

Technical Note prepared by Beicip-Franlab/IFP

Principles of Athos dual medium reservoir simulation

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The successful management of an asset depends often on the ability to properly simulate the production mechanisms occurring on a fractured reservoir. In fact most of the oil companies conduct numerical simulation studies to predict the future reservoir performance. If the production mechanisms are not properly represented in the numerical simulation model then the prediction runs can be based on wrong History Matching parameters which reduces the accuracy of these prediction runs.

The principles of the IFP Group ATHOS reservoir simulator approach for fractured reservoir simulation are described in this document. Beicip-Franlab believes that the ATHOS formulation is the most advanced in the market and represents better the production mechanisms occurring in a fractured reservoir.

ATHOS is a multipurpose numerical simulation software with manuals in English, Russian and Spanish.

We also include in this note the replies we provided to some of our clients concerning the way Athos represents and simulates fractured reservoirs.

Another very important aspect in simulating fractured reservoirs is the ability to properly describe the fracture network (block dimensions, fracture density, fracture properties) to input in the numerical model. Beicip-Franlab uses their propriety software, FRACA, which is able to model the fracture network by taking into account the dynamic data available (well tests, mud losses, core descriptions, Log responses, etc.).

It is therefore crucial to consider these two aspects, the fracture characterisation (Frac) and the fracture simulation (Athos), for which Beicip-Franlab has developed state of the art software.

1 INTRODUCTION : GENERAL PRINCIPLES

The method for dual porosity simulation has been developed in the early 90s and has continuously been improved through IFP research programs and field studies.

The key points of this approach are the following:

- a) It is based on the dual-porosity dual-permeability concept with major evolutions and improvements, as described hereafter.
- b) A fractured cell is represented as a Warren & Root “sugar cube” model (Fig. 1). The input parameters for such a cell are fracture permeability, fracture porosity and matrix block sizes (a, b, c). The IFP Group has developed a dedicated software (Frac) to properly characterize these parameters from Discrete Fracture Network Models. Shape factors can be deduced from a, b and c but are not used as such in the formulation.

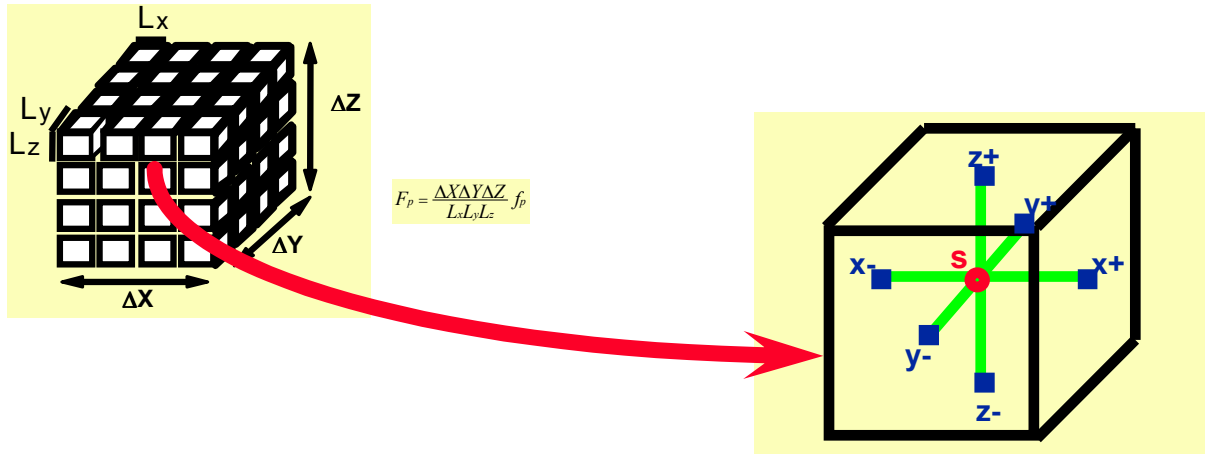


Fig. 1: Representation of a fractured reservoir cell

Based on the Warren & Root geometrical representation, matrix-fracture fluxes (f_p) are computed independently for:

Each phase (oil, water, gas)

Each face of the matrix block (X+, X-, Y+, Y-, Z+, Z-)

Each mechanism: expansion, capillarity, gravity, viscosity, as follows:

$$f_p = - \sum_{i=1}^6 \frac{k_i k_{rp}}{\mu_p} (\Phi_{ip}^f - \Phi_{sp}^m) \frac{2A_i}{L_i}$$

$$\begin{aligned} \Phi_{ip}^f - \Phi_{sp}^m = & (p_{so}^f - p_{so}^m) && \text{Expansion} \\ & + \alpha_c (P_{cp}^f - P_{cp}^m) && \text{Capillarity} \\ & + \alpha_g (\rho_p^m - \rho^{f*}) g (z_i - z_s) && \text{Gravity} \\ & + \alpha_v [(\Phi_{ip}^f - \Phi_{sp}^f) - (\rho_p^m - \rho^{f*}) g (z_i - z_s)] && \text{Viscosity} \end{aligned}$$

With f_p : total matrix-fracture flux for phase p (oil, gas, water)

p: index for phase p

i: index of the block face (X-, X+, Y-, Y+, Z-, Z+)

m: stands for matrix

f: stands for fracture

k: matrix permeability

Kr: relative permeability

A_i : surface of the block face i

L_i : distance between face I and the block center

Φ_{ip}^f : potential of face i in phase p in the fracture medium

Φ_{sp}^m : potential in phase p at the center of the matrix block

P: pressure

P_{cp} : capillary pressure of phase p (m and f stand for matrix and fracture)

ρ_p : density of phase p

ρ^{f*} : average fluid density in the fracture system (weighted by saturations)

g: gravity

z: depth

$\alpha_c, \alpha_g, \alpha_v$: scaling coefficients for capillary, gravity and viscosity fluxes

Scaling factors α_c, α_g or α_v represent the effect of change of scale from the size of block (where exchange processes really occur) to size of cells at the centre of which computations are being made). In conventional simulators, these factors are taken equal to 1. In Athos, they are recalculated dynamically in separate subroutines.

Hence, contrary to other dual porosity simulators, there is not a unique shape factor. In Athos, shape factors are automatically deduced from the flow direction (6 directions, 3 block dimensions), the exchange mechanisms and the size of blocks. Moreover, shape factors depend on time.

Recent major improvements were introduced to adjust the shape factors at each time step according to the saturations of the matrix blocks. With these evolutions, both capillary imbibition and gravity drainage processes (as well as any combination of these two processes) are reliably simulated in terms of transient recovery as well as final recovery.

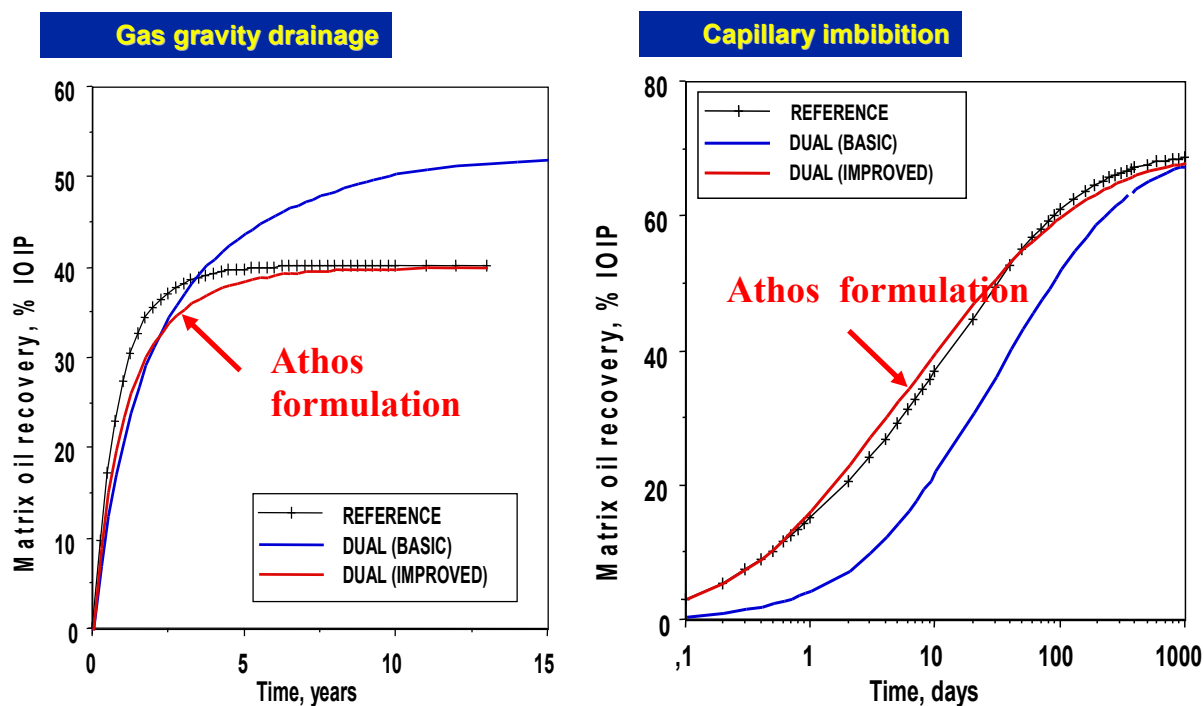
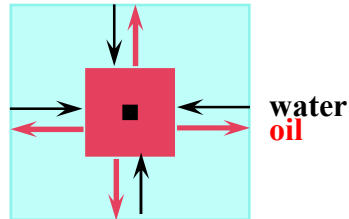


Fig. 2: simulation of gas gravity drainage and capillary imbibition with Athos

For the previous figure, gravity drainage and capillary imbibition processes were simulated with Athos on single matrix block (oil saturated) surrounded respectively by water and gas. Reference solutions have been obtained with very fine simulations using a single porosity model. The “basic” solution represents the “conventional” dual porosity approach. The “improved” solution is the Athos formulation.

To detail the previous point, let us consider the water-oil imbibition process on a 2D single matrix block surrounded with fractures. Initially, oil is present in the matrix and water in the

fractures. During the imbibition process, the water invades the matrix block. The contact surface between oil and water decreases, which affects the imbibition kinetic. Athos considers this effect and consequently changes the imbibition scaling factor (αc) as a function of the water saturation in the matrix block. Athos automatically adjust this scaling factor, in a predictive manner.



For the gravity drainage process, the scaling factor (αg) for the gravity fluxes is also dynamically computed according to the saturations of the matrix block. Athos ensures that the initial kinetic of the gravity drainage process is accurately simulated. In addition, the vertical equilibrium in the matrix block is dynamically computed according to the PC curve, the density of fluids and vertical block size, so that the gravity scaling factor can be reliably adjusted and, moreover, the final recovery from the block is rigorously computed.

As shown in Fig. 2, the Athos formulation (dynamic computation of capillary and gravity scaling factors) has been validated against reference solutions.

Dual permeability option, as well as specific block to block reimbibition functions, is available to address the capillary continuity cases (vertical or horizontal).

To conclude, the Athos formulation is significantly more precise than the classical dual-porosity concept based on the Warren & Root representation with a single shape factor. Moreover, we believe that Athos simulates much better multiphase matrix-fracture exchanges than other commercial simulators, especially for the key recovery processes such as capillary imbibition and gravity drainage.

2 ANSWERS TO CLIENT'S QUESTIONS

The following descriptions summarize our views on the questions and comments received from some of our clients:

2.1 *The use of a single shape factor in most numerical models is a limitation to a proper representation of the block dimensions. Is this the case for ATHOS?*

Shape factors are not input to Athos neither Athos deal with a unique shape factor. In Athos, "shape factors" change with flow directions, with recovery processes and with time, and therefore Athos does not have the drawback mentioned in NIOC remark.

Matrix-fracture fluxes are calculated separately for each phase, each face of the matrix block and each recovery mechanism. Therefore, the role of every dimensions of the matrix block is properly captured by the Athos method.

2.2 *The use of a constant shape factor during reservoir's history, generate problems in correctly calculating different production mechanisms? How is this handled by ATHOS?*

Again, shape factors are not constant in Athos. Recent methods used in Athos enable to adjust automatically the equivalent shape factors according to the history (saturations and processes)

of the grid cell. This ensures a proper kinetic and a proper final recovery (final gravity-capillarity equilibrium) as indicated in Fig. 2.

2.3 The fluid path in the model is different from the actual path in the reservoir. What are your comments?

Since the actual fractured medium is modelled with a simplified representation (Warren & Root), the fluid flow path cannot be the same as the actual one. This remark is not only valid for fractured media but also for any heterogeneous reservoir. In any case, and especially for fractured media, the reliability of the fluid flow simulation depends on the accuracy of the upscaling process. Our approach ensures that computed flow rates from cell to cell and, within cell, from block to block, as well as fluid flow rates from matrix to fracture, are the same as the actual ones. This is the reason why IFP group developed specific and advanced upscaling functions in Fraca software (1997).

The current Fraca-Athos workflow properly addresses this recurrent issue of dual porosity model representativity.

2.4 The vital process of block-to-block is not present in most numerical models. Is it the case for ATHOS?

In Athos, block to block reimbibition process (Fig. 3) is indeed simulated using a specific relative permeability function for fracture to matrix oil fluxes, which controls the block to block reimbibition within a single cell. The user can input the minimum oil saturation in the fracture ($S_{so\ min\ f}$: the end point of the k_r curve) above which the oil enters the matrix.

$$K_{r_o} = K_{r_o\ max}^m \cdot S_o^{f*}$$

$$S_o^{f*} = \frac{S_o - S_{so\ min\ f}}{1 - S_{wi} - S_{so\ min\ f}}$$

with S_o : oil saturation

S_w : water saturation

K_{r_o} : relative permeability to oil

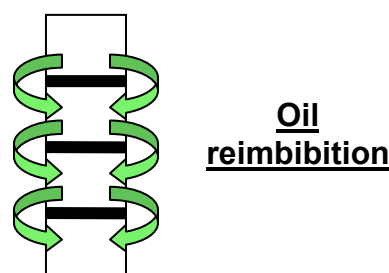


Fig. 3: illustration of block to block reimbibition

2.5 The dual permeability formulation is not far from the dual porosity one. Do you agree?

Beicip-Franlab uses the dual permeability option to simulate capillary continuity from one grid block to another. There are two main situations:

- a) Some reservoir zones are not fractured (areas or layers)
- b) There is vertical capillary continuity because the matrix block height is larger than the layer thickness.

Such situations cannot be handled without the dual permeability option.

2.6 Most dual porosity models cannot handle partial capillary continuity. Is it the case for ATHOS?

This remark refers to the case where matrix blocks are lumped together. The capillary continuity is due to small vertical bridges between blocks (as illustrated in Fig. 4). In terms of kinetic, the gravity drainage process in those blocks is complex. First, all blocks are drained independently, and progressively, the vertical equilibrium converges toward a unique drained matrix column.

It is possible to model “partial capillary continuity” in an adequate manner with Athos, using the dual permeability option and reducing the vertical matrix-matrix transmissivity.

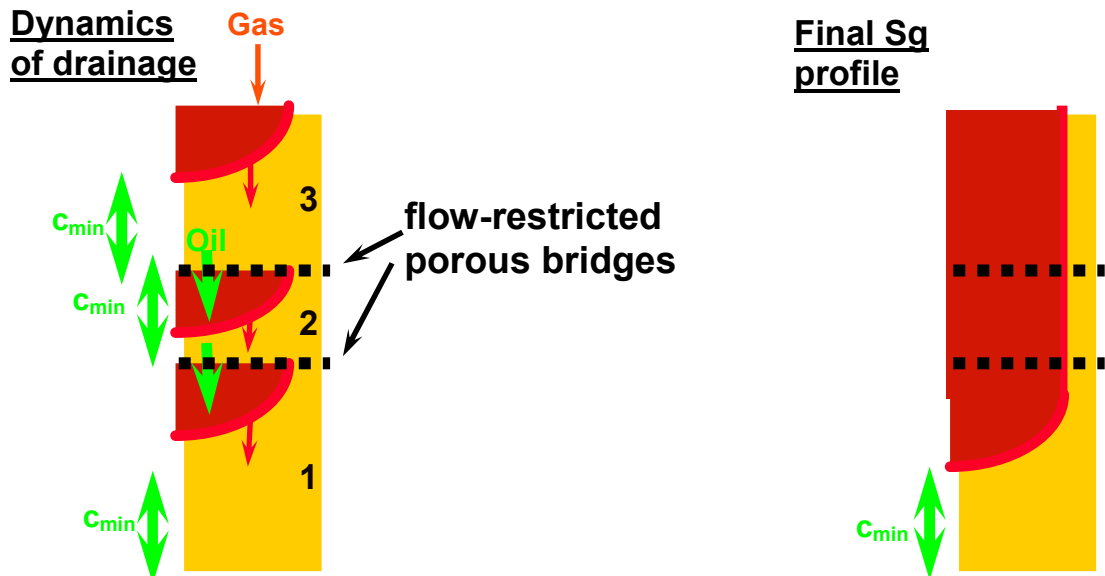


Fig. 4: Gravity drainage with partial capillary continuity

2.7 The vertical equilibrium option does not correctly function in many models. How do you handle it with ATHOS?

A specific method has been developed in Athos to address the gravity/capillary gas-oil (or water-oil) drainage process. It especially focuses on the vertical equilibrium as the latter controls the final recovery from the matrix blocks. Actually, the vertical equilibrium is computed “in advance” from the PC curve, block thickness, density etc... to better control the process.

2.8 How does ATHOS handle the change of interfacial tension?

Athos accurately simulates the change of interfacial tension depending on the local pressure in each cell of the model. It also models the impact of the interfacial tension on the capillary pressure and the relative permeability curves, again in each cell of the reservoir grid.

2.9 The gravity drainage and imbibition processes are not rigorously simulated in many models. Is this the case for ATHOS?

As described in the introduction, recent major improvements were introduced regarding the drainage and imbibition processes. The formulation Athos gives very satisfactory results in terms of kinetics and final recovery for drainage/imbibition process, as demonstrated by comparison of the reference solution and the Athos solution in Fig. 2.

2.10 Most of the commercial dual porosity models have no capabilities of directly calculating thermal convection. What is the situation for ATHOS?

Thermal convection occurs in fracture systems (with high vertical permeability) when the oil density at the bottom of the reservoir is lower than the one at the top. This negative density gradient with depth is causing thermal convection. In Athos, densities are functions of temperatures. Therefore, its formulation allows theoretically simulating thermal convection fluxes. However, for practical reasons, simulating the development of convective cells along fracture zones would require very small time steps and very small cells. It is therefore very difficult to directly simulate convection with numerical simulators whether they are dual porosity or single porosity models.

Alternative solutions can be applied. IFP has acquired experience in using a large diffusion coefficient to mimic the convection effect. By doing so, the effects of thermal convection during production are modelled: the lighter oil components move up rapidly to the gas cap and the oil composition along the column tends to be homogenized. This work was published in SPE paper 59044, “Implementing Convection in a reservoir Simulator: A Key Feature in Adequately Modelling The Exploitation of the Cantarell Complex”, Manceau E. (IFP) & al.

2.11 The fictitious method of calculating thermal convection, by using a very large vertical component of fracture diffusion coefficient, causes numerical dispersion and other problems. Do you agree?

Numerical dispersion is a major drawback for simulating straight saturation fronts (due to water injection, for instance). Physically, thermal convection does not create straight composition fronts but would rather be responsible for natural physical dispersion (the oil composition tends to be homogenized due the convection). Therefore, numerical dispersion is not such a drawback for simulating the effects of thermal convection.

However, using a very large vertical diffusion coefficient makes the numerical problem more complex. It has a similar effect as introducing large heterogeneities in petrophysical properties, like very large vertical permeability values.

In such cases, the inversion of the linear problem at each time step may be more difficult. However, Athos linear numerical solvers have considerably improved in the past few years (thanks to the research programs performed by the Applied Mathematics Research Division of the IFP), so that complex numerical problems are reliably solved with a low overhead in terms of computation time.

As an example, our experience in using a large vertical diffusion coefficient on a Cantarell cross-section simulations showed no dramatic increase of the computation time while providing reliable physical results.

2.12 Can ATHOS handle the important oil-oil diffusion process?

In the case of Athos the diffusion process is properly modelled for oil-oil, gas-oil and gas-gas matrix fracture exchanges.

2.13 Can ATHOS simulate the re-pressuring process in reservoirs with a large gas invaded zone?

The IFP group do believe that it is possible to simulate a re-pressuring process with Athos.

Let summarize the mechanisms that occur in such a process. The starting point is gas-oil equilibrium in the matrix blocks. Due to pressure increase (re-pressuring), the interfacial

tension changes accordingly, which changes the oil-gas capillary pressure curve (especially the capillary threshold), and finally results in an additional recovery by gravity drainage.

All these mechanisms are simulated in Athos, therefore we do not see any limitation to handle re-pressurisation.

2.14 Can ATHOS handle non-equilibrium gas-gas gravity drainage, which is a more efficient process than diffusion process?

Looking at the equation used for the computation of gravity fluxes (see the introduction) in Athos, one can see that the method computes the difference, for each phase, between the phase density (ρ_{mp}) in the matrix and an average density in the fracture (ρ^{f*}).

In a non-equilibrium gas-gas case, this difference is the density gradient between the two gases. Therefore, the gas-gas gravity drainage is simulated.

2.15 Due to several less known parameters, fractured reservoirs could be easily History Matched with irrelevant different set of parameters. Do you agree?

This is common sense to say that the more parameters, the more possibilities to get a match. Two strong ideas to avoid matching with wrong parameters:

- a) Use the IFP Fraca methodology: the purpose of this methodology and software is to better characterize the fracture system, reduce the uncertainties on the fracture properties and provide a reliable upscaling of the equivalent parameters.
- b) Phenomenological studies: to really understand the key processes that drive the field behaviour and to evaluate the most appropriate parameters for the simulation of the specific case studied.

Fractured reservoirs are complex. The key points for a successful simulation study are the understanding of the key field mechanisms and the knowledge of the simulator capabilities and options.

3 REFERENCES OF IFP & BEICIP-FRANLAB DUAL POROSITY SIMULATION STUDIES WITH ATHOS

To make short, only a few references are listed here below:

Fields with large conductive features (sub-seismic faults and fracture swarms): Ghawar, SPE68184, “Integrated Study of a Fractured Middle East Reservoir with Stratiform Super-K Intervals – Part 2: Upscaling and Dual Media Simulation”, Cosentino L. (Beicip-Franlab) & al.

Fields with diffuse fractures (systematic joints, dense and extended fracture networks):

Cantarell (Mexico), SPE59044, “Implementing Convection in a reservoir Simulator: A Key Feature in Adequately Modelling The Exploitation of the Cantarell Complex”, Manceau E. (IFP) & al.

Bati Raman (Turkey), EAGE 97, Paper 032, “Numerical Simulation of CO₂ Injection in a Heavy Oil Fractured Reservoir – Case study of Bati-Raman Field, Turkey”, Faure F. (Beicip-Franlab) & al.