Measurement of Emulsion Flow in Porous Media: Improvements in Heavy Oil Recovery

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Abstract. Many heavy oil and bitumen reservoirs in the world are too small or thin for thermal enhanced oil recovery methods to be economic. In these fields, novel methods of less energy intensive, non-thermal technologies are required. Previous experience has shown that the injection of low concentrations of aqueous alkali-surfactant solutions into the reservoir can significantly improve the oil recovery, beyond that of waterflooding. This is due to the in-situ formation of emulsions, which plug off the water channels and lead to improved sweep efficiency in the reservoir. The proper control of these floods requires methods for monitoring the formation and effect of these emulsions. In this paper, the results of laboratory core floods are interpreted to demonstrate how the pressure and flow response can be related to the formation of these emulsions. A new technique (low field NMR) is also used to directly measure W/O emulsions in porous media. Finally, a numerical study is performed in order to demonstrate how the in-situ formation of emulsions can be simply represented in simulation software.

1. INTRODUCTION
Several countries in the world contain significant resources of heavy oil and bitumen, which is characterized by having high viscosity, and density similar to that of water. For countries such as Canada, Venezuela and China, this oil resource constitutes a significant part of the economy, and as oil demand rises worldwide this unconventional crude oil could be could an important source of global energy in years to come.

In Canada alone, the total bitumen resource base is estimated at approximately 270 billion m³ of oil in place (AEUB, 2007). From this incredible resource, the oil volumes that can be recovered under current technology (i.e. the oil reserves) are approximated at 10% of the total oil in place (Radler, 2006). A fraction of this oil can be recovered through surface mining, but over 90% of the oil in place has to be recovered through in-situ technologies (AEUB, 2007). This presents a tremendous challenge for increasing the amount of oil that can be economically recovered from these reservoirs.

In most cases, bitumen is found in unconsolidated, high porosity and permeability sand deposits. Ease of flow is therefore not a major concern in these reservoirs; rather the high oil viscosity is the single greatest impediment that must be overcome in order to produce the oil. As a result, most enhanced oil recovery schemes tend to focus on some variation of thermal injection, whereby the oil is heated to reduce its viscosity and induce flow. In order for these thermal methods to be applied, it is generally accepted that the reservoir must be more than 10 m thick (AEUB, 2007) or heat loss to the overburden and underburden will be too significant.
Heavy oil is a special subset of these bitumen deposits, whereby the oil is slightly less viscous and therefore has some limited mobility at reservoir conditions. The oil may initially contain some solution gas, so approximately 5% of the oil may be recovered through primary solution gas drive mechanisms. This leaves significant volumes remaining for improved oil recovery. In many cases, however, the reservoirs are relatively thin (under 10 m in thickness) and may have been disturbed to an unknown extent during primary production. Many reservoirs also may contain bottom water aquifers, or gas caps. All of these conditions make them poor candidates for thermal oil recovery processes, and less-energy intensive non-thermal methods are required to produce this remaining oil.

Chemical flooding is a relatively old technology (Nutting, 1925; Reisberg and Doscher, 1956), and has been applied in enhanced recovery schemes for conventional oil for several decades. In this technique, a surface-active agent (surfactant) is injected along with water to reduce the interfacial tension between oil and water. This in turn enables displacement of discontinuous oil ganglia that are present after waterflooding. Chemical flooding is therefore a tertiary recovery process in conventional oil, and is performed with the goal of reducing the residual oil saturation in waterflooded zones. Alkali flooding is a special subset of surfactant flooding, whereby the surfactants are generated in-situ through the reaction between the injected alkali and organic acids from the oil. This recovery technique is highly sensitive to factors such as the salinity of the aqueous phase (Nelson et al., 1984), thus surfactants are often injected along with the alkali to stabilize the system. This procedure, known as alkali-surfactant flooding, provides similar stability as conventional surfactant floods, while substantially reducing the cost of the required surfactant.

In heavy oil systems, chemical flooding has also been shown to yield improved oil recovery compared to waterflooding (Scott et al., 1965; Dranchuk et al., 1974; Farouq Ali et al., 1979; Dong et al., 2007). A common observation made in these floods was that the injection of alkali and/or surfactant appeared to lead to the generation of W/O emulsions. These emulsions were expected to be more viscous than the constituent oil, thus the proposed recovery mechanism was that of mobility ratio enhancement by displacing heavy oil by a higher viscosity W/O emulsion phase (Farouq Ali et al., 1979; Dong et al., 2007). However, it is not clear how the emulsion phase could be displaced in a stable fashion by the aqueous solution at the injection end of the flood, nor is it clear where the emulsions are forming and from where oil is being displaced.

In waterflooding, oil is significantly by-passed by water due to the disparity between the oil and water viscosity. Chemical injection still involves the displacement of viscous oil by a low viscosity aqueous solution, so the improved oil recovery observed must be somehow related to the generation and movement of emulsions in the porous media. In order to properly understand these recovery mechanisms, techniques need to be developed to interpret the response of the system to chemical injection. Specifically, the presence and effect of emulsions must be quantified before any attempt can be made to model this improved oil recovery response. Once methodologies are present for measuring the generation and effect of these emulsions, then it will be possible both to predict their behaviour in both laboratory and field scale projects. Thus, the development of techniques for measuring emulsions is key to the design and control of chemical floods in heavy oil systems. In this work a suite of core floods was performed, and the in-situ formation of emulsions was identified through measurements of pressure and produced fluids, and through spectra acquired using low field nuclear magnetic resonance. The observations made allowed for an improved understanding of how heavy oil is recovered through alkali-surfactant injection.

2. MATERIALS AND PROCEDURES
In previous work (Bryan and Kantzas, 2007), core floods were performed at ambient temperature (23°C) on a heavy oil in sand packs of varying permeability. The oil used in this study comes from a field in Saskatchewan, Canada. It has a viscosity of 11,500 mPa·s at 23°C, and a density of 982 kg/m³. Although all the oil came from the same field, it was still heterogeneous so some of the core floods were performed with oil that had a viscosity of 15,000 mPa·s. The surfactant is a commercial anionic sodium alkane sulphonate (Bio-Terge PAS-8S) and was supplied by Stepan Company. The alkali
used was sodium carbonate, Na$_2$CO$_3$, which was chosen over other alkali agents due to its buffering capacity and the fact that it is less sensitive to variations in water chemistry than NaOH (Martin and Oxley, 1985). Measurements of oil-water interfacial tension showed that under relatively low chemical concentrations (0.1 wt% surfactant and < 1 wt% alkali in water), the interfacial tension could be reduced by approximately three orders of magnitude. Thus, ultra-low interfacial tensions are possible even in viscous oil systems. This is a necessary requirement for emulsion formation, but it does not explain which emulsion (O/W or W/O) will form. Through phase behaviour testing, it was observed that when the aqueous phase contained 2 wt% NaCl, only viscous W/O emulsions would be generated, even for systems containing significantly more water than oil (Bryan and Kantzas, 2007). This is due to the fact that oil is much more viscous than water, thus in an emulsion system oil will more easily become the continuous phase (Garret, 1972; Isaacs and Chow, 1992). In chemical floods performed using brine (2 wt% NaCl in water), it was therefore expected that only W/O emulsification would occur.

Table 1 lists the dimensions of the core floods performed with brine being the aqueous phase. In all tests, the cores were first saturated with brine, and the permeability to brine was measured. The cores were then flooded to irreducible water saturation ($S_{wi}$) by injecting heavy oil at a fixed rate. Subsequently, the cores were then either flooded by brine, alkali-surfactant (AS) solution, or a combination of the two. All the chemical floods were conducted using a fixed concentration of 0.1 wt% surfactant and 0.5 wt% alkali in brine.

Experiments Q – T, Y and Z were conducted as primary AS floods, meaning that in these systems the AS solution was injected directly into the core that contained oil and irreducible water saturation. In these tests, approximately five pore volumes of fluid were injected. In floods U – X and AA – AC, brine injection was first carried out at the same fixed rate for five pore volumes, followed by an additional 1 – 2 pore volumes of AS injection at varying rates.

Table 1. Chemical Core Floods Performed Using Brine as the Aqueous Phase

| Core ID | D (m) | L (m) | Porosity | k (D) | $S_{wi}$ | $\mu_o$ (mPa s) | WF rate (m/d) | AS rate (m/d) |
|---------|-------|-------|-----------|-------|---------|----------------|----------------|----------------|
| Q       | 0.011 | 0.103 | 0.45      | 15.98 | 0.163   | 11,500         | 0.51           | 0.51           |
| R       | 0.011 | 0.103 | 0.45      | 11.04 | 0.255   | 11,500         | 0.51           | 0.51           |
| S       | 0.011 | 0.103 | 0.45      | 15.9  | 0.159   | 11,500         | 0.51           | 0.51           |
| T       | 0.011 | 0.103 | 0.45      | 11.74 | 0.250   | 11,500         | 0.51           | 0.51           |
| U       | 0.011 | 0.103 | 0.45      | 17.94 | 0.194   | 11,500         | 0.51           | 0.51           |
| V       | 0.011 | 0.103 | 0.45      | 11.55 | 0.243   | 11,500         | 0.51           | 0.51           |
| W       | 0.011 | 0.103 | 0.45      | 11.81 | 0.150   | 15,000         | 0.51           | 0.26           |
| X       | 0.011 | 0.103 | 0.45      | 10.24 | 0.135   | 15,000         | 0.51           | 1.02           |
| Y       | 0.011 | 0.105 | 0.49      | 1.48  | 0.109   | 11,500         | 0.51           | 0.51           |
| Z       | 0.011 | 0.105 | 0.49      | 1.19  | 0.203   | 15,000         | 0.51           | 0.51           |
| AA      | 0.011 | 0.105 | 0.49      | 0.92  | 0.105   | 15,000         | 0.51           | 0.51           |
| AB      | 0.011 | 0.105 | 0.49      | 0.97  | 0.165   | 15,000         | 0.51           | 0.26           |
| AC      | 0.036 | 0.211 | 0.45      | 9.05  | 0.115   | 11,500         | 0.42           | 0.42           |

In all of the tests, the pressure gradient across the core was monitored, as was the ratio of water and oil produced. Specifically, the relationship between the pressure gradient and the oil recovery was compared between chemical flooding and waterflooding, in order to identify the influence of the W/O emulsions, and to determine the efficiency of the oil displacement. Several core floods were performed in high permeability cores (values on the order of 11 – 15D), while other tests were performed in cores with permeabilities on the order of 1D. In systems where O/W emulsions formed preferentially to W/O emulsions, it had been observed that different recovery profiles were generated for high vs. low permeability sand (Bryan and Kantzas, 2007). In the high permeability cores, chemical injection led to the generation of a pressure build-up in the system, with a corresponding
drop in the produced water cuts. Despite the observed alteration in the behaviour of the system, oil and water appeared to be produced as separate phases. In contrast, when O/W emulsions were generated in low permeability sand, these emulsions were actually produced, with a corresponding loss in the flood efficiency (Bryan and Kantzas, 2007). In these tests, therefore, one of the objectives was to determine if the same differences in flood response would be observed in the production and displacement of viscous W/O emulsions.

Finally, several core floods were performed in a TECAPEEK™ core holder, which is NMR-transparent. The sand pack measured was approximately 0.5 m in length, and spectra were acquired at four locations within the sand pack. The spectra were then interpreted to separate the oil and water signals, and the water spectra were used to identify the presence of in-situ W/O emulsions. These tests all allowed for improved visualization of the effect of emulsion generation on improved oil recovery.

3. PRIMARY AND SECONDARY CHEMICAL FLOODING

In reservoir flooding applications, chemical flooding could be carried out either as a primary process (i.e. directly into the sand that contains oil and irreducible water saturation), or after waterflooding. Figure 1 compares the oil recovery response waterfloods and primary AS floods. Both configurations are qualitatively similar: oil recovery is high during the first 1 – 2 PV injected, and the slope of the recovery profile is less at later times. In general, chemical flooding recovers more oil than waterflooding.

![Fig. 1](image-url) Oil recovery profiles from constant rate waterflooding (a) and primary AS flooding (b)

The viscosity of water and AS solution are essentially the same, thus the improved oil recovery response in Figure 1 is not a reflection of a higher viscosity aqueous phase, as is the case in polymer flooding. Rather, the low interfacial tension and shear due to flow through rock pores leads to the generation of emulsions, and these alter the flow properties of oil and water in the pores of the rock. A key to understanding the flood response is to compare the oil recovery up to the point of breakthrough, and after breakthrough. These results are summarized in Table 2.

In heavy oil flooding, the actual point of breakthrough is difficult to determine accurately, since it happens very quickly, and only discrete samples of produced oil and water are measured so it is likely that the actual point of breakthrough does not correspond to a sampling time. However, it is evident from Figure 1 that the change in slope of the oil recovery (indicative of a continuous aqueous phase) occurs within the first PV of fluid injection. Therefore, in Table 2 the recovery values are summarized for the first PV of fluid injection and for the subsequent injected volumes separately.

On average, the waterflood recovery was 0.16 for the first PV of water injection, compared to 0.33 during the first PV of primary AS injection. The recovery is therefore significantly higher during the chemical floods. Even after water breakthrough, it appears that when W/O emulsions are formed the flood still behaves more efficiently than a waterflood. However, the difference in flood efficiency (oil
recovery/PV injected) is less significant at later times. The important contribution of primary chemical flooding appears to be in improving the breakthrough oil recovery.

Table 2. Oil Recovery Values for Waterflooding and AS Flooding

| Core ID | WF Recovery (1st PV Inj) | WF Recovery (last 4 PV) | Primary AS (1st PV Inj) | Primary AS (last 4 PV) | Secondary AS (1st PV inj) |
|---------|--------------------------|-------------------------|-------------------------|------------------------|--------------------------|
| Q       | 0.315                    | 0.276                   | 0.445                   | 0.236                  | 0.143                    |
| R       | 0.456                    | 0.128                   | 0.382                   | 0.156                  | 0.150                    |
| S       | 0.306                    | 0.198                   | 0.280                   | 0.214                  | 0.300                    |
| T       | 0.382                    | 0.156                   | 0.306                   | 0.198                  | 0.199                    |
| Y       | 0.382                    | 0.156                   | 0.306                   | 0.198                  | 0.123                    |
| Z       | 0.315                    | 0.276                   | 0.445                   | 0.236                  | 0.169                    |
| U       | 0.153                    | 0.046                   | 0.151                   | 0.044                  | 0.143                    |
| V       | 0.156                    | 0.055                   | 0.151                   | 0.088                  | 0.150                    |
| W       | 0.172                    | 0.084                   | 0.151                   | 0.088                  | 0.300                    |
| X       | 0.156                    | 0.055                   | 0.151                   | 0.088                  | 0.199                    |
| AA      | 0.144                    | 0.061                   | 0.144                   | 0.061                  | 0.123                    |
| AB      | 0.128                    | 0.088                   | 0.128                   | 0.088                  | 0.169                    |
| AC      | 0.128                    | 0.088                   | 0.128                   | 0.088                  | 0.405                    |

AS flooding is more expensive than waterflooding, and is much more difficult to design at the field scale. It is therefore unlikely that chemical floods will be carried out without first recovering some oil by less-expensive waterflooding. In the waterfloods, continuous channels of water form quickly due to the adverse mobility ratio between oil and water. After breakthrough, these water channels act as low-resistance pathways for flow, therefore most of the injected water simply flows through these fingers and by-passes the oil. This is evidenced by the decline in the oil production for both waterfloods and primary chemical floods in Figure 1. Therefore, a inference that could be made is that for secondary AS flooding, the injected chemical will simply flow through these channels and not contact significantly more oil. In reality, however, it was observed that secondary AS injection still led to an improvement in the recovery response. Figure 2 shows the oil production and water cut profiles for a case where a constant rate waterflood was conducted for 4.5 PV, followed by AS injection at the same rate. The response of the system to chemical injection is evident in both the reduction in the water cut and the increase in recovery.

![Pressure with oil recovery](a)  ![Pressure with water cut](b)

Fig. 2  Pressure with oil recovery (a) and water cut (b) profiles for secondary AS flooding
Even though continuous water channels were already present across the core at the start of AS injection, the presence of surfactants still led to an increase in the oil recovery compared to waterflooding. The response shown in Figure 2 is that of Experiment AC in Table 2; most of the core floods did not exhibit such a high secondary flooding recovery enhancement. On average, secondary chemical flooding leads to an additional recovery of 21% more oil. This is similar to the recovery efficiency of the primary chemical floods in the last four PV of fluid injection (0.2 Oil RF/PV Injected). Therefore, the formation of emulsions seems to be effective as a heavy oil recovery mechanism even in reservoirs that have been previously waterflooded.

One observation that could be made from Figure 2 is the presence of very high maximum pressures for both waterflooding and AS flooding. The fact that pressure builds up in the system could be evidence not of emulsions, but rather the simple formation and subsequent displacement of an oil bank. This is the common interpretation of such a response in enhanced oil recovery projects (Green and Willhite, 1998). If this were the actual displacement mechanism, then the improved oil recovery is simply a reflection of an increase in the pressure gradient that is applied across the core. Thus, in order to properly understand the enhanced oil recovery mechanism, this interpretation must be validated. Figure 3 compares the ratio of the AS/waterflood pressure gradients to their recoveries. In all the cores tested, the recovery of oil for the same pressure gradient is higher under chemical flooding. Therefore, AS injection does not simply lead to mobilization of oil and the subsequent formation of an oil bank. Rather, for the same pressure gradient applied across the core, more oil is displaced by the chemical than by water.

![Fig. 3 Correlation between recovery and max pressure for waterflooding vs. AS flooding](image)

The results from Figures 1 to 3 show how simple measurements of pressures and produced fluids can be used to make important observations regarding the nature of heavy oil displacement by chemical solution. Even with no additional information available, it is possible to determine that AS injection results in changes in the flow properties of oil and water in porous media, and that this is responsible for improved oil recovery. Thus, in both laboratory and field studies, measurements of the pressure vs. production response are key to identifying that a change has actually occurred. The mechanism proposed is that of the formation of W/O emulsions, as observed in bulk liquid phase behaviour studies. However, simple pressure measurements cannot definitively identify the presence of the emulsions. Therefore, a more detailed study was also performed using low field NMR.

4. NMR MEASUREMENTS OF IN-SITU WATER EMULSIFICATION

Low field nuclear magnetic resonance (NMR) has been applied in the petroleum industry for several decades (Brown and Gamson, 1960). NMR logging tools are commonly used to predict rock properties such as porosity and permeability (Straley et al., 1997; Coates et al., 1999). In recent years, applications of NMR technology have also been identified in heavy oil and bitumen formations, for
the determination of in-situ oil viscosity (Bryan et al., 2007) and fluid content in oil sand samples (Bryan et al., 2006). Recently, methodologies were developed (Mai, 2008; Bryan et al., 2008) to determine the in-situ distribution of water in porous media. In this work, these methodologies were used to provide quantitative evidence of W/O emulsification during chemical flooding.

NMR measures the response of hydrogen in the presence of magnetic fields. Hydrogen has a property known as “spin”, causing protons to behave essentially like tiny bar magnets, lining up in the direction of magnetic field lines. In an NMR experiment, radio-frequency pulses are applied to tip the protons onto a perpendicular plane, known as the transverse plane. The time for them to return to their equilibrium position (lined up with the external magnetic field lines) is recorded as a decaying signal on the transverse plane. Subsequently, this data is converted into a spectrum of amplitudes and associated relaxation time constants and all analysis is performed on these spectra.

Relaxation rates (and therefore relaxation times) depend on both the physical properties of the fluid being measured and the location of the fluids in the porous medium. The total relaxation is the summation of bulk relaxation – proportional to the fluid viscosity, and surface relaxation – proportional to the size of the pore containing the fluid (Straley et al., 1997; Coates et al., 1999).

Figure 4 shows the spectra of fluids at four length locations in the unconsolidated sand pack in the NMR-transparent core holder.

For low viscosity fluids like water, the bulk relaxation is significantly slower than the surface relaxation, so the spectra of water in porous media are analogous to the pore size distribution of the sand (Straley et al., 1997; Coates et al., 1999). In the sand pack shown in Figure 4(a), there is a low fraction of small pores with relaxation times between 5 – 10 ms, but the majority of the pores have relaxation times between 10 – 200 ms. All four length fractions show similar T2 peak locations, so the pore sizes are homogeneous along the length of the core. The core was then flooded down to irreducible water saturation (Swi) using the same viscous heavy oil as in the other core floods, and the resulting spectra at the same four locations are presented in Figure 4(b). These spectra all have a large, fast-relaxing peak under 10 ms. This is the signal from the viscous oil; for high viscosity fluids the relaxation times are governed by the fluid viscosity, thus the relaxation times of the oil are essentially independent of any influence from the porous medium (Bryan et al., 2007). The signal from the oil therefore does not provide any information about where the oil is located, but the signal from any water remaining is still a reflection of the physical location of the water. In Figure 4(b), the signal after the oil peak is the contribution from connate water; most of the amplitude between 10 – 200 ms has disappeared, so oil is physically present in the larger pores.

The sand pack was first waterflooded for approximately 5 PV’s at a constant rate, followed by AS injection at the same rate. The resulting spectra after the AS flood are shown in Figure 5, for the same
four locations in the sand pack. When comparing the amplitude of the first peak of the spectra in Figures 5 and 4(b), it is evident that the amplitude is lower after waterflooding and AS flooding. This is therefore an indication that there is less oil remaining to give off an NMR signal, so the spectra validate the fact that oil has been displaced out of the core. It is significant, however, that there does not appear to be an obvious difference in the oil amplitudes with length. This shows that oil was displaced all along the sand pack, and the chemical flood did not lead to the generation of a high oil saturation bank anywhere in the core.

Any signal after the first peak is the contribution from water. During the waterflood, as the oil amplitude decreased, a water peak formed between 10 – 200 ms. This was water relaxing in the pores of the sand, and corresponds to injected water that has displaced oil completely out of pores. This signal is therefore that of the continuous water channels formed during the waterflood (Mai, 2008; Bryan et al., 2008). In Figure 5, however, there is additional signal relaxing after 200 ms. There were no pores present to give such a slow relaxing signal, so this water is still physically in the same size of pore. The slower relaxation times indicate that protons in the water are no longer in contact with the sand, so the surface relaxation effects are reduced and the water is now relaxing closer to its bulk values. This is direct and quantitative evidence of W/O emulsions that have formed within the core.

In Figure 5, it is also evident that W/O emulsions form all along the length of the sand pack; once again there was no significant variation in the emulsion amplitude with length. The water saturation in the pores and in emulsions was therefore averaged for the four locations, and the mean values of saturation are plotted in Figure 6, for time of the AS flood. The water in the pores decreases from 40% saturation down to 20%. As this happens, the saturation of W/O emulsions increases from 10% up to 50%. The total water saturation increases during the chemical flood, indicating that additional oil is displaced out of the core and this pore space is now occupied by chemical solution.

The majority of emulsions are formed within the first half a PV of secondary AS injection. During this time, pressure would build up in the core, as shown in Figure 2. The pressure build up was accompanied by a reduction in the produced water cut, and correspondingly an increase in the oil recovery. These results present an important implication of chemical flooding: as the majority of W/O emulsions are forming, this leads to a decrease in the water production in the system. The improved recovery response from chemical flooding is therefore at least partially a reflection of the formation of these W/O emulsions all along the length of the system.
The utilization of low field NMR for measurements of in-situ fluid distributions therefore provides a valuable contribution to the pressure and recovery data measured during the core floods of Tables 1 and 2. Specifically, the spectra validate the hypothesis that emulsification is somehow responsible for improved oil recovery, compared to the concept of an oil bank formation. Thus, NMR technology can be used at least at the laboratory scale to monitor the formation and presence of in-situ W/O emulsions.

5. PREDICTIONS OF HEAVY OIL RECOVERY BY W/O EMULSIFICATION
With the combined methods for measuring emulsion formation and its effect on the produced fluids, a mechanism can now be proposed to explain how chemical injection can lead to enhanced heavy oil recovery. This proposed mechanism is then tested through a simple reservoir simulation model.

5.1 Proposed AS Flooding Recovery Mechanism
In Figure 7, a waterflood was conducted for approximately ten PV’s of fluid injection, followed by an additional three PV’s of AS injection. The oil recovery profile is compared against the predicted recovery, which was made by following the same trend of the waterflood for many more PV’s of constant rate injection.

It is possible that with very long times left for the waterflood, similar oil recoveries may be possible for waterflooding and chemical flooding. The chemical flooding appears to provide an acceleration to the oil recovery, thus the value of chemical injection is mostly in the fact that oil can be recovered.
much more quickly due to the build-up of pressure in the system. Moreover, after the pressure has once again declined, there is still 30 – 40% of oil remaining in the sand pack. Therefore, chemical flooding does not necessarily yield lower residual oil saturations, as is expected in conventional oil surfactant flooding (Green and Willhite, 1998), but the oil is simply recovered much more quickly than if waterflooding were continued.

The data from the experiments can be summarized in several key observations. First, the injection of chemical, whether as a primary or secondary agent, leads to a more efficient displacement of oil for any given pressure gradient. Emulsions are formed all along the length of the system, and correspondingly oil is produced along the length of the core instead of as an oil bank. During the time when most of the emulsions are forming, pressure builds up in the core and correspondingly water production decreases and oil recovery increases. By focusing on measurements of flow of multiple fluid phases and in-situ emulsification, it is now possible to propose a mechanism by which the injected chemical is displacing the oil.

AS solution mixes with oil, and the combination of low interfacial tension and shear due to flow through rock pores leads to the formation of W/O emulsions. During secondary AS injection, these emulsions are forming in the continuous water channels, as evidenced by the decrease in surface water saturation in the NMR spectra. When these emulsions form, they effectively block off the water channels, so the produced water cuts decrease. These emulsions cannot be easily propagated through the rock pores, so they will instead block off the water channels and lead to improved sweep efficiency of the flood. In this manner, oil is recovered much more quickly, compared to waterflooding. In primary AS flooding, the same mechanisms are present – instead of water fingering through the oil, emulsions form and block off the water channels. This in turn leads to improved breakthrough recovery of the oil. After continuous emulsion channels form along the length of the core, the plugging of these channels is much more difficult and subsequent chemical injection will not be as efficient. Therefore, AS injection will result in maximum oil recovery within the first pore volume; at later times pressure once again declines in the core and the oil rates decline as well.

In order to model emulsion flow in porous media, mathematical formulations have been proposed in the literature (Alvarado and Marsden, 1979; Abou-Kassem and Farouq Ali, 1995), incorporating emulsion viscosity as a function of shear rate. However, in systems where emulsions are formed in-situ, the total multi-phase flow condition involves emulsion formation, breaking, plugging and flow, along with flow of un-emulsified fluids. Therefore, a simpler approach is to incorporate all of these unknown parameters into the effective relative permeability of the oil and water. If the mechanism of improved oil recovery is really that of plugging of the water channels and improved sweep efficiency, then a simple way to model and predict the chemical flooding response is simply to reduce the apparent relative permeability to water. Using the data from the core floods in Tables 1 and 2, relative permeability relationships were developed by assuming a simplistic Darcy’s Law relationship. These relative permeability values are apparent values, since the true relative permeability behaviour cannot be determined in unstable flooding configurations. However, for these systems, the apparent oil and water relative permeability behaviour could be summarized in the following expressions:

\[ k_{ro} = 1.015(1 - S_e)^{0.2997} \]  \hspace{1cm} (1)

Where \( k_{ro} \) = the apparent relative permeability to oil  
\( S_e \) = normalized water saturation.

For waterflooding and AS flooding, the corresponding relative permeability relationships are:

\[ k_{rw} = 0.0148(S_e)^{2.0161} \]  \hspace{1cm} (2)

And
In these expressions, the normalized water saturation is defined as:

\[ S_e = \frac{S_w - S_{wi}}{(1 - S_{ce}) - S_{wi}} \]  

(4)

The correlations for Equations (1) to (3) were developed empirically, using the normalized water saturations for all of the core floods performed. The resulting water saturations are shown in Figure 8.

Fig. 8  Predicted oil and water relative permeability curves

The apparent water relative permeability values are much lower than those of oil, due to the significant viscosity difference between the oil and water. It should be noted that for the data obtained in this study, there was no distinct difference in the oil relative permeability behaviour for waterflooding vs. chemical flooding, so only one relationship was developed for the oil. This is in contrast to what other researchers have found (Wang et al., 2008). The main contribution from the chemical injection is a reduction in the relative permeability to water, which should theoretically reduce the production of water. This was tested in a simple reservoir simulation study.

### 5.2 Numerical Simulation of AS Flooding

A simple model for simulating waterflooding and chemical flooding in a heavy oil sand pack was constructed using CMR Stars™ (2006.10). This model is a laboratory scale simulation, containing dead oil and aqueous phase (either water or AS solution) as the two components in the reservoir. The model was run isothermally at 25°C, using the input parameters summarized in Table 3.

| Input Parameter                  | Value                  |
|----------------------------------|------------------------|
| Length of model                  | 10.3 cm                |
| Cross-sectional area             | 0.933 cm²              |
| Gridblocks in “i” direction      | 20 (0.515 cm long)     |
| Gridblocks in “j” direction      | 1 (0.966 cm long)      |
| Gridblocks in “k” direction      | 10 (0.0966 cm long)    |
| Porosity                         | 0.45                   |
| Oil viscosity                    | 11,500 mPa.s           |
| Irreducible water saturation     | 0.187                  |
The reservoir consists of two layers: the first eight rows have a permeability of 6 D in all directions. The bottom two layers have a permeability of 21 D. Overall the permeability of the model is 9 D; the two layers are present in order to simulate unequal displacement through the higher permeability layer. This leads to early breakthrough of water, which occurs during viscous fingering in heavy oil waterfloods. Figure 9 shows a schematic of this system, with a single injector at the inlet face of the model and the producer at the outlet.

Fluids were injected at 2 mL/hr, giving a frontal velocity of 0.51 m/day, which is the same as what was used in the core floods in Table 1. In one case, waterflooding was carried out at a fixed injection rate, using the relative permeability to water given by Equation (2). In a separate run, AS solution was injected at the same fixed rate, by using the relative permeability to water given by Equation (3). The oil recovery profiles for waterflooding vs. primary AS flooding are shown in Figure 10. It is evident from this plot that the main contribution from the primary AS flood is a higher breakthrough recovery. This is similar to the behaviour shown in Figure 1.

After water breakthrough the slope of the oil recovery from the AS flood is still higher than that of waterflooding, indicating that even at later times when the pressure has already declined across the core, chemical flooding is still more efficient due to plugging of some of the water channels. As expected, therefore, the improved recovery of the primary AS flood can be modeled by a simple change in the apparent relative permeability to water.
Figure 11 shows the pressure gradient with its associated production and water cut response to a waterflood with a secondary AS flood. Waterflood was carried out for approximately four PV, followed by another three PV of AS injection. Approximately 23% of the oil was recovered during the waterflood, followed by another 20% of oil that was mainly recovered during the first PV of chemical injection. The profiles in Figure 11 are qualitatively very similar to what was observed in the laboratory experiments exemplified in Figure 2, but no attempt was made in this study to actually history match the production data obtained.

The results of Figures 10 and 11 demonstrate how a simple change in the apparent relative permeability to water can be used to generate the flood responses observed in the laboratory core floods. It is also important to note that in both primary and secondary AS flooding systems, the same water relative permeability relationship was used. The injected chemical therefore behaves similarly in both flooding configurations, which is expected. The oil relative permeability is also unaffected by the injection fluid, since the main influence of the AS solution is to plug off the water channels through the formation of emulsions.

6. CONCLUSIONS
By properly monitoring the response of the system, both through quantitative NMR spectra and even through simple measurements of pressure vs. produced fluids, an improved understanding of chemical flooding was achieved. This understanding was validated through numerical simulation.
Upon injection of chemical, pressure builds up again in the system, and this corresponds to lower water cuts and improved production of oil. In this study, measurements were made of these multiphase systems in order to identify the mechanism by which chemical injection can be used to recover oil. Using a combination of pressure measurements, collection of produced oil and water, and low field NMR of in-situ water distributions, the recovery mechanism has been identified. Alkali-surfactant solutions reduce interfacial tensions and result in the formation of W/O emulsions. These emulsions plug off the water channels, leading to improved sweep efficiency in the system.

The consequence of this recovery mechanism is that chemical injection in heavy oil may not necessarily lead to lower residual oil saturations, as is the case in conventional oil surfactant flooding. The presence of emulsions simply accelerates the oil recovery, thus alkali-surfactant injection behaves almost like a polymer flood in heavy oil applications. In order to model the response from chemical injection, the apparent relative permeability of the aqueous phase is reduced. With this simple change in the relative permeability behaviour, the response from both primary and secondary chemical flooding can be modeled.

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NOMENCLATURE

| Symbol | Description | Unit |
|--------|-------------|------|
| AS | Alkali-surfactant flooding |  |
| D | Diameter | [m] |
| k | Permeability | [D, \(\mu\)m\(^2\)] |
| \(k_{ro}\) | Apparent relative permeability to oil |  |
| \(k_{rw}\) | Apparent relative permeability to water |  |
| L | Length | [m] |
| NMR | Nuclear magnetic resonance |  |
| PV | Pore volume |  |
| RF | Recovery factor |  |
| \(S_e\) | Normalized water saturation |  |
| \(S_{or}\) | Residual oil saturation |  |
| \(S_{swi}\) | Irreducible water saturation | [fraction] |
| \(T_2\) | NMR transverse relaxation time | [ms] |
| W/O | Water in oil |  |
| WF | Waterflood |  |

Greek Letters

| Symbol | Description | Unit |
|--------|-------------|------|
| \(\mu_o\) | Oil viscosity | [mPa\cdot s] |

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