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Abstract

The primer objective of this thesis was to implement and test, in the automated drilling hydraulics laboratory at the University of Stavanger, a system for automatic adjustment of viscosity of a fluid. The fluid used to simulate the drilling fluid was to be a mixture of silicone oil and water. Due to the long waiting times and high prices of the required equipment, the project came to a halt and the nature of this study had to be changed into a more theoretical one, with limited time available.

Given that, we will look at the possibilities regarding the automation in the adjustment of drilling fluids properties, focusing only on the adjustment of density and viscosity.
First, drilling fluids are described as to their functions and properties. The property known as viscosity is described in more detail for a better understanding of the work carried on this thesis.

Two implementation proposals, one for automatic density adjustment and one for automatic viscosity adjustment will be presented, using Simulink.

A proposal for the mentioned experiment in the automated drilling hydraulics laboratory will be presented, along with a third Simulink implementation, designed for the experiment.

Two experiments that were carried out in the drilling fluids laboratory will be presented and their results discussed. The objective of these experiments was to demonstrate the effect of a polymer viscosifier on a fluid and how the solubility of that viscosifier is affected by a change in other properties of the fluid, such as salinity.

Acknowledgements

This thesis is one of several studies regarding automation in drilling operations, jointly performed by IRIS, Statoil, NTNU and UIS. It was written as the final work in the Master program in Petroleum Engineering – Drilling at the University of Stavanger. Although drilling fluids are not totally unfamiliar to me, trying to create an automated system demands new forms of looking at the existing structure of the drilling operations and crew.

A great part of the knowledge presented in this study was obtained through conversation with oilfield professionals over the past years and from own experience in offshore drilling operations in the Norwegian Continental Shelf.

Special thanks go to my colleagues at M-I Swaco for what they have taught me in the past two years and also to Mette Økland, personnel coordinator at M-I Swaco, for making it possible to combine my offshore work with the pursuit of a Master's degree at UIS.

Finally, I would like to thank Gerhard Nygaard for proposing the topic for this thesis. I would also like to thank Sivert Bakken Drangeid at the Institute of Petroleum Technology at UIS for the help provided in the planning of the experiments carried out in the drilling fluids laboratory.

Content

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1. Introduction

With the technological advances in the field of automation in other industries, it is inevitable for the drilling industry to also embrace automation as the way forward.

Several technical reasons can be argued in favor of automated drilling operations, such as higher ROP, faster connection times or more focus on well control by the driller. In addition, there are also some HSE advantages such as less exposure of the crew to health or safety hazards.

The eventual implementation of an automated drilling fluid properties adjustment system would play a significant part in the improvement of HSE standards on the drill site by eliminating the hazard of contact with or breathing of particles from fluid additives by the crew.

Nowadays, the drilling fluids engineer collects a sample of the drilling fluid (also known as mud), during drilling operations, and performs a full check consisting of several tests, usually at least twice during a twelve-hour shift. From the results of these tests, he then orders the addition of certain products, called additives. The viscosity measurements are taken at different shear rates, and the readings are used to calculate the Yield Point (YP) and the Plastic Viscosity (PV). If implemented, a system for continuous measurement and adjustment of the fluid properties would ensure the good condition of the drilling fluid, which can have a big impact on the success of the operation. Several models for describing the rheology of a drilling fluid exist, and will be later explained, but in this thesis, only the Bingham Plastic model has been used to calculate viscosity values.

Existing studies and literature

Several entities are making efforts to develop, test and implement automatic systems for a continuous measurement of the drilling fluids properties.

These efforts are described in publications such as:

- IADC/SPE 112687 - *Automatic Measurement of Drilling Fluid and Drill Cuttings Properties*
- SPE 150439 - *The Development and Successful Application of an Automated Real-Time Drilling Fluids Measurement System*
- IADC/SPE 151459 - *Real-Time Drilling Fluid Monitoring and Analysis - Adding to Integrated*
- *Drilling Operations* – Oilfield Review Summer 2012: 24, no.2. Schlumberger.

With so much attention being drawn to the automated measurement of the properties, very little is taking place regarding the automated adjustment of these same properties.

Two recent publications approach this problem:

- SPE/IADC 139943 – *Automation of the Drilling Fluid Mixing Process, Field Experiences and Development from North Sea Operations* [1]
- SPE/IAC 163473 – *Automatic Mud Mixing* [2]

The first study describes today's situation and shows the example of an existing system onboard Valhall WIP, which automatically mixes a drilling fluid from a preset recipe introduced by the Drilling Fluids Engineer. It also mentions the existence of a system for automatic density adjustment by addition of barite or light premix. It does not, however, discuss the implementation of a continuous viscosity adjustment system.

The second publication presents simulations in Matlab of a system for automatically adjusting density and viscosity of a fluid. Only the formulas for density adjustment are present in the publication.
In the model used, the effect of the addition of barite, bentonite and water is assumed, but not tested. This makes the model inapplicable in real-life situations as the effect of bentonite or a Polymer viscosifier is unpredictable due to the many variables that affect the efficiency and solubility of the additive, as we will discuss later.

2. Drilling fluids

The drilling fluid is one of the most important components of an oil-well drilling operation. It may in some cases represent the highest fraction of the overall cost of a drilling operation.

2.1 The drilling fluid circulation system

The circulating system on most drilling rigs consists of the same components, as shown in Figure 1, and usually comprises the following:

- Active pits/tanks, where the drilling fluid which is circulated into the well is stored.
- Mud pumps, used to pump the drilling fluid into the well.
- Standpipe, the pipe that carries the fluid into the top of the rotary equipment.
- Rotary hose, the hose that carries the fluid into the rotating drill pipe.
- Mud return line, the line that carries the fluid to the solids removal equipment after it has been circulated in the well.
- Shale shaker, the solids removal equipment designed to remove the largest cuttings/solids transported by the drilling fluid to the surface. The samples of the cuttings to be analyzed by the Mud Logger are taken from the shale shakers.
- Desilter, solids removal equipment designed to remove smaller particles from the drilling fluid.
- Desander, solids removal equipment designed to remove sand particles from the drilling fluid.
- Degasser, equipment used for the eventual removal of gas dissolved in the drilling fluid.
- Reserve pits/tanks, used for storage of extra of drilling fluid, not being used to circulate in the well.

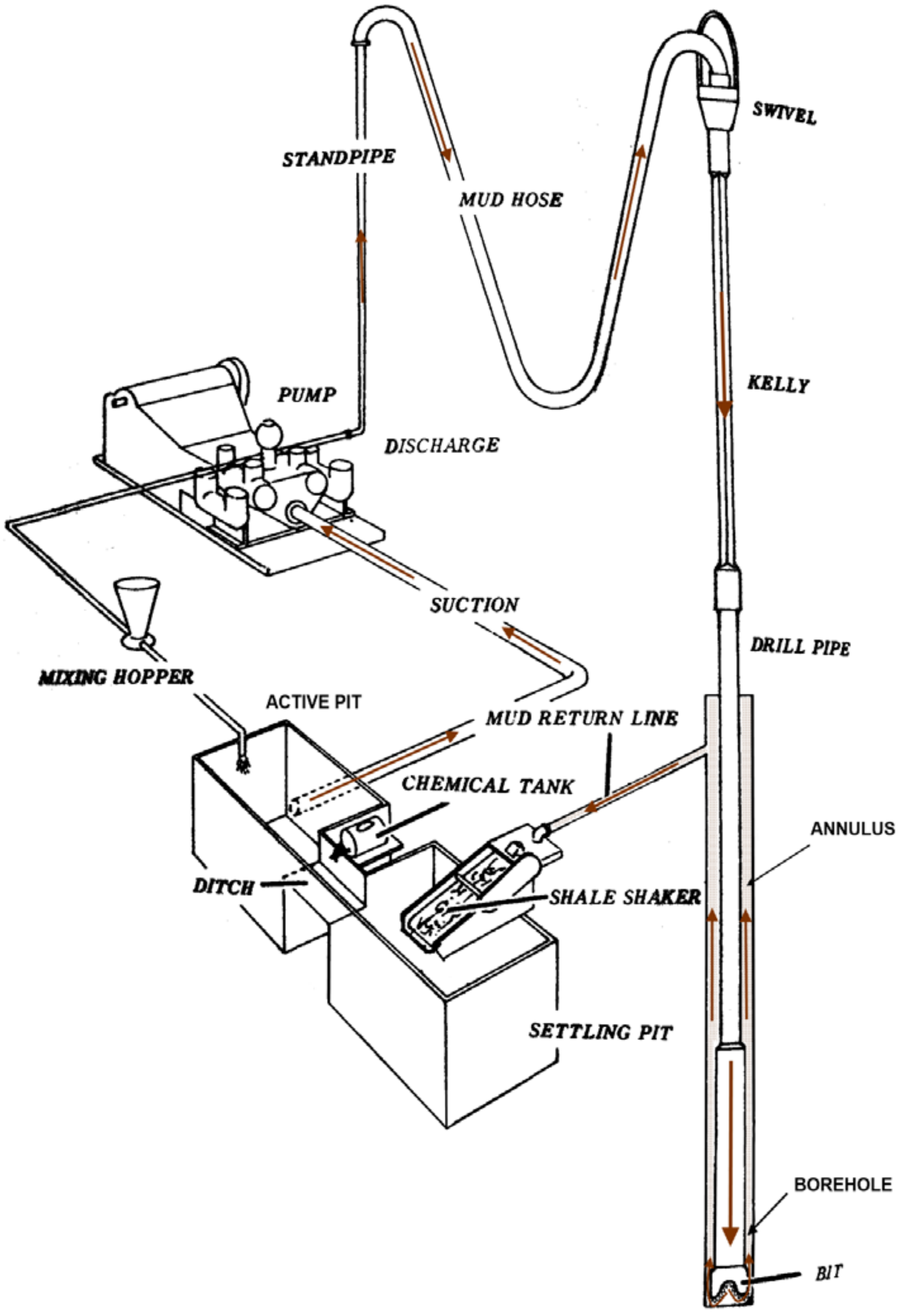

Figure 1 – The drilling fluid circulation system [3]

Starting in the mud tanks or pits, the fluid goes through the pumps, then up the standpipe, through the rotary hose, into the drill pipe, out through the bit and then up though the annulus until it reaches the surface. At surface, it is directed to the solids removal equipment and back into the mud pits or tanks.

Mixing of new drilling fluid usually takes place in the reserve pits or tanks, but additives for property adjustment are mixed into the fluid passing through the active pits/tanks.

2.2 Functions of the drilling fluid

Some functions of the drilling fluid can vary with the type of well or formation, but the basic functions remain the same for most oil-well drilling operations. Two of the most important functions are controlling the formation pressure and the transport of the cuttings from the bottom of the well up to the surface.

The importance of a certain function of a drilling fluid will depend on the specific well being drilled. The following description of the functions of the drilling fluids was entirely adapted from the *M-I drilling fluids engineering manual* [4].

2.2.1 Remove cuttings from the well

The drilled cuttings that are generated by the drill bit must be removed from the well. As the drilling fluid is circulated as described above, it carries the cuttings with it to the surface. This removal, also called hole cleaning, is a function of cuttings size, shape and density, rate of penetration (ROP), drill string rotation, and of the viscosity, density and annular velocity of the drilling fluid.

The viscosity has a significant role in hole cleaning, as cuttings will settle quicker if the fluid viscosity is low. A high viscosity usually means better hole cleaning.

The fact that the drilling fluid is thixotropic means that when there is no circulation, the cuttings can be suspended by the gelled fluid.

2.2.2 Controlling formation pressures

Controlling the pressure of the formation is one of the basic functions of the drilling fluid in order to prevent the influx of formation fluid into the well. This is achieved by controlling the density of the fluid with weighting agents such as barite. The hydrostatic pressure exerted by the drilling fluid must be equal or higher (preferably higher) than the formation pressure. This exerted pressure is a function of the True Vertical Depth (TVD). Geologists and Petrophysicists will provide a prognosis of the formation pressure. In the mud program, the drilling fluid density specification is given as a pressure gradient, usually specific gravity or pounds per gallon.

In case there is loss of well control (influx of formation fluid), a higher density fluid is pumped into the well to regain control of the well.

2.2.3 Suspend and release cuttings

As mentioned in the first point, when there is no circulation in the well, the drilling fluid must be able to suspend the cuttings, avoiding the accumulation of cuttings at the bottom of the well, also called pack off. Cuttings suspension is better achieved when a fluid has high viscosity.

On the other hand, when the fluid passes the solids control equipment, a low viscosity would be ideal, so that the cuttings are released by the fluid. The solution for this is the shear thinning nature of the drilling fluid, which allows for the cuttings to be removed.

The fluid must also be able to suspend the weighting material used, otherwise it will sag and the density will not be homogeneous throughout the drilling fluid.

2.2.4 Seal permeable formations

Because the hydrostatic pressure created by the drilling fluid column is higher than formation pressure, some of the fluid will enter the formation around the well bore. The fluid is designed to minimize this invasion, by the addition of fluid loss agents. A high fluid loss is undesirable because it can contaminate the formation and have a negative effect on wellbore stability and future production from the well. The protective layer, also called filter cake, produced should be easily removable if the well is to be used for production or injection.

2.2.5 Maintain wellbore stability

Wellbore stability depends on both chemical and mechanical factors. If the drilling fluid is not compatible with the formation, this may swell and cause the drill string to become stuck. Additives, such as KCl, which works a shale inhibitor, can help reduce the danger of this happening. The density also plays a role in wellbore stability by balancing the mechanical forces that act on the wellbore, thus avoiding collapse of the formation.

2.2.6 Minimize formation damage

If the objective of drilling a well is to produce oil or gas, then the damage caused by the drilling operation must be minimized. An affected reservoir may present a reduction in productivity. The type of completion chosen dictates the importance of limiting the damage while drilling. The liquid fraction of the drilling fluid, which enters the formation during drilling, must be compatible with the formation and with the formation fluid.

2.2.7 Cool, lubricate and support the bit and drilling assembly

While drilling, the rotation of the drill string and the circulation of the drilling fluid create friction forces that generate heat. As one drills deeper, the formation temperature also increases significantly. All this heat combined can be excessive for the bit, mud motor or other down hole equipment, and the drilling fluid helps to reduce the bottom hole temperature. Some rigs may have a mud cooler installed at surface, when bottom hole temperatures are elevated.

Lubrication is also provided by the fluid and this will depend on the drill solids content, pH, salinity and hardness of the fluid.

Support of the drilling assembly is achieved by buoyancy. This helps reduce the hook load when running the drilling assembly and casing strings.

2.2.8 Transmit hydraulic energy to tools and bit

Down hole tools like Measurement While Drilling (MWD) and Logging While Drilling (LWD) are usually powered by the energy of the flowing drilling fluid. The same happens when drilling with mud motors. To achieve good hole cleaning, the sizes of the bit nozzles are usually chosen so that the hydraulic efficiency at the bit is high. This has a great positive impact removal of cuttings from the well.

2.2.9 Ensure adequate formation evaluation

During a drilling operation, the cuttings retrieved at the solids control equipment and the mud returning from the well, are analyzed and monitored for traces of oil and gas. The drilling fluid must allow a clear distinction between the hydrocarbons and the fluid, as well as the identification of the minerals present in the rock.

The chemical composition of the drilling fluid also affects the readings from the logging tools, taken either while drilling or at a later stage. These readings are of extreme importance for the operator company to obtain more knowledge of the subsurface and the formation around the specific well.

2.2.10 Control corrosion

In order to increase lifetime of the equipment, corrosion should be minimized. The drilling fluid has an important role in this. Corrosion can originate in dissolved gasses, such as oxygen, carbon dioxide and hydrogen sulfide. To limit the corrosion caused by these gasses, the pH should be kept above a certain level. Chemical inhibitors or scavengers may also be used in situations where the danger of corrosion is high or upon the presence of H_2S gas, which is both corrosive and deadly to humans. The drilling fluid should also be compatible with all the rubber or elastomer parts of the drilling equipment.

2.2.11 Facilitate cementing and completion

For a good completion and cementing operation, the wellbore should ideally be near gauge size and have a thin and slick filter cake. The viscosity should be low and so should be the gel strengths, when running the casing string and cementing it. This is to minimize pressure surges which cause fracture-induced lost circulation. Perforation operations may also be affected by the properties of the fluid in the well.

2.2.12 Minimize impact on the environment

Ideally the drilling fluid should be reused at all times. This is not always a possibility and it may happen that some drilling fluid is disposed of. When that is the case, the drilling fluid must fulfill the local environmental regulations to minimize its impact on nature and people.

The drilled cuttings may be disposed of on site, re-injected or treated and destroyed. The ability to dispose of cuttings depends solely on the nature of the drilling fluid and its additives.

2.3 Types of drilling fluids

Drilling fluids are categorized in terms of the base fluid used as well as the type of additives that it contains.

There are three main groups of drilling fluids which are gaseous, water-based and oil-based.

Gaseous drilling fluids are not as commonly used as water- or oil-based fluids. Water-based fluids can further be divided according to the additives into clay-based or polymer-based fluids.

Oil-based fluids generally use synthetic oil as a base fluid, but diesel-based drilling fluids may still be found in some parts of the world. The newer synthetic oils, also called mineral oils, are less harmful to the health of the drilling crew and therefore preferred.

When choosing a drilling fluid, one must always find a balance between the specific needs of the well and the cost of the fluid. The drilling fluids cost can vary quite substantially and may represent a big share of the total cost of the well. For example, an oil-based fluid may be better for hole stability and ECD, but if the cuttings cannot be injected, they must be treated before disposal, and that increases the overall cost of using that fluid. There may also be some restrictions regarding the base fluid or additives used, depending on local regulations.

Overall, companies choose the drilling fluid based on past experience from similar wells in the same area, or when no data is available, based on experience from wells in other locations and on the prognoses given by the Geologists and Petrophysicists.

2.4 Composition of drilling fluids

Modern drilling fluids may comprise of an extremely complicated chemistry depending on the application. The simplest type of drilling fluid used is probably the so called “spud mud”, due to its use in top-hole sections. This fluid is usually constituted only of water and a viscosifier. As wells are drilled deeper and into more demanding formations, more additives are needed to control several properties, from density to shale inhibition and lubricity. Many types of additives are used, some as simple as nutshells, used to seal fractures and stop fluid loss, others more complex such as advanced lubricants and polymer viscosifiers.

2.5 Properties of drilling fluids

During a normal drilling operation, the drilling fluid is tested at least twice per 12 hour shift to determine the values of a set of properties. The monitored properties depend mostly on the type of fluid being used, and can include the following:

2.5.1 Density

The density of the drilling fluid is one of the most important properties and should always be adjusted to the specified value. Besides controlling the flow of formation fluids into the well, it also impacts hole cleaning. It is therefore a very important property to monitor and one of the two that we will focus on when designing an automated fluid property adjustment system.

2.5.2 Viscosity

After density, the viscosity of the drilling fluid is the next most important property to be monitored and corrected as it has influence in several of the functions that the fluid should provide during a normal drilling operation. For that reason, it is of great value to implement a system for automatic adjustment of this property, so that the efficiency of the operation can be maximized and not be conditioned by the attention or availability of the crew to treat the drilling fluid.

Shear dominates most of the viscosity-related aspects of drilling operations. Because of that, shear viscosity (or simply, “viscosity”) of drilling fluids is the property that is most commonly monitored and controlled. [5]

To better understand how it affects the overall operation, the meaning and definition of viscosity must be understood. The following definitions of viscosity and rheology models were entirely adapted from *Drilling fluids processing handbook* [5]:

In general, rheology is the study of the deformation and flow of matter.
The property called viscosity is a measure of the resistance offered by that matter to a deforming force.
Shear viscosity, which is present in drilling operations, is defined by the ratio of shear stress τ to shear rate γ:

$$\mu = \frac{\tau}{\gamma}$$

The traditional unit for viscosity is the Poise (P), or 0,1Pa-sec (also 1 dyne-sec/cm^2), where Pa=Pascal.

For Newtonian fluids, such as pure water or oil, viscosity is independent of shear rate.

Plotting τ versus γ obtained from the rearranged equation $\tau = \mu \cdot \gamma$ will give a straight line with a slope of μ that intersects the ordinate at zero, as seen in Figure 2.

In the case of non-Newtonian fluids, such as drilling fluids, viscosity depends on shear rate and is expressed as:

$$\mu_e = \frac{\tau}{\gamma}$$

where μ_e is called the “effective” viscosity. As this effective viscosity varies with the shear rate, the shear rate at which it is measured must be reported.

Drilling fluids are usually shear-thinning, which means that their viscosity decreases as shear rate increases.

To be able to study viscosity, several mathematical models have been created. The most used are the Bingham Plastic, Power Law, and Herschel-Bulkley. All three are represented in Figure 2.

The first model and the most commonly used, the Bingham Plastic, introduces a nonzero shear stress at zero shear rate:

$$\tau = \mu_p \cdot \gamma + \tau_0 \qquad \text{or} \qquad \mu_e = \frac{\tau}{\gamma} = \mu_p + \frac{\tau_0}{\gamma}$$

where μ_p is the plastic viscosity and τ_0 the yield stress. The yield stress is the stress required to initiate flow. The plastic viscosity μ_p is analogous to μ in the equation for Newtonian fluids.

As the shear rate increases, the ratio $\frac{\tau_0}{\gamma}$ will approach zero and μ_e will approach μ_p.

If the shear stress τ is plotted versus shear rate γ, μ_p is the slope and τ_0 is the value where the line intercepts the y axis.

The Bingham Plastic model does not work well for describing low-shear-rate viscosity of a fluid, based on high-shear-rate measurements, leading to an overestimated value.

The second mentioned model, known as Power Law, is defined as:

$$\tau = K_p \cdot \gamma^{n_p} \quad \text{or} \qquad \mu_e = \frac{\tau}{\gamma} = K_p \cdot \gamma^{n_p - 1}$$

where K_p is the consistency and n_p the flow behavior index.

Although this model underestimates the low-shear-rate viscosity, it is the most appropriate of the three for describing the behavior of polymer-based, water-based fluids.

To solve this inaccuracy of the Bingham Plastic and the Power Law, the Herschel-Bulkley model is used. It conjugates both previous described models and is as follows:

$$\tau = K \cdot \gamma^{n} + \tau_0 \qquad \text{or} \qquad \mu_e = \frac{\tau}{\gamma} = K \cdot \gamma^{n-1} + \frac{\tau_0}{\gamma}$$

This model is more adequate for oil-based fluids and for clay-based water-based fluids.

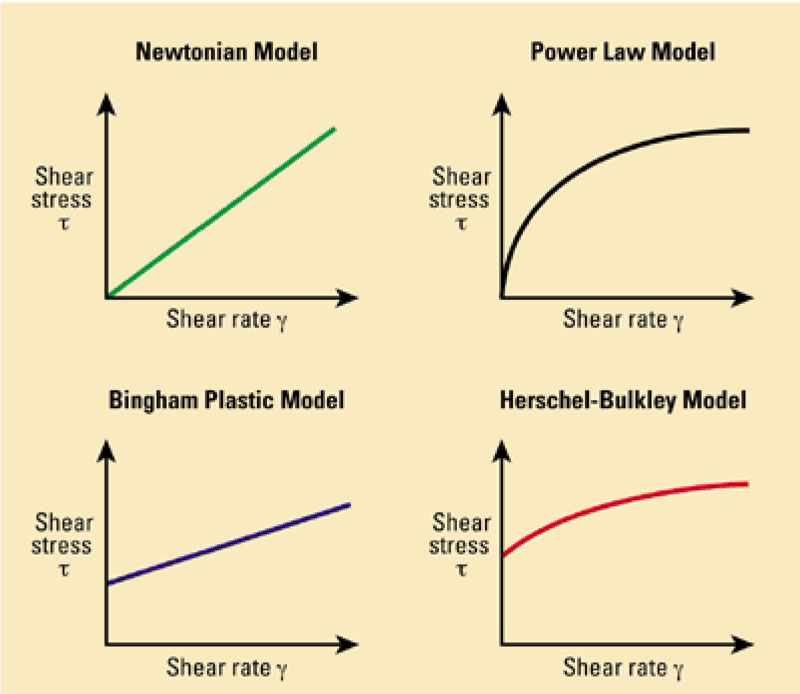

Figure 2 - The different rheological models [6]

2.5.3 Fluid loss

The fluid loss reveals the ability of the drilling fluid to form a barrier, called filter cake, which will prevent the loss of fluid into the area of the formation around the wellbore. This fluid is composed by the liquid fraction of the drilling fluid and is known as filtrate.

The filter cake should be thin and smooth, and the fluid loss should be low. The specification value for the fluid loss varies from well to well. Fluid loss is measured by placing the fluid in a cell, over a piece of filter paper and exerting back pressure, to simulate the situation found during drilling.

2.5.4 pH

The pH of a drilling fluid is important for controlling corrosion and the development of bacteria that can consume polymer additives and produce H_2S gas. It also affects the efficiency of additives such as viscosifiers and may influence the lubricity of the fluid. The pH is usually specified as a range of values and is measure using a pH-meter or by titration, in oil-based fluids.

2.5.5 Alkalinity

Measured in a similar way to the pH, the alkalinity measurement determines the OH^-, ${HCO_3}^-$ and ${CO_3}^{2-}$. Just like the pH, the alkalinity also affects the effect of additives.

2.5.6 Salt content

The salt content is also one factor that affects the efficiency of viscosifiers since is leaves less “free water” available for hydration. Its measurement enables the calculation of the water activity.

2.5.7 Oil-water ratio

The oil-water ratio is related to oil-based fluids only and is also a monitored parameter. In oil-based fluids, water acts as a visosifier and reduces the fluid loss. The ratio is measured using a retort cell, for distillation of the liquid fraction of the drilling fluid. In the measuring cylinder, the water can easily be distinguished from the oil visually and the ratio calculated.

2.5.8 Sand content

It is important to maintain a low level of sand content in the drilling fluid due to its abrasiveness on equipment such as pumps and pipes. The sand should be removed by the solids control equipment.

2.5.9 Solids content

The total solids content of a drilling fluid is measured with the same test mentioned for the oil-water ratio, with the solids fraction being the volume of the initial fluid not distilled in the retort. The data is usually introduced in computer software for calculating the low gravity solids (LGS) and high gravity solids (HGS).

The low gravity solids content should be kept at low levels and is usually one of the specified parameters in a fluid program. The amount and nature of these solids will affect the density and viscosity of the fluid, filter cake build up, hole cleaning, increase pressure losses due to friction and may also limit the solubility of viscosifiers.

2.5.10 Hardness

The hardness of the drilling fluid is obtained by measuring the Calcium and Magnesium content.

The calcium content of the drilling fluid may be one of the specifications on the mud program. This can have an effect on the lubricity of the fluid as well as in the solubility of viscosifiers.

2.5.11 Electrical stability

The electrical stability is measured with a ES-meter and describes the state of an emulsion. The smaller the droplets of water in mixed in the oil, the more stable is the emulsion. This is, of course, only applicable in oil-based fluids.

2.5.12 Other properties considered in specific applications

Other parameters are also monitored when using a specific type of drilling fluid. These can be, for example, the KCl or the glycol content.

In some specific cases and when other properties are needed, additives such as corrosion inhibitors or lubricants are used and should also be added if their content is less than the desired value.

The decision to adjust any of the properties close to or back to the value or range specified in the drilling program depends on the nature and stage of the operation. At all times an evaluation of the economical versus operational impact of the parameter to be corrected is done before any treatment is initiated. This decision is taken in cooperation with the drilling supervisor (company representative), who has the last word.

2.6 Mixing of drilling fluids

When the drilling fluids to be used in the drilling of a well are not received from the base, they must be mixed on the platform/rig. This can be either a ready to use fluid or the so called premix, which is used to dilute the fluid during the operation in order to reduce its density or viscosity.
The mixing equipment must be able to provide shear, to improve the fluid quality and to avoid so called “fish eyes”. It must also allow for the rapid mixing of additives or new drilling fluid in case of unexpected problems during the operation.
The equipment used for this mixing operation varies from installation to installation, but in general, one or the combination of several is used:

2.6.1 Mud Hopper

The mud hopper is the most commonly used equipment for mixing or adding chemicals and other additives to the drilling fluid. It consists of a funnel shaped upper part, where the additives are inserted, which is connected to the top of a venturi pipe. A venturi pipe is a pipe with varying diameter. As the flow is directed through it, there is a suction created which will force the additive into the fluid flow. The venturi pipe works according to Bernoulli’s principle, describing the conservation of energy. It says that the sum of pressure and velocity is constant throughout a pipe, which means that the change in diameter in the venturi pipe creates a change in the fluid velocity, which creates a pressure difference. This pressure difference, along with gravity, draws the additive placed inside the mud hopper and mixes it with the existing fluid.
This mixing process induces some shear to the fluid, which is specially desired when adding viscosifiers such as bentonite or polymers.
The use of a conventional hopper means that the operator has to cut the sacks, with for example a knife, and then pour the contents into the upper, funnel shaped part of the mixer. This can lead to inhalation of fine particles or dust by the operator, which in many cases can represent a health hazard. It also requires, most of the times, the manual lifting of each individual sack of chemical to be added.

2.6.2 Sack cutter/mixer

A sack cutter is a machine where a bag with chemicals to be mixed in the drilling fluid is inserted. The sack is cut by the machine inside a protected container and the contents are mixed into the fluid. The use of this equipment improves the working environment drastically, compared to the usual hopper since the operator is not exposed to the particles released when cutting and mixing the sack.

2.6.3 Chemical tanks

In some offshore installations, systems can be found that make use of chemicals pre-loaded into tanks. These tanks are filled at the base and shipped to the rig location. Once at the rig, the tanks are loaded on top of the mixing system with a forklift and the dosage is controlled by a computer or console. In the computer, the operator can choose the total weight of chemical to add and the rate, in kilogram per minute.

2.7 Example of equipment currently in use

Gullfaks B

The drilling crew onboard Gullfaks B has available the following setup:

- 11 tanks for drilling fluid and waste fluid from washing and other sources. The total capacity available is 555 cubic meters;
- 2 mud hoppers, for manual addition of chemicals provided in sacks;
- 2 barite surge tanks installed above each mud hopper;
- 4 stations for addition of chemicals using the Procon tank system;
- 2 mixing lines, A and B.

The Drilling fluid is pumped through the so called mixing line from and to the tanks, passing through the mud hopper. The mixing line and the pump are connected only to some of the tanks. Chemicals can be added to a maximum of two tanks at a time, by using the lines A and B. Additions to be made to the active mud, flowing into and out of the well, are made by using one of the mixing lines as well.

The mud hoppers are as described in 2.6.1, each with a surge tank of barite on top and a venturi pipe through where the additives and the barite pass when being added to the drilling fluid. Both hoppers have also an input for the addition of chemicals in liquid state.

The barite surge tanks store a limited amount of barite only for “daily usage”. For storing higher quantities, the rig disposes of three barite bulk storage tanks with the capacity of over 130 tons each.

The Procon tanks are metal tanks which are pre-loaded with chemical additives at the base by the chemical provider. These tanks are placed over a conveyer belt which carries the additive into an Archimedes screw, which then carries it into the mud hopper. The addition is controlled by a computer where the crew can set the desired rate. All four stations can be used simultaneously [7].

Pictures of the equipment currently available on Gullfaks B are attached in Appendix E.

Mærsk Innovator

Similarly to the Procon tanks, on Mærsk Innovator, mud chemicals are delivered in so called “Big Bags”. As the tanks, their content can be added by using computer controlled equipment, where the rate can be set. They are delivered in a range of 400, 500 and 1000kg. Similarly to the tanks on Gullfaks B, the bags are placed on a dedicated system with an Archimedes screw for transporting the additives. They are transported to the rig by boat and inside a regular transport container [8].

2.8 Chemical storage in sacks versus storage in tanks

HSE – Regarding HSE, the Procon tanks and big bags represent a big difference for the operator on the site since there is no contact with the chemical, no need for manual lifting of the sacks and no particles are released into the air during addition. In the case of the Procon tanks used onboard Gullfaks B, the chemicals are loaded into the tanks at the M-I Swaco base in Florø. In this case, the chemicals are transferred from normal 25kg sacks which are emptied into the tank. If this process is done manually, then the HSE risk is not eliminated, but only transferred from the rig site to the base. Some rigs are equipped with machines that can lift single bags and transport them to the hopper with a swinging arm. Others have small lifts that elevate the sack to the same height as the hopper. Even more advanced are systems that automatically feed sacks into the hopper with a conveyor belt and can be programmed to add the chemicals at a specified rate.

Chemical degradation – In the case of Procon tanks, the chemicals are protected from the weather by the sealed tank, which represents more protection than storage in sacks.

Risk of plugging – Some chemical additives, like for example sodium bicarbonate are known to plug the outlet of the Procon tank due high exposure to moisture.

The Procon tanks have the advantage of being transported without the need of an additional container like chemicals provided in sacks do. They can also be lifted by the onboard crane directly, again, without the need of another container.

3. Adjustment of drilling fluids properties

As mentioned before, the density and viscosity of a drilling fluid are two of the most important properties to be taken into consideration. As they are of such importance to the success of the operation, their values must be monitored and adjusted to be kept in the range specified in the drilling fluid program.

The 3RPM reading and the Plastic viscosity are usually regarded as the most important of the viscosity measurements, and are therefore the viscosity parameters of the drilling fluid that receive more focus. The Plastic Viscosity is a result of the presence of drilled solids in the fluid, while the 3RPM reading relates to the ability of the fluid to transport the drilled cuttings. The fluid requirements stated in the fluid program for a specific well are normally given in terms of these two properties, instead of the apparent or cinematic viscosity.

The viscosity specifications are given in terms of the 3RPM reading because this is the fluid characteristic that has the greatest impact in hole cleaning [9].

3.1 Importance of continually adjusting the density and viscosity while drilling

Besides the crucial role density in well control, there are other reasons why the density should be adjusted whenever it deviates from the set value. Density and viscosity strongly affect hole cleaning, which is decisive for the success of the operation.

Viscosity plays a significant role, especially in deviated wells, where the danger of forming a cutting bed is higher. In those types of wells, increased AV coupled with low PV, elevated low-shear-rate viscosity, and high drill string RPM will generally tend to minimize formation of a cuttings bed [5].

Fluids that are shear thinning and have elevated viscosities at low annular velocities have proven to be best for efficient hole cleaning [4].

The density, together with viscosity and annular velocity, also affects the carrying capacity of the fluid as a low density will provide less buoyancy for the cuttings during their transport to surface.

When it comes to rate of penetration, or ROP, it is the density that plays the biggest role in achieving the optimal rate. A lower fluid density will exert less pressure on the formation and the pieces of rock are removed with more ease. That is one of the advantages of underbalanced drilling, where rates of penetration are usually higher than in conventional drilling.

The effect of viscosity on the ROP is such that generally, a formation drills faster the more shear-thinning and flatter the rheological profile of the mud [5].

3.2 How drilling fluids properties vary during operations

Viscosity and density might be deliberately increased or reduced from one section to the next or even within a section of the well according to the specifications included in the fluid program.
These changes are planned for and are included in the time budget for the well.
Besides these planned changes, the necessity may exist to adjust these properties due to contamination or influx of formation fluids.
In that case, treatment must depend on the cause. Contaminants that can increase the viscosity are for example clay, cement or high solids content. Water influx will reduce the viscosity.

If the contamination is by clay or too high solids content, decreasing the viscosity (dilution) is one possibility. On the other hand, if there is cement contamination, other chemicals must also be added, such as for example sodium bicarbonate and citric acid. Viscosity variations alone do not reveal what type of contamination that is present.
One must therefore be cautious when implementing an automated viscosity adjustment system and continuously monitor all the parameters to be able to spot any contaminations to the fluid and act accordingly.

Cement contamination is sometimes expected, for example when placing a cement plug in the well and circulating out the excess or simply when drilling through an existing cement plug.

Density changes can be caused by water influx or solids contamination. When doing slot recovery operations, the fluid behind the casing being cut may have suffered sagging, and will therefore be of lower density at the top and higher density at the bottom. When incorporating this old fluid into the fluid currently in use, the density will have to be adjusted. The solution is to add barite when the fluid density decreases and to add light premix when the density is higher than desired.

3.3 Density adjustment

Density increasing additives include barite, hematite, magnetite and ilmenite. Barite is more commonly used because the other three are very damaging to the solids control equipment.

To adjust the density of a drilling fluid, the normal procedure is to use barite for increasing the density, and a lighter drilling fluid (premix) for reducing it. In the case of a drilling fluid system that uses a finer grade of barite that is not available offshore, a heavier drilling fluid or concentrate is used to increase the density.

The formula for increasing the density of a fluid by the addition of barite can be written as:

$$m_{barite} = \left[\frac{4{,}2 \cdot (\rho_{desired} - \rho_i)}{4{,}2 - \rho_{desired}}\right] \cdot V_i \cdot 1000$$

where m_{barite} is the mass of barite to be added in kilogram, V_i is the initial volume of fluid in cubic meter, $\rho_{desired}$ is the desired density and ρ_i is the initial density of the fluid.

For decreasing the density by the use of a lighter fluid (premix), the following formula can be used:

$$\rho_{final} = x_i \cdot \rho_i + x_{premix} \cdot \rho_{premix}$$

Where x_i is the weight fraction of the initial fluid with density ρ_i , x_{premix} is the weight fraction of the premix and ρ_{premix} is the density of the premix, assuming that the volume of the solution is proportional to the mass and that the proportionality constant is the same for the initial fluid and the premix being added.

3.4 Viscosity adjustment

Adjustment of the viscosity in a drilling fluid is done by addition of either a viscosifier, if the goal is to increase the viscosity or of water/base oil/thinner drilling fluid, in case the goal is to decrease the viscosity.

The viscosifiers used are mainly bentonite or polymers. Bentonite increases the viscosity by swelling in the presence of water, a process also known as hydration. This process is highly sensitive to other parameters of the drilling fluid, such as pH, salt content or the presence of various metallic ions.

Polymers have a more stable and predictable effect than bentonite. Nevertheless, their efficiency is also affected by properties like pH and salt content and hardness.

Polymers are used instead of bentonite clays mostly because they provide viscosity and suspension capacity without increasing the solids content as bentonite does.

There are several polymers available in the market and their names and formula depend on the company providing them. They originally assume a balled form and elongate and expand in contact with water molecules, also known as hydration.

As described in the chapter about the properties of the drilling fluids (2.5), some of them have an influence on the solubility of polymer viscosifiers. These are the pH of the fluid, salt content, metal ion content, hardness (calcium and magnesium content) and the previously existing concentration of that additive.

pH affects the solubility of the polymer additive by influencing the ionization of the molecules needed for the polymer to take effect.

The salt content inhibits the capacity of the polymer to elongate itself and therefore reduces its solubility. There will be less “free” water available for the polymer to hydrate and expand itself. If the salt content is increased, it will steal the water being used by the polymer and viscosity will eventually be reduced.

For instance, PAC (Polyanionic Cellulose) or xanthan gum may require twice their normal concentration, or even more, to perform in a saline environment [4].

Similarly to the salt content, a high concentration of the additive previously in the fluid will decrease the effect of newly-added polymer viscosifier because there will be less water available for the new additive to attach itself to.

Calcium and magnesium content also have a large impact on the solubility of polymers because the hydrate water in an even higher degree than salts. Some types of polymers may also be precipitated in the presence of calcium ions [4].

The following explanation of how polymers induce thixotropy is taken from the M-I drilling fluids engineering manual [4].

The electrostatic interactions between the polymer molecules are weak and when shear is applied to the system, the attractive forces holding the polymers together are pulled apart. As the hydrogen bonding breaks, the viscosity of the fluid thins. When the shear is removed, the polymer chains resume their intermolecular hydrogen bonding and their original viscosified state returns.
Xanthan gum and a similar biopolymer called welan gum are two of only a few commercial polymers that produce thixotropic properties (gels) in water-based fluids. The concentration of xanthan necessary to develop thixotropic properties depends on the makeup water.

When reducing the viscosity of a fluid, a thinner fluid with the same characteristics is used. Another option would be to add a deflocculant, although the first option is the one commonly used.
The effect of deflocculant is very hard to control. When using deflocculant, there is a risk of adding a too high dosage, which would quickly make the mud too thin [9].

4. Automation of drilling fluids properties adjustment

4.1 Automation of drilling operations

With automation of most of the mechanical part of drilling operations soon becoming a reality, the automation of the drilling fluid handling will eventually follow.
According to Professor Thomas B. Sheridan, the evolution of drilling automation should follow these 10 degrees of automation, as described in Schlumberger's Oilfield review Summer 2012 [10]:

1. Offers no assistance; driller must take all decisions and take action
2. Offers a complete set of decision and action alternatives
3. Offers a set of alternatives and narrows the selection
4. Suggests a single course of action
5. Selects and executes a suggestion if the driller approves
6. Allows the driller a restricted time to veto an action before automatic execution
7. Executes an action automatically, then necessarily informs the driller
8. Executes an action automatically and informs the driller only if asked
9. Executes an action automatically and informs the driller only if it takes action
10. Decides everything and acts autonomously

As mentioned in the introduction, several publications have shown the study of automatic measurement of drilling fluid properties. If implemented, such a system would provide a continuous stream of measurements of the fluid properties, with at least the same accuracy that exists today.
A big advantage would be the continuous monitoring of the parameters that today is done with a several hours interval between measurements. Nowadays, the drilling fluid engineer collects a small sample of around 800ml sometimes only twice per shift, which does not give a good overall picture of the condition of the whole drilling fluid in the system.

An automated and continuous measurement system would give the drilling fluid engineer the ability to switch his focus from laboratory testing to simulating the hole conditions using real-time values.
Moreover, the development and use of advanced hydraulic simulation programs frequently employed for extended reach drilling and managed pressure drilling (MPD) have increased the focus on more reliable and more frequent operational inputs [11].

4.2 Automation of property adjustment

If the condition of the fluid is known and available in digital form, the implementation of an automated system that reacts to changes of certain parameters can be performed.
This would represent not only an improvement in terms of safety and working environment, but also in terms of accuracy.

In order to implement such a system, we must first establish a relation between the measured values in the laboratory and the existing mathematical models. Regarding viscosity, we will focus only in the Bingham plastic model for the purposes of this study.

The description of viscosity calculations below was adapted from *Drilling fluids processing handbook* [5].

When the viscosity of a fluid is measured with a concentric cylinder rotary viscometer like the Fann VG-meter (described in 4.3), the relation between the measurements and the variables in the Bingham Plastic model is as follows:

$$\vartheta_\omega = \left[\frac{\vartheta_{600} - \vartheta_{300}}{600 - 300}\right] \cdot \omega + [\vartheta_{300} - (\vartheta_{600} - \vartheta_{300})]$$

where ϑ_{600} and ϑ_{300} are the Fann Readings at Fann Speeds of 600 and 300 rpm, respectively;
This enables the calculation of a Fann Reading ϑ_ω (degrees) at a Fann Speed ω (rpm) based on the readings taken at 300 and 600RPM.

According to the Bingham Plastic model:

$$\frac{\vartheta_{600} - \vartheta_{300}}{600 - 300} = \mu_p \qquad \text{and} \qquad \vartheta_{300} - (\vartheta_{600} - \vartheta_{300}) = \tau_0$$

In the oilfield, the plastic viscosity PV is known as $\vartheta_{600} - \vartheta_{300}$ and τ_0 as the yield point YP.

This gives $PV = \mu_p \cdot (600 - 300) = 300\mu_p$,

and $\vartheta_\omega = \frac{PV}{300} \cdot \omega + YP$

To calculate the eventual viscosity at the desired shear rate we then use the initial formula for viscosity in, centiPoise:

$$\mu_\omega = \frac{\vartheta_\omega \cdot 511}{\omega \cdot 1{,}7}$$

Shear rates in a drill pipe are usually within the range from 511 to 1022 sec^{-1}, which corresponds to the Fann Speeds of 300 to 600RPM, respectively. In the annulus, the rates are usually within the range of 5.1 to 170 sec^{-1}, which corresponds to the Fann Speeds of 3 to 100RPM, respectively.

To convert the Fann Speed from rpm to to sec^{-1}, the speed ω is multiplied by 1,7034.
To convert the Fann Reading from degrees to $dyne/cm^2$, the reading ϑ is multiplied by 5,11.

YP is actually in units of degrees but is usually reported as $lb/100ft^2$, since the units are nearly equivalent: 1 degree = 1,067$lb/100ft^2$.

4.3 Drilling fluids laboratory experiments

Two experiments were carried out in order to test the possibility of predicting the effect of a viscosifier. They may be seen as an example of how one would have to proceed to be able to predict the behavior of any additive to be used in automated adjustment of drilling fluid properties.

The objective Experiment 1 was to find out the shear stress increase due to the addition of a known concentration of Polymer viscosifier in a sample with fixed pH and salinity.
In Eperiment 2, calcium chloride salt was added to the initial sample to observe the difference in behavior of the viscosifier when salinity is increased. A similar procedure as the one for Experiment 1 was followed, but with addition steps of 1gram instead of 0,25gram and 1gram.
The procedures followed in both experiments are attached as Appendices A and B.

Workplace number 6 was used in the drilling fluids laboratory E-156 at the University of Stavanger. The equipment used was:

- Fann VG-meter (marked with number 15) and cup:
- Timer
- Hamilton Beach mixer and cup
- An electronic scale
- Thermometer
- Measuring glass (capacity)
- pH-meter
- Syringe (10ml)

The chemicals used where:

- Duo-Vis (polymer viscosifier provided by M-I Swaco)
- Sodium hydroxide (NaOH) 5%
- Potassium chromate (K_2CrO_4)
- Silver Nitrate ($AgNO_3$) 0,0282M
- Calcium chloride ($CaCl_2$) – used only in Experiment 2

Pictures of the equipment and chemicals used are attached as Appendix F.

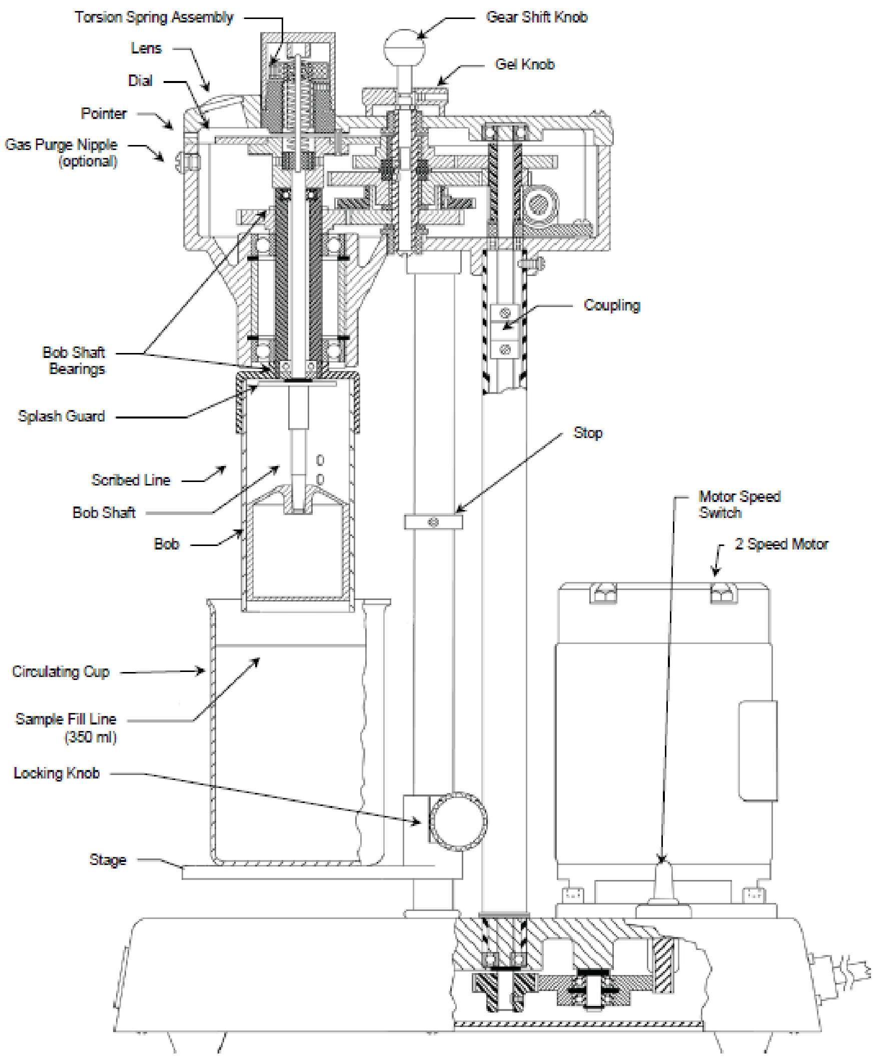

Figure 3 – Fann model 35 viscometer [12]

The Fann VG-meter

This brand and model of viscometer, shown in Figure 3, is the most commonly used in the drilling industry. It is also called a direct-indicating viscometer because the dial readings are true viscosity values in centiPoise at the chosen shear rate. The gel strength is also read directly from the dial and is in $lb/100ft^2$ [13]. It is equipped with a two speed motor, and provides readings at six different shear rates. The speeds that can be chosen and corresponding shear rates are:

- 600RPM - 1022,04 sec^{-1}
- 300RPM - 511,02 sec^{-1}
- 200 RPM - 340,68 sec^{-1}
- 100 RPM - 170,34 sec^{-1}
- 6 RPM - 10,22 sec^{-1}
- 3 RPM - 5,1102 sec^{-1}

The measurement is performed by submerging the bob and the rotor sleeve into the fluid and choosing the desired shear rate. The outer cylinder (rotor sleeve) will rotate and the inner cylinder (bob) will be dragged due to the forces exerted on it by the fluid. The inner cylinder is attached to a spring, which restrains its movement, and to a dial where the values are read.
The calculation of the plastic viscosity PV and the yield point YP is performed as described in chapter 4.2.
The Fann recommended procedure for measuring gel strength is attached as Appendix K.

The Hamilton Beach mixer

The Hamilton Beach mixer has three set speeds that can be chosen: low, medium and high.
In the first steps of Experiment 1, the low setting was used due to the low viscosity of the fluid. Using a higher setting would have caused the fluid to exit the mixing cup. From step 8, the high setting was used. Due to the higher viscosity, the fluid remained inside the cup, even when mixing at the high setting.

The chloride test was performed by adding 5 drops of potassium chromate (K_2CrO_4) to 1ml of fluid sample and then titrating it with silver nitrate ($AgNO_3$) 0,0282M. The amount in milliliters of Silver Nitrate needed for the color of the sample to turn from yellow to brick red is multiplied by 1000 to obtain the concentration of Cl^- in milligram per liter.

The density was measured by weighting an empty syringe, resetting the scale and weighting the same syringe filled with 10ml of fluid. The density was obtained by dividing the weight by 10.

The pH was measured directly with the pH-meter.

The order of the measurements was the same as in the table where they are displayed: temperature, 600, 300, 200, 100, 6, 3 RPM readings and 10-second and 10-minute gel strengths.
The results and plots for each experiment are presented in Appendices C and D.

To draw a comparison between the solubility of Duo-Vis in Experiment 1 and 2, several plots were made, and they can be seen on Figures 4, 5, 6, 7 and 8.

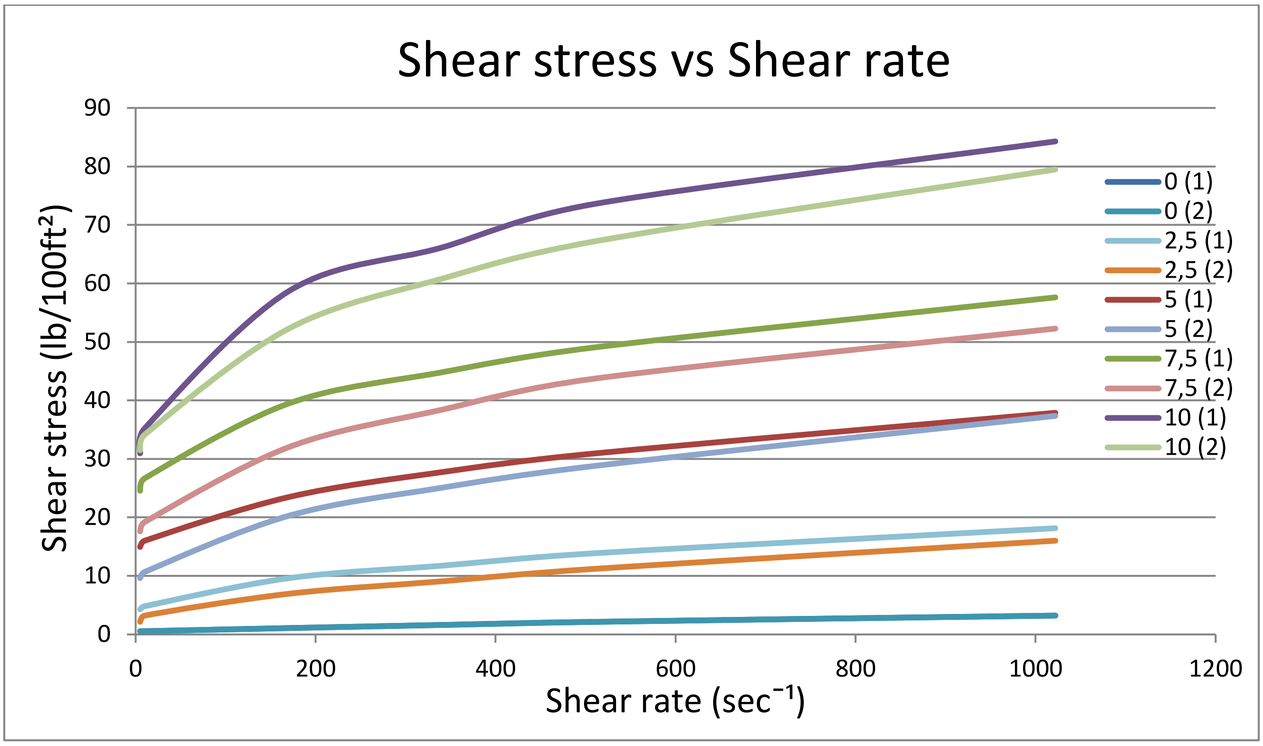

Figure 4 - Shear stress for different concentrations (in kg/m³) in Experiment 1 and 2

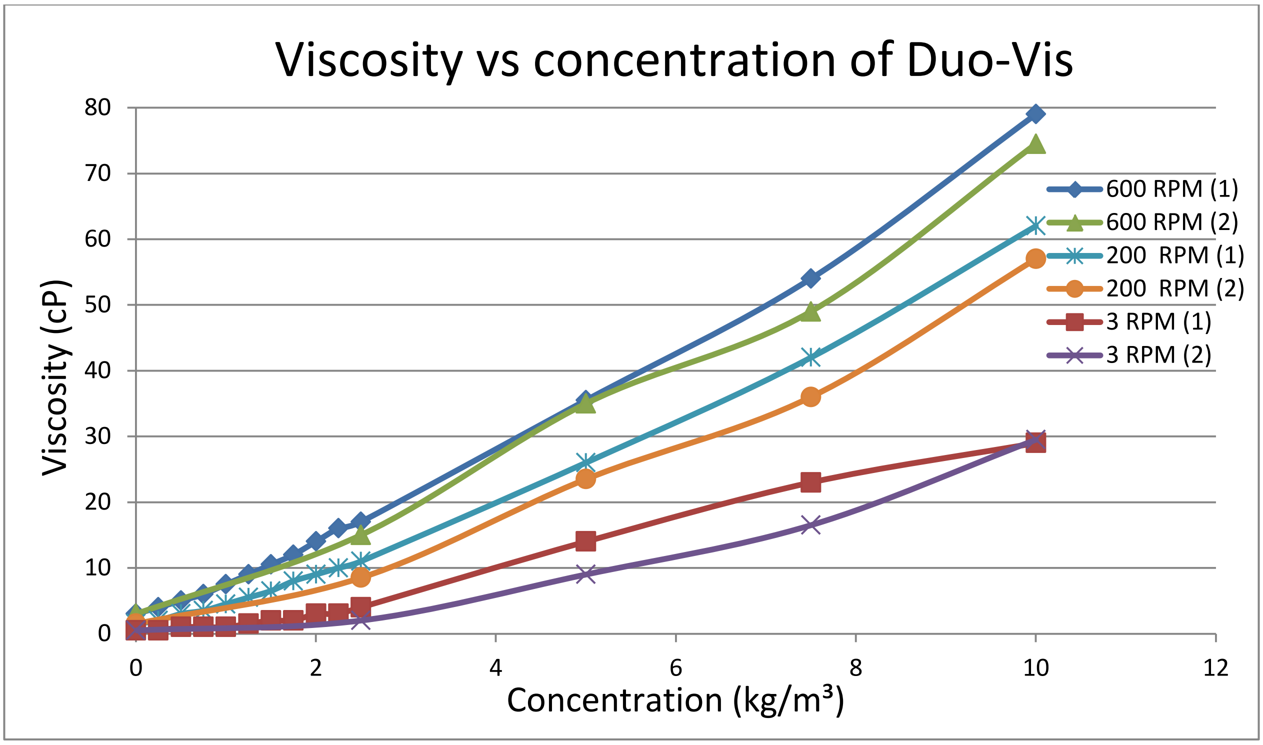

Figure 5 - Viscosity at 600, 200 and 3RPM in Experiment 1 and 2

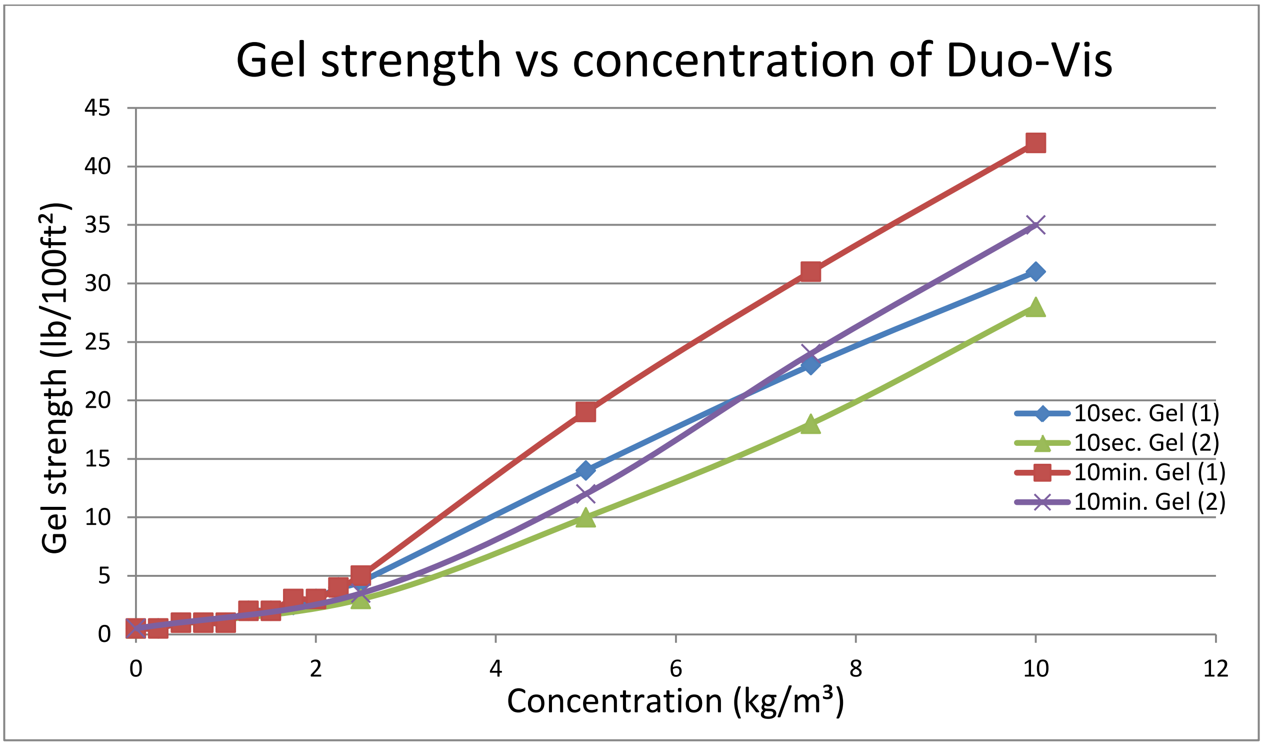

Figure 6 – Gel strengths measured in Experiment 1 and 2

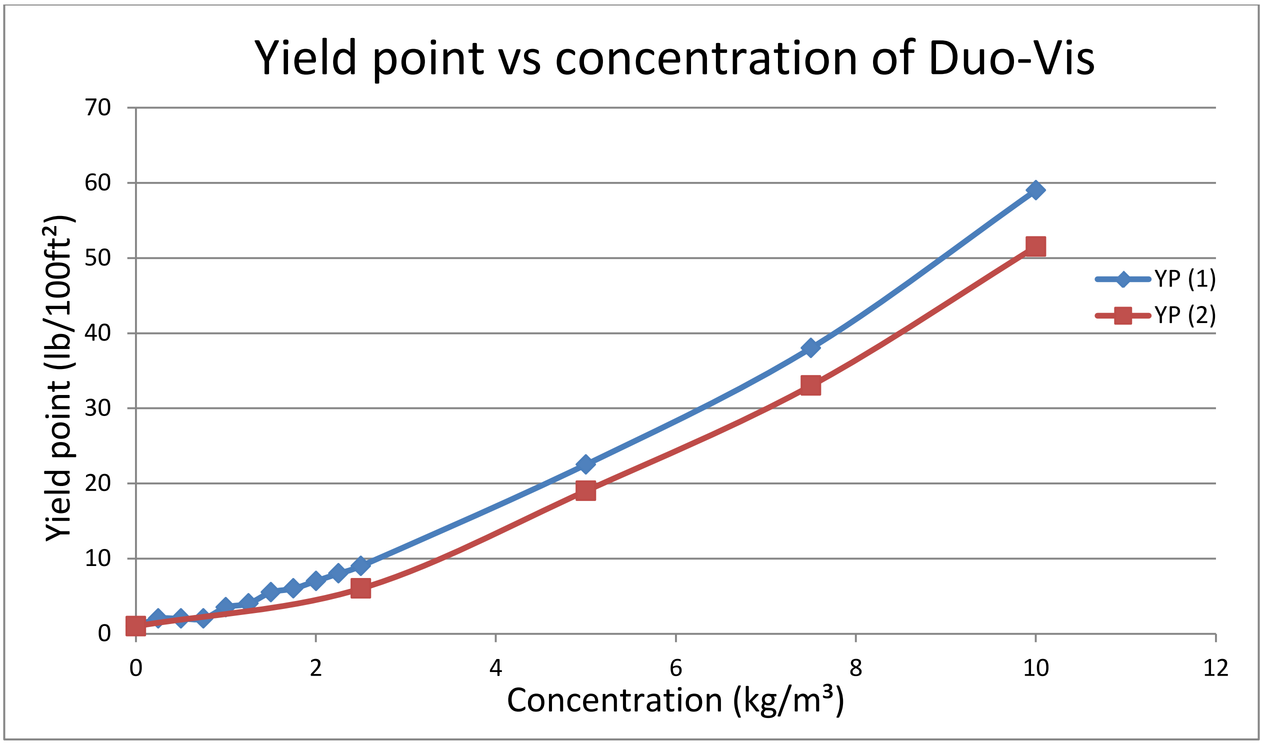

Figure 7 – Yield point calculated from results of Experiment 1 and 2

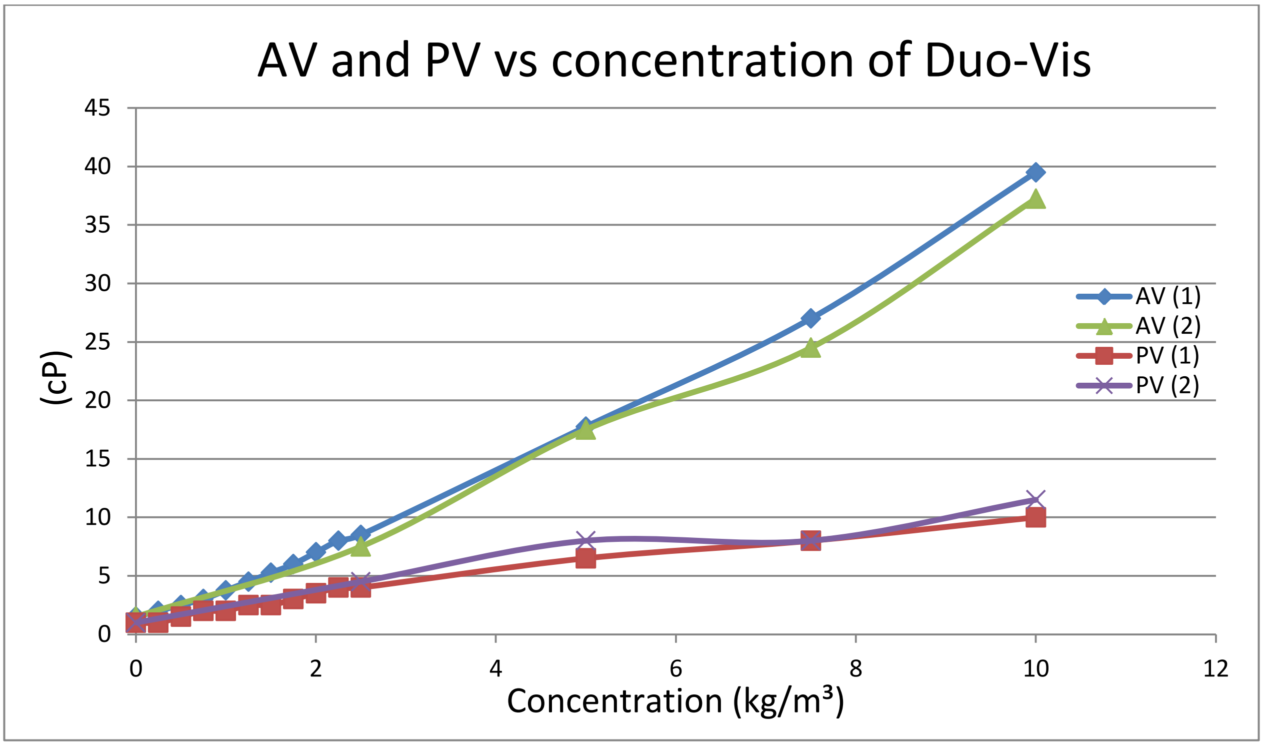

Figure 8 – Apparent viscosity and plastic viscosity calculated from results of Experiment 1 and 2

Comments

We can clearly see that the solubility of Duo-Vis in Experiment 2 was lower than in Experiment 1, with a significantly lower shear stress for the same amounts added. This was expected since the salinity has a big influence in the efficiency of polymer viscosifiers, as discussed in earlier chapters.

Gel strengths and the Yield Point were also considerably lower in Experiment 2.

The Plastic Viscosity values were lower than in Experiment 1, but not significantly, although they show a less linear development in Experiment 2.

The increase in temperature measured is due to the higher friction experienced by the fluid as the shear stress increases.

It can be concluded that for the solubility of a certain viscosifier to be known for all pH, salinity, solid content and metal ion content values, a great number of experiments would have to be carried out. This means that predicting the behavior of a viscosifier is very difficult and therefore any automated adjustment system cannot rely on preset values for the effect and solubility an additive.

4.4 Drilling fluid processing system layout

Assuming that an automatic measuring system is already implemented, the following changes in layout of the addition of equipment should be done in order to use an automated adjustment system:

- In rigs where a Procon tank or Big Bag system is already in place, there is no need for any change in layout, but the control interface between the measuring system and adjustment system must be designed and installed. The crew must be able clearly supervise every step of the process and to override the automated system if necessary

- For rigs with no programmable mixing system, one would need to be installed such that it could receive input parameters from the measuring system and act upon changes in fluid properties.

Ideally, there should be measuring systems installed for evaluating the fluid properties as it exits and as it enters the well. The system should also be used when adjusting the properties of the fluid in the reserve tanks. For that effect, the measuring system should be placed in the tank/pit room and as close as possible to the mixing system so that the fluid passing through the mixing lines can be evaluated.

Knowing the quantities of viscosifier previously added and analyzing the resulting changes in viscosity, the operator should be able to adjust the system in order to increase accuracy.

Such a system could also provide data about the solubility of the specific viscosifier and compare it with changes in other properties to acquire a database of solubility for that additive.

5. Laboratory implementation of automated property adjustment system

5.1 The automated drilling hydraulics laboratory at the University of Stavanger

As mentioned in the abstract, the initial objective of this thesis was to implement and test an automated system for adjusting the viscosity of a fluid. As the price of and delivery times for the equipment needed were too great, it was decided that the experiment would not be performed this semester, but it would be planned for future implementation. As this thesis is being written, a system for obtaining automatic and continuous readings of viscosity and density, called Instrumented Standpipe (Figure 9), is being constructed in the automated drilling hydraulics laboratory at the University of Stavanger. This will feed the necessary inputs for a system that automatically adjusts the density and viscosity of the fluid in circulation.

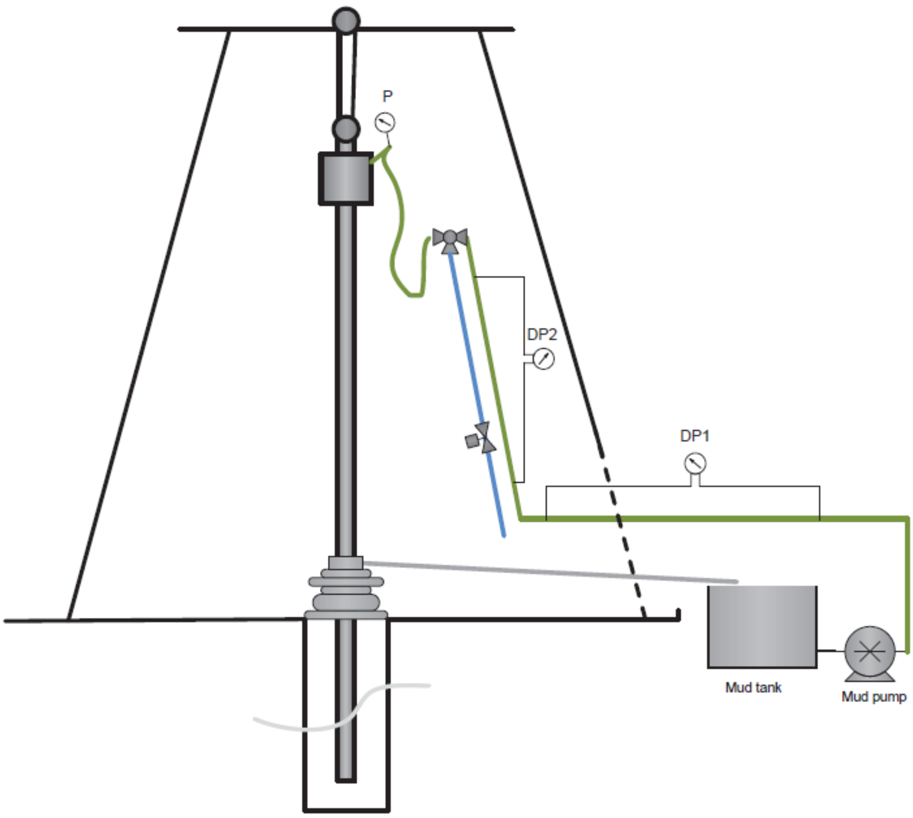

Figure 9 - The instrumented standpipe setup [14]

Today, the laboratory has a flow loop designed to simulate the behavior of an oil well and the problems that can occur during a drilling operation, such as gas influx, water influx and leaks. All the simulations carried out at the laboratory at this point are done with water only. A diagram and a picture of the current installation are shown in Appendix G.

A diagram of the planned future setup is shown in Appendix H.
This includes the instrumented standpipe, a system for automatic mixing of drilling fluids and a system for automatic adjustment of viscosity. This will be achieved by using a blend of water and silicone oil to simulate a drilling fluid. Using this blend will allow the re-use of both the water and the oil, by separating it in a settling tank.

A page of the Material Safety Datasheet (MSDS) for the silicone oil chosen is in attached as Appendix I. The density of the oil is of 0,97sg, and therefore the density changes of the mixture will be minimal. On the other hand, the viscosity of the silicone oil is of 50centistokes, which allows a vast range of viscosities to be achieved, in theory, from 1centistoke to 50centistokes.

The viscosity of several blends of silicone oil and water should be performed in order to verify that the formulas used for calculating the viscosity of the blend are correct and that the provided Simulink (chapter 5.2) model is valid.

The equipment needed for the properties adjustment part will be:

- 2 tanks, one for water and one for silicone oil
- 1 or 2 venturi pipes, depending on design choice
- 2 valves to be controlled by the computer via Simulink
- Settling tank for separation of the oil/water mixture

The working principle of the venturi pipe to be used in the experiment is the same as described for the venturi found in the mud hopper (chapter 2.6.1). The tanks and the venturi pipes should be placed in line with the loop so that the oil or water is added to the flowing fluid as shown in Figure 10. Alternative 1 requires one and Alternative 2 requires two venturi pipes.
The venturi should be installed right after the outlet of the pump in the laboratory.

The proposed model of the venturi pipe to be used is the 684 from Mazzei Injector Company and a schematic is attached as Appendix J.

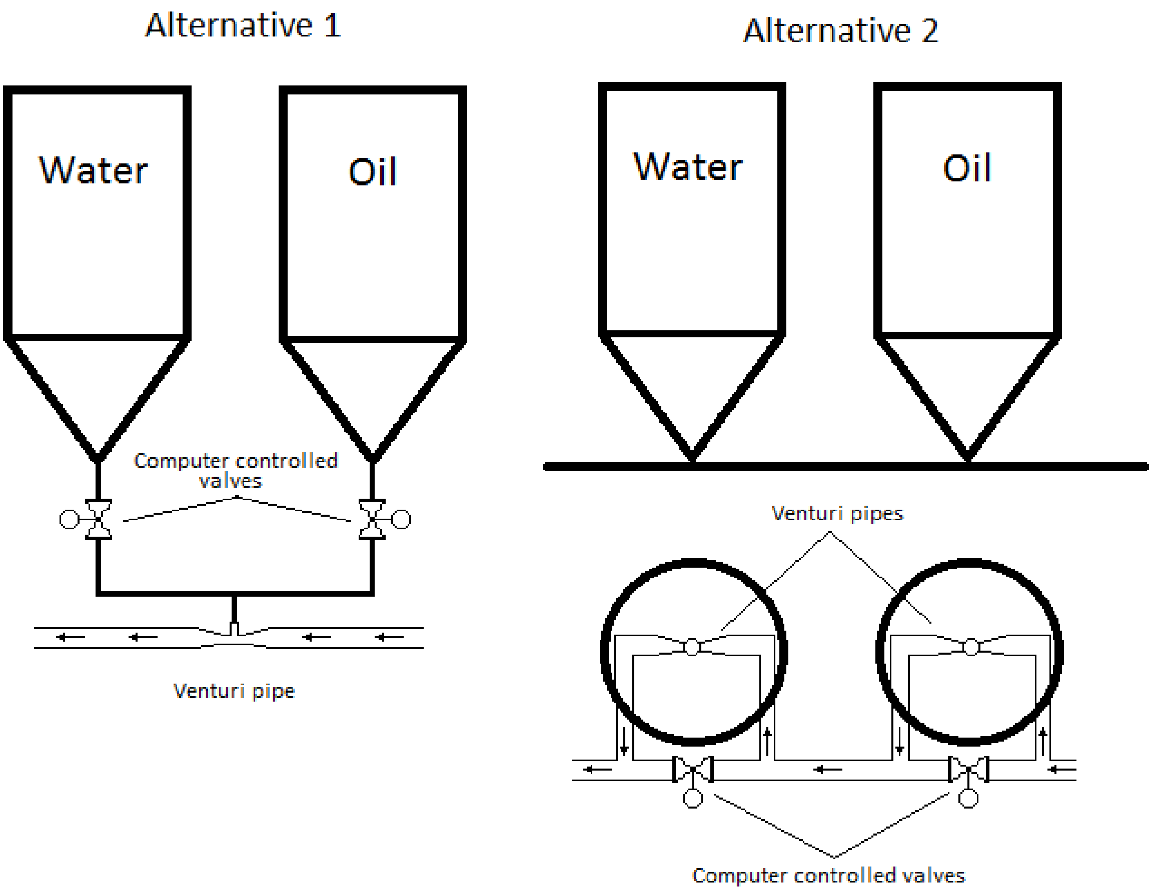

Figure 10 – Proposal for tank setup in the automated drilling hydraulics laboratory

Alternative 1 is the preferred since the Simulink program can directly control the inflow of water or oil. In Alternative 2, when the valves are open, no water or oil is added. By closing the valves, the flow will be directed through the venturi and the suction created will draw the water or oil into the flow. Further studies would have to be carried out, in order to implement Alternative 2, to determine the opening percentage of the valves which will give the desired rate of addition. For that reason, Alternative 1 is the simplest to implement.

The above mentioned Instrumented Standpipe will provide the kinematic viscosity. Using this as an input, the system should adjust the viscosity whenever a variation occurs. For that, a Simulink model was designed, which will control the valves according to the addition rate.

5.2 Simulink model for viscosity adjustment in the laboratory

For the mixing of two fluids of different viscosities we will be using the Refuta's equation [15].
In this method, which can used to calculate the viscosity of a blend of two or more fluids of different viscosities, one must first calculate the VBN (viscosity blending number) of each fluid, using the following equation:

$$(1)\ VBN = 14{,}534 \cdot ln[ln(\upsilon + 0{,}8)] + 10{,}975$$

where υ is the kinematic viscosity in centistokes (cSt).

The viscosity blending number of the blend will be:

$$(2)\ VBN_{blend} = [x_A \cdot VBN_A] + [x_B \cdot VBN_B]$$

where x_A and x_B are the mass fraction of fluid A and B, respectively.

To calculate the kinematic viscosity of the blend, equation (1) is used:

$$(3)\ \upsilon_{blend} = e^{\left(e^{\left(\frac{VBN_{blend}-10{,}975}{14{,}534}\right)}\right)} - 0{,}8$$

In this Simulink model, we are using these equations to calculate how much oil or water is needed to add to the current fluid to increase or decrease the viscosity, respectively.

The variables were named as follows:

tvis: target viscosity [cSt]
ovis: silicone oil viscosity [cSt]
orho: oil density [sg]
q: volume flow rate [liter/min]
tVBN: target VBN
cVBN: current fluid VBN
oVBN: silicone oil VBN

cvis: current viscosity [cSt]
wvis: water viscosity [cSt]
wrho: water density [sg]
qo: volume flow rate of oil being added [liter/min]
qw: volume flow rate of water being added [liter/min]
wVBN: water VBN

The input parameters for this model are the volume flow rate *q*, the current density at the outlet of the well *crho* and the current viscosity at the outlet of the well *cvis*, which should be acquired by the use of the instrumented standpipe.

Then, the VBN for each of the fluids is calculated:

$$tVBN = 14{,}534 \cdot ln[ln(tvis + 0{,}8)] + 10{,}975$$
$$cVBN = 14{,}534 \cdot ln[ln(cvis + 0{,}8)] + 10{,}975$$
$$oVBN = 14{,}534 \cdot ln[ln(ovis + 0{,}8)] + 10{,}975$$
$$wVBN = 14{,}534 \cdot ln[ln(wvis + 0{,}8)] + 10{,}975$$

For increasing the viscosity, we use equation (2), and the weight fraction of oil to be added can be calculated by using the target VBN *tVBN*, the current VBN *cVBN* and the oil VBN *oVBN*:

$$tVBN = [x_c \cdot cVBN] + [mixwo \cdot oVBN]$$

Since $x_c = (1 - mixwo)$, we get:

$$tVBN = [(1 - mixwo) \cdot cVBN] + [mixwo \cdot oVBN]$$

Rearranging the equation, the weight fraction of oil to be added *mixwo* is:

$$mixwo = \frac{(tVBN - cVBN)}{(oVBN - cVBN)}$$

Similarly, for decreasing the viscosity, the weight fraction of water to be added will be:

$$mixww = \frac{(tVBN - cVBN)}{(wVBN - cVBN)}$$

Since the mass flow rate before the venturi pipe is equal to:

$$qm = crho \cdot q$$

the mass flowrate of the mix after the venturi pipe will be:

$$qm_{mix} = rho_{mix} \cdot q$$

And the mass flow rate of the water or oil will be:

$$qmo = mixwo \cdot qm_{mix} \qquad qmw = mixww \cdot qm_{mix}$$

We can finally calculate the volume flow rate of oil *qo* and water *qw* to be added in liter/min:

$$qo = \frac{mixwo \cdot rho_{mix} \cdot q}{orho} = \frac{mixwo \cdot [crho + mixwo \cdot (orho - crho)] \cdot q}{orho}$$

$$qw = \frac{mixww \cdot rho_{mix} \cdot q}{wrho} = \frac{mixww \cdot [crho + mixww \cdot (wrho - crho)] \cdot q}{wrho}$$

where the density of the resulting mixture was calculated as

$$rho_{mix} = x_c \cdot crho + mixwo \cdot orho, \quad \text{for the oil case and}$$
$$rho_{mix} = x_c \cdot crho + mixww \cdot wrho \quad \text{for the water case.}$$

This formula for the density of the mixture assumes that the volume of the solution is proportional to the mass and that the proportionality constant is the same for the fluids being added (water or oil) and the existing fluid.

Density formulas and assumptions taken from Wikibooks [16].

The implementation in Simulink is as follows:

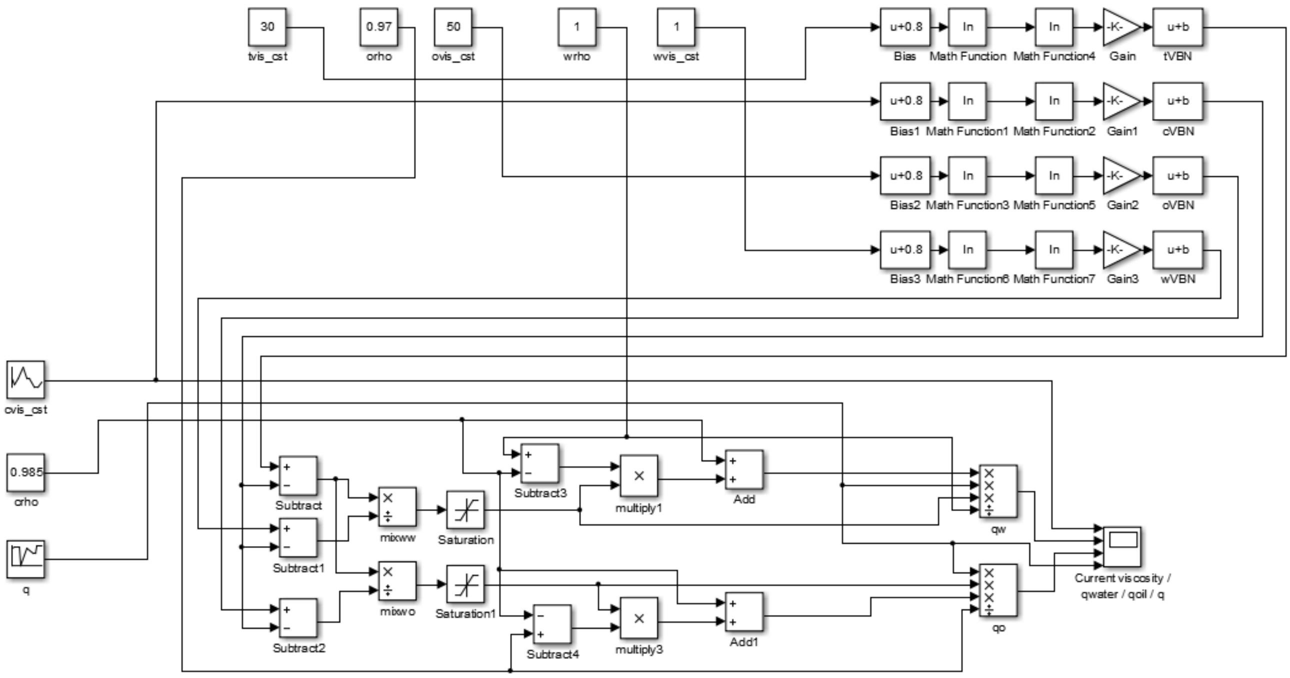

Figure 11 – Simulink diagram for viscosity adjustment in the laboratory

The signal for the current viscosity *cvis* should be replaced by the results given by the instrumented standpipe in the laboratory. The addition rates of water and silicone oil are given as *qw* and *qo*, respectively. In the case displayed, the specified viscosity was of 30cSt.

The result seen on the scope is:

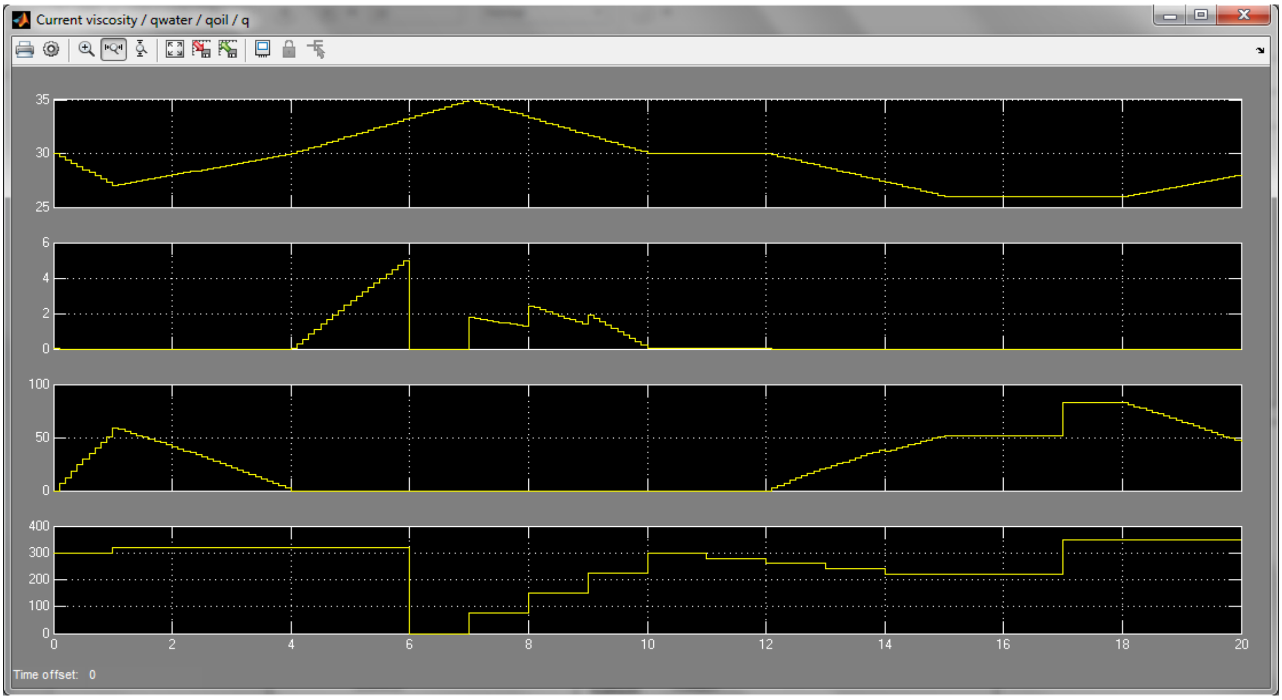

Figure 12 – Scope results from viscosity adjustment Simulink model

As seen on the scope, when the current viscosity *cvis* (first plot) rises above the target viscosity *tvis* of 30cSt, the addition of water is activated (second plot) at the rate of *qw*, in liter per minute.
When the current viscosity *cvis* falls below the target viscosity *tvis* of 30cSt, the addition of Silicone oil is activated (third plot) at the rate of *qo*, also in liter per minute.

Both addition rates are dependent on the current flow rate *q* (fourth plot). When the flow rate is zero, there is no addition.

Upon the installation of the tanks and venturi pipe in the laboratory, tests should be conducted in order to determine the fluid travelling time from the Instrumented Standpipe to the addition point and some delay should be added to the control model.

6. Rig implementation of the system

Two Simulink models were created, one for density and one for viscosity adjustments, to be used in a real life situation.

Their implementation would require the input from the measuring system. The models provide an output signal for the rate of additives or premix that is to be added.

No delay has been added, but it should be included and it will depend on the distance between the measurement and the place where the additives are mixed.

6.1 Simulink for density adjustment

In the Simulink model for density adjustment, we are using the equations mentioned in chapter 3.3 to calculate how much barite or light premix is needed to add to the active volume to increase or decrease the density, respectively.

The same Simulink model can be used for adjusting the properties of the fluid in the reserve tanks.

By adapting the formulas discussed earlier, the implementation in Simulink is as described:

The variables were named as follows:

crho: current density [sg]

trho: target density [sg]

brho: barite density [sg]

pmixrho: premix density [sg]

q: volume flow rate [liter/m]

qpmix: volume flow rate of premix being added [liter/min]

qb: mass rate of barite being added [kg/min]

If the density *crho* is lower than the target density *trho*, the amount of barite to be added per minute is:

$$qb = \left[\frac{brho \cdot (trho - crho)}{brho - trho}\right] \cdot q$$

in kilogram per minute.

If the current density *crho* is lower than the target density *trho*, the volume of light premix to be added per minute is:

$$qpmix = \frac{q \cdot (trho - crho)}{pmixrho - trho}$$

in liter per minute.

The implementation in Simulink is as follows:

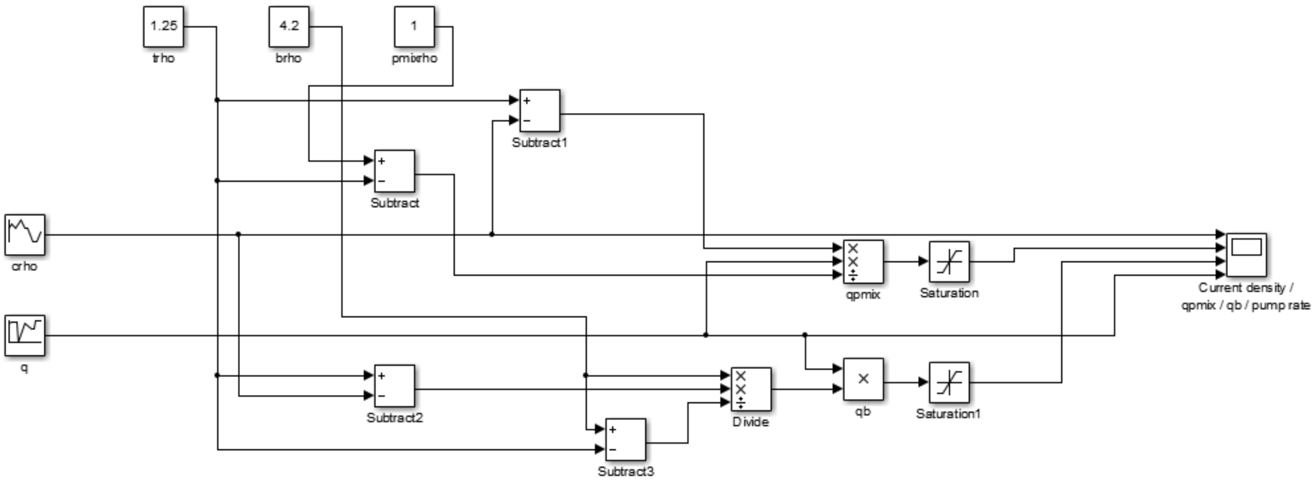

Figure 13 – Simulink diagram for density adjustment on a rig

Here, a signal for the current density *crho* is generated, analyzed and the addition rates of light premix and barite are given as *qpmix* and *qb*, respectively.

The result seen on the scope is:

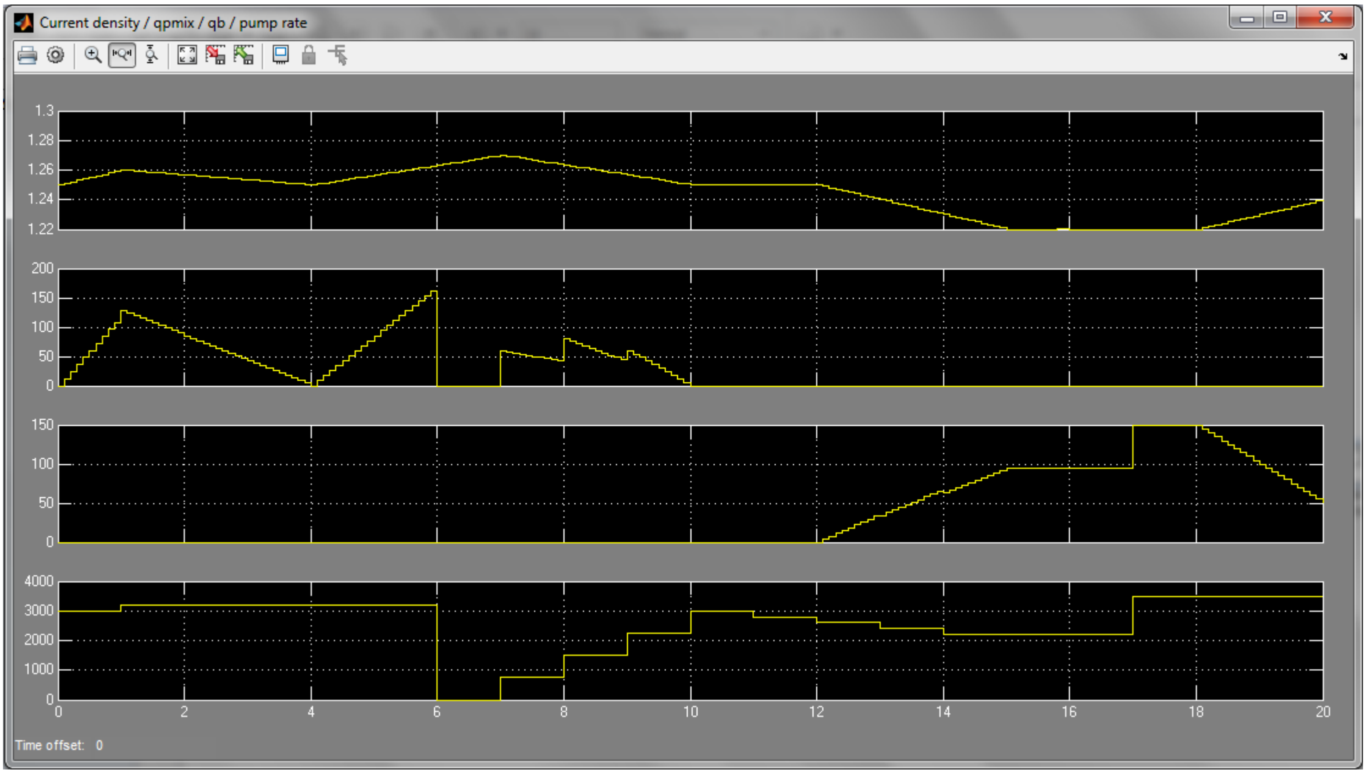

Figure 14 – Scope results from density adjustment Simulink model

When the current density *crho* (first plot) rises above the target density *trho* of 1,25sg, the addition of light premix is activated (second plot) at the rate of *qpmix*, in liter per minute.

When the current density *crho* reading is lower than the target density *trho* of 1,25sg, the addition of barite is activated (third plot) at the rate of *qb*, in kilogram per minute.

Both addition rates are dependent on the current flow rate *q* (fourth plot). When the flow rate is zero, there is no addition.

6.2 Simulink for viscosity adjustment

For viscosity adjustment on a rig, the solution proposed here is to use a thin premix to reduce the viscosity, by using the previously shown equations for the laboratory experiment, and the addition of a viscosifier to increase the viscosity. The premix should be of equal density as the current fluid. Any reduction of the viscosity will only take place if the current viscosity is above the upper limit of the range presented in the specifications or drilling fluid program.

As in the Simulink designed for the laboratory experiment, the equations used as a starting point are: For calculating the VBN (viscosity blending number) of each fluid:

$$(1)\ VBN = 14{,}534 \cdot ln[ln(\upsilon + 0{,}8)] + 10{,}975$$

where υ is the kinematic viscosity in centistokes (cSt), and the viscosity blending number of the blend:

$$(2)\ VBN_{blend} = [x_A \cdot VBN_A] + [x_B \cdot VBN_B]$$

where x_A and x_B are the mass fraction of fluid A and B, respectively.

For calculating the kinematic viscosity of the blend:

$$(3)\ \upsilon_{blend} = e^{\left(e^{\left(\frac{VBN_{blend} - 10{,}975}{14{,}534}\right)}\right)} - 0{,}8$$

We assume that the premix to be added has the same density as the drilling fluid in the well.

The variables were named as follows:

tvis_min: minimum target viscosity [cP]
tvis_max: maximum target viscosity [cP]
tvis: target viscosity [cP]
cvis: current viscosity [cP]
crho: current density [sg]
pmixvis: premix viscosity [cP]
pmixvis_cstk: premix in centistokes [cst]
q: volume flow rate [liter/min]
qpmix: volume flow rate of premix being added [liter/min]
tVBN: target VBN
cVBN: current fluid VBN
pmixVBN: premix VBN

The input parameters for this model are the volume flow rate *q*, the current viscosity at the outlet of the well *cvis*, which should be acquired by the use of the instrumented standpipe or another automatic measuring system.

The target viscosity *tvis* will then be the arithmetic mean of the range specified in the drilling fluid program:

$$tvis = \frac{tvis_{min} + tvis_{max}}{2}$$

The first step is to convert the viscosities from centipoise to centistokes:

$$tvis_{cstk} = \frac{tvis}{crho} \qquad cvis_{cstk} = \frac{cvis}{crho} \qquad pmixvis_{cstk} = \frac{pmixvis}{crho}$$

Then, the VBN for each of the fluids is calculated:

$$tVBN = 14{,}534 \cdot ln[ln(tvis_{cstk} + 0{,}8)] + 10{,}975$$
$$cVBN = 14{,}534 \cdot ln[ln(cvis_{cstk} + 0{,}8)] + 10{,}975$$
$$pmixVBN = 14{,}534 \cdot ln[ln(pmixvis_{cstk} + 0{,}8)] + 10{,}975$$

Using equation (2), the weight fraction of premix *mixwpmix* to be added to reduce the viscosity can be calculated by using the target VBN *tVBN*, the current VBN *cVBN* and the premix VBN *pmixVBN*:

$$tVBN = [x_c \cdot cVBN] + [mixwpmix \cdot pmixVBN]$$

Since $x_c = (1 - mixwpmix)$, we get:

$$tVBN = [(1 - mixwpmix) \cdot cVBN] + [mixwpmix \cdot pmixVBN]$$

Rearranging the equation:

$$mixwpmix = \frac{(tVBN - cVBN)}{(pmixVBN - cVBN)}$$

The mass flow rate before the venturi pipe is equal to:

$$qm = crho \cdot q$$

As the resulting mixture will have the same density, the mass flow rate of the mix after the venturi pipe will be the same:

$$qm_{mix} = crho \cdot q = qm$$

And the mass flow rate of the premix will be:

$$qm_{pmix} = mixwpmix \cdot q\mathrm{m}$$

We can finally calculate the volume flow rate of premix to be added in liter/min:

$$qpmix = \frac{qm_{pmix}}{crho} = \frac{mixwpmix \cdot q\mathrm{m}}{crho} = \frac{mixwpmix \cdot crho \cdot q}{crho} = mixwpmix \cdot q$$

As expected, since both fluids will have the same density.

In case the current viscosity *cvis* is lower than the lower limit of the viscosity range presented in the program, a viscosifier will be added to the fluid in the well.
As discussed previously, the effect of the addition of a viscosifier cannot be easily predicted, due to the many variables that affect its solubility.
Because of this, the viscosifier will be added in steps until the viscosity is within the desired range.

The mass flow rate of viscosifier will be implemented here in Simulink for two cases:

- Water-based drilling fluid, with the use of a polymer viscosifier like Duo-Tec NS;
- Oil-based drilling fluid, with the use of Bentone 128 as a viscosifier.

The rule of thumb used by most offshore drilling fluid engineers using these two viscosifiers in Norway is that to increase the VG-meter 3RPM reading by 1cP, it takes 0,25kg of Duo-Tec NS and 0,5kg of Bentone 128 per cubic meter of fluid, for water- and oil-based drilling fluids, respectively.

Knowing this, the offshore engineers always order the addition of less quantity as a precaution. They will afterwards test the fluid again to measure the effect of the added viscosifier and if needed, they will order the addition of more in the next circulations. Adding too much would make it necessary to dilute the drilling fluid, which incurs unnecessary costs and time expenditure.

The solution presented here will be the addition of 75% of the calculated amount with the target viscosity being the arithmetic mean of the range specified in the drilling fluid program as in the case for reducing the viscosity.

We then name the variable as follows:

tvis_min: minimum target viscosity [cP]
tvis: target viscosity [cP]
q: volume flow rate [liter/min]
diff: difference between the lower limit of the target viscosity and the current viscosity [cP]

tvis_max: maximum target viscosity [cP]
cvis: current viscosity [cP]
qv: mass rate of viscosifier being added [kg/min]

The target viscosity *tvis* will be:

$$tvis = \frac{tvis_{min} + tvis_{max}}{2}$$

$$diff = tvis - cvis$$

For the case of water-based fluid and Duo-Tec NS:

$$qv = 0{,}75 \cdot diff \cdot 0{,}25 \cdot \frac{q}{1000}$$

For the case of oil-based fluid and Bentone 128:

$$qv = 0{,}75 \cdot diff \cdot 0{,}5 \cdot \frac{q}{1000}$$

in kilogram per minute.

The implementation in Simulink is as follows:

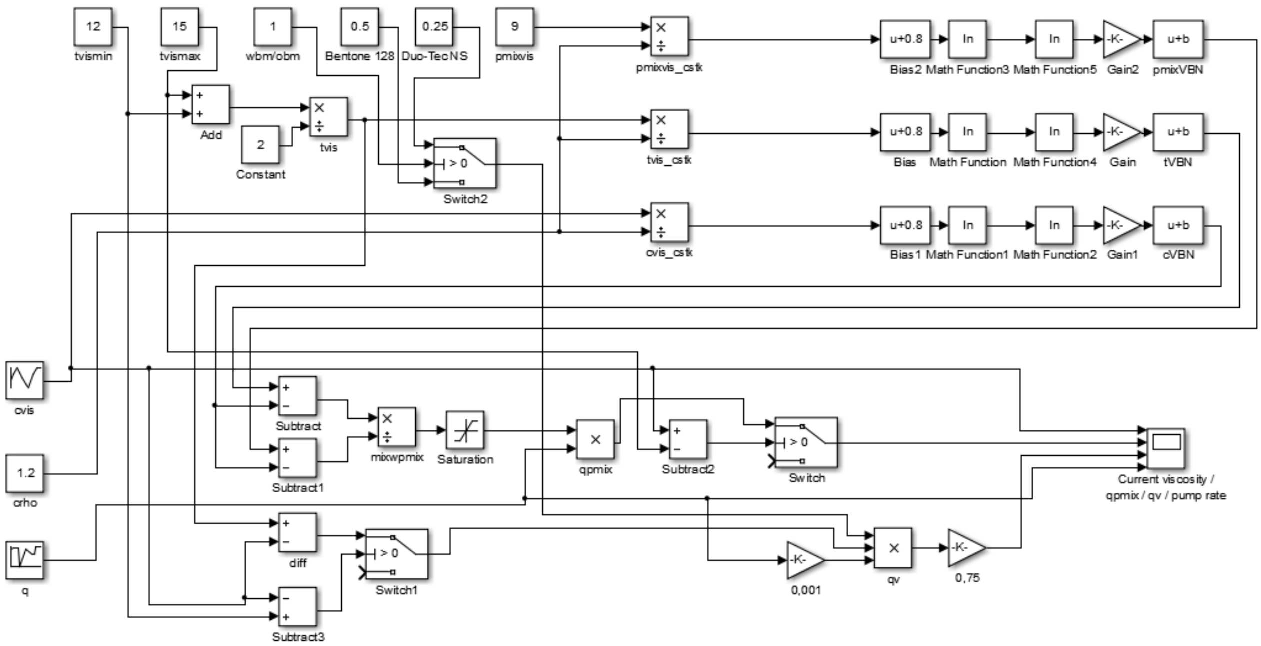

Figure 15 - Simulink diagram for viscosity adjustment on a rig

Here, a signal for the current viscosity *cvis* is generated, analyzed and the addition rates of thin premix and vicosifier are given as *qpmix* and *qv*, respectively. The rate of viscosifier is reduced to 75% of the calculated value as discussed previously.

The choice between Duo-Tec NS or Bentone 128 is done by setting the *wbm/obm* constant to 1 or 0, respectively.

Here the specified viscosity range is from 12 to 15cP, and the target viscosity *tvis* is the arithmetic mean of the minimum and maximum values of the range.

The system will then add viscosifier until the current viscosity is within the desired viscosity range.

The result seen on the scope is:

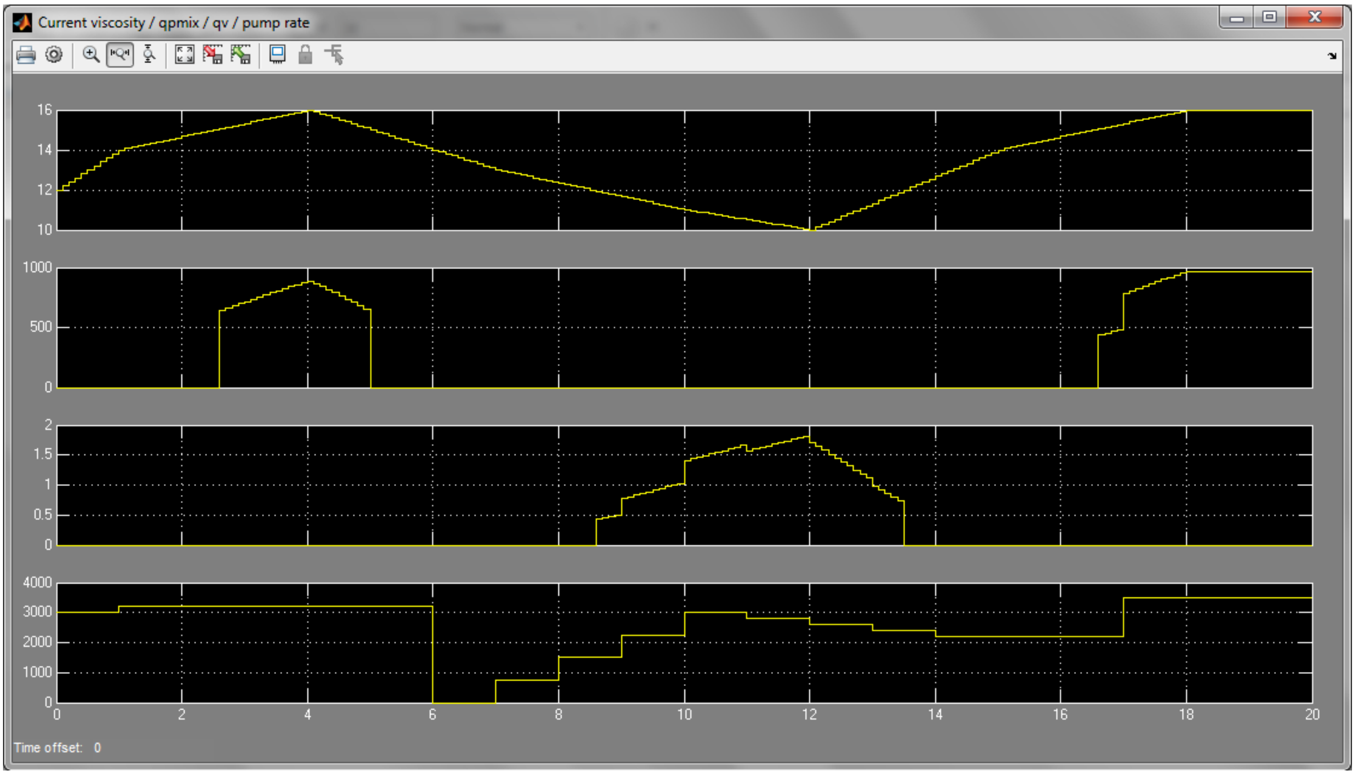

Figure 16 - Scope results from density adjustment Simulink model

As seen on the scope, when the current viscosity *cvis* (first plot) rises above the maximum value of the specified range, 15cP, the addition of thin premix is activated (second plot) at the rate of *qpmix*, in liter per minute.

When the current viscosity *cvis* falls below the minimum value of the specified range, 12cP, the addition of viscosifier is activated (third plot) at the rate of *qv*, in kilogram per minute.
In both cases, the system adjusts with a target viscosity of the arithmetic mean, 13,5cP.

As in the density adjustment, both addition rates are dependent on the current flow rate *q* (fourth plot). When the flow rate is zero, there is no addition.

7. Advantages of the automated system with regard to health, safety and environment

Health

With regards to health, an automated fluid adjustment system would represent a big improvement compared to using the manual mud hopper. The crew would no longer be exposed to physical contact with the chemical additives and with dust or particles which can be inhaled.

Manual lifting of sacks would no longer be required which would reduce the incidence of back injuries due to repeated heavy lifting.

Safety

Safety of the crew would be improved by less time spent outside of the control cabin, which leads to less exposure to safety hazards.

Safety of the overall drilling operation would be improved due to the continuous and automatic monitoring and adjustment of fluid density.

Environment

By using additives preloaded into tanks or big bags, which are reusable, the disposal of single sacks of chemicals would be eliminated. This would only represent an improvement if no single sacks were used when loading the tanks or bags with the additives.

8. Accuracy and practicality of the automated system

The accuracy of the presented automated adjustment systems has not tested.

The first step to do so would be to implement it at the automated drilling hydraulics laboratory at the University of Stavanger as proposed in this study.

Afterwards, a similar setup could be used at the same laboratory, but using a real-life drilling fluid provided by a drilling fluid provider.

The third step should be to implement the automated system on a rig to test its accuracy and practicality. The rig of choice would be one with an already installed automated fluid property measuring system and with a programmable addition system, like the Procon or Big Bag.

9. Cost comparison

The programmable systems existing nowadays, such as the Procon or Big Bag described earlier, require the installation of special mixing units and control consoles.

Until all fluid additives can be provided in the mentioned tanks or bags, there will always be the need for a manual mud hopper as well.

An automated fluid adjustment system would require the existence of such programmable systems, and would require the installation of interface and control consoles between the measuring system and the programmable addition systems. This means that for a rig already equipped with programmable addition systems, little additional equipment would be needed, and therefore the cost of such installation, would not be very high.

The operation of the systems would not require significant additional training. On the other hand, troubleshooting the equipment could require extensive training or hiring of service provider technicians due to its higher complexity. This could lead to waiting periods where the operation would have to be paused if the chemicals are not available in regular sacks that can be added manually.

In terms of savings, the time needed to adjust the fluid properties would be less.
Significant savings could be achieved due to the continuous good condition of the drilling fluid, although this cannot be quantified. The probability of non-productive time due to hole problems resulting from poor hole cleaning for example would be reduced, as well as the probability of lost well control.

10. Conclusion

The automation of the measurement of drilling fluid properties will open the door for the implementation of automated systems that can adjust the same properties.
The automatic adjustment of the density of a drilling fluid is simple and has already been implemented in some drilling rigs, but the adjustment of the viscosity is more complex.

Since there are many variables that influence the effect of a viscosifier, such as pH, salt content and solids content, the solution must be the gradual addition of viscosifier to avoid excessive thickening of the drilling fluid, which leads to the need of diluting it.

It can be concluded that for increasing the viscosity, the automated system should be such that it ads viscosifier in steps until the viscosity is within the desired range of values.
For reducing the viscosity, the addition of thin premix should be used, using the discussed equations.

Focus should be put into the interface, which should be easy to understand and control by anyone who would need to use it.

If needed, the operating companies should consider whether to continue specifying the viscosity requirements in terms of the 3RPM reading or to give it as cinematic viscosity.

The Simulink models created in this study should be implemented as proposed, first in the laboratory, and at a later stage on a rig for testing and for possible tuning.

Abbreviations

ROP	Rate of penetration
HSE	Health, Safety and Environment
YP	Yield point
PV	Plastic viscosity
TVD	True vertical depth
KCl	Potassium chloride
MWD	Measurements while drilling
LWD	Logging while drilling
H_2S	Hydrogen Sulphide
ECD	Equivalent circulating density
LGS	Low-gravity solids
HGS	High-gravity solids
ES	Electrical stability
RPM	Rotations per minute
AV	Apparent viscosity
PAC	Polyanionic Cellulose
MPD	Managed pressure drilling
MSDS	Material safety data sheet
VBN	Viscosity blending number

Nomenclature

Symbol	Description	Practical unit
μ	Viscosity	cP
τ	Shear stress	$lb/100ft^2$
γ	Shear rate	sec^{-1}
μ_e	Effective viscosity	cP
μ_p	Plastic viscosity for the Bingham plastic model	cP
τ_0	Yield point	$lb/100ft^2$
K_p	Consistency index for the Power law model	$lb/100ft^2 * s$
n_p	Flow behavior index for the Power law model	dimensionless
K	Consistency index for the Herschel-Bulkley model	$lb/100ft^2 * s$
n	Flow behavior index for Herschel-Bulkley model	dimensionless
PV	Plastic viscosity	cP
AV	Apparent viscosity	cP
m_{barite}	Mass of barite to add	kg
$\rho_{desired}$	Desired density	sg
ρ_i	Initial density	sg
V_i	Initial volume	m^3
x_i	Weight fraction of the initial fluid	dimensionless
x_{premix}	Weight fraction of premix	dimensionless
ρ_{premix}	Density of premix	sg
ϑ_ω	Fann reading at Fann speed ω	degrees
ω	Fann speed	RPM
ϑ_{600}	Fann reading at 600RPM	degrees

ϑ_{300}	Fann reading at 300RPM	degrees
μ_{ω}	Viscosity at Fann speed ω	cP
υ	Kinematic viscosity	cSt
VBN_{blend}	Viscosity blending number for the blend	dimensionless
VBN_A	Viscosity blending number for fluid A	dimensionless
VBN_B	Viscosity blending number for fluid B	dimensionless
x_A	Mass fraction of fluid A	dimensionless
x_B	Mass fraction of fluid B	dimensionless
tvis	Target viscosity	cSt
cvis	Current viscosity	cSt
ovis	Silicone oil viscosity	cSt
wvis	Water viscosity	cSt
crho	Current density	sg
orho	Silicone oil density	sg
wrho	Water density	sg
q	Volume flow rate	liter/min
qo	Volume flow rate of oil	liter/min
qw	Volume flow rate of water	liter/min
tVBN	Target viscosity blending number	dimensionless
cVBN	Current fluid viscosity blending number	dimensionless
wVBN	Water viscosity blending number	dimensionless
oVBN	Silicone oil viscosity blending number	dimensionless
x_c	Weight fraction of the current fluid	dimensionless
$mixwo$	Weight fraction of oil to be added	dimensionless
$mixww$	Weight fraction of water to be added	dimensionless

qm	Mass flow rate	kg/min
qm_{mix}	Mass flow rate of the mix	kg/min
rho_{mix}	Density of the mix	sg
qmo	Mass flow rate of oil	kg/min
qmw	Mass flow rate of water	kg/min
$pmixrho$	Premix density	sg
$brho$	Barite density	sg
qb	Mass flow rate of barite	kg/min
$qpmix$	Volume flow rate of premix	liter/min
$tvis_{min}$	Minimum target viscosity	cP
$tvis_{max}$	Maximum target viscosity	cP
$pmixvis$	Premix viscosity	cP
$tvis_{cstk}$	Target viscosity in centistokes	cSt
$cvis_{cstk}$	Current viscosity in centistokes	cSt
$pmixvis_{cstk}$	Premix viscosity in centistokes	cSt
$pmixVBN$	Premix viscosity blending number	dimensionless
$mixwpmix$	Weight fraction of premix	dimensionless
$diff$	Difference between $tvis_{min}$ and $cvis$	cP
qv	Mass rate of viscosifier	kg/min

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Appendices

Appendix A - Procedure for Experiment 1

Preparation

Build a water-based system:
1. Freshwater - 400ml
2. NaOH 5% – 0,5ml
3. Mix for 1 minute

Measurements:
1. Measure pH
2. Measure density
3. Measure the Cl^- content

Sample pH =
Sample Cl^- =
Sample density =

Experiment

Take the 400ml of the prepared fluid
1. Measure the viscosity
2. Add 0,1g of Duo-Vis (0,25kg/m3)
3. Mix for 5 minutes – low setting
4. Measure the viscosity
5. Repeat step 3 and 4 until achieving two consecutive equivalent viscosity readings
6. Repeat from step 2 until having added a total of 1gram
7. Add 1g of Duo-Vis (2,5kg/m3)
8. Mix for 10 minutes – high setting
9. Measure the viscosity
10. Repeat from step 7 until having added a total of 3grams

	Base	0,25kg/m3 5 minutes	0,25kg/m3 10 minutes	0,5kg/m3 5 minutes	0,5kg/m3 10 minutes	0,75kg/m3 5 minutes	0,75kg/m3 10 minutes
Temp. (ºC)							
600 RPM							
300 RPM							
200 RPM							
100 RPM							
6 RPM							
3 RPM							
10sec Gel							
10min Gel							

	1kg/m3 5 minutes	1kg/m3 10 minutes	1,25kg/m3 5 minutes	1,25kg/m3 10 minutes	1,5kg/m3 5 minutes	1,5kg/m3 10 minutes
Temp. (ºC)						
600 RPM						
300 RPM						
200 RPM						
100 RPM						
6 RPM						
3 RPM						
10sec Gel						
10min Gel						

	1,75kg/m3 5 minutes	1,75kg/m3 10 minutes	2kg/m3 5 minutes	2kg/m3 10 minutes	2,25kg/m3 5 minutes	2,25kg/m3 10 minutes
Temp. (ºC)						
600 RPM						
300 RPM						
200 RPM						
100 RPM						
6 RPM						
3 RPM						
10sec Gel						
10min Gel						

Stage 4	2,5kg/m3 5 minutes	2,5kg/m3 10 minutes	5kg/m3 10 minutes	7,5kg/m3 10 minutes	10kg/m3 10 minutes
Temp. (ºC)					
600 RPM					
300 RPM					
200 RPM					
100 RPM					
6 RPM					
3 RPM					
10sec Gel					
10min Gel					

Appendix B - Procedure for Experiment 2

Preparation

Build a water-based system:

1. Freshwater - 400ml
2. NaOH 5% – 0,5ml
3. NaCl – 10g
4. Mix for 1 minute

Measurements:

1. Measure pH
2. Measure density
3. Measure the Cl^- content

Sample pH =
Sample Cl^- =
Sample density =

Experiment

Take the 400ml of the prepared fluid

1. Measure the viscosity
2. Add 1g of Duo-Tec NS (2,5kg/m3)
3. Mix for 10 minutes
4. Measure the viscosity
5. Repeat from step 2

	Base	2,5kg/m3 10 minutes	5kg/m3 10 minutes	7,5kg/m3 10 minutes	10kg/m3 10 minutes
Temp. (°C)					
600 RPM					
300 RPM					
200 RPM					
100 RPM					
6 RPM					
3 RPM					
10sec Gel					
10min Gel					

Appendix C - Measured values and plots from Experiment 1

Measurements:

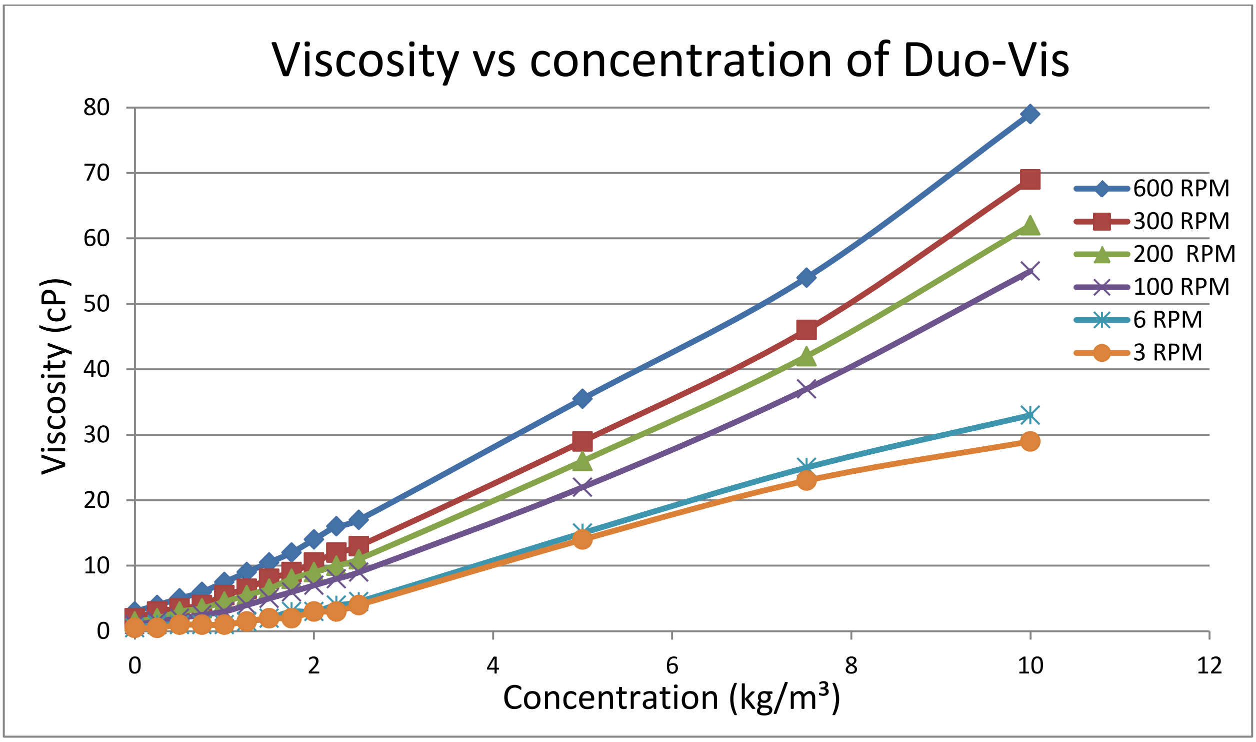
1. pH = 10,05
2. density = 1,005sg
3. Cl^- content = 100mg/l

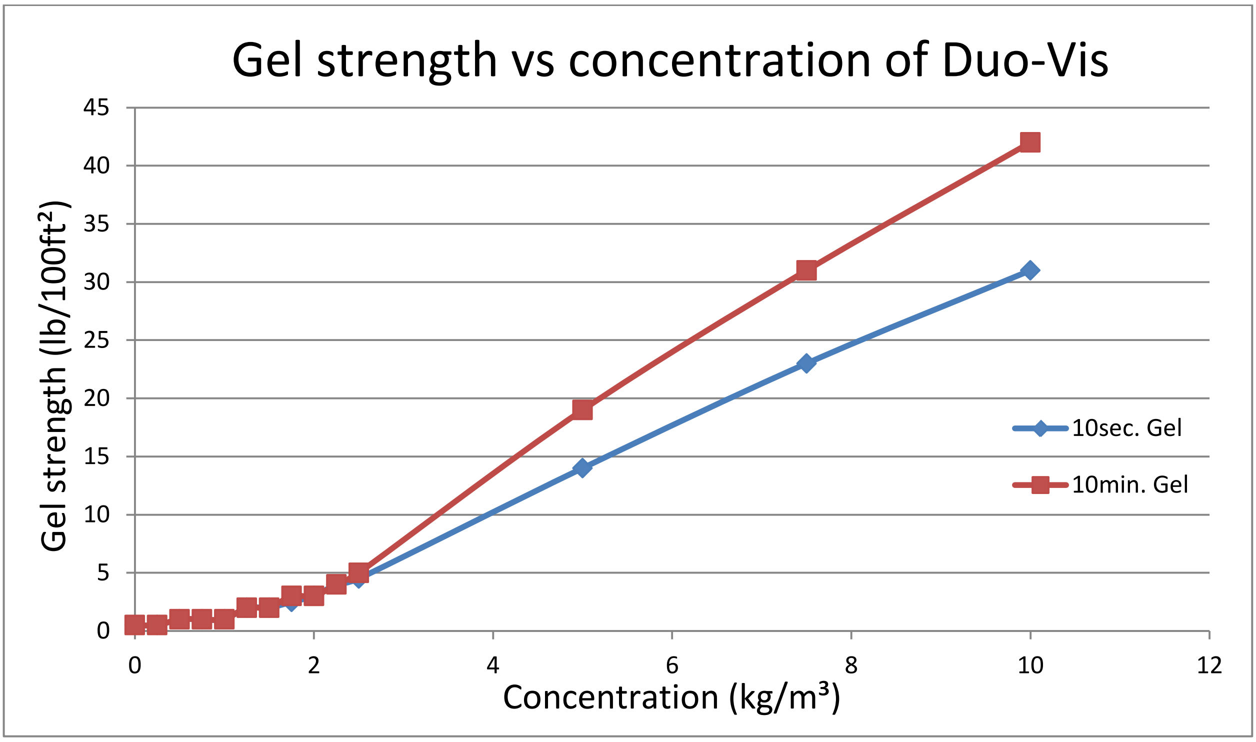
Concentration (kg/m³)	0,00	0,25	0,25	0,50	0,50	0,75	0,75
Volume added (g)	0,00	0,10	0,10	0,20	0,20	0,30	0,30
Mixing time (minutes)	0	5	10	5	10	5	10
Temp (°C)	14,1	18,2	20,2	21,2	22,3	22,9	23,3
600 RPM (cP)	3,0	4,0	4,0	5,0	5,0	6,0	6,0
300 RPM (cP)	2,0	3,0	3,0	3,5	3,5	4,0	4,0
200 RPM (cP)	1,5	2,0	2,0	2,5	3,0	3,5	3,5
100 RPM (cP)	1,0	1,5	1,5	2,0	2,0	2,5	2,5
6 RPM (cP)	0,5	1,0	1,0	1,0	1,0	1,0	1,0
3 RPM (cP)	0,5	0,5	0,5	1,0	1,0	1,0	1,0
10sec. Gel (lb/100ft²)	0,5	0,5	0,5	1,0	1,0	1,0	1,0
10min. Gel (lb/100ft²)	0,5	0,5	0,5	1,0	1,0	1,0	1,0
AV (cP)	1,5	2,0	2,0	2,5	2,5	3,0	3,0
PV (cP)	1,0	1,0	1,0	1,5	1,5	2,0	2,0
YP (lb/100ft²)	1,0	2,0	2,0	2,0	2,0	2,0	2,0

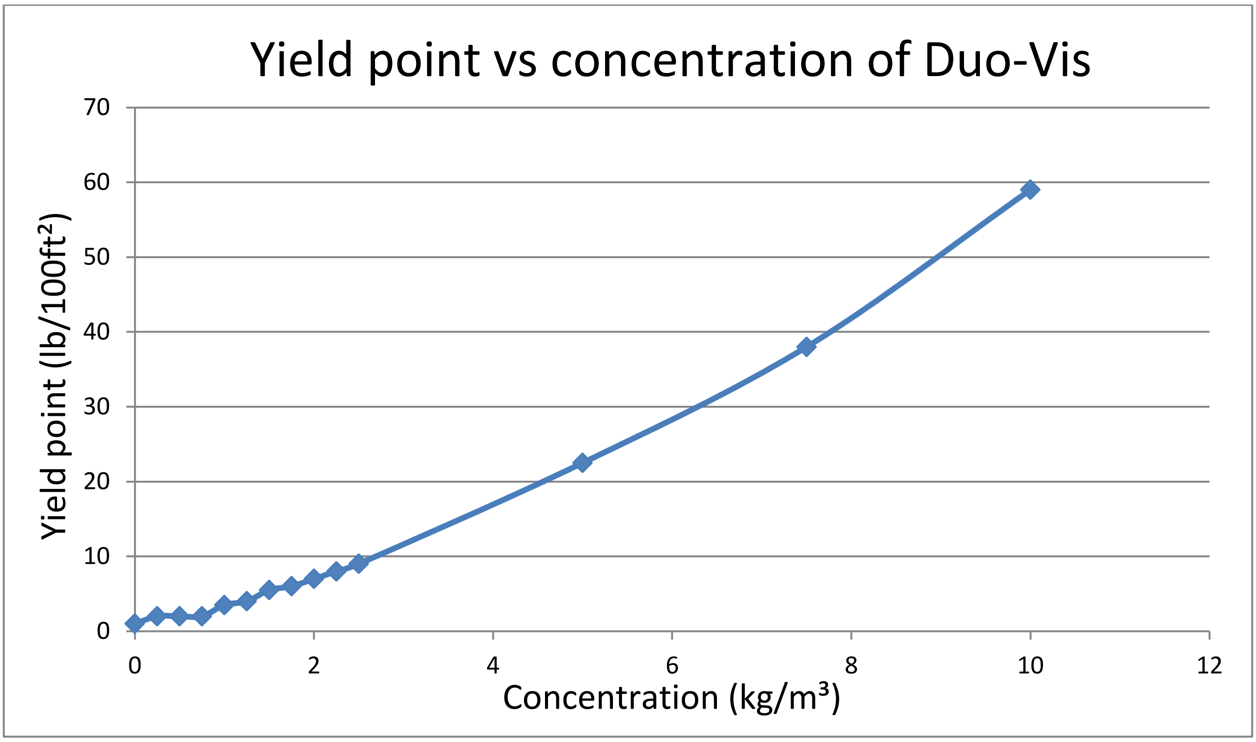
Concentration (kg/m³)	1,00	1,00	1,25	1,25	1,50	1,50
Volume added (g)	0,40	0,40	0,50	0,50	0,60	0,60
Mixing time (minutes)	5	10	5	10	5	10
Temp (°C)	23,8	24,1	24,2	24,4	24,4	24,8
600 RPM (cP)	7,5	7,5	9,0	9,0	10,5	10,5
300 RPM (cP)	5,5	5,5	6,5	6,5	8,0	8,0
200 RPM (cP)	4,5	4,5	5,5	5,5	6,5	6,5
100 RPM (cP)	3,0	3,0	4,0	4,0	5,0	5,0
6 RPM (cP)	1,0	1,0	1,5	1,5	2,0	2,0
3 RPM (cP)	1,0	1,0	1,5	1,5	2,0	2,0
10sec. Gel (lb/100ft²)	1,0	1,0	2,0	2,0	2,0	2,0
10min. Gel (lb/100ft²)	1,0	1,0	2,0	2,0	2,0	2,0
AV (cP)	3,8	3,8	4,5	4,5	5,3	5,3
PV (cP)	2,0	2,0	2,5	2,5	2,5	2,5
YP (lb/100ft²)	3,5	3,5	4,0	4,0	5,5	5,5

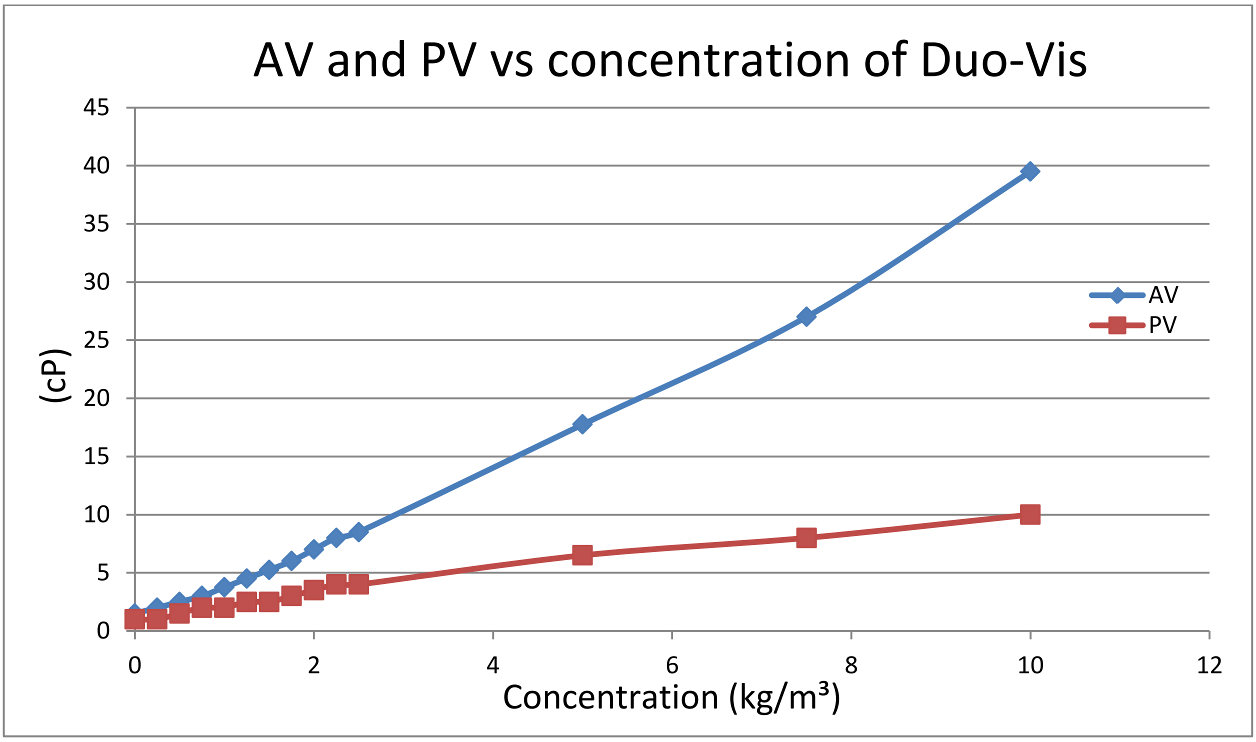
Concentration (kg/m³)	1,75	1,75	2,00	2,00	2,25	2,25
Volume added (g)	0,70	0,70	0,80	0,80	0,90	0,90
Mixing time (minutes)	5	10	5	10	5	10
Temp (°C)	25,0	25,1	24,8	24,9	24,8	24,9
600 RPM (cP)	12,0	12,0	14,0	14,0	16,0	16,0
300 RPM (cP)	9,0	9,0	10,5	10,5	12,0	12,0
200 RPM (cP)	8,0	8,0	9,0	9,0	10,0	10,0
100 RPM (cP)	6,0	6,0	7,0	7,0	8,0	8,0
6 RPM (cP)	2,5	3,0	3,0	3,0	4,0	4,0
3 RPM (cP)	2,0	2,0	2,5	3,0	3,0	3,0
10sec. Gel (lb/100ft²)	2,5	2,5	3,0	3,0	3,0	4,0
10min. Gel (lb/100ft²)	2,5	3,0	3,0	3,0	4,0	4,0
AV (cP)	6,0	6,0	7,0	7,0	8,0	8,0
PV (cP)	3,0	3,0	3,5	3,5	4,0	4,0
YP (lb/100ft²)	6,0	6,0	7,0	7,0	8,0	8,0

Concentration (kg/m³)	2,50	2,50	5,00	7,50	10,00
Volume added (g)	1,00	1,00	2,00	3,00	4,00
Mixing time (minutes)	5	10	10	10	10
Temp (°C)	24,8	25,1	33,2	40,1	45,3
600 RPM (cP)	17,5	17,0	35,5	54,0	79,0
300 RPM (cP)	13,0	13,0	29,0	46,0	69,0
200 RPM (cP)	11,0	11,0	26,0	42,0	62,0
100 RPM (cP)	9,0	9,0	22,0	37,0	55,0
6 RPM (cP)	4,5	4,5	15,0	25,0	33,0
3 RPM (cP)	4,0	4,0	14,0	23,0	29,0
10sec. Gel (lb/100ft²)	4,5	4,5	14,0	23,0	31,0
10min. Gel (lb/100ft²)	5,0	5,0	19,0	31,0	42,0
AV (cP)	8,8	8,5	17,8	27,0	39,5
PV (cP)	4,5	4,0	6,5	8,0	10,0
YP (lb/100ft²)	8,5	9,0	22,5	38,0	59,0

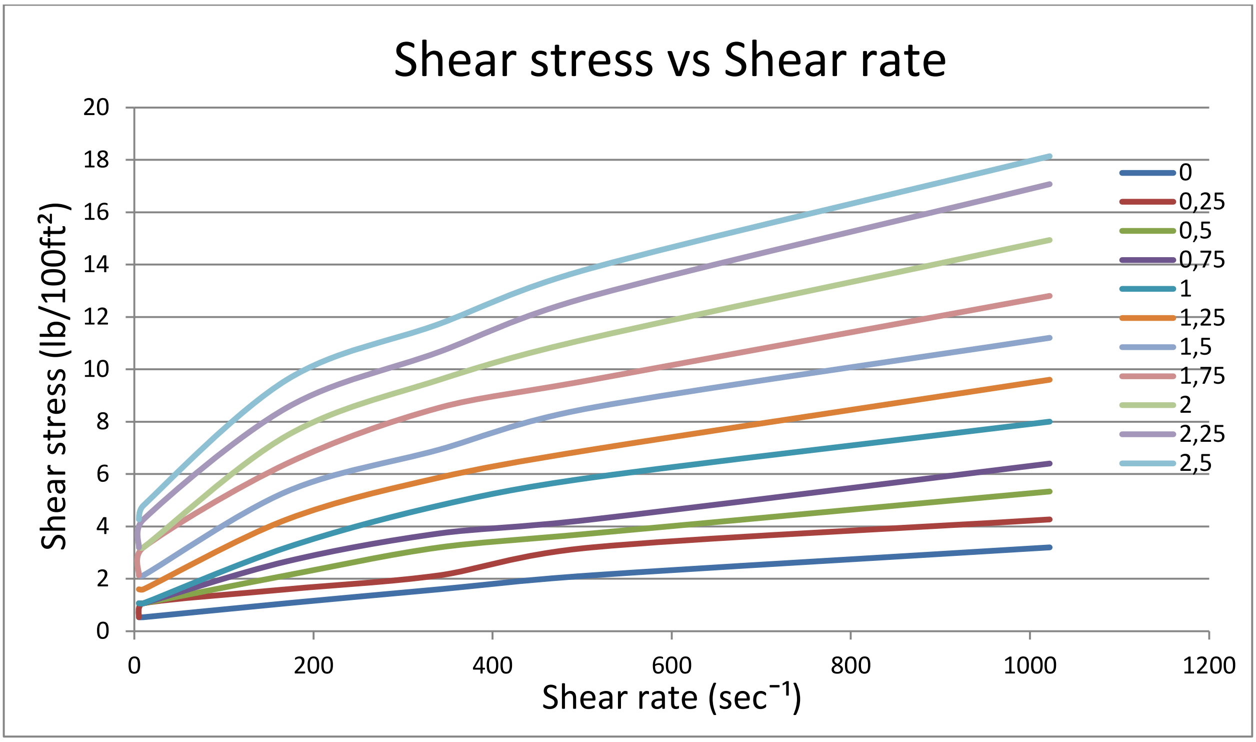

Viscosity vs concentration of Duo-Vis
Viscosity (cP)
80
70
60
50
40
30
20
10
0
0
2
4
6
8
10
12
Concentration (kg/m³)
600 RPM
300 RPM
200 RPM
100 RPM
6 RPM
3 RPM

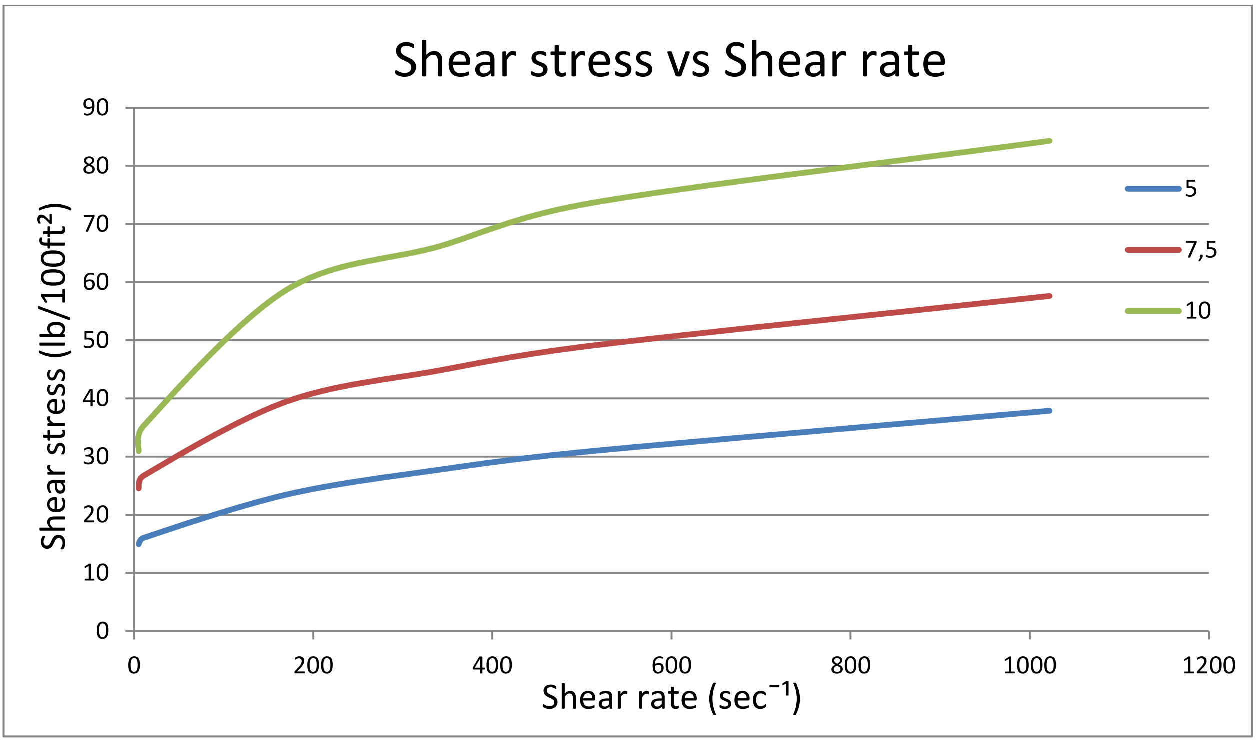

Gel strength vs concentration of Duo-Vis
Gel strength (lb/100ft²)
45
40
35
30
25
20
15
10
5
0
0
2
4
6
8
10
12
Concentration (kg/m³)
10sec. Gel
10min. Gel


Yield point vs concentration of Duo-Vis
Yield point (lb/100ft²)
70
60
50
40
30
20
10
0
0
2
4
6
8
10
12
Concentration (kg/m³)

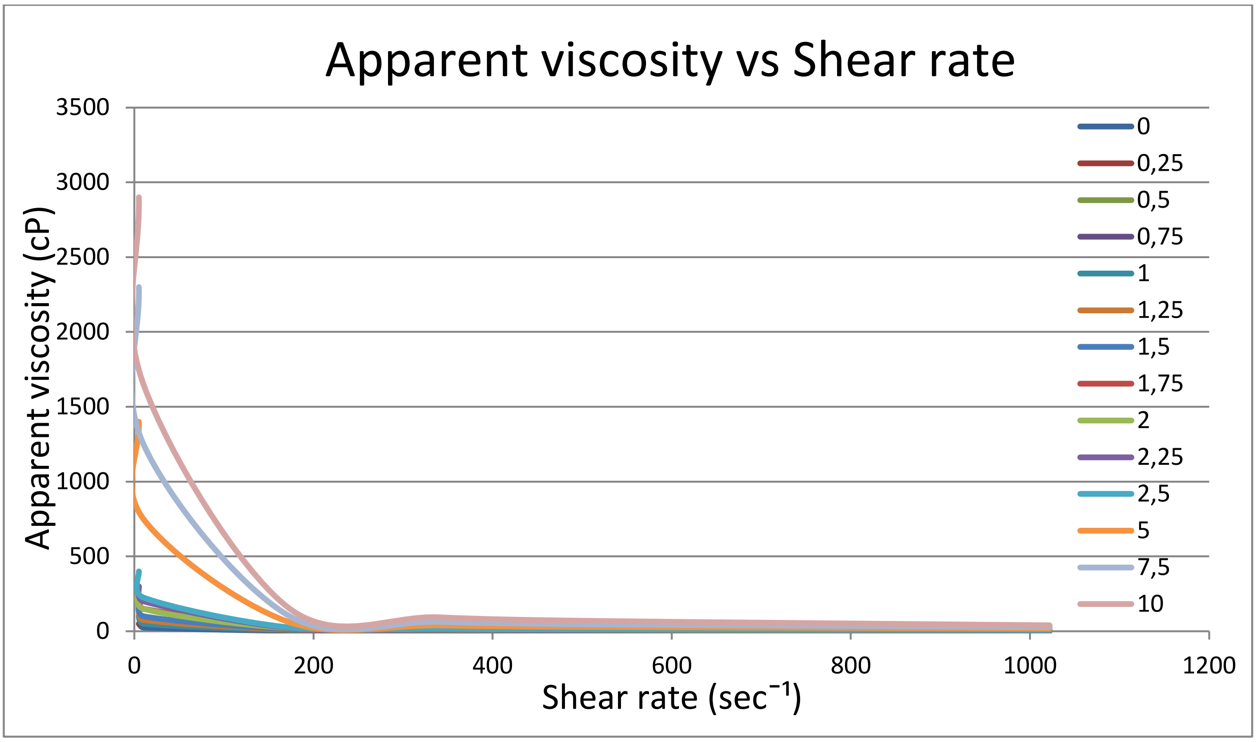

AV and PV vs concentration of Duo-Vis
(cP)
45
40
35
30
25
20
15
10
5
0
0
2
4
6
8
10
12
Concentration (kg/m³)
AV
PV

	Shear rate (sec^{-1})						
Concentration (kg/m^3)	1022,04	511,02	340,68	170,34	10,2204	5,1102	Shear stress ($lb/100ft^2$)
0	3,201	2,134	1,6005	1,067	0,5335	0,5335	
0,25	4,268	3,201	2,134	1,6005	1,067	0,5335	
0,5	5,335	3,7345	3,201	2,134	1,067	1,067	
0,75	6,402	4,268	3,7345	2,6675	1,067	1,067	
1	8,0025	5,8685	4,8015	3,201	1,067	1,067	
1,25	9,603	6,9355	5,8685	4,268	1,6005	1,6005	
1,5	11,2035	8,536	6,9355	5,335	2,134	2,134	
1,75	12,804	9,603	8,536	6,402	3,201	2,134	
2	14,938	11,2035	9,603	7,469	3,201	3,201	
2,25	17,072	12,804	10,67	8,536	4,268	3,201	
2,5	18,139	13,871	11,737	9,603	4,8015	4,268	
5	37,8785	30,943	27,742	23,474	16,005	14,938	
7,5	57,618	49,082	44,814	39,479	26,675	24,541	
10	84,293	73,623	66,154	58,685	35,211	30,943	





Concentration (kg/m³)	Shear rate (sec^{-1})						Apparent viscosity (cP)
	1022,04	511,02	340,68	170,34	10,2204	5,1102	
0	1,5	2	2,25	3	25	50	
0,25	2	3	3	4,5	50	50	
0,5	2,5	3,5	4,5	6	50	100	
0,75	3	4	5,25	7,5	50	100	
1	3,75	5,5	6,75	9	50	100	
1,25	4,5	6,5	8,25	12	75	150	
1,5	5,25	8	9,75	15	100	200	
1,75	6	9	12	18	150	200	
2	7	10,5	13,5	21	150	300	
2,25	8	12	15	24	200	300	
2,5	8,5	13	16,5	27	225	400	
5	17,75	29	39	66	750	1400	
7,5	27	46	63	111	1250	2300	
10	39,5	69	93	165	1650	2900	

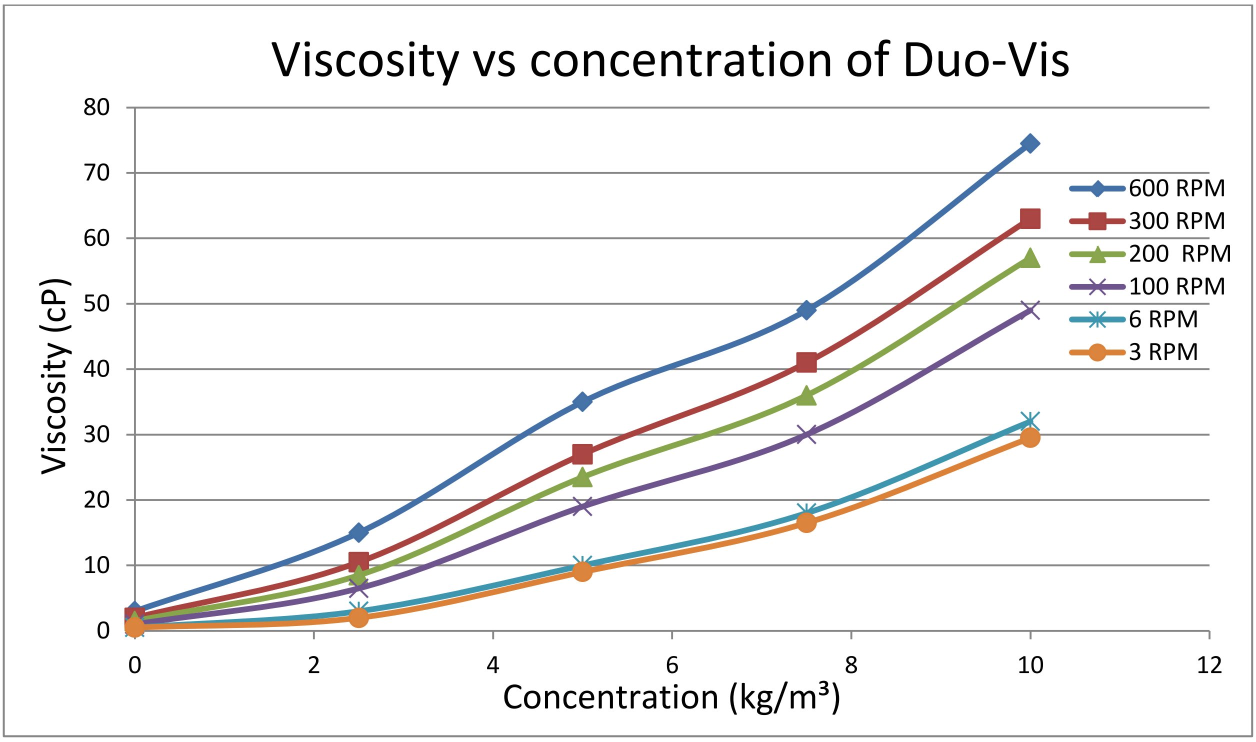

Apparent viscosity vs Shear rate
Apparent viscosity (cP)
3500
3000
2500
2000
1500
1000
500
0
0
200
400
600
800
1000
1200
Shear rate (sec⁻¹)
0
0,25
0,5
0,75
1
1,25
1,5
1,75
2
2,25
2,5
5
7,5
10

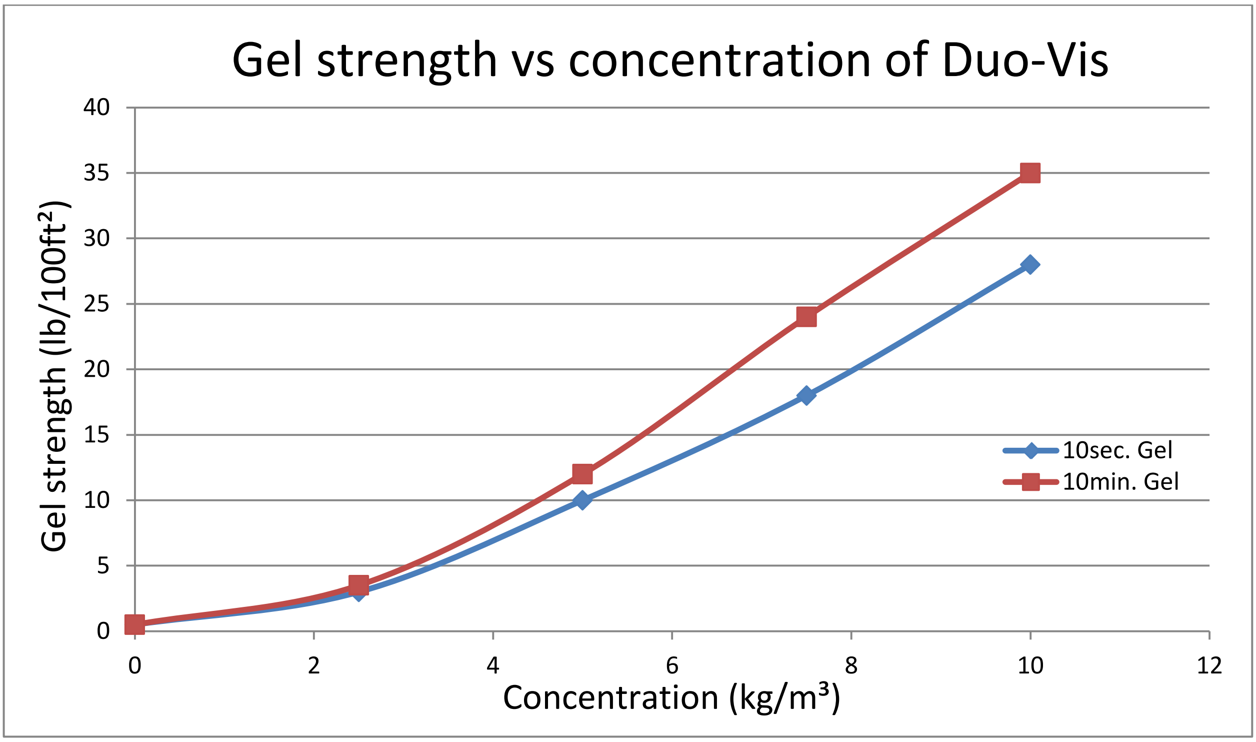
Appendix D - Measured values and plots from Experiment 2

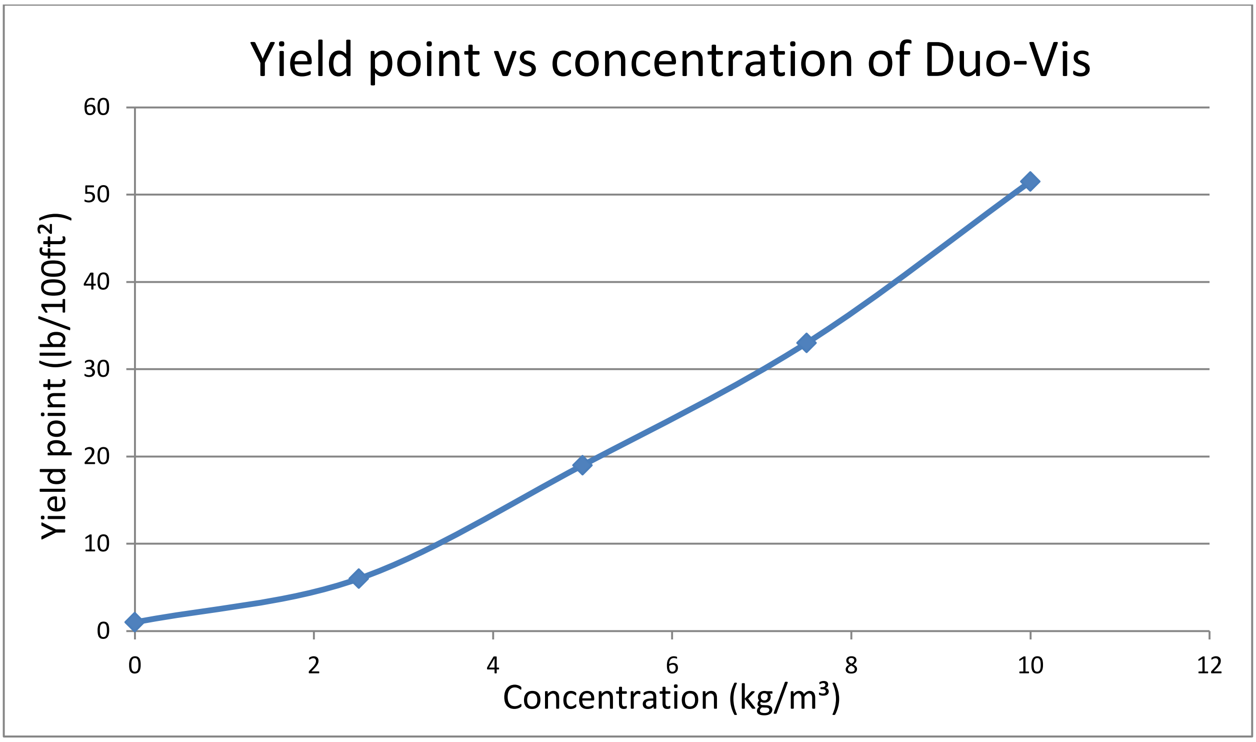
Measurements:

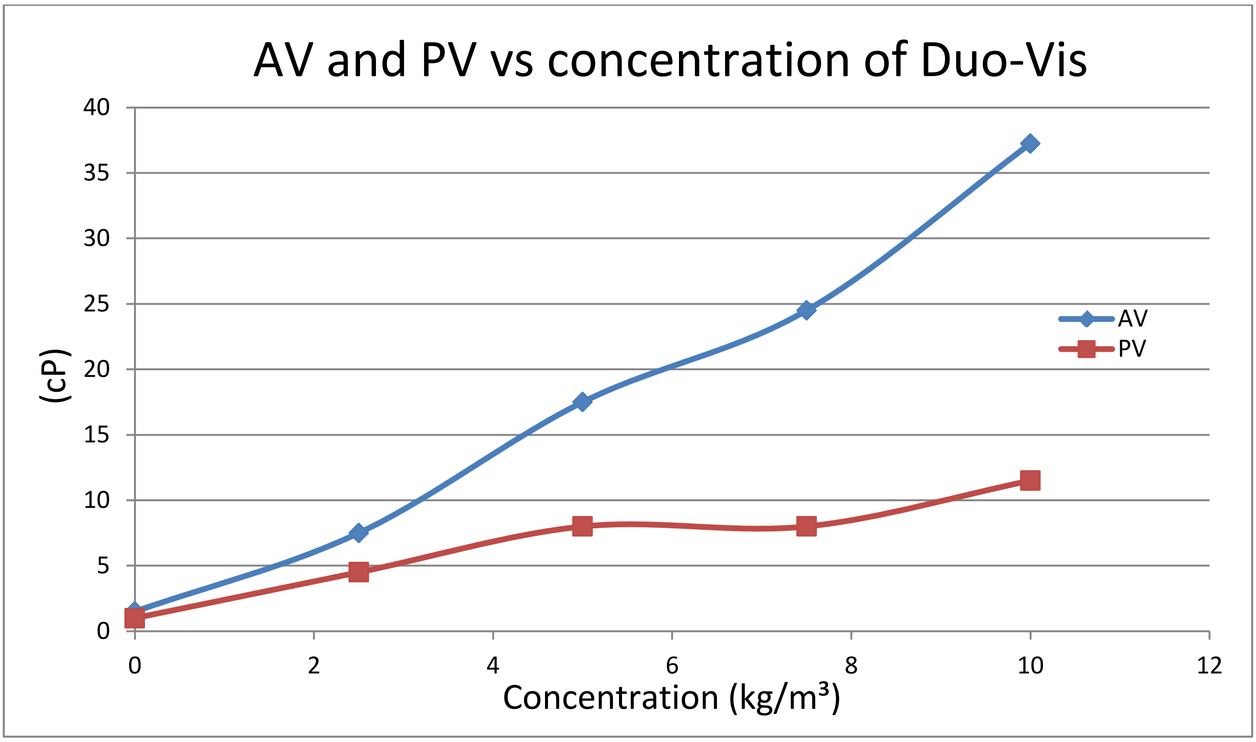
1. pH = 9,95
2. density = 1,023sg
3. Cl^- content = 14300mg/l

Concentration (kg/m³)	0,00	2,50	5,00	7,50	10,00
Volume added (g)	0,00	1,00	2,00	3,00	4,00
Mixing time (minutes)	0	10	10	10	10
Temp (°C)	18,1	23,1	31,1	36,0	40,3
600 RPM (cP)	3,0	15,0	35,0	49,0	74,5
300 RPM (cP)	2,0	10,5	27,0	41,0	63,0
200 RPM (cP)	1,5	8,5	23,5	36,0	57,0
100 RPM (cP)	1,0	6,5	19,0	30,0	49,0
6 RPM (cP)	0,5	3,0	10,0	18,0	32,0
3 RPM (cP)	0,5	2,0	9,0	16,5	29,5
10sec. Gel (lb/100ft²)	0,50	3,00	10,00	18,00	28,00
10min. Gel (lb/100ft²)	0,50	3,50	12,00	24,00	35,00
AV (cP)	1,5	7,5	17,5	24,5	37,3
PV (cP)	1,0	4,5	8,0	8,0	11,5
YP (lb/100ft²)	1,0	6,0	19,0	33,0	51,5

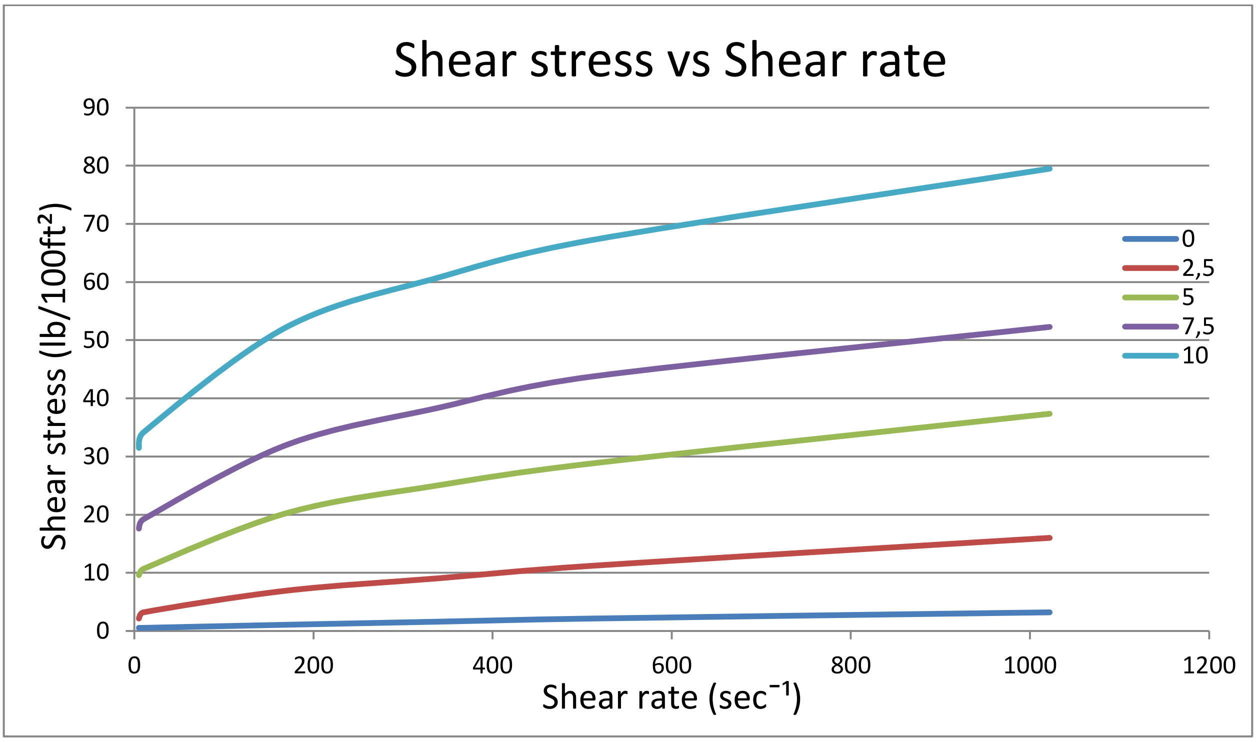



Gel strength vs concentration of Duo-Vis
Gel strength (lb/100ft²)
0
5
10
15
20
25
30
35
40
0
2
4
6
8
10
12
Concentration (kg/m³)
10sec. Gel
10min. Gel

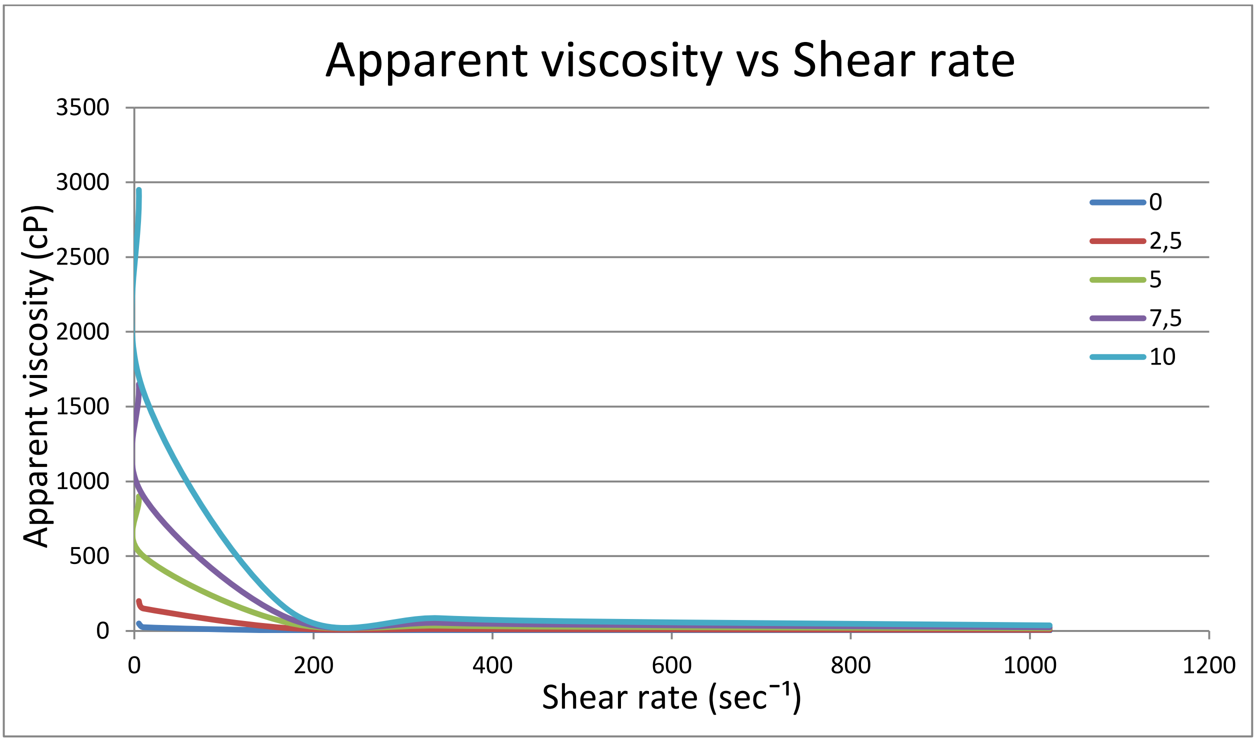

Yield point vs concentration of Duo-Vis
Yield point (lb/100ft²)
0
10
20
30
40
50
60
0
2
4
6
8
10
12
Concentration (kg/m³)



Concentration (kg/m³)	Shear rate (sec⁻¹): 1022,04	511,02	340,68	170,34	10,2204	5,1102	
0	3,201	2,134	1,6005	1,067	0,5335	0,5335	Shear stress (lb/100ft²)
2,5	16,005	11,2035	9,0695	6,9355	3,201	2,134	
5	37,345	28,809	25,0745	20,273	10,67	9,603	
7,5	52,283	43,747	38,412	32,01	19,206	17,6055	
10	79,4915	67,221	60,819	52,283	34,144	31,4765	



		Shear rate (sec⁻¹)						
		1022,04	511,02	340,68	170,34	10,2204	5,1102	
Concentration (kg/m³)	0	1,5	2	2,25	3	25	50	Apparent viscosity (cP)
	2,5	7,5	10,5	12,75	19,5	150	200	
	5	17,5	27	35,25	57	500	900	
	7,5	24,5	41	54	90	900	1650	
	10	37,25	63	85,5	147	1600	2950	

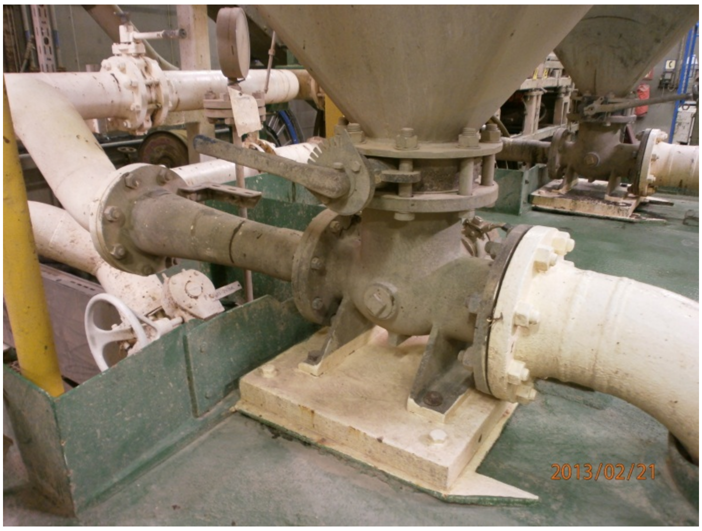


Appendix E - Equipment onboard Gullfaks B

Drilling fluid laboratory

The mixing system

The mud hoppers



Detail of the venturi pipe of the hopper

Input for liquid additives

Procon tank on its station

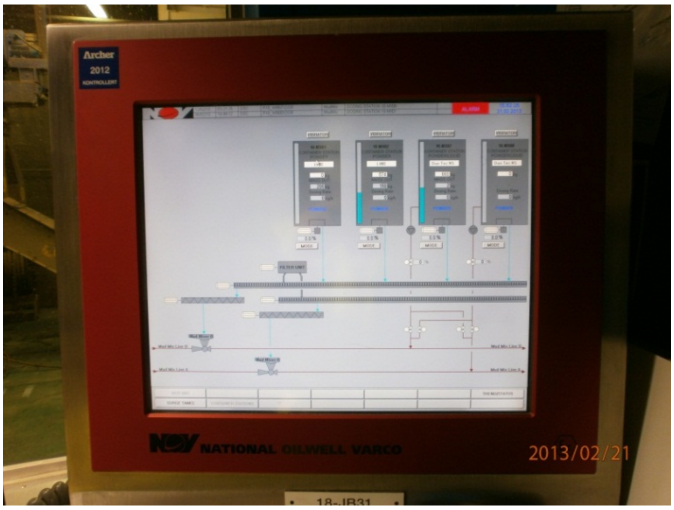
Two Procon tanks side by side

Detail of tank with chains for crane lifting

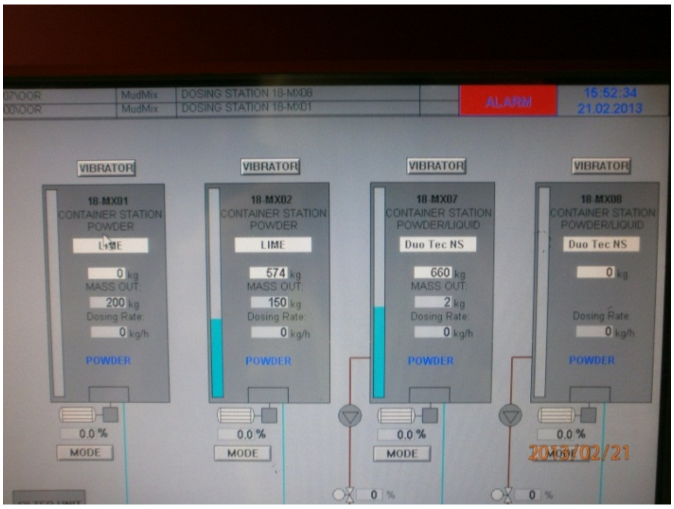
Detail of label on Procon tank

Empty station

The drilling fluid control room



Detail of the Procon control console



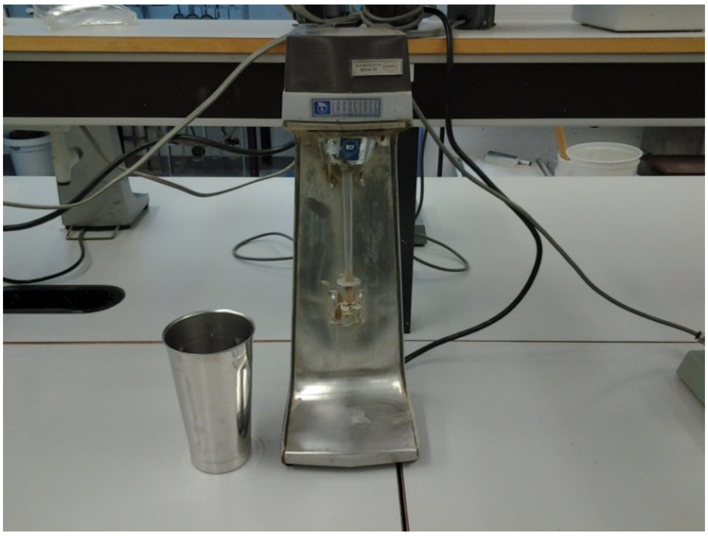
Second control station outside the control cabin

Sacks of lost circulation material (LCM)

Appendix F - Equipment used in Experiment 1 and 2

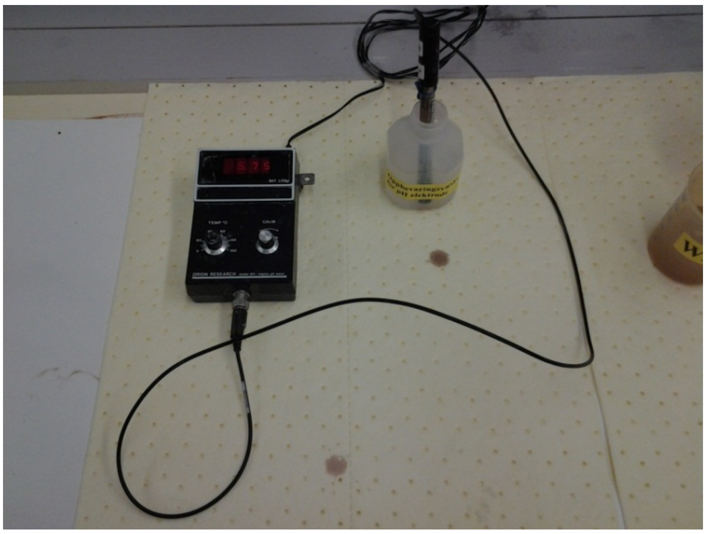
Measuring cup

Thermometer

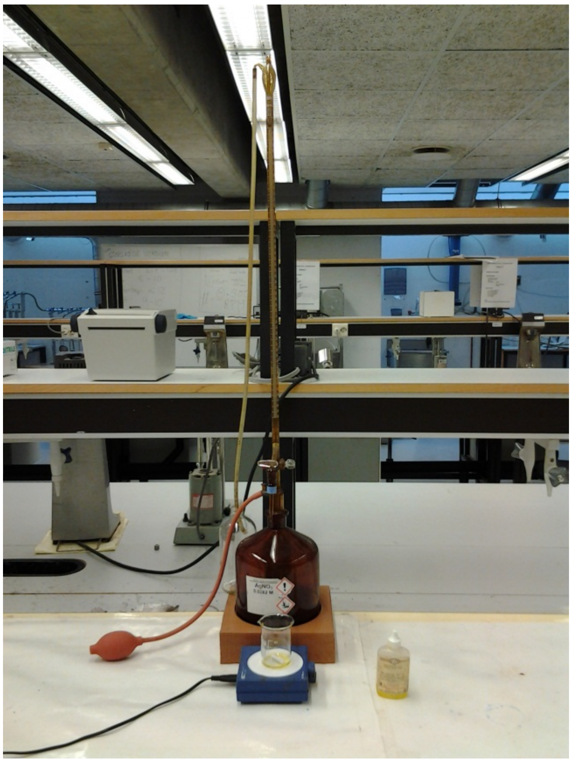


Hamilton Beach mixer

Fann VG-meter 35 (six-speed)



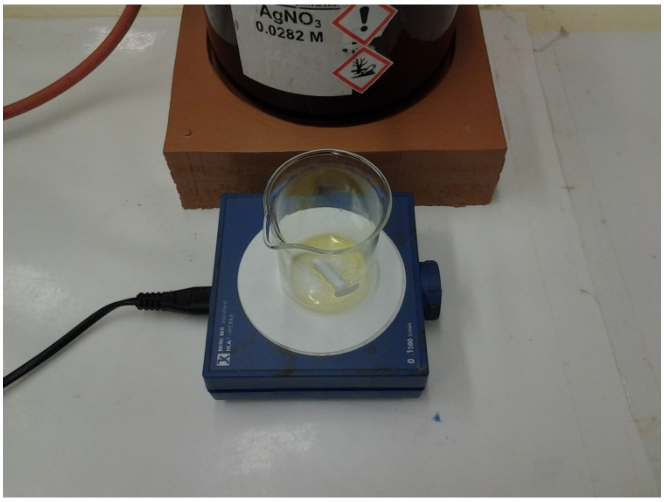
pH-meter



Silver nitrate bottle used for titration

Potassium chromate indicator

Duo-Vis – polymer viscosifier



Measuring cup, magnet and stirrer plate

Scale and weighting container

Appendix G - Current flow loop at the laboratory at the University of Stavanger

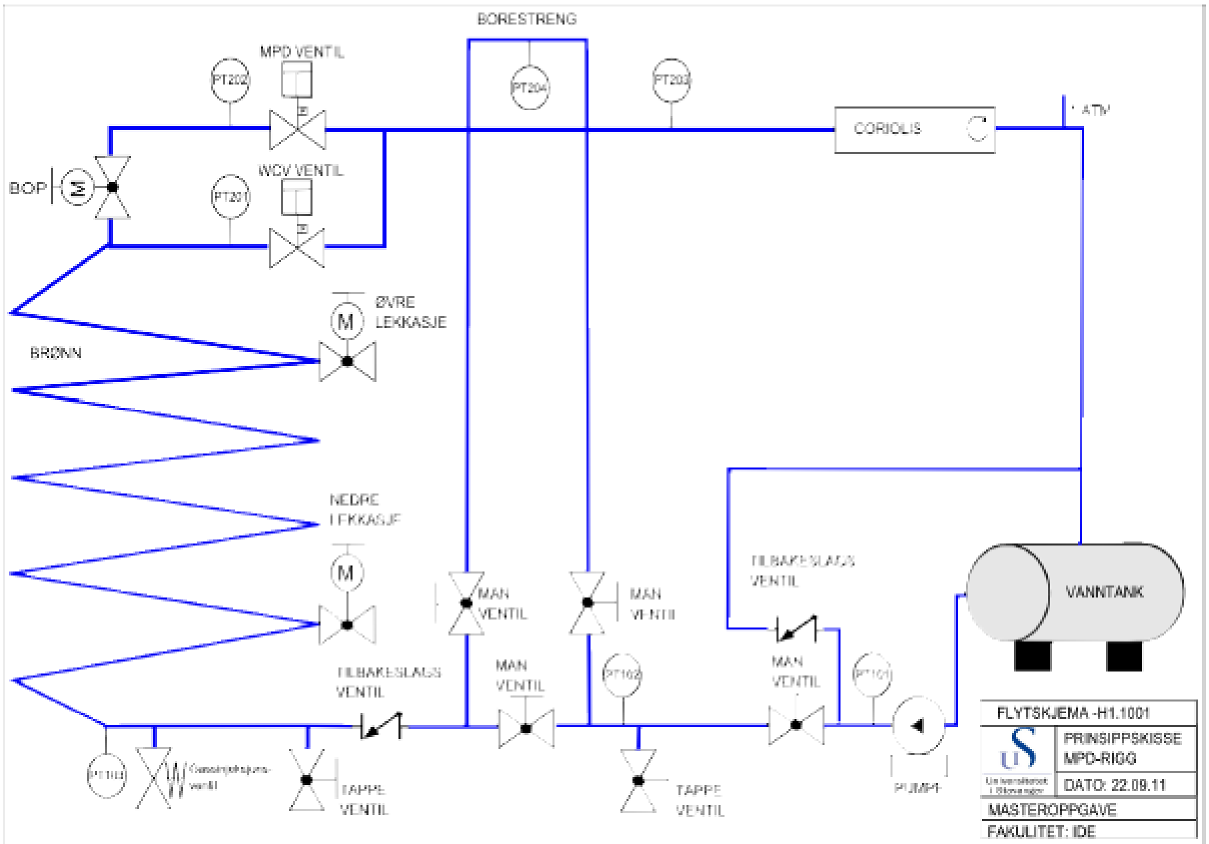
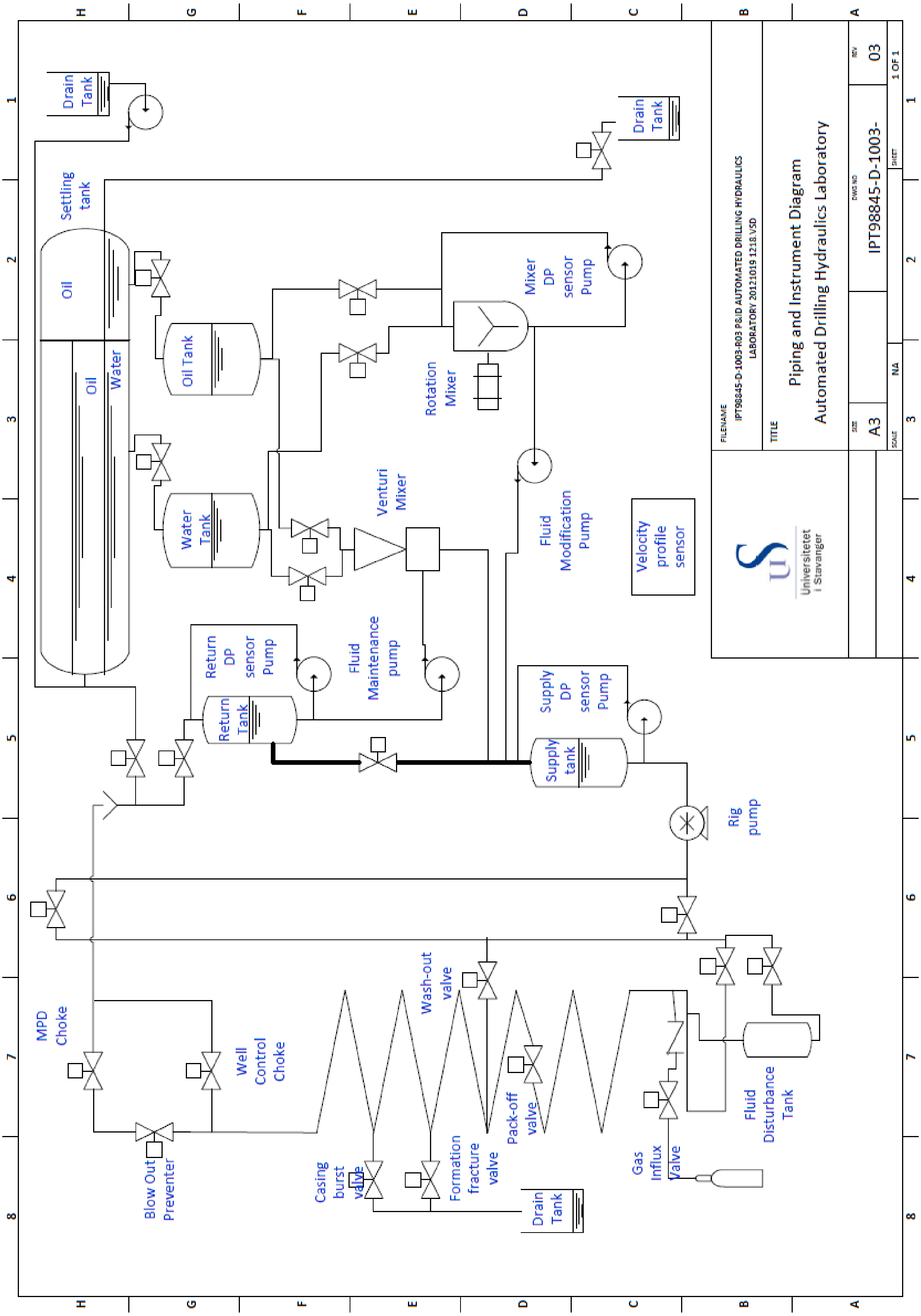


Diagram of the Flow loop at the laboratory [17]

Flow loop at the laboratory

Appendix H - Future Setup of the laboratory at the University of Stavanger [18]



Appendix I - MSDS for silicone oil to be used in future experiments

MOMENTIVE
performance materials

Material Safety Data Sheet

Version: 1.2
01/31/2008

SF96-50 55G-Drum (440.0LBS-199.76KG)
DIMETHYLPOLYSILOXANES

EYE AND FACE PROTECTION
Safety glasses with side-shields

OTHER PROTECTIVE EQUIPMENT
Wear suitable protective clothing and eye/face protection.

Exposure Guidelines

Component	CAS RN	Source	Value

Absence of values indicates none found

PEL - OSHA Permissible Exposure Limit; TLV - ACGIH Threshold Limit Value; TWA - Time Weighted Average

OSHA revoked the Final Rule Limits of January 19, 1989 in response to the 11th Circuit Court of Appeals decision (AFL-CIO v. OSHA) effective June 30, 1993. See 29 CFR 1910.1000 (58 FR 35338).

9. PHYSICAL AND CHEMICAL PROPERTIES

BOILING POINT - C & F:	>200 °C; 392 °F; Polymer
VAPOR PRESSURE (20 C) (MM HG):	1MM HG
VAPOR DENSITY (AIR=1):	> 1
FREEZING POINT:	< -25 °C; -13 °F
MELTING POINT:	< -25 °C; -13 °F
PHYSICAL STATE:	Liquid
ODOR:	Mild
COLOR:	Clear
EVAPORATION RATE (BUTYL ACETATE=1):	< 1
SPECIFIC GRAVITY (WATER=1):	ca. 0.97
DENSITY:	ca. 0.958 g/cm3
ACID / ALKALINITY (MEQ/G):	No data available
pH:	Not applicable
SOLUBILITY IN WATER (20 C):	Insoluble
SOLUBILITY IN ORGANIC SOLVENT (STATE SOLVENT):	Slightly in Toluene

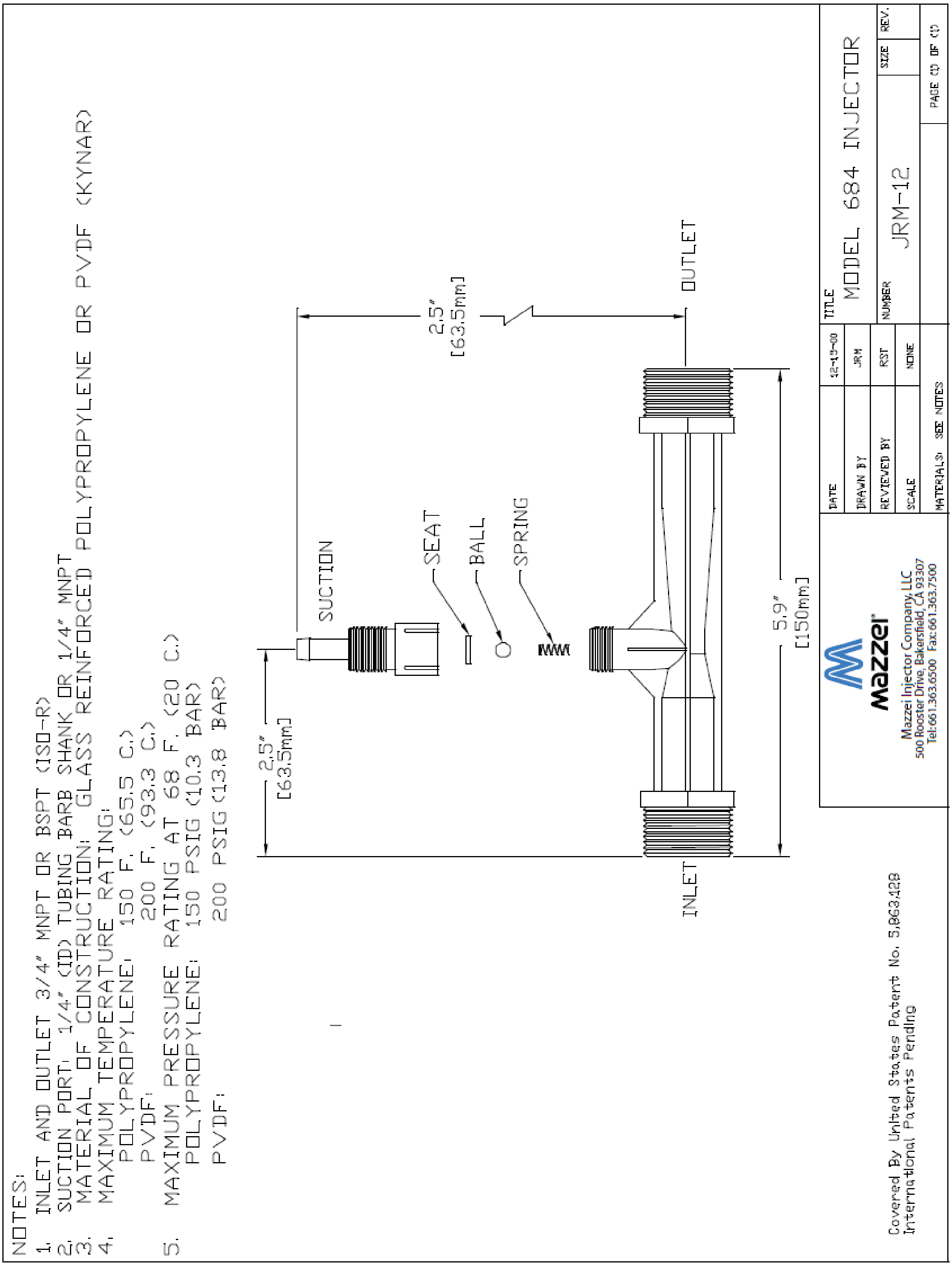
10. STABILITY AND REACTIVITY

STABILITY
Stable

HAZARDOUS POLYMERIZATION
Will not occur.

HAZARDOUS THERMAL DECOMPOSITION / COMBUSTION PRODUCTS
Burning can produce the following combustion products:; Carbon dioxide (CO_2); Carbon monoxide; Silicon dioxide.; Formaldehyde; Carbon monoxide is highly toxic if inhaled; carbon dioxide in sufficient

Appendix J - Mazzei Injector Company venturi pipe model 684



Mazzei Injector Company, LLC- Injector Performance Table

Injector Model 684 7/22/04

Operating Pressure kg/cm2		Water Suction	
Injector Inlet	Injector Outlet	Motive Flow l/min	Water Suction LPH
0.35	0.00	13.3	103.9
	0.07		76.7
	0.14		52.3
	0.21		25.0
	0.28		21.3
0.70	0.00	18.8	103.1
	0.14		103.5
	0.35		70.0
	0.49		41.2
	0.56		22.9
1.05	0.00	23.0	98.8
	0.35		98.9
	0.49		94.9
	0.70		48.7
	0.84		26.5
1.41	0.00	26.5	95.1
	0.35		95.5
	0.70		95.5
	0.84		69.7
	1.05		39.5
1.76	0.00	29.7	93.9
	0.35		94.2
	0.70		94.3
	1.05		92.2
	1.41		19.6
2.11	0.00	32.5	92.8
	0.35		93.2
	0.70		93.3
	1.05		93.1
	1.41		55.8
	1.76		25.6
2.46	0.00	35.1	93.6
	0.35		93.2
	0.70		93.7
	1.05		93.7
	1.41		94.3
	1.76		48.9
2.81	0.00	37.5	94.5
	0.35		94.7
	0.70		95.1
	1.05		94.7
	1.41		94.9
	1.76		93.7
	2.11		41.0
3.16	0.00	39.8	94.7
	0.35		94.8
	0.70		94.8
	1.05		94.9
	1.41		95.0
	1.76		95.1
	2.11		78.1
	2.46		31.8
3.52	0.00	41.9	94.8
	0.35		94.5
	0.70		94.6
	1.05		94.9
	1.41		94.3
	1.76		94.5
	2.11		64.9
	2.46		34.7
	2.81		25.4

Operating Pressure kg/cm2		Water Suction	
Injector Inlet	Injector Outlet	Motive Flow l/min	Water Suction LPH
4.22	0.00	45.9	95.2
	0.35		94.8
	0.70		96.0
	1.05		95.8
	1.41		95.5
	2.11		95.4
	2.46		95.3
	2.81		51.1
	3.16		26.9
4.92	0.00	49.6	96.2
	0.35		96.0
	0.70		96.6
	1.05		96.2
	1.41		96.9
	2.11		96.4
	2.81		96.4
	3.16		78.4
	3.52		40.0
	3.87		26.2
5.62	0.00	53.1	96.6
	0.35		96.6
	0.70		96.8
	1.05		97.0
	1.41		97.1
	2.11		97.0
	2.81		96.9
	3.52		97.2
	4.22		59.4
	4.57		19.1
6.33	0.00	56.3	97.5
	0.35		97.8
	0.70		97.4
	1.41		97.7
	2.11		97.8
	2.81		97.9
	3.52		97.8
	4.22		97.9
	4.92		97.3
	5.27		50.6
7.03	0.00	59.3	89.0
	0.35		91.7
	0.70		91.7
	1.41		90.5
	2.11		90.7
	2.81		90.8
	3.52		90.6
	4.22		90.5
	4.92		91.2
	5.62		81.7
8.44	0.00	65.0	92.9
	0.35		94.5
	0.70		93.4
	1.41		93.2
	2.11		93.6
	2.81		92.8
	3.52		92.6
	4.22		93.5
	4.92		93.0
	5.62		82.2
	6.33		73.6
	7.03		68.6

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Mazzei Injector Company, LLC- Injector Performance Table

Injector Model 684 7/22/04

Operating Pressure kg/cm2		Air Suction	
Injector Inlet	Injector Outlet	Motive Flow l/min	Air Suction l/min
0.35	0.00	12.7	4.3
	0.07		2.7
	0.14		1.4
	0.21		0.5
	0.28		0.1
0.70	0.00	18.0	6.3
	0.14		4.4
	0.35		1.7
	0.49		0.7
	0.56		0.4
1.05	0.00	22.0	7.3
	0.35		3.4
	0.49		2.1
	0.70		1.0
	0.84		0.5
1.41	0.00	25.4	11.1
	0.35		7.1
	0.70		2.7
	0.84		1.8
	1.05		0.8
1.76	0.00	28.4	13.0
	0.35		9.3
	0.70		3.9
	1.05		1.8
	1.41		0.8
2.11	0.00	31.1	14.4
	0.35		11.2
	0.70		5.6
	1.05		2.8
	1.41		1.6
	1.76		0.6
2.46	0.00	33.6	15.6
	0.35		12.2
	0.70		7.7
	1.05		4.2
	1.41		2.6
	1.76		1.4
2.81	0.00	36.0	16.6
	0.35		12.8
	0.70		9.9
	1.05		5.6
	1.41		3.8
	1.76		2.3
	2.11		1.6
3.16	0.00	38.1	17.4
	0.35		14.1
	0.70		11.2
	1.05		7.3
	1.41		4.6
	1.76		3.1
	2.11		1.9
	2.46		1.2
3.52	0.00	40.2	19.8
	0.35		15.6
	0.70		13.4
	1.05		9.2
	1.41		5.7
	1.76		3.8
	2.11		2.8
	2.46		1.8
	2.81		1.0

Operating Pressure kg/cm2		Air Suction	
Injector Inlet	Injector Outlet	Motive Flow l/min	Air Suction l/min
4.22	0.00	44.0	20.2
	0.35		16.5
	0.70		14.9
	1.05		13.0
	1.41		8.1
	2.11		4.4
	2.46		3.2
	2.81		2.5
	3.16		1.5
4.92	0.00	47.6	20.3
	0.35		18.7
	0.70		16.6
	1.05		14.9
	1.41		12.8
	2.11		6.4
	2.81		3.9
	3.16		2.8
	3.52		2.1
	3.87		1.3
5.62	0.00	50.9	20.3
	0.35		19.8
	0.70		17.3
	1.05		16.3
	1.41		15.2
	2.11		8.1
	2.81		5.2
	3.52		3.1
	4.22		2.0
	4.57		1.4
6.33	0.00	53.9	20.4
	0.35		20.0
	0.70		18.6
	1.41		16.2
	2.11		11.7
	2.81		7.0
	3.52		4.8
	4.22		3.4
	4.92		2.0
	5.27		1.4
7.03	0.00	56.9	20.6
	0.35		20.4
	0.70		19.9
	1.41		18.0
	2.11		15.6
	2.81		8.5
	3.52		6.2
	4.22		4.5
	4.92		3.1
	5.62		1.9
8.44	0.00	62.3	20.7
	0.35		20.4
	0.70		20.1
	1.41		18.8
	2.11		18.2
	2.81		12.9
	3.52		8.6
	4.22		6.5
	4.92		5.1
	5.62		3.9
	6.33		2.8
	7.03		1.8

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Appendix K - Recommended procedure for measuring gel strength [13]

fann Model 35 Viscometer Instruction Manual

5.3 Measuring Gel Strength

The commonly used procedure for measuring gel strength is as follows:

1. Stir the sample thoroughly at 600 rpm.
2. Set the gear shift knob to the 3 rpm position, and then turn the motor to the OFF position.
3. After the desired wait time, turn the motor to the ON position at low speed.
4. Read the dial at the moment the gel breaks as noted by a peak dial reading. The gel strength units are $lb/100ft^2$.

An alternative method for measuring gel strength is as follows:

1. Stir the sample thoroughly at 600 rpm.
2. Turn the motor to the OFF position.
3. After the desired wait period, turn the gel knob (located below the gear shift knob) slowly counterclockwise.
4. Read the dial at the moment the gel breaks as noted by a peak dial reading. The gel strength units are $lb/100ft^2$.