Sharif University of Technology
Department of Chemical and Petroleum Engineering

Course Project Report

- Advanced Well-Testing -

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Contents

1 Introduction

A naturally fractured reservoir (NFR) are defined as a reservoir that contains a connected network of fractures created by natural processes that have or predicted to have an effect on the fluid flow. [1] These type of reservoirs contain more than 20% of the world's hydrocarbon reserves. Furthermore, most of unconventional reserves lie within fractured reservoirs. Kuchuk and Biryukov (2014) categorized naturally fractured reservoirs as:

1. Continuously fractured reservoirs
2. Discretely fractured reservoirs
3. Compartmentalized faulted reservoirs
4. Unconventional fractured basement reservoirs

Traditionally, dual-porosity models have been used to model NFRs where all fractures are assumed to have identical properties. Barenblat (1960) first proposed the concept of homogeneous fluid flow in fractures. One of the most prominent models in this regard is Warren and Root (1963) sugar cube model in which matrix provides storage while fractures provide flow medium. In their model, the interporosity flow is assumed to be pseudo-steady state. Another dominant inter-porosity model used in the literature is Kazemi's (1969) unsteady-state (transient) slab model. One of the most famous characteristics of dual-porosity flow is appearance of a V or U shaped segment in the log-log pressure derivative plot.

Dual-porosity models assume uniform matrix and fractures properties throughout the reservoir which may not be true in actual reservoirs. An improvement to this drawback is to consider two matrix systems with different properties which is called triple-porosity models. There were myriad triple-porosity systems introduced including two-matrix single-fracture, two-fracture single-matrix, and matrix-vug-fracture systems. This type of flow is usually characterized by two consecutive V-shaped segments on the derivative plot.

The fact that vugs are common in many arbonate reservoirs and have significant effects on petrophysics, has been recognized throughout literature. Abdassah and Ershaghi (1986) presented the triple-continuum model covering matrix, fractures, and vugs in an extension to Warren and Root (1963) model. Most of other vuggy triple-porosity models are based on their work. Camacho-Velazquez et al. (2005) proposed an analytical approach for pressure transient analysis in naturally fractured vuggy reservoirs. They explored pressure and production responses during transient and boundary-dominated flow periods in the high secondary porosity of naturally fractured vuggy reservoirs. They stated that the presence of vugs may have a definitive influence on the decline curve and cumulative production behaviors, and proved that it was necessary to incorporate the secondary porosity in the process of type curve matching.

A large vug is usually treated as a one medium and the inter-porosity flow equations are used to describe the flow within the matrix-fracture-vug system. In the study under investigation by this report, it is stated that the pressure in a large vug spreads in waves satisfying the mass, momentum and energy conservation equations simultaneously. Then, the solution of the proposed mathematical model is obtained based on Laplace transformation and numerical inversion. The type curves of wellbore pressure and derivative are plotted, and six flow regimes are recognized. [3]

2 Methodology

There are two regions defined in the physical model: (1) outer formation; simplified as a triple-continuum media including matrix, fractures, and vugs, and (2) inner formation; the wellbore is connected with the large vug. The assumptions of the model are as follows:

- The vug connected with the wellbore is cylindrical and homocentric with the wellbore. Only vertical flow is considered.
- The formation is isotropic and cylindrical. Constant production, q
- The reservoir with constant rock properties contains oil with constant properties.
- The outer formation consists of inter-connected matrix, fractures, and vugs. The oil in both fractures and vugs infiltrate to wellbore and large vug.
- Isothermal and Darcy flow is present.

The triple-porosity model proposed by reference [2] is solved for two cases of triple-porosity single-permeability and triple-porosity dual-permeability. The model uses pseudo-steady state interporosity flow. The system of equations are written in cylindrical coordinates, and are taken to the Laplace domain to solve for dimensionless pressures. The Laplace space equations are then numerically inversed using the *Stehfest* algorithm in order to illustrate type curves.

3 Results

The equations that are referred to in this section are all available in the source paper. [2]

3.1 Unconnected Vugs

First Eq. (A-17) is plotted for several parameters in Figure 1.

$$\overline{P}_D = \frac{K_0(\sqrt{g})}{u\sqrt{g}K_1(\sqrt{g})} \tag{1}$$

Where g is derived according to Eq. (A-18) in general or (A-21) for the basic Warren and Root model. It is seen that larger vug-fracture interporosity coefficient produces later transition. The black curve represents the Warren and Root model which does not consider vugs.

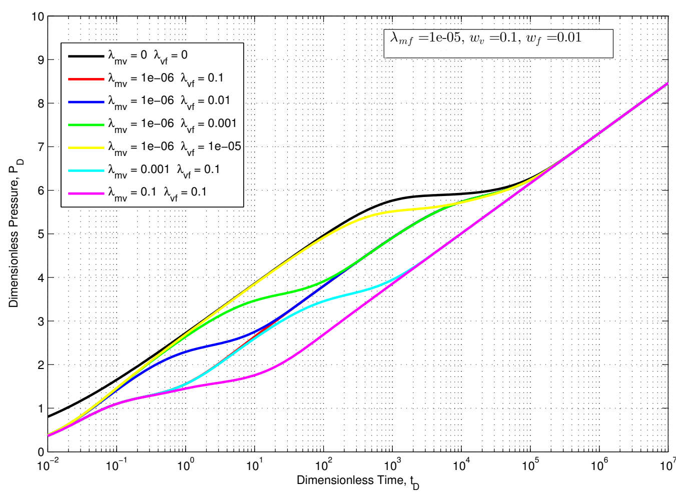

Figure 1: Pressure transient behavior for unconnected vugs

Figure 2 is also drawn using the above equation for different set of parameters. The two first cases (red and black curves) are considered to follow the Warren and Root model.

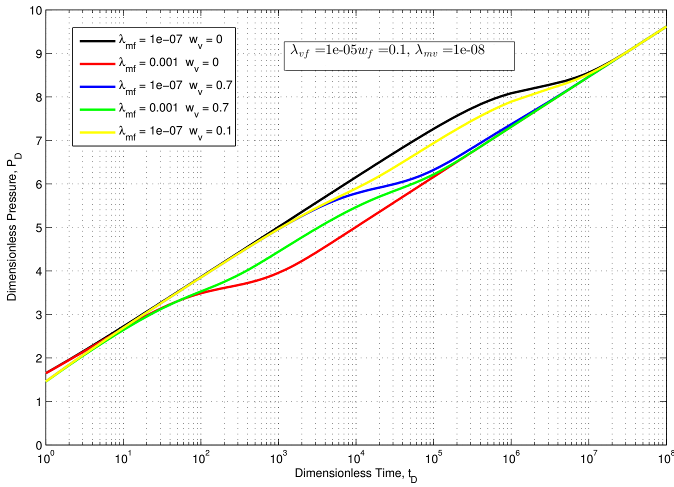

Figure 2: Pressure transient behavior for unconnected vugs

Similarly Figure 3 shows the pressure transient curves on a semi-log scale for another set of parameters. Same equation is used to produce these curves. The two first curves are derived using Warren and Root's double porosity model.

Next, the analytical solution of laplace space pressure using the Stehfest algorithm is compared to the long-time approximation given for g function as in Eq. (A-27) which leads to the approximation in Eq. (A-34) This comparison is reported for two cases in Figure 4.

It should be noted that no skin and no wellbore storage have been considered for these cases.

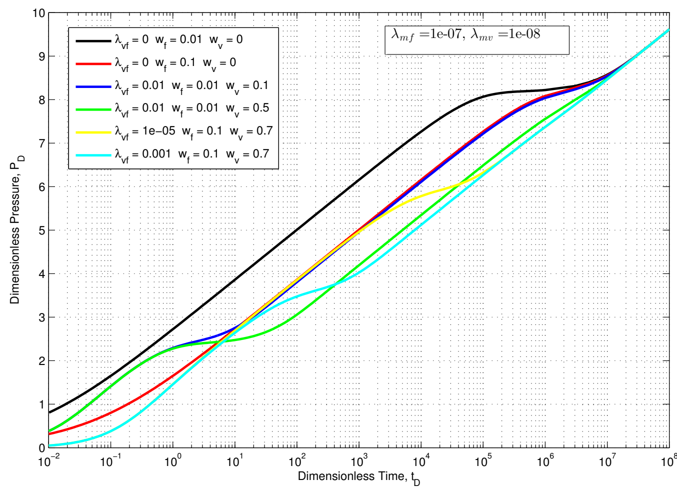

Figure 3: Pressure transient behavior for unconnected vugs

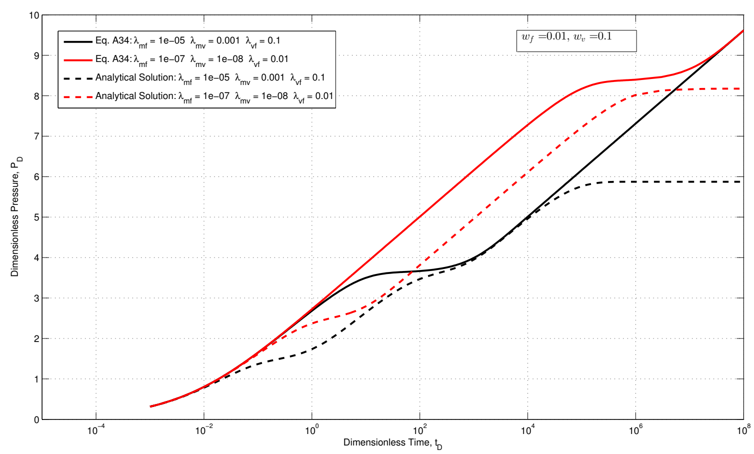

Figure 4: Long-time approximation for unconnected vugs

The type curves for the unconnected vugs (i.e. $\kappa = 1$) are illustrated in Figures 5 and 6. The first type curve is for altering λ_{mf} where the second one considers a range for λ_{vf}. The fracture storativity for both cases is constant where vug and matrix storativity changes. These figures are obtained using Eq. (B-26) for zero skin and storage and $\kappa = 1$. Eq. (B-26) is derived for the case of triple-porosity dual-permeability, however, the assumption that $\kappa = 1$ essentially turns it back to equation (B-21).

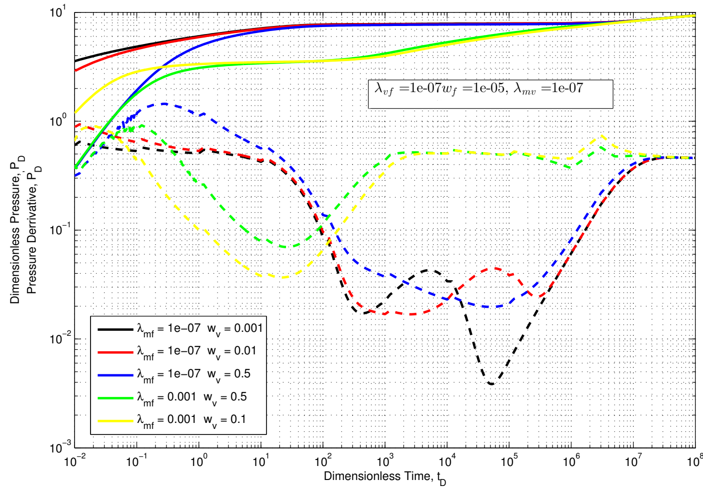

Figure 5: Transient type curve for unconnected vugs

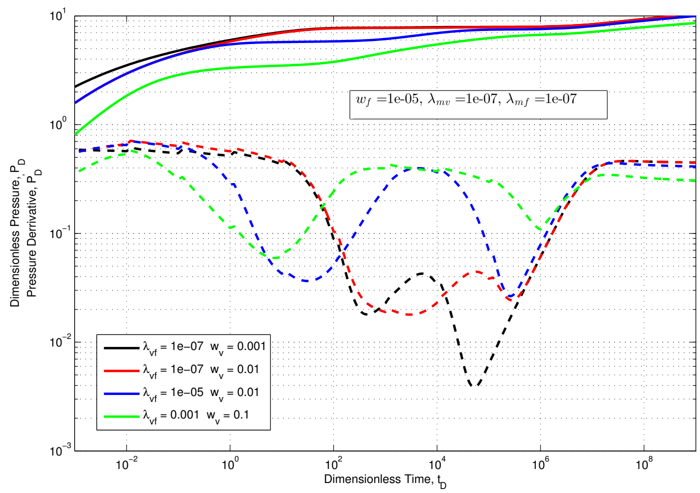

Figure 6: Transient type curve for unconnected vugs

3.2 Connected Vugs

In Figures 7, 8, and 9 the vugs are connected, and κ is no longer equal to 1. A comparison is done between connected and unconnected vugs. When vugs are connected and vug storativity is high, double porosity behavior is masked by decreasing κ and the semi-log line in Figure 8 resembles one for a homogeneous reservoir.

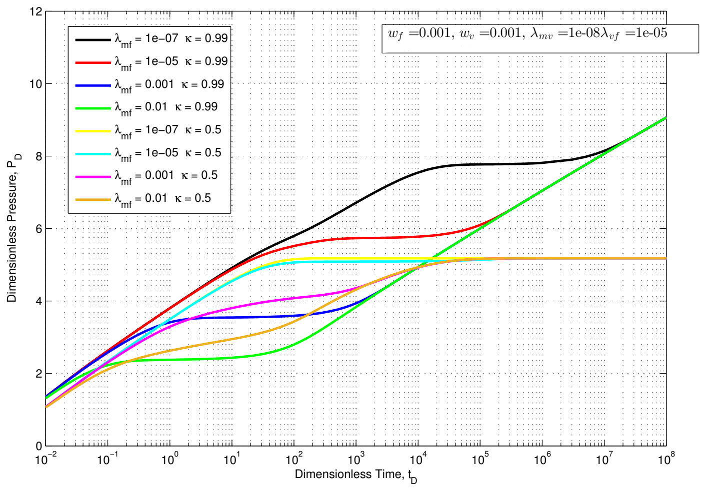

Figure 7: Transient pressure behavior for unconnected and connected vugs

It should be noted that a constant pressure boundary is somehow seen at late-times due to a glitch in the software. It only happens at medium values of κ in the connected vug case.

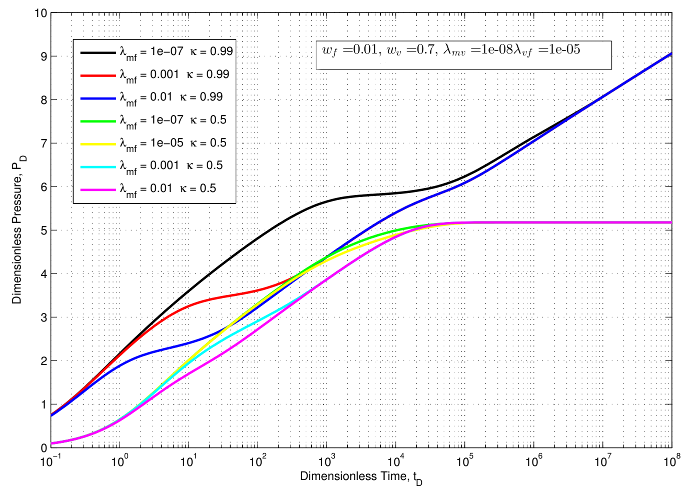

Figure 8: Transient pressure behavior for unconnected and connected vugs, high vug storativity

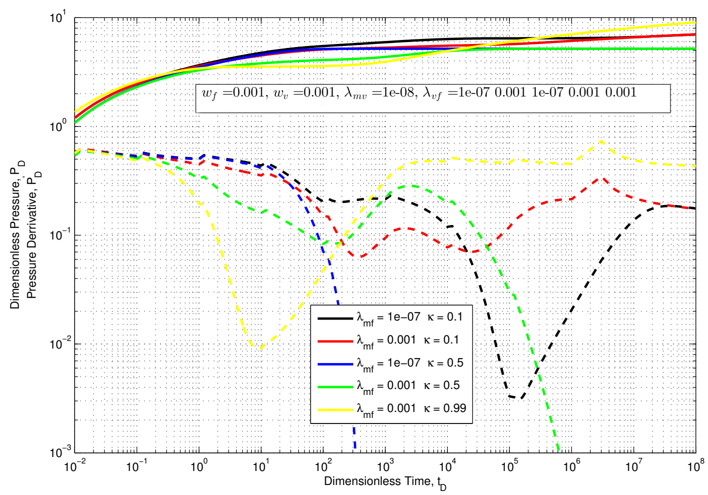

Figure 9: Transient type curve for connected vugs

3.3 Skin and Wellbore Storage

A sensitivity test has been run for the effect of skin and wellbore storage which are demonstrated in Figures 10 and 11. Until now all of the figures were generated considering zero skin and storage and therefore the equations were simplified. But the below two figures show the effect of skin factor and wellbore storage on transient type curves using Eq. (B-26). κ is assumed equal to one.

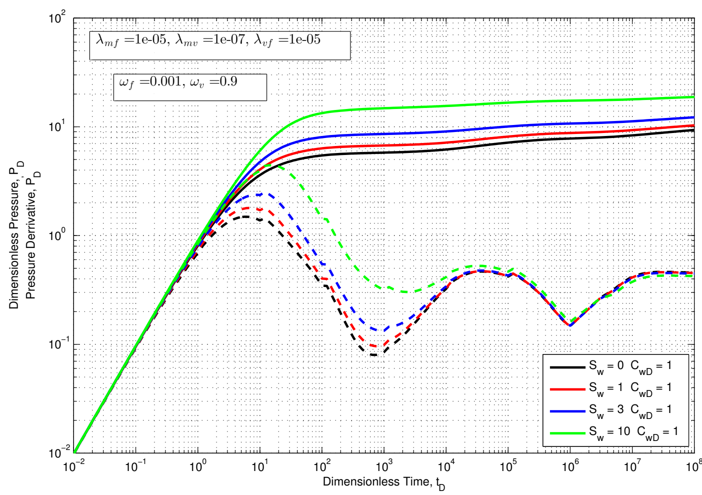

Figure 10: The effect of wellbore skin on transient type curve.

As expected, higher skin results in an upwards shift of pressure drop curve, and increasing wellbore storage shifts the curve to right. The above figure is based on data provided in Fig. 5 of reference [3], and is fairly similar to it.

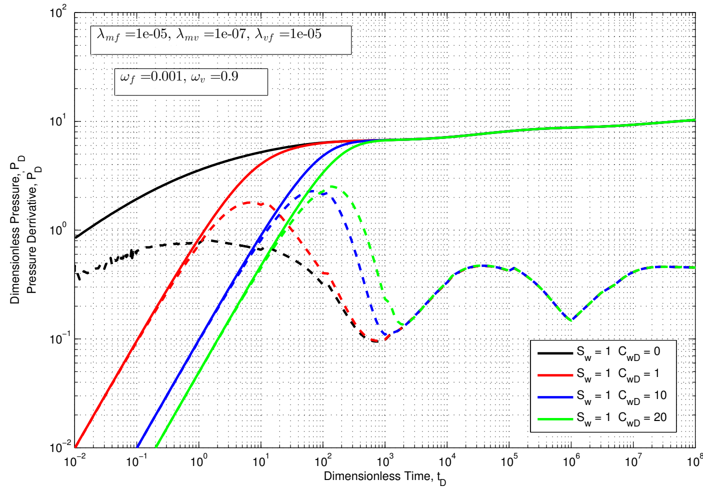

Figure 11: The effect of wellbore storage on transient type curve.

References

[1] Hasan A Al-Ahmadi, Robert A Wattenbarger, et al. Triple-porosity models: one further step towards capturing fractured reservoirs heterogeneity. In *SPE/DGS Saudi Arabia section technical symposium and exhibition*. Society of Petroleum Engineers, 2011.

[2] Rodolfo Camacho-Velazquez, Mario Vasquez-Cruz, Rafael Castrejon-Aivar, Victor Arana-Ortiz, et al. Pressure transient and decline curve behaviors in naturally fractured vuggy carbonate reservoirs. In *SPE Annual Technical Conference and Exhibition*. Society of Petroleum Engineers, 2002.

[3] Xin Du, Zhiwei Lu, Dongmei Li, Yandong Xu, Peichao Li, and Detang Lu. A novel analytical well test model for fractured vuggy carbonate reservoirs considering the coupling between oil flow and wave propagation. *Journal of Petroleum Science and Engineering*, 173:447–461, 2019.