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INTERPRETATION OF WELL TEST ANALYSIS INTO RESERVOIR SIMULATION FOR A DUAL POROSITY MODEL

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ABSTRACT

Most of geothermal reservoirs are observed to be fracture dominated. The fractured systems are usually modeled by means of a dual porosity, where fluids exchange between the high porous matrix blocks and high permeable fracture systems is governed by transfer function. Understanding of the unique reservoir behavior of naturally fractured reservoirs is required.

This study is focused on well testing as a tool to better understand and describe these type of reservoirs. In well testing, Warren and Root (1963) defined a dimensionless storage coefficient or well known as the storativity ratio, ω. Storativity ratio is the ratio of fracture storage to total storage of the formation. If the matrix and fracture compressibilities are assumed equal, then the storativity ratio parameter is a function of the porosity ratio. A second well test parameter derived by Warren and Root is called the matrix to fracture transfer rate referred to as the interporosity flow parameter , λ. It is a measure of the mass transfer rate from the matrix to the fracture network. The interporosity flow parameter is a function of the permeability ratio between the matrix and fracture.

Both the dimensionless storativity ratio and interporosity flow parameter are key parameters evaluated by well test. Those parameters provide useful information from interpretation of pressure data. The information gained from well testing analysis will influence reservoir simulation. Up to now, those key parameters have not been used for a given value in reservoir simulation. It means that there is still a gap between and this study builds a link for the gap.

INTRODUCTION

The concept of treating a naturally fractured reservoir as a dual porosity medium was introduced by Barrenblat et al. (1960) and later by Warren and Root (1963). Due to complex permeability nature of fluid flow in naturally fractured reservoirs (NFR) modeling and numerical simulation of such reservoirs are more complicated than those of the conventional reservoirs. Properties of reservoir for given values in naturally fractured reservoirs is a critical factor to acquire an accurate dual porosity reservoir modeling. The scope of this study is about well test and its interpretation into reservoir modeling for dual porosity. In Warren and Root model, matrix element shape used is cube shape.

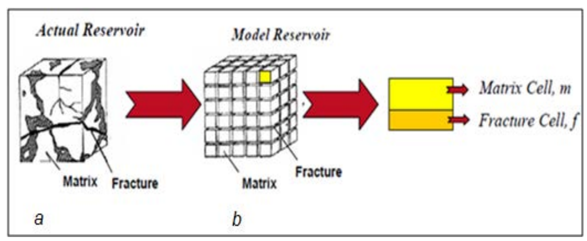

Figure 1: Idealized model of fractured reservoirs by Warren and Root (1963)

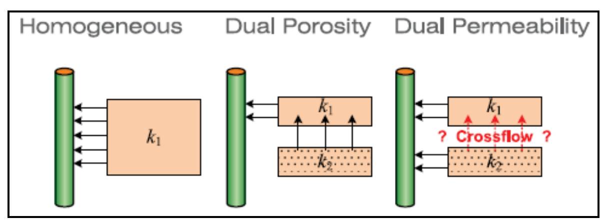

Figure 2: Model of reservoirs

In dual porosity, only porosity 1 is connected to the well, and the porosity 2 acts like a source. Example : naturally fractured reservoir whereas fissures (1) and matrix (2). In dual permeability, each porosity is connected to the well. Example : two layers commingled at the well. Crossflow in the reservoir may or may not exist.

Two main parameters resulted from well test analysis are storativity ratio which has a typical range of ω is 0.01 to 0.1

$$\omega = \frac{(\phi h c_t)_f}{(\phi h c_t)_{f+m}}$$

Where :
ω : storativity ratio
h : thickness
c_t : total compressibility
ϕ : porosity

And interporosity flow ratio, in general the interporosity flow parameter ranges between 10^{-4} and 10^{-8}

$$\lambda = \sigma \left(\frac{k_m}{k_f} \right) r_w^2$$

Where :
- λ : interporosity flow coefficient
- k_m : matrix permeability
- k_f : fracture permeability
- r_w : wellbore radius
- σ : shape factor

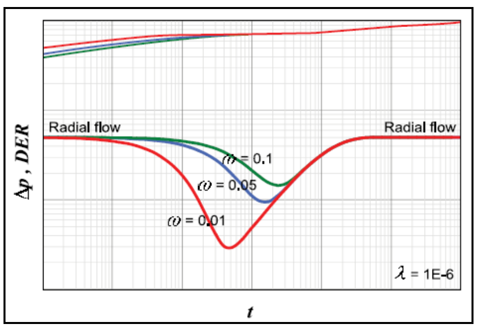

Figure 3: Effect of storativity ratio (ω)

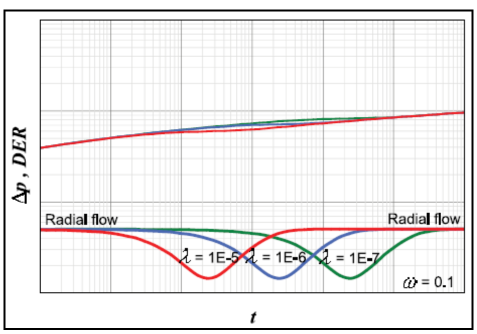

Figure 4: Effect of interporosity flow

The shape factor σ is a geometric factor that depends on the geometry and the characteristic shape of the matrix-fissures system, and has the dimension of a reciprocal of the area and controls interporosity fluid flow. Shape factor is a geometric component that was initially introduced by Barenblatt et al. (1960), to reflect the geometry and imposed boundary conditions of the matrix block.
They introduced shape factor to describe the relation between matrix-fracture pressure difference and flow rate under pseudo steady state condition.

$$q = \sigma \frac{V_b k_m}{\mu} (P_m - P_f)$$

Where :
σ : shape factor related to the specific surface of the fractures
p_m : average pressures in the matrix domains
p_f : average pressures in the fracture domains
q :fluid transfer rate between the matrix and fracture
k_m : matrix permeability
μ : fluid viscosity
V_b : Volume of bulk

The cubic law is the simplest way to describe fluid flow through rock joints. The flow through a rock fracture is governed by the Navier–Stokes equations, which are a set of three coupled non-linear equations difficult to solve. In case of a fracture bounded by smooth parallel walls, these former equations can be highly simplified and lead to the cubic law, which is still used in the literature in the rock joints context due to its simplicity even if deviations from experimental data due to joint roughness have been observed
The law may be given in simplified form by :

$$\frac{Q}{\Delta h} = C(2b)^3$$

Where ;
Q : flow rate, m^3/hr
Δh : difference in hydraulic head, m
C : constant that depends on the flow geometry and fluid properties
2b : Fracture aperture, m

Table 1. Characteristics of the dual porosity model

Permeability	Aperture	Flow Mechanism	Guiding Equation
Matrix	µm to mm	Darcian flow field Laminar	$k_f = \frac{\eta v L}{\rho g (N d^3)}$
Fracture	10 µm to 10 mm	Cube law. Mostly laminar; may be non-linear components	$\frac{Q}{h} = \frac{C}{f} b^3$

METHODOLOGY

The methodology uses dual-porosity model in naturally fractured reservoir simulation. A reservoir model is set up using simulation software called Petrasim 5.1.2030 (MINC model). It is based on the method of "multiple interacting continua" (MINC) as develop by Pruess (1982). The method of MINC is conceptually similar to the well known double porosity approach (Barrenblat et al., 1960 ; Warren and Root, 1963).
This model is based on the assumptions stated below:

1. Homogeneous reservoir (permeability of the matrix is homogeneous)
2. No flow boundary and all fractures are open
3. Flow occurs only from matrix blocks to fractures

Permeability and porosity of matrix blocks, and length of fractures are given values for the model. Then, run the model in natural state condition. The result (pressure and flow) will be used in well test simulator, Saphir 3.2. Evaluation will done by matching the curve. Key parameters determined from well test simulator then to be evaluated to get correlation the properties of reservoir.

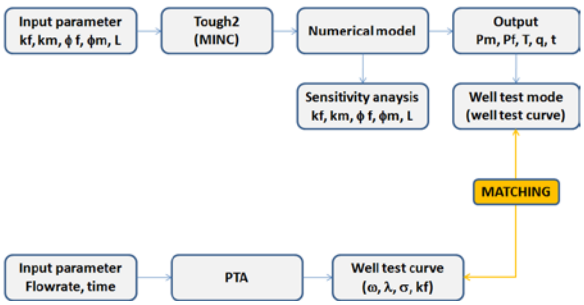

Figure 5: Methodology of this study

BUILD A DUAL POROSITY MODEL

Two dimensional model was built, 500 x 500 x 50 m. These model was set similar to natural fracture reservoir. The assumption of reservoir model as cited by Warren and Root are stated as below :

1. Homogeneous reservoir
2. Isotropic
3. Single phase fluid

Table 2. The parameters of synthetic model

Reservoir parameter	Values
Density	2600 kg/m^3
Thermal conductivity	2.4 W/m-C
Heat capacity	1000 J/kg-C
Fracture permeability	1 x 10^{-14} m^2
Matrix permeability	1 x 10^{-18} m^2
Matrix porosity	10%
Fracture spacing	10 m
Number of interacting continua	2
Volume fraction	0.05

The synthetic model assumed to be isotropic, where the permeability value both of matrix and fracture are equal in all directions. Fracture spacing was assumed equal in all three directions, x, y and z (L). The initial reservoir pressure is 35 bar and temperature 210 °C. The producing well is constrained by a bottom hole pressure of 30 bar. Simulation of production was run up to 1 month and flow rate of producing well is 0.6 m^3/hr. Build up test simulated up to 3 months to obtain adequate data for analysis. Pressure and flow rate as a function of time resulted from build up test. Those data represent response of the reservoir during build up test, until it reachs pressure equilibrium.

MATCHING MODEL

Two parameters were resulted from build up mode, pressure and flow. Those parameters are given values for well test simulator, Saphir 3.2. Several values in Saphir need to be adjusted (by doing trial and error) in order to obtain good shape of curve. Measured curve and calculated curve must have same or identical shape to convince that two key parameters of well test are valid.

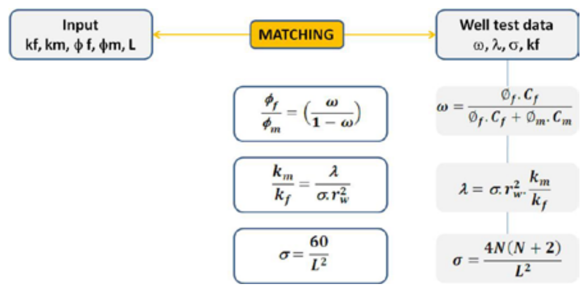

Figure 6: Correlation between well test parameters and properties of reservoir

Given value for well test simulator (SAPHIR 3.2.)

	Time	new model
	hr	bara
1	0.03	30.0800
2	0.08	30.1400
3	0.19	30.2200
4	0.42	30.3700
5	0.86	30.6600
6	1.75000	31.1300
7	3.53000	31.7800
8	7.08000	32.4600
9	14.1900	33.0000
10	28.4200	33.3300
11	56.8600	33.5300
12	113.750	33.6600
13	227.530	33.7400
14	455.090	33.7800
15	910.200	33.8100
16	1820.42	33.8500
17	2160.00	33.8700

	Duration	Liquid Rate	G	G
	hr	m3/hr		
1	720.860	0.603		
2	2879.14	0		

Fig. 7. Data as a given value for well test simulator

The figure below shows measured and calculated curve

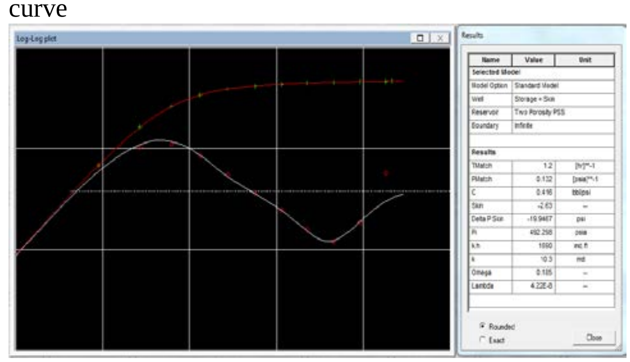

Figure 8: Well test simulator (Saphir) result

In practical application, matrix permeability (k_m) and matrix porosity (ϕ_m) can be approximated from core data, but in this study ratio of matrix permeability (k_m) and matrix porosity (ϕ_m) obtained from sensitivity analysis. Fracture permeability, k_f, is generally obtained from well test analysis. Wellbore radius, rw is normally a known parameter. In practice, the matrix permeability value, k_m is available from core data. Furthermore, fracture permeability and fracture porosity are calculated by following equations.

Storativity ratio :

$$\frac{\phi_f}{\phi_m} = \left(\frac{\omega}{1-\omega}\right) = \left(\frac{0.185}{1-0.185}\right) = 0.226$$

Interporosity flow :

$$\frac{k_m}{k_f} = \frac{\lambda}{\sigma . r_w^2} = \frac{4.22\ x\ 10^{-8}}{\sigma\ x\ r_w^2}$$

From sensitivity analysis, it is shown that λ = 4.26 x 10^{-8} obtained from ratio $\frac{k_m}{k_f}$ = 2.5 x 10^{-2} is the closest one to 4.22 x 10^{-8}.

Fracture permeability :

This parameter is known from well test simulation result, kf = 10.3 x 10^{-15} md. The fracture permeability value leads to fracture width with Cubic law approach.

$$k_f = \frac{w^2}{12}$$

$$w = 3.51\ x\ 10^{-7} m$$

Matrix permeability :

The matrix permeability value can be calculated from obtained permeability ratio

$$k_m = 2.58\ x\ 10^{-16}$$

Warren and Root introduced shape factor to describe the relation between matrix-fracture pressure difference and flow rate under pseudo steady state condition. In this equation, σ has the dimensions of reciprocal area

$$q = \sigma \frac{V_b k_m}{\mu} (P_m - P_f)$$

Where :

Flow rate, q = 0.603 m^3/hr = 511.11 ft^3/day

Matrix permeability, k_m = 2.58 x 10^{-16} m^2 = 0.258 md

Fluid viscosity, μ = 1.66 x 10^{-6} kg/m.s = 0.00166 cP

Matrix rock volume, V_b = 50 m^3 = 1765.7 ft^3

Matrix pressure, P_m = 3332500 Pa = 33.32 Psi

Fracture pressure, P_f = 3339600 Pa = 33.39 Psi

$$\sigma = \frac{\left({}^{q}/_{V_b}\right)\mu}{k_m(P_f - P_m)} = \frac{\left({}^{511.11}/_{1765.7}\right) x\ 0.00166}{0.258\ x\ (33.39 - 33.32)} = 0.026\ ft^{-2}$$

Hence, fracture spacing can be calculated from shape factor equation for two dimensional model (n = 2) :

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

$$L^2 = \frac{32}{0.026\ ft^{-2}} = 1202.7\ ft^2$$

$$L = 34.68\ ft = 10.57\ m$$

Size of matrix block can be calculated from substraction of fracture length to half of fracture width.

$$matrix\ size = 10.57 - \left(2\ x \left(\frac{3.51\ x\ 10^{-7}}{2}\right)\right)$$

$$matrix\ size = 10.569\ m$$

$$volume\ of\ matrix\ block = 1180.93\ m^3$$

Volume of bulk :

Dimension of synthetic model is equal to bulk volume

$$V_b = 500\ m\ x\ 500\ m\ x\ 50\ m = 12.500.000\ m^3$$

Volume of fracture :

Fracture volume obtained from substraction of "gross volume" (calculated volume from fracture length) to volume of matrix block.

$$V_f = (10.57^3 - 10.569^3) = \frac{0.33\ m^3}{matrix\ block}$$

Fracture porosity :

$$\phi_f = \frac{V_f}{V_b} = \frac{3547.44}{12500000} = 0.028$$

Matrix porosity :

$$\phi_m = 0.125$$

Reservoir properties below are calculated from well test analysis

Table 3. The parameters of synthetic model

Reservoir parameter	Values
Fracture permeability	1.03 x 10^{-14} m^2
Matrix permeability	2.57 x 10^{-16} m^2
Fracture spacing	10.57 m
Volume fraction of matrix	0.125
Volume fraction of fracture	0.028

Some of reservoir properties close to given values of the synthetic model such as fracture permeability, matrix permeability and fracture spacing. Volume fraction of fracture reflects difference, it might be caused by shape factor used. In practice, volume fraction of fracture normally less than 0.05, nonetheless it is difficult to prove.

Next modeling is made for better understanding of shape factor effect. Fracture spacing value will be corrected by applying previous shape factor evaluation as introduced by Adrianto (2012).

Shape factor for a two dimension model as introduced by Warren and Root (1963) :

$$\sigma = \frac{32}{L^2}$$

Shape factor for a two dimension model as evaluated by Adrianto (2012) :

$$\sigma = \frac{28.05}{L^2}$$

Corrected fracture spacing will be :

$$\frac{32}{L_{wr}^2} = \frac{28.05}{L_a^2}$$

$$L_a = 9.89\ m$$

Table 4. The parameters of synthetic model for shape factor evaluation

Reservoir parameter	Values
Density	2600 kg/m^3
Thermal conductivity	2.4 W/m-C
Heat capacity	1000 J/kg-C
Fracture permeability	1 x 10^{-14} m^2
Matrix permeability	1 x 10^{-16} m^2
Matrix porosity	0.125
Fracture spacing	9.89 m
Number of interacting continua	2
Volume fraction	0.028

The objective of this modeling is to prove the influence of shape factor to the result of simulation. L_a is new fracture spacing resulted from shape factor as evaluated by Adrianto (2012) to be used for a new model. The purpose of this evaluation is to acquire distinct relation of shape factor and accuracy of new shape factor coefficient as introduced by Adrianto (2012). The pressure and flow resulted from this simulation to be compared with initial model that has been made.

Table 5. Comparison results

	Initial model		Shape factor evaluation model	
Time, hours	**Pm, bar**	**Pf, bar**	**Pm, bar**	**Pf, bar**
0.03	30.01	31.47	30.04	31.67
0.08	30.05	31.90	30.11	32.07
0.19	30.12	32.16	30.24	32.31
0.42	30.27	32.36	30.50	32.50
0.86	30.56	32.54	30.95	32.65
1.75	31.05	32.70	31.59	32.78
3.53	31.72	32.86	32.31	32.91
7.08	32.44	33.04	32.92	33.06
14.19	32.99	33.22	33.31	33.23
28.42	33.33	33.40	33.54	33.41
56.86	33.53	33.55	33.68	33.57
113.75	33.66	33.67	33.76	33.69
227.53	33.74	33.74	33.80	33.77
455.09	33.78	33.78	33.83	33.80
910.20	33.81	33.81	33.88	33.83
1820.42	33.86	33.86	33.89	33.88
2160.00	33.87	33.87	33.87	33.89
Flowrate	**0.14281 kg/s**		**0.14381 kg/s**	

SENSITIVITY ANALYSIS

Sensitivity analysis has made to understand the behavior of reservoir in terms of any adjustment in several parameters. Sensitivity was performed with variable L values of 1, 5, 10, 20, 30, 40 and 50 m with varied fracture permeability values of 1 x 10^{-13}, 1 x 10^{-14}, 1 x 10^{-15} and varied fracture permeability values of 1 x 10^{-16}, 5 x 10^{-16}, 1 x 10^{-17}, 1 x 10^{-18}, 1 x 10^{-19}, 1 x 10^{-20}, 5 x 10^{-20}. 105 cases were run to understand the influence parameters. A log-log plot of L vs $\frac{r_w^2}{\lambda}$ and ratio $\frac{k_m}{k_f}$ have been made. The design of sensitivity analysis is described below :

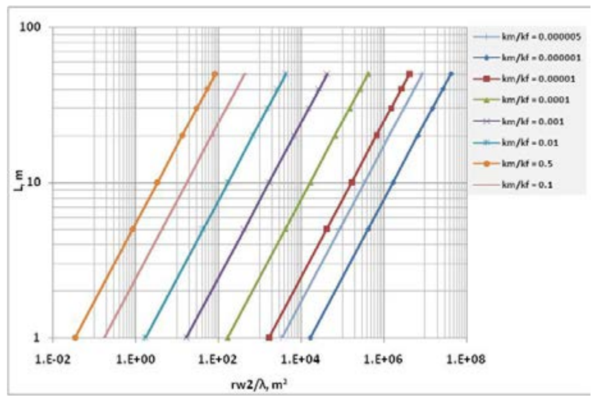

Fig. 9. Sensitivity analysis of fracture spacing for varied ratio of k_m to k_f

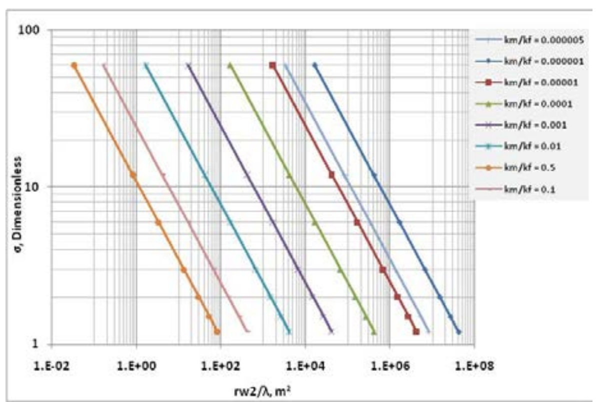

Fig. 10. Sensitivity analysis of shape factor for varied ratio of k_m to k_f

RESULT OF THE STUDY

From well test analysis, two important reservoir properties (permeability and porosity) had obtained. The following conclusions can be derived from this study are :

1. Storativity ratio is in linear function of ratio $\frac{\phi_f}{\phi_m}$

2. Interporosity flow has non linear function of fracture length, but it has linear function of ratio $\frac{k_m}{k_f}$
3. Cubic law equations can be used for estimating fracture width
4. In practice, fracture porosity value obtained from geometrical matrix block with values of fracture width *b* and matrix block size *a* can be given by core analysis. In this study, fracture porosity obtained from fraction of fracture volume to bulk volume.
5. Well test results (storativity ratio and interporosity flow) can be used for a given values in reservoir simulation for a dual porosity model

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