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A criterion for evaluating the efficiency of water injection in oil sand reservoirs

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ABSTRACT

Steam Assisted Gravity Drainage (SAGD) has been implemented at a large scale in the development of ultra-heavy oil reservoirs in Karamay city, the Xinjiang province of China. Before circulating steam, byproduct water from previous SAGD projects is injected into a SAGD wellpair in order to create a dilative and highly permeable zone in the inter-well domain. A criterion is desired to evaluate how efficient this injection/stimulation has been performed. The criterion was based on pore pressure distribution in the domain encompassing the dual wells, which was the outcome from finite element analysis using the Drucker-Prager model to describe oil sand. The analysis used constitutive parameters calibrated by laboratory results and the real-time injection data input as loading conditions. Based on the simulated pressure profile, communication parameter (CP) was proposed to represent the efficiency of water injection, with a magnitude varying from 0 to 1. It was found that CP gradually and continuously increased with the injection process, demonstrating that the efficiency increases with time and pressure. Moreover, by monitoring the time point at which the injection rate dramatically increased in the field, a group of threshold CPs were established based on the previously completed stimulation projects on a variety of oil sand reservoirs. The criterion was then fulfilled by comparing the calculated CP to the threshold CP of a specific reservoir type. By applying the criterion in the stimulation projects of two wellpairs in the field, it was observed that immediately after the CP exceeds the threshold value of the corresponding reservoir type, the pressure of the dual wells was quickly responsive to each other and the injection rates sharply increased. The preheating periods of the two wellpairs decreased from conventionally 180–300 days to 60 and 90 days, implying the success of reservoir stimulation. The proposed criterion can not only be used to quantitatively describe how efficient a water injection process has achieved, but also to determine whether the stimulation of an oil sand reservoir has been successfully accomplished. When the criterion is satisfied, the field engineers can confidently move on to the steam circulation stage.

1. Introduction

Steam assisted gravity drainage (SAGD) has become the predominant method of recovery to develop the heavy and ultra-heavy oil resources in Xinjiang, northwest China. Its application comprises mainly of two stages known as preheating and circulation. At present, a water injection process prior to preheating is commonly implemented in field practices. The procedure involves injecting byproduct water at 20–80 °C into the injection well (I well) and production well (P well) simultaneously in several pressure increments. It is intended to create a homogeneously dilated zone encompassing the dual wells, therefore shortening the time span of preheating and saving cost both economically and environmentally (Yuan et al., 2011a, 2011b, Dragani and Drover 2016). However, when this procedure can be considered as successfully accomplished is unclear up to date.

Because the oil sand is intrinsically a material of sand grains wrapped by a mixture of bitumen, clay and water, previous investigation on the injection-induced dilation of the pay zone naturally borrowed the idea from classic soil mechanics on the sand behavior. A category of Canadian researchers began to experimentally study the geomechanics of the oil-free oil sand to better understand the permeation and deformation of the Alberta oil sand reservoirs during the steam-injecting recovery processes in the past century (e.g., Dusseault, 1977, Dusseault and Morgenstern, 1978, Agar et al., 1983). Later on, the roles of geomechanics, especially the shear dilation of sand grains, on the enhancement of the SAGD production process were thoroughly examined (Chalaturnyk et al., 1995, 1997; Carlson, 2003; Collins et al., 2002, 2005). Meanwhile, a model for permeability

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changes in oil sand due to shear dilation were developed to implement shear-induced permeability anisotropy in the recovery activities (Wong and Li, 2001; Wong, 2003). In their model, hydraulic flow anisotropy was simulated as a linear correlation of strain anisotropy, where the strains are total strains incorporating both elastic and plastic strains (if any).

The aforementioned research efforts mainly focused on the use of geomechanics to improve the production when the heavy oil has been heated to the fluid state. Because shortening the preheating period requires stimulation of the reservoir, as previously discussed, several researchers proactively utilized geomechanics to enhance the recovery by hydraulically fracturing the reservoir before preheating (Yuan et al., 2011a, 2011b, Yuan, 2013). The geomechanical behavior used in the analysis was based on the experimental investigation on undisturbed oil sand specimens (Oldakowski, 1994; Samieh, 1995; Wong, 1999). It must be noted that “water injection” instead of “hydraulic fracturing” is a more appropriate term to describe the stimulation of heavy-oil reservoirs (Lin et al., 2016a), because the stress shadow effect typical of hydraulic fracturing is unlikely occurring during the stimulation of an unconsolidated reservoir. Also, the duration of implementation for the hydraulic fracturing (hours) is much shorter than the water injection for the stimulation of oil sand reservoirs; the latter usually lasts one week or so. The primary mechanisms of water injection resulting in the expansion of the pore space and improvement of the permeability were identified as (1) shear-induced and (2) tensile-parting induced dilation (Yuan et al., 2011a, 2011b).

At present, no quantitative approach is available in literature to evaluate how efficient such a water injection stimulation has been accomplished. The situation hinders the design of a proper water injection scheme before its implementation. Therefore, this article is dedicated to proposing a criterion for evaluating the efficiency of water injection in heavy oil sand reservoirs, which is based exclusively on a quantified parameter.

2. Materials and methods

2.1. Petrophysical properties of the oil sand samples

The heavy oil sand reservoirs were deposited during the Jurassic period in the Qigu and Badaowang formations. The major reservoir areas are located at the Fengcheng oilfield, which is 130 km to the northwest of Karamay city, Xinjiang province, northwest China. The formations are formed of oil sand grains filled with bitumen and mud, overlying an overlapping pinch-out belt on the upper side of the Karamay-Wuerhe overthrust belt in the northwestern margin of Junggar basin. The oil sand formation usually has a Young’s modulus less than 1 GPa (e.g., Table 2) and has widely been described as “unconsolidated” in literature (e.g., Chalaturnyk et al., 1995, 1997; Collins et al., 2002; Carlson, 2003; Yuan et al., 2011a, 2011b), as compared to highly cohesive rock formations such as tight sandstone, chalk, limestone and shale with a Young’s modulus ranging from several tens to a hundred GPa (Fjar et al., 2008).

Nine wellpairs were selected for the development of the criterion and marked as A-1, B-1–B-8. As indicated, one was from area A and the others from area B. These reservoirs were chosen because they were among the very few completed ones that had recorded a detailed set of petrophysical and injection data. Moreover, the oil sand cores used for laboratory tests were collected from these two areas. The depth of the reservoirs ranges from 321 to 461 m with a pay zone thickness varying from 15 to 28 m. The collected oil sand samples were classified to five types based on their relative composition of bitumen and fines. The petrophysical properties are listed in Table 1.

In Table 1, the porosity and permeability data are relevant to the in-situ stress conditions. As illustrated, both the absolute and effective permeability decrease with an increase of either bitumen or fines content due to a reduced pore volume (Lin et al., 2016a). According to the petrophysical database provided by the consultant, the horizontal effective permeability is approximately at a ratio of 0.2–0.5 to the vertical. In the following simulation the hydraulic anisotropy was assumed a constant ratio of 0.5.

2.2. Numerical simulation scheme

The Drucker Prager (D-P) failure criterion has been frequently used in the simulation of water injection in heavy oil sand reservoirs (e.g., Settari, 2001, Xu and Wong, 2010, 2013, Yuan et al., 2011a, 2011b). The linear D-P model used is conceptually illustrated in Fig. 1, where $d\varepsilon^p$ represents the plastic strain increment.

As shown in Fig. 1, the linear extended D-P failure criterion (yield function) can be expressed as:

$$f = q - p' \tan\beta - d = 0 \tag{1}$$

where β and d are the D-P friction angle and cohesive strength, respectively. p' and q are the mean effective stress and Mises stress expressed as

$$p' = \frac{1}{3}I_1 = \frac{1}{3}\sigma'_{ii} \tag{2}$$

$$q = \sqrt{3J_2} = \frac{\sqrt{6}}{2}(s_{ij}s_{ij})^{\frac{1}{2}} \tag{3}$$

$$\sigma'_{ij} = \sigma_{ij} - \alpha_b P_w \tag{4}$$

$$s_{ij} = \sigma'_{ij} - I_1\delta_{ij} \tag{5}$$

where I_1 and J_2 are the first stress invariant and second deviatoric stress invariant; σ'_{ij}, σ_{ij} and s_{ij} are the effective stress, total stress and deviatoric stress, respectively; δ_{ij} is the Kronecker delta; α_b is the Biot coefficient; P_w is the pore fluid pressure. In this scenario, the only flowing fluid is water. Because oil sand is as compressible as soil, the corresponding Biot coefficient α_b can be taken as unity (Fjar et al., 2008). Terzaghi’s effective stress concept was adopted for the analysis by assuming that the reservoir was completely saturated in the water phase during injection. The elastic strains of the reservoir deformation are

$$\dot{\varepsilon}^e_{ij} = C_{ijkl}\dot{\sigma}'_{kl} \tag{6}$$

where C_{ijkl} is the elastic flexibility tensor; whereas non-associated flow rule is applied through the following equation to describe the evolution of plastic strains:

$$\dot{\varepsilon}^p_{ij} = \dot{\lambda}\frac{\partial g}{\partial \sigma'_{ij}} \tag{7}$$

where $\dot{\varepsilon}^p_{ij}$ is the plastic strain rate, g is the potential function defined by

$$g = q - p' \tan\psi \tag{8}$$

here ψ is the dilation angle, and $\dot{\lambda}$ is the plasticity multiplier characterized by

$$\dot{\lambda} = \frac{\dot{\varepsilon}^p_{11}}{1 - \tan\psi/3} \tag{9}$$

where hardening is defined through uniaxial compression tests (Niels and Matti, 2005; ABAQUS, 2014). The constitutive parameters of the model were deduced from drained triaxial tests. The mechanical properties of the selected oil sand samples are summarized in Table 2. As shown in Table 2, the Young’s modulus of the oil sands for this study have a magnitude ranging from 282 to 673 MPa, implying that the samples are unconsolidated material as previously discussed.

The $p' - q$ failure envelope was determined from drained triaxial tests on specimens under effective confining stresses of 0.5, 1.0, 2.0 and 5.0 MPa. An example of the fitted envelope (Type 3 sample in Table 2) is displayed in Fig. 2, resulting in a friction angle (β) of 46°