# THREE-PHASE RELATIVE PERMEABILITIES AND TRAPPED GAS MEASUREMENTS RELATED TO WAG PROCESSES.

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## ABSTRACT

Three-phase relative permeability has been calculated from unsteady state experiments. Gas or water were the injected phase in these displacements. The core material include both outcrop and reservoir sandstones with different wettability.

The results show that the residual oil saturation can be significant lower by three-phase flow compared to two-phase waterflood or gas injection. The paper summarize the results of three-phase relative permeability at different wettability for water-wet, intermediate and more oil-wet cores. Relations for trapped gas from three-phase flow were investigated, and a new approach to model relative permeability hysteresis for WAG processes have been proposed.

## INTRODUCTION

For immiscible WAG processes, the microscopic displacement efficiency is usually regarded to be determined by gas residual oil saturation in gas invaded zones and by waterflood residual oil saturation in the water dominated zones. When hydrocarbon gas is the injected gas phase, vertical segregated zones with gas migrating to the top are dominant in reservoirs where vertical communication is good. The viscous-gravity ratio determines the extent of the zone of dispersed three-phase flow. Oil recovery is estimated by Sorg where gas flows, while in the water flooded parts the minimum oil saturation is determined by Sorw. Under these assumptions, the oil recovery can be optimized depending on efficiency of gas and water (Sorg,Sorw). For such WAG processes three-phase relative permeabilities may be of less importance as the three-phase zone can be of negligible extent. However, the residual oil saturation in the three-phase zone may be reduced. Earlier results show that microscopic displacement efficiency by WAG is improved compared to waterflooding and gas injection[1]. The mobility of the phases are in some cases reduced in a three-phase flow situation compared to two-phase flow[1,2]. Both these arguments may lead to an extension of the three-phase zone.

The objectives of the experimental studies reported in this paper has been to measure microscopic displacement by WAG and to compare to gas injection and waterflooding. This paper tries to summarize the experience of measurements of relative permeabilities from a large number of unsteady-state experiments or displacements by injection of either gas or water. The oil recovery from some of the displacements reported here have been presented earlier[2], but the relative permeability data from this large database have not been reported.

The most extensive experimental study of three-phase relative permeability have been the work of Oak[3]. These steady-state relative permeability work have included different wettability and was recently summarized by Baker[4]. The relative permeability of the non-wetting phase can be susceptible to dependence of saturation history. At intermediate wettability it is shown that it is important to maintain the capillary force equilibrium during displacement[5,6]. These arguments favours that the most representative relative permeability data are obtained by a saturation path similar to the process in the reservoir, i.e. unsteady state experiments at reservoir rates should be the best approach to respect the force balances and process path of any three-phase displacement process in a reservoir. An other question which arise is that three-phase relative permeabilities may be so sensitive to specific reservoir and process properties that little generalization can be made. If so the only approach is to do measurements in each case. The paper attempt to pursue these arguments.

## EXPERIMENTAL

The core material used in the core displacement experiments was sandstone cores either outcrop Berea or North Sea reservoir rock. Cores from four different oil reservoirs have been included and compared to displacement with Berea (B) and silanized Berea(TB). The reservoir rock material from the four reservoirs applied in the reported experiments had different permeabilities in the ranges as follows; R1 (100-500mD), R2 (30-300mD), R3 (800-2000mD), and R4 (300-800mD).

The core length varied from 40 cm to 100 cm. the reservoir core models consist of several core pieces butted together in a tri-axial coreholder. Each core piece was carefully machined to ensure good capillary contact in the mounted core model. The core diameter was either 3.7 cm or 5.0 cm. The pore volume of the composite core models ranged from 70 to 470 ml.

The wettability-modified Berea core was treated by displacing 7 pore volumes of 5 wt% Drifilm (dimethyldichlorosilane) in hexane through the core. This procedure has earlier been reported to result in oil wet cores[7]. In other wettability studies silanized Berea have shown changing wettability upon fluid displacements[8].

In the sequential flow experiments each displacement was continued until the oil production ceased. A minimum of 2-3 pore volumes were injected. The flow rates were generally defined to be lower than the critical velocity for stable flow. The flow rates for cores with diameter of about 3.7 cm were usually about 6 cc/h. Gas injection was performed on horizontal oriented cores for series B, TB, and R1 utilizing a constant differential pressure of 1.05 bar/m. All other gas injections were vertical gravity stable displacements.

The core was mounted in a triaxially core holder with confining pressure. Floating piston cylinders connected to a volumetric displacement pump were used to inject fluids at a constant volumetric rate. The injection fluids were stored in a thermostated oven, and all high pressure fluid lines were heat traced to avoid retrograde condensation of gas and possible wax/asphalthene precipitation from the oil due to temperature gradients.

The reservoir cores were cleaned with toluene/methanol and dried. All cores were evacuated and initially saturated by brine before water permeability was measured. Then the cores were drained to irreducible water saturation by a high viscous paraffinic oil (Marcol 172).

The experimental conditions of the displacement experiments varied depending on the reservoir temperature and pressure. The experiments with reservoir cores have been performed at temperatures in the range of 100C and at pressure of about 300 bars. The fluids were recombined reservoir oil and gas, and all fluids including brine were equilibrated at the specific reservoir conditions. The core floods with outcrop cores were made with synthetic fluids. Equilibrated mixtures of methane and decane defined the gas and oil phase at the selected pressure. The experiment temperature was always at ambient conditions for all the outcrop core floods.

The reservoir fluids were either sampled at reservoir conditions or produced through a back pressure regulator into an atmospheric separator system. An automatic data acquisition system collected and stored the phase-volumes injected and produced, pressure, and temperature data. For the compositional studies, the produced gas and oil phases were sampled and analyzed to calculate correct phase composition at reservoir conditions.

## Core wettability

The wettability of the five different types of core material have been compared by determination of the Amott wettability index. The Amott index for the Berea cores were 0.7-0.9, while the silanized Berea core also changed to water wet condition after the series of displacements were completed, WI = 0.85. Initial displacements just after the silane treatment showed a more oil wet behavior, the end point water relative permeability at Sorw was 0.4 compared to 0.07 for the water wet Berea cores. The silanized Berea clearly changed wettability during displacement, which indicate that the silane adsorption on the surface of the rock is reversible. The reservoir cores show wettability indices of 0.3-0.5 for R1, 0.2-0.4 for R2, < 0.3 for R3 and >0.3 for R4. The wettability index measurements were performed at ambient conditions and changes in wettability may occur for the displacements at reservoir conditions.

The oil production after water breakthrough during waterflood is an other indication of the wettability. Both Berea, R1 and R4 show very little oil production after breakthrough, about 2% of the pore volume. The other core material TB, R2 and R3 show destingtly more oil produced after breakthrough of water, in the range of 5-7 %PV. The R1 cores also gave a low krw at Sor 0.13, compared to more oil wet behavior of the R2 and R3 core material with krw(Sor) equal to 0.4.

## Three-phase relative permeabilities

All relative permeability data were measured by displacement (unsteady-state) experiments. The three-phase relative permeability was calculated by the standard approach described and/or used in several papers[9-12]. The figures attached presenting the relative permeability data are plotted against normalized total mobil phase saturation

The displacement process was defined by G for gas injection and W for water flooding. The number behind the letter refers to either primary, secondary or tertiary injection sequence, as an example W3 refers to a tertiary waterflood. The oil phase saturation is always decreasing in all the displacement, either water or gas was the injected (increasing) phase. The kr data were tried to visualized in different geometric realisations, but we found the best representation of the data to be standard graphs when only a few figures could be presented.

## Saturation estimations and displacement front stability

The gas injection sequences were conducted in two different ways to reduce effects of front instability problems. Either the gas was injected at a constant pressure gradient of 1.05 bar/m, or the gas injection was done gravity stable at constant rate. Figure 1 shows the changes in average saturation between start- and endpoint of each displacement for a water wet case. Analogous, Figure 2, shows the estimated saturation at x=L from the same core material, this is also the position where the relative permeabilities were estimated. The start- and end-point of the trajectories should be the same as in Figure 1. The agreement was reasonable remembering that relative permeability were estimated when two or three phases flow simultaneously. Viscous fingering of gas will only influence the saturation on a local level, but because of mass balances the saturation at the outflow end will be on average correctly estimated with the standard Buckley/Leverett and Welge method.

## Water wet cores

The water wet cores used were either Berea outcrop cores or sandstone reservoir cores R1 and R4. Gas is regarded as the non-wetting phase for water-wet, intermediate-wet and oil-wet cores. The liquid phases, water and oil, are regarded as wetting phase and intermediate wetting phase depending on the wettability of the core.

The water wet cores show a slight tendency to hysteresis in the water relative permeability curves, Figure 3. The water kr seems only to depend on the water saturation. The results from steady state gas-oil-water relative permeability studies in ref. 4 show similar conclusions as the relative permeability of a wetting phase depends most strongly on the saturation of that phase, and hysteresis were only a minor factor for the wetting phase.

The oil relative permeabilities were all obtained from experiments where oil saturation was decreasing. Therefore this study cannot conclude on the possible hysteresis in the oil relative permeability. As the experiments were sequences of waterfloods and gas injection a dependence on the saturation history may occur. The data show very little tendency to systematically changes with injected phase or saturation history, Figure 4. The trend in the oil isoperms were a curvature of concave towards oil for the water wet cores, as also has been concluded by others[4].

The shape of the gas relative permeability curves from constant pressure gradient experiments could indicate a functional representation independent of saturation. Secondly, the gas relative permeability does not go to zero continuously. One explanation of this unusual behavior could be viscous fingering, i.e. gas bypassing a resident fluid (in this case oil and water). The gas would prefer to flow in the channels already occupied by gas, and the estimated relative permeability may become larger than "true" values, due to reduced pressure gradients after gas breakthrough. The gas kr remains constant due to insignificant pressure drop by gas and nearly constant fractional flow after breakthrough.

The gas relative permeabilities show a strong dependence on process path i.e. increasing or decreasing saturation change. However, there were little changes between primary and tertiary gas injection. An observed variation/spread of the relative permeabilities data can be due to dependence on more than one phase saturation, Figure 5. Also steady state data[4] observe hysteresis for the non-wetting phase.

## Oil wet

The Berea cores were silanized to make the surface of the rock oil wet. As reported earlier the wettability altered during stages of several experiments. After a total of seven flooding sequences the core was showing water wet properties when water flooded and core plugs used for wettability study show water wet wettability index. The saturation changes and endpoint relative permeabilities of the displacement experiments are shown in Table 1.

The water kr show hysteresis especially when comparing secondary water flood with tertiary gas injection, Figure 6. The more oil wet cores generally show stronger hysteresis in krw, and also show a dependence on the saturation history. However, the influence of varying wettability on the silanized Berea makes it hard to draw conclusions from these experiments.

The oil kr show only minor change with saturation history, but the last few displacements show some deviation, Figure 7. These changes is most likely due to changes in the wetting properties during continuous flooding experiments. The oil relative permeabilities seems to primary be a function of oil saturation only for the more oil wet cores. The gas kr show very reduced permeability for tertiary gas injection compared to primary gas injection, Figure 8.

## Intermediate wettability

The R2 cores have shown wetting behavior in the range of intermediate or mixed wettability. The water relative permeability was found to depend on the saturation history, Figure 9. Secondary waterflood after gas injection show much lower water relative permeability than primary water injection.

The oil relativé permeability is shown in Figure 10. The kro show strong variation with process and sequence. the relative permeability is history dependant and may also depend on more than only the oil phase saturation. The oil kr is highest for the primary gas injection, while secondary water flood gave the lowest relative permeability.

The data on gas relative permeability is limited and no conclusions can be made with respect to saturation dependence and hysteresis, Figure 11. However, gas injection after water flood show strongly reduced krg compared to primary gas injection, see Table 1.

## Relative permeability hysteresis

krg show strong hysteresis effects independent of the wetting state of the core, and the gas relative permeabilities for decreasing gas saturation were generally lower than for data at increasing gas saturation. Comparing the endpoint gas relative permeabilities after primary gas injection with secondary and tertiary gas injection, Table 1, show a reduced gas relative permeability after water saturation has been increased above connate / irreducible saturation.

The conventional hysteresis models (Carlson[13] and Killough[14]) assume that secondary drainage (decreasing gas saturation) follows the primary drainage relative permeability curves above the hysteresis inflexion point. Most experimental data show that secondary drainage (decreased gas) exhibits very low mobility. A new approach to model gas hysteresis is shown in Figure 12. Scanning (hysteresis) curves can be defined within each of primary drainage/imbibition and secondary drainage/imbibition envelopes. The new model have been implemented in a standard reservoir simulator and applied for WAG experiment simulation. The model seems to be stable even though a sudden change in relative permeability is defined, when the process shifts from primary imbibition to secondary drainage.

## Trapped gas from waterflooding after gas injection or WAG experiments

The waterflood trapped gas saturation have been measured for all the different core material. These seems not to be systematical variation of the trapped gas saturation with change in wettability. However, as seen in Table 1, the trapped gas saturation was strongly related to the initial gas saturation. The trapped gas increases with increase in the initial gas saturation. From many WAG experiments with different core material, trapped gas saturation were measured in the range of (0.17-0.21). The small variations in Sgt is probable due to the almost constant WAG ratio and WAG slug size, and was limited by the maximum gas saturation achieved during these experiments.

The data was fitted to a Land-type of equation[15]. The dependence of the trapped gas saturation on the initial or maximum gas saturation seems to be a very strong relationship as the core data include different wettabilities, permeabilities, and displacement processes/saturation history. The data fit was somewhat improved with the modified trapped gas relation, as presented in Figure 13.

### Microscopic displacement by WAG

The two phase relative permeability data including the information on trapped gas have been used at input to simulation of the WAG experiments. Simulations of the WAG experiments were prediction in the sense that no adjustments on the input data were made. The ECLIPSE simulation based on two-phase kr-data, trapped gas saturation, and the new hysteresis model show a reasonable agreement of the effluent production and differential pressure. There were only small changes in the simulation results with regard to production, when using different three-phase relative permeability models such as, Stone I, Stone II or ECLIPSE default model.

## CONCLUSIONS

The residual oil saturation by three-phase flow was significantly lower than the residual oil saturation from two-phase waterflood and gas injection.

Relative permeability hysteresis was more pronounced for the non-wetting phase (gas). Gas kr was generally lower for decreasing saturations compared to increasing gas saturation.

The wetting phase was found to be primary a function only of the wetting phase saturation.

The general trends of these unsteady state three-phase relative permeability data are in surprising agreement with conclusions from the steady state results of Oak and coworkers summarized in ref. 4.

Trapped gas saturation was found to be strongly dependent on the maximum gas saturation during the displacement process independent of the core wettability.

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**Table 1. Summary of initial, endpoint saturations, and relative permabilities**

| | | **Initial** | | | **Endpoint** | | | |
|---|---|---|---|---|---|---|---|---|
| **Core** | **Exp.** | **Sw** | **Sg** | **So** | **Sw** | **Sg** | **So** | **kri** |
| Berea | G1 | .267 | .0 | .733 | .267 | .52 | .213 | .29 |
| | W2 | .267 | .52 | .213 | .556 | .365 | .079 | .114 |
| | G3 | .556 | .365 | .079 | .395 | .53 | .075 | .21 |
| | W1 | .270 | .0 | .730 | .560 | .0 | .440 | .214 |
| | G2 | .560 | .0 | .440 | .411 | .151 | .438 | .294 |
| | W3 | .411 | .151 | .438 | .479 | .129 | .391 | .113 |
| Silanized | G1 | .275 | .0 | .725 | .274 | .490 | .236 | .90 |
| Berea | W2 | .274 | .49 | .236 | .532 | .31 | .158 | .42 |
| | G3 | .532 | .31 | .158 | .503 | .341 | .156 | .09 |
| | W1 | .301 | .0 | .699 | .853 | .0 | .147 | .146 |
| | G2 | .853 | .0 | .147 | 0.609 | .25 | .141 | .34 |
| | W3 | .609 | .25 | .141 | .736 | .175 | .089 | .086 |
| R1 | G1 | .308 | .0 | .692 | .308 | .462 | .23 | .33 |
| | W2 | .308 | .462 | .23 | .498 | .301 | .201 | .08 |
| | G3 | .498 | .301 | .201 | .315 | .494 | .191 | .05 |
| | W1 | .222 | .0 | .778 | .623 | .0. | .377 | .051 |
| | G2 | .623 | .0 | .377 | .33 | .311 | .359 | .041 |
| | W3 | .33 | .311 | .359 | .522 | .174 | .303 | .040 |
| | WAG | .343 | .0 | .637 | .637 | .169 | .194 | |
| R2 | G1 | .36 | .0 | .64 | .36 | .29 | .35 | .27 |
| | W2 | .36 | .29 | .35 | .70 | .14 | .16 | .05 |
| | W1 | .37 | .0 | .63 | .72 | .0 | .28 | .45 |
| | G2 | .72 | .0 | .28 | .46 | .36 | .18 | .08 |
| | WAG | .43 | .0 | .57 | .75 | .21 | .04 | |
| R3 | G1 | .225 | .0 | .775 | .225 | .682 | .093 | .57 |
| | W1 | .212 | .0 | .788 | .855 | .0 | .145 | .45 |
| | WAG | .218 | .0 | .782 | | | .132 | |
| R4 | G1 | .619 | .0 | .381 | .612 | .197 | .191 | .29 |
| | W2 | .611 | .197 | .191 | .786 | .069 | .145 | .034 |
| | W1 | .511 | .0 | .489 | .782 | .0 | .218 | .066 |

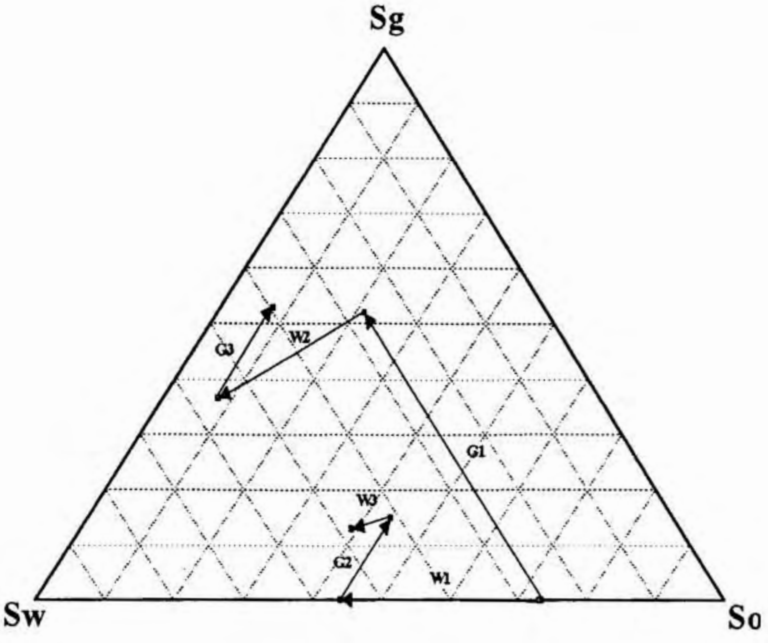


Figure 1, Average saturation at start and end of all displacements, water wet Berea core.

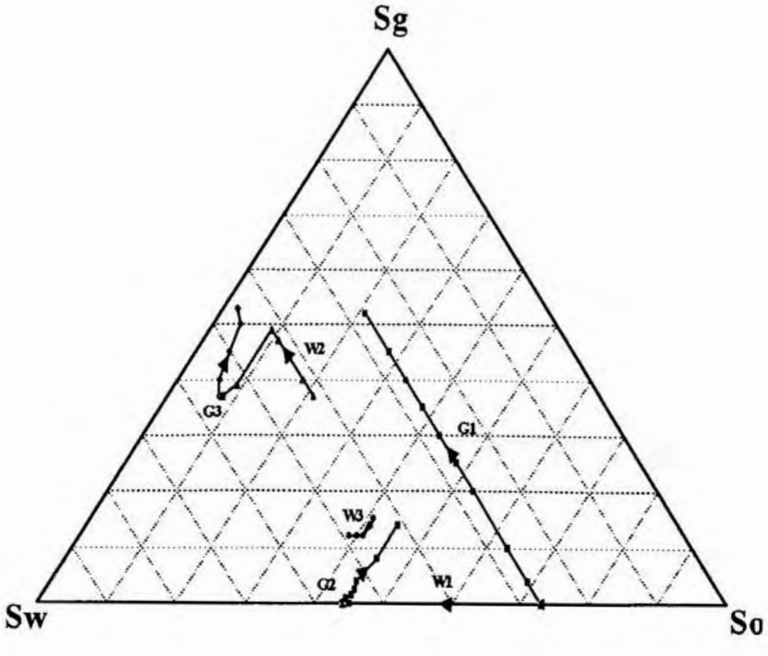


Figure 2, Trajectories of outflow end saturation from water wet Berea core.

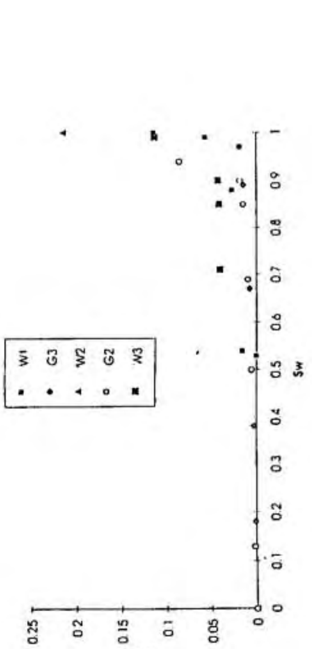


Figure 3. Water relative permeabilities, water wet cores

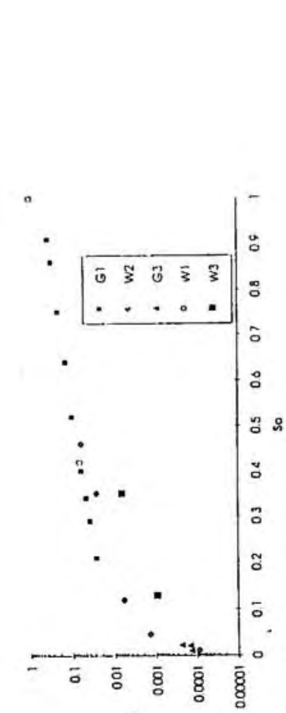


Figure 4. Oil relative permeabilities, water wet cores

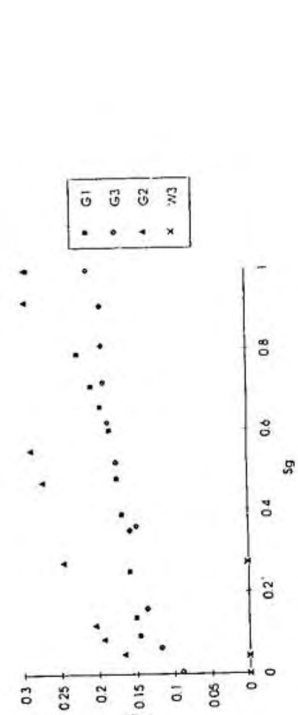


Figure 5. Gas relative permeabilities, water wet cores

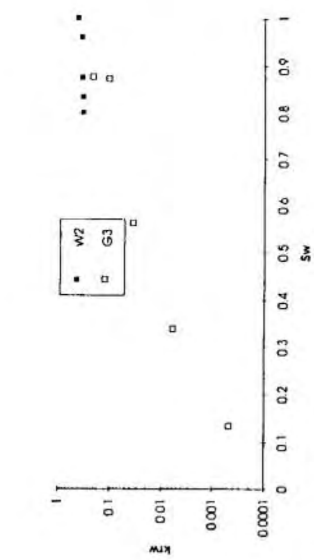


Figure 6. Water relative permeabilities, oil wet cores

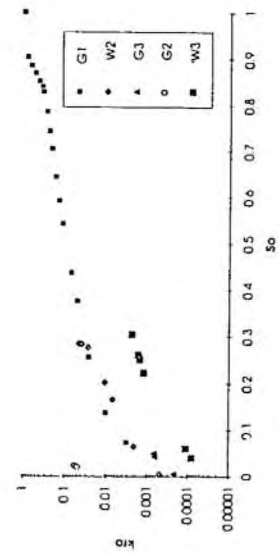


Figure 7. Oil relative permeabilities, oil wet cores

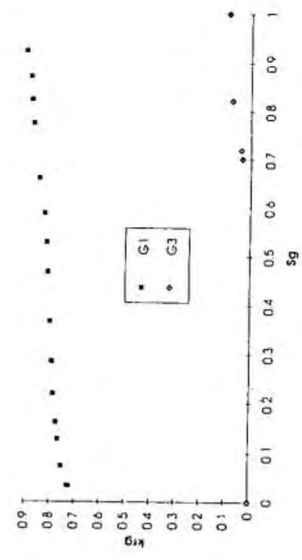


Figure 8. Gas relative permeabilities, oil wet cores

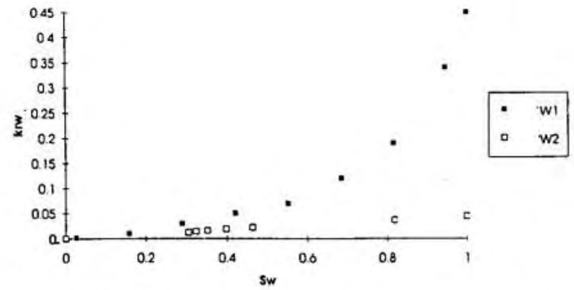


Figure 9. Water relative permeabilities, intermediate wettability

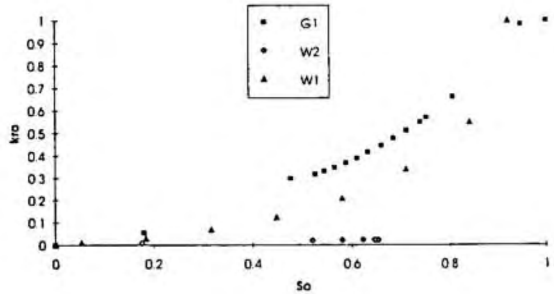


Figure 10. Oil relative permeabilities, intermediate wettability

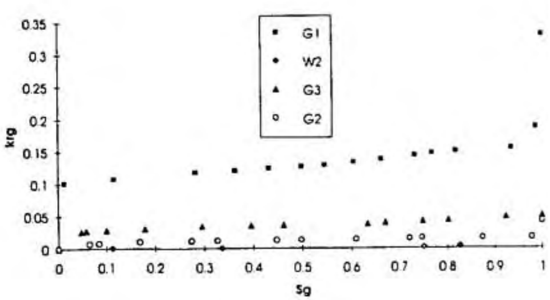


Figure 11. Gas relative permeabilities, intermediate wettability

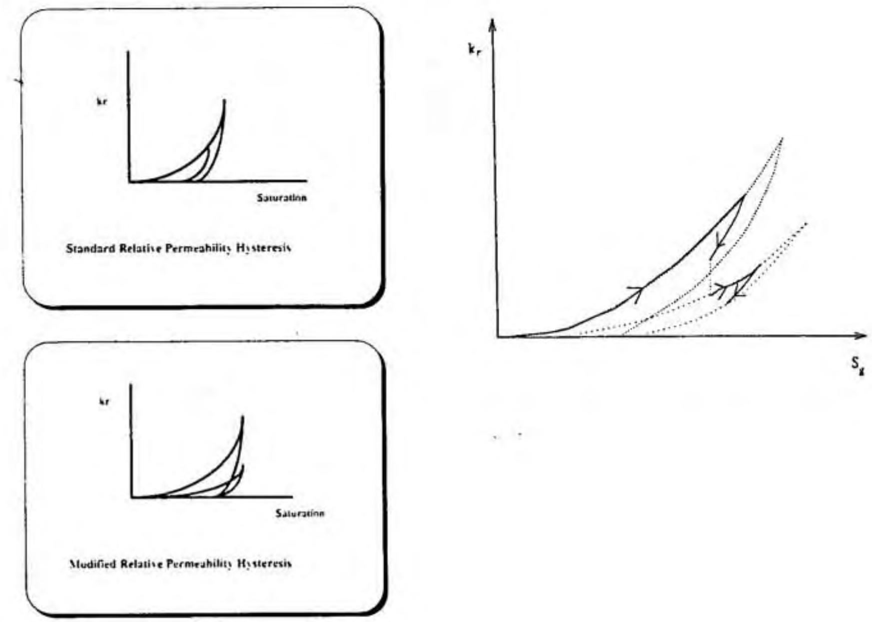


Figure 12. Relative permeability hysteresis model

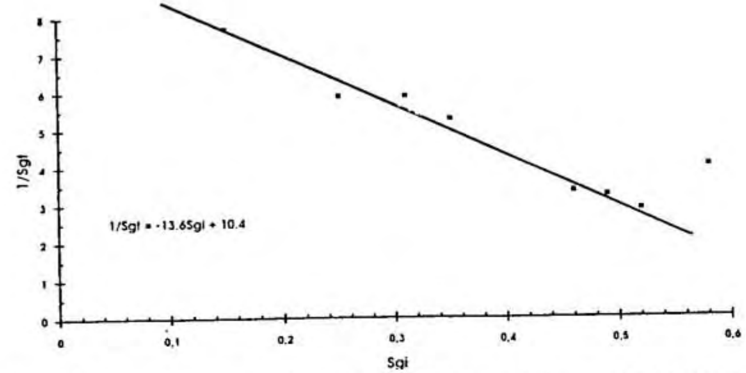


Figure 13. Trapped gas from water displacement after gas injection or WAG experiments