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# Supercritical CO<sub>2</sub> Foam Enhanced Oil Recovery: From Mechanistic Model Fit to Lab Experiments to Field-Scale Evaluation

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**SUPERCRITICAL CO<sub>2</sub> FOAM ENHANCED OIL RECOVERY:  
FROM MECHANISTIC MODEL FIT TO LAB EXPERIMENTS TO  
FIELD-SCALE EVALUATION**

A Dissertation

Submitted to the Graduate Faculty of the  
Louisiana State University and  
Agricultural and Mechanical College  
in partial fulfillment of the  
requirements for the degree of  
Doctor of Philosophy

in

The Craft & Hawkins Department of Petroleum Engineering

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## ABSTRACT

This study investigates how a mechanistic foam modeling approach based on bubble population balance is applied to a series of laboratory experimental data of a supercritical CO<sub>2</sub> foam in reservoir conditions to extract model parameters (topic 1). The model with model parameters determined from the fit is then used to estimate how far fine-textured strong foam can propagate into the reservoir, before turning into coarse-textured weak foam and before being segregated by gravity (topic 2). With the help of mechanistic model, a possible range of gas mobility for supercritical CO<sub>2</sub> foam is calculated and the resulting gas-phase mobility reduction factor (MRF) are applied to the field-scale EOR reservoir simulations (topic 3).

A mechanistic foam model that honors three different foam states and two steady-state strong-foam flow regimes is used to fit coreflood experimental data from Yin (2007). The results show why supercritical CO<sub>2</sub> foams are fundamentally different compared to other gaseous foams. The role of mobilization pressure gradient is shown to be the key to this difference – the pressure gradient required for supercritical CO<sub>2</sub> foam is much lower, and thus the attainment of strong foam in the reservoir is easier.

This study shows how far strong foams injected into the injection well can propagate at different injection foam qualities and velocities, which is one of the most important questions in actual field applications. Two main mechanisms that limit field foam propagation, such as “conversion from strong foam to weak foam” and “gravity segregation”, are examined. The results show that foam propagation distance increases with increasing injection pressure or rate and increases with decreasing foam quality

down to a certain threshold foam quality below which the distance is not sensitive to foam quality any longer.

CMG STARS simulations for a sector with an inverted 5-spot pattern are performed to evaluate how oil recovery changes at different injection foam qualities and velocities. The pre-determined values of gas mobility required for the simulation are guided by the mechanistic model. The use of sweep-efficiency contour plots is shown to be a convenient graphical method to determine the optimum injection foam quality that changes at different injection rates.

## CHAPTER 1. OVERVIEW OF THIS STUDY

### 1.1. Introduction of CO<sub>2</sub> foam EOR

Enhanced oil recovery (EOR) is considered a vital option to increase ultimate hydrocarbon recovery from both conventional and unconventional reservoirs depleted by primary and secondary processes. EOR processes are classified into three major categories; thermal process, gas injection, and chemical process. Gas injection is the most widely used method, together with thermal process, and the gas phase is injected either as miscible or immiscible with reservoir fluids.

CO<sub>2</sub> injection, especially with supercritical CO<sub>2</sub>, is very popular among various gas types (eg. N<sub>2</sub>, hydrocarbon gas, flue gas, etc.) due to easier attainment of supercritical condition, better miscibility with reservoir fluids, higher density and viscosity, and higher societal need in conjunction with carbon capture and storage. CO<sub>2</sub> sequestration into the petroleum reservoirs is indeed considered one of the most efficient means for the disposal of a large quantity of CO<sub>2</sub>, ultimately reducing greenhouse carbon emission. However, irrespective of gas types, gas injection inevitably encounters limitations such as fingering, channeling, and gravity segregation in the field.

Foaming the gas phase either in-situ or pre-generated prior to injection is a proven technology to improve sweep efficiency in the laboratory and field for more than 50 years. Foam is created by injecting gas with surfactant solutions. There are many successful field pilot tests reported in the literature including recent project such as CO<sub>2</sub> foam field test conducted in Salt Creek, WY (Mukherjee et al. 2016), and SAG treatment for conformance control in Lower Mirador formation, Cusiana Field, Columbia (Ocampo et al. 2013; Rossen et al. 2017).



Before applying foam injection in the field, several coreflood experiments are typically conducted to understand foam properties and flow characteristics. Then a modeling study is performed to obtain model parameters and to determine how much foam can reduce gas mobility. Modeling of foam rheology, especially in reservoir scale, is challenging because the model must replicate experimental data collected from small lab scale and must be able to predict how foam propagates in the large field scale. This study investigates multiple aspects of such supercritical CO<sub>2</sub> foams, from a fit of mechanistic foam model to laboratory coreflood data to field-scale evaluation of foam EOR applications.

## **1.2. Chapter description**

The content of each chapter is summarized as follows: chapter 1 gives a brief introduction of the problem solved in this study. Chapter 2 provides detailed descriptions about the mechanistic foam modeling approach used in this study. This chapter shows (i) how to use the model to make a fit to coreflood data extracted from the literature, and then (ii) what makes supercritical CO<sub>2</sub> foams special compared to other gaseous foams by investigating the effect of mobilization pressure gradient. Chapter 3 shows how to use the mechanistic model to estimate foam propagation distance in large-scale applications. This chapter deals with two major events that limit foam propagation - “conversion from strong foam to weak foam (csw)” and “gravity segregation (gs)”. Chapter 4 presents an example of field-scale supercritical CO<sub>2</sub> foam EOR (Lisama field, Colombia) by using CMG STARS simulator. The selection of required gas-phase mobility reduction factors

(MRF) is guided by the mechanistic model. This chapter provides details about how to optimize the injection strategies (injection rate, injection foam quality) in the field. Chapter 5 concludes this study with recommendations.

## CHAPTER 2. BUBBLE POPULATION BALANCE MODELING FOR SUPERCRITICAL CO<sub>2</sub> FOAM EOR PROCESSES: FROM PORE-SCALE TO CORE-SCALE AND FIELD-SCALE EVENTS

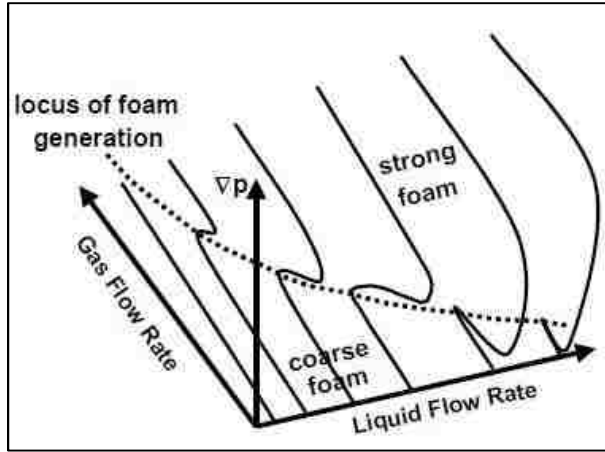
### 2.1. Introduction

Although less severe due to higher density and viscosity, dense or supercritical CO<sub>2</sub> EOR processes encounter essentially the same fates such as fingering, gravity segregation, and channeling, just like any other gas injection methods. Foaming the injected CO<sub>2</sub> by using surface-active agents (or, surfactants), the first attempt dated back to Bond and Holbrook (1958), has long been a promising candidate in the field to delay the breakthrough of injected gas and hence improve the overall sweep efficiency. Lee and Kam (2013) reviews several successful foam field projects, cited often in the literature.

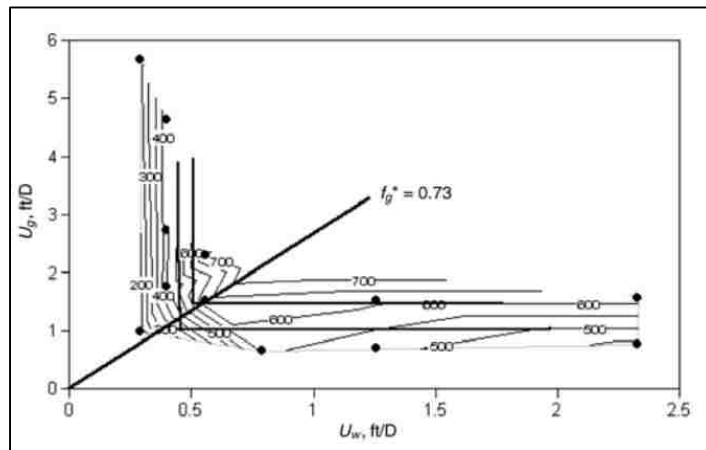
Foams in porous media can be created and destroyed in-situ as foam films (or lamellae) travel along the complicated pore structures. The number of liquid films in unit pore volume, referred to as foam texture ( $n_f$ ), is an outcome of dynamic mechanisms of in-situ lamellae creation and coalescence, which is a key parameter to understand non-Newtonian foam rheology through the changes in gas relative permeability, gas viscosity, trapped gas saturation, and so on.

Three main mechanisms identified for in-situ lamellae creation are leave-behind, snap-off, and lamellae mobilization and division, while there is a major lamella-coalescence mechanism identified, that is, a sudden rupture of foam films above limiting capillary pressure  $P_c^*$  (or, below limiting water saturation,  $S_w^*$ , equivalently), as fully described by earlier studies (Ransohoff and Radke, 1988; Khatib et al., 1988; Rossen, 1996; Hirasaki et al., 1997).

Once present, foam exhibits a hysteretic behavior represented by three different states as shown in Figure 2.1(a) from Gauglitz et al. (2002) such as weak-foam state, strong-foam state, and intermediate state in between. The coarse-textured foam showing a relatively moderate decrease in gas mobility (or, the lower surface at lower  $\nabla P$ ) is called weak foam, while the fine-textured foam showing a drastic decrease in gas mobility (the upper surface at higher  $\nabla P$ ) is called strong foam. Once the strong-foam state is obtained, foam rheology can be represented by two distinct rheological behaviors in a contour plot of the steady-state pressure gradient as a function of gas (y axis) and liquid (x axis) velocities, as first shown by Osterloh and Jante (1992). Alvarez et al. (2001) confirmed the same behavior in a wide range of experimental conditions putting them into the high-quality and low-quality regimes. The two flow regimes are separated by a threshold foam quality ( $f_g^*$ ). For example, the  $f_g^*$  is shown to be 0.73 in Figure 2.1(b).



(a)



(b)

Figure 2.1. Key features of core-scale events to be honored in this study: (a) three different foam states (weak-foam (or coarse-foam) state, strong-foam state, and intermediate state (between weak-foam and strong-foam states curving back); Gauglitz et al., 2002) and (b) two steady-state strong-foam flow regimes (Alvarez et al., 2001).

There are largely two types of foam modeling techniques available in the literature, namely, local steady-state (or, local equilibrium) modeling and bubble population balance modeling. The population balance model, to be applied in this study, is designed to capture foam texture and its relationship with other foam properties such as effective gas

viscosity, relative permeability, and trapped gas saturation and so on to capture non-Newtonian foam rheology. This technique is more complicated than the local steady-state modeling that uses a pre-specified mobility reduction factor (MRF) but produces more physically sound results based on robust mathematical framework. Different versions of population-balance models exist in the literature depending upon how to handle foam flow in porous media mathematically (Friedmann et al., 1991; Kavscek and Radke, 1994; Kavscek et al., 1995; Myers and Radke, 2000; Kam and Rossen, 2003; Kam, 2008; Farajzadeh et al., 2015). Recent modeling studies introduce a new type of foam simulation technique, so-called implicit-texture foam model (Farajzadeh et al, 2015; Lotfollahi et al., 2016). Although it does not calculate bubble population by solving population-balance partial differential equations per se, this technique employs model parameters to capture foam fundamentals near limiting capillary pressure and water-/oil-sensitive foam stability, and thus improves simulation capability significantly in large field-scale events adding computational efficiency.

## 2.2. Motivations and Objectives

An earlier study from Gauglitz et al. (2002), showing foam generation experiments with N<sub>2</sub> foams and supercritical CO<sub>2</sub> foams, presented interesting results as shown by Figure 2.2 (a). That is, the critical pressure gradient (or, the mobilization pressure gradient,  $\nabla P_o$ ) for supercritical CO<sub>2</sub> foams is a couple of orders of magnitude lower than that for N<sub>2</sub> foams, decreasing with increasing permeability (k). Because of  $\nabla P_o = 4 (\sigma / R_t)$ , smaller  $\nabla P_o$  is caused by lower interfacial tension ( $\sigma$ ) at given pore throat sizes ( $R_t$ ). Figure 2.2 (b) shows another example from Aarra et al. (2014), that is, gaseous CO<sub>2</sub>

foams (backpressure 30 bar) exhibit higher steady-state pressure drop ( $\Delta P$ ) than supercritical CO<sub>2</sub> foams (backpressures 120 and 280 bar). This is, again, because of a reduction in  $\sigma$  and, therefore, a reduction in  $\nabla P_0$ . (Note that the pressure drop ( $\Delta P$ ) is measured in individual coreflood experiments, while the mobilization pressure gradient ( $\nabla P_0$ ) is a parameter dependent upon rock and fluid properties.)

Reaching a strong-foam state at lower pressure gradient due to lower  $\nabla P_0$  means easier formation of piston-like displacement, which results in higher oil recovery and more efficient sweep in the field conditions, as demonstrated by Lee and Kam (2014) by using three-phase Method of Characteristics solutions. For example, when the absolute permeability is about 1  $\mu\text{m}^2$  for Boise sandstone in Figure 2.2, supercritical CO<sub>2</sub> foam forms strong foams at  $1 \times 10^4$  Pa/m (or, 0.442 psi/ft), but N<sub>2</sub> foam still does not form strong foams until  $1 \times 10^6$  Pa/m (or, 44.2 psi/ft), clearly showing the benefit of supercritical CO<sub>2</sub> foams conceptually.

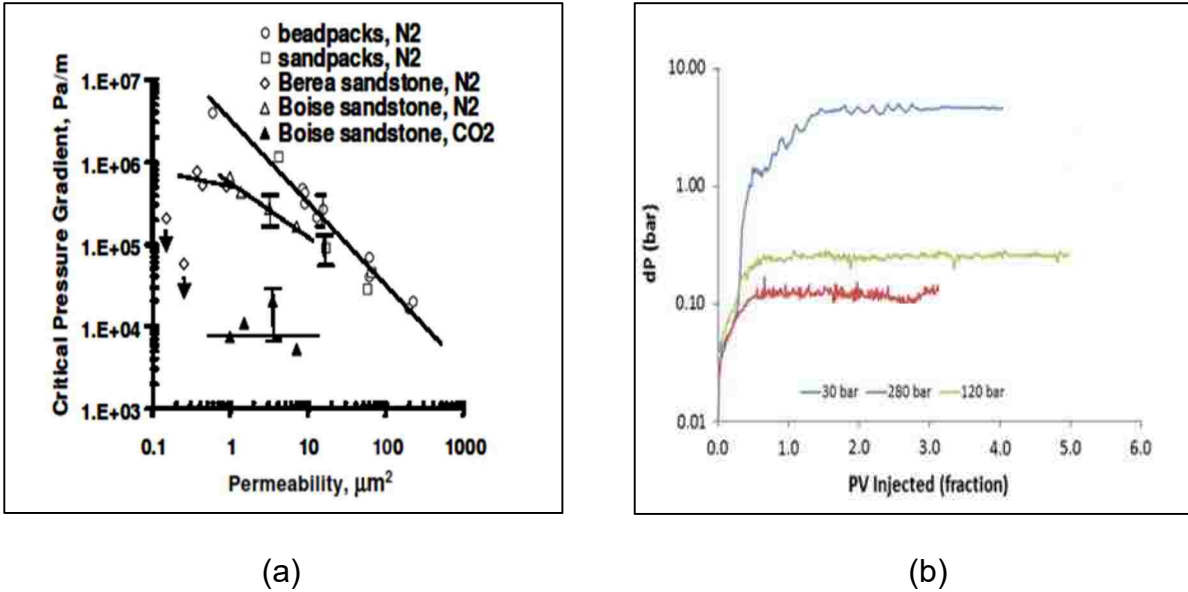


Figure 2.2. Experimental data showing the difference between supercritical CO<sub>2</sub> foams and other gaseous foams: (a) mobilization pressure gradient required for foam generation for supercritical CO<sub>2</sub> foams and N<sub>2</sub> foams (Gaughlitz et al., 2002) and (b) pressure-drop comparison for supercritical CO<sub>2</sub> foams and gaseous CO<sub>2</sub> foams in Berea sandstone (Aarra et al., 2014).

The objective of this study is to investigate (i) how to fit a population-balance foam model (based on pore-scale events) to supercritical CO<sub>2</sub> foam experimental data (core-scale events) and extract model parameters, and (ii) apply the modeling technique to field-scale events to understand the fundamental mechanisms of CO<sub>2</sub> foams propagation into the reservoir. This study must be distinguished from previous studies of Kam and Rossen (2003), Kam (2008), Afsharpoor et al. (2010) and Lee et al. (2016) - the previous studies deal with gaseous foams (eg., N<sub>2</sub> foams) showing three distinct foam states (i.e., foam rheology surface curving back and forth (Figure 2.1(a)), while this study, for the first time, deals with supercritical CO<sub>2</sub> foams (at extremely low  $\nabla P_0$ ) showing a smooth change from weak-foam to strong-foam state (without intermediate state), revealed as one of the major conclusions. Such a characteristic of supercritical CO<sub>2</sub> foams, compared to



gaseous foams, is endowed by much lower (more than a couple of orders of magnitude difference) interfacial tension between emulsion-like supercritical CO<sub>2</sub> and surfactant solutions. Throughout this study, the focus is made to show why supercritical CO<sub>2</sub> foam should be looked at differently, and how much difference it causes when the propagation in the field-scale event is taken into consideration. In this study, it is believed that CO<sub>2</sub> in its supercritical condition to form foams is fundamentally different from other gaseous foams (i.e., gaseous hydrocarbon foams, flue-gas foams, nitrogen foams, carbon-dioxide foam, etc.). It is because it behaves more like emulsions with much higher density and much lower interfacial tension. In field applications, supercritical CO<sub>2</sub> exhibits more complicated phase interactions with reservoir fluids (solubility, swelling effect, acidity and resulting chemistry). The effect of oil is not included in this study yet. It is because the primary goal of this study is to examine foam propagation distance based on unique properties of supercritical state of CO<sub>2</sub> once the steady state is obtained, rather than dynamic interactions between foams and reservoir fluids during the transient state. The finding of this study can be combined with dynamics foam simulations (Kam, 2008) and the interaction with foams and reservoir oils as a next step (Ashoori et al., 2010; Conn et al., 2014), however. The heart of this study touches the issue of how to upscale lab-scale data to field-scale applications during which the nature of flow typically changes from linear to radial or spherical, which has long been questioned in this research area (Kovscek et al., 1997; Li et al., 2006). The field-scale foam propagation shown in this study covers the issue by using pressure-gradient-dependent (and thus velocity-dependent) foam flow characteristics.

### 2.3. Methodology

Population balance modeling used in this study is considered a mechanistic model, because the model keeps track of a wide range of foam mechanisms independently and puts them together. Falls et al. (1988) and Patzek (1988) are the examples of early days of mechanistic foam modeling effort. They are followed by numerous studies afterwards such as Friedmann et al. (1991), Kovscek and Radke (1994) and Kam and Rossen (2003), among many.

The mechanistic foam model in this study defines lamellae creation function as shown below, by incorporating the concept of mobilization pressure gradient ( $\nabla P_0$ ) (Rossen and Gauglitz, 1990) into the equation (Kam, 2008; Afsharpoor et al., 2010):

$$R_g = \frac{C_g}{2} \left\{ \operatorname{erf} \left( \frac{\nabla P - \nabla P_0}{\sqrt{2}} \right) - \operatorname{erf} \left( \frac{-\nabla P_0}{\sqrt{2}} \right) \right\} \quad (2.1)$$

In Equation 2.1,  $R_g$  is the rate of lamella creation (i.e., change in bubble population within unit space over time),  $C_g$  is the model parameter,  $\nabla P$  is the pressure gradient, and erf is the error function. Note that  $\nabla P_0$  is the pressure gradient to mobilize existing foam films to create a population of bubbles subsequently in the downstream of porous media (Kam and Rossen, 2003). The two parameters ( $C_g$  and  $\nabla P_0$ ) handle foamability of surfactant solutions (including formulation and concentration) with a specific type of gas (e.g.,  $N_2$ ,  $CO_2$ , supercritical  $CO_2$ ) in a pore network with a certain pore size distribution and wettability. As shown in Figure 2.3, at given  $\nabla P_0$ , the rate  $R_g$  remains low if local  $\nabla P$  is

lower than  $\nabla P_0$ .  $R_g$  increases rapidly as  $\nabla P$  approaches  $\nabla P_0$ , and finally levels off if  $\nabla P$  becomes higher than  $\nabla P_0$ .

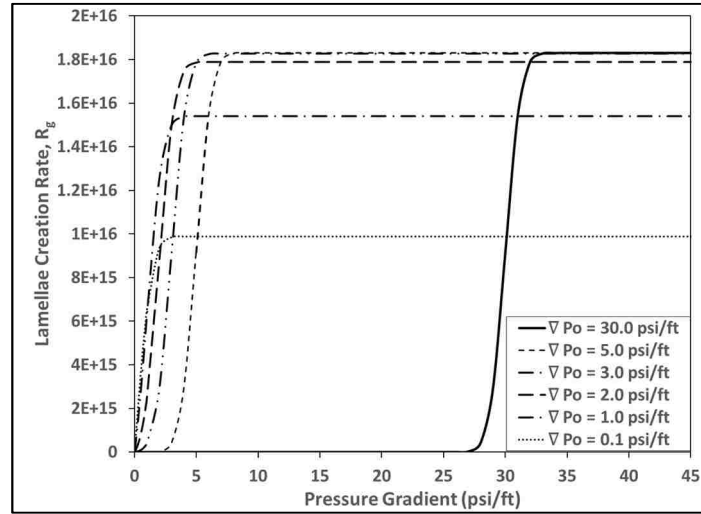


Figure 2.3. The rate of in-situ lamellae creation as a function of pressure gradient at various mobilization pressure gradient ( $\nabla P_0$ ) values.

Gauglitz et al. (2002) derived an explicit relationship between  $\nabla P_0$  and the absolute permeability ( $k$ ) of bead-packs. They combined the Ransohoff and Radke (1988) capillary number and Darcy law, and then utilized it with the Blake-Kozeny correlation for permeability to solve for the mobilization pressure gradient as

$$\nabla P_0 = \frac{8f_{nw}\sigma}{L} \sqrt{\frac{4\phi^3}{150k(1-\phi)^2}} \quad (2.2)$$

where,  $f_{nw}$  is the fractional flow of gas (non-wetting phase),  $\sigma$  is gas-liquid interfacial tension,  $L$  is the length of individual pore, and  $\phi$  and  $k$  are the porosity and permeability of the sample. Because  $L \sim R_t \sim k^{-1/2}$ ,  $\nabla P_0$  scales like  $\sim k^{-1}$  which is consistent with Figure

2.2 (a) for N<sub>2</sub> foams in unconsolidated porous media (bead-packs and sand-packs in Figure 2.2 (a), for example). In addition, because of lower  $\sigma$ , supercritical CO<sub>2</sub> foam shows lower  $\nabla P_0$ , compared to the gaseous foams (e.g., N<sub>2</sub> or CO<sub>2</sub> foams).

On the other hand, the lamellae coalescence function is given by

$$R_c = C_c n_f \left( \frac{S_w}{S_w - S_w^*} \right)^n \quad (2.3)$$

where,  $R_c$  is the rate of lamella coalescence (i.e., change in bubble population within unit space over time),  $C_c$  is the model parameter,  $n$  is the coalescence rate exponent, and  $n_f$ ,  $S_w$  and  $S_w^*$  represent foam texture, aqueous phase (water) saturation, and limiting water saturation, respectively. The rate  $R_c$  stays low when  $S_w$  is relatively high and increases rapidly as  $S_w$  approaches  $S_w^*$ . In the steady-state mechanistic foam modeling, the rate of lamella creation and the rate of lamella coalescence are balanced. Therefore, the steady-state foam texture ( $n_f$ ), that is, the number of lamellae (or bubble population) within unit space, can be explicitly calculated as follows, by making Equations 2.1 and 2.3 equal:

$$n_f = \frac{C_g}{2C_c} \left( \frac{S_w - S_w^*}{S_w} \right)^n \left\{ \operatorname{erf} \left( \frac{\nabla P - \nabla P_0}{\sqrt{2}} \right) - \operatorname{erf} \left( \frac{-\nabla P_0}{\sqrt{2}} \right) \right\} \quad (2.4)$$

Note that for any situations with  $S_w < S_w^*$ , there is no foam ( $n_f = 0$ ). If calculated  $n_f$  is greater than  $n_{f \max}$ , it is set to be  $n_{f \max}$  which is a typical behavior of strong foams in the

low-quality regime because diffusion within a pore does not allow bubbles to be smaller than the pore size (Alvarez et al., 2001). Therefore,  $n_{f \max}$  corresponds to the minimum bubble size, that is, roughly the average pore size.

The transport of foam in porous media is expressed by Darcy's equation as follows:

$$u_w = \frac{kk_{rw}(S_w)\nabla P}{\mu_w} \quad (2.5)$$

and

$$u_g = \frac{kk_{rg}^o(S_w)\nabla P}{\mu_g^o} \quad \text{or} \quad u_g = \frac{kk_{rg}^f(S_w)\nabla P}{\mu_g^f} \quad (2.6)$$

for water and gas (superscripts "o" and "f" represent states without and with foams), respectively. Foam consists of a dispersed internal gas phase and a continuous external liquid phase stabilized by surfactants. The gas phase then divides into two parts: trapped gas and flowing gas. Because the trapped gas is stationary due to capillary pressure, Darcy's equation for the gas phase is modified with a reduction in gas relative permeability (through the fraction of trapped gas saturation) (Kovscek, 1994). On the contrary, there is no change in Darcy's equation for the liquid phase because it forms the external phase as suggested by experimental studies (Bernard et al. 1965; Holm, 1968; and Friedmann and Jensen, 1986).

The liquid relative permeability is given by

$$k_{rw}(S_w) = A \left( \frac{S_w - S_{wc}}{1 - S_{wc} - S_{gr}} \right)^{m_1} \quad (2.7)$$

where,  $A$  and  $m_1$  are the parameters for Corey-type liquid relative permeability,  $S_{wc}$  is the connate water saturation, and  $S_{gr}$  is the residual gas saturation. The gas relative permeability is given by

$$k_{rg}^0(S_w) = B \left( \frac{1 - S_w - S_{gr}}{1 - S_{wc} - S_{gr}} \right)^{m_2} \quad (2.8)$$

in the absence of foams and

$$k_{rg}^f(S_w) = B \left( X_f \frac{1 - S_w - S_{gr}}{1 - S_{wc} - S_{gr}} \right)^{m_2} \quad (2.9)$$

in the presence of foams, where  $B$  and  $m_2$  are the parameters for Corey-type gas relative permeability, and  $X_f$  is the fraction of flowing gas phase. Of course, the sum of flowing gas fraction and trapped gas saturation is one ( $X_f + X_t = 1$ ). The trapped gas fraction is calculated by

$$X_t = X_{t \max} \left( \frac{\beta n_f}{1 + \beta n_f} \right) \quad (2.10)$$

following Kavscek and Radke (1994). Note that  $X_{t \max}$  is the maximum trapped gas fraction that can be estimated using tracer tests, commonly ranging 0.5 – 0.9 (Kavscek and Radke, 1994; Kavscek et al., 1995; Chen et al., 2010; Lotfollahi et al., 2016), and  $\beta$  is a model parameter relating gas trapping to foam texture.

Following Hirasaki and Lawson (1985), gas viscosity in the presence of foam is

$$\mu_g^f = \mu_g^0 + \frac{C_f n_f}{\left(\frac{u_g}{\phi S_g X_f}\right)^{\frac{1}{3}}} \quad (2.11)$$

where,  $\mu_g^0$  is gas viscosity in the absence of foam,  $S_g$  is gas saturation,  $C_f$  is the model parameter,  $\phi$  is the porosity of the medium, and  $X_f$  is the fraction of flowing gas phase. Once strong-foam state is achieved, the upper surface of foam-rheology surface (i.e., Figure 2.1(a)) can be reasonably captured by the power-law model, for example,

$$\nabla P = u_g^{\sigma_L} \quad (2.12)$$

and

$$\nabla P = u_w^{\sigma_H} \quad (2.13)$$

for the low-quality regime and high-quality regime, respectively. The exponents ( $\sigma_L$  and  $\sigma_H$ ) are one if Newtonian, greater than one if shear-thickening, and less than one if shear-thinning.

The ability for foams to reduce gas mobility is expressed by mobility reduction factor (MRF) which is defined by

$$\text{MRF} = \frac{k_{rg}^o \mu_g^f}{k_{rg}^f \mu_g^o} \quad (2.14)$$

which allows the fractional flow of water ( $f_w$ ) in the presence of foams to be written as follows:

$$f_w = \frac{u_w}{u_w + u_g} = \frac{Q_w}{Q_w + Q_g} = \frac{\frac{k_{rw}}{\mu_w}}{\frac{k_{rw}}{\mu_w} + \frac{k_{rg}^f}{\mu_g^f}} = \frac{\frac{k_{rw}}{\mu_w}}{\frac{k_{rw}}{\mu_w} + \frac{k_{rg}^o}{\mu_g^o} \text{MRF}} = 1 - f_g \quad (2.15)$$

where Darcy's velocity is defined by flow rate (Q) divided by cross-sectional area (A) (i.e.,

$$u_w = Q_w/A, u_g = Q_g/A, \text{ and } u_t = u_w + u_g = Q_w/A + Q_g/A = Q_t/A).$$

Table 2.1 lists the properties and parameters involved in this model, grouped into the basic rock and fluid properties, basic foam parameters, and mechanistic foam modeling parameters for this study. Note that the first group is what is needed for conventional gas-liquid two-phase flow (no foam), the second group is what can be either directly read from experimental data ( $n_{f \max}$  from the average pore size,  $\sigma_H$  and  $\sigma_L$  from foam coreflood experiments) or estimated from the literature ( $X_{t \max}$  and  $\beta$ ), and the third



group is what makes the fit to the three foam states (i.e., S-shaped curve) and the reference pressure contour for strong foams (showing both high-quality and low-quality regimes) possible. The limiting water saturation,  $S_w^*$ , is somewhat special in that it first needs to be determined experimentally (just like the ones in the second group), then fine-tuned with other model parameters in the third group. More details on this issue are shown in the Result section below.

Table 2.1. Properties and parameters required for mechanistic foam modeling in this study.

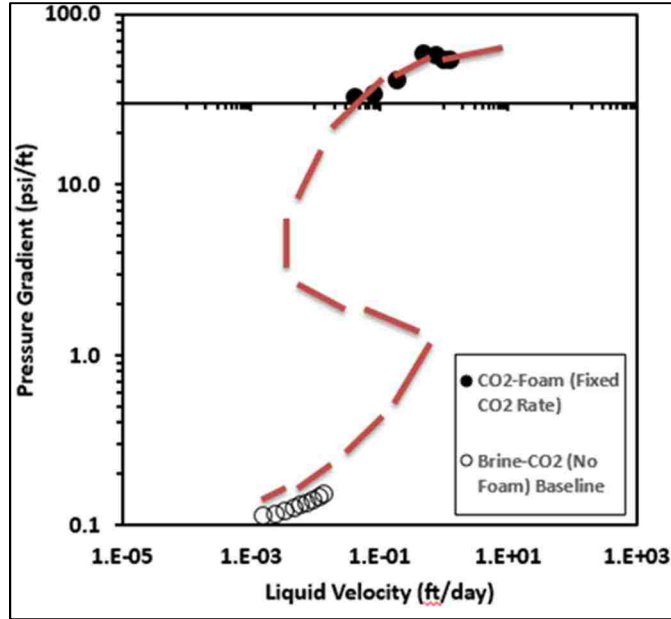
Basic Rock and Fluid Properties	Basic Foam Parameters	Foam Modeling Parameters
Permeability ( $k$ )	Maximum foam texture	Lamellae mobilization pressure
Porosity ( $\phi$ )	( $n_{fmax}$ )	( $\nabla P_o$ )
Brine viscosity ( $\mu_w$ )	Maximum trapped gas	Lamellae coalescence exponent
Gas viscosity ( $\mu_g$ )	fraction ( $X_{tmax}$ )	( $n$ )
Connate water saturation ( $S_{wc}$ )	Trapping parameter ( $\beta$ )	Limiting water saturation ( $S_w^*$ )
Residual gas saturation ( $S_{gr}$ )	Low-quality regime power-	Coefficient for lamellae creation
Corey-type relative permeability	law exponent ( $\sigma_L$ )	function ( $\frac{C_g}{C_c}$ )
parameters ( $A, B, m_1, m_2$ )	High-quality regime power-	Coefficient for foam viscosity
	law exponent ( $\sigma_H$ )	function ( $C_f$ )

Among many in the literature, the experimental study of Yin (2007) for supercritical CO<sub>2</sub> foam in Berea sandstone is selected because it offers much of the data required for model fit in a series of core-scale experiments. A companion study, Liu et al. (2010), provides relevant rock properties including relative permeability data at the same

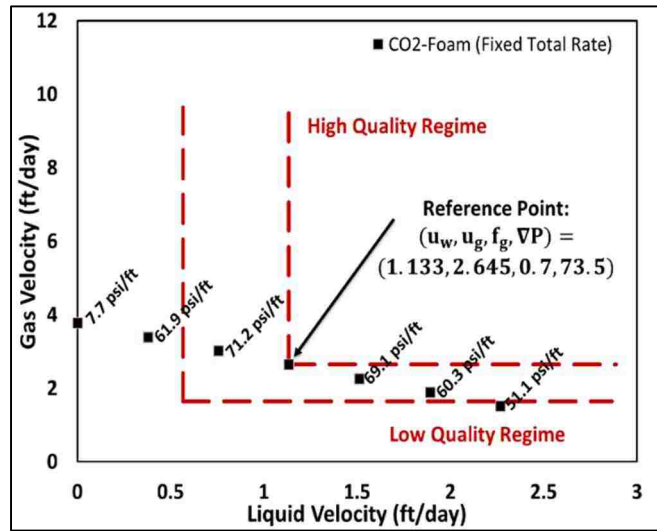
experimental conditions. Their original data points are shown in Figure 2.4 (filled squares and open/filled circles) modified in the format required for this study. Briefly, Yin (2007) conducted two types of supercritical CO<sub>2</sub> foam coreflood experiments, one by varying liquid velocity ( $u_w = 0.042 - 1.256$  ft/day) at fixed gas velocity ( $u_g = 1.51$  ft/day), and the other by varying foam quality ( $f_g = 50\% - 90\%$ ) at fixed total velocity ( $u_t = 3.778$  ft/day). Other experimental conditions are summarized in Table 2.2. Note that the brine viscosity is estimated from McCain (1991) and supercritical CO<sub>2</sub> viscosity from Fenghour and Wakeham (1997). The approach applied in this study does not deal with capillary pressure directly but takes care of its effect implicitly through water saturation (e.g., limiting water saturation, relative permeability a function of saturation). This helps reducing the number of model input parameters.

Table 2.2. Conditions for coreflood experiments.

Experimental Conditions	Berea Core Rock Properties	Gas and Liquid Properties
Pressure: 1540 psig	Core length: 0.5 ft	Brine Viscosity: 0.65 cp (McCain, 1991)
Temperature: 110 °F	Core diameter: 0.169 ft	
Gas Phase: CO <sub>2</sub>	Pore Volume: 0.00241 ft <sup>3</sup>	Gas Viscosity: 0.07 cp (Fenghour and Wakeham, 1998)
Aqueous Phase: 3 wt % NaCl brine	Porosity: 22.29 %	
Surfactant: Chaser CD1045™ 0.05 wt% concentration	Liquid Permeability: 450 md	



(a)



(b)

Figure 2.4. Original coreflood data points from Yin (2007) and Liu et al. (2010) in a format required for this study with expected model fits (dashed lines): (a) onto the S-shaped curve and (b) onto the two foam-flow regime pressure contours.

## 2.4. Results

This section consists of three parts: Part 1 shows how to determine the basic model parameters (i.e., first and second groups in Table 2.1), Part 2 presents how to make a fit to the S-shaped curve (i.e., hysteresis with three foam states) as well as two flow-regime pressure contours (i.e., high-quality and low-quality regimes) by determining foam model parameters (i.e., third group in Table 2.1), and Part 3 covers how foam propagates in a large system. For clarification, “a successful fit” in this study means that the model (based on pore-scale events) captures the trend shown by one representative S-shaped curve (showing the path from weak-foam to strong-foam state) and two representative pressure contours (showing both high-quality and low-quality regimes) of strong foam state (shown in core-scale events). For example, Figure 2.4(a) shows coreflood data points, with strong foams as the upper surface and no foams as the lower limit for weak-foam surface, and Figure 2.4(b) shows the pressure responses of strong foams collected experimentally at different gas and liquid velocities (keeping the total velocity the same). The trend traced by dashed lines are what the population balance model aims to match in this study.

### 2.4.1. Part 1: How to determine basic model parameters

Each of these parameters are determined as follows.

CO<sub>2</sub>-Brine Relative Permeability Curve: The Corey-type relative permeability functions are used for supercritical CO<sub>2</sub> and brine two-phase flow. Figure 2.5 shows how 4 parameters ( $m_1, m_2, A$  and  $B$ ; see Equations 2.7 and 2.8) are determined to fit the experimental data from Liu et al. (2010) by performing curve fitting.

Maximum Foam Texture ( $n_{f_{max}}$ ): The maximum foam texture ( $n_{f_{max}}$ ) can be determined directly from the average pore size, i.e.,  $n_{f_{max}} = 1/(\text{volume of individual pore})$ . Beard and Weyl (1973) provided correlations between porosity, permeability, and grain size of different sandstone rocks, and in relatively homogeneous unconsolidated rocks, the average pore size is approximately 25 - 30% of the grain size. For a 450 md Berea sandstone sample in this study, the correlations provide the average grain size about 0.044 mm and thus the average pore size about  $1.12 \times 10^{-14} \text{ m}^3$ . Therefore,  $n_{f_{max}}$  is approximately  $8.0 \times 10^{14} \frac{1}{\text{m}^3}$  which is used as a model parameter (Table 2.3).

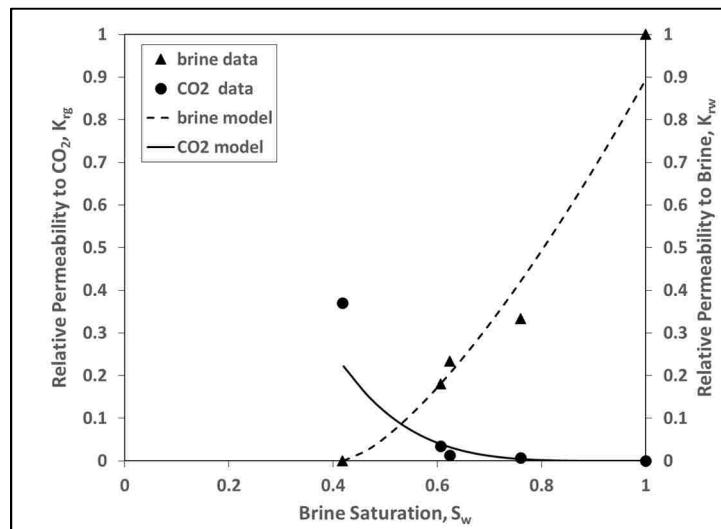


Figure 2.5. Determination of supercritical CO<sub>2</sub>-Brine two-phase relative permeability curves by using Corey-type functions.

Mobility Reduction Factor (MRF) and Limiting Water Saturation ( $S_w^*$ ): The magnitude of MRF (Equation 2.14 and Equation 2.15) can be determined by plotting fractional flow curves (i.e.,  $f_w$  vs.  $S_w$ ) at various MRF values and choosing the one that

fits the experimental data appropriately. Figure 2.6 shows an example. The curve with  $MRF = 1$  is for the case of conventional gas-water (i.e., supercritical  $CO_2$  and brine) two-phase flow with no foams. With foams present in the media, the fractional flow curve shifts to the left (cf. Equation 2.15). Overall, the data points from Yin (2007) suggest the MRF in this experiment falls between 100 and 1000. In addition, no matter what MRF values are, the fractional flow curves steeply fall to join no-foam fractional flow curve ( $MRF=1$ ) as  $S_w$  approaches  $S_w^*$ . It is because the rate of lamellae coalescence increases dramatically near  $S_w^*$  (cf. Equation 2.3). The figure suggests that the range of limiting water saturation is around 0.42 - 0.43, slightly above the connate water saturation ( $S_{wc} = 0.42$ ).

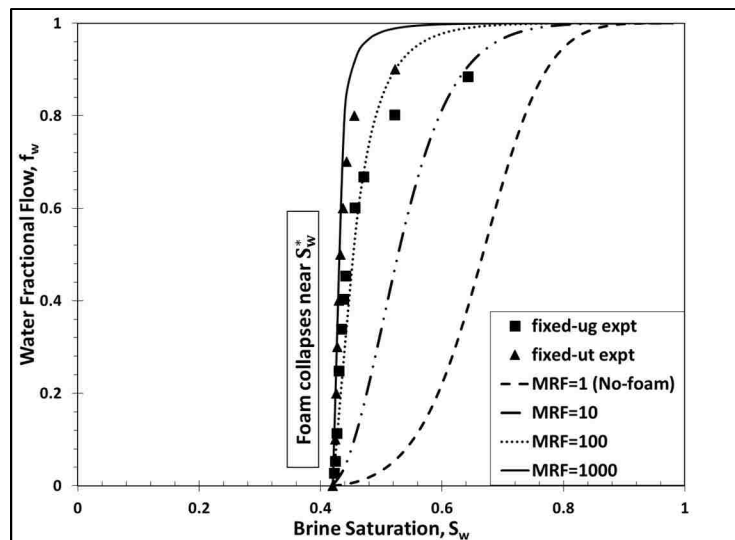


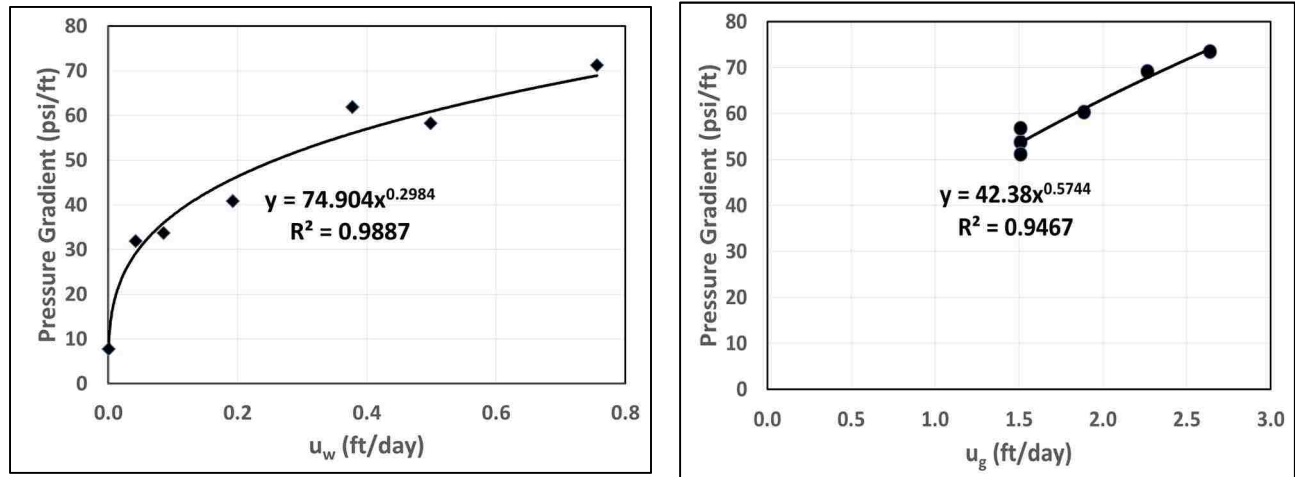
Figure 2.6. Construction of fractional flow curves at various MRF values to capture the range of MRF and  $S_w^*$  (experimental data from Yin (2007)).

Shear thinning/thickening parameters: The gap between pressure contour lines in the two flow-regime map in Figure 2.4(b) can be used to determine if foams in the high-quality and low-quality regimes are shear-thinning, shear-thickening, or near-Newtonian. The data points for  $f_g = 0.7$  through  $f_g = 1.0$  in Figure 2.4(b) are used to calculate the power-law exponent in the high-quality regime ( $\sigma_H$ ), while the data points for  $f_g = 0.5$  through  $f_g = 0.7$  in Figure 2.4(b) are used to calculate the power-law exponent in the low-quality regime ( $\sigma_L$ ). The original data at foam quality less than 50% ( $f_g < 0.5$ ) is neglected because they are too wet to call foam. Figure 2.7 illustrates how to determine  $\sigma_H$  ( $\sigma_H = 0.2984$ ) and  $\sigma_L$  ( $\sigma_L = 0.5744$ ) plotting the pressure gradient as a function of gas and liquid velocities, respectively.

Mobilization Pressure Gradient: When Figure 2.2(a) from Gauglitz et al. (2002) is used for the permeability of sandstone used in this study (200-500 md),  $\nabla P_o$  ranges from 7 to 30 psi/ft (or, about 158,000-678,000 Pa/m) for  $N_2$  foams and 0.4 to 6 psi/ft (or, about 9,000-135,000 Pa/m) for supercritical  $CO_2$  foams.

Lamellae Coalescence Exponent: The lamellae coalescence exponent ( $n$ ) in Equation 2.3 describes the rate of kinetics of lamella coalescence mechanism, i.e., how quickly lamella coalescence occurs when  $S_w$  approaches (decreases) to  $S_w^*$ . There are no experimental studies reported in the literature to measure  $n$  value within the porous media, to our knowledge. Most of the previous studies use  $n$  value of either 1 (Friedmann et al., 1991; Kavscek and Bertin, 2002; Kam, 2008) or 2 (Kavscek et al. (1995)) as a

reasonable approximation. These previous studies show that  $n$  does not affect the steady-state model fit significantly except for foams in very high  $f_g$  (or,  $S_w$  very close to  $S_w^*$ ) but does impact the stability and convergence of dynamic foam simulation.



(a)

(b)

Figure 2.7. Determination of power-law exponents: (a) for the high-quality regime ( $\sigma_H$ ) from  $\nabla P$  vs.  $u_w$  plot and (b) for the low-quality regime ( $\sigma_L$ ) from  $\nabla P$  vs.  $u_g$  plot.

Maximum Trapped Gas Fraction and Trapping Parameter: The trapped gas fraction,  $X_t$ , is calculated by using an equation similar to Langmuir isotherm (Equation 2.10) that has the maximum trapped gas fraction ( $X_{t\max}$ ) and trapping parameter ( $\beta$ ). There are some studies that measured  $X_{t\max}$  experimentally by using tracer tests or numerically calculated from pressure response, while there are no experimental studies that reported  $\beta$  values- once again it is because of difficulties measuring the dynamics of lamella movement within the porous media. Kovscek and Radke (1994) reported the value of 0.9 for  $X_{t\max}$  and  $10^{-9} \text{ m}^3$  for  $\beta$  in their model fit to experimental data. Kam (2008),



Afsharpoor et al. (2010), and Lee et al. (2016) used 0.8 and  $10^{-11} \text{ m}^3$  for  $X_{t \text{ max}}$  and  $\beta$  respectively. Chen et al. (2010) had the maximum trapped gas fraction of 0.78 for the  $\text{N}_2$  foam in Berea sandstone. Lotfollahi et al. (2016) estimated values of  $X_{t \text{ max}}$  and  $\beta$  for the  $\text{CO}_2$  foam in South Cowden Unit Cores 0.5 and  $10^{-9} \text{ m}^3$  respectively. This study assumes  $X_{t \text{ max}}$  to be 0.7 and  $\beta$  to be  $5 \times 10^{-14} \text{ m}^3$ .

Table 2.3. Basic model parameters and their values.

Parameter Name	Parameter Value	Parameter Name	Parameter Value
Corey-type coefficient for water relative permeability (A)	0.893	Mobilization pressure gradient ( $\nabla P_o, \frac{\text{psi}}{\text{ft}}$ )	$0.4 \leq \nabla P_o \leq 6.0$
Corey-type exponent for water relative permeability ( $m_1$ )	1.41	Maximum trapped gas fraction ( $X_{t \text{ max}}$ )	0.7
Corey-type coefficient for gas relative permeability (B)	0.222	High quality regime Power-law exponent ( $\sigma_H$ )	0.2984
Corey-type exponent for gas relative permeability ( $m_2$ )	4.45	Low quality regime Power-law exponent ( $\sigma_L$ )	0.5744
Connate water saturation ( $S_{wc}$ )	0.42	Limiting water saturation ( $S_w^*$ )	$0.42 < S_w^* \leq 0.43$
Residual gas saturation ( $S_{gr}$ )	0.0	Lamellae coalescence exponent (n)	1.0
Maximum foam texture ( $n_{f \text{ max}}, \frac{1}{\text{m}^3}$ )	$8.0 \times 10^{14}$	Trapping parameter ( $\beta, \text{m}^3$ )	$5.0 \times 10^{-14}$

### 2.4.2. Part 2: How to determine mechanistic model parameters

With the basic parameter values as discussed and summarized in Table 2.3, there are five more model parameters required ( $\nabla P_o$ ,  $S_w^*$ ,  $n$ ,  $\frac{C_g}{C_c}$ , and  $C_f$  (see the third column of Table 2.1)) in order to fit the experimentally measured S-shaped curve and two flow-regime contours. Note that  $\nabla P_o$  and  $S_w^*$  values are not determined yet (the ranges are estimated in Part 1, 0.4-6 psi/ft and 0.42-0.43 respectively, however). Also note that  $\frac{C_g}{C_c}$ , as a single parameter, plays a role in steady-state modeling, although they split into two different parameters playing different roles in dynamic simulations (Kam, 2008). This study selects  $\nabla P_o$  of 5 psi/ft as a base case first and investigate how the fit changes at different  $\nabla P_o$  values.

Figure 2.8 shows a model fit to both S-shaped curve and two flow-regime pressure contours. In the two flow regime contours, the point of  $(u_w, u_g) = (1.133 \text{ ft/day}, 2.645 \text{ ft/day})$ , giving  $f_g^* = 70\%$  and  $\nabla P = 73.5 \text{ psi/ft}$ , is selected as the reference point (i.e., the boundary between the high-quality regime and low-quality regime). With given values of  $n$  and  $\nabla P_o$ , a selection of  $S_w^*$  allows two other parameters ( $\frac{C_g}{C_c}$  and  $C_f$ ) to be determined automatically. Three sets of plots, Figures 2.8(a) through 2.8(c), are created at  $S_w^* = 0.421, 0.422,$  and  $0.426$  respectively, and those corresponding sets of five parameters are tabulated in Table 2.4. Although all three pairs of figures look equally nice, a couple of differences are observed: (i) the match to the upper surface of the S-shaped curve deviates further and further as  $S_w^*$  increases; (ii) the turning point from the weak-foam to intermediate state occurs at lower liquid velocity as  $S_w^*$  increases; and (iii) the pressure contours in the high-

quality regime tend to be more vertical with a sharper transition between the two flow regimes (the pressure contours in the low-quality regime tends to remain almost the same, however). With further lab-measured information (for example, the onset of foam generation (i.e., the turning point from weak-foam to intermediate state), pressure data for weak-foam state, or additional steady-state pressure-gradient data in the two flow-regime map (especially in the upper left corner of the plot)), one can further narrow down the set of input parameters. It must be re-emphasized that the changes shown in Figures 2.8(a) through 2.8(c) happen within the range of  $S_w^* = 0.421$  through  $0.426$  (about 1.5%). Such a precision is often very difficult to obtain even in the sophisticated coreflood tests, but causes a considerable difference in terms of model fit. This again proves the validity of the approach in this study – determine the range of  $S_w^*$  from lab tests and then pinpoint exactly what value to be used in numerical simulations from mechanistic foam model. As described earlier,  $\nabla P_o$  ranges from 0.4 to 6.0 psi/ft for supercritical CO<sub>2</sub> foams for the permeability range of 200 to 500 md. In addition to the base-case  $\nabla P_o$  value of 5 psi/ft, the calculations are extended to  $\nabla P_o = 1$  and 30 psi/ft for sensitivity study, as shown in Figures 2.9 and 2.10 respectively, still at the same three  $S_w^*$  values of 0.421, 0.422, and 0.426. Both  $\nabla P_o$  values capture the trend reasonably well, showing the same symptoms presented in the base case (i.e., the upper surface of the S-shaped curve shifting to the right, the transition from the weak-foam to intermediate state happens at lower liquid velocity, and the contours in the high-quality regime more vertical as  $S_w^*$  increases). It is interesting to find that  $\nabla P_o = 1$  psi/ft provides almost no intermediate state, while  $\nabla P_o = 30$  psi/ft provides much more elongated weak-foam state as well as intermediate state. This explains why placing supercritical CO<sub>2</sub> foams further into the reservoir is much easier than

gaseous foams – with a lower  $\nabla P_0$  as an input parameter, foams can be created and mobilized at lower pressure-gradient conditions, allowing the placement further into the reservoir. The input parameters for Figures 2.9 and 2.10 are shown in Tables 2.5 and 2.6, respectively.

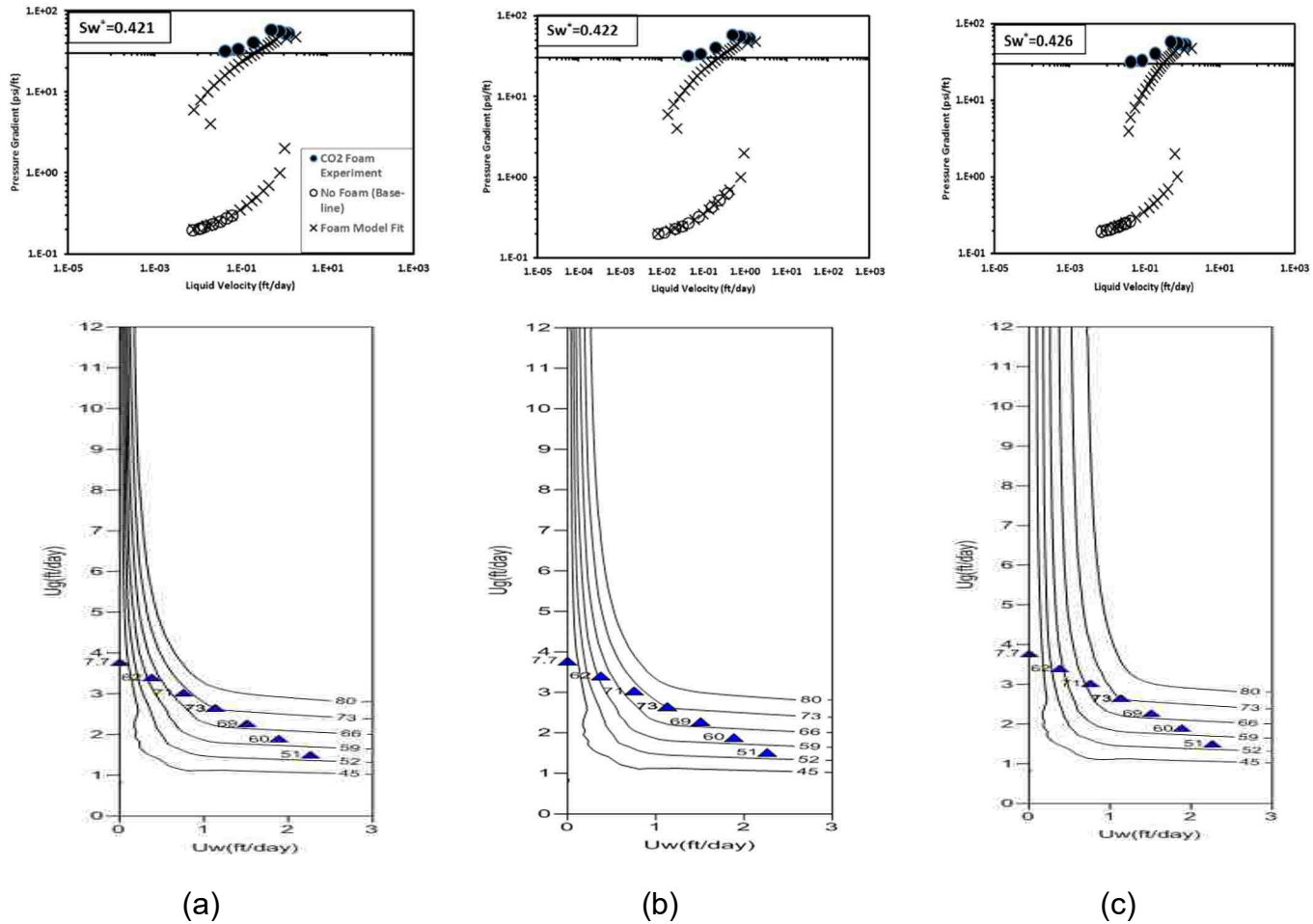


Figure 2.8. Model fit to three foam states as well as two foam-flow regime pressure contours at  $\nabla P_0 = 5$  psi/ft at three different sets of parameters represented by (a)  $S_w^* = 0.421$ , (b)  $S_w^* = 0.422$ , and (c)  $S_w^* = 0.426$  (See Table 2.4 for more details).

Table 2.4. Summary of base-case model parameters ( $\nabla P_o = 5$  psi/ft) to fit three foam states (S-shaped curve) and two flow regimes (see Figure 2.8).

Foam Model Parameters	@ $S_w^* = 0.421$	@ $S_w^* = 0.422$	@ $S_w^* = 0.426$
$\nabla P_o$ , (psi/ft)	5.0	5.0	5.0
n, (dimensionless)	1.0	1.0	1.0
$\frac{c_g}{c_c}$ , ( $s^2/(kg.m^2)$ )	$3.30743 \times 10^{16}$	$3.65796 \times 10^{16}$	$6.34985 \times 10^{16}$
$C_f$ , ( $m^{7/3}.kg/s^{4/3}$ )	$2.07342 \times 10^{-21}$	$2.07342 \times 10^{-21}$	$2.07342 \times 10^{-21}$

Table 2.5. Summary of base-case model parameters ( $\nabla P_o = 1$  psi/ft) to fit three foam states and two flow regimes (see Figure 2.9).

Foam Model Parameters	@ $S_w^* = 0.421$	@ $S_w^* = 0.422$	@ $S_w^* = 0.426$
$\nabla P_o$ , (psi/ft)	1.0	1.0	1.0
n, (dimensionless)	1.0	1.0	1.0
$\frac{c_g}{c_c}$ , ( $s^2/(kg.m^2)$ )	$3.93113 \times 10^{16}$	$4.34776 \times 10^{16}$	$7.54726 \times 10^{16}$
$C_f$ , ( $m^{7/3}.kg/s^{4/3}$ )	$2.07342 \times 10^{-21}$	$2.07342 \times 10^{-21}$	$2.07342 \times 10^{-21}$

Table 2.6. Summary of base-case model parameters ( $\nabla P_o = 30$  psi/ft) to fit three foam states and two flow regimes (see Figure 2.10).

Foam Model Parameters	@ $S_w^* = 0.421$	@ $S_w^* = 0.422$	@ $S_w^* = 0.426$
$\nabla P_o$ , (psi/ft)	30.0	30.0	30.0
n, (dimensionless)	1.0	1.0	1.0
$\frac{c_g}{c_c}$ , ( $s^2/(kg.m^2)$ )	$3.30743 \times 10^{16}$	$3.65796 \times 10^{16}$	$6.34985 \times 10^{16}$
$C_f$ , ( $m^{7/3}.kg/s^{4/3}$ )	$2.07342 \times 10^{-21}$	$2.07342 \times 10^{-21}$	$2.07342 \times 10^{-21}$

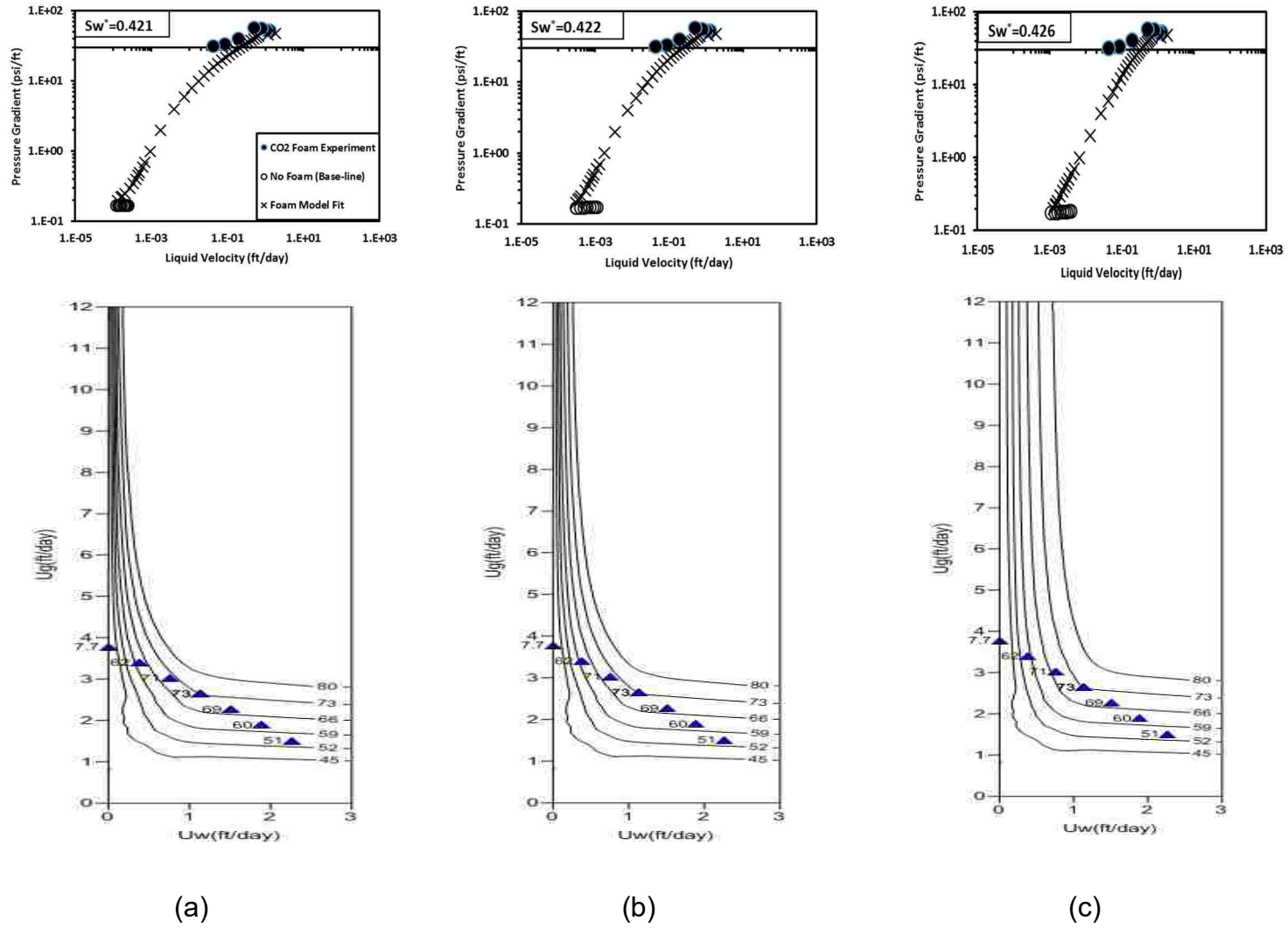
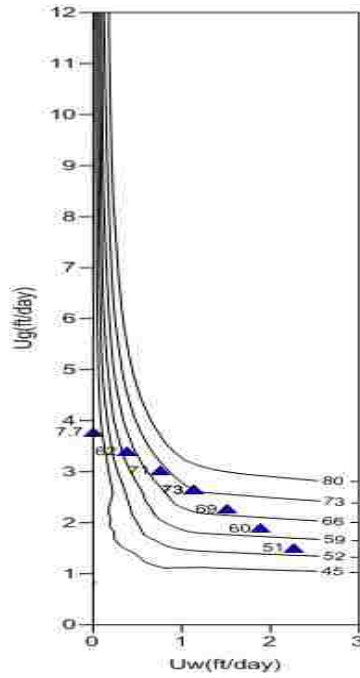
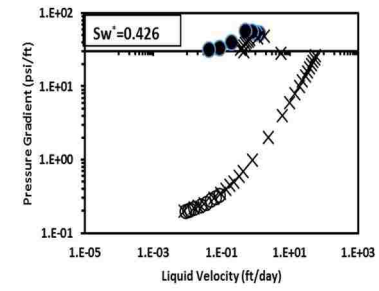
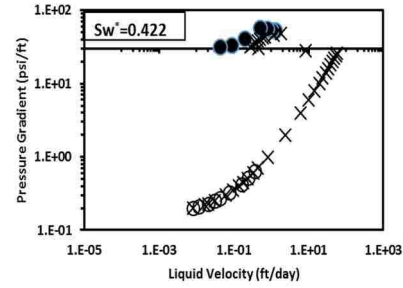
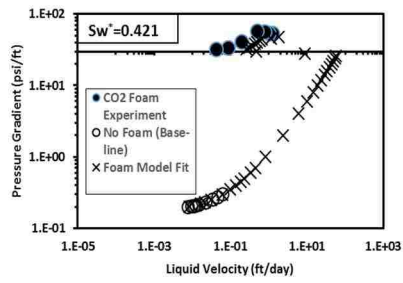
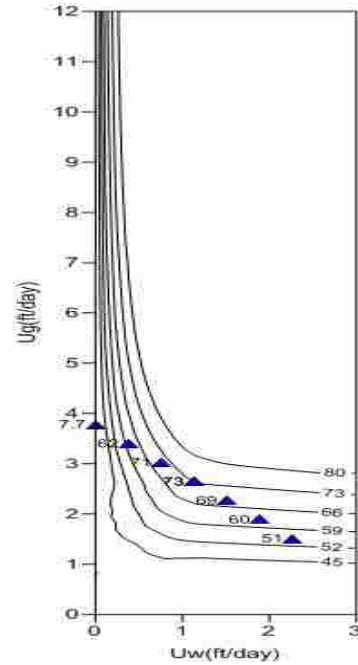


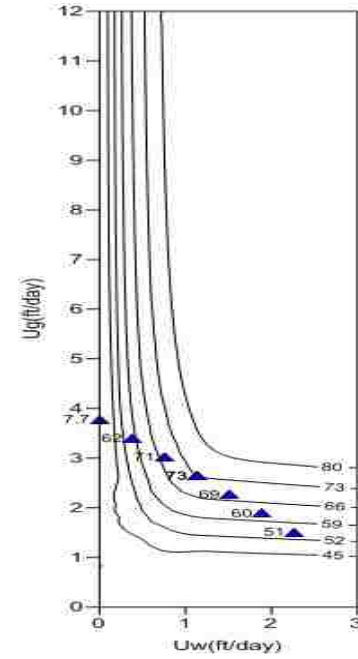
Figure 2.9. Model fit to three foam states as well as two foam-flow regime pressure contours at  $\nabla P_o = 1$  psi/ft at three different sets of parameters represented by (a)  $S_w^* = 0.421$ , (b)  $S_w^* = 0.422$ , and (c)  $S_w^* = 0.426$  (See Table 2.5 for more details).



(a)



(b)



(c)

Figure 2.10. Model fit to three foam states as well as two foam-flow regime pressure contours at  $\nabla P_0 = 30$  psi/ft at three different sets of parameters represented by (a)  $S_w^* = 0.421$ , (b)  $S_w^* = 0.422$ , and (c)  $S_w^* = 0.426$  (See Table 2.6 for more details).



The sensitivity of model fit to other model parameters is also conducted, but not included, due to the limited space. Briefly summarizing, for example, larger  $n$  (foam coalescence exponent; Equation 2.3), let's say,  $n = 2$  rather than 1, does not make any noticeable changes except where foam rheology is governed by  $S_w^*$  (or, strong foams in the high-quality regime). Because bubble instability, as  $S_w$  approaches  $S_w^*$ , occurs more rapidly with larger  $n$ , the top of the S-shaped curve tends to be flattened out and the contours in the high-quality regime become more vertical. Another example is the trapped gas fraction ( $X_{tmax}$ ) and related kinetic parameter ( $\beta$ ) (Equation (2.10)), where the former is estimated from similar experiments in the literature while the latter has never been measured from the lab (but only estimated in some previous modeling studies). Lower  $X_{tmax}$  tends to cause the the transition from the weak-foam to intermediate state at lower pressure gradient (meaning a shift of S-shaped curve to the lower-left), because foam approaches the finer-texture condition more easily. On the contrary, lower  $\beta$  tends to delay reaching the strong foam state and thus stretches out the transition from the intermediate to strong foam state vertically. In fact, a better fit to the S-shaped curve can be made, but with a sacrifice in two-flow regime contours. The interplay between  $X_{tmax}$  and  $\beta$  to data fit is more complicated, however.

### **2.4.3. Part 3: How to determine foam propagation in the field scale**

The model fit to core-scale experimental data can be used to understand how far from the wellbore foam propagates in field-scale applications (note that the propagation distance coincides with the radial region in which MRF values are relatively high, representing the top surface of the S-shaped curve). As an example, this study assumes

a hypothetical cylindrical reservoir (wellbore radius = 0.42 ft and height = 275 ft, from a supercritical CO<sub>2</sub> foam pilot test of the Weber Sand Unit of Rangely field, Colorado (1990)) with total injection rate ( $Q_t$ ) of 17,970 ft<sup>3</sup>/day (3,200 bbl/day or 0.01797 MMscf/day, equivalently). Both gas and liquid can be viewed incompressible in this test, which is believed to be a reasonable assumption at high reservoir pressure and supercritical CO<sub>2</sub> phase. Two injection conditions are considered such as injection foam quality of 90% (i.e.,  $Q_w = 320$  bbl/day and  $Q_g = 0.016173$  MMscf/day) and 60% (i.e.,  $Q_w = 1280$  bbl/day and  $Q_g = 0.010782$  MMscf/day). They represent strong foams in the high-quality regime and low-quality regime, respectively, as shown in Figures 2.11 and 2.12, at three different  $\nabla P_o$  values (see Tables 2.4, 2.5, and 2.6 for input parameters).

A few interesting observations are made. First, the plots show that the MRF (y axis) folds back and forth for  $\nabla P_o = 5$  and 30 psi/ft, presenting multi-valued solutions to the radial distance, while MRF changes rather smoothly for  $\nabla P_o = 1$  psi/ft, presenting a single-valued solution. This behavior is consistent with Figures 2.8 through 2.10. Second, in both high-quality-regime and low-quality-regime foams, foams with lower  $\nabla P_o$  propagate much further into the reservoir. Such results demonstrate the advantage of supercritical CO<sub>2</sub> foams over other gaseous foams (for example, Figure 2.11 shows only “4 and 25 ft for  $\nabla P_o = 30$  and 5 psi/ft respectively” vs. as much as “136 ft (MRF = 100) and 418 ft (MRF = 10) for  $\nabla P_o = 1$  psi/ft”. Similarly, Figure 2.12 shows only “5 and 35 ft for  $\nabla P_o = 30$  and 5 psi/ft, respectively” vs. “362 ft (MRF = 100) and 1077 ft (MRF = 10) for  $\nabla P_o = 1$  psi/ft”. Third, the propagation distance for low-quality-regime foams is more than that for high-quality-regime foams. It is because the former has more stable foams (away from  $S_w^*$  )

with fine foam texture ( $n_f = n_{f_{\max}}$ ), while the latter has less stable foams (near  $S_w^*$ ) with coarse foam texture ( $n_f \ll n_{f_{\max}}$ ). Last, the MRF values for the low-quality-regime foams are higher compared to those for the high-quality-regime foams. Note that the change in MRF in Figures 2.11 and 2.12 in fact reflects the change in apparent foam viscosity (cf. Equations 2.11 and 2.14) that accommodates foam stability at different capillary pressure environments as well as resulting non-Newtonian foam rheology and bubble population balance.

It must be emphasized that the propagation radial distance (x axis in Figures 2.11 and 2.12) is inversely proportional to reservoir thickness. Therefore, if the thickness were 10 times less (27.5 ft rather than 275 ft), the propagation distance in Figures 2.11 and 2.12 would be 10 times more at the same injection rate. How far foam travels in a large field-scale system during EOR processes depends on foam rheology, mobility as well as segregation by gravity in a multi-dimensional space. The next chapter investigates such issues relying on the population-balance model presented in this chapter.

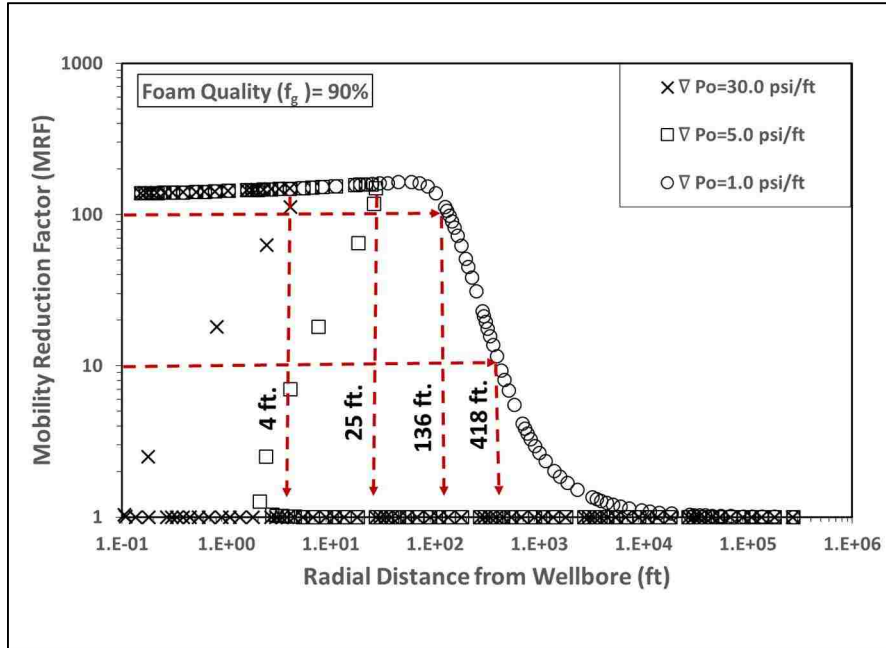


Figure 2.11. Foam propagation in a 275-ft thick cylindrical reservoir at three different values of mobilization pressure gradient (1.0, 5.0, and 30.0 psi/ft) by using high-quality-regime foams (foam quality = 90%) (See Tables 2.4, 2.5, and 2.6 for input parameters).

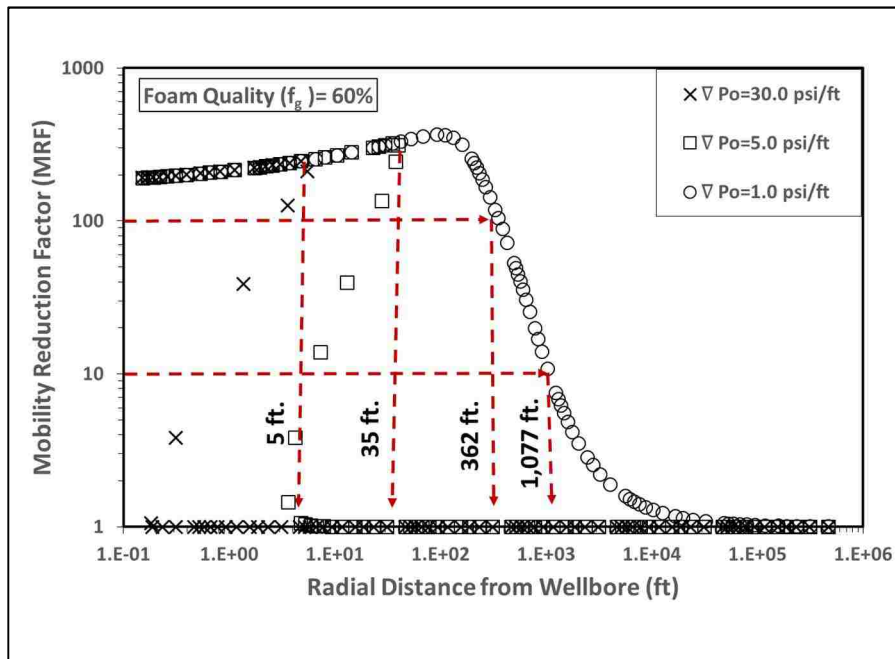


Figure 2.12. Foam propagation in a 275-ft thick cylindrical reservoir at three different values of mobilization pressure gradient (1.0, 5.0, and 30.0 psi/ft) by using low-quality-regime foams (foam quality = 60%) (See Tables 2.4, 2.5, and 2.6 for input parameters).

## 2.5. Discussions

The model fit to experimental data of three foam states and two strong-foam flow regimes (Figures 2.8, 2.9, and 2.10) helps determine many of model parameters but, in its current form, this study cannot pinpoint the sets of input parameters further unfortunately (for example, Figures 2.8(a) vs. 2.8(b) vs. 2.8(c)). It is because the experimental data available to this study have the properties of strong foams, just like the way foams are injected in the field tests; the prediction of foam propagation using bubble population model requires properties of weak-foam and intermediate states as well, however, in addition to strong-foam state. Such a gap suggests that design and implementation of field-scale EOR treatments have both of numerical modeling/simulation and lab experiment components aligned together cohesively.

The following chapter compares this population-balance model with implicit-texture foam model, when supercritical CO<sub>2</sub> foams are injected into a cylindrical reservoir in EOR processes. When the reduction in gas-phase mobility is determined from the mechanistic model (cf. Figures 2.11 and 2.12) and the resulting distance-averaged MRF values are carefully selected, the two modeling techniques predict comparable foam propagation distances. The study demonstrates how the two modeling techniques – one computationally more intensive but based on detailed mechanistic mechanisms, while the other more user-friendly and simpler but still capturing key mechanisms - help each other to improve the quality of reservoir simulations.

This study demonstrates another interesting point on why supercritical CO<sub>2</sub> foams are better than gaseous foams to improve oil recovery in the field. Typical justifications behind the use of supercritical CO<sub>2</sub> foams include a favorable miscibility condition with oleic components, a swelling behavior when in contact with reservoir oil, and high-density and high-viscosity property of a supercritical phase of CO<sub>2</sub>. The results from this study show another important reason, that is, supercritical CO<sub>2</sub> foams can propagate more easily, being placed deeper into the reservoir much further than gaseous foams (even a few orders of magnitude more), because of much lower mobilization pressure gradient ( $\nabla P_o$ ), and thus improve sweep efficiency greatly.

There are many physical and chemical properties that obviously affect foam rheology in lab experiments but do not show up explicitly in the model used in this study. The model, however, is equipped with capabilities dealing with those properties indirectly. For example, a better foamer (e.g. by changing surfactant formulation and concentration endowing foams improved stability) can be represented by higher yield stress of lamellae, higher foam viscosity, higher  $f_g^*$ , and higher trapped gas saturation. More oil-wet media can be represented by properties similar to a poorer foamer (i.e., opposite to the previous example) as well as changes in relative permeability curves. A change in interfacial tension can be incorporated by foam stability and lamella creation and coalescence mechanisms (through mobilization pressure and limiting water saturation).

It must be commented that the experimental results for continuous foam rheology surface as shown in Figures 2.1(a) and 2.1(b), exhibiting the data points for both “three different foam states” and “two strong foam regimes”, are very rare in the literature. In

fact, even though there is sufficient experimental evidence in pieces, the only complete data set available in the literature is for N<sub>2</sub> gaseous foams (Gauglitz et al., 2002; Kam and Rossen, 2003). As a result, the fact that the model fit in this study is made for supercritical CO<sub>2</sub> foams without data points in the intermediate state (cf. Figures 2.4(a) and 2.4(b)) adds some uncertainty to this study, and this in turn emphasizes the importance of experimental studies for modeling purpose. See Yu et al. (2018) for more discussions on this aspect.

## 2.6. Conclusions

This chapter investigates the mechanisms of supercritical CO<sub>2</sub> foam propagation by using a mechanistic foam model. The procedure to fit to the coreflood experimental data is presented in detail, together with the uniqueness of the input parameters and implication of the model in large field-scale applications. The major findings can be summarized as follows:

- This study investigates the mechanisms of supercritical CO<sub>2</sub> foam propagation by using a bubble-population-balance foam model based on pore-scale events. How to fit the model to lab coreflood data, which is core-scale events, is presented in a step-by-step manner, including three foam states and two foam-flow regimes for supercritical CO<sub>2</sub> foams. This is the first attempt of mechanistic foam modeling, in its kind, focusing on supercritical CO<sub>2</sub> foams with much lower mobilization pressure gradient ( $\nabla P_o$ ) than other gaseous foams, which has not been studied earlier.
- The results also provide a theoretical reasoning why supercritical CO<sub>2</sub> foam can propagate further into the reservoir, as much as a few orders of magnitude, than other gaseous foams, and how much quantitatively. It is primarily because of lower mobilization pressure gradient ( $\nabla P_o$ ) of supercritical CO<sub>2</sub> foams, which leads to smooth and monotonic changes from weak-foam to strong-foam state directly with no intermediate state in between. As a result, it seems very realistic that supercritical CO<sub>2</sub> foams with the mobilization pressure gradient less than 1 psi/ft can propagate a few hundreds or thousands of feet easily.



- With model parameters determined, the mechanistic model is applied to field-scale CO<sub>2</sub> foam EOR events, showing key concepts of foam propagation in large-scale applications. The results based on foam fundamentals and theoretical grounds demonstrate why the propagation distance is greater when wetter foams are used than drier foams. It is because of improved foam stability in the low-quality regime than in the high-quality regime.

## **CHAPTER 3. INVESTIGATING SUPERCRITICAL CO<sub>2</sub> FOAM PROPAGATION DISTANCE: CONVERSION FROM STRONG FOAM TO WEAK FOAM VS. GRAVITY SEGREGATION**

### **3.1. Introduction**

#### **3.1.1. EOR using gas and water injection**

Gas injection is one of the most widely used methods in enhanced oil recovery (EOR) processes, because of its economic advantages. The gas phase (commonly CO<sub>2</sub>, N<sub>2</sub>, produced natural gas, flue gas, or a combination of these) is injected into the reservoir either as miscible or immiscible with reservoir oil. Since these gas phases generally have lower viscosity and density compared to the reservoir fluids, an early breakthrough of the injected gas into the production well typically occurs resulting in poor sweep efficiency. The main underlying mechanism behind it is the instability at the interface between the displacing and displaced phases caused by poor mobility ratio (leading to fingering or channeling) and density contrast (leading to gravity segregation).

Extensive research efforts have been made to predict the volume fraction of a reservoir that can be swept by gas injection at different reservoir and fluid conditions. For example, many laboratory studies in early days (Dyes et al. 1954; Offerlinga and Van Der Poel 1954; Blackwell et al. 1959) found out that the low-viscosity and low-density gas tends to channel through and bypass oil in sands with no dip angles. Therefore, in horizontal sands, gas flooding is less efficient as the oil viscosity increases, and the desired oil recovery can be achieved only by injecting a large volume of gas. For dipping sands, there is a competition between gravity segregation and channeling (Lacey et al. 1958). There exists a critical rate (Hill and Inst 1952; Dietz 1953) below which gravity

segregation prevails and no channeling occurs, and above which channeling plays a more significant role.

Caudle and Dyes (1957) first suggested the simultaneous injection of water and gas as a method to improve sweep efficiency over gas injection. It was based on the fact that water, if flowing together with gas, decreases gas relative permeability. They attempted to determine the optimal gas-water injection ratio, by using relative permeability curves and fluid viscosities, resulting in the conditions at which gas and water flow at the same velocity.

It is sometimes more convenient in the field tests to inject water alternatively with gas, rather than water and gas co-injection, and this process is called water alternating gas (WAG). Christensen et al. (2001) provide a thorough review of WAG field experiences. The initial design of a WAG process is usually constructed by reservoir simulation studies and then the design is optimized, as the field process matures, with recommended gas slug size (i.e., volume of gas to be injected) and WAG ratio (Attanucci et al. 1993). Blackwell et al. (1959) investigated the effect of gravity on WAG process to find that the mobility of gas-water region becomes less of an issue as gas and water segregate more rapidly.

Stone (1982) first investigated the gravity segregation of gas from liquid for water and gas co-injections in a homogenous reservoir once water fractional flow ( $f_w$ ) or gas fractional flow ( $f_g$ ) is given (note  $f_w + f_g = 1$ ). He developed an analytical equation by

applying the Buckley-Leverett (1942) theory to predict the size of the region around the injection well where vertical conformance was good before complete segregation. Jenkins (1984) extended Stone's equations to obtain a closed-form solution to the equations for estimation of incremental recovery beyond waterflooding for homogenous reservoirs. Combining these two together, so-called Stone and Jenkins model is shown to be also valid in the presence of surfactants (Rossen and Shen 2007), even though it was originally designed for gas-water co-injection. Figure 3.1 shows three constant regions at the steady state which represent a gas override region (i.e., only gas flowing ( $f_g = 1$  and  $f_w = 0$ ) at residual water saturation ( $S_{wr}$ )), a water underdrive region (i.e., only water flowing ( $f_g = 0$  and  $f_w = 1$ ) at residual gas saturation ( $S_{gr}$ )), and a mixed region in between (i.e., both gas and water flowing at constant water saturation ( $S_w$ )). Note that the prediction of "travelling distance before complete segregation by gravity ( $R_{gs}$ )" is key to successful field implementation during gas-liquid co-injection EOR processes.

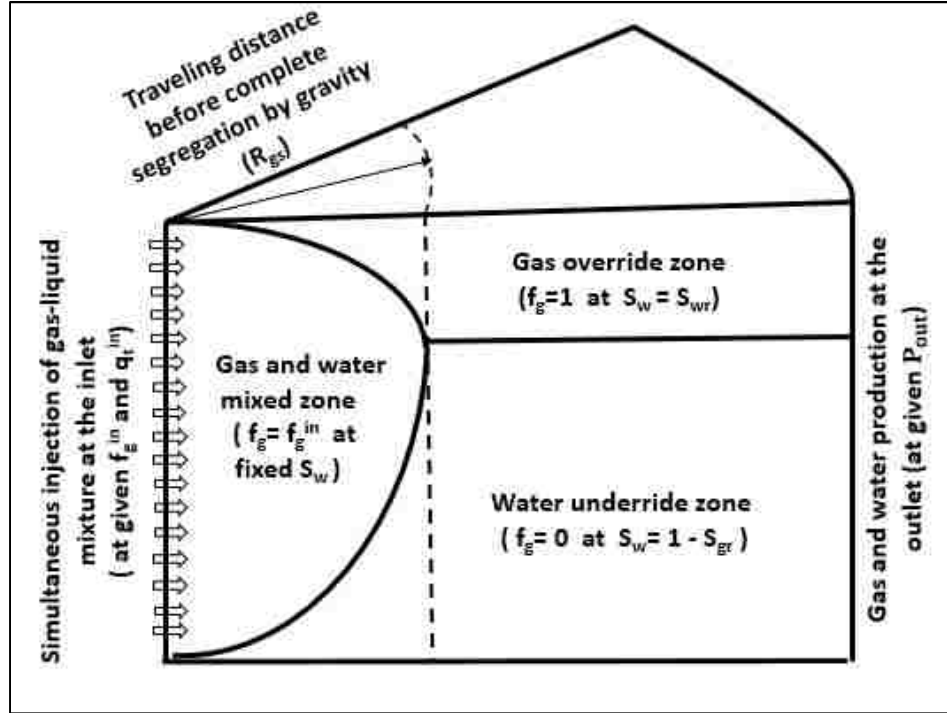


Figure 3.1. Three constant-state regions observed at the steady-state gas-liquid co-injection in 2D space predicted by earlier studies (Stone (1982), Jenkins (1984), and Rossen and Shen (2007)) (gas and liquid phases are assumed to be incompressible).

### 3.1.2. Gravity segregation during foam EOR process

Foaming gas with surfactant solutions has been suggested to mitigate gravity segregation and improve the mobility ratio within the mixed region (Shi and Rossen 1998). From a series of two-dimensional laboratory experiments, Holt and Vassenden (1997) found reasonably good agreement between the Stone and Jenkins model and their experimental results for the complete gravity segregation distance (i.e.,  $R_{gs}$  in Figure 3.1) in gas and water co-injection tests. They observed, however, that when foam is injected, the segregation into gas and liquid is difficult to measure in small-scale experiments because of kinetics involved in foam decay. Rossen and van Duijn (2004) showed that

the Stone and Jenkins model is rigorously correct to use for foam if several assumptions are met. Those assumptions include (a) homogenous reservoir, although anisotropic, (b) cylindrical reservoir with open outer boundary, (c) injection well penetrates full reservoir height, (d) steady-state conditions reached during the injection, (e) incompressible phases, (f) no dispersion, and (g) Newtonian rheology for all phases. Analytical modeling (Stone 1982; Jenkins 1984), simulation studies (Shi and Rossen 1998) and experimental results (Holt and Vassenden 1997) indicate that gravity override in foam depends on dimensionless gravity number that is the ratio of gravity force to viscous force.

Shi and Rossen (1998) performed several numerical simulations with homogeneous and anisotropic rectangular and radial reservoirs using UTCOMP (University of Texas Compositional Flood Simulation). They found that the Stone and Jenkins model matches remarkably well with simulation results over a wide range of reservoir properties, geometries, flow rates, foam qualities (or, gas fractions ( $f_g$ ), equivalently), foam strengths, foam collapse mechanisms, and coarseness of simulation grids. The results also confirmed that a successful gas injection EOR to overcome gravity segregation, with and without foams, requires horizontal pressure gradient outweigh vertical pressure gradient. Performing N<sub>2</sub> foam numerical simulation using CMG-STAR3, Rossen and Shen (2007) observed that at fixed injection rate, the length of injection interval does not affect the distance for gravity segregation. They proposed a first guess in required injection pressure by providing an explicit relationship between the injection well pressure and distance to the point of segregation.

### 3.1.3. Conversion of strong foam to weak foam

In addition to gravity segregation, there is another mechanism that limits foam propagation in field applications, that is, the conversion of strong foam into weak foam, as demonstrated in Figure 3.2. There is a threshold distance ( $R_{CSW}$ ) beyond which fine-textured strong foam created near the well (often caused by the turbulence in the well) turns into coarsely-textured weak foam, as foam moves away from the injection well. Such a concept of three different states of foam when the pressure gradient ( $\nabla P$ ) is controlled was first suggested by the experimental study of Gauglitz et al. (2002) and incorporated into the mechanistic foam modeling later (Kam and Rossen 2003; Lee et al. 2016).

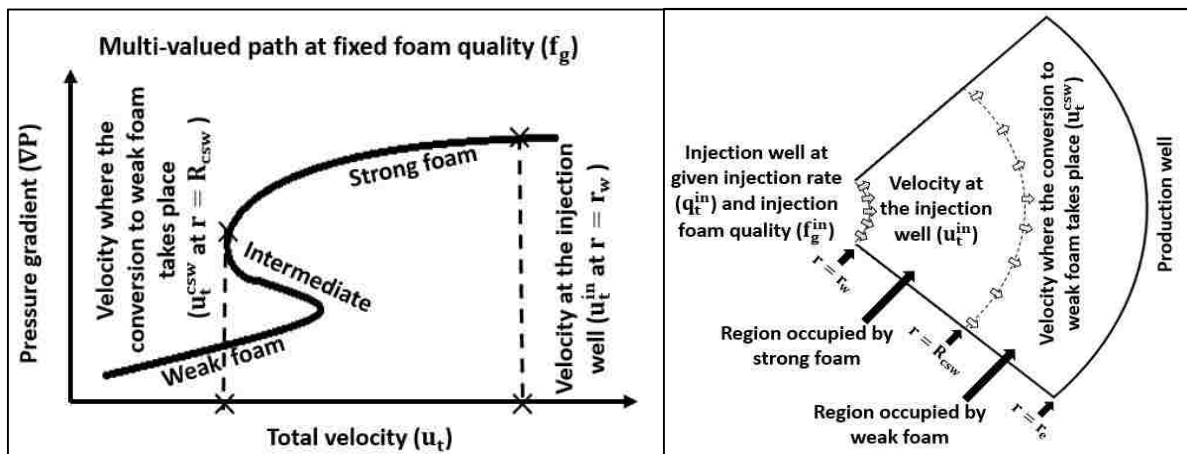


Figure 3.2. Three different foam states and its implication in field-scale applications (Gauglitz et al. (2002), Kam and Rossen (2003), and Lee et al. (2016)).

Figure 3.2 shows more details about what happens when strong foam is injected into a cylindrical reservoir at the total injection flow rate  $q_t = q_t^{\text{in}}$  that corresponds to the

total injection velocity  $u_t = u_t^{in}$ . Note that  $q_t$  remains the same at any radial distance ( $r$ ) between the wellbore radius ( $r_w$ ) and the radius to the external boundary ( $r_e$ ), if gas and liquid are incompressible, while  $u_t$  decreases with  $r$  (i.e.,  $u_t = \frac{q_t}{2\pi rH}$  at any  $r$ , for a cylindrical reservoir with the uniform thickness of  $H$ ). It is the pressure gradient ( $\nabla P$ ) that governs which state of foam is to be formed at given radial distance, because foam texture ( $n_f$ ) increases with the pressure gradient ( $\nabla P$ ) monotonically (Kam and Rossen 2003). For example, starting from the injection well ( $r = r_w$ ), the reservoir is occupied by strong foam up to the distance where the conversion from strong foam to weak foam takes place ( $r = R_{csw}$ ), and then by weak foam for the radial distance beyond ( $r > R_{csw}$ ). Once strong foam is formed, the rheology follows the two flow regimes of strong-foam state as discovered by Osterloh and Jante (1992) and Alvarez et al. (2001). Foam rheology in the high-quality regime of strong-foam state is governed by bubble stability near the limiting capillary pressure ( $P_c^*$ ) (or limiting water saturation ( $S_w^*$ )). On the contrary, foam rheology in the low-quality regime of strong-foam state is governed by the transport of bubbles at or near the maximum foam texture ( $n_f = n_{fmax}$ ). Bubble population balance modeling, which this study is based on, is a modeling technique that deals with physical phenomena of bubble creation and coalescence, gas trapping, non-Newtonian rheology, and fluid transports in porous medium. It has been widely used in mechanistic foam modeling in the literature (Kovscek et al. 1995; Friedmann et al. 1991; Kam and Rossen 2003; Lee et al. 2016). Nearly all experimental foam studies have been conducted in linear system assuming the velocity remains constant as foam propagates into the system. In field scale, however, as foam moves away from the wellbore, the velocity decreases because of its radial



geometry. Due to the difficulty of conducting radial foam flow experiments in the lab, a mechanistic foam model is essential to translate foam rheology from linear to radial system.

### 3.2. Motivations and Objectives

The objective of this chapter is to predict how far supercritical CO<sub>2</sub> foam can propagate based on two different mechanisms, (i) the conversion of strong foam to weak foam ( $R_{csw}$ ) and (ii) gravity segregation ( $R_{gs}$ ), in a wide range of injection conditions. This study can be distinguished from other previous studies on similar topics as follows.

- First, how strong foam would propagate into the reservoir (before turning into weak foam) where the velocity monotonically decreases with radial distance has not been investigated before, especially when supercritical CO<sub>2</sub> foam with very low mobilization pressure gradient ( $\nabla P_o$ ) is applied;
- Second, gravity segregation simulations with commercial software have been performed by many previous studies, but none of them employed gas-phase mobility reduction factors actually calibrated from mechanistic foam model (based on true foam physics and whose model parameters determined from actual model fit to lab data);
- Third, none of the previous studies in the literature have put the above two mechanisms together to demonstrate which of the two becomes more influential under what circumstances; and

- Finally, this study makes a unique contribution by presenting contour maps to show how far foam can travel, before converting to weak foam or gravity segregation, as a function of injection foam quality ( $f_g^{in}$ ) and total injection rate ( $q_t^{in}$ ), (or injection pressure ( $P_{in}$ ), equivalently). This is especially important to fill the current gap present for the field implementation of supercritical CO<sub>2</sub> foams.

Note that a mechanistic model from Izadi and Kam (2018) (previous chapter) is used to provide mobility reduction factors (MRF) as an input parameter for gravity segregation simulations by CMG STARS. This study deals with a relatively ideal reservoir (i.e., large homogeneous cylindrical reservoir) in the absence of oil, as a first step, prior to the application in the real situations.

### **3.3. Methodology**

#### **3.3.1. Population balance modeling**

A mechanistic modeling approach based on bubble population balance makes it possible to keep track of the population of bubbles (i.e., foam films or lamellae, equivalently), as foam propagates further into the reservoir. The mechanistic modeling approach captures not only the number of bubbles in unit volume of space (i.e., foam texture ( $n_f$ )) but also the relationship between foam texture and other variables such as effective gas viscosity ( $\mu_g^f$ ), changes in gas relative permeability ( $k_{rg}^f$ ), trapped and flowing gas saturations ( $S_{gt}, S_{gf}$ ), non-Newtonian flow behavior and so on. Because this chapter investigates supercritical CO<sub>2</sub> foam placement in a homogeneous reservoir, a population

balance model based on the mobilization and division mechanism is applied. More details of such a model are available in the literature (Kam and Rossen 2003; Kam 2008; Lee et al. 2016; Ortiz Maestre, 2017), and all relevant equations are tabulated in Table 3.1 following the study of Izadi and Kam (2018). Note that the minimum mobilization pressure gradient ( $\nabla P_o$ ) is defined as

$$\nabla P_o = 4 \left( \frac{\sigma}{R_t} \right), \quad (3.1)$$

for a foam film to be mobilized out of pore throat with its radius  $R_t$ , if the interfacial tension between gas and liquid is given by  $\sigma$ . The minimum mobilization pressure gradient ( $\nabla P_o$ ) for supercritical CO<sub>2</sub> foam can range less than 1.0 psi/ft easily (i.e., 0.05 – 5 psi/ft) with effective foamers, while it ranges around 10 – 30 psi/ft at a typical reservoir permeability (50 – 500 md) (Gauglitz et al., 2002; Georgiadis et al., 2010). The coefficient in Equation 3.1 is 4, rather than 2 (typically shown in Laplace equation), because a foam film consists of two gas-liquid interfaces with almost identical curvatures.

Table 3.1. A summary of bubble population balance model used in this study (see Izadi and Kam (2018) for more information).

Definition	Equation	Definition	Equation
Lamella creation rate	$R_g = \frac{C_g}{2} \left\{ \operatorname{erf} \left( \frac{\nabla P - \nabla P_0}{\sqrt{2}} \right) - \operatorname{erf} \left( \frac{-\nabla P_0}{\sqrt{2}} \right) \right\}$	Gas relative permeability (no foam)	$k_{rg}^0(S_w) = B \left( \frac{1 - S_w - S_{gr}}{1 - S_{wc} - S_{gr}} \right)^{m_2}$
Lamella coalescence rate	$R_c = C_c n_f \left( \frac{S_w}{S_w - S_w^*} \right)^n$	Gas relative permeability with foam	$k_{rg}^f(S_w) = B \left( X_f \frac{1 - S_w - S_{gr}}{1 - S_{wc} - S_{gr}} \right)^{m_2}$
Foam texture	$n_f = \frac{C_g}{2C_c} \left( \frac{S_w - S_w^*}{S_w} \right)^n \left\{ \operatorname{erf} \left( \frac{\nabla P - \nabla P_0}{\sqrt{2}} \right) - \operatorname{erf} \left( \frac{-\nabla P_0}{\sqrt{2}} \right) \right\}$	Trapped gas fraction	$X_t = X_{t \max} \left( \frac{\beta n_f}{1 + \beta n_f} \right)$
Gas transport	$u_g = \frac{kk_{rg}^0(S_w)\nabla P}{\mu_g}, \quad u_g = \frac{kk_{rg}^f(S_w)\nabla P}{\mu_g^f}$	Flowing and trapped gas saturation	$S_{gf} = S_g(1 - X_t)$ $S_{gt} = S_g X_t$ $S_g = S_{gf} + S_{gt}$

(table cont'd.)

Definition	Equation	Definition	Equation
Liquid transport	$u_w = \frac{k k_{rw}(S_w) \nabla P}{\mu_w}$	Gas viscosity with foam	$\mu_g^f = \mu_g^o + C_f n_f \left( \frac{u_g}{\phi S_g X_f} \right)^{-\frac{1}{3}}$
Liquid relative permeability	$k_{rw}(S_w) = A \left( \frac{S_w - S_{wc}}{1 - S_{wc} - S_{gr}} \right)^{m_1}$	Mobility reduction factor	$MRF = \frac{k_{rg}^o \mu_g^f}{k_{rg}^f \mu_g^o}$

### 3.3.2. Conversion from strong-foam to weak-foam states

Details on the model fit to CO<sub>2</sub> foam coreflood experiments are shown in Izadi and Kam (2018) (previous chapter). An example of foam model parameters from the study to match three different foam states (weak-foam, intermediate, and strong-foam states) and two flow regimes of strong foam state (high-quality regime and low-quality regime) is presented in Table 3.2. These input parameters are used as a basis for the prediction of foam propagation distance before strong foam turns into weak foam ( $R_{CSW}$ ) in this chapter, which is demonstrated in Figure 3.2 above.

Table 3.2. Mechanistic model parameters for supercritical CO<sub>2</sub> foam at different mobilization pressure values ( $\nabla P_o$ ) fitting three different foam states and two flow regimes of strong foam state (see Table 3.1 for equations).

Foam Model Parameters	$\nabla P_o$ (Pa/m; psi/ft) = 22620.6; 1.0	$\nabla P_o$ (Pa/m; psi/ft) = 113103; 5.0	$\nabla P_o$ (Pa/m; psi/ft) = 678618; 30.0
n (dimensionless)	1.0	1.0	1.0
$\frac{C_g}{C_c}$ (1/m <sup>3</sup> )	$4.35 \times 10^{16}$	$3.66 \times 10^{16}$	$3.66 \times 10^{16}$
$C_f$ (m <sup>7/3</sup> .kg/s <sup>4/3</sup> )	$2.07 \times 10^{-21}$	$2.07 \times 10^{-21}$	$2.07 \times 10^{-21}$

(In all cases,  $S_w^* = 0.422$ ;  $X_{tmax} = 0.7$  and  $\beta = 5 \times 10^{-14}$ ;  $f_g^* = 70\%$  at  $u_g = 9.331 \times 10^{-6}$  m/s and  $u_w = 4.0 \times 10^{-6}$  m/s. see Izadi and Kam (2018) for other petrophysical and fluid properties.)

In the case of gas-liquid co-injection EOR (at fixed  $f_g$  condition), the pre-specified total injection rate ( $q_t$ ) corresponds to the total superficial velocity ( $u_t$ ) that changes as a function of radial distance (Note that gas and liquid compressibility can be reasonably assumed negligible at the field pressure condition). For a homogeneous reservoir with constant thickness (H), the total velocity ( $u_t$ ) at any given radial distance (r) is given by

$$u_t = \frac{q_t^{\text{in}}}{2\pi r H} \quad \text{for } r_w \leq r \leq r_e \quad (3.2)$$

As described earlier, the region with  $u_t > u_t^{\text{CSW}}$  (or  $r < R_{\text{CSW}}$ ) is occupied by strong foam, while the region beyond with  $u_t < u_t^{\text{CSW}}$  (or  $r > R_{\text{CSW}}$ ) is occupied by weak foam as depicted in Figure 3.2. Note that  $u_t$  decreases monotonically with  $r$ , even though the total rate ( $q_t$ ) remains the same (i.e.,  $q_t = q_t^{\text{inj}}$ ) at any  $r$ . Therefore  $r = r_w$  corresponds to the highest  $u_t$ , and  $r = r_e$  corresponds to the lowest  $u_t$ . The mechanistic foam model allows velocity-dependent foam rheology to be calculated at three different foam states.

### 3.3.3. Gravity segregation of foam into gas and liquid

The models presented by Stone (1982) and Jenkins (1984) can be combined together and formulated for foam flow by introducing mobility reduction factor (MRF) for gas mobility. Then, the distance for foam to travel before gravity segregation ( $R_{\text{gs}}$ ) becomes

$$R_{\text{gs}} = \sqrt{\frac{q_t}{\pi k_z (\rho_w - \rho_g) g \left( \frac{k_{\text{rg}}}{\mu_g} \times \frac{1}{\text{MRF}} + \frac{k_{\text{rw}}}{\mu_w} \right)}} \quad (3.3)$$

or,

$$R_{\text{gs}} = \sqrt{\frac{q_t}{\pi k_z (\rho_w - \rho_g) g \left[ B \left( \frac{1 - S_w - S_{\text{gr}}}{1 - S_{\text{wc}} - S_{\text{gr}}} \right)^{m_2} \times \frac{1}{\text{MRF} \times \mu_g} + A \left( \frac{S_w - S_{\text{wc}}}{1 - S_{\text{wc}} - S_{\text{gr}}} \right)^{m_1} \times \frac{1}{\mu_w} \right]}} \quad (3.4)$$

in full equation. Note that  $q_t$  is total injection rate,  $k_z$  vertical absolute permeability,  $\rho_w$  and  $\rho_g$  water and gas densities,  $g$  gravitational acceleration,  $S_w$  average water saturation in the mixed foam region,  $S_{wc}$  and  $S_{gr}$  connate water saturation and residual gas saturation respectively, MRF is mobility reduction factor,  $\mu_w$  and  $\mu_g$  water and gas viscosities,  $A$  and  $m_1$  coefficient and exponent for Corey-type water relative permeability, and  $B$  and  $m_2$  coefficient and exponent for Corey-type gas relative permeability. If rock and fluid properties are available at given total injection rate, calculation of  $R_{gs}$  requires two main input parameters such as  $S_w$  and MRF in the mixed region where foam is present (see in Figure 3.1). These two parameters are constant values in the original studies of Stone's and Jenkins's for gas-water co-injection, while they are variables for foam applications as shown by the mechanistic foam model. Because multi-dimensional foam simulation in CMG-STARs also assumes constant  $S_w$  and MRF values, the space-averaged  $S_w$  and MRF values calculated from mechanistic foam model are used as input parameters for CMG-STARs simulations. More details on this follow below. How CMG-STARs performs foam simulation can be found in the manual (CMG 2016).



### 3.4. Results

For field-scale supercritical CO<sub>2</sub> foam propagation prediction, this study uses a hypothetical cylindrical reservoir with an injection well at the center, penetrating the entire reservoir thickness. Reservoir and operational conditions are selected similar to the Rangely Weber Sand Unit, CO (Jonas et al. 1990) where supercritical CO<sub>2</sub> and surfactant solutions are co-injected during field EOR tests (as shown in Table 3.3). This particular field is chosen because it is relatively homogeneous with a good reservoir thickness (H = 275 ft). Table 3.4 shows a brief summary of operational conditions in foam field EOR applications available in the literature.

Table 3.3. Rock and fluid properties of a cylindrical reservoir of interest to be tested in this study.

Reservoir Parameter	Parameter Value
Absolute permeability (md; m <sup>2</sup> )	450; 450 x10 <sup>-15</sup>
Porosity (%)	22
Reservoir thickness (ft; m)	275; 83.8
Reservoir temperature (°F; °C)	110; 43.3
Reservoir pressure (psia; Pa)	1555; 1.07x10 <sup>7</sup>
Brine density (lb/ft <sup>3</sup> ; kg/m <sup>3</sup> )	62.6;1002.76
Gas density (lb/ft <sup>3</sup> ; kg/m <sup>3</sup> )	36.5;584.67
Brine viscosity (cp;Pa s)	0.65; 0.00065
Gas viscosity (cp;Pa s)	0.07;0.00007
Brine relative permeability	0.893[(S <sub>w</sub> - 0.42)/0.58] <sup>1.41</sup>
Gas relative permeability	0.222[(1.0-S <sub>w</sub> )/0.58] <sup>4.45</sup>
Total injection rate (ft <sup>3</sup> /day;m <sup>3</sup> /s)	17970;0.00589

Table 3.4. Examples of foam field EOR tests in the literature with operation conditions.

Field	Foam Type	Injection Pressure (psia; Pa)	Foam Quality (%)	Pattern Spacing (acre; m <sup>2</sup> )	Injection Intervals (ft; m)
Siggins, IL	N <sub>2</sub>	430; 2.97x10 <sup>6</sup>	99	2.5; 10117	44;13.4
Wilmington, CA	N <sub>2</sub> ,CO <sub>2</sub>	1300; 8.96 x10 <sup>6</sup>	90	-	70;21.3
Rock Creek, VA	CO <sub>2</sub>	1000; 6.90 x10 <sup>6</sup>	80	19.65; 79520	24.6;7.5
Rangely, CO	CO <sub>2</sub>	3942; 2.72 x10 <sup>7</sup>	78	20; 80937	275;83.8
North Ward Estes, TX	CO <sub>2</sub>	1600-1800; 1.1-1.24x10 <sup>7</sup>	-	20; 80937	60;18.3
EVGSAU, NM	CO <sub>2</sub>	-	80	38, 80; 153781,323749	20-50; 6.1,15.2
East Mallet, TX	CO <sub>2</sub>	-	60 - 80	20, 40; 80937,161874	-
McElmo Creek, UT	CO <sub>2</sub>	-	-	160;647497	-
Salt Creek, WY	CO <sub>2</sub>	1600; 1.1x10 <sup>7</sup> (THP)*	80 - 85	15.3;61916	70-80; 21.3,24.4
Delhi, LA	CO <sub>2</sub>	1800; 1.24x10 <sup>7</sup> (THP)*	70 - 94	40;161874	100;30.5

\* THP: tubing head pressure

### 3.4.1. Propagation distance based on conversion from strong-foam to weak-foam state ( $R_{CSW}$ )

How far the fine-textured strong foam injected at the center propagates into the reservoir before it converts into weak foam is evaluated at three different values of mobilization pressure gradient ( $\nabla P_o = 1.0, 5.0, \text{ and } 30.0 \text{ psi/ft}$ ).

The first step is to make a fit to experimental data showing three foam states and two flow regimes of strong-foam state (not shown; see Izadi and Kam (2018) for more). Figure 3.3 shows the results of pressure gradient ( $\nabla P$ ) as a function of total velocity ( $u_t$ ) at  $\nabla P_o = 1.0, 5.0, \text{ and } 30.0 \text{ psi/ft}$  at  $f_g^{in} = 70\%$ . For  $\nabla P_o = 5.0, \text{ and } 30.0 \text{ psi/ft}$ , the S-shaped curve folding back and forth showing three foam states are shown clearly (eg.  $\nabla P < 25.0 \text{ psi/ft}$  for weak foam state,  $25.0 \text{ psi/ft} < \nabla P < 30.0 \text{ psi/ft}$  for intermediate state, and  $\nabla P > 30.0 \text{ psi/ft}$  for strong foam state for  $\nabla P_o = 30.0 \text{ psi/ft}$ ). The fact that the curve does not fold back and forth at low  $\nabla P_o$  looks interesting. In such a case, there is a smooth transition from weak-foam to strong-foam state without intermediate state as shown in the case of  $\nabla P_o = 1.0 \text{ psi/ft}$ . By using the results in Figure 3.3 and reservoir properties in Table 3.3 for a hypothetical cylindrical reservoir, Figures 3.4 through 3.6 show how MRF and  $S_w$  values are distributed as a function of radial distance ( $r$ ) for  $\nabla P_o = 30.0, 5.0, \text{ and } 1.0 \text{ psi/ft}$ , respectively. These figures show the steady-state results when foam is injected into the cylindrical reservoir at  $q_t^{in} = 17,970 \text{ ft}^3/\text{day}$  at a pre-specified  $f_g^{in}$ , ranging from 60% (i.e., wet foam) to 99 % (i.e., dry foam). Note that  $q_t$  is identical at any  $r$  (i.e.,  $q_t = q_t^{inj}$ ) due to incompressible gas and liquid phases, and thus  $f_g$  is assumed to be identical at any radial

and vertical locations (i.e.  $f_g = f_g^{in}$ ). The threshold foam quality separating the high-quality regime from the low-quality regime ( $f_g^*$ ) is slightly greater than 70%.

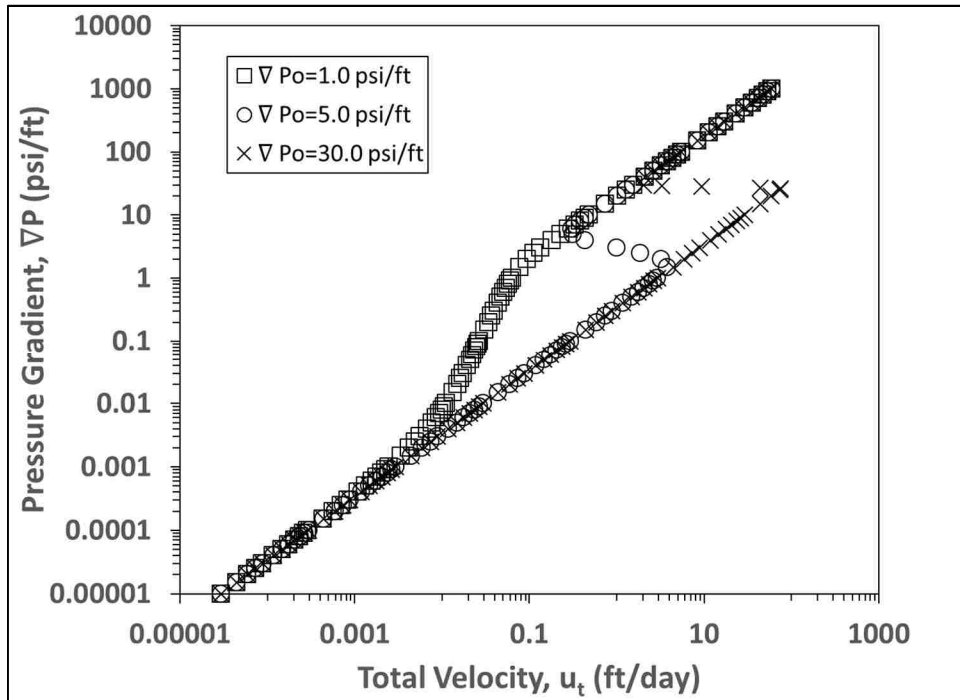
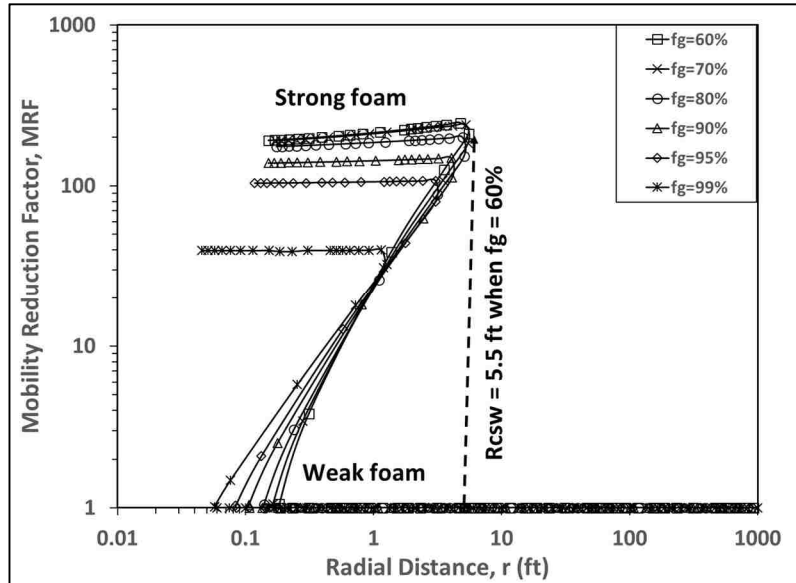


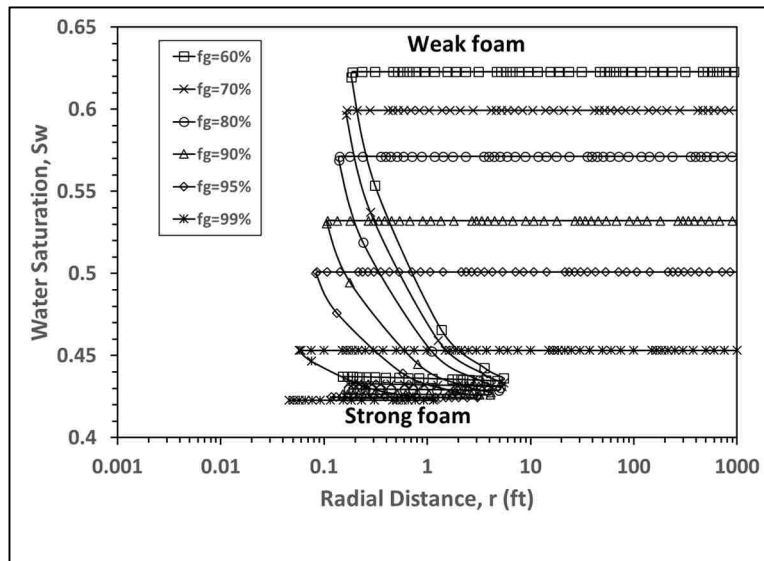
Figure 3.3. Foam flow characteristics showing three foam states (strong-foam, weak-foam, and intermediate state) at the mobilization pressure gradient ( $\nabla P_o$ ) of 1.0, 5.0, and 30.0 psi/ft (injection foam quality ( $f_g^{in}$ ) = 70%).

Figures 3.4(a) and 3.4(b) show the steady-state response of mobility reduction factor (MRF) and water saturation ( $S_w$ ) as a function of radial distance ( $r$ ) when  $\nabla P_o = 30.0$  psi/ft. The results show folding curves that are consistent with three foam states. Strong foam that is injected at the center of the cylindrical reservoir propagates further out up to the

point where the curves fold back, beyond which the strong foam turns into weak foam. This point, as described in Figure 3.2, is called  $R_{CSW}$ . For example, for  $f_g = 60\%$ , MRF remains high (between 200 and 300) and  $S_w$  remains low (between 43 and 44%), which is a typical response for strong foam, until  $r = R_{CSW}$  (about 5.5 ft). For  $r > R_{CSW}$ , MRF remains low and  $S_w$  remains high, which is a typical response for weak foam. The portion of the curves folding back (representing the intermediate state) and the weak-foam portion of the curves for  $r < R_{CSW}$  do not appear explicitly, because they are hidden solutions (Gauglitz et al. 2002). Similar aspects are shown in Figures. 3.5(a) and 3.5(b) when  $\nabla P_o = 5.0$  psi/ft with  $R_{CSW}$  about 39.7 ft.

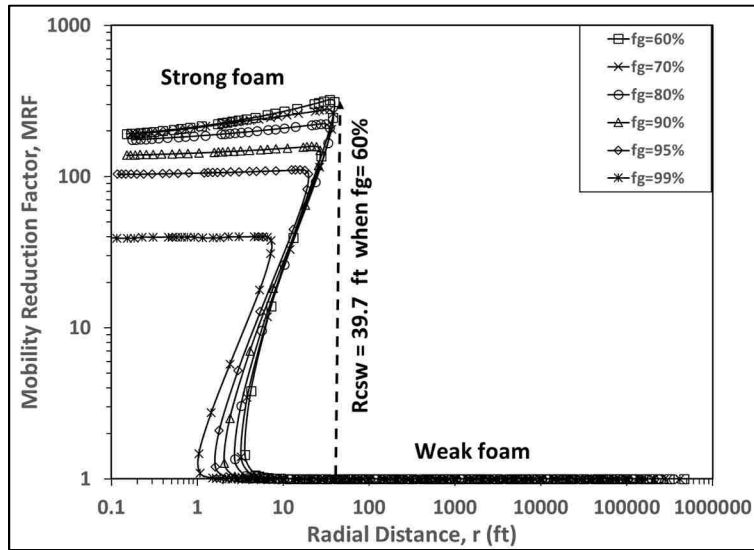


(a)

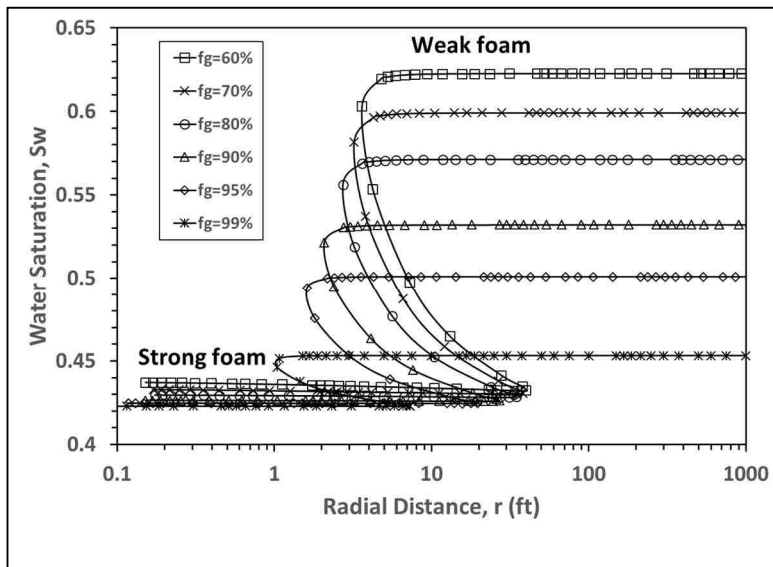


(b)

Figure 3.4. Results showing foam propagation distance for strong foam to convert into weak foam ( $R_{csw}$ ) ( $q_t^{in} = 17,970$  ft<sup>3</sup>/day in a range of  $f_g^{in}$ ) at the mobilization pressure gradient ( $\nabla P_o$ ) of 30.0 psi/ft: (a) MRF vs. radial distance and (b)  $S_w$  vs. radial distance.



(a)



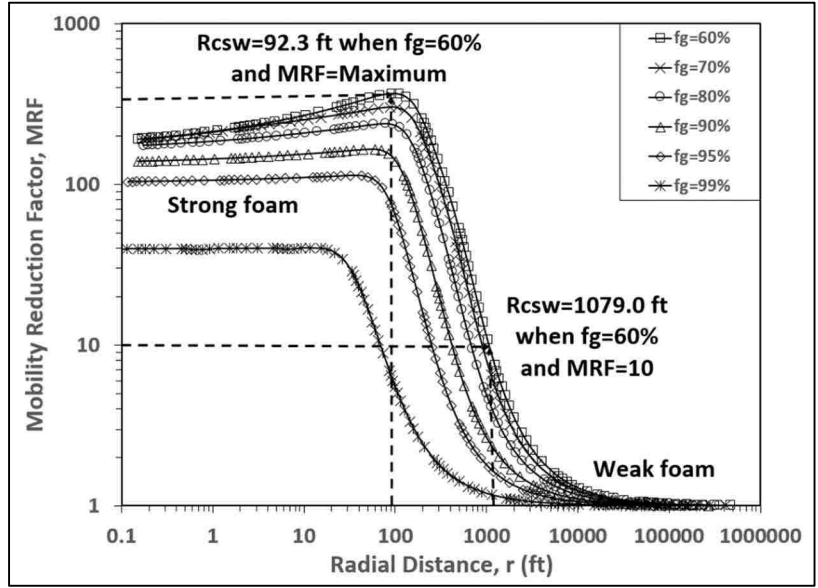
(b)

Figure 3.5. Results showing foam propagation distance for strong foam to convert into weak foam ( $R_{csw}$ ) ( $q_t^{in} = 17,970$  ft<sup>3</sup>/day in a range of  $f_g^{in}$ ) at the mobilization pressure gradient ( $\nabla P_o$ ) of 5.0 psi/ft: (a) MRF vs. radial distance and (b)  $S_w$  vs. radial distance.

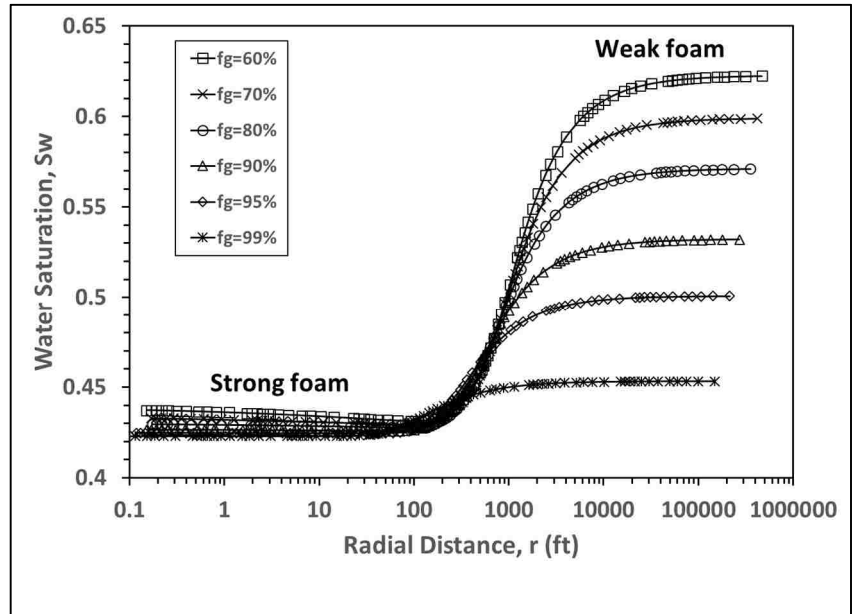
A couple of interesting observations can be made in Figures 3.4 and 3.5 that investigate a range of  $f_g$  at  $q_t^{in} = 17,970 \text{ ft}^3/\text{day}$  and  $H = 275 \text{ ft}$ . First, the cases of  $\nabla P_o = 30.0$  and  $5 \text{ psi/ft}$  allow foam propagation distance of only about  $5.5$  and  $39.7 \text{ ft}$ , respectively, which seems to be unacceptable in most EOR field applications. Second, thinking of the fact that  $q_t^{in}$  is proportional to " $H \times R_{CSW}$ ", this could be translated into  $55$  and  $397 \text{ ft}$  (or,  $R_{CSW}$  10 times higher) if the reservoir thickness were  $27.5 \text{ ft}$  (or,  $H$  10 times lower), which then becomes quite acceptable. Last, for strong foams in the low-quality regime ( $f_g = 60$  and  $70\%$ ) at  $r < R_{CSW}$ , MRF values are comparable and  $R_{CSW}$  values are almost the same. On the contrary, for strong foams in the high-quality regime ( $f_g = 80, 90, 95$  and  $99\%$ ) at  $r < R_{CSW}$ , both MRF and  $R_{CSW}$  values decrease sensitively as foam becomes drier. This demonstrates the importance of injection foam quality: (i) propagation of dry foam becomes increasingly more difficult with increasing foam quality and (ii) even when relatively wet foam is required for propagation of stable foams, there is not much benefit of going below  $f_g^*$ . The former is because of foam instability at high foam quality, and the latter is because of foam texture near its maximum if the condition falls in the low-quality regime. Figures 3.6(a) and 3.6(b) show the steady-state response of mobility reduction factor (MRF) and water saturation ( $S_w$ ) as a function of radial distance ( $r$ ) when  $\nabla P_o = 1.0 \text{ psi/ft}$ . The results do not show the intermediate state in this case; rather, in both MRF and  $S_w$  plots, the transition from the strong foam to weak foam takes place progressively with radial distance.



One complication with low  $\nabla P_o$  is that there is no clear cut for  $R_{CSW}$  because the curve does not fold back. Thus,  $R_{CSW}$  is evaluated in two different ways in such a case: (i)  $R_{CSW}$  determined based on the maximum MRF and (ii)  $R_{CSW}$  determined based on a pre-specified MRF value that is still meaningful in the field applications (MRF = 10 seems to serve as a reasonable target as chosen by this study). Of course, the former (cut-off based on maximum MRF) provides much more conservative  $R_{CSW}$  values than the latter (cut-off based on MRF=10). Note that the former (cut-off based on maximum MRF) is in some sense consistent with the earlier examples with folding-back curves (Figures 3.4 and 3.5), but the latter (cut-off based on MRF=10) seems more reasonable way to account for the benefits of lower  $\nabla P_o$  (One may choose MRF value other than 10 such as 20 or 50, but the major findings remain the same).



(a)



(b)

Figure 3.6. Results showing foam propagation distance for strong foam to convert into weak foam ( $R_{csw}$ ) ( $q_t^{in} = 17,970$  ft<sup>3</sup>/day in a range of  $f_g^{in}$ ) at the mobilization pressure gradient ( $\nabla P_o$ ) of 1.0 psi/ft: (a) MRF vs. radial distance and (b)  $S_w$  vs. radial distance.

An example is shown in Figure 3.6(a) where two horizontal lines determine two different cut-off points, and therefore two different  $R_{CSW}$  values. For  $f_g = 60\%$ , the cut-off based on maximum MRF gives  $R_{CSW} = 92.3$  ft, while the cut-off based on MRF=10 gives  $R_{CSW} = 1079.0$  ft. This proves the benefit of injecting  $CO_2$  with low  $\nabla P_o$  values – that way, supercritical  $CO_2$  foam can travel a quite significant distance before turning into weak foam. Except  $f_g = 99\%$ , all other foam qualities ranging from 60 to 90% allow stable foam to propagate as much as hundreds or thousands of feet easily, if MRF=10 is used as a cut-off line. Once the results similar to Figures 3.4 through 3.6 are constructed, the use of contour plot offers a convenient means to predict how far strong foam propagates before turning into weak foam ( $R_{CSW}$ ) as a function of total injection rate and injection foam quality. Such a contour plot, shown in Figures 3.7 through 3.10, is especially helpful to guide field implementation of foam EOR processes (These contours are constructed based on the calculated values at the positions specified by blue open circles (Figures 3.7 through 3.10)). Note that  $R_{CSW}$  values in these plots are for the reservoir thickness (H) of 275 ft – for other reservoir thickness, the new propagation distance then becomes  $(H \times R_{CSW})/h$ , h being the new thickness of interest, at given  $q_t^{in}$  and  $f_g^{in}$ .

Figures 3.7 and 3.8 show the contours of propagation distance ( $R_{CSW}$ ) at  $\nabla P_o = 30.0$  and 5.0 psi/ft, respectively. The contour plots show the values of  $R_{CSW}$  in [ft] at different combinations of  $q_t^{in}$  and  $f_g^{in}$  (H = 275 ft). The results show that one can make strong foam propagate more, by using higher  $q_t^{in}$  if  $f_g^{in}$  is fixed, or lower  $f_g^{in}$  if  $q_t^{in}$  is fixed. The sensitivity of  $R_{CSW}$  to  $f_g^{in}$  at given  $q_t^{in}$  becomes more significant as foam becomes drier in general,

while such a tendency is negligible when foam is wet enough, especially  $f_g^{in} < f_g^*$  (i.e., foams in the low-quality regime ( $f_g^*=70\%$ )). Figures 3.9 and 3.10 show the contours of propagation distance ( $R_{csw}$ ) at  $\nabla P_o = 1.0$  psi/ft, using the cut-off based on maximum MRF and MRF = 10, respectively. The same trend as shown in Figures 3.7 and 3.8 is observed. As discussed earlier, the use of CO<sub>2</sub> foams with lower  $\nabla P_o$  (see Equation 3.1) seems much more advantageous when it comes to foam placement deep in the reservoir.

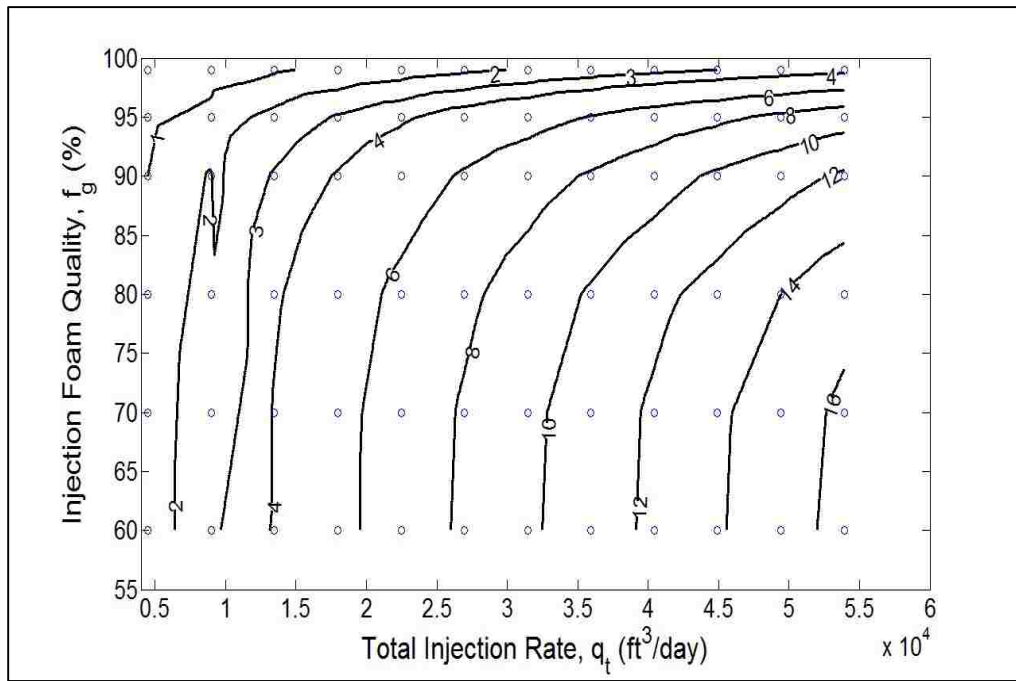


Figure 3.7. Contour plot of strong-foam propagation distance (ft) before turning into weak foam ( $R_{csw}$ ) based on bubble population balance model at the mobilization pressure gradient ( $\nabla P_o$ ) of 30.0 psi/ft (reservoir thickness ( $H$ ) = 275 ft).

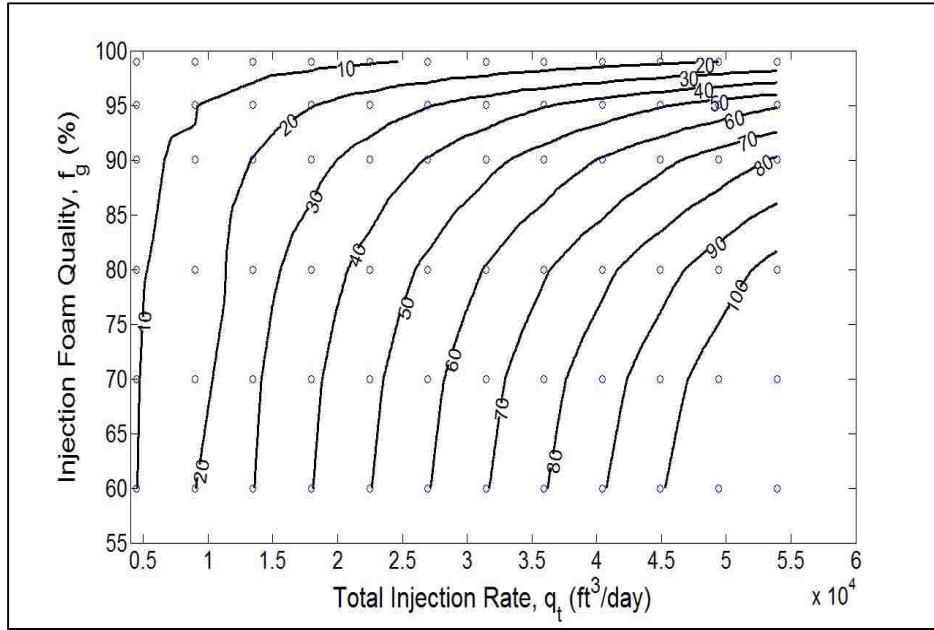


Figure 3.8. Contour plot of strong-foam propagation distance (ft) before turning into weak foam ( $R_{CSW}$ ) based on bubble population balance model at the mobilization pressure gradient ( $\nabla P_0$ ) of 5.0 psi/ft (reservoir thickness ( $H$ ) = 275 ft).

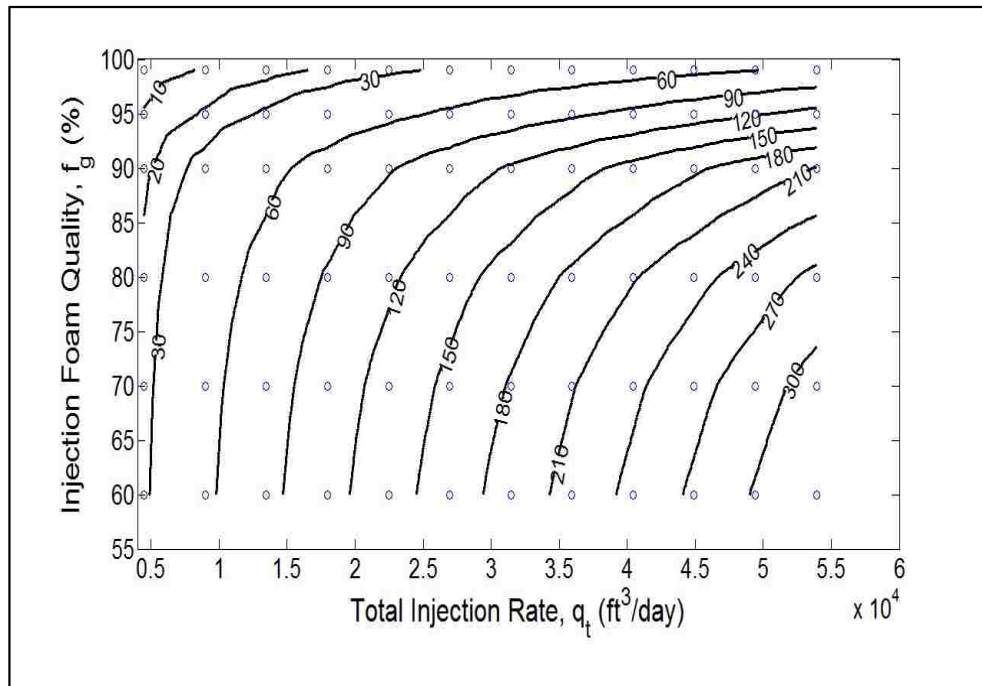


Figure 3.9. Contour plot of strong-foam propagation distance (ft) before turning into weak foam ( $R_{CSW}$ ) based on bubble population balance model at the mobilization pressure gradient ( $\nabla P_0$ ) of 1.0 psi/ft (reservoir thickness ( $H$ ) = 275 ft): cut-off based on maximum MRF.

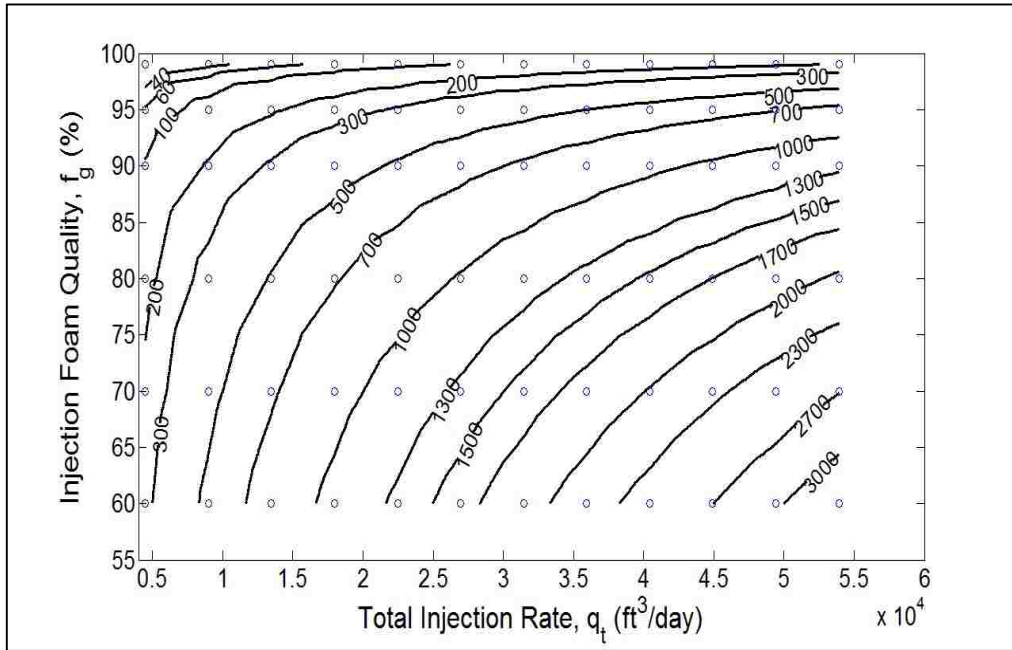


Figure 3.10. Contour plot of strong-foam propagation distance (ft) before turning into weak foam ( $R_{CSW}$ ) based on bubble population balance model at the mobilization pressure gradient ( $\nabla P_0$ ) of 1.0 psi/ft (reservoir thickness ( $H$ ) = 275 ft): cut-off based on  $MRF = 10$ .

### 3.4.2. Propagation distance based on gravity segregation ( $R_{gs}$ )

In addition to the conversion to weak foam, foam propagation is also limited by gravity segregation. This section deals with how to determine the distance before foam segregates into gas and liquid ( $R_{gs}$ ) in two different methods: Stone and Jenkins model and CMG-STARs simulation. The former is a simplified approach assuming fixed values of reservoir and fluid properties, and the latter is more realistic, but complicated, approach accounting for those properties as a function of pressure, temperature, and radial and vertical locations. To evaluate  $R_{gs}$ , the same cylindrical reservoir is selected as shown in the previous section (Table 3.3). Because both methods assume a fixed and constant value of  $MRF$  in the mixed region (even though it is not true physically as shown in Figures

3.4 through 3.6), the results from the mechanistic foam modelling in the previous section are used as input parameters. More specifically, for the mixed region properties, the Stone and Jenkins model uses the maximum MRF value (see Figures 3.4(a) through 3.6(a)) and its corresponding  $S_w$  value (see Figures 3.4(b) through 3.6(b)) to determine  $R_{gs}$ . This means, for example, MRF = 240 for  $\nabla P_0 = 30.0$  psi/ft, MRF = 278 for  $\nabla P_0 = 5.0$  psi/ft, and MRF = 303 for  $\nabla P_0 = 1.0$  psi/ft, when  $f_g^{in} = 70\%$ , while MRF = 149 for  $\nabla P_0 = 30.0$  psi/ft, MRF = 158 for  $\nabla P_0 = 5.0$  psi/ft, and MRF = 165 for  $\nabla P_0 = 1.0$  psi/ft, when  $f_g^{in} = 90\%$  ( $q_t^{in}$  remains the same at 17,970 ft<sup>3</sup>/day). In CMG-STARS simulations,  $R_{gs}$  is determined by using these MRF values but letting  $S_w$  values be calculated by the simulator. These  $S_w$  values calculated by the simulator are essentially the same as those  $S_w$  values used for input in the Stone and Jenkins model in Figures 3.4(b) through 3.6(b).

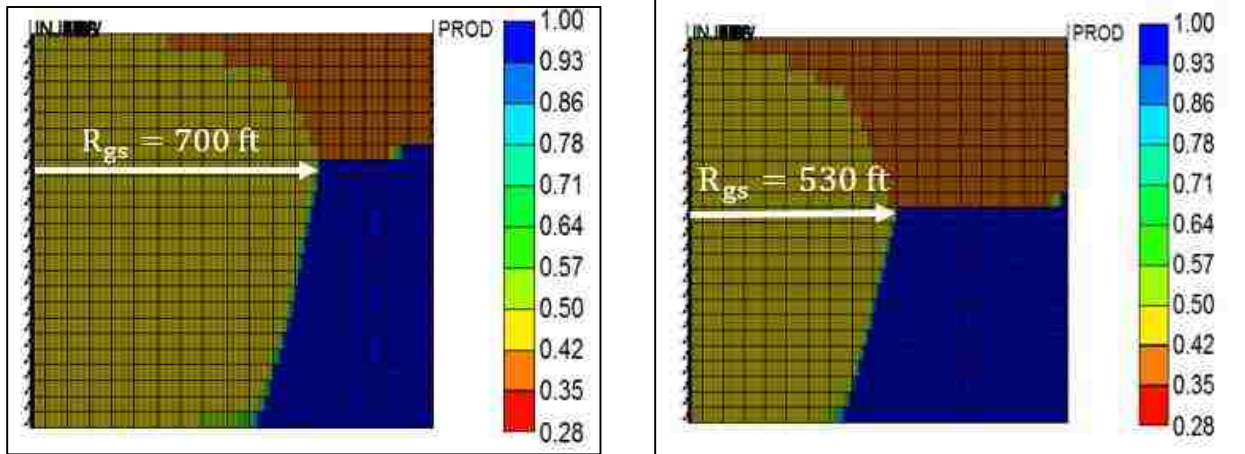
Figures 3.11 through 3.13 show the results of CMG-STARS simulations to evaluate the cases of  $\nabla P_0 = 30.0, 5.0,$  and  $1.0$  psi/ft, respectively, at  $f_g^{in} = 70$  and  $90\%$  ( $q_t^{in} = 17,970$  ft<sup>3</sup>/day). In all cases, the reservoir has wellbore radius ( $r_w$ ) of 0.42 ft, radial distance to the reservoir boundary ( $r_e$ ) of 1000.0 ft, and reservoir thickness of 275.0 ft. Gas and surfactant solutions, which create strong foam inside the well, are co-injected at the total injection rate ( $q_t^{in}$ ) of 17,970 ft<sup>3</sup>/day into the reservoir initially saturated with water. The two injection foam qualities ( $f_g^{in}$ ), 70% and 90%, are chosen to represent wet-foam and dry-foam scenarios (or, foams in the low-quality regime and in the high-quality regime) respectively. These results are based on 4,000 days of foam injection, which is shown to be (near) steady-state results after some trial-and-error simulations. Additional input

parameters specific to CMG-STARS for this simulation task are shown in Table 3.5 (See CMG (2016) for more details on these parameters).

Table 3.4. Additional foam simulation parameters required by CMG-STARS for gravity-segregation simulation (See CMG (2016) for more details).

Parameter	Value	Parameter	Value
FMSURF	$1.4389 \times 10^{-5}$	EPOIL	0
FMCAP	0	EPGCP	0
FMOIL	0	SFDRY*	0.425-0.441
FLOIL	0	SFBET	600
FMGCP	0	SFSURF	0
FMMOB*	174	EFSURF	0
EPSURF	4	SFCAP	0
EPCAP	0	EFCAP	0

\* Values from mechanistic modelling in the previous section (Figures 3.4 through 3.6)

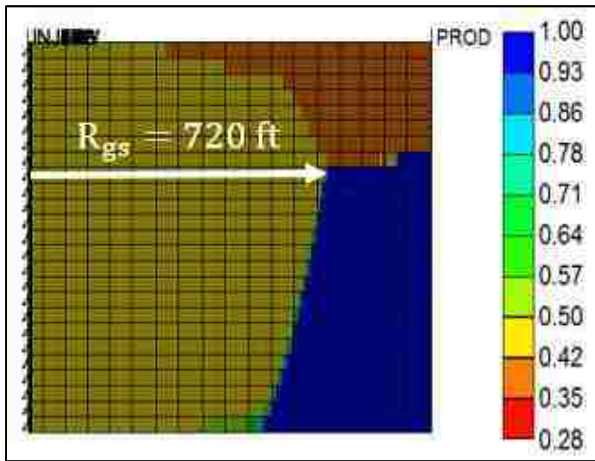


(a)

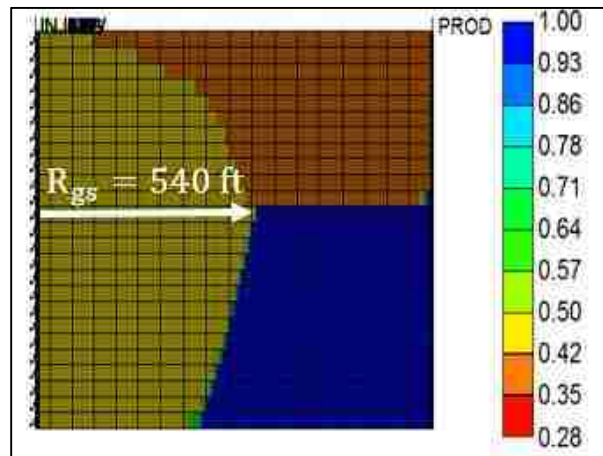
(b)

Figure 3.11. Simulation results showing foam propagation distance before gravity segregation ( $R_{gs}$ ) when the mobilization pressure gradient ( $\nabla P_o$ ) is 30.0 psi/ft: (a)  $f_g^{in} = 70\%$  at MRF=240 and (b)  $f_g^{in} = 90\%$  at MRF=149 (Stone and Jenkins model predicts  $R_{gs} = 801$  and  $701$  ft respectively).



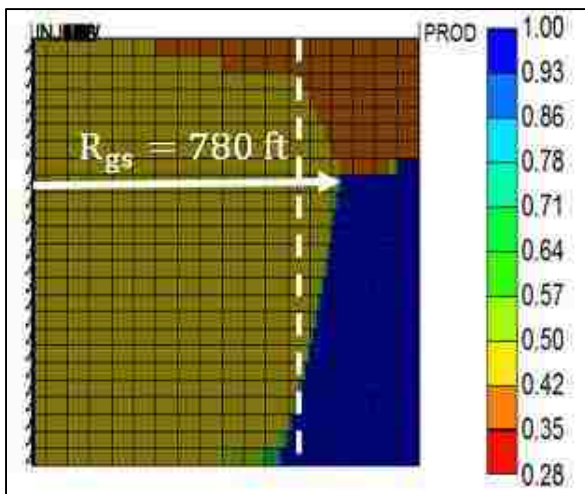


(a)

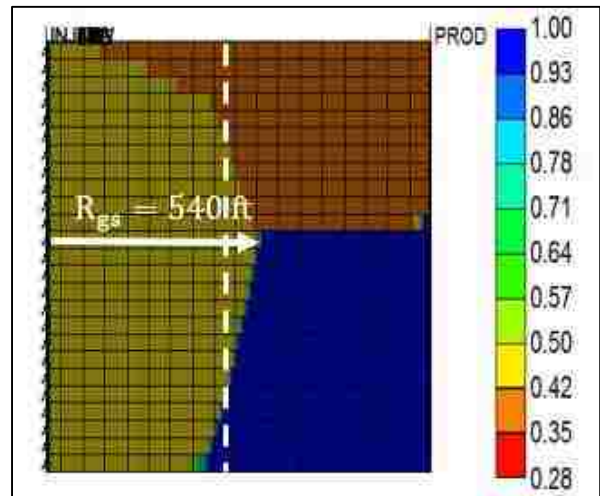


(b)

Figure 3.12. Simulation results showing foam propagation distance before gravity segregation ( $R_{gs}$ ) when the mobilization pressure gradient ( $\nabla P_o$ ) is 5.0 psi/ft: (a)  $f_g^{in} = 70\%$  at MRF=278 and (b)  $f_g^{in} = 90\%$  at MRF=158 (Stone and Jenkins model predicts  $R_{gs} = 858$  and 720 ft, respectively).



(a)



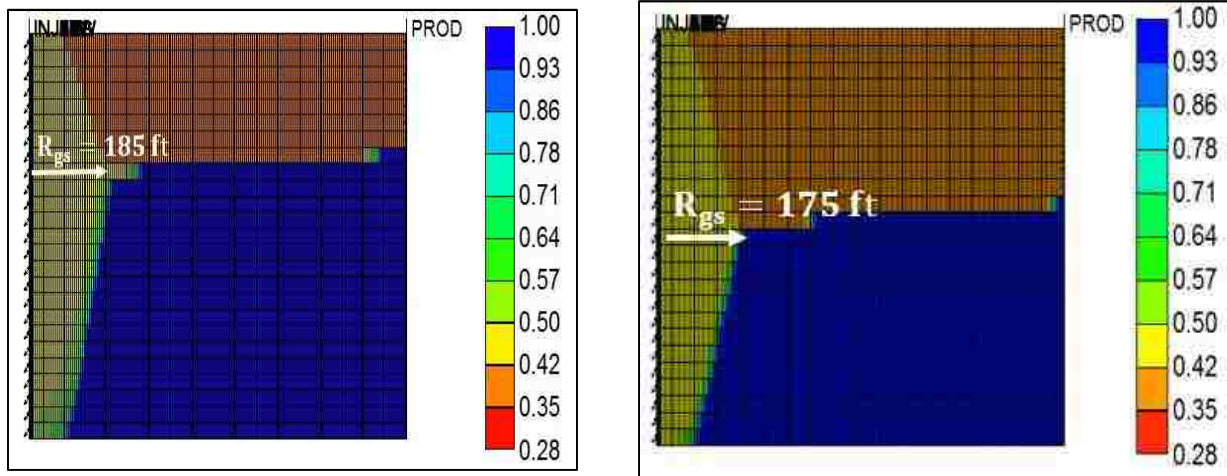
(b)

Figure 3.13. Simulation results showing foam propagation distance before gravity segregation ( $R_{gs}$ ) when the mobilization pressure gradient ( $\nabla P_o$ ) is 1.0 psi/ft (cut-off based on maximum MRF): (a)  $f_g^{in} = 70\%$  at MRF=303 and (b)  $f_g^{in} = 90\%$  at MRF=165 (Stone and Jenkins model predicts  $R_{gs} = 884$  and 734 ft, respectively).

Figure 3.11 shows simulation results in terms of the steady-state water saturation for  $\nabla P_o = 30.0$  psi/ft. When the injection foam qualities ( $f_g^{in}$ ) are 70% (Figure 3.11(a)) and 90% (Figure 3.11(b)), the corresponding MRF values are about 240 and 149 (see Figure 3.4(a)), with  $R_{gs}$  from simulations leading to 700 and 530 ft, respectively. Drawing horizontal lines from the injection well to the contact point of the three regions, the water saturations in the mixed region are 0.430 and 0.426 in Figure 3.11(a) and 3.11(b), respectively. For the same case, the Stone and Jenkins model predicts  $R_{gs}$  values of 801 and 701 ft for  $f_g^{in} = 70\%$  and  $90\%$ , respectively. Although there is some difference, the results are comparable showing the same trend. It is believed that the difference is caused by multiple aspects including changes in fluid properties (density, viscosity, compressibility, etc.) as well as simulation artifacts at the injection and production wells (fluid redistribution at the inlet face, capillary end effect, etc.), and as a result the simulation slightly underpredicts  $R_{gs}$  compared to the Stone and Jenkins model. Figure 3.12 shows similar simulation results for  $\nabla P_o = 5.0$  psi/ft. For the injection foam qualities ( $f_g^{in}$ ) of 70% (Figure 3.12(a)) and 90% (Figure 3.12(b)), the corresponding MRF values are 278 and 158 (see Figure 3.5(a)), the  $S_w$  values are 0.430 and 0.426, and the  $R_{gs}$  values are 720 and 540 ft, respectively. The Stone and Jenkin's model predicts  $R_{gs}$  of 858 and 720 ft. Once again, the trend is well captured, and the simulation predicts somewhat lower  $R_{gs}$  values compared to the Stone and Jenkin's model.

Figure 3.13 shows the steady-state simulation results for  $\nabla P_o = 1.0$  psi/ft with the cut-off based on maximum MRF. For the injection foam qualities ( $f_g^{in}$ ) of 70% (Figure

3.13(a)) and 90% (Figure 3.13(b)), the corresponding MRF values are 303 and 165 (see Figure 3.6(a)), the  $S_w$  values are 0.429 and 0.426, and the  $R_{gs}$  values are 780 and 540 ft, respectively. The Stone and Jenkin's model predicts  $R_{gs}$  of 884 and 734 ft. The results are consistent with other cases. Figure 3.14 shows simulation results for  $\nabla P_o = 1.0$  psi/ft with the cut-off based on  $MRF=10$ . This situation is somewhat tricky, because the mechanistic modeling results in Figure 3.6(a) show that the MRF values are mostly much greater than 10 for the region occupied by strong foams. Even so, it is believed to provide a useful insight when compared with Figure 3.13. For the injection foam qualities ( $f_g^{in}$ ) of 70% (Figure 3.14(a)) and 90% (Figure 3.14(b)) both with  $MRF = 10$ , the simulation shows the  $S_w$  values of 0.494 and 0.456, and the  $R_{gs}$  values of 185 and 175 ft, respectively. The Stone and Jenkin's model predicts  $R_{gs}$  of 211 and 204 ft. These  $R_{gs}$  values in Figure 3.14 are less than those in Figure 3.13, because the use of smaller MRF (i.e.,  $MRF = 10$  in Figure 3.14) provides lower pressure gradient ( $\nabla P$ ), resulting in lower  $R_{gs}$ .

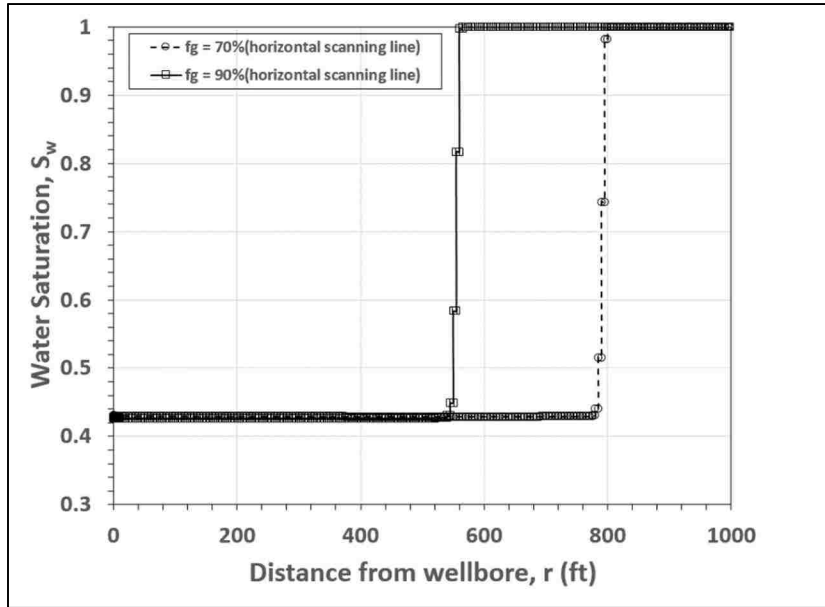


(a)

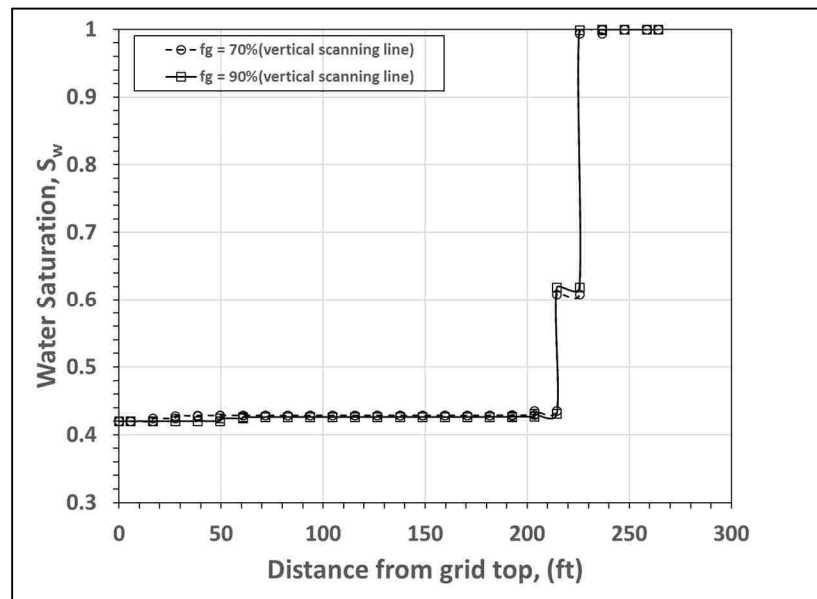
(b)

Figure 3.14. Simulation results showing foam propagation distance before gravity segregation ( $R_{gs}$ ) when the mobilization pressure gradient ( $\nabla P_o$ ) is 1.0 psi/ft (cut-off based on MRF=10): (a)  $f_g^{in} = 70\%$  at MRF=10 and (b)  $f_g^{in} = 90\%$  at MRF=10 (Stone and Jenkins model predicts  $R_{gs} = 211$  and 204 ft, respectively).

In order to verify the assumption of constant water saturation in the three constant regions in the Stone and Jenkins model, scanning the saturation map in vertical and horizontal directions works as a convenient means. As shown in each of Figures 3.13(a) and 3.13(b), one horizontal line through the contact point of three regions (not shown, but the same as the horizontal arrows shown) and the other vertical line somewhat before the contact point, where  $r < R_{gs}$ , are selected as an example. Figure 3.15 shows the change in water saturation along the vertical and horizontal scanning lines (shown in Figure 3.13) from the simulations. It clearly shows three different constant state regions – the gas override region where  $S_w$  is near  $S_{wc}$ , the water underdrive region where  $S_w$  is near  $1 - S_{gr}$ , and the mixed region in between with foams at its steady-state  $S_w$  that matches with MRF values from mechanistic model.



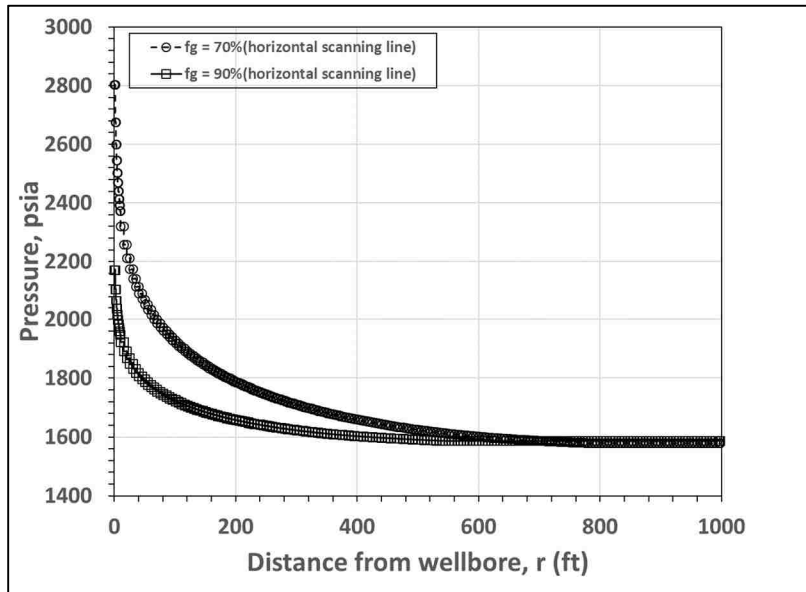
(a)



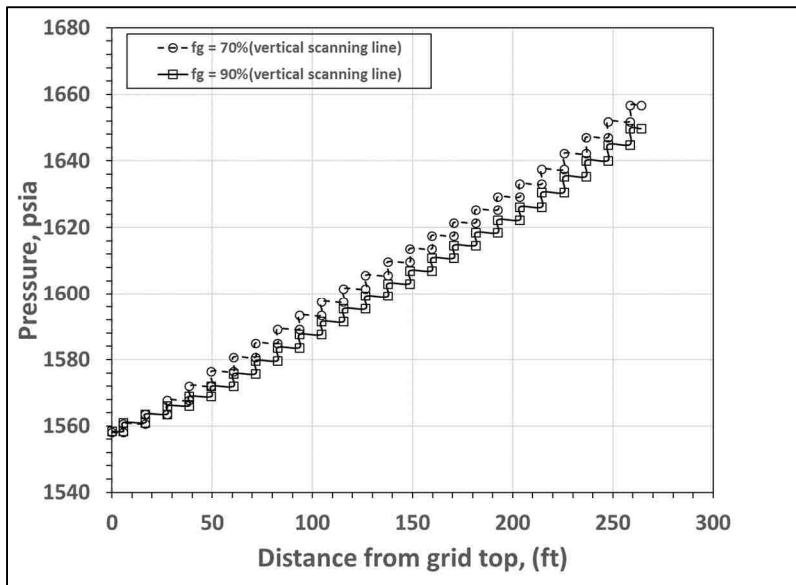
(b)

Figure 3.15. Steady-state water saturation profiles along the scanning lines (horizontal (a), vertical (b)) in Figure 3.13 from gravity-segregation simulations showing three constant regions as approximated by Stone and Jenkins model (1982, 1984).

Figure 3.16 shows the pressure profiles for the same scanning lines as shown in Figure 3.13. The pressure decreases sharply along the horizontal scanning line up to  $r = R_{gs}$  because of high MRF value in the presence of foams, followed by mild change to the outlet because of single-phase flow of water. The pressure profile along the vertical direction follows hydrostatic pressure gradient concept (higher hydrostatic pressure gradient in the underdrive region, and lower hydrostatic pressure gradient in the override and mixed foam regions). Figure 3.17 shows how the bottomhole injection pressure changes for those examples shown in Figures. 3.15 and 3.16, until it reaches 4,000 days of foam injection that is believed to be at, or close to, the steady state after some trial-and-error simulations. In both cases, the Injection pressure rapidly increases with time in the beginning as strong foam enters, and then levels off gradually as the system approaches the steady state. The cases with higher MRF have higher injection pressures. Note that the outlet back pressure is 1555.0 psia. Similar to  $R_{csw}$  contours in Figures 3.7 through 3.10, the results from the Stone and Jenkins model for  $R_{gs}$  can be plotted as a function  $q_t^{in}$  and  $f_g^{in}$  as well. Figures 3.18 through 3.21 show how far foam propagates before gravity segregation ( $R_{gs}$ ) when the MRF values are borrowed from the mechanistic foam model for  $\nabla P_o = 30.0, 5.0, \text{ and } 1.0$  (cut-off based on maximum MRF and cut-off based on  $MRF = 10$ ) psi/ft (Figures 3.7 through 3.10), respectively. It is interesting to find that  $R_{gs}$  is also very sensitive to  $f_g^{in}$ , i.e., it is becoming increasingly difficult to make drier foams propagate deep into the reservoir, while such a sensitivity is much less for relatively wet foams. Similar to  $R_{csw}$  contours,  $R_{gs}$  contours also show longer propagation distance at high injection rate (or higher injection pressure, equivalently).



(a)



(b)

Figure 3.16. Steady-state pressure profiles along the scanning lines (horizontal (a), vertical (b)) in Figure 3.13 from gravity-segregation simulations showing three constant regions as approximated by Stone and Jenkins model (1982,1984).

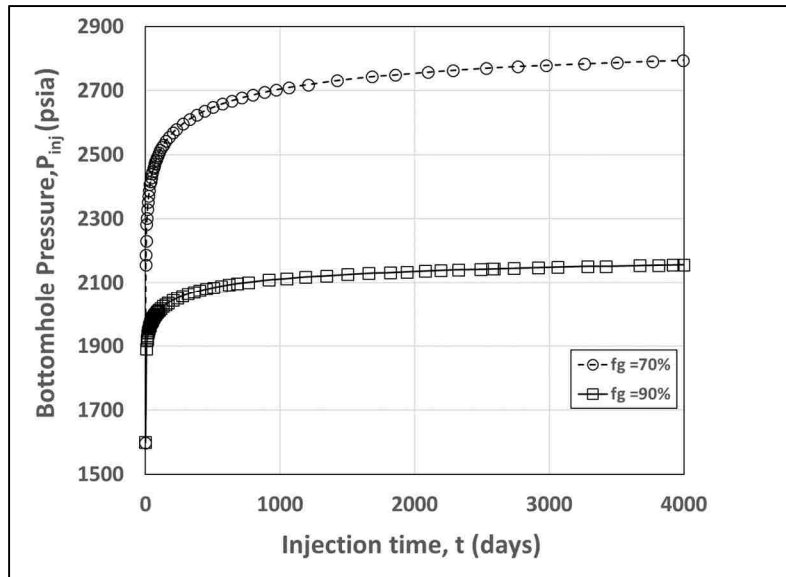


Figure 3.17. Change in bottomhole injection pressure with time simulated by CMG-STARS to reach (close to) the steady state at 4000 days of foam injection.

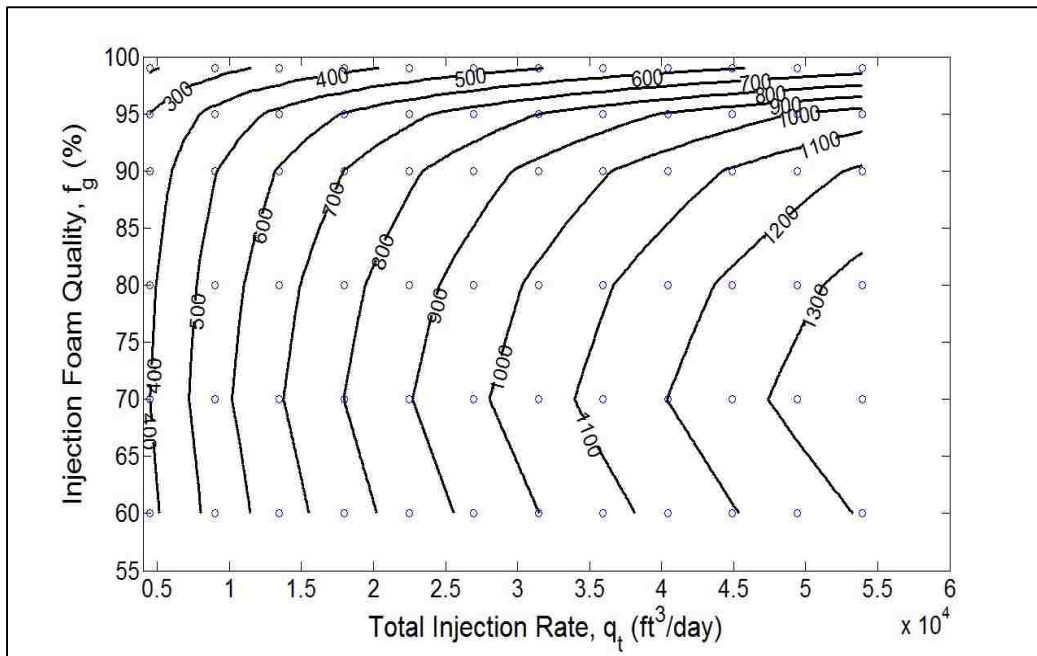


Figure 3.18. Contour plot of foam propagation distance (ft) before gravity segregation ( $R_{gs}$ ) based on Stone and Jenkins model (MRF taken from mechanistic foam model at the mobilization pressure gradient ( $\nabla P_0$ ) of 30.0 psi/ft).



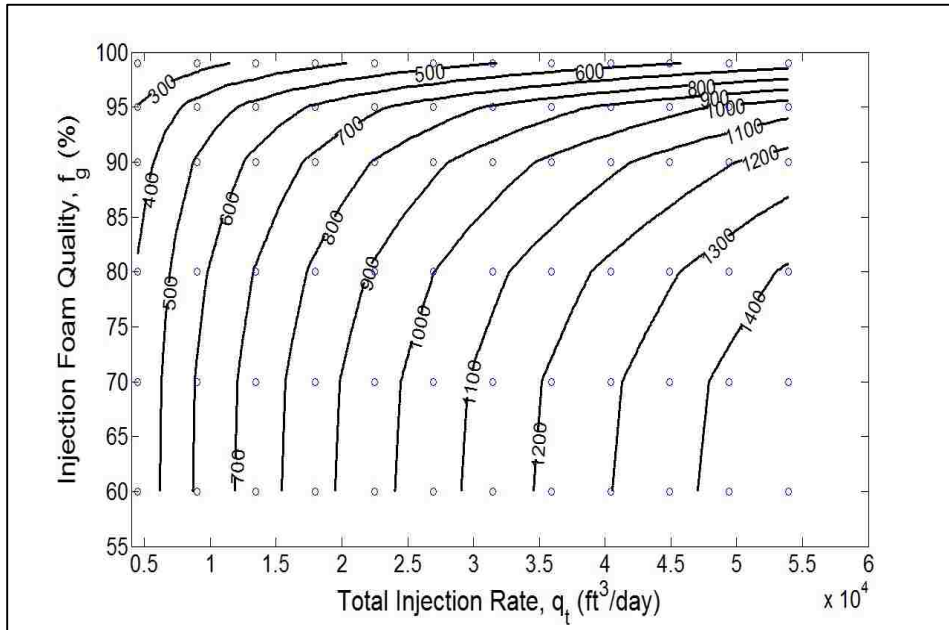


Figure 3.19. Contour plot of foam propagation distance (ft) before gravity segregation ( $R_{gs}$ ) based on Stone and Jenkins model (MRF taken from mechanistic foam model at the mobilization pressure gradient ( $\nabla P_o$ ) of 5.0 psi/ft).

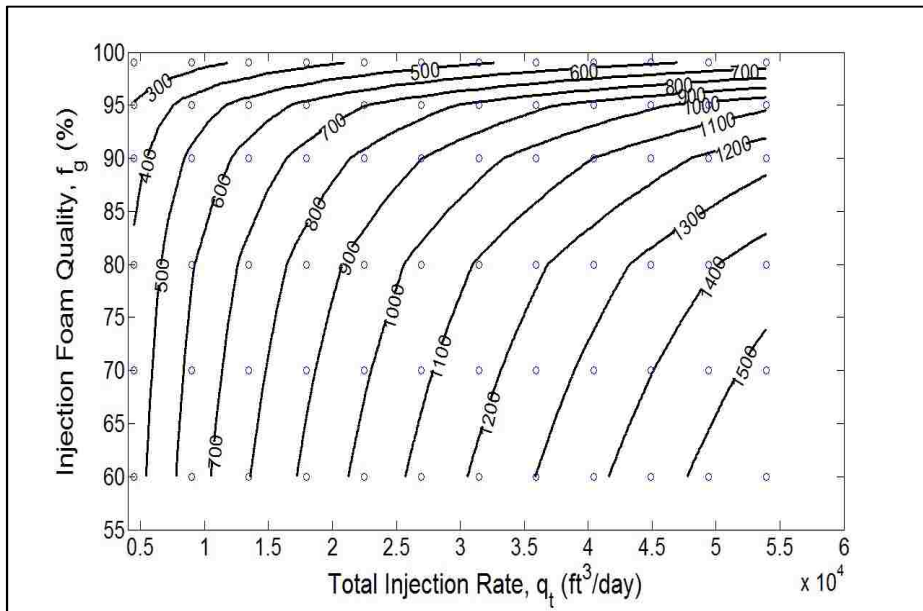


Figure 3.20. Contour plot of foam propagation distance (ft) before gravity segregation ( $R_{gs}$ ) based on Stone and Jenkins model (MRF taken from mechanistic foam model at the mobilization pressure gradient ( $\nabla P_o$ ) of 1.0 psi/ft (cut-off based on maximum MRF)).

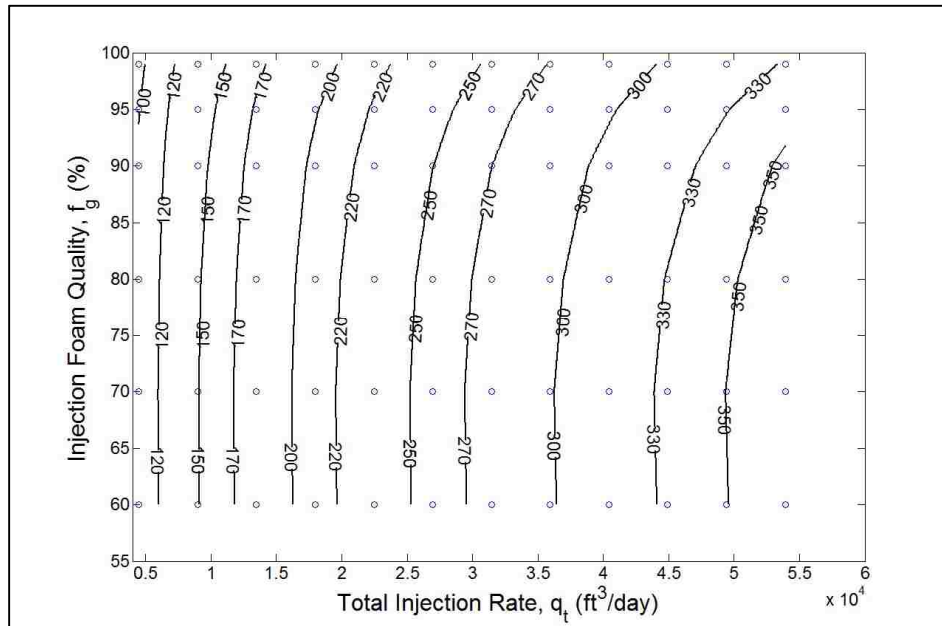


Figure 3.21. Contour plot of foam propagation distance (ft) before gravity segregation ( $R_{gs}$ ) based on Stone and Jenkins model (MRF taken from mechanistic foam model at the mobilization pressure gradient ( $\nabla P_0$ ) of 1.0 psi/ft (cut-off based on MRF = 10).

### 3.4.3. Combined results and discussions

The two mechanisms that limit foam propagation in the field-scale foam EOR can be analyzed together based on the results given in the previous sections. Figures 3.22 and 3.23 show such results at the injection foam qualities ( $f_g^{in}$ ) of 70% and 90%, respectively, for  $\nabla P_0 = 30.0, 5.0,$  and  $1.0$  as well as  $\nabla P_0 = 0.1$  psi/ft. Note that when  $\nabla P_0$  is low (1.0 and 0.1 psi/ft), both results from the cut-off line based on maximum MRF as well as MRF = 10 are used. Note in such cases that the results at MRF = 10 overpredicts  $R_{CSW}$  compared to maximum MRF (see Figure 3.6), while the results at MRF = 10 underpredicts  $R_{gs}$  compared to maximum MRF because of lower lateral pressure gradient (see Figures 3.20 and 3.21). Both figures show that there is a threshold value

(or, range) of  $\nabla P_0$ , below which foam propagation is limited by gravity segregation ( $R_{gs}$ ) and above which foam propagation is limited by the conversion of strong foam to weak foam ( $R_{csw}$ ). Because of relatively steep slope in  $R_{csw}$  curve, foam injection conditions at lower  $\nabla P_0$  (i.e., left-hand side of the figure) have advantages in placing foams deep into the reservoir. Foam propagation distance is less sensitive to  $\nabla P_0$  at lower  $\nabla P_0$ , while foam propagation distance can still be improved significantly by making  $\nabla P_0$  lower at higher  $\nabla P_0$ . Comparing Figures 3.22 and 3.23, it also shows foams in the high-quality regime is more difficult to be placed deep in the reservoir than foams in the low-quality regime. Note from Equation 3.1 that lower  $\nabla P_0$  translates lower interfacial tension and higher pore throat size, which can be achieved more easily at higher pressure, with better foamer, and at higher absolute permeability.

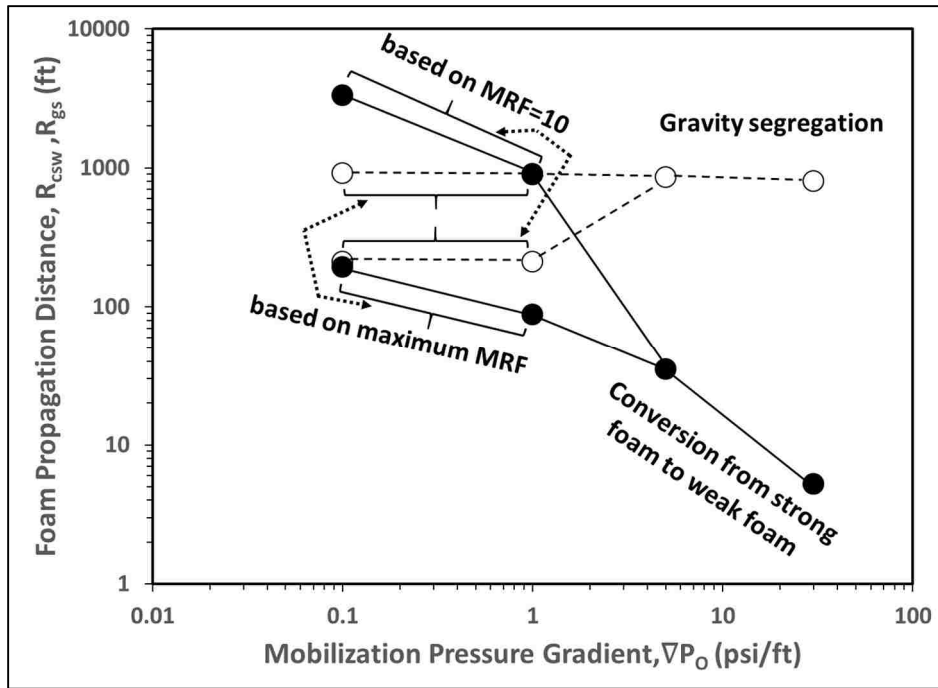


Figure 3.22. Prediction of propagation distance (ft) of 70% quality foams by combining both mechanisms (conversion to weak foam vs. gravity segregation).

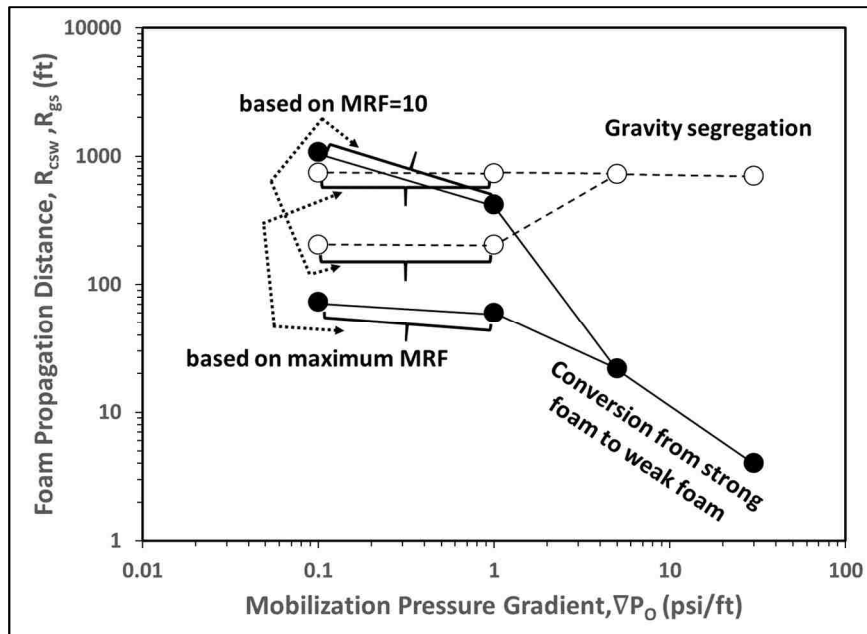


Figure 3.23. Prediction of propagation distance (ft) of 90% quality foams by combining both mechanisms (conversion to weak foam vs. gravity segregation).

This study greatly improves the prediction of  $R_{gs}$ , by using representative MRF values from mechanistic foam model. At the same time, it should be pointed out that, there still is room to improve the prediction further, because both Stone and Jenkins model and CMG simulation assume constant values of MRF as an input parameter (see Equations 3.3 and 3.4). When it comes to possible errors associated with a constant-MRF assumption, the case with lower  $\nabla P_0$  (Figure 3.6) would show more errors than the case with higher  $\nabla P_0$  (Figures 3.4 or 3.5), because it presents a continuous and progressive change from strong-foam to weak-foam state without showing hysteretic behaviors (i.e., multi-valued foam rheology surface that folds back and forth). A three-dimensional reservoir simulation with mechanistic modeling capability is believed to reduce the gap

essentially. Even though this study shows how foam propagates in a large system, the results are limited to homogeneous cylindrical reservoirs at the moment. In order to take the results to the real-world field cases, there are challenges to overcome, including (but not limited to) heterogeneity of the system and interaction between foams and reservoir oils. The major finding of this study, however, still holds true – foams with lower  $\nabla P_0$  (e.g. supercritical CO<sub>2</sub> foams) are more advantageous over other gaseous foams with higher  $\nabla P_0$  (e.g. foams with gas CO<sub>2</sub>, gas N<sub>2</sub>, hydrocarbon gas, flue gas, etc.). It should be noted that the importance of small lab-scale coreflood experiments based on the field rock and fluid samples and selected foaming agents cannot be underestimated, because they allow mechanistic model fits to recommend appropriate MRF values at different injection scenarios.

### 3.5. Conclusions

Foam propagation is limited in field EOR processes by two main mechanisms as investigated in this study – the first, conversion from strong-foam to weak-foam state, and the second, gravity segregation of foam into gas and liquid. Dealing with an ideal (large homogeneous cylindrical) reservoir, the results of this study can be summarized as follows:

- The population-balance foam model shows that the propagation distance before strong foam converts to weak foam ( $R_{CSW}$ ) primarily depends on the mobilization pressure gradient ( $\nabla P_o$ ). This explains why foams with lower  $\nabla P_o$  (e.g. supercritical CO<sub>2</sub> foams) can propagate much further than other gaseous foams with higher  $\nabla P_o$ . The results also show theoretically why wetter foams can propagate further than drier foams, and why higher injection rates help longer propagation distance.
- CMG STARS simulation and the Stone and Jenkins model confirm that gravity segregation also limits foam propagation distance. Foam propagation distance before gravity segregation ( $R_{gs}$ ) primarily depends on the mobility reduction factor (MRF) that is calibrated by mechanistic model based on fundamental foam physics in this study.
- Combining both mechanisms together, the results show that foams with lower  $\nabla P_o$  tends to have gravity segregation more dominating factor for foam propagation. On the contrary, foams with higher  $\nabla P_o$  tends to have the conversion to weak foam more dominating factor.

## CHAPTER 4. A FIELD CASE STUDY ON THE OPTIMIZATION OF SUPERCRITICAL CO<sub>2</sub> FOAM EOR PROCESSES

### 4.1. Introduction

Enhanced oil recovery (EOR) is defined as a series of processes in which a fluid is injected into the reservoir to change either rock or fluid properties to eventually produce more oil and gas from the reservoir that otherwise would not have been produced any longer with primary depletion mechanisms (van Poolen 1980). EOR methods are considered as a useful and efficient means to produce more hydrocarbons from depleted reservoirs worldwide, by using gas injection, thermal process, and chemical flooding typically. In addition to secondary water injection, gas injection (such as N<sub>2</sub>, CO<sub>2</sub>, produced hydrocarbon gas, flue gas, etc., either at miscible or immiscible condition) is a common EOR method because of abundance and easy operation in the field. Water and gas injections, however, share similar limitations, that is, relatively low sweep efficiency caused by gravity segregation (either underdrive or override) as well as unfavorable mobility compared to reservoir oil. Such limitations result in relatively high remaining oil saturation after the treatments.

Literature review shows that significant efforts have been made to overcome poor sweep efficiency associated with water and gas injection. For example, an early study of Caudle and Dyes (1957) proposed a method that is, injecting water along with gas as a miscible slug. They found that the sweep was improved by the reduced mobility of gas phase in the presence of relatively high water saturation. Field tests of gas and water co-injection by Stone (1983) proved that injecting water alternatively with gas (or, water-



alternating gas, “WAG”) is more feasible if gas-to-water ratio and interval of each injection period are selected carefully. If achieved, the suitable injection ratio that is primarily a function of mobilities of existing fluids is shown to keep the gas zone at a constant volume between water and miscible front zones. There exist numerous WAG field tests reported in the literature (Sanchez 1999; Christensen et al. 2001; Barati Ghahfarokhi et al. 2016). Following Caudle and Dyes (1957), Blackwell et al. (1959) reported that gravity causes gas and water injected together to segregate rapidly within the reservoir. Therefore, the mobility of water or gas zone is not significantly improved. One way to mitigate gravity segregation is foaming the injected gas phase with surfactant solutions. Foam, which is a colloidal system in which gas phase is dispersed in surfactant-laden liquid phase, has liquid films (or, lamellae) that block the gas phase and thus reduce gas mobility. The mobility reduction factor (MRF) defines how much gas mobility is reduced when foam is present. Similar to water and gas injection, foam can be injected by introducing gas and surfactant solutions together (so called, “coinjection”) or surfactant solutions alternating with gas (so called “SAG”). There are numerous foam pilot tests available in the literature: CO<sub>2</sub>/N<sub>2</sub> foam project consisting of eight cycles of SAG performed in Wilmington field, California (Holm and Garrison 1988); CO<sub>2</sub> foam field test in Rangely Weber Sand Unit in northwestern Colorado (Jonas et al. 1990) to block high permeability thief zones and keep gas production low; CO<sub>2</sub> foam field test conducted in Salt Creek, WY (Mukherjee et al. 2016); and SAG treatment for conformance control in Lower Mirador formation, Cusiana Field, Columbia (Ocampo et al. 2013; Rossen et al. 2017), among many. For a given foam type (CO<sub>2</sub>, N<sub>2</sub>, etc. together with a certain surfactant formulation and concentration),

the effects of injection pressure or total injection rate, foam quality, pattern spacing, and injection interval length are typically investigated in the design stage.

#### **4.2. Objectives of this study**

The objective of this chapter is to show how to determine the optimum injection conditions for gas-water EOR at various injection gas fraction (or foam qualities ( $f_g$ ), equivalently) and total injection rates ( $Q_t$ , that is, a sum of gas and liquid rate, i.e.,  $Q_t = Q_g + Q_w$ ) with or without foams, in order to guide field development planning by using reservoir simulations performed by CMG-STARs. In addition, how such optimum conditions can shift depending on foam quality ( $f_g$ ) and mobility reduction factor (MRF) is examined by using a graphical method. The field of interest is a sector in Lisama field, Colombia, with an inverted 5-spot well pattern (i.e., one injection well near the center surrounded by four production wells). A mechanistic foam model in the literature (Izadi and Kam 2018) is extended to define foam flow characteristics. It should be noted that the optimum conditions found in this study is field-specific; the systematic approaches and procedures to reach the optimum conditions are universal to any field developments, however.

### **4.3. Methodology**

#### **4.3.1. Field of Interest**

Lisama field is located in the eastern part of the Middle Magdalena Valley Basin in Colombia (Rodriguez 2009) (Figure 4.1). It was discovered in 1935, and estimated to hold approximately 0.25 billion STB of oil in place (Jaimes et al. 2014). Lisama reservoir mainly consists of two main sandstone formations, Mugrosa and Colorado interbedded with shale streaks (Gomez et al. 2009). The fluvial system of Meandric Rivers is the environmental deposition of Lisama formations, and therefore it possesses complex channels of changing sandstone thickness and lateral and vertical changes of rock types (Sandoval et al. 2009). Production from Lisama field moves gradually from the primary to the secondary and tertiary recovery processes. Water and gas flooding techniques are expected to follow in the near future.

The sector of interest in this study has an inverted 5-spot pattern with approximately 22 acres drainage area and reservoir gross thickness of 335 ft with similar structural, and petrophysical characteristics to those of the Mugrosa formation in Lisama field. As shown in Figure 4.2, four producers (L-8, L-44, L-52, and L-56) are located at the edge of the modeled sector with an injection well located approximately in the middle (slightly closer to L-8 and L-56 by about 130 ft, compared with L-44 and L-52). The injection well is located down-dip from L-8 and up-dip from L-44, L-52, and L-56. Table 4.1 summarizes reservoir rock and fluid properties used in this study following Naranjo (2010). The pattern consists of four heterogeneous sandstone layers, each separated by thin impermeable shale streaks - the top layer (A) is 55 ft thick with a permeability

distribution ranging from 20 to 200 mD; the second layer (B), 60 ft thick from 20 to 30 md; the third layer (C), 35 ft thick from 80 to 100 md, and the fourth layer (D), 90 ft thick from 20 to 100 md.

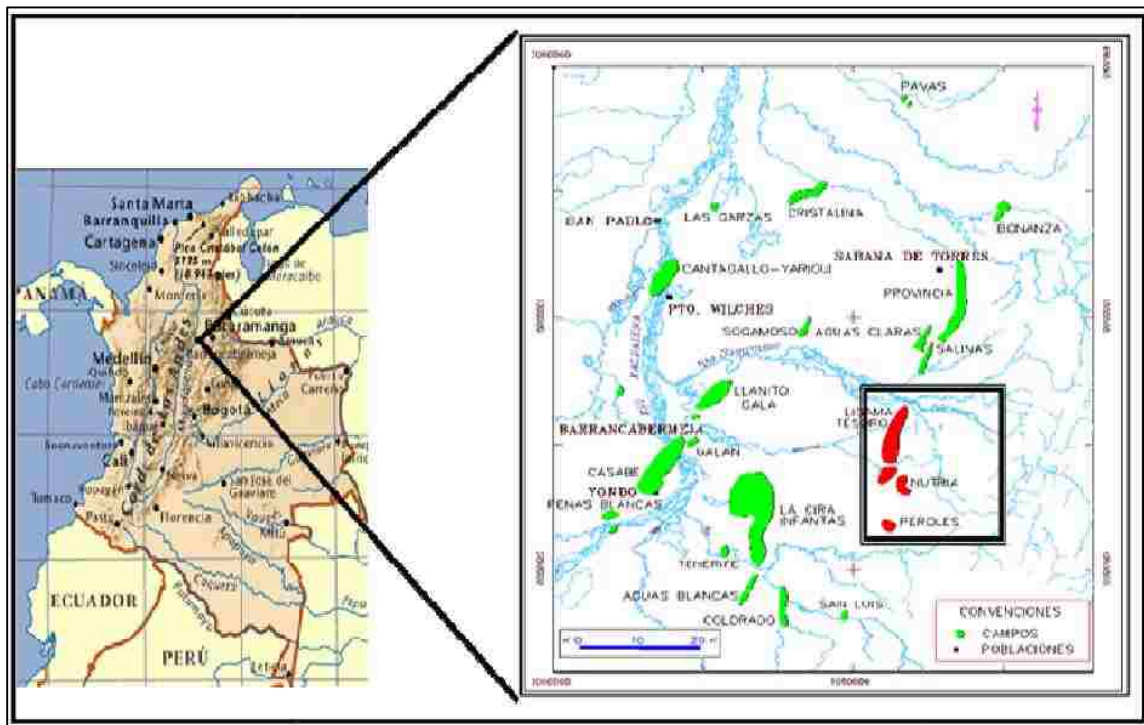


Figure 4.1. Field map of Lisama field, Colombia, investigated in this study (Rodriguez 2009).

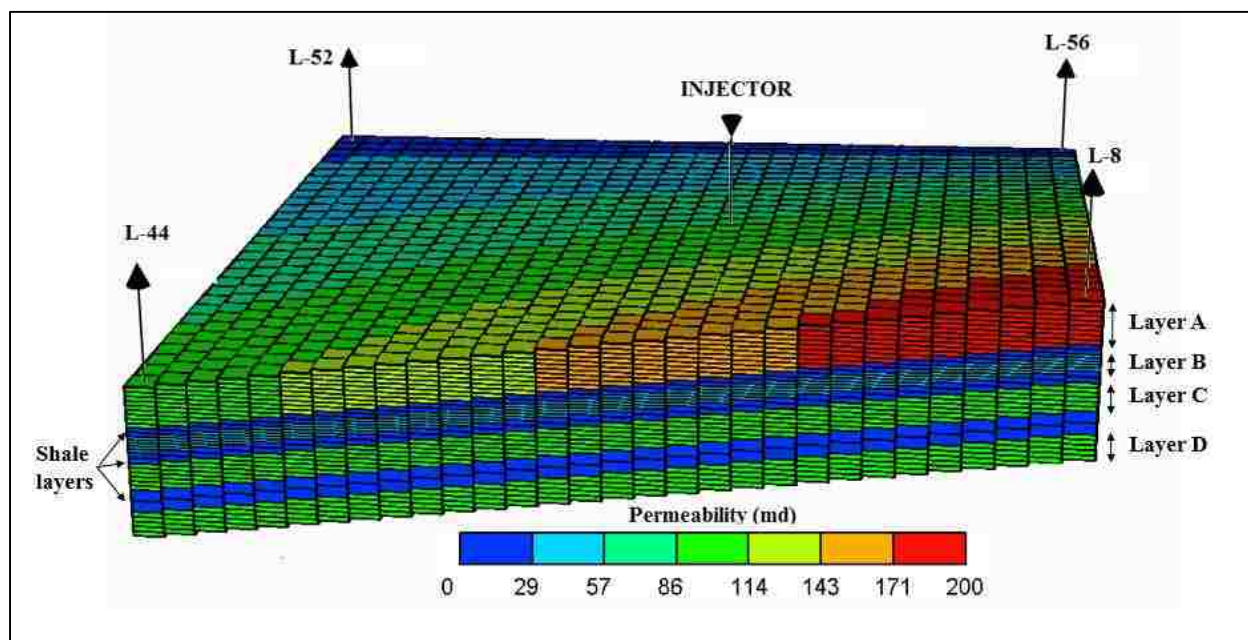


Figure 4.2. Three-dimensional grid system of a sector to be investigated in this study (Mugrosa formation in Lisama field) with permeability distribution in sandstone layers A, B, C and D isolated by impermeable shale layers.

Table 4.1. Reservoir rock and fluid properties of Mugrosa formation in Lisama field used in this study.

Reservoir pressure (psia)	2500
Reservoir temperature (°F)	140-160
Bubble point pressure (psia)	2500
Oil viscosity (cp) @ 2500 psia	1.7
Water viscosity (cp) @ 2500 psia	0.43
Average initial oil saturation (%) right before gas-liquid injection	45
Connate water saturation (%)	25
Average porosity (%)	18.5
Permeability range (md)	20-200

### 4.3.2. Simulation Methods

There are two main simulation approaches for foam-associated EOR processes in the literature. The first is a mechanistic modeling approach that keeps track of the change in bubble population through bubble creation, bubble coalescence, trapped gas saturation and so on, often called bubble population balance modeling (Falls et al. 1988; Kavscek and Radke 1994; Kam and Rossen 2003), while the second is based on local steady-state, or local equilibrium, foam behavior, typically incorporating a pre-determined level of mobility reduction for the gas phase (Cheng et al. 2000). The field-scale simulation in this study applies CMG STARS module by incorporating MRF (the second approach), while the selection of MRF at different  $f_g$  and  $Q_t$  is based on the mechanistic modelling (the first approach).

Reservoir simulations are based on the conservation of mass and heat. The equation of continuity for a multi-component system takes the transport for each component in each phase into account. For an isothermal three-component system of oil, water, and gas, the equation of continuity is defined as follows for component  $i$  (Klins 1984), if chemical reactions, dispersion, and adsorption on the rock surface are negligible:

$$-\vec{\nabla} \cdot \sum_{i=1}^{N_c} (\rho_o \omega_{io} \vec{u}_o + \rho_g \omega_{ig} \vec{u}_g + \rho_w \omega_{iw} \vec{u}_w) = \frac{\partial}{\partial t} (\phi S_o \rho_o \omega_{io} + \phi S_g \rho_g \omega_{ig} + \phi S_w \rho_w \omega_{iw}) \quad (4.1)$$

Note that  $\rho_j$  is the density of phase  $j$  ( $j = o, w, \text{ and } g$  for oil, water and gas phases respectively),  $\omega_{ij}$  the mass fraction of component  $i$  in phase  $j$ ,  $\vec{u}_j$  the velocity of phase  $j$ ,  $\phi$

the porosity of the medium, and  $S_j$  the saturation of phase  $j$ . For fluid flow in porous media, the transport equation is represented by Darcy's equation, i.e.

$$\vec{u}_j = -\frac{k k_{rj}}{\mu_j} (\nabla p_j - \gamma_j \nabla z) \quad (4.2)$$

where,  $k$  is the absolute permeability of medium,  $k_{rj}$  the relative permeability to phase  $j$ ,  $\mu_j$  the viscosity of phase  $j$ ,  $\nabla p_j$  the pressure gradient of phase  $j$ , and  $\gamma_j \nabla z$  the gravity potential for dipping strata for phase  $j$ . CMG STARS foam model modifies gas phase mobility by reducing gas relative permeability ( $k_{rg}$ ), the degree of which is specified by MRF (CMG 2016; CMG STARS uses the term FM to represent MRF). Therefore, the gas relative permeability in presence of foam ( $k_{rg}^f$ ) is defined as

$$k_{rg}^f = k_{rg}(S_w) \times \text{MRF}^{-1} \quad (4.3)$$

The 5-spot sector model of this study for Lisama field is discretized using Cartesian center-point variable-depth/variable-thickness gridding system (Figure 4.2). There are 30 grid blocks in each of  $x$  and  $y$  directions, and 31 blocks in  $z$  direction. As a result, each grid block is about 66.7 ft wide in  $x$  and  $y$  directions and 7 to 11 ft thick in  $z$  direction. All wells are fully penetrating the sandstone layers, and shale streaks are not perforated, unless otherwise noted. This study considers three total injection rates ( $Q_t$ ) ( $Q_t = 23,358$ ,  $46,717$ , and  $70,075$  ft<sup>3</sup>/day for low, intermediate, and high  $Q_t$  values, respectively), at various  $f_g$  values (from  $f_g = 100$  % (meaning only gas injection) to  $f_g = 0$  % (meaning only

liquid injection)). The values of MRF=1, 10,100, and 1000 represent the cases with no foam (simply gas and water coinjection), low-strength, intermediate-strength and high-strength foam, respectively.

#### **4.4. Results**

A total of 132 scenarios (i.e.,  $3Q_t$ ,  $11f_g$ , and 4 MRF values) are simulated at first assuming completely impermeable shales between layers, while additional follow-up scenarios are evaluated allowing a limited level of transmissibility through shales. The results are evaluated in terms of cumulative oil recovery and sweep efficiency after 20 years of injection. Each scenario has the same initial condition, that is, the remaining oil saturation ( $S_o$ ) of 0.45 at the end of the primary depletion, the detailed condition of which is shown in Table 4.1. Simulation details are in the following sections categorized in terms of total injection rate ( $Q_t$ ).

##### **4.4.1. Intermediate injection rate ( $Q_t = 46,717 \text{ ft}^3/\text{day}$ ; base case)**

The simulation results are summarized in Tables 4.2 for MRF = 1, 10,100, and 1000 respectively, showing the 20-year cumulative oil recovery and sweep efficiency in a wide range of injection gas fractions.

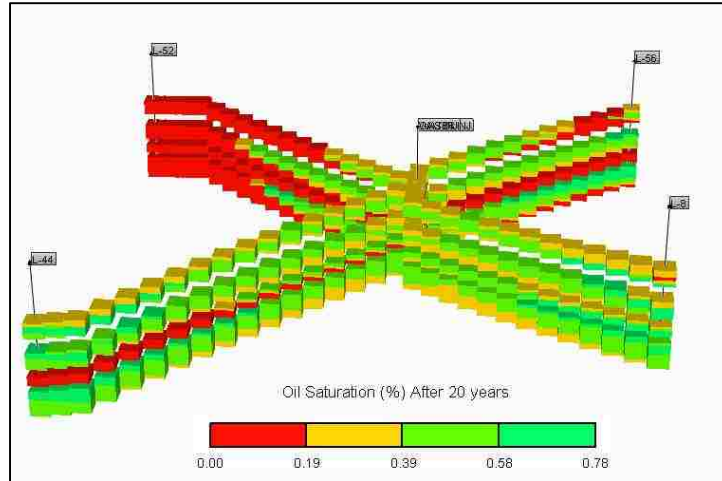


Table 4.2. Summary of simulation results for the base case (intermediate) injection rate ( $Q_t = 46,717 \text{ ft}^3/\text{day}$ ) after 20 years.

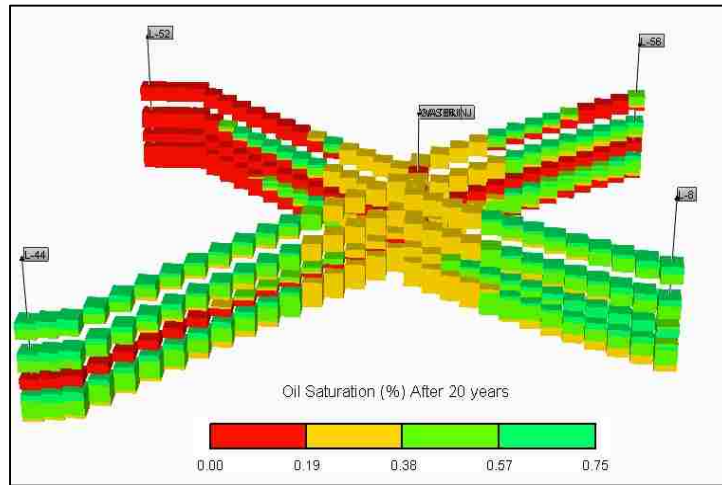
$f_g$ (%)	Cumulative recovery (Mstb)				Sweep efficiency* (%)			
	MRF=1	MRF=10	MRF=100	MRF=1000	MRF=1	MRF=10	MRF=100	MRF=1000
100	3,263	3,263	3,263	3,263	22.4	22.4	22.4	22.4
90	4,277	4,323	4,783	4,961	29.3	29.6	32.7	33.9
80	4,773	4,867	5,518	6,067	32.7	33.3	37.8	41.5
70	5,015	5,125	5,789	6,767	34.4	35.1	39.6	46.3
60	5,169	5,260	5,902	7,382	35.4	36.0	40.4	50.5
50	5,287	5,359	5,970	7,811	36.2	36.7	40.9	53.5
40	5,393	5,451	6,005	7,994	36.9	37.3	41.1	54.7
30	54,95	5,536	5,994	7,851	37.6	37.9	41.0	53.7
20	5,666	5,624	5,937	7,350	38.8	38.5	40.6	50.3
10	5,697	5,711	5,837	6,627	39.0	39.1	39.9	45.4
0	5,745	5,745	5,745	5,745	39.3	39.3	39.3	39.3

(\*Sweep efficiency is defined as  $([\text{the change in average oil saturation during gas and liquid injection } (\Delta S_o)] / [\text{the average oil saturation at the beginning of gas-liquid injection } (S_o)]) \times 100$ )

When MRF =1 and 1000, for example, Figures 4.3 and 4.4 show the distribution of oil saturation along multiple cross-sectional areas of the sector after 20-year injection at the injection gas fraction ( $f_g$ ) of 90% and 50%, respectively, which represent relatively dry and wet injection conditions. Figures 4.5 and 4.6 show the daily oil, gas, and water production rates at  $f_g = 90\%$  and  $50\%$  respectively.

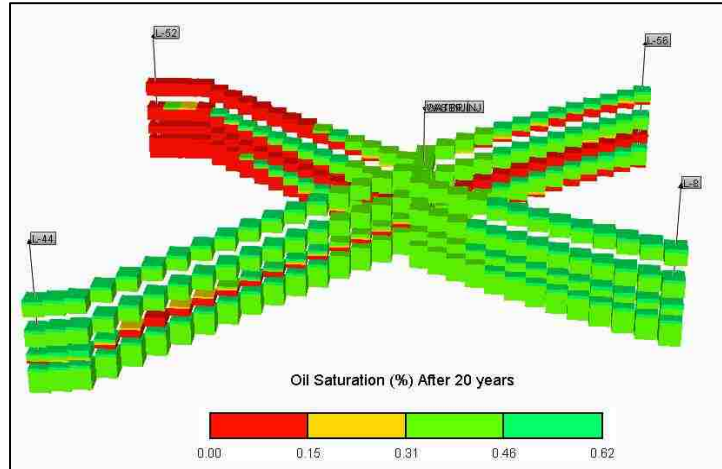


(a)

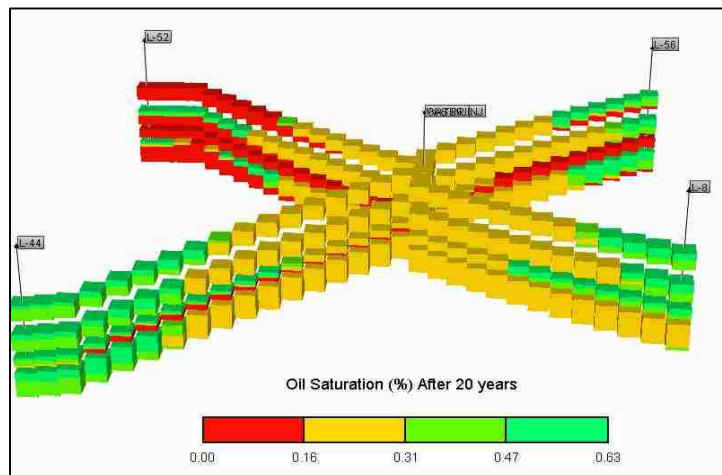


(b)

Figure 4.3. Cross-sectional map showing oil saturation distribution after 20 years for base case (intermediate) total rate ( $Q_t = 46,717 \text{ ft}^3/\text{day}$ ) at dry injection condition ( $f_g = 90\%$ ): (a) no foam (MRF=1) and (b) high-strength foam (MRF=1000).

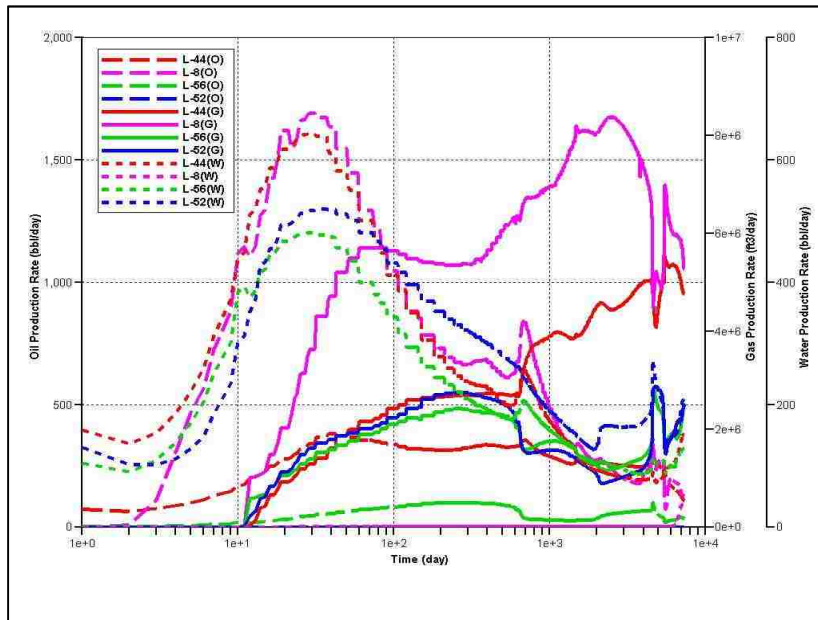


(a)

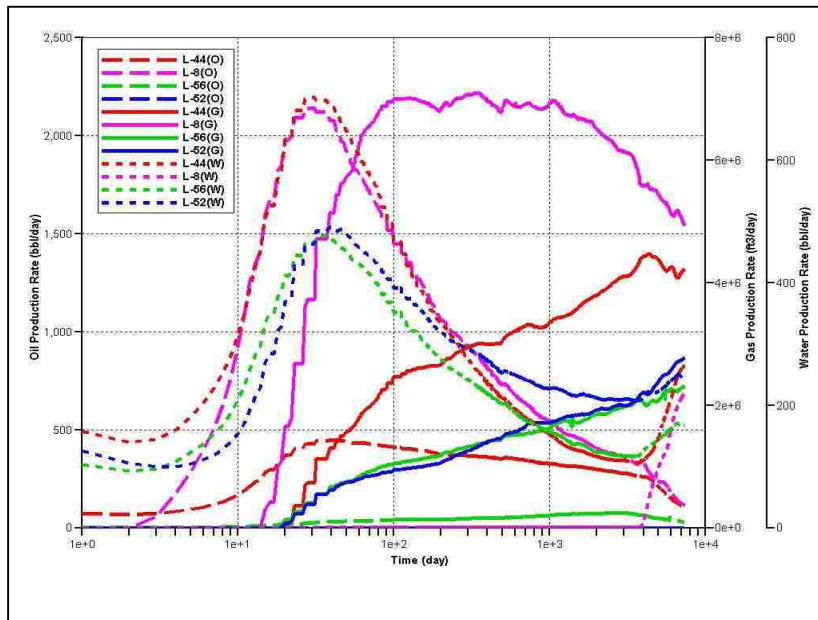


(b)

Figure 4.4. Cross-sectional map showing oil saturation distribution after 20 years for base case (intermediate) total rate ( $Q_t = 46,717 \text{ ft}^3/\text{day}$ ) at wet injection condition ( $f_g = 50\%$ ): (a) no foam (MRF=1) and (b) high-strength foam (MRF=1000).

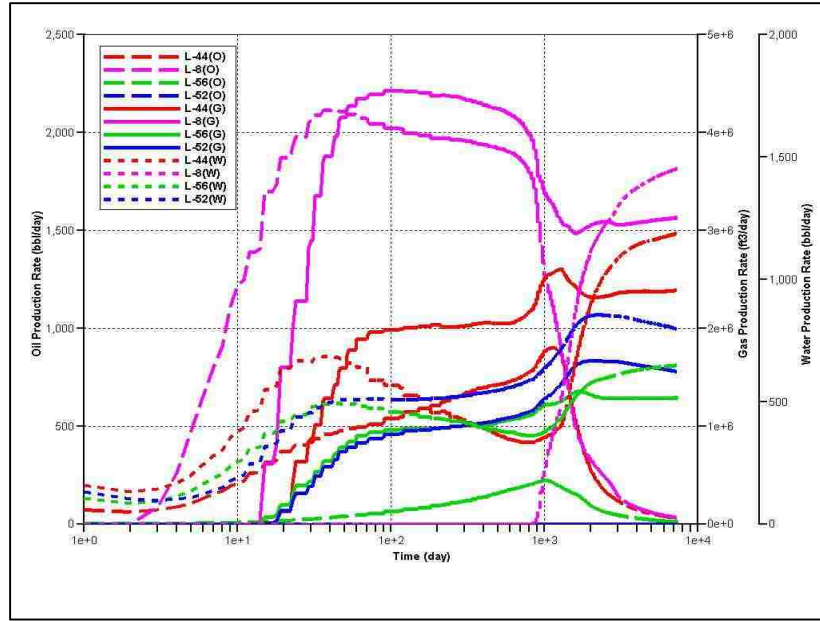


(a)

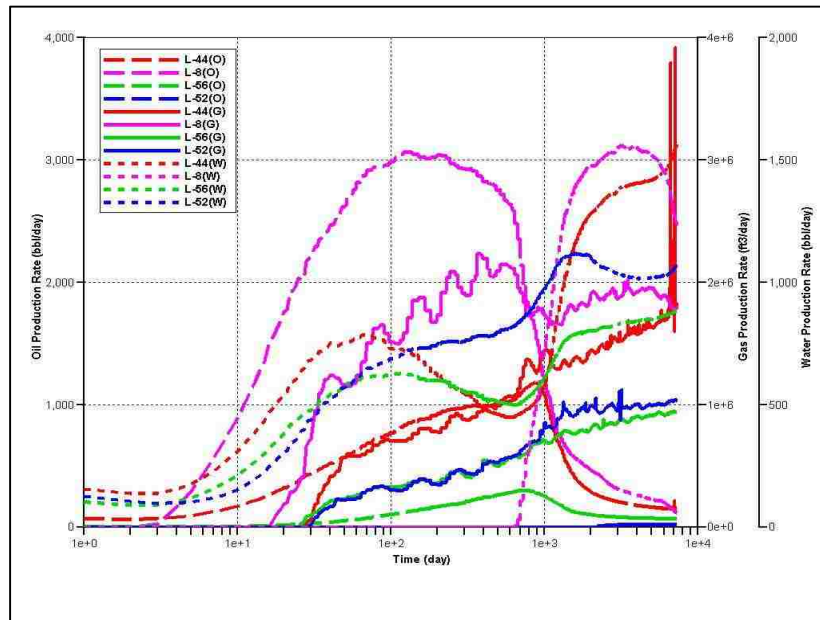


(b)

Figure 4.5. Daily oil, gas, and water production rates at 4 producers ( $Q_t = 46,717 \text{ ft}^3/\text{day}$  (base case),  $f_g = 90\%$ ): (a) MRF=1 and (b) MRF=1000.



(a)

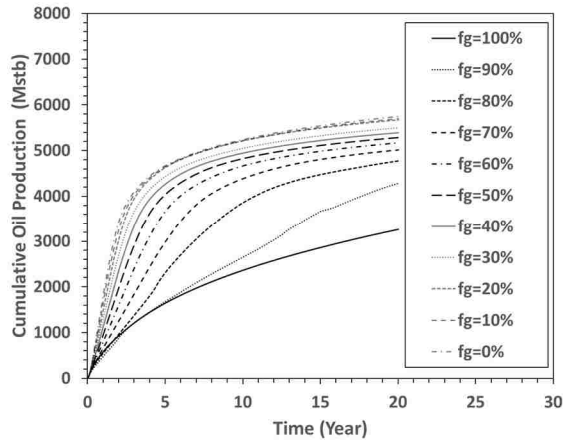


(b)

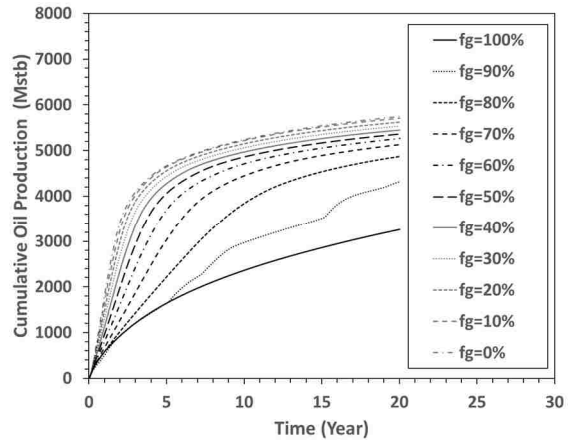
Figure 4.6. Daily oil, gas, and water production rates at 4 producers ( $Q_t = 46,717 \text{ ft}^3/\text{day}$  (base case),  $f_g = 50\%$ ): (a) MRF=1 and (b) MRF=1000.

In the case of dry injection condition ( $f_g = 90\%$ ) with  $MRF=1$ , the injected gas predominantly follows either up-dip direction towards well L-8 or high-permeability direction towards well L-44 to show an early breakthrough (cf. Figure 4.2). Such an effect is reflected by the map of oil saturation (Figure 4.3(a)) as well as production history (Figure 4.5(a)). In the case with  $MRF=1000$ , however, the injected gas sweeps almost in a piston-like manner, especially around the injection well. As a result, the average oil production rate for well L-8 is around 298 bbl/day when  $MRF=1$ , while the average oil production rates for this well goes up to 374 bbl/day when  $MRF=1000$ . In addition, the gas breakthrough occurs after 10 days in well L-44 when  $MRF=1$ , while the breakthrough is delayed until 18 days when  $MRF=1000$ . In the case of wet injection condition ( $f_g = 50\%$ ), the dip angle plays an important role showing more variation in terms of oil saturation along the vertical direction (Figure 4.4). Because gravity is helping the process (i.e., water supporting from the bottom), the oil production is improved compared to  $f_g = 90\%$  (Figure 4.6). As a result, the average oil production rate for well L-44 is around 239 bbl/day when  $MRF=1$ , while the average production for this well increases to 340 bbl/day when  $MRF=1000$ . In addition, the gas production is retarded and the water production is accelerated. Figure 4.7 shows how cumulative oil recovery changes with time for  $MRF = 1, 10, 100, \text{ and } 1000$ , respectively. There are two distinct features that can be learned from this example: (i) the cumulative oil production increases with  $MRF$ , and (ii) wetter injection condition (or, lower  $f_g$  equivalently) generally improves the cumulative oil production when  $MRF$  is relatively low (meaning the bottom-support mechanism is more pronounced when  $MRF$  is low). As  $MRF$  increases, however, the maximum recovery occurs at an intermediate  $f_g$ , implying the mobility control plays more important roles. The

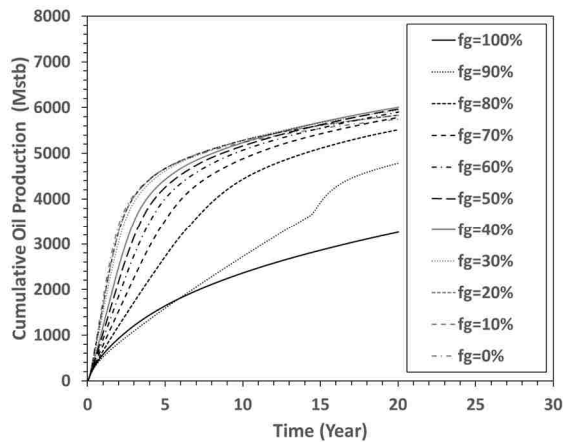
first is what is expected because of more efficient mobility control at higher MRF, while the second is more field-specific indicating that the role of gravity in this sector of interest is not negligible.



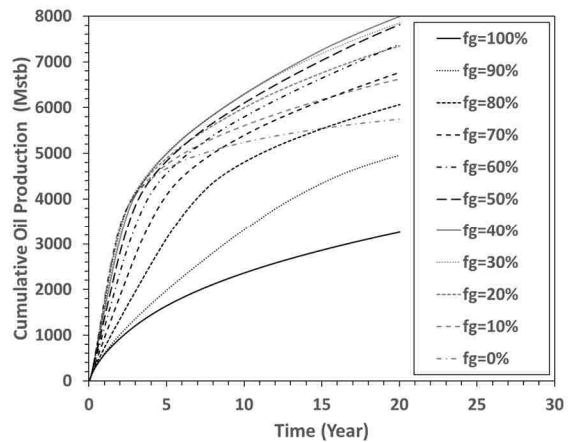
(a)



(b)



(c)



(d)

Figure 4.7. Comparison of cumulative oil production at base case (intermediate) injection rate ( $Q_t = 46,717 \text{ ft}^3/\text{day}$ ): (a) MRF=1, (b) MRF=10, (c) MRF=100, and (d) MRF=1000.

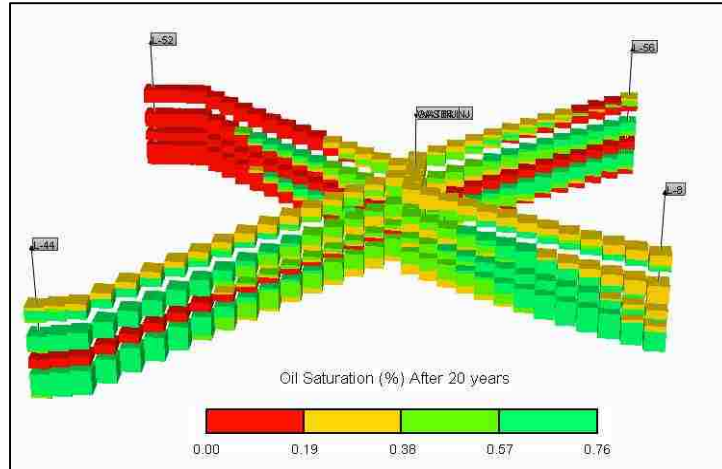
#### 4.4.2. Low injection rate ( $Q_t = 23,358 \text{ ft}^3/\text{day}$ )

The same simulations are repeated at the lower injection rate ( $Q_t = 23,358 \text{ ft}^3/\text{day}$ ), as shown in Figures 4.8, 4.9, and 4.10. The results are also summarized in Table 4.3. In all cases, the average daily oil production rates for all 4 producing wells are reduced compared to those from the intermediate injection rate (Figures 4.3, 4.4, and 4.7). As a result, when  $f_g = 90\%$ , the average production rate for well L-44 is down from 239 bbl/day to 202 bbl/day when  $\text{MRF} = 1$ , from 240 to 197 bbl/day when  $\text{MRF} = 10$ , from 252 to 207 bbl/day when  $\text{MRF} = 100$ , and from 248 to 214 bbl/day when  $\text{MRF} = 1000$ . Such a result is primarily caused by the fact that a smaller pore volume is injected by moving from the intermediate  $Q_t$  to low  $Q_t$ . The cumulative oil recovery trend observed at low  $Q_t$  is also consistent with intermediate rate – more oil produced with higher MRF. The injection  $f_g$  at which the maximum oil recovery occurs slightly decreases at low  $Q_t$ .

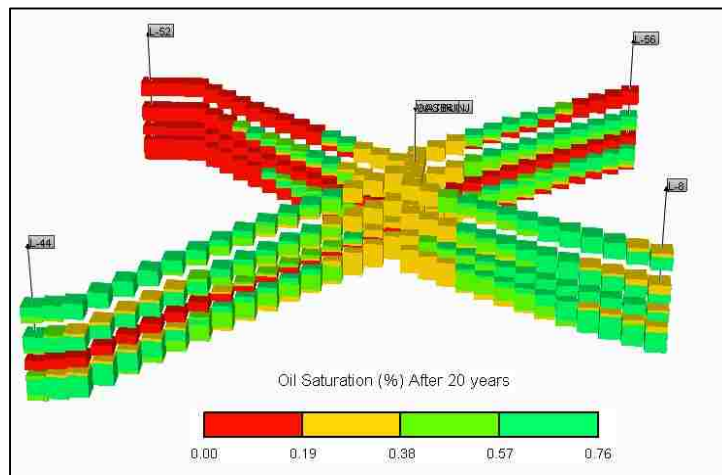


Table 4.3. Summary of simulation results for the case of low injection rate ( $Q_t = 23,358$  ft<sup>3</sup>/day) after 20 years.

$f_g$ (%)	Cumulative recovery (Mstb)				Sweep efficiency (%)			
	MRF=1	MRF=10	MRF=100	MRF=1000	MRF=1	MRF=10	MRF=100	MRF=1000
100	2,307	2,307	2,307	2,307	15.8	15.8	15.8	15.8
90	2,549	2,744	2,896	3,111	17.4	18.8	19.8	21.3
80	3,835	3,927	4,308	4,916	26.2	26.9	29.5	33.6
70	4,518	4,589	4,954	5,596	30.9	31.4	33.9	38.3
60	4,858	4,910	5,220	6,029	33.2	33.6	35.7	41.3
50	5,049	5,087	5,371	6,309	34.6	34.8	36.8	43.2
40	5,179	5,208	5,475	6,456	35.4	35.6	37.5	44.2
30	5,286	5,308	5,542	6,444	36.2	36.3	37.9	44.1
20	5,381	5,396	5,573	6,254	36.8	36.9	38.1	42.8
10	5,425	5,444	5,526	5,928	37.1	37.3	37.8	40.6
0	5,511	5,511	5,511	5,511	37.7	37.7	37.7	37.7

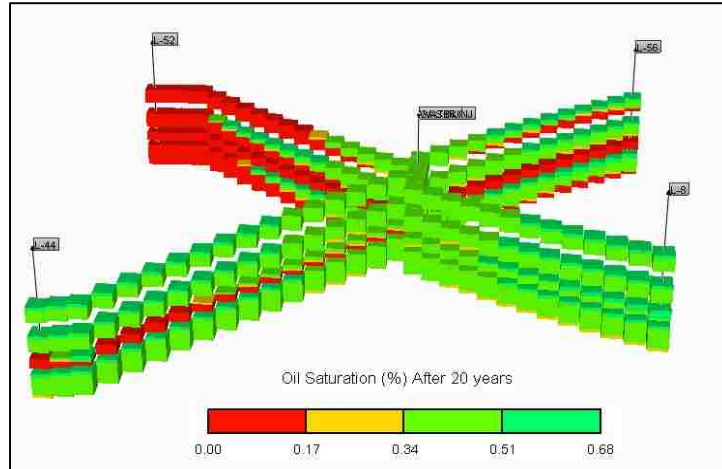


(a)

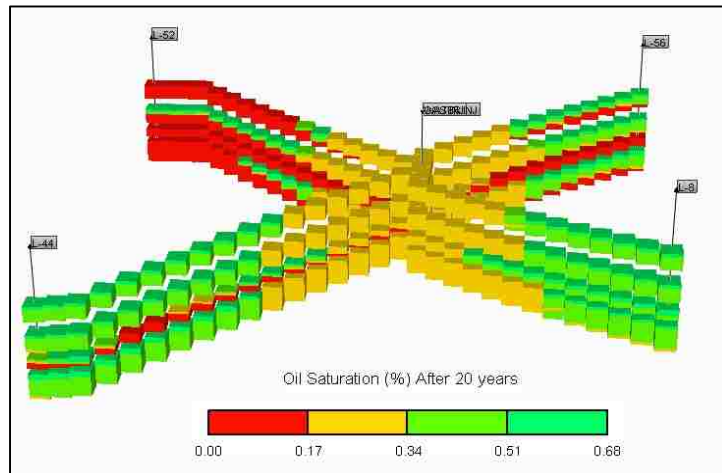


(b)

Figure 4.8. Cross-sectional map showing oil saturation distribution after 20 years for low total rate ( $Q_t = 23,358$  ft<sup>3</sup>/day) at dry injection condition ( $f_g = 90\%$ ): (a) no foam (MRF = 1) and (b) high-strength foam (MRF = 1000).

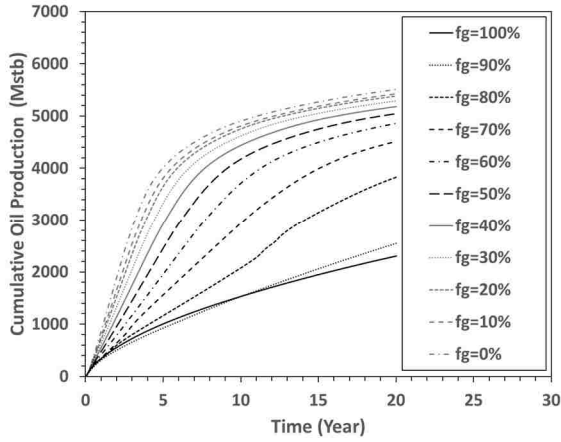


(a)

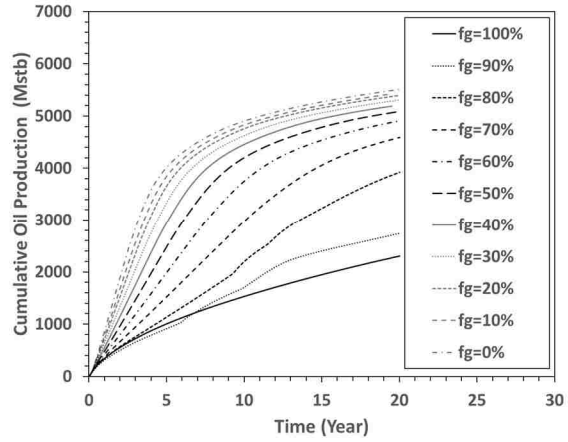


(b)

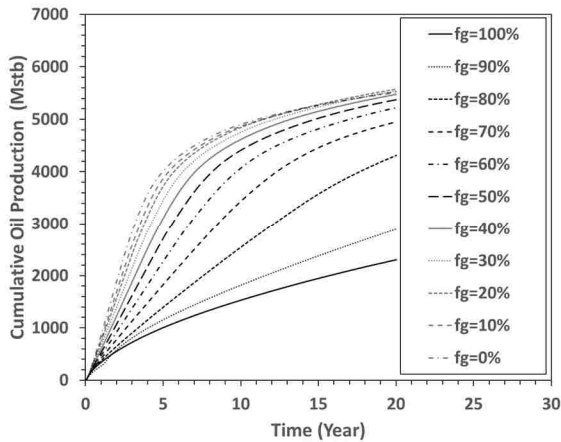
Figure 4.9. Cross-sectional map showing oil saturation distribution after 20 years for low total rate ( $Q_t = 23,358 \text{ ft}^3/\text{day}$ ) at wet injection condition ( $f_g = 50\%$ ): (a) no foam (MRF = 1) and (b) high-strength foam (MRF = 1000).



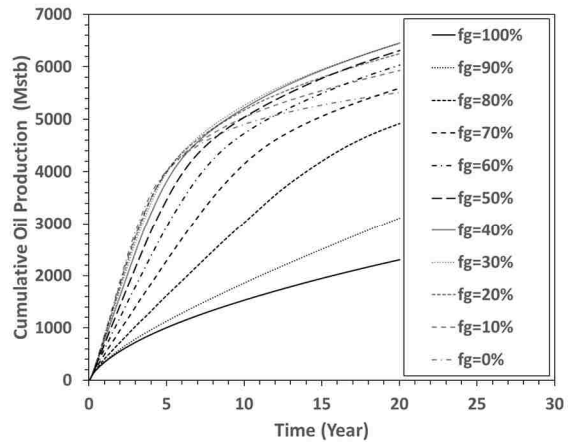
(a)



(b)



(c)



(d)

Figure 4.10. Comparison of cumulative oil production at low injection rate ( $Q_t = 23,358$   $\text{ft}^3/\text{day}$ ): (a) MRF = 1, (b) MRF = 10, (c) MRF = 100, and (d) MRF = 1000.

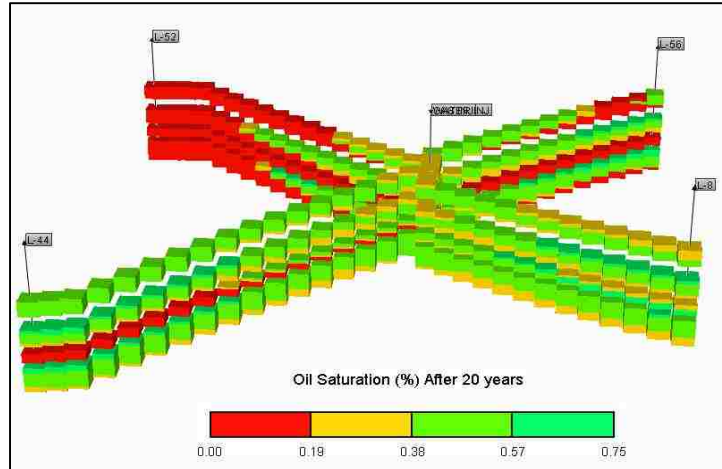
#### 4.4.3. High injection rate ( $Q_t = 70,075$ $\text{ft}^3/\text{day}$ )

The same simulations are repeated at the higher injection rate ( $Q_t = 70,075$   $\text{ft}^3/\text{day}$ ), as shown in Figures 4.11, 4.12, and 4.13. The results are also summarized in Table 4.4. In all cases, the average daily oil production rates for all 4 producing wells are improved compared to those from the low and intermediate  $Q_t$  values. As a result, for  $f_g = 90\%$ , the

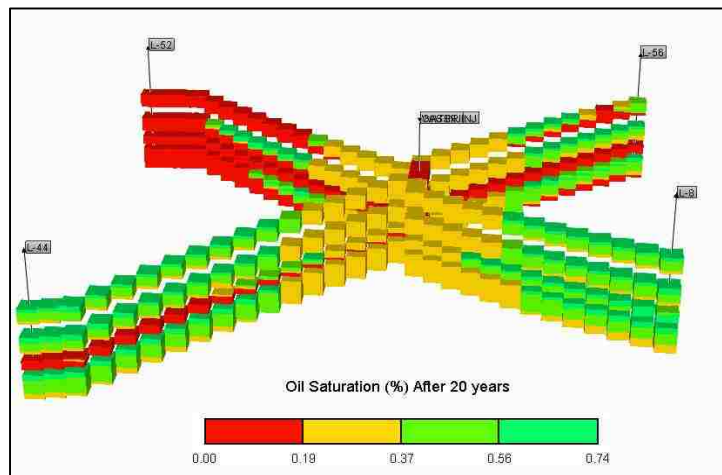
average production rate for well L-8 is 352 bbl/day when MRF =1, 365 bbl/day when MRF =10, 415 bbl/day when MRF = 100, and 446 bbl/day when MRF = 1000. Such a result is caused by the fact that a larger pore volume is injected by moving from the low to high  $Q_t$  values.

Table 4.4. Summary of simulation results for the case of high injection rate ( $Q_t = 70,075$  ft<sup>3</sup>/day) after 20 years.

$f_g$ (%)	Cumulative recovery (Mstb)				Sweep efficiency (%)			
	MRF=1	MRF=10	MRF=100	MRF=1000	MRF=1	MRF=10	MRF=100	MRF=1000
100	3,991	3,991	3,991	3,991	27.3	27.3	27.3	27.3
90	4,691	4,798	5,380	5,587	32.1	32.8	36.8	38.2
80	4,929	5,067	6,040	6,745	33.7	34.7	41.3	46.2
70	5,091	5,249	6,284	7,716	34.8	35.9	43.0	52.8
60	5,216	5,341	6,333	8,408	35.7	36.5	43.4	57.6
50	5,322	5,417	6,321	8,819	36.4	37.1	43.3	60.4
40	5,423	5,497	6,259	8,826	37.1	37.6	42.8	60.5
30	5,537	5,582	6,137	8,498	37.9	38.2	42.0	58.2
20	5,652	5,679	5,990	7,753	38.7	38.9	41.0	53.1
10	5,781	5,792	5,885	7,008	39.6	39.6	40.3	48.0
0	5,848	5,848	5,848	5,848	40.0	40.0	40.0	40.0

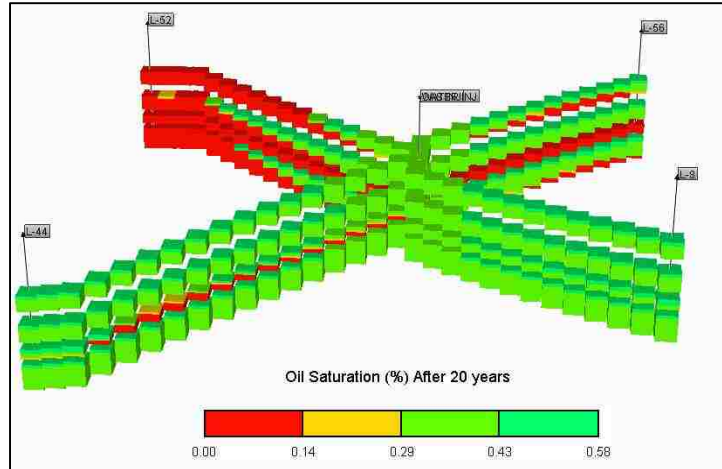


(a)

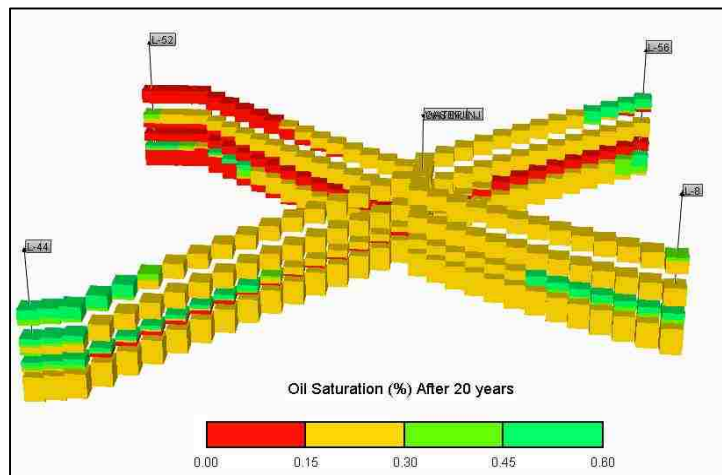


(b)

Figure 4.11. Cross-sectional map showing oil saturation distribution after 20 years for high total rate ( $Q_t = 70,075 \text{ ft}^3/\text{day}$ ) at dry injection condition ( $f_g = 90\%$ ): (a) no foam (MRF=1) and (b) high-strength foam (MRF = 1000).



(a)



(b)

Figure 4.12. Cross-sectional map showing oil saturation distribution after 20 years for high total rate ( $Q_t = 70,075 \text{ ft}^3/\text{day}$ ) at wet injection condition ( $f_g = 50\%$ ): (a) no foam (MRF = 1) and (b) high-strength foam (MRF = 1000).

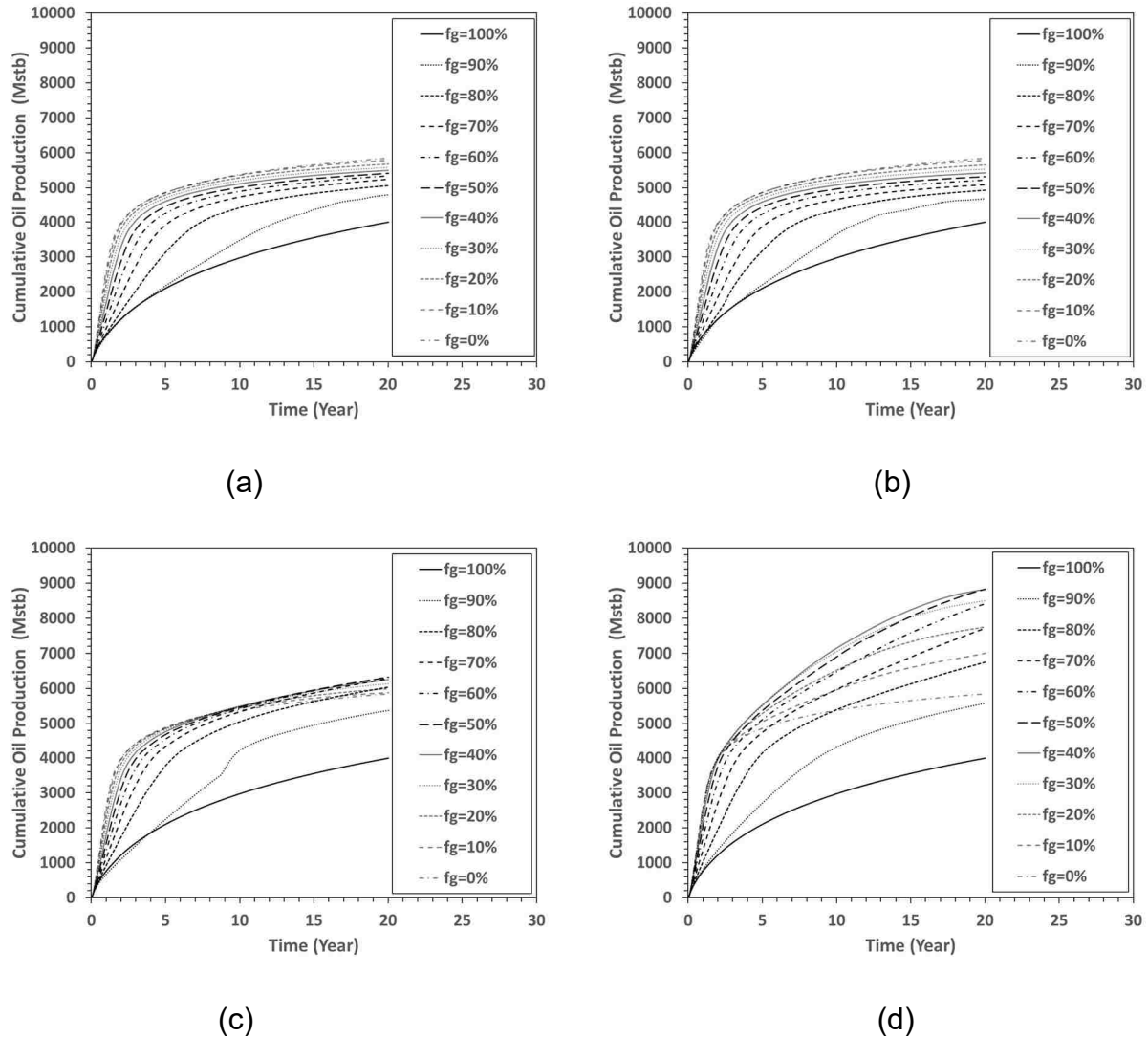


Figure 4.13. Comparison of cumulative oil production at high injection rate ( $Q_t = 70,075$   $\text{ft}^3/\text{day}$ ): (a) MRF = 1, (b) MRF = 10, (c) MRF = 100, and (d) MRF = 1000.

#### 4.4.4. Determination of optimum injection condition

Determination of the optimum injection condition requires lab coreflood experimental data on how MRF changes at different  $Q_t$  and  $f_g$  values, which of course depends on many field-specific conditions. To name a few, they include rock and fluid



properties, chemical formulations and concentrations (such as surfactants and additives), and interactions between foam films with reservoir fluids (especially reservoir oils) within the pores with certain surface properties. Because there are no coreflood experimental studies available from Lisama field, this study borrows the mobilities of gas and liquid, with and without foams, from Yin (2007). The mechanistic modeling technique from Izadi and Kam (2018) can be used to fit the coreflood data and further calculate the MRF values at different injection conditions.

Figure 4.14 shows the steady-state two flow-regime map of strong foams at the three  $Q_t$  values which correspond to the total injection velocity ( $u_t$ ) of 1.89, 3.78, and 5.67 ft/day. The map clearly shows a regime with almost vertical pressure contours (called the high-quality regime) and the other with almost horizontal pressure contours (called the low-quality regime) separated by a threshold foam quality,  $f_g^*$ . The population balance model of Izadi and Kam (2018) allows MRF values to be determined and plotted as a function of  $f_g$  for each of  $u_t$  values, as shown in Figure 4.15. Figure 4.15 demonstrates the behavior of two strong-foam flow regimes well: (i) in the low-quality regime (LQR) where foams are relatively wet and MRF is maintained within a narrow range due to bubble size staying near its minimum (around the average pore size), and (ii) in the high-quality regime (HQR) where foam are relatively dry and MRF sharply decreases with  $f_g$  due to bubble instability near the limiting capillary pressure. Such behaviors are consistent with existing studies (Kam and Rossen 2003; Lee et al. 2016).

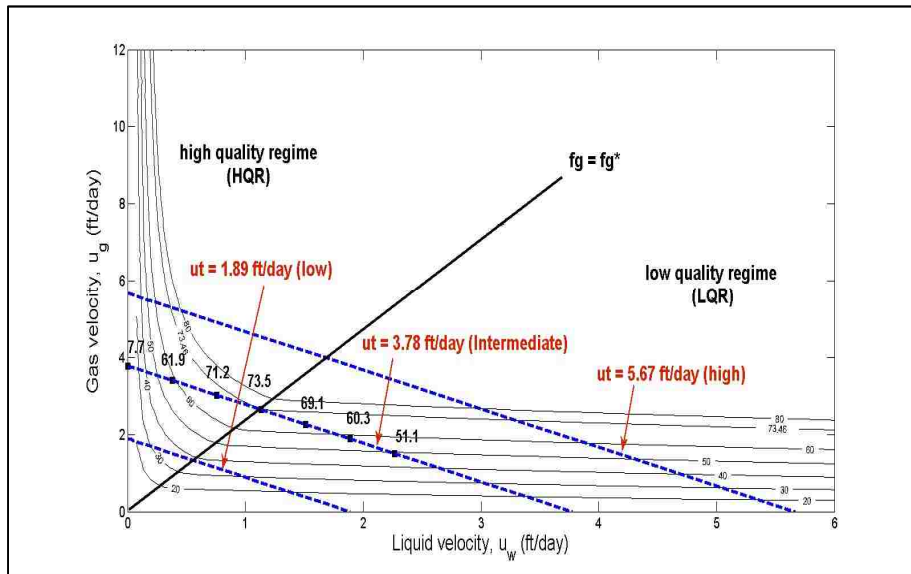


Figure 4.14. Two flow regimes of strong foams constructed in this study by using the model of Izadi and Kam (2018): low, intermediate, and high superficial velocities ( $u_t$ ) correspond to total injection rates ( $Q_t$ ) of 23,358, 46,717, and 70,075  $\text{ft}^3/\text{day}$ .

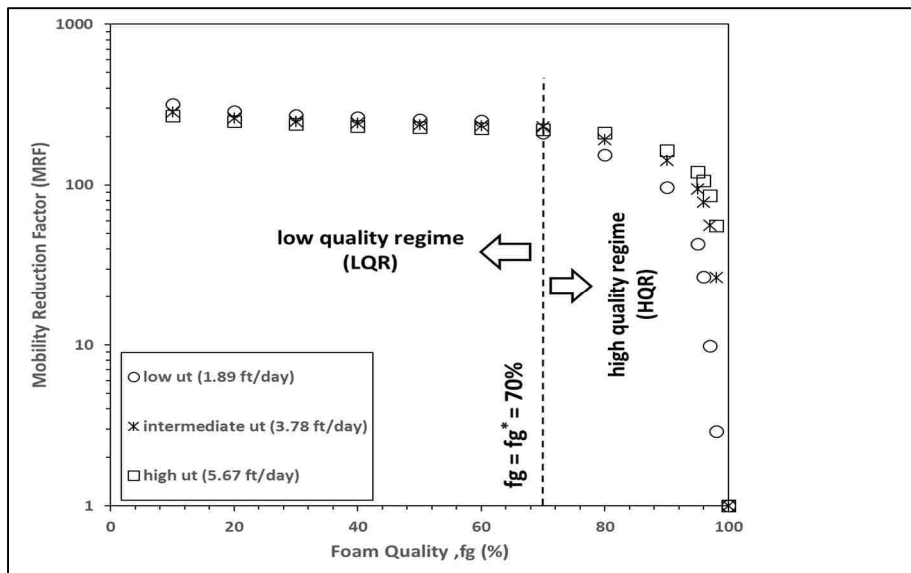


Figure 4.15. Results from mechanistic foam model (Izadi and Kam 2018) for Lisama field application showing how mobility reduction factor (MRF) changes with injection foam quality ( $f_g$ ): the corresponding paths shown in Figure 4.14.

The sweep efficiency from the simulations (as summarized in Tables 4.2, 4.3, and 4.4) at various MRF and  $f_g$  values can be used to construct sweep-efficiency contours. In addition, MRF as a function of  $f_g$  from mechanistic model can be imposed on the top of contours. These results are shown in Figures 4.16 through 4.18 for  $Q_t = 46,717$ , 23,358, and 70,075  $\text{ft}^3/\text{day}$ , respectively. Figure 4.16 shows the results of sweep efficiency (which is, in fact, equivalent to the cumulative oil production) at the intermediate  $Q_t$  as a function of MRF and  $f_g$  values. The MRF calculated in Figure 4.15 (i.e., the dashed curve in Figure 4.16) is mapped out on the sweep-efficiency contours. The same can be performed for low and high  $Q_t$  values, as shown in Figures 4.17 and 4.18.

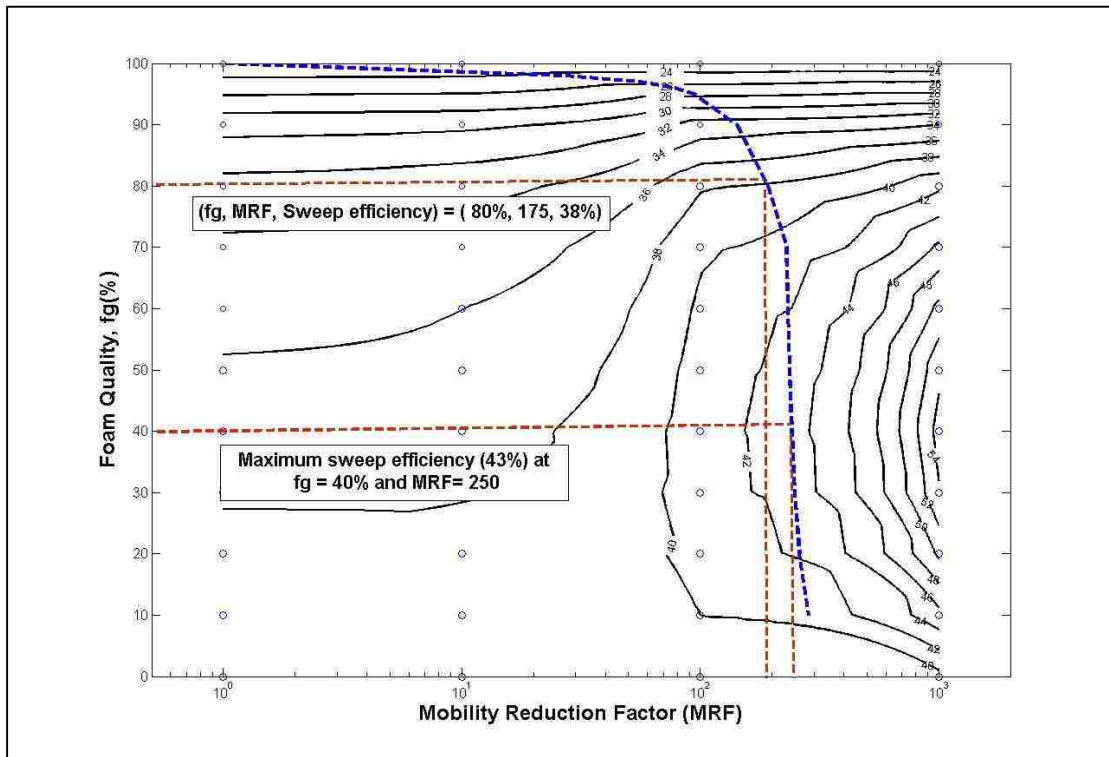


Figure 4.16. Mapping of MRF- $f_g$  path from mechanistic model on the sweep-efficiency contour map: base case (intermediate) injection rate ( $Q_t = 46,717 \text{ ft}^3/\text{day}$ ).

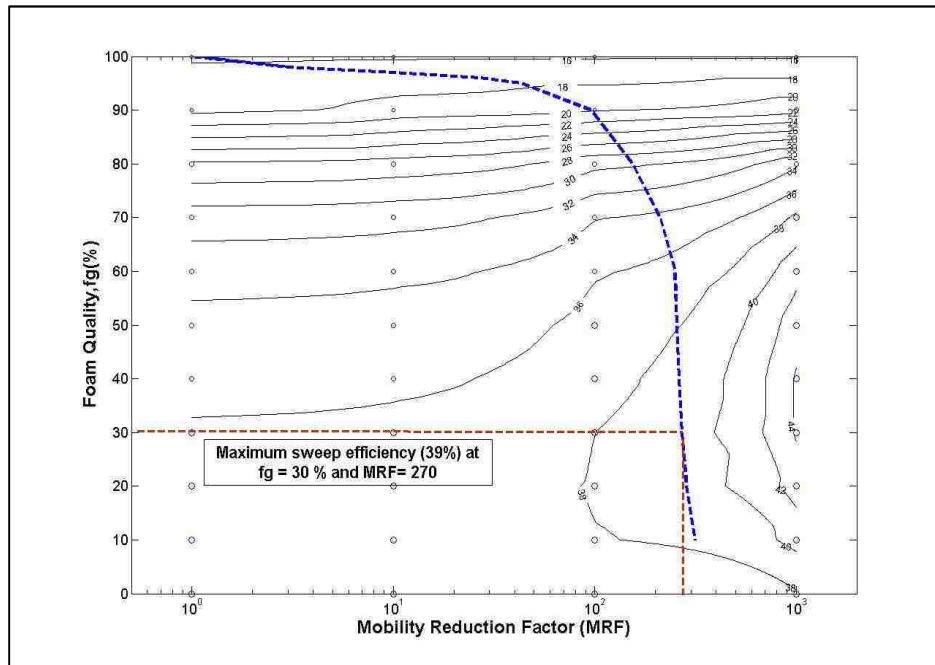


Figure 4.17. Mapping of MRF- $f_g$  path from mechanistic model on the sweep-efficiency contour map: low injection rate ( $Q_t = 23,358 \text{ ft}^3/\text{day}$ ).

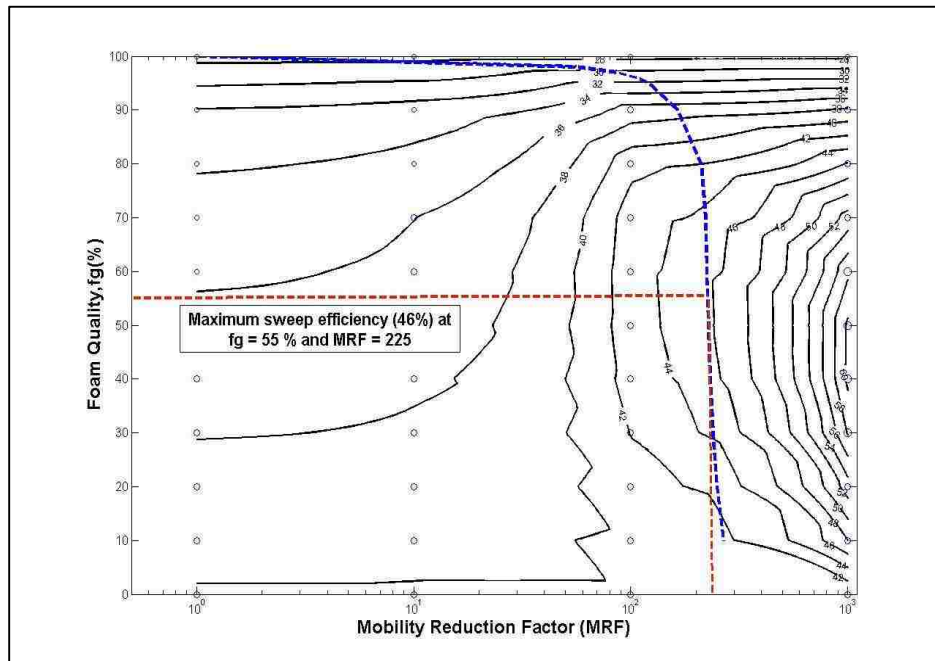


Figure 4.18. Mapping of MRF- $f_g$  path from mechanistic model on the sweep-efficiency contour map: high injection rate ( $Q_t = 70,075 \text{ ft}^3/\text{day}$ ).

One may then notice from Figures 4.16 through 4.18 that any intersection point between a particular sweep-efficiency contour and the MRF- $f_g$  path allows a data set of ( $f_g$ , MRF, sweep efficiency) to be determined. For example, in the base case (Figure 4.16), an intersection point of the two near  $f_g = 80\%$  provides ( $f_g$ , MRF, sweep efficiency) = (80%, 175, 38%) approximately, meaning that 38% of sweep efficiency can be obtained from  $f_g = 80\%$  that has an MRF value of 175 from mechanistic foam modeling (or, core flood experiments). Because the sweep-efficiency contours in Figure 4.16 are curved to the right, this implies that the sweep efficiency increases with decreasing  $f_g$  (when  $f_g > 40\%$ ), down to about  $f_g = 40\%$  where the sweep efficiency is about 43%, beyond which the sweep efficiency decreases with decreasing  $f_g$  (when  $f_g < 40\%$ ). That particular point providing the maximum sweep efficiency is defined as the optimum condition in this study, that is, ( $f_g$ , MRF, sweep efficiency) = (40%, 250, 43%) approximately in Figure 4.16. Figures 4.17 and 4.18 also show similar behaviors. Figure 4.19 shows a summary of such an analysis, plotting the sweep efficiency as a function of  $f_g$  for all three  $Q_t$  values. The trend is consistent as expected from Figure 4.15 that there is a particular value of  $f_g$  at which the sweep efficiency reaches the maximum, and those  $f_g$  values change with  $Q_t$  values. In general, higher  $Q_t$  leads to higher sweep efficiency that occurs at higher optimum  $f_g$ .

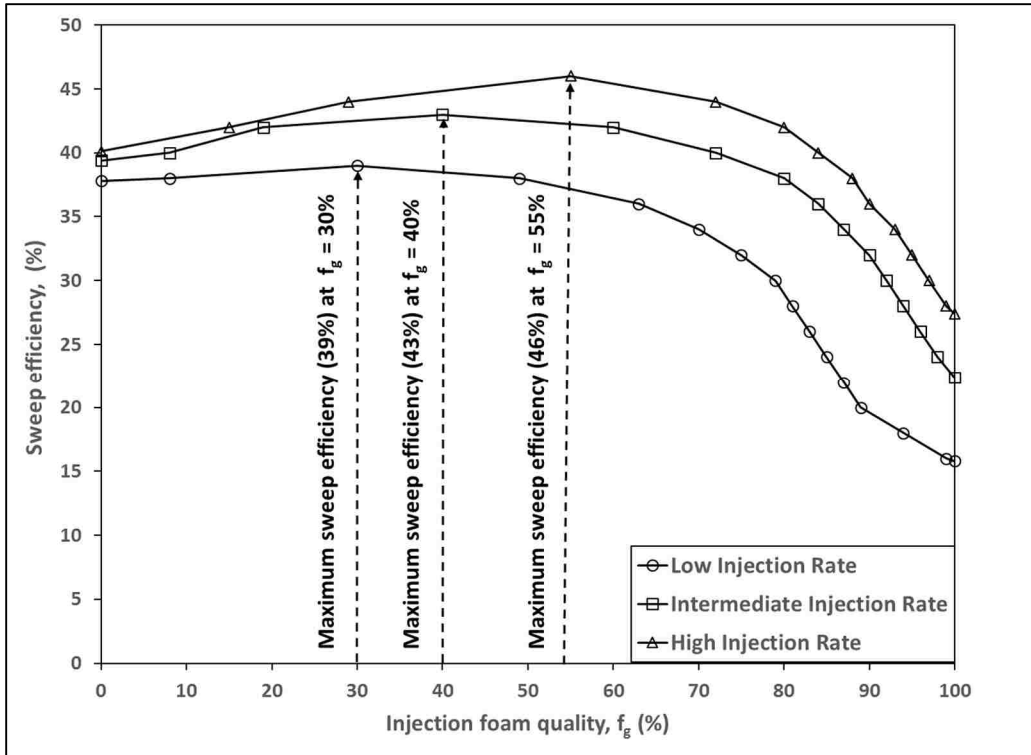
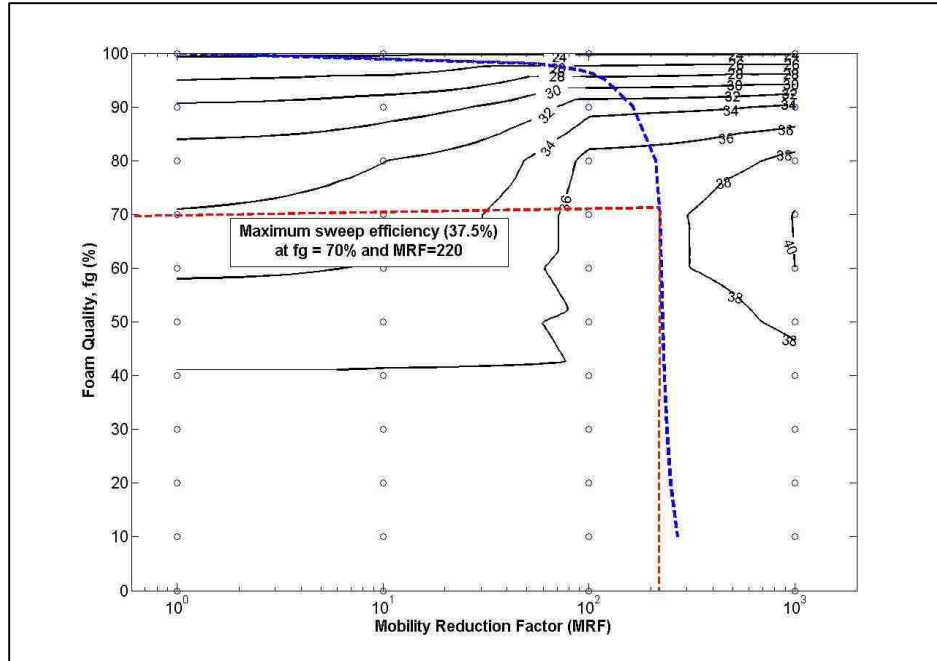


Figure 4.19. Summary of Figures 4.16 through 4.18 showing the effect of total injection rate on the sweep efficiency as well as optimum injection foam quality.

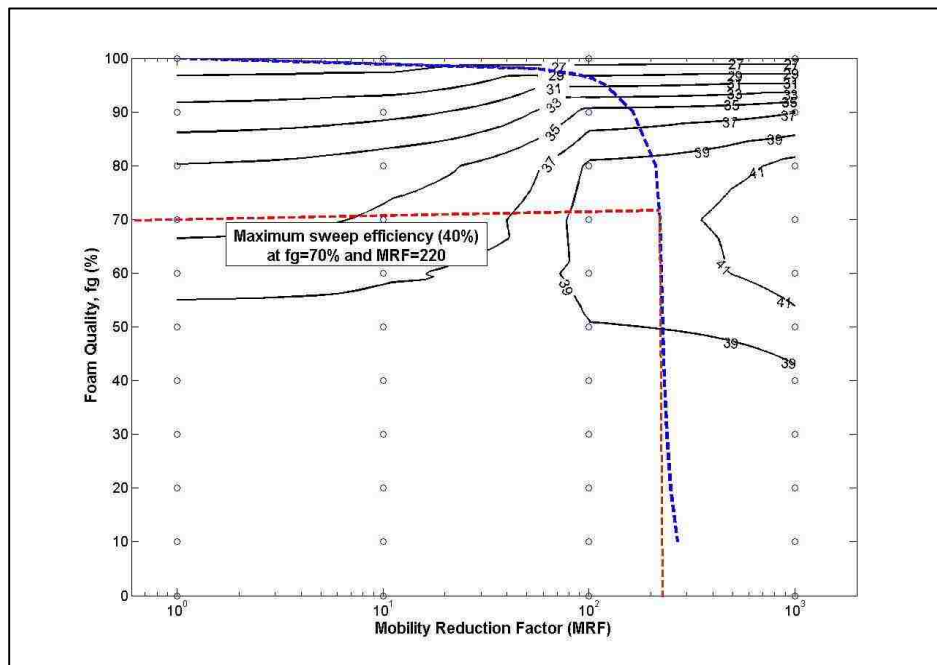
## 4.5. Discussions

This new technique and resulting plots presented in Figures 4.16 through 4.19 are believed to be a simple but robust tool to help making technical and business decisions – not only showing how sweep efficiency changes at different foam qualities and strengths, but also how such an optimum condition may shift depending on different operation conditions (see Figures 4.16 through 4.19 as an example to demonstrate the use of this technique to predict the impact of total injection rates). This section shares a few more examples showing how this new technique can be applied.

The first example is to evaluate the effect of transmissibility through shales, slightly permeable (i.e., shale permeability = 5 md, 0.1 md, 0.01 md, and 0.001 md in Figures 4.20(a) through 4.20(d)) rather than impermeable. When the shale layers are allowed to communicate vertically with surrounding layers at the higher injection rate ( $Q_t = 70,075$  ft<sup>3</sup>/day), the results construct contours as shown in Figure 4.20 (this can be compared with Figure 4.18 at the same  $Q_t$  but zero shale permeability). Two main observations are made. First, the presence of shale permeability (Figures 4.20(a) through 4.20(d)) changes the optimum injection foam quality to around  $f_g = 70\%$  (from 55% when no shale permeability (Figure 4.18)), which is caused by more severe gravity segregation for a thicker reservoir. Second, the maximum sweep efficiency is about 37.5%, 40%, 41% and 41% at the shale permeability = 5 md, 0.1 md, 0.01 md, and 0.001 md, respectively, which again shows difficulties in dealing with a thicker reservoir due to gravity segregation. These values are considerably lower than the maximum sweep efficiency (46%) when there is no shale permeability (Figure 4.18). This example emphasizes the importance of detailed and reliable reservoir description for better EOR design and implementation.



(a)

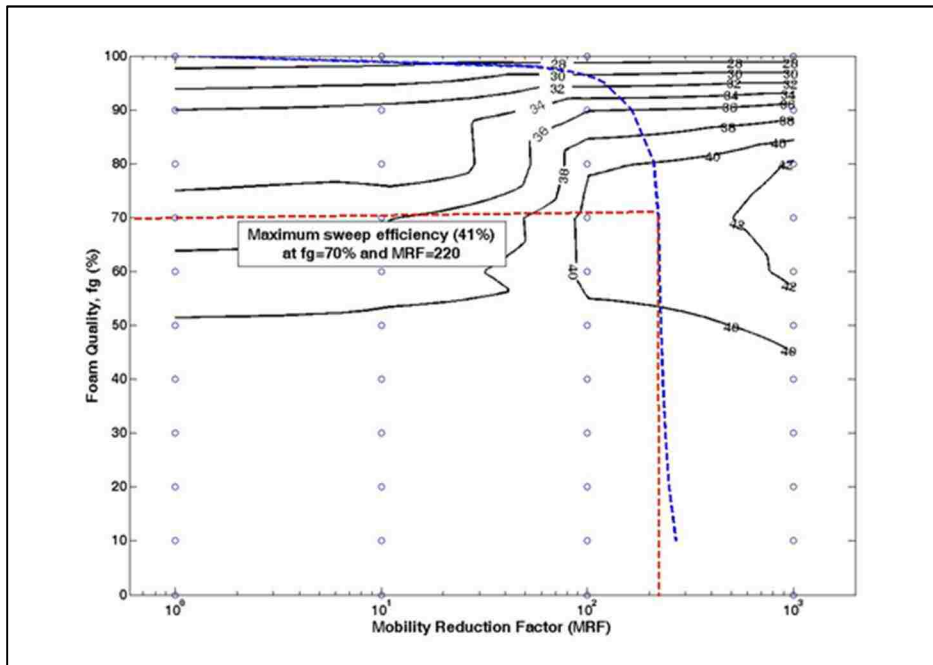


(b)

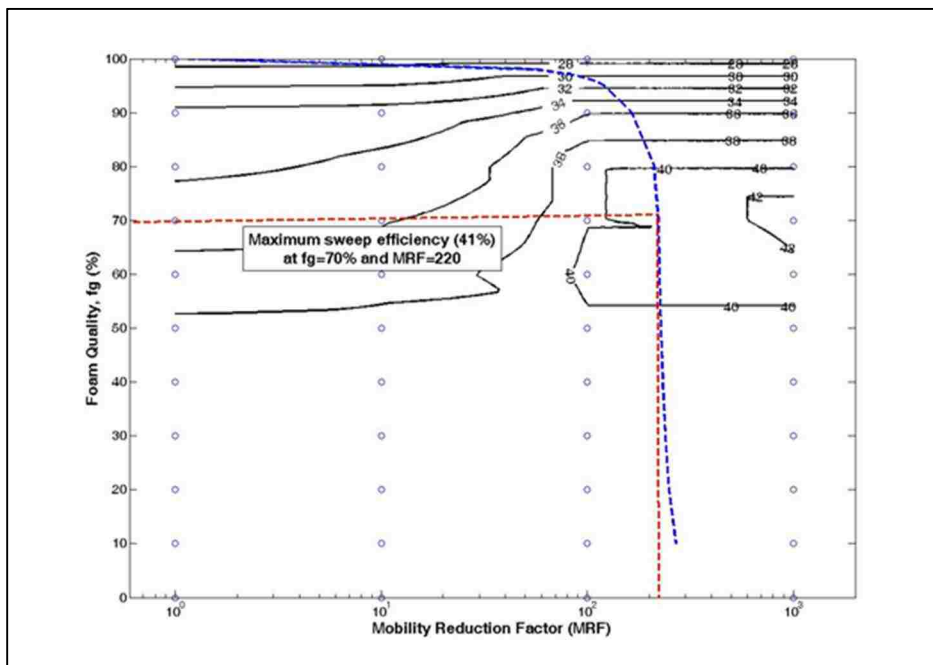
Figure 4.20. Contours showing the effect of shale permeability ( $Q_t = 70,075 \text{ ft}^3/\text{day}$ ) in comparison with no shale permeability (Figure 4.18): (a) shale permeability = 5 md; (b) 0.1 md; (c) 0.01 md; and (d) 0.001 md.



(figure cont'd.)

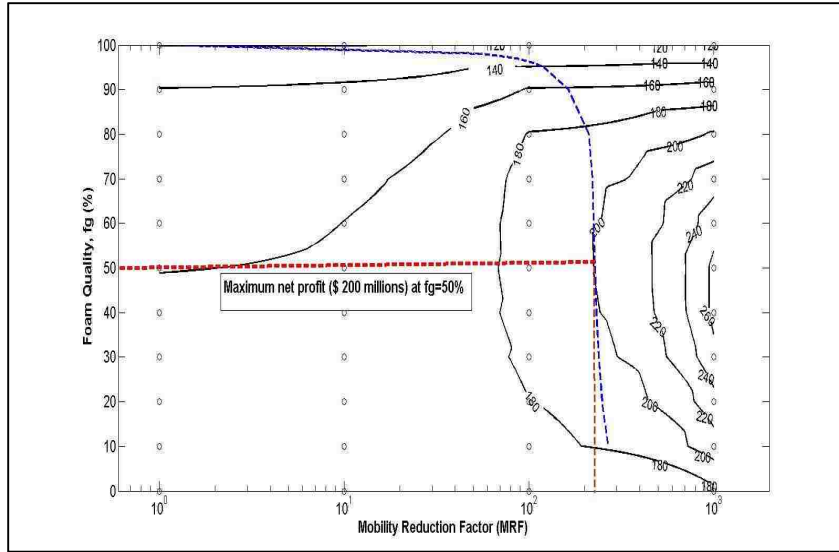


(c)

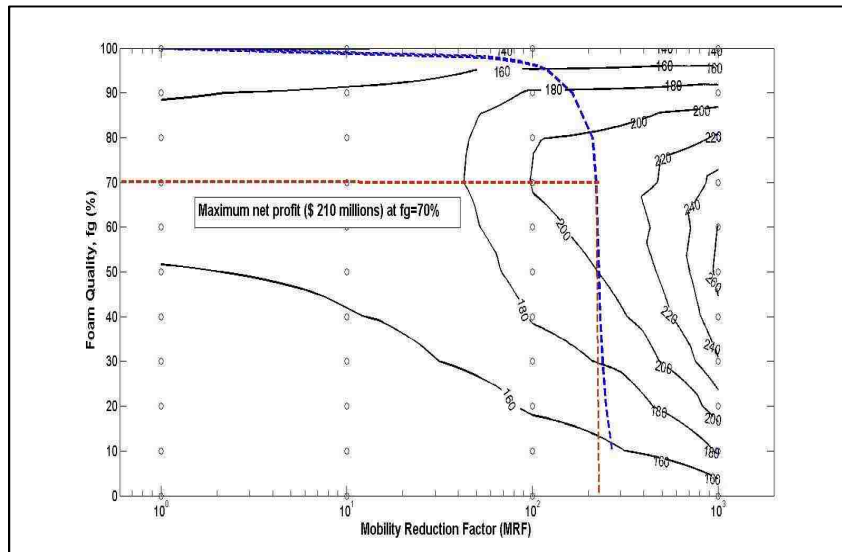


(d)

The second example is to take the effect of CO<sub>2</sub> and surfactant costs into accounts. Suppose one barrel of oil produced from this process makes a net profit of \$30. The sweep efficiency at  $Q_t = 70,075 \text{ ft}^3/\text{day}$  (Figure 4.18) and the corresponding cumulative oil recovery (Table 4.4) allow the total profit contours (in million \$) to be determined as shown in Figure 4.21(a). Note that these contours in Figure 4.21(a) are the same as those in Figure 4.18, but with total profits rather than sweep efficiency values, assuming that CO<sub>2</sub> and surfactant chemicals do not make any price or economic advantages as raw materials to be injected. Using  $f_g = 50\%$  as a basis, suppose CO<sub>2</sub> is advantaged over surfactant chemicals, economically, such that 10% increase in  $f_g$  (meaning 10% reduction in  $f_w$ ) helps the net profit by \$1.00 per barrel of oil produced at the same  $Q_t$ . This means that one barrel of oil has \$30 net profit when  $f_g = 50\%$ , but \$35 and \$25 net profits when  $f_g = 100\%$  and  $f_g = 0\%$ , respectively. This economic advantage of CO<sub>2</sub> over surfactant, as shown in Figure 4.21(b), causes the change in contours, making drier injection condition more favored, shifting the optimum injection  $f_g$  value for maximum net profit (from \$200 million at  $f_g = 50\%$  to \$210 million at  $f_g = 70\%$ ). It should be noted that there is no change in sweep efficiency in Figures 4.21(a) and 4.21(b), but the market and economic situations can distort such an analysis outcome. In addition to CO<sub>2</sub> and surfactant costs, other factors can be incorporated similarly such as oil price, transportation cost, equipment cost, operation cost, and so on.



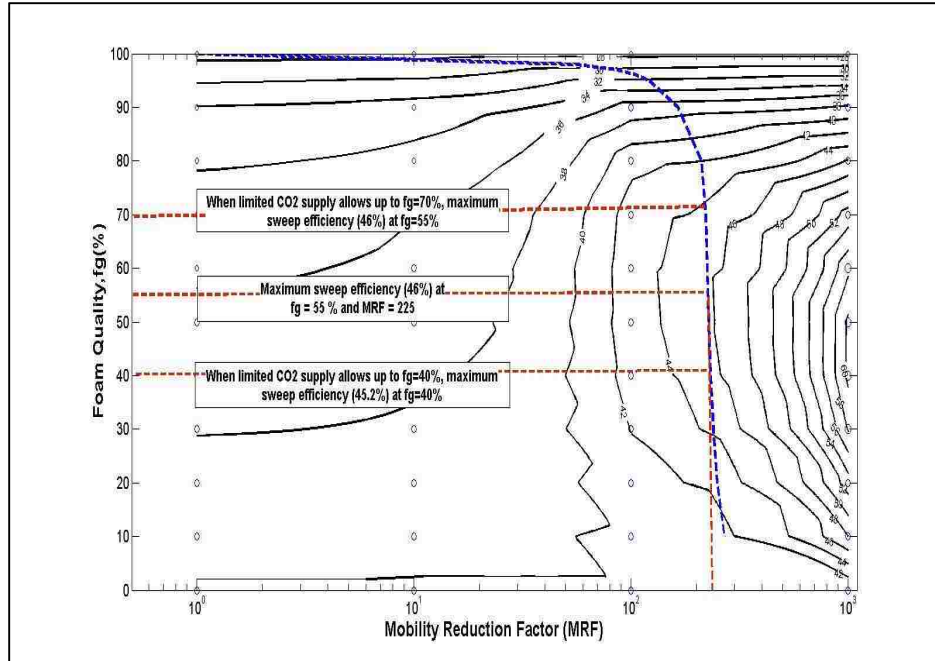
(a)



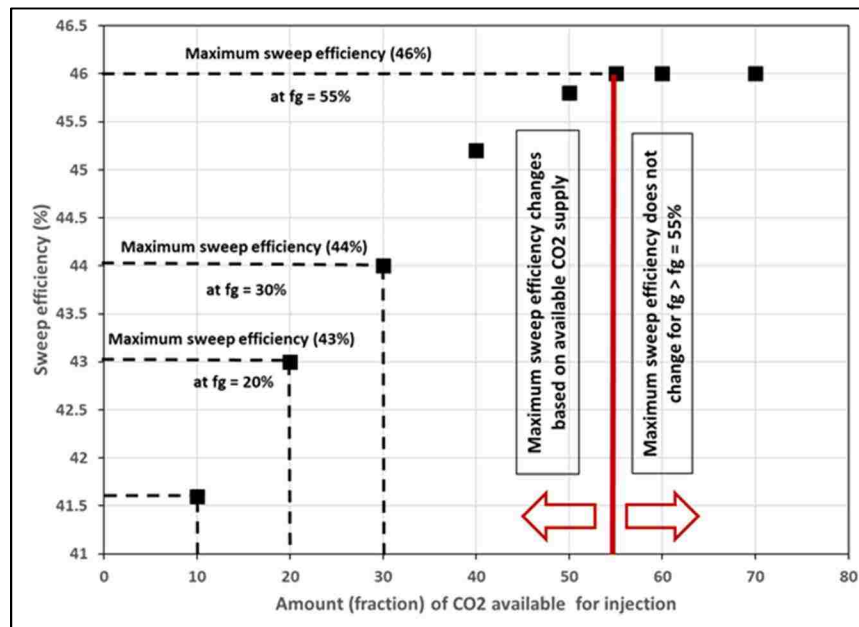
(b)

Figure 4.21. Contours showing total profits (million \$) to find the optimum condition for business decision ( $Q_t = 70,075 \text{ ft}^3/\text{day}$ , Figure 4.18) when the net profit is \$30/bbl: (a) when  $\text{CO}_2$  and surfactant, as raw materials to be injected, make no economic advantages compared each other and (b) when  $\text{CO}_2$  makes economic advantages over surfactant.

The third example is to consider the case when there is a limited supply of CO<sub>2</sub> that may happen, for example, due to geographical and geopolitical aspects. If  $Q_t = 70,075 \text{ ft}^3/\text{day}$  (Figure 4.18) is used as an example, Figures 4.22(a) and 4.22(b) show illustrations with horizontal lines when  $Q_g$  is limited to  $49,053 \text{ ft}^3/\text{day}$  ( $f_g = 70\%$ ) and  $28,030 \text{ ft}^3/\text{day}$  ( $f_g = 40\%$ ), respectively. Such a limitation does not affect the optimum condition if the injection  $f_g$  is greater than the optimum  $f_g$  (Figure 4.22(a)), while it reduces the maximum sweep efficiency if the injection  $f_g$  is less than the optimum  $f_g$  as much as the shift in  $f_g$  due to the limited supply (Figure 4.22(b)). This example can also be used in the field when the quantity of overall CO<sub>2</sub> supply is fixed but needs to be distributed into multiple sectors where each of which has its own optimum condition. Similar approaches can be used when additional constraints exist for other chemicals (e.g., limitation in terms of surfactant chemicals, water supply, etc.)



(a)



(b)

Figure 4.22. Effect of a limited CO<sub>2</sub> supply on the optimum condition ( $Q_t = 70,075$  ft<sup>3</sup>/day, Figure 4.18): (a) sweep efficiency contour lines with such constraints (b) Implication to determine the optimum  $f_g$ .

## 4.6. Conclusions

This study performs reservoir simulations for a sector with one injection well and four production wells in Lisama field, Columbia, in order to determine the optimum injection strategies for gas-water coinjection as well as foam treatments. A wide range of scenarios are evaluated including low, intermediate, and high injection rates ( $Q_t = 23,358, 46,717$  and  $70,075$  ft<sup>3</sup>/day), various injection gas fractions ( $f_g = 100$  to  $0\%$ ), and different foam strengths (no foam, low-strength foam, intermediate-strength foam and high-strength foam with mobility reduction factor (MRF) of 1, 10, 100, 1000). Mechanistic foam model from Izadi and Kam (2018) is applied and calculates MRF values to reflect complex foam rheological properties with two strong-foam flow regimes. The following conclusions can be drawn from this study:

- In all cases investigated at given  $Q_t$  values, the sweep efficiency (or the cumulative oil production) increases with increasing MRF. This indicates the use of mobility-control foam can be a promising solution to improve oil recovery from the field.
- The optimum condition changes with  $Q_t$  values such that the injection  $f_g$  that provides the maximum sweep efficiency increases with increasing  $Q_t$ . This means that at low  $Q_t$ , gravity helps oil recovery for water to support from the bottom, while at high  $Q_t$ , high MRF takes over and becomes a dominating factor making more piston-like displacement front.

- This study shows how the contours of sweep efficiency as a function of injection foam quality and MRF can be used together to come up with the optimum injection strategy graphically, resulting in the maximum oil recovery. How certain constraints present in the field can be applied to determine the optimum injection strategy (i.e., total injection rates and foam quality) is also demonstrated graphically by using examples. These examples also prove the versatility and robustness of this technique of combining sweep-efficiency contours and MRF- $f_g$  path.

## CHAPTER 5. CONCLUSIONS AND RECOMMENDATIONS

The conclusions related to each topic are provided at the end of each chapter.

After putting all results together, the followings summarize the findings of this study:

- Model fit to laboratory experimental data is necessary to calibrate mechanistic foam models. Supercritical CO<sub>2</sub> foam has very low mobilization pressure gradient ( $\nabla P_0$ ), and therefore it has unique advantages compared to other gaseous foams (gas CO<sub>2</sub>, N<sub>2</sub>, hydrocarbon, flue gas etc.) to create stable foams at low pressure-gradient environment and place foams deep into the reservoir.
- Mechanistic foam modeling can help designing field foam EOR processes including reservoir-scale simulations. Such an example is shown with CMG STARS foam simulations (with gas mobility taken from mechanistic modeling) is demonstrating how to select optimum injection conditions in terms of injection foam quality and injection rate.

The following recommendations can be made based on this study:

- When coreflood experiments are conducted, additional experiments to capture the transition from weak foam to strong foam are highly recommended. This onset of strong foam generation can greatly improve the quality of mechanistic foam modeling. At a minimal level, a series of coreflood data is needed for model fit, such as steady-state pressure measurements varying total velocity at the same foam quality, varying gas velocity at the same liquid velocity, or varying liquid velocity at the same gas velocity, as shown in this study.



- Not many coreflood experimental studies in radial geometry are available in the literature. Such experimental data would be very valuable to calibrate foam model, filling the gap between small lab-scale linear flow experiments and large-scale radial flow field EOR processes.
- This study only focuses on the steady-state responses. Dynamic transient simulations are required to investigate how the system changes with time. The presence of oil in the reservoir should be accounted for in realistic EOR applications to calculate oil recovery.

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## **VITA**

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