A TRANSIENT PRESSURE STUDY ON THE INFLUENCE OF BLOCK SIZE FOR DRAWDOWN TESTS IN NATURALLY FRACTURED RESERVOIRS

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ABSTRACT

Block size has been concluded to be one of the main parameters of a naturally fractured reservoir. In one-phase flow, it controls the transition from the early fracture dominated stages of production to asymptotic composite (fracture plus matrix) behavior. Classical well test analysis in terms of a semilogarithmic graph of pressure vs time, has shown that drawdown pressures are not sensitive enough to the variation of block size method. This work presents the results of a study aimed at characterizing the naturally fractured reservoir by means of the transition period behavior of the pressure derivative function $t_D p'_w$. Based on the numerical Laplace inversion results, it was observed that the pressure derivative function for the different block sizes can be correlated through a horizontal displacement of the $t_D$ axis, when multiplied by the ratio $\left( \frac{h_{ma2}}{h_{ma1}} \right)^2$, where $h_{ma1}$ and $h_{ma2}$ are two block sizes satisfying $h_{ma2} > h_{ma1}$. A discussion of previous results by Braester analyzed by means of the radial flow semilog graph of pressure vs time is also included.

INTRODUCTION

An important portion of the hydrocarbon and most geothermal reservoirs are contained in naturally fractured reservoirs (NFR’s). Optimizing the exploitation of these reservoirs requires a complete description of the formation. A reliable characterization of a reservoir can be achieved through an integrated approach, combining data from geophysics, geology, well logging, well tests, core and fluid analysis, and well flow rates, which allows the estimation of reservoir geometry, reserves, and flow characteristics of the formation, among other factors. Well testing provides a useful tool to find the reservoir-flow parameters and to detect and evaluate heterogeneities that affect the flow process in the formation.

A NFR is created under highly complex subsurface conditions. Fig. 1.a shows a portion of the rock in these types of systems, that may include several elements, such as fractures and matrix, and in sedimentary formations, vugs. Reservoir fluids (and heat) are contained in both fractures and rock matrix; usually fractures act as channels to yield high well-flow rates. Reservoir studies must carefully consider these heterogeneities because they significantly affect the energy recovery. Because of the importance of NFR’s, many publications are available that provide an understanding of the behavior of these systems. Currently, important advances in well test analysis allow a more accurate characterization of these systems, based on new flow models that better account for heterogeneities of fractured reservoirs.

Block size has been concluded to be one of the main parameters of a NFR. In one phase flow it controls the transition from the early fracture dominated stages of production, to asymptotic composite (fracture plus matrix) behavior. Among other methods, block size can be estimated through well logging (Najurieta, 1980), well test analysis (Cinco Ley and Samaniego, 1982; Da Prat, 1990) and tracer tests (Ramírez et al., 1995).

Classical analysis in terms of a semilogarithmic graph of pressure vs time, has shown that drawdown pressures are not sensitive enough to the variation of the block size (Braester, 1984). In 1984 Braester published an important paper which thoroughly addresses this type of transient pressure analysis. The author also presents drawdown solutions for variable block size conditions. The main conclusion of this paper based on numerical solutions to the flow problem in NFR’s, with ordered fractures and blocks, computed through the Galerkin method, was already stated in this paragraph.

The purposes of this paper is to present the results of a study aimed at characterizing NFR by means of the transition period behavior of the pressure derivative
function \(I_D \rho'_D\). The reservoir is represented by parallelepiped shaped matrix blocks alternated with fractures. A discussion of the radial flow semilog graph of pressure vs time is also included.

**DESCRIPTION OF THE FLOW PROBLEM**

Several reservoir flow models have been proposed to describe the behavior of NFR’s (Cinco Ley, 1996): (1) homogeneous reservoir, (2) multiple region or composite reservoir, (3) anisotropic medium, (4) single fracture system, and (5) double-porosity medium. The discussion of the present paper will be focus on the so-called classic model for NFR’s: the double-porosity model (Barenblatt et al., 1960, Warren and Root, 1963; de Swaan, 1976). We call this model as the first generation NFR model; it considers that the formation is composed of two media: fracture network and rock matrix. The models used to date in this category to represent the real fractured formation shown in Fig.1.a, consider regularly shaped matrix blocks represented by parallelepipeds and cubes, as shown in Figs. 1.a and 1.b, and also by cylinders and spheres.

Fig. 2 shows the different flow periods for a well in a NFR composed of strata (parallelepipeds or slabs). At early times fluid production is due to expansion in the fractures, and fluid transfer from matrix to fractures is negligible (Fig. 2.a). This flow behavior is referred to as the fracture storage dominated flow period. As time goes on, the fluid transfer from matrix to fractures becomes important; as most of the fluid production is due to expansion in the matrix and for matrix transient linear flow conditions as shown in Fig. 2.b, the prevailing flow is called as matrix transient linear flow (Cinco Ley and Samaniego, 1982). In this work the model is particularized to the NFR representation of slabs, Fig. 2. It is assumed that the porous medium has a bulk fracture permeability \(k_{fb}\) and a bulk fracture porosity \(\phi_{fb}\); the matrix, has an intrinsic permeability \(k_{ma}\) and a porosity \(\phi_{ma}\). The fracture and matrix total compressibility are \(c_{tf}\) and \(c_{tma}\), respectively. In addition, it is assumed that flow towards the well occurs only through the fractures, and flow from matrix to fractures is under unsteady-state flow conditions.

The flow equation in dimensionless form is as follows:

\[
\frac{1}{r_D} \frac{\partial}{\partial r_D} \left( r_D \frac{\partial p_{jd}}{\partial r_D} \right) = \omega \frac{\partial p_{jd}}{\partial \tau} + \int_{r_0}^{r_D} \frac{\partial p_{jd}}{\partial \tau} F(\eta_{maD}, t_D - \tau) d\tau,
\]

where the dimensionless variables are defined as:

Dimensionless pressure drop \(p_{jd}\):

\[
p_{jd} = \frac{k_{fb} h(p_i - p_f(r,t))}{\alpha q B \mu} ;
\]
Dimensionless time $t_D$:

$$t_D = \frac{\beta k_{fb} t}{(\phi c_i)_{,}, \mu r_w^2},$$  

(3)

where $\alpha$ and $\beta$ are unit conversion constants (see the nomenclature).

Dimensionless radius:

$$r_D = \frac{r}{r_w};$$  

(4)

Dimensionless fracture storativity (fracture storage parameter) $\omega$:

$$\omega = \frac{\phi_{fb} c_{sf}}{\phi_{fb} c_{sf} + \phi_{ma} c_{ma}} = \frac{\phi_{fb} c_{sf}}{(\phi c_i)_{,}};$$  

(5)

Dimensionless matrix hydraulic diffusivity $\eta_{maD}$:

$$\eta_{maD} = \frac{r_w^2}{h_{ma}^2} = \frac{k_{ma} (\phi c_i)_{,} r_w^2}{k_{fb} (\phi c_i)_{ma} h_{ma}^2};$$  

(6)

Dimensionless fracture area $A_{fD}$:

$$A_{fD} = \frac{A_{fb} h_{ma} V_h}{V_{ma}} = A_{ma} h_{ma};$$  

(7)

Fluid matrix-fracture transfer function for the slab geometry $F(\eta_{maD}, t_D - \tau)$:

$$F(\eta_{maD}, t_D - \tau) = 4\eta_{maD} \sum_{n=0}^{\infty} e^{-\eta_{maD}(1+1)^{2n+1}} \pi^2 (t_D - \tau).$$  

(8)

The behavior of double-porosity models is characterized by four dimensionless parameters. The first three are the fracture storativity $\omega$ defined by Warren and Root (1965), Eq. 5, the dimensionless matrix hydraulic diffusivity $\eta_{maD}$, Eq. 6, and the dimensionless fracture area $A_{fD}$, Eq. 7. In addition for NFR with fractures partially filled by minerals, which reduce the flow interaction between matrix and fractures, a fourth parameter referred to as fracture skin factor, $S_{maD}$, has been defined (Cinco-Ley et al., 1985):

$$S_{maD} = \frac{k_{ma}}{k_d h_{ma}};$$  

(9)

where $x_d$ and $x_f$ are the average fracture-damage thickness and permeability. For high $S_{maD}$ values (severe restriction in the matrix-fracture interaction), the NFR can be described by two parameters only: $\omega$ and $\lambda$. The $\lambda$ results from a combination of $A_{fD}$, $S_{maD}$, and $\eta_{maD}$ as

$$\lambda = \frac{A_{fD} \eta_{maD}}{S_{maD}}.$$

(10)

A high value of this parameter indicates a fast interaction between matrix and fractures and viceversa. This flow case is referred to as the pseudosteady-state matrix model, or the Warren and Root model.

The solution for radial flow described by Eq. 1, with constant flow rate at the wellbore, was obtained by means of the Laplace transform method, resulting in Eq. 11:

$$\bar{p}_{fD} = \frac{K_o r_D s^{1/2} \left[\omega + (1 - \omega) A_{fD} \bar{f}(\eta_{maD}, s)\right]^{1/2}}{s^{1/2} \left[\omega + (1 - \omega) A_{fD} \bar{f}(\eta_{maD}, s)\right]^{1/2} \sqrt{1 + K_i \left[\omega + (1 - \omega) A_{fD} \bar{f}(\eta_{maD}, s)\right]^{1/2}}},$$

(11)

Wellbore storage and skin effects can be easily incorporated into the solution (Cinco Ley and Samaniego, 1982).

**DISCUSSION OF RESULTS**

Results were calculated by applying the Stephest numerical algorithm (Stephest, 1970) to invert the Laplace space solution given by Eq. 11. As already mentioned, a slab matrix-fracture geometry was used in this study.

Fig. 3 shows a schematic semilogarithmic drawdown graph of the pressure drop $\Delta p_w$ vs time $t$, for the matrix transient and for the pseudosteady-state matrix flow models. The difference occurs during the
transition period between the two parallel semilog straight lines. For the flow period of interest in this study, the unsteady-state, when most of the fluid production is due to expansion in the matrix and for matrix transient linear flow conditions (Fig. 2.b), the wellbore pressure behavior expressed in dimensionless form is given by Eq. 12:

\[
P_w = \frac{1}{4} \ln t_D - \frac{1}{2} \left[ (l - \omega) A_{fD} \sqrt{\eta_{maD}} \right] + 0.2602 + S.
\]  

Eq. 12 defines a semilog straight line of slope equal to half the slope of the parallel straight lines, corresponding for early times to fracture flow and for later times to the total-system dominated flow period, which occurs for small values of \( \omega \) (\( \omega \leq 5 \times 10^{-2} \)).

With regard to the previous discussion, it can be stated that regardless of the value of the fracture storativity parameter \( \omega \), a minimum intermediate semilog slope \( m_{min} \) is shown during a drawdown test, which ranges from the lowest possible value of 0.50 (Eq. 12) to 1.0. Fig. 4 shows the relationship between the minimum slope ratio \( m_{min} / m \) and \( \omega \), where the strata (slabs) and the sphere matrix-fracture geometry are considered. Fig. 5 presents results for the intersection time between the minimum slope semilog straight line and the third straight line vs \( \omega \). It can be noticed that the higher the value of \( \omega \) the higher the intersection time, and for small values of \( \omega \), the intersection is independent of this storativity parameter, and occurs at

\[
t_{D\text{int}} = \frac{0.5615}{A_{fD} \eta_{maD}}, \tag{13}
\]

or

\[
t_{\text{int}} = \frac{0.5615}{\beta A_{fma}^2 \eta_{ma}}. \tag{14}
\]

Estimation of the group \( A_{fma}^2 \eta_{ma} \), or any combination of the variables involved, is possible provided the pressure data display the second and third straight lines; for small values of \( \omega \) Eq. 14 can be used. For conditions where the slope ratio of the second and third straight lines is greater than 0.5, the following equation is used instead of Eq. 25 (Cinco Ley and Samaniego, 1982):

\[
p_w = \frac{1}{2} \left[ \ln t_D + 0.80907 \right]. \tag{15}
\]

where \( \left( A_{fma}^2 \eta_{maD} t_D \right)_{\text{int}} \) is obtained from Fig. 5. It should be emphasized based on the results of this figure, that for small values of \( \omega \) (< 10^{-2}) the parameter \( A_{fma}^2 \eta_{ma} \) is independent of the matrix geometry.
Braester (1984) presented an excellent study aimed at analyzing the influence of block size on the transition curve for a drawdown test. The Galerkin finite-element numerical solutions, were only studied by means of semilog radial flow graphs of pressure vs flowing time. The main conclusion of this work was that through this particular method of analysis, drawdown pressures are not sensitive enough to the variation of the block size, because results were quite similar. Fig. 6 presents a semilog drawdown dimensionless graph of the wellbore pressure vs flowing time, for three different block sizes, which closely resembles similar dimensional graphs of Braester.

In addition to the pressure derivative function diagnostic tool, in a recent study, with the purpose of better characterizing a NFR through the analysis of the transition matrix linear flow pressure data, a logarithmic pressure derivative function \( d\left(\log (t_D \cdot p'_{wD})\right)/d\left(\log t_D\right) \) has been defined (Cinco Ley, 1998; Rodríguez-Nieto, 2000; Rodríguez-Nieto et al., 2000). Fig. 8 presents an example of the application of this new logarithmic derivative function to same the cases discussed in Fig. 6 and 7.

Last, a brief discussion is included of a field build up test originally presented by Najurieta (1980), run in a NF carbonate reservoir, after a long producing time, \( (t_p=8611/\text{hours}) \). The author indicated that through the analysis of all available information, the formation could be considered as stratified, with block size \( h_{ma} = 17 \text{ ft} \). Fig. 9 shows a semilog graph of the pressure data and indicates that two straight lines can be drawn, the first with a 16.5 psi/cycle slope and the second with 30 psi/cycle. This yields a slope ratio equal to 0.55. The pressure data was also plotted (Fig. 10) in terms of the pressure derivative function \( \Delta t \cdot p'_{wD} \) vs shut-in time \( \Delta t \). It is important to mention that this data was recorded by means of a low accuracy pressure gauge, which explains its non smooth behavior. In spite of this problem, the intermediate and late times straight lines can reasonably be observed in Fig. 10, which helps toward getting a better test analysis.
Next, the estimation of the matrix (slab) size will be presented (Cinco Ley and Samaniego, 1982). From the graphical results of Fig. 9, the intersection time between the two straight lines occurs at 1.7 hours. Through the slope ratio for this test of 0.55 and the results of Fig. 4, a value of 6 x 10^{-2} is estimated for the fracture storativity $\omega$. With this value and the results of Fig. 5, the intersection time dimensionless group

$$\frac{A_{ma}^2 \eta_{ma} t_D}{\beta t_{nt}} = 0.57$$

can be estimated; then from Eq. 16,

$$A_{fma} = \frac{k_{ma}}{A_{ma}} \frac{(A_{ma}^2 \eta_{ma} t_D)}{\phi c \mu} \frac{B t_{nt}}{2.637 \times 10^{-4} \times 1.7 (\text{hours})}$$

$$= 4.7 \times 10^{-2} \text{md}^{1/2} \text{ft}$$

Najurieta stated that matrix permeability estimated from core analysis is 0.1 md, and considered that for a slab matrix-fracture geometry $A_{fma} = 2/h_{ma} =$}

$$h_{ma} = \frac{2 \sqrt{k_{ma}}}{4.7 \times 10^{-2}} = \frac{2 \sqrt{0.1 (\text{md})}}{4.7 \times 10^{-2} (\text{md}^{1/2} / \text{ft})}$$

$$= 13.5 \text{ ft}$$

This result is within 20 percent difference from the value of 17 ft given by Najurieta, calculated from core studies.

CONCLUSIONS

This study has presented a discussion related to the estimation of matrix block size in naturally fractured reservoirs, mainly based on the analysis of pressure data for the transition matrix transient flow, from the early fracture dominated stage of production to the asymptotic composite (fracture plus matrix) behavior. It has been confirmed that classical analysis in terms of a semilogarithmic graph of pressure vs time, show that drawdown pressures are not sensitive enough to the variation of block size. It has been concluded that the use of the pressure derivative function and of the new logarithmic pressure derivative function $d[\log (t_D \ p_w')] / d[\log t_D]$ improves the flow diagnosis capabilities. Once this step is accomplished, the estimation of block size can be carried out through already available methods.

NOMENCLATURE

$A_{fma}$ = Fracture area per unit of matrix volume
$A_{fb}$ = Fracture area per unit of bulk volume
$A_{fD}$ = Dimensionless fracture area
$B$ = Formation volume factor
$c$ = Fluid compressibility
$c_s$ = Fracture system total compressibility
$c_t$ = Total compressibility
$h$ = Formation thickness
$h_{ma}$ = Strata (matrix) height (size)
$k$ = Permeability
$p$ = Pressure
$p_D$ = Dimensionless pressure
$p'_D$ = Dimensionless pressure derivative
$p_i$ = Initial reservoir pressure
$\Delta p$ = Pressure change
$q$ = Well flow rate
$r$ = Distance to production well
$r_w$ = Wellbore radius
$S$ = van Everdingen and Hurst skin factor
$S_{maD}$ = Dimensionless damage parameter
$s$ = Laplace transform variable for matrix fracture flow restriction
$t$ = Time
\( t_D \) = Dimensionless time
\( V \) = Volume
\( x \) = Distance, thickness
\( \alpha, \beta \) = Unit conversion constants (for the English system, 141.2 and 2.637x10^{-4}
\( \lambda \) = Interporosity flow coefficient
\( \eta \) = Hydraulic diffusivity
\( \rho \) = Fluid density
\( \mu \) = Fluid viscosity
\( \phi \) = Porosity
\( \tau \) = Dummy integration variable
\( \omega \) = Dimensionless fracture storativity

**SUBSCRIPTS**

\( b \) = Bulk, beginning
\( d \) = Damaged
\( D \) = Dimensionless
\( e \) = End
\( i \) = Initial
\( int \) = Interception
\( ma \) = Matrix
\( t \) = Total

**REFERENCES**


