Drilling fluids: Formates, exotic mud systems enhance efficiency

IADC/SPE 59186

The Application of New Generation CaCl2 Mud Systems in Deepwater Gulf of Mexico

Today, the latest generation of calcium chloride (CaCl2)/polymer-base drilling fluid systems are showing the most promise in terms of shale inhibition and wellbore stability in the deepwater Gulf of Mexico. This paper describes the evolution of these systems and the lessons learned during this experience, including mixing and shearing procedures to eliminate the shaker screen blinding seen on previous designs and onboard equipment requirements to handle comparatively large dilution volumes. Experience from several wells using this system with modifications to improve its efficiency has allowed the development of a decision tree to determine optimum applicability.

The authors will review the application of the newest generation CaCl2 system, which employs a uniquely engineered encapsulating polymer. Among the field trials to be reviewed is one from a newly built drillship, which used the system to drill its debut well in the deepwater Gulf of Mexico. Further, the paper will examine the performance of this new system compared with water-base systems traditionally used to drill similar intervals.

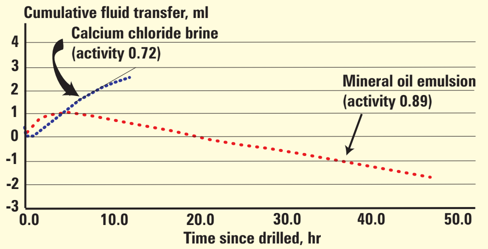
—D R Paul, Conoco Inc
—R Mercer and J R Bruton, M-I Drilling Fluids Co. LLC

IADC/SPE 59187

Application of Novel Technologies in the Design and Engineering of Synthetic Based Mud Used to Drill and Complete Horizontal, High-Temperature/High-Pressure Wells in the Central North Sea, Marnock Field

The Marnock field is located in the Eastern Trough, UK Central North Sea, some 130 miles east of Aberdeen in water depths of 300 ft. The reservoir is Triassic fluviatile sandstone. Reservoir fluid is gas condensate at a temperature of 310° F and pressure of 9,100 psi at 11,500 ft (3,500 m) TVD. The main risks of drilling the reservoir sections and in running the sand face completions for Marnock come from the combination of high permeability and horizontal well geometry with HTHP conditions. Hydrostatic profiles change constantly with operation due to temperature changes

IADC/SPE 59190: Fluid transfer during diffusion osmosis*



* Fluid transfered at a sandpack at the outer periphery of a Gulf of Mexico shale specimen when exposed to drilling fluids with no hydraulic pressure differential

and this increases the risk of well control incidents and lost circulation. Stuck pipe and stuck screen incidents are also statistically significant in these wells. In addition to drilling risks, post-well intervention is costly, high risk, and technology-limited due to the horizontal HTHP conditions. Therefore, the prevention of formation damage and completion impairment has to be addressed in the drilling phase. Decision making in determining the balance of risks to productivity requires a full understanding of all the factors affecting drilling, completion and production.

—B W Swanson,BP Amoco, *et al*

IADC/SPE 59188

Drilling Fluid Plays Key Role in Developing the Extreme High-Temperature/High-Pressure Elgin/Franklin Field

Elgin/Franklin is an extreme high-temperature/high-pressure (HTHP) project with static bottomhole temperatures (BHTs) and bottomhole pressures (BHPs) in excess of 205° C and 1,050 bar, respectively. 10 wells have been drilled with trajectories from 0°-37°.

Critical design features for the drilling fluid were stability at the high temperatures and weights required to drill these reservoirs, coupled with minimum equivalent circulating densities (ECDs) to avoid the loss/gain situation commonly encountered when drilling through the narrow window of fracture versus pore pressure typical of HTHP wells. Reaching total depth (TD) and ensuring the liner was run and cemented successfully were also critical factors.

The unique n-alkane synthetic-base fluid (SBM) was formulated to minimise barite sag and maintain fluid properties, even when left at BHTs for over 100 hours without circulation.

The success of the drilling phase of this project has been largely due to the drilling fluid meeting its design criteria in practice. Barite sag was never an issue, and early instances of well instability could be understood and successfully controlled. Electric logs were run without the need for time-consuming wiper trips, and the liners were run and cemented successfully, which was essential to having a well that was "fit for purpose".

—B L Fitzgerald and A J McCourt, Baroid Ltd
–M Brangetto, Elf Exploration UK plc

IADC/SPE 59189

Application of Novel Downhole Hydraulics Software to Safely, and Economically Drill a North Sea High-Temperature/High-Pressure Exploration Well

The use of the integrated suite of software provides more insight into the downhole hydraulics behavior of a drilling fluid, which is an essential factor in avoiding well control situations, wellbore stability problems, and lost circulation.

This paper will describe the development of the software and its successful application in a North Sea well drilled under HTHP conditions (358° F, 14,645 psi). The authors will detail the application of the software, which accurately predicted downhole pressures while both drilling and tripping. The well required mud weights up to 18.0 lb/gal in zones where the fracture gradient was 18.1 lb/gal. Tripping speeds were optimized based on software pressure predictions. The accurate prediction of downhole pressures reduced the time and expense required for well observation time, while also avoiding well control incidents and lost circulation.

—A U Thorsrud, Phillips Petroleum Co Norway, *et al*

IADC/SPE 59190

Diffusion Osmosis: An Unrecognized Cause of Shale Instability

This paper presents results obtained using laboratory procedures that allowed preserved specimens of Gulf of Mexico Pleistocene shale to be restored to in-situ conditions of stresses and temperature prior to being drilled. These studies show that diffusion osmosis can cause water and solutes to be transferred from a water-base drilling fluid to a shale even whether is no chemical osmotic force or hydraulic pressure differential. If a chemical osmotic force predominates and is extracting water from a shale, diffusion osmosis can still cause solutes to invade the shale and create instability.

Destabilizing ionic reactions within a shale can be minimized if a suitable nonionic polyol (methyl glucoside) is used to reduce the activity of a freshwater drilling fluid. In certain situations the addition of salt to a water-base drilling fluid to reduce the water activity can cause an increase in the diffusion osmotic force that offsets some of all of the desired increase in chemical osmotic force.

Chemical osmotic effectiveness can be improved by emulsification of a nonaqueous phase in the drilling fluid. A fresh-water drilling fluid containing methyl glucoside for activity control and emulsified pentaerythritol oleate prevented hydration and maintained stability of the Pleistocene shale. Drill cuttings from such a drilling fluid should be environmentally acceptable for discharge at offshore or land locations.

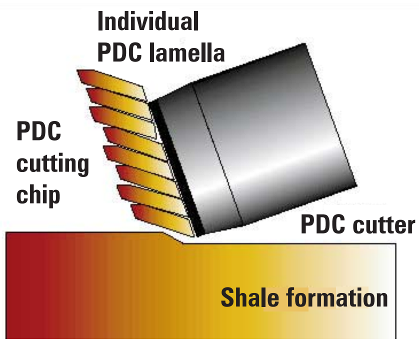
—J Simpson,
O'Brien-Goins-Simpson Associates
–H L Dearing,OGS Laboratory Inc

IADC/SPE 59191

The Evolution and Application of Formate Brines in High-Temperature/High-Pressure Operations

High-density formate brine-base mud systems have emerged as viable drill-in and completion fluid options for deep high-temperature wells. Upon their introduction in the early 1990s, these systems were shown to possess a unique combination of properties that could be exploited to engineer high-density fluids that would comprise minimal solids, maintain rheological stability at high temperatures, minimize reservoir damage and satisfy environmental requirements.

This paper describes the evolution of these systems and their most recent application in the drilling of deep, slim hole wells in northern Germany. Not only did the formate-base systems exhibit faster penetration rates than the water-base fluids used previously, they also eliminated the solids sag problems



IADC/SPE 59192: This paper will present complete laboratory results showing how the basic PDC-bit drilling mechanics and balling mechanisms were altered to make possible drilling at high ROPs without bit and BHA balling.

experienced with water-base muds used in technically and economically demanding high-temperature environments. Furthermore, the formate brine-base systems were shown to improve well productivity.

Through an examination of 15 deep gas wells completed in Germany, the authors will review the performance of formate brines as drill-in, completion and workover fluids.

—D J.Bungert,
Mobil Erdgas-Erdoel GmbH, *et al*

IADC/SPE 59192 (ALTERNATE)

Drilling More Stable Wells Faster and Cheaper With PDC Bits and Water-Base Muds

This paper will present full scale laboratory results showing how basic PDC drilling mechanics and balling mechanisms were altered to make drilling at high rates of penetration without bit and BHA balling possible. In addition, new insights into the structure of cuttings and their breakdown with mud additives will be discussed. The difference in borehole wall damage and stability caused by steel tooth and PDC bits in clean and sharp as well as heavily balled condition was determined using pore pressure transmission testing (PPT) on borehole wall plugs.

The merits of optimizing the bit/fluid system has been validated in several wells in the Gulf of Mexico with ROPs equaling or sometimes even exceeding offsets drilled with oil base mud. The authors will document cost savings, which can be as high as US $1.65 million dollars per well. The improved borehole quality will be illustrated using caliper logs from comparable wells.

—R G Bland, Baker Hughes Inteq
—R C Pessier, Hughes Christensen Co

IADC/SPE 59193 (ALTERNATE)

Anglia In-Fill Drilling Campaign: Drill-In Fluid Design and Application

The Anglia gas field was originally developed in the late 1980s with the wells being drilled with mineral oil-based mud. In most cases, production from the original wells was below expectation and only 5 years later, plans were being made to re-develop the field in order to maintain its economic viability as a gas producer.

Wellbore placement and drilling fluid selection were determined to be critical factors in ensuring the success of planned in-fill wells.

This paper reports on the planning and testing which was conducted during the selection of the drilling fluid for the reservoir phase of the new wells, changes in drilling practice and the subsequent production obtained from utilising this new approach, in comparison to the production from the original wells.

Reasons for the poor production from the first phase of the development are discussed. Due to the more complex trajectories and longer well-paths required by the well design team, additional difficulties were created for the drilling fluid, notably that of lubricity.

Final production data on 3 wells drilled during 1997-9 are reported in the paper.

—D S Marshall, Baker Hughes Inteq
–D M Haywood, Ranger Oil UK Ltd