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A new practical method for determination of critical flow rate in Fahliyan carbonate reservoir

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ABSTRACT

In this study, a series of core flooding experiments has been carried out to determine the critical injection flow velocity in the porous media of the Fahliyan carbonate formation. For this purpose, a new practical method is employed and applied in two steps. First, a base-line permeability corresponding to a base rate is adopted and the injection rate is then returned to the base rate after each incremental stage in order to recalculate the permeability. Then a predefined parameter called 'degree of formation damage' is calculated at the base-line permeability at each stage. Experimental data shows that there is a linear relationship between the flow rate and the degree of formation damage. The critical injection rates corresponding to different degrees of formation damage, reported only as estimation in other works, are also calculated accurately in this study.

1. Introduction

For most oilfield operators it is crucial to reach a high production rate. This is usually achieved by using such techniques as stimulation and EOR. However, the negative impacts of extreme fluid velocities in the porous media including excessive pressure drops and/or formation damage should be properly predicted. The latter could occur in the form of physical, chemical, biological and thermal damage (Miranda and Underdown, 1993; Moghadasi et al, 2002; Civan, 2007; Renpu, 2011). It could both be temporary, e.g. exceeding the turbulent limit of fluids in porous media and permanent, e.g. fine and sand production or fissure and fracture activation.

Most reservoirs contain small-diameter colloidal particles in contact with reservoir fluids. During drilling, completion, stimulation, workover, water injection and oil production operations different types of fluids interact with these uncemented particles and in some cases force and dislodge them from their original locations (Egbogah, 1984; Amaefule et al., 1988; Rahman et al., 1994). Miranda and Underdown (1993) reported that high fluid flow rate in the porous media was the main reason for fine migration in certain reservoirs. The minimum flow rate at which small particles detach and migrate within the pores of the formation is called "critical flow rate" (Mueke, 1979; Gabriel and Inamdar, 1983; Leone and Scott, 1988; Amaefule et al., 1988; Miranda and Underdown, 1993).

Type, location, size and concentration of fines in the pore network are physical factors determining the hydrodynamic conditions required for fine migration (Porter, 1989; Ohen and Civan, 1991; Zeinijahromi et al., 2011a, 2011b). On the other hand, Read (1989) stated that the pore geometry and the moving fluid viscosity are the important parameters for the determination of critical flow rate (CFR) in porous media (Read, 1989). According to Amaefule et al. the ionic strength and the pH of the injecting fluid, interfacial tension, pore geometry and morphology, and the wettability of rock and fine particles are the dominant factors that control the critical velocity (Amaefule et al., 1988). The critical flow rate/velocity may suspend fines or force them to move and precipitate in the pore spaces and result in pore plugging (Sharma, 1985; Wojtanowicz et al., 1987; Nguyen et al., 2012; Zeinijahromi et al., 2012). Consequently, the pressure drop along the porous media will become higher and cause a reduction in the permeability. In some cases a reverse phenomenon could occur where the permeability would show an abrupt increase due to a possible fracture opening (stimulation). Also there might be occasions where the permeability has a slight increase even at lower flow rates. This is due to core cleaning where fines smaller

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than the pore size are detached and entrained within the flow to the outlet. According to Khilar and Fogler, this phenomenon is called piping or washout of fines (Khilar and Fogler, 1998). Both of these phenomena causing the permeability to increase are also referred to as formation damage in this work.

There are not many published works on the effect of flow rate on permeability damage. Nevertheless, a few experimental techniques have been proposed for the determination of CFR through core-flooding tests (Forchheimer and Hydraulik, 1914; Amaefule et al., 1988; Leone and Scott, 1988; Miranda and Underdown, 1993; Renpu, 2011). One method that was introduced by Forchheimer (Forchheimer and Hydraulik, 1914) is to calculate the differential pressure across the core divided by flow velocity and then plot it as a function of flow velocities (DP/U vs. U). According to this theory, the ratio DP/U remains constant when there is no fine migration. But for velocities higher than the critical velocity the pressure drop across the core will increase gradually leading to a decrease in the calculated permeability value. So, the ratio should lie on the original value; otherwise the formation damage caused by fine migration for elevated pressure drops is likely to occur.

Leone and Scott conducted a comprehensive test series for a high clay content reservoir using two brines named as A and B (Leone and Scott, 1988). In their work, severe permeability damage was observed when decreasing the flow rate from 2 cc/min to 0.5 cc/min in a step-wise manner. The permeability damage was determined to be about 70% during the test. The results of the tests by different non-damaging brines confirmed the occurrence of mechanical fine migration as primary damage mechanism.

Miranda and Underdown proposed a method for the determination of CFR in core samples at reservoir conditions (Miranda and Underdown, 1993). According to this approach, the fluid is injected at a very low injection rate called base-line permeability. Then, the rate is increased in a step-wise manner and then returned to the initial rate (base-line permeability) after each incremental stage. Experimentally derived flow rate and permeability data are converted to bottom hole and wellhead production rates using completion data and well geometry (Miranda and Underdown, 1993).

Renpu (2011) used a parameter called degree of formation damage, D_k, in order to evaluate the sensitivity of core permeability to the flow rate. D_k is defined as below:

$$D_k = \frac{K_{i-1} - K_i}{K_{i-1}} \times 100 \quad (1)$$

where K_{i-1} is the permeability at flow rate Q_{i-1}, K_i the permeability at flow rate Q_i and D_k the degree of formation damage.

The value of D_k calculated by this equation depends on the permeability change caused by the changes in flow rate. As long as $D_k \le 5$, there will be no damage in the core sample. The different formation damage boundaries are defined in Table 1.

The above definition that is derived from a Chinese Standard (SY/T5358-2002) was employed by Renpu (2011) who used the results of flooding tests on 10 core samples to quantify the formation damage. He increased the flow rate by injecting kerosene to quantify the degree of formation damage in linear and radial flow. In his tests, however, he did permeability calculations at increased flow rates and not at the base rate as he did not return to a predefined initial rate after raising the rate at each step. The problem with this approach is that any permeability reduction is interpreted as formation damage.

In core-flooding experiments, after increasing the injection rate the differential pressure normally goes up due to the turbulency. As a result, the calculated permeability will be slightly lower. In these cases, if the rate is returned to the baseline rate, the permeability will also get back to its initial value indicating no formation damage. In this work, in order to avoid misjudgment on the occurrence of formation damage, degree of formation damage is determined only at base rate and comparison is made based on the values obtained at baseline. Therefore a combination of two approaches, i.e. Miranda and Underdown (Miranda and Underdown, 1993) and Renpu (Renpu, 2011), is employed here to do the permeability measurements and to calculate the degree of formation damage. In other words, a base rate hence a base-line permeability is adopted and the injection rate is returned to the base rate after each incremental stage. Then the degree of formation damage is determined through Eq. (1) at consecutive baseline permeabilities. Since the positive and negative signs are only an indication that the permeability goes up or down, the absolute value of D_k is used here to show the magnitude of permeability alteration and formation damage. An accurate and reliable quantification of formation damage and corresponding critical flow rates in plug samples taken from Fahliyan formation are carried out by the proposed technique in this work.

2. Material and methods

2.1. Core samples

The plug samples used in this work were obtained from Fahliyan carbonate formation in one of Iranian oil wells. Yadavaran Oilfield is located around 70 km to the southwest of Ahwaz and near the Iran–Iraq border in SW of Iran, and spreads out over a large geographical area stretching some 45 km from north to south and 15 km from east to west. In Yadavaran field, there are three main oil-bearing formations, namely Sarvak, Gadvan and Fahliyan.

After cleaning by methanol for a period of time and measuring the petrophysical properties such as porosity and air permeability, core samples were saturated by 4% KCl (synthetic brine) under sufficient vacuum pressure. Table 2 shows the specifications of plug sample used for flooding experiments. Plugs were selected from upper, middle and lower parts of Fahliyan formation.

Fahliyan formation is mostly composed of calcite and dolomite. The composition of the selected plugs (obtained from XRD data) is presented in Table 3:

Table 2
Description of the plug sampled from Fahliyan carbonate formation.

Plug No.	Depth (m)	Porosity (∅)	Air permeability (md)	Plug dimensions	
				D (cm)	L (cm)
1	4134.84	21.70	5.308	3.81	5.10
2	4202.39	20.34	4.9	3.81	5.14
3	4280.53	15.88	12.45	3.81	5.13

Table 1
Evaluation criteria for degree of rate sensitivity damage.

Formation damage degree (%)	$D_k \le 5$	$5 < D_k \le 30$	$30 < D_k \le 50$	$50 < D_k \le 70$	$D_k > 70$
Scale of damage	None	Weak	Medium to weak	Medium to strong	Strong