**An OpenFOAM Application for Solving the Black Oil Problem**

Soledad Fioroni*a*, *b*, \*, Axel E. Larreteguy(http://orcid.org/0000-0003-0785-874X)*a*, and Gabriela B. Savioli*c*

*aUniversidad Argentina de la Empresa (UADE), Instituto de Tecnología (INTEC), Buenos Aires, Argentina*

*bCONICET, Buenos Aires, Argentina*

*cUniversidad de Buenos Aires, Facultad de Ingeniería, Instituto del Gas y del Petróleo, Buenos Aires, Argentina*

*\*e-mail:* *sfioroni@uade.edu.ar*

# Abstract—An OpenFOAM application to address black oil problems using the finite volume technique and first results obtained with this new solver are presented. The black oil formulation is well known in petroleum reservoir engineering and widely implemented in primary and secondary recovery processes. Simulation of three-phase flow in porous media including fluid and rock compressibility requires careful consideration in the numerical model to guarantee a conservative calculation. Therefore, a detailed mathematical model and its implementation, with emphasis on the numerical treatment, are presented in this work. The solver is validated over several case studies comparing its results against a semi-analytical solution and those obtained by both in house and commercial simulators reported in the literature, thus proving to successfully represent compressible and incompressible multiphase flow in porous media.

# Keywords:black oil, OpenFOAM, porous media, IMPES

# 1. INTRODUCTION

The simulation of multiphase fluid flow in porous media is of interest in many areas of science and engineering, e.g., biodegradation, hydrology and groundwater flow, and oil and gas reservoirs [1–7]. This type of problems requires solving a system of coupled nonlinear partial differential equations. When addressing oil and gas reservoir cases the black-oil formulation is usually implemented, which is a simplified version of the compositional model, suitable for nonvolatile hydrocarbons. It considers three phases: gas, oil, and water. There is no mass transfer between water and gas, and water and oil. Besides, the oil phase consists of two components: the dissolved gas measured at standard conditions (GAS) and the residual oil (OIL) that remains at standard conditions when this gas is liberated [[10].](#bookmark36)

The black oil formulation is applied to simulate primary and secondary recovery processes. The mathematical models are built by combining each component’s mass conservation equation with the Darcy’s empirical law, which describes flow in porous media for each phase. Along with these governing equations, state equations (thermodynamic model) and a reservoir description (geological model) are included [[11].](#bookmark37) The state equations are based on the PVT laboratory measurements, that is, the phase’s volume factors and the gas solubility in oil [10].

To test the ability of the finite volume method to properly represent the complex process of both compressible and incompressible multiphase flow in porous media we generalized the toolbox *porousMultiphaseFoam* [[3].](#bookmark29) This toolbox was recently developed in the OpenFOAM framework and is capable of simulating two-phase incompressible flow in porous media, including capillary effects. Regarding flow in porous media, the main difference between the *porousMultiphaseFoam* and the general OpenFOAM approach is that the later solves a modified Navier–Stokes equation, not considering some essential aspects of reservoir simulation, such as phase saturations, relative permeability and capillary models, and some specific boundary conditions.

In this work, we present the first results of an extended version of the *porousMultiphaseFoam*, the *blackOilFoam*, that includes the presence of a third phase and considers fluids and rock compressibility, along with several time-step limitations for dealing with the strong nonlinearities of the equations to be solved.

The paper is organized as follows. In section 2, the mathematical model of the black oil formulation and its implementation in OpenFOAM is described. Then, in section 3 we present the numerical model, and finally, in section 4, we validate the simulator over several case studies.

# 2. MATHEMATICAL MODEL

The black oil model considers three flowing phases: water (w), oil (o), and gas (g), which are allowed to be compressible. It also considers three components: OIL, GAS (hydrocarbon liquid and gas at standard conditions), and WATER.

A compressible multiphase flow in porous media requires the solution of the mass conservation equation for each component, which reads

|  |  |
| --- | --- |
| $div\left(c\_{ij}ρ\_{j}v\_{j}\right)+q\_{i}=\frac{∂}{∂t}(φc\_{ij}ρ\_{j}S\_{j})$. | (1) |

Here, we introduce the subscripts *i* for the components (*i* = G, O, W) and *j* for the phases (*j* = g, o, w). The source/sink term $q\_{i}$ represents the rate of addition/subtraction of mass of component *i* per unit of total volume. Also, $ρ\_{j}$is the phase *j* density; $c\_{ij} $determines the mass fraction of component *i* in phase *j;*$v\_{j}$ is the Darcy velocity of phase *j*, and $φ$ is the rock porosity.

The $c\_{ij}$ coefficients are determined using the hypothesis of the black oil model, i.e., there is no mass transfer between water and the other phases and GAS can be dissolved in the oil phase, but OIL cannot be vaporized into the gas phase. Therefore, $c\_{Ww}= c\_{Gg}=1$, $c\_{Wg}= c\_{Wo}=c\_{Gw}=c\_{Ow}=c\_{Wg}=0$, and $c\_{Go}$, $c\_{Oo}$are computed using PVT parameters (volume factors $B\_{j} $and gas solubility in oil $R\_{s}$) as $c\_{Go}= R\_{s}ρ\_{Gs}/B\_{o}ρ\_{o}$, $c\_{Oo}= R\_{s}ρ\_{Os}/B\_{o}ρ\_{o}$, where $ρ\_{Gs}$and $ρ\_{Os}$ denote the gas and oil densities under standard conditions [10]. The Darcy phase velocities $v\_{j}$are determined by the Darcy’s law:

$v\_{j}=-K\frac{k\_{rj}}{μ\_{j}}(∇p\_{j}-ρ\_{j}g∇D)$. (2)

In Eq. (2), $k\_{rj}$ and $μ\_{j}$are the relative permeability and viscosity of phase *j*, *D* is the depth, and **K** isthe rock absolute permeability tensor.

Combining E[qs. (1)](#bookmark0) and [(2)](#bookmark1) and dividing by the corresponding component density, the governing equations for gas, oil, and water components give

$div\left(K\frac{k\_{rg}}{μ\_{g}B\_{g}}\left(∇p\_{g}-ρ\_{g}∇D\right)+K\frac{k\_{ro}R\_{s}}{μ\_{o}B\_{o}}\left(∇p\_{o}-ρ\_{o}∇D\right)\right)+q\_{G}^{SC}=\frac{∂}{∂t}\left[φ\left(\frac{S\_{g}}{B\_{g}}+S\_{o}\frac{R\_{s}}{B\_{o}}\right)\right]$, (3a)

$div\left(K\frac{k\_{ro}}{μ\_{go}B\_{o}}\left(∇p\_{o}-ρ\_{o}g∇D\right)\right)+q\_{O}^{SC}=\frac{∂}{∂t}\left(S\_{o}\frac{φ}{B\_{o}}\right)$, (3b)

$div\left(K\frac{k\_{rw}}{μ\_{w}B\_{w}}\left(∇p\_{w}-ρ\_{w}g∇D\right)\right)+q\_{W}^{SC}=\frac{∂}{∂t}\left(S\_{w}\frac{φ}{B\_{w}}\right)$, (3c)

where $q\_{j}^{SC}$ denotes the volumetric injection or production rate per unit of total volume of each component *j*. Equations (3a)–(3c) are then reformulated by replacing [Eq. (3a)](#bookmark0) by the sum of Eqs. (3a)–(3c), and this latter equation is called the *pressure equation*.

In order to simplify the pressure equation, we first adopt the notation from [[3],](#bookmark29) defining the phase mobility $M\_{j}=Kk\_{rj}/μ\_{j}B\_{j}$ and the gravitational contribution $L\_{j}=M\_{j}ρ\_{j}$*,* bothunder the standard condition (SC).

<…>

3. NUMERICAL MODEL

We developed a solver based on the philosophy of the opensource platform OpenFOAM [[12].](#bookmark45) As a collocated finite volume-based code, all variables are calculated in the cell center, and interpolated to the faces of the cell when needed.

To simplify even further the formulation presented in section 2, we use the notation in [[3]](#bookmark29) and define three different fluxes that depend on pressure gradient, gravity, and capillary pressure, namely

$ψ\_{p}= M\_{w\_{c\rightarrow f}}+\left(1+R\_{s}\right)M\_{o\_{c\rightarrow f}}+M\_{g\_{c\rightarrow f}}∇p\_{o}S\_{f}$, (6a)

$ψ\_{gr}= L\_{w\_{c\rightarrow f}}+\left(1+R\_{s}\right)L\_{o\_{c\rightarrow f}}+L\_{g\_{c\rightarrow f}}g∇DS\_{f}$, (6b)

$ψ\_{pc}= ψ\_{pcow}- ψ\_{pcgo}=$ $\left[M\_{w}\left(\frac{dp\_{cow}}{dS\_{w}}∇S\_{w}\right)-M\_{g}\left(\frac{dp\_{cgo}}{dS\_{g}}∇S\_{g}\right)\right]S\_{f}$. (6c)

Here, $S\_{f}$ is the outward normal vector of the cell face, whose magnitude is the face area. The operator c *→* fimplies that the cell-centered value of the variable is interpolated to obtain the face-centered value of the variable in each face of the computational grid. Customary interpolation schemes are upwind for relative permeabilities and harmonic for absolute permeability.

<…>

# 4. RESULTS

As a preliminary and almost obligated test of *blackOilFoam* we addressed the classical Buckley–Leverett displacement problem: a 1D two-phase incompressible case with semi-analytical solution, in which water is injected at one end displacing the oil originally present in the domain [19]. Although we skip here most of the details for brevity purposes, it is important to say that the solution is characterized by a discontinuity representing the sharp front of saturation of the displacing fluid. In a numerical solution, however, the front is usually somehow diffused, making this difference a suitable candidate for comparison purposes. Our solver had no difficulties in dealing with this problem, producing results in which the front lies within a 5% error (-norm) from the semi-analytical solution.

After this preliminary step turned successful, we were able to approach more complex cases involving the three phases the code should be able to deal with. We started by simulating Example 1 in [[20],](#bookmark42) a 1D saturated case with three-phase compressible flow, non-negligible formation compressibility, and capillary effects. Then, we engaged a 2D problem discussed in [[21],](#bookmark43) considering gas oil compressible flow and the presence of a third irreducible water phase, with negligible rock compressibility and capillary effects. Finally, we focused on the 1st *SPE comparative case*, which consists in a 3D three-phase compressible problem with gas injection [[22].](#bookmark44)

*1D Compressible Case*

Example 1 in [[20]](#bookmark42) considers a linear compressible formation of length *L* = 1000 m with three-phase compressible flow. Pressure is set as constant Dirichlet conditions at both ends, being *p*(0) = 19 MPa and *p*(*L*) = 16 MPa, with the initial saturation profiles *S*g*i*, *S*o*i*, and *S*w*i* shown in Fig. 1. Given the compressible nature of the phases, we use the PVT parameters given in [[20],](#bookmark42) modeled as *R*s = 7.25 × 10–6*p*o, *B*w = 1 – 2.61 × 10–9*p*o, *B*o = 1 + 2.17 × 10–8*p*o, and *B*g = (6 + 8.7 × 10–6*p*o)–1, where *p*o is in pascals, *Bj* is in m3 RC/m3 SC, and *R*s is in $m\_{gas}^{3}$ SC/$m\_{oil}^{3}$ SC. The phase viscosities are given in centipoises; $μ\_{o}$ = 0.35, $μ\_{g}$ = 0.012 + (4.35 × 10–9)*p*o, and $μ\_{w}$ = 0.8 – (1.45 × 10–8)*p*o, and the formation compressibility is accounted for by using a porosity linearly dependent on pressure, i.e., $φ$ = 0.2 + (2.9 × 10–10) *p*o.

<…>

*2D Compressible Case*

In this case we compared the performance of the *blackOilFoam* with the *Single Well* simulator developed in [[21]](#bookmark43) and the public domain simulator *BOAST* [[11].](#bookmark37) We simulated the radial flow of oil and gas towards a well in an initially undersaturated reservoir (*S*o = 0.88) with water present as a third immobile phase (*S*wc = 0.12). Geometric and fluid properties are as follows:  is the reservoir thickness; *r*e = 233.87 m and *r*w = 0.10 m are the external and well radii, respectively; *S*or = 0.40 and *S*gc = 0.01 are the residual oil and critical gas saturations; and *P*b = 27.67 MPa is the bubble point pressure. The reservoir is initially at *p*o = 31.02 MPa.

<…>

*3D Compressible Case*

The 1st SPE case study gathered several oil companies to test and compare their solvers using a three-dimensional three-phase compressible problem [[22].](#bookmark44) It consists of an initially undersaturated three-layered anisotropic reservoir, with gas injection and oil production. Water is also present, only as an immobile phase. We considered the case with constant bubble-point pressure, set equal to the original value (Case 1).

<…>

Figure [4](#bookmark23) shows the evolution of pressure in both the injector and the producer well cells. From the seven companies that participated in [22] we chose to compare our results with only those of Shell, Intercomp and Mobil to enhance the readability of the figures. The first two are based on the IMPES method, while the latter is a fully implicit solver.

It is important to remember that wells are modelled as source/sink terms and that the pressure in the well is not calculated explicitly from the flow rates. However, they do impact on the pressure of the cell that contains the well. Given that the pressure we report is that of the cell and not of the well itself, this difference may account for the slight deviation of our results. In addition, the cumulative material balance error in *BOAST* of nearly 8.5% increase of the gas phase volume certainly favored the early arrival of gas to the producer and hence, the pressure to peak sooner. There is no available information about this subject for the other solvers.

<…>

# 5. CONCLUSIONS

The formulation of *blackOilFoam*, a new OpenFOAM application to address black-oil problems, was presented and successfully tested in several cases. The solver is able to deal with three-phase flow in porous media including fluids and rock compressibility. Aside from the classical Buckley–Leverett testing problem, three different cases were considered, namely

1. a three-phase compressible flow in a saturated 1D reservoir, with non-negligible capillary effects and rock compressibility;
2. a radial two-phase compressible flow, in the presence of a third irreducible phase, in an initially undersaturated reservoir; and
3. a three-phase compressible flow, with gas injection, in an initially undersaturated 3D reservoir.

The comparison against semi-analytical solutions and results from other authors has proven the solver to successfully represent both compressible and incompressible multiphase flow in porous media.

<…>

#

# FUNDING

This research was supported by Universidad Argentina de la Empresa and CONICET through the PhD grant ACyT D16T02. G.B. Savioli thanks to ANPCyT, Argentina (PICT 2015 1909) and Universidad de Buenos Aires (UBACyT 20020190100236BA).

CONFLICT OF INTEREST

The authors declare that they have no conflicts of interest.

# REFERENCES

1. Amani, E. Jalilnejad, and S. M. Mousavi, “Simulation of phenol biodegradation by *Ralstonia Eutropha* in a packed-bed bioreactor with batch recycle mode using CFD technique,” J. Ind. Eng. Chem. **59**, 310–319 (2018). https://doi.org/10.1016/j.jiec.2017.10.037.

2. A. A. Lyupa, D. N. Morozov, M. A. Trapeznikova, B. N. Chetverushkin, N. G. Churbanova, and S. V. Lemeshevsky, “Simulation of oil recovery processes with the employment of high-performance computing systems,” Math. Models Comput. Simul. **8** (2), 129–134 (2016). https://doi.org/10.1134/S2070048216020095.

3. P. Horgue, C. Soulaine, J. Franc, R. Guibert, and G. Debenest, “An open-source toolbox for multiphase flow in porous media,” Comput. Phys. Commun. **187**, 217–226 (2015). http://doi.org/10.1016/j.cpc. 2014.10.005.

<…>

10. K. Aziz and A. Settari, *Petroleum Reservoir Simulation* (Elsevier, London, 1985).

<…>

15. R. Issa, T. Daltaban, and C. Wall, “Simulation of recovery processes in gas condensate reservoirs,” in *Proc*. *Third European Meeting on Improved Oil Recovery* (Rome, 1985), pp. 16–18.

<…>

22. A. S. Odeh, “Comparison of solutions to a three-dimensional black-oil reservoir simulation problem (includes associated paper 9741),” J. Pet. Technol. **33** (01), 13–25 (1981). https://doi.org/10.2118/9723-PA.

TABLES

**Table 1.** Fluid properties of the 2D compressible case

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| *p*, MPa | *B*o, m3 RC/m3 SC | $μ\_{o}$, Pa s | *R*s, $m\_{gas}^{3}$ SC/$m\_{oil}^{3}$ SC |  *B*g, m3 RC/m3 SC  | $μ\_{g}$, Pa s |
| 0.1 | 1.063 | 0.001047 | 0 | 0.9358 | 0.0000081 |
| 1.83 | 1.151 | 0.000981 | 16.39 | 0.0679 | 0.0000096 |
| 3.55 | 1.208 | 0.000913 | 32.30 | 0.0352 | 0.0000113 |
| 7 | 1.297 | 0.000836 | 65.09 | 0.0179 | 0.0000142 |
| 14 | 1.440 | 0.000701 | 111.78 | 0.0091 | 0.0000192 |
| 17.67 | 1.507 | 0.000649 | 136.06 | 0.0073 | 0.0000212 |
| 21 | 1.572 | 0.000600 | 162.24 | 0.0061 | 0.0000233 |
| 27.67 | 1.705 | 0.000516 | 220.73 | 0.0046 | 0.0000275 |
| 35 | 1.682 | 0.000564 | 220.73 | 0.0036 | 0.0000315 |

**Table 2.** Stratification and reservoir properties of the 3D compressible case

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | $$φ$$ | *h*, ft | *Kx* and *Ky*, mD | *Kz*, mD | *S*w | *S*o |
| Layer 1 | 0.3 | 20 | 500 | 100 | 0.12 | 0.88 |
| Layer 2 | 0.3 | 30 | 50 | 37.5 | 0.12 | 0.88 |
| Layer 3 | 0.3 | 50 | 200 | 20 | 0.12 | 0.88 |

**Table 3.** Reservoir data and constraints of the 3D compressible case

|  |  |
| --- | --- |
| Parameter | Value |
| Initial pressure at cell centers of layer 3 | 33.09 MPa (4800 psi) |
| Gas injection rate | 32.69 m3/s (100 MMscf) |
| Maximum saturation change per  |  |
| Rock compressibility | 4.35 × 10–10 Pa–1 (3 × 10–6 psi–1) |
| Bubble point pressure, $p\_{b}$ | 26.68 MPa (4014.7 psi)  |
| Wellbore radius, $r\_{w}$ | 0.0762 m (0.25 ft)  |

<…>

FIGURE CAPTIONS

**Fig. 1.** Water, oil, and gas saturations at 0, 100, 500, and 1000 days—1D compressible case.

**Fig. 2.** Evolution of the bottomhole pressure in the wellbore cell—2D compressible case.

**Fig. 3.** Evolution of the oil saturation in the wellbore cell—2D compressible case.

**Fig. 4.** Evolution of pressure at Producer and Injector—3D compressible case.

**Fig. 5.** Evolution of gas saturation at the producer—3D compressible case.

**Fig. 6.** Evolution of gas–oil ratio (GOR) at the producer—3D compressible case.

FIGURES

<…>



Fig. 6.

<…>