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Gas-condensate production improvement using wettability alteration: A giant gas condensate field case study

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ABSTRACT

Productivity loss due to condensate blockage is the main and common problem in gas condensate reservoirs around the world. Several methods such as gas recycling, hydraulic fracturing and solvent injection have been proposed to overcome this problem. But these methods usually are effective just for short periods of time. A novel approach in gas condensate reservoirs is altering the wettability of the reservoir rocks from strongly liquid wetness to preferential gas wetness or intermediate-wetting by treating them with chemicals. Most of experimental studies have focused on finding chemicals to perform a permanent wettability alteration in lab scale, but the effect of wettability alteration on production improvement in field scale has not been studied well enough, yet.

In this paper, the effect of wettability alteration on gas-condensate production improvement in field application was studied. First a radial single compositional well model was constructed using fluid and reservoir data from a giant gas condensate field in the Middle East located in the south of Iran. Three different relative permeability curves have been used in the model which represent three different wettability states.

The results showed that field gas-condensate cumulative production was improved greatly after the wettability of porous media was altered from liquid-wetting to intermediate- or gas-wetting by changing relative permeabilities for a treatment radius of 5 m around the wellbore. Production improvement in the intermediate-wetting state was maximized. Also, wettability alteration results in decreasing condensate saturation around the well and increasing the well bottomhole flowing pressure and productivity index.

1. Introduction

The reservoir studied in this paper is one of the world's largest gas condensate fields located in the Middle East. This field has been produced for about 10 years and the reservoir pressure has dropped below the dew point.

In gas condensate reservoirs, when the reservoir pressure falls below the dew point, a condensate phase will form and accumulate around wells. This liquid accumulation which is known as condensate blockage, results in well productivity reduction. As a consequence of this problem, gas and condensate production rates decrease dramatically (Fevang, 1995). Many investigators have proposed several methods such as gas recycling, hydraulic fracturing and solvent injection to restore gas and condensate production rates when condensate blockage has been occurred. These methods have not enough positive effects on this problem (Fernandez, 2011).

In recent years, wettability alteration, as a new method, has become more attractive for researchers in industry. Most of the gas-condensate reservoirs rocks are naturally liquid-wetting. Altering the wettability of the reservoir rock from strongly liquid wetness to preferential gas wetness or intermediate-wetting can increase the mobility of condensate and the relative permeability to gas.

Li and Firoozabadi (2000) modeled the wettability alteration in hydrocarbon systems of gas-condensate-rock. Using experimental methods, it was shown that the wettability of porous media in gas–liquid–rock systems could be changed from strongly liquid-wetness to preferential gas-wetness (Li and Firoozabadi, 2000). The wettability of the rock was altered by treating it with the chemical solutions FC759 and FC722 at laboratory conditions.

Tang and Firoozabadi (2002, 2003) performed wettability alteration at high temperatures up to 90 °C and measured the effect

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of wettability alteration on liquid mobility. This work has continued by Fahes and Firoozabadi (2005) for higher temperatures up to 140 °C. The results showed that at high reservoir temperatures, wettability could be permanently altered from liquid-wetting to intermediate gas-wetting and wettability alteration significantly increased liquid mobility at reservoir conditions.

Kumar et al. (2006) studied improvement of the gas and condensate relative permeabilities using chemical treatments under reservoir conditions. The experimental results showed that when Novec FC 4430 polymeric surfactant was used in the methanol-water mixture as the solvent, the productivity index was improved by a factor of 2–3 for sandstone cores over the temperature range of 145–275 °F.

Noh and Firoozabadi (2008) investigated the effect of wettability on the high-velocity coefficient in two-phase flow. The measurements showed that when the core is strongly water-wetting, the high-velocity coefficient increases (about 270-fold) in two-phase flow of water and gas. It has been concluded that altering the wettability by treatment of the wellbore region can greatly improve the well deliverability.

Zoghbi et al. (2010) studied an optimum wettability condition to maximize production enhancement. The simulation results indicated that when intermediate gas-wetting state was applied in the near-wellbore region, the gas-condensate well productivity increased significantly.

Wu and Firoozabadi (2011) showed that the change in the mobility of gas-phase is a function of the minimum liquid saturation. It has been confirmed that the wettability alteration may result in a substantial decrease in the two-phase high-velocity coefficient (β). The increase in the relative permeabilities and a decrease in the high-velocity coefficient of the two-phase flow from the wettability alteration will improve gas well productivity.

Li et al. (2011) conducted a series of experiments in the rock sampled from Dongpu gas condensate field located in Henan, China and developed a new and cheaper chemical to alter the rock wettability to gas-wetness effectively. The results indicated that after wettability alteration from preferential water to preferential gas-wetness, the relative permeabilities of both the gas and the water phases were increased remarkably. Also the residual water saturation was decreased and the gas production was enhanced significantly.

As it has been reviewed above, most studies have focused on finding chemicals to perform permanent wettability alteration experiments in lab scale, but the effect of wettability alteration on production improvement in field scale has not been studied well enough.

In this paper, first a single model is constructed to simulate one of the world's largest gas condensate fields located in the Middle East. Several runs were performed to investigate the effect of wettability alteration on gas-condensate production, to show field simulation effects of wettability alteration.

2. Methodology

In this study, first a cylindrical single well model was constructed. Then the model was validated using a downhole well testing data. Next, for investigation of wettability alteration, three different wettability cases were defined and finally the productivity and recovery of different cases were compared.

2.1. Fluid behavior

The target field is a giant gas condensate field with initial reservoir pressure and temperature of 365 bars and 376 K, respectively. The initial condensate to gas ratio (CGR) of reservoir fluid is around 2×10^{-4} Sm^3/Sm^3. According to PVT experiments results, the dew point pressure is 317 bar. The composition of the reservoir fluid is given in Table 1.

A PVT simulation has been performed based on the data presented above, and laboratory tests namely CVD, CCE tests. PR3 equation of state (3-PR-EOS) and Lorentz Bray Clark viscosity correlation were used to simulate the physical properties of the reservoir fluids. The EOS parameters have been tuned with CCE and CVD test data. The liquid dropout behavior of the tuned PVT model is shown in Fig. 1.

2.2. Reservoir simulation

The studied field is an offshore structure located in the south of Iran. The reservoir consists in four gas bearing in Kangan and Dalan formations, so-called layers 1 to 4 from top to bottom. Kangan and Dalan formations are mainly established of dolomite with some layers of limestone and anhydrite. Some detailed SCAL measurements were implemented to thoroughly characterize the rock types that showed dolomitic and limestone rock types have different pore sizes and saturation distributions.

Because of high thickness of productive zones of Kangan and Dalan formations, drilling of horizontal wells is out of the scope of the master development plan of the field. The exploration well of each phase in the field has been drilled vertically.

To characterize the geological 3D model of the reservoir a coherent study had been led by using the detailed petrographical, sedimentological, log typing, and SCAL works. This geological model has been used to construct the reservoir simulation model by means of special upscaling methods and dynamic information about the reservoir.

A single well radial model was constructed based on the valid reservoir data. The well is vertical and located at the center of the model with radius (r_w) of 0.15 m. The well produces at a constant surface gas flow rate of about 3×10^6 Sm^3/day.

Different block sizes in r, θ and Z directions were examined and suitable grid sizes were selected. The number of grid blocks in r, θ and Z-directions are 38, 1, and 10 respectively. The thickness of the reservoir is 430 m and the well is perforated along the whole reservoir thickness. The reservoir was assumed to be homogeneous of uniform thickness and its characteristics are constant and are shown in Table 2. In order to accurate simulation of the flow behavior of gas and condensate near wellbore, cells are smaller near well and their size increases logarithmically away from the well and high capillary number effects, were activated at the reservoir model. The reservoir has 4 main geological layers (A, B, C and D). Table 3 shows the properties of all layers.

Table 1
Composition of the reservoir fluid (a large gas condensate field in the south of Iran).

Component	H_2S	CO_2	N_2	C_1	C_2	C_3	iC_4	nC_4	iC_5	C_5	nC_5	C_6	C_{7+}
Mole (%)	0.15	1.92	3.28	82.8	5.23	1.95	0.42	0.72	0.32	0.01	0.29	0.4	2.51