Investigation of the Potential of Low Salinity Water Flooding as a Tertiary Process in Forties Sandstone Formation Fields

By

Guillaume POINT-DUMONT

A report submitted in partial fulfilment of the requirements for the MSc and/or the DIC

September 2013
DECLARATION OF OWN WORK

I declare that this thesis

*Investigation of the Potential of Low Salinity Water Flooding as a Tertiary Process in Forties Sandstone Formation Fields*

is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

Signature:

Name of student: Guillaume POINT-DUMONT

Name of College supervisor: Martin BLUNT

Name of Company supervisors: Max HARPER and Peter AQUILINA
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# TABLE OF CONTENTS – MAIN BODY

Abstract .................................................................................................................. 1  
Introduction ........................................................................................................... 1  
Low salinity water flooding mechanisms ............................................................... 2  
  Theoretical mechanisms ..................................................................................... 2  
  Field data and analogue response ..................................................................... 3  
Analytical study – Buckley-Leverett theory ......................................................... 5  
Numerical simulation ............................................................................................ 7  
  Reservoir model description ............................................................................ 7  
    Static model ..................................................................................................... 7  
    PVT data ......................................................................................................... 8  
    Initialisation .................................................................................................... 8  
    Well placement and constraints ..................................................................... 9  
Experimental design ............................................................................................. 9  
Results and analysis .............................................................................................. 9  
Conclusions ........................................................................................................... 13  
Recommendation for further study ..................................................................... 13  
Nomenclature ....................................................................................................... 144  
References .......................................................................................................... 145  
Appendices ........................................................................................................... 17

# TABLE OF CONTENTS – APPENDICES

Appendices ........................................................................................................... 17  
  A. Critical Literature Review ............................................................................. 17  
  B. Channels and Overbanks Facies Relative Permeability Curves Sets .......... 27  
  C. Buckley-Leverett Analysis Curves ................................................................ 28  
  D. Sensitivity analysis ....................................................................................... 30
LIST OF FIGURES – MAIN BODY

Fig. 1 : Sketch map of the Forties Fan (Hempton et al., 2005)................................................................. 2
Fig. 2 : Original Oil / Water relative permeability curves measured for channels facies from (Hughes, 1990) and the model created for a weakly water-system, using Corey exponents.................................................................................. 3
Fig. 3 : Different wettability systems relative permeability curves for high and low salinity for channels facies derived by varying Corey exponents.................................................................................. 5
Fig. 4 : Fractional flow curves for channel facies with an oil-wet system...................................................... 6
Fig. 5 : Saturation profile for channel facies with an oil-wet system.............................................................. 6
Fig. 6 : PVI vs PVR plot for channels facies with an oil-wet system ............................................................. 6
Fig. 7 : Porosity distribution in the numerical model...................................................................................... 8
Fig. 8 : Oil saturation after initialisation....................................................................................................... 8
Fig. 9 : Tornado chart presenting the sensitivity of different parameters on the incremental oil recovery as a percentage of the oil initially in place.......................................................................................... 10
Fig. 10 : Surface plot of incremental oil recovery Vs connate water salinity and start point of LSWF. ...................... 11
Fig. 11 : LSWF vs HSWF comparison for the best case scenario................................................................. 11
Fig. 12 : Incremental oil recovery Vs low salinity water PVI for the best case scenario................................. 12
Fig. 13 : Cells below the upper and lower salinity thresholds (best case scenario / connate water salinity 55,000 ppm) ................................. 12
Fig. 14 : Cells below the upper and lower salinity thresholds (worst case scenario / connate water salinity 135,000 ppm). ...... 13

LIST OF FIGURES – APPENDICES

Figure 15 : Different wettability systems relative permeability curves for high and low salinity for overbanks facies generated by varying Corey exponents.................................................................................. 27
Figure 16 : Fractional flow curves for overbanks facies with an oil-wet system.............................................. 28
Figure 17 : Fractional flow curves for channels facies with a weakly water-wet system.................................. 28
Figure 18 : Fractional flow curves for overbanks facies with a weakly water-wet system................................ 28
Figure 19 : PVI vs PVR plot for overbanks facies with an oil-wet system..................................................... 29
Figure 20 : PVI vs PVR plot for channels facies with a weakly water-wet system........................................ 29
Figure 21 : PVI vs PVR plot for overbanks facies with a weakly water-wet system........................................ 29
Figure 22 : Correlation between Simulated and Predicted Values from the Gaussian Correlation (Oil-wet system) ................................................................................................................................................. 30
Figure 23 : Correlation between Simulated and Predicted Values from the Gaussian Correlation (Mixed-wet system) ................................................................................................................................................. 30
Figure 24 : Correlation between Simulated and Predicted Values from the Gaussian Correlation (Weak water-wet system) ................................................................................................................................................. 31
Figure 25 : Surface Plot of Incremental Oil Recovery Vs Oil Viscosity and Injection Rate .................................. 31
LIST OF TABLES – MAIN BODY

Table 1 : Indicators of low salinity water flooding key parameters and their correlations from experiments ................................................. 3
Table 2 : Low salinity water flooding key parameters comparison in Prudhoe Bay and the Forties formation ........................................... 4
Table 3 : Relative permeability curves sets parameters ................................................. 4
Table 4 : Static model rock properties ........................................................................ 7
Table 5 : PVT Data used in the numerical model (Brand et al., 1996; Hughes et al., 1990). ..................................................... 8
Table 6 : Numerical model volume statistics .................................................................. 8
Table 7 : Sensitivity analysis parameters and ranges .......................................................... 9
Table 8 : Parameters and results of the best and worst case scenarios ................................ 10

LIST OF TABLES – APPENDICES

Table 9 : Complete Sensitivity Analysis - Oil-wet system ........................................................................................................ 30
Table 10 : Complete Sensitivity Analysis - Mixed-wet system ................................................................................................... 30
Table 11 : Complete Sensitivity Analysis - Weak water-wet system ................................................................. 31
Investigation of the Potential of Low Salinity Water Flooding as a Tertiary Process in Forties Sandstone Formation Fields

Guillaume Point-dumont, Martin Blunt, Imperial College London, Max Harper, Peter Aquilina, Senergy, SPE.

Abstract
The Forties sandstone formation is located in the south central graben of the North Sea. It contains some of the biggest North Sea oil reservoirs that have already been in production for decades. Even if the recovery factor is now close to the maximum forecast, for many of these reservoirs a large amount of oil is left behind.

In order to improve the recovery, reservoirs have been successfully waterflooded as a secondary recovery process. The injected water was a blend of produced water and make up sea water resulting in very high salinity injection water. A Low Salinity Water Flooding (LSWF) process could be a promising technique to implement on these fields to enhance oil recovery.

To define this potential in the Forties sandstone formation, this study presents an analysis of the expected response of these reservoirs to a LSWF. The fractional flow theory is applied to a one-dimension model to have a first idea of the potential of LSWF in an ideal reservoir. Then a generic Forties sandstone numerical reservoir model is used to refine this estimation. A sensitivity analysis is also presented and can be used to predict the potential of various fields based on their properties having the greatest impact on this process.

The conclusions of this study show that the results due to this EOR technique are mainly dependent on the initial wettability of the reservoir and the original connate water salinity. Oil-wet systems with a low connate water salinity can give very favourable results with an incremental oil recovery of about 10% oil initially in place (OIIP) based on a generic Forties sandstone model. However, the potential of LSWF decreases rapidly when conditions are not optimum and water-wet and high salinity reservoirs show very low potential. Reservoirs wettability varies across the Forties formation from water-wet to more oil-wet. Thus interesting results could be obtained with low salinity water-flooding in some cases.

Introduction
The upper Paleocene Forties sandstone formation is located in the south central graben of the North Sea. Some of the biggest North Sea oil fields, for instance Forties, Nelson, Montrose and Pierce, are part of the Forties sandstone, as presented in Figure 1.

Many of these reservoirs have been developed over several decades and are now very mature. Most of them have been produced using water flooding as a secondary recovery technique. However, a non-negligible amount of oil (typically more than 40%) still remains in these reservoirs. Therefore, Low Salinity Water Flooding (LSWF) can represent an interesting Enhanced Oil Recovery (EOR) technique. Used as a tertiary recovery process, a significant incremental oil recovery may be achieved and for a modest investment (Verbeek, 2009).
This paper investigates the potential of LSWF applied to a generic Forties sandstone reservoir by using first fractional flow theory and then numerical simulations on a representative sector model.

The first effects of LSWF were observed at the end of the 1960’s (Bernard, 1967) in cores containing clay. Later, many similar experiments have been carried out using cores from other formations (Jadhunandan and Morrow, 1995; Tang and Morrow, 1997) and show a change of wettability depending on reservoir conditions and an increase of the oil recovered as the salinity of the flooding water decreased. However, on the other hand Zhang et al. (2007) report that LSWF does not always result in additional recovery.

The mechanism behind this phenomenon is still not well understood. Most of the experiments conducted on cores seem to show a change of wettability toward a more water-wet system (Lager et al., 2006; Ligthem et al., 2009; Lee et al., 2010; Pu et al., 2010). The presence of clay (kaolinite, smectite, illite etc.) also seems to play a role in increasing the oil recovery (Lager et al., 2006). Many theories have been investigated and proposed to explain this effect, such as fines propagation (Thyne et al., 2011), mineral dissolution (Pu et al., 2010), wettability alteration (Alotaibi, 2010), pH effects (Austad, 2010), pressure change (Pu et al., 2010), ion exchange (Lee et al., 2010) and decrease of relative permeability (Webb et al., 2008). The recovery increase has then been observed on single well pilots (Mc Guire et al., 2005) and at the field scale (Lager et al., 2008).

Fractional flow theory was first applied to EOR by Pope (1980), but only years later to LSWF (Triphati et al., 2007). The first models to be applied numerically simulate this effect were based only on a variation of the relative permeability with the salinity (Jerauld et al., 2006), whereas more recent software is able to simulate ion exchanges. Field scale simulations are still rare.

**Low salinity water flooding mechanisms**

**Theoretical mechanisms.** Even if the effect of LSWF has been demonstrated in laboratory experiments on cores and at well and field scales, the mechanisms explaining this effect are not well understood. Seven theories have been proposed.

- **Osmosis mechanism** (Buckley, 2009): Clays separate high and low salinity brines, acting as a semi-permeable membrane. A pressure drop is created by the difference of salinity between brine and fresh water, enhancing the water drive.
- **Clay particles movement** (Tang et al., 1999): Clay or other mixed-wet fines detach from the rock surface during low salinity water flooding, exposing a more water-wet surface. Also, these fines may block preferential paths and force injected water to flood new pore spaces.
- **Alkaline flooding behaviour** (Buckley, 2009): An in-situ saponification occurs with certain compounds of oil, leading to a reduction of the interfacial tension between water and oil, and reducing the residual oil saturation.
- **Mineral dissolution** (Pu et al., 2010): Low salinity water enables anhydrites to be dissolved. This dissolution decreases the pH, thus changes the wettability of the reservoir toward a water-wet system.
- **Multicomponent Ion Exchange (MIE)** (Lager et al, 2006; Ligthem et al., 2009; Lee et al., 2010; Nasralla et al., 2012): Ca²⁺ ions will replace bound charged organic compounds of oil that are initially fixed on clay molecules, leading to a more water-wet system.
- **pH driven** (Austad et al., 2010; Nasralla et al., 2012): pH change would be the origin of cation exchange capacity of clay, controlling the reservoir wettability.
From the literature and all the experiments that have been done on low salinity water flooding, it is possible to see what reservoir characteristics might define a potential candidate for LSWF. Six parameters appear to play a significant role in the success of a LSWF implementation. These parameters are summarised in Table 1, including a correlation factor, estimated from the recurrence of this particular parameter influence in studies, and references.

Table 1: Indicators of low salinity water flooding key parameters and their correlations from experiments.

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Correlation</th>
<th>References</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clay content of formation in 7%-30% range</td>
<td>High</td>
<td>Austad et al., 2010; Lee et al., 2010</td>
</tr>
<tr>
<td>Presence of polar compounds in crude oil (medium to high total acid or base number)</td>
<td>High</td>
<td>Lee et al., 2010, 2011; Wickramathilaka et al., 2011; Aloabi et al., 2010; Rivet et al., 2010</td>
</tr>
<tr>
<td>Initial oil or mixed wettability state</td>
<td>Medium</td>
<td>Hadia et al., 2011; Shiran et al., 2012</td>
</tr>
<tr>
<td>Presence of soluble minerals in formation</td>
<td>Medium</td>
<td>Aloabi et al., 2010; Pu et al., 2010; Thyne et al., 2011</td>
</tr>
<tr>
<td>Formation water pH&lt;7</td>
<td>Medium</td>
<td>Reinholdtussen et al., 2011</td>
</tr>
<tr>
<td>Moderate reservoir temperature</td>
<td>Low</td>
<td>Rezaeidoust et al., 2010</td>
</tr>
</tbody>
</table>

When it is observed, the overall effect of low salinity water flooding is a change of relative permeability curves towards a more water-wet system. It produces two main effects, first it increases the speed of recovery by changing the oil/water relative permeabilities and secondly it increases the ultimate recovery by decreasing the residual oil saturation ($S_{or}$). From this it is then possible to model a LSWF in a reservoir based on the high and low salinity relative permeability curves.

Field data and analogue response. The Forties sandstone formation is made up of different facies that will be simplified to two major ones in our model: channels and overbanks. The relative permeability curves used were taken from Hughes et al., 1990. The original curves have been approximated using Corey exponents. Then a series of three relative permeability curves have been derived by varying the Corey exponents in order to obtain a model of a weakly water-wet system, a mixed-wet system and an oil-wet system. Figure 2 shows the oil/water relative permeability curves for channels facies for a water-wet system, modelled using Corey exponents.

For overbanks, the Corey exponents have been assumed to be the same but the connate water saturation is much higher, up to 40% and the residual oil saturation is equal to the $S_{or}$ value for channel facies.

![Fig. 2: Original Oil / Water relative permeability curves measured for channels facies from (Hughes, 1990) and the model created for a weakly water-system, using Corey exponents.](image)

Usually to determine the potential of LSWF in a field, core plugs from the reservoir are taken and sent to a laboratory to then be flooded with low salinity water in conditions as close to reality as possible. In Forties sandstone
fields, no data regarding low salinity laboratory tests is available. Thus an analogue unit has been identified based on the key parameters of LSWF. This analogue unit is Prudhoe Bay, a reservoir located on the Alaska’s North Slope and well documented for LSWF techniques (McGuire et al., 2005; Jerauld et al., 2005).

Key parameters of low salinity water flooding on the two fields are summarised in Table 2.

**Table 2: Low salinity water flooding key parameters comparison in Prudhoe Bay and the Forties formation.**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Prudhoe Bay</th>
<th>Sources</th>
<th>Forties Formation</th>
<th>Sources</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clay content of formation in %</td>
<td>Kaolinite predominant 9 to 45% 20% average</td>
<td>Almond et al., 1990</td>
<td>12 to 30% 19% average</td>
<td>Hughes et al., 1990; Davis et al., 2009</td>
</tr>
<tr>
<td>Presence of polar compounds in crude oil (medium to high total acid number)</td>
<td>Acid number: 0.12 mg KOH/g</td>
<td>Buckley, 1998</td>
<td>0.09 mg KOH/g</td>
<td>Chevron, 2013; BP, 2013</td>
</tr>
<tr>
<td>Initial oil or mixed wettability state</td>
<td>Mixed-wet reservoir</td>
<td>Jerauld et al., 1997</td>
<td>Mixed-wet to water-wet reservoir</td>
<td>Hughes et al., 1990; Turran et al., 2002</td>
</tr>
<tr>
<td>Presence of soluble minerals in formation</td>
<td>97 to 247 ppm of Ca 25 to 156 ppm of Mg</td>
<td>McGuire et al., 2005</td>
<td>3110 ppm of Ca 480 ppm of Mg</td>
<td>Mitchell et al., 1980</td>
</tr>
<tr>
<td>Formation water pH&lt;7</td>
<td>7 to 8</td>
<td>McGuire et al., 2005</td>
<td>5.6</td>
<td>Mitchell et al., 1980</td>
</tr>
<tr>
<td>Moderate reservoir temperature</td>
<td>99°C (210°F)</td>
<td>McGuire et al., 2005</td>
<td>76°C (169°F) 96°C (205°F)</td>
<td>Brand et al., 1996; Hughes et al., 1990</td>
</tr>
</tbody>
</table>

From this comparison, we can see that reservoirs from the Forties formation are close to Prudhoe Bay in terms of LSWF key parameters. Forties formation reservoirs present better characteristics in terms of the presence of soluble minerals and pH but have a lower concentration of polar compounds in the crude oil by 25%. Only information about acid number is available, no information has been found regarding the base number. Prudhoe Bay is mixed-wet, similar to some parts of the Forties sandstone formation.

The amount of polar compounds in the crude oil seems to be an important factor in the LSWF potential. Researches have been conducted to find a correlation between different parameters influencing the LSWF potential and their effect on recovery (Aladasani et al., 2012) but no clear trend has been defined. In order to be conservative on the LSWF effect on the Forties formation, the assumption is taken that the S\text{or} reduction would be about 25%. From what has been observed in laboratory core tests, (Hadja et al., 2011; Shiran et al., 2012) we can expect the highest S\text{or} reduction for an oil-wet reservoir, and then decreasing as the system comes closer to a water-wet state.

The final state of the reservoir after LSWF is close to a water-wet system when the process is fully effective. In order to represent the LSWF response in terms of relative permeability, the assumption has been made that the low salinity relative permeability curves would be close to data from Hughes (1990), known to be a water-wet reservoir in the Forties formation. The S\text{or} for the different curves will then vary linearly from the more oil-wet to the more water-wet system. The Forties field S\text{or} is about 20% (Hughes et al., 1990).

The different parameters of these relative permeability curves are summarised in the Table 3 and relative permeability sets are presented in Figure 3.

**Table 3: Parameters determining relative permeability curves.**

<table>
<thead>
<tr>
<th>Wettability</th>
<th>S\text{or} High Salinity</th>
<th>S\text{or} Low Salinity</th>
<th>Fractional change in S\text{or}</th>
</tr>
</thead>
<tbody>
<tr>
<td>oil wet</td>
<td>0.2</td>
<td>0.162</td>
<td>19%</td>
</tr>
<tr>
<td>mixed wet</td>
<td>0.185</td>
<td>0.148</td>
<td>17%</td>
</tr>
<tr>
<td>weakly water wet</td>
<td>0.17</td>
<td>0.1445</td>
<td>15%</td>
</tr>
</tbody>
</table>
Fig. 3: Different wettability systems relative permeability curves for high and low salinity for channels facies derived by varying Corey exponents.

The same process has been applied to overbank facies and the relative permeability curves are presented in Appendix B.

**Analytical study – Buckley-Leverett theory.** Using fractional flow theory an analytical model can be created. Main assumptions in this model are one-dimension flow in a homogeneous, isotropic, isothermal porous medium. Fluids are incompressible and gravity and fingering are not taken in account. Such an ideal reservoir is far from representing the reality but, it is possible to have a general estimation of the potential of the LSWF technique. The reservoir model has an injector well on its origin and a producer on its end. On any point, initially the water saturation is equal to the connate water saturation, which means that the fractional flow is equal to \(1-S_w\). Water injection starts at \(t=0\) with a composition of 100% water. The mass balance is applied to the reservoir model enabling to predict the production. Using Buckley-Leverett analysis, it is possible to plot the fractional flow curves for the two relative permeabilities (high salinity and low salinity) using equation (1).

Figure 4 represents the fractional flow curves for the oil-wet system. The LSWF potential clearly appears. The distance between the two curves indicates a difference of shock front speed and thus the possibility to create an oil bank to increase the speed of recovery. The difference in \(S_w\) also indicates a higher ultimate recovery. These elements can be seen in Figure 5, representing the saturation profile. In comparison, the weakly water-wet system, shown in Appendix C, presents a lower potential since the two fractional flow curves are closer one to another and the oil bank is much more reduced.

\[
f_w = \frac{\mu_o}{\mu_w} \frac{k_{rw}}{k_{row}}
\]

**Equation 1.1**

\(f_w\) Water fractional flow
\(k_{rw}\) Relative permeability to water
\(k_{row}\) Relative permeability to water
\(\mu_w\) Water dynamic viscosity (cp)
\(\mu_o\) Oil dynamic viscosity (cp)
The recovery acceleration and additional recovery are more visible when plotting pore volume injected (PVI) versus pore volume recovered (PVR) (Figure 6). Figure 6 shows the PVI vs PVR plot for the channels facies using the oil-wet relative permeability curves set. As the pore volume recovered curve keeps increasing with pore volume injected, the start of LSWF flooding implementation seems to play a role in the potential of this technique. Indeed, the longer high salinity water is injected, the more oil is produced and thus less is left for LSWF. The first rapid increase of PVR in the early time of low salinity water injection is due to the production of the oil bank until the low salinity water breakthrough. The curve then increases less rapidly since the oil cut is less important until the ultimate recovery is reached. This part corresponds to the left part of the Figure 5.

The low salinity water flooding enables a faster oil recovery because the wettability of the reservoir moves toward a more water-wet system. Thus water becomes the wetting fluid and will be in contact with reservoir rock. Oil will be able to flow in the centre of the pores and the relative permeability to oil will increase. More details about the Buckley-Leverett solution can be find in Tripathi (2007) and Pope (1980).

Besides, the $S_w$ reduction will increase the ultimate recovery and enable the production of additional oil even after a long time of HSWF.
Once again, as presented in Appendix C, the impact of LSWF is much lower for the weakly water-wet system but also on the overbanks facies where the oil saturation is initially lower than in the channels facies.

This analysis is only a 1D simulation and based on the assumption of a homogeneous reservoir. It cannot be used to predict the additional recovery due to LSWF. However, it shows a potential of performing such EOR technique on a reservoir showing the same characteristics as the Forties sandstone formation reservoirs.

**Numerical simulation**

To analyse and quantify the potential of the low salinity water flooding in the Forties sandstone formation, a numerical simulation must be done using a representative geological model.

In order to simulate low salinity water flooding on a reservoir model, the software STARS™ from CMG™ has been used. The LSWF simulation is based on interpolation between two sets of relative permeability curves. The model used is very close to the one published by Jerauld et al. (2006). Sodium, chloride or salt is considered as a separate compound in the aqueous phase. The concentration in each cell is calculated and used to define which relative permeability curve has to be used.

If the salt content in a cell is above an upper threshold value defined by the user, then the high salinity relative permeability curves are used. If the salt content is below a lower threshold value defined by the user, then the low salinity relative permeability curves are used. If the salt content is in between the two thresholds, then the software does a linear interpolation between the two curves.

The value of the upper threshold is usually in the range of 5000 to 3000 ppm and the lower threshold is usually between 1000 and 0 ppm (Jerauld et al., 2006). Jerauld (2006) demonstrated that the grid resolution has an impact on the accuracy of the simulation. Indeed, by comparing a fine model and a coarse model, it has been proven that in order to compensate the numerical dispersion in the coarse model, salinity thresholds have to be increased in order to get the same result as the fine model.

The model used in this study is a coarse grid model. The grid resolution brings a high numerical dispersion minimising the low salinity flooding effect. In order to compensate for this effect, thresholds have been increased to a 2000 ppm for the lower one and 20,000 ppm for the upper one. This range is based on the studies and observations of Jerauld et al., 2006.

**Reservoir model description**

**Static model.** The 3D static model used in this study is an un-faulted structural model populated with facies and properties based on published data for the Forties formation. The main hydrocarbon bearing reservoir in the cluster is the Forties sandstone member of Palaeocene origin. The reservoir is characterized by laterally-extensive submarine fan deposits. Localised thick channelling trending NW-SE is widespread.

Thick sand bodies are separated by laterally-extensive mudstone. The facies distribution has been simplified to consist of channel and overbanks. It has been assumed that each facies represents 50% of the distribution. The model dimensions are 7000ft × 7000ft to represent the modelling area of a sector model. Reservoir properties are also based on published data for the Forties sandstone formation field (Hogg et al., 2003; Ahmadi et al., 2003) and are presented in Table 4.

**Table 4 : Static model rock properties.**

<table>
<thead>
<tr>
<th>Rock properties</th>
<th>Channel</th>
<th>Overbanks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Facies distribution (in % GRV)</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>Width – thickness ratio</td>
<td>1:10 – 1:40</td>
<td>N/A</td>
</tr>
<tr>
<td>Net to gross – range (average)</td>
<td>0.6 – 1 (0.3)</td>
<td>0 – 0.5 (0.3)</td>
</tr>
<tr>
<td>Porosity – range (average)</td>
<td>0.22 - 0.3 (0.28)</td>
<td>0.03 - 0.22 (0.12)</td>
</tr>
<tr>
<td>Permeability – range (average) (mD)</td>
<td>40 - 2000</td>
<td>0.2 – 40</td>
</tr>
</tbody>
</table>

The inner part of the model was given a dip of 0.57 degree and the outer part a dip of 7.1 degree based on average information from the a top structure map for a typical Forties sandstone field.
PVT data. A black oil model has been used along with an additional component to represent the salts in the aqueous phase. Parameters used in the numerical are presented in Table 5.

Table 5 : PVT Data used in the numerical model (Brand et al., 1996; Hughes et al., 1990).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir temperature (°C/°F)</td>
<td>96 / 204.8</td>
</tr>
<tr>
<td>Reservoir pressure @ 8025 ft (bara/psia)</td>
<td>241.3 / 3,500</td>
</tr>
<tr>
<td>Oil viscosity @ reservoir conditions (cp)</td>
<td>0.8</td>
</tr>
<tr>
<td>Oil gravity (°API)</td>
<td>37</td>
</tr>
<tr>
<td>Oil density @ reservoir conditions (kg/m³/lb/ft³)</td>
<td>673 / 42</td>
</tr>
<tr>
<td>Connate water salinity (ppm of Cl⁻)</td>
<td>55,000</td>
</tr>
<tr>
<td>Connate water viscosity @ reservoir conditions (cp)</td>
<td>0.47</td>
</tr>
<tr>
<td>Oil compressibility @ reservoir conditions (Pa⁻¹/psi⁻¹)</td>
<td>4.41×10⁻⁵ / 6.4×10⁻⁶</td>
</tr>
<tr>
<td>Water compressibility @ reservoir conditions (Pa⁻¹/psi⁻¹)</td>
<td>2.07×10⁻³ / 3.0×10⁻⁶</td>
</tr>
<tr>
<td>Estimated rock compressibility (Pa⁻¹/psi⁻¹)</td>
<td>2.76×10⁻² / 4.0×10⁻⁶</td>
</tr>
</tbody>
</table>

Initialisation. The top of the reservoir is 8025 ft True Vertical Depth Subsea (TVDss). The model was initialized with an Oil Water Contact (OWC) at 8250 ft TVDss and a pressure of 3500 psia at a reference depth of 8025 ft TVDss. The pore volume and fluid in place are shown in the Table 6.

Table 6 : Numerical model volume statistics.

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Pore volume (MMrüb) (including aquifer)</td>
<td>15,540</td>
</tr>
<tr>
<td>Hydrocarbon pore volume (MMrüb)</td>
<td>146.1</td>
</tr>
</tbody>
</table>

The model includes an aquifer. The aquifer support is known to be very strong in the Forties sandstone formation fields (Brand et al., 1996). It is responsible for half the production in our model. The aquifer influx is from the outer cells of the model on the whole thickness of the reservoir which have been increased in size by a factor of 2000 to represent the volume of the connected aquifer.
**Well placement and constraints.** The model includes five wells; three producers and two injectors. Injectors are located at the periphery of the model to inject water at the inner edge of the existing aquifer. One producer has been placed in a mid-flank location and the remaining two in up dip locations. The precise locations were chosen to maximise the $k \times h$ in the well, i.e. connection with the channel bodies.

At the point of injection it is important not to exceed the pressure that would fracture the cap rock. Based on Edward et al., 1998, the pressure at the point of injection should be limited to 5500 psia. In order for the pressure not to drop below the bubble point in the reservoir, the pressure at the producers has been limited to 2500 psia.

**Experimental design.** Reservoir properties vary across the formation. In order to investigate as accurately as possible the potential of low salinity water flooding in the whole Forties formation, a series of simulations were run to identify the impact of each factor on the field production and quantify it. A full factorial experimental design is used to get the most reliable analysis of the situation. However, due to the high number of simulations required and time constraints, the parameters have been chosen carefully to best understand the potential of this EOR process in these fields.

The first parameter studied will be the initial wettability of the reservoir based on the relative permeability curves sets generated earlier. Three systems will be used, oil-wet, mixed-wet and weak water-wet. Very few data are available but this range should be large enough to investigate the expected range of wettability that can be observed in the Forties formation.

The oil viscosity and initial connate water salinity are the PVT parameters that vary the most across the different formation reservoirs and their impact on production is important. Therefore, a representative range of values has been used (Hughes et al., 1990; Brand et al., 1996; Alusta et al., 2012).

As this study is about Low Salinity Water Flooding used as a tertiary recovery technique in mature water flooded fields, the starting of low salinity water injection has been studied depending on the watercut of the field operated using high salinity water flooding as a secondary recovery technique. A range of high watercuts has been used to represent the late implementation of the EOR technique: 90%, 91%, 93%, 94% and 95%. (Enquest, 2011; Kosztin et al., 2012).

The last parameter to vary is the injection rate, assumed constant during high salinity flooding and low salinity flooding. It is based on the range of rates observed in the North Sea. The first value of 6% of HCPV per year represents a low to average value whereas the second value of 9% represents a high value.

The Table 7 represents the different ranges of each factor. The total number of runs is 300.

### Table 7: Sensitivity analysis parameters and ranges.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Reservoir Wettability</td>
<td>Oil-wet / Mixed-wet / Weak water-wet</td>
</tr>
<tr>
<td>Oil Viscosity (cp)</td>
<td>0.4 / 0.8</td>
</tr>
<tr>
<td>Initial Connate Water Salinity (ppm)</td>
<td>55,000 / 75,000 / 95,000 / 115,000 / 135,000</td>
</tr>
<tr>
<td>Start Point of LSWF (value of water cut after HSWF) (%)</td>
<td>90 / 91 / 93 / 94 / 95</td>
</tr>
<tr>
<td>Injection Rate (% of HCPV/ Year)</td>
<td>6% / 9%</td>
</tr>
</tbody>
</table>

**Results and analysis**

For all cases, the incremental oil recovery is calculated by taking the difference between the cumulative oil production after 4.5 HCPV of LS water injected and the equivalent cumulative oil production using HSWF. This value is then normalised by the OIIP.

An analysis of variance has been done on all the results of the different simulations. The variation in incremental recovery is mainly due to the initial wettability of the system and to the connate water salinity as presented on the Tornado chart in Figure 9. This Tornado chart is based on a base case with the following parameters: Mixed-wet system, 55,000 ppm connate water salinity, start of LS water injection at a water cut of 93%, injection rate of 6% HCPV per year, oil viscosity of 0.8cp.
Fig. 9: Tornado chart presenting the sensitivity of different parameters on the incremental oil recovery as a percentage of the oil initially in place.

Table 8 summarises the best case and worst case scenario parameters in terms of incremental oil recovery.

Table 8: Parameters and results of the best and worst case scenarios.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Best Case Scenario</th>
<th>Worst Case Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial reservoir wettability</td>
<td>Oil-wet</td>
<td>Weak water-wet</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>0.4 cp</td>
<td>0.8 cp</td>
</tr>
<tr>
<td>Initial connate water salinity</td>
<td>55,000 ppm</td>
<td>135,000 ppm</td>
</tr>
<tr>
<td>Start point of LSWF</td>
<td>90% water cut</td>
<td>95% water cut</td>
</tr>
<tr>
<td>Injection rate</td>
<td>9% of HCPV per year</td>
<td>6% of HCPV per year</td>
</tr>
<tr>
<td>Incremental oil recovery (%OIIP)</td>
<td>9.91%</td>
<td>1.04%</td>
</tr>
</tbody>
</table>

The connate water salinity has clearly a major impact on the incremental oil recovery for all wettability systems. Indeed, in order to see a “low salinity effect” on the reservoir, the connate water salinity has to drop below the upper salinity threshold. Thus the more salty connate water initially is, the more dilution is required to see an impact on the recovery. The starting point of LSWF also has an impact on the incremental oil recovery but much smaller. The effect of oil viscosity is negligible in the range of value considered, but a higher oil viscosity will increase the fingering effect and thus decrease the sweep efficiency. The recovery will be lower and LSWF may no longer be an interesting EOR process.

Figure 10 shows the evolution of incremental oil recovery versus the two major parameters for each wettability system based on a Gaussian correlation. The variations are not linear and can be approximated by a combination of exponential and polynomial functions on both parameters.
The injection rate has a much lower impact on the incremental oil recovery and the oil viscosity has almost no impact. For these parameters, their behaviour can be approximated by a linear function as shown in Figure 31 in Appendix D.

In general, the incremental oil recovery seems to stabilise after 4 to 4.5 HCPV of low salinity water injected as shown on Figure 11 and 12. But the time and volume of injection water required in order to reach this value is likely to make the project uneconomic. Usually the pore volume of water injected during a secondary recovery process is in the rage of 1.5 to 2 PVI (Terrado et al., 2007; Sheng, 2013). In order to define the time after which the injection is no longer economically viable, the produced oil rate will have to be balanced with the cost of operations and the cost of maintenance of surface installations. This cost can increase rapidly as equipment wears out with time and have usually not been designed for such a long period of usage. Each field will thus have a different duration of low salinity water injection and a different achievable incremental oil recovery.

Fig. 10: Surface plot of incremental oil recovery vs connate water salinity and start point of LSWF.

Fig. 11: LSWF vs HSWF comparison for the best case scenario.
As presented in Figure 12 showing the incremental oil recovery versus pore volume of low salinity water injected, the incremental oil recovery is not very significant before one pore volume of low salinity water injected. Nevertheless the “low salinity effect” doesn’t affect the entire reservoir. The low salinity injected water is subject to more dispersion in high salinity connate water before the lower salinity threshold (2,000 ppm) is obtained. Below this threshold, the low salinity relative permeability curves are applied to the considered cell. Thus the maximum oil is recovered.

As shown on Figure 13, for the best case scenario, after 4.5 HCPV of low salinity water has been injected, 84% of the reservoir is below the upper salinity threshold and thus see a “low salinity effect”. But only 18% of the reservoir is below the lower salinity threshold and therefore sees a maximum “low salinity effect”.

As shown on Figure 14, representing the same scenario but with a connate water salinity of 135,000 ppm (2.45 times higher), the “low salinity effect” is significantly reduced because more dilution is required from the higher connate salinity to reach the threshold salinities.

---

Fig. 12: Incremental oil recovery as a function of pore volume injected for the best case scenario.

Fig. 13: Cells below the upper and lower salinity thresholds (best case scenario / connate water salinity 55,000 ppm) after 4.5 pore volume of low salinity water injected.
Fig. 14: Cells below the upper and lower salinity thresholds (worst case scenario / connate water salinity 135,000 ppm) after 4.5 pore volume of low salinity water injected.

Conclusions
LSWF simulations were performed on a generic Forties sandstone model in order to investigate the potential of such an EOR technique as a tertiary process in Forties formation reservoirs.

A sensitivity analysis has then been done on major parameters that vary from one reservoir to another across the formation.

The simulations indicate that Forties sandstone formation reservoirs may have low salinity water flooding potential with expected incremental oil recovery varying from about 1% OIIP for the worst case scenario to about 10% OIIP for the best case scenario.

The response of this EOR process is mainly dependent on the initial wettability of the system and the original connate water salinity.

The ideal candidate would be an oil-wet reservoir with low connate water salinity. For Forties formation reservoirs already extensively water flooded and with a proven water-wet wettability, the potential of low salinity water flooding is low. It can be more interesting for a mixed-wet reservoir but is still more modest than the best case scenario of this study.

Recommendations for further study
The present study is based on analogue response to low salinity water flooding on the Prudhoe Bay field. Even if the key parameters related to this EOR process are very close in both cases, there is still a large uncertainty on the LSWF behaviour in Forties sandstone formation reservoirs. Core flood experiments and single well tracer tests should be carried on to determine the actual effect of this technique at real field conditions.

Moreover, in this paper no different geological realizations have been studied since the model used is a generic model of the Forties sandstone formation. Nevertheless in reality, reservoirs are different depending on their location in the formation. Variations in geology could be studied and modelled to get a more realistic estimation of the LSWF potential in each field.
**Nomenclature**

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>API</td>
<td>American Petroleum Institute</td>
</tr>
<tr>
<td>Ca</td>
<td>Calcium</td>
</tr>
<tr>
<td>CH</td>
<td>Channels Facies</td>
</tr>
<tr>
<td>EOR</td>
<td>Enhance Oil Recovery</td>
</tr>
<tr>
<td>GRV</td>
<td>Gross Rock Volume (m³)</td>
</tr>
<tr>
<td>HCPV</td>
<td>Hydrocarbon Pore Volume (MMrb)</td>
</tr>
<tr>
<td>HS</td>
<td>High Salinity</td>
</tr>
<tr>
<td>HSWF</td>
<td>High Salinity Water Flooding</td>
</tr>
<tr>
<td>KOH</td>
<td>Potassium Hydroxide</td>
</tr>
<tr>
<td>krow</td>
<td>Oil relative permeability</td>
</tr>
<tr>
<td>kw</td>
<td>Water relative permeability</td>
</tr>
<tr>
<td>LS</td>
<td>Low Salinity</td>
</tr>
<tr>
<td>LSWF</td>
<td>Low salinity Water Flooding</td>
</tr>
<tr>
<td>Mg</td>
<td>Magnesium</td>
</tr>
<tr>
<td>NW-SE</td>
<td>North West - South East</td>
</tr>
<tr>
<td>OIP</td>
<td>Oil Initially In Place (MMrb)</td>
</tr>
<tr>
<td>OV</td>
<td>Overbank Facies</td>
</tr>
<tr>
<td>OWC</td>
<td>Oil Water Contact</td>
</tr>
<tr>
<td>pH</td>
<td>Potential of Hydrogen</td>
</tr>
<tr>
<td>PVI</td>
<td>Pore Volume Injected</td>
</tr>
<tr>
<td>PVR</td>
<td>Pore Volume Recovered</td>
</tr>
<tr>
<td>PVT</td>
<td>Pressure Volume Temperature</td>
</tr>
<tr>
<td>Sw</td>
<td>Residual oil saturation</td>
</tr>
<tr>
<td>SPE</td>
<td>Society of Petroleum Engineers</td>
</tr>
<tr>
<td>Sw</td>
<td>Water saturation</td>
</tr>
<tr>
<td>Swc</td>
<td>Connate Water Saturation</td>
</tr>
<tr>
<td>TVDss</td>
<td>True Vertical Depth subsea</td>
</tr>
</tbody>
</table>

**References**

### A. Critical Literature Review

<table>
<thead>
<tr>
<th>Paper number</th>
<th>Year</th>
<th>Title</th>
<th>Authors</th>
<th>Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPE 1725</td>
<td>1967</td>
<td>“Effect of Floodwater Salinity on Recovery Of Oil from Cores Containing Clays”</td>
<td>Bernard, George G., Union Oil Research Center</td>
<td>First to observe an additional oil recovery due to fresh water flooding on cores</td>
</tr>
<tr>
<td>SPE 22597</td>
<td>1995</td>
<td>“Effect of Wettability on Waterflood Recovery for Crude-Oil/Brine/Rock Systems”</td>
<td>P.P. Jadhunandan, SPE, Inst. Teknologi Bandung; N.R. Morrow, SPE, New Mexico Petroleum Recovery Research Center</td>
<td>First to describe a change in production due to wettability, using water flooding on cores</td>
</tr>
<tr>
<td>SPE 102239</td>
<td>2006</td>
<td>“Modeling Low-Salinity Waterflooding”</td>
<td>Gary R. Jerauld, SPE, C.Y. Lin, Kevin J. Webb, SPE, and Jim C. Seccombe, SPE, BP</td>
<td>First to numerically model the LSWF by interpolation between two relative permeability curves</td>
</tr>
<tr>
<td>SPE 109965</td>
<td>2007</td>
<td>“Low-Salinity Waterflooding to Improve Oil Recovery-Historical Field Evidence”</td>
<td>Eric P. Robertson, Idaho National Laboratory</td>
<td>First to demonstrate the effect of LSWF on a field scale due to accidental fresh water injection</td>
</tr>
<tr>
<td>SPE 113976</td>
<td>2008</td>
<td>“LoSal Enhanced Oil Recovery: Evidence of Enhanced Oil Recovery at the Reservoir Scale”</td>
<td>A. Lager, K.J. Webb, and I.R. Collins, BP, EPTG, Pushing Reservoir Limits, Sunbury, UK, and D.M. Richmond, BP, BP Exploration (Alaska), Anchorage, AK, USA</td>
<td>First to demonstrate the effect of LSWF on a field scale due to voluntary low salinity injection</td>
</tr>
<tr>
<td>SPE 134459</td>
<td>2010</td>
<td>“A Discussion of the Low-Salinity EOR Potential for a North Sea Sandstone Field”</td>
<td>Alireza RezaeiDoust, Tina Puntervold, and Tor Austad, University of Stavanger</td>
<td>First to discuss the potential of LSWF in a North Sea sandstone reservoir</td>
</tr>
<tr>
<td>SPE 147375</td>
<td>2011</td>
<td>“Comparison of Oil Recovery by Low Salinity Waterflooding in Secondary and Tertiary Recovery Modes”</td>
<td>Pubudu Gamage and Geoffrey Thyne, Enhanced Oil Recovery Institute, University of Wyoming</td>
<td>First to compare the LSWF as a secondary and tertiary recovery process</td>
</tr>
<tr>
<td>SPE 161750</td>
<td>2012</td>
<td>“Low Salinity Enhanced Oil Recovery - Laboratory to Day One Field Implementation - LoSal EOR into the Clair Ridge Project”</td>
<td>Enis Robbana, Todd Buikema, Chris Mair, Dale Williams, Dave Mercer, Kevin Webb, Aubrey Hewson, and Chris Reddick, BP</td>
<td>First full field offshore project using LSWF</td>
</tr>
</tbody>
</table>
SPE 1725 (1967)

Effect of Floodwater Salinity on Recovery of Oil from Cores Containing Clays

Authors: Bernard, George G., Union Oil Research Centre

Contribution to the understanding of the LSWF process:
Not much because this paper just describe a difference of oil cumulative production during high salinity and low salinity water flooding.

Objective of the paper:
To compare high salinity water flooding and low salinity water flooding in terms of oil recovery

Methodology used:
Core samples containing clay have been used. They have been initially saturated with water, then with oil to reduce the water saturation to residual water saturation. Once the cores are saturated with oil, they are either flooded with brine or fresh water and the oil recovery is measured. Cores are flushed either at constant rate or constant pressure.

Conclusions reached:
1- When hydratable clay are present, a fresh floodwater can produce more oil than brine
2- This process can lower the permeability and result in a relatively high pressure drop

Comments:
Clay containing cores were synthetic core made of from sand Montmorillonite and Lucite. Clay swelling might have been more important.
Effect of Wettability on Waterflood Recovery for Crude-Oil/Brine/Rock Systems

Authors: P.P. Jadhunandan, SPE, Inst. Teknologi Bandung; N.R. Morrow, SPE, New Mexico Petroleum Recovery Research Center

Contribution to the understanding of the LSWF process:
Medium. This paper presents a large range of core flood test comparing different initial wettabilities and oil.

Objective of the paper:
Demonstrate the effect of wettability on recovery using waterflooding.

Methodology used:
Several cores from the Berea sandstone have been prepared, saturated with water and oil and then aged at high temperature for different durations in order to change the wettability of the core. Then cores have been flooded with brine to compare the oil production. Wettability has been measured after flooding using the Amott method.

Conclusions reached:
- Oil recovery by waterflooding increased with change in wettability from strongly water to a maximum at close to neutral wettability.

Comments:
No consideration about the salinity of flooding water
SPE 93903 (2005)

Low Salinity Oil Recovery: An Exciting New EOR Opportunity for Alaska’s North Slope


Contribution to the quantification of the impact of LSWF:
Good. This describe core flood and single well tracers leading to proven production increase.

Objective of the paper:
Describe tests and experiments lead on the Alaska’s North Slope.

Methodology used:
Field cores have been used to compare low salinity and high salinity flooding in field conditions. Also single well tracers have been used to evaluate the efficiency of this process in real conditions. Prudhoe Bay and Endicott fields have been both studies and additional recoveries due to Low Salinity Water Flooding have been observed and measured.

Conclusions reached:
1- Low salinity water flooding creates an increase in oil recovery at core scale and well scale.
2- Incremental recoveries of 6 to 12% are possible in the North Slope

Comments:
Prudhoe Bay field conditions are quite close to the Forties sandstone formation fields in terms of LSWF key parameters.
Modeling Low-Salinity Waterflooding

Authors: Gary R. Jerauld, SPE, C.Y. Lin, Kevin J. Webb, SPE, and Jim C. Seccombe, SPE, BP

Contribution to the LSWF modeling: Major. This paper presents a simple model based on the interpolation between two relative permeability curves, one for low salinity, one for high salinity.

Objective of the paper: Propose a model to simulate low salinity water flooding.

Methodology used: Based on core flood experiments, two relative permeability curves have been defined, one for low salinity water flooding, the other one for high salinity water flooding. Relative permeabilities are believed to be constant above an upper water salinity threshold and below a lower water salinity threshold. In between, a linear interpolation can be done to approximate a relative permeability value. A fine and a coarse model have been built. Salinity threshold have been adjusted on the coarse model to match the fine model results and compensate the numerical dispersion.

Conclusions reached:
- A model of wettability change using two relative permeability curves can be used to simulate low salinity water flooding

Comments: The model is fairly simple but gives very good results, check with real low salinity flooding experiments on core scale.
Low-Salinity Waterflooding to Improve Oil Recovery-Historical Field Evidence

Authors: Eric P. Robertson, Idaho National Laboratory

Contribution to the understanding of the LSWF process:
Medium. This paper describes the effect of low salinity water flooding on fields flooded with water from low salinity aquifer by chance.

Objective of the paper:
To describe the effect of low salinity water flooding based on old fields flooded with low salinity water.

Methodology used:
In the US, oil fields have been flooded using low salinity water from an aquifer. This LSWF happened by chance. Production history has been obtained from public records. In another hand, core flood experiments have been carried on to simulate the production of these fields using either low salinity or high salinity water flooding. A comparison of the two has then been done in order to match the real production with the core flood experiments.

Conclusions reached:
1- Even if it is hard to quantify the improved oil recovery due to LSWF, a trend can be find in historical field data
2- Oil recovery tends to increase as the salinity ratio of waterfloods decreases.

Comments:
Few details are available regarding the geology of the studied fields.
SPE 113976 (2008)

LoSal Enhanced Oil Recovery: Evidence of Enhanced Oil Recovery at the Reservoir Scale

Authors: A. Lager, K.J. Webb, and I.R. Collins, BP, EPTG, Pushing Reservoir Limits, Sunbury, UK, and D.M. Richmond, BP, BP Exploration (Alaska), Anchorage, AK, USA

Contribution to the quantification of the impact of LSWF:
Not much because no precise figures are given but just a trend has been identified on the reservoir scale.

Objective of the paper:
Identify an enhanced oil recovery at reservoir scale due to LSWF.

Methodology used:
Single well tests and long duration low salinity water flooding have been performed in Alaska’s North Slope reservoirs. Oil production and produced water composition have been recorded and analysed, showing an enhanced recovery and a dramatic change in water composition. The timing of the effect had been predicted using a numerical model.

Conclusions reached:
1- A measurable drop in water/oil ratio was observed and the production doubled during 12 months of production
2- No pore plugging or clay swelling has been observed

Comments:
No numerical values are given regarding the additional oil recovered. Few data about the fields are specified.
SPE 134459 (2010)

A Discussion of the Low-Salinity EOR Potential for a North Sea Sandstone Field

Authors: Alireza RezaeiDoust, Tina Puntervold, and Tor Austad, University of Stavanger

Contribution to the LSWF potential evaluation:
Fair. Different LSWF key parameters effect have been studied on many core flood experiments

Objective of the paper:
To study the potential of LSWF used as a tertiary process in a North Sea Field (Varg field)

Methodology used:
Many cores from the field have been used to perform LSWF as a tertiary process. Key parameters have been measure on cores and on oil as well as on connate water and flooding water.
These parameters are:

3- Crude acidic number
4- Clay content
5- Reservoir temperature
6- Formation water salinity
7- Formation water Ca\(^{2+}\) and Mg\(^{2+}\) concentration

Cores have been aged at different temperatures and then flooded with brine and low salinity water.
The oil production has been recovered and compared.

Conclusions reached:
1- For an aging at a low temperature (60°C) and high temperature (130°C), no additional recovery has been observed.
2- For an aging temperature of 90°C, an additional recovery of about 6% of OIIP has been observed.
3- A decrease of the LSWF effect has been observed when decreasing the clay content of the core.

Comments:
No information on the initial wettabilities of the cores.
Comparison of Oil Recovery by Low Salinity Waterflooding in Secondary and Tertiary Recovery Modes

Authors: Pubudu Gamage and Geoffrey Thyne, Enhanced Oil Recovery Institute, University of Wyoming

Contribution to the quantification of the impact of LSWF:
Good. The paper presents a clear and reliable comparison process, with numerical figures.

Objective of the paper:
Compare the effect of the LSWF used as a secondary and tertiary technique.

Methodology used:
Core from the Berea sandstone and Minnelusa reservoir have been used with two types of Minnelusa crude oil. For the secondary process, oil saturated cores have been flooded directly with low salinity water. For the tertiary process, oil saturated cores have been flooded first with brine and in a second time with low salinity water. Oil recovery has been recorded as well as pH and conductivity.

Conclusions reached:
1- Small increase in pH have been observed after LSWF
2- Secondary experiments produced more oil than tertiary experiments

Comments:
There is almost no information on the clay content of cores samples or on any other LSWF key parameters.
SPE 161750 (2012)

Low Salinity Enhanced Oil Recovery - Laboratory to Day One Field Implementation - LoSal EOR into the Clair Ridge Project

Authors: Enis Robbana, Todd Buikema, Chris Mair, Dale Williams, Dave Mercer, Kevin Webb, Aubrey Hewson, and Chris Reddick, BP

Contribution to the LSWF potential evaluation:
Fair. Little precise information is actually communicated.

Objective of the paper:
Present the development of LSWF on Clair Ridge field and explain the estimation of the potential of such an EOR technique.

Methodology used:
Clair Ridge is a green field development. Thus, no field trials can be done prior to the platform construction. However, data from numerous core flood experiments have been used to estimate the potential of LSWF and be used in a numerical simulation.

Conclusions reached:
• Additional recovery could be between 9 to 13.1%

Comments:
Little precise information is actually communicated.
B. Channels and Overbanks Facies Relative Permeability Curves Sets

Fig. 15: Different wettability systems relative permeability curves for high and low salinity for overbanks facies generated by varying Corey exponents.
C. Buckley-Leverett Analysis Curves

Fig. 16: Fractional flow curves for overbanks facies with an oil-wet system

Fig. 17: Fractional flow curves for channels facies with a weakly water-wet system

Fig. 18: Fractional flow curves for overbanks facies with a weakly water-wet system
Fig. 19: PVI vs PVR plot for overbanks facies with an oil-wet system

Fig. 20: PVI vs PVR plot for channels facies with a weakly water-wet system

Fig. 21: PVI vs PVR plot for overbanks facies with a weakly water-wet system
D. Sensitivity analysis

![Graph showing correlation between simulated and predicted values from the Gaussian correlation for an oil-wet system.](image)

**Fig. 22**: Correlation between Simulated and Predicted Values from the Gaussian Correlation (Oil-wet system)

**Table 9**: Complete Sensitivity Analysis - Oil-wet system

<table>
<thead>
<tr>
<th>Column</th>
<th>Theta Sensitivity</th>
<th>Total Main Effect</th>
<th>Oil Viscosity Interaction</th>
<th>Injection Rate Interaction</th>
<th>Start Point of LSWF Interaction</th>
<th>Connate Water Salinity Interaction</th>
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<tbody>
<tr>
<td>Oil Viscosity</td>
<td>0.1075028</td>
<td>0.0022471</td>
<td>0.0020063</td>
<td>0.001487</td>
<td>0.0009535</td>
<td>3.8558e-5</td>
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<tr>
<td>Injection Rate</td>
<td>0.0323501</td>
<td>0.069056</td>
<td>0.0064915</td>
<td>0.001487</td>
<td>0.0001164</td>
<td>0.0001489</td>
</tr>
<tr>
<td>Start Point of LSWF</td>
<td>0.0348294</td>
<td>0.020778</td>
<td>0.0016755</td>
<td>0.0009535</td>
<td>0.001154</td>
<td>0.0002323</td>
</tr>
<tr>
<td>Connate Water Salinity</td>
<td>3.0446e-5</td>
<td>0.998493</td>
<td>0.9890632</td>
<td>3.8558e-5</td>
<td>0.001499</td>
<td>0.0002323</td>
</tr>
</tbody>
</table>

![Graph showing correlation between simulated and predicted values from the Gaussian correlation for a mixed-wet system.](image)

**Fig. 23**: Correlation between Simulated and Predicted Values from the Gaussian Correlation (Mixed-wet system)

**Table 10**: Complete Sensitivity Analysis - Mixed-wet system

<table>
<thead>
<tr>
<th>Column</th>
<th>Theta Sensitivity</th>
<th>Total Main Effect</th>
<th>Oil Viscosity Interaction</th>
<th>Injection Rate Interaction</th>
<th>Start Point of LSWF Interaction</th>
<th>Connate Water Salinity Interaction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Viscosity</td>
<td>0.316831</td>
<td>0.0007875</td>
<td>0.0004069</td>
<td>5.0018e-5</td>
<td>7.1539e-5</td>
<td>0.000259</td>
</tr>
<tr>
<td>Injection Rate</td>
<td>0.0368154</td>
<td>0.0117712</td>
<td>0.014069</td>
<td>5.0018e-5</td>
<td>7.14e-6</td>
<td>0.000307</td>
</tr>
<tr>
<td>Start Point of LSWF</td>
<td>0.0132296</td>
<td>0.0068839</td>
<td>0.0058986</td>
<td>7.1539e-5</td>
<td>7.14e-6</td>
<td>0.0002157</td>
</tr>
<tr>
<td>Connate Water Salinity</td>
<td>2.1023e-6</td>
<td>0.9518634</td>
<td>0.9806826</td>
<td>0.000259</td>
<td>0.000307</td>
<td>0.0002157</td>
</tr>
</tbody>
</table>
Fig. 24: Correlation between Simulated and Predicted Values from the Gaussian Correlation (Weak water-wet system)

Table 11: Complete Sensitivity Analysis - Weak water-wet system

<table>
<thead>
<tr>
<th>Column</th>
<th>Total Sensitivity</th>
<th>Main Effect</th>
<th>Oil Viscosity Interaction</th>
<th>Injection Rate Interaction</th>
<th>Start Point of LSWF Interaction</th>
<th>Coremate Water Salinity Interaction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Viscosity</td>
<td>0.5446334</td>
<td>0.0019157</td>
<td>0.0008201</td>
<td></td>
<td>0.0002371</td>
<td>0.0001036</td>
</tr>
<tr>
<td>Injection Rate</td>
<td>0.092229</td>
<td>0.0097364</td>
<td>0.0064351</td>
<td>0.0002371</td>
<td>0.0001292</td>
<td>0.000935</td>
</tr>
<tr>
<td>Start Point of LSWF</td>
<td>0.0689392</td>
<td>0.0674887</td>
<td>0.0665065</td>
<td>0.0001033</td>
<td>0.0001292</td>
<td>0.00094414</td>
</tr>
<tr>
<td>Coremate Water Salinity</td>
<td>0.6292e-6</td>
<td>0.9840913</td>
<td>0.981359</td>
<td>0.000856</td>
<td>0.000935</td>
<td>0.0009414</td>
</tr>
</tbody>
</table>

Fig. 25: Surface Plot of Incremental Oil Recovery Vs Oil Viscosity and Injection Rate