Developing and evaluating a model for Surfactant-Foam Flooding

Marit I.C. Knol
DEVELOPING AND EVALUATING A MODEL FOR SURFACTANT-FOAM FLOODING

by

Marit I.C. Knol

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Student number: 4015800
Supervisors: Prof. Ir. C. van Kruijsdijk, Delft University of Technology and Shell Global Solutions B.V.
Dr. A. Mar-Or, Shell Global Solutions B.V.
Dr. S. Vincent Bonnieu, Shell Global Solutions B.V.
Thesis committee: Prof. Dr. Ir. T.J. Heimovaara, Delft University of Technology
Prof. Dr. W.R. Rossen, Delft University of Technology

TU Delft
Delft University of Technology
ABSTRACT

Many reservoirs are considered unsuitable candidates for Enhanced Oil Recovery. Surfactant-Foam flooding, also referred to as Low-Tension-Gas flooding, could be a solution to enhance the oil recovery in tight, saline or high temperature reservoirs. SF-flooding combines reduction of the oil-water interfacial tension by surfactant, with mobility control provided by foam. While coreflood experiments have been performed, no Surfactant-Foam model has been developed yet. Therefore, the objective of this research is to develop and evaluate a conceptual model for Surfactant-Foam flooding.

Several available foam- and surfactant flooding models are analyzed. By comparing the various approaches, two models are selected based on the identified modelling objectives, model complexity and available experimental data. In this study a Surfactant-Foam model is developed that combines an implicit-texture foam model with a two-phase effective surfactant model. The model assumes foam is in local-equilibrium and correlates salinity and a minimum surfactant concentration with a lowered water-oil interfacial tension.

The performance of the combined model is evaluated with a reservoir simulator. According to the simulation study the surfactant model affects the gas relative permeability through a correlation with the connate water saturation. The defined chemical connate water saturation always affects the gas mobility, either by reducing the gas relative permeability, or by minimizing the impact of the limiting capillary pressure. The results show that an experimentally applied salinity gradient, correlated with a decrease and increase in water-oil interfacial tension, cannot be modelled with capillary number dependent relative permeability curves. In this research it is assumed that the water-oil interfacial cannot increase, after it achieved an ultra-low value. According to the current desaturation approach, oil prefers to flow in the presence of water in stead of gas at ultra-low interfacial tension. More research is required to investigate if this can be related with physics, or if it is purely a modelling artifact. Furthermore, the simulation study shows that the foam matching parameters of the implicit-texture model require optimization for cores with a mutual difference in connate water saturation, due to variation of the impact of the limiting capillary pressure.

Simulations are performed to history match experimental data and are aimed to match the measured pressure drop, oil production and effluent salinity profiles. As Surfactant-Foam flooding is taking its first steps in the laboratory, the accuracy and amount of available data is limited. To improve the validity of the model parameters, coreflood experiments in which the foam and surfactant processes are decoupled were interpreted. The surfactant concentration and water saturation are identified as the main drivers affecting the foam texture. Waterflooding pressure data was used to determine the non-chemical relative permeability parameters. The analyzed Surfactant-Foam corefloods are conducted in tight Indiana Limestone cores. Carbonates often have a complex pore structure due to their dual porosity. The experimental data suggests the presence of heterogeneities such as high permeable zones. Therefore, a one-dimensional model is expanded to a two-dimensional model, represented by two layers.

Both the one and two-dimensional Surfactant-Foam model achieve a reasonable history match with the cumulative oil recovery and pressure gradient. The two-dimensional model, with a small difference in flow capacity between the layers, successfully matches the size of the oil cut. With the two-dimensional model an improved match with the effluent salinity profile can be achieved at the expense of the oil cut and recovery match. The contribution of measurement errors and heterogeneities to the effluent salinity profile requires more research. As the experimental data are subject to a high level of uncertainty, more corefloods should be performed to identify the most suitable geological representation of the Indiana Limestone.
Contributing to research. Was I capable in doing so? During conversations it was always an easy and safe answer to say 'I'm no Albert Einstein, I don't reinvent wheels'. However, when I was introduced to my project I secretly knew that only the tires were there. The past 10 months have been an academic roller coaster. The ride had its up and downs. With uncertain, challenging, emotional but above all fun moments along the way. Surfactants and foam managed to capture me in their bubble, and even managed to unlock my inner Einstein. Most importantly, my research learned me how important it is to believe in your own capabilities.

I would like to express my gratitude to all persons who helped me accomplish this study, with a special appreciation to the following. Thank you UT Austin, for providing me with the experimental Surfactant-Foam data. Thank you Shell Global Solutions, for the unique opportunity to experience and learn from your company. Thank you Assaf, for reading every single letter of my report and for making me smile with your inspiring quotes. Thank you Sebastien, for our motivating discussions and for your perseverance and patience in convincing me. And, thank you Cor, for believing in my capabilities, at moments I did not.

“Anyone who has never made a mistake has never tried anything new” - Albert Einstein.

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NOMENCLATURE

SUBSCRIPT/SUPERSCRIPT

- **c**: Connate
- **p**: Denotes over- or under-optimum salinity
- **f**: Flowing
- **opt**: Optimum
- **i**: Refers to a component
- **j**: Refers to a phase
- **r**: Relative
- **t**: Trapped or Total

COMPONENT

- **g**: Gas
- **o**: Oil
- **w**: Water

PHASES

- **a**: Aqueous
- **f**: Foam (Note: physically not a separate phase. Foam consists of an aqueous and a gaseous phase.)
- **g**: Gaseous
- **m**: Micro-emulsion
- **o**: Oleic

STARS-MODEL

- **fmgcp**: Critical capillary number for foam generation
- **fmomf**: Critical oil mole fraction
- **fmoil**: Critical oil saturation above which foam is completely destroyed
- **fmsurf**: Critical surfactant concentration
- **fmdry**: Critical water saturation below which foam collapses
- **f_{dry}**: Dry-out function
- **epcap**: Exponent for capillary number contribution
- **epgcp**: Exponent of critical capillary number
- **fmsalt**: Exponent of critical mole fraction
- **epsurf**: Exponent parameter
- **floil**: Lowest oil saturation to destabilize foam
- **flsalt**: Lowest salt mole fraction
- **FM**: Mobility reduction factor
- **f_{oil}**: Oil effect function
epoil Positive constant
fmcap Reference capillary number
fmmob Reference mobility reduction factor of the gas phase
\( C_{salt} \) Salt concentration
epsalt Salt exponent
\( f_{cap} \) Shear-thinning function
epdry Slope tuning the abruptness of the dry-out effect
\( f_{surf} \) Surfactant concentration function
\( C_{surf} \) Surfactant concentration

**SYMBOLS**

K Absolute permeability
\( C_s \) Adsorbed surfactant concentration
\( J_a \) Advection mass flux
ASF Alkaline-Surfactant-Foam
ASP Alkaline-Surfactant-Polymer
\( \mu_f \) Apparent foam viscosity
\( k_f^g \) Apparent relative foam permeability
BT Breakthrough
\( N_c \) Capillary number
\( P_c \) Capillary pressure
\( \nu_j \) Characteristic velocity of phase j
Z Compressibility factor
c Compressibility
\( S_{wc} \) Connate water saturation
\( a \) Constant of proportionality that varies with the absolute permeability and type of surfactant
\( \psi \) constant of proportionality
\( \theta \) Contact angle (degrees)
L Core length
\( g \) Corey exponent of phase j
\( C_c \) Corey parameter at chemical-flood conditions (high capillary number)
\( C_w \) Corey parameter at water-flood conditions (low capillary number)
CMC Critical micelle concentration
\( u_j \) Darcy velocity of phase j
\( \rho \) Density
\( t_D \) Dimensionless distance
\( x_D \) Dimensionless time
\( J_d \) Dispersion mass flux
\( D_{eff} \) Effective dispersion coefficient
<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\alpha_{eff}$</td>
<td>Effective dispersivity</td>
</tr>
<tr>
<td>$K_{r,j}$</td>
<td>Endpoint permeability of phase j</td>
</tr>
<tr>
<td>EOR</td>
<td>Enhanced Oil Recovery</td>
</tr>
<tr>
<td>e.g.</td>
<td>exempli gratia (for the sake of example)</td>
</tr>
<tr>
<td>$c$</td>
<td>Exponent that expresses the shear thinning behavior of the foam. Often approximated as $c = \frac{1}{3}$.</td>
</tr>
<tr>
<td>$X_f$</td>
<td>Flowing gas fraction</td>
</tr>
<tr>
<td>$S_f$</td>
<td>Flowing gas saturation</td>
</tr>
<tr>
<td>$n_f$</td>
<td>Foam texture</td>
</tr>
<tr>
<td>$f_j$</td>
<td>Fractional flow of phase j</td>
</tr>
<tr>
<td>GOR</td>
<td>Gas-oil-ratio</td>
</tr>
<tr>
<td>i.e.</td>
<td>Id est (that is)</td>
</tr>
<tr>
<td>$S_{oi}$</td>
<td>Initial oil saturation</td>
</tr>
<tr>
<td>$\sigma_{huh,p}$</td>
<td>Interfacial tension according to the Huh correlation</td>
</tr>
<tr>
<td>$\sigma$</td>
<td>Interfacial tension between the aqueous and oleic phase</td>
</tr>
<tr>
<td>IFT</td>
<td>Interfacial tension</td>
</tr>
<tr>
<td>$v_j$</td>
<td>Interstitial velocity of phase j</td>
</tr>
<tr>
<td>$T_k$</td>
<td>Krafft point</td>
</tr>
<tr>
<td>$P_c^*$</td>
<td>Limiting capillary pressure</td>
</tr>
<tr>
<td>$S_w^*$</td>
<td>Limiting water saturation</td>
</tr>
<tr>
<td>$z$</td>
<td>Matching parameter of the reference mobility reduction factor ($fmmob$)</td>
</tr>
<tr>
<td>$a_{max}$</td>
<td>Maximum adsorption</td>
</tr>
<tr>
<td>$X_{t,max}$</td>
<td>Maximum fraction of trapped foam</td>
</tr>
<tr>
<td>MMP</td>
<td>Minimum miscibility pressure</td>
</tr>
<tr>
<td>$\lambda_j$</td>
<td>Mobility of phase j</td>
</tr>
<tr>
<td>M</td>
<td>Mobility ratio</td>
</tr>
<tr>
<td>OOIP</td>
<td>Oil originally in place</td>
</tr>
<tr>
<td>$X_{opt}$</td>
<td>Optimum salinity</td>
</tr>
<tr>
<td>$Z_{opt}$</td>
<td>Optimum solubilization ratio</td>
</tr>
<tr>
<td>$X_{over}$</td>
<td>Over-optimum solubilization parameter</td>
</tr>
<tr>
<td>ppm</td>
<td>Parts per million</td>
</tr>
<tr>
<td>$N_{pe}$</td>
<td>Peclet number</td>
</tr>
<tr>
<td>$\eta$</td>
<td>Percolation exponent for 3D lattices. Approximated as $\eta = 0.4$</td>
</tr>
<tr>
<td>$f_f$</td>
<td>Percolation fraction of flowing foam</td>
</tr>
<tr>
<td>$f$</td>
<td>Percolation fraction</td>
</tr>
<tr>
<td>PV</td>
<td>Pore volume</td>
</tr>
<tr>
<td>$r$</td>
<td>Pore-throat size (cm)</td>
</tr>
<tr>
<td>$\nabla P_j$</td>
<td>Pressure gradient of phase j</td>
</tr>
<tr>
<td>$P_{nw}$</td>
<td>Pressure in non-wetting phase</td>
</tr>
</tbody>
</table>
$P_w$  Pressure in wetting phase
P  Pressure
$k_{rj}$  Relative permeability of phase j
ROIP  Residual oil in place
$S_{or_w}$  Residual oil saturation after waterflood
X  Salinity
T  Scaling parameter in the desaturation model that determines the location of the slope change (transition at $N_c = 1/T$)
$a_{slope}$  Slope of the adsorption
$Z_p$  Solubilization ratio for over- or under-optimum salinity
$C_f$  Surfactant concentration in the fluid
SAG  Surfactant-Alternating-Gas
SF  Surfactant-Foam
$S_g$  Total gas saturation
$M_t$  Total mobility
$q_t$  Total volume flow rate
C  Tracer concentration
$f_g^*$  Transition foam quality
$X_t$  Trapped gas fraction
$\beta$  Trapping parameter
$X_{under}$  Under-optimum solubilization parameter
$\mu_j$  Viscosity phase j
$q_j$  Volume flow rate of phase j
INTRODUCTION

In this chapter an introduction to Enhanced Oil Recovery (EOR) and Surfactant-Foam (SF) flooding is presented. Furthermore, the research objectives and the structure of the report are discussed. Scientific models are created to understand and visualize everything we see, or not see, around us. All models are simplified reflections of reality. However, a model with valid assumptions can generate accurate and valuable predictions. The objective of this thesis is to derive a model of an Enhanced Oil Recovery method known as Surfactant-Foam flooding.

Enhancing the recovery of oil is of crucial importance to meet the current and future demand of crude oil by society and to develop the reserves of the earth in a responsible manner. A wide variety of EOR methods is researched and developed to improve the recovery of the oil in place. Alkaline-Surfactant-Polymer (ASP) is such an EOR technique that combines chemical mechanisms to optimize the recovery of oil. The ASP-method injects alkaline and synthetic surfactants to reduce the oil-water interfacial tension. Thereafter the mobilized oil is displaced with a polymer enriched water flood. However, the ASP technique is not suitable for all reservoir conditions such as high prevailing salinities and tight reservoirs. This stimulated the idea of Alkaline-Surfactant-Foam (ASF) flooding, which could have a broader range of application.

In ASF-flooding the polymer drive is replaced with a foam drive, which makes it suitable for low permeability formations. As ASF-flooding is a new concept, alkaline is left out of the process for a better understanding of both the experimental and simulation results. To translate and upscale experimental results of SF-flooding to field scale, it is important to establish a conceptual SF-model.

1.1. INTRODUCTION TO SURFACTANT-FOAM FLOODING

Many reservoirs are considered unsuitable candidates for EOR [1]. Surfactant-Foam flooding could be a solution to enhance the oil recovery in tight, saline or high temperature reservoirs. In literature SF-flooding is also known as micellar-foam, micellar-gas, surfactant-gas and low-tension-gas flooding [2] [3] [4] [5]. For the purpose of this research the term SF is used. In conventional ASP-flooding, polymer is added to the flood to make the water more viscous to improve both the displacement and sweep efficiency. In tight reservoirs however, polymers can plug the reservoir and are subject to mechanical shear degradation. Furthermore, at elevated temperatures, high salinities, or the presence of micro-organisms, polymers can degrade resulting in loss of solution viscosity [6] [7]. SF-flooding allows surfactant enhanced oil recovery in tight formations (< 20 mD), in which the polymer is replaced by foam [8]. In this research non-miscible gas foam is assumed. There are two main mechanisms in the SF-process:

1. Reduction of the oil-water interfacial tension by the surfactant
2. Mobility control by the foam.

Surfactant formulations during SF-flooding consists of two type of surfactants. Namely, surfactants to provide ultra-low interfacial tension and surfactants to generate foam for mobility control. It is important to understand the foam and surfactant processes separately, before developing a conceptual model in which the processes are combined.
1.2. ENHANCED OIL RECOVERY

There are two main reasons why oil cannot be completely swept from a reservoir. Firstly, the oil is trapped on pore scale resulting in a residual oil saturation (microscopic displacement efficiency). The second phenomenon is a poor displacement efficiency on reservoir scale due to gravity override, channeling and viscous fingering (macroscopic displacement efficiency).

**Capillary number**

Residual oil is a function of the balance between viscous and capillary forces. This relationship is described by the capillary number ($N_c$). There are two main approaches in calculating the capillary number. Eq. 1.1 is the simplest definition and the most commonly used.

\[
N_c = \frac{\mu_\alpha v_\alpha}{\sigma} \quad (1.1)
\]

\[
N_c = \frac{K \nabla P_a}{\sigma} \quad (1.2)
\]

in which $\mu_\alpha$ is the dynamic viscosity of the aqueous phase $\alpha$, $v_\alpha$ the characteristic velocity of the aqueous phase $\alpha$, $\nabla P_a$ the pressure gradient of the aqueous phase and $\sigma$ the interfacial tension (IFT) between the aqueous and oleic phase. It is assumed that the aqueous phase is the displacing phase and the oleic phase the displaced phase. As can be seen in Fig. 1.1 the residual oil saturation decreases when the capillary number increases. Capillary numbers larger than approximately $\approx 10^{-5}$ will result in a significantly improved microscopic displacement efficiency [1]. Raising the capillary number with several orders is primarily done by lowering the IFT between the aqueous and oleic phase. The IFT can be lowered by adding surfactants to the water. Surfactants tend to arrange themselves at the interface of two phases, with their hydrophobic tail and hydrophilic head, resulting in a reduced IFT.

![Figure 1.1: Desaturation curve: relationship between capillary number and residual oil saturation](Source: Lake [1])

**Mobility ratio**

The stability of displacement on reservoir scale is described with the mobility ratio ($M$). This is the ratio of the displacing phase mobility ($\lambda_\alpha$) divided by the displaced phase mobility ($\lambda_\alpha$):

\[
M = \frac{\lambda_\alpha}{\lambda_\alpha} = \frac{k_{r\alpha}}{k_{r\alpha}} \frac{\mu_\alpha}{\mu_\alpha} \quad (1.3)
\]

in which $k_{rj}$ is the relative permeability and $\mu_j$ the viscosity of phase $j$. Mobility ratios below one are preferred as the injected fluid can displace the oil (more) stable. The mobility ratio can be lowered by injecting gas. Gas solubility in oil results in oil swelling and a reduced oil viscosity. However, this is only applicable if the injected gas is miscible at reservoir conditions. Another possibility to reduce the viscosity of the oil is with thermal methods such as steam injection. The mobility ratio can also be lowered by increasing the viscosity.
of the drive fluid, for example with polymers. Foam reduces the mobility of the gas by decreasing the relative permeability and increasing the apparent gas viscosity.

1.3. Research Objectives

The objective of this research is to develop and evaluate a conceptual model for Surfactant-Foam flooding. While models exist to describe the two mechanisms separately, no existing models describe their combination. SF-flooding therefore bridges the gap between two areas of research. The model will be developed using the in-house reservoir simulator MoReS of Shell Global Solutions B.V. Besides developing a model that combines a desaturation model with a foam model, the ultimate goal of this research is to provide insight in how the model works and to highlight limitations and areas of improvement. The model is analyzed with a one- and two-dimensional grid. By providing the oil and gas industry with a SF-model, experimental results can be translated into a simulation model. Furthermore, this research marks the starting point of three-dimensional simulations which can be used to identify the SF-potential on field scale.

The conceptual model is developed by analyzing available foam- and surfactant flooding models. By comparing the various approaches, two models will be selected based on the identified modelling objectives, model complexity and the available experimental data. The interpretation of experimental SF-data will contribute to capture the relevant processes in the model and helps to determine the modelling objectives. Thereafter the model is incorporated into a reservoir simulator to evaluate the performance of the used algorithms. The simulations are used to history match the experimental data and give insight in the application and areas of improvement of the combined model.

1.4. Structure of report

To meet the objective to develop a conceptual Surfactant-Foam model, an extensive literature study, experimental study and reservoir simulation study are performed. The report is structured in the same order, introducing the reader to SF-flooding with a summary of the available literature. As surfactants play an important role in both surfactant and foam flooding, the surfactants principles are discussed in Chapter 2. The foam principles are covered in Chapter 3. In Chapter 4 and Chapter 5 the available foam and surfactant models are presented. In Chapter 6 the experimental results and interpretations of the SF-corefloods are discussed. The results of the literature and experimental study are used to design a SF-model, which is discussed in Chapter 7. In Chapter 8 the results of the separate foam and surfactant models are presented. Simulation results of the combined SF-model, such as interpretations, limitations and history matches will be discussed in Chapter 9 (one-dimensional model) and Chapter 10 (two-dimensional model). The report concludes with a Discussion (Chapter 11) and Conclusion and Recommendations (Chapter 12).
In this chapter the basic principles of surfactants will be discussed. Surfactants play a fundamental role in the SF-process, they have two main purposes:

1. Reducing the residual oil saturation by reduction of the interfacial tension between the oil and water
2. Stabilizing the foam by reduction of the interfacial tension between the gas and water

The denser the foam texture (i.e. bubbles per unit volume), the more surfactant is required to stabilize the foam. Therefore, there is a competition between the oil/water and gas/water interface.

### 2.1. Structure and Application

Surfactants have a hydrophobic tail and a hydrophilic head and arrange themselves in oriented monolayers at the interface of two phases (Fig. 2.1). An interfacial tension can be measured due to cohesive energy present at the interface arising from the imbalance of forces between molecules at the interface. The adsorbed monolayer provides an expanding force acting against this interfacial tension, resulting in a lowered interfacial tension. The monolayer of surfactants increases the interfacial viscosity. In case of a gas-liquid interface this can provide mechanical resistance to film thinning and rupturing [9]. At higher concentrations of a surfactant, the surfactant molecules tend to form micelles (Fig. 2.1). The concentration at which this happens is called the critical micelle concentration (CMC). Micelles are only formed above a certain temperature, the so-called Krafft point ($T_k$). Below this temperature the solubility of surfactants is too low for micellization. As micelles are more soluble than a single surfactant molecule, the solubility of surfactants also increases above $T_k$. Above $T_k$ a maximum reduction in interfacial tension occurs at the CMC [9].

![Surfactant molecules and micelles in foam configuration. Source: Schramm (9)](image-url)
2.2. **Surfactant-water-oil phase behavior**

Surfactants reduce the interfacial tension between the oil and water phase. When surfactants are added to a system with oil and water, emulsions are formed. When the emulsion is thermodynamically stable and transparent, it is referred to as a micro-emulsion. When the emulsion is thermodynamically unstable it is called a macro-emulsion. Macro-emulsions cannot form spontaneously and are opaque to light. The oil-water-surfactant phase behavior was first described by Winsor (1954) and is often illustrated on a ternary diagram (Fig. 2.2). The salinity of the brine phase is an important parameter influencing which type of behavior occurs, as it changes the surfactants solubility [1]. For a range of salinities, the surfactant forms its own phase in which both oil and water are solubilized. Due to the presence of this middle-phase micro-emulsion (Type III), three components and three-phases are present in the system. Salinities below and above this salinities range are referred to as under-optimum and over-optimum salinities. At under-optimum salinity surfactants reside in the water external micro-emulsion phase, in which they form an oil-in-water micro-emulsion (Type II-). At over-optimum salinity surfactants reside in the oil external micro-emulsion phase, in which they form an water-in-oil micro-emulsion (Type II+) [1].

Measured IFT is strongly correlated with the micro-emulsion phase behavior [10]. Optimum salinity and the presence of a middle-phase micro-emulsion is preferred because it achieves ultra-low interfacial tension and results in the mobilization of residual oil. However, the viscosity of the middle-phase micro-emulsion can be larger than the viscosity of the individual components [11]. Therefore, the benefits of ultra-low interfacial tension could disappear. Besides salinity, other parameters influencing which type of phase behavior occurs are: surfactant concentration, temperature, type of surfactant, co-surfactant concentration, type of oil and water/oil ratio [12] [1].

![Figure 2.2: Ternary diagram representation of surfactant-water-oil phase behavior. Source: Lake [1]](image)

2.3. **Adsorption**

Surfactants adsorb to the rock surface due to the electrostatic interactions between the surfactants and the rock. This causes retardation and consumption of the surfactant. Surfactants are classified according to the charge of the hydrophilic part into four types: anionic, cationic, non-ionic and amphoteric. To minimize adsorption, the electrostatic interactions between the surfactants and rock surface need to be minimized [13]. According to Ma et al. [13] anionic surfactants are preferred to flood sandstone rock due to the low adsorption by the negatively charged silica. Positively charged clay particles tend to adsorb anionic surfactant. The amount of adsorption is therefore mainly determined by the amount and distribution of clay minerals. The surfactant screening for carbonate rock is more complex. While (expensive) cation surfactants are in general preferred to flood carbonate rock, high adsorption can take place if the material is not pure carbonate.

2.4. **Alkaline flooding**

It is optional to add alkaline to the SF-flood. It has two main purposes:

1. Reduction of chemical losses due to adsorption
2. Formation of in-situ surfactants
Positively charged clay particles tend to adsorb anionic surfactants. Alkaline reverses the charge of the clay particles due to its high pH, resulting in the reduction of adsorption of anionic surfactant. The second role of alkaline is to convert the fatty acids contained in crude oil into natural surfactants [3]. It is expected that during SF-flooding the interplay between foaming and non-foaming surfactants plays a crucial role. The foaming properties of the in-situ surfactants are unknown and therefore its practical use is questioned. More research on the use and role of alkaline in SF-flooding is required. Because alkaline is not used in the SF-experiments that are investigated for this research, it does not fit the scope of this thesis.

2.5. FOAMING ABILITY

Each surfactant has its own foaming ability, depending on its chemical structure. In surfactant-foam flooding the first main step is to reduce the oil-water interfacial tension. When the surfactant is co-injected with gas, non-foaming properties are preferable, because foam bubbles have the tendency to adhere to the rock resulting in the loss of surfactant [14]. The second main step is to provide mobility control with foam. In this case surfactants with strong-foaming properties are preferable. During the experiments analyzed in this research, the surfactant formulation is not optimized regarding its foaming ability. The non-foaming, sulfonate surfactant has been excluded from the drive solution as it mainly tackles the oil-water interfacial tension and does not provide mobility control.

In the book of Rosen and Kunjappu [14] the foaming ability of surfactants is quantified by distinguishing the efficiency (bulk phase concentration) and effectiveness (maximum foam height) of the surfactant. Branched-chain surfactants and surfactants containing a centrally located hydrophobic group are expected to produce higher volumes of initial foam and thus improve the effectiveness of the foaming agent. Too short hydrophobic chains result in unstable foams due to insufficient cohesion. Increasing the length of the hydrophobic chain decreases the CMC of the surfactant and improves the efficiency of the foaming agent.
In this chapter the fundamentals of foam in porous media will be discussed as well as the existing approaches to model foam behavior. Foam arises from the presence of a gas in a liquid. Most of the volume is occupied by the tightly packed gas bubbles. Unlike the gas phase, the liquid phase, present as lamellae and associated Plateau borders, is continuous (Fig. 3.2) [15]. Surface acting agents, also known as surfactants, stabilize the foam by arranging themselves at the gas-liquid interface. This results in both a lowered gas-water interfacial tension and an increase in the interfacial viscosity. The interfacial tension indicates how much energy is required to extend the surface area of a fluid. Due to the high surface area of foam, it is naturally unstable. At a lower interfacial tension, less Gibbs free energy is required to stabilize the foam [16] [15]. The increased interfacial viscosity can provide mechanical resistance to film thinning and rupturing [9].

3.1. FOAM IN POROUS MEDIA

There is a fundamental difference between foam in bulk and in porous media. If the confinement is larger than the size of the bubbles, the term bulk foam is used. Within porous media the foam bubbles exceed the pore size and individual lamellae are separating two bubbles of gas, as illustrated in Fig. 3.1. From an enhanced oil recovery perspective, the latter will be relevant for this thesis. Foam in porous media consists of individual liquid lamellae separating bubbles of gas. A fraction of the lamellae is set in motion while others remain static. Foams can be classified into continuous or discontinuous gas foams. In a continuous-gas foam there is at least one pathway in the pore network for the gas to flow. In a discontinuous gas foam all pathways are blocked by the liquid lamellae. Lamellae must be transported through the system for gas to flow and this requires a minimum pressure gradient. Verification of the location and movement of lamellae can only be done indirectly [17]. While miscible gas-injection has a good microscopic displacement efficiency, it lacks sweep efficiency i.e. macroscopic displacement efficiency. Foam can improve the sweep efficiency in porous media by reducing the mobility of the gas. Foam also tends to have a lower mobility in higher permeable layers and selectively blocks swept zones [17]. This reduces channeling in heterogeneous reservoirs.
3.2. GAS MOBILITY

Foam reduces the mobility of the gas. Studies reveal that foam does not directly affect the mobility of the water [19]. The gas mobility ($\lambda_g$) is defined as the absolute permeability ($K$) times the gas relative permeability ($k_{rg}$), divided by the gas viscosity ($\mu_g$):

$$\lambda_g = \frac{K k_{rg}}{\mu_g} \quad (3.1)$$

Foam reduces the gas mobility in porous media in two ways:

1. Increasing the apparent gas viscosity
2. Reducing the gas relative permeability

Due to a high trapped gas saturation only a fraction of the gas flows (discontinuously or continuously), resulting in a reduction of the gas relative permeability. The dragging of flowing lamellae along pore walls in discontinuous-gas foams leads to an additional resistance to flow. This resistance of foam to flow through the pore system results in the increase in apparent gas viscosity. While the viscosity of the gas itself is not changed.
by the foam, the *apparent* gas viscosity does change, due to the presence of liquid lamellae. Continuous-gas foams only affect the relative permeability because the gas can flow without liquid lamellae blocking the way. Higher permeable layers have lower capillary pressures resulting in a preferred flow-path for liquid lamellae. Foam therefore selectively impedes flow in higher-permeable regions.

### 3.2.1. Darcy’s Law

Darcy’s Law relates the pressures and saturations of each phase with the superficial velocity. It is used in reservoir simulations to model multiphase flow. Both the relative permeability and gas viscosity are represented in Darcy’s Law. While physically the relative permeability and viscosity can be separated, mathematically they cannot [20]. Darcy’s Law for multiphase flow is defined as:

\[
 u_j = -\frac{K k_{rj}}{\mu_j} \Delta P_j
\]

(3.2)

in which \(u_j\) is defined as the Darcy velocity of phase \(j\), \(K\) as the absolute permeability, \(k_{rj}\) as the relative permeability of phase \(j\), \(\mu_j\) as the viscosity of phase \(j\) and \(\Delta P_j\) as the pressure gradient. Darcy’s Law assumes stationary, laminar and incompressible flow. Further it assumes continuity of the pressures in each phase. As the gas phase flows discontinuously during foam flow this assumption is questioned.

### 3.2.2. Apparent Gas Viscosity

A theory for the apparent gas viscosity in foams has been developed by Hirasaki and Lawson [21]. Using a capillary-tube set-up a relation between gas and apparent foam viscosity was experimentally derived, in which three principle contributions are incorporated. These contributions are:

1. The slugs of liquid between the gas bubbles resisting flow. The thickness of the liquid film wetting the solid is a factor in the resistance to flow. The thickness of this film is dependent on the radius of curvature of the gas/liquid interface.

2. The resistance to deformation of the interface of a bubble by viscous and capillary forces.

3. In the presence of surface active material, the surface tension at the front of the bubble is greater than at the back due to expansion and compression of the bubble interface. This difference in surface tension results in a surface tension gradient that resists flow.

The above concepts are illustrated in Fig. 3.3. The relation neglects the energy dissipation by extension and contraction of foam lamellae moving through the pore system, as the relation is derived for smooth capillaries [21] [22]. The foam texture plays a crucial role in determining the extent of the above mentioned contributions. The foam texture gives information on the number of lamellae per unit length and the radius of curvature of the gas/liquid interface.

The general form of the expression for foam in porous media introduced by Hirasaki and Lawson [21] is defined as [19] [23]:

\[
 \mu_f = \mu_g + \alpha \frac{n_f}{v_f^c}
\]

(3.3)

in which \(\mu_f\) is the apparent foam viscosity, \(\alpha\) is a constant of proportionality that varies with the absolute permeability and type of surfactant, \(n_f\) is the foam texture, that is (i.e.) the number of bubbles per unit volume flowing gas, \(v_f\) is the interstitial velocity of the foam and \(c = \frac{1}{3}\) an exponent that expresses the resistance to flow. This exponent represents the effect of the bubble velocity on apparent viscosity and is experimentally determined by Hirasaki and Lawson [21].

According to Eq. 3.3 the viscosity of the foam increases with finer textured foams, but decreases when the interstitial velocity increases. This represents the shear thinning behavior of the foam. When the bubble density is small, i.e. \(n_f\) tends to zero, the foam viscosity reduces to the bulk gas viscosity. The foam texture can be determined with models that dynamically track the bubble density or with models that assume a local-equilibrium, which will be explained in chapter 4.
3.2.3. Relative Permeability

The relative permeability of the gas increases with increasing area through which it flows. The relative permeability of the gas is only a function of the flowing gas saturation \( S_f \), as illustrated in Fig. 3.4. Using generalized Corey-type relative permeability functions for a gas/water system (see section 7.4), the relative permeability of the foam \( k_{rf} \) can be determined according to [24]:

\[
S_f = X_f S_g \quad (3.4)
\]

\[
X_f + X_t = 1 \quad (3.5)
\]

\[
k_{rf} = K_{rg} f(X_f) = K_{rg} \left( \frac{S_f}{1 - S_{wc}} \right)^g \quad (3.6)
\]

in which \( X_f \) is the flowing gas fraction, \( X_t \) the trapped gas fraction, \( S_g \) the total gas saturation, \( K_{rg} \) the endpoint relative gas permeability, \( S_{wc} \) the connate water saturation and \( g \) a Corey exponent. The trapped and flowing gas fraction add up to unity.

The trapping of foam is a dynamic process. Trapping and mobilization of gas happens on pore scale, also in macroscopic steady-state foam flow [25]. Little is known about the functional dependence of the trapped gas fraction. However, it is assumed to be dependent of the pressure gradient, pore geometry, foam texture, water saturation and capillary pressure [26] [19] [27]. Throughout the past 25 years several methods are developed to determine or estimate the flowing gas fraction.

Experimental determination

Various experiments for steady-state foam flow have been conducted to measure the fraction of flowing gas with a gas-tracer technique in combination with X-ray CT images. Friedmann et al. [28] reported a constant trapped gas saturation at steady state foam flow. Tang et al. [26] reported that an increase in gas velocity resulted in a greater fraction of mobile gas, while an increase in liquid velocity yielded a reduced fraction of mobile gas. They also reported that an increase in surfactant concentration reduced the fraction of mobile gas.
3.2. Gas mobility

Kovscek et al. [27] write the trapped gas fraction as a function of the foam texture, based on an empirical relation:

\[ X_t = X_{t,max} \left( \frac{\beta n_f}{1 + \beta n_f} \right) \]  

(3.7)

in which \( X_{t,max} \) is the maximum fraction of trapped foam and \( \beta \) a trapping parameter. The formulation is similar to the Langmuir adsorption isotherm. Kovscek et al. [27] assume that the trapped fraction remains constant and that trapped gas does not get mobilized.

**Statistical determination**

Bertin and Kovscek [23] outline a network percolation scaling analysis to determine the fraction of trapped gas. See section C.3 for an introduction to the percolation theory. The percolation theory is a statistical method in which a network with sites is occupied with a certain probability. When neighboring sites are occupied, clusters are formed. The clusters grow in size until a critical value is reached in which one large cluster dominates the connectivity of the network, also referred to as the percolation threshold \( f_c \) [29]. When applying this theory to foam, flowing gas bubbles percolate the network until the percolation threshold is reached. Near the percolation threshold, the fraction of percolated pores increases with [30]:

\[ S_g \sim (f - f_c)^\eta \]  

(3.8)

in which \( f \) is the percolation fraction and \( \eta = 0.4 \) the percolation exponent for 3D lattices. The total and flowing gas saturation are related according to:

\[ X_f = \frac{S_f}{S_g} = \left( \frac{f_f - f_c}{f - f_c} \right)^\eta \]  

(3.9)

It is assumed that foam flows just above this percolation threshold. Therefore, the percolation fraction of flowing foam (\( f_f \)) and the percolation threshold differ with a perturbation related to the pressure gradient. Bertin and Kovscek [23] finally write the trapped gas fraction as:

\[ X_t = \left[ \psi \frac{\| \nabla p \|}{K^{1/2} n_f f_c} \right]^\eta \]  

(3.10)

in which \( \psi \) is a constant of proportionality, \( K \) the absolute permeability and \( \nabla p \) the pressure gradient over the network.

How to appropriately retrieve or model the flowing gas fraction still needs to be addressed, both for steady-state and transient foam flow. While it seems valid to assume that the fraction of flowing gas remains constant during steady state foam flow as shown by Tang et al. [26], estimating the value of the fraction is a challenge. For transient flow the flowing gas fraction will change with time and currently no models are available to describe this process.

Figure 3.4: Flowing and trapped gas in porous media. Source: Kovscek et al. [27]
3.3. **MECHANISMS INFLUENCING FOAM MOBILITY**

The texture of the foam plays a dominant role in affecting the gas mobility. The mobility of the liquid phase is assumed to be unaffected by foam [17]. The foam texture \( n_f \) is defined as the number of lamellae per unit volume of gas, which is related to the bubble size. The finer the texture, the larger the number of lamellae that must be transported through the system [19]. During foam flow lamellae are continuously created and destroyed.

3.3.1. **FOAM GENERATION**

As discussed by Rossen [17] and Falls *et al.* [19] important mechanisms for the creation of lamellae in porous media are:

- **Capillary snap-off** Liquid flows into the pore neck due to a lower liquid-phase pressure. The liquid accumulates and bridges across the constriction, forming a lamellae. For snap-off to occur the liquid saturation should be relatively high.

- **Leave behind** When gas enters a with surfactant-solution saturated porous medium from separate directions, lamellae are created between pore bodies. Foam is only generated with the leave-behind when the gas saturation is rising.

- **Lamellae division** Lamellae are divided at a pore branch when the pressure gradient is large enough to mobilize lamellae in both branches.

3.3.2. **FOAM DESTRUCTION**

Likewise there are also mechanisms that destroy foam. In general three main mechanisms are distinguished:

- **Drainage** Liquid drains out of the lamellae due to gravity. The drainage rate depends on the difference in density between the liquid and the gas [15].

- **Coalescence** Foam coalesces when the lamellae film ruptures. Many factors affect the stability of the lamellae and it is therefore the least understood mechanism of foam evolution [15]. The capillary pressure and the lamellae thickness play a dominating role [17]. The capillary pressure at which the lamellae ruptures is called the limiting capillary pressure (see section 3.5). The limiting capillary pressure is a function of the surfactant solution and the reservoir properties [31] [32]. Low permeable rock promotes foam collapse due to its greater hydrophilic surface. Hence, foam tends to have lower mobility in higher permeable layers. Other factors that affect the stability of foam are the elasticity of lamellae, the presence of hydrophobic surfaces such as oil and the adsorption of surfactant at the interfaces of oil/water emulsions [19].

- **Coarsening** Gases transfer between bubbles by pressure-driven diffusion. Gas dissolves and diffuses through the liquid film, which is affected by the diffusivity of gas in water. Large bubbles grow at the extent of the smaller bubbles, as smaller bubbles tend to have higher pressures.

Above mentioned mechanisms are strongly coupled. For example, a drained foam coalesces and coarsens more easily. Foam is generated when more lamellae are created than destroyed, resulting in a reduction of the gas mobility. The occurrence of the mechanisms that are discussed and thus the texture of the foam, depend on many parameters. Important parameters are the gas fraction, water saturation, surfactant type and concentration, presence of oil, gas velocity and liquid velocity [17] [20] [33]. At a low pressure gradient of the gas phase, mechanisms such as capillary snap-off alter the texture in-situ. Foam shows shear-thinning behavior, indicating that an increase in gas velocity causes a decrease in foam apparent viscosity [33]. Other factors influencing the texture of the foam are brine salinity [34], wettability [17], temperature and permeability [35].
3.4. GAS FRACTIONAL FLOW

The foam quality describes the gas fractional flow, flowing through the foam system. The gas fractional flow \( f_g \) is defined as the gas volume flow rate \( q_g \) divided by the total volume flow rate \( q_t \):

\[
f_g = \frac{q_g}{q_t}
\]

(3.11)

The high-quality regime indicates a relatively high gas fractional flow and low water saturation; the stability of the foam is dominated by the capillary pressure. Due to the high gas fractional flow, lamellae are mobilized and generated by lamellae division \([2]\). The high-quality regime is often associated with a strong or fine-textured foam. In the low-quality regime, with low gas fractional flow and high water saturation, lamellae are generated by the capillary snap-off and leave behind mechanisms. Lamellae do not get mobilized and remain static. This restricts the number of lamellae that are present and ultimately results in a reduced resistance to flow \([2]\). The low-quality regime is often associated with a weak or coarse-textured foam.

3.5. LIMITING CAPILLARY PRESSURE

The efficiency of foam in a reservoir depends on its stability and generation in the reservoir. Between the gas and liquid lamellae a pressure difference exist, known as the capillary pressure. Above the limiting capillary pressure \( P_{\text{c}}^* \), lamellae become too thin and the lamellae film ruptures. This in-situ mechanism destroying the foam is earlier referred to as coalescence. The limiting capillary pressure corresponds with the boundary of the high-quality regime with the low-quality regime, known as the transition foam quality \( f_g^* \). The limiting capillary pressure is a function of the surfactant solution and the reservoir properties \([31]\) \([32]\). The capillary pressure in porous media is inherently related with the water saturation. The foam collapses when the water saturation drops below the limiting water saturation \( S_{\text{w}}^* \). However, recent experimental data shows that for high permeability rocks foam does not collapse at a constant water saturation. Instead a range of water saturations at which foam weakens is expected before it entirely collapses \([36]\).

3.6. INJECTION STRATEGY

Both in field as well as laboratory studies, gas and a surfactant solution can be injected simultaneously (co-injection) or alternately injecting slugs of surfactant solution and gas (SAG-injection). Direct injection of foam can be impractical due to poor injectivity. SAG-injection reduces the mobility at the displacement front, while foam dries out behind the displacement front closer to the injection well. This improves the injectivity. Injecting foam in SAG-mode also reduces risks related to material compatibility and risks of corrosion \([31]\).
Various foam modelling techniques have been introduced to model foam flow through porous media in the best possible way. The physics of foam is complex due to the many factors influencing the mobility and stability of foam. In this chapter various foam models will be discussed and a comparative analysis will be performed. This knowledge will be used to select a foam model that will fit the purpose of this research.

The foam modelling techniques can be categorized into two groups: local-equilibrium models and population-balance models. Population-balance models use conservation equations to dynamically track the changes of foam texture in time and relate this with the foam mobility. Local-equilibrium models do not dynamically track the changes and assume that the foam obtains its texture instantaneously. This is based on the assumption that the generation and destruction of foam is fast compared with the time scale of foam transport through porous media [20]. Local-equilibrium models modify the gas relative permeability or apparent gas viscosity based on experimental data (no calculation of foam texture), or obtain the foam texture with the use of an algebraic equation as described in subsection 4.2.2. The advantages and shortcomings of the available type of models are discussed and of each model a specific type is highlighted.

4.1. LOCAL-EQUILIBRIUM MODELS: IMPLICIT-TEXTURE APPROACH

With the implicit-texture approach, the effect of the foam texture on the gas mobility is not directly represented. Implicit-texture models modify the gas relative permeability or apparent gas viscosity based on experimental data. Therefore, in literature it is also referred to as an empirical or semi-empirical model. The gas mobility is affected by the foam texture, which is defined by the surfactant concentration, phase saturations, gas velocity, gas fractional flow, pressure gradient, oil and formation permeability, shear thinning behavior or a combination of these. The concept of using a dimensionless mobility reduction factor $F_M$ was introduced in 1995 and is adopted in several foam models [20]. With this approach the pressure drop over a core with and without foam is measured at different gas fractional flows. The difference in pressure drop indicates the reduction of gas mobility in the presence of foam. $F_M$ is retrieved by matching the calculated experimental apparent viscosity with the modelled apparent viscosity. Because the $F_M$ factor captures the effect of foam on the gas mobility, either the gas relative permeability ($k_{rg}$) or the gas viscosity ($\mu_g$) is modified according to:

$$k'_{rg} = k_{rg} \cdot F_M$$  \hspace{1cm} (4.1)

$$\mu_f = \frac{\mu_g}{F_M}$$  \hspace{1cm} (4.2)

with the apparent relative foam permeability $k'_{rg}$ and the apparent foam viscosity $\mu_f$. The advantage of implicit-texture models is that they require less parameters than population-balance models and do not need numerical schemes to solve the equations. The STARS foam model will be highlighted, as it includes many features of foam behavior and is incorporated into various foam simulators.
4.1.1. STARS MODEL

The STARS foam model is an implicit-texture model developed by the Computer Modeling Group [37]. The STARS model uses the concept of a mobility reduction factor which modifies the gas relative permeability. The model assumes that the relative permeability of the liquid phase remains unchanged. The recent version of the FM factor represents seven functions that describe different features affecting the texture of the foam:

$$FM = \frac{1}{1 + f_{mmob} \prod_{i=1}^{7} F_i}$$

(4.3)

in which $f_{mmob}$ is the reference mobility reduction factor of the gas phase. $F_1$ to $F_7$ represent the effect of surfactant concentration ($F_1 = surf$), oil saturation ($F_2 = oil$), shear thinning ($F_3 = cap$), minimum pressure gradient ($F_4$), oil-component ($F_5$), salinity ($F_6$) and water saturation ($F_7 = dry$) on the foam strength [37]:

$$F_1 = F_{surf} = \left(\frac{C_{surf}}{f_{msurf}}\right)^{epsurf}$$

(4.4)

$$F_2 = F_{oil} = \left(\frac{f_{moil} - S_o}{f_{moil} - f_{oil}}\right)^{epoil}$$

(4.5)

$$F_3 = F_{cap} = \left(\frac{f_{mcap}}{C_a}\right)^{epcap}$$

(4.6)

$$F_4 = \left(\frac{f_{mgcp} - C_a}{f_{mgcp}}\right)^{epgcp}$$

(4.7)

$$F_5 = \left(\frac{f_{momf} - C_o}{f_{momf}}\right)^{epomf}$$

(4.8)

$$F_6 = \left(\frac{C_{salt} - f_{lsalt}}{f_{msalt} - f_{lsalt}}\right)^{epsalt}$$

(4.9)

$$F_7 = F_{dry} = 0.5 + \frac{\arctan(epdry(S_w - f_{mdry}))}{\pi}$$

(4.10)

For the definitions of the foam model parameters, see the nomenclature. Depending on the experimental set-up, such as the presence of oil, a combination of functions is selected to match the experimental data. In various papers on foam modelling such as Farajzadeh et al. [36], Kapetas et al. [35] and Lotfollahi et al. [38] only the dry-out function ($F_{dry}$) and shear-thinning function ($F_{cap}$) are incorporated. The dry-out function represents the effect of the water saturation on foam strength and is capable in describing the sharpness of the transition zone at which foam collapses.

From experimental data the apparent foam viscosity for a range of different gas fractional flows ($m = 1, \ldots, n_{data}$) is obtained:

$$\mu^{exp}_{f,m} = \frac{K}{u_{t,m}} |\nabla P^{exp}_i|$$

(4.11)

in which $u_{t,m}$ is the total Darcy velocity for gas fractional flow $m$. Combining Darcy’s Law with a Corey-type relation, the water saturation ($S_w$) for each data point can be calculated. The associated water saturations are used as an input in the modelled apparent foam viscosity. The apparent viscosity of foam ($\mu_{foam}$) is calculated by:

$$\mu_{foam}(\mathbf{x}, S_w) = \left(\frac{k_{rw}(S_w)}{\mu_w} + \frac{k_{rg}(\mu_{foam}, \mathbf{x}, S_w)}{\mu_g}\right)^{-1}$$

(4.12)

$$\mathbf{x} = [f_{mmob}, f_{msurf}, epsurf, f_{moil}, f_{oil}, epoil, f_{mcap}, epcap, f_{mgcp}, epgcp, f_{momf}, f_{msalt}, f_{lsalt}, epsalt, f_{mdry}, epdry]$$

in which $\mathbf{x}$ represents the foam model parameters, $\mu_w$ the water viscosity and $\mu_g$ the gas viscosity. Eq. 4.12 is non-linear because the relative gas permeability is a function of the apparent foam viscosity. The shear-thinning function and pressure-gradient function represented in the mobility reduction factor incorporate the capillary number and thus implicitly the apparent foam viscosity (Eq. 1.1). Therefore, the apparent foam
viscosity needs to be solved numerically. Subsequently, the implicit formulation of the foam model parameters requires a non-linear solver to retrieve a proper fit between the modelled and experimentally determined apparent foam viscosity [16].

As is discussed in Chapter 3.3 not all factors influencing the foam texture are explicitly incorporated into the STARS model, examples are the reservoir temperature and permeability of the rock. Kapetas et al. [35] state that the permeability is implicitly related with the dry-out function, as the water saturation at which foam coalesces tends to decrease as the permeability increases. Experiments also show that an increase in temperature results in a decrease in surface tension between the surfactant solution and the gas and therefore a reduction in the apparent foam viscosity. While the surface tension is implicitly included in the shear thinning function, there is no explicit way to capture the effect of temperature on the foam texture. The physical relationship between all parameters is complex. Care should be taken to maintain the physical soundness of the STARS model, when fitting it with experimental data.

4.2. POPULATION-BALANCE MODELS

Population-balance models can be divided into two versions: the local-equilibrium version and the dynamic-texture version. Population-balance models have two main purposes: to obtain the foam texture and to determine the foam mobility. The foam texture is obtained by solving a continuity equation. The pioneering population-balance equation was introduced by Falls et al. [19] and the general form is depicted below [20]:

\[
\frac{\partial}{\partial t} \{\phi(S_f n_f + S_t n_t)\} + \nabla \cdot (u_f n_f) = \phi S_g (R_g - R_c) \tag{4.13}
\]

in which is stated that the rate of change in flowing and static bubble density plus the net convection of flowing bubbles into the volume is equal to the rates of foam generation \((R_g)\) and coalescence \((R_c)\). The bubble density, i.e. foam texture, is divided into a flowing gas \((n_f)\) and trapped gas density \((n_t)\). The superficial velocity of the flowing gas phase \((u_f)\) is equal to the superficial velocity of the gas phase \((u_g)\), as the velocity of the trapped gas is zero. The gas saturation \((S_g)\) is divided into flowing and trapped gas saturations \((S_f = X_f S_g)\) and \((S_t = (1 - X_f) S_g)\). In the balance the effects of pressure-driven diffusion, condensation and evaporation are neglected.

The population-balance equations proposed by various authors have different formulations and differ especially in the approach of bubble generation (such as snap-off mechanism [19], effect of pressure gradient [39], stochastic growth process [22] and more). The models also lack consistency in describing the coalescence of the foam. Destruction functions rely on foam texture, gas velocity, surfactant concentration, capillary pressure/water saturation or a combination hereof [20].

After obtaining the foam texture, population-balance models compute the mobility of the gas. The gas relative permeability is modified with the flowing gas fraction \((X_f)\) as described in subsection 3.2.3. More research has to be conducted on modelling the trapped gas fraction, as little is known on its functional dependence. The gas viscosity is determined based on the work of Hirasaki and Lawson [21] as described in subsection 3.2.2. While the relation includes three main mechanisms affecting the apparent viscosity such as the deformation of the interface in smooth capillaries, it neglects the energy dissipation by extension and contraction of foam lamellae moving through the pore system. This dissipation could be of significant importance as a pore network is a complex network of extended and contracted flow paths.

While population-balance models aim to mechanically model foam behavior, they do include parameters that are assumed constant or are determined by experiments. Also population-balance models have not included the presence of oil in their coalescence functions, with an exception of the model of Myers and Radke [24].

4.2.1. DYNAMIC-TEXTURE APPROACH

Dynamic-texture population-balance models describe foam from first principles: the foam texture is used to quantify bubble population and correlate it to foam mobility. The dynamic-texture function solves a partial differential equation to obtain the foam texture [19]. It takes more time to solve the numerical schemes, it adds computational costs and numerical challenges need to be faced. Kapetas et al. [40] incorporate the dry-out function of the STARS foam model into their population-balance model to model the weakening of foam around the limiting capillary pressure.

The population-balance foam model by Falls et al. [19] will be highlighted, as it is the pioneering work on this type of model. This model is based on the generation of foam by capillary snap-off. The model by Kam
et al. [39] will also be discussed, as it is a recent example of a population-balance model capturing modern knowledge of foam behavior. This model is based on the generation of foam by mobilization and division of lamellae.

**Dynamic-texture: Falls et al. Model 1988**

Falls et al. [19] define a population-balance equation for the flowing and stationary bubbles:

\[
\frac{\delta}{\delta t}(\phi S_g X_f n_f) + \nabla \cdot (u_g n_f - J_K) = D_f - \theta + q_{bf}
\]

(4.14)

\[
\frac{\partial}{\partial t}[\phi S_g (1 - X_f)n_f] = D_t + \theta + q_{bt}
\]

(4.15)

in which \(X_f\) is the fraction gas phase flowing, \(J_K\) the number flux of bubbles caused by hydrodynamic dispersion, \(\theta\) is the rate at which bubbles are removed from the flowing phase by trapping, \(D\) represents the rate at which bubble number density changes without bubbles changing identity, \(q_b\) represents the rate of generation. A model for total generation of foam lamellae by the capillary snap-off mechanism is introduced, a separate generation and destruction function is not distinguished. It is assumed capillary snap-off was the only mechanism changing the bubble density. The rate of generation is described as the number of capillary snap-off sites (\(n_n\)), related to the foam texture, divided by the total time to form a lamellae by snap-off. The total time to form a lamellae consists of the time for liquid to accumulate in the neck and the time for the lamellae to exit a constriction:

\[
q_{bf} = R_g - R_c = \frac{n_n}{\frac{\alpha}{L_p} + \frac{\nu_g}{v_g}} \quad P_c < P_c^*
\]

(4.16)

in which \(\alpha\) is a constant of proportionality, \(L_p\) the characteristic length of the pore constriction and \(v_g\) the interstitial velocity of the gas. At the limiting capillary pressure it is assumed that the rate of generation is equal to zero. The effect of oil on foam texture is not included.

Falls et al. [19] assume that the fraction of gas flowing through the pore network remains constant. The stationary bubble balance of Eq. 4.15 disappears, as it is only coupled with the flowing bubble balance through \(X_f\). It is mentioned that a theory needs to be developed to describe the fraction of the gas that is flowing as a function of foam texture and other parameters.

**Dynamic-texture: Kam et al. Model 2007**

Kam et al. [39] argue that mobilization of lamellae and lamellae division are dominating foam generation, in stead of the capillary snap-off mechanism. They introduce a model for total generation of foam lamellae controlled by the pressure gradient. Also the water saturation is integrated. At a higher water saturation, more liquid lenses are present in the pore network. Therefore, foam generation is easier. A simple relationship between the pressure gradient and foam generation is used in which \(c_g\) and \(m\) are model parameters:

\[
R_g = c_g S_w (\nabla p)^m
\]

(4.17)

The destruction function is based on the water saturation and the limiting water saturation in which \(c_c\) and \(n\) are model parameters. The effect of oil on foam texture is not included. As the water saturation approaches the limiting water saturation, the rate of lamellae destruction diverges toward infinity:

\[
R_c = c_c n f \left( \frac{1}{S_w - S_w^*} \right)^n
\]

(4.18)

The model is matched with steady-state experimental data for all foam states and regimes and proved to be successful. However, both the generation and destruction function are non-mechanistic as their exact relationship is unknown. Also the modelling parameters are non-unique.

**4.2.2. Local-equilibrium Approach**

In the local-equilibrium version it is assumed that the in-situ foam texture is in dynamic balance. Therefore, the local generation and local destruction of lamellae are equal (\(R_g = R_c\)). This assumption is based on experiments suggesting that steady state is rapidly reached, except at the entrance region [41]. The foam texture is obtained by equating and rewriting the foam generation and coalescence functions. Therefore, less
parameters in comparison with the dynamic-texture population-balance models are required. Due to this simplification of the population-balance the equation can be solved without the use of numerical schemes [29]. This simplification can be applied to all dynamic-texture population-balance models, this is illustrated with the model of Kam et al. [39].

**Local-equilibrium: Kam et al. Model 2007**

The generation (Eq. 4.17) and coalescence (Eq. 4.18) functions presented by Kam et al. [39] can be equated to obtain the foam texture. The foam texture is a function of the water saturation and pressure gradient:

\[ n_f = \frac{c_g}{c_c} S_w (S_w - S_w^*) n (\nabla P)^m \]  

(4.19)

**4.3. Comparative analysis**

In Table 4.1 the advantages and shortcomings of the modelling techniques are summarized. Lotfollahi et al. [38] compared both local-equilibrium and population-balance models with steady state experimental data. Both approaches showed a proper fit with the data.

While population-balance models describe foam from first principles, they are mutually inconsistent and fail to fundamentally capture all mechanisms influencing the texture of the foam. Some models focus on the generation of foam controlled by the pressure gradient, while others mention that the capillary pressure determines the foam texture. Population-balance models also require fitting parameters and data about the trapped gas fraction and/or the limiting capillary pressure. Therefore, population-balance models require a lot of (experimental) data concerning the foam. Current population-balance models, with an exception of the model by Myers and Radke [24], do not include the effect of oil on the foam texture. An advantage of population-balance models is that they can dynamically model in-situ generation of foam, when the foam has not yet reached a local-equilibrium. This is for example the case around the core entrance or injection well [42], at which the generation of foam is slow compared with the time scale of foam transport. Local-equilibrium models are based on the assumption that the generation and destruction of foam is fast compared with the time scale of foam transport.

In comparison to population-balance models, implicit-texture local-equilibrium models require less parameters and are easier and quicker to solve. The STARS model by the Computer Modeling Group [37] incorporates most foam features, such as the effect of oil or surfactant concentration on the foam texture. The model allows to select the relevant functions affecting the foam texture. The physical relationship between the foam features is complex and the necessity and dependency of the parameters is not yet fully understood. Therefore, implicit-texture models raise the question if they are not merely a fitting exercise. However, it showed to be successful in honoring the behavior of the foam, especially in describing the sharpness of the transition zone.

The selection of the foam model depends on the modelling objectives. For example: the generation of foam can be modelled dynamically around the core entrance or a steady-state foam can be assumed. It also depends on the available data of the properties and propagation of the foam. The foam modelling objectives during this research are determined by the experimental data. When scaling SF-flooding to reservoir scale, different criteria might be required than those relevant when matching a coreflood. The experimental data is discussed in chapter 6, after which a final selection of the foam model is presented in chapter 6.
4.3.1. **FOAM FLOWCHART**

A flowchart is created to summarize the main steps in modelling foam behavior. The fundamental input parameters that are required, such as the foam texture and flowing gas fraction, are indicated.

Figure 4.1: **Flow chart** A general impression of modelling foam flow. Note that different modelling approaches are available.
### 4.3. Comparative Analysis

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Shortcomings</th>
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<tr>
<td><strong>Local-equilibrium models</strong></td>
<td></td>
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<tr>
<td>Implicit-texture</td>
<td>• Fewer input parameters required</td>
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<td></td>
<td>• No numerical schemes, less computational time</td>
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<td></td>
<td>• Able to describe sharpness of transition zone [38]</td>
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<td></td>
<td>• Includes the effect of oil on foam texture</td>
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<td></td>
<td>• Implemented in available software [37]</td>
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<tr>
<td><strong>Population-balance models</strong></td>
<td></td>
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<tr>
<td>Dynamic-texture</td>
<td>• Fundamentally based on physics</td>
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<td></td>
<td>• No local-equilibrium assumption, able to dynamically model in-situ generation of foam</td>
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Table 4.1: The advantages and shortcoming of foam modelling techniques summarized.
While a broad range of foam modelling techniques have been introduced to capture the physics of foam flow through porous media, a smaller range of surfactant models are presented in literature. Two main modelling approaches exist and these approaches differ in implicitly or explicitly modelling the micro-emulsion phase. In this chapter both models are briefly discussed and the advantages and shortcomings are highlighted. The chapter continues with describing the modelling steps of a two-phase surfactant-flooding model.

The description of the two-phase surfactant-flooding model starts with the modelling assumptions, which determine which physics is captured or neglected. As surfactants reduce the interfacial tension between the oil and water phase, an interfacial tension model will be discussed. After reduction of the interfacial tension residual oil can be mobilized. Therefore, a desaturation model is required. The oil-water interfacial tension is a function of salinity and surfactant concentration. Both salts and surfactants are dispersed in the porous medium. Without a dispersion model, the salt and surfactant are modelled as a piston like displacement. A dispersion model is able to capture the effect of complex structures of the porous medium and molecular diffusion across streamlines on the effluent salinity and surfactant profiles. Surfactants are adsorbed to the rock due to electrostatic interactions between the surfactants and the rock surface. Therefore, this chapter concludes with a surfactant adsorption model.

5.1. AVAILABLE SURFACTANT MODELS
Surfactant-flooding models fundamentally differ in the way phase behavior is modelled, considering either two or three phases. Slangen [43] compares the different approaches for two and three-phase surfactant flooding. A two-phase model can suffice when no middle-phase micro-emulsion is present. When a three-phase system is expected, this can be modelled with both a two- or three-phase model.

The research reservoir simulator UTCHEM [44] considers a three-phase model based on Hand's rule [45]. While this approach is physically more correct, its shortcoming is that it requires more (unknown) input parameters. It also requires more computational power. Shell uses the in-house simulator Modular Reservoir Simulator (MoRes). MoRes considers an effective two-phase model. MoRes captures the main aspects of the AS-process without explicitly modelling the micro-emulsion phase. This approach is less complex, requires less parameters and can be used in a wide range of applications. Its shortcoming is that it does not model the presence of a third phase, resulting in a loss of physical soundness. The chapter continues with describing the modelling steps of a two-phase surfactant-flooding model as the simulations will be performed in MoReS.

5.2. SURFACTANT MODELLING ASSUMPTIONS
To model a surfactant flood, modelling assumptions are defined to simplify the model and to provide insight in the simulations. The assumptions, specifically related to surfactant-flooding, are:

1. No explicit modelling of micro-emulsion phase
2. No modelling of geochemistry, such as homogeneous aqueous reactions and ion-exchange reactions with rock minerals.
3. No partitioning of surfactant into the oil phase
4. IFT solely dependent on salinity, assuming a minimum surfactant concentration
5. Desaturation parameters are independent of rock or facies type

5.3. INTERFACIAL TENSION MODEL

As described in section 2.2, the water-oil interfacial tension is strongly correlated with the phase behavior and with the solubility of oil and brine into the surfactant rich-phase [46] [10]. Huh [46] proposed a relationship between the IFT at the micro-emulsion and brine/oil interface and the solubilization ratio. The solubilization ratio is defined as the ratio of solubilized brine or oil to the surfactant volume. Its initial use was to calculate the IFT at optimum salinity conditions. However, its application extended to the entire range of salinity conditions, correlating the solubilization parameters with the IFT:

\[ \sigma_{huh,p} = \frac{c}{Z_p^2}, \quad p = \text{over, under} \]  

in which \( \sigma_{huh,p} \) is the interfacial tension, \( c \) is a constant (often approximated at \( c=0.3 \)) and \( Z_p \) the solubilization ratio. The correlation assumes that the surfactant concentration is above the CMC. \( \sigma_{huh,i} \) requires upscaling if the surfactant concentration is lower than the CMC. As no micro-emulsion is explicitly modelled, Liu [47] defined a parametrization to describe the solubilization ratio as a function of salinity:

\[ Z_{\text{under}} = Z_{\text{opt}} e^{x_{\text{under}}(1-\frac{C}{C_{\text{opt}}})}, \quad C < C_{\text{opt}} \]  

\[ Z_{\text{over}} = Z_{\text{opt}} e^{x_{\text{over}}(\frac{C}{C_{\text{opt}}}-1)}, \quad C > C_{\text{opt}} \]

in which \( Z_{\text{opt}} \) is the optimum solubilization ratio, retrieved from phase behavior tests, at which excess oil and brine are in equilibrium. \( x_{\text{under}} \) and \( x_{\text{over}} \) are solubilization parameters used to match the data. \( C \) and \( C_{\text{opt}} \) define the salinity and optimum salinity respectively.

5.4. DESATURATION MODEL

When the oil-water interfacial tension is reduced due to the presence of surfactant, residual oil can be mobilized. As the capillary forces decrease, the capillary number (Eq. 1.1) increases. The mobilization of residual oil as a function of capillary number is illustrated in Fig. 1.1. As a result the relative permeability curves change. The desaturation equation by UTCHEM [44] relates the capillary number with the relative permeability parameters:

\[ C(N_c) = C_c + \frac{C_w - C_c}{1 + T N_c} \]

in which \( C \) is a Corey parameter, \( C_c \) the parameter at chemical-flood conditions (high capillary number), \( C_w \) the parameter at water-flood conditions (low capillary number), \( N_c \) the capillary number and \( T \) a scaling parameter that determines the location of the slope change (transition at \( N_c = 1/T \)). The desaturation model only applies for the oil and water input parameters of the Corey relative permeability model. An illustration of the desaturation model applied to the relative oil permeability can be seen in Fig. 5.1 and Fig. 5.2. The capillary number determines the Corey parameters and the shape of the relative permeability curve. The water saturation determines the actual oil relative permeability within the curve.
5.4. Desaturation Model

Figure 5.1: Illustration of desaturation model applied to the relative oil permeability, \( k_{ro} \), as a function of the capillary number and the water saturation. Source: A. Fadili, Shell Global Solutions B.V.

Figure 5.2: Oil-water relative permeability model with capillary number dependent relative permeability curves. The Corey parameters are scaled with Eq. 5.4, resulting in a set of curves from low to high \( N_c \).
5.5. Dispersion Model

A porous medium often consists of complex structures, causing some particles to move faster than others. Furthermore, unstable displacement can result in viscous fingers, which accelerates the breakthrough of the injected fluid. A dispersion model is able to capture the effect of complex structures of the porous medium and molecular diffusion across streamlines on the effluent salinity and surfactant profiles. Without a dispersion model, the displacement of salt and surfactant due to convection of the fluid is modelled as a piston-like displacement.

When experimental effluent data is available a dispersion coefficient can be determined by solving the advection-diffusion equation. The modelled IFT is dependent on the salinity and surfactant concentration present in the water phase. Therefore, it is important to determine the experimental dispersion coefficient. The determined dispersivity can be used as an input in the simulation model. It can also be used to quality check if the dispersivity coefficient that is used to history match the experimental tracer data has any physical validity.

Dispersion is caused by two main physical mechanisms: mechanical dispersion arising from complex structures of the porous medium and molecular diffusion across streamlines [48]. Mechanical dispersion takes place along the flow direction, also referred to as longitudinal dispersion, and perpendicular to the flow direction, also referred to as transverse dispersion. Longitudinal dispersion is caused by flow which is faster in certain pores due to permeability variations (Fig. 5.5) and by shear stresses at the pore wall which spread out tracer particles in the flow direction. Transverse dispersion is caused by the tortuosity of the rock [49] [50]. In this model it is assumed that diffusion and dispersion together represent the hydrodynamic dispersion.

The mass flux vectors describing the tracer mass transport can be divided into an advection- (Eq. 5.6) and dispersion mass flux (Eq. 5.7). Advection is mass transport due to the bulk motion of the carrying fluid. The continuity equation for mass transport, including advection and dispersion, is given by the following equation [51] [52]:

\[
\frac{\partial \phi C}{\partial t} + \nabla \cdot (C \mathbf{u}) - \nabla \cdot (\phi D \nabla C) = 0 \quad (5.5)
\]

\[
\mathbf{J}_a = C \mathbf{u} \quad (5.6)
\]

\[
\mathbf{J}_d = -\phi D \nabla C \quad (5.7)
\]

in which \( C \) is the tracer concentration, \( \mathbf{u} \) the Darcy vector velocity of the liquid phase, \( D \) the dispersion, \( J_a \) the advection mass flux and \( J_d \) the dispersion mass flux. As is discussed dispersion takes place in various flow directions. With this dispersion model a coreflood will be matched, in which one-dimensional, constant uniform flow throughout the length of the flow field is assumed. It is assumed the concentrations are well mixed in the other directions. During 1D-flow the dispersion within the core is upscaled to an effective dispersion value. Therefore, \( D \) becomes \( D_{eff} \). Furthermore, a homogeneous and isotropic porous medium is assumed without mass transfer between the solid and liquid phase. Eq. 5.5 can be rewritten in a non-dimensional form, introducing the dimensionless Peclet number (Eq. 5.11). For mass transfer the Peclet number \( (N_{Pe}) \) describes the ratio between the advective and diffusive transport rate.

\[
\frac{\partial C_D}{\partial t_D} + \frac{\partial C_D}{\partial x_D} - \frac{1}{N_{Pe}} \frac{\partial^2 C_D}{\partial x_D^2} = 0 \quad (5.8)
\]

\[\begin{align*}
 t_D &= \frac{u_4 t}{\phi L} \\
 x_D &= \frac{x}{L} \\
 N_{Pe} &= \frac{L u_s}{\phi D_L} \\
 C_D &= \frac{C_i - C(x, t)}{C_i - C_j} 
\end{align*}\quad (5.9) (5.10) (5.11) (5.12)
An analytical solution to Eq. 5.8, with the boundary conditions described in Eq. 5.14, can be given using the Laplace Transform. The Laplace Transform introduces a so-called Gauss error function. The solution to the 1D advection-dispersion equation at a fixed distance (i.e. effluent concentration) for a semi-infinite medium \((0 \leq x < \infty)\) is described by Ogata and Banks [53] and Van Genuchten and Parker [54] and is as follows:

\[
C_D(1, t_D) = \frac{1}{2} \left[ \text{erf}c \left( \frac{1 - t_D}{2\sqrt{t_D/L Pe}} \right) \right] \quad (5.13)
\]

\[
C_D(x_D, 0) = 0 \quad C_D(0, t_D) = 1 \quad C_D(\infty, t_D) = 0 \quad (5.14)
\]

\(\text{erf}c\) represents the complementary error function, \(t_D\) the dimensionless time, \(L\) the length of the core, \(x\) the position along the core, \(C_D\) the dimensionless tracer concentration, \(C\) the effluent (experimental) tracer concentration, \(C_i\) the initial tracer concentration and \(C_j\) the injected tracer concentration. Eq. 5.13 can be fitted with the experimental data by tuning the effective dispersion coefficient \(D_{eff}\), which is represented in the Peclet number. In Fig. 5.4 the effect of the Peclet number on the tracer profile is depicted. As can be observed the profiles are symmetrical, due to the assumption of a homogeneous, semi-infinite model. A Peclet number of one results in a dispersivity equal to the core length, while an infinite Peclet number results in no dispersion. In the model the effective dispersivity \(\alpha_{eff}\) [m] per tracer needs to be specified, which together with the Darcy velocity of the liquid phase \(u_x\) [m/s] makes up the effective dispersion coefficient \(D_{eff}\) [m\(^2\)/s]:

\[
D_{eff} = \alpha_{eff} \frac{u_x}{\phi} \quad (5.15)
\]

5.5.1. Principle of superposition

When a salinity gradient is applied, the injected tracer concentration is not a constant. The solution to the 1D advection-diffusion equation with a change in boundary conditions can be found by applying the superposition principle. The superposition principle assumes a linear differential equation and superposes a linear combination of particular solutions i.e. the effluent salinity profile is the sum of the separate salinity responses. Fig. 5.19 illustrates a two-time change in injection salinity. At \(t_s\) the injection concentration changes from \(C_{j,1}\) to \(C_{j,2}\). The analytical solution of this system is described by:

\[
C_{D, total}(1, t_D) = \frac{C_i - C_{j,1}}{C_i - C_{j,2}} C_D(1, t_D) + \frac{C_{j,1} - C_{j,2}}{C_i - C_{j,2}} C_D(1, t_D - t_s) \quad (5.16)
\]

With:

\[
\frac{C_i - C_{j,1}}{C_i - C_{j,2}} + \frac{C_{j,1} - C_{j,2}}{C_i - C_{j,2}} = 1 \quad (5.17)
\]

Figure 5.3: At \(t_s\) the injection concentration is changed from \(C_{j,1}\) to \(C_{j,2}\).

The injected liquid PV at which the salinity breaks through is dependent on the mobile PV. When the core is saturated with oil, the residual oil saturation reduces the PV available to flow.
5.5.2. **Multi-layer solution**

To achieve non-symmetrical tracer profiles, the model requires extension to a multi-layer model. In a one-dimensional model without dispersion, an applied salinity gradient behaves as a step function in the effluent salinity profile caused by advection. In a multi-layer model with different permeabilities, the effluent salinity profile without dispersion is determined by the distribution of flow. The advection mass flux of each layer is different as each layer has its own Darcy velocity (Eq. B.10). The flow capacity \( F_i \) of layer \( i = 1 \ldots n \), assuming Darcy’s Law and no cross-flow, is determined by the permeability-thickness product \([55]\):

\[
F_i = \frac{K_i h_i}{\sum_{j=1}^{n} K_j h_j}
\]  

(5.18)

in which \( K_i \) is the absolute permeability and \( h_i \) the thickness of layer \( i = 1 \ldots n \). The principle of superposition is applied to the separate responses of each layer. The step functions are smoothed by introducing dispersion. When assuming a two-layer system with a two-time change in injection salinity (i.e. salinity gradient), the analytical solution of the system is described by the summation of four error functions:

\[
C_{D,\text{total}}(1, t_D) = F_1 \cdot \frac{C_i - C_{i,1}}{C_i - C_{i,2}} \cdot C_D(1, t_D) + F_2 \cdot \frac{C_i - C_{i,1}}{C_i - C_{i,2}} \cdot C_D(1, t_D) + F_1 \cdot \frac{C_{j,1} - C_{j,2}}{C_i - C_{j,2}} \cdot C_D(1, t_D - t_S) + F_2 \cdot \frac{C_{j,1} - C_{j,2}}{C_i - C_{j,2}} \cdot C_D(1, t_D - t_S)
\]

(5.19)

---

![Figure 5.4: Effect of the Peclet number on the tracer profile according to Eq. 5.13. The dimensionless time of coreflood [3] is plotted. When the Peclet number is infinite, the effluent profile is a step function i.e. no dispersion.](image-url)
5.6. ADSORPTION MODEL

Surfactants are adsorbed to the rock due to electrostatic interactions between the surfactants and the rock surface, which causes retardation and consumption of the surfactant. Adsorption can be modelled with the so-called Langmuir isotherm, which assumes an ideal solid surface with a series of sites capable of adsorbing one molecule each. It is assumed that when a particle is adsorbed it is immobile and cannot interact with other molecules [56]. Furthermore, it is assumed that the surfactant adsorption is irreversible.

\[
C_s = \frac{C_f}{a_{\text{slope}}} + \frac{C_f}{a_{\text{max}}} \quad (5.20)
\]

in which \( C_s \) is the adsorbed surfactant concentration, \( C_f \) the surfactant concentration in the fluid, \( a_{\text{max}} \) the maximum adsorption and \( a_{\text{slope}} \) the slope of the adsorption. While in this study no experimental surfactant production is available, a sensitivity study is performed to analyze the effect of surfactant adsorption on the results.

Figure 5.5: Dispersion caused by the presence of heterogeneities. \( K_1 \) represent the high-permeability streaks in comparison with \( K_2 \).

Source: Freeze and Cherry [49]
5.7. SURFACTANT FLOWCHART

A flowchart is created to summarize the main steps in modelling surfactant flooding. The input parameters that are required, such as the fluid compositions and desaturation parameters, are also indicated.

---

**Figure 5.6:** Flow chart Modelling surfactant flooding
6

SURFACTANT-FOAM EXPERIMENTAL STUDY

While a large amount of literature is available on foam- and surfactant flooding, their combination is less well understood. To investigate the potential of surfactant-foam flooding, several core-flooding experiments have been performed. The corefloods are carried out by Das et al. [57] at the University of Texas at Austin. For the purpose of this research, data from five different corefloods are interpreted. An understanding of the experimental data will contribute to capture the relevant processes in the model. It will also help to validate the model and can be used to foresee certain pitfalls. First data and results of previous surfactant-foam studies are discussed. Thereafter the experimental procedures, the experimental results and a qualitative interpretation are provided.

6.1. PREVIOUS SURFACTANT-FOAM STUDIES

The amount of literature on surfactant-foam flooding is limited. From the available literature the most relevant results and interpretations have been summarized. While in all experiments the concept of surfactant-foam is applied, the execution of each experiment is different. In some experiments gas is already co-injected during the chemical slug, while others only co-inject gas with the drive solution. A main emphasis is to highlight the effect of the rock type on the performance of the flood, as this is underexposed in most articles. The experiments of Lawson et al. [58] and Szlendak et al. [2] have a similar approach as the experiments that are analyzed during this study. While the other studies have different objectives and research cores with different rock properties, they can be used to highlight important results of the general surfactant-foam flooding process. These findings will be summarized at the end of this chapter.

6.1.1. SURFACTANT-FOAM COREFLOODS

Initial surfactant-foam corefloods were performed in 1970 by Kamal [4]. Kamal and Marsden [59] showed that surfactant-foam flooding leads to additional oil recovery in unconsolidated sands (23.6 D). The foam was prepared in advance before injecting it into the core. A 0.05 PV micellar slug chased by foam resulted in an insignificant increase of 5.8% of the OOIP. However, a 0.10 PV micellar slug chased by foam resulted in an increase of 23.5% of the OOIP, recovering 84.6% of the OOIP after tertiary flooding.

Lawson et al. [58] performed successful SF-experiments in SAG-mode for both Berea sandstone cores (≈ 500mD) and tight carbonate cores (≈ 25mD, Indiana Limestone and San Adres Dolomite). A remaining oil saturation of 0.02 to 0.08 is observed in the sandstone cores, while a remaining oil saturation of 0.09 to 0.13 is observed in the carbonate cores. A high loss of anionic surfactant could be the cause of the higher remaining oil saturation, due to the higher rock adsorptivity of anionic surfactants by carbonates. Nevertheless, observed oil desaturation in the carbonate cores exceeded results of mobility control by polymers. Lawson et al. [58] mention that besides the enhanced oil recovery by SF-flooding, there are additional indicators for the efficiency of the foam drive. A minimal emulsion production during all experiments is observed, while poor mobility control results in diffuse surfactant production, and consequently, in emulsion production. Furthermore the observed tracer fronts were sharp, suggesting successful mobility control.

Srivastava et al. [60] performed coreflooding experiments for both sandstone and carbonate samples (Silurian dolomite core). Their objective was to study the effect of the chemical slug size, surfactant type, polymer and rock type on the performance of the ASF-process. A chemical formulation for both a chemical slug and
chemical drive is designed. First an increase in pressure gradient is observed, which is explained by the mobilization of residual oil. At the start of the drive injection the pressure decreases, due to the lower surfactant concentration and weaker foam in the drive solution. A stronger foam and slightly increase in pressure drop is observed during the salinity transition from a Type III to Type I environment. Suggesting that an under-optimum salinity environment has a positive contribution to the foam stability. Contradictory to previous experiments, a higher oil recovery of the ROIP was observed in the carbonate (87%) in comparison with the sandstone (67%) while having similar permeabilities ($\approx 200 mD$). The effluent salinity profile of the carbonate is more diffused in comparison with the sandstone, in which a relatively sharp salinity front is observed. This could indicate that the carbonate cores have a high dispersive-mixing character. Srivastava [61] studied the effect of a micro-emulsion environment on SF-flooding more thoroughly. In a Type I(-) environment the most stable foaming was observed. Type III is associated with destabilizing effects on foam stability. A Type II(+) environment showed the poorest foam stability. Guo et al. [3] performed ASF-experiments on Bentheimer sandstone cores ($\approx 1.3 D, \phi = 0.20$). First an SF-flood without the presence of gas is performed, resulting in an oil recovery of 43% of the ROIP. Cross sections of the core confirmed unstable macroscopic displacement (i.e. viscous fingering) due to poor mobility control. However, microscopic displacement efficiency was proven successful, with almost no residual oil observed in the swept parts of the core. The pressure drop remains relatively constant, confirming the poor mobilization of oil. The ASF-flood, with AS preflush and a foam quality of 80%, recovered 60% after 1.0 PV and 94% after 5.0 PV. It is observed that the mobility reduction increases with decreasing foam quality. Szlendak et al. [2] performed experiments with a similar set-up as Lawson et al. [58] for tight-limestone cores ($\approx 3 - 15 mD, \phi = 0.20$, Texas Cream limestone). With surfactant-foam flooding 91% of the ROIP was recovered, resulting in a total recovery of 95% of the OOIP. Of the recovered oil 30% was produced as a bonded micro-emulsion. This contrasts with the findings of Lawson et al. [58], in which minimal emulsion production is observed. During a repeated surfactant-foam flood 75% of the ROIP was recovered. The reduction in oil recovery is not fully understood. A reference chemical flood (without gas) resulted in a recovery of 28% of the ROIP and a reference gas injection (without surfactant) resulted in a recovery of 13% of the ROIP. The effluent salinity profile shows a sharp transition from the in-situ salinity to the salinity of the chemical slug. Therefore, the often dispersive-character of the limestone is not observed during this experiment. During the salinity transition from a Type III to Type I environment, the pressure gradient remains constant, suggesting that the salinity environment does not significantly influences the foam stability. Above findings contrasts with the findings of Srivastava et al. [60].

### 6.1.2. Surfactant-Foam Field Trial

Demin et al. [5] performed both laboratory and field tests for the Daqing Oilfield in China. The pilot area has been characterized as a deltaic sandstone deposit, with a permeability of circa 600 mD. Demin et al. [5] added gas to an ASP-flood to increase the volumetric sweep efficacy. Approximately an additional 12% oil recovery is observed during the corefloods, in comparison with the ASP flood without foam. The total incremental oil recovery is circa 30%, recovering 70% of the OOIP after tertiary flooding. During the Daqing Oilfield pilot test, injection problems were encountered due the low mobility of foam. Therefore, the gas-liquid ratio was lowered to 0.34:1 in stead of the designed 1:1 ratio. An increased injection pressure in comparison with water flooding and a reduced GOR indicate that a stable foam slug was displaced in the formation. The cumulative oil recovery of the OOIP raised within 3.5 years from 50.58% after waterflooding, to 65.6% during chemical flooding. A final recovery of 72% of the OOIP is expected.

### 6.1.3. Surfactant Corefloods

McCool et al. [62] researched chemical floods without gas for both Berea sandstone ($\approx 150 mD, \phi = 0.18$) and Indiana limestone cores ($\approx 200 mD, \phi = 0.18$). The core is saturated with Wharman Oil with a viscosity of 7.5 cP. A significant difference in oil recovery is reported. A recovery of >95% for the Berea sandstone and a recovery of $\approx 40\%$ for the Indiana Limestone respectively. The poor recovery is suspected due to a greater anionic surfactant adsorption/retention in the limestone core. Also the high dispersive-mixing character of limestone cores, resulting in mixing of the surfactant slug with the more saline synthetic brine, could result in higher salinities of the chemical slug. Therefore, the slug salinity deviates from its optimal salinity and not all residual oil is mobilized. McCool et al. [62] altered the surfactant formulation and flooded the Indiana limestone again, resulting in an improved oil recovery of $\approx 79\%$. The improve in oil recovery could be explained by a lower surfactant adsorption or a less heterogeneous limestone core. Early surfactant breakthrough during this coreflood suggests the lack of mobility control.
Previous surfactant-foam studies show that surfactant-foam flooding is successful in enhancing the recovery of the oil. The overall trend is that SF-flooding performs better in sandstone cores in comparison with carbonate cores, with an exception of the results by Srivastava et al. [60]. McCool et al. [62] explain this by a greater anionic surfactant adsorption and by the high dispersive character of carbonates. Ma et al. [13] also state that carbonates tend to adsorb anionic surfactant more than sandstone cores. When McCool et al. [62] change their surfactant formulation to flood the Indiana limestone, the oil recovery increases from ≈ 40% to ≈ 79%. Therefore, it is not grounded to compare the success of the SF-flood of different reservoir rocks with similar surfactant-formulations, as both sandstones and carbonates require their own optimized surfactant formulation depending on their surface charge i.e. adsorption of the reservoir rock.

The results of McCool et al. [62] (surfactant-flooding) and Srivastava et al. [60] (surfactant-foam flooding) show a highly diffused salinity profile in the Indiana Limestone and Silurian dolomite cores, suggesting that the carbonate cores have a high dispersive-mixing character in comparison with the sandstone cores. The effect of the salinity environment and the presence of micro-emulsions on the foam stability remains controversial and requires more research.

6.2. Designing a Surfactant-foam Coreflood

Several factors determine the success of a surfactant-foam flood, as is shown by the previous surfactant studies. Important options to design a SF-coreflood that are identified are:

1. **Screening of reservoir properties.** Properties such as the temperature and pressure of the reservoir and rock properties such as the porosity, permeability and heterogeneity need to be identified. Other important properties are the rheological properties of the reservoir fluids, the salinity of the formation water and injection water.

2. **Screening of surfactants.** The type, concentration, slug size and combination of surfactants determine the phase behavior (i.e. IFT), adsorption and foaming ability. This is inherently related with the performance and stability of surfactants at different salinities, temperatures and crude oil properties. The formulation of surfactants should reduce the IFT while generating the desired foam strength.

3. **Type of injected gas and foam quality.** The type of injected gas determines if there is interaction between the oil and gas. Certain gasses can alter the viscosity of the oil and lower the IFT between the oil and gas. The volume rate of the injected gas determines the foam quality, which is related with the stability of the foam.

4. **Injection strategy.** Important decisions are the salinity of the waterflood, the composition and salinity of the slug- and drive solution, the injection rate and the decision to opt for co-injection or SAG-injection.

Above design options are related to each other. For example: the salinity of the injection water affects the type and selection of the surfactant formulation. The surfactant formulation subsequently determines the salinity of the slug- and drive solution. The foaming ability of the surfactant formulation also determines the injectivity and the injection rate of the chemical slug.

6.3. Experimental Procedures

Surfactant-foam corefloods have been designed to determine the potential of SF-flooding for an onshore carbonate reservoir located in the Middle East. The oil recovery, oil cut, salinity and sectional pressure drop were measured to evaluate the flood. A low-quality-foam and low-rate injection strategy was applied. This is a similar strategy as applied in the SF-experiments by Szlendak et al. [2]. The reasoning behind this strategy is that a high-quality-foam is not suitable for tight reservoirs because of the ultra-high flow rates and pressure drops associated with the creation and propagation of high-strength foam. It is assumed that a low-quality-foam can provide the desirable flow-resistance factor for the displacement of light crudes in porous media. The surfactant screening, experimental set-up and coreflooding procedures will be discussed. Furthermore, a table with the rock, fluid and injection properties will be given.
6.3.1. **Surfactant Screening**

Chemical formulations and surfactant concentrations were screened on their phase behavior at reservoir temperature. This included the formation of micro-emulsions and the aqueous stability at a range of salinities. The main criterion was an optimum salinity close to the salinity of the injection water while maintaining aqueous stability. Two anionic surfactant formulas, Formula 87 and Formula 113/114 respectively, were selected for the corefloods. Both Formula 87 and 113/114 consists of a blend of a proprietary and sulfonate surfactant. During the drive solution a different surfactant formulation was injected. The sulfonate surfactant was excluded from the formula, as this is a weak foamer and mainly lowers the IFT between the oil and water.

A negative salinity gradient was applied in the experiments. A gradient in salinity will ensure that optimum salinity is achieved in the core. At optimum salinity the lowest IFT occurs, resulting in desaturation of oil. Under-optimum salinity has the advantage of a lower surfactant retention and a decreased microemulsion viscosity associated with Type III [57]. The optimum salinity is determined by phase behavior tests in test tubes. However, phase behavior can behave differently in the core due to adsorption or degradation of surfactant, activity of the crude oil and geochemistry such as ion exchange reactions with rock minerals [2]. Therefore, the optimum salinity in the core may differs with the optimum salinity measured in the lab.

6.3.2. **Experimental Set-up**

A vertical core-set up is used with outcrop cores of Indiana Limestone. The Indiana Limestone can be characterized as a calcite cemented grainstone consisting of oolites and fossil fragments [63]. The rock properties of the cores can be found in Table 6.2. The core was heated to the reservoir temperature of 69 °C and vacuumed to establish the core wettability. Two holes for pressure taps were drilled. Therefore, the pressure drop over three sections of the core can measured.

The gas rate is regulated by a mass flow controller. The upstream pressure at the core inlet is regulated by the gas supply. A backpressure regulator was used to maintain pressure at the core-outlet. A pressure of 480 psi or 1000 psi respectively, was applied to minimize gas expansion. The minimum miscibility pressure (MMP) for nitrogen is expected around the order of >5000 psi [64]. Therefore, no miscibility effects are assumed. The desired gas flow rate in the core is translated back to the pump conditions using the ideal gas law and the compressibility factor \((Z)\) of nitrogen. The liquid is injected with a syringe pump. Assuming the liquid is incompressible, the liquid rate remains constant throughout the system. For a more extensive description of the experimental set-up, please consult Das et al. [57].

![Figure 6.1: Schematic of the coreflood set-up. Source: Das et al. [57].](image-url)
6.3.3. **COREFLOOD DESIGN**

In total five corefloods have been carried out, with a common objective to understand the processes during surfactant-foam flooding. The corefloods differ in the presence of hydrocarbons, salinity gradient and surfactant concentrations. During all corefloods surfactant is injected. The objectives of the corefloods are summarized in Table 6.1. Coreflood [1] and coreflood [2] differ in the surfactant formulation of the chemical slug and drive and their applied salinity gradient. Coreflood [3] tests the compatibility of the system and contains no oil nor gas. Coreflood [4] establishes the propagation of foam without the presence of oil. Coreflood [5] establishes the relative contribution from surfactant flooding without the presence of gas. The experimental properties, injection strategy and results are summarized in Table 6.2.

<table>
<thead>
<tr>
<th>Coreflood</th>
<th>Objective</th>
</tr>
</thead>
<tbody>
<tr>
<td>[1]</td>
<td>SF-flood: surfactant formulation 87 and corresponding (optimum) salinity</td>
</tr>
<tr>
<td>[2]</td>
<td>SF-flood: surfactant formulation 113/114 and corresponding (optimum) salinity</td>
</tr>
<tr>
<td>[3]</td>
<td>Test compatibility of the system (no oil and gas)</td>
</tr>
<tr>
<td>[4]</td>
<td>Reference foam flood (no oil)</td>
</tr>
<tr>
<td>[5]</td>
<td>Reference surfactant flood (no gas)</td>
</tr>
</tbody>
</table>

Table 6.1: Coreflood objectives

6.3.4. **COREFLOODING PROCEDURES**

Depending on the design of the coreflood, the following procedures were carried out:

1. **Brine saturation** \([K]\)
   The core is saturated with Lekwair Formation Brine. The pore volume (PV) is determined using the mass balance equation. At steady state the pressure drop across the core and the injection rate are used in Darcy’s Law to calculate the absolute permeability of the rock (Eq. 6.4).

2. **Oil saturation** \([S_{oil}, K_{ro}]\)
   Crude oil is injected at reservoir temperature. The initial oil saturation is determined using the mass balance equation. The end point relative permeability of oil is calculated at steady state using the pressure drop across the core and the injection rate (Eq. B.10). Coreflood [3] and [4] are not saturated with oil.

3. **Waterflood** \([S_{or}, K_{rw}]\)
   The core is waterflooded with Lekwair Formation Brine until no oil is observed in the effluent. The end point relative permeability of water is calculated at steady state using the pressure drop across the core and the injection rate (Eq. B.10). The residual oil saturation after waterflood is determined using the mass balance equation.

4. **Injection of chemical slug**
   A chemical slug of 0.5 liquid PV is co-injected with nitrogen at 50 % gas fraction and optimum salinity. During coreflood [3] and [5] no gas is co-injected.

5. **Injection of drive solution**
   A drive solution is co-injected with nitrogen at 50 % gas fraction until no (emulsified) oil is observed in the effluent. The drive solution is injected at under-optimum salinity and contains a lower surfactant concentration in comparison with the chemical slug. During coreflood [3] and [5] no gas is co-injected.

The surfactant formulation for both the chemical slug and drive solution have been optimized regarding their phase behavior at a salinity close to the injection water. The formulation is not optimized regarding its foaming ability.
### 6.4. Table: Rock, Fluid and Injection Properties

<table>
<thead>
<tr>
<th>Constant rock and fluid properties</th>
<th>Symbol</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Core length</td>
<td>L</td>
<td>cm</td>
<td>30.48</td>
</tr>
<tr>
<td>Diameter</td>
<td>D</td>
<td>cm</td>
<td>3.81</td>
</tr>
<tr>
<td>Formation brine salinity</td>
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<td>$\mu_w$</td>
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<td>$\sigma_{\text{wo}}$</td>
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<td>–</td>
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<td>Rock density, carbonate</td>
<td>$\rho_r$</td>
<td>kg/m³</td>
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<td>Optimum solubilization ratio</td>
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<tr>
<td>Chemical IFT water-oil</td>
<td>$\sigma_{\text{huh, opt}}$</td>
<td>mN/m</td>
<td>$9.3 \cdot 10^{-4}$</td>
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<td>Component</td>
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<td>oil</td>
<td>gas</td>
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<td>N/A</td>
<td>gas</td>
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<td>Permeability</td>
<td>$K$</td>
<td>mD</td>
<td>11</td>
<td>10</td>
<td>7</td>
<td>8</td>
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<td>$\phi$</td>
<td>–</td>
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<td>0.254</td>
<td>0.257</td>
<td>0.228</td>
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<td>Pore volume</td>
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<td>Tubing dead volume</td>
<td>$PV$</td>
<td>cm³</td>
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<td>14.4</td>
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<td>15.8</td>
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<td>–</td>
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<td>0</td>
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<td>Residual oil saturation, water flood</td>
<td>$S_{\text{orw}}$</td>
<td>–</td>
<td>0.24</td>
<td>0.22</td>
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<td>N/A</td>
<td>0.33</td>
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<td>N/A</td>
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<td>Total recovery of ROIP</td>
<td>–</td>
<td>%</td>
<td>75</td>
<td>82</td>
<td>N/A</td>
<td>N/A</td>
<td>28</td>
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<tr>
<td>Total recovery of OOIP</td>
<td>–</td>
<td>%</td>
<td>87</td>
<td>90</td>
<td>N/A</td>
<td>N/A</td>
<td>62</td>
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<td>Endpoint relative oil permeability</td>
<td>$K_{\text{ro}}$</td>
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<td>N/A</td>
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<td>0.16</td>
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<td>N/A</td>
<td>0.1</td>
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<td>Surfactant formulation</td>
<td>–</td>
<td>–</td>
<td>87</td>
<td>113/114</td>
<td>113/114</td>
<td>113/114</td>
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<td>Waterflood salinity</td>
<td>$C_{\text{wat}}$</td>
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<td>160000</td>
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<td>Optimum salinity, equal to slug salinity</td>
<td>$C_{\text{opt}=j,1}$</td>
<td>ppm</td>
<td>170070</td>
<td>152000</td>
<td>152000</td>
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<td>Drive salinity</td>
<td>$C_{\text{j,2}}$</td>
<td>ppm</td>
<td>46600</td>
<td>124000</td>
<td>124000</td>
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<td>$C_{\text{slug}}$</td>
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<td>10000</td>
<td>10000</td>
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<tr>
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<td>$C_{\text{drive}}$</td>
<td>ppm</td>
<td>1000</td>
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<td>Water volume rate (waterflood)</td>
<td>$Q_w$</td>
<td>cm³/hr</td>
<td>10</td>
<td>12</td>
<td>14.7</td>
<td>14.9</td>
<td>7.2</td>
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<tr>
<td>Injected PV during waterflood</td>
<td>$PV_{\text{water}}$</td>
<td>cm³</td>
<td>1.53</td>
<td>1.48</td>
<td>2.09</td>
<td>2.43</td>
<td>1.86</td>
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<td>Injected PV chemical slug size</td>
<td>$PV_{\text{slug}}$</td>
<td>cm³</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
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<tr>
<td>Liquid volume rate (core conditions)</td>
<td>$Q_l$</td>
<td>cm³/hr</td>
<td>5.7</td>
<td>6.0</td>
<td>7.4</td>
<td>3.7</td>
<td>7.2</td>
</tr>
<tr>
<td>Gas volume rate (core conditions)</td>
<td>$Q_g$</td>
<td>cm³/hr</td>
<td>5.7</td>
<td>6.0</td>
<td>N/A</td>
<td>3.7</td>
<td>N/A</td>
</tr>
<tr>
<td>Total fluid injection volume rate</td>
<td>$Q_t$</td>
<td>cm³/hr</td>
<td>11.4</td>
<td>12</td>
<td>7.4</td>
<td>7.4</td>
<td>7.2</td>
</tr>
<tr>
<td>Foam quality</td>
<td>$f_g$</td>
<td>%</td>
<td>50</td>
<td>50</td>
<td>N/A</td>
<td>50</td>
<td>N/A</td>
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<tr>
<td>Backpressure</td>
<td>$P_{\text{back}}$</td>
<td>psi</td>
<td>480</td>
<td>1000</td>
<td>1000</td>
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Table 6.2: Rock and fluid properties and injection strategy of the experimental core floods
6.5. EXPERIMENTAL RESULTS AND INTERPRETATION

A qualitative interpretation of the measured data will be given. All data has been plotted against the injected liquid PV [-], as the liquid volume stays constant with fluctuating pressures. In Fig. 6.2 the cumulative enhanced oil recovery and oil cut during chemical flooding of the different corefloods are depicted. In Fig. 6.5 and Fig. 6.6, the pressure drop over the core during waterflood and during chemical injection can be observed. In Fig. 6.9 the oil and water solubilization data for the surfactant blend can be observed. In Fig. 6.12 and Fig. D.5 the effluent salinity profiles are given. The results will be discussed in the same order.

6.5.1. CUMULATIVE OIL RECOVERY AND OIL CUT DURING CHEMICAL FLOOD

Coreflood [1], [2] and [5] were initially saturated with oil and waterflooded until no oil was observed in the effluent. Coreflood [3] and [4] are not saturated with oil. During the injection of the chemical-flood the core starts to desaturate i.e. residual oil is mobilized and an oil bank is formed. The production profiles suggest that oil is first produced by an oil bank. The decrease in oil cut and long-tail production after the oil bank are associated with the breakthrough of the micro-emulsion, judged by its brownish colored appearance. The diffused oil bank suggests the displacement of oil is affected by low mobility control.

As can be seen in Fig. 6.2 and Table 6.2 the coreflood without gas [5] shows a poor cumulative enhanced oil recovery i.e. recovery of residual oil in place (≈ 28%) in comparison with the corefloods with gas (≈ 80%) at 1.3 injected liquid PV. The oil bank observed in coreflood [5] is smaller of size and has a lower oil cut. These findings could suggest unstable macroscopic displacement (i.e. viscous fingering) due to poor mobility control. Guo et al. [3] have a similar observation during their surfactant-flood and assume a successful microscopic displacement efficiency, but poor macroscopic displacement efficiency. This is confirmed by cross sections of the core, obtained after the surfactant-flood.

The oil cut and recovery of coreflood [1] and [2] show many similarities and both succeed in a cumulative enhanced oil recovery of approximately 80%. Coreflood [2] shows an earlier breakthrough (BT) and a slightly larger oil bank (Δ0.05PV) in comparison with coreflood [1]. The larger oil bank could suggest favorable mobility control, explaining the higher cumulative oil recovery. A favorable mobility control will reduce mixing between the injected chemicals and the oil bank. Differences in dispersivity of the cores could also account for the observed changes. Due to the requirement to select the surfactant formulation with an optimum salinity close to the salinity of the injection water (160000 ppm), surfactant formulation 113/114 with an optimum salinity of 152000 ppm is selected for corefloods [2] to [5].

Oilbank A region of increased oil saturation is referred to as an oil bank. The establishment and propagation of an oil bank through the core is a function of desaturation, driven by low IFT, and the ratio of the displacing phase mobility with the displaced phase mobility. As residual oil gets mobilized, the oil saturation will increase until the oil achieves a greater mobility than water as shown in Fig. 6.7. Thereafter the oil bank will propagate faster through the core than the water. This results in an expanding oil bank [2]. The better the micro- and macroscopic displacement efficiency, the larger the oil bank.

![Figure 6.2: Oil recovery of residual oil in place (ROIP) and oil cut during chemical slug and drive solution. [1]: Oil bank BT = 0.35 PV, micro-emulsion BT =0.5 PV || [2]: Oil bank BT = 0.25 PV, micro-emulsion BT = 0.45 PV || [5]: Oil bank BT = 0.42 PV, micro-emulsion BT = 0.55 PV.](image-url)
6.5.2. Pressure Drop

The pressure drop over the core for both the waterflood and chemical flood will be discussed. The pressure drop data is interpreted by relating it to the total relative mobility. The relationship between the pressure drop and total relative mobility is given by rewriting Eq. B.6 for a one-dimensional, three-phase system. In this example it is assumed the gas phase is slightly compressible ($c_g \approx 1.1 \cdot 10^{-3}$ 1/psi at 1000 psi [65]), the water and oil phase are incompressible and capillary and gravity forces are neglected:

$$\frac{d}{dx} \left(K \left( \frac{k_{rw}}{\mu_w} + \frac{k_{ro}}{\mu_o} + \frac{k_{rg}}{\mu_g} \right) \frac{dP}{dx} \right) = 0 \quad (6.1)$$

$$\frac{dP}{dx} = \frac{c}{K M_t} \quad (6.2)$$

$$S_o + S_w + S_g = 1 \quad (6.3)$$

in which $M_t$ is the total mobility and $c$ a constant. Eq. 6.2 indicates that the total relative mobility is proportional with the pressure drop. If the summation of the water mobility, oil mobility and gas mobility achieves a minimum, the pressure drop is the highest. During waterflooding no gas is present and the total mobility is represented with a two-dimensional plot (Fig. 6.7). During the chemical flood three phases are present. Therefore, the total mobility is represented by a three-dimensional surface (Fig. 6.8). The minimum of the surface represents the highest pressure drop.

The pressure drop across the core is also used to determine the apparent viscosity. This is useful when comparing data with different core properties or injection rates. The apparent viscosity is calculated by applying Darcy’s Law for a one-dimensional system (Fig. D.1):

$$\mu_{app} = -\frac{K}{u_t} \frac{\Delta P}{L} \quad (6.4)$$

in which $K$ is the absolute permeability, $u_t$ the total Darcy velocity, $L$ the length of the core and $\Delta P$ the pressure drop over the core.

Waterflood

The corefloods that are initially saturated with oil ([1], [2] and [5]), show an initial increase in pressure drop, indicating a reduction in total mobility. Thereafter a decrease in pressure drop is observed, indicating an increase in total mobility. This can be explained with Fig. 6.7. During the waterflood the water saturation increases. The relative mobility will decrease until the minimum apparent fluid mobility is achieved. Thereafter, the relative mobility will increase and the pressure drop will decrease. When waterflooding a core with a low initial oil saturation, for example $S_{i_o} < 0.52$ in Fig. 6.7, the pressure drop will merely decrease as the minimum apparent fluid mobility is already achieved. The corefloods without oil, [3] and [4], show a constant pressure drop. This confirms single-phase flow of water in the core. The relative permeability curves remain unchanged.

Chemical flood

During the chemical flood gas is injected, resulting in a system with three phases. The chemical flood consists of a chemical slug of 0.50 injected liquid PV, followed by a chemical slug with a lower surfactant concentration, also referred to as the ‘drive solution’. The results for the chemical flood will be separately discussed for each coreflood. First the coreflood without oil and gas is interpreted [3], followed by the reference foam flood [4], reference surfactant flood [5] and the surfactant-foam corefloods [1] and [2].
Coreflood [3] Coreflood [3] is performed to test the compatibility of the system, no hydrocarbons are present in the core. A constant pressure drop of 7 psi is measured, confirming single-phase flow of the chemical solution in the core. The apparent viscosity is used to quality check the data. The apparent viscosity when when no hydrocarbons are present is 0.7 mPa·s (Fig. D.1). For a brine with a salinity of 130000 ppm, temperature of 69°C and pressure of 1000 psi this matches with literature [66].

Coreflood [4] Coreflood [4] is performed to test the performance and propagation of foam through the core without the presence of oil. It can be used to quantify the contribution of foam to the pressure drop and increase in apparent viscosity. However, as discussed in section 3.3, oil affects the stability of the liquid lamellae due to its hydrophobic surface. This mechanism could (partly) destroy the foam, increasing the mobility of the gas. It is assumed that the apparent foam viscosity measured during coreflood [4] gives an indication of the maximum foam strength in the presence of oil during coreflood [1] and [2].

The pressure drop builds up starting at 8 psi until 28 psi, suggesting that foam is generated. After 0.5 injected liquid PV, at the start of the drive solution, the pressure drop decreases rapidly. The drive solution contains a lower surfactant concentration in comparison with the chemical slug. A decrease in surfactant concentration is accompanied by an increase in surface tension, which causes a local decrease in film thickness [15]. This results in a decrease in limiting capillary pressure which causes foam bubbles to coalesce. Therefore, the drive solution results in a weaker foam with a lower apparent foam viscosity.

Within approximately 0.1 injected liquid PV the pressure drops to its new steady state value. It is expected that the foam is in a transient state and that the foam strength is reduced in front of the injected drive solution. This could for example be caused by the reduced pressure drop which affects the stability of the lamellae through the entire core, resulting in a domino effect. The pressure drop stabilizes at approximately 16 psi, equal to an apparent foam viscosity of \( \mu_{foam} = 1.75 \) mPa·s. The corresponding mobility-reduction factor (MRF), with brine as a reference case, is 2.35.

Coreflood [5] Coreflood [5] is a reference surfactant flood in which no gas is injected. In subsection 6.5.1 it is discussed that the surfactant flood shows a poorer recovery due to a poor macroscopic displacement efficiency in comparison with coreflood [1] and [2]. The pressure drop over the core during waterflooding stabilizes at 73 psi. The initial pressure drop at the slug and drive is measured at 70 psi, which is an acceptable measurement difference.

The pressure drop remains constant until 0.38 injected liquid PV, just before the BT of the oil bank. The pressure drop increases with approximately 10 psi due to the mobilization of residual oil in the core (moving towards the left in Fig. 6.7). As a small oil bank is established, the increase and decrease in pressure drop is relatively small in comparison with coreflood [1] and [2]. At 0.5 injected liquid PV, at the start of the drive solution, the pressure drop starts to decrease again. However, the oil cut is still increasing and the micro-emulsion did not breakthrough yet (0.55 injected liquid PV). This is different in comparison with coreflood [1] and [2], in which the BT of the micro-emulsion marked a decrease in pressure drop.

As only a small oil bank is established, the residual oil saturation in the core after the chemical flood remains relatively high. This suggests a lower total mobility in the core, explaining the higher pressure drop (Eq. 6.2) in comparison with coreflood [1] and [2].

Coreflood [1] Coreflood [1] shows a small increase in pressure (0.03 injected liquid PV), after which it continuously decreases. When both residual oil is mobilized and foam is generated, the pressure is expected to increase due to a decrease in total apparent fluid mobility (increasing oil and gas saturation in Fig. 6.8). This pattern cannot be recognized in coreflood [1].

The pressure drop over the core during waterflooding stabilizes at 60 psi. The flowrate of the chemical slug is increased with a factor 1.14. Therefore, an initial pressure drop of approximately 68 psi is expected (Eq. 6.4). However, an initial pressure drop of 88 psi is measured. This suggests that the data of the pressure build-up (≈ 17 psi) is missing or the pressure is incorrectly measured at the pressure gauge.

At 0.5 injected liquid PV (BT of the micro-emulsion) a steeper decrease in pressure drop is observed. A possibility is that the micro-emulsion has a higher viscosity than the oil phase [67], which contributes to an increase in total fluid mobility during its progression out of the core section. Furthermore, at 0.5 injected liquid PV a weaker foam is injected, which also contributes to an increase in total fluid mobility as described with Eq. 6.1.

The apparent viscosity of the foam will influence the total mobility of a three phase system, as is illustrated in Fig. 6.8. In Fig. 6.8 the apparent foam viscosity is lower than the oil viscosity, but higher than the water
viscosity. At the connate water saturation of $S_w=0.35$ and a gas saturation of $S_g=0.23$ the relative minimum apparent fluid mobility is achieved. When no foam is generated, gas injection will always increase the total mobility as is illustrated in Fig. C.2. In the foam experiments, the apparent foam viscosity stabilizes on 1.75 mPa·s. The corresponding mobility-reduction factor (MRF), with brine as a reference case, is 2.35.

Coreflood [2] The pressure drop over the core during the waterflood stabilizes at 65 psi. The total fluid injection volume rate of the chemical slug is equal to the waterflood. Therefore, an initial pressure drop of approximately 65 psi is expected (Eq. 6.4). However, an initial pressure drop of 37 psi is measured. It is expected that this is related with the closing and opening of the valves. If the pressure in the gas phase has yet not overcome the entry pressure, the pressure gradient is only determined by the volume injection rate of the liquid phase.

An increase in pressure drop until 0.45 injected liquid PV is observed. The pressure drop increases due to the mobilization of residual oil in the core and the generation of foam (increasing oil and gas saturation in Fig. 6.8). When the oil bank is produced at 0.25 injected liquid PV, the pressure drop continues to increase but at a lower rate. An explanation could be that the foam generated in the core has a lower mobility than the produced oil bank, which contributes to the decrease in total fluid mobility. This is in contrast with coreflood [1], where a decrease in pressure drop is observed during the production of the oil bank.

The pressure drop of coreflood [2] starts to decrease at the BT of the micro-emulsion at 0.45 injected liquid PV. A possibility is that the micro-emulsion has a higher viscosity than the oil phase [67], which contributes to an increase in total fluid mobility during progression out of the core section. Furthermore, at 0.5 injected liquid PV a weaker foam is injected, which also contributes to an increase in total fluid mobility as described in Eq. 6.1. The pressure stabilizes when all mobile oil is produced and steady-state flow is achieved in the core.
6.5. EXPERIMENTAL RESULTS AND INTERPRETATION

Figure 6.6: Pressure drop over the core during chemical slug and drive solution.

Figure 6.7: Total mobility during a two-phase waterflood (no gas), using data of coreflood [5]: $\mu_w=0.8$ cP, $\mu_o=2.3$ cP, $N_w=3$, $N_o=2$, $S_{wc}=0.15$, $S_{or}w=0.33$, $K_{rwe}=0.1$, $K_{roe}=0.57$. At a water saturation of $S_w=0.48$ the relative minimum apparent fluid mobility is achieved.
Figure 6.8: Total mobility during a three-phase chemical flood (high $N_c$). The apparent viscosity of the gas phase is dependent on the foam strength, in this example the apparent foam viscosity is lower than the oil viscosity. Input values of coreflood [2] and chemical desaturation parameters as defined in Table 9.2: $\mu_w=0.8$ cP, $\mu_o=2.3$ cP, $\mu_g=0.02074$ cP, $\mu_{foam}=1$ cP, $N_w=1$, $N_{o,w}=1$, $N_{o,g}=3$, $N_g=2.43$, $S_{wc}=0.35$, $S_{g,c}=0$, $S_{o,w,c}=0.04$, $S_{o,g}=0$, $K_{rw}=1$, $K_{r_o,w}=1$, $K_{r_o,g}=1$, $K_{rg}=0.73$. At the connate water saturation of $S_w=0.35$ and a gas saturation of $S_g=0.23$ the relative minimum apparent fluid mobility is achieved.
6.5.3. SOLUBILIZATION DATA

In section 5.3 the interfacial tension model is described. This model is used to analyze the solubilization data of the surfactant blend (Formulation 113/114), which is injected in coreflood [2] to [5]. In Fig. 6.9 the solubilization data of the blend can be observed. The optimum salinity of $C_{opt} = 152000$ ppm corresponds to an optimum solubilization ratio of $Z_{opt} = 18 \text{ [-]}$. At optimum solubilization the IFT according to Eq. 5.1 is $\sigma_{hub, opt} = 9.3 \cdot 10^{-4}$ Dyne/cm. The sensitivity of the solubilization parameter $X_{under}$ on the IFT for over- and under optimum conditions has been plotted in Fig. 6.11 and Fig. 6.10 respectively. The input values for surfactant formation 113/114 as listed in Table 6.2 are used. For example: if $X_{under} = 10 \text{ [-]}$, the IFT at under-optimum conditions is approximately equal to the IFT at optimum conditions.

![Figure 6.9: Oil and water solubilization data for surfactant formulation 113/114. Optimum salinity of $C_{opt} = 152000$ ppm corresponds to an optimum solubilization ratio of $Z_{opt} = 18 \text{ [-]}$. At optimum solubilization the IFT according to Eq. 5.1 is $\sigma_{hub, opt} = 9.3 \cdot 10^{-4}$ Dyne/cm.](image)

![Figure 6.10: Sensitivity of over-optimum solubilization parameter on IFT. Input values of surfactant formulation 113/114 (corefloods [2]:[5]) are used: $Z_{opt}=18 \text{ [-]}$, $C_{opt-x,1}=152000$ ppm, $C_{j,2}=124000$ ppm, c=0.3](image)

![Figure 6.11: Sensitivity of under-optimum solubilization parameter on IFT. Input values of surfactant formulation 113/114 (corefloods [2]:[5]) are used: $Z_{opt}=18 \text{ [-]}$, $C_{opt-x,1}=152000$ ppm, $C_{j,2}=124000$ ppm, c=0.3](image)
6.5.4. Salinity data
The effluent salinity is determined by measuring the conductivity of the effluent. In Fig. 6.12 the effluent salinity profile of coreflood [2] to [5] can be observed. In Fig. D.5 the effluent salinity profile of coreflood [1] can be observed. The effluent salinity profile of coreflood [1] corresponds with a different surfactant formulation and different salinity profile. Chemical formulation 113/114 is tested for salinities between 10,000 to 160,000 ppm, aqueous stability was observed during the entire salinity range. A Type III phase behavior was observed from a salinity of 124,000 to 160,000 ppm. The salinity of the entire injection strategy (Table 6.2) falls within this range. This could suggest the presence of a micro-emulsion within the core if a minimum concentration of surfactant is present.

The effluent salinity profiles give an indication of the fluid dispersion within the core (see Section 5.5). As observed in Fig. 6.12 the effluent salinity immediately drops after injection of the chemical slug. Indicating that a change in injection salinity almost immediately affects the effluent salinity. While good macroscopic displacement efficiency is expected during the surfactant-foam corefloods [1] and [2], expecting a sharp transition in salinity as is illustrated in Fig. 5.5, a gradual transition in salinity is observed. This could indicate that the core is heterogeneous and introduces mechanical dispersion as is described in section 5.5. McCool et al. [62] also report a higher dispersive-mixing characteristic in Indiana limestone. Another observation is that the effluent salinity profile drops below the injected slug salinity while the chemical slug is still injected. During coreflood [3] no oil is present. It is expected that the effluent salinity at 0.5 injected liquid PV is a mixture of the waterflood salinity (160,000 ppm) and the slug salinity (152,000 ppm). However, an effluent salinity of 150.000 ppm is measured at 0.4 injected liquid PV. This suggests that the data contains measurement errors.

In section 5.5 a 1D dispersion model is described, including the solution when a double salinity step is applied. This model is used to analyze the effluent salinity data and to determine the analytical effective dispersivity of the porous media. The model does not take into account viscous fingering (macroscopic displacement efficiency) and could overestimate the dispersivity of the core. A tracer can only advect in the movable water phase. Therefore, \( PV_{\text{mov}} = PV - S_{\text{arc}} \). For example: if in a homogeneous medium \( S_{\text{arc}}=0.24 \), the tracer breaks through after \( \approx 0.76 \) injected liquid PV. Note that diffusion can also cause mixing from and into the stagnant phase.

The effective dispersivity is retrieved by plotting the experimental effluent salinity profile and fitting the solution to the 1D advection-dispersion equation (Eq. 5.13) by tuning the effective dispersion coefficient. The one-dimensional analytical matches of surfactant-foam coreflood [2] and surfactant flood [5] are illustrated in Fig. 6.13 and Fig. 6.14. As can be observed in Table 6.3 the dispersivity of surfactant-foam coreflood [2] is lower in comparison with coreflood [3] to [5]. This could be the result of the improved macroscopic displacement efficiency, which reduces viscous fingering and mixing of fluids. More surfactant-foam floods should be performed to confirm this statement, as the used Indiana Limestone cores also differ to a certain extent in their heterogeneity and dispersivity. For the analytical match of the other corefloods see Appendix D.2. The slope of the data gives a reasonable match, with an exception of the timing of the measurements i.e. the injected chemical liquid PV. Several reasons could explain this behavior:

Movable pore volume
A tracer can only move in pore volumes that are available for flow. The tracer breakthrough is dependent on the (residual) oil and gas saturation within the core. While in the analytical solution it assumed that \( PV_{\text{mov}} = 1 - S_{\text{arc}} \), the actual movable pore volume is a function of the desaturation mechanism. When gas is present in the core, this increases the complexity. A numerical model is required to capture a combination of mechanisms, such as a changing movable pore volume and heterogeneities within the core. The numerical solution is discussed in chapter 10.

Measurement errors
The differences can be explained by errors in the measurements, which is supported by the observation that salinities below the injection salinity are measured. These errors can be caused by errors in the conductivity measurements, by the measurement approach with tubes or by the experimental set-up (for example the dead volume). The salinity of the fluid is measured in tubes of 5 ml. To conduct conductivity measurements, sometimes tubes are added together. A maximum measurement error of 10 ml, equal to \( \pm \text{PV} = 0.10 \) to 0.13, is assumed. The maximum expected error per coreflood due to the measurement approach is listed in Table 6.4. The dead volume of the experimental set-up can also introduce an error and is listed in Table 6.4. It is assumed that the dead volume is the maximum error caused by the experimental set-up. The dead volume and measurement error together are an indication of the maximum expected error.
Errors bars are represented in the effluent salinity profile of the surfactant-foam coreflood [2] in Fig. 6.13. When assuming a delay of $\Delta PV=0.25$ in the measurements of coreflood [2], the analytical match improves as is illustrated in Fig. 6.13. The required shift to achieve the best match is $\Delta PV=0.40$. However, this does not agree with the maximum expected error of $\Delta PV=0.25$. This could suggest that the effluent salinity profile is affected by heterogeneities in the core.

**Heterogeneities**

The solution to the 1D advection-dispersion equation results in a symmetrical tracer profile. The experimental salinity profile is not symmetrically shaped, but shows a fast change in salinity with a relatively long tail. This could suggest the presence of high-permeable streaks, which is not captured by a one-dimensional model. In subsection 5.5.2 it is described how the dispersion model applies to a multi-layer system. This description is used to determine the geology of a two-layer model, by analytically matching the effluent salinity data of coreflood [5]. The effluent salinity profile of Surfactant-foam coreflood [2] is numerically matched in chapter 10, as the movable pore volume is unknown due to the presence of oil and gas in the core. A tracer can only move in the movable water phase. Therefore, it is assumed $PV_{mov} = PV - S_{sw}$.

Without dispersion the effluent salinity response is determined by advection. The flow capacity of each layer is described by Eq. 5.19. While both the permeability and thickness of the two layers can be altered, the optimization is limited to the average permeability determined by the experiments (listed in Table 6.2).

Fig. 6.14 shows the 1D analytical match of coreflood [5]. After 0.5 injected liquid PV the injection salinity changes as is listed in Table 6.2. The 1D analytical solution, including dispersion, does not fit within the proposed error range. Fig. 6.15 illustrates a 2D analytical solution of coreflood [5] with a 6 & 10 mD layer of equal thickness. Due to the differences in permeability the effluent salinity profile is shifted towards the left. The analytical solution now fits within the error bars of the experimentally measured salinity. In this example it is assumed that the effluent salinity match is achieved both by introducing heterogeneities, while assuming errors in the measurements. Fig. 6.16 illustrates a 2D analytical solution of coreflood [5] with a 1 & 15 mD layer of equal thickness. In this example it is assumed that the effluent salinity match is mainly determined by heterogeneities within the core.

The scenarios are simulated in chapter 10. If a high permeable thief zone is present, this is reflected in the oil recovery data. The effluent salinity profile and oil recovery data together contribute to the knowledge of the heterogeneities within the core. By combining the interpretation of the modelled effluent salinity data with the modelled oil recovery data, it is determined which contribution to the effluent salinity profile is caused by the heterogeneous medium and/or caused by measurement errors.
# 6. Surfactant-Foam Experimental Study

## Table 6.3: Analytical effective dispersivity and dispersion by fitting the solution to the 1D advection-dispersion equation (Eq. 5.13) with the experimental data.

<table>
<thead>
<tr>
<th>Coreflood</th>
<th>Component</th>
<th>Dispersivity $a_{eff}$ [m]</th>
<th>Dispersion $D_{eff}$ [m$^2$/s]</th>
<th>Peclet nr. $N_{Pe}$ [-]</th>
<th>Darcy velocity $u_x$ [m/s]</th>
</tr>
</thead>
<tbody>
<tr>
<td>[1]</td>
<td>oil, gas, water</td>
<td>0.020</td>
<td>$1.08 \cdot 10^{-7}$</td>
<td>15</td>
<td>$1.39 \cdot 10^{-6}$</td>
</tr>
<tr>
<td>[2]</td>
<td>oil, gas, water</td>
<td>0.012</td>
<td>$6.46 \cdot 10^{-8}$</td>
<td>25</td>
<td>$1.47 \cdot 10^{-6}$</td>
</tr>
<tr>
<td>[3]</td>
<td>water</td>
<td>0.051</td>
<td>$3.58 \cdot 10^{-7}$</td>
<td>6</td>
<td>$1.79 \cdot 10^{-6}$</td>
</tr>
<tr>
<td>[4]</td>
<td>gas, water</td>
<td>0.020</td>
<td>$7.16 \cdot 10^{-8}$</td>
<td>15</td>
<td>$9.06 \cdot 10^{-7}$</td>
</tr>
<tr>
<td>[5]</td>
<td>oil, water</td>
<td>0.038</td>
<td>$3.91 \cdot 10^{-7}$</td>
<td>6</td>
<td>$1.76 \cdot 10^{-6}$</td>
</tr>
</tbody>
</table>

## Table 6.4: Mapping the measurement uncertainties of the effluent salinity profile. *A maximum measurement approach error of 10 ml for all corefloods is assumed. The dead volume defines the maximum experimental set-up error. The error in the measurement approach with tubes and the experimental set-up together define the maximum measurement error.

<table>
<thead>
<tr>
<th>Coreflood</th>
<th>Component</th>
<th>Dead volume $\Delta PV / T_D$ [-]</th>
<th>Tube measurement* $\Delta PV / T_D$ [-]</th>
<th>Maximum PV shift $\Delta PV / T_D$ [-]</th>
</tr>
</thead>
<tbody>
<tr>
<td>[1]</td>
<td>oil, gas, water</td>
<td>0.48</td>
<td>0.11</td>
<td>0.49</td>
</tr>
<tr>
<td>[2]</td>
<td>oil, gas, water</td>
<td>0.15</td>
<td>0.10</td>
<td>0.25</td>
</tr>
<tr>
<td>[3]</td>
<td>water</td>
<td>0.18</td>
<td>0.11</td>
<td>0.29</td>
</tr>
<tr>
<td>[4]</td>
<td>gas, water</td>
<td>0.18</td>
<td>0.11</td>
<td>0.29</td>
</tr>
<tr>
<td>[5]</td>
<td>oil, water</td>
<td>0.25</td>
<td>0.13</td>
<td>0.38</td>
</tr>
</tbody>
</table>

---

Figure 6.12: Effluent salinity profile during chemical injection of coreflood [2], [3], [4] and [5].
6.5. EXPERIMENTAL RESULTS AND INTERPRETATION

Figure 6.13: Retrieving the one-dimensional effective dispersivity of coreflood [2]. $PV_{mov} = 1 - S_{orc} = 0.96$. The maximum shift in experimental data, as listed in Table 6.4, is also indicated.

Figure 6.14: The one-dimensional analytical match of coreflood [5]. $PV_{mov} = 1 - S_{orc} = 0.76$. The homogeneous solution breaks through at 0.76 injected liquid PV and $0.76 + 0.50 = 1.26$ injected liquid PV.
Experimental data coreflood [1] Normalized with salinity gradient

---

Figure 6.15: Improving the analytical match of coreflood [5] by introducing a second layer. In this example the 6 & 10 mD layer are of equal thickness. \( PV_{mov} = 1 - S_{oil} = 0.76. \) The fast layer \( (PV_{mov}=0.38), \) breaks through after \( 0.38/(10/16) = 0.61 \) injected PV and \( 0.61+0.50 = 1.11 \) injected liquid PV. The slow layer breaks through after \( 0.38/(6/16) = 1 \) injected PV and \( 1+0.50 = 1.5 \) injected liquid PV.

---

Figure 6.16: Improving the analytical match of coreflood [5] by introducing a second layer. In this example the 1 & 15 mD layer are of equal thickness. \( PV_{mov} = 1 - S_{oil} = 0.76. \) The fast layer \( (PV_{mov}=0.38), \) breaks through after \( 0.38/(15/16) = 0.41 \) injected PV and \( 0.41+0.50 = 0.91 \) injected liquid PV. The slow layer (1 mD) does not contribute to the salinity profile within the range of injected liquid pore volumes.
Based on the interpretations of the experimental data (chapter 6), the comparative analysis of the foam models (section 4.3) and the described surfactant model (chapter 5) a combined surfactant-foam model is developed. In this chapter the surfactant-foam model is described which will be used as an input for the reservoir simulator. The model is used to history match experimental data. The modelling assumptions, the geological model, PVT-model and the relative permeability model are described. This chapter is concluded with a selection of the foam and surfactant model. The results of the surfactant-foam model are described in chapter 8, chapter 9 and chapter 10.

7.1. **Surfactant-Foam Modelling Assumptions**

The surfactant-foam modelling assumptions are:

1. Foam is in local-equilibrium
2. The water saturation and surfactant concentration determine the texture of the foam
3. 1D: The foam matching parameters are independent of permeability
   2D: The foam matching parameters are dependent of permeability
4. No explicit modelling of micro-emulsion phase
5. 1D: The core plug is isotropic and homogeneous
   2D: The core plug consists of two homogeneous, isotropic layers
6. Capillary pressure is neglected
7. No modelling of geochemistry, such as homogeneous aqueous reactions and ion-exchange reactions with rock minerals
8. No partitioning of surfactant into the oil phase
9. IFT solely dependent on salinity, assuming a minimum surfactant concentration
10. Desaturation parameters are independent of rock or facies type
11. Rock and fluids are incompressible
12. Fluid flow according to the extended version of Darcy’s Law and approximation of the relative permeability with the Corey correlation.
13. The water-oil interfacial cannot increase, after it achieved an ultra-low value (see subsection 8.2.4)
14. The connate water saturation remains constant throughout the water- and chemical flood (see subsection 8.2.4)
7.2. GEOLOGICAL MODEL
The decision to simulate with a one-dimensional or two-dimensional geological model of the core depends on various criteria. For example the heterogeneity of the core, the stability of the fluid displacement or the complexity of the simulations. As is discussed in section 5.5 dispersion is a measure of the heterogeneity of the rock. The effluent salinity data suggests the presence of high-permeable streaks, which cannot be described with a one-dimensional model. Therefore, both one-dimensional and two-dimensional models are analyzed.

7.2.1. ONE-DIMENSIONAL MODEL
A linear one-dimensional (1D) model is defined with 100 gridcells in the z-direction. The grid resolution determines the data accuracy. A finer grid is more accurate in modelling phase behavior and fluid fronts. An optimum grid size is a grid that balances simulation results with run-time and/or computational capabilities. A one-dimensional model assumes that the core plug is isotropic and homogeneous. It cannot capture effects such as channeling and transverse dispersion. It also assumes stable-displacement. Therefore, it cannot capture viscous fingering and gravity override.

7.2.2. TWO-DIMENSIONAL MODEL
The one-dimensional model is extended to a two-dimensional (2D) model to analyze the effect of heterogeneities on the simulation results. For the purpose of this research one high-permeable streak is modelled. A linear two-dimensional model is defined with 100 gridcells in the z-direction and 2 gridcells in the x-direction, as is illustrated in Fig. 7.1. The average permeability of the core has been determined by experiments. An arithmetic average approach is used to determine the permeabilities of the two separate layers. Various combinations of arithmetic averages are analyzed, based on the analytical matches discussed in subsection 6.5.4.

7.3. PVT-MODEL
The Pressure-Volume-Temperature model (PVT) describes the behavior of reservoir fluids, such as the viscosity, density and composition, at surface and reservoir conditions. In these studies the black oil fluid description is applied, expressing the volumetric properties and fluid flow as a function of pressure for both water, oil and gas. It is assumed that no solution gas is present in the liquid phase. The injection compositions in MoReS are defined with mass-fractions, while the injection compositions in the SF-experiments are defined with volume-rates. The reference pressure and temperature in the PVT-model is set at core conditions (see Table 6.2), as this simplifies the translation from mass-fractions to volume-rates.

7.3.1. DENSITY
The change in density with pressure is defined by the compressibility ($c$):

$$c = \frac{1}{\rho} \frac{d\rho}{dP}$$  \hspace{1cm} (7.1)
in which \( \rho \) is the density and \( p \) the pressure. The density of Nitrogen at 1000 psi and at 69°C is 60.46 kg/m\(^3\) (see Table 6.2). As can be seen in Fig. 7.2 the compressibility of Nitrogen changes with pressure. At a back pressure of 1000 psi and a maximum pressure drop over the core of approximately 100 psi, the compressibility remains relatively constant. Therefore, a constant Nitrogen compressibility of \( c_g = 1.1 \cdot 10^{-3} \) 1/psi is defined. The compressibilities of water and oil are derived from literature and are defined as a constant: \( c_w = 6.9 \cdot 10^{-9} \) 1/psi and \( c_o = 6.9 \cdot 10^{-7} \) 1/psi [68].

7.3.2. Viscosity

The oil and water viscosities can be found in Table 6.2. The viscosity of Nitrogen at core conditions is derived from Fig. 7.3: \( \mu_g = 0.0207 \) cP. The supercritical state of Nitrogen does not seem to affect the compressibility and viscosity of nitrogen. It is assumed that the viscosities of oil and water are independent of pressure. The viscosity of the gaseous phase at reference pressure is derived from Fig. 7.3: \( \mu_g = 7.04 \cdot 10^{-4} \) 1/bar. As is described in chapter 3 foam increases the apparent gas viscosity, this is separately addressed by the foam model (see section 7.5). It is assumed that the presence of a micro-emulsion does not influence the viscosity of the aqueous or oleic phase.

Figure 7.2: Compressibility of nitrogen at 69°C. The thermophysical properties are derived from the National Institute of Standards and Technology [65]. The experiments are performed at a back pressure of 1000 psi with a maximum pressure drop over the core of \( \approx 100 \) psi.

Figure 7.3: Viscosity of nitrogen at 69°C. The thermophysical properties are derived from the National Institute of Standards and Technology [65]. The experiments are performed at a back pressure of 1000 psi with a maximum pressure drop over the core of \( \approx 100 \) psi.
7.4. RELATIVE PERMEABILITY MODEL

In multi-phase flow in porous media, the relative permeability is a dimensionless measure of the ability of a phase to flow in the presence of others. Depending on the number of phases that flow, two-phase or three-phase relative permeabilities models are defined.

7.4.1. TWO-PHASE RELATIVE PERMEABILITY

Several models exist that describe the two-phase relative permeability. In this surfactant-flooding model the simplified Corey model is used. The model can describe a gas/oil, gas/water or water/oil system. The Corey correlations are defined as [69]:

\[ k_{r,j} = K_{r,j} (\bar{S}_j)^{n_j} \]  

in which \( k_{r,j} \) is the relative permeability of phase j, \( K_{r,j} \) the endpoint permeability of phase j and \( n_j \) the Corey exponent of phase j with a range from 1 to 6. The value of the Corey-exponent of oil is dependent on the presence of gas or water. The Corey-exponent is an empirical parameter that determines the curvature of the relative permeability curves. The normalized saturation \( \bar{S}_j \) is defined as:

\[ \bar{S}_j = \frac{S_j - S_{j,c}}{1 - S_{wc} - S_r} \]  

in which \( S_j \) is represented by \( S_{orw}, S_{org}, \) or \( S_{gr} \) depending on the two-phase system. With a decrease in interfacial tension, the curvature of the relative permeabilities is reduced. When the displaced and displacing fluids approach miscible conditions i.e. the IFT approaches zero, the curves tend towards a straight line [70]. The fluids do not inhibit each other to flow and the relative permeability is purely a function of saturation. When the interfacial tension between the fluids becomes zero, the fluids flow as one-phase. The concentration of the components can still be prone to incomplete mixing conditions.

7.4.2. THREE-PHASE RELATIVE PERMEABILITY

Experimental data on three-phase relative permeabilities is much rarer in comparison with two-phase relative permeabilities. It is also reported that data on three-phase flow shows more inconsistencies and uncertainties due to the increased complexity [71]. For three-phase flow, the relative permeability is commonly generated using the two-phase relative permeability curves. When assuming oil is the intermediate wetting phase, the relative permeability of the oil is expressed as a function of the saturation. It is assumed that the relative permeability of the water and gas are only a function of their own saturation, regardless of combinations of the other phases. The results can be depicted in a ternary diagram in which the two-phase curves are represented when either the gas or water achieves its residual saturation.

Several models are available that predict the three-phase oil relative permeability. The default model in MoReS generates linear isoperms, connecting the data from the water-oil relative permeability \( k_{r,ow} \) and gas-oil relative permeability \( k_{r,og} \) with straight lines. An advantage of this approach is that the three-phase relative oil permeability has consistent values. A shortcoming is that the linear interpolation is not based on a physical concept. Other benchmark models in the oil-industry are the models proposed by Baker and Stones [71]:

**Baker** The three-phase oil relative permeability of Baker is based on saturation-weighted interpolation between the two-phase relative permeabilities (Eq. 7.2):

\[ k_{ro} = \frac{(S_w - S_{wc}) k_{r,ow} + (S_g - S_{gc}) k_{r,og}}{(S_w - S_{wc}) + (S_g - S_{gc})} \]  

**Stones** The models proposed by Stones assume a water-wet porous medium and are not suited for intermediate wet or oil wet systems [71]. Stones proposed two models, known as StonesI and StonesII, based on a flow channel model of a porous medium. StonesI model incorporates the normalized saturations as defined in Eq. 7.3:

\[ k_{ro} = \frac{\bar{S}_o k_{r,ow} k_{r,og}}{k_{r,j} (1 - \bar{S}_w) (1 - S_g)} \]
In Fig. C.3 a plot of the StonesI model is presented (See Appendix C). In this example there is only a relatively small area where three-phase flow occurs. The StonesII model gave inconsistent results with negative relative permeabilities as is illustrated in Fig. C.4. This confirms that three-phase relative permeabilities is a complex concept that requires awareness and quality checking when used in reservoir simulations. In the presented surfactant-foam model the three-phase relative permeabilities are determined using linear isoperm between the water-oil and gas-oil relative permeabilities, as this approach always delivers a consistent output.

7.5. SELECTION OF FOAM MODEL

Based on the comparative analysis discussed in section 4.3, it is decided that the implicit-texture STARS model (subsection 4.1.1) is the most suitable model to history-match the experimental data. The experimental data is discussed in chapter 6. Only pressure data of the foam flood is available (coreflood [4]), no experimental bulk-foam tests or tests to determine the flowing gas fraction are performed. Therefore, too little information is known to model the foam behavior using a population-balance model. The STARS model allows to model foam flooding, while requiring little input parameters. It also allows for a selection of the dominating functions that affect the texture of the foam. The selection of foam functions is based on the literature and experimental coreflood study.

According to Kapetas et al. [35], the limiting water saturation is correlated with permeability. At a permeability of 6 mD, a limiting water saturation of \( S_w^* = 0.55 \) was observed. While at a permeability of 90 mD, a limiting water saturation of \( S_w^* = 0.34 \) was observed. The lower the permeability, the higher the critical water saturation, i.e. foam collapses at relatively high water saturations. No correlation was found between permeability and the transition abruptness. During these experiments cores with a low permeability \((\approx 10 mD)\) are analyzed. Therefore, \( F_{dry} \) is expected to play an important role.

In the experiments it also observed that the texture of the foam is influenced by the surfactant concentration (discussed in Equation 6.5.2). The drive solution contains a lower surfactant concentration and generates a weaker foam with a lower apparent viscosity. Therefore, \( F_{surf} \) is expected to play an important role. No information is known about the surfactant concentration below which foam collapses, also referred to as the critical surfactant concentration \( (F_{msurf}) \).

During the surfactant-foam corefloods [1] and [2] a total fluid injection volume rate of 11.4 cm\(^3\)/hr and 12 cm\(^3\)/hr is applied. Not enough experiments at different velocities are performed to analyze the shear-thinning behavior of the foam \( (F_{cap}) \). While oil is present in the system, the effect of the oil on the destabilization of foam is unknown \( (F_{oil}) \). The same applies for the effect of the pressure gradient on foam generation \( (F_4) \), the oil-component-dependent function \( (F_5) \) and the effect of salinity on the foam stability \( (F_6) \). Only functions will be included for which data is available to match, to prevent that the model becomes purely a fitting exercise.

As is stated above, it is assumed that during these experiments the water saturation and surfactant concentration are the main drivers of the foam texture. The variables in the STARS model are (see Table 9.2):

1. \( F_{mmob} \). The reference mobility reduction factor of the gas
2. \( F_{surf} \): \( F_{msurf} \) & \( epsurf \). The critical surfactant concentration \( (fmsurf) \) and the transition zone \( (epsurf) \).
3. \( F_{dry} \): \( F_{mdry} \) & \( epdry \). The limiting water saturation \( (fmdry) \) and the transition zone \( (epdry) \).

7.6. SELECTION OF SURFACTANT MODEL

In chapter 5 a two-phase surfactant-flooding model is described. This model will be used in the surfactant-foam model. The dispersivities, calculated in subsection 6.5.4, will be used as an input in the simulation model.
In this chapter the results and interpretation of the one-dimensional model are described. First the results of the separate surfactant and foam models are presented. The results and interpretations of the one-dimensional Surfactant-Foam model are discussed in chapter 9. The Surfactant-Foam model described in chapter 7, is programmed into the in-house reservoir simulator MoReS (version 2014.1.0), to evaluate the performance of the used algorithms. Furthermore, simulations provide insight in understanding the experimental observations.

Experimental data of five corefloods with different objectives are available (see subsection 6.3.3). Their common objective is to understand the processes during surfactant-foam flooding. To gain insight in the implemented combined model, the simulations are performed and interpreted in the following order:

1. Water flooding, section 8.1 [coreflood 1, 2 and 5]
2. Surfactant flooding, section 8.2 [coreflood 5]
3. Foam flooding, section 8.3 [coreflood 4]
4. Surfactant-foam flooding, chapter 9 [coreflood 1 and 2]

The Surfactant-Foam model parameters are listed in Table 9.2. The rock, fluid and injection properties are listed in Table 6.2. The chemical flood and water flood are injected with different flow rates. Therefore, a sudden change in pressure is observed at the start of the chemical flood. It is chosen to depict the cumulative oil recovery, oil cut and pressure drop as a function of injected liquid PV, as the liquid volume stays constant with fluctuating pressures. The injected liquid PV starts with a water flood, followed by a chemical slug (0.5 injected liquid PV) and a drive solution.
8.1. WATER FLOODING
Before the chemical flood, the core is waterflooded until no (emulsified) oil is observed in the effluent. The waterflood is history matched to retrieve the input parameters of the Corey relative permeability model. The waterflood furthermore represents the starting point of the chemical flood. Pressure data and the residual oil saturation are available. The relative permeability (Eq. 7.2) is a measure of the ability of a phase to flow in the presence of others and determines the total relative mobility. The relationship between the pressure drop and total relative mobility is given by Eq. 6.2. The corefloods with single-phase flow (no oil, [3] and [4]) will not be discussed, as relative permeability models only apply to multi-phase flow.

8.1.1. HISTORY MATCH OF WATER FLOOD
Fig. D.6 in section D.3 explains how pressure data of the waterflood can be history matched with the Corey relative permeability model. The end-point permeability of oil \( (K_{ro}) \) and the connate water saturation \( (S_{wc}) \) determine the initial pressure. If the core is waterflooded until no oil is observed in the effluent, the pressure is determined by the end-point relative permeability of water \( (K_{rw}) \) and the residual oil saturation \( (S_{orw}) \). The Corey-exponents \( (n_{ow} \text{ and } n_{w}) \) determine the slope of the curves.

According to literature (Goda et al. [72]) Corey-exponents below two are unlikely during waterflooding. For this reason, the Corey exponents are bound from below by 2.0 during the history match. While the end-point permeabilities have been determined experimentally, an accurate fractional flow measurement has not been performed. Therefore, endpoint permeabilities can be optimized during the history match. The initial oil saturation is used to determine the connate water saturation. In low-permeable i.e. tight reservoirs, the connate water saturation can reach values up to 60% [35], due to the strong capillary forces that trap the water. During the experiments the core is saturated with oil until no water is observed in the effluent. The (maximum) connate water saturation can be represented by \( 1 - S_{oi} \). The oil saturation after waterflooding has been determined experimentally via a mass balance equation and will remain unchanged throughout the history match.

The Corey parameters determined from history matching the waterfloods are listed in Table 9.2. The determined endpoint water relative permeability ranges from \( K_{rw} = 0.12 \) to \( 0.18 \), the endpoint oil relative permeability ranges from \( K_{ro} = 0.69 \) to \( 0.86 \), the Corey water exponent ranges from \( N_{w} = 2.1 \) to \( 3.4 \) and the Corey oil exponent ranges from \( N_{o} = 2 \) to \( 2.1 \).

**History match coreflood [1]** The history match of the waterflood of coreflood [1] can be observed in Fig. 8.2. To match the initial pressure, the experimentally determined end point relative permeability (see Table 6.2) of the oil phase is increased from 0.68 to 0.86 [-]. This indicates that the oil phase flows more easily than determined, resulting in a decrease in the pressure drop. When the connate water saturation is decreased, the pressure drop increases. This is due to the shift of the oil relative permeability curve, in which the end points are defined at the connate water and residual oil saturation. However, the connate water saturation already achieved its maximum value \( (1 - S_{oi} = 0.55) \) and cannot be used to decrease the pressure drop. In Fig. 8.1 the simulated saturations and total mobility along the core at 0.11 injected liquid PV are shown. The total fluid mobility achieves a minimum in the core. Therefore, the pressure drop across the core first increases followed by a decrease (see subsection 6.5.2).

**History match coreflood [2]** The history match of the waterflood of coreflood [2] can be observed in Fig. 8.3. The experimental determined end-points give a relatively good match with the initial and final state of the pressure data. Solely the relative end point permeability of the water phase is increased from 0.16 to 0.18 [-], which indicates that the water flows more easily than determined. The determined connate water saturation is equal to \( 1 - S_{oi} = 0.59 \).

**History match coreflood [5]** The history match of the waterflood of coreflood [5] can be observed in Fig. 8.4. The best match is retrieved by increasing the experimentally determined end-point oil relative permeability from 0.57 to 0.87 [-]. This indicates that the oil phase flows more easily than experimentally determined. The endpoint water relative permeability is decreased from 0.13 to 0.12 [-]. The connate water saturation is \( S_{wc} = 0.27 [-] \). The connate water saturation of coreflood [5] is lower in comparison with coreflood [1] and [2], as a different oil saturation technique is applied.
8.1. WATER FLOODING

Figure 8.1: Saturations and total mobility along the core during simulations of coreflood [5] at 0.11 injected liquid PV. The total fluid mobility achieves a minimum in the core. Therefore, the pressure drop across the core first increases followed by a decrease.

Figure 8.2: History match of pressure drop during waterflood of coreflood [1]. Pore volumes injected during waterflood: 1.53 PV. Final history match of coreflood [1]: $N_w=2.2$, $N_o=2$, $S_{wc}=0.55$, $S_{io}=0.45$, $S_{orw}=0.24$, $K_{rwc}=0.145$, $K_{roe,w}=0.86$. 
Figure 8.3: History match of pressure drop during waterflood of coreflood [2]. Pore volumes injected during waterflood: 1.48 PV. History match of coreflood [2]: $N_w=3.4$, $N_o=2$, $S_{wc}=0.59$, $S_{ig}=0.41$, $S_{orw}=0.22$, $K_{rw}=0.18$, $K_{ro}=0.69$.

Figure 8.4: History match of pressure drop during waterflood of coreflood [5]. Pore volumes injected during waterflood: 1.86 PV. Final history match of coreflood [5]: $N_w=2.1$, $N_o=2.0$, $S_{wc}=0.27$, $S_{ig}=0.62$, $S_{orw}=0.33$, $K_{rw}=0.115$, $K_{ro}=0.85$. 
8.2. SURFACTANT FLOODING
The desaturation model addresses the microscopic displacement efficiency and reduces the residual oil saturation. The surfactant model described in chapter 5 will be used to history match surfactant coreflood [5]. Both pressure data as well as oil recovery data is available. As a one-dimensional model is analyzed, characteristics of unstable-displacement such as viscous fingering cannot be captured. In this section the modelled salt dispersion, desaturation mechanism, history match and limitations of the surfactant model are discussed.

8.2.1. SALT DISPERSION
It is important to capture the dispersion of salt, as the modelled interfacial tension is a function of a salinity. In section 5.5 a 1D dispersion model is discussed, which is used to analytically determine the salt dispersion within the cores (explained in subsection 6.5.4). The dispersivity values are listed in Table 6.3. A poor match between the analytical and experimental effluent salinity profile was observed. This is explained by measurement errors, heterogeneities within the core and/or the assumption of a constant movable pore volume. The 1D surfactant-foam model assumes that a maximum error in the effluent salinity data is present, without assuming the presence of heterogeneities. In chapter 10 the results are compared with a two-dimensional model, including the presence of heterogeneities.

The 1D numerically modelled effluent salinity data of coreflood [5], is compared with the 1D analytical solution. The comparison is illustrated in Fig. 8.5. The analytically determined dispersivity value of coreflood [5], $D_{eff} = 0.038$ metres, and the lowest dispersivity value of coreflood [2], $D_{eff} = 0.012$ metres, are used as an input in the numerical simulation model. As expected, the analytically determined dispersivity value of coreflood [5] gives the best match. A small discrepancy ($\approx 0.025$ injected liquid PV) between the analytical and numerical solution is observed. This could be caused by the assumption of the analytical solution that the movable pore volume is constant ($PV_{mov} = PV - S_{arc}$). It could also be caused by numerical diffusion introduced by the simulator.

![Comparison of the analytical solution with the numerically modelled tracer dispersion.](image)

8.2.2. DESATURATION MECHANISM
The surfactant model described in chapter 5 is implemented in MoReS. Fig. 8.6 illustrates how the model works in a profile of the core. The interfacial tension drops to an ultra-low value when the optimum salinity of 152.000 ppm is achieved. The interfacial tension above and below the optimum salinity is determined by the solubilization ratio as described in Eq. 5.2 and Eq. 5.3. When the water-oil interfacial tension decreases, the capillary number increases as described by Eq. 1.1. When the capillary number increases, the mobility of
the oil and water phase increases due to the capillary number dependent relative permeability curves. During the simulations of the surfactant model, numerical instabilities occurred. These instabilities were solved by changing numerical settings as described in section E.3.

**Figure 8.6:** Illustration of how the desaturation mechanism works in MoReS.

### 8.2.3. History Match Surfactant Flood

A waterflood match of coreflood [5] is described in subsection 8.1.1. As is illustrated in Fig. 8.7 and Fig. 8.8, a best match in pressure drop and oil recovery was achieved by maintaining \( K_{rw} = 0.12 \) (similar to the non-chemical endpoint of water). The breakthrough of the oil bank shows a proper match at \( \approx 2.25 \) injected liquid PV. A profile through the core can be observed in Fig. 8.9. When introducing surfactant dispersion, the oil bank shows an earlier break through and the oil cut is smoothed due to the gradual change in concentration.

As little change in pressure is observed in the experimental data, the chemical parameters during a one-dimensional simulation should not achieve their optimum values at optimum salinity. A low chemical water end-point relative permeability models more resistance to flow and gives a better match with the experimental data. It is questioned if this is physically a correct approach, as the end-point relative permeabilities of both water and oil increase at a lowered water-oil interfacial tension. As described in section 6.1, Guo et al. [3] observe viscous fingering in core sections during their surfactant flood, suggesting that the chemical parameters can achieve good microscopic displacement efficiency, but only in certain parts of the core (poor macroscopic displacement efficiency). This confirms why a low \( K_{rw} \) results in a good match, as the mobilization of residual oil is averaged over the core. A two-dimensional model is able capture the viscous fingers and would be physically sounder to match a surfactant-flood.

During surfactant-foam flooding the foam provides mobility control and a relatively stable-displacement is expected. This is confirmed by the high cumulative oil recovery (\( \approx 80\% \)) in comparison with the recovery during surfactant flooding (\( \approx 28\% \)). Therefore, its more physical sound to model the surfactant-foam flood with a one-dimensional model.
8.2. Surfactant Flooding

Figure 8.7: History match of oil recovery and oil cut with or without surfactant dispersion. Dispersion has a negligible impact on the cumulative oil recovery profile. Therefore, no distinction is made between the oil recovery with or without dispersion. Chemical flood starts at 1.86 injected liquid PV. Chemical Corey parameters: $N_w=2$, $N_o=1.2$, $S_{wc}=0.15$, $S_{or_w}=0.24$, $K_{rw}=0.12$, $K_{ro}=1$. Dispersivity surfactant = 0 or 0.012 m, salinity = 0.038 m.

Figure 8.8: History match of pressure drop. The chemical flood starts at 1.86 injected liquid PV. The change in chemical endpoint permeability does not affect the waterflood i.e. the graphs are equal during the waterflood. Chemical Corey parameters: $N_w=2$, $N_o=1.2$, $S_{wc}=0.15$, $S_{or_w}=0.24$, $K_{rw}=0.12$ or 0.6, $K_{ro}=1$. Dispersivity surfactant = 0.012 m, salinity = 0.038 m.
8.2.4. **Reversibility in desaturation curves**

The desaturation model generates capillary number dependent relative permeability curves. At high capillary numbers (Eq. 1.1) the model uses the Corey parameters at chemical-flood conditions. During desaturation, the residual oil saturation decreases and the relative oil and water permeabilities increase. During a salinity gradient, the capillary number first increases (towards optimum-salinity) after which it decreases again (under-optimum salinity). Hence, the model shifts towards a different relative permeability curve. However, as is illustrated in Fig. 8.10 the end-point relative permeability of a lower capillary number curve is defined at a lower water saturation. Therefore, nonphysical values of the relative permeability are modelled, as the prevailing saturation exceeds the defined end-point saturation as is illustrated in Fig. 8.11. At a constant water saturation of 0.96 [-] and increasing IFT, the water relative permeability increases from 0.2 [-] until 0.85 [-]. Therefore, reversibility in relative permeability curves during chemical-flooding is not physically grounded.

The correct approach to model a salinity gradient, i.e. reversibility in relative permeability curves, requires more research as current models are not able to capture this physical behavior. In this research it is assumed that no reversibility in relative permeability curves can take place, the interfacial tension cannot increase after it reached a minimum. This limitation is captured in the desaturation mechanism by stating that the under-optimum solubilization ratio, described in the interfacial tension model (section 5.3), will not affect the modelling results.
8.2. SURFACTANT FLOODING

Figure 8.10: Limitations of desaturation model: when the interfacial tension increases due to the applied salinity gradient, nonphysical values of the relative permeability are taken as the prevailing saturation exceeds the defined end-point saturation. In this example:

- $S_{wc}=0.15$, $S_{wc,c}=0.05$, $S_{or,wc}=0.33$, $S_{or,wc,c}=0.05$, $K_{rw}=0.1$, $K_{rw,c}=0.4$, $K_{ro}=0.57$, $K_{ro,c}=1$.

Figure 8.11: At a constant water saturation of 0.96 [-] and increasing IFT, the water relative permeability increases from 0.2 [-] until 0.85 [-]. This is due to the limitation of the model, which takes nonphysical relative permeability values.
8.3. FOAM FLOODING WITHOUT OIL
The foam model addresses the macroscopic displacement efficiency and reduces the gas mobility. Foam coreflood [4] does not contain oil and is history matched to determine the foam model parameters. Furthermore, an illustration of the foam mechanism, the sensitivity of the connate water saturation, surfactant adsorption and surfactant dispersion on the foam strength are discussed. During these simulations the de-saturation model is not included, as no oil is present in the core.

8.3.1. FOAM MECHANISM
The foam model described in subsection 4.1.1 is implemented in MoReS. Fig. 8.12 illustrates how the model works. The surfactant front together with the gas generates foam, modelled as an increase in gas viscosity by Eq. 4.2. The foam reduces the total mobility in the core and therefore an increase in pressure drop is observed. Due to the reduced total mobility of the gas, the gas saturation increases. When the surfactant concentration decreases from 10000 ppm to 1000 ppm, the gas viscosity decreases as a weaker foam is generated by the surfactant function ($F_{surf}$). Due to the improved total mobility of the gas, the gas saturation decreases.

![Figure 8.12: Illustration of how the foam mechanism works in MoReS at 0.065 injected liquid PV.](image)

8.3.2. HISTORY MATCH OF FOAM FLOOD
The selection of the foam model and associated parameters can be found in section 7.5. The generation of foam during the chemical slug is matched by incorporating the dry-out function (Fdry) and the reference mobility reduction factor (Fmmob). Table 9.2 lists the dry-out and Corey gas parameters obtained from literature. $F_{mmob}$ is used as parameter to history match the foam texture during the chemical flood. Fig. 8.13 shows the history matched results for various values of $F_{mmob}$ and $epsurf$. The best match is obtained with $F_{mmob} = 4 \times 10^3 \text{ [-]}$ and $epsurf = 4 \text{ [-]}$. In the one-dimensional model the matching parameters are independent of the permeability.

In this research the effect of foam on the gas mobility is captured by modification of the gas viscosity. The pressure match is achieved by reducing the gas viscosity with 115 times during the chemical slug ($\mu_{foam} = 2.5 \text{ mPa} \cdot \text{s}$) and by reducing the gas viscosity with 55 times during the drive solution ($\mu_{foam} = 1.1 \text{ mPa} \cdot \text{s}$). The modelled gas viscosities of the foam match in the absence of oil, can be used as a guideline during the surfactant-foam history match. Provided that the Corey gas parameters remain constant (i.e. the definition of the initial gas mobility).

The effect of the surfactant concentration ($F_{surf}$) on the foam texture becomes visible at the start of the...
drive solution, when the surfactant concentration is lowered. The limiting capillary pressure decreases at lower surfactant concentrations, causing foam to collapse. The critical surfactant concentration \( f_{\text{msurf}} \) at which the foam starts to collapse, is set lower than the injected surfactant concentration during the chemical slug. No information is known about the real value of the critical surfactant concentration. Therefore, the influence of the surfactant concentration on the foam texture can be matched by both tuning the critical surfactant concentration and the transition zone. To understand the effect of the parameters defining the foam surfactant function \( F_{\text{surf}} \) (Eq. 4.4), \( F_{\text{surf}} \) is plotted against a dispersed surfactant profile. If a change in surfactant concentration is a step function (i.e. no dispersion), only the final value of \( F_{\text{surf}} \) influences the foam texture. If the surfactant concentration is dispersed, as is illustrated in Fig. D.7, \( \varepsilon_{\text{surf}} \) determines the slope of the transition, while \( f_{\text{msurf}} \) determines the concentration at which \( F_{\text{surf}} \) starts to play a role. If the surfactant concentration reaches a steady state, the final value of \( F_{\text{surf}} \) influences the foam texture.

**Dynamic behavior**  The STARS foam model was successful in modelling the pressure trend during the chemical slug, as illustrated in Fig. 8.15, with an exception of the steep slope observed during injection of the drive solution. At the start of the drive solution the surfactant concentration is lowered with a factor ten, resulting in weaker foam as discussed in Equation 6.5.2. The decrease in pressure drop during injection of the drive solution does not show a linear trend, indicating that the velocity at which foam (partly) coalesces changes. It is assumed that the foam is in a dynamic state and collapses in front of the injected drive solution. A possibility is that this is caused by the reduced pressure drop which affect the stability of the lamellae through the entire core, resulting in a domino effect. The exact cause is unknown and more corefloods should be performed to research this behavior.

The STARS local-equilibrium model assumes the foam texture is in dynamic balance, i.e. it obtains its texture instantaneously. Therefore, it is not able to match the dynamic behavior. It is investigated if surfactant adsorption and dispersion can improve the history match. As the pressure gradient of the surfactant-foam flood is dominated both by the generation of foam and mobilization of residual oil, it is unknown if and to what extent dynamic modelling of foam is required.

### 8.3.3. Sensitivity connate water saturation

The connate water saturation determines at which water saturation the end-point relative permeability of oil is defined. The water saturation in the model will always be higher or equal to the defined connate water saturation. Therefore, the defined connate water saturation also affects the foam model, as the dry-out function \( F_{\text{dry}} \) defines a critical water saturation below which foam collapses.

A sensitivity analysis has been performed to analyze the effect of the connate water saturation on the foam strength. All others parameters are kept constant. In Fig. 8.15 and Fig. 8.14 it can be observed that a stronger foam is generated at a higher connate water saturation, due to a bigger impact of \( F_{\text{dry}} \) on the mobility reduction factor (\( FM \)). A connate water saturation of \( S_{\text{wc}} = 0.15 \) results in a maximum pressure drop of \( \approx 15 \) psi and \( F_{\text{dry}} = 2.9 \cdot 10^{-5} \text{[-]} \). A connate water saturation of \( S_{\text{wc}} = 0.35 \) results in a maximum pressure drop of \( \approx 25 \) psi and \( F_{\text{dry}} = 7.7 \cdot 10^{-3} \text{[-]} \). A connate water saturation of \( S_{\text{wc}} = 0.55 \) results in a maximum pressure drop of \( \approx 165 \) psi and \( F_{\text{dry}} = 9.4 \cdot 10^{-1} \text{[-]} \). As described by Eq. 4.2, a larger \( F_{\text{dry}} \) models a higher apparent foam viscosity. The corefloods in this research all have a different connate water saturation, which indicates that the determined foam model parameters of coreflood [4] are not suitable to match the other corefloods.

During coreflood [4] the connate water saturation is unknown, as the entire core is saturated with water. As is discussed the connate water saturation has a big impact on the history match of the foam. The lowest connate water saturation determined during these experiments is 0.27 [-] and the largest 0.59 [-]. In coreflood [4] a connate water saturation of 0.35 [-] is assumed, which agrees with literature [63].

### 8.3.4. Sensitivity surfactant adsorption

It is researched if surfactant adsorption can improve the history match of the foam flood. As no experimental data on surfactant production is available, a qualitative study is performed on the effect of adsorption on the development of the foam strength. It is assumed that the adsorption is irreversible. During the chemical slug and drive solution, respectively 10000 ppm and 1000 ppm of surfactant concentration is injected. The rock first contacts with the chemical slug and therefore it is assumed that only loss of surfactant during the chemical slug will take place. It is assumed that 25 mg of surfactant is adsorbed per 100 grams of rock [73], the weight of the core is 700 grams, 100 grams of fluid is present within the pores and the weight percentage of the injected surfactant is 1 %; the adsorbed concentration percentage of surfactants is \( \approx 17\% \). This indicates that
1700 ppm of surfactant is adsorbed on the rock when injecting 10000 ppm. An adsorption model is described in section 5.6. It is assumed that the maximum surfactant adsorption $a_{\text{max}}=1700$ ppm. Furthermore, it is assumed that the slope of adsorption remains constant and is equal to $a_{\text{slope}}=100000$ ppm.

The sensitivity of the surfactant adsorption on the pressure profile can be observed in Fig. 8.16. Adsorption will both retard the surfactant front and reduces the amount of surfactant that is available to generate foam. In the model with adsorption, less foam is generated during the drive solution. A lower increase in pressure drop is observed in comparison with the model without adsorption. At the start of the drive solution the surfactant front with adsorption has travelled less far in comparison with the surfactant front without adsorption due to the retardation, as is illustrated in Fig. 8.17. In this example an adsorption of 1000 ppm, retards the front with $\approx 12$ cm. Therefore, the pressure drop continues to increase during injection of the drive solution, until foam has been generated throughout the entire core. As is shown in Fig. 8.16 the pressure drop during the experiment decreases immediately during injection of the drive solution. Therefore, adsorption decreases the quality of the history match, at it retards the surfactant front and fails to capture the sudden decrease in pressure drop.

8.3.5. Sensitivity Surfactant Dispersion

It is researched if surfactant dispersion can improve the history match of the foam flood. As no experimental data on surfactant production is available, a qualitative study is performed on the effect of dispersion on the development of the foam strength. Due to the high prevailing salinity and the use of a non-pure surfactant cocktail, current methods such as titration and high performance liquid chromatography (HPLC) are not able to measure the surfactant production. However, effluent salinity data is available and it is assumed that physically the surfactant and salt travel through the same pores and throats. Therefore, it is assumed that the dispersion of surfactant is equal to the dispersion of salt.

Foam generation is a function of surfactant concentration. As can be seen in Fig. 8.18, dispersion smoothens the transition in foam quality, as it gradually changes to the injected surfactant concentration. In this example a surfactant dispersivity of 0.038 m delays the generation of a steady-state foam with $\approx 0.7$ injected liquid PV. Dispersion decreases the quality of the history match, as it disperses the foam front. Therefore, it fails to capture the sudden decrease in pressure drop.

Surfactant adsorption and dispersion did not improve the history match of the foam flood. This suggests that a dynamic-texture foam model is required to model the transient behavior of the foam.
Figure 8.13: Match of foam for different numbers of fmmob and epsurf. The chemical flood starts at 2.43 injected liquid PV. \( F_{\text{msurf}} = 2000 \text{ PPM}, S_{wC} = 0.35 \) and no surfactant dispersion/adsorption is assumed. For constant foam parameters see Table 9.2.

Figure 8.14: Dry-out function \( (F_{d,y}) \) and water saturation \( (S_w) \) plotted along the core for various connate water saturations at 2.93 injected liquid PV (end of chemical slug).
Figure 8.15: Sensitivity of connate water saturation on foam strength. The chemical flood starts at 2.43 injected liquid PV. For constant foam parameters see Table 9.2.

Figure 8.16: The effect of surfactant adsorption on the pressure profile. The chemical flood starts at 2.43 injected liquid PV. No surfactant dispersion is assumed. For constant foam parameters see Table 9.2. The chemical flood and the injection of gas starts at 2.43 injected liquid PV.
8.3. Foam flooding without oil

Figure 8.17: Location of the foam front at the start of the drive solution for a model with and without surfactant adsorption (at 0.5 chemical injected liquid PV). The foam front with surfactant adsorption has traveled less far due to the reduced amount of surfactant available to generate foam.

Figure 8.18: The effect of surfactant dispersion on the pressure profile. The chemical flood starts at 2.43 injected liquid PV. No surfactant adsorption is assumed. The chemical flood and the injection of gas starts at 2.43 injected liquid PV.
8.4. Foam Flooding with Oil

It is studied how the results and matches discussed in section 8.3 will change if oil is present in the core. The desaturation and interfacial tension model are not included. Solely the effect of mobility control by the foam is modelled and compared with gas flooding. These simulations are conceptual, no experimental data is available to match the simulations. The surfactant formulation during the experiments both reduce the interfacial tension and generate foam. The input parameters can be seen in Table 8.1 and are based on data and history matches of coreflood [2] and [4].

Fig. 9.12 depicts a profile of the core at 0.065 injected liquid PV showing the saturations and total mobility. The total mobility changes at three locations. The first change in total mobility is caused by the presence of gas, this is also referred to as free gas. While gas and surfactant are co-injected, the gas moves faster than the surfactant front. Without surfactant no foam is generated. Thereafter, the mobility changes due to a region of increased oil saturation, referred to as an oil bank. During the waterflood the core has been flooded until the residual oil saturation to water. However, the residual oil saturation to gas is lower as is illustrated in Fig. 9.3. Fig. 9.5 illustrates the difference in cumulative oil recovery and oil cut between foam- and gas flooding. The presence of foam reduces the gas mobility and increases the gas saturation ($S_g = 0.27$). The higher the gas saturation, the lower the residual oil saturation as is illustrated in Fig. 9.3. Fig. 9.11 shows that during gas injection, the gas has a relatively low gas saturation ($S_g = 0.07$) due to the high gas mobility. Therefore, only little oil is mobilized. Foam flooding will both improve the macroscopic displacement efficiency as well as the microscopic displacement efficiency, due to mobility control and mobilization of residual oil by gas. In Fig. 9.6 the change in pressure drops can be observed. The generation of foam reduces the total mobility and increases the pressure drop. At 2.93 injected liquid PV a reduce in pressure drop is observed, when a weaker foam is generated in-situ. The pressure drop during the gas flood immediately drops as no foam is generated and a negligible amount of oil is mobilized.

<table>
<thead>
<tr>
<th>Parameters for foam flooding with oil</th>
<th>Symbol</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial oil saturation</td>
<td>$S_{io}$</td>
<td>–</td>
<td>0.50</td>
</tr>
<tr>
<td>Residual oil saturation, after waterflood</td>
<td>$S_{orw}$</td>
<td>–</td>
<td>0.33</td>
</tr>
<tr>
<td>Endpoint relative oil permeability</td>
<td>$K_{ro}$</td>
<td>–</td>
<td>0.69</td>
</tr>
<tr>
<td>Endpoint relative water permeability</td>
<td>$K_{rw}$</td>
<td>–</td>
<td>0.18</td>
</tr>
<tr>
<td>Connate water saturation</td>
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<td>–</td>
<td>0.35</td>
</tr>
<tr>
<td>Corey oil exponent (oil-water)</td>
<td>$n_{ow}$</td>
<td>–</td>
<td>2</td>
</tr>
<tr>
<td>Corey water exponent</td>
<td>$n_{w}$</td>
<td>–</td>
<td>3.2</td>
</tr>
</tbody>
</table>

Table 8.1: Model set-up for foam flooding with oil (no experimental data available). For input parameters of foam model and surfactant model, see Table 9.2.
ONE-DIMENSIONAL RESULTS: SURFACTANT-FOAM FLOODING

The foam model and surfactant model are combined to a Surfactant-Foam model. In this chapter the results and interpretation of the one-dimensional Surfactant-Foam model are described. During surfactant-foam flooding three phases are present. It is first analyzed how the desaturation model performs with a three-phase system.

9.1. DESATURATION MODEL WITH THREE-PHASE SYSTEM

The desaturation model addresses the lowered interfacial tension between the oil-water phase. The foam model captures the lowered interfacial-tension between the gas-water phase. Therefore, the desaturation model only addresses the input parameters of the oil and water phase of the Corey relative permeability model. The Corey gas parameters remain unaffected.

9.1.1. GAS RELATIVE PERMEABILITY

While the Corey gas parameters remain unaffected, the gas end-point relative permeability is defined at

$$S^\text{max}_g = 1 - S_{wc} - S_{gr}.$$  

As the connate water saturation decreases during desaturation, the gas relative permeability is indirectly affected by the desaturation model as is illustrated in Fig. 9.1. Higher capillary numbers reduce the gas relative permeability. A reduced gas relative permeability, reduces the mobility of the gas. As a consequence a stronger foam is simulated when an ultra-low interfacial tension is present. Therefore, the gas relative permeability is both affected by the foam- and desaturation mechanisms. However, as is described in chapter 4, the effect of foam can also be captured by modifying the apparent gas viscosity.

When coupling the desaturation model with the foam model, above interpretation is confirmed as is illustrated in Fig. 9.2. The relative permeability curves are traced for one gridcell of the foam- and surfactant-foam model. A different gas relative permeability curve is taken when including the desaturation model, with the end-point defined at the chemical connate water saturation $S_{wc,c}=0.15$. When the desaturation model is excluded, the gas end-point permeability is defined at the non-chemical connate water saturation $S_{wc}=0.59$. The desaturation model is a function of salinity. If the salinity gradient is modelled as a step function i.e. without salt dispersion, the high capillary number relative permeability curve is immediately followed. If dispersion of salt is modelled, a gradual change in relative permeability curve is made due to a gradual change in IFT and capillary number, as is illustrated in Fig. 9.2.

A change in gas relative permeability may conflict with the foam model. The gas relative permeability curves remain consistent if the connate water saturation remains unchanged. However, the connate water saturation also affects the foam strength as is described in subsection 8.3.3. In both approaches the chemical connate water saturation affects the gas mobility: either by reducing the gas relative permeability, or by minimizing the impact of the limiting capillary pressure. Both approaches will be modelled and analyzed. The (chemical) connate water saturation also determines the end-point of the oil and water relative permeability and affects the mobility of oil and water in a three-phase system.
9.1.2. **OIL AND WATER RELATIVE PERMEABILITY**

The desaturation model addresses the input parameters of the oil and water phase of the Corey relative permeability model as is discussed in section 5.4. The three-phase relative oil permeability at high capillary number (i.e. ultra-low interfacial tension) is shown in Fig. 9.4. In this example oil is mobile through the entire region and water can also efficiently displace the oil without leaving an oil residual behind. The linear isoperms are more tilted in comparison with the isoperms of the foam model without desaturation, as is illustrated in Fig. 9.3. This indicates that if the water saturation increases, the residual oil saturation decreases i.e. oil is more mobile to water than gas. This is in contrast with the interpretation of the foam model that excludes the interfacial-tension model, in which oil is more mobile to gas than water (see section 8.4). The desaturation model only applies to the oil and water input parameters of the Corey relative permeability model. During desaturation due to a lowered water-oil interfacial tension, this results in a transition from oil which is more mobile to gas, to oil which is more mobile to water.

![Figure 9.1: Oil-gas relative permeability model.](image1)

![Figure 9.2: The relative permeability curves traced for one gridcell in the model. As can be observed a different gas relative permeability curve is taken when the desaturation model is included.](image2)
9.2. SURFACTANT-FOAM MODEL WITH INCONSISTENT GAS RELPERM CURVES

In section 8.4 foam flooding is analyzed and compared with gas flooding, without achieving an ultra-low interfacial tension. Now the interfacial tension and desaturation model are included. It is assumed that the chemical connate water saturation is zero ($S_{wc,c} = 0$). A consequence of this approach is that it causes inconsistent gas relative permeability curves. The same model description is used as the foam matches in the presence oil (Table 8.1). No experimental data is available to match the simulations. After interpretation of this data, the experimental surfactant-foam coreflood is matched and interpreted. The models are analyzed by comparing the following mechanisms:

- Gas flooding (Fig. 9.11)
- Surfactant-Gas flooding, at inconsistent $S_{wc}$ (Fig. 9.13)
- Foam flooding (Fig. 9.12)
- Surfactant-Foam flooding, at inconsistent $S_{wc}$ (Fig. 9.14)

When comparing gas flooding with surfactant-gas flooding at 0.065 injected liquid PV, it can be observed that during gas flooding no oil bank is generated. The ultra-low interfacial tension in combination with the presence of gas does result in a propagating oil bank. Due to the high mobility of the gas, the gas saturation is low ($S_g = 0.07$). Therefore, little oil is mobilized due to the presence of gas. When surfactant is present, the mobilization of oil is dominated by the ultra-low interfacial tension. Only little oil is mobilized due to the presence of gas.

When comparing foam flooding with surfactant-foam flooding at 0.065 injected liquid PV, it can be observed that a larger oil bank with higher oil saturation is generated in the surfactant-foam model. The surfactant mobilizes residual oil due to the lowered water-oil interfacial tension. It can also be observed that foam reduces the total mobility, but when including the desaturation mechanism the total mobility increases despite the presence of foam. The total mobility consists of the summation of the separate phase mobilities, as explained subsection 6.5.2. In this example the sum of the phase mobilities increases despite the reduction of the gas mobility.

In Fig. 9.5 and Fig. 9.6 the cumulative oil recovery, oil cut and pressure drop during the waterflood, chemical slug (0.5 injected liquid PV) and drive solution can be observed for the mechanisms listed above. The interpretation of the graphs for the gas and foam flood are already discussed in section 8.4. Notable is that the surfactant-foam flood shows the fastest increase in cumulative oil recovery, but is overtaken by the surfactant-gas flood at 3.0 injected liquid PV. Both floods are discussed separately:

**Surfactant-Foam flood**  The cumulative oil recovery of the surfactant-foam flood steeply increases until 2.9 injected liquid PV, after which the foam bank breaks through. The breakthrough of the foam bank marks the end of the oil bank. Therefore, a lower oil cut is observed. During the drive solution at 2.93 injected liquid PV a lower surfactant concentration is injected, resulting in the generation of a weaker foam. The weaker foam changes the saturation profile by increasing the water saturation and decreasing the gas saturation. As is illustrated in Fig. 9.4 the oil saturation decreases due to the increase in water saturation (only applies at high capillary numbers). Therefore, at 3.5 injected liquid PV the slope of the cumulative oil recovery increases again. The pressure initially increases and decreases at the breakthrough of the oil bank. Foam decreases the gas mobility, but is not strong enough to decrease the total mobility due to an increase in oil and water mobility.

**Surfactant-Gas flood**  Due to the high mobility of gas and rock heterogeneities, gas may finger through the oil resulting in an early breakthrough and poor recovery [74]. However the one-dimensional model cannot capture viscous fingering. During gas-flooding the gas saturation is lower in comparison with foam flooding due to the higher mobility of the gas. As is illustrated in Fig. 9.4, the oil saturation is lower for higher water saturations (only applies at high capillary numbers). Explaining why the surfactant-gas flood recovers more oil in the one-dimensional model in comparison with the surfactant-foam flood. However, a one-dimensional model fails to capture the correct physics of a surfactant-gas flood.
Figure 9.3: Three-phase relative oil permeability without desaturation. If the gas saturation increases, the residual oil saturation decreases due to a lower residual oil saturation to gas than water: $S_{or\,w} = 0.33$, $S_{or\,g} = 0.0$, $S_{wc} = 0.35$

Figure 9.4: Three-phase relative oil permeability at high capillary nr. and inconsistent connate water saturation. Oil is mobile throughout the entire region. In this example water can also displace all the oil without leaving a residual behind: $S_{or\,w,c} = 0$, $S_{or\,g} = 0$, $S_{wc,c} = 0$
9.2. SURFACTANT-FOAM MODEL WITH INCONSISTENT GAS RELPERM CURVES

Figure 9.5: Oil cut and oil production for several mechanisms at inconsistent connate water saturation. The chemical flood starts at 2.43 injected liquid PV. Modelling assumptions: no surfactant dispersion/adsorption, 0.012 m dispersivity of salt.

Figure 9.6: Pressure drop for several mechanisms at inconsistent connate water saturation. The chemical flood starts at 2.43 injected liquid PV. Modelling assumptions: no surfactant dispersion/adsorption, 0.012 m dispersivity of salt.
9.3. **Surfactant-Foam Model with Consistent Gas Relperm Curves**

To keep the gas relative permeability curves consistent, the connate water saturation is kept constant throughout the water and chemical flood. Also referred to as a consistent chemical $S_{wc,c} = S_{wc,c}$. This will only affect the models in which the relative permeability curves are a function of the capillary number, i.e. the models including the desaturation mechanism. In Fig. 9.7 the three-phase oil relative permeability at high capillary number and consistent connate water saturation is illustrated. In comparison with the three-phase oil relative permeability at inconsistent connate water saturation (Fig. 9.4 and Fig. 9.8), the region where oil is mobile decreased due to the constant connate water saturation. The oil is relatively more mobile at the same water saturation, as the end-point relative permeability of oil is defined at a higher connate water saturation. In Fig. 9.9 and Fig. 9.10 the oil recovery, oil cut and pressure drop of the following mechanisms are compared with each other:

- Surfactant-Gas flooding at inconsistent $S_{wc}$ (Fig. 9.13)
- Surfactant-Gas flooding at consistent $S_{wc}$ (Fig. 9.15)
- Surfactant-Foam at inconsistent $S_{wc}$ (Fig. 9.14)
- Surfactant-Foam flooding at consistent $S_{wc}$ (Fig. 9.16)

As can be seen in Fig. 9.9 the cumulative oil recovery at 4.0 injected liquid PV increases from 0.67 to 0.82 [\_] for the surfactant-foam flood and from 0.69 to 0.86 [\_] for the surfactant-gas flood. The oil is relatively more mobile at the same location in the ternary diagram, as is illustrated in Fig. 9.4. Therefore, an increase in oil recovery is observed. Another observation is that the presence of a weaker foam (i.e. drive solution at 2.93 injected liquid PV) does not significantly change the slope of the oil recovery, while in the inconsistent model the weaker foam influences the slope. When looking at the saturation profile illustrated in Fig. 9.16, it can be observed that the residual oil saturation through the core already achieved a low value. Therefore, a decrease in gas saturation (increase in water saturation) does not significantly reduce the residual oil saturation.

When looking at the pressure drop (Fig. 9.10) it can be observed that a higher pressure drop is measured during the consistent surfactant-foam flood as a stronger foam is modelled. A stronger foam is generated due to the lower impact of the dry-out function as a consequence of the higher connate water saturation, as is described in subsection 8.3.3. This is also observed in Fig. 9.16 and Fig. 9.14, which illustrate a profile of the core at 0.065 injected liquid PV. The total mobility in the core during consistent surfactant-foam flooding is lower ($M_t \approx 400 \ 1/[Pa \cdot s]$), than the total mobility of the inconsistent flood ($M_t \approx 700 \ 1/[Pa \cdot s]$).

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**Figure 9.7:** Three-phase relative oil permeability at high capillary nr. and consistent connate water saturation. In this example water can also displace all the oil without leaving a residual behind: $S_{orw,c} = 0, S_{org} = 0, S_{wc,c} = 0.35$

**Figure 9.8:** Three-phase relative oil permeability at high capillary nr. and inconsistent connate water saturation. Oil is mobile throughout the entire region. In this example water can also displace all the oil without leaving a residual behind: $S_{orw,c} = 0, S_{org} = 0, S_{wc,c} = 0$
9.3. Surfactant-Foam Model with Consistent Gas Relative Permeability Curves

Figure 9.9: Oil cut and oil production for several combined mechanisms with consistent gas relative permeability curves. The chemical flood starts at 2.43 injected liquid PV. Modelling assumptions: no surfactant dispersion/adsorption, 0.012 m dispersivity of salt.

Figure 9.10: Pressure drop for several combined mechanisms with consistent gas relative permeability curves. The chemical flood starts at 2.43 injected liquid PV. Modelling assumptions: no surfactant dispersion/adsorption, 0.012 m dispersivity of salt.
Figure 9.11: **Gas flooding** without generating a foam and without achieving an ultra-low interfacial tension. All profiles at 0.005 injected liquid PV. No surfactant dispersion/adsorption. Salt dispersivity = 0.002 m.

Figure 9.12: **Foam flooding** without achieving an ultra-low interfacial tension.

Figure 9.13: **Surfactant-Gas flooding** with achieving an ultra-low interfacial tension at **inconsistent** connate water ($S_{wc,c}=0$) saturation, without generating a foam.

Figure 9.14: **Surfactant-Foam flooding** with achieving an ultra-low interfacial tension at **inconsistent** connate water saturation ($S_{wc,c}=0$).

Figure 9.15: **Surfactant-Gas flooding** with achieving an ultra-low interfacial tension at **consistent** connate water saturation ($S_{wc,c}=0.35$), without generating a foam.

Figure 9.16: **Surfactant-Foam flooding** with achieving an ultra-low interfacial tension at **consistent** connate water saturation ($S_{wc,c}=0.35$).
9.4. HISTORY MATCH SURFACTANT-FOAM FLOOD [2]

In section 6.5 the interpretation of the surfactant-foam coreflood experiments is described. The interpretation of the experiments and earlier discussed simulation results are used to history match surfactant-foam coreflood [2]. During coreflood [1] a different surfactant formulation is injected with unknown solubilization parameters. Furthermore, the data is less reliable due to a lower applied back pressure. Therefore, it is decided not to history match surfactant-foam coreflood [1].

First the difference in consistent and inconsistent gas relative permeability curves is researched. Thereafter a case with foam and no foam (i.e. solely gas) is simulated. This contributes to the knowledge of the effect of the strength of the foam on the results. Thereafter, the history match is improved by optimizing the surfactant model and optimizing the foam model. This is followed by a sensitivity study of other desaturation parameters, surfactant dispersion and surfactant adsorption on the results. This chapter is concluded with a final history match.

9.4.1. CONSISTENT AND INCONSISTENT GAS RELPERM CURVES

Fig. 9.17 and Fig. 9.18 depict the results of the oil recovery, oil cut and pressure drop with consistent and inconsistent chemical connate water saturations. The foam parameters determined from coreflood [4] are used as an input for the foam model. The input parameters of the surfactant model are assumed to achieve their optimum, chemical values (see Table 9.2). Both models show an early breakthrough of the oil bank with \( \approx 0.15 \) injected liquid PV. The model with the consistent chemical connate water saturation shows a higher oil recovery and oil cut. The oil is relatively more mobile if a higher chemical connate water saturation is defined, as described in section 9.3. Therefore, at 3.0 injected liquid PV an increase in cumulative oil recovery (OOIP) of \( \approx 0.22 \) [-] is observed.

Another observation in Fig. 9.18 is that the model with the consistent chemical connate water saturation simulates a significantly higher pressure drop of \( \approx 200 \) [psi]. The pressure drop decreases at the start of the drive solution, when a weaker foam is injected. The total mobility is dominated by the apparent foam viscosity and the pressure drop continues to increase during the production of the oil bank. The effect of the apparent foam viscosity on the total mobility is discussed in Section 6.5.2.

In the model with the consistent chemical connate water saturation, the pressure drop decreases during the production of the oil bank. This suggests that the lowered water-oil interfacial tension dominates the total mobility and the apparent foam viscosity is too low to decrease the total mobility. The impact of the foam and desaturation model on the total mobility is illustrated in Fig. 9.19, which represents the core at the end of the chemical slug. The model with the consistent connate water saturation significantly increases the gas viscosity from 0.02074 cP up to \( \approx 30 \) cP and manages to lower the total mobility. The model with the inconsistent connate water saturation generates a very weak foam, increasing the gas viscosity from 0.02074 cP to \( \approx 0.5 \) cP. This is due to the water saturation \( S_{w} = 0.4 \) [-], which is below the limiting water saturation \( S_{w}^{*} = fmdry = 0.5 \) [-]. Therefore, the foam fails to reduce the total mobility.

The determined foam model parameters of coreflood [4] are used as an input in the model, in which an apparent foam viscosity of \( \approx 2.5 \) cP is achieved for a connate water saturation of \( S_{wc} = 0.35 \) [-]. With the same foam model parameters, an apparent foam viscosity of \( \approx 30 \) cP is achieved for a (consistent) connate water saturation of \( S_{wc} = 0.59 \) [-]. I.e. coreflood [4] gives a poor estimate of the foam behavior for the SF-case. The foam model parameters require optimization for every coreflood, due to variations in connate water saturation. The foam model parameters are optimized in subsection 9.4.4 to match the surfactant-foam coreflood.
Figure 9.17: Sensitivity consistent and inconsistent approach. Simulation of oil cut and recovery of coreflood [2] with consistent ($S_{wc,c} = 0.59$) and inconsistent ($S_{wc,c} = 0.0$) gas relative permeability curves. The chemical flood starts at 1.48 injected liquid PV. Modelling assumptions: no surfactant dispersion/adsorption, 0.038 m dispersivity of salt.

Figure 9.18: Sensitivity consistent and inconsistent approach. Simulation of pressure drop of coreflood [2] with consistent ($S_{wc,c} = 0.59$) and inconsistent ($S_{wc,c} = 0.0$) gas relative permeability curves. The chemical flood starts at 1.48 injected liquid PV. Modelling assumptions: no surfactant dispersion/adsorption, 0.038 m dispersivity of salt.
Figure 9.19: Total mobility and gas viscosity through the core at the end of the chemical slug [2]. The chemical slug ends at 1.98 injected liquid PV. Modelling assumptions: no surfactant dispersion/adsorption, 0.038 m dispersivity of salt.
9.4.2. Influence of Foam Strength

To determine the effect of foam on the recovery and pressure profiles, a surfactant-gas flood is modelled and compared with a surfactant-foam flood. In both models, oil is initially produced due to the presence of free gas that evolves ahead of the injected surfactant front, as a consequence of the higher interstitial velocity of the gas than the surfactant. As is depicted in Fig. 9.20, the model with foam has a smaller, but higher oil cut. This results in a faster recovery of the cumulative oil. A (stronger) foam will advance the breakthrough of the oil bank, as it reduces the effective pore volume for liquid to flow due to an increase in gas saturation. Due to the low mobility of the foam, the gas saturation substantially increases ($S_g \approx 0.39$) as is illustrated in Fig. 9.22. Due to the high chemical connate water saturation ($S_{wc,c} = 0.59$), relatively only little gas is required to achieve the residual oil saturation to gas ($S_g = 0.41$, $S_{org} = 0$), as is illustrated in the ternary diagram of Fig. 9.3. Due to the high gas saturation, only little effective pore volume is available for liquid to flow. Therefore, the water saturation remains constant (i.e. equal to the connate water saturation), as is illustrated in 9.22. Therefore, the mobilization of oil is mainly driven by gas saturation, rather than a reduction in water-oil interfacial tension. As is observed in Fig. 9.21, the pressure continues to increase during the production of the oil bank and decreases at the start of the drive solution. An elaborate interpretation of the consistent surfactant-foam pressure data is discussed in subsection 9.4.1.

In the model without foaming surfactant, the gas has a very high mobility and is not able to substantially increase the gas saturation ($S_g \approx 0.1$) as is illustrated in Fig. 9.22. The desaturation of oil is mainly determined by the lowered interfacial-tension between the water and oil. As the water saturation gradually increases, the oil is produced in a long tail. In Fig. 9.21 the pressure drop during the chemical flood is observed. As no foam is generated, the pressure drop decreases when the oil bank is produced.

The match without foam gives the match of the oil cut and the slope of the oil recovery. Both models result in an oil recovery of 95 % of the OOIP, while in the experiments a recovery of 90 % is observed. The match can be improved by reducing the chemical connate water saturation, as described in section 9.3, or by increasing the residual oil saturation to water and gas. Both models simulate a poor pressure match with the experimental data. The pressure drop of the model with foam is approximately three times too big, while the pressure drop of the model without foam is $\approx 30\%$ too low. This suggests that to history match the data, a relatively weak foam is required to improve the match of the pressure drop. This agrees with the surfactant-foam objective of this research. Fig. 9.20 illustrates that the foam strength does not affect the cumulative oil recovery. Therefore, the cumulative oil recovery is matched by optimizing the desaturation model. After which the foam model is optimized to match the pressure drop.
**Figure 9.20: Sensitivity of foam strength.** Simulation of oil cut and recovery of coreflood [2] with and without foam. The chemical flood starts at 1.48 injected liquid PV. Modelling assumptions: no surfactant dispersion/adsorption, 0.038 m dispersivity of salt. Consistent set up with $S_{cw} = S_{cw,c} = 0.59$.

**Figure 9.21: Sensitivity of foam strength.** Simulation of pressure drop of coreflood [2] with and without foam. Modelling assumptions: no surfactant dispersion/adsorption, 0.038 m dispersivity of salt. Consistent set up with $S_{cw} = S_{cw,c} = 0.59$. 
Figure 9.22: **Sensitivity of foam strength.** Saturation profile of model during injection of the chemical slug with and without foam. Consistent set up with $S_{cw} = S_{cw,c} = 0.59$.

Figure 9.23: **Instabilities in saturation profile** (chemical $S_{wc,c} = 0.49$) which causes instabilities in the oil cut, oil recovery and pressure data.
9.4.3. Optimization desaturation model

The history match of the cumulative oil recovery can be improved by reducing the efficiency of the desaturation model and/or by increasing the residual oil saturation to gas. This can be done by reducing the chemical connate water saturation or by increasing the residual oil saturation to water and gas. Both approaches are modelled and analyzed.

**Chemical connate water saturation**  
As is described in section 9.3 the chemical connate water saturation influences the oil relative permeability as it defines the end-point at which oil flows. By reducing the chemical connate water saturation the oil is less free to flow, resulting in a reduced cumulative oil recovery as is illustrated in Fig. 9.24. In Fig. 9.25 the pressure drop is observed. A lower pressure drop is observed as a weaker foam is modelled due to a minimized impact of the limiting capillary pressure, as is discussed in subsection 8.3.3.

At the start of the drive solution, instabilities in the phase saturations indirectly cause instabilities in the oil cut, oil recovery and pressure data. This is illustrated in Fig. 9.23. The observed instabilities are numerical artifacts introduced by the foam model. Their fundamental cause is unknown. Both a constraint in saturation gradients and an increased number of grid cells did not resolve the problem. Introducing surfactant dispersion smoothens phase transitions as is illustrated in Fig. 8.7. Nevertheless, this did not reduce the observed instabilities either.

**Residual oil saturation**  
As three phases are present during surfactant-foam flooding, the residual oil saturation is both determined by the residual oil to water and gas, as is illustrated in Fig. 9.3. If the gas saturation is low, the residual oil saturation to water ($S_{orgw}$) mainly determines the residual oil saturation. If the gas saturation is high and the water saturation is close to the connate water saturation, the residual oil saturation to gas ($S_{orgg}$) mainly determines the residual oil saturation.

As is observed in Fig. 9.26 the cumulative oil recovery is sensitive to changes in the residual oil to gas ($S_{org}$). Due to the high gas saturation, the water saturation is not able to increase and does not contribute to mobilization of residual oil in the core as illustrated in Fig. 9.22. Fig. 9.27 shows the pressure drop during the surfactant-flood. The modelled foam is too strong and has an apparent gas viscosity of $\approx 30$ cP during the chemical slug, while in the history match of foam flood [4] an apparent gas viscosity of $\approx 2.5$ cP is modelled. Therefore, the simulated pressure drop is too high.

The experimental cumulative oil recovery can be matched both by optimizing the chemical connate water saturation and the residual oil saturation to gas and water. It is chosen to match the cumulative oil recovery by optimizing the residual oil saturation to gas and water, as the inconsistent chemical connate water saturation introduces numerical instabilities and uses inconsistent gas relative permeability curves.
Figure 9.24: **Sensitivity of chemical connate water saturation.** Simulation of oil cut and recovery of coreflood [2] by changing the chemical connate water saturation. The chemical flood starts at 1.48 injected liquid PV.

Figure 9.25: **Sensitivity of chemical connate water saturation.** Simulation of pressure drop of coreflood [2] by changing the chemical connate water saturation.
Figure 9.26: Sensitivity of residual oil saturation. Simulation of oil cut and recovery of coreflood [2] by changing the residual oil to gas and the chemical residual oil to water. Consistent set up with $S_{cw} = S_{cw,c} = 0.59$. The chemical flood starts at 1.48 injected liquid PV.

Figure 9.27: Sensitivity of residual oil saturation. Simulation of pressure drop of coreflood [2] by changing the residual oil to gas and the chemical residual oil to water. Consistent set up with $S_{cw} = S_{cw,c} = 0.59$. 
9.4.4. Optimization Foam Model

While the final cumulative oil recovery is matched, the modelled oil cut breaks through too early, is too small and the pressure drop too high. As is shown in subsection 9.4.2 the match can be improved by changing the foam model. In the previous approach the foam strength was too strong (i.e. \( \approx 30 \) cP), resulting in a high pressure drop and a small oil bank. The foam strength is reduced by reducing the reference mobility reduction factor of the gas phase \((f_{mob})\) and by optimizing the critical surfactant concentration below which foam collapses \((f_{surf})\). The apparent foam viscosity measured during the coreflood [4] in the absence of oil, is used to quality check the model. The match of coreflood [4] is achieved with an apparent foam viscosity of \(2.5 \text{ mPa} \cdot \text{s} \) during the chemical slug and \(1.1 \text{ mPa} \cdot \text{s}\) during the drive solution. It is assumed that these apparent foam viscosities are an indication of the contribution of foam to the total apparent viscosity during coreflood [1] and [2].

Fig. 9.28 shows the recovery when \(f_{mob}\) is reduced from \(2.5E3 \) to \(1.6E2 \), the match is improved due to the reduced foam strength, as discussed in subsection 9.4.2. The injected surfactant concentration during the chemical slug is 10000 ppm and during the drive solution is 1000 ppm. No difference in oil recovery is observed between the model with \((f_{surf}=2000 \text{ ppm})\) or without \((f_{surf}=1 \text{ ppm})\) the impact of the surfactant concentration on the foam strength. During the chemical slug an oil recovery of 85 % is achieved and therefore a change in foam strength at the start of the drive solution has little impact on the oil recovery. This is in contrast with the observations discussed in section 9.3. In Fig. 9.29 the pressure drop can be observed. The match significantly improved in comparison with Fig. 9.27. The modelled apparent gas viscosity is \(3.3 \text{ cP}\) during the chemical slug and \(3.3 \text{ cP or 1.7 cP}\) during the drive solution (Fig. 9.30). This is in the same order of magnitude as the foam viscosities modelled during coreflood [4]. The model with the constant gas viscosity gives the best pressure match. However, the observations during foam coreflood [4] suggest that the apparent foam viscosity decreases at a lower injected surfactant concentration i.e. during the drive solution. It is researched if the optimization of other desaturation parameters can improve the pressure match, i.e. increase the pressure drop at the final state of the coreflood. This is discussed in subsection 9.4.5.

In the experimental data a slower increase in pressure drop is observed. This can be explained by various reasons, extensively discussed in chapter 11. First of all the foam model assumes that foam is instantaneously generated. However, during early stages of the injection, the foam has not yet reached a local-equilibrium. Therefore, the local-equilibrium model can initially model a foam that is too strong. It is also observed that the oil bank in the experimental data varies in oil saturation and does not immediately reach a maximum oil saturation. Initially less oil is mobilized, which also results in a slower increase in pressure drop. This could be caused by viscous fingering, which cannot be captured with the described one-dimensional model.

Figure 9.28: Sensitivity of foam parameters. Simulation of oil cut and recovery of coreflood [2] by changing the foam parameters. Consistent set up with \(S_{cw} = S_{cw,c} = 0.59, S_{gr}=0.01, S_{grw}=0\). The chemical flood starts at 1.48 injected liquid PV.
9.4. History match surfactant-foam flood [2]

- Pressure drop model: $F_{mmob}=1.6E2$, $f_{msurf}=2000$ ppm
- Pressure drop model: $F_{mmob}=1.6E2$, $f_{msurf}=1$ ppm
- Experiment: pressure drop

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**Figure 9.29: Sensitivity of foam parameters.** Simulation of pressure drop of coreflood [2] by changing the foam parameters. Consistent set up with $S_{cw}=S_{cw,c}=0.59$, $S_{arg}=0.01$, $S_{arg}=0$.  

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**Figure 9.30: Profile of core with gas viscosities at 0.75 injected liquid PV (during injection of the drive solution) for different foam parameters.** Consistent set up with $S_{cw}=S_{cw,c}=0.59$, $S_{arg}=0.01$, $S_{arg}=0$.  

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9.4.5. SENSITIVITY OF CHEMICAL COREY PARAMETERS
In previous simulations, only the chemical connate water saturation and residual oil saturation are optimized. The other chemical Corey parameters are assumed to achieve their optimum, chemical values (see Table 9.2). Fig. 9.33 and Fig. 9.34 illustrate the sensitivity of $K_{ro}$ and $n_{ow}$ on the recovery and pressure data. Fig. 9.31 and Fig. 9.32 illustrate the sensitivity of $K_{rw}$ and $n_{ow}$ on the recovery and pressure data. Reducing the end-point relative water permeability and increasing the Corey water exponent positively improves the pressure match, as it introduces resistance to flow of water. Reducing the end-point relative oil permeability and increasing the Corey oil exponent reduce the quality of the history match. This introduces resistance to flow of oil and reduces the cumulative oil recovery. The oil parameters do not affect the final state of pressure match as solely water flows through the core when the pressure drop achieves a steady state.

The end-point relative water permeability and the Corey water exponent can be used as matching parameters to improve the history match. The chemical Corey parameters can never achieve values which are less favorable than their waterflooding values. In the final history match the chemical end-point water relative permeability is increased from 0.18 to 0.7 [-] and the chemical Corey water exponent is reduced from 3.4 to 1.6 [-]. The oil parameters remain unchanged. This indicates that the lowered water-oil interfacial tension improves the fluid-flow of the water phase, without achieving its optimum values.

9.4.6. SENSITIVITY SURFACTANT DISPERSION AND ADSORPTION
The sensitivity of surfactant dispersion and adsorption on the pressure drop during foam flooding is discussed in section 8.3. Both surfactant dispersion and adsorption reduced the quality of the pressure history match. While no surfactant production data is available, surfactant dispersion and adsorption are physical phenomena that are expected to occur during surfactant-foam flooding. Based on the assumptions stated in subsection 8.3.4 and subsection 8.3.5, a surfactant adsorption of $a_{\text{max}}=1700$ ppm and surfactant dispersion of 0.012 m is modelled. The slope of the surfactant adsorption $a_{\text{slope}}=100000$ ppm.

In Fig. 9.37 and Fig. 9.38 the recovery and pressure drop can be observed. Fig. 9.35 and Fig. 9.36 show the location of the oil and foam bank at 0.20 and 0.50 injected liquid PV for various adsorption and dispersion scenarios. Surfactant dispersion without adsorption increases the oil cut at the front of the oil bank, as the surfactant and foam front have travelled further in the core at the same injected liquid PV. Therefore, an initial increase in pressure drop is observed in comparison with the model without dispersion. The oil is produced in a tail due to the gradual change in surfactant concentration as illustrated in Fig. 9.35 and Fig. 9.36. Adsorption retards the surfactant front and reduces the amount of surfactant that is available to lower the interfacial tension and to generate foam. An extended oil bank with a lower oil saturation is observed. The lower oil cut and retarded foam bank also results in a lower initial pressure drop. When modelling both surfactant adsorption and dispersion, the recovery and pressure are an averaged result of the model with adsorption or dispersion.

Both surfactant adsorption and dispersion improve the history match of the oil cut, as this results in an extended oil bank with a longer and smoothed tail. This is similar to what is observed in the experimental data.
Figure 9.31: **Sensitivity of water chemical Corey parameters** on simulations of oil cut and recovery of coreflood [2]. The chemical flood starts at 1.48 injected liquid PV. $F_{\text{mob}}=1.6E2 [-]$, $F_{\text{surf}}=2000$ ppm. Optimum chemical desaturation parameters: $K_{ro}=1$, $K_{rw}=1$, $n_{ro}=1$, $n_{rw}=1$. Consistent set up with $S_{cw} = S_{cw,c} = 0.59$.

Figure 9.32: **Sensitivity of water chemical Corey parameters** on simulations of pressure drop of coreflood [2]. $F_{\text{mob}}=1.6E2 [-]$, $F_{\text{surf}}=2000$ ppm. Optimum chemical desaturation parameters: $K_{ro}=1$, $K_{rw}=1$, $n_{ro}=1$, $n_{rw}=1$. Consistent set up with $S_{cw} = S_{cw,c} = 0.59$. 
Figure 9.33: **Sensitivity of oil chemical Corey parameters** on simulations of oil cut and recovery of coreflood [2]. The chemical flood starts at 1.48 injected liquid PV. Fmmob=1.6E2 [-], fmsurf=2000 ppm. Optimum chemical desaturation parameters: $K_{ro}=1$, $K_{rw}=1$, $n_{ow}=1$, $n_{w}=1$. Consistent set up with $S_{cw} = S_{cwc} = 0.59$.

Figure 9.34: **Sensitivity of oil chemical Corey parameters** on simulations of pressure drop of coreflood [2]. Fmmob=1.6E2 [-], fmsurf=2000 ppm. Optimum chemical desaturation parameters: $K_{ro}=1$, $K_{rw}=1$, $n_{ow}=1$, $n_{w}=1$. Consistent set up with $S_{cw} = S_{cwc} = 0.59$. 

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9. **ONE-DIMENSIONAL RESULTS: SURFACTANT-FOAM FLOoding**

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Figure 9.35: Sensitivity of surfactant adsorption and dispersion. Oil saturation and gas viscosity profile at 0.20 injected liquid PV for several surfactant and dispersion scenarios. Fmmob=1.6E2 [-], fmsurf=2000 ppm. Consistent set up with $S_{cw} = S_{cw,c} = 0.59$.

Figure 9.36: Sensitivity of surfactant adsorption and dispersion. Oil saturation and gas viscosity profile at 0.50 injected liquid PV (end of chemical slug) for several surfactant and dispersion scenarios. Fmmob=1.6E2 [-], fmsurf=2000 ppm. Consistent set up with $S_{cw} = S_{cw,c} = 0.59$. 
9. One-Dimensional Results: Surfactant-Foam Flooding

Figure 9.37: Sensitivity of surfactant adsorption and dispersion on simulations of oil cut and recovery of coreflood [2]. The chemical flood starts at 1.48 injected liquid PV. Surfactant dispersivity = 0.012 m, surfactant adsorption = 1700 ppm. Fmmob=1.6E2 [-], fmsurf=2000 ppm. Consistent set up with $S_{cw} = S_{cw,c} = 0.59$.

Figure 9.38: Sensitivity of surfactant adsorption and dispersion on simulations of pressure drop of coreflood [2]. Surfactant dispersivity = 0.012 m, surfactant adsorption = 1700 ppm. Fmmob=1.6E2 [-], fmsurf=2000 ppm. Consistent set up with $S_{cw} = S_{cw,c} = 0.59$. 
9.4.7. One-dimensional history match

As is discussed in previous sections, the simulated recovery and pressure profiles are determined by various foam and surfactant parameters. However, the degrees of freedom of the Surfactant-Foam model are limited. First of all, the foam strength measured in the foam experiments in the absence of oil gives an indication of the maximum foam strength during the surfactant-foam flood. During the experiments it is observed that a weaker foam is generated during the drive solution. Therefore, it is assumed this should be captured by the surfactant-foam model. A chemical connate water saturation close to the waterflood connate water saturation ($S_{wc}=0.59$), achieved the best surfactant-foam history match and suggests that a small effective pore space is present. Furthermore, it is assumed that the chemical connate water saturation should remain equal to the waterflood connate water saturation, to achieve consistency in the gas relative permeability curves. Salt dispersion, surfactant dispersion and surfactant adsorption are physical phenomena that are expected to occur during surfactant-foam flooding. While no surfactant data is available, the surfactant dispersion is assumed to be equal to that of the salt. A value of surfactant adsorption is based on literature. Based on the assumptions and results of previous sections, a base-case of the final history match of coreflood [2] is presented in Fig. 9.39 and Fig. 9.40. In the history match the chemical end-point water relative permeability and the chemical Corey water exponent are optimized, as discussed in subsection 9.4.5. The oil parameters remain unchanged. The model parameters of the base-case history match are listed in Table 9.1 or Table 9.2.

Delaying the oil production

A reasonable history match is achieved, with an exception of the early production of oil by free gas and the early breakthrough of the oil bank ($\approx 0.15$ injected liquid PV). Initially oil is produced due to the presence of free gas that evolves ahead of the injected surfactant front, as a consequence of the higher interstitial velocity of the gas than the surfactant. Possibilities to delay the breakthrough of the oil bank are increasing the amount of surfactant adsorption, decreasing the surfactant dispersion or reducing the foam strength. A weaker foam will delay the breakthrough of the oil bank, as it increases the effective pore volume for liquid to flow due to a decrease in gas saturation.

An increase in surfactant adsorption from $a_{max}=1700$ ppm to $3400$ ppm, negligible influence the breakthrough of the oil bank. Adsorption decreases the velocity at which the oil bank advances and therefore also affects the height of the oil cut. Based on literature, it is assumed that a maximum surfactant adsorption above $3400$ ppm is nonphysical [73]. The breakthrough of the oil bank can also be delayed by reducing the dispersion of surfactant, as illustrated in Fig. 9.42. Reducing the dispersion of surfactant delays the breakthrough of the oil bank, as the surfactant and foam front have travelled less far in the core at the same injected liquid PV. Therefore, mobilization of residual oil is delayed.

Fig. 9.41 illustrates that the early oil breakthrough is caused by the mobility of the gas. By decreasing the gas Corey parameter from $N_g=2.43$ to $N_g=1.5$, the gas relative permeability increases and therefore the mobility of the gas increases. This results in a lower gas saturation and therefore less oil is mobilized by the presence of free gas. Furthermore, a weaker foam will delay the breakthrough of the oil bank, as it increases the effective pore volume for liquid to flow due to a decrease in gas saturation. The improved the history match as is illustrated in Fig. 9.43. Due to the higher mobility of the gas phase, the total mobility in the core increases, resulting in a decrease in pressure drop as is illustrated in Fig. 9.44.

Due to an increase in gas mobility by reducing the gas Corey parameter, the pressure drop decreases as is illustrated in Fig. 9.44. The modelled pressure drop during the drive solution is too low in comparison with the experimentally pressure drop. In the base-case model it is assumed that the foam strength reduces during injection of the drive solution, due to a lower concentration of surfactant. This assumption is based on the observations of foam coreflood [4]. When it is assumed that the foam strength remains constant throughout the chemical flood, an optimized final history match as is illustrated in Fig. 9.45 and Fig. 9.46 is achieved.

By decreasing the modelled gas mobility with a factor two (from $230$ to $110$ $1/ Pa \cdot s$) by reducing $fmnob$, the history match of the oil cut and oil recovery is improved as illustrated in Fig. 9.47 and Fig. 9.48. However, a too low foam strength negatively influences the match of the pressure drop. The presented surfactant model assumes a constant viscosity of the oleic phase. An increase in micro-emulsion viscosity [67] lowers the total fluid mobility and could therefore contribute to an observed increase in pressure gradient.

A grid sensitivity analysis has been performed on the base-case of the final history match. The number of grid cells in the z-direction is increased from $z=100$ to $z=1000$ cells. The refinement negligibly improved the accuracy of the results. Suggesting that the grid with 100 cells balances simulation results with simulation run-time. For the graphs see Appendix E.
### Table 9.1: Base case. One-dimensional model parameters of final history match coreflood [2]).

<table>
<thead>
<tr>
<th>Final match: model parameters</th>
<th>Symbol</th>
<th>Units</th>
<th>[2]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference mobility reduction factor</td>
<td>fmmob</td>
<td>–</td>
<td>1.6E2</td>
</tr>
<tr>
<td>Critical surfactant concentration</td>
<td>fmsurf</td>
<td>ppm</td>
<td>2000</td>
</tr>
<tr>
<td>Surfactant exponent parameter</td>
<td>epsurf</td>
<td>–</td>
<td>1</td>
</tr>
<tr>
<td>Abruptness of the dry-out effect [35]</td>
<td>epdry</td>
<td>–</td>
<td>1.52</td>
</tr>
<tr>
<td>Critical water saturation [35]</td>
<td>fmdry</td>
<td>–</td>
<td>0.5</td>
</tr>
<tr>
<td>Max. surfactant adsorption</td>
<td>a\textsubscript{max}</td>
<td>ppm</td>
<td>1700</td>
</tr>
<tr>
<td>Slope of adsorption</td>
<td>a\textsubscript{slope}</td>
<td>ppm</td>
<td>100000</td>
</tr>
<tr>
<td>Effective salt/surfactant dispersivity</td>
<td>a\textsubscript{eff}</td>
<td>[m]</td>
<td>0.012</td>
</tr>
<tr>
<td>Connate water saturation, high N\textsubscript{c}</td>
<td>S\textsubscript{wc,c}</td>
<td>–</td>
<td>0.59</td>
</tr>
<tr>
<td>Residual oil to water, high N\textsubscript{c}</td>
<td>S\textsubscript{orw,c}</td>
<td>–</td>
<td>0.01</td>
</tr>
<tr>
<td>Residual oil to gas</td>
<td>S\textsubscript{org}</td>
<td>–</td>
<td>0.02</td>
</tr>
<tr>
<td>Residual gas saturation</td>
<td>S\textsubscript{gr}</td>
<td>–</td>
<td>0.01</td>
</tr>
<tr>
<td>Endpoint relative oil permeability, high N\textsubscript{c}</td>
<td>K\textsubscript{ro,c}</td>
<td>–</td>
<td>1</td>
</tr>
<tr>
<td>Endpoint relative water permeability, high N\textsubscript{c}</td>
<td>K\textsubscript{rw,c}</td>
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<td>0.7</td>
</tr>
<tr>
<td>Corey oil exponent (oil,water), high N\textsubscript{c}</td>
<td>n\textsubscript{ow,c}</td>
<td>–</td>
<td>1</td>
</tr>
<tr>
<td>Corey oil exponent (oil-gas) [35]</td>
<td>n\textsubscript{og}</td>
<td>–</td>
<td>3</td>
</tr>
<tr>
<td>Corey water exponent, high N\textsubscript{c}</td>
<td>n\textsubscript{w,c}</td>
<td>–</td>
<td>1.6</td>
</tr>
<tr>
<td>Corey gas exponent [35]</td>
<td>N\textsubscript{g}</td>
<td>–</td>
<td>2.43</td>
</tr>
</tbody>
</table>
9.4. History match surfactant-foam flood [2]

Figure 9.39: **Base case.** History match of oil cut and recovery of coreflood [2]. The chemical flood starts at 1.48 injected liquid PV. \( F_{\text{mob}} = 1.6 \times 10^2 \, [-] \), \( f_{\text{surf}} = 2000 \, \text{ppm} \). Surfactant/salt dispersivity = 0.012 m, surfactant adsorption = 1700 ppm. Consistent set up with \( S_{\text{cw}} = S_{\text{cw},c} = 0.59 \).

Figure 9.40: **Base case.** History match of pressure drop of coreflood [2]. \( F_{\text{mob}} = 1.6 \times 10^2 \, [-] \), \( f_{\text{surf}} = 2000 \, \text{ppm} \). Surfactant/salt dispersivity = 0.012 m, surfactant adsorption = 1700 ppm. Consistent set up with \( S_{\text{cw}} = S_{\text{cw},c} = 0.59 \).
9. ONE-DIMENSIONAL RESULTS: SURFACTANT-FOAM FLOODING

Figure 9.41: Sensitivity of gas Corey exponent. Profile through core at 0.15 injected liquid PV for two scenarios: the base case with $N_g=2.43$ (Table 9.1) and with $N_g=1.5$. Surfactant dispersivity = 0.012 m.

Figure 9.42: Sensitivity of gas Corey exponent. Profile through core at 0.15 injected liquid PV for two scenarios: $N_g=1.5$ and 0.012 m surfactant dispersivity and $N_g=1.5$ and no surfactant dispersion.
9.4. History match surfactant-foam flood [2]

Figure 9.43: Delaying the breakthrough of the oil bank by reducing the Corey gas parameter for several surfactant dispersion scenarios. The chemical flood starts at 1.48 injected liquid PV. \( \text{Fmmob}=1.6\times10^2 \) [-], \( \text{fmsurf}=2000 \) ppm. Base case: Surfactant/salt dispersivity = 0.012 m, surfactant adsorption = 1700 ppm, \( N_g=2.43 \). Consistent set up with \( S_{cw} = S_{cw,c} = 0.59 \).

Figure 9.44: Delaying the breakthrough of the oil bank by reducing the Corey gas parameter for several surfactant dispersion scenarios. \( \text{Fmmob}=1.6\times10^2 \) [-], \( \text{fmsurf}=2000 \) ppm. Base case: Surfactant/salt dispersivity = 0.012 m, surfactant adsorption = 1700 ppm, \( N_g=2.43 \). Consistent set up with \( S_{cw} = S_{cw,c} = 0.59 \).
Figure 9.45: Optimized case. History match of oil cut and recovery of coreflood [2]. Model with Nc=1.5 + surfactant dis. 0.006 m and constant foam strength (no influence of $F_{\text{surf}}$).

Figure 9.46: Optimized case. History match of pressure drop of coreflood [2]. Model with Nc=1.5 + surfactant dis. 0.006 m and constant foam strength (no influence of $F_{\text{surf}}$).

Figure 9.47: Reducing the foam strength. History match of oil cut and recovery of coreflood [2]. Reducing fmmob from 1.6E2 to 5E1. Model with Ng=1.5 + surfactant dis. 0.006 m and constant foam strength (no influence of $F_{surf}$).

Figure 9.48: Reducing the foam strength. Reducing fmmob from 1.6E2 to 5E1. History match of pressure drop of coreflood [2]. Model with Ng=1.5 + surfactant dis. 0.006 m and constant foam strength (no influence of $F_{surf}$).
9.5. **Table: 1-D Surfactant-Foam Model Parameters**

<table>
<thead>
<tr>
<th>Grid cells</th>
<th>Symbol</th>
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<th>Value</th>
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<tbody>
<tr>
<td>1D z-direction</td>
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### PVT-model (at 69°C, 1000 psi)

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<th>Symbol</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water viscosity</td>
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<td>cP</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>µ_o</td>
<td>cP</td>
</tr>
<tr>
<td>Nitrogen viscosity [65]</td>
<td>µ_g</td>
<td>cP</td>
</tr>
<tr>
<td>Nitrogen viscosity [65]</td>
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</tr>
<tr>
<td>Water density</td>
<td>µ_w</td>
<td>kg/m³</td>
</tr>
<tr>
<td>Oil density</td>
<td>µ_o</td>
<td>kg/m³</td>
</tr>
<tr>
<td>Nitrogen density [65]</td>
<td>µ_g</td>
<td>kg/m³</td>
</tr>
<tr>
<td>Water compressibility</td>
<td>c_w</td>
<td>1/psi</td>
</tr>
<tr>
<td>Oil compressibility</td>
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<td>1/psi</td>
</tr>
<tr>
<td>Nitrogen compressibility</td>
<td>c_g</td>
<td>1/psi</td>
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### Foam and Surfactant model constants

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</tr>
</thead>
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<td>Surfactant concentration slug</td>
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<td>ppm</td>
</tr>
<tr>
<td>Surfactant concentration drive</td>
<td>-</td>
<td>ppm</td>
</tr>
<tr>
<td>Solubilization parameter, under-optimum</td>
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</tr>
<tr>
<td>Solubilization parameter, over-optimum</td>
<td>X_over</td>
<td>-</td>
</tr>
<tr>
<td>Optimum solubilization ratio [113/114]</td>
<td>Z_opt</td>
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<tr>
<td>Chemical IFT water-oil [113/114]</td>
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<td>mN/m</td>
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<td>Residual gas saturation</td>
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</tr>
<tr>
<td>Residual oil saturation to gas</td>
<td>S_org</td>
<td>-</td>
</tr>
<tr>
<td>Endpoint relative gas permeability [35]</td>
<td>K_g</td>
<td>-</td>
</tr>
<tr>
<td>Corey gas exponent [35]</td>
<td>N_g</td>
<td>-</td>
</tr>
<tr>
<td>Corey oil exponent (oil-gas) [35]</td>
<td>N_o</td>
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### Foam model

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<tr>
<td>Reference mobility reduction factor</td>
<td>fmmob</td>
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<td>-</td>
<td>1.6E2</td>
<td>-</td>
<td>1.5E3</td>
</tr>
<tr>
<td>Critical surfactant concentration</td>
<td>fmsurf</td>
<td>ppm</td>
<td>-</td>
<td>2000</td>
<td>-</td>
<td>2000</td>
</tr>
<tr>
<td>Surfactant exponent parameter</td>
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<td>-</td>
<td>1</td>
<td>-</td>
<td>4</td>
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<tr>
<td>Abruptness of the dry-out effect [35]</td>
<td>edp</td>
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<td>-</td>
<td>152</td>
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<td>152</td>
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<tr>
<td>Critical water saturation [35]</td>
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<td>0.55</td>
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<td>Max. surfactant adsorption</td>
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<td>-</td>
<td>-</td>
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<td>Slope of adsorption</td>
<td>a_slope</td>
<td>ppm</td>
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<td>100000</td>
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### Surfactant model

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</tr>
</thead>
<tbody>
<tr>
<td>Connate water saturation, high N_c</td>
<td>S_wcc</td>
<td>-</td>
<td>0.59</td>
<td>⚫</td>
<td>-</td>
<td>0.15</td>
</tr>
<tr>
<td>Residual oil saturation to water, high N_c</td>
<td>S_orw</td>
<td>-</td>
<td>0.01</td>
<td>0</td>
<td>-</td>
<td>0.24</td>
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<td>Endpoint relative oil perm, high N_c</td>
<td>K_ro</td>
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<td>1</td>
<td>-</td>
<td>1</td>
</tr>
<tr>
<td>Endpoint relative water perm, high N_c</td>
<td>K_rw</td>
<td>-</td>
<td>0.7</td>
<td>1</td>
<td>-</td>
<td>0.12</td>
</tr>
<tr>
<td>Corey oil exponent, high N_c</td>
<td>n_o</td>
<td>-</td>
<td>1</td>
<td>1</td>
<td>-</td>
<td>1.2</td>
</tr>
<tr>
<td>Corey water exponent, high N_c</td>
<td>n_w</td>
<td>-</td>
<td>1.6</td>
<td>1</td>
<td>-</td>
<td>2</td>
</tr>
<tr>
<td>Effective salt and surfactant dispersivity</td>
<td>a_eff</td>
<td>[m]</td>
<td>0.020</td>
<td>0.012</td>
<td>-</td>
<td>0.020 0.038</td>
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</table>

### Waterflood Corey parameters

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<tbody>
<tr>
<td>Endpoint relative oil permeability, low N_c</td>
<td>K_r</td>
<td>-</td>
<td>0.86</td>
<td>0.69</td>
<td>-</td>
<td>-</td>
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<tr>
<td>Endpoint relative water perm, low N_c</td>
<td>K_rw</td>
<td>-</td>
<td>0.145</td>
<td>0.18</td>
<td>-</td>
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<tr>
<td>Connate water saturation, low N_c</td>
<td>S_wc</td>
<td>-</td>
<td>0.55</td>
<td>0.59</td>
<td>-</td>
<td>0.35</td>
</tr>
<tr>
<td>Corey oil exponent (oil-water), low N_c</td>
<td>n_bo</td>
<td>-</td>
<td>2</td>
<td>2</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Corey water exponent, low N_c</td>
<td>n_w</td>
<td>-</td>
<td>2.2</td>
<td>3.4</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 9.2: Surfactant-foam model parameters. The PVT-model is specified at core conditions (69°C and 1000 psi).

* = dependent on consistent or inconsistent connate water saturation.
The one-dimensional model is extended to a two-dimensional model to study the effect of a heterogeneous core on the simulation results. Carbonates, such as the Indiana limestone, often have a complex pore structure due to their dual porosity [75]. Dual porosity refers to porous features across multiple length scales. MicroCT scans of the Indiana Limestone, depicted in Figure A.1, illustrate the complex pore structure.

As is discussed in the dispersion model (section 5.5), heterogeneities such as a high-permeability streak contribute to macroscopic dispersion. In the one-dimensional model the effect of dispersion on the effluent salinity is captured by introducing an effective dispersivity coefficient. However, the effective dispersivity coefficient cannot capture the effect of a high-permeable streak on the fluid flow (i.e. advection) within the core.

10.1. SENSITIVITY OF GEOLOGY
The influence of a high-permeable streak on the salinity profile, oil cut and oil recovery is studied. A high-permeable streak results in an earlier breakthrough of the injection salinity and a delay in producing the full injection salinity, also referred to as the tail. In all corefloods analyzed during this research a fast change in salinity is observed (subsection 6.5.4), which could suggest the presence of a thief-zone. In subsection 6.5.4 the experimental effluent salinity data is matched with an analytical solution to the 1D advection-diffusion equation. In this chapter the two-dimensional scenarios of coreflood [2] and [5] are modelled numerically.

First the effluent salinity profile without the presence of foam is modelled and compared with the experimental data of surfactant coreflood [5]. Thereafter the salinity profile with the presence of foam is modelled (coreflood [2]). This introduces complexities as the strength of the foam influences the salinity profile, due to variations in the movable pore volume.

10.1.1. SURFACTANT FLOODING
Two heterogeneous models, as proposed in subsection 6.5.4, are simulated (listed in Table 10.1). According to the analytical solution illustrated in Fig. 6.16, a 1 and 15 mD layer with equal thickness gives the best match with the experimental data. The input parameters of surfactant flood [5] are used, as listed in Table 6.2. In Fig. 10.1 the numerical solution of the effluent salinity profile can be observed. The solution of the breakthrough times agrees with the analytical solution. When including the effective dispersivity value calculated in subsection 6.5.4, the effluent salinity profile disperses as illustrated in Fig. 10.2.

SCENARIO 1:
The biggest permeability-thickness product (1 and 15 mD, equal thickness) results in the best match of the initial and final state of the effluent salinity profile. The slope of the effluent salinity profile gives a poorer match. A change in salinity gradient is observed at $\approx 0.65$ injected liquid PV, while the experimental data depicts a gradual change. Due to the high difference in permeability-thickness product between the layers, an early oil breakthrough with $\approx 0.2$ injected liquid PV is observed (Fig. 10.3 and Fig. 10.3). The high-permeable layer acts as a thief zone. Therefore, an early breakthrough of the oil bank and a poor cumulative oil recovery is observed.
**Scenario 2**

According to the analytical solution illustrated in Fig. 6.15, a 6 and 10 mD layer of equal thickness shifts the effluent salinity profile close to the corrected experimental salinity. A discrepancy of $\Delta PV \approx 0.07$ is observed between the experimental salinity profile and the modelled salinity profile, as is illustrated in Fig. 10.2. The presence of the high permeable layer results in an early oil breakthrough with $\approx 0.04$ injected liquid PV (Fig. 10.3). After production of the high permeable layer, the low permeable layer contributes to the oil recovery. Therefore, two stages of oil production are observed in the oil cut. The experimental data shows a diffused oil cut with local variations in the saturation, suggesting that the presence of permeability differences in the core might be a realistic case.

The simulations results suggest that the presence of a high-permeable streak, with a large difference in flow capacity between the layers (flow capacity 0.0625 : 0.9375), has a positive influence on the history match of the effluent salinity profile. However, the thief zone has a negative impact on the history match of the oil cut and cumulative oil recovery. In subsection 6.5.4 the possibility is discussed that errors in the salinity measurement are expected. These errors can be caused by errors in the conductivity measurements, by the measurement approach with tubes or by the experimental set-up. By shifting the salinity data, an improved match between the experimental profile and modelled profile is observed, as illustrated in Fig. 10.2. The 6 & 10 mD Scenario (flow capacity 0.375 : 0.625), assumes that both a shift in experimental effluent salinity data and introduction of heterogeneities are required, to achieve a history match with the experimental salinity and recovery data.

![Salinity experiment vs Salinity model](image)

**Figure 10.1:** Surfactant coreflood [5]: Effluent salinity profile of a homogeneous core and two different permeabilities combinations without salt dispersion. **Note:** there is a difference between injected chemical liquid PV and injected liquid PV, which also includes the waterflood.
10.1. SENSITIVITY OF GEOLOGY

Figure 10.2: **Surfactant coreflood [5]**: Effluent salinity profile of a homogeneous core and two different permeabilities combinations. Salt dispersivity = 0.038 m. Both the original and corrected measurement (with $\Delta PV = 0.38$) are represented. *Note:* there is a difference between injected chemical liquid PV and injected liquid PV, which also includes the waterflood.

Figure 10.3: **Surfactant coreflood [5]**: Oil cut and oil recovery of various permeability combinations. Salt dispersivity = 0.038 m. No surfactant adsorption/dispersion is modelled. The chemical flood starts at 1.86 injected liquid PV.
Figure 10.4: Surfactant coreflood [5]: Pressure plot of various permeability combinations. Salt dispersivity = 0.038 m. No surfactant adsorption/dispersion is modelled. The chemical flood starts at 1.86 injected liquid PV.

### 10.1.2. Foam Diversion

The effluent salinity profile during surfactant-foam flooding is dependent on the strength of the foam. Foam reduces the movable pore volume available for tracers, i.e. salt and surfactant, to flow. In the one-dimensional model it is assumed that the foam matching parameters are independent of permeability. Higher permeable layers have lower capillary pressures resulting in a preferred flow-path for liquid lamellae. Therefore, foam tends to have a lower mobility in high permeable layers and selectively blocks swept zones. In the one-dimensional model no variety in permeability was captured and a constant foam mobility was assumed. Now a relation between permeability, the dry-out function ($F_{dry}$) and the reference mobility reduction factor [35] is introduced:

\[
F_{dry} = 0.46 \cdot K^{-0.068} \\
Ep_{dry} = 65400/K \\
F_{mmob} = K \cdot 12.8 + z
\]

in which $K$ [mD] is the absolute permeability and $z$ [-] a matching parameter of the reference mobility reduction factor. The matched values according to the original foam model are: $F_{dry}=0.55$, $Ep_{dry}=152$ and $F_{mmob}=1.6E2$ [-] (see Table 9.2). The apparent foam viscosity measured during coreflood [4] without oil, is used to quality check the modelled apparent foam viscosity. It is assumed that the foam strength measured in foam coreflood [4] in the absence of oil gives an indication of the foam strength during the surfactant-foam flood.

The foam diversion principle, applied to surfactant-foam coreflood [2], is illustrated in Fig. 10.5. The chemical slug is injected after $\approx 0.4$ days, while the drive solution (i.e. weaker foam) is injected after $\approx 0.7$ days. The apparent gas viscosity is higher in the layers with a larger permeability, resulting in a reduced mobility of the foam. For example: during the chemical slug of Scenario 1, an apparent foam viscosity of $\approx 3.8$ cP is modelled in the 10 mD layer, while an apparent foam viscosity of $\approx 2.6$ cP is modelled in the 8 mD layer. The average apparent foam viscosity is $\approx 3.2$ cP, which is in the same order of magnitude as the foam...
viscosities modelled during foam coreflood [4] in the absence of oil. In Fig. 10.6 and Fig. 10.7 the original foam model is compared with the permeability dependent foam model. The gas mobility is reduced in the high permeable layer and increased in the low permeable layer. Therefore, more oil is recovered from the low-permeable layer and an increase in cumulative oil recovery is observed.

Figure 10.5: Foam diversion (traced in one grid block): a stronger foam is modelled in the layers with a higher permeability. Scenario 1: 8 & 12 mD layer with equal thickness. Scenario 2: 6 & 14 mD layer with equal thickness. The apparent foam viscosities determined in coreflood [4] are an upper limit of the average foam viscosity in the surfactant-foam flood.

Figure 10.6: Foam diversion in Scenario 1: comparison of oil recovery of original foam model with the permeability dependent foam model.
10.1.3. SURFACTANT-FOAM FLOODING

The permeability dependent foam parameters, discussed in subsection 10.1.2, are incorporated into the surfactant-foam model. The results of a homogeneous scenario and two heterogeneous scenarios are compared. The scenarios are listed in Table 10.1. As is discussed in subsection 6.5.4, no double-layer analytical match of the effluent salinity profile of coreflood [2] is achieved. A variation in movable pore space, due to mobilization of residual oil and variations in the gas saturation, increased the complexity of analytically determining the breakthrough times. Therefore, the sensitivity of the geology on the effluent salinity profile is numerically determined with a reservoir simulator. The input parameters of the surfactant-foam model as described in subsection 9.4.4, with optimum and consistent desaturation parameters, are used as an initial model input (listed in Table 9.2). Surfactant dispersion and adsorption or not (yet) included.

The one-dimensional model and the homogeneous two-dimensional model are compared in Fig. E.3 and Fig. E.4. The two-dimensional model uses the permeability dependent foam parameters and therefore models a slightly different apparent foam viscosity (3.2 cP instead of 3.25 cP). Two heterogeneous scenarios are introduced, as listed in Table 10.1. The effluent salinity profiles of the homogeneous model and the two heterogeneous models, with and without dispersion, are illustrated in Fig. 10.8 and Fig. 10.9. Both heterogeneous models simulate inconsistencies after 1.1 injected liquid PV. Larger differences in flow capacity between the layers worsen the inconsistencies and are therefore not analyzed. No inconsistencies are observed in the heterogeneous model without permeability dependent foam parameters.

All modelled salinity profiles show a poor match with the corrected experimental salinity profile. Scenario 1 (8 & 12 mD) and the homogeneous match result in a relatively good match with the slope of the salinity profile, but requires an extra delay of ≈ 0.25 PV. This scenario (flow capacity 0.4 : 0.6) assumes that both a shift in experimental effluent sanity data and introduction of heterogeneities is required. Scenario 2 (6 & 14 mD) achieves a better match at the initial times of the effluent salinity profile, until ≈ 0.6 injected liquid PV. The larger difference in flow capacity (0.3 : 0.7) between the layers, causes a long tail in the salinity profile. Therefore, the history match is of poor quality > 0.6 injected liquid PV.

The oil recovery and pressure profiles of the different geological scenarios are illustrated in Fig. 10.10 and Fig. 10.11. Both scenario 1 and 2 elongate the size of the oil bank and delay the cumulative oil production in comparison with the homogeneous model. Due to the presence of a high permeable layer in both scenarios,
an earlier breakthrough of the oil bank is observed. This reduces the quality of the history match with the oil cut. Due to the slower production of oil, the decrease in pressure drop is delayed. Using the knowledge of the sensitivity study on the one-dimensional model, discussed in section 9.4, the two-dimensional simulations of scenario 1 (8 & 12 mD) are optimized.

**Figure 10.8:** Surfactant-Foam coreflood [2]: Effluent salinity profile of a homogeneous core and two different permeabilities combinations without salt dispersion. Both the original and corrected measurement (with $\Delta PV = 0.25$) are represented. *Note:* there is a difference between injected chemical liquid PV and injected liquid PV, which also includes the waterflood.

**Figure 10.9:** Surfactant-Foam coreflood [2]: Effluent salinity profile of a homogeneous core and two different permeabilities combinations with 0.012 m salt dispersion. Both the original and corrected measurement (with $\Delta PV = 0.25$) are represented. *Note:* there is a difference between injected chemical liquid PV and injected liquid PV, which also includes the waterflood.
10.2. DimenSional resuLts

Figure 10.10: Surfactant-Foam coreflood [2]: Oil cut and oil recovery of various permeability combinations. Salt dispersivity = 0.012 m. No surfactant adsorption/dispersion is modelled. The chemical flood starts at 1.48 injected liquid PV.

Figure 10.11: Surfactant-Foam coreflood [2]: Pressure plot of various permeability combinations. Salt dispersivity = 0.012 m. The chemical flood starts at 1.48 injected liquid PV.
10.2. SURFACTANT-FOAM FLOOD OPTIMIZATION

The history match of Scenario 1 (8 & 12 mD, with equal thickness) is optimized using the knowledge of the sensitivity study discussed in section 9.4. Mechanisms such as surfactant adsorption and dispersion are included in the model. When introducing surfactant dispersion, the permeability dependent foam model cannot be executed due to numerical limitations of the simulator. Therefore, this section is continued with the original foam model, without permeability dependent foam parameters. A disadvantage of this approach is that less physics is captured by the model. A lower cumulative oil recovery is simulated with the original foam model, as illustrated in Fig. 10.6.

The parameters determined during the one-dimensional history match are used as input parameters (listed in Table 10.1). In comparison to the one-dimensional model parameters, the residual oil to gas ($S_{org}$) and the chemical residual oil to water ($S_{rwc}$), are equal to zero. This improves the history match as less oil is recovered due to the presence of a thief zone. Furthermore, the presence of a high permeable layer results in an earlier breakthrough of the oil bank. This reduces the quality of the history match of the oil cut. When it is assumed that the foam strength remains constant throughout the chemical flood, an optimized final history match as is illustrated in Fig. 10.12 and Fig. 10.13 is achieved. By decreasing the gas Corey parameter from $N_g=2.43$ to $N_g=1.5$, the gas relative permeability increases and therefore the mobility of the gas increases. A weaker foam will delay the breakthrough of the oil bank (illustrated in Fig. 10.16), as it increases the effective pore volume for liquid to flow due to a decrease in gas saturation. Due to the higher mobility of the gas phase, the total phase mobility in the core increases. As a consequence a decrease in pressure drop is observed. The increase in mobility of the gas, was not able to significantly delay the oil bank.

The breakthrough of the oil bank can be delayed by reducing the dispersion of surfactant, as illustrated in Fig. 10.14 and Fig. 10.15. The surfactant and foam front have travelled less far in the core at the same injected liquid PV. Therefore, mobilization of residual oil is delayed as is illustrated in Fig. 10.17. As surfactant dispersion is a physical phenomenon that is expected to occur, it is questioned to which extent it can be used as a matching parameter. Availability of surfactant production data will contribute to the understanding of the surfactant dispersion.

COMPARISON OF ONE-DIMENSIONAL AND TWO-DIMENSIONAL MODEL

Both the one-dimensional and two-dimensional Surfactant-Foam model achieve a reasonable history match with the cumulative oil recovery and pressure gradient. A two-dimensional model, with a small difference in flow capacity between the two layers, successfully matches the size of the oil cut. Furthermore, it is also capable in introducing variations in the saturation of the oil cut. Layers contribute to the recovery of oil with different speeds, without entirely bypassing lower-permeable zones. However, the presence of a thief zone will advance the breakthrough of the oil bank, which reduces the quality of the recovery history match. This can be compensated for with i.e. the dispersion of surfactant, adsorption of surfactant and the strength of the foam. The pressure drop and surfactant production data will contribute to limit the degrees of freedom of these matching parameters. With the two-dimensional model an improved match of the effluent salinity profile can be achieved at the expense of the oil cut and recovery match. Due to the high uncertainty of the experimental data, more corefloods should be performed to identify the most suitable geological representation of the Indiana Limestone.
10. Two-Dimensional Results

Figure 10.12: Surfactant-Foam coreflood [2]: Oil cut and oil recovery of various scenarios. Salt dispersivity $= 0.012$ m. Surfactant dispersivity base case $= 0.012$ m. Optimized match: $N_g=1.5$ and variation in surfactant dispersion. The chemical flood starts at 1.48 injected liquid PV.

Figure 10.13: Surfactant-Foam coreflood [2]: Pressure plot of various scenarios. Salt dispersivity $= 0.012$ m. Surfactant dispersivity base case $= 0.012$ m. The chemical flood starts at 1.48 injected liquid PV.
10.2. **Surfactant-Foam Flood Optimization**

Oil cut model: \( N_g = 2.43 \), no surf. dis

Oil RF model: \( N_g = 2.43 \), no surf. dis

Oil cut model: \( N_g = 1.5 \), no surf. dis

Oil RF model: \( N_g = 1.5 \), no surf. dis

Experiment: oil cut

Experiment: oil RF

---

**Figure 10.14:** Surfactant-Foam coreflood [2]: Oil cut and oil recovery of various scenarios. Salt dispersivity = 0.012 m. No surfactant dispersivity. Optimized match: \( N_g = 1.5 \) and variation in surfactant dispersion. The chemical flood starts at 1.48 injected liquid PV.

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**Figure 10.15:** Surfactant-Foam coreflood [2]: Pressure plot of various scenarios. Salt dispersivity = 0.012 m. No surfactant dispersivity. The chemical flood starts at 1.48 injected liquid PV.
Figure 10.16: Surfactant-Foam coreflood [2] (traced in one grid block): Oil and gas saturation in the two layers for two scenarios. Surfactant dispersivity = 0.012 m.

Figure 10.17: Surfactant-Foam coreflood [2] (traced in one grid block): Oil and gas saturation in the two layers for two scenarios. No surfactant dispersion.
10.3. **Table: 2-D Surfactant-Foam Model Parameters**

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**Model parameters coreflood [5]**

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<tr>
<td>Heterogeneous Scenario 1, layers with equal thickness</td>
<td>mD</td>
<td>K</td>
</tr>
<tr>
<td>Heterogeneous Scenario 2, layers with equal thickness</td>
<td>mD</td>
<td>K</td>
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**Model parameters coreflood [2]**

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
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<td>K</td>
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<tr>
<td>Heterogeneous Scenario 1, layers with equal thickness</td>
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<td>K</td>
</tr>
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<td>Heterogeneous Scenario 2, layers with equal thickness</td>
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<td>Effective salt/surfactant dispersivity</td>
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<td>[m]</td>
</tr>
</tbody>
</table>

Table 10.1: **Base case.** Surfactant-foam model parameters for a two-dimensional model. For PVT-parameters consult Table 9.2.
The research objective of this work is to develop a combined Surfactant-Foam model, to provide insight in how the model works and to highlight limitations and areas of improvement. In this chapter the most important findings and limitations are discussed. Starting with the selected foam and surfactant model. Thereafter, the combined Surfactant-Foam model and the results of the history matching are discussed. This chapter is concluded with the limitations of the provided experimental data.

11.1. IMPLICIT-TEXTURE STARS FOAM MODEL

In this research the implicit-texture STARS foam model is used to model the foam strength. The use of an implicit-texture model that assumes a local-equilibrium introduces several advantages and shortcomings. The implementation of the implicit-texture model is relatively easy and it allows to select the main functions that effect the texture of foam.

11.1.1. MODELLING OF FOAM STRENGTH

The determination of the apparent foam viscosity and selection of the main drivers affecting the foam texture are based on the pressure data of a single foam flood. During the Surfactant-Foam coreflood, the change in pressure drop is expected to be dominated by the generation of foam, the mobilization of residual oil and the formation of a micro-emulsion. Therefore, the SF pressure data cannot be used to directly derive the apparent foam viscosity.

It is assumed that the mobility reduction factor measured during the foam experiment gives an indication of the maximum foam strength in the presence of oil during coreflood [1] and [2]. However, the pressure drop is measured during a single coreflood, with a different total fluid injection rate and different core properties. During the foam flood the total fluid injection rate is 7.4 cm$^3$/hr, while during the Surfactant-Foam flood the total fluid injection rate is 12 cm$^3$/hr. This results in a higher pressure gradient during the Surfactant-Foam flood. Kam et al. [39] describe in their population-balance model (Equation 4.2.1), that the generation of foam lamellae is controlled by the pressure gradient. Furthermore, foams show shear thinning behavior when the interstitial velocity increases. Therefore, the total fluid injection rate influence the foam strength. In addition, during the Surfactant-Foam coreflood oil is present in the core. Oil affects the stability of the foam due to destabilization of the lamellae by hydrophobic surfaces. Besides, competition of surfactant between the gas/water and oil/water interface might be present. More research is required to determine the gas mobility during the Surfactant-Foam coreflood. Execution of a foam flood with a similar total fluid injection rate as the Surfactant-Foam coreflood is recommended.

The determination of the main drivers affecting the foam texture, i.e. the surfactant concentration and the water saturation, are also based on the pressure data of a single foam flood. During the drive solution a lower surfactant concentration is injected, resulting in the generation of a weaker foam. However, the exact critical surfactant concentration below which foam collapses is unknown. During the Surfactant-Foam simulations it is assumed $fnsurf = 2000$ ppm. More research is required to determine the critical concentration. During a different coreflood and the presence of oil, the influence of the surfactant concentration and water saturation on the foam strength might be different. According to the salinity correlation presented by the STARS implicit-texture foam model, a decrease in salinity has a positive impact on the foam strength [37]. Therefore, it is
expected that the drop in pressure gradient has no correlation with a change in salinity.

### 11.1.2. Transient Foam Behavior

The local-equilibrium model assumes the foam texture is in dynamic balance i.e. it obtains its texture instantaneously. During injection of the chemical slug of the foam coreflood, a linear increase in pressure drop is observed. The STARS foam model was successful in modelling the pressure trend during the chemical slug. After 0.5 injected liquid PV (≈ 1 PV), the pressure drop suddenly decreases. As previously discussed, at 0.5 injected liquid PV, a lower surfactant concentration is injected, expecting to generate a weaker foam. However, the sudden drop in pressure does not show a linear decrease. The STARS foam model was unsuccessful in modelling this pressure trend, but was able to match the final pressure drop of the drive solution. As the pressure gradient of the Surfactant-Foam flood is dominated both by the generation of foam and mobilization of residual oil, it is unknown if and to what extent dynamic modelling of foam is required.

Ma et al. [76] performed foam experiments in which a core is first flooded with a surfactant solution, after which gas is injected. A drop in pressure gradient is observed at 1.4 injected PV, as is illustrated in Fig. 11.1. The decrease in pressure drop is related to the dry-out effect. In the Surfactant-Foam floods analyzed in this research, it is expected that the decrease in pressure drop is related with the surfactant concentration, in stead of a partial collapse of foam due to a low water saturation.

![Figure 11.1: Transient experimental data. Source: Ma et al. [76].](image-url)
11.2. EFFECTIVE TWO-PHASE SURFACTANT MODEL

The Surfactant-Foam model presented in this work incorporates a two-phase surfactant model. The main aspects of the Surfactant-Foam flood are captured, without explicitly modelling the micro-emulsion phase. This approach is less complex and requires less input parameters. However, its shortcoming is that it does not model the actual presence of a micro-emulsion phase, resulting in loss of physical soundness. Other limitations of the two-phase surfactant model are discussed below.

11.2.1. MODELLING OF SALINITY GRADIENT

In the Surfactant-Foam experiments studied here, the optimum salinity is achieved by applying a salinity gradient. During the salinity gradient the water-oil interfacial tension can fluctuate. In the desaturation model this is modelled with capillary number dependent relative permeability curves. The end-point saturation defined at a high capillary number exceeds the defined end-point saturation at a low capillary number, due to the mobilization of residual oil. At the end-point saturation of a high capillary number, no relative permeability is defined for a low capillary number. Therefore, reversibility in desaturation curves is not physically sound. The interfacial tension in the model cannot increase, after it achieved an ultra-low value. The consequence of this assumption requires more research. It is expected that the difference in IFT between over-optimum, optimum and under-optimum plays a role in justification of the assumption. It might be possible that a new relative permeability model is required to describe the transition from high to low capillary number.

11.2.2. INTERFACE TENSION MODEL

The interfacial tension model proposed by Huh [46], correlates solubilization ratio with interfacial tension. The solubilization ratio is dependent of the phase behavior of the system. The model assumes that the surfactant concentration is larger than the critical micelle concentration. A correlation between solubilization ratio and salinity is described by Liu [47]. According to Nelson et al. [77], optimum salinity decreases with decreasing surfactant concentration. Furthermore, ion exchange with the rock can cause optimum salinity to change during a chemical flood. Geochemistry and the correlation between optimum salinity and surfactant concentration are not captured by the presented interfacial tension model.

11.2.3. MICRO-EMULSION PHASE

The presented model does not explicitly model the micro-emulsion phase. Multi-phase flow is modelled with the use of relative permeabilities. More research on four-phase flow and the correlation of the phases to describe their relative permeability is required. Especially, as three-phase relative permeability is already a complex concept; in three-phase flow data inconsistencies and uncertainties are observed [71].

The presented surfactant model assumes a constant viscosity of the oleic phase. However, experimental observations indicate that the viscosity of the micro-emulsion phase is dependent on phase behavior [67]. An increase in micro-emulsion viscosity lowers the total fluid mobility and could therefore contribute to an observed increase in pressure gradient. A consequence of not capturing this is physics, could be the over-estimation of the foam strength. The modelled foam strength contributes to the stability of the displacement and to the mobilization of oil by gas. Micro-emulsion viscosity measurements could give an indication of the contribution of the micro-emulsion to the pressure profile. A modelling suggestion is to introduce phase dependent (oil) viscosities. Humphry et al. [11] present the results of a micro-emulsion rheology study and show that the in-situ viscosity of a micro-emulsion can be 1.5 to 6 times larger than the viscosities measured in a conventional shear rheometer.
11.3. **Surfactant-Foam Model**

The surfactant and foam model are combined to model three-phase flow at ultra-low interfacial tension conditions. The Surfactant-Foam model showed several limitations.

11.3.1. **Desaturation Model with Three-Phase System**

The performance of the desaturation model during three-phase flow was researched. The desaturation model addresses the input parameters of the oil and water phase of the Corey relative permeability. When the chemical connate water saturation is decreased, the gas relative permeability is indirectly decreased as the gas end-point relative permeability is defined at $S_{g}^{\text{max}} = 1 - S_{wc} - S_{gr}$. It is questioned if a lowered interfacial tension should affect the gas relative permeability. The gas relative permeability curves remain consistent if the connate water saturation remains constant throughout the water and chemical flood. However, the defined connate water saturation affects the strength of the foam. At a high chemical connate water saturation, the foam experiences less impact from the dry-out function. The dry-out function defines a critical water saturation below which foam collapses, due to the limiting capillary pressure. In both approaches the desaturation model reduces the gas mobility: either by reducing the gas relative permeability or by minimizing the impact of the limiting capillary pressure. Physically, during desaturation, a reduced connate water saturation is expected due to the improved mobility of both oil and water. The extent of the mobilization of connate water, at ultra-low interfacial tension conditions, is unknown and would require more research.

A chemical connate water saturation close to the initial connate water saturation, resulted in the best history match. The consistent approach favors the mobility of oil. The oil is relatively more mobile at the same location in the ternary diagram of the three-phase relative oil permeability due to a reduced effective pore space. A consistent approach in connate water saturation reduces the degrees of freedom of the Surfactant-Foam model, as it prevents a change in gas relative permeability. Furthermore, an inconsistent chemical connate water saturation introduced numerical instabilities.

11.3.2. **Modelling Three-Phase Flow at Ultra-Low IFT**

During Surfactant-Foam flooding both the gas saturation and the lowered oil-water interfacial tension contribute to mobilization of residual oil. At the initial oil-water interfacial tension, i.e. low capillary number, oil is more mobile to gas. While at ultra-low oil-water IFT, i.e. high capillary number, oil is more mobile to water. This is a consequence of the relative permeability models. The lowered interfacial tension favors the water and oil input parameters of the Corey model. The gas Corey parameters remain unchanged.

The foam strength determines the mobility of the gas and therefore the gas saturation. Due to the above-mentioned argument, a weak foam is favorable at ultra-low interfacial tension. A weak foam improves the gas mobility and reduces the gas saturation. It therefore allows the water saturation to increase, which enhances mobilization of oil due to a lowered water-oil interfacial tension. More research is required to analyze three-phase flow at ultra-low interfacial tensions, to investigate if this can be related with physics, or if this is purely a modelling artifact.

11.3.3. **Capillary Pressure**

The simulations are performed without explicitly including capillary pressure, as no capillary pressure data was available. Furthermore, it reduced the complexity of the model. The foam model implicitly includes the influence of the limiting capillary pressure with the $F_{dry}$ function. During three-phase flow, three capillary pressures arise between the oil-water, gas-water and gas-oil phase. More research is required to investigate the effect of oil (saturation and composition) on the limiting capillary pressure concept and foam-model parameters [78].

Capillary pressure is the difference in pressure across the interface between two immiscible fluids. According to the Young-Laplace equation the capillary pressure is proportional to the interfacial tension and inversely proportional to the pore-throat size [79]:

$$P_c = P_{nw} - P_w = \frac{2\sigma \cos \theta}{r} \quad (11.1)$$

in which $P_c$ is the capillary pressure, $P_{nw}$ the pressure in the non-wetting phase, $P_w$ the pressure in the wetting phase, $\theta$ the contact angle, $r$ the pore-throat size and $\sigma$ the oil-water interfacial tension. The capillary pressure is higher for smaller pore diameters, i.e. lower permeabilities. The corefloods analyzed during this research are tight ($\approx 10 \text{mD}$) and water-wet to mixed-wet. The tight rock suggests that capillary pressure
might play an important role. Capillary pressures could introduce capillary-end effects, which affects the determination of the actual end-point relative permeability. The interfacial tension during the chemical flood is reduced to ultra-low values due to the presence of surfactants, which reduces the influence of capillary pressure.

**Capillary-end effect**

Due to the capillary-end effect the fluid saturation is usually not uniform across the core during a core flood. Which influences the determination of the actual end-point relative permeability. The capillary-end effect arises from the discontinuity of capillarity in the wetting phase at the core outlet. The wetting fluid preferentially wants to stay in the porous medium, which leads to accumulation of the wetting-phase at the core outlet [80]. The drainage process, i.e. replacing water with oil, establishes the end-point oil relative permeability, which is the starting point of the waterflood. After breakthrough of the oil in a water-wet core, the water capillarity tends to increase the water saturation towards the core outlet. The increase in water saturation is correlated with an increase in pressure drop. The oil relative permeability is calculated using the average pressure drop measured over the entire core, assuming a uniform saturation profile. However, a higher pressure gradient close to the core outlet results in a lower averaged oil relative permeability. Therefore, the actual oil relative permeability can be higher than determined by experiments. The capillary-end effect tends to increase the water saturation. When correcting for this effect, the actual water saturation after saturating the core with oil would be lower than determined by experiments. The influence of the capillary-end effect reduces with core length.

Above concept is applied to the sectional pressure data of Surfactant-Foam coreflood [2]. The core consists of one slab and has a length of 30.48 cm. In the Surfactant-Foam experiments, the pressure drop between three different core sections is measured. The end-point relative permeability to oil ($K_{ro}$) across the core sections are 0.72, 0.63 and 0.80 respectively. These values vary with less than 15 % from the core average relative permeability ($K_{ro}=0.69$). If the capillary-end effect influenced the data assuming a water-wet to mixed-wet core, a higher pressure drop and a lower endpoint relative oil permeability would have been expected. The experimental data suggest a limited influence of the end effect on relative permeability calculations within the error bars of typical core flood experiments. An in-situ saturation profile obtained from scanning methods can provide knowledge about the capillary-induced non-uniform saturation profile and can be used to validate this statement.
11.4. SURFACTANT-FOAM HISTORY MATCH

The Surfactant-Foam history match presented in section 9.4 and chapter 10, is validated against a limited amount of experimental data. A sensitivity study was performed on the STARS foam model parameters, desaturation parameters, Corey gas parameters, surfactant and salt dispersion, surfactant adsorption and with a one and two-dimensional model. Prior to the history match of the chemical flood, the pressure data of the waterflood is matched.

In this research a limited amount of final solutions to the history match is presented, based on the knowledge of the sensitivity study. For future purposes, it would be relevant to perform a model optimization for a certain set of parameters, with the use of an objective function, to research other possibilities in the solution space. By applying a statistical study on the various solutions, a variance-covariance matrix can be constructed. A variance-covariance matrix is a statistical tool that compares the influence of certain parameters on the solution space (variance). Furthermore, it gives insight in the correlation of the parameters (co-variance).

11.4.1. WATERFLOOD

The match of the waterflood is the baseline for the entire history match and is used to retrieve the input parameters of the Corey relative permeability. These relative permeability parameters define the fluid flow properties in the core at the start of the chemical flood. A determination of relative permeability parameters based on a pressure match is a non-unique solution. Availability of oil production data and saturation profiles contribute to a decrease of the solution space.

A reasonable waterflood history match was achieved for all corefloods. Noticeable in the waterflood history match of Surfactant-Foam flood [2], is the high connate water saturation $S_{wc}=0.59$. Indiana Limestone analogues generally have a connate water saturation of $S_{wc} \approx 0.2 - 0.35$ [63]. A decrease in connate water saturation, from $S_{wc}=0.59$ to 0.35, showed a negative impact on the history match as illustrated in Fig. 11.2. While an increase in oil relative permeability (from $K_{ro}=0.69$ to 0.85) can decrease the pressure drop measured at the boundary conditions, it fails to compensate for the decrease in connate water saturation. Several reasons, or a combination hereof, are suggested that can explain why a modelled high connate water saturation results in a history match.

- **Oil saturation method.** The connate water saturation is the minimum water saturation which remains adhered to the pores and stays immobile. The initial water saturation is generally higher or equal to the connate water saturation. The Indiana Limestone was flooded with oil until no water was observed in the effluent ($S_{oil}=0.41$). The remaining water is adhered to the pores, trapped in dead-end pores and trapped due to capillary-end effects. The actual connate water saturation might be lower, than the practical connate water saturation. The success of achieving an initial water saturation close to the connate water saturation depends on the oil saturation method. In the tight Indiana Limestone, the viscous forces have to overcome the capillary forces to successfully displace the movable water saturation. During surfactant coreflood [5] an improved oil saturation method is applied. The core is first vacuumed after which oil is injected at a maximum pressure of 300 psi/ft, achieving an initial oil saturation of $S_{oil}=0.62$. A waterflood pressure match is achieved with a connate water saturation of $S_{wc}=0.27$. This confirms the influence of the oil saturation method on the practical connate water saturation and the relative permeability parameters. Saturating a core with a porous plate or high-speed centrifuge method are known as reliable methods to achieve an initial water saturation close to the connate water saturation [81].

Furthermore, Salathiel et al. [82] observed that the connate water saturations from reservoir rock samples can be substantially lower, than achieved when a rock sample is water flooded and then oil flooded. They suggest this is caused by the mixed-wettability conditions. Initially the reservoir rock was water-wet, achieving low water saturations after invasion with oil. After contact with oil, the wettability of the rock surface can change from water-wet to oil-wet. When a mixed-wet core is flooded with oil, applicable to this research, the connate water saturation is not achieved as water in the oil-wet portions of the rock becomes trapped.

- **Presence of heterogeneities.** The presence of a thief zone reduces the effective pore space for fluid flow. Fluids prefer to flow through the high-permeable layer, which reduces the resistance to flow. This is illustrated in Fig. 11.3, in which a lower pressure drop is observed when a high-permeable layer is introduced. When the modelled connate water saturation is decreased, the pressure drop increases. This
is due to the shift of the oil relative permeability curve, in which the end points are defined at the the connate water and residual oil saturation. Therefore, the presence of a high-permeable streak allows to reduce the connate water saturation due to a compensation in pressure. However, as illustrated in Fig. 11.3, the presence of a high-permeable streak fails to compensate for the decrease in connate water saturation from \( S_{wc}=0.59 \) to 0.35. Furthermore, the presence of a thief zone reduces the quality of the cumulative oil recovery match as illustrated in Fig. 11.4. However, in this example it is assumed that oil is uniformly distributed throughout the porous medium. In a water-wet to mixed-wet system, it could be argued that the larger pores, i.e. high-permeable streak, are saturated with oil. This would increase the cumulative oil recovery, as the high-permeable streak is the preferred flow path during water flooding. Nevertheless, an early breakthrough of the oil bank will be observed. An in-situ saturation profile obtained from scanning methods can be used to validate this assumptions.

11.4.2. Surfactant-Foam Flood
Initially oil is produced due to the presence of free gas that evolves ahead of the injected surfactant front, as a consequence of the higher interstitial velocity of the gas than the surfactant. The mobility of this free gas is described by the gas Corey parameters. Furthermore, it is observed that a stronger foam will advance the breakthrough of the oil bank, as it reduces the effective pore volume for liquid to flow due to an increase in gas saturation.

A chemical connate water saturation close to the waterflood connate water saturation (\( S_{wc}=0.59 \)), achieved the best Surfactant-Foam history match and suggests that a small effective pore space is available for oil and gas to flow. An explanation could be that the lowered water-oil interfacial tension fails to mobilize a significant amount of connate water saturation and therefore does not significantly increase the effective pore space. A high chemical connate water saturation, i.e. small effective pore volume, increases the mobility of oil. The end-point relative permeability of oil is defined at a higher connate water saturation. Therefore, the oil relative permeability is more sensitive to changes in saturation. A constant connate water saturation throughout the water and chemical flood, generates consistent gas relative permeability curves as discussed in subsection 11.3.1.

The cumulative oil recovery is matched by optimizing the residual oil saturation to water \( (S_{orw,c}) \) and gas \( (S_{org}) \). The presence of a relatively strong foam (i.e. high gas saturation), significantly reduces the effective pore volume which is available for liquid to flow and will advance the breakthrough of the oil bank. The mobilization of oil will be dominated by the presence of gas, as illustrated in Fig. 9.22 and Fig. 9.26. The residual oil saturation is history matched by optimizing \( S_{org} \). In the Surfactant-Foam floods analyzed in this research a weak foam is generated, therefore the effective pore volume allows mobilization of oil both by gas and a lowered water-oil interfacial tension. A history match of the residual oil saturation is achieved by optimizing both \( S_{orw,c} \) and \( S_{org} \). More research is required to relate this with physics and to determine the dominating desaturation mechanism at the presence of a weak and strong foam.

11.4.3. One and Two-Dimensional Model
Carbonates, such as the Indiana limestone, often have a complex pore structure due to their dual porosity [75]. Dual porosity refers to porous features across multiple length scales. MicroCT scans of the Indiana Limestone, depicted in Figure A.1, illustrate the complex pore structure. Both one-dimensional and two-dimensional simulations are performed to history match Surfactant-Foam coreflood [2].

One-dimensional model
A reasonable Surfactant-Foam history match of the cumulative oil recovery, oil cut and pressure drop is achieved with a one-dimensional model. The introduction of salt and surfactant dispersion could only partly history match the diffused oil cut. This suggests that the presence of heterogeneities might contribute to the observed variations in the oil cut. A poor match with the effluent salinity profile is achieved. Between the experimentally measured salinity and the simulated salinity, a maximum discrepancy of 0.5 injected liquid PV is observed.

Two-dimensional model
To study the impact of a high-permeable streak on the results, two-dimensional simulations were performed. The early breakthrough observed in the effluent salinity data could suggests the presence of a high-permeable streak. Furthermore, irregular variations observed in the oil cut also suggest the presence of heterogeneities. The introduction of an extra layer, with a small difference in flow capacity (e.g. 1.5), succeeded in matching
the cumulative oil recovery and the size of the oil cut. The presence of a high-permeable layer also introduced variations in the oil cut. However, the high-permeable layer results in an earlier breakthrough of the oil bank. Furthermore, it did not significantly improve the match with the effluent salinity profile.

When introducing an extra layer with a large difference in flow capacity, the history match of the effluent salinity profile improved during initial times. However, it reduced the quality of the effluent salinity match at late times, as the high-permeability streak models a long tail in the salinity profile. Furthermore, the presence of the thief zone reduced the quality of the oil recovery match as discussed in subsection 11.4.1. The modelling of foam diversion increases the recovery from the low-permeable layer and therefore improves the quality of the oil recovery match. However, this principle does not improve the recovery history match of the waterflood. A non-uniform distribution of oil in the porous medium could increase the cumulative oil recovery. Nevertheless, it would still advance the breakthrough of the oil bank.

**Comparison of models**

When comparing the results of the one-dimensional and two-dimensional model, it is observed that both models achieve a reasonable history match with the cumulative oil recovery and pressure gradient. A challenge with both models was to history match the breakthrough of the oil bank. Examples of mechanisms to delay the breakthrough of the oil bank are increasing the amount of surfactant adsorption, decreasing the surfactant dispersion or reducing the foam strength. The presence of a high-permeable zone, advanced the breakthrough of the oil bank.

The one-dimensional model was unable to describe the size of the oil cut. The two-dimensional model, with a small difference in flow capacity between the layers, successfully matches the size of the oil cut. Layers contribute to the recovery of oil with different speeds, without entirely bypassing lower-permeable zones. With the two-dimensional model an improved match of the effluent salinity profile can be achieved at the expense of the oil cut and recovery match. As the experimental data are subject to a high level of uncertainty, more corefloods should be performed to identify the most suitable geological representation of the Indiana Limestone.

![Figure 11.2: Sensitivity of connate water saturation on pressure drop. History match of waterflood of coreflood [2]. Pore volumes injected during waterflood: 1.48 PV. History match of coreflood [2]: N_w=3.4, N_o=2, S_{wc}=0.35 or 0.59, S_{io}=0.41, S_{or}=0.22, K_{rw}=0.18, K_{ro}=0.69 or 0.85.](image-url)
11.4. SURFACTANT-FOAM HISTORY MATCH

Figure 11.3: Sensitivity of thief zone (1 & 19 mD) on pressure drop. Average permeability = 10 mD. History match of waterflood of coreflood [2]. Pore volumes injected during waterflood: 1.48 PV. History match of coreflood [2]: $N_w=3.4$, $N_o=2$, $S_{wc}=0.35$ or 0.59, $S_{io}=0.41$, $S_{orw}=0.22$, $K_{rw}=0.18$, $K_{ro}=0.69$.

Figure 11.4: Sensitivity of thief zone (1 & 19 mD) on oil recovery. Average permeability = 10 mD. History match of waterflood of coreflood [2]. Pore volumes injected during waterflood: 1.48 PV. History match of coreflood [2]: $N_w=3.4$, $N_o=2$, $S_{wc}=0.35$ or 0.59, $S_{io}=0.41$, $S_{orw}=0.22$, $K_{rw}=0.18$, $K_{ro}=0.69$. 
11.5. Experimental data

Surfactant-Foam flooding is taking its first steps in the laboratory. Which limits both the amount of data available and the accuracy of the data. During this research data of five different corefloods was available, addressing different objectives. The limited amount of data introduces a high uncertainty and furthermore a gap in knowledge.

11.5.1. Data accuracy

As only one coreflood per experiment is carried out, the analyzed experimental data are subject to a high level of uncertainty. By repeating experiments, the uncertainty of the data is reduced by mapping contributions from measurement errors, the geology and the Surfactant-Foam process itself. In the following data ambiguities have been observed.

Effluent salinity

In the proposed Surfactant-Foam model, the interfacial tension is a function of salinity. Therefore, it is very important to capture the experimental salinity profile in the model. The salinity data shows a highly dispersed profile, suggesting a high dispersive-mixing character in Indiana limestone. This observation is confirmed by McCool et al. [62]. The data accuracy of the effluent salinity regarding the injected liquid pore volume is questioned. Between the experimentally measured salinity and the one-dimensional modelled salinity, a maximum discrepancy of 0.5 injected liquid PV is observed. The contribution from measurement errors, effective pore volume and heterogeneities to this discrepancy is not well understood.

Pressure measurements

At the end of the waterflood a change in injection strategy, due to a switch in valves, affects the pressure data. In the pressure data of Surfactant-Foam coreflood [1] it appears if data is missing. While an initial pressure drop of approximately 68 psi is expected, an initial pressure drop of 85 psi is measured. In the pressure data of Surfactant-Foam coreflood [2] a too low pressure is observed. While an initial pressure drop of approximately 65 psi is expected, an initial pressure drop of 37 psi is measured. The inconsistency in measured pressure drop is only observed for the Surfactant-Foam corefloods.

If the pressure in the gas phase has yet not overcome the entry pressure, the pressure gradient is only determined by the volume injection rate of the liquid phase. This concept is illustrated in Fig. 11.5, in which an improved pressure match at the boundary conditions is observed when assuming the gas volume rate 0 cm$^3$/hr, in stead of 6 cm$^3$/hr.

The pressure drop data of the Surfactant-Foam flood plays an important role in capturing the correct physics during the history-match, as it allows to separate the contribution of the generation of foam and the mobilization of residual oil. The boundary conditions of the modelled coreflood are determined by the total fluid injection volume rate and do not take into account a loss in pressure due to a switch in valves. As a consequence a mismatch of the initial pressure drop is modelled.

Oil saturation procedure

Different oil saturation procedures are applied to maximize the initial oil saturation in the low-permeable Indiana limestone cores. To successfully compare Surfactant-Foam floods, a similar saturation procedure should be applied.

11.5.2. Knowledge gap

The limited amount of data causes a gap in knowledge. Availability of the following data would enhance the understanding of Surfactant-Foam flooding and improve the Surfactant-Foam model.

Oil production during waterflood

The determination of the waterflood Corey parameters is solely based on a pressure match. The match of the waterflood is the baseline for the entire history match, as it defines the fluid flow properties in the core at the start of the chemical flood. No oil production data during the waterflood was available. The production data contributes to the justification of the Corey parameters and decreases the solution space. Furthermore, a fast production of the injected water could indicate the presence of a high-permeable streak.
**Surfactant production**

No surfactant production data is available. Surfactant data provides information about the surfactant dispersion and adsorption. Values of surfactant dispersion are based on the dispersion of salt. A value of surfactant adsorption is based on literature. Due to the high prevailing salinity and the use of a non-pure surfactant formulation, current methods such as titration and high performance liquid chromatography (HPLC) are not able to measure the surfactant production.

**Interfacial-tension**

Interfacial-tension measurements during over-optimum, optimum and under-optimum salinity could give an indication of the (variation in) oil-water IFT. The measured IFT can be compared with the modelled interfacial tension. Interfacial tension measurements could highlight the importance of achieving optimum conditions in the core. This contributes to identify the importance of the effluent salinity history match. Furthermore, no cross sections of the core are obtained after the corefloods. Cross sections can be used to distinguish poor microscopic displacement (oil mobilization), with poor macroscopic displacement (mobility control).

**Rheological properties**

The presented surfactant model assumes a constant viscosity of the oleic phase. Rheological measurements of the micro-emulsion could give an indication of the viscosity at over-optimum, optimum and under-optimum salinity. This would give an indication of the contribution of the micro-emulsion to the pressure profiles.

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**Figure 11.5:** Final model as presented in subsection 9.4.7 with a total fluid injection volume rate of 12 cm$^3$/hr. Gas volume rate 6 cm$^3$/hr. Liquid volume rate 6 cm$^3$/hr. And the initial pressure match with a total fluid injection volume rate of 6 cm$^3$/hr. Gas volume rate 0 cm$^3$/hr. Liquid volume rate 6 cm$^3$/hr.
Based on the literature, experimental and reservoir simulation studies the conclusions and recommendations of this research are presented in this chapter.

12.1. CONCLUSION

The conclusions of this research are listed below. Model and history matching related conclusions are distinguished.

12.1.1. MODEL RELATED CONCLUSIONS

- In this study a Surfactant-Foam model is developed that combines an implicit-texture foam model with a two-phase effective surfactant model. The model assumes foam is in local-equilibrium and correlates a lowered water-oil interfacial tension with salinity and a minimum surfactant concentration. Surfactant adsorption and salt and surfactant dispersion are included in the model. The presented model does not explicitly model the micro-emulsion phase.

- The surfactant model affects the gas relative permeability through a correlation with the connate water saturation. To achieve consistency in the gas relative permeability curves, the connate water should remain consistent throughout the water and chemical flood. According to the simulation study the defined chemical connate water saturation always affects the gas mobility, either by reducing the gas relative permeability, or by minimizing the impact of the limiting capillary pressure.

- During three-phase flow at ultra-low interfacial tension, residual oil is mobilized both by a lowered water-oil interfacial tension and the presence of gas. According to the current desaturation approach, oil prefers to flow in the presence of water in stead of gas at ultra-low interfacial tension. Three-phase flow at ultra-low interfacial tension requires more research, to investigate if this can be related with physics, or if it is purely a modelling artifact.

- The experimentally applied salinity gradient, correlated with a decrease and increase in water-oil interfacial tension, cannot be described with the current modelling approach. The simulation study shows that reversibility in the desaturation curves is not physically sound. The end-point saturation defined at a high capillary number exceeds the end-point saturation defined at a low capillary number, due to the mobilization of residual oil. In this research it is assumed that the interfacial tension cannot increase, after it achieved an ultra-low value.

- According to the simulation results a stronger foam will advance the breakthrough of the oil bank, as it reduces the effective pore volume for liquid to flow due to an increase in gas saturation. Furthermore, the modelled foam strength contributes to the role of the mobilization of residual oil by gas.

- An increase in chemical connate water saturation, increases the recovery of oil within a finite flooding time due to an increase of the mobility of oil. The end-point relative permeability of oil is defined at a higher connate water saturation. Therefore, the oil relative permeability is more sensitive to changes in saturation.
12.1.2. **History Matching Related Conclusions**

- A Surfactant-Foam coreflood in tight Indiana Limestone is history matched with a one-dimensional and two-dimensional model. Both models achieve a reasonable history match with the cumulative oil recovery and pressure gradient. The two-dimensional model was successful in history matching the size of the oil cut. An improved match of the effluent salinity profile is correlated with a degraded match of the oil recovery and oil cut. No final conclusion regarding the most suitable geological representation of the Indiana Limestone is made.

- The results show that the matching parameters of the implicit-texture foam model require optimization for cores with a mutual difference in connate water saturation. The water saturation at which foam starts to collapse, i.e. the dry-out function, has less impact on the foam strength at a higher connate water saturation.

- In this study the surfactant concentration ($F_{surf}$) and water saturation ($F_{dry}$) are identified as the main drivers affecting the foam texture. Too little data is available to draw final conclusions regarding the correlation and influence of other parameters that affect the foam texture. The influence of oil saturation on the foam strength is currently unknown.

12.2. **Recommendations**

The substantive recommendations of this research are listed below. Model and experimental related recommendations are distinguished.

12.2.1. **Model Related Recommendations**

- A final solution to the history match is presented, based on the knowledge of a sensitivity study. For future purposes it would be relevant to perform a model optimization for a certain set of parameters, with the use of an objective function, to research other possibilities in the solution space.

- Lotfollah *et al.* [45] presented a four-phase flow model to simulate chemical Enhanced Oil Recovery with gas. Comparison of the results and modelling approach will provide insight in the applicability and quality of the presented three-phase model.

- Modelling assumptions are defined to simplify the model and to provide insight in the simulations. The model can be extended with physics such as capillary pressure, geochemistry with the rock and partitioning of surfactant into the oil phase. Furthermore, the geology of the two-dimensional model can be expanded with multiple layers and local permeability differences. This will contribute to identify the most suitable geological representation of the Indiana Limestone. To simulate Surfactant-Foam flooding on field scale, the geological model requires extension to a three-dimensional grid.

- The model assumes a constant viscosity of the oleic phase. Rheological measurements of the micro-emulsion could give an estimation of the viscosity at over-optimum, optimum and under-optimum salinity. A modelling suggestion is to introduce phase dependent viscosities.

- The simulation of foam diversion combined with surfactant dispersion in a two-dimensional model, caused numerical instabilities. Due to exclusion of foam diversion, less physics is captured by the model. As a result a lower cumulative oil recovery is simulated with the heterogeneous models. It should be researched how these numerical limitations can be solved.

12.2.2. **Experimental Related Recommendations**

An understanding of the experimental data will contribute to capture the relevant processes in the model. Recommendations regarding experimental data are proposed, which will result in better understanding of Surfactant-Foam flooding. This will contribute to improve the Surfactant-Foam model.

- The experimental data analyzed in this research is subject to a high level of uncertainty, as a single coreflood per experiment is performed. By repeating experiments, the uncertainty of the data is reduced by mapping contributions from measurement errors, the geology and the Surfactant-Foam process itself. The contribution of measurement errors and heterogeneities to the effluent salinity profile requires more research. Furthermore, more corefloods should be performed to assess and compare the parameters affecting the foam texture.
• Three-phase flow at ultra-low interfacial tension requires more research, to investigate the oil mobility in the presence of water and gas at ultra-low interfacial tension. According to the current desaturation approach, at ultra-low interfacial tension oil prefers to flow in the presence of water in stead of gas.

• By performing a foam coreflood that uses a surfactant-formulation that solely generates foam, i.e. similar to the drive solution, the incremental oil recovery from a Surfactant-Foam flood can be analyzed. This will also improve the understanding of the contribution of foam and lowered oil-water IFT to the pressure profile.

• In the Surfactant-Foam corefloods a fifty percent gas fraction is injected. Surfactants compete between the oil-water and gas-water interface. A sensitivity study of variation in gas fractions, can contribute to the knowledge about the competition of the surfactant between the oil-water and gas-water interface.
BIBLIOGRAPHY


Pore Structure of Indiana Limestone

Freire-Gormaly et al. [75] analyzed Indiana Limestone samples with microCT and SEM image data. The samples have a different porosity (≈ 19 %) and brine permeability (≈ 70 mD), than the samples analyzed in this research. The images give a general representation of the pore structure of the Indiana Limestone.

Figure A.1: (a) MicroCT data cross-section of Indiana Limestone at 8.3 µm resolution at 6 mm diameter. (b) SEM image of Indiana Limestone, length bar represents 1 mm. Source: Freire-Gormaly et al. [75]
This appendix paraphrases the basic fluid flow equations as described by Aziz and Settari [83]. The continuity equation describes transport of a conserved quantity such as mass [84]:

$$\frac{\partial \Psi}{\partial t} + \nabla \cdot V = s$$  \hspace{1cm} \text{(B.1)}

When no sink or source terms are assumed ($s = 0$), Eq. B.1 becomes a conservation law. The equation for mass conservation for multi-phase flow is defined by [83]:

$$\Psi = \rho_i S_i \phi$$  \hspace{1cm} \text{(B.2)}

$$V_i = \rho_i S_i \phi v_i$$  \hspace{1cm} \text{(B.3)}

$$-\nabla \cdot (\rho_i \phi v_i S_i) = \frac{\partial \rho_i \phi S_i}{\partial t}$$  \hspace{1cm} \text{(B.4)}

In which the divergence operator on the left-hand side can be expanded in any co-ordinate system. The mass flux terms are expressed in terms of a superficial (Darcy) velocity.

$$u_i = v_i (\phi S_i)$$  \hspace{1cm} \text{(B.5)}

The conservation of mass (Eq. B.4) for a one-dimensional model in the x-direction, in the Cartesian system of co-ordinates, becomes:

$$\frac{\partial \rho_i \phi S_i}{\partial t} + \frac{\partial (\rho_i u_i)}{\partial x} = 0$$  \hspace{1cm} \text{(B.6)}

When assuming incompressible flow and a rigid solid matrix, the equation simplifies to the so-called saturation equation:

$$\rho_i = \text{constant}$$  \hspace{1cm} \text{(B.7)}

$$\frac{\partial \phi}{\partial t} = 0$$  \hspace{1cm} \text{(B.8)}

$$\phi S_i + \frac{\partial u_i}{\partial x} = 0$$  \hspace{1cm} \text{(B.9)}

Darcy described a relationship between the flow rate and pressure gradient. For multi-phase flow Darcy’s Law is described by:

$$u_j = -\lambda_j \left( \nabla P_j + \frac{\rho_j g}{g_c} \right)$$  \hspace{1cm} \text{(B.10)}

With:

$$\lambda_j = \frac{K_{rj}}{\mu_j}$$  \hspace{1cm} \text{(B.11)}
The flow equations for multi-phase flow are obtained by combining the equation of mass conservation with Darcy’s Law. The fluid density is expressed implicitly or explicitly as a function of pressure using an equation of state. In this example, incompressible flow is assumed. When capillary forces and gravity forces are neglected, the fractional flow is a function of the phase mobilities:

\[ f_j = \frac{\lambda_j}{\lambda_t} \]  
\[ \lambda_t = \sum_{j=1}^{n} \lambda_j \]  
\[ u_j = f_j u_t \]  
\[ u_t = \sum_{j=1}^{n} u_j \]

Using Eq. B.14, Eq. B.13, Eq. B.15 and Eq. B.16, Equation B.9 can be rewritten as:

\[ \phi S_i \frac{\partial}{\partial t} + \frac{\partial u_t f_j}{\partial x} = 0 \]  \hspace{1cm} (B.17)

Eq. B.17 can be rewritten as the Buckley-Leverett fractional flow formulation:

\[ \frac{S_i}{\phi} \frac{u_t}{\phi} \frac{\partial f_j}{\partial S_j} \frac{\partial S_j}{\partial x} = 0 \]  \hspace{1cm} (B.18)
C

MULTI-PHASE FLOW

C.1. THREE-PHASE TOTAL MOBILITY

In Fig. 6.8 a three-phase total mobility plot is depicted in which it is assumed that the foam has a lower viscosity ($\mu_{\text{foam}} = 1$ cP) than the oil phase. However, if a strong foam is present, the foam can have a higher viscosity than the oil and water phase, as is illustrated in Fig. C.1. When no foam is present, as is illustrated in Fig. C.2, the total mobility of the three-phase system always increases when gas is injected.

Figure C.1: Total mobility during a three-phase chemical flood with foam (high $N_c$). The apparent viscosity of the gas phase is dependent on the foam strength, in this example the apparent foam viscosity is higher than the water- and oil viscosity. Input values of coreflood [2] and chemical desaturation parameters: $\mu_w=0.8$ cP, $\mu_o=2.3$ cP, $\mu_g=0.02074$ cP, $\mu_{\text{foam}}=3$ cP, $N_w=1$, $N_o,w=1$, $N_o,g=3$, $N_g=2.43$, $S_w,c=0.59$, $S_g,c=0$, $S_o,w,c=0.04$, $S_o,g=0$, $K_{r,w}=1$, $K_{r,o,w}=1$, $K_{r,o,g}=1$, $K_{r,g}=0.73$. Also see Table 9.2.

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Figure C.2: Total mobility during a three-phase chemical flood without foam (high $N_c$). The apparent viscosity of the gas phase is dependent on the foam strength, in this example no foam is generated. Input values of coreflood [2] and chemical desaturation parameters: $\mu_w=0.8\,\text{cP}, \mu_o=2.3\,\text{cP}, \mu_g=0.02074\,\text{cP}, N_w=1, N_o,w=1, N_o,g=3, N_g=2.43, S_{wc}=0.59, S_{gc}=0, S_{og,c}=0.04, S_{og}=0, K_{rw}=1, K_{ro,w}=1, K_{ro,g}=1, K_{rg}=0.73$. Also see Table 9.2.
C.2. THREE-PHASE RELATIVE PERMEABILITY MODELS

In subsection 7.4.2 the three-phase relative permeability models of Baker and Stones are discussed. Fig. C.3 depicts the relative oil permeability using the StonesI model. Fig. C.4 depicts the relative oil permeability using the StonesII model. As can be observed this model gives an inconsistent output with negative oil relative permeabilities (the blank space in the figure).

Figure C.3: Three-phase relative oil permeability using the STONESI model. Input values of coreflood [2]: \( N_w = 3, N_{o,w} = 2, N_{o,g} = 2, N_g = 2, S_{wc} = 0.15, S_{gc} = 0, S_{o,w} = 0.22, S_{o,g} = 0.15, K_{rw} = 0.16, K_{ro,w} = 0.69, K_{ro,g} = 1, K_{rg} = 1 \).

Figure C.4: Three-phase relative oil permeability using the STONESII model. The white space represents inconsistent, negative relative permeability values. Input values of coreflood [2]: \( N_w = 3, N_{o,w} = 2, N_{o,g} = 2, N_g = 2, S_{wc} = 0.15, S_{gc} = 0, S_{o,w} = 0.22, S_{o,g} = 0.15, K_{rw} = 0.16, K_{ro,w} = 0.69, K_{ro,g} = 1, K_{rg} = 1 \).
C.3. PERCOLATION THEORY

To model the distribution of oil and gas inside a porous medium, the percolation theory can be used as an idealized and simple model [30]. The percolation theory is a statistical method in which a network with bonds is occupied with a certain probability \((p)\). When neighboring bonds are occupied, clusters are formed. The clusters grow in size until a critical value is reached in which one large, percolating cluster dominates the connectivity of the network, also referred to as the percolation threshold \((p_c)\) [29]. The quantity of the percolation threshold depends on the number of connections of a site \((z)\) and the dimension of a network. For example, in a simple cubic network each site has six connections and its percolation threshold is \(p_c = 0.25\) [85].

The percolation theory can be used to describe three-phase steady state flow, which is applicable when foam is present in the system i.e. oil, water, gas. The model requires the flow to be in equilibrium, which is only the case when the capillaries (i.e. bonds) filled with a certain phase can form a percolating cluster [85]. The phase remains trapped if no percolation cluster can be formed. Consequently a phase can only flow if the fraction of capillaries containing the phase exceeds the percolation threshold. The probability a capillary contains a certain phase depends on its size and the wetting capability of the phases. The thinnest capillaries contain the wetting phase (i.e. water), the intermediate capillaries the middle phase (i.e. oil) and the largest capillaries contain the non-wetting phase (i.e. gas). The fraction of bonds that contain a certain phase is therefore not equal to the saturation of that phase. As gas occupies the largest pores, the fraction of occupied capillaries is expected to be lower than the gas saturation.

According to the percolation theory, flow of all three-phases is only possible in a region where all saturations exceed their residual saturation (Fig. C.3) and if the fraction of bonds available for flow exceed the percolation threshold. Within a simple cubic network, characterized by a percolation threshold of \(p_c = 0.25\), four-phase flow is impossible as the summation of the fractions of bonds occupied by each phase would exceed unity [85]. However, if a fraction of bonds that are not occupied by a certain phase are available for flow of multiple phases, this assumption is invalid and four-phase flow might be possible. This same concept explains that a disconnected phase (with a fraction below the percolation threshold) can still be mobile.
**D.1. APPARENT VISCOSITY**

The pressure drop data of the corefloods is used to determine the apparent viscosity, which is useful when comparing data with different core properties or injection rates. Fig. D.1 shows the apparent viscosity during injection of the chemical slug and drive solution for the five different corefloods. Consult subsection 6.5.2 for more information.

Figure D.1: Apparent viscosity during injection of the chemical slug and drive solution.

<table>
<thead>
<tr>
<th>Chemical slug</th>
<th>PV</th>
<th>Drive solution</th>
<th>Chemical slug</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.5 liquid PV</td>
<td>30.48 cm</td>
<td>(lower concentration)</td>
<td>3.81 cm</td>
</tr>
</tbody>
</table>

Figure D.2: Schematic of the corefloods.
D.2. SALT DISPERSION

In section 5.5 a dispersion model is discussed which is used to history match the experimental data in subsection 6.5.4. The salinity matches of coreflood [3] and [4] can be observed in Fig. D.3 and Fig. D.4. Fig. D.5 depicts the effluent salinity profile of coreflood [1].

Figure D.3: Retrieving the effective dispersivity for coreflood [3] by matching Eq. 5.13 with the experimental salinity data.

Figure D.4: Retrieving the effective dispersivity for coreflood [4] by matching Eq. 5.13 with the experimental salinity data.
Figure D.5: Effluent salinity profile during chemical injection of coreflood [1].
D.3. HISTORY MATCHING A WATERFLOOD

In section 8.1 the history matches with the experimental data are discussed. Fig. D.6 shows which parameters in the Corey model determine the pressure drop. The end-point permeability of oil ($K_{ro}$) and the connate water saturation ($S_{wc}$) determine the initial pressure. If the core is waterflooded until no oil is observed in the effluent, the pressure is determined by the end-point relative permeability of water ($K_{rw}$) and the residual oil saturation ($S_{orw}$). The Corey-exponents ($n_{ow}$ and $n_{w}$) determine the slope of the curves.

![Figure D.6: History matching pressure data of a waterflood using the two-phase Corey model (Eq. 7.2).](image)

D.4. SENSITIVITY OF FOAM SURFACTANT FUNCTION

In subsection 8.3.2 it is discussed how the surfactant function ($F_{surf}$) of the foam model is influenced by $fmsurf$ and $epsurf$, as illustrated by Fig. D.7.

![Figure D.7: Fsurf is plotted against a dispersed surfactant profile ($Npe = 10$) for different numbers of $fmsurf$ and $epsurf$.](image)
E.1. Grid Sensitivity

A grid sensitivity study has been performed on the history match of surfactant-coreflood [2], as discussed in subsection 9.4.7. The number of gridcells is increased from \(z=100\) to \(z=1000\).

![Grid sensitivity plot](image)

Figure E.1: Grid sensitivity on final history match of the oil recovery of coreflood [2], increasing the amount of gridcells from \(z=100\) to \(z=1000\).
E. Simulation study

Figure E.2: Grid sensitivity on final history match of the pressure drop of coreflood [2], increasing the amount of gridcells from $z=100$ to $z=1000$.

E.2. Comparison approach foam model

The foam parameters in the one-dimensional model are independent of permeability. In the two-dimensional model permeability dependent foam functions are introduced, as is discussed in subsection 10.1.2.

Figure E.3: Oil cut and oil recovery of the one-dimensional surfactant-foam model and the two-dimensional homogeneous surfactant-foam model of coreflood [2], which uses permeability dependent foam parameters.
E.3. Numerical Instabilities

During the simulations of the surfactant-model, numerical instabilities occurred. The instabilities were solved by changing several numerical settings. By prioritizing the desaturation calculations during the flow equations, as is illustrated in Fig. E.5 and Fig. E.6, the discrepancy of one timestep between the salinity and capillary number was solved.

By decreasing the initial and maximum timestep, numerical oscillations in the one-dimensional model were reduced, as illustrated in Fig. E.7 and Fig. E.8. In Fig. E.9 the effect of changing the tracer solver method from explicit to implicit is shown. The implicit method is unconditional stable, but introduces numerical diffusion. This is due to the upwind algorithm that averages the tracers over the entire cell volume. Therefore, the decision for a tracer-solver approach should be based on the impact of the numerical instabilities or numerical diffusion on the simulation results.

Figure E.4: Pressure plot of the one-dimensional surfactant-foam model and the two-dimensional homogeneous surfactant-foam model of coreflood [2], which uses permeability dependent foam parameters.
Figure E.5: Negative priority of capillary number and IFT calculations in flow equations.

Figure E.6: Positive priority of capillary number and IFT calculations in flow equations.
Figure E.7: Numerical oscillations in simulation output. Initial $\Delta t = 0.05$ hour. Maximum $\Delta t = 1$ hour.

Figure E.8: Simulation output. Initial $\Delta t = 0.01$ hour. Maximum $\Delta t = 0.05$ hour with explicit tracer solver method.
Figure E.9: Simulation output. Initial $\Delta t = 0.01$ hour. Maximum $\Delta t = 0.05$ hour with implicit tracer solver method. The implicit method is unconditional stable, but introduces numerical diffusion. This is due to the upwind algorithm that averages the tracers over the entire cell volume.