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Parametric Analysis of MPD Hydraulics

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Abstract

Managed pressure drilling is a process that utilizes friction pressure and annular back-pressure in addition to conventional hydrostatic column pressure to allow drilling of difficult formations. There are many parameters that play a part in the managing of wellbore pressure during fluid flow. Wellbore pressures are impacted by fluid density and rheologic properties, injection rates, cuttings transport, influx while drilling, wellhead or choke pressure, hole geometry and drillstring configuration. The effects of these parameters on wellbore pressure are different, but interact with one another. Therefore, careful consideration is needed when choosing which parameter(s) should be adjusted to manage the wellbore pressure during any particular operation.

A good understanding of the effects of these operating parameters on wellbore pressure is essential in the optimum design of an MPD project. This is especially true of the rheologic properties of MPD fluids. Rheologic properties of drilling fluids play important roles in the variation of wellbore pressure during any MPD operation. Most drilling fluids (WBM, SBM, or OBM) currently used in the field have a non-zero yield point (YP). A non-zero YP causes a sudden bottom hole pressure (BHP) jump when fluid starts to move or when fluid is about to stop moving. It also causes a sudden BHP jump when the drillstring starts to move up or down during tripping or connections regardless of how slow the pipe moves. The sudden pressure jump makes it difficult to minimize BHP variations.

This paper discusses the effects of various operating parameters on wellbore pressure and provides guidelines for managing wellbore pressure by adjusting those operating parameters. A simple equation to predict the sudden pressure jump caused by YP is provided. Field cases are used to illustrate managing wellbore pressure by adjusting various operating parameters.

Controllable Parameters

When preparing for MPD, careful consideration is required to choose the parameters that can be controlled to ensure those parameters that make the biggest difference are selected for control. Whether drilling or designing the MPD application, the interaction between all controllable parameters must be kept in mind during the process.

To better understand how the controllable parameters interact with one another, a typical offshore well will be used as an example (Figure 1). This well is located in approximately 5,900 ft of water. The wellbore interval used for illustration is the 8-1/2 in wellbore drilled directionally below 9-5/8 in casing from 9,300 ft MD to total depth of 15,775 ft MD (10,920 ft TVD.)

Often parameters that might otherwise be controllable are dictated or fixed prior to the realization that MPD will be required to enable the prospect to be drilled.

Pressure Window

The prime example of such a parameter is the operating pressure window, which is not commonly considered a controllable parameter. The window itself is defined by a lower limit, which may be either pore pressure or wellbore stability (collapse) pressure and an upper limit, which in the case of most MPD is defined by the fracture gradient exposed to the wellbore.

Figure 2 shows the pressure window for the example wellbore. The upper limit, designated as fracture pressure in the figure, is simply sea water gradient down to the mud line. Below that point the upper limit of allowable pressure in the wellbore is the actual fracture gradient, while the lower limit is the pore pressure. The casing seat indicated at approximately 9,300 ft in the figure serves to isolate a narrow pressure operating window above that point from a wider window below that point.

The pressure operating window is shown on a larger scale in Figure 3. Over the interval of wellbore to be exposed to MPD, the apparent window between pore pressure and fracture gradient ranges from 0.7 ppg (9.7 ppg to 10.4 ppg EMW) at the 9-5/8 in casing seat at 9,300 ft MD to 1.7 ppg (9.9 ppg to 11.6 ppg EMW) at TD. However, the actual operating window is only 0.4 ppg (10.0 ppg to 10.4 ppg EMW), which is the range between the highest pore pressure and the lowest fracture gradient exposed in the well bore at any one time. As Figure 3 also illustrates, the only other level of control afforded to this critical parameter other than wellbore geometry, is the artificial imposition of arbitrary kick and trip margins. During MPD, if the truly controllable parameters are controlled, these artificial limits can be successfully eliminated.

The key to controlling the window, and the only parameter that can conveniently be used to control the operating window, is wellbore geometry. Geometry controls the operating window through selection of hole interval allowed to be exposed to the wellbore at any one time. In other words, casing seat selection is the principal means of controlling the pressure window.

When need be, the operating pressure window parameter can potentially be altered through artificial means of improving the strength of the formation itself or changing the state of stress in the rock. These techniques are beyond the scope of this paper but are reported in the literature.[1, 2, 3]

Wellbore Geometry

Another example of a parameter that is commonly fixed prior to MPD planning is the geometry of the wellbore itself. The geometry, including wellbore trajectory, hole size, and drill string configuration will impact each of the other parameters in ways that may not be obvious with only a cursory examination.

However, the most obvious effects are the impacts of wellbore geometry on hydrodynamic friction and on hydrostatic head. The annular clearance can either increase or decrease the friction of the fluid moving through the annulus. Wellbore inclination, especially in the case of horizontal drilling, can cause long sections of wellbore to be exposed to the same hydrostatic pressure. An often overlooked or forgotten effect is the impact of annular back pressure at the surface when the well bore is vertical vs. horizontal. Such back pressure will have a much higher equivalent fluid density at shallow vertical depths than on deeper horizons.

The effect of geometry in some cases will be detrimental to control of annular pressure while in other cases the same geometry may prove beneficial to effective control of the annular pressure. Unfortunately, the geometry is often fixed by drivers external to the drilling process. Consequently, other parameters will have to be adjusted during drilling to compensate for the geometry.

Fluid Density

The most commonly controlled parameter in any drilling operation is the density of the fluid being circulated through the wellbore. This is especially true of MPD projects.

When defining the operating pressure window it is often useful to thinking terms of fluid density, since that is the primary means by which the pore pressure window will be approached. It is important to understand the concepts of Equivalent Mud Weight (EMW), Equivalent Circulating Density (ECD) and, more recently, Equivalent Static Density (ESD).

EMW and ECD are technical the same thing, though most practitioners refer to EMW when thinking in terms of a hydrostatic condition or a pressure downhole and refer to ECD when thinking in terms of a dynamic, circulating condition. Both terms will include the effect of back pressure at the surface friction generated by movement of the fluid.

Drillers using Synthetic-based and oil-based mud (SBM and OBM) recently have noted sometimes dramatic effect of compressibility of the fluid under certain conditions of depth and temperature. The effective density of the fluid downhole may be 0.5 ppg more downhole than measured in the pits at the surface. To account for this compressibility, the term ESD has come into vogue. ESD, used correctly, will account for all elements acting to change the effective hydrostatic head of the fluid, again including back pressure, but expanding the view to account for not only compressibility but also cuttings loading as well.

If all cuttings are not removed from the wellbore prior to making a connection for example, then the effect of cuttings concentration on the effective density must be taken into account.

Circulation Rate and Hole Cleaning

The effect of cuttings loading on torque and drag, stuck pipe propensity, and even rheology has been appreciated for decades, but only in the past few years have drilling personnel begun to fully appreciate the effect that cuttings concentration has on the effective pressure throughout the annulus. Most hydraulics modeling either ignores the effect or attempts to address it through use of one empirical correlation or another.

The effect of circulation rate on cuttings concentration and on bottom hole pressure (BHP) in the wellbore is shown in Figure 4. As the circulation rate of drilling mud increases, the BHP decreases. The cuttings concentration in the annulus is decreasing at the same time and this effect is in fact the very reason the BHP does decrease.

Eventually the cuttings concentration approaches a level below which it has very little continued effect on the BHP. Once this level is reached, continued increase in circulation rate causes the BHP to increase. This effect is caused by the predominance of dynamic friction over the other effects of circulation. The sudden increase in BHP that is apparent between 420 and 450 gpm circulation rate is caused by a transition from laminar flow in the annulus to turbulent flow, the absence or presence of which is closely related to the base rheology of the circulating fluid.

The effect of cuttings loading in the example well is clearly illustrated in Figure 5. With the same fluid and at the same circulation rate, cuttings always contribute to a higher BHP (the blue curve in the figure) than if there are no cuttings involved (pink curve in the figure). When circulation is sufficient (circulation rate greater than 400 gpm in this case), the two curves in Figure 5 are near parallel. However, when the circulation rate is below the optimum rate (400 gpm in this case) the blue curve shows BHP starts to increase, while the pink curve shows a decreasing BHP with the reduction of circulation rate. This indicates that with insufficient circulation rate, cuttings start to accumulate and result in a heavier fluid column in the annulus. Although one may still be able to drill with circulation less than the optimum rate, the cuttings accumulation in the annulus can cause downhole problems and reduce drilling efficiency.

Two other controllable parameters that are closely related to hole cleaning and cuttings concentration are drillstring eccentricity and drillstring rotation.

Eccentricity in this instance relates to how centered in the wellbore the drillstring remains during drilling. This, in turn, is affected by wellbore geometry, since drillpipe in a horizontal or directional wellbore is much more likely to be eccentric than is the drillpipe in a vertical wellbore. When the drillstring is off center in a wellbore it creates differences in hole cleaning between the "wide" side of the hole and the "narrow" side of the hole. Pipe eccentricity may also reduce the friction pressure on the "wide" side of the hole and increase it on the "narrow" side.

Drillstring rotation results in two opposing effects at the same time. When the drillstring is rotated, the absolute velocity of the circulating fluid is increased, tending to increase frictional pressure and hence ECD. While this is happening, the increased absolute velocity helps carry cuttings more effectively, reducing ECD. The predominating effect is generally going to be beneficial in reducing ECD, but will ultimately depend on the size of cuttings and the rate at which they are being generated (i.e., Rate of Penetration, ROP.) Meanwhile, the drilling engineer must not lose sight of the other benefits of rotating pipe, mainly the reduction in torque and drag generally afforded by pipe rotation.

While increasing circulation rate helps remove cuttings from the well bore, this parameter is interdependent with the other parameters discussed, but is most closely affected by fluid rheology.

Rheology

Rheologic properties of drilling fluids play important roles in managing wellbore pressure. Most drilling mud (WBM, SBM, or OBM) currently used in the field have a non-zero Yield Point (YP). A non-zero YP causes a sudden pressure jump when the fluid starts to move (pressure increase) or when the fluid is about to stop moving (pressure decrease.)

What is Yield Point?

YP is the term used to measure the intersection of the shear stress axis by the relation between shear stress (τ) and shear rate (γ) of a fluid (i.e., YP is the shear stress at zero shear rate, as shown in Figure 6.)

Some fluids (such as Newtonian fluids and Power-Law fluids) intersect the shear stress axis at the origin point (YP = 0). However, most drilling mud is non-Newtonian and consequently has a non-zero yield point. The term YP was first introduced with the Bingham Plastic model. It later was also used in conjunction with the Herschel-Bulkley model (also referred as Modified Power-Law model).

Historically, YP has been estimated as the difference between the 300 RPM reading and the PV estimated as the difference in the 600 rpm reading and the 300 rpm reading from the Fann viscometer. This approximation was necessitated by the capability of early viscometers in the field and by the need for a quick and easy estimation of rheology. Unfortunately, except in rare cases, this estimation is usually grossly overestimated. Because the YP is defined as the shear stress at a zero shear rate, it might be better estimated using a low shear rate reading from the Fann Viscometer, and when calculated correctly will give a value slightly less than the 3 rpm shear rate reading.

That most drilling mud is better represented by the Herschel-Bulkley model than by any of the other three most used rheology models in drilling fluids technology (Newtonian, Bingham Plastic, and Power-law) has become generally accepted as common knowledge. The Herschel-Bulkley model is mathematically represented by Equation 1.

$$\tau = YP + \mu\gamma^n \text{ .... } (1)$$

As indicated by Equation 1, in order for the fluid to move (shear rate greater than zero), shear stress must be greater than YP. In other words, when shear stress is less than or equal to YP, the fluid behaves like a solid.

YP is similar to mud gel strength. However, the major difference between YP and gel strength in term of hydraulics is that gel strength will not exist once the fluid is moving and the gel has been broken, while the effect of YP will not disappear when the fluid is moving. Figure 7 shows the pump pressure caused by gel strength and YP at the beginning of pumping. As indicated by the right plot in Figure 7, the pressure surge caused by gel strength at the beginning of pumping disappears quickly. The pressure surge caused by YP (left plot of Figure 7) does not.

The pressure surge created by YP must be accounted for on every connection while drilling, and will also have implications to consider when tripping out of the hole, especially if the mud in the wellbore is hydrostatically underbalanced. The effects on tripping and connections are discussed more fully below.

Choke Pressure

Manipulation of chokes to control bottom hole pressure has its genesis in well control applications. Control of choke pressure (or back-pressure, or surface annular pressure) during MPD is normally only going to be required if the mud in the wellbore is hydrostatically underbalanced. In some cases control of the choke pressure will only be required during connections and some portions of a trip, but in some special applications choke pressure may require manipulation during circulation while drilling. These cases are flirting with true underbalanced drilling.

In a historical sense choke pressure control was tied directly to control of the drill pipe pressure, or standpipe pressure. For MPD the choke pressure will be controlled based on BHP, and if a PWD device is present in the drillstring, those measurements will be used to control the choke pressure. However, when the PWD tool is a mud pulse tool, neither PWD measurements nor drill pipe pressure measurements will be available during the actual event of controlling the pressure (e.g., during a connection.) Consequently, the interaction between choke pressure and all other controllable parameters will have to be noted and continued while the choke pressure is being manipulated.

Control of annular pressure is the most common and simple means employed to attempt to maintain constant BHP, the original goal of MPD.

Application

During execution of MPD many parameters in addition to those described above can and should be monitored whenever possible. Those parameters described above may be more easily thought of as parameter categories. Ultimately, the only true parametric category is control of the EMW. This level of control requires understanding of not only each individual parameter, but also an understanding of the interdependence of all parameters.

MPD is simply the application of this interdependence to manipulate the annular pressure to maintain “constant BHP” (CBHP). CBHP, while a worthy goal is actually a misnomer precisely because of the interdependence of parameters. In a horizontal wellbore, the BHP along the horizontal leg will approach a constant when the well is static. Any back pressure applied at the surface will have the same effect at each point along the horizontal extension because the TVD is the same. However, when circulation begins again, the ECD will always be higher at the toe of the lateral than it is at the heel, no matter what sort of manipulation is carried out on the other parameters. Similarly, in a vertical wellbore ECD will be higher at the bit and any back pressure applied at the surface will be felt as a higher EMW nearer the surface than at the bit. The consequence of these geometric effects is that the best we can hope for is a constant BHP at a given particular point. Efforts to control BHP must be directed at remaining within a window rather than at maintaining CBHP.

During Drilling

There are three major components that create BHP during drilling operations: fluid column density, surface choke pressure, and frictional pressure along the wellbore annulus. All three of these major components are controllable, and all three are interdependent with the others. By the time the drilling phase of the project is met the geometry of the wellbore is fixed for the most part. However, if a real need presents itself minor modifications can be made to geometry by altering the drill string.

Immediately prior to drilling the principal means of controlling BHP will be through adjustment of the fluid density. During drilling, fluid density can be further altered, but the quickest means of control will be by changing the choke pressure. Alteration in back pressure will have an immediate effect whether while circulating or while the drilling fluid is static, as during connections, for instance.

The frictional pressure in the annulus can be controlled through two means. The rheology of the fluid can be designed such that the viscosity component of dynamic pressure is fixed within the desired range. While it will be possible to alter fluid rheology during the drilling operation, this is normally not done unless the rheologic parameters are altered by downhole conditions to the point where they become the primary reason the BHP is out of the operating window. In most cases it will be much easier and faster to alter the friction pressure in the wellbore by adjusting circulation rate. Meanwhile, wellbore geometry effects must be accounted for, especially if the anticipated geometry is not met due to hole washout, challenges with directional control, changes made to the drilling assembly, or any other reason.

Hole cleaning and cuttings concentration must be continually controlled as well because this parameter affects and is affected by the density and frictional pressure parameters.

During Connections

Maintaining constant BHP during connections may require use of a Continue Circulating System (CCS). If a steady state can be reached downhole and then not changed, theory says the formations downhole will not experience a change in imposed pressure. A CCS will maintain the circulation in the wellbore even while making connections. More than one mechanical device is available to help accomplish this goal[5, 6] and while they come close to maintaining a steady state and CBHP, ultimately the friction pressure changes as a function of changing geometry while the drill string progresses down the wellbore. At any given connection, the BHP can be held constant compared to circulating and drilling just prior to and immediately after making the connection. Even with circulation maintained at the same rate whether drilling or making connections, the density of the circulating fluid will vary slightly due to a reduction in cuttings concentration once drilling ceases and the bit stops producing cuttings. The longer the event continues without making new hole, the lower the cuttings concentration and the lower the fluid density becomes.

Since at least 2004, a local circulation technique has been used to attempt to maintain the BHP during connections without the need of a CCS. Instead of injecting fluid into drillstring and returning it from the annulus, this technique directs the circulation fluid directly to the surface choke and applies a higher choke pressure to offset the frictional pressure loss that does not exist during connections. In other word, the friction pressure lost when drilling fluid stops circulating is replaced with back pressure at the surface imposed by circulating the same fluid across the annulus.

As discussed earlier, this technique really only maintains the BHP constant at one point in the annulus. The operator will control where in the wellbore that constant BHP will occur. In addition to the variations in BHP resulting from changing the frictional parameter when the rig pumps go off the hole and the variations in EMW imposed by changing the annular back pressure vs. depth, there is often a serious pressure change or jump created by YP just by ceasing or starting circulation downhole. This YP pressure jump must be accounted for and controlled by controlling the other parameters, most notably the circulation rate and the back pressure, at the same time.

Control of the YP pressure jump requires a carefully designed pump and choke operating schedule and good cooperation between the pump and choke operators. During shut down of the rig pump the circulation rate must be decreased step by step, while the choke pressure must be increased accordingly at each step to offset the decrease of frictional pressure loss due to the reduction of circulation rate. To keep the BHP during the connection the same as during drilling, the total increase of choke pressure when the pump is completely shut down should be equal to the total annular frictional pressure loss plus the total weight of cuttings in the annulus during drilling. In practice this is simplified by allowing the cuttings concentration to remain the same during the connection as when drilling. A reverse incremental increase of pump circulation rate corresponding to an incremental decrease in choke pressure should be followed during the resumption of circulation after the connection is made.

One of the first steps in developing such a schedule is to calculate the pressure jump caused by YP referenced above. A simple means of determining this pressure jump due to YP is given by equation 2[7]

$$\mathrm{d}P/\mathrm{d}L = YP/[200(d_2-d_1)] \qquad (2)$$

This pressure drop represents the last increment of choke pressure that must be imposed prior to shutting the rig pumps completely off the hole before making a connection and represents the first increment of choke pressure that must be bled off the annulus when the rig pumps are put back on the hole after making the connection.

Any accurate hydraulics model can be used to calculate the friction pressure represented by any given increment of circulation rate. For example, if the total circulation rate is 400 gpm while drilling, and adjustments to the circulation rate (and by correspondence to the choke pressure) will be made in ten increments, then for each decrease of 40 GPM in the circulation rate, a frictional pressure loss can be calculated. The incremental frictional pressure losses correspond one-to-one with incremental choke pressure adjustments to be made prior to breaking the connection.

During Tripping

Maintenance of a CBHP at some point in the annulus during a trip becomes an even more incremental process. Typically, back pressure must be imposed at the surface to offset the loss of frictional pressure as described above for making connections. The drillstring can then be stripped out of the hole holding this backpressure constant. Note that some adjustment may be required to account for swab effects as the BHA is withdrawn from the wellbore.

However, unless the operator desires to snub out of the hole, at some point the surface back pressure will need to be eliminated. To accomplish this, heavier fluid must be placed in the well to offset the surface choke pressure, which was imposed to offset frictional pressure loss along the annulus that existed during drilling. Drilling fluid can be replaced by the heavier fluid throughout the entire wellbore or only at the bottom of the well or only across the top section of the well. The density of the heavier fluid can be calculated using Equation 3

$$\rho_{new} = \rho_{old} + (\Delta P_f + P_c)/(0.052 \times D_v) \qquad (3)$$

Where ρ_{new} is the heavier mud weight (ppg), ρ_{old} is the drilling mud weight (ppg), ΔP_f is the total frictional pressure loss along annulus (psi), P_c is the surface choke pressure (psi), and D_v is the true vertical length of the new fluid.

When displacing the drilling fluid with the heavier fluid, the pressure jump attributable to YP must again be accounted for when the heavy fluid circulation begins. A pump rate change vs. choke pressure change schedule will be required for this operation as well.

When full account is made of the effects of circulating different mud weights, swab pressures induced, and replacing frictional pressure first with back pressure and then with hydrostatic pressure, a multi-stage displacement and trip process may be required. The end result will be a longer process both for tripping out of the hole and for tripping back in.

Conclusions

Consideration of as many parameters as possible along with consideration for interaction between parameters is critical to effective application of MPD.

The effects of operational parameters (circulation rate, choke pressure, and hole cleaning) and fluid parameters (MW and rheology properties) on MPD hydraulics have been demonstrated with an example well.

A good understanding of the effects of these parameters/properties is essential in the optimum design of any MPD project. Careful consideration is needed when choosing which parameter(s) should be adjusted to manage the wellbore pressure during a particular operational event.

Rheology of MPD fluids plays an important role in frictional pressure loss. Rheology model parameters should be determined by readings at all six speeds on the viscometer. Rheology parameters determined by only two readings (600 rpm and 300 rpm) may cause inaccurate wellbore pressure prediction.

A non-zero YP causes a sudden pressure jump when fluid starts to move or when fluid is about to stop moving. It also causes a sudden BHP jump when the drillstring starts to move up or down during tripping regardless of how slow the pipe moves. Low YP fluids help to reduce the pressure jump.

Circulation rate should always be equal to or greater than the optimum rate for MPD. Cuttings accumulation along the wellbore can cause not only downhole problems and reduce drilling efficiency, but also can create higher or unstable wellbore pressure, and has significant impact on the other controllable parameters.

Drillstring rotation and eccentricity affect frictional pressure loss and hole cleaning but in opposite directions. It would be better to circulate sufficient fluid to prevent cuttings beds from forming than to depend on drillstring rotation to remove a cuttings bed.

A specially designed pump schedule should be followed during connections when applying choke pressure to compensate for frictional pressure loss. The pressure profile along the entire open-hole section, not just the BHP, needs to be considered in the process of pump schedule design.

A multi-stage tripping concept is introduced. This technique is used to create multiple hydrostatic gradients while tripping out and to offset the swab pressure during tripping.

Nomenclature

τ	Shear Stress, $lb_f/100ft^2$
YP	Yield Point, $lb_f/100ft^2$
μ	Viscosity, cp
γ	Shear Rate, min^{-1}
$\mathrm{d}P/\mathrm{d}L$	Pressure Gradient, psi/ft
d_1	Pipe Diameter, inches
d_2	Annulus Diameter, inches
ρ	Fluid Density, ppg
ΔP_f	Friction Pressure Loss, psi
P_c	Choke Pressure, psi
D_v	Vertical depth, ft

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Figures

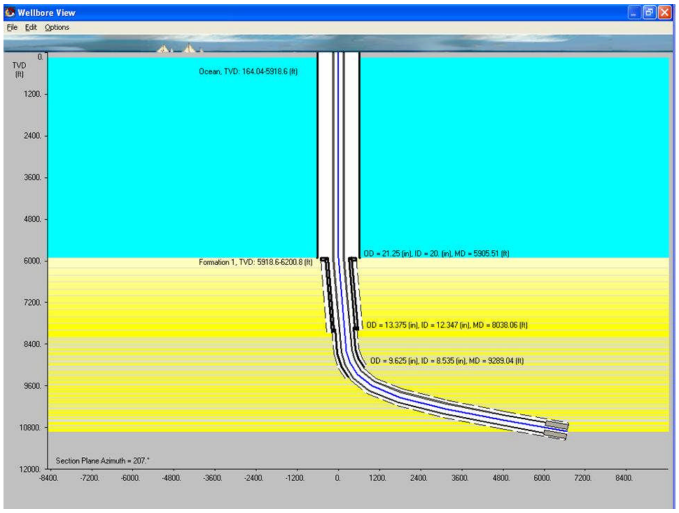

Figure 1. Example Wellbore

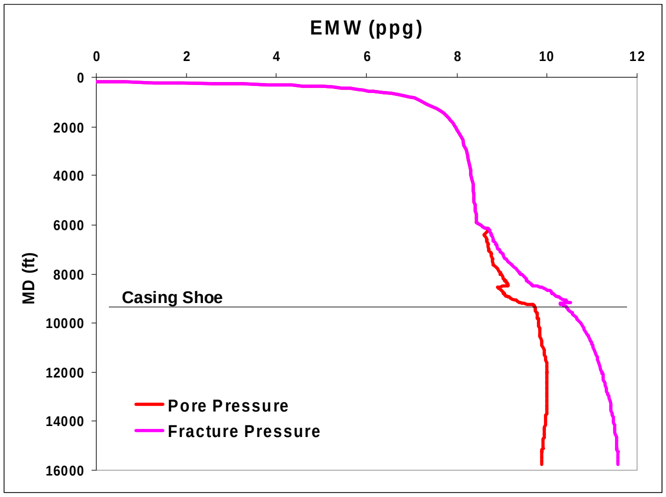

Figure 2. Operating Pressure Window (EMW)

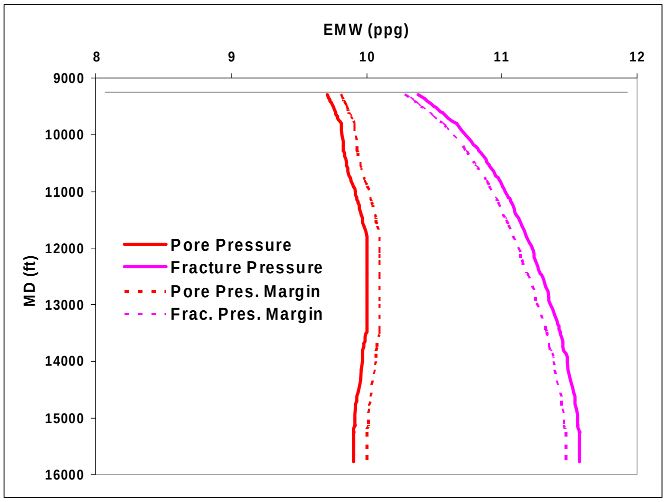

Figure 3. Operating Pressure Window Margins

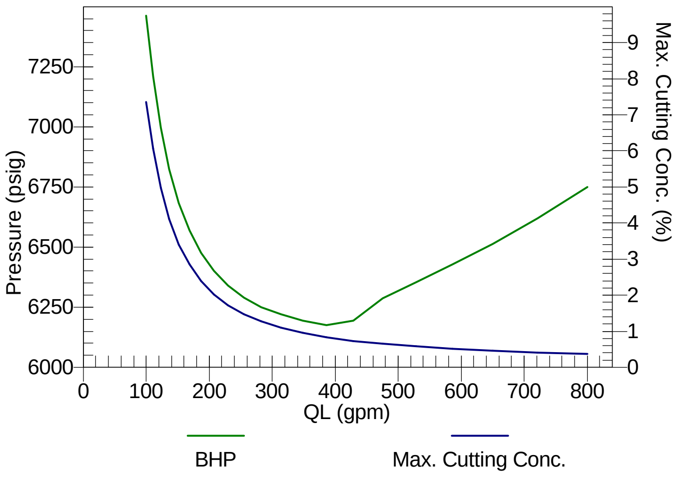

Figure 4. Effect of Injection Rate on Hole Cleaning and BHP

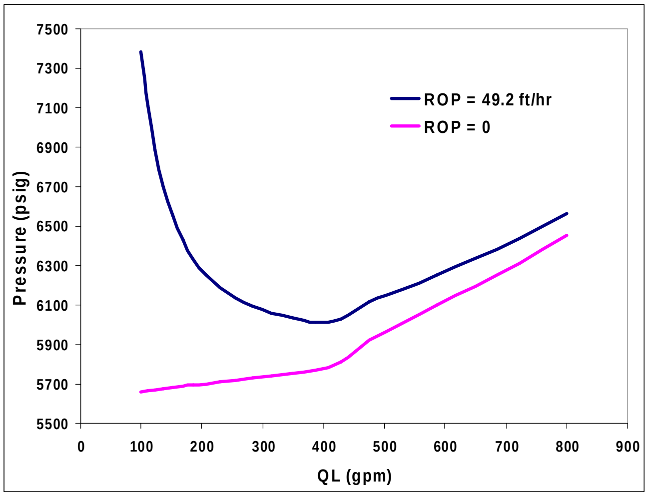

Figure 5. Effect of Cuttings Concentration on ECD

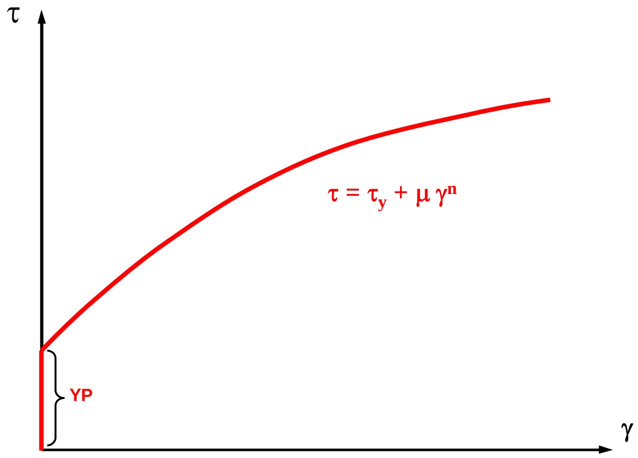

Figure 6. Herschel-Bulkley YP

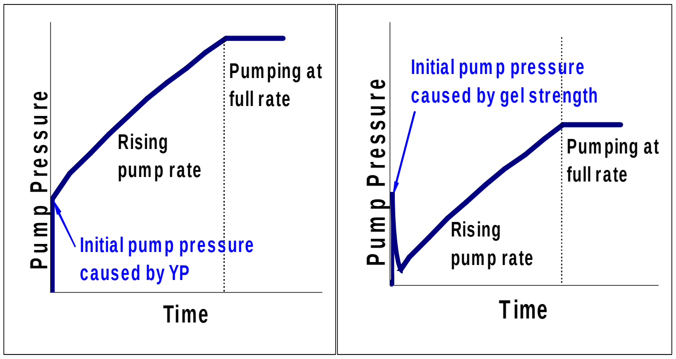

Figure 7. Effect of YP and Gel Strength on Pump Pressure