

## Final Project Report

### Core plug preparation procedure

Project number and location (UiS, NORCE, IFE): P.no 100161 NORCE, Stavanger

Project duration: August 2014-Nov 2021

Project manager: Ingebret Fjelde

PhD students and postdocs: Cooperation with PhD-student Samuel Erzuah in the project "Wettability estimation by oil adsorption"

Other key personnel: NORCE: Aruoture Voke Omekeh, Arnold Paul Gonnewardene; UIS: Mona Wetrhus Minde

## 1. Executive summary

Since the reservoir rock state is changed during sampling, mud contamination, storage and solvent cleaning, reliable procedures for preparation of reservoir core plugs are required to secure that representative wettability conditions are established for wettability, SCAL and EOR-experiments. Water flooding results are usually used as reference for the EOR flooding experiments. If wrong potential estimate is used as reference, the potential estimates for the EOR-methods will also be wrong.

The main objective for the project “Core plug preparation procedure” has been to identify critical steps in core preparation procedures. The project has cooperated with the PhD-project “Wettability estimation by oil adsorption” on wettability measurements and estimation (Erzuah, 2019).

The main conclusion in the project is that it should be determined whether the reservoir rock samples are contaminated by mud before the samples are used in experiments, e.g. wettability, SCAL and EOR studies. The analytical methods that should be used to detect possible contamination depend on the mud composition. It is therefore required that the mud composition is known when the core preparation is started. If rock samples are found to be contaminated by mud, they should not be used before controlled cleaning have been carried out. The types of solvents to be used in cleaning will depend on the mud composition. It should after the cleaning be controlled that the contaminations have been removed. If it is not possible to remove the contaminations, the core plugs should ideally not be used in wettability, SCAL and EOR studies. If contaminated reservoir core plugs have to be used, the core plugs with the lowest contamination should be used for the most important experiments. It has in the project been shown that contamination of rock samples by mud filtrate can have dramatic effects on the oil recovery in spontaneous imbibition and polymer flooding. In the cleaning of the reservoir rock samples, it is very important that minerals are not removed. Removal of sulphate during cleaning has been shown to strongly affect the established wettability conditions and oil recovery.

The crude oil samples to be used in the experiments should also be free of contaminations. Analysis should always be carried out to determine whether the crude oil samples are contaminated. The analytical methods to be used will depend on the mud composition. Samples can be analyzed for mud specific components, e.g. emulgators by interfacial tensions (IFT). For oil-based muds, the oil samples can be analyzed for base-oil components to determine the degree of mud contamination. Oxidation of crude oil samples will increase the concentration of polar oil components and this can affect the established wettability conditions. It should therefore always be confirmed that crude oil samples are not oxidized.

Accurate formation water composition is critical for the established wettability conditions. Formation water composition are often derived from analysis of water sample taken during drilling operation. It is important to determine whether these samples are contaminated by mud. The change in conditions during sampling and transportation could also lead to loss of some components from the sampled formation water. A procedure for obtaining representative formation water composition has therefore been established.

## 2. Introduction and background

Both pressure and temperature are reduced during retrieval of rock samples from the reservoirs, this can change the solubility of minerals and organic and inorganic components in the residual reservoir fluids in the samples. A gas phase will also be formed when the pressure is reduced below the bubble point. Invasion of mud components can alter the rock properties. Wettability can be changed by adsorption of mud components. Invasion of particles, polymer and resins from the mud can also reduce the permeability of the reservoir rock. The ionic composition of the brine in the mud system is different from the formation water (FW) composition. The surface properties of the minerals can therefore be changed due to mud filtrate invasion. In the preparation of reservoir rock samples in the laboratory, it is important to establish wettability conditions representative of the oil reservoir. Mud contamination and precipitates from the reservoir fluids should be removed, prior to wettability, SCAL and EOR-experiments. It is important that the selected composition of the FW is as similar as possible to the real reservoir FW. Preparation of the reservoir rock with incorrect compositions of the FW can give unrepresentative surface properties of the minerals and thereby wettability conditions which are not representative of the reservoir. The crude oil samples and formation water samples should also be analyzed for contaminations. Representative wettability conditions are required in wettability, SCAL and EOR-experiments (e.g. smart water and polymer flooding). The project has contributed mainly to the milestones 1 and 3 in the National IOR Centre, but also 8-16.

The main tasks have been:

- Evaluation of standard procedures for preparation of reservoir core plugs to identify critical steps
- Procedures to determine whether reservoir core plugs are contaminated by mud
- Procedures to determine whether mud contamination is removed during cleaning
- Effect of mud contaminations of rock samples on spontaneous imbibition and polymer flooding
- Crude oil sample quality
- Representative formation water compositions

### Collaboration

Wettability determination by the Drop Shape Analyzer (DSA) device method was studied together with Prof. Dr.-Ing. Mohd Amro and his groups at the Institute of Drilling Engineering and Fluid Mining, Technical University of Bergakademie Freiberg, in Freiberg, Germany.

Oil companies (Equinor, Lundin Energy Norway, Aker BP, ConocoPhillips) have supplied reservoir rock samples and service companies (Halliburton, Schlumberger) have supplied mud samples that have been used in the experiments.

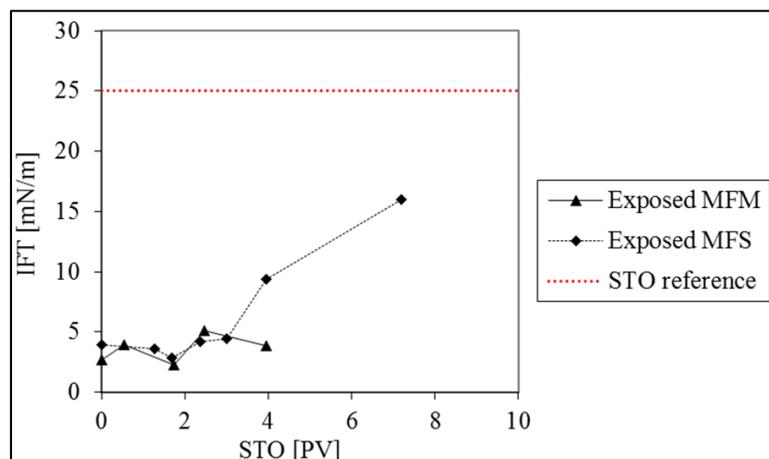
The project has cooperated with the PhD-project "Wettability estimation by oil adsorption" on wettability measurements and estimations. The PhD-student Samuel Erzuah was enrolled at the University of Stavanger (UiS). MSc-students from UiS have also studied effects of mud contaminations on wettability at NORCE, Stavanger.

### 3. Results

The focus in the project has been on critical steps in core plug preparation procedures. Below is given summaries of project results from studies of contaminations of rock by mud (oil-based and water-based), core cleaning and original ions/minerals in reservoir rocks, oxidation of minerals/rocks, crude oil contamination and oxidation, and selection of formation water composition.

#### *Reservoir rock contaminations*

It is very important to detect contamination in reservoir rock samples as early as possible and before the main preparation of rock samples for SCAL-, wettability- and EOR-experiments. In the project, experiments were carried out to detect invasion from oil-based mud (OBM) and water-based mud (WBM) to sandstone rocks (Fjelde et al., 2015). The potential to remove mud components were also studied. For the used OBM-systems, it was found that emulsifiers from OBM can be detected by measuring the interfacial tension (IFT) between effluent and synthetic brine during STO-injection into core plugs (Figure 1). The STO injection was stop when the differential pressure across the core plugs was constant. In the same study it was found that contamination of the sandstone core plugs with mud filtrate from OBM containing asphalt products, decreased the spontaneous imbibition of water and the wettability was therefore altered to less water-wet conditions (Figure 2). Later contamination of reservoir core plugs with mud filtrate from OBM containing no asphalt products, has been found to alter the wettability to more water-wet conditions (example of spontaneous imbibition is shown in Figure 3) (Fjelde, 2022a). The measured Capillary Desaturation Curve (CDC) for a reservoir sandstone rock with potential contamination with oil-based mud, was found to depend on the cleaning procedure (Figure 4) (Fjelde et al., 2015). Atypical CDC values were observed after methanol cleaning, and typical CDC values for water-wet rock after strong cleaning with methanol/toluene, acetic acid and ethanol. The strong cleaning might have altered the rock composition, i.e. dissolution of carbonate minerals by acetic acid.



*Figure 1 Interfacial tension between effluent and water during injection of stock tank oil to sandstone core plugs exposed to mud filtrate of OBM containing asphalt product, MFM = Mud Filtrate Mineral base oil and MFS = Mud Filtrate Synthetic base oil. STO was injected instead of mud filtrate to the reference core plug (Fjelde et al., 2015).*

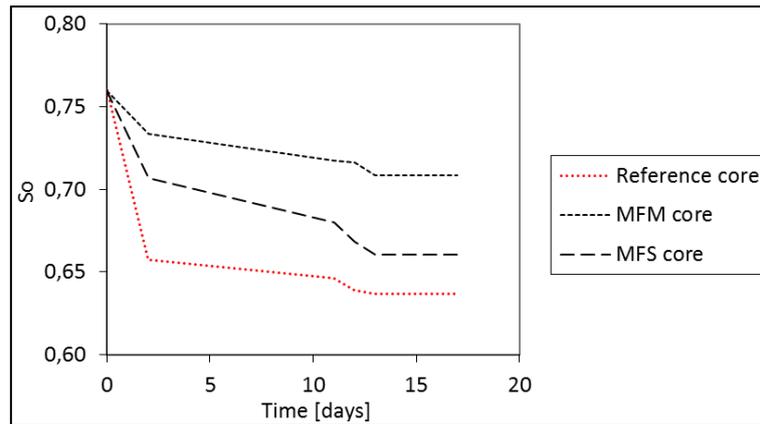


Figure 2 Spontaneous imbibition of formation water for core plugs exposed to mud filtrates from OBM containing asphalt product (MFM and MFS: Mud filtrates with mineral and synthetic base oils) and core plug not exposed (Reference core) (Fjelde et al., 2015).

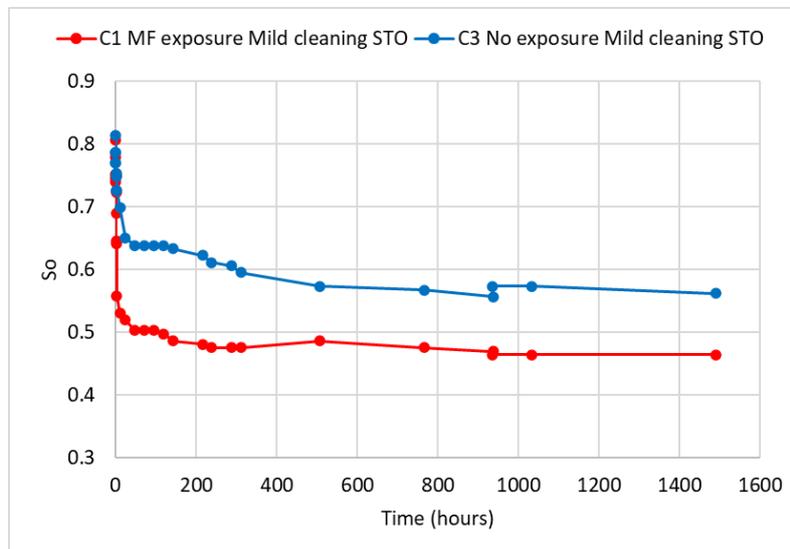


Figure 3 Spontaneous imbibition of formation water at 60°C for core plug exposed to mud filtrate from OBM without asphalt product (C1 MF exposure Mild cleaning) and core plug not exposed (C3 No exposure Mild cleaning STO), both core plugs were cleaned by injection of STO at  $S_{wi}$  (Fjelde, 2022a).

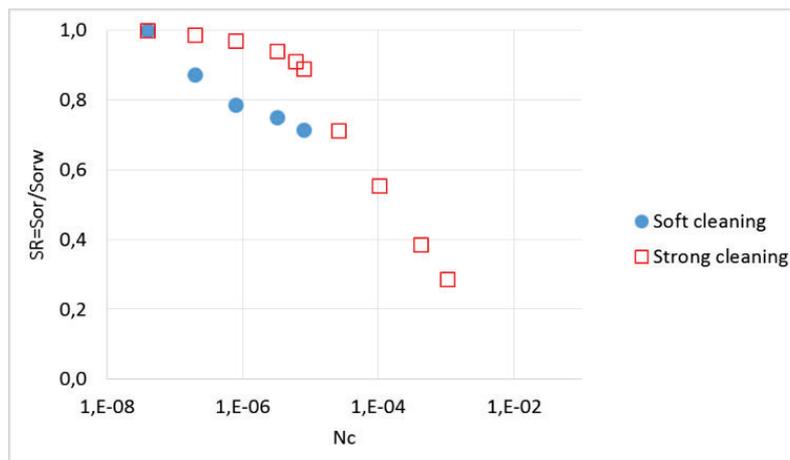


Figure 4 Capillary Desaturation Curve (CDC), normalized residual saturation vs capillary number ( $S_{R=S_{or}/S_{orw}}$  vs  $N_c$ ) after methanol cleaning (soft) and after cleaning with methanol/toluene, acetic acid and ethanol cleaning (strong) of reservoir core (Fjelde et al., 2015).

For WBM, it was found that invasion can often be detected by measuring ionic/element composition of the effluent during injection of synthetic brine or cleaning of reservoir core plugs. Invasion of KCl-based WBM in high permeability sandstone core plugs, was detected during injection of synthetic FW by analyzing effluent samples by ionic chromatography (Figure 5) (Fjelde et al., 2015). It was observed that the K-concentration in the beginning was much higher (up to 12000ppm) than in the reference K-concentration in FW, 278ppm (Figure 5a). The sulphur concentration was also unexpected high in the beginning of the FW injection, indicating contamination of at least one sulphur component from the mud (Figure 5b). The Ca, Mg and Na concentrations were lower in the beginning of the FW flood because the FW in the reservoir rock had been displaced by the mud brine with low concentration of these ions (Figure 5c-e). These concentrations were gradually increased up to the levels in the injected FW. High K concentration in invaded the mud filtrate can reduce the concentration of divalent cations onto clay surfaces and thereby alter the wettability to more water wet condition (see results related to low salinity water flooding presented by Fjelde et al. (2017a)). It is therefore important to confirm that the effluent ionic composition becomes as in injected FW. Mud particles and polymers were detected by Scanning Electron Microscopy (SEM)-analysis, also after water flooding (Figure 6). This showed that it is very difficult to remove mud particles from reservoir core plugs with mud invasion.

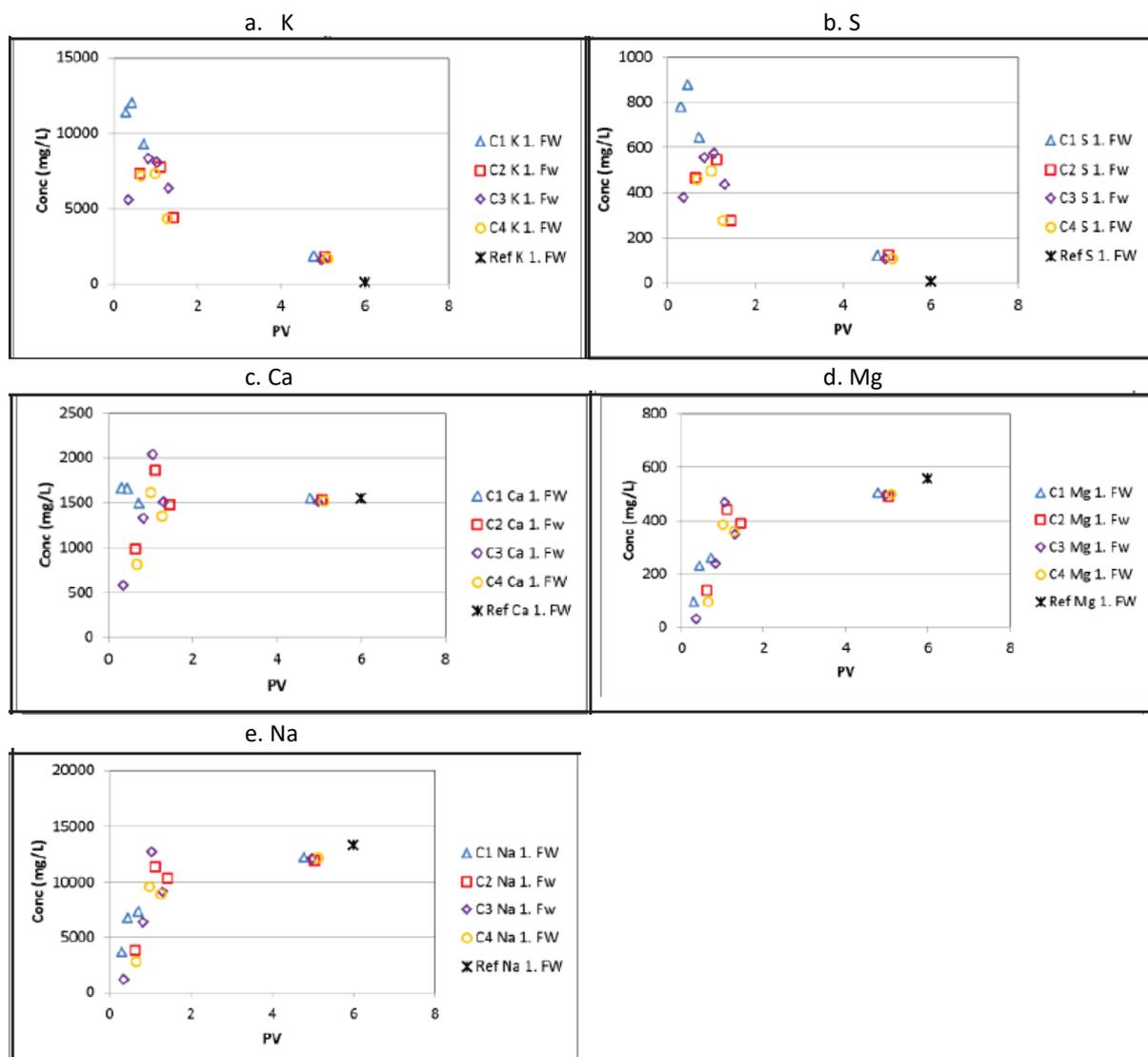


Figure 5 Effluent element concentrations during SFW injection before solvent cleaning of four core plugs (Fjelde et al., 2015).

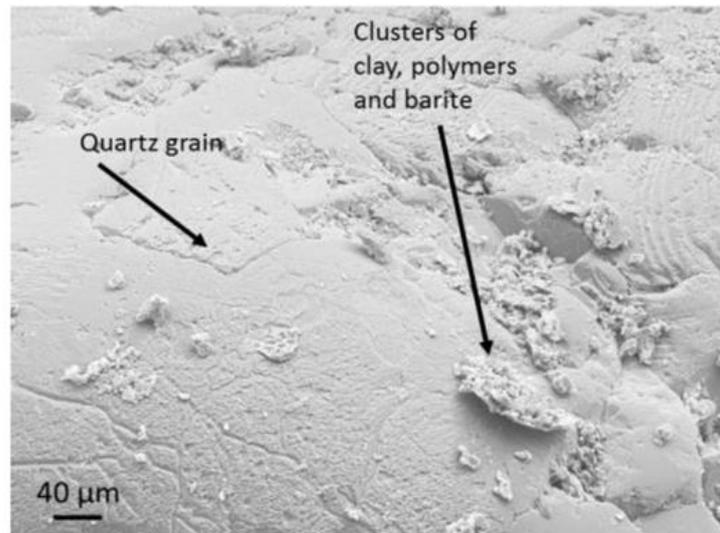


Figure 6 Detection of mud additives by SEM and EDAX on a core slice after water flooding (Fjelde et al., 2015).

Polymer flooding experiments were also carried out in sandstone core plugs contaminated by mud filtrate from OBM containing no asphalt products. Core plugs without mud filtrate contamination were used as references (Fjelde, 2022b). Initial water saturation ( $S_{wi}$ ) was first established in all core plugs before aging of core plugs with STO. Mud filtrate was prepared by filtration of mud samples through 3 $\mu$ m filter before it was injected to two of the core plugs. STO was injected in mild cleaning of one mud contaminated core plug. Another contaminated core plug was first cleaned by toluene/methanol cycles (Strong cleaning) before  $S_{wi}$  was reestablished and core plug aged with STO. As references, two core plugs without mud filtrate exposure were prepared with mild cleaning and strong cleaning, respectively. When the polymer floods were carried out at 60°C, the reference core plugs showed similar differential pressure (dP) profiles (Figure 7), independent of the cleaning method. The mud exposed core plug with mild cleaning, gave very high dP from the beginning of the polymer flood. For the exposed core plug with strong cleaning, a gradually increase in dP was observed during the polymer flood. The exposed core plugs gave higher residual oil saturation than the reference core plugs without mud filtrate exposure. After the polymer floods, the permeability of formation water was for the mud contaminated core plugs only 10% of the permeability to non-contaminated core plugs. The results showed that cleaning, both mild cleaning and strong cleaning, was not able to remove the formation damage caused by mud filtrate invasion. It is concluded that use of mud contaminated core-plugs can give too low estimate of the potential for polymer flooding.

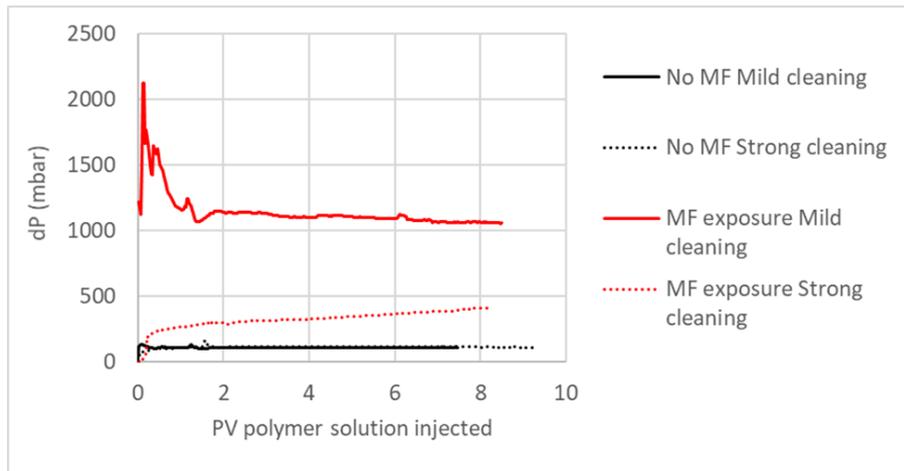


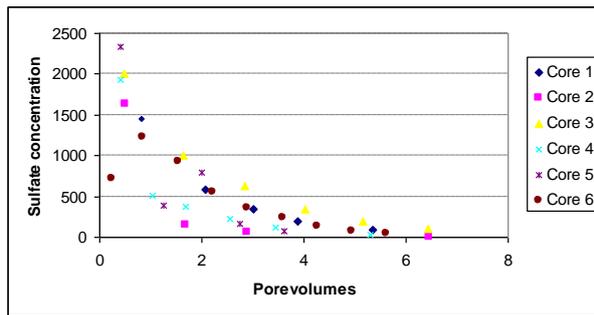
Figure 7 Differential pressure (dP) during polymer flooding experiments using core plugs with and without mud filtrate contamination. The core plugs were prepared by either mild cleaning (STO injection) or strong cleaning (toluene/methanol cycles) (Fjelde, 2022b).

#### Minerals and ions in original reservoir rocks

Minerals present in the reservoir rock samples should not be removed during preparations of reservoir rocks, because this will change the mineral composition and can thereby affect the established wettability composition. If important ions are removed, they should be reintroduced during the core preparation, e.g. during injection of representative formation water composition.

It has been reported that sulphate was present in rock samples from two chalk reservoirs (Figure 8) (Fjelde, 2008). It was first assumed that the sulphate in the reservoir chalk samples was from contamination by sea water. It was therefore decided to remove the sulphate by flooding with a brine without sulphate. Later it was shown that the sulphate was not from contamination by sea water. The sulphur isotopic ratio of sulphate in the global ocean has varied with geological time. The sulphur isotopic ratio of the sulphate in reservoir chalk samples (Field 1 and Field 2) and in produced water samples (Field 2), was found to be in the same range as estimated for the sulphate in the global ocean at the time for sedimentation of the chalk reservoirs (Figure 9 and Figure 10) (Fjelde, 2019). It was therefore concluded that the sulphate found in the chalk field samples were from the original reservoirs, i.e. the samples were not contaminated by sea water. It was also found that similar amount of sulphate as in the reservoir chinks gave more water-wet reservoir rocks and higher spontaneous imbibition of sea water (Figure 11) (Fjelde and Asen, 2015). It was also shown that sulphate in original reservoir chinks was released when desulphated sea water was injected to reservoir chalk (Figure 12) (Fjelde, 2018).

Chalk field A



Chalk field B

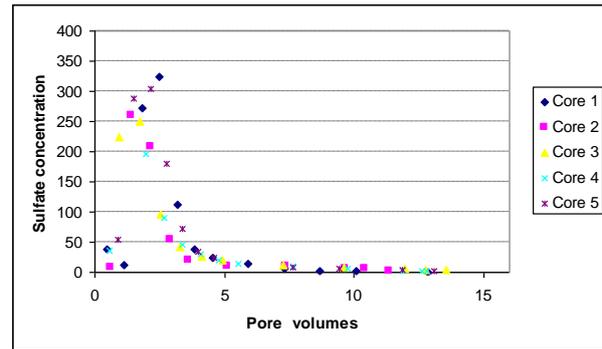


Figure 8 Effluent sulphate concentration during injection of synthetic formation water without sulphate to reservoir chalk plugs from two fields (Fjelde, 2008).

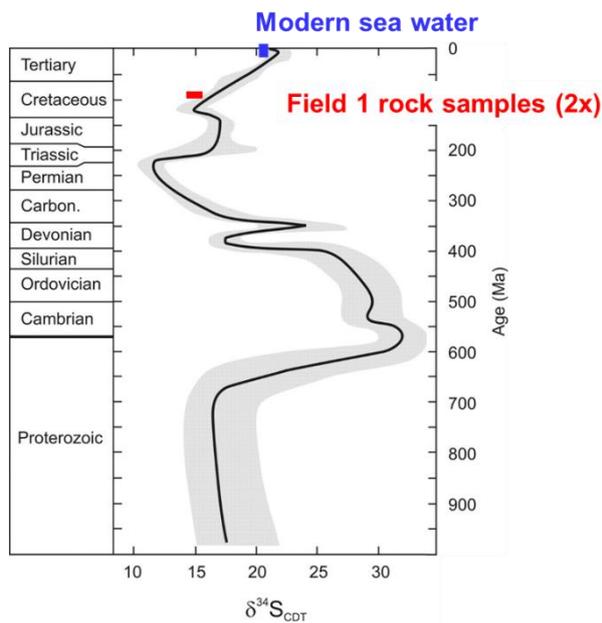


Figure 9 Sulphur isotopic ratio ( $\delta^{34}S_{CDT}$ ) for  $BaSO_4$ -filtercakes precipitated from dissolved Field 1 rock compared to modern sea water samples (Fjelde, 2019).

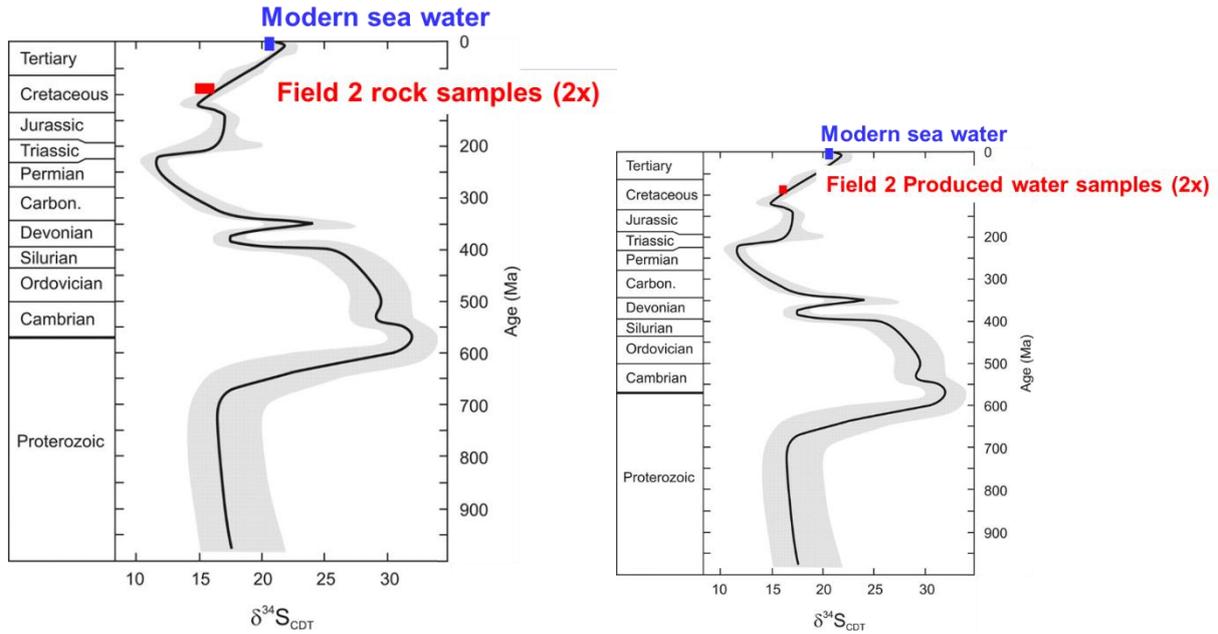


Figure 10 Sulphur isotopic ratio ( $\delta^{34}S_{CDT}$ ) for  $BaSO_4$ -filtercakes precipitated from dissolved Field 2 rock and from produced water samples compared to modern sea water samples (Fjelde, 2019).

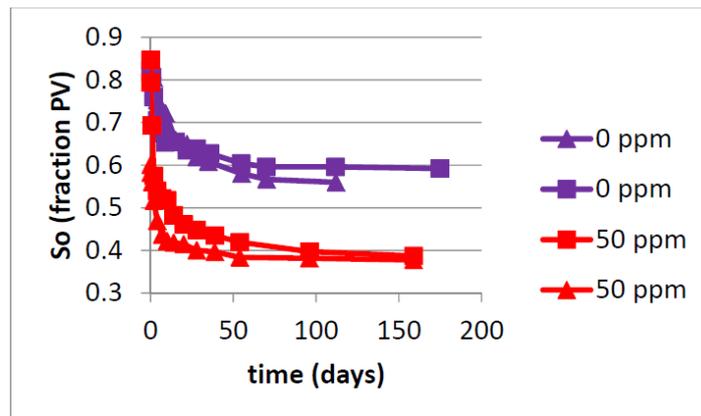


Figure 11 Oil saturation ( $S_o$ ) vs time during spontaneous imbibition of sea water into core plugs prepared by formation water with (50ppm) and without (0ppm) sulphate (Fjelde and Asen, 2015).

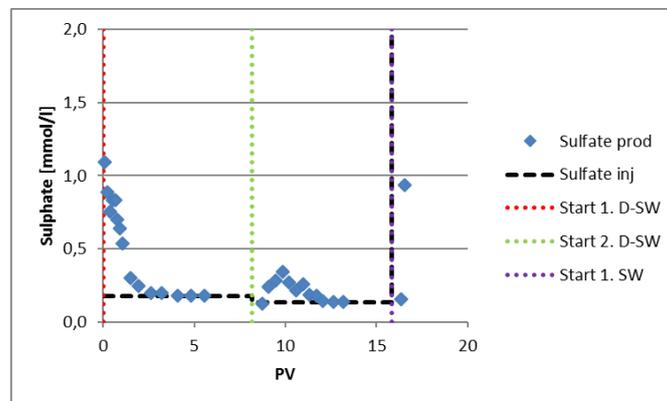


Figure 12 Production of sulphate from reservoir chalk by injecting desulphated sea water (D-SW) (Fjelde, 2018).

### Oxidation of minerals/rocks

Oxidation of  $Fe^{2+}$  to  $Fe^{3+}$  in sandstone rocks has been reported to affect established wettability conditions (Rajapaksha et al., 2014). The effects of  $Fe^{2+}$  oxidation and cation bridging by  $Fe^{3+}$  on wettability was therefore studied in the project. It was shown that  $Fe^{2+}$  was oxidized to  $Fe^{3+}$  during storage of FW at aerobic conditions and realistic reservoir temperature. In flotation experiments, low concentration of  $Fe^{3+}$  was found to alter the wettability of glauconite clay to less water-wet (Figure 13) (Fjelde et al., 2017b). Geochemical simulations showed that the change in the concentration of multivalent cations on clay mineral surfaces was negligible and could not explain the wettability alteration. The alteration of the wettability of glauconite by  $Fe^{3+}$  to less water-wet was probably due to precipitation of surface-active Fe-oxides/hydroxides on the glauconite surfaces. Combination of experiments with geochemical simulations were found to be useful in the interpretation of different types of experiments.

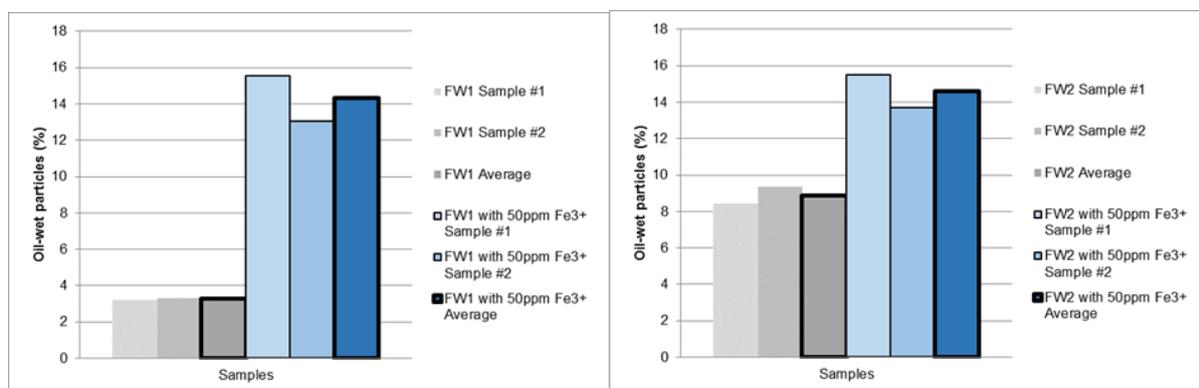


Figure 13 Concentration of oil-wet particles in flotation experiments with Glauconite and STO and two different formation waters (FW1 and FW2) (Fjelde et al., 2017b).

Rajapaksha et al. (2014) proposed a new restoration method to reduce the  $Fe^{3+}$  ions to  $Fe^{2+}$  and remove  $Fe^{3+}$  by injecting sodium dithionite, EDTA and sodium bicarbonate. A flotation method was used to study the effects of this chemical package, its components and  $Fe^{3+}$  ions on the wettability of glauconite, hematite and goethite (Magnussen, 2017). Addition of  $Fe^{3+}$  to the brine gave higher concentration of oil-wet glauconite particles. EDTA had surprisingly the same effect on glauconite and increased the concentration of oil-wet particles. Although it reduced the concentration of oil-wet particles for both hematite and goethite. The restoration package had a reducing effect on the concentration of oil-wet particles for glauconite, while the effect of the restoration chemicals was significant for the hematite and goethite samples. Based on the results, it is concluded that the effects of the chemical restoration package and its components on wettability should be evaluated before the chemical package is used in preparation of the reservoir core plugs.

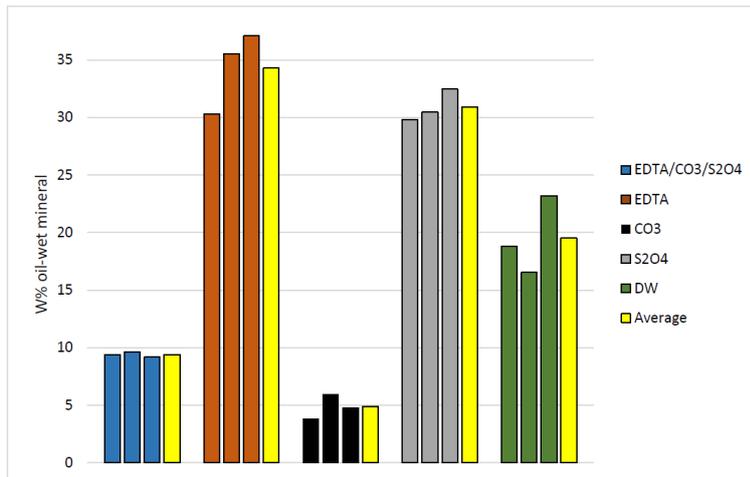


Figure 14 Concentration of oil-wet glauconite clay particles when exposed to chemical package and its components. CO3 = Sodium bicarbonate, S2O4=sodium dithionite, DW=diluted water (Magnussen, 2017).

### Fluid samples

#### Crude oil samples

Crude oil samples to be used in experiments should be free of contaminations. These samples can be analyzed for OBM specific components to determine whether the contamination has taken place. The analytical methods that should be used to detect mud contamination depend on the mud composition e.g. measurement of low IFT between crude oil and a brine can be used to detect emulsifiers from OBM. If contamination of the crude oil sample is detected, it can be analyzed for base-oil concentration by gas chromatography to determine the degree of contamination. Contamination of crude oil samples by OBM will also dilute the samples. Since the base-oil in OBM is often low aromatic, the potential for precipitation of asphaltene will also increase. In addition to dilution of the crude oil, precipitation of asphaltene will also reduce the concentrations of polar oil components. This can give preparation of wrong wettability conditions.

For crude oil samples that have been stored and exposed to oxygen, oxidation can increase the concentration of polar oil components, e.g. acidic components. This will increase the Total Acid Number (TAN) and reduce the IFT between the crude oil and a brine. Crude oil samples with high TAN and low IFT should not be used without further analyses to confirm that the crude oil sample is not oxidized. In the project, crude oil samples taken before and after steady-state relative permeability experiments without any actions to remove oxygen, were found to have TAN in the same range, i.e. the crude oil was not oxidized during the experiment.

Most of the components in WBM have very low solubility in crude oils, but the risk for contamination of crude oil samples by components from WBM should be evaluated based on the WBM composition.

### Selection of formation water composition

Accurate FW composition is critical for selection of oil production method and strategy. FW compositions are often derived from analysis of water sample taken during drilling operation. It is important to determine whether these samples are contaminated by mud. The analytical methods to detect contaminations are mud specific. The change in temperature, pressure and gas loss during sampling and transportation could also lead to precipitation of some components from the sampled formation water. In addition, there could be errors in the procedure and or method for the analysis of the collected samples. A procedure for obtaining a more representative FW composition has therefore been established.

### Correction for mud contamination

It is common practice to use tracers (e.g. SCN) in the drilling mud that are usually not found in FW. The tracer should be non-reactive and not retained in the reservoir rock during invasion of the mud. The following methods can be employed in effecting a correction for the mud contamination:

*Linear Regression method:* A known concentration of the tracer is added to the mud system. The concentration of the tracer in the sampled water is then used to estimate the mixing ratio between mud brine and the original FW. The derived mixing ratio is used to make corrections for all the constituents of the sampled water to arrive at the composition of the original FW. This procedure is assuming that the mud brine was not reactive with the formation. Possible reactions include: Dissolution of rock components by mud brine, precipitation of new mineral phases that are formed upon mixing of mud brine with the original FW and ion-exchange between the mud brine and the reservoir rock. These reactions would create water phases that are not representative of the original FW. However, the assumption of non-reactive mud brine is valid in cases of clean reservoir sands and non-precipitable components in the mud brine.

*Reactive Transport modelling:* In situations where the reactivity of the mud brine when in contact with the formation (rock and formation water) cannot be neglected, reactive transport modelling can be employed to identify the original FW (McCartney et al., 2018). The aim is to simulate the mud invasion process and the associated reactions that may have taken place. Input into the simulators are the mineral phases in the rock, cation exchange capacity of the rock, mud brine composition and an assumed FW composition. The predicted mix of the mud brine can then be compared with the water sample to check the validity of the inputted FW sample. The modelling can be performed with any simulator capable of reactive transport modelling e.g. IORSIM.

### Charge balance

It is very important to check for charge balance in the composition of the brine obtained after analysis. A large imbalance in the brine is an indication that errors in the analysis of the sampled FW are significant. Minor imbalance in the given composition can be corrected with the chlorine concentration since in most FW compositions, the chloride ion constitutes the largest mass (Hanor, 1994).

### Solubility at room temperature and reservoir/test temperature

The change in temperature, pressure and loss of gas phase during sampling may lead to precipitation of some phases out of solution. On the other hand, prepared brine sample at room conditions, may lose some components at the test temperature and pressure due to precipitation. Simulations of the saturation state at all operating conditions should be performed to identify the mineral phases that can potentially precipitate out of solution. Corrections to the analyzed FW sample composition can be made if simulations suggest that the sampled brine is supersaturated at any point during the sampling

process. Typical minerals that can precipitate out of FW include barite and calcite (Ramstad et al., 2017).

#### Equilibrium with Rock Mineral Phases

The relative proportions of ions in FW are in many cases controlled by the equilibrium between the mineral phases and the brine (Houston et al, 2011). The correct formation composition can be obtained from such equilibrium simulations if appropriate constraints of the reactions are known. These constraints include charge balance (determined mainly by the chloride concentration), the pH of the brine temperature, the fugacity of CO<sub>2</sub> and the mineral assemblage present (Hanor, 1994). These constraints are often problematic to determine and may vary in the formation and over time. However, useful information about the brine composition can be obtained from such simulations.

#### Identification of Trends

The FW in a basin tend to follow trends based on their mode of origin. Comparison of the given FW with composition from other FW databases (Warren and Smalley, 1994) is very useful in identifying such trends and then predicting the composition of ions that might not be analyzed correctly or are affected by contamination or precipitation.

#### 4. Conclusions

The main conclusions from the project are:

Before the main preparation of reservoir core plugs is started, it should always be determined whether the rock is contaminated by mud invasion/coring fluid. The analytical methods to be used for detection of mud invasion depend on the mud composition. The composition of the mud should therefore be known before the work is started.

If invasion of mud is detected, mud components that may affect wettability and permeability and thereby the fluid flow properties, should be removed by core cleaning. The solvents to be used in the cleaning will depend on the mud composition. It should be confirmed that these mud components are removed after the cleaning. The methods to confirm the removal of contaminations depend on the mud composition. If contamination is not removed, the core plugs should ideally not be used for wettability, SCAL and EOR studies.

If contaminated reservoir core plugs have to be used, the core plugs with the lowest contamination should be used for the most important experiments. The degree of mud invasion can be determined by analyzing core plugs for the volume of mud filtrate in the core plugs. The mud filtrate volume in the core plugs can be estimated from effluent profile for mud components during cleaning, e.g. ions like potassium in WBM and base-oil in OBM.

Important minerals should not be removed from the original reservoir rock during cleaning because this can affect the established wettability conditions. Important ions that are removed from mineral surfaces during cleaning should be restored by injecting representative formation water composition.

Oxidation of iron-minerals inside reservoir rocks can be affect the established wettability. Chemical packages used for restoration of these reservoir rock samples should not itself alter the wettability of the rock.

It should always be verified that the crude oil samples are not contaminated by mud because adsorption of mud components and dilution of polar crude oil components can affect the established wettability. It is also important to control that the crude oil sample is not oxidized.

Selection of representative formation water composition is critical for the established wettability conditions. It should always be determined whether formation water samples are contaminated by mud. The analytical methods to be used are mud specific.

## 5. Future work/plans

The following publications will be finished in the beginning of next year:

Fjelde, I. 2022a. Effect of mud exposure of sandstone rocks on spontaneous imbibition of brine.

Fjelde, I. 2022b. Effect of mud exposure of sandstone rocks on polymer flooding.

## 6. Dissemination of results

Publications from the project is given in the reference list below.

The methods for detection of contaminations in reservoir rocks, crude oil samples and formation water samples are proposed for new projects at NORCE.

## 7. References

Fjelde, I. 2008. Sulfate in rock samples from carbonate reservoirs. SCA2008-19. International Symposium of the Society of Core Analysts, Abu Dhabi, UAE. October 29 - 2 November, 2008.

Fjelde, I. 2018. Sulphate in Original Reservoir Chalk Rocks: Release of Sulphate By Desulphated Sea Water And Effects On Wettability. SPE-190844-MS. SPE Europec featured at 80<sup>th</sup> EAGE Annual Conference & Exhibition, Copenhagen, Denmark, 11-14 June 2018.

Fjelde, I. 2019. Determination of Sulphur Isotopic Ratio to Identify the Source for Sulphate in Reservoir Chalks and Formation Water. 20<sup>th</sup> European Symposium on Improved Oil Recovery (IOR 2019), Pau, France, 8-11 April 2019.

Fjelde, I. 2022a. Effect of mud exposure of sandstone rocks on spontaneous imbibition of brine.

Fjelde, I. 2022b. Effect of mud exposure of sandstone rocks on polymer flooding.

Fjelde, I. and Asen, S.M. 2015. Effect of Initial Sulfate in Reservoir Chalks on the Spontaneous Imbibition of Sea Water. 18th European Symposium on Improved Oil Recovery, Dresden, Germany, 14-16 April 2015.

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