Modeling of Fracturing Half-length and Spacing in Shale Reservoir

by

Mohamed Ahmed Ibrahim

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Dissertation submitted in partial fulfillment of
the requirements for the
Bachelor of Engineering (Hons)
Perak Darul Ridzuan (Petroleum)
January 2015

Universiti Teknologi PETRONAS
Bandar Seri Iskandar
31750 Tronoh
Perak Darul Ridzuan

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____

Dr. Mohammed Abdalla Ayoub

Universiti Teknologi PETRONAS
Tronoh, Perak
January 2015

CETRIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons

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Mohamed Ahmed Ibrahim

ABSTRACT

Shale gas reservoirs are proven to be of increasing importance day after another supported by the increase in the energy demand and the drop in the conventional reservoirs hydrocarbon reserves. This project is executed to investigate the effect of the fracture half-length and spacing in shale gas reservoir expressed in production rates and pressure drop rates. The study is to understand the factors that affect the flow behavior in the shale gas reservoir as Knudsen, Klinkenberg effects and non-Darcy flow nonetheless the dual porosity due to fractured system. By analyzing different proposed mathematical models for shale gas reservoir modeling. The most suitable mathematical model is to be selected similarly suitable parameters for the reservoir system, simulation model is to be created to investigate and model the suitable half-length and spacing for the shale gas reservoir. The project is aimed to investigate the effect of matrix permeability and natural fracture network permeability on the design of the fracture parameters.

ACKNOWLEDGEMENT

The Author would like to express his gratitude to Professor Dr. Mohammed Abdalla Ayoub, who has supervised this project and provided his guidance along the way.

The author would also like to extend his gratitude to Ir. Abdulazim Abbas for his guidance during model building and validation. And Finally I would like to extend my gratitude for the department of petroleum engineering in Universiti Teknologi PETRONAS, for the continuous support and guidance throughout the project and generally the university life.

Contents

TABLE OF FIGURES

TABLE OF TABLES

ABBREVIATIONS AND NOMENCULTURE

ω	Storativity
λ	Inter-porosity Flow Term
ψ	Pseudo-pressure
τ	Dimensionless time
R	Dimensionless radius
EIA	Energy Information Administration
X_e	Hydraulic Fracture Half-Length
CBM	Coal Bed Methane
EOS	Equation of State
K_f	Natural Fracture Permeability
K_m	Matrix Permeability
Y_e	Fracture Spacing
BHP	Bottom-Hole Pressure

Chapter 1
INTRODUCTION

Oil and gas industry plays an undeniable role in fulfilling the world energy demand. Being a non-renewable source of energy, hydrocarbon potential of conventional sources is dropping while the energy demand is rising. This has led to an increasing importance of unconventional sources of hydrocarbon.

Fortunately, high oil price leads to a feasible process of producing unconventional hydrocarbon. As a result produced gas from shale reservoir has been a considerable source of energy in the past few years. A huge amount of research and resource is being directed for better understanding for Shale Gas Reservoirs.

1.1 Background

Few decades ago, shale reservoirs were considered an unfeasible source of hydrocarbon due to the availability of sandstone reservoir which was characterized by higher permeability that yields to a higher primary recovery than shale reservoirs. As the energy demand increases followed by an increase the energy price, shale gas became of an increasing market value thus feasible for production.

Shale reservoirs are characterized by a low permeability, Javadpour stated that the permeability of shale bedrock is mostly 52nd where pore diameter is averaged between 4-200nm. Shale reservoirs are characterized by a network of natural fractures.

In shale gas reservoirs shale are stored in three forms of:

- Free gas stored in fractures and pores.
- Absorbed gas on the surface of bedrock.
- Dissolved gas stored in the kerogen.

Possible feasibility of shale gas has resulted in an increasing research with the aim of finding the most suitable models to represent the flow motion in the shale gas reservoirs. Similarly, researches aimed to optimize the most suitable method for shale reservoir development.

1.2 Problem Statement

To enhance the production from a shale gas reservoir a hydraulic fracture is done around the well as a proven technology to produce gas from shale formations. However, optimizing the fracture parameters in sand reservoirs was done using Darcy flow models or an ideal diffusive flow assuming the shale to be coal bed methane.

In shale gas reservoirs Darcy model is no longer applied due to the presence of external factors affecting the flow behavior. In the organic nano pores, slippage effect (Klinkenberg effect), gas diffusion (Knudson diffusion), viscous flow, non-Darcy flow at the wellbore and desorption from Kerogen plays a significant rule in gas flow. Similarly in the fracture network viscous and slippage effect for the gas coexist.

Therefore modeling the flow motion has raised the need for an effective method to model shale gas reservoirs. Consequently, this model shall lead to the optimum parameters of Hydraulic fractures.

1.3 Objectives

In this project, it is required to choose the most suitable model for modeling the flow motion in shale gas reservoirs to count for the additional factors affecting the flow in the shale gas reservoir. Subsequently, using this model to investigate the suitable fracture half-length and spacing for shale gas well hydraulic fracturing.

The expected outcome of the project is a simulation model for shale gas reservoir measuring the pressure drop, pseudo pressure behavior with time as well as the connectivity of the model by using different fracture half-length and spacing.

This project is aimed to investigate the effect of different reservoir permeability on the optimum fracturing parameters.

1.4 Scope of Study

The scope of this study will cover the following aspects:

- Analyzing the flow motion types in the shale gas reservoirs.
- Selecting the most suitable current mathematical model to model the shale gas reservoirs based on the assumptions used.
- Using this model assumption, creating simulation models to investigate the suitable fracture half-length and spacing.
- Investigating the effect of the reservoir matrix, natural fracture permeability on the fracture parameters optimization.

CHAPTER 2

LITERATURE REVIEW

2.1 Conventional Modeling:

Production of hydrocarbon from a reservoir has been explained by Diffusivity equation

$$\frac{1}{r_D}\frac{\partial}{\partial r_D}(r_D\frac{\partial P_D}{\partial r_D})=\frac{\partial P_D}{\partial t_D} \tag{1}$$

This equation is a combination of continuity, Equation of state and Darcy equation. Diffusivity equation is able to model the drop in pressure with time and location and related to the production rate. By considering the fracture in a sandstone reservoir the model used to explain the reservoir system is duel porosity model as introduced by Warren and Root in 1963.

Warren and root suggested a dichotomy of internal voids by dividing the porous system into two:

- Primary porosity this is the system of intergranular voids which is created by deposition and lithification and dependent on grain distributions and voids sizes
- Secondary porosity which is the system of fractures, permeability and porosity is higher than the intergranular system.

Based on the assumptions of:

- The material of the primary porosity is homogenous and isotropic and contained in identical arrays of rectangular parallelopipeds.
- All of the secondary porosity is contained within an orthogonal system of continuous, uniform fractures which are oriented so that each fracture is parallel to one of the principal axes of permeability; the fractures normal to each of the principal axes are uniformly spaced and are of constant width; a different fracture spacing or a different width may exist along each of the axes to simulate the proper degree of anisotropy.

- The complex of primary and secondary porosities is homogeneous albeit anisotropic; flow can occur between the primary and secondary porosities, but flow through the primary-porosity elements can't occur.

The duel porosity model is created for Darcy flow system reservoirs.

$$\frac{k_{2x}}{\mu}\frac{\partial^2 P_2}{\partial x^2}+\frac{k_{2y}}{\mu}\frac{\partial^2 P_2}{\partial y^2}-\phi_1 c_1\frac{\partial P_1}{\partial t}=\phi_2 c_2\frac{\partial P_2}{\partial t} \tag{2}$$

Defining the terms of storativity ratio ω and inter-porosity flow term λ as ω is identified as the ratio of storage volume in the fracture system to the total system storage; similarly λ defines the flow from the matrix system to the adjacent fracture.

The dual porosity yielded to the equation of:

$$\psi(1,\tau)\cong(\frac{2}{R^2-1})\left(\frac{1}{4}+\tau+\frac{(1-\omega)^2}{\lambda}\left\{1-\exp\left[\frac{-\lambda\tau}{\omega(1-\omega)}\right]\right\}\right)-\left[\frac{3R^4-4R^4\ln R-2R^2-1}{4(R^2-1)^2}\right] \tag{3}$$

Where ψ is the Pseudo-pressure, τ is dimensionless time and R is dimensionless radius.

By using this model it was possible to understand the behavior of conventional naturally fractured reservoirs. Similarly type curves for this type of reservoirs were created defined by the factors of storativity and inter-porosity terms.

2.2 Shale Gas reservoir

In the last Decade shale gas exploration and production process has been vital and growing especially in USA, China and Canada. **Error! Reference source not found.** learly demonstrates the active work taking place in exploration of shale reserves. This work is reflected in the proven reserves amount that increased more than 6 times over the duration of 2007 to 2013.

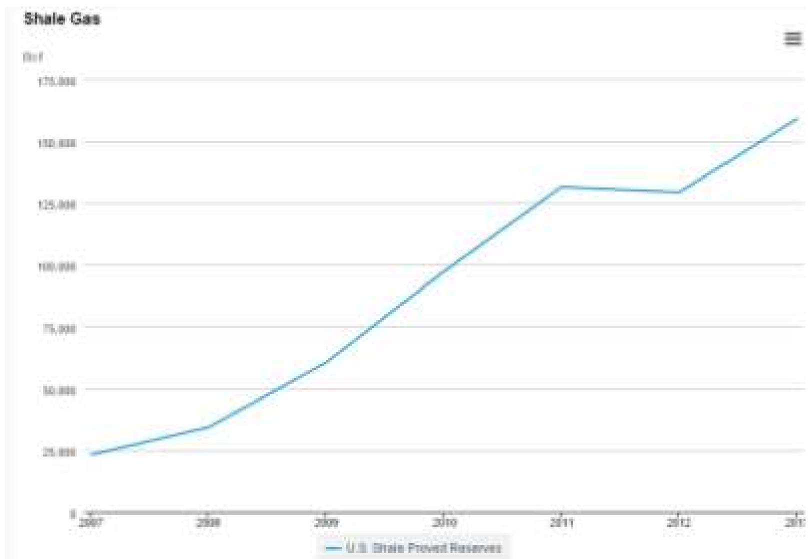

Figure 1 US Shale Proven Reserves (US EIA,2014)

Similarly in Canada and China shale gas reserves are believed to be 573, 1115 trillion cubic feet respectively, as shown in Figure 12.

As shown in Figure 10 the production of gas from Shale reservoirs is increasing and approaching half of the gas production in USA. Similarly in Figure 11 the Shale gas is anticipated to be the highest contributor to the gas energy demand in USA by the year 2020. In Figure 12, the reserves of the shale gas qualify it to be the main source of gas in the coming decades in a worldwide scale.

On the other hand, currently the shale gas reservoirs are not sufficiently understood and defined that leads to certainty in its development method. Shale reservoirs are known for their extremely low permeability, network of natural fractures and the clay formation.

These factors lead to a different nature of flow in the shale reservoirs from the flow in the conventional reservoir rocks.

In shale Reservoirs, these additional parameters play an important role in flow behavior:

- Non-Darcy flow
  Near the wellbore the velocity of the flow increases due to the small area of flow leading to a turbulent flow this flow is explained by the Forchheimer equation which adds the nonlinear term(s) to the Darcy equation of flow, which is quadratic in some papers and quadratic + cubic terms in other papers.
- Knudsen diffusion
  The gas tends to diffuse from the kerogen to the pores after depletion due to the concentration difference governed by Fick's law of diffusion.
- Stress dependent natural fracture permeability
  The permeability of the fracture is inserted as an exponential function of pressure to count for closing of fractures by pressure drop in the reservoir
- Klinkenberg effect (Slippage flow)
  At low pressure the gas velocity tends to accelerate due to slippage of molecules across the pores wall this may lead to overestimating the permeability of the system. At low permeability in shale reservoirs especially it is attached by a turbulent flow the Klinkenberg effect tends to appear
- Adsorption and desorption effect
  In Shale reservoirs the gas is present as adsorbed molecules to the surface of the organic element (Kerogen) surface, as a result an desorption process takes place as the pressure or the concentration of the reservoir drops.

Over the last decade a significant number of research papers were done in an attempt to model the flow in shale gas reservoir due to the presence of different flow factors.

Chaohua G., et.al (2014), Kim T.H., et.al (2014) and Ozkan , et.al. (2010) came with modified models to suit the factors of flow involved in the shale gas reservoirs. However, there is no exact proven model to consider in the shale gas.

Chaohua G., et.al. (2014) have developed a mathematical model considering the flow motion due to:

- Viscous flow
- Knudsen Diffusion
- Slip-flow (Klinkenburg)
- Non-darcy flow behavior (Forchheimer effect)
- Adsorption and desorption (Langmuir effect)

While Kim T.H., et.al (2014) have modeled the shale with regards to the flow by:

- Viscous flow
- Slip-flow (Klinkenburg)
- Non-darcy flow behavior (Forchheimer effect)
- Adsorption and desorption (Langmuir effect)

However the paper has ignored the effect of the diffusion on the flow in the shale gas reservoir.

Ozkan, et.al. (2010) have developed the dual porosity dual mechanism model, this model has counted for the flow by:

- Viscous flow
- Knudsen Diffusion
- Slip-flow (Klinkenburg)
- Non-darcy flow behavior (Forchheimer effect)
- Stress dependent fracture permeability

The paper has intentionally avoided the effect of Langmuir due to the lack of important parameters governing the desorption of the gas from kerogen as the volume and maturity of the organic content and the Langmuir isotherms, distribution of kerogen, exposed surface areas of the nanopores and pressure profiles. Nonetheless Langmuir theory is based on the assumptions that the surface containing the adsorbing sites is perfectly flat plane assuming a perfectly homogeneous.

2.3 Hydraulic Fracture in Shale Reservoirs

Hydraulic fracture is a well-known method to enhance well surroundings conditions in conventional reservoirs. However, in tight reservoirs and specially shale gas reservoirs it is believed to be a must to get a production out of these reservoirs.

A hydraulically fractures well in a conventional reservoir, flow take certain patterns starting with Linear, Bilinear, Formation Linear, then elliptical then Pseudo-radial flow. In conventional reservoirs, the pseudo radial flow is the dominant flow and it lasts for large time comparing with other flow patterns unless the fracture is near the boundary thus it is masked by boundary dominant flow.

Brown M. (2011) mentioned that the flow in a hydraulically fractured tight gas or shale gas reservoir can’t be modeled using the hydraulic fractured well type curves. Since the type curves of the hydraulically fractured well in conventional reservoir assumes that the linear flow period is short and can be totally masked by the wellbore storage effect.

However due to the extremely low permeability in the shale reservoir the linear flow is likely to last for a long time. By using the equation defined by Gringarten et al. (1974), Pseudo-radial flow is established after time.

$$t \geq \frac{1.14 \times 10^4 \phi c_t \mu x_f^2}{k} \tag{4}$$

Therefore by having a formation of Shale where k is in nano-scale nevertheless, hydraulic fracture half-length X_e is large compared to drainage area, the time for pseudo-radial flow to develop is most likely not to be seen in the well life time.

In designing for fracture half-length and spacing, it is believed that the conductivity of the fractures is the designing factor. Tuning of the hydraulic fracture conductivity for the most suitable production is the main process of fracture design.

The conductivity of the hydraulic fracture increase will yield to an increase in the production and debottleneck the production due to low permeability; especially it is expected to merge with the natural fracture network. However, if the conductivity increases over a certain limit it won't affect the production since the production is limited by the matrix flow to the natural fractures then to the hydraulic fracture.

Therefore, it is vital to have a designed hydraulic fracture in order to achieve the highest production rate and simultaneously cutting the fracking cost to minimal.

2.4 Coal Bed Methane

In order to understand the modeling of Shale gas motion it is vital to understand the modeling of Coal Bed Methane. The CBM reservoirs are naturally fractured reservoirs, where the gas is adsorbed to the coal surface.

Therefore the flow motion in the CBM similar to Shale gas is based on the concepts of Darcy flow, Diffusion and Desorption. However, the CBM is signified by the fact that the adsorbed gas can be considered uniform since the gas adsorbs to the coal, while in shale gas adsorbs to the randomly Kerogen .

Based on the great similarities between the CBM and Shale gas reservoir, the best method to model the Shale Gas Reservoirs using Schlumberger Simulator Launcher (Eclipse 100) is by using Coal Bed Methane keyword.

In CBM, the Adsorption effect is modeled using Langmuir Curves since the adsorption is evenly distributed over the coal surface. However, this is not the case in Shale gas.

Therefore, in our model the adsorption effect is ignored since it cannot be modeled accurately in the Shale Gas Reservoirs.

In our model the Langmuir tables should be corrected and tuned to count for zero adsorption effect and keep the diffusion effect of the gas by inputting equal adsorption and desorption rates at different pressures.

CHAPTER 3
METHODOLOGY

3.1 Description of Project Activities Flow Chart

- Problem Definition

The problem is defined by accessing the bottleneck faced in the industry with the aim to formulate a solution for the problem.

- Data Gathering

The datum will be obtained from journals, thesis paper, and research paper on the existing fracture designs and current mathematical models used to describe the flow in the shale gas reservoirs.

- Data Analysis

Different mathematical models and factors affecting the flow behavior will be studied to come up with the best representative mathematical model for the system based on the assumptions to be created for model development.

- Model Development

Shale gas reservoir model will be created based on the mathematical model chosen to study the different parameters effect on the pressure profiles and production profiles.

- Model Validation

A Base Case model is to be created using CMG, this model is to include the same parameters used for the results of the chosen mathematical model. The results created from the model and the paper are to be compared for model verification.

- Design Selection

The Fracture parameters with maximum production rate and minimum pressure drop with time will be chosen as the best model for fracture half-length and spacing.

- Sensitivity Analysis

Developing cases of different matrix permeability and fracture permeability and investigate its effect on the most suitable fracture parameters.

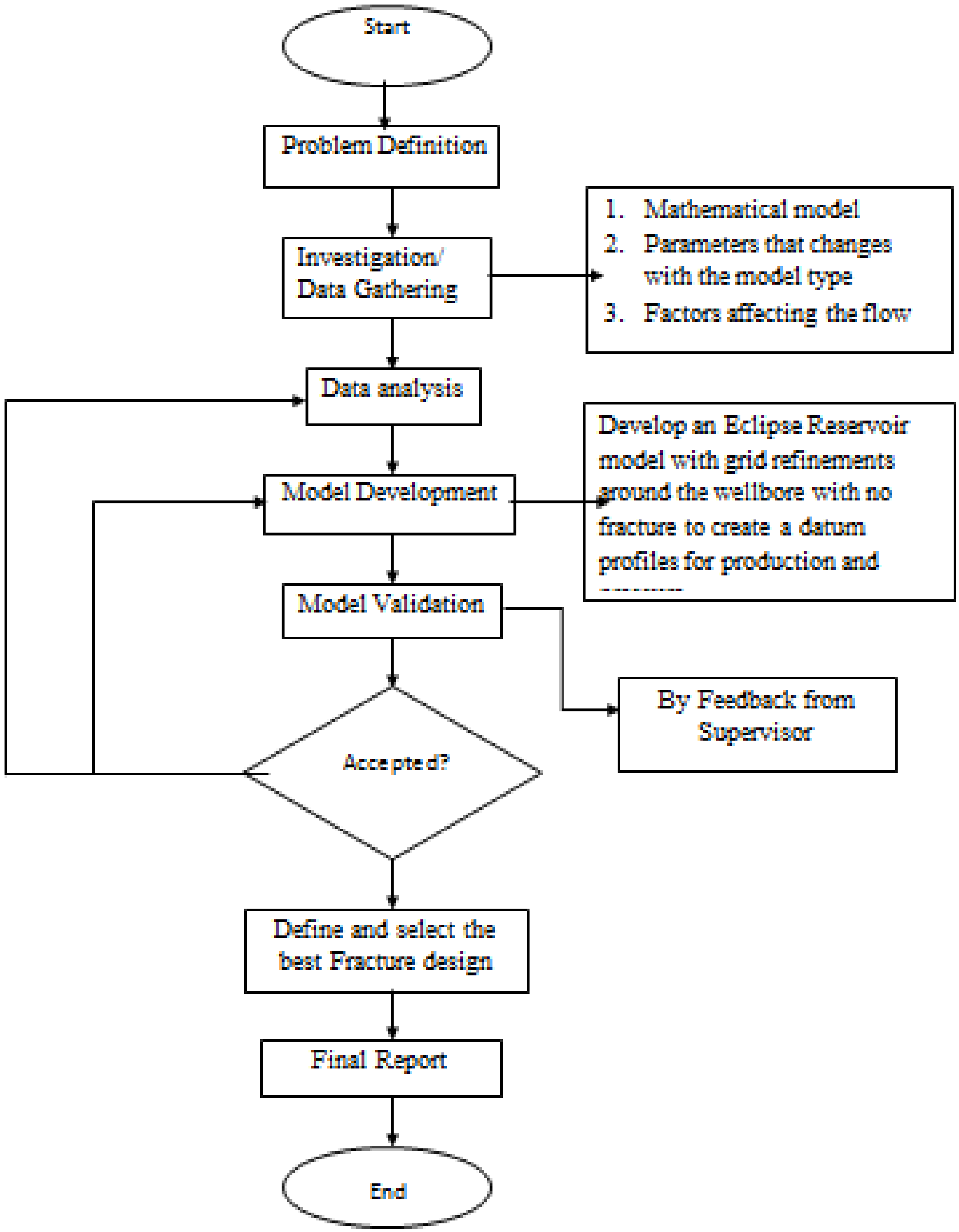

Figure 2 Flow Chart of Work plan

Table 1 Gantt Chart for FYP1 and FYP2

Gantt Chart with Key Milestones for FYP1 and FYP2																														
NO	Task	FYP1															FYP2													
		1	2	3	4	5	6	7	8	9	10	11	12	13	14		1	2	3	4	5	6	7	8	9	10	11	12	13	14
	Topic Selection		*																											
1	Problem defination																													
	Extended Proposal Submission						*																							
2	Investigation and Data Gathering																													
	Proposal Defence								*																					
3	Data Analysis																													
	3.1 Mathematical Model selection																													
	3.2 Determining the parameters of the system																													
	3.3 Formulating the system																													
	Submission of Interim Report														*															
4	Model Development																													
	4.1 Familiarizing with Eclipse																													
	4.2 Creating the reservoir model in Eclipse																													
	4.3 Creating the results with no fracture induced																													
5	Investigation of Fracture Effect																													
	5.1 Creating different models with different fracture half-length																													
	5.2Creating different models with different fracture spacing																													
6	Result Analysis																													
	6.1 Selection of best half-length and Spacing																													
	6.2 Analysing the selection with the mathematical model																													
7	Final Report																											*		

In this study 27 cases were run for different matrix permeability over the matrix permeability of 1E-8 md, 1E-10 md and 1E-12 md yielding to a total of 81 cases.

The 27 cases are a combination of:

- Fracture Spacing of 166 ft., 250 ft., 500ft.
- Fracture half Length of 150 ft., 200ft., 250 ft.
- Natural fracture permeability of 1000 md, 2000md, 3000md

The sensitivity analysis was done based on the values of:

- Time to reach boundary dominated flow
- Pressure at 5 years
- Cumulative production after 5 years

In order to get the time consumed to reach the reservoir boundary, well test analysis was done on each case using Greengarten method by measuring the slope of the pseudo-pressure derivative.

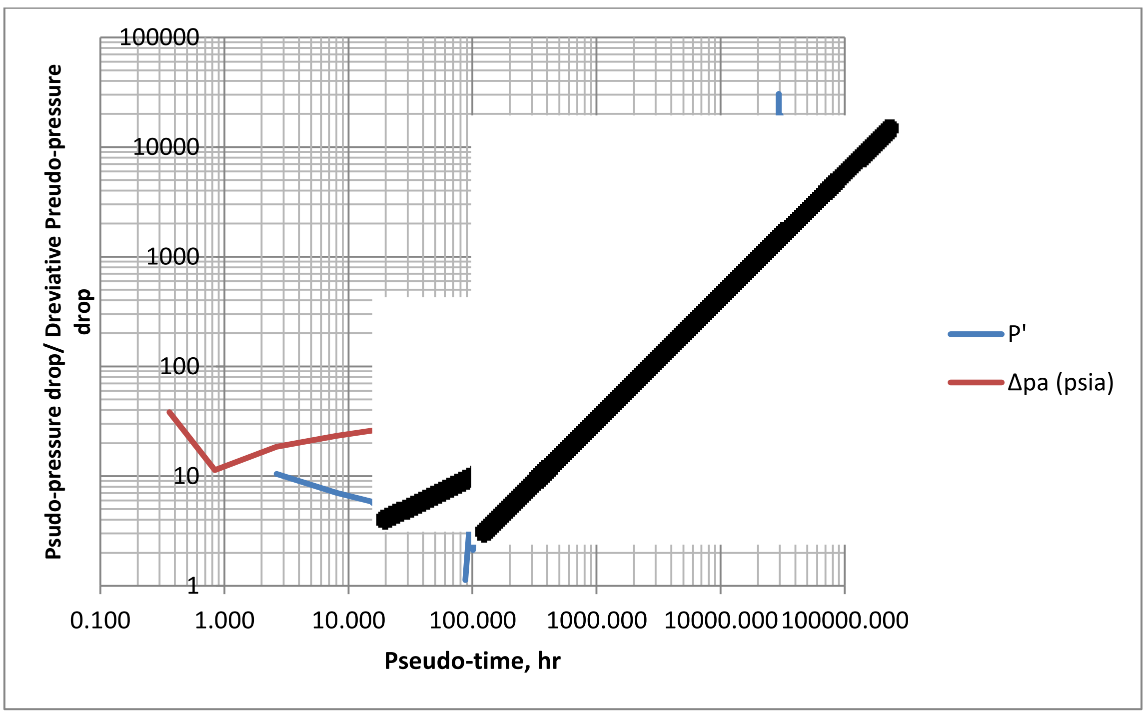

Figure 3 Example of Greengarten Graph

The slope of the early slope line indicated a slope of 0.56 this slope promotes a linear flow due to the hydraulic fracture domination, however the flow develops into boundary dominated flow with no obvious pseudo-radial flow region. Using this method the time to reach boundary was calculated.

By Using the Base case results of Pseudo-pressure vs time from Ozkan (2010) paper and comparing the results with the Base model using the same reservoir parameters, the following graph was obtained.

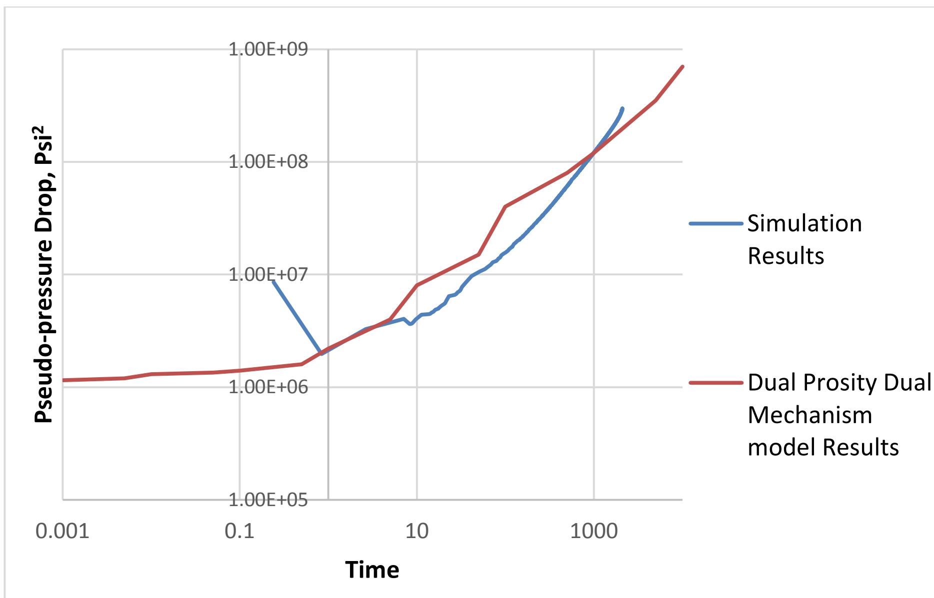

Figure 4 Model Validation Comparison

The model is matching the reference model, however there is a mismatch period of 4 hrs, this can be explained as the effect of the non-Darcy flow, since the Forchheimer coefficient value was not specified in the model parameters. However, since the non-Darcy flow is noticed as a skin factor it is expected to appear in the early time.

CHAPTER 4

RESULTS AND DISCUSSION

4.1 Research Results and Discussion

Shale gas reservoirs system consists of clays, kerogen (Oil Shale) and the gas in place. The gas in place is present as free and adsorbed gas, where the adsorbed gas is adsorbed on/in the kerogen for Barnett Shale (Schamel S., 2005).

Schamel has stated that Barnett Shale rocks are formed of 27% clay, 45% quartz, 10% carbonate, 5% feldspar, 5% pyrite and 5% organic matter (including mainly kerogen) and little to nonexistent free water.

For shale gas reservoirs the production is contributed to by the adsorbed and the free gas. The adsorbed gas tends to be released from the surface of the kerogen as the pressure of the reservoir drops.

By analyzing Chaohua G. et al. model, there are few assumptions which were found critical and need to be analyzed:

- Rock is incompressible and porosity is constant by assuming no rock deformation:

In dual porosity model, the fracture network permeability is critically dependent on the rock compressibility and the drop in pressure, therefore assuming incompressible rock will affect the results.

- Gas sorption and desorption follows Langmuir curve:

For a given system to follow Langmuir curve it needs to satisfy the assumptions of:

1. The surface containing the adsorbing sites is perfectly flat plane with no corrugations (assume the surface is homogeneous).
2. All sites are equivalent.

Shale reservoir system doesn't satisfy these assumptions therefore the results of the system are not anticipated to be accurate.

- Ideal gas behavior from the natural gas where Z=1.

However, this model counts for the adsorption, diffusive flow, Darcy flow and slippage effect.

Similarly the mathematical model presented by Kim T.H. et al. is analyzed this model was found to count for adsorption, Darcy, non-Darcy flow and slippage effect. Nonetheless this model was found to assume that the adsorption follows Langmuir curve by counting for diffusive flow as a mass accumulation term where matrix block is presented as a sink.

In Ozkan E. et al. 2010 the model was meant to count for the Darcy flow, slippage effect and Diffusive flow. However, this model relay on more accurate assumptions, since the model derivation depends on Fick's law of diffusion, Henry's law and Graham's law. Therefore the mathematical form of the model appears to be accurate.

However, this model doesn't count for the effect of desorption of gas from the kerogen surface, since the accurate modeling of effect require the knowledge about:

1. Volume and Maturity of the organic origin
2. Langmuir Isotherms and the pressure profile
3. Distribution of Kerogen
4. The exposed surface area of the nanopores in the shale matrix

Therefore, the effect was regarded but the author would recommend the incorporation of the effect to future models provided the presence of an accurate modeling.

The disregarding of desorption effect was investigated to affect the production prediction as stated by several literatures. However, an accurate method of modeling is required in order to model the effect reliably.

Nonetheless, this model counts for the change in fracture permeability with the change in pressure by mentioned the term stress dependent permeability.

By combining this mathematical model with the hydraulic fracture model (Trilinear-Model) created by Brown M. it is possible to create a model that counts for hydraulic fractures, non-Darcy flow represented as flow convergence skin factor.

As a comparison between the models we find that Ozkan, Brown is believed to be the most accurate and suitable model to use.

Model	Chaohua	Kim	Ozkan/Brown
Accuracy	Fair	Fair	High
Type of flow motions counted for	High	Fair	High
Clarity of the model	Fair	Fair	High
Clarity of the results	Fair	High	Fair

Table 2 Comparison Between Models

The model by Ozkan is presented as:

$$\frac{1}{R_D}\frac{\partial}{\partial R_D}\left(R_D\frac{\partial \bar{m}_{fD}}{\partial R_D}\right)-sf(s)\bar{m}_{fD}=0 \tag{5}$$

Where, $$f(s)=f(r_D=1,s)=1-\frac{\lambda}{5s}\left[1-\sqrt{\frac{15\omega}{\lambda}s}\coth\left(\sqrt{\frac{15\omega}{\lambda}s}\right)\right]$$

4.2 Model Development Parameters

During this study the model was created using CMG simulator. The Model was built as dual porosity model.

In this model, Fluid data was calculated using simple EOS, and empirical equations. The data is represented in the following table:

Pressure	Reduced Pressure	Reduced Temp.	Z factor	Formation factor	Formation factor	μ/μ1	Viscosity
Psia	_	_	_	*cf/scf*	*Rb/Mscf*	_	*cP*
14.7	0.021703532	1.675845035	1	1.094230769	194.8763614	1	0.0136
164.7	0.243168149	1.675845035	0.99	0.096686948	17.21940308	1.02	0.013872
514.7	0.75991892	1.675845035	0.96	0.030001524	5.34310319	1.05	0.01428
1014.7	1.498134308	1.675845035	0.92	0.014583992	2.597327202	1.1	0.01496
2517.4	3.716766835	1.675845035	0.885	0.005654801	1.007088275	1.5	0.0204
3014.7	4.45099586	1.675845035	0.9	0.004802028	0.855214204	1.75	0.0238
5014.7	7.403857412	1.675845035	0.95	0.003047228	0.542694157	2.1	0.02856
9000	13.28787698	1.675845035	1	0.001787244	0.318298057	3.145	0.042772
2300	3.395790784	1.675845035	0.85	0.005944528	1.058687015	1.35	0.01836

Table 3 Gas Properties

The Model main data was extracted from the Ozkan 2010 Paper, with the intention of using the results from the paper for validation of the model.

Specific gravity of gas, SG	0.55	Initial Fracture Permeability, md	2000
Molecular weight of gas, Ib_m/Ib_m-mol	16	Initial Fracture Porosity	0.45
Initial reservoir pressure, psi	2300	Initial Fracture compressibility, psi^{-1}	9E-4
Reservoir Temperature, F	109	Fracture Thickness, ft.	0.001
Formation Thickness, ft.	250	Number of fractures per net pay	20
Wellbore Radius, ft.	0.25	Hydraulic fracture porosity	0.38
Reservoir size perpendicular to well	500	Hydraulic fracture permeability, md	1E5
Initial Viscosity, cP	0.0184	Hydraulic fracture compressibility, Psi^{-1}	9E-4
Constant matrix permeability, md	1E-8	Hydraulic fracture half-length, ft.	250
Initial Matrix Compressibility, Psi^{-1}	9E-4	Hydraulic fracture width, ft.	0.01
Initial Matrix Porosity	0.05	Production rate, Mscf/D	200

Table 4 Reservoir Properties

4.3 Modeling Results and Discussion

4.3.1 The Effect of Fracture Spacing:

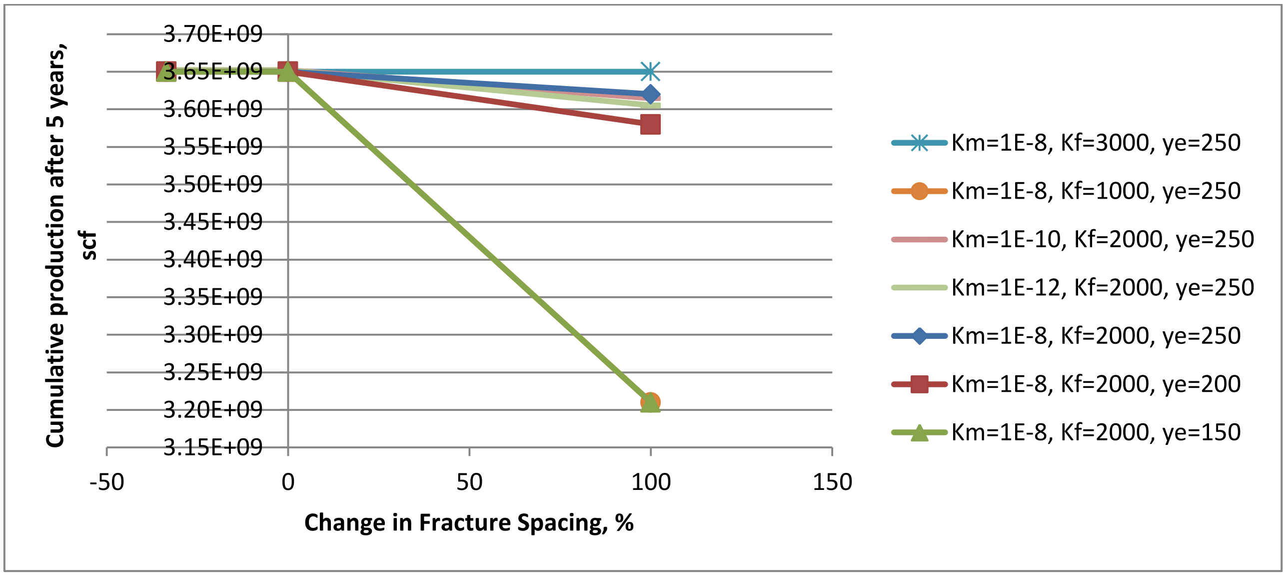

Figure 5 The Effect of Fracture Spacing on cumulative production at Different K_f, K_m and Y_e

This Graph shows the effect of Fracture Spacing on the cumulative production after 5 years, the graph shows the change in this effect as the matrix permeability, natural fracture permeability and hydraulic fracture half-length changes.

From the graph we can conclude that at fracture spacing equal to or less than 250 ft the production is not disturbed throughout the 5 years. However, when the fracture spacing rises to 500 ft. we can find a noticeable effect on the production.

The effect changes based on the case, as we can see the cumulative production as well as its sensitivity for fracture spacing are mostly affected by the drop in hydraulic fracture half-length and natural fracture permeability. Nonetheless the effective of the fracture permeability is clearly more significant than the matrix permeability.

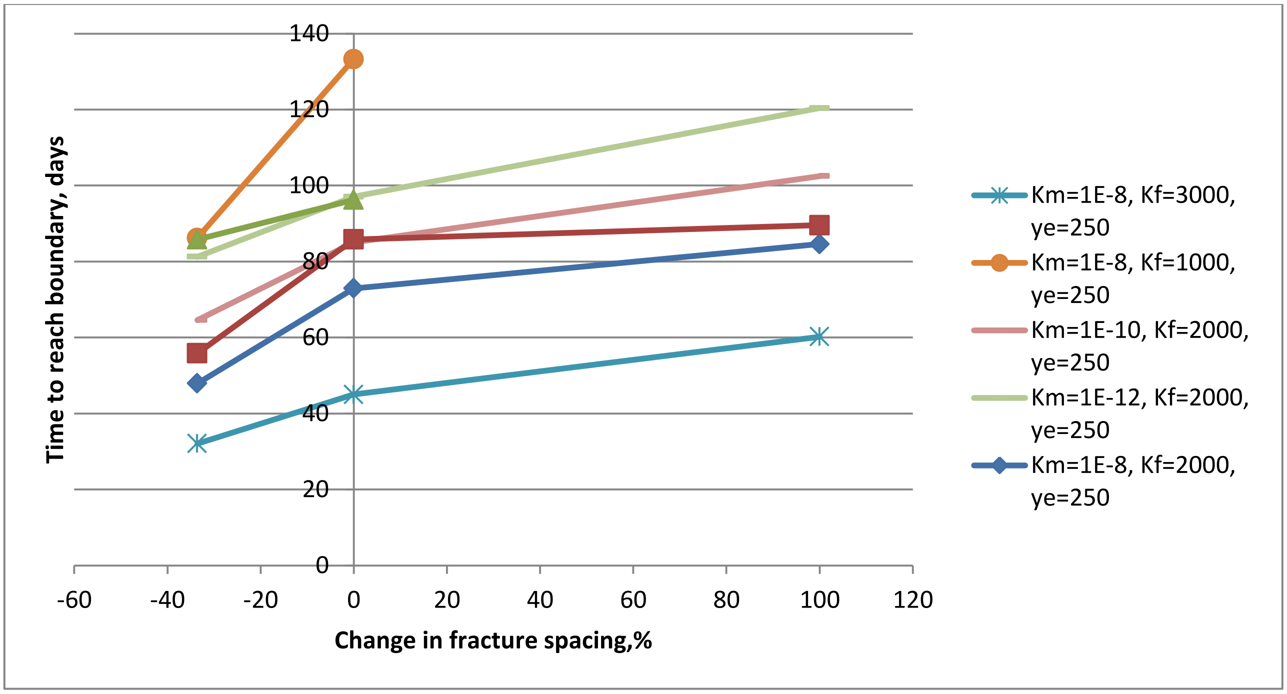

Figure 6 The effect of Fracture Spacing on time to reach boundary at different K_m, K_f, Y_e

It is shown in the graph that in general the sensitivity of the reservoir connectivity to the well represented in the time to reach the boundary dominated flow increases as the fracture spacing drops. Nonetheless it is clear that the boundary dominated flow is not clearly developed in some cases due to the low connectivity however those cases are discovered to suffer from disturbed production.

It is also clear that the connectivity is most sensitive to the hydraulic fracture half-length, and more sensitive to fracture permeability than matrix permeability. Nevertheless it can be shown that the sensitivity for fracture spacing increases as the fracture permeability and hydraulic fracture half-length decreases.

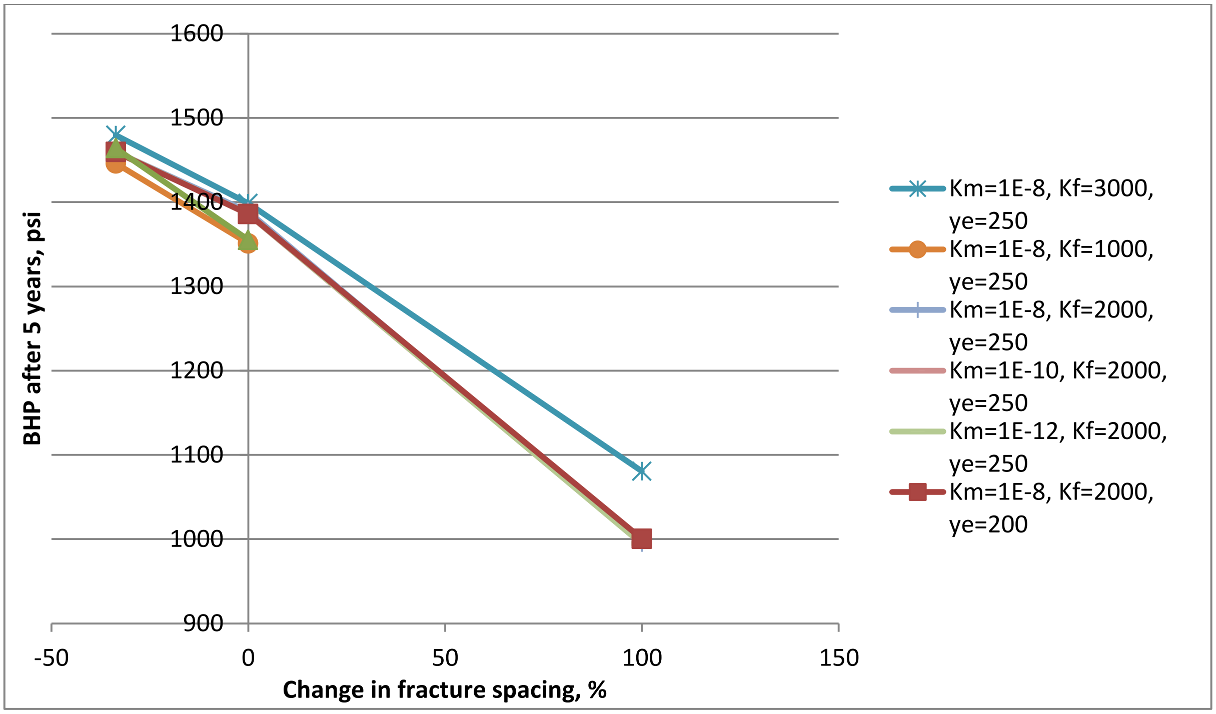

Figure 7 The effect of Fracture Spacing on BHP after 5 years at different Km, Kf, Ye

From Figure 6, it is comprehended that the bottom-hole pressure is most sensitive to the fracture spacing. Similarly it is shown that the BHP is not affected by the change in the matrix permeability, however, it is affected by the fracture permeability and the fracture half-length.

4.3.2 The Effect of Fracture Half-Length

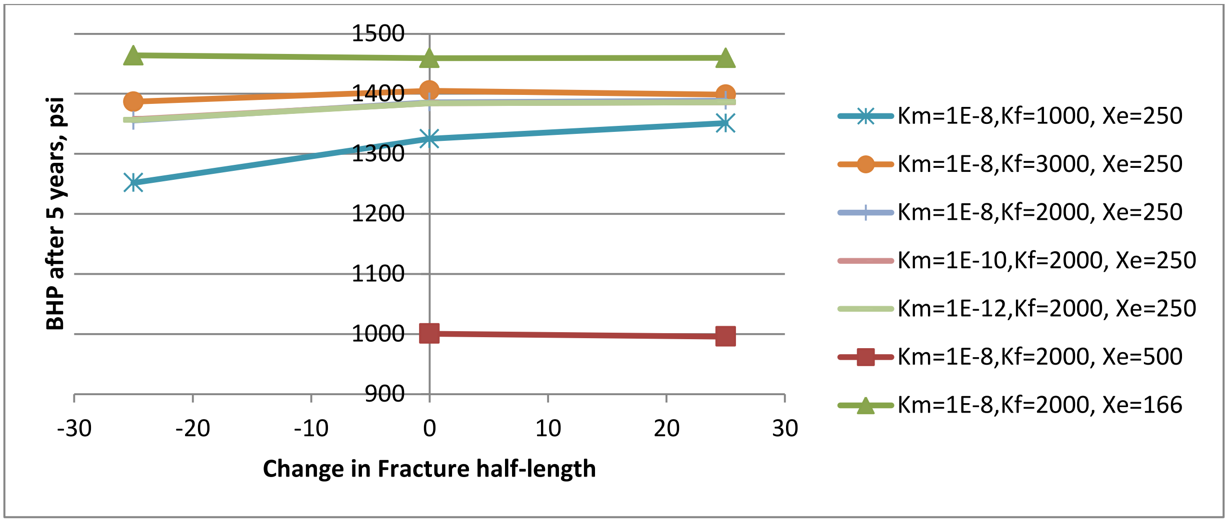

Figure 8 The effect of Fracture half-length on BHP after 5 years at different Km, Kf, Xe

The figure confirms the high sensitivity of BHP for the fracture spacing and the moderate sensitivity for natural fracture permeability and fracture half length, the graph also shows that the sensitivity of BHP for the fracture half-length increases as the natural fracture permeability decreases

Nevertheless, the graph shows that at fracture half-length higher than 200 ft the sensitivity of the BHP to the half-length vanishes.

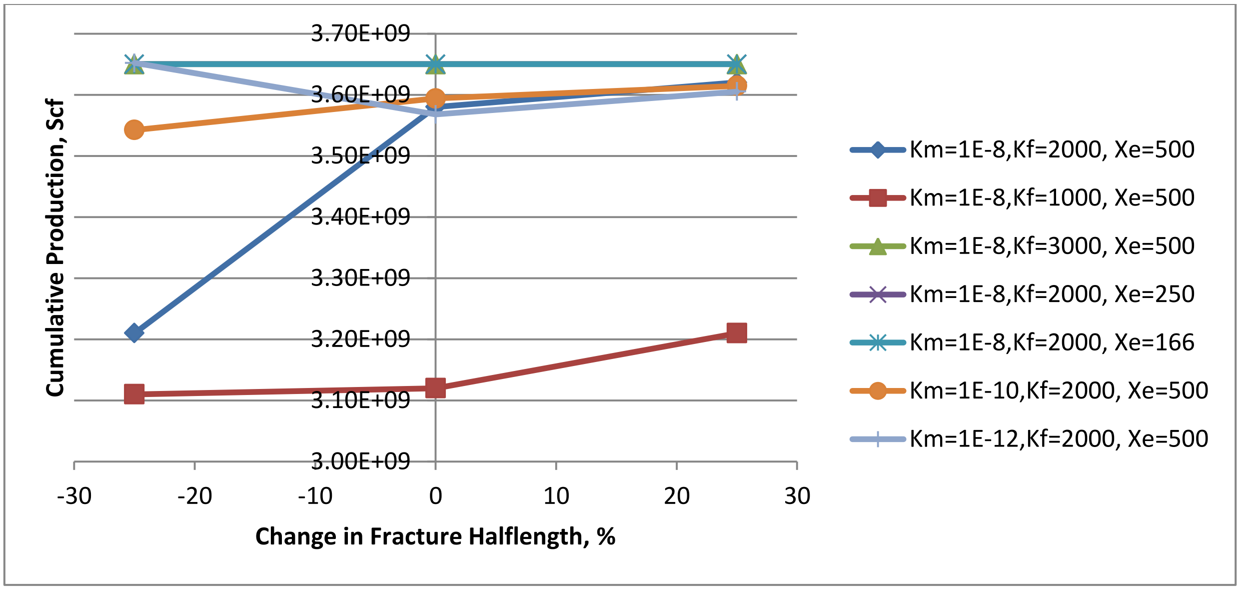

Figure 9 The effect of fracture half-length on the cumulative production at different Km, Kf, Xe

This graph aims to show the effect of the fracture half-length at high fracture spacing. It is clear that the sensitivity of the fracture half-length alters from the zone of 150-200 ft. to the zone of 200-250 ft. as the fracture permeability drops.

4.4 General Discussion of results

The graphs explained above are pointing to few interesting facts regarding the design of the fracture parameters in shale gas reservoirs.

Firstly, it shows that the effect of matrix permeability effect is negligible on the reservoir connectivity and internal energy; however the matrix permeability effect slightly increases as the fracture permeability drops. This can be related to the low matrix permeability and to the dual porosity modeling assumption of no flow between matrices blocks.

Second, the sensitivity of the connectivity of the reservoir is higher for the half-length, fracture permeability that it is for the fracture spacing. Contrarily, the reservoir energy represented in the BHP after 5years is more sensitive for the fracture spacing. This indicates that the fracture half-length enhances the extent of the well drainage area, however the fracture spacing enhances the quality of connectivity throughout the drainage area.

This section has figured that depending on the natural fracture permeability and the matrix permeability a balance should be obtained between the fracture half-length and the fracture spacing to reach the optimum design parameter, it also shows that the fracture spacing decrease is more effective into a certain extent. Similarly, depending on the designed drainage area the fracture half-length increase is more effective into a certain extent.

5. Conclusion and Recommendations

By modeling the Shale gas reservoirs there are some parameters that showed be addressed that affect the flow behavior is such reservoirs. These parameters are Diffusive flow, Slippage effect, Non-Darcy flow, Adsorption and stress dependent permeability of natural fractures.

In hydraulically fractured Shale reservoirs, the flow behavior tends to stay linear flow for the well time without reflecting a sign of pseudo-radial flow, due to the low permeability as the area outside the fracture zone appears to be idol and not supporting the drainage area.

The design of the fracture spacing and fracture half-length is dependent on the reservoir parameters where the fracture spacing is sensitive to the natural fracture permeability as well as the matrix permeability, while fracture half-length is insignificantly dependent on the matrix permeability.

In the process of Hydraulic fracture design, it is vital to consider the economics of the fracture parameters and hence reach to the optimum effective parameters due to the decreased sensitivity with the parameters enhancement increase.

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Appendices

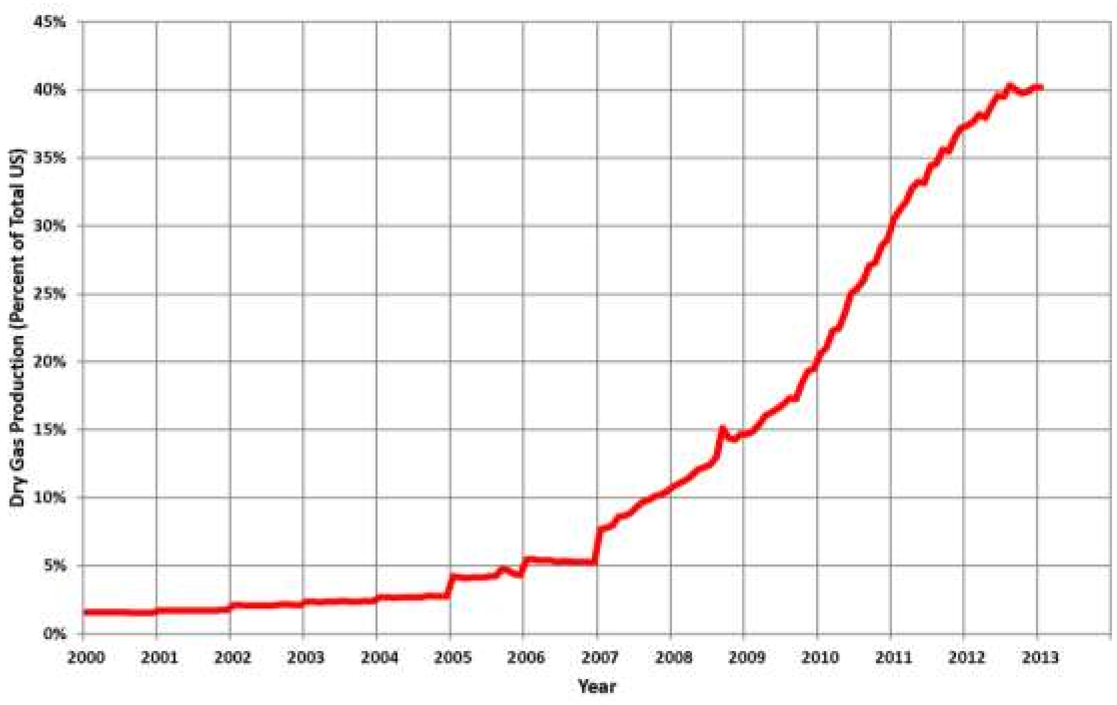

Figure 10 Percent of US Natural Gas Production from shale, 2000-2013 (Wikipedia, 2014)

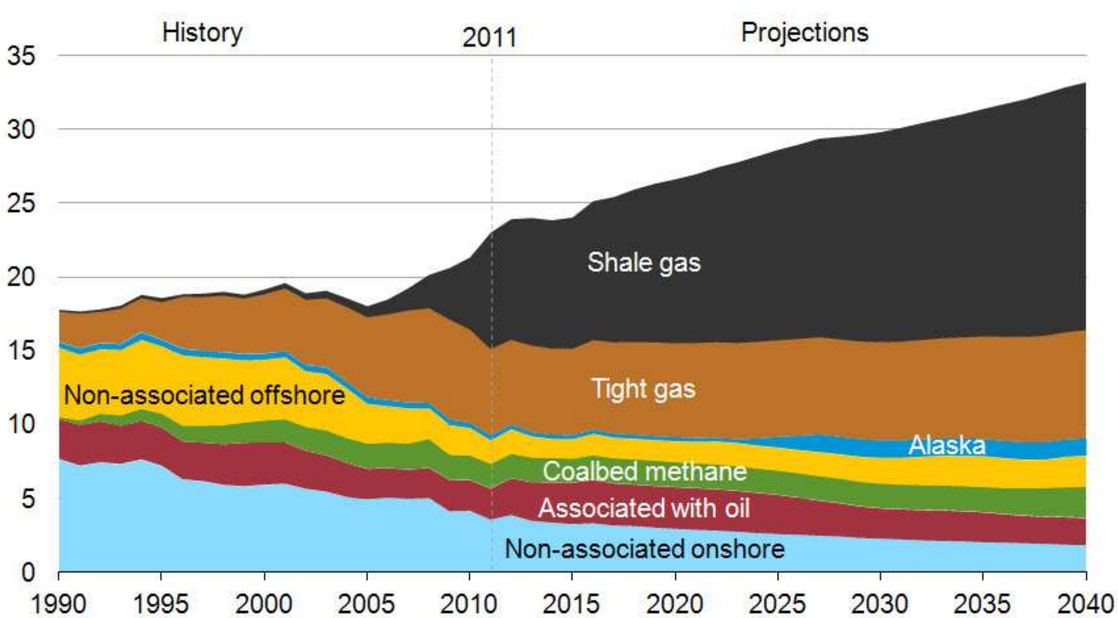

Figure 11 US Dry Natural Gas Production in Trillion cf (Wikipedia, 2014)

Rank	Country	Shale gas (trillion cubic feet)	
1	China	1,115	
2	Argentina	802	
3	Algeria	707	
4	U.S.[1]	665	(1,161)
5	Canada	573	
6	Mexico	545	
7	Australia	437	
8	South Africa	390	
9	Russia	285	
10	Brazil	245	
	World Total	**7,299**	**(7,795)**

Figure 12 Top 10 Countries with Technically Recoverable Shale Gas Resources (EIA, 2014)

Trilinear Model combined with Dual Porosity-Dual Mechanism Model

$$\bar{m}_{wD} = \frac{\pi}{C_{FD} s \sqrt{\alpha_F} \tanh\left(\sqrt{\alpha_F}\right)} + S_{C'}$$

$$C_{FD} = \frac{k_F w_F}{\tilde{k}_I x_F}$$

$$\alpha_F = \frac{2\beta_F}{C_{FD}} + \frac{s}{\eta_{FD}}$$

$$\eta_{FD} = \frac{\eta_F}{\eta_I}$$

$$\beta_F = \sqrt{\alpha_R} \tanh\left[\sqrt{\alpha_R}\left(y_{eD} - w_{FD}/2\right)\right]$$

$$\alpha_R = \frac{\beta_R}{C_{RD} y_{eD}} + u$$

$$C_{RD} = \frac{\tilde{k}_I x_F}{k_O y_e}$$

$$\beta_R = \sqrt{s/\eta_{RD}} \tanh\left[\sqrt{s/\eta_{RD}}\left(x_{eD} - 1\right)\right]$$

$$\eta_{RD} = \frac{\eta_O}{\eta_I}$$

$$\eta_\xi = \frac{k_\xi}{(\phi c_t)_\xi \mu}$$

$$u = sf(s)$$

$$f(s) = f(r_D = 1, s) = 1 - \frac{\lambda}{5s}\left[1 - \sqrt{\frac{15\omega}{\lambda} s} \coth\left(\sqrt{\frac{15\omega}{\lambda} s}\right)\right]$$

$$k_{am} = k_m \left(1 + \frac{b_{am}}{p_m} \right)$$

$$s_c = \frac{k_I h}{k_F w_F} \left[\ln\left(\frac{h}{2r_w} \right) - \frac{\pi}{2} \right].$$

$$b_{am} = \frac{D_g \mu_g c_g p_m}{k_m}$$

$$k_f = k_{fi} \exp\left[-d_f \left(p_{fi} - p_f \right) \right] = k_{fi} e^{-d_f \Delta p_f}$$

$$\omega = \frac{(\phi c_t)_{mi} V_m}{(\phi c_t)_{fi} \left(V_f / 2 \right)} = \frac{(\phi c_t)_{mi} (4/3) \pi r_m^3}{(\phi c_t)_{fi} 4\pi r_m^2 \left(h_f / 2 \right)} = \frac{2 (\phi c_t)_{mi} r_m}{3 (\phi c_t)_{fi} h_f}$$

$$\lambda = \sigma L^2 \left[\frac{k_{ami} V_m}{k_{fi} \left(V_f / 2 \right)} \right] = \sigma L^2 \left[\frac{k_{ami} (4/3) \pi r_m^3}{k_{fi} 4\pi r_m^2 \left(h_f / 2 \right)} \right] = \sigma L^2 \left(\frac{2 k_{ami} r_m}{3 k_{fi} h_f} \right)$$