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Simulation study of Surfactant Transport Mechanisms in Naturally Fractured Reservoirs

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Simulation study of Surfactant Transport Mechanisms in Naturally Fractured Reservoirs

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Dedicated to my beloved parents
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Abstract

Simulation study of Surfactant Transport Mechanisms in Naturally Fractured Reservoirs

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Surfactants both change the wettability and lower the interfacial tension by various degrees depending on the type of surfactant and how it interacts with the specific oil. Ultra low IFT means almost zero capillary pressure, which in turn indicates little oil should be produced from capillary imbibition when the surfactant reduces the IFT in naturally fractured oil reservoirs that are mixed-wet or oil-wet.

What is the transport mechanism for the surfactant to get far into the matrix and how does it scale? Molecular diffusion and capillary pressure are much too slow to explain the experimental data. Recent dynamic laboratory data suggest that the process is faster when a pressure gradient is applied compared to static tests. A mechanistic chemical
compositional simulator was used to study the effect of pressure gradient on chemical oil recovery from naturally fractured oil reservoirs for several different chemical processes (polymer, surfactant, surfactant-polymer, alkali-surfactant-polymer flooding). The fractures were simulated explicitly by using small gridblocks with fracture properties. Both homogeneous and heterogeneous matrix blocks were simulated. Microemulsion phase behavior and related chemistry and physics were modeled in a manner similar to single porosity reservoirs.

The simulations indicate that even very small pressure gradients (transverse to the flow in the fractures) are highly significant in terms of the chemical transport into the matrix and that increasing the injected fluid viscosity greatly improves the oil recovery. Field scale simulations show that the transverse pressure gradients promote transport of the surfactant into the matrix at a feasible rate even when there is a high contrast between the permeability of the fractures and the matrix. These simulations indicate that injecting a chemical solution that is viscous (because of polymer or foam or microemulsion) and lowers the IFT as well as alters the wettability from mixed-wet to water-wet, produces more oil and produces it faster than static chemical processes. These findings have significant implications for enhanced oil recovery from naturally fractured oil reservoirs and how these processes should be optimized and scaled up from the laboratory to the field.
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CHAPTER 1: INTRODUCTION

Approximately 60% of the world's oil is found in carbonate reservoirs (Akbar et al. 2000). Many carbonate reservoirs are naturally fractured and are oil-wet or mixed-wet (Roehl and Choquette 1985; Chillenger and yen 1983). A naturally fractured reservoir (NFR) is a reservoir with a connected network of fractures created by natural processes such as diastrophism and volume shrinkage (Ordonez et al. 2001). Naturally fractured reservoirs are characterized by two distinct media, a low permeability matrix and a high permeability fracture system. This distinction can lead to early water breakthrough and poor water flood recovery. The amount of the oil recovered from naturally fractured carbonate reservoirs is often much less than one-third.

Wettability is a key reservoir property which has been long recognized as affecting the rock-fluid properties such as residual oil saturation, relative permeability and capillary pressure. Wettability of a mineral surface is often described by a contact angle (through the water phase by convention) \( \phi \) formed at the solid-oil-water contact line. If \( \phi < 60^\circ \), the solid is considered water-wet; if \( \phi > 120^\circ \), oil-wet, and if \( \phi \) is between these numbers, intermediate-wet. Wettability depends on brine, oil, and mineral compositions. Often, the reservoir rocks are heterogeneous in terms of mineral composition. Consequently the wettability is not necessarily homogeneous over the pore surface. If part of the pore surface is water-wet and the other part oil-wet, the rock is called mixed-wet (Salathiel, R. A. 1973). Wettability is often characterized by the Amott wettability index (WI). WI ranges from -1.0, strongly oil-wet, to +1.0 strongly water-wet. Systems with 0.3>WI>0.3 are referred to as mixed-wet.
Water flooding produces oil from NFRs through spontaneous capillary imbibition of water from the fractures into the rock matrix and through the fractures to the production wells. The capillary driving force is strong only when the matrix is water-wet. Unfortunately, many NFRs are mixed-wet or oil-wet with low matrix permeability, so the driving force is weak or non-existent and the oil recovery is very low. The oil recovery can be improved in such cases by using chemicals. The two primary effects of chemicals are known to:

- Decrease the interfacial tension (IFT) between oil and water
- Change the matrix wettability from mixed or oil-wet to water-wet

Many papers in the literature have reported wettability alteration by surfactants (Seethpalli et al., 2004; Standnes and Austad, 2000b). Usually surfactants also reduce the interfacial tension to a significant degree. Wettability alteration results in a more positive capillary pressure and a greater oil relative permeability while the latter causes an increased relative permeability and a reduced residual saturation. A drawback of reducing the IFT is the lost capillary pressure while an advantage is the enhanced gravity drainage (Yang and Wadleigh 2000, Austad and Milter 1997).

All of the above mentioned effects assumed that the surfactant or chemical solution is in contact with the oil. This is a challenge in NFRs since the fracture network contains a very small amount of oil compared to the lower-porosity and extremely lower-permeability matrix to which it is connected. The distinction between matrix and fracture
permeability can be as high as 1 to 10000. So the task is to transport the surfactant solution from the fracture far into the matrix in an efficient and practical way. The chemical transport mechanisms between matrix and fracture are widely accepted to be:

- Capillary imbibition
- Buoyancy
- Viscous forces
- Diffusion
- Possibly Maragoni effect/Spontaneous emulsification

However, few attempts have been made to analyze all of the above mentioned mechanisms in a systematic and step-wise fashion. A complete understanding of the role of chemicals in improving oil recovery from naturally fractured reservoirs can not be reached without a mechanistic study of different mechanisms and processes. This thesis thus attempts to consider all of the above listed mechanisms in a sequential approach.

This Master's thesis includes 7 chapters. Chapter 2 presents the literature review which includes useful information on previous studies. This review includes mainly static imbibition experiments and simulations. The fourth section of this chapter summarizes the conclusions of previous studies and addresses their limitations and applications. The final section of this chapter reviews the UTCHEM models which are the key to understanding the simulation results presented in the Chapters 3-6.
Chapter 3 presents simulations that compare static and dynamic imbibition tests. This chapter provides insights into the problem and the need for dynamic imbibition simulations and experiments in NFRs.

Chapter 4 discusses a wide range of small-scale simulations. Sensitivity simulations on various parameters are performed: pressure gradient, diffusion coefficient, capillary pressure parameters, etc. Different chemical solutions are injected and oil recovery curves are compared. The chemical solutions include those which lower the IFT, alter the wettability, are viscous, or a combination of all three.

Chapter 5 covers a wide range of large-scale simulations on a homogenous fractured block. This is done to determine whether the findings of small-scale simulations will still hold on a larger scale. Seven series of simulations are performed. In each series, the relative effectiveness of capillarity and viscous forces is altered. In each series, different chemical solutions are injected and oil recovery curves are compared. The chemical solutions include those which lower the IFT, alter the wettability, are viscous, or a combination of all three. Finally, the findings are compared with those of small-scale simulations.

Chapter 6 discusses on a wide range of large scale simulations on a heterogeneous fractured block. This is done to determine whether the findings of small-scale and large scale-simulations (performed in Chapters 4 and 5) will still hold if matrix heterogeneity is introduced. Both horizontal wells and vertical wells are simulated. We varied the relative effectiveness of capillarity and viscous forces in different simulations. A variety of
chemical solutions are injected and oil recovery curves are compared. Injections in this chapter include both continuous and slug injection. The chemical solutions include those which lower the IFT, alter the wettability, are viscous, or a combination of these three.

Finally, Chapter 7 summarizes the findings of this thesis and provides recommendations for future work on NFRs.
CHAPTER 2: LITERATURE REVIEW AND BACKGROUND

This chapter starts with fundamental information on static imbibition experiments. It then continues with the summary of the scale-up factors that have been derived by different experimentalists and briefly discusses their limitations. The third section of this chapter reviews the previous work on static imbibition experiments. The fourth section summarizes the findings in the third section and motivates us to do a further study on surfactant transport mechanisms. This chapter ends with the review of UTCHEM models which are important to understand the simulation results.

2.1: STATIC IMBIBITION TEST

Spontaneous capillary imbibition is a process where a wetting phase displaces the non-wetting phase in a porous medium by capillary force. It is important for fractured reservoirs to produce oil from the rock matrix. A large body of literature has reflected the role of capillary imbibition, gravity and diffusion, as matrix-fracture interaction agents, on oil recovery through small-scale static imbibition tests. For these experiments, the effects of matrix shape factor, matrix wettability, matrix permeability, boundary conditions, the type of displacing chemical solution, etc, on the recovery have been evaluated.

In a static imbibition test, a sample core, which is usually cylindrical, is first saturated with the target oil. The core is usually saturated with oil at initial water condition. Then the core is put in an imbibition cell which is often mounted vertically (Figure 2.1). There
exists an annular space between the core and the cell walls. This gap is filled with the chemical solution of interest in such a way that the rock is fully immersed. As time passes, oil imbibes out of the rock matrix and accumulates at the top of the imbibition cell, where its volume is measured and recorded versus time; the oil recovery data. Variation in the initial wettability of the rock can be obtained by aging the cores in the oil for different time intervals at elevated temperatures.

This testing procedure allows us to examine different types of imbibition. The type of transfer is determined by the boundary conditions created by the coating procedure. Counter-current imbibition can be obtained by coating all faces except the bottom face of the sample with epoxy or by coating only the top and bottom face of the sample. Co-current imbibition can be tested by only leaving the top and bottom face open. In addition, imbibition can be examined through different boundary conditions as shown in Figure 2.2 (Babadagli, 2001).

2.2: STATIC IMBIBITION TEST SCALE UP FACTORS

Many studies have characterized and scaled spontaneous water imbibition in oil/water/rock systems (Li et al. 2002; Tong et al. 2001; Zhou et al. 2001; Babadagli 2001; Kashchiev and Firoozabadi 2002; Civan and Rasmussen 2001; Akin et al. 2000; Cil et al. 1998; Perkins and Collins 1960; Mattax and Kyte 1962; Du prey 1978; Hamon and Vidal 1986; Reis and Cil 1993; Cuiec et al. 1994; Ma et al, 1995; Chen et al. 1995; Zhang et al. 1996; AlLawati and Saleh 1996; Babadagli 1997; Li and Horne 2002). These scale-up groups have been long used as a predictive tool to estimate the field performance
of fractured reservoirs subject to water flood. While these scale-up factors might succeed in predicting water flood performance, they are less useful in processes that include wettability and IFT modification using chemicals. Among many static scale up groups found in the literature, a couple of the most common ones are discussed here. It is important to keep in mind that none of these scale-up groups include the effect variation in wettability and/or IFT.

**Scale up group by Mattax and Kyte and further modified by Ma et al.:**

\[
t_{pc} = \frac{\sqrt{k / \phi \sigma}}{\sqrt{\mu_o \mu_w L_c^2}} t
\]

(2.1)

\[
L_c = \sqrt{\frac{V_b}{\sum_{i=1}^{n} A_i l_{A_i}}}
\]

where \( t_{pc} \) is the dimensionless time, \( k \) is the rock permeability, \( \phi \) is the porosity, \( \sigma \) is the IFT between the wetting and non-wetting phases, \( t \) is the imbibition time, \( \mu_o, \mu_w \) are the non-wetting and wetting phase viscosities, \( L_c \) is the characteristic length, \( V_b \) is the core bulk volume, \( A_i \) is surface area open to imbibition, \( l_{A_i} \) is the distance from \( A_i \) to no flow boundary, and \( n \) is the number of surfaces open to imbibition. This model has been validated for very strong water-wet cores. The dimensionless time defined in Eq. 2.1 is suitable for oil/water/rock systems under specific conditions. These include the
following: (1) wettability is constant, (2) relative permeability is constant, (3) capillary pressure functions is proportional to IFT and (4) gravity is neglected.

**Scale up group by Haggort:**

\[
t_{Dg} = \frac{k k_{ro} \Delta \rho}{(S_{oi} - S_{or}) \phi \mu_o L_c} t
\]  

(2.2)

where \( k_{ro} \) is the relative permeability to oil, \( S_{oi}, S_{or} \) are initial and residual oil saturations, and \( \Delta \rho \) is the density difference between wetting and non-wetting phases. This model has been validated only for the 1D gravity-driven processes and thus does not support capillarity.

**Scale up group by Zhou et al.:**

\[
t_D = \alpha \sqrt[3]{\frac{k \sigma}{\phi L_c^3}} \frac{1}{\sqrt{\lambda_{rw} \lambda_{rw}}} \sqrt{M^* + \frac{1}{M^*}} t
\]  

(2.3)

\[
\lambda^* r = \frac{k^* r}{\mu}
\]

\[
M^* = \frac{\lambda_{rw}^*}{\lambda_{rw}^*}
\]
where $\lambda_{rw}^*$ is the characteristic mobility and $M^*$ is the characteristic mobility ratio. This model has been validated for only counter-current 1D capillary imbibition. The data used was obtained for water-oil imbibition experiments in low-permeability diatomite cores.

**Scale up group by Li and Horne:**

\[
t_D = c^2 \frac{\lambda_{wP} c}{\phi} \frac{S_{wf} - S_{wi}}{L_c^2} t
\]

\[
c = \frac{\Delta \rho g L}{(S_{wf} - S_{wi}) P_c}
\]

(2.4)

where the effects of surface tension, wettability, initial saturation, and gravity are included. Li and Horne further tried to consider the effect of relative permeabilities. They validated their theoretical model for 1-D co-current imbibition only or for counter-current imbibition only. Also inherent in their assumptions is that the imbibition process is piston-like.

**Scale up group by Viksund et al.:**

\[
R_N = 1 - \frac{1}{(1 + 0.04 t_D)^{1.5}}
\]

(2.5)

\[
t_D = c^2 \frac{\lambda_{wP} c}{\phi} \frac{S_{wf} - S_{wi}}{L_c^2} t
\]

\[
R_N = \frac{R}{R_w}
\]
where $R$ is recovery and $R_\infty$ is the final recovery. This model was validated only for strongly water-wet cores with zero initial water saturation in sandstone and chalk core samples.

### 2.3: CHEMICAL IMBIBITION EXPERIMENTS & SIMULATIONS IN THE LITERATURE

This section begins with work of pioneers such as Austad and Schechter and continues with a review of more recent experiments and simulations. Although there are many papers published on the subjects relevant to this thesis, only seven papers are reviewed here. Effort has been made to select and discuss on papers which will provide an almost complete perspective on different aspects of the problem at hand.

#### 2.3.1: T. Austad and J. Milter (1997)

Austad and Milter (1997) studied improved spontaneous imbibition of water into oil-saturated low-permeable (2-3 md) chalk cores by means of surfactant. The experiments were conducted at room temperature, using long cores (55 cm) and short cores (5 cm) of different wettabilities, i.e., water-wet, mixed-wet, and nearly oil-wet. An anionic surfactant of the type alkyl-propoxy-ethoxy sulfate was used for the water-wet and mixed-wet cases while a cationic surfactant of the type dodecyltrimethyl ammonium bromide was used for the oil-wet case. The anionic surfactant produced an IFT of 0.02 mN/m with the oil while the cationic surfactant produced an IFT of 1 mN/m.
Typical oil recovery data from their experiments are shown in Figure 2.3. This Figure covers the water-wet and mixed-wet recovery data in the small core test. Cases with and without surfactant are shown. They observed that for the water-wet case, the fluid flow is countercurrent at high IFT (37 mN/m) and governed by capillary forces. However, in the presence of surfactant (IFT reduced to 0.02 mN/m), they observed a crossover from a countercurrent flow at the start to a co-current flow governed by gravity forces (Figure 2.4). They concluded that the oil production rate in the countercurrent regime is too high to be governed only by capillary forces. They suspected that another mechanism such as the maragoni effect (gradients in IFT) may be responsible for the high imbibition rate in the countercurrent regime. A similar trend was observed for the mixed-wet case. As can be seen from Figure 2.3, the expulsion of oil is extremely slow at low IFT. In this case, there is also a crossover from countercurrent to co-current flow, but at an earlier stage compared to water-wet cores.

By looking at Figure 2.3, one might conclude that lowering the IFT reduces the recovery factor in both water-wet and mixed-wet cases. However, a couple of points should be noted regarding these experiments. First, in the presence of the surfactant, some oil will be expelled as microemulsion, which is not measured in this experiment. Second, in the case of mixed-wet cores, there is no comment on the extent to which the anionic surfactant changes the wettability of the core. Third, the author suspects that the adsorption of surfactant on the core surface might have plugged this low-permeability core's surfaces and therefore precluded further imbibition.
While some features of oil recovery by spontaneous imbibition are perfectly demonstrated by Austad, the existing uncertainties prevent the generalization of his conclusions. Of course, if capillary pressure is killed due to the reduced IFT and diffusion and buoyancy are dismantled due to a plugged core, there will be no further mechanism left to transport the surfactant into the core matrix in this static imbibition test.

2.3.2: Schechter, Denqen Zhou and Orr (1991)

In this work, the effect of reduced IFT on oil recovery by spontaneous imbibition and gravity segregation is investigated experimentally for a wide range of IFTs in cores oriented vertically. Schechter used isooctane (IC8), brine (2 wt. % CaCl2) and isopropanol (IPA) in his experimental studies. Brine concentration was altered and three different IFTs along with three $\Delta \rho$ s and three viscosity ratios $\frac{\mu_w}{\mu_o}$ were achieved. One limestone core with a permeability of approximately 15 md and three sandstone cores with permeabilities of above 100 md were used. The inverse Bond numbers for all experiments were reported to be significantly greater than 1.

Schechter suggests that the oil is recovered by some combination of capillary imbibition and gravity-driven flow. His results indicate that there is a crossover from capillary to gravity-driven imbibition. He further suggests that gravity segregation dominates flow in high permeability sandstone cores whereas capillary forces were more important in the low permeability limestone core. Finally, he suggests that imbibition can occur in three differing regimes: capillary dominated, gravity dominated, and a region where both
forces affect imbibition. The curves from this paper are depicted in Figures 2.5 through 2.8.

With regard to this work, several points should be made: (1) Schechter concludes that capillary force is more important in the low permeability core (Figure 2.5), but as can be seen from this Figure, the final recovery is higher in the case of the reduced IFT. (2) This work does not make clear the wettability states of the cores. We know that recovery is a strong function of the initial wettability and the extent to which it is altered.

These objections prohibit us from drawing conclusions on the effect of permeability on the type of recovery process; neither do they allow us to infer that lowering IFT is beneficial or detrimental with respect to any level of permeability.

2.3.3: Xie and Weiss (2004)

In this work, static imbibition tests were done for a cationic surfactant, cocoalkyltrimethyl ammonium chloride, and a nonionic surfactant, an ethoxylated alcohol. Over 50 core samples of mixed-wet dolomite cylindrical cores from actual reservoirs with corresponding oil and brine were tested. When reservoir brine was used as the imbibition fluid, oil recovery was in the range of 0-35 % OOIP. After imbibition of reservoir brine had ceased, the cores were transferred into surfactant solutions to be tested for enhanced oil recovery by further imbibition. Typically immersion in the surfactant solution resulted in 5 to 10% OOIP of additional recovery. The lengths of the cores were around 5 cm and permeabilities ranged from 1 to 100 md. The porosities were all around
15%. The oil was of a light type with gravity of around 35 API. More experimental data can be found in the paper.

The main focus of this work has been to study the effectiveness of nonionic and cationic surfactants to enhance the oil recovery by inducing water-wetness and therefore spontaneous imbibition in the cores. The cationic surfactant produced an IFT of around 0.3 mN/m, while the nonionic surfactant produced a higher value of around 5.5 mN/m in almost all experiments. Gravity segregation was not found to be a dominant recovery mechanism in their experiments, which is reasonable because the cores were short and the IFTs were not reduced to ultra-low values. They concluded that the rate of recovery by spontaneous imbibition from dolomite cores treated with nonionic surfactants tended to be faster than for cationic surfactants, mainly because of the former had the higher IFT with the crude oil. They further infer that for improved recovery, wettability should be changed to some optimal water-wet condition while keeping the interfacial tension relatively high.

With regard to this conclusion one should be aware of the following points: First, in none of the experiments is the IFT reduced to ultra-low values. This means that there is no detrapping of the oil in the matrix and no further benefit from buoyancy. Second, the cores have already been placed in contact with brine and the capillary pressure has been almost dead at the end of the brine imbibition period. Therefore, the only mechanism for transporting the surfactant into the cores is diffusion (and possibly spontaneous emulsification). This fact is important to keep in mind since there is no experimental data
on the rate of diffusion for these two surfactants. Consequently, it is not obvious whether the rate of surfactant diffusion through brine plays a part here.

2.3.4: Adibahtla and Mohanty (2008)

This paper focuses on a parametric study of surfactant-aided gravity drainage of an initially oil-wet core. Surfactant concentration, water/oil ratio (WOR), salinity, matrix dimensions, permeability, and initial gas saturation were varied, and their impact on the process was studied experimentally. Also, the results were compared with the simulations performed by a 3D, finite volume, two phase, four-component, implicit simulator developed by Adibahtla et al. 2005.

Anionic surfactants of sulfate and sulfonate type were used. The surfactant solutions were prepared at their optimal salinity (Na2CO3) concentration. Limestone cores with a 1.5 inch diameter were used. One group of cores had permeabilities of approximately 150 md and porosities of around 22.5% while another group had permeabilities of approximately 7 md and porosities of around 29%. Nitrogen was used for studying the effect of initial gas saturation on recovery rates. The wettability measurements were done on calcite plates using a goniometer. Each core was drained to its initial water saturation, aged to get the desired initial wettability and then placed in an imbibition cell and surrounded by a surfactant solution. More specific details are given in the paper.
The surfactants produced low IFTs of approximately $10^{-3}$ to $10^{-2}$ dynes/cm. Most of the surfactants altered the wettability of the oil-wet carbonate surface to intermediate or moderate water-wet states.

According to the author, the rate of oil recovery by surfactant imbibition process is a gravity-driven process, but it is initially diffusion limited. This can be seen in Figure 2.9 in which the recovery of a 7 md core has been scaled to match the result a 150 md core. The scale using the capillary-scaling formula did not match while the gravity-scaling formula gave a good match. Additionally, the results show that increasing the surfactant concentration increases the rate of surfactant diffusion into the core and that it enhances the initial rate of recovery, but it does not affect the final recovery.

On the effect of wettability alteration, it was observed that surfactants that lower the IFT but do not alter the wetability produce much less oil than surfactants that lower the IFT and alter wetability (see Figure 2.10). Three of the surfactants shown in the Figure give a final recovery of around 40% while the other two do not produce more than approximately 20%. The simulations also demonstrated that increasing the extent of wettability alteration increases the rate of recovery.

The most significant conclusion of this work is that altering the wetability to more water-wet at a low IFT produces more oil. It is suggested in the paper that as surfactant diffuses into the core, IFT and wettability are altered. As IFT drops, the inverse Bond number falls below 1, and the gravity drainage starts to work. As wettability is altered, a small
countercurrent imbibition takes place due to lowered capillary pressure. However, it should be noted that this work does not examine the recovery behavior at different IFTs.

2.3.5: Adibahtla and Mohanty (2007)

In this study, a 3-D, finite-volume, two-phase, multi-component, fully implicit numerical simulator was developed and used that incorporates the adsorption, phase behavior, wettability alteration, and related capillary pressure and permeability variations. The authors claim that reliability of the simulator is established by comparing the core-scale simulation results with the experimental results obtained in their lab. IFT reduction, wettability alteration, and permeability are varied to study the sensitivity of the surfactant-aided gravity drainage to these process parameters.

The conclusions to their simulations are the following: (1) Surfactants that lower the wettability to a water-wet regime give higher recovery rates for higher IFT cases. (2) Surfactants that do not alter the wettability give higher recovery for lower IFT cases. (3) For low permeability reservoirs, if the surfactant can change the wettability to water-wet, the recovery rate is significantly greater with higher IFT; that is, cationic surfactants are preferable. (4) For high permeability reservoirs, if the surfactant can change the wettability to water-wet, the recovery rate is slightly greater with higher IFT. The choice between anionic and cationic surfactant depends on surfactant cost.

There are a couple of points that challenge the validity of these results. First, in their experimental work (as discussed in the previous section), the author concludes that the
gravity-aided drainage is the key mechanism in producing oil from their cores which was accomplished by lowering the IFT. If this is the case, then how could simulations indicate that keeping the IFT at high values is more productive? This is a clear contradiction. Second, the details of the simulations are not included in the paper. Also, the simulator is two-phase and not capable of capturing the different types and features of microemulsions which, as we will see in the next chapter, plays a significant role.

2.3.6: Hatiboglu and Babadagli (2008)

This study compares the recovery efficiencies of two cases: (a) primary countercurrent spontaneous imbibition followed by the diffusion of a miscible phase (secondary recovery), and (b) primary diffusion of miscible fluid without preflush of matrix by spontaneous imbibition. For these recovery strategies, the effects of matrix shape factor, matrix wettability, and type of miscible displacement phase on the rate of recovery and ultimate recovery were clarified experimentally. Cylindrical water-wet Berea sandstone and weakly water-wet Indiana limestone samples with different shape factors were used. The external surface except for one end was coated with epoxy. Static imbibition experiments were conducted on vertically situated samples in which the fractures were at the bottom and matrix/fracture interaction took place in an upward direction.

Two typical curves from this work are presented. The results from the primary diffusion of the solvent are depicted in Figure 2.11, whereas the results of primary imbibition followed by diffusion are shown in Figure 2.12. U in these figures means uncoated, while
all others have only one end open. In addition, different core shapes and their corresponding recovery curves are presented.

Evident from these two figures is that primary diffusion results in a much higher ultimate recovery in all cases. This means that starting with a lower IFT is more profitable than starting with water imbibition. This is shown to be true for both limestone and sandstone cores. Therefore, the initial wettability does not affect this conclusion. On the other hand, the author has calculated the recovery efficiency by dividing the ultimate recovery by the recovery time and has arrived at a reverse conclusion. The recovery efficiency was found to be higher in the case of starting with water imbibition and following with solvent diffusion. This was more pronounced for water-wet cases though.

A couple of points should be made here. (1) The solvent is not miscible with the water phase and so its diffusion into the matrix is different from diffusion of a surfactant that is soluble in water. This is very important to keep in mind since the distribution of the imbibed water becomes important as the secondary diffusion starts. Therefore, the results of the second case of experiments in this work might not be valid if surfactant solution is used instead of solvent. (2) In the coated sample experiments, only one end faces of the cores have been open which only favors countercurrent imbibition. One should be careful about generalizing these results as the recovery trends may change if other boundary conditions are imposed.
2.3.7: Delshad, Najafabadi and Sepehrnoori (2008)

A compositional chemical reservoir simulator with the wettability alteration capability was used for this study. This work focused on the scale-up simulations of two different oil recovery experiments in carbonate rocks using chemicals that modified the wettability. Several imbibition-rate scaling groups were tested in attempt to scale the lab results to larger field-scale matrix blocks.

The first experiment was the laboratory alkaline/surfactant imbibition experiment reported by Hirasaki and Zhang (2004) and was used for the scale-up study based on the static imbibition cell experiments. The experiments were conducted with formation brine, crude oil, and core samples of the dolomite formation from Yates field (Yang et al., 2000). Spontaneous imbibition did not occur when partially oil-saturated dolomite core samples were placed in a cell test filled with brine for one to two weeks. This a confirmation of the oil-wet nature of the cores used. The core and fluid properties are summarized in detail and can be found in this paper.

There was significant spontaneous imbibition when the brine was replaced with an anionic surfactant/alkaline solution. The buoyancy-driven gravity drainage was reported to be the dominant recovery mechanism rather than countercurrent capillary imbibition. A 3D numerical model was set up to simulate the experiment (Delshad et al., 2006). A good match between experimental and simulated oil recoveries was obtained. The effect of matrix block size on oil recovery was investigated keeping the same simulation model properties as those obtained by history match of the imbibition cell test.
Several simulations were performed by increasing the height and areal extent of the core as much as 20 times. Then, the simulation results were normalized for different matrix heights by the characteristic length of equation 2.1 to the power of two \((L_c^2)\). However, the recovery curves did not converge when the simulation time was scaled using \(L_c^2\), as suggested by Ma et al. (1995) and Li and Horne (2006). The normalization was then done using only \(L_c\) as suggested by equation of 2.2. The match shown in Figure 2.13 indicates a gravity dominated flow where the dominant mechanism is buoyancy under the low interfacial tension condition of the experiment. According to these results, if it takes 10 years for a 1 m wide by 1 m high block to recover a certain amount of oil, then it will take 100 years for a 10 m wide by 10 m high block to recover the same amount of oil.

In the second experiment, nine Texas cream limestone blocks of 3" by 3" by 1" were placed together following the pattern shown in Figure 2.14. Water, alkali, and surfactant/alkali were injected sequentially. The water injection with 4.8 wt% NaCl at 5 mL/hr resulted in 15% oil recovery. Next, water containing 1 wt% sodium metaborate and 3.8 wt% NaCl injected at the same flow rate recovered additional 15% OOIP. Following that, a mixture of alkali/surfactant was injected rendering incremental recovery of 6% OOIP. The pressure drop across the core was constant at about 0.8 psi/ft throughout the experiment. More details on the experimental procedure can be found in Delshad et al. (2008).

This experiment was modeled using a 3D discrete fracture model as shown in Figure 2.14 and a good match was obtained. Again, the effect of matrix block size on oil recovery
was investigated keeping the same simulation model properties as those obtained from the history match of the experiment. The block area was increased as much as much as 81 times keeping the height the same. The volume of the matrix block was increased as much as 64 times with all faces open to flow. Simulation results for different block areas are plotted versus dimensionless time of equation 2.1 in Figure 2.15. The results indicated that larger block sizes recover oil faster as the result of viscous gradient that is not accounted in Ma's dimensionless time. The gravity reference time $t_{Dg}$ also gave a very poor scaling.

This work concludes that the rate of imbibition and oil recovery were much faster under the low IFT conditions compared to diffusion-dominated high IFT experiments reported in the literature. It also implies that even a small viscous gradient aided in recovery of oil from larger matrix blocks and so a new dimensionless group is required to adequately scale the results of this experiment by taking into account different recovery mechanisms.

2.4: CONCLUSION TO LITERATURE REVIEW; MOTIVATION

Having reviewed the papers in the previous section, one can conclude that there are significant contradictions regarding the conditions under which highest ultimate oil recovery or highest rate of oil recovery can be obtained from sample cores. For example, while some suggest that recovery is fastest under high IFT conditions, others suggest that lowering the IFT is more beneficial. It should be noted that in some experiments, the IFT is not reduced to ultra-low values. Additionally, the wettability status of the rock or the ability of the chemical to alter the wettability is not always investigated. Some
experimentalists did not use surfactants, but used solvents. There is a big difference between the transport mechanism of a solvent and that of a surfactant and therefore the experimental results can not be comparable. There have been also attempts to correlate the effect of IFT with the permeability, or to scale the oil recovery behavior according to the various static scale-up factors. However, the validity of these scale-up groups is limited. For example, one can understand the limitations of the scaling factors by reviewing the section 2.2 of this thesis.

Additionally, as suggested by Austad et al., there are other mechanisms, such as the Margoni effect, that may be responsible for a high imbibition rate found in some experiments. None of the scaling-factors or experimental interpretations (in terms of IFT reduction or wettability alteration), or the simulators, that are developed based on static imbibition tests, take these mechanisms into account. On the other hand, recent work by Delshad et al, suggests that viscous forces play an important role in oil recovery from fractured reservoirs and that the effect of viscous forces might dominate the effect of diffusion (and other possible mechanisms). Therefore, by analyzing dynamic imbibition rather than static imbibition data, the contradictions found in the literature may be resolved, or at least reduced. Thus, this thesis attempts to accomplish the following:

- Understand the limitations of static imbibition tests and their possible link to the contradictions found in the literature
- Understand the relative importance of the viscous transport mechanism compared to other transport mechanisms.
Understand the relative effect of IFT reduction and wettability alteration on oil recovery from NFRs by performing dynamic imbibition simulations.

2.5: UTCHEM MODEL DESCRIPTION

UTCHEM is a 3D, multicomponent, multiphase, compositional model of chemical flooding processes. The model accounts for surfactant/brine/oil phase behavior and interfacial tension, two and three phase relative permeabilities as a function of trapping number, aqueous electrolyte chemistry, precipitation/dissolution of minerals, and reaction of acidic components of crude oil with the alkali to generate surfactant in-situ. The flow and mass transport equations are solved for any number of user-specified chemical components. Chemical flooding of naturally fractured reservoirs is modeled using either discrete fractures or the multicomponent multiphase dual porosity model.

Wettability alteration is modeled with changes in relative permeability and capillary pressure. A brief description of the model is given here. Corey-type relative permeabilities are calculated or each gridblock as follows:

$$k_{rl} = k^0_{rl} S_{nl} \quad l = 1, 2, 3$$

(2.6)

where \(l\) is either water, oil or microemulsion phases, \(k^0_{rl}\) is the relative permeability endpoint for phase \(l\) and \(S_{nl}\) is the normalized saturation of phase \(l\) calculated as follows:
\[ S_{nl} = \frac{S_l - S_{lr}}{1 - \sum_{l=1}^{3} S_{lr}} \quad l = 1, 2, 3 \] (2.7)

where \( S_l \) is the saturation of phase \( l \) and \( S_{lr} \) is the residual saturation of phase \( l \).

As mentioned before, in addition to the wettability alteration effect, surfactants also reduce the interfacial tension between the oil, microemulsion and the aqueous phases and help in the oil mobilization. This effect is modeled by means of a dimensionless number called trapping number, which is a combination of capillary number and Bond number to adequately model the combined effect of viscous, capillary and buoyancy forces in three dimensions. As the surfactant enters a gridblock, it reduces the interfacial tension and as a result, trapping number increases. Interfacial tension reduction affects the residual phase saturations, endpoint relative permeabilities, and exponents. The effect on residual phase saturations is modeled in UTCHEM as follows:

\[ S_{lr} = \min[S_l, (S_{lr}^{high} + \frac{S_{lr}^{low} - S_{lr}^{high}}{1 + T_l N_{TL}})] \quad l = 1, 2, 3 \] (2.8)

where \( S_{lr}^{high} \) and \( S_{lr}^{low} \) are residual saturations of phase \( l \) at high and low trapping numbers, respectively (given as input parameters), \( T_l \) is the input trapping parameter of phase \( l \) and \( N_{TL} \) is trapping number of phase \( l \). \( S_{lr}^{high} \) is typically zero. The trapping number for phase \( l \) displaced by phase \( l' \) is defined as follows:

\[ N_{TL} = \left| \frac{\bar{k} \cdot (\nabla \Phi_i + g \Delta \rho \nabla D)}{\sigma_{il}} \right| \quad l = 1, 2, 3 \] (2.9)
Mobilization effects on endpoint relative permeabilities are modeled using the following correlation:

\[ k_{rl}^0 = k_{rl}^{0\text{low}} + \frac{S_{lr}^{\text{low}} - S_{lr}^{\text{high}}}{S_{lr}^{\text{low}} - S_{lr}^{\text{high}}}(k_{rl}^{0\text{high}} - k_{rl}^{0\text{low}}) \quad l = 1, 2, 3 \]  

(2.10)

where, \( S_{lr} \) is the residual saturation of the conjugate phase e.g. oil is the conjugate phase for microemulsion phase and \( k_{rl}^{0\text{low}} \) and \( k_{rl}^{0\text{high}} \) represent the endpoint relative permeability of phase \( l \) at low and high trapping numbers, respectively. The relative permeability exponents are also a function of trapping number:

\[ n_l = n_l^{\text{low}} + \frac{S_{lr}^{\text{low}} - S_{lr}^{\text{high}}}{S_{lr}^{\text{low}} - S_{lr}^{\text{high}}}(n_l^{\text{high}} - n_l^{\text{low}}) \quad l = 1, 2, 3 \]  

(2.11)

where \( n_l^{\text{low}} \) and \( n_l^{\text{high}} \) represent the relative permeability exponents for low and high trapping numbers, respectively and are specified as input parameters.

The above equations are solved once for the initial reservoir wettability condition \((k_r^{\text{initial}})\) and once for the altered condition of strongly water-wet \((k_r^{\text{final}})\). Two sets of relative permeability \((k_{rl}^0, S_{lr}, n_l)\) and trapping numbers \((T_l)\) are required as input parameters corresponding to each wettability state. The relative permeability in each gridblock \((k_{rl})\) is then obtained by linear interpolation between the relative permeability corresponding to the two wettability conditions, provided that the concentration of the surfactant in the gridblock is greater than the critical micelle concentration. Interpolation is made based on the scaling factor \(\omega\):

\[ k_{rl} = \omega k_{rl}^{\text{final}} + (1 - \omega)k_{rl}^{\text{initial}} \quad l = 1, 2, 3 \]  

(2.12)
where $k_{rl}^{\text{final}}$ and $k_{rl}^{\text{initial}}$ represent the relative permeabilities corresponding to the two extreme wetting cases, i.e. final and initial wettability states, respectively. The scaling factor is either a constant user input parameter or is related to the concentration of surfactant adsorbed in each gridblock as follows:

$$\omega = \frac{\hat{C}_{\text{surf}}}{\hat{C}_{\text{surf}} + C_{\text{surf}}}$$  \hspace{1cm} (2.13)

where $\hat{C}_{\text{surf}}$ and $C_{\text{surf}}$ represent the adsorbed and total concentration of surfactant, respectively. The historical maximum of $\omega$ in each gridblock is used for the interpolation.

The capillary pressure as a function of wettability is also modeled using linear interpolation between the capillary pressure of the initial wetting state and final condition:

$$P_c = \omega P_c^{\text{final}} + (1 - \omega) P_c^{\text{initial}}$$  \hspace{1cm} (2.14)

where the capillary pressure $P_c$ is scaled with the interfacial tension as follows:

$$P_c = P_{\text{cow}} \frac{\sigma_{om}}{\sigma_{ow}}$$  \hspace{1cm} (2.15)

where

$$P_{\text{cow}} = C_{pc} (1 - S_{nl})^{E_{pc}}$$  \hspace{1cm} (2.16)
Examples of wettability effects on oil/water relative permeability endpoints, and relative permeability and oil capillary desaturation curve in Berea sandstone are those measured by Mohanty and Morrow et al.

An example of capillary desaturation curves, relative permeability endpoints, and relative permeability exponents as a function of trapping number for different wettability conditions of water-wet and mixed-wet are given in Figures 2.16 through 2.18. Table 1 lists the relative permeability capillary pressure parameters for this example. Relative permeabilities are then calculated using Equations 2.6 to 2.12 with a constant wettability scaling factor of 0.5. The base relative permeability parameters listed in Table 2.1 for water-wet and mixed-wet conditions are based on the relative permeability measurements of Morrow et al. Relative permeabilities are calculated for different trapping numbers of $10^{-7}, 10^{-5}, 10^{-3}$ given in Figures 2.19 through 2.21. Figure 2.22 shows the capillary pressure curves calculated for water-wet and oil-wet conditions using equation 2.16 and a mixed-wet curve using the scaling factor of 0.5 in equation 2.14.

Polymer solutions reduce the mobility of the water phase by increasing its viscosity and reducing the effective permeability of the porous medium. The permeability reduction is measured by a permeability reduction factor, $R_k$ defined as:

$$R_k = \frac{\text{effective permeability of water}}{\text{effective permeability of polymer}}$$  \hspace{1cm} (2.17)
The change in mobility due to the combined effect of increased viscosity and reduced permeability is called resistance factor, $R_f$ calculated by

$$R_f = \frac{R_e \mu_p}{\mu_w} \quad (2.18)$$

The effect of permeability reduction lasts even after the polymer solution has passed through the porous medium and is called the residual resistance factor, $R_{RF}$ defined as

$$R_{RF} = \frac{\text{mobility before polymer solution}}{\text{mobility after polymer solution}} \quad (2.19)$$

The permeability reduction factor in UTCHEM is modeled as

$$R_k = 1 + \left( \frac{R_{k,\text{max}} - 1}{b_{\text{rk}} C_{4l}} \right) \frac{b_{\text{rk}} C_{4l}}{1 + b_{\text{rk}} C_{4l}} \quad (2.20)$$

$$R_{k,\text{max}} = \min \left\{ \left[ 1 - \frac{c_{\text{rk}} \left( A_p l C_{\text{SEP}} \right)^{1/3}}{\frac{\sqrt{k_x k_y}}{\phi}} \right], R_{\text{cut}} \right\} \quad (2.21)$$

and $l$ refers to the phase with the highest polymer concentration, $b_{\text{rk}}, C_{\text{rk}}$ and $R_{\text{cut}}$ are the input parameters.
Liquid phase viscosities in UTCHEM are modeled in terms of pure component viscosities and the phase concentrations of the oil, water and surfactant:

$$\mu_l = C_{1l}\mu_w e^{\alpha_1(C_{2l}+C_{3l})} + C_{2l}\mu_o e^{\alpha_2(C_{1l}+C_{3l})} + C_{3l}\alpha_3 e^{(\alpha_4 C_{1l}+\alpha_5 C_{2l})} \quad \text{for } l = 1, 2, 3$$ (2.22)

where the $\alpha$ parameters are determined by matching laboratory microemulsion viscosities at several compositions. In the absence of surfactant and polymer, water and oil phase viscosities reduce to pure water and oil viscosities ($\mu_w, \mu_o$). When polymer is present, $\mu_w$ is replaced by $\mu_p$. 
<table>
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<td>Capillary pressure exponent (EPC)</td>
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<td>2</td>
<td></td>
</tr>
</tbody>
</table>
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Figure 2.22 - Calculated capillary pressure curves for different wettability conditions
CHAPTER 3: STATIC VERSUS DYNAMIC

The purpose of this chapter is to demonstrate the limitations of the static imbibition tests and to understand the necessity of performing dynamic imbibition experiments and simulations. This chapter includes simulations that explain these limitations.

3.1: MODEL DESCRIPTION

The model reservoir to investigate the limitations of the static imbibition test is shown in Figure 3.1. The figure presents the permeability distribution. The blue represents the fracture and the pink represents the matrix. This is a 1 ft by 0.25 ft by 0.07 ft horizontal fractured block modeled with UTCHEM. There are 31 grid blocks in the X direction, 11 grid blocks in the Y direction and 3 grid blocks in the Z direction. The fractures are modeled as discrete fractures. There are two parallel fractures along the X axis. There are also four parallel fractures along the Y axis, perpendicular to the direction of the injection/production. As shown in the figure, one of these four fractures contains the injection well; two are in the middle and the last one contains the production well. The height of this fractured block is chosen small in order to minimize the effect of gravity. The top, bottom and sides of the block are sealed. The block matrix is homogenous and has a permeability of 30 md. The fractures are also homogenous. The block physical properties are listed in Table 3.1.

The initial water saturation is 0.84 in the matrix and 0.99 in the fracture. Initially the matrix is mixed-wet. The capillary pressure in the fracture is always zero. The capillary
pressure for the matrix is calculated using the Brook-Corey model. The relative permeability parameters are calculated as described in Chapter 2.5. For simplicity, only in current chapter, we consider a surfactant that does not alter the wettability but does lower the interfacial tension to ultra-low values (kills capillary pressure). In current chapter, in all cases where surfactant is involved, surfactant forms a type III microemulsion with oil. The Initial condition parameters together with rock and fluid properties are listed in Table 3.2.

The injections are continuous, i.e. it is only water flood or surfactant flood in a single simulation. The injection and production wells are vertical, constrained to constant pressures and completed in the leftmost and rightmost fractures, respectively. The well data are listed in Table 3.3.

This model contains 1023 grid blocks, 298 of which are fracture grid blocks. The total simulation time is 9 days. UTCHEM solves the equations using the IMPES technique. The simulation parameters are listed in Table 3.4.

3.2: SIMULATION SEQUENCE

To mimic the static imbibition experiments, a very low pressure drop of 0.1 psi/ft is constructed between the injector and the producer. A simulation is run with injecting water for 9 days. The result is shown as the blue curve in Figure 3.2. This figure shows the cumulative oil recovery versus pore volumes of the injected solution. The water flood oil recovery is no more than 25% after two pore volumes.
Now, to simulate a static chemical imbibition experiment, it is assumed that initially, the surfactant is present in all fracture grid blocks. This is attainable by assigning the initial surfactant concentration of all fracture grid blocks to 0.02 ($c_{si} = 0.02$), which is the same surfactant concentration as in the injected water. The resulting cumulative oil recovery is the red curve depicted in Figure 3.2.

Now, if the assumption that the surfactant is present in the fracture from the beginning ($c_{si} = 0$) is discarded, we are one step closer to simulating a dynamic imbibition process. The oil recovery curve for this case is shown in Figure 3.3 (the black curve).

Finally, if the pressure drop is increased from 0.1 psi/ft to 1 psi/ft, a dynamic imbibition process can be simulated. The new recovery curves for the water flood and the surfactant flood are presented in Figure 3.5. Here the solid curves are the recovery for the 0.1 psi/ft case, which is the same as presented in Figure 3.3, and the dotted curves are the recovery curves for the 1 psi/ft case. S in this Figure denotes surfactant flooding and w denotes water flooding.

### 3.3: Interpretation of the Simulation Results

The oil recovery by water flooding and surfactant flooding shown in Figure 3.2 are typical of those found in various papers. Figure 2.5, in the literature review chapter, is an example. Initially, the surfactant oil recovery curve falls below the water oil recovery
curve because the surfactant has been in contact with the whole matrix from the start and has killed the capillary pressure at all locations. On the other hand, the water flood is recovering oil by taking advantage of capillary pressure.

After 1 pore volume, however, the surfactant flooding recovery curve catches up with the water flooding recovery curve. This can be explained as follows: the water flooding recovery curve flattens out because as water imbibes into the matrix, the capillary pressure drops gradually and so does the oil recovery. In contrast, in the case of surfactant flooding, the surfactant has reduced the residual oil saturation and mobilized the oil trapped in the matrix by increasing matrix relative permeability to water. Therefore surfactant flooding tends to produce more and more oil.

Now, if the assumption that the surfactant is present in the fracture from the beginning is discarded, a surprisingly high shift in the oil recovery will be attained. This upward shift can be observed in Figure 3.3. The red and black curves in this figure represent the recovery with and without the assumption that the surfactant is initially present in the fracture. It can be observed that the surfactant flood that recovered less oil than water flood during the first pore volume is now outperforming the water flood during the whole simulation period.

To explain this contradiction, Figure 3.3 illustrates the two cases schematically: one represents the static imbibition \((c_{si} = 0.02)\) and the other represents the dynamic imbibition \((c_{si} = 0)\). The gray thicker rectangles represent the matrices while the thinner rectangles represent their adjacent fractures. The yellow color is the injected surfactant
solution and the blue color is the water initially in the fracture. Here, we are looking at a fixed pore volumes of the injected surfactant. Also, shown here are the injected surfactant fronts in the fracture and in the matrix. The surfactant front has advanced very little in the matrix because the permeability of the matrix is much lower compared to that of the fracture. As can be seen in the case of static imbibition, the capillary pressure at the fracture/matrix contact is always zero. In contrast, in the case of dynamic imbibition, the capillary pressure is positive ahead of the surfactant front and is producing oil. Therefore, the fact that it takes time for the surfactant front to get from the injector to the producer allows the un-contacted locations to benefit from the capillary force. This, as evident from the results, is yielding this upward shift.

However, the question is how the surfactant flood is outperforming the water flood if the surfactant reduces the IFT, and thus also the capillary pressure, to zero. In other terms, how is the surfactant getting into the matrix if the capillary pressure is reduced to zero? Diffusion cannot be responsible for this transport as the diffusion parameters are set to zero in these simulations. Gravity is also inexpressive here as its direction is parallel to the fractures, the simulated block thickness is very small, and the wells are vertical.

The question can be answered by a careful review of the simulation results illustrated in Figure 3.4. At the top of this figure, we have the tracer concentration, which shows us that at this specific time, which is before surfactant breakthrough, tracer or surfactant has actually penetrated into the matrix. The reason can be found in the pressure profile curves. If we calculate the pressure profiles in the matrix and in the fracture we observe an interesting contrast. In the region behind the surfactant front in Figure 3.4, the aqueous
pressure in the fracture is actually higher than that of the matrix. This transverse pressure difference is actually able to push the surfactant into the matrix. The existence of microemulsion in this region is responsible for this pressure difference. As the oil imbibes into the fracture and mixes with the surfactant there, it creates microemulsion, and because the microemulsion has a higher viscosity than both oil or water, it creates an induced pressure gradient. Now, the fact that microemulsion has a higher viscosity is crucial and if it did not have a higher viscosity, the pressure profiles would no longer look the same as in Figure 3.4. The actual pressure profile from the simulation is shown at the bottom of Figure 3.4, which verifies our interpretation.

Figure 3.5, on the other hand, demonstrates the fact that oil recovery is strongly dependent on the pressure gradient (equivalently injection rate). As we can see from this figure, increasing the pressure drop reduces the oil recovery. This drop is due to the reduced contact time between the surfactant solution and the oil in the matrix because of the increased injection rate. In other words, at the same pore volumes, a lower injection rate will allow more time for the oil to imbibe into the fracture and for the surfactant to be transported farther into the matrix.

In addition to the general trend explained above, more detailed contrasts between the two groups of curves are provided below. In the magnified part of Figure 3.5, the initial recovery curves are compared. We observe here that the initial recovery curves for the surfactant flooding and water flooding coincide in the case of a 0.1 psi/ft pressure drop. This phenomenon does not hold anymore for the case of a 1 psi/ft pressure drop, in which
the surfactant outperforms water from the very beginning. This difference in initial recoveries can be explained by looking at Figure 3.6:

In the case of a 1 psi/ft pressure gradient, it can be shown that the injection rate in both water and surfactant flooding cases is higher than the imbibition rate. As a result, the fracture does not completely get filled with oil as the fronts move towards the producer. Now, in the case of surfactant flooding, because of the higher microemulsion viscosity forming behind the surfactant front, the injection rate goes down (remember that our simulations are performed at fixed pressure drops), and consequently there is more contact time available for the fluids to exchange. In other terms, at the same injected pore volumes, in the case of surfactant flooding, capillary pressure has more time to imbibe the oil into the fracture. Consequently, in Figure 3.6, the part of the fracture that is in front the surfactant front contains more oil in the case of surfactant flooding compared to water flooding.

However, in the case of 0.1 psi/ft pressure gradient, the imbibition rate is already higher than the injection rate in both flooding cases and therefore the fractures are already completely filled with the oil. As a matter of the fact, the extra residence time available in the case of surfactant flooding does not constitute an advantage here. As a result, in Figure 3.5, their respective recovery curves coincide up to the breakthrough time.
3.4: Conclusions

Simulations presented in this chapter indicate that there are several drawbacks associated with static imbibition experiments and their interpretations reported in the literature. It is evident from the simulations that the role of viscous forces is important and this has not been reported in the literature. The major limitations of static imbibition tests are as follows:

1. In a real reservoir, unlike in imbibition cells, the surfactant does not initially touch the entire matrix. When surfactant is injected, it takes time for the surfactant to get to the producer (Figure 3.3). The impact of this delay can be huge because it explains several contradictions discussed in the previous chapter.

2. Second, and most important of all, the higher microemulsion viscosity actually induces transverse pressure gradients that can push the surfactant farther into the matrix and increase the sweep efficiency. This effect is shown schematically in Figure 3.4. This effect is not captured in imbibition cells because, in an imbibition cell, microemulsion flows out of the matrix and accumulates at the top by help of buoyancy. In other terms, the oil or microemulsion that is flowing out of the matrix is separated from the fracture right away.

3. As can be seen from Figures 3.5 and 3.6, recovery in a fractured system is a function of both capillary imbibition rate and injection rate. Optimization of the injection rate is important prior to conducting any kind of flooding in a naturally fracture reservoir (Putra et al. 1999). As the flow rate increases, the contact time between matrix and fluid in a
fracture decreases, thereby reducing the effect of capillary pressure, chemical transport, diffusion, etc.

In summary, one should consider the following points:

(1) Viscous forces might play the most important role in transporting the surfactant into the matrix. (2) Pressure gradients need to be taken into account in laboratory experiments. (3) Scale up groups developed from static laboratory tests might not be appropriate for field predictions.
Table 3.1 - Physical properties for the static versus dynamic simulations

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Block Length</td>
<td>1 ft</td>
</tr>
<tr>
<td>Block Width</td>
<td>0.25 ft</td>
</tr>
<tr>
<td>Block thickness</td>
<td>0.07 ft</td>
</tr>
<tr>
<td>Matrix size</td>
<td>0.02778 ft by 0.02778 ft by 0.02778 ft</td>
</tr>
<tr>
<td>Fracture spacing</td>
<td>0.25 ft in X and 0.0833 ft in Y direction</td>
</tr>
<tr>
<td>Aperture</td>
<td>0.003281 ft</td>
</tr>
<tr>
<td>Matrix porosity</td>
<td>0.298</td>
</tr>
<tr>
<td>Matrix permeability</td>
<td>34 md</td>
</tr>
<tr>
<td>Fracture porosity</td>
<td>1</td>
</tr>
<tr>
<td>Fracture permeability</td>
<td>2000 md</td>
</tr>
<tr>
<td>Total Fracture Porosity</td>
<td>5%</td>
</tr>
<tr>
<td>Block dip angle</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 3.2 - Rock and Fluid Properties for the static versus dynamic simulations

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of phases in the reservoir</td>
<td>Up to 3; water, oil, and microemulsion</td>
</tr>
<tr>
<td>Residual water saturation in matrix at low capillary number</td>
<td>0.1</td>
</tr>
<tr>
<td>Residual water saturation in fracture at low capillary number</td>
<td>0.05</td>
</tr>
<tr>
<td>Initial water saturation in matrix</td>
<td>0.86</td>
</tr>
<tr>
<td>Initial water saturation in fracture</td>
<td>0.99</td>
</tr>
<tr>
<td>Residual oil saturation in matrix at low capillary number</td>
<td>0.4</td>
</tr>
<tr>
<td>Residual oil saturation in fracture at low capillary number</td>
<td>0.35</td>
</tr>
<tr>
<td>Parameter</td>
<td>Value</td>
</tr>
<tr>
<td>------------------------------------------------------------</td>
<td>----------------------------</td>
</tr>
<tr>
<td>Initial oil saturation in matrix</td>
<td>0.14</td>
</tr>
<tr>
<td>Initial oil saturation in fracture</td>
<td>0.01</td>
</tr>
<tr>
<td>Residual microemulsion saturation in matrix at low capillary number</td>
<td>0.1</td>
</tr>
<tr>
<td>Residual microemulsion saturation in fracture at low capillary number</td>
<td>0.05</td>
</tr>
<tr>
<td>Residual saturation of all phases at high capillary number</td>
<td>0</td>
</tr>
<tr>
<td>Endpoint relative permeability of water at low capillary number</td>
<td>0.3 for matrix, 0.4 for fracture</td>
</tr>
<tr>
<td>Endpoint relative permeability of oil at low capillary number</td>
<td>0.4 for matrix, 0.6 for fracture</td>
</tr>
<tr>
<td>Endpoint relative permeability of microemulsion at low capillary number</td>
<td>0.3 for matrix, 0.4 for fracture</td>
</tr>
<tr>
<td>Relative permeability exponent of aqueous phase at low capillary number</td>
<td>2 for matrix, 1.5 for fracture</td>
</tr>
<tr>
<td>Relative permeability exponent of oil phase at low capillary number</td>
<td>3 for matrix, 1.8 for fracture</td>
</tr>
<tr>
<td>Relative permeability exponent of microemulsion phase at low capillary number</td>
<td>2 for matrix, 1.5 for fracture</td>
</tr>
<tr>
<td>Endpoint relative permeability of all phases at high capillary number</td>
<td>1</td>
</tr>
<tr>
<td>Relative permeability exponent of all phases at high capillary number</td>
<td>1</td>
</tr>
<tr>
<td>Matrix positive capillary Pressure Endpoint</td>
<td>0.1</td>
</tr>
<tr>
<td>Matrix negative capillary Pressure Endpoint</td>
<td>-0.15</td>
</tr>
<tr>
<td>Matrix capillary pressure parameter EPC0</td>
<td>3</td>
</tr>
<tr>
<td>Matrix critical water saturation SSTAR (transition saturation from Pc+ to Pc-)</td>
<td>0.41</td>
</tr>
<tr>
<td>Molecular diffusion coefficients of all components</td>
<td>0</td>
</tr>
<tr>
<td>Dispersivity of all phases</td>
<td>0</td>
</tr>
<tr>
<td>Surfactant adsorption parameters</td>
<td>AD31: 1.5, AD32: 0.15, B3D:1000</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>-------------------------------</td>
</tr>
<tr>
<td>Cation Exchange</td>
<td>N/A</td>
</tr>
<tr>
<td>Water viscosity</td>
<td>1 cp</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>10.5 cp</td>
</tr>
<tr>
<td>Microemulsion viscosity</td>
<td>ALPHAV1 = 2.5</td>
</tr>
<tr>
<td>parameters</td>
<td>ALPHAV2 = 2.45</td>
</tr>
<tr>
<td></td>
<td>ALPHSV3-5 = 0</td>
</tr>
<tr>
<td>CMC</td>
<td>0.0005</td>
</tr>
<tr>
<td>Lower type III salinity</td>
<td>0.77</td>
</tr>
<tr>
<td>Higher type III salinity</td>
<td>1.15</td>
</tr>
<tr>
<td>Initial reservoir salinity</td>
<td>0.82</td>
</tr>
</tbody>
</table>

Table 3.3 - Well Properties for the static versus dynamic simulations

<table>
<thead>
<tr>
<th>Number of Injectors</th>
<th>1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of producers</td>
<td>1</td>
</tr>
<tr>
<td>Distance between injector and producer</td>
<td>1 ft</td>
</tr>
<tr>
<td>Perforation layers of injector</td>
<td>All layers</td>
</tr>
<tr>
<td>Perforation layers of producer</td>
<td>All layers</td>
</tr>
<tr>
<td>Producer BHP</td>
<td>14.7 psi</td>
</tr>
<tr>
<td>Injector BHP</td>
<td>14.8 psi &amp; 15.7 psi</td>
</tr>
<tr>
<td>Constraint on injector or producer</td>
<td>unlimited injection or production rates</td>
</tr>
<tr>
<td>Injected surfactant concentration, if any</td>
<td>2%</td>
</tr>
<tr>
<td>Injected alkali concentration</td>
<td>0</td>
</tr>
<tr>
<td>Injected polymer concentration</td>
<td>0</td>
</tr>
<tr>
<td>Injected salinity</td>
<td>0.94 (inducing phase III microemulsion)</td>
</tr>
</tbody>
</table>
Table 3.4 - Simulation Parameters for the static versus dynamic simulations

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total number of grid blocks</td>
<td>1023</td>
</tr>
<tr>
<td>Total number of fracture grid blocks</td>
<td>294</td>
</tr>
<tr>
<td>Method of solution</td>
<td>IMPES</td>
</tr>
<tr>
<td>Simulation time</td>
<td>9 days - around 2 pore volumes</td>
</tr>
</tbody>
</table>
Figure 3.1 - Reservoir model for the static versus dynamic simulations
Figure 3.2 - cumulative oil recovery for 0.1 psi/ft pressure gradient

Figure 3.3 - Comparing the static and dynamic imbibition tests
Figure 3.4 - Schematic to explain the role of induced transverse pressure gradients

Figure 3.5- Effect of the Pressure Gradient on cumulative oil recovery
Injection rate > Imbibition rate

- Water Flooding, 1 psi/ft

![Image of water flooding schematic]

- Surfactant flooding, 1 psi/ft

![Image of surfactant flooding schematic]

Injection rate < Imbibition rate

- Water Flooding, 0.1 psi/ft

![Image of water flooding schematic]

- Surfactant flooding, 0.1 psi/ft

![Image of surfactant flooding schematic]

Figure 3.6- Schematic to explain the interplay between the capillary and the injection rate
In this chapter, we simulate dynamic imbibition on a small scale homogenous fractured block. The purpose is to seek optimum conditions under which the oil recovery is maximal. In order to do this, we consider a base case simulation and then we do sensitivity analyses on several parameters. The injections are all continuous. Various chemical solutions are injected. These include: water, polymer, surfactant, alkali, and different combinations of them. For convenience of simulation, although this is not physically correct, alkali represents the wettability modifying agent, while the surfactant is the agent that lowers the IFT to ultra-low values. Therefore, a simulation labeled AS indicates that the injected chemical solution lowers the IFT to ultra low values as well as alters the wettability from mixed-wet to water-wet. On the other hand, a simulation labeled ASP does the above task as well as making the chemical solution viscous (polymer). The recovery curves are compared for each sensitivity analysis and appropriate profiles are demonstrated in order to understand the results.

4.1: Base-Case Model Description and Simulation Results

The base case model in this chapter is basically the same one as in the previous chapter and is shown in Figure 4.1. The figure shows the porosity distribution. The blue represents the fracture and the pink represents the matrix. The red arrow shows the injection direction. This is a 1 ft by 0.25 ft by 0.07 ft horizontal fractured block modeled with UTCHEM. There are 31 gridblocks in the X direction, 11 gridblocks in the Y direction and 3 gridblocks in the Z direction. The fractures are modeled as discrete
fractures. There are two parallel fractures along the X axis. There are also four parallel fractures along the Y axis, perpendicular to the direction of the injection/production. As shown in the figure, one of these four fractures contains the injection well; two are in the middle and the last one contains the production well. The height of this fractured block is small in order to minimize the effect of gravity. The top, bottom and sides of the block are sealed. The block matrix is homogenous and has a permeability of 30 md. The fractures are also homogenous. The block physical properties for the base case are listed in Table 4.1.

The initial water saturation is 0.14 in the matrix and 0.99 in the fracture. There is a 1 psi pressure drop between the wells. Initially the matrix is mixed-wet. The capillary pressure in the fracture is always zero. The capillary pressure for the matrix is calculated using the Brook-Corey model. The relative permeability parameters are calculated as described in Chapter 2.5. In current chapter, in all cases where surfactant is involved, surfactant forms a type III microemulsion with oil. Alkali, when present, changes the wettability with a constant value of $\omega = 0.5$ in Equation 2.14. This is an approximation, but it has been found to be convenient to match the experimental data. The Initial condition parameters together with rock and fluid properties for the base case study are listed in Table 4.2. The word "altered", wherever seen in this table, represents the value of the same parameter in a completely water-wet condition.

The injection in the base case includes 5 different scenarios, namely: water only (W), surfactant only (S), alkaline only (A), alkaline-surfactant (AS), and alkaline-surfactant-polymer (ASP). The injection and production wells are vertical, constrained to constant
pressures and completed in the leftmost and rightmost fractures, respectively. The well data for the base case study are listed in Table 4.3.

This model contains 1023 grid blocks, 298 of which are fracture grid blocks. The total simulation time is 9 days. The UTCHEM solves the equations using the IMPES technique. The simulation parameters for the base case are listed in Table 4.4.

The base case simulation results are depicted in Figure 4.2. As we can see, AS flooding has a higher and faster oil recovery than A or S alone. However, the behavior of S flooding relative to A flooding is not that simple. Initially curve S starts off faster than curve A, then curve A catches the curve S at around 0.25 pore volumes and stays above it until the S curve catches up finally at 2.5 pore volumes and outperforms it afterwards. This seems logical as the surfactant initially produces a viscous fluid in-situ and kills the capillary pressure as it progresses through the fracture. On the other hand, the water flood recovery is shown to be the poorest. Finally, ASP performs better than all other injection scenarios. The first conclusion from these results is that a viscous chemical recovers more oil than the same chemical solution that is not viscous. In other terms, ASP performs better than AS. Another conclusion is that AS (or ASP) acts better than A, or S alone. Therefore, a chemical solution that alters the wettability as well as reduces the IFT to ultra low values produces more oil at a given pore volumes of the injected fluid.

4.2: SENSITIVITY ON PRESSURE GRADIENT/INJECTION RATE
To test the effect of pressure gradient or injection rate, all the injection scenarios discussed in Chapter 4.1 were tested with a low pressure drop of 0.1 psi/ft, thereby reducing the effect of viscous forces and favoring for effect of capillarity. This is done to examine if the order of increasing oil recovery, observed in the case of 1 psi/ft, still holds. Those parameters that differ in this simulation from the base case simulation are listed in Table 4.5.

The simulation results are demonstrated in Figure 4.3. As we can see, AS flooding has a higher and faster oil recovery than A or S alone. However, the behavior of S flooding and A flooding almost look the same up to 0.2 pore volumes which is the total injection time for this simulation. Here the water flood recovery is shown to be the poorest again. Finally ASP performs better than all other cases. The main conclusion from this sensitivity study is that a viscous chemical recovers more oil than the same chemical solution that is not viscous irrespective of the pressure gradient. In other terms, AS (or ASP) acts better than A or S alone, even for a very low pressure gradient. Therefore, a chemical solution that alters the wettability as well as reduces the IFT to ultra low values produces more oil at a given pore volumes of the injected fluid.

4.3: SENSITIVITY ON DIFFUSION COEFFICIENT

To understand if the diffusion coefficient of the chemical plays an important role here, a sensitivity study has been done. For the sake of this study, we temporarily put the polymer aside and compare the recoveries of the AS, A and S flooding at a nominal diffusion coefficient value and at high and low injection rates. The reason is that adding
the polymer does not change the relative behavior of the recovery curves if they happen to be the same as in the base case simulation. Those parameters that differ in this simulation from the base case simulation are listed in Table 4.6.

The simulation results for 1 psi/ft and 0.1 psi/ft pressure drop cases are shown in Figures 4.3 and 4.4, respectively. We observe that diffusion does not make a significant difference in Figure 4.3; neither does it in Figure 4.4. A direct conclusion is that viscous forces make the effect of diffusion negligible and this is true even in the case of a low pressure drop. Of course, as others have done, it is possible to exaggerate the effect of diffusion by assigning a large value to the diffusion coefficient parameter in models, but then it will not be realistic.

4.4: SENSITIVITY ON CAPILLARY PRESSURE PARAMETERS

We know that the matrix capillary pressure has a significant effect on oil recovery from fractured reservoirs. To understand this effect, we simulate 3 different cases including: One case with zero capillary pressure endpoint, one with low capillary pressure endpoint and the last one with high capillary pressure endpoint (These are all for matrix. The fracture capillary pressure is always zero). The parameters for this sensitivity study are listed in Table 4.7. For each case, we simulate 3 injection scenarios, namely A, S, and AS.

The simulation results for surfactant flooding, alkaline flooding and alkaline-surfactant flooding are depicted in Figures 4.6, 4.7 and 4.8, respectively. Three conclusions can be
drawn from these figures. First, increasing the capillary pressure endpoints enhances the oil recovery rate in all three cases. This is more pronounced in the case of alkaline flooding (Figure 4.7). Second, the effect of capillary pressure on recovery curve diminished after some time; all recovery curves collapse on each other after almost 3 pore volumes. This is consistent with the fact that capillary pressure goes to zero if the critical saturation in a block is reached or if the surfactant concentration has exceeded the CMC in that block. Third, no matter how high the capillary pressure is, injecting an alkaline-surfactant solution produces more oil and produces it faster than injecting the alkali alone or surfactant alone. This can be seen by comparing Figure 4.8 with Figure 4.6 and 4.7. AS flooding results in a recovery of around 45% after 3 pore volumes, while those of A or S flooding do not exceed 35% at the same pore volumes.

4.5: SENSITIVITY ON MICROEMULSION VISCOSITY

As discussed in Chapter 3, microemulsion viscosity plays an important role in recovery from fractured reservoirs. This idea is further tested in this section by performing sensitivity simulations on microemulsion viscosity parameters ALPHAV1 and ALPHAV2. We know that increasing these parameters directly increases the microemulsion phase viscosity (The microemulsion viscosity model is described in section 2.5). Therefore, we investigate whether increasing the microemulsion viscosity enhances or reduces the oil recovery. The new ALPHAV1 and ALPHAV2 values are listed in Table 4.8.
The simulation results for surfactant flooding and alkaline-surfactant flooding are shown in Figures 4.9 and 4.10. The effect of increasing the ALPHAV1 and ALPHAV2 values is the same in both figures. In both cases therefore, increasing the microemulsion viscosity enhances the oil recovery versus pore volumes of the injected fluid. The reason is that the existence of microemulsion (mainly in fracture) produces the same effect as the polymer does. Hence, the more viscous the microemulsion, the better the sweep efficiency will be when flooding the fractured reservoirs.

4.6: SENSITIVITY ON POLYMER PERMEABILITY REDUCTION FACTOR

In order to investigate the effect of polymer permeability reduction factor, we simulated five cases with different permeability reduction factors (CRK). These values can be found in Table 4.9. The injection is surfactant-polymer here. We want to know whether a higher CRK translates into a higher oil recovery or vice versa. The UTCHEM model for polymer permeability reduction is discussed in Chapter 2.5.

The simulation results are demonstrated in Figure 4.11. The recovery consistently increases as the CRK value is raised. For the case of CRK=0.25, the recovery approaches to 50% after 0.7 pore volumes of injection. We should keep in mind that the recovery curves are drawn versus pore volumes, not time. The reason for the observed behavior is that as polymer enters the fracture, it reduces its permeability and therefore the permeability contrast between the fracture and the matrix reduces. An equivalent interpretation is that the effective mobility of the injected fluid reduces as the CRK value is increased and this, in turn, results in a better sweep.
4.7: CONCLUSIONS TO LAB-SCALE SIMULATION FINDINGS

Small-scale simulations indicate that no matter how high the capillary pressure or how low the pressure gradient is, ASP flooding outperforms the other injection scenarios. In other terms, lowering the IFT to ultra values and switching the wettability at the same time produces the best result. Diffusion is also shown to have an insignificant effect on the recovery curve. The simulations show that even a small viscous gradient is more effective than diffusion or capillarity and that lowering the IFT and killing the capillary pressure does not necessarily translate into a lower or slower oil recovery. Polymer is shown to enhance the oil recovery by decreasing the permeability contrast and increasing the sweep. The conclusion to these simulations is that injecting a chemical solution that is viscous, lowers the IFT, and changes the wettability to water-wet is most beneficial.
### Table 4.1 - Physical properties for the base simulation case

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Block Length</td>
<td>1 ft</td>
</tr>
<tr>
<td>Block Width</td>
<td>0.25 ft</td>
</tr>
<tr>
<td>Block thickness</td>
<td>0.07 ft</td>
</tr>
<tr>
<td>Matrix size</td>
<td>0.02778 ft by 0.02778 ft by 0.02778 ft</td>
</tr>
<tr>
<td>Fracture spacing</td>
<td>0.25 ft in X and 0.0833 ft in Y direction</td>
</tr>
<tr>
<td>Aperture</td>
<td>0.003281 ft</td>
</tr>
<tr>
<td>Matrix porosity</td>
<td>0.298</td>
</tr>
<tr>
<td>Matrix permeability</td>
<td>34 md</td>
</tr>
<tr>
<td>Fracture porosity</td>
<td>1</td>
</tr>
<tr>
<td>Fracture permeability</td>
<td>2000 md</td>
</tr>
<tr>
<td>Total Fracture Porosity</td>
<td>5%</td>
</tr>
<tr>
<td>Block dip angle</td>
<td>0</td>
</tr>
</tbody>
</table>

### Table 4.2 - Rock and fluid properties for the base case simulation

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of phases in the reservoir</td>
<td>Up to 3; water, oil, and microemulsion</td>
</tr>
<tr>
<td>Residual water saturation in matrix at low capillary number</td>
<td>0.1 , altered: 0.2</td>
</tr>
<tr>
<td>Residual water saturation in fracture at low capillary number</td>
<td>0.05 , altered: 0.1</td>
</tr>
<tr>
<td>Initial water saturation in matrix</td>
<td>0.14</td>
</tr>
<tr>
<td>Initial water saturation in fracture</td>
<td>0.99</td>
</tr>
<tr>
<td>Residual oil saturation in matrix at low capillary number</td>
<td>0.4, altered: 0.2</td>
</tr>
<tr>
<td>Residual oil saturation in fracture at low capillary number</td>
<td>0.35, altered: 0.05</td>
</tr>
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<td>Number</td>
<td>Value</td>
</tr>
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<td>-----------------------------------------------------------------------</td>
<td>--------------------------------------------</td>
</tr>
<tr>
<td>Initial oil saturation in matrix</td>
<td>0.86</td>
</tr>
<tr>
<td>Initial oil saturation in fracture</td>
<td>0.01</td>
</tr>
<tr>
<td>Residual microemulsion saturation in matrix at low capillary number</td>
<td>0.1, altered: 0.2</td>
</tr>
<tr>
<td>Residual microemulsion saturation in fracture at low capillary number</td>
<td>0.05, altered: 0.1</td>
</tr>
<tr>
<td>Residual saturation of all phases at high capillary number</td>
<td>0</td>
</tr>
<tr>
<td>Endpoint relative permeability of water at low capillary number</td>
<td>0.3 (altered: 0.2) for matrix, 0.4 (altered: 0.3) for fracture</td>
</tr>
<tr>
<td>Endpoint relative permeability of oil at low capillary number</td>
<td>0.4 (altered: 0.7) for matrix, 0.6 (altered: 1) for fracture</td>
</tr>
<tr>
<td>Endpoint relative permeability of microemulsion at low capillary number</td>
<td>0.3 for matrix (altered: 0.2), 0.4 (altered: 0.3) for fracture</td>
</tr>
<tr>
<td>Relative permeability exponent of aqueous phase at low capillary number</td>
<td>2 for matrix (altered: 2.5), 1.5 (altered: 2) for fracture</td>
</tr>
<tr>
<td>Relative permeability exponent of oil phase at low capillary number</td>
<td>3 for matrix (altered: 2), 1.8 (altered: 1.5) for fracture</td>
</tr>
<tr>
<td>Relative permeability exponent of microemulsion phase at low capillary number</td>
<td>2 for matrix (altered: 2.5), 1.5 (altered: 2) for fracture</td>
</tr>
<tr>
<td>Endpoint relative permeability of all phases at high capillary number</td>
<td>1</td>
</tr>
<tr>
<td>Relative permeability exponent of all phases at high capillary number</td>
<td>1</td>
</tr>
<tr>
<td>Matrix positive capillary Pressure Endpoint</td>
<td>0.1 (altered: 0.1)</td>
</tr>
<tr>
<td>Matrix negative capillary Pressure Endpoint</td>
<td>-0.15 (altered: 0)</td>
</tr>
<tr>
<td>Matrix capillary pressure parameter EPC0</td>
<td>3 (altered: 3)</td>
</tr>
<tr>
<td>Matrix critical water saturation SSTAR (transition saturation from Pc+ to Pc-)</td>
<td>0.41 (altered: N/A)</td>
</tr>
<tr>
<td>Wettability alteration parameter</td>
<td>$\omega = \text{constant} = 0.5$</td>
</tr>
</tbody>
</table>
### Molecular diffusion coefficients of all components
0

### Dispersivity of all phases
0

### Surfactant adsorption parameters
AD31: 1.5, AD32: 0.15, B3D:1000

### Polymer Viscosity parameters

### Polymer Permeability reduction parameter
CRK=0.12

### Cation Exchange
N/A

### Water viscosity
1 cp

### Oil viscosity
10.5 cp

### Microemulsion viscosity parameters
\( \text{ALPHAV1} = 2.5 \)
\( \text{ALPHAV2} = 2.45 \)
\( \text{ALPHSV3-5} = 0 \)

### CMC
0.0005

### Lower type III effective salinity
0.77

### Higher type III effective salinity
1.15

### Initial reservoir effective salinity
0.82

<table>
<thead>
<tr>
<th>Table 4.3 - Well data for the base case simulation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Number of Injectors</strong></td>
</tr>
<tr>
<td><strong>Number of producers</strong></td>
</tr>
<tr>
<td><strong>Distance between injector and producer</strong></td>
</tr>
<tr>
<td><strong>Perforation layers of injector</strong></td>
</tr>
<tr>
<td><strong>Perforation layers of producer</strong></td>
</tr>
<tr>
<td><strong>Producer BHP</strong></td>
</tr>
<tr>
<td><strong>Injector BHP</strong></td>
</tr>
<tr>
<td><strong>Constraint on injector or producer</strong></td>
</tr>
<tr>
<td><strong>Injected surfactant concentration, If any</strong></td>
</tr>
<tr>
<td>Parameters</td>
</tr>
<tr>
<td>----------------------------------------------</td>
</tr>
<tr>
<td>Injected alkali concentration, If any</td>
</tr>
<tr>
<td>Injected polymer concentration, If any</td>
</tr>
<tr>
<td>Injected salinity</td>
</tr>
<tr>
<td>Chemicals injected</td>
</tr>
</tbody>
</table>

**Table 4.4 - Simulation parameters for the base case simulation**

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total number of grid blocks</td>
<td>1023</td>
</tr>
<tr>
<td>Total number of fracture grid blocks</td>
<td>294</td>
</tr>
<tr>
<td>Method of solution</td>
<td>IMPES</td>
</tr>
<tr>
<td>Simulation time</td>
<td>9 days</td>
</tr>
</tbody>
</table>

**Table 4.5 - Sensitivity on pressure drop**

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure gradient</td>
<td>0.1 psi/ft</td>
</tr>
<tr>
<td>Chemicals injected</td>
<td>W, S, A, AS, ASP</td>
</tr>
</tbody>
</table>

**Table 4.6 - Sensitivity on diffusion parameter**

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surfactant diffusion coefficient in water/Microemulsion</td>
<td>$10^{-6}$ ft²/day</td>
</tr>
<tr>
<td>Alkali diffusion coefficient in water/Microemulsion</td>
<td>$10^{-6}$ ft²/day</td>
</tr>
<tr>
<td>Pressure gradient</td>
<td>1 psi/ft &amp; 0.1 psi/ft</td>
</tr>
<tr>
<td>Chemicals injected</td>
<td>AS, S, A</td>
</tr>
</tbody>
</table>

**Table 4.7 - Sensitivity on capillary pressure**

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Positive capillary pressure endpoint</td>
<td>0, 0.3</td>
</tr>
<tr>
<td>Negative capillary pressure endpoint</td>
<td>0, -0.45</td>
</tr>
<tr>
<td>Chemicals injected</td>
<td>AS, A, S</td>
</tr>
<tr>
<td>--------------------</td>
<td>----------</td>
</tr>
</tbody>
</table>

Table 4.8 - Sensitivity on microemulsion viscosity

<table>
<thead>
<tr>
<th>Microemulsion viscosity parameters</th>
<th>ALPHAV1 = 1, 5</th>
<th>ALPHAV2 = 1, 5</th>
<th>ALPHHSV3-5 = 0</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemicals injected</td>
<td>S, AS</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 4.9 - Sensitivity on polymer permeability reduction factor

<table>
<thead>
<tr>
<th>CRK</th>
<th>0, 0.05, 0.18, 0.25</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemicals injected</td>
<td>SP</td>
</tr>
</tbody>
</table>
Figure 4.1 - Reservoir model for small-scale simulations
Figure 4.2 - Base case simulation results

Figure 4.3 - Sensitivity on pressure gradient
Pressure Drop= 1 psi/ft

Pressure Drop=0.1 psi/ft

Figure 4.4- Sensitivity on Diffusion Coefficient, Pressure Drop =1 psi/ft

Figure 4.5- Sensitivity on Diffusion Coefficient, Pressure Drop =0.1 psi/ft
Figure 4.6 - Sensitivity on Capillary pressure endpoints - Surfactant flooding

Figure 4.7 - Sensitivity on Capillary pressure endpoints - Alkaline flooding
Figure 4.8 - Sensitivity on Capillary pressure endpoints; Alkaline-Surfactant flooding

Figure 4.9 - Sensitivity on microemulsion viscosity - Surfactant flooding
Figure 4.10 - Sensitivity on microemulsion viscosity - Alkaline surfactant flooding

Figure 4.11 - Sensitivity on polymer permeability reduction factor
CHAPTER 5: SIMULATION OF LARGE-SCALE HOMOGENOUS FRACTURED BLOCKS

In this chapter we perform dynamic imbibition simulations on a large scale homogenous fractured block. This is the next step after the small scale simulations performed in Chapter 4. The purpose is to seek optimum conditions under which the oil recovery is maximal in a larger scale model. In order to do this, we consider 7 different cases with varying relative importance of capillarity and viscous forces. The injections are all continuous. Various chemical solutions are injected. These include: water, polymer, surfactant, alkali, and different combinations of them. For convenience of simulation, even though this is not physically correct, alkali represents the wettability modifying agent, while the surfactant is the agent that lowers the IFT to ultra low values. Therefore, a simulation labeled AS indicates that the injected chemical solution lowers the IFT to ultra low values as well as alters the wettability from mixed-wet to water-wet. On the other hand, a simulation labeled ASP does the above task as well as making the chemical solution viscous (polymer). The recovery curves are compared for each case number and appropriate profiles are demonstrated in order to understand the results.

5.1: MODEL DESCRIPTION

The Simulation model, shown in Figure 5.1, is basically the same as the one in the previous chapter, but with minor modifications. It has enlarged dimensions and varying gridblock sizes. The figure shows the porosity distribution. The blue represents the fracture and the pink represents the matrix. The red arrow shows the injection direction. This is a 48.5 ft by 33.3 ft by 10 ft horizontal fractured block modeled with UTCHEM.
There are 28 grid blocks in the X direction, 13 grid blocks in the Y direction and 3 grid blocks in the Z direction. The fractures are modeled as discrete fractures. There are two parallel fractures along the X axis. There are also four parallel fractures along the Y axis, perpendicular to the direction of the injection/production. As shown in the figure, one of these four fractures contains the injection well; two are in the middle and the last one contains the production well. The height of this fractured block is 10 ft and therefore the gravity effect is important here. The top, bottom and sides of the block are sealed. The block matrix is homogenous and has a permeability of 30 md. The fractures are also homogenous. The block physical properties are listed in Table 5.1.

The initial water saturation is 0.99 in the fracture and is variable in the matrix (Table 5.5). Initially the matrix is mixed-wet. The capillary pressure in the fracture is always zero. The capillary pressure for the matrix is calculated using the Brook-Corey model. The relative permeability parameters are calculated as described in Chapter 2.5. In current chapter, in all cases where surfactant is involved, surfactant forms a type III microemulsion with oil. Alkali, when present, changes the wettability with a constant value of $\omega = 0.5$ in Equation 2.14. This is an approximation, but it has been found to be convenient to match the experimental data. The Initial condition parameters together with rock and fluid properties are listed in Table 5.2. The word "altered", wherever seen in this table, represents the value of the same parameter in a completely water-wet condition.

Seven different chemicals are injected: water only (W), surfactant only (S), alkaline only (A), polymer only (P), alkaline-polymer (AP), surfactant-polymer (SP), and alkaline-
surfactant-polymer (ASP). The injection and production wells are vertical, constrained to constant pressures and completed in the leftmost and rightmost fractures, respectively. The well data are listed in Table 5.3.

This model contains 1092 grid blocks, 300 of which are fracture grid blocks. The total simulation time is 3 pore volumes. The UTCHEM solves the equations using the IMPES technique. The simulation parameters are listed in Table 5.4.

5.2: STUDY CASES

To examine whether or not the findings of the small scale simulations still hold in a larger scale model, we consider 7 study cases. The parameters for each study case are tabulated in Table 5.5. As we can see, different cases with different pressure gradients, initial matrix water saturation, and capillary pressure endpoints are examined. This is to alter the relative importance of the capillarity and viscous forces and to determine which kind of chemical flooding produces more oil in each case. For example, case # 2 favors mostly for viscous forces, because the pressure gradient is high, initial matrix water saturation is high (which means capillary pressure is weak), and the capillary pressure endpoints are low. In contrast, case # 5 favors mostly for capillarity as it has a low pressure gradient, low initial matrix water saturation, and high capillary pressure endpoints. For each case, different chemicals are injected and recovery curves are compared. Case # 7, on the other hand, is analyzed separately. As can be seen in Table 5.5, case # 7 has an extremely high capillary pressure. For this case, only alkaline flooding and alkaline-surfactant flooding are compared. Therefore we can determine whether or not injecting a surfactant that kills
the capillary pressure (AS flooding), even in this extreme case, produces more oil than injecting a surfactant that does not (A flooding).

5.3: SIMULATION RESULTS AND CONCLUSIONS

Six different cases (Table 5.5, Case#1-6) and each one with seven different injection scenarios were simulated totaling 42 simulations. The results are categorized and demonstrated in two different ways. First, simulations results are categorized for each one of the 7 injection scenarios (Figures 5.2-5.8) and second, they are categorized for each one of the 6 different cases (Figures 5.9-5.14). Case #7 pertains to Figure 5.15 on which we discuss at the end of this section.

Figures 5.2-5.8 compare the oil recovery curves of different case studies for each injection scenario. For water flooding and polymer flooding, the interesting observation is that cases 1,2,3,6 show almost the same recovery trend. These cases do not produce more than 1% of oil after 3 pore volumes. However, case 4 and 5 show a significantly more recovery. Case 5 outperforms case 4 mainly because of its lower pressure drop and consequently more contact time. If we look back at Table 5.5, we see that the major difference between this case and other cases is the initial water saturation in the matrix. The initial water saturation for case 4 and 5 is 20% compared to 30% for other cases. This shows that if the critical water saturation in the matrix (0.41 in this case) is much more than its initial water saturation (0.2 in cases 4 and 5), water and polymer flooding have the potential to produce some oil.
Figures 5.4 and 5.5 show an interesting behavior. First of all, again, case 4 and 5 outperform other cases as we observed in Figures 5.2 and 5.3. This is because of low initial water saturation and high capillary pressure endpoints. However, Case 5 outperforms case 4 in alkaline flooding (Figure 5.4), while case 4 outperforms case 5 in surfactant flooding (Figure 5.5). If we look back at the Table we see that case 5 has a lower pressure drop which in turn means that the injected solution in case 5 should have more contact time than in case 4. This is, of course, the reason why alkaline flooding produces more oil in case 5 but the reverse is seen in surfactant flooding. The reason here might be that the higher pressure drop in the case of surfactant flooding helps push the surfactant further into the matrix and therefore compensates for the reduced contact time.

Figures 5.6 (AP flooding) and 5.7 (SP flooding) show the same features as those of Figures 5.4 and 5.5. However, the distinction between cases 4 and 5 is more in Figure 5.6 (compared to Figure 5.4) and is less in Figure 5.7 (compared to Figure 5.5). These curves just seem logical as introducing polymer favors the contact time for alkaline flooding and reduces the importance of injection rate for surfactant flooding. Finally Figure 5.8 (ASP flooding), shows that case 5 produces more oil and produces it faster than the other cases. This is mainly because of the increased capillary pressure endpoints, lower initial water saturation and lower pressure drop.

Figures 5.9-5.14, in contrast, compare the oil recovery curves of different injection scenarios for each case. We observe that ASP flooding is always beneficial and it does not matter which case we are considering. The recovery curves for A (or AP) flooding and S or (SP) flooding, however, do not show a single trend. In some cases surfactant flooding oil recovery dominates the alkaline flooding oil recovery and in some other
cases the reverse happens to be true. The maximum cumulative oil recovery for ASP flooding is the one in case 5. This is primarily because of the lower injection rate (more contact time) and higher capillary pressure endpoints.

One question rises here: What if the capillary pressure endpoints are so high that introducing the surfactant becomes detrimental? In other terms, if the capillary pressure is very strong, the common sense is that killing the IFT will drastically lower the recovery and therefore A will outperform S and even AS? To investigate this, we simulated case#7 (Table 5.5). We considered a high positive capillary pressure endpoint of 100 and of course a high negative capillary pressure endpoint of -150 without changing the critical water saturation. Then, we simulated S, A, and AS flooding. Alkaline flooding only alters wettability while AS reduces the residual oil saturation and further increases the oil relative permeability as well. The result is shown in Figure 5.15. While alkaline flooding outperforms surfactant flooding up to the simulation time, alkaline-surfactant flooding oil recovery still dominates the alkaline flooding oil recovery. This is a significant result which further shows that reducing the IFT to ultra low values is always beneficial as long as the wettability is altered by a significant degree at the same time.
Table 5.1 - Physical properties for the large-scale homogeneous fractured block

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Block Length</td>
<td>48.5 ft</td>
</tr>
<tr>
<td>Block Width</td>
<td>33.3 ft</td>
</tr>
<tr>
<td>Block thickness</td>
<td>10 ft</td>
</tr>
<tr>
<td>Matrix size</td>
<td>2 ft by (7 or 2 or 1) ft by 3.33 ft</td>
</tr>
<tr>
<td>Fracture spacing</td>
<td>0.25 ft in X and 0.0833 ft in Y direction</td>
</tr>
<tr>
<td>Aperture</td>
<td>0.15 ft</td>
</tr>
<tr>
<td>Matrix porosity</td>
<td>0.07</td>
</tr>
<tr>
<td>Matrix permeability</td>
<td>100 md</td>
</tr>
<tr>
<td>Fracture porosity</td>
<td>1</td>
</tr>
<tr>
<td>Fracture permeability</td>
<td>50000 md</td>
</tr>
<tr>
<td>Total Fracture Porosity</td>
<td>around 30%</td>
</tr>
<tr>
<td>Block dip angle</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 5.2 - Rock and fluid properties for the large-scale homogeneous fractured block

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of phases in the reservoir</td>
<td>Up to 3; water, oil, and microemulsion</td>
</tr>
<tr>
<td>Residual water saturation in matrix at low capillary number</td>
<td>0.1, altered: 0.2</td>
</tr>
<tr>
<td>Residual water saturation in fracture at low capillary number</td>
<td>0.05, altered: 0.1</td>
</tr>
<tr>
<td>Initial water saturation in matrix</td>
<td>Variable (see Table 5.5)</td>
</tr>
<tr>
<td>Initial water saturation in fracture</td>
<td>0.99</td>
</tr>
<tr>
<td>Residual oil saturation in matrix at low capillary number</td>
<td>0.4, altered: 0.2</td>
</tr>
<tr>
<td>Residual oil saturation in fracture at low capillary number</td>
<td>0.15, altered: 0.05</td>
</tr>
<tr>
<td>Parameter</td>
<td>Value</td>
</tr>
<tr>
<td>--------------------------------------------------------------------------</td>
<td>----------------------------------------------------------------------</td>
</tr>
<tr>
<td>Initial oil saturation in matrix</td>
<td>variable (see Table 5.5)</td>
</tr>
<tr>
<td>Initial oil saturation in fracture</td>
<td>0.01</td>
</tr>
<tr>
<td>Residual microemulsion saturation in matrix at low capillary number</td>
<td>0.1, altered: 0.2</td>
</tr>
<tr>
<td>Residual microemulsion saturation in fracture at low capillary number</td>
<td>0.05, altered: 0.1</td>
</tr>
<tr>
<td>Residual saturation of all phases at high capillary number</td>
<td>0</td>
</tr>
<tr>
<td>Endpoint relative permeability of water at low capillary number</td>
<td>0.3 (altered: 0.2) for matrix, 0.4 (altered: 0.3) for fracture</td>
</tr>
<tr>
<td>Endpoint relative permeability of oil at low capillary number</td>
<td>0.4 (altered: 0.7) for matrix, 0.6 (altered: 1) for fracture</td>
</tr>
<tr>
<td>Endpoint relative permeability of microemulsion at low capillary number</td>
<td>0.3 for matrix (altered: 0.2), 0.4 (altered: 0.3) for fracture</td>
</tr>
<tr>
<td>Relative permeability exponent of aqueous phase at low capillary number</td>
<td>2 for matrix (altered: 2.5), 1.5 (altered: 2) for fracture</td>
</tr>
<tr>
<td>Relative permeability exponent of oil phase at low capillary number</td>
<td>3 for matrix (altered: 2), 1.8 (altered: 1.5) for fracture</td>
</tr>
<tr>
<td>Relative permeability exponent of microemulsion phase at low capillary number</td>
<td>2 for matrix (altered: 2.5), 1.5 (altered: 2) for fracture</td>
</tr>
<tr>
<td>Endpoint relative permeability of all phases at high capillary number</td>
<td>1</td>
</tr>
<tr>
<td>Relative permeability exponent of all phases at high capillary number</td>
<td>1</td>
</tr>
<tr>
<td>Matrix positive capillary Pressure Endpoint</td>
<td>variable (see Table 5.5)</td>
</tr>
<tr>
<td>Matrix negative capillary Pressure Endpoint</td>
<td>variable (see Table 5.5)</td>
</tr>
<tr>
<td>Matrix capillary pressure parameter EPC0</td>
<td>3 (altered: 3)</td>
</tr>
<tr>
<td>Matrix critical water saturation SSTAR (transition saturation from Pc+ to Pc-)</td>
<td>0.41 (altered: N/A)</td>
</tr>
<tr>
<td>Wettability alteration parameter</td>
<td>$\omega = \text{constant} = 0.5$</td>
</tr>
<tr>
<td>Molecular diffusion coefficients of all components</td>
<td>0</td>
</tr>
<tr>
<td>Dispersivity of all phases</td>
<td>0</td>
</tr>
<tr>
<td>Surfactant adsorption parameters</td>
<td>AD31: 1.5, AD32: 0.15, B3D:1000</td>
</tr>
<tr>
<td>Polymer Viscosity parameters</td>
<td></td>
</tr>
<tr>
<td>Polymer Permeability reduction parameter</td>
<td>CRK=0.12</td>
</tr>
<tr>
<td>Cation Exchange</td>
<td>N/A</td>
</tr>
<tr>
<td>Water viscosity</td>
<td>1 cp</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>10 cp</td>
</tr>
</tbody>
</table>
| Microemulsion viscosity parameters | ALPHAV1 = 2.5  
ALPHAV2 = 2.45  
ALPHSV3-5 = 0 |
| CMC | 0.0005 |
| Lower type III effective salinity | 0.77 |
| Higher type III effective salinity | 1.15 |
| Initial reservoir effective salinity | 0.82 |

Table 5.3 - Well data for the large-scale homogeneous fractured block

| Number of Injectors | 1 |
| Number of producers | 1 |
| Distance between injector and producer | 48.5 ft |
| Perforation layers of injector | All layers |
| Perforation layers of producer | All layers |
| Producer BHP | 14.7 psi |
| Injector BHP | Variable (see Table 5.5) |
| Constraint on injector or producer | Unlimited injection or production rates |
| Injected surfactant concentration, If any | 2% |
Injected alkali concentration, If any | 1  
---|---  
Injected polymer concentration, If any | 0.1 wt%  
Injected salinity | 0.94 (inducing phase III microemulsion)  
Chemicals injected | Cases 1-6: W, S, P, A, SP, AP, ASP  
| Case 7: A, S, AS  

Table 5.4- Simulation data for the large-scale homogeneous fractured block

| Total number of grid blocks | 1092  
---|---  
| Total number of fracture grid blocks | 300  
| Method of solution | IMPES  
| Simulation time | 3 pore volumes  

Table 5.5 - Case studies for the large-scale homogeneous fractured block; Case # 7 is analyzed separately

| Case # | Pressure drop (psi/ft) | Initial water saturation in matrix | positive capillary pressure endpoint | negative capillary pressure endpoint  
---|---|---|---|---  
| 1 | 1 | 30% | 1 | -1.5  
| 2 | 1 | 30% | 0.2 | -0.3  
| 3 | 1 | 30% | 5 | -7.5  
| 4 | 1 | 20% | 5 | -7.5  
| 5 | 0.5 | 20% | 5 | -7.5  
| 6 | 0.5 | 30% | 1 | -1.5  
| 7 | 0.5 | 20% | 100 | -150  


Figure 5.1 - Reservoir model for the large-scale homogeneous fractured block simulations
Figure 5.2 - Comparing water flooding oil recoveries for 6 different cases

Figure 5.3 - Comparing polymer flooding oil recoveries for 6 different cases
Figure 5.4 - Comparing alkaline flooding oil recoveries for 6 different cases

Figure 5.5 - Comparing surfactant flooding oil recoveries for 6 different cases
Figure 5.6 - Comparing AP flooding oil recoveries for 6 different cases

Figure 5.7 - Comparing SP flooding oil recoveries for 6 different cases
Figure 5.8 - Comparing ASP flooding oil recoveries for 6 different cases

Figure 5.9 - Comparing oil recoveries for different injection scenarios, case 1
Figure 5.10 - Comparing oil recoveries for different injection scenarios, case 2

Figure 5.11 - Comparing oil recoveries for different injection scenarios, case 3
Figure 5.12 - Comparing oil recoveries for different injection scenarios, case 4

Figure 5.13 - Comparing oil recoveries for different injection scenarios, case 5
Figure 5.14- Comparing oil recoveries for different injection scenarios, case 6

Figure 5.15- Comparing oil recoveries for A and AS injection scenarios, case 7
CHAPTER 6: SIMULATION OF LARGE-SCALE HETEROGENEOUS FRACTURED BLOCKS

In this chapter, we perform dynamic imbibition simulations on a large scale heterogeneous fractured block. This is the final step after small-scale simulations performed in Chapter 4 and large-scale homogenous-block simulations in Chapter 5. The purpose is to seek optimum conditions under which maximum oil can be recovered in large-scale extremely-heterogeneous reservoirs. In this chapter, we only consider horizontal wells. However, we simulate both continuous and slug injection scenarios. Various chemical solutions are injected. These include: water, polymer, surfactant, alkali, and different combinations of them. For convenience of simulation, although this is not physically correct, alkali represents the wettability modifying agent, while the surfactant is the agent that lowers the IFT to ultra-low values. Therefore, a simulation labeled AS indicates that the injected chemical solution lowers the IFT to ultra low values as well as alters the wettability from mixed-wet to water-wet. On the other hand, a simulation labeled ASP does the above task as well as making the chemical solution viscous (polymer). The recovery curves are compared and appropriate profiles are demonstrated in order to understand the results.

6.1: MODEL DESCRIPTION

The Simulation model is a large-scale extremely-heterogeneous fractured block and is shown in Figure 6.1. This figure illustrates the distribution of the porosity. The white grid blocks indicate fractures. This is a 41.5 ft by 41.5 ft by 24.7 ft fractured block modeled
with UTCHEM. There are 18 grid blocks in the X direction, 18 grid blocks in the Y direction and 11 grid blocks in the Z direction. The fractures are modeled as discrete fractures. There are two vertical fractures along the X axis and two vertical fractures along the Y axis. There are also three horizontal fractures perpendicular to the Z axis. As shown in the figure, one of these three horizontal fractures contains the injection well (at the bottom), one is in the middle and the last one contains the production well (at the top). The production well is shown by the blue array at the top of the block. The injection well has exactly the same orientation but is located under the block. Because the height of this fractured block is 24.7 ft and the wells are horizontal, buoyancy is should play a role here. The top, bottom and sides of the block are sealed. The block matrix is extremely heterogeneous with a Dykstra-Parson coefficient of 0.95. The values for matrix permeability were generated using the FFT program. The porosities were then generated from the permeabilities according to the following correlation:

\[
\phi = \left( \frac{k}{2 \times 10^9} \right)^{1/8}
\]

(6.1)

where \( k \) has a unit of md. The block physical properties are listed in Table 6.1.

The initial water saturation is 0.2 in the matrix and 0.99 in the fracture. Initially the matrix is mixed-wet. The capillary pressure in the fracture is always zero. The capillary pressure for the matrix is calculated using the Brook-Corey model. The relative permeability parameters are calculated as described in Chapter 2.5. In current chapter, in all cases where surfactant is involved, surfactant forms a type III microemulsion with oil.
Alkali, when present, changes the wettability with a constant value of $\omega = 0.5$ in Equation 2.14. This is an approximation, but it has been found to be convenient to match the experimental data. The Initial condition parameters together with rock and fluid properties are listed in Table 6.2. The word "altered", wherever seen in this table, represents the value of the same parameter in a completely water-wet condition.

Eight different chemicals are injected: water only (W), surfactant only (S), alkaline only (A), polymer only (P), alkaline-surfactant (AS), alkaline-polymer (AP), surfactant-polymer (SP), and alkaline-surfactant-polymer (ASP). The injection and production wells are horizontal, constrained to constant pressures and completed in the lowermost and uppermost fractures, respectively. The well data are listed in Table 6.3.

This model contains 3564 grid blocks, 1516 of which are fracture grid blocks. The total simulation time is 3 pore volumes. The UTCHEM solves the equations using the IMPES technique. The simulation parameters are listed in Table 6.4. The study cases are described in the upcoming sections.

### 6.2: Continuous-Injection Case Studies and Results

Two case studies for continuous injection are considered (Table 6.5). One case has a high pressure drop of 1 psi/ft and a low capillary pressure while the other one has a low pressure drop of 0.5 psi/ft and a higher capillary pressure. It should be noted that the chemicals are injected against the gravity direction (from bottom to top) and therefore the effective pressure drop will be much lower for each study case compared to what is stated
in Table 6.5. Different chemicals are injected in each case: W, S, P, A, AS, SP, AP and ASP.

The oil recovery curves for the first case and the second case are depicted in Figures 6.2-6.3 and 6.4-6.5, respectively. Figure 6.2 and 6.4 show the oil recovery versus PVs while Figures 6.3 and 6.5 show the oil recovery versus time. By looking at Figures 6.2 and 6.4, we observe that ASP flooding results in the highest and fastest oil recovery. This result is therefore independent of how high or low the contrast between the capillarity and viscous forces is. The second highest oil recovery goes to SP flooding. In both Figures, alkaline flooding is inferior to surfactant flooding. In contrast, Figures 6.3 and 6.5 reveal that AS flooding has the best performance when oil recovery is compared versus time. The second best performance goes to surfactant flooding in Figure 6.3 and alkaline flooding in Figure 6.5. This seems reasonable as capillarity is dominant in Figure 6.5 whereas viscous forces are dominant in Figure 6.3. The superiority of AS flooding in Figures 6.3 and 6.5 shows that lowering the IFT to ultra-low values, and altering the wettability at the same time produce the best result. The reason that AS is inferior to ASP, when analyzing the recoveries versus time, is only because the polymer reduces the injection rate (in our fixed pressure simulations).

6.3: Slug-Injection Case Studies and Results

These final series of simulations determine what the optimal conditions should be in order to produce the maximum amount of oil, when injecting a chemical solution into a heterogeneous fractured reservoir. Nine cases for slug injection are considered (Table
All cases include a chemical slug size of between 0.3 and 0.5 pore volumes. The chemical slug is, in all cases, followed by a continuous slug of polymer until a total of three pore volumes have been injected. In all cases, the chemical slug includes polymer as well. The concentration of the polymer in the chemical slug is always equal to that of the polymer drive. Additionally, there is always a salinity gradient established between the initial reservoir salinity, slug salinity and polymer-drive salinity (Table 6.2). Cases 1-6 investigate the effect of slug-size and polymer concentration on the recovery. On the other hand, Cases 7-9, when compared with cases 1-3, evaluate the effect of the reduced pressure gradient and the increased capillary pressure. It should be noted that the chemicals are injected against the gravity direction (from bottom to top) and therefore the effective pressure drop will be much lower for each study case compared to what is stated in Table 6.6. The injected chemicals in this section are ASP and AP only. Hence, we will be able to determine which chemical produces a better result in terms of a faster and higher ultimate recovery.

In the case of ASP flooding, Figure 6.6 shows that increasing the polymer concentration from 0.1 wt% to 0.2 wt%, drastically enhances the oil recovery versus pore volumes injected. The ultimate oil recovery is around 11% for a polymer concentration of 0.2 wt% (cases 1-3) whereas 7% (cases 4-6) for a polymer concentration of 0.1 wt%. This is because of the increased sweep efficiency and the greater transverse pressure gradients. On the other hand, the effect of slug size on oil recovery is very small. The reason is that most of the injected chemicals are transported through the fractures (where there is no matrix rock) and therefore the surfactant adsorption is small. Another reason is that a
value of zero has been assigned to diffusion and dispersion coefficients in these simulations. Consequently the dilution of the chemical slug should be insignificant.

In the case of AP flooding, Figure 6.7 shows the same effect of increasing the polymer concentration from 0.1 wt% to 0.2 wt%, as in the case of ASP flooding. For these simulations, however, the adsorption parameter for the chemical has been set to zero. The result of doing so was that the slug size did not affect the recovery curves at all. This result confirms that dilution and adsorption are the two reasons for loss of a chemical slug.

Figure 6.8 summarizes the results of the simulations for cases 1-6 and compares their oil recoveries versus days. We can observe that ASP flooding is absolutely superior to AP flooding even when the recoveries are compared on a time basis. Additionally, we can deduce that increasing the polymer concentration from 0.1 wt% to 0.2 %, results in a much higher ultimate oil recovery, although the recovery curve starts off slower. This is consistent in both ASP and AP flooding cases.

Finally, Figures 6.9 and 6.10 depict the recovery curves for cases 7-9 and versus pore volumes and day, respectively. We observe that ASP flooding still outperforms AP flooding and this is irrespective of what the time basis is (PV or day). Comparing the Figure 6.9, together with Figures 6.6 and 6.8, reveal that cases 7-9 yield a much higher oil recovery compared to those of cases 1-3. This is mainly because of the reduced pressure drop and consequently the increased contact time. The slug size effect is again insignificant for the reason previously mentioned.
Table 6.1 - Physical properties for the large-scale heterogeneous fractured block

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Block Length</td>
<td>41.5 ft</td>
</tr>
<tr>
<td>Block Width</td>
<td>41.5 ft</td>
</tr>
<tr>
<td>Block thickness</td>
<td>24.7 ft</td>
</tr>
<tr>
<td>Matrix size</td>
<td>(4,3,2,1,0.75) ft by (4,3,2,1,0.75) ft by (4,2,0.1) ft</td>
</tr>
<tr>
<td>Fracture spacing</td>
<td>20 ft in X and Y direction</td>
</tr>
<tr>
<td>Fracture aperture</td>
<td>0.75 ft for vertical and 0.5 ft for horizontal fractures</td>
</tr>
<tr>
<td>Average matrix porosity</td>
<td>0.075</td>
</tr>
<tr>
<td>Dykstra-Parson coefficient</td>
<td>0.95</td>
</tr>
<tr>
<td>Min and max matrix porosities</td>
<td>0.03 and 0.18</td>
</tr>
<tr>
<td>Average matrix permeability</td>
<td>13.15 md</td>
</tr>
<tr>
<td>Min and max matrix permabilities</td>
<td>0.0013 md and 2077 md</td>
</tr>
<tr>
<td>Fracture porosity</td>
<td>1</td>
</tr>
<tr>
<td>Fracture permeability</td>
<td>10000 md</td>
</tr>
<tr>
<td>Total effective permeability</td>
<td>1000 md</td>
</tr>
<tr>
<td>Total Fracture Porosity</td>
<td>50%</td>
</tr>
<tr>
<td>Block dip angle</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 6.2 - Rock and fluid properties for the large-scale heterogeneous fractured block

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of phases in the reservoir</td>
<td>Up to 3; water, oil, and microemulsion</td>
</tr>
<tr>
<td>Residual water saturation in matrix at low capillary number</td>
<td>0.1 , altered: 0.2</td>
</tr>
<tr>
<td>Residual water saturation in fracture at low</td>
<td>0.05 , altered: 0.1</td>
</tr>
<tr>
<td>capillary number</td>
<td>Initial water saturation in matrix</td>
</tr>
<tr>
<td>------------------</td>
<td>-----------------------------------</td>
</tr>
<tr>
<td></td>
<td>Initial water saturation in fracture</td>
</tr>
<tr>
<td></td>
<td>Residual oil saturation in matrix at low capillary number</td>
</tr>
<tr>
<td></td>
<td>Residual oil saturation in fracture at low capillary number</td>
</tr>
<tr>
<td></td>
<td>Initial oil saturation in matrix</td>
</tr>
<tr>
<td></td>
<td>Initial oil saturation in fracture</td>
</tr>
<tr>
<td></td>
<td>Residual microemulsion saturation in matrix at low capillary number</td>
</tr>
<tr>
<td></td>
<td>Residual microemulsion saturation in fracture at low capillary number</td>
</tr>
<tr>
<td></td>
<td>Residual saturation of all phases at high capillary number</td>
</tr>
<tr>
<td></td>
<td>Endpoint relative permeability of water at low capillary number</td>
</tr>
<tr>
<td></td>
<td>Endpoint relative permeability of oil at low capillary number</td>
</tr>
<tr>
<td></td>
<td>Endpoint relative permeability of microemulsion at low capillary number</td>
</tr>
<tr>
<td></td>
<td>Relative permeability exponent of aqueous phase at low capillary number</td>
</tr>
<tr>
<td></td>
<td>Relative permeability exponent of oil phase at low capillary number</td>
</tr>
<tr>
<td></td>
<td>Relative permeability exponent of microemulsion phase at low capillary number</td>
</tr>
<tr>
<td></td>
<td>Endpoint relative permeability of all phases at high capillary number</td>
</tr>
<tr>
<td></td>
<td>Relative permeability exponent of all phases at high capillary number</td>
</tr>
<tr>
<td></td>
<td>Matrix positive capillary Pressure Endpoint</td>
</tr>
<tr>
<td>Parameter</td>
<td>Value</td>
</tr>
<tr>
<td>--------------------------------------------------------------------------</td>
<td>--------------------------------</td>
</tr>
<tr>
<td>Matrix negative capillary Pressure Endpoint variable</td>
<td>variable (see Table 6.5 and 6.6)</td>
</tr>
<tr>
<td>Matrix capillary pressure parameter EPC0</td>
<td>3 (altered: 3)</td>
</tr>
<tr>
<td>Matrix critical water saturation SSTAR (transition saturation from Pc+ to Pc-)</td>
<td>0.41 (altered: N/A)</td>
</tr>
<tr>
<td>Wettability alteration parameter ω = constant</td>
<td>0.5</td>
</tr>
<tr>
<td>Molecular diffusion coefficients of all components</td>
<td>0</td>
</tr>
<tr>
<td>Dispersivity of all phases</td>
<td>0</td>
</tr>
<tr>
<td>Surfactant adsorption parameters</td>
<td>AD31: 1.5, AD32: 0.15, B3D:1000</td>
</tr>
<tr>
<td>Polymer Viscosity parameters</td>
<td></td>
</tr>
<tr>
<td>Polymer Permeability reduction parameter CRK</td>
<td>0.12</td>
</tr>
<tr>
<td>Cation Exchange</td>
<td>N/A</td>
</tr>
<tr>
<td>Water viscosity</td>
<td>1 cp</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>10 cp</td>
</tr>
<tr>
<td>Microemulsion viscosity parameters</td>
<td>ALPHAV1 = 2.5</td>
</tr>
<tr>
<td></td>
<td>ALPHAV2 = 2.45</td>
</tr>
<tr>
<td></td>
<td>ALPHSV3-5 = 0</td>
</tr>
<tr>
<td>CMC</td>
<td>0.0005</td>
</tr>
<tr>
<td>Lower type III effective salinity</td>
<td>0.77</td>
</tr>
<tr>
<td>Higher type III effective salinity</td>
<td>1.15</td>
</tr>
<tr>
<td>Initial reservoir effective salinity for continuous-injection</td>
<td>0.82</td>
</tr>
<tr>
<td>Initial reservoir effective salinity for slug-injection</td>
<td>1.3</td>
</tr>
<tr>
<td>Slug effective salinity</td>
<td>0.95</td>
</tr>
<tr>
<td>Polymer-drive effective salinity</td>
<td>0.6</td>
</tr>
</tbody>
</table>

Table 6.3 - Well data for the large-scale heterogeneous fractured block

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Injectors</td>
<td>1</td>
</tr>
<tr>
<td>Number of producers</td>
<td>1</td>
</tr>
<tr>
<td>---------------------</td>
<td>---</td>
</tr>
<tr>
<td>Distance between injector and producer</td>
<td>48.5 ft</td>
</tr>
<tr>
<td>Perforation grids for injector</td>
<td>(9, 1-18, 1)</td>
</tr>
<tr>
<td>Perforation grids for producer</td>
<td>(9, 1-18, 11)</td>
</tr>
<tr>
<td>Producer BHP</td>
<td>14.7 psi</td>
</tr>
<tr>
<td>Injector BHP</td>
<td>Variable (see Table 6.5 and 6.6)</td>
</tr>
<tr>
<td>Constraint on injector or producer</td>
<td>Unlimited injection or production rates</td>
</tr>
<tr>
<td>Injected surfactant concentration, If any</td>
<td>2%</td>
</tr>
<tr>
<td>Injected alkali concentration, If any</td>
<td>1</td>
</tr>
<tr>
<td>Injected polymer concentration, If any</td>
<td>0.1 wt% for continuous-injection variable for slug-injection (Table 6.6)</td>
</tr>
<tr>
<td>Injected salinity</td>
<td>0.95 (inducing phase III microemulsion)</td>
</tr>
<tr>
<td>Chemicals injected</td>
<td>W, S, P, A, AS, SP, AP, ASP for continuous-injection ASP, AP for slug-injection</td>
</tr>
</tbody>
</table>

Table 6.4- Simulation data for the large-scale heterogeneous fractured block

<table>
<thead>
<tr>
<th>Total number of grid blocks</th>
<th>3564</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total number of fracture grid blocks</td>
<td>1516</td>
</tr>
<tr>
<td>Method of solution</td>
<td>IMPES</td>
</tr>
</tbody>
</table>
Table 6.5 - Case studies - Continuous-injection

<table>
<thead>
<tr>
<th>Case #</th>
<th>Pressure drop (psi/ft)</th>
<th>positive capillary pressure endpoint</th>
<th>negative capillary pressure endpoint</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>5</td>
<td>-5</td>
</tr>
<tr>
<td>2</td>
<td>0.5</td>
<td>10</td>
<td>-10</td>
</tr>
</tbody>
</table>

Table 6.6 - Case studies - Slug-injection

<table>
<thead>
<tr>
<th>Case #</th>
<th>Pressure drop (psi/ft)</th>
<th>Slug size (PV)</th>
<th>Polymer concentration in surfactant slug (=surfactant concentration in drive slug) (wt %)</th>
<th>positive capillary pressure endpoint</th>
<th>negative capillary pressure endpoint</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>0.3</td>
<td>0.1</td>
<td>5</td>
<td>-5</td>
</tr>
<tr>
<td>2</td>
<td>1</td>
<td>0.4</td>
<td>0.1</td>
<td>5</td>
<td>-5</td>
</tr>
<tr>
<td>3</td>
<td>1</td>
<td>0.5</td>
<td>0.1</td>
<td>5</td>
<td>-5</td>
</tr>
<tr>
<td>4</td>
<td>1</td>
<td>0.3</td>
<td>0.2</td>
<td>5</td>
<td>-5</td>
</tr>
<tr>
<td>5</td>
<td>1</td>
<td>0.4</td>
<td>0.2</td>
<td>5</td>
<td>-5</td>
</tr>
<tr>
<td>6</td>
<td>1</td>
<td>0.5</td>
<td>0.2</td>
<td>5</td>
<td>-5</td>
</tr>
<tr>
<td>7</td>
<td>0.5</td>
<td>0.3</td>
<td>0.1</td>
<td>10</td>
<td>-10</td>
</tr>
<tr>
<td>8</td>
<td>0.5</td>
<td>0.4</td>
<td>0.1</td>
<td>10</td>
<td>-10</td>
</tr>
<tr>
<td>9</td>
<td>0.5</td>
<td>0.5</td>
<td>0.1</td>
<td>10</td>
<td>-10</td>
</tr>
</tbody>
</table>
Figure 6.1 - Reservoir model for the large-scale heterogeneous fractured block simulations
Figure 6.2 - Comparing oil recovery versus PV for different chemicals, DP=1psi/ft

Figure 6.3 - Comparing oil recovery versus time for different chemicals, DP=1psi/ft
Figure 6.4 - Comparing oil recovery versus PV for different chemicals, DP=0.5 psi/ft

Figure 6.5 - Comparing oil recovery versus time for different chemicals, DP=0.5 psi/ft
Figure 6.6 - Comparing oil recoveries for ASP flooding, Cases 1-6

Figure 6.7 - Comparing oil recoveries for AP flooding, Cases 1-6
Figure 6.8 - Comparing oil recoveries for ASP & AP flooding, Cases 1-6

Figure 6.9 - Comparing oil recovery versus PV for ASP & AP flooding, cases 7-9
Figure 6.10 - Comparing oil recovery versus time for ASP & AP flooding, cases 7-9
CHAPTER 7: SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

The objectives of this research in the field of chemical EOR from fractured reservoirs were the following:

- Understand the limitations of static imbibition tests and their possible links to the contradictions found in the literature
- Understand the relative importance of the viscous transport mechanism compared to other transport mechanisms
- Understand the relative effect of IFT reduction and wettability alteration on oil recovery from naturally fractured reservoirs by performing dynamic imbibition simulations

A comparison of static imbibition simulations with dynamic simulations revealed serious limitations associated with the conclusions that can be drawn from static tests. For example, a candidate surfactant that has the best performance in a static imbibition test might not perform best in the corresponding dynamic test and vice versa. Consequently, scale-up groups that are developed from static laboratory tests might not be directly applicable in the field. These limitations are caused by the fact that in static imbibition lab tests:

- Viscous forces are negligible
• The chemical is in contact with the entire core from the beginning

• The interaction between the capillarity and the fracture fluid dynamics do not reflect field conditions

A systematic series of dynamic simulations ranging from lab-scale to large-scale, homogenous-matrix to heterogeneous-matrix, vertical well to horizontal well and continuous chemical injection to slug chemical injection provided us with a clear basis for understanding how to maximize oil recovery from naturally fractured reservoirs using chemicals. Additionally the simulations seem to have resolved the contradictions found in the literature regarding the optimum conditions under which maximum oil recovery can be obtained. In all simulations, a chemical solution that had all of the following characteristics produced more oil and produced it faster than did other chemical solutions:

• Increases the viscosity (because of polymer or foam or microemulsion)
• Lowers the IFT to ultra-low values
• Alters the wettability from mixed-wet to water-wet

Viscous forces were found to dominate the effect of diffusion in terms of transporting the surfactant from the fracture into the matrix in naturally fractured reservoirs. Microemulsion was found to reshape the pressure profile in the fracture and therefore introduced a transverse pressure gradient that helped transport the chemical into the matrix. This effect cannot be observed in a static imbibition test.

The findings from this research recommend that dynamic imbibition tests should replace static imbibition tests in laboratories. Any scale-up group development or history
matching should be performed on dynamic-imbibition data rather than on static-imbibition data. The reason is that two additional mechanisms might play a significant role in the surfactant transport in static tests: spontaneous emulsification and the maragoni effect. There is little information in the literature regarding how important these mechanisms are in recovering oil from naturally fractured reservoirs. Therefore, an attempt to history match static imbibition data might result in erroneous history-match parameters. For example, in order to compensate for the maragoni effect in a static test, extremely large values might be assigned to capillary pressure parameters, which is a mistake. Consequently, the selected parameters match only one set of experimental data and are unlikely to match the data from another experiment or predict the field performance. In a dynamic test, however, spontaneous emulsification and the maragoni effects are likely to be dominated by the effect of viscous forces under most conditions. Therefore, history matching of dynamic data is more likely to produce a consistent model that will successfully predict the field performance.
APPENDIX A
Sample input file

A Discrete Model for a Fractured Heterogeneous Reservoir: Case1 in Table 6.6.

CC*******************************************************************************
CC                                                                 *
CC     BRIEF DESCRIPTION OF DATA SET : UTCHEM (VERSION 9.95 )       *
CC                                                                 *
CC*******************************************************************************
CC                                                                 *
CC Surfactant Injection (Large)                                         *
CC                                                                 *
CC LENGTH (FT) : 41.5                                               *
CC THICKNESS (FT) : 24.7                                           *
CC WIDTH (FT) : 41.5 average POROSITY : 0.08                       *
CC NJ. RATE (FT3/DAY) : NA                                         *
CC GRID BLOCKS : 18x18x11 COORDINATE : CARTesian                    *
CC DATE : 08/15/2009                                               *
CC cmc=.0005                                                      *
CC*******************************************************************************
CC                                                                 *
CC*******************************************************************************
CC                                                                 *
CC    RESERVOIR DESCRIPTION                                         *
CC                                                                 *
CC*******************************************************************************
CC Run number
*---- RUNNO
Horizontal well
CC
CC Title and run description
*---- title(i)
Large scale constant pressure Drop injection
Sol in frac.=0.01, Sor in frac.=0.15

CC
CC SIMULATION FLAGS
*---- IMODE IMES IDISP IC WM ICAP IREACT IBIO ICOORD ITREAC ITC IGAS IENG
  1  1  3  0  0  0  0  1  0  0  0  0
CC
CC no. of gridblocks,flag specifies constant or variable grid size,unit
*---- NX NY NZ IDXZ YUNIT
  18 18 11 2 0
CC
CC GRID SIZE OF BLOCK IN X DIRECTION
*---- EX(I), FOR I=1 TO NX
  4 3 2 1 .75 1 2 3 4 4 3 2 1 .75 1 2 3 4
CC
CC GRID SIZE OF BLOCK IN Y DIRECTION
*---- DY(I), FOR I=1 TO NY
  4 3 2 1 .75 1 2 3 4 4 3 2 1 .75 1 2 3 4
CC
CC GRID SIZE OF BLOCK IN Z DIRECTION
*---- DZ(I), FOR I=1 TO NZ
  .1 2 4 4 2 .5 2 4 4 2 .1
CC
CC total no. of components,no. of tracers,no. of gel components
*---- n no ntw nta ngc ng noth
  10 0 2 0 0 0 0 0

120
Name of the components:

*----spname(i) for i=1 to n

Water
Oil
Polymer
Chloride
Calcium
NotUsed
Alkali
Tracer1

Flag indicating if the component is included in calculations or not

*----icf(kc) for kc=1,n

1 1 1 1 0 0 0 1 1

Output options:

*---- ICUMTM ISTOP IOUTGMS

1 1 0

Flag indicating if the profile of KTH component should be written

*---- IPRFLG(KC),KC=1,N

1 1 1 1 1 0 0 0 1 1

Flag for Pres.,Sat.,Total Conc.,Tracer Conc.,Cap.,Gel, Alkaline Profiles

*---- IPRES IPSAT IPECTOT IPBI0 IPCAP IPGEL IPALK ITEMP IPOBS

1 1 1 0 0 0 0 0

Flag for writing several properties to unit 4 (Prof)

*---- ICKL IVIS IPER ICMN IPSE IHYSTP IPOAMP IONEQ

1 1 1 1 1 1 0 0 0 0

Flag for variables to PROF output file

*---- IADS IVEL IRKF IPHSE

1 1 1 1

Reservoir properties:

Max. simulation time (PV)

*---- TMAX

3

Rock compressibility (1/PSI), stand. pressure(PSIA)

*---- COMPR FSTAND

0 0

Flags indicating constant or variable porosity, x,y,and z permeability

*---- IPOR1 IPERMX IPERMY IPERMZ IMOD itranz ntg

2 2 3 3 0 0 0 0

Variable porosity over reservoir

*---- FOR(I),FOR I=1 TO NX*NY*NZ

< Include porosity file>

Variable permeability over reservoir

*---- PERMX(I),FOR I=1 TO NX*NY*NZ
<INCLUDE PERMEABILITY FILE>

CC

Y DIRECTION PERMEABILITY IS DEPENDENT ON X DIRECTION PERMEABILITY
*---- CONSTANT PERMEABILITY MULTIPLIER FOR Y DIRECTION PERMEABILITY
  1

CC

Z DIRECTION PERMEABILITY IS DEPENDENT ON X DIRECTION PERMEABILITY
*---- CONSTANT PERMEABILITY MULTIPLIER FOR Z DIRECTION PERMEABILITY
  1

CC

FLAG FOR CONSTANT OR VARIABLE DEPTH, PRESSURE, WATER SATURATION, INITIAL AQUEOUS PHASE
COMPOSITIONS
*---- IDEPTH IPRESS ISWI ICWI
    0 1 2 2

CC

CONSTANT DEPTH (FT)
*---- D111
     0.0

CC

INITIAL PRESSURE FOR A POINT AT A SPECIFIED DEPTH IS SPECIFIED
*---- PINIT HINIT
     14.7  0

CC

INITIAL WATER SATURATION FOR EACH GRIDBLOCK IS SPECIFIED
*---- S(I), I=1 TO NX*NY*NZ

324*.99

4*.2 .99 8*.2 .99 4*.2
4*.2 .99 8*.2 .99 4*.2
4*.2 .99 8*.2 .99 4*.2
4*.2 .99 8*.2 .99 4*.2
18*0.99
4*.2 .99 8*.2 .99 4*.2
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18*0.99
4*.2 .99 8*.2 .99 4*.2
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18*0.99
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4*.2 .99 8*.2 .99 4*.2
4*.2 .99 8*.2 .99 4*.2
18*0.99
4*.2 .99 8*.2 .99 4*.2

CC water
CC INITIAL CONCENTRATION IN THE AQUEOUS PHASE AT Ith GRIDBLOCK
*---- cwi(I,KW) for i=1, NXxNYxNZ, for kw=1,n(8+no)
10000*1

CC oil
CC INITIAL CONCENTRATION IN THE AQUEOUS PHASE AT Ith GRIDBLOCK
*---- cwi(I,KW) for i=1, NXxNYxNZ, for kw=1,n(8+no)
10000*0

CC surf
CC INITIAL CONCENTRATION IN THE AQUEOUS PHASE AT Ith GRIDBLOCK
*---- cwi(I,KW) for i=1, NXxNYxNZ, for kw=1,n(8+no)
10000*0

CC polymer
CC INITIAL CONCENTRATION IN THE AQUEOUS PHASE AT Ith GRIDBLOCK
*---- cwi(I,KW) for i=1, NXxNYxNZ, for kw=1,n(8+no)
10000*0

CC
CC*******************************************************************
CC                                                                  *
CC    PHYSICAL PROPERTY DATA                                        *
CC                                                                  *
CC*******************************************************************

CC OIL CONC. AT PLAIT POINT FOR TYPE II(+)AND TYPE II(-), CMC
*---- c2plc  c2prc  epsme  ihand
0  1  0.0005  0
CC flag indicating type of phase behavior parameters
  *** ifg8n
  0
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2X OPT SALINITY
CC FOR ALCOHOL 1
  *---- hbs70  hbc70  hbs71  hbc71  hbs72  hbc72
       0  0.037  0  0.035  0  0.038
CC SLOPE AND INTERCEPT OF BINODAL CURVE AT ZERO, OPT., AND 2X OPT SALINITY
CC FOR ALCOHOL 2
  *---- hbs80  hbc80  hbs81  hbc81  hbs82  hbc82
       0  0  0  0  0  0
CC
CC LOWER AND UPPER EFFECTIVE SALINITY FOR ALCOHOL 1 AND ALCOHOL 2
  *---- csel7  cseu7  csel8  cseu8
       0.77  1.15  0  0
CC
CC THE CSE SLOPE PARAMETER FOR CALCIUM AND ALCOHOL 1 AND ALCOHOL 2
  *---- beta6  beta7  beta8
       0  0  0
CC
CC FLAG FOR ALCOHOL PART. MODEL AND PARTITION COEFFICIENTS
  *---- ialc  opsk7o  opsk7s  opsk8o  opsk8s
       0  0  0  0  0
CC
CC NO. OF ITERATIONS, AND TOLERANCE
  *---- nalmax  epsalc
       20  0.0001
CC
CC ALCOHOL 1 PARTITIONING PARAMETERS IF IALC=1
  *---- akwc7  akws7  akm7  ak7  pt7
       4.671  1.79  48  35.31  0.222
CC
CC ALCOHOL 2 PARTITIONING PARAMETERS IF IALC=1
  *---- akwc8  akws8  akm8  ak8  pt8
       0  0  0  0  0
CC
CC ift model flag
  *** ift
  1
CC
CC INTERFACIAL TENSION PARAMETERS
  *---- chuh  ahuh
       0.2  9
CC
CC LOG10 OF OIL/WATER INTERFACIAL TENSION
  *---- xiftw
       1.3
CC
CC ORGANIC MASS TRANSFER FLAG
  *---- imass  icor
       0  0
CC
*------IWALT  IWALF
       1  2
CC
*---- fw1  pcw1
       0.5  0.5
CC
CC CAPILLARY DESATURATION PARAMETERS FOR PHASE 1, 2, AND 3
  *---- itrap  t11  t22  t33
       2  30000  1868  342
CC
CC
*---- t11(2)  t22(2)  t33(2)
      5000  3000  342
CC
CC FLAG FOR RELATIVE PERMEABILITY AND CAPILLARY PRESSURE MODEL
  *---- iperm  irtype
CC irtype=1
C
*------ NREGION
  2
C
*------ S1r , S2r , S3r
  0.05 0.15  0.05
  0.1  0.4  0.1
C
*------ P1rw P2rw P3rw
  0.4  0.6  0.4
  0.3  0.4  0.3
C
*------ E1w E2w E3w
  1.5  1.8  1.5
  2    3    2
CC Altered
CC s1r s2r s3r
*-------------
  0.1  0.05  0.1
  0.2  0.2   0.2
CC
CC p1 p2 p3
*-------
  0.3  1    0.3
  0.2  0.7  0.2
CC
CC e1 e2 e3
*---------
  2    1.5  2
  2.5  2    2.5
CC
CC RES. SATURATION OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*----S1RC S2RC S3RC
  .0  .0  .0
CC
CC ENDPOINT REL. PERM. OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*----P1RC P2RC P3RC
  1.  1.  1.
CC
CC REL. PERM. EXPONENT OF PHASES 1,2,AND 3 AT HIGH CAPILLARY NO.
*----E13C E23C E31C
  1.  1.  1.
CC
CC WATER AND OIL VISCOSITY , RESERVOIR TEMPERATURE
*---- VIS1 VIS2 TSTAND
  1   10  0
CC
CC COMPOSITIONAL PHASE VISCOSITY PARAMETERS
*---- ALPHA1 ALPHA2 ALPHA3 ALPHA4 ALPHA5
  2.5  2.45  0   0.9   0.7
CC
CC PARAMETERS TO CALCULATE POLYMER VISCOSITY AT ZERO SHEAR RATE
*---- AP1 AP2 AP3
  13  64  75
CC
CC PARAMETER TO COMPUTE CSEP,MIN. CSEP, AND SLOPE OF LOG VIS. VS. LOG CSEP
*---- BETAP CSEP1 SSLOPE
  1   0.01  -0.2398
CC
CC PARAMETER FOR SHEAR RATE DEPENDENCE OF POLYMER VISCOSITY
*---- GAMMA1 GAMMAF POWN   ipmod ishear rshear
  130  400  2.3  0   0   0.25
CC
CC CC FLAG FOR POLYMER PARTITIONING, PERM. REDUCTION PARAMETERS
*---- IPOLYM EPHI3 EPHI4 BRK   CRK   rcut
  1   1   1  100  0.12  100

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CC SPECIFIC WEIGHT FOR COMPONENTS 1,2,3,7,8, Coefficient of oil and GRAVITY FLAG
*----- DEN1 DEN2 DEN23 DEN3 DEN7 DEN8 IDEN
  0.433  0.384982517  0.382  0.433  0.346  0  2
CC
CC FLAG FOR CHOICE OF UNITS ( 0: BOTTOMHOLE CONDITION, 1: STOCK TANK)
*----- ISTB
  0
CC
CC COMPRESSIBILITY FOR VOL. OCCUPYING COMPONENTS 1,2,3,7, AND 8
*----- COMPC(1) COMPC(2) COMPC(3) COMPC(7) COMPC(8)
  0  0  0  0  0
CC
cc
cc
cc
IOW
  2
Cc
Cc
IrTYPE=1
*----- CPCw EPCw CPCo EPCo SSTAR
  0  3  0  3  0.4
  5  3  5  3  0.4
Cc
Cc altered
*----- IOW
  0
Cc
Cc Altered
*----- CPC EPC
  0  3
  5  3
Cc
CC MOLECULAR DIFFUSION COEF. KCTH COMPONENT IN PHASE 1
*----- D(KC,1), KC=1, N
  0  0  0.000  0  0  0  0  0  0  0  0  0
CC
CC MOLECULAR DIFFUSION COEF. KCTH COMPONENT IN PHASE 2
*----- D(KC,2), KC=1, N
  0  0  0  0  0  0  0  0  0  0  0  0
CC
CC MOLECULAR DIFFUSION COEF. KCTH COMPONENT IN PHASE 3
*----- D(KC,3), KC=1, N
  0  0  0.000  0  0  0  0  0  0  0  0  0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 1
*----- ALPHAL(1) ALPHAT(1)
  0  0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 2
*----- ALPHAL(2) ALPHAT(2)
  0  0
CC
CC LONGITUDINAL AND TRANSVERSE DISPERSIVITY OF PHASE 3
*----- ALPHAL(3) ALPHAT(3)
  0  0
CC
CC flag to specify organic adsorption calculation
*----- IADSO
  0
CC
CC SURFACTANT AND POLYMER ADSORPTION PARAMETERS
*----- AD31 AD32 B3D AD41 AD42 B4D IADK IADS1 FADS REFK
  1.5  0.15  1000  0  0  100  0  0  0  0  50
CC
CC PARAMETERS FOR CATION EXCHANGE OF CLAY AND SURFACTANT
*----- QV XK C XKS EQW
  0  0  0  804
CC
cc
*----- TK(I)
  0  0
cc
**---- TKS(I)
  0 0 0
**
**---- RDC(I)
  0 0
**
**---- RET(i)
  0 0
**
*************************************************************************************
** WELL DATA
*************************************************************************************
**
** FLAG FOR SPECIFIED BOUNDARY AND ZONE IS MODELED
**---- IBOUND IZONE
  0 0
**
** TOTAL NUMBER OF WELLS, WELL RADIUS FLAG, FLAG FOR TIME OR COURANT NO.
**---- NWELL IRO ITIME NWREL
  2 2 0 2
**
** WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
**---- IDW IW JW IFLAG RW SWELL IDIR IFIRST ILAST IPRF
  1 9 11 3 0.01 0 1 1 18 0
**
** WELL NAME
**---- WELNAM
**
** ICHECK, MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
**---- ICHECK PWFMIN PWFMAX QTMIN QTMAX
  0 0 10000 0 10000
**
** WELL ID,LOCATIONS,AND FLAG FOR SPECIFYING WELL TYPE, WELL RADIUS, SKIN
**---- IDW IW JW IFLAG RW SWELL IDIR IFIRST ILAST IPRF
  2 9 1 2 0.01 0 1 1 18 0
**
** WELL NAME
**---- WELNAM
**
** ICHECK, MAX. AND MIN. ALLOWABLE BOTTOMHOLE PRESSURE AND RATE
**---- ICHECK PWFMIN PWFMAX QTMIN QTMAX
  0 0 10000 0 10000
**
** ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
**---- ID QI(M,L) C(M,KC,L)
  1 0.002 .98 0 0 0 .1 0.95 0 0 0 1 1
  1 0 0 0 0 0 0 0 0 0 0 0
  1 0 0 0 0 0 0 0 0 0 0 0
**
** ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
**---- ID P(psi)
  1 39.4
**
** ID,INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
**---- ID P(psi)
  2 14.7
**
** CUM. INJ. TIME , AND INTERVALS (PV OR DAY) FOR WRITING TO OUTPUT FILES
**---- TINJ CUMPR1 CUMHI1 WRHPV WRPRF RSTC
  0.3 0.03 0.03 0.03 0.03 0.2
**
** THE INI. TIME STEP,CONC. TOLERANCE,MAX.,MIN. time steps

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*---- DT DELC(I) DTMAX
DTMIN
1.0E-04 0.0001 0.0001 0.0001 0.0001 0.0001 0.0001 4*0.0001 0.0003
0.00003
CC***** INJECT Polymer Drive ***************
CC FLAG FOR INDICATING BOUNDARY CHANGE
*---- IBMOD
0
CC
CC IRO, ITIME, NEW FLAGS FOR ALL THE WELLS
*---- IRO ITIME IFLAG
  2 0 3 2
CC
CC NUMBER OF WELLS CHANGES IN LOCATION OR SKIN OR PWF
*---- NWEL1
0
CC
CC NUMBER OF WELLS WITH RATE CHANGES, ID
*---- NWEL2 ID
  1 1
CC
CC ID, INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*---- ID QI(M,L) water oil surf polymer Chlor divalent
  1 0.002 1.0 0. 0. 0.1 0.6 0. 0. 0. 0. 1
  1 0. 0. 0. 0.0. 0. 0. 0. 0. 0. 0.
  1 0. 0. 0. 0.0. 0. 0. 0. 0. 0. 0.
CC
CC ID, INJ. RATE AND INJ. COMP. FOR RATE CONS. WELLS FOR EACH PHASE (L=1,3)
*---- ID P(psi)
  1 39.4
CC
CC CUM. INJ. TIME, AND INTERVALS (PV) FOR WRITING TO OUTPUT FILES
*---- TINJ CUMPR1 CUMHI1 WRHPV WRPRF RSTC
  2 0.03 0.03 0.03 0.03 2.5
CC
CC FOR IMES=4, THE INI. TIME STEP, CONC. TOLERANCE, MAX., MIN. TIME STEPS
*---- DT DCLIM CNMAX CNMIN
  0.0001 12*0.01 0.1 .01
*****************************************************************************
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VITA

Yousef Abbasi-Asl was born in Tehran, Iran on September 15, 1984. He got his diploma in Physics and Mathematics in Tehran, Iran in 2001. He then entered the 14th National Physics Olympiad in the same year and earned a gold medal. As a consequence, he was exempted from the university entrance exam and also given the opportunity to enter the 33rd International Physics Olympiad held in Bali, Indonesia, July 2002, which earned him another gold medal. He earned his Bachelor's degrees in Electrical Engineering and Petroleum Engineering (Dual degree) from Sharif University of Technology in 2007. He entered the University of Texas at Austin in January 2008 and got his Master's degree in Petroleum Engineering in December 2009.

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