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**Numerical Simulation Study of Low-Tension-Gas (LTG)
Flooding for Enhanced Oil Recovery in Tight
Formations**

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Flooding for Enhanced Oil Recovery in Tight
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THESIS

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Dedicated to my family.

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Numerical Simulation Study of Low-Tension-Gas (LTG) Flooding for Enhanced Oil Recovery in Tight Formations

Marilena Papadopoulou, M.S.E.
The University of Texas at Austin, 2017

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This thesis focuses on the numerical simulation of Low-Tension-Gas (LTG) process, that involves the injection of surfactant and gas to generate and propagate foam for mobility control, and to mobilize the residual oil to waterflood by reducing the interfacial tension between oil and water. This EOR process, is an alternative to surfactant-polymer process and is applicable to challenging conditions including tight formations, high temperature and high salinity reservoirs where polymer implementation is not feasible due to physical and/or economic constraints. In this study, the experimental data used for numerical simulation involve tight carbonate rock with high formation salinity.

For the numerical simulation study, a LTG model developed by the University of Texas at Austin and incorporated into the compositional equation-of-state CMG/GEM simulator is utilized. The model includes the modeling

of IFT reduction, surfactant partitioning, relative permeability, foam, and adsorption.

In some case, a numerical simulation model may involve a large number of uncertain parameters, which often exceeds the experimental data available. Hence, there may exist more than one combination of the parameters that provide a good agreement between the model and the experiments. Therefore, a numerical simulation study is undertaken in order to develop a methodology for determining the LTG model parameters through a series of simulations and data-fitting of strategically selected experimental data to reduce the non-uniqueness of the problem while preserving the physics of the process.

Low capillary number water-oil relative permeability parameters are determined through matching of waterflood experimental data, which is a preliminary procedure of LTG flooding. In addition, the reference foam mobility reduction factor, the dry-out function, and the gas relative permeability curve are estimated through matching of foam quality tests. Thereafter, a sensitivity analysis of the remaining uncertain parameters is performed to investigate the significance of the parameters on the oil recovery and pressure drop. Data-fitting of the LTG flood experimental data is then performed to determine estimations for the rest of the parameter space, including surfactant adsorption, dispersivity, intermediate capillary number and associated oil-water relative permeability curves, oil-gas curvature, and the rest of the foam parameters.

In conclusion, this thesis provides a methodology for estimating relative permeability, foam strength, adsorption and dispersivity parameters for

LTG simulation. These findings will be proven useful for understanding LTG flooding behavior in EOR processes.

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Chapter 1

Introduction

1.1 The Low Tension Gas Process

Enhanced Oil Recovery (EOR) encompasses advanced processes of hydrocarbon production which involve sophisticated techniques of injection of selected substances into hydrocarbon reservoirs [43], [44]. These techniques include low salinity water flooding, gas injection, polymer injection, alkaline flooding, surfactant flooding and various combinations of the above [44],[9],[25], [32].

These processes are typically implemented for tertiary recovery, to mobilize the residual oil that is left behind by waterflooding, due to either macroscopic permeability heterogeneity or poor displacement efficiency. Surfactant-polymer (SP) processes have shown effective oil recovery, by lowering the interfacial tension between oil and water using surfactant and by providing mobility control through the use of polymer. The implementation of the process to tight formations [77], [79] and in conditions of high salinity and high temperature [13], is not feasible due to economic and/or physical limitations.

The Low Tension Gas (LTG) process, is an alternative to SP method, where surfactant injection is preserved for IFT reduction and mobilization of

the otherwise immobile oil, but instead of polymer, foam is used for liquid mobility control. Foam is generated and propagated by surfactant and typically nitrogen or hydrocarbon gas. Therefore, the use of surfactant has two purposes; for emulsification and foaming for mobility control and improved displacement and sweep efficiency.

Das *et al.* (2016) applied the LTG process to a tight reservoir (<10 mD) with high formation salinity (200,000 ppm) successfully, and observed that oil breakthrough and ultimate recovery are strongly affected by foam injection quality [14]. Nguyen *et al.* (2015) demonstrated the applicability of the process to high salinity (>189,000 ppm) and high temperature (85 °C) sandstone reservoirs and also showed that salinity gradient design plays a key role in determining LTG flood performance [50]. Szlendak *et al.* (2013) examined the effectiveness of the LTG method for tertiary recovery in tight formations (2 - 35mD) and indicated that 50% foam quality resulted in the highest oil recovery [77].

1.2 Problem Statement

1.2.1 Research Significance

The Low Tension Gas Process is a potentially significant method of oil recovery due to its applicability in challenging reservoir conditions. Yet, field implementation of the methodology is not currently undertaken due to the fact that this method is new, and its success relies on improved understanding of the interactions between salinity, surfactant concentration, microemulsion

phase behavior, foam strength and related parameters, such that the method can be repeatedly and reliably verified.

In order to improve or confer current understanding of the LTG process, a numerical simulation study is undertaken using a model developed by the University of Texas at Austin and implemented into the compositional equation-of-state simulator CMG/GEM of the Computational Modeling Group (CMG) [36]. The model has not been extensively verified due to limited available experimental data, thus only certain parameters could be determined. This study is necessary in order to develop a methodology to estimate the model parameters using strategically selected experimental data, to provide physical meanings of the parameters, and to evaluate the ability of the model to match laboratory data.

1.2.2 Research Problems

One important aspect of the numerical simulation of the LTG process is the large number of uncertain parameters and the limited experimental data available. Model physical properties, such as foam strength and gas relative permeability, are difficult to be measured. Therefore, they can only be determined through modeling of the process.

In view of the fact that the number of uncertain physical parameters incorporated in the numerical simulation model often exceeds the number of available experimental information, the problem is under-determined and thus may be non-unique. Within a certain margin of tolerance the number of

parameter permutations that provide reasonable solutions is non unique [3].

The systematic estimating of parameters to be used in the CMG model, is an important stage in the numerical analysis of LTG process. Therefore, in this study, we seek to develop a methodology such that parameter space is systematically determined in order to find the parameter sets that ultimately satisfy the experimental results.

The parameter groups examined in the study include relative permeability, foam strength, and surfactant adsorption and dispersion. The methodology followed to obtain estimations for these parameter groups, is described in the following section.

1.3 Research Objectives and Methodology

1.3.1 Objectives

The objectives of this study are as follows:

- Identify the significance of the key parameters on the cumulative oil recovery and pressure drop during LTG flooding.
- Establish a procedure to reduce the non-uniqueness of the model parameters through strategic matching of experimental data.

1.3.2 Methodology

An extensive literature review was conducted in order to obtain state of the art information on foam and surfactant behavior and their effects on oil

interactions.

Experimental results were used for calibration and subsequently determination of the matching effectiveness of the model. For the determination of the model parameters a staged parameter group estimation technique was undertaken whereby the parameter groups were determined in transient stages and were integrated in the final physical process. Thus, certain parameters were estimated through matching of a series of laboratory experiments, including water-flooding and foam quality tests.

Residual oil and water saturations, and water-oil end-point relative permeability taken from waterflood and oil flood experimental data, together with data extracted from literature, were used to perform a waterflood match to find the curvatures of the oil-water relative permeability curves and the oil-water end-point relative permeability.

Matching of the foam quality tests, which were performed after the drive injection and at residual oil saturation, was undertaken in order to get an estimation for the reference foam mobility reduction parameter, the dry-out function, and the gas relative permeability curve.

A sensitivity study was then performed to examine the significance of the parameters on the cumulative oil recovery and the pressure drop across the core. It is evident that conducting a full scale parametric study to fully assess the effect of each parameter would be computationally inefficient, and also various parameters affecting the model are not independent but are inter-

related. Therefore, the sensitivity of the parameters is first evaluate by groups and then individually within each group.

Matching of the LTG process followed to obtain estimations for the relative permeability, surfactant adsorption, dispersion, oil-gas curvature, and foam model parameters describing the effect of microemulsion phase behavior and oil saturation of the excess phase.

Finally, a few possible upgrades of the model were proposed in order to improve the capabilities of the model to simulate the true physical behavior of the LTG process. Recommendations on possible experiments that will help the modeling of the LTG process were also provided.

1.4 Outline

This thesis contains five chapters, the contents of which are briefly described below:

Chapter 2

Chapter 2 provides a comprehensive background on the subjects of foam structure and stability, surfactant behavior and importance, foam transport through porous media, and microemulsion phase behavior. It also reviews state of the art research in the area of the Low Tension Gas process.

Chapter 3

Chapter 3 provides a review of the LTG model used in this study and it explains the analytical basis of IFT-reduction, surfactant partitioning, relative permeability, foam and surfactant adsorption modeling.

Chapter 4

Chapter 4 presents the methodology for implementing the research tasks, the experimental procedure which provides the results for calibrating the simulator and the simulation set-up. Results relating to the above, including sensitivity and matching studies are also presented and discussed.

Chapter 5

Chapter 5 concludes the findings from the work presented in this thesis and provides recommendations for further research.

Chapter 2

Literature Review

2.1 Overview of EOR processes

2.1.1 General

Oil production is generally divided into three main stages [44], [43], [25] as shown in Figure 2.1 below:

- Primary
- Secondary
- Tertiary or Enhanced

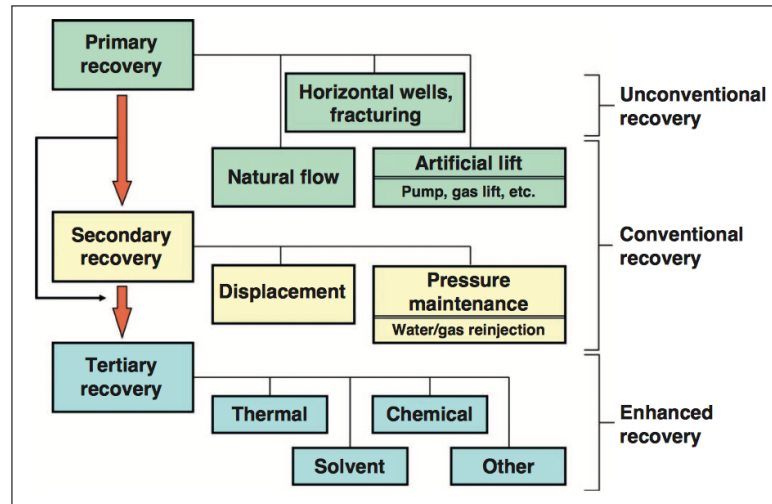


Figure 2.1: Oil recovery classifications [44]

In Primary production, naturally occurring energy (pressure) within the reservoir is used to drive oil to the surface [44], [25]. Secondary production is achieved by injecting water (water-flooding) or by pumping compressed gas into the reservoir [44], [25]. It is well documented though, that only a fraction (approximately 10% -15%) of the petroleum in reservoirs can be recovered with primary and up to 33% after secondary production [32], [2], [84], while the growing energy demand will require improved production from mature fields in the coming years [4].

Therefore, Tertiary production or Enhanced Oil Recovery (EOR) incorporates advanced processes of hydrocarbon production, which involve injection of heat energy (Thermal) or chemical agents (surfactants or solvents) into hydrocarbon reservoirs or injection of gas, to cause physical or chemical changes that will increase production [44], [43], [25], [66].

2.1.2 Thermal Techniques

Thermal techniques involve the introduction of heat energy into oil reservoirs. By increasing reservoir temperature, a consequent decrease in oil viscosity results in lower mobility ratio [66], and due to the fact that the effect of temperature is especially pronounced for viscous crudes, these processes are normally applied to heavy and viscous oil formations [42].

The most popular thermal techniques are Cyclic Steam Injection also referred to as Huff & Puff, Steamflooding, and Steam- Assisted Gravity Drainage (SAGD) [4].

2.1.3 Chemical Techniques

Chemical Techniques consist of injecting various chemical additives in the porous formation to mobilize the oil, so that it can be extracted. The main chemical techniques used are [44], [41], [25], [66], [76]:

- Polymer flooding
- Surfactant Polymer flooding
- Alkaline flooding
- Micellar flooding
- Alkaline Surfactant Polymer flooding

Typically, the mixture consists of a solution of polymer in water (polymer flooding) or in conjunction with a surfactant (surfactant-polymer flooding,) and/or a solution in water of an alkaline chemical, such as hydroxide, carbonate or orthosilicate of sodium (alkaline flooding), or a combination of a micellar and a polymer slug driven by brine (micellar flooding) and more recently, a combination of alkali-surfactant-polymer flooding (ASP) [44], [25], [66].

Polymers generally improve mobility ratios and surfactants substantially reduce interfacial tension and produce oil-water emulsions [25], [66]. Alkalis generate soap by reacting with the acidic components of the crude oil and reduces surfactant absorption by the formation [76].

2.1.4 Gas Injection Techniques

Gas injection techniques involve the displacement of oil towards the production well by the injection of gas. The gas (commonly CO_2 , Nitrogen or hydrocarbon) is injected in the oil bearing stratum at high pressure [4]. The fact that CO_2 is miscible with crude oil, meaning that they mix into a single phase fluid [84], it costs lower than other gases, and due to the possibility of CO_2 sequestration, make this gas a popular choice [4], [66]. The process of CO_2 injection for enhanced oil recovery is schematically demonstrated in figure 2.2 [34].

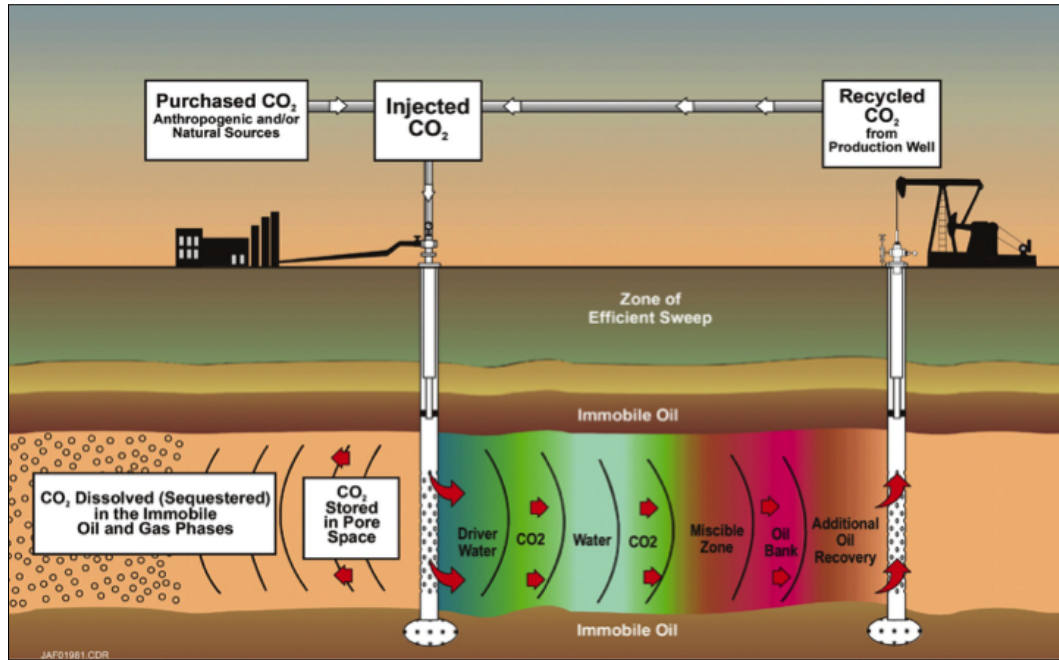


Figure 2.2: CO_2 Injection for EOR [34]

Reservoir temperature and pressure conditions as well as oil character-

istics affect the phase behavior of the mixture of gas and oil [58], and thus two distinct cases of gas injection are identified: Miscible and immiscible recoveries.

The main mechanisms of miscible recovery, is reduction of interfacial tension, viscosity reduction and enhanced mobility [66], [58]. In general immiscible EOR occurs when reservoir pressure is below the Minimum Miscibility Pressure and is less efficient than miscible recovery [58].

2.2 Foam

2.2.1 Foam Structure

Foams are dispersions of a gas phase in a liquid phase. The liquid phase consists mainly of water or a water/hydrocarbon mixture, while the two most common gas phases used in petroleum engineering are N_2 and CO_2 .

The volume of the gas phase is generally larger than the liquid and is made discontinuous by thin (two-dimensional) interfaces, in which the presence of liquid is in the form of thin films, which surround the gas bubbles. These regions, consisting of the liquid film and the interfaces to the gas phase, are referred to as the lamellae [70]. Gauglitz *et al.* [23] have defined foam structure in porous media as “a dispersion of gas in a continuous liquid phase with at least some gas flow paths made discontinuous by thin liquid films called lamellae”.

The liquid-filled interstitial channel between three bubble lamellae is called the Plateau border, as shown in the schematic in figure 2.3, acknowledging the contribution of the Belgian physicist Joseph Plateau in the 19th

century who defined a set of geometrical rules governing foam structure [55]:

- Foams consist of smooth surfaces (bubbles)
- The mean curvature of films is constant for a particular foam
- Bubbles meet in threes at an angle of 120 degrees forming liquid filled borders (Plateau Border)
- Plateau Borders meet at junctions at a tetrahedral angle to form a vertex

Plateau borders meet at junctions to form networks and thus the foam structure can be thought of as consisting bubbles, films, plateau borders and junctions with precise but simple geometry. Films not only are an evident feature of the foam structure, they also play an important role in its stability.

The most common method of industrially forming a foam is gas saturation of the liquid, by injecting gas under pressure [85], [70].

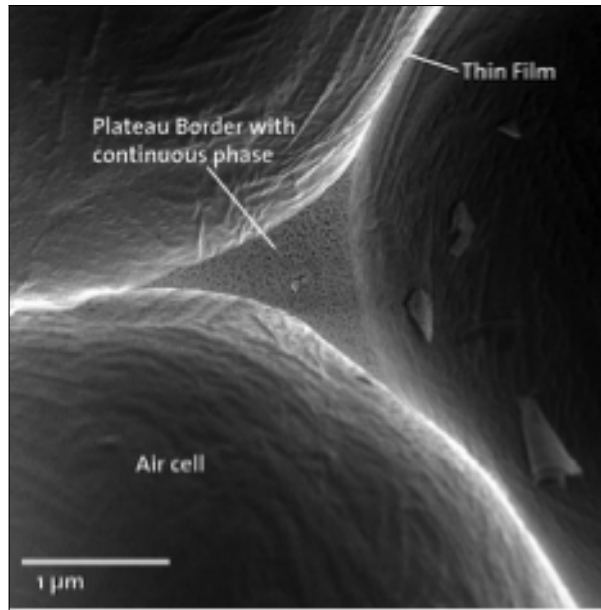


Figure 2.3: Schematic of the plateau border between air bubbles

2.2.2 Foam Stability

2.2.2.1 Destabilizing Mechanisms

Foams have thermodynamically unstable structures that are time related. Foam bubbles are initially quite large and then they undergo various processes mainly related to gas pressure equilibrium. Mechanisms of destabilization related to foam structural changes are:

- Drainage: defined as the liquid flow from the foam structure to the pure liquid phase. It is important that gas saturation occurs faster than drainage.
- Coalescence: the merging of two smaller bubbles to form one larger

caused by the rupture of the interstitial film. Film Rupture occurs when a foam film gets too thin and/or weak and ruptures.

- Coarsening or Disproportionation: the process through which bubbles grow in size while smaller shrink or disappear due to the gas pressure differential between bubbles and gas diffusion.
- Creaming: the rise of bubbles to the top of the system due to their lesser density and segregation.

The term stability refers to a state where the foam is relatively stable in a kinetic sense. The following foam physiochemical parameters control foam stability [70]:

- Surface Tension
- Capillary suction
- Surface elasticity
- Viscosity
- Electric double layer repulsion
- Disjoining Pressure

2.2.2.2 Interfacial Tension and Surface Elasticity

The interfacial tension (IFT) or surface tension is defined as the force per unit length that is required to hold two surfaces together at equilibrium.

The Gibbs elasticity of foam films is the ratio of the change in surface tension to the change in film surface area. It is basically a measure of the films capacity to undergo changes of deformation without rupture.

Capillary Suction occurs due to the curvature of the liquid meniscus inducing a pressure difference across the meniscus. This pressure depends on interfacial tension and the radius of curvature of the meniscus.

The electric double layer arises due to the fact that dispersed particles carry an electrical charge. Charges are carried by ions and the medium, as a whole, must be neutral. Therefore, considering each particle separately, it must be surrounded by an electric double layer. One layer consists of the charge on the surface of the particles and the other by the opposing ions in the solution and its stability depends on the strength of this layer [81] ,[16].

2.2.2.3 Interfacial Viscosity

The existence of a surface viscosity was first proposed by the Belgian physicist Joseph Plateau in the 19th century [55], [47].

Foams are compressible media with rather large viscosities. For Newtonian fluids dilatational viscosity may be neglected, although in the case of interfaces, both fundamental deformations taking place at the interface must

be considered: The shear viscosity and dilatational viscosity.

Shear viscosity is related to the yielding of a fluid surface to an applied shear stress whereas dilatational viscosity expresses the magnitude of the viscous forces during a rate expansion of a surface element.

The dilatational viscosity of the surface is attributed to microscale shearing flow of viscous fluid through thin liquid films and Plateau borders as well as to surface viscous effects.

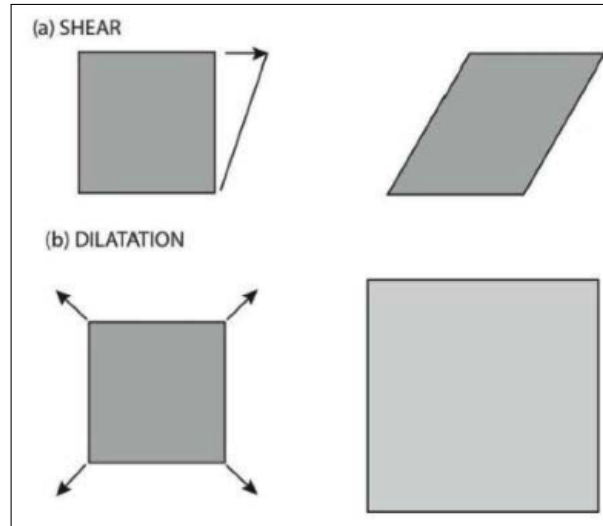


Figure 2.4: Schematic of shear and dilatational viscosity

Therefore, both elastic and viscous resistances oppose the expansion and deformation of surface films. The dynamic surface tension experienced during a rate-dependent surface expansion is the resultant of the elastic forces, the surface shear, and dilatational viscosities.

2.2.2.4 Disjoining Pressure

The disjoining pressure is the total pressure difference between the gas phase and the liquid phase within a film and it is highly dependent on the film thickness [70]. It is the negative derivative of the Gibbs energy per unit area with respect to distance, and it is the force per unit area between colloidal species, which is interpreted as the pressure required on the film surface in order to maintain its thickness [88].

The disjoining pressure is composed of three components: electrostatic repulsion, van der Waals attraction, and steric/hydration forces. Positive disjoining pressure occurs when the lamella forces are repulsive, and attractive forces cause negative values of the disjoining pressure. The attractive van der Waals component results from the dipole-induced-dipole interactions between molecules across the film. These forces dominate where surfactant is absent making disjoining pressure negative and hence lamellae short lived.

Disjoining pressure is a controlling parameter of lamella stability and is highly dependent on the film thickness [70]. As film thickness decreases, a primary maximum of disjoining pressure occurs when the repulsive electrostatic force becomes larger than the van der Waals attraction. Films at this thickness are referred to as common black films (CBF). At a further decrease of film thickness, a minimum of disjoining pressure occurs when steric/hydration forces become large enough compared to the attraction force. Newton black films occur past this branch when the steric/hydration forces initiate a very steep repulsive branch [88].

The stability of foams is determined by the processes of film thinning, when two or more bubbles come closely together but do not touch each other and there is no change in the total surface area, and film rupturing, when two or more bubbles fuse together to form a single, larger bubble. However, lifetime stability of foams is determined primarily by the film thinning time rather than the film rupturing time.

An agent is hence necessary to prevent the coalescence and coarsening to reduce capillary forces and surface tension between the bubble surfaces and improve foam stability [70] [20].

2.3 Surfactants

Surfactants are chemical substances that find an application in almost every chemical industry. This includes the oil industry, in which they have an important role in enhanced and tertiary oil recovery among others [80]. These substances are amphiphilic or amphipathic meaning that they have a double affinity; one for polar media and one for non polar media consisting of amphiphilic molecules with a hydrophilic part and a hydrophobic part. Therefore, they exhibit the tendency to attach on interfaces and orient themselves such that the polar part lies in water and the non polar out of it. Their presence results in the significant alteration of the interfacial properties, leading to a decrease of the surface or interfacial tension (IFT) [25].

The term surfactant (short for surface-active-agent) defines a compound which demonstrates interfacial activity such as the one described above [39].

2.3.1 Classification of Surfactants

The structure of a surfactant molecule, as shown in the schematic in Figure 2.5, consists of a hydrocarbon (nonpolar) portion, the “tail”, and an ionic (polar) portion, the “head”. The nonpolar portion, which is also referred to as the lipophilic part, interacts very weakly with water molecules in the aqueous solution, and the polar portion, which is also referred to as the hydrophilic part, interacts strongly with water molecules. The balance between the lipophilic and hydrophilic parts of a surfactant characterizes its behavior as a surface-active agent, its tendency to solubilize in oil or water, and consequently its tendency to form water-in-oil or oil-in-water emulsions [25]. More detail about the formation of microemulsions will be given in section 2.7.

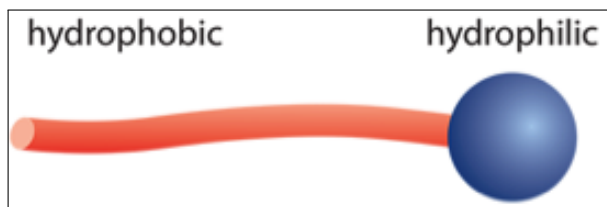


Figure 2.5: Schematic structure of a surfactant molecule [15]

Surfactants are classified into four types that are distinguished by the electric charge of the surfactant molecules polar group [25], [80].

- Anionics: The polar group of an anionic surfactant carries a negative charge (anion) and the counter cation is positioned into the liquid side of the interface. Anionic surfactants are resistant to retention and chemically stable.

- Cationics: The polar group of a cationic surfactant carries a positive charge (cation) the counter anion is positioned into the liquid side of the interface. Cationic surfactants strongly adsorb on the surfaces of clays and sands.
- Nonionics: The polar group of a nonionic surfactant has no apparent ionic charge. Nonionic surfactants are less sensitive to high salinities.
- Zwitterionic (Amphoterics): Zwitterionic molecule can carry both positive and negative charge in the surface active portion [61].

In the oil industry and in particular in EOR processes, anionic surfactants have been the most widely used due to their ability to reduce the IFT, their stability, their relatively low adsorption on reservoir rock, and their economic manufacturing process. Nonionic surfactants have a higher tolerance to high salinity brine compared to anionic, and have poorer surface-active properties, hence are usually used as cosurfactants to improve the behavior of surfactant systems [25]. On the other hand, cationics have a strong adsorption to reservoir rocks and thus are not usually used.

Once the surfactant molecules are introduced into the system, they are attached on the gas liquid interface and strengthen the electrical-double layer which is the source of a repulsive force that stabilizes the lamellae by lowering interfacial tension. The balanced interfacial condition requires some time to stabilize. The ionic strength of the solution relates to the degree of stabilization provided by the surfactant. By reducing surface tension and forming a

protective film at the bubble surfaces it acts to prevent coalescence with other bubbles and reduces the total surface energy needed for foam formation.

2.3.1.1 Effect on Film Elasticity

Surfactants have an important effect on film elasticity. The Gibbs-Marangoni effect caused by surfactant absorption counteracts film rupture and in this respect improves film elasticity and can be briefly described as follows: The Gibbs effect is the reduction of interfacial tension due to the introduction of a surfactant into the system. If a foam film stabilized by a surfactant undergoes a volume increase, then surfactant absorption is reduced leading to increased surface tension and contraction of the surface, and corresponding liquid flow from the non-contracted surface to the contracted surface. This is termed the Marangoni effect. Therefore, the combined result is the Gibbs-Marangoni effect, which along with the increase of the interfacial viscosity provide a mechanical resistance to film thinning and rupturing and thus improves foam stability.

The Marangoni elasticity can be determined experimentally from dynamic surface tension measurements that involve known surface area changes. However such measurements include some contribution from surface dilatational viscosity and emphasize the difficulty in isolating the effect of a single parameter in studying foam behavior. Surface tension variations other than surfactant introduction occur due to changes in solute concentration and temperature gradients through the system.

In experiments with selected surfactants to investigate foam stability in the absence and presence of oil, the high viscosity of certain surfactants demonstrated increased foam stability due to slower drainage and improved resistance to film thinning [52]. In some cases, improved foam stability is attributed to the formation of a liquid-crystalline surface phase acting as a viscous surface layer [62], [70].

The dilatational elasticity of the surface, which depends on the chain length of the surfactant is proportional to both the foaminess and foam stability and thus to the thin-film drainage time. The dilatational viscosity of the surface is inversely proportional to the surface mobility and hence proportional to the drainage time.

The primary viscous stress of wet foam (low dispersed-phase volume fraction) is localized within the Plateau borders and derived from interfacial viscous properties, whereas for dry foams (dispersed-phase volume fraction approaching 1) the total viscous stress is distributed throughout the thin liquid films.

2.3.1.2 Surfactant Concentration

The drainage and stability of single-foam lamellae and bulk foams depend on the surfactant concentration. In an aqueous solution, surfactants at low concentration act like normal electrolytes [71]. Therefore, at low concentrations the drainage is governed by the surface tension gradient, whereas at high concentrations, the formation of micelles govern the stability. Micelles

are clusters of molecules, which protect the hydrophobic chains by orientating them towards the inside of the particles [68], [61].

The micelles form in two different ways depending on the solvent. If the solvent is water, the micelles will form with the tail part directed in the center of the micelle, and the water would be the continuous phase. On the other hand, if the solvent is a hydrocarbon, then the head part of the molecule will be directed in the center of the micelle and the hydrocarbon would be the continuous phase [25]. Micelles formed in a water solvent are shown in the lower right corner of Figure 2.6, whereas micelles formed in a hydrocarbon solvent are shown in the upper right.

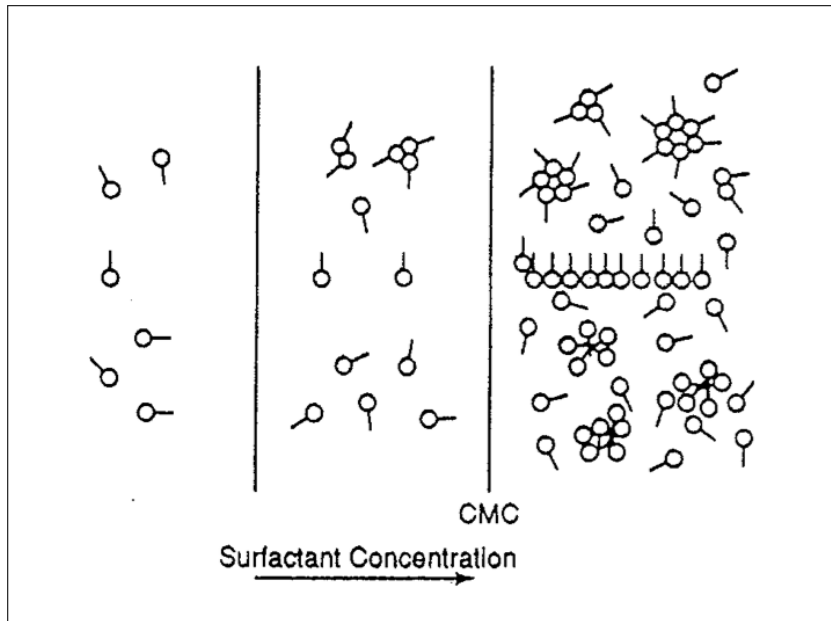


Figure 2.6: Schematic of micelles formation [25]

By directing the hydrophobic groups toward the interior of the cluster

and their hydrophilic groups directed toward the solvent the free energy of the solution is minimized.

The concentration at which the micelle formation becomes significant is called the critical micelle concentration (CMC) [68]. Further addition of surfactant above CMC results in formation of additional micelles, but the concentration of monomers remains essentially the same. This procedure is explained in a simple schematic in Figure 2.6 [25].

At low surfactant concentration, bubbles approach each other under the capillary pressure acting normal to the surfaces causing liquid to be squeezed out of the thinning film (foam lamellae) into the adjoining Plateau borders. At high surfactant concentration, above CMC, the effect of surface rheological properties is less pronounced and plays a secondary role in the film stability.

However, film stability still increases above CMC due to ordered microstructure formation in the draining foam films. The importance of film microstructuring in foams with stratifying films is that it increases the stability and the lifetime of the foams.

At high surfactant concentrations, well above CMC, thin foam films get thinner by going through metastable states before attaining an equilibrium film thickness. The film thickness transitions usually occur when there is a sufficiently large number of vacancies and as a result, a spot is formed and gradually increases its area. By increasing the number of micelles, the number of vacancies decreases and thus the thickness transition will be slower. The

number of stepwise transitions increase with surfactant chain length since the CMC will be lower. At the same surfactant concentration more micelles are present in the solution of the longer chain surfactants, and thus, the easier the micelle ordering [68].

Solubilization may be defined as the dissolution of a large amount of an otherwise insoluble material, in surfactant solutions at concentrations above the CMC [61].

When micelles solubilize a phase that is immiscible with the solvent, then swollen micelles or microemulsions are formed. The term microemulsions is usually used to refer to solutions where oil, water, and surfactant co-exist and are thermodynamically stable, and according to the aggregate size, can be transparent or semi-transparent to the eye. They can be either water-external or hydrocarbon-external type, where the external phase is the continuous phase [25].

This liquid flow results in the convective flux of surfactant in the sub-layer, increasing the surfactant concentration in the direction of the flow, which in turn results in decreased surface tension and a force opposite to the liquid flow, which opposes the film drainage and can create immobile and more stable film surfaces. Surfactant concentration also affects foam texture. Foam bubbles grow in volume as surfactant concentration decreases due to increasing interfacial tension.

Surface tension reduces significantly with the increasing concentration

of the surfactant, as surfactant molecules are accumulated at the interface [73]. Once the lamellae are saturated, the addition of more surfactant is not as effective in decreasing the interfacial tension.

Various other parameters relate to surfactant concentration [72] such as optimum salinity [30],[48].

When surfactant is added in a solution at very low concentrations, the dissolved molecules are dispersed as monomers. However, there exists a critical surfactant concentration above which the surfactant molecules tend to aggregate and form colloidal aggregates, or otherwise, micelles. This concentration is called the critical micelle concentration (CMC).

Surfactant types and concentrations have an important impact on foam texture and viscosity. Increase of surfactant concentration leads to smaller bubble sizes and therefore increase in foam viscosity.

In a system of two immiscible liquids, such as water and oil that are in contact when a surfactant is added to the system, the surfactant molecules adsorb on the interface by consequently displacing some of the water and oil molecules. The hydrophilic part of the surfactant molecule is directed towards the water phase and the lipophilic part towards the oil phase. The concentration of surfactant molecules at the interface distorts the fluid structure in this region and consequently reduces the IFT. The decrease in the IFT continuous as the surfactant concentration increases up to the CMC. Above CMC, a more gradual or even negligible decrease of IFT is observed, as shown in the more

general behavior of IFT with a relatively pure surfactant solution in Figure 2.7. The excess surfactant above CMC would mainly contribute to the formation of micelles [25] [80].

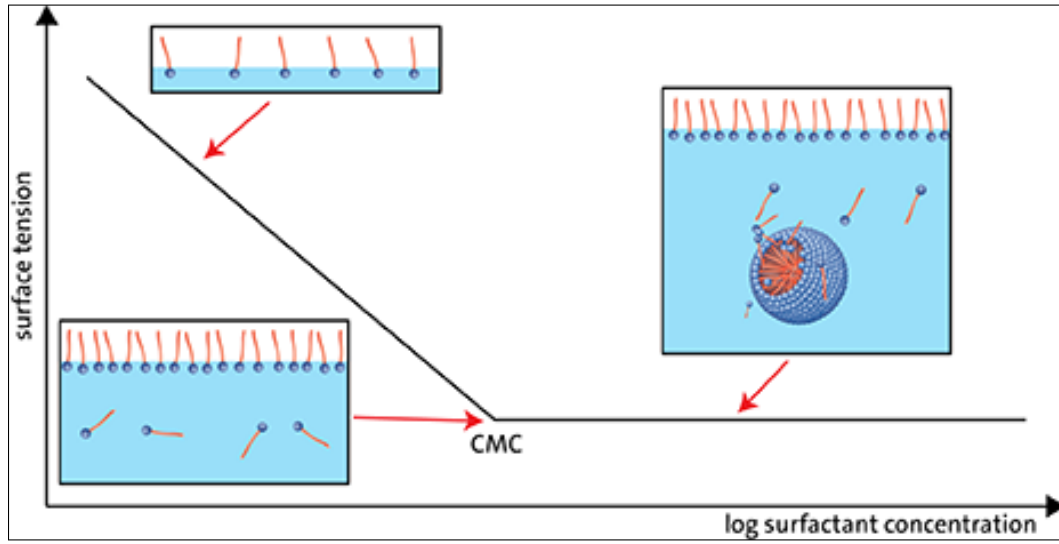


Figure 2.7: IFT reduction with respect to surfactant concentration [15]

Many parameters affect the IFT between an aqueous and a hydrocarbon phase and would possibly affect this trend. These include the salinity, temperature, surfactant concentration, surfactant type and purity, and the nature of the hydrocarbon phase. In surfactant mixtures, in comparison to single-component surfactants, the CMC is not sharp and IFT may continue to decrease at surfactant concentration above CMC [25].

2.4 Foam - Oil Interaction

Gas injection into reservoirs can be used to increase oil recovery. However, reservoir heterogeneity and high gas mobility reduce sweep efficiency and decrease recovery. Using foam can reduce gas mobility and therefore increase sweep efficiency. Foam is thermodynamically unstable, so it is important to predict the foam stability [60]. The efficiency of a foam displacement process depends on the stability of foam films when in contact with oil. Experimental studies have demonstrated the detrimental impact of oil on foam stability [6]. Oil droplets enter into the foam lamella and spread on the gas-liquid interface [8]. The gas-water interface becomes a gas-oil interface, which changes interfacial forces and makes lamella unstable [40], [69], [52].

Film stability is improved by increasing micellar concentration, decreasing film area, decreasing electrolyte concentration and lowering the temperature [70]. However, oil solubilization gives the opposite results. Oil solubilization increases micelle polydispersity aggregation number of the surfactant micelles and the intermicellar attractions and thus increases the number of film-thickness transitions, which result in the formation of loose less packed colloid crystal-like structure inside the thinning film which in turn results in faster stepwise transitions, less stability of the colloid structure and lower foam stability [70]. Foam Stability in the presence of oil has been found to be related to the molecular weight of the oil molecule. Foam generation and stability is possibly connected to the surfactant's ability to solubilize oil molecules [83], [19].

Moreover, foam lamella generation requires a water-wet porous medium. Foam formation in oil-wet formations requires a surfactant, which can change wettability from oil-wet to water-wet [67]. Wettability indicates the affinity of the medium to be in contact with one fluid rather than another. In a water-wet case, oil remains in the center of the pores. The reverse condition holds if all surfaces are oil-wet. In the mixed-wet case, oil has displaced water from some of the surfaces, but is still in the centers of water-wet pores [1].

Most natural soils have an affinity towards water and therefore water flows freely in the smallest interconnected formation pore channels, On the other hand oil will flow in larger channels and/or remain towards the center of the pores .

At high surfactant concentrations, a thicker more stable film is expected because it contains more micellar layers even at high capillary pressure. The presence of fine hydrophobic particles dispersed into the oil phase helps to prevent the formation of very small oil drops and the spreading of oil at the water-air interface, which help stabilize foam. Increased oil viscosity and density have been shown to have a positive impact on foam stabilization [52]. Also long chain alkane molecules have also been shown to improve foam stability attributed to the accumulation of oil droplets in the Plateau borders [74].

When the pseudo emulsion films are stable, the oil stabilizes the foam whereas when they are relatively unstable, the oil will act as an antifoam and when the stability is intermediate the stabilizing and destabilizing effects will compete. The measured stability is the sum of the two effects and can be

higher or lower than the stability of the oil-free system. The stabilizing effect is stronger if the drops are larger and it can overcompensate for the negative effect of the solubilized oil.

The destabilisation of foam by oil, when the pseudo emulsion films are unstable, has applications as antifoaming or defoaming. Antifoaming is when foam inhibiting agents, are mixed into the liquid prior to foam formation whereas defoaming is when foam-breaking agents are added to the foam to destroy it.

2.5 Emulsion Influence on Foam Stability

The stability of emulsion drops inside three-phase foam systems has an influence on the foam stability. When the oil drops collect in the Plateau borders, the drops are compressed and give rise to the formation of pseudo-emulsion films [71] [86], a water film, between an oil drop trapped inside the Plateau border and the gas phase. Manlowe and Radke visually witnessed the negative effect of oil on foam stability, which related on the stability of the emulsion film between a bubble and oil [35].

It is not always certain however, that foam stability will be affected. In the presence of emulsified oil (three-phase foam) stability depends on the pseudo-emulsion film. If the pseudo emulsion film is stable, the larger drops formed from the unstable emulsion get trapped faster in the Plateau borders and inhibiting foam drainage and stabilize the foam. Drops do not coalesce, and the foam stability is not affected. If the pseudo-emulsion film is unstable,

then the oil acts as an antifoam [86]. The larger drops bridge easier and break the foam lamellae faster, oil drops coalesce in the Plateau borders and then, on further foam drainage, the large drops relocate, under the action of the capillary pressure, into the wedges of the Plateau borders [71].

Solubilized oil decreases the stability of the foam by accelerating the film thinning process. Its effect is connected to the configuration of oil relative to the aqueous and gas phases. The oil either does not have any interaction with the solution surface, or it interacts with the solution surface the drop deforms and is separated by a pseudo emulsion film from the gas phase, or the oil drop enters the surface by forming a lens on the solution surface or the oil spreads as a layer on the solution surface. Therefore, the stability of the pseudo emulsion film is a controlling factor in the stability of three-phase foams within porous media [70].

The structure and stability of the pseudo emulsion film depend on:

- surfactant concentration
- electrolyte concentration
- film size
- capillary pressure (drop size)

Important parameters which affect foam stability, such as oil volume fraction, drop size, and oil phase density, were identified and the effect of these

parameters on foam stability was experimentally verified. It was found that the stability increased with the oil fraction in the foam. The foam stability was found to go through a minimum as a function of drop size, due to competing effects of emulsion viscosity at smaller drop sizes and the higher accumulation of oil at larger drop sizes. The density of the oil phase directly influenced the oil accumulation and thus the foam stability [38].

2.6 Foam Transport in Porous Media

2.6.0.1 Foam Behavior in Porous Media

When surfactant molecules congregate at the water-gas interfaces, the interfaces become stabilized to some extent so that bubbles that come into contact with each other do not immediately coalesce. A sufficient concentration of surfactant causes a distinct change in the flow regime through porous media as well as in pipes, thus, much of the gas phase in the rock is unable to flow freely in its own dedicated channels, but is inhibited by lamellae.

Surfactant adsorption and desorption equilibrium is not immediate, but requires appreciable time. Therefore, in many laboratory experiments such equilibrium may not be attained.

At that stage foam in porous media does not consist of large numbers of bubbles within the pore space as in the case of bulk foam [39]. Such foam in the pores of the rock would have a greater effective viscosity and would be extremely difficult to move into, through, or out of the pores than would a collection of larger bubbles in the pores, or than simply a relatively few

lamellae distributed through the pores. Foam in porous media that is movable by the available pressure gradients in a reservoir can consist only as individual gas bubbles separated by liquid lamella that are in direct contact with the wetting fluid of the pore walls [39], [63]. Foam propagates in reservoir rock as a bubble train, where each gas bubble is separated from the next gas bubble by a liquid lamellae film. The length of a foam gas bubble in porous media is on the order of, or exceeds, one pore length [63]

Foam stability and performance in porous media is strongly influenced by lamellae pore surface interactions. Foam texture is believed to be controlled by the porous media.

The behavior of foam in porous media is related to the pore-size distribution, pore shape, pore body-to throat ratio, and the wettability of the solid particles.

Foam texture is a measure of the average gas bubble size. In general, as a foam texture becomes finer, the foam will have greater resistance to flow in matrix rock.

Major foam dynamic processes include foam generation, destruction, and trapping which affect foam flow and flow regimes and mobility all of which are of paramount importance in oil recovery.

2.6.1 Foam Generation

A porous medium shapes foam as confined bubbles and lamellae. Foam can be generated under conditions of simultaneous injection of gas and surfac-

tant solution at a variety of gas rates but at fixed liquid rates or otherwise.

There are three fundamental pore-level mechanisms of foam generation [39]:

- Neck Snap-off,
- Lamella Division and
- Leave behind.

The snap-off mechanism is a mechanical process that describes the formation of bubbles in multiphase flow with or without surfactant when a gas finger invades the gas-liquid interface through a pore throat and then the interface is snapped off. For this reason bubbles generated by Snap-off have approximately the size of the pores of the medium.

The division of lamella or bubble division happens by subdividing existing foam bubbles or lamellae when they approach a branching point.

The leave-behind mechanism describes the formation of liquid lenses left behind as two gas menisci (“fingers”) invade adjacent liquid-filled pore bodies and converge downstream. Lenses created by leave-behind do not make the gas phase discontinuous [88] [51].

As the mixture of gas and surfactant solution flows through the porous rock, rapid shear strain occurs and leads quite naturally to the generation and stretching of bubbles within the pores.

The rate of generation depends on the pore sizes and complexity, and is roughly proportional to the flow rate. The rate of decay depends partly on the surfactants ability (strength) to stabilize the foam. It also depends on the coalescence of bubbles when the lamellae become thin enough to break only where the bubbles of gas approach each other very closely. The frequency of this event depends on the average gas fraction, the flow rate and the geometry of the pore space [39].

Foam texture is a description of the manner in which the gas bubbles are distributed throughout the liquid phase of the foam.

Foams are liquids that depend on shear history. The texture of foam will reach an equilibrium state at a particular shear rate. Finer textured, more dynamically stable foams are produced at high shear rates, higher pressure, and with higher quantities of surfactant, therefore at downhole conditions during fracture stimulations (conditions of high pressure and shear), foams are finely textured with parallel-piped uniform bubbles.

2.6.2 Foam Destruction

Foam destruction refers to decay and coalescence. The main source of foam destruction is lamella destabilization [51] brought on by capillary suction and gas diffusion [39].

Capillary suction coalescence is the dominant mechanism for lamellae breakage during foam flow in porous media and is strongly affected by the surfactant used in the foam [39].

When capillary suction pressure increases to match the lamella rupture disjoining pressure the film ruptures [57]. If the lamellae of a foam can withstand the imposed capillary suction pressure, such a foam is termed a “strong foam”.

In general a limiting capillary pressure, P_c^* , exists above which no foam bubbles can be sustained, foam coalescence is significant and below which coalescence is minimal. Limiting capillary pressure varies with gas flow rate, absolute permeability, and the surfactant used in the foam. The limiting capillary pressure of flowing foam in porous media is typically on the order of (3 kPa) [39].

In certain instances, gravity can also contribute to foam decay when there is a significant density difference between the gas and liquid phases of the foam.

The gas diffusion mechanism leads to coarsening of the flowing foam and is normally of minor consequence for foam flow in porous media.

2.6.3 Foam Trapping

In both continuous and discontinuous foam, trapped gas constitutes the majority of the gas volume in the medium. Trapped foam reduces the effective permeability of gas moving through porous medium by blocking all but the least resistive path therefore reducing the void volume of the porous medium available for flow.

Most important factors that affect bubble trapping are pressure gradi-

ent, capillary pressure, gas velocity, pore geometry, foam texture and bubble-train length, and injection conditions [88], [64] In some gas-occupied channels, confined foam bubbles transport as bubble-trains. The flow resistance of transporting bubble-trains is best addressed in terms of an effective gas viscosity [31].

Generally, there is low trapping for coarse textured foam and a gradual rise to a maximum trapping for finer-textured foam. The trapped foam strongly influences the foam relative permeability by reducing the mobile foam saturation.

2.6.4 Foam Flow in Porous Media

Foam flow in porous can be defined as a dispersion of gas in liquid such that the liquid phase is interconnected and at least some of the gas flow paths are blocked by lamella [18].

Foam flow is dependent on the number of lamellae present, which in turn govern viscosity, relative permeability, fluid distribution, and interactions between fluids [88].

It has been established by previous research that lamellae move through media pores by translation and that rupturing of lamella and bubble coalescence and reformation are uncommon and that the viscosity of lamellae in uniform smooth capillaries relates to the mobility of foam [31].

For flow through porous media, the mobility can be separated into two factors: one has to do with the properties of the rock and the other with the

properties of the fluid.

2.6.5 Regimes of Foam Flow

The quality of foam is defined as the volume fraction of the discontinuous gas phase. Depending on the gas fraction in the foam flow, two flow regimes can be identified [17], [53]. In the high-quality regime, the pressure gradient is independent of gas superficial velocity and dependent on the liquid velocity, whereas in the low-quality regime, the pressure gradient is independent of liquid superficial velocity and dependent on the gas velocity.

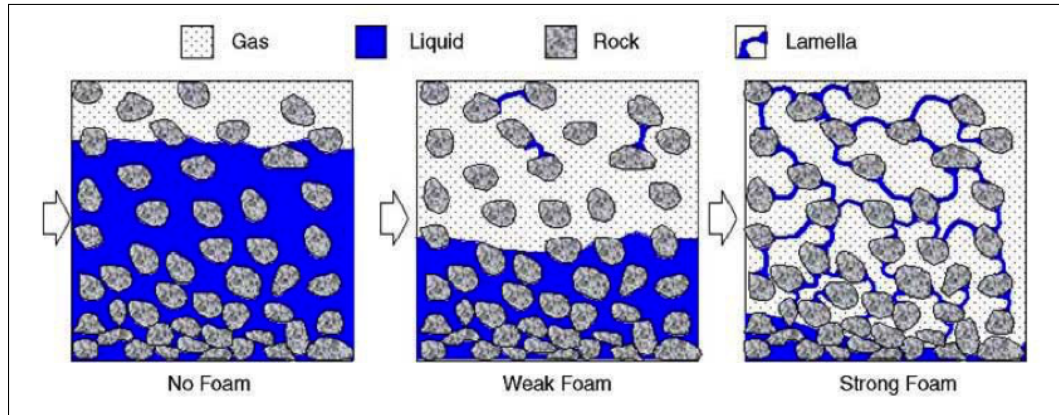


Figure 2.8: Foam Flow Regimes

The transition between high-quality and low-quality foam-flow regimes, depends on critical capillary pressure, gas velocity and surfactant formulation and concentration [5], [37], [22]. Through experiments it has been suggested that an intermediate unstable regime exists between the weak and strong foam regimes [23].

Above critical capillary pressure, lamellae cannot be sustained. A specific value of foam quality, divides the foam flow into the two regimes. The high-quality regime is dominated by coalescence near the critical capillary pressure and the low-quality regime by bubble trapping and mobilization [5], [37], [65].

Most foam-displacement applications in reservoir media use reasonably high gas fractional flows where the gas-aqueous phase capillary pressure is high [39].

2.6.6 Foam Mobility Reduction

Mobility defines the ability of particles to move through the medium. It is well established that mobilities of continuous newtonian fluids in reservoir media are inversely proportional to their viscosities.

The importance of mobility reduction in oil recovery is due to the fact that gas drive fluids are not very viscous and are highly mobile. Therefore, they preferentially flow through zones of high permeability rather than efficiently displacing the oil. Being less dense than both brine and crude oil they also rise to the top of reservoirs. Surfactant-stabilised foams are therefore used to reduce the mobility of the gases in porous media [39].

The mobility of a foam compared to the mobility of the originating gas phase is substantially reduced. Effective viscosity of an elongated inviscid gas bubble, at low capillary numbers is actually larger than that of an equivalent volume of liquid. This is because the shear rate of the liquid in the thin films

near the front and back of the bubble is larger than that of simple parabolic flow of the liquid phase [39].

Foam quality relates to the gas content. Foam mobility is inversely proportional to foam quality up to an upper foam quality stability limit.

Foam mobility reduction results from a combination of foam induced permeability reduction and, on the macro scale, apparent foam induced viscosity enhancement.

Foam induced mobility reduction is caused by at least two different mechanisms: the formation of, or an increase in, the trapped residual gas saturation and increased resistance to flow of the gas phase resulting from the drag of propagating the foam lamellae aqueous films through constricting pore bodies and, especially, through constricted pore throats.

Coarsely textured foam with large bubbles is often referred to as weak foam because there is a moderate reduction in gas mobility. As the texture of a foam becomes finer, the apparent viscosity of the foam increases, and the foam mobility decreases. This occurs because the number of foam lamellae films within a given volume of the porous rock has increased. Finely textured foam with small bubbles is referred to as strong foam because it reduces gas mobility remarkably. Reduced gas mobility in the presence of foam in porous media typically ranges from 10 to 100 times with weak foam and more than 10,000 times with strong foam [88]. thus, foam texture is an important variable in determining the amount of mobility reduction that will occur during foam

flow.

Mobility is reduced by a greater fraction in high than in low permeability rocks by foams that exhibit selective mobility reduction (SMR).

2.7 Phase Behavior of Microemulsions

2.7.1 Microemulsion Definition

Microemulsions are complex systems that are used in EOR processes as oil recovery agents, due to their ability to have ultra-low IFT with either aqueous or hydrocarbon phase. The study of the phase behavior of microemulsion systems can indicate regions of high solubilization of oil and water by the microemulsion system, which are in turn, regions of ultra-low IFT's [25].

Many parameters influence the phase behavior of microemulsions, some of which are the types and concentrations of surfactants, cosurfactants, hydrocarbons, and brine, as well as brine salinity, and temperature. In addition, pressure has also some effect, but it is less pronounced [25].

2.7.2 Effect of Brine salinity on phase behavior

Salinity plays an important role in phase behavior, because by increasing salinity, surfactant solubility in an aqueous phase decreases and vice versa. According to Healy *et al.* [28], an ideal microemulsion system divides into three basic types of microemulsion depending on the salinity of the system. The terminology used in this work, was originally used by Windsor [87], who used the term Type I for the equivalent lower-phase terminology used by Healy *et al.*

[28], Type III for the equivalent middle-phase, and Type II for the equivalent upper-phase.

Type I phase environment, corresponds to relatively low brine salinity, where the solution divides into a water-external microemulsion and an excess-oil phase, as shown on the left of Figure 2.9. Since the microemulsion is the aqueous phase, it resides below the less dense oil phase. At high salinity, Type II phase environment, the system divides into an oil-external microemulsion and an excess-water phase, as shown on the right of Figure 2.9. In contrast to the Type I phase, in Type II the excess-water phase resides below the microemulsion phase due to density effects. At an intermediate salinity, a Type III environment forms, where the systems divides into three phases that co-exist in equilibrium; an excess-water phase, a microemulsion and an excess-oil phase, as shown in the middle of Figure 2.9. The microemulsion, that is saturated with both oil and water and has an intermediate to oil and water density, resides at the middle of the other two phases [25] [28]. Furthermore, it is important to note that, surfactant concentration changes the range of salinity where the three-phase environment exists.

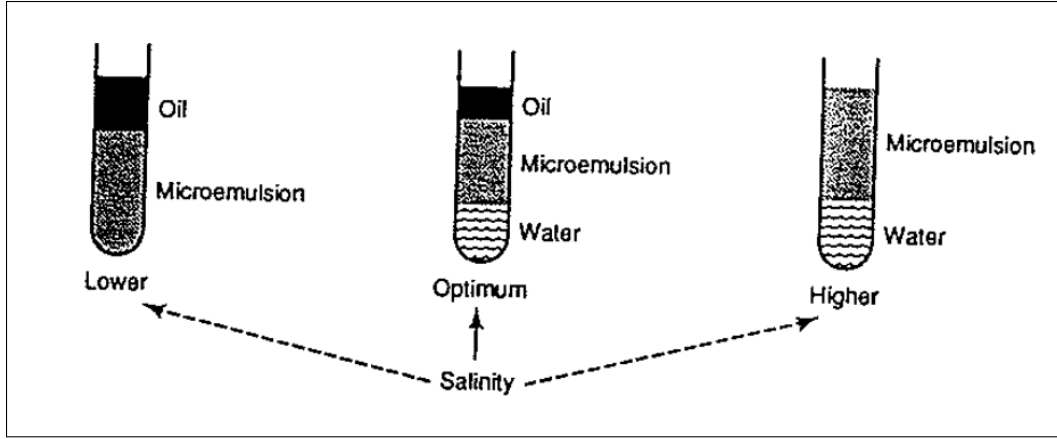


Figure 2.9: The effect of salinity on microemulsion phase behavior [25]

The three-phase environment is associated with the lowest interfacial tension to both oil and water and has a high degree of oil solubility relative to surfactant concentration [78], and thus, it is of particular interest for EOR processes. According to Nelson and Pope [49], in EOR processes, the transition from Type I to Type II environment, or vice versa, is not observed. However, by increasing the salinity it always goes through the Type III environment to reach the Type II high salinity environment.

2.7.3 Solubilization Ratios

In an oil-water-surfactant system, the volume of oil and water solubilized by the microemulsion phase by a unit of surfactant is of great interest [25]. Healy *et al.* [28] expressed this in terms of solubilization ratios as shown in equation 2.7.1, where $l = o, w$ corresponds to either water or oil, and $V_{l,m}$ and $V_{s,m}$ correspond to the volume of oil/water and surfactant in the microemulsion

phase, respectively.

$$R_l = \frac{V_{l,m}}{V_{s,m}} \quad (2.7.1)$$

The parameter $V_{s,m}$ does not include co-surfactant and is assumed to be in the microemulsion phase and not in excess oil or water phases [28]. As explained earlier, the salinity has a great effect on the system formed, and since the solubilization ratios are calculated based on the microemulsion formed (Type I, II, and III), they are also affected by the salinity. Figure 2.10, is a representative plot of the change of the solubilization ratios with respect to salinity.

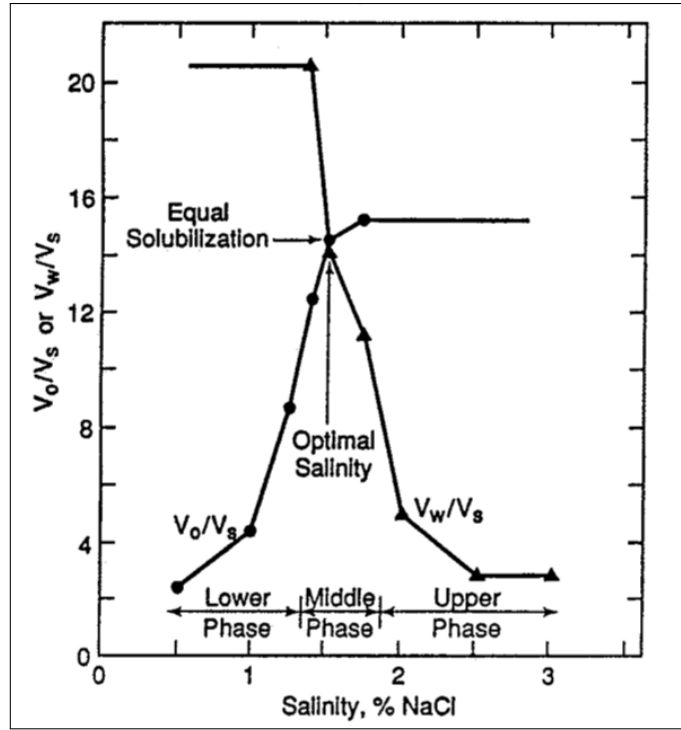


Figure 2.10: Solubilization ratios vs. Salinity [28]

As described in section , Type I microemulsion system is more aqueous, thus all the water is solubilized by the microemulsion and hence the ratio $\frac{V_o}{V_s}$ is constant as shown in Figure 2.10. In the same way, in Type II microemulsion system, which is more oleic, the ratio $\frac{V_w}{V_s}$ is also constant. On the other hand, in Type III the ratios increase or decrease monotonically with salinity and are equal at one specific salinity concentration, called the optimal salinity for phase behavior [25].

2.7.4 Correlation of IFT and microemulsion phase behavior

Since surfactants have an effect on the Interfacial tension (IFT) between phases as discussed earlier, and affect the microemulsion phases formed, there must be a correlation between the IFT and the phase behavior of a microemulsion system. Using the same reasoning, as phase behavior is also affected by salinity, IFT would also be a function of salinity [28] [25]. A usual plot of the IFT as a function of salinity, with typical values measured in EOR systems, is shown in Figure 2.11, where σ_{mo} and σ_{mw} correspond to the IFT between the excess-oil and microemulsion phases, and the excess-water and microemulsion phases, respectively.

The σ_{mo} follows a decreasing trend as the salinity changes from the lower phase system to the middle phase microemulsion system. The reason behind this, is the increase of the oil in the microemulsion and consequently, its decrease from the excess-oil phase. In an analogous way, the σ_{mw} increases as the salinity increases from the middle phase system to the upper phase system, as the water of the excess-water phase increases and the water in the microemulsion phase decreases consequently. It should also be noted, that in the absence of an excess phase, for example the absence of the excess-oil phase in the upper phase system, the σ_{mo} is undefined. This is because of all the oil being solubilized by the microemulsion phase. Correspondingly, at the lower phase system, the σ_{mw} is undefined. Furthermore, there is a value of salinity, at which $\sigma_{mo} = \sigma_{mw}$, and it is called the optimal salinity for IFT [25] [28].

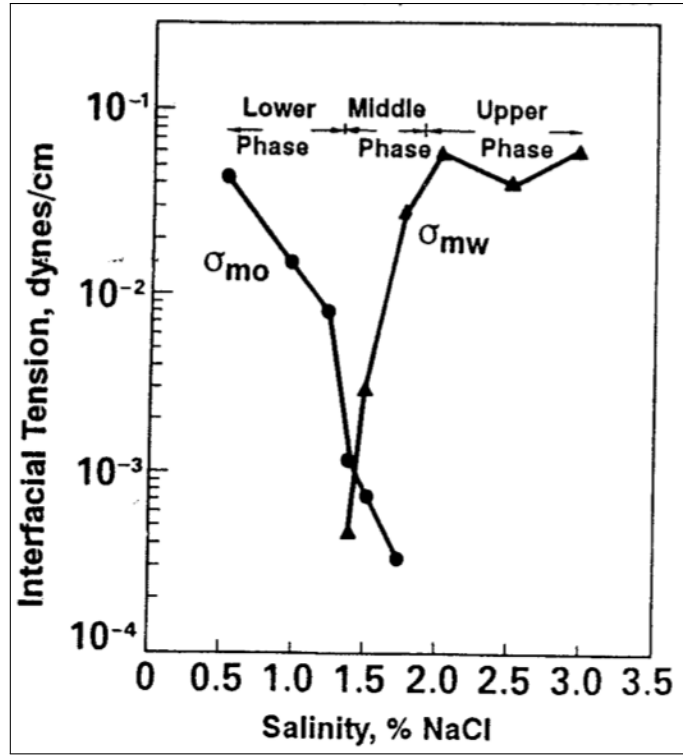


Figure 2.11: IFT as a function of salinity [28]

By comparing the two plots on figures 2.10 and 2.11, it can be noted that there exists a correlation between the IFT between the excess phases and the microemulsion phase, and the solubilization ratios of the excess phases. The Chun Huh [33] correlation is used in this work. More details on this correlation are given in section 3.2.

In addition, the optimal salinity for IFT and phase behavior is very similar, giving rise to important practical aspects, such as the measurements of the optimal salinity for phase behavior and from that the estimation of the optimal salinity for IFT, as measurements of IFT are very difficult to perform

[25] [28].

Although, the usual plots of the solubilization ratios and IFT as a function of salinity have been shown, it is important to note that they will be modified for different cases, due to the many parameters that affect the phase behavior of microemulsions, and consequently the solubilization ratios and the IFT. These include the temperature, pressure, brine, surfactant, and oil composition and water-to-oil ratio (WOR) [25] [28].

2.8 Previous Studies Leading to the Low-Tension-Gas Process

2.8.1 Alkaline-Surfactant-Gas (ASG) Process

Srivastava et al. (2009) [76] investigated the effects of chemicals, Winsor-type phase environment, rock type and heterogeneity of foam to better understand the behavior of foam related to ASG process. Furthermore the performance of ASG flooding was compared with ASP flooding to determine the feasibility and applicability of the process for EOR. Aqueous stability and phase behavior test and foam stability test were performed to determine the stability of the chemicals and the ability of the surfactants to stabilize foam respectively. ASG coreflood experiments were then conducted using the optimal chemical and surfactant formulation identified from the previous tests. Many corefloods were conducted in order to investigate the effect of the slug size, surfactant type, polymer and rock type on oil recovery, pressure gradient and surfactant retention. A sequence of vacuuming, brine saturation, oil sat-

uration, waterflooding, slug injection and drive injection was followed for all the corefloods and effluent samples were collected at every step and analyzed. The experiments showed that the size of the slug is constrained by design and economic constraints. If the slug size is very small, mixing with the formation brine at the leading end and drive fluid at the tail will result in the dilution of the chemical slug, which may not be effective in mobilizing oil, whereas if it is large, the entire slug volume will not be affected by mixing. The results from the foam stability tests highlight the fact that in order to achieve effective mobility control in the drive, the surfactant should not only be a good foamer but also it needs to be able to possess a low adsorption coefficient and be able to provide foam stability in microemulsion environment. The effect of polymer on foam stability was investigated but no final conclusion could be inferred due to lack of experimental results, although the oil recovery was found to improve with the addition of polymer. Coreflood experiments on dolomite samples were performed and demonstrated successful application of ASG process, concluding that this process is feasible for chemical EOR in carbonate rocks such as dolomite. Furthermore, it was observed that negative salinity gradient in chemical floods improves foam stability by mobilizing trapped surfactant as salinity changes from Type II to Type I microemulsion, via Type III. It was also observed that foam strength increased in Type I environment, therefore it was concluded that an optimized design should be such that the drive salinity remains in the Type I environment. An advantage of foam over polymer is the fact that foam is stronger in high permeability regions whereas

polymer strength generally stays uniform irrespective of rock permeability. The strong foam in high permeability regions can divert the injected fluid to low permeability regions providing better conformance control than polymer.

Srivastava et al. (2010) [75] investigated the mobility control characteristic of dispersed flow by evaluating the pressure response, oil recovery and gas and surfactant breakthrough times from surfactant-gas corefloods on carbonate cores. The effect of permeability, gas and liquid injection rates (or injection foam quality), and chemical slug size on the displacement efficiency was studied. The foam relative mobility at different permeability values was calculated to investigate the potential of efficient conformance control in ASG process. The relative mobility values from the corefloods indicate that foam has a strong dependence on rock permeability and therefore demonstrated great potential of good conformance control in ASG process. Foam has higher apparent viscosity in high permeability regions than in low permeability regions, hence due to significant flow resistance exerted by foam in high permeability regions, the injected fluid will be diverted to low permeability regions, resulting in volumetric sweep efficiency improvement. Furthermore, although the experiments showed that mobility control in low permeability cores was not efficient, the fact that foam did not cause plugging, shows the potential of using ASG process in low permeability rocks. Experiments showed that the gas injection rate is important in determining the extent of foam propagation and improving oil recovery. The results showed that low gas velocity (low quality coreflood) corresponds to low foam mobility and therefore a more stable foam

with a better propagation. For the investigation of the effects of slug size on foam propagation experiments using 0.15PV of chemical slug were compared with the base case results of the corefloods that used 0.3PV of chemical slug. Lower oil recovery was observed for the 0.15PV of chemical slug and this was attributed to the fact that less amount of surfactant injected in the core. Less amount of surfactant was available for mobilization therefore this resulted to less oil mobilization. However, the results showed late gas production indicating mobility control and potential of ASG process in conditions that require small slug sizes

2.8.2 LTG in High Salinity - Low Permeability reservoirs

N. Nguyen et al. [50] focused on the performance of LTG flood in high salinity and high temperature sandstone reservoirs. The investigation included the effect of surfactant formulations on the oil/water microemulsion phase behavior and optimum salinity. In addition, the effect of slug salinity on the process performance and drive solution composition on the oil recovery, pressure drop and effluent salinity were investigated. The use of alkyl polyether sulfonate significantly improved salinity tolerance of chemical formulation and by adjusting its concentration, desired salinity windows for different types of microemulsion can be obtained. High and low Type III ME salinity were compared to determine the effect of optimum salinity reduction on LTG performance. The results showed that lower Type III ME produced lower cumulative oil recovery and earlier oil bank breakthrough, indicating unstable oil

bank displacement due to insufficient mobility control during chemical injection. Furthermore, the pressure and effluent salinity profiles showed a more gradual trend compared to high Type III ME creating a favorable environment for the formation of Type II(+) ME within the mixing zone between slug and formation brine. For permeable sandstones, injected slug salinity close to or at the Type III Type II(-) ME boundary is beneficial in improving mobility control through foamed flow regime, and reducing the production of unwanted emulsified oil, however this is true for a sufficiently small difference between optimum salinity and formation salinity. For large differences in salinity this might not be suitable as it promotes the formation of microemulsion in an over-optimum salinity environment which adversely affects surfactant transport. For the investigation of the drive solution composition effect, a drive solution having the same composition with slug but with reduced component concentrations (LTG 3) was compared with a drive solution where only the internal olefin sulfonate (LTG 1) was used. Although the oil recovery was slightly lower for LTG 3, the effect of drive composition can be thought as insignificant under these conditions.

A. Das et al. [14] work objectives were to optimize a chemical formulation that exhibits good oil/water microemulsion phase behaviors (i.e. low IFT, low microemulsion viscosity, and fast microemulsion equilibration), good solubility in high salinity brine, and good foam stability as well as to optimize the chemical slug and drive compositions and injected foam qualities. Alkyl polyglucoside surfactant was found to be a chemical formulation with very

attractive properties and qualities for LTG flooding in high salinity environments. Experiments showed that the injection of slug at optimum salinity improved oil recovery considerably whereas increasing foam quality to 70% or reducing the surfactant concentration was found to marginally reduce oil recovery. Furthermore, reducing both the surfactant concentration and foam quality showed to drastically decrease oil recovery due to reduced mobility control owing to foam instability.

2.8.3 LTG in carbonate reservoirs

S.M. Szlendak et al. (May 2013) [77], experimentally tested and investigated the low-tension gas (LTG) process to establish it as a method for submiscible tertiary recovery in tight sandstone and carbonate reservoirs. Experiments of nitrogen and a slug/drive surfactant solution co-injection were performed and indicate favorable mobilization and displacement efficiency of residual crude oil in both reservoirs. Results were compared both with surfactant flooding and gas flooding independently and show greater ROIP tertiary recovery. This process was also evaluated as a potential secondary recovery method, by using high initial oil saturation. The results showed high recovery of OOIP indicating its feasibility as a secondary recovery method. The results also showed that the potentially destabilizing effects of high initial oil saturation on lamellae stability and foam strength did not noticeably affect displacement and other mechanisms. Flooding showed to decrease the pressure drop associated with secondary recovery compared to waterflood, a con-

sequence of oil high relative mobility and reduced overall relative mobility due to incomplete displacement during waterflood. Furthermore, gas was observed to breakthrough early due to free gas present that evolves ahead of an injected surfactant front. This was caused by reduced rate of advance of free surfactant relative to bulk injected fluids because of adsorption and partitioning at the oil/water interface and because of higher interstitial velocity of injected gas vs injected surfactant liquid caused by reduced PV available for a third gas phase. An elongated oil bank, which allows earlier production and more immediate payback was observed, due to low oil viscosity and tight saturation window. LTG gas saturation was observed to be increased during slug breakthrough compared to the gas saturation observed by has co-injection. This indicated a high degree of dispersed gas which is often associated with lamellae production and therefore with the propagation of stable foam. Mobility ratios were also calculated and compared with surfactant flooding. The mobility ratios were found to be near 1.0 indicating that stable displacement of light crude oil in tight formations is feasible in contrast with higher mobility ratios and consequently lower displacement efficiency for surfactant flooding. Steady-state apparent viscosity of injected fluids was also calculated to be much higher than that for gas co-injection flooding indicating a degree of foaming that caused mobility control.

S.M. Szlendak et al. [79], investigated the effect of gas fractional flow on the oil recovery. Two data sets were tested, the first was performed at differing but constant-throughout gas fractional flow (co-injection), whereas

the second one was performed at cycle-dependent changing gas fractional flow (SAG). The results from the first dataset showed that higher fractional flow during co-injection gives higher oil recovery. Gravity impacts are likely to increase the gas fractional flow and saturation in the upper portions of a flow unit and lower these attributes for the lower portions of a flow unit. These results were then compared with the results of the second dataset to observe that surfactant-alternating-gas injection demonstrated improved displacement and overall oil recovery at the same overall average gas fractional flow from the first dataset. The reason behind this is not captured by averaged pressure data during flooding but may indicate the importance of hysteresis (gas/liquid replacing each other) and/or the creation of acute ultra-low mobility states as SAG cycles alternate. Observations show a stable trapped gas saturation, during liquid injection, contradicting with gas injection, which controls liquid mobility. This trapped gas provides diversion of injected chemical into small pore-networks with residual crude oil explaining the increase of tertiary oil recovery and displacement. Careful consideration should be given for upscaling core-scale SAG behavior to the field.

S. Jong [36] expands upon previous work by investigating the specific role that salinity gradient, and by extension the microemulsion type, plays in effective design and optimization for LTG flooding. Different salinity gradient designs are obtained by reducing slug salinity from optimum salinity to Type III/Type I microemulsion phase behavior boundary region while keeping formation and drive solution salinity fixed. The effects of these salinity

gradients on oil/water microemulsion phase behavior and fluid mobility control are tested and quantified. Pressure gradient, cumulative production, and salinity of produced fluids are monitored to determine in-situ fluid mixing, oil mobilization, and sweep efficiency.

2.9 UTCHEM Model Review

UTCHEM is a multiphase, multicomponent simulator that can be used to model advanced reservoir processes including amongst others, polymer and surfactant flooding, and alkaline surfactant polymer (ASP) [59], [12], by using in general mechanistic models [12], [24].

The simulator can generate up to four phases (gas, aqueous, oleic, and microemulsion), whereas CMG does not explicitly model the microemulsion phase. Among the many capabilities of the simulator, the modeling of up to four-phase relative permeabilities as a function of trapping number and non-equilibrium mass transfer between phases should be noted [24].

UTCHEM simulator can also model the viscosity of the microemulsion as a function of water, oil, and surfactant concentrations in the microemulsion phase [24].

The phase behavior model in UTCHEM is based on Hand's rule [24], and for the calculation of the interfacial tension, UTCHEM utilizes a Healy and Reed [27] formulation as modified by Hirasaki [29], [59], or the Huh's formulation where the interfacial tensions between microemulsion and excess

phases are functions of solubilization parameters/ratios.

The dependence of residual saturations on interfacial tension is modeled in UTCHEM as a function of the trapping number, which is a dimensionless number that includes both gravity and viscous forces [59]. Residual saturations at high and low trapping numbers are used as inputs in the model, as well as the endpoints and exponents of the relative permeability curves. The residual saturation at a particular trapping number, is then computed as a function of the trapping number [59]. The endpoints and exponents in relative permeability functions are then computed as a linear interpolation between the given input values at low and high trapping numbers [59].

Chapter 3

Modeling LTG Process

3.1 LTG Model Review

In this work, the LTG Model developed by Jong *et al.* [36] and incorporated into the compositional equation-of-state simulator CMG/GEM, is employed. The LTG model is based on minimal experimental data for calibration and combines the modeling of the IFT-reduction, surfactant partitioning, relative permeability, foam and surfactant adsorption to describe both the effect of microemulsion phase behavior on oil-water relative permeability and the effect of foam on gas relative permeability.

Although the microemulsion phase has an effect on oil transport through porous media by reducing the interfacial tension between oil and water through the use of surfactant, the modeling of the Winsor Type III microemulsion phase is assumed to be avoidable because in an optimum LTG design, its volume has to be minimized. Both economic and technical constraints are accountable for this optimum design, as chemical usage and microemulsion production are costly and a significant volume of viscous microemulsion leads to high pressure gradients and poor transport [36].

According to the principle of controlling IFT described by Healy and

Reed (1997) [28], in a Type III environment, the oil-microemulsion and water-microemulsion interfaces may be condensed to one oil-water interface. It is believed that the higher IFT between oil-microemulsion and water-microemulsion IFTs will control the performance in a surfactant process [36].

The surfactant distribution in the system, is important at all times of the simulation process as it is used to trigger both the IFT-reduction when it falls above the Eff-CMC, the effective critical micelle-concentration, and foam mobility control, through the surfactant concentration effect parameter. Its distribution in the system is calculated through mass balance, thus is important to model how surfactant partitions between the oil and water phases as microemulsion phase is not explicitly modeled. For the surfactant partitioning model used in this work, surfactant partitions between water and oil according to the volume of oil and water in the microemulsion phase and affects the properties of the water and oil phase, although realistically the surfactant should alter the properties of the microemulsion phase, making it more viscous.

Although gas trapping and its remobilization are thought to occur during the LTG process, the modeling of this dynamic behavior has not yet been introduced in the current model. The static process of gas trapping though is currently modeled by adjusting the residual gas saturation in the presence of foam [36], leading to its over- and under-estimation spatially and temporally. However, in this work we are interested in the end-effect gas mobility reduction, while at the same time, it is acknowledged that this limitation of the model might reflect on our results.

Foam is utilized in LTG process, to increase the volume of gas in the high permeability regions and to divert the surfactant solution to the less accessible regions, thus improving surfactant efficiency. This foam mobility control is modeled through the use of *STARSTM* [12] foam model, which incorporates a mobility reduction factor applied to the gas relative permeability, that includes the effects of surfactant concentration, oil saturation and composition, shear thinning and generation, salinity and foam dry-out.

Relatively low rates of injection are used in the field, making the assumption of local equilibrium suitable, although it might not be valid for laboratory scale processes. Therefore, for a given gridblock, the effect of microemulsion or foam is dependent on the current state ignoring any previous states of the gridblock [36].

The assumptions of this LTG model simplify the system (from four phases to three phases), by reducing complexity, uncertainty, and computational expense from four phase capillary desaturation and relative permeability and still maintaining the important physics of the process[36].

3.2 Modeling IFT Reduction

3.2.1 Oil and Water Solubilization Ratios

The microemulsion phase behavior model is based on the routinely measured experimental results of solubilization. The solubilization ratios of water and oil with respect to surfactant, are defined as the the volume of the water and oil solubilized respectively, per unit of surfactant volume, as shown

in equation 3.2.1.

$$R_l = \frac{V_l}{V_s} \quad (3.2.1)$$

where $l = o, w$ corresponds to either water or oil.

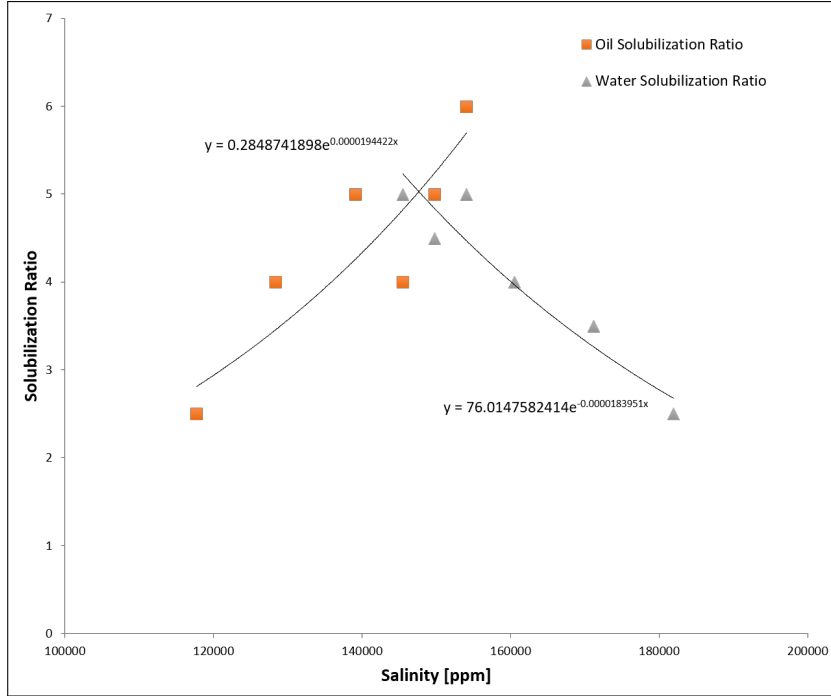


Figure 3.1: Oil and Water Solubilization Ratio vs. Salinity

The oil and water solubilization ratio, obtained through work by the experimental group, are shown in Figure 3.1 with increasing salinity. It can be observed that the optimum salinity is reached at a salinity of 148,000 ppm. These data are then used to calculate the oil-water IFT through the Chun Huh correlation [33].

3.2.2 Condensed water-oil IFT

The Chun Huh correlation (3.2.2) [33], relates the water and oil solubilization ratios to the interfacial tension between oil and microemulsion, and water and microemulsion respectively.

$$\sigma_{ml} = \frac{c}{R_l^2}, \quad (3.2.2)$$

where c corresponds to the Chun Huh constant.

The solubilization experiments are performed for a range of varying salinity, which is a critical parameter for the LTG process that controls the microemulsion phase behavior [36].

In the simulation, depending on the salinity of the water at a specific point in time, an interpolation between the different salinity values is performed to obtain the solubilization ratios for that specific salinity. The two interfacial tensions are then calculated according to equation 3.2.2.

Since the microemulsion phase is not modeled in this LTG model, an IFT between oil and water should be calculated. Previous researchers [36] have used a weighted-average IFT method that depends on the volume of oil and water in the microemulsion phase. In this way, as the volume of oil in the microemulsion phase increases, the microemulsion-water interfacial tension was more strongly considered and as it decreases, the microemulsion-oil interfacial tension was more strongly considered, thus, the higher and controlling IFT,

was strongly honored, while the lower IFT for the other interface was not neglected.

However, in this work it is thought that the lower IFT does not influence the controlling IFT and that only the highest IFT of the two controls the system. Thus, in this study, the IFT between water and oil is assumed to be equal to the highest of the microemulsion-oil IFT and the microemulsion-water IFT.

3.3 Modeling Surfactant Partitioning

For Type I and II phases, oil and water solubilization ratios (the amount of surfactant solubilized into oil and water), respectively, are typically low. For a Type III microemulsion, since the microemulsion phase is not modeled, surfactant should partition between water and oil phases based on the solubilization ratios, and consequently on a microemulsion composition weighting factor ϕ [36], as shown in eq. 3.3.1 - 3.3.5. $V_{o,m}$ and $V_{w,m}$ refer to the volume of oil and water in the microemulsion phase, whereas $V_{s,o}$, $V_{s,w}$, and $V_{s,t}$ correspond to the volume of surfactant in the oil phase, water phase and the total volume of surfactant, respectively.

$$V_{o,m} = R_o \times V_{s,t} \quad (3.3.1)$$

$$V_{w,m} = R_w \times V_{s,t} \quad (3.3.2)$$

$$\phi = \frac{V_{o,m}}{V_{o,m} + V_{w,m}} \quad (3.3.3)$$

$$V_{s,o} = \phi \times V_{s,t} \quad (3.3.4)$$

$$V_{s,w} = (1 - \phi) \times V_{s,t} \quad (3.3.5)$$

3.4 Modeling Relative Permeability

From the oil-water interfacial tension (the maximum between σ_{mo} and σ_{mw}), the capillary number is calculated by the correlation shown in eq. 3.4.1, where k is the absolute permeability of the rock and $\nabla\Phi_o$ is the potential gradient across the oleic phase [36].

$$N_c = \frac{k\nabla\Phi_o}{\sigma_{ow}} \quad (3.4.1a)$$

$$\Phi_o = P + \rho_o gh \quad (3.4.1b)$$

Three sets of oil-water relative permeability curves are used that correspond to low, intermediate, and high capillary number data. An interpolation is performed between these three data sets and if the calculated capillary number falls between the low and intermediate capillary number, then the interpolation is conducted according to eq. 3.4.2. *RPV* corresponds to the

relative permeability value at the calculated capillary number (N_c), RPV_{low} and RPV_{interm} are the values at low and intermediate capillary numbers, respectively. F_{N_c} is the logarithmic weighting parameter used to interpolate between the intermediate and low capillary number limits that correspond to $N_{c,interm}$ and $N_{c,low}$, respectively [36]. Similarly, if the capillary number falls between the intermediate and high capillary number sets, the equations are used accordingly.

$$RPV = F_{N_c} \times RPV_{interm} + (1 - F_{N_c}) \times RPV_{low} \quad (3.4.2)$$

$$F_{N_c} = \frac{\log N_c - \log N_{c,low}}{\log N_{c,interm} - \log N_{c,low}} \quad (3.4.3)$$

This interpolation represents the curvature of a capillary desaturation data on a logarithmic plot as shown in the example on Figure 3.2. Since no data exists that can accurately represent the desaturation curve, it is assumed that a linear interpolation between two capillary numbers is a reasonably good approximation to the curve, and simplifies the system to one conjugate phase with one capillary number. Residual phase saturations, relative permeability endpoints and curvatures, are linked to this capillary number.

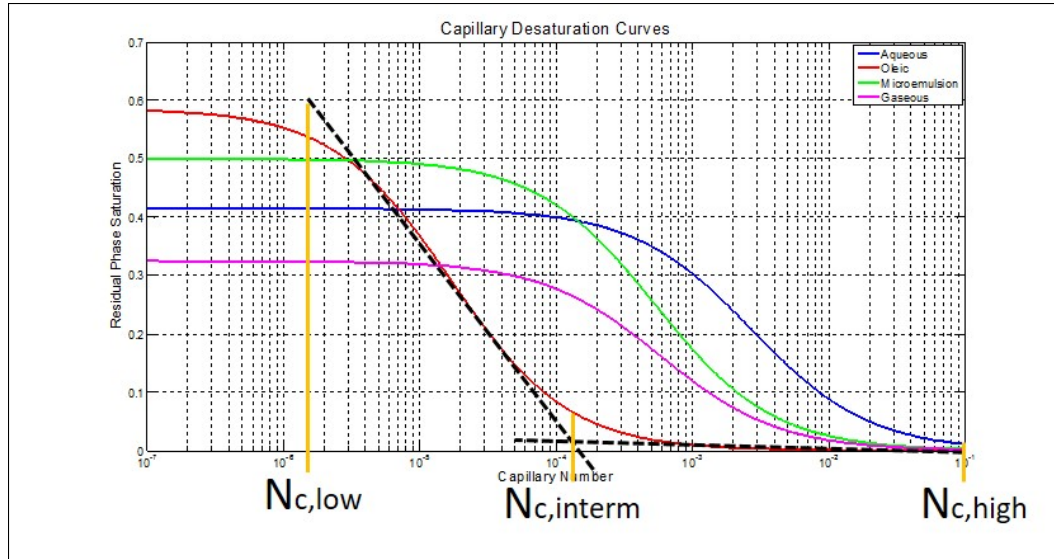


Figure 3.2: Schematic of the interpolation between capillary numbers; example of capillary desaturation curves for aqueous, oleic, microemulsion and gaseous phases [36]

Oil-water relative permeability data for the low and high capillary number are needed for this interpolation to take place. It is widely acknowledged that the low capillary number relative permeability curve represents waterflood conditions, whereas the high capillary number relative permeability curve corresponds to miscible flooding conditions where relative permeability follows a straight line from zero saturation to a fully saturated system (Gupta 1979, Bardon and Longeron 1980, Habert 1983, Ronde 1992). Therefore, at an intermediate capillary number, water and oil desaturate independently, following the capillary desaturation curve as shown in Figure 3.2 [36].

The calculation of the oil relative permeability k_{ro} when three phases are present in a water-wet system, through Stone's first model, is based on k_{rorw}

and k_{rog} values. This model was decided to be used as previous researchers [21] have shown that it can better approximate two-phase experimental data compared to Stone's second model, when the oil relative permeability at connate water saturation, k_{row} , is not close to unity, as the values faced in this work ($k_{row} = 0.468, 0.682, 0.88$).

Details on the gas relative permeability and its modification when foam is present, are discussed in following section 3.5.

3.5 Modeling Foam

For the modeling of the foam process, the *STARSTM* [12] mobility-reduction model is used. A mobility reduction factor scales down the mobility of gas directly by a factor FM, which is equivalent to modeling the apparent viscosity of foam [36] as shown in equation 3.5.1. The superscripts f and nf refer to foam and no-foam respectively.

$$k_{rg}^f = k_{rg}^{nf} \times FM \quad (3.5.1)$$

The FM factor involves six functions that describe different factors that influence the gas mobility reduction such as oil saturation, water saturation, surfactant concentration and capillary effects, and it is defined as shown in equation 3.5.2. It theoretically ranges from $FM = 0$ (strongest foam allowing no gas to flow) to $FM = 1$ (no foam), although the range is practically narrower [12] [36].

$$FM = \frac{1}{1 + fmmob \times F1 \times F2 \times F3 \times F4 \times F5 \times F6 \times FDRY} \quad (3.5.2)$$

The FM MOB parameter represents the maximum mobility reduction factor or otherwise the reference mobility factor in the absence of contribution from other factors at measured values of surfactant concentration, capillary number (flow rate), zero oil saturation, $S_o = 0$, and oil mole fraction of component [12].

The remaining parameters account for the effects of surfactant concentration, the detrimental effect of oil, the flow velocity for both shear thinning and generation effects, the oil composition, the positive effect of salt and the foam dry-out effect respectively [12].

For the case of lab experiments, where the velocities are considerably low compared to the field, shear thinning and generation effects are neglected. Surfactant concentration effect is also neglected, since it is assumed that the surfactant concentration in the system is always higher than the critical. Salinity has shown to affect the stability of foam as a controlling parameter in microemulsion phase behavior [36] and it is believed that the excess oil saturation also affects foam stability.

Therefore, in this work we focus on the detrimental effect of oil (F2), the salt concentration (F6) and the dry-out (FDRY) functions, which are defined in the $STARST^M$ model as:

$$FDRY = 0.5 + \frac{1}{\pi} \arctan(sf\beta(S_w - sf\text{dry})) \quad (3.5.3)$$

$$F2 = \left(\frac{fmoil - S_o}{fmoil - floil} \right)^{epoil} \quad (3.5.4)$$

$$F6 = \left(\frac{x_{salt} - flsalt}{fmsalt - flsalt} \right)^{epsalt} \quad (3.5.5)$$

In the dry-out function (equation 3.5.3), the parameter $sf\beta$ controls the sharpness of transition of foam from a high-quality regime to a low-quality regime (dry-out slope); a very high value for $sf\beta$ represents a sharp transition and foam collapse within a narrow range of saturation whereas a low value of $sf\beta$ represents a foam collapse that is not abrupt, where foam coarsens in texture over a range of water saturations [22]. The parameter $sf\text{dry}$ is the water saturation at which foam experiences significant coalescence (maximum dry-out value) [12].

Equation 3.5.4 refers to the detrimental effect of oil saturation on foam strength, where S_o is the oil saturation of the excess phase in the system, and $fmoil$ and $floil$ correspond to the critical and lowest oil saturation in the system, respectively, that affect foam stability.

In equation 3.5.5, $flsalt$ and $fmsalt$ correspond to the minimum salt mole fraction (maximum contribution to foam mobility reduction) and the critical salt mole fraction (minimum contribution to foam mobility reduction)

respectively. These limits correspond to the Type I and Type III microemulsion regions respectively. The current state of salinity is represented by x_{salt} in terms of mole fraction and $epsalt$ is an exponent that determines the contribution of salt concentrations and consequently microemulsion phase behavior to foam stability [12] [36].

3.6 Modeling Surfactant Adsorption

In an LTG flood, gas and surfactant are co-injected in the core, and some surfactant is adsorbed on the reservoir rock and the rest is utilized for reducing the interfacial tension between oil and water, and for foaming.

The modeling of the adsorption of surfactant is modeled, through Eff-CMC or the effective critical micelle concentration, which is implemented in the simulation to be a lower limit of surfactant concentration, below which no microemulsion exists and all the surfactant remains in the water phase [36]. Therefore, as surfactant concentration increases in the system above Eff-CMC, surfactant effect on both IFT-reduction and foaming comes into effect.

Chapter 4

Numerical Simulation of the LTG process

4.1 Methodology and Material

The provision of data is of paramount importance in the modeling of complex systems. The data assimilation procedure included obtaining experimental information. A brief description of the experimental procedure, performed by other members of the research group, is outlined in the next section. For further details about the experiments performed, refer to A. Das et al. [14].

In the following sections the simulation set up and procedure is described, and the proposed methodology for the determination of certain parameters is explained and implemented in the matching of the LTG process. Trends observed in experimental data, are highlighted and discussed.

4.2 LTG Experiments

4.2.1 Experimental Description

The outcrop cores used for these experiments are from drilled Indiana Limestone slabs. The cores were first cleaned and then saturated with formation brine (214,000 ppm), from which the porosity and permeability to

brine of the cores were measured. Following the brine flood, the core was vacuumed thoroughly to enable oil to enter the smallest pores, as in such low permeability rocks there is a lot difficulty in achieving the actual saturation conditions found in the reservoir. Furthermore, it is important to note that vacuuming also minimizes the capillary-end effects, which are usually significant in drainage processes in water-wet cores where oil displaces water. The core was then saturated with oil from the bottom of the core, and injecting at different rates aid to the measurement of the permeability of the core to oil. A waterflood was then performed, at an injection salinity of 160,000 ppm, where the effluent fluid was collected and used for the measurement of the residual oil saturation.

All of the above experiments, are performed in order to bring the core to similar conditions to the field before performing the Low-Tension-Gas flood. At conditions of residual oil saturation, a surfactant slug of 0.5 liquid pore volumes (PV) is co-injected along with nitrogen N_2 at optimum salinity of 148,000 ppm or at boundary salinity of 130,000 ppm. The slug solution was then followed by the drive solution, which had exactly the same composition to the slug solution, but at lower concentration of surfactant and lower salinity of 100,000 ppm. The drive solution was continued up to the point where no more oil was collected at the effluent. Comparing the salinity of the injected solution for each stage of the experiments, it can be seen that the concept of negative salinity gradient [36], [76], [75], [77], [79], [50], [14], is applied.

Oil recovery, pressure drop, and effluent salinity data were recorded for

each stage of the core flood design, and were used to assess the performance of the core floods. Fluids collected at the effluent were used to calculate oil recovery and analyze salinity, whereas pressure data were used to analyze the foam strength.

4.2.2 Experimental Findings

4.2.2.1 Waterflood Findings

As explained earlier, brine saturation, oil saturation and waterflood occur before the injection of gas and surfactant in the core. During the waterflood, the oil recovery and pressure drop are monitored and recorded and are used for the matching procedure of the LTG. All of the experiments exhibit similar trends, where the oil is recovered immediately while water is pushing it at the effluent, as shown on the oil recovery plots, and when the oil in the core reaches residual saturation, the cumulative oil recovery plot reaches a plateau, the maximum recovery. On the pressure drop plot on the other hand, a pressure drop buildup is initially observed up to the point where water breaks-through at the effluent and at that point the pressure drop follows a decline and reaches steady state when the oil saturation in the core reaches residual. For the LTG experiments, different trends are observed between experiments, since different surfactant concentrations and foam qualities are injected into each core.

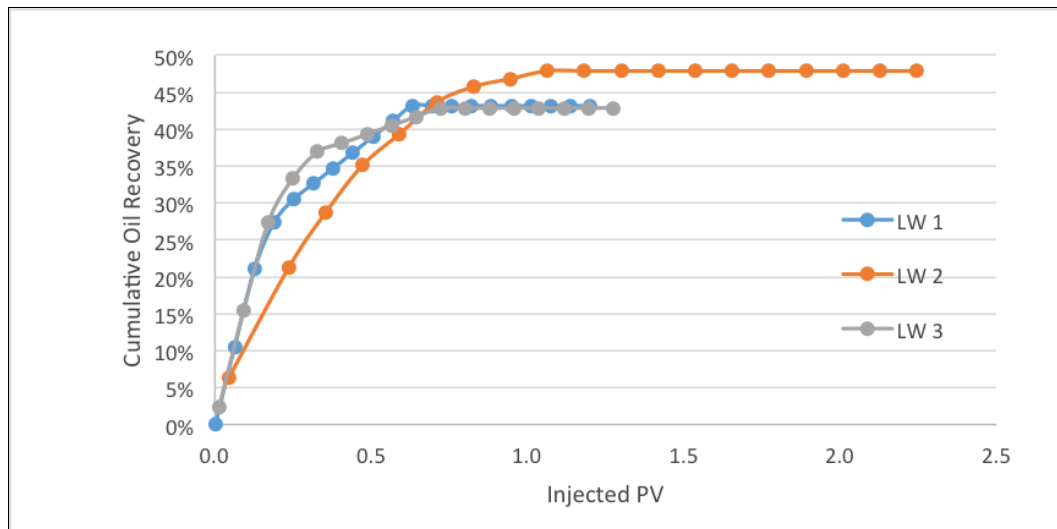


Figure 4.1: The cumulative oil recovery percentage of initial oil in place for three waterflood experiments

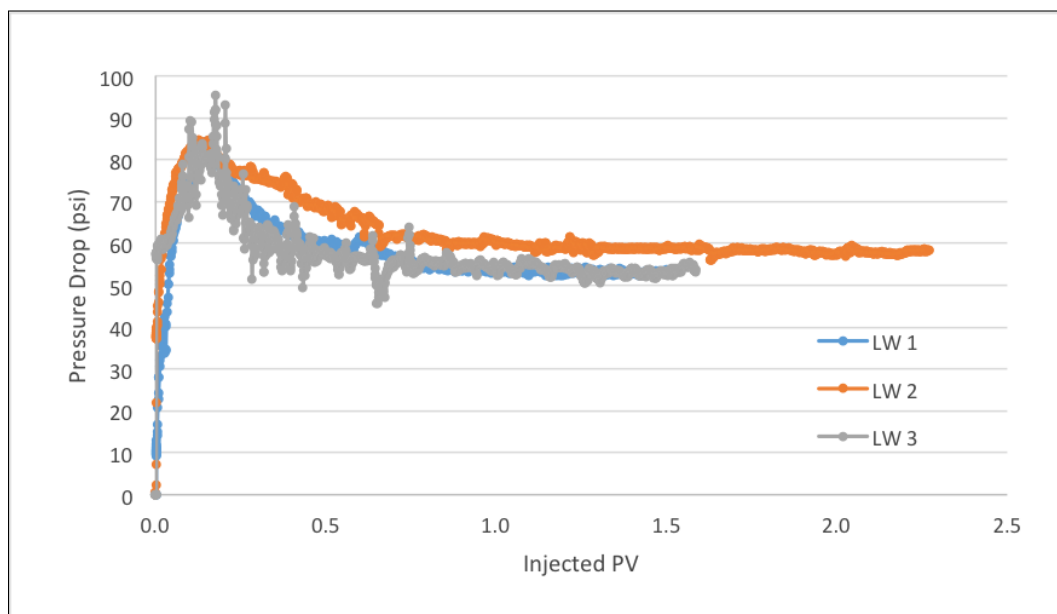


Figure 4.2: The pressure drop measured across the core for three waterflood experiments

4.2.2.2 LTG Findings

Three LTG experiments are investigated in this study, with differences in porosity, permeability, liquid and gas injection rates, foam quality, surfactant concentration, and injection salinity, as shown in Table 4.1.

Table 4.1: Porosity, permeability, liquid and gas injections rates, surfactant concentration and injection salinity for all three LTG experiments for both the slug and drive solution

Parameter	LTG1	LTG2	LTG3
Porosity (%)	20	22	27
Permeability (mD)	7.3	4.6	9
Slug Solution			
Liquid rate [ml/hr]	4.3	2.9	6.0
Gas rate [ml/min]	0.07	0.11	0.1
Foam Quality [%]	50	70	50
Surfactant concentration [%wt]	1.0	1.0	0.5
Injection Salinity [ppm]	148 000		
Drive Solution			
Liquid rate [ml/hr]	4.3	2.9	6.0
Gas rate [ml/min]	0.07	0.11	0.1
Foam Quality [%]	50	70	50
Surfactant concentration [%wt]	0.2		
Injection Salinity [ppm]	100 000		

In all three experiments, it is observed that around 1.0 - 1.5 PV for LTG 1 and LTG 3 and at 2.0 PV for LTG 2, the pressure drop shows a sudden

decrease which is indicating of the total oil bank breaking through. This is consistent with the plot of the oil recovery where at the same PV oil recovery reaches around 40 - 50 %.

Experiment LTG 1 the ultimate oil recovery is the highest of the three experiments, achieving 85% of residual oil after waterflood, and an oil breakthrough at 0.6 PV of total injected liquid and gas. The observed pressure drop indicates that the formation of a “thick” oil bank accounts for the high oil recovery and the delay of oil breakthrough at the effluent.

In experiment LTG 2 the pressure drop is shown to go through an initial peak at around 0.2 total injected PV, which is not something observed in the other experiments. Since this happens at a very early stage of the process is thought to be explained by the gas expansion at the early time of the experimental process through which these data were obtained. To initiate the LTG experiments, the slug solution is first injected into the core until the pressure reaches steady-state and at that point the gas is then injected into the core as well. This difference in time might create a shock in the core and gas expansion, thus a peak in the pressure drop, as observed here. Since this is only an experimental error, it is not expected that our model should be able to simulate this.

In terms of the oil recovery, the oil breaks-through at 1.13 total injected PV. Therefore, it is expected that up to this point the pressure drop will be continuously increasing since the oil bank is building up. At 1.13 total injected PV the oil bank breaks-through, but the pressure drop will continue

increasing since the injected surfactant will increase the microemulsion phase thus increase the mobilized oil and thus create a more elongated oil bank. The pressure drop will begin to drop when the oil bank is not increased anymore but is only produced and will reach a steady-state value when most of the oil bank is produced at about 2.5 total injected PV in this experiment.

Comparison of results with core flood LTG 1 shows that an increase in foam quality for the slug resulted in a modest decrease in oil recovery, which might be due to higher capillary pressure in tight formations. Injection foam quality of 70% could produce a sufficiently dry foam, governed by a limiting capillary pressure above which foam destruction dominated foam flow behavior. Faster production in LTG 1 indicates better mobility control, and consequently better sweep efficiency, as compared to LTG 2. Prolonged pressure buildup in LTG 1 than LTG 2, also indicates the formation of a more stable oil bank. On the other hand, both experiments reach similar pressure drop at the end of the experiment. However, this may not reflect a similar effect of mobility control, but could instead be because of the remaining oil saturation in LTG 2 being higher (lower recovery, 80%) than LTG 1 (higher recovery, 85%).

Interestingly, comparing the results of LTG 1 and LTG 3, although the production trend of both experiments is almost identical, it is observed that the oil breakthrough occurs at a later time around 0.8 PV of total liquid and gas injected, and the oil recovery is reduced by 5% in experiment LTG 3, as compared to core flood LTG 1, for a 50% reduction in slug surfactant

concentration. The reason behind this, is the reduced amount of available surfactant for foam generation for mobility control after adsorption. Hence, although oil is mobilized due to the ultra-low IFT leading to 80% ultimate oil recovery, the reduced mobility control leads to later oil breakthrough [14].

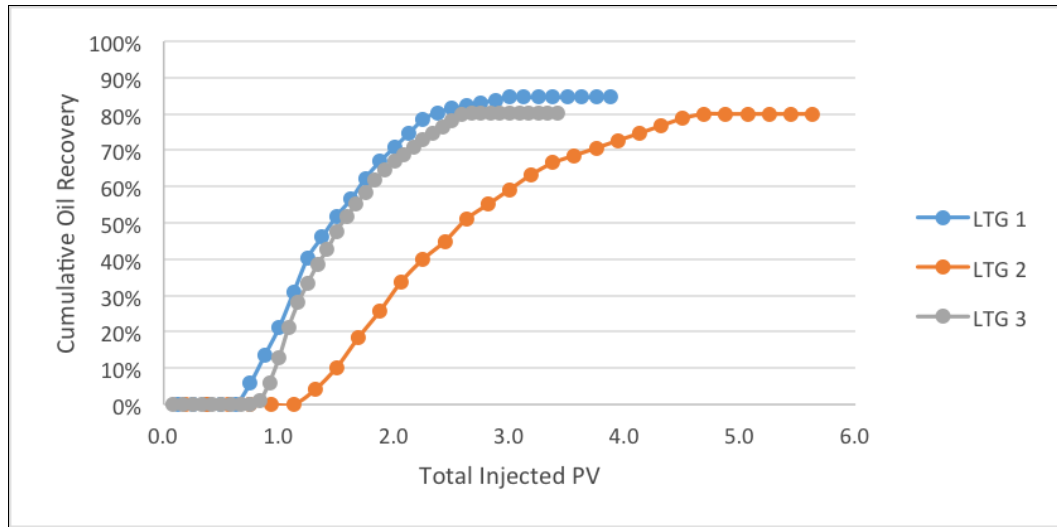


Figure 4.3: The cumulative oil recovery percentage of initial oil in place, after waterflood, for three experiments

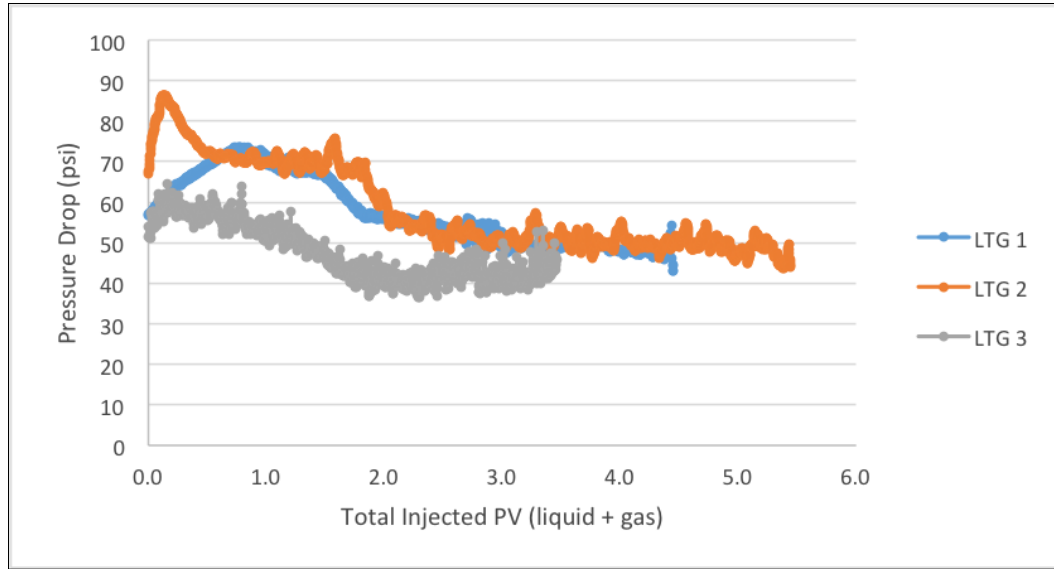


Figure 4.4: The pressure drop measured across the core for three experiments

4.2.3 Simulation Set-up and Procedure

Each simulation is set up by creating a $1 \times 1 \times 30$ grid that models the core, and is oriented vertically just like the experiments are performed. Core dimensions, such as the length and diameter of the core as well as initial conditions of the experiment, such as pressure and temperature, and water and oil saturation, are used as inputs in the simulation. Moreover, rock properties including porosity, permeability, oil, water and gas viscosity, and oil and water solubilization ratio that are available from different experiments are also used as inputs. Finally, injection rates for both gas and liquid, surfactant concentrations, and brine salinity for the slug and drive, are also used as inputs for the LTG simulation. Some of these properties, that are constant for all of the experiments, are shown in Table 4.2.

Table 4.2: Experimental Properties

Inputs	Value	Dimension
Core Length	12	in.
Core diameter	1.5	in.
Temperature	69	° C
Pressure at core condition	1000	psi
Water viscosity	0.85	cp
Gas viscosity	0.019647	cp
Oil viscosity	2.0789	cp

4.2.4 Strategy to match the LTG - process

In this study, a strategy is proposed for obtaining the parameters using information collected through a series of simulations of experiments, to determine certain groups of parameters, as illustrated in the diagram of Figure 4.5.

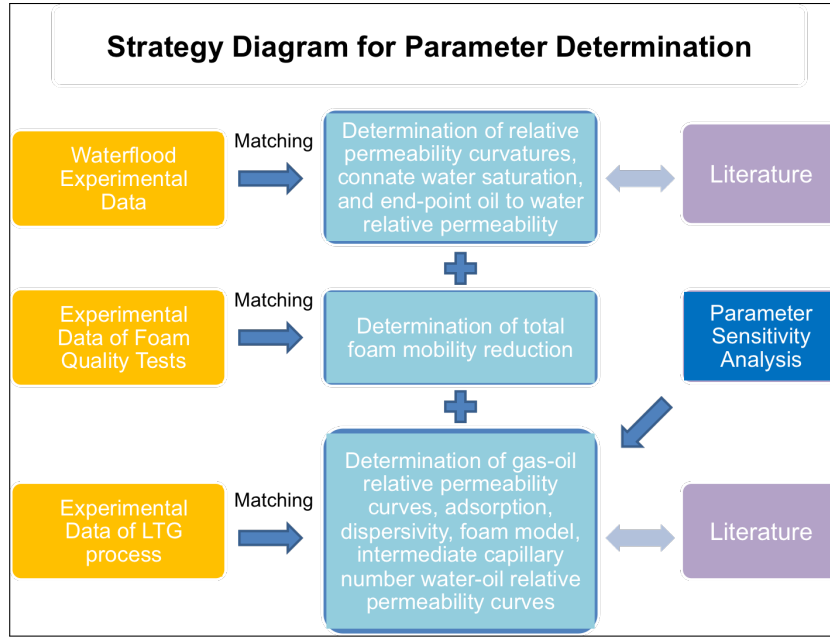


Figure 4.5: Diagram showing the strategy followed to match the LTG process

In order to constrain the parameters of the LTG process, so that we could possibly arrive into a solution in a deterministic manner, a calibration procedure was adopted in which the simulator (CMG/CMOST) was used to match the response of the experimental data by varying the parameters until agreement was achieved.

By using an assemblage of simulations for matching of experiments that all conform to the same geological formation, we attempt to establish the mean values of the main parameters for simulating the LTG process. Reference is made to mean values of the estimates because of the uncertainty in the estimate.

Considering the fact that the solution relates to a physical problem and not an abstract mathematical formulation, the parameter combinations must be limited by the physics of the system and therefore the assemblage of simulations is expected to reduce the degree of under-determinacy.

Once a set of parameters fitting the physics of the problem is established, then parameters for which the degree of confidence is high or for which the system is insensitive may be fixed. Of course in each simulation, the physical feasibility of the parameters value obtained is evaluated, as well as the limitations of both the experimental data given and the LTG model itself are considered.

The set of parameters that are dealt with in this work, are shown in Table 4.3, and are categorized in groups according to the part of the model in which they contribute. These include: Waterflood - Low N_c , Intermediate N_c , Foam Model, Gas Relative Permeability, Dispersivity, Eff-CMC or effective critical micelle concentration (proxy for adsorption).

Table 4.3: The set of all the parameters used for the simulation of the LTG - process

Waterflood - Low N_c Oil-Water Relative Permeability	Intermediate N_c Oil-Water Relative Permeability	Foam Model	Gas Relative Permeability	Dispersivity and Adsorption
n_o	$n_{o,2}$	$fmmob$	n_{og}	DISP
n_w	$n_{w,2}$	$sfbet$	n_g	Eff-CMC
k_{rorw}	$k_{rorw,2}$	$sfdry$	k_{rorg}	
k_{rwro}	$k_{rwro,2}$	$fmsalt$	k_{rgrl}	
S_{orw}	$S_{orw,2}$	$flsalt$	S_{org}	
S_{wro}	$S_{wro,2}$	$epsalt$	S_{gcon}	
$N_{c,low}$	$N_{c,interm}$	$fmoil$		
		$floil$		
		$epoil$		

From these parameters, the ones that are known through the experiments performed, are the end-point residual oil and water saturations, and the end-point oil and water relative permeability, of the Waterflood group. In addition, the residual liquid saturation to gas and the liquid relative permeability to gas are fixed in the simulation to equal the corresponding values of the water-oil relative permeability curve for a water-wet medium [12].

The rest will be determined through a series of simulations, including a match of a waterflood and a match of foam quality tests (surfactant-nitrogen co-injection flood at residual oil saturation after drive injection), where some of the parameters, shown in Table 4.3, are determined. The objective of per-

forming a waterflood match is to reduce the parameter space for the LTG simulation, by determining the curvatures of the low capillary number limit oil and water relative permeability curves. However, the study will show that the connate water saturation and the end-point oil relative permeability to waterflood will also be determined through literature and matching, respectively. The foam quality tests are then fitted to obtain the reference foam mobility reduction factor, f_{mmob} , the foam dry-out function, which is modeled by s_{fbet} and s_{fdry} , and the gas relative permeability (n_g , k_{rg1} , S_{gcon}).

For the rest of the parameters, a sensitivity study is performed, to examine the significance of the parameters on the oil recovery and the pressure drop. A Low-Tension-Gas match is then performed, where these parameters are determined, and the limitations of the model to simulate the experimental performance of a Low-Tension-Gas process are discussed.

4.3 Results and Discussion

4.3.1 Waterflood performance

4.3.1.1 Determination of the water-oil relative permeability curves

Three different experiments were considered to validate the accuracy and feasibility of the procedure to match waterflood experimental data. All cores are from the same rock, but have slightly different porosity, absolute permeability, oil and water end-point saturation, and end-point oil and water relative permeability, due to the heterogeneity of the rock itself. Several parameters were imported from the experimental data, as shown in Table 4.4,

and the simulation was performed to determine the water and oil relative permeability curvatures.

Table 4.4: Simulation Input parameters for the Base Case

Parameter	LW1	LW2	LW3
n_o	1 – 4		
n_w	1 – 4		
$\log(N_{c,low})$	–6.37		
k_{rorw}	0.52	0.62	0.92
k_{rwro}	0.21	0.16	0.26
S_{orw}	0.32	0.34	0.31
S_{wro}	0.38	0.40	0.45
ϕ	0.22	0.23	0.22
Absolute k [mD]	6.9	10.4	6.1

The water and oil relative permeability curves are calculated using the Correy correlation

$$k_{rw} = k_{rw}^0 \left(\frac{S_w - S_{wc}}{1 - S_{wc} - S_{orw}} \right)^{n_w} \quad (4.3.1)$$

$$k_{ro} = k_{ro}^0 \left(\frac{1 - S_{orw} - S_w}{1 - S_{wc} - S_{orw}} \right)^{n_o} \quad (4.3.2)$$

where S_{wc} is the connate water saturation and S_{orw} is the residual oil saturation to waterflood. Since the connate water saturation could not be

measured through experiments, the S_{wro} residual water saturation to oil flood was used instead.

A simulation was performed to simultaneously match the cumulative oil recovery and the pressure drop of the waterflood data, by varying the curvatures of the water-oil relative permeability curves from 1 to 4, and fixing the low capillary number using equation 3.4.1, and the end-point relative permeability and saturation parameters constant. The values obtained for each of the varying parameters for Case 1, are shown in Table 4.5 for all three waterfloods. The oil recovery and pressure drop optimum match for LW1 is shown as Case 1 in Figure 4.6 and 4.7, and the plots for LW2 and LW3 are shown in Figures 4.8, 4.9, 4.10, and 4.11 respectively.

Table 4.5: The values obtained for the varying parameters in Case 1 for LW1, LW2, and LW3

Parameter	LW1	LW2	LW3
n_o	1.66	2.035	1.915
n_w	1.5	1.0	1.60

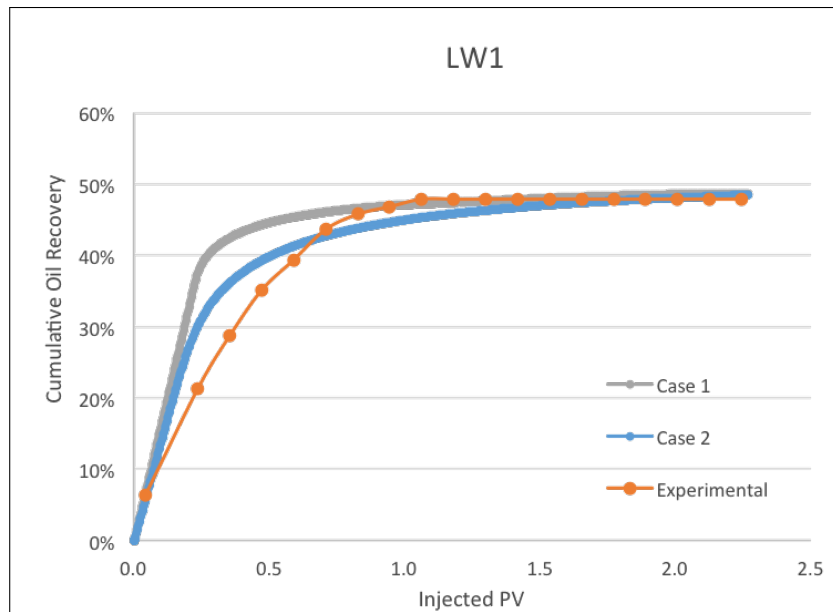


Figure 4.6: Oil Recovery as a function of Total PV Injected for LW1

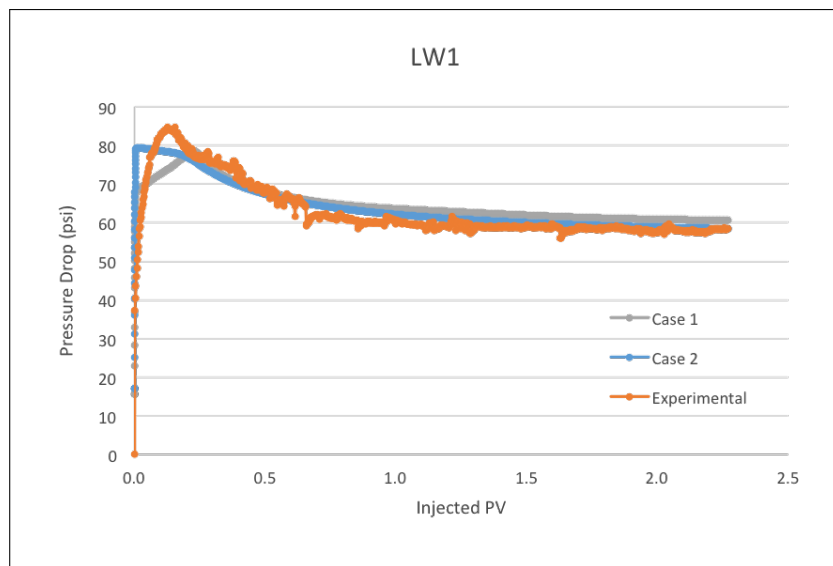


Figure 4.7: Pressure drop along the core as a function of Total PV Injected for LW1

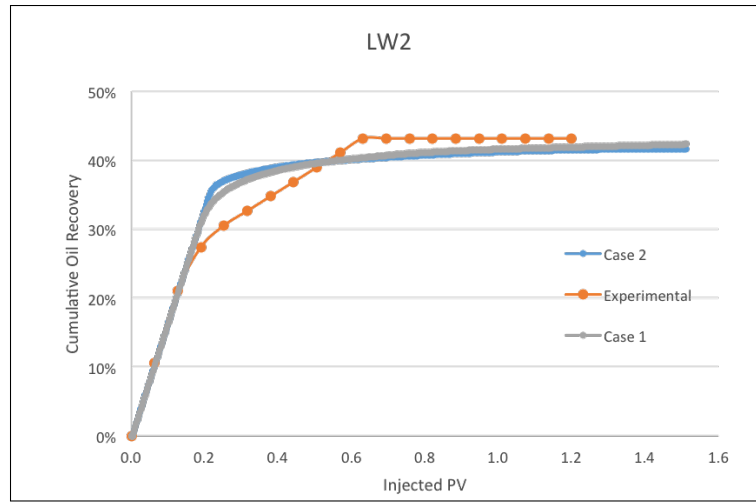


Figure 4.8: Oil Recovery as a function of Total PV Injected for LW2

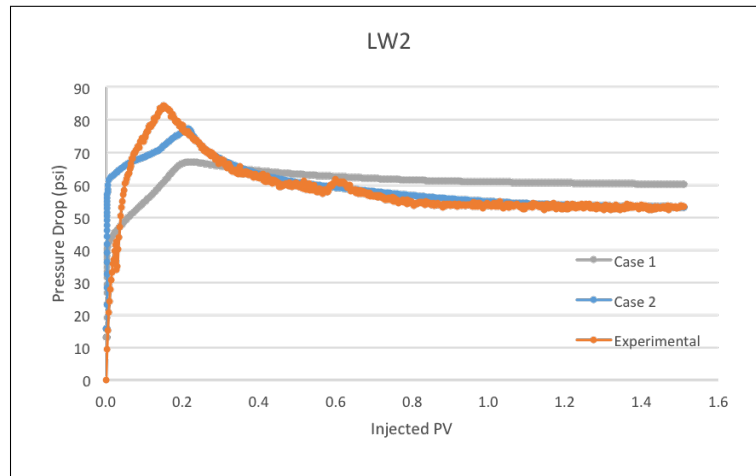


Figure 4.9: Pressure drop along the core vs. Total PV Injected for LW2

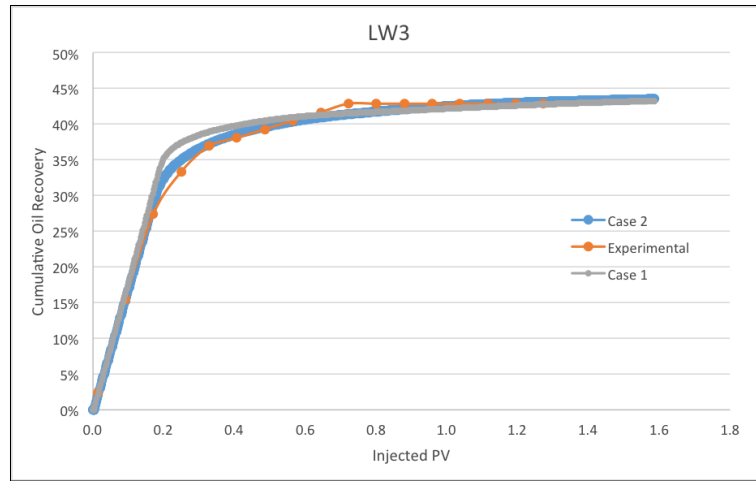


Figure 4.10: Oil Recovery as a function of Total PV Injected for LW3

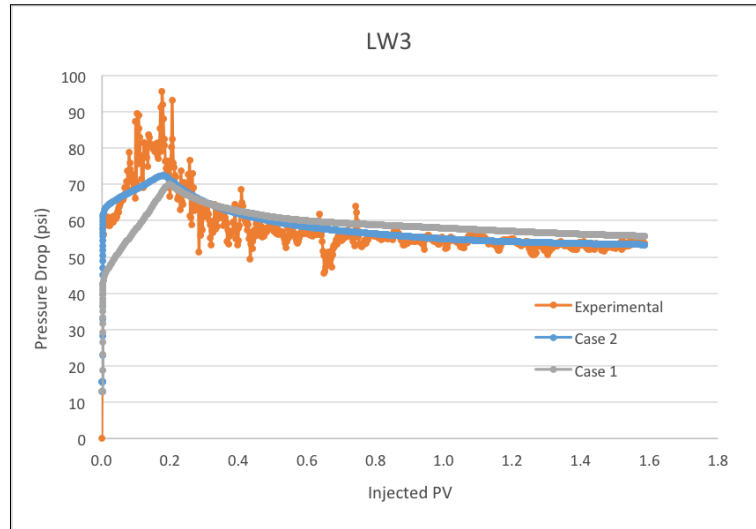


Figure 4.11: Pressure drop along the core vs. Total PV Injected for LW3

It can be seen from the plots for LW1, that important aspects of the trend are matched quite well, such as the final pressure drop and cumulative oil recovery obtained, but some, such as the initial pressure drop up to 0.35

PV injected and the water-breakthrough (turning point of the gradient of the oil recovery) on the oil recovery plot are not matched very well. Similar observations regarding the pressure drop plot can be seen for LW3. However, for LW2 the final pressure drop is not matched either. Regarding the oil recovery plot, LW2 and LW3 match the initial oil recovery versus PV injected gradient and final cumulative oil recovery, but LW2 had some discrepancies from 0.2 PV to 0.8 PV.

It is acknowledged, that discrepancies between experimental and matched data might be observed due to both the limitations of the simulator and the experimental errors. Therefore, it was decided to perform a second case, where apart from varying the water and oil curvatures, the parameters that were fixed from the experiments, would also be varied in a range of $+/- 10\%$ of the experimental value, as it is assumed to be the experimental error accepted. In this way, the effect of the experimental errors on the measurements of water and oil end-point saturation and relative permeability, would be accounted for.

The results of the Case 2 simulations, are shown on the same plots as Case 1 and the values obtained for all six parameters that define the water-oil relative permeability curves are shown in Table 4.6. It is observed, that S_{orw} and k_{rwro} remain fairly constant in both Cases for all three waterfloods, whereas S_{wro} and k_{rorw} tend to be lower than the experimentally measured value, affecting significantly the curvatures, and consequently, the whole trend of the relative permeability curves. However, Case 2 plots show a better match to the experimental result, giving a lower error at the initial part of the exper-

iment in both the oil recovery and pressure drop plots. Apart from that, the final pressure drop is also matched, giving a much better result than Case 1, especially for LW2.

Table 4.6: The values obtained for the varying parameters in Case 2 for LW1, LW2, and LW3

Parameter	LW1	LW2	LW3
n_o	2.065	1.63	1.975
n_w	1.03	3.31	1.705
k_{rorw}	0.468	0.56	0.83
k_{rwro}	0.231	0.176	0.29
S_{orw}	0.301	0.35	0.405
S_{wro}	0.342	0.36	0.30

An interesting point observed from the results of LW1 in Case 2, is that the water-curvature n_w , has decreased significantly compared with Case 1, and is nearly equal to 1. A curvature of 1, represents a straight line from the point $(S_{wro}, 0)$ to $(1 - S_{orw}, k_{rwro})$, which has not been previously reported in the literature.

It can be concluded from this investigation, that experimental errors should be taken into account when performing a match, because they can significantly change the results.

4.3.1.2 Effect of Capillary pressure on Waterflood performance

Carbonate reservoirs are highly heterogeneous, which can affect the capillary pressure P_c and relative permeability k_r behavior. For both static and dynamic modeling of heterogeneous carbonate reservoirs, capillary pressure data are important and vital, specifically for the initialization of reservoir static models, where drainage capillary pressure data are used [46].

Up to this point, the residual water saturation was used instead of the connate water saturation to obtain the curvatures of the relative permeability curves during waterflood, due to the difficulty in measuring the connate water saturation of the outcrop in the laboratory. From the results of the above investigation, it was concluded that the curvature of the water relative permeability curve, n_w , was very close to one, which is unusual and has not been reported before in the literature. The reason behind this is the use of the residual water saturation, i.e. 0.342 for LW1, rather than the actual connate water saturation, which would probably be much lower than this, and thus the use of the effective relative permeability curves rather than the intrinsic. Adding capillary pressure and connate water saturation data to obtain a more realistic determination of the waterflood relative permeability curvatures, n_w and n_o , and the end-point oil to water relative permeability, was then implemented.

Due to lack of experimental results of capillary pressure, data from literature [46] were used in this work. The choice of data used corresponds to similar rock type - Indiana Limestone, and similar porosity and permeability values. For a permeability in the range of 0.5 - 10 mD and a porosity between

16 - 30 %, an entry pressure P_{ce} of about 5 psi with a clear Pc plateau and a capillary pressure of 100 psi at 0.1 connate water saturation, were the data used to describe the drainage capillary pressure [46].

The oil-water capillary pressure function is expressed by several authors [54], [10], [22] as

$$P_c = P_{c@S_{wc}}(1 - bS_{wD})^{-1/\lambda} \quad (4.3.3)$$

where S_{wD} is the normalized water saturation defined as

$$S_{wD} = \frac{S_w - S_{wc}}{1 - S_{wc} - S_{orw}} \quad (4.3.4)$$

and b is a constant defined as

$$b = 1 - \left(\frac{P_{ce}}{P_{c@S_{wc}}} \right)^{-\lambda} \quad (4.3.5)$$

where λ is the sorting factor.

It can be assumed that the capillary pressure can be related to the water relative permeability through the following correlation [11], [54]

$$k_{rw} = k_{rw}^0 \frac{\int_0^{S_w} dS_w / P_c^2}{\int_0^1 dS_w / P_c^2} \quad (4.3.6)$$

Inserting P_c from Eq. 4.3.3 and integrating, a relationship between the Corey exponent for water relative permeability and the sorting factor in the capillary pressure function can be obtained as shown in Eq. 4.3.7

$$n_w = 1 + \frac{2}{\lambda} \quad (4.3.7)$$

and hence Eq. 4.3.6 can be re-written as

$$k_{rw} = k_{rw}^0 \frac{1 - (1 - bS_{wD})^{n_w}}{1 - (1 - b)^{n_w}} \quad (4.3.8)$$

The oil recovery and pressure drop optimum match for LW1 is shown as Case 3 in Figure 4.12 and 4.13, and the plots for LW2 and LW3 are shown in Figures 4.14, 4.15, 4.16, and 4.17, respectively. It is observed that in LW1 and LW2 corefloods, a much more improved match of the oil recovery is achieved. Regarding the pressure drop plot, there are still some discrepancies between the experimental data and the matched trend, mainly at the early times (around 0.2 PV) of the experiment and can be attributed to the initialization of the experiment. For LW3, the matched results have greater discrepancies, which are thought to be attributed to the input capillary pressure and specifically connate water saturation data. However, it is still believed that adding capillary pressure data into the calculation of the relative permeability curves increases the physical meaning of the match. A connate water saturation of 0.1 is still used for this experiment though, for consistent implementation of the methodology.

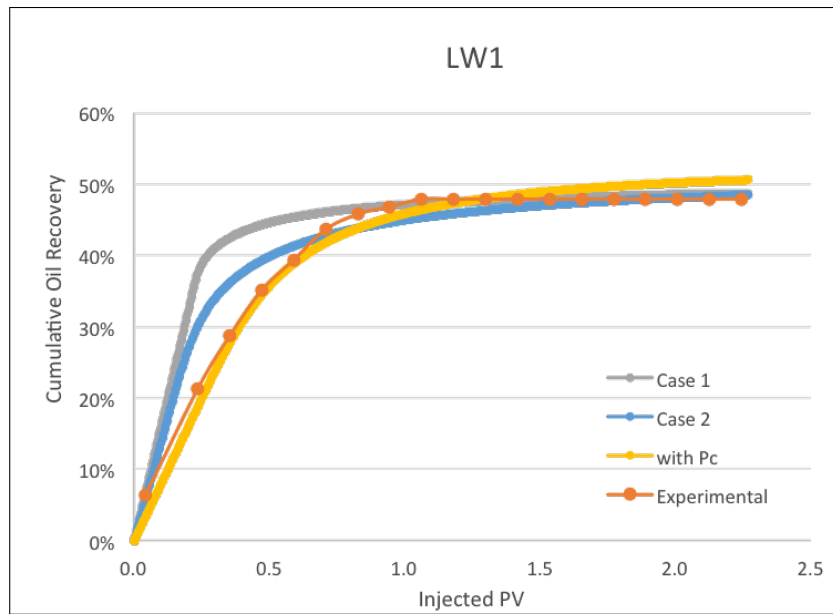


Figure 4.12: Oil Recovery vs. Total PV Injected for LW1; In Case 3, relative permeability curves are calculated with the inclusion of the capillary pressure

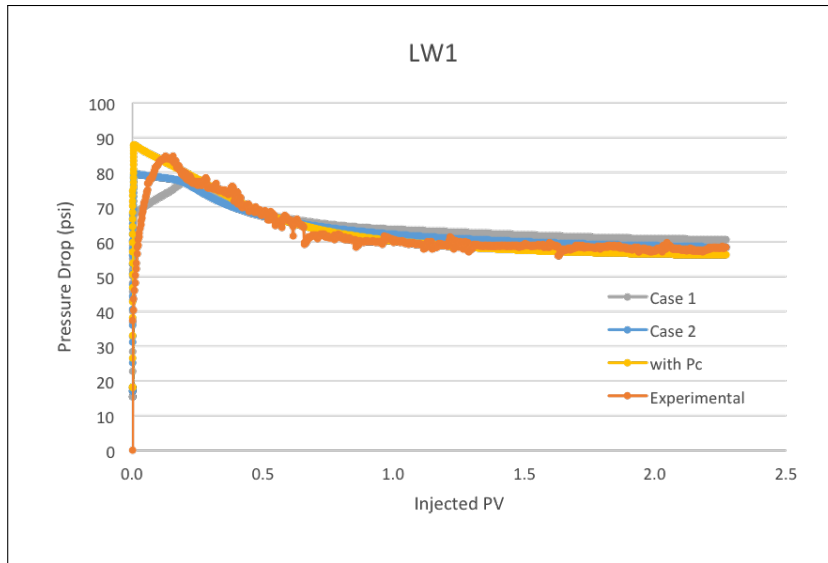


Figure 4.13: Pressure drop along the core vs. Total PV Injected for LW1; In Case 3, relative permeability curves are calculated with the inclusion of the capillary pressure

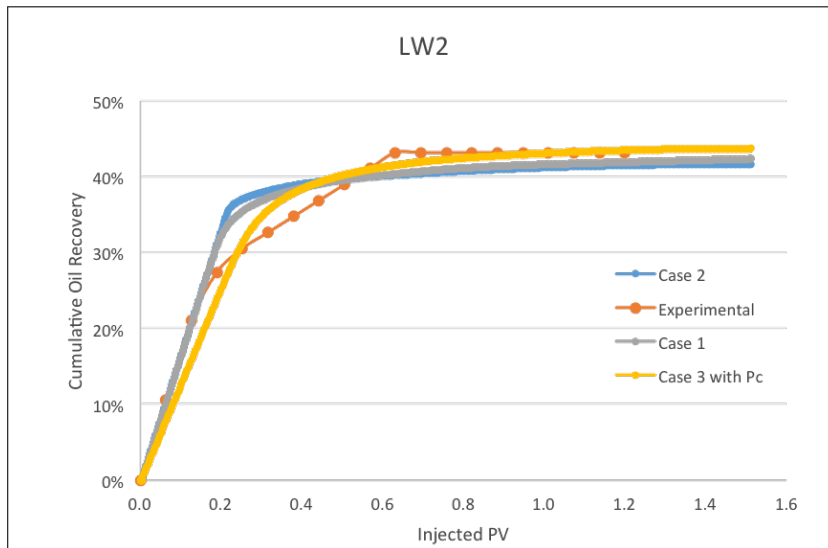


Figure 4.14: Oil Recovery vs. Total PV Injected for LW2; In Case 3, relative permeability curves are calculated with the inclusion of the capillary pressure

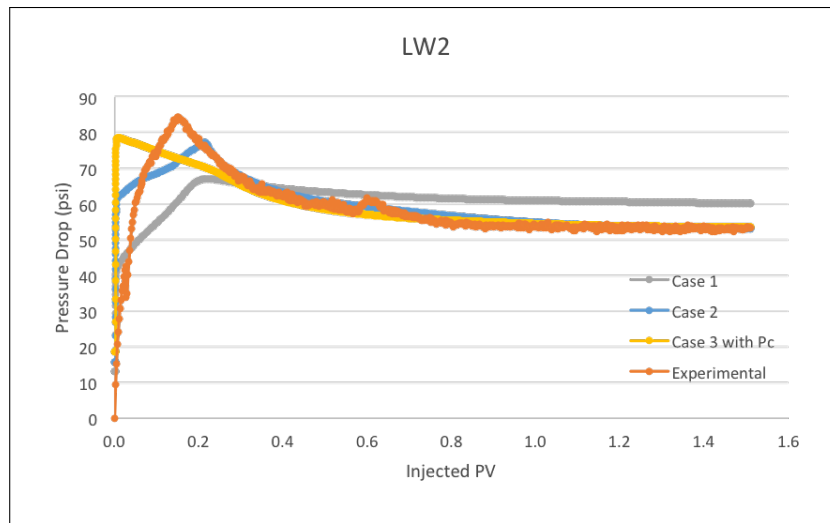


Figure 4.15: Pressure drop along the core vs. Total PV Injected for LW2; In Case 3, relative permeability curves are calculated with the inclusion of the capillary pressure

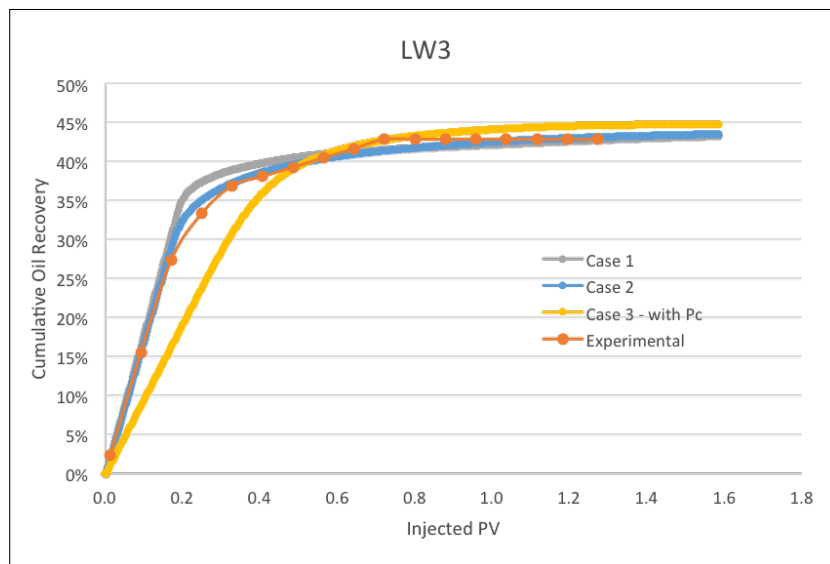


Figure 4.16: Oil Recovery vs. Total PV Injected for LW3; In Case 3, relative permeability curves are calculated with the inclusion of the capillary pressure

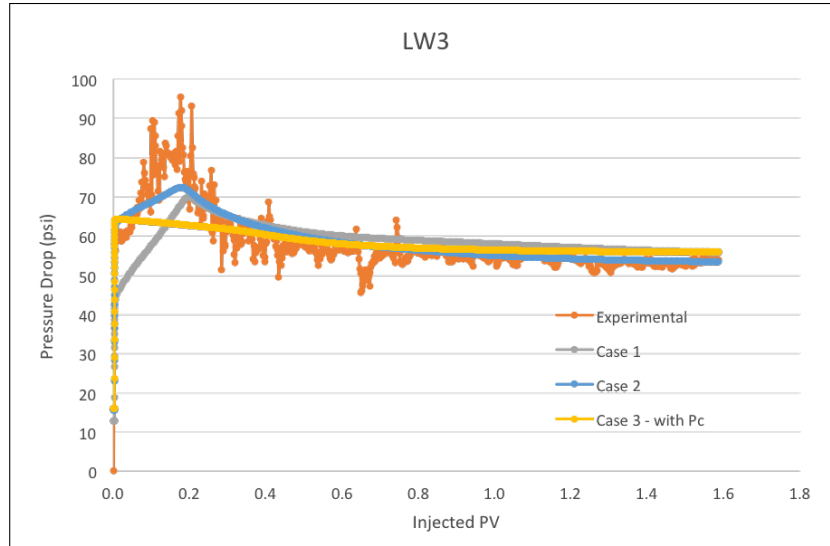


Figure 4.17: Pressure drop along the core vs. Total PV Injected for LW3; In Case 3, relative permeability curves are calculated with the inclusion of the capillary pressure

The matched values for all the parameters are shown in Table 4.7. It is observed that the curvatures of the water-oil relative permeability curves have increased for all three experiments and are both in close proximity between the different experiments, whereas the results obtained for the previous two cases were shown to have greater inconsistency.

These values are carried out for the work that follows on the Foam model and consequently, on the LTG process. Although the values for the connate water saturation and the drainage capillary pressure curve were obtained from literature, it was observed that the value used initially for the connate water saturation was significantly affecting the results, showing that better estimations of the entry pressure, connate water saturation, and cap-

illary pressure at connate water saturation, possibly through experiments on the specific outcrop cores used, would increase the accuracy of the results.

Table 4.7: The values obtained for the varying parameters of the optimum case with capillary pressure for LW1, LW2, and LW3

Parameter	LW1	LW2	LW3
n_o	1.24	1.33	1.27
n_w	2.95	2.935	4.0
k_{rorw}	0.468	0.682	0.88
k_{rwro}	0.218	0.174	0.255
S_{orw}	0.322	0.34	0.31
S_{wro}	0.1	0.1	0.1

Although, the waterflood data experimentally obtained for each core-flood might vary due to the local heterogeneity of the reservoir, it was decided to use the waterflood relative permeability curve of LW1 for the matching of all Low-Tension-Gas experiments that follow. This is due to the fact, that LW1 corresponds to one of the LTG experiments, whereas waterflood data for the other two LTG experiments were not considered reliable to use and that LW1 is more closely related to those data. Furthermore, field predictions will follow-up this work, where the macro-heterogeneities of the reservoir might be averaged and thus small differences in the waterflood conditions should not affect the reliability of the method.

4.3.2 Strategy to determine the Foam model parameters

4.3.2.1 Sensitivity Study - Numerical artifacts observed

A simulation where the core was fully saturated with water (no oil) and gas was injected at constant surfactant concentration, constant total rate, but varying gas and water rate (varying foam quality) was performed, to investigate the effect of f_{mob} by itself and thereafter in conjunction with f_{dry} ($s_{fbet} + s_{fdry}$). The pressure drop, water saturation, and water and gas relative permeability versus foam quality were investigated. During this process, the limitations and weaknesses of the model were evaluated, before attempting to match a coreflood of similar conditions to determine these parameters.

The values used in this sensitivity study, $f_{mob} = 502.3$, $s_{fdry} = 10\,000$, and $s_{fbet} = 0.367$, were obtained from Rouhi *et al.* [22].

The effect of f_{mob} was first investigated and it was observed that the gas relative permeability as a function of foam quality reaches a plateau at high qualities, as shown in Figure 4.18.

This was further explored to increase the understanding of the numerical simulation. The gas relative permeability curve calculated using equation 3.5.1 and the numerically calculated gas relative permeability curve were plotted and compared on Figure 4.19. It is observed that for gas saturation higher than the end-point gas saturation initially defined in the simulation, the gas relative permeability remains constant. In this case the gas saturation was defined up to 0.6.

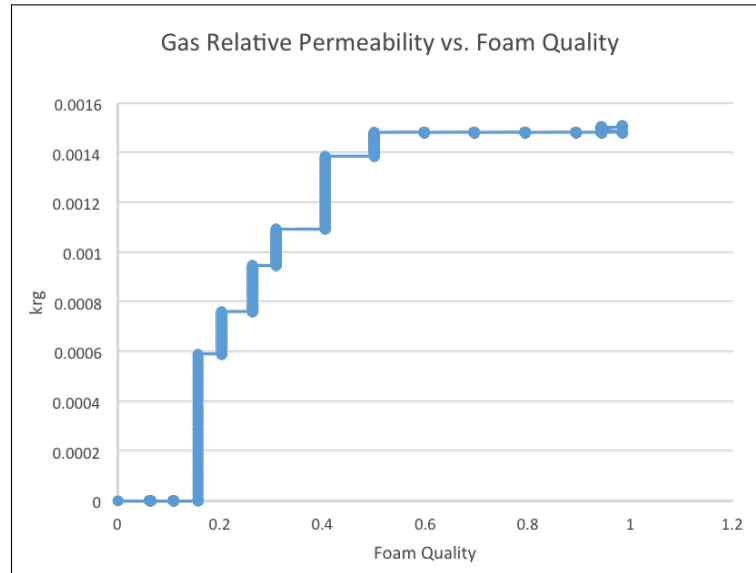


Figure 4.18: Gas relative permeability curve when $f_{mob} = 502.3$

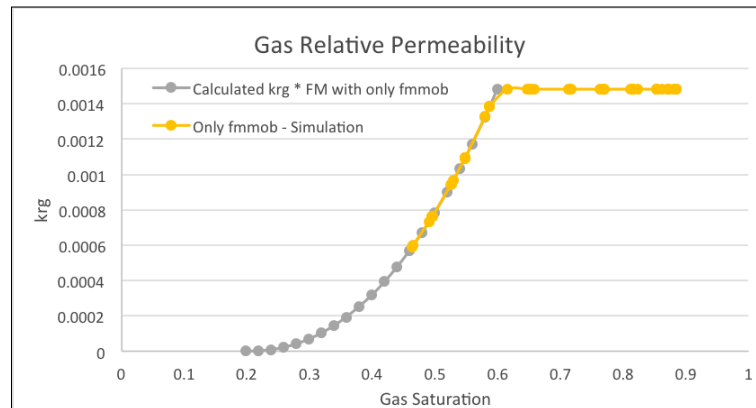


Figure 4.19: Gas relative permeability curve manually and numerically calculated

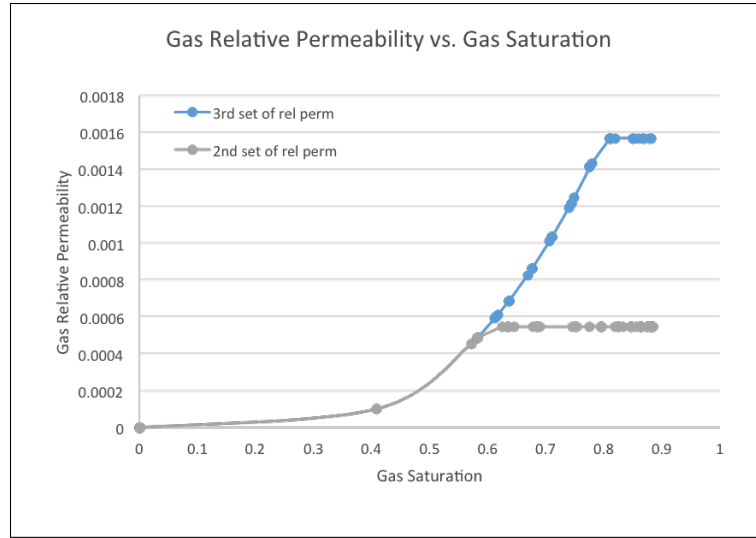


Figure 4.20: Gas relative permeability curves defined up to a 60% and 80% gas saturation

Two different sets of gas relative permeability, one defined up to a saturation of 0.6 and one extrapolated up to a saturation of 0.8, as shown in Figure 4.20 were used and their effect on the pressure drop was examined. It can be seen on Figure 4.21 that for constant gas relative permeability, the pressure drop increases significantly, thus this effect is attributed to the water relative permeability instead. On the other hand, for the extrapolated curve the increase in pressure drop is less severe. The effect of this difference is then extended to the case where the dry-out function is also used.

According to previous studies [22] the value of sf_{bet} does not influence much the results, unless it's value is very low, hence two different values of sf_{dry} , 0.367 and 0.2, were used to investigate the effect of the dry-out function. Figure 4.22 shows the gas relative permeability when only f_{mob} is used, and

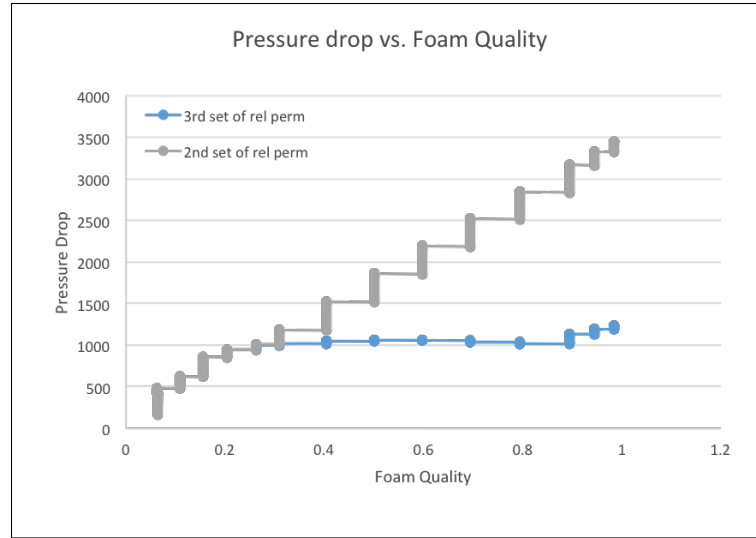


Figure 4.21: The pressure drop across the core when the gas relative permeability curves are defined up to a 60% and 80% gas saturation

when the gas relative permeability is defined up to a gas saturation of 0.6 and how this changes when the dry-out function is used. It can be seen that for $s_{fdry} = 0.2$ the gas relative permeability follows the plateau line up to a gas saturation of 0.8 and then it increases abruptly. This is expected as the dry-out function describes that the foam dies at a water saturation of 0.2. In a system of only water and gas, this means that the gas saturation will be 0.8. However, since it is not defined in this range, the gas relative permeability follows the plateau and consequently the pressure drop increases as shown in Figure 4.23.

Comparing the pressure drop results of Figure 4.23 with the pressure drop data of the extrapolated gas relative permeability curve shown in Figures 4.24 and 4.25, it can be seen that the pressure drop has a less severe increase.

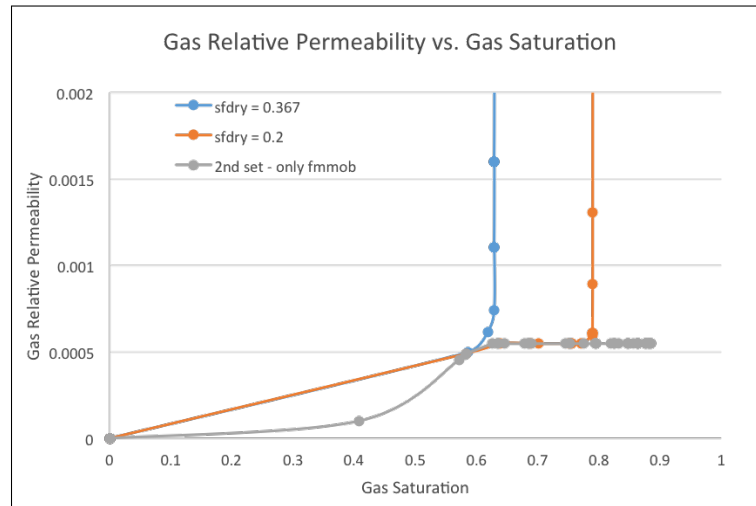


Figure 4.22: The gas relative permeability curves when only fmmob is used and when sfdry takes the values of 0.2 and 0.367, and gas relative permeability curves are defined up to a 60% gas saturation

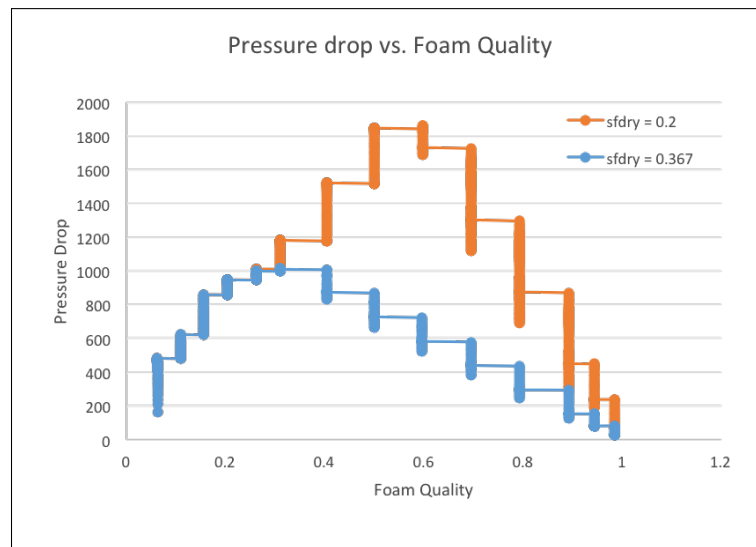


Figure 4.23: The pressure drop across the core when the gas relative permeability curves are defined up to a 60% gas saturation, for sfdry values of 0.2 and 0.367

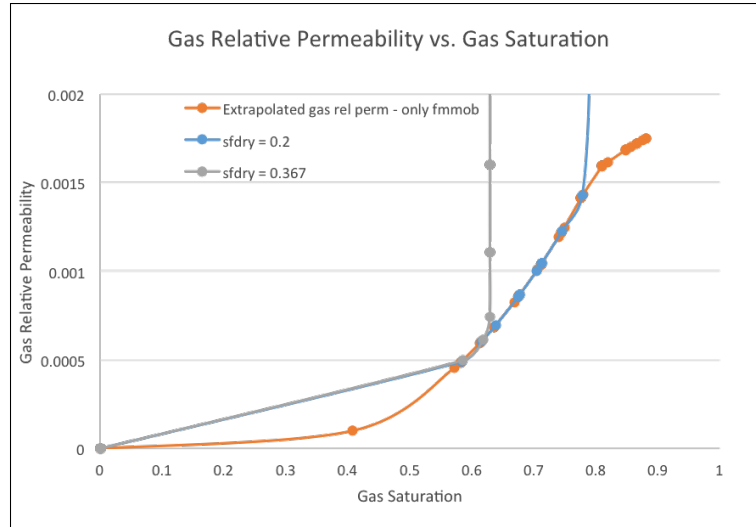


Figure 4.24: The gas relative permeability curves when only fmmob is used and when sfdry takes the values of 0.2 and 0.367, and gas relative permeability curves are defined up to a 80% gas saturation

This numerical artifact is statically fixed in the simulation by extrapolating the gas relative permeability curve.

A similar numerical artifact was observed during the interpolation of the water-oil relative permeability curves. In the case of high water saturation but very low salinity, the system falls in the first relative permeability curve. However, the first set of relative permeability is not defined for saturations higher than $1 - S_{orw}$, thus the simulation tries to find those points by interpolating back and forth between the three relative permeability curves, creating problems and giving spikes in the pressure drop. This was statically fixed, by creating points of higher saturation for the first relative permeability curve by extrapolation. Further improvement of this numerical artifact should be

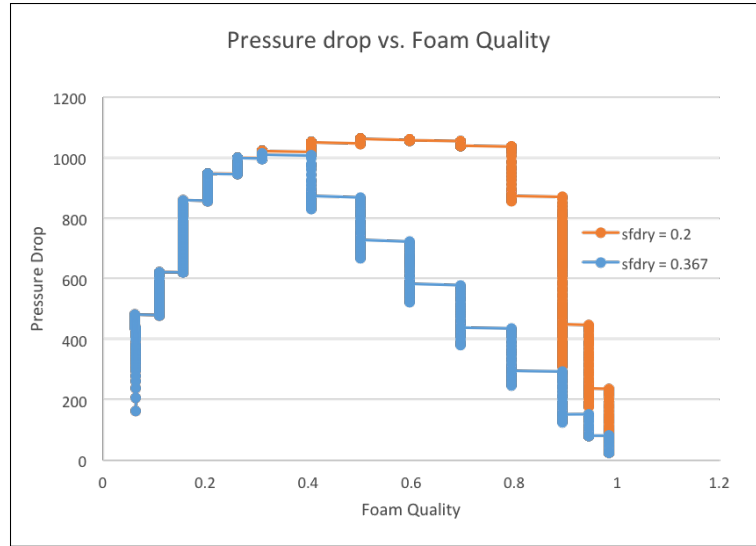


Figure 4.25: The pressure drop across the curve when the gas relative permeability curves are defined up to a 80% gas saturation, for sfdry values of 0.2 and 0.367

implemented.

4.3.2.2 Reference foam mobility reduction factor and Foam Dry-out

For the determination of the foam mobility reduction factor FM, the reference foam mobility reduction factor, $fmmob$, the foam dry-out function which is defined through $sfdry$, and $sfbet$, and the gas relative permeability curve defined by n_g , k_{rgrl} , and S_{gcon} , will be fitted to experimental data of foam quality tests. All of these parameters are rock dependent, and thus should be determined as a set.

The foam quality tests were performed after the slug and drive of experiment LTG 2, where the oil saturation is at residual. Surfactant concentration

and salinity remained identical to the drive solution and the foam quality was varied by keeping constant the total (liquid + gas) rate of injection.

The water-oil relative permeability curves obtained earlier through the matching of the waterflood are now fixed at the determined averaged values. The end-point oil saturation S_{org} and end-point relative permeability k_{rorg} are fixed to be equal with the respective values of the water-oil relative permeability curves S_{orw} and k_{rorw} . The oil-gas relative permeability curvature n_{og} , although unknown, is fixed in this case to reduce the complexity of the matching, as it is believed to have no effect on the results since oil is at residual.

For the simulation, $fmmob$ was allowed to vary between 5 - 100, which is the normal range for $fmmob$ depending on the strength of the foam [12]. $Sfbet$ was allowed to vary between 0 - 10 000 and $sfdry$ is varied in a range 0.01 - 0.05 above the residual water saturation after waterflood [12]. Gas curvature n_g was varied between 1 - 4, end-point gas saturation S_{gcon} between 0 - 0.2, and end-point gas relative permeability k_{rgrl} between 0.5 - 1.0.

The optimum results from this simulation are shown in Figure 4.26 and the obtained parameters are shown in Table 4.8.

Table 4.8: The determined values of f_{mob} , s_{fbet} , s_{fdry} , and gas relative permeability curve

Parameter	Value obtained
n_g	1.91
S_{gcon}	0.135
k_{rgrl}	0.899
f_{mob}	15.4
s_{fdry}	7750
s_{fbet}	0.375

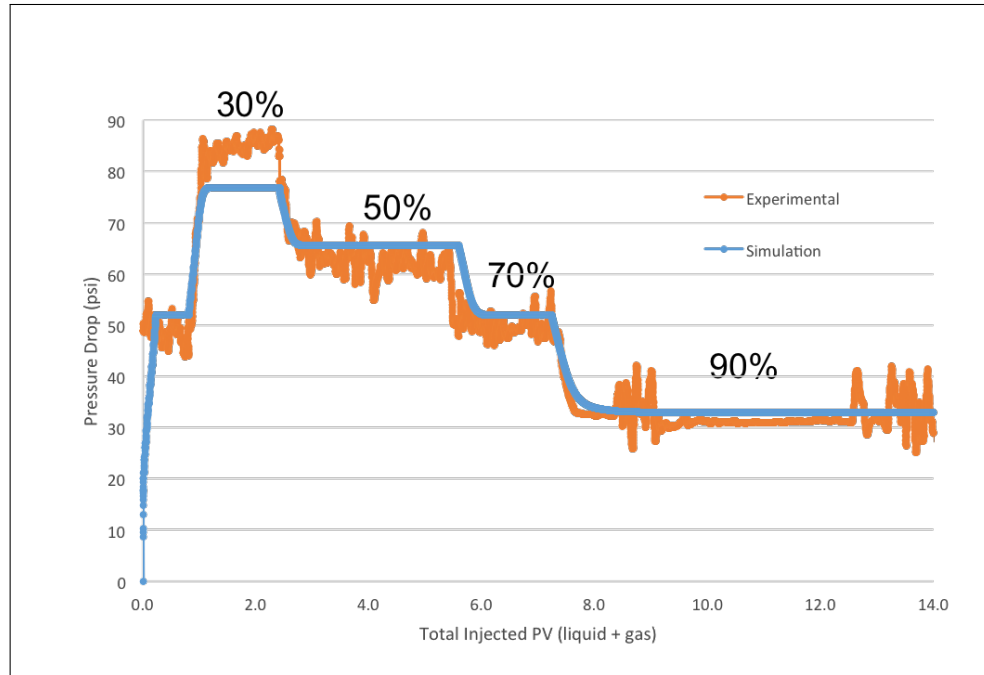


Figure 4.26: Foam quality tests simulation for the determination of f_{mob} , the dry-out function, and the gas relative permeability curve

The obtained parameters were compared with the steady-state foam apparent viscosity calculation method proposed by previous researchers [22], [45]. The apparent viscosity plot of the experimental results, and the curve obtained through the use of the equations in the above mentioned papers and the obtained $fmmob$, $sfdry$, $sfbet$, and the gas relative permeability curve used, are shown in Figure 4.27.

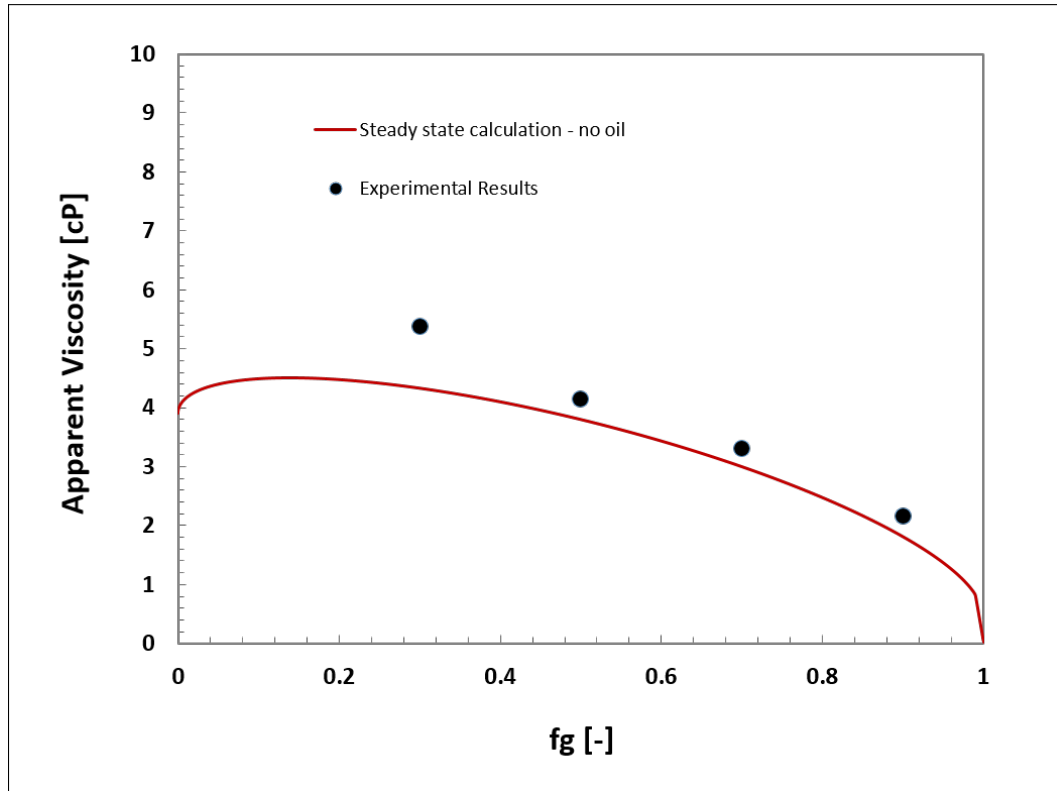


Figure 4.27: Foam Apparent Viscosity using steady-state calculations

Although the results show to match in shape and in magnitude, it is important to note that, the calculation by Farazjadeh *et al.* and Ma *et al.* is

based on cases where the core is saturated with brine and gas only, and where no oil exists, in contrast to the above simulation where residual oil is present in the core. Discrepancies between the results can also be attributed to the fact that the calculation of foam apparent viscosity is based on the assumption that all water is consumed by foam and that no excess water phase exists.

The determined values of the parameters are then fixed for the following simulations of the complete LTG process.

4.3.3 LTG Flooding Performance

The simulation of an LTG process, apart from determining the rest of the foam model parameters (ϵ_{salt} , f_{moil} , f_{loil} , and ϵ_{poil}), it also involves the determination of the intermediate capillary number oil-water relative permeability curves, gas-oil relative permeability curves, adsorption and the isotropic dispersivity coefficient. All of these parameters are shown in Table 4.9 and are grouped in the five families described.

The possible range of variation of each parameter was chosen based on CMG and model restrictions, and literature. The intermediate relative permeability curves, since by definition lie between the low and high capillary number curves are bounded by the waterflood determined curves and the miscible curves (straight lines).

The foam model parameter ϵ_{salt} that determines the degree by which foam stability scales with microemulsion phase behavior, is taken to be negative in order to describe the inverse relationship between salinity and foam

mobility reduction. Thus, it is allowed to vary between -4 and 0. On the other hand, ϵ_{oil} that determined the degree by which foam stability scales with oil saturation is taken to be positive and allowed to vary between 0 and 4. The critical and lower oil saturation, f_{moil} and f_{loil} respectively, are both allowed to vary between 0-1 with the restriction of f_{loil} always lower than f_{moil} .

Furthermore, the oil-gas curvature is allowed to vary between 1.5-4. The dispersivity coefficient for carbonates, is suggested by [82] and [56] to be between 0 - 0.01 [m]. Finally, the effective CMC, which is a proxy for adsorption and has units of molality (mole of surfactant per kg of water), is restricted to be lower than half of the injected surfactant in the slug solution. The injected slug surfactant concentration in terms of molality, is 0.0234 mol/kg for LTG 1 and LTG 3, and 0.0117 for LTG 2.

Table 4.9: The set of unknown parameters used for the simulation of the LTG - process, divided into four groups including, Intermediate relative permeability, foam model parameters, oil-gas curvature, dispersivity coefficient, and effective-CMC (proxy for adsorption)

#	Description	Symbol
Intermediate Relative Permeability		
1	Intermediate Capillary Number	$N_{c,interm}$
2	Curvature oil relative permeability to water at $N_{c,interm}$	$n_{o,2}$
3	Curvature of water relative permeability to oil at $N_{c,interm}$	$n_{w,2}$
4	End-point oil relative permeability to water at $N_{c,interm}$	$k_{rorw,2}$
5	End-point water relative permeability to oil at $N_{c,interm}$	$k_{rwro,2}$
6	Residual oil saturation to water at $N_{c,interm}$	$S_{orw,2}$
7	Residual water saturation to oil at $N_{c,interm}$	$S_{wro,2}$
Foam model parameters		
8	Exponent of microemulsion phase behavior effect on foam stability	$epsalt$
9	Critical limit of oil saturation effect on foam stability	$fmoil$
10	Lower limit of oil saturation effect on foam stability	$floil$
11	Exponent of oil saturation effect on foam stability	$epoil$
Oil-gas curvature		
12	Curvature of oil relative permeability to gas	n_{og}
Dispersion		
13	Isotropic velocity-dependent Dispersivity Coefficient	DISP
Adsorption		
14	Effective Critical Micelle Concentration (proxy for adsorption)	Eff-CMC

4.3.3.1 Sensitivity Study of LTG Model Parameters

Before determining the absolute value of these unknown parameters, a sensitivity study was performed to evaluate their significance on the oil recovery and pressure drop. The sensitivity of the parameters is evaluated firstly by families, and then individually each parameter within each family. It is chosen to evaluate by families because the effects of the parameters within each family and sometimes between families, are interrelated, and this way helps isolating the effects.

Figure 4.28 shows the effect of the dispersivity coefficient, when all other unknown parameters are fixed, on the oil recovery and the pressure drop. It is observed that the reduction of dispersion led to a quicker transition to lower salinity, and thus to reduced mobility control and slower production.

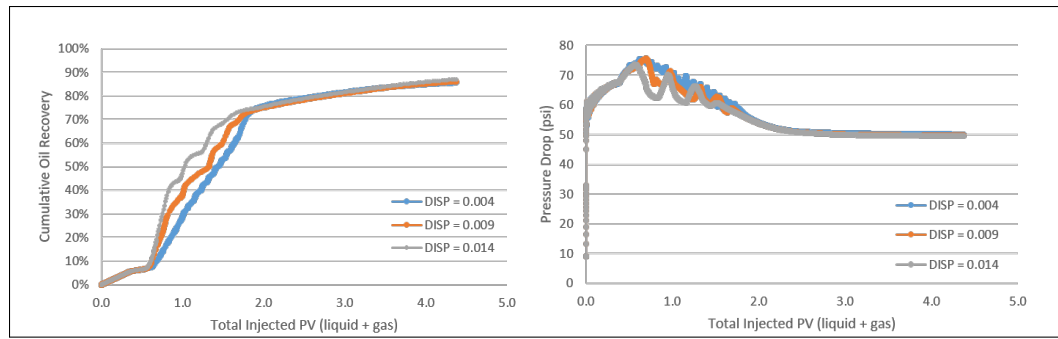


Figure 4.28: Sensitivity analysis of the dispersivity coefficient on both the oil recovery and pressure drop

Figure 4.29 shows that increasing CMC and consequently adsorption, leads to reduced amount of available surfactant for foam generation, thus re-

duced mobility control as observed by the slower production. CMC values shown are in terms of molality (mole of surfactant per kg of water).

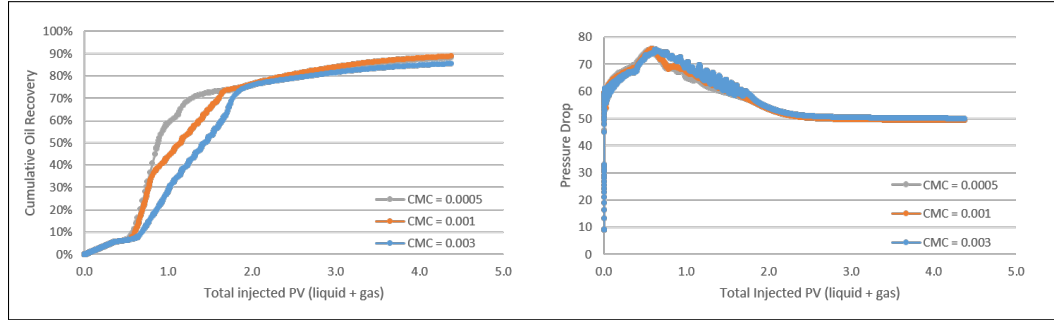


Figure 4.29: Sensitivity analysis of the Eff-CMC parameter, which is a proxy for adsorption, on both the oil recovery and pressure drop

The foam parameters as a family should affect both the oil recovery and pressure drop, as they affect the foam strength and consequently the amount of oil pushed and recovered. By examining individually the parameters, it is observed that increasing f_{moil} , as shown on Figure 4.30, makes stronger foam as indicated by the increased pressure drop. It is also observed that the effect of decreasing f_{moil} on the oil recovery, reaches an optimum and then continued decreases of the parameter decreases again the oil recovery. This observation indicates that although foam becomes weaker, there is a threshold, below which no more oil is recovered. Similar observations are drawn for e_{poil} as shown in Figure 4.32, and for f_{loil} the effects are shown in Figure 4.31 to be less pronounced.

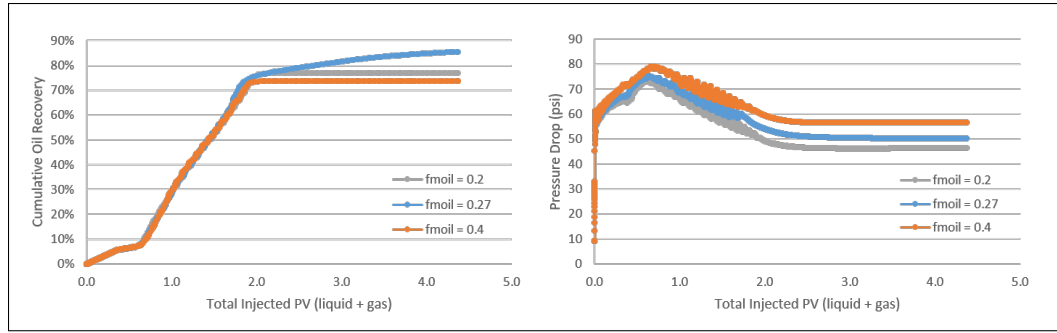


Figure 4.30: Sensitivity analysis of the f_{moil} parameter on both the oil recovery and pressure drop

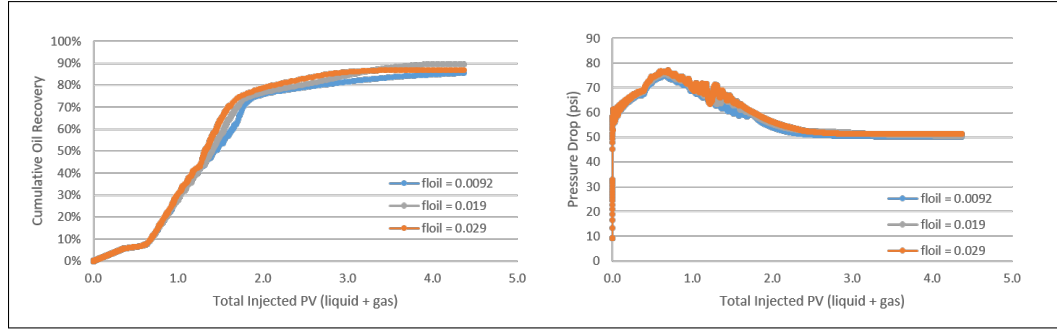


Figure 4.31: Sensitivity analysis of the f_{oil} parameter on both the oil recovery and pressure drop

Figures 4.32 and 4.33, which show the effect of the oil saturation and salinity exponents of the foam model on the oil recovery and pressure drop, indicate that their effect is opposite. Increasing $epoil$ indicates a weaker foam, which also reaches a higher ultimate oil recovery, whereas the negative increase of $epsalt$ induces a much stronger foam as shown by the late-time pressure buildup.

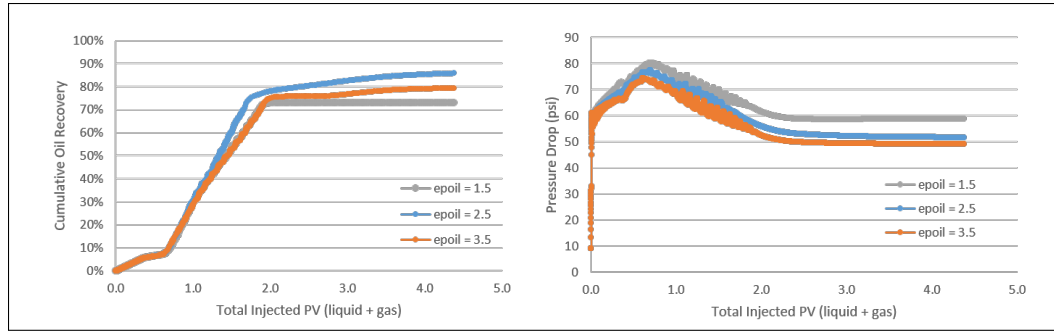


Figure 4.32: Sensitivity analysis of the epoil parameter on both the oil recovery and pressure drop

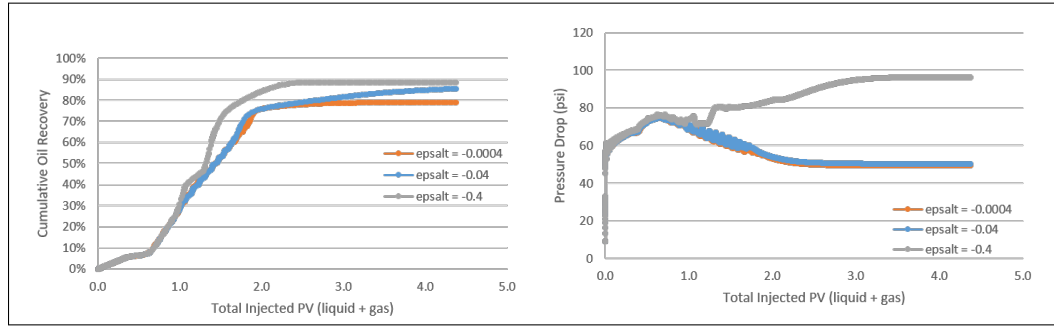


Figure 4.33: Sensitivity analysis of the epsalt parameter on both the oil recovery and pressure drop

Figure 4.34 shows that the increase of the oil-gas curvature n_{og} , reduces the relative permeability of oil to gas k_{rorg} , and thus delays the oil breakthrough point and increases the initial pressure drop. Hence, the production reaches a higher ultimate oil recovery.

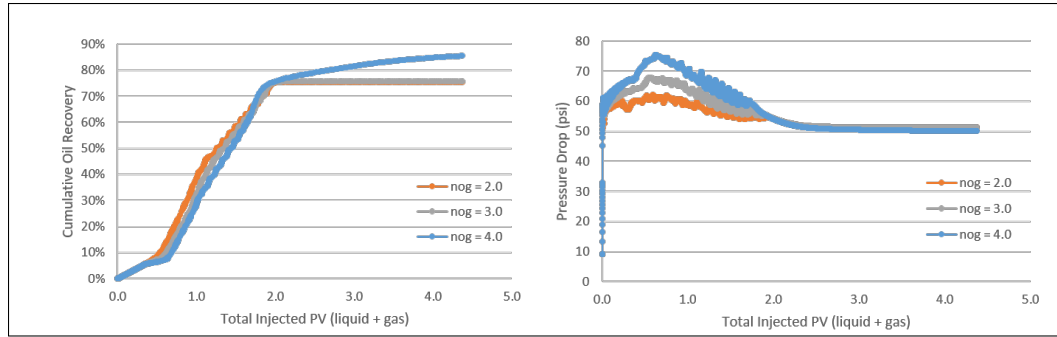


Figure 4.34: Sensitivity analysis of the nog parameter on both the oil recovery and pressure drop

The intermediate capillary number and its associated relative permeability curves have a significant effect, both on the oil recovery and the pressure drop, as they control how oil and water flow at the specified conditions of surfactant concentration and foam quality. The individual effect of the intermediate capillary number is shown in Figure 4.35. It is observed, that the capillary number for a fixed set of intermediate relative permeability curves affects significantly both the oil recovery and the pressure drop, as it affects the oil-water relative permeability curve interpolation performed.

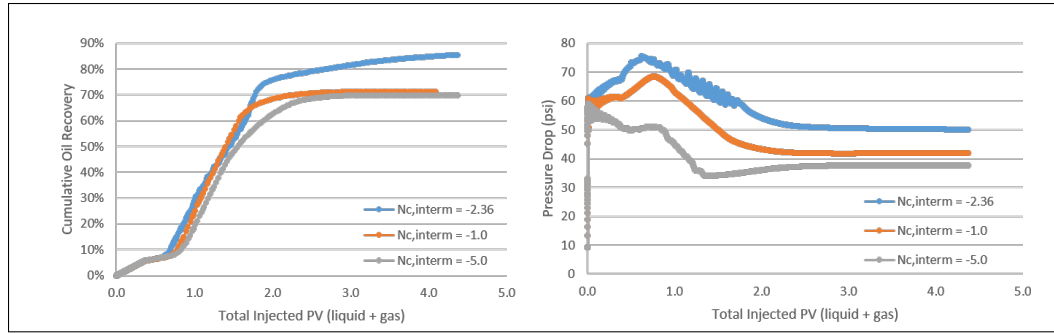


Figure 4.35: Sensitivity analysis of the intermediate capillary number $N_{c,interm}$ on both the oil recovery and pressure drop

Figure 4.36 focuses on the effect of the intermediate curve oil curvature. The decrease of the oil curvature, increases the relative permeability of oil to water for a given water saturation, and thus reaching a higher oil recovery with slightly reducing the pressure drop as expected due to the better mobility of oil. However, in this case the observations are not striking since the range of variation of $n_{o,2}$ is very narrow because it is limited by the corresponding parameter of the waterflood relative permeability curves. Similar observations can be seen in Figure 4.37, where the decrease of the water curvature, increases the relative permeability of water to oil, thus decreasing the ultimate oil recovery and decreases the pressure buildup in the core as water has better mobility.

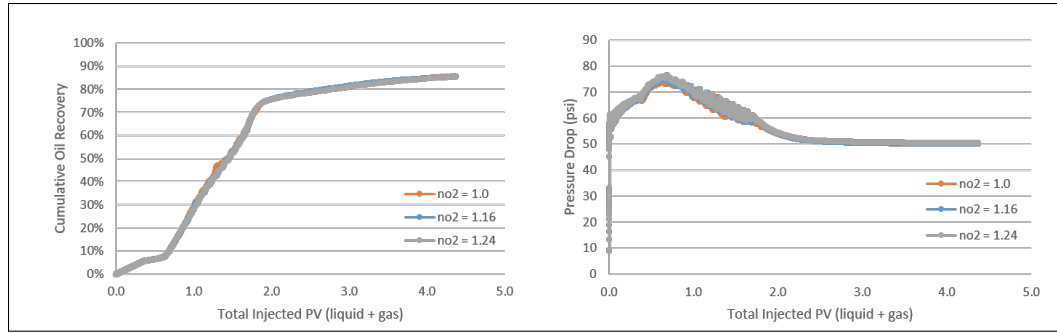


Figure 4.36: Sensitivity analysis of the intermediate oil curvature $n_{o,2}$ on both the oil recovery and pressure drop

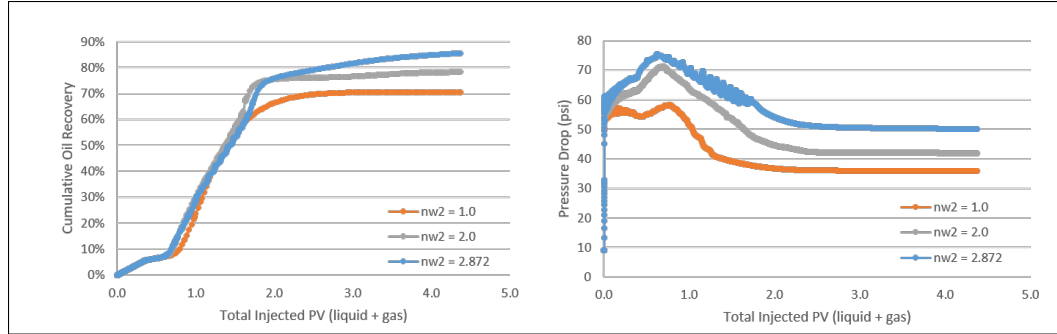


Figure 4.37: Sensitivity analysis of the intermediate water curvature $n_{w,2}$ on both the oil recovery and pressure drop

Figures 4.38 indicate that the increase of the end-point oil-water relative permeability at constant curvature, gives greater mobility to oil at any given saturation and thus reaches higher oil recovery. Similarly, Figure 4.39 shows that the increase of the end-point water-oil relative permeability at constant curvature gives greater mobility to water at any given saturation and thus reaching a lower oil recovery, since more water is produce and less oil. The increase of water mobility leads to less pressure built up in the core.

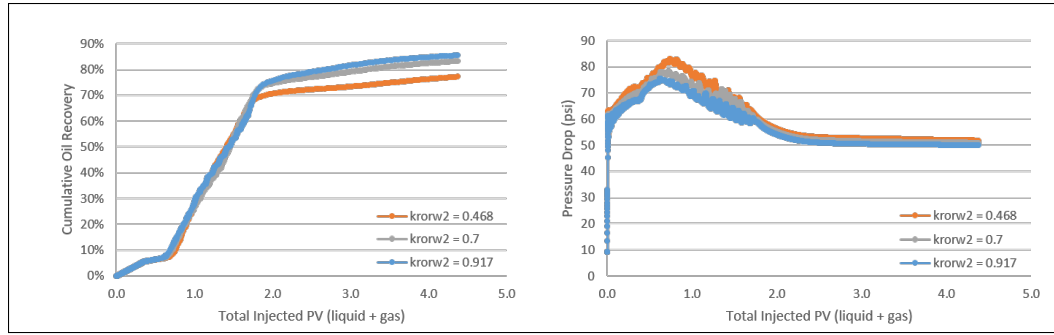


Figure 4.38: Sensitivity analysis of the intermediate end-point oil-water relative permeability $k_{rorw,2}$ on both the oil recovery and pressure drop

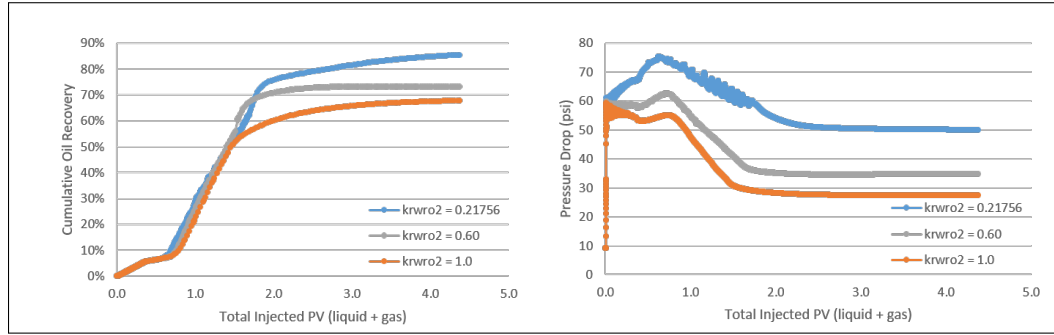


Figure 4.39: Sensitivity analysis of the intermediate end-point water-oil relative permeability $k_{rwro,2}$ on both the oil recovery and pressure drop

Figure 4.40 shows that the increase of the end-point remaining oil saturation, for a constant curvature and end-point relative permeability, decreases the relative permeability of oil at any given saturation, and thus the oil recovery is minimal. However, this decrease in oil relative permeability consequently increases the water relative permeability, and thus leads to a pressure drop.

Similar effects are observed in Figure 4.41 for $s_{wro,2}$. The increase of the end-point water saturation decreases the relative permeability of water

and thus more oil is produced. The effects on the pressure drop are shown to be minimal, but this is due to the fact that the range between which $S_{wro,2}$ is varied, is very narrow.

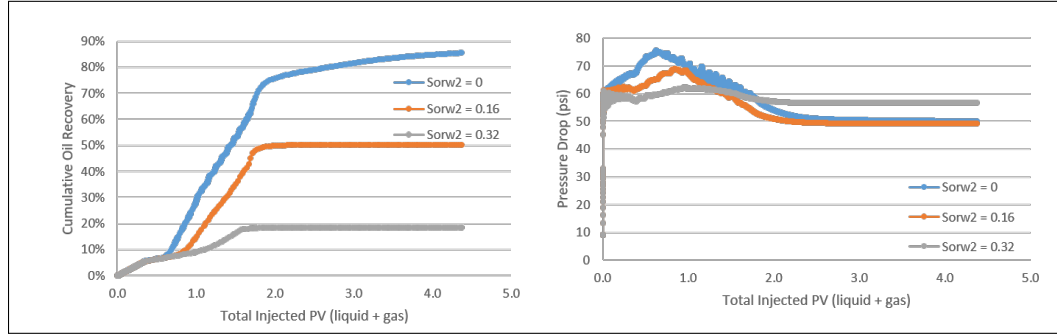


Figure 4.40: Sensitivity analysis of the intermediate end-point oil saturation $S_{orw,2}$ on both the oil recovery and pressure drop

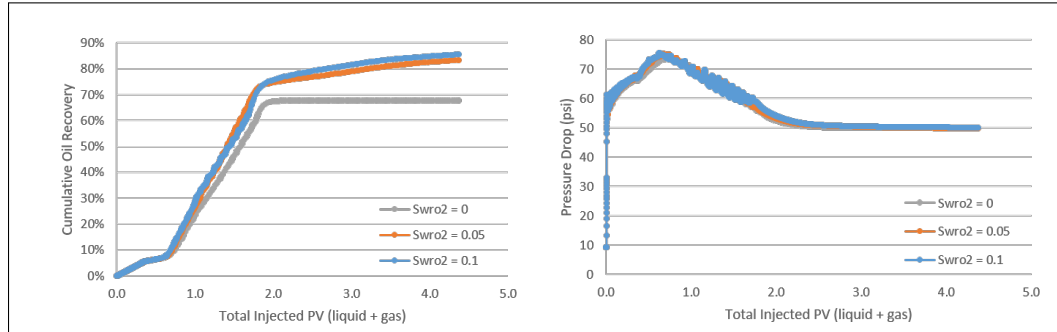


Figure 4.41: Sensitivity analysis of the intermediate end-point water saturation $S_{wro,2}$ on both the oil recovery and pressure drop

4.3.3.2 Modeling Results of LTG Process

For the validation of the accuracy of the LTG matching results and the procedure followed, three experiments are used. Experiments LTG1, LTG2,

and LTG3, are used to calibrate the unknown parameters, by performing a data-fitting simulation to the experimental results.

Experimental data such as the liquid and gas rates, surfactant concentration and injection salinity for both the slug and drive solutions were used to accurately represent the laboratory experiments, as shown earlier in Table 4.1. As described earlier, *fmsalt* and *flsalt* are fixed to the salinity of the Type III microemulsion salinity boundaries. Table 4.10 shows the values of these parameters for all three experiments.

Table 4.10: Summary of fixed foam parameters for all three LTG experiments

Parameter	LTG1	LTG2	LTG3
<i>fmsalt</i>	0.064		
<i>flsalt</i>	0.033		

Figures 4.42 & 4.43, 4.44 & 4.45, and 4.46 & 4.47, show the optimum match obtained for each LTG experiment, and Table 4.11 shows the matched results for all the unknown parameters.

The matching results show an accurate representation of the oil recovery in all three experiments, and a good match of the pressure drop as well. However, differences at early times of the LTG 2 experiment are observed. As stated earlier, the early time shock in pressure drop of the experimental results is due to the gas expansion and thus, for that portion of the data a lower weighting factor is used and more focus is given to the late time data.

Therefore, although it is observed that the model cannot fully capture the early time data, it can capture the full extend of the late-time pressure. For the unmatched portion, the sensitivity study performed earlier has helped determine what causes the pressure to follow this trend in the simulation. The initial pressure increase observed is due to the gas injection. Initially, gas saturation in the core is zero, thus when gas is injected it experiences low relative permeability. The parameter S_{gcon} , which represents statically the trapped gas, has shown to have a great effect at the initial portion of the trend. By increasing it, the spike becomes more dramatic, as it makes the gas to flow even harder initially. Once gas saturation increases beyond a certain point, it experiences high relative permeability and thus a pressure drop decrease is observed.

A comparison of the exponents of the power law relations that describe the relative importance of oil saturation and microemulsion phase behavior on foam stability, led to the conclusion that foam stability has a greater sensitivity to oil saturation than to microemulsion phase behavior for the given system, as the exponents of oil saturation are much greater than the exponent of microemulsion phase behavior for all three experiments. Stephen *et al.* has previously shown that values of ϵ_{salt} for sandstones were much higher (-2.03, -1.3), leading to the conclusion that the effect of salinity and consequently microemulsion on foam stability in carbonates, is possibly not as strong as in sandstones.

It is also believed that the oil effect (oil saturation and microemulsion

phase behavior effects), as well as the salt should not be different between the three experiments irrespective of the injection salinity, surfactant concentration and foam quality in the system. These parameters describe the functions that affect the foam stability, for a given oil composition, a given microemulsion system and a given surfactant component, thus should be identical for all three corefloods. The matching values obtained for epoil , epsalt , fmoil , and floil for all three LTG experiments are thought to be very similar, and thus confirming this assumption.

The oil to gas curvature is shown to be the greatest in LTG1, decrease in LTG2, and decrease even further in LTG3. This trend is associated with the pressure buildup as was observed during the sensitivity analysis. A less pronounced initial pressure buildup in LTG2 corresponds to a decrease in n_{og} and similarly for LTG3.

The rest of the unknown and varying parameters including the Dispersivity coefficient, Effective CMC, intermediate capillary number and associated relative permeability curves are believed to be dependent on foam mobility control and IFT-reduction, and are thus expected to be different between experiments. However, the matched results show that the effective CMC and dispersivity coefficient are very similar between experiments. This indicates that the cores for these three cases are close in morphology and pore size distribution and that the difference in performance between the three LTG experiments is controlled by the oil-gas curvature and the intermediate capillary number and associated oil-water relative permeability curves.

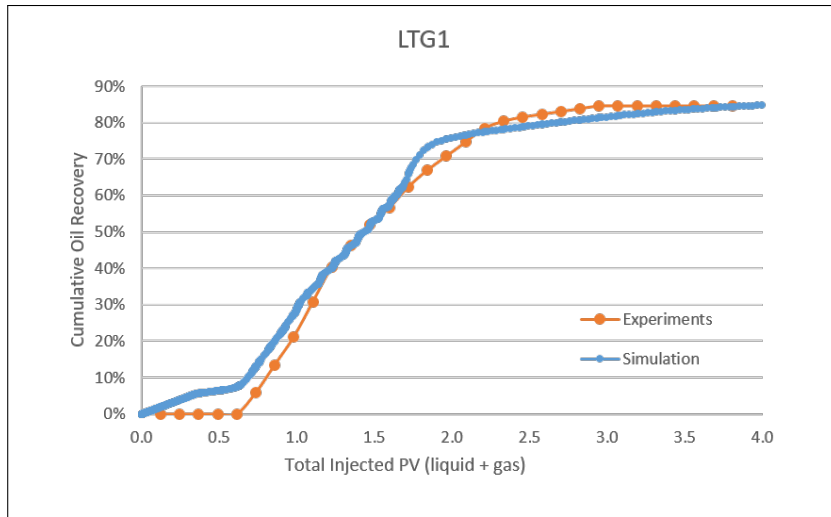


Figure 4.42: Matched cumulative oil recovery of LTG1

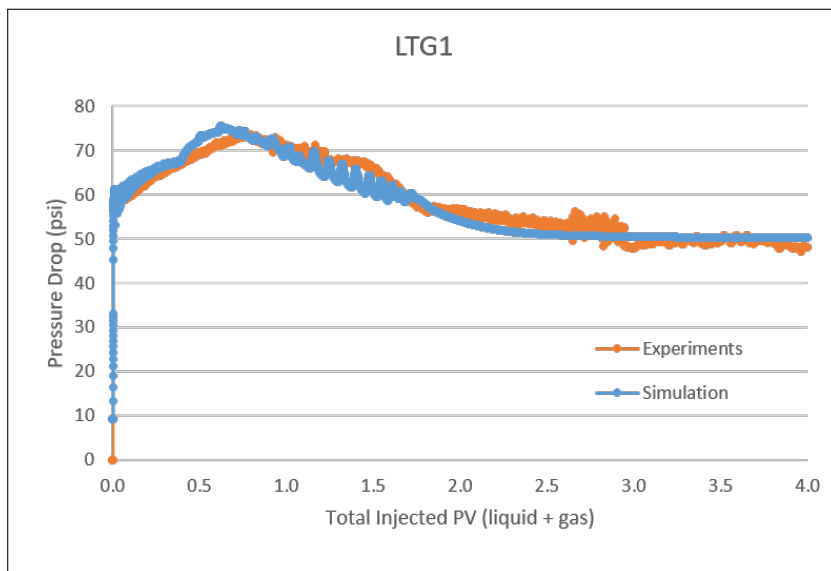


Figure 4.43: Matched pressure drop of LTG1

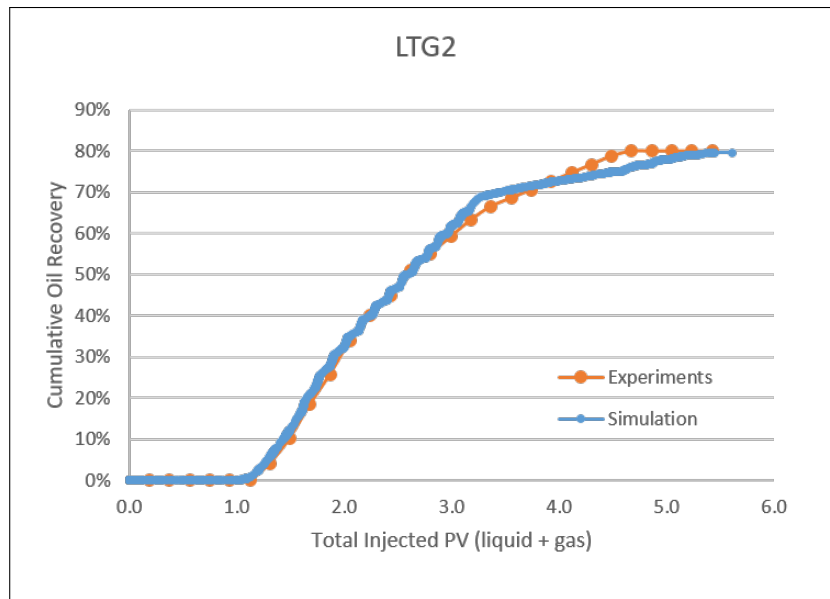


Figure 4.44: Matched cumulative oil recovery of LTG2

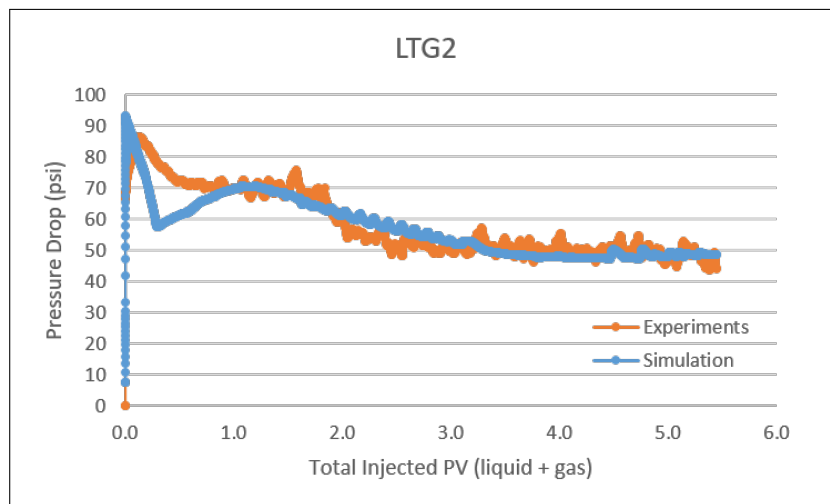


Figure 4.45: Matched pressure drop of LTG2

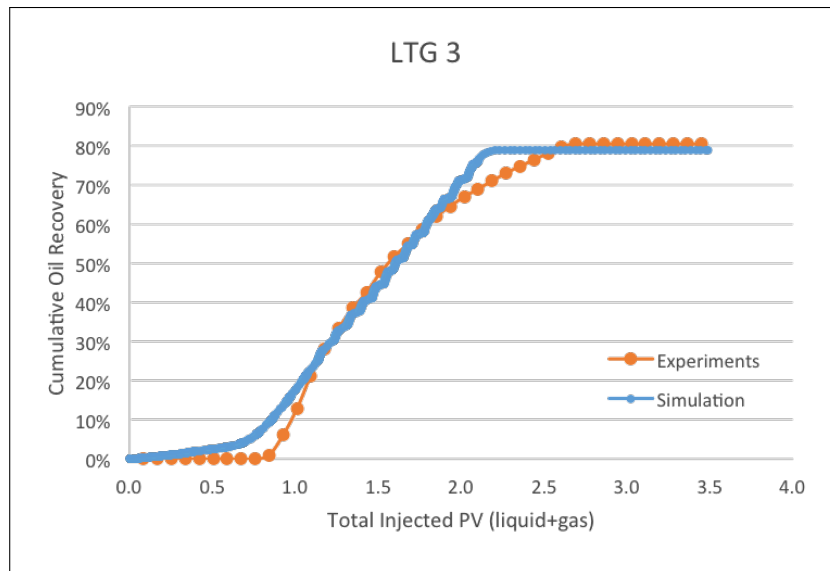


Figure 4.46: Oil Recovery as a function of Total PV Injected for LTG 3

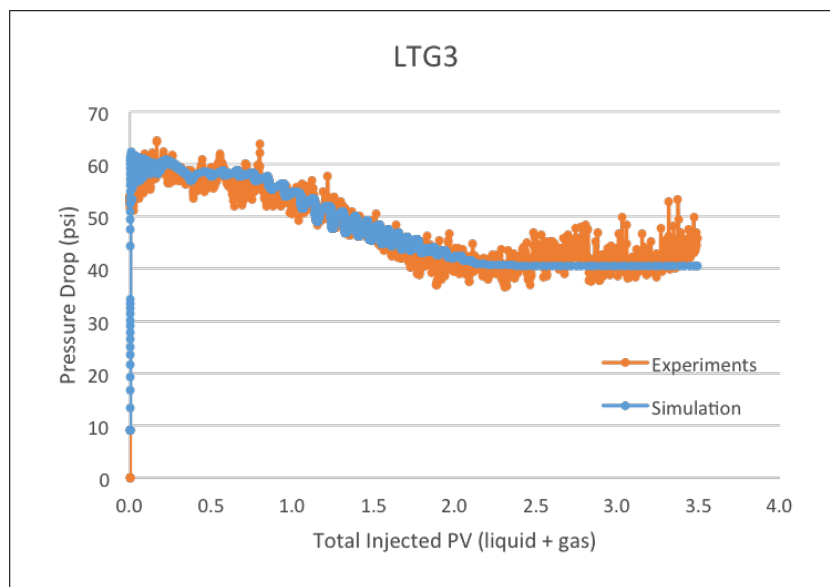


Figure 4.47: Pressure drop along the core vs. Total PV Injected for LTG 3

Table 4.11: Summary of matched parameters for LTG1, LTG2, and LTG3 experiments

Parameter	LTG1	LTG2	LTG3
epsalt	−0.04	−0.00509	−0.0365
fmoil	0.273	0.2075	0.243
fmoil	0.0092	0.0019	0.0022
epoil	3.01	3.92	3.92
nog	4	3.30	2.29
Dispersivity Coefficient [m]	0.00408	0.00447	0.00357
Eff-CMC [mole surf./kg water]	0.003	0.00271	0.00288
$N_{c_{interm}}$ [log]	−2.53	−2.98	−3.19
no_2	1.16	1.1	1.04
nw_2	2.87	2.88	2.32
$krorw_2$	0.918	0.984	0.989
$krwro_2$	0.218	0.331	0.389
$Sorw_2$	0	0	0
$Swro_2$	0.1	0.1	0.1

Chapter 5

Conclusions and Recommendations

5.1 Summary of Main Findings

In this thesis, a deterministic strategy for the estimation of key petrophysical and foam parameters is proposed and its implementation in simulating the LTG process is investigated. The strategy is proven to be a very valuable method in constraining key parameters and thus reducing problem non-uniqueness.

Our investigation indicated that physical processes involved, are non-linear and thus the response is very sensitive to minor variations and uncertainties in the system parameters. The problem is further exacerbated by the interrelating character of the physical properties.

From the data-fitting of the waterflood experiments procedure, it was concluded that drainage capillary pressure data added significant value both to the physical process captured by the model and to the matching results obtained.

Considering the unavoidable simulation uncertainty, this study demonstrated that the model provides reasonably accurate and reliable data-fittings. Furthermore, the speed of problem convergence and the repeatability of the

results improves.

Comparing the parameters obtained through matching of the experimental data, it was observed that for this given system, foam stability has a greater sensitivity to oil saturation than to salinity and consequently microemulsion phase behavior. Low values of ϵ_{salt} , compared with values of ϵ_{salt} obtained by Stephen *et al.* for a study on sandstones, indicate that the effect of salinity and consequently microemulsion on foam stability in carbonates, is possibly not as strong as in sandstones.

5.2 Recommendations for Future Work

- Numerical artifacts observed, which were resolved by statically extrapolating the gas relative permeability curve to higher gas saturations, as well as the water relative permeability curve to higher water saturations to avoid pressure drop spikes, could be further implemented in the model.
- The foam parameters and gas relative permeability curve were determined through matching of foam quality tests performed at residual oil. Further improvement for better estimations of these parameters, would include experiments of chemical and gas injection at initial conditions without oil.
- Adsorption is currently implemented through the use of Eff-CMC, the effective critical micelle concentration. An alternative would be to use the adsorption Langmuir isotherm [26], [7] and use CMC as the actual

micelle concentration (much lower). Although this will add two unknown parameters (ADACSTC and ADAMAXC [12]) to the simulation procedure, instead of one when using CMC, it will more accurately capture the physical process of adsorption, as CMC models adsorption statically at the initialization of the experiment.

- It is acknowledged that, although the numerical simulations performed for the determination of the LTG model parameters for each experiment were performed individually, a simultaneous match of two or three of the experiments would determine the parameters that should remain the same for all three experiments. However, this procedure is currently limited by the simulator.

Nomenclature

λ	Sorting factor
$\nabla\Phi_o$	Potential gradient across the oleic phase
ϕ	Microemulsion composition weighting factor
ρ_o	Oil density
σ_{ml}	Interfacial tension between oil/water and microemulsion phase
σ_{mo}	Interfacial tension between excess oil and microemulsion phase
σ_{mw}	Interfacial tension between excess water and microemulsion phase
b	Constant of capillary pressure equation
c	Chun Huh constant
$DISP$	Isotropic dispersivity coefficient
$Eff - CMC$	Effective critical micelle concentration - proxy for adsorption
$epoil$	Exponent of oil saturation contribution to dimensionless foam interpolation
$epsalt$	Exponent of salt/microemulsion phase behavior contribution to dimensionless foam interpolation
$epsurf$	Exponent of surfactant contribution to dimensionless foam interpolation

F_{N_c}	Logarithmic weighting parameter used for relative permeability interpolation
F_{DRY}	Foam dry-out function
f_{loil}	Lower oil saturation value used in dimensionless foam interpolation
f_{lsalt}	Lower salt mole fraction value used in dimensionless foam interpolation
FM	Foam mobility reduction factor
$fmmob$	Reference foam mobility reduction factor
$fmoil$	Critical oil saturation value used in dimensionless foam interpolation
$fmsalt$	Critical salt mole fraction value used in dimensionless foam interpolation
$fmsurf$	Critical component mole fraction of surfactant component in the aqueous phase
g	Gravitational acceleration
h	Height
k	Absolute permeability of the rock
k_{rgrl}	End-point gas relative permeability to liquid
k_{rg}^f	Gas relative permeability with foam modification
k_{rg}^{nf}	Gas relative permeability with no-foam
k_{rorg}	End-point oil relative permeability to gas

$k_{rorw,2}$	End-point oil relative permeability to water of intermediate capillary number
k_{orw}	End-point oil relative permeability to water
$k_{rwro,2}$	End-point water relative permeability to oil of intermediate capillary number
k_{rwro}	End-point water relative permeability to oil
k_{rw}	Water relative permeability
k_r	Relative permeability
M	M-factor for oil relative permeability to gas modification
$N_{c,interm}$	Intermediate capillary number
$N_{c,low}$	Low capillary number
N_c	Capillary number
n_g	Curvature of gas relative permeability to liquid curve
$n_{o,2}$	Curvature of oil relative permeability to water curve of intermediate capillary number
n_{og}	Curvature of oil relative permeability to gas curve
n_o	Curvature of oil relative permeability to water curve
$n_{w,2}$	Curvature of water relative permeability to oil curve of intermediate capillary number
n_w	Curvature of water relative permeability to oil curve

P	Pressure
P_{ce}	Entry capillary pressure
P_c	Capillary pressure
P_c^*	Limiting Capillary Pressure
R_l	Oil/Water Solubilization Ratio
RPV	Relative permeability value
RPV_{interm}	Relative permeability value at intermediate capillary number
RPV_{low}	Relative permeability value at low capillary number
S_{gcon}	Connate gas saturation
S_{org}	End-point oil saturation to gas flood
$S_{orw,2}$	End-point oil saturation to waterflood of intermediate capillary number
S_{orw}	End-point oil saturation to waterflood
S_o	Oil Saturation in the system
S_{wc}	Connate water saturation
S_{wD}	Normalized water saturation
$S_{wro,2}$	End-point water saturation to oil flood of intermediate capillary number
S_{wro}	End-point water saturation to oil flood
S_w	Water saturation in the system
$sfbet$	Reference dry-out slope used in dimensionless foam dry-out calculation

sf_{dry}	Maximum dry-out value used in dimensionless foam dry-out calculation
$V_{l,m}$	Volume of oil/water in the microemulsion phase
$V_{o,m}$	Volume of oil in the microemulsion phase
$V_{s,m}$	Volume of surfactant in the microemulsion phase
$V_{s,o}$	Volume of surfactant in the oil phase
$V_{s,t}$	Total volume of surfactant
$V_{s,w}$	Volume of surfactant in the water phase
$V_{w,m}$	Volume of water in the microemulsion phase
x_{surf}	Surfactant mole fraction in the aqueous phase

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