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Production of Natural Gas and Fluids Flow in Tight Sand Reservoirs

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Abstract

The dependencies between macroscopic tight sand gas reservoir parameters and microscopic fluid flow dynamics are investigated by identifying the main transport mechanisms at the pore scale that should affect fluids flow at the reservoir scale. A critical review of commercial reservoir simulators used to predict tight sand gas reservoir revealed that many are deficient when used to model fluid flow through tight reservoirs, given that certain phenomena are ignored altogether or modeled incorrectly. Phenomena such as, Knudsen diffusion, electro-kinetic effects, ordinary diffusion mechanisms and water vaporization are not adequately captured in the transport equation of these simulators. We developed a 2-D numerical simulator based on equations that capture the above mentioned phenomena among others. Dynamic implications of new equations are comprehensively discussed in this paper and their relative contribution to the flow rate is evaluated for different Knudsen numbers (going from continuum to transition flow regime). Our proposed formulation may have impacts beyond that of natural gas flow in tight sands. Other areas that could benefit from a more comprehensive understanding of the gas transport through tight porous systems are: heterogeneous catalysis and adsorption problems associated with in-situ remediation techniques for removal of Volatile Organic Compound (VOCs) and Non-Aqueous Phase Liquid (NAPLs) as well as predicting gas transport into surrounding media at hazardous waste sites, among others.

Keywords

Low permeability, reservoir simulation, multiphase transport, porous media, Klinkenberg effect.

1. Introduction

The forecast of U.S. natural gas demand indicate an increase of around 17 percent by 2025 (U.S. Energy Information Administration, 2005). Most of the needed additional supply of domestic natural gas production will come from low-permeability reservoirs, such as tight sand, coal-bed methane and shale gas reservoirs. Recent assessments of marginal resources indicate that thousands of Tcf of gas exists in-place in domestic onshore low permeability reservoirs, but only a small portion of this vast potential resource is economically recoverable using current exploration and production technologies. The understanding of low permeability gas systems needs to be improved to enable a more accurate appraisal, forecast of production and further development of these potential resources.

Production forecasts have traditionaly been based on reservoir simulations studies. The main goal of a reservoir simulator is to predict future performance of the reservoir and to allow the study of alternatives to increases the final recovery (Munka and Papay, 2001). However, comercial reservoir simulators could be inapropiated tools to predict low permeability reservoir behaviors, because the transport equations on which they are based, do not consider properly some rock-fluids interactions, which may be dominating the flow dynamics in these low permeability reservoirs. Previous works on this topic indicate that more reliable modeling is required (Sung and Ertekin, 1986; Ertekin et al., 1986; Chawathe et al., 1996; Jalal et al., 2004).

We preformed a critical review in order to evaluate the predictive capability of commercial reservoir simulations when used for tight sand gas reservoir studies. The in-situ permeability of tight sands reservoirs is less than 1 mD (National Petroleum Council, 1980). From our review we detected misinterpretations of the commonly termed Klinkenberg effect, which leads to large errors of fluid flow predictions through tight sand reservoirs. We developed a 2-D numerical simulation model to quantify the importance of different phenomena at pore-scale, such as Knudsen diffusion, electro-kinetic effects, ordinary diffusion mechanisms, etc on the predictions of fluid flow at reservoir scale. In this present paper we summarize our main observations to conventional approaches while we discuss the alternative formulation on which our simulator is based.

2. Objectives

The main goal of this work is to identify microscopic flow mechanisms that may affect the macroscopic dynamics of tight sands reservoirs. We performed a critical preliminary analysis of the reservoir simulators utilized to predict behaviors of gas and water flow in tight sands reservoirs. In this paper we offer an alternative formulation that incorporates the relevant mechanisms in order to achieve a proper modeling of their dynamics.

3. Methodologies

The critical review of reservoirs simulators utilized to predict gas tight-sands fields production was divided in three major areas:

1. Reservoirs characterization: Permebilities, porosities, capillary pressure and relative permeability, pores sizes and morphology, spatial distribution, clays content, water properties, pore volume compressibility, gas slippage effect, sensitivity of permeability to overburden pressure, etc

2. Relevant field experiences: Water production, long-flowing wells decline curves analysis, role of natural and artificial fractures, infill well, etc.

3. Reservoir modeling and simulation: Multiphase transport equations, closure relations, physicals and numerical assumptions, etc.

A careful analysis of these aspects confirmed that discrepancies between the assumptions behind conventional reservoir simulators utilized to predict tight sands reservoir’s performance and fluid-rock characteristics in tight sands could be responsible of unexpected behaviors of some fields.

Following a dual-mechanistic flow approach, a system of four macroscopic transport equations that model two-phase (gas-water) flow through tight sands was developed. The porous medium was modeled using a dual-porosity and dual-permeability approach. The mass balance of methane molecules contained in the gas and the liquid phase are two equations, one for the porous matrix and other for the fractured regions that can be expressed both as:

$$\frac{\partial}{\partial t}\left(\phi^{j}\,\frac{S_g}{B_g}+\phi^{j}\,\frac{S_l}{B_l}R_s\right)=\vec{\nabla}\cdot\left(\vec{V}_{D_g}^{m\ j}+\vec{V}_{D_l}^{m\ j}+\vec{V}_{C_g}^{m\ j}+\vec{V}_{C_l}^{m\ j}\right)+\left(\frac{T_g^{M\rightarrow F}}{B_g}+\frac{T_l^{M\rightarrow F}}{B_l}R_s\right)\tag{1}$$

Analogously, the mass balance of water molecules in the liquid phase and evaporated in the gas phase is ($j=M,F$; see table 1):

$$\frac{\partial}{\partial t}\left(\phi^{j}\,\frac{S_l}{B_l}+\phi^{j}\,\frac{S_g}{B_g}r_s\right)=\vec{\nabla}\cdot\left(\vec{V}_{D_g}^{w\ j}+\vec{V}_{D_l}^{w\ j}+\vec{V}_{C_g}^{w\ j}+\vec{V}_{C_l}^{w\ j}\right)+\left(\frac{T_l^{M\rightarrow F}}{B_l}+\frac{T_g^{M\rightarrow F}}{B_g}r_s\right)\tag{2}$$

where,

$$\vec{V}_{D_g}^{m\ j}=\frac{S_g D_g^{*m\ j}}{B_g x_g^m}\frac{\partial x_g^m}{\partial P}\vec{\nabla}P\,,\qquad \vec{V}_{D_l}^{m\ j}=\frac{S_l D_l^{*m\ j}R_s}{B_l x_l^m}\frac{\partial x_l^m}{\partial P}\vec{\nabla}P\tag{3}$$

are the flow of methane due to the dispersive mechanism,

$$\vec{V}_{C_g}^{m\ j}=\frac{K_g^j k_{rg}}{\mu_g B_g}\vec{\nabla}P\,,\qquad \vec{V}_{C_l}^{m\ j}=\frac{K_l^j k_{rl}}{\mu_l B_l}R_s\vec{\nabla}P\tag{4}$$

are the flow of methane due to the “convective” mechanism,

$$\vec{V}_{D_g}^{w\ j}=\frac{S_g D_g^{*w\ j}r_s}{B_g x_g^w}\frac{\partial x_g^w}{\partial P}\vec{\nabla}P\,,\qquad \vec{V}_{D_l}^{w\ j}=\frac{S_l D_l^{*w\ j}}{B_l x_l^w}\frac{\partial x_l^w}{\partial P}\vec{\nabla}P\tag{5}$$

are the flow of water due to the dispersive mechanism, and

$$\vec{V}_{C_g}^{w\ j}=\frac{K_g^j k_{rg}r_s}{\mu_g B_g}\vec{\nabla}P\,,\qquad \vec{V}_{C_l}^{w\ j}=\frac{K_l^j k_{rl}}{\mu_l B_l}\vec{\nabla}P\tag{6}$$

are the flow of water due to the convective mechanism through the *i*-phase, and

$$K_g^j=K_\infty^j\left(1+\frac{b}{P_g}\right),\quad K_l^j=\left(K_\infty^j\right)^{1.32}\tag{7}$$

are the “absolute” permeability to gas and to liquid respectively.

The source/sink term is $T_i=q_i/V$. This is the injected/extracted flow rate q_i in a cell of total volume *V*. In our case (double porosity rock), the mass transfer from the porous matrix into the fractures was considered (Evans, 1981):

$$T_i^{M\to F} = -T_i^{F\to M} = 4\left(\frac{2}{l^2}\right)\frac{K_i^M k_{ri}}{\mu_i}\left(P_i^M - P_i^F\right),\ i = g, l \tag{8}$$

The meanings of parameters involved in the above equations are specified in the Table 1.

Table 1: Nomenclature.

Symbol	Meaning	Symbol	Meaning
ϕ^j	*j*-system porosity	ρ_i	*i*-phase density
τ^j	*j*-system tortuosity	g	Gravity
t	time	b	Klinkenberg's parameter.
S_i	*i*-phase Saturation	z	Gas compressibility factor
B_i	*i*-phase's Formation Volume Factor	D_K	Knudsen diffusion coefficient
R_s	Solution gas-water ratio	Kn	Knudsen number
r_s	Vaporized liquid-gas ratio	**Subscript:**	
K_i^j	*j*-system "absolute" permeability to *i*-phase	g	Gas Phase
K_∞^j	Absolute permeability	l	Liquid phase
k_{ri}	*i*-phase relative permeability	D	Dispersive
$\vec{V}_{N_i}^k$	*k*-component flow in the *i*-phase by the *N*-mechanism	C	Convective
$D_i^{*k\ j}$	Dispersion coeff. of *k*- component in *i*-phase through the *j*-system	PC	Pure Convective (without Knudsen)
D_i^k	Diffusion coeff. of *k*-component in *i*-phase.	Kn	Knudsen
q_i	Caudal of *i*-phase injected.	**Superscript**	
x_i^k	Mole fraction of *k*-component in *i*-phase	w	Water
l	fracture spacing	m	Methane
μ_i	*i*-phase viscosity	M	Matrix
P_i	*i*-phase pressure	F	Fracture

Notice that the contribution of Knudsen diffusion is introduced in the "convective" term through the parameter *b*. It is useful for our study to consider the Knudsen diffusion contribution separated from the pure convective term. Thus we express:

$$\vec{V}_{C_g}^{m\ j} = \vec{V}_{PC_g}^{m\ j} + \vec{V}_{Kn_g}^{m\ j}\text{, with } \vec{V}_{PC_g}^{m\ j} = \frac{K_\infty^j k_{rg}}{\mu_g B_g}\vec{\nabla}P \text{ and } \vec{V}_{Kn_g}^{m\ j} = \frac{K_\infty^j k_{rg}}{\mu_g B_g}\frac{b^j}{P_g}\vec{\nabla}P \tag{9}$$

At this point a simple procedure is proposed to evaluate the potential relevance of our formulation in comparison with a Black-oil conventional simulator. In this sense, and using equations from (3) to (7) and equations (9), we evaluated the ratios $\left(V_{D_g}^k + V_{D_l}^k\right)/\left(V_{C_g}^k + V_{C_l}^k\right)$ and $\vec{V}_{Kn_i}^{k\ j}/\vec{V}_{PC_i}^{k\ j}$ for a representative range of pressures and Klinkenberg permeabilities of tight sands reservoirs. It is assumed that the change in pressure is due to changing the total number of moles in the system by keeping volume, temperature and the proportion of number of moles of water and methane constant.

The PVT parameters were estimated by correlations. The real gas equation of state (EOS) is used to calculate B_g and the *z* factor involved is estimated from the Starling modification of Benedict-Webb-Rubin EOS (p. 131, Danesh, 1998). The water density correlation from Batzle M, Wang Z (1992) is used for B_l estimation. *Rs* is computed from the Henry law (p. 114, Danesh, 1998) with the Henry constant for Methane at normal pressure extracted from a semi-empirical correlation (Harvey, 1996) and a salinity correction from the correlation of McKetta-Wehe (p. 91, Danesh, 1998). The Lee correlation (p. 83, Danesh, 1998) and the Kestin correlation (Kestin et al, 1981) were used to estimate μ_g and μ_l respectively. The water content in gas phase, r_S, is calculated from Raoult's Law (p. 87, Danesh, 1998).

The dispersion coefficients are being considered for low Peclet number (Pe < 0.3). In this case they are given by (Sahimi, 1993):

$$D_i^{*k\,j} = \frac{\phi^j}{\tau^j} D_i^{k\,j} \text{, with } i = g,l \text{, } k = m,w \text{ and } j = M,F\,. \tag{10}$$

The diffusivities coefficients were considered to comply the Onsager relation, through which $D_g^m = D_g^w$ and $D_l^w = D_l^m$. The self-diffusion of methane (Lee and Thodos, 1983) is used to compute D_g^m and the aqueous diffusion coefficient of methane (Hayduk and Laudie, 1974) was used to estimate D_l^m.

Rock-fluids interactions phenomena such as the electro-kinetic effect and Knudsen diffusion are captured in our formulations through correlations. The electro-kinetic effects, for the liquid phase, are introduced by considering the klinkenberg permeability elevated by the exponent 1.33 (Jones and Owen, 1980) in the equation (7). The Knudsen diffusion effect is captured from its relation with the Klinkenberg parameter *b* as obtained from the Dusty Gas Model (Thorstenson and Pollock, 1989)

$$D_K = \frac{b}{\mu_i} K_\infty\,. \tag{11}$$

We plotted data from many experiments (Chowdiah, 1988; Jones and Owen, 1880; Randolph and Soeder, 1984; Soeder and Chowdiah, 1990) and the best curve centered in this data was:

$$D_K = 185525\, K_\infty^{0.7014}, \tag{12}$$

with both, D_K and K_∞ expressed in SI of units. Then, equations (11) and (12), considering the point $\left(b, K_\infty\right) = \left(6 \cdot 10^5\ P\text{a}\,,\ 2.37\times 10^{-17}\ m^2\right)$ (Li et al. 2004), are used to obtain:

$$b = 6\times 10^5 \left(\frac{2.37\times 10^{-17}}{K_\infty} \right)^{0.2986}\,. \tag{13}$$

The relative pemeabilities have been considered as $k_{rg} = S_g$ and $k_{rl} = S_l$. More realistic curves do not necessarily introduce accuracy in the predictions presented in this work, because the two-phase effective dispersive coefficients are also considered proportional to the phase saturation.

4. Results

The literature widely reports very small characteristic size for the flow path openings in tight sands. Bossier sands, for instance, have effective porosities that vary from 1 % to 17 %, while permeability ranges from 0.001 to 1 mD. When the pore size is so small that its dimension is comparable to the mean free path of molecules, the governing equations of fluid motion are different than those that govern flow in conventional porous media. In this scenario, commercial reservoir simulators may have important limitations to model fluid flow in tight reservoirs given that certain phenomena are ignored altogether or even worse, modeled incorrectly.

Two decades ago a “dual” mechanisms of production was proposed for the tight sand reservoirs (Ertekin et al., 1986). This dual mechanism contains the dispersive and the convective contribution to the flow. Even though the idea is plausible, different considerations in the approach followed presented several limitations, among which are:

- The micro-pores were considered accessible only to gas, whereas the water primarily resides in the macro-pores. However, the distribution of fluids is highly different in tight sands since water should be the wetting phase.
- It is said that when a pressure gradient is imposed, the thermodynamic equilibrium is distorted between the gas that is in solution in the water and the gas that is present in the micro-pores, creating local concentration gradients. Following our line of thought, gas should be driven into the macro-pores by diffusion. However, if water is the wetting phase, with gas in the small pores and water in the large pores, the system is not in thermodynamic equilibrium, even before of the imposed pressure gradient, since capillary pressure would favor the flow of the gas towards the large pores.
- The equations are supposed to capture the slippage effect through a dispersive term that explicitly appears in the equation. However, a huge misunderstanding of the contribution of ordinary diffusion and Knudsen diffusion is evidenced when the Klinkenberg parameter *b* is obtained as a function of the ordinary diffusion coefficient.

Thus, what in principle seemed an adequate approach became in a really confusing effort. We retake the original idea by formulating a dual mechanism of flow (see previous section) in order to evaluate the need of this approach for reliable forecasts of tight sands gas reservoir. Potential relevance of the dispersive terms introduced in our formulation on the flow predictions is shown through maps of the iso-lines of $\left(V_{D_g}^k + V_{D_l}^k\right) \Big/ \left(V_{C_g}^k + V_{C_l}^k\right)$ values, obtained by equations (3) to (7) and $V_{PC_l}^m \big/ V_{Kn_l}^m$ by equations (9), in a (K_∞, P) coordinates space. Given that the pore radius in general satisfies the relation $R \propto \sqrt{K_\infty}$ with the permeability, the coordinate space used here is also representative of a (R, P) Knudsen space.

Figure 1a reveals that the dispersive transport of methane in gas phase can not be neglected in general when the flow is occurring through a porous media of permeability in the range from 10^{-4} to 10^{-2} mD for typical temperatures of these reservoirs. It shows that for a given permeability, when pressure increases from 1 to 500 bar, the dispersive term contribution to flow

decreases. In principle dispersive contributions smaller than 0.1 times the “convective” input can be ignored.
Notice that in Figure 1, for temperatures of 240 ^{o}F and 400 ^{o}F the iso-lines are observed only for pressures above the saturation pressures, which are 1.72 bar and 17.0 bar, respectively. This occurs because below these pressures, there is only gas phase and our assumption of constant moles number ratio of water and methane implies no mole fraction gradients and consequently the dispersive contribution vanishes. In the actual reservoirs dynamic however, we may have concentration gradients in the gas phase.

In addition, it is not obvious how to identify the effect of time and distance from the well on the balance between these two terms. Pressure depends on the distance from the well in such a way that it decreases when this distance also decreases and it also vary with production time. Therefore, further evaluation of the dispersive term contribution should be performed in the context of a dynamic reservoir simulation.

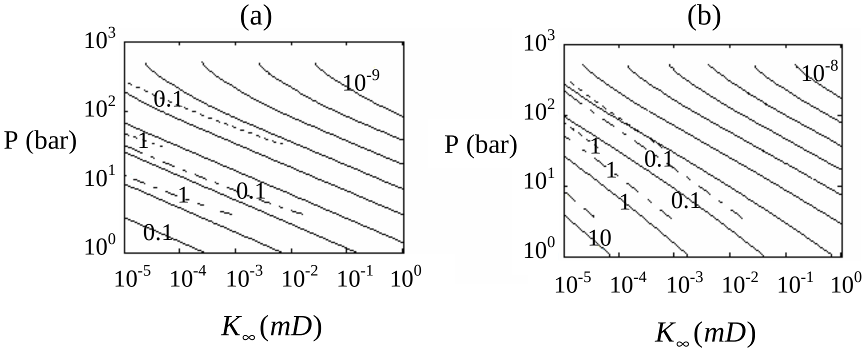

Figure 1: Iso-lines of $\left(V_{D_g}^k + V_{D_l}^k\right)/\left(V_{C_g}^k + V_{C_l}^k\right)$**. (a) Methane** $(k = m)$ **and (b) Water** $(k = w)$**. Continuous line for 70 ^{o}F, dot-dashed line for 240 ^{o}F and dotted line for 400 ^{o}F.**

From Figure 1b can be seen that the dispersive contribution to the flow of water is also relevant in general. In this case for permeabilities larger than 0.01 mD the dispersive contribution to the water flow seems not to be significant to the flow for any pressure and temperature value. The analysis arose above which turn out the conclusion that we are underestimating the dispersive input is valid also in this case.

Moreover, notice that in equation (9) the dispersion coefficient is being considered for Pe < 0.3 (Peclet number), which actually means that we are only considering the diffusive effect. The dependence of dispersion with Pe (Sahimi, 1993), would imply that, depending on the fluids velocity, the dispersive terms could be up to about four orders of magnitude larger than those estimated in this work. Consequently, when the dependence with Pe is introduced in the estimations we would see that dispersion is actually dominating the fluid flow dynamic through the whole range tight sands permeabilities.

On the other hand, the “convective” term plotted in Figure 1 contains the contribution of the Knudsen diffusion (see equation (9)) through the Klinkenberg parameter *b*. Figure 2 allow to see how much of the “convective” contribution is due to the Knudsen diffusion input. It is observed that more than 50 % of the “convective” term contribution is dominated by the Knudsen diffusive transport. The increasing direction of Knudsen number (Kn) is represented in this graph in order to give an idea of its effect.

In this work we have been considering the Klinkenberg parameter *b* independent of pressure as conventionally assumed. However many experimental observations have demonstrated that this parameter is not constant when the mean pore pressure change (Klinkenberg, 1941; Li et al. 2004). This fact that has been ignored in this preliminary evaluation could produce an increase of the relevance of the flow regimes captured in the Klinkenberg parameter *b*. Previous efforts (Ertekin et al., 1986) to clarify the pressure dependence of *b* are unacceptable because of several physical inconsistencies, such as eq. 16 of Ertekin et al. It shows a misunderstanding of the advection diffusion equation where the pressure dependence of parameter *b* is explained to be a consequence of considering a real gas. In addition, the physical meaning of the diffusion coefficient *D* was unclear and it was arbitrarily assumed as a constant equal to 0.215 cm^2/s. Moreover, gas properties, such as viscosity and gas compressibility, for different pressure and temperature values were calculated from correlations validated for hydrocarbon gases (Carr et al., 1954; Hall and Yarborough, 1973), but not for air which was the gas used in the Klinkenberg experiments the author intended to reproduce. Ignoring the misinterpretation of the advection diffusion equation mentioned above, the use of valid correlations for air (Perry and Green, 1997), makes that the increasing behavior with the pressure of $P\mathrm{c}_g\mu$ quantity does not reproduce in any way the increasing behavior with pressure of the Klinkenberg experiment studied by Ertekin.

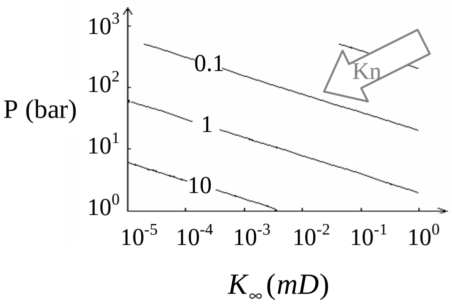

Figure 2: Iso-lines of the ratio $V^m_{Kn_l} \big/ V^m_{PC_l} = b \big/ P_g$ (from equation 9) in a $\left(P, K_\infty\right)$ space.

Figure 3a is useful to observe that most of water flow occurs while the water is in gas phase for typical reservoir conditions. Figure 3b shows the ratio between dispersive and convective terms presented in the numerator of the ratio plotted in the Figure 3a. According to this figure the dispersive mechanism is non-negligible in general. Again, here our estimations of this mechanism of flow are under-estimated for the reasons already discussed before.

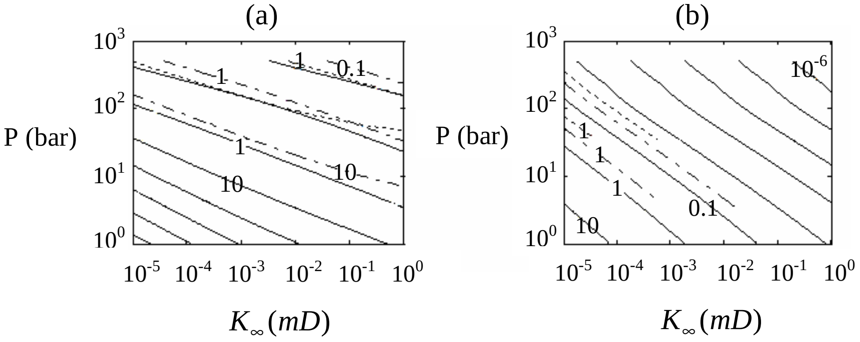

Figure 3: Iso-lines of the ratio (a) $\left(V^w_{D_g} + V^w_{C_g}\right) \big/ \left(V^w_{D_l} + V^w_{C_l}\right)$ and (b) $V^w_{D_g} \big/ V^w_{C_g}$. Continuous line for 70 °F, dot-dashed line for 240 °F and dotted line for 400 °F.

5. Conclusions

A new formulation that considers a multi-mechanistic flow approach is proposed and evaluated for modeling the tight-sands gas reservoirs performance. The flow of methane in both phases, gas and liquid, was found impacted by the dispersive mechanism contribution in a non negligible magnitude in general. In particular, this mechanism of flow was observed as dominating the dynamic for the lower range of pressure and Klinkenberg permeabilities evaluated. Moreover, when the input of the Knudsen Diffusion process to the "convective" term was evaluated the actual contribution of the pure convective term turned on even smaller. The estimations that originated our results took place under the most unfavorable conditions for dispersion mechanism predominance ($Pe<0.3$). This imply that the contribution of dispersive mechanism of transport quantified here could be larger various orders of magnitude.

The vaporized water flow contribution is dominating the water transport, for typical temperatures of tight sands reservoirs, in almost the whole range of pressures and permeabilites evaluated. Similar to methane gas flow, the water vapor flow was obtained from partially to totally controlled by the dispersive mechanism of transport.

6. Recommendations

A new generation of reservoir simulator able to properly capture the dispersive contribution to the flow through tight sands gas reservoir need to be implemented. The dependence of Klinkenberg parameter *b* with pressure need to be carefully studied in order to introduce it in the predictions.

7. Acknowledgements

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