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Experimental research of condensate blockage and mitigating effect of gas injection

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The condensate blockage causes a substantial decrease in well productivity for gas condensate reservoirs. Based on the previous studies, a novel experimental method was designed to evaluate condensate blockage and the mitigating effect of gas injection. The method considers the stacking effect in the near wellbore region and the gas flow in the far wellbore region. There is an intermediate vessel containing condensate gas at the entrance of core holder in the experimental apparatus. In the process of pressure depletion experiment in a long core model, the vessel is connected to the core and the pressure of the vessel remains above the dew point pressure. The seriousness of condensate blockage is investigated by this research. When pressure drops to maximum retrograde condensation pressure, the gas permeability decreases by 80% compared with the initial gas permeability. Contrastive experiments were conducted to study the removal effect of different injection fluids and different injection volumes. The results show that CO_2 injection is more effective than methanol in mitigating condensate blockage and the optimal CO_2 injection volume is around 0.15 HCPV.

1. Introduction

For gas condensate reservoirs exploited by pressure depletion, heavy ends in gas liquefy into condensate in reservoir when the formation pressure is below the dew point pressure. Condensate adheres to rock surface as oil film, or stays in the pore as oil droplet. Condensate cannot be mobilized due to adsorption and capillary force until its saturation is over critical flow saturation. In reservoir, there is a zone of increased condensate blockage called “condensate bank” or “condensate ring”. Both area and condensate saturation of the zone increase gradually [1]. The condensate accumulation will block gas flow, reduce the gas relative permeability, and ultimately weaken the well's productivity [2–4]. This is known as condensate blockage, which was first addressed by Muskat in gas cycling operations [5].

The condensate saturation in the near wellbore region can reach as high as 50%–60% under pseudo steady-state flow of gas and condensate [6]. Simulation and laboratory studies have indicated that condensate saturation around the wellbore may reach 70% [7]. The decrease of gas relative permeability by 70%–95% was measured for cores from gas condensate reservoirs in Saudi Arabia [8]. Paiaman conducted a field case study work of well MN-222 in Khami gas-condensate reservoir. The well MN-222 was in severe loss of productivity, the pressure of which decreased from 6300 Psia to 4200 Psia just after 3 years of production [9]. In Barnum's study of a gas condensate reservoir, the gas well productivity decreased rapidly until zero after the bottom hole flowing pressure is below the dew point pressure [10]. For a high-saturated condensate gas reservoir with rich condensate oil, 80% of condensate oil remains in the reservoir [11]. Single well simulation demonstrated that condensate blockage can increase the pressure drop up to 200% of the pressure drop in the tubing [12].

The gas condensate reservoir can be divided into three different

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regions according to the fluid flow condition as following [13,14]:

Region 1: An inner region near well bore containing gas and condensate where both gas and condensate flow simultaneously at different velocities.

Region 2: A middle region containing gas and condensate where only gas is flowing.

Region 3: An outer region containing single-phase and saturated with the original gas.

The condensate accumulation around the wellbore comes from both Region 1 and Region 2. The condensate forming in Region 2 can be divided into two parts. Part of condensate adheres to the rock surface, and can not move because its saturation is lower than the critical flow saturation. Another part of condensate is dispersed in gas in the form of droplet, and will move to and stay at Region 1 with gas flowing from Region 2 to Region 1, which can be called as the stacking effect. The experimental method proposed in this paper considers this mechanism.

At present, experiment, well testing interpretation and numerical simulation are the main research methods to evaluate condensate blockage. The variation of gas relative permeability is the main evaluation index [15]. Experiments of quantifying the loss in relative permeability values showed that gas and condensate relative permeability values are almost equal at steady state flow of gas and condensate, and dynamic condensate accumulation is influenced by flow rate [16]. The condensate blockage is serious regardless of reservoir permeability. Based on numerical compositional simulation, Allahyari confirmed that the reduction of well deliverability for a low-permeability gas reservoir is more than that of the high-permeability [17]. Anazi confirmed that significant productivity loss can also occur in high permeability reservoirs. The gas relative permeability reduction of more than 90% resulting from condensate blockage was measured both in 2–5 mD limestone cores and in 246–378 mD sandstone cores [18]. Long core experiments conducted by Tang showed that 70% gas phase permeability decrease occurs in the range of 20% condensate saturation [19]. This result suggested that condensate blockage is very serious in the early stage of its occurrence. Liu tested the effect of condensate blockage on gas relative permeability for rich condensate content fluid (347.65 g/m^3). Conduct core depletion experiment first, thus measure gas relative permeability with equilibrium gas displacement. Experiment results showed that gas permeability reduces by almost half when the pressure falls to maximum retrograde condensation pressure [3]. Mott designed a pseudosteady-state experiment method to measure the high-rate relative permeability of North Sea sandstone core. The method adds an inlet accumulator containing gas-condensate fluid at a higher pressure than core pressure. Only gas from the inlet accumulator was injected into the core, which mimics the process in the near well region, where rich gas flows into a region of lower pressure, condensing liquid and increasing the liquid saturation until it is mobile. This technique measures krg as a function of krg/kro and capillary number [6]. High flowing rate affects capillary number and forms inertial flow. The capillary number has positive influence on mobility, while inertial flow has negative influence on mobility. The high-rate permeability experiment conducted by Mott showed that the positive influence of capillary number is primary [20]. App measured relative permeability for a rich gas condensate reservoir using a live, single-phase reservoir fluid. Two-phase-flow tests were performed across a range of pressures and flow rates to simulate reservoir conditions from initial production through depletion [21].

The methods to mitigate the condensate blockage include injecting solvents and wettability-alteration chemicals, gas cycling, injecting nitrogen and carbon dioxide, drilling horizontal wells, hydraulic fracturing and acidizing. Sayed presented the advantages and disadvantages and field application of these methods [22]. In this paper, the effects of injecting methanol and carbon dioxide on mitigating condensate blockage are studied.

Methanol is a volatile polar substance, which can dissolve in water and oil, promote evaporation of water, and reduce the interfacial tension. Asgari experimentally investigated the application of methanol injection. The results showed that gas relative permeability increased by approximately 30%–60%. A greater reduction in gas relative permeability occurred in the presence of water saturation [23]. Asgari simulated the effect of methanol treatment on condensate blockage using the cubic-plus-association (CPA) equation of state The result showed that methanol treatment can improve gas permeability by a factor of about 1.3–1.6 [24]. Hamoud found that methanol treatments resulted in a significant and temporary enhancement in productivity for both low and high permeability cores by experimental research [18].

CO_2 can dissolve in condensate, swell condensate and reduce its viscosity and promotes the evaporation of condensate as well. The acidity of formation water increases after CO_2 dissolution. The injected CO_2 can be miscible with the remaining fluid system, vaporize the hydrocarbon, and maintain the system as a single gas phase [25]. CO_2 injection is one of the most effective technical remedies to reduce the liquid formation and achieve higher gas production. Simulation-based optimization of CO_2 injection found that CO_2 injection can improve the C_7^+ component recovery by more than 40% [26]. Fath investigated the effects of different types of gases (CO_2, N_2 and C_1) for gas cycling through a compositional simulation of an Iranian gas condensate reservoir [27]. CO_2 injection shows the best efficiency. Furthermore, Fath evaluated different CO_2 injection parameters to determine optimum conditions for CO_2 injection [28]. Optimization of huff-n-puff gas injection in a shale gas condensate reservoir found that the optimum injection time is the time during which the pressure of the main condensate region is higher than dew point pressure [29]. Su conducted experimental investigations and modeling simulation of CO_2 injection, which showed that CO_2 injection is more effective than water flooding. CO_2 treatment can improve gas productivity by a factor of about 1.39 compared with the water flooding [30]. Abri experimentally studied velocity-dependent relative permeability and recovery efficiency of supercritical CO_2 injection into gas condensate reservoirs [31]. Results showed that slower displacement flow rates yield greater condensate recovery and later breakthrough for condensate displacement, while faster rates yield better sweep efficiency and relative permeability for gas displacement.

The core flooding experimental methods used to study condensate blockage can be divided into steady-state and pseudosteady-state. The steady-state is established by injecting both gas and condensate from separate vessels at a constant rate. In steady-state method, the liquid saturation cannot exceed the critical condensate saturation. The steady-state method does not reflect the condensate gas phase characteristics caused by pressure reduction. The pseudosteady-state method injects gas into the core, and reduces core pressure. The pseudosteady-state method reflects the liquefaction of condensate gas in the core, but ignoring the stacking effect.

The experiment method designed by Du [32] connects a container with gas sample in the core holder inlet, which simultaneously depletes with core to mimic the gas single-phase flow in far wellbore and stacking effect in near wellbore. One deficiency of this approach is that part of condensate settles at the bottom of a vessel by gravity when the vessel pressure is lower than dew point pressure. Therefore, the condensate blockage measured by the experiment method is underestimated. In view of this problem, this paper proposes an improved condensate blockage evaluation

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