# Drilling and Completion Fluids

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Drilling and completion (D&C) fluids are used in every well and are critical to drilling efficiency and reservoir productivity. Technological advances of D&C fluids are more evolutionary than revolutionary. Over time, these evolutionary changes have accumulated such that the quantity of knowledge and available technologies is extensive. This is where we are today for all fluids-related technologies.

Clearly, the industry has more scientific knowledge about how fluids behave, and the number of unique options available to drill or complete a particular well has never been greater. Recent advancements of note are nonaqueous fluids (the rheology of which is affected less by temperature), novel weighting agents, increasingly complex drill-in fluids, cleanup options for openhole completions, and significantly improved fluids-processing equipment.

The difficult part is sorting out what to use and when. Keep in mind that many of these new technologies have increasingly narrow applications. As engineers, our goal should be to select the most effective technology for a particular task, not necessarily the most recently developed "new technology." Many fluids with a history of use in a given area or for a particular application are used for good reason; they work well! But the world is changing. D&C costs are increasing at rates not seen for more than 25 years, and the kinds of wells being drilled are changing. So it is critical to re-examine each application continually and strive to choose fluids that minimize problems and yield a better-quality well.

I frequently am surprised when people do not understand the fundamental information about fluids that is documented in classic SPE technical papers. Only by understanding these fundamentals can a person make good decisions about which fluid or technology to use in a given application. For those of you who are new to the industry and are interested in D&C fluids, I recommend that you take time to read classic fluids papers and keep up with at least the topics of currently published papers. While they have not been updated recently, I recommend and often cite information from the SPE Reprint Series, especially *No.44 Drilling Fluids* and *No. 22 Drilling.*

Please take time to read the paper summaries that follow as well as the papers listed below; you will learn something. **JPT**

**Drilling and Completion Fluids additional reading available at the SPE eLibrary: www.spe.org**

***SPE 108653*** • *"Assessment of the Fate and Ecological Risk of Synthetic-Paraffin-Based-Drilling-Mud Discharges Offshore Sarawak and Sabah (Malaysia)" by P.B. Dorn, Shell, et al.*

***SPE 112687*** • *"Automatic Measurement of Drilling-Fluid and Drill-Cuttings Properties" by A. Saasen, SPE, StatoilHydro, et al.*

***SPE 110341*** • *"Unique Characteristics of Mixed-Metal-Oxide Fluid Cures Lost Circulation While Meeting European Environmental Regulations" by Reinhard Oswald, Petrom, et al.*

***Additional reading available at OnePetro: www.onepetro.org***

***OTC 19210*** • *"Understanding the Impact of Completion-Brine Packer Fluids on Cracking Susceptibility of CRA Materials for Deepwater Applications" by Paul H. Javora, BJ Services, et al.*

# Manganese Tetraoxide Weighted Invert Emulsions as Completion Fluids

**Traditionally, completion equipment is run in clear fluids, brines, or base oils to minimize the potential for solids to plug equipment. Base oils typically have approximately 0.8 specific gravity (SG), which has well-control implications, and brines can be prohibitively expensive where high densities are required. A novel approach was used by a UK operator to address these problems by compromising between the shale stability provided by oil and the density achievable with brine.**

## Introduction

Once the drilling phase is complete, most operators clean up the well before running the completion string. With nonaqueous fluids (NAFs), cleanup can be quite complicated, requiring a sequence of surfactant pills to remove mud residue from the wellbore and casing. The objective is to leave the well with a clean fluid that has very-low solids content (typically less than 0.05%) or meets a clarity specification. This process can result in large volumes of fluid that are considered to be contaminated to the point of requiring disposal. Where an NAF is used, environmental limitations usually require the contaminated fluid to be contained for special disposal.

Manganese tetraoxide ($Mn_3O_4$) has been used as an alternative weighting agent in both water-based and nonaqueous drilling fluids where equivalent circulating density and sag performance have precluded use of barite-weighted fluids. The combination of small particle size, spherical shape **(Fig. 1),** and high SG (4.8 g/cm$^3$) makes $Mn_3O_4$ an ideal weighting agent for fluids in which a low viscosity profile and low gel strength are required.

*This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 112313, "Manganese-Tetraoxide-Weighted Invert Emulsions as Completion Fluids," by **L.P. Moroni,** SPE, **J.R. Fraser,** and **R. Somerset,** Baker Hughes; **A. Jones,** Oilexco North Sea; and **A. Guarneri,** Eni AGIP SpA, originally prepared for the 2008 SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, 13–15 February. The paper has not been peer reviewed.*

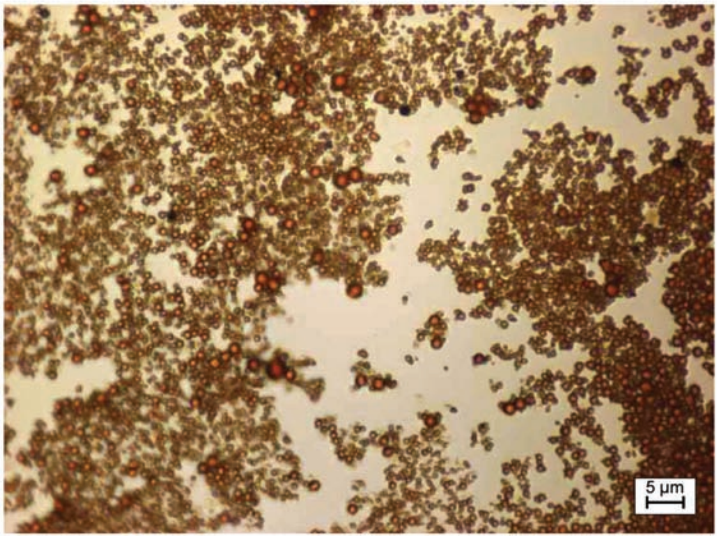



***Fig. 1—Microphotograph of $Mn_3O_4$ in completion fluid.***

## Case History 1

A temporary completion fluid with 1.95 SG was required while running the completion string to provide a secondary well-control barrier in addition to the cemented liner while the blowout-preventer (BOP) stack was replaced with the Christmas tree. Use of cesium formate was one alternative explored by the operator, but the cost was considered prohibitively high. A previous application that used a water-based mud containing ultrafine barite failed on three issues: The fluid was prone to barite sag, the fluid left a coating on tubulars that was virtually impossible to remove, and the fine barite particles plugged surface well-test-line valves. One of the major concerns was the tight clearance (0.1 in.) of the hydraulically set packer and the risk of setting prematurely because of pressure surges while displacing to the oil-based packer fluid. The wellbore geometry consists of a long tangent between 40 and 50º, so sag prevention is a key requirement.

**Fluid Design.** A fluid was designed that used a mineral-oil invert emulsion containing $Mn_3O_4$ weighting agent. Laboratory work focused on many aspects of the fluid characteristics, with special attention paid to sag and sedimentation over a 10- to 14-day period, and on film-forming characteristics on pipe and tool surfaces. One of the benefits of using $Mn_3O_4$ as a weighting agent is its low settling velocity, which permits use of lower-viscosity fluid.

The filming effect of the test fluids was measured by dipping a steel plate into the test fluid at the selected temperature and allowing it to equilibrate over a 15-min-

*For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.*

ute period. The plate then was removed from the test fluid and allowed to drip dry for 1 minute. The combined weight of the plate and fluid was recorded. The film thickness was calculated on the basis of the weight of the clean plate and the surface area coated with the test fluid. Because the thickness of the fluid film is related directly to the viscosity of the fluid, the test demonstrated the benefit of the low viscosity profile of the fluid.

To characterize the sag performance of the selected fluid, tall (300-mm) aging cells with screw-cap ends were used. This allowed the fluid-column density to be measured throughout the column, including the very bottom of the cell. By use of this process, no gradual particle agglomeration leading to a range of settling rates was observed. Instead, the selected fluid showed some syneresis with time but with a uniform settling rate. Even after 14 days of static aging at 100°C, the bulk of the fluid column displayed uniform density.

From the laboratory results, an invert-emulsion fluid with an 80:20 oil/water ratio (OWR) was determined to be the best fluid. This fluid showed good sag performance and minimal filming tendencies compared to lower- and higher-OWR fluids. The formulation for the selected fluid is given in Table 1 in the full-length paper.

## Field Application

The $Mn_3O_4$-weighted completion fluid (MWCF) was prepared on location. After the inflow test was performed, the cleanup string was run to displace the drilling oil-based mud (OBM) to seawater. Having cleaned up the well, the seawater then was displaced to the 1.95-SG MWCF. The reservoir has a high hydrogen sulfide content, so a 1.95-SG fluid is required to provide a barrier until the hydraulically set permanent packer is in place. After running the completion string, the BOPs were removed and the Christmas tree installed.

Ten days after displacing the well to MWCF, the well was displaced to the permanent oil-based packer fluid. The MWCF in the well had been contaminated with seawater during the initial displacement and had a higher rheology than expected. The MWCF initially was reverse circulated to break gels and establish a stable pressure without the risk of putting pressure on the packer because it was feared that the packer would set prematurely if excessive pressure was applied. Only minimal pressure was required to initiate circulation. This was a clear indication that there was no development of progressive, high gels while the fluid was in place. The well then was circulated conventionally, staging up the circulating pressure to the given 3-bbl/min maximum flow rate. Pump pressures were modeled on the basis of a 2.5-bbl/min displacement rate, which gave a value of 6,100 psi. This turned out to be a very conservative figure because the actual displacement was performed at 3 bbl/min, and the maximum pump pressure was 5,900 psi. Two intermediate-density spacers were pumped before displacement to the oil-based packer fluid to minimize base oil channeling through the higher-density completion fluid.

## Case History 2

The operator was drilling deviated, directional wells geosteered through the reservoir. The horizontal reservoir section is approximately 4,000 ft long. The reservoir sand is bounded by often-encountered water-sensitive clay and shale formations that, because sand-screen completions are run, could prove to be problematic. To prevent borehole-stability problems associated with the clay/shale formations, the reservoirs are drilled with OBM. To place the sand screens successfully, the operator chose to displace the well to a completion fluid that would be compatible with the formations and the original OBM drilling fluid.

**Fluid Design.** The operator requested a solids-free NAF for running the completion screens. One of the disadvantages of using an NAF for the completions is the limited fluid density achievable in a solids-free system. A second consideration was the possibility of destroying the filter cake while running the sand screens, leading to downhole losses. To maintain wellbore stability and overbalance for well control, the drilling mud was 1.38 to 1.44 SG. Consequently, the completion fluid had to be formulated up to 1.44 SG

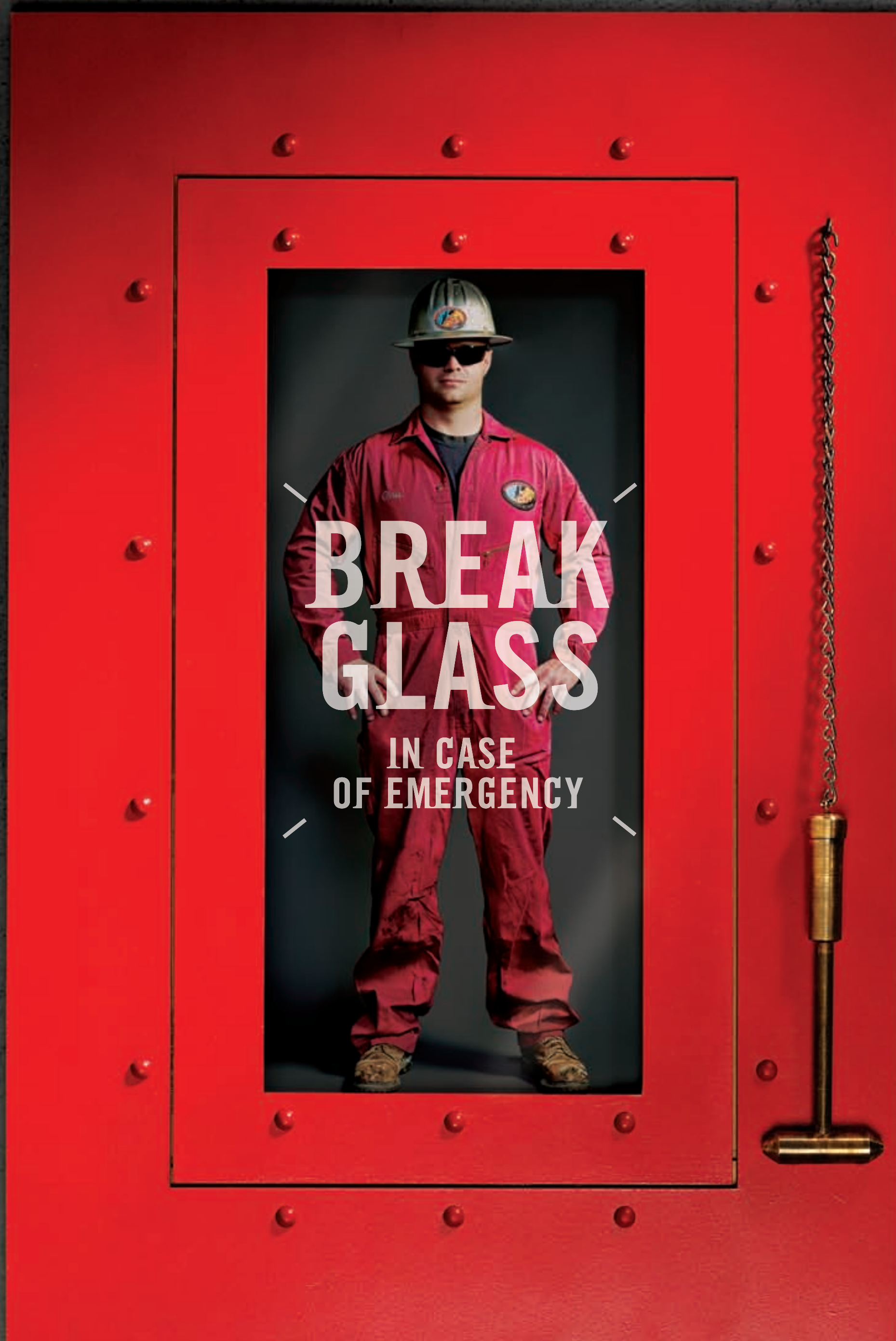
A base, unweighted, 1.28-SG invert-emulsion fluid formulation was proposed that included calcium bromide ($CaBr_2$) in the internal phase. To increase the density to 1.44 SG, the formulation included $Mn_3O_4$ as a weighting material. Fine-grade calcium carbonate also was included in the formulation to provide some bridging and to repair any damage to the filter cake while running the sand screens. Flow-through tests were performed on the designed fluid to confirm that all the solids were sufficiently fine to backflow through the sand screens.

**Field Application.** The reservoir was drilled with a reservoir drill-in fluid (RDIF). The MWCF was flow-through tested on surface with screen coupons the same size as the completion screens to ensure that there were no plugging solids in the completion fluid. After performing a wiper trip to the shoe, the RDIF was circulated over fine shaker screens to remove large solids that could contaminate the completion fluid. The RDIF was displaced out of the well by use of an oil-based and viscous MWCF spacer.

Once the 1.38-SG MWCF had been displaced into the well, additional flow-through tests were performed over a complete circulation to ensure that no plugging solids had been picked up. The completion screens then were run, and the packer and GT plug were set in place. Once the packer had been set, the casing was cleaned up and displaced to brine for running the upper completion. The MWCF in and across the screens was produced back during the well test with no problems.

## Conclusions

1. $Mn_3O_4$ weighting material in invert-emulsion fluids leads to good sag characteristics and a low filming tendency.
2. The small particles of $Mn_3O_4$ have a low tendency to agglomerate and avoid the hard packing that can occur with barite-weighted fluids.
3. If a high-density fluid is required to displace an NAF in a reservoir, a formulation using $CaBr_2$ as the internal phase and $Mn_3O_4$ can be used. This will produce a fluid that is fit for purpose and can be formulated to give properties similar to those of an RDIF.
4. It is practical to mix this formulation on site using conventional mud-mixing and -handling equipment.
5. Flow-through tests should be conducted on the MWCF before it is displaced into the open hole and after a final circulation over fine shaker screens to ensure that no large solids have been picked up during the displacement.
6. Field studies prove that screens can be run trouble free in wells with this type of fluid. **JPT**

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# Optimized Solids Control Provides Opportunities for Drilling Depleted Reservoirs

Experience has shown that adding suitable particles to drilling fluid can improve formation strength. This is beneficial when drilling wells with a narrow operational window, as is the case when drilling depleted reservoirs. Successful operations have used several types of particles, including graphite and calcium carbonate ($CaCO_3$). For this approach to work, it is important to establish an optimal particle composition in the drilling fluid. The full-length paper details an offshore operation where coarse shaker screens were used to allow relatively large particles to re-enter the well during circulation. The monitoring equipment allowed close control of the particle-size distribution (PSD) of the drilling fluid flowing into and out of the well during drilling.

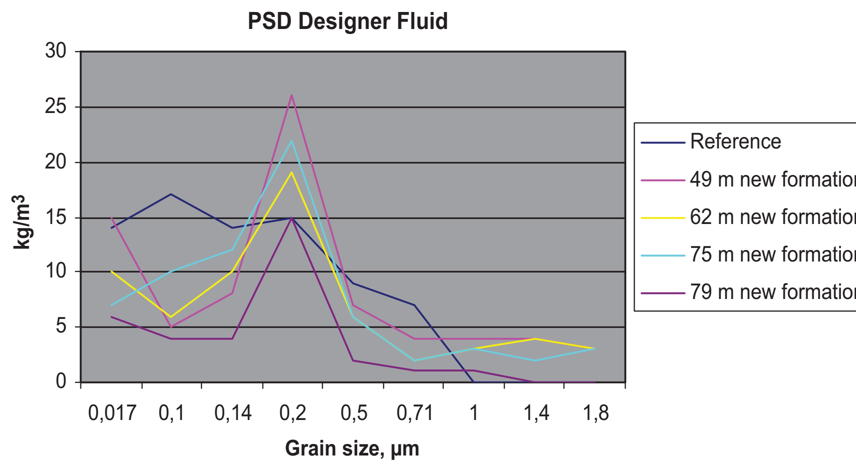


*Fig. 1—Particle–size analysis performed during drilling.*

## Introduction

Drilling through depleted reservoirs is a challenge because the pressure difference between the fracture pressure and the pore pressure is small or sometimes even negative. During the last decade, a technique was suggested that increases the fracture strength. This method is based on fracturing the borehole wall with small fractures and then filling these fractures with impermeable particles to stop further fracture propagation.

Theoretical analysis and analysis of field experience with formation strengthening conclude that it is necessary to optimize the PSD of the added solids. The fracture must be sealed by a nonpermeable, easily plugging material. The plugging is caused by arching or gel formation or a combination of these two. Arching in pipes and conical sections has been a subject for research the last century, and the results are included in most textbooks on soil or powder mechanics. Although this subject is well established theoretically, there still is a need for experimentally optimizing PSD and particle content. Furthermore, this PSD must be optimized with respect to drilling-fluid viscosity profile, gel formation and fragility, and viscoelastic properties as well as chemical properties of the fluid and particles.

Knowledge of what type of particle to be used is necessary to apply this technology successfully. However, it is equally important to control the particle content on an offshore application. Shaker performance and the mechanisms for wear on shaker screens must be known to ensure that only desired particles are returned to the well. The PSD must be quantified. A practical measurement tool has been developed for measuring the PSD of drilling fluids. In the full-length paper, a field test is described where drilled solids and added particles are allowed to be recirculated and thereby naturally achieve formation strengthening. The test is based on the solids-control methods and equipment described in previous papers.

## Field Case

The active use of solids-control equipment as a tool to control the PSD of solid particles in drilling fluid first took place during drilling of the reservoir section of a well in a high-pressure/high-temperature field offshore Norway. The pressure depletion in the field resulting from production was estimated to be approximately 100 bar, causing a reduction in the

*This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 110544, "Optimisation of Solids Control Opens Up Opportunities for Drilling of Depleted Reservoirs," by **T.H. Omland,** SPE, and **B. Dahl,** Statoil ASA; **A. Saasen,** SPE, Statoil ASA and U. of Stavanger; **K. Taugbøl,** SPE, Statoil ASA; and **P.A. Amundsen,** SPE, U. of Stavanger, originally prepared for the 2007 SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, 30 October–1 November. The paper has not been peer reviewed.*

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fracture gradient. The previous well drilled in this reservoir suffered massive losses of drilling fluid because the fracturing pressure was exceeded. Effective downhole drilling-fluid density could not be reduced sufficiently to compensate for the reduced fracture gradient because the reservoir was not homogeneous, with possibilities of drilling into zones having original reservoir pressures. A strategy for drilling this formation was to add particles to the drilling-fluid system to increase the fracture strength during drilling of the depleted zones.

The $8^1/_2$-in. section was drilled using a cesium formate brine-based drilling-fluid system. The particles added to the system were bridging particles for fluid-loss control in the permeable formation and particles added for fracture strength enhancement. This particle blend consisted of a blend of different grades of $CaCO_3$, graphite, and nut shells. The total concentration of particles added was limited to 140 $kg/m^3$, and distribution was selected on the basis of laboratory optimization with respect to both slot openings of varying size and porous ceramic disks. This optimized blend was added as the initial particle content in the fluid. As drilling began, the drilling fluid picked up drill solids that would be removed over the shale shakers. Before drilling, a plan was developed to monitor and control the particle content and size distribution. A premix consisting of a high concentration of coarse particles was prepared. This premix was bled into the active system to compensate for the coarsest particles removed on the shale shakers. The addition rate was determined on the basis of various laboratory techniques to ensure that the fluid system contained sufficient particles to seal any induced fractures.

The planned method of using the solids-control equipment to control the PSD was to be by controlling the feed to each shaker. All shakers were dressed with different sets of screens to create the desired PSD. Fig. 1 in the full-length paper shows the proposed initial shaker-screen configuration for the different shakers to obtain this effect. Because of difficulties in handling the flow, the concept was abandoned and the fluid was run over coarse screens to keep the particles in the fluid system. For drilling short intervals and/or with simple fluid systems, the original strategy might succeed.

To control the feed rate of new particles and the fluid flow over the different shaker screens, continuous PSD-analyses were performed offshore during drilling by use of a laboratory sieve stack. A reference test was run before drilling out of the $9^5/_8$-in. shoe, as shown in **Fig. 1.**

As can be seen, the PSD changes rapidly during the drilling phase, even over relatively short lengths. This illustrates how the drilling operations continuously affect the particles in the fluid system throughout the drilling operation. The measurements given indicate a continuous decrease in the cumulative amount of particles in the system as drilling progresses, even with particle additions. They also demonstrate a relative decrease in the concentration of coarse particles as a result of the drillstring grinding effect. This indicates that the feed rate of new particles was too low. Even though the amount of coarse particles decreased, the fluid still was efficient in plugging even the largest slot size of 1000 µm. The slot sizes used in these tests were chosen on the basis of rock-mechanics estimations of expected fracture sizes for the given reservoir depletion.

Permeable plugging tests also were run to measure the plugging ability toward the formation. Tests were run using 20-µm discs at 500 psi differential pressure and the 150°C reservoir temperature. The results showed that the fluid-loss control was good throughout the drilling. The coarse particles were not expected to have a big influence on the fluid-loss results.

PSD analyses also were performed on samples sent to an onshore laboratory. In these analyses, a fully automated laser diffraction apparatus was used. These analyses give a more continuous analysis throughout the different sizes, also measuring the small-sized particles that were added for fluid-loss control against the pore openings of the sandstone formation. The analyses show a shift in the PSD from coarse to finer from the start of drilling. The PSDs measured after 58 and 93 m are relatively similar, but with less coarse material than at the starting point. This indicates that the addition of coarse material was too low to keep up with the loss of these particle sizes. A similar development was seen using the sieve stack offshore. At 93 m, a treatment was performed bringing the PSD back on track. At total depth of the section, the fluid was screened to take out the coarsest particles before running the liner. This is clearly demonstrated in the PSD analysis of this sample.

## Discussion

Use of particle additions for formation-strength enhancement has long been recognized to minimize lost-circulation incidents. Despite significant laboratory research in the area, one is still reluctant to trust the solids-control equipment and/or continuous particle additions to have the same effect in the field. For applications where the solids-control equipment is used for removal of drilled solids, the efficiency of this process is likely to influence the effect of particles on formation-strength enhancement. That is, having poor control of screen wear might in many cases benefit the operation as more particles are recirculated back to the borehole. For complete process control, this is not an appropriate approach.

Application of different measurement techniques for determining the ability of the particles to plug the formation during this field trial provides information complementary to the currently available techniques. This information can be used to determine how different operations affect the capability of the fluid to plug the formation, whether it is optimization for lost-circulation prevention, reduction of formation damage, or for other purposes. Until recently, these techniques have not been applied actively in the field, but now they bring into question the meaning of extensive laboratory studies optimizing ideal particle blends that will not be the field composition after only a short period of drilling. Because of discrepancy in results from the various tests performed, further investigation should be performed to reveal the weaknesses of each test method in combination with further development of techniques that ultimately can monitor the particle type and content continuously. **JPT**


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# Optimization of Deep-Drilling Performance

Full-scale laboratory testing was conducted under a joint-industry and US Department of Energy program. Seven bits and 12 drilling fluids were tested in three different rocks at a variety of drilling conditions. Phase-1 results were reported in a previous paper. The goal of Phase-2 testing was to evaluate bit features and mud additives that might enhance rate of penetration (ROP) under high-pressure conditions. The test protocols developed in Phase 1 to simulate Arbuckle-play and Tuscaloosa-trend drilling at pressures greater than 10,000 psi were used to evaluate these features.

## Introduction

An important factor in future gas-reserves recovery is the cost to drill a well. This cost is dominated by the ROP, which becomes increasingly important with increasing depth. The object of this study was to improve the economics of deep exploration and development.

In September 2002, the US Department of Energy's National Energy Technology Laboratory awarded funding to the Deep Trek program to develop technologies that make it feasible economically to produce deep oil and gas reserves and increase the ROPs in deep drilling. The researcher's proposal was to test drill bits and advanced fluids under high-pressure conditions. Phase 1 of the proposal was to establish a baseline of performance and provide data upon which to make design improvements. Phase 2 was to establish improvements in design. Phase-2 tests were an extension of Phase 1 and attempted to improve significantly the ROP and mechanical specific energy with modified drill bits and enhanced drilling fluids. There were 21 tests run during Phase 2. For consistency, the type of rock used in Phase 2 was the same as in Phase 1.

The drill bits selected for Phase-2 testing included a roller-cone bit to re-establish a baseline, three polycrystalline-diamond-compact (PDC) bits, and a diamond-impregnated bit. One of the PDC bits, a seven-blade bit, was identical to the one used in Phase 1; all others were modified. The drilling fluids used in Phase 2 included an 11-lbm/gal water-based mud for four tests, a 16-lbm/gal cesium formate brine for five tests, and 16-lbm/gal oil-based fluids for the others.

*This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 112731, "Optimization of Deep-Drilling Performance With Improvements in Drill-Bit and Drilling-Fluid Design," by* ***Alan D. Black,*** *SPE, TerraTek;* ***Ronald G. Bland,*** *SPE, Baker Hughes;* ***David A. Curry,*** *SPE, and* ***L.W. Ledgerwood III,*** *SPE, Hughes Christensen;* ***Homer A. Robertson,*** *SPE, and* ***Arnis Judzis,*** *SPE, TerraTek;* ***Umesh Prasad,*** *SPE, Hughes Christensen; and* ***Timothy Grant,*** *US Department of Energy, originally prepared for the 2008 IADC/SPE Drilling Conference, Orlando, Florida, 4–6 March. The paper has not been peer reviewed.*

## Methods and Materials

**Test Facilities.** All drilling experiments were performed at a drilling-and-completions laboratory under simulated downhole conditions in a wellbore simulator that applied overburden and confining stresses to the rock. The drillstring loading and rotation were provided by the full-scale laboratory drill rig. The drilling and rock-loading parameters used during Phase-2 testing are provided in Table 1 in the full-length paper.

**Rock Samples and Preparation.** The rock used for the tests included Crab Orchard sandstone, Carthage marble, and Mancos shale. Cylindrical rock samples 15½ in. in diameter and 36 in. long were prepared, placed on a steel endcap, and enclosed inside a polyurethane jacket. The jacket provided a seal between the rock and the confining fluid when in the wellbore simulator.


***Fig. 1—Drill bits used in Phase-2 testing.***

Four full-length cylinders of Crab Orchard sandstone were used for drilling tests. Two-part composite cylinders, configured with 17 in. of Mancos shale on the top and 19 in. of Carthage marble on the bottom or with 17 in. of Mancos shale on the top and 19 in. of Crab Orchard sandstone on the bottom, were used for most of the tests. The composite cylinders were glued together. Two tests were run with all three rock types included in the cylinders.

**Drill Bits.** All rock bits tested were 6 in. in diameter **(Fig. 1).** Ten of the 21 tests were run with a seven-blade PDC bit (identical to the M333 used in Phase 1), two tests were run with a seven-blade PDC bit with an elongated configuration and designated as M333L, four with a four-blade PDC bit (M233), three with an impregnated bit (M841), and two with a carbide-insert roller-cone bit (737). Bit nozzles were

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selected to achieve the desired hydraulic horsepower per square inch.

**Drilling Fluids.** The drilling fluids used in Phase 2 were a combination of formulations used in Phase 1 to better compare the performance of new bit designs and/or operating conditions with those used in Phase 1, along with new formulations to explore performance-enhancement opportunities either identified in Phase 1 or resulting from field observations.

An 11-lbm/gal freshwater-dispersed mud was used in Phase 1 to represent the low-mud-weight freshwater-dispersed drilling fluids commonly used in the deep Arbuckle. The formulation was used in Phase 2 to evaluate the effects of higher weight on bit (WOB) than was used in Phase 1 with the carbide-insert roller-cone bit.

A 16-lbm/gal mineral-oil-based mud (OBM) was used in Phase 1 to represent the high-mud-weight nonaqueous OBMs used to drill the deep Tulcaloosa. The formulation was used in Phase 2 to compare performance of new bit designs with designs from Phase 1 using the same mud formulations.

***A 16-lbm/gal Cesium Formate Brine.*** The results from Phase 1 verified the improved drilling efficiency experienced at the wellsite using clear fluids in controlled laboratory conditions with full-sized bits drilling at 10,000-psi borehole pressure compared to fully formulated mud designs where mud up decreased ROP as much as 80%. Such simple formulations as clear, neat water or nonaqueous base fluids are unsuitable for deep drilling because of the need for higher-density fluids to control downhole pressures, the requirement for bridging agents/fluid-loss-control additives to prevent leak off of fluids into permeable formations, and the need for suspension aids to suspend drill cuttings in commercial wells. While higher-density fluids are commonly achieved by adding high-density powdered minerals such as barite or hematite during mud up, density can be increased through the use of high-density soluble salts or electrolytes such as the halide salts of potassium, sodium, calcium, and zinc, and the formate salts of cesium and potassium. Use of cesium formate formulations allowed direct comparison of minimum-suspended-solids fluids to 16-lbm/gal OBM containing a typical concentration of suspended solids for this density. One test was run without the addition of any simulated drill solids, and four were run with the addition of 20 lbm/bbl of simulated drill solids added to the cesium formate brine compared with the addition of 35 lbm/bbl of simulated drill solids to the nonaqueous/mineral OBMs.

***A 16-lbm/gal Mineral OBM With Lubricant.*** Unpublished field reports suggest that adding effective lubricants to OBMs can increase drilling efficiency and increase ROP. Evaluation of the lubricant effectiveness could be conducted efficiently as an add-on to the end of the 16-lbm/gal OBM testing, which provided a relevant control without the need to build additional base mud or to conduct additional control tests.

***A 16-lbm/gal OBM With "Altered" Solids Distribution.*** Conventional wisdom in the drilling industry has long attributed the loss of drilling efficiency as a result of mud up and/or retention of drill solids in the mud to the increase in concentration of suspended solids and to the fact that the finer solids are the most detrimental. If this is so, it seems reasonable to believe that aggregation of the finer solids might increase drilling efficiency, and unpublished laboratory results suggested that this could be achieved at least partially in the 16-lbm/gal OBM by using an alternative surfactant package.

***A 16-lbm/gal Manganese Tetroxide OBM.*** The detrimental effects of suspended solids on drilling efficiency are attributed by many in the drilling-fluid industry to increased viscosity and/or lower filtration rates. The need to keep these solids suspended in the drilling mud requires the use of suspending aids, which necessarily imparts additional viscosity to the mud. Conventional weight materials display a $D_{50}$ of approximately 20 µm, and shaker screens typically used with materials of this weight seldom have openings much smaller than 100 µm. Some of the newer, ultrafine-weight materials such as manganese tetroxide display a $D_{50}$ of only approximately 1 to 3 µm, with correspondingly much lower Stokes settling rates. These finer-weight materials allow finer shaker screens, which in turn result in finer retained drilled solids with lower Stokes settling rates. These slower Stokes settling rates, in turn, allow formulations with lower concentrations of suspending aids and/or viscosifiers to be used, which should result in lower viscosities and improved drilling efficiency. Manganese tetroxide weighted muds also exhibit higher filtration rates unless supplemental filtration-control additives are added, and the higher filtration rates also could increase drilling efficiency if the conventional wisdom is valid.

## Testing

Test parameters for each Deep Trek test are listed in Table 5 in the full-length paper. Test numbers begin with 17 for continuity with the 16 previous tests in Phase 1.

## Conclusions

- Mud type and mud additives can enhance ROPs in high-pressure conditions significantly and may play a larger role than bit-design features.
- A 16-lbm/gal cesium formate brine increased ROPs 100% compared to 16-lbm/gal OBM in Carthage marble and Mancos shale. The cesium formate improved ROPs by increasing both the efficiency of the drilling and the aggressiveness of the bit.
- A 16-lbm/gal OBM weighted with manganese tetroxide increased ROPs in Crab Orchard sandstone 100% compared to the same-density mud with conventional weighting material. The manganese tetroxide improved ROPs by increasing the efficiency of the drilling, but it did not have a measurable effect on bit aggressiveness.
- It appears that the enhanced ROPs realized with cesium formate may occur only in conjunction with PDC-type bits.
- The 16-lbm/gal OBMs formulated with an alternative surfactant and with a drilling lubricant did not achieve an ROP faster than the reference 16-lbm/gal OBM.
- Four-blade PDC bits tended to yield higher ROPs than seven-blade bits. The four-blade bits were more aggressive than the seven-blade bits, but not more efficient.
- A seven-blade PDC bit with a longer profile did not achieve an ROP faster than the normal-profile seven-blade bit.
- An impregnated bit balled up when drilling through Mancos shale, even though an OBM was being used and the bit was being operated with reasonable levels of hydraulic horsepower.
- The same trend of ROP as a function of bit weight observed with roller-cone bits at normal bit weights continues to very high bit weights (80,000 lbm on a 6-in. bit). **JPT**