

# Effect of Relative Permeability on Well Testing Behavior of Naturally Fractured Lean Gas Condensate Reservoirs

G.H. Montazeri, Z. Dastkhan, H. Aliabadi

**Abstract**—Gas condensate Reservoirs show complicated thermodynamic behavior when their pressure reduces to under dew point pressure. Condensate blockage around the producing well cause significant reduction of production rate as well bottom-hole pressure drops below saturation pressure. The main objective of this work was to examine the well test analysis of naturally fractured lean gas condensate reservoir and investigate the effect of condensate formed around the well-bore on behavior of single phase pseudo pressure and its derivative curves. In this work a naturally fractured lean gas condensate reservoir is simulated with compositional simulator. Different sensitivity analysis done on Corry parameters and result of simulator is feed to analytical well testing software. For consideration of these phenomena eighteen compositional models with Capillary number effect are constructed. Matrix relative permeability obeys Corry relative permeability and relative permeability in fracture is linear. Well testing behavior of these models are studied and interpreted. Results show different sensitivity analysis on relative permeability of matrix does not have strong effect on well testing behavior even most part of the matrix around the well is occupied with condensate.

**Keywords**—Lean Gas; Fractured Condensate Reservoir; Capillary Number; Well Testing Analysis; Relative Permeability;

## I. INTRODUCTION

CHARACTERIZATION of gas condensate reservoirs is a difficult task, since multiphase-flow in the reservoir and change of the mixture composition as fluid flows towards the well complicates the interpretation of well tests considerably. Gas condensate-related topics (well deliverability, well test interpretation, flow in reservoir in general) have been long-standing problems. Analyzing well test data is one of the most common methods for characterizing dual porosity dual permeability reservoir parameters. But interpretation of the well test data in gas condensate reservoir, particularly in complicated geological reservoir (e.g. dual porosity dual permeability reservoir) is not straightforward. When the bottom-hole pressure of a gas condensate reservoir is reduced below the dew point, a bank of condensate is formed around the well-bore. Recently, investigators [1]-[4] show that the loss of well productivity can be compensated by high capillary number effects within near wellbore region, where high gas velocities and low interfacial tension improve the relative permeability curves.

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The fluid saturation profiles should be investigated in order to understand the production mechanism of gas condensate reservoirs and to get a better analysis of well response in these reservoirs. Different authors [5]-[9] have suggested variety of regions for saturation profile in gas condensate reservoirs with bottom-hole pressure below dew point pressure. By using dry gas pseudo-pressures, some parameters in a gas condensate reservoir, for example the effective permeability, skin and radius of the condensate bank can be calculated approximately [8]-[10]. These parameters are important in the formulation of the production strategy and reservoir management of a gas condensate field. Montazeri et al., [11]-[12] studied effect of relative permeability on single phase and two phase pseudo pressure derivative curves in Homogenous Gas Condensate Reservoirs and showed effective permeability reduces according to variable condensate saturation around the well bore. As far as authors are aware, there is no relevant duplicated paper about analyzing condensate bank effect on the well test data in a dual porosity-dual permeability reservoir using dry gas pseudo pressure method. Xu and Lee [13]-[14] used two phase pseudo pressure for analyzing a set of well test data, which were generated using a simulator in a gas condensate naturally fractured reservoir. In this paper we have tried to investigate effect of different parameters in Correy relative permeability function in naturally fractured lean gas condensate reservoir and their effect on pressure build up analysis.

## II. DESCRIPTION OF MODEL

The PVTi module of ECLIPSE has been used to perform PVT experiments. A real lean Gas Condensate fluid is simulated with this simulator and result is used in compositional E300 simulator. The reference pressure, temperature and further information about the fluid and model are used as Montazeri et al., [11]-[12]. A radial grid model has been constructed. The grid was divided to 80 cells in the R-direction and a single layer in the z-direction (180 ft). Matrix and Fracture have absolute permeability of 5, 1000 md and porosity of 20%, 1% respectively. For better observation of Dual Porosity-Dual permeability (DpDk) behavior in Well Testing Analysis, Sigma is considered quite low ( $\sigma = 0.00037$ ). The fluid flow is only in the R-directions. According to Montazeri et al., [11]-[12] most radial grid cell sizes are generated using a logarithmic distribution with the ratio between two consecutive cell sizes usually being 0.15 (i.e.  $\ln(r_{i+1}/r_i)=0.15$ ). This causes minimum fluctuation in the wellbore pressure data. The described grid structure and a

PVT sample data are used in a compositional simulator for generating well test data in a dual porosity-dual permeability reservoir. Since pressure changes drastically at the beginning of Test, Time Steps considered quite low at the beginning and logarithmically increase with time. Retrograde condensation occurs when the flowing bottom-hole pressure declines below the dew point pressure, creating three regions in the reservoir with different liquid saturations. Away from the well, an outer region has the initial liquid saturation; next, nearer the well, there is a rapid increase in liquid saturation and a decrease in the gas mobility. Liquid in that region is immobile. Closer to the well, an inner region is formed where liquid saturation is higher than a critical condensate saturation and both oil and gas phases are mobile. Finally, in the immediate vicinity of the well, there is a region with lower liquid saturation due to capillary number effects, which represents the ratio of viscous to capillary forces. Such a region has been inferred from a number of experimental core studies at low interfacial tension and high flow rates. The existence of the fourth region is important because it counters the reduction in productivity caused by liquid drop-out. The capillary number relates fluid velocity and viscosity (viscous forces) to interfacial forces, according to:

$$N_c = \frac{\mu v}{IFT} \quad (1)$$

Relevant capillary numbers on well deliverability are dependent of flow rate, fluid type, and well-flowing pressure, Pwf. Typical capillary numbers range from 10<sup>-6</sup> to 10<sup>-3</sup>. The flow rate dependence with relative permeability can be explained based upon the relationship between capillary and viscous forces. Wells with higher pressure drop drain more condensate. Another capillary number definition can be obtained from the rock properties as:

$$N_c = \frac{4\mu v r}{IFT} \left( \frac{P}{2(IF T) \cos \theta} \right) \quad (2)$$

Since capillary number has enough effect on saturation profile of condensate around the well, so we consider this effect in all models.

### III. RELATIVE PERMEABILITY

There is no definitive relative permeability model to represent fluid flow in gas condensate reservoirs due to the complexity of the laboratory measurements required and the dependency on interfacial tension, capillary forces, flow rate, and other parameters. Corey's relative permeability correlation was used for Matrix and linear relative permeability for Fracture. In order to cover a wide range of possibilities, 15 different sets of relative permeability curves were used as a database to form well test data. All the curves present a reduction of relative gas permeability (or mobility) when condensate saturation increases. Once the simulation model was defined, it was run with various sets of the 15 relative permeabilities and lean gas condensate fluid. Each of the simulations was begun at the pressure above the dew point

pressure of the fluid at the conditions selected with the purpose being to evaluate the results of well test analysis and the phase behavior of the condensate in the two-phase region, where condensate and gas coexist together and go through significant composition changes. Because the composition changes with position and time, it is reasonable that wettability, and therefore relative permeability, would also change. Corey's relative permeability correlation has been found useful for describing low capillary number behavior of steady-state data measured for gas condensate cores.

$$k_{rg} = k_{rg}^{\max} \left( \frac{s_g - s_{gc}}{1 - s_{gc} - s_{wc}} \right)^{n_g} \quad (3)$$

$$k_{rog} = k_{rog}^{\max} \left( \frac{1 - s_g - s_{oc} - s_{wc}}{1 - s_{oc} - s_{wc}} \right)^{n_o} \quad (4)$$

All of the relative permeability curves which used in this study were generated using Corey's equation. Henderson et al. [15] found that gas condensate flow can be extremely affected by the actual distribution and magnitude of connate water. Understanding the factors affecting the oil saturation profiles is important to evaluate the interpretations from transient pressure using the single-phase analogy. In the single-phase analogy, the liquid phase is neglected and its effect is modeled by an altered permeability zone. Because the permeability in this altered zone is considered uniform, if the transition zone is large, the effect of the liquid phase can not be modeled by an altered zone with uniform permeability.

### IV. RESULT AND DISCUSSION

Relative permeability is a key parameter affecting on production and amount of condensate around the well bore if bottom hole pressure fall under dew point pressure. In this work effect of Swc, Soc, Krg max and Corey's correlation exponent (no, ng) on Build up well testing behavior of DpDk lean gas condensate reservoir have been studied. A test consists of 3 Draw Down (DD) and 3 Build up (Bu) was performed and all build ups were analyzed. Further information about the test can be seen in table (1).

TABLE I  
 TRANSIENT TEST SCHEDULE

Test Number	Test Duration(day)	Production Rate (MSCFD)
DD1	1	2000
BU1	50	0
DD2	100	70000
BU2	50	0
DD3	200	140000
BU3	50	0

#### A. Effect of Connate Water Saturation (Swc)

It is important to perform a sensitivity study to understand the effect of connate water saturation on well pressure

behavior of gas condensate well undergoing depletion.

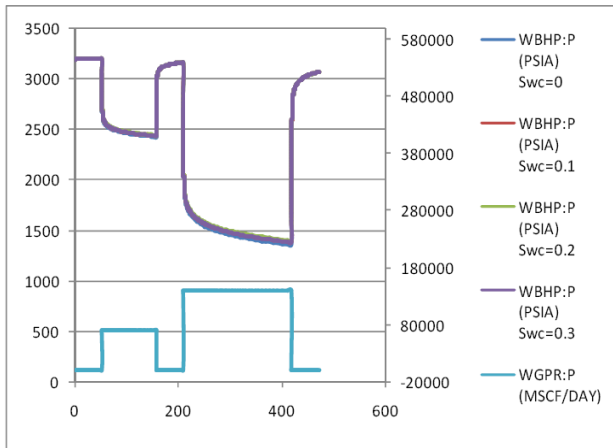
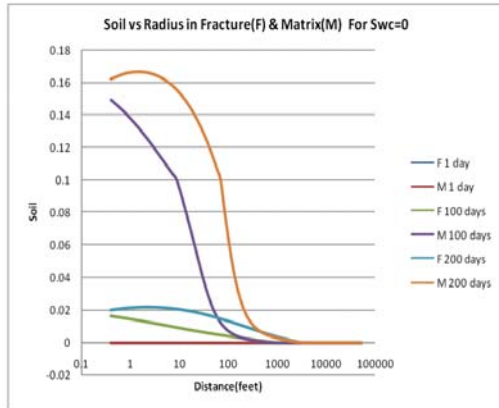
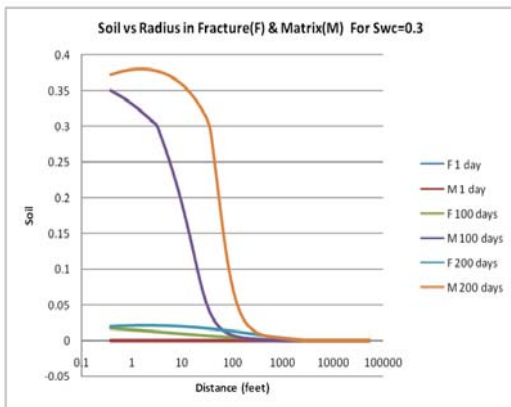


Fig. 1 effect of Swc on pressure behavior

Figure (1) shows that Swc has no affect on wellbore pressure behavior of gas condensate reservoirs because pressure profiles coincide together. In addition, according to figure (2) Swc has negligible effect on matrix and fracture condensate saturation, but generally condensate saturation in matrix decreases with decreasing Swc. Fracture condensate saturation does not affected by Swc.



(a)



(b)

Fig. 2 effect of Swc on matrix & fracture condensate saturation a: Swc=0, b: Swc=0.3

**B. Effect of critical condensate saturation (Soc)**

The critical condensate saturation was varied between 10 to

30% and the resulting effect on well test behavior and saturation profile is shown on figures (3) and (4).

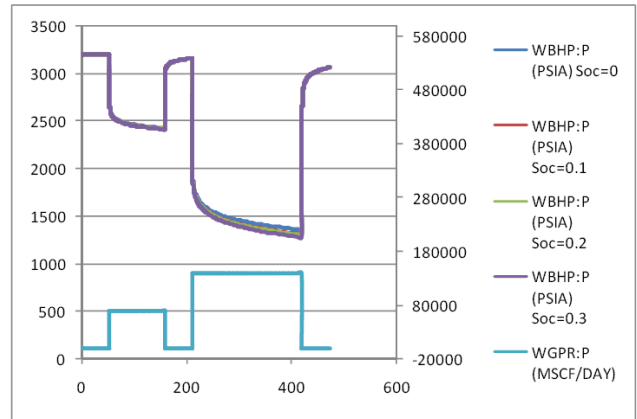
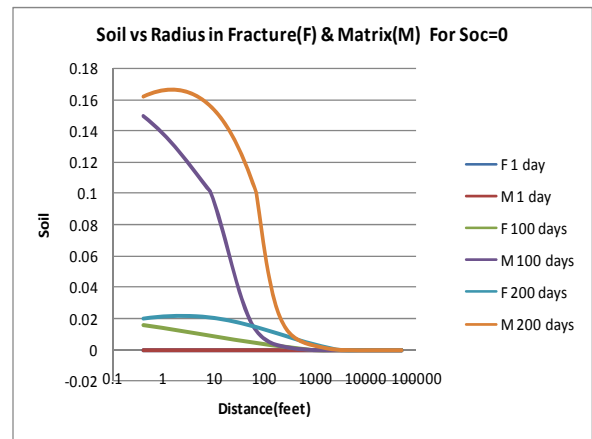
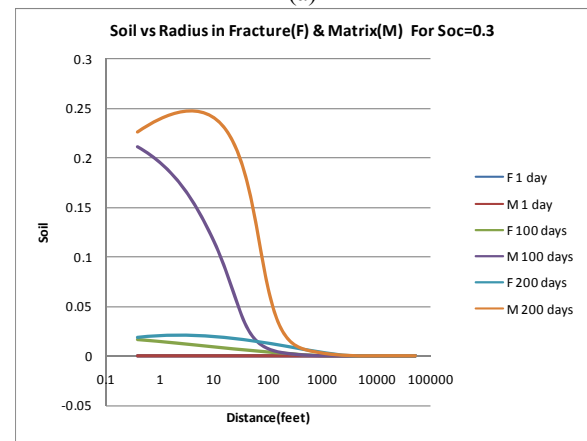


Fig. 3 effect of Soc on pressure profile



(a)



(b)

Fig. 4 effect of Soc on matrix & fracture condensate saturation a: Soc=0, b: Soc=0.3

For this case, all the parameters including the relative permeability curve were kept the same and the Soc was varied. Figure (3) shows that Soc changes do not affect the pressure behavior of condensate reservoirs. Figures (4a) and (4b) show Soc has no effect on saturation profiles of this kind of reservoirs. Generally speaking, matrix condensate saturation is higher than fracture condensate saturation.

C. Exponent Effect (n)

The exponent of the Corey's equation is a key parameter that also affects the relative permeability curves. According to our model, there is some discrepancy between the pressure profiles at far distances and this indicates that the capillary number affects the pressure behavior at later distances from the wellbore and derivative curves (figure (5)).

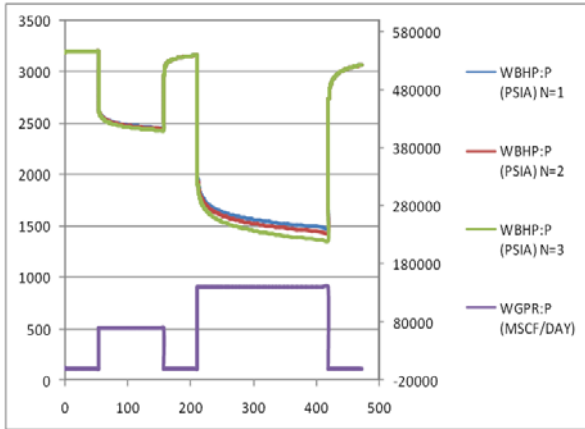
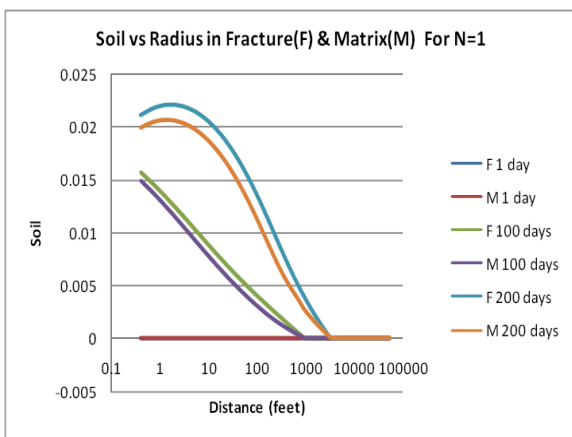
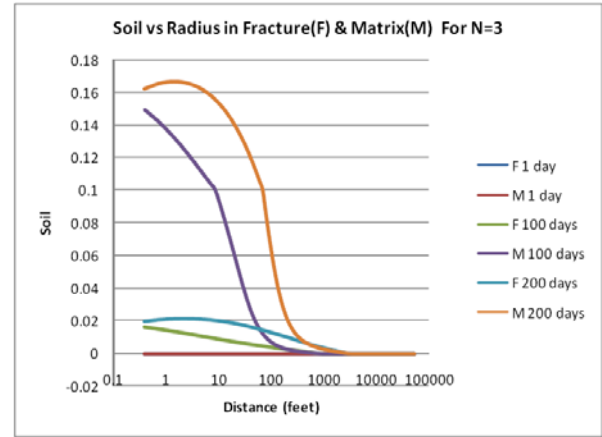


Fig. 5 effect of Corry exponent on pressure profile

According to figures (6a) and (6b) we also examined the effect of Corry exponent parameter on saturation profile and concluded that at higher Corry exponent parameter its effect on condensate saturation profile is not sensible and the difference between the matrix and fracture condensate saturation relatively remains constant, but the difference between the matrix and fracture condensate saturation in lower Corry exponent parameter decreases and the saturations of fracture and matrix become close together.



(a)



(b)

Fig. 6 effect of Corry exponent parameter on saturation profile a: N=1, b: N=3

D. Effect of  $k_{rg}^{max}$

$k_{rg}^{max}$  is one of important parameters that affect the pressure and flow behavior in gas reservoirs. In this study, we also modeled the effect of  $k_{rg}^{max}$  on pressure and saturation profiles with four different values (1, 0.9, 0.7, and 0.5) in order to better understand how it affects the saturation.

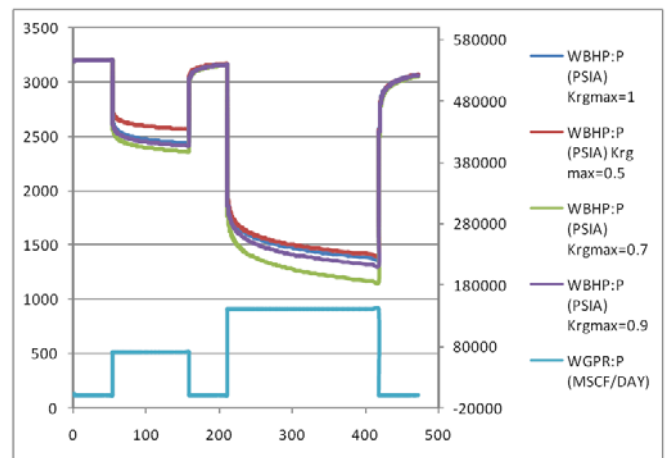
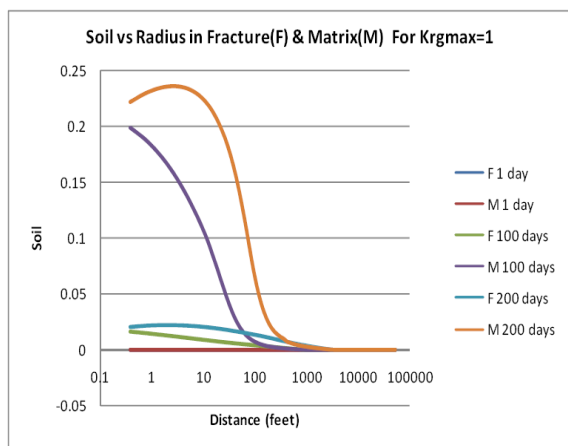
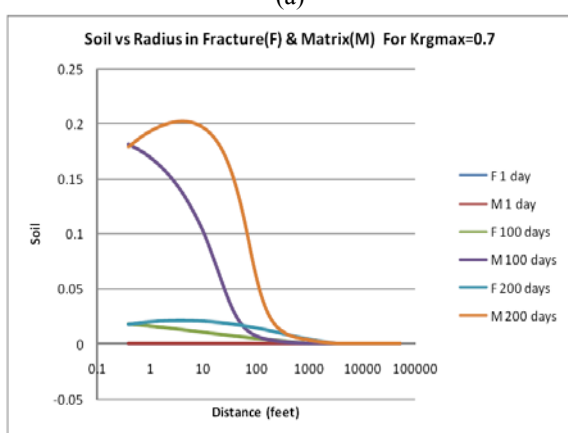


Fig. 7 effect of  $k_{rg}^{max}$  on pressure profile

According to the pressure behavior profile, it highly affects the pressure near and far distances from the wellbore (figure 7). It slightly affects the condensate saturation. With decreasing the  $k_{rg}^{max}$ , matrix condensate saturation a bit decreases, but it has no sensible effect on fracture condensate saturation (figures 8a and 8b).



(a)



(b)

Fig. 8 Effect Of  $k_{rg}^{\max}$  On Saturation Profile A:  $k_{rg}^{\max} = 1.0$ ,  
B:  $k_{rg}^{\max} = 0.7$

#### V. CONCLUSION

It was concluded that the Swc and Soc have no effect on pressure profiles, and capillary number only affect the far distances pressure behavior. But,  $k_{rg}^{\max}$  affects near and far distances from the wellbore. Swc and Soc also have no sensible effect on saturation profile. But, Capillary number affects the saturation in a way that at lower capillary numbers the condensate saturation of the fracture increases and become closer to matrix condensate saturation. Finally,  $k_{rg}^{\max}$  has no sensible effect on fracture condensate saturation, but with decreasing the  $k_{rg}^{\max}$ , the matrix condensate saturation a bit decreases.

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