



# Specially Treated Drilling Fluid Weighting Agent Facilitates Development of Maturing Reservoirs

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## Abstract

The increasing use of Through Tubing Rotary Drilling (TTRD) and Extended Reach Drilling (ERD) techniques to extend the life of maturing reservoirs has increased the stress on drilling fluids employed for those applications. Optimal hydraulic efficiency is best achieved using drilling fluids with low viscosity. However, low-viscosity fluids are unable to adequately suspend the weight material used to control formation and well bore pressures. Optimizing this conflicting rheological need for hydraulic efficiency and adequate suspension of weight material has proved difficult to reconcile as wells have become increasingly more complex in the last decade.

This paper describes how a novel barite treatment process that reduces the particle size of conventional drilling-grade barite from 75 to less than 5 microns substantially improves the performance properties of both drilling and completion fluids using this novel weight material.

This new drilling fluid technology allows complex extended reach wells to be drilled economically from existing producing facilities, to the extremities of maturing reservoirs and adjacent satellite fields, without requiring more costly subsea development and tie-backs. The author will discuss case histories from the North Sea.

## Introduction

Barite is a dense, naturally occurring mineral that historically has been used to increase the density of fluids for oil and gas well drilling. In 2004, an estimated 7.2 million tons of barite was mined annually, of which 85 to 90% is used for oil-well drilling.<sup>1</sup> Barite has been the product of choice for densifying drilling fluids since the early 1920's<sup>2</sup> for the following reasons:

- has a relatively high specific gravity of  $>4.2 \text{ g/cm}^3$
- is readily available
- is relatively low cost
- is non-corrosive
- is non-abrasive
- is insoluble and non-toxic
- can be easily ground to a pre-determined particle size.

## Specifications for Drilling Grade Barite

As early as 1939,<sup>3</sup> specifications for drilling-grade barite were already in place both for density ( $>4.25 \text{ g/cm}^3$ ) and particle size, which stipulated that 98.75% should pass through a 300-mesh (45-micron equivalent) screen.

Since then, several refinements to the specification have been made through the American Petroleum Institute (API),<sup>4</sup> so that now, the density should be  $>4.20 \text{ g/cm}^3$ ; the maximum size particle retained on a 75-micron screen is 3% and particles less than 6 micron equivalent spherical diameter should be no more than 30%. The upper and lower particle sizes largely reflect the performance in a drilling fluid. Should the particle size be too coarse, barite is likely to segregate from the fluid in the surface mixing tanks as well as in the wellbore, with the rate of settlement largely dictated by Stokes Law of Settling, a fact recognized by the early pioneers using barite for density control in drilling fluids.<sup>2</sup>

To a large degree, the rheological stability of drilling fluids is governed by controlling the surface area and surface properties of solids in the drilling fluid. If the fine particle size fraction of barite in a drilling fluid is too high, the rheology is likely to increase undesirably, hence the specification of no more than 30% less than 6 micron.

Since they were first introduced nearly 70 years ago, specifications on weight material for drilling and completion fluids were effective for the type of wells which were drilled during this period. However, the complexity of many of the wells being drilled today with the advent of horizontal, small bore and long-reach drilling techniques, as well as the modern fluids used to drill them, have caused many to question whether strict adherence to using API Specification Grade Barite is necessary for some of the more complex wells characterizing today's drilling climate.

A long overdue requirement exists to overcome many of the limitations of API Specification Barite for the more challenging well types found in the maturing oil provinces in which these drilling techniques are commonly used.

## Drilling Fluid Requirements for Drilling Mature Reservoirs

Approximately 45% of the current oil production comes from reservoirs that have passed their peak production.<sup>5</sup> Extending the producing life of declining reservoirs by accessing remaining oil pools at the extremities of reservoirs and nearby satellite fields using extended reach, horizontal, through tubing and slimhole drilling techniques with complex well trajectories is increasing.<sup>6,7,8,9,10</sup> The demands on drilling fluid performance are related directly to the complexity of the well, with the following factors being the most critical to achieving the drilling objectives:

- **ECD Management:** In the lower sections of the wellbore, managing the Equivalent Circulating Density (ECD) becomes more difficult as the operating window between pore pressure and fracture pressure narrows such as in deviated wellbores. Maintaining a fluid rheology as low as possible with flow rates as high as possible for optimal hole cleaning are parameters often difficult to reconcile.
- **Hole Cleaning:** Inadequate hole cleaning leads to the formation of cuttings beds, effectively reducing hole diameter, increasing torque, drag, overpull on trips and higher ECD's. Increasing flow rate and pump pressures without compromising ECD, together with higher pipe rotation speeds, are the recommended remedial treatments.
- **Barite Sag:** A fluid column of uneven density inevitably leads to well-control issues, an unstable wellbore, increased torque and drag, stuck pipe and poor cement job quality. Circulating and conditioning the fluid to obtain a homogeneous fluid density in the wellbore while increasing the fluid low-shear-rate rheology, if ECD considerations permit, is the best field practice, but raises the risks of higher non-productive time (NPT).
- **Downhole Tool Performance:** Optimum MWD, LWD and wireline tool performance is achieved with drilling fluids of low rheology that provide good acoustic transmittance, high flow rates for downhole turbines coupled with fluids of low compressibility and low coefficient of friction.
- **Cement Job Quality:** The physical and chemical properties of drilling fluids directly influences cement job quality. Low rheology drilling fluids facilitate turbulent flow placement of cement slurries, reduced ECD, and reduced risk of losses to the formation for complete zonal isolation.
- **Reservoir Productivity:** In order not to compromise productivity any drilling fluid that drills a producing formation must be optimized for the specific producing formation and the method of completion.

It is apparent that for many wells engineering compromises need to be made by reconciling the conflicting needs of:

- a) Low drilling fluid rheology to control ECD in narrow 'mud weight' windows in which the difference between the pore pressure and fracture pressure is increasingly difficult to manage and sufficiently high annular flow velocities to remove drilled cuttings and other debris from the annulus without exceeding the pressure of the mud pumps.
- b) High drilling fluid rheology to maintain suspension of API grade barite in the fluid system. An uneven fluid density will compound the difficulties of managing ECD, thus increasing the risk of fluid influxes from the formation, lost circulation, differential sticking, logging difficulties and increased torque and drag.

In practical terms, maintaining a high drilling fluid rheology has an overriding priority for well-control reasons. Arguably, for many of the more challenging wells of today, API Specification Barite can be considered a troublesome product that is required by necessity to provide density to a drilling fluid - the most important drilling fluid property for well-control purposes. Other than density, API Specification Barite provides little value to a drilling fluid. Indeed, as mentioned previously, barite is prone to settle and sag, thereby requiring the addition of viscosifiers and other gellants to keep it suspended. Moreover, the drilled solids that are inevitably incorporated into a drilling fluid quickly assume the particle size of API Specification Barite, resulting in reduced, or poor, solids separation efficiency by shakers and centrifuges.

### A New Weighting Agent Concept for Drilling Fluids

Reducing the particle size of barite weighting agents so the majority of particles are less than 5 micron is a viable solution to overcome these deficiencies of API Specification Barite. However, reducing the particles to colloidal sizes by conventional grinding techniques will also cause undesirable increases in drilling fluid rheology due to the increased surface area of the particles.

This apparent dichotomy was overcome by the development of a treatment process that reduces the particle size of minerals to less than 5 microns and nullifies the surface area effects of ultra fine particles. The resulting product is a high-density liquid suspension, up to 2.4-sg density, in which the average particle size of the suspended matter is less than 2 microns. The carrier fluid may be either oil or water and extensive research has shown this treatment process can be applied to the majority of the common minerals used in drilling and completion fluids, including calcium carbonate, hematite, ilmenite, siderite and other minerals. The high-density slurry, or concentrate, is then diluted to the required

drilling fluid density and other products added to provide other essential fluid properties such as filtration control and an emulsified brine phase.

This reduction in particle size of more than an order of magnitude from standard API Grade Barite provides unique properties to the drilling and completion fluids into which this treated barite is added.

### Field Examples

The rheological properties of fluids using the treated barite have characteristically very low rheologies and zero barite sag as compared to those with API Specification Barite (Table 1). Plastic viscosity (PV) and yield point (YP) are substantially reduced from 35 cP to 25 cP; and 17 to 7 lb/100 ft<sup>2</sup> respectively. The low-shear-rate rheology expressed as the 6 and 3 rpm values are reduced from greater than 10 to less than 4 using treated barite weight material. Gel strengths are also reduced, while all other essential drilling fluid parameters, including high-temperature, high pressure (HTHP) fluid-loss control and water activity, remain the same as normal. No special suite of products is required for treated barite fluids.

For the reasons mentioned previously, these unique formulated treated barite fluids are being used for the more critical and extreme well sections in the North Sea for extended reach, through tubing and HTHP wells. Some examples are described.

#### Case History 1

A 3,179-ft, 5 $\frac{1}{2}$ -in. TTRD reservoir section was drilled from 10,830 ft from a 60° kick-off angle, dropping to 35° and then building back to 75° at TD. For the complex well geometry from this maturing oil field in the North Sea, managing ECD and barite sag would have been problematic using conventionally weighted systems. Formulating a 13 lb-gal oil-based fluid with the micronized, treated barite weighting agent meant that very low rheology drilling fluids could be utilized to control ECD and reduce drilling risk. Compared to offset wells, the ECD was maintained at 13.25 lb/gal, but pump rates were increased by more than 15 gal/min. Shaker screen sizes were reduced from typically 170 and 200-mesh screens to 210 and 250-mesh at 530-gal/min flow rates using the treated barite system. The combination of low fluid rheology and finer shakers screens resulted in drier cuttings being discharged and dilution factors reduced from 5 bbl of fluid lost per bbl of hole drilled to 2.1 bbl/bbl. No mud weight variation was noted after trips and drilling fluid properties remained stable throughout the section. The interval was completed on schedule.

#### Case History 2

The key criteria for success on a 4,222-ft, 8 $\frac{1}{2}$ -in. section drilled offshore Norway from 9,075 ft was to drill, run liner and cement the well at TD with controllable drilling fluid properties and no losses to the formation.

The fluid density was 13.7 lb/gal and the hole angle was 60°. The treated barite system was selected to provide greater control of rheology and to increase the margins of drilling risk. ECD's were reduced by up to 0.3 lb/gal towards the end of the section, despite higher pump rates (3,700 lb/in<sup>2</sup>) than offset wells at the same depth and hole angle. Four shale shakers were configured with three 250-mesh screens, and one 200-mesh screen, which handled the full flow of 555 gal/min - the average of 19 offset wells could only be dressed with 200-mesh screens before blinding. Like the previous example, dilution factors were reduced from 2.4 to 1.5 bbl fluid lost per bbl hole drilled, and taking into account all losses, fluid consumption was reduced from 4.1 to 2.6 bbl/bbl.

A surprising, but nevertheless consistent feature of the drilling fluid systems formulated with the new weight material, is the significant reduction in the coefficient of friction. The coefficient of friction inside casing was measured in the field at 0.15, compared to 0.17 on offset wells. In open hole, the reduction was even more dramatic with a reduction from 0.19 to 0.14 – a 26% reduction. On the same section, the actual torque measured for running the liner was 24kNM, compared to a simulated 27kNM. The reasons for this are not yet fully understood benefit, but confirms lab studies using both lab and field fluids.

#### Case History 3

In another example offshore Norway, a 3,189-ft 5 $\frac{1}{2}$ -in. TTRD reservoir section was drilled from 13,441 ft. The maximum inclination was 78° and fluid density was 13.2 lb/gal. The original producing well was plugged and abandoned in the 7-in. tubing requiring a new well to be drilled out into new formation from the existing completion to access known pools of hydrocarbons. Due to the narrow annular tolerances, ECD management was critical for this section where a narrow pore pressure and fracture pressure window existed. Hydraulics optimization was further complicated by the need for high flow rates to power a downhole geosteering tool. Drilling fluids using the new treated barite system was engineered with characteristically low fluid rheologies (3 rpm reading of 2 – 3 Fann Units) to control ECD without risking barite settlement at this critical mud weight and to deliver between 135 and 185 gal/min to the geosteering tool. The geosteering tool was successfully deployed in this new fluid system and the section completed without incident. No density variations were noted after trips. The actual ROP was 16 to 18 m/hr, 10% above program at 15 m/hr. Three shakers were configured with top screens of 190 and 210 mesh and bottom screens of 250 mesh which resulted in dilution factors of 3.9 bbl/bbl compared to 8.7 bbl/bbl on offset TTRD wells using conventional oil-based drilling fluid. Overall fluid costs were under budget by 18% as a result.

### Case History 4

In another 8½-in. reservoir section, a 9,130-ft long section drilled from 12,093 ft with 13.0 lb/gal and 70° sail angle dropping to 57° would have placed severe constraints on ECD control using conventionally weighted drilling fluids. Barite settlement in this long inclined section would have been problematic. Using the specially treated barite in an oil-based drilling fluid system, the section was successfully drilled without incident. Compared to an offset well drilled in the same area using conventionally weighted fluid of the same bit size and well trajectory, rotary torque in open hole was 26% lower. With 3 of the 5 shakers dressed with either 260 mesh; 270 mesh or 325 mesh handling full flow at 422 to 500 gal/min, dilution factors were reduced from an average of 1.6 bbl of fluid per bbl of cuttings drilled to 0.87 bbl/bbl. There was no evidence of uneven mud weight after trips. On one occasion towards the end of the 8½-in. section, a bit change necessitated leaving the fluid static in the well for five days. After 5 days static, circulation was broken and the mud weight taken every 10 minutes with no fluctuations in fluid density observed at the flowline, despite the 6 and 3 rpm readings of the treated barite system measuring only 3 and 2 Fann units.

### Conclusion

The treated barite drilling fluid system has been extensively used to drill many mature reservoirs in the North Sea where the complex well trajectories and narrow drilling tolerances of extended reach drilling, through tubing drilling and horizontal drilling techniques in reservoir sections require high performance and highly engineered drilling fluid systems that are not always attainable with conventionally weighted systems.

Compared to conventionally weighted systems, drilling fluids formulated with the newly developed treated barite weighting agent deliver improved control on ECD management by virtue of the very low fluid viscosities without any compromise on barite sag or settlement properties in inclined wells. The unique combination of micron-size particles and lower fluid viscosities enhance solids separation efficiency, reducing dilution factors by up to 50%. In addition rotary torque is reduced by up to 26% in open hole.

The author concludes that the use of specially treated weighting agents in drilling and completion fluids offers substantial benefits for drilling sections in maturing reservoirs by reducing overall drilling risk, and cost, in wells with complex trajectories.

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### SI Metric Conversion Factors

(°F -32) /1.8	= °C
bbl x 1.589 873	E-01 = m <sup>3</sup>
cP x 1.0 *	E+00 = mPa·s
in. x 2.54*	E+00 = cm
lb x 4.535 924	E-01 = kg
lb/gal x 1.198 264	E+02 = kg/m <sup>3</sup>
lb/gal x 1.198 264	E-01 = sg
lb <sub>m</sub> /bbl x 2.853	E+00 = kg/m <sup>3</sup>
psi x 6895	E+02 = Bar

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**TABLE 1** – Comparison of rheology between API Barite weighted drilling fluid system and micronized, treated weighting agent.

	API Barite weighted fluids	Micronised treated barite fluids
Mud Weight	13.2 lb/gal	13.2 lb/gal
Fann 35 rheology:		
600rpm	87	57
300 rpm	52	32
200 rpm	40	23
100 rpm	27	14
60 rpm	21	10
30 rpm	16	6
6 rpm	11	3
3 rpm	10	2
Gel Strength (10sec/10min)	15/30	4/6
Plastic Viscosity (cps)	35	25
Yield Point (lbs/100sq.ft)	17	7
Low Shear Yield Point*	9	1
HTHP Fluid Loss	<2mls	<2mls
Low Gravity Solids	<6%	<6%
Water Activity	0.85 to 0.93	0.85 to 0.93

\* twice 3 rpm value minus 6 rpm