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The Application of Single porosity Model to Predict the Performance of the Low Permeability Naturally Fractured Formations

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The Application of Single porosity Model to Predict the Performance
of the Low Permeability Naturally Fractured Formations

Martial Hermann Tchuindjang Yatchou

Thesis submitted to the
Benjamin M. Statler College of Engineering and Mineral Resources
at West Virginia University
in partial fulfillment of the requirements
for the degree of

Master of Science
in
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2012

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ABSTRACT

The Application of Single porosity Model to Predict the Performance of the Low Permeability Naturally Fractured Formations

Martial Hermann Tchuindjang Yatchou

Natural gas extraction from shale is currently an expensive endeavor due to the tight reservoir rock with nano-darcy permeability. New technology in the form of horizontal drilling and hydraulic fracturing (fracturing through the use of high pressure liquids) has overcome the flow capacity problem of shale to achieve economic production. The low permeability shale formations, such as Marcellus Shale, contain a natural fracture system with extremely low permeability. The characteristics of the natural fracture system are non-existent; therefore the application of single porosity model to predict the production performance of the shale formations can reduce the need for detail fracture system characteristics.

The objective of this research is to conduct a reservoir modeling study to investigate the applicability of the single porosity model to predict the performance of hydraulically fractured shale reservoirs. A commercial reservoir simulator (ECLIPSE) was employed to generate different production profiles for a hydraulically fractured shale reservoir using the dual porosity model. The production profiles were then history-matched with a single porosity model. The history matching results were then utilized to determine the single porosity model parameters that approximate the dual porosity behavior. The results suggested that the entire production history cannot be matched with a single set of parameters for single porosity model. The time over which the production can be approximated by single porosity model was also identified. The results are used to investigate the impact of hydraulic fractures at the early production period.

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CHAPTER I

INTRODUCTION

In the United States, the gas production has increased significantly due to the discovery of the unconventional (low permeability) gas reservoirs. The resources associated with unconventional gas include low-permeability shale oil and gas reservoirs, and tight gas formations. Unconventional resources, characterized by their low gas recovery rate are seen as challenging. For example, gas recovery factor for these unconventional resources is estimated at 10-30% of GIP, much lower from conventional gas reservoirs (SPE 142884). Shale reservoirs have low permeability (less than 0.01 mD) and hence cannot be extracted via conventional methods. Technology such as horizontal drilling coupled with hydraulic fracturing to force natural gas from these low permeability geologic formations has greatly expanded the ability of the producers to profitably recover natural gas.

Natural fractures are important in the economical production of low permeability formations. A naturally fractured reservoir (NFR) can be defined as a reservoir that contains fractures (planar discontinuities) created by natural processes like volume shrinkage, distributed as a consistent connected network throughout the reservoir (Ordonez et al., 2001).

The effective modeling technique of naturally fractured reservoirs (NFR) has been through a dual porosity approach, where the fracture and matrix systems are separated into two different continuums, each with its own set of properties. Introduced in the late 1940s (Clark 1949; Howard and Fast, 1970), hydraulic fracturing has been used commonly to stimulate well production in gas industry in the last few decades. Horizontal wells with multiple fracture treatments have proven to be an effective method for producing economically from shale.

For this study, two main approaches including single porosity (SP) and Dual porosity (DP) have been used. The history matching results were then utilized to determine the single porosity model parameters that approximate the dual porosity behavior. To achieve this goal, several cases were modeled using different drainage areas to evaluate the production performance of fractured horizontal wells.

CHAPTER II

LITERATURE REVIEW

II. 1 Unconventional gas reservoirs

Unconventional gas is poised to dominate U.S gas production in coming decades. In the USA, the production from unconventional gas resources has increased since late 2000 and now approximates 87 Tcf/yr, as shown in Figure1.

Figure1: Unconventional gas projection in the U.S (EIA, 2008)

As illustrated in Figure 2, conventional reservoirs, are limited in volume, high in permeability and easy to develop, unconventional reservoirs on the other hand are expansive in volume, very low in permeability (micro-Darcy range or less) but difficult to develop. They are not feasible to be produced at economic flow rates, therefore require special gas extraction techniques.

Figure 2: Resource triangle for unconventional gas (Holditch, 2006)

The commonly types of unconventional gas reservoirs are tight gas, coal bed methane and shale gas. They currently accounts for 58 percent of the total U.S production.

II. 2 Shale Gas

Shale gas production is expected to be the driving force behind increased natural gas production, increasing from 5.0 trillion cubic feet in 2010 to 13.6 trillion cubic feet in 2035, accounting for nearly half of all domestic natural gas production as illustrated in Figure 3. (Image: U.S EIA 2012). With technically recoverable U.S. shale gas resources now estimated at 1,744 trillion cubic feet (Tcf) including 211 Tcf of proven reserves. Shale gas resources constitute 34 percent of the domestic natural gas resource (AEO, 2011) and 44 percent of lower 48 onshore resources Figure 4 is a visualization of lower 48 states shale plays.

Figure 3: Future projections of natural gas production (trillion cubic feet)

Source: ALL Consulting, Modified from USGS & other sources

Figure 4: United States shale Gas plays in U.S

Shale is a sedimentary rock formation which contains clay, quartz and other minerals. In terms of chemical composition, gas produced from the Shale is typically dry gas composed primarily of methane, but water can also be produced from shale gas formations. The Antrim shale and New Albany shale are the typical cases as shown in Table 1 (J. Daniel Arthur et al. 2008).

Shale reservoirs have low permeability (less than 0.01 mD). Aside from permeability, their key properties, when considering gas potential, are total organic content (TOC) and thermal maturity. TOC is the total amount of organic material (kerogen) present in the rock, expressed as a percentage by weight.

$$TOC = \frac{\phi_{ker} \rho_{ker}}{\rho_b K}$$

Where ϕ_{ker} = Kerogen volume (volume/volume)

ρ_{ker} = Kerogen density (g/ cubic centimeter)

ρ_b = Bulk density (g/ cubic centimeter)

K = Kerogen conversion factor

Generally, the higher the TOC, the better is the potential for hydrocarbon generation. Table 1 summarizes the TOC of different type of shale formations. The thermal maturity of the rock is a measure of the degree to which organic matter contained in the rock has been heated over time, and potentially converted into liquid and/or gaseous hydrocarbons. Thermal maturity is measured using vitrinite reflectance (R_o) which is measured by the core analysis. Table 2 summarizes the vitrinite reflectance for shale reservoirs.

Table 1: Comparison of data for the shale in U.S (J. Daniel Arthur et al., All Consulting 2008)

Comparison of Data For The Gas Shales In The United States							
Gas Shale Basin	Barnett	Fayetteville	Haynesville	Marcellus	Woodford	Antrim	New Albany
Estimated Basin Area, square miles	5,000	9,000	9,000	95,000	11,000	12,000	43,500
Depth, ft	6,500 - 8,500 ¹⁰	1,000 - 7,000 ¹⁰	10,500 - 13,500 ¹¹	4,000 - 8,500 ¹	6,000 - 11,000 ¹⁰	600 - 2,200 ¹⁰	500 - 2,000 ¹⁰
Net Thickness, ft	100-600 ¹⁰	20-200 ¹⁰	200 ¹⁰ - 300	50-200 ¹²	120-220 ¹³	70-12 ¹⁰	50-100 ¹⁰
Depth to Base of Treatable Water, ft	~1200	~500 ¹⁴	~400	~850	~400	~300	~400
Rock Column between Pay and Base of Treatable Water	5,300-7,300	500 - 6,500	10,100 - 13,100	2,125 - 7,650	5,600 - 10,600	300 - 1,900	100 - 1,600
Total Organic Carbon, %	4.5 ¹⁰	4.0-9.8 ¹⁰	0.5 - 4.0 ¹¹	3-12 ¹⁵	1-14 ¹⁶	1-20 ¹⁰	1-25 ¹⁰
Total Porosity, %	4-5 ¹⁰	2-8 ¹⁰	8-9 ¹¹	10 ¹⁷	3-9 ¹⁸	9 ¹⁰	10-14 ¹⁰
Gas Content, scf/ton	300-350 ¹⁰	60-220 ¹⁰	100-330 ¹⁹	60-100 ¹⁷	200-300 ²⁰	40-100 ¹⁰	40-80 ¹⁰
Water Production, Barrels water/day	0 ¹⁰	0	0	0		5-500 ¹⁰	5-500 ¹⁰
Well spacing, Acres	60-160 ¹⁰	80-160	40-560 ²¹	40-160 ²¹	640 ²¹	40-160 ¹⁰	80 ¹⁰
Original Gas-In-Place, Tcf ²²	327	52	717	1,500	52	76	160
Reserves, Tcf ²²	44	41.6	251	363 ²³ , 500 ²⁴	11.4	20	19.2
Est. Production, mcf/day/well	338 ²⁴	530 ²⁴	625-1,800 ²⁵	3,100 ²⁶	415 ²⁴	125-200 ²⁴	
mcf = thousands of cubic feet of gas. NOTE: Data derived from various sources and research analysis. Information from some basins was unable to be identified and confirmed at the time of this paper and has been left blank. # - for the Depth to base of treatable water data, the data was based on depth data from state oil and gas agencies and state geological survey data.							

Table 2: Vitrinite reflectance for shale gas reservoirs

Vitrinite reflectance for shale reservoirs			
Ro %	Thermally Immature	Oil window	Gas window
	0.1 - 0.5	0.6 - 1.1	1.2 - 2.0

The total amount of gas in place within the shale will determine how economical the shale play is. The gas is a combination of 1) free gas in the pores (G_f), 2) absorbed gas on the organics (G_a), 3) dissolved gas into the liquid hydrocarbon (G_{SO}) and 4) dissolved gas into the formation water (G_{SW}).

Hence, the total gas in place (G_{st}) is defined as: $G_{st} = G_f + G_a + G_{SO} + G_{SW}$ (Eq. 1)

Where

$$G_f = 32.0368 \frac{\phi (1 - S_w - S_o)}{\rho_b B_g} \quad (\text{Eq. 2})$$

$$G_a = G_{SL} \frac{P}{P + P_L} \quad (\text{Eq. 3})$$

$$G_{SO} = \frac{32.0368}{5.6146} \frac{\phi S_o R_{SO}}{\rho B_o} \quad (\text{Eq. 4})$$

$$G_{SW} = \frac{32.0368}{5.6146} \frac{\phi S_w R_{SW}}{\rho B_w} \quad (\text{Eq. 5})$$

However (Eq. 4) and (Eq. 5) are not applied. These are usually ignored or lumped in with adsorbed gas.

Given the low permeability of these shale reservoirs, the gas must be developed via special techniques including Horizontal drilling and fracture stimulation both have been crucial in the development of the shale gas industry.

II. 3 Technique of gas extraction

II. 3. 1 Drilling Methods

Horizontal drilling is a technique that allows the wellbore to come into contact with significantly larger areas of hydrocarbon bearing rock than in a vertical well Figure5. As a result of this increased contact, production rates and recovery factors can be increased. As the technology for horizontal drilling and hydraulic fracturing has improved, the use of horizontal drilling has increased significantly. Much more sophisticated drilling technologies such as multilateral drilling have done their appearances these recent years. According to the TAML group (Technical Advancements of Multi-Laterals), multilateral wells are wells with several laterals either vertical or any inclination up to or greater than horizontal. The following schematic represents the multilateral configurations.

Figure 5: Basic multilateral configurations (Schlumberger: oilfield review autumn 2002)

II. 3. 2 Hydraulic fracturing

The most common method of well stimulation is hydraulic fracturing as illustrated in figure 5.

Introduced in the late 1940s (Clark 1949; Howard and Fast, 1970),

Hydraulic fracturing is a formation stimulation practice used to create additional permeability in a producing formation. By creating additional permeability, hydraulic fracturing facilitates the migration of fluids to the wellbore for purposes of production (Veatch, Ralph W. Jr. et al.).

According to Ozkan et al (2009), hydraulic fracturing objectives are to increase fracture density and decrease fractures spacing, therefore can both increase production rates and increase the total amount of gas that can be recovered from a given volume of shale. The process of hydraulic fracturing involves the pumping of thousands of barrels of mixed sand and water into the target shale zone. Figure 6 shows a brief view of the technique. Fluids pumped into the shale creates fractures or openings through which the sand flows, at the same time acts to pro open the fractures that have been created (J. Daniel Arthur et al. 2008)

The important factor in hydraulic fracturing is the Dimensionless fracture conductivity (C_{rD}).

The conductivity is the product of the thickness of zone times its permeability. According to John Lee (2003), the fracture conductivity is given by the following formula:

$$C_{rD} = \frac{K_f w}{\pi K_m X_f}$$

Where

$C_{rD} > 100$, the fracture behavior is considered infinite conductivity.

$C_{rD} < 100$, the fracture behavior is considered finite conductivity.

Figure 6: Representation of shale gas extraction technique (Hydraulic fracturing 2011)

II. 4 Dual Porosity Model

The shale formation is typically a naturally fractured system. A qualitative description of a naturally fractured reservoir was given as early as 1953 by Pirson as reservoir with two porous structures-matrix (porous rock) and fracture. The most prevalent approach in the simulation of naturally fractured formation is a dual porosity formulation in which the rock matrix is defined as a series of discontinuous matrix blocks within a continuous fracture system.

The foundations of the dual porosity model were constructed by Barenblatt et al. (1960) and Warren and Root (1963). The assumptions for, their dual porosity model was as following:

- Uniform continuity of fracture network parallel to the principal axes of permeability.
- The matrix blocks and the fracture network are identical in shape (rectangular parallelepipeds) and located in the same space.
- There is an isotropic and homogeneity within the matrix blocks.

The Warren and Root (1963) model is illustrated in Figure 7.

Figure 7: Schematic of Dual porosity model using the Warren and Root model (1963)

The mathematical approach that model is a 2D fracture domain and slightly compressible fluids (Warren and Root, 1963), defined as:

$$\frac{K_{fx}}{\mu} \frac{\partial^2 P_f}{\partial x^2} + \frac{K_{fy}}{\mu} \frac{\partial^2 P_f}{\partial y^2} - \phi_m C_m \frac{\partial P_m}{\partial t} = \phi_f C_f \frac{\partial P_f}{\partial t} \quad (\text{Eq. 6})$$

According to Warren and Root (1963), The Darcy's flow is applicable if the pseudo steady state exists in the matrix system, therefore the following equation must be satisfied.

$$\phi_m C_m \frac{\partial P_m}{\partial t} = \frac{\sigma K_m}{\mu} (P_f - P_m) \quad (\text{Eq. 7})$$

Where

(Eq.6) is the equation governing fluid flow in the fracture system

(Eq. 7) is the equation governing the matrix system

$$\sigma = \frac{4n(n+2)}{l^2} \quad (\text{Eq. 8})$$

The Factor defines the isotropic of matrix blocks and also controls fluid exchange between fractures and matrix

There are two types of porosity existing in naturally fractured reservoirs: fracture porosity and matrix porosity. The fluid flows from a porous matrix (low permeability) usually representing the reservoir storage volume for free gas and adsorbed gas into a fractured system (high permeability) then to the wellbore. In the case of injection, the injected fluid displaces the fluid inside the matrix. (John D. Hudson, 2011)

Figure 8 illustrates the fluid displacement inside of the reservoir. (John D. Hudson, 2011)

Figure 8: Fluid displacement inside of the reservoir. The small arrows represent flow from the porous matrix to the fracture network and the large arrows represent flow inside the matrix.

CHAPTER III

OBJECTIVES & METHODOLOGY

III. 1 Objective

The goal of this research was to investigate the applicability of the single porosity model.

To achieve this goal, the following tasks were performed and are described here:

- Develop a reservoir model using a commercial reservoir simulator (ECLIPSE)
- Establish of production profiles for dual and single porosity models.
- History-match of production profiles obtained from dual porosity model with a single porosity model to determine the single porosity model parameters that approximate the dual porosity behavior.
- Identify the intervals over which the production can be approximated by different set of single porosity model parameters.

III. 2. Methodology

III.2.1. Reservoir Models and Assumptions

Two reservoir base models were developed using the software ECLIPSE by Schlumberger to generate different production profiles for hydraulically fractured formations. Figure 8 & 9 illustrate the configuration models. A dual porosity (DP) model and single porosity (SP) model were considered with absorbed gas accounting for the dual porosity. One layer was used for both models (DP & SP) to run the simulation. A horizontal well is centered in the middle of the reservoir using no fracture, 1, 3, 4, 5, 6, 7 and 11 fractures. The mathematical model constructed for this study is a 3D Cartesian with regular grids. Using the single porosity model, the need of detailed parameters was reduce, just one set of data was used and it was easy to run; while more assumption modes and too much detailed parameters for the dual porosity model.

III.2.1.2 Model parameters

The parameters used for simulation in this study were based on the published data (Belyadi et Al. 2010), Table 3 summarizes the parameters used to generate the basic model.

Reservoir Parameters	
Depth, ft	8000
Thickness, ft	80
Rock Properties	
Fracture spacing, σ , 1/ft ²	0.001
compressibility, 1/psia	1 E-6
Density, lb/ft ³	120
Initial conditions	
Initial Reservoir Pressure, Psia	3000
Water saturation, fraction	0.2
Natural Fracture Properties	
Porosity Type	Dual
Fracture Porosity, fraction	0.01
Matrix Porosity, fraction	0.05
Fracture Permeability, I, j, k, md	0.005, 0.005, 0.0005
Matrix Permeability, I, j, k, md	0.0002, 0.0002, 0.00002
Hydraulic Fractures Properties	
Half length, ft	500
width, in	0.1
Top of Fracture, ft	8000
Bottom of Fracture, ft	8080
Permeability, md	20,000
Porosity, fraction	0.01
Well Production Controls	
P _{wf} , psia	500
Fluid Properties	
Standard Pressure, psia	14.7
Standard temperature, °F	60
Reference Temperature, °F	120
Adsorption	
Diffusion coefficient, ft ² / day	1
Sorption Time, day	65
Langmuir Pressure, psia	670
Langmuir Concentration, SCF/ ton	0.099999

Table 3: Parameters and values used for the base model (Abass Belyadi 2010)

III.2.1.3 Model Development

The geometric drainage shape of the reservoir was rectangular. Various reservoir drainage areas were considered and are illustrated in Table 4.

Table 4: Various reservoir drainage areas configuration

Various drainage areas reservoirs configuration			
Geometric Shape	Horizontal well Length	Drainage areas	Model
Rectangular	3000 ft	4000 ft x 1000 ft	Dual Porosity, Single porosity
		4000 ft x 2000 ft	

The analysis was performed using the completions tool model template in ECLIPSE. The developed reservoirs were producing at constant rate with 40 years length simulation. More than 300 runs were done to better understand the applicability of the single porosity. Marcellus shale characteristics are the main component of this simulation model.

Figure 9: 4000ft x 2000ft Drainage area with 3000 ft lateral at the center

Figure 10: 4000ft x 1000ft Drainage area with 3000 ft lateral at the center

Once the both reservoir models (DP & SP) were developed, the production profiles were then simulated. A history matching was conducted for each evaluated study cases to determine the single porosity model parameters that approximate the dual porosity behavior. By setting up the dual porosity parameters and keeping them constant and by varying just the single parameters, the results were determined.

The values of dual porosity model parameters were either increased or decreased based on different case scenarios. The single porosity parameters were varied until getting the closest value that approximate the dual porosity curve

The coal bed methane template was considered to account for the absorbed gas. Table 5 shown below summarizes the different evaluated study cases conducted in this simulation.

Table 5: Evaluated case studies used

Evaluated Case Studies									
CASE # 1		CASE # 2		CASE # 3		CASE # 4		CASE # 5	
Dual Porosity		Dual Porosity		Dual Porosity		Dual Porosity		Dual Porosity	
Kf	0.005	Kf	0.002	Kf	0.008	Kf	0.005	Kf	0.005
Kmatrix	0.0002	Kmatrix	0.0002	Kmatrix	0.0002	Kmatrix	0.0002	Kmatrix	0.0002
ϕ_f	0.01	ϕ_f	0.01	ϕ_f	0.01	ϕ_f	0.02	ϕ_f	0.01
ϕ_{matrix}	0.05	ϕ_{matrix}	0.05	ϕ_{matrix}	0.05	ϕ_{matrix}	0.05	ϕ_{matrix}	0.06

III.2.1.4. The Analysis Process

The set of parameters for single porosity model were obtained using the flowchart in Figure 10 that explains how the entire process was carried out.

Figure 11: Flowchart of the Analysis Process

CHAPTER IV

RESULTS AND DISCUSSIONS

IV. 1. Results

The main objective of this chapter is to determine a set of the single porosity model parameters that approximate the dual porosity model. The results obtained derive from 5 different case studies (refer to Table 3). Two different drainage areas with same horizontal lateral configuration (4000 ft * 1000 ft, 4000 ft * 2000 ft and 3000 ft lateral) were utilized for each case. However for the second drainage area only for 7, 9 and 11 hydraulic fractures were simulated. All production profiles were generated with a simulation length of 40 years period.

The following are the results for different cases with different drainage areas.

Drainage area: 4000 ft * 1000 ft at 10 years

Table 6: Summary of case # 1 and case # 2

	CASE # 1		CASE # 2
# FRACS	DP-($\phi = 0.05$, $k_f = 0.005$, $K_m = 0.0002$)	# FRACS	DP-($\phi = 0.05$, $k_f = 0.002$, $K_m = 0.0002$)
No	SP-($\phi = 0.056$, $K = 0.005$)	No	SP-($\phi = 0.056$, $K = 0.0021$)
1	SP-($\phi = 0.056$, $K = 0.005$)	1	SP-($\phi = 0.056$, $K = 0.0021$)
3	SP-($\phi = 0.056$, $K = 0.005$)	3	SP-($\phi = 0.056$, $K = 0.0021$)
4	SP-($\phi = 0.056$, $K = 0.005$)	4	SP-($\phi = 0.056$, $K = 0.0021$)
5	SP-($\phi = 0.056$, $K = 0.005$)	5	SP-($\phi = 0.056$, $K = 0.0021$)
6	SP-($\phi = 0.056$, $K = 0.005$)	6	SP-($\phi = 0.056$, $K = 0.0021$)
7	SP-($\phi = 0.056$, $K = 0.005$)	7	SP-($\phi = 0.056$, $K = 0.0021$)
9	SP-($\phi = 0.061$, $K = 0.005$)	9	SP-($\phi = 0.061$, $K = 0.0021$)
11	SP-($\phi = 0.061$, $K = 0.005$)	11	SP-($\phi = 0.061$, $K = 0.0021$)

Table 7: Summary of case # 3 and case # 4

	CASE # 3		CASE # 4
# FRACS	DP-($\theta = 0.05$, $k_f = 0.008$, $K_m = 0.0002$)	# FRACS	DP-($\theta_f = 0.02$, $k_f = 0.005$, $K_m = 0.0002$)
No	SP-($\theta = 0.056$, $K = 0.008$)	No	SP-($\theta = 0.066$, $K = 0.005$)
1	SP-($\theta = 0.056$, $K = 0.008$)	1	SP-($\theta = 0.066$, $K = 0.005$)
3	SP-($\theta = 0.056$, $K = 0.008$)	3	SP-($\theta = 0.066$, $K = 0.005$)
4	SP-($\theta = 0.056$, $K = 0.008$)	4	SP-($\theta = 0.066$, $K = 0.005$)
5	SP-($\theta = 0.056$, $K = 0.008$)	5	SP-($\theta = 0.066$, $K = 0.005$)
6	SP-($\theta = 0.056$, $K = 0.008$)	6	SP-($\theta = 0.066$, $K = 0.005$)
7	SP-($\theta = 0.056$, $K = 0.008$)	7	SP-($\theta = 0.066$, $K = 0.005$)
9	SP-($\theta = 0.061$, $K = 0.008$)	9	SP-($\theta = 0.071$, $K = 0.005$)
11	SP-($\theta = 0.061$, $K = 0.008$)	11	SP-($\theta = 0.071$, $K = 0.005$)

Table 8: Summary of case # 5

	CASE # 5
# <i>FRACS</i>	<i>DP-($\Theta_m = 0.06$, $k_f = 0.005$, $K_m = 0.0002$)</i>
<i>No</i>	<i>SP-($\Theta = 0.064$, $K = 0.0052$)</i>
<i>1</i>	<i>SP-($\Theta = 0.064$, $K = 0.0052$)</i>
<i>3</i>	<i>SP-($\Theta = 0.064$, $K = 0.0052$)</i>
<i>4</i>	<i>SP-($\Theta = 0.064$, $K = 0.0052$)</i>
<i>5</i>	<i>SP-($\Theta = 0.064$, $K = 0.0052$)</i>
<i>6</i>	<i>SP-($\Theta = 0.064$, $K = 0.0052$)</i>
<i>7</i>	<i>SP-($\Theta = 0.064$, $K = 0.0052$)</i>
<i>9</i>	<i>SP-($\Theta = 0.071$, $K = 0.0052$)</i>
<i>11</i>	<i>SP-($\Theta = 0.071$, $K = 0.0052$)</i>

Figure 12: Impact of Hydraulic Fractures on Permeability

Figure 13: Impact of Hydraulic Fractures on Porosity

Drainage area: 4000 ft * 2000 ft at 10 years

Table 9: Summary of case # 1 and case # 2

	CASE # 2		CASE # 2
# FRACS	$DP-(\theta = 0.05, k_f = 0.005, K_m = 0.0002)$	# FRACS	$DP-(\theta = 0.05, k_f = 0.002, K_m = 0.0002)$
7	$SP-(\theta = 0.056, K = 0.005)$	7	$SP-(\theta = 0.056, K = 0.0021)$
9	$SP-(\theta = 0.061, K = 0.005)$	9	$SP-(\theta = 0.061, K = 0.0021)$
11	$SP-(\theta = 0.061, K = 0.005)$	11	$SP-(\theta = 0.061, K = 0.0021)$

Table 10: Summary of case # 3 and case # 4

	CASE # 3		CASE # 4
# FRACS	$DP-(\theta = 0.05, k_f = 0.008, K_m = 0.0002)$	# FRACS	$DP-(\theta = 0.02, k_f = 0.005, K_m = 0.0002)$
7	$SP-(\theta = 0.056, K = 0.008)$	7	$SP-(\theta = 0.066, K = 0.005)$
9	$SP-(\theta = 0.061, K = 0.008)$	9	$SP-(\theta = 0.071, K = 0.005)$
11	$SP-(\theta = 0.061, K = 0.008)$	11	$SP-(\theta = 0.071, K = 0.005)$

Table 11: Summary of case # 5

	CASE # 5
# FRACS	$DP-(\theta_m = 0.06, k_f = 0.005, K_m = 0.0002)$
7	$SP-(\theta = 0.064, K = 0.0052)$
9	$SP-(\theta = 0.071, K = 0.0052)$
11	$SP-(\theta = 0.071, K = 0.0052)$

Figure14: Impact of Hydraulic Fractures on Permeability

Figure15: Impact of Hydraulic Fractures on Porosity

Drainage area: 4000 ft * 1000 ft. Before 10 years

Table 12: Summary of Case # 1

	<i>CASE # 1</i>
# <i>FRACS</i>	<i>DP-($\phi = 0.05$, $k_f = 0.005$, $K_m = 0.0002$)</i>
<i>No</i>	<i>SP-($\phi = 0.053$, $K = 0.005$)</i>
<i>1</i>	<i>SP-($\phi = 0.053$, $K = 0.005$)</i>
<i>3</i>	<i>SP-($\phi = 0.053$, $K = 0.005$)</i>
<i>4</i>	<i>SP-($\phi = 0.053$, $K = 0.005$)</i>
<i>5</i>	<i>SP-($\phi = 0.053$, $K = 0.005$)</i>
<i>6</i>	<i>SP-($\phi = 0.053$, $K = 0.005$)</i>
<i>7</i>	<i>SP-($\phi = 0.053$, $K = 0.005$)</i>
<i>9</i>	<i>SP-($\phi = 0.06$, $K = 0.005$)</i>
<i>11</i>	<i>SP-($\phi = 0.06$, $K = 0.005$)</i>

Drainage area: 4000 ft * 2000 ft. Before 10 years

Table 13: Summary of Case # 1

	<i>CASE # 1</i>
# <i>FRACS</i>	<i>DP-($\phi = 0.05$, $k_f = 0.005$, $K_m = 0.0002$)</i>
<i>7</i>	<i>SP-($\phi = 0.053$, $K = 0.005$)</i>
<i>9</i>	<i>SP-($\phi = 0.06$, $K = 0.005$)</i>
<i>11</i>	<i>SP-($\phi = 0.06$, $K = 0.005$)</i>

Figure16: detailed curve case # 1. Early period

Matching Parameters $\Phi = 0.053$; $K = 0.005$

Figure17: detailed curve case # 1. Late period

Matching Parameters $\Phi = 0.06$; $K = 0.005$

Drainage area: 4000 ft * 1000 ft. After 10 years

Table 14: Summary of Case # 1

	<i>CASE # 1</i>
<i># FRACS</i>	<i>DP-($\varnothing = 0.05$, $k_f = 0.005$, $K_m = 0.0002$)</i>
<i>No</i>	<i>SP-($\varnothing = 0.06$, $K = 0.005$)</i>
<i>1</i>	<i>SP-($\varnothing = 0.06$, $K = 0.005$)</i>
<i>3</i>	<i>SP-($\varnothing = 0.06$, $K = 0.005$)</i>
<i>4</i>	<i>SP-($\varnothing = 0.06$, $K = 0.005$)</i>
<i>5</i>	<i>SP-($\varnothing = 0.06$, $K = 0.005$)</i>
<i>6</i>	<i>SP-($\varnothing = 0.06$, $K = 0.005$)</i>
<i>7</i>	<i>SP-($\varnothing = 0.06$, $K = 0.005$)</i>
<i>9</i>	<i>SP-($\varnothing = 0.061$, $K = 0.005$)</i>
<i>11</i>	<i>SP-($\varnothing = 0.061$, $K = 0.005$)</i>

Drainage area: 4000 ft * 2000 ft. After 10 years

Table 15: Summary of Case # 1

	<i>CASE # 1</i>
<i># FRACS</i>	<i>DP-($\varnothing = 0.05$, $k_f = 0.005$, $K_m = 0.0002$)</i>
<i>7</i>	<i>SP-($\varnothing = 0.06$, $K = 0.005$)</i>
<i>9</i>	<i>SP-($\varnothing = 0.061$, $K = 0.005$)</i>
<i>11</i>	<i>SP-($\varnothing = 0.061$, $K = 0.005$)</i>

IV. 2. Discussion

All figures listed in appendix A illustrate the impact of hydraulic fractures on single porosity model parameters (porosity and permeability) for all different 5 cases. The fractures are uniformly spaced and have same properties. The first 10 years production is investigated for economic reason because of the production depletion. Figures A, B, C, D, and E in Appendix A compare both dual and single porosity curves. For each case listed with different number of hydraulic fractures from 0 to 11 fractures; the trends are similar.

When we look at the whole 40 years of production especially at 10 years, it is seen that from 0 to 7 hydraulic fractures the entire production cannot be matched just with one set of parameters of single porosity model, while the number of hydraulic fractures increase from 9 to 11 fractures the dual porosity and single porosity curves got a perfect match. That means the production is not longer controlled by the single porosity model but by the hydraulic fractures. Therefore when the number of fractures increase the production becomes significant. Figures A, B, C, D, and E in appendix A illustrate that. Seen that the entire production cannot be matched by a set of parameters, two periods of production have been identified to clearly approximate the production by the different set of parameters.

The first period investigated is the early period (before 10 years). As it is seen, the dual porosity model can only be approximated by a single set of parameters, but the late period is not getting matched. That means after the first 10 years different set of parameters is needed in order to approximate the production as shown in case # 1, Figures Fs. To better clarify the approximation of the production at first period, Case # 1 has been investigated as an example for both different drainage areas accounting for 0, 1, 3, 4, 5, 6, 7, 9 and 11 fractures. Referring to the single set of parameters at 10 years period Table # 6, the porosity value is either increased or decreased until get close enough to the match. For instance, case # 1(Figure 16: 1 fracture) shows that the single porosity model curve clearly matches the dual porosity curve at the early stage.

The second period is the late period (after 10 years). By having a sight on all Figures Gs listed in the in appendix A, the production can be approximated but not at the early period. Therefore, only a different set of parameters of single porosity can only be adjusted to match the dual porosity curve.

Varying different porosities values as it is for the early period, the closest approximation has been achieved. The case # 1 (Figure 17: 1 fracture) has still been detailed as example.

All different set of parameters for with their different intervals of time is illustrated in Table # 6 through Table # 15.

Although there are some differences in the production profiles generated by the two models, the results are very similar. An interesting observation made is that increasing the drainage area width from 1000 ft to 2000 ft does not have any particular effect on the single porosity model. All set of parameters for single porosity model on both drainage are similar.

As it has been said in the previous chapter that the model accounts for absorbed gas; based on previous literature reviews, desorption gas was found to have no impact during early production (Belyadi, et al 2010 and 2012).

CHAPTER V

CONCLUSIONS

The objective of this research was to investigate the applicability of the single porosity model to predict the performance of hydraulically fractured shale reservoirs. In addition, the intervals over which the production can be approximated by single porosity model was also identified. The results from this work allow drawing the following conclusions:

- The entire production history cannot be matched with a single set of parameters for the single porosity model.
- The single porosity parameters are not impacted by the drainage area.
- As the number of hydraulic fractures increase, the production becomes significant.

Therefore the application of single porosity model to predict the production performance of the shale formations can reduce the need for detail fracture system characteristics.

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APPENDICES

Dual porosity and single porosity curves at 10 years.

Drainage area 4000 ft x 1000 ft

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Drainage area 4000 ft x 1000 ft

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Drainage area 4000 ft x 1000 ft

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Drainage area 4000 ft x 2000 ft

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Dual porosity and single porosity curves before 10 years.

Drainage area 4000 ft x 1000 ft

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Dual porosity and single porosity curves after 10 years

Drainage area 4000 ft x 1000 ft

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APPENDIX A

Figure A, B, C, D and E: Dual porosity and single porosity curves at early and late production period.

Drainage area: 4000 ft x 1000 ft

Case # 1

Figure A -1

Figure A -2

Figure A -3

Figure A -4

Figure A -5

Figure A -6

Figure A -7

Figure A -8

Figure A -9

Case # 2

Figure B -1

Figure B -2

Figure B -3

Figure B -4

Figure B -5

Figure B -6

Figure B -7

Figure B -8

Figure B -9

Case # 3

Figure C -1

Figure C -2

Figure C -3

Figure C – 4

Fig C – 5

Fig C – 6

Fig C - 7

Fig C - 8

Fig C - 9

Case # 4

Fig D – 1

Fig D – 2

Fig D – 3

Fig D - 4

Fig D - 5

Fig D - 6

Fig D - 7

Fig D - 8

Fig D - 9

Case # 5

Fig E - 1

Fig E - 2

Fig E - 3

Fig E – 4

Fig E – 5

Fig E – 6

Fig E – 7

Fig E – 8

Fig E – 9

Drainage area: 4000 ft x 2000 ft

Case # 1

Fig A-10

Fig A-11

Fig A-12

Case # 2

Fig B-10

Fig B-11

Fig B-12

Case # 3

Fig C-10

Fig C-11

Fig C-12

Case # 4

Fig D-10

Fig D-11

Fig D-12

Case # 5

Fig E-10

Fig E-11

Fig E-12

Before 10 years production
Drainage Area 4000 x 1000 ft
Case # 1

Fig F-1

Fig F-2

Fig F-3

Fig F-4

Fig F-5

Fig F-6

Fig F-7

Fig F-8

Fig F-9

After 10 years production
Drainage Area 4000 x 1000 ft
Case # 1

Fig G-1

Fig G-2

Fig G-3

Fig G-4

Fig G-5

Fig G-6

Fig G-7

Fig G-8

Fig G-9