NUMERICAL INTERPRETATION OF GAS/OIL SCAL

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Abstract
Gas/oil unsteady state imbibition experiments are numerically interpreted. With this method, gas/oil SCAL pitfalls such as gravity override and gas compressibility can be taken into account. It is shown that in the experiments analyzed, especially the compressibility of the gas is of major importance. In the analytical interpretation of the measurements, compressibility is not taken into account, thereby overestimating the gas relative permeability by typically a factor 3 when no back pressure is applied. The re-interpreted relative permeability approaches the one obtained by model liquid experiments.

Introduction
Using gas and oil in special core analysis (SCAL) is prone to give wrong results. The reasons are plentiful: displacing oil with gas can lead to viscous fingering, the compressibility of the gas is not accounted for in the analytical interpretation, high gas flow rates are necessary because of the low viscosity, density differences may induce fluid separation, and the fluids may not be in equilibrium. It is therefore proposed [1] to use model liquids when gas/oil or gas/condensate relative permeabilities are needed. Meanwhile, gas/oil SCAL is still done, and sometimes it is the only source of information. In this article we show that a reservoir simulator can be used to resolve part of the problems mentioned above.

Method
At Shell it is preferred to numerically model SCAL measurements. Since the physics involved in core flooding is not different from that in the field, a reservoir simulator can be used for this. The advantage of this method is mainly that the intertwined mechanisms of capillary pressure and relative permeability can correctly be taken into account in the interpretation, whereas the analytical formulas used in SCAL to interpret relative permeability measurements omit capillary pressures. Especially when measuring residual oil, the numerical interpretation can be quite different from the incorrect analytical one.

Of the typical gas/oil SCAL pitfalls mentioned above, gas compressibility and gravity effects can be taken into account by the reservoir simulator. Experimentally, it is best practice to use a back pressure of around 80 bar. This way, the pressure drop over the core is much smaller than the back pressure, and the gas compressibility is much less important. However, this is often not done since it complicates measurement procedures. The correct relative permeability can in this case still be retrieved from the measurement, when the gas and oil production is modeled in the SCAL simulator. The relative permeability is then used as a fit parameter, and changed until a matching production is found (Figure 1).

In our two dimensional SCAL simulator we introduced the following physics: non Darcy flow effects, gravity, plug heterogeneity and compressibility of the fluids. To assess the importance of the effects, we evaluated a set of gas/oil imbibition unsteady state gas floods on five samples. Unstable displacement (viscous fingering) is presently not taken into account. Evaporation can be introduced as well, but since the experiments were done with stabilized fluids, this effect is not presently researched.

Experiments and numerical analysis
Five imbibition experiments were analyzed, of which the two permeability extremes are presented here. The other three analyses showed similar results.

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The experiments are done with Isopar and nitrogen. Experiment 1 is done on an intermediate permeability (53mD) core, experiment 2 on a low permeability (2mD) core. Experimental data are given in Table I. Productions versus time are given in Figures 2a and 2b; note that the production is given on a log-log scale. The relative permeability as derived with the JBN [2] method can be seen in Figures 3a and 3b, respectively, where it is plotted as a function of the wetting phase (oil) saturation. Breakthrough takes place around t=0.01h, after which the relative permeability can be calculated. The shock front saturation is around 0.8, and with a connate oil of 0.6, the relative permeability can be measured in the saturation range 0.6 – 0.8.

Base case: For our base case, we use the JBN relative permeabilities, and the reservoir simulator without the additional features mentioned above, i.e. 1-dimensional, uncompressible Darcy flow through a homogeneous sample. Trivially, the simulator then computes the productions as measured (Figures 4a and 4b), with a slight mismatch for the oil in Figure 4b, which is probably due to the use of a simplified JBN formula. Now the additional features can be introduced in the simulator, and their importance can be assessed.

Non-Darcy flow: In reservoirs, close to the well bore gas may reach velocities where the pressure drop is not linear with gas speed (as expected from Darcy's law), but develops a quadratic dependence. This effect is known as non-Darcy flow, and is due to the inertia of the gas. The non-Darcy flow parameter β for these plugs was measured and could be correlated as β = 1.4e11 / K^1.33. As can be observed in Figures 5a and 5b, introducing non-Darcy flow yields the same calculated production, i.e. non-Darcy flow is not important in the present experiments. This can be calculated analytically as well: it only contributes to about 1% of the total pressure drop in these experiments.

Gravity: Because of the large density difference in gas/oil floods, in horizontal cores separation can take place and the gas can override the oil. For the present experiments, this effect is not important (Figure 5a,b).

Plug heterogeneity: Heterogeneity can be modeled numerically by assigning different permeabilities to the grid blocks of which the core is built. This can be done in a layered way or completely at random. In this work, a spread with standard deviation 0.2*K was introduced both in layers as well as per grid block. Whereas the heterogeneity per grid block gave marginal differences with the base case, the layered heterogeneity resulted in somewhat earlier breakthrough and a higher production (Figures 6a and 6b), although the difference is only 10% in production, and therefore hardly visible on a logarithmic scale. The misinterpretation in relative permeability is consequently not dramatic.

Gas compressibility: In the interpreted measurements, no back pressure was used. Since pressure drops are between 0.9 and 7 bar in the present experiments, and the exit pressure is atmospheric, at entry the gas is considerably compressed. In a large part of the core the gas occupies a small pore volume, whereas a large amount of gas flows at the atmospheric endpoint: it can be intuitively understood that applying the theory as if no compression is present will overestimate the relative permeability. As stated, the JBN interpretation omits compressibility, and the authors of the original paper warn against using their method in these cases. It is common practice to account for the compressibility by using the mean pressure $(P_{in} + P_{out})/ 2$ in the JBN calculation, but as shown below, this does not solve the problem.

The impact of gas compressibility is found when the compressibility of the nitrogen is assigned to the gas phase in the simulator. Figure 7a and 7b show the errors that can be made. There the simulator calculates the production with (denoted in the figures as base + compressibility) and without (denoted as base) assigning compressibility to the gas phase. The production with compressibility is about factor 2-3 higher than without. Consequently, when trying to fit the experimental values with the correct numerical model, lower relative permeabilities will be found. The fit (lines) of Figures 8a and 8b was obtained using the relative permeabilities of Figures 9a and 9b.

With a similar flow rate as in experiment 1, the lower permeability of experiment 2 resulted in higher applied pressures, increasing gas compression at entrance and therefore a larger error in the analytical interpretation. This trend is expected, and found in all five numerical interpretations. The error increase is not linear with the pressure difference, both because the pressure drop in the core is not linear, and because the error is partly compensated by using the mean pressure in the analytical calculation.

Since the oil is virtually incompressible, and assumed so in the theory, this relative permeability is still correct.

Discussion

What can be learned from the present work; does it help to obtain better estimates for gas/oil relative permeabilities? For reasons given in the introduction, gas/oil SCAL is in our view not a preferred technique. It is shown here that a numerical re-interpretation can remove part of the pitfalls, but not all. The limited saturation regime that can be probed can of course not be improved, and the possibility of unstable displacement cannot be circumvented with the numerical analysis.
One important pitfall *can* be removed: by assigning the correct compressibility to the gas phase in a numerical description of the gas-flood, the experimental production can be used to approach the real relative permeability. Other effects, such as non-Darcy flow, core heterogeneity and gravity effects, are for the five examples analyzed here not of importance.

We believe the solution of these problems can be found using model liquids for the gas and oil, such as water for the non-wetting, and decane for the wetting phase [1]. This way, on the same core material (from another well), we obtained the relative permeabilities given as the dotted lines in Figures 9a and 9b. These model liquid relative permeabilities were recently reproduced by gas/condensate measurements at Heriot Watt University [3]. It can be observed that the numerical re-interpretation of the gas/oil floods shifts the relative permeability of the non-wetting phase towards the ‘real’ model liquid relative permeabilities, but still does not overlap them. This may be due to unstable displacement. The present technique can definitely be used to assess the error that is made while doing gas/oil SCAL.

Conclusion

Gas/oil SCAL is prone to give erroneous results and should therefore be avoided. Instead model liquids should be used. When gas/oil SCAL is the only source of information, a numerical simulator can be used to approach the real relative permeabilities or at least to assess the errors that were made: the measured production is compared to the calculated production from a reservoir simulator, and the relative permeability is changed until the production matches.

As already stated by the authors, the JBN theory can not be used when the pressure drop over the core is comparable to or larger than the back pressure. We showed that for the analyzed experiments, in this case the JBN interpreted gas relative permeabilities are typically over estimated by a factor 3 compared to the correct numerical interpretation. Other effects not taken into account by JBN -- non-Darcy flow, gravity segregation and rock heterogeneity -- were not important for the five measurements studied.

References:

[1] “Experimental evidence for improved condensate mobility at near-wellbore flow conditions”, W. Boom, K. Wit, J.P.W. Zeelenberg, H.C. Weeda, and J.G. Maas, SPE **36714**

[2] “Calculation of relative permeability from displacement experiments”, A.F. Johnson, D.P. Bossler, and V.O. Naumann, Trans. AIME **216** 1959

[3] N. van der Post, A. Danesh, G. Henderson and D. Tehrani, to be published.

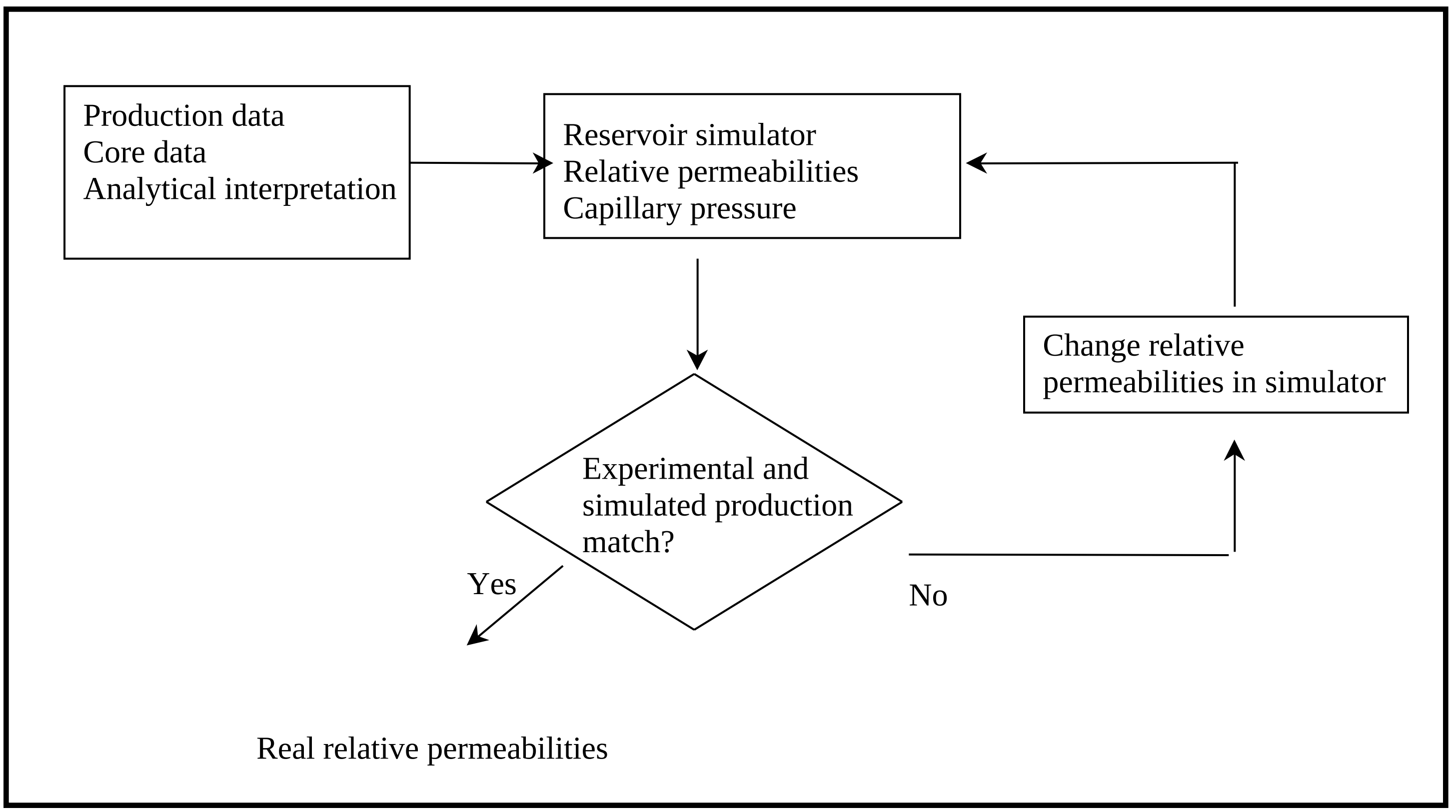
List of symbols

Φ	Porosity
K	Absolute permeability
Krg	Gas permeability
Sw	Wetting phase saturation
L	Core length
β	Non Darcy flow parameter
P_{in}	Entry pressure
P_{out}	Outlet pressure

Table I: Parameters of the Experiments

	Experiment 1	Experiment 2
Φ	0.14	0.087
K gas (mD)	53	2.5
L (cm)	5.01	4.86
Diameter (cm)	3.75	3.75
Gas viscosity (cP)	0.0175	0.0175
Oil viscosity (cP)	0.89	0.89
Pressure drop (bar)	0.90	6.8

Fig 1: Flowchart showing the method used in this paper to determine the real relative permeabilities



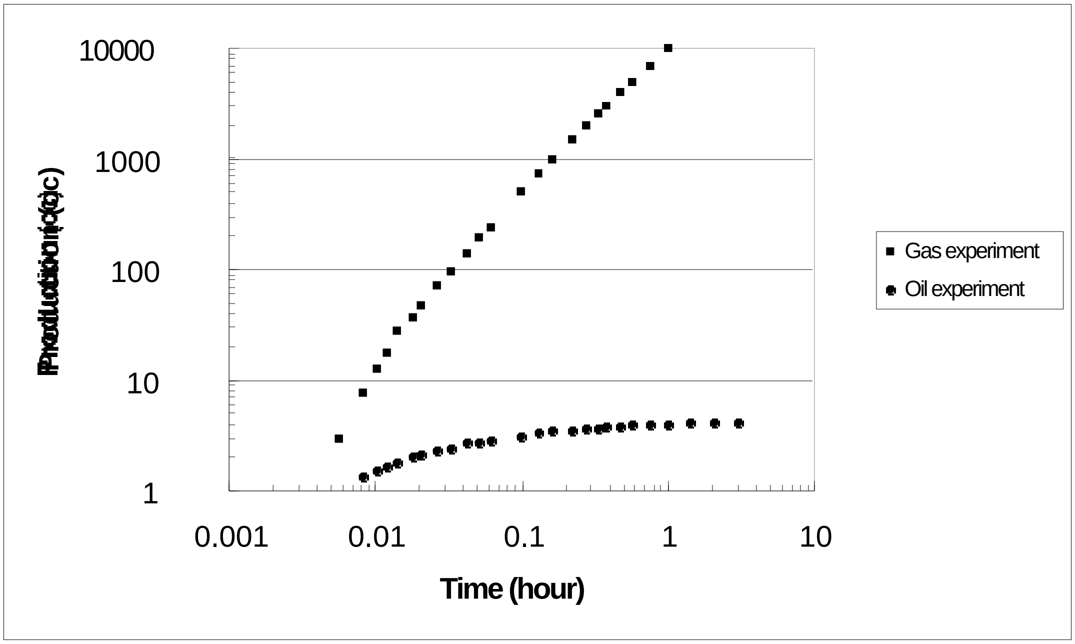


Figure 2a: Oil and gas production of experiment 1.

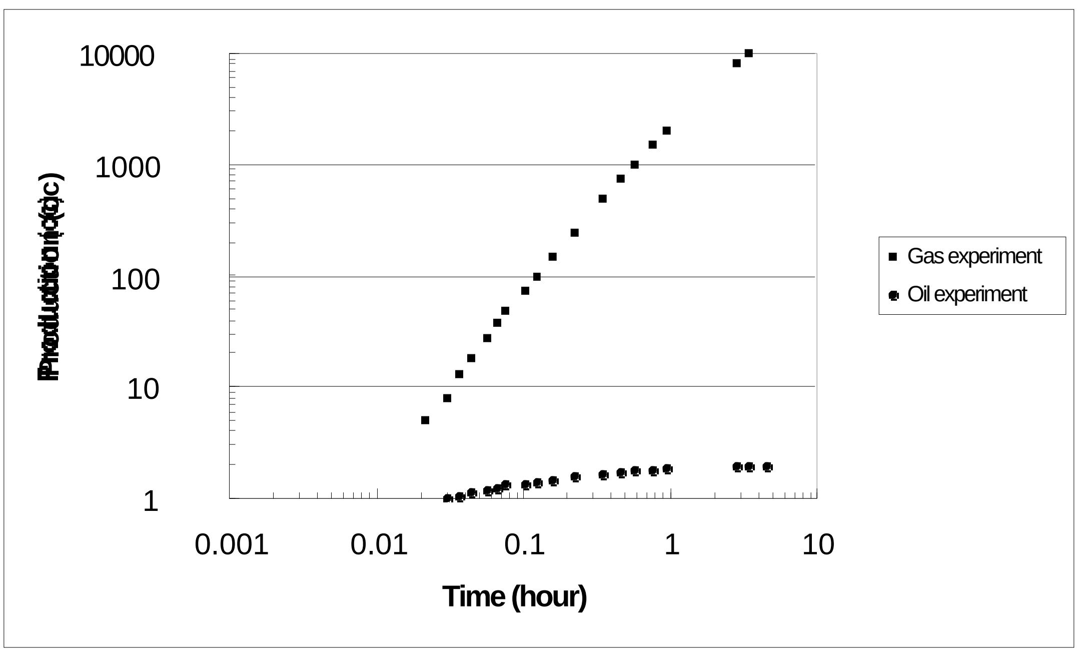


Figure 2b: Oil and gas production of experiment 2.

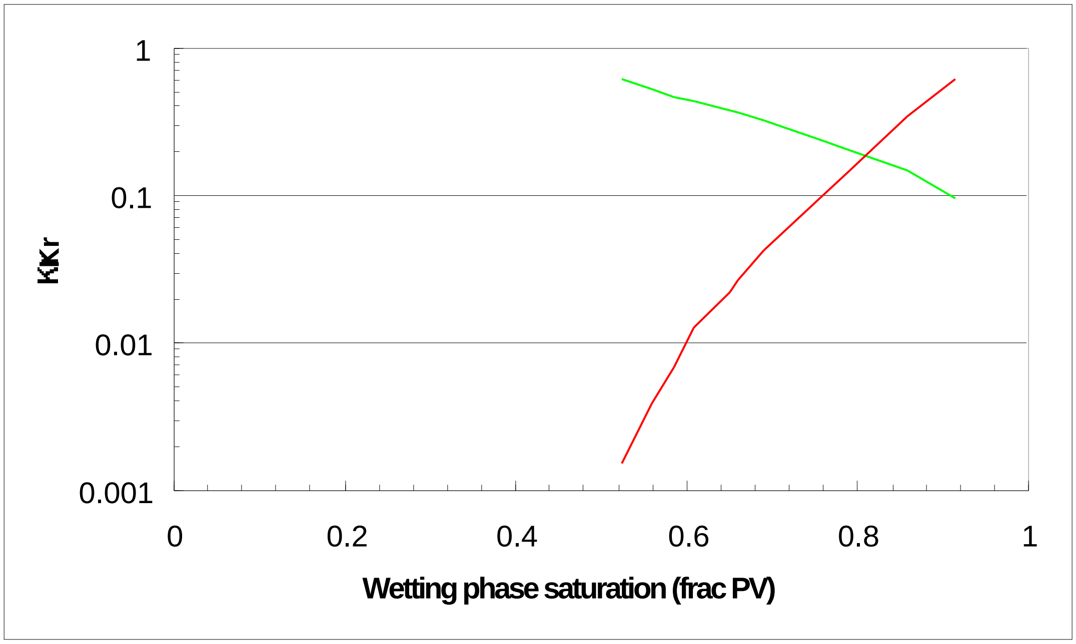


Figure 3a: Analytical (JBN) interpreted relative permeabilities of experiment 1.

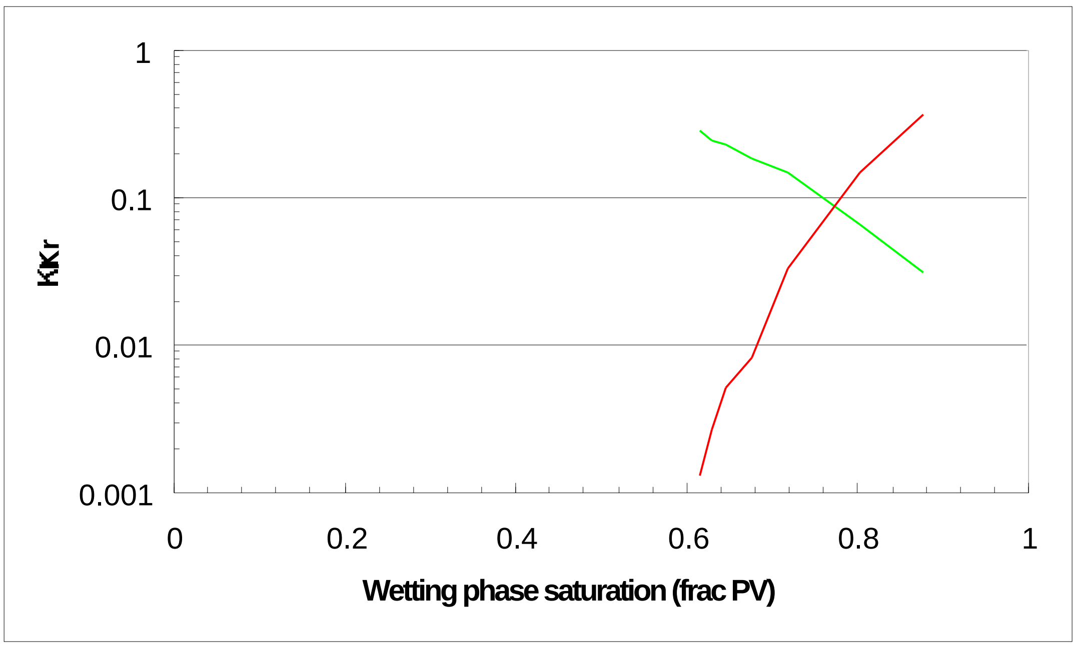


Figure 3b: Analytical (JBN) interpreted relative permeabilities of experiment 2.

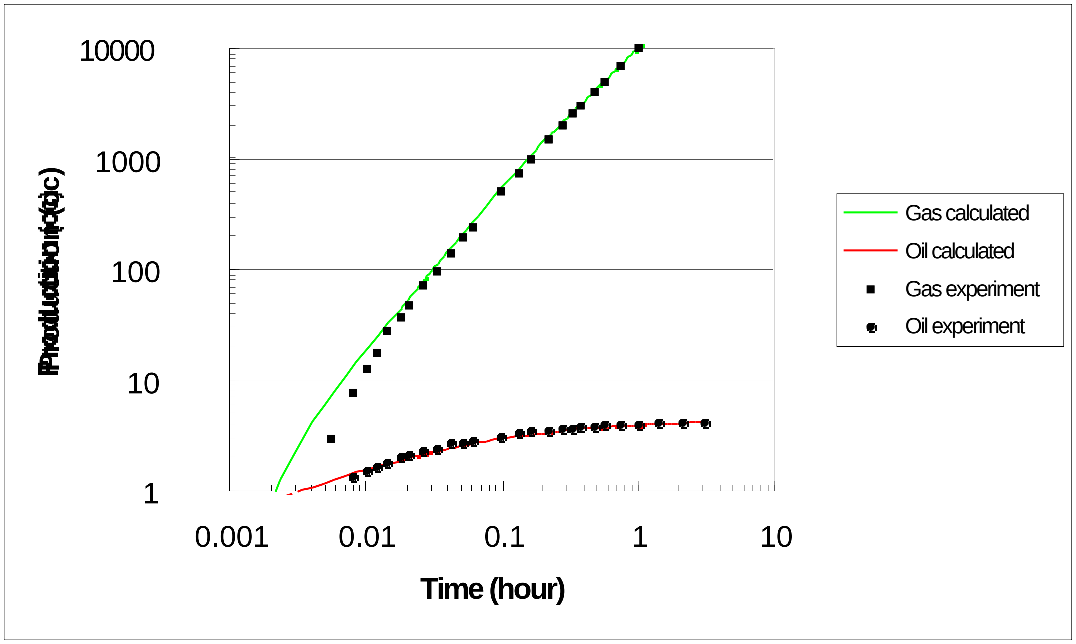


Figure 4a: Experimental production of experiment 1 compared to numerical base case run.

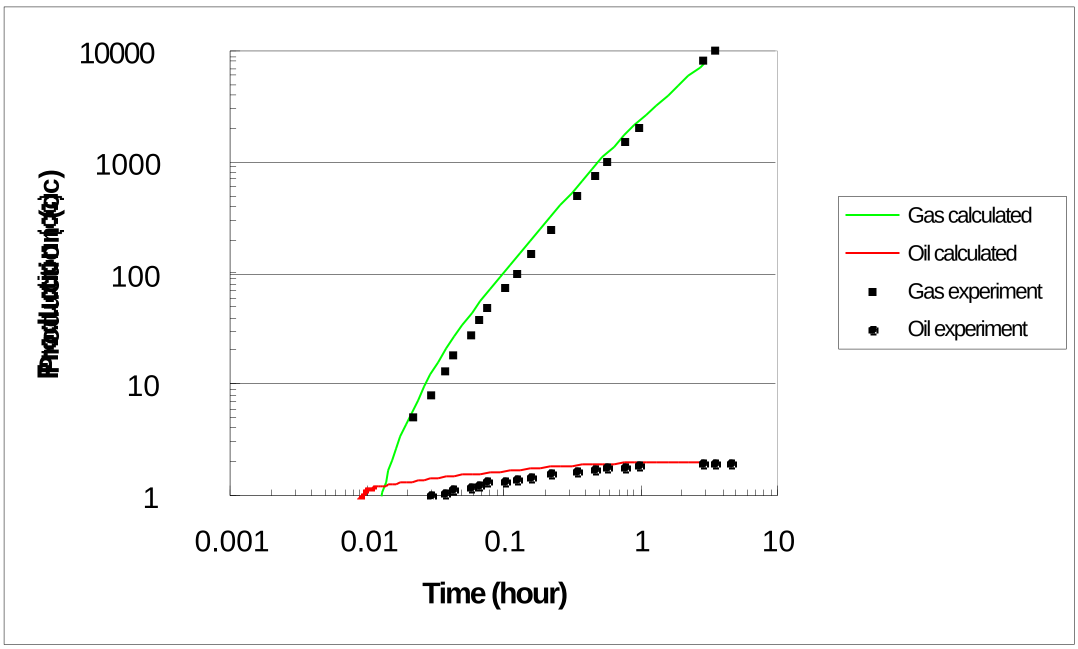


Figure 4b: Experimental production of experiment 2 compared to numerical base case run.

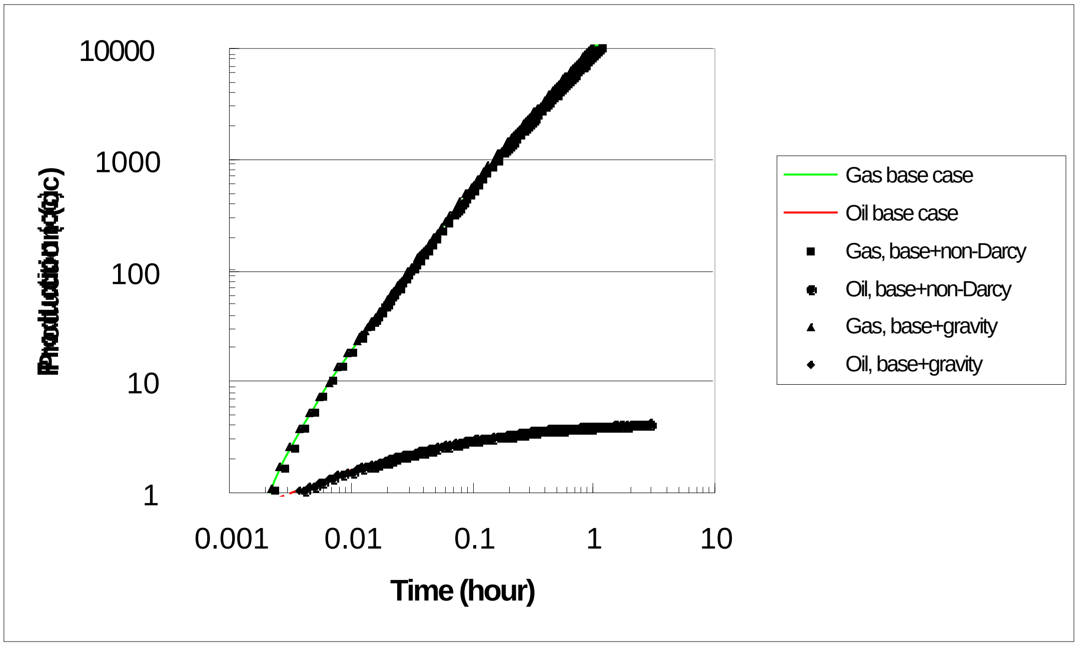


Figure 5a: Experiment 1. Numerical calculations of the base case, and productions after introduction of non-Darcy flow and possibility for gravity segregation.

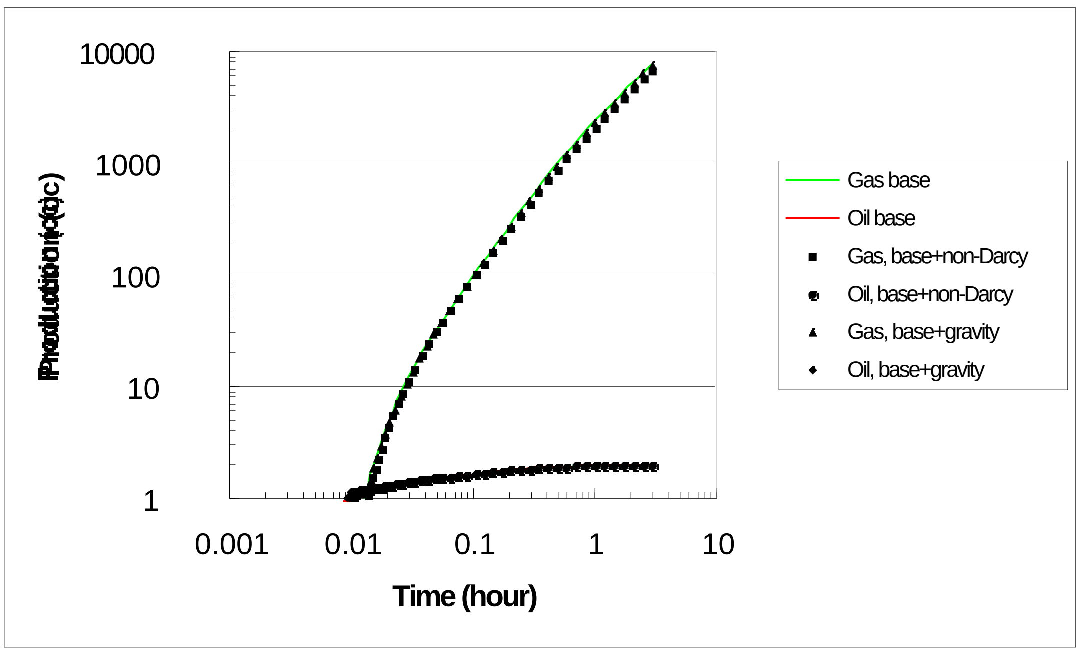


Figure 5b: Experiment 2. Numerical calculations of the base case, and productions after introduction of non-Darcy flow and possibility for gravity segragation.

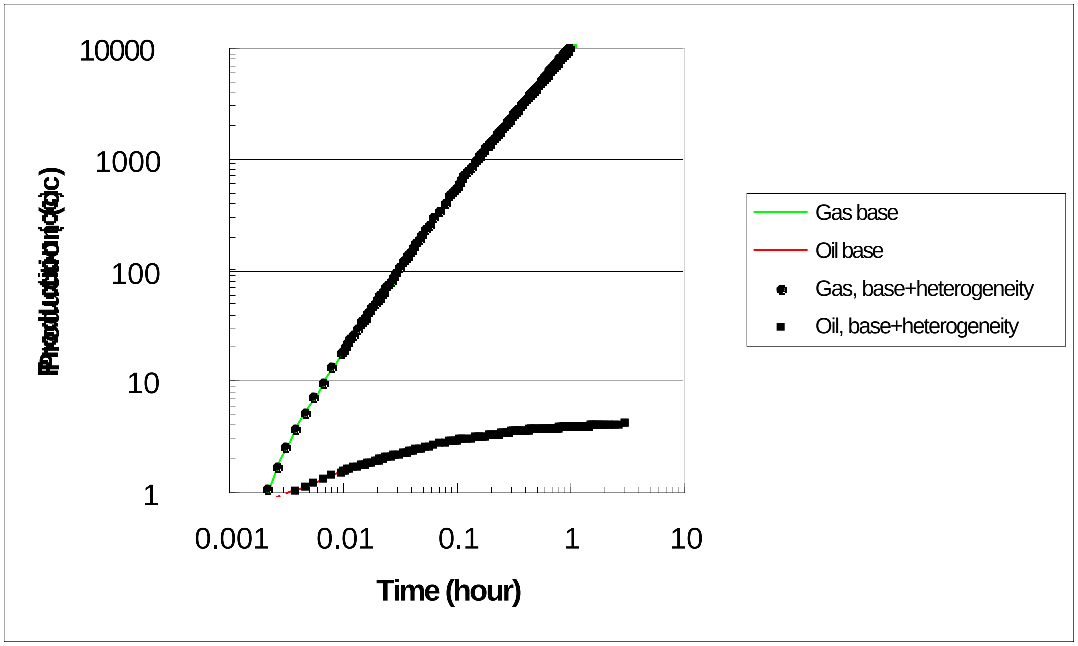


Figure 6a: Experiment 1. Numerical calculations of the base case, and productions after introduction of rock heterogeneity

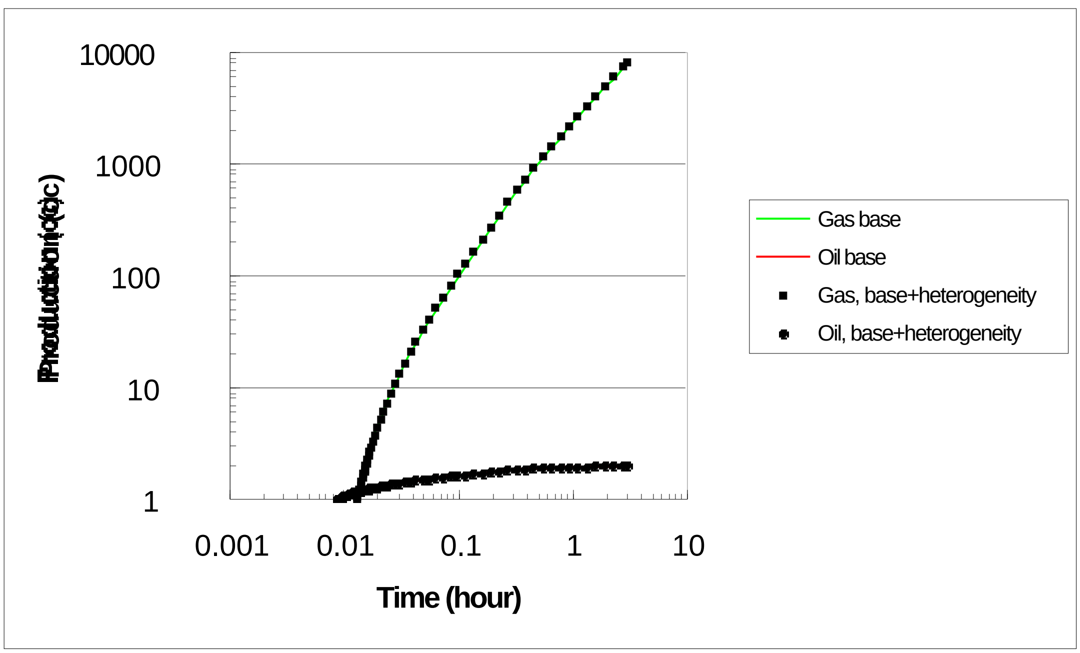


Figure 6b: Experiment 2. Numerical calculations of the base case, and productions after introduction of rock heterogeneity

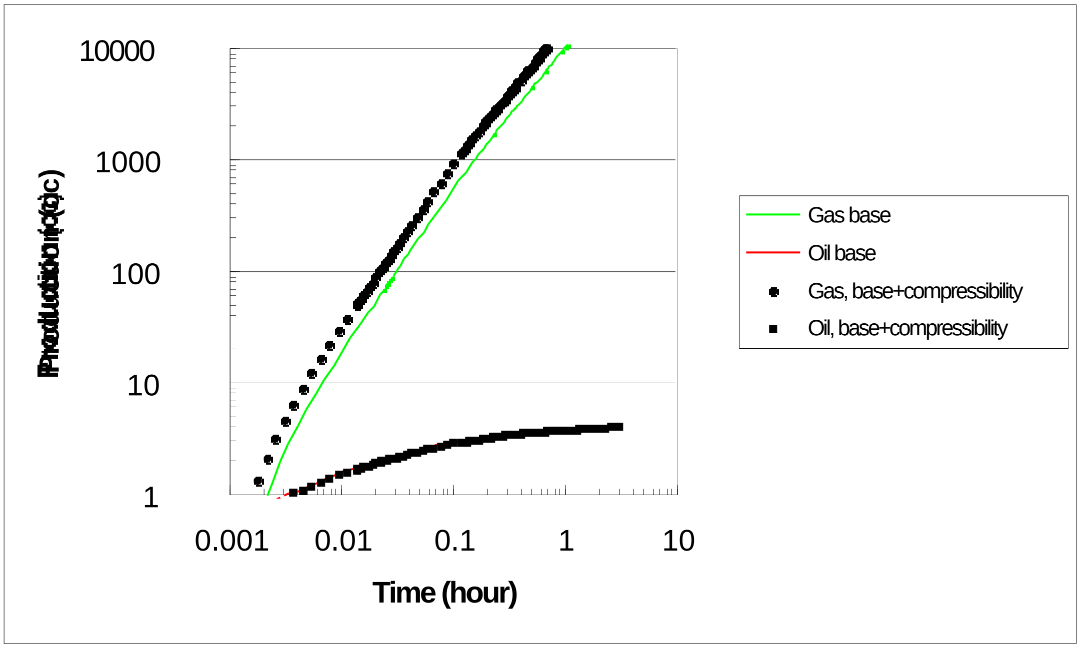


Figure 7a: Experiment 1. Base case production compared to the production after gas compressibility was introduced in the simulator. With that, the gas production increases by a factor ~2.

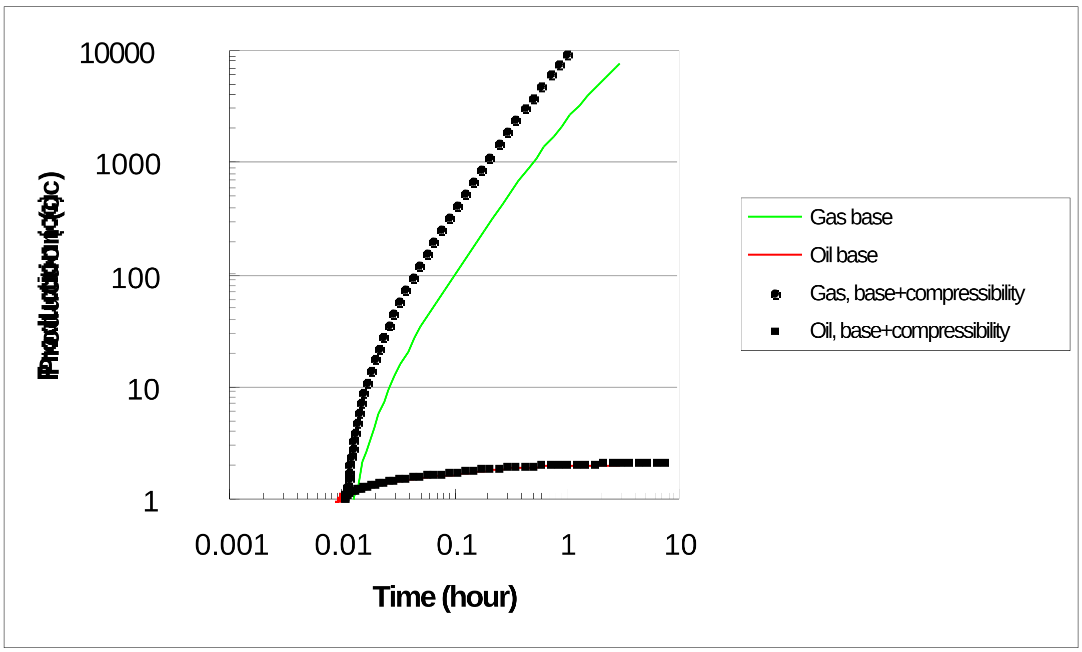


Figure 7b: Experiment 2. Base case production compared to the production after gas compressibility was introduced in the simulator. With that, the gas production increases by a factor ~3.

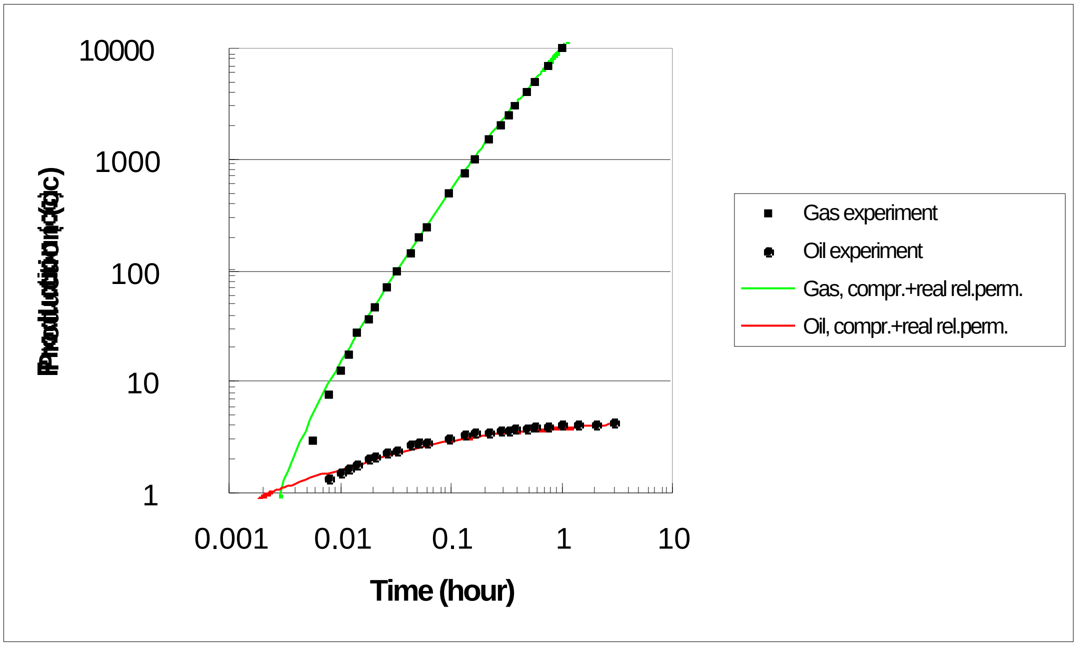


Figure 8a: Experiment 1. New gas relative permeabilities were fed to the simulator, until after a sequence of runs this match with the experiment is obtained. Relative permeabilities are given in

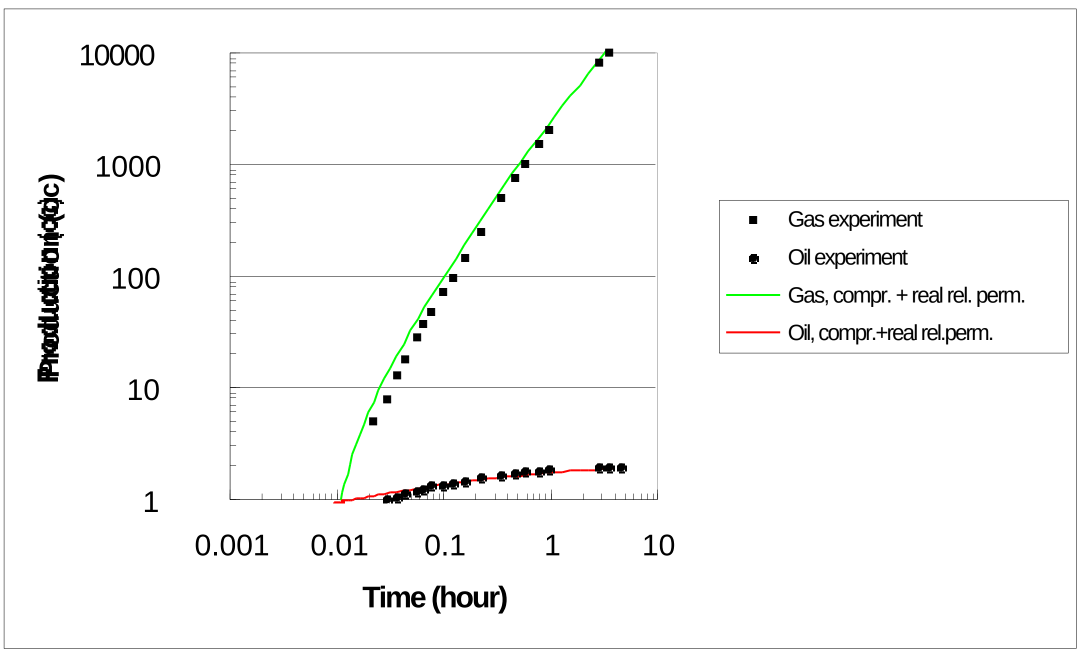


Figure 8b: Experiment 2. New gas relative permeabilities were fed to the simulator, until after a sequence of runs this match with the experiment is obtained. Relative permeabilities are given in Figure 9b.

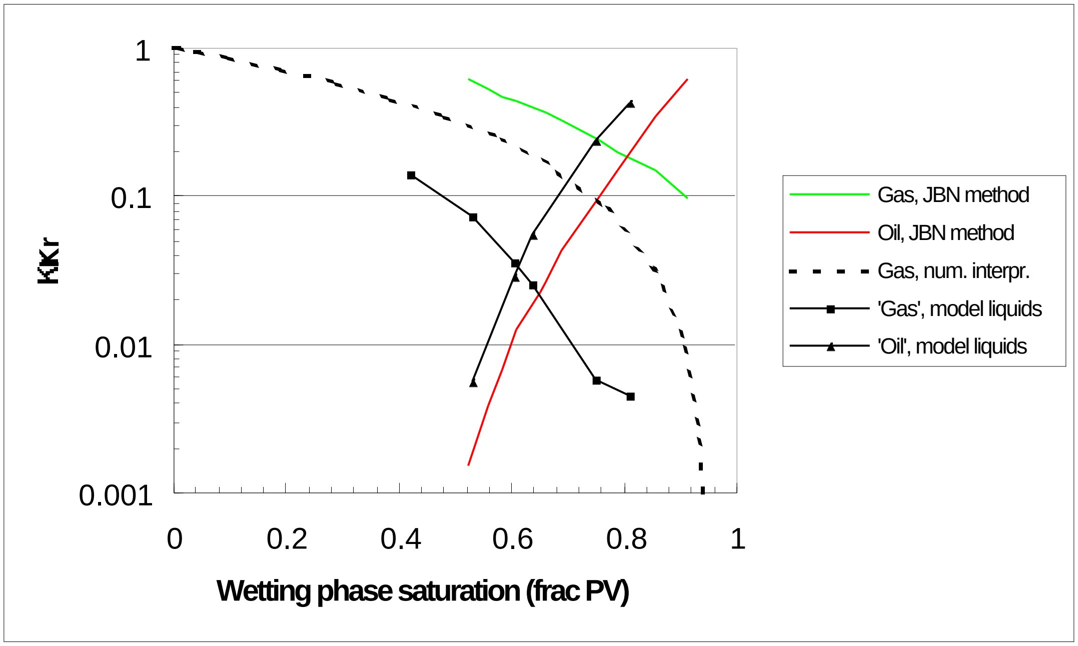


Figure 9a: Experiment 1. Dotted line: relative permeability obtained by numerical re-interpretation. Line with blocks: non-wetting phase relative permeability obtained by using model liquids.

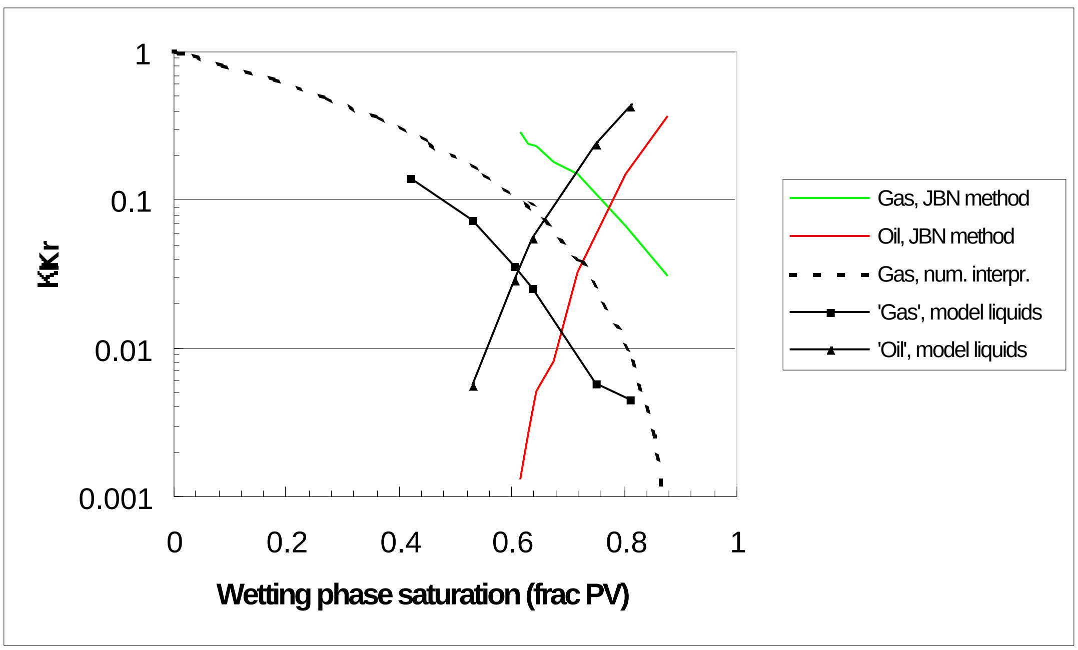


Figure 9b: Experiment 2. Dotted line: relative permeability obtained by numerical re-interpretation. Line with blocks: non-wetting phase relative permeability obtained by using model liquids.