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

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ABSTRACT

Most geothermal reservoirs are observed to be fracture dominated and are usually modeled with dual porosity. Well testing is a tool for better understanding and describing these types of reservoirs. Properties of naturally fractured reservoirs are critical parameters to acquire to enable accurate dual porosity reservoir modeling. Nonetheless, up to now well test analysis and reservoir simulation for dual porosity model are not well integrated. The aim of this study is to correctly characterize the reservoir properties, e.g., the permeability, storativity and interporosity flow.

A simple synthetic model of a reservoir is built to facilitate the understanding of a well test. It employs several assumptions as cited by Warren and Root, 1963. A build-up test was simulated for 3 months to obtain adequate data for analysis. Pressure and flow rate as a function of time resulting from the build-up test are used in a well test simulator. The evaluation is done by matching the curve and the resulted key parameters can be interpreted in terms of reservoir properties. A sensitivity analysis has been used to investigate the effects of reservoir properties on well test analysis for a dual porosity system.

Some of reservoir properties obtained are close to the given values of the synthetic model, such as fracture permeability, matrix permeability and fracture spacing. Volume fraction of fracture reflects a difference, which might be caused by the shape factor used. A case study was also carried out to validate the methodology of this study by comparing measured PT data and simulation result. The result indicate a slight different between measured data and simulation result.

Well test analysis has proven very important for reservoir simulation, in order to get better results and accurate predictions of reservoir behaviour. This study helps to simplify the reservoir simulation process because reservoir properties to be used for reservoir simulation can be obtained from well test analysis. Thus well test results will provide a useful basis for reservoir simulation. The more accurate the reservoir properties, the better will be history matching and future predictions.

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 the complex nature of fluid flow in naturally fractured reservoirs (NFR), modeling and numerical simulation of such reservoirs is more complicated than for conventional reservoirs.

Properties of naturally fractured reservoirs are critical parameters to acquire to enable accurate dual porosity reservoir modeling. The scope of this study is about analysis of well tests and their interpretation to provide parameters for reservoir modeling using a dual porosity approach. In the Warren and Root model, the matrix element shape used is cube.

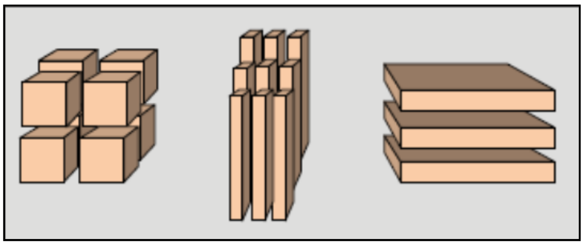


Figure 1: Matrix element shapes

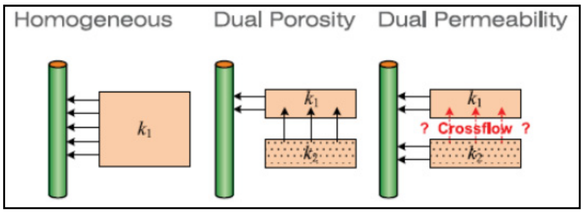


Figure 2: Model of reservoirs

In dual porosity, only porosity 1 is connected to the well, and the porosity 2 acts like a source. In a naturally fractured reservoir the fissures are represented by porosity 1 and matrix by porosity 2. In a dual permeability model, both porosity materials are connected to the well and thus the two porosity layers are commingled at the well. Crossflow within the reservoir may or may not exist.

The first of the two main parameters obtained from well test analysis is the storativity ratio ω which has a typical range of 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 : total compressibility
ϕ : porosity

The second important parameter is the 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 :

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

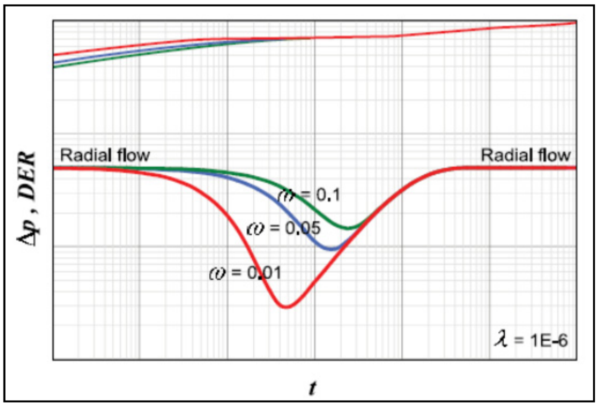


Figure 3: Effect of storativity ratio (ω)

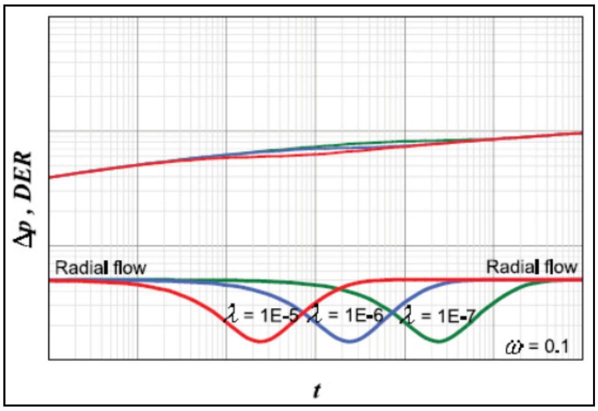


Figure 4: Effect of interporosity flow

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. The 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.

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

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, and are difficult to solve. In case of a fracture bounded by smooth parallel walls, these 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 cubic law was found to be valid whether the fracture surfaces were held open or were being closed under stress, and the results are not dependent on rock type. Permeability was uniquely defined by fracture aperture and was independent of the stress history used in these investigations. The equation below is the basis for what is often called the "cubic law" for flow in a fracture.

$$K_f = \frac{(2b)^2 \rho g}{12\mu}$$

Where :

b : aperture half width, m
g : acceleration of gravity, m/s^2
ρ : fluid density, kg/m^3
μ : fluid viscosity, cp
r_e : outer radius, m
r_w : well radius, m
k_f : hydraulic conductivity of fracture, md

The Well Index (WI) plays a key role in reservoir simulation as it defines the relationship between well pressure and flow rate and reservoir properties and pressure. Accurate well modeling is very important for flow simulations in reservoir engineering. The key point of well modeling is to perform accurate fluid flow simulations in the near-well region. The computational accuracy of well parameters such as the well flow rate or the wellbore pressure depends greatly on the near-well flow modeling.

The main difficulty in well modeling is the problem of the difference in scale between the small wellbore diameter (less than 0.3m) and the large wellblock grid dimensions used in the simulation (from tens to hundreds of meters). Also with a large model it is difficult to capture the radial nature of the flow near the well (i.e. nonlinear, logarithmic ,variations of the pressure away from the well). Thus, the wellblock pressure calculated by standard finite-difference methods is not the wellbore pressure. Peaceman has defined an equivalent well-block radius, r_e as the radius at which the steady state flowing pressure in the reservoir is equal to the numerically calculated pressure, p_o of the block containing the well. This definition of r_o can be used to relate the well pressure, p_w, to the flow rate, q, through p_o:

$$q = \frac{2\pi k h}{\mu}\left[\frac{P_o - P_w}{ln\left(\frac{r_o}{r_w}\right)}\right]$$

Where :

p_w : pressure of well, bar
p_o : pressure of cell, bar
q : flow rate, m^3/hr
r_w : wellbore radius, m
r_o : equivalent well block radius, m
k : isotropic reservoir permeability, md
h : reservoir thickness, m
μ : fluid viscosity, cp

METHODOLOGY

The methodology uses a dual-porosity model to simulate a naturally fractured reservoir. 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 developed 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

The permeability and porosity of matrix blocks, and the length of fractures are specified parameters for the model. Then, the model is run to a natural state. The results (pressure and flow) are then used in the well test simulator. Evaluation is done by matching the curve. Key parameters determined from the well test simulator then are evaluated to get a correlation with the properties of the reservoir.

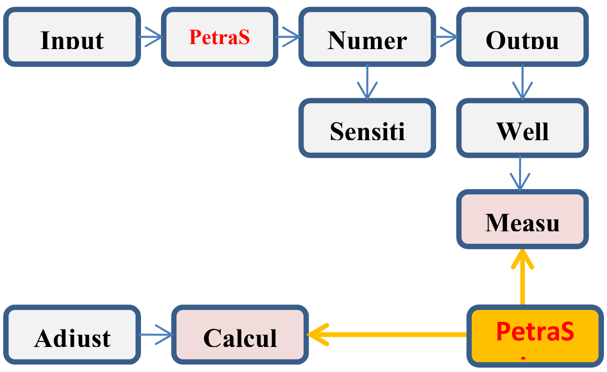


Figure 5: Work-flowpath

RESERVOIR SIMULATION AND WELL TEST RESULTS

A simple synthetic model of a reservoir is built to facilitate understanding of well test. A synthetic model simulates mass transfer between matrix and fracture with the application of the dual porosity concept. The parameters of synthetic model are given below:

Table 1: 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	1×10^{-14} m^2
Matrix permeability	1×10^{-16} m^2
Matrix porosity	10%
Fracture spacing	10 m
Number of interacting continua	2
Volume fraction	0.05

The 2-dimensional model was 500 x 500 x 50 m in size, and a reservoir with a producing well in the center was simulated. The synthetic model was assumed to be isotropic, where the permeability values for both matrix and fracture are equal in all directions. Fracture spacing was assumed to be equal in all three directions, x, y and z (L). The initial reservoir pressure is 35 bar and the temperature is 210 °C. The producing well is constrained by a bottom hole pressure of 30 bar. A simulation of production was run for 1 month and flow rate of the producing well set at 0.608 m^3/hr. A build-up test of 3 months was simulated to obtain adequate data for analysis.

The output data extracted from Petrasim are flow rate and pressure of fracture and matrix as a function of time. The pressure from the cell consists of fracture and matrix pressures.

The main difficulty of well modeling is the problem of the difference in scale between the smaller wellbore diameter (less than 0.3m) and the much larger wellblock grid dimensions used in the simulation (from tens to hundreds of meters).

In reservoir simulation, flow models that define the relationship between wells and reservoirs play a key role. The Peaceman equation below describes this relationship.

$$p_{well} - p_{cell} = \frac{1}{2\pi}\frac{Q\mu}{Kh} ln\left(\frac{0.208\Delta x}{r_w}\right)$$

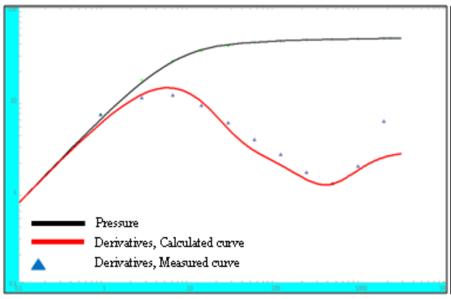
If the parameters are known, the Peaceman equation can be simplified to find pressure of the well, assuming that the pressure in the blocks adjacent to the well block is computed exactly by the radial flow model, where $r_o = 0.208\ \Delta X$. The radius of well, r_w is assumed to be 7 inches.

Table 2: Data as input for the well test simulator

	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		

From well test simulation, storativity ratio (ω) and interporosity flow (λ) are obtained. The result of well test simulation can be viewed in the figure below:



Name	Value	Unit
Selected Model		
Model Option	Standard Model	
Well	Storage + Skin	
Reservoir	Two Porosity PSS	
Boundary	Infinite	
Results		
TMatch	1.48	(hr)**-1
PMatch	0.194	(psia)**-1
C	0.496	bbl/psi
Skin	0.0402	—
Delta P Skin	0.207534	psi
Pi	491.571	psia
kh	2490	md.ft
k	15.2	md
Omega	0.27	—
Lambda	3.45E-08	—

Figure 6: Curve matching result

In practical applications, the 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) were obtained from sensitivity analysis. Fracture permeability, k_f, is also generally obtained from well test analysis. Furthermore, fracture permeability and fracture porosity are calculated by the following equations.

Storativity ratio :

$$\frac{\phi_f}{\phi_m} = \left(\frac{\omega}{1-\omega}\right) = \left(\frac{0.27}{1-0.27}\right) = 0.37$$

Interporosity flow :

$$\frac{k_m}{k_f} = \frac{\lambda}{\sigma . r_w^2} = \frac{3.45 \; x \; 10^{-8}}{\sigma \; x \; r_w^2}$$

From the sensitivity analysis, it is shown that interporosity flow, λ = 3.6 x 10^{-8} obtained from ratio k_m to k_f = 2.5 x 10^{-2}, is the closest value to the interporosity flow, of 3.45 x 10^{-8} obtained from the well test analysis.

Fracture permeability :
This parameter is known from well test simulation results, k_f = 1.52 x 10^{-14} m^2. The fracture permeability value leads to fracture width from the Cubic law approach.

$$w = 4.27 \; x \; 10^{-7} m \; k_f = \frac{w^2}{12}$$

Matrix permeability :
The matrix permeability value can be calculated from the obtained permeability ratio

$$k_m = 3.79 \; x \; 10^{-16} \frac{k_m}{k_f} = 2.5 \; x \; 10^{-2}$$

Warren and Root introduced a shape factor to describe the relation between matrix-fracture pressure difference and flow rate under pseudo steady state condition.

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

$$= \frac{\left(511.11/1765.7\right) x \; 0.00166}{0.379 \; x \; (33.39 - 33.32)}$$

$$= 0.018 \; ft^{-2}$$

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

$$L = 42.36 \; ft = 12.91 \; m\sigma = \frac{4n \; (n+2)}{L^2}$$

Volume of fracture :

$$V_f = (12.91^3 - 12.909^3) = \frac{0.499 \; m^3}{matrix \; block}$$

Fracture porosity :

$$\phi_f = \frac{V_f}{V_b} = \frac{2903.76}{12500000} x \; 100 = 0.023$$

Matrix porosity :

$$\phi_m = \frac{(1-\omega)C_f . \phi_f}{C_m}$$

$$\phi_m = \frac{(1-0.27) \; x \; 0.043 \; bar^{-1} \; x \; 0.023}{9.86 \; x \; 10^{-5} \; bar^{-1}}$$

$$\phi_m = 7.41 \; \%$$

Reservoir properties below were calculated from the well test analysis

Table 3: Results of well test analysis

Reservoir parameter	Model	Result
Fracture permeability	1 x 10^{-14} m^2	1.52 x 10^{-14} m^2
Matrix permeability	1 x 10^{-16} m^2	3.79 x 10^{-16} m^2
Fracture spacing	10 m	12.91 m
Porosity of matrix	10	7.41
Porosity of fracture	0.05	0.023

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

Shape Factor evaluation

Next modeling was carried out to better understand the shape factor effect. The fracture spacing value was corrected by applying a previous shape factor evaluation as introduced by Adrianto (2012).

The shape factor for a two dimensional model as introduced by Warren and Root (1963) is:

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

The shape factor for a two dimensional model as evaluated by Adrianto (2012) is:

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

The corrected fracture spacing then will be :

$$\frac{32}{L_{wr}^2} = \frac{28.05}{L_a^2} \qquad \frac{32}{12.91^2} = \frac{28.05}{L_a^2}$$

$$L_a = 12.08\ m$$

Table 4: The parameters of the 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	1.52 x 10^{-14} m^2
Matrix permeability	3.79 x 10^{-16} m^2
Matrix porosity	7.41%
Fracture spacing	12.08 m
Number of interacting continua	2
Volume fraction	0.023

The objective of this stage of modeling was to prove the influence of the shape factor on the results of the simulation. L_a is the new fracture spacing that resulted from the shape factor as evaluated by Adrianto (2012) and used in a new model. The pressure and flow result from this simulation were then compared with the results from initial model that had been set up.

Table 5: Comparison of results

	Initial model		Shape factor evaluation model	
Time, hours	Pm, bar	Pf, bar	Pm, bar	Pf, bar
0.03	30.01	31.47	30.01	32.24
0.08	30.05	31.90	30.02	32.57
0.19	30.12	32.16	30.03	32.78
0.42	30.27	32.36	30.07	32.93
0.86	30.56	32.54	30.15	33.03
1.75	31.05	32.70	30.30	33.10
3.53	31.72	32.86	30.57	33.16
7.08	32.44	33.04	31.04	33.23
14.19	32.99	33.22	31.73	33.35
28.42	33.33	33.40	32.56	33.53
56.86	33.53	33.55	33.31	33.74
113.75	33.66	33.67	33.82	33.96
227.53	33.74	33.74	34.13	34.17
455.09	33.78	33.78	34.32	34.33
910.20	33.81	33.81	34.45	34.45
1820.42	33.86	33.86	34.50	34.50
2160.00	33.87	33.87	34.50	34.50
Flowrate	0.14281 kg/s		0.26885 kg/s	

The comparison indicates that there are significant differences between results from the initial model and those from the shape factor evaluation model. This may be caused by different reservoir parameters being used, in the second case case the porosity of matrix which resulted from well testing was used. The porosity of the matrix derived from well test analysis is lower than the value used in the initial model, which means that the storage ability of matrix is less than in the initial model.

The pressure and flow rate results from the corrected shape factor model are higher than the conventional shape factor as introduced by Warren and Root (1963). As the shape factor is inversely proportional to fracture length, then the corrected fracture length will be higher than the initial fracture length. Fracture length influences the geometry of the matrix block, and further, it influences the value of porosity both matrix and fracture. Higher permeability of matrix and fracture may lead to higher flow rate and pressure of matrix and fracture, as shown in Table 5 above.

Statistical Analysis

Some figures below show other cases of synthetic models, with varying fracture lengths. Each model was evaluated and calculated to obtain reservoir parameters. The result of well test analysis is then compared with given values of each synthetic model. Statistical analysis was employed to analyse the data, and provides a way to summarize some data into a shorter form.

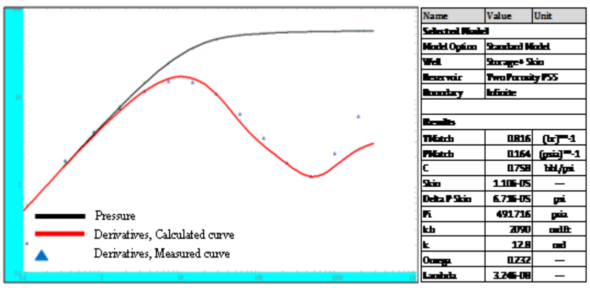


Figure 7: Curve matching with k_m/k_f = 0.001, L = 5 m

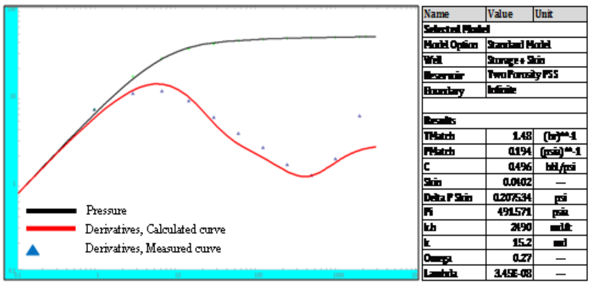


Figure 8: Curve matching with k_m/k_f = 0.025, L = 10 m

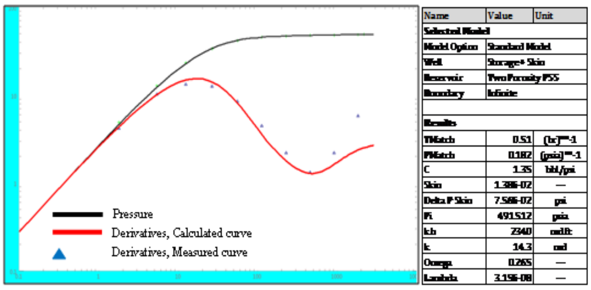


Figure 9: Curve matching with k_m/k_f = 0.01, L = 20 m

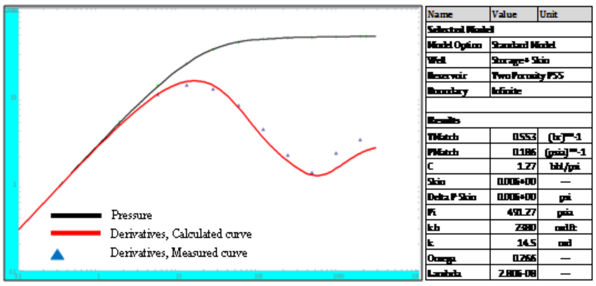


Figure 10: Curve matching with k_m/k_f = 0.025, L = 30 m

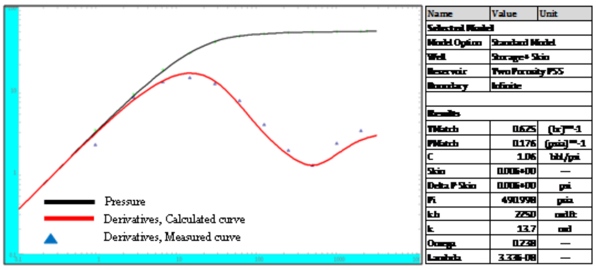


Figure 11: Curve matching with k_m/k_f = 0.05, L = 40 m

The summary of statistical analysis below shows the standard deviation and variance of each parameter compared to the parameters of the synthetic model. It can be seen from the standard deviation and variance of the well test results that the differences are not large compared to the parameters of the synthetic model. This indicates the consistency of the results.

Table 6: Summary of statistical analysis

	Parameters of synthetic model					Well test results				
	L	ϕm	ϕf	Kf	Km	L	ϕm	ϕf	Kf	Km
a	5	10%	0.05	1.00E-14	1.00E-17	4.20	6.02%	0.143%	8.72E-15	8.72E-18
b	10	10%	0.05	1.00E-14	1.00E-16	10.64	5.76%	0.085%	1.03E-14	2.58E-16
c	20	10%	0.05	1.00E-14	1.00E-16	18.20	5.98%	0.049%	8.41E-15	8.41E-17
d	30	10%	0.05	1.00E-14	2.50E-16	28.90	5.87%	0.042%	9.69E-15	2.42E-16
e	40	10%	0.05	1.00E-14	5.00E-16	35.77	6.09%	0.034%	8.72E-15	4.36E-16

Case study

Figure below is the result of build up test of Well-YY in XX field, and demonstrates a case study to implement fractured reservoir simulation. Well test results of Well-YY in XX field were used to estimate parameters for a dual-porosity reservoir simulation to obtain better accuracy of reservoir simulation for a fracture-dominated reservoir.

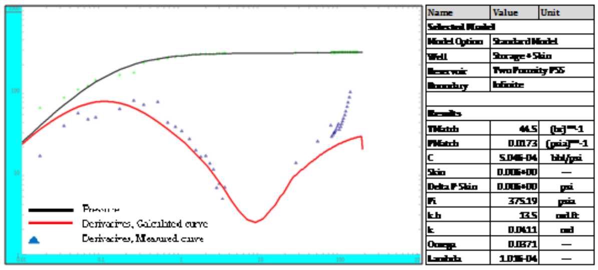


Figure 12: Curve matching result of XX-YY

As seen in the above figure, the pressure response has not yet reached radial flow state. The matching of the calculated curve (red line) compared to measured curve (blue triangle) is difficult to do. The edge of the measured curve is close to radial flow line. The calculated curve is hard to match with the measured curve.

From tabulation of the data for the well test in XX-YY, reservoir properties are:

Table 7: Tabulated data of well test in XX-YY

Reservoir properties	
L, m	104.28
ϕm	9.77%
ϕf	0.007%
Kf, m^2	1.18E-18
Km, m^2	1.18-19

These reservoir properties will be used as given values for the reservoir simulation of XX, in this case only for the area of XX-YY. The purposes of making this simplified model is to facilitate reservoir simulation for fractured reservoir and make the simulation simple

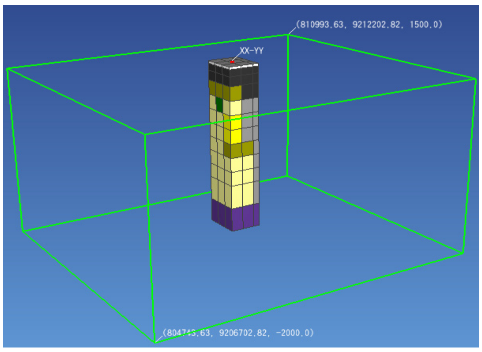


Figure 13: Model of XX-YY for dual porosity

The aim of the simulation above is to validate the methodology of this study. Validation is done by comparing measured PT data and simulation result. The table below indicates a small difference between measured data and simulation result. Also shown below is the result from the previous history matching.

Table 8: Comparison of P and T XX-YY

Measured			Simulation result		
Depth	**Temp**	**Press**	**Depth**	**Temp**	**Press**
0	239.60	33.05	50	241.09	33.98
100	241.00	33.44	350	242.31	34.84
200	242.40	33.93	650	243.15	35.36
300	243.20	34.32	950	243.96	35.87
400	243.50	34.52			
500	244.10	34.72			
600	244.40	34.72			
700	244.20	35.01			
800	244.20	35.01			
830					
840					
850					
900	244.20	35.01			
950	244.50	35.21			

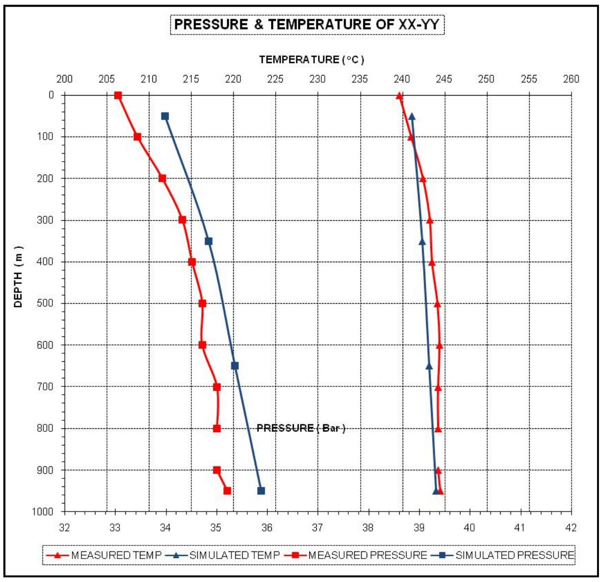


Figure 14: Graph of pressure and temperature q of XX-YY

Up to now, well test analysis and reservoir simulation for dual porosity models have not been well integrated. Well test analysis and reservoir simulation are carried out separately. However, the gap between well test results (involving two dimensionless parameters) and reservoir simulation can be bridged. This study helps to simplify reservoir simulation because reservoir properties for reservoir simulation can be obtained from well test analysis. The more accurate the reservoir properties, the better results for history matching and future prediction will be.

The table and figure below show a comparison of result between measured data and previous simulation (previous history matching) where the data from well test results were not included. The match of the model results to the data is not quite good as the results of the reservoir simulation when the data from well test results are included. Well test analysis has proven to be very important for reservoir simulation, in order to get better results and more accurate predictions.

Table 9: Comparison of P and T XX-YY from previous simulation (previous history matching)

Measured			Previous simulation result		
Depth	**Temp**	**Press**	**Depth**	**Temp**	**Press**
0	239.60	33.05	50	243.85	35.81
100	241.00	33.44	350	242.74	35.12
200	242.40	33.93	650	241.44	34.35
300	243.20	34.32	950	240.80	33.95
400	243.50	34.52			
500	244.10	34.72			
600	244.40	34.72			
700	244.20	35.01			
800	244.20	35.01			
830					
840					
850					
900	244.20	35.01			
950	244.50	35.21			

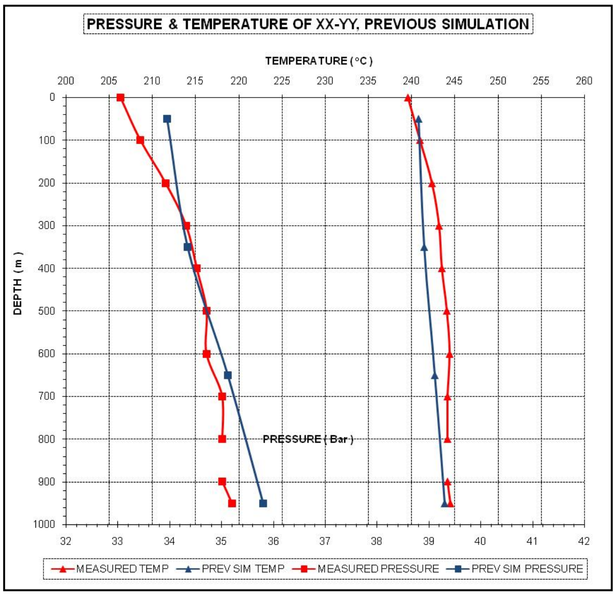


Figure 15: Graph of pressure and temperature of XX-YY (previous history matching)

SENSITIVITY ANALYSIS

Sensitivity analysis is a quantification of the effect of the input parameters on the simulation model response. Analysis is made of the changes in the simulation model output for different combinations of the input variables. On the basis of results from the sensitivity analysis, variables can be eliminated that do not have a sufficient effect on reservoir simulation model results. The key purpose of sensitivity analysis is to identify and focus on key data and assumptions that have most influence on the result. It can be used to simplify data collection and analysis without compromising the robustness of the result or to identify crucial data that must be thoroughly investigated.

Sensitivity analysis has been used to investigate the effects of reservoir properties on well test analysis for a dual porosity system. Based on reservoir simulation results, the analysis showed that certain reservoir parameters like fracture spacing are most likely to affect interporosity flow. All sensitivity runs use some characteristic reservoir properties some of which are varied because they were found to be important in determining the outcome.

The sensitivity study of well test parameters was conducted by Garcia Perez in her thesis in 2005. Sensitivity analysis was carried out for various models of oil reservoirs, for both homogeneous and heterogeneous reservoirs. Heterogeneity of reservoirs were also considered, for low and moderate anisotropy and heterogeneity. Distinct relationships between well test parameters and reservoir properties were explained in detail.

The equations below show the correlation between fracture spacing and well test result (interporosity flow). The shape factor can be estimated from λ using the following equation:

$$\sigma = \frac{\lambda\, k_f}{k_m\, r_w^2} \qquad L^2 = \frac{60\,\frac{k_m}{k_f} r_w^2}{\lambda}$$

Based on the above equation, fracture spacing can be expressed as a non linear function of λ and linear function of ratio $\frac{k_m}{k_f}$. A log-log plots of L vs $\frac{r_w^2}{\lambda}$ and ratio $\frac{k_m}{k_f}$ are shown in figure below :

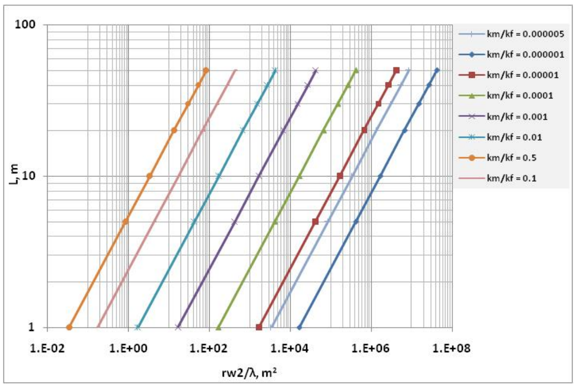


Figure 16: Sensitivity analysis of fracture spacing for varied ratio of k_m to k_f

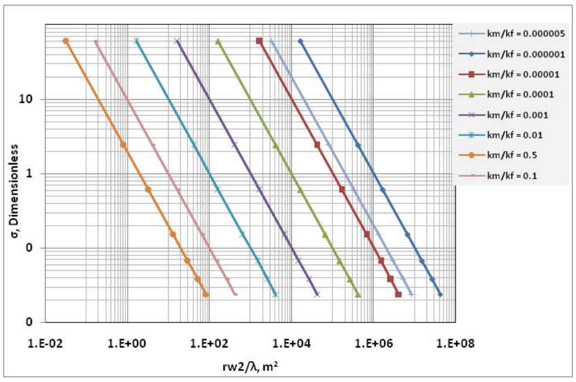


Figure 17: Sensitivity analysis of shape factor for varied ratio of k_m to k_f

CONCLUSIONS

The following conclusions can be drawn from this study, bridging the gap between reservoir simulation and well test analysis. The results derived from this study are :

1. Storativity ratio is a linear function of the ratio of fracture porosity to matrix porosity.

2. Interporosity flow is a nonlinear function of fracture length, but it is a linear function of the ratio of matrix permeability to fracture permeability.

3. The cubic law equations can be used for estimating fracture width.

4. In practice, the fracture porosity value obtained from geometrical matrix blocks with values of fracture width b and matrix block size a can be obtained by core analysis. In this study, fracture porosity was obtained from the fraction of fracture volume to bulk volume.

5. The benefits of this study is in assisting the industrial sector to interpret well test results for obtaining paprmeters for a reservoir simulation. Better accuracy of the model parameters, results in better predictions of productivity.

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