Gas relative permeability and its modeling in tight and ultra-tight porous rocks

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Abstract

Abstract Gas relative permeability, krg, is a key parameter to determine gas production in unconventional reservoirs. Several theoretical approaches were proposed to study gas relative permeability in tight and ultra-tight porous rocks. Some models are based on a "bundle of capillary tubes" concept. Some others were developed based upon a combination of universal scaling laws from percolation theory and the effective-medium approximation (EMA). Although applications from the EMA have been successfully used to estimate single-phase permeability in permeable media (Ghanbarian et al., 2017; Ghanbarian and Javadpour, 2017), non-universal scaling from the EMA has never been invoked to model gas relative permeability in tight and/or ultra-tight porous rocks. In this study, it was assumed that pore-throat sizes follow the log-normal distribution. It was further assumed that gas transport in shales is mainly controlled by molecular and hydraulic flow, two mechanisms contributing in parallel. Using the EMA, effective pore-throat radii, effective conductances, and gas relative permeabilities were determined at various gas saturations. Comparison with three-dimensional pore-network simulations showed that the proposed krg model estimated gas relative permeability accurately. We also compared our model with experimental data reported in Yassin et al. (2016) including three Montney tight gas siltstone samples from the Western Canadian Sedimentary Basin. Results showed that our model estimated krg reasonably well, although it slightly overestimated krg. This might be because the fitted log-normal probability density function underestimated the probability of small pore-throat sizes. References Ghanbarian, B., & Javadpour, F. (2017). Upscaling pore pressure-dependent gas permeability in shales. Journal of Geophysical Research: Solid Earth, 122(4), 2541-2552. Ghanbarian, B., Torres-Verdin, C., Lake, L. W., & Marder, M. P. (2017). Upscaling gas permeability in tight-gas sandstones. AGU Fall Meeting Abstracts. New Orleans LA. Yassin, M. R., Dehghanpour, H., Wood, J., & Lan, Q. (2016). A theory for relative permeability of unconventional rocks with dual-wettability pore network. SPE Journal, 21(06), 1970-1980.

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BACKGROUND

Factors affecting gas permeability in tight media

- Connectivity
- Pore-throat size distribution
- Slip flow and Knudsen diffusion
- Tortuosity
- Porosity
- Pore shape geometry
- …

Theoretical upscaling techniques

- Bundle of capillary tubes approach
- Effective-medium approximation (EMA)
- Critical path analysis (CPA)
- Perturbation theory
- Volume averaging method
- …

PURPOSES AND ASSUMPTIONS

Objectives

- ✓ To evaluate EMA's reliability in the estimation of gas transport and more specifically gas relative permeability k_{rg} in tight and ultra-tight porous rocks.
- ✓ To estimate k_{rg} from mercury intrusion capillary pressure curve or pore-throat size distribution.
- ✓ To compare EMA results with pore-network model simulations and experiments.

Assumptions

- ❑ Pores can be either cylindrical or slit-shaped.
- ❑ Gas transport is dominated by two mechanisms contributing in parallel: (1) slip flow, and (2) Knudsen diffusion.
- ❑ Contact angle is about 140° for mercury.
- ❑ The air-mercury interfacial tension is 485 mN/m.

MATERIALS AND METHODS

Hydraulic flow in a tube

$$g_h = \beta F \frac{\pi R^4}{8\mu l} \qquad F = 1 + \left(\frac{8\pi R_g T}{M_m}\right)^{0.5} \frac{\mu}{pR}\left(\frac{2}{TMAC} - 1\right)$$

β is the gas compressibility factor.

Molecular flow in a tube

$$g_m = \alpha \pi R^2 \sqrt{\frac{R_g T}{2\pi M_m}}$$

$$\alpha = 1 + y^2 - y\sqrt{1+y^2} - \frac{\left[(2-y^2)\sqrt{1+y^2} + y^3 - 2\right]^2}{4.5y\sqrt{1+y^2} - 4.5\ln\left(y + \sqrt{1+y^2}\right)}$$

$y = l/(2R)$.

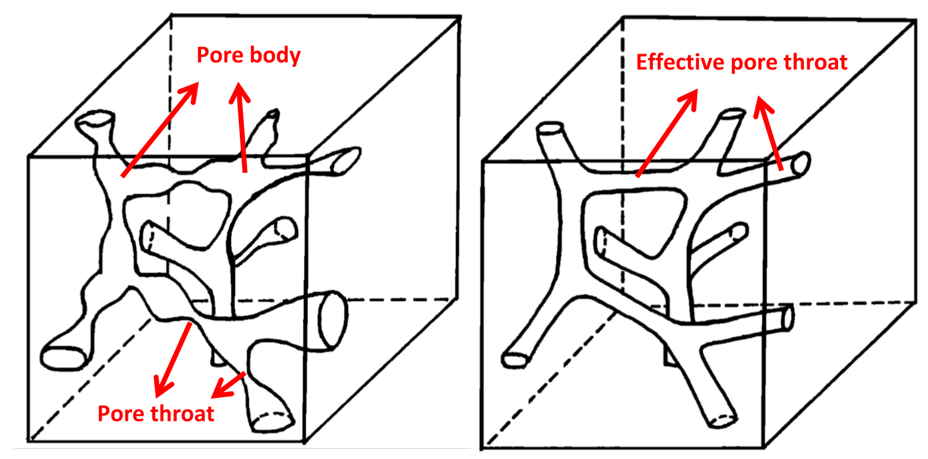
Assuming that gas flow is mainly controlled by hydraulic and molecular flow (two mechanisms contributing in parallel) in a single cylindrical nanotube with radius R and length l, the total conductance, g_t, in the pore throat is given by

$$g_t = g_h + g_m = \beta F \frac{\pi R^4}{8\mu l} + \alpha \pi R^2 \sqrt{\frac{R_g T}{2\pi M_m}}$$

The effective-medium approximation (EMA)

An upscaling technique from statistical physics appropriate in homogeneous and relatively heterogeneous porous rocks. Effective conductance can be determined from the following EMA governing equation:

$$\int_{g_{tmin}}^{g_{tmax}} \frac{g_e(S_g = 1) - g_t}{g_t + \left[\frac{1 - S_{gc}}{S_{gc}}\right] g_e(S_g = 1)} f(g_t)\, dg_t = 0$$



Single-phase permeability

The upscaled EMA permeability model is (Ghanbarian and Javadpour, 2017):

$$k = \frac{2 r_e \mu M}{3 R_g \rho} \frac{\phi}{\tau} \left(\frac{8 R_g T}{\pi M}\right)^{0.5} + F \frac{\phi}{C_s \tau} \frac{r_e^4}{\langle r_b^2 \rangle} \qquad \mathrm{TMAC} = 1 - \log\left(1 + K_n^{0.7}\right) \qquad K_n = \frac{k_B T}{2\sqrt{2}\pi d_m^2 p r_e}$$

Gas relative permeability

For partially-saturated conditions, one has

$$\int_{g_{tmin}}^{g_t} \frac{g_e(S_g) - 0}{0 + \left[\frac{1 - S_{gc}}{S_{gc}}\right] g_e(S_g)} f(g_t)\, dg_t + \int_{g_t}^{g_{tmax}} \frac{g_e(S_g) - g_t}{g_t + \left[\frac{1 - S_{gc}}{S_{gc}}\right] g_e(S_g)} f(g_t)\, dg_t = 0$$

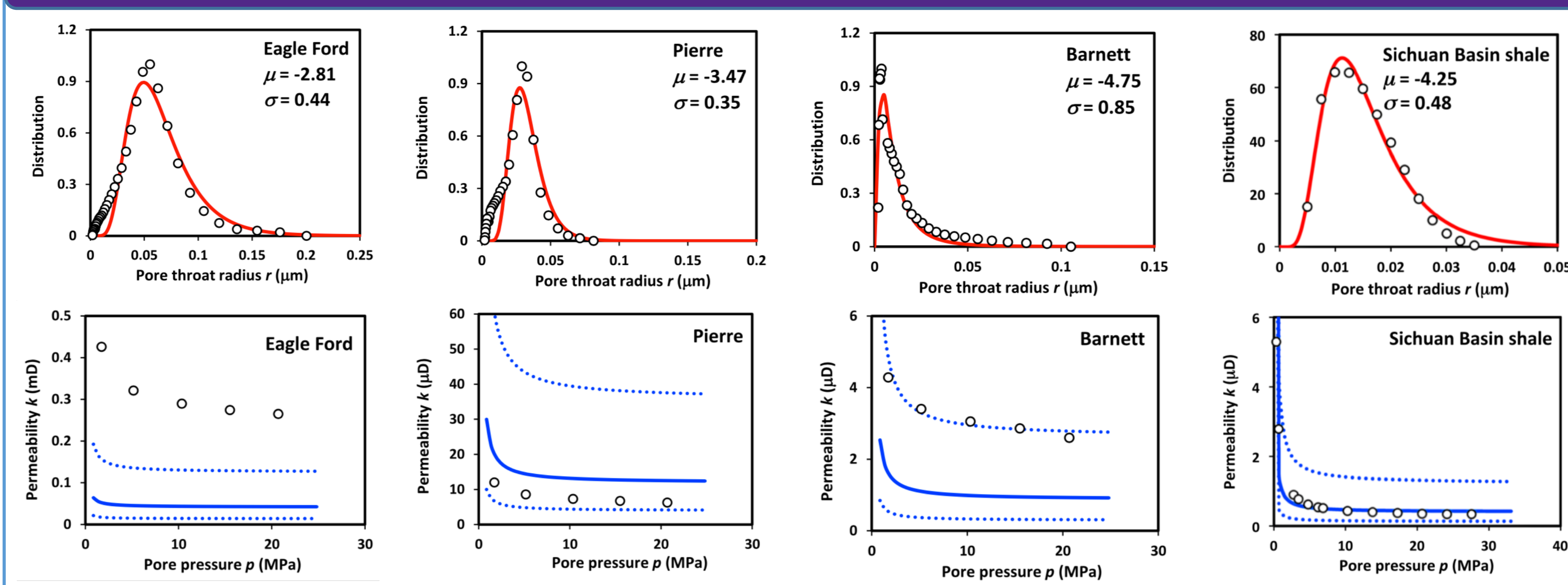
Since gas permeability is proportional to the effective conductance, we define k_{rg} as (Ghanbarian, 2018)

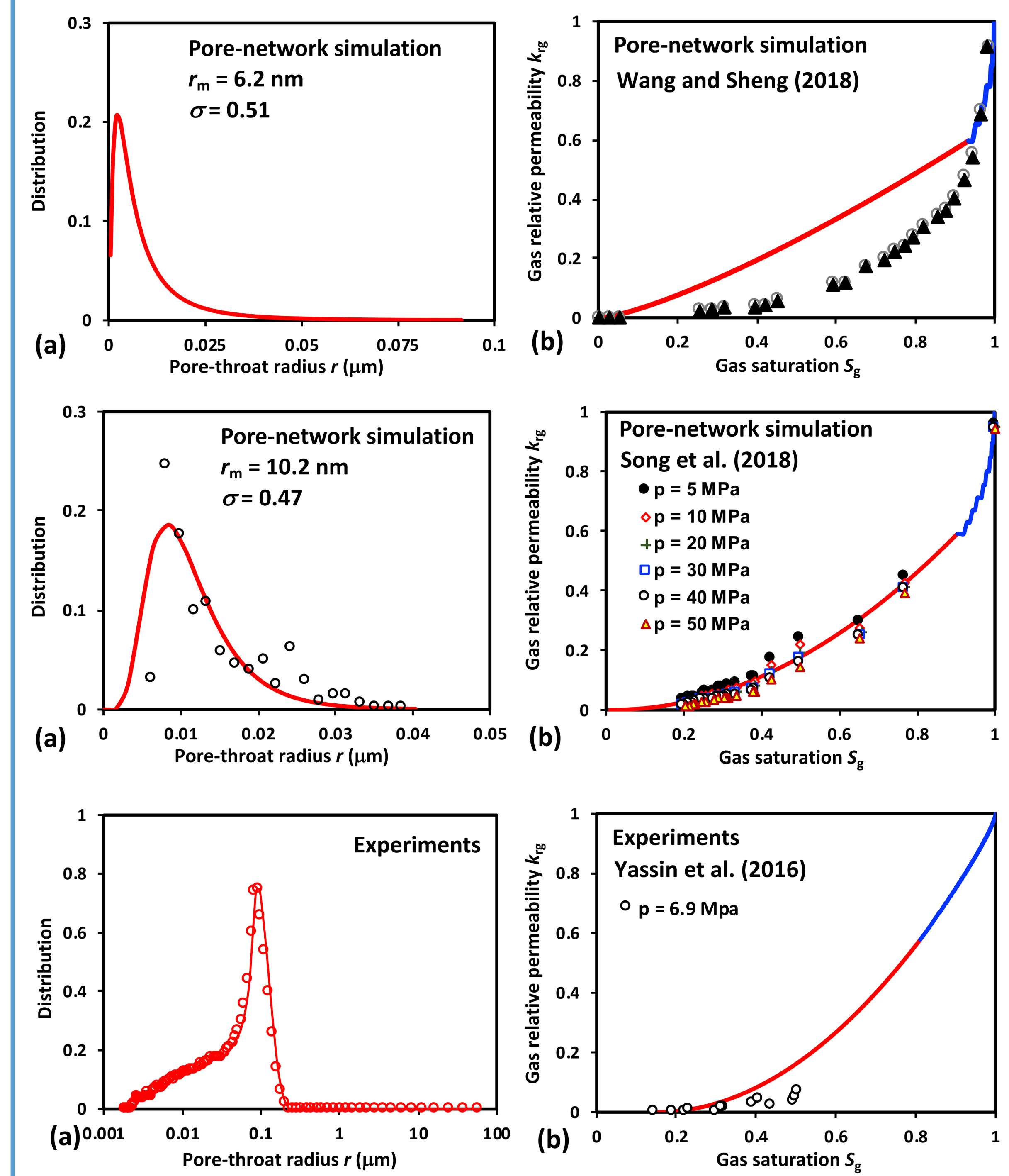
$$k_{rg} = \frac{k_g(S_g)}{k_g(S_g = 1)} = \frac{g_e(S_g)}{g_e(S_g = 1)}$$

We use the EMA at high to intermediate gas saturations and apply the following universal power-law scaling from percolation theory at low gas saturations near S_{gc}

$$k_{rg} = k_0 \left(S_g - S_{gc}\right)^2, \qquad S_g > S_{gc}$$

RESULTS





CONCLUSION

- ❑ Comparison with 2D pore-network simulations showed that the proposed model estimated gas relative permeability well at high gas saturations. However, it overestimated k_{rg} at intermediate saturations.
- ❑ By comparison with 3D pore-network simulations, we found that our model estimated k_{rg} over the entire range of gas saturation accurately.
- ❑ Using experimental data reported in Yassin et al. (2016) including samples from the Western Canadian Sedimentary Basin, we showed that our model estimated k_{rg} reasonably well, although it slightly overestimated k_{rg}.

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