High-Pressure, High-Temperature Well Construction

Drilling and completing wells in HPHT environments is difficult and dangerous. But as activity in these areas expands, transferring experience, expertise and knowledge about the best techniques from person to person and well to well is essential to reduce risks, increase safety and efficiency, and ultimately, improve financial returns.

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CemCADE, DensCRETE, FMP (Drilling fluids monitoring package), MudCADE, MUDPUSH, PRISM (precision recording for job supervision and monitoring) and ULTIDRILL are marks of Schlumberger.
The principles of well construction in high-pressure, high-temperature (HPHT) wells are not significantly different from those used in less demanding wells, but challenges remain because of conditions that limit the range of suitable materials and affect equipment performance. The margins for error are small and the potential consequences of failure are great.

Despite the challenges, interest in these wells has remained high and the number of HPHT wells has grown steadily. Reservoir pressures in excess of 10,000 psi [68.9 MPa] have been exploited in many parts of the world, particularly in the search for gas. High-temperature wells have been successfully drilled into reservoirs where temperatures exceed 300°F [149°C] in Qatar, Ras al Khaimah, Sudan and elsewhere. In China exploitation of 500°F [260°C] reservoirs is being planned for 1998.

Even more challenging conditions exist where high pressures and temperatures are present together as in Angola, the USA, Yemen and the North Sea. In these regions it is not uncommon for well temperatures exceeding 350°F [177°C] to coexist with pressure gradients requiring mud weights in excess of 16 ppg [1.9 g/cm³]. The most extreme wells in the North Sea (Ranger well 29/5B-4), Yemen (Shell Abbass 1 well) and the USA (Sohio M.E. Coward well) have temperatures above 400°F [204°C] and pressures in excess of 16 ppg [1.9 g/cm³]. The most extreme wells in the North Sea (Ranger well 29/5B-4), Yemen (Shell Abbass 1 well) and the USA (Sohio M.E. Coward well) have temperatures above 400°F [204°C] and pressures in excess of 16 ppg [1.9 g/cm³].

Even with growing experience, many aspects of drilling and completing HPHT wells continue to demand special attention. For example, secondary well control relies on surface equipment being able to function reliably under extreme conditions. Blowout preventer (BOP) elastomers and flexible hoses must be rated to withstand the temperatures and pressures for long enough to evacuate a rig during the worst-case scenario (often considered to be complete expulsion of drilling fluid from the well after loss of well control).

Evaluating HPHT wells requires special logging and testing tools, with downhole mechanical and electrical equipment capable of withstanding harsh conditions of elevated temperature and pressure, high-temperature explosives for perforating, and procedures for their successful operation. These aspects of exploiting HPHT wells are addressed elsewhere in this issue (see “High-Pressure, High-Temperature Well Logging, Perforating and Testing,” page 50).

Oilfield Review first evaluated HPHT drilling in 1993.¹ Much progress has been made in the last five years. This article examines recent advances in HPHT well construction, drilling fluids and cementing techniques, with examples of procedures and guidelines for routine and contingency actions. We evaluate current well-control practices that emphasize the application of computer simulations to model downhole temperatures and drilling fluid properties. When combined with sophisticated hydraulic models, these simulations help well engineers reliably predict downhole pressures to within 1% of the actual conditions. Techniques for measurement of drilling fluid parameters at surface to the same accuracy complement the models, permitting control of fluid properties and ultimately downhole pressures. Finally, we review new cementing practices developed specifically for HPHT wells.

Planning for Success
Most of the hazards of drilling HPHT wells are related to overpressured formations. Ideally, such wells would be drilled with high enough mud weight to give a comfortable safety margin over pore pressure. The mud engineer’s job in formulating the mud would then be relatively straightforward: minimize formation damage and maximize rate of penetration.

An overpressured formation becomes a major problem when the formation fracture pressure is close to that in the overpressured zone. This results in drilling conditions where kicks are easily taken, and where fractures can be inadvertently initiated, resulting in drilling fluid losses that are difficult to control.

These problems are clearly illustrated in the Elgin and Franklin fields, operated by Elf Exploration UK Plc, in the North Sea approximately 240 km [150 miles] east of Aberdeen, Scotland.² Reservoirs in the Upper Jurassic Franklin sands and the Middle Jurassic Pentland sands are hot (up to 392°F [200°C]) and deep (18,370 ft [5600 m]). The pressure gradient exhibits a marked increase below the


Kimmeridge claystone with reservoir pressure of 16,330 psi [112.5 MPa] (below). These considerable drilling challenges are compounded by the small margin—approximately 1400 psi [9650 kPa]—between fracture and pore pressure in the lowermost intervals. A 1400-psi hydrostatic pressure window at 15,000 ft [4750 m] corresponds to a small increment in mud weight of 1.8 ppg [0.22 g/cm³]. Similar conditions—with even smaller margins—exist in other North Sea wells, such as those in the Heron project operated by Shell Expro, and in other HPHT fields around the world.

Above all other considerations, risk reduction drives the planning needed to overcome these challenges. Given the potential hazards and costs, experience gained in previous operations must be channeled into maximizing safety, eliminating unproductive time and increasing efficiency. With HPHT well costs of $20 million becoming relatively common, and with HPHT rig rates among the highest in the industry, time spent correcting well-control problems is expensive.

The cornerstone of this preventive planning is the transfer of HPHT experience, captured in guidelines, procedures and checklists. Some countries have legislation or government recommendations to guide operators; other procedures are based on industry best practices. An example is the UK Institute of Petroleum “Model Code of Safe Practice” for HPHT wells. In addition to formal guidelines, North Sea operators usually seek input from contractors and others experienced in HPHT well construction.

Shell Expro, and its lead contractor Sedco Forex, adopted the policy of mobilizing experienced crews in advance of particularly challenging projects, such as their North Sea Mallard and Heron field developments. This policy ensures that HPHT crews have had previous experience working as a team on less challenging wells, which is seen as a sound investment in achieving a satisfactory outcome on subsequent HPHT wells.

In planning the detailed program for the Mallard wells, Sedco Forex, Shell Expro and other subcontractors met to work through procedures for all critical eventualities and produced a comprehensive, practical HPHT manual. Open communication throughout the discussions helped to achieve a consensus on best practices. One- and two-day training courses familiarized personnel with the procedures, along with refresher sessions on the rig. Feedback during the training sessions and as actual operations progress results in refinements and improvements to procedures.

Much of the Mallard HPHT manual comprises procedures for drilling, well control, suspension or abandonment, and emergency planning—along with descriptions of personnel responsibilities. For example, the manual spells out the need for skilled personnel to ensure continuous and diligent monitoring of key parameters when drilling the reservoir section. Another requirement is the transfer of HPHT experience, captured in guidelines, procedures and checklists. Some countries have legislation or government recommendations to guide operators; other procedures are based on industry best practices. An example is the UK Institute of Petroleum “Model Code of Safe Practice” for HPHT wells. In addition to formal guidelines, North Sea operators usually seek input from contractors and others experienced in HPHT well construction.

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are communicated. An example is the driller’s “Tour Checklist,” which requires the driller to carry out a physical check of mud density, viscosity and temperature every 15 minutes up to the tour change, and communicate this information to the mud engineer, mud logger and drillers, as well as to the new crew. Frequent checks of these critical parameters may reveal any early signs of potential trouble.

Kick control, the most critical of all procedures, starts with an awareness of the risks during each phase of drilling. Sedco Forex uses a three-level “Kick Alert Status” to focus the attention of rig personnel on specific procedures (above). The highest alert level requires adherence to all procedures, precautions and checklists set out in the HPHT manual.

Prevention is, of course, better than a cure for kicks, and procedures capture the mud engineers’ calculations regarding maximum pump rates, tripping speeds and tolerances on parameters. The rig superintendent checks these hydraulic calculations daily to minimize the risk of a kick or of fracturing the formation.


Similar procedures were in place during the recent drilling of three Heron wells for Shell Expro. Not a single kick was taken when drilling the reservoir sections, and this success was largely attributed to the thoroughness of the procedures established to control drilling parameters, such as tripping speeds. On the one occasion that a kick was taken when drilling above the reservoir in a Mallard well, it was detected after only 8 bbl [1.3 m³] flowed, allowing prompt action to control it.

In some cases, the conflicting demands of pore pressure and fracture pressure are difficult to reconcile, and a risk analysis may be needed to determine which one is more important to address. An informed decision might be made to risk fracturing the formation, rather than take a kick, based on the relative ease with which fractures can be plugged or cemented.

**Drilling Fluid Properties**

Hole cleaning and control of formation pressures are critical functions of the drilling fluid. These are achieved when the mud pressure is sufficient to hold back pore pressure and the viscosity is sufficient to transport cuttings from the bit to surface. Viscosity must also be sufficient to hold mud solids in suspension.5

Conventional calculations of downhole pressure, which assume constant drilling fluid properties, are both practical for day-to-day use and accurate enough for routine wells. Downhole static pressures are easy to calculate from mud weight measured at surface, while additional pressures due to circulation can be calculated using established relationships between pump rate and drilling fluid rheological properties.

Errors that result from ignoring variations in mud properties are small in relatively shallow wells. In these settings, mud engineers can concentrate on formulating drilling fluid properties for maximum rates of penetration and optimal hole condition. Formations can commonly withstand moderate overpressure before being fractured, which permits mud engineers to add a comfortable safety margin when weighting the mud.

However, mud properties do vary with downhole pressure and temperature, affecting the accuracy of both surface measurements and downhole estimations of mud weight and viscosity. In HPHT wells these variations can be significant because of the limited safety margins available.

Clearly the ability to predict these effects is critical to the successful drilling of HPHT wells. Small but serious errors in computing the drilling fluid pressure at the reservoir may result from ignoring uncertainties due to either temperature or fluid properties. Simulation of downhole temperature profiles at all phases of the drilling operation is therefore the key to understanding the behavior of HPHT drilling fluids.

**Fluid Simulator**

Simulation starts with a well model that includes a profile of temperatures in different sections of the well and the heat transfer between them under relevant flow conditions. The thermodynamics of the heat transfer can be modeled as a “countercurrent heat exchanger,” familiar to engineering students.

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Circulating fluid moving along the well gains or loses heat from or to its surroundings (previous page, top). The rate of heat exchange depends on the temperature and velocity of the fluid, the thermal conductivity of the formation, the geothermal gradient in the undisturbed reservoir, the specific heat capacity of the mud and other factors. In the presence of casing strings, significant vertical conduction of heat further complicates the temperature profile.

There is a net transfer of heat from the formation to the mud as it goes down the well. On reaching the bit, the mud is still cooler than the surrounding formation. The mud continues to heat up as it returns to surface until it reaches a depth where the formation temperature equals the mud temperature. Above this depth, the mud cools on its way to surface.

Steady-state temperature profiles can be computed once a satisfactory model has been developed. With time, thermal equilibrium can be achieved in two ways—after circulation has ceased or under constant circulating conditions. The static steady-state profile approaches the geothermal gradient, while the circulating temperature profile will vary with pump rate.

The MudCADE program developed by Dowell computes vertical temperature profiles under various conditions. This program has been validated with field data from numerous other HPHT operations. The main inputs are specific heat capacity and thermal conductivity of each component, and the main outputs are the temperatures of the mud inside the drillstring, and the mud inside the annulus, between the drillstring and the casing (right).

Between steady-state circulation and stabilized static conditions, the temperature profiles change with time (previous page, bottom). In theory, after circulation ceases it takes approximately 16 hours for the mud temperature to approach within 10% of the geothermal gradient, while circulating temperatures can take over 6 hours to equilibrate. The temperature simulator must predict temperature transients to enable computation of well pressure during and after changes in pump rate. Where safety margins above pore pressure are small, the reduction in static pressure after circulation may be considerable. Once the details of well temperature are known, the effective mud weight (EMW) can be computed from the relationship between local density, pressure and temperature.
Equivalent circulating density (ECD). During circulation, the pressure increment needed to overcome friction in the annulus and circulate the drilling fluid from a particular depth to surface represents an annular pressure loss (APL). APL increases with pump rate \(\text{(left)}\), and drilling fluid viscosity, and adds to hydrostatic pressure, increasing the total pressure at total depth during circulation. Pump rates must not allow mud pressure to exceed formation fracture pressure \(\text{(right)}\). At each pump rate an equivalent circulating density can be computed that would result in the same total pressure at a particular depth. Since annular pressure losses are a function of viscosity and well geometry, the concept of ECD is most useful when viscosity is well-defined and APL can be modeled as a function of pump rate.

Computing Downhole Fluid Pressure

Instead of using EMW and ECD when calculating pressure in HPHT wells, it is more accurate to consider static, dynamic and cuttings pressures as components of the total downhole fluid pressure.

Static pressure—Static pressure is computed by integration of hydrostatic pressures at each depth. To achieve this, pressure-volume-temperature (PVT) analysis is usually performed on the mud or base fluid \(\text{(above right)}\). Many base fluids used for oil-base muds have high compressibility compared with water-base muds.

By starting at the surface where the pressure and temperature are known, the local density of the fluid can be computed. The predicted hydrostatic pressure and temperature permit the density at the next deeper level in the well to be computed. At the wellsite, the measured mud weight is used as the starting point, increasing the accuracy of the initial conditions. With PVT data, static pressure at each depth can be computed with Dowell MudCADE and DSHyd software.

Dynamic pressure—The dynamic pressure term is more comprehensive than permitted by the concept of ECD. It can account for annular pressure losses (APL) due to moving fluids, pipe velocity (swab and surge) and inertial pressure from string acceleration when tripping and excess pressure required to break thixotropic gels \(\text{(next page, top)}\). Predicting the dynamic pressure contribution to the total pressure requires accurate modeling of mud rheology. Several different relationships are available to relate shear stress to shear rate, and define dynamic viscosity at a given shear rate and temperature.

Depending on the fluid, the mud engineer selects an appropriate rheological model on the basis of fitting a curve to data from HPHT viscometer tests \(\text{(next page, middle)}\). Alternatively, the mud properties may conform to established relationships, such as Bingham plastic model or an empirical power law model with parameters chosen to represent the specific mud behavior \(\text{(next page, bottom)}\).

Modeling software such as the Dowell DSHyd and MudCADE programs incorporates the algorithms for computing dynamic pressure from either Bingham plastic or power law models. The advantage of these \(\text{(over more complex models)}\) is that the rheology parameters derived from them can be easily compared to wellsite measurements made using viscometer readings.
Cuttings pressure—An additional component of the total pressure is from cuttings accumulation, known as the cuttings pressure. Although high-density muds used in HPHT wells tend to reduce cuttings accumulation, their contribution to total mud pressure cannot be ignored. As cuttings are more dense than mud, any accumulation of cuttings in the wellbore will increase the mud pressure acting on the borehole. The additional pressure from cuttings is affected by rate of penetration (ROP), pump rate, cuttings size and distribution.

High ROP increases accumulation of cuttings, and creates large cuttings, which have a higher settling velocity. Although both these effects can be reduced by increasing pump rate, they increase dynamic circulating pressure at the bit. Therefore, during drilling there is a limit to how much the dynamic pressure can be reduced before benefits are overcome by increased cuttings pressure. When cuttings pressure becomes significant at maximum pump rates, it can be controlled by reducing ROP.

Swab and surge. Movement of a pipe through a viscous fluid causes shearing in the boundary layer adjacent to the pipe, accompanied by a shear strain in the fluid. The shear strain is seen as a pressure difference, \( \Delta P \), in the fluid, which adds to the hydrostatic pressure (a). Bottomhole pressure is reduced when pulling pipe out of hole (swabbing) (b) and increased while running pipe into the hole (surging) (c). The changes in pressure are a function of fluid viscosity, well geometry and pipe velocity. Pulling pipe out of the hole at excessive speeds can result in well pressure falling below formation pressure, inducing a kick. Conversely, running pipe in hole at excessive speeds may result in the formation fracture pressure being exceeded. Modeling the dynamic pressures created during swabbing or surging enables the mud engineer to determine safe tripping speeds.

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\Delta P_{\text{hydrostatic}} + \Delta P_{\text{dynamic}}
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\Delta P_{\text{APL}} + \Delta P_{\text{hydrostatic}}
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\[\Delta P_{\text{hydrostatic}}\]

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<th>Rating</th>
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HPHT rheometers. A model of drilling fluid viscosity at downhole conditions is essential to account for dynamic forces correctly, and begins with measurement of drilling fluid viscosity at downhole temperature and pressure. These measurements can be made with either a Fann 70 or a Huxley-Bertram HPHT rheometer. The Fann 70 rheometer is rugged enough for wellsite measurements. The Huxley-Bertram is a coaxial cylinder laboratory rheometer in which an outer rotating cylinder applies shear stress to a fluid that, in turn, directly transmits measurable shear to an inner stationary probe. Temperature and pressure may be varied independently, permitting modeling of most wellbore conditions. The Huxley-Bertram rheometer has five times the resolution at the lower end of the shear stress range and can measure density, compressibility and long-term gel strength under HPHT conditions.

ULTIDRILL fluid behavior matched to power law model. A model of the relationship between shear stress and shear rate can be chosen after establishing the relationship at a given set of downhole conditions (using an HPHT rheometer). In this example, ULTIDRILL fluid behaves according to the power law model, so its viscosity can be predicted across a range of shear rates for the given conditions. Occasionally, drilling fluids may demonstrate behavior similar to more than one model under different conditions. By making a series of laboratory tests, it is possible to predict viscosity across a range of downhole conditions.
Pressure is shown. The average error in the predicted measurement is less than 2%.

A comparison of standpipe pressure predicted in this way with measured model and other models. After making wellsite viscosity measurements to define the model, mud engineers compute pressure losses using software like the Dowell DSHyd program. A comparison of standpipe pressure predicted in this way with measured pressure is shown. The average error in the predicted measurement is less than 2%.

Total pressure—The total pressure is the sum of static, dynamic and cuttings pressure. Expressing the downhole pressure in this general form covers all phases of the operation. The total pressure can be balanced between the lowest safe static pressure and the highest acceptable circulating pressure by achieving a compatible balance of the different terms. The lowest pressures are achieved while accelerating the pipe during pulling out of hole (swabbing) after circulating bottoms up. The highest pressures occur while drilling with high pump and penetration rates, while breaking circulation or while the pipe is accelerating during running in through gelled fluid.

During drilling, mud properties may vary with time to such an extent that the rheological model might need to be changed. Temporary variations in mud properties can cause the same fluid to behave as a power law fluid at one time and as a Bingham plastic fluid at another time, even in the same hole section. The ability to compare actual behavior to both models at the wellsite, and to select the appropriate one, is of great benefit in accurately predicting APL. In practice, the DSHyd program routinely achieves average differences of less than 2% between predicted and measured standpipe pressures.

Pressure Control
Drillers try to avoid fracturing the formation, but at critical depths the difference between the pore pressure and the fracture pressure—mud pressure margin—is very small in some wells, on the order of 500 psi [3.4 MPa]. If total pressure approaches fracture pressure, the first option is to reduce the dynamic pressure. Control of downhole pressure within the mud pressure window can be achieved in many ways. Viscosity, mud weight, mud solids content, pump rate and ROP can be manipulated to change the various terms in the total pressure expression.

Updated pressure predictions, based on wellsite measurements, can aid in deciding which parameters need to be changed to retain the desired downhole fluid properties. Reducing pump rate or mud viscosity while maintaining the pump rate high enough to clean the hole and prevent excessive cuttings pressure can help. The objective is to find a pump rate that minimizes the contributions from dynamic and cuttings pressure.

While dynamic pressure is controlled by reducing the viscosity, care must be taken to ensure that weighing material stays in suspension. Mud solids falling out of suspension cause density segregation of the drilling fluid called sagging. The greatest problem caused by sag is the poor control of bottomhole pressures. Unusually high mud weight can cause induced fractures and lost circulation while low mud weight permits formation fluid influx and wellbore instability. Sagging can occur in both dynamic and static conditions but is most likely to occur under low shear-rate conditions before static viscosity is achieved.

Reduction of total pressure by manipulating static pressure can be achieved only at the expense of the safety margin above formation pore pressure. When the well is at a critical stage, this margin may need to be further reduced while drilling, with additional circulating pressure preventing influx. The well would then have to be circulated to heavier mud prior to tripping. In such cases, extreme care must be taken when making drillpipe connections, as the absence of dynamic pressure may permit influx of well fluid (connection gas).

Manipulation of the drillstring must be done carefully, lifting slowly to minimize swabbing, and steadily, because low acceleration minimizes inertial pressures. Pump rate must also be carefully controlled when displacing lighter mud to heavier mud before tripping. During tripping the cuttings pressure will be zero if the hole has been cleaned properly. The effects of tripping speed and acceleration on the total pressure can be predicted by a simulator such as the DSHyd or MudCADE programs. Optimal speeds can be determined and used in planning the well construction.
Choosing Oil- or Water-Base Mud

The decision to drill with oil- or water-base mud is likely to be made before detailed analysis of the mud properties is attempted. Water-base muds (WBM) include conventional bentonite muds and polymer systems, while oil-base mud can be an invert emulsion, all-oil system, or synthetic oil-base. Each has advantages in cost, environmental impact and drilling performance.

The stability—as defined by rheology and fluid-loss control—of oil-base muds at high temperatures is a clear advantage in HPHT wells. Most are stable to at least 450°F [230°C] in 16-hour laboratory tests. However, oil-base muds do have some significant disadvantages under HPHT conditions. Possibly the greatest of these is the solubility of gas in the base fluid, which makes kick detection more difficult. A gas influx while drilling will go into solution and remain there without causing a significant increase in mud volume until it is relatively near the surface. On coming out of solution, the gas rapidly increases in volume, requiring quick reactions to control the well. Also, the thermal expansion of oil-base muds is higher than water-base muds, which can lead to pressurization of the annulus.

The conventional advantages and disadvantages of oil-base mud also apply to HPHT wells: good protection against differential sticking, reservoir protection and wellbore stability in shales, claystones and salt. ULTIDRILL synthetic oil-base mud is biodegradable and has low toxicity, reducing the potential for environmental damage during its use. It has been successfully used at temperatures up to 395°F [202°C].

Optimizing HPHT Drilling

Careful engineering and monitoring are needed to reconcile the demands made of mud systems (above right). Procedures for using the mud must be consistent with practical tripping speeds while ensuring preservation of safety margins under all conditions.

Mud engineering—Consideration must be given to maintaining the drilling fluid in good condition through efficient solids control, minimization of dilution requirements and the reduction of fluid retention by cuttings (right). Although many criteria must be considered when designing HPHT drilling

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**Key drilling fluid properties.** Mud engineers must consider many aspects of mud performance when designing an HPHT drilling fluid system. The table shows the effect of several key drilling fluid properties on mud performance.
Effects of barite quality. Susceptibility to sagging in a drilling fluid is greatly affected by the particle size of the weighting material. The smaller the particle size, the slower the speed with which it falls through a static fluid, and static sag is less likely to occur. The effects of barite quality are summarized in the table, which shows the plastic viscosity (PV), yield point (YP), API fluid loss and qualitative particle suspension of a water-base bentonite mud recipe made up with five different barite samples. Suspension properties have been rated as follows: VG = very good, G = good, P = poor. The barite particle size is reflected by the surface area (m²/g). The smaller the particles, the greater their surface area per gram, so the finer barite has a larger surface area (as in sample C).

Gel strength needs to be sufficient to support the heavy particles in the mud but no more, otherwise excessive pressures may be needed to break the gel. The pressures needed to break circulation can be modeled at the design stage, and the implications of these additional dynamic pressures accounted for in the design.

Excessive gel strength can result in a further hazard—trapped pressure (next page, top). An influx of formation fluid below a gel will not be observed as a flow at surface until the gel is broken, by which time a large influx may have occurred, resulting in a rapidly deteriorating well-control situation. The problem is magnified by the ability of gas influx to

Dowell mud design flow chart. Dowell has developed a standard procedure to optimize mud rheology and hydraulics. Starting with hole cleaning performance, a range of properties of the proposed mud are checked by modeling. Parameter changes are made as required until the properties and performance of the proposed mud system meet specifications.

cause gelling in water-base muds under certain conditions. If the gas contains carbon dioxide \( \text{CO}_2 \), the pH is reduced, causing dispersants to become less effective, and the carbonate and bicarbonate ions in the mud to continue promoting gelation. Freshwater gel muds with high solids contents are particularly susceptible to this effect. To minimize trapped pressure, the gel content must be kept as low as practically possible.

**Controlling mud density—**Frequent checks of mud density are essential to maintaining downhole pressures within the mud pressure operating window. Recently a technique has been developed to correct surface measurements of mud density for temperature effects and has been used by Shell UK and Dowell in drilling Heron and Shearwater HPHT wells in the UK sector of the North Sea.\(^6\) The drilling program for these wells specified that the overbalance should be limited to 200 psi [1.4 MPa]. Based on the conventional procedure for measuring the mud weight, the error in mud-pressure gradient resulting from a temperature that was 5°F to 15°F [3°C to 8°C] different from the assumed temperature was estimated at 1.5 pptf (psi per thousand ft) to 4.5 pptf [0.0035 SG to 0.0104 SG]. With true vertical depths (TVD) in excess of 15,000 feet, the errors in downhole pressure were estimated at up to 67 psi [460 kPa], far greater than what was acceptable with such a small planned overpressure. By modifying the procedure for taking the mud sample temperature during measurement of the mud weight, such errors have been largely eliminated.

**Pump rates—**Minimum pump rates to clean the well are usually low due to the buoyancy of cuttings in high-density drilling fluids. Therefore, in vertical boreholes, hole cleaning is not usually a big concern in HPHT wells, and pump rates in HPHT wells are more likely to be decided by other factors. Although low pump rates help maintain low ECD, the well program may call for higher rates to reduce bottom-up time and permit timely analysis of drilled cuttings lithology, background or connection gas, and mud solids. It is good practice to design for pump pressures below rig capacity to enable dynamic kill, the intentional increase of dynamic pressure by increasing annular flow rates, to be used when attempting to control the well.

**Controlling sag—**If hole cleaning is not a concern, the mud engineer can focus on assessing the possibility and effects of sagging. Modeling sagging behavior is difficult, and is usually empirically assessed in lab experiments and minimized as far as possible. Schlumberger Cambridge Research, Cambridge, England has conducted ambient temperature and pressure experiments with a dynamic sag tester from which guidelines on the effects of the type of weighting agents, sag mechanisms and low-sag additives have been derived. Procedures written into well programs for mud conditioning, monitoring of mud weight and tripping can all help minimize the effects of sagging.

At the wellsite, the amount of sag occurring in a mud can be quantified from the heaviest and the lightest components of the circulating mud. After assessment of the amount of sag of the circulating mud, appropriate procedures are used to minimize it. In particular, if changes in mud weight indicate density segregation is occurring, laminar shear at low pump rates (which promotes sag) should be avoided (below). Similarly, circulation at low pump rates prior to cementing should be minimized.

Once sag behavior is defined, the hydraulic properties of the mud formulation can be considered in the design process. The goal of the mud engineer is to design a mud that will continue to function between pore pressure and fracture pressure at all times. These pressure limits define the critical mud pressure operating window and must include margins to account for dynamic pressure resulting from swab and surge when tripping.

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6. API specification for barite is that residue greater than 75 μm is a maximum of 3.0% by weight.
Mud Stability

In HPHT wells, the temperature stability of the mud is a key consideration in completing the mud design. The degradation of mud products is temperature and time dependent and can affect all mud properties. Both oil-base and water-base muds can suffer from high-temperature gelation, though the mechanisms are different. Fluid loss increases with temperature and is affected by both product degradation and gelation. Finally, small changes in solids content that result from fluid loss can have a significant impact on viscosity in the high-solids muds typical of HPHT applications.

Temperature stability is tested by hot-rolling mud samples in the lab. Samples are placed in pressure vessels known as bombs and heated to test temperature in an oven while being continuously agitated by rolling. A cycle of temperatures and pressures with periodic assessment of properties tests the ability of a mud formulation to withstand drilling conditions. In some cases, samples may be intentionally contaminated to test for potential adverse interactions.

Quality control of raw materials is essential if the drilling fluid is to behave as expected. Particle size is important in defining sagging and rheology, so it is critical that laboratory tests be carried out on representative samples. Batch numbers and mixing procedures ensure that the mud that goes in the well is as close as possible to the proposed formulation and to that tested in the lab.

After establishing test results and optimizing the drilling fluid, the formulation of the drilling fluid can be recorded for mixing in bulk. In particularly sensitive conditions, the formulation includes batch numbers for products to permit traceability. Procedures for mixing and remixing the mud after aging accompany the formulation to ensure consistent performance in the field.

Data logger for mud control—To monitor mud continuously during HPHT operations, Dowell has developed a data logger called the FMP drilling fluids monitoring package (above). The FMP data logger records mud density, temperature, rheology (yield point and plastic viscosity at a given temperature) and, in water-base mud, pH typically at 10-minute intervals.

The mud data are analyzed by PRISM precision recording for job supervising and monitoring software, and presented as a log of fluid parameters against time. The ability to see trends in these data is of great value in cross-checking other measurements and alerting the crew to changing conditions. For example, the mud balances used on HPHT wells comprise matched components, which, if accidentally mixed between sets, could result in uncalibrated readings. An inconsistent reading from such a balance could be seen quickly, and corrective action taken immediately.

Cementing

After casing is set, the final step in constructing a new well is sealing the annulus between the casing and borehole with cement. One of the objectives of the cementing design is to remove the mud from the annulus with a spacer and then to displace the spacer entirely with cement, leaving no channels or other flaws. To achieve this, the spacer and cement are formulated with a hierarchy of both density and viscosity: the spacer should be more viscous and more dense than the mud it displaces, and the cement more viscous and dense than the spacer.

The normally preferred turbulent flow technique for mud removal is impractical for HPHT applications due to the high viscosity and density of both spacer and cement. Flow rates in excess of 20 bbl/min [0.48 to 0.79 m³/min] are achievable, before the dynamic pressure generated would lead to the bottomhole pressures exceeding the formation fracture pressure.

Modeling hydraulic flow during HPHT cementing is essential to achieve the highest practical annular flow rates. Software, such as the Dowell CemCADE program, simulates the job based on well geometry, reservoir pore and fracture pressures, fluid densities and rheology and casing strength. Several combinations of pump rate, fluid densities and rheology are modeled with manual iteration to find the widest possible pump rate range, the shortest time to complete the job with the best chance of mud removal. Temperatures after circulating and during cementing are also computed by CemCADE software for use in judging the slurry retardation needed.

Spacer design becomes more challenging with oil-base mud. The spacer must be compatible with both the mud and cement while remaining stable at high temperature, retaining high viscosity and preventing excessive fluid loss. Spacer and slurry must also be compatible with downhole elastomers. Oil-water emulsions, such as the Dowell MUD-PUSH-XEO spacer are being successfully used to tackle these demands in HPHT wells.
Cement slurry design—Slurry design generally consists of formulating cement additives to give the desired density, fluid-loss control, rheology while pumping, the appropriate setting time and adequate strength when set. Slurry properties must ensure solids stay in suspension, just as barite must be suspended in mud. Failure to do so can result in loss of well control and channeling on the high side of deviated holes. As cement particles settle to the low side, a continuous water channel may form on the upper side of the hole, creating a path for gas migration.3

Cement slurry design involves special considerations in HPHT wells. Neat cement (without additives) is susceptible to loss of strength and increasing permeability due to shrinkage at temperatures above 230°F [110°C]. To prevent this, part of the cement, typically 25%, is routinely replaced by silica flour (grain size 40 to 50 μm). Slurry density of up to 17.5 ppg [2.1 g/cm³] can be achieved by adjusting solids content. Slurry densities greater than this are frequently needed in HPHT wells, and can be achieved by adding hematite to the slurry design (above right).

Avoiding unpredictable slurry performance is the highest priority in cementing HPHT wells. Long displacement times can be expected because of the depth and low pump rates needed to minimize dynamic pressure. When these factors are combined with the elevated temperatures encountered, there is significant risk of premature cement thickening if the formulation is not appropriate. An additional consideration with HPHT wells is that in long liner intervals the temperature at the top of the liner can be up to 50°F [28°C] lower than at the bottom. However, retarding the cement slurry adequately in the bottom of the hole may result in excessive thickening times in the top section.

Dispersant, retarder and other additives are typically supplied as powder to be mixed into the slurry at the wellsite. Many of these powders start life as liquids before being freeze-dried into powders for ease of handling. In the last year, Dowell has reverted to using the liquid forms directly for preparing sensitive HPHT slurries. These can be prepared and tested in bulk before being shipped to the wellsite. Homogenous liquids help improve control of the recipe, and volumes of liquid can be measured more easily than weights of powder. Slurry samples taken at the wellsite are verified with laboratory tests.

Liquid retarder has additional benefits. The Dowell retarder D161, for example, results in slurries that have long thickening times when moving, but which start to set when pumping stops. This behavior permits over-retarding of the slurry, providing a significant safety factor against premature setting at the bottom of a long interval, while ensuring satisfactory setting in 10 to 12 hours after pumping stops at the top of an interval. Appropriate in long liners where a large safety margin is needed, this approach has been used by Shell in the North Sea in their HPHT Shearwater field and elsewhere by other operators. Liquid dispersants, used to thin the slurry, are available to complement liquid retarders.

Latex, for example, is used as an additive to control fluid loss and rheology in the slurry. In cement it improves tensile strength and prevents gas migration. Latex, supplied as a liquid of finely dispersed particles in water, may be needed as an additive at around 13% of the slurry volume.

Quality assurance—Laboratory testing of cement recipes is critical to ensuring the success of the job, but is valuable only if the mixing process at the wellsite can ensure the same formulation. For demanding HPHT jobs, the use of precisely the same ingredients as those tested is ensured by specifying lot numbers. While small quantities of additives present no problem, large quantities often do. Control of inventory to ensure availability of the same batch in sufficiently large quantities can be an added complication for the cementing contractor.

Best practice requires that all material be available in double the required quantity at the wellsite, in case slurry needs to be dumped for any reason after mixing (for example, due to contaminated mix water).

The Balancing Act

Well construction strives to balance many conflicting requirements. Drilling performance must not compromise well control, and cementing pressure must not jeopardize formation integrity. In HPHT wells, the margins between these conflicting constraints are narrow and careful analysis is required to plan for success. Implementation of the HPHT well construction program requires skilled personnel, guided by established procedures, with accurate information on surface parameters. Software models and downhole measurements help complete the picture by predicting downhole fluid behavior with enough accuracy to permit safe drilling. With all these factors in place, increasingly challenging HPHT wells will continue to be successfully and safely constructed in the future.

—DH, RR, RH