Pre-operational drilling fluid evaluation of oil- and water-based drilling muds considering the impact on core analysis. A case study from the Upper Jurassic in the Northern North Sea

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Abstract. Core analysts are commonly not involved in the drilling fluid design for well operations although the selected drilling fluid can have a major impact on the later results. This paper presents an integrated pre-operational study which was run to select the best fluid for drilling operations as well as for core analysis. Two water-based (WBM) and one oil-based drilling mud (OBM) were selected for the study. Target formation is the Upper Jurassic (Oxfordian, Kimmeridge) in the Northern North Sea. The laboratory program was designed to evaluate parameters relevant for drilling performance and borehole stability, e.g. clay swelling, and post-drilling core analysis. Core analysis related tests covered detectability of fluid contamination, interfacial tension measurements (IFT) on mud filtrates, flow through cleaning efficiency (mass balance), wettability alteration (half-Amott test) and alteration of reservoir quality (pre- and post-routine core analysis, µ-CT, XRF screening of trim ends cut post-fluid treatment). Sample material used for clay swelling tests were cuttings from the target formations. As no preserved core material was available Kirby Sandstone was selected as outcrop analogue for core analysis. Kirby sandstone consists of quartz and feldspar with only minor impurities. Two groups of test plugs were run. One group with an average gas-permeability Kg of 20 mD and another one with an average Kg of 40 mD. Porosity of both groups was around 20 %. These groups were expected to cover the reservoir quality expected in the target formations. Dummy plugs, which were not treated with drilling mud, were run as baseline reference. Comparing the results relevant for core analysis, the performance of the OBM was better when it comes to flow through cleaning efficiency and alteration of the reservoir quality. Spontaneous Imbibition tests showed a measurable change towards less water-wet by the two WBM samples. Wettability alteration by the OBM is most significant. Balancing these results against the evaluation of drilling performance and borehole stability it therefore was decided to select the OBM for operations. Although drilling performance and borehole stability commonly out-weight the arguments for core analysis when it comes to drilling fluid selection this study is a good example how an integrated pre-operational workflow should look like.

1 Introduction

The selection and design of drilling fluids is generally carried out by the drilling department during the planning phase of a well and other disciplines are commonly not involved. Designed primarily to provide optimal drilling results under given conditions, the drilling fluid can also affect the data acquisition, reservoir fluid sampling and core analysis. Therefore, cooperation between the disciplines involved can consider the different requirements and be beneficial to the entire operation. To minimize the influence of the drilling fluid on subsequent analysis programs and to optimize drilling performance and borehole stability a laboratory study was run to select the best fluid. Two water-based (WBM) and one oil-based drilling fluid (OBM) were tested on cuttings material from neighboring wells from the target formations in the Upper Jurassic (Oxfordian and Kimmeridgian sandstones) in the Northern North Sea and on core plugs of Kirby Sandstone outcrop analogue material.

Selection of the two water-based drilling fluids was driven by the assumption that water-based systems do not alter reservoir rock wettability. Another important selection criteria were the traceability of drilling fluid contamination. #1 OBM consists of a synthetic base oil

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detectable and distinguishable from reservoir crude oil by distinct hydrocarbon chains.

This paper illustrates the steps and results of a two months pre-operational laboratory study, which included the characterization of the drilling fluids and the rock material, as well as the interaction between drilling fluid and cuttings, and between fluid and the core plug analogue material.

2 Motivation

Log interpretation in the Upper Jurassic oil reservoir indicated that re-charge mechanisms might be active. To better understand the reservoir rock, sidewall cores were planned in a new well. Repeated Imbibition and Drainage cycles should be run within the core analysis program to measure hysteresis effects. Wettability has a major impact on fluid exchange mechanisms and might be altered by drilling fluid contamination (Ballard and Dawe, 1998, Menezes et al., 1989, Patel and Growcock, 1999, Sanner and Azar, 1994). To avoid any negative impact by the drilling fluids a laboratory test program was designed together with the drilling engineers to qualify a fluid system suitable for drilling operations as well as core analysis.

3 Materials and Fluids

3.1 Drilling Fluids

Three different drilling fluids are tested. One oil-based system and two water-based system. The main characteristics are given in Table 1 and Table 2.

Table 1. Tested Drilling Fluids and their characteristics.

Fluid	System	Characteristics
#1 OBM	Oil based	Paraffin base oil
#2 WBM	Water based	Inhibited fluid (KCl brine), Barite weighted
#3 WBM	Water based	Inhibited fluid, dense brine phase (NaBr), no Barite

Table 2. Composition of #1 OBM.

Concentration (kg/m^3)	Purpose
404	Base fluid (base oil)
45	Emulsifier
12	Viscosifier
20	Viscosifier
5	Fluid loss control
252	Internal phase (brine)
9	Alkalinity
50	Bridging particle ($CaCO_3$)
50	Bridging particle ($CaCO_3$)
605	Weighting Agent (Barite)

3.2 Cuttings to be used in the clay swelling study

3 kg of cutting material from Heather (Oxfordian) and Draupne (Kimmeridge) formations were required for fluid compatibility tests.

Cuttings material came from nearby wells and covered good reservoir sands and shale rich layers. These shale rich layers have the highest probability to cause borehole instability.

It was necessary to combine samples within a reservoir depth range of up to 50 m to have enough material for all fluid tests. This was done based on log interpretation.

3.3 Outcrop Sandstone Analogue

As no plug material was available for experiments on a possible wettability change, outcrop Kirby sandstone was selected, matching the petrophysical parameters of the target formations (see Table 3).

Kirby sandstone consists of up to 92 wt.-% quartz, 6 wt.-% feldspars and minor impurities like mica and Fe-minerals. Kirby sandstone contains no illite and kaolinite which are present in reservoir sandstones of Kimmeridge and Oxfordian formations. In the Kimmeridge total clay content can reach up to 70 wt.-%. In the Oxfordian sandstone formation total clay contents of up to 30 wt.-% were measured.

Table 3. Average parameters of the target formations.

Formation	**Kimmeridge**	**Oxfordian**
Reservoir Rock	Sandstone	Sandstone
Mineralogy (based on whole rock XRD, > 1 wt.-%)	Illite-Smectite, Illite, Mica, Kaolinite, Chlorite, Feldspars, Quartz, Siderite, Pyrite	Illite, Mica, Kaolinite, Quartz, Feldspars, Fe-Dolomite, Pyrite
Fluid(s):	oil and/or condensate, brine	oil and/or condensate, brine
Temp. (°C)	118	120
Top Reservoir Pressure (bar)	350-370	350-370
Porosity (%)	17	17
Permeability (mD)	<0.1 - 10	10 - 50
Max. Pore throat radius (µm)	10	30

Selected Kirby sandstone plugs have similar petrophysical parameters as pore throat size (PTR) distributions.

One testing group of plugs have a Klinkenberg permeability (Kkl) close to 40 mD correlating with a maximum PTR of approximately 20 – 30 µm. The other group has a Kkl close to 20 mD correlating with a maximum PTR of approximately 10 µm. Each drilling mud was tested on both groups.

3.4 Synthetic formation water (SFW)

The composition of the synthetic formation water is based on water analysis from the Oxfordian. The composition used in the study is given in Table 4.

Table 4. Synthetic formation water (Oxfordian).

Salt	**g/L**
NaCl	11.06
$CaCl_2 * 2H_2O$	0.30
$MgCl_2 * 6H_2O$	0.19
$SrCl_2 * 6H_2O$	0.01
KCl	0.25
Na_2SO_4	0.03
$NaHCO_3$	2.29
TDS	13.96

3.5 Laboratory oil

As laboratory oil, a medical white oil of saturated hydrocarbons was used. It does not contain any polar components altering the wettability of rocks. The density is 0.812 g/cc at T=20°C and 0.750 g/cc at T=50°C.

4 Program

The laboratory program was designed to be finished within approximately two months and covered the following studies (Gant and W. G. Anderson, 1988, McPhee et al., 2015, API RP40, 1998).

4.1 Drilling Fluid Characterization

- Grain size distribution of drilling fluid solids using laser particle sizer analysis (LPSA)
- Gas-chromatography of paraffin base oil (only #1 OBM)
- Interfacial tension measurement (IFT) (drilling fluid filtrates vs. SFW and/or Laboratory oil)

4.2 Cuttings and drilling fluid interaction

- Linear Clay swelling meter tests on cutting material from Kimmeridge and Oxfordian (all drilling muds and tap water as reference)

4.3 Core Analysis Study on outcrop analogue

- Preparation of Oxfordian synthetic formation water (SFW) including fluid properties.
- XRF (X-ray fluorescence) scans of Kirby sandstone (Baseline measurement clean samples).
- Measurement of petrophysical base parameters (RCA) of Kirby sandstone plugs (pre-study on 8 plugs, 1.5” diameter, 2 plugs selected as dummies).
- Saturation of Kirby sandstone plugs (S_w=1) with SFW and drainage to S_{wi} with laboratory oil by multi-step ultracentrifuge runs (8 plugs).
- Low speed ultracentrifuge run of Kirby sandstone plugs at S_{wi} surrounded by drilling fluid for 24 h at 50°C (6 plugs, 2 plugs for each drilling fluid) to simulate drilling fluid exposure at the sand face. The remaining 2 plugs were kept aside as reference material.

- Flow through of 5 PV's laboratory oil (6 plugs).
- Spontaneous Imbibition of SFW within Amott cell (8 plugs, 4 weeks).
- Single side trimming of plugs (8 plugs)
- Cold Soxhlet cleaning using Ethanol (8 plugs)
- Measurement of petrophysical base parameters (RCA) on Kirby sandstone plugs (8 plugs post-study)
- µ-CT scans on trim ends (6 samples)
- XRF (X-ray fluorescence) scans on inner and outer surface of trim ends for contamination detection (6 samples).

5. Methodology

5.1 Gas-Chromatography

Gas chromatography allows for separating and analysing compounds that can be vaporized without decomposition. The base oil samples were analysed according to standard DIN 51435 qualitatively using an Agilent GC 7890A

5.2 Linear clay swelling meter test

100 g of cleaned and oven dried cuttings are milled and compacted in cylindrical wafers. The samples are then brought into contact with the test fluid at a constant temperature. The (linear) height increase of the sample is measured and recorded over time.

This is a measure of the reactivity of the sample due to the presence and amount of swelling clay minerals.

Commonly tap water is used to create a baseline measurement for comparison. The linear clay swelling meter used (OFITE©) allows the simultaneous measurement of 4 samples.

5.3 Laser particles size analysis (LPSA) of drilling fluids

Laser particle size analysis (LPSA) uses a monochromatic laser beam. When the beam hits solid particles it is scattered. The angle of light scattering is inversely proportional to particle size, i.e. the smaller the particle size, the larger the angle of light scattering.

For laser particle size analysis, the particles of a sample are dispersed in a fluid, e.g. brine or oil, and are permanently pumped through a circuit passing the laser beam. The resulting diffraction patterns are measured and interpreted. This results in a volumetric grain size distribution. Grain sizes from 0.05 up to 1000 µm are covered with this method.

5.4 Interfacial tension measurement (IFT)

In this study the pendant drop method was used to measure interfacial tension (IFT). A droplet of filtered drilling fluid is created within an embedding fluid. This is laboratory oil for the water-based fluids and SFW for the oil-based system. At constant time-steps a drop shape analysis is carried out until the droplet is in equilibrium with the embedding fluid. Knowing volume and density of the droplet one can calculate IFT by knowing the gravity force acting. All measurements in the study were carried out at a temperature of 50°C.

5.5 Grain density (GD) and porosity (Φ)

Porosity (Φ) calculation (Equ. 1) is based on measured grain volume (GV) and bulk volume (BV) calculated by calliper. He-Pycnometer is used to measure grain volume of the dry samples.

A pycnometer uses Boyle-Mariott's law to derive volume changes based on pressure measurements. Calibrated sample and reference cells are used to calculate the grain volume of the sample. Plugs were dried at T=60° until dry weight stabilized.

$$\Phi = PV/BV*100 = (BV-GV)/BV*100 \qquad (1)$$

$$GD = m_d/GV \qquad (2)$$

$$BV = \pi * r^2 * h \qquad (3)$$

5.6 Steady-State Gas-Permeability (K_g)

Gas-Permeability is measured at ambient conditions using Stead-State method and a Hassler type flow cell. A constant flow rate is set, and pressure gradient measured when equilibrium of the gas flow is reached. Measurement gas is air. An axial confining pressure of 20 bar is applied to avoid bypass-flow. Klinkenberg corrected permeability is calculated based on running measurements at 4 different mean pressures.

5.7 Ultracentrifuge Multi-Speed Drainage

An ultracentrifuge (Vinci Technologies) is used to drain the brine saturated plug samples down to initial water saturation S_{wi}. Four samples of almost equal permeability were run simultaneously. Laboratory oil was used as imbibing fluid. Maximum capillary pressure applied was 3.65 bar. Saturation changes are measured by video monitoring the produced fluid volume. After establishing S_{wi} plugs were stored in Oxfordian SFW for one week.

5.8 Drilling fluid treatment

After establishing S_{wi}, Kirby sandstone plugs were treated with drilling fluid. In total 6 plugs were run. Two plugs with #1 OBM, two plugs with #2 WBM and 2 plugs with #3 WBM. Two dummy plugs remained in brine as reference samples. The treatment was carried out by covering each plug with drilling mud and spinning the plugs in the ultracentrifuge for 24 hours at a temperature of 50°C. Centrifuge speed selected was 1500 rpm to avoid brine mobilisation.

After being unmounted, plugs were immersed in laboratory oil at T=50°C.

5.9 Flow-Through cleaning with laboratory oil

Flow-through cleaning with base oil or laboratory oil is commonly used in core analysis when dealing with fresh state plugs (McPhee et al., 2015). This workflow step was adopted for this study as fresh state plugs are planned to be run during the core analysis study.

Each plug was mounted in a Hassler cell and 5 pore volumes of laboratory oil flooded through the pore space. Flow rates were adjusted to avoid brine mobilization, Effluents were collected for further investigations.

5.10 Spontaneous Imbibition (Amott Cell)

Cleaned and dummy samples were mounted in a Amott cell and covered with Oxfordian SFW. Laboratory oil spontaneously produced in the Amott Cell was measured over time. Total duration of the experiment approximately 2 weeks.

5.11 µ-CT Imaging

Trim ends of 1 cm thickness were cut from each plug for visual inspection. Non-destructive X-rays are used to create a grey scale image based on density contrast of the investigated material. In this way pores can be distinguished from minerals and a pore network of the samples generated. The aim in this study was to detect high density minerals, e.g. calcite, baryte, deposited by the drilling fluid (Schroeder and C. Torres-Verdin, 2019).

5.12 X-ray fluorescence (XRF)

X-ray fluorescence delivers the elemental composition of a sample. It is a non-destructive method and is based on the interpretation of X-ray spectra measured while scanning a sample surface. As lighter elements do not interact with X-rays. Elemental composition is limited to the elements of the periodic system having an atomic number higher than sodium (Na).

5.13 Soxhlet cleaning

After spontaneous imbibition and prior to post-study measurements of the petrophysical base parameters, samples were Soxhlet cleaned with Ethanol for 5 days.

6 Results

6.1. Gas-chromatography of paraffin base oil of #1 OBM

Figure 1 shows the gas-chromatograph of the synthetic bas oil. The distinct peaks between the hydrocarbon chains n-C11 and n-C14 allows the identification of the base oil in effluents collected while core analysis.

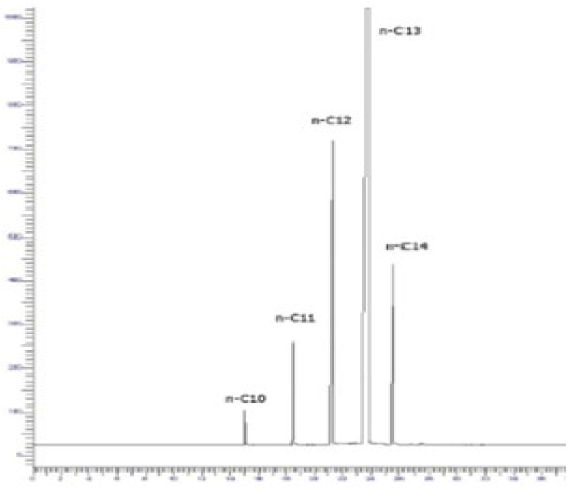

Fig. 1. Gas-chromatograph showing the hydrocarbon fingerprint of #1 OBM synthetic base -oil.

6.2 Linear clay swelling meter test

Table 5 gives the results of the measured cuttings and drilling mud interaction. Tap water proves intrinsic swelling reactivity of the clays. Cuttings material from the Kimmeridge is more reactive than cuttings from the Oxfordian (ca. 30 % vs. ca. 20%).

Optimum clay control is given by #1 OBM (swelling < 4.5%). Both WBM solutions result in a swelling rate in between tap water (no inhibition) and #1 OBM (best inhibition) with #2 WBM showing higher swelling rates.

Kimmeridge cuttings are less reactive in #1 OBM compared to the WBM options (vice versa for Oxfordian), but differences 4.5% vs. 2.3% are small and within the range of accuracy.

Table 5. Results of the linear clay swelling meter tests. Tap water is used as reference.

	Swelling (%)			
Formation	Tap Water	#1 OBM	#2 WBM	#3 WBM
Oxfordian	20.6	4.5	12.2	9.7
Kimmeridge	31.4	2.3	18.6	15.8

6.3 Grain size distribution in drilling fluids

Grain size distributions (Table 6) show that key parameters D10, D50 and D90 increase in the order #1 OBM, #2 WBM and #3 WBM.

Table 6. Grain size distribution statistics

Fluid	#1 OBM	#2 WBM	#3 WBM
D10 (μm)	1	1	3
D50 (μm)	6	17	22
D90 (μm)	32	50	68

D10 is equal between #1 OBM and #2 WBM. The WBM systems show closest D50 and D90 values. The D50 and D90 values of #1 OBM are 2-3 times smaller compared to #3 WBM.

6.4 Interfacial Tension (IFT)

The measurement of IFT of all muds (Table 7) in either synthetic formation brine or laboratory oil as embedding phase show similar values of #2 WBM and #1 OBM of around 5 mN/m. #2 WBM has the lowest IFT of 3 mN/m.

Table 7. Results IFT Measurements.

Droplet Phase	**Embedding Phase**	**IFT (mN/m)**	**Droplet Stability (Min.)**
#1 OBM	SFW	5.3	Up to 80
#2 WBM	Lab. Oil	5.2	Up to 20
#3 WBM	Lab. oil	3.1	Up to 2

6.5 RCA Kirby Sandstone Samples

Eight Kirby Sandstone plugs were selected for the drilling fluid tests.

Table 8. Petrophysical Properties of Plug samples and tested drilling fluid.

ID	Fluid	L (cm)	D (cm)	GD (g/cc)	Φ (%)	Kkl (mD
17	Dummy	7.6	3	2.62	20.6	30.1
8	Dummy	7.61	3	2.60	20.9	41.5
15	#1 OBM	7.59	2.99	2.63	20.4	27.5
10	#1 OBM	7.6	3	2.60	20.8	36.4
5	#2 WBM	7.61	3	2.60	20.1	27.8
7	#2 WBM	7.6	3	2.60	20.7	37.8
14	#3 WBM	7.6	2.97	2.62	20.9	27.4
16	#3 WBM	7.6	2.99	2.63	21.0	38.4

Four samples with Klinkenberg corrected gas-permeabilities (Kkl) of around 30 mD (Plugs 5, 14, 15 and 17) and four plugs with a Kkl of around 40 mD (Plugs 7, 8, 10 and 16). Out of each group one plug was selected to be brought in contact with a drilling mud type.

In addition, out of each group one dummy plug was run as reference. Table 8 lists the physical properties of the plugs and the drilling fluids tested.

6.6 Initial Water Saturation (S_{wi})

All selected plugs were saturated with synthetic formation brine of the Oxfordian formation and drained to initial water saturation in an ultracentrifuge at T= 50°C. Laboratory oil was used as imbibing fluid and a maximum capillary pressure of 3.7 bar was applied. Initial water saturations achieved are between 21 and 38 % Sw (Fig. 2).

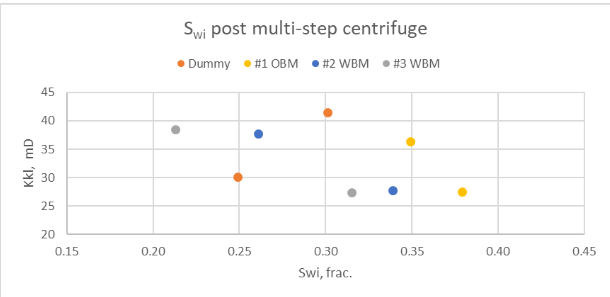

Fig. 2. Klinkenberg Permeability versus S_{wi} after multi-step centrifuge drainage.

6.7 Mass Balance after flow through cleaning

Plug weight was measured before and after injection of 5 PV of laboratory oil. This should give an indication of drilling mud contamination and its removal.

Mass balance of #1 OBM is almost within accepted measurement error (Table 9) and below 0.54 g. #2 WBM shows an average remaining mass increase of 1 g independent of sample permeability. #3 WBM shows highest mass increase which could not be reduced by flowing laboratory oil through the pore space. The weight increase by being in contact with this drilling fluid is more than 2 g.

Table 9. Weight changes of the plugs before and after mud contamination with **#1 OBM**, and flow-through cleaning. As reference weight after establishing S_{wi} is given.

Plug ID	10	15
Weight at S_{wi} (g):	120.3	120.3
Weight after flow-through cleaning	120.11	120.84
Weight difference	-0.19	+0.54

Table 10. Weight changes of the plugs before and after mud contamination with **#2 WBM**, and flow-through cleaning. As reference weight after establishing S_{wi} is given.

Plug ID	5	7
Weight at S_{wi} (g):	121.03	120.33
Weight after flow-through cleaning (g):	122.14	121.37
Weight difference (g):	1.11	1.04

Table 11. Weight changes of the plugs before and after mud contamination with **#3 WBM**, and flow-through cleaning. As reference weight after establishing S_{wi} is given.

Plug ID	14	16
Weight at S_{wi} (g):	119.36	120.34
Weight after flow-through cleaning (g):	121.78	122.67
Weight difference (g):	2.42	2.33

6.8 Spontaneous Imbibition

After flow-through cleaning, the plugs were mounted in Amott cells to run spontaneous imbibition with synthetic formation brine at a temperature of 50°C. Duration of spontaneous imbibition was approximately 2 weeks (Fig. 3 and 4).

#2 WBM performs best, achieving highest oil production compared to the other mud systems. #3 WBM performs similar in the high permeability sample group but achieves less total oil production in the high permeability group. #1 OBM achieves lowest oil production with lowest imbibition rate.

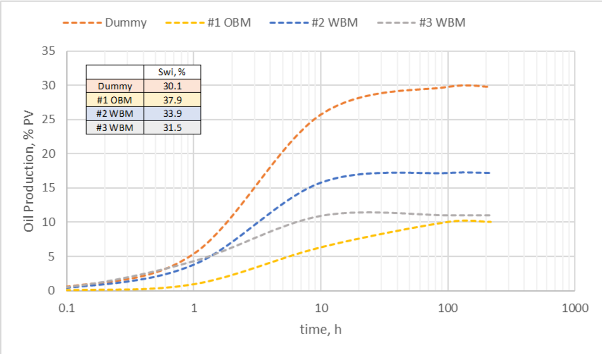

Fig. 3. Spontaneous Imbibition curves of the low permeability sample group.

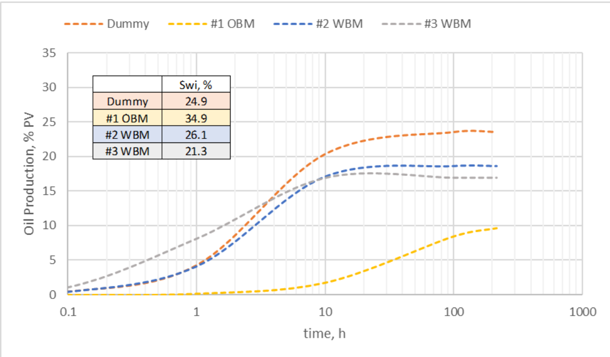

Fig. 4. Spontaneous Imbibition curves of the high permeability sample group.

Figure 5 shows the change of water saturation versus permeability. In each permeability class the dummy plugs show the largest increase of S_w (> 20%). All plugs brought in contact with drilling fluid reached values below 20 % S_w.

Plugs being in contact with #2 WBM show an increase of S_w of 15-18%. The 40 mD plug treated with #3 WBM acts similar, whereas the Plugs with a Kkl of 30 mD treated with #2 WBM acts like the #1 OBM plug (~ 10% S_w). In general, all plugs which were in contact with #1 OBM show the smallest increase in S_w (< 10%).

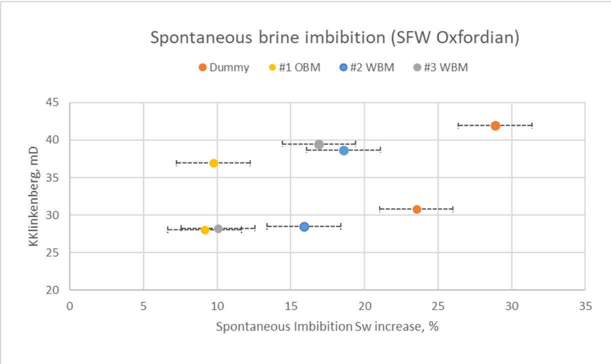

Fig. 5. Results of the spontaneous imbibition test. Increase in water saturation (Sw) is plotted versus Klinkenberg permeability (Kkl). Error bars are given as grey horizontal lines. Errors are based on repeated reading statistics.

6.9 µ-CT scans and XRF-results on trim-ends

After spontaneous imbibition an approx. 1.5 cm trim-end was cut off from each plug (Figure 6). The trim-ends were oven dried (T=60°C) and µ-CT scanned to visualize potential formation damage. Figures 7 and 8 show a comparison of the trim-end of plug 8 (dummy) with trim-end from plug 5 (#2 WBM).

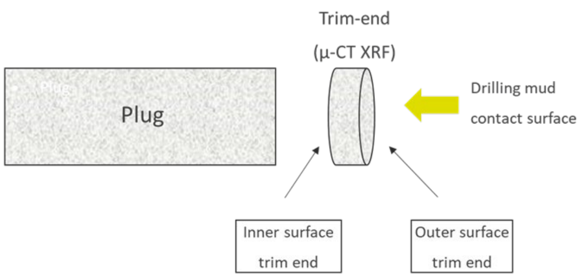

Fig. 6. Plug preparation after spontaneous imbibition test.

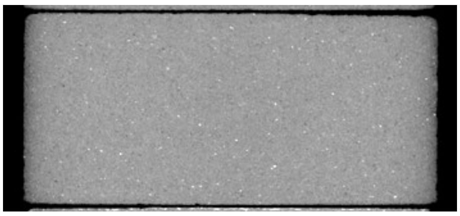

Fig. 7. µ-CT scan tomogram trim-end plug 8 (Dummy). The outer surface at top, left and right, inner surface at bottom.

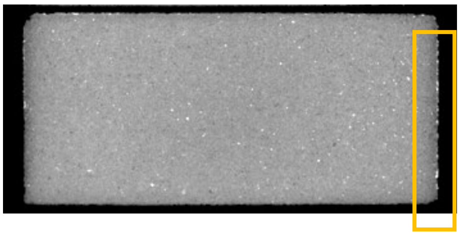

Fig. 8. µ-CT scan tomogram trim-end plug 5 (#2 WBM). Outer surface at top, left and right. Inner surface at bottom. The outer surface with visible barite is framed.

Figure 8 shows bright glimmering particles at the outer surface of the trim-end. This is high density barite from the solid fraction of the drilling fluid. These particles are also visible on the outer surface of plug 7, which was also treated with #2 WBM, but has higher permeability. The inner surface of these trim ends (Fig. 8) which was not in direct contact with the #2 WBM does not show any barite.

As in Figure 7 (dummy plug) all other µ-CT trim-end images show no indication of barite at the inner or outer surface. These include dummy plugs and plugs treated with #1 OBM and #3 WBM.

Table 12. Key elements found at the inner and outer surface of the trim-ends. Increased values compared to other samples and Kirby sandstone reference are highlighted.

Trim End Inner Surface (Average Content, wt.-%)						
	SiO_2	SO_3	Cl-	CaO	Br-	BaO
Dummy	89.0	0.1	0.8	0.0	0.0	0.0
#1 OBM	88.0	0.0	1.6	0.4	0.0	0.0
#2 WBM	88.7	0.1	0.9	0.1	0.0	0.0
#3 WBM	87.7	0.0	1.6	0.1	0.1	0.0
Trim End Outer surface (Average Content, wt.-%)						
Outer surface	SiO_2	SO_3	Cl-	CaO	Br-	BaO
Dummy	49.8	0.1	18.0	17.7	0.0	0.0
#1 OBM	49.2	2.3	14.4	19.8	0.0	0.0
#2 WBM	43.6	7.1	12.0	15.3	0.0	10.9
#3 WBM	53.4	0.1	16.1	18.0	0.8	0.0
Kirby Sst. (Average Content, wt.-%)						
	SiO_2	SO_3	Cl-	CaO	Br-	BaO
Clean Plug	89.5	0.1	0.2	0.1	0.0	0.0

Table 12 gives the key elements found at the trim end surfaces. These elements are also found in the tested drilling muds and synthetic brine composition. As reference the abundance of these elements in a clean Kirby sandstone is given. Dummy plugs are also listed as they were in contact with laboratory oil and synthetic brine in this study.

The XRF results on the trim-ends surface (Table 12) indicate NaCl and CaO precipitation at the outer surface of every plug. High BaO values on the #2 WBM treated plugs are consistent with the µ-CT scan results. No BaO was found at the inner surface of the #2 WBM trim-ends. Bromide (Br^-) added to #3WBM was found at the outer and inner surface of the trim-ends.

#1 OBM and #2 WBM treated plugs show slightly increased Sulphate (SO_3) at the outer surfaces. Inner surface measurements on #1 OBM trim-ends show higher CaO. Increased Chloride contents are found on the inner surface of #1 OBM as well as #3 WBM plugs.

6.10 RCA post-testing

Petrophysical parameters after the tests were compared to the pre-test results to document permanent changes by the drilling fluids. Post-Test results and changes in porosity and Klinkenberg permeability are listed in Table 13 and shown in Fig. 9 and 10. These figures include confidence intervals of +/- 0.5 % porosity and +/- 5% of measured permeability. These intervals are based on API RP 40, (1998) and give the accepted error range, measurements on a same sample should be repeatable using the same method and measurement parameters.

Table 13. Post-test petrophysical parameters and changes to pre-test data.

ID:	Fluid:	GD [g/cc]	Φ [%]	Kkl [mD]	Delta-Φ [%]	Delta-Kkl [mD]
8	Dummy	2.60	19.8	37.7	-1.1	-3.8
17	Dummy	2.62	19.9	28.2	-0.6	-1.9
10	#1 OBM	2.62	20.3	33.6	-0.5	-2.8
15	#1 OBM	2.62	19.8	25.6	-0.6	-1.9
5	#2 WBM	2.61	19.5	26.9	-0.6	-0.9
7	#2 WBM	2.61	19.4	32.0	-1.3	-5.8
14	#3 WBM	2.60	18.9	22.6	-2.0	-4.7
16	#3 WBM	2.61	19.7	35.6	-1.3	-2.9

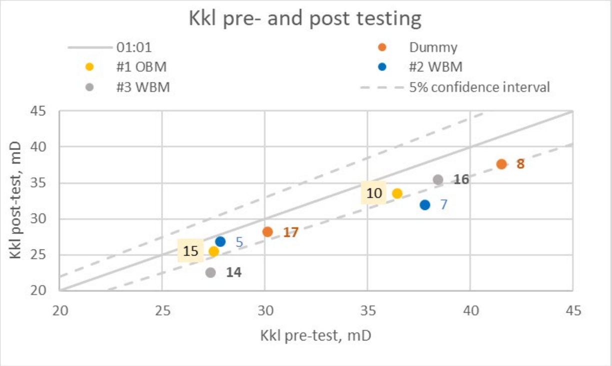

Fig. 9. Comparison of pre- and post- test Klinkenberg permeability. 1:1 line and confidence intervals of +/- 5% of measured permeability are included.

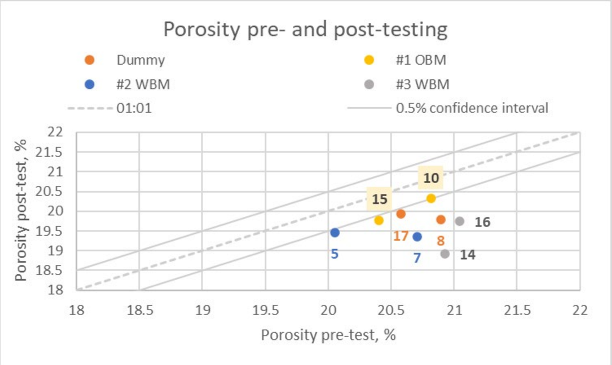

Fig. 10. Comparison of pre- and post- test porosity. 1:1 line and confidence intervals of +/- 0.5 porosity-% is included.

All samples show a decrease in porosity and permeability. Four plugs are outside a confidence interval of +/- 0.5 % porosity (Fig. 10). Two are outside the confidence interval of +/-5 % Kkl These are Plug 8 (dummy plug), plug 7 (#2 WBM) and Plugs 14 and 16 (#3 WBM).

7 Interpretation and discussion

This study had the objective to evaluate three different drilling fluids considering borehole stability (clay swelling) and impact on post-drilling core analysis.

The focus on the latter were alteration of reservoir rock wettability and formation damage. As it was considered to run the core analysis on fresh state plugs, any kind of alteration of the rock properties by the drilling fluid must be avoided or should be reversible.

To be able to react to the presence of the drilling fluid in the core material the mud must be traceable. This was another important criterion for the selection of the muds for this study. Figure 1 shows the distinct GC fingerprint of #1 OBM. #3 WBM contains NaBr and #2 WBM Barite which potentially can be used as tracers dependent on the background concentration in the formation brine.

Clay swelling test run with tap water show that cuttings from the Oxfordian (~20%) and Kimmeridge (~30%) are reactive. #1 OBM reduced the clay swelling to less than 5 % compared to the #2 and #3 WBM. (> 10%).

Measuring interfacial tension on filtrates of the muds show that #3 WBM has a slightly higher tendency to be miscible with laboratory oil (IFT = 3 mN/m) than #2 WBM (~ 5 mN/m). The IFT of #3 OBM versus synthetic formation water is equal to the value of #2 WBM.

Spontaneous Imbibition tests show that all drilling fluids lead to an alteration of wettability. This was not expected for the two WBM systems. As expected, #1OBM lead to the most significant alteration. However, wettability alteration could not be excluded for all drilling fluids.

XRF measurements on trim-ends also showed indications of mud contamination. Bromide (Br-) was detected in the #3 WBM plugs. Barite was detected by µ-CT on the surface of the #2 WBM plugs as well as by XRF, however there are no indications it has entered the pore-space.

Petrophysical parameters measured pre- and post-study showed 4 plugs with a significant reduction in porosity and permeability. Plug 8 (dummy plug), plug 7 (#2 WBM) and Plugs 14 and 16 (#3 WBM). The latter three showed the highest weight increase after the ultracentrifuge run embedded in the drilling fluids.
Reduction on Plug 8 might be due to salt precipitation from the SFW.

Comparing the grain size distributions of the mud systems formation damage results might be biased. D10, D50 and D90 grain size fractions are higher in the tested mud formulations of (#2 WBM) and (#3 WBM). Find below the comparison of grain sizes and pore throat diameters of Kirby sandstone (Table 14).

Table 14: Comparison of the key grain size parameters of the mud systems and pore throat diameters of Kirby sandstone.

	#1 OBM	#2 WBM	#3 WBM	Kirby Ss. (PTD/µm)
D10/µm	1	1	3	0.1
D50/µm	6	17	22	5.9
D90/µm	32	50	68	12.5

8 Summary

This study shows the benefit of core analysts being involved in the drilling fluid selection in advance of the laboratory program. Testing the impact of drilling fluids on core analysis results may not outweigh the selection criteria for borehole stability, however, it enables to be prepared and modify the core analysis program design due to a proper knowledge of drilling mud behaviour. Also cleaning routines can be adjusted to remove drilling fluid residuals without loosing time on pre-studies when cores arrive, and reservoir properties are urgently needed.

In this study one oil-based drilling mud and two water-based muds were tested. #1 OBM was selected due to the traceability of the synthetic base oil by gas-chromatography. #2 WBM and #3 WBM were assumed not to alter wettability. This is important as one main objective of the core analysis program was to run drainage and imbibition cycles on fresh state plugs.

Results show that all three drilling fluids alter the wettability of the tested Kirby sandstone analogue. As expected, wettability alteration by the #1 OBM is most pronounced. However also the two WBM’s show a measurable impact.

#2 WBM shows the least wettability alteration, however, leads to most pronounced clay swelling. Also, the #2WBM shows a high degree of adsorption to the rock surface. Formation damage was proven on the higher permeability sample tested (Kkl= 32 mD), whereas the lower permeability sample (Kkl= 27 mD) shows no significant reduction in porosity and permeability.

#3 WBM almost shows same wettability alteration as #1 OBM, has lowest IFT and droplet stability and shows highest adsorption to the rock surface, which was hardly removed by flowing 5 PV of laboratory oil. Bromide was detected inside the pore space which proves mud infiltration. Clay swelling was intermediate compared to the other drilling fluids. Formation damage is hardly measurable.

#1 OBM showed highest wettability alteration. CaO as part of the solid fraction seems to have infiltrated the pore space. #1 OBM was easily removed from the rock surface by flowing 5 PV laboratory oil which results in no measurable formation damage. Performance in Clay swelling is best and reduced to < 5%. IFT is comparable to #2WBM however droplet stability is higher.

Considering all the results #1 OBM was selected for drilling conventional and sidewall cores. Using #1 OBM, wettability alteration might be still an issue in case of contamination, however being involved early in the drilling fluid selection, proper measures can be taken to adjust the core analysis program, e.g. cleaning procedure, and to implement proper QC steps for tracking mud contamination.

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Nomenclature

BV: bulk volume, in cc

D10: 10% quantile of a sorted data-set, here cumulative grain size distribution or pore throat diameters.

D50: 50% quantile of a sorted data-set (Median)

D90: 90% quantile of a sorted data-set

GD: grain density, in g/cc

GV: grain volume, in cc

h: sample height, in cm

Kkl: Klinkenberg corrected gas permeability in mD

LPSA: laser particle size analysis

$m_{d:}$ dry sample mass, in g

OBM: Oil Based Mud

PV: Pore volume in cc

r: radius r, in cm

RCA: routine core analysis

SFW: synthetic formation water

S_w; water saturation

S_{wi}: initial water saturation

WBM: Water Based Mud

XRF: x-ray fluorescence

Φ: Porosity in %

µ-CT: micro-computer tomography