Simulation of CGW Injection in Parts of a Fluvial Deposited Reservoir

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Abstract

Poor sweep efficiency and early break through is a main concern with respect to improved oil recovery by gas injection processes. These adverse effects may be eliminated by combined gas and water (CGW) injection. The efficiency of a CGW injection process is strongly related to the size of the mixed gas/water flow zone in the reservoir.

The work presented here deals with reservoir heterogeneities and geometry within a single conducting channel in a fluvial deposited reservoir.

Heterogeneities in terms of variable permeability was generated by stochastic simulation. These permeabilities were furthermore modified to study the effect of different heterogeneity profiles in terms of average permeability versus depth, and of heterogeneity contrast in terms of the spread of permeability around this average value.

The importance of compositional effects, was studied.

The main conclusions are:

1. Larger heterogeneity contrast extends the mixed flow zone.
2. Within a conducting channel, the mixed zone is larger than what may be derived from Stone's segregation model. This is due to capillary effects and mixing due to heterogeneity contrast.

3. Stone's model is, however, a suitable tool for a rough estimation of the size of the mixed zone, both for simultaneous and alternating gas and water injection.
4. Strong improvement can be obtained by using CGW injection compared with pure gas injection.

Introduction

Poor sweep efficiency and early break through is a main concern with respect to improved oil recovery by gas flooding in general.

The sweep efficiency may be improved in combined gas/water (CGW) injection processes through reduced gas mobility. The efficiency of a CGW injection process is strongly related to the size of the mixed gas/water flow zone in the reservoir. The fractional size of this mixed zone with respect to the flooded reservoir volume, depends on reservoir parameters such as the length/height ratio of the reservoir segment in question, the reservoir heterogeneities at different scales, capillary pressure and the dynamic reservoir parameters.

The present paper deals with the effect of reservoir heterogeneities within a fraction of a fluvial deposited reservoir. Heterogeneities in terms of variations in permeability was generated through

stochastic simulation. These heterogeneities were furthermore modified to study the effect of different kinds of heterogeneity profiles in terms of average permeability in each layer versus depth, and to study the effect of varying heterogeneity contrast in terms of variation around a mean value within each layer.

The main simulations were run on the black oil simulator SIMBEST II /1/, while the studies of compositional effects were run on ECLIPSE 300 /2/ in black oil and compositional mode.

Reservoir model

The selected model is based on reservoir and geological data from a fluvial deposited North Sea reservoir. These data formed the basis for stochastic reservoir simulation. Two realizations were used.

A small section of the model, representing a single conducting channel within the fluvial system was used in the simulations.

The grid model consists of $25 \times 8 \times 20$ blocks, covering an area of $1825 \text{ m} \times 1260 \text{ m}$ with an average thickness of 6 m. The model has an overall dip of 3.5° , and the injector is located up-dip. Both wells are perforated in all layers.

Seven different heterogeneity patterns within the channel was generated by modifying the original stochastically generated realization:

- Equally distributed heterogeneities (average 200 mD), low (original) contrast.
- Equally distributed heterogeneities, high contrast.
- Upwards increasing sequence (average from 100 mD to 2000 mD varying linearly on logarithmic scale), low (original) contrast.
- Upwards increasing sequence, high contrast.
- Downwards increasing sequence, low (original) contrast.
- Thief zone on top (average 3000 mD, rest with average 200 mD), low (original) contrast.
- Thief zone on bottom, low (original) contrast.

The basic reservoir data are shown in Table 1.

Table 1 Basic reservoir data.

Initial reservoir pressure	382 bar
Reservoir temperature	100 °C
Reservoir depth	2475 m
Water oil contact depth	2561 m
Initial gas oil ratio	121

Generating heterogeneity profiles

The heterogeneity profiles were generated as outlined below:

First, the geometric average horizontal permeability for each layer in the original realization was calculated for x and y directions separately:

$$\bar{k}_{xk}^o = k_0 \exp \left(\frac{1}{N_x N_y - q} \sum_{i,j} \ln (k_{xijk}^o / k_0) \right). \quad (1)$$

Only active blocks are included in the summation, and blocks with a permeability less than 0.1 mD are considered inactive. The average is calculated separately for the permeability in x and y direction.

The horizontal permeability for each block for the desired heterogeneity profile is calculated using the following formulation:

$$k_{xijk}^n = \left[\frac{k_{xijk}^o}{\bar{k}_{xk}^o} \right]^b \cdot \bar{k}_{xk}^n, \quad (2)$$

where the superscript n indicate the desired heterogeneity profile. The exponent b is included to be able to adjust the heterogeneity contrast. For $b = 1$, the original contrast is retained, while an exponent $b > 1$ generate a higher contrast, and $b < 1$ a lower contrast.

The permeability in the x and y direction is calculated separately by the same formula (by exchanging the subscript x with y).

New vertical permeabilities are calculated using the following formulation:

$$k_{zijk}^n = \left[\frac{k_{zijk}^o \cdot k_{zijk}^o}{\bar{k}_{xk}^o \cdot \bar{k}_{yk}^o} \right]^{b/2} \cdot \bar{k}_{xk}^n. \quad (3)$$

Relative permeability and capillary pressure

When a reservoir section is subjected to WAG injection, the water saturation in parts of the section will oscillate over time. The water saturation will increase as a result of a water injection cycle, and decrease following a gas injection cycle. This implies that the effect of relative permeability and capillary pressure hysteresis must be included in a simulation study. To model hysteresis in the simulators, two sets of relative permeability and capillary pressure curves must be supplied: Drainage curves, applicable when the water saturation is decreasing, and imbibition curves, applicable when the water

saturation is increasing. When the saturation change in a particular grid block changes direction, a scanning curve running between the two pure curves is traced.

In a WAG situation, gas injection will be related to the drainage process and water injection to the imbibition process.

The simulators that have been used employ different hysteresis models. Care has been taken to give input data that give as close results as possible.

In a heterogeneous reservoir, the permeability variations will be accompanied by variations in relative permeability and capillary pressure. It was decided to model this by defining five different rock types and assigning grid blocks to rock type according to the criteria given in Table 2. Within each permeability interval, the relative drainage capillary pressure curves used is of Corey type /3,4/:

$$P_c = P_e \left(\frac{S_w - S_{wi}}{1 - S_{wi}} \right)^{\frac{1}{\lambda}} \quad (4)$$

The drainage relative permeabilities are based on the same formalism:

$$k_{rw}^{dr} = \left(\frac{S_w - S_{wi}}{1 - S_{wi}} \right)^{\frac{2+3\lambda}{\lambda}} \quad (5)$$

$$k_{row}^{dr} = k_r^o \cdot \left(\frac{S_o}{1 - S_{wi}} \right)^2 \left[1 - \left(\frac{1 - S_o - S_{wi}}{1 - S_{wi}} \right)^{\frac{2+\lambda}{\lambda}} \right] \quad (6)$$

$$k_{rog}^{dr} = k_r^o \left(\frac{S_o - S_{org}}{1 - S_{wi} - S_{org}} \right)^2 \left[1 - \left(\frac{S_o - S_{org}}{1 - S_{wi} - S_{org}} \right)^{\frac{2+\lambda}{\lambda}} \right] \quad (7)$$

and

$$k_{rg}^{dr} = k_r^o \cdot \left(\frac{S_g}{1 - S_{wi}} \right)^2 \left[1 - \left(\frac{1 - S_g - S_{wi}}{1 - S_{wi}} \right)^{\frac{2+\lambda}{\lambda}} \right] \quad (8)$$

Imbibition relative permeabilities and capillary pressure curves have been chosen such that they follow the drainage curves at high saturations. However, at a selected point ($S_d = 0.4$) they start to deviate so that they end in the appropriate end points, S_{orw} and S_{gr} . This is obtained by using the drainage curve, and applying a linear scaling of the saturations over the interval between S_d and the end point.

The relative permeability parameters used for each of the five rock types are given in Table 2.

Table 2 Relation between permeability and the parameters determining the relative permeabilities and the capillary pressure data.

Abs.per m. (mD)	Poros. (frac)	λ	S_{wi}	S_{orw}
< 40	0.14	1.0	0.35	0.10
40-200	0.17	2.5	0.30	0.15
200-1000	0.20	3.0	0.25	0.20
1000-4000	0.23	3.5	0.20	0.25
> 4000	0.264	4.0	0.10	0.30
Abs.per m. (mD)	S_{org}	S_{gr}	P_{ce} (bar)	k_r^o
< 40	0.05	0.05	0.06	0.65
40-200	0.07	0.06	0.05	0.70
200-1000	0.10	0.07	0.04	0.76
1000-4000	0.12	0.08	0.03	0.80
> 4000	0.15	0.10	0.01	0.85

The end point saturations for oil and gas are selected to be highest in the high permeability zones and lowest in the low permeability zones.

In the simulators, three phase relative permeability are calculated on the basis of two phase data. The simulated efficiency of a WAG process may depend on the choice of three phase relative

permeability correlation. In SIMBEST II, a modification of a Dietrich-Bonder equation /1,5/ was employed:

$$k_{ro} = k_r^o \left[\left(\frac{k_{row}}{k_{ro}} + k_{rw} \right) \left(\frac{k_{rog}}{k_r^o} + k_{rg} \right) - k_{rg} - k_{rw} \right] \quad (9)$$

In ECLIPSE, the eclipse default model /2/ was used:

$$k_{ro} = \frac{S_g k_{rog} + (S_w - S_{wi}) k_{row}}{S_g + S_w - S_{wi}} \quad (10)$$

Fluid description

The pVT data used in the main part of the study, employ live oil ($R_s \neq 0$) and dead gas ($R_v = 0$), and are relevant for injection of equilibrium gas. For the study of compositional effects, three new pVT models were generated: An 8 component compositional model, and two black oil models. The black oil models were intended to reproduce the phase behavior of the compositional model as closely as possible. One of the models is relevant for injection of equilibrium gas, while the other model is relevant for injection of separator gas. Both new black oil models include live oil ($R_s \neq 0$) and live gas ($R_v \neq 0$).

Compositional model

The Intera PVT program /6/ was used to tune an eight component compositional model employing the SRK equation of state with a volume shift parameter. The main goal in the tuning process was to create a compositional model that reproduce the black oil data of the original model as closely as possible.

Black oil models

The compositional model was used as a basis for generating the new black oil models with live oil ($R_s \neq 0$) and live gas ($R_v \neq 0$). The Intera PVT program was employed for this. Black oil tables generated by this program are independent of the injection gas used, and are mainly relevant for depletion processes or injection of equilibrium gas. An alternative algorithm for generating black oil data more relevant for gas injection processes, with respect to phase behavior, was used.

Figure 1 Phase diagram of a two component system (oil and gas), and method for generating black oil data intended to represent gas injection processes.

The method is illustrated in Figure 1: Depending on pressure and the relative amounts of initial undersaturated reservoir oil and injection gas, the reservoir hydrocarbon system will exist in one of four states: Gas, oil, gas and oil at coexistence, or supercritical. The initial reservoir fluid ① contains some dissolved gas (initial R_s). When the pressure is reduced, the coexistence line is crossed at the initial bubble point pressure ②, and the equilibrium gas ③ contains some dissolved oil (initial R_v). The density of coexisting oil and gas define B_o and B_g at the given (bubble point) pressure. Additional points on the coexistence curve are found from the properties of mixtures of reservoir fluid and injection gas: Each mixture ④ contains an increased amount of dissolved gas, and the coexistence line is crossed at a higher bubble point pressure ⑤. The new equilibrium gas ⑥ typically contain an increased amount of dissolved oil. The density of coexisting oil and gas define B_o and B_g at the new bubble point pressure. Note that, due to the changed surface density, the B_o and B_g values of the mixture must be adjusted so that the correct reservoir densities are reproduced:

$$\begin{aligned} B_o &= \left(\frac{\rho_{os} + R_s \rho_{gs}}{\rho'_{os} + R_s \rho'_{gs}} \right) B'_o \\ B_g &= \left(\frac{\rho_{gs} + R_v \rho_{os}}{\rho'_{gs} + R_v \rho'_{os}} \right) B'_g \end{aligned} \quad (11)$$

The difference between the three black oil models are illustrated in Figure 2. The original model and the equilibrium gas model are very similar up to a pressure of $p \approx 300$ bar, where vaporization becomes important. The separator gas swells more oil, and is miscible above $p \approx 300$ bar. Note that above this pressure, the method outlined above gives a two phase zone of

basically zero thickness. The finite thickness shown in Figure 2 was obtained by arbitrarily lifting the gas coexistence (i.e. R_v) line to avoid numerical problems resulting from an instant jump from 100% oil to 100% gas.

Simulation results

Simulation constraints were selected such that the results would be less sensitive to other variables than heterogeneities and geometry. An updip injection was therefore used so that the draw-back of high gas mobility compared to water was compensated by gravity advantages.

The water/gas ratio was chosen equal to one. This gives breakthrough for water and gas at approximately the same time in the base case.

The WAG cycle length was 200 days starting with 100 days of water injection.

The injection rate is chosen in order to flood the reservoir segment with one pore volume in 4500 days, corresponding to 500 Rm^2/day for the base case. Due to the choice of porosity versus permeability, the pore volumes are different in the different cases. Keeping the average interstitial velocity constant, the injection rates were varied from 453 Rm^3/d to 532 Rm^3/d for the heterogeneity cases. For the cases where the thickness was increased, the rate was correspondingly increased in order to keep the interstitial velocity constant. Initially there was no gas cap.

Gas and water breakthrough

Early breakthrough of injection fluids will normally lead to reduced oil rates, and low sweep efficiency

One idea behind a WAG injection is to delay the breakthrough time, by controlling the mobility of the injected gas.

The results, related to breakthrough time of gas and water in the heterogeneous cases, are given in Figure 3. There is a significant difference between the heterogeneity profiles, and a small difference between the two realizations. However the tendency within each realization is the same.

Hence the conclusions are not sensitive to the choice of realization.

Gas is the breakthrough fluid for all the heterogeneous profiles except for downwards increasing and thief zone on bottom profiles. These two profiles are less favorable for gas override so a later gas breakthrough in these cases should be expected.

Figure 2 Phase diagrams corresponding to the three different black oil models. The original dead gas model (a), the equilibrium gas model with live gas (b), and the separator gas model (c).

Figure 3 Gas and water breakthrough times, in units of pore volume injected, for the different heterogeneity profiles and realizations.

Comparing the cases of low and high permeability contrast the water breakthrough is earlier for the case having high contrast. For gas breakthrough this is only true for the equally distributed profile. The results are opposite for the upwards increasing sequence. A larger contrast will promote the mixing of phases and thus postpone the breakthrough. The creation high conductivity channels by heterogeneity induced viscous fingers will, on the other hand, also be promoted. In the upwards increasing profile the gas will have a stronger tendency for overriding. The channeling mechanism should thus be stronger in the top layers promoting an earlier breakthrough of gas. However, the opposite is observed indicating that the mixing promotion is dominating.

Mixed zone sweep efficiency

For combined gas/water injection, Mobility control of the injected fluid(s) can only take place in the mixed flow zone.

The mixed volumetric sweep is defined as the fraction of the reservoir blocks where the saturation of both gas and water has increased by a fraction of at least 0.05 at any time during the simulation. Results from the simulations are shown in Figure 4. There is a significant difference in mixed volumetric sweep between the different heterogeneity profiles.

The heterogeneity contrast seem to have a uniform influence on the size of the mixing zone.

Figure 4 Mixed volumetric sweep for the different heterogeneities and realizations.

A larger mixed zone will delay the breakthrough of the injected fluid and increase the recovery. The larger mixing zone correlates well to the data of breakthrough.

An other important aspect is the location and saturation of the mixed zone. Figure 5 shows the location and saturation change in the mixed zone for heterogeneity profiles of "equally distributed," "upwards increasing," and "downwards increasing" of Realization 5 for a selected x - z cross section running through the injection well ($j = 4$).

Figure 5 Extension of mixed zone in xz cross section ($j=4$) at 0.67 pore volumes injected. Contours describes the saturation changes of the phase (gas or water) with least change in either gas or water saturation at each point. Note that all grid blocks are drawn as unit cubes and are not to scale.

For the upwards increasing sequence (Figure 5, lower left) the zone swept by gas is identical to the mixed zone in the selected cross section. There is no gas zone, only the mixed zone above the gas/water contact. However, on this particular case with very low permeability at the bottom layers, the simulator closes the well in these bottom layers during gas injection in order to avoid back flow.

The situation for the equally distributed (upper left) sequence, a very thin gas zone can be observed on the top. The vertical size of the mixed zone is increased in relation to the upwards increasing sequence.

For the downwards increasing sequence (upper right) the vertical size of the free gas and mixed zone is increased.

Common for all of the cases is that the gas segregation do not go further than a distance of about 400 meters from the injection well. This distance is approximately 0.3 of the distance between the wells and can be compared directly to the viscous to gravity ratio, VGR, in the segregation model of Stone.³ For the current cases VGR is estimated to about 0.01, which in the near well region, where the flow is approximately radial, corresponds to a relative distance of $\sqrt{\text{VGR}} \approx 0.1$. The comparison with the theory is elaborated upon in Section 0 below.

Another aspect in the situation after the stabilization of the segregation at $x > 0.30$, is the

thickness of the mixed zone. The thickness of the mixed zone will correspond to a transition zone related to the capillary pressure curve. As long as the gas velocity is small enough, the process will be controlled by capillary equilibrium ($P_c = \Delta\rho gh$). This effect is confirmed in a run where capillary pressure was reduced by two orders of magnitude. The thickness of the transition zone is then reduced to slightly more than a single block as determined by numerical dispersion.

Analytical theory for the size of the mixed zone

Analytical expressions for the shape of the mixed zone are given by Stone /7/ and Jenkins /8/. These expressions are valid under the following conditions:

- Simultaneous injection of water by miscible gas, at rates constant in time and along the injection well.
- Homogeneous non dipping reservoir of constant thickness.
- Steady state.
- Zero capillary pressure.
- Zero compressibility.

The theory may be extended to immiscible displacement by noting that the oil saturation reaches the end point values S_{org} and S_{orw} after gas and water flooding, respectively. Similarly an end saturation of S_{orm} is reached after mixed flooding.

In the present simulations the water and gas injection is alternating. This implies that steady state conditions are never reached. The size and location of the mixed zone will change during the injection cycle. The zone reaches its maximum in the near well region at the end of gas injection, the maximum point, 0.67 pore volumes injected, has been used here.

In the near well region we may assume radial displacement and the height of the water zone is then given by

$$h_w(r) = \frac{M_{gw} \text{WAG}}{\alpha + M_{gm} \text{VGR}(R^2 / r^2)} h, \quad (12)$$

with

$$\alpha = 1 + M_{gw} \text{WAG} - M_{gm}. \quad (13)$$

WAG is the WAG ratio, i.e. the volumetric ratio of injected water to gas, and VGR is the viscous to gravity ratio defined by

$$\text{VGR} = \frac{q_t}{\Delta \rho \cdot k_v g \cdot a(\lambda_{gm} + \lambda_{wm})}. \quad (14)$$

M_{gw} and M_{gm} are mobility ratios:

$$M_{gw} = \frac{\lambda_{gg}}{\lambda_{ww}}, \text{ and } M_{gm} = \frac{\lambda_{gg}}{\lambda_{gm}}. \quad (15)$$

VGR has been calculated for a semicircle of radius $R = \frac{1}{2} L_y$, where L_y is the

width of the reservoir, and a sweep efficiency of 80%.

The theoretical predictions, for a flat homogeneous reservoir of height 6 m and ignoring the small dip ($\approx 3^\circ$), are compared to simulation results in Figure 6.

In the simulations, the mixed zone boundary is defined as the 10% change level in the simulations (Figure 5).

Figure 6 Extension of the mixed zone in xz cross section ($j=4$) for different geometries: Unmodified (upper left), double height (upper right), four times the height (lower left), and half length (lower right). Simulated results are compared with the theory of Jenkins [8].

Considering all the non valid approximations, the analytical theory performs surprisingly well in giving estimates for the size of the mixed zone.

Compositional effects

The equally distributed, upwards increasing, and downwards increasing heterogeneity distributions based on one of the realizations, were simulated using the different fluid descriptions described in section 0 to evaluate compositional effects: Compositional simulations using equilibrium gas and separator gas as injection gas, and the two new black oil models employing live gas.

The break trough times, size of mixed zone, and recovery is heavily dependent on the fluid description. However, the main conclusions as stated in section 0 below remain valid independent of fluid description.

Conclusions

The results from the simulations of the current reservoir segment using varying "heterogeneity profiles" have lead to the following conclusions:

- 1) Heterogeneity contrasts extend the gas/water mixed zone.
- 2) Mixed zone within thin conducting channels is greater than what may be derived from Stone's segregation model.
- 3) The segregation model of Stone seem to be good enough for a rough estimation of the size of the mixing zone.
- 4) Simulations based on the two realizations show the same trends in the simulated results.
- 5) Strong improvement can be obtained by using up-dip WAG injection instead of pure gas in thin reservoirs with dip.
- 6) Within a certain maximum channel thickness, the thickness of the channel seems to be less important.

Nomenclature

Symbols

a	= Swept area
b	= Heterogeneity index
B	= Formation volume factor (subscript for phase)
g	= Acceleration of gravity
hw(r)	= Height of water zone in radial model
k	= Permeability

$\bar{k}$	= Geometric average permeability (in one layer)
k	= Permeability (Subscript for phase)
M	= Mobility ratio
N _x , N _y	= Number of blocks in x and y direction, respectively
P _{ce}	= Entry capillary pressure
P _c	= Capillary pressure
q	= Number of dead blocks in the grid model / volumetric rate
R	= Radius (total)
R _s	= Dissolved gas (gas oil ratio)
R _v	= Dissolved oil (oil gas ratio)
r	= Dimensionless distance from injection well in radial system
S	= Saturation
VGR	= Viscous gravity ratio
WAG	= WAG ratio
λ	= Pore distribution index / mobility
Δρ	= density difference
ρ	= density

Subscript

g	= Gas
gg	= Gas in gas zone
gm	= Gas in mixed zone
gr	= Residual gas
L	= Liquid
o	= Oil
org	= Residual oil in oil-gas system
orm	= Residual oil in mixed zone
orw	= Residual oil in oil-water system
rg	= Relative to gas
ro	= Relative to oil
row	= Relative to oil in water oil system
rw	= Relative to water
rog	= Relative to oil in gas oil system
t	= Total
v	= Vertical
w	= Water
wi	= Irreducible water
wm	= Water in mixed zone
ww	= Water in water zone
wt	= Irreducible wetting phase
xijk	= X-direction in block ijk
xk	= X-direction in layer k
zijk	= Z-direction in block ijk
zk	= Z-direction in layer k
0	= Reference

Superscript

dr	=	Drainage
o	=	Reference
*	=	Effective
n	=	New modified / desired

Abbreviations etc.

pVT	=	Pressure-volume-temperature
CGW	=	Combined gas water injection
WAG	=	Water alternating gas injection

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