# Drilling fluid meets deep gas drilling challenges

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**GROWING DEMAND FOR** natural gas in North America is driving the E&P industry to look for resources in previously unexplored areas. One region attracting a lot of attention is the deep Gulf of Mexico Continental Shelf. Over 35,000 wells have been drilled in the Outer Continental Shelf (OCS) yet only 5% have drilled below 15,000 ft (subsea) and less than 500 have drilled below 18,000 ft[1,2] even though the Minerals Management Service (MMS) has estimated deep gas recoverable resources at 5 to 20 Tcf.

Several factors have combined to make deep shelf gas increasingly attractive:

- Royalty relief for new wells in less than 200 meters of water and production below 15,000 ft;
- Additional royalty relief for production below 18,000 ft;
- Abundant infrastructure in the way of platforms, producing facilities and pipelines on the shelf that allow new production to flow quickly to market'
- New technology such as 3D seismic and faster computers to locate potential formations.

## DRILLING FLUID CHALLENGES

Developing deep shelf gas requires overcoming some formidable drilling challenges. Rigs capable of drilling to these depths are larger, more robust and more expensive. Penetration rates tend to be low, extending time on location and adding to drilling costs.

The extreme pressures, temperatures and acid gas levels limit down-hole tool, material and fluid selection. These limitations will be so severe toward bottom that MWD/LWD tools will be unusable, meaning downhole annular pressure measurements used for pressure management will be unavailable.

This places additional demands on the drilling fluid and temperature/hydraulic models as they become our best, if not our only, source for down-hole pressure information. These models are based on surface inputs and laboratory measured fluid properties under downhole conditions.

During the planning stage for several potential record depth deep gas wells currently drilling, not only did this information not exist, laboratory equipment capable of operation at the required temperatures and pressures didn't exist.

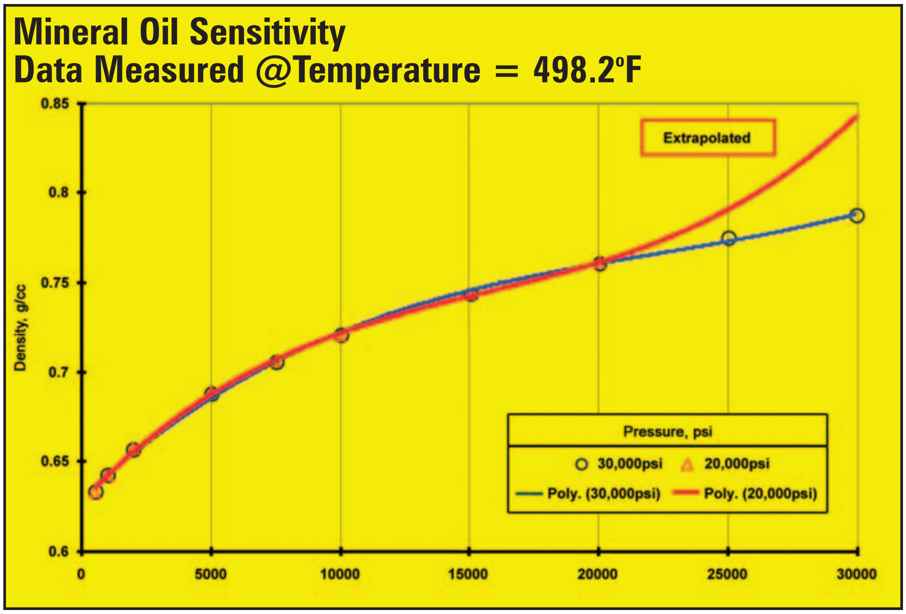
## PRESSURE/VOLUME/TEMP (PVT)

Downhole pressures are commonly calculated using depth and surface measured mud weight. While this approach is adequate for less demanding wells, critical applications require adjustments for the pressure and temperature-driven fluid compression and expansion, respectively.

These compression and expansion effects are quantified in fluid PVT measurement under expected downhole conditions that, until recently, ranged from 15 psi/75°F to about 20,000 psi/350°F (1 bar/23.8°C – 1378.9 bar/176.7°C), which covered industry needs. Deep gas drilling pressures and temperatures, however, will far exceed this envelope.

Laboratory measured data to 30,000 psi are represented by the blue circles; a third-degree polynomial (blue line) provides a good fit for these measurements.

Using a third-degree polynomial based on historically available 20,000 psi data and extrapolating to 30,000 psi (red curve) will substantially overestimate the degree of compression, introducing significant errors in downhole pressure calculations. This example highlights the necessity for measured data reflecting down-hole conditions.




The extrapolated vs measured density of a commonly used base-fluid as a function of pressure.

## VISCOMETER

With the onset of deep gas drilling, a technology gap was recognized in the measurement of fluid viscosity at down-hole conditions. Current viscometer technology is limited to measurements at 500°F/20,000 psig. Some of the deep shelf HPHT wells currently drilling have anticipated bottomhole conditions approaching 600°F and 40,000 psig. Since this was a major shortfall and fluid behavior has never been evaluated at these extreme conditions, Baker Hughes Drilling Fluids set out to develop a new viscometer for the industry. Criteria for the new HPHT viscometer included:

- Working pressure up to 40,000 psig;
- Working temperature up to 600°F;
- Magnetic couple design that allows accurate viscosity measurements on fluids containing magnetic materials (ferromagnetic and magneto-rheological fluids).

The first two criteria are rather obvious but the third may not be quite as apparent. Current HPHT viscometers use a magnetically coupled drive to rotate the outer sleeve. The magnets are located in the lower portion of the measurement chamber and in contact with the test fluid. Weight materials such as hematite and ilmenite typically contain only small

| PRODUCT | PRIMARY FUNCTION | SECONDARY FUNCTION |
|---|---|---|
| CARBO-MUL HT | Emulsifier | |
| OMNI-MUL* | Emulsifier | |
| MAGMA-VERT | Emulsion stability | Solids Tolerance/ HPHT FL |
| MAGMA-GEL | Primary viscosifier | HPHT Fluid Loss |
| MAGMA-GEL SE | Sag preventer | Rheology Modifier |
| MAGMA-TROL | HPHT Fluid Loss | Viscosity |
| MAGMA-SEAL | HPHT Fluid Loss | |
| MAGMA-PLEX | Rheology Modifier | Syneresis Suppression |
| CARBO-TROL XHT | HPHT Fluid Loss | |
| CARBO-TEC S | Syneresis Suppression | Emulsion |

* Can be used, consult operations / technical representative

The table above contains components of Baker's' new MAGMA-DRILL system.

amounts of ferromagnetic material but the concentration is large enough to collect on the magnets, perturbing the flow and introducing uncertainty in the measurements. Finer material tends to stay suspended, creating a magnetic fluid that displays structure and additional viscosity in magnetic fields.

Barite is typically free of ferromagnetic material but this is not necessarily true of barite-weighted field mud. Rotation of the drill string inside casing results in metallic wear particles that are typically ferromagnetic.

Ditch magnets may remove the larger particles but the fines tend to concentrate in the mud with time interfering with surveys[3] and introducing uncertainty in viscosity measurements where magnetic couples are in contact with the mud.

**Chandler Engineering** was selected as a partner in this development project and after six months of design review meetings and fabrication work, a new HPHT viscometer capable of testing fluids used for deep gas drilling is now available to the industry. This new viscometer, the Chandler 7600, shown in Figure 3, has met the design criteria - 40,000 psig/600°F and is capable of accurate measurements in fluids containing iron-based ferromagnetic material.

## DRILLING FLUID FORMULATION

Invert emulsion fluids have been utilized for drilling HPHT wells and the technology is adequate for 500°F but the new deep gas drilling presents even harsher environments with estimated bottom hole temperature (BHT) approaching 600°F. Recognizing the need for fluids with higher temperature stability, Baker Hughes Drilling Fluids set out to develop a line of products specifically engineered to withstand the extreme BHT conditions of wells drilled beyond 25,000 ft TVD. An engineering project was launched that resulted in a new line of products capable of withstanding extended exposure to 600°F.

The choice of products utilized for a particular drilling project is based on anticipated bottom hole temperature. Each fluid is engineered to meet specific requirements of the operator. Consistometer results have demonstrated the MAGMA-DRILL system exhibits stable properties after 16 hours at 590°F and 29,500 psig.

## WELL MONITORING

As wells get deeper, temperatures increase beyond the temperature limits of downhole tool components, rendering the tools unusable. Yet adequate knowledge of down-hole pressure is essential to adequately manage kicks, stuck pipe and to reach deep reservoir targets safely.

Accurate hydraulics software can provide the operator with some of these pressure-related parameters such as equivalent circulating density (ECD), equivalent static density (ESD), and overall system pressure losses for stand pipe pressure (SPP) predictions. Accuracy of the model is dependent on the accuracy of the input variables and a sound theoretical approach. One such model, ADVANTAGE ENGINEERING®, utilizes:

•Rheological properties measured on a HPHT viscometer operating at down-hole pressures and temperatures;

• Base-fluid density adjusted for the measured PVT behavior of the fluid at downhole pressures and temperatures;

• Drilling fluid compositional model reflective of the actual mud used;

• The Herschel-Bulkley rheological model to calculate circulating system pressure losses.

## GAS SOLUBILITY

As wells are drilled deeper, hydrocarbon gas solubility in drilling fluids can make kick detection more difficult. While gas solubility in water-base fluids is typically very small, gas solubility in invert emulsions generally increases with pressure and can be significant[4].

Consequently, when gas enters the wellbore during drilling operations, the associated pit volume increase can be much smaller as compared to water-base fluids.

This difference in response should be included in rig crew training when drilling deep gas wells. Once detected, the pressure of gas from deep zones and its volume expansion may require modifications to conventional well control techniques.

When drilling gas-producing formations, flow checks are routinely performed by shutting down the rig pump for a few minutes and observing the well for indications of flow.

Standard flow checks of five minutes or less may be inadequate, particularly when the gas is deep in the well.

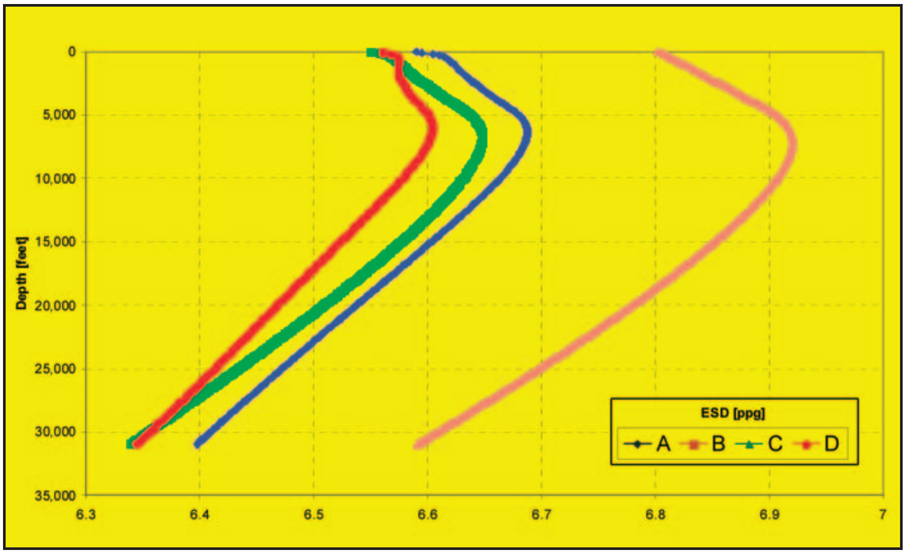
A minimum flow check of 10 minutes is recommended to allow the flow to manifest. Repeating the flow check after circulating for a few minutes may make a suspected flow easier to detect by moving the gas higher in the wellbore.

Documenting flow-back patterns or "fingerprints" of flow checks can help distinguish between an actual formation fluid influx and drilling fluid thermal expansion, borehole deformation, or fracture closure.

## OTHER CONSIDERATIONS

Trip time increases with depth and con-


The Chandler 7600 HPHT mud viscometer is designed for 40,000 psig/600°F operating conditions.




Base-fluid equivalent static density (ESD) comparison of four commonly used base-fluids as a function of depth (at predicted pressures and temperatures).

sequently exposure of the drilling fluid to temperature and pressure under static conditions. Staging into the hole after a trip not only helps minimize surge pressures but also helps normalize fluid temperature and weight by circulation.

Running to bottom and circulating cooler, denser fluid around can significantly increase the chances of fracturing the formation.

The swabbing effect when tripping out also generally increases with depth, but has also been shown to occur when tripping in the hole, due to drillstring elasticity and oscillation[5].

Hydraulic modeling can help optimize trip speed to prevent formation fracture or influx.

High flowline temperatures are also a concern with regard to well control equipment elastomers. Mud coolers or chillers have made significant contributions to reducing mud temperatures while circulating.

Some mud coolers have been shown to reduce mud circulating temperature by approximately 15ºF per cooling unit.

This temperature reduction also benefits down-hole tools and temperature-sensitive mud products while reducing the possibility of the drilling fluid reaching its flash point at the surface.

## HPHT EXPERIENCE

Recent work on deeper wells in the Gulf of Mexico, as indicated in the chart below, has allowed Baker Hughes Drilling Fluids to field test new products and validate modeling software under operating conditions.

Actual operations often expose a wide array of challenges, some of which may be easily overlooked in the well planning stages.

While the focus of this article has been on fluid technology, experience has shown that servicing these critical wells also places higher demands on warehouses, mud plants and inventory, as well as operational personnel.

## ACKNOWLEDGMENTS

The authors wish to thank Baker Hughes Drilling Fluids for permission to publish this paper, **Andy Brooks** with **Baker Hughes INTEQ** for the magnetic fluid image and **David Schwertner** with **Baker Hughes Drilling Fluids** for his advice and counsel on deep gas drilling.

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