



Full Length Article

An integrated experimental approach to quantify the oil recovery potential of seawater and low-salinity seawater injection in North Sea chalk oil reservoirs



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ABSTRACT

In this study, the oil recovery potential of seawater (SW), SW with different ion compositions, low-salinity seawater (LSSW), and formation water (FW), is investigated, using chalk reservoir cores and crude oil from the North Sea. Furthermore, the impact of temperature on SW flooding performance is addressed.

A series of flooding experiments were conducted at reservoir conditions (2800 psi and 60 °C), followed by spontaneous imbibition tests. Secondary SW and FW flooding led to the same oil recovery. Tertiary SW injections, performed after secondary FW flooding and secondary LSSW injection, did not lead to any extra oil recovery at 60 °C. Injecting SW at 100 °C did not lead to additional recovery either. Spiking the SO_4^{-2} content of SW by four times, at 60 °C, did not show any additional oil production as well as increasing the concentration of Ca^{+2} and the $\text{Ca}^{+2}/\text{Mg}^{+2}$ ratio at 60 °C. Conversely, tertiary LSSW injection, after secondary SW injection, led to 2.5% OOIP additional oil recovery. More importantly, secondary LSSW injection, compared to the secondary SW and FW injection, led to around 8% OOIP extra oil recovery. Consistently, the results of the imbibition test showed the same trend: tertiary LSSW imbibition, after secondary SW imbibition, led to 4.25% OOIP extra oil recovery.

This study, through employing chalk reservoir cores and crude oil, reveals that LSSW flooding in examples of silica containing chalk reservoirs in the North Sea, has a better oil recovery potential compared to both SW and FW flooding. This is in contrast to other published results as it will be discussed in the paper.

1. Introduction

The majority of discovered oil reservoirs in the North Sea are mature and have already been waterflooded or in the process of being flooded. A big portion of these reservoirs, in particular in the Danish and Norwegian sectors of the North Sea, are chalk reservoirs. The main characteristics of these chalk reservoirs are the low matrix permeability (mostly less than 1 mD), pore throat sizes less than one micron, high porosity, and presence of natural fractures and micro-fractures which define a high degree of heterogeneity [1]. Due to the combined effects of these parameters, enhancing oil production from this type of reservoirs is challenging. However, the reservoir oil is very light, with viscosities ranging from 0.98 to 1.3 cP at reservoir conditions. The water sweep efficiency is favored by the low oil viscosity, and this is one of the reasons why conventional waterflooding by seawater (SW) has been quite successful in these reservoirs. Since a significant amount of

oil remains trapped in the reservoir, after SW flooding, implementing an Enhanced Oil Recovery (EOR) scenario, as a tertiary injection scenario, is essential. At the same time, EOR scenarios could be applied as a secondary injection mode, in the fields that have only been exploited by primary depletion.

There have been several publications on SW flooding as a possible wettability modifier of chalk oil reservoirs, mostly performed by Austad et al. [2–8]. Through imbibition experiments on Stevns Klint outcrop chalk samples, they indicated that SW can act as a wettability modifier for chalk rocks and changes the rocks wettability from mixed-wet towards more water-wet conditions. They hypothesized that Ca^{+2} , Mg^{+2} and SO_4^{-2} act as the potential determining ions and are responsible for changing the wettability of chalk. When the sulfate ions are adsorbed on the chalk surface, the positive surface charge of chalk decreases. As a result, an excess of Ca^{+2} concentrates near the chalk surface. Ca^{+2} interacts with the negatively charged carboxylic groups –COO– in the

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oil, causing the release of some carboxylic material from the surface. When the temperature increases, Mg^{+2} becomes active, and in the presence of SO_4^{-2} , displaces the calcium-carbonate complexes $[-\text{COOCa}]^+$ from the rock surface. They mentioned that this mechanism is more active at higher temperatures (above 100°C). Furthermore, they observed that spiking the sulfate concentration of brine by four times led to a better oil recovery. However, great care must be taken when injecting SW with high sulfate content, as it can easily lead to souring of sweet reservoirs [9]. The presence of sulfate in injected SW provides nutrients for sulfate reducing bacteria (SRB), which are responsible for the reservoir souring and the oil degradation [10–12]. SRB oxidize organic carbon (oil organics) with the sulfates in the injection SW, to CO_2 and sulfide:



In addition to reservoir souring and oil degradation, formation of in situ CO_2 in chalk oil reservoirs can cause calcite precipitation, thus pore plugging. The high amount of Ca^{2+} ions in the formation brine favor the calcite precipitation, due to the reaction with the in situ CO_2 , as presented in the following reactions:



Furthermore, when the porous medium contains formation water rich in barium and strontium, injecting SW with a high sulfate content causes severe precipitation. This leads to scale formation in the production tubing, pore plugging, and severe injectivity losses [13].

In another study, Fathi and Austad [14] claimed that the amount of the non-active salts in the brine, like NaCl, has an impact on the wettability alteration. They performed spontaneous imbibition tests on Stevns Klint outcrop chalk samples, with seawater, seawater depleted in NaCl, and seawater depleted in NaCl and spiked by sulfate. Removing NaCl from the seawater resulted in an extra 5% of OOIP oil recovery, compared to the original seawater. In addition, when seawater was spiked with sulfate, they recorded an increase of 5 to 18% of OOIP compared to the seawater without NaCl.

In all the aforementioned studies [2–8,14,15] Stevns Klint outcrop chalk cores were applied. This outcrop chalk is generally considered a good analogue for the North Sea chalk reservoir rocks. However, the surface chemistry can be significantly different from the reservoir chalk. The differences in surface chemistry can result in a different oil recovery behavior. The impact of chalk type on oil recovery during spontaneous imbibition, at 130°C , was addressed by Fernø et al. [16]. They used three types of outcrop chalks: Rørdal, Niobrara, and Stevns Klint. From the three, only Stevns Klint chalk exhibited increased oil recovery, with increased concentration of sulfate in the imbibing water, during spontaneous imbibition. The two other outcrop chalks did not show any increase in oil recovery when the sulfate concentration in the brine was increased. Their results highlighted the crucial role of chalk type on the oil recovery mechanism and thus oil recovery. Furthermore, Romanuka and coworkers [17] findings acknowledged the fact that the surface chemistry of various carbonate rocks can be contrasting, thus they react differently as they come in contact with diverse injection brine. Based on their study, through a series of integrated imbibition experiments over six carbonate samples, including Stevns Klint, they revealed that lowering brine salinity, enhance tertiary incremental oil production by 4–20% OOIP. However, consistently with the previous results of Austad et al. [2–8], Stevns Klint outcrop chalk samples were an exception and presented an increase in oil recovery when the sulfate concentration was increased.

In another study, Strand et al. [18] pointed out that extra care must be taken, when reservoir chalk material is substituted with outcrop samples, due to the differences in surface chemistry. They mentioned

that differences in silica contents and silica types between chalk samples lead to different wettability state of the rocks. They documented that the surface chemistry and wetting conditions of chalk samples from Aalborg, which contained a significant amount of silica (6.3 wt%), were quite different from the surface chemistry and wetting conditions of Stevns Klint and Liège that contain 1.4 wt% and 2.8 wt% silica. However, the wetting conditions of Stevns Klint and Liège outcrop chalk samples were similar, as their silica content was quite similar. It should be noted that silica contents of chalk not only impacts its wettability state, but it also impacts the strength of chalk. DaSilva et al. and Risnes et al. [19,20] indicated that the strength of a chalk increases with increasing silica content.

From the aforementioned studies, it can be concluded that there is a significant difference between reservoir, and outcrop chalk samples. This difference may strongly impact the recovery behavior of SW and low-salinity sea water (LSSW), during secondary or tertiary injection. This discrepancy can also impact our previous expectations regarding the role of ions such as Ca^{+2} , Mg^{+2} , and SO_4^{-2} in altering the wettability and improving oil recovery. Therefore, to better understand the oil recovery potentials of SW, different ions, LSSW, and formation water (FW) on chalk reservoir cores, a series of flooding experiments were performed, under conditions pertinent to chalk oil reservoirs in the Danish sector of the North Sea. Chalk reservoir cores, as well as the reservoir crude oil from the same field, were used in these experiments. Based on the flooding results, a series of imbibition experiments were designed and performed.

2. Experimental setups and procedures

2.1. Coreflooding rig

The rig used during flooding experiments is presented in Fig. 1. All the fluids, as well as coreholder and backpressure regulator, are housed inside an oven at a constant temperature. Two injection pumps are connected, respectively, to the injection cylinders and to the core holder, to maintain the pressure. The differential pressure across the core is monitored through pressure transducers located by the inlet and outlet of the coreholder. The produced fluids will go into a separator where the level of produced oil and brine can be read.

2.2. Imbibition setup

Fig. 2 presents the glass cell utilized during the imbibition test. The prepared core is positioned vertically inside an imbibition cell which is filled with desired brine and it is placed in an oven at a constant temperature of 60°C . With time, as the fluid imbibes into the core and oil production starts, the amount of recovered oil is recorded.

2.3. Fluid properties and preparation

2.3.1. Brine

Several brine types were employed in this study, to systematically address the impact of brine salinity and different ionic effect on oil recovery from North Sea chalk reservoirs. Formation water (FW) and seawater (SW) were prepared based on the actual measurements. Tables 1 and 2 represents the compositions of the brine employed in this study. To investigate the impact of salinity on oil recovery, low-salinity seawater (LSSW) was prepared by 10 times diluting seawater (SW) using deionized water. Brine SW2 was obtained removing NaCl from SW. This brine was prepared to examine the effect of the non-active ions on oil recovery. To understand the influence of sulfates, brine SW3 was prepared by spiking the amount of sulfates in SW2 by four times. Furthermore, to address the impact of high Ca^{+2} to Mg^{+2} ratio, two brine types called SW4 and SW5 were prepared. SW4 has a lower salinity compared to SW5 due to the absence of Magnesium Chloride. Furthermore, the amount of Calcium Chloride in SW5 is

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