Please read as supplementary text to lectures. Please focus on the discussions of physical behavior. Sections on reservoir simulation are not relevant for this course

Dual Porosity, Dual Permeability Formulation for Fractured Reservoir Simulation

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Abstract

This study reviews key physical mechanisms and calculation methods for modelling of fluid flow in North Sea fractured reservoirs. The main matrix-fracture fluid exchange mechanisms described are gravity drainage, capillary imbibition and molecular diffusion. Important issues such as capillary continuity between matrix blocks, reinfiltration of fluids from higher to lower blocks and effect of block shape on flow processes are also addressed.

Simulation studies of water-flooding in fractured reservoirs are reported for the purpose of identifying the effects of gravity and capillary forces on oil recovery. Included are studies of effects of capillary continuity and degree of wetting. The results show that for intermediately wetted systems, such as the Ekofisk reservoir, capillary continuity has a major effect on oil recovery.

Laboratory processes involving high pressure gas injection in fractured systems have been studied by compositional simulation. The results show that changes in interfacial tension caused by diffusion, may have dramatic effects on oil recovery.

Computational aspects of fluid exchange processes are discussed, including conventional dual porosity formulation, use of matrix-fracture transfer functions, and detailed numerical calculation. The only solution to more representative modelling of flow in fractured reservoirs is more detailed calculations. A multiple grid concept is proposed which may drastically increase the detail of the simulation.

Introduction

Based on the theory of fluid flow in fractured porous media developed in the 1960's by Barrenblatt *et al.*[1], Warren and Root[2] introduced the concept of dual-porosity models into petroleum reservoir engineering. Their idealized model of a highly interconnected set of fractures which is supplied by fluids from numerous small matrix blocks, is shown in Fig. 1. Kazemi *et al.*[3] were the first to incorporate the dual-porosity concept into a numerical model, with application to fluid flow on a large scale.

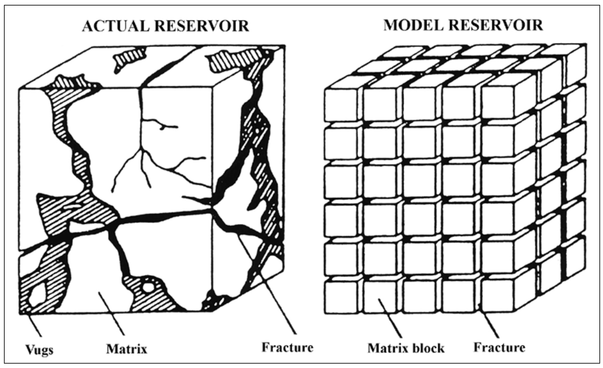

Fig. 1 Idealization of a fractured system (from Warren and Root[2])

Since that time, numerical modelling of naturally fractured reservoirs using dual-porosity models has been the subject of numerous investigations. In the dual-porosity and dual-porosity/dual-permeability formulations most commonly used to model fractured reservoirs, proper representation of imbibition and gravity drainage is difficult. In some formulations, attempts have been made to represent correct behavior by employing a gravity term, and assuming a simplified fluid distribution in the matrix.[4-6] Several authors[7-10] have made use of capillary pressure pseudofunctions for the matrix and/or the fracture that employ matrix fluid distributions obtained through some type of history matching with a fine-grid model of a single matrix block. Others[6,11-12] have refined the matrix blocks into multiple blocks. The more recent of these publications on dual-porosity modelling deal with enhancements of the representation of gravity effects in the matrix-fracture transfer calculation.

In the North Sea, the Ekofisk Field has been subject to several simulation studies, such as Phillips' study of water imbibition[13] and Petrofina's study,[14] which includes an evaluation of the effect of capillary continuity on recovery.

Current state-of-art in the area of fractured reservoir simulation, with emphasis on gas/oil gravity drainage in terms of block-to-block processes, is reviewed by Fung.[15] He classifies the current methods into four groups: 1) gravity-segregated, 2) subdomain, 3) pseudofunction, and 4) dual-permeability models. Fung proposes a new approach for calculation of pseudo capillary pressure pressures, either *a priori* if vertical equilibrium can be assumed, or by fine grid simulation if not.

Although several publications have discussed reimbibition of oil from higher matrix blocks into lower matrix blocks, all models reviewed by Fung[15] neglect capillary continuity (Fig. 2), except the dual-permeability model, where the matrix is assumed to be completely continuous.

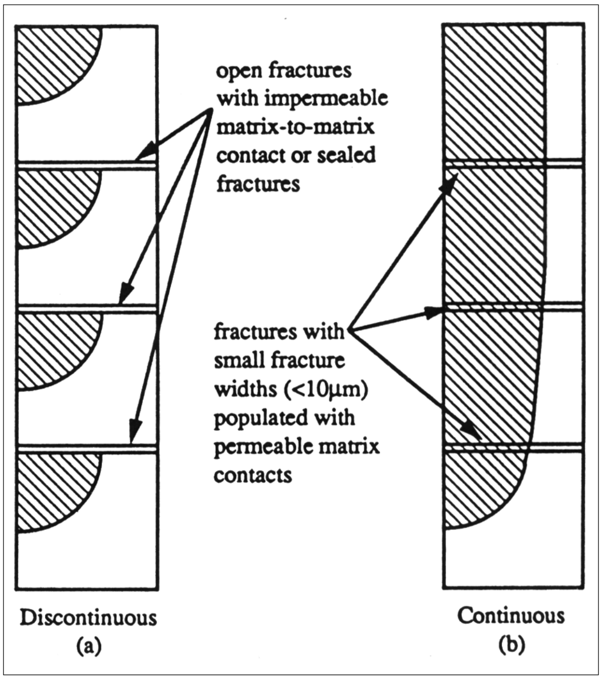

Fig. 2 Effect of vertical capillary continuity on saturation distribution (from Fung[15])

None of the models treats the reinfiltration phenomenon properly (Fig. 3). Finally, the importance of the effect of *gas-gas* and *gas-liquid* diffusion on recovery from fractured reservoirs during a gas/oil drainage process has not been extensively treated in the literature.

It is obvious that the current computational procedures are insufficient to represent the physical flow phenomena taking place between fracture and matrix in highly fractured reservoirs such as in the North Sea. Clearly, additional details in

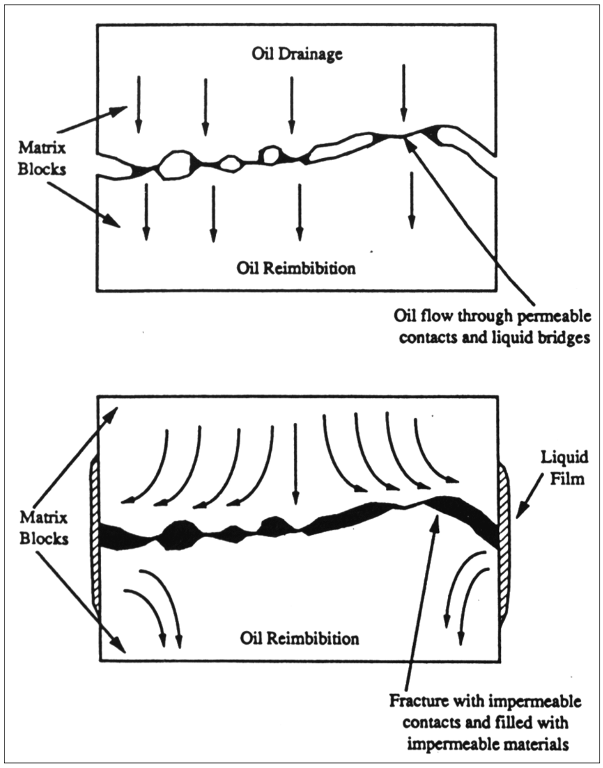

Fig. 3 Reinfiltration of fluids from higher to lower matrix blocks (from Fung[15])

the description of the flow processes in the models are required.

Simulation of fractured reservoirs using the dual-porosity (and dual-permeability) approach involves discretization of the solution domain into two continua called the matrix and the fracture. The original idealized model of Warren and Root[2] assumes that the matrix acts essentially as a source or sink to the fracture, which is the primary conduit for fluid flow. In multiphase flow situations, however, complex gravity and capillary pressure driven fluid exchange between fractures and matrix is occurring, and these processes are not well understood.

Especially the *gas-oil* gravity-drainage process in fractured reservoirs will require improved modelling in order to obtain efficient field-scale simulation. The gravity segregation in a dual-porosity medium is highly affected by capillary continuity between matrix blocks across fractures, and by the process of oil reinfiltration from fractures to matrix blocks. These mechanisms are not adequately represented in today's simulation models and several research groups are working on the problem.[15-19] Luan[20] presented a systematic study and a comprehensive discussion of the fundamental physical involved in gravity drainage of fractured reservoirs.

The computational side of fractured reservoir modelling is particularly difficult due to the large scale differences. Important flow processes are taking place at a scale much smaller than the grid blocks normally employed in dual porosity models. Uleberg[21] has made a study of application of local grid refining techniques in dual-porosity formulations for detailed computation of matrix-fracture fluid exchange.

Physical Characteristics and Fluid Flow Mechanisms

Capillary Continuity

The concept of capillary continuity between matrix blocks in fractured reservoirs is now widely accepted. A schematic comparison of capillary-gravity dominated saturation distributions for a discontinuous system and a system with capillary contact between matrix blocks is shown in Fig. 2. However, the discontinuous concept is still being used in most commercial dual-porosity models to handle block to block interactions.

Festøy and van Golf-Racht[22] presented simulation results where the fracture system allowed for various degrees of matrix to matrix contact. Their results show dramatically higher recoveries for capillary continuous systems compared to discontinuous ones. They suggested that the matrix is better described as tortuously continuous.

Luan´s[20] discussion on this subject concludes that the end effects may be important in a drainage process in fractured reservoirs. The saturation distribution at the endface of the blocks is dependent on the wetting conditions and the properties of the fractured medium. Experimental studies[23,24] show that the end effects (caused by saturation discontinuity) can be reduced by increased contact areas between blocks (applying overburden pressure in the laboratory).

Reinfiltration

An important aspect in gas-oil gravity drainage of fractured reservoirs is the process of reinfiltration. When drained oil from an upper matrix block enters into a matrix block underneath, the process is called reinfiltration. Several publications[17,18] have shown that the reinfiltration is a function of both capillary forces and gravity, therefore the term *reinfiltration* should be used instead of the much used word *reimbibition*, since the latter could imply the capillary effect only.

The flow from one block to another (reinfiltration) is either achieved by 1) film flow across contact points or 2) by liquid bridges. This liquid transmissibility across the fracture is therefore an important parameter for calculating the rate of drainage of a stack of matrix blocks. Fig. 3 illustrates the contact points and the liquid bridges.

Experimental results[18] have shown that the transmissibility across a fracture is very sensitive to the fracture aperture, but not so sensitive to the number of contact points or contact area. The reinfiltration mechanism is also time dependent, since liquid bridging provides the main transmissibility in the initial stage of the gravity drainage process. Later the oil saturation in the fractures will be very low and the main liquid transmissibility from block to block is due to film flow. This final period is of long duration and is very important for the overall recovery. The reinfiltration process is not adequately modelled in the reservoir simulators used to predict gravity-drainage oil recovery in fractured reservoirs.

Da Silva and Meyer[16] conducted a simulation study of reinfiltration, and concluded that this may be an important mechanism for systems of capillary continuity and large fracture angles.

Diffusion

Oil may be recovered by diffusion during gravity drainage in fractured reservoirs. Methods for estimating the amount and rate of this recovery in such reservoir processes are in early stages of development and poorly tested. It is very limited published data against which theories and prediction methods can be tested adequately. However, according to Orr,[25] the scaling efforts based on fundamental physics must be continued, specially in fractured reservoir problems, including work on diffusion/dispersion as well as gravity, viscous and capillary forces. An interesting effect may be due to interfacial tension gradients caused by diffusion of gas into the oil. The interfacial tension induced capillary pressure gradients may result in unexpected saturation profiles.[26-27] Hua *et al.*[27] conducted a series of simulations, and were able to reproduce the experimental results. However, the effects of diffusion on overall recovery is probably very small and can for most systems be neglected for practical purposes.

Matrix Block Shape and Size

The shape and size of matrix blocks will strongly affect the matrix-fracture fluid exchange process. Torsæter and Silseth[28] conducted water imbibition experiments on chalk and sandstone cores of different shapes and sizes, and typical results are presented in Fig. 4. Obviously, within a gridblock of a dual-porosity simulation model, matrix blocks of varying shape and size will exist.[29] One improvement that could be incorporated in such models, would be the inclusion of some form of distribution of size and shape, as indicated in Fig. 5. The computation of fluid exchange between matrix and fracture in a matrix block would then be the sum of computed exchange from a number of different geometries.

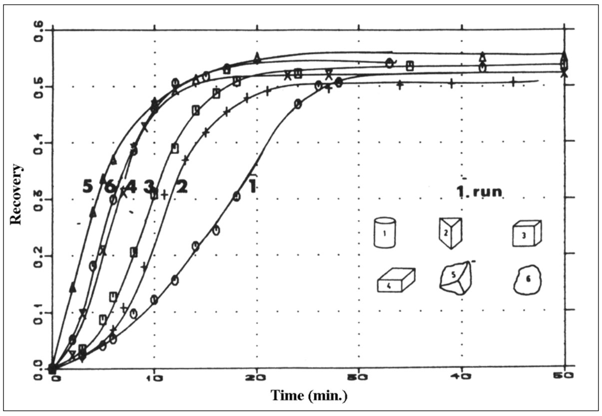

Fig. 4 Effect of size and shape on imbibition oil recovery (from Torsæter and Silseth[28])

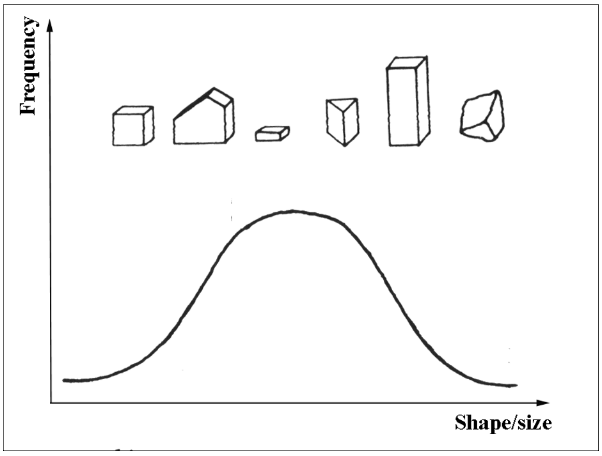

Fig. 5 Frequency distribution of representative matrix blocks (from Torsæter et al.[29])

Co-Current and Counter-Current Flow

Several authors have reported simulation studies for the purpose of matching results of laboratory experiments.[30-35] Such matching of experimental results is not trivial, as reported by Kvalheim[23] and by Beckner *et al*.[24] The outcome of the simulations is very sensitive to the shape and magnitude of the capillary pressure curve.

A major cause of the difficulties reproducing experimental results is probably that the capillary pressure and relative permeability curves used in the simulations were measured at flow conditions different from those of the experiments. An important issue to be addressed in fractured reservoir simulations is the one of co-current vs. counter-current flow. As reported by Bourbiaux and Kalaydjian,[36] the experimental imbibition results are very much affected by the boundary conditions imposed.

Water Flooding Simulation Studies

Matrix-fracture fluid exchange in a fractured reservoir is controlled mainly by a combination of capillary and gravity forces. The shape and size of matrix blocks, and the inclination of fractures will affect recovery of oil by water flooding. Several simulation studies[37-42] investigating the effects of these factors have been conducted. In the following, the most important results will be presented.

Most of the studies in the past dealing with oil displacement by water in a fractured reservoir pertain to strong water-wet matrix where capillary imbibition dominates the process of fluid transfer between the matrix block and the fracture. Few studies have been reported dealing with water flooding in intermediate wet systems where both capillary and gravity forces play key roles. In certain situations, the role played by gravity forces may be so dominant that the limited recovery due to spontaneous imbibition in case of an intermediate wet rock is significantly improved.[43]

Block to block processes for a gas-oil system has been intensively studied by many authors.[15,22,44] Festøy and van Golf-Racht[22] showed that for a gas-oil system, matrix to matrix contact area in a vertical stack of blocks significantly improves the recovery. No such study for oil-water system has been reported in the literature.

Pratap[40] conducted fine grid simulations using a similar geometry in order to understand in detail the block to block processes involved in oil displacement by water in a fractured reservoir. GeoQuest´s Eclipse 100 model was used for the simulations. The study makes use of oil-water relative permeability and capillary pressures for the Ekofisk Field, as reported by Thomas *et al.*[45]

Results of the study show that a significant fraction of oil expelled from the down-dip matrix block into the separating fracture reinfiltrates into the block above. This reentering of oil into the matrix block above is a result of the change in oil pressure in the separating fracture. In the early phase of production, the oil pressure in the separating fracture is less than that of the matrix grid cells above as well as below. Thus, oil will flow to the separating fracture from both the matrix blocks. The oil discharged to the separating fracture flows laterally to the vertical fracture. There it joins the mainstream of oil produced by spontaneous imbibition of water from the lateral sides of the blocks as they are surrounded by water in the vertical fracture. After some time, the oil pressure of the separating fracture exceeds the oil pressure of the matrix grid cells of the up-dip block in contact with the fracture. This results in significant fraction of oil in the separating fracture (produced from lower block) to flow into the upper block. This block to block process which starts at the edge blocks marks the beginning of the late phase. As time progresses, more and more inner matrix grid blocks undergo the process of oil redrainage. This late phase production continues for a long time.

The study also examines the effect of matrix to matrix contact on oil recovery from a vertical stack of blocks. The result shows that in absence of capillary continuity between the blocks, the oil recovery is low. The presence of matrix to matrix contact increases the ultimate recovery from the stack dramatically. However, the oil recovery rate is higher at early times if the contact area between the matrix blocks exceeds 5 %. With a matrix to matrix contact of only 1 %, a long time is required to obtain the ultimate recovery. Some of these results are shown in Figs. 6-7.

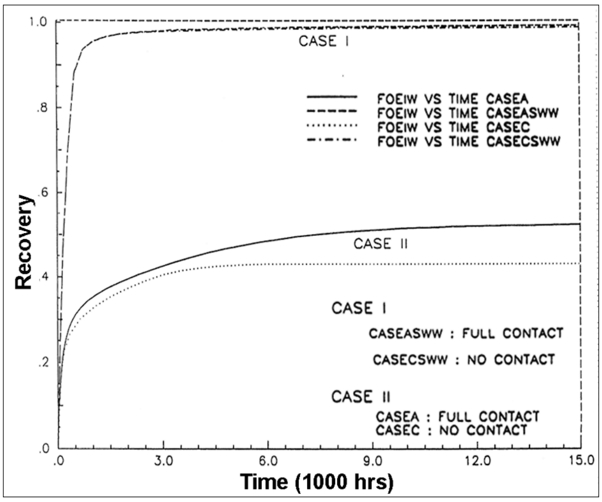

Fig. 6 Effect of capillary continuity on oil recovery for water wet (I) and mixed wet (II) systems (from Pratap[30])

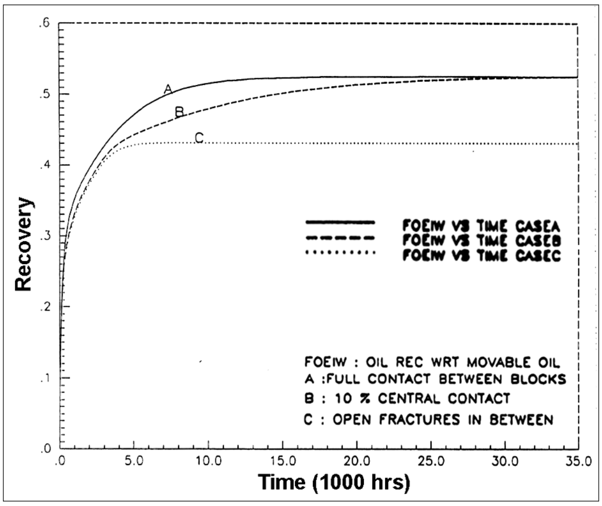

Fig 7 Effect of degree of capillary contact on oil recovery (from Pratap[30])

The position of the matrix to matrix contact with respect to the vertical axis of the cylindrical blocks also affects the recovery time. For example, a 10 % contact at the edge of the matrix block gives faster ultimate recovery as compared to the same contact located at the center. The study on a gas-oil system by Festøy and van Golf-Racht[22] showed that with a contact of 25 % between the matrix blocks, the time to obtain the ultimate recovery is close to that with 100 % contact, and the present study for an oil-water system confirms their findings. It also shows that 30% contact between matrix blocks is sufficiently effective to drain the oil in a reasonable time.

A comparison has been made with a case of strong water wet matrix block (Fig. 7). The results show that oil redrainage does not take place if the rock is strongly water wet, as the oil phase pressure of separating fracture never exceeds that of the upper matrix block.

The process of oil redrainage from the lower matrix block to the upper matrix block in case of oil-water system has not previously been reported in the literature. Neither is the finding that the position of the contact influences the time to reach ultimate recovery. The effect of vertical capillary continuity and its effect on oil recovery for intermediate wet rock has been extensively studied for the first time.

High Pressure Gas Injection

Despite the efficiency of waterflooding in fractured reservoirs, considerable oil will be left behind due to relatively high residual saturations. This residual oil may be a target for high pressure gas injection.

The recovery mechanisms involved in high pressure gas injections in fractured reservoirs are complex and not fully understood. They include viscous displacement, gas gravity drainage, diffusion, swelling and vaporization/stripping of the oil. Interfacial tension gradients caused by diffusion may also play an important role on the overall recovery. Viscous displacement normally plays a minor role, except perhaps in the near vicinity of the wells where the pressure gradients are large.

Contrary to conventional reservoirs, diffusion may play an important role in fractured reservoirs. The injection gas has a tendency to flow in the fractured system, resulting in relatively large composition gradients between fracture gas and matrix hydrocarbon fluids. Thus, there is a potential for transport by molecular diffusion. This is especially the case in reservoirs with a high degree of fracturing (small matrix block sizes). Diffusion is difficult to model correctly in a simulator. The diffusion flux for a given phase is often modelled as

$$J_{ip} = T_d(\phi S_{cp}) D_{ip}\, \Delta C_{ip},$$

where T_d is the diffusion transmissibility, D_{ip} is the effective diffusion coefficients, and the product ϕS_{cp} represents the fraction of the gridblock interface where diffusion takes place. The saturation term, S_{cp}, is normally chosen as the minimum saturation of the adjacent grid blocks. Using this formalism, a problem arises when gas is injected in an undersaturated reservoir. The minimum contact saturation, S_{cp}, between the fracture and matrix grid block will be zero, and no diffusion between the two media will be calculated. With matrix block heights lower than the capillary entry height, no mass transfer between fracture and matrix systems will occur. In some simulators this problem is circumvented by choosing S_{cp} as the maximum saturation between neighbouring grid blocks or by introducing gas-liquid diffusion. This does not give a physically correct description of a diffusion process in general, and is therefore not recommended.

Physically, the mechanism for gas entering from the fracture to an undersaturated oil would require an ultra-thin contact zone at the fracture/matrix interface. In this zone a small amount of equilibrium gas will exist, and diffusion transfer between fracture and matrix can occur via this zone, as *gas-gas* diffusion between fracture gas and equilibrium gas in the two-phase zone, and as *liquid-liquid* diffusion between undersaturated matrix oil and saturated oil in contact zone.

Fig. 8 shows the system layout of an experiment performed at Reslab by Øyno and Whitson,[46] where methane was injected around cores filled with a highly undersaturated oil. The cores were initially filled with Ekofisk oil, and methane gas was then injected into the annulus system.

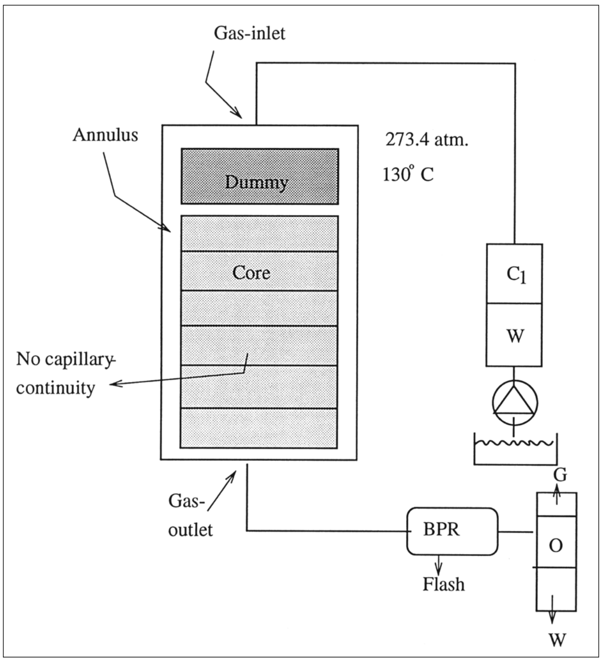

Fig. 8 Laboratory setup (from Øyno and Whitson[46])

The experiment was simulated using a fully implicit compositional simulator (SSI's COMP4 model) that accounts for both molecular diffusion and dynamic IFT-scaled capillary pressure. The effective matrix block height of the laboratory system was lower than the capillary entry pressure, so without any modifications to the system set-up, no oil production could be observed in the simulations. When a thin (1 mm) two phase zone was introduced (Fig. 9), mass transfer by diffusion could take place. Fig. 10 shows the experimental results and the simulated best-fit using a thin two-phase zone.

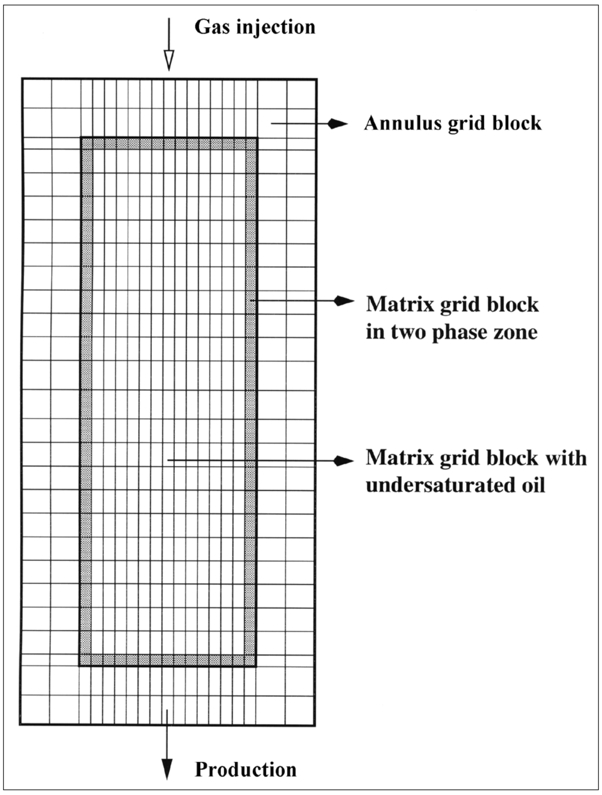

Fig. 9 Grid system used for modelling of laboratory experiment (from Øyno et al.[49])

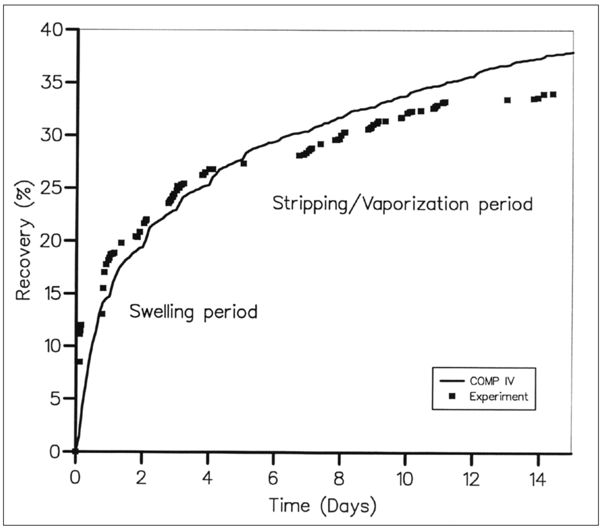

Fig. 10 Experimental and modelled oil recovery vs. time (from Øyno et al.[49])

The simulated results indicate that the recovery can roughly be divided into three production stages

1. primary swelling of the oil
2. secondary swelling and vaporization
3. final vaporization of the oil.

The initial stage is dominated by swelling of the oil inside the core, due to *liquid-liquid* diffusion between the undersaturated oil inside the core and the saturated oil at the outer surface of the core. The light components of the oil (mostly methane), diffuse into the core, while the intermediate oil components from the core diffuse to the outer contact zone. During this stage there is some viscous flow from the center of the core to the fracture, due to swelling of the oil and interfacial tension gradients. The oil produced to the fractures is vaporized by the injection gas, and no free oil is observed.

The first stage ended when some of the oil within the core first became saturated. This marks the beginning of the second stage, where a free gas saturation advances toward the center of the core. As the gas front advances, the *gas-gas* diffusion will play a more dominant role on the recovery process. During this stage, mainly light-intermediate, and the intermediate components of the oil are vaporised.

When the light-intermediate and most of the intermediate components have been recovered, the third stage begins. During the last stage, mostly heavy-intermediate and heavy components are vaporized. This stage is slow compared to the first two stages, but a large additional recovery may be achieved.

It is worth noticing that there was no significant IFT reduction during production and therefore a

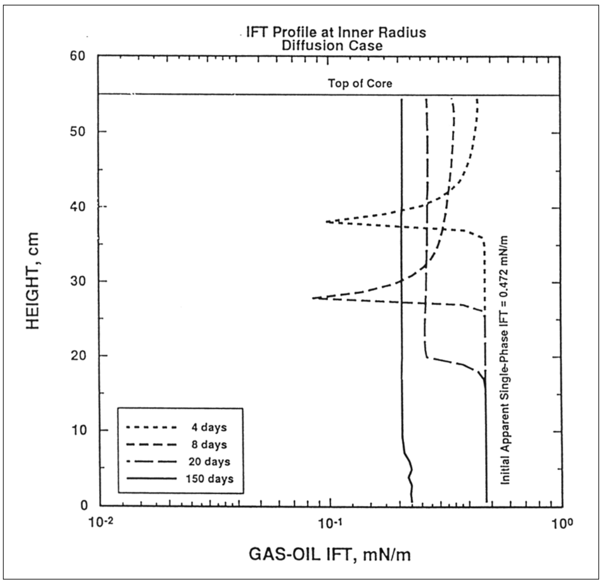

Fig. 11 IFT profile at core center as function of time - with diffusion (from Øyno et al.[49])

negligible production by gravity drainage. The IFT changes due to diffusion may in other cases have a drastic effect on the recovery.[47-48] Fig. 11 shows the interfacial tension profile in a core after high pressure gas injection around a core filled with recombined reservoir oil.[49]

In this experiment the frontal IFT is reduced drastically as gas advances down the core. Compositional changes due to gas diffusion cause the IFT behind the gas front to increase again. The resulting IFT gradient is so strong that oil is sucked upward against gravity, resulting in the somewhat strange saturation profile given in Fig. 12.

If diffusion and IFT scaling of capillary pressure are not included in the simulator, these IFT effects will not be accounted for. Fig. 13 shows the saturation profile for the same experiment when diffu-

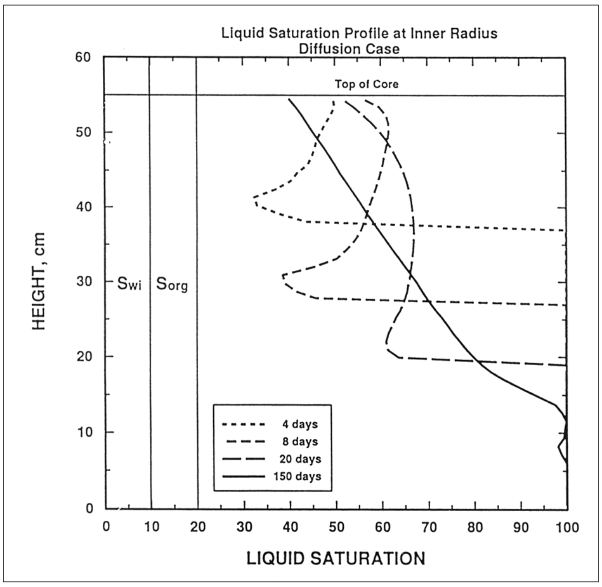

Fig. 12 Saturation profile at core center as function of time - with diffusion (from Øyno et al.[49])

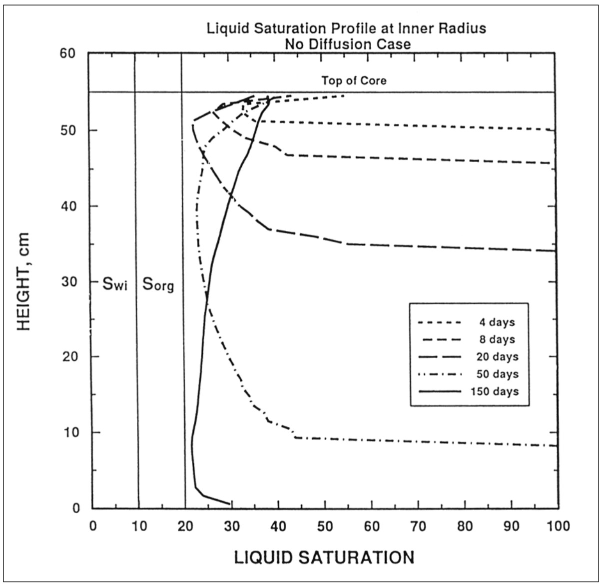

Fig. 13 Saturation profile at core center as function of time - no diffusion (from Øyno et al.[49])

sion is not included. The IFT gradients are not so pronounced as in the diffusion case, and therefore not strong enough for the oil to imbibe upwards. This results in a smaller oil saturation behind the advancing *gas-oil* front, see Fig. 14.

It was observed that the IFT at the gas front for some cases (mainly depending upon initial gas-oil ratio), were almost vanishing. This resulted in almost 100 % recovery by gravity drainage. We feel that the dynamic composition variations, and the influence on IFT's, are important issues that need to be addressed in more detail.

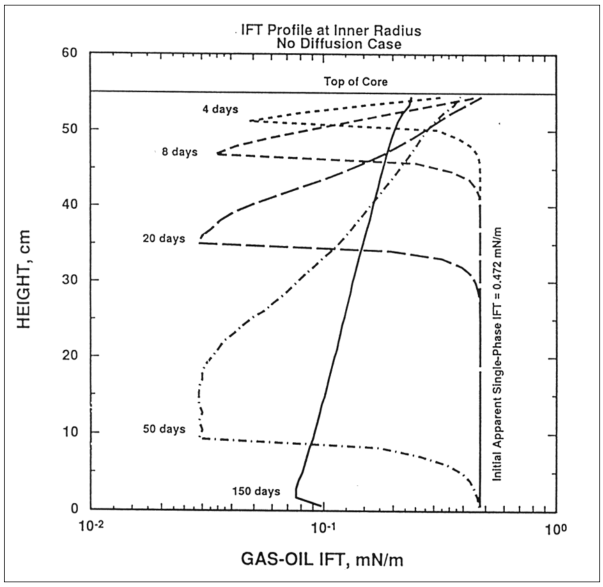

Fig. 14 IFT profile at core center as function of time - no diffusion (from Øyno et al.[49])

Mathematical Model Development

Current state of the art has been reviewed by Fung.[15] Current models are insufficient for proper modelling of most fluid exchange processes between matrix blocks and fractures. In North Sea fractured reservoirs, matrix blocks sizes are typically much less than 1 m^3. Thus, a normal grid block employed in reservoir simulations would contain several tens of thousands of matrix blocks. Obviously, some form of detailed description of the flow processes must be included in the models.

The dual-porosity and the dual-porosity/dual-permeability formulations are the most common approaches used to represent a large number of individual matrix blocks in larger computational blocks. In these models, the processes of water/oil imbibition and gas/oil drainage have caused particular difficulties. Attempts to represent correct behavior by modifications of the gravity term or by use of capillary pressure pseudofunctions have generally not been successful. Others have refined the matrix blocks into multiple blocks.

Fig. 15 presents the *multiple grid concept* for improving the fractured reservoir simulation. The upper grid system represents the coarse grid normally used in dual-porosity simulators. Inside each grid block, a large number of individual matrix blocks exist. It is, of course, not possible to do individual computation on each matrix block. However, assuming that the large scale grid blocks are chosen so that all the matrix blocks inside exhibit similar behavior (for practical purposes), we may do individual computation on one representative matrix block inside each large grid block, and multiply the results with the number of grid blocks present. In principle, as previously suggested, a distribution of different matrix block geometries could be included in the matrix block descriptions, so that individual computations are conducted on a number of block groups. The matrix block would be locally gridded in 1, 2 or 3 dimensions, depending on the situation, and the behavior simulated using local time steps for fixed boundary conditions during each large time step of the coarse model. This system would be well suited for parallel computing using massive parallel computers.

Fig. 16 presents another improvement suggested for improvement of the fluid flow representation in dual-porosity models. It is proposed that the conventional Warren and Root model with discontinuous matrix blocks is replaced by a model where all matrix blocks have capillary contact

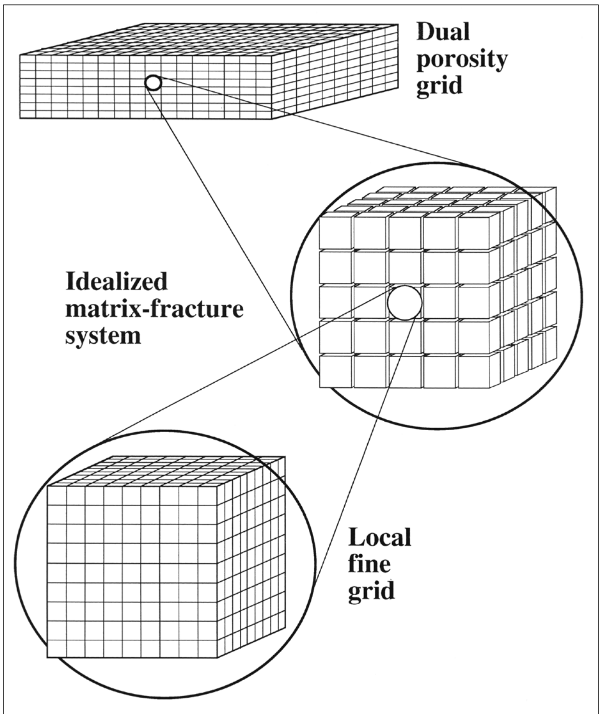

Fig. 15 Multiple grid concept for fractured reservoir simulation

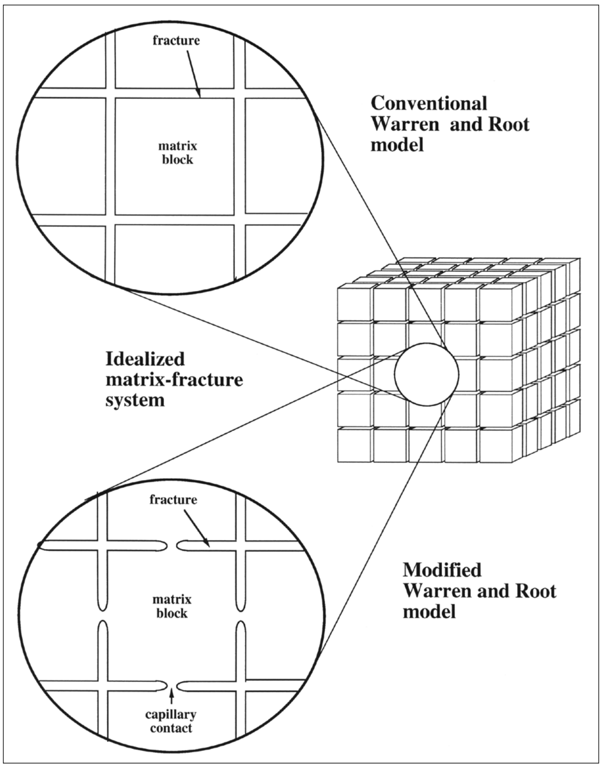

Fig. 16 Improved Warren and Root model

with adjacent blocks. This is of particular importance in the vertical direction.

The method has so far been developed and tested for single and two phase flow[50-52] and is currently being extended to a three phase model. The fine grid calculations together with the iterations between the two grid systems require substantially more computing time. However, the method is well suited for parallelization, since each inner block solutions can be computed separately once the boundary conditions from the coarse grid are given. So far, the computational speed has been improved by a factor of 10 by vectorization and parallelization (Fig. 17).

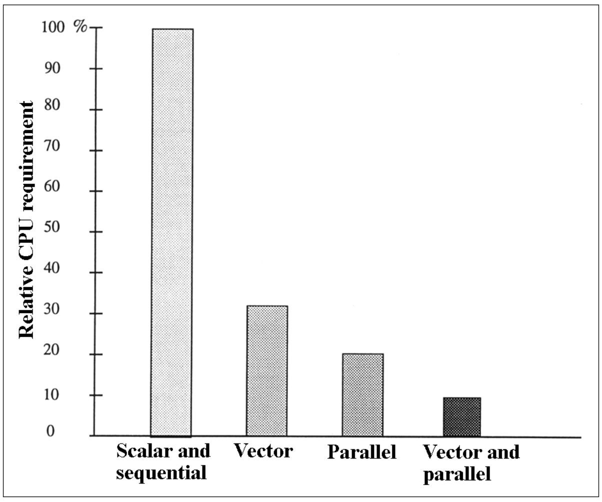

Fig. 17 Computational speed improvements by vectorization and parallelization.

Conclusions

1. Based on a systematic study of physical mechanisms and parameters affecting flow in fractured reservoirs, it is concluded that all major flow mechanisms and flow processes must be incorporated in a model for fractured reservoirs. These include gravity, capillary forces, gravity drainage, diffusion, capillary continuity, and reinfiltration.
2. The key to improved modelling of fractured reservoirs is to include sufficient detail in the calculation so that all these flow mechanism are represented. A multiple grid concept for this purpose is recommended.
3. Simulation studies of water flooding of fractured reservoirs show that capillary continuity between matrix blocks is of high importance for mixed wetted systems.
4. High pressure gas injection may yield high oil recoveries due to reduction in interfacial tension caused by diffusion.
5. Literature review shows that current models based on the dual-porosity, dual-permeability concept using simple fluid transfer terms between fractures and matrix blocks, are not sufficiently accurate or representative in most cases.

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