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Recovery Mechanisms in Fractured Reservoirs and Field Performance

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Abstract

Fractured petroleum reservoirs provide considerable challenge in studying natural depletion, immiscible gas injection, miscible gas injection, and water injection. In this overview, certain key aspects of two-phase flow in relation to gas injection and water injection in fractured reservoirs are reviewed. One main conclusion from the review is that the field performance can be very efficient by water injection in some weakly water-wet fractured reservoirs despite the poor recovery in the laboratory by the conventional imbibition tests.

Introduction

Fractured hydrocarbon reservoirs provide over 20% of the world oil reserves and production. Examples of the prolific fractured petroleum reservoirs are: 1) the Asmari limestone reservoirs in Iran, 2) the vugular carbonate reservoirs in Mexico, and 3) the group of chalk reservoirs of the North Sea. These prolific reservoirs produce more than five million barrels of oil a day; their common feature is a long life span, which could last several decades. There are a large number of other fractured hydrocarbon reservoirs that may have features very different from the above reservoirs. Examples of such reservoirs are the Austin chalk field and the Keystone (Ellenberger) field in Texas, and the Tempa Rossa field in Italy. In the Keystone field, the average matrix porosity is around 2.5%; the Austin chalk and Tempa Rossa also have very low porosity. On the other hand, the average matrix porosity of the Ekofisk chalk field in the North Sea is around 35%.

Fractured reservoirs can be classified into three different groups. For group one, the bulk of the hydrocarbon resides in the matrix and fracture pore volume (PV) is very small in comparison to the matrix PV. The Ekofisk field in the North Sea is an example of this group[1]. In group two, most of the hydrocarbon is in the matrix, but fracture PV could be as high as 10 to 20%. The Asmari limestone reservoirs are an example of the second group[2]. For group three, more than half of the hydrocarbon resides in the fracture; in some cases, the contribution of the matrix can be negligible. The Keystone (Ellenberger) field in Texas is an example of a fractured reservoir where most of the hydrocarbon is from the fractures[3]. There are very few reports of the production performance of group three in the literature. For all three groups, the matrix permeability is often low—of the order of several md to less than 0.01 md. The effective permeability due to fractures increases from one to several orders of magnitude. In some of the reservoirs of group three, the productive life varies from less than one year to several years. The ultimate recovery from fractured reservoirs varies widely—from less than 10% to over 60%. The recovery factor in group three could vary from 10% to over 60%; the recovery factor of 10% is mostly from the fracture and rock compressibility, and the recovery of 60% is mainly from gravity drainage. Later we will study the key factors that affect recovery performance of fractured reservoirs.

There are fundamental differences between recovery performance of fractured and unfractured reservoirs. Capillarity is the main cause of this difference. More specifically, the difference in capillary pressure of matrix and fractures has a significant effect on recovery performance of fractured reservoirs.

In the following, gas displacement and water displacement processes in fractured porous media and a brief description of compressibility effect are presented.

Gas-Oil Displacement in Fractured Media

Gas-oil immiscible displacement in the form of gas-oil gravity drainage could contribute to substantial recovery in fractured reservoirs. Two mechanisms affect the efficiency of gas-oil gravity drainage: 1) reinfiltration, and 2) capillary continuity. Reinfiltration may direct the path of oil flow to be primarily in the tight matrix, not through the high permeability fractures. Capillary continuity between the matrix blocks may improve the final recovery drastically. However, due to the contrast in matrix and fracture capillary pressure, the rate of drainage in fractured porous media can be substantially less than in a homogeneous tight matrix. Next we discuss reinfiltration in fractured porous media and then gravity drainage in layered and fractured media to elucidate these two mechanisms.

Reinfiltration in Fractured Porous Media

The rate of oil flow in a one-dimensional matrix block in the vertical direction is given by[4]

$$q = \frac{kk_{ro}}{\mu_o}\left[\Delta\rho g - \frac{dP_c}{dS_o}\frac{dS_o}{dz}\right] \quad \text{......(1)}$$

where $\Delta\rho$ is the density difference between the oil and gas phases, P_c is the gas-oil capillary pressure, S_o is the oil saturation, z is the vertical distance (positive upwards), k and k_{ro} are the absolute permeability and oil relative permeability, respectively, μ_o is the oil viscosity, and q is the rate of oil drainage or infiltration and is assumed to be positive in the downward direction. This equation gives the rate of drainage at the bottom face (z = 0) and the rate of reinfiltration of oil at the top face (z = L) of a matrix block. The term dS_o/dz could be positive, zero, or negative. The term dP_c/dS_o is never positive. At z = 0, when the matrix is fully saturated, $dS_o/dz = 0$, and the initial rate is:

$$q\big|_{z=0} = \frac{kk_{ro}}{\mu_o}\Delta\rho g \quad \text{......(2)}$$

As the matrix block desaturates

$$dS_o / dz\big|_{z=0} < 0$$

and the rate of drainage decreases. Therefore, the rate of drainage from the bottom face of the matrix block is always,

$$q\big|_{z=0} \le \frac{kk_{ro}}{\mu_o}\Delta\rho g \quad \text{......(3)}$$

From the top face of the matrix block at z = L, the rate of oil reinfiltration can be computed using Equation (1). If enough liquid is provided, $S_o\big|_{z=L} = 1$ and $dS_o / dz\big|_{z=0} > 0$, and therefore,

$$q\big|_{z=0} \ge \frac{kk_{ro}}{\mu_o}\Delta\rho g \quad \text{......(4)}$$

The implication of the relationships given by Equations (3) and (4) is that as the matrix desaturates, the rate of reinfiltration is higher than the rate of drainage and, therefore, oil flows through the matrix. The above results are in the context of gas and oil flow far away from the wellbore where viscous effects are not pronounced.

Note that reinfiltration applies to gas-oil systems but not to water-oil systems (when water is the wetting-phase). When oil is the wetting-phase in a water-oil system, then the oil in fractures could reinfiltrate back into matrix rock. For the weakly water-wetting in oil-water flow, the rate of reinfiltration of the produced oil from a matrix block to the neighboring matrix blocks may not be significant.

Gas-Oil Gravity Drainage in Layered and Fractured Media

Let us consider two sand columns each of 18 m height. One sand column is homogeneous and has a permeability of 750 md. The other sand column is layered with alternate layers of 750 md and 7,500 md. The height of each layer in the layered column is 1.8 m. The geometric average permeability of the layered column is about 2,200 md—about three times the homogeneous column. The porosity and residual oil saturations of the less permeable sand and the more permeable sand are assumed the same [see theory and details in Firoozabadi[5] and Correa and Firoozabadi[6]].

Figure 1 shows the drainage rate and the cumulative production of the two columns. Note that the less permeable sand column has a better recovery efficiency than the more permeable layered-sand column. The main reason for the difference in recoveries is due to the capillary pressure contrast between the two layers. From the drainage rate results (see Figure 1), one may confidently conclude that there is no meaning to an average capillary pressure for a layered system when there is a contrast in capillary pressures. One may not also provide scale up for such a drainage problem.

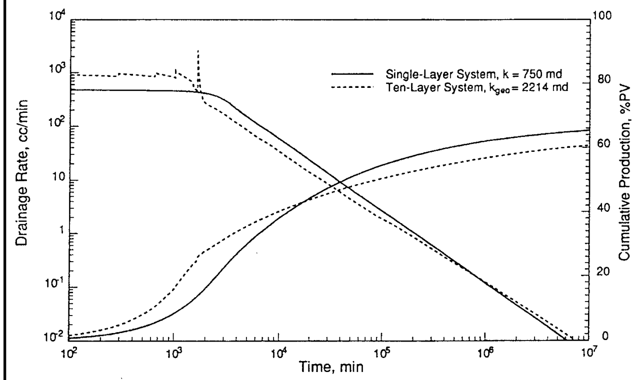

FIGURE 1: Gas-oil gravity drainage in a homogenous and in a layered column (adapted from Reference 6).

Let us now consider the drainage performance of a 1.8 m long homogenous Berea sandstone with a cross sectional area of 220.5 cm^2. After measuring the drainage performance of this tall block, it was cut into three equal pieces of 0.60 m height each[7]. These blocks were stacked on top of each other. Four metallic spacers of 100 micron thickness and areal dimensions of 2 $\times$ 2 cm were inserted in the space between the matrix blocks. The insertion of spacers ensures uniform fracture aperture between the matrix blocks. The drainage performance of the three-block stack was also measured. Figure 2 shows the drainage performance of the tall block and the three-stacked blocks. There is a significant difference between the two recovery curves. While the permeability of the stacked block system is more than the permeability of the tall block, the capillary pressure contrast between the fracture and the matrix media affects the recovery in favour of the less permeable tall block. Figure 3 shows the fracture and matrix capillary pressures that were used to simulate the drainage results shown in Figure 2 [see Reference (8)].

The two examples above reveal that the capillary pressure contrast between the two media next to each other has a pronounced adverse effect on recovery performance by gas-oil gravity drainage. When the two capillary pressures become identical, the gas-oil gravity drainage recovery performance improves significantly. One may reduce capillary pressure contrast by reducing the interfacial tension between the gas and oil phases through miscible displacement. Miscible displacement in fractured porous media can be a viable option for improved oil recovery. It will be discussed briefly next.

Miscible Displacement in Fractured Porous Media

The common understanding of flow in fracture porous media is

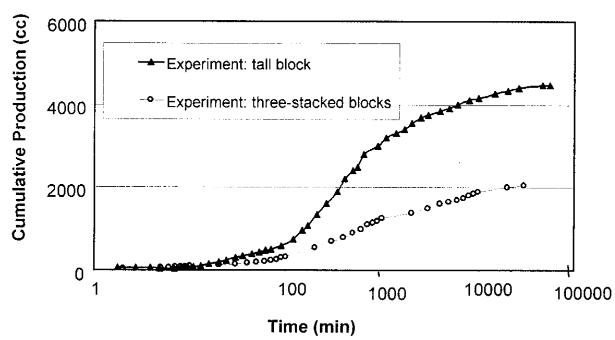

FIGURE 2: Gas-oil gravity from a tall block, and a stacked-block system (adapted from Reference 7).

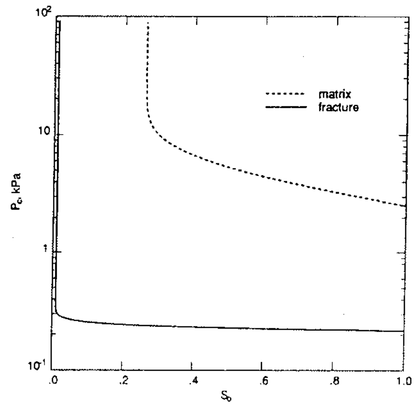

FIGURE 3: Matrix and fracture drainage capillary pressures (Reference 8).

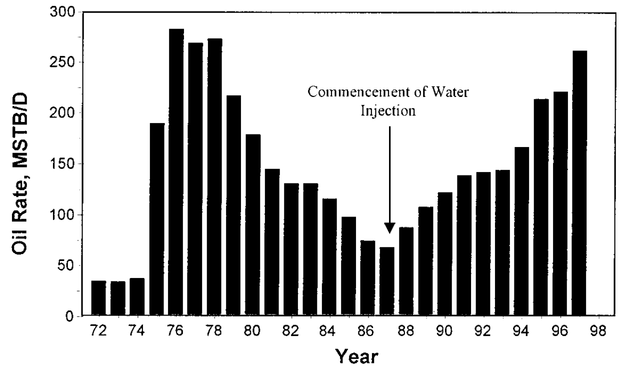

FIGURE 4: Ekofisk Field oil production rates and the response to water injection (adapted from Reference 1).

that fractures provide the oil flow path and the matrix provides the storage. This understanding is true in 1) single phase flow, 2) water-wet fractured media for water displacement of oil, and 3) flow around the wellbore with high viscous forces. As we have seen above, it may not be valid for gas-oil gravity drainage. When miscible injection in fractured porous media is considered, we need also to modify our thinking. In general, there are various crossflows between a less permeable and a more permeable medium due to capillary, gravity, and viscous forces or due to diffusion. Both experimental data and theoretical analysis[9 – 11] show that in a miscible injection process, the injected fluids do not flow through the high permeability fractures. There is strong gravity and viscous crossflows between fractures and matrix. As a result, miscible gas injection in fractured porous media can be very efficient. State of the art in dual-permeability modelling does not currently allow to account for some of the basic crossflows in miscible gas injection in fractured reservoirs.

Water Displacement in Fractured Media

Water injection has been very efficient in some fractured reservoirs. However, the general thinking in the literature centres around the idea that water injection in fractured reservoirs is mainly efficient for water-wet conditions. On the basis of this belief, laboratory experiments are conducted by immersing an oil-saturated core plug into water to study the imbibition recovery. The immersion forces the imbibition to be countercurrent. In the past, when the countercurrent imbibition tests in the laboratory gave poor recovery, water injection was assumed to be inefficient. As we will demonstrate soon, one can measure very poor recovery by countercurrent imbibition testing in the laboratory, but in the field, water injection may be very efficient. In other words, there may be no relation between laboratory measurements of spontaneous imbibition and field performance, even when the reservoir wettability state is perfectly restored in the laboratory. Hermansen et al.[1] have reviewed water injection performance of the Ekofisk fractured field in the North Sea. The field data show that the water-injection performance in Ekofisk is independent of its wettability state. Figure 4 shows the oil production rate in Ekofisk from 1972 to 1997. Water injection in the field commenced in 1987. Figure 4 shows the dramatic increase (from 70,000 BOPD in 1987 to 260,000 BOPD in 1997) in rate after water injection commencement. In the upper formation (where the reservoir is less water-wet) in situ saturation measurements showed that recoveries were better than laboratory measured values. Field data show that in this fractured field there has been limited water breakthrough even after ten years of waterflood operation.

Now we discuss water injection in both water-wet and weakly water-wet (that is, intermediate-wet) fractured porous media.

The fracture network does not become flooded at once from water injection; the water-oil level in the fractures has an advancing behaviour. Therefore, imbibition in a water-wet matrix block of a fractured medium may not be only due to countercurrent imbibition. When a water-wet matrix block is partially covered by water, oil recovery can be either mostly by cocurrent imbibition or by both countercurrent and cocurrent imbibition.

Pooladi-Darvish and Firoozabadi[12] have shown that the scaling of countercurrent imbibition, which is often used to evaluate water injection in water-wet fractured reservoirs may lead to pessimistic recovery performance. In countercurrent imbibition, the oil flow path is in two-phase; in cocurrent imbibition, the flow path for oil is mainly in single-phase, which can be very efficient. Figure 5 shows the recovery performance of a single matrix block from water injection from the bottom, and immersion in water[13]. A single block of an outcrop chalk ($k \approx 1.5$ md, $\phi \approx 30\%$) was placed in a visual coreholder and was surrounded by top, bottom, and side fractures. Figure 5 shows that the initial rate of imbibition for the immersion tests is high. This is due to large contact area between the matrix block and the fracture water. Later on, however, production rate for injection tests is higher than the immersion tests. The immersion forces countercurrent imbibition, whereas injection gives the matrix a choice for cocurrent or countercurrent depending on rate of injection. Figure 6 presents the fine grid simulation results of water injection from the bottom of the matrix surrounded by fractures. The height at zero is the bottom and top of the block is at 30 cm. The water saturation in the fracture at 0.1 and 0.3 PV injection and the corresponding oil flux from the matrix to the fracture, and the water flux from the fracture to the matrix

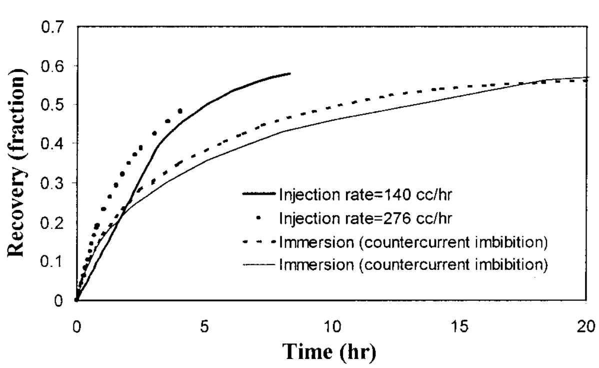

FIGURE 5: Recovery Performance of a Water-Wet Chalk Matrix Block (*k*=1.5md, ϕ = 30%) to water injection and to immersion (adapted from Reference 13).

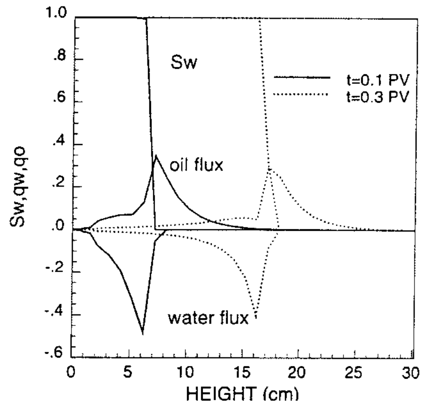

FIGURE 6: Fracture water saturation, and water and oil fluxes from fine-grid simulation(14).

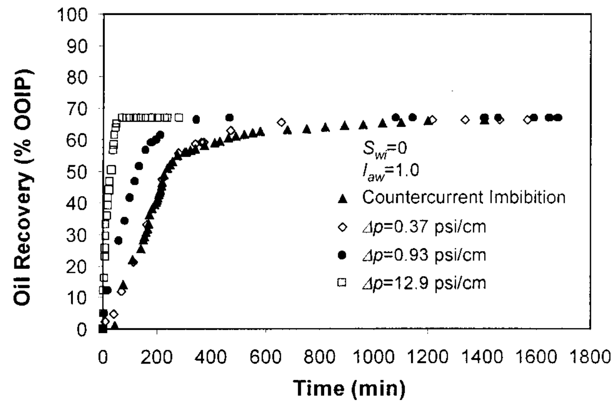

FIGURE 7: Effect of Pressure Gradient on Oil Recovery from the Chalk Sample (*k*=1.3m d, ϕ = 30%): Water-Wet (I_{aw}=1.0) (adapted from Reference 15).

show that most of the oil is produced by cocurrent imbibition (the rates in the Figure 6 are dimensionless). In other words, the oil is produced mainly above the water-oil contact in the fracture and water imbibes below the water-oil contact(14).

Figure 7 shows the effect of pressure gradient across a rock sample on oil recovery in a water-wet tight rock plug(15) (k = 1.3 md, ϕ ≈ 30%, L ≈ 6 cm, d = 5.1 cm). This figure also shows the recovery performance from countercurrent imbibition for the same rock. Note that the final oil recovery is around 68% and is independent of the pressure gradient. The recovery from countercurrent imbibition is also 68%. In the countercurrent imbibition test, the oil-saturated rock is immersed in water. In the coreflooding tests, the core was sealed across the circumference and water was injected at a constant pressure. The outlet was at atmospheric pressure.

Figure 8 plots the recovery performance of the weakly water-wet core (with the same permeability, porosity, and dimensions and similar to the core plug of Figure 7). The Amott wettability index to water(16) is 0.09. Figure 8 also shows the recovery performance of the water-wet rock as a reference when it is subjected to countercurrent imbibition. For the countercurrent imbibition test in the weakly water-wet rock, there is no water imbibition to a time of about six days. The period in which the rate of imbibition is zero at the beginning is called the induction time, which is a common feature in a nucleation phenomena(17). Even when the imbibition begins, the rate is low. The final recovery is only about 5%. In the flooding test, the recovery increases with the increase of pressure gradient. At a pressure gradient of 0.96 psi/cm, the induction time is about 14 days and the final recovery is about 11%. As the pressure gradient increases, the recovery performance improves. At pressure gradients of 3.85 and 13.5 psi/cm, the final recoveries are about 50% and 78%, respectively. Note that the final recovery for the countercurrent imbibition of the water-wet rock is about 68%.

Figure 9 shows the estimated capillary pressures for the water-wet (I_{aw} = 1.0) and the weakly water-wet (I_{aw} = 0.09) rocks. Only the negative capillary pressures are estimated; the final recovery and pressure data from the corefloodings were used to estimate the capillary pressure, which is defined from $P_c = p_0 - p_w$. Note that at P_c = 0, the water saturations are five and 65% for the weakly water-wet and water-wet cores, respectively. These saturations are consistent with the countercurrent imbibition tests in Figure 7. Note that there is no extra recovery for the water-wet rock at high negative capillary pressures. On the other hand, there is a major increase in oil recovery for the weakly water-wet rock as capillary pressure decreases. The contribution for the negative side of the capillary pressure curve to recovery is often called forced imbibition; the recovery from the positive side is called spontaneous imbibition.

Fracture-Matrix-Fluid Compressibility

Knowledge of formation compressibility can be very important when a highly undersaturated oil in a fractured reservoir is considered. The total compressibility becomes critical when gas and water injection options are not available. Suppose we neglect the pore compressibility, and the fluid compressibility is $+6 \times 10^{-6}$ 1/psia; then the recovery from 4,000 psi pressure drop would be 2.4%. However if the combined fracture/matrix pore compressibility is $c_f = +2 \times 10^{-5}$ 1/psia, then the recovery would be 10.4%, which is substantial. High compressibility allows economical depletion of fractured reservoirs of group three (with no matrix porosity) where there is no active aquifer and there is a substantial oil undersaturation (say 4,000 to 5,000 psi).

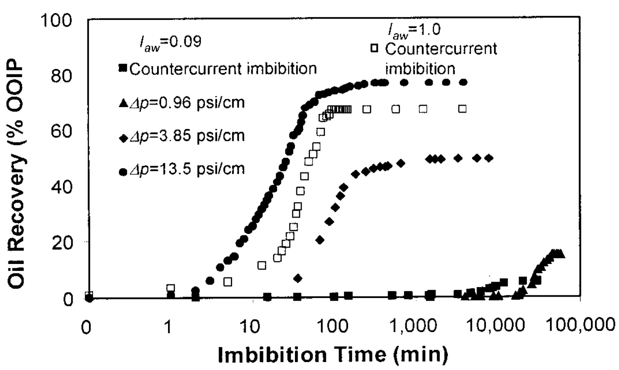

FIGURE 8: Effect of Pressure Gradient on Oil Recovery from the Chalk Sample (*k*=1.3m d, ϕ ∪ 30%): Water-Wet (I_{aw}=1.0) and Weakly Water-Wet (I_{aw}=0.09) (adapted from Reference 15).

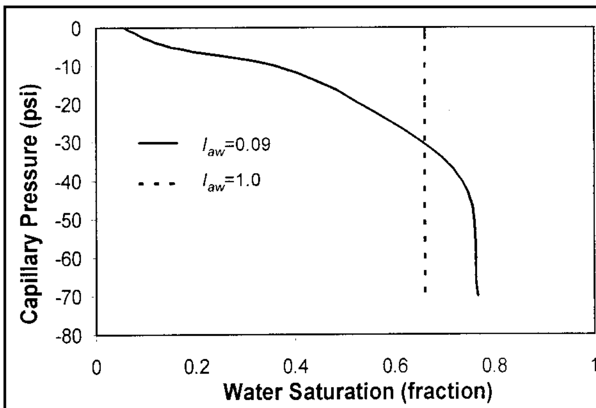

FIGURE 9: Estimated Negative Capillary Pressure Curves for Water-Wet (I_{aw}=1.0) and Weakly Water-Wet (I_{aw} = 0.09) Chalk Sample (*k*=1.3md) (adapted from Reference 15).

Discussion and Concluding Remarks

Fractured petroleum reservoirs are currently characterized by two main models. In the so-called sugar-cube model, all the fractures are connected and the size of the matrix blocks surrounded by fractures is an important parameter. Dual-porosity models are extensively used to simulate various production schemes from such characterization [Gilman and Kazemi(18), and Thomas et al.(19)]. In the discrete fracture model, the connectivity of fractures are realistically described. Efforts towards the use of discrete-fracture representation of fractured reservoirs in multiphase flow has begun(20). In each of these two models it is a challenge to include various mechanisms of water and gas displacement. Nevertheless, as the understanding of physical processes improves, we use the improved physical understanding of flow processes either directly or indirectly in appropriate models for the characterization of fractured reservoirs. It seems that the combination of laboratory research and interpretation of field performance is our best course of action for efficient production from fractured reservoirs.

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NOMENCLATURE

cf	=	formation compressibility
d	=	core diameter
g	=	acceleration due to gravity
I_{aw}	=	Amott wettability index to water
k	=	permeability
k_{ro}	=	oil relative permeability
L	=	core length
p	=	pressure
P_c	=	capillary pressure
p_o	=	oil phase pressure
p_w	=	water phase pressure
q	=	oil flow rate
S_o	=	oil saturation
z	=	height
$\Delta\rho$	=	gas-oil density difference
μ_o	=	oil viscosity

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