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Methanol treatment in gas condensate reservoirs: A modeling and experimental study

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ABSTRACT

Well productivity in gas condensate reservoirs is reduced by condensate blockage when the bottom-hole pressure drops below dew point pressure. The present experimental study on limestone cores shows that the relative permeability of gas decreases due to liquid blockage; furthermore, methanol has proven effective in the removal of condensate and restoration of gas relative permeability. In this research, the decrease in gas relative permeability caused by condensate banking and the effect of methanol treatment on condensate-blocked rocks was simulated using the cubic-plus-association (CPA) equation of state. The CPA equation of state was applied to the modeling of two-phase flows through cores for methanol–hydrocarbon mixtures due to charge transfer and hydrogen bonding, both of which may strongly affect the thermodynamic properties of such mixtures. Differential equations were solved by means of the orthogonal collocation method, a method particularly attractive for solving nonlinear problems. The modeling results confirm the experimental results, and both methods indicate that significant productivity loss can occur in retrograde gas condensate reservoirs when the flowing bottom-hole pressure falls below dew point pressure. Moreover, the results show that methanol treatment can improve gas relative permeability by a factor of about 1.3–1.6. These results may help reservoir engineers and specialists to restore the lost productivity of gas condensate.

Keywords: Gas condensate reservoir; Relative permeability; CPA equation; Orthogonal collocation; Core flood apparatus; Methanol treatment

1. Introduction

At present, natural gas reservoirs are one of the world's main sources of energy, accounting for approximately a quarter of worldwide energy demand. It is also worth noting that global demand for natural gas has been growing rapidly in recent years (BP, 2013). According to recent figures provided by the International Energy Agency (IEA), world gas consumption is expected to rise by 1.5% per annum by 2030. Many of the largest natural gas reservoirs have retrograde properties, which result in liquid accumulation near the wellbore due to pressure drop occurring during the production of gas. This formation of liquid around the wellbore reduces gas relative permeability and thus well productivity. The phase behavior of a gas condensate reservoir is strongly dependent on the P–T envelope and thermodynamic conditions of the hydrocarbon mixture. Gas condensate reservoirs generally produce gas in the range of 30–300 STB/MMSCF (standard barrels of liquid per million standard cubic feet of gas). In addition, the ranges of pressure (P) and temperature (T) for this type of gas reservoir are usually between 3000 and 8500 psi and 150–400 °F, respectively (Zendehboudi et al., 2012).

Fevang and Whitson (1995) have characterized retrograde gas reservoirs to exhibit three different regions. Region 1 is the part around the wellbore where condensate can flow, while region 2 is the part of the reservoir where condensate begins to form but cannot flow. Region 3, on the other hand, is the mid-to-outer boundary of the reservoir where only single-phase gas exists.

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Nomenclature

A	core cross-section area (cm^2)
BPR	back pressure regulator
g	radial distribution function
K	equilibrium constant
k	absolute permeability (md)
k_i	effective permeability of fluid i (md)
k_{ri}	relative permeability of fluid i
L	core length (cm)
PV	pore volume of injected
q	flow rate (cm^3/min)
R	core radius
S_i	saturation of phase i
u	fluid velocity (cm/min)
x	mole fraction in liquid phase
y	mole fraction in gas phase
Z	compressibility factor
z	initial composition of reservoir gas

Greek symbols

ρ_g	gas density (g/cm^3)
μ_g	gas viscosity (cP)
ΔP	pressure drop across the core (psia)
∇	association strength
ε	association (interaction) energy parameter
β	association volume parameter
η	reduced fluid density
φ	core porosity

Several methods have been proposed to improve gas relative permeability in the event of condensate aggregation around the wellbore. Gas injection (Abel et al., 1970; Kossack and Opdal, 1986; Sänger and Hagoort, 1998; Hoier et al., 2004) and water-altering gas (Cullick et al., 1993; Henderson et al., 1991; Jones et al., 1993; Fishlock and Probert, 1996) are two methods used to maintain reservoir pressure above dew point pressure. However, these two methods are not economical due to the large initial investment required and higher operational costs involved (Ahmed et al., 2000). Hydraulic fracturing and horizontal wells have also been used to enhance gas productivity (Settari et al., 1996; Al-Hashim and Hashmi, 2000; Kumar, 2000; Lolon et al., 2003; Mohan, 2005). By inducing a hydraulic fracture, the bottom-hole pressure and area available for gas and condensate flow can be increased. Nonetheless, the success of hydraulic fracture stimulation depends on many parameters, such as reservoir permeability, fluid composition, proppant volume, and the degree to which the fracture cleans up after the treatment. Many researchers have also proposed chemical-based treatments. It has been shown that altering wettability from oil-wet to intermediate gas-wet leads to reduced oil saturation (Jadhunandan and Morrow, 1991; Owolabi and Watson, 1993; Chen et al., 2004). Li and Firoozabadi were the first who proposed the enhancement the gas deliverability via altering wettability using a phenomenological model and laboratory experiments in gas condensate reservoirs. They also succeeded in altering the wettability of Berea sandstone and Kansas chalk from water-wet to intermediate gas-wet using various chemicals at room temperature (Li and Firoozabadi, 2000a, 2000b; Bang et al., 2010). Gilani et al. (2011) performed similar experiments on sandstone and limestone cores. However, chemical treatment, particularly non-ionic surfactant on limestone, does not cause significant improvement in gas relative permeability. There is a clear need for an effective treatment solution for carbonate rocks as many of the world's hydrocarbon reservoirs, including those in Iran, are based on carbonate rock formation. Nevertheless, methanol treatment has proved effective for this type of reservoir rock. The use of an inexpensive solvent such as methanol to improve the productivity of gas condensate reservoirs presents an attractive approach. Walker (2000) and Du et al. (2000) investigated the applicability of methanol treatment to improve the productivity of gas condensate fields. Their research revealed that the removal of the condensate bank is temporary, and that the formation of a condensate bank does not occur immediately. They proposed that the residual methanol in the pores delayed the reformation of the condensate bank. Al-Anazi et al. (2002, 2003) studied the effect of methanol on limestone and sandstone cores. Their study showed that methanol can displace water and condensate and improve the relative permeability of gas. Al-Anazi et al. (2005) reported a successful case of methanol injection in Alabama (Hatter's Pond Field). In this study, methanol was injected at a rate of 8 bbl/min, resulting in increases in both gas and condensate production rates by a factor of 2 over the first 4 months and by 50% thereafter. Alzate et al. (2006) investigated the effect of alcohol-based and inhibited-diesel on the gas effective permeability on both Mirador formation in Cupiagua Main Field, Colombia and Berea sandstone. They showed that alcohol labeled 21-NE-06 and inhibited-diesel increase the gas effective permeability. The properties of gas and condensate flow when pressure falls below dew point are significantly different from those of conventional gas–oil systems. Muskat (1949) and Fetkovich (1973) modeled gas condensate reservoirs and presented a simple method for estimating the radius of condensate blockage as a function of time, gas rate, and reservoir rock and fluid properties. Narayanaswamy et al. (1998, 1999) proposed an analytical approach to calculate the non-Darcy flow coefficient for heterogeneous reservoirs. Kniazeff and Naville (1965) and Eilerts et al. (1965) were the first to numerically model radial gas-condensate well deliverability. These studies represent radial saturation and pressure profiles as functions of time and other operational variables, confirming that condensate blockage indeed reduces well deliverability. Fevang and Whitson (1995) presented an accurate method for modeling the deliverability of gas condensate wells. In this study, well deliverability was calculated using a modified version of the Evinger–Muskat pseudo-pressure model, with the gas condensate reservoir being divided to three flow regions. Mott (2003) proposed a novel technique to estimate gas condensate well production performance using the pseudo-pressure model. Bonyadi et al. (2012) also presented a new method for the prediction of condensate well productivity. The model was tested and compared with the results of the fine-grid simulation of two cases, namely rich and lean gas condensate fluids. In the present study, the effect of methanol on the phase behavior of reservoir fluids at reservoir conditions was simulated; moreover, two-phase flow equations in cylindrical coordination across the radial and axial orientations were solved. What distinguishes this investigation from previous works is the use of an attractive yet seldom applied method called orthogonal collocation for the solution of reservoir nonlinear equations and the application of the cubic-plus-association (CPA) equation of state, which is the most effective equation of state for the prediction of the phase behavior of alcohol–hydrocarbon