# Hydrodynamic Modelling of Petroleum Reservoirs using Simulator MUFITS

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# Hydrodynamic modelling of petroleum reservoirs using simulator MUFITS

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**Abstract**

An extension of MUFITS reservoir simulator for modelling oil and gas reservoirs using black-oil approach is presented. We give an overview of multi-segment well technique implemented in MUFITS for coupled reservoir-wellbore simulations. SPE comparative studies with vertical wells are simulated in order to verify the correctness of technique implementation in the code. The simulation results, in particular calculated wells bottom-hole pressures, match results of other codes.


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*Keywords:* *Hydrodynamic modelling; Reservoir simulation; Black oil; Comparative study;Bottom-hole pressure; MUFITS*

## 1. Introduction

Hydrodynamic modelling is crucial technique in petroleum engineering. For a given geological model of petroleum reservoir, the hydrodynamic simulations are used for recovery scenarios optimization as well as for forecasting of future oil and gas production [1,2]. The modelling is conducted using hydrodynamic simulators – program codes which are capable of comprehensive engineering data for geological settings, well operations, fluid properties, etc. Complicated hydrodynamic modelling techniques can be tested in research codes serving as computational platforms (e.g. [3,4]), and, if they prove their robustness, they can be introduced in commercial engineering codes.

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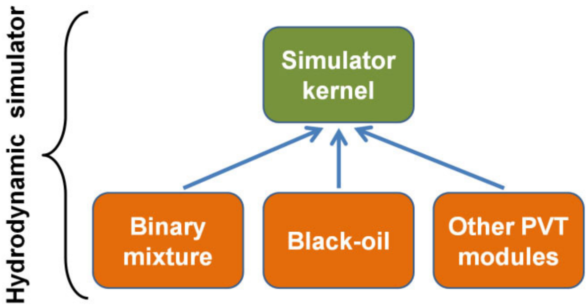


Fig. 1. MUFITS modules.

In most cases, both research and commercial codes use similar technique for modelling multiphase flows in porous media which is based on finite volume method and upwind approximations [1]. One of the main differences rises in treatment of wells. The standard approach for modelling coupled reservoir-wellbore flows is based on a preliminary (possibly iterative) solution of hydraulic equations along the wellbore and calculation of fluxes between wellbore and reservoir [5]. These fluxes are used as source/sink terms for grid blocks in which the well is completed. They also affect the construction of Jacobian matrix making it denser. The standard approach is basically used for vertical wells, whereas for inclined and horizontal wells the multi-segment well approach is more preferable [6]. In multi-segment approach well is discretized, and finite-difference balance equations are formulated for every well segment. These equations are solved together with the balance equations for grid blocks. In terms of linear (and nonlinear) solver coupling between reservoir and wells can be different (e.g. [7-9]). One option is that full Jacobian matrix is decoupled in two submatrixes for reservoir and wells, which are inverted separately.

In this work, we present MUFITS research simulator [3] technique for coupled reservoir-wellbore simulations. It is similar to the multi-segment approach in which finite-difference equations for reservoir and wells are solved simultaneously and fully implicitly in every iteration of the Newton method. The well segments are not used for calculating preliminary solution for wells only, but full Jacobian is inverted. The linear solver solution is used for updating variables both in grid blocks and in well segments. The special feature of our technique lies in the way we organize control on well operations. We introduce pumping device (a down-hole pump) controlling hydraulics in wellbore.

In terms of reservoir fluid PVT properties, the recent development of MUFITS code architecture is related to the code decomposition in kernel and PVT-module (EOS-module) (Fig.1). The simulator kernel contains all program procedures which do not depend on fluid properties: simulation control procedures; grids; wells; saturation functions; linear and nonlinear solvers; finite-difference approximations; data loaders; “global” keywords; static properties (e.g. porosity) and associated mnemonics. In PVT-module, all parameters/procedures dependent on the fluid are defined: procedures for fluid thermophysical properties calculation; balance equations to be solved; primary variables; PVT data loaders; dynamic properties (e.g. oil saturation) and associated mnemonics. The kernel can be linked with various PVT-modules extending application area of the code. Previously, we used the PVT-module for non-isothermal modelling of binary mixture flows (Fig. 1) in problems of underground $CO_2$ storage [10] and flows in hydrothermal systems [11]. Recently, we have developed other PVT-modules, in particular black-oil module for hydrodynamic modelling of petroleum reservoirs. Farther, we discuss coupled reservoir-wellbore simulations using black-oil PVT-module because it can be used in simulations of SPE case studies (see overview in [12]) which contain wells and, therefore, provide good comparative scenarios for testing. However, the discussed reservoir-wellbore modelling technique is the same when using other PVT-modules, because the corresponding coupling procedures belong to the simulator kernel.

## 2. Modelling technique

### *2.1. Multiphase flow in porous media*

For modelling multiphase flows in porous media, we use mass balance equations for oil, water and gas as well as the Darcy correlation. Single-phase, two-phase and three-phase black-oil models can be simulated by disabling the balance equation of the corresponding component. Optionally, gas can dissolve in oil phase. The gas condensate option is also available. We use conventional technique for numerical solution of flows in porous media: e.g. finite-volume method, fully-implicit method and upwind scheme. We use primary variables switching technique if the reservoir fluid phase state is changing.

The reservoir grid is converted to 3D graph when it is loaded into simulator kernel (Fig. 2). The nodes of the graph correspond to the grid blocks, whereas the edges linking the nodes correspond to interfaces between grid blocks. In Fig. 2, a simple grid 3×3 grid blocks is converted to 3×3 graph. When loading in kernel, we calculate volume (pore volume) for every node and transmissibility for every edge. The fluid accumulates in nodes, and it can be transported only between each two connected nodes. Thus, we consider hydrodynamics on graph.

### *2.2. Coupled reservoir-wellbore flows*

The conversion to graph is also used when wells are loaded into simulator kernel. Let us consider a simple scenario with a well completed in each of the three layers, as shown in Fig. 2. In the kernel, the well can be presented as stock tank and several pipe segments linked by a single pumping device and by several pipe junctions. The graph nodes associated with the well are linked with reservoir nodes (grid blocks) by well completions. We use different relations for accumulated mass of fluid for different types of graph nodes. For instance, the fluid mass in the grid block is fluid density multiplied by pore volume, whereas in pipe segments (in stock tanks) the fluid density is multiplied by pipe segment (stock tank) volume. Similarly, we use different relations for fluxes between nodes for different types of the graph edges. We use Darcy correlation to calculate fluxes on the interfaces and Dupuis formula for well completions, and we apply more complicated relations for pipe junctions. The uppermost pipe segment below the pumping device is considered as the reference node for the well bottom-hole parameters. The pressure in this pipe segment is the bottom-hole pressure.

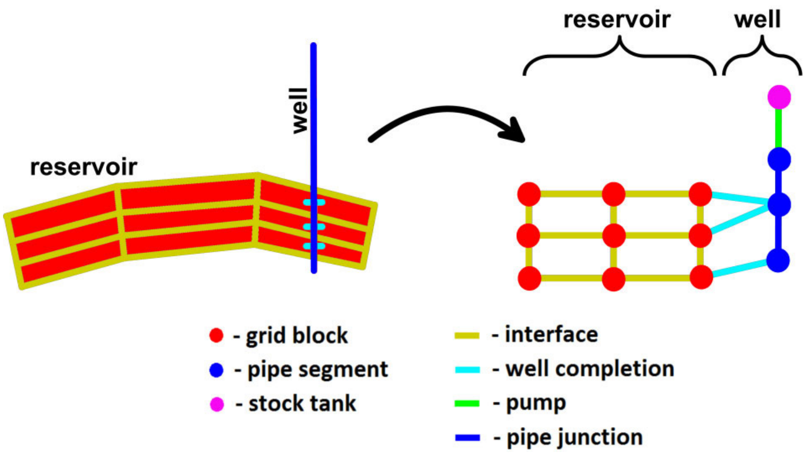


Fig. 2. Schematic view of reservoir model (left) conversion to graph (right).

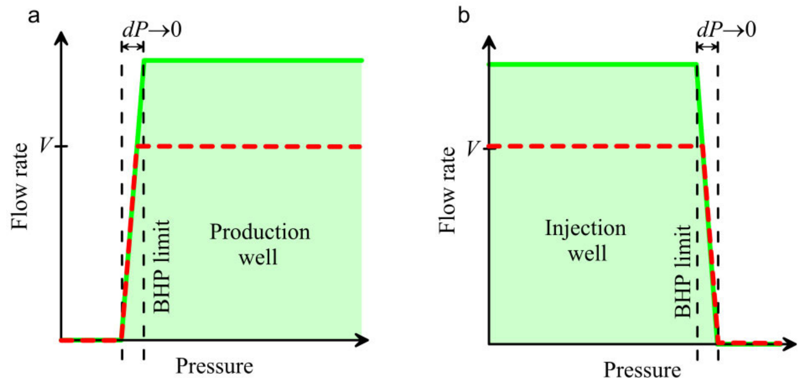


Fig. 3. Allowed pumping device flow rate for production well (a) and injection well (b) is highlighted. Red lines show pump rate for a given well operation rate $V$.

The pumping device controls the well operations. For production wells, the device pumps fluid from pipe segment into the stock tank. The maximum allowed volumetric rate of fluid is defined by a piecewise linear function of the bottom-hole pressure, as shown in Fig. 3a. If the pump inlet pressure (i.e. pressure in the pipe segment) exceeds the bottom-hole pressure limit, the well is operating under given volumetric production rate $V$. If the bottom-hole pressure decreases below the limit, the pump volumetric rate drops down abruptly within the pressure gap $dP \to 0$ . Thus, the well production rate decreases, and the bottom-hole pressure limit is reached within accuracy $|dP| \to 0$ . The numerical solution automatically determines pump rate maintaining given bottom-hole pressure limit. The produced fluid composition is equal to the fluid composition in the uppermost pipe segment. For production wells, the parameters in the stock tank do not affect the production rates.

For injection wells, the device pumps fluid from stock tank into the uppermost pipe segment. The maximum allowed volumetric rate is defined by a piecewise linear function of the bottom-hole pressure, as shown in Fig. 3b. If the pump outlet pressure (i.e. pressure in the pipe segment) is less than the bottom-hole pressure constraint, the well is operating under given volumetric injection rate $V$. If the bottom-hole pressure increases exceeding the limit, the pump volumetric rate drops down abruptly within the pressure gap $dP \to 0$ . Thus, the well injection rate decreases, and the bottom-hole pressure limit is maintained within accuracy $|dP| \to 0$ . The pumping device defines only the well injection rate, whereas the injected fluid parameters, e.g. the fluid composition, are specified by the parameters in the stock tank.

The case of well operating under given mass rate or volumetric rate of specific component can be reduced to the situations described above by using simple pump rate scaling.

In Newton method iterations, the fluid is balanced over full graph, including nodes and edges for wells. This is implemented by inserting equations in the Jacobian matrix for every node. For example, for three-phase black-oil model the number of equations is $3N$, where $N$ is the total number of nodes ($N$=13 in Fig. 2). Thus, we simultaneously solve flow equations both in porous media and in wellbore.

In the following sections we present first results of this method application to reservoir modelling. We consider scenarios where each well comprises a single pipe segment connected to every grid block in which the well is completed. Thus, we average fluid properties along the wellbore. This is justified by the fact that we consider scenarios only with vertical wells.

## 3. Comparison with SPE case studies

### *3.1. 1st SPE case study*

The first SPE case study is a basic test for three-phase three-dimensional black-oil modelling technique [13]. We consider only case 2 of the comparative study with variable bubble-point pressure. The problem involves oil productions from an initially undersaturated reservoir (Fig. 4a). There are 300 grid blocks in total (grid 10×10×3).

The porosity and permeability for every layer are given. There are two vertical wells in the study located in the opposite corners of domain. Hydrocarbon gas is injected through one of the wells, whereas oil is produced from the bottom layer through the second well. The gas injection results in swelling of oil and in gas sweep towards production well.

The graph constructed in MUFITS kernel for the 1st SPE study is shown in Fig. 4b. Each well comprises a single pipe segment and a single stock tank. The injector pipe segment is linked only with the top grid block (1,1,1) because it is completed only in the top layer. The producer pipe segment is linked only with the bottom grid block (10,10,3) because it is completed only in the bottom layer. The oil production rate, gas-oil ratio of produced fluid as well as other parameters of the 1st SPE problem, calculated by MUFITS, match results of other codes (Fig. 5).

### *3.2. 2nd SPE case study*

The second comparative test is a three-phase black-oil conning study [14]. The problem involves oil production from saturated reservoir with gas cap (Fig. 6a). Initial oil and gas densities are nearly equal. There are 150 grid blocks in total (radial grid 10×1×15). This is axisymmetric simulation study with a single producer at the center of domain, completed in oil zone. Production result in water breakthrough to the well from the water zone as well as gas breakthrough from the gas cap. The producer operation controls are altered during 900 days of production.

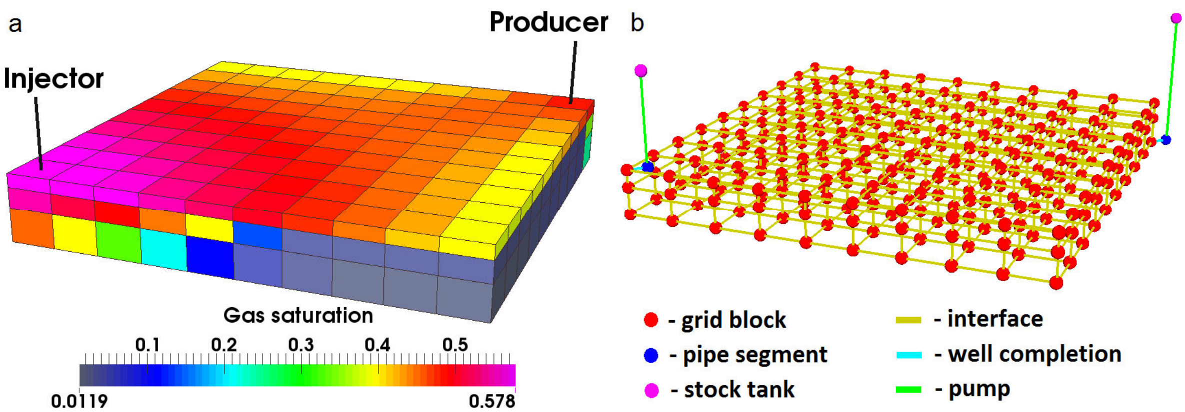


Fig. 4. 1st SPE case study: gas saturation at 10 years of production (a) and graph constructed in kernel (b).

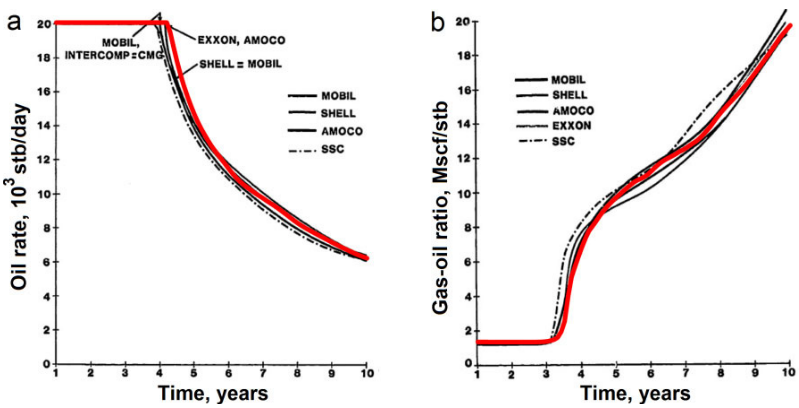


Fig. 5. Oil production rate (a; stb/day – barrels per day) and producer gas-oil ratio (b; Mscf/stb – $10^3$ cubic feet per barrel) in 1st SPE study. Red lines show MUFITS results (modified after [13]).

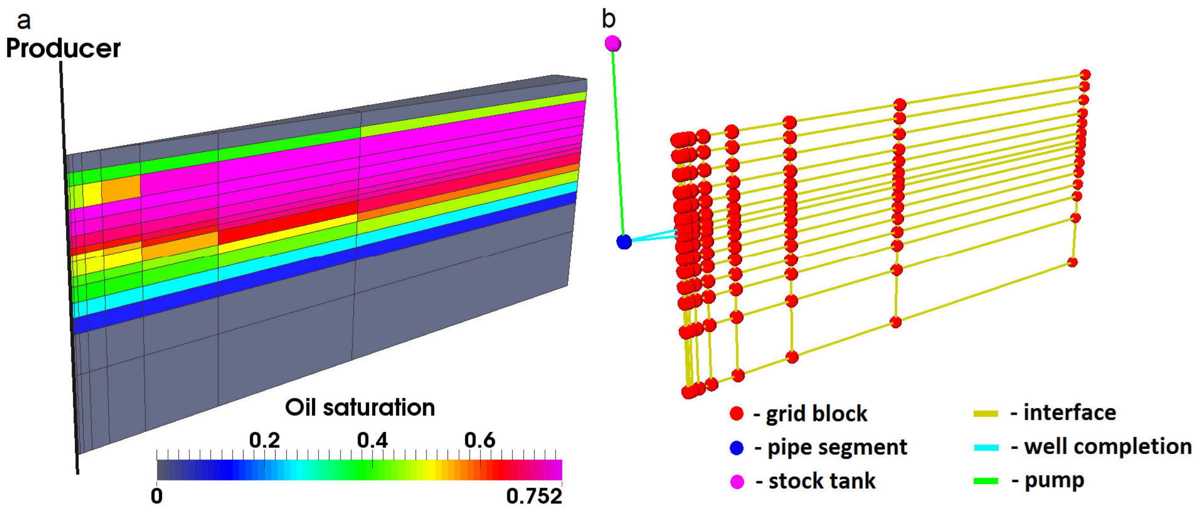


Fig. 6. 2nd SPE case study: oil saturation at 900 days of production (a) and graph constructed in kernel (b). A small sector of the full circle is shown.

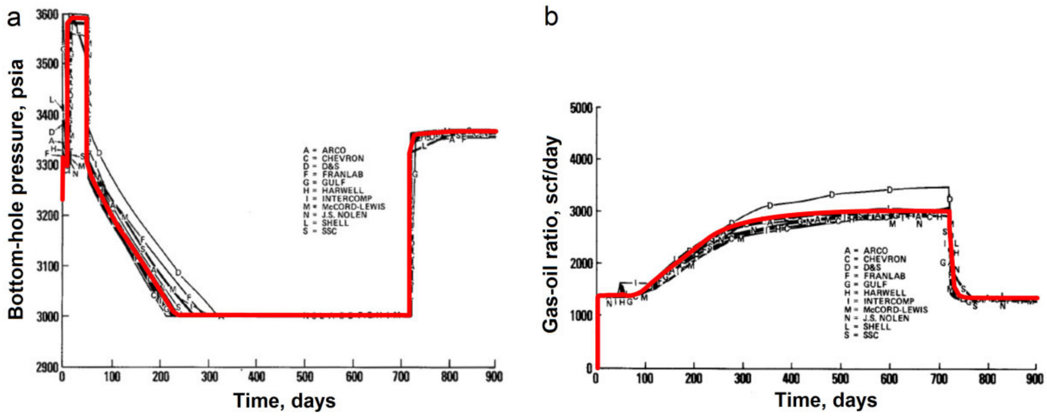


Fig. 7. Bottom-hole pressure (a; psia - pounds per square inch) and producer gas-oil ratio (b; scf/day – cubic feet per barrel) in 2nd SPE study. Red lines show MUFITS results (modified after [14]).

The graph constructed in MUFITS kernel for the 2nd SPE study is shown in Fig. 6b. The well comprises a single pipe segment and a single stock tank linked by pumping device. The pipe segment is linked only with two grid blocks because the well is completed only in layers 7 and 8. The well bottom-hole pressure, gas-oil ratio as well as other parameters of the problem, calculated by MUFITS, match results of other codes (Fig. 7).

### *3.3. 9th SPE case study*

The ninth SPE case study is an extended test for three-phase black-oil modelling technique. The problem involves oil production from a dipping initially undersaturated reservoir (Fig. 8) [15]. There are 9000 grid blocks in total (rectilinear grid 24×25×15). The permeability distribution is heterogeneous, and the porosity distribution is homogeneous in every layer. The dip angle is 10 degrees. The oil-water capillary pressure is exposed to rapid variations under small saturation changes. There are 25 production wells and a single water injection well completed below oil-water contact.

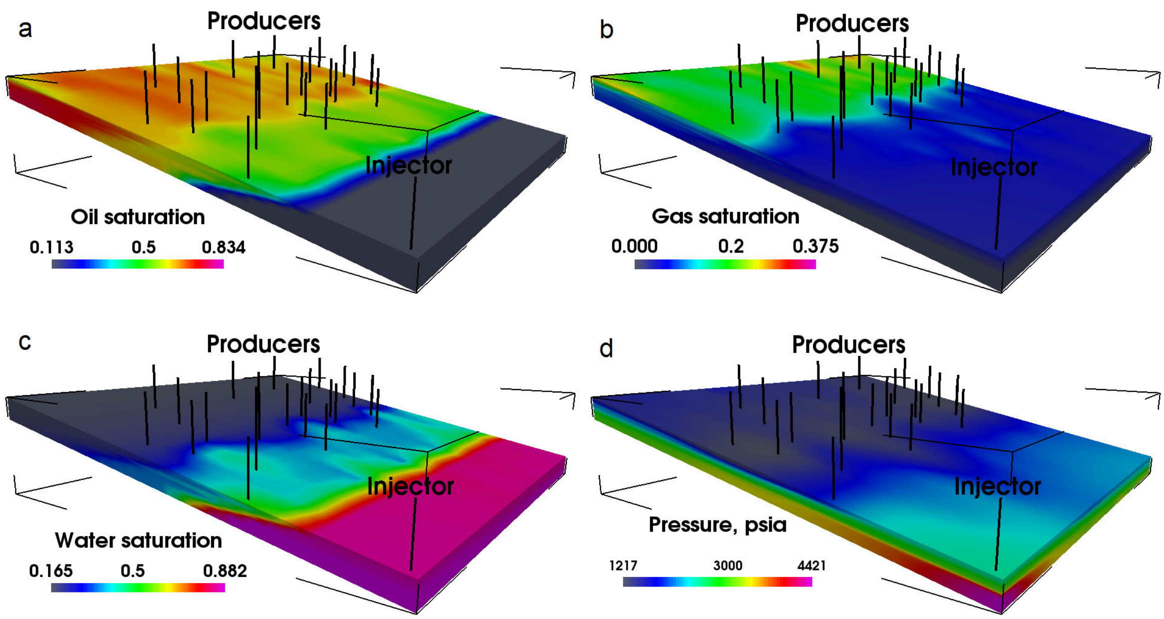


Fig. 8. 9th SPE case study: oil saturation (a), gas saturation (b), water saturation (c), and pressure (d) at 900 days of production.

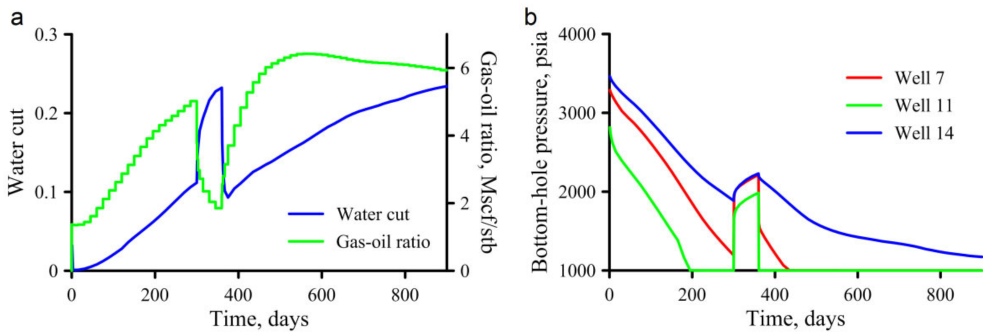


Fig. 9. Field water cut and gas-oil ratio (a) and bottom-hole pressures for wells 7, 11 and 14 (b) in 9th SPE (compare with bar chats in [15]).

We do not present the kernel 3D graph for this case study because it is difficult to visualize it properly due to large number of grid blocks and wells. However, as in the previous examples we balance the fluid simultaneously between reservoir and all 26 wells when solving the problem numerically. The field water cut, gas-oil ratio, well bottom-hole pressures as well as other parameters of the 9th SPE problem, calculated by MUFITS, match results of other codes (Fig. 9) [15].

*3.4. 10th SPE case study (model 1)*

The model 1 from the 10th SPE problem is a two-phase immiscible dead oil-dry gas comparative study [16]. The problem involves a vertical cross-section with highly heterogeneous permeability distribution (Fig. 10a). The porosity distribution is uniform. Initially, the reservoir is filled with oil. There are two wells on the opposite sides of the cross-section completed in every layer. Hydrocarbon gas is injected through one well with constant injection rate. The second well is operating under constant bottom-hole pressure. The injection results in gas sweep towards production well through high permeable pathways. Due to the buoyancy gas is flowing closer to the caprock. Here, we consider full problem, not applying any upscaling technique.

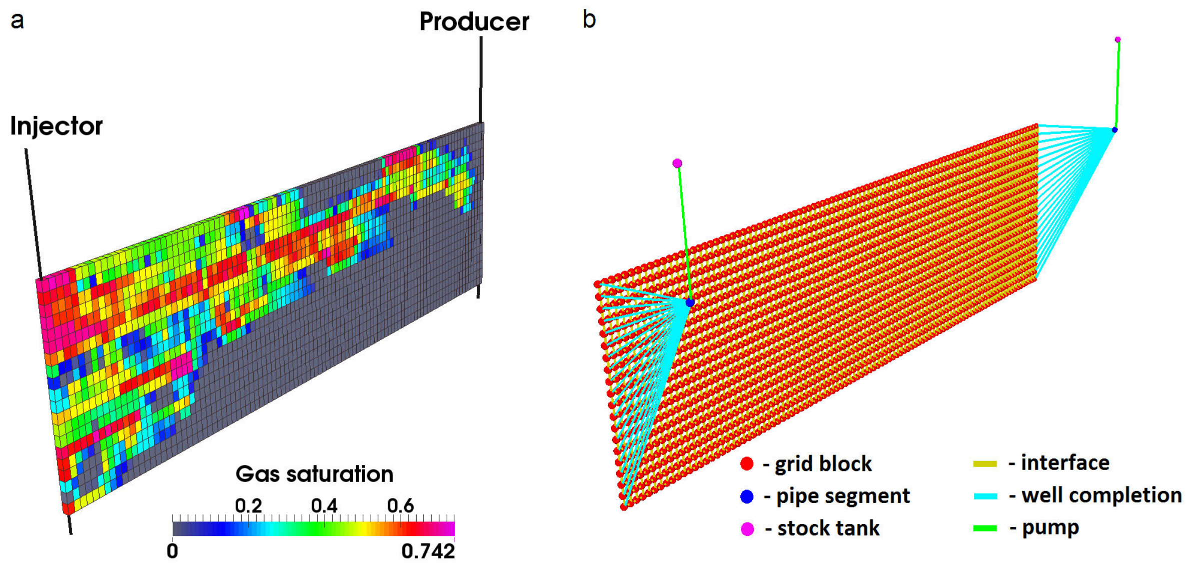


Fig. 10. 10th SPE case study: Gas saturation at 540 days (a) and graph constructed in kernel (b).

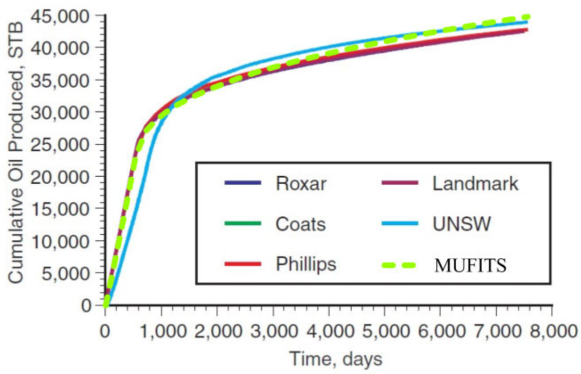


Fig. 11. Total oil produced in 10th SPE model 1 (stb – barrel). The dashed green line shows MUFITS result (modified after [16]).

The graph constructed in MUFITS kernel for the 10th SPE study is shown in Fig. 10b. Both the producer and injector pipe segments are linked with every grid block in corresponding column of grid blocks because each well is completed in every layer of the reservoir. The total oil production calculated by MUFITS for 10th SPE is close to other codes but it is a little overestimated. This is because we average fluid properties in the production well by modelling it with a single pipe segment. Thus, the pressure difference between reservoir and wellbore at the bottom completions level is overestimated, what result in higher oil production rate through the bottom completions.

## 4. Discussion and conclusions

The advantage of used well treatment is in parallel simulations. When modelling in parallel, we decompose the full kernel graph, including well nodes, between supercomputer cores. Therefore, we do not need to design independent MPI communications between cores for reservoir and wells, or we do not need to care that every well is completed in the same region of domain partition. Actually, in our treatment different pipe segments of the same well can belong to different computer cores. Another advantage is that our approach is very flexible. In future developments, it can be easily extended for the case of parallel modelling of reservoirs with advanced deviated/horizontal/multi-lateral wells and for coupled reservoir-wellbore-surface pipeline network modelling [7,8].

Certainly, the proposed method for coupled reservoir-wellbore modelling can decrease the stability of numerical algorithm, e.g. it can result in time step reduction. First, the additional equations for pipe segments and stock tanks can increase the condition number of full Jacobian matrix because the volumes of the corresponding nodes can be relatively small whereas the transmissibilities for associated edges can be high [9]. However, our simulations of SPE case studies, and other tests as well, indicate that the linear solver (GMRES preconditioned by ILUT) can easily cope with these matrixes. Second, the parameters in pipe segments (e.g. pressure or fluid composition) are exposed to rapid variations when well is temporary stopped or switched from production to injection. These situations are overcome by using potential ordering technique [17] which is applied to the "global" full graph, including reservoir and well nodes. If it is applied, the number of Newton iterations is controlled by parameters of the flow in porous media, not in the wells.

Another point is that the well bottom-hole pressure constraint is not meet exactly but within accuracy $|dP| \to 0$. We use $dP = 0.1$ bar which is an irrelevant quantity for field operations. The presented simulation results indicate that this value do not affect well rates. Wells are switching from given rate to bottom-hole pressure constraint at the same moment of time they switch in the standard well treatment. The bottom-hole pressure returned by the simulator (e.g. see 2nd and 9th SPE case studies) match results of other codes.

Therefore, we can conclude that multi-segment well treatment implemented in MUFITS is a viable technique allowing to obtain correct results in petroleum reservoir simulations. Here, we present its testing results only for SPE case studies. More test cases also supporting this conclusion can be found at MUFITS website [3].

## Acknowledgements

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## Supplementary materials

The simulator input data, ParaView (www.paraview.org) state files for simulation results post-processing and animated figures for presented case studies can be found at MUFITS website [3].

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