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A method for assessing drilling fluid induced formation damage in permeable formations using ceramic discs

Karl Ronny Klungtvedt [a], Arild Saasen [b,*]

[a] EMC AS, NO-4033 Stavanger, Norway
[b] University of Stavanger, NO-4036, Stavanger, Norway

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ABSTRACT

When drilling an oil and gas or geothermal well, the formation's ability to produce or flow may be reduced because of exposure to the drilling fluid during the drilling operation. To evaluate such formation damage, core flooding tests are typically conducted using representative samples of rock to measure the change in the formation permeability in the zone near the wellbore. Disadvantages of core flooding tests include time and cost of a test and potential limited access to representative cores. Therefore, core flooding tests are generally not practical to use for screening and adjustment of drilling fluid compositions when a high number of tests are planned.

A method has been suggested to allow for time and cost-effective testing of mass change of ceramic discs, such that a high number of tests may be completed within a limited timeframe and budget. However, so far only limited testing had been conducted to understand the potential for measuring permeability change. In the present study, the method was applied to test for change in permeability of ceramic discs following HTHP tests. A reverse flow of fluid was applied to lift off the filter-cakes and then a breaker fluid was applied. Thereafter the permeabilities to air and water and the dry disc mass was measured and compared with the original value to detect any changes.

The repeated tests showed very high correlations between changes in permeability to air, permeability to water and changes in disc mass, ranging from 0.906 to 0.984. The tests were repeated by different researchers and the results of the two test-series showed high correlations between the original and repeated test series. The overall results provide a high degree of consistency and confirmed findings in past research conducted on core flooding tests.

Present study inferred that the simplified method for assessing formation damage produces consistent results and may be used as a cost-effective method for comparing different drilling fluids and methods for removing the filter cakes, ahead of potential core flooding tests.

1. Introduction

The standard, ANSI/API 13B-1 (2019), describes a procedure for measuring fluid loss under high temperature and high-pressure conditions (HTHP), related to drilling of wells for oil or gas production. These conditions are typically a temperature requirement of 90 °C, a differential pressure of 3.45 MPa (500psi) and a test period of 30 min. These procedures are designed to be practical for a drilling fluid engineer to conduct at a rig site to monitor the performance of the fluid. The procedure neither cater for measuring the fluid's ability to seal fractured formations nor any impact on drilling fluid induced formation damage. Materials used for preventing or treating lost circulation (LCM) of drilling fluid are tested using different methods. For functionality beyond the limitations of the procedure described by ANSI/API 13B-1, however, no consistent method seems to have been established.

Lost circulation materials have been categorised by Alsaba et al. (2014a) and classified into seven categories based on physical and chemical characteristics, appearance, and application: granular, flaky, fibrous, LCM's mixture, acid/water soluble, high fluid loss squeeze, swellable/hydratable combinations, and nanoparticles.

Jeennakorn et al. (2017, 2019)identified that different test conditions could yield different results when testing lost circulation materials. Their testing was focused on identifying maximum sealing pressures using slotted discs to simulate fractures. Further, the performance of

* Corresponding author.
E-mail address: arild.saasen@uis.no (A. Saasen).

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LCM will be impacted by the characteristics of the base fluid they are blended into, and the wear the fluid is exposed to over time in downhole conditions and at the solids-control stage. A study was conducted by Alshubbar et al. (2018) on LCM performance under conditions of annular flow. It was found that higher circulation rates led to higher fluid losses, potentially as the particles forming the seal were more disturbed by a higher flow compared to a lower flow. Also, they identified that LCM particles with lower specific gravity were less impacted by the annular flow conditions, and hence might be more suitable for preventative treatment of lost circulation.

In a study comparing LCM from different categories of materials, Alsaba et al. (2014a,b), showed that LCM made of fibers should give the best sealing ability and seal integrity on tapered slotted discs. In their study they obtained sealing pressures up to 20.2 MPa (2925 psi) for slotted discs with a 1.0 mm fracture tip. They compared fibrous materials with granular materials such as $CaCO_3$ and graphite and found that the seal integrity was lower with granular materials. The performance of fibre-based LCM was further studied by Khalifeh et al. (2019), where LCM materials sealed slotted discs from 400 μm and up to 2500 μm at pressures exceeding 34.5 MPa (5000 psi) without failing. In this study it was shown that the seals were dynamically built to withstand higher pressures, which may indicate that LCM pill applications should be pressurised to the equivalent circulating density (ECD) to ensure good integrity during the drilling operation.

Saasen et al. (2018) used an alternative approach, where LCM were tested using a coarse gravel bed as well as on slotted discs. The objective was to study curing of large losses of drilling fluids. They found that the addition of short fibers could reduce fluid loss in porous and permeable formations, whereas longer fibers were more effective in curing large losses in fractured formations.

Particle size distribution (PSD) has been widely used with regards to understand mechanisms for treating lost circulation. An early study of the ability of dry powders to block hopper openings was conducted by Enstad (1975), where he showed that granules could block openings of several times their own dimensions. When studying similar effects in a drilling fluid, the mechanical properties of the fluid will also interact and change the mechanism of sealing. Whitfill (2008) proposed a method where the D50 value of the particles should be equal to the fracture width to ensure the formation of an effective seal. Alsaba et al. (2016) built further on these studies and investigated how the shapes and PSD of LCM materials impacted sealing of fractures up to 2000 μm. They found that a D90 value which was equal to or slightly larger than then fracture width, was required for a strong seal to form. However, to reduce the fluid loss, finer particles were needed to reduce the permeability of the seal.

Alsaba et al. (2017) conducted a study of sealing prediction and found that after the fracture width and fluid density, the D90 value was the most significant factor influencing the sealing pressure. Hoxha et al. (2016) also studied the degradation of $CaCO_3$ and graphite due to exposure to fluid shear. They found a 25–40% reduction in the D50 values of medium grade $CaCO_3$ after 30 min of shearing. Using different methods for measuring PSD, they noted that the D50 value of graphite was recorded to be reduced between 20% and 70%. The methods for particle size selection do not provide evidence regarding how the seals or plugs impact the permanent permeability of the formation, after the drilling operation has been completed. Klungtvedt et al. (2021a) showed that a specially designed cellulose-based drilling fluid additive could enable effective HTHP sealing of permeable discs, even without the presence of solids that are conventionally applied as bridging particles.

Lee and Taleghani (2020) studied properties lost circulation in relation to geothermal drilling and found that parameters such as fluid viscosity, particle size and friction coefficient and Youngs' modulus were important. By applying a parametric study, they discovered that thermal degradation reduced the capacity to seal fractures.

A study of filter-cakes and return permeability was conducted by Pitoni et al. (1999). They found that the solids composition of the fluids impacted the filter-cakes and return permeability. With higher solids content, they discovered that the filter-cakes became softer and thicker. In contrast, higher clay content gave thinner and harder filter-cakes, suggesting that the clay particles pack together tightly. Also, the increasing concentration of clay reduced the measured return permeability. They also proposed a method of using coarser bridging particles in a sacrificial manner, as increasing the PSD yielded better return permeability values.

Complementing the results from Pitoni et al. a study by Green et al. (2017) found that the lowest fluid filtrate loss did not necessarily correspond to the lowers permeability damage. They concluded that the filter-cakes ability to stick to the formation and if it could be removed during operation were the determining factors of formation damage. Czuprat et al. (2019) conducted long term (14 days) static aging tests and formation damage tests on sandstone samples. They concluded that slower build-up of the filter-cake would be a result of lower solids content in the drilling fluid. After conducting the experiments, they also concluded that the extended test period may make it impractical for service companies to conduct tests using the methodology before selecting a drilling fluid.

Numerous studies have been conducted on water-based drilling fluids and impact on return permeability. Khan et al. (2003) studied the formation damage characteristics of xanthan gum using core flow experiments, also investigating the extensional viscosity of the fluid in addition to shear viscosity, filtration loss and pressure drop. The xanthan gum solutions tested had low yield stresses but showed increasing extensional viscosity with increasing concentration of xanthan gum and that higher extensional viscosity led to lower fluid filtrate volumes. Also, they found that flow of xanthan gum through a porous media may significantly reduce the original permeability. Khan et al. (2007) showed that polymers such as xanthan gum, poly-anionic cellulose and starch had little impact of reducing fluid loss on its own in conditions where pore-throats were exceeding 20 μm, differential pressures exceeding 3.45 MPa (500 psi).

For low permeability reservoirs, Cobianco et al. (2001) developed a fluid using biopolymers, highly crosslinked starch and micro fibrous cellulose. They found that when the fluid contained cuttings, the return permeability was slightly lower than for the fluid without cuttings. SEM micrographs indicated that the cuttings invasion was limited to the first 100 μm of the 20–100 mD Portland limestone cores. Nelson (2009) found that reservoir sandstones generally had pore-sizes greater than 20 μm, however, with pore-throat openings greater than 2 μm, and that testing sandstone reservoirs on 20 μm ceramic discs may be representative of many reservoir formations.

Further challenges in optimal fluid design appear when reservoir formations exhibit significant heterogeneity in terms of pore sizes and permeability. Yang et al. (2020) conducted a study on selective plugging of such reservoir formations using microfoam selective water plugging agent, where the core permeabilities ranged from 7.87×10^{-3} μm^2 – 736×10^{-3} μm^2. Considering the presence of such high formation heterogeneity, a reservoir drilling fluid may need to be tested on a large range of permeable formations to provide a robust picture of the performance through the various parts of the reservoir.

Siddig et al. (2020) conducted a review of different approached for chemically removing the filter-cake when using water-based drilling fluids. Their findings were that different approaches were recommended for different weighting materials and different reservoir rock conditions. Also, with high concentrations of weighting agents, the filter-cakes would become heterogeneous, where one layer would consist mainly of the weighting agent and one layer of polymers, thereby also potentially introducing the need for a dual- or multistage chemical treatment.

Viewing reservoir formation damage in multiple contexts, Civan (2020) shows different forms of formation damage, such as e.g., fines and solids migration, phase trapping, biological and chemical mechanisms. The research literature shows that results using different test methodology to a certain degree are inconsistent. A considerable part of the research is conducted using rock cores, which are tested using a different procedure than the practical testing using ANSI/API 13B-1. Therefore, such testing is normally not available to a drilling fluid engineer in a practical situation.

The conclusions of Czuprat et al. (2019) and Green et al. (2017) support the need for a cost-effective screening method for selecting a drilling fluid before a verification test on a representative core or when no core is available for testing. Klungtvedt et al. (2021b) developed a methodology for assessing signs of formation damage by measuring changes to permeable discs, as a sign of invasion of e.g., solids, polymers or fibers. Data showed that it was possible to measure changes in disc mass accurately, however, the experiments did not sufficiently study changes in permeability to verify its applicability. Therefore, the methodology developed by Klungtvedt et al. was applied in the present study to investigate the changes in disc permeability after HTHP tests and compare these results with changes in disc mass. Further, the tests were repeated by a different researcher, and the data compared.

The objective of present study was to identify if multiple indicators of formation damage would yield consistent and reliable results, thereby enabling a cost-effective method for assessing formation damage. A series of experiments were set up to test application of the method proposed by Klungtvedt and verify if the extension to measure changes in permeability would provide consistent results.

The present objectives are:

- To verify if the methodology proposed by Klungtvedt et al. (2021b) would yield consistent results when applied to measure changes in permeability in ceramic discs by using different fluid compositions and repeated tests with different researchers.
- To verify if the three indicators of formation damage, namely disc mass change, change in permeability to air and change in permeability to water, yield consistent results.
- To apply the methodology to very that a KCl Polymer fluid may produce formation damage and further to verify that such formation damage may be reduced by addition of $CaCO_3$ and cellulose fibres.
- To apply the methodology to investigate if xanthan gum and low viscosity poly-anionic cellulose may be replaced by modified starch additives and provide satisfactory results with regards to formation damage as well as rheology and fluid loss.

The tests were designed to assess the consistency of the results obtained when calculating the disc' change in permeability to water and air following the HTHP tests and a subsequent process of applying a reverse flow for filter-cake lift-off and an oxidizing breaker for further removal of filter-cake residue. Four different fluid compositions were tested for rheology, fluid loss and signs of formation damage, particularly related to change in permeability. The four tests were repeated by a different researcher using the same procedure, recipe, and equipment, but separated by a period of four weeks. The fluid composition was designed to replicate a typical fluid that might be used for drilling either a producer or injector well for oil and gas or a geothermal well. Also, by using inert ceramic discs, the study focuses on the functionality of the drilling fluid and the breaker application alone, without considering any chemical or mechanical interaction between the fluid and the rock formation.

2. Methods

The methodology is centered around conventional HTHP test for fluid loss using permeable discs as these are commonly used in the industry. The main addition to the process is to document the permeability and mass of the discs prior to the HTHP tests and thereafter measure changes in these parameters after conducting the fluid loss test and reverse flow for filter-cake removal. This enables studying the changes a fluid may have on the permanent permeability of the formation, without needing to conduct a more comprehensive dynamic core flooding test. The change in disc mass was documented by Klungtvedt et al. (2021b), however, the present study was conducted to verify if the method of detecting formation damage by measuring changes in permeability could provide reliable results.

The key elements of the process are to first measure the mass and permeability of ceramic discs before conducting an HTHP test using the procedure from ANSI/API 13B-1, or potentially under a higher applied differential pressure. The permeability of the discs was first measured by flowing air through the discs and measuring applied pressure, flowrate, and air temperature. By restricting the flow area of the disc to an area slightly smaller than that of the HTHP test, the change in permeability after exposure to the drilling fluid may be measured quite accurately. The equipment was first calibrated by measuring the pressure drop in the system when flowing air at different flowrates without the disc present. Using tables of viscosity of air, the dimensions of the flow area, disc thickness, applied pressure and air flowrate, it was possible to calculate the average permeability. Thereafter, a similar process was applied for flowing water through the disc. Prior to the flow test, the fluid and the disc were placed in a vacuum for 5 min to remove air bubbles.

The HTHP tests were conducted at 6.9 MPa (1000psi) using a nitrogen pressure source. Thereafter the discs are placed in a customized acrylic cell, where brine is flushed through the discs in the reverse direction of the HTHP test to study the ease of lifting the filter-cakes, as shown in Fig. 1. Thereafter the discs are submerged into a breaker fluid before permeability and disc mass is measured and compared with the original values. At this stage of the process, the permeability to water was measured first, then the disc was dried in the Moisture Analyser and weighed before the permeability to air was measured. The methodology used for the testing is presented in detail in the Appendix.

Conventional equipment used for HTHP Fluid loss testing according to ANSI/API13-B.

- Hamilton Beach Mixer, for mixing of drilling fluids
- Ohaus Pioneer Precision PX3202, for weighing the drilling fluid ingredients
- Ofite Filter Press HTHP 175 ml, Double Capped cell for HTHP fluid loss test
- Ofite Viscometer model 900, for measuring fluid rheological parameters
- Ofite roller-oven #172-00-1-C, for aging the drilling fluid samples
- Apera pH90, pH meter, for pH measurements

Special experimental set-up.

- Ohaus MB120 Moisture Analyser, for weighing the discs in dry conditions at 105 °C
- Custom built transparent acrylic cell with stand for enabling of reverse flow of fluid through the ceramic discs and viewing of filter-cake removal
- Festo pressure regulator LRP-1/4–2.5 and LRP-1/4–0.25, for regulating air pressure that is driving the reverse flow of fluid through the disc or for permeability measurements
- Festo Pressure Sensor SPAN-P025R and SPAN-P10R for measuring the applied pressure for filter-cake lift-off or for permeability measurement
- Festo Flowmeter SFAH-10U, for measuring the flow of fluid through the disc
- Nitrogen source and manifold for pressure up to 1350psi, Ofite #171-24
- Vacuum machine, DVP EC.20–1, for removal of air from fluid and discs when conducting HTHP tests and permeability measurements

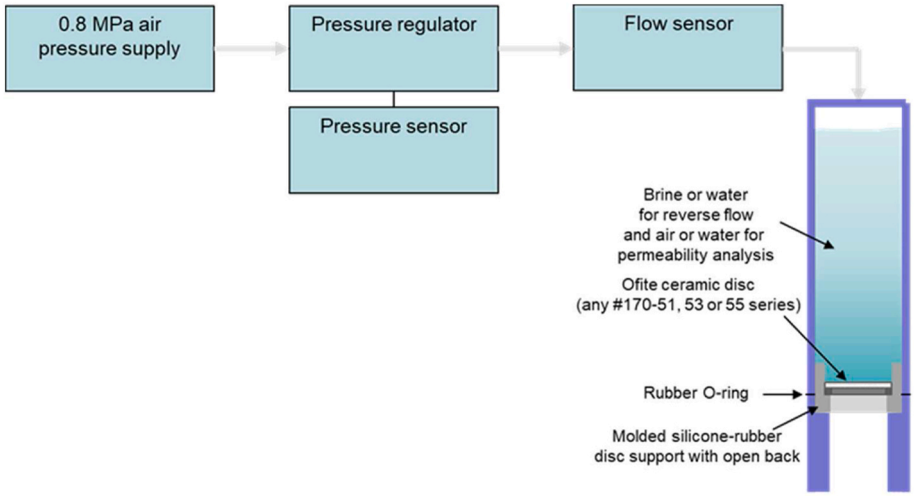

Fig. 1. Schematic of equipment for reverse flow and permeability measurement.

3. Results

3.1. Drilling fluid composition and rheology

Four fluid compositions, shown in Table 1, were selected, and tested with a one-month interval and tested by different personnel to evaluate reproducibility. Fluid 1 was selected to be a KCl polymer fluid without any solids or fibres, using conventional xanthan gum and low viscosity poly-anionic cellulose. Such a fluid was expected to result in high fluid loss and formation damage following the findings of Khan et al. (2003, 2007), where polymer damage to the formation was detected. The other three fluids contained solids to reflect the findings of Pitoni et al. (1999), who found that the solids composition impacted fluid loss and return permeability. Fluid 2 used the same base mixture as Fluid 1. However, bentonite was added to represent fine drill solids or clay. Fluid 3 and 4 were also KCl polymer fluids. These had the same concentration of $CaCO_3$ and a cellulose based fibre with a D90 value of 75 µm. (AURACOAT UF, provided by EMC AS). The difference between Fluids 3 and 4 were the polymers used for viscosity and fluid loss. Fluid 4 used conventional xanthan gum and low viscosity poly-anionic cellulose, whereas Fluid 3 used a designed mixture of starch-based polymers (PureBore and PureBore ULV, provided by Clear Solutions International Limited). The concentration of KCl was selected as an average between what might be applied when drilling oil and gas wells and geothermal wells.

Figs. 2 and 3 show the shear stress vs shear rate diagrams for the fluids after hot-rolling and at a temperature of 49 °C, focussing on the dynamic conditions on the drilling operation. All the fluids showed shear-thinning or thixotropic behaviour. At shear rates more than 200 (1/s), Fluid 3 showed the lowest viscosity and Fluid 4 showed the highest viscosity. The only difference between the two fluids were the polymers selected for viscosity and fluid loss. In the range up to a shear rate of 34 (1/s), Fluid 3 showed the highest viscosity and Fluid 1 showed the lowest viscosity. In total, Fluid 3 showed the most shear thinning or thixotropic behaviour. If the fluids were applied in a 17 ½” or 12 ¼” sections, the shear rates would typically be in the range below 200 reciprocal seconds, and the rheological properties would be relatively similar. For a permeable well section of 8 ½” or smaller diameter, the shear rates may be more variable depending on the selection of drill-pipe outer diameter etc.

Table 1
Drilling fluid recipes 1-4.

Component and Mixing sequence	Fluid 1	Fluid 2	Fluid 3	Fluid 4
Water	971g	961g	928g	926g
Soda Ash	0.06g	0.06g	0.06g	0.05g
Caustic Soda	0.71g	0.71g	0.66g	0.66g
Xanthan Gum	3.43g	3.39g		3.17g
Low viscosity poly-anionic cellulose	14.3g	14.2g		13.23g
Polymer blend for viscosity and fluid loss (PureBore)			6.6g	
Polymer blend for fluid loss (PureBore ULV)			8.0g	
MgO	2.86g	2.83g	2.65g	2.65g
KCl	50.0g	49.5g	46.3g	46.3g
Bentonite		28.3g		
Ground marble ($CaCO_3$) < 53 µm			52.9g	52.9g
Cellulose fibre for fluid loss control (AURACOAT UF)			13.2g	13.2g

3.2. Ceramic discs and permeability measurements

Prior to the HTHP tests, the ceramic discs were weighted and permeabilities to air and water were measured. The respective data for each disc used for the tests are presented in Fig. 4. The discs are specified as having a mean pore-throat size of 20 µm and permeability to air of 2 D. Given that the outer dimensions are identical and uniform materials are used for manufacturing the discs, a low disc mass may indicate high porosity and permeability, and visa-versa for a high mass disc. Fig. 5 shows the plot of permeability to air against disc mass for the discs used. The relationship between disc mass and air permeability is negative, and the calculated correlation is −0.961. This confirms the relationship between disc mass and permeability, where a higher disc mass is correlated to a reduction in permeability (thus the negative correlation coefficient). Table 2 lists the correlation between the three measurements for each disc, showing positive correlation between permeability to air and water. Correlation between disc mass and permeability to water was also negative. The difference in permeabilities might also be a factor that should be considered when comparing results of experiments where the specific discs have been used, rather than assuming that any two discs with a specified mean pore-throat size of 20 µm have the same porosity, permeabilities and pore-throat sizes. As an example, From Fig. 4 it can be seen that the discs used for Fluid 2 had slightly higher permeability and lower mass than then discs used for Fluid 4. The least permeable discs were used when testing Fluid 3.

3.3. Fluid loss measurements

The fluid loss curves are represented in Fig. 6, for testing at a differential pressure of 6.9 MPa (1000psi) and temperature of 90 °C. All

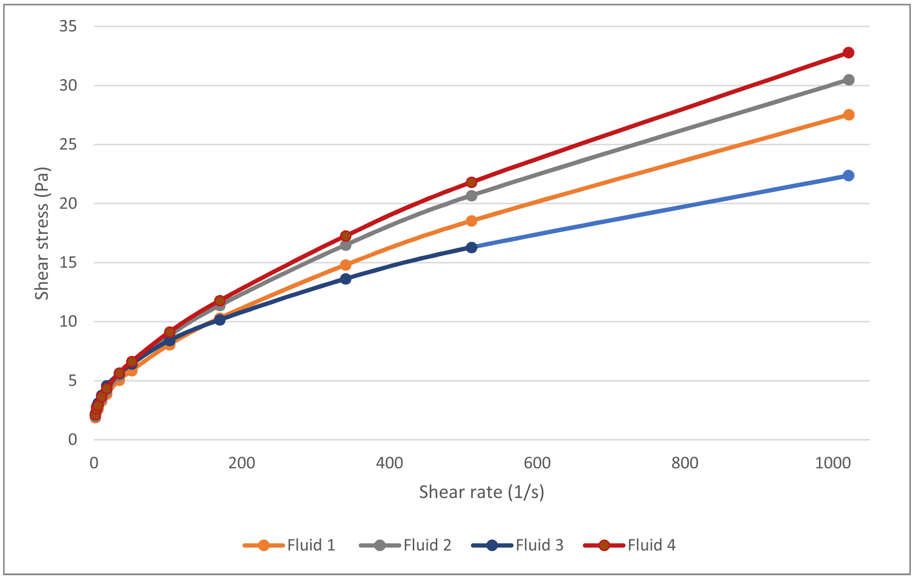

Fig. 2. Rheological flow curves of Fluid 1–4 at full share rate range.

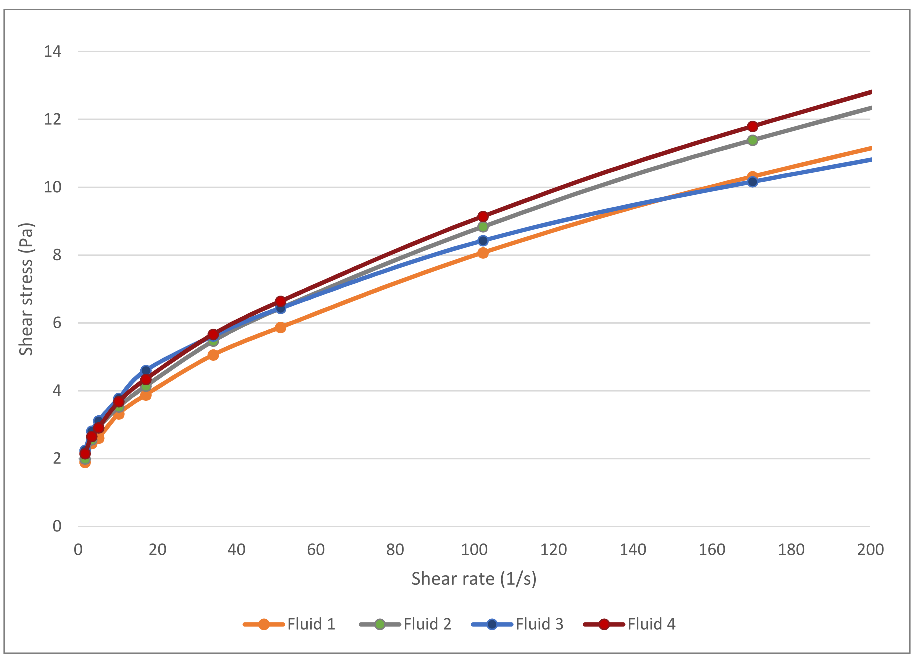

Fig. 3. Rheological flow curves of Fluid 1–4 at low-to moderate shear rates.

tests were conducted using ceramic discs with specified median pore size of 20 μm. The two test-series yielded consistent results, with less than 8% difference in fluid loss between any of the two corresponding tests. For both tests of Fluid 1, containing XC and PAC, a total loss was recorded, and the tests stopped within the first few seconds. Fluid 2 replicated the recipe of Fluid 1, however, with the addition of 28.3 kg/m^3 (10 lb/bbl) of bentonite, which was sufficient to limit the fluid loss to 32–35 ml. Fluids 3 and 4 contained the same concentration of $CaCO_3$ particles and the short fibers, whereas Fluid 3 contained the starch-based polymer blends instead of xanthan gum and ultra-low viscosity poly-anionic cellulose used in Fluid 4. The two tests with Fluid 3 and Fluid 4 recorded fluid losses of around 17 ml and around 21 ml, respectively.

The fluid loss data as a loss rate of ml/min are presented in Fig. 7. It excludes the test with Fluid 1 on the 20 μm ceramic disc as this yielded a total loss. The figure gives an insight into the gradual development of the fluid loss rates over time implicitly also the development of the permeability of the filter-cakes. The two tests with Fluid 2 saw the loss rates fall to 0.21 ml/min and 0.23 ml/min. Fluid 3 and 4 both showed lower loss rates than Fluid 2, where the loss rates fell to 0.18 ml/min and 0.19 ml/min for Fluid 3 and 0.17 ml/min and 0.19 ml/min for Fluid 4. The low differences in fluid loss rates over time also highlight that the main difference in fluid loss between Fluids 2, 3 and 4 occur during the initial spurt-loss recorded during the first 15 s of the test, and hence during the initial build-up of the filter-cakes. The lower spurt-losses of Fluids 3 and 4, relative to Fluid 2 may be attributed to the higher concentration of solids in Fluid 3 and 4. However, the relative difference between Fluid 3 and 4 may be related to the different polymers used, given that the concentration of $CaCO_3$ and fibers were similar. The indications or arguments can, however, not be considered as conclusive

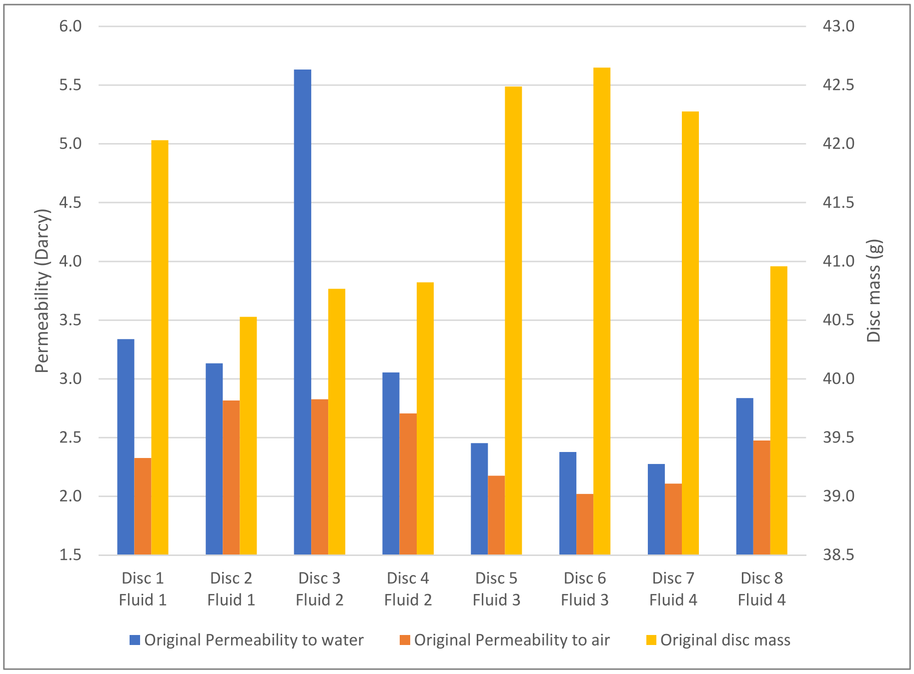

Fig. 4. Measurements of 20 μm ceramic discs before HTHP testing.

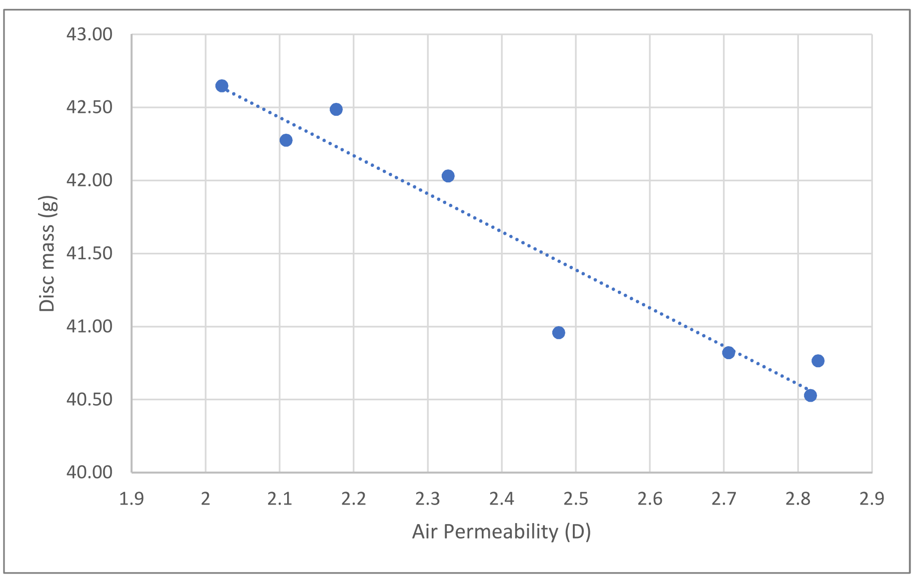

Fig. 5. Plot of disc mass vs air permeability of 20 μm discs.

Table 2
Correlations between measured permeabilities and mass for each disc.

Correlation	Permeability to air	Disc mass
Permeability to water	0.693	−0.561
Permeability to air		−0.961

evidence given that the discs had different original permeabilities and disc mass.

A comparison of the original disc permeability and the measured fluid loss is shown in Fig. 8 for Fluids 2–4. For each of the respective fluids there was a negative correlation between the original disc permeability and the fluid loss, i.e., each of the tests with the higher permeability disc recorded a smaller fluid loss given the same fluid has been used.

With the original disc permeability and the fluid loss rate development data, it is possible to provide some simple estimates for the combined permeability of the internal and the external filter-cakes. In reality, the fluid filtrate composition will vary a little for each test, and hence also the viscosities of the fluid filtrates and the thickness of the filter-cakes. As a reference, the original disc permeabilities were in the range of 2.3–5.6 Darcy. The filtercakes were circa 1 mm thick, and for simplicity, assuming that the fluid filtrate showed Newtonian behaviour with a viscosity of 1 Pa*s, the permeabilities of the filter-cakes may be calculated. In the period from 20 to 30 min, the fluid loss rates were ranging from 0.17 ml/min to 0.225 ml/min. This yields that the filter-cakes obtained a permeability as low as 1.6–2.1*10^{-7} Darcy.

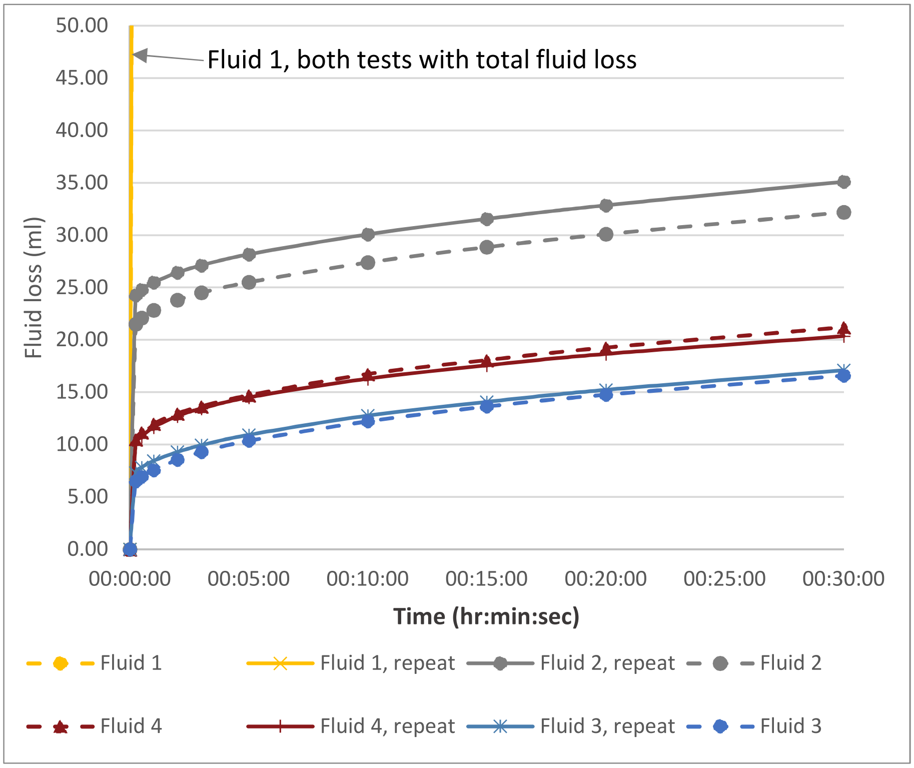

Fig. 6. Fluid loss of Fluid 1–4 at 6.9 MPa differential pressure at 90 °C.

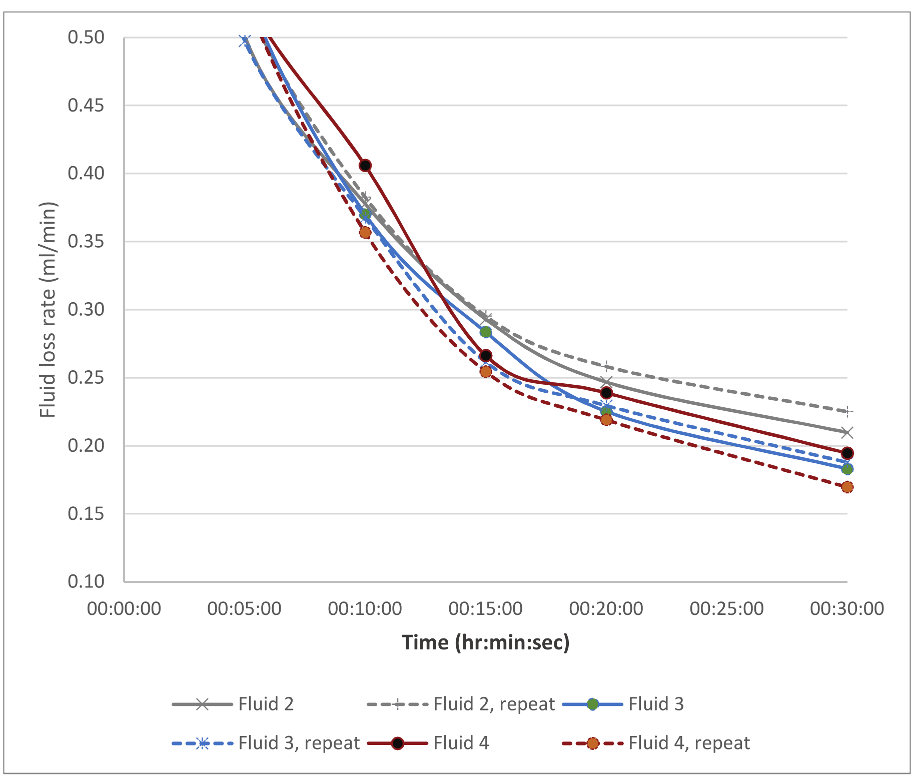

Fig. 7. Fluid loss rate development for Fluid 2-4.

3.4. Filter-cakes

The polymer residue from Fluid 1 on the ceramic disc is shown in Fig. 9, together with the filter-cakes from testing of Fluid 2 and 4. The disc from testing of Fluid 1, had no distinct filter-cake, but more of a semi-sticky polymer coating. Also, the rear of the disc showed signs of polymers after the total loss during the HTHP test. The filter-cakes made by Fluid 2 and Fluid 4 were even and shiny.

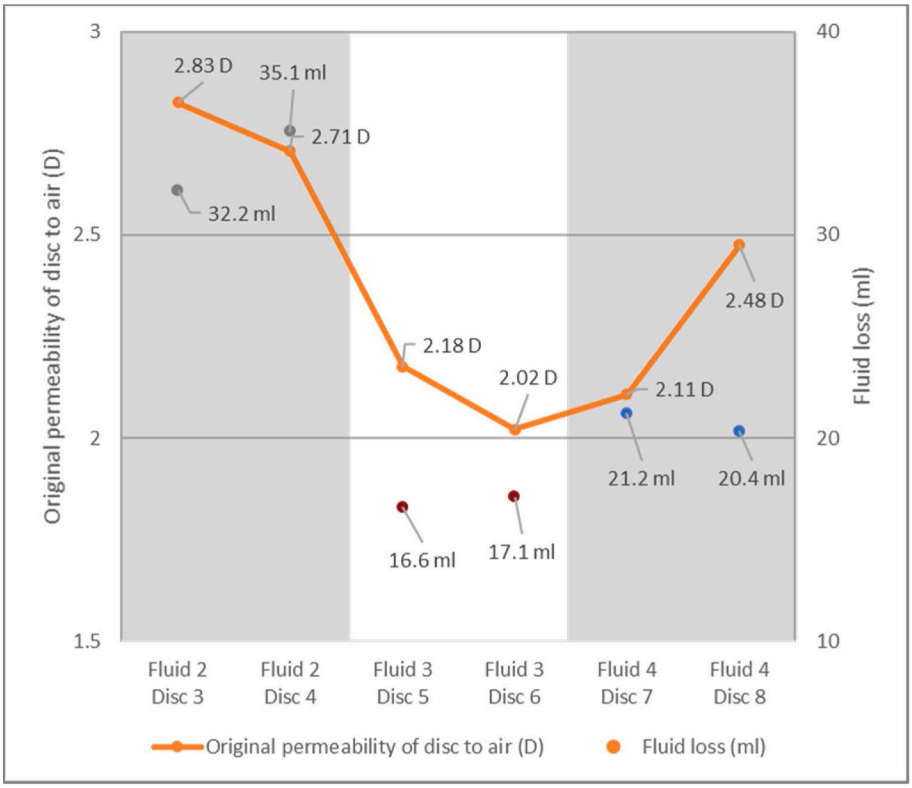

Fig. 8. Fluid loss (right axis) and original disc permeability (left axis) comparison.

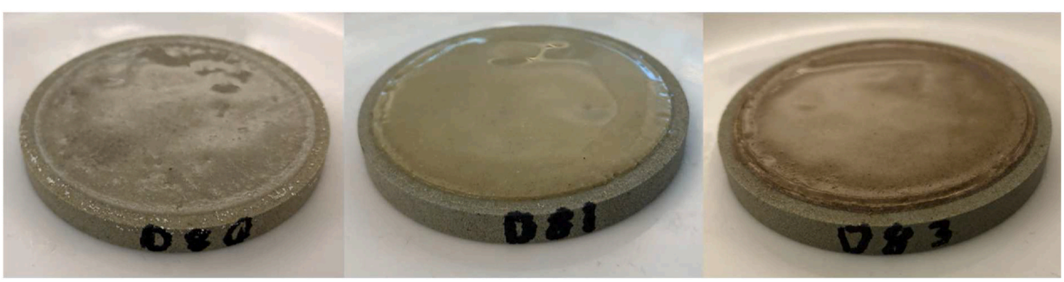

Fig. 9. From left: Residue from Fluid 1 (Disc 2) after total loss, and filter-cakes from Fluid 2 (Disc 4) and Fluid 4 (Disc 8).

The filter-cake formed by Fluid 3 (Disc 7), was a little distinct as it appeared to be a continuous piece or mat. The filter-cake and the disc and after filter-cake removal, with reverse flow of brine, is shown in Fig. 10. Even before the application of the breaker fluid, the traces of the filter-cake had almost disappeared.

3.5. Estimation of formation damage

Following the HTHP tests, the discs with the filter-cakes were back-flowed with brine and the discs placed in a bath with an oxidizing breaker fluid at 90 °C for 4 h. Thereafter permeability changes and disc

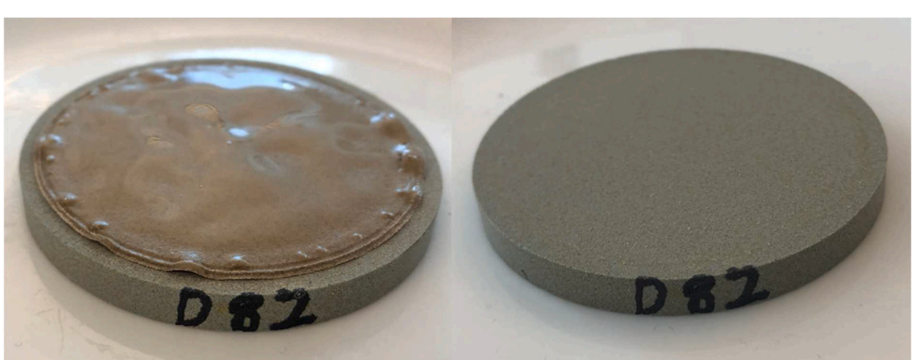

Fig. 10. Disc 7, from testing of Fluid 3 with filter-cake (left) and after filter-cake had been lifted by reverse flow (right).

mass increases were measured. The results of these tests are presented in Fig. 11. The data indicate that both the permeability to air and water were considerably reduced after the HTHP tests with Fluid 1, with measured permeability reductions ranging from 65 to 78%. This was considerably higher than for any of the other fluids, and the permeability data were also supported by the tests for Fluid 1 also having the largest mass increases. Considering that Fluid 1 contained polymers, but no solids nor fibers, the mass increase and reduction in permeability is highly related to the polymers being used. Also, it showed that the breaker that had been applied did not fully dissolve the polymers nor remove the polymers from the ceramic disc. Further, it should be considered that since the test yielded a total loss, drilling fluid or drilling fluid filtrate would penetrate the formation considerably deeper than the near wellbore region that the ceramic disc represents. Therefore, when comparing the results from testing of Fluid 1 with the other fluids in the tests, it needs to be understood that the consequential formation damage of deeper penetration into the reservoir is likely to be much higher for Fluid 1 than for the other fluids. Disc mass increases were 248–275 mg.

For Fluid 2, the inclusion of bentonite reduced the fluid loss and improved the results with regards to avoiding formation damage relative to Fluid 1, with permeability reductions ranging from 5 to 44% and lower disc mass increases of 29–62 mg.

Fluid 3, with $CaCO_3$ and the short fibers, yielded much lower permeability reductions of 9–28% and disc mass increases of 21–23 mg. The best results were obtained with Fluid 4 with reductions in permeability of 2–16% and disc mass increases of 7–13 mg. Given that Fluid 4 yielded a higher fluid loss then Fluid 3, there is, however, a potential that more formation damage might occur further into the reservoir formation than for Fluid 3, where the fluid losses were lower in both tests.

The data presented in Fig. 11 indicate high consistency in the data obtained for changes in permeability to air and water as well as increases in disc mass. The calculated correlations between the three indicators of formation damage are shown in Table 3. With all correlations being positive and above 0.9, it can be concluded that the data obtained have a high consistency. The highest correlation was obtained between changes in permeability to air and increase in disc mass, with a correlation as high as 0.984. Relative to the data in Table 2, the correlations are calculated to a reduction in permeability, and hence the coefficients of correlation with changes in disc mass are positive.

Table 3
Correlations between indicators of formation damage.

Correlations	Reduced Permeability to air	Disc mass increase
Reduced Permeability to water	0.906	0.932
Reduced Permeability to air		0.984

Further, the correlations between the first and the second test of each individual fluid with regards to the three indicators of formation damage are listed in Table 4. Although the data set is small, it is reassuring to see that the correlation data are positive and in the range of 0.686–0.997.

4. Discussion

The tests were conducted with the objective of assessing if the methodology could be applied consistently and if the indicators of formation damage would yield consistent results. All the evidence collected strongly support that the methodology yields consistent results and that the three indicators of formation damage yield consistent results.

From a practical point of view, it was most difficult to measure the permeability to water, as inclusion of air bubbles in the fluid significantly impacted the fluid flow at a given pressure, and hence also the calculation of permeability. This was solved by placing the disc and the fluid in vacuum before the permeability tests.

It may, however, be argued that neither of the indicators of formation damage as tested here fully replicate the damage that might occur when drilling a reservoir formation and therefore a core-flood test would be a more correct representation of such. From a purely scientific

Table 4
Correlation of results between first and second tests for each fluid.

Correlation	Fluid 1	Fluid 2	Fluid 3	Fluid 4
Correlation: 1st and 2 tests (reduced permeability to water and air and increase in disc mass)	0.997	0.872	0.982	0.686

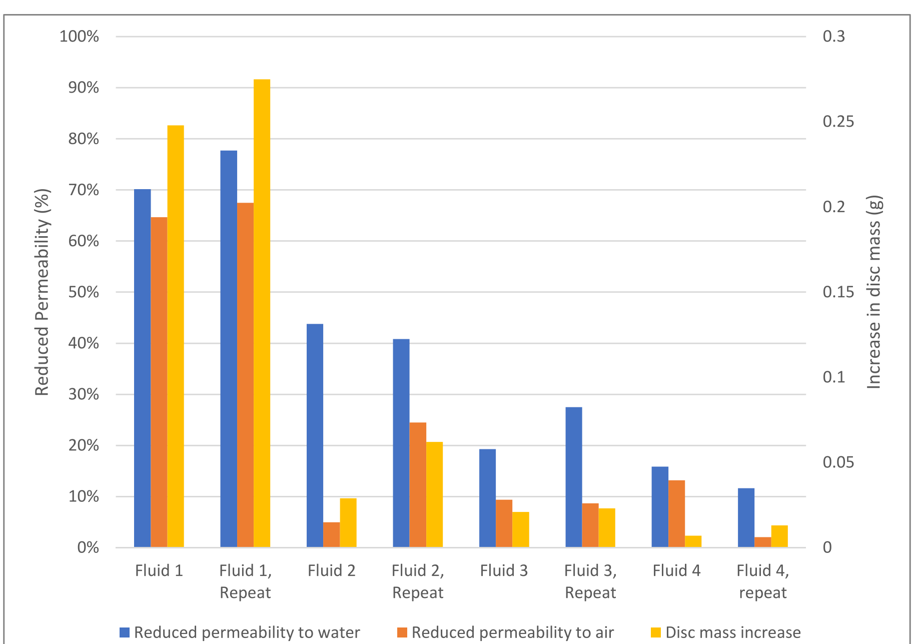

Fig. 11. Indicators of formation damage for tests with Fluid 1–4, with original test and repetition test for each fluid.

perspective each of the methods have limitations in replicating wellbore and reservoir conditions. When testing using ceramic discs, the size and shape of pore-throat openings will differ from those appearing in actual rock formations. However, when testing is carried out using actual reservoir cores, there will be an uncertainty with regards to the heterogeneity of the reservoir section, where the production zone may extend hundreds or thousands of meters. One might therefore consider that the applied testing methodology in the present study assesses the performance of the drilling fluids against a generic formation, whereas a core-flooding test assesses the performance of the drilling fluid in a specific rock formation. From a practical perspective, a core-flooding test is generally considered to be a time-consuming and costly exercise, leading to a low number of tests being conducted for each relevant reservoir. Also, for a new field, representative cores may be non-existent before the selection process of the drilling fluid is concluded. When testing using ceramic discs, it is a relatively fast and low-cost process. This enables higher volumes of testing and testing using different permeabilities, which may represent different parts of a reservoir formation. The higher volumes may be used to reduce the statistical uncertainty of the results, it may allow for testing of different fluid compositions with different breaker applications, and also assess the performance of the fluid is parts of the reservoir formation exhibit other properties than any specific core. Also, from a field perspective, it may be possible to monitor the performance of the drilling fluid as the drilling progresses and obtain relevant data to adjust the fluid properties during drilling.

Further testing should be conducted to compare the results of the test method used with equivalent core flooding tests. This may give valuable insight into the benefits of each testing methodology.

The application of the methodology did, however, replicate other results obtained by applying core flood tests. The test with Fluid 1 showed strong signs of formation damage using a polymer fluid without bridging materials. This is consistent with the findings of both Khan et al. (2003, 2007) and Audibert et al. (1999).

Green et al. (2017) conducted a series of core flooding tests and subsequent Micro-CT scanning to detect particle migration and formation change. They concluded that the key "zone" for permeability alteration in the samples was the first pores in the wellbore, regardless of the volume of filtrate loss or thickness of remnant drilling fluid filter-cake. This supports the idea of studying formation damage in the near wellbore region and that ceramic discs with a thickness of 6.3 mm will have considerably more depth than what might be necessary to study formation damage as the thickness represents around 25 times the pore size of a 250 μm disc and more than 300 times the pore size of a 20 μm disc.

Further, the study revealed that with the specific breaker fluid applied, the higher fluid loss of Fluid 4 relative to Fluid 3 did not correspond with a higher formation damage. In contrast, Fluid 1 and Fluid 2 both led to higher fluid loss and formation damage than Fluid 3 and Fluid 4. These results are also consistent with the findings of Green et al. (2017), where there the lowest permeability alterations did not correlate with the lowest drilling fluid filtrate loss volume.

Civan (2020), provide a deep insight into a number of causes of formation damage. It gives an insight into challenges such as drilling fluid to formation fluid incompatabilities, drilling fluid to rock incompatabilities, phase trapping, chemical adsorption or wettability alteration and biologic activity. These causes of formation damage are not covered in the present study. Further studies may be conducted where e.g. the original and final permeabilies are measured using a fluid replicating the reservoir fluid, which may yield an insight into aspects of fluid to fluid incompatabilities.

Given that the methodology focusses on the formation damage occurring in the depth of the disc only, no quantitative measure of deeper formation damage caused by the fluid filtrate is provided. Further testing could be conducted to measure the constituents and the characteristics of the fluid filtrate, as this might yield further information about likely formation damage beyond the near wellbore region of the part of the formation represented by the ceramic disc.

5. Conclusions

The primary conclusion of the study is that high correlations were found between the measured changes in disc mass and changes in permeability to air and water. This was verified by the two independently run test series which yielded highly correlated results.

The conclusions regarding the main objectives of the study are as follows:

- The method proposed by Klungtvedt yielded consistent results also when applied to measure changes in permeability in ceramic discs by using different fluid compositions and repeated tests with different researchers.
- The three indicators of formation damage, namely disc mass change, change in permeability to air and change in permeability to water, yield consistent results with high correlations.
- The method provided evidence that a KCl Polymer without bridging particles may produce formation damage, which is in line with past research conducted on core samples.
- Polymer formation damage may be significantly reduced by addition of a combination of $CaCO_3$ and cellulose fibres.
- The methodology provided evidence that xanthan gum and low viscosity poly-anionic cellulose may potentially be replaced by modified starch additives and provide satisfactory results with regards to formation damage, rheology, and fluid loss. Further analysis using breaker fluids designed for starch should be investigated.
- The overall results support the practical application of the methodology for assessing near wellbore formation damage. This may be particularly beneficial when it is important to test a series of different fluids and potentially with different formation permeabilities.
- The methodology, including permeability analysis, may be beneficial as part of a screening process ahead of a core flood test or in situations when a core flood test is not practical.
- The application should be relevant for both drilling of oil- and gas wells and geothermal wells, where the permanent permeability of the formation may be important.
- The tests were conducted using an oxidizing breaker fluid. Further test should be conducted without a breaker fluid or using different breaker fluids to identify how different clean-up methods may impact the removal of the filter-cakes and the consequences for estimated formation damage

Credit author statement

Karl Ronny Klungtvedt: Conceptualization, Methodology, Validation, Investigation, Writing – original draft, Writing – review & editing, Funding acquisition, Arild Saasen: Writing – original draft, Writing – review & editing, Supervision

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix

Procedure for measuring change in disc mass and change in permeability and relevant calculations following Klungtvedt et al. [24],

1. Mix drilling fluid according to the recipe allowing sufficient time for mixing of the various additives.
2. Measure pH and rheology.
3. Hot-roll for 16 h at 90 °C and if applicable degrade by high-shear stirring or other degradation method.
4. Measure pH and rheology after hot-rolling and any degradation.
5. Mark and weigh disc in dry condition using the moisture analyser (M_b). Moisture analyzer shall be set to dry disc at 105 °C until change in mass is less than 1 mg/60 s.
6. Optional step: place disc in acrylic cell and measure air temperature and flowrate at different pressures to calculate average permeability to air (K_{ab}).
7. Optional step: place disc in acrylic cell and place arrangement with water in vacuum (circa −0.96 bar for 5 min) to remove any air from disc or water. Flow thereafter water through disc and measure water temperature and flowrate at different pressures to calculate average permeability to water (K_{wb}).
8. Soak disc in brine (40 g NaCl per 1000 g freshwater) in vacuum.
9. Conduct HTHP test at desired pressure, typically 3.45 MPa (500 psi) or 6.9 MPa (1000 psi), and measure both volume (V_f) and mass (M_f) of fluid filtrate at point in time of 15 s, 30 s, 1 min, 2 min, 3 min, 5 min, 10 min, 15 min, 20 min and 30 min (V_f). Calculate fluid filtrate density.
10. Weigh disc with filter-cake and observe filter-cake.
11. Place disc in acrylic cell and reverse flow with 1 L (40 g NaCl per 1000 g water) heated to 60 °C and then with 1 L water heated to 60 °C to remove traces of salt before drying. Note pressure required to enable reverse flow through disc.
12. Optional step: place disc in breaker fluid for required time and at required temperature. Place disc in acrylic cell and flow disc with 1 L water at ambient temperature to remove any dissolved filter-cake residue.
13. Optional step: place disc in acrylic cell and place arrangement with water in vacuum to remove any air from disc or water. Flow thereafter water through disc and measure water temperature and flowrate at different pressures to calculate average permeability to water (K_{wa}).
14. Weigh disc in dry condition using moisture analyser (M_a) using the same settings as in step 5.
15. Optional step: place disc in acrylic cell and measure air temperature and flowrate at different pressures to calculate average permeability to air (K_{aa}).

Depending on the number of optional steps included in the procedure, it enables collection of a large amount of data in addition to observing the filter-cake and the fluid filtrate volume $V_{f.}$

The moisture analyser used for weighing the discs was set to heating the discs to 105 °C and continue drying until the mass change due to moisture evaporation was less than 1 mg per 60 s. The drying process then stopped automatically, and the mass of the disc displayed. The precision of the instrument is 1 mg. The change in disc mass was then simply calculated as:

$$(M_a) - (M_b) = M_{change}$$

By placing a digital weight under the graduated cylinder used to measure fluid filtrate, it was possible to simultaneously record the mass of the fluid filtrate and read the volume of the filtrate. This enabled a precise estimation of the fluid loss profile and calculating the fluid filtrate density (D_f), calculated as:

$$(M_f)/(V_f) = (D_f)$$

The permeability was calculated as an average of multiple readings within certain flow-rate ranges. Darcy's law was used in a rearranged form as follows:

$$K = \eta \frac{Q * \Delta L}{A * \Delta P}$$

where K is the calculated permeability coefficient (m^2), η is the viscosity of the fluid (Pa * s), Q the fluid flowrate (m^3/s), ΔL the disc thickness (m), A the areal of flow into the disc and ΔP the pressure differential over the disc (Pa).

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