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Effect of Oil on Gravity Segregation in SAG Foam Flooding

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Introduction

Foam EOR has been proposed as an extension to gas-injection EOR (CO_2, hydrocarbon gas, N_2, or steam). Though gas has an excellent microscopic displacement efficiency, it suffers from poor sweep efficiency due gravity segregation and viscous instability between injected gas and water/oil. By applying foam, a better sweep efficiency could be obtained than with conventional gas injection, combined with the excellent microscopic displacement efficiency of gas (Schramm, 2005; Rossen, 1995). However, publication of field application of foam EOR is limited. An overview of Exxon's foam applications can be found in Teletzke *et al.* (2010), and recently foam has been applied for EOR by Statoil in Norway (Skauge *et al.*, 2002) and by Denbury Resources in the US gulf coast region (Chabert *et al.*, 2016). It was found that small intermittent injection cycles in SAG mode had a beneficial impact on averting gas override (Skauge *et al.*, 2002), though no comparison was made with simulation results of a single-cycle SAG flood.

Previous research on foam-front propagation has focused largely on its behaviour in reservoirs without any mobile oil; however foam is in contact with mobile oil in the reservoir. Similarly, Shan and Rossen (2002) found that the optimal SAG injection strategy in reservoir without any mobile oil is single-cycle injection at constant, maximum injection pressure. We seek to understand the behaviour of foam in a reservoir with mobile oil, by investigating the foam front propagation by single-cycle SAG injection and multiple-cycle SAG injection.

Theory

The foam model used here takes into account the effects of water saturation, oil saturation, and surfactant concentration in the aqueous phase on foam strength. The viscosity of the gas phase in the absence of foam (λ_{rg}^{nf}) is scaled by a function, MRF, to take into account the effect of foam lamellae on gas viscosity, while the liquid viscosities remain unchanged. Parameter *fmmob,* in equation **(1)** below, is the maximum increase of the gas viscosity, in the absence of factors that increase the average bubble size (Surguchev *et al.*, 1995). In this study *fmmob* is taken as 1000, the same as in Namdar Zanganeh and Rossen (2013). F_w, F_o, and F_s describe the stability of foam as a function of water and oil saturations and surfactant concentration respectively. F_o and F_s are adapted from the Computer Modelling Group (2007), and the modified F_w is adapted from Namdar Zanganeh and Rossen (2013); see equations **(2)**, **(3)** and **(4)** in the appendix. In our foam model, low water saturation can weaken foam, as defined in F_w. In addition, oil saturation above a certain threshold value kills foam, as defined in F_o. F_s reaches its maximum above a certain surfactant concentration, C_s* (0.12 wt% in our simulations). In this foam model, a small change in water saturation can cause an abrupt change in foam strength, which is in agreement with laboratory data (Cheng et al., 2000; Khatib et al., 1988).

$$\mu_g^f = \mu_g^{nf} * MRF, \qquad where$$
$$MRF = 1 + fmmob \times F_w \times F_o \times F_s \tag{1}$$

To calculate the three-phase relative permeabilities we used a saturation-weighted model (Baker, 1988).

The surfactant concentration in the surfactant slug is 0.24 wt%, which is well above the minimum concentration required for foaming in the model. The water phase and oil phase are incompressible, and the gas phase is slightly compressible in the simulations (i.e., c_g = 1.68 X 10^{-8} Pa^{-1}). The simulation assumptions in this study are the same as in Namdar Zanganeh and Rossen (2013); see ***Table 1***, ***Table 2***, and ***Table 3***.

We are interested in foam-front propagation, by SAG-injection, in a water-flooded oil reservoir. Therefore, we set the initial oil saturation in the reservoir to the residual oil saturation to waterflood (S_{orw}), which is 0.3. There is neither gas nor foam in the reservoir at time $t = 0$. Moreover, in our simulations we assume that the injected surfactant does not affect the interfacial tension between the oil phase and the aqueous phase enough to affect oil displacement. Since the level of surfactant adsorption does not fundamentally alter the foam-displacement process, it is excluded in this study for simplicity. Our results apply to a process with adsorption with a correspondingly larger surfactant slug. The three fluids are assumed to be completely immiscible. We set the residual oil saturation to gas flood (S_{org}) at 0, which is lower than S_{orw}, and thus, though the injected gas is defined to be immiscible with the oil, the gas is capable of displacing the remaining oil.

Our reservoir model is adopted from Namdar Zanganeh and Rossen (2013). The 3D reservoir is homogeneous, box-shaped, 100 m X 100 m X 30 m and modeled with 10 X 10 X 10 gridblocks, unless mentioned otherwise. The reservoir is sealed on all bounding surfaces. The reservoir has one vertical injection well and one vertical production well, located at opposite corners of the reservoir, in the middle of the corner gridblocks. The wells are perforated over the entire interval and operate at a constant prescribed pressure. The reservoir simulator uses the Peaceman model (Peaceman 1966) for injectivity into and productivity from the well gridblocks. This model is used in all of the simulations reported here.

This research is performed as a case study to shed light on the competing goals behind foam processes, and does not describe any particular field application.

Foam injection strategy

Shan and Rossen (2002) discussed the optimal injection strategies for foam EOR to overcome gravity override in a homogeneous reservoir without mobile oil. Their results show that a single-cycle SAG flood, with fixed injection pressure, can be remarkably successful in overcoming gravity override in a homogeneous reservoir (see also Grassia *et al.* 2014). Well-to-well pressure difference was more important than foam strength. Multiple-cycle SAG processes were less successful in overcoming gravity see also Kloet et al. (2009). We extend this study to see if the presence of mobile oil substantially changes these conclusions.

We performed our single-cycle SAG flood by starting with surfactant injection (injection rate of 365 m^3/day or 0.006 PV/day), followed by gas injection (injection rate depends on near-well reservoir pressure). The gas-injection period was fixed at 250 days. We conducted simulations with various injected surfactant slug volumes. The moment that the injection well switches from surfactant injection to gas injection is called the *switching time*, t_s. By conducting simulations with different cumulative injected surfactant volumes we investigate its impact on total oil production. Furthermore we simulate a single-cycle SAG process to investigate how oil impacts the foam-front propagation through the reservoir.

Figure 1 confirms that foam front propagates without significant gravity override in a single-cycle-SAG process, without any mobile oil present, as reported in Shan and Rossen (2002).

In our multiple-cycle SAG floods, similar to the single-slug SAG simulation, we start by injecting surfactant into the reservoir. However, in this case each gas and liquid slug is 0.2 pore-volumes (PV) in size at reservoir condition. We simulate five cycles of surfactant and gas injection, thus injecting a total of 2 PV by the end of the simulation. By injecting multiple SAG cycles into the reservoir we investigate the impact of SAG cycles on the foam-front propagation and cumulative oil production. For benchmarking, we also simulate a single-cycle SAG process in which we inject a surfactant slug of 1 PV and a gas slug of 1 PV.

Results

1. Impact of oil on foam-front propagation with single-cycle SAG. A SAG simulation was conducted with a switching time of 0.37 PV, to investigate the impact of oil on foam-front stability. Results showed that foam was not present in every gridblock at the end of the simulation and the foam front was not stable; see ***Figure 2***. This result was different from the stable foam-front in contact with immobile oil; seen by Shan and Rossen (2002). To investigate the cause of the foam-front instability, we looked at the parameters, other than surfactant concentration, that impact foam viscosity: namely, water saturation and oil saturation. ***Figure 3*** shows water saturation in the gridblocks at the end of the simulation, and it can be seen that the water saturation at top of the reservoir is below 0.20, which is the threshold value below which foam is weaker. *fmoil* is the threshold value above which foam cannot exist, and it is set to 0.40 in these simulations. ***Figure 4*** shows the oil saturation in the gridblocks at the end of the simulation. The foam front is unstable because the water saturation is too low for foam to exist at top of the reservoir, and the oil saturation is too high at the bottom of the reservoir for foam to exist there (***Figure 3*** and ***Figure 4***).

The foam front is unstable because the water saturation is too low, but we do not know why the water saturation decreases. Therefore, we investigated the fluxes of water, oil, and gas. A similar simulation was conducted in a 2D reservoir, with a similar end-state as in ***Figure 2***. The 2D reservoir has dimensions 10 m X 100 m X 30 m (modeled with 1 X 10 X 10 gridblocks). ***Figure 5*** shows the oil, and water, and the gas net volume fluxes after 1.63 PV of surfactant injection and 100 days of gas injection, equal to 0.49 PV. A relatively high volume flux of gas exists at the top of reservoir, pushing the oil and water forward and downward. In parallel, gas moves to the top of the reservoir, a low water saturation is generated at the top of the reservoir, and high oil saturation at the bottom of the reservoir. ***Figure 6*** shows the volume fluxes after simulation has ended after 250 days of gas injection, equal to 2.21 PV. A high volume flux of gas exists at the top of the reservoir, though there is also a relatively high gas volume flux at the bottom of the reservoir, pushing the oil and water out of the reservoir. In the center of the reservoir foam still exists, as in ***Figure 2***, which is the reason for the high volume fluxes of water and oil there. ***Figure 5*** and ***Figure 6*** show that the tendency of the gas to move upward, resulting in water and oil being pushed downward, leading to the end-state of ***Figure 2***.

The volume fluxes of the phases, as can be seen in ***Figure 5*** and ***Figure 6***, and the saturation profiles as can be seen in ***Figure 3*** and ***Figure 4***, can be described as gas overriding the foam at the top of the reservoir, and foam overrides the oil at the bottom of the reservoir. This can be explained as following: as foam dries out at the top of the reservoir, most of the injected gas flows thereto, pushing down oil and water. Eventually the water saturation is too low for stable foam to exist at the top of the reservoir, and similarly the oil saturation will be too high at the bottom of the reservoir. As a result foam exists only in the center of the reservoir, but nonetheless it diverts gas flow to the bottom of the reservoir, as can be seen in ***Figure 6***. These findings are different from what was found in the case without any mobile in the reservoir (Shan and Rossen 2002), in that a single-cycle SAG can still suffer from segregation.

2. Optimal surfactant slug size when followed by 250 days of pressure-controlled gas injection. The top graph in ***Figure 7*** shows that switching time impacts the cumulative gas injected and the cumulative oil produced differently. If less than 0.1 PV of surfactant is injected, the cumulative oil produced and gas injected go down with increasing surfactant slug volume, yet the ratio of cumulative gas injected over oil produced stays almost the same; see the bottom graph in ***Figure 7***. This result is as expected. Because of the small surfactant slug, the foam front is mainly located around the injection well. Once gas breaks through the front of the surfactant bank, the effectiveness of foam drops sharply. Thus, if not enough surfactant is injected, the foam-front will not be able to push the oil bank ahead of it to the production well. Therefore, in these cases the foam is located only around the injection well, and reduces cumulative gas injection without improving the gas sweep efficiency. As a result, if less than 0.1 PV surfactant is injected, the ratio of gas injection to oil production is not impacted by the injected surfactant slug; see the bottom graph in ***Figure 7***.

In our SAG simulations for which the surfactant slug was larger than 0.1 PV, but smaller than 0.37 PV, the ratio of gas injected to oil produced decreases sharply with increasing surfactant slug size; see the bottom graph in ***Figure 7***. In these cases, because more surfactant is injected, the foam front can reach further from injection well, pushing the oil bank ahead of it, to the production well.

We expected to achieve the highest cumulative oil with a surfactant slug smaller than 0.5 PV for the following reason: the volume of reservoir occupied by surfactant is the injected PV divided by average water saturation where surfactant is located. If foam were present everywhere at $S_w = fmdry = 0.2$, a 0.2 PV surfactant slug would in principle suffice to fill the reservoir with foam. In reality, average water saturation is greater; see ***Figure 3***. ***Figure 7*** shows that the optimal slug size is 0.37 PV, for which the maximum cumulative oil production and the minimum ratio in gas injected to oil produced is reached.

3. Impact of oil on foam front propagation by multiple–cycles SAG. To investigate foam-front propagation in a five-cycle SAG flood and how it differs from its benchmark, we examine their gas and oil saturation profiles (***Figure 8***, ***Figure 9***, ***Figure 10***, and ***Figure 11***). In both cases, five-cycles and one-cycle SAG, water saturation is below *fmdry* at the top of the reservoir, meaning that foam cannot exist there. However, in the one-cycle case the high oil-saturation zone is spread out over the bottom of the reservoir, whereas in the five-cycles SAG case the oil is present as a bank. This is expected because in this case the injected surfactant slugs displace the oil bank at the bottom of the reservoir. This was not possible with the single-cycle SAG case, as the oil saturation at the bottom of the reservoir was equal to S_{orw} during the surfactant flood.

To compare the effectiveness of the two different foam-injection schemes and conventional gas flood in oil production, we investigate the produced oil as a function of the injected gas and water; see ***Figure 12***. A single-cycle SAG has a prolonged impact on the oil-production profile compared to the conventional gas flood. The five-cycle SAG flood shows a higher cumulative oil production, in agreement with their saturation profiles. Therefore, in this comparison, multiple-cycle SAG is superior in displacing oil out of a reservoir compared to a single-cycle SAG flood.

Conclusions

1. In the case that mobile oil is present in the reservoir, a single-cycle SAG flood can result in foam overriding oil, and gas overriding the foam. The key factor missing in the theory of Shan and Rossen (2002) is non-uniform mobility at and behind the front of the foam bank. Hence gas advances faster at the top of the bank and an override zone develops. Eventually a region with a high gas saturation (where water saturation is below *fmdry*) forms at the top of the reservoir, where foam cannot not exist. Simultaneously, a region with high water and oil saturation (above *fmoil*) forms at the bottom of the reservoir, where foam cannot exist.

2. In our simulations with different injected surfactant-slug volumes, followed by 250 days of pressure-controlled gas injection, cumulative oil production *decreases* with increasing surfactant-slug size, for surfactant-slug volumes between 0 and 0.10 PV. This is because the small surfactant slug reduces gas injectivity, though the generated foam bank is not large enough to displace the oil bank ahead of it to the production well. However, for surfactant slugs between 0.10 and 0.37 PV, cumulative oil production increases with a larger surfactant slug. This is because in this case larger surfactant slugs result in a larger portion of the oil bank ahead of the foam front reaching the production well. Production reaches its maximum with a 0.37 PV surfactant slug. A larger surfactant slug does not result in more cumulative oil production or less cumulative gas injection, and in this case the surfactant reaches almost every gridblock. A 0.37-PV surfactant-slug results in approximately the same cumulative oil production compared to a conventional gas flood, though with twenty times less cumulative gas-injection.

3. For our case, if multiple-cycle SAG is applied instead of a single-cycle SAG, a more stable foam front can be achieved, resulting in a more effective oil displacement. Multiple-cycle SAG results in a different front because the small surfactant slugs displace the oil bank with high oil saturation at the bottom of the reservoir. This is in contrast to the theory by Shan and Rossen (2002), as they showed that in a reservoir without any mobile oil, a single-cycle SAG injection gives better sweep than multiple-cycle SAG.

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Appendix

Equation (**1**) describes how the foam modifies the gas mobility; the factors F_o, F_s, and F_w are defined below. Foam collapses if the water saturation is below the threshold value (*fmdry)*; F_w describes the effect of water saturation on gas mobility; see equation **(2)**. This relationship is adapted from Namdar Zanganeh and Rossen (2013).

$$F_w = \frac{arctan[epdry(S_w - fmdry)]}{\pi} - \frac{arctan[epdry(S_{wir} - fmdry)]}{\pi} \tag{2}$$

The relationship of foam strength and oil saturation is adapted from STARS 2007; see equation **(3)**.

$$F_o = \begin{cases} 1 & S_o < floil \\ \left(\dfrac{fmoil - S_o}{fmoil - floil}\right)^{epoil} & floil \le S_o \le fmoil \\ 0 & fmoil \le S_o \le (1 - S_{wr}) \end{cases} \tag{3}$$

The relationship between foam strength and surfactant concentration in the aqueous phase is given in equation **(4)**.The critical surfactant concentration (C_S^*) is 0.0012 kg/kg, and this is half the concentration in the injected water.

$$\begin{aligned} F_s &= Cs/Cs^* \quad Cs < Cs^* \\ F_s &= 1 \quad\quad\quad Cs > Cs^* \end{aligned} \tag{4}$$

Tables

Parameters	**Values**
epdry	1000
epcap	1
epoil	1.5
epsurf	1
floil	0
fmdry (S_w*)	0.2
fmmob	1000
fmoil (S_o*)	0.4
fmsurf (C_s*)	0.0012
k_{rg}^0	0.94
k_{rog}^0	0.8
k_{row}^0	0.8
k_{rw}	0.3
n_g	3
n_{og}	3
n_{ow}	2
n_w	4
S_{gr}	0
S_{org}	0
S_{orw}	0.3
S_{wir}	0.1
S_{wi}	0.7

Table 1: Parameters of the relative permeability model and foam model **(Namdar Zanganeh and Rossen 2013)**)

Parameters	Values
Length (m)	100
Width (m)	100
Height (m)	30
Depth (m)	1600
Δx (m)	10
Δy (m)	10
Δz (m)	3
ϕ	0.2
k_x (mD)	100
k_y (mD)	100
k_z (mD)	10
$C_{s,inj} = 2C_s$*	0.0024
P_{ref} (bar)	165
P_{wf}^{inj} (bar)	250
P_{wf}^{prod} (bar)	145
*2.4 g of surfactant in 1 kg of surfactant solution	

Table 2: Reservoir properties, simulation parameters, and well constraints **(Namdar Zanganeh and Rossen 2013)**

Parameters	Values
μ_g (cp)	0.02
μ_o (cp)	5
μ_w (cp)	0.47
ρ_g (kg/m^3)	306.6
ρ_o (kg/m^3)	900
ρ_w (kg/m^3)	985
c_g (Pa^{-1})	1.68×10^{-8}
c_o (Pa^{-1})	0
c_w (Pa^{-1})	0

Table 3: Fluid properties at reservoir conditions (160 Bar, 60 °C) **(Namdar Zanganeh and Rossen 2013)**

Figures

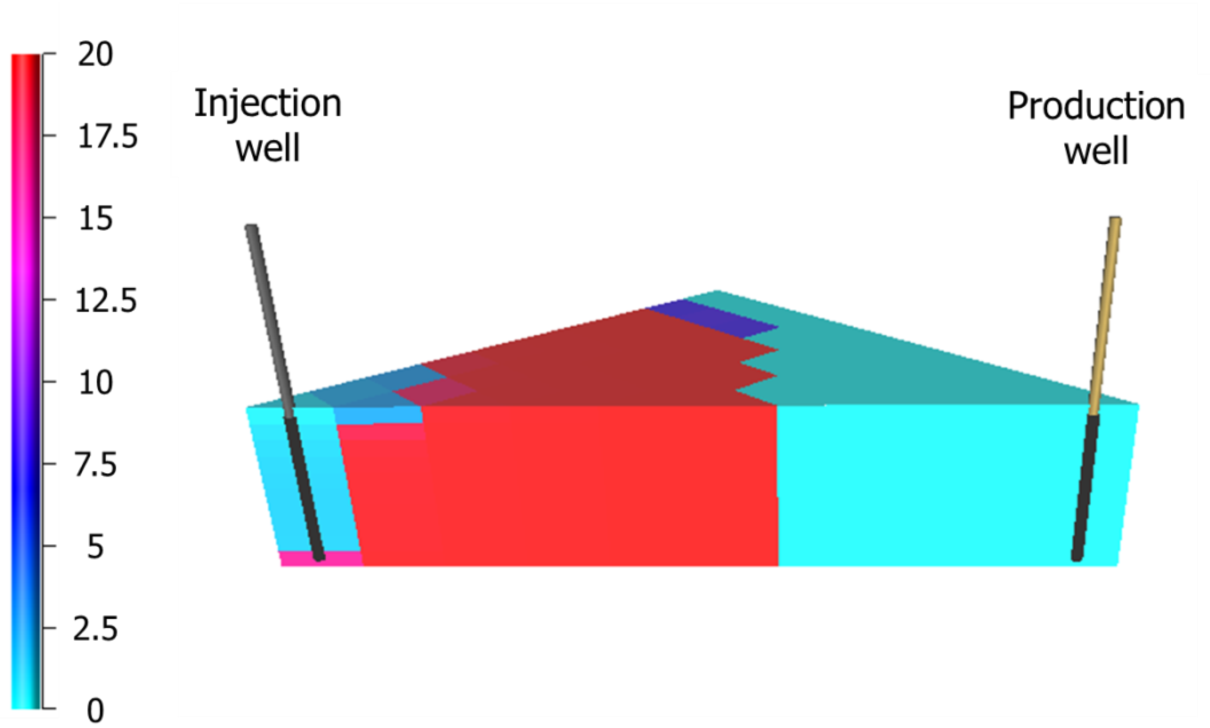


Figure 1 *Gas viscosity (cP) at the end of the simulation, for switching time = 0.37 PV and 250 days of gas injection, equivalent to 0.25 PV. No oil in reservoir.*

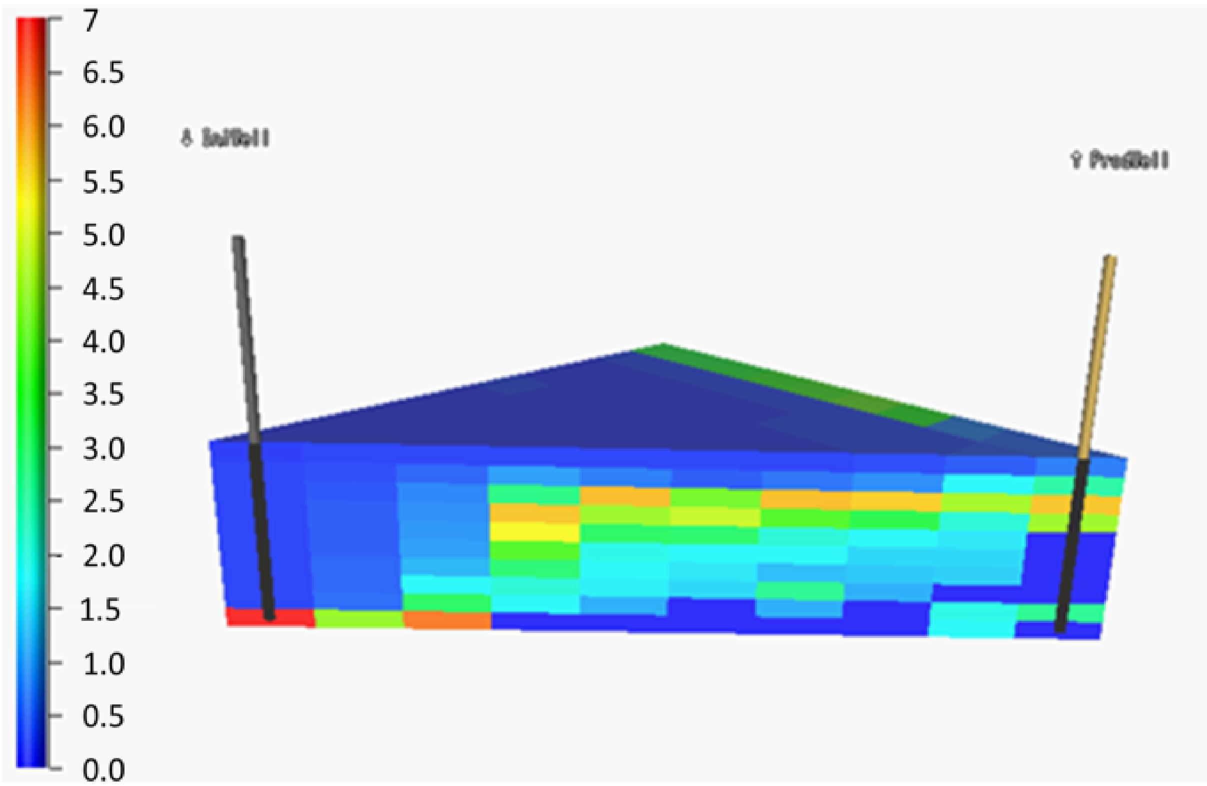


Figure 2 *Gas viscosity (cP) at the end of the simulation, for switching time = 0.37 PV, and gas injection time = 250 days, equivalent to 0.64 PV. In this figure and those to follow, the initial oil saturation is 0.3*

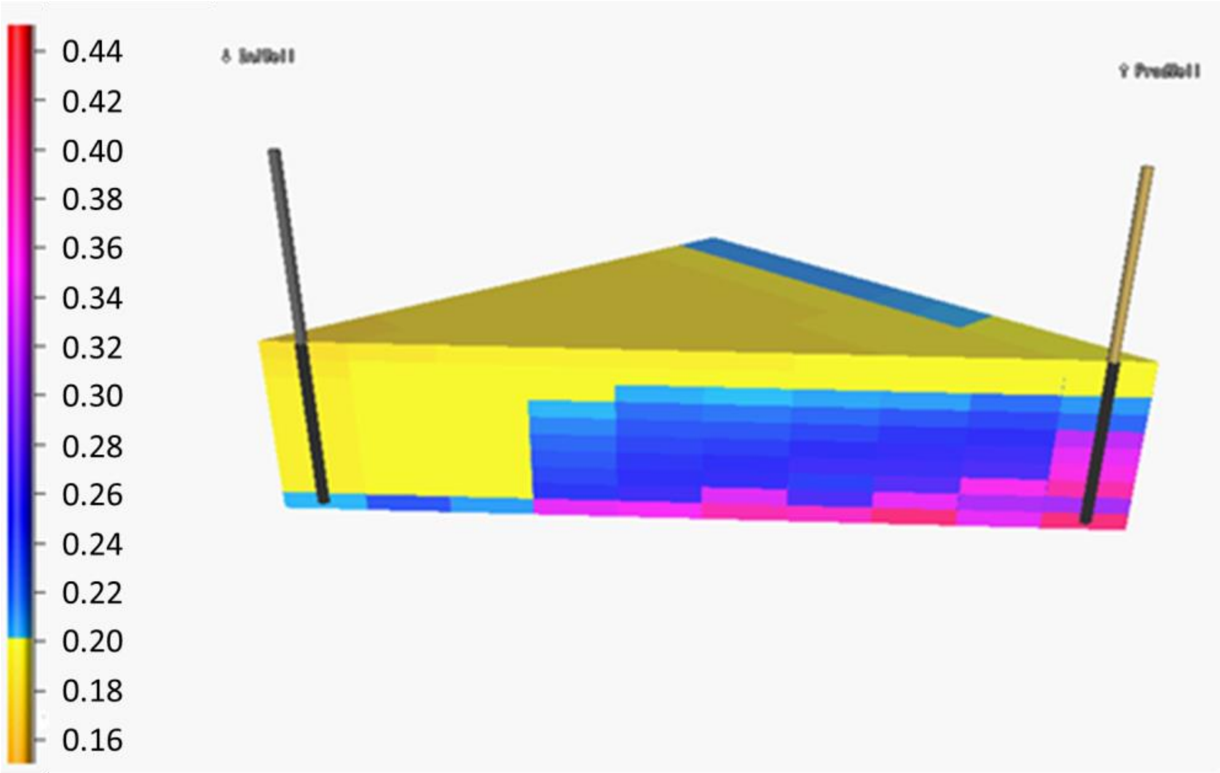


Figure 3 *Water saturation in the gridblocks, for switching time 0.37 PV, and 250 days of gas injection, equivalent to 0.64 PV.*

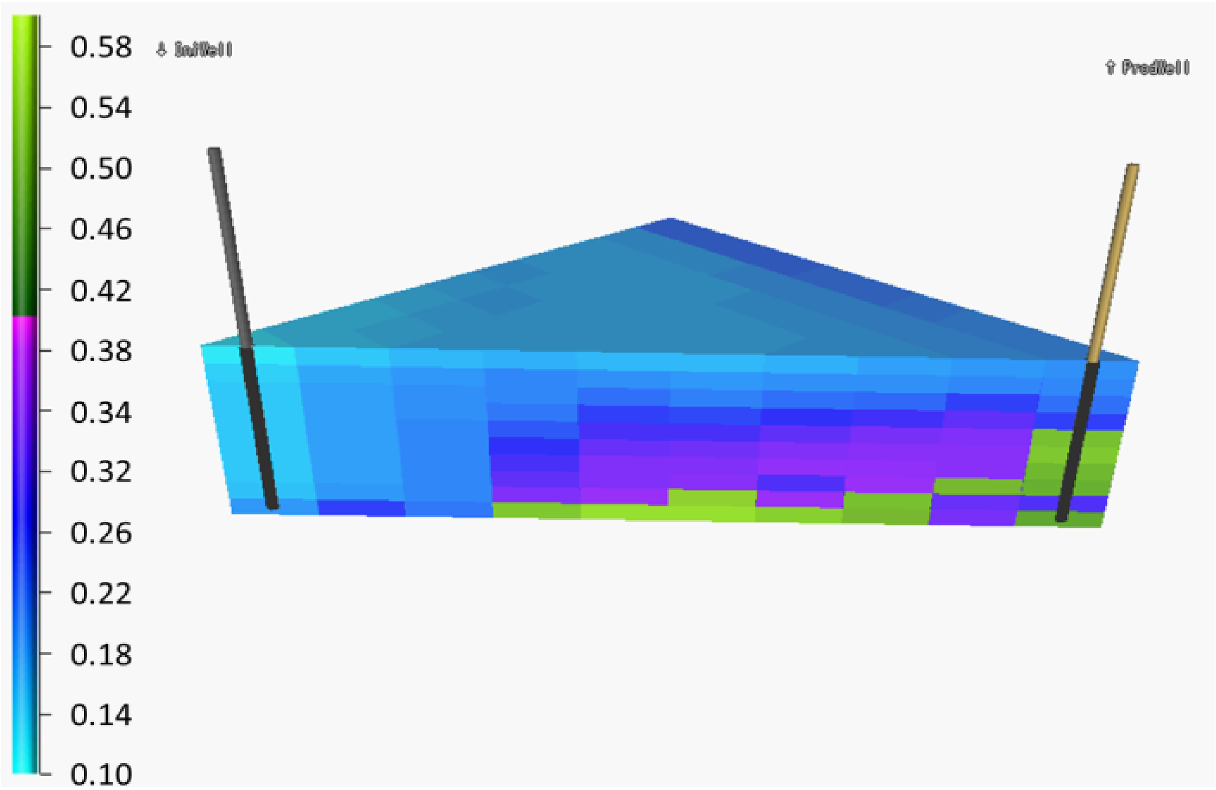
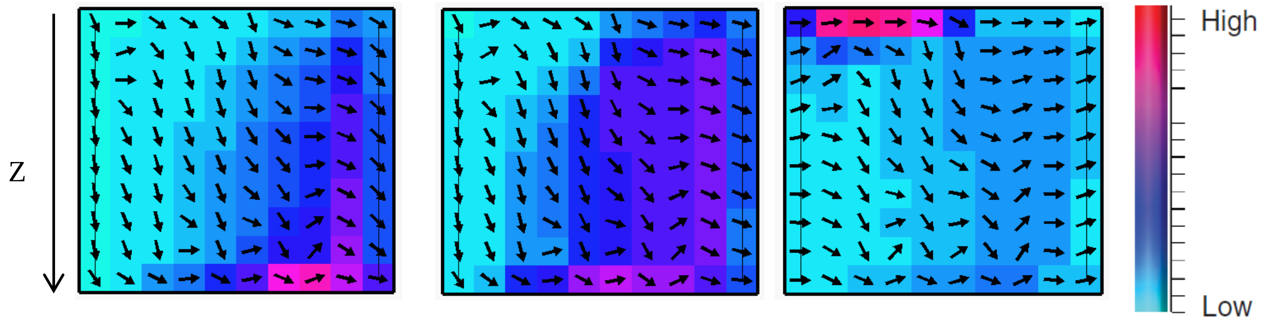
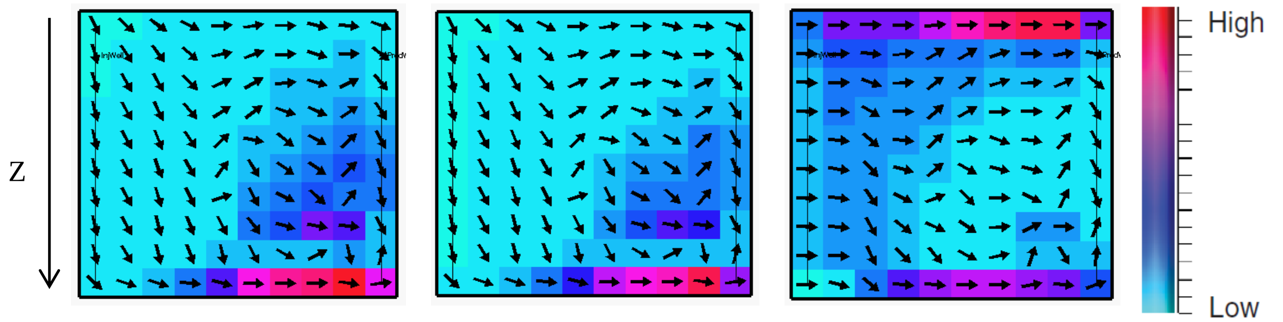


Figure 4 *Oil saturation, switching time = 0.37 PV, and 250 days of gas injection, equivalent to 0.64 PV.*



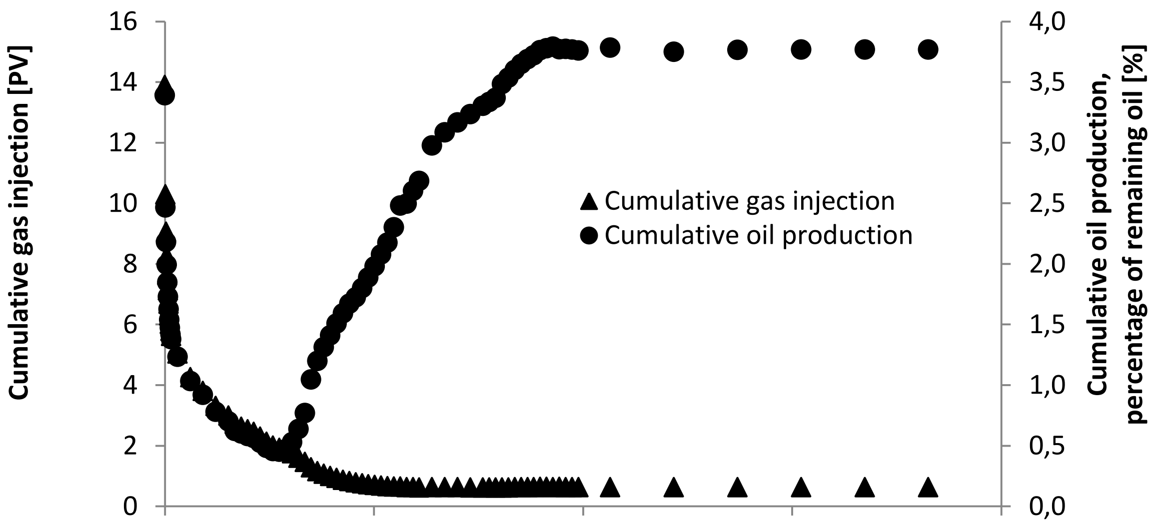
Water volume flux | Oil volume flux | Gas volume flux | Relative volume flux scale

Figure 5 *SAG process in a 2D reservoir, with dimensions 1m x 100m x 30m, and modeled with 1 X 10 X 10 gridblocks. These figures show the net volume fluxes of the phases between the gridblocks at reservoir conditions at the end of the simulation. Switching time = 1.63 PV, gas injection period = 100 days, equal to 0.49 PV*



Water volume flux | Oil volume flux | Gas volume flux | Relative volume flux scale

Figure 6 *SAG process in a 2D reservoir, with dimensions 10m x 100m x 30m, and modeled with 1 X 10 X 10 gridblocks. These figures show the net volume fluxes of the phases between the gridblocks at reservoir conditions at the end of the simulation. Switching time = 1.63 PV, gas injection period = 250 days, equal to 2.21 PV*



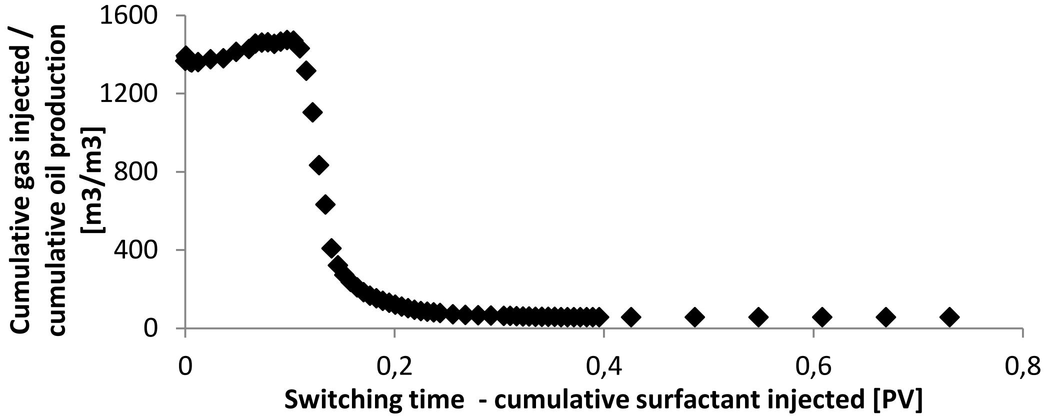


Figure 7 *Top: cumulative oil produced and cumulative gas injected vs. surfactant injected in pore volumes [PV]. Bottom: the ratio of the cumulative gas injected over cumulative oil production achieved for the same switching times as for the figure above. A single, independent simulation with a certain switching time is represented by one point displaying the cumulative oil produced and one point displaying the cumulative gas injected. Gas injection was pressure- controlled and fixed to 250 days.*

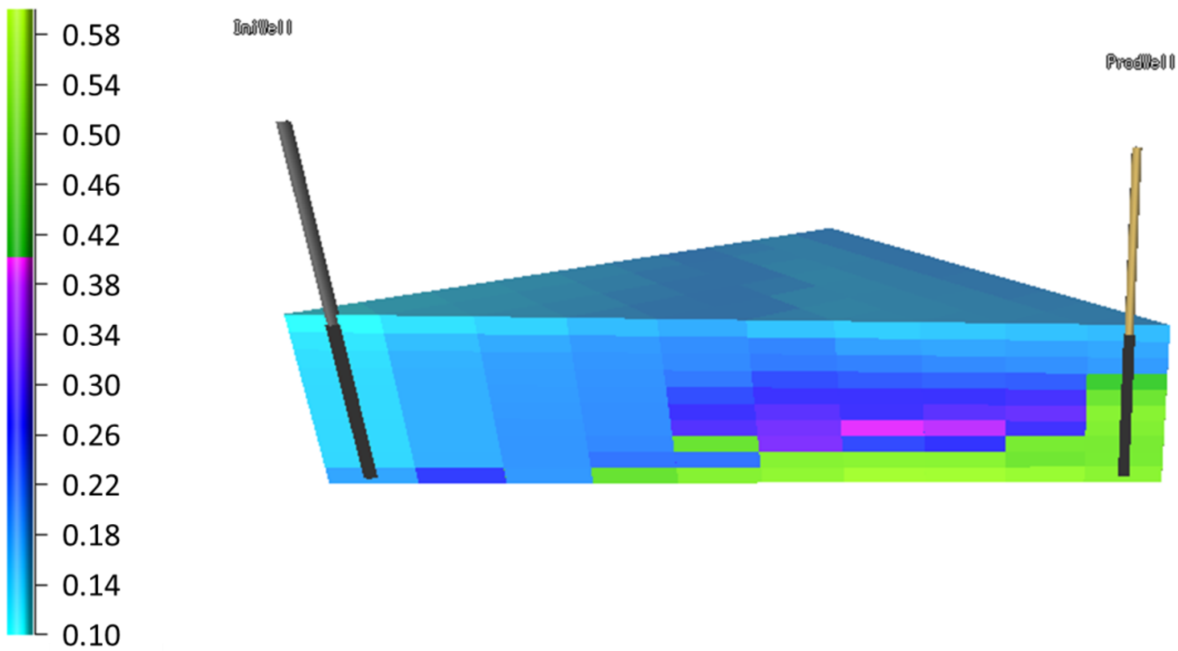


Figure 8 *Oil saturation, switching time = 1 PV, and 1 PV of gas injection.*

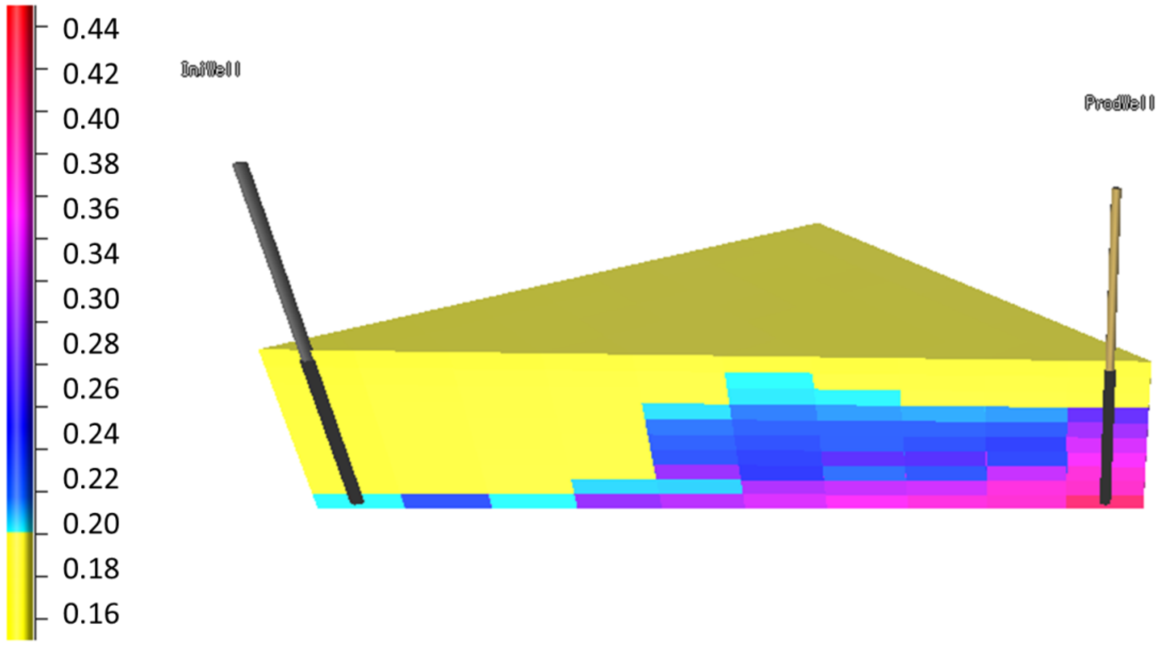


Figure 9 *Water saturation, switching time = 1 PV, and 1 PV of gas injection.*

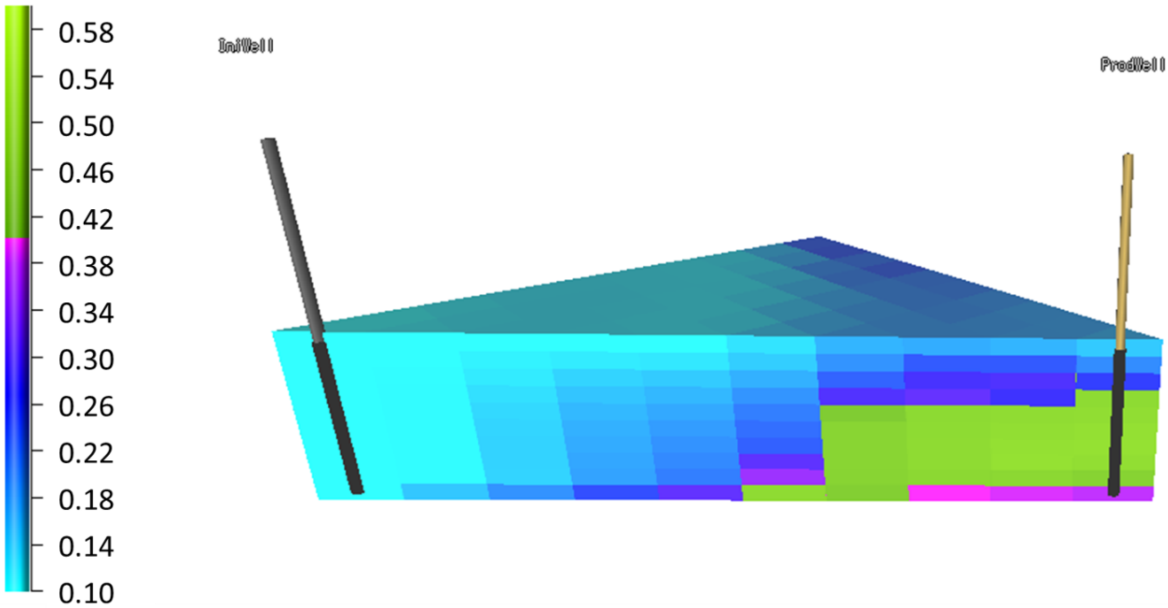


Figure 10 *Oil saturation, five SAG cycles of 0.2 PV for each slug, resulting in 1 PV of surfactant injection and 1 PV of gas injection.*

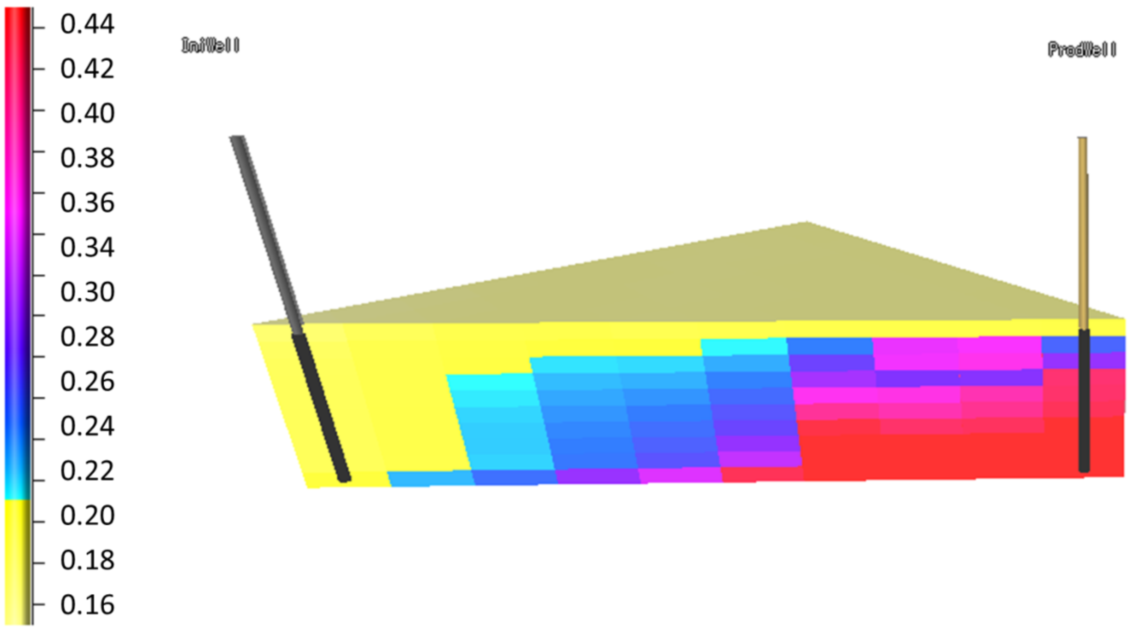


Figure 11 *Water saturation, five SAG cycles of 0.2 PV for each slug, resulting in 1 PV of surfactant injection and 1 PV of gas injection.*

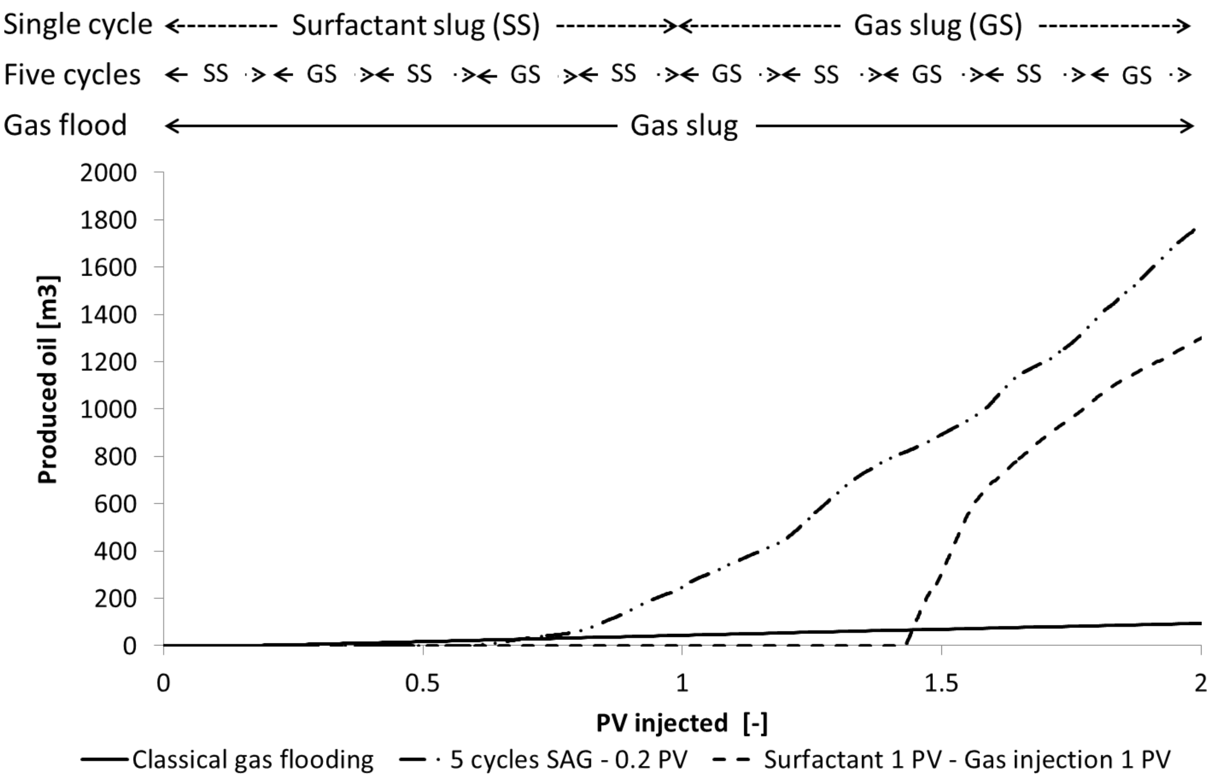


Figure 12 *Produced oil vs injected volume. The simulations were made with the same reservoir model and foam model.*