GeoBalance® MPD Services
Controlling Collapse Pressure
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The Effects of Stress
The earth’s crust is continually moving through a process known as plate tectonics. This process creates stresses within the crust. These subsurface stresses can be categorized into three principal stresses, all mutually perpendicular to one another. The relative size of each of these stresses is used to classify the type of fault regime. When the overburden is the highest of the three stresses, the fault regime is classed as normal. When one of the horizontal stresses is the highest, the overburden is the intermediate stress, and the second horizontal stress is the lowest, the fault regime is classed as strike-slip. When the overburden is the lowest stress, the fault regime is classed as reverse.

The stress magnitude affects both wellbore collapse and fracture pressure. The relationship of these three principal stresses has significant impact on wellbore stability in relation to direction and inclination. Therefore, accurately constraining such stresses can help create greater precision when defining borehole pressure limits. The stress magnitude also controls the rate of sediment compaction affecting the rock properties and driving pore pressure generation mechanisms.

The purpose of a horizontal well is to maximize reservoir exposure to help optimize production. The use of horizontal drilling has become popular in reservoirs classified as “unconventional,” where the permeability of rock is marginal and hydraulic stimulation is often necessary. An unconventional reservoir is typically organic-rich shale, a tight-gas sandstone, or coal-bed methane (CBM). Because unconventional formations have low permeability and porosity, the primary production mechanism is the natural fracture system.
Intersecting fractures requires geomechanical knowledge with respect to stress orientation. Often, the direction is of the least principle stress, which can be a more problematic drilling direction in terms of borehole stability and might also require mud weights greater than those of a vertical well. To maximize the production potential of a well, a lateral that can intersect a high quantity of fractures is often planned.

Quite often, a mud program is designed based on predicted or observed events, such as losses, break out, and kicks from previous wells. The accuracy of such predictions and observations can impact the level of certainty with respect to pore, fracture, and collapse pressure profiles of the well being drilled. This approach could lead to higher mud weights than necessary, resulting in increased equivalent circulating densities (ECD), slow penetration rates (ROP), and damage to any microfractures that could contribute to production.

Depending on the hole size, flow rates, fluid properties, and temperature, ECD can become substantially high as the lateral is drilled. Within narrow drilling windows, the ECD could exceed the fracture pressures of rock, minimally causing ballooning. Ballooning, in essence, is hydraulic fracturing of rock while drilling. Once ballooning begins, losses occur immediately, but can be gradual and can go unnoticed on the rig site. What is not immediately observed is the gas that can be produced from the dilated fractures once the pumps are shut off for connections and the ECD effect is relieved (pressure cycling the formation). One theory with respect to long laterals is that the gas bubble will travel along the lateral and will only begin expansion once it has reached the vertical section. At this point, an influx is detected at surface, and standard shut-in procedures and pressures can lead to a misinterpretation of the actual pore pressures along the lateral attributed to gas expansion affects.

![](image)

*Pore pressure along the lateral attributed to gas expansion effects.*
The conventionally drilled lateral exerts stress cycles in the range of several hundred psi on the formation and could lead to further instability when transitioning from circulating to non-circulating, particularly in shale. This pressure cycling forces fluids into the fissile planes, which could destabilize the formation, lead to sloughing and, as mentioned previously, affect the pressure model for both the well being drilled and future wells.

![Fissile Shale: to shell or break stone into plates](image)

*Pressure cycling forces fluids into fissile planes, destabilizing the formation.*

A worst-case-scenario for the effect of higher ECD in laterals is that, once the fracture gradient is exceeded, total losses can occur, which could lead to loss/kick scenarios, wellbore collapse (if weaker formations are exposed), stuck pipe, or sidetracks. These types of issues have historically caused cessation of drilling, failure to achieve the required exposure to the reservoir, reservoir damage, and extreme costs incurred by an already strained economic asset.

In narrow pressure windows, challenges remain even after drilling has concluded. Once total depth (TD) has been reached, dealing with surge/swab effects on trips and while running casing has, in some cases, exacerbated or recreated the entire ECD scenario depicted, adding additional cost and risk to the well during a critical point of the construction stage. While running casing, the surge pressures often exceed the fracture pressure as soon as the shoe enters the openhole; thus, losses are experienced running the casing, sticking is possible, and, once cementation begins, zonal isolation might not be achieved because of weakened rocks and elevated ECD.
Managed Pressure Drilling (MPD)

Managed pressure drilling (MPD) is a recent technological improvement that is helping create an entirely new economic outlook for unlocking unconventional resources. MPD and associated automation techniques allows operators to improve the economic risk of unconventional assets by reducing overall drilling and exploitation costs.

During typical operations in areas of high tectonic stress, wellbore incidents while building the curve can be encountered, which can result in nonproductive time (NPT) up to several days. ROP improvement is another primary challenge for operators related to wellbore construction time.

MPD addresses such challenges by allowing the well to be drilled using a closed-loop system. The closed loop is formed with a rotating control device (RCD) mounted on top of the rig’s annular blowout preventer (BOP). The sole purpose of the RCD is to safely divert flow away from the rig floor to the choke manifold. The choke manifold is the pressure regulator of the system.
The chokes deployed with the MPD system can be used in full automation or operated manually. The choke skid consists of three hydraulic gate seat type chokes in which the trims can be configured for anticipated flow rates, mud weights, and well pressures. Each choke can be individually isolated by either pneumatic or manual valves.

Because the choke is the pressure regulator of the closed-loop system, flow across the choke must be maintained at all times. This is especially true for a well having a narrow margin between the pore /collapse pressure and fracture gradient.

To maintain the flow across the choke during connection and while tripping, a novel technique of diverting the flow from the rig’s standpipe to the chokes with a rig pump diverter (RPD) has been developed. The RPD technology has been implemented in the field for over a year and has become a key element to the optimization process.

The MPD Process

Before any MPD equipment is mobilized, a fundamental understanding of the drilling environment must exist. To design the MPD program, a dedicated engineer is assigned to build a hydraulic pressure profile, create process flow diagrams, valve numbering diagrams, make recommendations regarding mud weights, design the tripping strategy, build operational procedures, perform a hazard identification/hazardous operation risk review, and select choke configuration.

Once the equipment is mobilized to the well site, rig crew training is conducted. As the crew becomes comfortable with the technology, the mud weights and bottomhole pressures (BHP) would be reduced until there was an indication that the BHP is approaching the pore or collapse pressure. Once this boundary has been identified, it will become the lower pressure limit for the system. Conversely, with the MPD system, dynamic leakoff tests or formation integrity tests can be performed at any time while drilling to ascertain the upper pressure limits.

The following log illustrates the MPD process. The far right column is pressures expressed in mud weight. The three curves in this track are the actual pressure measured using pressure while drilling (PWD) (red), the desired control pressure (light blue dotted), and the mud weight (solid blue). The third track is choke surface pressure given in psi, which is used to control the BHP. The curves in this track consist of the set points sent to the chokes from the real-time hydraulics model (dashed black) and the actual choke response (red solid). The second track is a time track with the on bottom indicator shown in green and in-slips indicator shown in blue. The first track consists of ROP (red solid) and block position (dashed black).
Haynesville Case History: Challenging Formation

The Haynesville formation, which is a Jurassic aged mudstone comprised of calcium carbonate and argillaceous material, underlies southern Arkansas, northwest Louisiana, and eastern Texas. The Haynesville formation dips to the south toward the Gulf of Mexico and, with this dip, pressures and temperatures are typically higher in the southern regions. Even in the northern regions, abnormal pressures occur with bottomhole temperatures (BHT) greater than 350°F. Because of the high BHT and the limited availability of ultra-hot hole MWD tools, the majority of production and exploration within this formation has been limited to the northern regions.

The Haynesville formation presents several challenges to wellbore construction attributed to high compressive abrasive rock strength, fracture networks with influxes of high shut-in pressure, and low ROP associated with horizontal drilling. Recently, operators have begun to use MPD to optimize the process. During MPD operation in this area, it was observed that the reduced mud weights used yielded lower circulating temperatures; it is believed that this reduction is the result of lower solids in the mud system.

The following trial discussed was conducted to verify temperature reductions and improved ROP observed in other wells. The operator’s goal was to test the success of the technology so that other properties could be exploited beyond the temperature limits of current hot hole tools.

Based on the offset wells, the operator wanted to reduce bottomhole circulating temperatures (BHCT) by drilling with a fluid system containing fewer solids. MPD helped accomplish this by allowing higher BHPs to be controlled with lower density fluids, as it is theorized that the solids in the drilling fluid are more thermally conductive than the base fluid (oil or water).
Haynesville Case History: MPD Trials

MPD for the particular wells discussed began at the kickoff point and a planned trip for bottomhole assembly (BHA) change out was made once the lateral was landed. The operator was concerned about the first well because of its history of higher background gas as well as a history of kicks and sloughing shale in the build section. Therefore, the request was made to control the well between a 16.0 and 16.2-ppg EMW until the lateral was landed. For the planned trip out, the MPD system was used to control the surge/swab effects until the bit was at shoe. At this point, a new barrier fluid system was used to help prevent gas migration and comingling of the MPD drilling fluid and the balanced mud cap. The barrier fluid used was an inorganic synthetic polymer with thixotropic properties that form a very rigid gel structure when the fluids are static, but becomes miscible once sheared. Shearing of the barrier pill was accomplished by simply tripping the pipe through the pill and circulating the pill out.

The barrier fluid was successful within this well at preventing the MPD fluid (14.6 ppg) and balanced mud cap (16.2 ppg) from comingling during back-to-back trips. During the first application, the logging while drilling (LWD) tool failed during displacement of the first mud cap to MPD fluid. Displacement was reversed mid-stream and the failed LWD tool was pulled out of hole. Upon displacing during the subsequent trip, a distinct density boundary was measured by the mud engineer to validate the trial.

Again, the objective was to validate the temperature reduction observed during other high-pressure/high-temperature (HP/HT) MPD operations. ROP increased by 50% and bottomhole temperatures (BHT) decreased by 20°F in both wells.
As stated previously, the well plan and temperature comparison were designed based on a direct offset wellhead 20 ft from the test well. While drilling the lateral, both mud weight and BHP were reduced to quantify the temperature effect. The graph below illustrates the step down of BHP while drilling the lateral. This step down was achieved using a patented process that allows control any point in the wellbore. An early MPD observation was that, for extended-reach wells, the well cannot be controlled at the bit in isolation. In this scenario, it would lead to a kick caused by pressure at the heel dropping below the formation pressure. For this reason, the test wells were designed for the MPD system to control to the heel of the lateral. The graph on the following page illustrates resultant temperatures observed within the first test well.

Step down of BHP while drilling the lateral.
The aqua colored trace is the direct offset well’s temperature profile. The light blue is a well several miles away and up structure, and brown is the test well. Because the goal of the trial was verification of temperature reduction to prolong LWD life, the temperatures from the three wells were measured using LWD sensors from the same vendor. The comparison of the first test well indicated the 1.8-ppg difference in mud weight yielded a 30°F BHCT difference. The 1.8-ppg reduction in mud weight had significant impact on the ROP. The improvement allowed the well to be control drilled for LWD log quality.

Even with the controlled drilling and relogging section for LWD, the test allowed improved ROP. When MPD operations began on the test well, it was four days behind the AFE. At TD, the actual days vs. depth was one day ahead of AFE.

The success of the trials confirmed to the operator that using the MPD technology could allow other properties to be exploited beyond the temperature limits of current hot hole tools used.