Low Equivalent Circulating Density Organoclay-Free Invert Emulsion Drilling Fluids

Vikrant Wagle
EXPEC ARC, Saudi Aramco,
Dhahran 31311, Saudi Arabia
e-mail: vikrant.wagle@aramco.com

Abdullah AlYami
EXPEC ARC, Saudi Aramco,
Dhahran 31311, Saudi Arabia
e-mail: abdullah.yami.4@aramco.com

Michael Onoriode
EXPEC ARC, Saudi Aramco,
C-176, Floor 1, East Wing, Bldg. 1020,
Udhailiyah 31311, Saudi Arabia
e-mail: michael.onoriode@aramco.com

Jacques Butcher
Halliburton,
11th Floor, Citibank Tower,
Dubai, UAE
e-mail: jacques.butcher@halliburton.com

High pressure and high temperature (HPHT) wells especially those with narrow pore/fracture pressure gradient margins present challenges in drilling. Maintaining optimum and low rheology for such wells becomes a challenge where a slight change in the bottom-hole pressure conditions can lead to nonproductive time. However, maintaining low viscosity profile for a drilling fluid can pose a dual challenge in terms of maintaining effective hole-cleaning and barite-sag resistance. This paper describes the formulation of 95pcf medium-density organoclay-free invert emulsion drilling fluids (OCIEF) with a low viscosity profile. The fluids gave lower plastic viscosity (PV), which ensured that the fluid presents low equivalent circulating density (ECD) contribution while drilling/circulating. These fluids were formulated with acid-soluble manganese tetroxide as weighting agent and a specially designed bridging-agent package. The fluids were hot rolled at 300 °F and their filtration and rheological properties were measured. The paper describes the static-aging, contamination, and high pressure/high temperature rheology measurements of the fluids at 300 °F. Particle plugging experiments were performed on the fluids to determine the invasion characteristics and the nondamaging nature of the fluids. These organoclay-free invert emulsion fluids (OCIEFs) were then field-trialed in different wells with good results. Field deployment of the 95pcf organoclay-free invert emulsion fluid helped to maintain the required hole stability in the high temperature and high pressure (HTHP) well. The well was displaced to 95pcf production screen test (PST) fluid and completed with a 4 ½ in. sand screen. The paper demonstrates the superior performance of the developed fluid in achieving the desired lab and field performance. [DOI: 10.1115/1.4053557]

Keywords: petroleum wells-drilling/production/construction, manganese tetroxide, equivalent circulating density

Introduction

High pressure, high temperature (HPHT) wells which operate on a narrow window between pore pressure and fracture gradient usually need effective management of equivalent circulating density (ECD). A drilling fluid required for effective ECD management needs to have lower viscosity [1,2]. However, maintaining low viscosity profile for a drilling fluid can pose a dual challenge in terms of maintaining effective hole-cleaning and barite-sag resistance.

Invert emulsion drilling fluids are generally preferred over their water-based counterparts for drilling HPHT wells. Although the water-based drilling fluids are cheaper as compared with the invert emulsion fluids, advantages such as wellbore stability, higher thermal stability, and lower friction coefficients make the invert emulsion drilling fluids more cost-effective [3]. However, the main drawback of the conventional organoclay-based invert emulsion drilling fluids is their tendency for barite sag [4,5]. This increased tendency to sag has been attributed to the limited gel network between the organophilic clays and the invert emulsion internal phase especially at higher temperatures [5]. Conventional drilling fluids have several limitations for offshore applications such as generation of excessive progressive gels strengths in static conditions, high viscosity, and high gel strength at low temperatures, but not enough yield point (YP) and low shear values at high temperatures [6]. Thus, the use of organoclay-based invert emulsion drilling fluids having the right rheology profile to give long-term stability as well as better ECD management in HPHT wells has been difficult.

In recent studies, different nanoparticles such as nanosilica, iron-based, and calcium-based nanoparticles have been used in nonaqueous drilling fluids to obtain viscosity profiles that would give good ECD management [7–11]. However, the use of such nanoparticles would increase the fluid cost. Thus, a two-pronged approach has been used to develop a drilling fluid that not only has the right rheology profile for better ECD management but also shows good thermal stability.

Low ECD drilling fluids require low viscosity while maintaining suspension properties of the drilling fluid to reduce or eliminate the occurrence of sag. Instances of sag instability increase the likelihood of losing wellbore control, possibly either fracturing the wellbore or taking a kick [12–15]. A two-pronged approach was devised to formulate low ECD fluids. The first approach was to formulate an organoclay-free invert emulsion drilling fluid by replacing the organophilic clay and organophilic lignite with a polymeric viscosifier and filtration control agent, respectively. The removal of these low gravity solids (LGS) with the polymeric additives would help to reduce and optimize the overall rheology of the fluid. This reduced rheology would in turn also reduce the strong surge and swab effects which would help in better ECD management [16–18]. The use of polymeric additives in the organoclay-free invert emulsion fluids (OCIEFs) would help to form a gel structure required to achieve the necessary viscosity control. This viscosity control would help to increase the sag resistance and the cuttings-carrying capacity of the fluid [19–21]. Another advantage of the organoclay-free invert emulsion drilling fluids is the fragile gel structure that they provide [22]. In static conditions, the organoclay-free fluid forms a gel structure rapidly, that breaks instantaneously on applying low shear or after resuming circulation. Such a behavior not only results in lower equivalent circulating densities but would also reduce downhole mud losses as compared with the organoclay-based invert emulsion drilling fluids [23–25].

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The second approach was to formulate organoclay-free invert emulsion fluids with acid-soluble micronized weighting agent, viz., manganese tetroxide. Formulations with micronized weighting agents have been known to give fluids with enhanced sag resistance and better ECD control [18,26]. The settling rate of micronized particles in a viscous medium is much lower as the sag resistance of such smaller particles is higher. Also, manganese tetroxide has a higher specific gravity of 4.8 as compared with the conventional weighting agent, viz., barite (specific gravity 4.2). The use of manganese tetroxide would help to decrease the solids loading as compared with a conventional organoclay-free invert emulsion fluid formulated with barite as the weighting agent. This decreased solids loading would result in a lower plastic viscosity (PV) and improved rheology profile, which subsequently would result in a lower equivalent circulating density [27].

The present paper describes the results of the formulation of an acid-soluble, low ECD organoclay-free invert emulsion drilling fluid formulated with acid-soluble manganese tetroxide and a specially designed bridging package. The fluid developed for field deployment has been designed to offer optimum rheology, stable filtration properties, and optimum particle size distribution (PSD) for drilling thereby maximizing well productivity. The fluids gave lower PV, which ensured that the fluid presents low ECD contribution while drilling/circulating. Sag factor analysis for the fluids after static aging (ASA) for 24 and 48 h showed excellent stability and minimal sag propensity. HPHT rheology showed that the fluids had consistent PV and YP values across a range of temperatures and pressures. Contamination studies showed that the effect of contaminants on the organoclay-free fluid was minimal and any change in properties can be easily controlled using conventional treatments. The nondamaging novel fluid owing to its superior rheology would result in lower ECD [18], excellent suspension properties for better barite-sag resistance [28] while also reducing the risk of stuck pipe and pack off.

Materials and Methods in Designing Acid-Soluble OCIEF for Reservoir Drilling Application

Formulation Overview of OCIEF for Reservoir Drilling Applications. The following design criteria for OCIEF formulations were developed based on the requirements of a good reservoir drilling fluid [29–31]:

- Nondamaging nature to enhance well productivity
- Acid-soluble formulations
- Application in slim hole drilling environment
- Long lateral sections where low rate of penetrations (ROPs) can be observed
- High static overbalance conditions of 3000 psi–4500 psi differential pressure
- Target reservoirs temperatures of −300 °F
- Registered and available additives and diesel base fluid
- Resilient to potential contamination
- Validated fluid stability over expected static periods
- Practical design for ease of use in field applications

The weight material selected for the OCIEFs was manganese tetroxide due to its inherent high density (specific gravity 4.8) and nondamaging nature. Previous work has indicated the acid solubility of manganese tetroxide when used as a weighting material in water-based drilling fluids [27]. The micronized, spherical nature of manganese tetroxide is believed to support ease of flow back through permeable formation when wells are produced [32].

The OCIEFs were formulated with 70/30 oil water ratio (OWR). Shale inhibition would be achieved with a calcium chloride brine internal phase and the water phase salinity (WPS) matched to offset field experience of 180,000 ppm–230,000 ppm.

Formulation Overview of Production Screen Test Fluids for Completion Applications. Production screen test (PST) fluids were required for the completion phase. The primary objective of the PST fluid was to ensure that there would be no mechanical skin developed on the 4 ½ in. sand screen while running the completion in hole or during initial well production.

The following design criteria for PST fluids were developed based on the requirements of a good PST fluid [33–35]:

- Nondamaging nature to enhance well productivity (PST compliance)
- Acid-soluble formulations
- Low rheology and nongelling nature
- Target reservoirs temperatures of −300 °F
- Registered and available additives with diesel base fluid. Utilizing same additives as OCIEF for compatibility.
- Ease of mixing and application.
- Nonimpairment characteristics to flow through and flow back, through the pore sizes of the lower completion tool.

Formulation of 95pcf OCIEF and Production Screen Test Fluids. Two fluid formulations were developed for the 95pcf OCIEF requirements (Table 1) and one 95pcf PST fluid was developed.

The 95pcf OCIEF formulations were based on differences in bridging package for laterals of varying length. From an initial design perspective, it was considered paramount to have two formulations developed so that the final fluid selected for field deployment would offer stable filtration properties and PSD for drilling and offering maximum well productivity.

The use of one emulsifier proved adequate for developing stable emulsification of the external phase and providing sufficient wetting of weight material additions as well as associated solids.

The 95pcf OCIEFs were formulated with one methylstyrene/acrylate copolymer based polymeric filtration control additive.

Table 1 95pcf OCIEF and PST fluid formulations

Additive	Function	Unit of measure (UoM)	95pcf OCIEF #1	95pcf OCIEF #2	95pcf PST fluid
Diesel	Base fluid	bbls/bbl	0.504	0.504	0.537
Emulsifier 1	Emulsification	lb/bbl	14.0	14.0	14.0
Lime	Alkalinity	lb/bbl	2.5	2.5	2.5
Rheology Modifier 1	Suspension	lb/bbl	0.5	0.5	1.0
Filtration control additive	Filtration control	lb/bbl	6.0	6.0	–
Fresh water	Internal phase	bbl/bbl	0.234	0.234	0.231
Calcium chloride	Shale inhibition	lb/bbl	29.0	29.0	32.2
Rheology Modifier 2	Suspension	lb/bbl	1.5	1.5	0.5
Manganese tetroxide	Weight material	lb/bbl	215.39	215.39	251.14
Wetting agent	Wettability	lb/bbl	0.5	0.5	–
Engineered bridging material package 1	Bridging	lb/bbl	40	–	–
Engineered bridging material package 2	Bridging	lb/bbl	–	40	–

The selection of a single polymeric filtration control additive was based on proven high sealing efficiency at high overbalance conditions and lower impact on high end rheology values. Two suspension agents were included in the 95pcf fluid formulations, with Rheology Modifier 2 supporting higher initial gel structure. Rheology Modifier 1 is a modified fatty acid and Rheology Modifier 2 is an amorphous fibrous clay mineral.

95pcf OCIEF #1 was developed with a bridging package of various sized ground marbles specifically for short laterals and applications with lower differential pressures. The sized ground marble has higher hardness and tighter modality values than commodity calcium carbonate grades. The acid solubility of the bridging package was considered to be an additional benefit of the OCIEF #1 formulation.

An alternative OCIEF #2 formulation (Table 1) was developed with sized ground marble, sized resilient graphite, and fiber for longer laterals where increased mechanical attrition of bridging solids would be expected [36]. A bridging package with improved PSD stability for longer slim hole lateral sections would provide greater assurance for mitigating the risk of differential sticking in higher over balance applications and when drilling formations with wide permeability ranges. The sized resilient graphitic materials are not acid soluble, but the sizing relative to test media (and expected formation permeability) and low concentration on a volume by volume basis was considered to present negligible damage potential. The sized resilient graphitic materials would form an integral part of the external filter cake. The inclusion of a fiber in the bridging package was considered advantageous due to the high aspect ratio of fibers in developing a filter cake relative to the graphite and ground marble.

The 95pcf PST fluid was developed for ease of mixing and handling in the field with a focus on achieving flow through properties, target density, proven emulsion stability, and adequate suspension of micronized weight material. The 95pcf PST fluid formulation detailed in Table 1 includes a low concentration of rheology modifiers to provide suspension of micronized weight material. A low rheological profile was desirable to minimize fluid friction losses during PST and flow back during production. Note that the polymeric fluid loss control additive was not added to the 95pcf PST fluid formulation. The potential risk and mitigation of experiencing lost circulation from damaged filter cakes during the trip out of hole with the clean out assembly were not considered at the time that the 95pcf PST fluid was formulated.

OCIEF Formulations Mixing Procedure. All OCIEFs were mixed according to the following procedure:

- OCIEFs were mixed in batches of four lab barrels on the Silverson mixer.

Table 2 95pcf conventional organoclay-based invert emulsion drilling fluid

Additive	Function	UoM	95pcf conventional fluid
Diesel	Base fluid	bbls/bbl	0.516
Emulsifier 1	Emulsification	lb/bbl	7.0
Emulsifier 2	Emulsification	lb/bbl	4.0
Lime	Alkalinity	lb/bbl	6
Primary viscosifier	Suspension	lb/bbl	5.0
Filtration control additive	Filtration control	lb/bbl	6.0
Fresh water	Internal phase	bbl/bbl	0.217
Calcium chloride	Shale inhibition	lb/bbl	30.4
Secondary viscosifier	Suspension	lb/bbl	1.5
Barite	Weight material	lb/bbl	245.8
Wetting agent	Wettability	lb/bbl	0.5

- The OCIEF additives (exclusive of the bridging materials) were mixed for a total of 60 min at 6000 rpm in order of addition detailed in Table 1.
- A water bath was used as a heat sink to ensure the temperature of the 2 l stainless steel mixing cup did not exceed 150 °F during the fluids mixing.
- The OCIEFs were poured into aging cells and a 150 psi nitrogen header pressure was applied to the cells prior to loading into the pre heated hot roll ovens
- The OCIEFs were hot rolled in the roller ovens for 16 h at 300 °F.
- After the dynamic aging period had elapsed, the ovens were switched off and the cells were removed. The aging cells were allowed to cool to ambient temperature for 60 min in a water bath.
- The aging cells were depressurized and the contents of the aging cells were transferred into the mixing cup.
- The hot rolled OCIEFs were mixed on the Silverson mixer at 11,500 rpm for 5 min.
- The bridging materials were added to the hot rolled OCIEFs and mixed on the Silverson Mixer for 8 min at 6000 rpm.

Production Screen Test Fluids Mixing Procedure. The PST fluids were mixed according to the following procedure:

- The PST fluids were mixed in batches of four lab barrels on the Silverson mixer. A total of 5 l of fluid required for the PST test.
- The PST additives were mixed for a total of 60 min at 6500 rpm. The additives were mixed according to the sequence indicated in Table 2.
- The PST fluid was mixed for a further 60 min on the Silverson mixer at 6500 rpm to simulate extended shearing time expected during deployment
- A water bath was used as a heat sink to ensure the temperature of the 2 l stainless steel mixing cup did not exceed 150 °F during the fluids mixing.

OCIEF and Production Screen Test Laboratory Testing and Evaluation. The candidate OCIEFs were qualified for application based on industry testing standards and procedures (RP API-13 B2). Extensive regain permeability studies were performed. Testing methods are further detailed in Regain Permeability Test of 95pcf OCIEFs section. Micro-computed tomography (CT) scan analysis was performed on the synthetic core material used in the regain permeability study. The Micro-CT scan was undertaken in a third party laboratory and briefly described in Micro-CT scan of synthetic core material section. Acceptance criteria for the fluid's development was determined as part of the project scope.

OCIEFs were tested and evaluated based on the following tests:

95pcf OCIEF Properties

(i) Select fluid properties were tested prior to dynamic aging and reported as Before Hot Roll (BHR).
(ii) All OCIEF properties were tested post 16 h hot roll at 300 °F and reported as After Hot Roll (AHR).
(iii) The 16 h hot rolled OCIEFs were subject to a 24 h static age period at 300 °F. Select properties of the 24 h static aged OCIEFs were then determined and reported as ASA 24 h.
(iv) The 16 h hot rolled OCIEFs were subject to a 48 h static age period at 300 °F. Select properties of the 48 h static aged OCIEFs were then determined and reported as ASA 48 h.
(v) The rheology of the drilling fluids was measured using Fann 35 rheometer. The uncertainty in the dial readings increases from 3 rpm to 600 rpm with the 600 rpm showing a maximum uncertainty of ±1.5 dial reading [37].

Contamination Testing of 95pcf OCIEFs

(i) The 16 h hot rolled OCIEFs were subjected to 10%v/v water contamination prior to an additional dynamic aging period of

16 h at 300 °F. Select properties of the 10%v/v water contaminated OCIEFs were then tested and reported.

(ii) The 16 h hot rolled OCIEFs were subjected to solids contamination (35 ppb synthetic drill solids) prior to an additional dynamic aging period of 16 h at 300 °F. Select properties of the synthetic drill solids contaminated OCIEFs were then tested and reported.

HTHP Rheology of 95pcf OCIEFs. The high temperature and high pressure (HTHP) Rheology was determined on a sample of 16 h hot rolled 95pcf OCIEF #1 and OCIEF #2 formulations. Tests were performed on a Fann 75 HTHP Rheometer.

Regain Permeability Test of 95pcf OCIEFs. An extensive regain permeability study was undertaken for both 95pcf OCIEF #1 and OCIEF #2 at a third party laboratory. 16 h hot rolled fluids were used for the regain permeability study.

(i) Core Selection and Preparation

Clashach synthetic core material was used for the regain permeability study as formation core was not available. Clashach sandstone had comparable minerology, porosity and permeability to the formation in which the organoclay-free fluid was going to be used. Clashach was considered to be a suitable standard based on X-ray diffraction (XRD) and thin section analysis which indicated fewer constituent minerals and smaller clay fraction. The bulk rock XRD analysis of Clashach core material indicated that quartz was the dominant mineral (95.4%) with potassium feldspar (3.4%) and illite/ mica (1.2%) also detected.

The core samples were subjected to submerged solvent cleaning techniques to prevent damage to clay minerals. Solvents were replaced until all residues or brine, filtrate and oil were removed from the core samples. Core samples were dried in a low temperature oven to prevent collapse of any delicate clay minerals. Rock flour was removed from the end faces (where appropriate) by acid peel technique. On completion of the cleaning phase, the base parameters were measured.

The core samples were 100% saturated in simulated formation brine (11.8% CaCl2, pH 8.5) in a pressure saturator. Two different core samples, viz., V3 (5.05 cm length × 2.54 cm diameter) and V14 (5.065 cm length and 2.54 cm diameter) were used for OCIEF#1 and OCIEF#2, respectively.

(ii) 95pcf OCIEF Application and Drawdown

- A base permeability measurement with (synthetic) formation brine was taken in the formation to wellbore direction at low flowrate and with 400 psi confining pressure. The core samples were then prepared to irreducible brine saturation using an ultracentrifuge (this process generated the appropriate capillary pressure to force CO_2 to replace formation brine by drainage).
- Once the core samples had achieved irreducible brine saturation, the cores were loaded into the HTHP core holders and effective pressure was gradually increased to 11,420 psi (effective wellbore pressure).
- At expected reservoir conditions (300 °F) the base effective permeability measurement at 5300 psi pore pressure and 16,270 psi overburden pressure was performed in the formation to wellbore direction with CO_2 @ 5 ml/min.
- Under the described reservoir conditions, the OCIEFs were applied dynamically across the wellbore face of the core samples at 4500 psi overbalance pressure and 3.33 ml/min for a 24 h period. Cumulative filtrate volume measurements were recorded versus time over the dynamic OCIEF application period.
- Following the OCIEF application, the drawdown to (simulated) production phase CO_2 was performed by flowing the gas through the sample in the direction of formation to wellbore at 5 ml/min while recording the differential pressure measurements. Drawdown continued until stable flow conditions were achieved. On completion of the drawdown phase, an effective permeability measurement to CO_2 at residual saturation was made in the formation to wellbore direction.
- The core samples were removed from the core holders and visually inspected, prior to removing OCIEF mud and filter cake remnants.
- The cleaned cores were then reloaded into the test equipment and recalibrated to reservoir conditions. An effective permeability to CO_2 was established in the formation to wellbore direction.
- The core samples were again unloaded from the core holder and spun down with an ultra centrifuge.
- The cores were then re-equilibrated to reservoir pressure conditions and an effective permeability to CO_2 at residual saturation was measured in the direction of formation to wellbore.

Micro-CT Scan of Synthetic Core Material. Micro-CT scanning of the Clashach core samples was performed before and after completing the coreflood procedure. The samples were scanned using Nikon/Xtec XTV 225ST system and the micro-CT scan images have a resolution of 15 μ. The 2D and 3D analysis of sub sampled regions of the core (post coreflood) provided unique depiction of the filtrate invasion and spatial distribution during the coreflood procedure.

The PST fluids were tested according to RP API-13 B2 and Company PST test procedures. Select properties were evaluated as follows:

(a) Density, rheology, gel strengths were determined on fresh mixed fluid (BHR)

(b) PST testing was performed on 5 × 1 L samples of fresh mixed PST fluid. The PST tests were performed against 250 μ screens with 10 psi header pressure.

(c) A PST test was performed on a solids contaminated 94pcf PST fluid (1pcf lower than target density of 95pcf recorded). The resulting density of 98pcf was measured after 5ppb Ground Marble 25 μ and 45ppb Ground Marble 50 μ was added to the 94pcf PST fluid and mixed for 10 min on the Silverson Mixer at 6500 rpm.

The PST test on the solids contaminated sample was also performed on 5 × 1 l sample against a 250 μ screen with a 10 psi header pressure.

Note that no aging tests were considered as the PST fluids would be mixed on surface and spotted in open hole. The PST fluids had inferred stability as the PST fluid was developed from qualified OCIEFs.

Formulation of Conventional 95pcf Organoclay-Based Oil Based Drilling Fluid. The performance of 95pcf OCIEF was compared with the conventional 95pcf organoclay-based invert emulsion drilling fluid. The fluid was formulated with conventional additives such as organoclay as the primary viscosifier and organolignite as a filtration control additive. A fatty acid based secondary viscosifier was used to boost up the rheology of the invert emulsion fluid. The fluid was formulated with 70/30 OWR and a calcium chloride brine internal phase with a water phase salinity of 220,000 ppm. The fluid was tested post 16 h hot roll at 300 °F and reported as AHR. The 16 h hot rolled conventional fluid was also subjected to a 48 h static age period at 300 °F. Table 2 gives the formulation for the conventional 95pcf organoclay-based invert emulsion drilling fluid.

Results and Discussion

The fluid properties of the two 95pcf OCIEFs are detailed in Tables 3 and 4.

Table 3 95pcf OCIEF#1 fluid: mixing, aging conditions, and properties

Temperature	F	300 °F					
Time	hrs	–	16	16D + 24S	16D + 48S	16D + 16D	16D + 16D
Aging condition			Dynamic	Static	Static	Dynamic	Dynamic
Mixer type/speed	rpm	Silverson Mixer					
Test results		BHR	AHR	ASA 24 hrs	ASA 48 hrs	10% Water contamination	35ppb Synthetic drill solids contamination
		Fann 35 dial readings @ 150 °F					
Θ600		66	79	80	78	108	115
Θ300		41	47	49	46	67	71
Θ200		32	36	38	35	52	55
Θ100		22	23	25	23	35	37
Θ6		8	7	8	7	11	13
Θ3		7	6	7	6	10	11
Plastic viscosity	cPs	25	32	31	32	41	44
Yield point	lb/100 ft^2	16	15	18	14	26	27
10 s Gel	lbf/100 ft^2	9	9	9	8	11	14
10 min Gel	lbf/100 ft^2	11	12	11	11	13	15
30 min Gel	lbf/100 ft^2	12	13	13	12	13	16
Mud weight	pcf		95			93	101
Electrical stability	Volts	253	165	169	197	187	265
Retort oil, vol.	%		54.35			48.5	
Retort water, vol.	%		24.2			31.6	
Retort solids, vol.	%		21.45			19.9	
Oil/water ratio			69.19/28.80			60.54/39.45	
Total WPS	ppm	229,950	231,318				
Excess lime	lb/bbl	0.76	0.76				
HTHP cake thickness	1/32 in.		2	2	2	2	2
HTHP fluid loss (300 °F)	ml	1	2	2.4	1.2	2.4	1.4
PPA @ 300 °F, 40 μ, Δ3000 psi							
Spurt [4V7.5-2V30], ml	ml		0.4				
Total [2V30], ml	ml		3				
PPA @ 300 °F, 10 μ, Δ3000 psi							
Spurt [4V7.5-2V30]	ml		1				
Total [2V30]	ml		3.4				
Sag testing							
Free oil, ml				0	0		
Top density	Specific gravity			1.474	1.49		
Bottom density	Specific gravity			1.561	1.579		
Sag factor				0.514	0.514		

95pcf OCIEF Properties. The fluid properties of both 95pcf OCIEFs are discussed in generalized terms as the two formulations are comparable, exclusive of the inert bridging material selection.

(i) Fluid Rheology and Gels

Fluid rheology and gel structure is stable across the BHR, AHR, and ASA range. Low 600 rpm can be attributed to the size and spherical nature of the micronized weight material in combination with the selection of the emulsifier and use of low end rheology modifiers. Low plastic viscosities observed across dynamic and static aged fluids infers low circulating pressures in slim hole applications while drilling and post tripping operations. The gel speed and nonprogressive gel structure is imparted by the use of Rheology Modifier 2. Gel strengths are considered adequate for a micronized fluid system designed for slim hole application.

(ii) Filtration characteristics

Filtration characteristics of both 95pcf OCIEFs are extremely tight as evidenced by low spurt and total filtrate recorded during the Particle Plugging Apparatus (PPA) Testing. The efficiency of the polymeric filtration control additive in combination with sized bridging materials were confirmed with successful tests on 10μ and 40 μ aloxite discs with differential pressures of 3000 psi–4500 psi. The validation of the sealing performance against two different permeable media was based on potentially intersecting formations that exhibit heterogeneity in lithology or potentially wide or uncertain porosity and permeability ranges. Drilling formations with uncertainties at high overbalance presents risk of differential sticking events.

(iii) Emulsion stability

Emulsion stability of the 95pcf OCIEFs is evidenced by the all oil filtrate observed in the HTHP Fluid loss test performed at 300 °F. The lack of free fluid and sag factor results can (in part) be attributed to the emulsion stability of the formulations. The emulsion stability is further validated by the fact that there is sufficient free emulsifier in the 95pcf OCIEF #1 that the 10% water contamination test also presented no breakout (water) in the HTHP filtrate.

(iv) Fluid Stability: Static Aging

Sag testing was performed on the 24 h and 48 h static aged 95pcf OCIEFs. Sag factors of 0.51 with no free fluid were observed after 48 h. The 48 h fluids did not exhibit thermal gelation tendencies when samples were drawn for the sag tests.

The stability of the 95pcf OCIEFs can be attributed to the selection of the emulsifier and rheology modifiers and low settling propensity of micronized weight material (Stoke's Law).

The negligible difference in sag factors observed between the test periods suggests low probability of sag occurrence during an extended static period under similar aging conditions.

Table 4 95pcf OCIEF#2 fluid: mixing, aging conditions, and properties

Temperature	F	300 °F					
Time	hrs	–	16	16D + 24S	16D + 48S	16D + 16D	16D + 16D
Aging condition			Dynamic	Static	Static	Dynamic	Dynamic
Mixer type		Silverson Mixer					
Mixer speed	rpm	6000					
Lab results		BHR	AHR	ASA 24 hrs	ASA 48 hrs	10% Water contamination	35ppb Synthetic drill solids contamination
		Fann 35 dial readings @ 150 °F					
Θ600		66	74	76	76	106	–
Θ300		41	45	47	46	66	–
Θ200		32	33	36	65	51	–
Θ100		22	22	25	23	34	–
Θ6		8	8	8	8	11	–
Θ3		7	7	7	77	10	–
Plastic viscosity	cPs	25	29	29	30	40	–
Yield point	lb/100 ft^2	16	16	18	16	26	–
10 s Gel	lbf/100 ft^2	9	9	9	8	11	–
10 min Gel	lbf/100 ft^2	11	12	12	11	14	–
30 min Gel	lbf/100 ft^2	12	12	12	12	14	–
Mud weight	pcf		95			93	–
Electrical stability	Volts	253	218	211	268	168	–
Retort oil, vol	%		52.63				
Retort water, vol	%		23.72				
Oil/water ratio			68.92/31.08				
Total WPS	ppm	229,950					
Excess lime	lb/bbl	0.76					
HTHP cake thickness	1/32 in.		2	2	2	2	
HTHP fluid loss (300 °F)	ml	1	2	1.6	2.4	2.4	
PPA @ 300 °F, 40 μ, Δ3000 psi							
Spurt [4V7.5-2V30]	ml		1.6				
Total [2V30]	ml		4.8				
PPA @ 300 °F, 10 μ, Δ3000 psi							
Spurt [4V7.5-2V30]	ml		0				
Total [2V30]	ml		0.7				
Sag testing							
Free oil, ml				0	0		
Top density	Specific gravity			1.512	1.522		
Bottom density	Specific gravity			1.552	1.602		
Sag factor				0.507	0.513		

Contamination Testing:

(i) 10%v/v Fresh Water Contamination
The 95pcf OCIEFs were contaminated with 10%v/v fresh water, which resulted in increased rheology and gel strength values recorded. The higher rheology and gel strengths can be attributed to the larger internal phase and expected reduction in relative solids wetting. The 95pcf OCIEFs exhibit adequate resilience to the 10%v/v water contamination with a tolerable increase in rheology while maintaining tight filtration control of 2.4 ml (HTHP @ 300 °F on filter paper). No free water was observed in this testing. A reduction in electrical stability was observed in the case of both 95pcf OCIEFs contaminated with 10%v/v water addition.10%v/v water contamination could be effectively treated with additions of Emulsifier 1.

(ii) 35ppb Synthetic Drill Solids Contamination
The 95pcf OCIEF #2 fluid was contaminated with 35ppb synthetic drill solids to simulate contamination by reactive clays. The rheology and gel strengths of the contaminated 95pcf OCIEFs increased primarily due to the reactive nature of the sodium montmorillonite as compared with the volume addition of the solids. The electrical stability values increased due to the higher solids content and fluid viscosity [38]. Increased HTHP filtration properties were also observed in the solids contaminated fluid and can be attributed to the higher rheology and filter cake building nature of the additional colloidal size clay particles. Note that the 35ppb synthetic drill solids contamination would be considered an extreme solids contamination test. The disproportionately high contamination level with reactive clays would not be expected in a sandstone reservoir drilled horizontally with a slim hole drilling assembly. The elevated rheology and gel strengths could be trimmed to within specification with a higher OWR pre-mix volume inclusive of increased concentrations of Emulsifier 1.

HTHP Rheology. The HTHP Rheology of the 95pcf OCIEFs were evaluated on the Fann 75 HTHP Rheometer. Both OCIEFs were subject to the same HTHP Rheology test protocol. Test temperatures and pressures were determined for 95pcf OCIEF #1 and OCIEF #2 based on points of interest in the well architecture and test results are detailed in Tables 5 and 6, respectively.

The HTHP rheology values are consistent between 95pcf OCIEF #1 and OCIEF #2 and validate that there is negligible change in rheology and no fluid thickening is observed when fluids are subject to varying temperatures and pressure regimes. Both test fluids exhibit satisfactory dynamic suspension characteristics across the range of defined HTHP conditions defined in the tests. The HTHP Rheology values indicate that the OCIEF formulations

Table 5 95pcf OCIEF#1 HTHP rheology

	Fann 35	Fann 75 testing									
Temperature	(°F)	150	150	150	150	267	267	311	311	331	331
Pressure	(psi)	0	0	1954	3457	5059	7272	6628	8469	7617	9733
Θ600		74	74	88	98	53	61	49	54	48	55
Θ300		45	46	51	57	34	38	32	36	31	34
Θ200		33	36	40	42	27	30	25	28	25	28
Θ100		22	25	28	28	19	20	18	20	19	21
Θ6		8	9	10	9	7	7	7	7	8	7
Θ3		7	7	7	7	5	5	5	5	6	5
Plastic viscosity	cPs	**29**	**28**	**37**	**41**	**19**	**23**	**17**	**18**	**17**	**21**
Yield point	lb/100 ft^2	**16**	**18**	**14**	**16**	**15**	**15**	**15**	**18**	**14**	**13**

Note: Bold values indicate plastic viscosity and yield point are rheological parameters that characterize a drilling fluid.

Table 6 95pcf OCIEF#2 HTHP rheology

	Fann 35	Fann 75 testing									
Temperature	(°F)	150	150	150	150	267	267	311	311	331	331
Pressure	(psi)	0	0	1954	3457	5059	7272	6628	8469	7617	9733
Θ600		79	83	104	115	59	68	52	60	52	57
Θ300		47	50	61	68	36	42	33	37	33	35
Θ200		36	38	45	50	30	35	28	30	27	29
Θ100		23	26	30	32	23	25	20	23	19	20
Θ6		7	9	9	9	10	11	7	10	7	8
Θ3		6	7	6	7	7	8	5	7	5	5
Plastic viscosity	cPs	**32**	**33**	**43**	**47**	**23**	**26**	**19**	**23**	**19**	**22**
Yield point	lb/100 ft^2	**15**	**17**	**18**	**21**	**13**	**16**	**14**	**14**	**14**	**13**

Note: Bold values indicate plastic viscosity and yield point are rheological parameters that characterize a drilling fluid.

have low inherent ECD potential for expected application. Note that the elevated HTHP rheology values observed in 95pcf OCIEF #2 at 1954psi and 3457psi test points cannot be explained. Considering that all other test data collected during the HTHP Rheology test on OCIEF #2 is comparable with equivalent test points recorded with OCIEF #1, the HTHP Rheology values recorded at 1954psi and 3457 psi is considered to be an artifact of testing.

Regain Permeability Testing of 95pcf OCIEFs. The test results for the OCIEF application and drawdown are detailed below and summarized in Table 7 and Figs. 1 and 2.

After the base parameters were established the core materials were saturated in brine. The cores were loaded in the core holder and 400 psi confining pressure was applied. Base permeability was established to formation brine in the formation to wellbore direction at a low flowrate: Core V3/95pcf OCIEF #1 Kw = 98.6 mD and Core V14/95pcf OCIEF #2 Kw = 131 mD. Irreducible formation brine saturation was attained using an ultracentrifuge. The cores were loaded in the core holder and equilibrated to reservoir conditions and base effective measurement to CO_2 at irreducible formation brine saturation was undertaken in the formation to wellbore direction: Core V3/95pcf OCIEF #1 Kg@Swi = 91.6 mD and Core V14/95pcf OCIEF #2 Kg@Swi = 129mD. OCIEFs were dynamically applied across the wellbore face of the core sample at overbalance pressure for 24 h. Cumulative filtrate volume loss: Core V3/95pcf OCIEF #1 = 1.383 ml and Core V14/95pcf OCIEF #2 = 1.648 ml. The core samples underwent drawdown to CO_2 in the formation to wellbore direction at constant flowrate and initial/final pressures were recorded as follows: Core V3/95pcf OCIEF #1 = 89.4 psi/1.53 psi and Core V14/95pcf OCIEF #2 = 70.4 psi/0.79 psi. An intermediate, effective permeability to CO_2 was then undertaken in the formation to wellbore direction at residual saturation post drawdown was recorded as follows: Core V3/95pcf OCIEF #1 Kg@Sr = 36.5 mD and Core V14/95pcf OCIEF #2 Kg@Sr = 70.4 mD. After cleaning the cores of mud/ filter cake, the core samples were reloaded and re-equilibrated to reservoir conditions. An intermediate effective permeability to CO_2 at residual saturation minus fluid/cake was undertaken in the

Table 7 95pcf OCIEF application and drawdown

Core sample	Pore volume	Fluid applied	Total filtrate volume loss (ml) (pore vol)	Base specific permeability to formation brine Kw (mD)	Base effective permeability to CO_2 Kg@Swi (mD)	Effective permeability to CO_2 after drawdown Kg@Sr (mD)	Effective permeability to CO_2 minus drilling mud cake Kg@Sr (mD)	Effective permeability to CO_2 after Spindown Kg@Sr (mD) Filtrate out [ml]
V3	2.873	95pcf OCIEF #1	1.383 (0.440)	98.6	91.6	36.5 (−60.2%)	37.0 (−59.6%)	88.7 (−3.17%) [0.65]
V14	3.046	95pcf OCIEF #2	1.648 (0.574)	131	129	70.4 (−45.4%)	83.0 (−35.7%)	126 (−2.33%) [0.40]

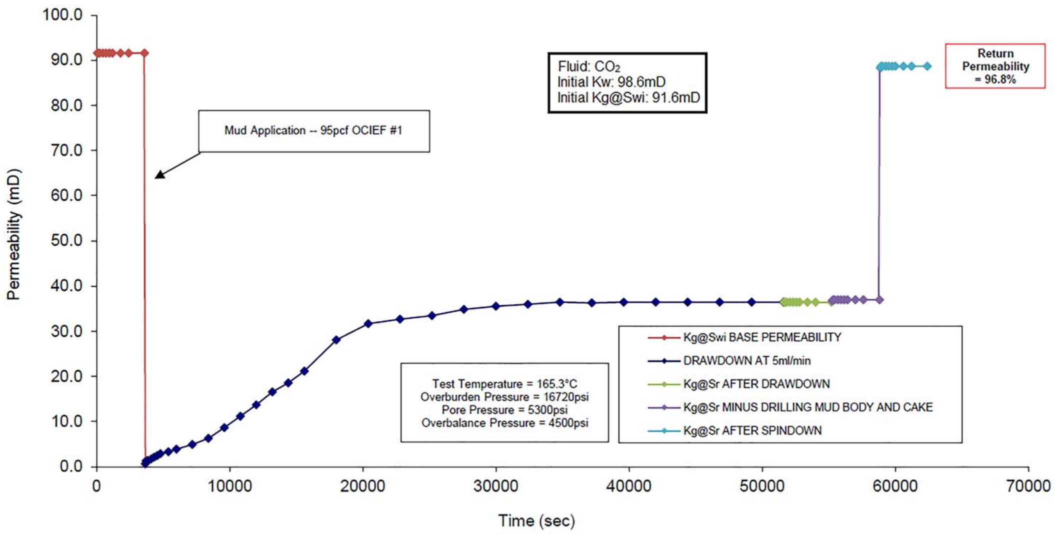

Fig. 1 95pcf OCIEF #1 Application/Drawdown to CO_2 at 5 ml/min

formation to wellbore direction. Core V3/95pcf OCIEF #1 Kg@Sr = 37mD and Core V14/95pcf OCIEF #2 Kg@Sr = 83 mD. The core materials were removed from the core holders and spun down in an ultracentrifuge and total filtrate volumes spun out of the core materials were recorded as follows: Core V3/95pcf OCIEF #1 = 0.65 ml and Core V14/95pcf OCIEF #2 = 0.4 ml. The core samples were again reloaded into the core holders and re-equilibrated to reservoir conditions. A final effective permeability measurement to CO_2 was undertaken in the formation to wellbore direction at residual saturation after spin down as follows: Core V3/95pcf OCIEF #1 Kg@Sr = 88.7 mD and Core V14/95pcf OCIEF #2 Kg@Sr = 126 mD.

The low filtrate values recorded at high overbalance test conditions validates the efficiency of the bridging materials and filter cake building additives within the 95pcf OCIEFs.

The spin down procedure with the ultracentrifuge gives is more representative of radial, long-term production after the back production has swept all the filtrate from the near wellbore area. In both tests there was an almost complete regain in permeability for the 95pcf OCIEF #1 and #2 formulations. The only slightly damaging mechanism that caused a reduction in permeability were any retained filtrate/fluid additives blocking some pore spaces in the wellbore face end of the core samples.

The 95pcf OCIEF #2 fluid does have marginally better final regain permeability (and higher regain permeability after drawdown and after cake removal) than the 95pcf OCIEF #1.

Micro-CT Scanning. Micro-CT scan analysis was performed on Clashach core (V3) before the coreflood experiment as indicated in Fig. 3. The (black) low X-ray density features represent open pore spaces throughout the subsampled body of the core sample. The (light) high X-ray intensity features represent high density grains or patches of cementation.

The 2D Micro-CT scan image (Fig. 4, upper image), indicated that within the sub sampled region of the wellbore end of the core sample exposed to 95pcf OCIEF #1, the filtrate invaded just the first few pore spaces to a depth of ~1 mm from the wellbore face after spin down. The top image is a 2D slice through the subsampled region and (white) high intensity features represent the OCIEF filtrate invasion into the pore spaces at the wellbore end. The (black) low intensity features represent pore spaces in the core sample.

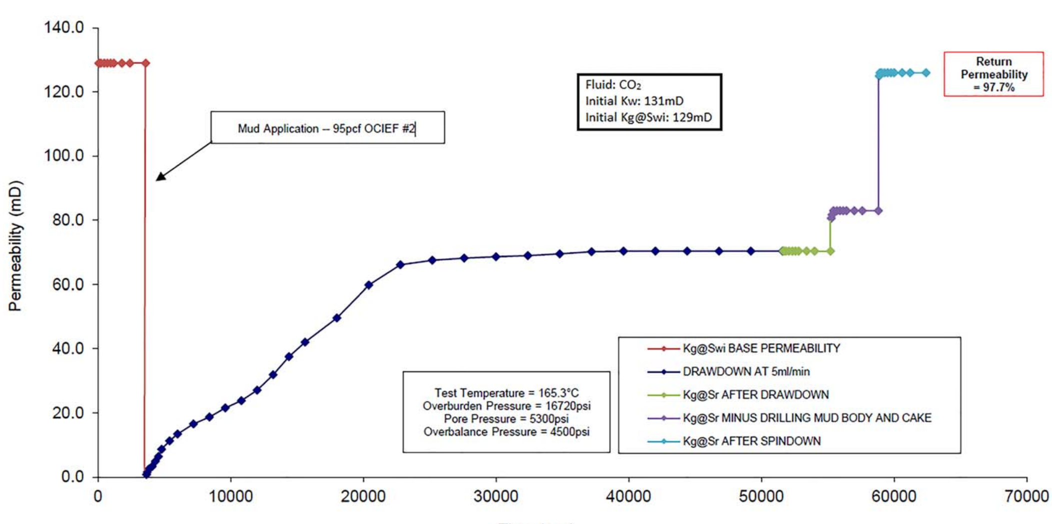

Fig. 2 95pcf OCIEF #2 Application/Drawdown to CO_2 at 5 ml/min

Fig. 3 Micro CT scan slice through V3 core sample prior to coreflood

The observation of low invasion is also shown by the 3D visualization of the invaded filtrate in Fig. 4 (lower image). The image indicates the spatial distribution of filtrate (blue) invasion. Note that the rock matrix has been removed in this image but the white boundary lines indicate the core sample outline.

The Micro-CT scan supports the results of the regain permeability study and tight filtration characteristics of the 95pcf OCIEF.

Formulation of Conventional 95pcf Organoclay-Based Oil Based Drilling Fluid. Table 8 shows the comparison between the rheological properties between 95pcf conventional organoclay-based and 95pcf organoclay-free invert emulsion drilling fluids. The formulation of the 95pcf conventional fluid was optimized to have a similar yield point and low end rheology to the 95pcf OCIEF#1 for fair comparison. 95pcf conventional fluid shows higher plastic viscosity and HTHP fluid loss as compared with the 95pcf OCIEF#1. The 95pcf conventional fluid due to the presence of organoclay shows progressive 10 sec, 10 min, and 30 min gel strengths as compared with the 95pcf OCIEF#1. Progressive gels is an undesirable feature of a drilling fluid as the fluid may require excessive pump pressures to break circulation. Static age studies of both the fluids showed that inspite of having similar rheology, the 95pcf OCIEF#1 gave low free oil separation and comparatively better sag factor than the 95pcf conventional fluid. Thus, a comparison of the rheological and filtration properties shows that the 95pcf OCIEF#1 performs much better than the 95pcf conventional organoclay-based fluid.

95pcf Production Screen Test Properties. 95pcf PST Fluids were tested and recorded properties are detailed in Table 9.

95pcf Production Screen Test Fluid Properties. Density of the PST fluid was 1pcf lower than the formulation which was probably due to some evaporation during mixing. As the fluid did not contain lost circulation material (LCM) or bridging materials, the 94pcf fluid was considered for PST testing. The PST fluid exhibited appropriate rheology and gel strength values for the intended application.

Production Screen Test Test Results. A PST test was performed on the 94pcf PST fluid and results detailed in Table 10 indicate that the fluid formulation (and fluid properties) do not present any risk of blinding the screen coupon. The 94pcf PST fluid passed the PST Test with all 5 × 1 1 volumes passing through the same screen coupon at a comparable time. The screen coupon did not have any residual buildup on the face of the coupon.

Production Screen Test Test Results on Solids Contaminated Sample. A solids contamination was performed on the 94pcf PST fluid with 50ppb bridging materials (which are the bridging materials and concentrations in the 95pcf OCIEF #1 fluid). Post solids

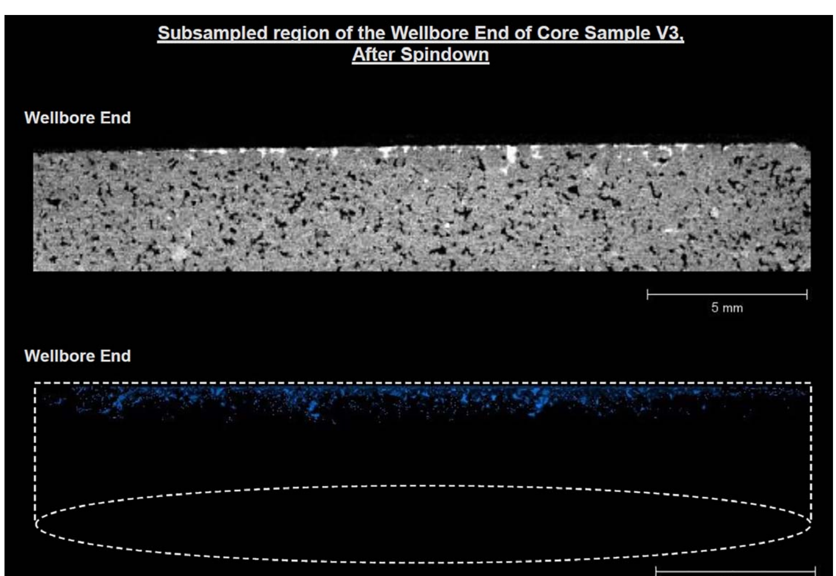

Fig. 4 2D and 3D micro-CT scan of core sample after spin down (95pcf OCIEF #1)

Table 8 Comparison between 95pcf conventional fluid and 95pcf OCIEF#1

Time		95pcf conventional fluid	OCIEF#1
Aging condition		Dynamic	Dynamic
Test results		AHR	AHR
Fann 35 dial readings @ 150 °F			
Θ600		86	79
Θ300		50	47
Θ200		38	36
Θ100		25	23
Θ6		7	7
Θ3		6	6
Plastic viscosity	cPs	36	32
Yield point	lb/100 ft^2	14	15
10 s Gel	lbf/100 ft^2	11	9
10 min Gel	lbf/100 ft^2	16	12
30 min Gel	lbf/100 ft^2	23	13
HTHP cake thickness	1/32"	4	2
HTHP fluid loss (300 °F)	ml	6	2
Sag testing			
Free oil, ml		8	0
Sag factor		0.528	0.514

Table 9 95pcf PST fluid

Property	UoM	95pcf PST fluid	95pcf PST fluid (contaminated)
Density	pcf	94	98
Fann 35 @ 150 °F: BHR properties			
Θ600		48	54
Θ300		32	36
Θ200		26	29
Θ100		18	20
Θ6		6	8
Θ3		5	7
Plastic viscosity	cPs	**16**	**18**
Yield point	lbs/100 ft^2	**16**	**18**
10 s Gel	lbs/100 ft^2	8	8
10 min Gel	lbs/100 ft^2	11	12
30 min Gel	lbs/100 ft^2	–	

Note: Bold values indicate plastic viscosity and yield point are rheological parameters that characterize a drilling fluid.

Table 10 PST Test (250 μ screen, 10 psi header pressure)

	PST test time (sec)	
Volume	94pcf PST fluid	98pcf PST fluid (solids contaminated)
1 l	12.06	12.7
1 l	10.5	11.3
1 l	10	10
1 l	10	Aborted
1 l	10.6	Aborted
Total time	53.16	–

addition the fluid density had increased to 98pcf with rheology and gels increasing slightly.

A PST test was performed on the 98pcf (solids contaminated) PST fluid and the results are detailed in Table 10. The complete test was aborted based on results of the 3 × 1 l sample results.

The 98pcf (contaminated) PST fluid also indicated that the fluid would pass through the screen coupon and the full test was aborted after the third liter passed through the screen with consistent timing. The fractional increase in PST time per 1 L volume passed with the 98pcf (contaminated) PST fluid may be due to the slight increase in frictional forces of the higher viscosity fluid relative to the 94pcf fluid.

Planning and Field Deployment of Organoclay-Free Invert Emulsion Fluid

Well Overview and Fluids Planning. The first deployment of the OCIEF was planned for a gas producing well. The well would produce from the reservoir formations that typically exhibit tight permeability.

The KPI's for the fluid design and execution were detailed as follows:

- Nondamaging fluid formulation to optimize production from an open hole completion
- Ensure zero stuck pipe incidents during drilling and completions operations
- Drill the section with zero downhole losses
- Run 4 ½ in. sand screens without incident and set at target depth

The 8 ⅜ in. interval would be drilled with 109pcf conventional oil based mud (OBM). The well design had the 7 in. liner set at an 89 deg inclination. The 5 ⅞ in. interval was planned to be drilled through the target reservoir holding 89 deg inclination and 302 deg azimuth. Based on offset experience in the field, low ROP was expected for the well. The well would be completed with 4 ½ in. sand screens.

A detailed Mud Program was prepared for the candidate well based on the pre drill data, offset analysis, risk assessments, fluids qualification, agreed KPI's and hydraulics modelling.

An 85pcf OCIEF was initially planned for use on the 5 ⅞ in. interval. The 85pcf OCIEF was required for wellbore stability and presented a 2810psi static overbalance across the reservoir section.

The contingency for higher mud weights of up to 95pcf was included in the Mud Program if the additional wellbore stability was required.

Field Deployment of OCIEF—Drilling Phase. Prior to mixing the fluid at the rig site, the planned OCIEF density was increased to 88pcf with a view to providing additional wellbore stability as required in offset wells. The fluids engineers and OCIEF additives were mobilized to location and the 88pcf (70/30) OCIEF was prepared as detailed in the mud program. A total of 1686 bbls OCIEF was mixed and sheared on surface through a custom built high pressure shearing unit [39] connected to the cement unit.

The 5 ⅞ in. drilling assembly was run in hole and the 7 in. shoe track and 10 ft of rat hole was drilled with the 109pcf OBM from the previous 8 ⅜ in. interval. The 109pcf OBM was displaced out of hole by pumping a 30bbl high viscosity 88pcf OCIEF spacer was pumped ahead of the 88pcf OCIEF. The 5 ⅞ in. hole was drilled at an azimuth of 302 deg and at an inclination of 88 deg at controlled ROP (10–28 ft/h). Drilling parameters were 70–100 rpm, weight on bit (WOB) 14–19 klbf, flowrates of 240–260 gpm, torque 5000–7200 ftlbs and SPP ranged from 2850 to 3585 psi. While drilling the interval, the measurement while drilling (MWD) tools failed necessitating a trip out hole. The assembly was pulled out on elevators and slick hole conditions were reported. A directional assembly with MWD and logging while drilling (LWD) tools was picked up and run in hole on elevators and the open hole was relogged. Drilling continued with the 5 ⅞ in. assembly when a pressure spike was noted with increased torque and the drill string stalled. The density of the OCIEF was increased to 92pcf in response to the indications of hole instability. Drilling resumed and the density of the OCIEF was increased to 95pcf in response to formation breakouts evidenced from LWD data. The 5 ⅞ in. interval was drilled with low ROP and the following typical drilling parameters: 100 rpm, WOB 6000–7400 klbf, flowrates of 200–

264 gpm, torque 10,000–17,000 ftlbs, and SPP ranged from 2450to 3800 psi. Tandem hole-cleaning pills were pumped with no notable increase in cuttings observed when circulated out of hole.

The hole was relogged and the assembly was run back in hole on elevators to bottom. A trip out of hole was planned to change out the MWD tools and test blowout preventers. The assembly was pulled out on elevators and no over-pull or drag was observed in open hole.

A 5 ⅞ in. directional assembly with MWD and LWD was run back in hole and various depths were relogged while running in hole to bottom. A sweep was pumped and circulated out of hole prior to performing a wiper trip to the 7" shoe. The drilling assembly was run back to bottom and hole swept clean with tandem pills prior to pulling out of hole.

Logging tools were picked up and run back in hole. Caliper data indicated hole enlargement of 12 in. below the 7 in. shoe. Another section of enlarged hole of 9 in. was observed at depth corresponding to where initial instability was observed. Reservoir temperature was recorded at 294 °F. Both wash out zones had high gamma ray readings confirming predominant argillaceous siltstone. The logging tools were pulled out of hole. Due to concerns regarding the risks associated with running a stiff lower completion in unstable and enlarged open hole, the decision was made to cut total depth short.

A 9 ⅝ in. × 7 in. scraper assembly was made up and run in hole. The hole was swept with tandem pills and the scraper assembly was pulled out of hole. A 5 ⅞ in. cleanout assembly was picked up and run in hole on elevators. Hole conditions were good as no tight spots were recorded in open hole. The hole was swept clean with tandem pills. The assembly was pulled to the 7 in. shoe while the fluids engineers prepared the 95pcf PST fluid for spotting in the open hole. The 5 ⅞ in. cleanout assembly was run back to bottom freely and a viscous spacer was pumped ahead of the 120 bbl 95pcf PST fluid that was spotted in the open hole section. The cleanout assembly was pulled inside the 7 in. liner. The cased hole volume of 95pcf OCIEF was circulated over fine shaker screens to remove LGS. The shale shakers were dressed with 270/325 mesh screens and the active system was circulated until the OCIEF was deemed PST compliant. The cleanout assembly was pulled out of hole.

The 4 ½ in. sand screens were picked up and run in hole to bottom without issue and the 4 ½ in. tubing hanger was set successfully.

95pcf Production Screen Test Fluids Testing and Conditioning—Completion Phase. The mixing and conditioning of the 95pcf PST fluid for spotting in open hole took longer than planned resulting in 5.75 h of non-productive time.

OCIEF and Production Screen Test Fluids Observations. The rapid increase of OCIEF density from 92pcf to 95pcf at 16,225 ft MD with direct additions of the weight materials to the circulating system resulted in an increase to plastic viscosity values of the OCIEF. The rapid addition of preferentially water wet micronized weight material placed increased demand on free emulsifiers within the circulating fluid. The subsequent addition of emulsifiers and increased oil content from 70/30 to 79/21 decreased plastic viscosity from a maximum of 44 cps to 32 cps.

The weight up and the increased oil and emulsifier treatments while drilling did impact the filtration characteristics. Additions of fluid loss control polymer and bridging materials were required to maintain target PPA properties of spurt $<$ 2 ml and total PPA $<$ 4 ml (40 μ, 300 °F).

The shearing unit mobilized to the drilling location supported the efficient mixing of fresh fluid and eliminated any flat time to shear fluid prior to drilling out the 7 in. casing. The 8 ⅜ in. interval was drilled with 109pcf OBM and 7 in. casing was run and set. While 88pcf OCIEF minimized static overbalance, it was evident from hole enlargement observed below the 7 in. shoe that the density of the OCIEF was insufficient for wellbore stability. The final 95pcf fluid density was adequate for wellbore stability as subsequent trips were performed on elevators. No hole enlargement was observed at depths beyond the fluid weight up to 95pcf. The formations drilled with 95pcf OCIEF had comparable gamma ray readings as observed in the previously referenced (two) wash out zones.

The increased emulsifier additions and increased oil content after weight up of the OCIEF to 95pcf presented some notable reduction to plastic viscosity and stand pipe pressure. The rapid change to OWR while drilling did however present some practical challenges to managing mixing and volumes as well as maintaining fluid properties. Heavy mud should be stored in reserve pits and transferred to active for more efficient management of fluid properties.

The combination of emulsifiers, polymers, and sized bridging materials provided effective bridging and sealing characteristics such that the fluid system could drill a high angle section with up to 3773 psi over balance (95 pcf).

The mixing and conditioning of the 95pcf PST Fluid for spotting in open hole took longer than anticipated at the rig site due to operational issues. 95pcf PST fluid should be reformulated with the inclusion of low concentrations of polymeric fluid loss control additives. The PST formulation should present a mitigation for risks associated with potential damage to the filter cake that may arise from tripping out of hole with the clean out assembly. The well production exceeded expectations validating the fluid design and deployment.

Conclusions

- Stable 95pcf organoclay-free IEFs formulated with two different bridging-agent packages showed good rheology and filtration properties. The fluids showed low plastic viscosity and optimum yield point and low end rheology values.
- Contamination studies with 35ppb synthetic drill solids and 10%v/v water showed that the OCIEFs were resistant to contamination
- Formulated OCIEFs showed consistent rheological properties over a wide high temperature and high pressure range
- Static-aging studies of both the 95pcf OCIEFs showed that the fluids had good sag resistance over extended period of time
- Both the 95pcf OCIEF#1 and OCIEF#2 showed high return permeability of 96.8% and 97.7%, respectively
- Field deployment of the 95pcf OCIEFs was successful with well production exceeding expectations, thereby validating fluid design and deployment.

Conflict of Interest

There are no conflicts of interest.

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