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A BENCHMARK CALCULATION OF 3D HORIZONTAL WELL SIMULATIONS

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Abstract. The simulation of realistic multiphase flow problems in petroleum reservoirs requires means for handling the complicated structure of the reservoirs such as complex boundaries, faults, fractures, and horizontal wells. A numerical reservoir simulator has recently been developed to be able to handle these features for a wide range of applications. This fully implicit simulator is based on a three-dimensional, three-phase black oil model. It can also be used to solve a dual-porosity, dual-permeability black oil model in a fractured reservoir. The space discretization method used in this simulator is based on a block-centered finite difference method with harmonic averaged coefficients (equivalently, a mixed finite element method). In this paper we report an application of this simulator to a problem involving injection and production from horizontal wells in a reservoir where a coning tendency is important, and present a benchmark comparison with other simulators by fourteen petroleum organizations.

Key Words. reservoir simulator, black oil model, horizontal well, block-centered finite difference, mixed finite element, numerical experiments.

1. Introduction

Because of improved drilling technology interest in the modeling and numerical simulation of horizontal wells in petroleum reservoirs has been rapidly increased [3]. The use of horizontal wells not only leads to the increased efficiency and economy of oil recovery operations, also it decreases the coning behavior with an increase in well length and enlarges oil sweeping volumes. For gas reservoirs with low permeability, it decreases turbulence effects at gas wells and increases production rates.

This paper studies a problem which is concerned with the effect of horizontal well lengths and rates on oil recovery. This effect is studied using a reservoir simulator we have recently developed. This simulator is fully implicit and is based on a three-dimensional, three-phase black oil model. It is capable of handling a fractured reservoir with dual-porosity and dual-permeability. It can model nonlinear flow around gas wells, treat some highly volatile oil and gas condensate systems, and implement complex reservoir depletion projects. The space discretization method used in this simulator is based on a block-centered finite difference method with harmonic averaged coefficients (equivalently, a mixed finite element method [5]).

In this paper we report an application of our simulator to a problem involving injection and production from horizontal wells in a reservoir where a coning tendency is important, and present a benchmark comparison with other simulators by fourteen petroleum organizations. The comparison is on oil production rates, water-oil

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production ratios, and pressures. This comparison indicates that our results are close to the mean values of those by these fourteen organizations' simulators, which shows the correctness and reliability of our simulator. After we are confident with our simulator, we use it to test well lengths and rates on oil recovery. This test predicts an increase in oil production and a decrease in coning effects with an increase in well length. We also present a benchmark comparison between the compressible case and the incompressible case for the black oil model considered. This comparison surprisingly shows that the numerical results match very well in these two cases for the present model, and thus the incompressible case is a quite reasonable approximation of the compressible case. This experiment provides a sound numerical basis for the common practice where the incompressible case is usually employed for reservoir simulation tests because of its simple implementation.

This paper is outlined in the following fashion. In the next section we review a three-dimensional, three-phase black oil model. Then, in the third section we introduce the physical data for our numerical tests. The comparisons are carried out in the fourth and fifth sections. Concluding remarks are given in the last section.

2. A Black Oil Model

In the black oil model problem considered, it is assumed that there are at most three distinct phases: gas, oil, and water. Usually water is the wetting phase, oil has an intermediate wettability, and gas is the nonwetting phase. Water and oil are assumed to be immiscible and they do not exchange mass. Gas is assumed to be soluble in oil but usually not in water. If the solubility of gas is assumed to be zero at stock tank conditions, then reservoir oil can be considered to be a solution of two components: stock tank oil and gas at standard conditions. Furthermore, in this kind of treatment it is assumed that the fluids are at constant temperature and in thermodynamic equilibrium throughout a reservoir. Under these conditions the model equations for mass balance are given by [1]

$$\begin{aligned}
&\frac{\partial}{\partial t}\left(\phi\rho_w s_w\right) + \nabla\cdot\left(\rho_w \mathbf{u}_w\right) = \rho_w q_w,\\
&\frac{\partial}{\partial t}\left(\phi\rho_o^o s_o\right) + \nabla\cdot\left(\rho_o^o \mathbf{u}_o\right) = \rho_o^o q_o,\\
&\frac{\partial}{\partial t}\left(\phi\left[\rho_o^g s_o + \rho_g s_g\right]\right) + \nabla\cdot\left(\rho_o^g \mathbf{u}_o + \rho_g \mathbf{u}_g\right) = \rho_o^g q_o^g + \rho_g q_g,
\end{aligned}$$

where the subscripts w, o, and g stand for water, oil, and gas, respectively, ϕ is the porosity of the reservoir, ρ_α, s_α, and $\mathbf{u}_\alpha$ are the density, saturation, and volumetric velocity of the α-phase, $\alpha = w, o, g$, and q_w, q_o, q_o^g, and q_g denote source/sink terms. The density ρ_o of the oil phase is

$$\rho_o = \rho_o^o + \rho_o^g,$$

where ρ_o^o and ρ_o^g indicate the partial densities of the two components in the oil phase. The phase densities at reservoir conditions are related to densities at stock tank conditions ($\bar{\rho}_w$, $\bar{\rho}_o$, and $\bar{\rho}_g$) as follows:

$$\rho_w = \frac{\bar{\rho}_w}{B_w}, \quad \rho_o = \frac{\bar{\rho}_o + R_s\bar{\rho}_g}{B_o}, \quad \rho_g = \frac{\bar{\rho}_g}{B_g},$$

where B_α is the formation volume factor of the α-phase, $\alpha = w, o, g$, and R_s is the gas solubility. Note that

$$\rho_o^o = \frac{\bar{\rho}_o}{B_o}, \quad \rho_o^g = \frac{R_s\bar{\rho}_g}{B_o}.$$