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A novel method for prediction of parameters of naturally fractured condensate reservoirs using pressure response analysis

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ABSTRACT

Producing from gas condensate reservoirs under dew-point pressure and at constant temperature shows a complex behavior because of existing liquid condensate around the well. Zones with different mobilities generate three zones as a zone away from the well containing only gas, a zone having liquid around the well and finally a zone containing movable oil and gas. Existence of condensate around wellbore reduces gas relative permeability and as a result productivity index of the well will decrease. In fact, this condensate acts like an additional skin and investigating of this behavior can be difficult because of the complex fluid flow processes. Well test analysis in naturally fractured reservoirs is generally based on radial flow. In this study, first, a naturally fractured condensate reservoir in a compositional simulator is created and then, using drawdown test, pressure data versus time is generated. By proposing a new method, the data is analyzed and static and dynamic reservoir parameters are obtained. Resulted values of these parameters are compared with real values, which were defined in the model. It is shown the proposed method estimates parameters and characteristics of reservoir much better than conventional dry gas techniques.

1. Introduction

Gas condensate reservoirs exhibit complex behavior when producing under dew-point pressure at constant temperature, due to existence of two-phase flow near the wellbore. In such a well, because of different values of movability, zones far from the well bore contains just gas phase but near the wellbore zone because of a sudden decrease in pressure, the liquid drops out the gas phase and a two-phase flow zone develops. This leads to irreversible decrease in production (Arabloo et al., 2013; Majidi et al., 2014; Mohammadi et al., 2013). Development and optimization of gas condensate reservoirs to acquire more recovery demands specific engineering methods and operations that are generally different from that for either gas or oil reservoirs. The fluid properties have direct influence on the performance and consequently the developmental program to optimize the recovery. Thus, to optimum management of gas condensate reservoirs a thorough knowledge of reservoir fluid properties and economic is mandatory. A look at a number of extensive studies that have been developed for parametric investigation in gas condensate reservoirs confirms the importance of the subject from both academic and industrial perspectives. In 1966, the method of single-phase pseudo-pressure was introduced by Al-Hussainy et al. (1966). This method is commonly utilized for dry gas, thus, it is just applicable for gas condensate reservoirs producing above the dew-point pressure. When the pressure drops below the dew-point pressure, application of this method does not result in acceptable accuracy (Al-Hussainy et al., 1966). In 1967, O'Dell (1967) introduced the stable two-phase flow for the first time. This method assumes two distinct zones based on movability values. The first simulation of gas condensate reservoirs was performed in 1973 by Fussell (1973). Due to hardware limitations, the mentioned model was so simple. He compared the acquired results by the numerical methods with the stable state proposed by O'Dell (1967). He concluded that the single-phase method is not adequate for the gas condensate reservoirs and it is necessary to utilize the two-phase model. In 1996, Fevang and Whitson (1996) introduced the two-phase pseudo-pressure for three zones. This model assumes two different zones based on the movability values. In 1997, Kroemer et al. (1997) by comparing some analytical models with the results of simulation concluded that there is no analytical model capable of forecasting production decrease of the fracture wells and also the liquid effects in the gas condensate systems adequately and the only mean to forecast is the full compositional simulation.

In 1999, Xu and Lee (1999a) made a thorough investigation on gas condensate reservoirs and tried to modify the pervious

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solutions by accounting two distinct flow zones. It should be mentioned that in a former study by Raghavan et al. (1999), the steady state flow was a two-zone radial composite model. However, their model exhibits well responses for gas condensate reservoirs, which are quite over the dew-point pressure. Xu and Lee (1999b) proposed the three-zone radial composite model for the reservoir.

In 2001, Roussennac (2001) reviewed the concepts of the steady state and fluid flow in three zones and showed that relative permeability affects the well performance in homogenous gas condensate reservoirs. In 2006, Zheng and Nowak (2006) proposed a new model for prediction the characteristics of the gas condensate reservoir using computer software and showed that the proposed method minimizes the uncertainties. The studies of Al-Hussainy et al. (1966), Roussennac (2001), Li and Horne (2003), Jatmiko et al. (1997), Shi (2009), and Al Ismail (2010) are of great importance in well testing of homogenous gas condensate reservoirs. In fractured gas condensate reservoirs, the multiphase flow simulation depends on the utilization of diagrams the relative permeability of matrix and fracture. The matrix relative permeability diagrams are somehow analogous to these of the homogenous reservoirs. In addition, it is common to consider that the fracture relative permeability has a linear relationship with each phase saturation (van Golf-Racht, 1982). This was proved by the experiments done by Romm (1966) in 1966, however, it is valid just for large fractures. In 2011, Montazeri et al. (2011) investigated the effects of the relative permeability charts on the behavior of the fractured gas reservoirs and demonstrated that the effects of these charts on formation of gas condensates are feasibly negligible.

1.1. Flow zones in gas condensate reservoirs

In 1996, Fevang and Whitson (1996) proposed a model, which consider three different flow zones in the formation during depletion. These zones are as follows:

Zone #1: This is an internal zone near wellbore in which both oil and gas are flowing simultaneously. This zone is responsible for deliverability decrease of the gas condensate well. With continual production, the liquid accumulates in this zone and consequently wane the relative permeability of the gas. Gradually the radius of this zone increases.

Zone #2: This is an intermediate zone near the wellbore in which the liquids drop out of the gas, however, just gas is moveable. In zone #2, the developed liquids have a very low movability and practically they are considered unmovable. In the outer rim of this zone (the boundary of the zone #3) the first droplets of liquid are developing. It is obvious that the composition of the gas changes as time goes on.

Zone #3: This is a zone far from the wellbore in which the only movable fluid is gas that is the initial fluid of the reservoir. The pressure of the zone #3 is over the dew-point pressure and the composition of the gas will never change. This zone is investigated to understand the effects of the single-phase gas flow in the well deliverability.

All the three mentioned zones are illustrated in Fig. 1. In 2000, Gringarten et al. (2000) in their study proposed there is a forth zone with a high capillary number around the wellbore. According to this study, in the farthest region around the well, there is a fourth zone, which is in over the dew-point pressure and contains the initial gas in reservoir. After that, there is the third zone in which a great fluctuation of gas condensate saturation exists, thus, there will be a sudden decrease in the gas relative permeability. Closer to the wellbore is the second zone in which liquid and gas moves simultaneously. The first zone is located in close vicinity of the wellbore.

1.2. Well testing of the gas condensate reservoirs

Generally, there are rare publications about the well testing of the gas condensate reservoirs. Most of the well testing analyses are

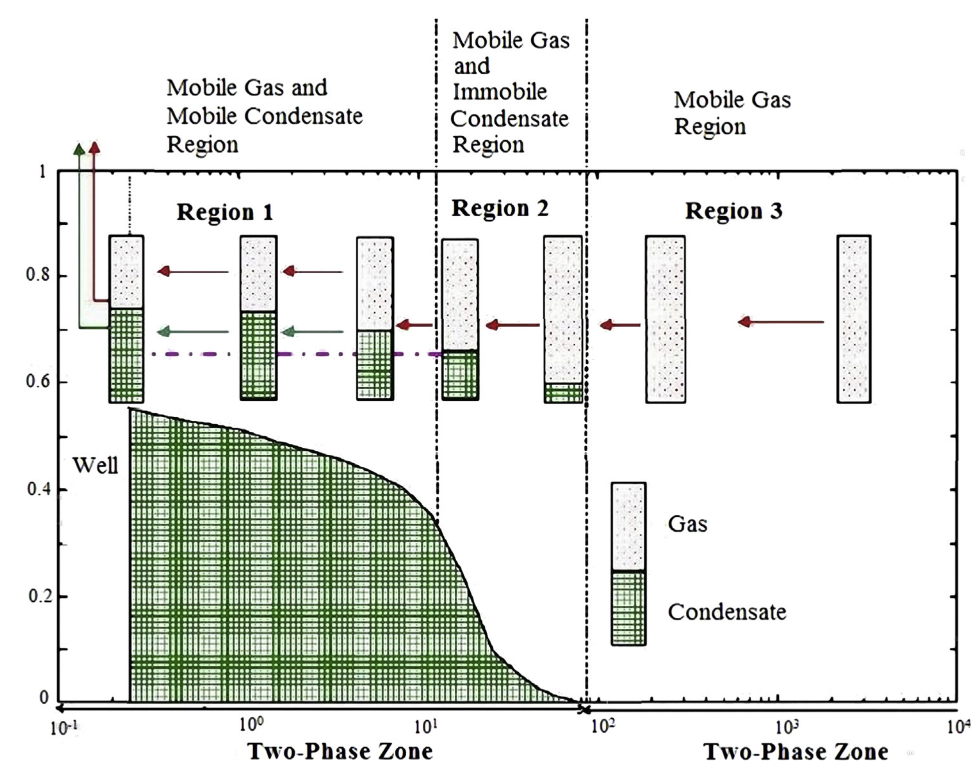

Fig. 1. Three different zones around the wellbore in a gas condensate reservoir (Sadeghi Boogar and Masihi, 2010).