General fundamentals

Drilling fluid maintenance costs, as well as overall well costs, can be reduced dramatically when proper solids control techniques are used. Early drilling operations were mostly in boreholes that could be drilled with water and did not require weighting agents to control high-pressure formations. Solids were simply settled as the drilling fluid passed through a series of pits before being pumped back downhole.

This method worked very well for shallow wells which contained no abnormal pressure formations. A drilling fluid which needed to be used in these wells could not allow all of the solids to settle and still retain the heavier mud weights needed to control the abnormally high-pressure. However, the full extent of the impact of retained drilled solids was not really appreciated until the mid to late 1900s.

After using the 'settling method' for many years, the next innovation in solids control came when shale shakers were introduced in the early 1930s. One of the first shakers was not actually a 'shaker' but a rotating drum of very coarse wire mesh. The drilling fluid would force the drum to turn, ejecting some of the solids, and retaining most of the liquid phase (and solids). The mining industry was using a vibrating screen for coal classification and was adopted by drillers to remove more solids and retain most of the weighting material. This machine used an unbalanced elliptical motion to move solids down the screen while forcing the drilling fluid to pass through the screen.

After these found success, the hydrocyclones were also adopted from the mining industry and developed during the 1940s for use on drilling rigs. These hydrocyclones spin the fluid inside a chamber causing the solids to be forced against the inside wall of the cone.

The next development was the centrifuge during the late 1940s and early 1950s. The centrifuge removes solids smaller than about 10 microns. Drilled solids that were not removed from the drilling fluid when they were large could be removed with the centrifuge. When they become smaller than the size of barite, salesmen frequently incorrectly labeled it as a "barite recovery" device. At this time, there is no equipment available for use on a drilling rig which will separate drilled solids from barite in the same size range. A centrifuge separates particles by mass not species, dimensions or composition. In a weighted drilling fluid, a centrifuge removes small drilled solids and small particles of barite; it recovers barite and drilled solids that are larger than about 10 microns.

By the early 1970s shale shakers had developed to the point where screens labeled 60 to 80 mesh were the finest that could be used on rigs. Solids between the finest mesh size opening (250 microns to 180 microns) and the maximum barite size (75 microns) could not be removed from the drilling fluid. These particles created poor filter cakes and also continued to degrade in to colloidal sizes. The mud cleaner was invented to remove drilled solids in this size range. Desilter hydrocyclones processed the drilling fluid and the underflow (containing these solids) was filtered through a fine screen. A single, four-inch desilter, at that time, could process about 50 gpm, with a 1 gpm underflow. This small flow rate could be processed using fine screens on the shale shakers available at that time. Using mud cleaners reduced the occurrences of stuck pipe and lost circulation. When the linear motion shale shakers were introduced, fine screens could be used which separated solids down below 75 microns. The use of mud cleaners decreased significantly, because the assumption was made that all of the fluid was being processed through the same size screen as the mud cleaner could use. However, to the surprise of many, when mud cleaners were used after processing "all" of the drilling fluid through a "200-mesh" screen, many solids were removed from the drilling fluid. In retrospect, this should have been anticipated. Desilters processing an unweighted drilling fluid would frequently plug with large solids even after passing through screens labeled "80-mesh" or 177 micron openings. The apex of a desilter is many times larger in diameter than 177 microns. This means that these solids bypassed the screen. In current drilling fluid processing, a mud cleaner still removes a large quantity of drilled solids and serves as a 'back-up' to the fine mesh screens used on the currently available linear and balanced elliptical motion shale shakers. When these fine screens break, the rig crew does not always quickly detect the break. Frequently, the screen breaks in a region covered by a pool of liquid and it is not visible until a connection is made. A mud cleaner provides insurance that the drilling fluid remains free of the detrimental drilled solids.

Drilling fluid processing

The mud tanks on a drilling rig should have three easily identifiable sections: 1) Removal Section; 2) Additions Section and 3) Suction Section. The size of these tanks depends on the drilling rig size. Rigs used to drill very shallow holes may have all of these sections in one or two tanks. Deep wells will require much more drilling fluid and the tank system will be very large.

Notes on safety

Design fluid processing areas to be safe. Drilling fluid residue on a steel deck presents an extreme slip hazard. Use serrated steel grating or fiberglass grating with a non-slip surface wherever possible. Non-slip stairway treads are a must. Use properly built hand rails with toe plates along all walkways, stairs and pit tops. Maintain a safe lighting level around all equipment, stairs and walkways. Wash equipment and clean up drilling fluid spills as soon as possible.

Eyewash stations and shower(s) should be provided throughout the surface drilling fluid system areas. Proper protective clothing in good condition should always be readily available to those mixing chemicals and they should be worn. Some combination of goggles, dust masks, face shields, rubber gloves and rubber aprons are required depending on the particular chemicals being mixed. Spilled chemicals and bags should be cleaned up quickly and disposed of in a proper manner according to company policy and/or environmental regulations.

A responsible qualified person should periodically inspect all electrical devices, electric cable lighting and fittings for physical damage or excessive corrosion. A shock hazard or explosion hazard can exist if this special equipment is not maintained in a proper state. Always use an approved Classified Area electrical device or fitting in an area requiring Division I/Zone I or Division II/Zone II explosion-proof or vapor tight electrical devices and fittings. The temperature class (T rating) should be considered when selecting lighting and electrical equipment to ensure that equipment is below auto-ignition temperature of any flammable gasses which are likely to be present.

Drilling fluid properties

A good drilling fluid should have the lowest possible viscosity when it strikes the bottom of the hole to remove drilled solids created by the drill bit. Then the fluid must have a sufficient viscosity to transport drilled solids out of the bore hole. This change in viscosity is created by having a fluid which changes viscosity with shear rate (**Figure FP-1**).

Viscosity is defined as the ratio of shear stress to shear rate. When the shear stress is expressed in dynes/cm^2 and the shear rate in reciprocal seconds, the viscosity has the units of poise. The rheological model normally used on drilling rigs is one of the simplest possible models to describe the relationship between shear stress and shear rate:

Shear Stress = (PV) (Shear Rate) + YP,

where PV is the plastic viscosity and YP is the yield point.

The equation is described as a straight line where PV is the slope and YP is the intercept on the Shear Stress axis at zero Shear Rate. This is called the Bingham Plastic rheology model.

Mathematically, if the value of Shear Stress is inserted into the definition of viscosity, then **Eq 1** is the result.

As shear rate gets larger and larger, the last term of the above equation gets smaller and smaller. If the shear rate goes to infinity, the viscosity is equal to the plastic viscosity. So PV is the viscosity the fluid would have at a very high shear rate—such as the shear rate through the bit nozzles. This high-shear-rate viscosity (PV) needs to be kept as low as possible to assist with the fluid hydraulic impact or hydraulic power being capable of removing the largest quantity of drilled cuttings. PV is controlled by four factors: liquid phase viscosity, size, shape and number of solids.

Transport of drilled solids requires increasing the low-shear-rate viscosity of the drilling fluid be sufficient to prevent solids from tumbling in the annulus. Currently, there are guidelines (API RP13D) available that work well for drilling fluid at angles less than the angle of repose of drilled solids in the well—around 35° to 40°. An empirical carrying capacity index (CCI) seems to work well with water-based or Non-Aqueous Drilling Fluid (NADF). (**Eq 2**).

Sharp edge cuttings are discharged from the shale shaker when CCI is equal to one. The "K" in the equation is the viscosity constant in the Power Law rheology model. (**Eq 3**).

The factor of "n" is usually less than '1' for drilling fluids. If n=1, the fluid is said to be Newtonian, where the shear stress increases uniformly with shear rate. This means the viscosity is constant, no matter how fast the fluid is moving. The definition of viscosity is the ratio of shear stress to shear rate. When the shear stress is measured in dynes/sq cm and the shear rate is measured in reciprocal seconds, the

Eq 1

$$\text{Viscosity: } ft^2 = \frac{\text{shear stress}}{\text{shear rate}} = \frac{(PV)(\text{shear rate}) + YP}{\text{shear rate}} = PV + \frac{YP}{\text{shear rate}}$$

Eq 2

$$CCI = \frac{(\text{mud weight, ppg})(\text{Annular velocity, ft/min})(K,\text{eff.cp.})}{400{,}000}$$

Eq 3

$$\text{Shear Stress} = K\,(\text{shear rate})^n$$

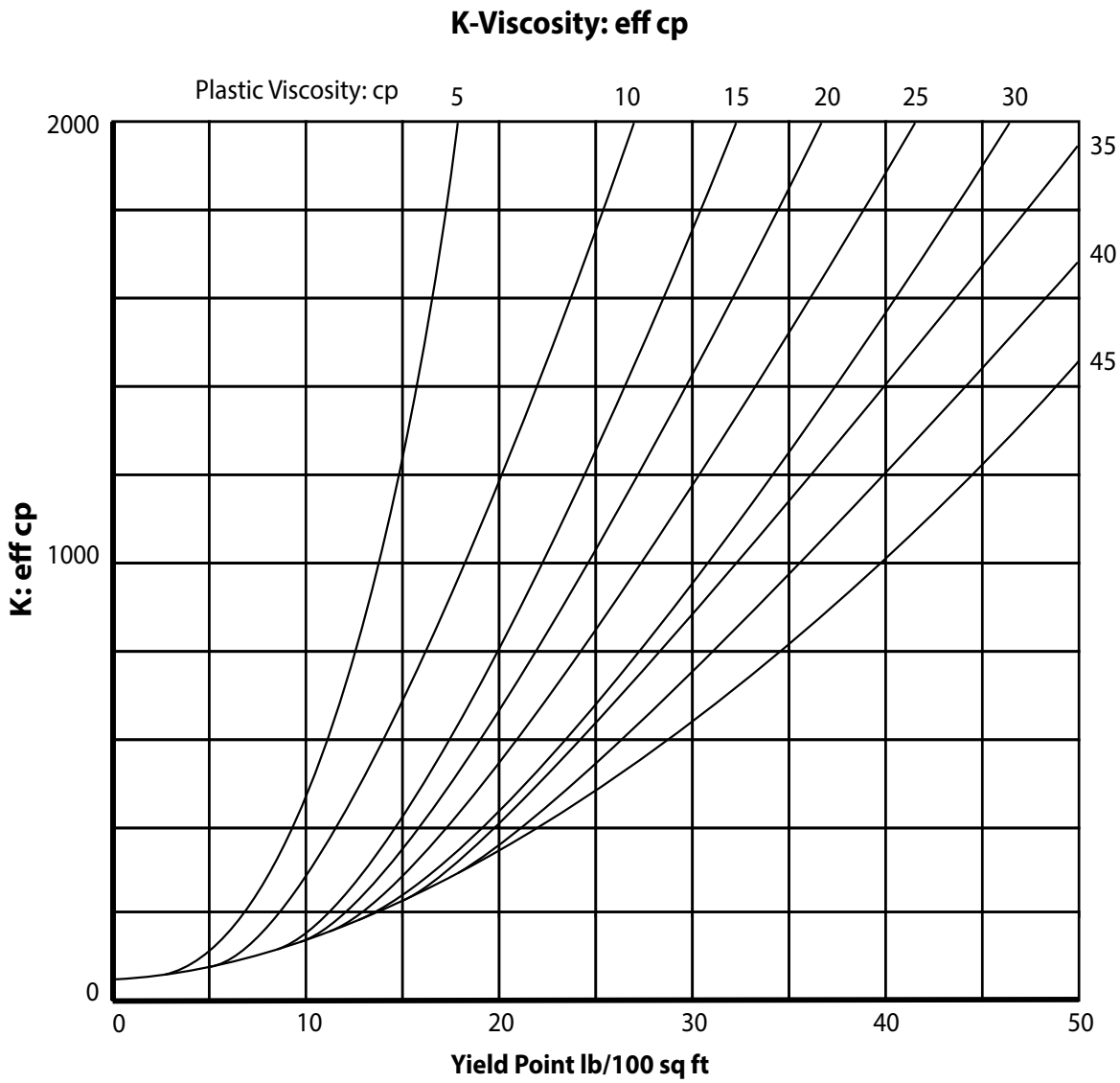


Figure FP-1: Effective viscosity vs Yield Point..

viscosity will have the units of 'poise'. With the rheometers used in drilling fluid measurements, the shear stress is measured at two different shear rates. With the concentric cylinder rheometer, the outer cylinder is rotated at 600 rpm or 300 rpm and the shear stress measured in lb/100 sq ft. The plastic viscosity (PV) of the drilling fluid is calculated by subtracting the 300-rpm shear stress (R300) from the 600-rpm shear stress (R600). The yield point of the drilling fluid (YP) is calculated by subtracting the PV from the R300 reading. Multiplying the rpm by 1.7 changes the units to reciprocal seconds. Multiplying the shear rate in lb/100 sq ft by 5.11 will change the units to dynes/sq cm.

The power law constants of 'n' and 'K' can be calculated from the equations:

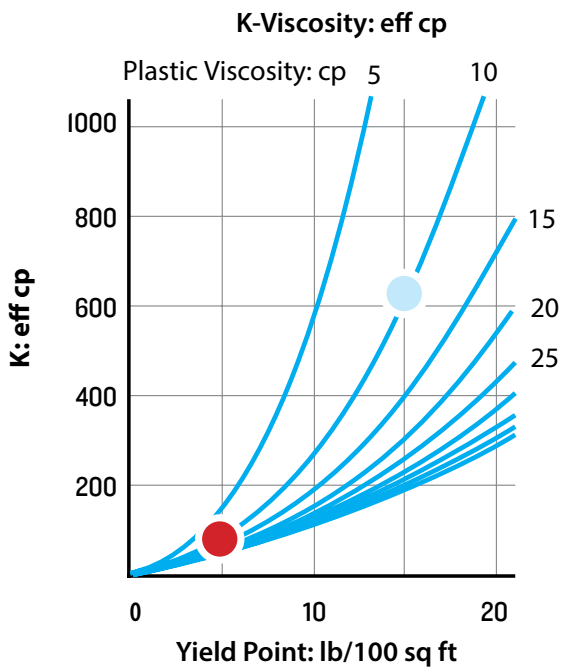
Eq 4 $n=3.322 \times \mathrm{Log}\,(R600/R300)$

Eq 5 $K= 511^{(1-n)} \times (R300)$

Usually, the morning report forms will provide the PV and YP of the drilling fluid, not the actual readings. The equations above can be modified for easier use:

Eq 7 $K= 511^{(1-n)} \times (R300)$

Eq 6 $$n = 3.322\,\mathrm{Log}\,\frac{2PV + YP}{PV + YP}$$



Because these equations are somewhat complicated, a graphical solution is provided. The CCI equation (**Eq 2**) contains an empirical number (400,000) that is an approximation. This value is useful to only one significant figure; consequently, the value of K does not have to be calculated to the nearest decimal value. This means that reading the number from a chart will be sufficiently accurate to provide guidance about what yield point will be needed.

Application:

Figure FP-1a: Determining Yield Point needed to clean hole properly.

Calculate the CCI for a 10-ppg drilling fluid with PV = 10 cp and YP = 5 lb/100 sq ft being circulated in a hole where the lowest annular velocity in a well is 65 ft/min.

From the **Figure FP-1a**, K = 130 cp (red circle).

$$CCI = 0.13$$

$$CCI = \frac{(10\ ppg)(80\ eff\ cp)(65\ ft/min)}{400{,}000}$$

With a value so much smaller than one, the cuttings are not being transported to the surface without tumbling. No cuttings would have edges as thin as fingernails. The YP needs to be increased so that CCI will be equal to one.

$$CCI = \frac{(10\ ppg)(K)(65\ ft/min)}{400{,}000} = 1$$

Solving this equation for the value of K:

$$K = \frac{400{,}000}{(10.0\ ppg)(65\ ft/min)}$$

$$K = 615\ eff\ cp$$

This value of K is shown by the blue circle in **Figure FP-1a**.

If the YP is increased to about 15 lb/100 sq ft, CCI will be about 1.0. This should greatly improve cuttings transport.

Note: The lowest annular velocity may be in a zone which is washed out, rather than in the casing/drillpipe annulus. In some cases, the CCI has had to be increased to 1.5 instead of 1.0. This also could be caused by the change in rheology of the drilling fluid because of temperature and pressure in the well bore. The yield point is measured at the same temperature daily. The wellbore temperature (and pressure for non-aqueous drilling fluids) changes the low shear rate viscosity. This change depends upon the ingredients in the drilling fluid and cannot be predicted. The empirical value of 400,000 for the constant seems to account for these changes reasonably well. The CCI concept has been field tested and, in most cases, works well. However, the technique simply provides some basic guidelines that should be modified as needed to ensure that the cuttings being transported in wells up to 35° will have sharp edges.

Good solids control actually starts at the drill bit. Cuttings made by the drill bit should be removed from the bottom of the hole before the next row of teeth regrind them. This means that the fluid should strike the bottom of the hole with the greatest force or impact possible OR the greatest power possible. Hydraulic optimization is necessary to insure that the cuttings are being removed as quickly as possible. A low plastic viscosity will enhance this. After the cuttings are removed from beneath the drill bit, they need to be brought to the surface without regrinding. The cuttings should have sharp edges on them. This means that they will be as large as possible when they are being processed by the shale shakers. Large solids are easier to remove than smaller ones.

A general "rule of thumb"[1] requiring annular velocity to be about 100 to 125 ft/min or higher to carry cuttings out of the wellbore is a good starting point. However, this annular velocity cannot always be achieved in washed-out zones and large diameter risers and casing. For this reason, the low-

[1]Preston Moore, Drilling Practices Manual, PennWell, 1975, p 229.

shear-rate viscosity must be elevated to allow the transport of drilled solids in the vertical and near-vertical sections of the well. The CCI applies only to holes at an angle lower than the angle of repose of solids on the side of the wellbore (usually around 42°).

Benefits of mechanically removing drilled solids

a. Raises the founder point of the bit which increases drilling penetration rate;

b. Decreases filter cake thickness, which:

- Reduces drillstring torque and drag;
- Reduces differentially pressure stuck pipe;
- Provides better electric logs;
- Allows cement to fill more of the annulus;
- Allows casing to be moved during cement placement.

c. Reduces wear of expendables in the drilling fluid system;

d. Reduces dilution costs to keep drilled solids concentration within specifications;

e. Enhances quality of electric logs;

f. Decreases volume of discarded fluid needed when controlling drilled solids with dilution;

g. Decreases the cost of building excessive volumes of drilling fluid as required by dilution.

From an economical point of view, the drilling benefits of removing drilled solids can be divided into two categories:

- Visible nonproductive Time (NPT);
- Invisible nonproductive Time (NPT).

Stuck pipe is a very visible NPT. The drilling rig cannot drill and must solve the problem by recovering the drillstring (or fish), sidetracking the well, or abandoning the well. The cost of this event is relatively easy to identify. However, drilling with a drill bit, when the bit loading has exceeded to founder point, results in a much lower drilling rate and increases the bit wear. This is an invisible NPT. Removal of drilled solids could increase the ability of the drilling fluid to remove cuttings from below the bit (decreasing plastic viscosity) and increase penetration rates. The question becomes is the rock "harder" or is the bottom of the hole not being cleaned by the hydraulics. Clearly, drilling half as fast as possible and using three bits instead of one in an interval would greatly affect the economics of drilling. The ability to properly cement a well is essential for the life of the well. Leaving a thick filter cake on the formation that cannot be removed by the cement could result in flow behind casing while the well is being produced. If this is not detected, a significant amount of production could be lost. This would be a large cost for an invisible NPT.

Drilling fluid particle sizes and effects

Drilling fluids are classified as water-based or Non-Aqueous Drilling Fluid (NADF). NADF can consist of a diesel oil, a mineral oil or a synthetic fluid (such as polyalpha olefin, esters, ethers or others). With the more frequent use of polycrystalline diamond compact (PDC) bits, more and more NADF are being used now even though it may be more expensive than water. The benefits from wellbore stability and enhancing the action of the PDC bits against the rock creates a less expensive hole even though the cost of the drilling fluid may be higher.

The solids phase of any drilling fluid are two basic types: Commercial solids and drilled solids.

Not all solids in the colloidal range are detrimental to a drilling fluid system. Some fine particles in the colloidal size range are necessary to build a thin, slick, compressible filter cake. These reduce the probability of differential pressure sticking of the drill string. They also increase the low-shear-rate viscosity of the drilling fluid used to transport drilled solids up the vertical (or almost vertical) part of the bore hole. Commercial solids also are used to build a gel structure which suspends the barite and drilled cuttings when the mud pumps are turned off.

The different sizes of particles in a drilling fluid have been labeled for ease of communication:

- Cuttings: 440 microns and larger;
- Sand: 75-440 microns;
- Silt: 2–75 microns;
- Clay: 0.5–2 microns;
- Colloids: less than 0.5 microns .

Note: 0.001 in. = 25.4 microns

A sand-size particle refers to the effective diameter of the particle NOT the material. In other words, barite particles larger than 75 microns would still be called "sand" in a drilling fluid report. These large particles in a filter cake would be detrimental to the filter cake quality. Particles larger than 75 microns should be removed from the drilling fluid even if they are diamond, gold, silver, barite or pearls. They destroy the filter cake quality. Too many small particles are also not desirable in a filter cake.

Drilled solids should be removed the first time they are circulated to the surface or they will eventually degrade to colloid sizes by continuous circulation through the mud pumps, drill

