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Sometimes Neglected Hydraulic Parameters of Underbalanced and Managed Pressure Drilling

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Abstract

Successful drilling, especially in very deep wells, may be driven by hydraulic limiting parameters. Two new technologies, UnderBalanced Drilling (UBD) and Managed Pressure Drilling (MPD) have emerged as solutions to specific hydraulic issues during drilling. A hydraulic parameter can be defined as any factor, mechanical, structural or fluid that impacts the exertion of hydrostatic head on the open hole. Hydraulic parameters, as a group, must be planned for and managed during all drilling operations to prevent unwanted or unsafe conditions.

Many hydraulic parameters are documented thoroughly and therefore well-known in the upstream oil and gas industry. They include; Pump Rate; Drillstring and Hole Geometry; Mud Rheology (including surge effect, swab effect, standpipe pressure and hole cleaning); Surface Backpressure; and Rate of Penetration (ROP). These factors are commonplace and routinely addressed as part of a complete drilling program. Other hydraulic limiting parameters are lesser known and sometimes not addressed in the basis of design for unconventional drilling prospects.

It is paramount that drillers consider all hydraulic parameters that influence UBD or MPD operations or the project can end in failure or with unsuccessful consequences. This paper discusses in general some of the lesser-known hydraulic issues that might be encountered when drilling vertical wells using UBD or MPD techniques, especially to deeper horizons.

MPD / UBD Overview

Hydraulic limits occur in both conventional wells and unconventional wells. The more critical wells experience limits that are unmanageable with conventional techniques; thus the emergence of UBD and MPD. MPD is defined by the International Association of Drilling Contractors (IADC) as “an adaptive drilling process used to more precisely control the annular pressure profile throughout the wellbore.” Simply put, drillers are concerned with the entire pressure profile in the open hole – including the annulus pressure at the casing shoe as well as bottomhole pressure (BHP). MPD does not encourage formation influx.

UBD operations involve drilling into any formation where the pressure exerted by the drilling fluid is less than the formation pressure. The technique reduces the hydrostatic pressure of the drilling fluid column so that the net pressure in the wellbore is less than the formation pressure. Consequently, the formation pressure may cause permeable zones to flow, if conditions allow flow at the surface. UBD can facilitate drilling of pressure-depleted formations and lessen formation damage for better productivity. UBD operations include formation influx in the operating plan except in the case of a hole being drilled for ROP applications in impermeable rock.

In MPD, the driller seeks to stay slightly above or “at-balance” to the downhole pore pressure (PP), or as close to near-balance as possible during the entire section of problem hole, during both drilling and connections. Precise control of downhole pressure allows the driller to effectively drill within the window between PP and fracture gradient (FG) without setting casing prematurely.

MPD largely draws on theory and tools developed for UBD, and therefore the commonality of tools can cause them to be mistaken for one another, causing drillers to develop an unwarranted, unfavorable opinion of the techniques. There are several differences between the two, but the main contrast is that MPD does not invite influx into the wellbore; whereas inviting influx is the objective of UBD. In MPD applications, the operating window is typically tighter and requires the driller to implement a more precise drilling campaign. Understanding this before starting an unconventional drilling project is the key to a successful campaign.

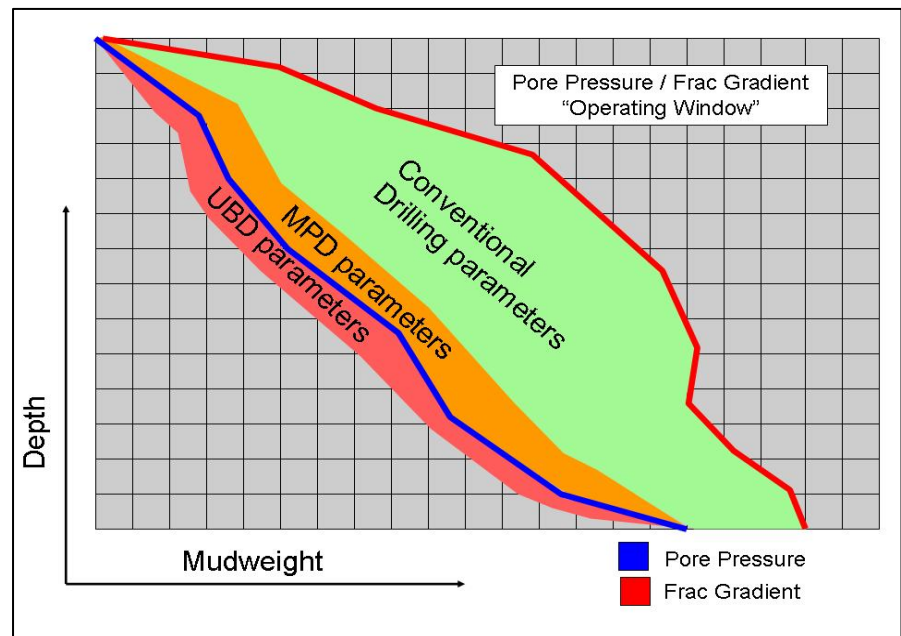


Figure 1: A hypothetical pore pressure / frac gradient operating window. Note that the MPD/UBD hydraulic limits are much narrower than the conventional drilling applications.

Hydraulic Limits

The term “hydraulic limits” appears to be somewhat misunderstood in the upstream oil and gas industry, perhaps because of the many various perceptions of the terminology. Since it is relatively easy to define hydraulics – “The topic of science and engineering dealing with the mechanical properties of liquids... focusing on the engineering uses of fluid properties” – it is the authors’ belief that the misconceptions may be founded in the varying definitions of “limits.” With regards to drilling, some associate the word “limits” with risks, such as underground blowouts, exceeding the FG, mud loss (and resulting differential sticking), twist-offs, or well control issues. Others interpret the word “limits” to mean limitations of drilling technology or application ability. Others associate the term with how light may the mudweight be to avoid influx when not circulating.

Rather than classifying hydraulic limits as “risks” or “limitations,” it is better to think of them as boundaries to which drillers must adhere while drilling. These boundaries often become narrower when drilling deeper, higher-pressured wells, much like a fairway on a golf course will become narrower at more prestigious courses.

Surface Backpressure

This hydraulic limit stands out because it is the only obvious parameter that is not connected to conventional drilling. Surface backpressure may be applied on the annulus to control the entire pressure profile within the open hole during MPD operations.

Increasing Open Hole Length

The PP/FG window typically is narrower in deeper environments and can pose hydraulic obstacles when overlooked. For instance, when drilling a UBD well, the depth of the hole cannot be increased indefinitely because of the increased friction on the open hole. As the well is drilled deeper, the Equivalent Circulating Density (ECD) increases when the pumps are on at the optimum pump rate.

As vertical well depth increases, the pressure exerted on the formation also increases. As the driller approaches the frac gradient at the top of the open hole interval, the pressure at the bottom of the hole may approach pore pressure.

UBD is dependent in most cases on specifically designed underbalanced margins. This may be due to permeability of the rock, fracture perm, and kick tolerance at other horizons in the open wellbore or other factors. It is possible with increasing depth to experience dynamic friction while circulating to clean the hole that negates the ability to continue drilling with a prescribed underbalanced margin.

Synthetic-Based Mud Rheology

Another minor hydraulic limiting parameter that comes into play during unconventional drilling occurs because of the compressibility of Synthetic-Based Mud (SBM). As the formation is drilled deeper, some synthetic drilling fluids tend to compress due to the pressure from the hydrostatic head. This is an “artificially created” contributor to hydraulic limit.

Circulation Rate

Oftentimes, drillers will attempt to decrease circulation rate to reduce ECD and consequent mud losses, but the mudweight may actually increase because the cutting concentration goes up. The drilling rate of penetration must be decreased in accordance with the circulation rate. While the cuttings concentration increases, the efficiency of hole cleaning decreases, and therefore ROP decreases naturally. This effect should be obvious, like a self-checking test, but problems can still arise when these hydraulic impacting issues are ignored.

Annulus Configuration

The pressure changes created by transitions between various drill string, drilling liner and/or casing diameters may alter hydraulic limits for drillers. Strange then, that these parameters are not often illustrated in drilling programs.

In a deep vertical well, the annulus cross-sectional area can change several times depending on the casing program. These changes in diameter affect mud flow, and therefore significantly affect the hydraulic boundaries of the wellbore. For instance, in a 20,000' vertical hole (Figure 2), there can be several annulus diameter transitions. In this hypothetical wellbore diagram, the 17 1/2" section of the hole is drilled with five-inch drillpipe. Then 13 3/8" casing is set, having an inside diameter (ID) of 12.252". In the next section a 12 1/4" hole is drilled and 9 5/8" casing is set with a 8.573 ID. In the third section, 3 1/2" drillpipe is used to drill 8 1/2" hole and 7" casing is set, with a 6.184" ID. The final open hole section is 6 1/8" in diameter.

At a depth of 20,000" the 3 1/2" drillstring causes too much standpipe pressure (SPP), so a tapered drill pipe string must be used. This factor, along with the BHA, contributes additional pressure transitions in the open hole that may significantly affect the hydraulic limits in the well.

Finally, in this example, the bottomhole PP/FG operating window has a very narrow 0.4 ppg margin, leaving the driller to maneuver precisely through a delicate operating window. To do this, all the contributing factors regarding hydraulic limits must be observed, as a very small mistake could lead to loss of the well.

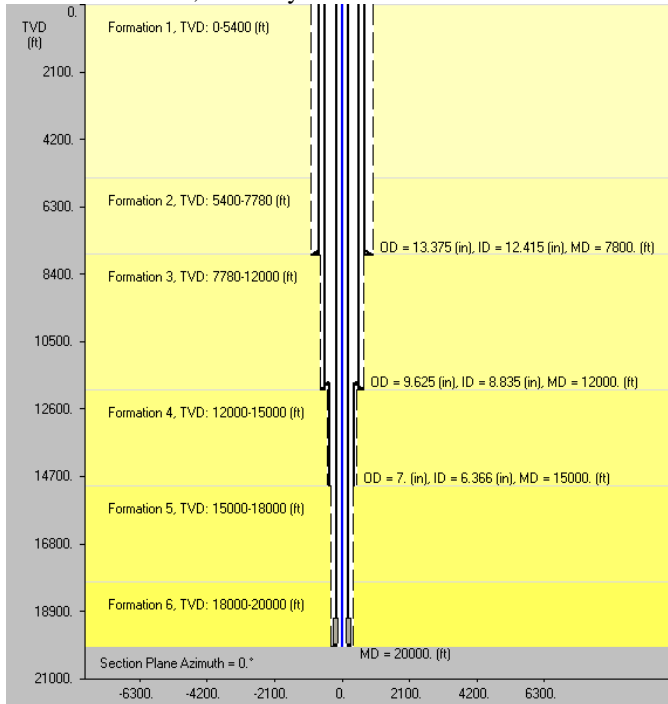


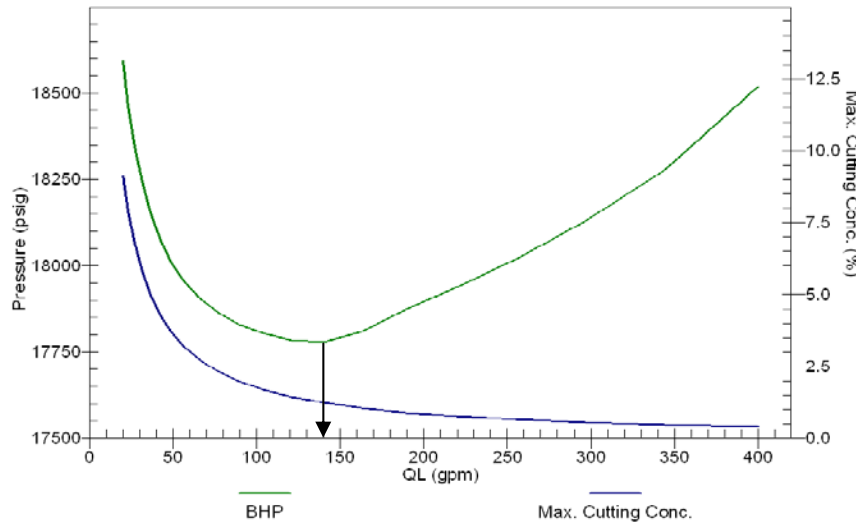
Figure 2 Wellbore configuration

Figure 2 shows the details of the wellbore configuration. The 5,000 ft open hole section penetrates through two layers of formations that have a narrow pore pressure (17 ppg) and fracture pressure (17.4 ppg) window. Due to the narrow operating window (0.4 ppg) along the open hole section, the selection of MW is especially important. With a 20,000 ft deep well, the ECD caused by frictional pressure loss along the annulus could be well above 0.4 ppg. Therefore, the MW to drill through the open hole section must be lighter than 17 ppg to avoid breakdown of the formation. On the other hand, a MW less than pore pressure could cause the well to be underbalanced if sufficient backpressure is not applied when the circulation is stopped (such as during connections). The lighter the MW, the higher backpressure is needed. Considering the limits of the surface equipment, a synthetic based mud (SBM) MW of 16.8 ppg is selected for drilling through the final hole section.

Another important parameter that should be carefully considered is the design of the circulating rate. Insufficient circulating rate will cause hole cleaning problems, while a higher than necessary circulating rate will cause higher frictional pressure losses, which makes it more difficult to maintain the wellbore pressure along the open hole section within the operating window. The BHP curve (the green curve) in Figure 3 is used to design the optimum circulating rate. The circulating rate corresponding to the minimum BHP is the optimum circulating rate (about 140 gpm in this case). Injecting less than the optimum rate will cause hole cleaning problems (cuttings accumulation along the wellbore annulus), which

results in a higher BHP (the left side of the green curve in Figure 3). On the other hand, injecting more fluid than the optimum rate will cause a higher frictional pressure loss, which also results in a higher BHP (the right side of the green curve in Figure 3).

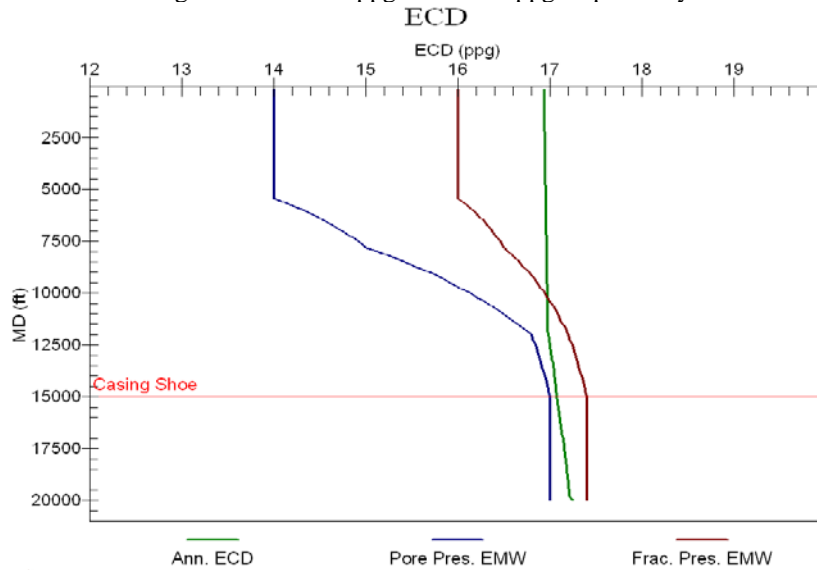
Pressure, Max. Cutting Conc. vs. Flow Rate(s)



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Figure 3 Optimum Circulating Rates

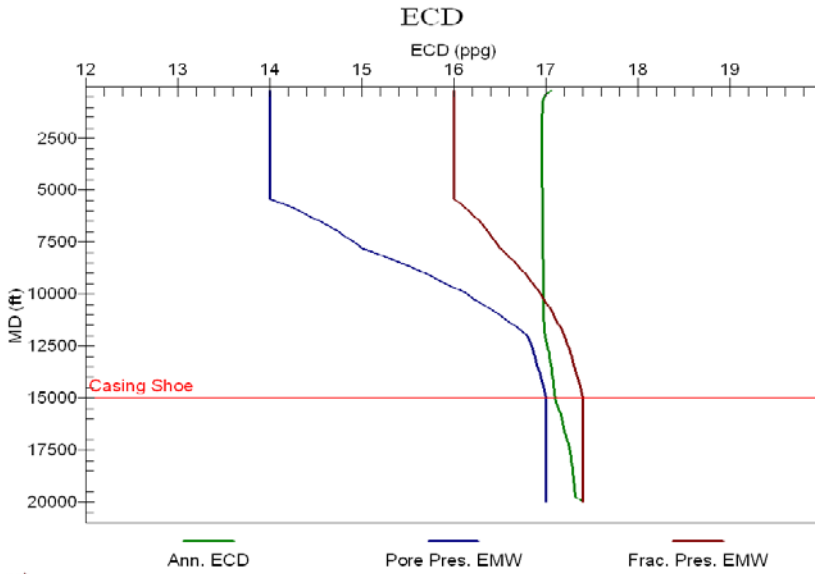
Figure 4 displays the profile of wellbore pressure (green curve) when injecting at the optimum circulating rate (140 gpm). The other two curves are the formation pore pressure and formation fracture pressure respectively. As shown in the figure, wellbore pressure along the open hole section falls within the operating window. The ECDs at the bottom of the open hole and at the casing shoe are 17.21 ppg and 17.07 ppg respectively.



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Figure 4 Pressure profile during drilling with the optimum pump rate (Q = 140 gpm)

Injecting SBM at a higher rate will increase pressures at the bottom and at the casing shoe. However, the amount of increase at the two locations may not be the same. Figure 5 displays the pressure profiles when injecting at 280 gpm. The pressures at the bottom and at the casing shoe in this case are 17.4 ppg and 17.1 ppg respectively. The increase of BHP is 0.19 ppg when changing injection rate from 140 gpm to 280 gpm, while it is only 0.03 ppg at the casing shoe. The difference in the pressure increase at the bottom of the hole and casing shoe is related to the wellbore/drillstring configuration as well as the inclination angle of the open hole section. A smaller annular section causes a more rapid increase of frictional pressure loss with a pump rate increase than a larger annular section would cause.



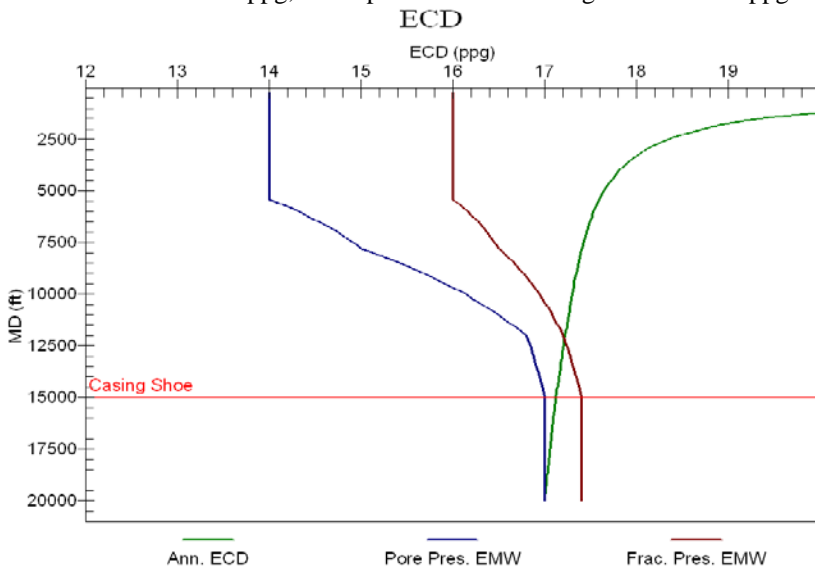
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Figure 5 Pressure profile during drilling with the maximum pump rate (Q = 280 gpm)

Considering both hole cleaning and the operating window, the injection rate could be between 140 gpm and 280 gpm. However, the injection rate may be limited by the pressure or power capacity of the injection equipment. With the 3 1/2" drill pipe, the injection pressure is 4000 psi when injecting at 140 gpm of SBM and over 9,000 psi when injecting at 280 gpm. Over 70% of the pump horsepower in this case is consumed by the drillstring due to the high friction inside the drillstring. A larger drill pipe may reduce the friction inside the drillstring significantly while increasing the friction in the annulus insignificantly. For example, if 4" instead of 3 1/2" drill pipe is used, the injection pressure will be 2890 psi when injecting at 140 gpm of SBM and 6480 psi when injecting at 280 gpm. About 50% of the pump horsepower is consumed by the drillstring in this case.

Besides using a larger size of drill pipe, using a less viscous mud could also reduce the friction inside the drillstring. However, a less viscous mud also has less cuttings transport capacity. It could be necessary to circulate at a higher pump rate to satisfy hole cleaning requirements. Higher circulating rates cause higher frictional pressure loss inside the drillstring. Reducing friction by using a less viscous mud may not be an option if hole cleaning is an issue.

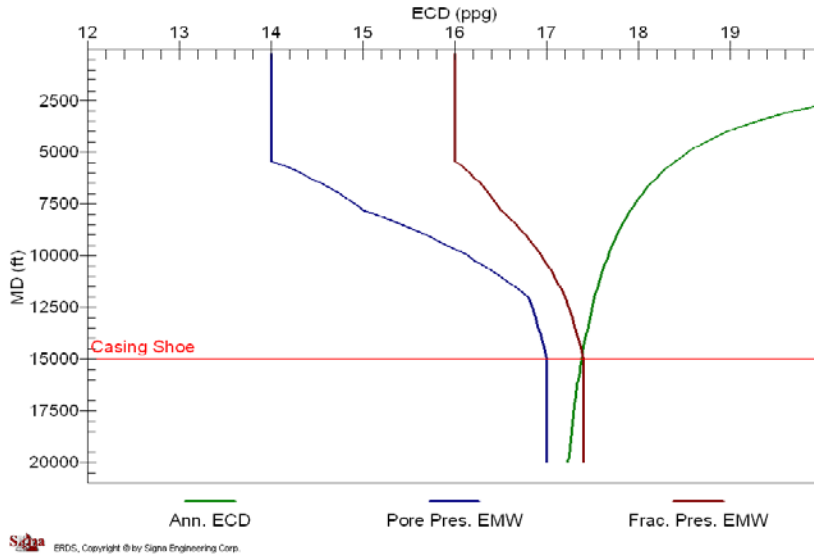
During the connections, either a continuous circulating system is needed to maintain the frictional pressure loss along the entire circulating system, or surface choke pressure is necessary to keep the wellbore pressure along the open hole section within the operating window. By a quick estimation, 208 psi is equivalent to 0.2 ppg at a vertical depth of 20,000 ft. However, due to the compressibility of the SBM, 200 psi choke pressure will result in a 0.2 ppg BHP increase during connections. Figure 6 shows the pressure profile when 200 psi choke pressure is applied after circulation is stopped. The BHP in this case is 17 ppg, while pressure at the casing shoe is 17.12 ppg.



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Figure 6 Pressure profiles during connection with 200 psi choke pressure

Figure 7 shows the maximum choke pressure (400 psi) that can be applied without breaking down the formation during a connection. The wellbore pressure in this case is 17.21 ppg at TD and 17.4 ppg at the casing shoe. The figure shows that, although BHP in this case is in the middle of the operating window, wellbore pressure at the casing shoe is right at the formation fracture pressure. Applying a choke pressure greater than 400 psi could break down the formation near the casing shoe.



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Figure 7 Pressure profiles during connection with 400 psi backpressure

Observation of the above figures reveals that the slope of wellbore pressure profiles (Annulus ECD) in the open hole section are different between drilling and connection. Wellbore pressure increases with depth during drilling due to frictional pressure loss (Figures 4 and 5) while it decreases with depth during connections due to the application of choke pressure at the surface (Figures 6 and 7). This makes the practice of keeping BHP constant during drilling and connections questionable. To keep BHP constant all the time, one may need to manage annulus pressure near the middle of the open hole window to prevent the well from getting underbalanced at the casing shoe during drilling and from breaking down the formation at the casing shoe during connection (as shown on the left side of Figure 8). In other words, managing for constant pressure at the bottom of the hole (BHP) all the time requires a wider operating window to allow the wider change of pressure at the casing shoe between drilling and connection. Keeping BHP constant all the time limits the maximum length of the open hole section that can be drilled within a given operating window. Constant BHP can be applied at only one depth.

A more reasonable practice is to consider the wellbore pressure over the entire open hole section not just the bottom of the hole (as shown on the right side of Figure 8). By moving the point of constant pressure from the bottom to a point between the bottom of the hole and the casing shoe, the pressure profiles during drilling and connections can fit into a narrower operating pressure window. This will extend the total length of the open hole section that can be drilled within a given operating window. Hydraulic modeling is needed to determine the optimum circulating rate during drilling and the optimum choke pressure during connections, as well as the pump rate versus choke pressure schedule to change wellbore pressure profiles in the open hole section smoothly between drilling and connections. This technique will allow wellbore pressures to vary at both TD and casing shoe between drilling and connections, but will reduce the pressure variation at the casing shoe compared with the constant BHP technique.

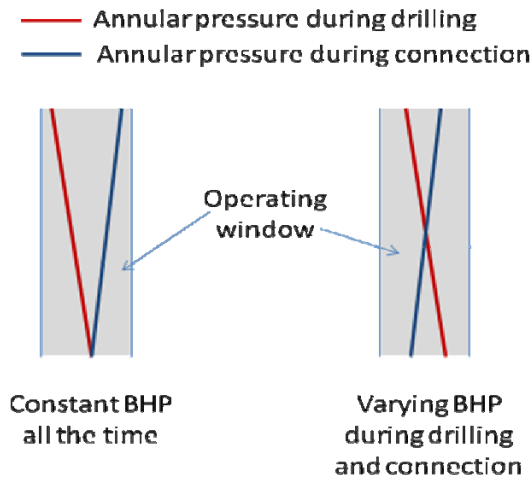


Figure 8 Constant BHP or varying BHP during drilling and connection

Conclusions

Both MPD and UBD are “job specific” technologies. That is, each job is a stand alone project and lessons learned on previous projects may apply in some ways, but most certainly do not apply in all cases. Engineers must do the science and study the application thoroughly before attempting either technique. Even with the best efforts in pre-planning, unconventional drilling applications still require a rigorous contingency plan effort and constant attention by someone with a keen understanding of associated hydraulic limits.

With a given hydraulic program and BHA, the depth that can be drilled underbalanced has a limitation. UBD may be feasible with a given hydraulic program and BHA at the casing shoe, but UBD conditions will experience an open hole length limit. Hydraulic limits are critical parameters that need to be considered, and can only be properly addressed when a robust computer software is used for flow modeling UBD or MPD wells.

Optimum EMW might not necessarily be right in the middle of the PP/FG window, where most drillers would assume it would be. The industry could also benefit from a flow modeling exercise which helps determine the optimum “point of constant pressure” control. This **point of constant pressure** would illustrate the optimum EMW at a desired depth with the mud in the hole at that time which fits most comfortably within the frac-pore limits and gives the widest margins of error between taking a kick and losing mud into the formation. A clearly defined point of constant pressure in the open hole would aid in determining how much lighter than conventional the mud should be at that depth to avoid the following:

- Mud loss upon regaining circulation after connections
- Minimum surface backpressure to avoid formation influx when the pumps are off
- Drilling more open hole than can be managed with the given frac and pore pressure window