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EFFECT OF RELATIVE PERMEABILITY CURVES ON NEAR WELL GAS-CONDENSATE FLOW

Debora Yohane Cunha Azevedo Silva
Paula Kozlowski Pitombeira Reis
Marcio S. Carvalho
Laboratory of Microhydrodynamics and Flow in Porous Media, Department of Mechanical Engineering, PUC-Rio, Rio de Janeiro, RJ, Brazil.
deboraycas@gmail.com; paulareis@lmmp.mec.puc-rio.br; msc@puc-rio.br

Abstract. *In gas-condensate reservoirs with pressures below the dew pressure, the productivity of wells can be compromised due to the accumulation of liquid in their surroundings. This phenomenon is known as condensate blockage and quantifying the severity of its impacts on gas flow can be very challenging. An important source of inaccuracy in condensate banking modeling stems from the determination of the relative permeability of the liquid and gas phases, which commonly relies on curves obtained from the extrapolation of few experimental data. Thus, important phenomena related to the coupled flow of gas and condensate in porous media can be misrepresented, compromising the precision of production forecasting. To investigate the effect of relative permeability curves on the formation of condensate banks, a reservoir-scale compositional model was developed for the study of flow of gas and condensate. With the model, the effects of using relative permeability curves obtained by simulating the gas-condensate flow at the pore-scale and with correlations proposed in the literature was evaluated. The main assumptions considered to implement the model are isothermal system, two-phase flow, and incorporation of capillary force effects through the relative permeability model. Molar balance and volume consistency equations form a nonlinear system solved by Newton's method that provides pressure and number of moles of each component, in all control volumes of the model, at each time step. For the phase equilibrium calculations, the Peng & Robinson equation was implemented in a constant pressure and temperature flash routine. The model was validated against the analytical solution for single-phase gas flow and, finally, the simulator obtained the temporal evolution of the pressure and saturation as a function of the distance from the well, to compare the effect of different models of relative permeability curves in the prediction of condensate blockage. The results were obtained by varying the absolute permeability of the medium and the gas flow imposed in the well, and the impact of these parameters on the accumulation of condensate was evaluated. The differences observed in cumulative production of gas and condensate are significant with low absolute permeability media and these differences are even more significant increasing the gas flow imposed in the well.*

Keywords: *Retrograde gas; Gas-condensate reservoir; Relative permeability; Compositional modeling*

1. INTRODUCTION

Gas-condensate reservoirs usually initiate their productive life containing only gas, as their pressure is generally above the dew pressure and their temperature lies between critical and cricondentherm temperatures. These conditions are represented in the phase diagram in Figure 1 by Point (1). During production, the pressure can drop below the dew point pressure, as represented by Point 2, leading to the formation of liquid phase in the porous medium. As the liquid phase has a lower mobility when compared to the gas (Whitson, Fevang, & Sævareid, 2003), it accumulates in the pore medium and obstructs gas flow paths, causing productivity loss. As the pressure is further reduced, as shown in Point 3, condensate revaporization may occur.

Near the production well, different flow regimes can occur, as sketched in Fig.2. Away from the well, the pressure is high enough and only the gas phase is present. Near the well, the pressure may drop below the dew point and two-phase flow occurs. The gas permeability may drop considerably due to the presence of the liquid phase. The two-phase flow behavior is directly related to the relative permeability of both phases. Typically, reservoir scale modeling is performed using relative permeability curves extrapolated from a few experiments. However, due to experimental operation constraints, these experiments seldom reproduce extreme pressure and temperature conditions or use complex fluid compositions normally occurring in gas condensate reservoirs. This leads to significant uncertainties in results since model fluids do not always accurately capture the flow characteristics of compositionally complex reservoir fluids and may not mimic the reservoir wettability. Several important physical phenomena are usually neglected, such as the dependence of the curves on the local capillary number of the flow.

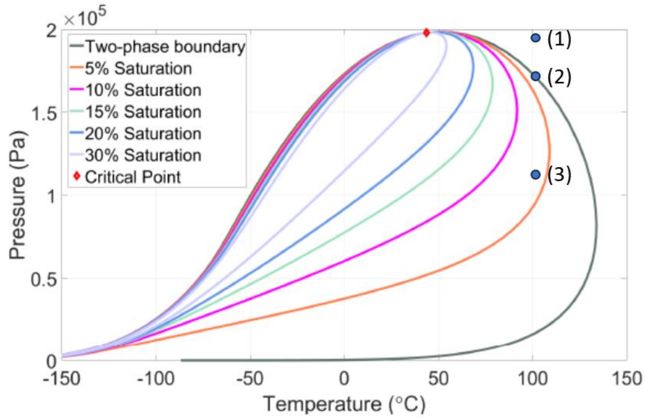

Figure 1: Phase diagram of a retrograde-condensate gas.

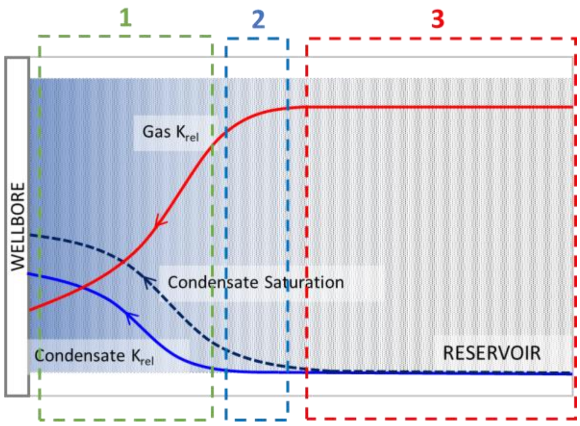

Figure 2: Three regions of gas-condensate behavior along the reservoir. Adapted from: *(Reis & Carvalho, 2020)*

As an alternative, similar data can be obtained via pore-scale modeling (Blunt et al., 2013). Pore-network models of multiphase flow could be particularly suitable for this purpose, as they have shown promising results for predictive purposes, while being computationally less demanding than direct models (Joekar-Niasar and Hassanizadeh, 2012). In the past decades extensive research effort has been directed to the development of this class of simulation tools, with a few regarding specifically gas and condensate flow. Reis and Carvalho (2021) proposed a compositional pore network model to determine the relative permeability curves of condensate-gas flow. The model can predict the flow behavior as a function of liquid composition, local flow velocity, pressure and temperature. The model was validated by comparing predictions of steady-state gas and condensate relative permeability curves with experimental data available in the literature. Results demonstrated that the model represented well the effect of condensate saturation, interfacial tension and velocity on gas-condensate flow.

In this work, near well gas-condensate flow is predicted using ad-hoc relative permeability curves obtained from extrapolation of experimental data, as generally used in the literature by (Hartman & Cullick, 1994), and relative permeability curves obtained from pore-network modeling of gas-condensate flow at different flow conditions, as two-scale model.

2. RESERVOIR-SCALE FLOW MODEL

2.1 Conservation Equations and Thermodynamic Model

The continuum flow model is based on molar balance and volume consistency equations. The molar concentration of each component *k* must be conserved:

$$\frac{\partial N^k}{\partial t} - \frac{V}{\phi r}\frac{\partial}{\partial r}\left(r m_k \frac{\partial P}{\partial r}\right) = 0 \, , \tag{1}$$

where ϕ is the porosity, N_k is the number of moles of component k, m_k is the mobility of component k that depends on the relative permeability and saturation of each phase. The sum of the volume occupied by each phase must be equal to the pore volume. The Peng-Robinson equation of state is used to describe the thermodynamic behavior of the fluids.

$$\begin{aligned} V\phi &= N_{liq}\left(\frac{Z_{liq}RT}{P} - \sum_{k=1}^{n_k} v_k x_k\right) + N_{gas}\left(\frac{Z_{gas}RT}{P} - \sum_{k=1}^{n_k} v_k y_k\right) \\ &= N_{liq}\left[\mathcal{L}\left(\frac{Z_{liq}RT}{P} - \sum_{k=1}^{n_k} v_k x_k\right) + (1-\mathcal{L})\left(\frac{Z_{gas}RT}{P} - \sum_{k=1}^{n_k} v_k y_k\right)\right] \quad , \end{aligned} \tag{2}$$

where Z_i is the compressibility of each phase i, x_k and y_k are the liquid and gas molar fraction of component k, v_k is the Darcy velocity of component *k*. The molar composition of each phase is determined by equating the fugacity of liquid and gas. The viscosity of both phases as a function of temperature, pressure and composition is evaluated by the Lohrenz-Bray-Clark (LBC) correlation. The interfacial tension is evaluated as a function of the liquid and gas phase properties and molar fraction of each component using the correlation proposed by Weinaug & Katz (1943).

As discussed before, two models for the relative permeability curves are used. The first was an emperical models proposed by Hartman and Cullick (1994) that interpolates the miscible and immiscible relative permeability curves using a weight function based on the interfacial tension between the gas and liquid phases.

$$k_{rliq} = f(\sigma)k_{rci} + (1 - f(\sigma))k_{rcm} \, , \tag{3}$$

$$k_{rgas} = f(\sigma)k_{rgi} + (1 - f(\sigma))k_{rgm} \, , \tag{4}$$

$$f(\sigma) = \left(\frac{\sigma}{\sigma^*}\right)^{\frac{1}{n}} \, . \tag{5}$$

The model is not able to capture all physical mechanisms that are relevant to condensate-gas flow in porous media and is constructed based on limited experimental data. The second approach is to use at each point relative permeability curves that are predicted by the compositional pore-network model developed by Reis and Carvalho (2021). Figure 3 presents some of these curves, showing the effect of local Darcy velocity and condensate saturation.

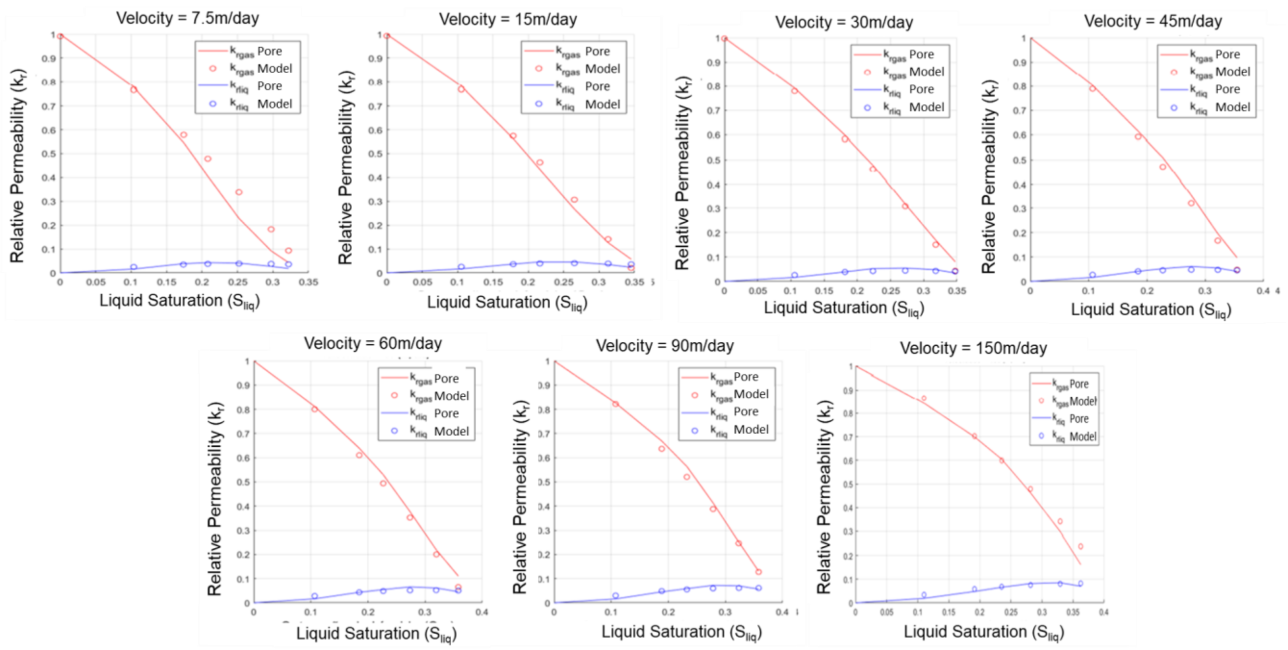

Figure 3: Permeability curve comparison from pore-scale model with the adjusted model for velocities from 7.5m/day to 150m/day.

Initially, we assume that the reservoir is at a constant pressure, above the dew point, only gas phase is present in the pore space. The reservoir is depleted at an imposed constant flow rate in the production well. The reservoir is considered impermeable in its outer boundary.

2.2 Model Parameters

The reservoir parameters are listed in Table 1.

Table 1: Reservoir parameters.

Absolute Permeability	5 mD
Porosity	17.1%
Reservoir's radius	177m
Reservoir's height	5m
Well radius	0.25m

The fluid composition and the corresponding phase diagram is presented in Fig. 4. We analyzed condensate gas flow at a fixed temperature of T = 80 ºC. The initial reservoir pressure was set to $P_{ini} = 2.25 \times 10^7 Pa$, which is above the dew point. Production continues until the well pressure reached $P_{ini} = 1.57 \times 10^7 Pa$, inside the two-phase region of the phase diagram, as shown in Fig. 4. The production flow rate was such that the Darcy velocity at the well bore was v = 200 m/day.

Component	Molar Fraction
CO_2	0.07
$C1$	0.65
$C2$	0.13
$C3$	0.07
$C6$	0.05
$C10$	0.025
$C16$	0.005

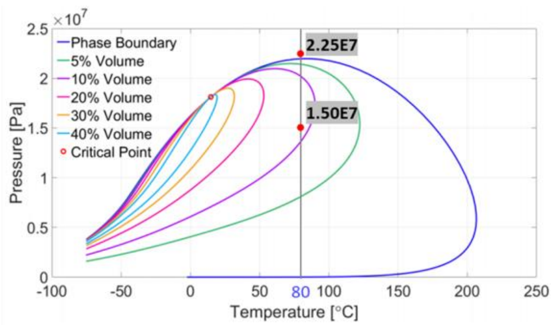

Figure 4: Fluid composition and corresponding phase diagram.

3. RESULTS

Figure 5 presents the evolution of the size of the condensate bank near the wellbore predicted by both models. Because of the high production rate, the pressure quickly reaches values below the dew point and condensate formation is observed since day 1. As the pressure drops, the size of the condensate bank grows until reaching the boundary of the reservoir at R = 177 m close to day 20. The predictions of both models are very close, showing that the relative permeability curve model has a weak effect on the size of the condensate bank.

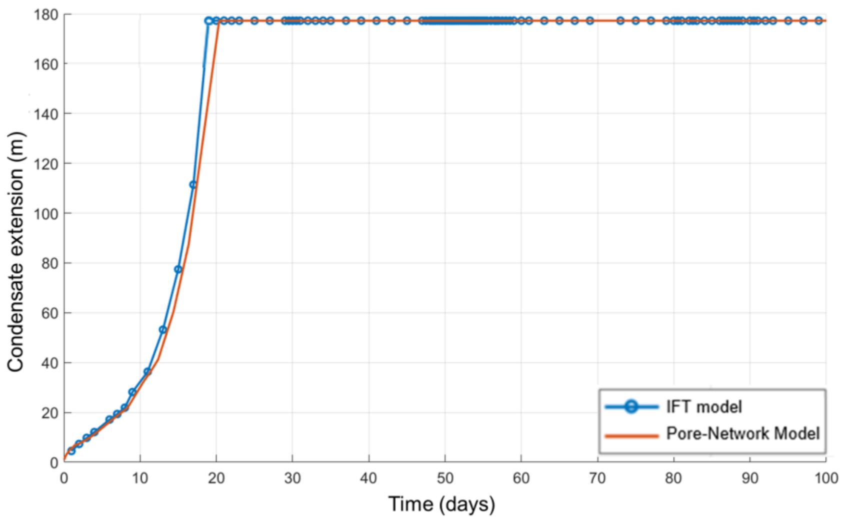

Figure 3: Extension of the condensate bank as a function of time.

The more accurate relative permeability curve model leads to a higher liquid saturation near the wellbore, as shown in Fig. 6. The higher liquid saturation causes stronger pore blocking near the production well, which hinders gas production, as indicated in Fig.7.

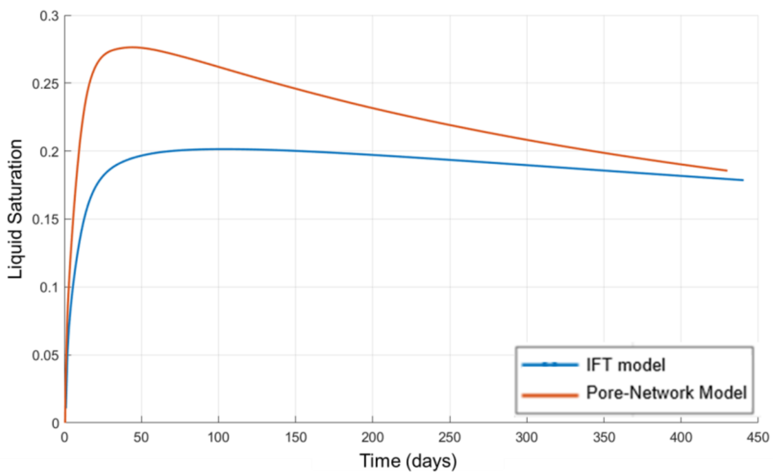

Figure 6: Evolution of liquid saturation at the wellbore.

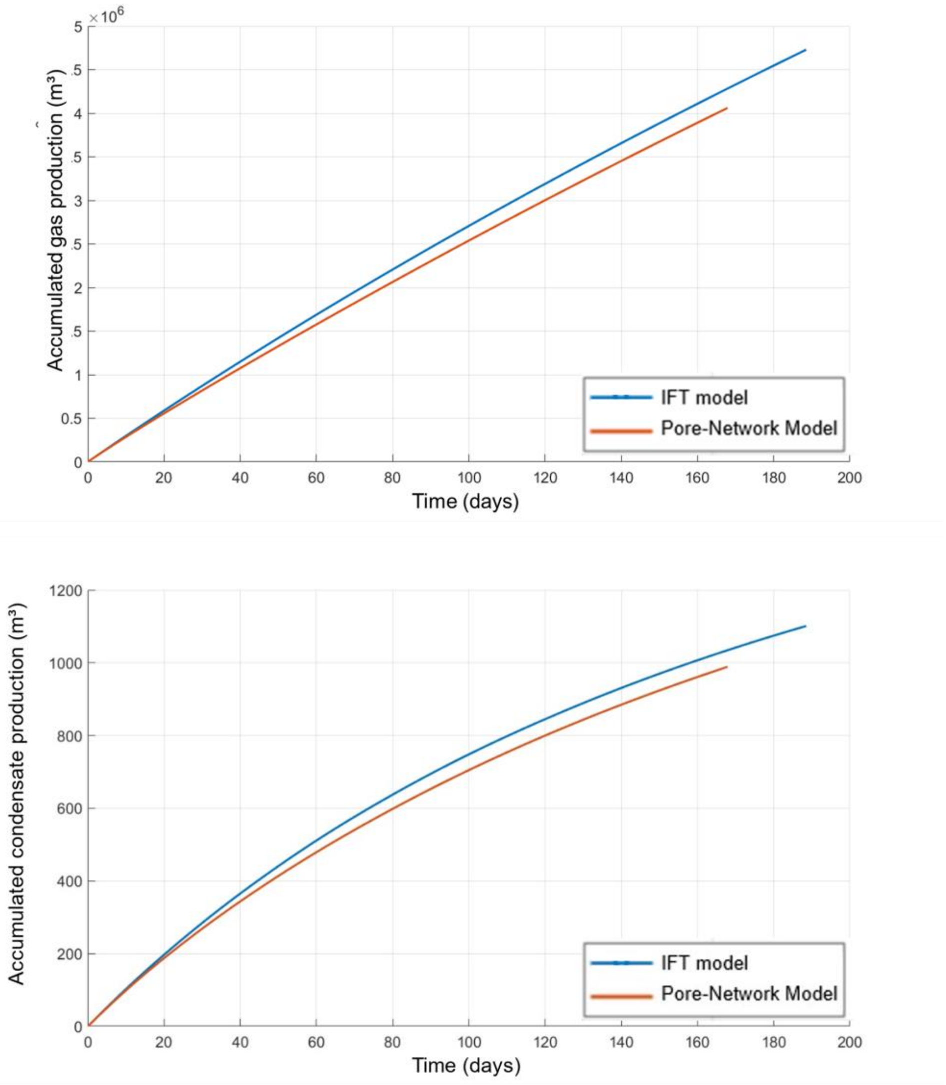

Figure 7: Accumulated production of gas and condensate.

4. FINAL REMARKS

Predictions of production of gas and condensate were obtained using two different relative permeability curves: ad-hoc relative permeability curves obtained from extrapolation of experimental data, as generally used in the literature and relative permeability curves obtained from pore-network modeling of gas-condensate flow at different flow conditions, as two-scale model.

The results show that using a relative permeability curve that does not consider all the physical mechanisms associated with condensate gas flow near a production well may lead to overprediction of production rate, which may compromise the planning and optimization of gas condensate fields.

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