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Full Length Article

Characterization of the reservoir property time-variation based on 'surface flux' and simulator development

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ABSTRACT

Many conventional reservoirs use water flooding to displace oil and supply energy to the formation. However, previous studies have established that water injection influences the pore structure of the reservoir rock, and thus, many important physical properties change with time during development. Most reservoir simulators neglect the alteration of reservoir properties during simulation, and thus, fail to reflect the real dynamic of the fluid flow and production performance. In this paper, a new parameter known as surface flux is introduced to continuously characterize the time-variation of a property during simulation. This new method overcomes the disadvantage of the previous characterization approach, which is strongly dependent on grid size.

A new numerical simulation software in which reservoir properties are considered functions of surface flux is developed based on the black oil model, and the new simulator is validated against commercial software. Additionally, the proposed method is validated in overcoming the disadvantage of the latest approach, which is dependent on grid size. Furthermore, the time-variation effects of different parameters are investigated, and the ultimate oil recovery of the synthetic reservoir is found to increase when taking the time-variation of the relative permeability curve into account, whereas the ultimate recovery of the synthetic reservoir declines when the time-variation of the absolute permeability is incorporated. Eventually, the newly developed simulator is applied to a real water flooding reservoir to illustrate how this simulator can facilitate the history matching process and enhance the numerical model reliability. The field water cut predicted with the traditional black oil simulator after history matching is higher than that of the real production, which is because the time-variation mechanism is neglected. The water cut obtained by our simulator after history matching can readily match the actual data because it successfully represents the variation in the reservoir properties during production.

1. Introduction

1.1. Literature review

For many decades, water flooding has been employed as an effective approach to enhance the recovery of oil reservoirs [1,2]. Long term injected water flushing has shown a significant influence on the microstructures and mineral contents of porous reservoir systems [3]. This influence includes the alteration of several reservoir properties, such as formation absolute permeability and wettability [4–6], which becomes more obvious during the high water cut stage as the extent of the reservoir property variations is directly proportional to cumulative water erosion [7].

Many previous studies have been conducted to investigate the relationship between the reservoir properties and water injection history. Laboratory core flooding experiments conducted by Zhang [8] showed that the core absolute permeability is enhanced while the residual oil saturation is reduced after water flushing. Zhang [8] also reported that the core wettability shifted from oil-wet to water-wet. Similarly, Ma [9] concluded that the rock becomes more water-wet after intensive water injection. Matthew [10] found that the wettability alteration that takes place during water flooding significantly enhances the ultimate oil recovery. Cui [11] discovered that water injection can enlarge the radius of the pore throat and thus significantly increase the permeability. Xu

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Nomenclature

B_o, B_g, B_w	Formation volume factor for oil, gas and water, dimensionless
D	Depth of the reservoir, m
Dx, Dy, Dz	Grid spacing in x, y and z directions, m
g	Gravitational acceleration, 9.8 m^2/s
K	Reservoir absolute permeability, m^2
K_{ro}, K_{rg}, K_{rw}	The relative permeability of oil, gas and water, dimensionless
M	Surface flux, m^3/m^2
M_t, M_d	Total and directional surface fluxes, m^3/m^2
M_x, M_y, M_z	Directional surface flux in x, y and z directions, m^3/m^2
p_o, p_g, p_w	Pressure of oil, gas and water, Pa
p_{cow}	Capillary pressure between oil and water, Pa
p_{cgo}	Capillary pressure between oil and gas, Pa
p_{wf}	Bottomhole flowing pressure, Pa
Q	Cumulative water flux flow through a surface, m^3
Q_x, Q_y, Q_z	Cumulative water flux flow through a surface in x, y and z directions, m^3
R_{wpv}	Ratio of cumulative flow through water volume to cell, dimensionless
R_{so}, R_{sw}	Dissolved gas-oil and gas-water ratios, dimensionless
S_o, S_g, S_w	Saturation for oil, gas and water, dimensionless
t	Time, s
q_{vo}, q_{vg}, q_{vw}	Sink and source terms for oil, gas and water, kg/(m^3·s)
ρ_o, ρ_g, ρ_w	Densities of oil, gas and water, kg/m^3
Φ	Porosity, dimensionless
μ_o, μ_g, μ_w	Viscosities of oil, gas and water, Pa·s
WWCT	Simulated well producing water cut, dimensionless
WOPR	Simulated well oil production rate, m^3/d

[12] experimentally studied the change in the characteristics of the relative permeability curves and discovered that the irreducible water saturation increases, whereas the residue oil saturation decreases due to water erosion. Xu [12] also found that the water relative permeability at residual oil saturation is abated after water injection.

As the change in such physical properties engenders a great impact on the production performance of the entire oilfield, it is vital to consider the effects of the reservoir parameter time-variations in numerical simulations [13,14]. However, most of the commonly used reservoir simulation software fails to incorporate this mechanism [15]. Without consideration of the property time-variation, it is difficult for traditional simulators to achieve accurate water cut history matching at a later stage [16,17]. In addition, it is important to find a reasonable and feasible way to characterize the time-variation of reservoir properties in the numerical simulator.

There are some studies that have attempted to couple this time-variation mechanism into a numerical simulation. Gai et al. [18,19] adopted a stage approach called the staged reservoir simulation, which divided the simulation process into several different stages with different reservoir parameters. However, the abrupt change in the input parameter from stage to stage resulted in convergence problems, and thus, the validity of the simulation result is questionable. To overcome the drawback of the staged simulation, some researchers [20,21] managed to treat such properties as a function of the water cut. Although this function method achieved a continuous change in reservoir parameters, the calculated water cut only changed slightly at the high water cut stage (above 90%) in contrast to the real reservoir property measurements [8,12]. More recently, Jiang et al. and Xu et al. [12,22] proposed a new parameter, which is defined as the ratio of the cumulative flow through water volume, to the pore volume to characterize this mechanism. This parameter can reasonably describe the cumulative water erosion in the high water cut stage. However, this proposed parameter is strongly dependent on grid size, which causes instability in the simulation. Further, this method could not describe the change of permeability in different directions.

The aim of this study is to propose a novel and effective method to continuously characterize the time-variation of the reservoir properties in a numerical simulation. In this paper, a newly defined parameter 'surface flux' is adopted to describe these time-variation relationships. In addition, a new numerical simulator based on this method is developed to investigate how the property time-variation affects oil recovery, and how this mechanism can facilitate the history matching and production forecast process.

1.2. Definition of surface flux

To avoid the drawbacks of the previous characterization methods discussed in the literature review, a parameter that is less relevant to the grid size is needed. Therefore, we define surface flux (M) as the ratio of the cumulative water flux flow through a surface to the area of that surface, as shown in Eq. (1), to describe the relationship between the water flux and time-variation in the reservoir properties.

$$M = \frac{Q}{A} \tag{1}$$

As seen from Eq. (1), the derivative of the surface flux is the flow velocity, and thus, this parameter has a clear physical meaning and can reasonably represent the cumulative intensity of the water erosion. For flow in different directions, the surface flux can also be calculated using the directional water flux. For an arbitrary grid in three-dimensional space, the 3-dimensional surface flux can be derived in Eq. (2). The total surface flux of this grid is the sum of all directional surface fluxes, which is shown in Eq. (3).

$$M_x = \frac{|Q_x|}{D_y D_z},\ M_y = \frac{|Q_y|}{D_x D_z},\ M_z = \frac{|Q_z|}{D_x D_y} \tag{2}$$

$$M_t = \frac{|Q_x|}{D_y D_z} + \frac{|Q_y|}{D_x D_z} + \frac{|Q_z|}{D_x D_y} \tag{3}$$

Below is a brief example used to illustrate the advantage of the surface flux (M) over the ratio of the cumulative flow through water volume to the pore volume (R_{wpv}). As shown in Fig. 1, there is a cylindrical core flooded by one-dimensional water injection. The cumulative injected volume is Q at a given time, the total pore volume of the core is PV, and the cross section of this core is A. If we regard the core as a single grid, then the R_{wpv} at a given point within this core equals Q/PV, and the surface flux at a given point is Q/A. However, if we divide the core into n, 2n and 3n grids, then the R_{wpv} of a given point within this core equals Q/(nPV), Q/(2nPV) and Q/(3nPV), but the surface flux at a given point is still Q/A. Therefore, surface flux is more suitable than R_{wpv} to characterize the property time-variation mechanism in the simulation, because with the same extent of water flooding, the parameter used to describe property time-variation should be the same.

Clearly, the surface flux is superior compared to R_{wpv} because of it is independent of the grid size. Therefore, surface flux is chosen to describe the property variations during the numerical simulation in this

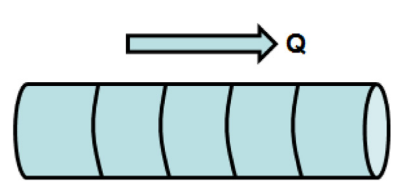

Fig. 1. Illustration of water injection into a cylindrical core.