Petroleum xxx (2018) 1–6

Contents lists available at ScienceDirect

Petroleum

journal homepage: www.keaipublishing.com/en/journals/petlm

Fluid flow with compaction and sand production in unconsolidated sandstone reservoir

Yu Xiong [a], Hongguang Xu [a,*], Yongqing Wang [a,**], Wensheng Zhou [b], Chen Liu [b], Ling Wang [c]

[a] State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu, Sichuan, 610500, PR China
[b] Cnooc Research Institute, Beijing, 100027, PR China
[c] Nanchong Professional Technic College, Nanchong, 63700, PR China

ARTICLE INFO

Article history:
Received 3 July 2017
Received in revised form
26 March 2018
Accepted 2 May 2018

Keywords:
Compaction
Sand production
Seepage
Unconsolidated sandstone

ABSTRACT

The fluid flow of unconsolidated sandstone reservoir can be affected by compaction and sand production which will damage the reservoir and affect oil well productivity. This study aims to measure how the two factors affect the fluid flow. Firstly, single-phase displacement test was applied to investigate how the permeability changed with compaction. Then two-phase displacement test assessed the influence of compaction on oil production. Finally, the characteristics of fluid flow with compaction and sand production were studied under different water content. The results demonstrate that the reduction of permeability with compaction is irreversible, which will result in lower productivity. In contrast, sand production can increase the permeability at mid and high water content, which slows down the decline of oil production. Generally, the oil well productivity is reduced because of compaction even with sand production, especially when the formation pressure drop varies from 2 MPa to 4 MPa. Consequently, advance water injection is necessary to keep the formation pressure and oil production during oilfield development of unconsolidated sandstone reservoir. Simultaneously, the study can provide theoretical basis and references for the similar reservoirs.

1. Introduction

The fluid flow in unconsolidated sandstone reservoir can be severely affected by many factors, especially compaction and sand production. Compaction and sand production are widespread and perplexing problems in unconsolidated sandstone reservoir. The problem can reduce the oil production, damage permeability and porosity and even cause reservoir impairment, surface subsidence and casing failure [1–5]. Therefore, it is crucial to know how and when compaction and sand production would occur so that proper measures could be adopted to guarantee the oil production. Some previous works have been developed to study the compaction behavior and sand production, including field or laboratory evaluation and theoretical modeling.

Several laboratory studies have focused on the compaction behavior of siliciclastic rock. An experimental approach was adopted to measure the production-induced compaction, which showed that the compaction was nonlinear [6,7]. Furthermore, physical properties and seepage characteristics of unconsolidated sandstone with compaction were investigated and the results revealed that the variation of porosity and permeability was irreversible, which could influence fluid flow in porous media [8]. Subsequently, several studies focused on the influence of the stress variations on the volumetric deformational behavior of some unconsolidated sands [9–16]. The results indicated that compaction could induce inelastic and irreversible deformation, which led to sand production simultaneously. After that, several laboratory experiments were applied to analyze sand production performance over time [17–19]. The research indicated that sand production was

* Corresponding author.
** Corresponding author.
E-mail addresses: xhg311312@126.com (H. Xu), swpiwyq@163.com (Y. Wang).
Peer review under responsibility of Southwest Petroleum University.

Production and Hosting by Elsevier on behalf of KeAi

https://doi.org/10.1016/j.petlm.2018.05.003

affected by the flow rates, water saturation, the salinity of injected water, the confining pressure, the drawdown and the viscosity of the formation fluid. These results could be used to improve field situation and provide important references for field management. However, most of the work focused on the mechanism of compaction and the factors on sand production. The influence of compaction and sand production on fluid flow was lacking, especially considering compaction and sand production simultaneously.

In this work, a series of core flooding tests were designed to investigate compaction and sand production on fluid flow of an unconsolidated reservoir located in the Bohai Sea. The cores and crude oil samples from the unconsolidated sandstone reservoir were used in the tests. The permeability, pressure drop, relative permeability and sand volume were measured concerning compaction and sand production. Three groups of experiments were conducted for different purposes: (1) single-phase displacement test; (2) two-phase displacement test with compaction; (3) two-phase displacement test with compaction and sand production. Finally, we got the fitting equation to calculate the oil production by the method of Levenberg-Marquardt [20] with compaction and sand production. These results were used to predict the reasonable formation pressure drop and producing drop pressure.

2. Experimental methodology

2.1. Experimental setup

The displacement experiments were conducted with a high pressure, 2.54-cm core holder (TY4). The core holder was operated with a high-pressure pump (up to 70 MPa) to control independently the confining pressure. The pore pressure regulation was achieved by a back pressure device, while the flow was generated by two syringe pumps.

In order to measure the low differential pressure, a couple of transformer sensors and a differential transmitter with high accuracy (±0.05%) were adopted. The experimental data was collected constantly by a date acquisition of pressure across the core holder and flow through the electronic balance by computer. The temperature controlling system consisted of a heat gun, temperature controller with a temperature probe (0−200 °C), and two fans to maintain constant and homogeneous temperature. Two transfer cylinders were used for injecting formation water and heavy oil. Fig. 1 presented a schematic of the experimental setup used for the displacement experiments.

2.2. Sample/fluid properties

The experiments were performed with unconsolidated sandstone from the corresponding oil layer of the Bohai Sea. The samples were prepared directly in the sleeve of diameter D = 2.51 cm. Porosity was measured by both weighting and gravity saturation. Absolute permeability was measured by an air permeameter with nitrogen and brine. Properties of rock used in the single-phase and two-phase displacement experiments were summarized in Table 1. The brine was reformulated of deionized water and $NaHCO_3$ and other salts with the salinity of 6000 mg/L according to the component analysis of formation water. The oil was prepared with crude oil and kerosene to get the desired viscosity.

2.3. The experimental procedure

2.3.1. Single-phase displacement experiment

Single-phase displacement experiment was performed to measure the variation of permeability with compaction by brine injection. The clean, dried core was first weighed and then placed into the core holder. After applying overburden pressure of 2 MPa, the temperature was set to the desired temperature. The transfer cylinder was filled with brine and allowed to equilibrate for 24 h. Core was vacuumed for 2 h and saturated 100% with brine to measure its porosity. Then brine was injected into the saturated core at a constant rate of 1 ml/min via a transfer cylinder. The back pressure was maintained by a back pressure regulator with the overburden pressure rising synchronously. The back pressure was set at the initial reservoir pressure of 15 MPa, and then the overburden pressure was raised to the initial pressure of 30 MPa gradually. The core was allowed to equilibrium for 1 h in each pressure. In the next phase of the experiment, the back pressure was reduced to current reservoir pressure gradually in successive stages from 15, to 12, 9, 7, and finally 5 MPa.

2.3.2. Two-phase displacement experiment with compaction

The experiment was performed to measure the flow characteristics of oil-water displacement system in porous media with the standard test method of two-phase relative permeability in rocks [21]. The core was first prepared the same as the experimental procedure in 2.3.1. Then oil was injected into the saturated core at a constant rate of 0.1 ml/min via a transfer cylinder with the overburden pressure of 5 MPa. Oil injection was maintained until establishing irreducible water saturation. During oil injection, effluent fractions were collected in the grated tubes while recording time. In the next phase of the experiment, oil and brine were injected into the core on the desired flow rate. Eventually, the brine was injected at a constant rate of 1 ml/min until residual oil saturation was established. Then overburden pressure was changed to the desired value and the experimental procedure above was repeated.

2.3.3. Two-phase displacement experiment with compaction and sand production

Through two-phase displacement experiment with compaction and sand production, it is possible to have a simultaneous flow of two phases in the porous media. The simulation oil and brine were applied in the experiment under the same sand control measure with the mesh size of 0.125 mm. Test preparation was the same as the process described for the two-phase displacement in 2.3.2. Then oil was injected into the saturated core at a constant rate of 0.5 ml/min via a transfer cylinder until irreducible water saturation was established. After that the original pore pressure of 15 MPa was maintained by a back press pump with the overburden pressure rising to 30 MPa. Then oil was injected into the core at a constant rate of 5 ml/min, while the flow rate of brine was 1 ml/min. Then the pore pressure was reduced to the desired value from 15, to 12, 9, 7, and 5 MPa. The data of pressure and flow rate were collected until the steady state was achieved. In the next phase, the flow rate of oil was changed at 3, 2, 1, 0.5, 0.2 ml/min while the flow rate of brine was unchanged at 1 ml/min to simulate different water content. The decline of pore pressure was repeated under different water content.

3. Experimental results and discussion

3.1. The petrophysical properties of sandstone with compaction

Fig. 2 presented the variation of permeability when the back pressure was changed. The permeability was decreased from 325mD to 155mD when the back pressure was decreased from 15 MPa to 5 MPa, a decline of 52.3%. The permeability was not restored when the back pressure was increased from 5 MPa to 15 MPa to simulate the process of water injection. The porosity was decreased from 34.3% to 29.5%, a decline of 13.8%. The permeability and porosity of unconsolidated sandstone were reduced with the

Please cite this article in press as: Y. Xiong, et al., Fluid flow with compaction and sand production in unconsolidated sandstone reservoir, Petroleum (2018), https://doi.org/10.1016/j.petlm.2018.05.003