enter between the layers causing an increase in the c-spacing. Consequently smectites have an expanding lattice, greatly increasing their colloidal activity.

The best known member of the smectite group is montmorillonite. It is the principal constituent of many clays added to the drilling fluids, best known is the Wyoming bentonite. In the octahedral sheet the predominant substitutions are Mg+2 and Fe+3 for Al+3, but Si+4 can replace the Al+3 in the tetrahedral sheet.

Montmorillonite swells greatly because of its expanding lattice, and the c-spacing depends on the exchangeable cations [19].

The behavior of clay is important because of its influence in fluid properties such as viscosity, yield limit and filter loss. There are four conditions clay particles can obtain in water (see figure 2.6), depending on the interaction between the clay crystal [21];

Dispersed system is when the breakdown of aggregates is complete, thus all the particles are in single platelets. A dispersed system can be both flocculated and deflocculated.

Flocculated system is when particles connect to each other and form a loose structure. This happens when clay crystals have positive charges on the surface, making a three dimension network. When a bentonite fluid flocculates the viscosity, yield point and filter loss increases.

Deflocculated system is when there are only repulsive forces between the individual particles. This happens normally when particles have the same charge. A complete deflocculating only occurs when adding chemicals which neutralize the positive charges on the surface. Since there is no electric attraction between the particles, filter loss and yield point in a deflocculated bentonite fluid will be low.

Aggregated system is when individual particles are bound together in aggregates. In general, a flocculated bentonite fluid will over time go into an aggregated condition, thus there will be fewer particles and the particle surface will become less. This condition gives a high filter loss.

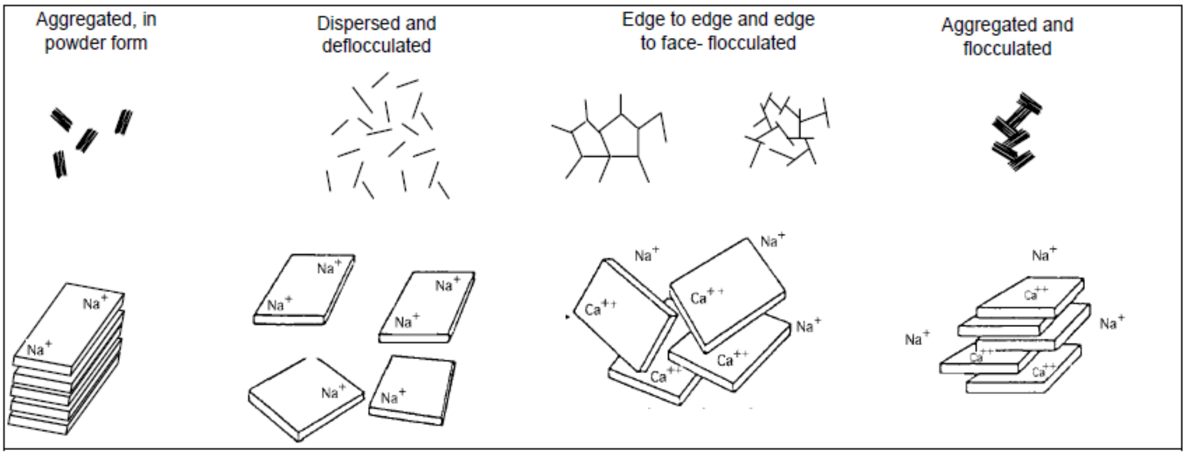


Figure 2.6: Four conditions for clay particles

2.6 Polymer

Since the 1930s, polymers have been used in drilling fluids. The unlimited potential makes polymers applicable to nearly every drilling fluid function. Using polymer technology makes it possible to analyze on a molecular level, and design the proper polymer for the exact situation. Hence, polymers are important in drilling fluids.

A polymer is defined as “a large molecule comprised of small, identical, repeating units” [22]. These units are called monomers. The number of times monomers are repeated is known as the degree of polymerization.

Polymers’ structures are classified as linear, branched or crosslinked (see figure 2.7), and there is an infinite possibility of structural variations. Factors affecting the performance of polymers are:

- Type of monomer or monomers.
- Molecular weight.
- Type and extent of subsequent chemical modification on the polymer.
- Number of branching or crosslinking groups in the polymer chain.

In drilling fluid, polymers can be classified in three ways; according to their chemistry (anionic or nonionic), by their function (such as viscosifier or filtration-control additive), or they can be classified by their origin. There are three types of categories when classifying by origin [22]:

1. Naturally occurring polymers are produced in nature, with material derived from natural sources such as plants. Their structure is more complex than for synthetic polymers, and they often have a higher molecular weight. They are less temperature stable and have a lower tolerance to degradation by bacteria than synthetic polymers. Starch is an example of a natural occurring polymer used in drilling fluids.
2. Modified naturally occurring polymers are common in drilling fluids. The modified polymers can have substantially different properties than its original.
3. Synthetically derived polymers are chemically synthesized, usually from petroleum derived products.

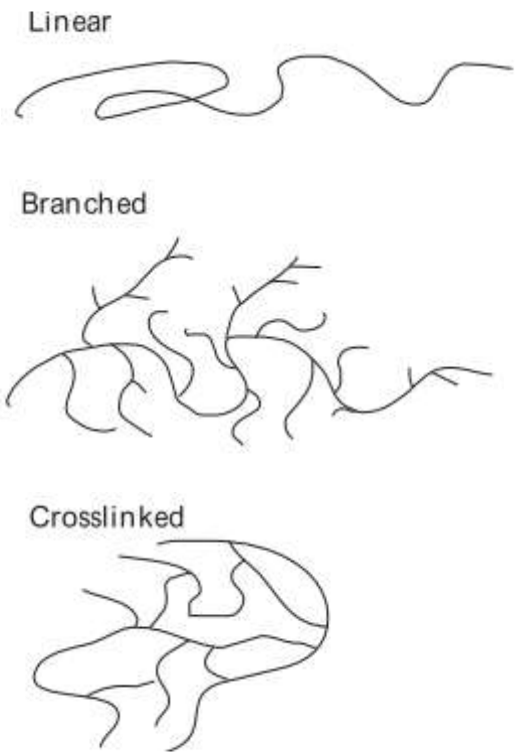


Figure 2.7: Polymers structures: linear, branched and crosslinked

In this thesis two polymers were used for analysis; Carboxymethyl Cellulose Sodium (CMC) and Polyanionic Cellulose (PAC), both are modified natural polymers. They are used in drilling fluids to help control fluid loss and to increase the viscosity of the fluid.

2.6.1 Carboxymethyl Cellulose Sodium

CMC has linear structure and is a polyelectrolyte. The molecular formula is $[C_6H_7O_2(OH)_2CH_2COONa]n$ (see figure 2.8). It is formed by the reaction of the sodium salt of monochloroacetic acid ($ClCH_2COONa$) with cellulose. It is most often at the ($-CH_2OH$) group the substitution occurs, forming a polyelectrolyte.

Several factors influence the properties of CMC, such as:

- The Degree of Substitution (D.S.).
- The Degree of Polymerization (D.P.).
- The uniformity of the substitution.
- The purity of the final product.

The degree of substitution (D.S.), refers to the number of substitutions that occur on a repeating ring structure. In figure 2.8 showing sodium CMC, there is one substitution on each ring structure, giving a D.S. factor of 1.0. Had the substitution occurred at either of the two hydroxyl (-OH) groups, the D.S. could have a potential of 3. The typical D.S. range for CMC is 0.7 to 0.8. When the D.S. reaches 0.45, water solubility is achieved.

The molecular weight is dependent on the D.P.; higher D.P. gives a higher molecular weight. As D.P. for CMS increases, so does the viscosity. Thus, high viscosity CMC has a higher molecular weight than low viscosity CMC [22].

CMC has two important functions;

1. It imparts water solubility.
2. The dissociation of Na^+ creates negative sites along the chain, causing the coiled chains to stretch and thereby the viscosity increases.

Carboxymethylcellulose has been used in water based drilling fluids since 1947, and Kirk-Othmer claimed in 2004 that CMC is one of the most used cellulosic in drilling. It is used as a filtration control agent and as a viscosifier (Kaveler, 1946) [19, 22].

In drilling fluids where bentonite is a component CMC can be used to increase the viscosity, control the fluid loss and maintain adequate flow properties at high temperatures [23].

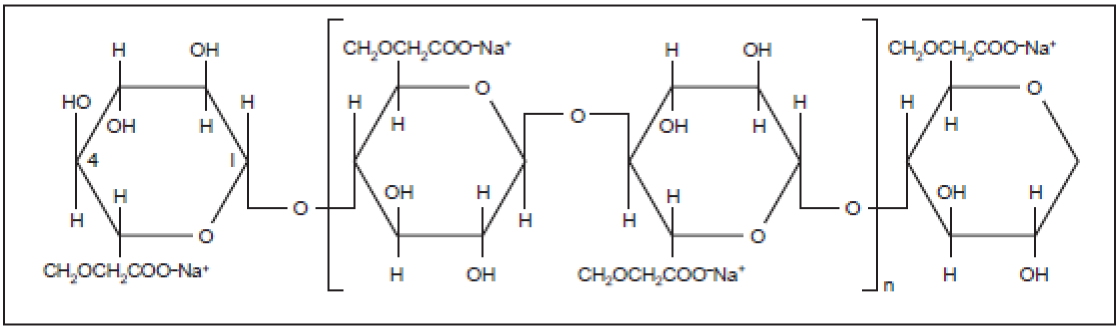


Figure 2.8: Structure of Sodium CMC [22]

2.6.2 Polyanionic Cellulose

PAC has the same chemical formula as CMC, $[C_6H_7O_2(OH)_2CH_2COONa]_n$ (see figure 2.9). When CMC is higher substituted it is called Polyanionic Cellulose (PAC). The D.P. and chemical structure are the same for the polymers, but there is a different in the D.S. PACs D.S. range from 0.9 to 1.0. Since the D.S. is higher for PAC, it is more soluble than CMC, giving the performance of PAC generally better than that of CMC.

PAC dissolves immediately in water and can be used as a thickening agent, rheology controller, bond, colloid protector, suspending agent, stabilizer and filtrate reducer.

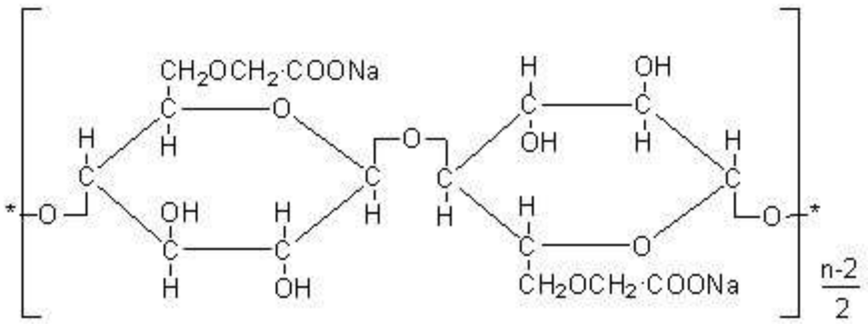


Figure 2.9: Structure of PAC [15]

Even when PAC and CMC have the same D.P. and D.S. they can perform differently. This is due to the uniformity of the substitution along the chain. A uniform substitution is preferred, and gives the best results. With substitution occurring at only one end or in the middle of the polymer it results in limited solubility and poor performance [22].

2.7 Nano silica

As mentioned, the use of nanoparticles in drilling fluid can have a positive effect on fluid properties.

The nano silica (15nm) used in this thesis was obtained from the EPRUI Nanoparticles & Microsheres Co. Ltd, China. Scanning Electron Microscopy (SEM) for imaging (figure 2.10) and Elemental Dispersive Spectroscopy (EDS) (figure 2.11) was used to characterize the particle for elemental identification. In figure 2.11 the purity of nano silica (Si and O) can be observed. Before identification and imaging by EDS and SEM, the particles were coated with Palladium (Pd).

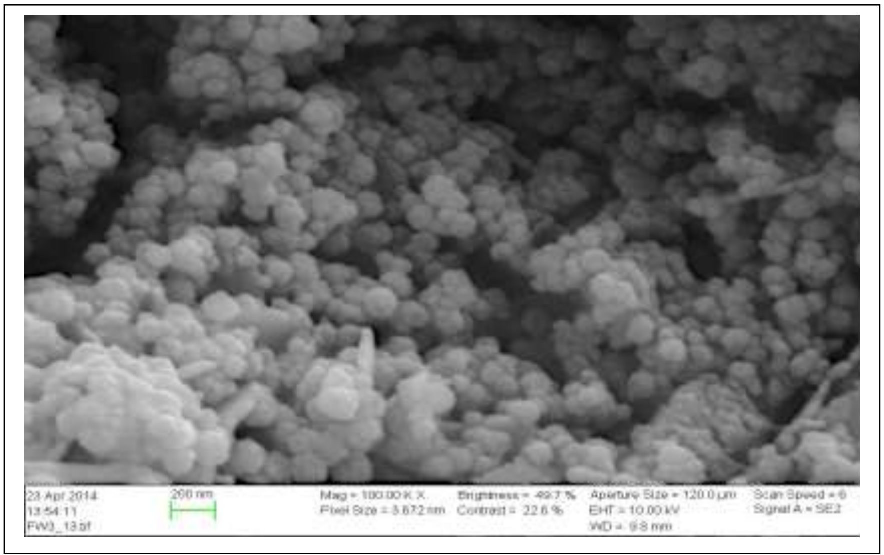


Figure 2.10: Scanning Electron Microscopy (SEM) of nano silica

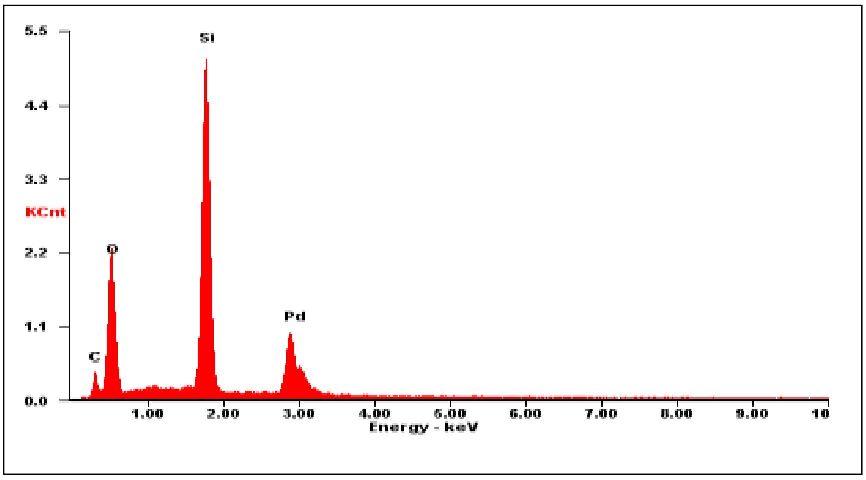


Figure 2.11: Elemental Dispersive Spectroscopy (EDS) of nano silica

2.8 Salt

Salt are used in WBMs for shale swelling control. Previous work has shown that salt in CMC fluids modified rheological parameters of the fluid. In figure 2.12 the effect of using salt in CMC fluids are seen, as the CMC chains breaks down into smaller pieces with the presence of salt [24].

In this thesis, potassium chloride, KCl and sodium Chloride, NaCl are used as additives in the drilling fluid.

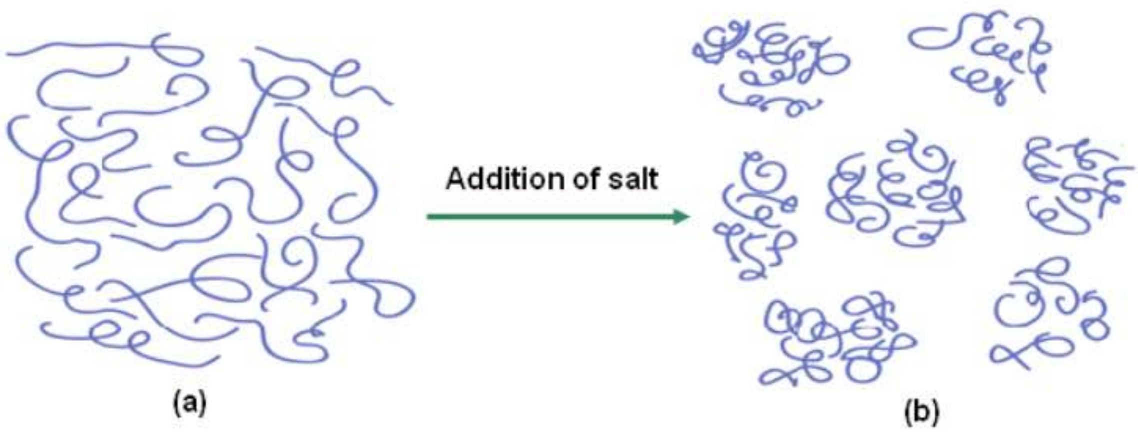


Figure 2.12: Structure of CMC chains: (a) in the absence of salts and (b) in the presence of salts [24]

2.8.1 KCl

Potassium fluids are the most widely accepted water fluid system for drilling water sensitive shales, and potassium chloride is the most widely used potassium source. The K^+ ions attach to clay surfaces, giving stability to shale exposed to drilling fluids by the bit. Another benefit gained from the K^+ ions is that they hold the cuttings together, minimizing dispersion into finer particles [25].

Potassium based fluids are superior to calcium fluids due to their shale-inhibition properties. Potassium is exchanged for sodium and calcium when drilling in shale that contains montmorillonite, resulting in a more stable fluid system which is less susceptible to hydration [26].

2.8.2 NaCl

Sodium chloride is less used in drilling fluids than potassium chloride. Na^+ is not as good as the K^+ ion, but has other advantages such as reducing the invasion of filtrate into the clay. Close to saturation, NaCl leads to large viscosities and a water activity lower than those observed with concentrated solutions of KCl. Concentrated solutions of NaCl in combination with silicates polyols and methylglucoside can improve the efficiency of the membrane (filter cake). The presence of Na^+ ions counteracts the benefits of K^+ ions, but is minimized by using fresh water instead of sea water [1].

2.9 Rheology

Rheology is the science and study of the deformation and flow of matter (Darby, 1976) [13], including solids and liquids, and is an important property of drilling fluids. Success of a drilling, workover or completion fluid depends on its viscosity at the shear rate. Fluids are exposed to a wide range of shear rates, therefor, a detailed understanding of fluid rheology and the influence of shear is necessary to optimize fluid design. The rheology model describes the relationship between the shear rate and the shear stress. Ideally, high viscosity is desirable under low shear rate conditions, and should decrease as flow rate increases [29]. Fluids rheology characteristics can be modified radically by adding a proper polymer.

Knowledge on fluid rheology is important for the drilling process, and is used in the following applications (American Petroleum Institute, 2010) [13]:

- Calculating frictional pressure loss in annuli and pipes.
- Determining flow regimes in the annulus.
- Estimating ECD of the fluid under downhole conditions.
- Estimating hole-cleaning efficiency.
- Estimating surge and swab pressures.
- Optimization of the circulating system for improved drilling efficiency.

Fluids are classified by their rheological behavior, as either Newtonian or Non-Newtonian. Non-Newtonian fluids does not conform a direct proportionality between shear rate and shear stress. Figure 2.13 illustrates how the different fluids react during an increased shear rate for four different fluids;

1. Newtonian fluid
2. Bingham plastic
3. Power law fluid
4. Herschel Buckley fluid

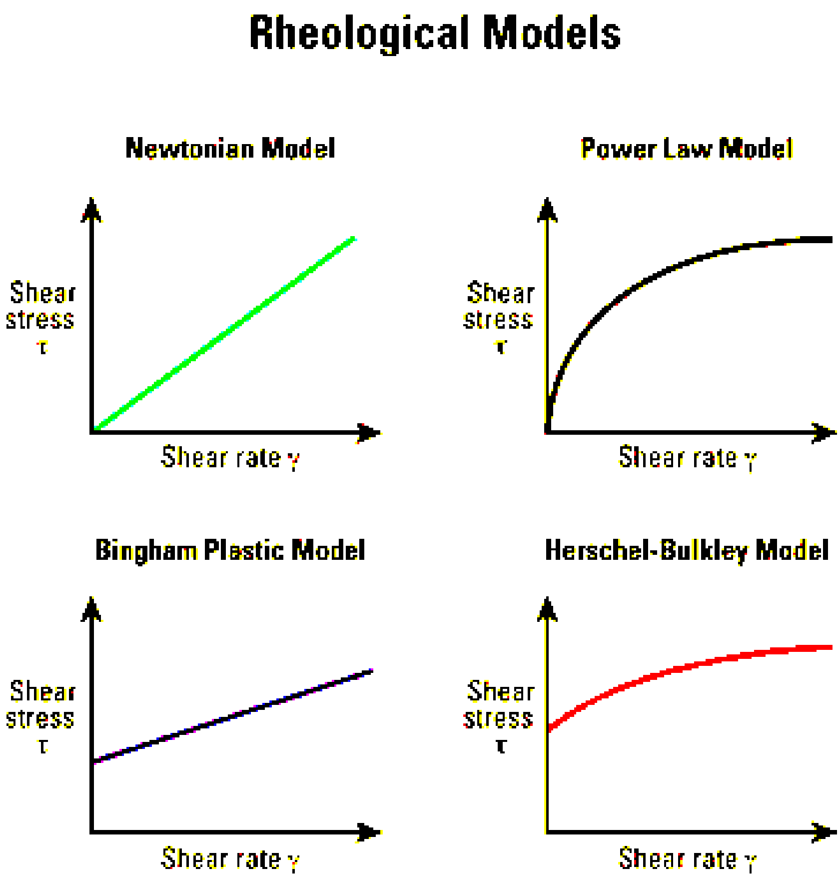


Figure 2.13: Graphical representation on how different fluids react when exposed to increased shear rate [28]

2.9.1 Newtonian Model

A Newtonian fluid has a linear proportional relationship between shear rate and shear stress. Fluid viscosity is the slope of the shear rate versus shear rate data. For a Newtonian fluid, viscosity is independent of shear rate. [27] Examples for Newtonian fluids are water, ethyl alcohol, benzene and most solutions of simple molecules.

The relationship between shear rate and shear stress is given by the equation [29]:

$$\tau = \mu_n \gamma \tag{2.4}$$

Where:

- τ - Shear stress [lbf /100ft^2]
- γ - Shear rate [1/sec]
- μ_n - Newtonian viscosity [cP]

2.9.2 Bingham Plastic Model

The Bingham Plastic Model is a two parameter rheology model that describes a fluid with a yield stress component and a Newtonian component. Ketchup and mayonnaise are examples of Bingham fluids [13]. The negative with this model is that it can't predict the fluid behavior accurately at very high shear rates (at the bit) or at low shear rates (in the annulus). The Bingham model have suffered during the evolution of clay based drilling fluids, but it is deficient when describing the overall rheological profile of polymer based fluids [27]. Drilling fluids tends to gel during stagnant conditions, requiring a certain shear stress to overcome the yield point. Thus this model is used when describing these drilling fluids [13].

The model is given as the equation [29]:

$$\tau = \tau_y + \mu_p \gamma \tag{2.5}$$

Where:

- μ_p - Plastic viscosity [cP]
- γ - Shear rate [1/sec]
- τ_y - Yield point [lbf /100ft^2]
- τ - Shear stress [lbf /100ft^2]

The rheology parameters can be determined from the rheological graph where the slope of the curve is the plastic velocity. Or a viscometer can provide 600 and 300 rpm readings used to measure the plastic viscosity and yield point. Then the rheological parameters of the Bingham fluid can be calculated using the equations [29]:

$$\mu p = R_{600} - R_{300} \tag{2.6}$$

$$\tau y = R_{300} - \mu_p \tag{2.7}$$

2.9.3 Power Law Model

The Power Law model is widely used to describe the behavior of oil field fluids and represents fluids without yield stress. The model is described by two parameters, given the equation [29]:

$$\tau = k\gamma^{n} \tag{2.8}$$

Where:

- k - Consistency index [lbf*sec^n/100ft^2]
- n - Flow behavior index []
- τ - Shear stress [lbf /100ft^2]
- γ - Shear rate [1/sec]

The consistency index serves as a viscosity index of the system, while the behavior index indicates the tendency of the fluid to shear thin [27]. The parameters, k and n, can be determined from the curve or the following equations [29]:

$$\mathrm{n} = 3.32\log\left(\frac{\mathrm{R}_{600}}{\mathrm{R}_{300}}\right) \tag{2.9}$$

$$k = \frac{R_{300}}{511^{n}} = \frac{R_{600}}{1022^{n}} \tag{2.10}$$

There are two types of power law fluids. Pseudoplastic fluids require the flow behavior index to be below one, n < 1. They have a shear thinning behavior, meaning they have less viscosity with higher shear rates. This behavior is found in polymer solutions used in drilling fluids.

The other less common type of power law fluid is dilatant fluids. These fluids require the flow behavior index to be greater than one, n > 1. They have a shear thickening behavior as their viscosity increases exponentially when the shear force is increased. An example of a dilatant fluid is quicksand [13].

2.9.4 Herschel-Buckley Model

The Herschel-Buckley model, also called Yield Power Law (YPL), expresses a fluid by three parameters that describes better than other models the behavior of yields pseudoplastic fluid. It is a combination of the Bingham and power law fluid models. Since it considers both a yield point and power law development with increasing shear rate, it is often used when describing drilling fluids in oil wells.

The model is described by the equation [13]:

$$\tau = \tau_o + k\gamma^n \qquad (2.11)$$

Where:

- τ - Shear stress [lbf /100ft^2]
- γ - Shear rate [1/sec]
- k - Consistency index [lbf*sec^n/100ft^2]
- τ_o- Yield stress [lbf /100ft^2]

When $n = 1$ the models becomes a Bingham Model
When $\tau_o = 0$ the model becomes a Power Law Model

2.9.5 Robertson-Stiff Model

The Robertson and Stiff Model are known for being superior to Bingham and Power law models, but since it is complex to evaluate its three parameters, A, B and C, it has not been used widely in the drilling industry. The model is a more adequate fit when determining rheological stress/rate of strain data.

The equation is as follows [29]:

$$\tau = A(\gamma + C)^B \qquad (2.12)$$

Where A [lbf*sec^B/100ft^2] and B [] can be considered as similar to the k and n parameters of the Power law model, and C [1/sec^B] is a correction factor to the shear rate. The term γ + C is the effective shear rate.

2.9.6 Unified Model

The drilling industry improved the Herschel-Bulkley model into a Unified model. For this model the calculations of the rheological parameters, n and k, require previous estimation of plastic viscosity, yield stress and yield point.

Equations for this model are the following [29]:

$$\tau_{yL} = (2R_3 - R_6) * 1.066 \tag{2.13}$$

Pipe flow:

$$n_p = 3.32\log\left(\frac{2\mu_p + \tau_y}{\mu_p + \tau_y}\right) \tag{2.14}$$

$$k_p = 1.066\left(\frac{\mu_p + \tau_y}{511^{n_p}}\right) \tag{2.15}$$

Annular flow:

$$n_a = 3.32\log\left(\frac{2\mu_p + \tau_y - \tau_y}{\mu_p + \tau_y - \tau_y}\right) \tag{2.16}$$

$$k_a = 1.066\left(\frac{\mu_p + \tau_y - \tau_y}{511^{n_a}}\right) \tag{2.17}$$

Where:

- τ_{yL} - Lower shear yield point [lbf /100ft^2]
- n_p -Flow behaviour index in the pipe []
- n_a -Flow behaviour index in the annulus []
- k_p - Consistency index of the pipe [lbf*sec^n/100ft^2]
- k_a - Consistency index of the annulus [lbf*sec^n/100ft^2]

Ratio τ_0/τ_y can be useful when characterizing if the fluids behavior is more plastic or pseudoplastic; if the ratio approaches 1, fluids have a Bingham plastic behavior, if it approaches 0, the fluids behave pseaudoplastic (Power-law).

2.10 Hydraulics

During the circulations of drilling fluid, friction between the drilling fluid and the drill pipe and annulus wall cause pressure loss. The pump pressure is affected by [29]:

- Frictional pressure losses (ΔP_s) in the surface equipment such as Kelly, swivel, standpipe.
- Frictional pressure losses (ΔP_{ds}) inside the drillstring (drillpipe, ΔP_{dp} and drill collar, ΔP_{dc}).
- Frictional pressure losses across the bit, ΔP_b.
- Frictional pressure losses in the annulus around the drillstring, ΔP_a.

The mathematical expression for the pump pressure is given [29]:

$$\Delta Pp = \Delta Ps + \Delta Pds + \Delta Pb + \Delta Pa \qquad (2.18)$$

Error in pump pressure is a combination of errors in the four elements.

In order to evaluate the hydraulic performance of the drilling fluid analyzed in the thesis, the Unified hydraulic model was chosen. Table 2.2 shows the summary of the model in tubing and annulus [29].

Table 2.2: Rheological and hydraulics equations for Unified model [29]

Unified model, $\tau = \tau_0 + k\gamma^n$	
Pipe Flow	**Annular Flow**
$\mu_p = R_{600} - R_{300}$ $\tau_y = R_{300} - \mu_p$ $\tau_0 = 1.066(2R_3 - R_6)$ μ_p= cp τ=lbf/100ft^2	
$n_p = 3.32 \log\left(\frac{2\mu_p + \tau_y}{\mu_p + \tau_y}\right)$ $k_p = 1.066\left(\frac{\mu_p + \tau_y}{511^{n_p}}\right)$	$n_p = 3.32 \log\left(\frac{2\mu_p + \tau_y - \tau_y}{\mu_p + \tau_y - \tau_y}\right)$ $k_p = 1.066\left(\frac{\mu_p + \tau_y - \tau_o}{511^{n_a}}\right)$ k=lbf*sec^n/100ft^2
$G = \left(\frac{(3-\alpha)n+1}{(4-\alpha)n}\right)\left(1 + \frac{\alpha}{2}\right)$ *α= 1 for pipe* *α= 1 for annuli*	
$v_p = \frac{24.51\, q}{D_P^2}$	$v_a = \frac{24.51\, q}{D_2^2 - D_1^2}$ v=ft/min
$\gamma_w = \frac{1.6 * G * v}{D_e}$ $\gamma_w = sec^{-1}$	
$\tau_w = [(\frac{4-\alpha}{3-\alpha})^n\ \tau_0 + k\, \gamma_w{}^n]$ τ_w=lbf/100ft^2	
$N_{Re} = \frac{\rho\, v_p{}^2}{19.36\tau_w}$	$N_{Re} = \frac{\rho\, v_a{}^2}{19.36\tau_w}$
$f_{laminar} = \frac{16}{N_{Re}}$ $f_{transient} = \frac{16\, N_{Re}}{(3470 - 1370np)^2}$ $a = \frac{\log n + 3.93}{50}$ } $b = \frac{1.75 - \log n}{7}$ } $f_{turbulent} = \frac{a}{N_{Re}^b}$	$f_{laminar} = \frac{24}{N_{Re}}$ $f_{transient} = \frac{16\, N_{Re}}{(3470 - 1370na)^2}$ $a = \frac{\log n + 3.93}{50}$ } $b = \frac{1.75 - \log n}{7}$ } $f_{turbulent} = \frac{a}{N_{Re}^b}$
$f_{partial} = (f_{transient}{}^{-8} + f_{turbulent}{}^{-8})^{-1/8}$	
$f_p = (f_{partial}{}^{12} + f_{laminar}{}^{12})^{1/12}$	$f_a = (f_{partial}{}^{12} + f_{laminar}{}^{12})^{1/12}$
$\left(\frac{dp}{dL}\right) = 1.076\frac{f_p v_p^2 \rho}{10^5 D_p}$ psi/ft $\Delta p = \left(\frac{dp}{dL}\right)\Delta L$ psi	$\left(\frac{dp}{dL}\right) = 1.076\frac{f_a v_a^2 \rho}{10^5 (D_2 - D_1)}$ psi/ft $\Delta p = \left(\frac{dp}{dL}\right)\Delta L$ psi
$\Delta p_{Nozzles,psi} = \frac{156\rho q^2}{(D_{N1}{}^2 + D_{N2}{}^2 + D_{N3}{}^2)^2}$ psi	

2.11 Viscoelasticity

Drilling fluids exhibit both viscous and elastic responses during deformation. Viscoelastic is a time-dependent property of the materials and the viscoelastic properties of drilling fluids are important to evaluate gel strength, gel structure, barite sag, solid suspension and hydraulic modelling [30]. The elastic properties of drilling fluids are of importance because it has a strong effect on the flow behavior and pressure drop.

Most materials have some fluid-like (viscous) properties as well as some solid-like (elastic) properties, and most fluids used in oil field applications are viscoelastic to a certain degree.

The most common method of quantifying the viscoelastic properties of fluids is to measure the fluids elastic modulus (G') and viscous modulus (G'') (figure 2.14). G' is also known as the storage modulus since elastic energy is stored, while G'' is also known as the loss modulus since the viscous energy is lost.

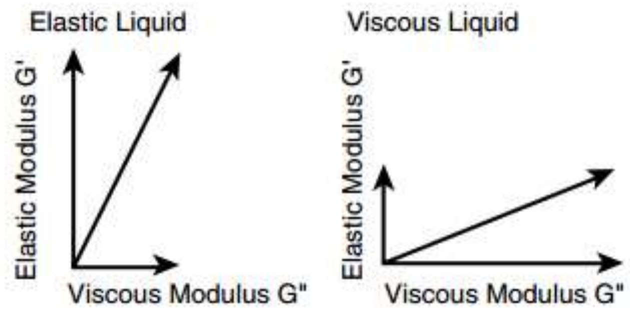


Figure 2.14: Modulus values for two fluids [27]

Viscoelasticity can`t be measured in the steady, uniform flow field found in viscometers, so oscillatory methods of measurements are used. A rheometer applies sinusoidally varying strain (deformation) to the fluid sample. The resulting stress is measured. For highly elastic samples, the stress and strain sine waves are in phase, while for highly viscous samples, the stress and strain will be 90° out of phase. If the phase angle has values between 0° and 90° it is a viscoelastic material (figure 2.15) [27].

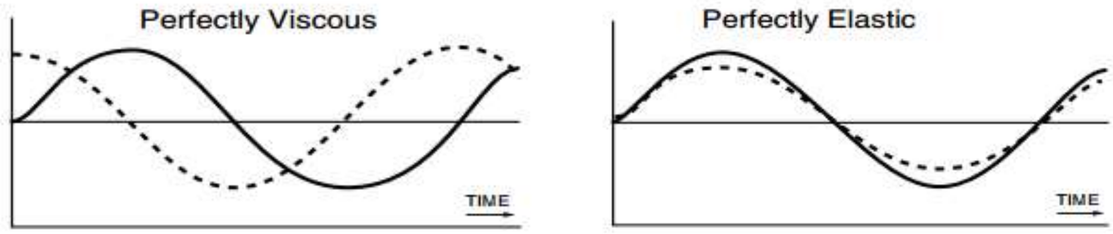


Figure 2.15: Viscous and elastic responses to an applied strain. Graph to left showing the stress (solid line) and strain (dashed line) are 90° out of phase. Graph to right showing the two lines in phase [27]

2.11.1 Oscillatory Test: Amplitude Sweep

The amplitude test is an oscillatory test, meaning that during an amplitude sweep test the amplitude of the deformation (amplitude of the shear stress) is allowed to vary while the frequency is held constant.

An amplitude sweep test measures the linear viscoelastic region (LVER). The LVER can determine the stability of a suspension, by measuring the length of the LVER of the elastic modulus (G'). If the fluid has a long LVER it is an indication that the system is well-dispersed and stable [31].

Figure 2.16 shows the storage modulus G' and the loss modulus G" plotted against the deformation. The figure shows the oscillation of the motion and the amplitude is the maximum of the motion [30, 32].

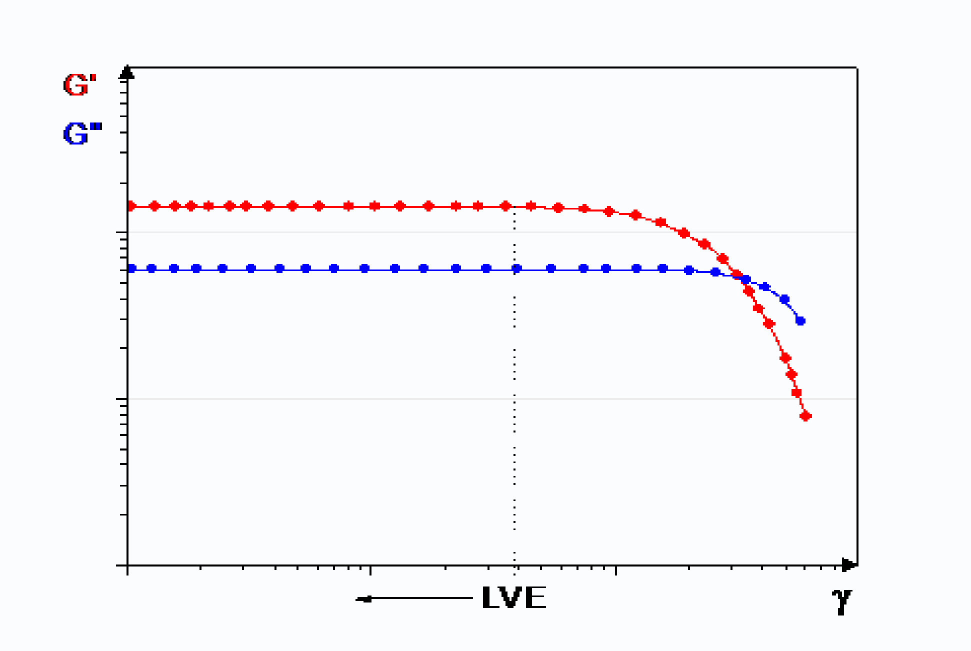


Figure 2.16: Amplitude Test, G' and G'' moduli plotted against the deformation [32]

When the deformation is low, G' and G" are constant, indicating that the structure is undisturbed. This is the LVER, and as shown in figure 2.16, as soon as the moduli start to decrease, it indicates that the structure is disturbed, thus reaching the end of the LVER.

When the storage and loss moduli cross (G'=G''), the material starts to flow. This is known as the flow point of the fluid, but in the drilling industry yield point is a more common name. The yield point is when the LVE plateau begins to deviate, hence the limit of the LVE range. Yield point can therefore be determined from the amplitude sweep test, either by using the point given by the end of the LVER, or by the intersection point of the curves for G' and G" [13, 32].

In this thesis, the point given by the end of LVER is used to determine yield point.

2.11.2 Oscillatory Test: Frequency Sweep

During a frequency sweep test the frequency is varied while the amplitude of the deformation (amplitude of the shear stress) is held constant. For the test the storage and loss modulus are plotted against the frequency (see figure 2.17). The data at high frequencies describe the behavior of the samples at fast changes of stress, while data at low frequencies describe behavior of the samples at slow changes of stress.

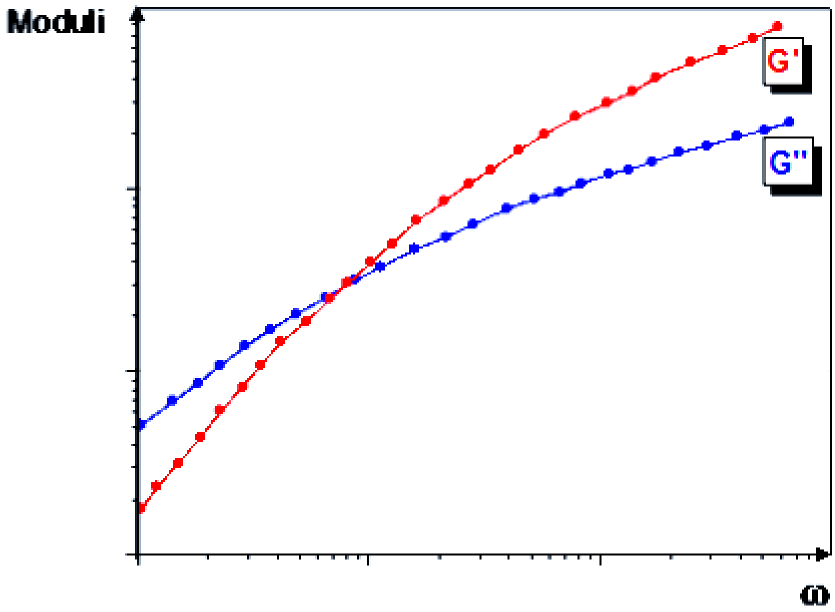


Figure 2.17: The Frequency Sweep Test [33]

Frequency sweep is very important for polymer fluids. When measuring frequency sweeps at different temperatures characteristics such as glass transition, entanglement density, melting point and rubbery-elastic characteristics can be determined [33].

3 Experimental evaluation of nano treated bentonite based drilling fluid

The fluid was prepared and investigated to determine the effect of nano, polymers and salt in bentonite treated WBM systems. The effect of temperature was also evaluated. The aim for the fluid system is to have little filtrate loss and suitable viscosity. A screening test was first performed to establish the right amount of polymer to add in the fluid system. Afterward another screening test was performed to find the right amount of salt to add in the fluid system. Then nano silica was added to evaluate the effects it had on the fluid system. This was done with different types of polymers and salts, as well as combined.

The drilling fluids were first measured with the Fann35 viscometer. The fluids were heated to desired temperature with the Tufel heating cup, and the measurements were performed under atmospheric pressure. Bingham rheology model was used to calculate plastic viscosity and yield strength, while Power Law rheology model was used for consistency index (k) and flow behavior index (n).

The drilling fluid system that showed the best results was selected for sand pack testing and viscoelasticity measurement.

3.1 Effect of polymer concentration (Screening test)

With the aim of finding a suitable concentration of polymer in the bentonite treated WBM, different amounts of CMC were added and investigated. Based on the results the screen out was performed to find the most optimum amount of polymer.

3.1.1 Description of CMC drilling fluid system

The drilling fluids that were prepared are shown in table 3.1. All were prepared with 500g H_2O and 25g bentonite (reference fluid). The amount of polymer CMC varied. Two days after preparing the fluids, the viscosity, filtration and pH measurements were performed.

The fluids were mixed in the order:

500g H_2O + Xg CMC + 25g Bentonite

Table 3.1: Test matrix for CMC fluid system

Test matrix for CMC fluid system				
Additives	Ref. Fluid Screening	Fluid 2	Fluid 3	Fluid 4
Water (H_2O)	500g	500g	500g	500g
Bentonite	25g	25g	25g	25g
CMC	0g	0,5g	0,75g	1,0g

3.1.2 Results and analysis of CMC drilling fluid

Rheology, pH and filtration were measured in order to perform the screening. Before performing the test, the fluids were blended for two minutes in order to get the most accurate results.

Table 3.2 shows the results achieved from the tests.

Visual inspection showed that fluids containing 0,75g CMC and 1,0g CMC were not suitable as drilling fluids due to high viscosity though the filtrate loss was sufficiently low. From table 3.2 it is seen that the viscosity parameters increases as the addition of CMC increases, until it reaches an insufficient level (seen from the visual inspection). The reason for the increase in PV (plastic viscosity) and YP (yield point) is that the carboxy group of CMC causes water dispersibility, resulting in an increased friction between particles, causing the shearing stress required to induce unit rate of shear to increase. Thus PV and YP increases as the concentration of CMC increases [34]. YP has an increase as high as 260% for fluid 4 compared to reference fluid at temperature 72°F (see appendix A.1).

Table 3.2: Results obtained from CMC fluid system

Reference fluid screening (500 g H_2O + 25 g Bentonite)			
Rheology parameters	**Temperature**		
	72°F	**100°F**	**130°F**
PV [cP]	5,0	4,0	5,0
YS [lbf/100ft^2]	10,0	12,5	15,0
LSYS [lbf/100ft^2]	6,5	8,0	10,0
YS/PV [(lbf/100ft^2)/cP]	2,0	3,1	3,0
n	0,42	0,31	0,32
k [lbf*sec^n/100ft^2]	1,13	2,34	2,69
Filtration [ml]	7		
pH	9,95		
Fluid 2: Reference fluid + 0,5g CMC			
PV [cP]	7,5	7,0	6,5
YS [lbf/100ft^2]	20,5	23,0	28,5
LSYS [lbf/100ft^2]	15,0	16,0	21,0
YS/PV [(lbf/100ft^2)/cP]	2,7	3,3	4,4
n	0,34	0,30	0,25
k [lbf*sec^n/100ft^2]	3,31	4,55	7,57
Filtration [ml]	4,5		
pH	9,80		
Fluid 3: Reference fluid + 0,75g CMC			
PV [cP]	8,0	7,5	7,0
YS [lbf/100ft^2]	27,5	31,5	32,0
LSYS [lbf/100ft^2]	20,0	21,0	21,0
YS/PV [(lbf/100ft^2)/cP]	3,4	4,2	4,6
n	0,29	0,25	0,24
k [lbf*sec^n/100ft^2]	5,71	8,02	8,84
Filtration [ml]	4,0		
pH	9,75		
Fluid 4: Reference fluid + 1,0g CMC			
PV [cP]	9,0	10,0	8,0
YS [lbf/100ft^2]	36,0	39,0	44,0
LSYS [lbf/100ft^2]	27,0	28,0	30,0
YS/PV [(lbf/100ft^2)/cP]	4,0	3,9	5,5
n	0,26	0,27	0,21
k [lbf*sec^n/100ft^2]	8,73	9,22	14,36
Filtration [ml]	4,0		
pH	9,85		

Filtrate test shown in figure 3.1 presents a better (smaller filtrate loss) for the fluids added CMC. The filtration decreases slightly with the amount of CMC added, but can be observed to be as close to stable at approximately 4,0ml. The decrease in filtrate loss and increase of plastic viscosity and yield point indicates that the adding of polymer provides a more dispersed flocculated fluid system.

Figure 3.2 shows that increasing the concentration of CMC in the drilling fluids increase the rheology curves measured by Fann viscometer. % Increase of results from Fann viscometer can be found in appendix A.2. Increasing amount of CMC to reference fluid increases the rheology curves significantly; fluid 4 containing 1,0g CMC gives an increase up to 74,5% compared to reference fluid.

It is seen from power law rheology parameters that for all temperatures, when increasing the amount of CMC, n decreases while k increases. $n<1$ for all fluids, thus they are shear-thinning. The decrease in n values and increase in k values improves the fluids hole cleaning performance by increasing the effective annular viscosity, since annular viscosity helps prevent particle breakage and moves the solids more directly up the hole [37].

The effect of temperature is little, but it can be seen from results that increasing temperature gives an increase in all of the rheology parameters, except PV. Increasing temperature have a positive effect on hole cleaning since n decreases and k increases at higher temperatures. Further comparison for the effect of temperature can be seen in section 3.7.

Based on the results it is concluded that 0,5g polymer provides the best results. Therefore, for the next sections covering effects of salts, when referring to reference fluid, this contains 500g H_2O, 0,5g CMC and 25g Bentonite.

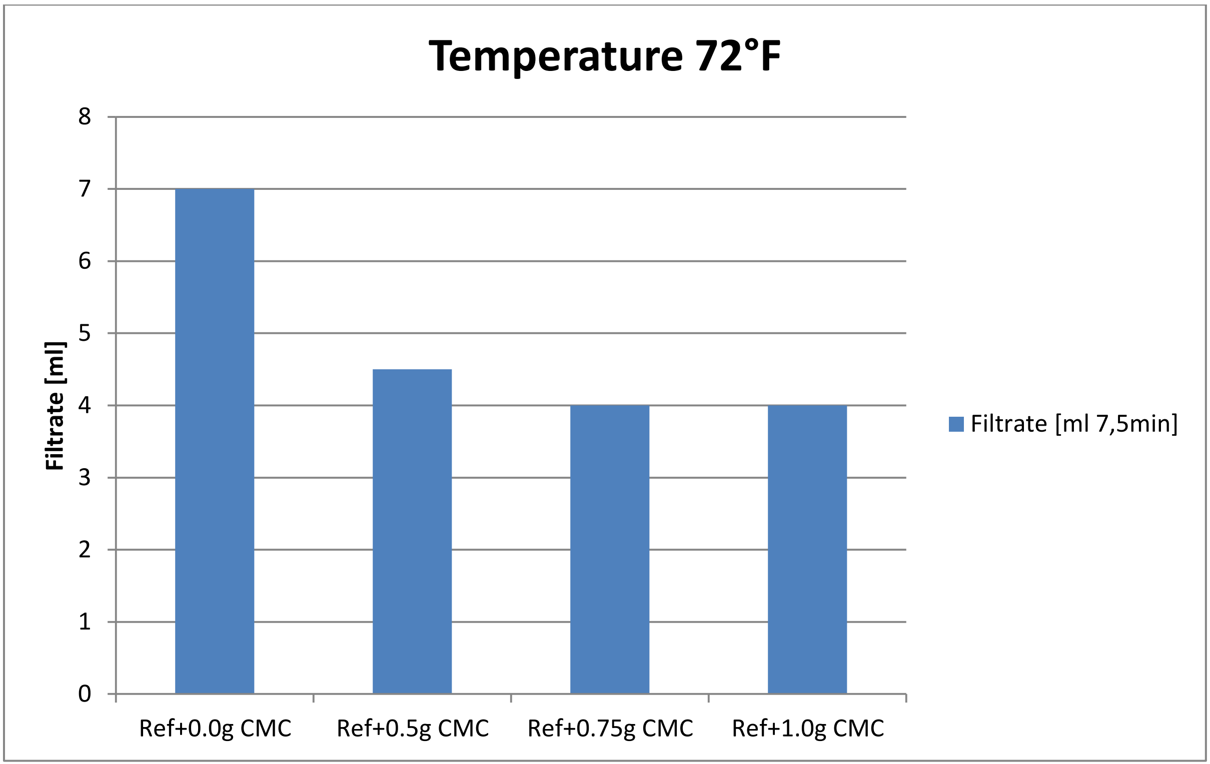


Figure 3.1: Diagram of CMC fluid system filtrate loss

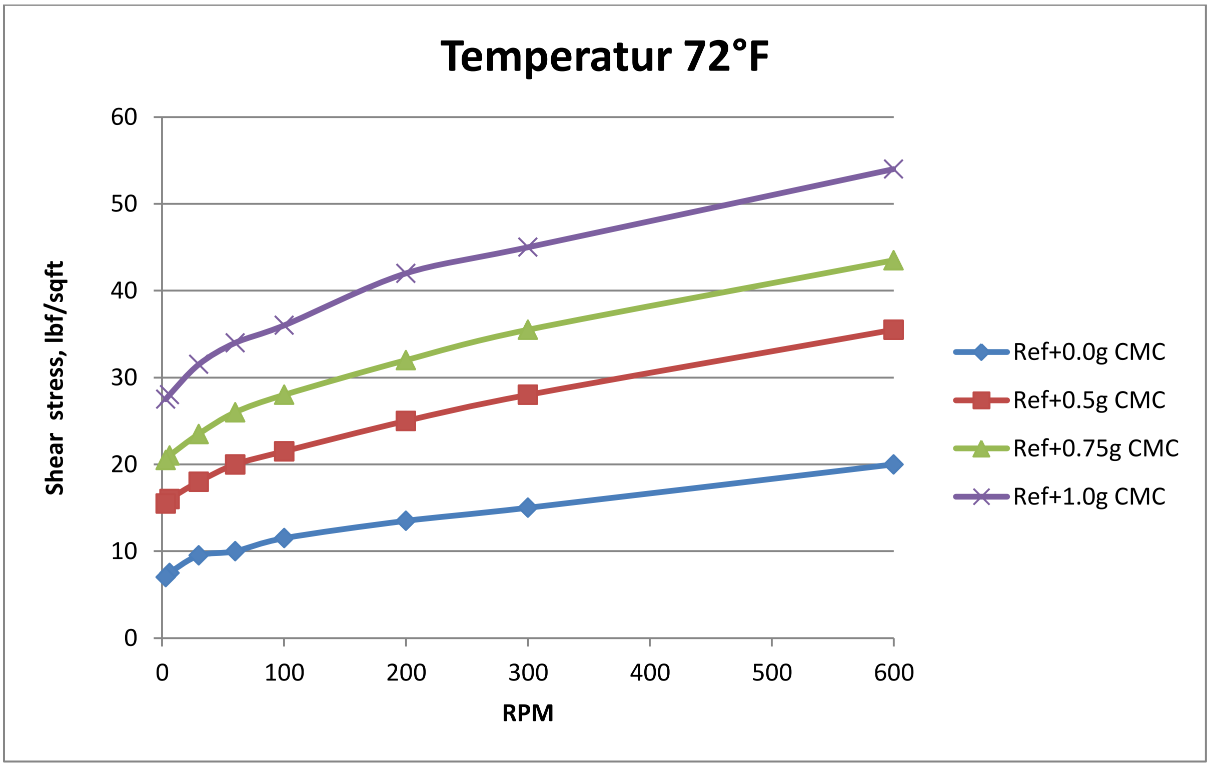


Figure 3.2: Rheology measurements for CMC drilling fluids

3.2 Effect of salt concentration (screening test)

To establish the right amount of salt to be added in the fluid system, different amounts of KCl was added to the reference fluid.

3.2.1 Description of KCl drilling fluid

For the KCl system three different test matrixes were prepared for testing.

1. 2,5g KCl
2. 5,0g KCl
3. 15,0g KCl

All fluids were prepared with new reference fluid based on polymer screening (see section 3.1.2) (500g H_2O + 0,5g CMC + 25g Bentonite) and with varied amount of nano silica.

The fluids were mixed in the order:

500g H_2O + Xg Nano +Yg KCl +0,5g CMC + 25g Bentonite

3.2.2 Results and analysis of KCl drilling fluid

The two fluids containing highest amount of KCl (5,0g and 15,0g) separated within 24 hours (see figure 3.3). This contributed to poor test results for the rheology and filtrate (see figure 3.4). The increase in filtrate loss and decrease in PV when increasing the amount of KCl indicate that KCl gives a more aggregated fluid. Reference fluid containing 15,0g KCl had an decrease for PV of 140% and an increase in filtration loss of 282,6% compared to reference fluid containing 2,5g. Increasing the concentration of KCl had a decreasing impact of rheology measures (see appendix B.3).

Test results for 5,0g and 15,0g KCl are listed in appendix B.1 and B.2, while results for 2,5g KCl are covered later in section 3.4.

Based on these results, 2,5g of KCl was selected for further testing in this thesis.

Figure 3.3: Separated 15,0g KCl drilling fluid

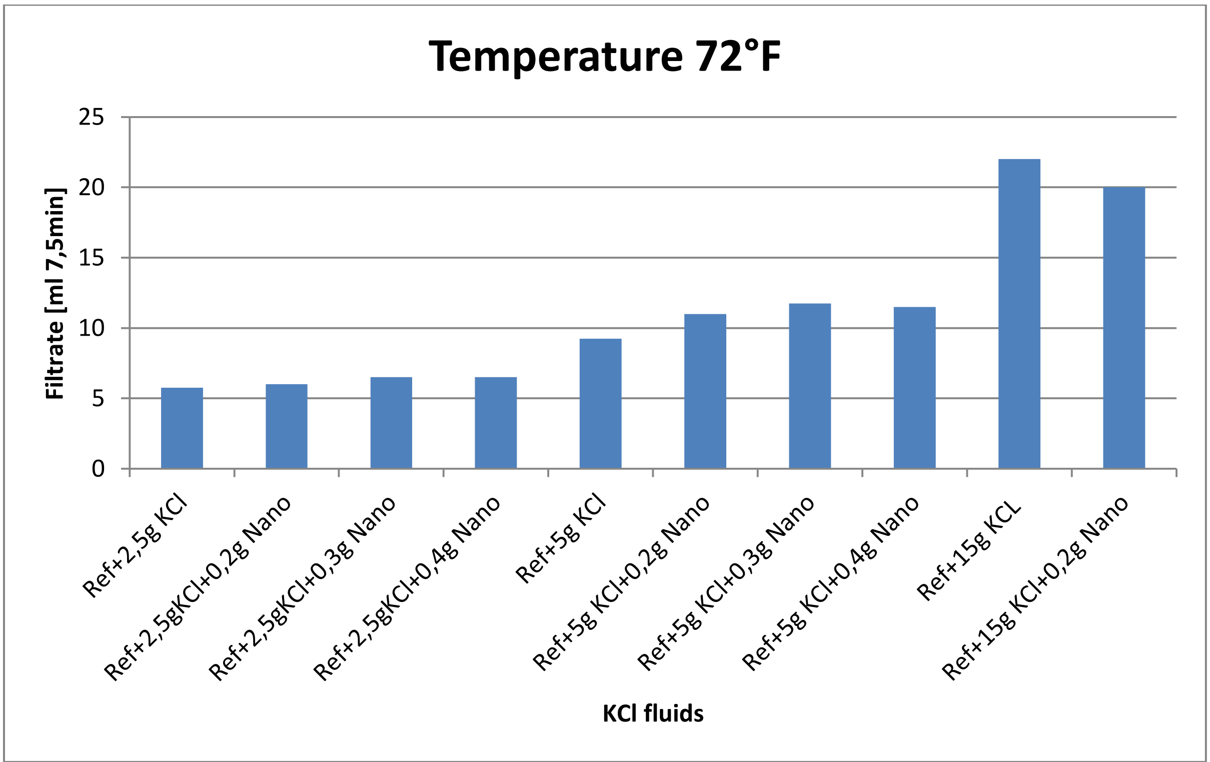


Figure 3.4: Diagram of KCl fluid system filtrate loss

3.3 Effect of nanoparticles in CMC polymer treated bentonite fluid

To evaluate the effect of nanoparticles in a polymer bentonite treated WBM, nano silica was added in different amounts to the CMC fluid system. Viscosity, filtrate and pH were measured to evaluate the effect of nanoparticles. The fluid system was also used to evaluate the effects temperature has on nanoparticles, and analysis of the results are covered in section 3.7.

3.3.1 Description of CMC drilling fluid containing nano silica

The drilling fluids that were prepared are shown in table 3.3. All were prepared with 500g H_2O and 25g bentonite. The amount of nano silica varied, as well as the process of adding it. For reference fluid CMC (500g H_2O + 25g bentonite + 0,5g CMC), the CMC was added ex-situ in bentonite fluid system to compare with fluid made in-situ from section 3.1.

Fluid 2 was made with just nano silica added, no CMC, to evaluate the effect gained by using nano silica. Fluids 3 and 4 contained 0,5g CMC and different amount of nano silica (0,5g and 1,0g).

Nano silica was added ex-situ (after the bentonite) for fluid 2, while for fluids 3 and 4 nano silica was added in-situ (before CMC and bentonite).

Table 3.3: Test matrix for nano silica in CMC fluid system

Test matrix for nano silica in CMC fluid system				
Additives	Ref. Fluid CMC	Fluid 2	Fluid 3	Fluid 4
Water (H_2O)	500g	500g	500g	500g
Bentonite	25g	25g	25g	25g
CMC	0,5g	0,0g	0,5g	0,5g
Nano silica	0,0g	0,5g	0,5g	1,0g

3.3.2 Results and analysis of CMC drilling fluid containing nano silica

The rheology, pH and filtration test were performed as described in section 3.1.2. The only difference is that the blending time was increased from two minutes to 10 minutes in order to assure that the nanoparticles were fully mixed. Results are listed in table 3.4.

Table 3.4: Results obtained from CMC fluid system containing Nano

Reference fluid CMC (500g H_2O + 25g bentonite + 0,5g CMC) (ex-situ)			
Rheology parameters	**Temperature**		
	72°F	**100°F**	**130°F**
PV [cP]	10,5	8,0	8,0
YS [lbf/100ft^2]	15,0	16,0	19,0
LSYS [lbf/100ft^2]	8,5	10,0	13,0
YS/PV [(lbf/100ft^2)/cP]	1,4	2,0	2,4
n	0,50	0,42	0,37
k [lbf*sec^n/100ft^2]	1,15	1,81	2,62
Filtration [ml]	4,5		
pH	9,55		
Reference fluid (without CMC)+ 0,5g Nano silica (ex-situ)			
PV [cP]	5,5	5,5	4,5
YS [lbf/100ft^2]	6,5	6,5	8,5
LSYS [lbf/100ft^2]	2,0	2,5	4,5
YS/PV [(lbf/100ft^2)/cP]	1,2	1,2	1,9
n	0,54	0,54	0,43
k [lbf*sec^n/100ft^2]	0,40	0,40	0,90
Filtration [ml]	7		
pH	9,40		
Reference fluid CMC + 0,5g Nano silica			
PV [cP]	9,0	8,0	6,0
YS [lbf/100ft^2]	11,0	11,5	14,0
LSYS [lbf/100ft^2]	4,5	5,0	6,5
YS/PV [(lbf/100ft^2)/cP]	1,2	1,4	2,3
n	0,54	0,50	0,38
k [lbf*sec^n/100ft^2]	0,71	0,90	1,90
Filtration [ml]	4,5		
pH	9,35		
Reference fluid CMC + 1,0g Nano silica			
PV [cP]	10,0	9,0	7,0
YS [lbf/100ft^2]	10,0	8,5	11,0
LSYS [lbf/100ft^2]	3,5	4,0	5,5
YS/PV [(lbf/100ft^2)/cP]	1,0	0,9	1,6
n	0,59	0,60	0,47
k [lbf*sec^n/100ft^2]	0,52	0,42	0,94
Filtration [ml]	5,25		
pH	9,15		

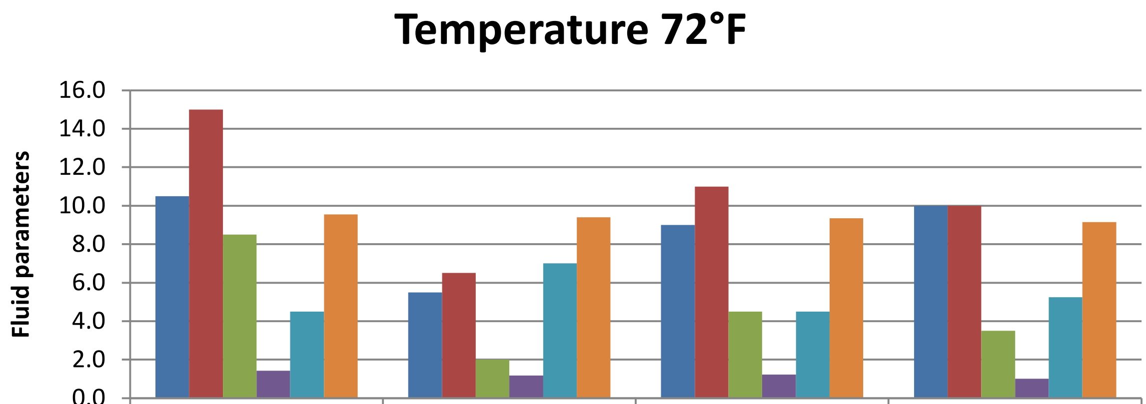
The results gained from the tests show that when using nano silica without polymer CMC the filtrate increases compared to fluid with CMC (see figure 3.5), but it is the same value as for reference fluid in section 3.1, containing nor CMC or nanoparticles. When using nano silica combined with CMC the filtrate loss stays at the same value as for the fluid used in the screen test containing just CMC (4,5ml). This indicates that CMC and nano silica together provide a low filtrate loss. Although test shows that for fluid 4, containing as much as 1,0g nano silica, the filtrate increases. Therefore nano silica will be added in lower concentrations.

When increasing the amount of nano silica from 0,5g to 1,0g power law parameters showed negative effects; n value had an increase while k had a decrease (see appendix C.1).

Nano silica caused a decrease in pH for the fluids.

The result showed that adding CMC in situ or ex-situ does not cause large differences in result (see appendix C.2). The filtrate loss stays the same (4,5ml) for both mixture procedures, but plastic viscosity increases when adding CMC ex-situ while YS decreases (See figure 3.6). Mixing CMC ex-situ had negative effects on power law parameters; n value had an increase while k had a decrease (compared to fluid mixed in-situ). Thus further work will mix polymer in-situ (before bentonite).

After analyzing both the fluid system with CMC (section 3.1) and nano silica as additives it is observed that temperature does not contribute to large differences (see section 3.7). Therefore further studies on higher temperatures (100°F and 130°F) were not performed for the remaining drilling fluids.



	Ref (ex)	Ref(-CMC)+0,5g Nano	Ref+0,5g Nano	Ref+1,0g Nano
PV	10.5	5.5	9.0	10.0
YS	15.0	6.5	11.0	10.0
LSYS	8.5	2.0	4.5	3.5
YS/PV	1.4	1.2	1.2	1.0
Filtrate	4.5	7	4.5	5.25
pH	9.55	9.4	9.35	9.15

Figure 3.5: Diagram of results gained from experiment at 72°F

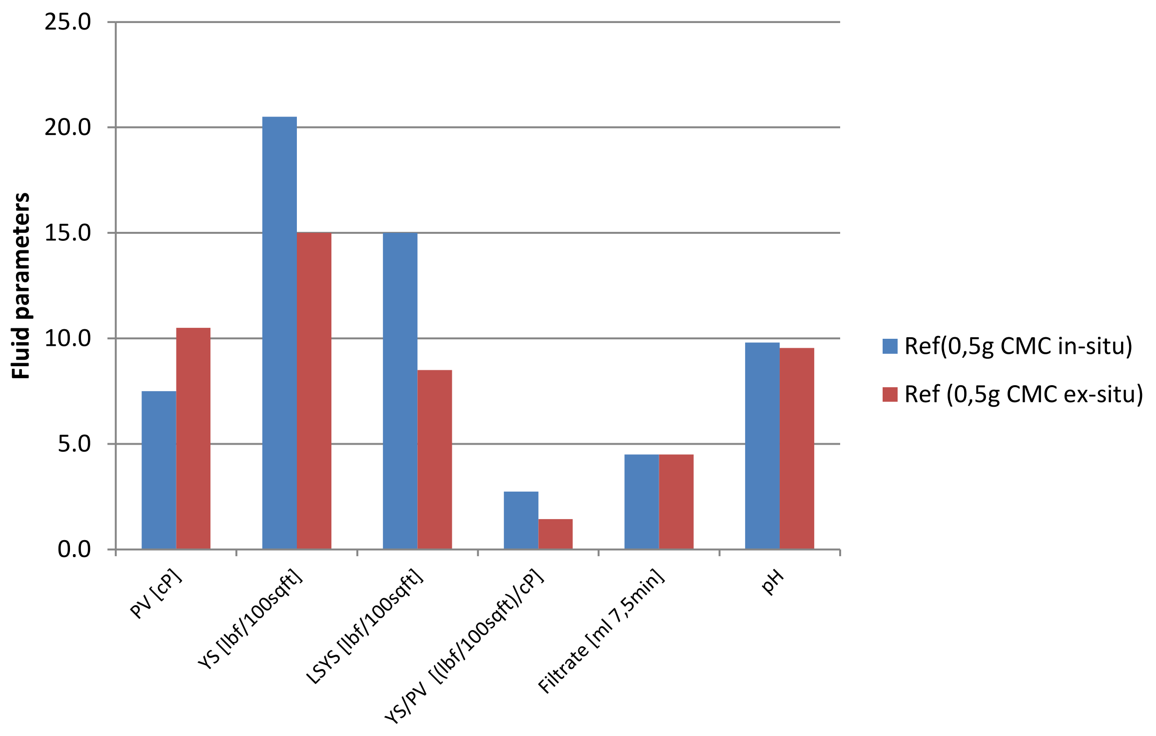


Figure 3.6: Comparison of different mixing procedures (in-situ and ex-situ) at 72°F

3.4 Effect of salt and nanoparticles in bentonite WBM with CMC

Three different fluid systems containing salt and nanoparticles in bentonite CMC treated water based fluid were prepared;

1. KCl fluid system
2. NaCl fluid system
3. KCl/NaCl fluid system

This was done in order to find the effect of different types of salt in water based drilling fluids, and evaluate the effect of nanoparticles combined with salt. All fluids have a reference fluid (Reference fluid salt) containing 500g H_2O, 0,5g CMC, 25g Bentonite and 2,5g salt (except KCl/NaCl fluid system which contains 5,0g salt).

3.4.1 Description of drilling fluid containing KCl and nano silica

A fluid system containing KCl was prepared and added nano silica in order to evaluate the properties gained from nanoparticles combined with KCl. The fluids are listed in table 3.5.

The fluids were mixed in the order:

500g H_2O + Xg Nano + 2,5g KCl + 0,5g CMC + 25g Bentonite

Table 3.5: Test matrix for nano silica in KCl fluid system

Test matrix for nano silica in KCl fluid system				
Additives	Ref. Fluid KCl	Fluid 2	Fluid 3	Fluid 4
Water (H_2O)	500g	500g	500g	500g
Bentonite	25g	25g	25g	25g
CMC	0,5g	0,5g	0,5g	0,5g
KCl	2,5g	2,5g	2,5g	2,5g
Nano silica	0,0g	0,2g	0,3g	0,4g

3.4.2 Results and analysis for KCl fluid system

The results gained from viscosity, pH and filtrate test are shown in table 3.6. Tests were performed at 72°F.

Table 3.6: Results obtained from KCl fluid system containing nano silica

Rheology parameters	Reference Fluid KCl	Fluid 2 (0,2g Nano)	Fluid 3 (0,3g Nano)	Fluid 4 (0,4g Nano)
PV [cP]	6,0	5,5	5,0	4,0
YS [$lbf/100ft^2$]	5,0	5,0	4,0	4,0
LSYS [$lbf/100ft^2$]	1,0	1,5	0,5	0,0
YS/PV [($lbf/100ft^2$)/cP]	0,8	0,9	0,8	1,0
n	0,63	0,61	0,64	0,59
k [$lbf*sec^n/100ft^2$]	0,22	0,24	0,20	0,21
Filtration [ml]	5,75	6	6,5	6,5
pH	9,25	9,2	9,2	9,15

It is observed that increasing the amount of nano silica in KCl fluids increases filtrate loss, while it decreases plastic viscosity and yield stress (see figure 3.7), effecting the fluids from dispersed towards a more aggregated system. Although for fluid 3 and 4 containing 0,3g and 0,4g nano silica the filtrate loss stays stable at 6,5 ml. Results from test performed with 5,0g KCl (see section 3.2) also showed an increase in filtrate loss when increasing nano silica (listed in appendix B.1).

Increasing the concentration of nano silica causes a decrease in the rheology measurements from Fann viscometer (see appendix D.1). A decrease of pH is also observed when increasing concentration.

Consistency index k increased and flow behavior index n decreased when adding nano silica to the reference fluid, improving the fluids hole cleaning capacity (see figure 3.8). This is contrary from the observed effect of nano silica in bentonite WBM containing CMC; here nano silica had negative effects for power law parameters. This may be because a higher concentration of nano silica was used for CMC fluid (0,5g and 1,0g).

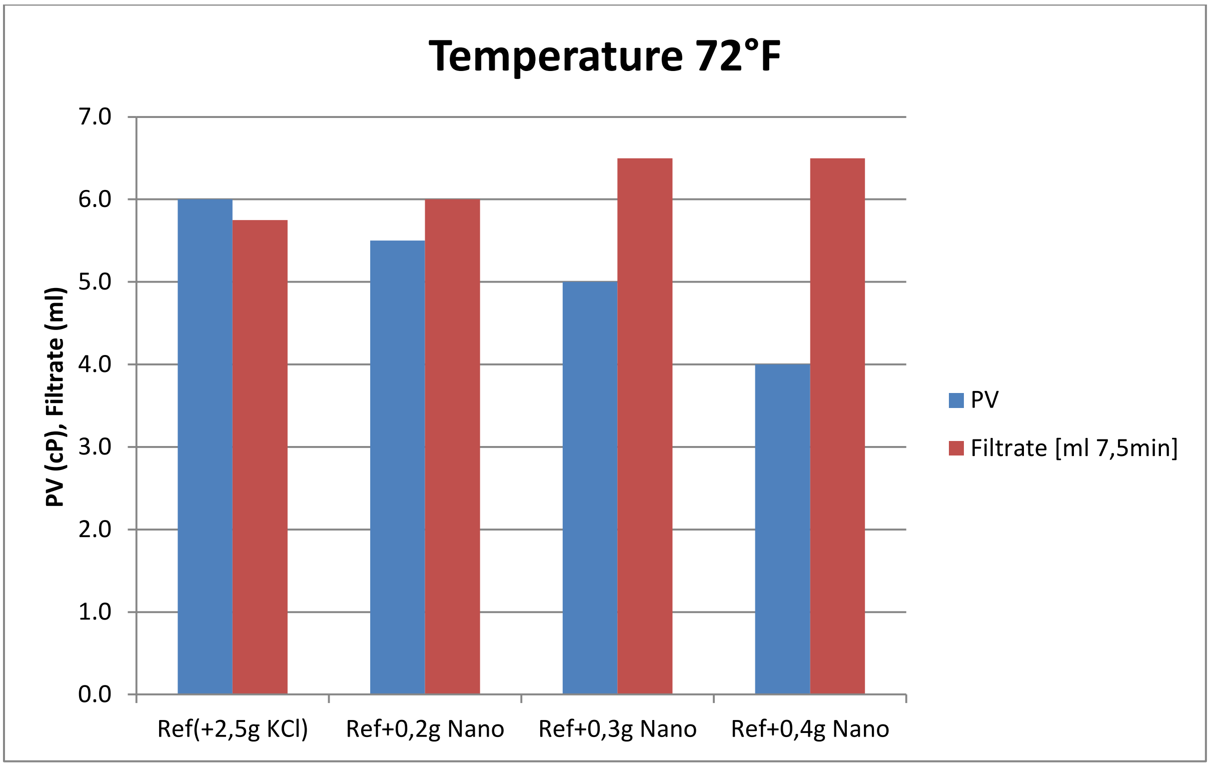


Figure 3.7: Diagram of PV and filtrate loss for the KCl fluid system

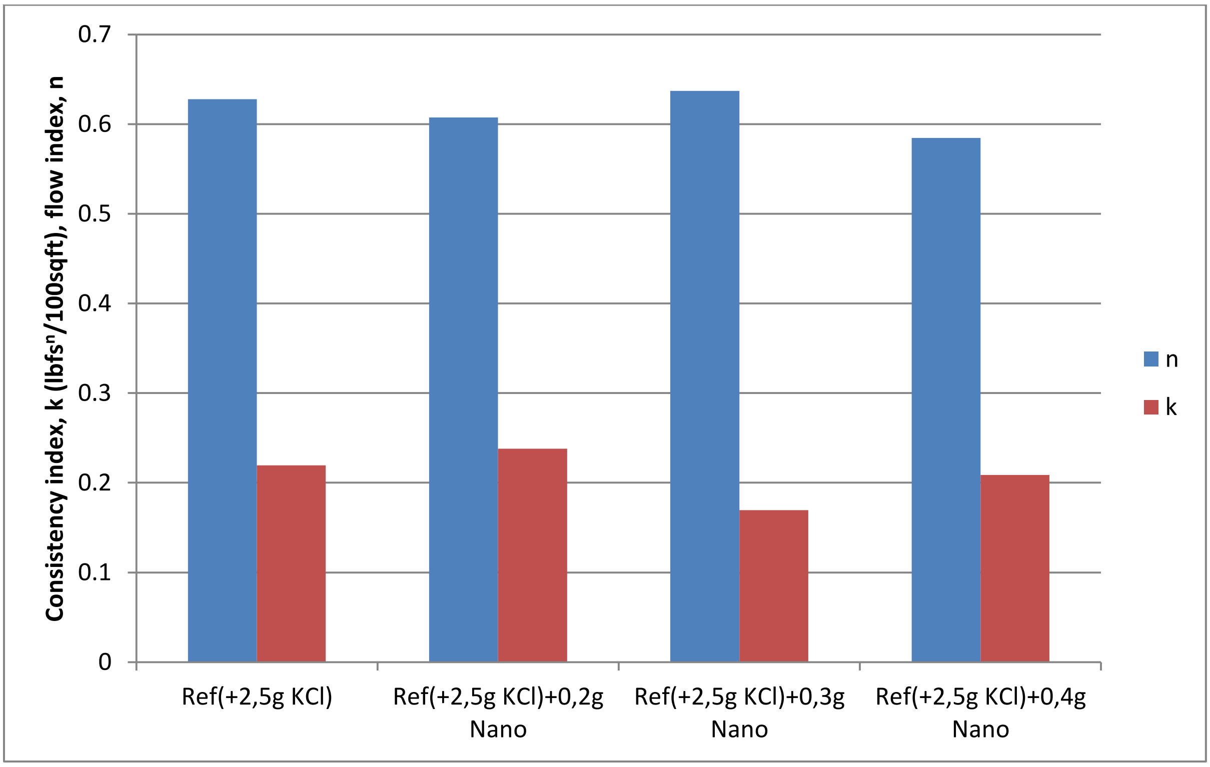


Figure 3.8: Power law parameters for KCl WBM system

3.4.3 Description of drilling fluid containing NaCl and nano silica

A fluid system containing NaCl was prepared and added nano silica in order to evaluate the properties gained from nanoparticles combined with NaCl. The fluids are listed in table 3.7.

The fluids were mixed in the order:

500g H_2O + Xg Nano + 2,5g NaCl + 0,5g CMC + 25g Bentonite

Table 3.7: Test matrix for nano silica in NaCl fluid system

Test matrix for nano silica in NaCl fluid system				
Additives	Reference Fluid NaCl	Fluid 2	Fluid 3	Fluid 4
Water (H_2O)	500g	500g	500g	500g
Bentonite	25g	25g	25g	25g
CMC	0,5g	0,5g	0,5g	0,5g
NaCl	2,5g	2,5g	2,5g	2,5g
Nano silica	0,0g	0,2g	0,3g	0,4g

3.4.4 Results and analysis for NaCl drilling fluid system

The results gained from viscosity, pH and filtrate test are shown in table 3.8. Tests were performed at 72°F.

Table 3.8: Results obtained from NaCl fluid system containing Nano

Rheology parameters	**Reference Fluid NaCl**	**Fluid 2 (0,2g Nano)**	**Fluid 3 (0,3g Nano)**	**Fluid 4 (0,4g Nano)**
PV [cP]	11,0	8,0	9,0	8,0
YS [lbf/100ft^2]	29,0	28,0	24,0	24,0
LSYS [lbf/100ft^2]	16,0	16,0	12,0	15,0
YS/PV [(lbf/100ft^2)/cP]	2,6	3,5	2,7	3,0
n	0,35	0,29	0,35	0,32
k [lbf*sec^n/100ft^2]	4,50	5,93	3,77	4,30
Filtration [ml]	5	5	4,8	5
pH	9,15	9,1	9,15	9,15

The result show that filtration loss stays sufficiently low for all amounts of nano silica added, with its minimum level at 0,3g nano added (4,8ml). Seen from the results it can also be concluded that using nano silica in NaCl fluids does not increase the filtration loss, as it did for the KCl system, but stays stable. Measures of pH also show stability.

NaCl fluid system shows a massive impact on rheology measurements compared to KCl fluids (see appendix D.2). The NaCl fluids exhibit a higher shear stress at given shear rates than the KCl fluids. The effect of nano silica is the same as for the KCl fluid system; the rheology measurements decreases when increasing amount on nano silica.

The NaCl fluid systems have the same tendency for parameters n and k as the KCl system; consistency index k increase and flow behavior index n decrease when adding nano silica to the fluid. But also for the NaCl fluids it is observed that when increasing the concentration of nano silica, n increases and k decreases. Like the 0,3g nano silica fluid in the KCl fluid system there is an unconformity for fluid 3 containing 0,3g nano in the NaCl fluid system; flow behavior index n is at its highest while flow consistency index k is at its lowest.

Furthermore, nano silica in NaCl fluids shows an improved capacity for hole cleaning compared to nano silica in KCl fluids, since n values are lower and k values are higher than for the KCl fluids (see appendix D.2).

Compared with the KCl reference fluid (without nano silica), the NaCl reference fluid (without nano silica) gives a smaller filtration loss, while PV and YS are higher when using NaCl (see figure 3.9). Yield point increases from 5 to 29 bf/100ft^2 when using NaCl instead of KCl, indicating that NaCl have a more tendency to flocculate the particles than KCl.

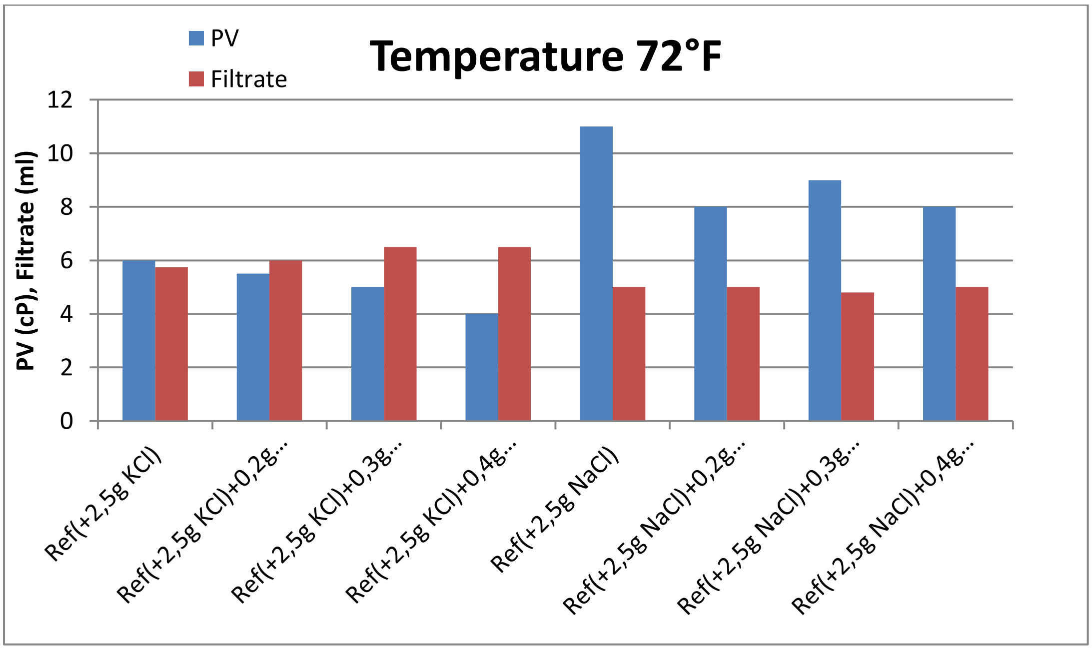


Figure 3.9: Comparison of PV and filtrate loss for the KCl (the first four) and NaCl (the last four) fluid systems

3.4.5 Description of drilling fluid containing KCl, NaCl and nano silica

When combining the two different salt 2,5g of each were used in the reference fluid. Different amounts of nano silica were added in order to evaluate the effects of nano silica in salt treated water based fluids (see table 3.9).

The fluids were mixed in the order:

500g H_2O + Xg Nano + 2,5g Salt + 0,5g CMC + 25g Bentonite

Table 3.9: Test matrix for nano silica in KCl/NaCl fluid system

Test matrix for nano silica in KCl/NaCl fluid system				
Additives	Reference Fluid KCl/NaCl	Fluid 2	Fluid 3	Fluid 4
Water (H_2O)	500g	500g	500g	500g
Bentonite	25g	25g	25g	25g
CMC	0,5g	0,5g	0,5g	0,5g
KCl	2,5g	2,5g	2,5g	2,5g
NaCl	2,5g	2,5g	2,5g	2,5g
Nano silica	0,0g	0,2g	0,3g	0,4g

3.4.6 Results and analysis for KCl/NaCl drilling fluid system

The results gained from viscosity, pH and filtrate test are shown in table 3.10. Tests were performed at 72°F.

Table 3.10: Results obtained from KCl/NaCl fluid system containing nano silica

Rheology parameters	Reference Fluid KCl/NaCl	Fluid 2 (0,2g Nano)	Fluid 3 (0,3g Nano)	Fluid 4 (0,4g Nano)
PV [cP]	7,0	4,5	5,0	7,0
YS [lbf/100ft^2]	8,0	9,5	5,0	11,0
LSYS [lbf/100ft^2]	5,0	3,5	2,0	6,5
YS/PV [(lbf/100ft^2)/cP]	1,1	2,1	1,0	1,6
n	0,55	0,40	0,59	0,47
k [lbf*sec^n/100ft^2]	0,48	1,14	0,26	0,94
Filtration [ml]	8,25	8,75	6,5	8,5
pH	9,05	9,1	8,95	9

Tests performed on the KCl/NaCl fluid system gave interesting results. The filtrate has its minimum loss for fluid 3 (0,3g nano silica), as well as increasing the PV (compared to fluid 2) and decreasing the YS (see figure 3.10). This may indicate that 0,3g nano silica provides a dispersed deflocculated system. Result gained from NaCl fluid system with nanoparticles also gave best filtration result for 0,3g nano silica. Therefore, this fluid system will be further analyzed and tested in the thesis.

Negative effects observed for fluid 3 are the same as seen in both previous salt drilling fluid systems. The tendency for values n and k are positive when adding nanoparticles to the fluid, but increasing the concentration of nano silica increases n and decreases k, and fluid 3 containing 0,3g nano silica gives the most negative values for n and k. Though this is negative for fluid 3, it is an interesting result since it is seen for all salt fluid systems (see appendix D.2)

Compared to the two fluid systems containing just one type of salt (KCl system and NaCl system), the fluid system containing both types gives a higher filtrate loss. This is probably due to the fact that the concentration of salt is higher for the KCl/NaCl system than for the systems containing just one type of salt, making the fluid more dispersed. Plastic viscosity and yield strength are higher than the KCl system, while it is lower than the NaCl system (see appendix D.2).

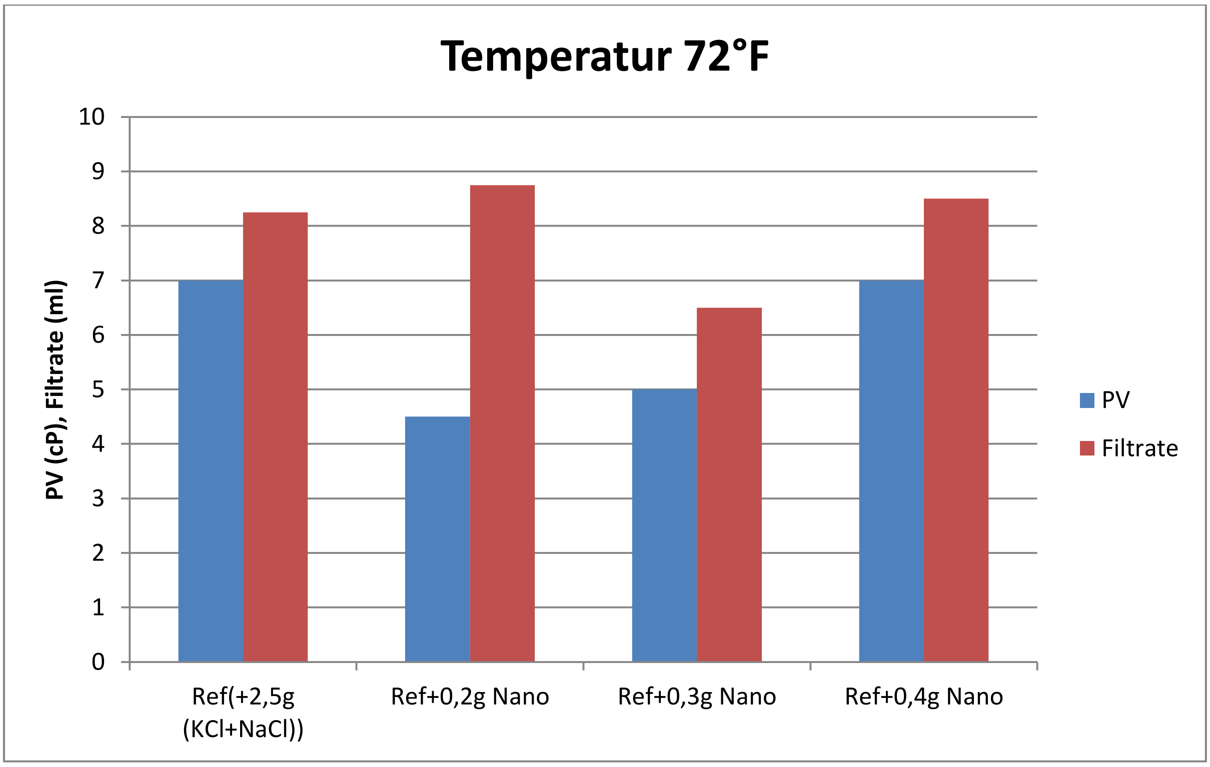


Figure 3.10: Diagram of PV and filtrate loss for KCl/NaCl fluid system

3.5 Effect of Polymer Type in bentonite fluid

In order to compare effects gained from different types of polymer in bentonite treated water based drilling fluid, a PAC fluid system was prepared and tested.

3.5.1 Description of drilling fluid containing PAC

A fluid system containing PAC was prepared in order to evaluate the properties gained from using PAC as the additive polymer instead of CMC (see table 3.11). The reference fluid is the same as the one used in section 3.1.

The fluids were mixed in the order:

500g H_2O + Xg PAC + 25g Bentonite

Table 3.11: Test matrix for PAC fluid system

Test matrix for PAC fluid system				
Additives	Reference Fluid	Fluid 2	Fluid 3	Fluid 4
Water (H_2O)	500g	500g	500g	500g
Bentonite	25g	25g	25g	25g
PAC	0,0g	0,5g	0,75g	1,0g

3.5.2 Results and analysis for PAC drilling fluid system

The results gained from viscosity, pH and filtrate test are shown in table 3.12. Tests were performed at 72°F.

Table 3.12: Results obtained from PAC fluid system

Rheology parameters	Reference Fluid	Fluid 2 (0,5g PAC)	Fluid 3 (0,75g PAC)	Fluid 4 (1,0g PAC)
PV [cP]	5,0	8,0	8,5	11,0
YS [lbf/100ft^2]	10,0	7,0	8,0	8,0
LSYS [lbf/100ft^2]	6,5	2,5	2,0	2,5
YS/PV [(lbf/100ft^2)/cP]	2,0	0,9	0,9	0,7
n	0,42	0,62	0,60	0,66
k [lbf*sec^n/100ft^2]	1,13	0,32	0,40	0,31
Filtration [ml]	7	4	4	3,5
pH	9,95	9,75	9,85	9,75

The results show that like the CMC system, the PAC fluid system have an increase in plastic viscosity when increasing the concentration of PAC in the fluid, while the filtrate loss decreases, making the fluid move from aggregated towards dispersed. The yield point increases as well, making the fluid more flocculated. The PAC fluids exhibit a lower shear stress at given shear rates than the CMC fluids (see appendix E.1).

A positive effect of using PAC instead of CMC is that the filtration loss is smaller (see figure 3.11). But PAC does not contribute to a better hole cleaning capacity as CMC, since parameters n and k don't have the same tendency as CMC fluid system, and the overall values for n and k are not as good as the CMC values (see figures 3.12 and 3.13).

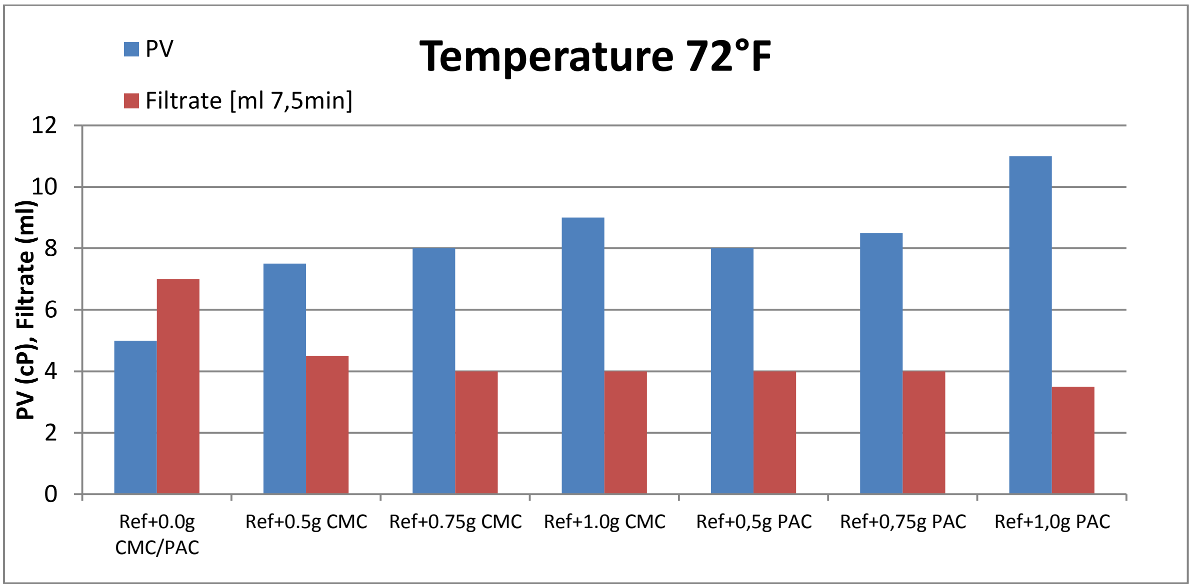


Figure 3.11: PV and filtrate measurements of CMC and PAC fluid systems

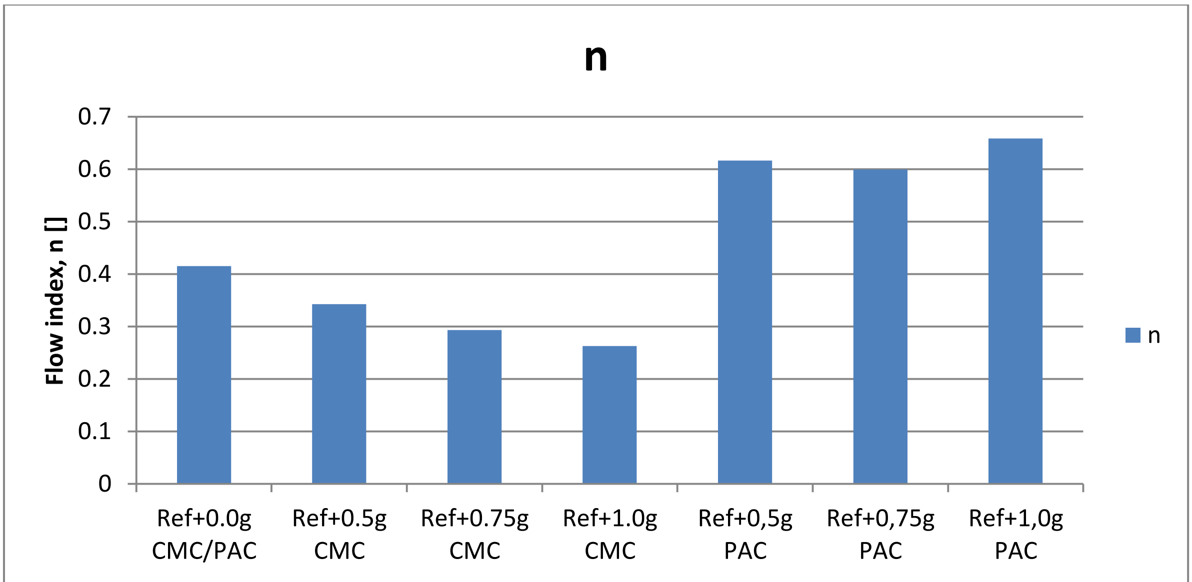


Figure 3.12: Comparison behaviour index for polymer fluid systems

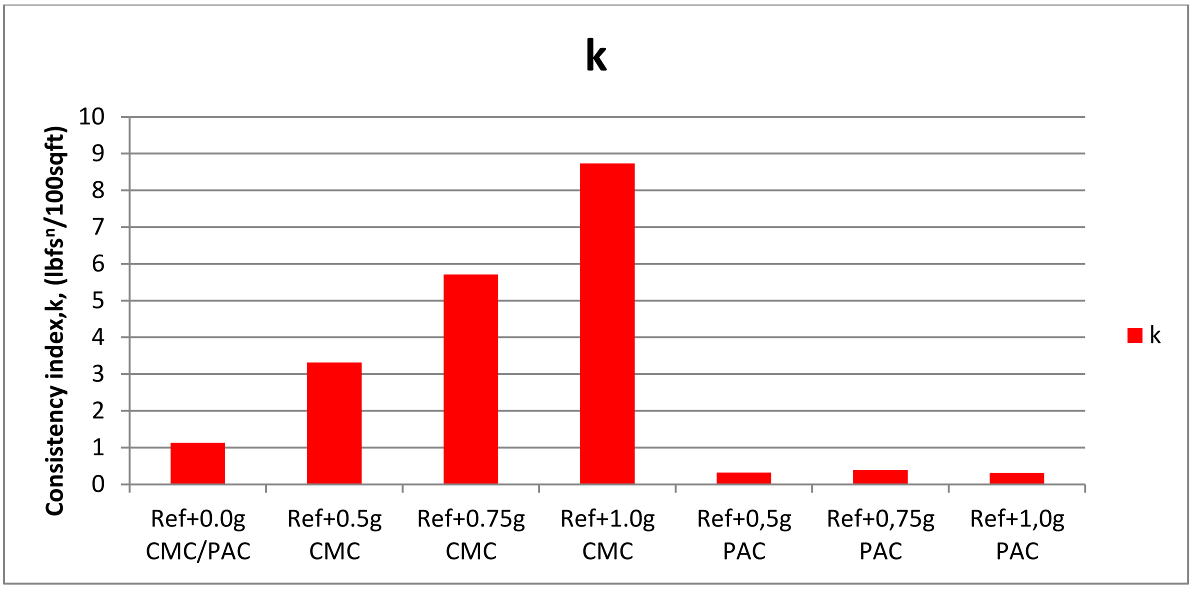


Figure 3.13: Comparison consistency index for polymer fluid systems

3.6 Effect of nano silica with different polymers in bentonite fluid

Two different fluid systems were prepared for testing the effect of nano silica combined with polymer in drilling fluid. First a fluid system containing PAC and nano silica was tested in order to find the effects gained from combining nanoparticles with PAC. Then a system fluid containing both CMC and PAC was prepared to analyze the effects given by adding nano silica in a combined polymer fluid.

3.6.1 Description of drilling fluid containing PAC and nano silica

To study the difference in fluid properties given by the two different polymers combined with nano silica, a fluid system consisting of PAC and nano silica were made (see table 3.13). The reference fluid was made ex-situ to find evaluate the effect in the two ways of making it.

Fluid 1 (reference fluid PAC):

500g H_2O + 25g Bentonite + 0,5g PAC

Fluids 2,3 and 4:

500g H_2O + Xg Nano + 0,5g PAC + 25g Bentonite

Table 3.13: Test matrix for nano silica in PAC fluid system

Test matrix for nano silica in PAC fluid system				
Additives	Reference Fluid PAC	Fluid 2	Fluid 3	Fluid 4
Water (H_2O)	500g	500g	500g	500g
Bentonite	25g	25g	25g	25g
PAC	0,5g	0,5g	0,5g	0,5g
Nano silica	0,0g	0,2g	0,3g	0,4g

3.6.2 Results and analysis for PAC fluid system containing nano silica

The results gained from viscosity, pH and filtrate test are shown in table 3.14. Tests were performed at 72°F.

Table 3.14: Results obtained from PAC fluid containing nano silica

Rheology parameters	Reference Fluid PAC	Fluid 2 (0,2g Nano)	Fluid 3 (0,3g Nano)	Fluid 4 (0,4g Nano)
PV [cP]	8,5	5,5	6,0	6,5
YS [lbf/100ft^2]	5,0	10,0	11,0	10,5
LSYS [lbf/100ft^2]	2,0	4,0	4,5	5,5
YS/PV [(lbf/100ft^2)/cP]	0,6	1,8	1,8	1,6
n	0,70	0,44	0,44	0,47
k [lbf*sec^n/100ft^2]	0,17	1,01	1,12	0,93
Filtration [ml]	4	4,25	4,9	4,25
pH	9,65	9,75	9,7	9,65

After analyzing the results gained from the test it is seen that the procedure of mixing the fluid (PAC in- situ or ex-situ) does not contribute to large differences in results (see appendix E.2). Mixing PAC ex-situ had negative effects on power law parameters; n value had an increase while k had a decrease (compared to fluid mixed in-situ). This is similar to the results shown for CMC.

The adding of nano silica provides a higher filtrate loss which increases as the concentration of nano silica increases. The filtration loss is highest when using 0,3g nano silica, before it decreases when using 0,4g nano silica. The PV decreases when first adding nano silica to the fluid, before it starts to increase when increasing the concentration of nano silica (see figure 3.14). Rheology measures shows that there is little effect when increasing concentration of nano silica to reference fluid, but a slight increase can be seen from the rheology curves (see appendix E.3).

Power law parameters have a positive tendency when increasing the amount of nano silica, but for the highest amount (0,4g), the tendency shifts, and n increases while k decreases. This indicates that 0,4g might be a too high amount of nano silica in PAC treated bentonite fluids (see figure 3.15). Increasing the concentration of nano silica decreases the pH of the fluids.

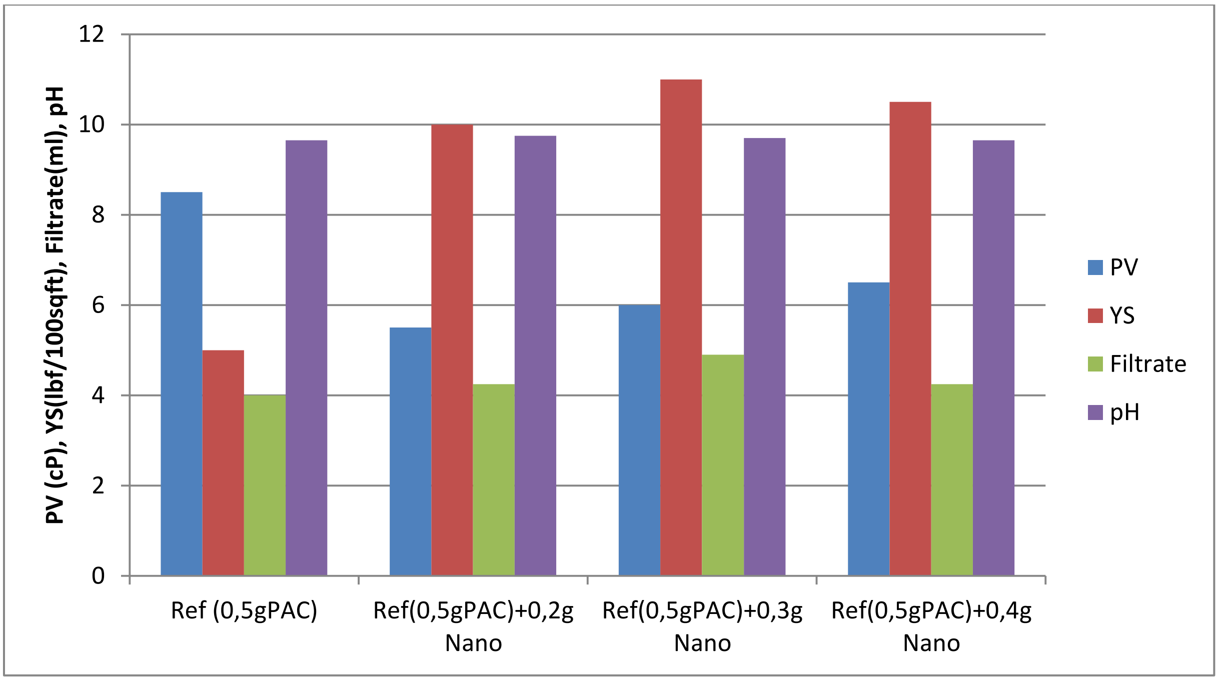


Figure 3.14: Results obtained from PAC system containing nano

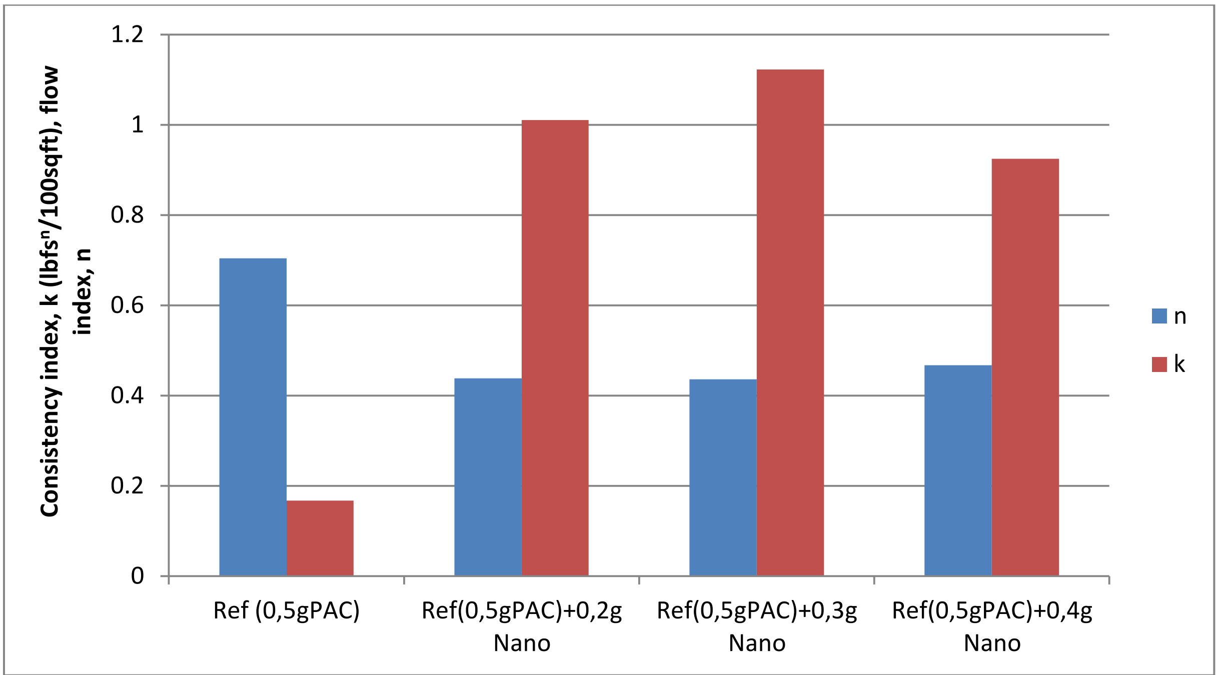


Figure 3.15: Power law parameters for PAC fluid system containing nano silica

3.6.3 Description of CMC/PAC drilling fluid system containing nano silica

A fluid system containing both CMC and PAC was added nano silica in order to evaluate the effects given by nano silica in a combined polymer fluid (see table 3.15).

The fluids were mixed in the order:

500g H_2O + Xg Nano + 0,25g CMC + 0,25g PAC + 25g Bentonite

Table 3.15: Test matrix for nano silica in CMC/PAC fluid system

Test matrix for nano silica in CMC/PAC fluid system				
Additives	Reference Fluid CMC/PAC	Fluid 2	Fluid 3	Fluid 4
Water (H_2O)	500g	500g	500g	500g
Bentonite	25g	25g	25g	25g
CMC	0,25g	0,25g	0,25g	0,25g
PAC	0,25g	0,25g	0,25g	0,25g
Nano silica	0,0g	0,2g	0,3g	0,4g

3.6.4 Results and analysis for CMC/PAC fluid system containing nano silica

The results gained from viscosity, pH and filtrate test are shown in table 3.16. Tests were performed at 72°F.

Table 3.16: Results obtained from CMC/PAC fluid system containing Nano

Rheology parameters	**Reference Fluid CMC/PAC**	**Fluid 2 (0,2g Nano)**	**Fluid 3 (0,3g Nano)**	**Fluid 4 (0,4g Nano)**
PV [cP]	9,0	9,5	9,0	8,0
YS [lbf/100ft^2]	9,5	8,5	9,0	11,0
LSYS [lbf/100ft^2]	3,5	3,5	5,5	6,5
YS/PV [(lbf/100ft^2)/cP]	1,1	0,9	1,0	1,4
n	0,57	0,61	0,60	0,51
k [lbf*sec^n/100ft^2]	0,52	0,40	0,50	0,81
Filtration [ml]	4,25	4	4	4,4
pH	9,8	9,75	9,8	9,65

Results shows that using CMC and PAC combined in fluid without nano silica does not contribute to large differences for rheology measures compared to PAC fluid system (see appendix E.4). When increasing the concentration of nano silica PV decreases while YS and filtration increases, resulting in a more aggregated flocculated system.

When comparing the fluids containing nano silica, it is observed that using CMC combined with PAC gives larger PV than PAC fluid system (see figure 3.16).

From figure 3.17 it is observed that the combined polymer fluid system (CMC+PAC) does not contribute to better hole cleaning capacity than fluid system consisting of just PAC as polymer, since flow behavior index are less for PAC fluids, and consistency index are higher.

When comparing reference fluid for the three polymer systems (CMC, PAC and CMC/PAC), it is seen from rheology measures that PAC reference fluid provides the lowest shear stress at given shear rates while CMC gives the highest. There are little differences in rheology parameters, but CMC fluid provides the highest YS, filtrate loss and consistency index, k (see appendix E.5).

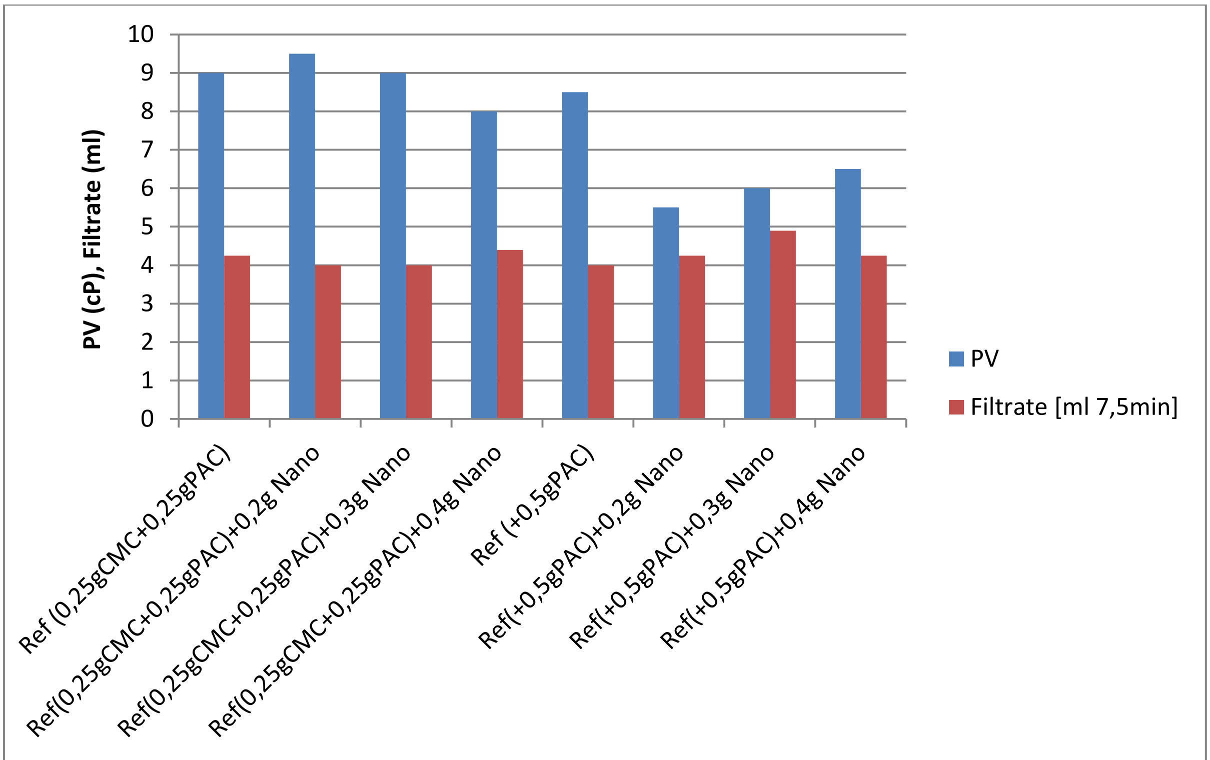


Figure 3.16: Comparison of CMC/PAC and PAC fluid system

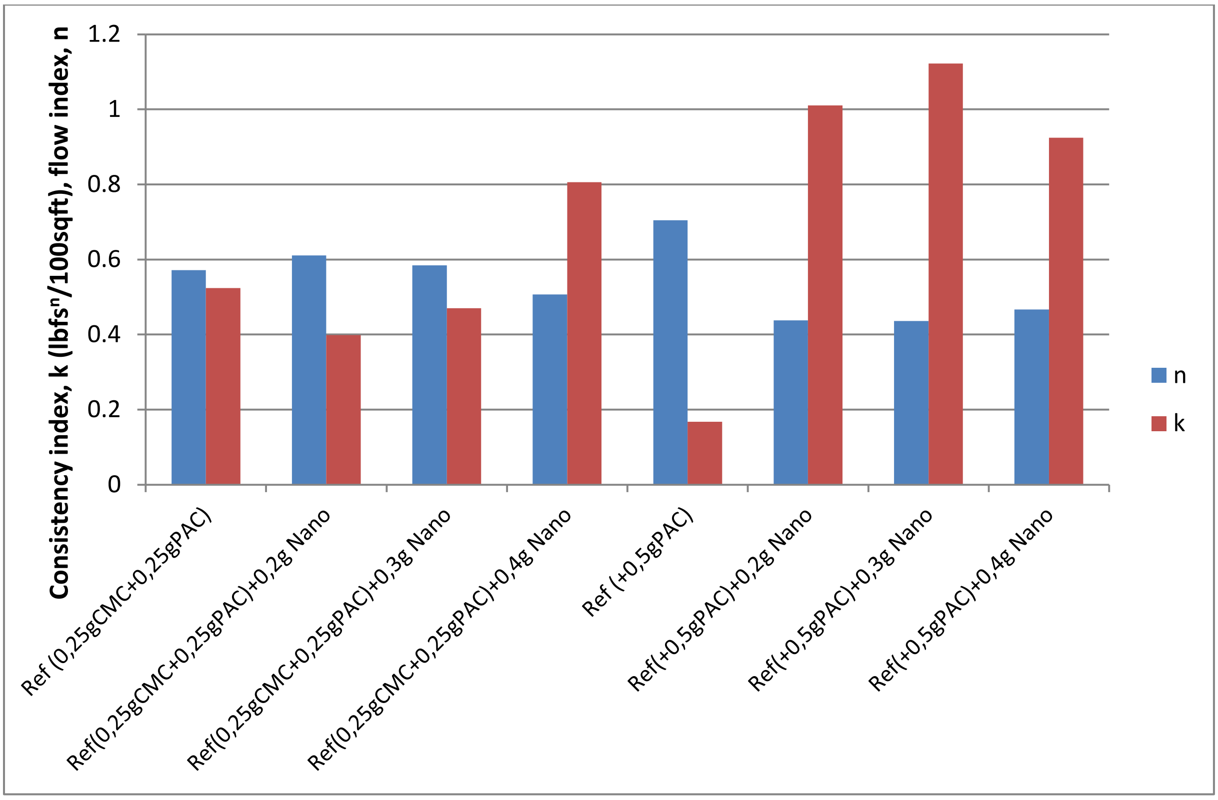


Figure 3.17: Power law parameters for polymer fluids containing nano silica

3.7 Effect of temperature on polymer treated WBM with nano silica

Fluid system from section 3.3 was used to determine the effect temperature has on nanoparticles in water based drilling fluids. Fluids 3 and 4 were measured at temperatures 70°F, 100°F and 130°F. Descriptions of fluids are listed in table 3.17.

Table 3.17: Test matrix for nano silica in CMC fluid system

Test matrix for nano silica in CMC fluid system				
Additives	Reference Fluid	Fluid 2	Fluid 3	Fluid 4
Water (H_2O)	500g	500g	500g	500g
Bentonite	25g	25g	25g	25g
CMC	0,5g	0,0g	0,5g	0,5g
Nano silica	0,0g	0,5g	0,5g	1,0g

3.7.1 Results and analysis

Figure 3.18 show that there are no large differences in rheology measures for the different temperatures. Figure 3.19 show that PV decreases with the temperature for both fluids, while

YS increases. The only unconformity is seen for fluid 4 at 130°F, here YS is at its highest (11 lbf/100ft^2).

Figure 3.20 shows power law parameters n and k. When increasing temperature, n decreases while k increases, improving the fluids capacity for proper hole cleaning. For fluid 3 this behavior is consistent. But for fluid 4 containing a higher amount of nanoparticles the results are not as consistent. Figure 3.21 shows % deviation when increasing temperature. Consistency index increases as much as 167% when increasing the temperature to 130°F.

When increasing the amount of nano silica to the system, the parameters n and k became more stable (see figure 3.21). This indicates that nano silica is able to retain fluid properties during temperature changes.

Overall results show that temperature causes an effect in polymer treated WBM containing nano silica, but the effects observed are not massive.

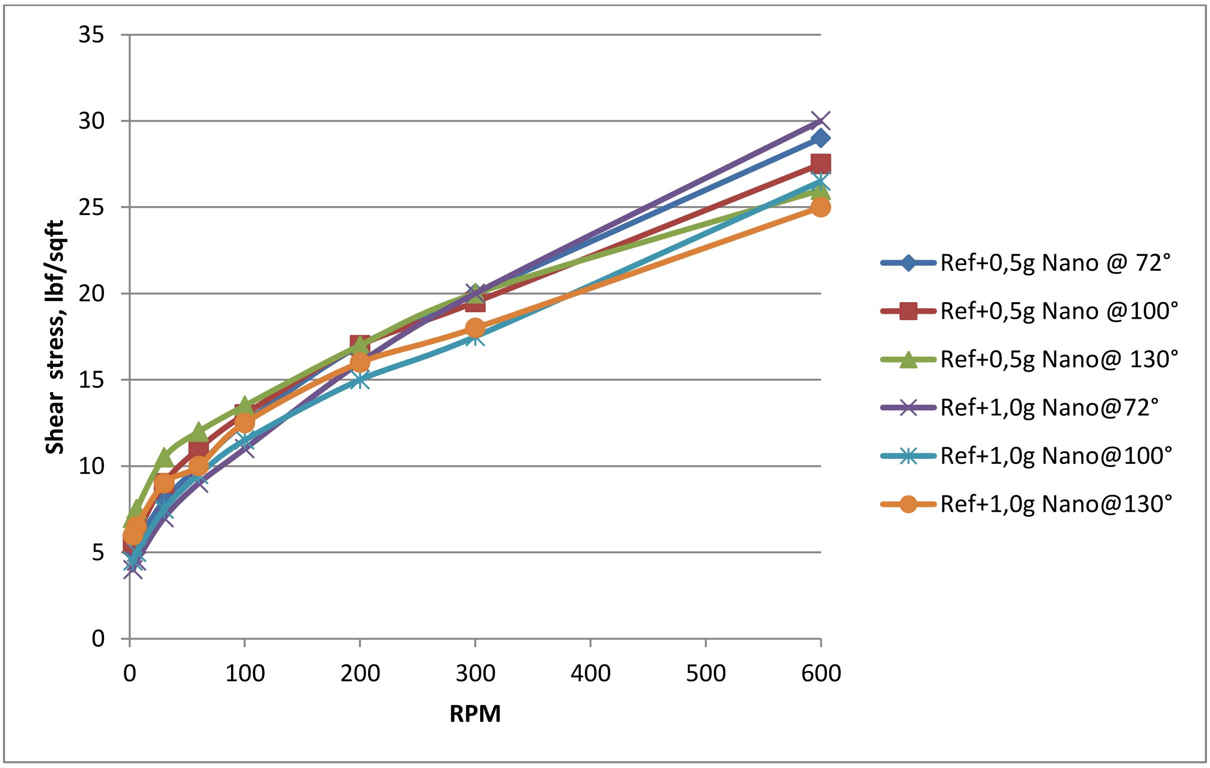
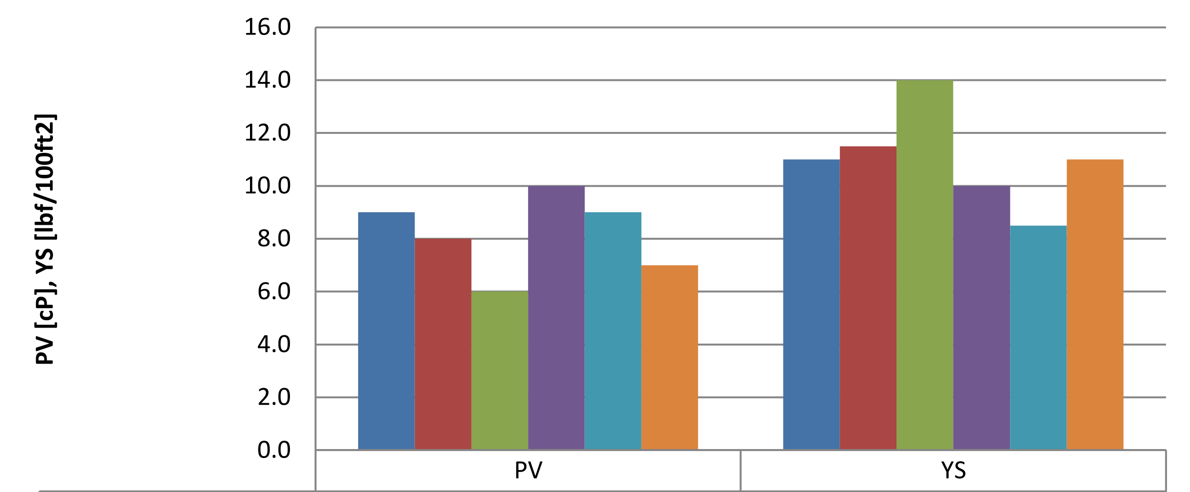


Figure 3.18: Viscosity measures for nano silica fluids at different temperatures



	PV	YS
Ref+0,5g Nano @ 72°	9.0	11.0
Ref+0,5g Nano @100°	8.0	11.5
Ref+0,5g Nano@ 130°	6.0	14.0
Ref+1,0g Nano@72°	10.0	10.0
Ref+1,0g Nano@100°	9.0	8.5
Ref+1,0g Nano@130°	7.0	11.0

Figure 3.19: Changes in PV and YS at different temperatures

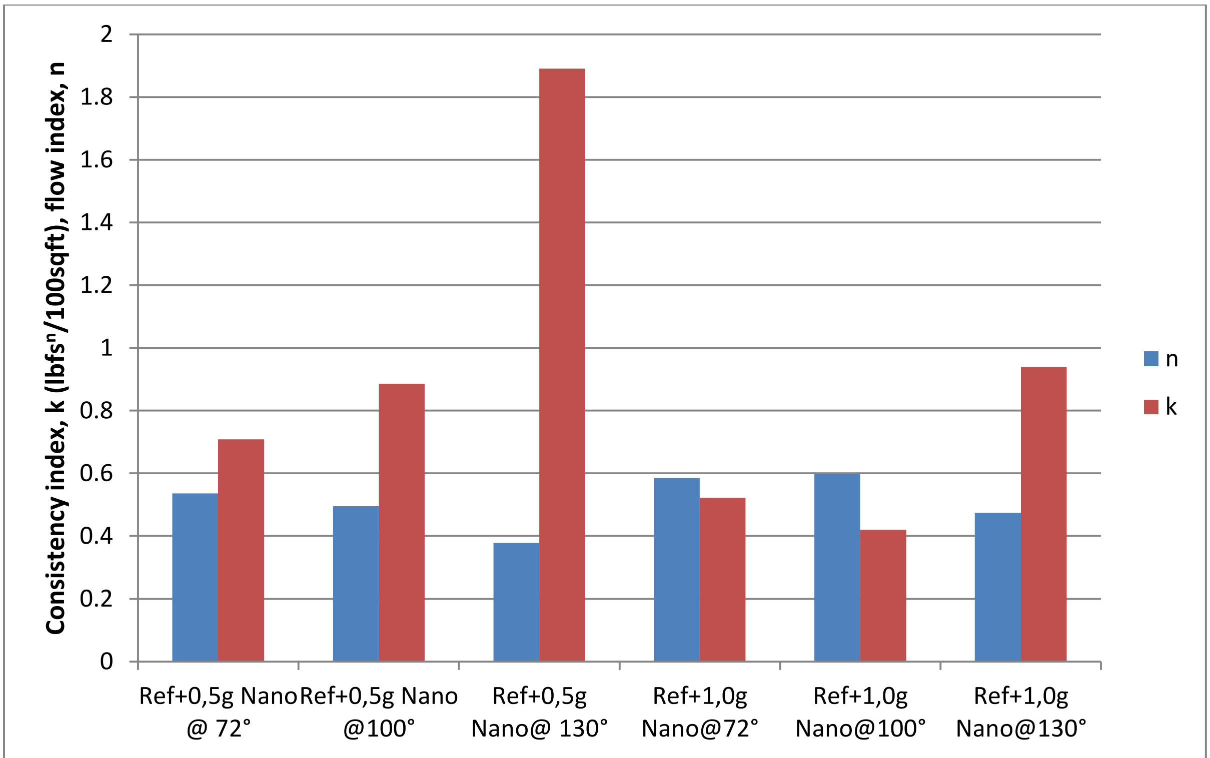


Figure 3.20: Power law parameters at different temperatures

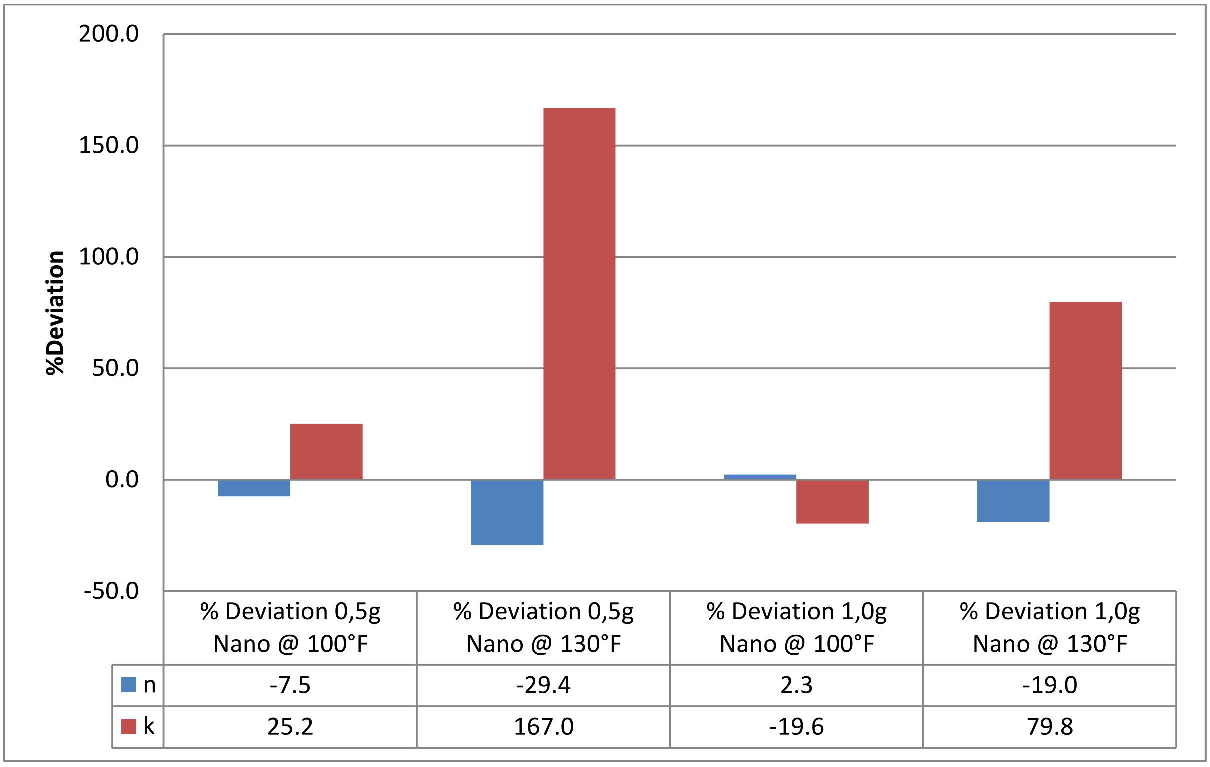


Figure 3.21: % Deviation for power law parameters when increasing temperature for fluid containing 0,5g and 1,0g nano silica

3.8 Viscoelasticity Test

Viscoelastic behaviors of the KCl/NaCl CMC treated bentonite fluid system containing nano silica were investigated by using Anton Paar MCR 301 Rheometer (see figure 3.22). The test includes Oscillatory Amplitude Sweep and Oscillatory Frequency Sweep Test. The tests were performed at 72^{o}F.

Figure 3.22: Illustration of Anton Paar MCR 301 Rheometer

3.8.1 Results Oscillatory Amplitude Sweep Test for KCl/NaCl fluid system containing nano silica

The first test performed in the experiment is the Oscillatory Amplitude Sweep Test which determine the linear viscoelastic range, the range of strain (or stress) where G' and G'' are constant. The sweep test also detects structural stability, strength and dynamic yield point of the drilling fluids.

Amplitude sweep tests were conducted with a constant frequency of 10 s^{-1} and a strain ramp from 0,0001 to 1000% for two drilling fluids in the KCl/NaCl system; 500g H_2O + Xg Nano + 2,5g KCl + 2,5g NaCl+ 0,5g CMC + 25g Bentonite with and without 0,3g nano silica (X).

Figure 3.23 shows the comparison of the amplitude sweep test results for the two drilling fluids. As observed from figure nano silica fluid has a higher storage modulus and loss modulus compared to reference fluid.

Before the intersection point the fluid deformation is dominated by elastic behavior, and after intersection point the behavior is viscous. This is because the loss modulus is greater than the storage modulus after the intersection point.

The plot of the storage and loss moduli proves that there is a LVE region in both fluids. Both fluids had a higher value of G' compared to G'' within the LVE region, verifying gel like behavior. Since the elastic portion dominates the viscous one there is certain stability in low shear range. The limit for the LVE region is approximately 1% for both fluids, and will be used for frequency sweep test.

Yield point from Anton Paar rheometer was found from the graph (where LVE region deviates). The yield points for both Anton Paar and Bingham are listed in table 3.18.

Table 3.18: Yield points obtained from Anton Paar and Bingham

Fluid	**Yield point, τ_y [Pa] (Anton Paar)**	**Yield point, τ_y [Pa] (Bingham)**
Reference (fluid 1)	0,310	4,088
Ref + 0,3g Nano (fluid 3)	0,395	2,555

Comparing the yield points obtained from both Bingham model and Anton Paar, it is observed that Bingham yield points are significantly higher. The Paar values give a decrease of 92,42% for reference fluid and 84,54% for nanoparticle fluid, compared to Binghams values.

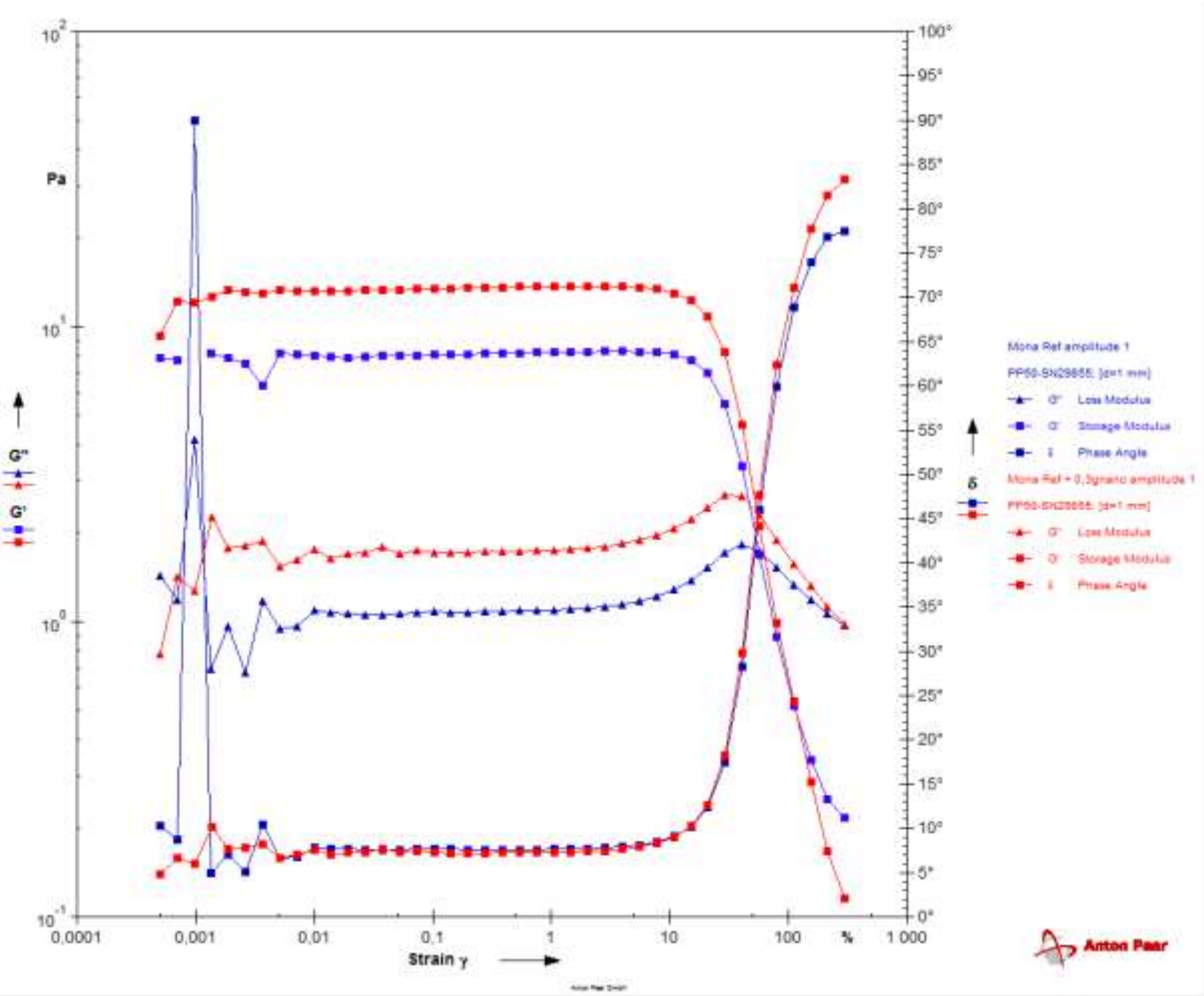


Figure 3.23: Amplitude Sweep Test for KCl/NaCl Reference (blue) and Nano (red) fluid

3.8.2 Results Oscillatory Frequency Sweep Test for KCl/NaCl fluid system containing nano silica

The Oscillatory Frequency Sweep Test was performed based on the result obtained from the amplitude sweep test. The linear viscoelastic range had a value of approximately 1%, while angular frequency was ramped from 0,01rad/s to 100rad/s.

Figure 3.24 shows that the elastic modulus was nearly independent of frequency for both fluids (G' curves are relatively flat). Frequency storage (G') is greater than loss modulus (G'') for both fluids, indicating a stable gel structure or a solid- like property. Thus the response of the samples to the deformation is dominated by elastic behavior. A stable structure is important for drilling fluids to keep small particles in suspension.

Observed from figure 3.24, nano silica fluid has a higher storage modulus and loss modulus compared to reference fluid.

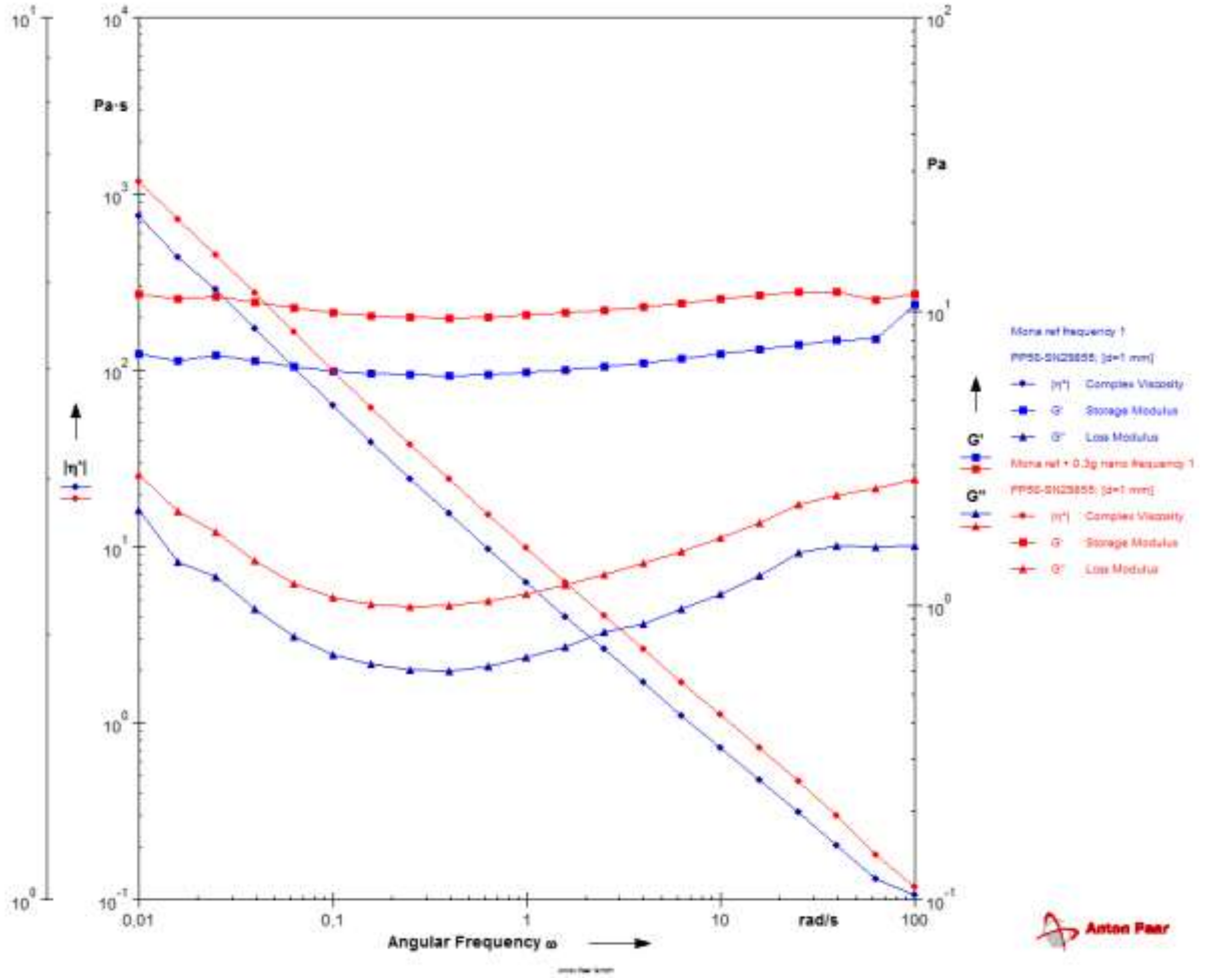


Figure 3.24: Frequency Sweep Test for KCl/NaCl Reference (blue) and Nano (red) fluid

3.9 Flow in Sand Pack Media

To investigate the rate of drilling fluid filtrate invasion into a porous media, two drilling fluids were selected from the KCl/NaCl system; (fluid 1) without nano silica, and fluid 3 containing 0,3g nano silica. These fluids were chosen based on the results gained from the rheology measurements.

Two different porous medias were used for comparison; one with low porosity (shale formation), and one with high porosity (unconsolidated formation).

The depth of fluid flow into the sand pack was measured every 30 min for 2,5 hours. A cylinder was used for the sand pack, and the depth of the fluid column was measured in order to ensure the same bottom hole pressure.

3.9.1 Results for low porosity sand pack

The reference fluid showed an instant diffusion (spurt loss) when tested. The fluid kept flowing into the sand pack until it stabilized at 1,6cm intrusion (figure 3.25). The fluid containing nanoparticles did not show an instant diffusion, but after 60min several repulsions up to 0,6cm were visible (figure 3.25).

Figure 3.25: Left : Diffusion for the reference fluid in low porosity sand pack, 72°F, left t = 0min, right = 150min
Right: Repulsion for the 0,3g nano silica fluid in low porosity sand pack, 72°F left t = 0 min, right t= 60min

3.9.2 Results for high porosity sand pack

The high porosity test gave spurt loss for both fluids. The reference fluid stabilized after 30min at 4,45cm intrusion (figure 3.26). The nano silica fluid had a severe spurt loss and suffered a total intrusion into the sand pack (8,2cm) after just 2 min (figure 3.26).

Test indicated that the use of nano silica is not suitable in highly unconsolidated formations.

Figure3.26: Left: Diffusion for reference fluid, 72°F left t = 0 min, right t= 30min
Right: Total intrusion for 0,3g nano silica fluid, 72°F left, t = 0 min, right, t = 2min

4 Performance evaluations of drilling fluid

The KCl/NaCl drilling system containing nano silica was evaluated for their performance in drilling operations. The performance was investigated by simulation and experimental work, to determine hydraulic and cutting transport, as well as analyzed by the rheology models covered in section 2.9.1.

The KCl/NaCl WBM system was selected due to the results gained from rheology parameters and filtration. The fluid system has a reference fluid of 500g H_2O, 25g bentonite, 0,5g CMC, 2,5g KCl and 2,5g NaCl. The system contains four fluids with different amounts on nano silica; 0,0g, 0,2g, 0,3g and 0,4g (figure 4.1).

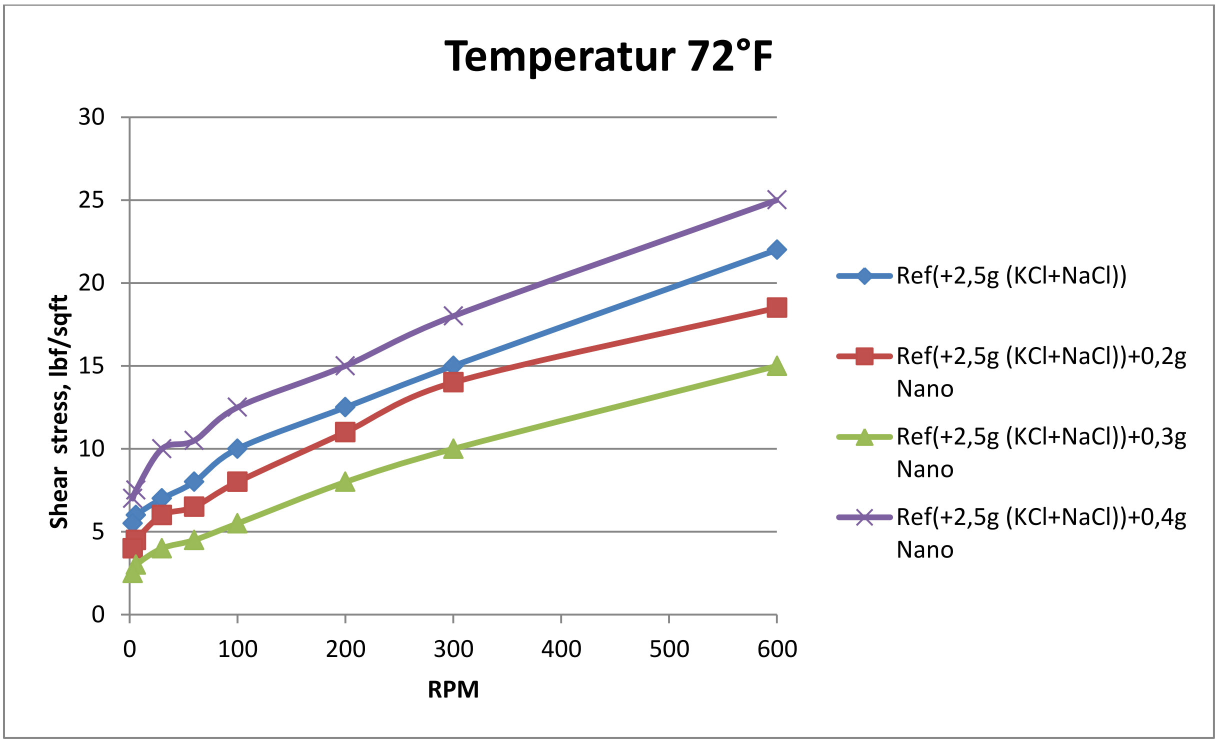


Figure 4.1: Description of KCl/NaCl fluid system used for further simulations and experimental work

4.1 Analysis of Rheology Models

The rheology models were used to analyze fluid 3 in the KCl/NaCl system. This fluid contained 0,3g nano silica and rheology and filtration parameters showed indications for being the optimum concentration of nano. Based on these results all six of the rheology models covered in literature section was analyzed to find which model that represent fluid 3 more correct (see figure 4.2)

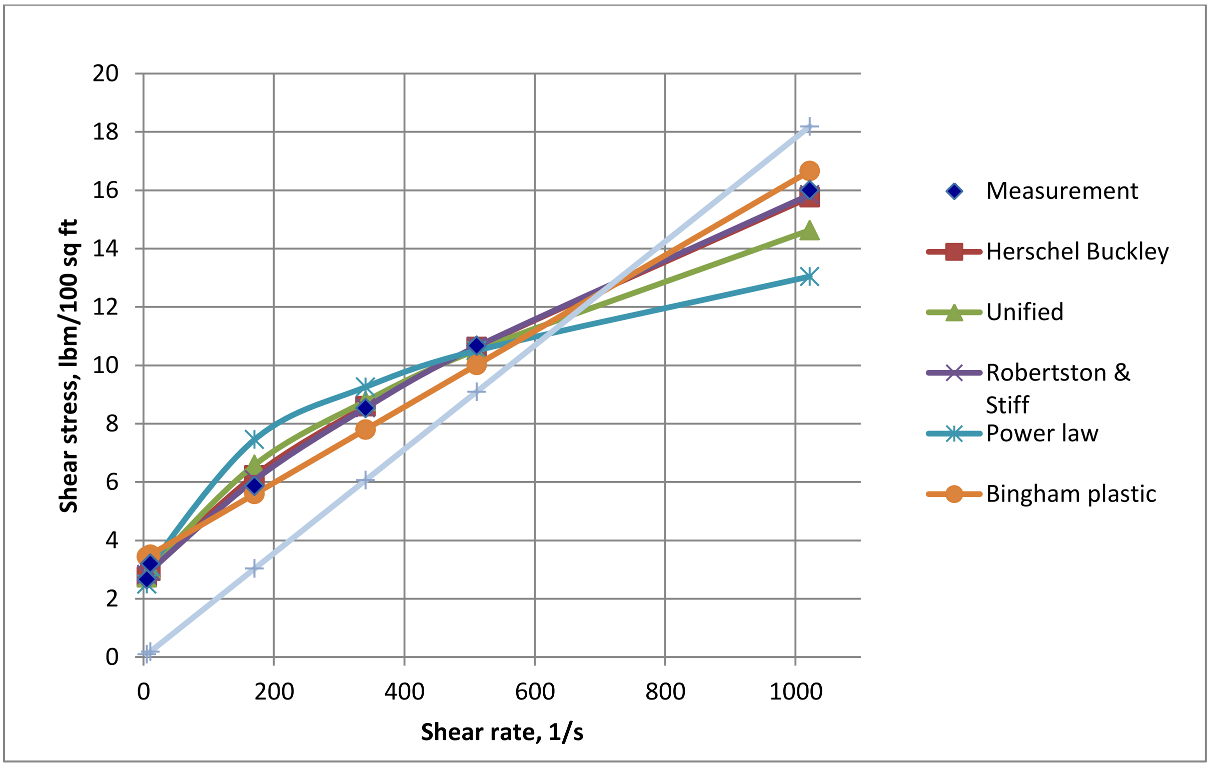


Figure 4.2: Comparison of different rheology models for 0,3g Nano KCl/NaCl fluid at 72°F

Figure 4.3 shows % deviation between model and measurements obtained. As can be seen the Herschel, Unified and Robertson describes the drilling fluid most sufficiently, while Newtonian gave the far worst result. For hydraulic calculations, the Unified model will be used based on this analysis.

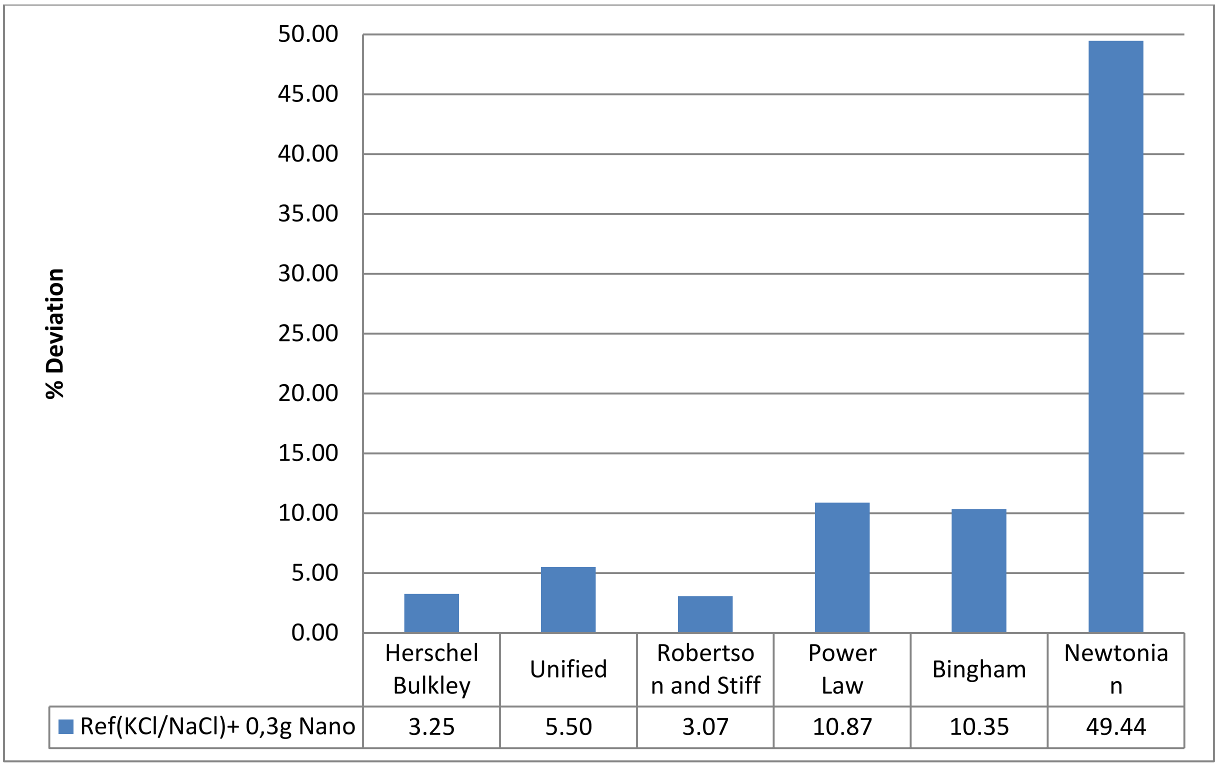


Figure 4.3: Comparison of the different rheology models errors for the 0,3g Nano KCl/NaCl fluid

4.2 Hydraulics performance of drilling fluid

ECD is an important parameter in the drilling industry. Well stability, stress in drill string and cutting transport are all functions of ECD. ECD is the sum of static mud weight and the annular friction loss, which is determined by hydraulic models. There are several hydraulic models in the industry, but based on rheology results which showed a low error for unified model, this model is chosen for the calculations.

4.2.1 Simulation arrangement

For the hydraulic calculations a vertical well with a total depth of 12000ft was considered. The well had 8,5inch casing, and the outer and inner diameters of the drill pipe were 5 inch and 4,8 inch respectively.

Surface pressure was assumed to be zero, and the drill bit had three nozzles at 28 inch size.

Figure 4.4 shows the experimental well.

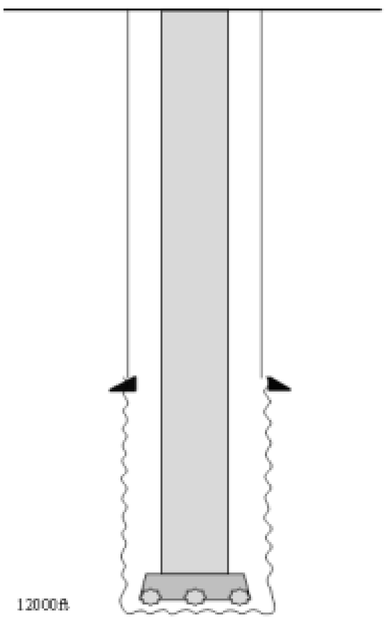


Figure 4.4: Simulation well for hydraulic simulation

4.2.2 Simulation result

Unified hydraulics model was used to calculate the frictional pressure losses for the four fluids in the KCl/NaCl fluid system. The simulation was performed by using the rheology data obtained from tests. During the simulation, the flow rate varied from 1 to 600 gpm.

The ECD results obtained from the simulation gave lowest ECD results for the fluid containing 0,3g nano (figure 4.5). The fluid had the lowest result throughout the simulation, except for the highest flowrate (600gpm). Here the fluid containing 0,2g nano silica gave a slightly lower ECD. Fluid containing 0,4g nano silica was the only nanoparticle fluid with a higher result than reference fluid, indicating that 0,4g is not a sufficient amount.

Pump pressure loss is the lowest for the 0,3g nano silica fluid, except at high pump pressures (see figure 4.6). Fluid containing 0,4g nano silica gave the highest pressure loss; giving further indications for 0,4g nano silica is a too high amount in the fluid system.

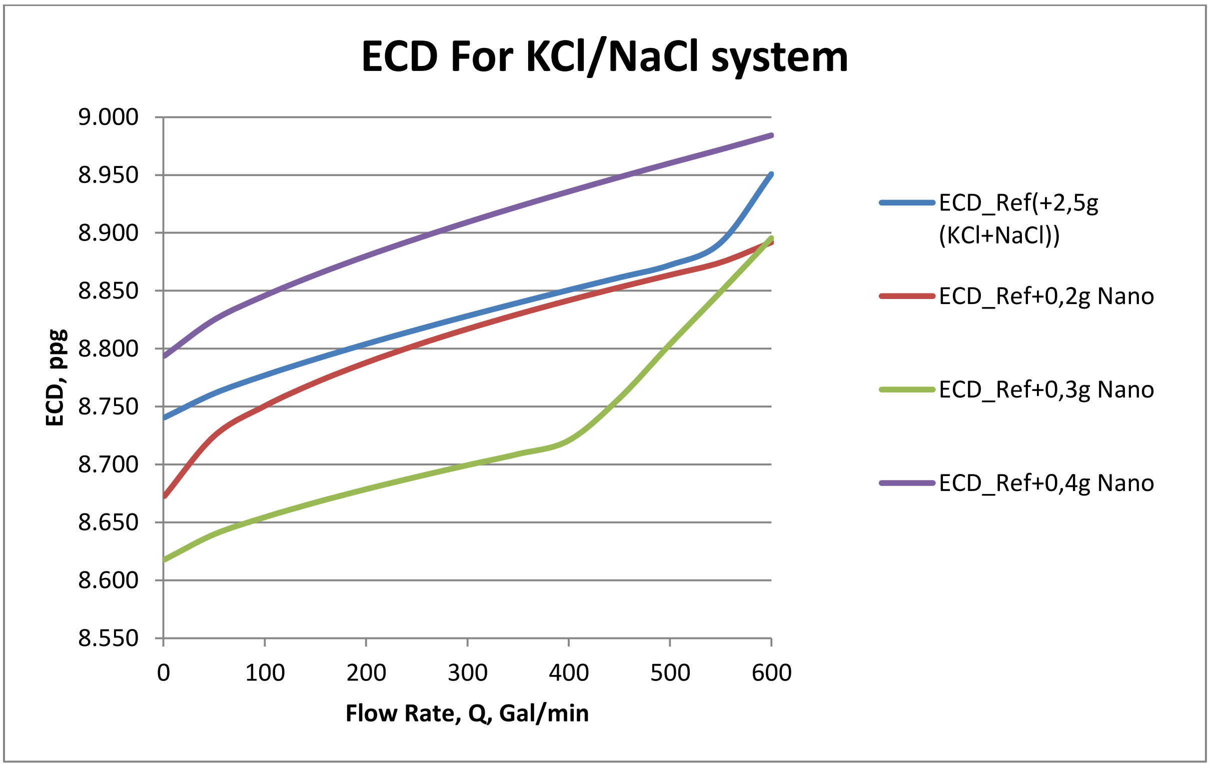


Figure 4.5: ECD calculation obtained from the Unified hydraulics model

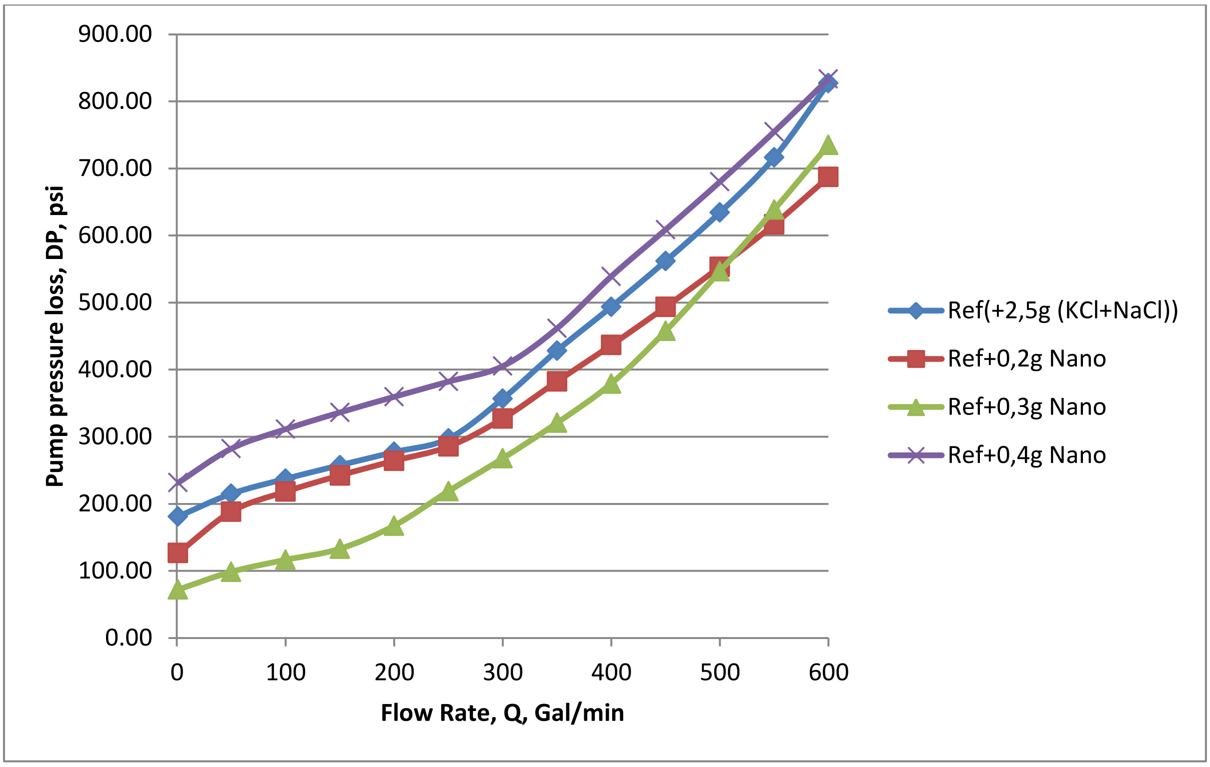


Figure 4.6: Comparison pump pressure loss for the four fluids based on the Unified Hydraulics model

4.3 Cutting transport

Cutting transport is important when considering proper hole cleaning during drilling operations. Drilling fluid returning to the surface transport the cuttings, and the capacity of the fluid to transport cuttings depends on several factors; rheology, density of fluid, flow rates, cutting properties and operational parameters (RPM and ROP) [3, 35].

In this section KCl/NaCl fluid system with nano silica will be evaluated with the assumption that the cutting and well operational parameters are constant.

4.3.1 Simulation arrangement

The experimental well shown in figure 4.7 is 11003,3ft measure depth long. The detail of the well and string data is shown in appendix F. The simulation is performed with Well-Plan^{TM} software [36], using the Power Law rheology model. The simulation determines the bed height and minimum flow rate for the fluid system, indicating the quality of cutting transport.

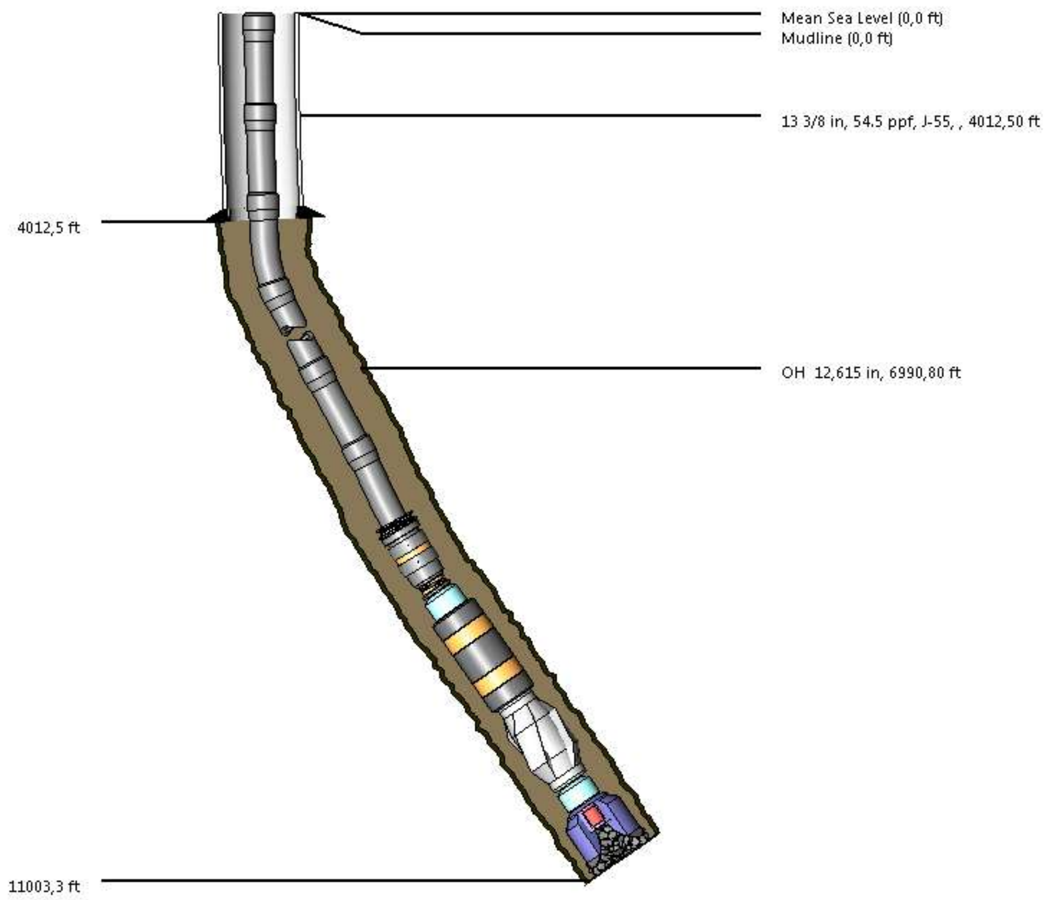


Figure 4.7: Simulation experimental well

4.3.2 Simulation results

Bed height

Bed height is the cuttings deposited on the bottom of the well. Bed height can cause several negative operational effects, such as; drill string buckling, increase torque and drag, increase hydraulic pressure and therefore increase ECD. Hence sufficient hole cleaning is of importance in order to avoid these effects [35].

Simulation was performed at a high pump rate, 600gpm. Other simulation inputs are shown in figure 4.8.

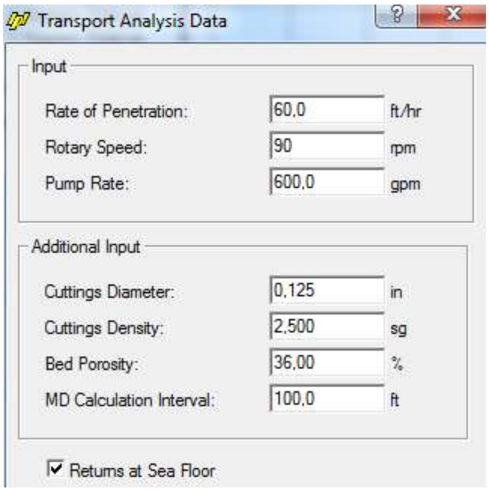


Figure 4.8: Transport Analysis Data for bed height simulation

The results in figure 4.9, shows that the well exhibits no cutting deposit up to approximately 5000ft. When the well starts to incline, the bed profiles follow the well inclination trends. The result show that the fluid containing 0,3g nano silica gives the lowest bed height (under 3in), giving further evidence for 0,3g to be the optimum amount of nano silica. The results confirm that adding nano silica in the salt polymer treated WBM system provides a better result considering cutting transport, since all three fluids containing nano silica gives a lower bed height than the fluid without nano silica.

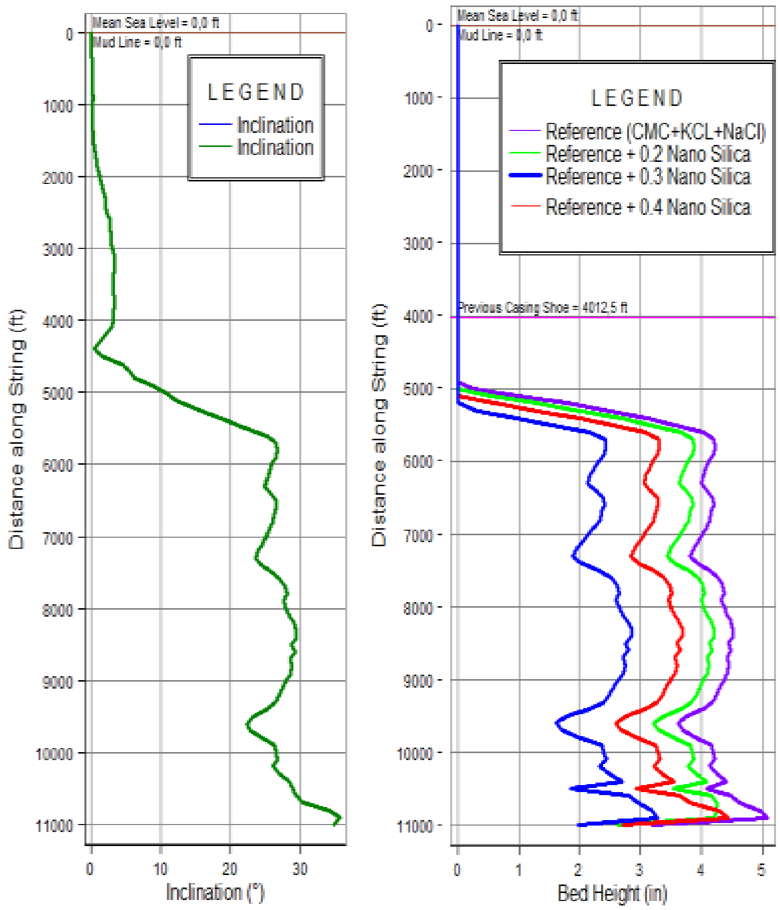


Figure 4.9: Well inclination of the simulation (left) and comparison of bed height for the 4 fluids (right)

Minimum flow rate

The simulation illustrates the demand for minimum flow rate to clean out cutting from the hole without bed deposits. If the flow rate is less than the minimum requirement, particles will begin to settle in the annulus. Low minimum flow rate will therefore the lower probability for cutting deposition.

The simulation inputs are given in figure 4.10.

Figure 4.10: Transport Analysis Data for minimum flow simulation

The results obtained from the simulation shows that also for minimum flow rate, the fluid containing 0,3g nano silica is the most sufficient fluid, due to the lowest required flow rate regardless of the hole angle (see figure 4.11). It is also seen that adding nano silica contributes to a smaller minimum flow rate, but for the 0,4g nano silica fluid, hole angles above 43° will require higher flow rates than for the reference fluid (without nanoparticles). Results gained from simulations contribute to the observation that 0,3g nano silica may be the optimal amount for the fluid.

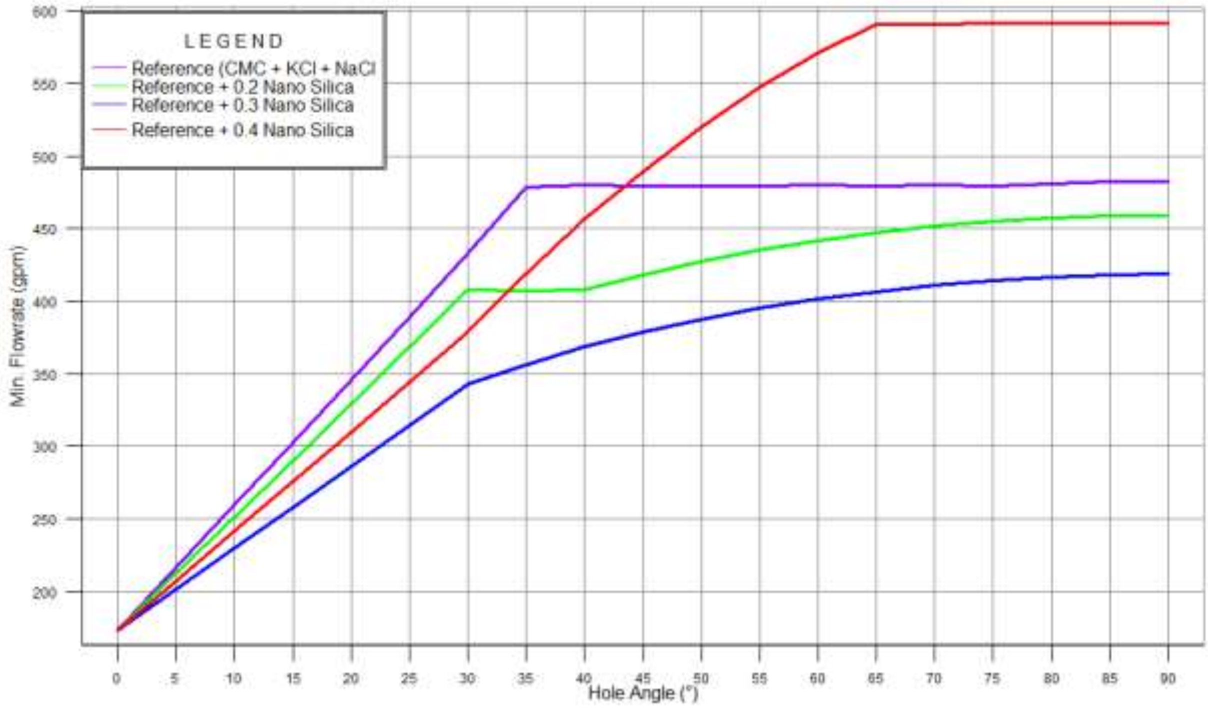


Figure 4.11: Comparison of minimum flow rate for the 4 fluids

5 Summary and Discussion

This section presents the summary and discussion of the overall study. The main purpose of the thesis was to investigate the effect of different additives to water based fluid system, as well as temperature. This investigation was done by experimental and simulation studies.

5.1 Effect of temperature and in –situ/ ex-situ mixing procedure

Rheology tests show that neither temperature nor mixing procedure for the polymer cause large effects on the drilling fluid. Temperature comparisons were performed for CMC treated bentonite water based fluid system with nano silica.

When increasing temperature, PV increased while YS had a decrease in fluid containing nano silica. The flow behavior index, n, decreased while consistency index, k, increased, improving hole cleaning capacity.

Temperature analysis showed that by increasing the amount of nano silica to the system, the parameters n and k became more stable. This is in accordance to prior studies where it was reported that nanoparticles provide stability in high temperature conditions (Abdo et al., 2013 [39]).

Polymers CMC and PAC were added to the fluids both in-situ and ex-situ compared to bentonite. For both polymer types the plastic viscosity had an increase while yield strength had a decrease when added ex-situ. Ex-situ showed negative effects on power law parameters; n value had an increase while k had a decrease (compared to fluid mixed in-situ). Filtrate loss was similar independent on mixing procedure.

5.2 Effect of polymer

High concentration of polymer made the fluid to viscous for a drilling fluid. This was concluded after visual inspection. The amount of 0,5g was therefore selected to be used for further drilling fluids prepared in the thesis.

The effects of using polymers in bentonite WBM systems were positive. Both polymers, CMC and PAC, gave a lower filtrate loss compared to fluid without polymer. The increase in PV and YS and decrease in filtrate loss indicates that one of the effects given from polymers is a more flocculated dispersed fluid system. This corresponds to the theory listed in section 2.6.

All polymer fluid tested were shear-thinning, i.e. $n<1$. Power law rheology results showed that when increasing the amount of CMC, n decreases while k increases. The decrease in n values and increase in k values improves the fluids hole cleaning performance by increasing the effective annular viscosity. The annular viscosity helps prevent particle breakage and moves the solids more directly up the hole [37].

The results were in accordance with prior studies where it was reported that increasing CMC concentration increases the viscosity at all shear rates and that CMC solutions exhibit shear thinning behavior (Kelessidis et.al.,2011 [38]).

Polymer PAC provided opposite result for n and k parameters compared to CMC results. Increased concentration of PAC caused an increase in flow behavior index and a decrease in flow consistency index.

5.3 Effect of salt

KCl and NaCl were used in the thesis to evaluate the effect of salt in WBM.

KCl was used in polymer treated bentonite water based drilling fluid in order to establish an optimal concentration. When high concentrations of KCl were used (15,0g), the fluid separated. The filtration increased while PV and YS decreased, making the fluid aggregated. The amount of 2,5g was concluded to be the best based on visual inspection of the separated fluid, as well as rheology parameters and filtration measurements. For combined salt fluid system (KCl + NaCl) a total amount of 5,0g salt was used.

PH decreased when increasing the amount of salt.

NaCl showed a more tendency to flocculate the system compared to KCl, since NaCl had a higher yield point. Plastic viscosity was also higher for the NaCl fluid while the filtration loss was lower.

NaCl provided better hole cleaning capacity than KCl, because flow behavior index, n was lower and consistency index k, was higher for NaCl fluid system than for KCl system.

For fluid system containing both KCl and NaCl the filtration increased. This is probably due to the fact that the overall concentration of salt increased from 2,5g to 5,0g (2,5g KCl + 2,5g NaCl).

5.4 Effect of nanoparticles

The effect of nano silica was evaluated through experimental and simulation results.

5.4.1 Effect for rheological properties

Results showed that using a low amount of nano silica (0,5g) without polymer or salt had no effect for filtrate loss; the loss was the same for fluid consisting of nano silica as for fluid without (7ml filtrate loss). Nano silica had little effect for the PV, but caused an increase in YS (35%). It was also observed that pH decreased when adding nano silica.

For fluid containing both CMC and nano silica, it was observed that nano silica did not cause large effects for the filtrate loss, since the filtrate loss was the same for fluid containing just CMC, as for fluid containing both 0,5g CMC and 0,5g nano (4,5ml filtrate loss). But fluid containing 1,0g nano silica had an increase in filtrate loss, indicating that the amount of nano silica should be less than 1,0g. PV and YS did not show large differences when increasing the concentration of nano silica in the CMC drilling fluid system.

Nano silica decreased the flow behavior index in all fluid systems except the combined polymer (CMC/PAC) system. Other work has also shown that nano silica has this effect on drilling fluids (G, Cheraghian, et al, 2013) [17]. But when increasing the concentration of nano silica, the flow behavior index also increased for all fluids systems except the combined polymer (CMC/PAC) system.

KCl and NaCl were used to evaluate the effect of nano silica in brine treated polymer WBM fluids. Results showed that increasing the concentration of nano silica in KCl fluid systems contributed to an increase in filtration and a decrease in PV; thus effected the fluid to move towards a more aggregated fluid. But for NaCl fluid system there was no increase in filtration loss when concentration of nano silica increased.

Using nano silica combined with salt contributed to better hole cleaning capacity for the drilling fluids than for fluids containing nano silica and CMC without salt. In salt fluid systems the amount of 0,3g nano silica in the fluids gave the highest value of n for all three salt systems (KCl, NaCl and KCl/NaCl).

Fluid containing both salt types and 0,3g nano silica had an increase in PV and YS and a decrease in filtration, providing a more dispersed flocculated system. This indicate that there is an optimum amount of nano silica between 0,2 - 0,4g, and the fluid system was therefore selected for further testing.

5.4.2 Effect for viscoelasticity

Viscoelastic properties of drilling fluids are important since they allow the evaluating of gel structure, gel strength, hydraulic modeling and barite sag. In this thesis amplitude and frequency sweep tests were performed for the KCl/NaCl drilling fluid system for reference fluid (nano-free) and fluid containing 0,3g nano silica.

Both amplitude and frequency sweep test showed that fluid containing 0,3g nano silica had higher storage modulus and loss modulus compared to nano-free fluid, which shows improved stability.

Amplitude sweep test showed that both fluids had a higher value of storage modulus than loss modulus before the intersection point (elastic behavior), and both fluids had a LVER.

Comparing yield points obtained from Anton Paar Rheometer and Bingham model showed that Anton Paar YPs had a decrease of 92,42% for reference fluid and 84,54% for nano silica fluid compared to Bingham YPs.

Frequency sweep test showed that the elastic modulus was nearly independent of frequency for both fluids. Frequency storage was greater than loss modulus for both fluids, indicating a stable gel structure or a solid- like property.

5.4.3 Effect for flow through porous media

The effect of nano silica for filtrate invasion into a porous media was evaluated. Results showed that fluid containing 0,3g nano silica did not have an instant diffusion in low porous media, as the nano-free fluid had. But for high porous media, fluid containing nano silica suffered a severe spurt loss resulting in a total intrusion shortly after the experiment started, indicating that fluid without nano silica is preferable in highly unconsolidated formations.

This observation is based on the considered system and cannot be drawn as a general conclusion. More extensive research is required.

5.4.4 Effects for hydraulics

Hydraulics properties of drilling fluids are important for drilling operations such as cutting transport and ECD managing. In this thesis simulation showed that Unified, Herschel Bulkley and Robertson Stiff rheology models gave the lowest error while the Newtonian gave the highest. Based on this the Unified Hydraulic model was selected for hydraulic calculations.

Results showed lowest pressure loss for the fluid containing 0,3g nano silica in the KCl/NaCl fluid system. Further results showed that only the fluid containing 0,4g nano silica gave a higher pressure loss then reference fluid without nanoparticles. This indicates that the use of nano silica provides positive effects for well stability, and that 0,3g nano silica is the optimal amount for the KCl/NaCl fluid system.

5.4.5 Effect on cutting transport

In this thesis cutting capacity of the KCl/NaCl drilling fluid system were evaluated by the use of simulation. The bed height and minimum flow rate required was obtained during the simulation.

Results showed that fluid containing 0,3g nano silica gave the best results for both bed height and minimum flow rate. Further results showed that the three fluids containing nano silica (0,2g, 0,3g, and 0,4g) had lower bed height than the nano-free reference fluid. For minimum flow rate the three fluids also had better results than the nano-free fluid for hole angles lower than 43°. For hole angles higher than this, fluid containing 0,4g nano silica required a higher flow rate than the nano-free fluid.

6 Conclusion

The objective of this thesis was to formulate an optimized nano-additive system, which improved the rheology and filtrate performances of a conventional water based fluid system. The effect of adding nano silica and salt to bentonite water based drilling fluids was investigated. Both nano silica and salt had a shear thinning effect on base fluid. Screening performed found an optimal concentration of salt at 2,5g. Experiments performed in the thesis conclude that effects given by salts are;

- Increased filter loss
- Decreased pH
- Decreased PV and YS- aggregated system

From the overall tests it was concluded that the fluid giving optimum results consist of: 0,3g nano silica + 0,5g CMC + 2,5g KCl + 2,5g NaCl in bentonite/ H_2O (25g/500g). Experiments and simulations performed in the thesis conclude that effects given by nano silica are;

- Improved hole cleaning capacity by decreasing flow behaviour index
- Improved hydraulic properties by decreasing pressure loss (when nano silica<0,4g)
- Improved cutting transport by decreasing bed height and minimum flow rate required
- Increased storage and loss modulus compared to nano-free fluid, which shows better stability

References

1 Khodja, M., Khodja-Saber, M., Canselier, J.P., Cohaut, N., Bergaya, F., "Drilling Fluid Technology: Performances and Environmental Considerations." InTech. ISBN: 978-953-307-211-1, 2010.

2 Cook, J., Growcock, F., Guo, Q., Hodder M., Oort, E.V. "Stabilizing the Wellbore to Prevent Lost Circulation". Oilfield Review Winter 2011/2012: 23, no. 4.

3 Bourgoyne, A.T. Jr., Millheim, K.K., Chenevert, M.E., and Young J, F.S., "Applied Drilling Engineering", SPE Textbook Series Vol. 2, 1991. Richardson, Texas (ISBN: 978-1-55563-001-0).

4 G. Stjern, A. A., P Horsrud., "Local rock mechanical knowledge proves drilling performance in fractured formations at the Heidrun field." Journal of Petroleum Science and Engineering 38(3-4): 83-96, 2003.

5 Rahul C. Patil and Abhimanyu Deshpande., "Use of Nanomaterials in Cementing Applications" SPE-155607 SPE International Oilfield Nanotechnology Conference and Exhibition, 12-14 June, Noordwijk, The Netherlands, 2012.

6 Aadnøy, B.S., "Geomechanical Analysis for Deep-water Drilling", SPE 39339 paper presented at the IADC/SPE Drilling Conference, Dallas, TX, 3 - 6 March, 1998.

7 Aadnøy, B. S., and Chenevert, M.E., "Stability of Highly Inclined Boreholes", Journal Paper SPE 16052-PA , SPE Drilling Eng, 1987.

8 Aston, M.S. Alberty. M.W. McLean, M.R. de Jong, H,J. Armagost, K. "Drilling Fluids for Wellbore Strengthening". BP Exploration, Drilling Conference. Dallas, Texas. 2-4 March, 2004 IADC/SPE 87130.

9 Aadnøy, B. S., and Looyeh, R., "Petroleum Rock Mechanics", First Edition 2011, ISBN 978-0-12-385546-6.

10 Fjær, E., Holt, R.M., Horsrud, P., Raaen, A.M., Risnes, R., "Petroleum Related Rock Mechanics", Elsevier, 1992. ISBN 978-0-444-50260-5.

11 Horsrud P., Bostrøm B., Sønstebø, E.F, and Holt, R.M., "Interaction between shale and water-based drilling fluids: Laboratory exposure tests give new insight into mechanisms and field consequences of KCL contents", SPE 48986. SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, 27-30 September 1998.

12 Messenger, J.U., “Lost Circulation”, Pennwell Publishing Company. Tulsa, Oklahoma, 1981, ISBN: 978-0878141753.

13 Kristensen, A. “Flow properties of water-based drilling fluids”. Norwegian University of Science and Technology, 2013.

14 http://www.dccleaningsystem.com/category/related-industries/uncategorized/page/2/ (Accessed: 18.03.15)

15 Economides, M.J., Watters, L.T., Dunn-Norman, S., “Petroleum Well Construction”, 1998 ISBN 0-471-96938-9.

16 Neff,J.M., “Composition, Environmental Fates, and Biological Effects of Water Based Drilling Muds and Cuttings Discharges to the Marine Environment: A Synthesis and Annotated Bibliography”. Prepared for Petroleum Environmental Research Forum and American Petroleum Institute, January 2005.

17 Cheraghian, G. Hemmati, M. Masihi, M. Bazgir, S. “An experimental investigation of the enhanced oil recovery and improved performance of drilling fluids using titanium dioxide and fumed silica nanoparticles”. Journal of Nanostructure in Chemistry, 2013 DOI 10.1186/2193-8865-3-78.

18 Shah, N. S., Shanker, H. N., Ogugbue, C. C., “Future Challenges of Drilling Fluids and Their Rheological Measurments”. American Association of Drilling Engineers, 2010.

19 Caenn, R., Darley, H.C.H., Gray. G, “Composition and Properties of drilling and Completion Fluids”, 6th edition 2012.

20 http://theses.ulaval.ca/archimede/fichiers/24888/ch01.html (Accessed: 15.04.2015).

21 Olaf Skjeggestad “Boreslam Teknologi”. Alma Mater Forlag, 1989. ISBN: 82-419-0010-4.

22 MISwaco Manual “Drilling Fluids Engineering Manual, Polymer chemistry and Applications”. Chapter 6, 1998.

23 Adel Benchabane and Karim Bekkour, “Rheological properties of carboxymethyl cellulose (CMC) solutions”. Colloid Polym Sci, 2008. DOI: 10.1007/s00396-008-1882-2

24 Khaled. B., Abdelbaki. B., "Rheological and electrokinetic properties of carboxymethylcellulose-water dispersions in the presence of salts". International Journal of Physical Sciences Vol. 7(11). DOI: 10.5897/IJPS11.1779. 9 March, 2012.

25 O'Brien D.E., Chenevert M.E., "Stabilizing Sensitive Shales with Inhibited Potassium-Based Drilling Fluids," Journal of Petroleum Technology 25, no. 9 (September 1973): 1089-1100.

26 Azar.J.J., Samuel.G.R., "Drilling Engineering". PennWell Corporation. Tulsa, Oklahoma, 2007.

27 Kelco Oil Field Group. "Rheology, Technical bulletin". 2006.

28 http://www.drillingformulas.com/drilling-fluid-properties/ (Accessed: 11.02.2015)

29 Ochoa, M.V. "Analysis of drilling fluid rheology and tool joint effect to reduce errors in hydraulic calculations" 2006. Texas A&M University.

30 Binh Bui, Arild Saasen, Jason Maxey, Mehmet E. Ozbayoglu, Stefan Z. Miska, Mengjiao Yu, Nicholas E. Takach., "Viscoelastic Properties of Oil-Based Drilling Fluids," Annual Transactions of the Nordic Rheology Society, Vol. 20, 2012.

31 Thomas G. Mezger. "The Rheology Handbook", 2002. ISBN 3-87870-745-2.

32 http://www.wee-solve.de/en/amplitude-sweep.html (Accessed: 18.05.2015).

33 http://www.wee-solve.de/en/frequency-sweep.html (Accessed: 18.05.2015).

34 Kumar, A.S., Mahto, V., Sharma, V.P., "Behaviour of organic polymers on the rheological properties of Indian bentonite-water based drilling fluid system and its effect on formation damage". Indian Journal of Chemical Technology, Vol.10. September 2003, pp. 525-530.

35 Nazari T., Hareland G., and Azar J.J., "Review of Cuttings Transport in Directional Well Drilling: Systematic Approach", SPE 132372, SPE Western Regional Meeting, 27-29 May 2010, Anaheim, California, U.S.A.

36 WellPlan (Landmark)TM Software, Halliburton.

37 Kelco Oil Field Group. "Drilling Fluid Rheology, "n" and "K" Applications" Technical bulletin, September 2005.

38 Kelessidis, V.C., Poulakakis, E., Chatzistamou. V., "Use of Carbopol 980 and carboxymethyl cellulose polymers as rheology modifiers of sodium-bentonite water

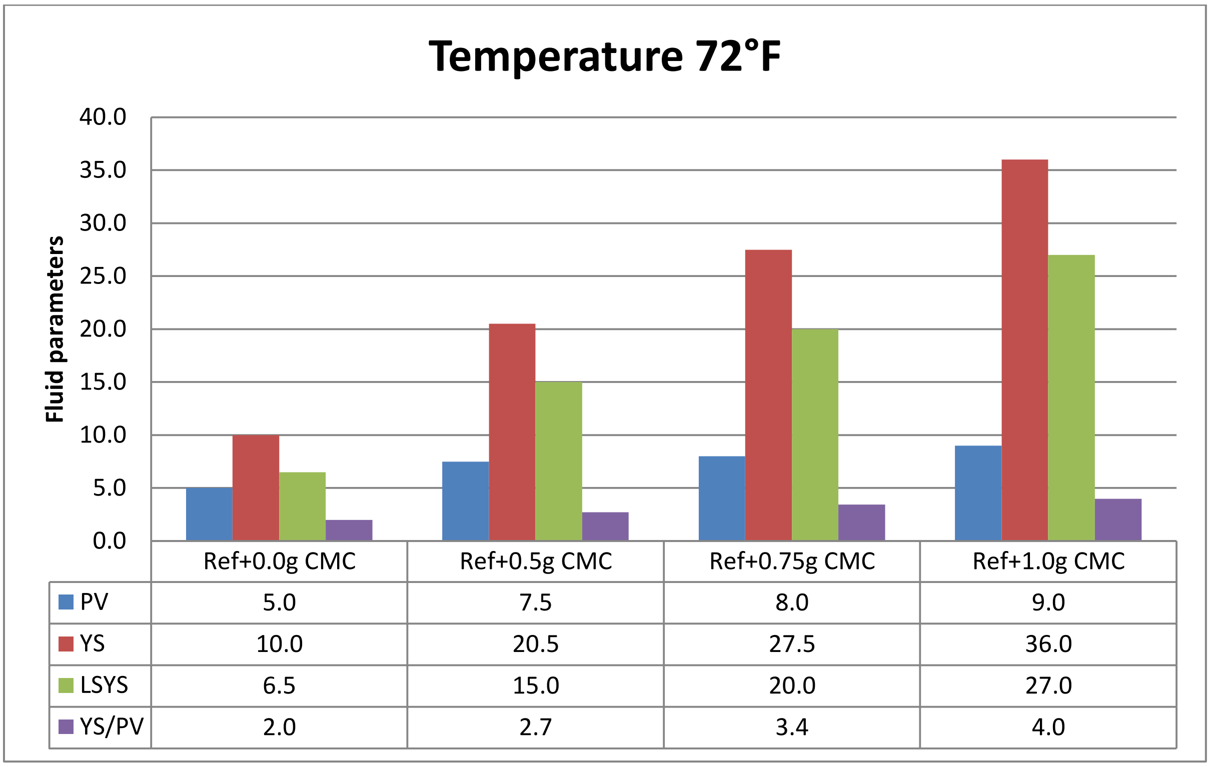
dispersions". Applied Clay Science, Vol 54, November 2011, pp. 63-69. DOI:10.1016/j.clay.2011.07.013.

39 Abdo. J., Haneef. M.D., "Clay nanoparticles modified drillingfluids for drilling of deephydrocarbon wells". Applied Clay Science,(2013). DOI: 10.1016/j.clay.2013.10.017.

Appendix

Appendix A- Effect of CMC in bentonite WBM system

A.1. Rheology parameters for CMC fluids



	Ref+0.0g CMC	Ref+0.5g CMC	Ref+0.75g CMC	Ref+1.0g CMC
PV	5.0	7.5	8.0	9.0
YS	10.0	20.5	27.5	36.0
LSYS	6.5	15.0	20.0	27.0
YS/PV	2.0	2.7	3.4	4.0

Figure A.1: Rheology parameters for CMC fluids

A.2. Increased Fann Viscometer readings for CMC fluids

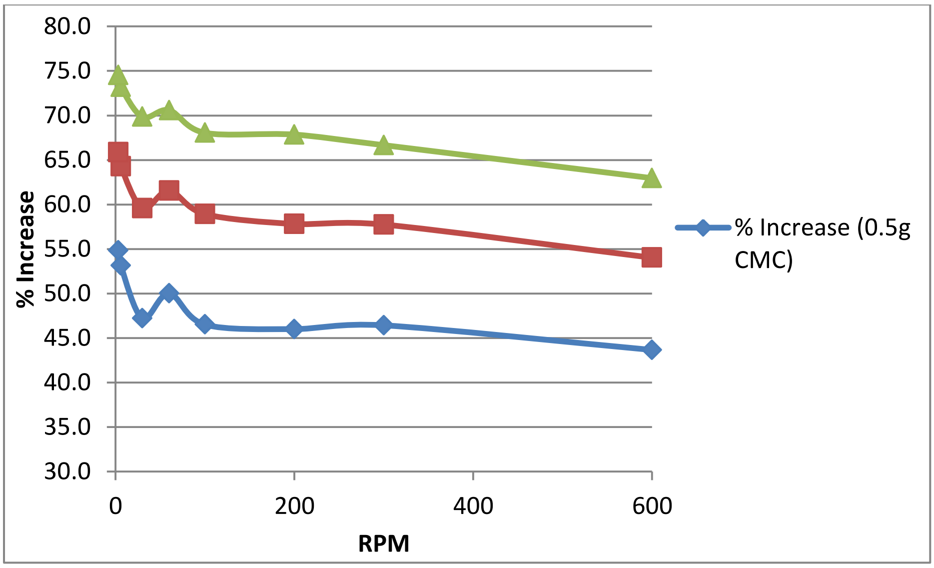


Figure A.2: Comparison the increase in viscosity reading for CMC fluids

Appendix B- Effect of salt concentration in CMC treated bentonite WBM system

B.1 Results for 5g KCl system

Rheology measures	Reference Fluid (5g KCl)	Fluid 2 (0,2g Nano)	Fluid 3 (0,3g Nano)	Fluid 4 (0,4g Nano)
Q600	5	5,5	5,5	5,5
Q300	3,5	3,5	3,5	3
Q200	2	3	3	2
Q100	1,5	2	2	1,5
Q60	1,25	1,5	1,25	1,25
Q30	1	1	1	1
Q6	0,75	0,75	0,75	0,75
Q3	0,5	0,5	0,5	0,5
PV [cP]	1,5	2,0	2,0	2,5
YS [lbf/100sqft]	2,0	1,5	1,5	0,5
LSYS [lbf/100sqft]	0,3	0,3	0,3	0,3
YS/PV [(lbf/100sqft)/cP]	1,3	0,8	0,8	0,2
n	0,51	0,65	0,65	0,87
k [lbf*sec^n/100ft^2]	0,14	0,06	0,06	0,01
Filtration [ml]	9,25	11	11,75	11,5
pH	9,05	9,1	9,1	9,05

Table B.1: Results from 5g KCl drilling fluid containing nano silica

B.2 Results for 15g KCl system

Rheology measures	Reference Fluid (15g KCl)	Fluid 1 (0,2g Nano)
Q600	7,5	6
Q300	5	4
Q200	4,5	3
Q100	2	2,5
Q60	1,75	1,5
Q30	1,5	1,25
Q6	1,25	1
Q3	1	0,75
PV [cP]	2,5	2,0
YS [lbf/100sqft]	2,5	2,0
LSYS [lbf/100sqft]	0,8	0,5
YS/PV [(lbf/100sqft)/cP]	1,0	1,0
n	0,58	0,58
k [lbf*sec^n/100ft^2]	0,13	0,10
Filtration [ml]	22	20
pH	8,95	8,95

Table B.2: Results from 15g KCl drilling fluid containing nano silica

B.3 Comparison of results for all KCl drilling fluids

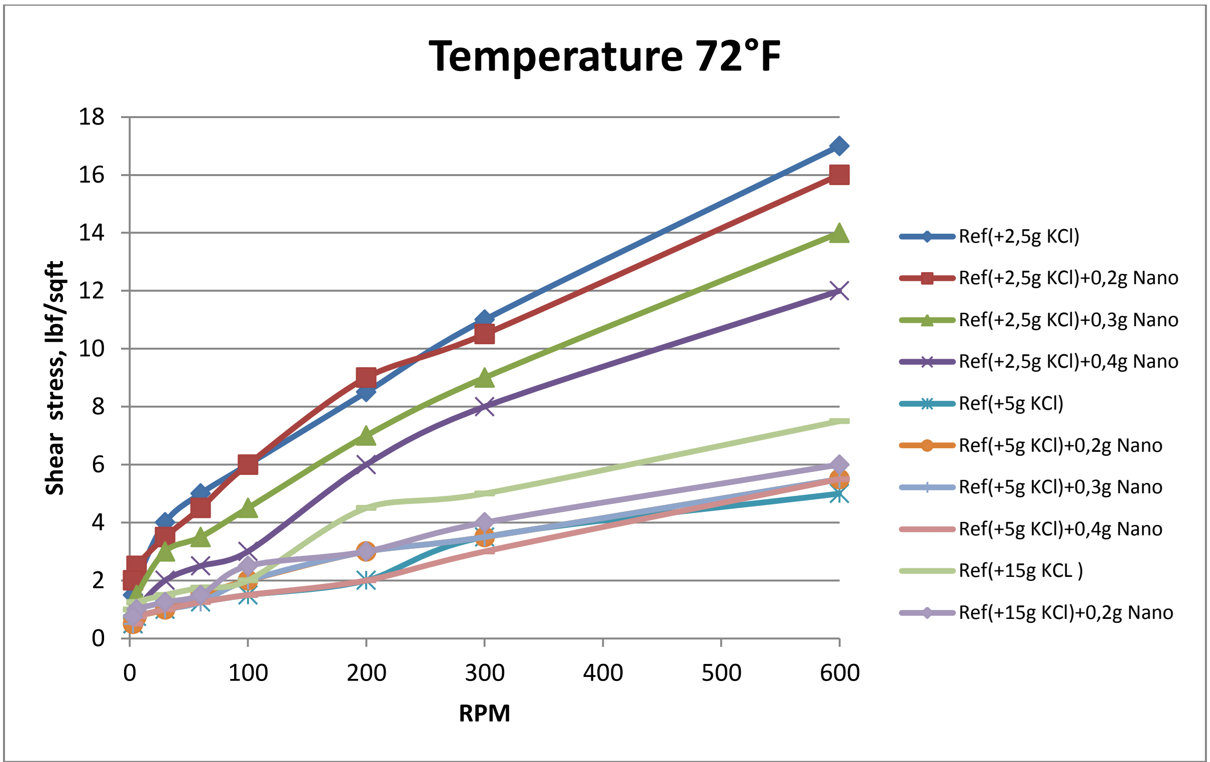
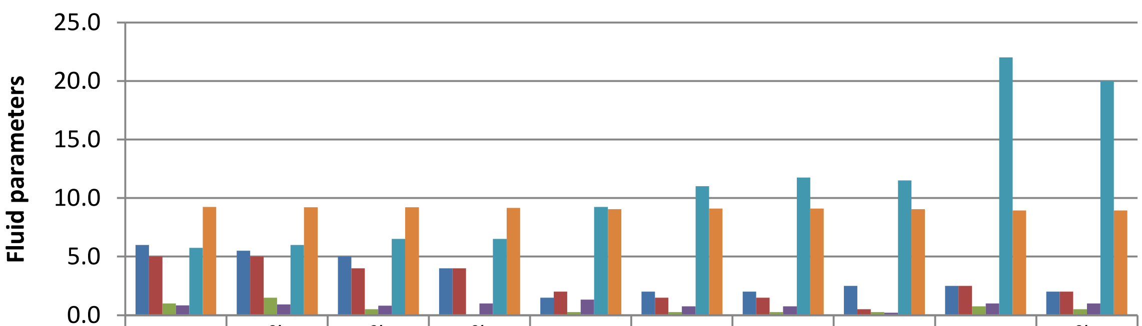


Figure B.1: Comparison for KCl drilling fluids containing nano silica



	Ref(+2,5g KCl)	Ref(+2,5g KCl)+0,2g Nano	Ref(+2,5g KCl)+0,3g Nano	Ref(+2,5g KCl)+0,4g Nano	Ref(+5g KCl)	Ref(+5g KCl)+0,2g Nano	Ref(+5g KCl)+0,3g Nano	Ref(+5g KCl)+0,4g Nano	Ref(+15g KCL)	Ref(+15g KCl)+0,2g Nano
PV	6.0	5.5	5.0	4.0	1.5	2.0	2.0	2.5	2.5	2.0
YS	5.0	5.0	4.0	4.0	2.0	1.5	1.5	0.5	2.5	2.0
LSYS	1.0	1.5	0.5	0.0	0.3	0.3	0.3	0.3	0.8	0.5
YS/PV	0.8	0.9	0.8	1.0	1.3	0.8	0.8	0.2	1.0	1.0
Filtrate	5.75	6	6.5	6.5	9.25	11	11.75	11.5	22	20
pH	9.25	9.2	9.2	9.15	9.05	9.1	9.1	9.05	8.95	8.95

Figure B.2: Rheology parameters for the different KCl drilling fluids with nano silica

Appendix C- Effect of nanoparticles in CMC WBM system

C.1. Effect for power law parameters

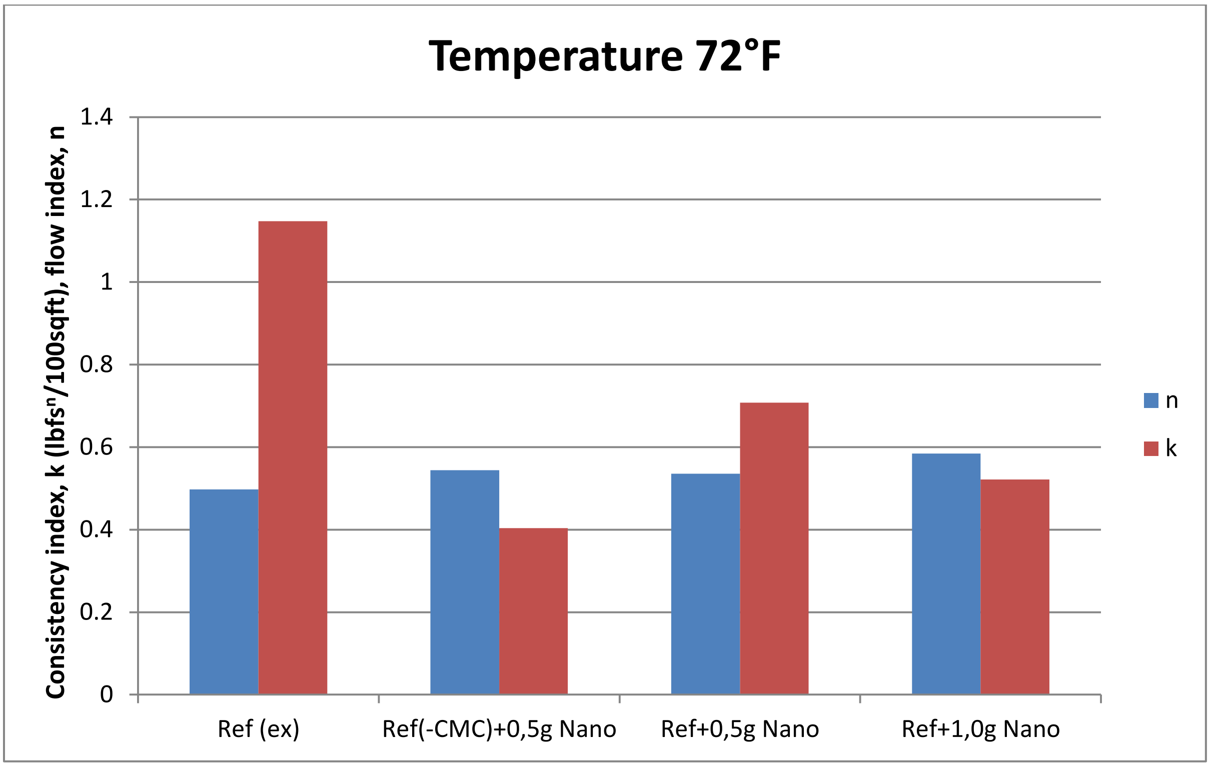


Figure C.1: Power law parameters for CMC WBM system containing nano silica

C.2. Comparison effect for in-situ and ex-situ mixing procedure

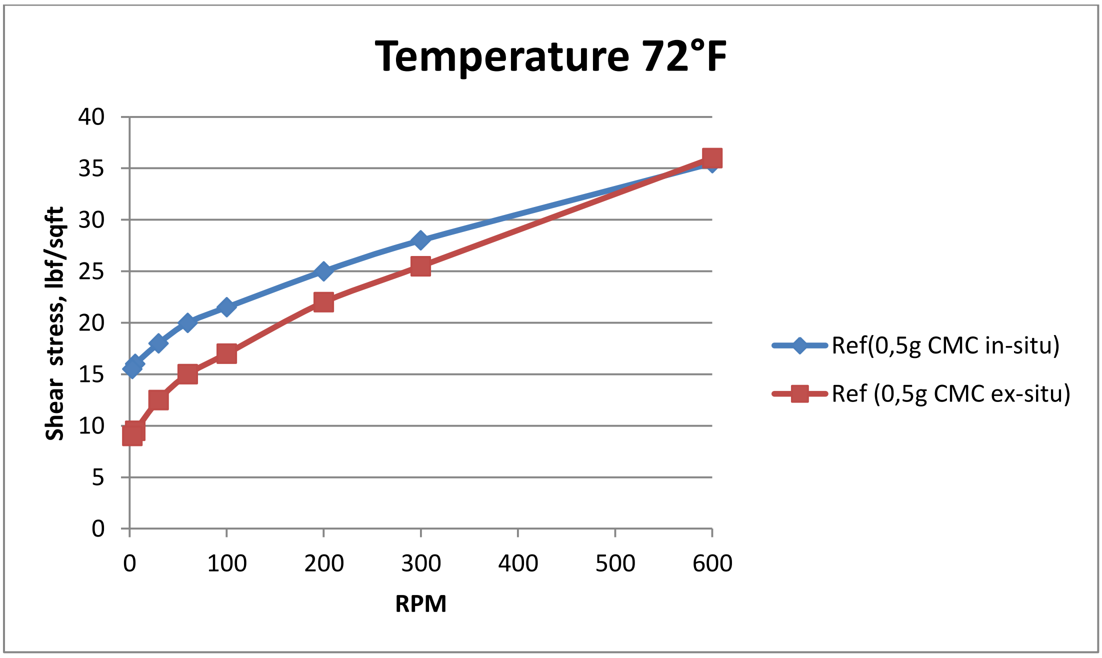


Figure C.2: Comparison of rheology measures for in-situ and ex-situ CMC drilling fluid

Appendix D- Effect of nanoparticles and salt in bentonite WBM with CMC

D.1. Effect of nano silica for KCl drilling fluid system

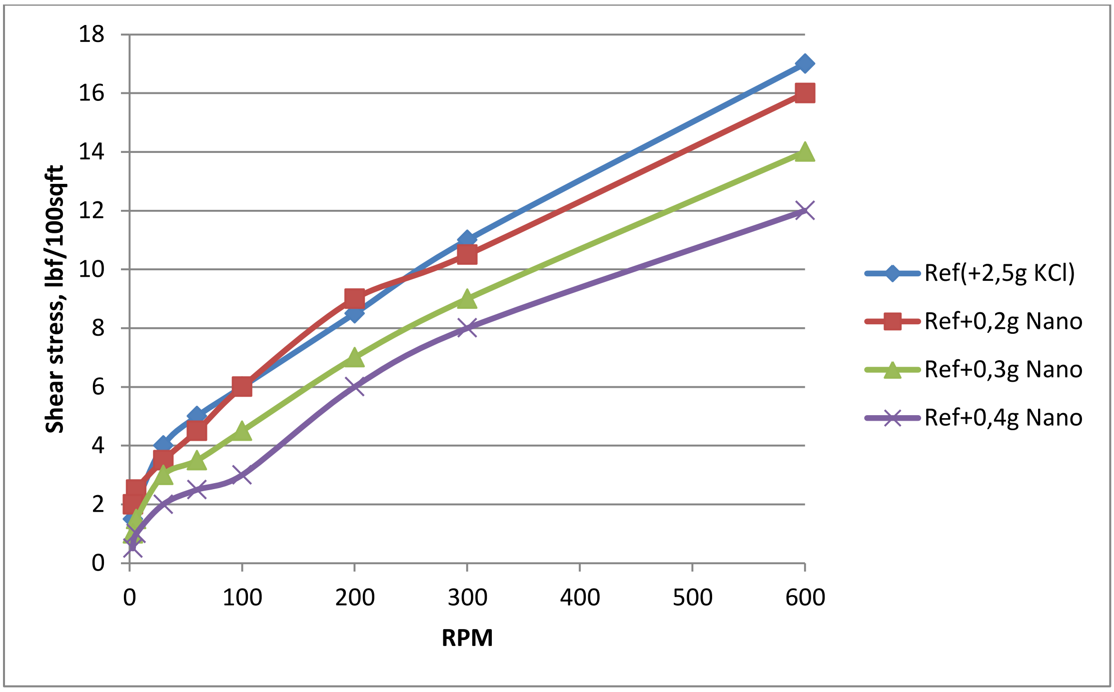


Figure D.1: Effect of nano silica for viscometer readings of KCl fluid system

D.2. Comparing the effect of nano silica for KCl, NaCl and KCl/NaCl fluid systems

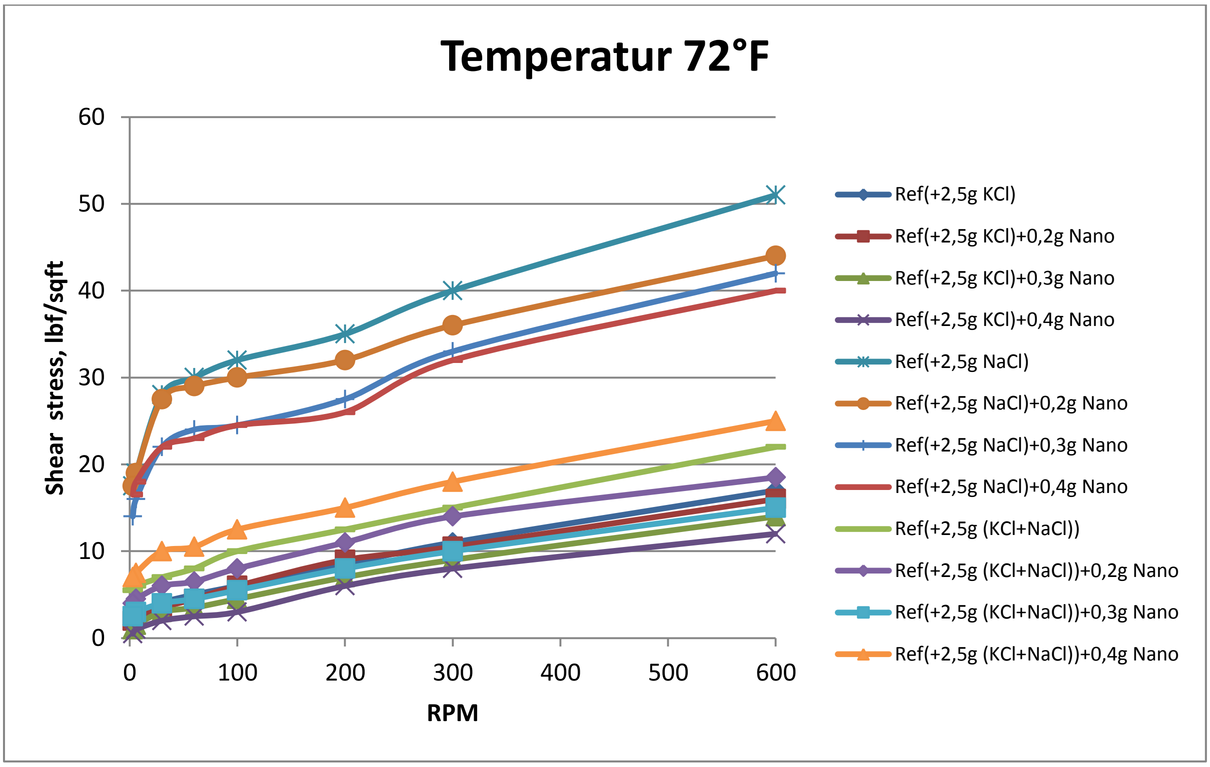


Figure D.2: Effect of nano silica for viscometer readings of salt WBM system

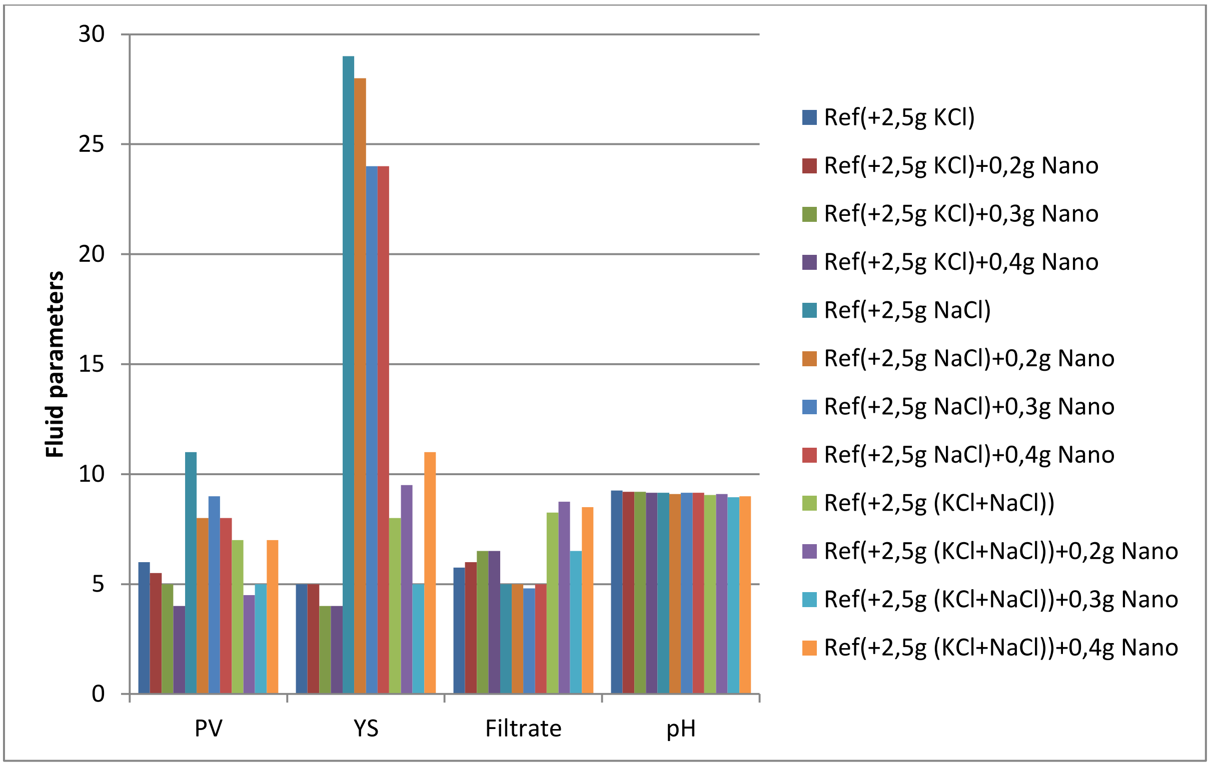


Figure D.3: Rheology parameters for salt WBM systems with nano silica

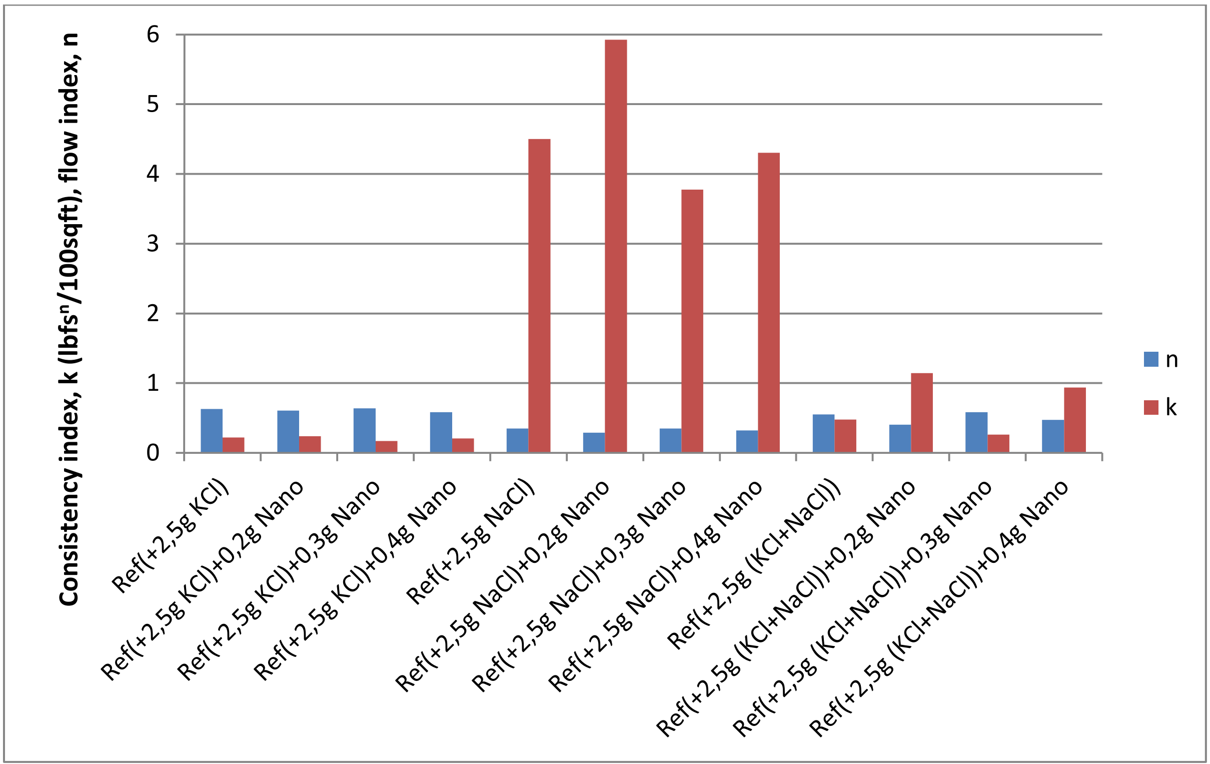


Figure D.4: Power law parameters for salt WBM systems containing nano silica

Appendix E- Effect of nanoparticles in polymer fluid systems

E.1. Comparing PAC and CMC fluid systems

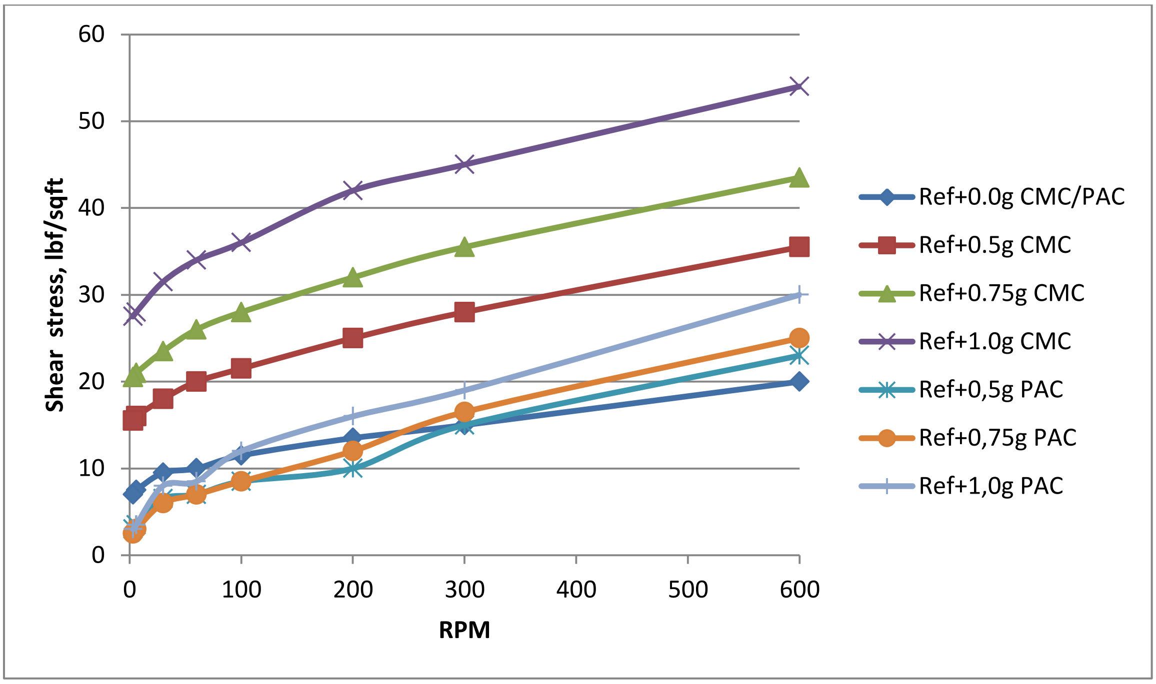


Figure E.1: Comparison the viscometer readings for both polymer WBM system

E.2. Comparing PAC fluids for in-situ and ex-situ mixing procedure

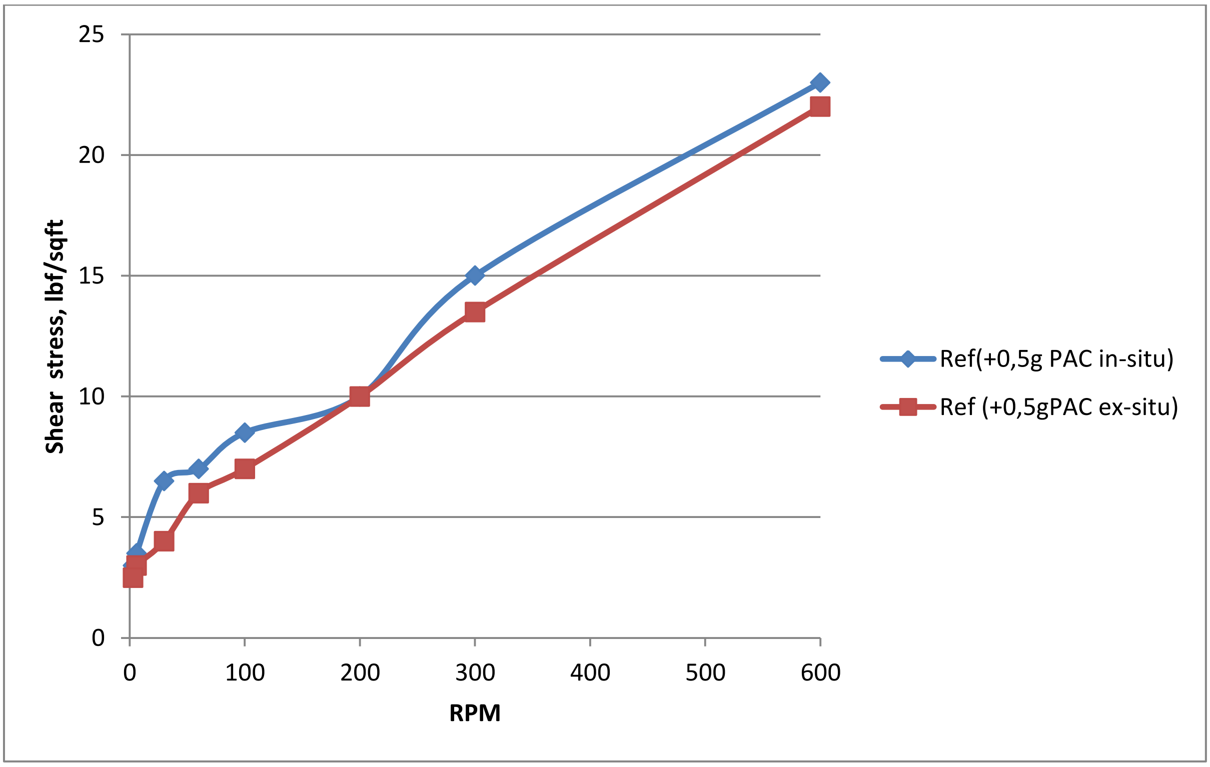


Figure E.2: Comparison of in-situ and ex-situ PAC drilling fluid

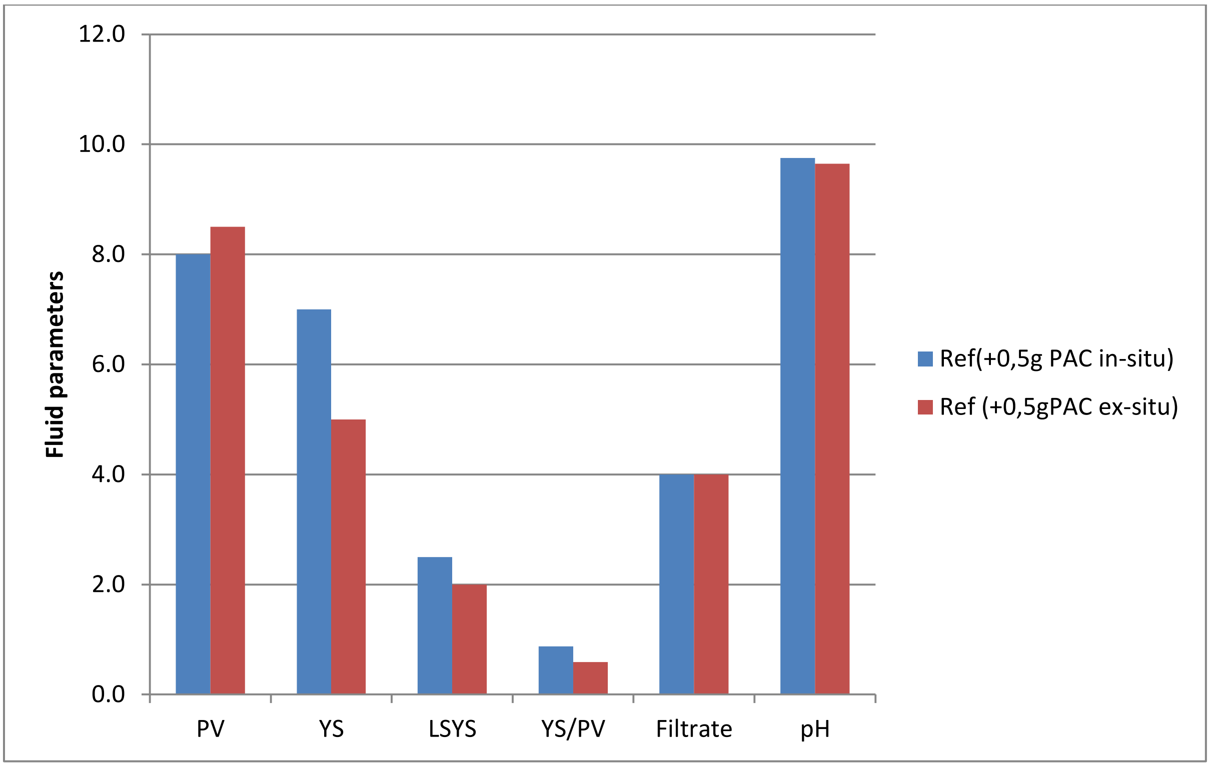


Figure E.3: Rheology parameters for in-situ and ex-situ PAC drilling fluids

E.3. Effect of nano silica in PAC fluid system

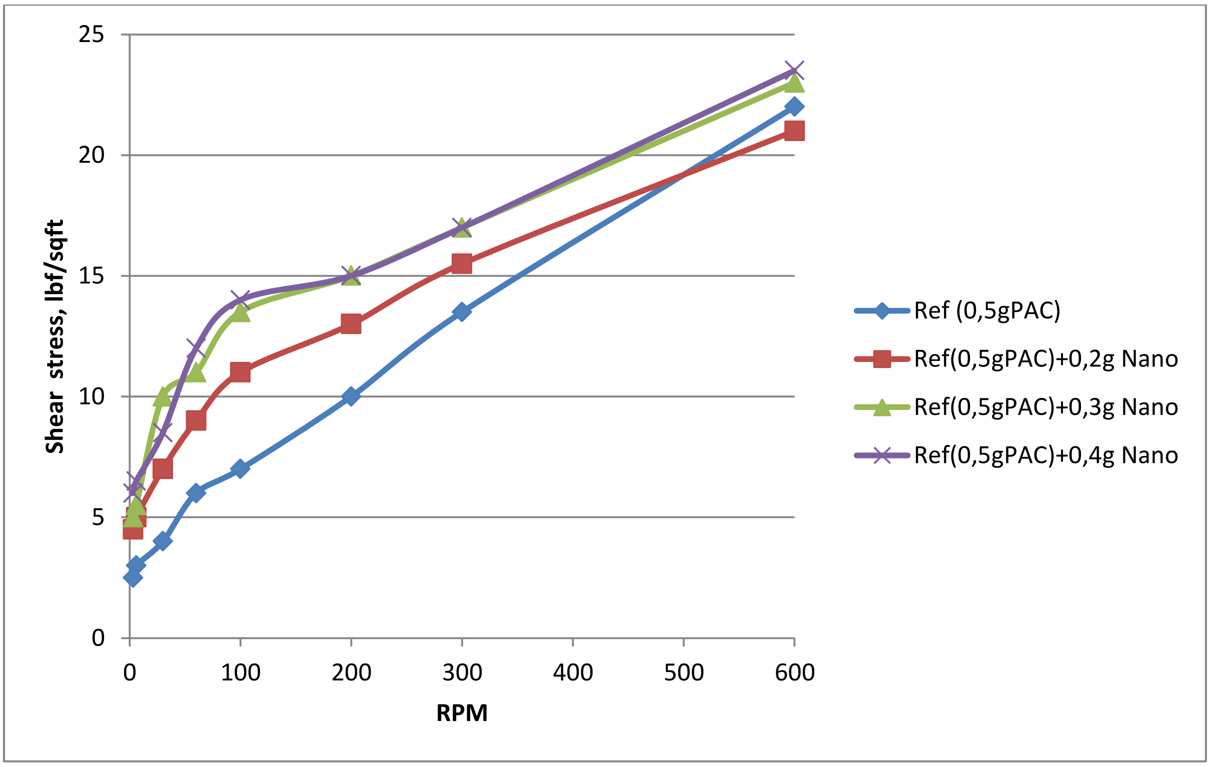


Figure E.4: Effect of nano silica for viscometer readings for PAC fluid system

E.4. Effect of nano silica in CMC/PAC and PAC fluid systems

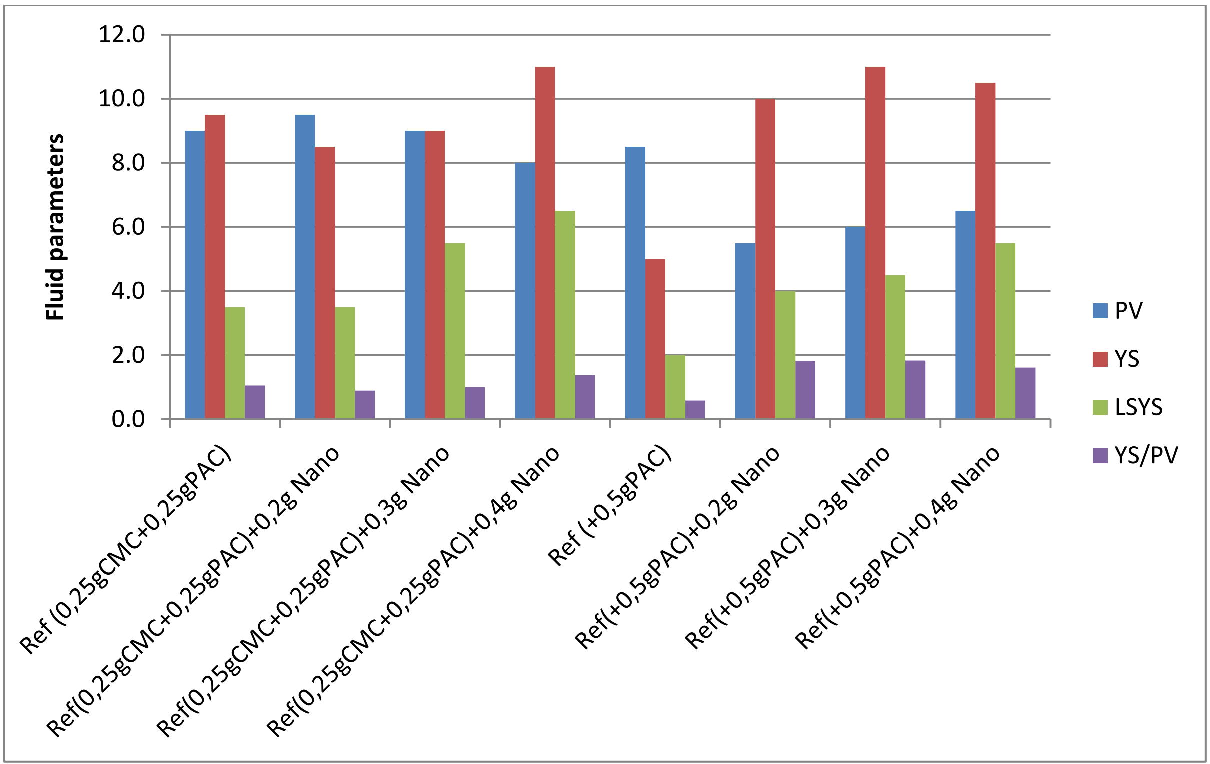


Figure E.5: Rheology parameters for CMC/PAC and PAC fluid systems with nano silica

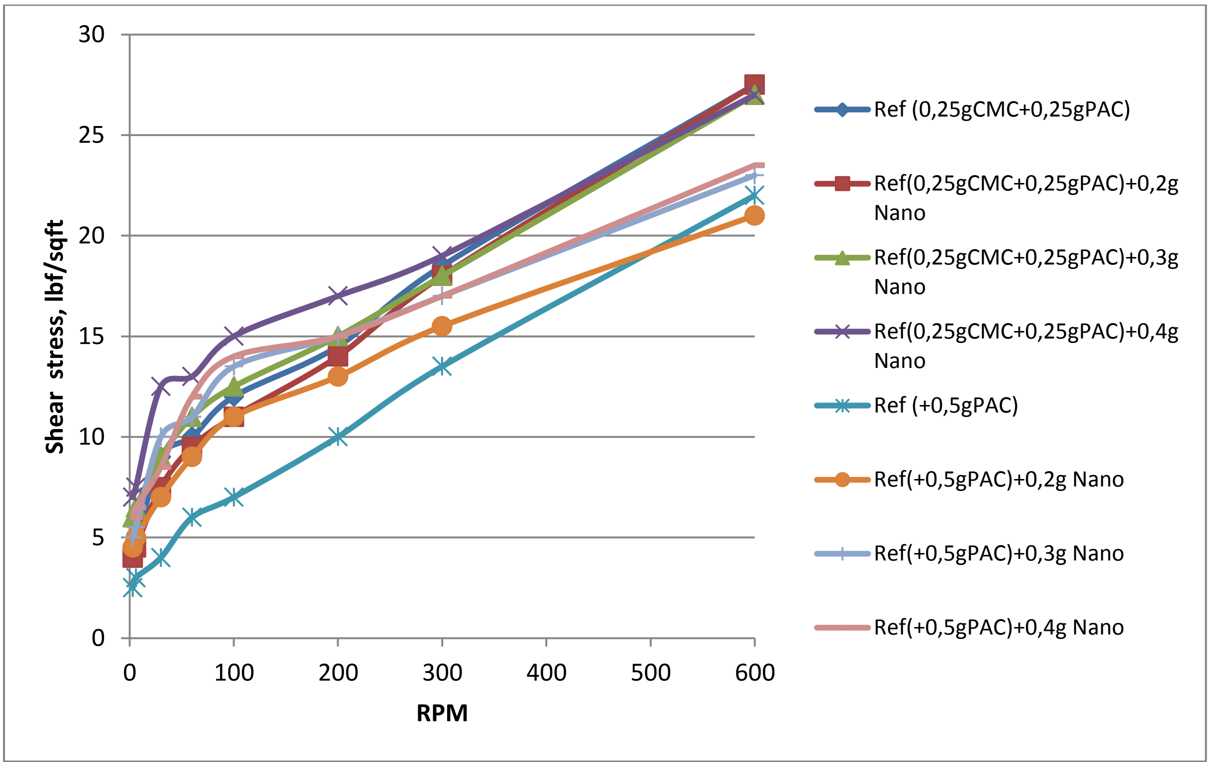


Figure E.6: Experimental results for CMC/PAC and PAC drilling fluids with nano silica

E.5. Comparison of CMC, PAC and CMC/PAC fluid systems

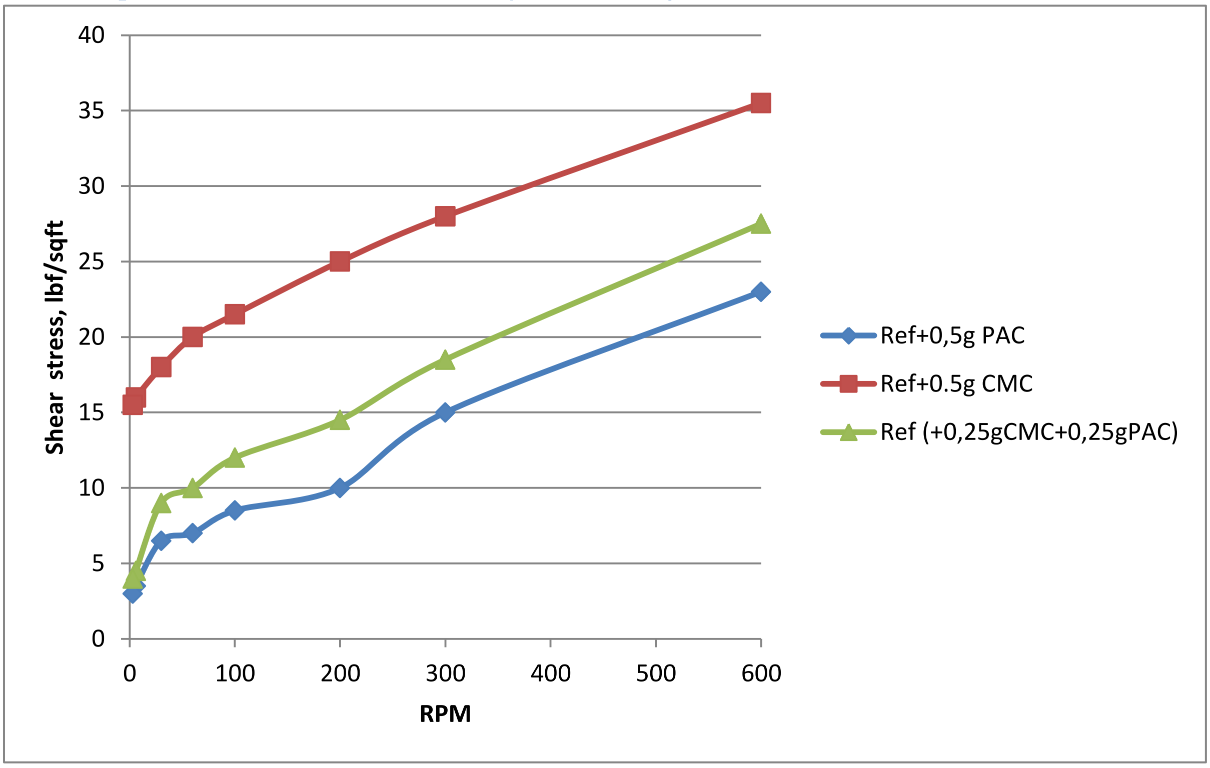


Figure E.7: Comparison of polymer type in drilling fluid

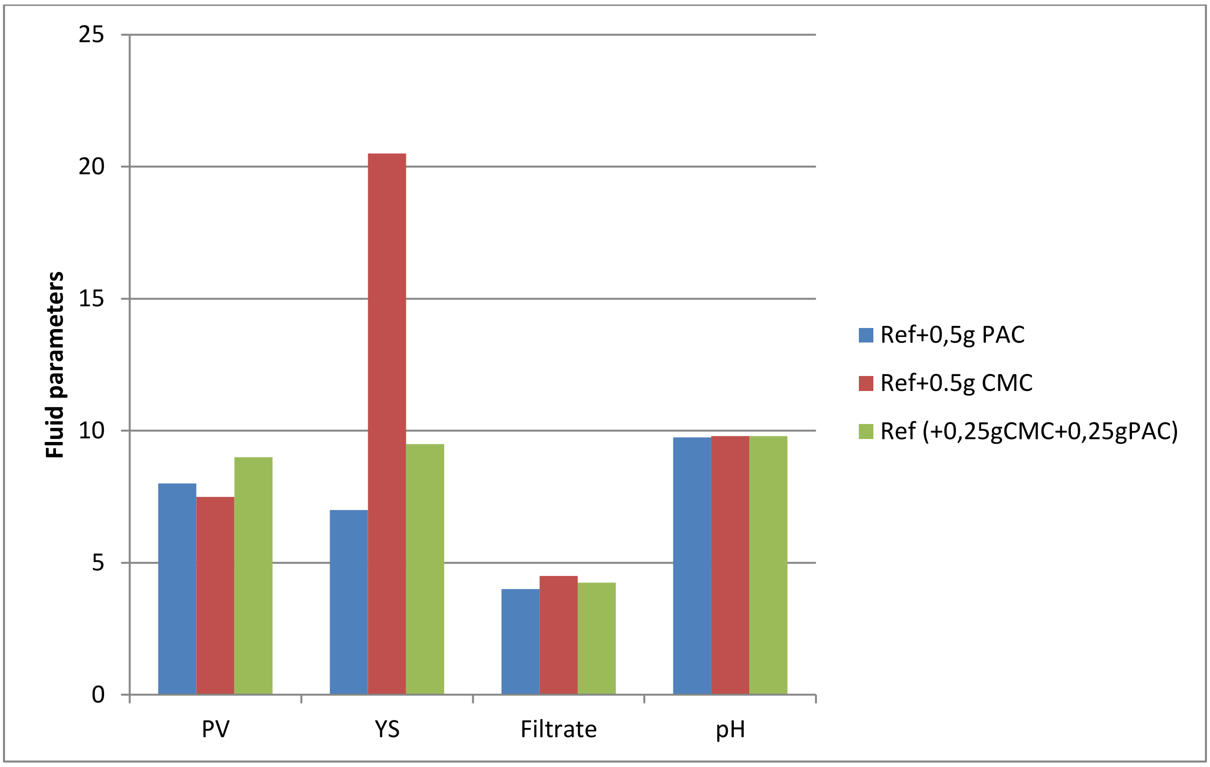


Figure E.8: Rheology parameters for different polymer fluids

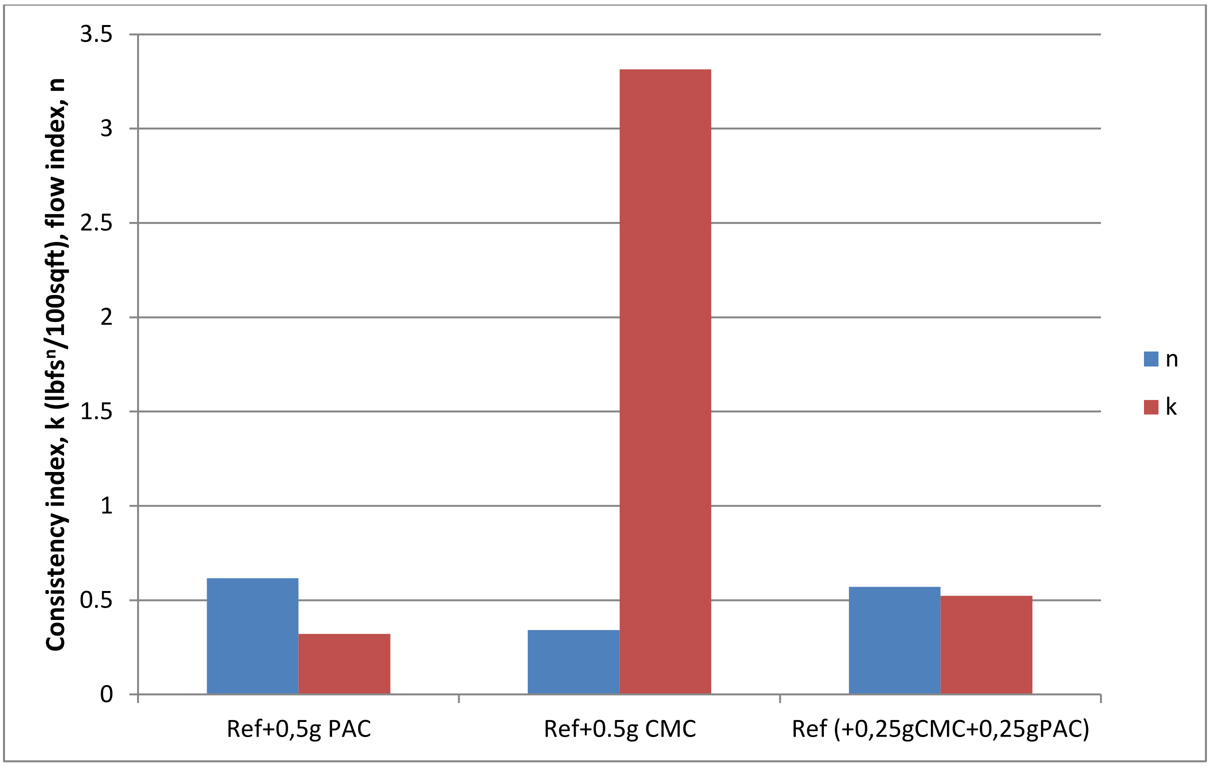


Figure E.9: Power law parameters for polymer WBM systems with nano silica

Appendix F- Hole and drill string data for simulation §4.3

Hole data (Casing + Open hole)

	Section type	Measured Depth (ft.)	Length (ft.)	Shoe Measured Depth (ft.)	Id (In)	Drift (In)	Effective Hole Diameter (In)	Friction factor	Linear Capacity (bbl/ft)	Excess (%)	Item Description
1	Casing	4012.5	4012.5	4012.5	12.250	12.459	12.615	0.25	0.1458		13 3/8in, 54.5ppf, J-55
2	Open Hole	11003.0	6990.50		12.250		12.250	0.30	0.1458	0.00	

Table F.1: Hole data (Casing + Open hole)

Drill String data (Drill pipe + BHA)

Type	Length	Depth	Body	Stabilizer/tool joint					Weight	Material	Grade	Class
	(ft)	(ft)	OD (in)	ID (in)	Avg.joint Length (ft)	Length (ft)	OD (in)	ID (in)	(ppg)			
Drill pipe	10445	10445.00	5.0	4.276	30.00	1.42	6.406	3.75	22.26	CS_API 5D/7	E	P
Heavy weight Drill pipe	120.0	10565.0	6.625	4.5	30.00	4.00	8.25	4.5	70.50	CS_1340 MOD	1340 MOD	
Hydraulic Jar	32.00	10597	6.5	2.75					91.79	CS_API 5D/7	4145H MOD	
Heavy weight Drill pipe	305.0	10902	5.0	3.0	30.00	4.00	6.50	3.063	49.7	CS_1340 MOD	1340 MOD	
Bit sub	5.00	10907	6.0	2.4					79.51	CS_API 5D/7	4145H MOD	
MWD tool	85.00	10992	8.0	2.5					154.36	SS_15-15LC	15-15LC MOD	
Integral blade stabilizer	5.00	10997	6.25	2.0		1.00	8.453		93.72	CS_API 5D/7	4145H MOD	
Bit sub	5.00	11002	6.0	2.4					79.51	CS_API 5D/7	4145H MOD	
Tri-cone bit	1.00	11003	10.625						166.0			

Table F.2: Drill String data (Drill pipe + BHA)

Abbreviations

CMC- Carboxymethyl Cellulose

D.P.-Degree of Polymerization

D.S.-Degree of Substitution

ECD- Equivalent Circulating Density

EDS- Elemental Dispersive Spectroscopy

HPHT- High Pressure High Temperature

LVER- Linear Viscoelastic Region

NPT- Non Productive Time

OBM- Oil Based Mud

PAC- Polyanionic Cellulose

PDC- polycrystalline diamond compact

PV- Plastic Viscosity

ROP- Rate of Penetration

RPM-Revolutions per Minute

SEM- Scanning Electron Microscopy

TVD- True Vertical Depth

US- United States

WBM- Water Based Mud

YP- Yield Point

YPL- Yield Power Law

YS-Yield Stress

Nomenclature

a – Frictional fractions parameters, []

b- Frictional fractions parameters, []

C_r - Rock matrix compressibility, 1/psi

C_b -Rock bulk compressibility, 1/psi

Co - Uniaxial compressive strength, 1/psi

D_p – Inside pipe diameter, in

D_n- nozzle diameter, in

$f_{laminar}$ -friction factor to laminar flow, []

f_p – friction factor to the pipe, []

$f_{partial}$ - intermediate friction factor (transient and turbulent), []

$f_{transient}$ - friction factor to transient flow, []

$f_{turbulent}$- friction factor to turbulent flow, []

G- Unified model parameter, []

g - Acceleration due to gravity, m/s^2

G'- Elastic modulus, Pa

G''- Viscous modulus, Pa

k - Consistency index, $lbf*sec^n/100ft^2$

k_p – Consistency index in the pipe $lbf*sec^n/100ft^2$

ΔL- change in length, ft

n - Flow behavior index, []

n_a- flow behavior index in the annulus, []

n_p – flow behavior in the pipe, []

N_{re}- Reynolds number, []

$\Delta P_{annulus}$/ ΔPa - Pressure loss in the annulus, psi

ΔPb – Pressure loss across the bit, psi

ΔPds- Pressure loss inside the drillstring, psi

P_o - Pore pressure, psi

ΔPp- Pump pressure, psi

ΔPs – Pressure loss in surface equipment, psi

P_{wf} - Fracturing pressure, psi

v_a – annular average velocity ft/min

v_p - pipe average velocity ft/min

(dp/dL) – Gradient pressure, psi/ft

ρ_{st} - Static mud weight, ppg

α - Biot coefficient []

β - Failure angle, degrees

σ_h, - Minimum in-situ horizontal stress, psi

σ_H - Maximum in-situ horizontal stress, psi

σ_t - Tensile strength of the rock, psi

σ'_h - Minimum effective stress, psi

σ'_H - Maximum effective stress, psi

τ - Shear stress, lbf /100ft^2

γ - Shear rate, 1/sec

μ_n - Newtonian viscosity, cP

μ_p - Plastic viscosity, cP

τ_y-Yield point, lbf /100ft^2

τ_{yL}- Lower shear yield point, lbf /100ft^2

δ- Phase angel, degrees

τ_w – wall shear stress, lbf/100ft^2

γ_w - wall shear rate, sec^{-1}