Improved Special Core Analysis: Scope for a reduced residual oil saturation

J.A. Kokkedee, W. Boom, A.M. Frens and J.G. Maas

Shell International Exploration and Production B.V., Research and Technical Services, P.O. Box 60, 2280 AB Rijswijk, The Netherlands

Abstract

The quality and reliability of Special Core Analysis data becomes more and more important with the ever increasing pressure to optimise field development. A large part of the limited SCAL data which is carried in "brown" fields is based on experiments carried out in the late 70's, early 80's. In those days, reservoirs were assumed to be water wet. SCAL experiments were in general carried out on cleaned unaged samples and data were interpreted analytically. Too high estimates of the residual oil saturation were often obtained.

Recent SCAL experiments at representative wettability using state-of-the-art measurement and interpretation techniques point to residual oil saturations, which are often about 10 -15 saturation percents lower than old estimates. In this paper various cases are presented, where improved SCAL techniques paved the road to these representative residual oil saturations. The impact of the smaller residual oil saturation and the inherent tail in the relative oil permeability on the production behaviour of the field is discussed.

1. Introduction

In more and more mature oil fields around the world, the cumulative oil recovery points towards residual oil saturations that are considerably lower (10% saturation or more) than anticipated from historical special core analysis (SCAL) data. Since there are no reasons that uncertainties, e.g. in the geological model could cause this, apparently the historic SCAL approach has resulted in systematic deviations from representative data. This paper will discuss how special core analysis can be improved towards reliably assessing residual oil saturation. In effect, the residual or immobile oil saturation itself is not the parameter of prime interest, but instead one should be concerned with the mobility of the oil at low oil saturations. Dependent on the geometry, or geology, low mobility oil may be economically producable within the normal life span of a reservoir. In this way, the movable oil can be extended by 10-15 saturation percents. Therefore, high quality SCAL data have a significant impact on field development planning in "brown", or mature fields, but also in "green" fields.

Before we discuss the impact of SCAL data for various field cases, we will first highlight some important pitfalls that exist in SCAL flow experimentation: the effect of a non-representative wettability on flow parameters and the presence of measurement artefacts. The two effects, in general, cause an higher apparent residual oil saturation, if not properly accounted for in the measurement procedure and interpretation. First, we will explain the route we follow to carry out SCAL measurements at a representative wettability. After that, the application of numerical modelling of SCAL flow experiments to account for measurement artefacts will be handled. It will be clarified how we obtain a coherent data set of relative permeabilities and capillary pressures from different experiments.

2. Wettability

As is very well known, SCAL flow parameters, like capillary pressure, relative permeability and residual oil saturation depend strongly on the wetting state of the rock material being investigated [1]. Therefore, for the determination of a set of representative SCAL data, the wettability state of the core sample in the laboratory should approach as close as possible the wettability state of the reservoir.

So far, no measurement technique exists to reliably measure the wettability of reservoir rock downhole in the field. NMR integrated in logging tools may be a good candidate, but these methods are still in an early stage of development [2]. In the absence of wettability information of the field itself, it is impossible to decide whether a certain wettability state is representative or not. Given that limitation, basically two approaches to a representative wettability remain.

The first approach relies on a sample, which is taken with such care from the reservoir, that ideally all the properties (including wettability) are conserved at the surface [3]. Ideally, the obtained SCAL data on these preserved core samples should then be representative for the field. Since drilling fluids are known to contaminate the rock during coring, special precautions have to be taken to reduce drilling fluid invasion [1,4]. In addition, to maintain the in-situ wettability as much as possible, SCAL measurements are usually done as soon as possible after the core has reached the surface. In many cases, without special measures for coring and core handling, it is possible that the wettability state of the preserved core does not correspond anymore to the wettability of the reservoir. In general, the fluid contents (saturation) in a preserved core sample can only be determined after all experiments have been carried out with rather inaccurate techniques.

The second approach calls for a cleaning stage to make the rock water wet, followed by a period of exposure with reservoir crude at the proper initial water saturation (ageing) to restore the original reservoir wettability. Although there is no guarantee that the actual reservoir wettability is restored, at least the sample undergoes the same life cycle as a virgin reservoir during charging. It is essential to apply a proper cleaning process, to ensure water-wetness after cleaning without the disturbance of clay and pore structure. During the wettability restoration process, fluid contents (saturation) are determined from the beginning of the experimental cycle.
A disadvantage of the restored state approach is the variation in ageing time: depending on the rock and crude, ageing may vary from a few days up to months. A recently developed measurement technique enables us to study wettability changes in the sample over time and to actually measure the time to reach a stable wettability state [5]. In addition, differences between ageing with live crude at reservoir conditions and ageing with dead crude at more moderate conditions of temperature and pressure can be investigated. Pending more results of this research, the restored-state approach with cleaning has resulted in reproducibility of the data under a

wettability that we believe to resemble reasonably well the wetting state of the reservoir.

Most of the old SCAL data of the mature fields has been gathered in the mid '80's or before. In those days, reservoirs were believed to be water wet. Therefore, SCAL data was usually measured on cleaned, water wet samples. In a water wet sample, oil is quite mobile until it is trapped at a high residual oil saturation. Relative oil permeability curves for water wet rock are characterised by high residual oil saturations (~ 35 %) and low Corey exponents (see for example the dashed curve in Figure 1). Ageing a core plug changes its wettability from water wet to mixed wet conditions. In a mixed wet sample, oil is less mobile but can in general be mobilised to much smaller oil saturations: the residual oil saturation is smaller in combination with a higher Corey exponent (see for example the solid curve in Figure 1).

3. Measurement artefacts

Neglecting measurement artefacts in the interpretation of laboratory data also leads to a higher apparent residual oil saturation. Conventionally, SCAL laboratory data are interpreted analytically. In the interpretation, the effect of capillary pressure in a relative permeability experiment is fully ignored and vice versa. In reality, both capillary pressure and relative permeability affect flow behaviour in any laboratory experiment. Only by applying different experimental techniques and using numerical simulations to reconcile all data with a single set of capillary pressure and relative permeability curves, can a consistent and hence reliable interpretation be obtained.

Below, we will discuss capillary pressure and relative permeability artefacts in more detail for the most commonly applied measurement techniques: the steady-state technique, the unsteady state or displacement technique and the centrifuge technique. Conventional analytical analyses allows the determination of both water and oil relative permeability from (un)steady-state data and the oil relative permeability or the negative branch of the capillary pressure from centrifuge data. The techniques are applied in imbibition mode, i.e. for decreasing oil saturations, like the waterflooding process in the field. The discussion is restricted to those artefacts that play a role at the tail-end part of the oil relative permeability, i.e. when approaching the residual oil saturation.

Let us first concentrate on artefacts caused by the capillary pressure. The oil-wet, negative part of the capillary pressure causes an oil end-effect to be present in relative permeability experiments at low oil saturations: some additional amount of oil is retained near the outlet face by the capillary forces, counteracting the viscous or centrifugal forces acting on the oil. Clearly, this causes the average oil saturation to be higher than the remaining oil saturation elsewhere in the sample (see Figure 2). If the end-effect is neglected in the analyses and the production or the average saturation is used as input, an apparently higher residual oil saturation results. The oil end-effect can be reduced by increasing the applied pressure difference or the centrifugal acceleration. Desaturation effects, however, have to be avoided and present an upper limit for the attainable reduction of the oil end-effect. Local, in-situ saturation measurements provide a way around the problem: the remaining oil saturation can directly be determined at a spot beyond the range of the capillary end-effect. Even better would be to measure the full saturation profile along the flow direction in the sample. This allows a check on the actual range of the end-effect. A direct extraction of the capillary pressure from measured saturation profiles is still an area of research.

Besides the capillary pressure, also the relative permeability causes artefacts in the interpretation of SCAL data. The low relative permeability of the oil near the residual oil saturation causes time to be a factor of importance in any laboratory experiment aimed at accessing this saturation range. Below we discuss the implications for relative permeability and capillary measurements in more detail.

In a relative permeability experiment, ample time is required to reach low oil saturations. The low mobility of the oil itself, which is to be measured, is the restricting factor for the rate of change in oil saturation. Clearly, only for those saturations that have actually been attained in the experiment, can relative permeability information be extracted. Frequently, (un)steady-state experiments are stopped too early and the remaining, low mobility oil in the sample is incorrectly quantified as residual oil, thus resulting in an apparently higher residual oil saturation. From an experimental point of view, this seems not illogical: the low oil mobility results in a very slowly decreasing oil saturation and an extremely low oil production rate. Simultaneously, the pressure difference over the sample is determined by the most mobile phase, the water, and since its relative permeability varies only little in the neighbourhood of the residual oil saturation, the pressure difference is nearly constant in time. In view of the above, an accurate, automated and highly stable production or local-saturation monitoring system is an absolute prerequisite to access the low oil saturation regime. For the steady-state, in addition, extremely low fractional flows, say between 0.01 and 0.00001, are required. Notably, for the centrifuge technique, suitable systems are readily commercially available.

As an illustration of relative permeability effects, Figure 3a shows the (first half hour of) production during an actual single-speed centrifuge experiment. On the basis of this data, an ultimate recovery estimate of 1.6 cc would not seem unreasonable. Figure 3b now shows the full production profile of the same experiment. Note the logarithmic time scale. Clearly, ultimate recovery is likely to be in excess of 2 cc, i.e. at least 25 % more than our initial estimate. Furthermore, as production is not yet seen to level off in Figure 3b, an extrapolation to an ultimate recovery on the basis of the available data is futile in this specific case.

From the same example we can argue how relative permeability effects may impact on multi-speed centrifuge experiments for the determination of capillary pressure. The analytical interpretation of such an experiment uses the equilibrium (ultimate) production levels at the various centrifuge speeds as input. Clearly, the relative permeability of the oil can prevent capillary equilibrium to be attained within the duration of a speed period. The low mobility oil still present at the end of each speed period is incorrectly interpreted as being capillary retained oil. This results in a shift of the capillary pressure to higher oil saturations, in particular at low oil saturations, where the oil is least mobile. In other words, this also yields a higher apparent residual oil saturation.

How can one proper deal with these artefacts in SCAL flow measurements and interpretation ? First of all, artefacts should be minimised by a proper design of the experiment along the lines described above. Nevertheless, artefacts can never be fully suppressed. For this reason, numerical simulations of laboratory experiments are a key element in the Shell Group's approach to SCAL measurements. Especially the use of different experimental techniques in combination with numerical simulations, aimed to history-match the different experimental data sets with a single set of capillary pressure and relative permeability curves, allows us to effectively combine the strengths of the various techniques, whilst at the same time consistently taking account of all artefacts. Moreover, numerical simulations can be used in the experimental design stage, for example to assess equilibration times in multi-speed centrifuge experiments, and for quality control on contractor interpretation of experimental data.

4. Impact of SCAL on field development

In Table I we have presented the old and new residual oil saturation for various fields of the Shell Group all over the world. A trend towards lower residual oil saturations is obvious. This directly translates into a significant increase in reserves. Below we will elaborate further on the importance of the tail-end of the oil relative permeability for field development.

Figure 4 shows a generic example of a dipping reservoir that has been developed under a water drive scenario. For this particular field, the oil relative permeability has been measured by a combination of steady-state and multi-speed centrifuge experiments. The two oil relative permeability curves presented in Figure 5 were obtained from the same experimental data: one by analytical interpretation (by a third party laboratory) and one by making use of numerical simulations (including the effects of capillary pressure). The two curves are identical for relative permeability values above 10^{-2}. Significant deviations are observed below 10^{-2}. The deviations can be explained by a capillary end-effect, which has gone unnoticed in the analytical interpretation.

Both curves have been used to predict the production characteristics and to assess the remaining oil saturation of the field (see Figure 6). Before water breakthrough, no significant differences are observed in production. This can be understood, from the fact that for this particular field, the remaining oil saturation behind the water front is approximately 0.30, corresponding to a relative permeability of 10^{-2}. After water breakthrough, however, significant deviations in production develop.

The analytically interpreted relative permeability curve drops steeply to zero near a water saturation of about 70 %. Consequently, oil is left immobile behind the water front and no further production is expected after breakthrough. The properly interpreted curve gradually decreases to zero at S_{or} of about 0.10. Now, oil is still mobile behind the front resulting in a tail end production at increasing, high water cuts. Depending on the mobility of oil and the geometry of the reservoir, this extra oil can be economically important. Gravity drainage will cause the remaining oil to migrate and accumulate in the top of the reservoir. Especially, in relatively thin oil columns an additional oil production after breakthrough can be expected as a result of gravity drainage. Although, this gravity segregation process is not a fast process, it should be noted that the distance to the top of the reservoir is usually several orders of magnitude less than the horizontal distance between injector and producer. As a consequence the oil will collect at the top of the reservoir within several years, and can possibly be economically produced.

It is obvious that the importance of the gravity drainage process will depend on other parameters, than the oil relative permeability only. Geometry and geology of the reservoir as well as the ratio of the capillary transition zone and the sand thickness will determine the remaining oil saturation in the swept zone [6]. Although tail-end production may not always be economic, for some cases it may account for an increase in ultimate recovery of 20 % or more [7]. If one uses the incorrect relative permeability for prediction purposes, scenarios like this can not properly be screened, leading to losses of ultimate recovery.

5. Conclusions

Recent state-of-the-art SCAL measurements at representative wettability conditions and taking account of both relative permeability and capillary pressure artefacts in the interpretation, systematically point to lower residual oil saturations for a growing number of reservoirs all over the world. The reduction in residual oil saturation typically amounts to 10-15 saturation percent as compared to old estimates. Crucial is the use of a combination of experimental techniques and the use of a numerical simulator for history matching the obtained laboratory data.

The business impact of quality SCAL is evident: a significant increase in reserves and a more realistic prediction of reservoir performance in time. In particular, quality SCAL gives a more reliable estimate of the time of water breakthrough. Also, quality SCAL allows proper economic screening of the potentially recoverable oil near the tail end-part of the oil relative permeability curve.

In view of this business impact, our approach to SCAL is disseminated to the operating companies of the Shell Group via courses and easy-to-use analytical and numerical tools. To guarantee software transportability, the analytical tools are available as Excel worksheets and the numerical simulation tools are built on top of MoReS, the Shell Group's flexible reservoir simulation package. A robust method for fully automatic history matching of laboratory data is yet under development. The aim of the knowledge dissemination is to create an awareness for the importance of SCAL data and the pitfalls in SCAL experiments, with the ultimate goal of improving the quality of (contractor) SCAL data in general, allowing a more optimal field development.

6. Acknowledgements

We would like to thank the management of Shell International Exploration and Production (SIEP) for permission to publish this paper.

References

1. "Wettability literature survey - Part 1 - 5", Anderson, G.A., JPT October 1986 - p.1125, November 1986 - p.1246, December 1986 - p.1371, October 1987 - p.1283 and November 1987 - p.1453.

2. "Nuclear magnetic resonance as a petrophysical tool", Kenyon, W.E., Nuclear geophysics, Vol. 6, No. 2, p. 153 - 171, 1992.

3. Wunderlich, R.W., "Obtaining samples with preserved wettability" in Interfacial Phenomena in Oil Recovery, N.R. Morrow editor, Marcel Dekker, Inc. New York City, 1990, p. 289 - 318.

4. Jia, D., Buckley, J.S., Morrow, N.R., "Alteration of wettability by drilling mud filtrates", SCA 9408 presented at the International Symposium of the Society of Core Analysts, September 1994.

5. "Towards Measurement of Capillary Pressure and Relative Permeability at Representative Wettability", J.A. Kokkedee, V.K. Boutkan, Proceedings of the 7th European Symposium on Improved Oil Recovery, Moscow, 1993, Vol. II, p. 28-34.

6. "Dependence of waterflood remaining oil saturation on relative permeability, capillary pressure and reservoir parameters in mixed-wet, turbidite sands", Hirasaki, G.J., paper 30763 presented at the SPE Annual Technical Conference and Exhibition, Dallas, 22-25 October, 1995.

7. "Draugen field development: the role of gravity drainage and horizontal wells", Rheinholdtsen, B., paper presented at the 8th EAPG Improved Oil Conference Symposium, PROC V 1, p. 113 - 123, Vienna, Austria May 1995.

Field Area		Current Residual Oil Saturation	Old Residual Oil Saturation
Europe	case 1	15%	28%
	case 2	15%	25-30%
	case 3	14%	29%
	case 4	10-15%	-
Africa	case 1	20%	-
	case 2	15-20%	25-35%
Middle-East	case 1	15-25%	-
	case 2	10-20%	-
North-America	case 1	10%	>=40%

Table I: Recent SCAL measurements, performed at representative wettability and using state-of-the-art equipment and interpretation techniques, systematically point to significantly lower residual oil saturations than those obtained from old SCAL measurements.

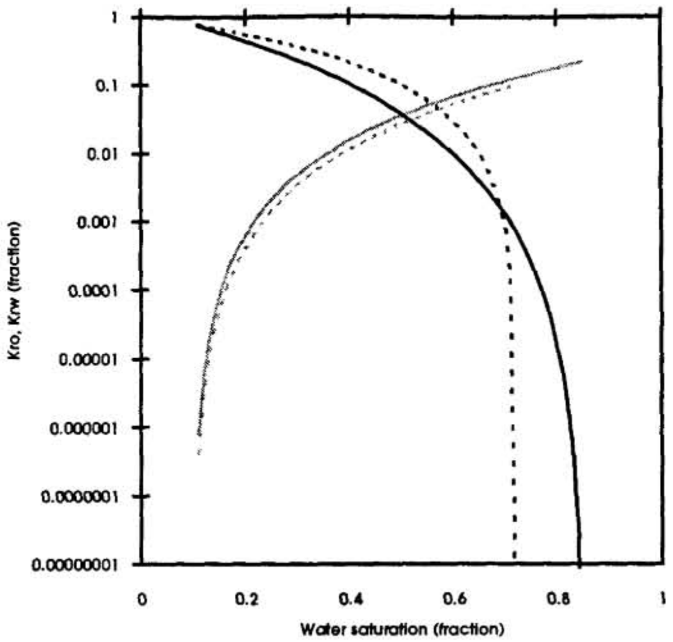


Figure 1: The impact of wettability on relative permeability, as measured for a sandstone oil reservoir in the North Sea (solid line: aged samples, dashed line: cleaned samples (old data)).

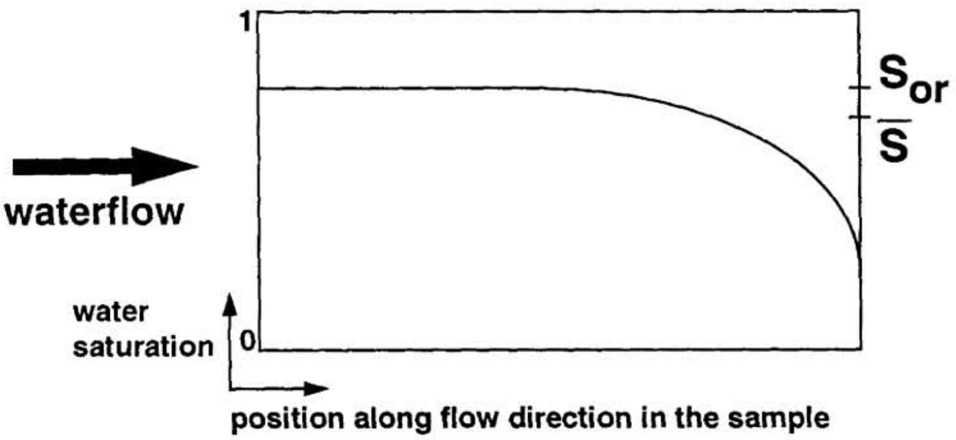
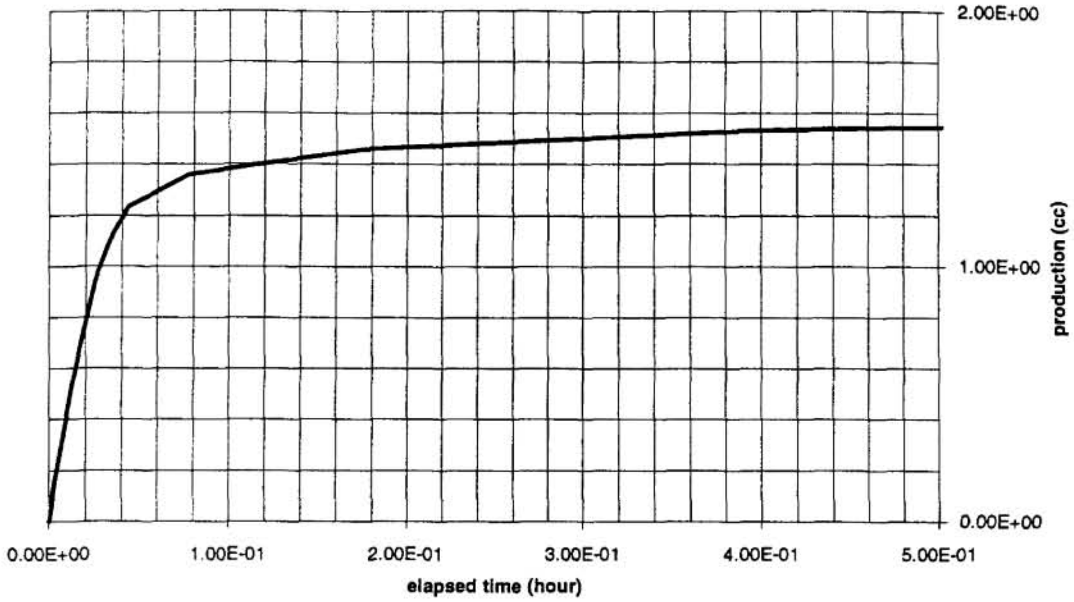


Figure 2: The presence of an oil end-effect (in the above unsteady-state experiment) causes the average oil saturation to be higher than the remaining oil saturation elsewhere in the plug. If the first is used in the analytical analysis, that neglects the end-effect, an apparently too high residual oil saturation results.

(A)



(B)

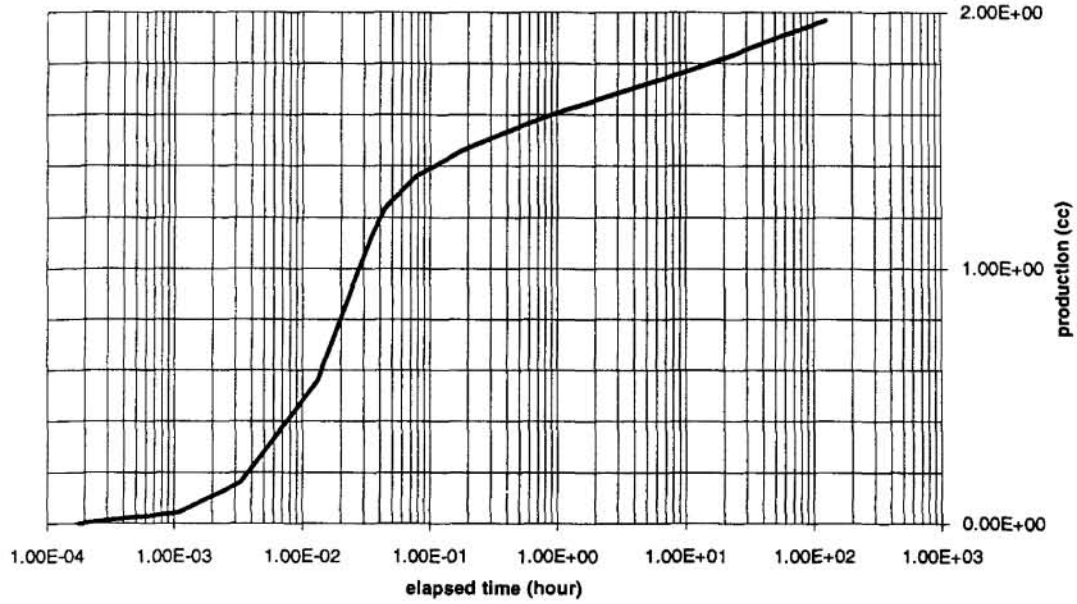


Figure 3: Different graphical representations (A) and (B) of the same production data of an actual single-speed centrifuge experiment. Although (A) suggests an ultimate recovery of around 1.6 cc, it is evident from (B) that the ultimate recovery is likely to be in excess of 2 cc. The tail-end of the relative permeability is responsible for the significant afterflow.

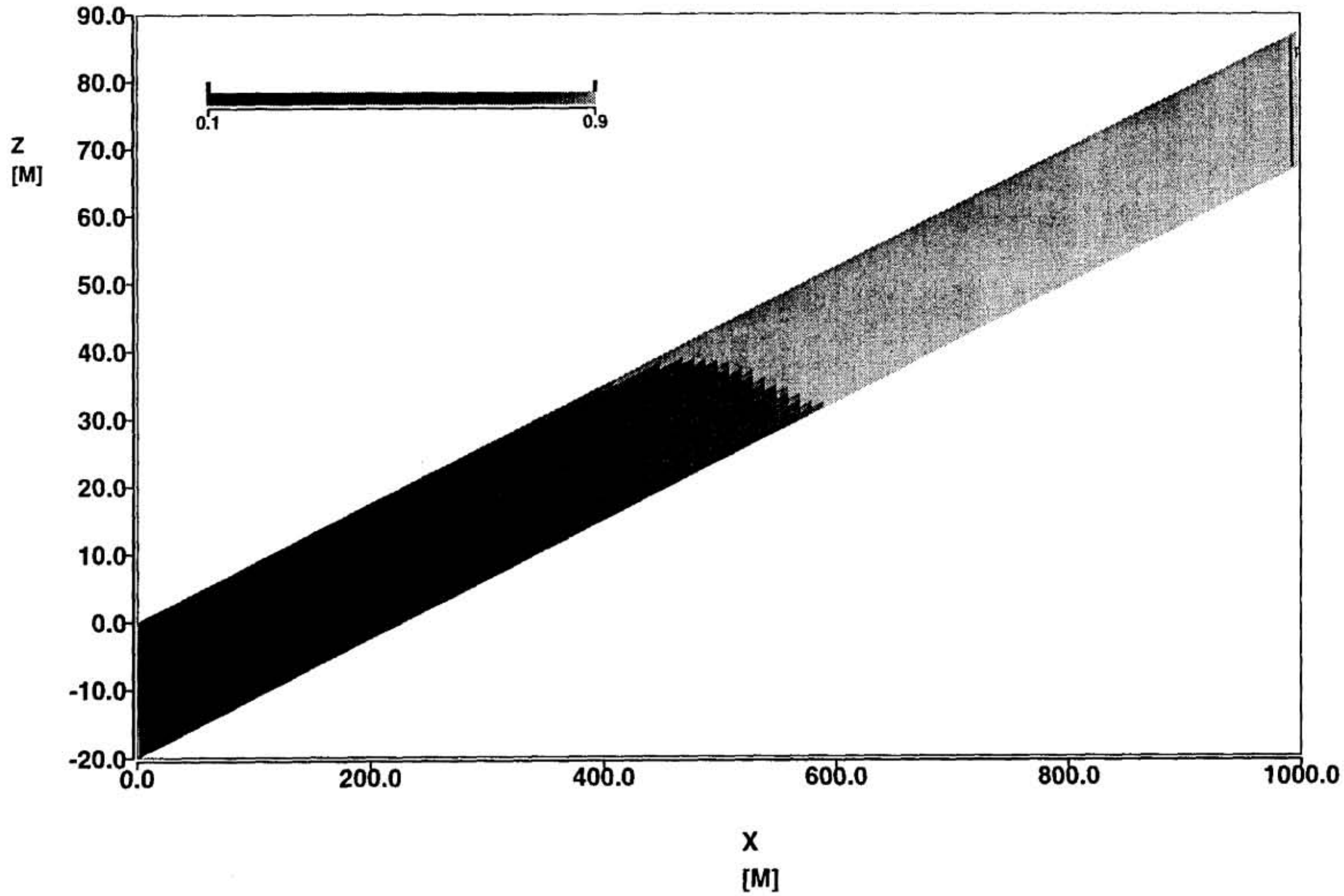


Figure 4: Simple 2D simulation model of a dipping reservoir, used to illustrate the impact of the tail-end of the oil relative permeability on reservoir performance. Water is injected at the bottom, oil is produced at the top.

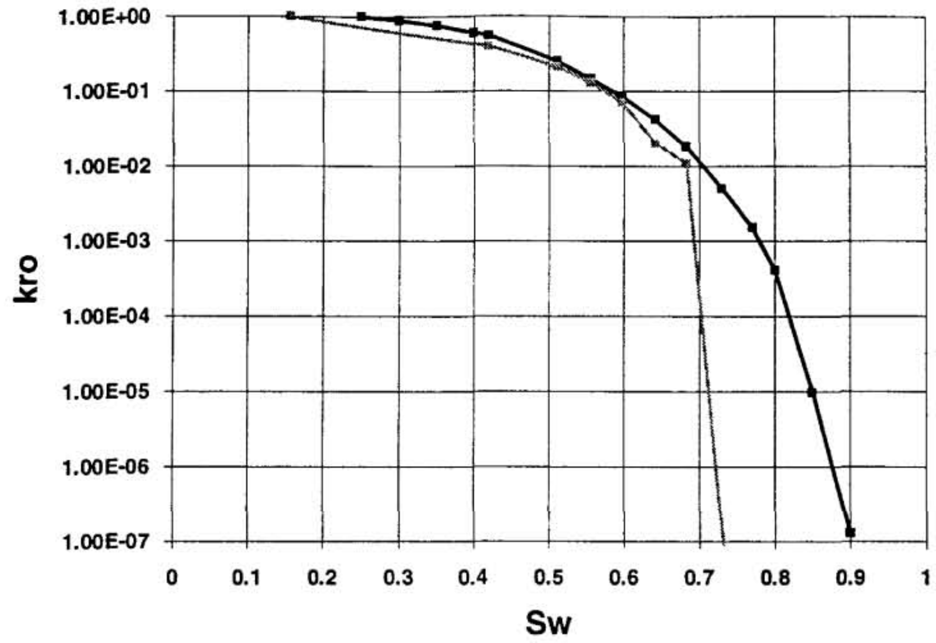


Figure 5: Oil relative permeability curves used in the dipping reservoir model of Figure 4. The curves are extracted from the same experimental data, either by analytical (grey, contractor) or numerical (black, Shell RTS) interpretation techniques.

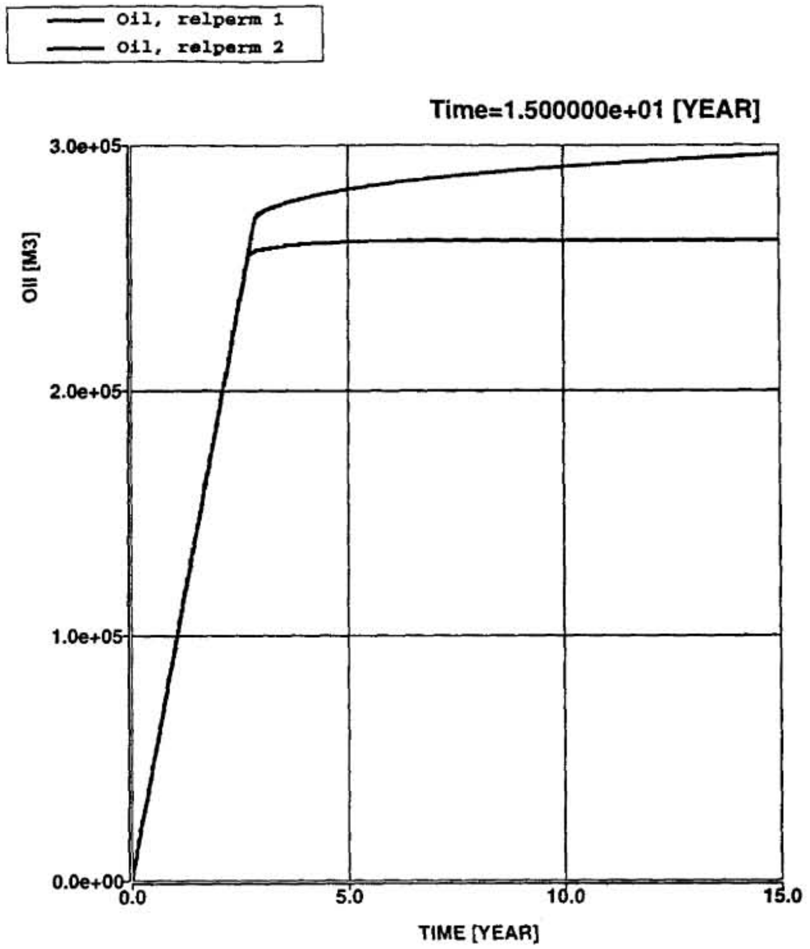


Figure 6: Simulated production profiles for the dipping reservoir model of Figure 4, obtained with the two different oil relative permeability curves of Figure 5. When the incorrect curve is used, production after breakthrough is fully eliminated in the simulation.