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Insights into the Fractional Flow of Low Salinity Water Flooding in the Light of Solute Dispersion and Effective Salinity Interactions
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Abstract

The objective of Low Salinity Water Flooding (LSWF) is to improve oil recovery. While a significant number of laboratory tests have been carried out to investigate the impact of LSWF, field scale modelling is often reported in the form of sector models with relatively coarse cells. This paper assesses the impact of simulating flow at very fine scales and informs on the properties that should be captured at the coarse scale to avoid numerical errors. We have found that the weighting function that is used to control changes to fluid mobility combines with numerical and physical diffusion to induce a retardation/acceleration effect. This is a physical effect rather than part of a chemical reaction.

In this study, numerous simulations of LSWF have been carried out at the reservoir scale to investigate flow behavior for various salt concentration (salinity) weighting functions and dispersion coefficients. We have examined the effective salinity range over which the weighting function is applied as well as considering various shapes. Dispersion was varied to represent physical and numerical effects. These have been compared to analytical solutions from fractional flow theory.

We also observed that the fractional flow of the oil bank will be same for both the secondary and tertiary flooding. We point out the relative importance of various parts of the relative permeability curves. An important finding of this work is that by spreading the salinity front through dispersion and setting a low value at which salinity impacts mobility, we saw the injected low salinity front advance more slowly while the high salinity front of formation water moves more quickly. This is an effective retardation effect. We related this to an effect equivalent to adsorption in the fractional flow theory and could measure it in a similar way. We were also able to develop a prediction of the effect using the analytical solution to the advection-diffusion equation.

The outcome is that we can estimate a corrective term for the flow behavior in situations where the dispersion is quite strong, particularly in numerical simulations. We consider that this enable corrections to be made for numerical dispersion effects in field scale models.

Keywords: Low Salinity Waterflooding, Fractional flow, Chemical Flooding and Salinity dispersion.

1. Introduction
   a. Background

Injection of low salinity water into oil filled cores has been reported by a number of researchers and has been found to increase oil recovery. It is now considered as an option for Enhanced Oil Recovery (EOR) as Low Salinity Water Flooding (LSWF). The mechanisms which bring about the improvement in recovery are also a subject of much research.

Martin (1959) proposed that clay swelling was the dominant process in LSWF, and Bernard (1967) considered that the effect was due to the presence of clay in the core sample. It has been reported that a reduction in the salinity of the injected water actually causes formation damage (Mungan, 1965; Porter, 1989; Azari and Leimkuhler 1990; Galliano et al., 2002), and thus it was considered undesirable. The advantages of LSWF were better appreciated in the 1990s (Yildiz and Morrow, 1996, 1995; Jadhunandan and Morrow, 1995; Tang and Morrow, 1997; Morrow et al., 1998; Tang and Morrow, 1999; Yildiz et al., 1999) as a useful process for EOR. Moreover, LSWF has been reported to delay water breakthrough and accelerate oil recovery (Thyne and Gamage, 2011; Shaddel and Nejad, 2015) with improved recovery of up to 17 % OOIP (Shaddel and Nejad, 2015). It is more efficient in terms of field process implementation (Dang et al., 2016), can be combined with
surfactant materials (Alagic and Skauge, 2010), is more eco-friendly as it does not contain toxic materials and can be cheaper (Dang et al., 2013; Barnaji et al, 2016) compared to other EOR chemicals.

Field scale studies have been successful (Robertson, 2009; Jerauld et al., 2010) although Masalmeh et al. (2014) reported that the 20% increase in oil recovery that they observed at the lab scale could be over optimistic due to differences in conditions where the lab flow is more capillary dominated. This is consistent with the observations of Thyne and Gamage (2011) for a range of EOR techniques, using polymer, CO₂ and surfactant as injected solvents or solutes.

Besides these worries, the mechanisms that give rise to incremental oil recovery by LSWF are still under debate (Shaddel and Nejad, 2015; Dang et al, 2016). Furthermore, research to investigate how to model these mechanisms remains limited (Dang et al., 2016), particularly in the role that water salinity has on macroscopic flow functions (Shojaei et al., 2015). This is the focus of our research.

This paper will address the movement of LSWF fronts and how we can use them to understand the impact of relative permeability and, in particular, how the function of effective salinity range affects water and salinity front movement. The aim of this paper is to deepen our knowledge about LSWF behaviour at the reservoir scale and develop appropriate modelling strategies, rather than focus on the chemical mechanisms at play. This will be helpful to predict the displacement of LSWF fronts and open a new window on how to best incorporate lab measurements of LSWF.

b. LSWF Mechanisms

Several mechanisms have been suggested to explain the effects of LSWF and these are still topics of active research (Zeinijahromi et al., 2015; McMillan et al., 2016). Permeability reduction was one of the earlier explanations for the apparent increased oil recovery during LSWF (Martin, 1959; Bernard, 1967), particularly in sandstones that contain clay. Formation damage could be due to clay fines migration (Jadhunandan and Morrow, 1995; Tang and Morrow, 1997,1999; (Zeinijahromi et al., 2013, 2014, 2015; Hussain et al., 2013;) or due to clay swelling (Shaddel and Nejad, 2015; Pouryousefy et al., 2016; Dang et al., 2016). Fines migration results in plugging of pores in the invaded zone, diverting subsequently injected water and thereby increasing sweep efficiency (Li, 2011). Lab tests have shown that the release of clay fines reduced permeability in the swept zone (Zhang and Morrow, 2006; Pu et al., 2010; Morrow and Buckley, 2011) as well as increased differential pressure in the rock matrix (Shaddel and Nejad, 2015). The benefits from LSWF have been seen without evidence of formation damage, however (Mcguire et al., 2005; Seccombe et al., 2008).

Observations of the link between pH change and formation damage during LSWF have been reported Mungan (1965). Austad (2008) has shown that pH could be increased as a result of clay dilution by the formation and due to dissolution of carbonate components (Shojaei et al., 2015) which can produce an in-situ surfactant. It is controlled by the chemical interaction between water and rock (Thyne and Gamage, 2011), which leads to the reduction of interfacial tension between water and crude oil, releasing the latter. It has been observed that pH affects wettability in carbonate formations during LSWF (Shojaei et al., 2015). In contrast, the benefits of LSWF were evident in lab tests using crude oil at an acid number less than 0.05 KOH/g while it is well known that at least 0.2 KOH/g is required to generate the necessary amount of surfactant to change the wettability of rock (Jensen and Radke, 1988; Dang et al., 2016). Moreover, LSWF benefits have been observed even when pH remained neutral (Pouryousefy et al., 2016).

Osmosis has been suggested as a potential factor. A sharp change in salinity between the injected and formation water is thought to lead to the generation of an osmosis movement that leads to greater in-situ pressure, resulting in an increased oil mobility (Fredriksen et al., 2016).

It has been hypothesised that the rock wettability is altered from hydrophobic to hydrophilic during LSWF as a result of either multi-component ion exchange or the effect of double layer expansion (Aladasani et al., 2012; Zeinijahromi et al., 2013; 2015). This is a widely popular
explanation. Austad (2008) explained that clay could act as a cation exchanger, where cations are replaced in order, as follow:

\[
\text{Li}^+ < \text{Na}^+ < \text{K}^+ < \text{Mg}^{2+} < \text{Ca}^{2+} < \text{H}^+
\]

Shaddel and Nejad (2015) stated that increased oil recovery was observed when the original wettability of the rock is more oil wet. This concept is broadly reported for carbonate formations (Aladasani et al., 2012, 2014; Al-Shalabi et al., 2013), and for carbonate field scale studies, such as in the Ekofisk field in the North Sea (Zhang et al., 2007). Thyne and Gamage (2011) support this through simulations and showed that anhydrite (CaSO\(_4\)) found in carbonate rock, plays an important role.

Desorption of oil from the pore surface, where the negative charge of the oil molecules is reduced so that they become repulsed, has been suggested as a mechanism by Ligthelm et al. (2009). This is a different process from ion exchange, which depends on the idea that bridge elements could build around the rock to attract oil, and entails a change in the rock itself rather than the oil. Shojaei et al. (2015) have reported that clay/rock surfaces became increasingly water wet through desorption of polar components. Also, Austad et al. (2010) reported that polar oil components adsorb on clay minerals due to the low salinity in injected water.

Several of the above mentioned processes may be taking place during LSWF (Mcguire et al., 2005; Salehi et al., 2016; Zeinijahromi et al., 2013; Shojaei et al., 2015). Various factors could be present in different situations, such as:

- formation type where sandstone or carbonate rock affect the presence of clay and divalent cations such as Ca\(^{2+}\) and Mg\(^{2+}\);
- crude oil type which controls the presence and the concentration of polar components in oil, i.e. acid group and acid number (Shaddel and Nejad, 2015; Dang et al., 2016);
- brine salinity and brine composition (Yildiz and Morrow, 1996);
- formation heterogeneity and the clay distribution (Shaddel and Nejad, 2015).
- initial wettability of the rock (Fjelde et al., 2012; Al-Shalabi and Sepehrnoori 2017), which can be identified by the initial charge of the rock using zeta potential (Jackson et al., 2016)

Al-Shalabi & Sepehrnoori (2015) suggested that the mechanism behind increased oil recovery from LSWF seems to be more complex in sandstone than in carbonates due to a combination of many factors, such as fines migration, pH increase, multicomponent ion exchange, which are all in agreement with the findings of Austad (2008). There are other plausible mechanisms, such as limited release of mixed wet particles, salinity shock, mineral dissolution, emulsification/ snap-off, saponification, and particle-stabilized interfaces/lamellae. For all the complexities and uncertainties about the mechanisms of LSWF, it seems clear that after LSWF the flooded formation behaves in a more water wet manner than was observed during High Salinity Water Flooding (HSWF) (Jadhunandan and Morrow, 1995; Hughes et al., 2012; Al-Shalabi et al., 2013). This creates the potential to simplify the modelling process, avoiding the need to model the physical and chemical mechanisms in detail, but instead to honour the change in wettability and thus the change in relative permeability functions that will occur when changing from HSWF to LSWF. However, caution is needed to ensure that the velocity of the front that instigates the change in wettability is correctly modelled, as there may be retardation effects arising from the physical and chemical mechanisms.

c. Effective salinity range

It is evident from the literature that the change in flow behaviour due to LSWF takes place at certain concentrations which is called the effective salinity range, and from this work we will see that
this is a crucial factor in modelling these processes. Previous work has shown that the salinity profile has an advection velocity that depends on the interaction between effective salinity range and dispersion (Al-Ibadi et al. 2018a; in press). In Black Oil models, LSWF is modelled using two sets of relative permeability functions, one representing displacement using water with similar salinity to the formation water salinity, while the other represents the impact of the injected low salinity water. The simulation requires a process for switching between relative permeability curves, and this is defined using the effective salinity range. The upper limit of this range indicates when the low salinity effect starts. The lower limit indicates the concentration below which no further salinity dependent changes to mobility occur.

However, just as there are disagreements about the nature of the LSWF mechanisms, there remains a difference of observations and opinion about this effective salinity range. Zhang & Morrow (2006) have suggested that the concentration ranges vary from one reservoir to another, and depend on the crude oil composition and the type of rock. The evidence of the effective range of low salinity is available from laboratory experiments as well as from field observations, and various data have been used in modelling LSWF. Figure 1 summarises the different ranges of concentrations that have been observed or simulated. It is clear from the literature that the effective salinity range is thought to vary with a number of factors (mineral compositions, formation water compositions, wettability condition amongst others) just as the low salinity process itself does, as described above. It is generally accepted that incremental oil can be obtained from sandstone samples when the injected salinity brine was <10,000 mg/L, though this is not always the case, while carbonate reservoirs could give incremental oil even at relatively high salinity, i.e. >35,000 mg/L. With carbonate samples, it is believed that optimal injected water should have low concentrations of $\text{Ca}^{2+}$ and $\text{Mg}^{2+}$ and high concentrations of $\text{SO}_4^{2-}$ (Puntervold et al., 2015), however that will be a function of initial wettability of the rock (Jackson et al., 2016). We do not discuss the various effects explicitly here, as in some cases these are hypothesised rather than proven. We do show in Figure 1 the different formation type (carbonate versus sandstone), which also controls the effects.
Figure 1. Comparison of effective salinity ranges reported in the literature, indicating on a log scale where the effect of salinity is variable. Changes to the salinity outside of the range had no noticeable effect. The arrows indicate groups of rock type which are carbonates (black), sandstone (red) and synthetic data (yellow). The bars are colour coded for the mechanisms identified in the references.

d. Modelling of LSWF

Despite the differences of opinions about the mechanisms of LSWF it is generally accepted that the process should be modelled as a wettability alteration effect represented through a change of relative permeability (i.e. mobility). Even those who suggest fines migration and changes to interfacial tension as the main mechanisms have adjusted relative permeability curves to match their experimental data (Aladasani et al., 2012). This is reasonable as the relative permeability curve is itself a proxy model for pore scale behaviour.

Jerauld et al., (2006, 2008) introduced a model of LSWF that is currently used in many black oil simulators, while Dang et al., (2015 and 2016) introduced a mechanistic model based on ion exchange that captures geochemical interactions in a compositional simulator. Basically, the black oil model of LSWF consists of the standard mass conservation equations reduced to oil and water phases along with dynamic modifications of relative permeability and capillary pressure curves corresponding to high and low salinity behaviour, with salinity change being tracked as a conservative tracer. For each grid cell at each time step, the simulator interpolates between the two curves based on the salinity in that grid cell at that time. Change in salinity is modelled using a mass conservation equation and depends on oil and water velocities. Several experiments have been history matched by changing relative permeability data (Aladasani et al., 2012a, 2012b, 2014; Shojaei et al., 2015). The high salinity flooding process is represented by either oil wet or mixed wet relative permeability data, while low salinity displacement is represented by more water wet relative permeability data. Jerauld et al., (2006; 2008) have suggested the approach for modifying relative permeability and this is used in commercial simulators (e.g. Schlumberger ECLIPSE 2015; CMG STARS 2015); we describe and apply this methodology here.

It has been reported that it is not just the water salinity itself that controls the mobility change and we could use the salinity mechanism to represent other specific solutes such as Ca\(^{2+}\) or Mg\(^{2+}\) (Puntervold et al., 2015). The model and our results could equally be applied provided the weighting function is adjusted appropriately. In addition to water composition and geochemistry, other sources of reaction can also have an impact. The only additional complexity, which we do not address, is that if the other solutes are involved in reactions that lead to retardation, then that could impact the velocity at which the concentration front travels.

A mixing parameter is used to interpolate between the relative permeabilities and defines the concentration weighting function:

\[
\Theta = 1 - \frac{C_S - C_S^{LS}}{C_S^{HS} - C_S^{LS}} \quad \text{for} \quad C_S^{LS} \leq C_S < C_S^{HS} \tag{1}
\]

Where \(C_S\) is the in situ salinity and \(\Theta = 1\) for \(C_S \leq C_S^{LS}\) and \(\Theta = 0\) for \(C_S \geq C_S^{HS}\). In this formulation the function is linear but simulators typically allow a tabular form and we later explore various non-linear representations of the concentration weighting function.

An effective end point is defined based on the concentration such that:

\[
S_{orw} = S_{orw}^{HS} + \Theta(S_{orw}^{LS} - S_{orw}^{HS}) \tag{2}
\]

where \(S_{orw}^{LS}\) and \(S_{orw}^{HS}\) are the residual oil saturations of the low and high salinity relative permeability curves, respectively. Other end points may be scaled equivalently.
The effective saturation, $S^*$, for a grid cell is calculated as:

$$ S^* = \frac{S_o - S_{arw}}{1 - S_{orw} - S_{orw}} $$  \[3\]

The effective relative permeability and Pc curves are calculated from

$$ k_{rw} = \Theta k_{r,LS}^{LS}(S^*) + (1-\Theta) k_{r,HS}^{HS}(S^*) $$  \[4\]

$$ k_{ro} = \Theta k_{r,LS}^{LS}(S^*) + (1-\Theta) k_{r,HS}^{HS}(S^*) $$  \[5\]

$$ P_{cow} = \Theta P_{c,LS}^{LS}(S^*) + (1-\Theta) P_{c,HS}^{HS}(S^*) $$  \[6\]

The superscripts LS and HS indicate low and high salinity curves, respectively. In this formulation, the relative permeabilities, $k_{ro}$ and $k_{rw}$ for oil and water, respectively, as well as the Pc curves are end-point scaled to the new effective residual oil saturation such that they are stretched or contracted, mapping to the new end-point. Then they are averaged using the weighting function, as in Equations 4-6.

Tripathi & Mohanty (2008) have suggested a very similar model. They also considered that the relative permeability curves could be represented using Corey exponents (Brooks and Corey 1966; Delshad and Pope, 1989) to define the shape with different exponents for either low or high salinity water. The exponents can be mixed linearly using a function similar to Equation 2. Relative permeability and Pc curves can be scaled according to wettability as well. Various combinations of just exponents, just scale terms and all combined were examined.

Despite it being generally accepted that the salinity weighting function should be expressed as a single linear function, the issue is still a matter of debate. For instance, Al-Shalabi et al. (2015) have suggested two weighting factors to simulate the wettability alteration during LSWF, reflecting different effects on oil and water. In fact, it is possible to suggest a myriad of different shapes and forms of the salinity weighting factors; e.g. in some cases, oil relative permeability curve should be adjusted due to LS flooding and water relative permeability curve will be fixed (Shojaei et al., 2015), while it is widely accepted that both curves should be adjusted to fit laboratory results (Brodie and Jerauld, 2014; Jerauld et al., 2008).

Relative permeability functions are used in the numerical representation of the mass conservation equations for oil, water and salinity. For a grid cell the mass conservation equation is:

$$ \frac{\Delta}{\Delta t} \left( \frac{V S_w}{B_w} \right) = \sum_{\text{all faces}} \left( \frac{T k_{rw}}{B_w \mu_w} \left( \delta P_w - \rho_w g D_z \right) \right) + Q_w $$  \[7\]

for water, with a similar equation for oil.

Since the salt component is assumed to be fully and exclusively dissolved in the aqueous phase, it will be transported based on the mass conservations equation:

$$ \frac{\Delta}{\Delta t} \left( \frac{V S_w C_s}{B_w} \right) = \sum \left( \frac{T k_{rw}}{B_w \mu_w \mu_{seff}} \left( \delta P_w - \rho_w g D_z \right) \right) C_s + Q_w C_s $$  \[8\]

In Eq. 7 and 8, $V$ is the block pore volume, $S_w$ is the water saturation, $C_s$ is the salinity in the aqueous phase, $B_w$ is the water formation volume factor, $\sum$ is the summation over the different directions on the grid, $T$ is the transmissibility for the traditional block centred form, $k_{rw}$ is the water relative permeability, $\mu_w$ is the viscosity of water, $\delta P_w$ is the difference in the water pressure between grid
cells, $\rho_w$ is the water density, $g$ is the acceleration due to gravity, $D_z$ is the depth of the cell centre, $Q_w$ is the water production rate at the surface (provided there is a well connection in the cell). $C_S$ is assumed to be a single component, i.e. it behaves as a single species.

2. **Simulation model description**

In this work, we focussed on the behaviour of LSWF at the reservoir scale. For this purpose, we have adopted a one dimensional Cartesian model (Fig. 2a), and to achieve better precision, the model was divided into 3500 grid blocks, each of which is 0.3048 m long. To tackle the problem of model stability due to numerical problems, the magnitude of the time step was kept small at 0.25 days. This enabled the simulation to resolve the movement of the fronts across the cells. Producer and injector wells were set at the extreme ends of the model. We used two sets of relative permeability data (Figure 2b) to simulate that behaviour, as suggested by (Jerauld et al., 2006; Schlumberger, 2015), with capillary pressure set to zero.

![Figure 2](image1.png)

**Figure 2:** (a) 3D representation of the 1D model with dimensions. Colours indicate saturation of oil as the two fronts pass through and (b) the input relative permeability curves for both high and low salinity cases, taken from Jerauld et al. (2006).

To pay more attention to the physical transportation of fluids and dissolved salt through the porous media, any chemical reaction with the rock was neglected, and injected dissolved salt was treated as a single component. For simplicity, we used a homogenous reservoir model with the petrophysical and other parameters shown in Table 1.
We also ignored the effect of capillary pressure by setting it to zero. This is generally valid for coarse scale simulations where the pressure difference from viscous forces is often much greater than from capillary forces. Moreover, the flow rates are relatively high in the simulation such that for small grid cells, capillary effects are minor. In water wet rocks, capillary pressure may introduce a form of physical dispersion. In reservoirs where the rocks are oil wet to high salinity formation water, the effect of capillary pressure actually encourages water fronts to stabilise as sharp discontinuities.

Apart from these reasonable approximations the aim is to build up our understanding of the behaviour relative to the idealised case where fronts are sharp, capillary pressure is negligible and the solution is obtained analytically via fractional flow theory. For this reason we also focus on flow in one dimension. This helps us to understand how accurately we can represent the core plug scale when discretising models with typical cell sizes. The results that we present are not without some practical relevance however. In reservoirs consisting of thin non-communicating homogeneous beds or layers, the flow is virtually one-dimensional during linear drive. This is more so when hydraulic fractures have been generated at wells in the direction perpendicular to the induced direction of flow. The results below are likely to be useful for five-spot pattern floods too where Buckley Leverett analysis has been shown to hold albeit different timings for the fluid movement compared to linear drive. In subsequent work we will investigate heterogeneity and gravity effects in more detail.

Many researchers (Brodie and Jerauld, 2014; Attar et al., 2016) have studied the total dispersion of the LSWF salinity front, including numerical and physical dispersion at the core scale. However, since physical dispersion is often outweighed by numerical dispersion, the former is ignored.

<table>
<thead>
<tr>
<th>Property</th>
<th>Value (units)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td>20%</td>
</tr>
<tr>
<td>Absolute permeability</td>
<td>200 mD</td>
</tr>
<tr>
<td>Net to gross</td>
<td>95%</td>
</tr>
<tr>
<td>Oil density</td>
<td>0.77 kg/L</td>
</tr>
<tr>
<td>Water density</td>
<td>1 kg/L</td>
</tr>
<tr>
<td>Rock compressibility at</td>
<td>5.843E-05 bar⁻¹</td>
</tr>
<tr>
<td>6500psi</td>
<td></td>
</tr>
<tr>
<td>Datum depth</td>
<td>2461 m</td>
</tr>
<tr>
<td>Initial pressure @datum</td>
<td>448 bar</td>
</tr>
<tr>
<td>S wi</td>
<td>20%</td>
</tr>
<tr>
<td>Depth of Water oil contact</td>
<td>2590 m</td>
</tr>
<tr>
<td>Capillary pressure @woc</td>
<td>0 bar</td>
</tr>
<tr>
<td>Injection rate</td>
<td>1749 Rm³/day</td>
</tr>
<tr>
<td>Production rate</td>
<td>1749 Rm³/day</td>
</tr>
<tr>
<td>Water viscosity</td>
<td>1 cP</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>1 cP</td>
</tr>
</tbody>
</table>

To characterise dispersion we use the Peclet number (e.g. Sorbie and Mackay, 2000)

\[ N_{pe} = \frac{v x}{D} \]  \[9\]

where \( x \) is the distance from the injector, \( v \) is the interstitial velocity of the water, and \( D \) is given by:

\[ D = a_{total} \times v \]  \[10\]
such that we assume molecular diffusion to be negligible compared to dispersion. The total dispersivity, $\alpha_{total}$, is made up of the physical and numerical dispersivity (Fanchi, 1983):

$$\alpha_{total} = \alpha_{physical} + \alpha_{numerical}$$ \hspace{1cm} [11]

where $\alpha_{physical}$ is a constant measured experimentally or by field test (set to zero in this study), while $\alpha_{numerical}$ can be calculated by:

$$\alpha_{numerical} = \left(\frac{\Delta x}{2}\right) + v_w \left(\frac{\Delta t}{2}\right)$$ \hspace{1cm} [12]

In the base case fine grid model, the numerical dispersivity was 0.2 m, while the Peclet number was 5,000. This means the flow was advection dominated, as the Peclet number was greater than 1,000.

The liquid production rate of 11,000 RB/day was set as the preferred control mode and pressure support was maintained by field voidage replacement. Pressure limits were never reached. Injected salinity was 1,000 mg/L; anything lower could cause formation damage (Lever and Dawe, 1984). The formation water salinity was 200,000 mg/L, which is a high value applicable to deep reservoirs and many Middle East reservoirs (Awadh, 2018). As suggested by many researchers, the base case effective salinity range was set to 1,000-7,000 mg/L as a single linear function. We have considered several different relative permeability curves with a base case shown in Figure 2 (from Jerauld et al., 2006). Unless otherwise stated, the results were qualitatively similar. These saturation dependent functions were added as a look up table in the simulator.

3. Simulations of LSWF displacement

By ignoring the impact of capillary pressure and the physical dispersion coefficient, simulating flow of incompressible fluids in a 1-D homogeneous reservoir can be represented using fractional flow theory equivalent to water flooding (Buckley and Leverett, 1942).

Patton et al. (1971) provide a good explanation of the analysis for polymer flooding, which is analogous to LSWF in that fluid mobility is altered by inclusion of a solute which itself must be modelled. Jerauld et al. (2006) carried out an equivalent analysis for LSWF with similar results. In this analysis it is assumed that the low salinity water enters the reservoir and travels with no dispersion, moving at constant speed controlled by the fractional flow of water. However, in previous work that related to the concept of modelling fractional flow, the analysis did not require nor include the concept of effective salinity which is necessary to control water mobility changes. Further, in simulations of EOR processes such as polymer flooding, the injected solute controls viscosity in a continuous manner, while in LSWF it is somewhat step-like, making LSWF unique.

Under the conditions described above, the salinity travels in a single front and there are two water fronts. A bank of high salinity formation water forms as one front and, with its higher mobility, moves faster than the low salinity front. The latter moves at the same speed as the salinity front, although we will show that this is not necessarily a good assumption for LSWF. The fractional flow analysis can be used to quantify this behaviour, giving the speed of the fronts and the saturations and fractional flows at which they travel. The fractional flow curves are used (Figure 3) corresponding to the relative permeability curves (Figure 2). For HSWF, the Welge tangent is used to identify the effective saturation ($S_{w1}$) and fractional flow ($f_{w1}$) of the water flood front by drawing a line from the formation water saturation, $S_{wc}$, to the tangent with the high salinity fractional flow curve (Buckley and Leverett, 1942; Welge, 1952). A similar approach is used for LSWF (Figure 3). The velocities of the salinity and low salinity water flood fronts depend on the fractional flow ($f_{w3}$) and saturation ($S_{w3}$) at the water front and can be determined from the flow equations (e.g. Patton, 1971; Pope, 1980). The constraint of conservation of volume, as used to obtain the Welge tangent for HSWF, gives $S_{w3}$ and
f_{w3} by drawing a straight line from the origin of the fractional flow plot to the tangent of the low salinity fractional flow curve. The dimensionless velocity (i.e. the fractional distance moved per pore volume injected) is given by the ratio of fractional flow to saturation at the tangent point (i.e. $f_{w3}/S_{w3}$). The faster moving high salinity front is also very sharp. The fractional flow ($f_{w2}$) and saturation ($S_{w2}$) of this front must lie on the high salinity fractional flow curve. On the other hand, conservation of volume means that the dimensionless velocity of the low salinity front depends on the ratio of change in fractional flow to change in saturation, $(f_{w3}-f_{w2})/(S_{w3}-S_{w2})$, going from the high salinity to low salinity front. Since the velocities of the dissolved salinity and LS water fronts are the same, then we can equate:

$$\frac{f_{w3}-f_{w2}}{S_{w3}-S_{w2}} = \frac{f_{w3}}{S_{w3}}$$  \hspace{1cm} [13]

Thus $f_{w2}$ and $S_{w2}$ lie at the intersection of the high salinity fractional flow curve and the tangent to the low salinity curve through the origin. The dimensionless velocity of the high salinity front is also obtained from $f_{w2}/(S_{w2}-S_{wc})$ by conservation of volume.

Figure 3: The fractional flow plot for LSWF model shows the possible shock fronts. The blue and red curves show fractional flow for high and low salinity, respectively, based on input relative permeability curves. The tangential line (“BL-front”) from the blue curve to the formation water, $S_{wc}$, is the traditional Welge tangent for HSWF, where the saturation and fractional flow at the Buckley-Leverett front are $f_{w1}$ and $S_{w1}$. The tangential line from the origin to the red curve gives the fractional flow, $f_{w3}$, and saturation, $S_{w3}$, at the low salinity front. By Equation 13, the formation water front saturation, $S_{w2}$, and fractional flow, $f_{w2}$, must lie on that the intersection of the LSWF tangent with the HS fractional flow curve.

In this paper we explore the degree to which the above analysis agrees with numerical simulations. We find that it is a good approximation, but ignores the impact of modelling a transition in salinity to change water mobility through the effective salinity range.

In production of an oil reservoir, it is conventional to refer to depletion as a “primary” mechanism and waterflooding as “secondary” due to the order in which these take place usually. EOR methods such as LSWF may be considered as a tertiary production process, following waterflooding, but they can be applied after depletion (or even before). We therefore use the term “secondary” to indicate that no fluids have yet been injected and “tertiary” to indicate that high salinity waterflooding
has already taken place. In simulations of an undersaturated reservoir as studied here, the “primary” process is modelled merely by choosing the initial pressure conditions.

As a secondary process, the LSWF model normally has two shock fronts (Figure 4). For tertiary LSWF, three shock fronts can form (Tripathi and Mohanty, 2008). This is in agreement with several laboratory observations (Yildiz and Morrow, 1996; Tang and Morrow, 1999; Yousef et al., 2011) as well as field scale tests (Zeinijahrami et al., 2015). In tertiary LSWF, the first front occurs due to HSWF. The second front forms as a result of oil becoming mobilised and flowing in combination with the previously injected high salinity water. The third front forms due to the low salinity water.

![Figure 4: A comparison between Secondary and Tertiary recovery of LSWF against injected pore volume (PVI), where two and three shock fronts were obtained respectively. The fractional flow curves from Figure 3 were used. Also, in both cases the velocities of LS-front and formation water front have not altered.](image)

The fractional flow of the formation water front from secondary LSWF (Figure 5) is the same as the fractional flow of the oil bank in tertiary recovery (Figure 6). This follows from the fact that the fractional flows of the fronts are the same in both scenarios (Claridge and Bondor, 1974). A comparison between the secondary flooding and tertiary flooding has been carried out to emphasize this observation (e.g. Figure 4).

Because the fronts are self-stabilising, as described above, the resulting mathematical and numerical solutions to the flow problem are affected by a subset of all available input relative permeability data. In secondary LSWF, only the intersection point of the HS fractional flow curve with the tangent line in Figure 4 is needed (Figure 5). Numerically we observe that the lower part of the curve may have some influence depending on numerical dispersion. Meanwhile the LS fractional flow curve behind the point \( (S_{w3}, f_{w3}) \) is needed theoretically. If the level of numerical dispersion is high then the fractional flow curves between \( S_{w2} \) and \( S_{w3} \) will affect the numerical result. The same applies for tertiary LSWF, except that the HS fractional flow curve is required for saturations above \( S_{w1} \), but the rest of the curve is needed if numerical dispersion is high.

In tertiary LSWF, the HS fractional flow curve (Figure 6) is important for saturations above the Buckley Leverett shock front saturation, depending on how much HS water invades. For example, Figure 6 displays the case where there is moveable water before injecting LS water, where the Buckley Leverett front and the oil has been swept out significantly before injecting LS brine. The LS fractional flow curve is important. Note, however, that the straight line of fractional flow through the two fronts does not intersect the origin; this will be discussed later.
Figure 5: The input relative permeability curves and the simulator fractional flow for secondary LSWF near the well. The fractional flow passes rapidly to the HS shock front saturation, albeit with some numerical dispersion. Later the LS front arrives and the saturation and fractional flow rises again. There are more points between shock front saturations due to the spread of the salinity.

Figure 6: The input relative permeability curves and the simulator fractional flow near the well for a case where HSWF is followed by LSWF once much of the initially mobile oil has been displaced.

An important observation from simulations is that the fronts of both the formation water and LS-front are related to each other. Depending on the relative permeability curve, any condition that alters the velocity of LS-front will also lead to a change in the velocity of the formation front. This has been observed for polymer flooding and other injected solutes which reduce the mobility of the injected fluid (Pope, 1980). It is also obvious from Figure 3 that if the shape of the fractional flow curves change then the resulting saturations and fractional flow solutions also change. On the other hand, it has been reported that for polymer flooding, adsorption also moves the tangential line to cross the saturation axis to the left of the origin. We focus on these interactions for the remainder of the paper.

4. Effective salinity and the weighting function in simulations
We now analyse the impact of simulating LSWF with several representations of the concentration weighting function (Eq. 1). We considered three scenarios for changing this function (Figure 7):

1. The minimum concentration, $C_s^{LS}$ was varied but we set the maximum, $C_s^{HS} = C_s^{LS} + 6,000$ mg/L, keeping the width of the range constant;
2. The minimum concentration $C_s^{LS}$ was fixed at 1000 mg/L and the width of the effective salinity range was varied;
3. Non-linear functions were used to represent the function.

![Figure 7: Various scenarios of weighting function (Eq. 1) that were investigated (a) $C_s^{LS}$ varied with fixed width of the effective salinity range of 6000 mg/L (b) $C_s^{LS}$ fixed at 1000 mg/L and width varied (c) non-linear representation with fixed limits.](image)

Although some of these scenarios could be unrealistic from the perspective of core flood results, studying these scenarios will help us to initiate a dimensionless relationship between the effective salinity on the one hand, and the difference in concentration between the formation water and the injected water on the other hand.

The choice of $C_s^{LS}$ and $C_s^{HS}$ control the dynamics of how salinity affects flow by focussing on different parts of the concentration front (which is spreading due to numerical and/or physical dispersion). Figure 8 shows the evolution of salinity (at the producer well) from 3000 to 3500 days (1.06-1.18 PVI). The salinity passes through the range of the weighting function ($C_s^{HS}$ down to $C_s^{LS}$) at different times depending on how it is set but also depending on the width of the dispersed salinity front. The lower that the range is set relative to the formation water salinity, then the longer we wait for the low salinity process to take effect. This creates a retardation/acceleration effect analogous to polymer adsorption in the fractional flow analysis (Pope, 1980). The behaviour depends critically on the mid-point concentration in the salinity front, $x_e^{mid}$, which we define as:

$$C_s^{mid} = \left( C_s^{formation} + C_s^{inj} \right)/2$$

[14]
where $c_{S}^{\text{formation}}$ is the formation water salinity prior to LSWF and $c_{S}^{\text{inj}}$ is the salinity of the injected water during LSWF and

$$c_{\text{eff}}^{\text{mid}} = \frac{(c_{S}^{\text{HS}} + c_{S}^{\text{LS}})}{2}$$  \[15\]

If $c_{\text{eff}}^{\text{mid}}$ is very close to $c_{S}^{\text{mid}}$ then the behaviour is straightforward, with frontal solutions given by the fractional flow theory described above, albeit with fronts that are dispersed numerically. However, if $c_{\text{eff}}^{\text{mid}}$ is higher than $c_{S}^{\text{mid}}$ then there is a delay with an effect equivalent to retardation while acceleration occurs if $c_{\text{eff}}^{\text{mid}}$ is less than $c_{S}^{\text{mid}}$. We will see that these effects are particularly evident for the cases where the width of the effective salinity range was fixed but $C_{S}^{\text{LS}}$ was altered (Figure 7a).

**Figure 8:** Illustration of the time dependence of the switch from HS to LS behaviour. The diffusion spreads the salinity front. The change in salinity has no effect until the $C_{S}^{\text{HS}}$ is reached and then the full LS effect is observed when $C_{S}^{\text{LS}}$ is met. The coloured lines indicate the times these are reached and their duration for $C_{S}^{\text{LS}}$ to $C_{S}^{\text{HS}}$ range of 1000 to 7000 mg/L (orange), 93,000 to 10,000 mg/L (green) and 193,000 to 200,000 mg/L (red).

The relative permeability curves in Figure 9 illustrate the role of the weighting function when switching from the HS to the LS curves. In the fractional flow theory (Patton et al., 1971), it is assumed that the jump from the formation water bank to the LS front is instantaneous. The data here shows that it is gradual and dependent on the spread of concentrations in the weighting function and how long concentration takes to change, through dispersion. The jump between curves is slowed down.
Figure 9: Relative permeability values for a grid cell in the model as the waterflood passes through indicating, first, the rise to the formation water bank (red) as numerical dispersion spreads the front and the HS relative permeability values are used. Next, the LS front begins to arrive and the relative permeabilities in the cell move over to the LS curves (green). Finally the cell uses the LS relative permeability values (yellow) until all mobile oil is displaced.

The results of varying the concentration functions according to Figure 7a are shown in Figure 10. In this figure we see that although the model was advection dominated (with Peclet number > 4,500 in which cell size was 0.3048 m) the waterflood velocities were still affected by varying the effective salinity ranges. With more dispersion the impact will be pronounced even further, but then the stability of the numerical solution may be compromised (Al-Ibadi et al., 2018b). The trend is that the lower \( C_{s,LS} \) was set, then the later the arrival time of the LS front and the earlier the arrival of the HS front. The saturation of the HS front also increased with this trend. The volume of water in the HS front appears to be greater but this is because it now included some of the injected water for which the LS effect had not yet taken place. A similar retardation effect was described by Pope (1980) for polymer adsorption, such that the tangent to the polymer affected fractional flow is drawn from a point to the left of the origin, modifying the analytical solutions from Figure 3. The tangent only goes through the origin for zero adsorption. The adsorption slows down the movement of the polymer front. However, the water injection rate is unaffected, and since the polymer front slows down, then to maintain material balance the formation water bank speeds up and contains some of the injected water, albeit stripped of polymer.

Figure 10: Water cut against injected pore volume (PVI) for various concentration weighting functions in Fig 7a where the \( C_{s,LS} \) is changed and the width of the range is fixed, for base case model in which Peclet number > 4,500.

We can see the effect of the retardation on fractional flow numerically (Figure 6 and Figure 11). The fractional flow in the cells follows the behaviour consistent with drawing the tangent to a point on the x-axis that corresponds to an effective retardation. On the other hand, we see an acceleration when \( C_{s,LS}^{mid} \) is changed and the width of the range is fixed, for base case model in which Peclet number > 4,500.

Figure 12a shows the impact of changing the width of the weighting function while fixing \( C_{s,LS} \). The shortest range is the same case as the model with the lowest value of \( C_{s,LS} \) in Figure 10. The
retardation effect is strongest for the lowest range but reduces as the range is increased. The effect of salinity on mobility begins earlier but it also takes longer for it to fully switch on. Thus the salinity front is somewhat delayed compared to the case with short width of effective salinity range and the impact on the high salinity water front is also reduced. Figure 12b compares two cases where $C_{\text{eff}}^{\text{mid}}$ equals $C_s^{\text{mid}}$ and the width of the effective salinity range is varied. The speed of the concentration front is relatively unchanged, and we only see the spread of the LS front in the case of the broader weighting function. The HS frontal velocity and saturation are unaffected.

Figure 11: The input fractional flow (blue and purple lines) and the simulator output fractional flow of the two models, where each model has different weighting function and that affects the velocities of shock fronts. Both models had Peclet number $= 64$ where $\Delta x = 21.336$ m and $\Delta t = 28$ day.

The result of using the non-linear weighting functions from Figure 7c are shown in Figure 13. In these cases, the range is quite small and $C_{\text{eff}}^{\text{mid}}$ is close to $C_s^{\text{mid}}$. When we keep the same with of the effective salinity range and change $C_s^{\text{LS}}$ we see the same retardation/acceleration effects described above, but otherwise there is little variation between the non-linear functions. The effect of the non-linearities is negligible. We deduce that the shape of the weighting function is much less important than where the mid-concentration of the weighting function lies relative to the formation and injection water salinities.

We have so far described the delay or early onset of the salinity effect due to dispersion as a retardation or acceleration effect. We now examine this effect in relation to the fractional flow theory to determine whether or not we can predict it.

Pope (1980), derived the velocity of a sharp polymer concentration front and associated shock front of water as:

$$\frac{dx}{dt} = \frac{q}{A\Phi} \frac{f_w}{S_w + D_{WF}}$$

where $x$ is the distance the front has moved relative to the injector, $q$ is the volumetric injection rate of the water phase, $A$ is the cross sectional area, $\Phi$ is the porosity, $f_w$ is the fractional flow of water, $S_w$ is the saturation and $D_{WF}$ is a retardation term slowing down the fronts due to adsorption. We develop a term equivalent to $D_{WF}$ for LSWF. We can measure it for simulations but we can also predict it using analytical solutions. This provides a method of using the simpler tangent solution from fractional flow theory to estimate the behaviour without doing full simulations.
We define a reference case where \( C_{eff}^{mid} \) equals \( C_{S}^{mid} \) such that the front velocities have not been affected by retardation or acceleration. Before discussing the analysis, we first describe the calculated velocities of the LS-front and formation water front and plot them in Figure 14 for the models above where \( C_{eff}^{mid} \) was varied. The velocities are anti-correlated as observed above and the velocities have a sigmoidal shape, suggestive of the dispersion effect.

**Figure 12:** Water cut from models with different weighting function (a) Fig 7b (fixed range) (b) ranges centred around the mid concentration of the salinity front.
Figure 13: Water cuts from models with weighting functions from Figure 7c.

Figure 14: Shows the velocities of both LS and formation water fronts from models calculated from simulator outputs at different $C_{\text{eff}}^{\text{mid}}$.

To calculate $D_{WF}$ for the different scenarios of weighting function, we observed that from fractional flow theory (e.g. Pope, 1980) the effective velocity of the salinity front (i.e. where salinity takes effect) is the same as the LS water front. From the same considerations and nomenclature as before that gave Equation 13:

$$f_{w2} - f_{w1} = \frac{f_{w3}}{s_{w3} + D_{WF}}$$

$f_{w}$’s and $s_{w}$’s are defined the same as in Figure 3 except that they will now be numerically different. In the base case $D_{WF} = 0$ and we can calculate the two terms from the model. In other cases, the left side can be calculated from the model and with the other fractional flow and saturations similarly available. $D_{WF}$ can then be estimated. Figure 15 illustrates these “measured” values of $D_{WF}$ against $C_{\text{eff}}^{\text{mid}}$. The retardation constant is zero for the reference case. Negative values of $D_{WF}$ indicate an acceleration. The shape of $D_{WF}$ versus mid-concentration weighting function is sigmoidal and similar to the shape of the salinity front. Therefore, it is possible to infer there is a direct link between salinity diffusion and $D_{WF}$. 

Figure 15: $D_{WF}$ for models with different mid concentration of the weighting function (scaled relative to the range of salinity).

To predict the value of $D_{WF}$ without carrying out simulations, we need to understand the relationship between the velocity of the salinity profile and the LS water fronts when the weighting function is changed. Figure 16 shows the relationship for the models indicating a correlation between velocities. The correction factor is 1.02 and 1.04 in Figure 16a and 16b respectively. This correction factor could be due to numerical error. Thus, we would assume that the LS-water front is always equal to the salinity velocity of the mid-concentration of the weighting factor.
Figure 16: Comparison between the velocity of salinity and the velocity of LS-water front for two locations: (a) \( x = 0.1L \), where the Peclet number is about 40, and (b) at the end of the model, \( x=L \), where the Peclet number is about 4500, i.e. advection dominates. \( L \) is the distance between injector and producer. Both graphs show correlation between the velocities of salinity and LS-water front with acceptable error of (a) 0.02 and (b) 0.04.

We find empirically that for these models, it is possible to predict the value of \( D_{WF} \) by considering the difference between \( V_i(C_{S}^{mid}) \), the number of pore volumes of fluid injected to ensure the salinity reaches \( C_{S}^{mid} \), and \( V_i(C_{eff}^{mid}) \), the volume required to ensure the salinity reaches \( C_{eff}^{mid} \) at a particular point in the reservoir.

The volumes are calculated using the analytical solution to the dispersion-advection equation in a semi-infinite medium assuming a single advection velocity (e.g. Brigham, 1974);

\[
C = C_{S}^{formation} - C_{S}^{mid} \text{erfc}(\frac{x-vt}{2\sqrt{D}}) = C_{S}^{formation} - C_{S}^{mid} \text{erfc}(\frac{1-V_i/V_p}{2\sqrt{D/V_pN_{pe}}}) \tag{18}
\]

Where \( v \) is the salinity front velocity of the base case, \( D \) is the total dispersion coefficient. In the second form, \( V_i \) is the volume injected to get an undispersed front to reach \( x \).

We also used the Peclet number to express the total salinity dispersion, i.e. physical dispersion added to numerical dispersion. We suggest the following term to estimate the \( D_{WF} \) term:

\[
D_{WF} = 12 \times \left( \frac{V_i(C_{S}^{mid})-V_i(C_{eff}^{mid})}{\sqrt{N_{pe}}} \right) \tag{19}
\]
This form has been tested with various simulator results to calculate the new form of $D_{WF}$ in multiple salt dispersion conditions. Figure 17 shows a comparison between predicted values of $D_{WF}$ (Eq. 19) and actual results from the simulations models (derived by estimating $D_{WF}$ from fractional flow plots via Eq. 17). Figure 17a is for models with advection controlled transportation, while Figure 17b is for dispersion dominated models. The calculation shows a very good match, particularly for advection dominated cases. The remaining mismatch may be due to numerical errors.

Figure 17: A comparison of predicted $D_{WF}$ and actual results from simulator versus mid-concentration of the weighting function for (a) advection dominated and (b) diffusion dominated flow.

The velocity of the salinity is a function of the Peclet number and so is the $D_{WF}$. The apparent value of $D_{WF}$ is a function of model length and longitudinal dispersion, because the front spreads as it propagates. Figure 18 shows that the impact of the mid-concentration of the weighting function is greater in the first quarter of the reservoir compared with the extreme end because the Peclet number is linear with model distance. The relative velocities of the fronts will be changing as they propagate with the difference decreasing in time. There may be a greater retardation or acceleration effect in strongly heterogeneous models and/or high physical diffusion where the Peclet number is small.
Figure 18: A comparison of the salinity front velocities at the producer and nearer the injector at different mid concentration weighting functions.

5. Discussion

This study has examined the movement of saturation and salinity fronts in various LSWF models at the reservoir scale and the impact of effective salinity range has been investigated. We focused on the shape and velocity of the shock fronts in the LSWF model, and thus we can infer the dominant intervals of the relative permeability curves. We also interpreted the relationship between effective salinities and shock front velocity to calculate the expected values in the LSWF model. For those who work on core experiments, this relationship could be extendable to their work where they could estimate the effective salinity by calculating the velocity of the water fronts.

The aim of this paper was to perform a theoretical study of a fairly light oil case. We chose equal viscosities for simplicity. We have examined higher viscosities for oil. The effects are quantitatively different but the final analysis is the same. The effect of increasing oil viscosity is to shift the fractional flow curves to the left and reduce the saturations of the formation and low salinity water fronts. The analytical solutions are not affected mathematically although the computed solutions change. The alterations to the fractional flow behaviour are also based on the same correction factor. We found that similar results are found when we change the relative permeability data. In this paper we used curves that were obtained from history matching of coreflood experiments that are presented in the literature. These were read into the simulator as tables. We have used more generic relative permeability data based on Corey exponents. The results are not shown here but the main effect is to alter the fractional flow curves. The numerical solutions change while the general pattern is preserved and the same mathematical form of the correction factors arise.

The main result of this study shows the relationship between the effective salinity and the frontal velocities. We showed that both LS and formation water front velocities are functions of the mid-salinity of the weighting function relative to the overall concentration range. The lower the salinity at which the mobility change effect begins, the later this will happen in time when combined with numerical or physical dispersion of the dissolved salt. This slows the movement of the low salinity water and speeds up the high salinity water. The outcome is similar to a retardation effect, which we have related to fractional flow theory.

We have derived and tested an empirical approach to predicting the strength of the retardation effect. If we assume that the salinity front moves according to the injection volume, then the
analytical solution provides an estimated retardation constant. We have tested this approach. This gives a method of predicting the strength of the effect of retardation, particularly as an effect of numerical dispersion. It also offers a numerical means of correcting simulation results of coarser scale models.

In order to obtain a precise empirical form, the main numerical results that were obtained in this work were for the base case model which is advection dominated. With more dispersive models, fractional flow of water and frontal velocities will be affected more strongly by salinity dispersion. At this point the effects are more strongly pronounced requiring proper analysis. However, with dispersed models, stability of the numerical solution will be an issue that needs to be addressed (Al-Ibadi et al., 2018b).

The fractional flow analysis of LSWF has been discussed in the literature previously (Jerauld et al., 2008; Tripathi and Mohanty, 2008; Attar, 2017). In that work, analytical solution of fractional flow supposed to be correct though they had misfit for cases affected by dispersion. However, mismatching was explained in different ways, such as due to fingering effect (Tripathi and Mohanty, 2008), numerical error (Jerauld et al., 2008) or because of trapped oil and chemical retardation (Alexeev, 2015). Tripathi and Mohanty (2008) saw a spread in predicted waterfronts but no change in the velocity. We have been the first to report that physical or numerical dispersion can lead to a retardation effect on waterfronts with a feedback to the salinity profile. In other work, any apparent retardation effect was always linked with chemical reactions and utilized to interpret the drive mechanism of low salinity (e.g. Sharma and Mohanty, 2018) without considering dispersion. We show clearly that the evolution of the mixing zone will lead to this retardation effect due to the fact that the transition to low salinity behaviour occurs over a limited effective salinity range. This is significant since dispersion in low salinity models can be induced by different factors such as fingering (Tripathi and Mohanty, 2008), heterogeneity (Attar, 2017) and numerically (Al-Ibadi et al., 2018b).

By analyzing the fractional flow behavior, we can identify which parts of the relative permeability data are important for simulation of LSW. Depending on whether or not the flood is secondary or tertiary, only certain parts of the flow curves are required when dispersion is minimal. As a secondary process, LSWF requires the lower saturations data of the high salinity fractional flow curves and higher saturations of the low salinity curves. Tertiary LSWF requires more precise description of the whole of the high salinity fractional flow curve. This has implications for history matching of core flood modelling also.

In this work we have explained the relationship between the salinity profile and fractional flow. We also give insights into the relationship between ion fronts, e.g. Ca$^{2+}$ and Mg$^{2+}$, and fractional flow where ions are transported in the same manner as the salinity mixing zone at the continuum scale. We do not consider chemical adsorption or desorption of ions but these could be added. The physical effects that we report would still be observed, albeit altered. For more details see (Al-Ibadi et al., in press). Of course, adding chemical reactions such as ion exchange would add further complications to the model and the behaviour.

Heterogeneity at the field scale will also result in physical dispersion. Replacing physical dispersion by numerical dispersion seems reasonable. Recently Ghanbari et al. (2018) reported an approach to relate numerical dispersion on a coarse grid to the dispersion that would be observed in miscible flooding on a fine grid due to heterogeneity effects. This followed work by Gelhar (1983) and Garmeh and Jones (2010) who were able to relate the length scale and magnitude of heterogeneity of random distributions of permeability to the equivalent numerical dispersion coefficient in advection-dispersion processes. It is apparent that a straight replacement of physical dispersion with a numerical equivalent remains non-trivial and is dependent on cell size compared to physical dispersivity.
The outcomes of this work can be used to produce a more precise numerical model. For instance, Al-Ibadi et al., (2018b) showed that increased numerical dispersion (by coarsening) will lead to slow down/or speed up the low salinity waterfront depending on the effective salinity range relative to the midpoint of salinity front. In our work, here, we show that the speed of LS-waterfront is also a function of effective salinity, thus we can tune the effective salinity range to mitigate (upscale) the effect of numerical dispersion for a coarse case scenario.

6. Conclusions

We arrive at the following conclusions which are of importance in the simulation of Low Salinity Water Flooding (LSWF) and how dispersion can be represented better at the field scale:

- The full representation of the relative permeability data are not required for simulation suggesting a more reliable form to match experiments of low salinity water flooding.
- Effective salinity is important when combined with dispersion, and it affects the speeds of the low salinity and high salinity water fronts.
- An effective retardation effect is introduced which is applicable for most cases.
- The fractional flow analysis can be augmented based on this information using a predicted effective retardation term.
- Although this study highlighted the impact of the salinity front on the fractional flow, this impact of the salinity front can be replaced by any ion front, e.g. Ca$^{2+}$ or Mg$^{2+}$.

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8. References


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Highlights

- We show that for low salinity water flooding (LSWF), precision of relative permeability data is required specifically in the lower saturations during high salinity flow and higher saturations of the low salinity flow.
- We also observe that tertiary LSWF requires more precise description of the whole of the high salinity fractional flow curve.
- Our results also show that fractional flow behaviour depends strongly on the specification of effective (critical) salinity range as well as dispersion. The impact is shown in the speeds of the formation and low salinity water fronts.
- A retardation like effect is observed due to the combined effect of salinity dispersion with the effective salinity range.
- We have suggested a modification to the analytical solution of fractional flow that can be used to better predict behaviour accounting for these effects.