Use of Production Data Inversion to Evaluate Performance of Naturally Fractured Reservoirs

T. Marhaendrajana, Institut Teknologi Bandung; T.A. Blasingame, Texas A&M University; and J.A. Rushing, Anadarko

Abstract

Many oil and gas production come from naturally fractured reservoirs. The reservoir properties and production performance of this reservoir show a unique behavior, which are different from the homogeneous reservoir. Hence, evaluation and forecasting production of these reservoirs require special models and approaches.

This paper attempts to utilize production data inversion method to obtain parameters such as permeability, skin factor, initial fluid-in-place and production potential in a naturally fractured reservoir. The model can then be used to forecast production from this type of reservoir.

The method uses type curve approach that incorporate concepts of both transient and boundary dominated flow models. Application of this method to oil field data is presented as well as comparison with results obtained from other methods (such as well test analysis and volumetric calculation).

The results of this research provide engineers a tool to evaluate and monitor production/reservoir performance of naturally fractured reservoirs regularly by analyzing production data (which are always recorded) without additional testing.

Introduction

Modeling of single phase flow in fractured reservoir involve the description of the shapes, orientation and sizes of fractures network, and the mechanism for the transfer of fluid from the matrix to the fracture network. The process of transfer of fluid between matrix blocks and fissures (or fractures) is the points at which various model differ. Some investigators have considered a pseudosteady-state relation for the interporosity flow term. This approach was first suggested by Barenblatt et al. and was taken up by Warren and Root in their pioneering study of the pressure response of naturally fractured reservoirs. Others considered the effect of transient interporosity flow. The transient model is physically much more appealing since it allows for all regimes of internal block flow, i.e., transient, late transient and pseudosteady-state. This was first proposed by Kazemi, where the matrix blocks were composed of slabs.

The analytical solution in Laplace space for the wellbore pressure response of a dual porosity reservoir has the form:

\[ p_m(s) = \frac{-1}{s} \frac{K_i}{K_m} \left[ h_w \sqrt{\frac{3(1-\omega)s}{\lambda}} \tanh \sqrt{\frac{3(1-\omega)s}{\lambda}} \right] + \frac{1}{s} \frac{h_w}{K_m} \left[ \frac{h_w}{K_i} + \frac{1}{K_m} \right] \left[ -K_i \sqrt{\frac{3(1-\omega)s}{\lambda}} \tanh \sqrt{\frac{3(1-\omega)s}{\lambda}} \right] s \rightarrow t_o \]

Eq. 1 is the constant well rate solution. The Laplace parameter function \( f(s) \) depends on the type of interporosity model and the matrix block geometries. This paper considers two models: (i) pseudosteady-state interporosity flow model with matrix blocks as cubes, and (ii) transient interporosity flow model with matrix blocks as slab (strata). The function \( f(s) \) for the two models are:

\[ f(s) = \omega + \frac{\lambda}{3s} \sqrt{\frac{3(1-\omega)s}{\lambda}} \tanh \sqrt{\frac{3(1-\omega)s}{\lambda}} \]

Pseudosteady-state interporosity flow model with matrix blocks as cubes:

\[ f(s) = \frac{\alpha(1-\omega)s + \lambda}{(1-\omega)s + \lambda} \]

Transient interporosity flow model with matrix blocks as slab (strata):

where:

\[ \lambda = \frac{a_k m w^2}{k_f h_m^2} \]

\[ \omega = \frac{(\phi_f)_f}{(\phi_f)_f + (\phi_f)_m} \]

The dimensionless pressure and dimensionless time are defined by:

\[ p_{FD} = \frac{k_f h (p_t - p_w)}{141.2qB\mu} \]
\[ t_D = \frac{0.0002637 k_f t}{(\phi e_i)_{mf}} \] \hspace{1cm} (7)

**Method for Production Data Inversion**

The wellbore rate response (solution) in Laplace space for a constant well flowing pressure can be obtained from Eq. 1 using the Duhamel principles that is:

\[ \tilde{q}_D(s) = \frac{1}{s^2 \tilde{p}_{MB}(s)} \] \hspace{1cm} (8)

The dimensionless rate is defined as

\[ q_D = \frac{141.2qB\mu}{kh(p_i - p_{wf})} \] \hspace{1cm} (9)

The real domain solution of Eq. 8 is obtained using numerical inversion so that for various values of \( \lambda, \alpha \), and \( r_{Df} \), the dimensionless well rate solution, \( q_D \), can be generated. Following Fetkovich,\(^9\) decline curve dimensionless time, \( t_{Dd} \), and decline curve dimensionless rate, \( q_{Dd} \), are defined by

\[ t_{Dd} = \frac{t_D}{0.5[r_{Df} - 1][\ln r_{Df} - 0.5]} \] \hspace{1cm} (10)

\[ q_{Dd} = q_D[\ln r_{Df} - 0.5] \] \hspace{1cm} (11)

The decline curve dimensionless rate for pseudosteady-state interporosity model is shown in Fig. 1. At early time fluid is produced from fracture networks and the flow regime is transient. When the entire fracture networks connected to the wellbore is affected by the production, the well rate decreases sharply. At this period the flow in the fracture is under pseudosteady-state flow. During this time the pressure in the fracture reduces substantially and the fluid flow from matrix into the fracture becomes dominant. This is shown by the flattening well rate, as an indication of pseudosteady-state interporosity flow. The well rate, again, decreases sharply as the entire system (fractures and matrix systems) is affected by the production.

Higher storativity or capacity ratio (\( \omega \)) means that the matrix storativity is less. Hence the early response (which is from fracture networks) is higher (denoted by dash-line). If the storativity ratio, \( \omega \), equal to one, fluid production comes from the fracture networks because the matrix system is not porous. Therefore, the well performance behaves as the reservoir is homogeneous.

As the interporosity flow parameter, \( \lambda \), smaller the fluid flow from matrix to the fracture system is smaller. When the interporosity flow is zero, there is no flow between the two systems (matrix and fractures). At this case, the well performance also behaves as the reservoir is homogeneous.

The decline curve type of naturally fractured reservoir using transient interporosity model is shown in Fig. 2. The obvious difference of the transient model from the pseudosteady-state model is the logarithmic well rate response decreases linearly (slope is equal to -0.5) with the logarithmic time. The comparison between both models is shown in Fig. 3.

**Cases where well flowing pressure or wellhead pressure data is available**

Next is to use the type curves model to perform production data inversion to obtain reservoir parameter, such as permeability, skin factor, drainage area and oil-in-place. The production data are matched with the decline type curve. Once a good match is obtained, we get match parameters, which are \( r_{Df}, \alpha, \lambda, [q/\Delta p]_{MP}, [t]_{MP}, [q_{Dd}]_{MP}, \) and \([t_{Dd}]_{MP}\). Hence we compute permeability and oil-in-place.

1. **Estimation of Permeability:**

Combining Eqs. 9 and 11 we obtain

\[ q_{Dd} = \frac{141.2qB\mu}{kh(p_i - p_{wf})}[\ln r_{Df} - 0.5] \] \hspace{1cm} (12)

Rearranging Eq. 9, permeability is computed by

\[ k = \frac{141.2B\mu}{h}[\ln r_{Df} - 0.5][q/\Delta p]_{MP}/[q_{Dd}]_{MP} \] \hspace{1cm} (13)

2. **Estimation of Original Oil-in-Place:**

Combining Eqs. 7 and 10

\[ t_{Dd} = \frac{0.0002637 k_f t}{(\phi e_i)_{mf}^2} \frac{1}{0.5[r_{Df} - 1][\ln r_{Df} - 0.5]} \] \hspace{1cm} (14)

or

\[ t_{Dd} = \frac{0.00634 k_f t}{(\phi e_i)_{mf}^2} \frac{1}{0.5[r_{Df} - 1][\ln r_{Df} - 0.5]} \] \hspace{1cm} (15)

Rearranging Eq. 15, the oil-in-place can be computed as follows

\[ N = \frac{1}{e_i}[t]_{MP}/[q_{Dd}]_{MP}/[q_{Dd}]_{MP} \] \hspace{1cm} (16)

3. **Estimation of Reservoir Characteristics:**

The relations given below are used to estimate volumetric and flow characteristics of the reservoir based on the results of the type curve match and the available data.

**Reservoir Drainage Area**

\[ A = 5.615 \frac{NB}{\phi h(1 - S_{wirr})} \] \hspace{1cm} (17)

**Reservoir Drainage Radius**

\[ r_e = \sqrt{\frac{A}{\pi}} \] \hspace{1cm} (18)

**Effective Wellbore Radius**

\[ r_{wa} = \frac{r_e}{r_{Df}} \] \hspace{1cm} (19)

**Skin Factor**
5. Estimation of Permeability

We can write

\[ q = \frac{kh(p_i - p_{wf})}{141.2B\mu [\ln r_D - 0.5]} \]..............................(21)

Defining the maximum rate (i.e. the rate of well produced at its maximum capacity)

\[ (q_t)_{max} = \frac{khp_i}{141.2B\mu [\ln r_D - 0.5]} \]..............................(22)

Writing decline curve dimensionless time (Eq. 10) in term of parameters in Eqs. 22 and 23, we have relation as follows

\[ t_{DD} = \left( \frac{(q_t)_{max}}{N_{pi}} \right) t \]..............................(24)

Recalling decline curve dimensionless rate

\[ q_{DM} = \frac{141.2qB\mu}{kh(p_i - p_{wf})} [\ln r_D - 0.5] \]..............................(25a)

or we can write

\[ q_{DM} = \frac{q}{(q_t)_{max}} \]..............................(25b)

1. Estimation of Permeability:

Rearranging Eq. 25 we compute permeability as

\[ k = \frac{141.2B\mu}{hp_i [\ln r_D - 0.5]} \frac{[q]_{MP}}{[q_{DM}]_{MP}} \]..............................(26)

2. Estimation of Original Oil-in-Place:

Oil-in-place can calculated from Eq. 24 and Eq. 25 as follows

\[ N = \frac{1}{c_i P_i} \left( \frac{q}{q_{DM}} \right)_{MP} \frac{t}{t_{DD}} \]..............................(27)

3. Estimation of Reservoir Characteristics:

The procedure and equations for this purpose are the same as in the case of pressure history is not available.

Field Application

Production data from well-1 producing from reservoir X were used to apply this method. Well-X is the only well producing from the reservoir X. This well has been produced for about 25 years as it is shown in Fig. 4.

The reservoir consists of reef limestones, and dolomitization process occurred in this reservoir. Core analysis results showed naturally fractured characteristics. This observation was supported by well test data taken recently in 2002. The Horner and log-log plot analysis of these data are shown in Figs. 5 and 6.

At first, the conventional Arps decline curve was used to analyze the production data of Well-1 and to identify reservoir character. This is shown in Fig. 7. At beginning, the data follows decline curve with \( b=0 \) indicating pseudosteady-state production under constant well flowing pressure. At about \( t_D=7 \), the data deviate from decline curve of \( b=0 \) and they do not fit any of \( b \) value. Instead, the data follows the half-slope decline indicating the transient interporosity flow from matrix system to fracture systems. At \( t_D \) of about 10 the data showing another sharp decline. An interesting fact is that the production data do not continue declining, but they show another level of interporosity flow. This may be an indication of three porosity systems. It also may be due to changing production constraint (e.g., changing choke size, closing and reopening well, and stimulation). At the end, production declines which indicates the entire system is under pseudosteady-state flow.

To avoid ambiguity the effect of production constraint should be eliminated by normalizing production rate with pressure drop, if flowing well pressure or wellhead pressure data are available. In our case, those data are not available.

The exercise using the Arps decline type curve showed that the use of Arps decline curve is not appropriate to analyze production data from Well-1, which is producing from a naturally fractured reservoir. The decline type curve generated for this type of reservoir (as mentioned in the previous sections) are used to evaluate the production data to obtain permeability, skin factor, drainage area, effective wellbore radius and original oil-in-place. The match results is shown in Fig.8 with parameters as follow:

\[ r_D = 1000 \quad \omega = 0.2 \quad \lambda = 4 \times 10^{-8} \quad \left[ t / t_{DD} \right]_{MP} = 400/1 \quad [q / q_{DM}]_{MP} = 15000/1 \]

Fluid and reservoir data are given in Table 1 below:

<table>
<thead>
<tr>
<th>Table 1 – Fluid and Reservoir Properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil viscosity</td>
</tr>
<tr>
<td>Oil FVF</td>
</tr>
<tr>
<td>Initial pressure</td>
</tr>
<tr>
<td>Net pay thickness</td>
</tr>
<tr>
<td>Porosity</td>
</tr>
<tr>
<td>Initial water saturation</td>
</tr>
<tr>
<td>Total compressibility</td>
</tr>
<tr>
<td>Wellbore radius</td>
</tr>
</tbody>
</table>

The analysis results of production data inversion are summarized in Table 2. The production data inversion yield very good agreement with well test data analysis for permeability, skin factor, and storativity ratio. The OOIP obtained from production data inversion 41.9 MMSTB which
is higher than that obtained volumetrically, which is 33 MMSTB. This may be caused by reservoir drive mechanism being strong water drive (this is supported by the fact that reservoir average pressure just slightly declines for almost 25 years production), which affects the analysis. Nevertheless, the estimated value of OOIP from production inversion is reasonable and provides confidence to the OOIP obtained using volumetric calculation, which has been questioned whether it is too optimistic.

The current recovery factor is about 14.7%, and using the type curve the production is forecasted based on current performance shown in Fig. 9. The EUR is predicted to be 15.5%. Low EUR under strong water drive may due to fluid flow from matrix to fracture networks is very small because of water encroachment into the fracture networks. Small interporosity flow is indicated by our analysis with small $\lambda$ of $4 \times 10^{-8}$. As a result, most of the remaining fluid is trapped in the matrix (which originally contributes to about 80% of the OOIP as indicated by storativity ratio of 0.2).

Table 2 – Results Summary of Production Data Inversion, Well Test Analysis, Volumetric Calculation

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Prod. Data Inversion</th>
<th>Well Test Analysis</th>
<th>Volumetric Calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td>$k$ (mD)</td>
<td>65</td>
<td>62.47</td>
<td>63.71</td>
</tr>
<tr>
<td>OOIP (MMSTB)</td>
<td>41.9</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>$A$ (acre)</td>
<td>631</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>$r_e$ (ft)</td>
<td>2958</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>$r_{w}$ (ft)</td>
<td>2.96</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>$S_w$</td>
<td>-2.3</td>
<td>-3.81</td>
<td>-3.7</td>
</tr>
<tr>
<td>$\lambda$</td>
<td>$4 \times 10^{-8}$</td>
<td>-</td>
<td>$2.72 \times 10^{-5}$</td>
</tr>
<tr>
<td>$\omega$</td>
<td>0.2</td>
<td>-</td>
<td>0.21</td>
</tr>
</tbody>
</table>

Conclusions

Our conclusions are as follows:

1. Conventional Arps decline curve may not be appropriate to used for analyzing production data from a naturally fractured reservoir when two ore more porosity systems contribute to the fluid flow.

2. We have constructed production data inversion using decline type curve for naturally fractured reservoirs. For this reservoir, the interporosity flow is indicated by flattening production (pseudosteady-state interporosity flow) or by declining rate with half-slope in log-log plot (transient interporosity flow).

3. We have demonstrated the application of this method to Well-1 producing from reservoir X. The results are in reasonable agreement with the results of well test analysis and volumetric calculation.

4. The use of this method does not require a specific testing. It needs only production rate data. For better accuracy in analyzing well performance and characterizing reservoir, well flowing pressure or wellhead pressure data should be also recorded during production, in addition to the production rate.

5. Accurate measurement of formation compressibility should be guaranteed to obtain accurate original oil-in-place.

Nomenclature

$A$ = drainage area, ft$^2$
$B$ = oil formation volume factor, vol/vol
$c_t$ = total compressibility, 1/psi
$h$ = thickness, ft
$k$ = permeability, md
$N$ = original oil-in-place, STB
$P_i$ = initial pressure
$P_{wf}$ = well flowing pressure, psi
$q$ = oil rate, STB/D
$q_{D}$ = dimensionless rate
$q_{Dm}$ = decline curve dimensionless rate
$r_e$ = drainage radius, ft
$r_w$ = wellbore radius, ft
$s_w$ = water saturation, fraction
$t$ = time, hr or day
$t_D$ = dimensionless time
$t_{Dm}$ = decline curve dimensionless time

Symbols

$\omega$ = storativity ratio
$\lambda$ = interporosity coefficient
$\mu$ = oil viscosity, cp
$\phi$ = porosity, fraction

Subscript

$m$ = matrix
$f$ = fracture
$D$ = dimensionless

References


Figure 1 – Decline type curve of naturally fractured reservoir for various $\omega$ and $\lambda$ at $r_eD=10$; pseudosteady-state interporosity model.

Figure 2 – Decline type curve of naturally fractured reservoir for various $\omega$ and $\lambda$ at $r_eD=10$; transient interporosity model.
Figure 3 – Decline type curves comparison; pseudosteady-state versus transient interporosity models.

Figure 4 – Production History of Well-1.
Figure 5 – Horner plot analysis of well test data; Well-1.

Figure 6 – Log-log plot analysis of well test data; Well-1.
Figure 7 – Match of production data on Arps decline type curve.

Figure 8 – Match of production data on decline type curve; naturally fractured reservoir model.
Figure 9 – Production forecast of Well-1.