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DRILLING FLUID DESIGN FOR GEOTHERMAL WELLS

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ABSTRACT

Drilling is a key process in the development of geothermal resources, whether at the exploration stage or in a fully developed field. It constitutes up to 35-50% of project costs. Successful completion of a well at minimal cost is, therefore, imperative. One area that highly affects both successful completion of a well and its cost is the drilling fluid program. Drilling fluids have advanced over the years, more so in petroleum drilling; however, some of the technologies in the oil sector may not be relevant in geothermal drilling and could just escalate the well costs. It is imperative to design a simple drilling fluid program that will not only ensure a quality well but also minimise the cost of the well. This paper seeks to address the selection of a drilling fluid best fit for geothermal wells.

1. INTRODUCTION

Drilling is a key process in the development of geothermal resources, whether at the exploration stage or in a fully developed field. It also constitutes one of the highest costs in geothermal projects, i.e. up to 35-50% (Kipsang, 2013). It is therefore imperative not only to successfully complete a well but also to ensure it is done at the minimum cost that is possible. One area that highly affects both the successful completion of a well and its costs is the drilling fluid program. A drilling fluid program entails details on the drilling fluid to be used in the various well sections and possible actions to be undertaken in case of special hole conditions. The drilling program is one of the critical components in successfully completing a drilling project. Selection of drilling fluids also involves appreciating the costs involved with each system. These can be either direct or indirect costs. Direct costs are those incurred in the purchase, handling and utilization of the drilling fluid. They include personnel costs and technology costs, for instance hiring an air drilling package, among others. These normally constitute up to 15% of the well costs (Kipsang, 2013). Indirect costs, on the other hand, are costs which can be traced to the effects of the drilling fluid technology used. This is because different fluid systems have varying effects on the well which could either enhance or impede the drilling process; these costs could be in terms of several extra drilling days or fishing operations among others. The reservoir quality is also affected by the drilling fluid as some fluids lead to more formation damage. Drilling fluids have advanced over the years, more so in petroleum drilling; however, some of the technologies in the oil sector may not be relevant in geothermal drilling and could escalate well costs. It is imperative to design a simple drilling fluid program that will not only ensure a quality well but also minimise the cost of the well.

2. DESCRIPTION OF DRILLING FLUIDS

The drilling process mainly involves cutting the rock and bringing the cuttings to the surface. A drilling rig is equipped with several tools and equipment to aid in the cutting and transportation of these cuttings. One of the key systems needed is the circulation system which includes pumps, compressors, tanks, a water pond and, most important, the drilling fluid.

In its simplest form, a drilling fluid is any fluid circulated in a well in order to bring out the cuttings from the wellbore. This can be as simple as plain water or as complex as a fluid mixture with several chemical additives. For a long time drilling fluids were mainly designed to bring cuttings to the surface; however, with advancement in the drilling sector, research has proven that drilling fluids affect drilling performance and, eventually, well performance (Baker Hughes, 1995). Today drilling fluids are designed to take care of more than just cuttings. There are basically three types of drilling fluid systems: mud, air and aerated systems (Ava, 2004).

For drilling fluid to function, a circulation system is needed; this can be either direct circulation or reversed circulation; in this study, we shall focus on direct circulation. Figure 1 shows the key equipment in a drilling fluid direct circulation system, for air/gas or aerated drilling systems; compressors and boosters are incorporated into the system.

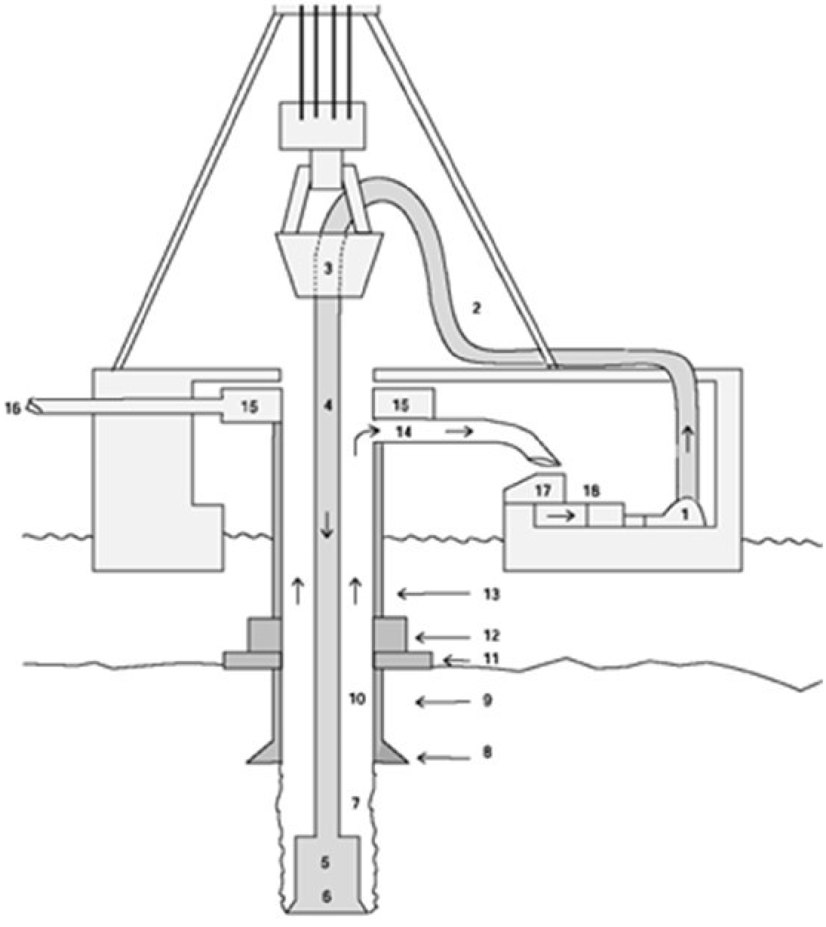

FIGURE 1: Circulation system (Ava, 2004)

The drilling fluid is pumped from the mud tanks up the Kelly hose through the drill pipe to the drill bit. At the drill bit, the fluid jets out at high pressure, lifting with it the freshly cut rock beneath the bit up the annulus, while cooling the bit and the formation at the same time. The fluid containing the rock must possess enough kinetic energy to move all the way to the surface with the cuttings. Once the fluid reaches the surface at the diverter, it flows to the shale shaker through the flow line where the cuttings are separated and the fluid is re-circulated. The quality of the fluid in the tank is continuously monitored for correct PH, viscosity and other parameters (Skalle, 2011).

2.1 Functions of drilling fluid

The initial key functions of drilling fluids were transporting cuttings to the surface, cooling the bit and drill string and controlling the sub-surface pressures. Today, however, with the advancement in drilling technologies, the drilling fluid has evolved to embrace several new functions. Nevertheless, the preceding still remain the key functions that any drilling fluid program must meet. Moreover, it is important that the drilling fluid is designed with the right properties for each function.

2.1.1 Hole cleaning

This involves carrying the cuttings from beneath the bit, transporting them to the surface and releasing them. The aim is to transport all the cut material as fast as possible to avoid any accumulation failure which could lead to several drilling challenges such as:

1. High torque which could lead to the drill stem snapping;
2. Stuck pipe, probably leading to the loss of the drill stem;
3. Hole pack off;
4. Damage to formation;
5. Excessive over pull during trips, hence reducing the life of the drill string; and
6. Slow rate of penetration.

Hole cleaning is the main action for which drilling fluid design is done. A fluid must have adequate viscosity, density and flow, at the right rate to carry the cuttings to the surface.

2.1.2 Well control

When preparing a drilling fluid, one must always remember that it is actually the key well control system. The pressures in a well increase with depth. When the formation fluid has higher pressures than those of the fluid in the well, a kick or blow out may occur. On the other hand, an overbalanced drilling fluid may cause formation damage by exerting excessive pressure on the formation wall. The key property of the fluid to be monitored in this case is the density.

2.1.3 Maintain borehole stability

A single well profile has formations with varying properties: some fractured, erodible or swelling. These could result in very problematic formations during the drilling process. The drilling fluid is the main option in addressing these and ensuring the borehole is kept stable to ensure the drill bit and stem runs through successfully to the total depth.

2.1.4 Protecting formation from damage

This has become an increasingly important function of drilling fluids. In geothermal drilling, aerated fluids are used in the production zone with the aim of minimizing formation damage. Formation damage may occur mainly due to plugging of the formation's natural porosity, either by solids or plugging associated with fluid filtration.

Other functions of drilling fluid include:

1. Cooling and lubricating the bit and drill stem;
2. Improving the rate of penetration by cleaning the surface to be drilled;
3. Contributing to drill string buoyancy; and
4. Retrieval of formation data.

2.2 Types of drilling fluids

A drilling fluid in its simplest form can be plain water; however, many times the properties of water must be improved to achieve the various tasks required of a drilling fluid. The basic composition of a drilling fluid is a base fluid, with a continuous fluid phase and can be water, oil or air. Various additives are introduced to these base fluids to achieve a given property, for instance viscosifiers are added to improve the viscosity of the fluid (Darley and Gray, 1988). The drilling fluids are, therefore, classified depending on the base fluid used: water, oil or air. Nevertheless, all drilling fluids have essentially the same properties; only the magnitude varies. These properties include density, viscosity, gel strength, filter cake, water loss, and electrical resistance (Baker Hughes, 1995). It is important to note that drilling fluids in geothermal drilling are rather simple since the formation that is drilled through many times is under-pressurised.

2.2.1 Water based drilling fluids

These have water as the continuous base and can be either fresh or saline water. This is the main type of fluid used in geothermal drilling, more so for the upper cased well sections. Active and inert solids are normally added to change the mud properties. Common active additives include bentonite and polymers, mainly used for improving on viscosity, which is important for the cuttings transport capacity of the mud. Inert solids include particles added to the mud, such as formation particles; a common substance normally added to increase mud density is barite (Darley and Gray, 1988). This, however, is rarely used in geothermal drilling.

Bentonite mud made by mixing bentonite into water has the advantage of gelling and also forming a filter cake around the wall of the well. The gel assists in suspending the cuttings in case the circulation is stopped, reducing the chance of the cuttings dropping down on the string. The filter cake is important in reducing loss of circulation since it forms an impermeable layer around the wall, and it also helps in increasing well stability. The filter cake, however, can be problematic if it is too thick and can also hinder good cementing jobs if not cleaned off. Polymers like bentonite are added with the aim of improving the viscosity of the mud; however, they have poor gelling properties and do not form a filter cake (Baker Hughes, 1995).

Other special water-based muds can be made to address specific well situations. These, however, are rare in geothermal drilling, but are common in oil drilling, and include:

1. Emulsion muds-oil in water;
2. Inhibited muds-large amounts of dissolved salts added to the mud; and
3. Lime treated muds.

Caustic soda is normally added to improve the pH of the fluid.

Also used in the oil sector is oil-based mud where oil is used as the continuous fluid phase and additives are put in to achieve various properties. This is rarely utilised in geothermal drilling, both because of costs and environmental concerns.

2.2.2 Air and aerated drilling fluids

Air drilling involves the utilisation of compressed air as the drilling fluid. Normally, this air is delivered through the string just like typical drilling mud, but with higher velocities and carries up with it the cuttings. It is a very efficient method for drilling in dry or frozen formations. Once water is encountered, then the cuttings transportation capacity is greatly hampered (Skalle, 2011). In geothermal drilling, this is mainly applied for drilling the surface section of the well where many times the rock is competent and very hard. Air hammer drilling is applied in Iceland and in the Kenya-Menengai geothermal project for drilling the surface hole (Thórhallson, 2014).

There are various types of air drilling, all depending on the liquid volume fraction, LVP, which indicates how much liquid is in the system and is a measure of the density of the fluid mixture: zero LVP implies no liquid, while one implies 100% liquid (Hole, 2006). All air drilling systems have LVP of less than one. Also of significance is the method of injection of the air stream into the system;

this can be either through the drill pipe or through the annulus (Lyons et al., 2009). In geothermal projects, the most common method used is the drill pipe injection method.

1. *Dust drilling:* Compressed air is used as the sole drilling fluid; this is ideal in dry areas where we do not expect to encounter liquids. It is used with air hammers. Normally, there is zero LVP, implying the system is 100% air.
2. *Mist drilling:* Air drilling with the addition of liquids, normally water and soap. This is introduced when a wellbore gets liquid influx during dust drilling.
3. *Foam drilling:* Foam is created by combining water, surfactants and air. Has better cuttings carrying capacity.
4. *Aerated drilling:* In this type of drilling, air or nitrogen is added to the drilling mud. The mud can be water-bentonite, water-polymer or water-foam. The water-foam drilling is also called stable foam drilling and involves the use of water mixed with surfactants or air. This is the most common form of aerated drilling used in the geothermal industry.

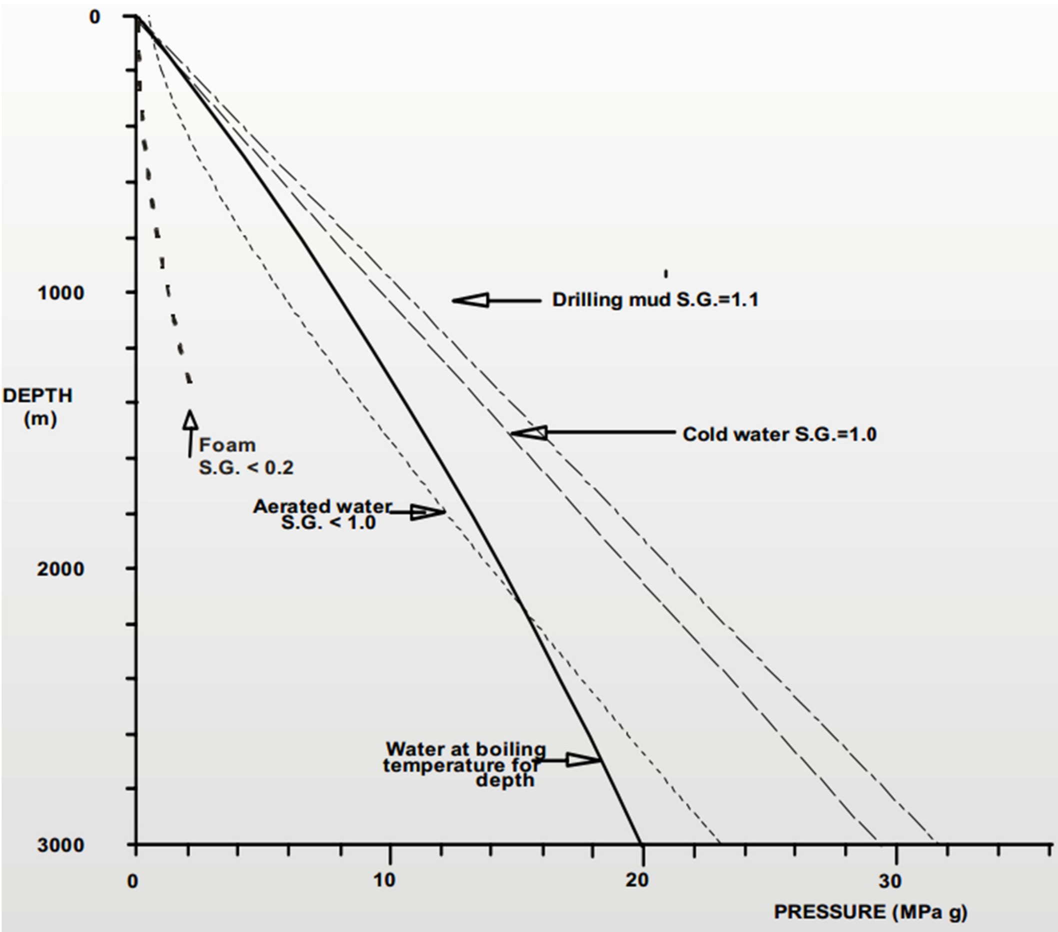

FIGURE 2: Down hole pressures (Hole, 2006)

The introduction of air drilling in geothermal systems is mainly due to the fact that most geothermal formation pressures are significantly lower than the hydrostatic column of water at any depth within the system, as illustrated in Figure 2 (Hole, 2006).

Figure 2 indicates the specific gravities of the various drilling fluid, indicating the importance of aerated systems in keeping the drilling fluid under-pressurised in comparison with the formation pressure.

2.3 Operating principle of drilling fluids

The working principle of any drilling fluid depends upon the function for which it is designed. Most drilling fluids are, from the onset, designed to lift the cuttings to the surface and control the well. As the drilling progresses and special conditions are encountered, the drilling fluid may be redesigned to perform other functions. However, in all cases the drilling fluid parameters considered are viscosity, velocity and density; other properties such as gel strength, filter cake, water loss, are dependent on the former (Darley and Gray, 1988).

To discuss the operation of drilling fluids, we shall consider the main functions of drilling fluids as identified earlier: hole cleaning, well control, protection of the formation and borehole stability.

2.3.1 Hole cleaning

Hole cleaning results from the continuous transportation of cuttings from beneath the bit to the surface where they are released. This is the key function of any drilling fluid and, hence, is the main controlling factor in fluid design. The key factors affecting cutting transportation are drilling fluid and cuttings velocity. The drilling fluid velocity depends on the rheological parameters of the fluid, density, the pump rate and the annular geometry of the well, whereas the key cuttings parameters are density, diameter and shape (Mitchell and Miska, 2011).

Cuttings generated in a well experience a downward movement due to gravity, resulting in negative velocity relative to the fluid's velocity. This negative velocity is termed cutting slip velocity, V_{sl}, and is key in determining cuttings transport. The movement of the cuttings up the annulus is the result of a net upward velocity, called cutting transport velocity, V_t; this is the difference between the fluid annular velocity V_a and the cuttings slip velocity V_{sl}. This implies that in designing a fluid for efficient hole cleaning, we must appreciate how the cuttings behave and calculate the expected slip velocity (Rehm et al., 2012).

The slip velocity can be determined depending on the type of fluid and flow regime; for laminar flows, there are different relationships for Newtonian and non-Newtonian fluids due to the effect of the fluid's rheological properties. In turbulent flow, the rheological properties have no effect (Darley and Gray, 1988).

Hole cleaning, however, is not just about carrying the cuttings out but also ensuring minimal cuttings concentration in the well during the drilling operation. For trouble free drilling, the cuttings concentrations in the well, C_a, should be below 5%, and the fluid parameters must be controlled to achieve this (Azar and Samwel, 2007). An additional way of designing a fluid is to consider its cuttings capacity index (CCI); this is a relationship based on various fluid parameters that are key for ensuring hole cleaning. This was arrived at from various field studies which concluded that for efficient hole cleaning in vertical and near vertical wells, CCI ≥ 1. The drill bit also plays a key role in effective hole cleaning; therefore, bit hydraulics must be considered when designing the drilling fluid (Rehm et al., 2012).

The following equations relate the various key hole cleaning parameters and how to arrive at them:

Critical annular velocity
This is a key parameter and is the minimal annulus velocity at which the cuttings concentration in the annulus reaches its threshold value and can be obtained by (Rahimov, 2009):

$$V_{ac} = \frac{1667 ROP D_b^2}{60 C_a \left(D_b^2 - D_p^2\right)} + V_{sl} \tag{1}$$

where V_{ac} = Critical annular velocity (ft/s);

V_{sl} = Slip velocity of cuttings (ft/s);
ROP = Rate of penetration (ft/hr);
C_a = Cuttings concentration in the annulus (%);
D_b = Drill bit diameter (in); and
D_p = Drill pipe outside diameter (in).

To maintain a specific cuttings concentration (C_a) in the annulus, the annular velocity must not go below this.

Cuttings slip velocity
Several correlations have been developed for slip velocity, all of them based on Stokes law with the exception of those developed by Walker and Mayes (Mitchell and Miska, 2011).

Cuttings slip velocity for Newtonian fluid, Stokes law.
From Stokes law, the slip velocity (V_{sl}) of an object falling through a viscous fluid is given by:

$$V_{sl} = \frac{d_s^2 g(\rho_s - \rho_f)}{18\mu} \tag{2}$$

$$V_{sl} = \frac{2}{3}\sqrt{\frac{3gd_s(\rho_s - \rho_f)}{f\rho_s}} \tag{3}$$

$$C_D = \frac{4}{3} g \frac{d_s}{V_{sl}^2}\left(\frac{\rho_s - \rho_f}{\rho_f}\right) \tag{4}$$

where d_s = Particle diameter (m);
ρ_S = Cuttings density (kg/m^3);
ρ_f = Fluid density (kg/m^3);
μ = Dynamic viscosity (kg/ms);
g = Acceleration due to gravity (m/s^2);
C_D = Drag Coefficient; and
f = Particle friction factor – obtained from graph in Appendix I.

Equations 2 and 3 apply for Newtonian fluids (e.g. water) in laminar and turbulent flow, respectively. Equation 4 gives the drag coefficient corresponding to the slip velocity calculated (Mitchell and Miska, 2011).

To determine the flow regime, we calculate the Reynolds number of the particles (Re_p):

$$Re_p = 928.2 \frac{\rho_f d_s V_s}{\mu} \tag{5}$$

where ρ_f = Fluid density (kg/m^3);
d_s = Particle diameter (m);
V_s = Slip velocity (m/s); and
μ = Newtonian viscosity of the fluid (Pa s).

When $Re_p \leq 1.0$, this defines a laminar flow regime; $1.0 \leq Re_p \leq 2000$ defines a transition flow regime, and $Re_p > 2000$ defines turbulent flow.

Calculation of slip velocity for Non-Newtonian drilling fluid
Stokes law does not give an accurate approach for determining the slip velocity in non-Newtonian fluids, due to the effect of rheological parameters on the fluid (Guo and Liu, 2011). Several correlations have been developed to determine slip velocity in non-Newtonian fluids, described below:

Moore correlation

Moore suggested the use of an apparent viscosity (μ_a) instead of the Newtonian viscosity of the fluid as used in Stokes law (Rahimov, 2009). Apparent viscosity is based on a pseudo plastic fluid model and is given by:

$$\mu_a = \frac{K}{144}\left(\frac{D_h - D_p}{V_a}\right)^{(n-1)}\left(\frac{2+\frac{1}{n}}{0.0208}\right)^n \tag{6}$$

And the slip velocity for laminar flow, where $Re_p \leq 1.0$, is given by:

$$V_{sl} = 82.86\frac{d_p^2(\rho_p - \rho_f)}{\mu_a} \tag{7}$$

Slip velocity for transitional flow, $1.0 \leq Re_p \leq 2000$:

$$V_{sl} = 2.90\frac{d_p(\rho_p - \rho_f)^{0.667}}{\rho_f^{0.333}\mu_a^{0.333}} \tag{8}$$

Slip velocity for turbulent flow, $\mathrm{Re_p} > 2000$:

$$V_{sl} = 1.54\sqrt{\frac{d_p(\rho_p - \rho_f)}{\rho_f}} \tag{9}$$

where K = Consistency index (lbf secn/100 ft^2);
n = Flow behaviour index (dimensionless);
ρ_f = Weight of drilling fluid (ppg);
ρ_p = Weight of rock particles (ppg);
V_a = Fluid velocity in annulus (ft/s);
μ_a = Apparent viscosity (cP);
D_h = Hydraulic diameter for annulus (in);
D_p = Pipe diameter (in); and
d_p = Diameter of cuttings (in).

Chien correlation

This is similar to Moore's correlation in that it also uses the apparent viscosity in calculating Reynolds number. Chien's analysis is based on a Bingham fluid model. The following equations apply:

$$\mu_a = \mu_p + 5\frac{\tau_y d_s}{V_a} \tag{10}$$

where μ_a = Apparent viscosity (cP);
μ_p = Plastic viscosity (cP);
τ_y = Yield stress (lbf/100 ft^2); and
V_a = Fluid velocity in annulus (ft/s).

$$V_{sl} = 0.0075\left(\frac{\mu_a}{\rho_f d_p}\right)\left[\left(\sqrt{\frac{36800 d_p\left(\frac{\rho_p-\rho_f}{\rho_f}\right)+1}{\frac{\mu_a}{\rho_f d_p}}}\right)-1\right] \tag{11}$$

Equation 10 gives the apparent viscosity to be used in polymer type drilling fluids. For bentonite, Chien proposed the use of plastic viscosity (Rahimov, 2009). Equation 11 gives accurate slip velocity when the viscous properties of drilling fluids are abnormally high, i.e. when $\mu_a / \rho_f d_p > 10$; otherwise, Chien proposed a simpler equation for normal fluids:

$$V_s = 1.44\sqrt{\frac{d_p(\rho_p - \rho_f)}{\rho_f}} \tag{12}$$

Walker and Mayes correlation
In this correlation, the drill cuttings are assumed to be shaped like a circular disc, unlike the above two cases where the particles are assumed to be spherical. Hence, the particles will fall through the fluid with the flat face lying horizontal. The shear rate, called the boundary shear rate (γ_b), at which a particle's movement switches from laminar to turbulent, is calculated by:

$$\gamma_b = \frac{186}{d_p\sqrt{\rho_f}} \tag{13}$$

The shear stress developed by the particles as they fall through the drilling fluid is given by:

$$\tau_p = 7.9\sqrt{T_p(\rho_p - \rho_f)} \tag{14}$$

Once the stress is determined, the corresponding shear rate is determined by using annular power law constants:

$$\gamma_p = \frac{\tau_p}{K_a}^{1/n_a} \tag{15}$$

If $\gamma_p < \gamma_b$ or $Re_p < 100$, then the slip velocity of a particle is in the laminar zone and is determined by:

$$V_s = 0.02\tau_p\left(\frac{\gamma_p d_p}{\sqrt{\rho_f}}\right)^{0.5} \tag{16}$$

If $\gamma_p > \gamma_b$ or $Re_p > 100$, then the slip velocity of a particle is in the turbulent zone and is determined by:

$$V_s = 0.28\frac{\tau_p}{\sqrt{\rho_f}} \tag{17}$$

where T_p = Particle thickness (in);
γ_b = Boundary shear rate (1/s);
γ_p = Shear rate corresponding to τ_p (1/s);
τ_p = Shear stress developed by particles (lbf/100 ft^2);
K_a = Consistency index in annulus (lbf secn/100 ft^2); and
n_a = Flow behaviour index in annulus (dimensionless).

Calculating minimum annular velocity for hole cleaning:

$$V_a = V_{sl} + V_t \tag{18}$$

$$V_t = \frac{\pi d_b^2}{4AC_a}\left(\frac{ROP}{3600}\right) \tag{19}$$

where ROP = Rate of penetration (ft/hr)-R_d;
C_a = Cutting concentration factor in the wellbore = 0.04;
d_b = Bit diameter in inches; and

A = Cross-sectional area of flow path (in^2).

But for best hole cleaning, the value of the rise velocity, V_t, should approach the annular velocity, (Rahimov, 2009).

From this, the minimum flow rate Q_{min} required for this velocity, V_a, is gotten by (Guo and Liu, 2011):

$$Q_{min} = 60\, V_a A V_{a-w} = \frac{\left[\frac{P_g}{P}\right]\left[\frac{T_{av}}{T_g}\right]\left(Q_g + Q_m\right)}{\frac{\pi}{4}\left(D_b^2 - D_P^2\right)} \tag{20}$$

where Q_m = Volumetric flow of drilling mud/water (m^3/s); and
V_a = Fluid velocity in annulus (m/s).

Another method based on a power law fluid, which closely represents the behaviour of drilling fluids, involves the determination of the minimum velocity required to transport the fluid and cuttings mixture V_{mix}; this is based on a cuttings concentration already defined earlier as C_a (Mitchell and Miska, 2011). The below equations are used:

$$V_{mix} = \frac{0.0475 V_{sl}}{0.05 - C_a} \tag{21}$$

$$V_{mix} = \frac{Q_c + Q_m}{A} \tag{22}$$

$$Q_c = V_t C_a \frac{\pi}{4}\left(D_h^2 - D_p^2\right) \tag{23}$$

where V_{mix} = Velocity of the cuttings and fluid mixture (m/s); and
Q_c = The volumetric flow rate of the cuttings generated at the bit (m^3/s).

By substituting Equation 23 into Equation 22, we solve for the value of Q_m, which is the volumetric flow of mud required to attain V_{mix}.

The efficiency of hole cleaning is checked by either monitoring the CCI, the annular volumetric cuttings concentration, C_a or the ratio of the cuttings transport velocity (CTR) R_t to the cuttings annular velocity V_a, R_t. In vertical drilling, it is recommended that R_t should be a minimum of 0.5-0.55 (Azar and Samuel, 2007).

$$CCI = \frac{\rho K V_a}{400{,}000} \tag{24}$$

$$C_a = \frac{R_d D_b^2}{1.27 R_t Q_m} \tag{25}$$

$$(CTR) R_t = 1 - \frac{V_{sl}}{V_a} \tag{26}$$

where CCI = Cuttings carrying index;
CTR = Cuttings transport rise; and
ROP = Rate of penetration (m/hr)-R_d.

The K factor power law fluids is shown in Appendix II.

Hole cleaning in aerated drilling

When designing hole cleaning for aerated drilling, the practise is to design the incompressible drilling fluid to have a minimum lifting capability for the planned open hole interval. This implies the fluid should be capable on its own in maintaining a minimum concentration of rock cuttings in the largest annulus section of the well (Lyons et al., 2009). The assumption in this approach is that the incompressible fluid can carry the cuttings on its own, and that the injection of air into the fluid will enhance this capacity.

To fulfil this, the average velocity of the incompressible fluid V_f in the largest annulus section must be equal or greater than the sum of the critical velocity V_c and the terminal velocity V_t of the average size rock cutting particle in the drilling fluid (Lyons et al., 2009). This is the same as in normal drilling while using mud, hence the equations described in the preceding section for minimum annular velocity and flow rates will apply in determining V_f.

However, the annular velocity of the air and the incompressible fluid mixture can be gotten by:

$$V_{a-w} = \frac{\left[\frac{P_g}{P}\right]\left[\frac{T_{av}}{T_g}\right](Q_g + Q_m)}{\frac{\pi}{4}(D_b^2 - D_P^2)} \tag{27}$$

And the volumetric flow of air Q_{air} at any depth in the well is given by:

$$Q_{air} = \left(\frac{P_g}{P}\right)\left(\frac{T_{av}}{T_g}\right)Q_g \tag{28}$$

where P_g = Atmospheric pressure at the compressor inlet (N/cm^2 abs);
P = Pressure entering the pipeline (N/cm^2 abs);
T_g = Temperature of the air entering the compressor (°C);
T_{av} = Average temperature of the air over a depth interval;
Q_g = Volumetric flow rate of the compressible gas (ft^3/s); and
Q_m = Volumetric flow rate of the incompressible fluid (ft^3/sec).

Q_m is the minimum mud flow rate required to attain the minimum annular flow velocity, V_f for efficient hole cleaning. Equation 27 shows that it is possible to increase the annular velocity without increasing the flow of mud by adjusting the flow rate of the air Q_g; this means better hole cleaning with minimal increase in fluid density, important for under-pressurised formations.

Aerated drilling using stable foam

Aerated drilling with stable foam introduces a new phase that must be monitored. Normally the surfactants, water and air, flow down the drill pipe as a normal aerated fluid. However, as it goes through the bit nozzles, the high shearing action leads to the generation of foam. This foam flows up the annulus as stable foam. To maintain the stability of this foam and avoid disintegration into a new phase, it is important to monitor a parameter known as the foam quality (Lyons et al., 2009). The foam quality at the entrance is defined by:

$$\Gamma = \frac{Q_g}{Q_g + Q_m} \tag{29}$$

where Γ = Foam quality.

Usually, the foam quality should be maintained at 0.98 at the exit point and at least 0.6 at the bottom hole. This is done by monitoring the pressure at which the mixture exits in the horizontal flow line at the surface. A gauge is normally installed at the surface at the back pressure valve in the horizontal flow line to check the exit pressure. The back pressure valve reading is calibrated to correspond to various foam quality values and can then be adjusted to achieve the required foam quality (Rehm et al., 2012). At the exit flow line, the volumetric flow rate, Q_{bp} for the compressed air exiting is used to calculate the foam quality and is gotten by:

$$Q_{bp} = \frac{P_g T_{av} Q_g}{P_{bp} T_g} \tag{30}$$

where P_{bp} = Back pressure.

The back pressure valve is adjusted to get the pressure necessary for the desired foam quality of 0.98.

Air drilling
The use of air, alone, as the drilling fluid is sometimes considered; this is especially beneficial if the water table is low or in areas with a scarce water resource. In geothermal drilling, an air hammer has been used in drilling the upper well sections which have hard rock and may take longer to drill using conventional rotary drilling. This has been practised with success in geothermal fields in Menengai, Kenya and in Iceland.

In designing the air system, the main issue is the minimum gas volume requirement for good hole cleaning. This can be determined by using the minimum velocity criterion or the minimum kinetic energy criterion. We shall consider the minimum velocity criterion. This criterion uses the same hole cleaning concept as in normal drilling, where the aim is to exceed the cutting terminal velocity; hence, we first determine this velocity in the air. Once this velocity is determined, then the fluid flow rate is designed to exceed it (Guo and Liu, 2011).

The minimum required gas velocity is given by (Guo and Liu, 2011):

$$V_g = V_{sl} + V_{tr} \tag{31}$$

$$V_{sl} = \sqrt{\frac{4gD_s(\rho_s - \rho_g)}{3\rho_g C_D}} \left(\frac{\varphi}{1 + {D_s}/{D_H}} \right) \tag{32}$$

The volumetric flow rate can then be obtained from:

$$Q_g = 60 \left(\frac{A}{144} \right) V_g \tag{33}$$

$$Q_{go} = \frac{P T_o}{T P_o} Q_g \tag{34}$$

where Q_g = Volumetric flow rate of gas (cfm);
Q_{go} = Volumetric flow rate of gas in the standard condition (scfm);
V_g = Minimum required gas velocity (ft/s);
D_s = Solid particle (ft);
ρ_S = Cuttings density (lbm/ft^3);
V_{sl} = Cutting slip velocity in air (ft/s);
C_D = Drag coefficient accounting for the effect of particle shape;
Ψ = Particle sphericity factor, obtained from graph in Appendix I (-); and
D_H = Hydraulic diameter of flow path (ft).

2.3.2 Well control

Well control is all about controlling kicks and eliminating kicks, hence limiting the chance of a blowout. Kicks and blowouts occur when the fluid pressure in the formation exceeds the pressure of the drilling fluid in the well. When a kick is not contained and stopped, it leads to a blowout which is a more difficult situation. In geothermal drilling, the fluid acts both to cool the hot fluid and also keep the formation fluid pressure under check. The key parameter checked is the mud weight. The hydrostatic pressure due to the drilling fluid is obtained from the formula:

$$P = MW * TVD * 0.052 \quad (35)$$

Another key parameter is the equivalent circulating density (ECD); this is the density of the mud due to the effect of pump pressure applied on it for circulation. This is normally higher than the fluid's specific density, and is given by:

$$ECD = \frac{MW + P_a}{0.052 * D} \quad (36)$$

The ECD results in a new pressure called the bottom hole circulating pressure (BHCP) which is the actual pressure the drilling fluid has during circulation (Azar and Samuel, 2007). It is important to consider this pressure during the design process in order to ensure that it is kept low; it is given by:

$$BHCP = ECD * 0.052 * D \quad (37)$$

where P =The hydrostatic pressure (bars);
MW =Mud density (kg/m^3);
P_a =Annulus frictional pressure drop at a given circulation rate (Pa); and
D =Depth (m).

In geothermal drilling the production zone is often drilled using aerated water and foam which, many times, is a form of underbalanced drilling; the aim is to allow formation fluid to flow into the well, hence reducing damage to the formation. This, however, exposes the operation to higher chances of a kick and/or a blowout.

2.3.3 Protection of formation

There are two main parts of borehole drilling, the upper section which is normally totally cased and cemented, and the pay zone, which in geothermal wells is usually cased using slotted liners. The pay zone, or the main hole, in many geothermal hot temperature wells ranges from 700 m up to 3000 m or beyond. Prevention of formation damage is especially important when drilling the pay zone. Permeability is one of the most important properties of a geothermal reservoir. During drilling, the cuttings generated can clog the rocks, leading to loss of permeability. The inert components of drilling fluids can also flow into the formation, blocking aquifers or other permeable zones.

In geothermal drilling, aerated drilling is often introduced in the production zones. This is because it is possible to achieve better hole cleaning with compressed air, hence reducing the tendency of cuttings to clog the formation. The aerated drilling fluid has a lesser density than normal mud, hence causing less formation damage. In some cases water is used to drill with high viscous polymer sweeps, used when making connections. The aim in both cases is to reduce the formation damage by having as few cuttings and other solids getting into the formation as possible (Hole, 2006).

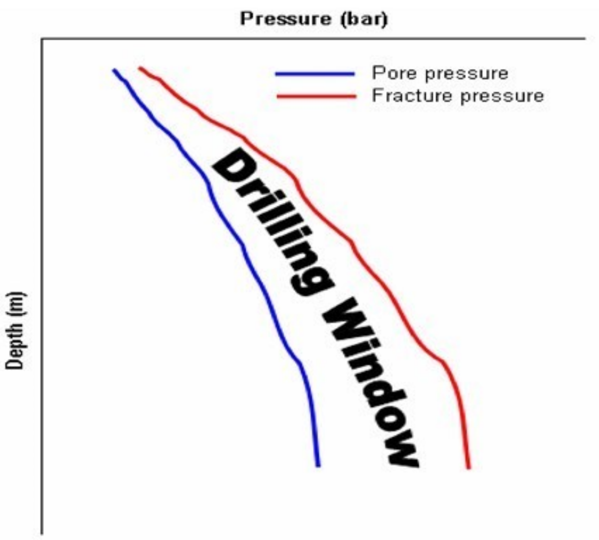

FIGURE 3: Drilling window (Rahimove, 2009)

Designing a drilling fluid to help reduce formation damage involves appreciation of the well's drilling window, which is the margin between the fracture and pore pressure, shown in Figure 3. As a drilling practise, wellbore pressure should always be greater than pore pressure, both in static and dynamic conditions. However, it should not surpass the fracture gradient; otherwise, costly drilling challenges such as loss of circulation and formation damage occur. Geothermal reservoirs are characterised with subnormal pore pressures. Hence, the drilling window is wider. The tighter the drilling window, the tougher the drilling will be (Vollmar et al., 2013). However, when drilling the main hole, pressures below the pore pressure are desired in order to reduce formation damage. Hence, aerated drilling is used to achieve this.

2.3.4 Maintain borehole stability

The aim of drilling is to create a pathway in the ground to access a given resource; in a geothermal system, the resource is hot fluid from the ground. This may require drilling to depths ranging from 500 m to 3000 m or beyond. It is important to keep this path, borehole, intact as we drill on. This is done by casing the various well sections and cementing them. However, prior to casing and cementing, there is still need for well stability. The drilling fluid provides this stability.

In an undisturbed formation, the rock matrix and the pore pressure are able to withstand the overburden pressure. When a borehole is made in this system, an imbalance of forces is created. There will be a net tangential force which tends to cause the formation to move to fill the new cavity formed. This increases with depth due to the increase in overburden pressure. The diagrams in Figure 4 illustrate the scenarios before, during, and after drilling (Ava, 2004).

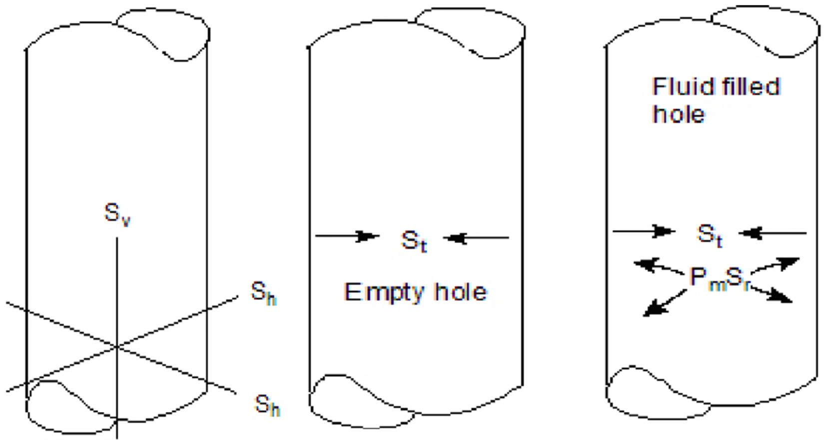

FIGURE 4: Stress conditions in a borehole (Ava, 2004)

The drilling fluid provides a radial pressure which balances against the instability created in the formation due to the borehole. The density of the drilling fluid is a key factor of this radial pressure. In some cases, barite or other inert solids are added to the drilling fluid in case of an over pressurised formation (Ava, 2004).

An unstable formation is also caused by fluid seepage from the borehole into the formation. Drilling fluids, such as bentonite, form an impermeable layer on the wall of the borehole which reduces the seepage. This is of great significance in clay formations (Chemwotei, 2011).

2.4 Drilling fluid equipment

The drilling fluid equipment forms the circulation system of the rig and is mainly used for applying pressure on the fluid and providing a channel for fluid to flow. The basic setup is made up of mud pits, mud pumps, mud mixing equipment and contaminant removal equipment. The mud pumps provide the pressure needed for the drilling fluid to flow through this system into the well and up with the cuttings. The selection of the pumps will depend upon the hydrostatic pressures expected to be handled during the drilling process.

In aerated drilling, an additional system is included, depending on the type of gas to be used. Most geothermal drilling uses aerated water and foam with two primary compressors and one booster.

2.4.1 Criteria for selection of drilling fluid equipment

The key equipment in the drilling fluid system is the mud pump. This is responsible for supplying the hydraulic pressure needed to move the drilling fluid from the pump through the entire drill string, and back to the mud tanks. Figure 5 illustrates the sum of the pressures that constitute the pressure to be supplied by the pump (Baker Hughes, 1995). Pumps are rated for hydraulic power, maximum pressure and maximum flow rate. Any of these can be used for our design criteria in selecting our pump. Once the drilling program is known, it is possible to determine the required flow rates and pressure in drilling the various well sections. Of significance is that the pump must supply adequate flow to achieve the required annular velocity for effective hole cleaning.

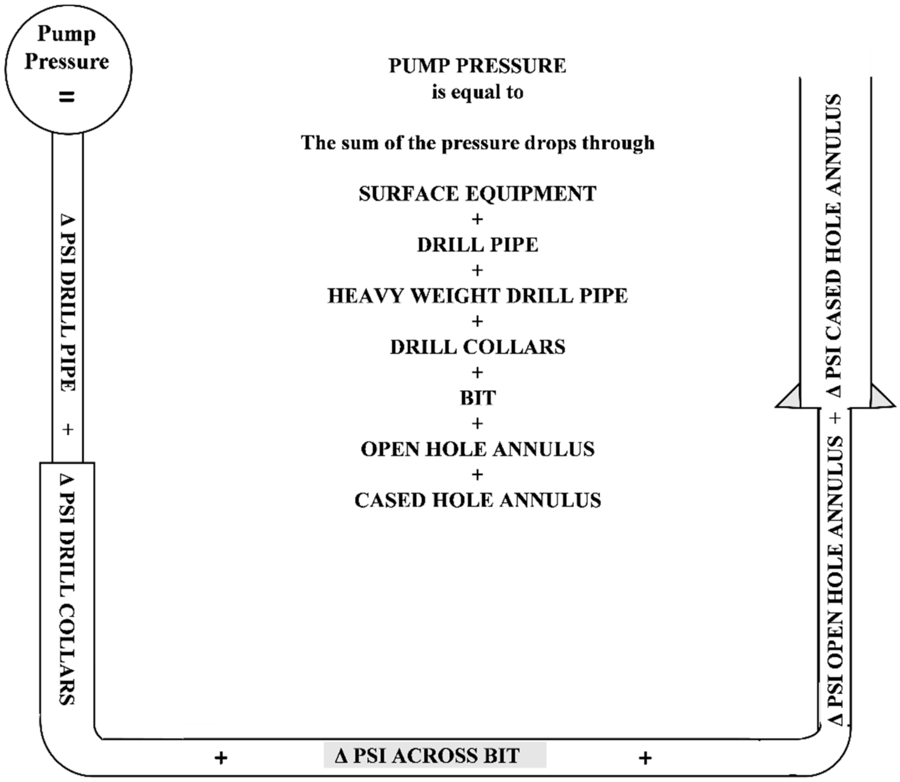

FIGURE 5: Pressure loss in a pump (Baker Hughes, 1995)

The required pump flow rate is calculated based on annular volumes and required up flow velocity (Lapeyrouse, 2002).

$$Q = \frac{\left(D_h^2 - D_p^2\right)}{24.5} * v \tag{38}$$

where D_h = Well or casing diameter (m);
D_p = Outside diameter of drill pipe (m); and
v = Desired annular velocity (m/s).

The ideal minimum velocity when using mud is 0.3 m/s and while using water is 0.7 m/s (Chemwotei, 2011).

The flow rate required is calculated for the various well sections and the maximum flow rate required is then used to select the pump. Another significant parameter is the pump pressure rating; this should normally be at least 1.5 times the total pressure losses, which are illustrated in Figure 5. The pressure losses are comprised of:

$$p_{total} = p1 + p2 + p3 + p4 + p5 \tag{39}$$

where $p1$ = Losses through surface equipment;
$p2$ = Losses through drill pipe/drill collars;
$p3$ = Losses through the rock bit;
$p4$ = Losses between the outer diameter of the drill pipe and drill collar, and wall of the hole; and
$p5$ = Losses in the mud motor (when used, e.g. directional drilling).

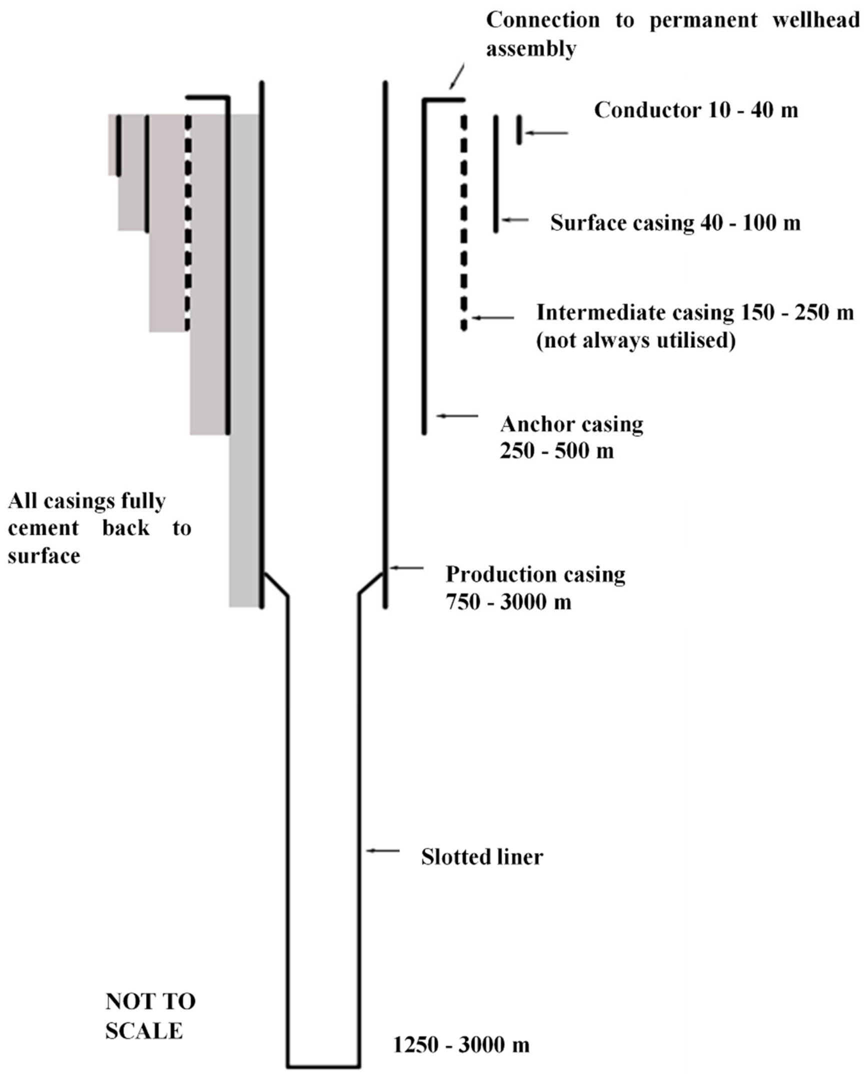

FIGURE 6: Well profile (Hole, 2007)

The pressure losses have the form (Gabolde and Nguyen, 2014):

$$p = NB \tag{40}$$

Calculation for N in the drill string is given by:

$$N = \frac{LQ^{1.8}}{901.63D^{4.3}} \tag{41}$$

Calculation for N in the annulus is given by:

$$N = \frac{LQ^{1.8}}{709.96(D_o + D_i)^{1.8}(D_o - D_i)^3} \tag{42}$$

where p = Pressure loss (kPa);
N = Pressure losses for pure water;
B = Coefficient corresponding to circulating mud;
D_o = Annulus outside diameter (in);
D_i = Annulus inside diameter (in);
Q = Drilling fluid flow rate (l/min); and
L = Length of drill string (for N in drill pipe is the length of the drill pipe for the drill collar and surface equipment) (m).

The coefficient B corresponds to circulating mud and is given by:

$$B = d^{0.8}\mu_p^{0.2} \tag{43}$$

Pressure loss in bit nozzles P_d is given by:

$$P_d = \frac{dQ^2}{(2959.41)(0.95^2A^2)} \tag{44}$$

Hence, we get:

$$P_{total} = (N_1 + N_2 + N_3 + N_4 + N_5)B + P_d d \tag{45}$$

where d = Specific gravity (kg/l);
μ_p = Plastic viscosity (cP);
A = Area of nozzles (in^2);
N_1 = Pressure loss coefficient in the surface equipment;
N_2 = Pressure loss coefficient in the drill pipe;
N_3 = Pressure loss coefficient in the drill collar;
N_4 = Pressure loss coefficient in the hole/drill collar annulus; and
N_5 = Pressure loss coefficient in the hole/drill pipe annulus.

Once these are calculated, the pump power required is calculated from:

$$P_{power} = \frac{pQ}{600\eta_m\eta_t} \tag{46}$$

where P_{power} = Pumping power (kW);
p = Pump discharge pressure (bar) =1.5*P_{total};
Q = Fluid flow rate (l/min);
η_m = Pump mechanical efficiency, assumed to be 0.85; and
η_t = Transmission efficiency, assumed to be 0.9 (for motor).

It is important to note that these losses depend upon fluid viscosity, density and the flow rate, so we must consider this effect as we design the fluid. Higher flow rates, viscosities and density imply higher pressure losses, hence a more expensive drilling fluid system. The system losses are normally higher for turbulent flow than for laminar flow; turbulent flow occurs at high velocity and smaller annular space, while laminar flow tends to occur at lower velocities. From the above calculations, we can select the right pump for the drilling activities.

2.5 Drilling fluids and challenges in geothermal drilling

Drilling challenges vary in type and severity depending upon the well. However, the main challenges encountered in most situations are stuck pipe, loss of circulation and well control. Most of these challenges are due to the geology of the formation.

Drilling challenges can either be due to formation challenges or equipment failure. The most difficult challenges are normally those associated with the formation since many times we are not able to see what is in the formation and have to rely on the data to try and visualise the actual situation in the borehole. One of the worst challenges is a stuck pipe situation. Many times this leads to loss of drilling time, expensive fishing operations, formation damage and possibly a loss of the drill string. Apart from depleting the moral of the crew, a stuck pipe leading to fishing operations normally escalates the price of the well. As such, any well advised drilling team will do all in its power to avoid a stuck pipe situation. Appreciation of drilling fluids and their interaction with various formations can help save a stuck pipe situation from escalating.

2.5.1 Loss of circulation

This is the total or partial loss of drilling fluids due to highly permeable zones, cavernous formations and natural or induced fractures during drilling. Often this affects well control, borehole stability and may lead to formation damage. Loss of circulation is often dependent on how the drilling fluid interacts with the formation during the drilling process. The main causes are:

1. Formation pore spaces are too large, or the particles in the fluid are too small to allow filter cake formation;
2. Hydrostatic pressure is sufficient enough to force wellbore fluids into the pore spaces;
3. Hydrostatic pressure causes a natural fracture to open up and take wellbore fluid; and
4. Hydrostatic pressure induces fractures in weak formations.

From the above causes, we notice that most of them are related to the hydrostatic pressure, which is a property of the drilling fluid, highlighting the significance of drilling fluids in managing loss of circulation challenges. There are other causes related to how fast the drill pipes or casings are run in hole, among other things (Baker Hughes, 1995).

The severity of the loss is classified by the volume of fluid loss per unit time: seepage losses with losses of up to 1.6 m^3/hr; partial losses with losses ranging from 1.6 m^3/hr to 79 m^3/hr; complete losses when no returns are got on surface. In order to determine the right treatment for the drilling fluid to heal the loss, we must identify the type of loss zone. The table below describes the common loss zones and the possible type of losses (Ava, 2004).

TABLE 1: Loss zones

Loss zones	Type of loss
Porous and permeable sands and gravel	Losses start as a gradual reduction in pit volume. If drilling proceeds, the losses could become complete. These zones usually occur near the surface.
Natural fractures	May occur in any type of rock. Usually these losses are partial but may progress to complete loss as drilling proceeds or if the fluid density increases.
Induced fractures	Sudden and complete losses.
Vugular formations	Usually located in limestone. Losses here can be sudden (located at the bit) and complete. On occasion, the bit may drop a few inches before the loss.

Losses in geothermal drilling are mostly due to encountering permeable zones or fractures, either natural or induced. There are several ways of handling loss of circulation, and many loss-of-circulation materials have been developed to suit various situations. However, in general the action taken depends upon the location of the loss zone within the well.

There are various loss-of-circulation policies applied in various situations, but the general tendency is to switch to water and drill blind whenever a complete loss is encountered. Minor or seepage losses can be controlled by adding 10-60 kg/m^3 of LCM to the drilling fluid. Increasing the quantity of LCM can be done to tackle higher losses. However, if the loss persists, then three main options can be explored:

1. Drill on blind with water;
2. Switch to aerated drilling; and
3. Stop and plug the well.

Table 2 gives a summary of some actions that can be taken to handle losses:

TABLE 2: Loss of circulation policy

Severity of loss	**Loss section**	**Action**
Seepage losses with losses of up to 1.6 m^3/hr	Upper well section	Add LCM to the drilling fluid, ranging from 10 to 60 kg/m^3.
	Main hole	Usually this section is drilled with water or aerated fluids. Continue drilling but spot polymer pills at every connection.
Partial losses from 1.6 m^3/hr to 79 m^3/hr	Upper well section	115-230 kg/m3 of LCM is spotted in pill form.
	Main hole	Switch to aerated drilling or drilling on with water but spot polymer pills at every connection.
Complete loss	Upper well section	230-430 kg/m^{3}of LCM is spotted in pill form. If loss persists, consideration of stopping the drilling to plug the loss zone should be looked into, to avoid hole cleaning challenges which could lead to stuck pipe.
	Main hole	Switch to aerated drilling or continue drilling with water and polymer pills at each connection. Proper hole cleaning and wiper trips should be done before any new connection.

The treatment given to loss of circulation in the main hole is applied in a manner such as to avoid any clogging of the cavities, since they are key to the well's production. Often the tendency is to drill blind. Hole cleaning challenges are handled by high viscosity polymer sweeps.

2.5.2 Stuck pipe

Stuck pipe can be described as a situation where both axial motion and sometimes rotary motion of a drill string in a borehole is lost. This, at times, may be accompanied with blocking of the bit such that circulation through the drill pipe is not possible. There are several causes of stuck pipe, however, most are due to geological challenges which are dependent on the nature of the formation. The most common formation challenge is instability. An unstable formation for whatever reason is more likely to cave in on the drill string and possibly lead to a stuck pipe. The other common cause of stuck pipe is poor hole cleaning situations, either due to loss of circulation or poor drilling fluid design and differential sticking.

Differential sticking is a result of the drill pipe getting stuck on the wall of the well. This is due to the formation of a sticky layer called a filter cake. The filter cake is a good property of any drilling fluid because it prevents losses of the drilling fluid. However, there is a limit to the thickness that is considered beneficial (Bourgoyne et al., 1991).

The best solution to handling stuck pipe is to avoid any stuck pipe situations. This can be done by keenly monitoring well lithology to appreciate the formation. Drilling parameters such as ROP, formation pressures, drilling fluid properties and losses are some of the key things to be checked. The common indication of an abnormality is an increase in torque during drilling, or an over pull encountered when tripping out of the hole. Proper data collection and interpretation is a sure way to minimize stuck pipe situations or to quickly solve such situations.

The role of drilling fluids in handling stuck pipe is more important in the prevention of stuck pipe than in freeing the stuck string or retrieving the fish. Since most stuck strings are due to formation challenges, it is important to appreciate the type of formation being drilled through, before redesigning the drilling fluid to combat it. The main types of problem formations are:

1. Erodible formations: These include soft tertiary sequence evaporates, permafrost and some highly fractured formations; these could also include unconsolidated formations of sand and gravel. Erosion of these formations may lead to an over-gauge borehole which leads to poor hole cleaning, one of the causes of stuck pipe. In some cases, if the formation is fractured, this could lead to slippage and, hence, stuck pipe.
2. Geo-pressured formations: These are formations with pore pressures higher than the hydrostatic pressure of the drilling fluid. These, if not permeable, tend to cave into the borehole once drilled through.
3. Dipping formations: These are formations that lie at an angle to the horizontal plane being drilled through. The challenge with this is if they are plastic (more common in slates and shales), they end up being mobile and flow into the borehole when drilled through.
4. Reactive formations: These are naturally occurring bentonitic shales which contain clays that react with the mud filtrate and hydrate. The hydrated shells then fall and swell into the borehole.

Other formation-related challenges could include collapsing cement blocks from an upper cased section and green cement (Ava, 2004).

2.5.3 Well control

Abnormal formation pressures are rarely encountered in geothermal systems. However, this still remains an area that must be watched in order to ensure proper well control. Most times, the drilling fluid pressure exceeds that of the formation in geothermal drilling. However, when drilling using aerated fluids, the density of the drilling fluid is reduced, and then the formation fluid pressure exceeds the drilling fluid pressure.

One of the challenges encountered in well control in geothermal drilling is poor cooling of the well, leading to high temperatures and, hence, high pressures. This may occur when there is continuous loss or a sudden total loss of circulation (Moore, 1974).

A key issue in well control is monitoring the drilling fluid to keep losses minimal and keep the drilling fluid pressure as near to the formation pressure as possible. This requires knowledge of the formation pressure. One way of estimating the formation pressure is using the *d* exponent, a dimensionless number. The *d* exponent is related to the differential pressure between the drilling fluid and the pore fluid. This value is used to adjust the drilling fluid density. The *d* exponent usually increases with depth but, as the formation becomes over pressured, it will decrease (Moore, 1974). The *d* component is given by:

$$d_{exp} = \frac{log\left(\frac{R}{60N}\right)}{\left(\frac{12W}{1000d_b}\right)} \tag{47}$$

where R = ROP;
N = Rotary RPM;
W = Force on bit;
d_b = Bit diameter; and
d_{exp} = Drilling exponent.

The d_{exp} is corrected for the effect of mud density changes, as well as changes in WOB, bit diameter and rotary, as follows (Moore, 1974):

$$d_{mod} = d_{exp}\frac{\rho_n}{\rho_e} \tag{48}$$

where ρ_n, the mud density, is equivalent to a normal pore pressure gradient and ρ_e is the equivalent mud density at the bit while circulating. The new d_{mod} is then used to calculate the equivalent mud density at that differential pressure and, finally, the formation pressure from the following equations:

$$\rho_e = 7.65log[(d_{mod})_n - (d_{mod})_{abn}] + 16.5 \tag{49}$$

$$P_f = 0.052 * \rho_e \tag{50}$$

where ρ_e = Is the equivalent mud density at the bit while circulating;
$(d_{mod})_n$ = Equivalent mud density at the normal pressure;
$(d_{mod})_{abn}$ = Equivalent mud density at abnormal pressure.

Once the formation pressure is determined, we compare it with the fluid density and adjust accordingly.

3. DRILLING FLUID DESIGN FOR DRILLING A 2500 M GEOTHERMAL WELL

The main interest in drilling a geothermal well is to access the steam resource located several hundred meters down, or more. To do this, we must drill through sections that are of less significance and may even block the producing reservoir with colder fluids. The most important part of the well is the steam zone, normally called the main hole. This is the area believed to be producing the required steam in the well. Wells normally have four main sections: surface hole, anchor hole, production hole and main hole. The first three sections are normally cased using steel casings and cemented off to seal off unwanted aquifers and also to stabilize the area as we drill on. The main hole, which can run from 800 m to 1500-3000 m depending on the well prognosis, is normally set with slotted liners. Figure 6 illustrates a 3000 m well casing design for a regular size well (Hole, 2006). There are many methods for determining the casing depths. However, as a general rule, the depths are set such that at least 1/3 of the entire well drilled is cased.

A typical well design would include:
Conductor casing: 30" set at a depth of 24 m, either driven or drilled.
Surface casing: 20" casing setting 26" diameter hole, drilled to 100 m depth.
Anchor casing: 13 3/8" casing set in a 17½" hole drilled to 300 m depth.
Production casing: 9 5/8" casing set in a 12¼" hole drilled to 850 m depth.
Open hole: 7" slotted liner set in an 8½" hole drilled to 2500 m – total depth.

Once the well design is done, the next stage is to identify the drilling fluid to be used and prepare an appropriate drilling fluid program.

3.1 Drilling fluid materials and properties

The final desired property of any drilling fluid will determine the materials it constitutes. As earlier discussed, the constitution of a drilling fluid is guided by optimising costs and performance; these are considered optimal when we have good hole cleaning and lowest circulation system pressure losses. Other issues, such as loss of circulation, are best handled when they arise. But, at the design stage, a guide is made on how to handle them. To optimise a fluid for hole cleaning and least pressure drop, we must appreciate the fluid's rheology, which describes the behaviour of a fluid when a force is applied to it. Once we characterise this behaviour, we can select what materials to add to our drilling fluid to improve upon its performance in hole cleaning and minimizing pressure drop.

The behaviour of fluids under force/stress can be characterised as: Newtonian - where the shear rate increases linearly with shear stress; these fluids include water and oil; non-Newtonian, which exhibit a non-linear relationship between shear stress and the shear rate. The behaviour of Newtonian fluids is undesirable in drilling as it leads to higher pressure loss in the system, due to increased viscosity, and also poor gel strength, which is key in hole cleaning. To correct these problems, various materials can be added, depending on which property is being corrected. The main properties checked are viscosity, yield point and gel strength (Darley and Gray, 1988).

Non-Newtonian fluids can be classified into four different types, depending on the additives. For geothermal drilling, the main additives are either bentonite or polymer, which are viscosifiers, leading to either a Bingham plastic fluid or pseudo-plastic / power law fluid. These fluids display a zero shear rate at the initial change in shear stress, after which the relationship is either linear or non-linear (Darley and Gray, 1988). Figure 7 illustrates the behaviour of various drilling fluids (Darley and Gray, 1988):

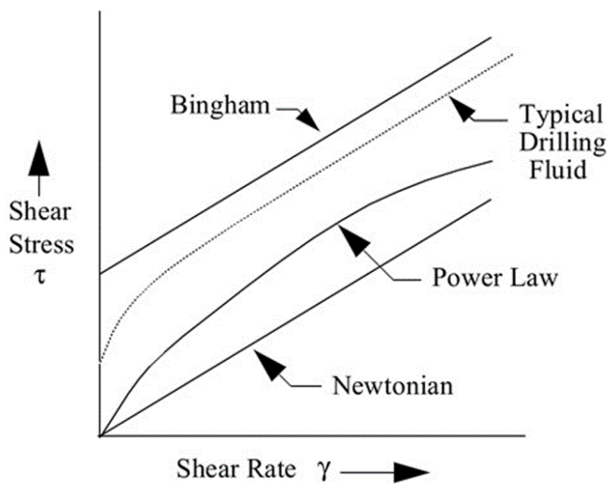

FIGURE 7: Fluid rheological behaviour (Baker Hughes, 1995)

As can be seen, Newtonian fluids do not exhibit the gelling property required. Bentonite-based mud normally exhibits a Bingham-plastic fluid model, which has a higher viscosity and high yield strength; the yield strength is a measure of its gelling strength. This is important for suspending cuttings when circulation stops. The water-polymer drilling fluid exhibits a power law of behaviour which has poorer gel strength but lower viscosities. However, increasing the concentration of polymers, such as starch in bentonite, results in a Dialant behaviour, in which there is an adverse rise in fluid viscosity (Darley and Gray, 1988).

Another key area in designing a fluid system is its flow regime. A fluid flow can be categorised as: plug flow, laminar flow, transitional flow or turbulent flow. The fluid's flow regime affects both the cutting carrying capacity and pressure losses in the system. In general, laminar flow leads to lower pressure loss but poorer hole cleaning. Turbulent flow leads to better hole cleaning but higher pressure losses.

From this we see that any drilling fluid design must consider viscosity, yield and gel strengths, and the density of the fluid.

3.1.1 Viscosity

Viscosity is a description of the thickness of a drilling fluid and, hence, its resistance to motion. It is normally measured in centipoises. In the field, it is a common practise to measure viscosity in terms of funnel viscosity, (secs/qt), which is how long it takes one quart of fluid to pass through the funnel. This gives a view of how thick a fluid is, but is not used in calculations regarding viscosity. For Bingham fluids (water-bentonite), we use plastic viscosity, which is the viscosity at which the fluid is past its yield point. This is measured using a viscometer. Figure 8 shows a Bingham plastic Rheogram.

Plastic viscosity is calculated once the viscometer readings at RPM of 300 and 600 are taken.

$$PV = \theta_{600} - \theta_{300} \tag{51}$$

$$YP = \theta_{300} - PV \tag{52}$$

where PV = Plastic viscosity, (cP);
YP = Yield point (dynes/cm2); and
$\theta_{600}, \theta_{300}$ = Dial readings at 600 and 300RPM.

This relationship is true whenever bentonite is used as the viscosifier. However, the introduction of other additives, such as starch polymers, leads to a more complex drilling fluid which is best analysed by the power law model (Baker Hughes, 1995).

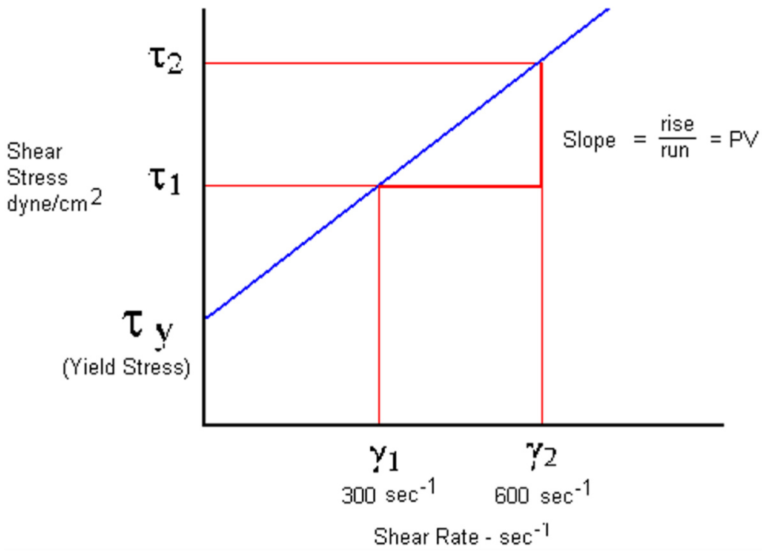

FIGURE 8: Bingham plastic rheogram (Ava, 2004)

Viscosity decreases with an increase in temperature, but increases with cuttings content. For geothermal drilling from various field results, a plastic viscosity of 10-20 centipoises is found appropriate for hole cleaning (Finger and Blankenship, 2010). This can be varied to optimise between hole cleaning and pressure drop. Efficient removal of solids at the surface is important in reducing the solid contents of a fluid. There are graphs that illustrate the effect of total solid content on viscosity; these should be used when designing for viscosity.

3.1.2 Yield point and gel strength

This behaviour indicates a resistance to flow until a certain minimum shear stress, the yield stress of the fluid, is reached. Every fluid exhibits this behaviour, at least some minimal value. This property determines the yield and gelling strengths of a fluid, properties which are of great significance in cutting carrying and suspension. The suspension is more important when circulation stops, so that the fluid can suspend the cuttings till circulation resumes; this property is not exhibited by water and is one key area where bentonite plays a major role. Bentonite and other clays, when mixed with water, result in a Bingham fluid with a higher gelling and yield point, as illustrated in Figure 7. Polymers, on the other hand, have poorer gelling properties. There is, however, a limit to the useful value of gelling; very high gel strength implies higher pressures needed to break the fluid to start flowing. Hence, bentonite is often mixed with starch to reduce its gelling property to acceptable limits.

Increased solid content leads to higher gel and yield strengths; efficient surface removal should be maintained to reduce this (Skalle, 2011). Yield strengths of 35-125 kPa are common in geothermal drilling (Finger and Blankenship, 2010).

3.1.3 Density

When designing for fluid density in geothermal drilling, we must appreciate that most geothermal systems have pore pressures lower than hydrostatic pressure, implying that we need to keep our density as low as possible. However, low density has two main disadvantages: lower cutting carrying capacity, and poorer filter cake formation. Filter cake is of high importance in geothermal drilling since we need to form a slight impermeable layer to reduce fluid loss into the formation during drilling; loss of drilling fluid is quite costly and can also lead to formation damage (Darley and Gray, 1988).

It is common to use a density ranging from 1.00 to 1.15 g/m^3 in geothermal drilling (Finger and Blankenship, 2010). However, if higher densities are needed, then barite is the most common material used as a densifier. A good understanding of the formation pressures expected is paramount in designing for density. The formation pressures can be estimated. Aerated drilling is one significant way of reducing the density of the fluid. This is employed in drilling the main hole. However, generally the lower the solids content of the drilling fluid, the lower the viscosity. Therefore, the surface removal system is key. Table 3 is a summary of the key drilling fluid properties and their values for geothermal drilling (Finger and Blankenship, 2010).

To achieve the parameters shown in Table 3 and keep within the desired range, a good mixing must be undertaken and keen monitoring of the fluid maintained. The graph in Appendix III shows the relationship of water-based bentonite, density, yield point viscosity and solid contents. Wyoming bentonite is normally used in geothermal drilling; this is because it has the highest yield, hence does not result in a high increase in fluid density, compared to other clays. This is illustrated in the graph in Appendix III.

TABLE 3: Fluid properties

Property	Range
Density	1.03-1.15 g/m^3
Funnel viscosity	35-55 Sec
Plastic viscosity	0.01-0.02 Pa-s
Yield	35-125 kPa
pH	9-10

3.1.4 Drilling fluid materials

These are added to the base fluid, water, to achieve specific properties for a given purpose. The main additives to water are weighting agents, viscosifiers, filtration control, LCMs, and conditioners for pH control materials. Geothermal fluids are normally simply, constituted of the base fluid-water, viscosifiers, either bentonite or polymer, and conditioners, usually caustic soda (Ava, 2004) (Table 4).

3.2 Calculation of key drilling fluid parameters

A drilling fluid program forms part of a well's drilling program and is simply a guide on the preparation and utilisation of the proposed drilling fluids for the various well sections. It is normally prepared by the drilling engineer with knowledge of the well's prognosis. The key part of the drilling program is determination of the drilling fluid parameters to be used when drilling the various well sections. This is important for good hole cleaning, minimising pressure drop in the system and optimising bit hydraulics. Here, we shall assume a regular well with a profile as described at the beginning of Section 3. The aim is to determine the drilling fluid parameters to be utilised for good whole cleaning, minimal pressure drop and optimised bit hydraulics. The equations described in the preceding sections will be applied. The following will be determined:

1. Minimum annulus velocity effective hole cleaning for the various well sections;
2. Minimum flow rate for the required annulus velocity for the various well sections for when using either mud or water;
3. System pressure drop;
4. Equivalent circulating density for the various well sections;
5. CCI and C_a; and
6. Summary.

TABLE 4: Drilling fluid additives

Type	Description/function	Material
Densifier	These are compounds dissolved or suspended in the drilling fluid to increase its density; can be any substance denser than water.	Commonly used is barite.
Viscosifiers	Improve on the drilling fluid viscosity, hence enhancing drilling fluid's ability to remove cuttings from the wellbore and to suspend cuttings and weight materials during periods of no circulation.	Mainly used in geothermal is bentonite; polymers are also used, however they lack gel strength, so do not suspend cuttings.
Filtration control material	These reduce the amount of filtrate lost from the drilling fluid into a subsurface formation.	Bentonite, polymers, starches, and thinners or deflocculates; all function as filtration-control agents.
Conditioners	These are alkalinity and pH-control additives which are used to optimize pH and alkalinity in water-base drilling fluids.	NaOH, KOH, $Ca(OH)_2$ and Mg $(OH)_2$.
LCM	These can be broadly defined to include any material that seals or bridges against permeable or fractured formations to inhibit the loss of whole drilling fluid.	In geothermal drilling, the most common is mica flakes.

Assumptions:

1. Mud density of 1150 kg/m^3 is used for mud drilling and water density of 1000kg/m^3;
2. Turbulent flow is assumed;
3. Drill pipe size of OD 5" is used in the calculations;
4. Aerated drilling commences in the main hole; and
5. The upper well section is drilled using either water or mud; no aerated drilling.

Steps of calculation:

1. Calculation of minimum annular velocity: Section 2.3.1 will be used to calculate the minimum annular velocity required for effective hole cleaning for the various well sections.
2. The minimum flow rate for the drilling fluid to achieve the minimum velocity is then calculated.
3. Calculate cuttings carrying index, and cuttings concentration ratio.
4. Calculate the ECD (equivalent circulating density) and BHCP (bottom hole circulation pressure).
5. The results of these are shown in Tables 5 and 6.

Results and analysis:

TABLE 5: Fluid parameters

Hole diameter (inches)	Hole depth (m)	Water: MW=1, Viscosity = 1.17 cP		Mud: MW=1, Viscosity = 15 cP		CCI	R_t	C_a
		Annular velocity (m/s)	Flow rate (l/m)	Annular velocity (m/s)	Flow rate (l/m)			
26"	100	0.7	13000	0.48	9500	1.5	0.65-0.78	0.021
17-1/2"	300	0.7	7980	0.5	5700	1.7	0.63-0.7	0.015-0.023
12-1/4"	850	0.7	4650	0.5	3618	1.6	0.67-0.78	0.011-0.017
8-1/2"	2500	0.78	2044	-	-	1.6	0.73	0.013

TABLE 6: Fluid parameters

Hole diameter (inches)	Hole depth (m)	Water: MW = 1, Viscosity 1.17 cP		Mud: MW = 1.15, Viscosity = 20 cP		CCI	R_t	C_a	ECD	BHCP
		Annular velocity (m/s)	Flow rate (l/m)	Annular velocity (m/s)	Flow rate (l/m)					
26"	100	0.7	13000	0.4	6620	-	0.55-0.78	0.021-0.053	-	-
17-1/2"	300	0.7	7980	0.3	2898	1.4	0.52-0.7	0.015-0.055	9.6	33
12-1/4"	850	0.7	4650	0.26	1560	1.3	0.45-0.78	0.011-0.058	8.36	83
8-1/2"	2500	0.78	2044	-	-	1.3	0.73	0.013	8.59	252

Discussion of tables

From Tables 5 and 6 we see the effects of changes in viscosity and density of mud on the various drilling parameters. Assuming a fixed size of the cuttings generated, we can compare the annular velocity, density and viscosity to the R_t, CCI, C_a, ECD and BHCP.

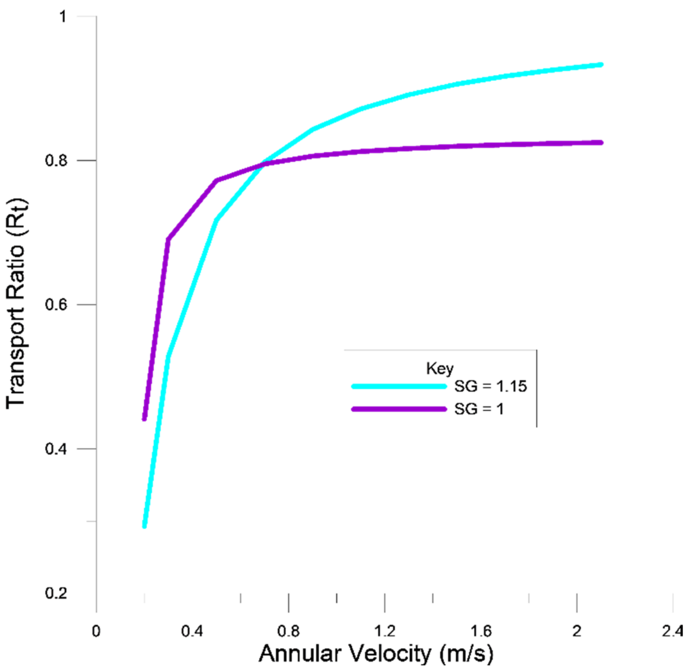

FIGURE 9: Graph of annular velocity vs. transport ratio

Transport ratio, R_t vs. annular velocity and density

This is an indication of hole cleaning efficiency and helps to indicate whether the annular velocity selected is sufficient to move the cuttings out of the hole for trouble-free drilling. As discussed earlier, this ratio should not be less than 0.5 for trouble-free drilling. From the two tables, we notice that an increase in annular velocity results in an increase in the transport ratio, well above the minimum of 0.5, and an increase in fluid density and viscosity equally results in an increase in the transport ratio. A plot of annular velocity against transport ratio is shown in Figure 9. The plots show the effects of density on R_t. It is, however, important to note that this increase in density must not be due to an increase of solid particles (cuttings) in the fluid, but as a fluid property in itself. This effect of density is important, more in the upper well sections. Where achieving the high flow rates for the required annular flow rates is difficult we can, instead, design a fluid with higher viscosity and density to increase the transport ratio.

Transport ratio vs. cuttings concentration
These two have an inverse relationship such that the increase in one leads to a reduction in the other. This creates a dilemma in selecting the fluid parameters and properties. From the results, it is clear that the increase in density and viscosity results in a reduction in C_a, yet the same results in an increase in R_t, due to a reduction in flow rates. Figure 10 shows plots illustrating this.

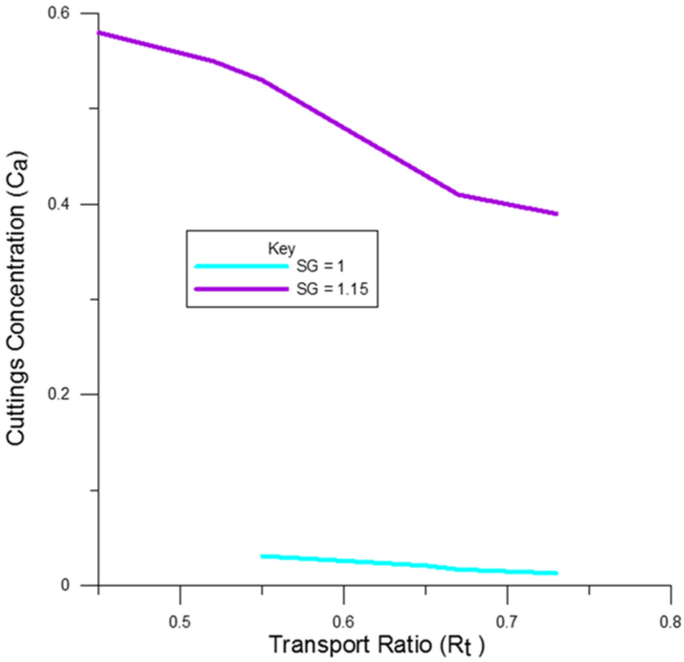

FIGURE 10: Graph of transport ratio vs. cuttings concentration

Flow rate vs. ECD and BHCP
The flow rate used is dependent upon the annular velocity and the well cross-section. If the cross- section is kept constant, the only variable we have is annular velocity. The higher the annular velocity required, the higher the flow rates needed. The annular velocity, as shown earlier, depends on the cuttings' slip velocity. If we have higher annular velocity and flow rates, we end up with higher ECD and eventually BHCP. This is because the pressure losses in the system are dependent on flow rate, density and viscosity of the fluid. The higher these parameters are, the higher the losses and pumping costs will be. In addition, higher BHCP implies higher chances of loss of circulation and formation damage.

3.3 Air and aerated drilling fluid

Aerated drilling is used in geothermal drilling with the aim of reducing the formation damage resulting from increased drilling fluid pressure on the formation wall. As drilling progresses, the density of the fluid increases because of cuttings and other solid content in the fluid; this increase results in higher BHCP with depth. Figure 11 shows a typical well, indicating the drilling window and the effect of increased mud density (Vollmar et al., 2013). Introduction of air in the fluid helps lower the density and

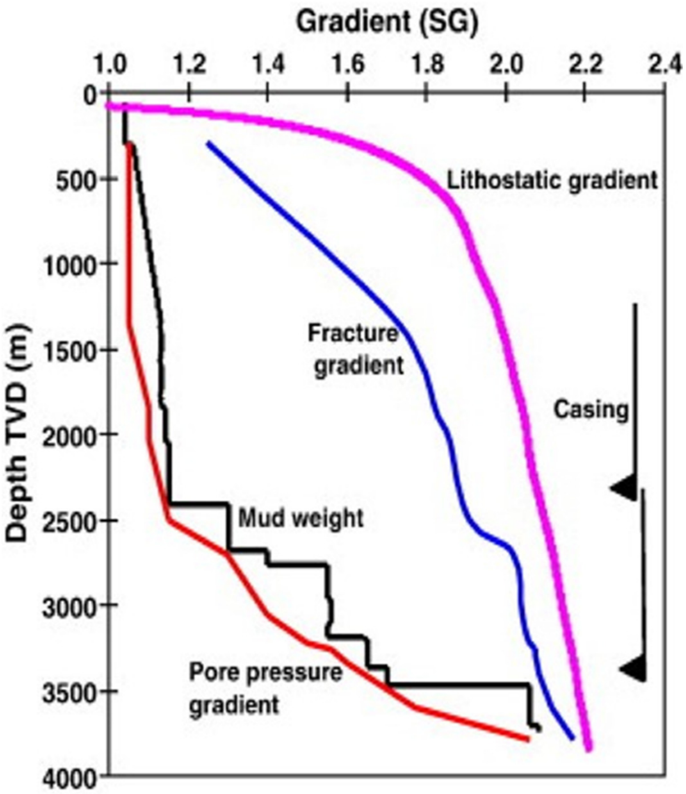

FIGURE 11: Drilling window (Vollmar et al., 2013)

subsequently reduces the damage on the formation.

As can be seen in Figure 11, the higher the fluid density, the greater the formation damage. When drilling the main hole, the tendency is to try and keep the fluid pressure below the pore pressure, which results in an underbalanced system. The ratio of air to water pumped into the hole, and the back pressure applied to the 'exhaust' or flow line from the well, allow the down-hole pressures in the hole to be 'balanced' with the formation pressure in the permeable zones, thus allowing for the return of the drilling fluids to the surface and, therefore, maintaining drilling fluid circulation. In fact, the term 'under-balanced' drilling, as applied to this form of geothermal drilling, is a misnomer (Hole, 2006).

Several graphs have been developed (Lyons et al., 2009), based on the criteria described earlier in the hole cleaning section, for selecting the minimum volumetric flow rates for various well profiles. One such graph is shown in Appendix IV. These can be used in selecting the adequate velocity for the well profile.

For aerated drilling, we must have knowledge of the formation pressures so that we intentionally design the drilling fluid to have lower pressure at the desired points. We first design for the minimum flow rate for optimum hole cleaning, as earlier described. Then we select the appropriate air flow rates for the system's mud flow rate at the desired depth. As to whether we achieve the desired underbalanced drilling can only be assessed by comparing the formation pressures at depth to the drilling fluid pressure.

4. CASE STUDIES

4.1 Drilling fluid design – Olkaria-Kenya scenario

Olkaria geothermal field is one of the largest geothermal production fields in Kenya, with over 300 MWe installed capacity. Several deep geothermal wells have been drilled in this field. A study of one of the wells, OW 717, was considered to appreciate the application of drilling fluid design in geothermal drilling. Well OW 717 is a vertical geothermal well drilled to 3000 m TVD. The well has a regular profile and was drilled in a total of 45 days. The parameters used for the various well sections are shown in Table 7 (KenGen, 2012):

TABLE 7: Fluid parameters

Hole diameter (inches)	**Hole depth (m)**	**Water**		**Mud**		**Pressure loss (bar)**	**CCI**	**C_a**	**ECD (bar)**	**BHCP (bar)**
		Annular velocity (m/s)	**Flow rate (l/m)**	**Annular velocity (m/s)**	**Flow rate (l/m)**					
26"	100	-	-	0.3	4792	59				
17-1/2"	303.5	-	-	0.3	3600	76	1.3	0.002	9.6	29
12-1/4"	749.5	0.9	3900	-	-	105	3.2	0.003	8.5	84
8-1/2"	3000	2.1	3300	-	-	137	7.3	0.018	8.59	252

Drilling upper well section hole

Drilling the 26" hole in Olkaria was done using water-based bentonite. Because of the larger annular cross-section, this section of the well required higher flow rates in order to achieve the minimum hole cleaning requirements. It is impractical to achieve high pumping rates of up to 10,000 lpm. The solution here was to adjust the drilling fluid to higher density and viscosity, hence lowering the flow rates. This, however, increased the bottom hole pressures encountered. It is common practise to spud with mud of viscosity of up to 15 cP. This is achieved by mixing high yield bentonite, like Wyoming bentonite, with water, commonly used in geothermal drilling.

A look at the CCI and C_a achieved with these parameters indicated excellent hole cleaning. The C_a was well below the maximum allowed for trouble-free drilling, implying an even higher rate of penetration could be achieved before the limit was reached.

The actual drilling parameters for drilling the 12-1/4" and 8-1/2" sections showed higher flow rates and velocities than recommended by previous calculations. The effect was a higher BHCP which could lead to formation damage. The higher pressure losses resulting from the higher flow rates also implied more fuel being utilised and poor bit hydraulics.

Aerated drilling
Aerated drilling in Olkaria is introduced whenever a large loss in circulation is encountered. However, the main well section that is designed for aerated drilling is the main hole section, drilled from the production casing depth to total depth, normally 3000 m. The parameters used are 3300 lpm as the flow rate of water and 1800 scfm.

Loss of circulation policy
Minor losses encountered when drilling the surface and anchor casing are treated by drilling blind and spotting mud pills when making connections. Losses encountered in the production hole are handled by drilling blind if the loss is partial, or switching to aerated drilling in cases of full loss. Plugging is rarely done to heal losses unless the well is suspected to have collapsing formations. The main hole is drilled with aerated water and foam.

4.2 Drilling fluid design – Iceland scenario

Table 8 lists the parameters used when drilling part of well RN-19 in Reykjanes.

TABLE 8: Fluid parameters, well RN-19

Hole diameter (inches)	Hole depth (m)	Water		Mud	
		Annular velocity (m/s)	Flow rate (l/m)	Annular velocity (m/s)	Flow rate (l/m)
26"	84	-	-	-	-
21"	349			0.8	3600
17-1/2"	746	0.5	4800		
12-1/4"	2500	1.0	3900	-	-

Drilling the upper well section
The surface hole was drilled to a 26" diameter using an air hammer to a depth of 84 m. The rest of the upper well section was drilled using mud with flow rates ranging from between 50 to 60 lps in the 21" hole to 80 lps in the 17-1/2" hole. The flow rates used in drilling the 17-1/2" section were high, indicating the challenge of drilling using water in large well sections. This can be seen in both the theoretical example and the Olkaria drilling scenario. The high flow rate implies higher frictional losses, hence higher BHCP, which leads to formation damage and possible drilling challenges.

Drilling the main hole
In Iceland, unlike Kenya, water is used in drilling the main hole. This was applied in drilling this well with a flow rate of 3900 lpm, giving an annular velocity of up to 1 m/s. Polymer pills were used in each connection to reduce challenges with the cuttings.

Loss of circulation policy
In Iceland, minor losses encountered during drilling are handled by drilling ahead with water and spotting with polymer or bentonite pills in every connection, when drilling the upper well section.

They can also be handled by using LCMs, such as mica flakes, introduced into the drilling fluid. Major losses encountered while drilling the upper well sections are healed by plugging, using cement.

4.3 Comparison and remarks

The key areas to be noted in drilling fluid design are hole cleaning, pressure losses and bit hydraulics. These, when optimised, will highly increase chances of successful drilling at lower drilling fluid costs. From the scenarios studied, the parameters calculated using the minimum annular velocity for hole cleaning resulted in the least pressure losses. This is because minimal flow rates were considered. The low pressure implies less BHCP which reduces formation damage in cases where drilling through a low pressure formation. The low pressure losses also imply less pumping power, hence saving on costs for drilling fluid.

In geothermal drilling, it is important to design a fluid utilising minimum flow rates. As shown above, the increase in pressure loss is highly dependent on the flow rates used, but it is advisable to begin with the minimum required rates for good hole cleaning, and advance to higher rates in case challenges are noted.

The two scenarios studied in Kenya and Iceland drilling used the actual field parameters used in drilling at the different sites. They both indicate parameters close to the theoretical minimum required, apart from in the main hole sections where much higher velocities were used. Whereas these all ensure excellent hole cleaning, as illustrated by the CCI and the C_a, the higher flow rates result in higher pumping pressures, which implies more fuel consumption. The higher pressure losses in the annulus also result in higher BHCP, which may lead to formation damage.

5. CONCLUSIONS

Fluid design is a wide and complex field of study. However, the key issues pertain to good hole cleaning and protection of a well's formation. Application of the hole cleaning principles gives good criteria for optimising the fluid system. It is important to keep the flow rates as near to the theoretical ones as possible to ensure optimal performance. Prior to any fluid design, the engineers must appreciate the formation profile, as well as the anticipated pore pressures and fracture pressures of the well. This will help in understanding the drilling window and in designing the mud. In general, in geothermal drilling, the tendency is to utilise fluid with densities as close to that of water as possible. Using annular velocities of 0.3 – 0.4 m/s for mud and 0.6 – 0.7 m/s for water is appropriate for good hole cleaning. A further study analysing the fluid parameters used in various wells and the formation pressure would be useful to further appreciate the application of the hole cleaning principles described herein.

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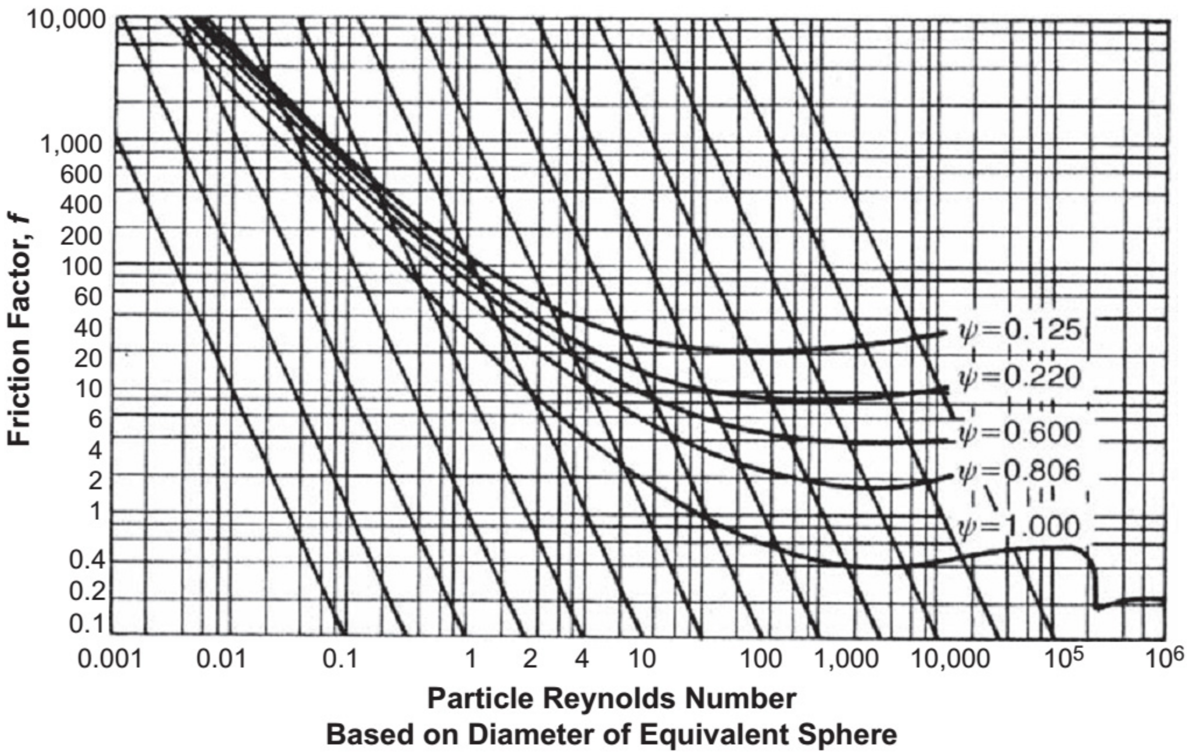
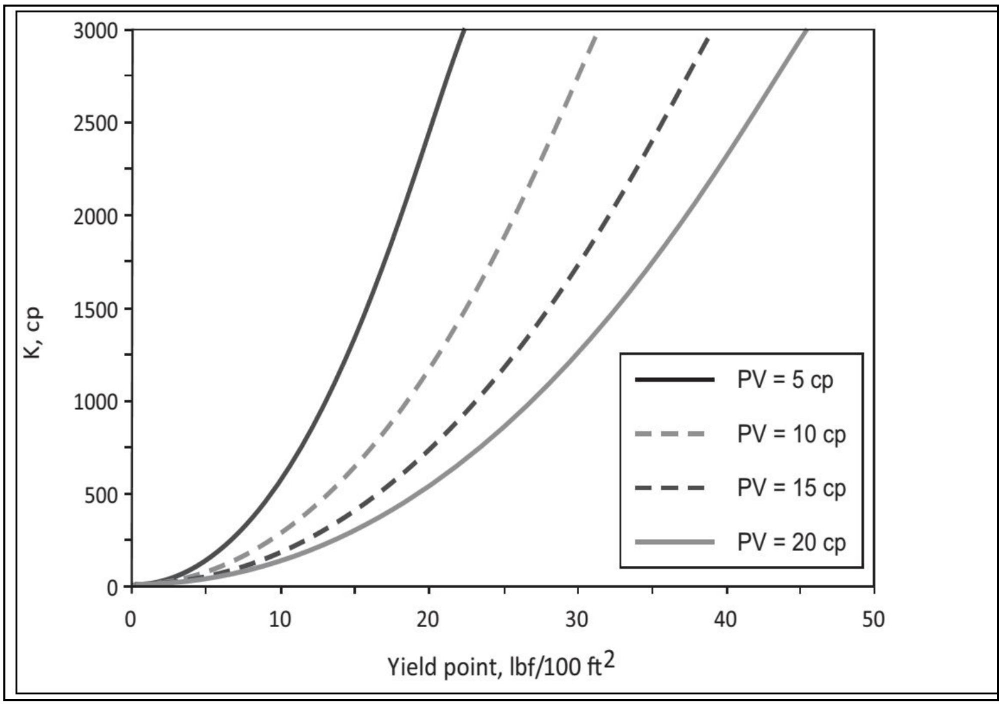
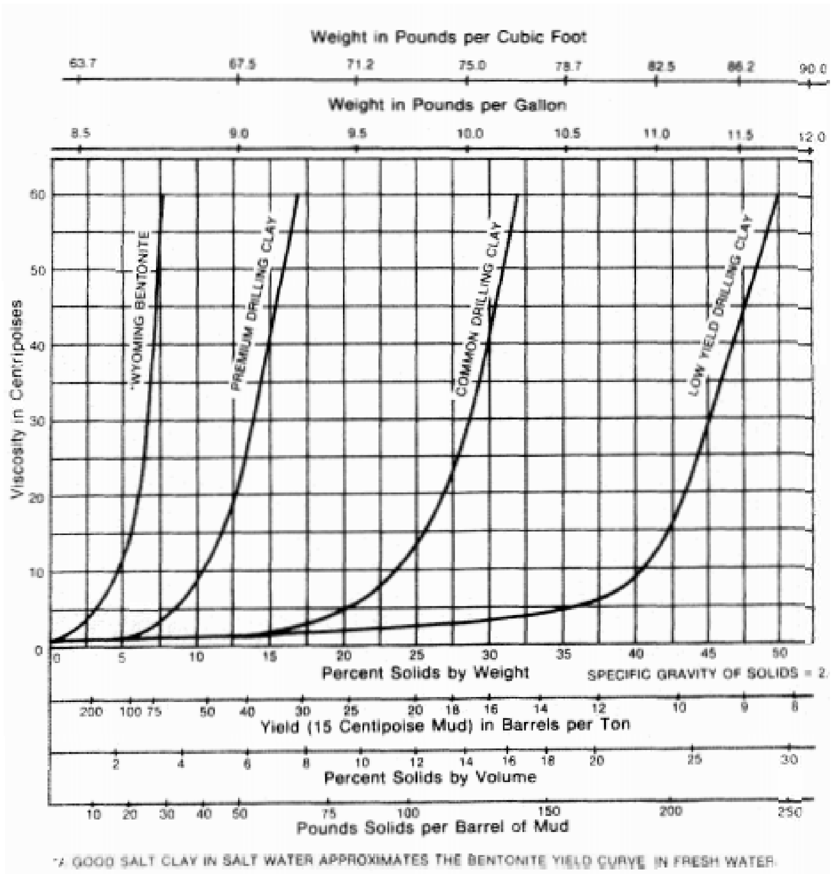
APPENDIX I: Friction factor for calculating Particle slip velocity (Mitchel and Miska, 2011)



APPENDIX II: K factor for power law fluid (Mitchel and Miska, 2011)



APPENDIX III: Effects of clay concentration on viscosity of fresh water (Darley and Gray, 1988)



APPENDIX IV: Direct circulation minimum volumetric flow rates (Mitchel and Miska, 2011)