HOW TO DISTINGUISH NATURALLY FRACTURED RESERVOIRS FROM STRATIFIED RESERVOIR SYSTEMS IN A WELL TEST ANALYSIS

by
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I. INTRODUCTION

In the real well test analysis, to identify an exact reservoir model in heterogeneous reservoirs is very difficult. The geological model will guide the direction of the well test interpretations. For the similar reservoir condition, a different geological model will result a different reservoir model. Moreover, in some cases it is still difficult to obtain "true" reservoir characteristic, because different models will give a fairy match pressure response in the type curves matching.

The objective of this paper is to examine the characteristic of heterogeneous reservoirs. Two heterogeneous models will be addressed, naturally fractured reservoirs and stratified reservoirs. Both the steady state and unsteady state naturally fractured reservoirs will be addressed.

II. PSEUDO STEADY STATE MODEL

The Eclipse program has been incorporated to justify the characteristic of pseudo steady state model. Several reservoir conditions have been run, these are including wellbore storage and skin factor. The analytical solution was then run under similar conditions, and the results were compared.

The pseudo steady state (PSS) model has been run under various reservoir parameters. A λ, which characterises the ability of fluid transfering from matrix to fracture has a range from as low as 1E-09 to as high as 50. This value has a proportion equal to the ratio of matrix permeability to the fracture permeability. To see the effect of λ, ω value was when λ is very small, the transition period was delayed quite considerably. As the value of λ increases, the impedance between the matrix and fractures getting smaller, therefore the fluid

flow more easily. Finally, for $\lambda = 50$ the curve exhibits the same performance with homogeneous reservoirs. It means there is no impedance at all between the matrix and the fracture. Figure 1 shows the typical pseudo steady state response in naturally fractured reservoirs.

To see the effects of storativity ratio of fracture to the total system, ω was varied from 1E-4 to 1, and similarly, λ was kept constant of 5E-06.

The results show the smaller the ω, which means the smaller the fracture storage, the earlier transition period will be.

For $\omega = 1E-4$, for example the transition period is achieved at $T_D = 10$, while for $\omega = 0.1$, $T_D = 100$. Secondly, the smaller the ω, the longer the transition period will be. According to the ω definition, we know when ω equal to 1, there is no matrix storativity at all, the fluid flow is only from fractures to the wellbore. For
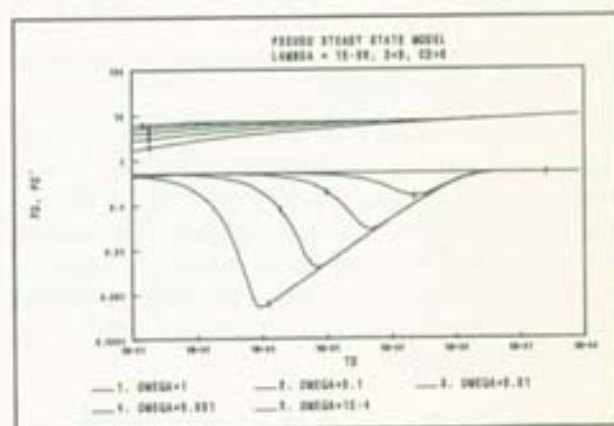

Figure 1
Pseudo steady state

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$\omega = 0.666$ the matrix and the fracture storativity are the same. In other words, for the same fracture storage, as the ω becomes smaller the matrix storage becomes bigger. As a result, the more fluid will be transfered from matrix to the fracture, because the only way to produce the matrix fluid is via the fractures.

The skin factor effects were included to the PSS model to see the effects of nonideality. For these cases, the skin factors were varied from 1 to 60, while other parameters were kept constant. The results show, when the skin factor is high, the transition period will be long. These effects as though similar to ω effects at a glance even though in this case the derivatives are sharper than before. However, if we examine the pressure behaviour, they are quite distinctive. The pressure responses for the later case are parallel, while for the previous case the pressure behaviour merge in an asymptotic line. Thus, by comparing those results, we can distinguish the effect of ω from skin factor effects.

The effect of wellbore storage is to delay the pressure response from the reservoir. Thus, for the same reservoir conditions, the longer well testing is needed.

The smaller the dimensionless wellbore storage, C_D, the shorter the time will be needed to achieve the transition period. For more serious problems, the double porosity behaviour will never be obtained, since it will be obscured by the well bore storage effects.

III. COMPARISON OF NUMERICAL MODEL WITH PSS MODEL

In order to validate the analytical solutions, these results were compared to numerical solutions. The numerical solutions were obtained from ECLIPSE, a 3 dimensional 3 phases reservoir simulator. This simulator is capable of handling double porosity problems.

The storativity ratio, ω and matrix block dimensions from the numerical solutions were compared to the analytical solutions.

IV. MATRIX BLOCK SIZE COMPARISON

In the simulator, we can specify the matrix block size by assigning sigmas. According to Warren & Root, sigma is defined as :

$$\sigma = \frac{4n(n+2)}{L^2} \qquad \cdots\cdots (1)$$

For the sake of simplicity, by assuming the matrix blocks are cubes, we arrive to the following relation.

$$L^2 = 12/\sigma \text{ for } n = 1 \qquad \cdots\cdots (2)$$
$$L^2 = 32/\sigma \text{ for } n = 2 \qquad \cdots\cdots (3)$$
$$L^2 = 60/\sigma \text{ for } n = 3 \qquad \cdots\cdots (4)$$

Where n is the number of flow directions in the fractures.

For uni direction, n equal to 1, and for bi direction n equal to 2 whereas for 3 dimensional flow n equal to 3.

For a three dimensional numerical model, the matrix block size is calculated as :

$$L = \sqrt{\frac{60}{\sigma}} \qquad \cdots\cdots (5)$$

On the other hand, the Warren & Root formulation is 1 dimensional model.

The linear flow equation from matrix to fracture is coupled into the radial fracture equation by substituting the dimensionless matrix pressure into the dimensionless fracture pressure in Laplace space.

Based on the λ definition, fracture block size is calculated according 60 [1] :

$$L^2 = 12 \, r_w^2 \, \frac{k_1}{k_2} \frac{l}{\lambda} \qquad \cdots\cdots (6)$$

λ is obtained from the analytical solution, whereas other parameters, such as km, kf, rw are obtained from the numerical inputs.

To calculate the fracture permeability, eclipse multiplies the intrinsic permeability, which is assigned to the fracture porosity.

Three simulated drawdown responses were obtained, and the results are shown in Figure 2 through Figure 4. The following results were calculated from both methods.
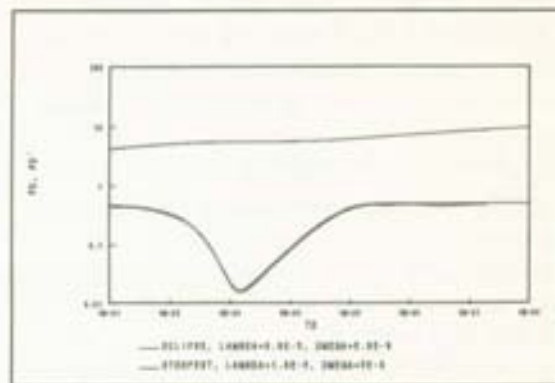
From the table, both the analytical and numerical solution give a good agreement.
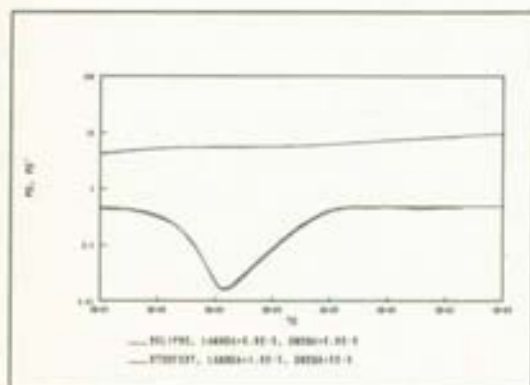
V. STORATIVITY RATIO COMPARISON

In the PSS model, storativity ratio, ω which comprises of both matrix and fracture compressibilities are treated explicitly in the equation. These parameters, along with other reservoir parameters determine the performance of dual porosity curves.
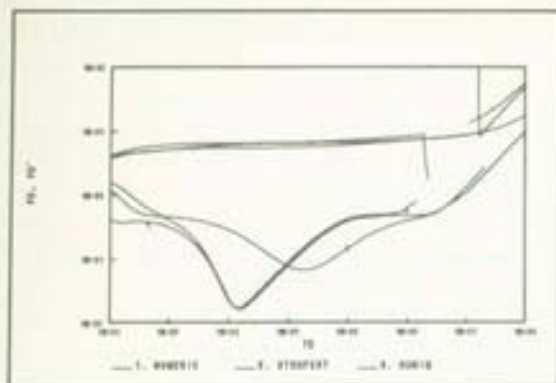
Figure 2
Pseudo steady state interporosity model
Red - 2000, σ = 01, KF = 5E4, KM = 1, PDRF = 001,
PDRF = 19

Figure 3
Pseudo steady state interporosity model
σ = 01, KF = 5E4, KM = 1, PDRF = 19, PDRF = 001

On the other hand in numerical solutions, as far as pressure analysis is concerned, the effects of rock compressibility variations are not significant. This parameter is used to calculate the material balance. Therefore, since there is no a sharp pressure decline, either single or dual compressibility is assigned, the pressure responses will be the same.

Figure 4
Pseudo steady state interporosity model
σ = 01, KF = 5E4, KM = 1, PDRF = 19, PDRF = 001

Tabel 1

Matrix block calculation

Case	Numeric	Analytic
Figure 2	24.5 ft.	21.9 ft.
Figure 3	77.5 ft.	65.5 ft.
Figure 4	244.9 ft.	201.9 ft.

For our case, we will take a rock compressibility to calculate the storativity ratio, and compare this with the analytical salution.

From Figure 1 through 3 the numerical solutions give ω of 2.6E-3 for matrix and fracture compressibility of 0.4E-5 and 0.2E-5 respectively. For the average rock compressibility of 0.3E-05, the numerical solutions yield ω of 5.2E-3. On the other hand, for the same reservoir conditions, the analytical solutions give ω value of 5E-3. Therefore, both solutions show a good agreement.

IV. UNSTEADY STATE MODEL

In this section we will discuss the differences and similarities of unsteady state, unsteady state (USS) interporosity naturally fractured reservoirs with cross flow in stratified reservoirs model.

First, we will examine the behaviour of USS model under several conditions. After that, the characteristic of stratified reservoirs with cross flow will be reviewed.

In order to compare those models, the cross flow and USS model were run under the equivalent conditions.

A. Performance of USS models

The USS models have been run under various reservoir parameters. λ which characterises the ability of fluid transferring from matrix to fracture has range from as low as 1E-09 to as high as 50. To see the affect of, ω walue was kept constant.

Figure 5 shows the typical unsteady state response in naturally fractured reservoirs.

Unlike in the PSS model, even for very early time, the matrix system has contributed to the total flow. It is described by the pressure derivatives which never reach line 0.5 at the beginning. The radial flow from fracture may only exist if the λ is very small. In general, however, the effects of permeability ratio of matrix to fracture in this model are similar to those of PSS model. The more contrast these permeability, the smaller the value of λ, thus the longer the transition period will be delayed.

For λ = 1E-07 for example, the end of the transition period is achieved at T_D = 1E08, while for λ = 0.1 it was achieved at T_D = 100.

The same procedures have been applied to see effects of λ. It has range from 1E-4 to 1, and λ was kept constant as 1E-06. The smaller the ω the earlier the transition period will be. We can see later, that this characteristic is very similar to the one of stratified reservoirs with cross flow. Whatever the value of omega was assigned, the derivatives never fall below 0.25 line in logarithmic scale. Again, for the value of omega = 1, the behaviour was similar to the one of homogeneous model.

B. Stratified reservoirs with cross flow performance

The cross flow program was used to distinguish the performance of stratified reservoirs with cross flow, with the one of unsteady state naturally fractured reservoirs. The reason to compare these models, is that the naturally fractured reservoir slab model is derived from
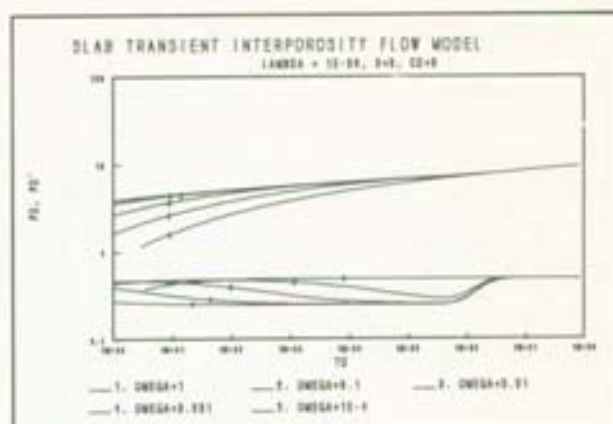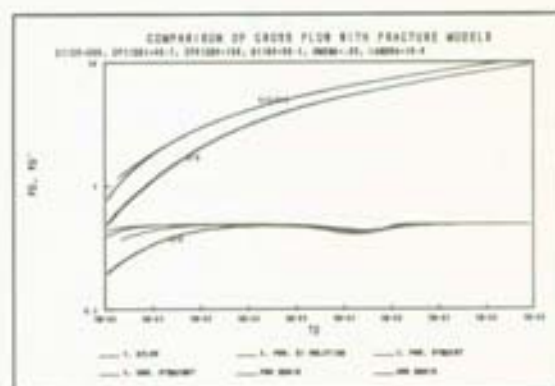

Figure 5
Slab transient interporosity flow model

Figure 6
Comparison of cross flow with fracture models

the two layer cases, e.g Stretlsova, De Swaan and Kazemi. Therefore, they might be giving the same results under several circumstances.

The cross flow program was run under several conditions. The permeability contrast is 300, while the storativity ratio was varied from 10 to 1000. The typical of stratified system is shown in Figure 6. From this figure we can see any value of storativity which never gives the derivative value less than 0.35.

The effect of permeability contrast is exactly the same with that of the naturally fractured reservoir models which is delaying the transition period.

The effect of permeability contrast is exactly the same with that of the naturally fractured reservoir models which is delaying the transition period.

The smaller the storativity ratio, which means in this case the smaller the more permeable layer, the earlier the transition period will be. In a-two layer-system as the fluid in the more permeable system depletes, the bigger and less permeable layer will repressurise the more permeable layer. The smaller the more permeable, the quicker the pressure of both reservoirs balance. After the transition period the reservoir is produced commingly from both layers. The pressure behaviour never reaches an asymptotic line, or if they do, it will be reached beyond $t_d = 1E9$. It means, until $t_d = 1E9$, the recond layer, representing matrix layer, still contributes the production to the well. It never stops contributing until all of the fluid will be produced.

D. *Comparison of USS with stratified reservoir with cross flow*

To compare the stratified model with the naturally fractured models, we run both program for equivalent values. As was stated earlier, the derivative of the cross flow model never falls below 0.35 line. If we force the naturally fractured models to match with a cross flow model, we should assign a very high value of ω, in this case is 0.65. In fact this value is unusual for naturally fractured models, neither for PSS nor USS models. In contrast, the value of $\lambda 5$, might be very similar to both models. It can be understood, since λ just delaying the transition period.

VIII. CONCLUSION

1. The pseudo steady state model in naturally fractured reservoir can be characterised by using pressure derivative method. For very big interporosity parameter, λ, the pseudo steady state model behaves as it is homogeneous reservoirs.

2. The smaller the fracture storage, the earlier the transition period will be.

3. Both the numerical and analytical method show a good agreement in matrix block calculation as well as in the storativity ratio calculation.

4. It is very clear to distinguish unsteady state naturally fractured reservoirs from the pseudosteady state model, since in the pressure derivative method, it never falls below 0.25 line.

5. The stratified system in heterogeneous reservoir can be identified by examining the pressure derivative value. It never falls below 0.35 in a log-log plot.

NOMENCLATURE

c_t	Total compressibility, 1/psi.
C	Wellbore storage constant, (bbl/psi).
$ei(x)$	Exponential integral function.
PSS	Pseudo steady state.
S	Skin factor, dimensionless.
S	Storage, (Φs_t), l/psi.
T	Transmissibility, (kh), ft^3.
USS	Unteady state
V_z	Matrix to fracture fluid flow, ft^3.
V_{fd}	Volumetric fracture density, ft^3.
z	Matrix thickness, ft.

Greek symbols

α	Interporosity flow shape factor, $1/ft^2$.
η	Formation diffusivity, (T/S), ft^2/hour.
λ	Dimensionless matrix to fracture interporosity flow.
σ	Matrix blocks shape factor, $1/ft_2$
Φ	Porosity, fraction.
ω	Dimensionless fracture to total storativity ratio. unit pressure drop, per unit bulk volume, stb/hr/psi/ft.

Subscript

D	Dimensionless.
ma,m	Matrix.
f	Fracture.

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