Measurement 129 (2018) 1–10

Contents lists available at ScienceDirect

Measurement

journal homepage: www.elsevier.com/locate/measurement

Estimation of oil reservoir parameters from temperature data for water injection

Yong-Le Nian, Wen-Long Cheng*

Department of Thermal Science and Energy Engineering, University of Science and Technology of China, Hefei, Anhui 230027, China

ARTICLE INFO

Keywords:
Heat and mass transfer
Water injection
Flow rate
Oil saturation
Inversion method
Reservoir temperature data

ABSTRACT

Fluids and oil flow rate, oil saturation and reservoir porosity as well as their measure method play a key role in petroleum engineering. Based on analysis of heat and mass transfer for hot water injection reservoir, this study presents a novel method to estimate the above parameters of oil reservoir simultaneously just from temperature data. The proposed method is an inversion method coupling with Monte Carlo stochastic approximation method. Firstly, a two-phase flow and heat transfer model in core flooding for hot water injection reservoir was built to simulate the reservoir temperature. Then, based on the built model, the concerned parameters were estimated sequentially by the inversion method from the reservoir temperature data which was obtained in a built experiment. Moreover, for determining sequence of parameters inversion, sensitivity analysis was performed to investigate correlation between the estimated parameters and reservoir temperature. Lastly, applying the presented method to two experimental water injection reservoirs, the transient flow rate, oil saturation and porosity during oil displacement were obtained. The prediction errors of oil flow rate and oil saturation for were less than 10% at all times, especially, the mean prediction accuracy for oil flow rate could reach 1.9%, and the mean accuracy for the oil saturation was about 2.0%.

1. Introduction

Despite rapid development of new energy technology; petroleum demand in the world grows steadily and faces limited supplies. Accurate assessment of oil and gas production is very important for the petroleum supply. Specially, the measurement of oil and gas flow rate for petroleum well is the most important work to evaluate petroleum production. In fact, the flow rate can be measured by the flow meter installed at wellhead. However, flow-rate metering gets an unsatisfactory achievement in the industry. For example, the individual well flow rate is assigned from total production with allocation algorithms, unless each production well is instrumented with a flow-meter well [1]. However, it was reported that there are just about 3000 three-phase flow meters installed on production facilities for 1 million wells worldwide [2]. For the individual well, well-testing technologies are widely used to predict petroleum production and reservoir flow, including pressure buildup testing and production testing. However, for the well with multi-production layers, the flow rate of each layer is usually uniform, but the estimation of flow rate for single layer is just by allocating the total flow rate to each layer equally by using the well testing technologies, it would introduce error to evaluate the flow rate of single layer [3,4]. Also, although using a flow meter for direct measurement at each layer can overcome the disadvantage by the allocation algorithms, the direct measurement of multiphase flow is still difficult work, because production fluids usually contain oil, water and gas, involving three-phase flow. Most of the flow meters are high-efficiency to measure the flow rate of complete flow, partial flow and separation of phases flow especially for oil-water flow [5], but the measurement accuracy for multiphase flow is usually lower than 5% [2,6].

As an important parameter for reservoir description, oil saturation represents the oil content in reservoir and characterizes petroleum reserves for an oil field. Although the measurement of oil or water fraction in oil-water flow pipes got a high precision now days [7–9], even the error lower 5% [7,10], the accurate measurement of oil saturation in petroleum reservoir under real geological conditions still was a difficulty work. Core analysis perhaps is the most direct method to measure oil saturation through collecting oil core chip and measuring parameters of reservoir rocks and fluids properties [11]. However, many factors can influence the precision of saturation measurement, more specially, it is difficult to collect core under initial rock pressure. Consequently, core analysis method for oil saturation measurement shows relative error about 10–30% [12,13]. As a widely applicable method for petroleum exploration and development, well logging technology based on geophysics is used to investigate rock and fluid

* Corresponding author.
E-mail address: wlcheng515@163.com (W.-L. Cheng).

https://doi.org/10.1016/j.measurement.2018.07.018
Received 9 May 2018; Received in revised form 5 July 2018; Accepted 6 July 2018
Available online 07 July 2018
0263-2241/

Nomenclature

Variables

A	reservoir area, m^2
A_k	uncertainty parameters, $k = 1, 2, 3$
b	reservoir thickness, m
j	variable denoting random values of uncertainty parameter
K	permeability, m/s
L	reservoir length, m
N	sample size
$PRCC$	Spearman's partial rank correlation coefficient
p	pressure, MPa
Q	production or flow rate, $mL \cdot min^{-1}$
$R(x_j)$	rank of random values of uncertainty parameter
$R(y_j)$	rank of simulated reservoir temperature
S	saturation
T	temperature, K
v_f	fluid velocity, m/s
V_{oi}	initial oil content, m^3
V_o	oil production volume, m^3
V_r	reservoir volume, m^3
x_j	uncertainty parameter
y_j	reservoir temperature simulated by uncertainty parameters

Greek letters

λ	thermal conductivity, $W \cdot m^{-1} \cdot K^{-1}$
(ρc)	volumetric heat capacity, $J \cdot m^{-3} \cdot K^{-1}$
φ	reservoir porosity
τ	injection time h
μ	viscosity mPa·s

Subscript

0	initial condition
f	total fluid
in	injection
o	oil
r	reservoir
s	solid
w	water

physical properties. The method can overcome the difficulty in the core analysis method for saturation measurement, because the oil saturation can be predicted indirectly by the electrical resistivity logging [14], pulsed neutron logging [15], nuclear magnetic resonance logging [16,17] and tracer technique [18]. However, some methods of well logging technology are not so satisfactory; for example, the error of electrical logging for oil saturation estimation is usually higher 10%, and it can be infeasible when different conductive properties of water in core [19,20]. Generally, the nuclear logging is suitable for large-porosity reservoir, and it is a long time for pulsed neutron logging to get sufficient accuracy because of the low testing speed.

Compared to other data by electrical, nuclear and acoustic logs, the temperature data can be obtained easily with high precision. However, at present the temperature data just can be applied to determine the position of productive strata by measuring the temperature gradient in wellbore during well testing, its application has been restricted. Especially for thermal oil recovery, it was confirmed that there are close correlations between the temperature and fluid, surrounding formation and reservoir parameters [21,22]. For example, the wellbore fluid temperature is influenced by flow rate and thermal properties of surrounding formation during the injection and production process. Therefore, some researchers tended to used temperature data for parameter estimation. Curtis [23] used the dynamic temperature log data to predict both mass and volumetric flow rate in production well and the production for each layer was obtained by the difference in flow rate between above and below layer. Izgec [1] estimated the production rate from the temperature and pressure data at wellhead, and two different methods were used respectively. Duru and Horne [24] coupled wellbore temperature model with a built reservoir temperature model to monitor transient bottom hole temperature, and based on the coupled model, they matched the temperature to obtain transient flow rate and reservoir properties. Barret [25] used the vertical temperature and pressure data to determine the gas flow rate distribution along wellbore, the estimated results were selected by minimizing the quadratic difference between the modeled results and measured data and the formation thermal conductivity also could be obtained by the method. Cheng [26,27] focused on the estimation of formation and reservoir thermal properties from temperature logs by a stochastic approximation method, and the distributions of thermal properties also could be obtained [28]. By building a transient fluid temperature model in wellbore, Hashmi [29] estimated the gas flow rate from the transient temperature data at different vertical points, the method was suggested for interpreting early-time cleanup data and formation permeability estimation.

It could be found that the previous studies mainly focused on the wellbore and modeling its flow and heat transfer, aiming to estimation of wellbore flow rate and surrounding formation parameters. The reservoir parameters such as oil saturation, flow rate and porosity were ignored. Especially, due to the well store effect and skin factor, the flow rate in the reservoir would differ from that in the wellbore. Thus, it inspires us to study reservoir parameters estimation from temperature data. In order to develop a method for reservoir description and parameter estimation, this study presents a novel method to predict the transient flow rate, reservoir porosity and oil saturation simultaneously through temperature data for water injection reservoir. A heat transfer and flow model for water injection reservoir was built to simulate reservoir temperature, and the transient temperature data came from a special experiment. Finally, systematic procedures to predict transient reservoir parameters were focused in this work and applied to reservoir description.

2. Two-phase flow and heat transfer in water injection reservoir

Comparing with heat conduction dominating the heat transfer in formation, the heat transfer in water injection reservoir characterizes process which involves multiphase flow and heat transfer in porous media, both conduction and convection heat transfer will occur in reservoir. For water injection reservoir, due to the temperature difference between the injected hot water and reservoir, the heat transfer will occur in reservoir during injection and oil displacement, when ingoing the gas phase, the two-phase flow and heat transfer occurs in the porous media of reservoir which shown in Fig. 1.

By assuming the thermal equilibrium between solid and fluid in homogeneous reservoir, and impermeable for adjacent rock. The energy equation for the porous media of water injection reservoir can be expressed as:

$$\frac{\partial}{\partial \tau}(\rho c)_r T_r + (\rho c \vec{u})_f \cdot \nabla T_r = \lambda_r \nabla^2 T_r + q_L \quad (1)$$

Where the T_f are the reservoir temperature; q_L is the heat loss to o adjacent rock.

$$(\rho c)_r = \varphi[(\rho c)_o S_o + (\rho c)_w S_w] + (1-\varphi)(\rho c)_s \quad (2)$$