Rheology and Hydraulics

Introduction

The physical properties of a drilling fluid, density and rheological properties are monitored to assist in optimizing the drilling process. These physical properties contribute to several important aspects for successfully drilling a well, including:

- Provide pressure control to prevent an influx of formation fluid.
- Provide energy at the bit to maximize Rate of Penetration (ROP).
- Provide wellbore stability through pressured or mechanically stressed zones.
- Suspend cuttings and weight material during static periods.
- Permit separation of drilled solids and gas at surface.
- Remove cuttings from the well.

Each well is unique, therefore it is important to control these properties with respect to the requirements for a specific well and fluid being used. The rheological properties of a fluid can affect one aspect negatively while providing a significant positive impact with respect to another aspect. A balance must be attained in order to maximize hole cleaning, minimize pump pressures and avoid fluid or formation influxes, as well as prevent loss of circulation to formations being drilled.

Rheology is the science of deformation and flow of matter.

Rheology and hydraulics are interrelated studies of fluid behavior. *Rheology* is the study of how matter deforms and flows. It is primarily concerned with the relationship of shear stress and shear rate and the impact these have on flow characteristics inside tubulars and annular spaces. *Hydraulics* describes how fluid flow creates and uses pressures. In drilling fluids, the flow behavior of the fluid must be described using rheological models and equations before the hydraulic equations can be applied.

This chapter discusses the rheological properties of drilling fluids, the factors that influence these properties and the impact they have with respect to performing work during the drilling operation. A discussion of the influence of rheological properties on hole cleaning, barite suspension and solids separation can be found in the chapters on Hole Cleaning, Barite Sag and Solids Control, respectively.

Rheology

Rheology is the science of deformation and flow of matter. By making certain measurements on a fluid it is possible to determine how that fluid will flow under a variety of conditions, including temperature, pressure and shear rate.

Viscosity… can be described as a substance's resistance to flow.

VISCOSITY

Of the rheological terms, viscosity is the most familiar. Viscosity in its broadest sense can be described as a substance's resistance to flow. In the oilfield, the following terms are used to describe drilling fluid viscosity and rheological properties:

1. Funnel viscosity (sec/qt or sec/l).
2. Apparent viscosity (cP or mPa•sec).
3. Effective viscosity (cP or mPa•sec).
4. Plastic viscosity (cP or mPa•sec).
5. Yield point (lb/100 ft^2 or Pa).
6. Low-shear viscosity and Low-Shear-Rate Viscosity (LSRV) (cP or mPa•sec).
7. Gel strengths (lb/100 ft^2 or Pa).

These are among the key values for treating and maintaining drilling fluids.

Funnel viscosity... should be used in the field to detect relative changes in the fluid's properties.

FUNNEL VISCOSITY

The funnel viscosity is measured using the Marsh funnel as described in the Testing chapter. Funnel viscosity is used as a relative indicator of fluid condition. It does not provide sufficient information to determine the rheological properties or flow characteristics of a fluid. It should be used in the field to detect relative changes in the fluid's properties. In addition, no one funnel viscosity can be taken to represent a correct value for all fluids. What works well in one area may fail in another, but, in general, a rule of thumb may be applied to clay-base drilling fluids. The funnel viscosity of most fluids is controlled at four times the density (lb/gal) or less. There are exceptions, however, as in areas where high-viscosity fluids are necessary. Polymer and invert-emulsion (oil- or synthetic-base) systems do not necessarily follow these rules.

This relationship between shear rate and shear stress for a fluid defines how that fluid flows.

SHEAR STRESS AND SHEAR RATE

The other terms for viscosity (μ) can be described in terms of the ratio of the shear stress (τ) to the shear rate (γ). By definition:

$$\text{Viscosity } (\mu) = \frac{\text{shear stress } (\tau)}{\text{shear rate } (\gamma)}$$

The concepts of shear rate and shear stress apply to all fluid flow. Within a circulating system, shear rate is dependent on the average velocity of the fluid in the geometry in which it is flowing. Thus, shear rates are higher in small geometries (inside the drillstring) and lower in larger geometries (such as casing and riser annuli). Higher shear rates usually cause a greater resistive force of shear stress. Therefore, shear stresses in the drillstring (where higher shear rates exist) exceed those in the annulus (where lower shear rates exist). The sum of pressure losses throughout the circulating system (pump pressure) is often associated with shear stress while the pump rate is associated with shear rate. This relationship between shear rate and shear stress for a fluid defines how that fluid flows. Figure 1 is a simplified depiction of two fluid layers (A and B) moving past each other when a force has been applied.

When a fluid is flowing, a force exists in the fluid that opposes the flow. This force is known as the *shear stress*. It can be thought of as a frictional force that arises when one layer of fluid slides by another. Since it is easier for shear to occur between layers of fluid than between the outermost layer of fluid and the wall of a pipe, the fluid in contact with the wall does not flow. The rate at which one layer is moving past the next layer is the *shear rate*. The shear rate (γ) is therefore a velocity gradient.

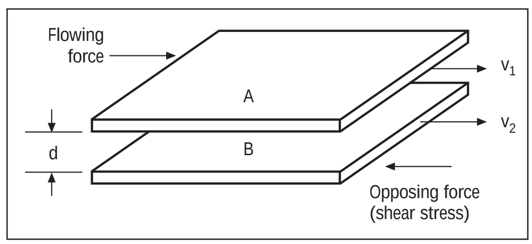

Figure 1: Shear rate and shear stress.

The formula for the shear rate (γ) is:

$$\gamma \,(\text{sec}^{-1}) = \frac{V_2 - V_1}{d}$$

Where:
γ = Shear rate in reciprocal seconds
V_2 = Velocity at Layer B (ft/sec)
V_1 = Velocity at Layer A (ft/sec)
d = Distance between A and B (ft)

The shear rate (γ), sec^{-1}, is equal to the mud viscometer RPM (ω) multiplied by 1.703. This factor is derived from the sleeve and bob geometry of the viscometer.

$$\gamma \text{ (sec}^{-1}\text{)} = 1.703 \text{ x } \omega$$

Shear stress

Shear stress is the force required to sustain the shear rate.

Shear stress (τ) is the force required to sustain the shear rate. Shear stress is reported in standard oilfield units as the pounds of force per hundred square feet (lb/100 ft^2) required to maintain the shear rate.

Mud viscometer dial readings (Θ) taken with the standard number one (1) bob and spring combination as described in the Testing chapter can be converted to a shear stress (τ) with lb/100 ft^2 units by multiplying the reading by 1.0678.

$$\tau \text{ (lb/100 ft}^2\text{)} = 1.0678 \text{ x } \Theta$$

Viscometer readings are often used as the shear stress (τ) in lb/100 ft^2 without this conversion since the difference is small.

A variety of viscometers are used to measure drilling fluid viscosity. Fann VG meters and rheometers are designed to simplify the use of rheological models. Viscometers are also used to measure the thixotropic properties or gel strengths of a fluid.

Effective viscosity

The viscosity of a non-Newtonian fluid changes with shear. The effective viscosity (μ_e) of a fluid is a fluid's viscosity under specific conditions. These conditions include shear rate, pressure and temperature.

Apparent viscosity

The effective viscosity is sometimes referred to as the Apparent Viscosity (AV). The apparent viscosity is reported as either the mud viscometer reading at 300 RPM (Θ_{300}) or one-half of the meter reading at 600 RPM (Θ_{600}). It should be noted that both of these apparent viscosity values are consistent with the viscosity formula:

$$\text{AV (cP)} = \frac{300 \text{ x } \Theta}{\omega}$$

Plastic viscosity

Plastic Viscosity (PV) in centipoise (cP) or milliPascal seconds (mPa•s) is calculated from mud viscometer data as:

$$\text{PV (cP)} = \Theta_{600} - \Theta_{300}$$

Plastic viscosity is usually described as that part of resistance to flow caused by mechanical friction. Primarily, it is affected by:

- Solids concentration.
- Size and shape of solids.
- Viscosity of the fluid phase.
- The presence of some long-chain polymers (POLY-PLUS®, Hydroxyethylcellulose (HEC), POLYPAC®, Carboxymethylcellulose (CMC)).
- The Oil-to-Water (O/W) or Synthetic-to-Water (S/W) ratio in invert-emulsion fluids.
- Type of emulsifiers in invert-emulsion fluids.

The solids phase is the chief concern of the fluid engineer. An increase in plastic viscosity can mean an increase in the percent by volume of solids, a reduction in the size of the solid particles, a change in the shape of the particles or a combination of these. Any increase in the total surface area of solids exposed will be reflected in an increased plastic viscosity. Breaking a solid particle in half, for instance, will result in two pieces with a combined exposed surface area greater than the original particle. A flat particle has more surface area exposed than a spherical one of the same volume. Most of the time, however, an increase in plastic viscosity is the result of an increase in the percentage of solids. This can be verified by density changes and/or retort analysis.

...the viscosity of the fluid should not be higher than that required for hole cleaning and barite suspension.

Changes in plastic viscosity can result in significant changes in pump pressure in the field.

Some of the solids in the fluid are there because they have been deliberately added. Bentonite, for instance, is good for increasing viscosity and decreasing fluid loss, while barite is necessary for density. A good rule is that the viscosity of the fluid should not be higher than that required for hole cleaning and barite suspension. When a fluid is failing to perform these functions, emphasis should be placed on raising the yield point and low-shear values (6 and 3 RPM) rather than the plastic viscosity.

Drilled solids, however, adversely affect rheological properties of the fluid and are undesirable. They are continually being added to the fluid during drilling, causing an increase in solids concentration. If the solids are not removed promptly, they continue to break up into smaller pieces as they are circulated and recirculated through the system. Viscosity problems will occur if drilled solids are not controlled.

There are three ways that drilled solids can be controlled:

1. Mechanical solids control.
2. Settling.
3. Dilution or displacement.

Chapter 8 discusses solids control and the removal of drilled solids in more detail.

Plastic viscosity is also a function of the viscosity of the fluid phase. As the viscosity of water decreases with increased temperature, the plastic viscosity will decrease proportionally. Brines have higher viscosities than freshwater fluids. Oil emulsified in water-base fluids also acts as a solid and will affect the plastic viscosity of the fluid.

Polymers added to the system for viscosity, fluid-loss control or shale inhibition may contribute to elevated plastic viscosities, especially after initially mixing the polymer. The long-chain polymers (POLY-PLUS, HEC, POLYPAC, CMC) have the greatest impact on plastic viscosity. The short-chain or low-viscosity variations of these polymers (POLYPAC UL, CMC LV) have a less significant impact on plastic viscosity. The increase in plastic viscosity is most apparent just after mixing these polymers. It is therefore recommended *not* to measure viscosity in the suction pit at this time. Generally, after a few circulations the plastic viscosity and rheological properties will decrease and stabilize.

With respect to invert-emulsion fluids (oil- and synthetic-base) the plastic viscosity can be adjusted with the O/W or S/W ratio. Generally, the higher the O/W or S/W, the lower the plastic viscosity. Also, the choice of primary emulsifier can have an impact on plastic viscosity.

Changes in plastic viscosity can result in significant changes in pump pressure in the field. This is extremely important in extended-reach as well as coiled-tubing drilling where longer, smaller-diameter tubulars are used. It is critical to minimize plastic viscosity in these situations. As a rule, plastic viscosity should be kept as low as practical in all cases because a low PV can result in greater energy at the bit, greater flow in the annulus for hole cleaning, as well as less wear and tear on the equipment, and lower fuel usage. A practical upper limit for the plastic viscosity is twice the fluid weight (lb/gal). Although this value may seem restrictive for high fluid weights, the solids are so crowded by weight material that these fluids have a very low tolerance for drill solids. The plastic viscosity is a good approximation of the viscosity through the bit nozzles.

Yield point... is a measurement of the electro-chemical or attractive forces in a fluid.

YIELD POINT

Yield Point (YP) in pounds per 100 square feet (lb/100 ft²) is calculated from Fann VG meter data as:

$$YP\ (lb/100\ ft^2) = 2 \times \Theta_{300} - \Theta_{600}$$
or
$$YP\ (lb/100\ ft^2) = \Theta_{300} - PV$$

or in Pascals:
$$YP\ (Pa) = 0.4788 \times (2 \times \Theta_{300} - \Theta_{600})$$
or
$$YP\ (Pa) = 0.4788 \times (\Theta_{300} - PV)$$

Yield point, the second component of resistance to flow in a drilling fluid, is a measurement of the electro-chemical or attractive forces in a fluid. These forces are a result of negative and positive charges located on or near the particle surfaces. Yield point is a measure of these forces under flow conditions and is dependent upon: (1) the surface properties of the fluid solids, (2) volume concentration of the solids, and (3) the electrical environment of these solids (concentration and types of ions in the fluid phase of the fluid). High viscosity resulting from high yield point or attractive forces may be caused by:

1. Introduction of soluble contaminants such as salts, cement, anhydrite or gypsum that result in flocculation clays and reactive solids.
2. Breaking of the clay particles by the grinding action of bit and drill pipe creating new residual forces (broken bond valences) on the broken edges of the particle. These forces tend to pull the particles together in disorganized form or flocs.
3. Introduction of inert solids into the system increases the yield point. This results in the particles being moved closer together. Because the distance between each particle is decreased, the attraction between particles is increased.
4. Drilled hydratable shales or clays introduce new active solids into the system, increasing attractive forces by bringing the particles closer together, and by increasing the total number of charges.
5. Under- or over-treatment with electrochemically charged chemicals increases the attractive forces.
6. The use of branched biopolymers (DUO-VIS,® FLO-VIS,® XCD,® Xanvis).
7. Overtreatment with organophilic clay or rheological modifiers in invert-emulsion systems (VERSA-HRP,® VERSAMOD™).

Yield point is that part of resistance to flow that may be controlled by proper chemical treatment. The yield point will decrease as the attractive forces are reduced by chemical treatment. Reduction of yield point will also decrease the apparent viscosity. In a clay-base, water-base mud, yield point may be lowered by the following methods:

1. Broken bond valences, caused by grinding the clay particles, may be neutralized by adsorption of certain anionic materials at the edge of the clay particles. These residual valences are almost satisfied completely by such chemicals as tannins, lignins (TANNATHIN,® XP-20,® K-17®), complex phosphates (Phos and SAPP), lignosulfonates (SPERSENE™) and low-molecular-weight polyacrylates (TACKLE,® SP-101®). The basic negative charge of the clay particle predominates so that the solids now repel each other.
2. In the case of contamination from calcium or magnesium, the cations causing the attractive force can be removed as an insoluble precipitate, thus decreasing the attractive force and yield point.

3. Water can be used to lower the yield point, but unless the concentration of solids is very high, this is relatively ineffective and can be expensive. Water alone may undesirably alter other properties of the fluid. This is particularly true of weighted fluids where water can increase fluid loss and lower fluid weight (necessitating weighting up again).

Generally in clay-base, water-base muds, anionic (negatively charged) materials deflocculate, reducing viscosity. Cationic (positively charged) materials promote flocculation and increase viscosity.

An increase in the yield point can be achieved through additions of a good commercial viscosifier. Also, anything that produces flocculation in a fluid will raise the yield point. A small amount of lime, for example, added to a freshwater fluid containing enough hydrated bentonite or other clays will produce flocculation and, hence, an increase in the yield point. It should be remembered, however, that flocculation can have undesirable effects on fluid-loss control, circulating pressures and gel strengths.

The yield point of dispersed lignosulfonate (SPERSENE) clay-fluid systems is typically maintained approximately equal to the mud weight. The yield point of low- or minimum-solids, non-dispersed fluids, may be run at considerably higher values, but these fluids are seldom used at densities in excess of 14 lb/gal.

…low-shear viscosity values…had a greater impact on hole cleaning than yield point…

Wetting agents or chemical thinners can be used to reduce yield point in invert-emulsion fluids. These materials can sometimes reduce the solids tolerance of the fluid. Usually the best method for reducing yield point in an invert system is to increase the O/W or S/W ratio by adding oil- or synthetic-base fluid.

The yield point is often used as an indicator of the shear-thinning characteristics of a fluid and its ability to suspend weight material and remove cuttings from the wellbore, but it can be misleading. Any fluid with a yield point greater than zero, shear thins to some degree. Fluids with very low yield points will not suspend weight material, but fluids with high yield points may not suspend weight material either. Solutions of CMC, Polyanionic Cellulose (PAC) and HEC polymers in water have yield points, but they will not suspend weight material under static conditions. Measurements of their shear stresses at low shear rates indicate that their shear stress at a shear rate of zero sec^{-1} is zero (0). The ability of a fluid to suspend barite is more dependent on gel strengths, low-shear viscosity and the thixotropy of a fluid.

LOW-SHEAR VISCOSITY AND LSRV

The increase in directional, extended-reach and horizontal drilling, and the use of biopolymers for rheological properties has altered the perception of which rheological properties are required for efficient hole cleaning in deviated wellbores. Through numerous laboratory studies and field experience, it was found that the low-shear viscosity values (6 and 3 RPM) had a greater impact on hole cleaning than yield point, in addition to providing barite suspension under dynamic as well as static conditions. These topics are covered in more detail in the Barite Sag and Hole Cleaning chapters.

In addition to 6- and 3-RPM readings, it was found that low-shear-rate viscosity created by the polymer network in FLO-PRO® systems was critical for hole cleaning and solids suspension in horizontal and high-angle wells. This LSRV is measured using a Brookfield viscometer at a shear rate of 0.3 RPM (the equivalent of 0.037 RPM on a VG meter).

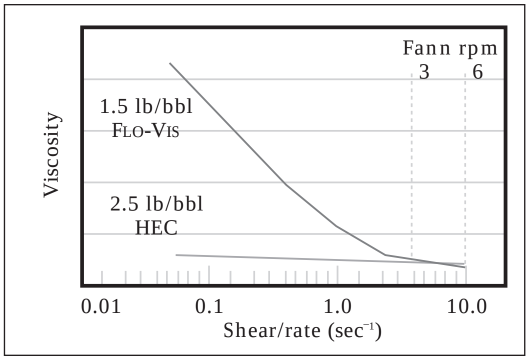

Figure 2: Comparison of FLO-VIS' LSRV to that of HEC.

Progressive gels or flash gels may reflect fluid system problems.

Figure 2 shows how similar viscosities at 6 and 3 RPM may not indicate true LSRV behavior.

These low-shear rheological properties fill the gap between traditional dynamic viscosity measurements of PV, YP and static measurements of gel strength.

THIXOTROPY AND GEL STRENGTHS

Thixotropy is the property exhibited by some fluids which form a gel structure while static and then become fluid again when shear is applied. Most water-base drilling fluids exhibit this property due to the presence of electrically charged particles or special polymers that link together to form a rigid matrix. Gel strength readings taken at 10-sec and 10-min intervals, and in critical situations at 30-min intervals, on the Fann VG meter provide a measure of the degree of thixotropy present in the fluid. The strength of the gel formed is a function of the amount and type of solids in suspension, time, temperature and chemical treatment. In other words, anything promoting or preventing the linking of particles will increase or decrease the gelation tendency of a fluid.

...anything promoting or preventing the linking of particles will increase or decrease the gelation tendency of a fluid.

The magnitude of gelation, as well as the type of gel strength, is important in the suspension of cuttings and weight material. Gelation should not be allowed to become any higher than necessary to perform these functions.

Excessive gel strengths can cause complications, such as the following:

1. Entrapment of air or gas in the fluid.
2. Excessive pressures when breaking circulation after a trip.
3. Reduction in the efficiency of solids-removal equipment.
4. Excessive swabbing while tripping out of the hole.
5. Excessive pressure surges while tripping in the hole.
6. Inability to get logging tools to the bottom.

Progressive gels or flash gels may reflect fluid system problems. A wide range between the initial and 10- or 30-min gel readings is called *progressive gels*, and is an indication of solids buildup. If the initial and 10-min gel readings are both high with little difference between the two, it is called *flash gels* and may indicate that flocculation has occurred. In the case of a FLO-PRO system, the gel strengths are elevated and flat, but this is due to the polymer network created. In addition to being elevated and flat, FLO-PRO gel strengths are also fragile and “break back” quite readily. Fragile gel strengths are very common in polymer drilling fluids. Figure 3 graphically illustrates the different types of gel strength.

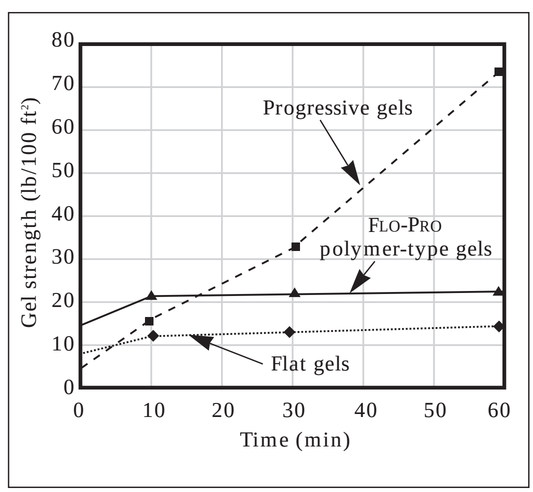

Figure 3: Gel strengths.

...gelation gives a fluid a "memory" of its past history...

Gel strength and yield point are both measures of the attractive forces in a fluid system. The initial gel strength measures the static attractive forces, while the yield point measures the dynamic attractive forces. Treatment for excessive initial gel strength is, therefore, the same as for excessive yield point.

In addition, gelation gives a fluid a "memory" of its past history and must be taken into account in making meaningful rheological property measurements. If a fluid has been allowed to stand for a period of time before making a measurement of shear stress at some shear rate, some time at that particular shear rate is required before an equilibrium shear stress can be measured. All of the bonds between particles that can be broken at that shear rate must be broken or the measured shear stress will be higher than the true equilibrium shear stress. The length of time required depends on the degree of gelation that has occurred in the sample.

After a measurement has been made at 600 RPM and the shear rate is slowed to 300 RPM, the fluid tends to remember its past shear history at 600 RPM. A period of time is required for certain bonds between particles that can exist at the reduced shear rate to re-form before a true equilibrium shear stress can be measured. The indicated shear stress will be too low at first and will gradually increase to an equilibrium value.

The first indicated value of shear stress at any shear rate is a function of the immediate shear history of the sample. If the initial gel strength of a fluid is measured immediately after shearing the fluid at 600 RPM, the indicated value will be less than the true yield stress of the fluid.

Since the formation or breakdown of a gel structure is time-dependent, many different shear-stress/shear-rate paths can be taken in moving from one shear rate to another. This is illustrated in Figure 4. The solid curve represents the equilibrium shear-stress/shear-rate relationship that will occur if the shear rate of the fluid is changed very slowly. If, however, the fluid starts at point A at an equilibrium value of high-shear stress that suddenly decreases to a shear rate of zero, the shear stress will follow the lower curve, which at all points is less than the equilibrium curve.

Upon standing quiescent, the gel strength will build up until point B is reached. If, after gelling to point B, the shear rate is suddenly increased, the shear stress will follow a higher path from point B to point C, which at all points is higher than the equilibrium curve. With time at this high shear rate, the shear stress will eventually decrease from point C to the equilibrium value at point A. Conversely, if, after gelling to point B the shear rate is slowly increased, the shear stress will decrease at first and then follow the equilibrium curve to point A.

The B-to-C curve can be followed if the drilling fluid is not properly treated. This would result in very high circulating pressures. Extended time periods could be required to reach equilibrium point A. Properly treated drilling fluids follow the shorter path to the equilibrium curve, resulting in lower pump pressures.

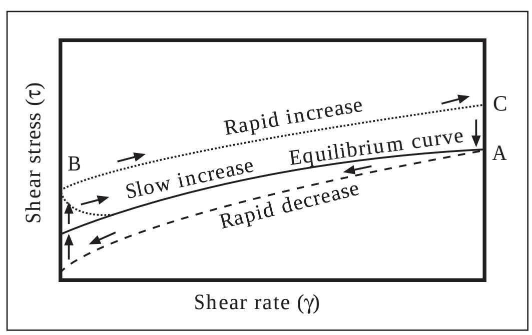

Figure 4: Thixotropic behavior.

EFFECT OF TEMPERATURE AND PRESSURE ON VISCOSITY

Increases in temperature and pressure affect the viscosity of the liquid phases of all drilling fluids. The effect on invert-emulsion fluids is more pronounced than on water-base fluids. Base oils and synthetics thin more appreciably under elevated temperature conditions. Each of the different oil- and synthetic-base fluids is affected somewhat differently by temperature.

Water-base fluids...do not compress appreciably under pressure.

Water-base fluids are nearly perfect hydraulic fluids. They do not compress appreciably under pressure. Oil- and synthetic-base fluids, on the other hand, are all compressible to some degree. Their compressibility varies with the base fluid, O/W or S/W ratio, and additives. In critical situations, the effects of temperature and pressure should be determined for the drilling fluid and the base liquid phases. The effects on viscosity can be determined with a high-temperature rotational viscometer such as the Fann Model 50 for water-base fluids or with a high-pressure, high-temperature viscometer such as the Fann Model 70 or the Huxley Bertram for oil or synthetic fluids.

The API equations to compensate for the effects of temperature and pressure require the effective viscosity (μ_e) at two temperatures.

$$\mu_{e(T_2)} = \mu_{e(T_1)}^{\left[ß \frac{T_2 - T_1}{T_1 T_2}\right]}$$

The temperature constant (ß) must be determined at each shear rate for each fluid.

$$\mu_{e(P_2)} = \mu_{e(P_1)}^{\alpha(P_2 - P_1)}$$

The pressure constant (α) must be determined for each drilling fluid.

M-I's VIRTUAL HYDRAULICS™ computer program uses data from the Fann Model 70/75 to determine the viscosity of the drilling fluid at any combination of temperature and pressure.

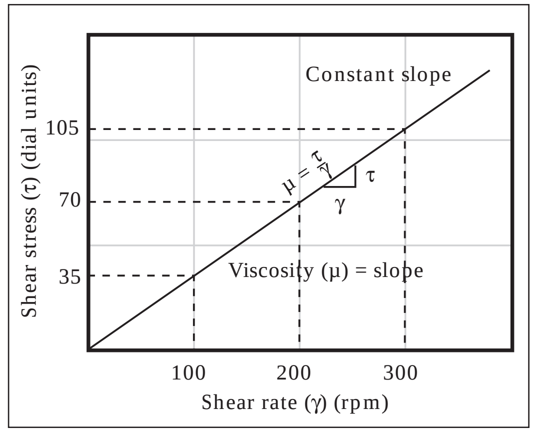

Figure 5: Newtonian fluid.

FLUID TYPES

Based on their flow behavior, fluids can be classified into two different types: Newtonian and non-Newtonian.

NEWTONIAN FLUID

In Newtonian fluids, the shear stress is directly proportional to the shear rate...

The simplest class of fluids is called *Newtonian*. The base fluids (freshwater, seawater, diesel oil, mineral oils and synthetics) of most drilling fluids are Newtonian. In these fluids, the shear stress is directly proportional to the shear rate, as shown in Figure 5. The points lie on a straight line passing through the origin (0, 0) of the graph on rectangular coordinates. Viscosity of a Newtonian fluid is the slope of this shear-stress/shear-rate line. The yield stress (stress required to initiate flow) of a Newtonian fluid will always be zero (0).

In the example, when the shear rate is doubled, the shear stress is also doubled. When the circulation rate for this fluid is doubled, the pressure required to pump the fluid will be squared (e.g. 2 times the circulation rate requires 4 times the pressure). For example, at 100 RPM the shear stress is 35 deflection units and doubling the shear rate doubles the shear stress to 70 deflection units, etc. This fluid would have a viscosity of 105 cP at 100 rpm. Newtonian fluids will not suspend cuttings and weight material under static conditions. When Newtonian fluids (freshwater, seawater, brines and oils) are used for drilling, the hole should be circulated or swept clean periodically and before trips.

The shear stress at various shear rates must be measured in order to characterize the flow properties of a fluid. Only one measurement is necessary since the shear stress is directly proportional to the shear rate for a Newtonian fluid. From this measurement the shear stress at any other shear rate can be calculated from the following equation:

$$\tau = \mu \times \gamma$$

This general definition is independent of units. VG meter data (converted to shear stress and shear rate) can be converted to viscosity with this formula:

$$\mu = \frac{1.0678 \times \Theta}{1.703 \times \omega}$$

The viscosity as determined by this formula is in English units (ft, lb, etc.), but the viscosity is reported in centipoise (cP or 0.01 dynes/cm^2) on the API Daily Mud Report. The factor for converting viscosity in English units to centipoise is 478.9. When this conversion factor is included in the formula, it becomes:

$$\mu\ (\text{cP}) = 478.9 \times \frac{1.0678}{1.703} \times \frac{\Theta}{\omega}$$

If the numerical values are simplified, this formula becomes:

$$\mu\ (\text{cP}) = 300 \times \frac{\Theta}{\omega}$$

This simple formula will be used to show that the viscosity of drilling fluids is far more complex than might be assumed.

Fluid flowing in a cylindrical pipe in laminar or streamline flow moves in concentric layers as shown in Figure 6a. A typical velocity profile for a Newtonian fluid flowing in a pipe is shown in Figure 6b. The flow profile is in the form of a parabola or bullet shape.

The slope of the velocity profile is maximum at the wall of the pipe and decreases to zero at the center of the pipe.

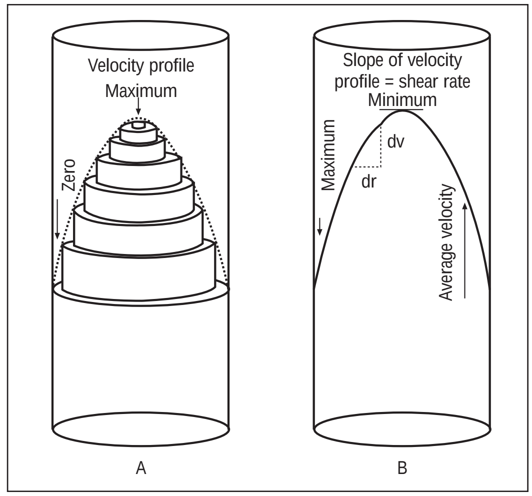

Figure 6: Newtonian velocity profile (laminar).

The rate of change of velocity with distance (shear rate) is the slope of the velocity profile at any point in the pipe. The slope of the velocity profile is maximum at the wall of the pipe and decreases to zero at the center of the pipe. Therefore, the shear rate is a maximum at the wall and zero at the center of the pipe. At the pipe wall, the slope of the velocity profile is parallel to the pipe wall and has an infinite slope (maximum). This slope decreases with distance away from the wall and at some point has a 45° slope that would have a slope of 1. In the center of the pipe, the slope of the velocity profile is perpendicular to the pipe wall and has a zero slope (minimum) (see Figure 6b). Consequently, the shear stress will also be maximum at the wall.

The shear rate (sec^{-1}) at the wall of a cylindrical pipe may be calculated in the following equation:

$$\gamma = \frac{8V}{D}$$

Where:
V = Average fluid velocity in the pipe (ft/sec)
D = Pipe diameter (ft)

...flattening of the velocity profile increases the sweep efficiency of a fluid...

This calculation is somewhat different in the case of concentric annuli, i.e., in a wellbore with drill pipe in the hole as shown in Figure 7. Here, the fluid is flowing around the drill pipe and inside either cased or uncased hole. The annular shear rate (sec^{-1}) for concentric pipes is calculated with the following equation:

$$\gamma = \frac{12V}{D_H - D_P}$$

Where:

V = Average fluid velocity in the pipe (ft/sec)
D_H = Diameter of the hole (ft)
D_P = Outside diameter of the pipe (ft)

The relationship $D_H - D_P$ is sometimes referred to as the hydraulic diameter.

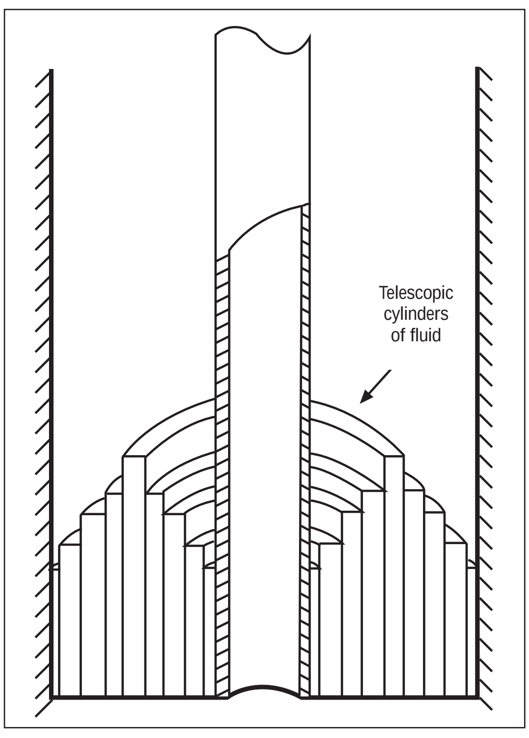

Figure 7: Newtonian velocity profile — concentric annulus (laminar).

NON-NEWTONIAN FLUIDS

When a fluid contains clays or colloidal particles, these particles tend to “bump” into one another, increasing the shear stress or force necessary to maintain a given flow rate. If these particles are long compared to their thickness, the particle interference will be large when they are randomly oriented in the flow stream. However, as the shear rate is

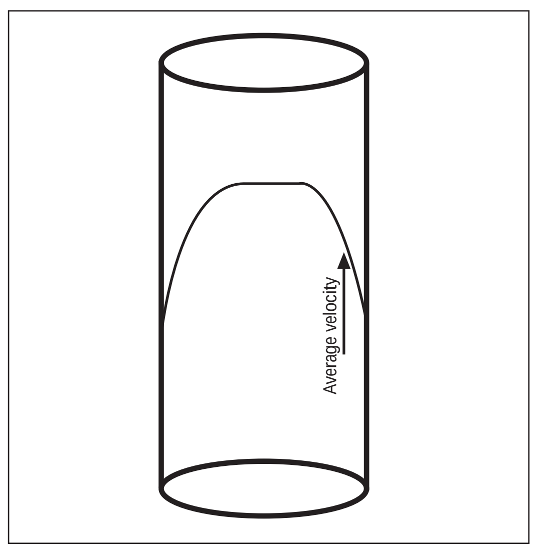

Figure 8: Non-Newtonian velocity profile (laminar).

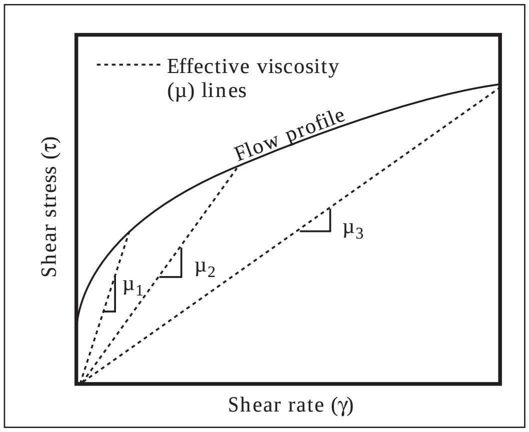

Figure 9: Effect of shear rate on effective viscosity of non-Newtonian fluid.

increased, the particles will "line up" in the flow stream and the effect of particle interaction is decreased. This causes the velocity profile in a pipe to be different from that of water. In the center of the pipe, where the shear rate is low, the particle interference is high and the fluid tends to flow more like a solid mass. The velocity profile is flattened as shown in Figure 8. This flattening of the velocity profile increases the sweep efficiency of a fluid in displacing another fluid and also increases the ability of a fluid to carry larger particles.

If the particles are electrically attracted to each other, the effect is similar. At low shear rates, the particles link together, increasing the resistance to flow, but at high shear rates the linking bonds are broken. Under these circumstances, the shear stress does not increase in direct proportion to the shear rate. Fluids that behave in this manner are called *non-Newtonian fluids*. Most drilling fluids are of this type.

...non-Newtonian fluid does not have a single or constant viscosity that describes its flow behavior at all shear rates.

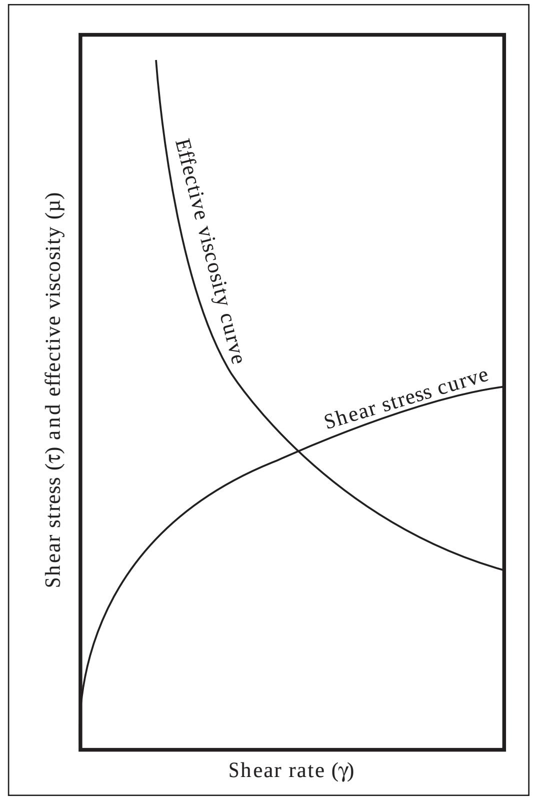

Figure 10: Shear-thinning effect in non-Newtonian fluids.

Non-Newtonian fluids exhibit a shear-stress/shear-rate relationship as shown in Figure 9. The ratio of shear stress to shear rate is not constant but different at each shear rate. This means that a non-Newtonian fluid does not have a single or constant viscosity that describes its flow behavior at all shear rates. To describe the viscosity of a non-Newtonian fluid at a particular shear rate, an "effective viscosity" is used. Effective viscosity is defined as the ratio (slope) of shear stress to shear rate at a particular shear rate, and is illustrated as the slope of a line drawn from the shear stress curve (at the shear rate of interest) back to the origin (see Figure 9). As

Rheological Models

A rheological model is a description of the relationship between the shear stress and shear rate.

Most drilling fluids are not true Bingham Plastic fluids.

shown, most non-Newtonian fluids exhibit "shear-thinning" behavior so that the effective viscosity decreases with increasing shear rate.

As shown in Figure 10, when the effective viscosity is plotted alongside the shear-stress-shear-rate curve, it is easy to see the shear-thinning nature that most drilling fluids exhibit. Shear-thinning has very important implications in drilling fluids as it provides what we desire most:

1. At high velocities (high shear rates) in the drillstring and through the bit, the mud shear thins to low viscosities. This reduces the circulating pressure and pressure losses.
2. At the lower velocities (lower shear rates) in the annulus, the mud has a higher viscosity that aids in hole cleaning.
3. At ultra-low velocity the mud has its highest viscosity and when not circulating will develop gel strengths that aid in suspending weight material and cuttings.

A rheological model is a description of the relationship between the shear stress and shear rate. Newton's law of viscosity is the rheological model describing the flow behavior of Newtonian fluids. It is also called the Newtonian model. However, since most drilling fluids are non-Newtonian fluids, this model does not describe their flow behavior. In fact, since no single rheological model can precisely describe the flow characteristics of all drilling fluids, many models have been developed to describe the flow behavior of non-Newtonian fluids. Bingham Plastic, Power Law and Modified Power Law models are discussed. The use of these models requires measurements of shear stress at two or more shear rates. From these measurements, the shear stress at any other shear rate can be calculated.

Bingham Plastic model

The Bingham Plastic model has been used most often to describe the flow characteristics of drilling fluids. It is one of the older rheological models currently in use. This model describes a fluid in which a finite force is required to initiate flow (yield point) and which then exhibits a constant viscosity with increasing shear rate (plastic viscosity). The equation for the Bingham Plastic model is:

$$\tau = \tau_0 + \mu_p \gamma$$

Where:

τ = Shear stress
τ_0 = Yield point or shear stress at zero shear rate (Y-intercept)
μ_p = Plastic viscosity or rate of increase of shear stress with increasing shear rate (slope of the line)
γ = Shear rate

Converting the equation for application with viscometer readings, the equation becomes:

$$\frac{\omega}{}$$

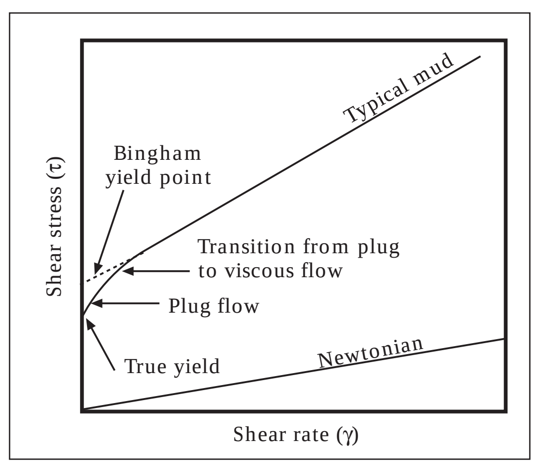

Figure 11: Flow diagram of Newtonian and typical mud.

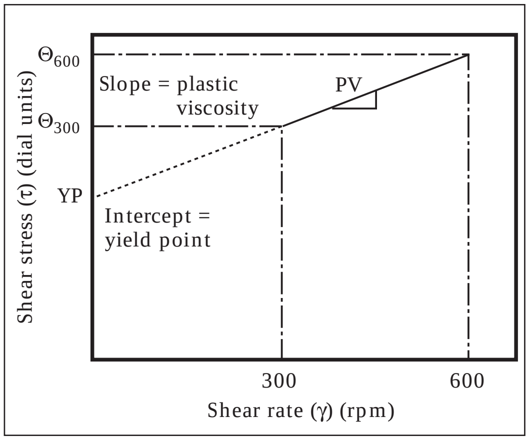

Figure 12: Bingham Plastic values from two measurements.

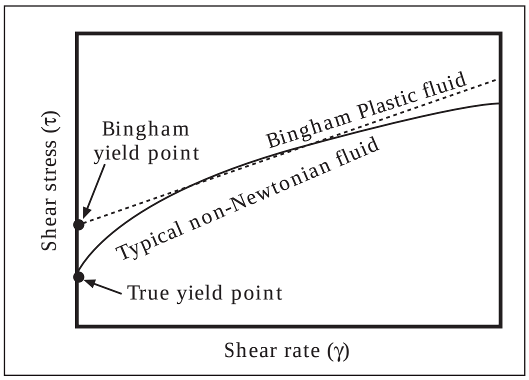

Figure 13: Bingham model and typical non-Newtonian fluid.

If a mud is a true Bingham Plastic fluid then the initial gel strength and yield point will be equal...

$$\Theta = YP + PV \text{ x } \frac{\quad}{300}$$

Most drilling fluids are not true Bingham Plastic fluids. For the typical mud, if a consistency curve for a drilling fluid is made with rotational viscometer data, a non-linear curve is formed that does not pass through the origin, as shown in Figure 11. The development of gel strengths causes the y-intercept to occur at a point above the origin due to the minimum force required to break gels and start flow. *Plug flow*, a condition wherein a gelled fluid flows as a "plug" with a flat viscosity profile, is initiated as this force is increased. As the shear rate increases, there is a transition from plug to viscous flow. In the viscous-flow region, equal increments of shear rate will produce equal increments of shear stress, and the system assumes the flow pattern of a Newtonian fluid.

The two-speed viscometer was designed to measure the Bingham Plastic rheological values for yield point and plastic viscosity. A flow curve for a typical drilling fluid taken on the two-speed Fann VG meter is illustrated in Figure 12. The slope of the straight-line portion of this consistency curve is plastic viscosity. From these two shear stress measurements, the plastic viscosity line can be extrapolated back to the Y-axis to determine the Bingham yield point that is defined as the Y-intercept. For most muds, the true yield stress is actually less than the Bingham yield point, as shown in Figures 11 and 13.

Figure 13 illustrates an actual drilling fluid flow profile with the ideal Bingham Plastic model. It shows not only the comparison of the "true yield point" to the Bingham yield point, but also shows the deviation in viscosity at low and high shear rate as compared to the Bingham Plastic viscosity. The Bingham yield point is higher than the true yield stress. The true yield point can usually be better estimated from the initial gel strength value.

The Bingham Plastic model accurately represents the shear-stress/shear-rate relationship of low-density, flocculated-clay, water-base muds (like Mixed Metal

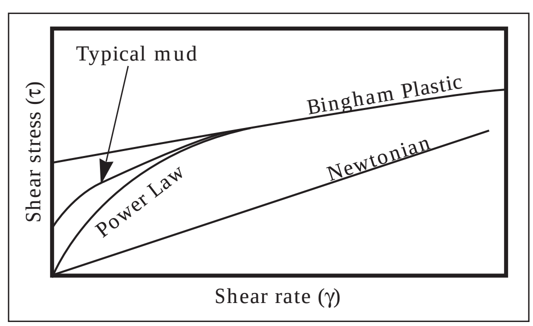

Figure 14: Power Law model comparison.

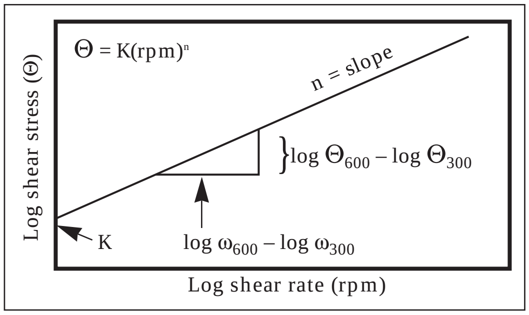

Figure 15: Log plot of Power Law model.

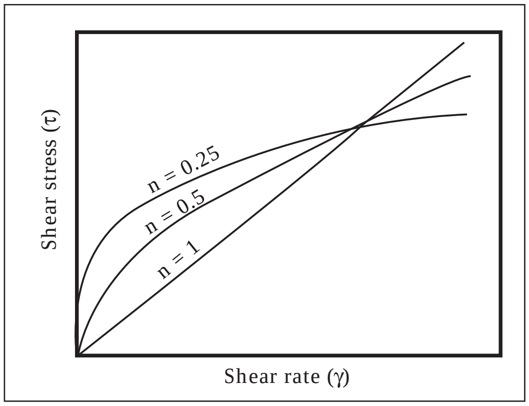

Figure 16: Effect of Power Law "n" on shape of flow profile.

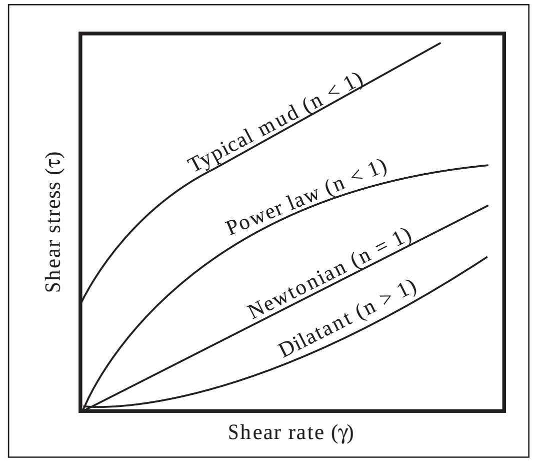

Figure 17: Effect of Power Law "n" on fluid behavior.

As the velocity profile becomes flatter the fluid velocity will be higher over a larger area...

The consistency index "K" is the viscosity at a shear rate of one reciprocal second...

Hydroxide (MMH)) and most other fluids at high shear rates (greater than 511 sec^{-1} or 300 RPM). Generally, the shear-stress/shear-rate values of most non-flocculated fluids diverge from the values predicted by the Bingham Plastic model as the shear rate is decreased. The greatest divergence is at the lowest shear rates. If a mud is a true Bingham Plastic fluid then the initial gel strength and yield point will be equal, as is the case with many flocculated clay water-base fluids.

POWER LAW MODEL

The Power Law model attempts to solve the shortcomings of the Bingham Plastic model at low shear rates. The Power Law model is more complicated than the Bingham Plastic model in that it does not assume a linear relationship between shear stress and shear rate, as shown in Figure 14. However, like Newtonian fluids, the plots of shear stress vs. shear rate for Power Law fluids go through the origin.

This model describes a fluid in which the shear stress increases as a function of the shear rate mathematically raised to some power. Mathematically, the Power Law model is expressed as:

$$\tau = K\gamma^n$$

Where:

τ = Shear stress
K = Consistency index
γ = Shear rate
n = Power Law index

Plotted on a log-log graph, a Power Law fluid shear-stress/shear-rate relationship forms a straight line, as shown on Figure 15. The "slope" of this line is "n." "K' is the intercept of this line.

The Power Law index "n" indicates a fluid's degree of non-Newtonian behavior over a given shear rate range. The lower the "n" value the more shear-thinning a fluid is over that shear rate range and the more curved the shear-stress/shear-rate relationship, as shown in Figure 16.

Depending on the value of "n," three different types of flow profiles and fluid behavior exist:

1. n < 1: The fluid is shear-thinning, non-Newtonian.
2. n = 1: The fluid is Newtonian.

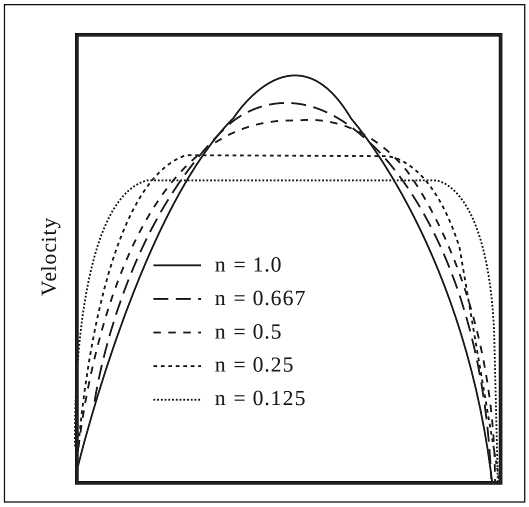

Figure 18: Effect of Power Law "n" on velocity profile.

3. n > 1: The fluid is dilatant, shear-thickening (drilling fluids are not in this category).

A comparison of a typical drilling fluid to a shear-thinning, Newtonian and dilatant fluid is shown in Figure 17.

The effect of "n" on flow profile and the velocity profile is very important for shear-thinning, non-Newtonian fluids. As the velocity profile becomes flatter (see Figure 18) the fluid velocity will be higher over a larger area of the annulus so that hole cleaning will be greatly improved. This is one of the reasons that low "n"-value fluids like FLO-PRO provide such good hole cleaning.

The consistency index "K" is the viscosity at a shear rate of one reciprocal second (sec^{-1}). It is related to a fluid's viscosity at low shear rates. A fluid's hole-cleaning and suspension effectiveness can be improved by increasing the "K" value. The consistency index "K" is usually reported as lb-sec^{-n}/100 ft^2, but may be reported in other units. The terms "K" and "n" only have real relevance when associated with a specific shear rate. However, where a fluid curve is described by a finite number of meas-

In clay-base drilling fluids, both the plastic viscosity and yield point of the mud affect the "K" coefficient.

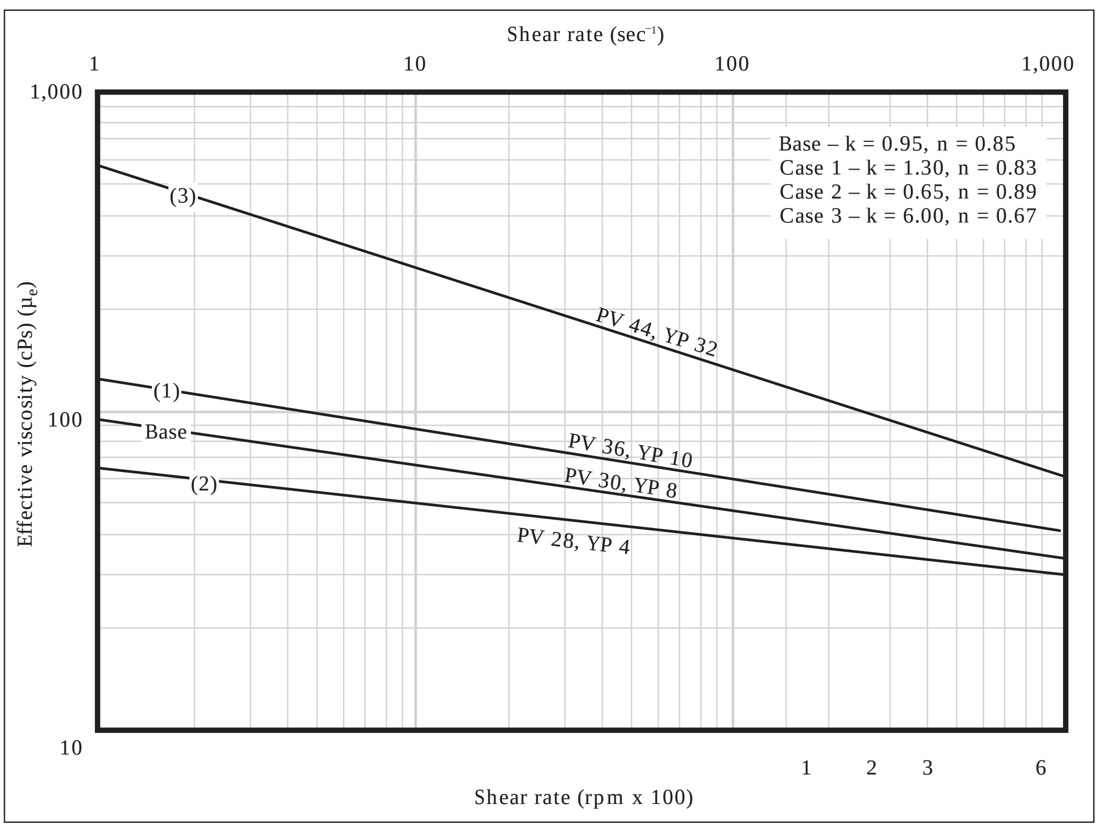

Figure 19: Power Law "K" and "n" relationship to Bingham PV and YP.

urements, the line segments for those particular measurements describe "K" and "n."

"K" and "n" values can be calculated from mud viscometer data. The general equations for "n" and "K" values are:

$$n = \frac{\log\left(\frac{\Theta_2}{\Theta_1}\right)}{\log\left(\frac{\omega_2}{\omega_1}\right)}$$

$$K = \frac{\Theta_1}{\omega_1^{\,n}}$$

Where:

n = Power Law index or exponent
K = Power Law consistency index or fluid index (dyne sec^{-n}/cm^2)
Θ_1 = Mud viscometer reading at lower shear rate
Θ_2 = Mud viscometer reading at higher shear rate
ω_1 = Mud viscometer RPM at lower shear rate
ω_2 = Mud viscometer RPM at higher shear rate

Relating (K, n) to (PV, YP)

In clay-base drilling fluids, both the plastic viscosity and yield point of the mud as shown in Figure 19 affect the "K" coefficient. Three cases are shown: (1) solids build-up, (2) decreasing solids and (3) flocculation due to contamination.

Case 1. Plastic viscosity has increased over that of the "base" due to solids increase with very little change in yield point. The viscosity curve is essentially parallel to the base curve, thus there is little change in "n." The overall viscosity has increased; therefore, "K" is a higher number.

Case 2. Plastic viscosity decreased due to solids removal; yield point also is reduced. As with Case 1, the viscosity curve is essentially parallel and there is little change in "n." "K" decreases due to a decrease in overall viscosity.

Case 3. Yield point and plastic viscosity increased due to contamination and solids increase. The ratio of YP to PV is greatly affected by the resultant flocculation and "n," the slope of the viscosity curve, decreased in value. "K" increases as a function of the changed slope ("n") and the overall increase in viscosity.

...pipe Power Law equations should be used whenever the shear rate is greater than 170 sec^{-1}.

The bulletin, "Recommended Practice on the Rheology and Hydraulics of Oil-Well Drilling Fluids" (API Recommended Practice 13D Third Edition, June 1, 1995), recommends two sets of rheological equations, one set for inside pipe (turbulent conditions) and one set for the annulus (laminar conditions).

The pipe Power Law equation is based on the mud viscometer 300- and 600-RPM (Θ_{300} and Θ_{600}) readings. When the shear rates (511 and 1,022 sec^{-1}) are substituted in the "n" and "K" equations and the equations are simplified, they become:

$$n_p = \frac{\log\left(\frac{\Theta_{600}}{\Theta_{300}}\right)}{\log\left(\frac{1,022}{511}\right)} = 3.32 \log \frac{\Theta_{600}}{\Theta_{300}}$$

$$K_p = \frac{5.11\Theta_{300}}{511^{n_p}} \text{ or } \frac{5.11\Theta_{600}}{1,022^{n_p}}$$

The annular Power Law equations are developed in the same manner, but use the 3- and 100-RPM (Θ_3 and Θ_{100}) values. By substituting the shear rates (5.1 sec^{-1} and 170 sec^{-1}, respectively) into the general equation, they simplify to:

$$n_a = \frac{\log\left(\frac{\Theta_{100}}{\Theta_3}\right)}{\log\left(\frac{170.2}{5.11}\right)} = 0.657 \log \frac{\Theta_{100}}{\Theta_3}$$

$$K_a = \frac{5.11\Theta_{100}}{170.2^{n_a}} \text{ or } \frac{5.11\Theta_3}{5.11^{n_a}}$$

These annular equations require a 100-RPM (Θ_{100}) viscometer reading. This is not available on two-speed VG meters. The API recommends that an approximate value be calculated for the 100-RPM reading when using two-speed VG meter data:

$$\Theta_{100} = \Theta_{300} - \frac{2(\Theta_{600} - \Theta_{300})}{3}$$

General Power Law equation for effective viscosity (cP):

$$\mu_e = 100 \text{ x } K\gamma^{n-1}$$

Effective viscosity, pipe:

$$\mu_{ep} \text{ (cP)} = 100 \text{ x } K_p \left(\frac{1.6 \text{ x } V_p}{D}\right)^{(n_p-1)} \left(\frac{3n_p + 1}{4n_p}\right)^{n_p}$$

Effective viscosity, annulus:

$$\mu_{ea} \text{ (cP)} = 100 \text{ x } K_a \left(\frac{2.4 \text{ x } V_a}{D_2 - D_1}\right)^{(n_a-1)} \left(\frac{2n_a + 1}{3n_a}\right)^{n_a}$$

Where:
D = ID drill pipe or drill collars
D_2 = ID hole or casing
D_1 = OD drill pipe or drill collars

Although the API refers to these equations as being annular and pipe Power Law equations, the shear rate in the annulus may fall in the range best described by the pipe equations. The shear rate in the pipe can fall in the range best described by the annular equations. In either of these cases, the Power Law equations that provide the best fit for the data should be used. Generally, the pipe Power Law equations should be used whenever the shear rate is greater than 170 sec^{-1}.

The modified Power Law...can approximate more closely the true rheological behavior of most drilling fluids.

MODIFIED POWER LAW

As mentioned above, the API has chosen the Power Law model as the standard model. The Power Law model, however, does not fully describe drilling fluids because it does not have a yield stress and underestimates LSRV, as shown previously in Figure 14. The modified Power Law or Herschel-Bulkley model can be used to account for the stress required to initiate fluid movement (yield stress).

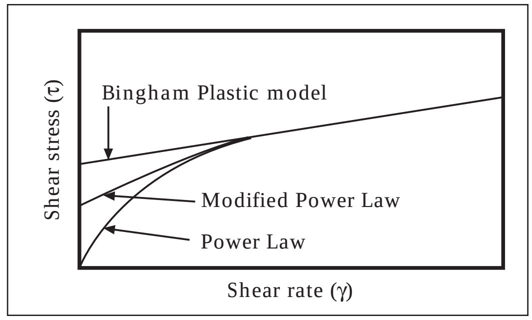

Figure 20: Rheological model comparison.

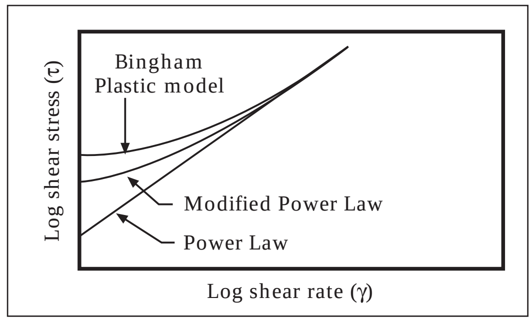

Figure 21: Log plot rheological model comparison.

The diagrams shown in Figures 20 and 21 illustrate the differences between the modified Power Law, the Power Law and Bingham Plastic models. Clearly, the modified Power Law model more closely resembles the flow profile of a typical drilling mud. A Fann VG meter has been used to get the dial readings at 600, 300 and 3 RPM. First, the three models are shown on rectangular coordinate paper (Figure 20), and then on log-log paper (Figure 21).

In each case, the modified Power Law is between the Bingham Plastic model, which is highest, and the Power Law, which is lowest. The modified Power Law is a slightly more complicated model than either the Bingham Plastic model or the Power Law. However, it can approximate more closely the true rheological behavior of most drilling fluids.

Mathematically the Herschel-Bulkley model is:

$$\tau = \tau_0 + K\gamma^n$$

Where:
τ = Shear stress

Stages of Flow

τ_0 = Yield stress or stress to initiate flow
K = Consistency index
γ = Shear rate
n = Power Law index

In practice, the yield stress has been accepted to be the value for the 3-RPM reading or initial gel on the VG meter. Converting the equations to accept VG meter data gives the equations for "n" and "K."

...true yield stress is related to the force needed to "break circulation."

$$n = \frac{\log\left(\frac{\Theta_2 - \Theta_0}{\Theta_1 - \Theta_0}\right)}{\log\left(\frac{\omega_2}{\omega_1}\right)}$$

$$K = \frac{\Theta_1 - \Theta_0}{\omega_1^{\,n}}$$

Where:
n = Power Law index or exponent
K = Power Law consistency index or fluid index (dyne sec^{-n}/cm^2)
Θ_1 = Mud viscometer reading at lower shear rate
Θ_2 = Mud viscometer reading at higher shear rate
Θ_0 = Zero gel or 3-RPM reading
ω_1 = Mud viscometer (RPM) at lower shear rate
ω_2 = Mud viscometer (RPM) at higher shear rate

The drilling fluid is subject to a variety of flow patterns during the process of drilling a well. These flow patterns can be defined as different stages of flow as depicted in Figure 22.

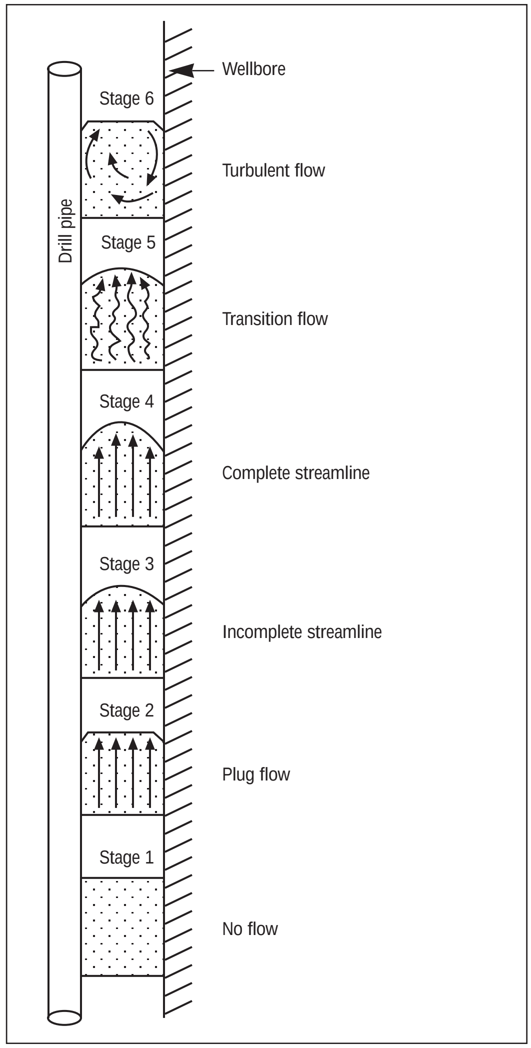

Figure 22: Stages of flow.

Stage 1 — No flow. Most drilling fluids resist flow strongly enough so that pressure must be applied to initiate flow. The maximum value of this force is the true yield stress of the fluid. In a well, the true yield stress is related to the force needed to "break circulation."

Stage 2 — Plug flow. When the true yield stress is exceeded, flow will commence as a solid plug. In plug flow, the velocity will be the same across the pipe diameter or annulus except for the fluid layer against the conduit wall. The flow of toothpaste from a tube is often used as an example of plug flow. The velocity profile of plug flow is flat.

Stage 3 — Plug to laminar flow transition. As the flow rate is increased, shear effects will begin to influence the layers within the fluid and reduce the size of the plug in the center of flow. The velocity will increase from the wellbore to the edge of the central plug. The velocity profile is flat across the plug that has the highest velocity, and tapers or decreases to zero at the conduit wall.

While drilling, the drillstring is almost always in turbulent flow, and the resulting increases in pressure loss can limit the flow rate.

Stage 4 — Laminar flow. As the flow rate is increased, the flow rate and wall effects on the fluid continue to increase. At some point, the central plug will cease to exist. At this point, the velocity will be highest in the center of flow and diminish to zero at the conduit wall. The velocity profile will resemble a parabola. The velocity of the fluid is related to the distance from the annulus or pipe wall. Inside a pipe, the flow can be depicted as a series of telescoping layers with each layer toward the center having a higher velocity. All of the fluid across the pipe or annulus will be moving in the direction of flow, but with different velocities. This stage of orderly flow is called *laminar* for the *layers* or *laminae* described by the differing velocities.

Stage 5 — Laminar to turbulent flow transition. As the flow rate increases, the orderly flow will begin to break down.

Stage 6 — Turbulent flow. As the flow rate continues to increase, the orderly flow will be completely disrupted, and the fluid will swirl and eddy. The bulk movement of fluid will continue to be along the annulus or pipe in one direction, but at any point within the body of fluid, the direction of movement will be unpredictable. Under these conditions the flow is turbulent. After these conditions are reached, any further increases in

Hydraulics Calculations

the flow rate will only increase the turbulence.

These flow stages have several different implications. The pressure required to pump a fluid in turbulent flow is significantly higher than the pressure required to pump the same fluid in laminar flow. Once the flow is turbulent, increases in the flow rate increase the circulating pressure geometrically. In turbulent flow, doubling the flow rate will increase the pressure by a factor of four (2^2). Increasing the flow rate three times will increase the pressure loss eight times (2^3).

While drilling, the drillstring is almost always in turbulent flow, and the resulting increases in pressure loss can limit the flow rate. The pressure losses associated with turbulent flow in the annulus can be critical when the Equivalent Circulating Density (ECD) approaches the fracture gradient. In addition, turbulent flow in the annulus is associated with hole erosion and washouts in many formations. In susceptible zones, the hole will erode to a diameter where the flow reverts to laminar. When drilling these zones, the flow rate and the mud's rheological properties should be controlled to prevent turbulent flow.

It is... imperative to optimize drilling-fluid hydraulics by controlling the rheological properties...

Once the rheological properties for a fluid have been determined and modeled to predict flow behavior, hydraulics calculations are made to determine what effect *this particular fluid* will have on system pressures. The critical pressures are total system pressure (pump pressure), pressure loss across the bit and annular pressure loss (converted to ECD).

Many wells are drilled under pressure limitations imposed by the drilling rig and associated equipment. The pressure ratings of the pump liners and surface equipment and the number of

The major goal of hydraulics optimization is to balance well control, hole cleaning, pump pressure, ECD and pressure drop across the bit.

mud pumps available limit the circulating system to a *maximum allowable circulating pressure*.

As wells are drilled deeper and casing is set, the flow rate will be decreased in the smaller diameter holes. The circulating pressures will increase because of the increased length of the drillstring and annulus as well as the possibly smaller-diameter drillstring. The mud pump liners will be changed to have smaller diameters and higher pressure ratings. This will increase the maximum allowable circulating pressure.

Under any set of hole conditions, a theoretical limit is imposed on the flow rate by the maximum allowable circulating pressure. Circulating pressures, and consequently the flow rate, are directly related to the wellbore and tubular geometry used, including special Bottom-Hole Assembly (BHA) equipment, as well as the fluid's density and rheological properties. It is therefore imperative to optimize drilling-fluid hydraulics by controlling the rheological properties of the drilling fluid to avoid reaching this theoretical limit. This is especially true in extended-reach drilling.

Guidelines for hydraulics optimization

The maximum allowable circulating pressure and circulating rate are limited assets that can be wasted or maximized. Rheology and hydraulics calculations provide the means for adjusting the mud's properties, the flow rate and the bit nozzles to optimize these assets under the constraints imposed by the rig equipment.

The major goal of hydraulics optimization is to balance well control, hole cleaning, pump pressure, ECD and pressure drop across the bit. The fluid's density and rheological properties are the parameters that affect this hydraulic efficiency. If it is assumed that fluid density is maintained at a minimal safe level for well control and wellbore stability, hydraulics optimization is then dependent on the fluid's rheological properties and the flow rate. In many cases, downhole equipment such as downhole motors, thrusters, and measurement-while-drilling and logging-while-drilling instrumentation has a minimum flow rate requirement to properly function. This leaves fluid rheological properties as the only variable in the optimization process.

API hydraulics equations

With one exception, the formulae in this chapter are generally consistent with those in the API bulletin, "Recommended Practice on the Rheology and Hydraulics of Oil-Well Drilling Fluids" (API Recommended Practice 13D Third Edition, June 1, 1995). The API equations determine, use and report velocities in the annulus and pipe in *feet per second*. M-I reports velocities in *feet per minute*. In this chapter, the API formulae have been modified to determine and use velocities in feet per minute. M-I's computer and calculator software (PCMOD3,™ HYPLAN,™ RDH™ and QUIK-CALC3™) use these hydraulics equations. There is an example problem at the end of this chapter to demonstrate the use of these equations.

Fluids in laminar flow "act" differently than fluids in turbulent flow. These differences make it necessary to use different equations to determine the pressure losses in laminar and turbulent flow. Different equations are also required to calculate the pressure losses in the annulus and drillstring because of different geometries.

The first step in hydraulics calculations is to determine which stage of flow is occurring in each geometric interval of the well. The velocity of the fluid in each of these intervals can be determined with the equations below.

A Reynolds number greater than 2,100 indicates turbulent flow.

AVERAGE BULK VELOCITY

The API refers to the velocity of fluid flowing in an annulus or pipe as the bulk velocity. This assumes that all of the fluid is flowing at the same velocity with a flat profile and no instantaneous velocity differences as occurs in turbulent flow. It is basically an average velocity.

Average bulk velocity in pipe (V_p):

$$V_p \text{ (ft/min)} = \frac{24.48 \text{ x } Q \text{ (gpm)}}{D^2 \text{ (in.)}}$$

Average bulk velocity in annulus:

$$V_a \text{ (ft/min)} = \frac{24.48 \text{ x } Q \text{ (gpm)}}{(D_2^2 - D_1^2)\text{(in.)}}$$

Where:
V = Velocity (ft/min)
Q = Flow ratio (gpm)
D = Diameter (in.)

REYNOLDS NUMBER

The Reynolds number (N_{Re}) is a dimensionless number that is used to determine whether a fluid is in laminar or turbulent flow. The assumption is made in "Recommended Practice on the Rheology and Hydraulics of Oil-Well Drilling Fluids" (API Recommended Practice 13D Third Edition, June 1, 1995), that a Reynolds number less than or equal to 2,100 indicates laminar flow. A Reynolds number greater than 2,100 indicates turbulent flow. Earlier API hydraulics bulletins and many hydraulics programs that predate the current API hydraulics bulletin define laminar and turbulent flow differently.

The general formula for Reynolds number is:

$$N_{Re} = \frac{V \, D\rho}{\mu}$$

$$\left(\frac{38{,}727 \text{ x } K_p}{\rho}\right)^{\left(\frac{1}{2-n}\right)} \text{ x } \left(\frac{1.6}{D} \text{ x } \frac{3n+1}{4n}\right)^{\left(\frac{n}{2-n}\right)}$$

Where:
V = Velocity
D = Diameter
ρ = Density
μ = Viscosity

$$\left(\frac{25{,}818 \text{ x } K_a}{\rho}\right)^{\left(\frac{1}{2-n}\right)} \text{ x } \left(\frac{2.4}{(D_2 - D_1)} \text{ x } \frac{2n+1}{3n}\right)^{\left(\frac{n}{2-n}\right)}$$

The Reynolds number for inside the pipe is:

$$N_{Re_p} = \frac{15.467 \text{ x } V_p \, D\rho}{\mu_{ep}}$$

The Reynolds number for the annulus is:

$$N_{Re_a} = \frac{15.467 V_a \, (D_2 - D_1)\rho}{\mu_{ea}}$$

Pressure-Loss Calculations

The sum of interval pressure drops is equal to the total system pressure loss…

Where:
D = ID drill pipe or drill collars
D_2 = ID hole or casing
D_1 = OD drill pipe or drill collars
μ_{ep} = Effective viscosity (cP) pipe
μ_{ea} = Effective viscosity (cP) annulus

CRITICAL VELOCITY

The critical velocity is used to describe the velocity where the transition occurs from laminar to turbulent flow. Flow in the drill pipe is generally turbulent. The equations for critical velocity in the pipe and in the annulus are listed below.

0	Standpipe/top drive/ kelly
1	Inside drill pipe
2	Inside drill collars
3	Inside downhole tools
4	Bit nozzle
5	Annulus open hole/drillstring
6	Annulus liner/drillstring
7	Annulus casing or riser/drillstring

Critical flow rate can be calculated from these equations.

Critical pipe velocity (V_{cp}):

V_{cp} (ft/min) =

Critical pipe flow rate:

$$Q_{cp}\ (\text{gpm}) = \frac{V_{cp}\ D^2}{24.51}$$

Critical annular velocity (V_{ca}):

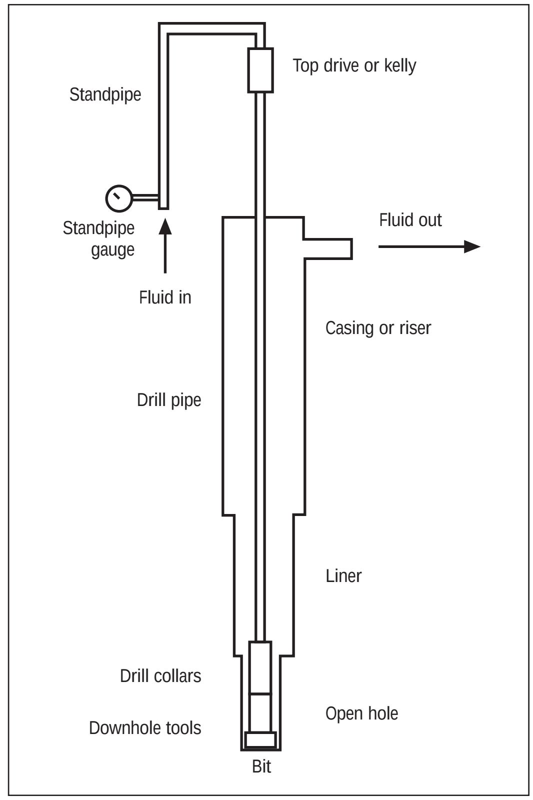

Figure 23: Schematic of a circulating system.

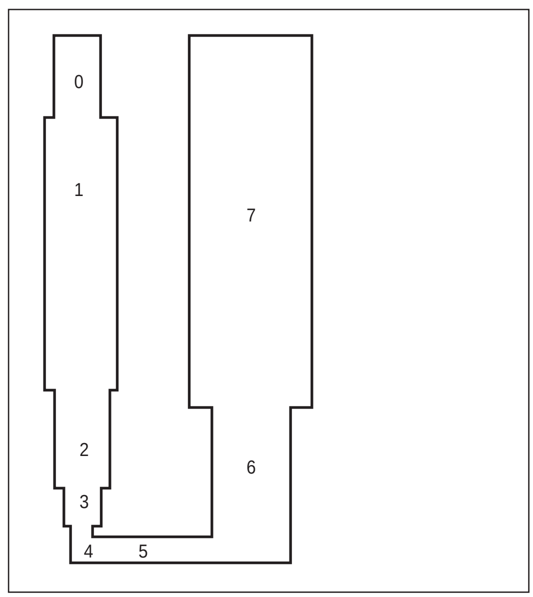

Figure 24: Simplified circulation system.

Surface pressure losses include losses between the standpipe pressure gauge and the drill pipe.

V_{ca} (ft/min) =

Critical annular flow rate:

$$Q_{ca}\ (\text{gpm}) = \frac{V_{ca}\ (D_2^2 - D_1^2)}{24.51}$$

CIRCULATING SYSTEM

The circulating system of a drilling well is made up of a number of components or intervals, each with a specific pressure drop. The sum of these interval pressure drops is equal to the total system pressure loss or the measured standpipe pressure. Figure 23 is a schematic of the circulating system. This figure can be simplified to Figure 24 that illustrates the relative flow area of each interval.

There can be any number of subintervals within the categories listed in the table below.

The total pressure loss for this system can described mathematically as:

$$P_{Total} = P_{Surf\ Equip} + P_{Drillstring} + P_{Bit} + P_{Annulus}$$

Each of these pressure groups is broken down into their component parts and appropriate calculations.

Case	Standpipe	Hose	Swivel, etc.	Kelly	Eq. Length 3.826-in. ID
1	40 ft long, 3-in. ID	45 ft long, 2-in. ID	20 ft long, 2-in. ID	40 ft long, 2.25-in. ID	2,600 ft
2	40 ft long, 3.5-in. ID	55 ft long, 2.5-in. ID	25 ft long, 2.5-in. ID	40 ft long, 3.25-in. ID	946 ft
3	45 ft long, 4-in. ID	55 ft long, 3-in. ID	25 ft long, 2.5-in. ID	40 ft long, 3.25-in. ID	610 ft
4	45 ft long, 4-in. ID	55 ft long, 3-in. ID	30 ft long, 3-in. ID	40 ft long, 4-in. ID	424 ft

SURFACE EQUIPMENT PRESSURE LOSSES

Surface pressure losses include losses between the standpipe pressure gauge and the drill pipe. This includes the standpipe, kelly hose, swivel, and kelly or top drive. To calculate the pressure loss in the surface connections, use the API pipe formula for pressure loss in the drill pipe. Common surface equipment geometries are listed in the table below.

TOP DRIVE SURFACE CONNECTIONS

There is no current standard case for top drive units. The surface connections of most of these units consist of an 86-ft standpipe and 86 ft of hose with either a 3.0- or 3.8-in. ID. In addition, there is an “S” pipe that is different on almost every rig.

DRILLSTRING PRESSURE LOSSES

The pressure loss in the drillstring is equal to the sum of the pressure losses in all of the drillstring intervals, including drill pipe, drill collars, mud motors, MWD/LWD/PWD or any other downhole tools.

FRICTION FACTOR

Before calculating the pressure loss, the Fanning friction factor (f_p) is calculated next with different equations being used for laminar and turbulent flow. This friction factor is an indication of the resistance to fluid flow at the pipe wall. The friction factor in these calculations assumes a similar roughness for all tubulars.

If the Reynolds number is less than or equal to 2,100:

$$f_p = \frac{16}{N_{Re_p}}$$

If the Reynolds number is greater than 2,100:

$$f_p = \frac{\left(\frac{\log n + 3.93}{50}\right)}{N_{Re_p}^{\left[\frac{1.75 - \log n}{7}\right]}}$$

PIPE INTERVAL PRESSURE LOSS

Drillstring (including drill collars) intervals are determined by the ID of the pipe. The length of an interval is the length of pipe that has the same internal diameter. The following equation is used to calculate the pressure loss for each drillstring interval.

$$P_p \text{ (psi)} = \frac{f_p V_p^2 \rho}{92{,}916D} \times L$$

Where:
V_p = Velocity (ft/min)
D = ID pipe (in.)
ρ = Density (lb/gal)
L = Length (ft)

PRESSURE LOSSES THROUGH MOTORS AND TOOLS

If the drillstring contains a downhole motor; an MWD, LWD or PWD tool; a turbine or a thruster, their pressure losses must be included in the system pressure losses when calculating the system's hydraulics. These pressure losses can significantly change the pressure available at the bit, as well as bypass flow around the bit.

The pressure loss through MWD and LWD tools varies widely with mud weight, mud properties, flow rate, tool design, tool size and the data transmission rate. Some manufacturers publish pressure losses for their tools but these pressure losses can be conservative, because they are usually determined with water.

The pressure loss through Positive Displacement Motors (PDM) (Moyno), thrusters and turbines is higher than the losses across MWD and LWD tools and subject to even more variables. With a PDM or thruster, increased weight on the bit increases the torque and pressure loss across the motor. The pressure drop through a turbine is proportional to the flow rate, the mud weight and the number of drive stages in the turbine. The pressure loss across motors and turbines cannot be accurately determined by formula, but, again, this pressure loss data is available from the suppliers.

PRESSURE LOSS AT THE BIT (FRICTION PRESSURE LOSS IN THE NOZZLES)

The pressure loss across the bit is calculated with the following equation:

$$P_{bit} = \frac{156 \rho Q^2}{(D_{n1}^2 + D_{n2}^2 + D_{n3}^2 + \cdots)^2}$$

In the case of coring or diamond bits, the Total Flow Area (TFA) and appropriate conversion factors are substituted into the equation to give:

$$P_{bit} \text{ (psi)} = \frac{\rho Q^2}{10{,}858(\text{TFA})^2}$$

Where:
ρ = Density (lb/gal)
Q = Flow ratio (gpm)
TFA = Total Flow Area (in.^{2})

The pressure loss for each interval must be calculated separately and added together for the total annular pressure loss.

Low hydraulic horsepower at the bit can result in low penetration rates and poor bit performance.

TOTAL ANNULUS PRESSURE LOSSES

The total annular pressure loss is the sum of all of the annular interval pressure losses. Annular intervals are divided by each change in hydraulic diameter. A change in drillstring outside diameter and/or a change in casing, liner or open hole inside diameter would result in a hydraulic diameter change. As with the drillstring pressure loss equations, the friction factor must first be determined before calculating the pressure loss for each annular section.

FRICTION FACTOR ANNULUS

If the Reynolds number is less than or equal to 2,100:

$$f_a = \frac{24}{N_{Re_a}}$$

If the Reynolds number is greater than 2,100:

$$f_a = \frac{\left(\frac{\log n + 3.93}{50}\right)}{N_{Re_a}^{\left[\frac{1.75 - \log n}{7}\right]}}$$

ANNULUS INTERVAL PRESSURE LOSS

The pressure loss for each interval must be calculated separately and added together for the total annular pressure loss. This equation is used to calculate the individual interval pressure losses.

$$P_a \text{ (psi)} = \frac{f_a V_a^2 \rho}{92{,}916\ (D_2 - D_1)} \times L_m$$

Where:
D_2 = ID hole or casing (in.)
D_1 = OD drill pipe or drill collars (in.)

EQUIVALENT CIRCULATING DENSITY

The pressure on a formation while circulating is equal to the total *annular* circulating pressure losses from the point of interest to the bell nipple, plus the hydrostatic pressure of the mud. This force is expressed as the density of mud that would exert a hydrostatic pressure equivalent to this pressure. This equivalent mud weight is called the Equivalent Circulating Density (ECD).

$$\text{ECD (lb/gal)} = \rho \text{ (lb/gal)} + \frac{P_a \text{ (psi)}}{0.052 \times \text{TVD (ft)}}$$

Excessive ECD may cause losses by exceeding fracture gradient on a well. It is important to optimize rheological properties to avoid excessive ECD.

BIT HYDRAULICS CALCULATIONS

In addition to bit pressure loss, several other hydraulics calculations are used to optimize the drilling performance. These include hydraulic horsepower, impact force and jet velocity calculations.

HYDRAULIC HORSEPOWER

The recommended hydraulic horsepower (hhp) range for most rock bits is 2.5 to 5.0 Horsepower per Square Inch (HSI) of bit area. Low hydraulic horsepower at the bit can result in low penetration rates and poor bit performance.

Generally, the goal is to use 50 to 65% of the maximum allowable circulating pressure to the bit.

HYDRAULIC HORSEPOWER AT BIT

The bit hydraulic horsepower cannot exceed the total system hydraulic horsepower.

$$hhp_b = \frac{QP_{Bit}}{1,740}$$

Where:

Q = Flow rate (gpm)
P_{Bit} = Bit pressure loss (psi)

HYDRAULIC HORSEPOWER PER SQUARE INCH OF BIT AREA

$$HSI = \frac{1.27 \text{ x } hhp_b}{\text{Bit Size}^2}$$

Where:

Bit Size = Bit diameter (in.)

SYSTEM HYDRAULIC HORSEPOWER

$$hhp_{System} = \frac{P_{Total}Q}{1,714}$$

Where:

P_{Total} = Total system pressure losses (psi)
Q = Flow rate (gpm)

NOZZLE VELOCITY (FT/SEC):

Although more than one nozzle size may be run in a bit, the nozzle velocity will be the same for all of the nozzles. Nozzle velocities of 250 to 450 ft/sec are recommended for most bits. Nozzle velocities in excess of 450 ft/sec may erode the cutting structure of the bit.

$$V_n \text{ (ft/sec)} = \frac{417.2 \text{ x } Q}{D^2_{n1} + D^2_{n2} + D^2_{n3} + \cdots}$$

Where:

Q = Flow rate (gpm)
D_n = Nozzle diameter (32nds in.)

PERCENT PRESSURE DROP AT THE BIT

It is generally desired to have 50 to 65% of surface pressure used across the bit.

$$\%\Delta P_{Bit} = \frac{P_{Bit}}{P_{Total}} \text{ x } 100$$

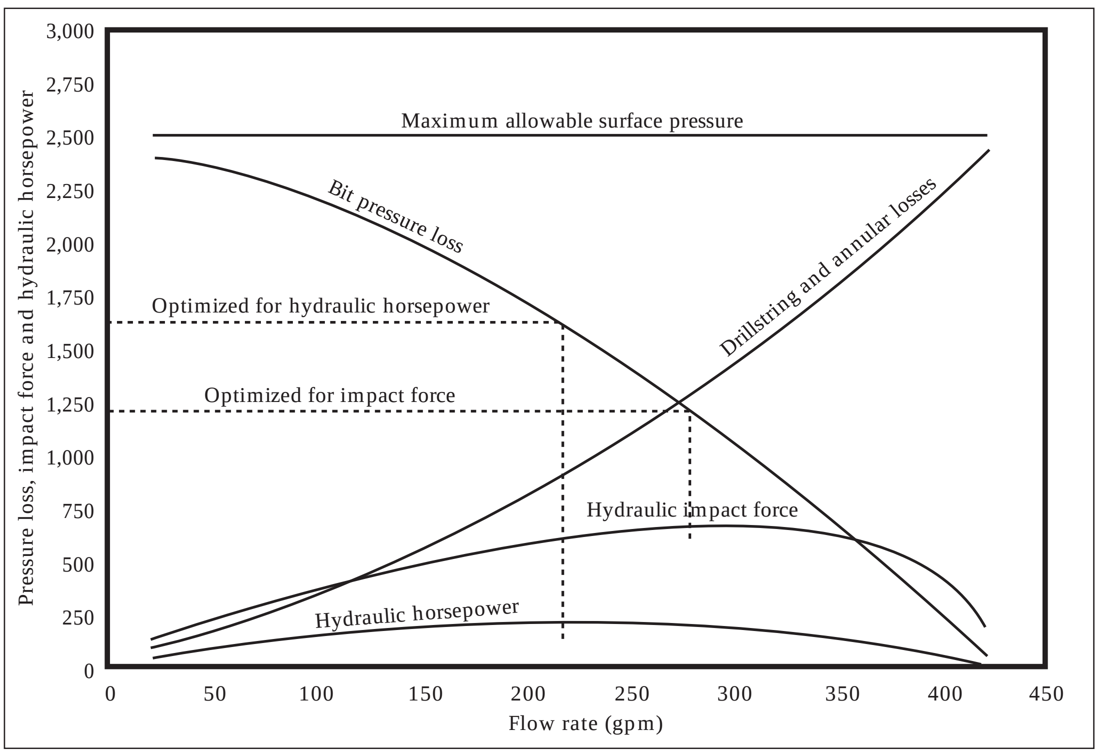

Figure 25: Effect of flow rate on pressure loss and bit hydraulics.

Care should be taken to not "optimize the nozzles down" to a size that will not permit the use of lost-circulation material.

HYDRAULIC IMPACT FORCE (IF)

$$\text{IF (lb)} = \frac{V_n Q \rho}{1{,}930}$$

Where:
V_n = Nozzle velocity (ft/sec)
Q = Flow rate (gpm)
ρ = Density (lb/gal)

IMPACT FORCE/IN.²

$$\text{IF (psi)} = \frac{1.27 \times \text{IF (lb)}}{\text{Bit Size}^2}$$

BIT HYDRAULICS OPTIMIZATION

In many areas of the world, rock bit hydraulics can be optimized to improve rate of penetration. There are a lot of factors that effect ROP including bit size, bit type, bit features, formation type and strength, and bit hydraulics. In hard rock areas, bit/formation interaction has a greater impact on ROP than bit hydraulics.

Bit hydraulics may be optimized on hydraulic impact, hydraulic horsepower, hydraulic horsepower per square inch of hole beneath the bit or nozzle velocity. Generally, the goal is to use 50 to 65% of the maximum allowable circulating pressure to the bit. Systems are considered optimized for impact force when the pressure loss at the bit is equal to 50% of the circulating pressure. When the pressure loss at the bit is equal to approximately 65% of the circulating pressure, the system is considered optimized for hydraulic horsepower. Figure 24 compares optimization by hydraulic horsepower and impact force. There is a tradeoff in optimizing with respect to one aspect vs. the other.

In the soft formations typical of offshore wells, the only limit on the penetration rate may be the connection time. The jetting action is not as critical. Under these conditions, high flow rates and turbulence beneath the bit to reduce balling of the bit and BHA (bit, collars, etc.) and cleaning the wellbore are the primary concerns. For these conditions, the bit can be optimized for impact force and flow rate. When optimized for impact force, approximately 50% of the maximum allowable circulating pressure will be lost at the bit.

When drilling hard shales at greater depths, chip hold-down and fines beneath the bit are the limiting factors for penetration rates. Under these conditions, relatively small increases in the penetration rate can lower well costs significantly. Jetting action is critical and drilling rates are improved when the bit is optimized for hydraulic horsepower with 65% of the maximum allowable circulating pressure loss at the bit.

LIMITATIONS OF OPTIMIZING FOR PERCENT PRESSURE LOSS AT THE BIT

While there is a need to achieve optimum drilling performance, there are upper limits to acceptable hydraulics. Excessive nozzle velocities may damage the cutting structures of bits and shorten bit life. Nozzle shear rates in excess of 100,000 sec^{-1} have been associated with hole washout.

In addition to upper limits there are also lower acceptable limits. Selecting the bit nozzles for 50 or 65% of the circulating pressure loss at the bit without considering the circulating system as a whole can create problems. As a well is drilled deeper, the pressure losses in the drillstring and annulus increase if the flow rate is maintained. As this occurs, a smaller percentage of the maximum allowable circulating pressure will be available for use at the bit. It will become impossible to maintain the flow rate and the bit pressure loss at 65% of the maximum allowable circulating pressure.

If the circulating rate is decreased, the pressure losses in the drillstring and annulus will decrease. The nozzles can

Using extended nozzles...can increase the jet intensity on the formation.

Drag reduction is the tendency of a fluid to delay the onset of turbulent flow.

then be sized to maintain the bit pressure loss at 65% of the maximum allowable surface pressure. Although the percent pressure loss at the bit can be maintained by decreasing the flow rate, the horsepower at the bit and the circulating rate will decrease with depth and drilling performance can suffer.

The flow rate must be maintained at adequate levels for hole cleaning, even though the bit pressure loss becomes less than desired. Care should also be taken to not "optimize the nozzles down" to a size that will not permit the use of lost-circulation material. This problem is sometimes avoided by blanking one of the nozzles and sizing the remaining nozzles for the total flow area. With one of the nozzles blanked, the bit can be optimized with larger-size nozzles.

Optimum flow rates change with the type of formation being drilled, the hole size, hole angle, and whether the bit is optimized for impact force or hydraulics. Use a hole cleaning computer model such as M-I's VIRTUAL HYDRAULICS or RDH, or charts for deviated wells to determine an appropriate flow rate.

DOWNHOLE TOOLS, BYPASSED FLOW

Downhole tools can also affect the ability to optimize bit hydraulics. Some (but not all) MWD and LWD tools bypass up to 5% of the flow. This bypassed fluid does not reach the bit and must be subtracted from the flow to the bit when optimizing bit hydraulics. The full flow rate (not reduced by the bypassed volume) is used for calculating annular hydraulics and pressure losses in the drill pipe and drill collars. The MWD and LWD manufacturer's representative should be contacted to determine if a specific tool bypasses flow, how much it bypasses and the estimated pressure loss through the tool.

The bearing sections of both PDMs and turbines require a portion of the flow for cooling. This fluid is directed to

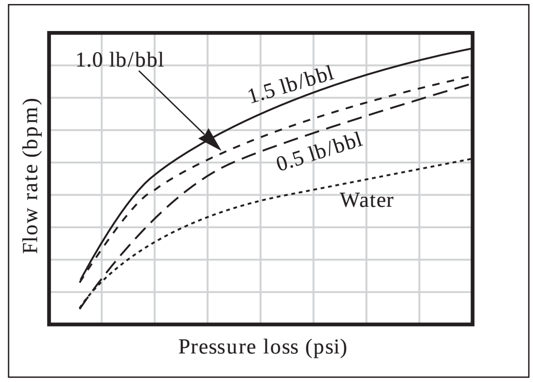

Figure 26: Drag reduction with FLO-VIS.

the annulus and bypasses the bit. The bypassed volume depends on a number of different variables, but usually ranges from 2 to 10% of the total flow rate. This bypassed fluid must be subtracted from the flow to the bit when optimizing bit hydraulics. The full flow rate (not reduced by the bypassed volume) is used for calculating annular hydraulics and pressure losses in the drill pipe and drill collars. The PDM or turbine manufacturer's representative should be contacted to determine the specific volume that is bypassed and the estimated pressure loss through the motor.

BOTTOM-HOLE CLEANING

In addition to providing energy at the face of the bit, the drilling fluid should also effectively remove the cuttings from beneath the bit to maximize ROP by avoiding "redrilling." Cleaning can be improved by several means, none of which affect the way pressure losses and energy at the bit are calculated. Increasing the intensity of the jet action from the nozzles on the face of the formation beneath the bit by extending nozzles will improve bottom-hole cleaning. Blanking a nozzle will permit better crossflow beneath the bit. A center jet improves cone cleaning to avoid bit balling.

The jet action is greatest as the mud exits the nozzles and diminishes with distance from the nozzles through interaction with the surrounding mud. Using

***...the maximum reduction in hydrostatic pressure is called the* swab pressure.**

extended nozzles that place the exits closer to the bottom of the hole can increase the jet intensity on the formation. Jet intensity can also be maintained by using asymmetric nozzle sizes (increasing the size of one nozzle while reducing the size of the others). This will maintain the desired total flow area and pressure loss at the bit while giving greater jetting intensity from at least one of the nozzles. The proximity of the nozzle to the bottom of the hole is often described with the H/D ratio, where H is the distance of the nozzle from the bottom of the hole and D is the nozzle diameter. This H/D ratio will indicate the intensity of the jetting action. The full intensity of the jet is maintained in the center of flow at H/D ratios of 8 or less and falls off rapidly at higher ratios. Increasing the nozzle diameter will lower the H/D ratio, but it also lowers the nozzle velocity and pressure drop through the bit.

PDC bit nozzle placement is designed to effectively remove cuttings from beneath the bit. The nozzle layout is also important to effectively cool the cutter faces.

DRAG REDUCTION

Drag reduction is the tendency of a fluid to delay the onset of turbulent flow. The result of this delay is decreased pressure loss. Figure 26 shows how increasing the concentration of FLO-VIS reduces circulating pressure. Several long-chain polymers (POLY-PLUS, FLO-VIS, DUO-VIS, HEC) promote drag reduction. A drop in pump pressure can be observed when these materials are added to the system. Drag reduction is a very complex behavior. It is not completely understood, and there is no model to predict or compensate for it. Drag reduction can be very time- and solids-dependent. The pump pressure increases gradually on subsequent circulations as the polymers are broken down or envelop solids.

VIRTUAL HYDRAULICS

The VIRTUAL HYDRAULICS computer program from M-I uses the vast number of variables that affect drilling fluid hydraulics to produce a clearer picture of the viscosities and pressure losses that are occurring under downhole conditions. It incorporates not only field viscosity data but also high-temperature and high-pressure viscosity to better predict the behavior of invert systems under non-standard conditions. VIRTUAL HYDRAULICS is also capable of accounting for subtle changes in pipe and wellbore geometry that heretofore had been averaged across an interval. The information produced by this program is extremely accurate and can be validated with downhole pressure measurement devices.

SWAB AND SURGE PRESSURES

When the drillstring is picked up to make a connection or trip out of the well, the mud in the annulus must fall to replace the volume of pipe pulled from the well. The hydrostatic pressure is momentarily reduced while the mud is falling in the annulus. This action is referred to as *swabbing* and the maximum reduction in hydrostatic pressure is called the *swab pressure*. Swab pressures are related to the frictional pressures of the mud flowing in the annulus to displace the drillstring, not the reduction in hydrostatic pressure due to the lower mud level in the annulus. If the swab pressure is greater than the hydrostatic pressure safety margin (overbalance pressure), formation fluids will be swabbed into the wellbore.

When the drillstring or casing is lowered or run into the well, mud is dis-

$$AV_{\text{Swab-Surge}}\ (\text{ft/min}) = \frac{V_{\text{MaxDrillstring}}\ (\text{ft/min}) \times \text{drillstring displacement (bbl/ft)}}{\text{annular capacity (bbl/ft)}}$$

The object of calculating swab and surge pressures is to determine safe pulling and running speeds and minimized trip times.

placed from the well. The frictional pressure losses from the flow of mud in the annulus as it is displaced by the pipe causes pressures in excess of the hydrostatic pressure of the column of mud in the wellbore. The elevated pressures caused by running the drillstring into the well are called *surge pressures*. If the surge pressure plus the hydrostatic pressure exceed the fracture gradient, the formation will be fractured with resultant loss of circulation.

Swab and surge pressures are related to the mud's rheological properties; the mud's gel strengths; the speed at which the pipe is pulled from, or run into, the well; the annular dimensions; and the length of drillstring in the well. The rheological properties affect swab and surge pressures in the same manner as they affect annular pressure losses. Increases in either the plastic viscosity or the yield point will increase the swab and surge pressures.

The velocity of the mud being displaced is different for each annular space and is directly related to the velocity of drillstring movement, whether tripping in or out of the well. Since the maximum (not average) swab and surge pressures must be less than the pressures needed to swab the well in or break the formation down, swab and surge pressures must be calculated

Summary

for the maximum drillstring velocity when tripping. This is generally calculated as one-and-one-half times the average drillstring velocity.

$$V_{MaxDrillstring} \text{ (ft/min per stand)} = 1.5 \text{ x } \frac{\text{stand length (ft)}}{\text{seconds per stand}} \text{ x 60 sec/min}$$

The annular velocity is calculated for each interval based on the drillstring displacement for that interval. The drillstring displacement is adjusted accordingly for free flow from or into the drillstring (no float, plugged bit, etc.) or for plugged drillstring where

Controlling the mud's rheological properties can optimize the performance while operating within the mechanical limits imposed by the rig.

Hydraulics Example Problem

the displacement plus capacity of the drillstring is used.

The annular velocity must be calculated for each annular space. These annular velocities should be substituted into the API equations for the annular pressure losses for each interval. The swab and surge pressures are then calculated in the same manner as the ECD.

The object of calculating swab and surge pressures is to determine safe pulling and running speeds and minimized trip times. This is done by changing the maximum or minimum time per stand and recalculating the swab and surge pressures until times per stand are found where the swab and surge pressures plus the hydrostatic pressure is approximately equal to the formation pressure and fracture pressure. This time per stand is only relevant for the present length of drillstring in the well.

As pipe is removed from the hole, the drillstring length decreases and the bottom hole assembly will be pulled into large diameter casing. This will make it possible to pull each stand faster without risk of swabbing in the well. When tripping in to the well, the length of drillstring will be increasing and the annular spaces will decrease as the BHA is run into smaller diameters. This will require that the running time per stand be increased to avoid fracturing the formation. The swab and surge pressures should be calculated at either 500- or 1,000-ft intervals.

Drilling performance is directly related to the mechanical limitations imposed by the drilling rig. Controlling the mud's rheological properties can optimize the performance while operating within the mechanical limits imposed by the rig. The mud's rheological properties should be controlled to deliver as much of the rig's maximum allowable circulating pressure as possible to the bit by reducing the parasitic pressure losses in the surface connections, drillstring and annulus without compromising hole cleaning or solids suspension.

PROBLEM:

MD/TVD: 12,031 ft
Surface casing: 2,135 ft of 13⅜-in. 61 lb/ft
Intermediate casing: 10,786 ft of 9⅝-in. 40 lb/ft
Bit: 8⅝ in.
Nozzles (32nds in.): 11, 11, 11
Surface connections: Case 3
Drill pipe: 4½ in., 16.6 lb/ft
Drill collars: 390 ft of 7 in. x 2¼ in.
Surface pressure: 3,000 psi

Mud weight: 12.8 lb/gal
Funnel viscosity: 42 sec/qt
Plastic viscosity: 19 cP
Yield point: 15 lb/100 ft^2
Initial gel: 8 lb/100 ft^2
Flow rate: 335 gpm

Calculations: Hydraulics calculations use a series of formulae that must be used in sequence. Since the mud velocity and viscosity change every time the internal diameter of the drillstring and annulus diameter changes, hydraulics must be calculated for each length of drillstring and annulus that has a different diameter. Although the same values are calculated for the annular and drillstring intervals, different formulae are used to compensate for the differences in flow in the drillstring and annulus. The sequence of calculations for each interval is as follows:

- "n" and "K" values.
- Bulk velocity.
- Effective viscosity.
- Reynolds number.
- Friction factor (one of two different formulae will be used depending on the value of the Reynolds number).
- Interval-pressure loss. The annular interval-pressure losses are totaled and used to calculate the equivalent circulating density. Pipe (drillstring) equations and the equivalent hydraulic pipe length of the surface connections are used to calculate the pressure loss of the surface connections.

The sum of the pressure losses in the surface connections, drillstring, downhole tools, bit and annulus should approximate the surface pressure.

$$\Theta_{300} = PV + YP = 19 + 15 = 34$$

$$\Theta_{600} = \Theta_{300} + PV = 34 + 19 = 53$$

$$\Theta_{100} = \Theta_{300} - \frac{2PV}{3} = 34 - \frac{2 \times 19}{3} = 21$$

The API annular hydraulics formulae use the 100-RPM VG meter reading. If six-speed mud viscometer data is available, use the 100-RPM reading rather than the calculated value.

Intermediate casing ID: 8.835 in.
Open hole interval:
MD – casing length
12,031 ft – 10,786 = 1,245 ft
Surface connection Case 3, equivalent length (ft): 610 ft of 3.826-in. ID pipe
Drill pipe ID: 3.826 in.

Drill pipe length: MD – collar length
12,031 ft – 390 ft = 11,641 ft of
4½ in. x 3.826 in.

$$100 \times 3.21\left(\frac{1.6 \times 560.23}{3.826}\right)^{(0.64-1)} \times \left(\frac{3 \times 0.64 + 1}{4 \times 0.64}\right)^{0.64}$$

ANNULAR GEOMETRY:

Interval #1:
Length: 10,786 ft; casing ID: 8.835 in.; drill pipe: 4½ in.
Start from the surface, with the drill pipe in casing as the first interval. The first interval length will be the shorter of the two, the casing length, 10,786 ft. The drill pipe is 855 ft longer than the casing (11,641 – 10,786). This 855-ft portion of the drill pipe will be used to calculate the length of the next interval.

$$100 \times 3.21\left(\frac{1.6 \times 560.23}{3.826}\right)^{(0.64-1)} \times \left(\frac{3 \times 0.64 + 1}{4 \times 0.64}\right)^{0.64}$$

Interval #2:
Length: 855 ft; open hole ID: 8⅝ in.; drill pipe: 4½ in.
Determine the length of the next geometry interval using the 855 ft of drillpipe that extends below the casing and the next hole interval, 1,245 ft of open hole. The shorter of the two, the drill pipe, determines the length of the second interval, 855 ft. The open hole is 390 ft longer (1,245 – 855) than the drill pipe. This length will be used to determine the length of the next geometry interval.

Interval #3:
Length: 390 ft; open hole ID: 8⅝ in.; drill collars: 7 in.
The next drillstring interval consists of 390 ft of drill collars. This length is equal to the length of the remainder of the open-hole interval from Interval #2; therefore the length of the final geometry interval is 390 ft.

Pipe "n" and "K" values:

$$n_p = 3.32 \log \frac{\Theta_{600}}{\Theta_{300}}$$

$$= 3.32 \log \left(\frac{53}{34}\right) = 0.64$$

$$K_p = \frac{5.11\Theta_{600}}{1{,}022^{n_p}}$$

$$= \frac{5.11 \times 53}{1{,}022^{0.64}} = 3.21$$

SURFACE CONNECTION:

Velocity:

$$V_p\ (\text{ft/min}) = \frac{24.48 \text{ x } Q\ (\text{gpm})}{D^2\ (\text{in.})}$$

$$= \frac{24.48 \text{ x } 335}{3.826^2} = 560.23 \text{ ft/min}$$

$$100 \text{ x } 3.21 \left(\frac{1.6 \text{ x } 1{,}619.91}{2.25}\right)^{(0.64-1)} \text{ x } \left(\frac{3 \text{ x } 0.64 + 1}{4 \text{ x } 0.64}\right)^{0.64}$$

Effective viscosity:

$$\mu_{e_p}\ (\text{cP}) =$$

$$100 \text{ x } K_p \left(\frac{1.6 \text{ x } V_p}{D}\right)^{(n_p-1)} \left(\frac{3n_p + 1}{4n_p}\right)^{n_p}$$

$$=$$

$$= 48.96 \text{ cP}$$

Reynolds number:

$$N_{Re_p} = \frac{15.467 \text{ x } V_p D \rho}{\mu_{e_p}}$$

$$= \frac{15.467 \text{ x } 560.23 \text{ x } 3.826 \text{ x } 12.8}{48.96}$$

$$= 8{,}667$$

Friction factor:

$$f_p = \frac{\left(\frac{\log n + 3.93}{50}\right)}{N_{Re_p}^{\left[\frac{1.75 - \log n}{7}\right]}}$$

$$= \frac{\left(\frac{\log (0.64) + 3.93}{50}\right)}{8{,}667^{\left[\frac{1.75 - \log (0.64)}{7}\right]}}$$

$$= 0.006025$$

Pressure loss:

$$P_p\ (\text{psi}) = \frac{f_p V_p^2 \rho}{92{,}916\ D} \text{ x } L_m$$

$$= \frac{0.006025 \text{ x } 560.23^2 \text{ x } 12.8}{92{,}916 \text{ x } 3.826} \text{ x } 610$$

$$= 41.53 \text{ psi}$$

DRILLSTRING INTERVAL #1 (DRILL PIPE):

Velocity:

$$V_p\ (\text{ft/min}) = \frac{24.48 \text{ x } Q\ (\text{gpm})}{D^2\ (\text{in.})}$$

$$= \frac{24.48 \text{ x } 335}{3.826^2} = 560.23 \text{ ft/min}$$

Effective viscosity:

$$\mu_{e_p}\ (\text{cP}) =$$

$$100 \text{ x } K_p \left(\frac{1.6 \text{ x } V_p}{D}\right)^{(n_p-1)} \left(\frac{3n_p + 1}{4n_p}\right)^{n_p}$$

$$=$$

$$= 48.96 \text{ cP}$$

Reynolds number:

$$N_{Re_p} = \frac{15.467 \text{ x } V_p D \rho}{\mu_{e_p}}$$

$$= \frac{15.467 \text{ x } 560.23 \text{ x } 3.826 \text{ x } 12.8}{48.96}$$

$$= 8{,}667$$

Friction factor:

Since the Reynolds number is greater than 2,100, use the turbulent equation.

$$f_p = \frac{\left(\frac{\log n + 3.93}{50}\right)}{N_{Re_p}^{\left[\frac{1.75 - \log n}{7}\right]}}$$

$$100 \text{ x } K_a \left(\frac{2.4 \text{ x } 141.66}{8.835 - 4.5}\right)^{(0.275-1)} \text{ x } \left(\frac{2 \text{ x } 0.275 + 1}{3 \text{ x } 0.275}\right)^{0.275}$$

$$= \frac{\left(\frac{\log (0.64) + 3.93}{50}\right)}{8{,}667^{\left[\frac{1.75 - \log (0.64)}{7}\right]}}$$

$$= 0.006025$$

Interval pressure:

$$P_p\ (\text{psi}) = \frac{f_p V_p^2 \rho}{92{,}916\ D} \text{ x } L_m$$

$$= \frac{0.006025 \text{ x } 560.23^2 \text{ x } 12.8}{92{,}916 \text{ x } 3.826} \text{ x } 11{,}641$$

$$= 792.52 \text{ psi}$$

DRILLSTRING INTERVAL #2 (DRILL COLLARS):

Bulk velocity:

$$V_p\ (\text{ft/min}) = \frac{24.48 \text{ x } Q\ (\text{gpm})}{D^2\ (\text{in.})}$$

$$= \frac{24.48 \text{ x } 335}{2.25^2} = 1{,}619.91 \text{ ft/min}$$

$$100 \text{ x } 26.1 \left(\frac{2.4 \text{ x } 151.47}{8.625 - 4.5}\right)^{(0.275-1)} \text{x} \left(\frac{2 \text{ x } 0.275 + 1}{3 \text{ x } 0.275}\right)^{0.275}$$

Effective viscosity:

$$\mu_{e_p} \text{ (cP)} = 100 \text{ x } K_p\left(\frac{1.6 \text{ x } V_p}{D}\right)^{(n_p-1)} \text{x} \left(\frac{3n_p + 1}{4n_p}\right)^{n_p}$$

$$=$$

$$= 27.6 \text{ cP}$$

Reynolds number:

$$N_{Re_p} = \frac{15.467 \text{ x } V_p D \rho}{\mu_{e_p}}$$

$$= \frac{15.467 \text{ x } 1{,}619.91 \text{ x } 2.25 \text{ x } 12.8}{27.6}$$

$$= 26{,}144$$

Friction factor:

Since the Reynolds number is greater than 2,100, use the turbulent equation.

$$100 \text{ x } 26.1 \left(\frac{2.4 \text{ x } 322.99}{8.625 - 7}\right)^{(0.275-1)} \left(\frac{2 \text{ x } 0.275 + 1}{3 \text{ x } 0.275}\right)^{0.275}$$

$$f_p = \frac{\left(\frac{\log n + 3.93}{50}\right)}{N_{Re_p}^{\left[\frac{1.75 - \log n}{7}\right]}}$$

$$= \frac{\left(\frac{\log (0.64) + 3.93}{50}\right)}{26{,}144^{\left[\frac{1.75 - \log (0.64)}{7}\right]}}$$

$$= 0.004434$$

Pressure loss:

$$P_p \text{ (psi)} = \frac{f_p V_p^2 \rho}{92{,}916 \text{ D}} \text{ x } L_m$$

$$= \frac{0.004434 \text{ x } 1{,}619.91^2 \text{ x } 12.8}{92{,}916 \text{ x } 2.25} \text{ x } 390$$

$$= 277.84 \text{ psi}$$

Total drillstring pressure loss:

$$P_{Drillstring} = P_{p1} + P_{p2} + \cdots$$

$$= 792.52 + 277.84$$

$$= 1{,}070.36 \text{ psi}$$

Annular pressure losses:

Annular "n" value:

$$n_a = 0.657 \log \left(\frac{\Theta_{100}}{\Theta_3}\right)$$

$$= 0.657 \log \left(\frac{21}{8}\right) = 0.275$$

Annular "K" value:

$$K_a = \frac{5.11\Theta_3}{5.11^{n_a}}$$

$$= \frac{5.11 \text{ x } 8}{5.11^{0.275}} = 26.1$$

ANNULAR INTERVAL #1 (8.835-IN. CASING X 4.5-IN. DRILL PIPE):

Annular velocity:

$$V_a \text{ (ft/min)} = \frac{24.48 \text{ x Q (gpm)}}{(D_2^2 - D_1^2)}$$

$$= \frac{24.48 \text{ x } 335 \text{ (gpm)}}{8.835^2 - 4.5^2 \text{ (in.)}}$$

$$= 141.86 \text{ ft/min}$$

Effective annular velocity:

$$\mu_{e_a} \text{ (cP)} =$$

$$100 \text{ x } K_a \left(\frac{2.4 \text{ x } V_a}{D_2 - D_1}\right)^{(n_a-1)} \text{x} \left(\frac{2n_a + 1}{3n_a}\right)^{n_a}$$

$$=$$

$$= 131.22 \text{ cP}$$

Annular Reynolds number:

$$N_{Re_a} = \frac{15.467 \text{ x } V_a \text{ x } (D_2 - D_1) \text{ x } \rho}{\mu_{e_a}}$$

$$= \frac{15.467 \text{ x } 141.86 \text{ x } (8.835 - 4.5) \text{ x } 12.8}{131.22}$$

$$= 927.82$$

Friction factor (if the Reynolds number is less than 2,100, use laminar equation):

$$f_a = \frac{24}{N_{Re_a}}$$

$$= \frac{24}{927.82} = 0.025867$$

Annular interval pressure loss, annular interval #1:

$$P_a \text{ (psi)} = \frac{f_a V_a^2 \rho}{92{,}916 \text{ x } (D_2 - D_1)} \text{ x } L_m$$

$$= \frac{0.025867 \text{ x } 141.86^2 \text{ x } 12.8}{92{,}916 \text{ x } 8.835 - 4.5} \text{ x } 10{,}786$$

$$= 177.94 \text{ psi}$$

ANNULAR INTERVAL #2 (8.625-IN. OPEN HOLE X 4.5-IN. DRILL PIPE):

Annular velocity:

$$V_a \text{ (ft/min)} = \frac{24.48 \text{ x Q (gpm)}}{D_2^2 - D_1^2 \text{ (in.)}}$$

$$= \frac{24.48 \text{ x } 335}{8.625^2 - 4.5^2}$$

$$= 151.47 \text{ ft/min}$$

Effective annular viscosity:

$$\mu_{e_a} \text{ (cP)} =$$

$$100 \text{ x } K_a \left(\frac{2.4 \text{ x } V_a}{D_2 - D_1}\right)^{(n_a-1)} \text{x} \left(\frac{2n_a + 1}{3n_a}\right)^{n_a}$$

$$=$$

$$= 120.72 \text{ cP}$$

Annular Reynolds number:

$$N_{Re_a} = \frac{15.467 \text{ x } V_a \text{ x } (D_2 - D_1) \text{ x } \rho}{\mu_{e_a}}$$

$$= \frac{15.467 \text{ x } 151.47 \text{ x } (8.625 - 4.5) \text{ x } 12.8}{120.72}$$

$$= 1{,}024.68$$

Friction factor (if the Reynolds number is less than 2,100, use the laminar equation):

$$f_a = \frac{24}{N_{Re_a}}$$