

## **Paper 5**

**Gravity segregation of foam  
using different injection methods**



# Gravity segregation of foam using different injection methods

Research report from work performed at University of Texas, Spring 2005.

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## Summary

In this study we have done foam injection simulation to investigate gravity segregation of injected liquid and gas. Especially we have focused on different injection methods influence on the gravity segregation length in cylindrical, homogenous reservoirs. The main issue for these experiments was to see if the different injection methods would improve the gravity segregation of foam in a reservoir. All the values for the segregation length from the simulations are compared to analytical models for gravity segregation. These models are explained in details by Shi and Rossen [1], Stone [2], and Jenkins [3].

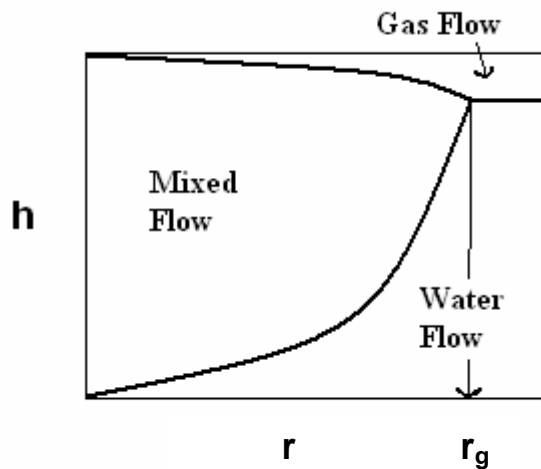
We have used the STARS simulator from Computer Modeling Group, Calgary, to simulate the different injection cases. Four different injection methods were used: 1) Co-injection in the bottom of the reservoir, 2) Uniform co-injection, 3) Injection of surfactant solution above gas, where gas is injected in the bottom half of the reservoir and surfactant solution in the upper half of the reservoir and 4) Injection of surfactant solution above gas in the bottom 2/5 of the reservoir. In all different cases a cylindrical reservoir has been used.

Different foam and reservoir parameters were varied to test the different injection methods. The reservoir size, the ratio between the horizontal and vertical permeability and the foam parameters in STARS have been varied. In some experiments the foam quality and the permeability in the horizontal direction were also varied. For most of the simulations the total injection rate are chosen so that the foam segregated at a distance of 75% of the total reservoir radius.

The results of these experiments indicate that the segregation length is almost identical for the four injection methods, when all other parameters are fixed. The uniform co-injection and the bottom co-injection cases gave approximately identical segregation lengths. Injection of surfactant solution above gas in the bottom of the reservoir also gave approximately the equal segregation length. For the case where water was injected in the upper half reservoir and gas in the bottom half reservoir, the segregation length was a bit larger than the other methods, but it is hard to say if this difference is significant.

# 1 Introduction

Applications of foam within improved oil recovery include foam for mobility control, and the use of foam to shut off unwanted production of gas in production wells [4-8]. Several of these projects have been successful, both technically and economically. There remain, however, many challenges in the description of foam properties and in, particularly, the prediction of foam behavior. Gas is much less dense than oil; therefore it tends to migrate to the top of the reservoir, overriding oil rich zones. Foam can reduce gas mobility significantly and prevent override, and in this way improve sweep efficiency. When surfactant solution and gas or pre-generated foam is injected into a reservoir, the fluids will eventually segregate in a gas phase and a liquid phase due to gravity (Figure 1). The position at which foam segregates is called the segregation length ( $r_g$ ).



**Figure 1: Schematic figure of the three zones in a cross-section of a foam flooded reservoir.**

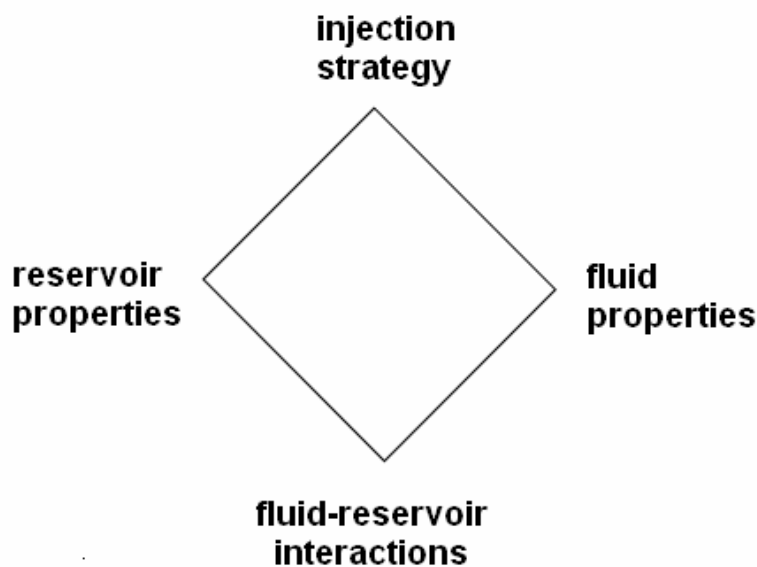
In this study we have focused on different injection methods influence on the gravity segregation length. First we have done a sensitivity study to see how changes in foam and reservoir properties influence the segregation length. We have also compared computer simulations of foam, simultaneous injection of surfactant and gas, to the analytical model presented by Stone [2] and Jenkins [3]. They originally derived this model for the water alternating gas injection method, but Shi and Rossen [1] have proved that it is also valid for foam displacement. Simulations were done for a wide range of foam and reservoir properties. Although Stone [2] and Jenkins [3] derived their models for displacement with oil present, for simplicity we have performed simulations without oil. The STARS simulator from the Computer Modeling Group (CMG) of Calgary, Canada, has been used in these simulations.

## 2 Method

First a few simulations without foam were done. Then a great number of different 2D simulations using a wide range of variation in the reservoir and fluid parameters were done. This will be explained in further detail in the next chapters.

### 2.1 Sensitivity study

The different areas in the sensitivity study are shown in Figure 2. The different parameters in each area of the sensitivity study are described in further detail below. The fluid-reservoir properties, where the main parameter is adsorption, have not been considered in this study.



**Figure 2: Sensitivity study**

#### Injection strategy

1. injection method
2. total injection rate
3. foam quality

#### Reservoir properties

1.  $k_z/k_x$  ratio
2. reservoir size

#### Fluid properties

1. Foam properties: The dimensionless interpolation factor FM that consists of the mobility reduction factor fmmob and 6 different functions. Only fmmob and two of the functions are used in this study.
2. solubility (has not been considered in this study)

#### Fluid-reservoir interactions

(have not been considered in this study)

### **2.1.1 Injection strategy**

The main issue in this study was to investigate injection methods influence on gravity segregation length of foam. Four different injection methods were used: co-injection from the bottom, uniform co-injection, injection of water/surfactant above gas where liquid is injected in the upper half and gas in the lower half of the reservoir, and liquid above gas injection in the bottom of the reservoir. The steady-state condition for the four different injection methods has been compared. The pathway in the simulation from the beginning to the steady-state has not been considered or compared for the different injection methods.

The range of the injection rate was varied such that the foam segregates within the reservoir. Most injection rates were chosen so that the foam segregated at about 75% of the reservoir length.

80% foam quality was used in most of the simulations, but 65% and 95% have also been used. The foam quality is the gas volume fraction in the foam.

### **2.1.2 Reservoir properties**

The horizontal permeability was kept at 1 D in all experiments, and the vertical permeability was either 0,1 D or 1 D. In this way the ratio between the vertical and horizontal permeability will be either 0,1 or 1.

The reservoir size was also varied to investigate the sensitivity and match to the Stone-Jenkins model using different reservoir height-length ratios.

### **2.1.3 Fluid properties**

The dimensionless interpolation factor FM, which includes the mobility reduction factor  $f_{mob}$ , has been varied to investigate foam with different strength. The different foam parameters are described in detail in chapter 3.

## **2.2 Stone and Jenkins model**

Stone and Jenkins model assume that when liquid and gas segregates, three regions with sharp boundaries between them will be observed in the reservoir: a foam zone of uniform saturation and mixed flow, an override zone in which no water flows, and an underride zone in which no gas is present (Figure 1). The other assumptions for the Stone and Jenkins model are explained in further detail by Stone [2], Jenkins [3], and Shi and Rossen [9]. Stone [2] and Jenkins [3] derived equations for the distance that the injected gas-liquid mixture flows before complete segregation ( $L_g$  in a rectangular reservoir and  $r_g$  in a cylindrical reservoir). Complete segregation means that only gas is flowing in the upper part of the reservoir and only water in the lower part. The Stone and Jenkins model for radial flow is given on the next page. The equation for  $L_g$  in rectangular reservoirs is found elsewhere [1, 2, 3].

$$\left( \frac{r_g}{r} \right)^2 = \frac{q_t}{k_z \cdot \Delta\rho \cdot a \cdot g \cdot \left( \frac{k_{rw}}{\mu_w} + \frac{k_{rg}}{\mu_g} \right)}$$

$r_g$	segregation length
$r$	outer radius of the reservoir
$q_t$	total injection rate
$k_z$	permeability in vertical direction
$\Delta\rho$	density difference between surfactant solution and gas
$a$	area, see formula below
$g$	gravity constant, 9,81 m/s <sup>2</sup>
$k_{rg}$	relative permeability of gas
$k_{rw}$	relative permeability of water
$\mu_w$	water viscosity
$\mu_g$	gas viscosity

For simulations using only a sector of a 360° reservoir the following equation for the area is used:

$$a = \pi \cdot r^2 \cdot \left( \frac{X}{360} \right)$$

$X$  degree of sector used in the simulation

The sector used in the 2D simulations is 45°.

This Stone [2] and Jenkins [3] analytical model gave a better understanding of gravity segregation in water alternation gas displacements without foam. Later Shi and Rossen [1] have shown that the model also applied to foam displacements.

$$r_g = \sqrt{\frac{q_t \cdot f_w}{k_z \cdot \Delta\rho \cdot \pi \cdot \left( \frac{X}{360} \right) \cdot g \cdot k_{rw}}}$$

$f_w$  water fractional flow in the foam

The theoretical value for the segregation length was calculated and compared to the simulation value in each simulation.

### 3 The STARS foam model

STARS, developed by the Computer Modeling Group (CMG) of Calgary, Canada, are the most widely used commercial foam simulator [10]. STARS is a three-phase multi component thermal and steam additive simulator. Cartesian or cylindrical grid systems can be used. In this work a cylindrical grid model were used in all 2D simulations. STARS can be used to simulate polymer, gel, emulsion and foam applications. For such cases the stabilized droplets or bubbles can be treated as components in the carrying phase. More complex problems like adsorption, blockage, dispersion and so forth can be considered. For simplicity, foam mobility reduction is determined through a modified gas relative permeability curve. A dimensionless interpolation factor, **FM**, is used as a weighting factor to determine gas relative permeability for a certain foam strength. At the lower limit of FM, the lowest foam mobility is determined by a reference gas relative permeability.

#### 3.1 FM, the dimensionless interpolation factor

The dimensionless interpolation factor, FM, depends on fmmob and 6 different functions F1-F6.

$$FM = \frac{1}{1 + fmmob \cdot F1 \cdot F2 \cdot F3 \cdot F4 \cdot F5 \cdot F6}$$

fmmob	reference mobility reduction factor
F1-F6	are functions that are dependent on the following properties:
F1	surfactant concentration
F2	water saturation
F3	oil concentration
F4	gas velocity
F5	capillary number
F6	critical capillary number

For each of the functions F1-F6, FX is one (X=1-6) when the foam is at maximum strength with respect to the dependent property. In this study only fmmob, F1 and F2 have been applied. These parameters will be described in further detail in the next chapters. In F3 the parameters are chosen depending on how sensitive the foam is to foam-oil interactions. F4 or F5 can be chosen to represent shear thinning effects and F6 can be used to add effects of the capillary number. The functions F3-F6 were all set equal to 1 representing maximum foam strength. Further details about F3-F6 can be found elsewhere [10].

The linear interpolation, FM is unity without foam, and decreases with the increasing foam strength (fmmob increases). The values of the parameters in the different FX-functions can be chosen in such a way that they have a great effect on FM or in a way that hardly gives any effect on FM.

##### 3.1.1 Fmmob

Fmmob is the reference mobility reduction factor. The simplest application of the foam interpolation option in STARS is to rescale gas relative permeability,  $k_{rg}$ , by dividing  $k_{rg}$  by fmmob.  $k_{rg}$  (simulator) for foam will have a value between the  $k_{rg}$  (no foam) curve and the



$k_{rg}/fmmob$  curve. If  $fmmob$  is high (100, 1000 and so forth) the  $k_{rg}$  (simulator) will be approximately equal to the  $k_{rg}$  (reference) value.

To rescale the  $k_{rg}$  curve the keyword *\*DTRAPW* has to be set equal to one divided by  $fmmob$  and the keyword *\*krgcw* has to be equal to the first entry of  $k_{rg}$  in the liquid-gas relative permeability curve divided by  $fmmob$  for the relative permeability tables for foam. *\*DTRAPW* is the value of wetting phase interpolation parameter for current rock-fluid data set. *\*krgcw* is the relative permeability to gas at connate liquid saturation.

### 3.1.2 F1

F1 is the surfactant concentration dependent function.

$$F1 = \left[ \frac{W_s}{fmsurf} \right]^{epsurf}$$

$W_s$	surfactant concentration in the grid block
$fmsurf$	critical surfactant concentration
$epsurf$	parameter that controls the gas mobility's dependence on surfactant concentration

$fmsurf$  represent the critical surfactant concentration. The foam is weaker if the surfactant concentration,  $W_s$ , in the grid block is below this value.

$fmsurf$  and  $epsurf$  are kept constant in this study.

### 3.1.3 F2

F2 is the water saturation dependent function.

$$F2 = 0,5 + \frac{\arctan(epdry(S_w - fmdry))}{\pi}$$

$S_w$	water saturation in the grid block
$fmdry$	critical water saturation
$epdry$	regulates the slope of the gas relative permeability curve near the critical water saturation

Foam mobility in the reservoir is dependent on the critical water saturation,  $fmdry$ , especially when the water saturation in the grid block is close to  $fmdry$ . When the water saturation is close to  $fmdry$ , the foam is about to collapse. Because of this the gas relative permeability will change dramatically in the region around  $fmdry$ . Maximum foam strength is achieved at water saturations well above the critical water saturation. The  $epdry$  value is important for prediction of the water saturation needed to get maximum foam strength. The maximum foam strength is achieved at lower water saturation for higher values of  $epdry$ .  $epdry$  is kept constant in this study.

## 4 Simulations input data

All simulations were done without oil present, and the gas was considered as incompressible. Simultaneous injection of gas and water or surfactant solution is used in all simulations, either co-injected or injected in separate intervals. The adsorption of surfactant is set to zero. The reservoirs are homogenous and are initially filled with brine.

### 4.1 1D simulation–theoretical fitting

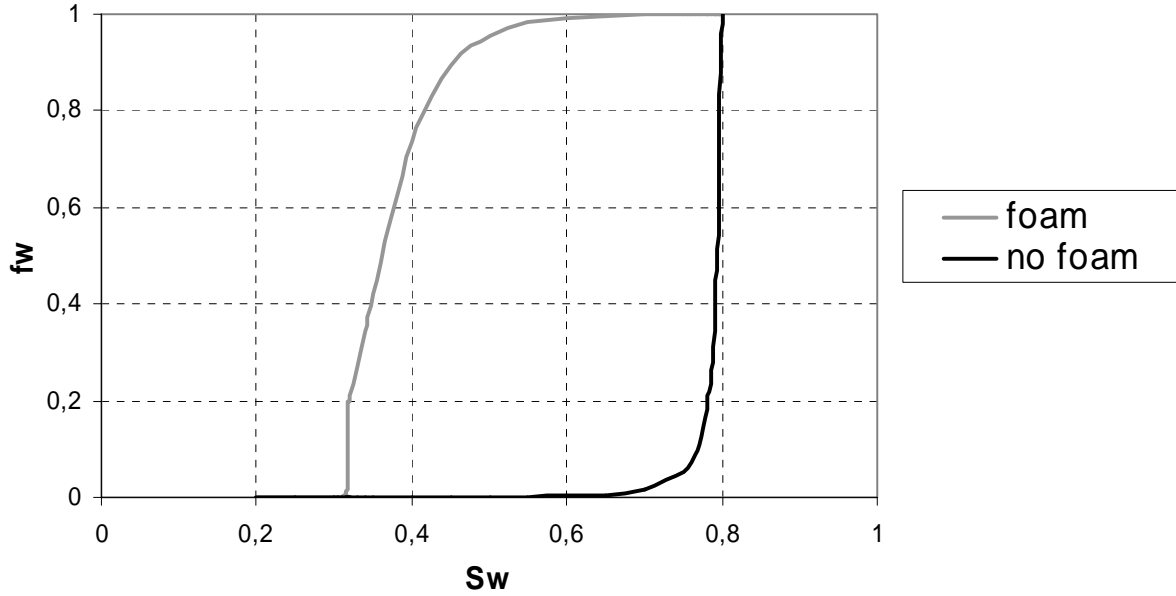
Using some assumptions the fractional flow theory can be used to predict dynamic foam displacement. Fixed capillary pressure and one dimensional flow are two of the assumptions used. This is explained in further detail by Rossen and Zhou [11] and Rossen [12]. Two different 1D simulations were performed. In simulation setup 1 the foam parameters and the fluid model are identical to the values used the diploma thesis of Reme [13]. In simulation setup 2 the foam parameters were more similar, and the fluid model was equal to the values used in the 2D simulations. The fluid model is explained in further detail in chapter 4.2.4. The parameters used in the two 1D rectangular simulations are given in Table 11, Table 12 and Table 13 in the appendix. One injector and one producer were used, and the flow was in the horizontal j-direction.

Simulation results were compared to the fractional flow theory. The relative permeability functions for gas and water are given in chapter 4.2.4. The fractional flow of water was calculated using the formula below.

$$f_w = \frac{1}{1 + \left( FM \frac{k_{rg} \mu_w}{\mu_g k_{rw}} \right)}$$

$f_w$	fractional flow of water
FM	the dimensionless interpolation factor
$k_{rg}$	relative permeability of gas
$k_{rw}$	relative permeability of water
$\mu_w$	water viscosity
$\mu_g$	gas viscosity

The fractional flow curve for foam and no foam cases for simulation setup 1 is presented in Figure 3.



**Figure 3: Fractional flow curve for foam and no foam for the 1D simulation setup 1.**

The theoretical water saturation value was compared to the corresponding water saturation reported in the simulator. The relative permeability for gas and water at this water saturation was found. In addition, the theoretical pressure gradients for the two phases were calculated. These pressure gradients ought to be equal and also equal to the pressure reported in the simulations. Because of the fixed capillary pressure model explained by Rossen and Zhou [11] and Rossen [12], the Darcy's law can be used to calculate the pressure gradient. The formulas for pressure gradients for water and gas are given below.

$$\nabla P_w = \frac{u_w \cdot \mu_w}{k \cdot k_{rw}}$$

- $\nabla P_w$  Pressure gradient for the water phase
- $u_w$  volumetric flux of water
- $k$  absolute permeability
- $k_{rw}$  relative permeability of water
- $\mu_w$  water viscosity

$$\nabla P_g = \frac{u_g \cdot \mu_g}{k \cdot k_{rg}} \cdot \frac{1}{FM}$$

- $\nabla P_g$  Pressure gradient for the gas phase
- $u_g$  volumetric flux of gas
- $\mu_g$  gas viscosity
- $k_{rg}$  relative permeability of gas
- $FM$  the dimensionless interpolation factor

## **4.2 2D simulation**

Most of the simulations were foam cases, but some no foam cases were performed. In the no foam cases brine was injected instead of surfactant solution. This was the only difference, the rest of the parameters were identical for both cases. In general the simulation period was  $10^6$  hours. The time the computer needed to do one simulation varied. Most of the simulations used only a few minutes, while others lasted for several hours. In the experiments gas was considered as non condensable. An example input file of water above gas injection in the bottom of the reservoir (simulation no. 10, see Table 9) is given in the Appendix.

### **4.2.1 Injection strategy**

To get a uniform injection, one injection well for each fluid in each grid block was used. The gas injection rates were equal in all of the gas injection wells and the water injection rates were equal in all of the water injection wells in the reservoir. The well radius was 0,1 ft in all simulations, and there were 10 grid blocks in the vertical directions in the reservoirs.

#### **1) Co-injection in the bottom of the reservoir:**

In this case surfactant solution and gas were co-injected in the bottom 20% of the total height of the reservoir. Two injection wells, one for gas and one for water, in each of the bottom two grid blocks were used.

#### **2) Uniform co-injection:**

In the uniform co-injection case equal amounts of water and gas was injected over the whole reservoir height. The total numbers of injection wells are 20, two in each of the 10 layers, one injection well for water and one injection well for gas in each layer.

#### **3) Injection of surfactant solution above gas using the entire reservoir height:**

In the third case surfactant solution was injected in the upper half of the reservoir and gas was injected in the lower half of the reservoir. The well configuration used was one injection well for water in each of the upper five grid blocks and one injection well for gas in each of the bottom five grid blocks.

#### **4) Injection of surfactant solution above gas in the bottom of the reservoir:**

In the case of injection of liquid above gas in the bottom 2/5 of the reservoir, gas was injected in the bottom two grid blocks (20% of the reservoir height) and surfactant solution in the two grid blocks directly above that. The number of injection wells was four for this case, gas was injected in the two lowest wells and water was injected in the two other wells.

### **4.2.2 Production**

There was only one production well in each reservoir model. The well was situated in the outer most grid block and was open over the whole reservoir height. The well radius for the production well and injection wells were all equal, 0,1 ft.

### 4.2.3 Reservoir properties

The reservoir was initially saturated with brine. Surfactant solution or water was then co-injected with gas. The mole fraction of surfactant was 0,0003% in the injected surfactant solution. Reservoir constants are given in Table 1 and grid distribution in the reservoir in Table 2.

**Table 1: Reservoir constants**

Parameter	Values
Porosity	20%
$k_x$ (horizontal)	1 D
Initial pressure	4500 psi
Back pressure	4300 psi
Max. operate pressure at injection well	12000 psi
Temperature	68° F

**Table 2: Grid distribution**

	i	j	k
Number of grids	50	1	10
Grid size	increasing	45°	uniform
500 ft reservoir	1 1,5 2,5 4 6 7 8 8 42*11 ft		
50 ft reservoir	0,5 0,5 0,6 0,7 0,8 0,8 1 1 42*1,05 ft		

In most simulations the grid blocks were smallest near the injection well and were increasing in the radial direction as shown in Table 2. In some simulations a uniform grid distribution was used, due to time step problems using the grid distribution given in Table 2. Especially in many simulations using a large injection rate this uniform distribution were used.

In some of the simulation the radius of the reservoir, the height of the reservoir or the ratio between the vertical and horizontal permeability were varied. The values used are given in Table 3. The horizontal permeability was always 1 D, and the vertical permeability was either 1 D or 0,1 D. In this way the permeability ratio is either 0,1 or 1 (Table 3).

**Table 3: Variation in reservoir parameters**

Parameter	Value 1	Value 2
radius (ft)	50	500
height (ft)	10	100
$k_z/k_x$	0,1	1

The reservoir with 500 ft radius and 100 ft height was used in a great number of simulations. In addition long and thin reservoirs (radius 500 ft and height 10 ft) and short and thick reservoirs (radius 50 ft and height 100 ft) were used in the simulations.

#### 4.2.4 Fluid Parameters

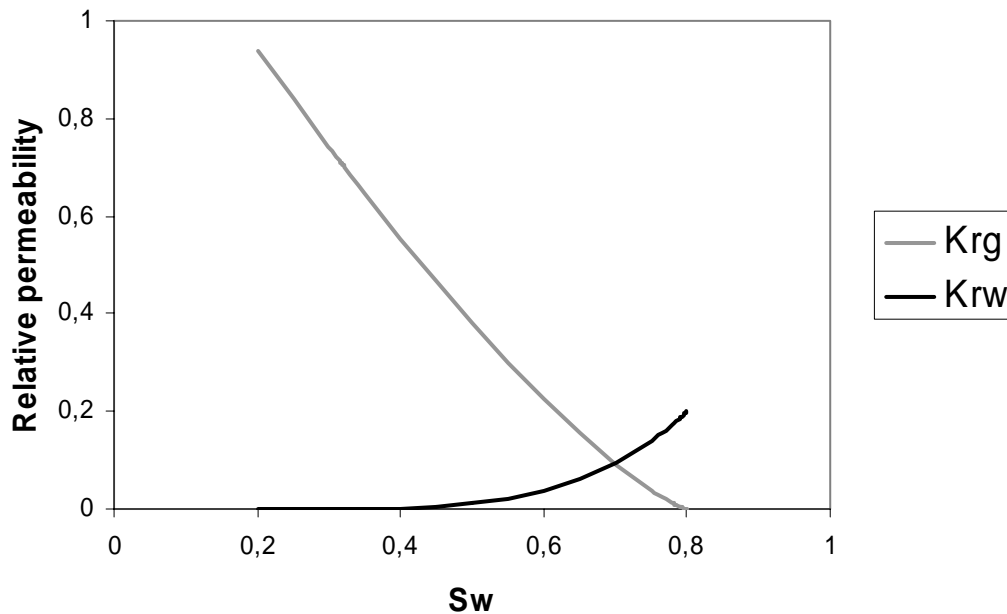
The water viscosity was 1 cp and the gas viscosity was 0,01886 cp. The gas viscosity was determined by the simulator based on the temperature in the reservoir and the fluid model.

The relative permeability functions used in the simulations are given below.

$$k_{rw} = 0,2 \left[ \frac{S_w - 0,2}{0,6} \right]^{4,2}$$

$$k_{rg} = 0,94 \left[ \frac{0,8 - S_w}{0,6} \right]^{1,3}$$

$k_{rw}$  relative permeability of water  
 $k_{rg}$  relative permeability of gas  
 $S_w$  water saturation



**Figure 4: Relative permeability curves.**

The simulator allows you to use different fluid models. The model is entered as: a b c d, where:

- a is the number of components
- b is the number of fluids
- c is the number of components in the liquid phase
- d is the number of water like components

In all the 2D simulations a 3 3 2 2 fluid model is used. (a= water, surfactant and gas, b= water, surfactant and gas, c= water and surfactant and d= water and surfactant) This means that gas is only allowed in gas phase.

### 4.2.5 Foam parameters

The foam quality is 80% in most of the simulations. A few simulations with 65% and 95% foam quality are also done. The values of the foam parameters used in the simulations are presented in Table 4. The only foam parameters that are varied in this study are the  $f_{mob}$  and  $f_{dry}$ , the other foam parameters are constant in all the simulations.

**Table 4: Foam parameters**

Foam parameter	value
$f_{mob}$	100 or 1000
$f_{dry}$	0,3 or 0,5
$e_{pdry}$	1000
$f_{msurf}$	$1 \cdot 10^{-5}$
$e_{psurf}$	1

The contour plots for the different combinations of  $f_{mob}$  and  $f_{dry}$  are given in the appendix. In a contour plot the volumetric flux of water,  $u_w$ , is plotted against the volumetric flux of gas,  $u_g$ , for different pressure gradients. By plotting the parameters in such a way it is possible to distinguish between the high and low foam quality regime. The contour lines will be close to horizontal in the low quality regime and close to vertical in the high quality regime.

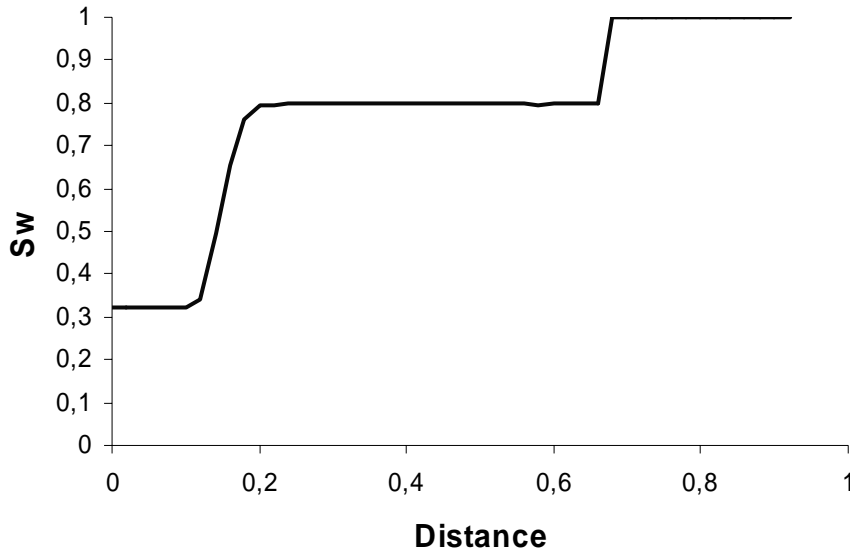
### 4.3 2D fitting to Stone Jerkins model

For each foam simulation the segregation length were compared to the theoretical value for the segregation length. The theoretical values for the segregation length were calculated using the formula in chapter 2.2.

## 5 Results

### 5.1 1D –theoretical fitting

Figure 5 presents the phase saturation profile for a simulation using setup 1 after 0,24 pore volume gas has been injected into the core model.



**Figure 5: Phase saturation profile after 0,24 pore volume gas injected into a brine filled core model.**

As shown in Table 5 and Table 6 there is a good match between the theoretical values from the fractional flow theory and the values from the simulator.

**Table 5: Simulation fitting values for simulation setup 1**

	calculated	simulator
$\nabla P_w$	187,39 psi/ft	183,51 psi/ft
$\nabla P_g$	188,50 psi/ft	
Sw	0,3191	0,3206

**Table 6: Simulation values for simulation setup 2.**

	calculated	simulator
$\nabla P_w$	3,75 psi/ft	3,72 psi/ft
$\nabla P_g$	3,74 psi/ft	
Sw	0,4600	0,4581



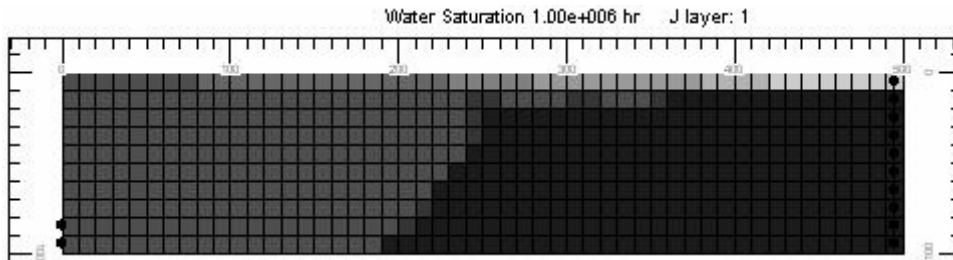
## 5.2 No foam 2D simulation

### 5.2.1 Injection strategy

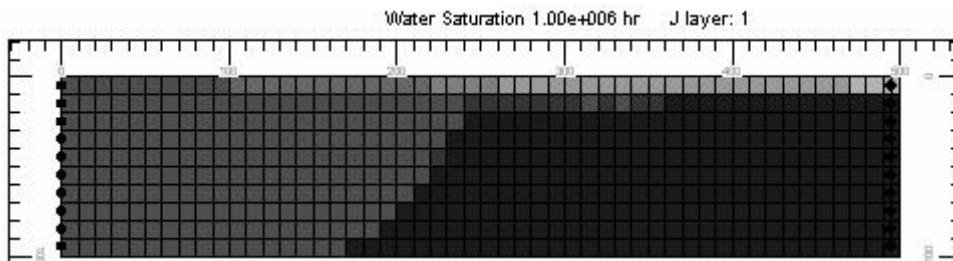
The different injection methods gave approximately identical segregation lengths (Table 7). The shapes of the foam bank are also quite similar for the four different injection methods. The figures of the water saturation for the different injection method are presented in Figure 6– Figure 9.

**Table 7: No foam simulations**

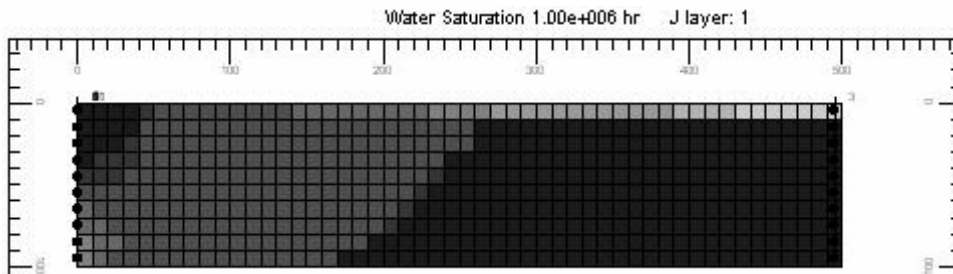
Segregation length (ft)				Reservoir and foam parameters			$Q_i$ (ft <sup>3</sup> /h)
Bottom injection	Uniform injection	Water above gas		r (ft)	h (ft)	kz/kx (D)	
		Upper 50% of h	In the bottom of the reservoir				
250	240	260	270	500	100	1	432



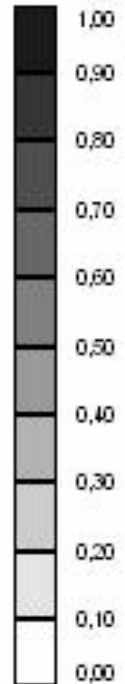
**Figure 6: Water saturation for no foam simulation using bottom co-injection.**

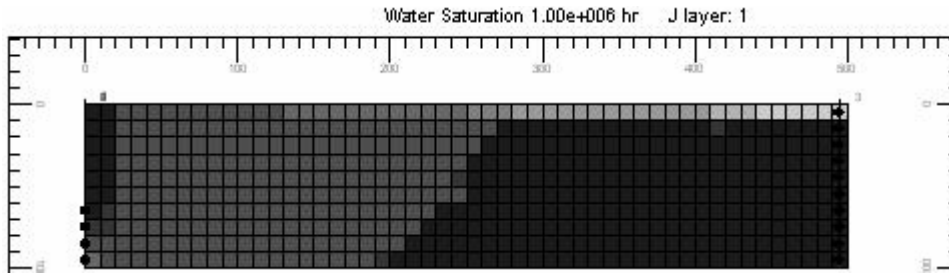


**Figure 7: Water saturation for no foam simulation using uniform co-injection.**



**Figure 8: Water saturation for no foam simulation using injection of water in the upper half and gas in the lower half of the reservoir.**





**Figure 9: Water saturation for no foam simulation using injection of water above gas in the bottom of the reservoir.**

## 5.3 Foam 2D simulations

### 5.3.1 Injection strategy

Both the segregation lengths and the shapes of the foam bank are a bit different for the four different injection methods. For the bottom and the uniform co-injection methods the foam bank is quite vertical at the point of segregation. For the two cases of injection of water above gas the slope of the foam bank at segregation is less steep. It is hard to say whether or not there are any major differences in gravity segregation length between the four injection methods. Both methods of injection of water above gas have slightly longer segregation lengths than the uniform co-injection case. The bottom co-injection case has the shortest segregation length. This is valid for many of the simulations, but far not for all of them, and the difference in most cases is quite small.

Table 8 show reservoir properties, foam parameters, total injection rates and the segregation length for a great number of different simulations using the four injection methods. The constant reservoir and foam parameters are given in the simulation input data chapter.

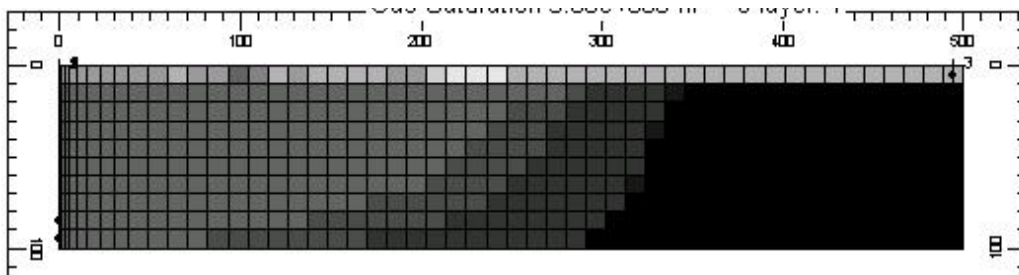
In the 500 ft radius and 100 ft height reservoirs, the segregation lengths were stable after about 50000 hours. For the tall and short reservoirs, radius 50 ft and height 100 ft, the simulations needed  $10^6$ h or longer time to get to steady state. The long and thin reservoirs, radius 500 ft and height 10 ft, needed about 5000h to get to steady state. Many of these last kinds of reservoirs had problems running properly because the total injection rate per ft was so large. At steady-state the surfactant concentration is zero in the gas override zone and uniform in the rest of the reservoir.

Stones model for cylindrical reservoirs were used. The theoretical segregation lengths of the experiments in Table 8 are 300 ft, for the 500 ft radius reservoirs and, 30 ft for the 50 ft radius reservoirs. In all these calculations a gas density of  $370 \text{ kg/m}^3$  and a gas viscosity of 0,01886cp were used.

**Table 8: Results of simulations with variation in injection method**

SIM No.	Segregation length (ft)				Reservoir and foam parameters					Q <sub>t</sub> (ft <sup>3</sup> /h)
	Bottom injection	Uniform injection	Water above gas		r (ft)	h (ft)	kz/kx (D)	fmmob	fmdry	
			Upper 50% of h water	In the bottom of the reservoir						
1	29	35,3	39,5	36,4	50	100	0,1	100	0,3	0,37
2	291	335	390	357	500	100	0,1	100	0,3	37
3	300	302	379	335	500	10	0,1	100	0,3	37
4	29	35,3	42,7	35,3	50	100	1	100	0,3	3,7
5	335	313	423	346	500	100	1	100	0,3	370
6	30,1		42,7	34,2	50	100	0,1	1000	0,3	0,08
7	313	335	390	313	500	100	0,1	1000	0,3	7,7
8	368	335	324	346	500	10	0,1	1000	0,3	7,7
9	30,1	36,4	40,6	36,4	50	100	1	1000	0,3	0,77
10	368	335	368	324	500	100	1	1000	0,3	77
11	29	34,3	39,5	34,2	50	100	0,1	100	0,5	0,37
12	302	291	346	346	500	100	0,1	100	0,5	37
13		313	346	335	500	10	0,1	100	0,5	37
14	29	31,1	37,4	35,3	50	100	1	100	0,5	3,7
15	291	269	258	324	500	100	1	100	0,5	370
16	28		35,3	32,2	50	100	0,1	1000	0,5	0,08
17	225	258	258	225	500	100	0,1	1000	0,5	8
18	260	240	269	204	500	10	0,1	1000	0,5	8
19	28	19,6	26,9	26,9	50	100	1	1000	0,5	0,8
20	258	225		258	500	100	1	1000	0,5	80

In some cases the shape of the foam bank for simulations where water was injected in the upper half of the reservoir and gas in the lower half of the reservoir was very different from the other injection methods; see Figure 10 - Figure 13. The figures show the water saturation for the different injection methods from simulation no. 2 (Table 8). The water saturation in the foam bank is almost uniform in the uniform and bottom co-injection simulations.



**Figure 10: Water saturation for simulation no. 2 using bottom co-injection.**

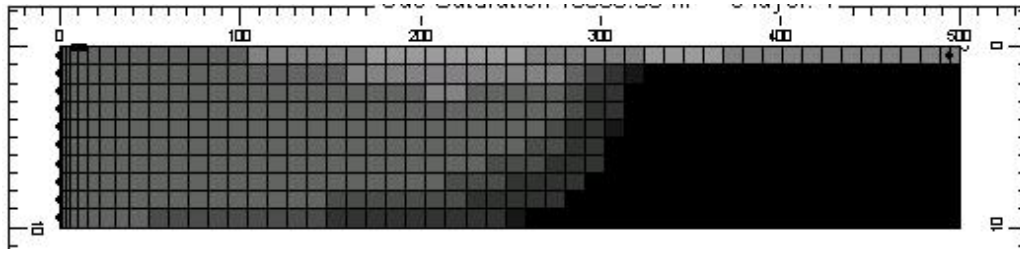


Figure 11: Water saturation for simulation no. 2 using uniform co-injection.

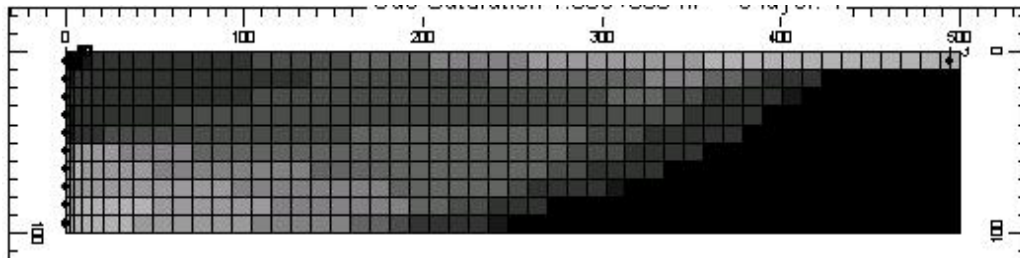


Figure 12: Water saturation for simulation no. 2 using injection of water the upper half of the reservoir and gas in the bottom half of the reservoir.

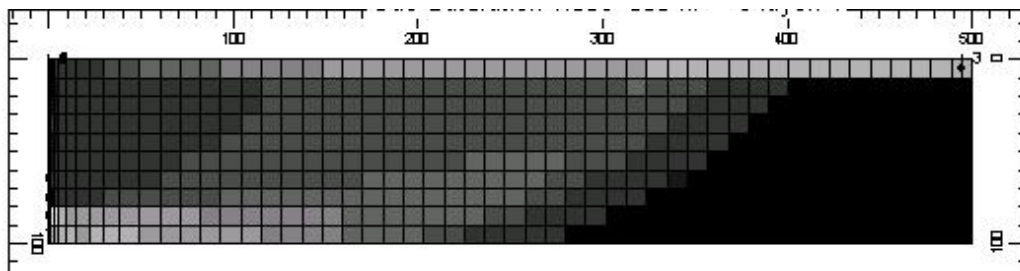


Figure 13: Water saturation for simulation no. 2 using water injected above gas in the bottom of the reservoir.

Table 9: Experiments with equal reservoir size (500x100 ft)

SIM No.	Segregation length (ft)					Reservoir and foam parameters			$Q_t$ (ft <sup>3</sup> /h)
	Theoretical	Bottom injection	Uniform injection	Water above gas		kz/kx (D)	fmmob	fmdry	
				Upper 50% of h water	In the bottom of the reservoir				
7	300	313	335	390	313	0,1	1000	0,3	7,7
10-Q7	95	115	137	130	115	1	1000	0,3	7,7
10	300	368	335	368	324	1	1000	0,3	77
5-Q10	130	150	148	181	160	1	100	0,3	77
15-Q10	129	130	159	159	160	1	100	0,5	77
20-Q10	222		225			1	1000	0,5	77

\*QX= equal total injection rate as simulation no. X

### 5.3.2 Injection rate

The only difference between simulation no. 10 and 10-Q7 is that the injection rate is ten times higher in simulation no. 10 (Table 9). The segregation length was three times longer when the injection rate was increased 10 times. This is in line with the Stones model.

### 5.3.3 Foam quality

A change in foam quality did not have an effect on the segregation length (Table 10). The theoretical segregation lengths were 300 ft for the simulations in Table 10. The reservoir was 500x100 ft and the permeability ratio was equal 1. The total injection rate was 77 ft<sup>3</sup>/h, fmmob was 1000, and fmdry was 0,3 for these simulations.

**Table 10: Simulations with different foam quality**

Foam quality	Segregation length (ft)			
	Bottom injection	Uniform injection	Water above gas	
			Upper 50% of h water	In the bottom of the reservoir
65%	346	324	356	330
80%	368	324		320
95%	368	324		324

### 5.3.4 Reservoir properties

The parameters for simulations 7 and 10-Q7 are given in Table 9. In both of these simulations the radius of the reservoir was 500 ft and the height of the reservoir was 100 ft. The only difference is that the ratio between the vertical and horizontal permeability is 0,1 in simulation 7 and 1 in simulation 10-Q7. The segregation length was reduced to about one third when the ratio between the vertical and horizontal permeability was reduced to 0,1. This is consistent with the Stones model.

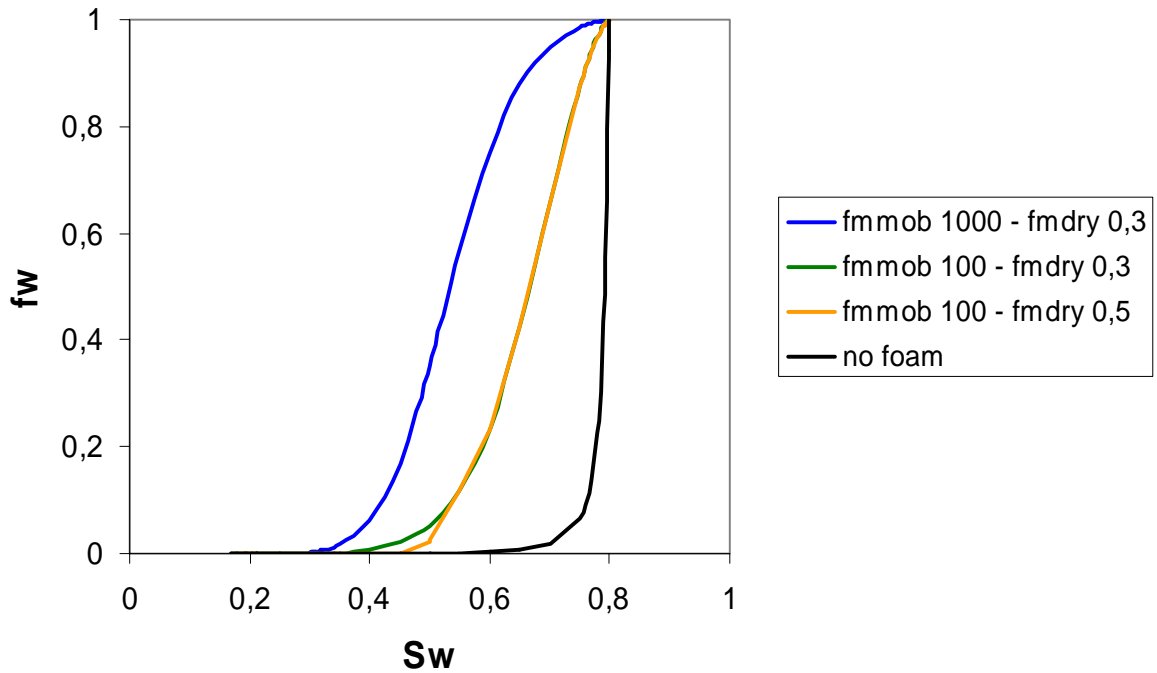
### 5.3.5 Fluid properties

All the theoretical and simulated values are presented in Table 9. In simulation 10 the fmmob is 1000 and the fmdry is 0,3. The gravity segregation length was about 350 ft when the injection rate was 77 ft<sup>3</sup>/h.

Simulation 10 and simulation 5-Q10 are almost equal, the only difference is that fmmob is reduced to 100 in simulation 5-Q10. This change in the fmmob value reduced the segregation length to about 2/5 of the segregation length in simulation no. 10.

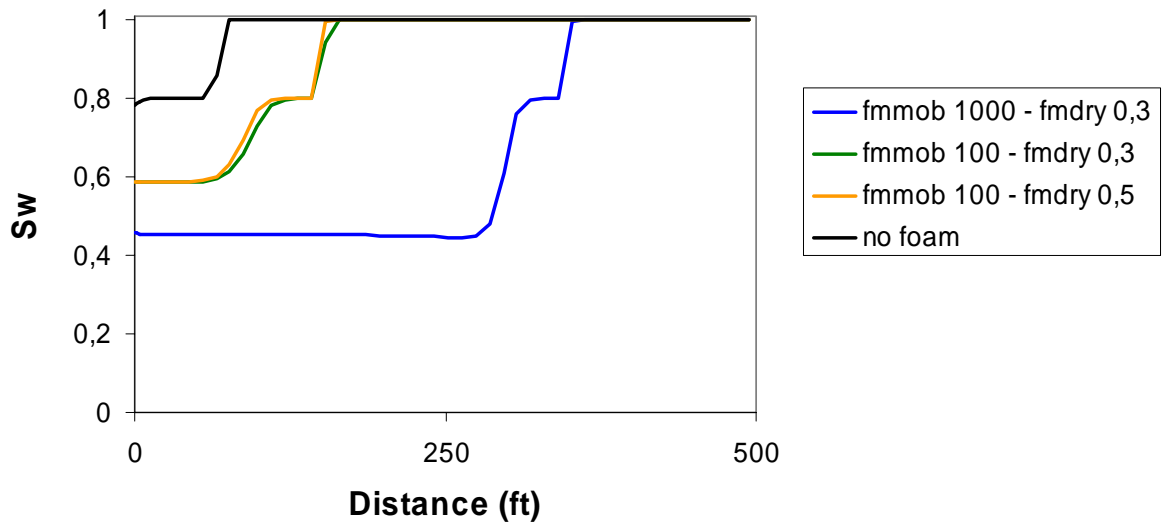
In simulation 15-Q10 the fmmob is 100 and the fmdry is 0,5, and in simulation 11 fmmob is 100 and fmdry is 0,3, the other parameters are equal. The segregation lengths for the two simulations were almost identical. If fmmob is 100 a change in fmdry from 0,3 to 0,5 do not seem to influence the segregation length. In simulation 20-Q10 fmmob is 1000 and fmdry is 0,5. The segregation length is now reduced to 2/3 of the segregation length of simulation no. 10. Reducing fmmob from 1000 to 100 will reduce the segregation length more than by increasing fmdry from 0,3 to 0,5.

Figure 14 show the theoretical fractional flow curves for the simulations 10, 5-Q10, and 15-Q10. The simulations have different combinations of  $f_{mob}$  and  $f_{dry}$ .



**Figure 14: Theoretical fractional flow curves for the different combinations of  $f_{mob}$  and  $f_{dry}$ , calculated by Darcy’s law.**

Figure 15 shows the water saturation in the reservoir after 1,5 pore volumes injected surfactant solution for simulations with variation in  $f_{mob}$  and  $f_{dry}$  using the uniform injection method. The  $f_{mob}$  and  $f_{dry}$  values are given in the figure and are presented in Table 9 (simulation 10, 5-Q10, and 15-Q10).



**Figure 15: Water saturation in the reservoir after 1,5PV injected surfactant solution.**

## 6 Conclusions

- The shapes of the foam banks are different for the four injection methods for simulations with foam, but quite similar for simulations without foam.
- The segregation lengths are almost equal for the four injection methods
- There is a quite good match between the simulation results and the Stone [2] and Jenkins [3] model for the segregation length of foam.

## References

1. J.-X. Shi and W. R. Rossen, SPE 35166, 1998.
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3. M. K. Jenkins, SPE/DOE 12632, 1984.
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5. M. G. Arra and A. Skauge, 21<sup>st</sup> Annual International Energy Agency Workshop and Symposium, Edinburgh, Scotland, 19-22 September 2000, paper 22.
6. V. O. Chukwueke, M. N. Bouts, and C. E. van Dijkum, SPE 39650, 1998.
7. A. Skauge, M. G. Arra, L. M. Surguchev, H. A. Martinsen, and L. Rasmussen, SPE 75157, 2002.
8. T. Blaker, M. G. Arra, A. Skauge, L. Rasmussen, H. K. Celius, H. A. Martinsen, and F. Vassenden, SPE 78824, 2002.
9. W. R. Rossen and C. J. van Duijn, J. Pet. Sci. Eng. 43 (2004) 99.
10. Computer Modeling Group, STARS users' guide, 2005.
11. W. R. Rossen and Z. H. Zhou, SPE 22627, 1995.
12. W. R. Rossen, S. C. Zellinger, J.-X. Shi, and M. T. Lim, SPE 57678, 1999.
13. A. B. Reme, Diploma thesis, NTNU, Norway, 1999.

# Appendix

## 6.1 Nomenclature

a	area
epdry	regulates the slope of the gas relative permeability curve near the critical water saturation
epsurf	parameter that controls the gas mobility's dependence on surfactant concentration
F1	surfactant concentration dependent function
F2	water saturation dependent function
F3	oil concentration dependent function
F4	gas velocity dependent function
F5	capillary number dependent function
F6	critical capillary number dependent function
FM	the dimensionless interpolation factor
fmdry	critical water saturation
fmmob	reference mobility reduction factor
fmsurf	critical surfactant concentration
$f_w$	fractional flow of water
g	gravity constant, $9,81 \text{ m/s}^2$
h	height of the reservoir
k	absolute permeability
$k_{rg}$	relative permeability of gas
$k_{rw}$	relative permeability of water
$k_x$	permeability in horizontal direction
$k_z$	permeability in vertical direction
$L_g$	segregation length in a rectangular reservoir
$q_t$ or $Q_t$	total injection rate
r	outer radius of the reservoir
rg	segregation length in a cylindrical reservoir
$S_w$	water saturation in the grid block
$u_g$	volumetric flux of gas
$u_w$	volumetric flux of water
$W_s$	surfactant concentration in the grid block
X	degree of sector used in the simulation
$\Delta\rho$	density difference between surfactant solution and gas
$\mu_w$	water viscosity
$\mu_g$	gas viscosity
$\nabla P_w$	Pressure gradient for the water phase
$\nabla P_g$	Pressure gradient for the gas phase



## 6.2 Tables

**Table 11: Input data for the 1D simulations**

Parameter	Value
$q_t$	0,00079119 ft <sup>3</sup> /h
foam quality	80%
$\mu_w$	1cp
k	0,53 D
porosity	20%
length	1ft (j)
area	0,164ft*0,164ft (i*k)
grid (i, j, k)	1, 50, 1 -uniform grids
initial temperature	68 F
initial pressure	2000 psi
bottom hole pressure in the producer	2000 psi

**Table 12: 1D simulation with values similar to the values used in the diploma thesis of Reme [13], simulation setup 1.**

Parameter	Value
$\mu_g$	0,01463 cp (found in the output file)
epdry	20000
fmdry	0,3164
fmmob	54958,16
epsurf	8
fmsurf	0,000143725
mole fraction surfactant	0,00028745
fluid model	3 3 3 2

**Table 13: 1D simulation values for simulation setup 2**

Parameter	Value
$\mu_g$	0,01886 cp (found in the output file)
epdry	1000
fmdry	0,3
fmmob	1000
epsurf	1
fmsurf	0,00001
mole fraction surfactant	0,0003
fluid model	3 3 2 2

### 6.3 Figures: Contour plots

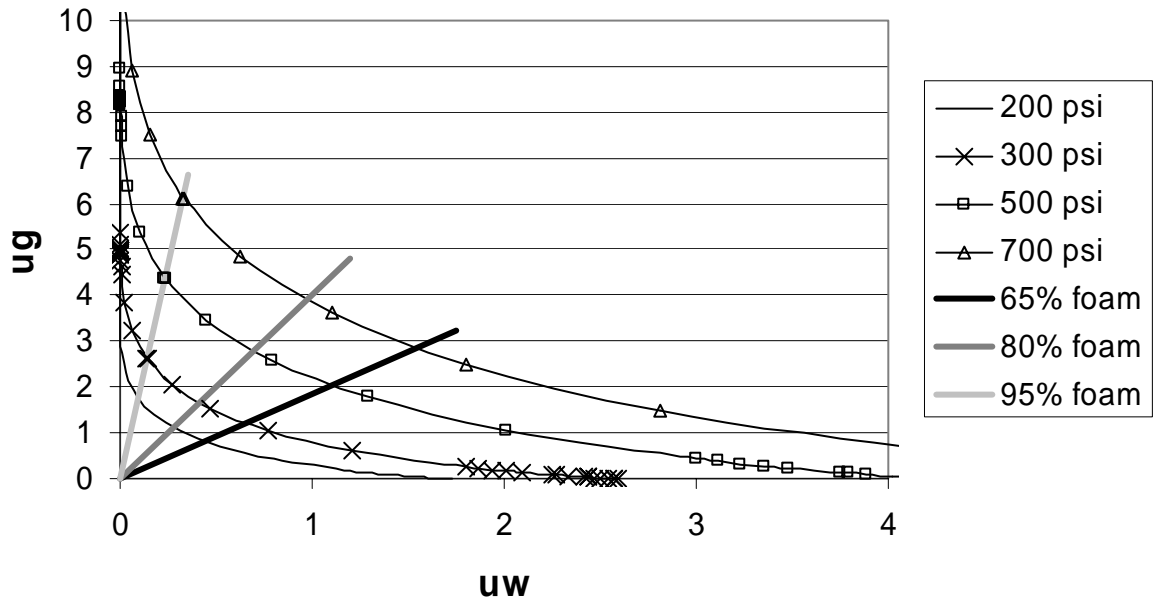


Figure 16: Contour plot using fmmob 100 and fmdry 0,3.

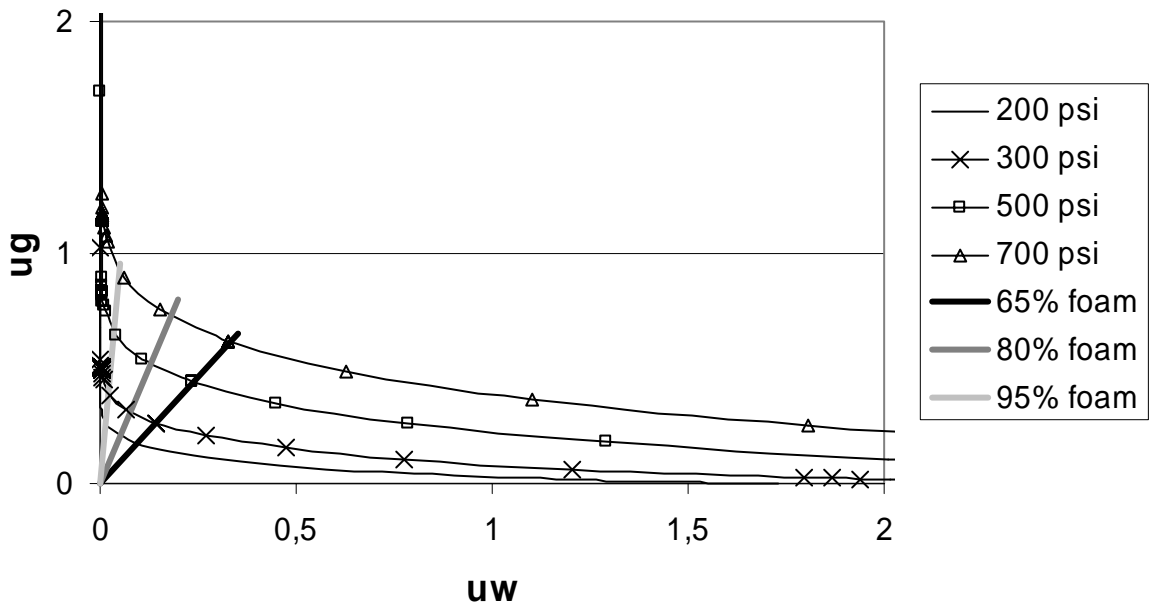


Figure 17: Contour plot using fmmob 1000 and fmdry 0,3.

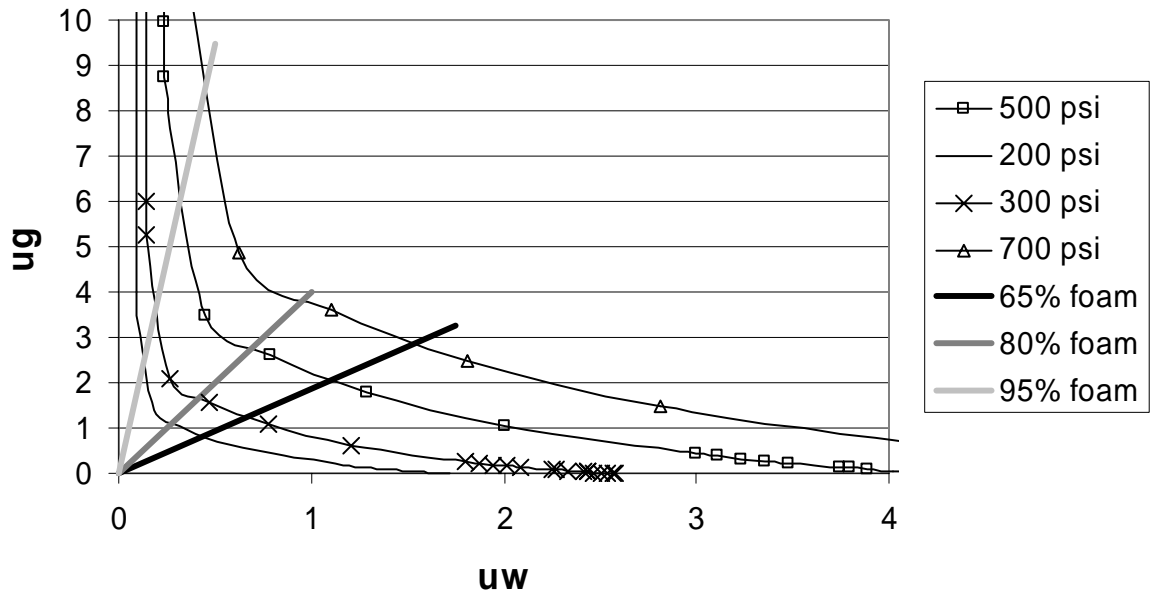


Figure 18: Contour plot using fmmob 100 and fmdry 0,5.

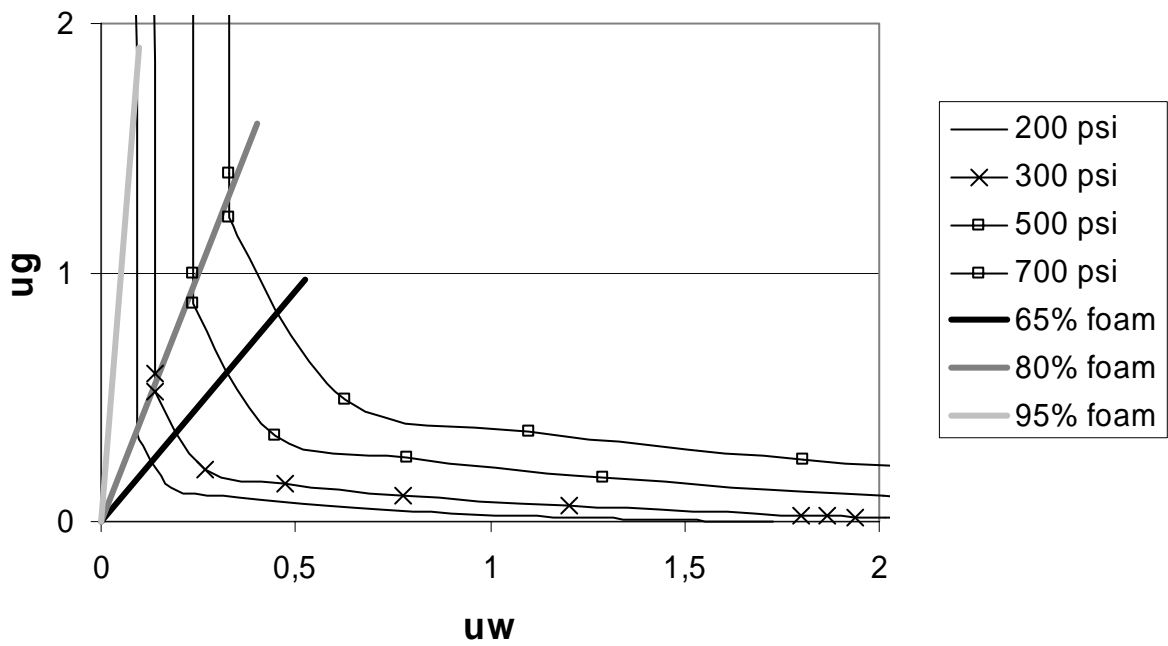


Figure 19: Contour plot using fmmob 1000 and fmdry 0,5.

## 6.4 Simulation file

Here is an example file of a simulation using injection of surfactant solution above gas in the bottom of the reservoir (simulation no. 10). The different parameter for this simulation is given in Table 9.

```
** ===== INPUT/OUTPUT CONTROL =====  
  
**CHECKONLY  
  
RESULTS SIMULATOR STARS  
  
*INTERRUPT *STOP  
**  
*TITLE1 'simulation 10'  
  
*inunit *field except 11 1 *(ft3 instead of bbl for fluid volume)  
      except 1 1 *(hours instead of days)  
  
*OUTPRN *GRID **PRES *TEMP *PCOW *PCOG  
      **SW *SO *SG *KRINTER *CAPN  
      **X *Y *W  
      **ADSORP *IFT  
      **MOLFR *ADSPCMP **SPECIAL ADSORPTION COMPONENT (MASS FR)  
      **VISW VISO VISG KRW KRO KRG PCOW PCOG MOLDENW MOLDENO MOLDENG  
MASDENW MASDENO MASDENG  
      **FRCFLOW  
*OUTSRF *GRID *PRES *SW *SO *SG *CAPN *KRINTER *KRG *KRSETN  
      *W **X *Y *W  
      *VISW *VISG *KRW *KRG *MASDENG  
      **ADSORP *IFT  
      **MOLFR *ADSPCMP **SPECIAL ADSORPTION COMPONENT (MASS FR)  
      **VISW VISO VISG KRW KRO KRG PCOW PCOG MOLDENW MOLDENO MOLDENG  
MASDENW MASDENO MASDENG GASMOB WATMOB TOTMOB  
      *WATFRFL *GASFRFL **VELOCRC **FLUXRC **OILFRFL  
*OUTPRN *WELL *WELLCOMP  
*OUTSRF *WELL *DOWNHOLE *LAYER *ALL ** VOLUME(DEFAULT)  
*OUTPRN *ITER *NEWTON      ** TSS  
*WRST time  
*WPRN *GRID time  
**WSRF *GRID 1000  
**WSRF *WELL 1000  
*WPRN *ITER 1  
  
**=====GRID AND RESERVOIR DEFINITION=====
```

```
*GRID *RADIAL 50 1 10  
*KDIR *DOWN  
**DTOP 100*2000  
*DI *IVAR 1 1.5 2.5 4 6 7 8 8 42*11  
*DJ *CON 45  
*DK *kvar 10*10  
*POR *IJK  
      1:50 1 1:10 0.2  
  
PERMI *CON 1000  
PERMJ *CON 1000  
PERMK *CON 1000  
*END-GRID
```

\*\*=====FLUID DEFINITIONS=====

model 3 3 2 2

```
compname  'Water'  'Surfact'  'Nitrogen'
**
cmm        18.02   310       28.031    ** molecular mass of component lb/lbmole
massden    62.5    62.5
pcrit      3198.08 2088.54  492.26    ** lb/ft3, N2 liquid density not used
tcrit      705.47 980.6    -232.51
*AVG       0.     0.     1.737E-04
*BVG       0.     0.     7.478E-01
kv1        0      0
kv2        0      0
kv3        0      0
kv4       -1     -1
kv5        0      0
```

```
*visctable
** Temp(F)  viscosity(cp)
   68    1.0    1    ** N2 liquid viscosity not used
```

\*\*=====ROCK FLUID PROPERTIES=====

\*ROCKFLUID

\*KRTYPE \*CON 1 \*\* Default curves which can be changed with well cards

```
** =====
*RPT 1 **
** =====
```

```
** Interpolation between 2 Sets : Zero and Strong Foam Curves
** Capillary Number Calculation is based on Aqueous surfactant IFT
** Specified at two temperatures and 2 surfactant concentrations
*INTCOMP 2 WATER
*INTLIN
*IFTTABLE **AQUEOUS MOLE FRAC IFT
   0.     50.
  0.003   1.
```

\*\* CRITICAL FOAM PARAMETERS

```
**
*fmdry 0.3 ** Sw*
*epdry 1000.0 ** regulates the slop of gas Kr curve near Sw*
*fmmob 1000 ** Mobility reduction factor

**fmcap 0.0000246 ** Reference capillary number value
**epcap 1.1215 ** Exponent for capillary number contribution

*fmsurf 0.00001 ** critical surfactant concentration
*epsurf 1.0 ** controls the gas mobility's dependence on surfactant concentration
*****
```

```

**-----
** SET # 1 : No Foam
**-----
*KRINTRP 1
*DTRAPW 1.0 ** No Mobility Reduction
*swt
** Water-oil relative permeabilities
   ** Persoff function  $K_{rw} = 0.2 * [(Sw - 0.2) / 0.6]^{4.2}$ 
   ** krwo is not used, just random values

```

```

**Sw  Krw  Krow
**-----

```

Sw	Krw	Krow
0.2	0	1
0.21	0.00000001	0.859620673
0.215	0.00000004	0.796235509
0.22	0.00000013	0.737039373
0.225	0.00000032	0.681787993
0.23	0.00000069	0.63024941
0.235	1.31184E-06	0.582203453
0.24	2.29851E-06	0.537441241
0.245	3.76953E-06	0.495764693
0.25	5.86771E-06	0.45698606
0.255	8.75625E-06	0.420927468
0.26	1.26191E-05	0.387420489
0.265	1.76616E-05	0.356305712
0.27	2.41105E-05	0.327432341
0.28	4.22447E-05	0.275847365
0.29	6.92809E-05	0.231616946
0.3	0.000107844	0.193806699
0.31	0.000160933	0.161585902
0.32	0.000231929	0.134217728
0.33	0.000324606	0.111050231
0.34	0.000443131	0.091508035
0.35	0.000592077	0.075084686
0.36	0.000776423	0.061335631
0.37	0.001001567	0.049871777
0.38	0.001273325	0.040353607
0.4	0.001982078	0.026012295
0.45	0.00505991	0.007820799
0.5	0.010881882	0.001953125
0.55	0.020791247	0.000378529
0.6	0.036428955	5.08053E-05
0.65	0.059743038	3.8147E-06
0.7	0.092996962	9.9229E-08
0.8	0.2	0
0.9	0.382125933	0
1	0.669534082	0

\*slt

\*\* Liquid-gas relative permeabilities  $K_{rg} = 0.94 * [(0.8 - S_w) / 0.6]^{1.3}$

\*\*SI Krg Krog

\*\*-----

0.2	0.94	0
0.21	0.919684449	9.9229E-17
0.22	0.89947194	5.08053E-14
0.23	0.879363713	1.95312E-12
0.24	0.859361045	2.60123E-11
0.25	0.839465253	1.93807E-10
0.26	0.819677692	1E-09
0.27	0.799999763	4.00425E-09
0.28	0.78043291	1.33183E-08
0.29	0.760978623	3.84434E-08
0.3	0.741638443	9.9229E-08
0.31	0.722413964	2.33977E-07
0.32	0.703306833	5.12E-07
0.33	0.684318756	1.05227E-06
0.34	0.665451501	2.05018E-06
0.35	0.646706902	3.8147E-06
0.36	0.62808686	6.81897E-06
0.37	0.60959335	1.17674E-05
0.38	0.591228425	0.000019683
0.39	0.572994221	3.202E-05
0.4	0.554892962	5.08053E-05
0.45	0.466465669	0.000378529
0.5	0.381758626	0.001953125
0.55	0.301198801	0.007820799
0.6	0.225356569	0.026012295
0.65	0.15504218	0.075084686
0.7	0.091523207	0.193806699
0.8	0	1
1	0	1

\*\*===== \*\*

\*\*SET # 2 : Foam

\*KRINTRP 2 \*COPY 1 1 \*\* Copy from first Set and then overwrite

\*DTRAPW 0.001 \*\* Strong Foam - Inverse Mobility Reduction Factor

\*krgcw 0.00094

\*\*

\*\*=====

\*\* ADSORPTION DATA

\*\*-----

\*\*ADSCOMP 'SURFACT' WATER \*\* Data for reversible aqueous surfactant adsorption.

\*\*ADMEXT 0 \*\* gmole surf/m3 PV - 0.05 mg surf/g rock \*\* 54.4

\*\* ===== INITIAL CONDITIONS =====

\*INITIAL  
\*PRES \*CON 4500  
\*sw \*con 1.00 \*\* So by difference  
\*TEMP \*CON 68  
\*mfrac\_wat 'Water' \*CON 1 \*\* initial mole fraction in the water phase  
\*MFRAC\_WAT 'Surfact' \*CON 0

\*\* ===== NUMERICAL CONTROL =====

\*NUMERICAL  
\*TFORM \*ZT  
\*ISOTHERMAL  
\*NORM  
\*PRESS 45 \*ZO 0.4 \*ZNCG 0.4 \*Zaq 0.4

\*\* ===== RECURRENT DATA =====

\*RUN  
\*TIME 0  
\*DTWELL 0.001  
\*\*KRSWITCH 1 \*\* Use this command only when you want to change rock type at certain time  
\*\*-----

\*WELL 1 '1' \*VERT 1 1  
\*INJECTOR \*MOBWEIGHT '1'  
\*INCOMP \*WATER 0.9997 0.0003  
\*OPERATE \*bhw 7.7  
\*OPERATE \*MAX \*BHP 12000 \*\*psi  
\*\* Well Geometry for the Injector  
\*\* RADIUS GEOFAC WFRAC SKIN  
\*GEOMETRY \*K 0.1 0.5 0.125 0.  
\*PERFV \*GEO 1  
7 1 \*\*100

\*\*-----  
\*WELL 2 '2' \*VERT 1 1  
\*INJECTOR \*MOBWEIGHT '2'  
\*incomp \*gas 0 0 1  
\*OPERATE \*bhg 30.8  
\*OPERATE \*MAX \*BHP 12000. \*\*psi  
\*\* Well Geometry for the Injector  
\*\* RADIUS GEOFAC WFRAC SKIN  
\*GEOMETRY \*K 0.1 0.5 0.125 0  
\*PERFV \*GEO 2  
9 1

\*\*-----  
\*WELL 3 '3' \*VERT 50 1  
\*PRODUCER '3'  
\*OPERATE \*MIN \*BHP 4300. \*\*psi  
\*\* Well Geometry for the Producer  
\*\* RADIUS GEOFAC WFRAC SKIN  
\*GEOMETRY \*K 0.1 0.5 1.0 0  
\*PERFV \*GEO 3  
1:10 1



```

**-----
*WELL 4 '4' *VERT 1 1
*INJECTOR *MOBWEIGHT '4'
*INCOMP *WATER 0.9997 0.0003
*OPERATE *bhw 7.7
*OPERATE *MAX *BHP 12000 **psi
** Well Geometry for the Injector
**      RADIUS  GEOFAC  WFRAC  SKIN
*GEOMETRY *K  0.1  0.5  0.125  0.
*PERFV *GEO 4
8 1 **100

```

```

**-----
*WELL 5 '5' *VERT 1 1
*INJECTOR *MOBWEIGHT '5'
*incomp *gas 0 0 1
*OPERATE *bhg 30.8
*OPERATE *MAX *BHP 12000. **psi
** Well Geometry for the Injector
**      RADIUS  GEOFAC  WFRAC  SKIN
*GEOMETRY *K  0.1  0.5  0.125  0
*PERFV *GEO 5
10 1

```

```

time 10
time 100
time 1000
time 5000
time 10000
time 25000
time 50000
time 100000
time 500000
time 1000000

```