Application of two-phase pseudo-pressure transform in gas-condensate well-testing with and without positive coupling and inertia.

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Summary

Well-test interpretation in gas condensate system is particularly challenging when condensation happens within the reservoir. This is not only due to the natural reduction of near wellbore mobilities, but also the existence of the velocity effects (i.e. positive coupling and inertia), which compete to revamp the relative permeabilities. In this study, a set of realistic build-up tests are generated using a compositional reservoir simulator, where measured (velocity dependent) relative permeabilities and a real gas condensate fluid model are used. The transient build-up tests are analysed using the real-gas and steady-state two-phase pseudo-pressures, and the (velocity dependent) reservoir integral transforms. The results show that the application of steady-state two-phase pseudo-pressure transform can result in a remarkable over-prediction of the reservoir permeability, when the velocity dependent relative permeabilities are in effect. Moreover, the traditional real-gas pseudo-pressure transform fails to estimate the reservoir properties particularly when the reservoir is initially below the dew point pressure. However, in either of situations (i.e. with and without velocity effects), using the reservoir integral transform leads to an excellent liquid analogy solution, where the reservoir properties can be accurately estimated.

Introduction

Well-test interpretation in the gas-condensate reservoir has been traditionally performed by aid of the dry-(or real-) gas pseudo–pressure transform (Al-Hussainy et al., 1966; Gringarten et al., 2000; Bozorgzadeh and Gringarten, 2004). The pseudo-pressure transform is aimed at reducing the nonlinearity of diffusivity equation, which is induced by the strong dependency of gas viscosity and z-factor with pressure. Application of such single-phase transforms is particularly useful in initial testing phases, and when we have long tests with large well-spacing (Raghavan, 2009). In these situations and in homogeneous reservoirs, the real-gas pseudo pressure yields a radial-composite behaviour on the log-log derivative plot of the build-up tests (Xu and Lee, 1999). Using a radial composite model, the total and the mechanical skin factors, and the reservoir permeability can be estimated (Hamdi et al., 2012). However, there are situations where the reservoir pressure is already below the dew point pressure or the composite behaviour is not depicted in the build-up response. Therefore, the skin factor and the reservoir permeability are either cannot be truly estimated or they are erroneous and misleading. To remove the effect of fluid heterogeneity and to have proper reservoir parameters estimation, the reservoir integral concept was introduced by Boe et al. (1989) for the solution gas drive reservoirs. In order to use the liquid analogy solution in gas-condensate reservoirs, Jones and Raghavan (1988) found that the reservoir integral transform (eq. 1), which was in absence of velocity effects, holds for the gas-condensate systems.

$$RI(p_{t_n}) = 2RT\int_{r_w}^{\infty}\left(\hat{\rho}_o\frac{k_{ro}}{\mu_o}+\hat{\rho}_g\frac{k_{rg}}{\mu_g}\right)_{t_n}\frac{dp}{dr'}dr' = 2RT\int_{p_w}^{p_i}\left(\hat{\rho}_o\frac{k_{ro}}{\mu_o}+\hat{\rho}_g\frac{k_{rg}}{\mu_g}\right)_{t_n}dp \quad (1)$$

where, $RI\ (p_{tn})$ is the reservoir integral calculated from the unsteady pressure-saturation (P-S) path at time t_n, k_{ro} and k_{rg} are the oil and gas relative permeabilities, $\hat{\rho}_o$ and $\hat{\rho}_g$ are the oil and gas molar densities, μ_o and μ_g are oil and gas viscosities, T is the absolute reservoir temperature, and R is the universal gas constant. The evaluation of this integral requires a pre-knowledge of unsteady-state pressure and saturation profiles within the reservoir (i.e. the instantaneous knowledge of relative permeabilities and fluid data as a function of pressure). However, Jones and Raghavan (1988) and Jones et al. (1989) suggested that the reservoir integral can be approximated by a steady-state two-phase pseudo-pressure (SSPP) (i.e. eq. 2), where the P-S paths are estimated using the constant-composition-experiment (CCE) results (eq. 3).

$$RI(p) \approx m_2(p) = 2RT \int_{p_o}^{p} \left(\hat{\rho}_o \frac{k_{ro}}{\mu_o} + \hat{\rho}_g \frac{k_{rg}}{\mu_g} \right)_{SS} dp \tag{2}$$

$$\frac{k_{ro}}{k_{rg}} = \frac{\hat{\rho}_g}{\hat{\rho}_o} \frac{\mu_o}{\mu_g} \frac{L}{V} \tag{3}$$

in which, SS represents the steady-state path, p_o is an arbitrary pressure (in the case of build-up tests the boundaries of integral for the reservoir integral and the SSPP would be from flowing pressure at shut-in time to current build-up pressure), and L and V are the equilibrium liquid and vapour (gas) mole fractions.. The steady-state assumption is based on a premise that there are two regions in the reservoir; a two-phase region close to the wellbore, where both condensate and gas are flowing and the total composition of flowing fluid is constant (i.e. $P<P_{dew}$); and a secondary region, where single-phase gas exists (i.e. $P>P_{dew}$). Later, Fevang and Whitson (1996) introduced an intermediate third region, within which the only flowing phase is (practically) the gas phase, and the P-S can be approximated by the constant-volume-depletion (CVD) liquid drop-out curves.

The simultaneous flow of gas and condensate in the two-phase region is affected by complex interaction of viscous, capillary and inertia forces (Jamiolahmady et al., 2010), which can dramatically revamp the base gas and oil relative permeability curves. In particular, the combined effect of positive coupling and negative inertia (Danesh et al., 1994; Whitson et al., 1999; Jamiolahmady et al., 2010) are of greatest importance in this region. The positive coupling that is attributed to the intermittent opening and closure of the gas passage by the condensate in pore level (Jamiolahmady et al., 2003) is reflected as an increase in relative permeability when fluid velocity increases or interfacial tension reduces. On the other hand, negative inertia or so-called non-Darcy flow (Forchheimer, 1914) is a reduction of relative permeability at high velocities. These effects can remarkably affect the well-test response of gas-condensate reservoirs and can complicate the well-test interpretation. The application of these so-called velocity effects in the well-test interpretation was first introduced by Gringarten et al. (2000), who introduced a fourth region close to the wellbore, where the permeability is locally improved. However, their well-test interpretation was based on a three-region radial composite model where the "dry-gas pseudo-pressure" transform is used.

In this study, synthetic transient build-up data, under different initial conditions, are generated using a commercialised compositional reservoir simulator (Schlumberger, 2012), and variant pseudo-pressure transforms are employed in well-test plots and interpretations. The SSPP is calculated using equation 2 where the required properties are estimated using a CCE test and equation 3. On the other hand, the relative permeabilities and the fluid data required for the reservoir integral are obtained from the simulation results at each time step. Some in-house codes are developed to calculate these integrals. The aptness of reservoir integral and SSPP in presence (and absence) of positive coupling and inertia are scrutinized, and some key conclusions are presented afterwards.

Simulation set-up

The single-well radial model used in this study is composed of 40 radial cells that are logarithmically expanded from the wellbore (i.e. 0.32ft) to an external no-flow-boundary located at 5000ft away from the well. The single-layer model has a thickness of 200ft, a uniform permeability of 150 md, and a porosity of 0.12. A very fine logarithmic time-stepping scheme has been used to simulate a set of transient tests with 4 days of draw-down at a constant production rate of 30 MMSCF/day, and 8 days of build-up.

The fluid used in this study is a rich gas-condensate fluid model consists of 10 pseudo components with a maximum liquid-drop-out of 0.32 (from CCE) and a dew point of 5342 psi measured at reservoir temperature of 250°F. A tuned Peng-Robinson Equation of State (PR-EOS) has been used to simulate the fluid behaviour during the well-test simulations.

A set of measured relative permeability data, in absence of the initial water saturation, are used in the simulations. The Models No.1 and No.2 available in Eclipse 300 (Schlumberger, 2012) were implemented to simulate the positive coupling and the inertia respectively. The required velocity dependent relative permeability parameters have been measured in the laboratory and assigned to the transient test simulations to mimic the combined effect of capillarity and inertia on the build-up results.

Results and discussion

Two different scenarios in the presence and the absence of velocity effects data are considered. Figure 1 (left) is the case where no capillary and inertia are included in the models, and the initial reservoir pressure is slightly above the dew point pressure. The results show that the SSPP method can roughly match the single-phase derivative curve for only a portion of two-phase region that is depicted in the early times. The derivative shows a dominant minimum in the derivative curve, which is postulated as an overcorrection of the steady-state model for ignoring the Fevang and Whitson's intermediate region (Fevang and Whitson, 1996). This region was not implemented in this study because the suggested methods for obtaining the boundaries of pseudo-pressure integral in the third region (Fevang and Whitson, 1996) were not successful for this fluid system. The figure also indicates that the reservoir integral approach can successfully eliminate the radial composite behaviour, when the real-gas pseudo-pressure is used to analyse the well-test data.

Figure 1 (right) shows that when the initial reservoir pressure is far below the dew point pressure (e.g. here with 400 psi) the minimum will disappear from the SSPP build-up derivative and the closest result to the single-phase response is obtained. It is worth noting that the real-gas pseudo-pressure does not show any radial composite behaviour within the test time, and the reservoir permeability estimation is highly erroneous (Fig. 1: right). In this situation, the reservoir integral approach still provides an excellent match with the reservoir permeability, while the skin estimation, which is reflected by the vertical distance between the pseudo-pressure drop and the pseudo-pressure derivative curves, is slightly over-predicted.

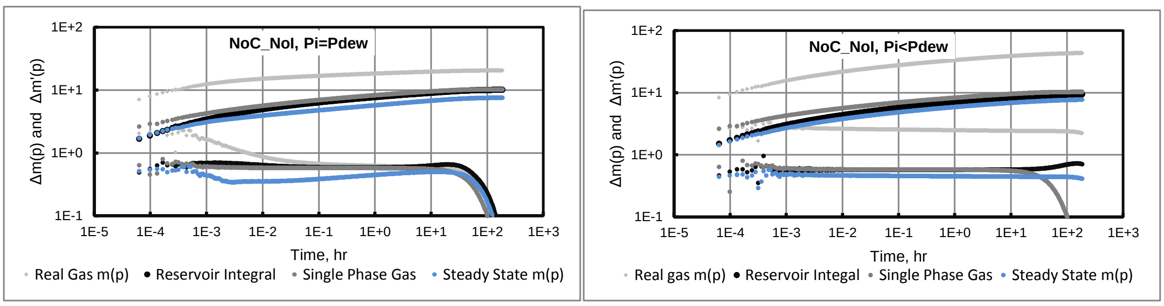

*Figure 1: The log-log build-up well-test responses of the gas-condensate system where P_i=P_{dew} (left) and P_i<<P_{dew} (right). The simulations are performed in "**absence**" of velocity effects and different pressure transforms are used in representation of log-log plot.*

Figure 2 represent the build-up responses of the cases with different initial pressures, where the velocity effects are activated in the system. The positive coupling and the negative inertia act in opposite directions to alter the relative permeabilities. Figure 2 (left) (i.e. when P_i=P_{dew}) indicates that the coupling is the dominant velocity effect, which improves the near wellbore relative permeabilities. This could effectively remove the strong composite behaviour of the real-gas pseudo-pressure derivative response, when the velocity effects are not included (Fig. 1: left). Fig. 2 (left) shows that although the real-gas pseudo-pressure derivative is practically providing the same value as the reservoir permeability, the slight effect of inertia still remains in the model (this is reflected as a slight vertical displacement of the corresponding pseudo-pressure drop curve compared to the base single phase case). The use of SSPP method leads to an over-prediction of reservoir permeability at early times, and results in a monotonic increase of the derivative. The derivative curve eventually meets the reservoir permeability at the later times of greater than 10 hr. This is while the reservoir integral approach, which takes into account the effect of the coupling and inertia, provides with an excellent match with the single-phase gas derivative and pseudo-pressure drop curves. The over-correction of SSPP method is even more pronounced when the initial reservoir pressure is far below the dew point pressure (Fig.2: right). In this case, where the near wellbore permeability has been largely improved by the capillary effect, the use of dry-gas pseudo-pressure gives rise to good reservoir permeability estimation and an over-prediction of the wellbore skin factor due to inertia.

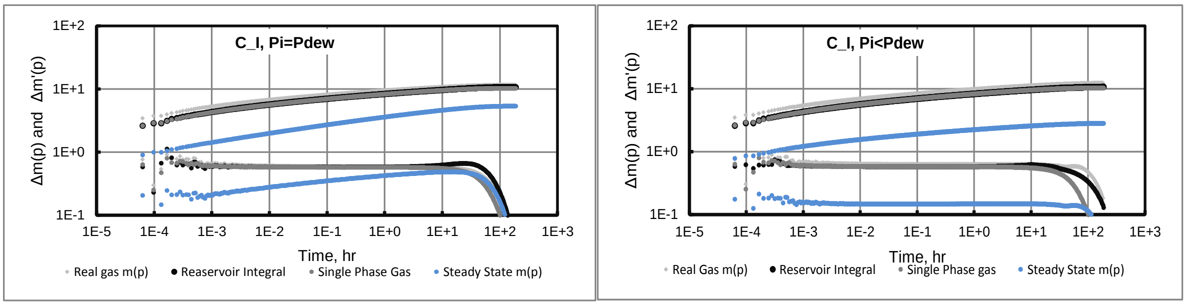

*Figure 2: The log-log build-up well-test responses of the gas-condensate system where P_i=P_{dew} (left) and P_i<<P_{dew} (right). The simulations are performed in "**presence**" of velocity effects, where different pressure transforms are used in representation of log-log plot.*

Conclusions

In this work, the applicability of the real-gas and SSPP, and the reservoir integral for the gas-condensate well-test interpretations were studied. Different conditions were considered, where the velocity effects and the initial reservoir pressure varied within the models. The simulations took advantage of the use of a set of measured relative permeability data (along with corresponding velocity dependent parameters), and a real rich gas-condensate fluid measured in Heriot-Watt Gas-Condensate Research Lab. The results showed that, when the velocity effects (i.e. coupling and inertia) are absent in the system, the SSPP provides a good estimation of the reservoir parameters, where the two-phase region is deep (i.e. P_i<<P_{dew}). In this case, the use of real-gas pseudo-pressure provides highly erroneous results, under-predicting the reservoir permeability. Here, the application of reservoir integral transform could completely remove the effect of the radial-composite behaviour depicted in the derivative curves. On the other hand, when the velocity effects are included in the simulations, the SSPP is either unable to correctly predict the reservoir pressure (when P_i=P_{dew}) or highly over-predicts the permeability values (when P_i<<P_{dew}). For such cases, as the dominant coupling effect dramatically improves the relative permeabilities, the real-gas pseudo-pressure could adequately estimate the reservoir permeability with an overproduction of the mechanical skin factor due to inertia. This is while the incorporation of velocity effects in the reservoir integral calculation could provide with excellent prediction of the permeability and the skin factor in either of simulations.

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