COMPARING HYSTERESIS MODELS FOR RELATIVE PERMEABILITY IN WAG STUDIES

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ABSTRACT
Immiscible WAG have been simulated by use of different relative permeability hysteresis models. The oil relative permeabilities were generated by a modified Stone I model. Experimental results especially from intermediate wetting systems have shown a significant drop in gas relative permeability between primary processes (gas saturation increasing first time) and tertiary processes (gas saturation increasing after an increasing-decreasing sequence). Numerical simulation of both 1D core-floods and 2D reservoir cross-sections were used in order to investigate WAG. The input to each model is selected from experimental measured data. The results show that standard hysteresis models for non-wetting phase relative permeability is lacking flexibility to describe experimental data important for the performance of the WAG process.

INTRODUCTION
Relative permeabilities are generally functional dependent of saturation and saturation history. The second dependency is in literature described as *relative permeability hysteresis.* The hysteresis behaviour in non-wetting phase (gas) relative permeability differs significant depending on wetting preferences of the system being investigated. Strongly water-wet systems show drainage-imbibition hysteresis as documented by many investigators in the literature[1,2]. In addition, intermediate-wetting systems show a complicated hysteresis behaviour depending on saturation cycle history[3]. Many reservoirs have intermediate-wetting properties, and a detailed study of the relative permeability hysteresis is important in processes involving saturation oscillation during three-phase flow.

The experimental investigation[3] , which forms a basis for this paper, numbered the displacements processes with primary, secondary and tertiary depending on the number of forgoing displacements cycles. In this way a tertiary drainage is an increasing gas saturation process after a secondary imbibition (decreasing gas saturation) and primary drainage. Oil saturation was decreasing in all displacements and water, and gas was the injected fluids. This investigation shows that in order to describe the WAG process, a set of both primary and secondary drainage water and primary and secondary drainage-imbibition gas relative permeabilities have to be measured. Then an ambiguous problem arises, because standard two-phase hysteresis models can not reproduce all the experimental information. The scope of this paper has been to show that the information lost when using two-phase hysteresis models can be important for the performance of the WAG process.

A hysteresis loop exists of a drainage process with a following imbibition process. It is frequently observed higher relative permeability to gas from a primary drainage than in a tertiary drainage process. The reduction of endpoint permeability can be as large as a factor of ten. These two processes are separated by a water-flood, indicating that trapping of non-wetting phase can have an important place in the hysteresis observed in intermediate wetting systems. The trapping process in three-phase systems is nonreversible, thus the imbibition curve will not be retraced when gas saturation is increasing after an imbibition process. In addition, a secondary drainage process gives reduced endpoint gas relative permeability approximately equal to a tertiary drainage process. A similar hysteresis[3] is often observed in the water phase. A mobility drop occurs between two imbibition processes separated with a gas-flood, both imbibition processes start from irreducible water saturation. The first process is a water-flood when oil is the non-wetting phase and the second is a water-flood when gas is the non-wetting phase and oil the intermediate-wetting phase, assuming water-wet conditions.

The necessity of using a hysteresis model for gas relative permeability in numerical simulation of WAG has been reported earlier[4]. In standard simulation study (without hysteresis) using only a primary drainage gas curve with no possibility of estimating trapped gas, the oil recovery was totally underpredicted compared to experimental data. In reservoir cross-section simulations gas segregated in a thin zone on the top of the reservoir, with a small three-phase area. Studies of modified gas relative permeability curves in standard simulations have not give any satisfactory results. Because of the extremely low residual oil saturation observed in WAG experiments, the Stone I model[5] was modified to match the observed values. In this case the residual saturation was table defined depending on either water saturation or gas saturation. The zero oil isoperm becomes concave towards the oil apex in a ternary diagram.

HYSTERESIS MODELS

A relative permeability hysteresis model should be evaluated whenever a simulation study involves saturation oscillations. In the literature, models for hysteresis in non-wetting phase permeability have mostly been restricted to extreme-wetting two-phase systems. In lack of three-phase hysteresis models, two phase hysteresis have been used as input to numerical simulation involving three-phase flow. Standard two-phase hysteresis models are founded on Land's empirical relation[6]

$$\frac{1}{S_{gt}} - \frac{1}{S_{gi}} = C \tag{1}$$

Although Land only showed the validity of (1) in two-phase gas/liquid systems. There is some evidence supporting that the relation can be valid for three-phase situations with different wetting properties[3,7].

Carlson hysteresis model[8] consist of a drainage-curve and the value of the constant C in equation 1. The imbibition curve can then be estimated from a maximum gas saturation to a trapped gas saturation using the drainage curve, Land's relation and the hypothesis that gas saturation can be separated in two parts; free saturation exhibiting flow and trapped saturation. A consequence is that all imbibition curves become parallel in spite of different origin on the primary drainage curve as showed in figure 1a. The coarse lines in figure 1a, that is the primary drainage curve connected with an imbibition curve originating from the largest possible non-wetting saturation, are a relative permeability envelope in which scanning-curves are generated. Whenever the drainage process is stopped, a subsequent imbibition process will follow a scanning-curve. The point where the displacement process shifts from drainage to imbibition is called the *inflection point.* After initiating an imbibition process all further processes are assumed reversible, i.e. the scanning-curve is followed back to the inflection point and then the primary drainage curve is followed to a new historical maximum of gas saturation. If the drainage process stops on the scanning-curve, relative permeability during saturation oscillation is computed from the same curve.

The Killough hysteresis model[9] for non-wetting phase is similar to Carlson's model founded on Land's empirical relation to estimate trapped gas as a function of the inflection point. This model also needs the drainage curve and the Land constant as input, and estimates the imbibition curves from the drainage curve using a parametric interpolation method or a normalised experimental data method. The interpolation method involves a free parameter that must be known. A water hysteresis scheme is also available[9], and separates the water relative permeabilities in a drainage curve and an imbibition curve. The scanning-curves are interpolated from these two curves. The imbibition curve is assumed reversible[9], thus hysteresis may occur after primary drainage process, but not after a primary imbibition. The water hysteresis scheme is shown in figure 1b.

A three-phase hysteresis model, based on the experimental measured results, should maintain the Land method to calculate trapped gas from the maximum historical gas saturation. The imbibition curve is normally not reversible, in this way drainage-curves correlated to water saturation can be generated for each hysteresis loop . A Carlson algorithm will then be valid between drainage and imbibition curves from the same hysteresis loop.

A new three-phase relative permeability model (SL) has been developed by Skauge, and is presented by Skauge and Larsen[4]. We see the SL model as a first approach to a three-phase hysteresis model, which is able to reproduce the hysteresis behaviour observed on intermediate wetting systems. This model contains two Carlson hysteresis envelopes, one counting for high mobility and one counting for low mobility. Each envelope obeys the rules of the Carlson model as stated in figure 1c. A simple treatment as in the SL model involves some ambiguous problems. First a jump between the envelopes makes the relative permeability curve discontinuous and secondly the jump must be activated when certain criterion is fulfilled. In order to be consistent with the experimental data the jump should be activated when gas saturation is increasing after an increasing-decreasing cycle. In numerical simulation of the WAG process small saturation oscillations based on stability problems occur most frequently. A jump can then be activated because of material balance problems, which will be strongly unwanted. To solve this problem we had to modify the SL model by implementing a tolerance limit which must be exceeded before a jump take place. The tolerance limit increased the stability in numerical simulation and decreased simulation time significant. The CPU needed to simulate 3000 days WAG performance of the cross-section model was reduced by a factor of two. Next the Land method to compute trapped gas saturation is not maintained when jumping between the envelopes, this is due to the way the hysteresis models are implemented in Eclipse. A pseudo hysteresis model for water phase is also available in the SL model, including table defined relative permeability without any scanning-curves. In this way two different water curves can be given as input, the routine shifts curves when the jump between envelopes in gas phase is activated, figure 1d.

PHASE MOBILITY OF FIELD-SCALE IMMISCIBLE WAG

An analytical model for predicting the WAG performance has been developed by Stone[10] and Jenkins[11]. Such an approach is limited by the ability to predict water and gas mobility in different parts of the reservoir and neither trapping of gas nor mobility of oil is accounted for in the analytical model. In numerical simulation a much more detailed study of WAG performance can be made, however, phase mobility and residual oil saturation are still important input. To investigate WAG performance based on experimental results of intermediate wetting systems, a simple homogenous reservoir model as in figure 2 and table 1 is adopted. The cross-section between two wells is initially filled with oil and water as indicated in figure 2. Due to equilibrium between capillary forces and gravity force a small vertical saturation gradient appear. At the top of the reservoir water is immobile. In figure 2, a WAG scheme has been adopted, injecting gas and water slugs to the reservoir. Adjacent to the injector a three-phase flow WAG zone develop, where both saturation oscillation and cross flow due to gravity difference between gas and water occur. At some distance from the injector, depending among other, on vertical communication, a gas-oil zone appear at the top of the reservoir and a water-oil zone at the bottom of the reservoir as in figure 2.

The injection of gas must be large enough to supply gas to the gas-water WAG front at the rate gas is entrapped by the advancing water slugs. The statement was first described by Blackwell et. al.[12] The optimum WAG ratio must fulfil the statement, but simultaneously give a minimum segregation effect. Three-phase flow occur in the WAG zone and according to the experimental data the gas relative permeabilities are similar to those found from secondary processes with reduced mobility. In the WAG zone gas is entrapped by advancing water slugs, any of the hysteresis models will be able to account for this entrapment.

In the water-oil zone the water permeability will be determined from the primary imbibition (water-oil) process. Further, the gas permeability in the gas-oil zone is determined from the primary drainage (gas-oil) process. When a model like figure 2 is adapted, there must be a transition region between the two-phase zones and the three-phase zone where gas and water permeabilities are neither completely controlled by a primary process nor by a secondary process. In the transition region both gas and water saturations can increase simultaneously. The discontinuous jump in the SL hysteresis model is only activated after a saturation oscillation in the gas phase. Since the SL model only accounts for the to extremes, high mobility or low mobility, the gas and water permeabilities will probably not be correct calculated in the transition region.

INPUT DATA TO DIFFERENT HYSTERESIS MODELS

In this section we will use the hysteresis model described earlier to evaluate the performance to simulate the WAG process and starts with non-wetting phase which is assumed to be gas. The experimental relative permeabilities reported earlier[3] is similar to the envelopes in figure 1c). In fact this curves are estimated directly from pressure and production data by an unsteady state method, i.e. no history matching. The scanning-curves in figure 1c) are estimated by the hysteresis model, and is not directly experimental verified.

The Carlson model can not account for low gas mobility in WAG zone and simultaneously high mobility in the gas zone. Then a choice must be made either by; 1) using a primary drainage at irreducible water saturation and a following secondary imbibition or 2) a secondary drainage and a following tertiary imbibition as input to the model. The first curves will probably be correct in the gas zone. Inverted the second set of curves will be a better choice in the WAG zone. The breakthrough of high speed gas from the top of the reservoir will reduce the oil recovery from the reservoir and similar a underpredicted WAG zone will decrease oil recovery. In order to not overestimate the oil recovery by WAG the first set of curves must be used. The Killough non-wetting phase hysteresis models has similar performance as the Carlson gas hysteresis model, and the same conclusion will be valid.

In the SL model an envelope of primary drainage and secondary imbibition curves together with an envelope of secondary drainage and tertiary imbibition will have the possibility to both estimate the high mobility gas zone and also the low mobility WAG zone. Numerical simulations show that oil recovery is very sensitive to trapped gas saturation, and decreasing trapped gas saturation will decrease oil recovery.

Only two wetting phase hysteresis models are available in this study. The difference in water relative permeability between imbibition starting at irreducible water saturation and a following drainage represent only a minor change for intermediate wet data[3,5]. When a WAG process is started in a reservoir initially saturated with oil and irreducible water, the Killough hysteresis model will always use only the water imbibition curve to predict relative permeabilities. Because the first mobile water which appears will necessary be in an imbibition process and this process is assumed to be reversible. We conclude that the Killough wetting phase hysteresis model for relative permeability has very limited use in WAG simulations. The SL pseudo hysteresis model for, wetting phase have the opportunity to select a curve representing high mobility in the water zone, and a curve representing low mobility in the WAG zone. However the jump between the two curves is connected to the same event in gas relative permeability thus a correct estimation of water mobility in the transition region will generally not be expected.

NUMERICAL SIMULATION OF THE WAG PROCESS

1D core-flood simulations and 2D cross-section simulations of a homogenous reservoir as in figure 2 have been used with Carlson, Killough and the modified SL model. The most important features of the simulation models are listed in table 1. Slugs of 0.1 PV of water and gas were injected in a WAG scheme. The injection rate was constant and equal for all hysteresis models. The production wells were controlled by bottom hole pressure. Inspection of figure 3 shows that the modified SL model gives nearly similar oil recovery in 2D models as the old SL model, this is also valid for 1D core-flood simulations. The objectives were twofold; first investigate the effects of reduced gas relative permeability, and secondly evaluate effects of reduced water relative permeability. All simulations utilized the Eclipse 94 numerical simulator.

1) By comparing SL model with Carlson and Killough when the water permeability representation is equal for all models gives an indication of the importance of reduction in gas permeability. Figure 4 shows oil recovery from these models in 1D core-floods when using a low mobility water representation. Since gas was the first injected fluid in the WAG process core-floods[3], water is assumed to have low mobility in 1D studies according to the experiments on intermediate wetting systems[3]. Both two-phase hysteresis models give approximately similar oil recovery, average oil saturation before and after WAG is respectively 66 % and 13.2 %. The SL model gives endpoint oil saturation by WAG of 11.6 % -about 1.5 % higher oil recovery. The corresponding experimental results are 66 % and 5 %. The simulations respect the core-flood data by using measured relative permeability input with no history matching. Still the gap between oil recovery from experiment and numerical simulation is significant. The reason for this can be twofold: a) modified Stone I underpredict oil relative permeability and b) the Land relation underpredicts trapped gas saturation. The first argument seems to be the most likely,

since experimental data of gas trapping has been shown to follow a Land type correlation[3]. Next, no capillary pressure hysteresis is accounted for in the simulations. The stairstep like production curves observed in figure 4 is due to 1D-simulations in which the injected slugs are maintained through the porous medium. This is also experimental verified[4]. In 2D cross-section simulations a larger difference between Killough and Carlson appear as in figure 5 and figure 6. This is mainly because the Killough model generally predicts higher trapped gas saturation on the specific relative permeability curves used in this study. The little difference in estimation of trapped gas between Carlson and Killough is due to the way these models are implemented in Eclipse. After 3000 days where nearly a steady state is reached, the SL model without any correction for trapped gas gives slightly larger oil recovery then other models. But during the period from 800 days to 2400 days the oil recovery from SL is significant larger then all other models. From figure 6 the effect of reduced gas mobility in the SL model gives delayed breakthrough of gas, 900 days compared to 400 days in the Killough and Carlson models. In figure 7 and figure 8 the gas fronts from SL and Killough models are given after 1000 days. In correspondence with the gas production curve, the SL gives larger area swept by gas.

2) By using a pseudo hysteresis water scheme in SL model we can examine the effects of reduced water mobility during WAG cycles. In 2D cross-section models the water permeability can not be fully modelled by either a primary or a secondary process. When using the secondary representation the water to oil mobility ratio, $M_{w\text{-}o}$ will be smaller then using a primary representation. Generally the representation which has the lowest $M_{w\text{-}o}$ gives the highest oil recovery due to better displacement, sweep efficiency etc. We then have a problem because the two curves will give significant different oil recovery , figure 5 and figure 9 gives oil recovery with secondary water and primary water respectively. Using both curves in a pseudo hysteresis model give oil recovery between the two extreme curves. General rules can not be given from such a simple treatment, but the simulations show that a detailed water permeability representation is very important when modelling the WAG process.

One important feature of the pseudo hysteresis model is the increase in segregation of water. When $M_{w\text{-}o}$ becomes smaller a more piston like water-oil displacement will be expected. The pseudo hysteresis model will in average give much lower $M_{w\text{-}o}$ than the simulations using a primary water representation, but from figure 10 and figure 11 water is only totally segregated when using the pseudo hysteresis model. At nearly steady state conditions the cross-section is completely swept by water when using primary and secondary water permeabilities, but applying the pseudo hysteresis model gives an area at the top of the reservoir that never will be reached by water, remembering that connate water saturation at the top of the cross-section is 0.34. This is due to a fast moving high mobility water front develops at the bottom of the reservoir and simultaneously the water is slowed down in top of the reservoir when using the pseudo hysteresis model.

CONCLUSIONS

- implementing hysteresis models which can reproduce experimental data in simulation studies favour the WAG process compared to standard hysteresis models

- the Killough and Carlson non-wetting phase hysteresis models have not the flexibility to reproduce experimental data in numerical simulation

- the Killough wetting phase hysteresis model for relative permeability have very limited use in WAG simulations. The SL pseudo hysteresis model for wetting phase gives the opportunity to select a curve representing high mobility in the water zone, and a curve representing low mobility in the WAG zone.

- the SL model can account for reduced mobility in both wetting and non-wetting phase observed experimentally during three-phase saturation oscillation.

- numerical simulation have shown the importance of including reduced mobility of gas and water for describing three-phase flow in immiscible WAG processes

NOMENCLATURE

C	Land's constant
k_{ro}	Relative Permeability to oil
k_{rw}	Relative permeability to water
m_o	Viscosity to oil
m_w	Viscosity to water
$M_{w-o} = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o}$	Water oil mobility ratio
S_{gi}	Historical maximum of gas saturation
S_{gt}	Trapped gas saturation

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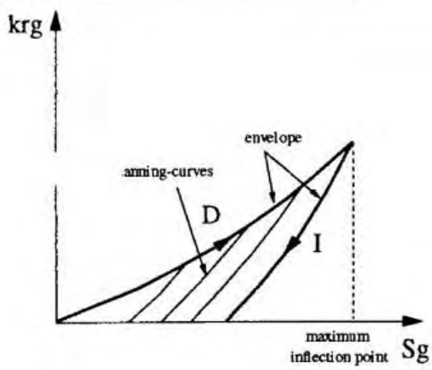
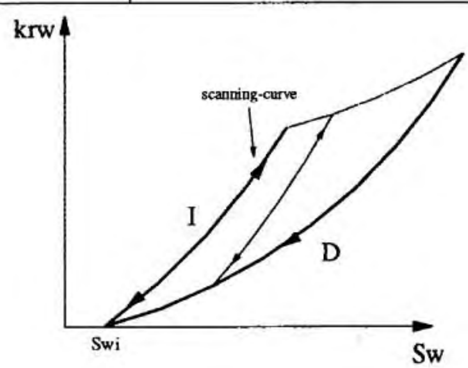
Table 1

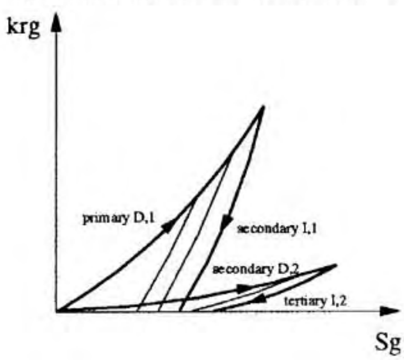
Physical property	1D core-floods	2D cross-section
porosity	0.215	0.250
absolute permeabilty (x,z)	(28,28) mD	(200,20) mD
length x,y,z direction	0.397, 0.0362, 0.0362 m	1000,10,100 m
numbers of gridboxes (x,y,z)	(100,1,1)	(100,1,50)
viscosity water, oil, gas	0.32, 0.30, 0.023 cp	0.32, 0.3, 0.023 cp
density water, oil, gas	1000, 641, 220 kg/m^3	1000, 545, 165 kg/m^3
initial saturation water, oil, gas	0.34, 0.66, 0	0.34, 0.66, 0 to 0.4, 0.6, 0
WAG ratio	1:1	1:1
endpoint of primary gas relative permeability (S_g , k_{rg})	(0.31,0.27)	(0.31,0.27)
endpoint of secondary gas relative permeability (S_g , k_{rg})	(0.5,0.08)	(0.5,0.08)
endpoint of primary water relative permeability (S_w , k_{rw})	(0.72,0.45)	(0.72,0.45)
endpoint of secondary water relative permeability (S_w , k_{rw})	(0.72,0.05)	(0.72,0.05)
bottom hole pressure producer	200 bars	300 bars



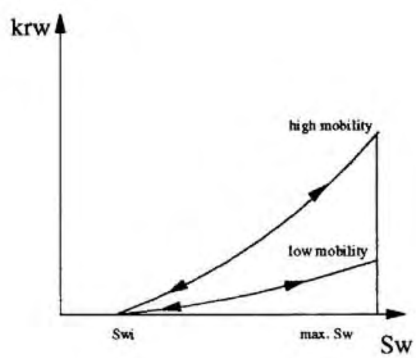
a) Carlson hysteresis model non-wetting phase



b) Killough hysteresis model wetting phase



c) SL model non-wetting phase



d) SL model wetting phase

Figure 1 Hysteresis models used in numerical simulation in order to model the WAG process

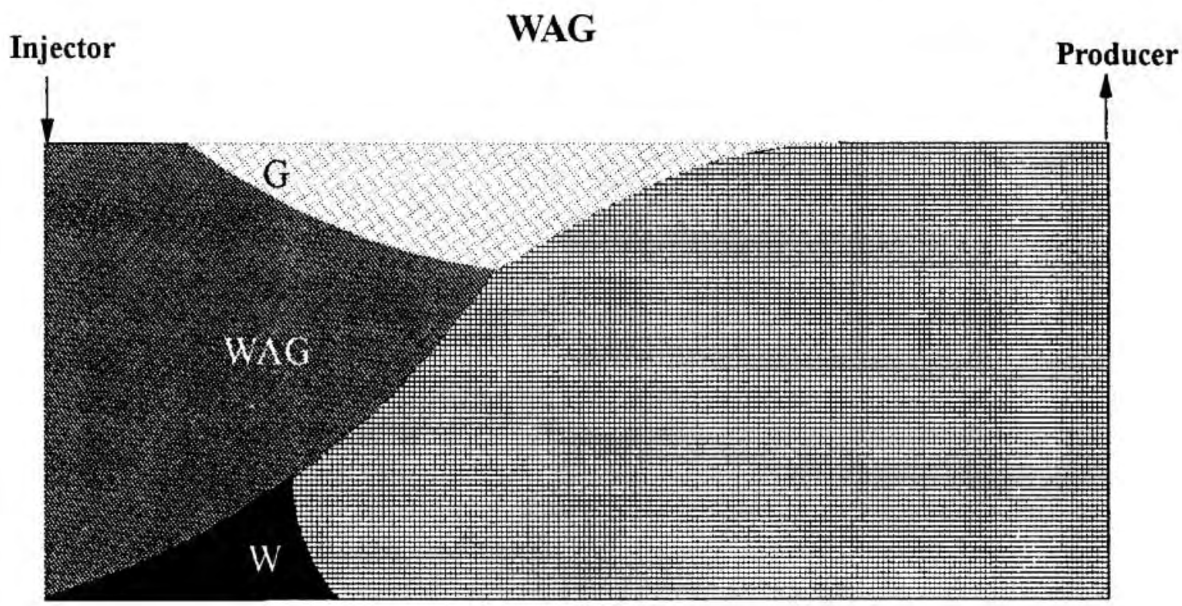


Figure 2 WAG performance in idealized reservoir

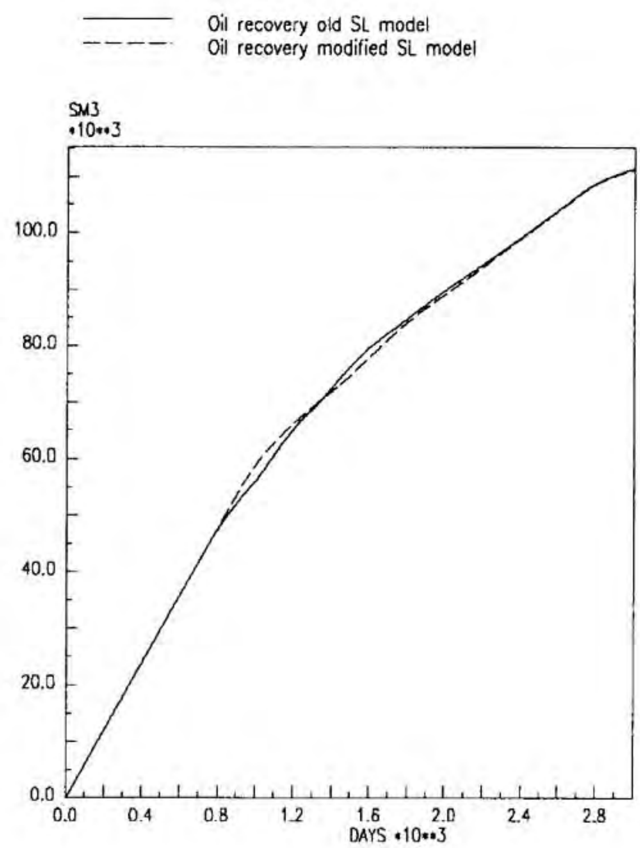


Figure 3 Comparing old SL with modified SL in cross-section model

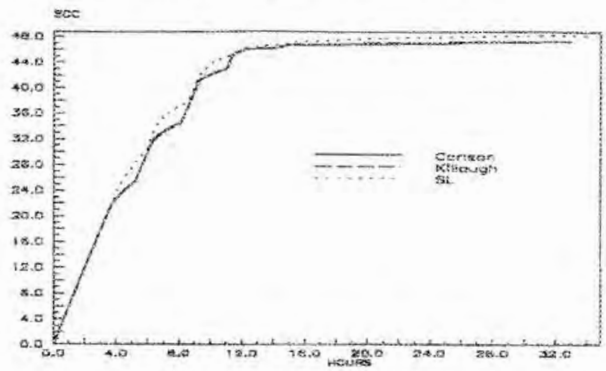


Figure 4 Oil recovery 1D core-floods

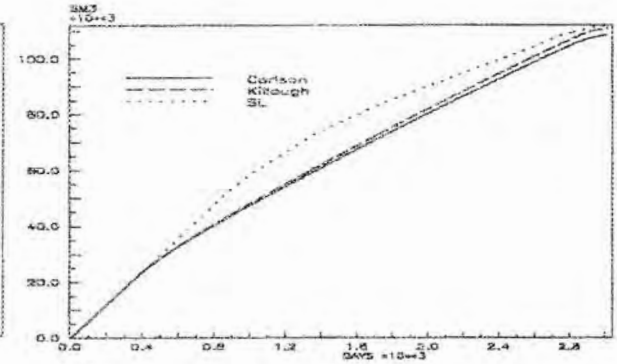


Figure 5 Oil recovery 2D reservoir model secondary water curve

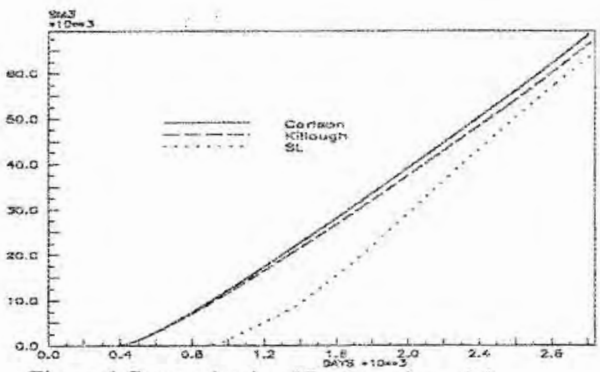


Figure 6 Gas production 2D reservoir model secondary water curve

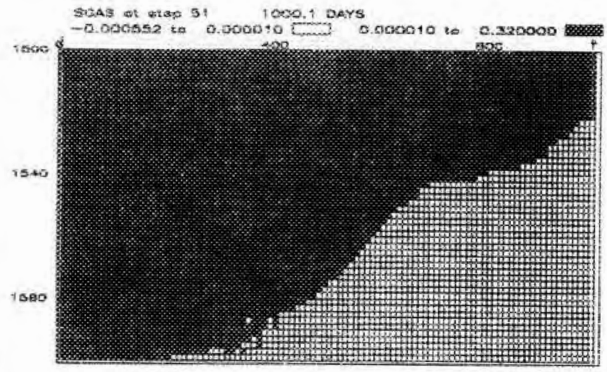


Figure 7 In-situ gas saturation SL model with primary water curve

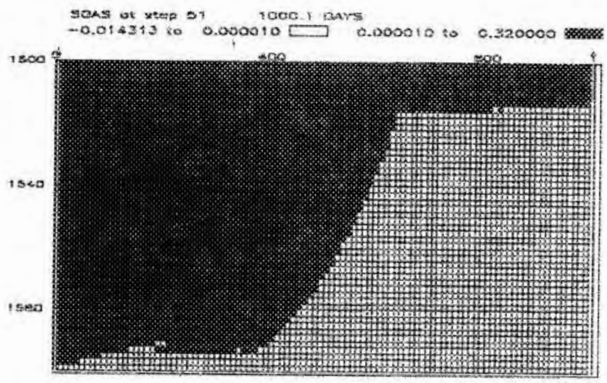


Figure 8 In-situ gas saturation Killough hysteresis model with secondary water curve

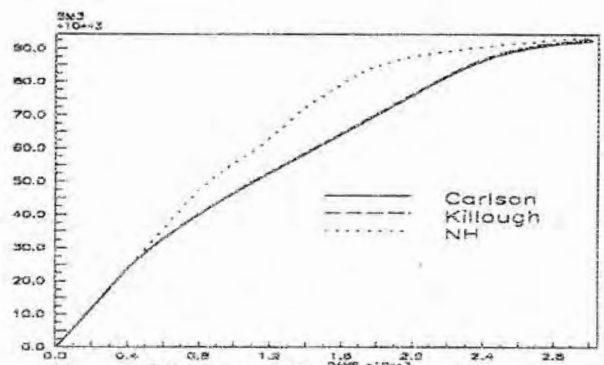


Figure 9 Oil recovery 2D reservoir model primary water curve

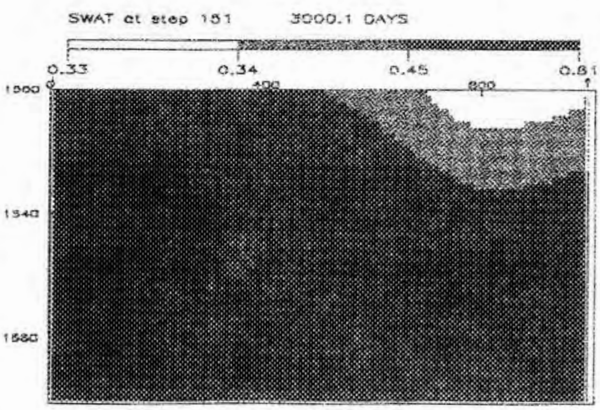


Figure 10 In-situ water saturation SL model with pseudo water hysteresis

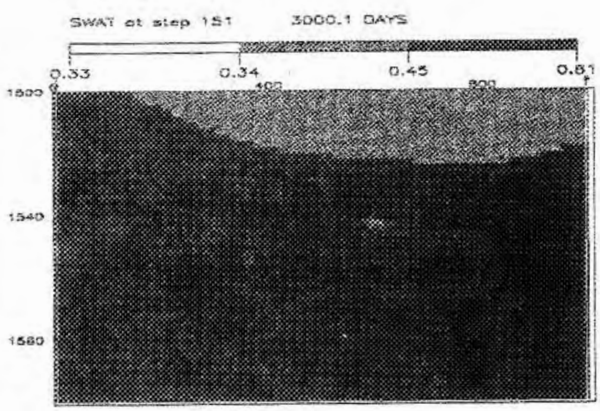


Figure 11 In-situ water saturation SL model with primary water curve