

**NUMERICAL SIMULATION OF  
PRESSURE TRANSIENT  
PERFORMANCES IN TIGHT  
FORMATION AND PRODUCTION  
DECLINE ANALYSIS**

A Thesis

Submitted to the Faculty of Graduate Studies and Research

in Partial Fulfillment of the Requirements

for the Degree of

Master of Applied Science

in

Petroleum Systems Engineering

University of Regina

By

Yue Zhu

Regina, Saskatchewan

July, 2015

Copyright 2015: Yue Zhu

**UNIVERSITY OF REGINA**  
**FACULTY OF GRADUATE STUDIES AND RESEARCH**  
**SUPERVISORY AND EXAMINING COMMITTEE**

Yue Zhu, candidate for the degree of Master of Applied Science in Petroleum Systems Engineering, has presented a thesis titled, ***Numerical Simulation of pressure Transient Analysis in Tight Formation and Field Data Categorization and Typical Well Production Data Analysis***, in an oral examination held on May 8, 2015. The following committee members have found the thesis acceptable in form and content, and that the candidate demonstrated satisfactory knowledge of the subject material.

External Examiner:	Dr. Hairuo Qing, Department of Geology
Co-Supervisor:	Dr. Gang Zhao, Petroleum Systems Engineering
Committee Member:	Dr. Amy Veawab, Environmental Systems Engineering
Committee Member:	Dr. Fanhua Zeng, Petroleum Systems Engineering
Chair of Defense:	Dr. Rene Mayorga, Industrial Systems Engineering

## **ABSTRACT**

Low to ultra-low permeability tight oil reservoirs have recently become a significant source of hydrocarbon supply in North America. Production and pressure transient analysis of tight oil reservoirs is one of the most difficult problems facing a reservoir researcher because of the extreme complexity inherent in tight formations, such as producing from multiple layers with effective permeability that is often enhanced by hydraulic fracturing. Unfortunately, limited productivity and unfavorable economics often prevent expenditures of money and time to collect the dynamic data needed for a comprehensive reservoir study. Horizontal well completion along with multi-stage hydraulic fracturing techniques has enabled economic production from these kinds of reservoirs. To produce oil and gas commercially from tight formations, naturally completed (open-holed) or cased horizontal wells with multi-stage hydraulic fractures are the most popular implementation for completion. The use of a combination of the multi-fractured horizontal wells is expected to create a complex sequence of flow regimes (Chen and Raghavan, 1997; Clarkson and Pederson, 2010). The proper analysis and identification of presence of flow regimes and sequence of emerging flow regimes are essential for obtaining efficient information about hydraulic fracturing optimization and the tight formation characterization.

This thesis provides a detailed discussion of diagnostic plots of pressure and its corresponding derivative responses for hydraulically fractured horizontal wells in a sizable naturally fractured and homogeneous (single-porosity) formation and provides

type-curve matching performance among different existing empirical rate-time relations and compared with simulation results based on the targeted Bakken and Viking Formation in Western Saskatchewan. We consider a naturally-completed (open-hole) and cased horizontal well with either single longitudinal or multiple transverse hydraulic fractures which are normal in the horizontal wellbore, and which might be surrounded by an area with natural fracture system which is simulated by dual-porosity idealization. The discussion is based on pressure-transient performances and characteristics of production data generated by employing a commercial reservoir simulator, CMG IMEX, a 3D finite-difference reservoir simulation package which is widely and popularly accepted by petroleum industry. Pressure transient features are discussed and compared. As noted by many findings, it is shown that fully-filled and regional natural fractures would display various pressure transient characteristics and, hence, considerably affects well production performance. In addition, these conductive, interconnected natural fractures dominate the pressure transient performances of horizontal wells in tight formations even with the presence of hydraulic fractures. Additionally, the simulation runs also indicate that if the reservoir is naturally fractured to some extent, hydraulic fracturing stimulation might not improve productivity significantly, unless a large amount of hydraulic fractures and infinite conductivities can be achieved. To demonstrate the feasibility and applicability of simulation models, there is no representative contrast between the simulated pressure transient responses and the corresponding analytical results from the widely-accepted west test model, Kappa. The comparison discussion would be based on the matching performances of a horizontal well with transverse fractures in a homogeneous reservoir. Field case studies are also provided for type-curve fitting and predicting EUR estimation.

## ACKNOWLEDGEMENTS

First and foremost I'd like to offer my sincerest gratitude to my dearest supervisor, Dr. Gang Zhao, who has supported me every step of the way with his patience and profession whilst allowing me to work in my own way. I attribute the level of my Master's degree to his encouragement and effort and without him this thesis, too, would not have been completed or written. One simply could not wish for an excellent or friendlier supervisor.

In my daily work I have been blessed with a friendly and cheerful group of fellow students. Lei Xiao, as well as the PhDs from our department, has provided good arguments about well testing theory and helped me regain some sort of fitness: healthy body, healthy mind. Mark Anthony amused me with his dry wit and a great no-nonsense Christmas shindig (and did a good job of trying to kill me with snakebite and black). Wanju Yuan was a good companion on an otherwise exhausting and disappointing course in simulation and was my lifelong friend. Meng Wu helped me get on the road to using CMG and provided not only an experienced ear for hearing my doubts about writing a thesis, but a heart full of loving care and tenderness. Di Lu has fascinated me with his ability to break computer systems but has also given me detailed explanations on mathematical theory and some good laughs.

The Department of petroleum engineering provided the support and equipment I needed to produce and complete my thesis. I gratefully acknowledge the Faculty of Graduate Studies and Research at the University of Regina and the Petroleum Technology Research Centre for financial support in the form of scholarships.

## **DEDICATION**

I dedicate my work to all those who have lovingly supported me throughout my life and all its travails.

Especially, I would like to thank my parents for their support with my studies and meticulous loving care with my life. I'm so honored to have you both as my parents; thank you for giving me a chance to prove and improve myself through all my walks of life. Please do not change. I love you!

## TABLE OF CONTENTS

<b>ABSTRACT.....</b>	<b>I</b>
<b>ACKNOWLEDGEMENTS .....</b>	<b>III</b>
<b>DEDICATION.....</b>	<b>IV</b>
<b>TABLE OF CONTENTS .....</b>	<b>V</b>
<b>LIST OF TABLES .....</b>	<b>VIII</b>
<b>LIST OF FIGURES .....</b>	<b>IX</b>
<b>NOMENCLATURE.....</b>	<b>XV</b>
<b>CHAPTER 1 INTRODUCTION.....</b>	<b>1</b>
1.1 Motivation.....	2
1.2 Objective of this study .....	4
<b>CHAPTER 2 LITERATURE REVIEW .....</b>	<b>6</b>
2.1 Introduction.....	6
2.2 Numerical modeling of multistage hydraulically-fractured horizontal wells in naturally-fractured reservoirs.....	7
2.3 Pressure transient and production data analysis.....	11
2.4 Flow regimes for fractured horizontal wells in tight formation.....	16
2.5 History matching and type-curve fitting methods .....	19
<b>CHAPTER 3 NUMERICAL SIMULATION OF PRESSURE TRANSIENT PERFORMANCE FOR IN A TIGHT RESERVOIR .....</b>	<b>21</b>

3.1	Introduction.....	21
3.2	Model development .....	21
3.3	Simulation model description and results.....	32
3.4	Identification of flow regimes and discussion of simulation results: .....	44
3.5	Sensitivity analysis.....	54
<b>CHAPTER 4 VALIDATION OF SIMULATION RESULTS AND</b>		
<b>COMPARISON BETWEEN ANALYTICAL AND NUMERICAL SOLUTIONS.. 59</b>		
4.1	Model description and assumption .....	59
4.2	Comparisons of pressure transient results between analytical solutions from Kappa and numerical results computed by CMG.....	61
4.3	Comparisons of pressure transient performance of horizontal wells in dual- porosity and triple-porosity reservoirs between the analytical model and CMG simulation.....	70
4.4	Summary of the comparisons between simulation performance and analytical solutions based on Kappa and semi-analytical models.....	85
<b>CHAPTER 5 FIELD DATA CATEGORIZATION AND PRODUCTION</b>		
<b>DATA ANALYSIS IN THE BAKKEN TIGHT FORMATION ..... 86</b>		
5.1	Introduction.....	86
5.2	General information about the target formation .....	88
5.3	Field data categorization.....	91
5.4	Comparison of empirical decline curve methods for Bakken Wells .....	98
5.5	numerically simulated production decline type-curves of horizontal wells with multiple hydraulic fractures in a homogeneous reservoir.....	113

5.6	Field case studies for wells from Dodsland Viking formation, Western Saskatchewan.....	122
<b>CHAPTER 6</b>	<b>CONCLUSIONS AND RECOMMENDATIONS.....</b>	<b>136</b>
6.1	Conclusions.....	136
6.2	Recommendations.....	137
<b>LIST OF REFERENCES</b> .....		<b>138</b>

## LIST OF TABLES

Table 3.1 — Reservoir and well input parameters for numerically simulated cases.....	29
Table 3.2 — Hydraulic fracture data .....	30
Table 3.3 — Dual-porosity data.....	31
Table 5.1 — Summary of history-matched results .....	133

## LIST OF FIGURES

Fig. 3.1 — Rectangular reservoir with a horizontal well (orange dotted line) which is located at the center of this reservoir. ....	24
Fig. 3.2 — Sketch for a horizontal well in the center of global, regional and homogeneous reservoirs.....	25
Fig. 3.3 — Sketch for a longitude fractured horizontal well in the center of global, regional and homogeneous reservoirs.....	26
Fig. 3.4 — Sketch for a horizontal well with multiple transverse hydraulic fractures in the center of a homogeneous reservoir .....	27
Fig. 3.5 — Sketch for a horizontal well with multiple transverse hydraulic fractures in the center of a globally and regionally naturally fractured reservoir.....	28
Fig. 3.6 — Dimensionless pressure and derivative responses for a horizontal wells in a homogeneous reservoir.....	33
Fig. 3.7 — Dimensionless pressure and derivative responses for longitudinal-fractured horizontal wells in a global, regional and homogeneous reservoir.....	34
Fig. 3.8 — Dimensionless pressure and derivative responses for open-holed horizontal wells with multiple transverse fractures in a homogeneous reservoir. ....	36
Fig. 3.9 — Dimensionless pressure and derivative responses for cased horizontal wells with multiple transverse hydraulic fracture in a homogeneous reservoir. ....	37
Fig. 3.10 — Dimensionless pressure and derivative responses for horizontal wells (cased and open-holed) with one transverse fracture in a homogeneous reservoir. ....	38

Fig. 3.11 — Dimensionless pressure and derivative responses for cased and open-holed horizontal wells with two transverse fractures in a homogeneous reservoir	39
Fig. 3.12 — Dimensionless pressure and derivative responses for open-holed horizontal wells with multiple transverse hydraulic fractures in a globally naturally fractured reservoir.....	40
Fig. 3.13 — Dimensionless pressure and derivative responses for open-holed horizontal wells with multi-transverse fractures in a regional naturally fractured reservoir. ....	41
Fig. 3.14 — Dimensionless pressure and derivative responses for cased horizontal wells with multi-transverse fractures in a globally naturally fractured reservoir..	42
Fig. 3.15 — Dimensionless pressure and its corresponding derivative responses for horizontal wells with one transverse and one longitudinal hydraulic fracture in a homogeneous reservoir. ....	43
Fig. 3.16 — Dimensionless pressure and derivative responses for horizontal wells with one transverse and longitudinal hydraulic fracture in a homogeneous reservoir .....	52
Fig. 3.17 — Dimensionless pressure and derivative responses for horizontal wells with one transverse and longitudinal fracture in a naturally fractured reservoir.	53
Fig. 3.18 — Effect of different matrix permeability( $K_m = 100, 1000, 10000\text{md}$ ) on dimensionless pressure drop and derivative responses for a horizontal well in a homogeneous reservoir .....	55
Fig. 3.19 — Effect of different hydraulic fracture conductivities ( $K_f = 100, 1000, 10000\text{md}$ ) on dimensionless pressure drop and derivative responses for a	

horizontal well with one transverse hydraulic fracture in a homogeneous reservoir .....	56
Fig. 3.20 — Effect of different hydraulic fracture conductivities ( $K_f = 100, 1000, 10000\text{md}$ ) on dimensionless pressure drop and derivative responses for a horizontal well with four transverse hydraulic fractures in a homogeneous reservoir .....	58
Fig. 4.1 — Contrastive plots of dimensionless pressure and its corresponding derivative responses for a single horizontal well in a homogeneous reservoir.....	62
Fig. 4.2 — Contrastive plots of dimensionless pressure and its corresponding derivative responses for a vertical well in a homogeneous reservoir .....	63
Fig. 4.3 — Contrastive plots of dimensionless pressure and derivative responses for a horizontal well with two transverse fractures in a homogeneous reservoir .	64
Fig. 4.4 — Contrastive plots of dimensionless pressure and derivative responses for a horizontal well with two transverse fractures in a homogeneous reservoir.	65
Fig. 4.5 — Contrastive plots of dimensionless pressure and derivative responses for a horizontal well in a naturally-fractured reservoir. ....	67
Fig. 4.6 — Contrastive plots of dimensionless pressure and its corresponding derivative responses for a horizontal well with two transverse fractures in a naturally fractured reservoir .....	68
Fig. 4.7 — Contrastive plots of dimensionless pressure and its corresponding derivative responses for a horizontal well with four transverse fractures in a naturally fractured reservoir.....	69
Fig. 4.8 — Idealization of the heterogeneous porous medium (Warren & Root, 1963)..	73

Fig. 4.9 — Contrastive plots of dimensionless pressure and derivative responses for a well in a dual-porosity cylindrical reservoir. ....	77
Fig. 4.10 — Top view of a horizontal well in a triple-porosity system. Red dotted lines indicate virtually no flow boundaries. Arrows indicate direction of the flow (Al-Ahmadi 2010).....	78
Fig. 4.11 — Top view of triple-porosity model generated by CMG simulation. ....	82
Fig. 4.12 — Contrastive plots of dimensionless pressure and its corresponding derivative responses for a horizontal well in a triple-porosity reservoir. ....	84
Fig. 5.1 — Geological location of Bakken formation in Williston Basin (From SPE 140252). ....	90
Fig. 5.2 — Type 1 log-log plot of oil production rate versus time. ....	94
Fig. 5.3 — Type 2 log-log plot of oil production rate versus time. ....	95
Fig. 5.4 — Type 3 log-log plot of oil production rate versus time. ....	96
Fig. 5.5 — Type 4 log-log plot of oil production rate versus time. ....	97
Fig. 5.6 — log-log plot of production history of four selected wells from type 1 to type 4, respectively. ....	100
Fig. 5.7 — log-log plot of matched performance for well (ID 191/01-33-006-09W2/00 (4414)) from type 1 using different empirical rate-time relations. ....	106
Fig. 5.8 — log-log plot of matched performance for well (ID 191/04-24-006-08W2/00 (4330)) from type 2 using different empirical rate-time relations. ....	107
Fig. 5.9 — log-log plot of matched performance for well (ID 191/14-09-010-07W2/00 (4414)) from type 3 using different empirical rate-time relations. ....	109

Fig. 5.10 — log-log plot of matched performance for well(ID 191/14-02-009-09W2/00 (4414)) from type 3 using different empirical rate-time relations. ....	111
Fig. 5.11 — log-log plot of historical production matched performance for well(ID 191/01-33-006-09W2/00 (4414)) from type 1 with simulation type-curves. ....	115
Fig. 5.12 — log-log plot of historical production matched performance for well (ID191/14-09-010-07W2/00 (4414)) from type 2 with simulation type-curves. ....	117
Fig. 5.13 — log-log plot of historical production matched performance for well (ID 191/14-09-010-07W2/00 (4414)) from type 3 with simulation type-curves ..... 118	118
Fig. 5.14 — log-log plot of historical production matched performance for well(ID 191/14-02-009-09W2/00 (4414)) from type 3 with simulation type-curves ..... 121	121
Fig. 5.15 — Viking Formation in Western Canada . ....	124
Fig. 5.16 — log-log plot of monthly oil production rate against material balance time for wells from Dodsland Viking Formation . ....	126
Fig. 5.17 — log-log plot of historical production matched performance for well 193/07-33-030-22W3/00 from Dodsland Viking Formation using different empirical rate-time relations . ....	130
Fig. 5.18 — log-log plot of historical production matched performance for well 193/07-33-030-22W3/00 from Dodsland Viking Formation with simulation type-curves . ....	131

Fig. 5.19 — Expected estimated ultimate recovery prediction results from five empirical  
decline analyses ..... 134

## NOMENCLATURE

$a$  = Constant

$b$  = Derivative of Decline rate

$C_t$  = Total compressibility, 1/KPa

$D$  = Decline rate

$L_h$  = Horizontal wellbore length, m

$r_w$  = Wellbore radius, m

$X_e$  = Reservoir size in X direction, m

$y_e$  = Reservoir size in y direction, m

exp = Exponential function

$h$  = Thickness of reservoir, m

$k$  = Permeability, md

$K_f$  = Natural fracture effective permeability, md

$K_m$  = Matrix permeability, md

$K_F$  = Hydraulic fracture effective permeability, md

$L_f$  = Fracture space, m

$m$  = Constant

$n$  = Constant

$P$  = Pressure, Psi

$P_d$  = Dimensionless Pressure

$dP_d/d\ln t_d$  = Dimensionless Pressure derivative responses

$P_{wf}$  = Bottomhole pressure, Psi

$P_i$  = Initial pressure, Psi

$q$  = Flux rate,  $m^3/s$

$q_D$  = Dimensionless Rate

$q_i$  = Initial flux rate,  $m^3/s$

$Q$  = Cumulative production rate,  $m^3$

$r_w$  = Inner wellbore Radius, m

SF = Source function

$t$  = Time, second

$w$  = Hydraulic fracture width, m

$X_f$  = Hydraulic fracture half-length, m

$x$  = Coordinate in x direction, m

$y$  = Coordinate in y direction, m

### **Greek Symbols**

$\alpha$  = Shape factor, fraction

$w$  = Fracture storability ratio, fraction

$\mu$  = Viscosity, Pa·s

$\tau$  = Time, second

$\phi_m$  = Matrix Porosity, fraction

$\phi_F$  = Hydraulic fracture Porosity, fraction

$\phi_f$  = Natural fracture Porosity, fraction

$\lambda$  = Inter-porosity flow parameter, fraction

### **Subscripts**

$F$  = Hydraulic fracture system

$f$  = Natural fracture system

$m$  = Matrix system

# **CHAPTER 1**

## **INTRODUCTION**

Reservoir characterization is a process of describing variations in rock and fluid properties related to the reservoir. Reservoir parameters found from pressure transient analysis (PTA) are then used to update geological models and to see if they are consistent with already known data. Pressure transient behavior of constant rate drawdown in a well is the main source used to identify a reservoir model. This is done by drilling a well and testing it following a well test procedure. In tight formations, when the matrix permeability is low and ultra-low, it is practical to use horizontal drilling in conjunction with hydraulic fracturing to accelerate recoverable reserves and improve exploration efficiency in a wide range of reservoir characteristics. Finding a way to perform pressure transient and production decline analysis for this kind of combination of exploration has become an significant problem among researchers. Estimation and identification of flow regimes and productivity measurements for horizontal wells are subject to more uncertainty and are more challenging than those in vertical wells. Our primary concern is how to use a more efficient and relatively accurate method to deal with these problems.

Unconventional reservoir systems such as tight oil and gas, shale oil/gas and coaled methane have been described as hydrocarbon accumulations which are very difficult to explore and operate by conventional development methods. There has been a great deal of interest in doing research to find feasible and applicable technologies for unconventional reservoir production; in such reservoirs a certain degree of heterogeneity

often exists so particular methods and solutions are needed to deal with this manifest phenomenon.

## 1.1 Motivation

Many methods for pressure and production transient analysis have come into use in recent years, but we need a comprehensive and systematic method to explain pressure and production transient behavior for horizontal wells and hydraulic fracturing. Many analytical solutions have been provided for the various models, such as a semi-analytical model generated by Medeiros et al. (2007), to account for transient pressure and production analysis of horizontal wells in a naturally fractured reservoir, because the ultra-low permeability causes a tremendously long period of transient flow. Pressure transient performance for a horizontal well with multiple transverse hydraulic fractures is controlled by a comprehensive set of parameters related to fractures, and numerical simulation modeling is used to investigate the pressure transient behaviors under the influence of open-holed or cased horizontal wells, hydraulic fractures in longitudinal and transverse directions, as well as different fracture properties. Furthermore, with the addition of natural fractures totally or regionally located in the reservoirs, these incorporating factors have made the numerical simulation performance more feasible and practical.

Flow regimes for horizontal wells with different numbers of hydraulic fractures are already being testified by many researchers: bilinear flow, early time linear flow, early radial flow, compound linear flow, late radial and ending up with boundary-dominated flow. The sequence of these flow regimes can be replaced and sometimes some flow regimes could not show up. There are so many factors that could be critical and

influential for these typical flow regimes, such as formation properties, reservoir structures and geometry, fracture configurations and conductivities, extension of hydraulic fractures and skin, etc. My motivation is to achieve the goal of making a persuasive and recognized simulation model that includes all these elements.

Furthermore, there has recently been growing interest in estimating pressure transient or flow rate data and to understand its flow behavior in tight reservoirs due to the difficulties in operating technologies and economic concerns. CMG is the most widely and extensively accepted engineering software which is convenient and user-friendly for reservoir engineers to handle and with the updated information and techniques they are getting involved in CMG's operation interface, such as flexible direct input parameters about hydraulic fractures, making this work possible and feasible.

To demonstrate the applicability and practicability of the pressure transient behavior simulated by CMG, comparisons have been made with analytical solutions generated by Kappa. Generally, naturally fractured reservoirs are described with a dual-porosity model to depict the heterogeneity of the reservoir, in order to compare the effectiveness of the dual-porosity model based on numerical solutions presented by CMG. The Warren and Root (1963) analytical solution of the dual-porosity model is used with a little adjustment in corresponding to the bounded reservoir with simulation results.

The main source of my motivation comes from that huge interest in exploring and developing tight oil reservoirs, as well as many other unconventional hydrocarbon resources, in the future. It is important to understand the flow behavior and well performance of unconventional reservoirs satisfying the energy demand. Production and

operation technology could be promoted with the advent of the exploration of future wells.

## 1.2 Objective of this study

The objective of this work was to develop a relatively comprehensive discussion on pressure transient performances for transverse or longitudinal-fractured horizontal wells hydraulic fractures in a naturally fractured reservoir in which the size of the natural fractures can be totally filled by the reservoirs or located around the near wellbore region. Based on the studies of pressure transient behaviors generated by the most widely-accepted commercial software numerical simulator, intensive comparisons of these performances have been made with Kappa, another popular and robust well testing tool. Additional comparisons have also been made with analytical solutions of the dual-porosity model developed by Warren and Root (1963) and a triple-porosity model generated by Al-Ahmadi (2010) to further demonstrate the heterogeneity and fracture properties of naturally fractured reservoirs. Most importantly, the final type-curve fitting performance and comparisons with other empirical analytical models for production decline analysis based on the trustworthy simulation approaches are presented.

This thesis is separated into total six parts. The organization and scope of my work is arranged in following way:

Chapter 1 is a general introduction of this thesis and is made up of motivation, objectives and an outline of the six parts.

Chapter 2 is a literature review that covers pressure transient and production data performance, history matching techniques, numerical modeling of horizontal wells in naturally fractured reservoirs and ways of identifying flow regimes.

In Chapter 3, a detailed discussion of pressure transient performances for horizontal wells with or without hydraulic fractures in sizable naturally fractured reservoirs are presented. Different flow regimes based on different cases are discussed and the effect of fracture properties is demonstrated.

In Chapter 4, detailed comparisons of pressure transient behaviors are made between numerical simulations and analytical solutions including cases for horizontal wells with transverse hydraulic fractures in a homogeneous or naturally fractured reservoir. Dual-porosity and triple-porosity models are compared through the use of numerical simulation and analytical models.

Chapter 5 describes the history matching performance of four recently developed empirical production decline models with actual field production rates from the Bakken and Viking formations respectively, which are compared with numerically generated production type-curves for horizontal wells with multi-staged hydraulic fractures.

Chapter 6 presents the conclusions and recommendations.

## **CHAPTER 2**

### **LITERATURE REVIEW**

#### **2.1 Introduction**

Economic extraction of hydrocarbon in unconventional reservoirs has been of great interest in recent years. A long horizontal lateral is intersected with multi-staged hydraulic fractures in tight reservoirs; due to the nature of the significantly low to ultra-low matrix permeability, transient flow regimes are the featured flow periods and sometimes even extend over the whole production life. The estimation of the pressure transient performance of a horizontal well is of considerable importance under the influence of complex hydraulic fracture distribution and it is critical to understand the pressure dynamic forecasting for such tight horizontal wells in both investigating reservoir drive mechanisms and fracture parameters, as well as to provide an insightful tool for the future interpretation of long-time tight oil production.

In order to provide a comprehensive set of numerical simulation models to understand the pressure transient behaviors of a horizontal well with multiple hydraulic fractures, a thorough literature review should be undertaken. Building a numerical simulation model with the influence of fracture parameters such as fracture spacing and numbers of fractures is my intention. The most important characteristics of the pressure transient type-curves based on different reservoir and fracture properties plus identifications of flow regimes of these type-curves are foundations for comparisons with analytical models. My primary object is to investigate and compare the difference in the presence of

pressure transient analysis and the accuracy of reorganization of flow regimes behind the numerical and analytical solutions. Hydraulically fracturing stimulation is extensively applied to increase the productivity around the wellbore, especially for tight formations. A type-curve format featuring stimulated reservoir region (SRV) (Gray Zhao, 2012) has shown that horizontal wellbore configuration is strongly related to the fracture influenced/dominated boundary flow regime.

Production decline analysis based on field production data is another part in this chapter, because, since pressure and production transient estimation share the same governing theory, production type-curves generated by CMG are used for curve fitting and history matching with production rates extracted from the Bakken and Viking formation. Both production decline characteristics could be used as diagnostic plots for identification of flow regimes.

## 2.2 Numerical modeling of multistage hydraulically-fractured horizontal wells in naturally-fractured reservoirs

### **2.2.1 Interpretation of naturally fractured reservoirs using dual-porosity and triple-porosity models**

As mentioned above, natural fractures rejuvenated during the hydraulic fracturing application complicate the analysis of pressure transient characteristics; because of the presence of two distinct porous media, the assumption of single-porosity reservoirs is no longer reasonable. There are two types of media existing in the system; they have different storage and conductivity properties so dual-porosity models are usually used to describe naturally-fractured reservoirs in which a rock matrix system is composed of natural fractures. Actually, these natural fractures are irregularly connected and

distributed underground, so approaching a true reflection in the numerical modeling of these underground fracture networks is not attainable without the assistance of seismic-mapping and other subsidiary information. Fortunately, it has been observed that a real naturally fractured reservoir has a characteristic and within a certain range of heterogeneity it can be described and interpreted by using a dual-porosity model.

Warren and Root (1963) first developed and presented the analytical solution of a dual-porosity model for analyzing a naturally fractured reservoir. The matrix has higher fluid storability relative to fracture and fracture has significantly larger value on permeability than the matrix; the production of hydrocarbons is highly dependent on the interactions between the matrix and fracture system with the assumption of pseudo-steady state flow. The composition of the matrix and fractures is idealized as a simple sugar cube sketch. Since then, several approaches have been provided as extensions of Warren and Root (1963) with the assumption that the fluid flow between the matrix blocks and fracture system is governed by an unsteady-state (transient) flow (Kazemi 1968; deSwaan 1975; Ozkan et al. 1987). A slab dual-porosity model was proposed by Kazemi (1969) with the development of a new shape factor for rectangular geometry by his simulator using numerical solutions of the finite difference method to account for the transient fluid flow between two different media. Other analytical models (Jalali and Ershaghi 1987) and semi-analytical models (Al-Fhamdi and Efshaghi 1996; Bui et al. 2000) have been developed to explain the naturally fractured reservoirs. The natural fracture forms a flow pathway connected directly to the wellbore as a feeding source and the matrix behaves like the storage of hydrocarbon in which flow can only be transferred into fractures.

By actualizing the real complex fracture systems into realization, triple-porosity models are considered by many researchers featuring different matrix or fracture properties instead of the uniform fracture features for the dual-porosity model. The first triple-porosity model featuring radial flow of a slightly compressible fluid under pseudo-steady assumption for the matrix and fracture transfer function was presented by Liu (1981, 1983) with two matrix systems and only one fracture. This method has never published in the petroleum industry literature and is rarely used. The other triple-porosity models with two matrix systems discussed in the petroleum literature were introduced by Abdassan and Ershaghi (1986) featuring two geometrical configurations by using the unsteady-state flow transfer function for radial flow. After that, Jalali and Ershaghi (1987) extended their predecessors' work to demonstrate the variances of matrix properties and under different matrix–fracture transfer functions. When it comes to the most popular dual-fracture triple-porosity model, the very first engineers to introduce that model for radial systems were Al-Ghamdi and Ershaghi (1996), in which two fracture systems own two types of fracture characteristics. After that, more triple-porosity models were introduced into the petroleum industry, such as a radial triple-continuum model provided by Liu (2003), an updated triple-continuum model developed by Wu (2004) and the Dreier's (2004) triple-porosity dual fracture model. The differences between all these models are related to the various assumptions on flow mechanisms and fracture properties under different combinations of fluid transfer among these media.

### **2.2.2 Modeling of horizontal wells with transverse hydraulic fractures in a homogeneous or naturally fractured reservoir**

Pressure transient flow features of horizontal wells are complicated, configuring the wellbore and tight formation system, with the addition of hydraulic fractures and multiple flow regimes induced by this complex system. Many researchers have spent much time on investigating pressure transient performance with more accuracy in estimating the flow regimes and time-efficiency of simulating pressure dynamic mechanisms.

The most basic models of pressure transient analysis for a horizontal well with transverse hydraulic fractures have developed since 1990s. Larsen and Herge (1991 and 1994) were the first to provide pressure transient behavior of a horizontal well completed with multiple fractures and corresponding multiple flow regimes, as well as its analytical solutions. At that time, the development of unconventional reservoirs was not as prosperous as nowadays, so it was published without attracting any attention and had very little application. The extensive proliferation of the development of unconventional reservoirs has relinked this model for production transient analysis and in recent publications in the petroleum literature (Al-Kobaisi et al. 2006, for instance), in which the flow regimes and the corresponding solutions for each flow period are summarized. This model used a simple reservoir and well configurations with transverse hydraulic fractures fully penetrating the total thickness of the reservoir, and the number of stages represents the same number of stimulated fractures.

Based on that model, Raghavan et al. (1997) studied the influence of fracture properties on pressure transient behavior like fracture spacing, numbers of fractures and direction of fractures in conventional reservoirs with high permeability. A more complex

model developed by Medeiros et al. (2008) discussed pressure and pressure derivative responses in a tight gas reservoir under the effect of matrix permeabilities (from 0.01 md to 0.001 md) and well spacing. Furthermore, they also provided the analysis for the flow regimes of inner naturally fractured regions featured with the dual-porosity model around the hydraulic fracture –wellbore system as well as the impact of different fracture spacing on the recognition of flow regimes. Later on, based on the work of Medeiros (2008), Ozkan et al. (2009) introduced a reservoir model with natural fractures surrounding each hydraulic fracture with dual-porosity idealization and a single porosity zone extending beyond the stimulation area.

More complex models are simulated to account for the influence of fracture heterogeneity, such as multiple fractures with different half-lengths and permeability for different fracturing stages and considering the complicated connection of reopening natural fractures with wellbore controlling the fluid flow in unconventional reservoirs (Apiwathanasorn and Ehlig-Economides, 2012). Seismic-mapping would help in the identification of the fracture system connections, taking the seismic images into the analysis of production and pressure transient analysis. Most importantly, Gary Zhao (2014) recently presented type curves which is the mainly source and my work origin under various conditions considering different fracture/wellbore combination and reveal factors hindering the realization of the correct SRV value of hydraulically fractured horizontal wells in tight formations Zhao, G., Xiao, L. 2014).

### 2.3 Pressure transient and production data analysis

Pressure transient and production data analysis are two major parts of well test analysis which aim at providing and describing spatial differences in rock and fluid

features connected with reservoirs. It can provide viable information related to flow rates, permeability, formation heterogeneity, completion and production efficiency and drawdown pressure with a combination of implementation, technology and the right methods. Having reservoir parameters evaluated from pressure and production transient analysis is helpful in completing reservoir geological models and better comprehending reservoir heterogeneities. And these are two indispensable and cost-effective tools that almost all reservoir engineers use for characterization of any kind of reservoir system, which would be impossible without them.

### **2.3.1 Pressure transient analysis for hydraulically fractured horizontal wells**

Pressure transient analysis is aimed at testing pressure changes with times to provide a context of in-situ reservoir characteristics of hydrocarbon formations; it has received a tremendous amount of attention in the past decades. Modern pressure transient analysis is based on interpreting the pressure derivative shape to identify the reservoir and well properties within the well drainage area, in order to predict the well's future performance. It has become a powerful well test tool for identifying reservoir characterization and detailed geology since the development of the first derivative responses were provided in 1983.

Horizontal well production or multistage popped hydraulic fractured horizontal wells are credited with the development of tight sand reservoirs in increasing the productivity and ultimate recovery. Both expected flow regime shapes share the same linear flow behavior through pressure derivative responses and these techniques change the flow geometry around the wellbore. Adding the effect of hydraulic fractures, or even having a complex natural fracture network, would complicate the flow regimes and the freedom of

the interpretation of fluid behavior. Many researchers have done some work on the investigation of pressure transient flow for explaining the pressure performance of the complexity induced by the configuration of fractured well reservoir systems. For example, Chen (2011) discussed the pressure transient performance of a fractured horizontal well in a shale gas well with the use of a numerical simulation model to consider the effect of various factors, such as conductivity of fractures, well spacing and matrix permeability. Sung Jun Lee (2013) presented a comprehensive reservoir simulation for pressure transient characteristics of hydraulically fractured horizontal wells with consideration of the nonlinear flow skin factor. An analytical trilinear flow solution of fractured horizontal wells in unconventional reservoirs presented by Brown and Ozkan (2011) simulated the pressure transient and production behaviors which is versatile enough to incorporate natural fractures and fundamental fluid exchange between different reservoir components. The pressure- behavior of naturally fractured reservoirs under the influence of various factors, such as a network of continuous finite or infinite conductivities and discrete fractures with new semi-analytical solutions, was developed by Kuchuk and Biryukov (2012). To demonstrate the effect of different lengths of horizontal wells and outer boundaries for various configurations on the pressure transient flow, Rbeawi and Tiab (2011) provided type-curves for characterizing inclined hydraulic fractures for fractured horizontal wells. Daviau (1985) presented pressure transient techniques and solutions for infinite isotropic reservoirs as well as finite reservoirs of outer boundaries. Carvalho and Rosa (1989) introduced a mathematical model to account for pressure estimation horizontal wells with infinite conductivity, and Odeh and Babu (1990) discussed the pressure transient behaviors either for pressure drawdown or buildup tests of horizontal

wells with transverse hydraulic fractures. These pressure transient techniques are applied extensively for the interpretation of horizontal wells completed with multiple fractures.

### **2.3.2 Production data analysis in tight formation**

Subsequently, numerous methods of evaluating production data have been presented by many authors. Analyzing production data for tight formation has gained much interest as the development of tight reservoirs with low permeability values are accelerating these years. Optimizing stimulating fracturing treatment and the effect of sensible combinations of horizontal wells and hydraulic fractures are critical problems for economic and effective exploration. Hydrocarbon production in tight formation often exhibits a long transient flow period, so the production analysis for this kind of well is very daunting. This is because of the uncertainty in predicting and estimating the future production trend based on the conventional production data analysis methods due to its low permeability (microarray). The complicated geology with the absence/presence of natural fractures plus the contribution from commingled layers and the geometries of the complexity of artificial popped fractures are all impediments for production data analysis and forecasting evaluation. So many authors demonstrate a collective application of analytical and numerical tools as a whole to analyze both short- and long-term production performances for hydraulically fractured horizontal wells in tight formation. These modern analyzing tools are 1) traditional decline curve analysis (Arps, 1945), 2) Valko's power-law exponential analytical rate-time relation (2009), 3) Ilk's stretched exponential method (2010), 4) rate-transient analysis and productivity index analysis to evaluate the stimulated reservoir volume, and lastly 5) numerical simulations to ascertain and compare existing flow regimes from log-log diagnostic plots.

Currie et al. (2010) presented a way to estimate the production data continuously because of the high certainty existing in evaluating production data for very long transient flow periods in tight formation with ultra-low permeability, and in the same year, other authors (Rushing et al. 2007) discussed a systematic approach to interpret production performance of life-cycle reservoirs. Kabir and Rasdi (2011) also presented a comprehensive study with the use of analytical models to forecast long- and short-time production and history matching of tight oil reservoirs. More recently, Qianbari and Clarkson (2014) improved the accuracy and simplicity of estimating the effect of permeability changes on rate transient analysis in stress-dependent reservoirs based on traditional production transient analysis of tight oil reservoirs, by incorporating stress sensitivity parameters into analytical models for each flow regime for a transverse hydraulically fractured horizontal well in a stimulated reservoir volume with no flow contribution from the outside unstimulated region. Medeiros and Ozkan (2007) provided a semi-analytical model to analyze production data from a hydraulically fractured horizontal well in a heterogeneous tight formation taking into consideration the orientation of fractures and the size of the natural fracture network. To date, dual-porosity and triple-triple porosity models are included in conducting production data analysis because of natural fracture systems in tight reservoirs. El-Bandi (1998) was the first researcher to provide the linear solution for a linear dual-porosity model which extended from the traditional dual-porosity model to account for a long-time transient linear flow (negative half-slope) observed on a log-log plot of production rate/pressure versus time. Bello and Wattenberger et al. (1998) extended Elbandi's (1998) linear solution into application in production transient analysis with the assumption of two sequential linear

flows, one from the matrix to adjoining fractures and the other from fractures to wellbore. When triple-porosity models are used to analyze linear flow from production data, many researchers propose the linear triple-porosity model to explain sequential linear flow, for example, Al-Ahmadi (2010). Another simplified triple-porosity model was used by Siddiqui et al. (2012) to obtain analytical solutions to evaluate flow regimes in naturally fractured tight formation.

## 2.4 Flow regimes for fractured horizontal wells in tight formation

Identification of flow regimes primarily comes from the interpretation of pressure transient or production transient data with the application of several diagnostic plots, such as straight-line techniques, to analyze the transient and boundary-dominated flow pattern. The most popular method is extracting indications of distinct flow regimes from pressure derivative responses on a log-log plot against time. A comprehensive investigation of flow patterns of hydraulically fractured horizontal wells gives insight into successfully evaluating fracturing stimulating effectiveness and predicting the future performance of fractured wells. Many researchers have described possible flow regimes expected in fractured vertical or horizontal wells. Lee et al. (1994) were the first to provide a conceptual derivative plot for a hydraulically fractured vertical well located in a homogeneous (single-porosity) reservoir. There are basically five sequential or separated flow regimes with transition periods occurring in fractures and formation around a vertical well, including bilinear flow, fracture linear flow, formation linear flow, elliptical flow, pseudo-radial flow and boundary dominated flow. The bilinear flow happens only in finite-conductivity fractures when both the simultaneous drainage evolves in the fractures themselves and fluid in the surrounding area flows normally into the adjoining

fractures before tips of fractures start to influence the flow behavior. Sometimes, when the conductivity of fractures is too large, the bilinear flow could possibly disappear. Fracture linear flow happens within the fractures and is often short-lived and might be covered and masked by the wellbore storage effect; during this period of fluid flows to the wellbore through the expansion in the fracture. Because the duration of this period is extremely short, we usually do not take it seriously in well test analysis. Formation linear flow happens when fluid flows linearly from the formation into fractures and after a sufficiently long production period, pseudo-radial flow evolves before the boundary dominated flow for bounded reservoir systems and the larger the conductivity of fractures, the later the essentially pseudo-radial flow occurs. And its evolution also depends on the fracture properties of long fracture half-length relative to drainage area, as there could be direct boundary dominated flow showing this transitional flow pattern.

As horizontal drilling and hydraulic fracturing increasingly become essential combinations for low permeability reservoirs, discussions about flow regimes for multi-staged hydraulically fractured horizontal wells have gained much attention from the petroleum industry. Chen and Raghavan (1997) provided flow regimes which used a conceptual radial derivative system and pressure transient techniques for fractured horizontal wells. When the fracture conductivity is finite, bilinear flow will occur due to fracture linear flow to the wellbore and formation linear flow to the fractures. So possible flow regimes for an infinite-conductivity system of fractured horizontal wells without wellbore storage in a single-porosity reservoir are bilinear flow, early linear flow, early radial flow, compound linear flow, pseudo-radial flow and boundary dominated flow. Fluid flows linearly and normally to individual fractures for the early linear flow and it is

followed by an early radial-flow evolving around the tip of each fracture separately if the fracture spacing is wide and relatively short. The requisition of large fracture spacing and short half-length is to ensure the fracture interference induced by close spacing would mask this early radial flow. Then, the compound linear flow might appear if the distance from fracture tips and reservoir boundary is relatively distant; it depends on the reservoir and fracture configuration. And lastly, the pseudo-radial flow from the formation to the inner stimulated system as a whole and the boundary dominated flow evolves; it could take a very long time for these two flow regimes to be observed during the production if the permeability is low such as in tight reservoirs.

These descriptions mentioned above are suitable for conventional reservoirs and unconventional reservoirs with low permeability; they are not necessarily applicable for those complex reservoirs like shale with ultra-low permeabilities where complicated fracture systems could reopen during fracture treatment. In a situation where that fractured horizontal well is in a complex fracture system, dual-porosity or triple-porosity models will be used to describe the flow behavior of ultra-low permeability reservoirs. A composite dual-porosity model provided by Brohi and Pooladi-Darvish (1994) proposes that possible flow regimes derived from its linear analytical solutions are fracture linear flow, fracture PSS, matrix linear and fracture PSS, and matrix PSS and fracture PSS. Siddiqui (2012) suggests that in a formation linear flow or a triple-porosity composite reservoir possible flow regimes are hydraulic fracture linear flow, bilinear flow in macro fractures and micro fractures, linear flow in micro fractures, bilinear flow in micro fractures and matrix, linear flow in matrix and boundary dominated flow. There are some other discussions about flow regimes by different authors; it is important to note that the

existence of flow regimes mainly depends on the assumptions of each model and the most significant signature of these models is that the linear flow regime is the primary flow regime. Because of the nature of low-permeability presence, transit linear flow could be caused by different factors like a high permeability layer draining adjacent relatively low permeability layers, early-time drainage from various reservoir geometries under constant-pressure conditions and hydraulic fracture draining a square geometry, etc.

Identifying and analyzing flow regimes are complicated but well-defined: hydraulic fracture properties, reservoir geometry and fracture-wellbore-reservoir configuration are decisive factors for interpreting and understanding flow patterns and behaviors of fractured horizontal wells in a tight reservoirs.

## 2.5 History matching and type-curve fitting methods

The Fetkovich type-curve analysis was the first method used for type-curve matching with production data. It is generated from an analytical solution of transient radial signature featuring a constant flowing bottom-hole pressure. This type-curve matching technique is only suitable for production under boundary dominated flow conditions. The traditional Fetkovich type-curve matching method focused on analyzing reservoir characteristics for vertical conventional oil and gas wells, but in recent times, it has been used in calculating original oil in place (OOIP) for unconventional reservoirs as a simple flowing material balance technique. Later on, Blasingame and Agarwal-Gardner type-curves were formed and can be used to analyze production data in transient flow periods for unconventional reservoirs specifically and with the consideration of derivative functions to aid the matching process. The inverse form of Agarwal-Gardner type-curves, known as normalized pressure integral (NPI) type-curves, has come into use and is

preferred in the pressure transient analysis domain because of the normalized pressure instead of the normalized rate dimensionless function. Since then, with the increasing and booming need to economically and reasonably exploit unconventional reservoirs with the horizontal well and hydraulic fracturing stimulation technique, Wattenbarger and Bello (2008) et al. (date) provided a set of type-curves especially for explaining and analyzing transient linear flow in tight or shale reservoirs; this method is primarily used for low-ultra-low permeability reservoirs which exhibit a long period of transient linear flow due to the tight nature before reaching the boundary and where sometimes the boundary effect cannot even be seen within the limited production years till abandonment. They presented corresponding equations for each flow regime which can be used in acquiring specific reservoir properties and fracture characteristics for horizontal wells with hydraulic fractures fully penetrating the rectangular reservoir which is characterized by a dual-porosity model because of the natural fracture system sometimes could be revitalized and reopened around the artificial hydraulic fractures in the process of hydraulic fracturing. They also offered type-curves for different values of fracture half-length/reservoir width to account for various reservoir wellbore fracture geometries and also including the semi-log pressure derivative curve.

# **CHAPTER 3**

## **NUMERICAL SIMULATION OF PRESSURE TRANSIENT PERFORMANCE IN A TIGHT RESERVOIR**

### **3.1 Introduction**

In this chapter, the discussion is based on numerically simulated pressure and its pressure-derivative responses built with the CMG Builder. The horizontal well is positioned at the center of the reservoir. There are four basic scenarios of horizontal wells with or without hydraulic fractures under different reservoir conditions. The modeling simulation results show that transient pressure consequences vary significantly owing to different reservoir patterns and a reservoir area that is embedded with fractures.

### **3.2 Model development**

Numerical simulation models are used for the generation of the comparison with characteristic analytical models. We consider the performance of horizontal wells in the production of single-phase fluid (oil) from a tight, isotropic formation. Simulations are built by using a reservoir simulator (IMEX, 2010, Computer Modeling Group Ltd). We simulate a reservoir block within global grid system is  $30 \times 25 \times 1$  and the single cell at the fracture location is locally refined by using the keywords “Hydraulically Fractured wells”, and the number of refined blocks in each direction is  $7 \times 7 \times 1$ .

There are four scenarios of simulated cases: Scenario 1 represents pressure transient performance for a horizontal well in a sizable dual-porosity and single-porosity reservoir

(**Fig. 2**); Scenario 2 (**Fig. 3**) is a longitudinally fractured horizontal well in the same reservoir conditions as those in Scenario 1; Scenario 3 (**Fig. 4**) and Scenario 4 (**Fig. 5**) present horizontal wells with multiple-transverse hydraulic fractures in a homogeneous reservoir and a sizable dual-porosity reservoir, respectively. In addition, for the last two scenarios, a cased horizontal well where only the part hydraulic fractures are perforated is simulated to characterize the effect of horizontal well.

Tables 1 and 2 show the well, reservoir and hydraulic fracture input data used for the development of the numerical simulation runs and Table 3 presents the properties of the natural fractures (NFs) system and the matrix for cases in which a naturally fractured zone surrounds the wellbore and hydraulic fractures as a whole. Also given in this table are the corresponding dual-porosity model parameters which are used to model the natural fracture system aforementioned. Natural fractures are assumed to cover the entire parts of reservoir or concentrated parts of grids around the horizontal well only. To demonstrate the natural fractures, Warren and Root (1963) dual-porosity model provided by the CMG option were used to simulate the effect of an entirely naturally fractured reservoir and adjusted the fracture porosity value to zero except for the area outside the dual-porosity region. Hydraulic fractures are modeled as isotropic porous media fully penetrating the entire thickness of the formation. Longitudinal fractures (LFs) are assumed to extend the entire length of the horizontal well (HW). Although specific and reasonable data and parameter sets were applied in my simulations, the identified flow regimes and pressure transient characteristics could be used as a relative and qualitative reference and supportive tool for interpreting and understanding similar well reservoir configurations.

The following are the assumptions of this basic model:

1. The reservoir is assumed to be a single-layer and rectangular system comprised of matrix blocks that is homogeneous and isotropic with dual or single porosity, and horizontal with uniform thickness.
2. Hydraulic Fracture and natural fracture system properties are assumed to be constant, respectively and LGR (local grid refinement) techniques are used for representing and modeling hydraulic fractures alongside the wellbore in which grids are logarithmically symmetrical for the representation for Scenarios 3 and 4.
3. The fracture does not penetrate the formation completely. In other words, the fracture height is not the same as net pay for Scenarios 3 and 4.
4. The fluid flow is under single oil phase and the bottom-hole pressure during the production is above the bubble point pressure.

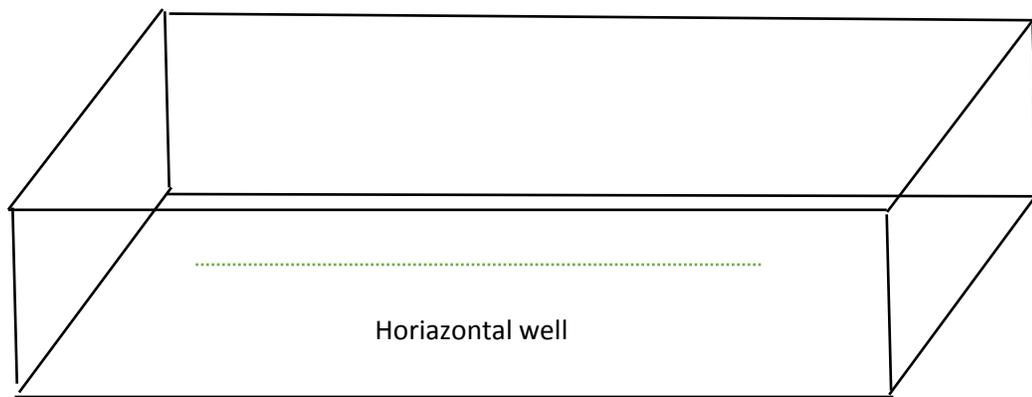


Fig. 3.1 — Rectangular reservoir with a horizontal well (orange dotted line) which is located in the center of this geometry.

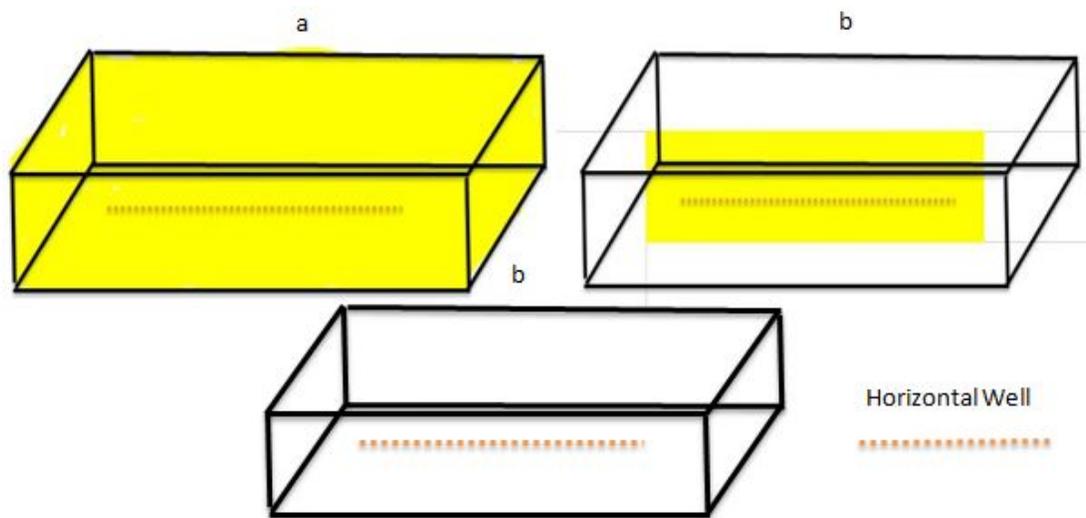


Fig. 3.2 — Sketch for a horizontal well in the center of global, regional and homogeneous reservoirs (not to scale)

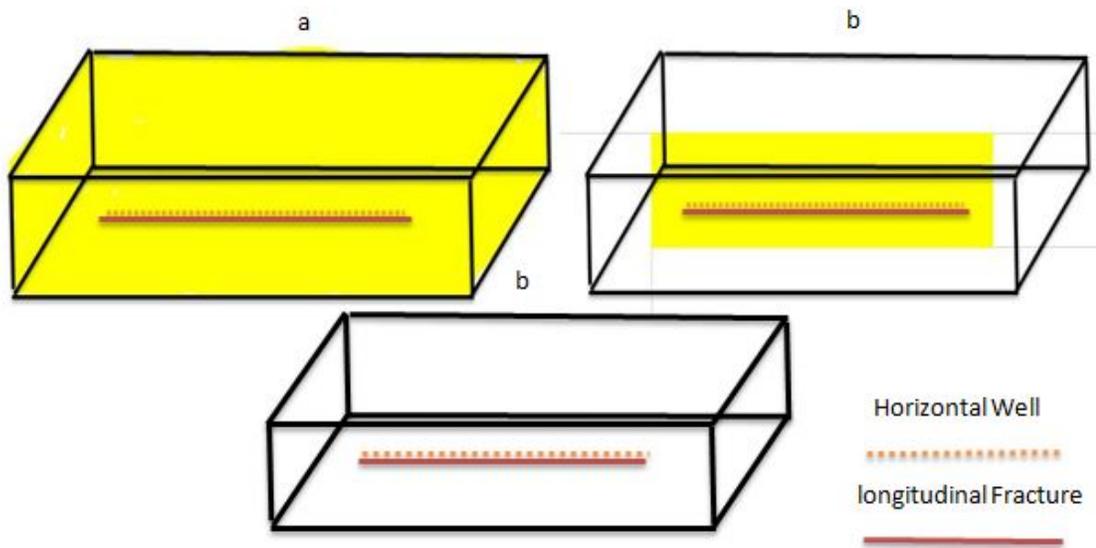


Fig. 3.3 — Sketch for a longitudinally fractured horizontal well located in the center of global, regional and single porosity reservoirs (Not to scale)

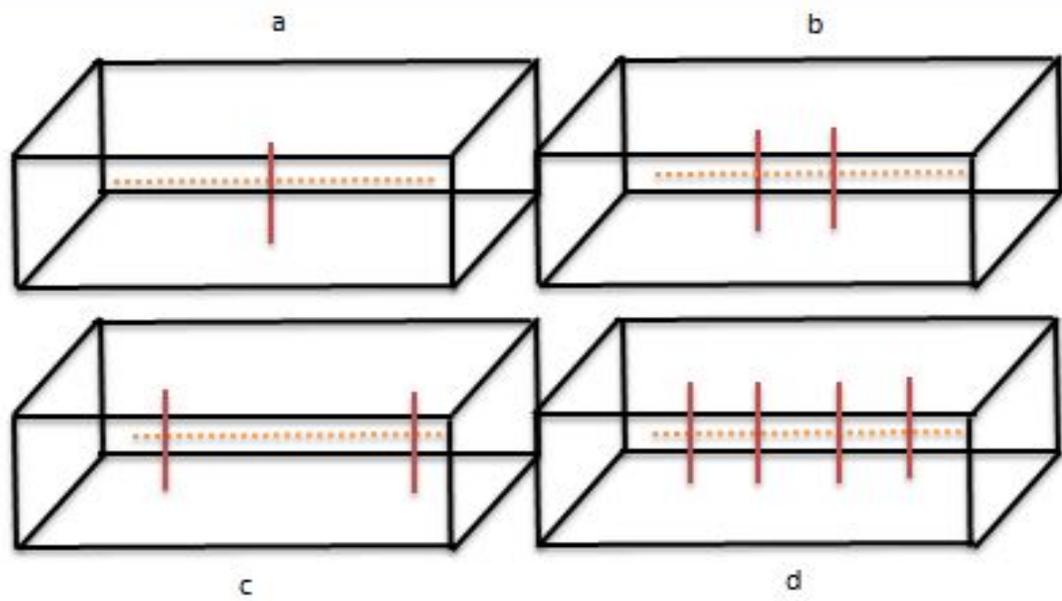


Fig. 3.4 — Sketch for a horizontal well with multi-stage transverse hydraulic fractures in the center of a homogeneous reservoir (Not to scale)

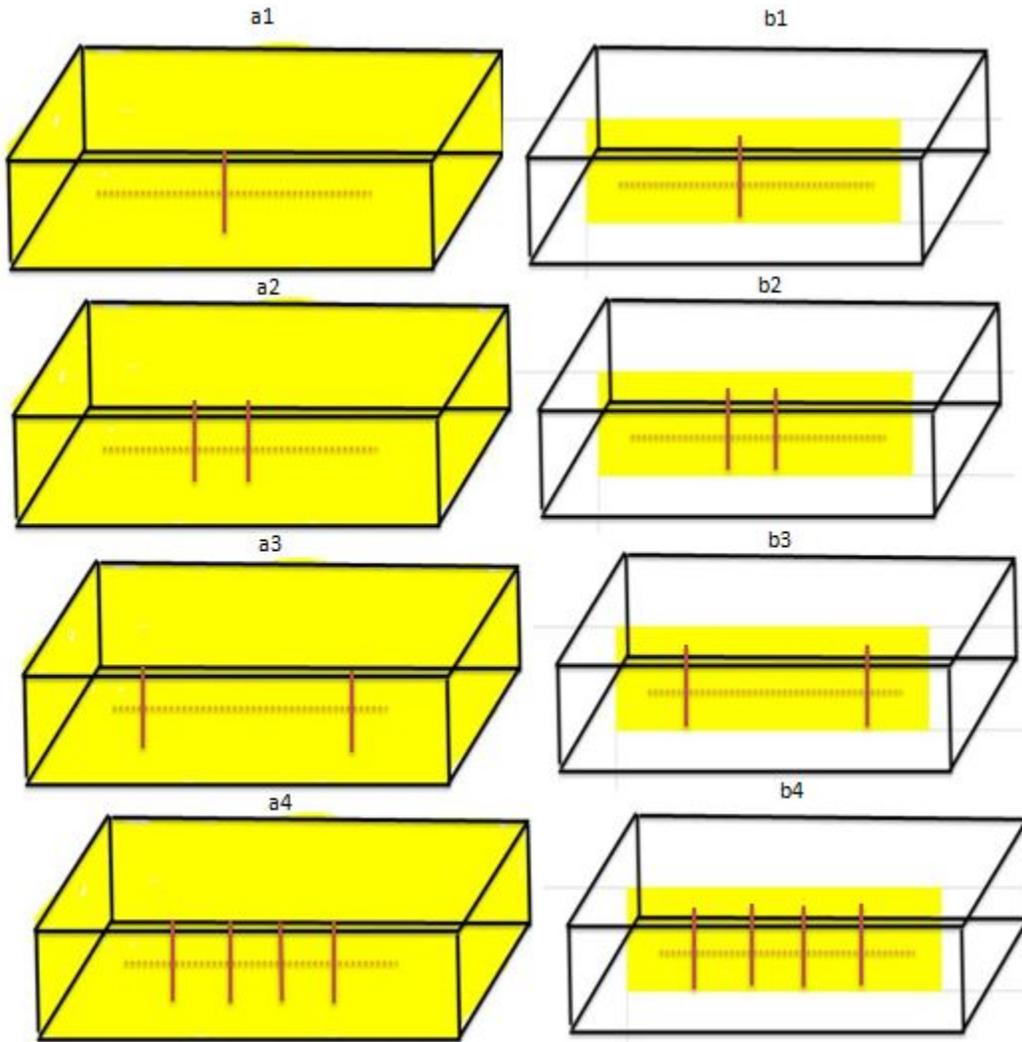


Fig. 3.5 — Sketch for a horizontal well with multiple transverse hydraulic fractures in the center of globally and regionally naturally fractured reservoirs (Not to scale)

Table 3.1 — Input reservoir parameters for simulation purposes

<b>TABLE 3.1 – WELL AND RESERVOIR DATA</b>	
Horizontal well length, $L_h$ , m	330
Wellbore radius, $r_w$ , m	0.09
Formation thickness, $h$ , m	18
Reservoir size in x-direction, $X_e$ , m	900
Reservoir size in y-direction, $y_e$ , m	375
Reservoir initial pressure, $P_i$ , psi	5000
Bottom hole pressure, $p_{wf}$ , psi	500
Viscosity, $\mu$ , pa.s	2.50E-05
Porosity, $\phi$	0.10
Total system compressibility, $c_t$ , $\text{kpa}^{-1}$	1.74E-05
Reservoir (matrix) permeability, $k$ , md	0.01

Table 3.2 — Input parameters of hydraulic fractures for simulation purposes

<b>TABLE 3.2 – HYDRAULIC FRACTURE INPUT DATA</b>	
<b>Longitudinal Fracture</b>	
Fracture half-length $X_f$ , m	121.91
Width, $w_f$ , m	0.03
Permeability, $K_f$ , md	1000
Porosity, $\phi_F$	0.1
<b>Transverse Fractures</b>	
Half length, $X_f$ , m	60.96
Width, $w_f$ , m	0.03
Permeability, $K_f$ , md	10000
Porosity, $\phi_F$	0.1

Table 3.3 — Input parameters of natural fractures for simulation purposes

<b>Table 3.3 – DUAL POROSITY DATA</b>	
<b>Matrix</b>	
Permeability, $K_m$ , mD	0.01
Porosity, $\phi_m$	0.1
<b>Natural Fracture</b>	
Permeability, $K_f$ , mD	1
Porosity, $\phi_f$	0.001

### 3.3 Simulation model description and results

#### 3.3.1 Modeling description for Scenario 1

Scenario 1 consists of three cases to demonstrate the pressure transient performances of a horizontal well in a single-porosity reservoir with the influence of the size of a natural fracture system, these three cases are represented by forms of abbreviation as HW+NF, HW+NF region and HW+homo, respectively and they are explained as follows

HW+NF reservoir: a horizontal well in a naturally fractured reservoir (dual-porosity model)

HW+NF region: the stimulated reservoir volume (SRV) (Mayerhofer et al., 2010) is limited to a region near the horizontal well, and the region outside the SRV is single porosity. The stimulated reservoir volume can be considered as a naturally fractured reservoir (dual-porosity model).

HW+Homo: a horizontal well in a homogeneous reservoir which is modeled by a single-porosity system

#### 3.3.2 Modeling description for Scenario 2

Details for Scenario 2 are described as below:

HW+LF+NF reservoir: a longitudinal horizontal well naturally completed (open-hole) in a naturally fractured reservoir.

HW+LF+NF region: a longitudinal horizontal well naturally completed (open-hole) in a regionally naturally fractured reservoir.

HW+LF+Homo: a longitudinal horizontal well naturally completed (open-hole) in a homogeneous reservoir

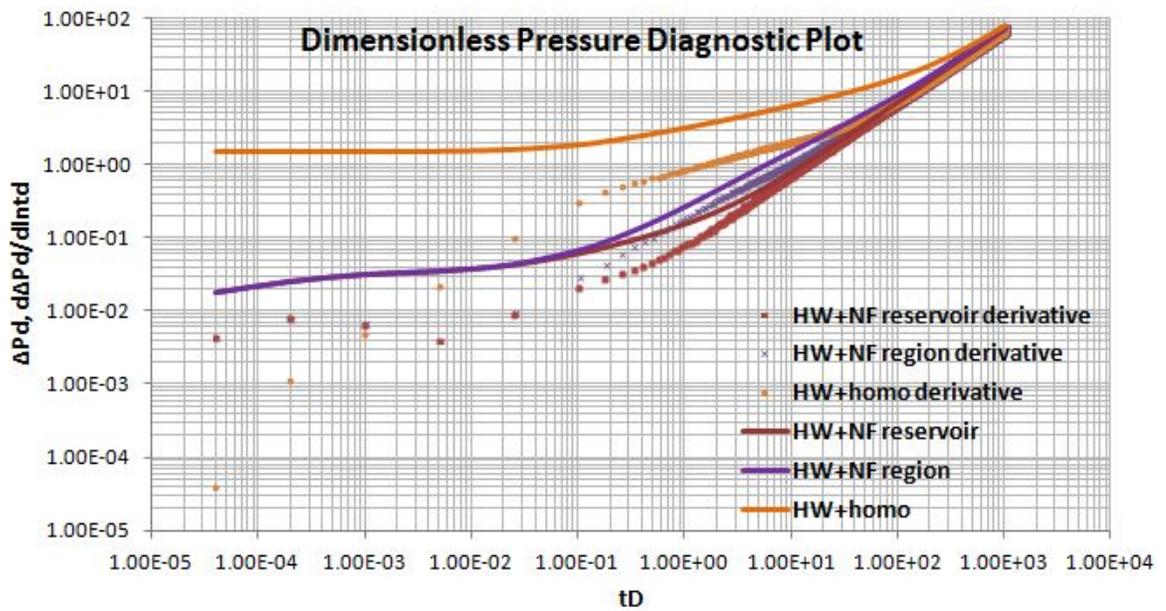


Fig. 3.6 — Dimensionless pressure and derivative responses for a horizontal well in a homogeneous reservoir

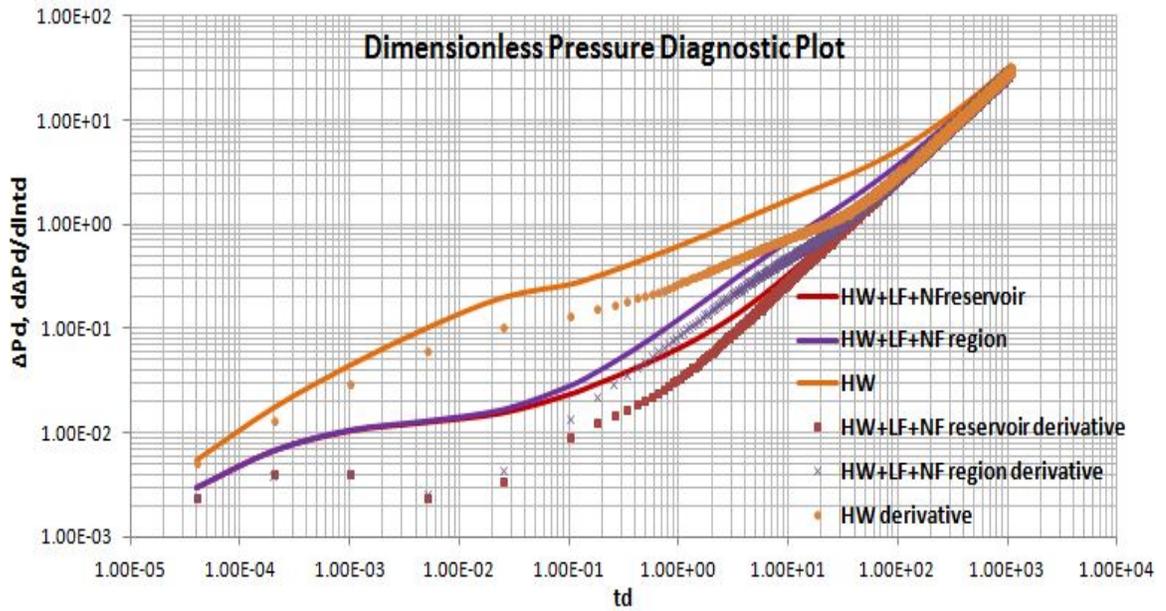


Fig. 3.7 — Dimensionless pressure and derivative responses for longitudinally fractured horizontal wells in global, regional and homogeneous reservoirs

### **3.3.3 Modeling description for Scenario 3**

HW+1TF: A horizontal well with only one transverse hydraulic fracture

HW+2TF(S): Two-transverse hydraulically fractured horizontal well with fracture spacing 60 m.

HW+2TF (L): Two-transverse hydraulically fractured horizontal well with fracture spacing 240 m.

HW+4TF: four transverse hydraulic fractures equally spaced with 60 m on the length of a horizontal well

### **3.3.4 Modeling description for Scenario 4**

HW+1TF+NF reservoir: A horizontal well with only one transverse hydraulic fracture in a globally naturally fractured reservoir

HW+2TF(S) + NF reservoir: A horizontal well with two transverse hydraulic fractures (fracture spacing is small, 60m) in a globally naturally fractured reservoir

HW+2TF (L) + NF reservoir: A horizontal well with two transverse hydraulic fractures (relatively large-spaced with 240 m) in a globally naturally fractured reservoir

HW+4TF+NF reservoir: A horizontal well with four transverse hydraulic fractures in a globally naturally fractured reservoir

HW+1TF+NF region: A horizontal well with only one transverse hydraulic fracture in a locally naturally fractured reservoir

HW+2TF(S or L) + NF region: A horizontal well with two transverse hydraulic fractures (small or large, 60m or 270 m) in a regionally naturally fractured reservoir

HW+4TF+NF region: A horizontal well with four transverse hydraulic fractures in a regionally naturally fractured reservoir

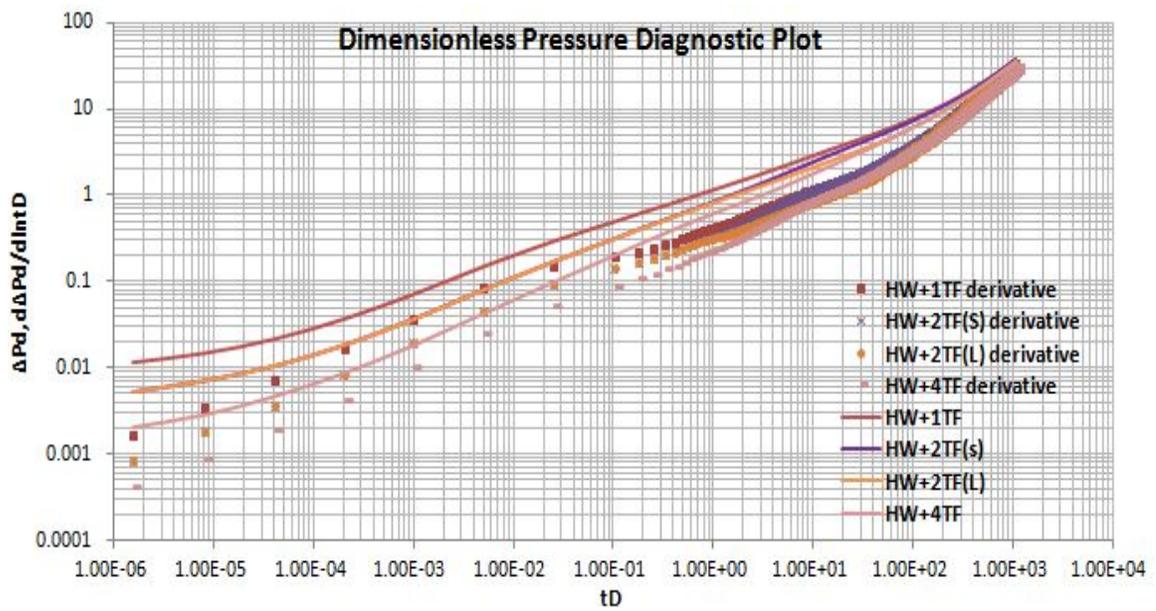


Fig. 3.8 — Dimensionless pressure drop and derivative responses of open-holed horizontal wells with multiple transverse fractures in a homogeneous reservoir

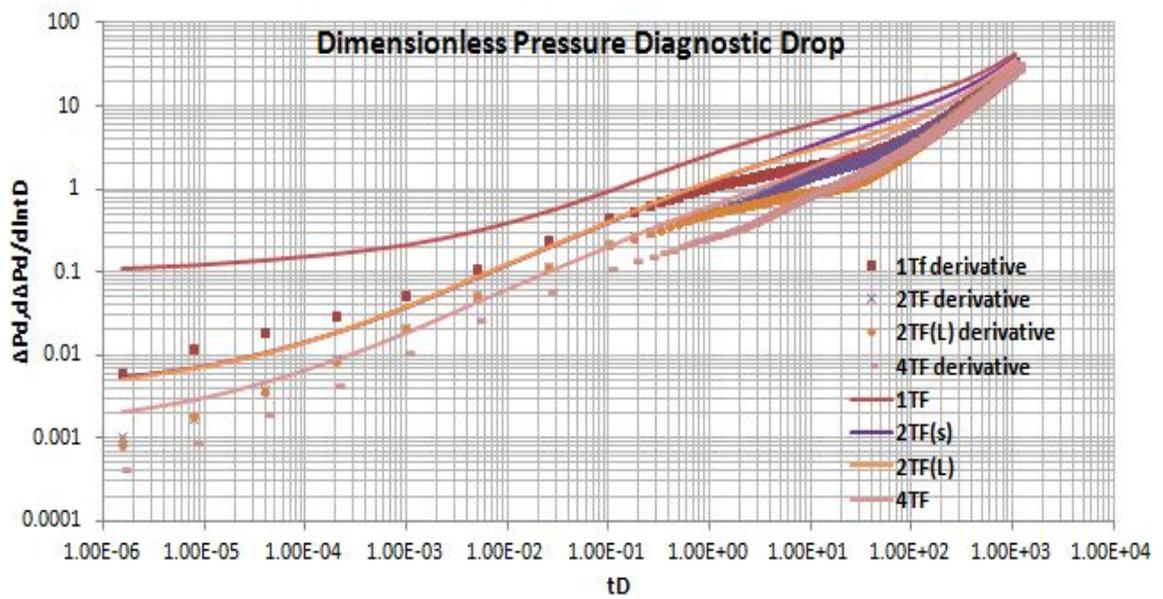


Fig. 3.9 — Dimensionless pressure and derivative performances for cased horizontal wells with different numbers of transverse hydraulic fractures in a homogeneous reservoir where the perforation only happens at the point open to fractures

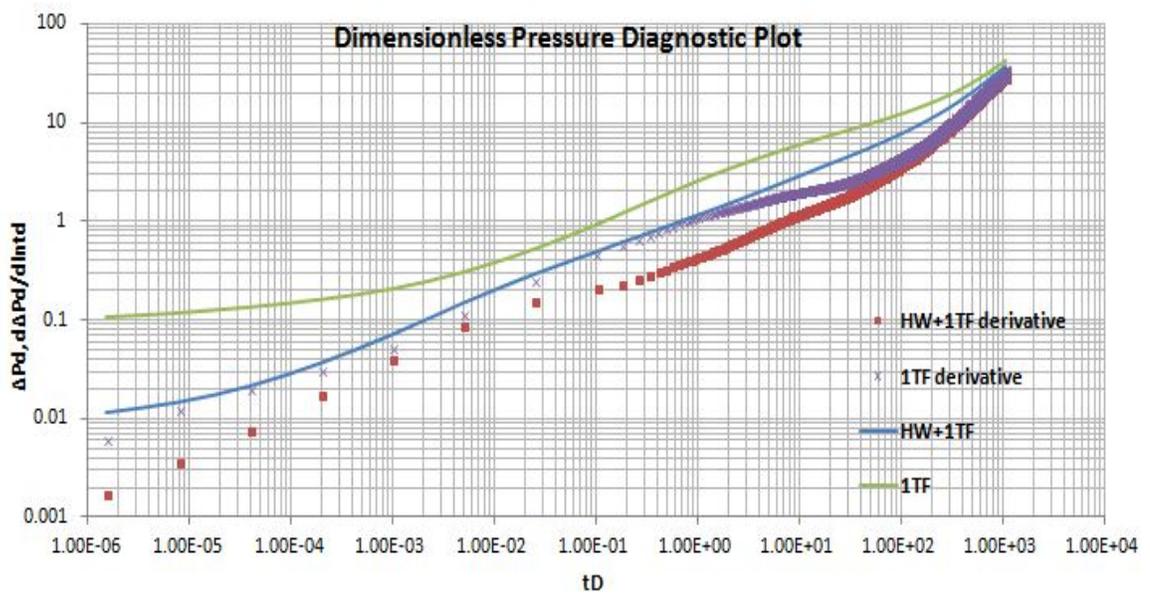


Fig. 3.10 — Dimensionless pressure and derivative responses for horizontal wells (cased and open-holed) with one transverse hydraulic fracture in a homogeneous reservoir

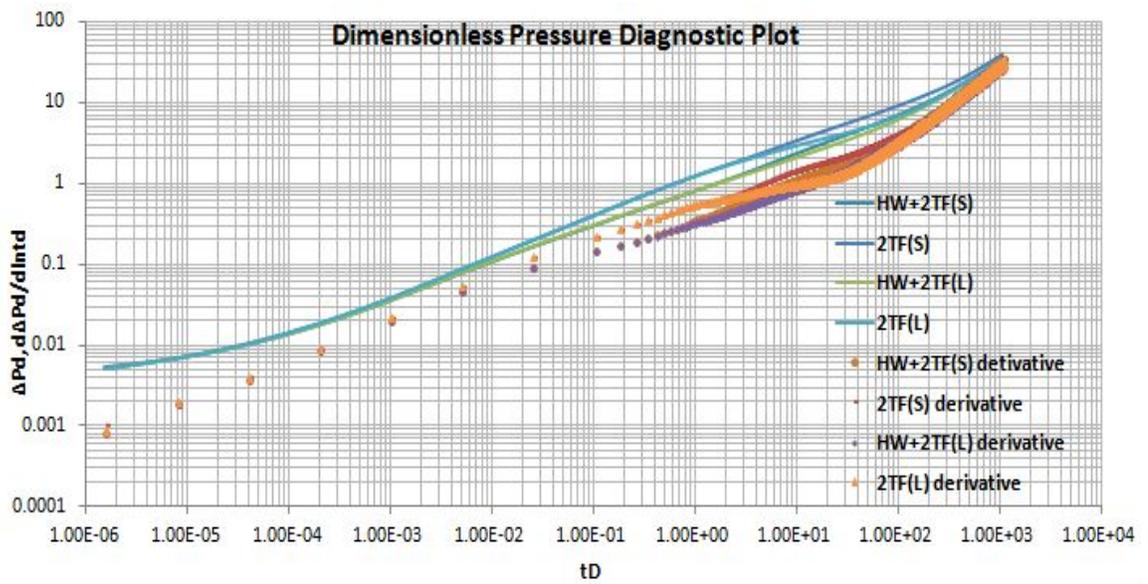


Fig. 3.11 — Dimensionless pressure and derivative responses for horizontal wells (cased and open-holed) with two transverse hydraulic fractures in a homogeneous reservoir

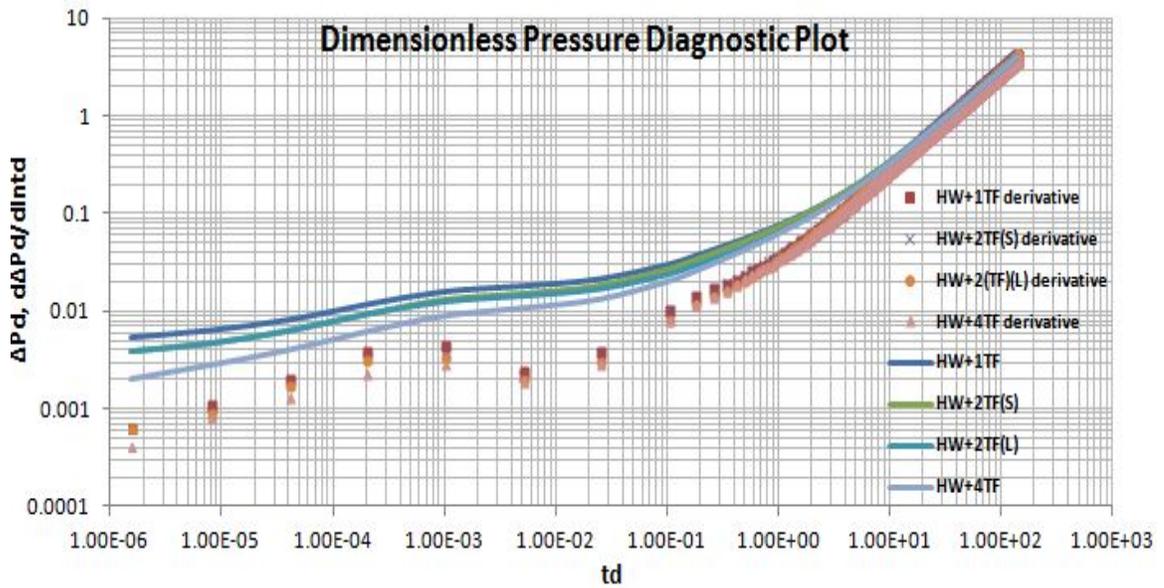


Fig. 3.12 — Dimensionless pressure and its corresponding derivative responses for open-holed horizontal wells with multiple transverse hydraulic fractures in a globally naturally fractured reservoir

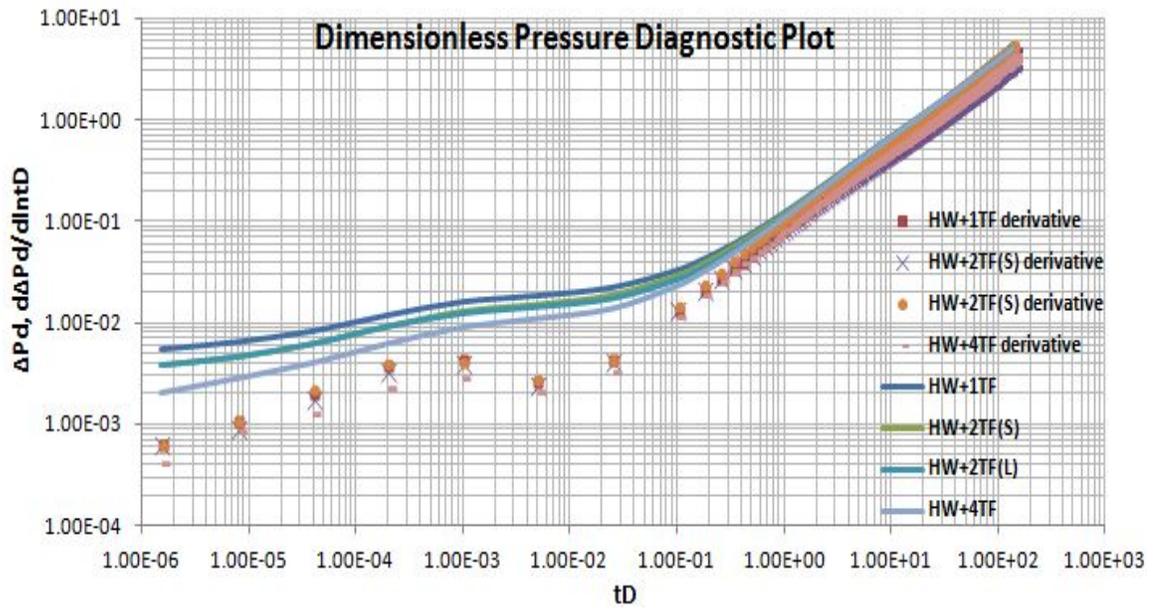


Fig. 3.13 — Dimensionless pressure and its corresponding derivative responses for open-holed horizontal wells with multiple transverse hydraulic fractures in a regionally naturally fractured reservoir

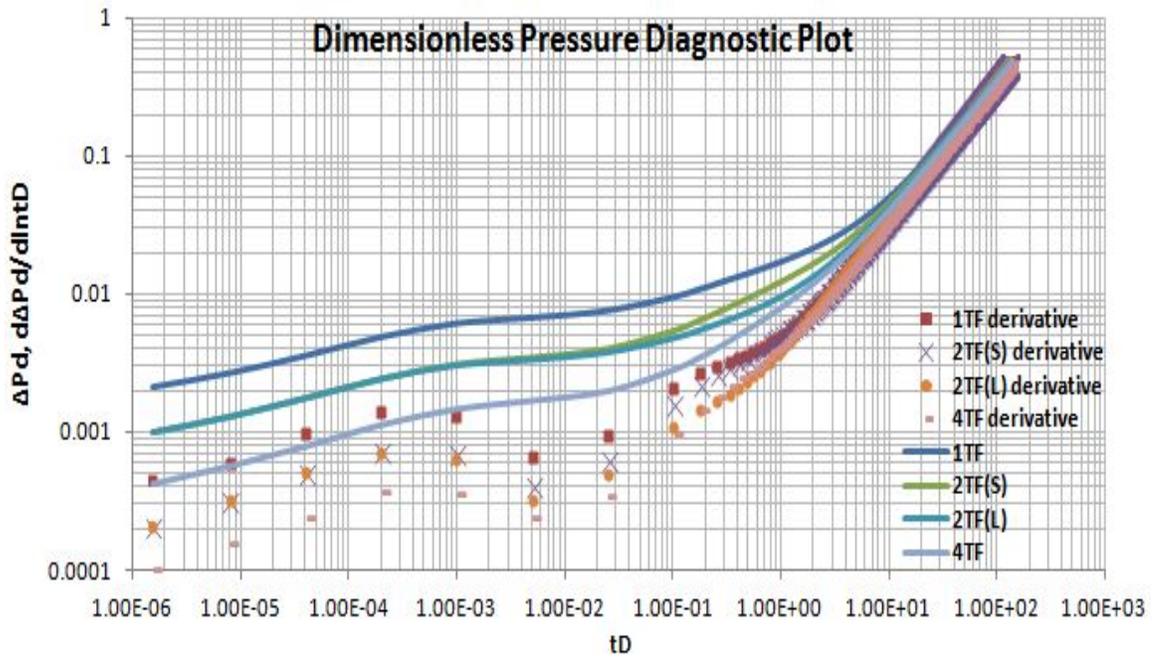


Fig. 3.14 — Dimensionless pressure and its corresponding derivative responses for cased horizontal wells with multi-transverse hydraulic fractures in a globally naturally fractured reservoir where the perforation only happens at the point open to fractures

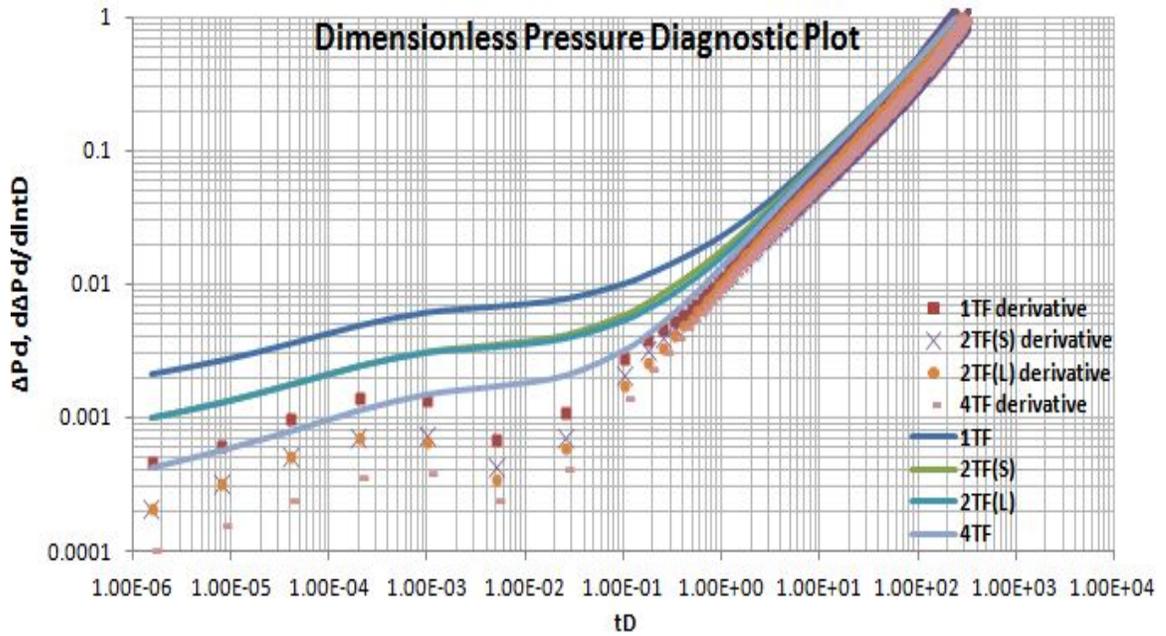


Fig. 3.15 — Dimensionless pressure and its corresponding derivative responses for cased horizontal wells with multi-transverse hydraulic fractures in a regionally naturally fractured reservoir where the perforation only happens at the point open to fractures

### 3.4 Identification of flow regimes and discussion of simulation results:

In this work, four possible scenarios of various reservoir combinations were presented. There are three cases for each (**Fig 3.2 and Fig 3.3**) with unfractured or longitudinally fractured horizontal and (**Fig 3.4 and Fig 3.5**) multiple transverse hydraulically fractured HW wells in dual-porosity, dual-porosity inner and outer single-porosity reservoirs.

#### **A single open-holed horizontal well (HW)**

We begin our discussion by considering a horizontal well in entirely, regionally and homogeneous reservoirs case by case. A sketch of the horizontal wellbore and reservoir geometry is graphed in **Fig 3.2**. Similar cases have been discussed in previous studies (see, for example, Daviau et al., 1985; Clonts and Ramey, 1986; Ozkan et al., 1989; Ozkan and Raghavan, 1991a; Ozkan, 2001; Soliman et al., 1990; Larsen and Hegre, 1991). These cases are presented here as a comprehensive reference for my discussions of the cases where the reservoir is naturally fractured.

**Fig. 3.6** shows pressure (fill-in markers) and its corresponding derivative (fill-in solid lines) responses for a horizontal well (HW) in a sizable naturally fractured and homogeneous reservoir; natural fractures are assumed to be globally naturally fractured and locally fractured representations, respectively and are modeled by using Warren and Root dual-porosity idealization (1963) with the parameters given in **Table 3.3**. Locally fractured reservoirs where the region has no natural fractures are modeled by single-porosity characteristics. Red markers indicate the responses for HW in a globally naturally fractured reservoir (HW+NF reservoir) and purple cross markers represent locally naturally fractured reservoirs (HW+NF region) respectively, while orange diamonds are the response for a horizontal well in a single-porosity reservoir.

As expected, flow regimes for globally and locally naturally fractured reservoirs are the same, except for the intermediate time when the pressure translates beyond the natural fracture region and enters into the single-porosity region. They both exhibit early fracture linear flow followed by a typical dip on the derivative responses plots which is diagnostic characterization of dual-porosity presence. Following the dip, an intermediate-time linear flow develops for the HW + NF reservoir whereas a nearly unit slope line appears at that time for the HW+NF region, then after a short transitional period, they both reach the boundary dominated flow with a straight unit slope shape.

#### **A longitudinally fractured open-holed horizontal well (HW+LF)**

Then we come to discuss the pressure transient performances of a horizontal well with a longitudinal hydraulic fracture in a sizable naturally fractured reservoir which is the same reservoir condition as in the 3.1.1 scenario. **Figure 7** shows the pressure drop and its derivative responses. The flow regimes for the longitudinally fractured horizontal well are the same as those for unfractured horizontal wells, but the flow regimes of HW + LF + homo are different starting from early time fracture flow and radial flow, then followed by little recognizable late-time linear flow and ending up with boundary dominated flow. The flow regimes indicate that a dual-porosity reservoir modeled by CMG would dominate the flow no matter if there is longitudinal fracture alongside the horizontal well. The late-time pseudo-radial flow is not clear for all three cases because the thickness of the reservoir is relatively small when compared to the length of the reservoir.

#### **An open-holed horizontal well with different transverse hydraulic fractures (HW+TF)**

Pressure transient characteristics of a horizontal well with multiple transverse hydraulic fractures are shown in **Fig. 8** (curves labeled as HW+TF). For this figure, the reservoir is assumed to be homogeneous with the properties of the matrix and modeled by using single-porosity options to represent this property. **Fig. 4** presents a sketch of the reservoir, the horizontal well and fracture geometry considered in these discussions.

We note from **Fig. 8** that the flow regimes for various combinations of multiple transverse fractures follow the same pattern. The pressure drop increases as the number of transverse fractures increases until the second linear flow is established; there are two trends then combined into one string when the last boundary dominated flow dominates. From the pressure derivative response, we can see that an early long-time linear flow normally towards fractures within the inner stimulated reservoir occurs with 1/2 slope indication followed by a transition to the second linear flow which is an intermediate-time linear flow or compound linear flow period contributed from the outer reservoir into the inner stimulated reservoir region. Relying on the reservoir dimensions and permeability anisotropy, the transitional period is likely to include a radial-linear or bilinear flow regime. As demonstrated by many authors previously, this transitional period may be defined as a quasi-steady state flow which can be approximated as a pseudo-radial flow with which the inner reservoir is depleting as there is little contribution from the outer region. Another attribute of this regime is that the insignificant pressure interference dominates while flowing across the boundary between the stimulated and unstimulated region and the slope of this transition is close to one but not an exact boundary unit-slope indication. Following the intermediate-time linear flow (ILF), a little discernible pseudo-radial flow (PRF) and clear boundary dominated flow

(BDF) appear for all cases. We then discuss where the horizontal well has two or four transverse hydraulic fractures in a homogeneous reservoir to demonstrate fracture disturbance on the performance of the pressure change. We have two options for the two-transverse fracture case, In the first option, the fracture spacing between the fractures is 60 m (labeled by S in **Fig. 8**) and in the second consideration, the spacing is 270 m (labeled by L in **Fig. 8**) in which the fractures are located at the very end of the horizontal well, respectively. Although the overall characteristics are not influenced by the fracture spacing, **Fig.8** shows significant impacts caused by the different spacing for intermediate time responses. At the very beginning, they both started from the long-time linear flow, followed by the early-time radial or bilinear flow and they did not separate until the second linear flow existed. It is interesting to note that for small fracture spacing (60 m, HW + 2TF(S)) it emerges into the curve of the one-transverse fracture case but for relatively large fracture spacing (270 m, HW + 2TF (L)), it combines with the four fracture case at the second linear flow period. This behavior demonstrates that the compound linear flow from the outer reservoir is attributed to this variance and different fracture spacing would have different inner stimulated reservoir geometry, which affects the shape of flow from the outer reservoir. The pressure responses for the four-transverse-fracture case show the smallest pressure drop at early time linear flow and the endurance of this linear period for the largest number of fracture cases ends latest due to the large fracture drainage area, and after the second linear flow, the four transverse-fracture case displays the same pressure and derivative response as for the two-transverse-fracture case with 270 m fracture spacing.

#### **Cased horizontal well with different transverse hydraulic fractures (TF)**

To illustrate the effect of the horizontal on the pressure derivative performance, I built another four cases in this scenario under the same conditions for the same reservoir and fracture geometry but without an open-holed horizontal well, in which the only perforation happens at the intersection point between hydraulic fractures and wellbore. From the derivative responses, the flow regimes are the same from the onset of the long-time reservoir linear flow with a little transition period into the pseudo-radial flow and ending up with one string boundary dominated flow, except for one fracture case which first showed a bilinear flow. This behavior might be attributed to simultaneous drainage from the finite-conductivity hydraulic fracture and homogeneous matrix grid. From **Fig. 3.9**, we can see that the late-time pseudo-radial flow becomes distinct and recognizable with the increasing of the number of transverse fractures, and pressure derivative responses for horizontal wells with two fractures demonstrate the same fractured interference behavior as those pressure responses with the effect of the horizontal well. A large spacing late-time trend moves close to the four fracture cases becoming one curve while smaller spacing moves to one fracture case.

A comparison of the pressure performance for the open-holed and cased horizontal wells in **Figs. 3.10** and **3.11** indicates that the pressure drop for the open-hole horizontal well is smaller than that for the cased horizontal well until the boundary-dominated flow is established. The pressure derivative performance of open-holed horizontal wells would probably present compound linear flow before late-time pseudo-radial flow or boundary dominated flow appears, depending on the dimensions of the reservoir geometry. This situation can be clearly seen in **Figs. 3.10** and **3.11**.

**An open-holed horizontal well with different transverse hydraulic fractures in a sizable naturally fractured (dual-porosity) reservoir (HW+TF+NF reservoir or region)**

This is the last scenario for my numerical simulation runs. **Fig. 3.12 ~ Fig. 3.17** present the pressure transient behaviors of the horizontal wells with the same multiple transverse hydraulic fracture combinations considered in **scenario 3.2.3** but in global (natural fractures fulfill the entire reservoir), local (natural fractures only exist in grids around wellbore) and homogeneous reservoirs. **Fig. 3.12** shows that pressure derivative responses display flow regimes of a horizontal well with multiple fractures in a globally naturally fractured reservoir starting from linear flow and followed by the characteristic dip of the dual-porosity system. After the dip, intermediate-time linear flow and slight pseudo-radial flow develop. At late times, boundary dominated flow shows the characteristic unit slope line for all cases.

We also consider the situation where there is a region of natural fractures area around the transverse hydraulic fractures and horizontal wellbore, shown in **Fig. 3.5**. As before, we discuss the four scenarios. **Fig. 3.13** shows the pressure (solid lines) and derivative (solid markers) responses for all four cases shown in **Fig. 3.12**. The flow regimes appear, chronologically, as linear flow followed by the characteristic dip of the dual-porosity signature, fracture linear flow, transitional period and the boundary dominated flow.

For horizontal wells in a reservoir entirely covered by natural fractures or localized natural fractures, there is no noticeable difference for flow regimes shown in the pressure responses of **Figs. 3.12** and **3.13**, and for all cases considered in these two figures, the features of naturally-fractured reservoir are evident. As for fracture interference, no

distinct variation can be seen on the pressure derivative responses of the two-transverse-fracture cases shown in **Figs. 3.12** and **3.13**. Increasing the number of hydraulic fractures to four, however, reduces the pressure drop until the transition flow period before the last unit slope line, and the variance between the cases with two and four fractures becomes constant (and negligible). This indicates that transverse fractures improve the drainage and productivity of the region containing natural fractures and the drainage of the relatively tight, single-porosity exterior region is controlled by the horizontal wellbore and the naturally fractured, dual-porosity systems of the reservoir.

**A cased horizontal well with different transverse hydraulic fractures in a sizable naturally fractured (dual-porosity) reservoir (HW+TF+NF reservoir or region)**

**Figs. 3.14** and **3.15** show their pressure and derivative behaviors for a cased horizontal well in a sizable naturally fractured reservoir. I built four identical cases to compare the results with open-holed horizontal well cases. There is no discernible difference on flow regime between cased and open-holed horizontal wells completed in a naturally fractured reservoir; however, pressure drops are more evident than those of open-holed horizontal wells with the increasing of transverse hydraulic fracture numbers, which shows that the horizontal well helps the drainage of the natural fracture regions. It is important to note that the major difference in the signature of flow regimes occurs at late times when the outer reservoir beyond the hydraulic fracture tips begins to affect. For a globally naturally fractured reservoir, there is a linear flow regime indicated by a half-slope identification before the appearance of the boundary dominated flow contributed from outer naturally fractured reservoir, whereas a close-to-unit slope line occurs during this period for a regionally fractured reservoir, which is due to the strong permeability contrast between

inner stimulated and outer single-porosity regions. This can be explained by the fact that the outer reservoir is assumed to be made out of the same matrix blocks. Insufficient support from the outer tight matrix property without the assistance of natural fractures could increase the drainage of the inner stimulated region and the hard-to-feel outer region acts like a boundary effect as there is low flow capacity of the matrix system when pressure propagates through the transition area.

### **Discussion of the effect of Longitudinal and Transverse Fractures**

Comparing the results for a fractured horizontal well in a homogeneous reservoir and in a naturally fractured reservoir **Fig. 3.15** and **Fig. 3.16**, we can see that the orientation of the hydraulic fractures does not affect the horizontal well flow regimes strongly during the entire production period. They both show fracture linear flow, early -time radial flow intermediate-time linear flow and the final boundary dominated flow. The only difference for a horizontal well with a longitudinal and transverse hydraulic fracture is that for the same fracture surface area, a longitudinal hydraulic fracture needs a smaller pressure drop than a transverse fracture under the same production rate constraint and other flow conditions. This is due to the additional pressure drop induced by flow choking around the horizontal well and the transverse fracture intersection (Al-Kobaisi et al., 2006, for a discussion of flow choking on pressure responses of transverse fractures), and much more contacting surface area between the longitudinal fracture and the horizontal wellbore. However, from my point of view, it is possible to create multiple transverse fractures along the horizontal well extension and increase the productivity because when hydraulic fracture spacing become too small, the added benefits and advantages could start decreasing due to the interference between adjacent fractures.

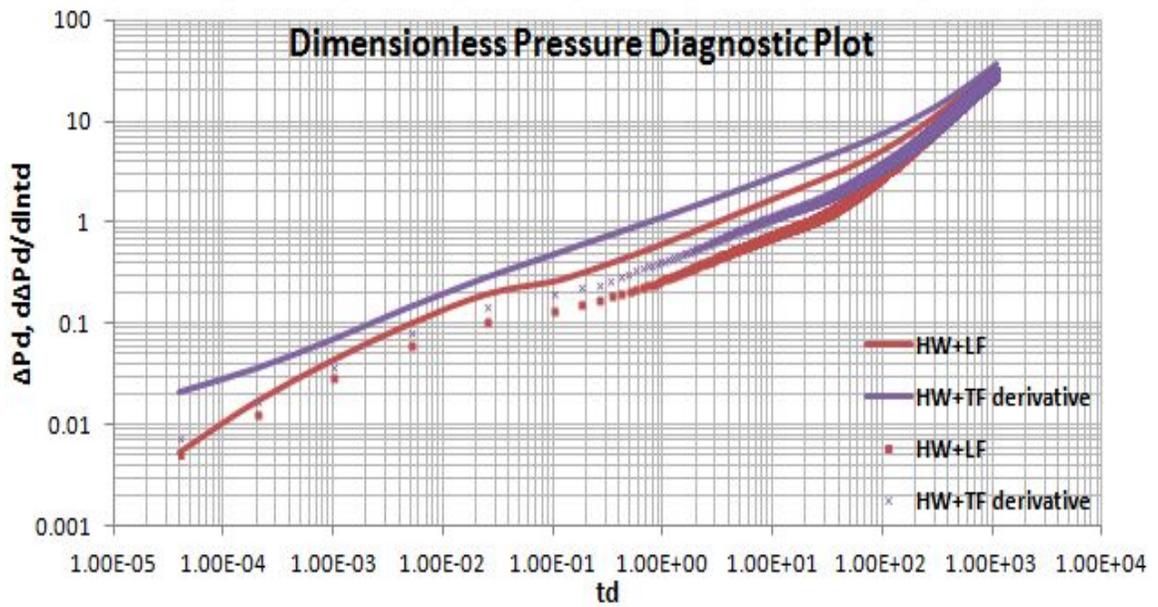


Fig. 3.16 — Dimensionless pressure and its corresponding derivative responses for horizontal wells with one transverse and longitudinal fractures in a homogeneous reservoir

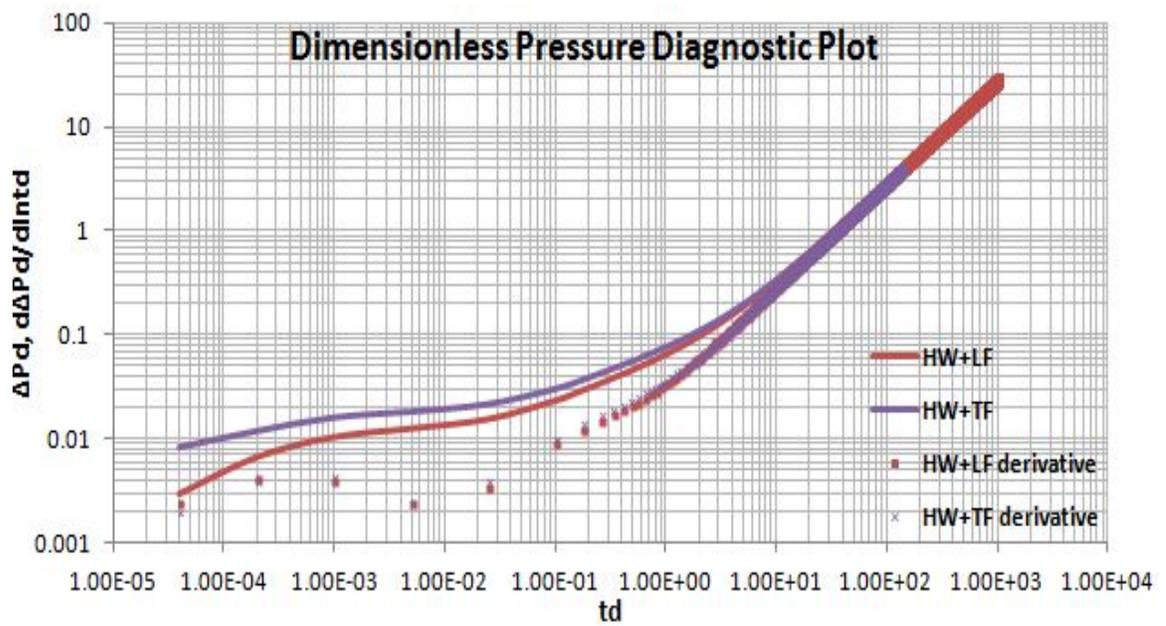


Fig. 3.17 — Dimensionless pressure and its corresponding derivative responses for horizontal wells with one transverse and longitudinal hydraulic fractures in a naturally fractured reservoir

### 3.5 Sensitivity analysis

We first started to see what the effect of different matrix permeability would have on the pressure diagnostic plots for a horizontal well completed in a tight reservoir. From the previous case presented in **Fig. 3.6** for a horizontal well in a single-porosity reservoir shows irregular flow-regimes-indications instead of early radial at very early times, but this early-time pressure data should be eliminated due to the inherent and intrinsically existed uncertainty numerically computed by CMG. Three matrix permeability values (0.01, 1, 10 md) were simulated. **Fig. 3.18** presented the comparisons of the pressure diagnostic characteristics among different matrix permeability values. Generally, half-slope and unit-slope which are indicative of two specific flow regimes are presented for these cases: linear flow and boundary dominated flow. **Fig. 3.18** shows that matrix permeability has a significant effect on the pressure transient responses at early times and a negligible impact on late-time performances for all cases. The larger the matrix permeability, the earlier the formation linear flow pops up and less disturbing derivative responses occur, especially at the beginning of production time, and late pseudo-radial flow becomes more distinct and evident as the matrix permeability decreases. Early pseudo-radial flow does not appear as expected for standard sequence of flow regimes of a single horizontal well completed in a homogeneous reservoir. At late times, all pressure drop and derivative responses start to merge together as one single stem when boundary dominated flow begins to prioritize. The lower the value of matrix permeability, and productivity is quickly dictated with the same given formation conditions. In addition, with the increasing of matrix permeability values, transient flow periods become more evident and making it difficult to recognize and identify the transitional flow regimes!

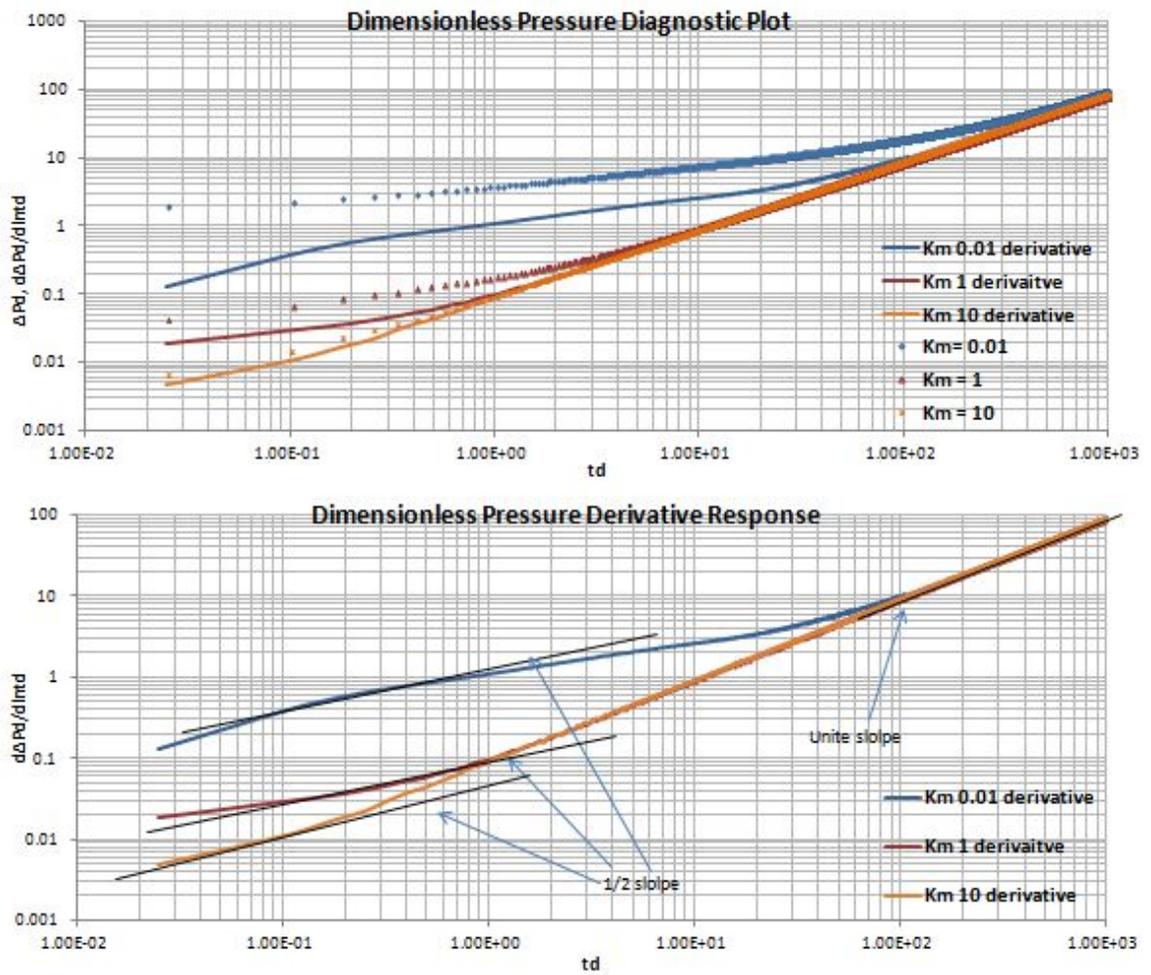


Fig. 3.18 — Effect of different matrix permeability values ( $K_m = 0.01, 10, 100$ ) on dimensionless pressure drop and derivative responses for a horizontal well completed in a homogeneous reservoir

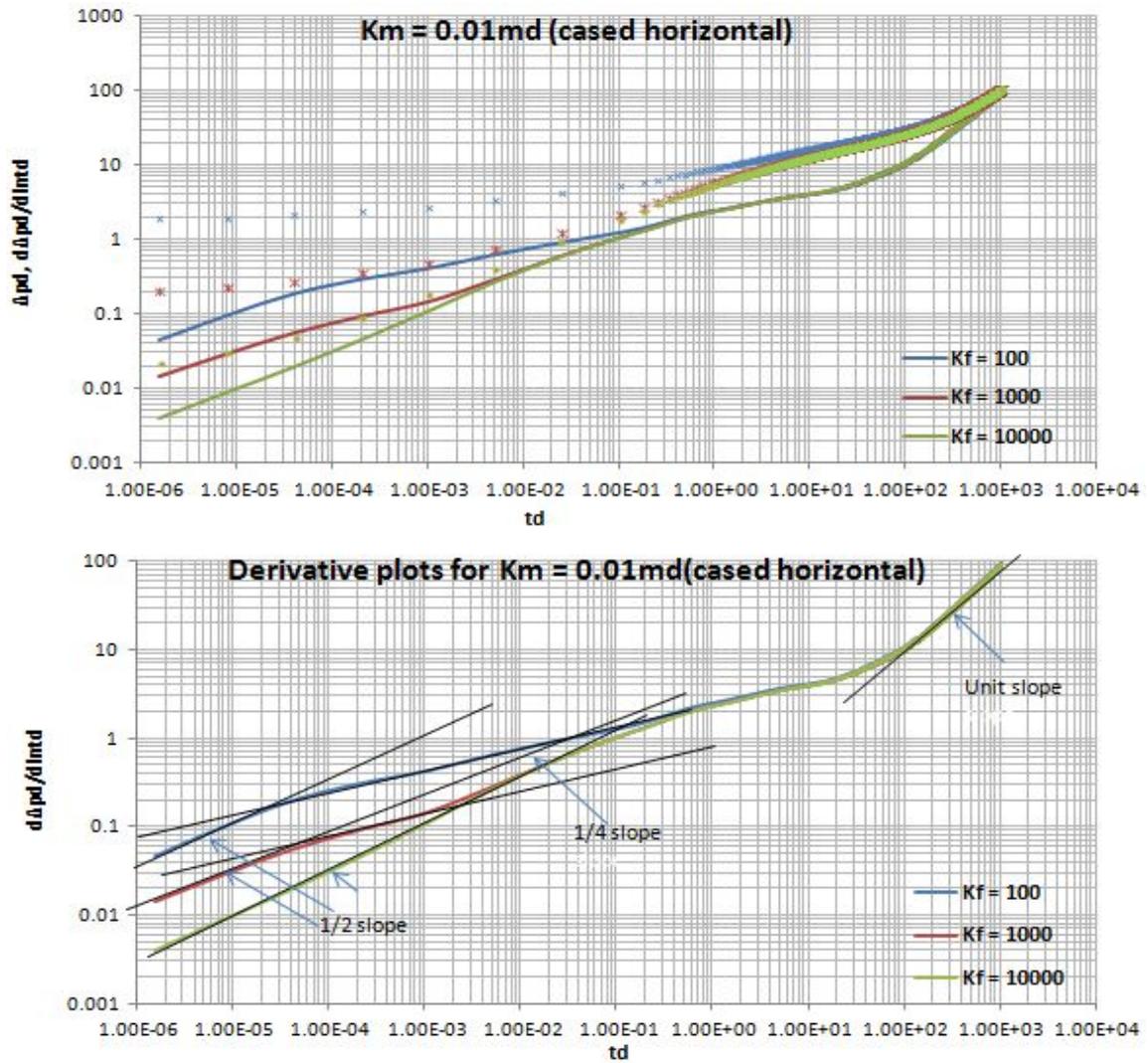


Fig. 3.19 — Effect of different hydraulic fracture conductivities ( $K_f = 100, 1000, 10000\text{md}$ ) on dimensionless pressure drop and derivative responses for a horizontal well with one transverse hydraulic fracture in a homogeneous reservoir

Then fracture permeability is the secondary factor that I consider. Fracture conductivity cases with different fracture permeability (100, 1000, 10000md) were simulated by CMG. Pressure transient performances for a horizontal well with only one transverse hydraulic fracture alongside the wellbore will be discussed first. The pressure derivative plot shown in **Fig.19** gave us a more discernible identification of flow regimes. Basically, there are three flow regimes: fracture linear flow, bilinear flow and boundary-dominated flow, as indicated by half-slope, quarter-slope and unit slope, respectively. Fracture linear flow is clear and dominant when  $K_f = 10000$  and the bilinear flow gradually fades out as the fracture permeability is raised.

Then, four equally spaced hydraulic fractures are presented. Formation linear flow, bilinear flow, outer reservoir compound linear flow and boundary dominated flow are basically flow regimes presented in **Figs. 3.20**, which show that for a transverse fractured horizontal well, conjunction disturbing influence could be negligible when the number of fractures reaches a certain amount, which is the major difference from one-fracture cases. It should be noted that when  $K_f = 10000$ md, the bilinear flow becomes the first flow regime followed by nearly two sets of linear flow. The first linear flow right after the bilinear behavior should be the formation linear flow and the second merged linear presence with  $K_f = 100$  should belong to the contribution of the inner reservoir which is known as the stimulated reservoir volume (SRV) region. So the last linear flow for all three cases is late-time outer linear flow from the unstimulated reservoir region. In addition, more complex combinations of fractures and horizontal wells would have more sophisticated pressure transient performances, however, these resulted flow regimes are more distinctly recognized by indications on derivative diagnostic plots.

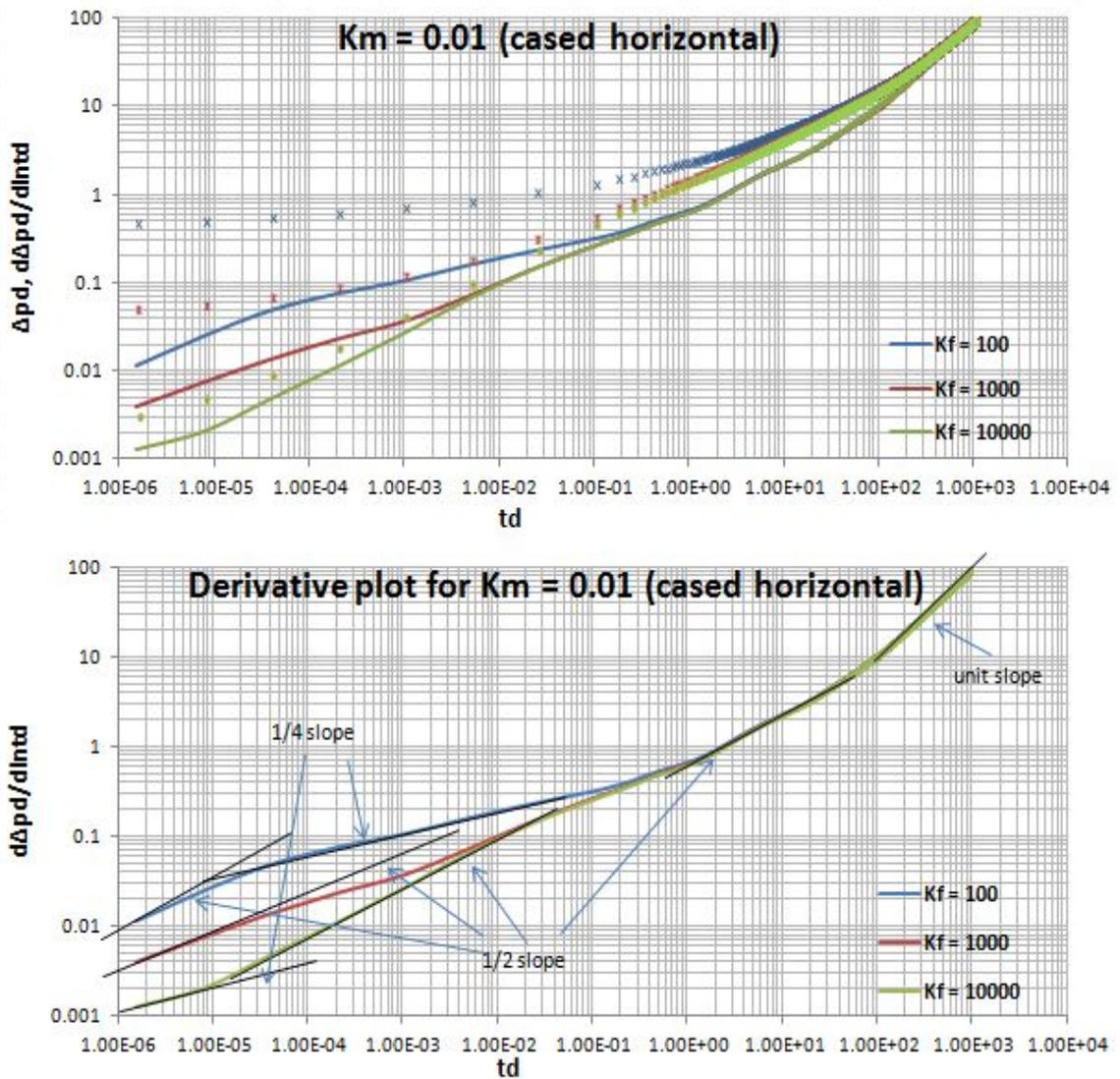


Fig. 3.20 — Effect of different hydraulic fracture conductivities ( $K_f = 100, 1000, 10000$ md) on dimensionless pressure drop and derivative responses for a cased horizontal well with four transverse hydraulic fractures in a homogeneous reservoir

## CHAPTER 4

### VALIDATION OF SIMULATION RESULTS AND COMPARISON BETWEEN ANALYTICAL AND NUMERICAL SOLUTIONS

#### 4.1 Model description and assumption

##### 4.1.1 Introduction of Kappa and CMG interpretation of reservoir characterization for pressure transient analysis

Today, safety and economics combined with technological developments mean that we need and are actually able to acquire, analyze, visualize and model on any scale in terms of time and dimension. Coupling this with the fact that reservoirs are of increasing physical complexity, data flow can be enormous and economics or lack of resources can limit the time spent on processing and analysis. There is clearly a need for an integrated tool suite to visualize, organize and analyze dynamic data on any scale or complexity, and Kappa is this kind of dynamic model. It can piece together any dynamic information happening within the reservoir during production or injection. The Kappa suite offers a workflow from the simplest near wellbore analytical analysis to the most complex full-field numerical cases with exotic geometry and fluids.

Saphir, the Pressure Transient (PTA) module of the Ecrin workstation were used to build up several cases with the same reservoir data input which was used for my CMG simulations. Because it offers an extensive and growing analytical model library and integrated numerical model with non-linearity, it is the most popular software among reservoir engineers. For numerical simulations, IMEX, CMG's new generation adaptive

implicit-explicit black-oil simulator were used which includes features such as local grid refinement, horizontal well and dual porosity options, etc. IMEX is a three-phase black-oil simulator; Cartesian grid systems are used for my simulation cases. Fully implicit modes for grids near the wellbore area and explicit grid blocks for the rest of the grids are applied when calculating simulation pressure drawdown performance; this could lead to a savings of one third to one half of the execution time instead of using fully implicit modes for all matrix blocks. For naturally fractured reservoirs, the dual-porosity of the Warren and Root option allows the discretization of matrix blocks and this approach idealizes the fractured reservoir as consisting of two parts: the primary porosity and the secondary porosity. The primary porosity (the matrix) represents the small intergranular pores in the rock matrix. The secondary porosity (the fractures) consists of fractures, joints, and/or vugs. The dual porosity approach is characterized by representing one reservoir volume with two continua. The fractures, having small storability, are the primary conduits of fluid flow, whereas the rock matrices have low fluid conductivities but larger storativities. A simple dual-porosity model using a one matrix/one fracture system may be specified. Shape factors are based on the work of Warren and Root (1963), so in all my cases, the matrix-fracture transfer is assumed to be under pseudo-steady flow.

The comparisons between numerical simulations and analytical solutions build based on CMG black oil builder and Kappa Sapphire give me a better understanding into the interpretation of the identification of flow regimes and further exploring into reservoir characteristics and properties interpretation of the identification of flow regimes and further exploring reservoir characteristics and properties.

## 4.2 Comparisons of pressure transient results between analytical solutions from Kappa and numerical results computed by CMG

Eleven typical cases were selected from the simulation interpretation for comparison with Kappa analytical results. These eleven cases were typically chosen from all four scenarios which represent general situations for fractured or unfractured horizontal wells in various-conditioned rectangular reservoirs.

### 4.2.1 Contrastive graphs of Pressure and its derivative responses generated by CMG numerical simulation and Kappa Saphir

A Homogeneous reservoir (homo):

Generally, the same trend is observed through numerical simulation modeling and analytical models run in Ecrin Saphir. Corresponding pressure and its derivative performances of CMG simulation analysis for all cases are generated in Kappa Engineering's Ecrin Saphir well test software. For horizontal wells completed with multiple transverse hydraulic fractures or longitudinal stimulated fracture which is located alongside the horizontal wellbore, pressure transient performances would present rigorous evidence and confidence in recognizing and identifying characteristics of flow regimes by specific indications like half-slope for linear flow regime and quarter-slope for bilinear flow regime. How do we weigh the dependability and credibility of numerical simulation results for pressure transient behavior of hydraulically fractured horizontal wells under various conditions?

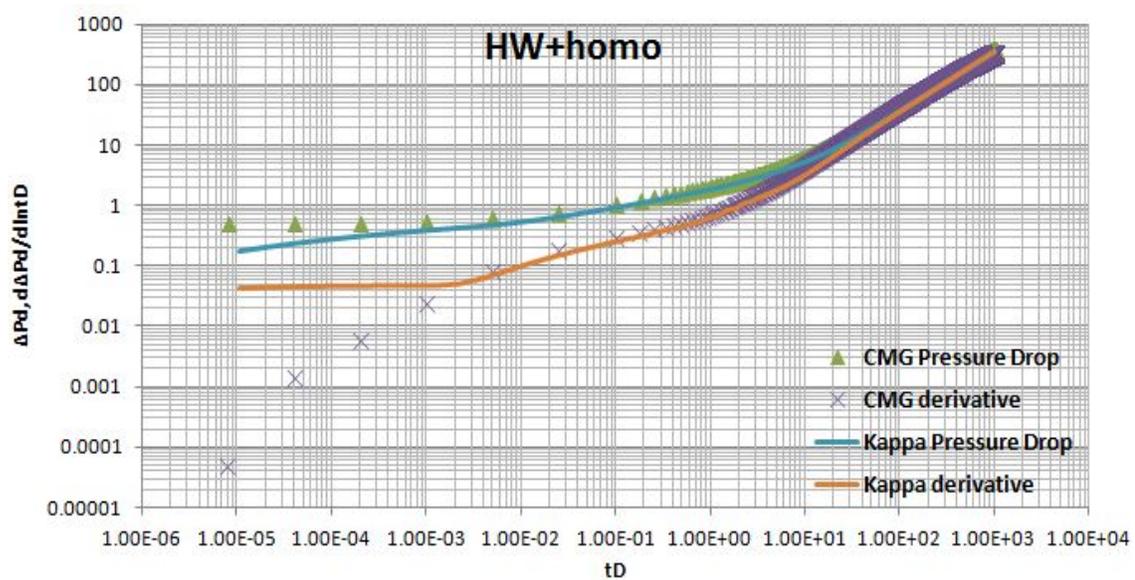


Fig. 4.1 — Contrastive plots of dimensionless pressure and its corresponding derivative responses for a single horizontal well in a homogeneous reservoir

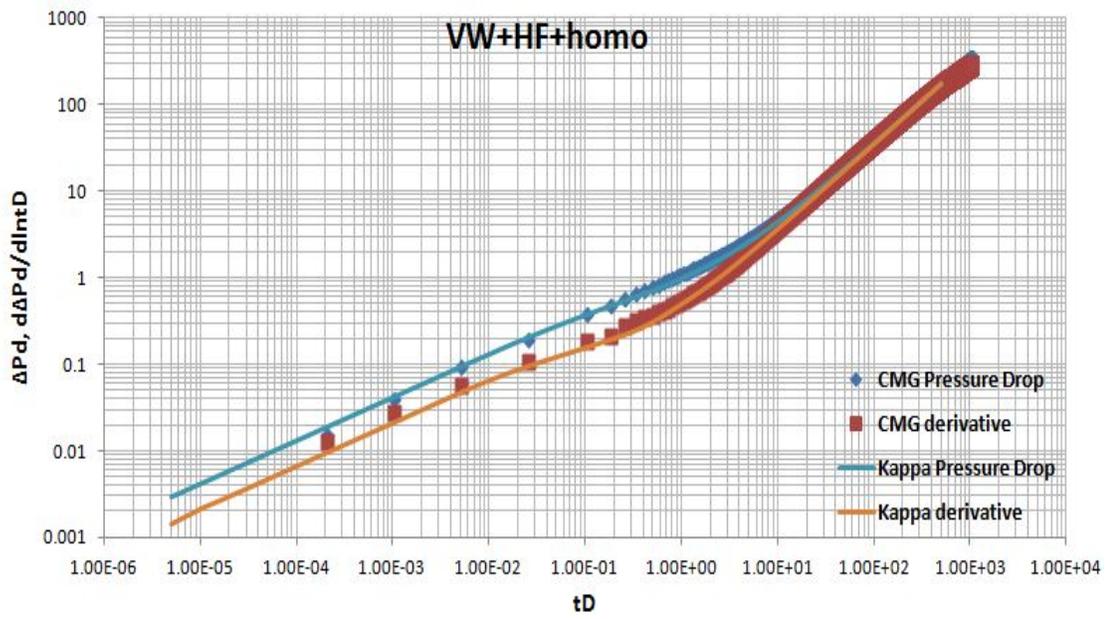


Fig. 4.2 — Contrastive plots of dimensionless pressure and its corresponding derivative responses for a vertical well in a homogeneous reservoir

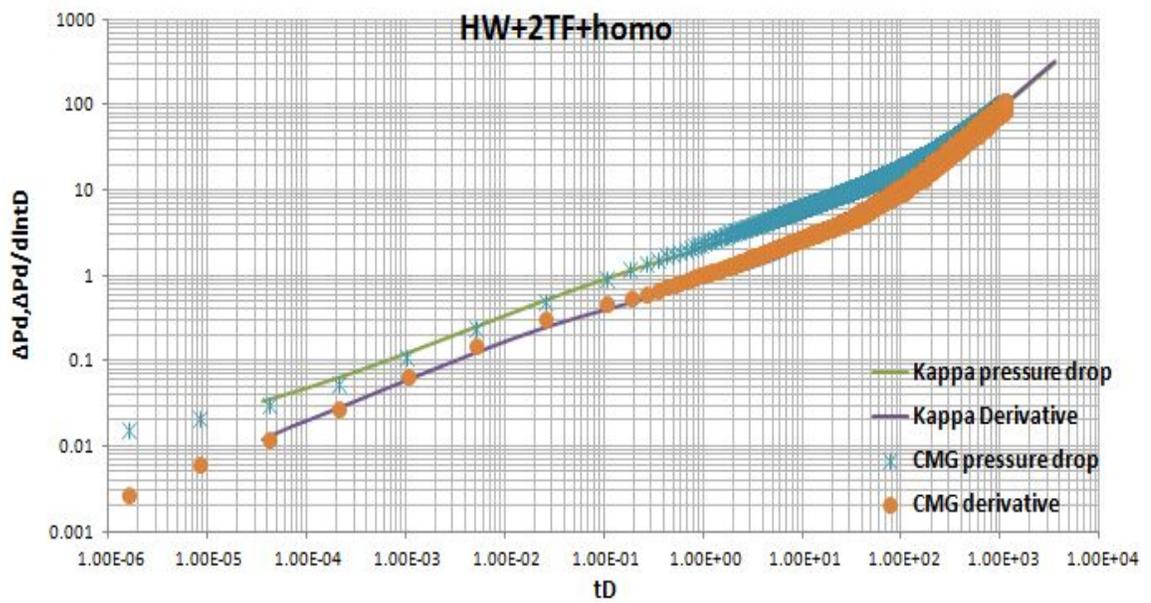


Fig. 4.3 — Contrastive plots of dimensionless pressure and its corresponding derivative responses for a horizontal well with two transverse fractures in a homogeneous reservoir

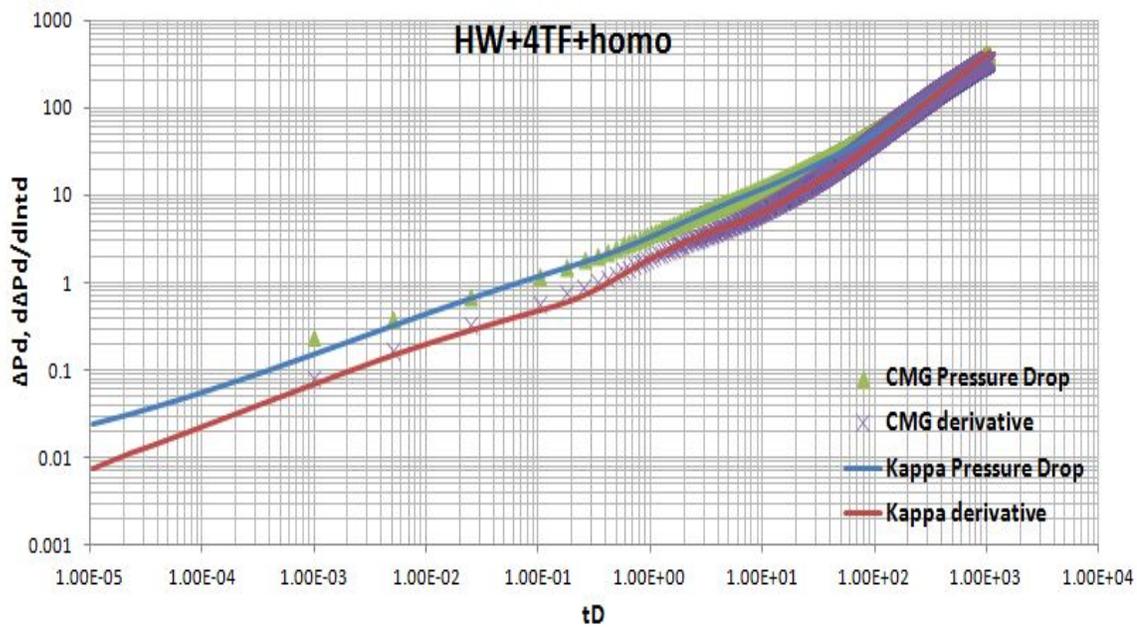


Fig. 4.4 — Contrastive plots of dimensionless pressure and its corresponding derivative responses for a horizontal well with four transverse fractures in a homogeneous reservoir

For the homogeneous reservoir, the comparison interpretation for flow regimes is identical for simulation performance and Kappa solutions with little discernible variance, the only difference happening at the early time, shown especially in **Fig. 4.1**. It did not show the early time radial flow expected for a horizontal well in a homogeneous rectangular reservoir like Kappa does, but an unrecognizable near unit slope line. To further understand this unexpected type of early flow, I built another case of a vertical well with a hydraulic fracture to represent a horizontal well draining from a rectangular geometry under the same conditions to compare the pressure transient performance with Kappa, as shown in **Fig.4.2**. The unrecognizable and indistinguishable difference in the matched curves on a log-log plot of pressure drop and its derivative gave me more confidence that the methodology and algorithm for the horizontal well in CMG computation may not have been very accurate because the well index used in CMG modeling may not precisely explain the flow inside the horizontal well blocks and the matrices connected to the horizontal wellbore.

As for the other cases selected for the comparison with Kappa analytical solutions, the dimensionless pressure drop and its corresponding derivative curves show a generally good match for horizontal wells with or without hydraulic fractures in homogeneous reservoirs.

#### **4.2.2 Comparisons of pressure drawdown performance between a finite-difference reservoir simulator, CMG IMEX and Kappa Ecrin analytical results for a fractured or unfractured horizontal well in a naturally fractured reservoir**

There are five matching log-log plots for horizontal wells with or without transverse fractures in a globally naturally fractured reservoir.

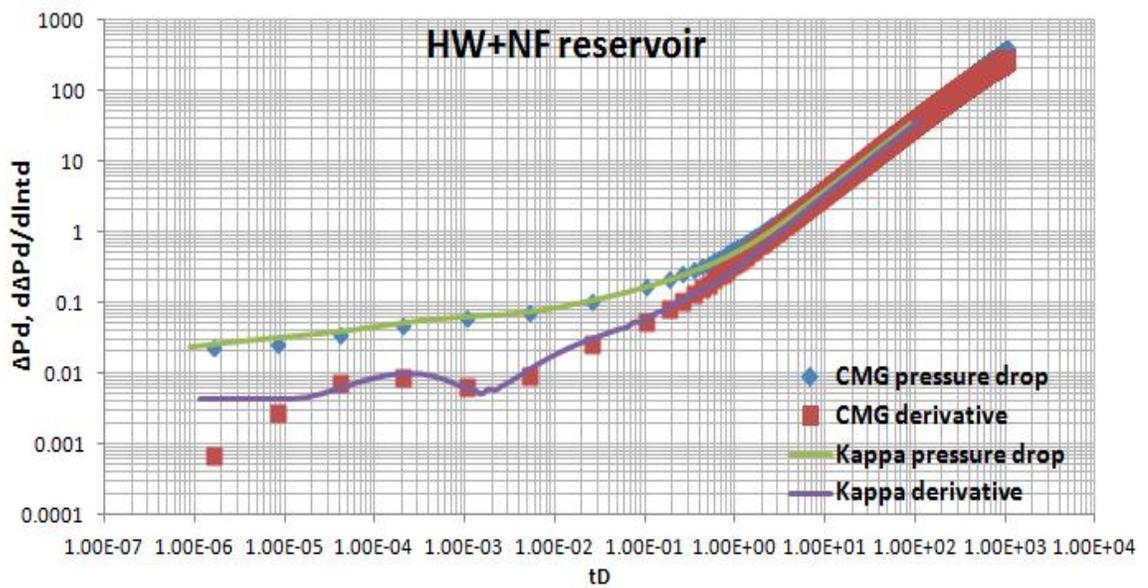


Fig. 4.5 — Contrastive plots of dimensionless pressure and its corresponding derivative responses for a horizontal well in a naturally fractured reservoir

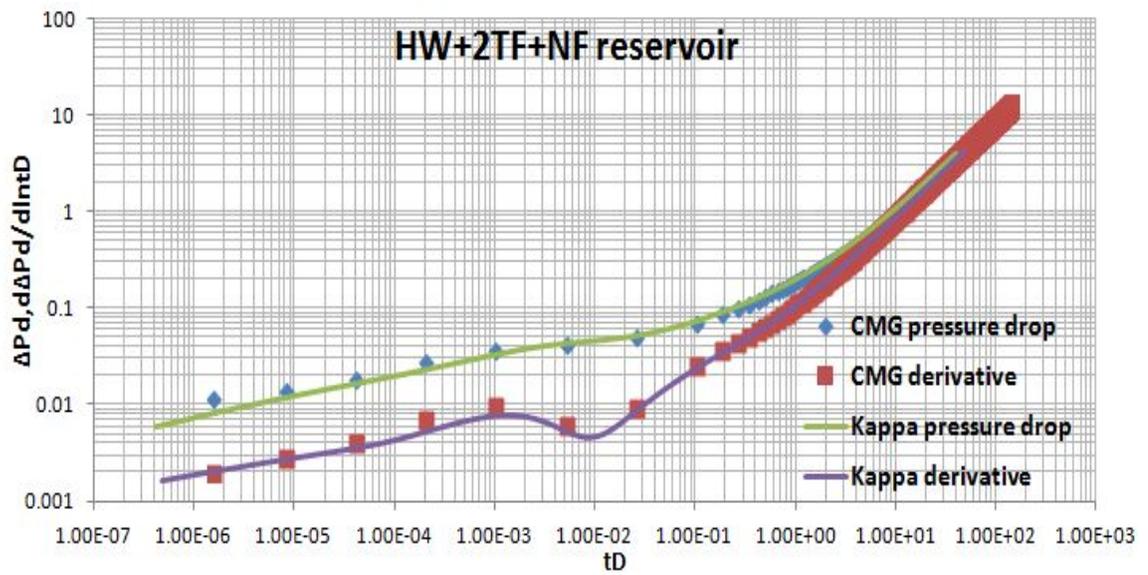


Fig. 4.6 — Contrastive plots of dimensionless pressure and its corresponding derivative responses for a horizontal well with two transverse fractures in a naturally fractured reservoir

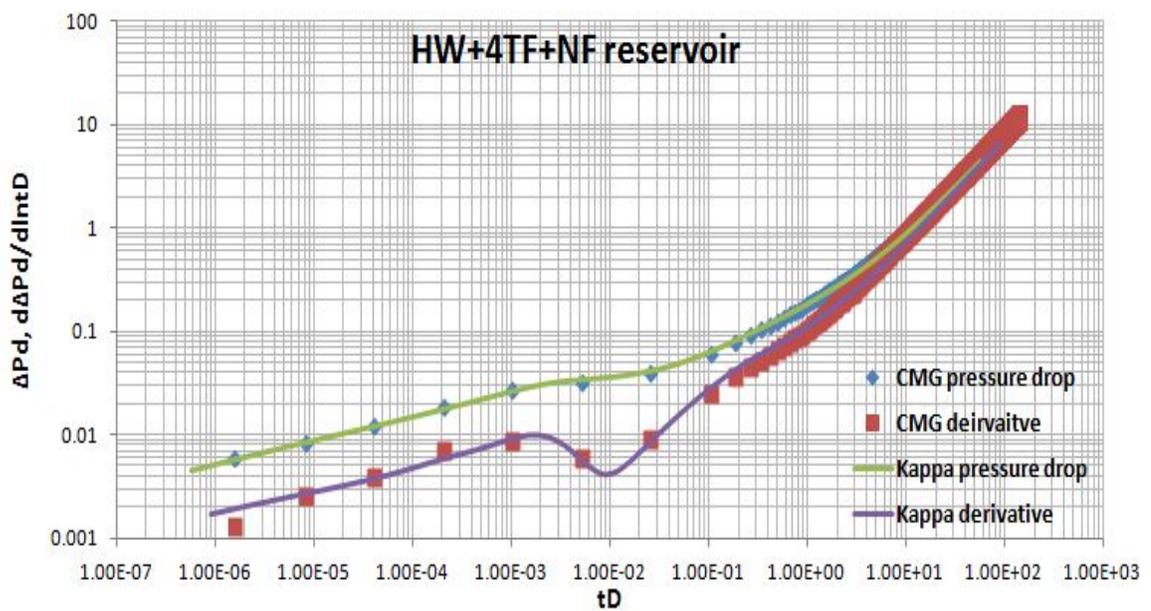


Fig. 4.7 — Contrastive plots of dimensionless pressure and its corresponding derivative responses for a horizontal well with four transverse fractures in a naturally fractured reservoir

From the matching results shown above, we can see that there is hardly any difference in the general trend of all the curves, the only variations happening at the very early time, shown in **Figs. 4.6** and **4.7**. This inconsistency can be attributed to the disturbance of unstable bottom pressure data resulting from the intrinsic algorithm for CMG's finite-difference numerical method. In the process of analyzing such a situation, these data are usually not taken into consideration. Particularly, as seen in **Figs. 4.3, 4.4** and **Figs. 4.5~Fig 4.7**, the effect of the horizontal well decreases when in the naturally fractured reservoir; the flow regimes does show much diversity when compared to that in a homogeneous reservoir when it comes to the late time flow period before boundary dominated approaches.

In general, these matching graphs show a good comparison consistency not only for open-holed horizontal wells with or without multiple transverse hydraulic fractures in a naturally fractured reservoir, but also for cased horizontal wells in which flow only occurs in the fracture. These comparison results sufficiently prove the credibility of all my simulation models and also improve the feasibility of numerical simulation for fractured or unfractured horizontal wells in a globally naturally fractured reservoir.

### 4.3 Comparisons of pressure transient performance of horizontal wells in dual-porosity and triple-porosity reservoirs between the analytical model and CMG simulation

#### 4.3.1 Introduction

In this section, we go to two semi-analytical models already developed in the industry, a dual-porosity system developed by Warren and Root (1963) and a triple-porosity model developed by Al-Ahmadi (2010), to describe flow performance and transient pressure behavior of a well in a naturally fractured reservoir. The comparison matching results are plotted in **Figs. 4.13** and **4.16** below to illustrate pressure drop and its corresponding derivative responses for a well in a dual-porosity and triple-porosity reservoir computed by the numerical simulator CMG and semi-analytical solutions.

#### 4.3.2 Dual-porosity model

Numerous analytical models have been presented recently to perform the pressure transient behavior of dual-porosity reservoirs which is a method most commonly used to describe naturally fractured formations. In this work, analytical solutions for sugar cube idealization of the dual-porosity system shown in **Fig. 4.8**, provided by Warren and Root (1963), is used to demonstrate the pressure transient performance of a vertical well in a naturally fractured reservoir.

Although naturally fractured reservoirs consist of irregular fractures, they can be represented by equivalent homogeneous dual-porosity systems (Warren and Root, 1963). This concept is composed of two porous media of different porosities and permeability. One medium, known as the primary porosity, is the matrix block, which contains the

majority of the fluid stored in the reservoir and processes a low conductivity. The other medium, the secondary porosity, is the fracture network, which acts as the conductive medium for fluid flow and processes a high flow capacity but a low storability (Warren and Root, 1963). This suggests that matrix function is a main source of hydrocarbons, while fractures become the flow path of hydrocarbon production. For this reason, interaction between the matrix and fractures should be considered. This interaction can be described by using a transfer function. The matrix-fracture function was given by Warren and Root (1963), as shown below, where  $q$  is the transfer rate,  $\alpha$  is the shape factor,  $k_m$  is the matrix permeability,  $\mu$  is the fluid viscosity and  $(p_m - p_f)$  is the pressure difference between the matrix blocks and the fracture system. The shape factor is commonly used and it is a crucial parameter in matrix-fracture transfer functions.

$$q = \alpha \frac{K_m}{\mu} (P_m - P_f) \quad (4.1)$$

The Warren and Root (1963) model was mainly developed for transient well test analysis in which they introduced two very important parameters,  $w$  and  $\lambda$ ; the storability ratio  $w$ , is defined by

$$\omega = \frac{(\phi V_{ct})_f}{(\phi V_{ct})_f + m} = \frac{(\phi V_{ct})_f}{(\phi V_{ct})_f + (\phi V_{ct})_m} \quad (4.2)$$

where  $V$  is the ratio of the total volume of one medium to the bulk volume of the total system and  $\phi$  is the ratio of the pore volume of one medium to the total volume of that medium. Subscripts  $f$  and  $f + m$  refer to the fracture and to the total system (fractures plus matrix), respectively. Consequently, the storability ratio is a measure of the relative fracture storage capacity in the reservoir.

Interporosity flow is the fluid exchange between the two media (the matrix and fractures) constituting a dual-porosity system. Warren and Root defined the interporosity flow coefficient,  $\lambda$ , as

$$\lambda = \alpha r w^2 \frac{K_m}{K_f} \quad (4.3)$$

Where  $k_m$  is the permeability of the matrix,  $k_f$  is the permeability of the natural fractures, and  $\alpha$  is the parameter characteristic of the system geometry.

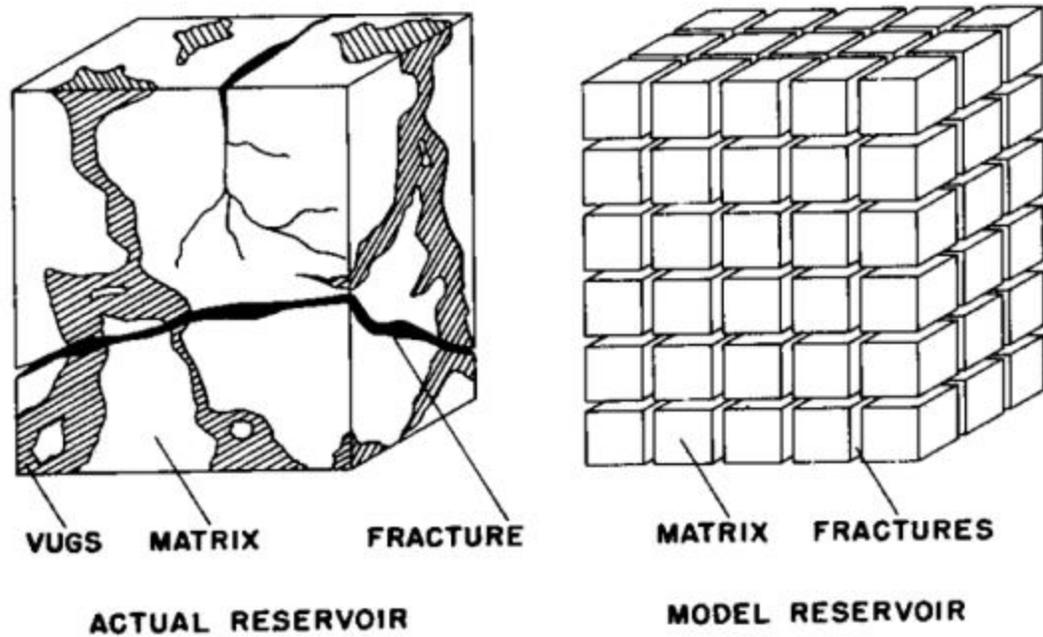


Fig. 4.8 — Idealization of the heterogeneous porous medium (Warren & Root 1963)

General assumptions and characteristics of the Warren and Root (1963) dual-porosity model

1. They assumed a pseudo-steady state flow between the matrix and fracture systems. This means that the pressure starts changing at each matrix block at time zero.

2. The naturally fractured reservoir (NFR) is simplified into blocks of matrix and fracture sets which look like sugar cubes (**Fig. 4.18**).
3. Each cube is known as a matrix that is contained within a systematic array of identical and rectangular parallelepipeds. Homogeneity and isotropy are assumed for matrix properties. All the fractures have constant characteristics; each fracture is parallel to one of the major axes so would be normal to the principle axis. All fractures are equally spaced with a uniform width and fill the entire reservoir.
4. The flow to the wellbore is sequential which means that fluid can only follow the pattern from the matrix blocks (primary porosity) to the fracture system (secondary porosity) then finally flow to the wellbore; it cannot happen between the matrix and the wellbore.

Governing equations for the Warren and Root (1963) mathematical dual-porosity model:

Based on the mass balance theory, the following equations are derived; “f” stands for fracture and “m” stands for matrix system:

$$\frac{\partial(\phi_m \rho)}{\partial t} + \text{div}(\rho v_m) + \mu^* = 0 \quad (4.4)$$

$$\frac{\partial(\phi_f \rho)}{\partial t} + \text{div}(\rho v_f) - \mu^* = 0 \quad (4.5)$$

The dimensionless forms for these governing equations are set as follows:

$$(1 - \omega) \frac{\partial P_{Dm}}{\partial t_D} - \lambda(P_{Df} - P_{Dm}) = 0 \quad (4.6)$$

$$\frac{1}{r_D} \frac{\partial}{\partial r_D} \left( r_D \cdot \frac{\partial P_{Df}}{\partial r_D} \right) - \omega \frac{\partial P_{Df}}{\partial t_D} - (1 - \omega) \frac{\partial P_{Dm}}{\partial t_D} = 0 \quad (4.7)$$

$$P_{Dm} = P_{Df} = 0 \quad (t_D = 0) \quad (4.8)$$

$$\left. \frac{\partial P_{Df}}{\partial r_D} \right|_{r_D=1} = -1 \quad (4.9)$$

By applying the Laplace transformation, these differential equations are defined as below:

$$\frac{d^2 \bar{P}_{Df}}{dr_D^2} + \frac{1}{r_D} \frac{d\bar{P}_{Df}}{dr_D} - \omega s \bar{P}_{Df} - (1-\omega) s \bar{P}_{Dm} = 0 \quad (4.9)$$

$$(1-\omega) s \bar{P}_{Dm} - \lambda (\bar{P}_{Df} - \bar{P}_{Dm}) = 0 \quad (4.10)$$

$$\left. \frac{d\bar{P}_{Df}}{dr_D} \right|_{r_D=1} = -\frac{1}{s} \quad (4.11)$$

$$\lim_{r_D \rightarrow \infty} \bar{P}_{Df} = \lim_{r_D \rightarrow \infty} \bar{P}_{Dm} = 0 \quad (4.12)$$

A small transformation on the boundary conditions was made and based on this model a semi-analytical solution was derived for my own case. The details are for the derivation of bounded boundary solutions, because the analytical solution of boundary conditions for the Warren and Root (1963) dual-porosity model is for a well-draining from an infinite reservoir situation, while my case is for a vertical well produced from a bounded cylindrical reservoir with no flow coming outside. The final contrastive plot for pressure transient behavior under constant production rate is shown in **Fig. 4.9**. we can see that the flow regimes illustrated from both analytical solutions (red solid line) and numerical simulations (blue solid diamonds) are pretty much the same and clearly demonstrate the flow regimes for a vertical well in a cylindrical reservoir: the early time radial flow around the wellbore is then followed by a dual-porosity characteristic dip, a pseudo-radial flow and ends with a unit slope line when pressure transient changes reach the boundary. No evident and conspicuous distinction in the matching trends could be seen; the

simulation trend does not have any fluctuation like other cases do; it is generally stable during the whole procedure. Traditionally, people used to think that the analytical model was more stable and constant in the production trend and especially for pressure transient analysis, but based on this comparison for pressure drop performance, simulation modeling is not really disappointing; at least it can be used for pressure transient analysis when it comes to modeling simple 1D flow in a naturally fractured reservoir.

### **4.3.3 Triple-porosity model**

To further estimate the behavior of naturally fractured reservoirs, a triple-porosity model were built through the application of CMG simulation to see if numerical simulation could be used to model more complex situations where the natural fracture system and matrix are modeled by a triple-porosity approximation.

Naturally fractured reservoirs are often modeled by using the dual-porosity system which assumes that the fracture and matrix blocks share the same properties throughout the whole reservoir. There are two major types of concept for triple-porosity, one is to consider different matrix systems and the other is dual-fracture properties without uniform fracture properties. The model used for pressure transient behavior comparison with simulation approximation is a dual-fracture triple-porosity model generated by Al-Ahmadi (2010). The sketch of this triple porosity model is shown in **Fig. 4.10**, in which the arrows indicate the fluid flow direction (Al-Ahmadi, 2010).

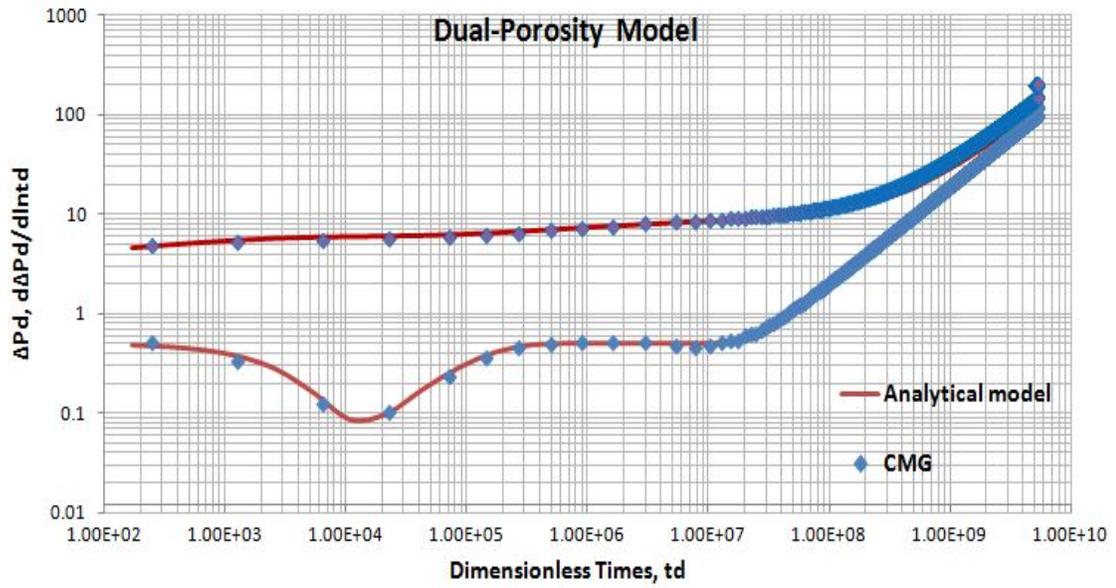


Fig. 4.9 — Contrastive plots of dimensionless pressure and its corresponding derivative responses for a well in a dual-porosity cylindrical reservoir

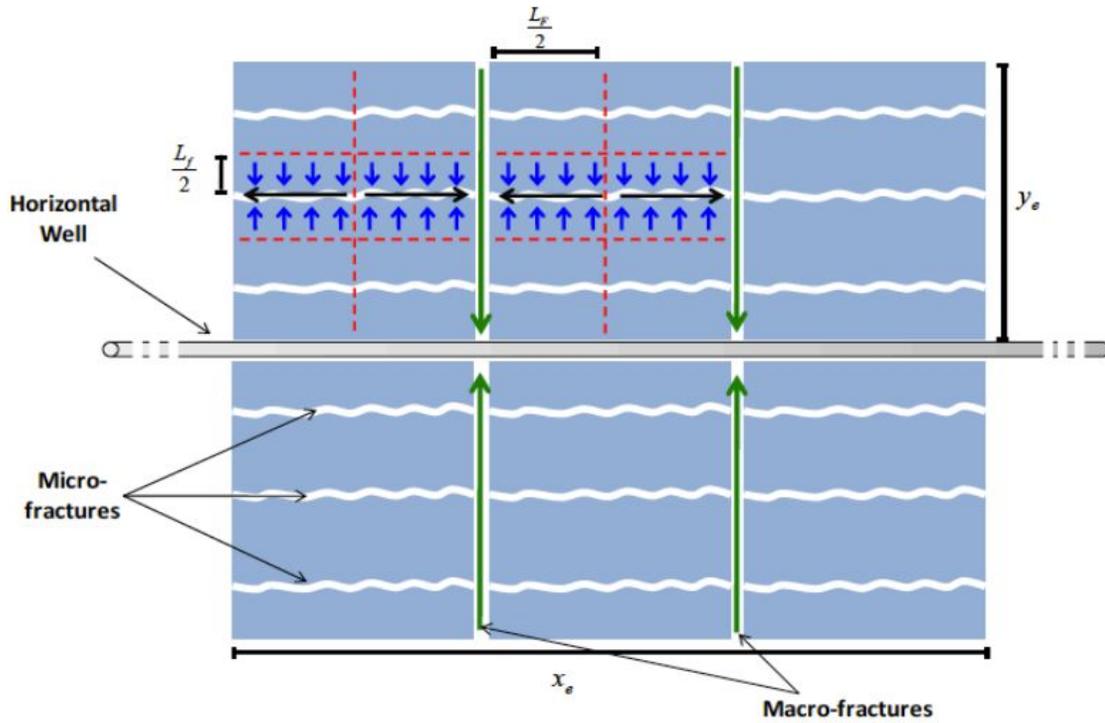


Fig. 4.10 — the top view of a horizontal well in a triple porosity system. Red dotted lines indicate virtually no flow boundaries. Arrows indicate direction of the flow (Al-Ahmadi, 2010)

Governing equations for this triple-porosity model are provided by Al-Ahmadi (2010):

$$\frac{12}{L_f^2} (P_m - P_f) = \frac{[\phi V \mu c t]_m}{K_m} \frac{\partial P_m}{\partial t} \quad (4.16)$$

$$-\frac{12}{L_f^2} (P_f - P_F) = \frac{[\phi V \mu c t]_m}{K_f} \frac{\partial P_m}{\partial t} + \frac{[\phi V \mu c t]_f}{K_f} \frac{\partial P_f}{\partial t} \quad (4.17)$$

$$\frac{\partial^2 PF}{\partial y^2} = \frac{[\phi V \mu c t]_m}{KF} \frac{\partial Pm}{\partial t} + \frac{[\phi V \mu c t]_f}{KF} \frac{\partial Pf}{\partial t} + \frac{[\phi \mu c t]_F}{KF} \frac{\partial PF}{\partial t} \quad (4.18)$$

General differential equations for three systems:

$$\text{Matrix: } \frac{12}{Lf^2} (pm - pf) = -\frac{[\phi V \mu c t]_m}{km} \frac{\partial Pm}{\partial t} \quad (4.19)$$

$$\text{Micro-fracture system: } -\frac{12}{Lf^2} (pf - pF) = \frac{[\phi V \mu c t]_m}{kf} \frac{\partial pm}{\partial t} + \frac{[\phi V \mu c t]_f}{kf} \frac{\partial pF}{\partial t}$$

(4.20)

$$\text{Macro-fracture system: } \frac{\partial}{\partial t}$$

The semi-analytical linear solution in Laplace space for constant production rate producing in a bounded reservoir is:

$$\overline{PwDl} = \frac{2\pi}{s\sqrt{sf(s)}} \left[ \frac{1 + \exp(-2\sqrt{sf(s)}yDe)}{1 - \exp(-2\sqrt{sf(s)}yDe)} \right] \quad (4.21)$$

Assumptions for this analytical model made by Al-Ahmadi (2010):

1. The horizontal well which is under a constant production rate is located at the center of a bounded rectangular reservoir.
2. The slightly compressible fluid flows strictly in a sequential pattern which is from the least permeable matrix to the middle permeable micro-fracture system and finally into the macro-fractures; there is no flow connection between any other media beyond that flow sequence.
3. This triple-porosity model is composed of a dual-fracture, one matrix system with uniform matrix properties and different fracture properties: less permeable micro-fractures and more permeable macro-fractures.
4. Homogeneity and isotropy are assumed for either matrix medium, or for two portions of fracture media.

Characteristics of my numerical simulation model (the sketch is shown in **Fig. 4.15**):

1. There are three systems in this triple-porosity approximation, uniform matrix blocks and two different sets of fracture media; the more permeable one fully penetrates macro-fracture approximation and the less permeable micro-fractures are normal to the macro-fracture.
2. There are specifically three sets of properties of porosities and permeabilities for each of the three systems.
3. The physical model of CMG simulation approximation is only two-thirds of the entire structure of the analytical triple porosity model, because to try to simulate sequential flow from one medium to another medium, I treated the horizontal well in the analytical model as a less permeable micro-fracture.

Input parameters used for triple porosity model interpretation and CMG simulation:

Table 4.1 — Input parameters of case studies

<b>Matrix blocks</b>	
Permeability	0.01
Porosity	0.1
<b>Horizontal Macro-Fractures</b>	
Half-length $X_f$ , m	450
Width, $w_f$ , m	0.5
Permeability, $K_f$ , md	10000
Porosity, $\phi_f$	0.00001
<b>Transverse Micro-Fracture Systems</b>	
Half length, $X_f$ , m	160
Width, $w_f$ , m	0.03
Permeability, $K_f$ , md	1000
Porosity, $\phi_f$	0.001

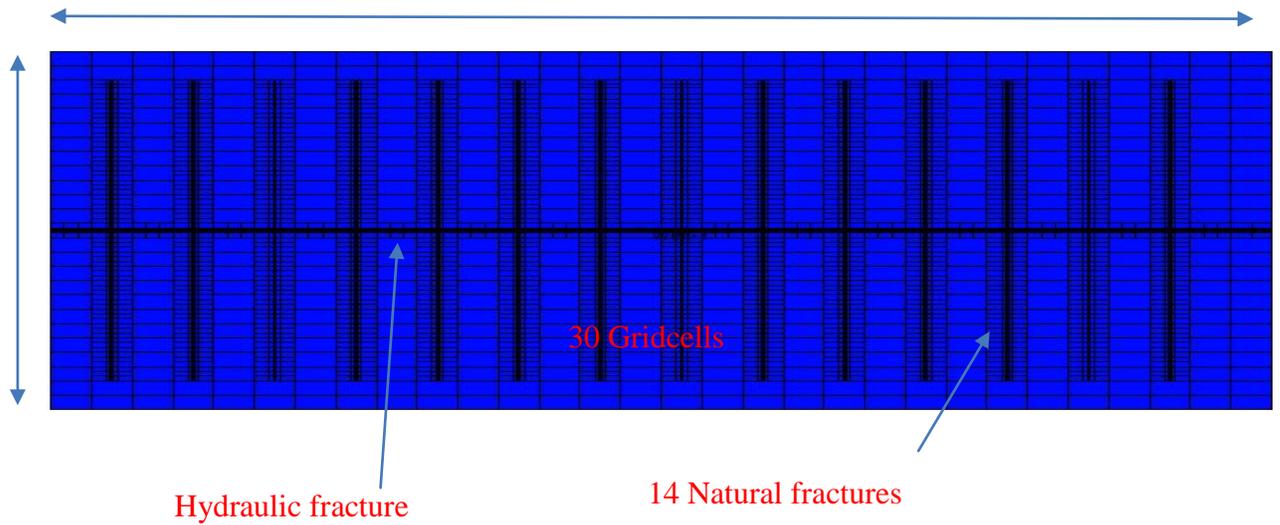


Fig. 4.11 — Top view of triple porosity model generated by CMG simulation

25

Gridcells

As we can see from **Fig. 4.12**, pressure drop (solid lines) and its corresponding derivative curves (solid markers) for analytical and numerical models show that they both present a constant trend and generally match to a limited extent, but the most important properties for the triple-porosity model are not shown clearly on the simulation derivative curve. There should be two characteristic dips which represent the properties of the triple-porosity model two transfer systems and the supplement of fluid between two media

could offset some pressure drop due to the drainage of the larger permeable medium. The reason CMG simulation could not show the first dip distinctively is that the flow cannot strictly follow the sequential pattern from high permeability to low permeability as the analytical triple-porosity model assumed, and the simultaneous drainage from any two systems might cover the additional dip appearance. And the occurrence of only the one dip in the simulation derivative responses is an indication of transfer between total fracture systems and matrix blocks.

Based on the discussion of the pressure transient performance comparison between the semi-analytical solution and CMG numerical approximation, we can draw the conclusion that the numerical simulation has the advantage of simplicity and transparency, but to some extent especially it models the horizontal well in a complex naturally fractured reservoir not only with natural fractures, but also with vugs, big holes and irregular fracture combinations. Simulation could not reach certain accuracy and might become distorted when dealing with late-time pressure data performance because of the limitation intrinsically within the algorithm of the numerical simulator as well as the sensitivity and susceptibility of the pressure data itself. However, matching performance from **Fig. 4.12** does show consistency and accuracy on presence and demonstration of flow regimes.

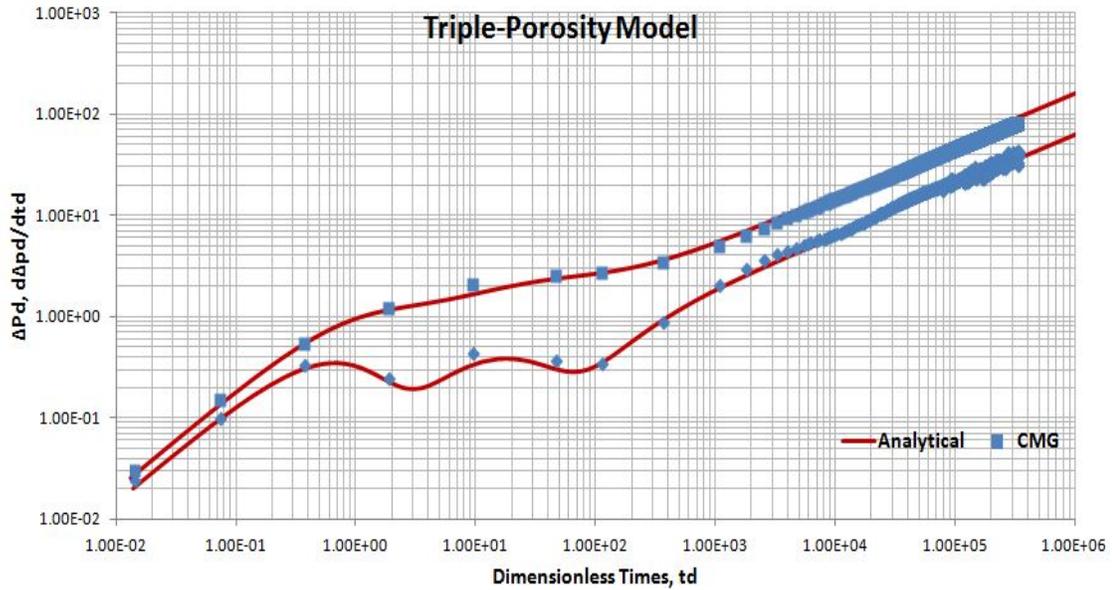


Fig. 4.12 — Contrastive plots of dimensionless pressure and its corresponding derivative responses for a horizontal well in a triple-porosity reservoir

#### 4.4 Summary of the comparisons between simulation performance and analytical solutions based on Kappa and semi-analytical models

1. The commercial software Kappa Ecrin Sapphire provides ergonomic tools that integrate, navigate and communicate within a single environment, cutting waste, time and training overheads, and it is always robust engineering software for well test pressure transient analysis and is an easily handled comparison tool. So the matching results between CMG numerical modeling and Kappa analytical

solutions showed us a perfect match, especially after the very early transient linear flow. This inconsistency might be intrigued by pressure distortion processed by the simulation algorithm, but the conclusion can be drawn as CMG is trustworthy commercial software.

2. The CMG numerical model gives a good indication of possible flow patterns or formation layouts in the reservoir due to its flexibility. It allows one to modify the reservoir model condition to understand different behaviors of the pressure response. In addition, CMG is very useful for modeling less complex reservoir conditions such as formations with heterogeneities to a certain extent.
3. When dealing with more complicated reservoirs with a lot of heterogeneity and complex combinations of natural fractures and hydraulic fractures, the numerical simulator has a problem with accuracy and time limitation.
4. CMG is the most fool-proof engineering software and it is commonly used by reservoir engineers. Even though the computing time and data fluctuation might be a problem, the accessibility and generally accurate identification of flow regimes could make it a feasible tool in the long run.

## **CHAPTER 5**

# **FIELD PRODUCTION DATA ANALYSIS IN THE BAKKEN AND VILKING FORMATION**

In this chapter, oil production data of 150 wells are extracted through Geoscout from the Bakken formation in Southeastern Saskatchewan, Canada to illustrate the production decline analysis based on the newly developed four empirical methods, along with the traditional and classical Arps rate-time relations, comparing the history matched performances with production type curves generated with the use of a CMG.

Four empirical methods are 1) the Power Law Exponential Decline, 2) the Stretched Exponential Decline, 3) Duong's Method, and 4) the Logistic Growth Model. The methods are compared with numerical simulation models in terms of accuracy and fitness with historic field production data. Each method has its own formulation forms and tuning parameters, and they were all developed recently for tight and shale reservoirs.

### **5.1 Introduction**

Analyzing production data and predicting performance of wells from tight oil formations is a challenging task. The complicated geological background for these types of reservoirs often provides daunting problems for reservoir engineers because the hydraulic fracturing stimulating process would re-open those preexisting natural fractures. Furthermore, production data are generally considered to be unstable in the process of acquisition. To date, there have been significant improvements in tools for

analyzing production decline behavior, in which reservoir engineers can extract the reservoir characteristics, such as permeability (K), reservoir thickness (h), hydraulic fracture half-length (L<sub>f</sub>) and stimulated reservoir volume, etc. The interpretation of modern production decline analysis can be summarized in four ways, as follows.

A: Type-Curve methods: Type-curves provide a powerful method for analyzing production data, by matching actual production rate to analytical solutions to flow equations which are casts in dimensionless form. Sometimes normalized rate and pressure functions (pseudovariables for gas) are used for decreasing the uncertainty and transforming the real production data onto the type-curves developed for slightly compressible fluid under a constant production rate or bottom-hole pressure constraints. Because they are usually plotted on logarithmic coordinates, it is convenient to compare actual field data plotted on the same coordinates to the type-curves. The results of the comparisons would provide us with not only qualitative but quantitative information on target formations. Fetkovich is like the predecessor to the present incipient type-curve plots; the Blasingame plot (Palacio and Blasingame, 1993) and Doublet (1994) provided another set of type-curves with different assumption opposed to Fetkovich where constant bottomhole pressure is always assumed.

B: Straight-line methods: These methods act like diagnostic plots assisting researchers with identification of flow regimes, cast in dimensionless form on Cartesian plots in which production data are plotted with time or cumulative production functions. Sometimes production data are corrected as normalized rate variable flowing bottomhole pressure. Specialty plots such as square-root-of-time plots and quarter-root -of-time plots are mainly used for the interpretation of linear flow regimes, especially for bilinear flow

with an extension of a straight line on such plots. With the assistance of these plots, some fracture properties like fracture half-length and a stimulated drainage area would be acquired.

C: Analytical and numerical simulation: these models have come into use to understand production behavior and the ability to forecast future performance by history-matching with actual production rate with the development of different operations of various qualities and quantities.

D: Empirical rate-time relations: Arps' decline analysis is used for the ultimate recovery of conventional oil and gas reservoirs through fitting and extrapolating production rate-time plots predicting long-time production performance, but this method is formulated by analyzing wells during boundary dominated flow. There are four empirical methods which can be used to reach fitting historical rates.

## 5.2 General information about the target formation

The Bakken formation is mainly prevalent in the Williston Basin area that is located in southern Saskatchewan and North Dakota; it stretches out into Manitoba, Canada, and Montana and South Dakota in the United States. It is divided into three formation layers and most of the production occurs at the middle Bakken which is deposited from the late Devonian-early Mississippian period as a relatively thin accumulation of siltstone and sandstone sandwiched between the upper and lower organic-rich shales. Exploitation of the middle Bakken formation is considered as a development of a low-permeability reservoir which has been produced over 40 years since the first production in the Roncott Pool in 1956 where very limited production was obtained as conventional vertical well production was used. The application of horizontal drilling and multi-stage hydraulic-

fracturing stimulation technologies as a combination has become a critical and economic implementation to commercially and effectively drain this kind of tight formation, allowing adequate productivity to make this play economically sufficient. The horizontal drilling along with the technology of hydraulic fracturing increases the exposure and surface contact area towards the target formation and fracturing-stimulated treatment boosts the low-permeability hydrocarbon production by building an effective connection between the horizontal wellbore and recoverable rocks around the completion area.

More recently, most of the production from the middle Bakken has been high-quality oil with API 40°, and monthly production data of those wells extracted through Geoscout within the investigation area in the Viewfield pool were found at an average depth of about 1500 m, with multi-stage hydraulic fracturing. The sketched view for the location of Williston Basin and the Viewfield area within the basin are shown in **Fig. 5.1** (Barry T, Hlidek and Brad Rieb (2011)).

The productive middle Bakken member depicted is composed of a medial calcite, or rare dolomite cemented fine, quartzose sandstone and siltstone with ripple, cross-bedding and flaser bedding, as well as interlamination of sandstone and claystone and local occurrences of oolitic calcarenite (Reported by Nordquist, 1953). The upper and lower organic-rich shale rocks contain an impoverished fauna and flora dominated by conodonts, lingulids and playnomorphs which were deposited in relatively deep marine conditions acts as a source rock with high maturity of Kerogen. The interpretation presented in this chapter includes monthly oil production data Bakken categorization based on sequence of different flow regime periods and comparisons of history matching

performance among empirical decline curve analysis and with numerical simulation matching presentation by using CMG.

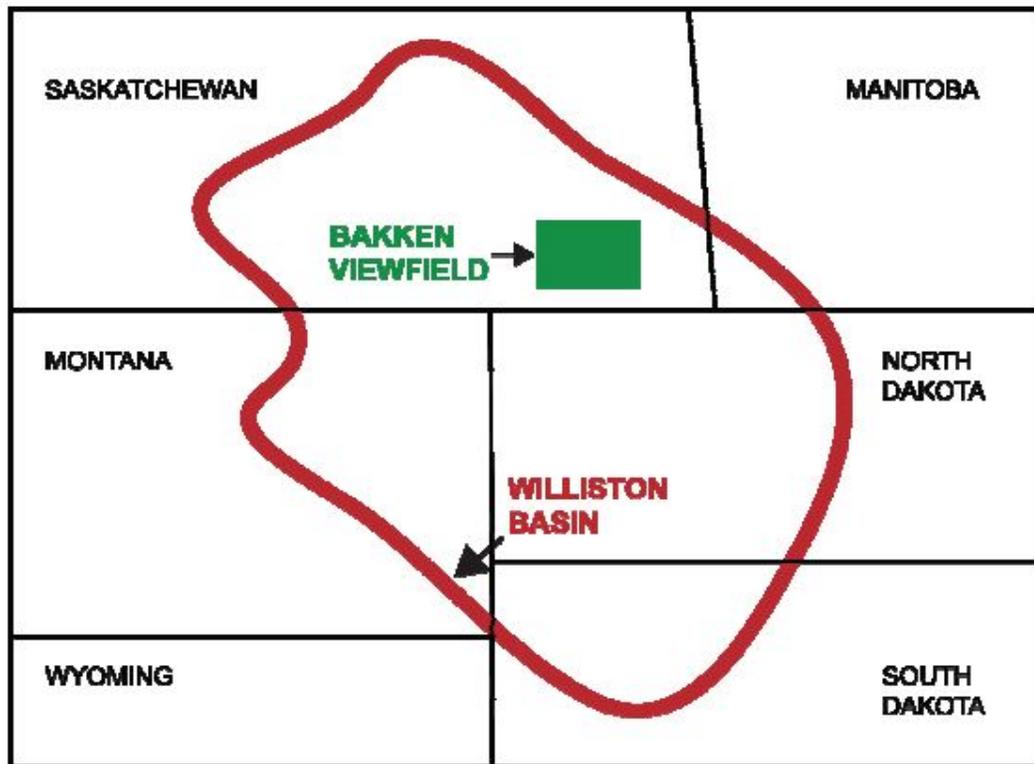


Fig. 5.1 — Geological location of Bakken formation in Williston Basin (Barry T, Hlidek and Brad Rieb (2011))

### 5.3 Field data categorization

There are 150 oil production wells being analyzed and categorized into four mainly different production decline trends depending on changing of flow regimes. They are assorted by various flow regimes of production decline characteristics appearing on the log-log plot of instantaneous production rate versus time which has a very important meaning for interpreting decline curve analysis. In the total of 150 wells, reservoir pressure is above the bubble point pressure and no gas is releasing out; oil flows as a single phase through the whole production time. The gas oil ratio (GOR) is almost a constant from the production history. This kind of plot is known as the most basic diagnostic tool, being a little more than visual observation-based approaches for the acquisition of flow regime identification. Pressure transient data are often treated like part of a controlled surveillance tool for analyzing production data because they share the same governing rules. When it comes to analyzing actual field production rates, there would always be tremendous and considerable variations occurring in the process of acquisition and the scattering production data often lead to uncorrected interpretation for obtaining the appropriate reservoir information. Therefore, empirical rate-time decline curves were applied plus type-curves generated by simulation modeling to history-match the historical oil production data and give a better understanding of predicting and forecasting future production trends and to compare the effectiveness and behavior of the aforementioned methods with my CMG based type-curves. In any case, the objective of

production decline analysis should be to model the production history of the line of the rate-time equation.

All of these types of production trends for wells are produced in the middle Bakken formation shown below in **Figs. 5.2 to 5.5**; they are plotted in logarithmic form of production rate versus time. We can see from these plots without the right axis showing that wellbore flowing pressure coupled with operation change helps me to visualize changes to assessing if these data are correlated; the premise of this work is that all data are accurate without correlation corruption. All four types of production decline shape show evidence of transient flow implying that well performance is tied to the reservoir properties and hydraulically fractured completion treatment in a low permeability formation. Most wells do not show boundary dominated flow which is due to the depletion or volumetric drainage outside of the contact reservoir because the low permeability delays the pressure propagation to the boundary.

Linear flow is observed and expected in all types of flow which is evidence of hydraulic fracturing stimulation. Sometimes bilinear flow, indicated by a quarter slope on a log-log plot of production rate against time, is followed by a transient linear flow which may be due to the presence of natural fractures or simultaneous drainage from both fracture systems and a certain amount of support from the matrix. There are two periods showing linear flow which illustrates a staircase in the logarithm plot, probably contributed from the compound linear flow outside of the hydraulic fractured area which is known as “stimulated reservoir volume (SRV)”. Analyzing production data should follow a step-by-step function provided by Blasingame and Ilk (2007): 1) Actual production data review and scrutiny; remove the spurious data for clarity identifying flow

regimes; 2) Identify flow regimes based on diagnostic plots which should be used through the normalized productivity index versus the material balance time logarithm plot or Blasingame plots; however I do not have any pressure data, so this part is only played by using the nearly visualized simple production history plots on the log-log dimensions; 3) Compare actual production data to analytical and simulation models and refine model parameters to improve the match; and 4) Summarize the matching results.

Type I production trend can be divided into two linear flow periods which exited a stepped transition within as we can see from **Fig. 5.2**, the reservoir characteristics can be described as that the production is declining initially due to the rapid drainage of oil linearly flowing from the hydraulic fracture into the horizontal wellbore which is characterized by a  $\frac{1}{2}$  slope indication, the second linear flow decline could be considered to be the fluid support from the surrounding matrix which flows normally to the fracture face or compound linear flow from the area beyond the wellbore/hydraulic fracture system. Production decline trend for type II shows a long time linear flow period for almost two log-cycles which means that fracture linear flow has generated during the whole production or this linear trend dedicated to the matrix system due to most fracture linear flow always displays rapidly without appearing on diagnostic plots. No matter this linear flow comes from fracture system or matrix blocks, multistage-hydraulic-fracture system could be large enough to sustain this long transient linear period. Type III and type IV both show incipient bilinear flow, concurrent drainage from any two of systems which consist of hydraulic fracture, natural fracture system and matrix blocks could account for this phenomenon since hydrocarbon generated is over pressuring the middle Bakken formation which resulted in creating natural fractures in the formation. Two

linear flow periods are also obtained as shown in Fig. 5.4 and bounded flow only exists in the type IV, detailed description would be discussed in the following discussion.

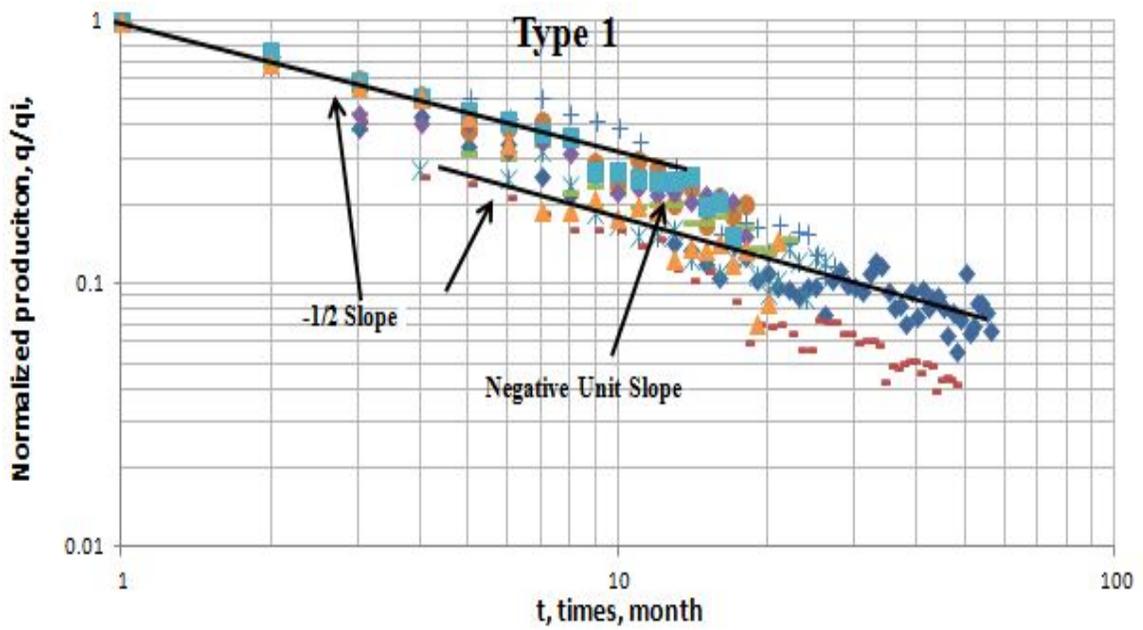


Fig. 5.2 — Type 1 log-log plot of oil production

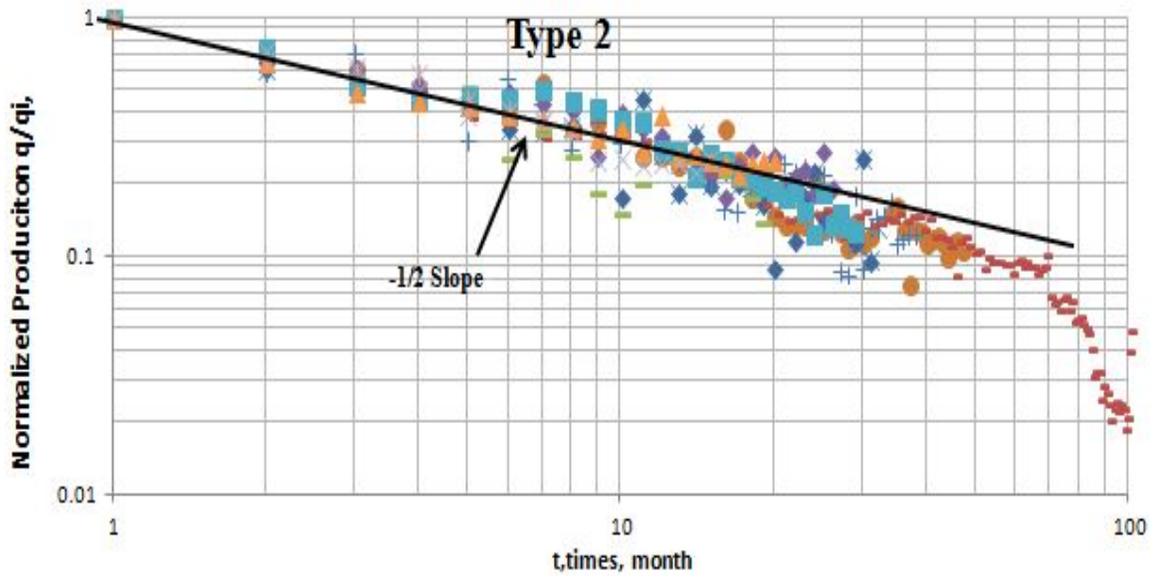


Fig. 5.3 — Type 2 log-log plot of oil production rate versus time

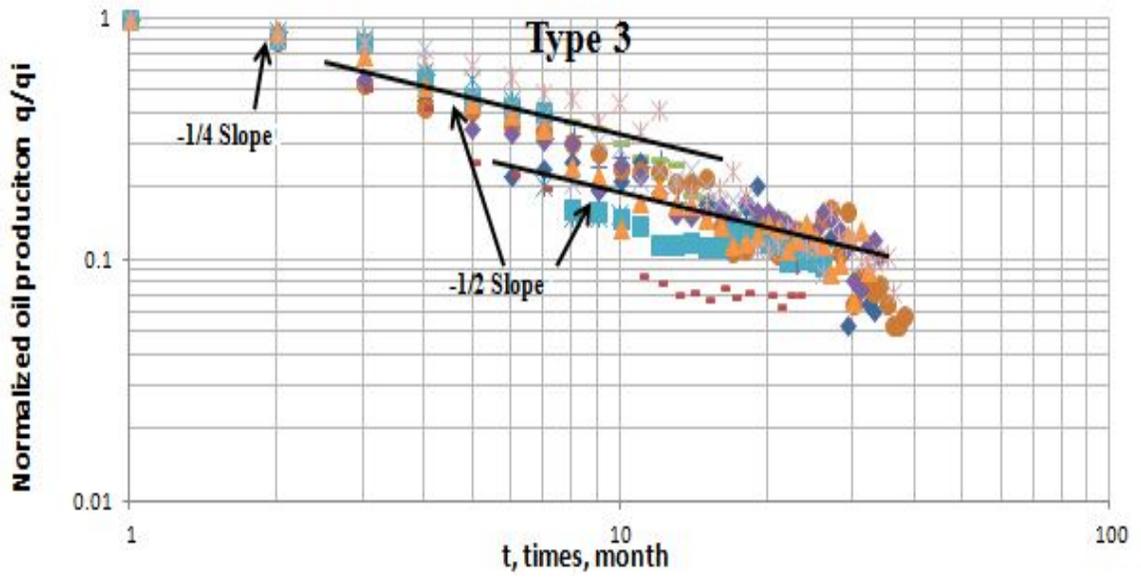


Fig. 5.4 — Type 3 log-log plot of oil production rate versus time

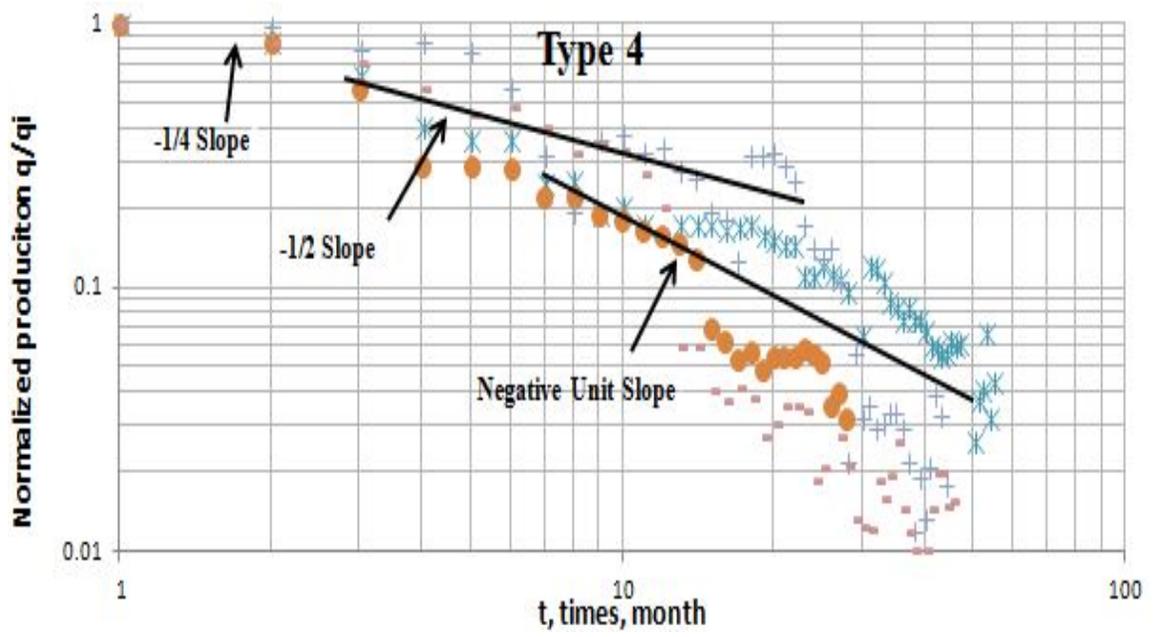


Fig. 5.5 — Type 4 log-log plot of oil production rate versus time

## 5.4 Comparison of empirical decline curve methods for Bakken Wells

Four wells typically chosen from type one to four are selected for history matching performances with analytical and simulation models: Well ID 191/01-33-006-09W2/00 (4414) is considered as well #1, Well ID 191/04-24-006-08W2/00 (4330) as well #2, Well ID 191/14-09-010-07W2/00 (4414) as well #3 and lastly Well ID 191/14-02-009-09W2/00 (4414) as well #4 in the following expanded description. Well #1, selected for detailed discussion from type 1, presented a stepped shape for the whole production history from the solid blue diamond markers in **Fig. 5.6**. As shown in the graph below, there are two recognizable linear flows characterized by half-slope indication with a transition period in between. Based on the logical theory and speculation from usual operation treatments and all the wells completed in the Viewfield area are hydraulically fractured and also drilled horizontally in the middle Bakkan formation. The first linear flow could be the representation of depletion from the matrix around the fracture system and the flow direction is normal to the fracture extension. The second linear flow might be induced by the outside area of the stimulated reservoir volume and the flow direction should be identical to the fracture completion area. Alternatively, there is another possibility that the first linear flow might be a fracture linear flow and second belongs to the inner reservoir linear flow between fracture systems. There are many explanations for these linear flows; a specific description can be made only after more detailed completion and operation information has been provided.

Then, continuing the discussion for flow regime characteristics, from the log-log plot of production rate versus time without any correction and adjustment of well #2, we can see that flow regimes illustrated in **Fig. 5.6** show a clearly distinct long-time linear flow for a duration of almost two log circles, which demonstrates that the transient linear flow is the dominant performance for this type of well. The reason for this long-time linear flow may be that a long, big fracture with high conductivity located in the production spot or a fracture system is stimulated and completed with multiple stages alongside the wellbore. In addition, the reactivated and reopened natural fractures around the hydraulic fracture stages during the stimulation process may be contributing to this long transient linear flow because of the low permeability and tight formation properties.

The third type of flow is the combination of bilinear flows, with two sets of linear interpretations. We can see from **Fig. 5.6** that well #3 exhibits a short period of bilinear flow at the beginning of production followed by two sets of nearly separated linear flows until the end of production. The whole process lasts one and a half log cycles, which is two years. Fracture indication is apparently evident by quarter and half slopes which could be the results of complex horizontal-fracture stages; each of the regime causes need to be discussed with the assistance of more detailed stimulation data and pressure information. In the last type of production trend provided by **Fig. 5.6**, with a variation of the previous flow regime from type 3, the boundary dominated flow is shown with some data fluctuation; the first bilinear and linear flows last for the duration of one log cycle. Since the middle Bakken has limited net pay, fracturing stimulation often penetrates the upper and lower organic rich shale with large hydraulic fracture half length. From the last type, the short presence of linear flow may be attributed to slight fracturing stimulation,

at least fracture half-length is not long enough to satisfy oil production from those tight shale formations, and the production seen from this plot is totally from the middle Bakken fine-grained silt sandstone.

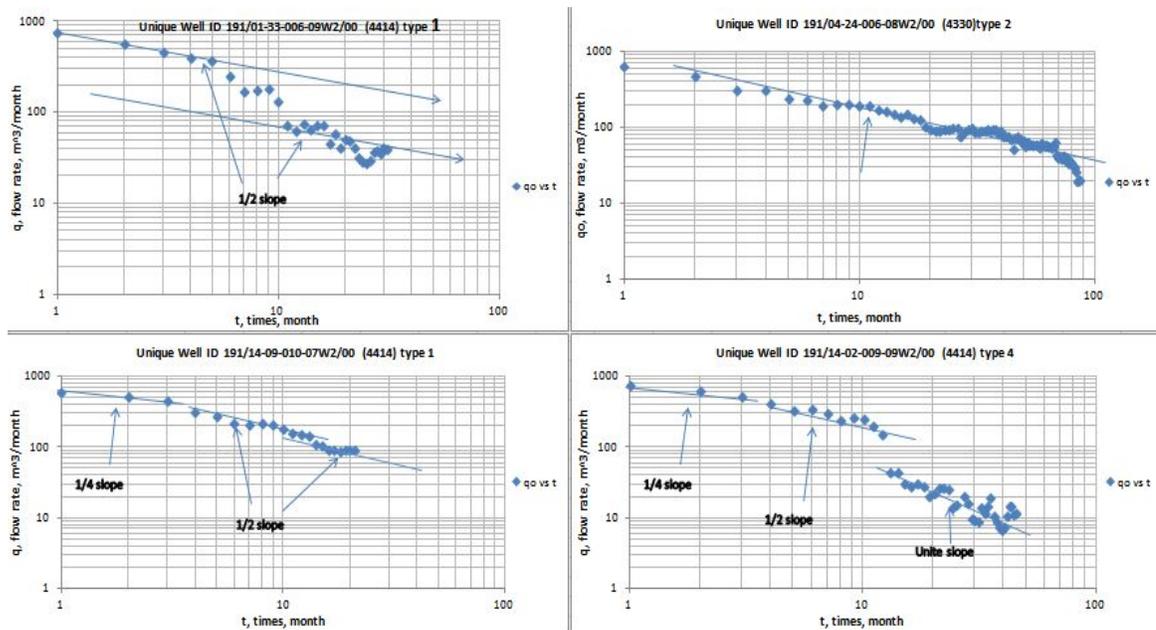


Fig. 5.6 — log-log plot of production history of four selected wells from type 1 to type 4, respectively

#### 5.4.1 Simple description of these empirical decline methods

Arps:

Arps (1945) laid a foundation for the development of modern production decline curve analysis after publishing a family of functional rate-time relations based on a comprehensive review of previous efforts for the graphical interpretation of production rate. Based on a variety of results, Arps proposed three types of rate-time relations including the exponential, hyperbolic and harmonic rate decline relations that still stand as benchmarks today to be used for decline curve analysis. The utility and popularity of this method is the applicability of the hyperbolic set of curves to model a wide range of production characteristics by extrapolating a production semi-log plot (log q vs. t).

The hyperbolic model is more general while the other two are degenerations of this model. Two important parameters present in Arps' decline curves are loss ratio: D and the derivative of loss ratio: b.

Arps' hyperbolic model:

$$q = q_0(1 + bDt)^{1/b} \quad (5.1)$$

The loss-ratio D is defined as:

$$b = \frac{d}{dt} \left[ - \frac{q}{dq/dt} \right] \quad (5.2)$$

The b value defined in these three models ranges from 0 to 1. It is an exponential flow when b = 0; b = 1 represents harmonic decline and the range of 0 to 1 of b is the hyperbolic model. When we analyze well data from conventional formations, the b value

is always less than 0 and this approach has a limit on the b value of no more than 1. However, with the shale and the tight oil and gas coming into force with very long-time production because of the low to ultra-low permeability without demonstrating boundary dominated flow, transient linear flow regime is the primary flow period which often took years during production for most wells. So it is usually observed that values of  $b > 1$  seem to match the field production data produced from shale and tight reservoirs.

Power-law exponential method (PLE):

This power-law concept was introduced by Ilk et al. (2009) to model the transient flow regions, like linear flow and bilinear flow of production data, by modeling the loss-ratio and its derivative which are in functional forms because they are computed continuously from the data. The forms of power-law loss-ratio and its derivative b are defined as follow:

$$D(t) = D_{\infty} + D_{int} t^{n-1} \quad (5.3)$$

$$b(t) = \frac{-\widehat{D}_{int}(n-1)nt^n}{(D_{\infty}t + \widehat{D}_{int}t^n)^2}$$

(5.4)

The loss-ratio terms exhibit power-law behavior at early times and become a constant at late times because the first term  $D_{\infty}$  can be considered negative at early times of modeling and becomes dominant after a long time, often exhibiting boundary dominated flow, and should be set as 0 when no boundary flow occurs. The loss-ratio derivative is a declining function as well. Ilk verifies that this power-law exponential model is flexible enough to model transitional linear flow and late-time boundary dominated flow without being hypersensitive, which gives practitioners a useful method for assessing production decline curves.

PLE rate-time relation:

$$q = q_0 \exp(-D\infty t - \frac{D}{n} t^n)$$

(5.5)

Stretched Exponential Decline (SEPD):

Valko (2009), and Valko and Lee (2010) developed this stretched exponential function which is a variation of Arps' rate-time model, but is better suited and readily manipulated with all the right ingredients for probabilistic performance forecasting for any individual well in unconventional applications because of its bounded nature and its straight-line behavior of RF or its expression against cumulative production (Valko and Lee, 2010). Parameters  $n$ ,  $q_i$ , and  $\tau$  give a finite value for the estimation of EUR when there are no abandonment constraints used in time  $t$  or rate  $q$ .

SEPD production rate expression as function of time:

$$q = q_0 \exp \left[ -\left(\frac{t}{\tau}\right)^n \right] \quad (5.6)$$

SEPD cumulative production as a function of time:

$$Q = \frac{q_0 \tau}{n} \left\{ \Gamma \left[ \frac{1}{n} \right] - \Gamma \left[ \frac{1}{n}, \left(\frac{\tau}{n}\right)^n \right] \right\} \quad (5.7)$$

The most popular complete gamma function and the incorporated incomplete gamma function (Abramowitz and Stegun, 1972) are the first and second terms respectively in the cumulative against-time equation; the natural logarithm of gamma functions is available in Microsoft Excel.

Duong's rate decline Method

Duong's rate decline method is based on the physical theory and field application that a long-time transitional flow, occurs in the low permeability reservoirs with fracturing

stimulation treatment and transient linear flow is prolonged over the production of a well.

The flow rate history behaves at the beginning like:

$$q = q_1 t^{-n} \quad (5.8)$$

Where n refers to indication of fracture flow, n = 0.5 for linear flow and n = 0.25 for bi-linear flow, q is the production rate, and  $q_1$  refers to the initial production rate.

The future production is defined and provided by Duong are as follows:

$$q = q_1 t(a, m) \quad (5.9)$$

Where

$$t(a, m) = t^{-m} \left( \frac{a}{1-m} (t^{1-m} - 1) \right) \quad (5.10)$$

Logistic Growth Model (LGM)

The Logistic Growth Model was first formulated by Pierre Verhulst in the 1830s to forecast population growth based on the concept that the growth would only be able to reach a certain size to stabilize without achieving infinite increasing. The model used in this work was adjusted and altered by Clark et al. (2011) by using carrying capacity for depicting the possible maximum growth to model single well production trend.

The rate-time equations are as follows:

$$q(t) = \frac{dQ}{dt} \frac{Knb t^{n-1}}{(a + t^m)^2} \quad (5.11)$$

Where a = Constant

K = Carrying Capacity

t = Time

n = Hyperbolic Exponent

#### 5.4.1 5.4.2 Forecasting comparison between these five empirical methods

Production from type 1 there are two stepped linear flow periods. The matching results are presented in **Fig. 5.7** with each method topped on every graph.

In **Fig. 5.7**, it provides us with a recognizable matching performance for well producing in Viewfield, Bakken selected from type 1. In general, the matching behaviour did not show a very good consistency for this kind of decline trend with the presence of nearly two parallel linear flows stepped as a staircase, especially for the second linear flow indication. Of course, the manifestation of linearity of the later linear flow is instinctively disrupted by accuracy of production rate, because for almost all actual wells, the applicability and accuracy of the raw flow rate is a challenge for reservoir engineers when doing production data analysis without the assistance of interpreting timely pressure data. Achieving a perfect history-matched appearance solely by relying on field data could be difficult. However, based on their own limitation due to the difficulty of extracting production data with little disruption, as well as the assumption and features of different models, these models could overall estimate the ultimate recovery in the future, and prove that, as all these five methods underestimate when doing forecasting performance for stepped linear flows, at least an estimation of recovery in the future production can be obtained.

Furthermore, to better evaluate the history matching procedure of production data analysis in tight formation, we need to understand the most important linear or bilinear flow causes and the tuning and adjustment of parameters within those analytical models. Sometimes, the linear flow can last for the whole production life of a well until its abandonment. Knowing how to choose appropriate empirical rate-time relations is crucial

and could have an impressive influence on the late-time presentation of the curve fitting which should be taken seriously and cautiously when analyzing production data with multi-staged hydraulic fracturing treatment. To have the utmost criterion for any empirical analysis to it is necessary to have a solid knowledge of reservoir conditions, target formation and completion details, etc. With this essential information in hand, it's hoped that a more accurate model could be reached.

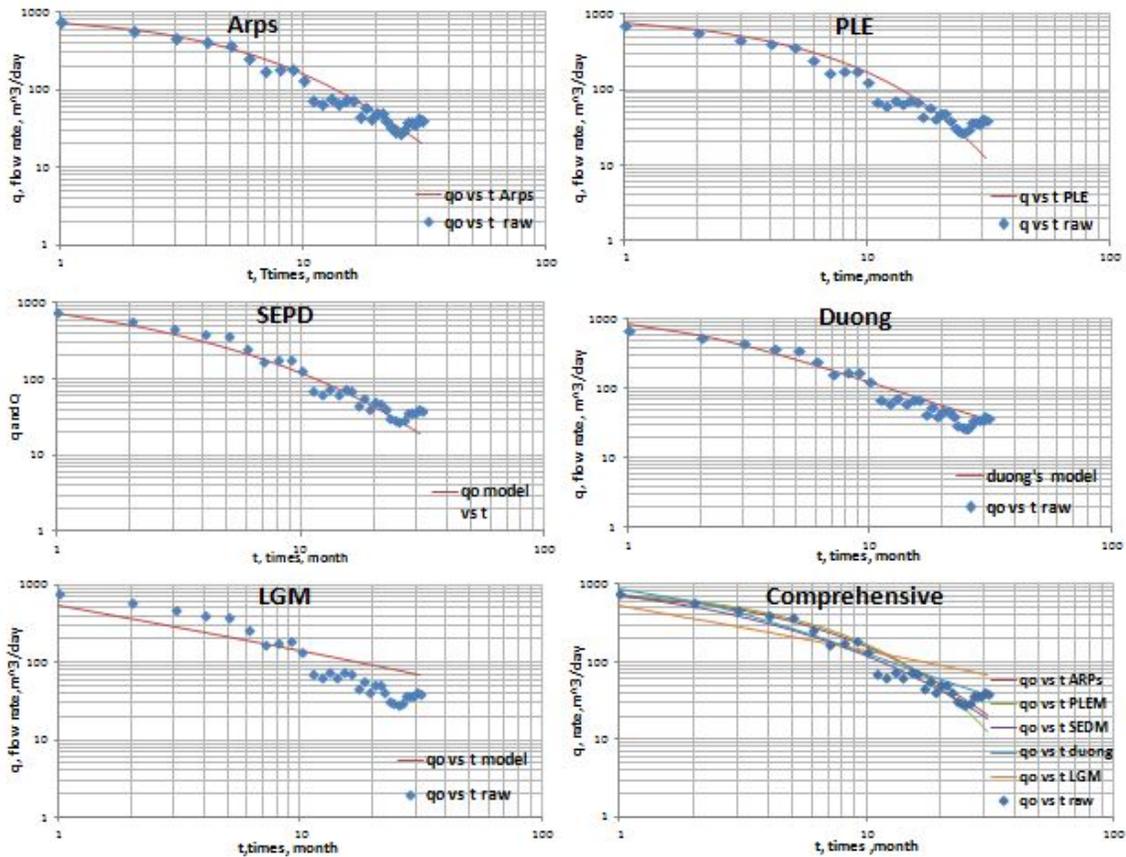


Fig. 5.7 — log-log plot of historical production matched performance for well #1 (ID 191/01-33-006-09W2/00 (4414)) from type 1 using different empirical rate-time relations

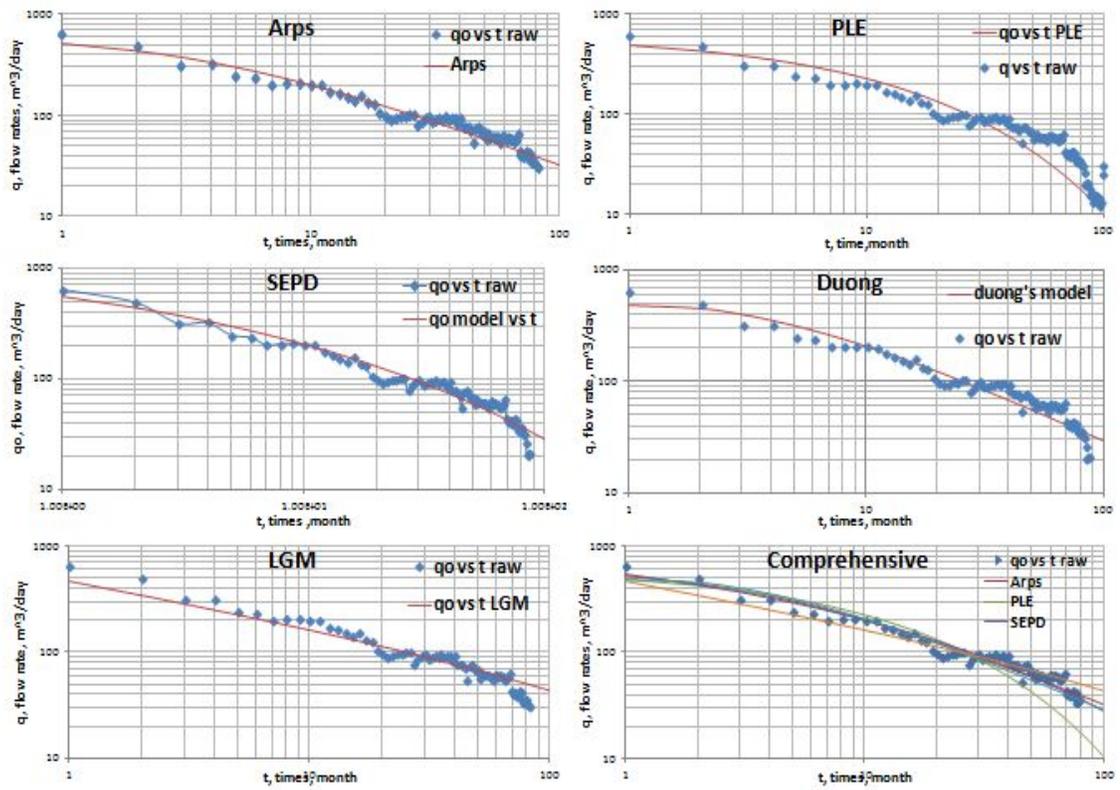


Fig. 5.8 — log-log plot of historical production matched performance for well #2 (ID 191/04-24-006-08W2/00 (4330)) from type 1 using different empirical rate-time relations

Well #2 is a hydraulically fractured horizontal well producing in the middle Bakken formation which has been experiencing a long-time linear flow for the duration of almost two log circles of its production history. This horizontal well in the Viewfield area (ID 191/01-33-006-09W2/00 (4414)) was drilled in December, 2003 by Canera Enrg Corp and abandoned in September, 2012. During nearly 8 years of production in middle Bakken it only exhibited a linear flow decline trend towards the end of its operation. Hydraulic fracturing treatment was implemented in the completion process and due to the low permeability properties of the tight formation; this long transient linear flow was possible and is evidenced in **Fig. 5.8**. It can be seen that a discernible boundary dominated flow signature indicated by small numbers of blue markers at late times manifested a phenomenon that this well type displayed distinct fracture possibilities. All these five empirical methods showed a decent and tolerable consistency, specifically for LGM and SEPD; the matching accuracy has reached an extent that could explain the well production behavior but overall tends to overestimate the future production. The Power Law Exponential model lately seems to be able to not over-predict performance but generally lacks accuracy and compatibility with historic production data of this well. As for the traditional Arps decline curve model, the matching result reached a reasonable

explanation for an overview point, but behaves inadequately at the middle linear flow curve fitting with the actual production rate. Duong's model is the least fitting method when it comes to linear flow production. It would probably underestimate the future production because it starts rapidly declining after reaching the first log cycle. The original decline for raw data seems to maintain a linear flow instead of showing straightforward decreasing at late time fitting performance.

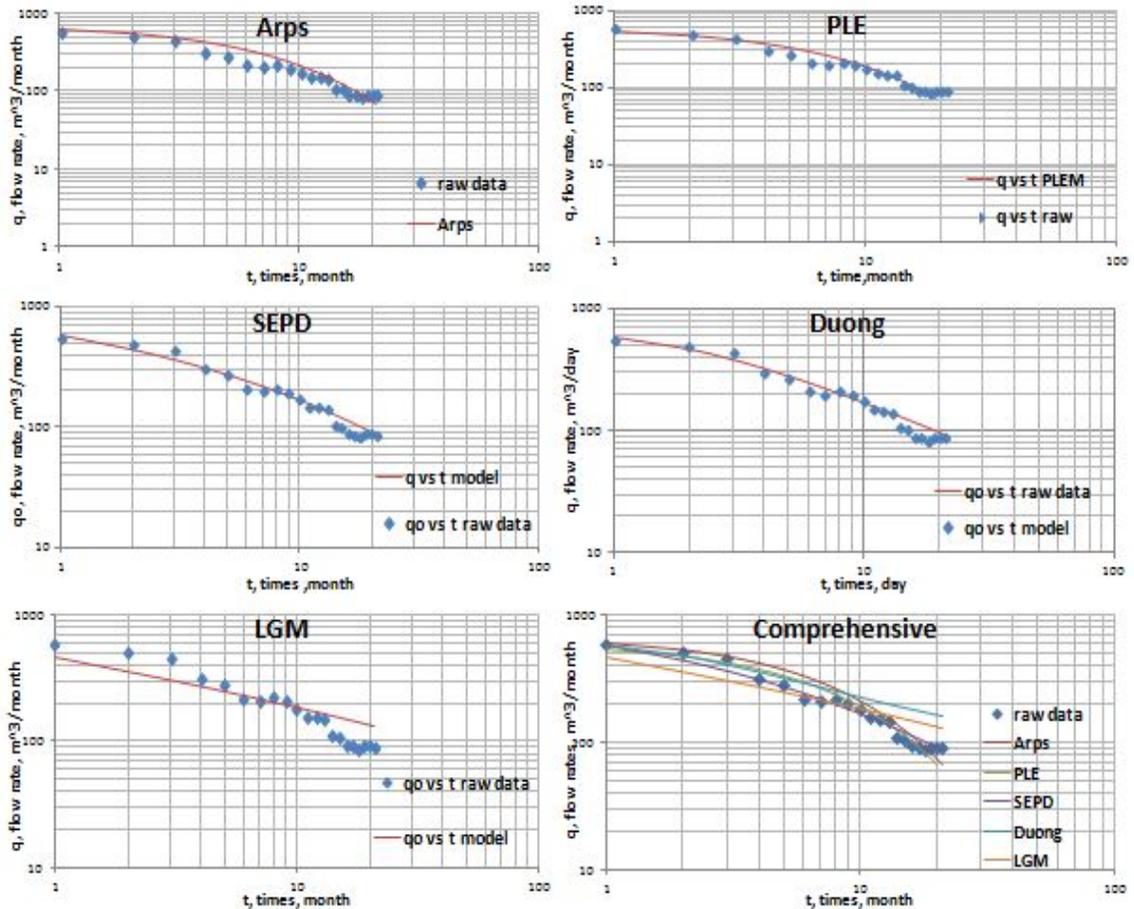


Fig. 5.9 — log-log plot of historical production matched performance for well #3(ID 191/14-09-010-07W2/00 (4414)) from type 3 using different empirical rate-time relations

Well #3 (ID 191/14-09-010-07W2/00 (4414)) is an active oil well located in the Viewfield Middle Bakken formation, Weyburn/Estevan Light, operated by Petrobakken Enrg Ltd. It started producing light oil in Sep, 2011. This well is chosen from type III as a typical combination of bilinear and linear flow sets to estimate the matching effort based on four different, newly developed empirical and analytical methods by researchers. The matching performances are shown above in **Fig. 5.9**, from which we can see that very few of these rate-time relations could explain the flow behavior for this type of well except for the Stretched Exponential Model (SEPD) which did not fall straight downward when reaching the second linear flow period. All the other three methods tend to deviate this linear behavior and approach inwardly trying to meet the horizontal axis which may result in underestimating when predicting the future production and performing the estimation of ultimate recovery. However, the SEPD rate-time relation seems to attain a reasonable estimation, especially when it comes to matching the historic decline trend, and its estimate seems reasonable for ultimate recovery for this oil well of type III. Overestimation could possibly and inevitably happen without further information and what the flow behavior would be like in the future after this second linear flow is unknown, which could have a tremendous effect on the estimation of production trends. The history-match performances on production decline show two sets of linear flow

periods with a stepped transition period. The worst matching performances could not be used for production decline analysis; for type III at least they should be attributed to the LGM model which did not grasp the main feature of the linear characteristic instead of leading to a deviation from the very first production till the end.

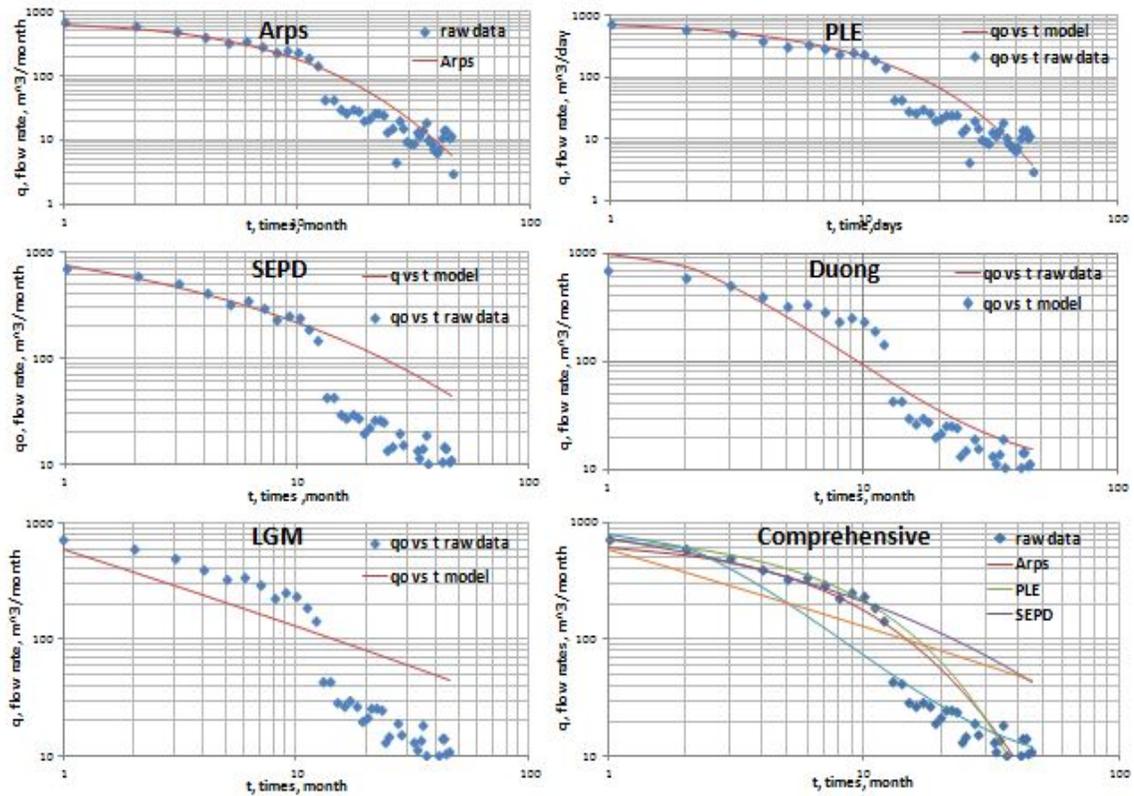


Fig. 5.10 — log-log plot of historical production matched performance for well #4(ID 191/14-02-009-09W2/00 (4414)) from type 4 using different empirical rate-time relations

The last type presents a combination of bilinear, linear and boundary dominated flows. Well #4 (ID 191/14-02-009-09W2/00 (4414)) is chosen for discussion of the matching and predicting effectiveness of these production analysis models. **Fig. 5.10** shows matching performances. This well is also an active oil well producing from middle Bakken, and is operated by Petrobakken Enrg Ltd. From an overall point of view, all rate-time empirical models performed badly, not only from the aspect of matching and especially when it comes to the last unit slope shape, but also in evaluations considering the prediction of future production approximation. Duong's method looks as if it could give us hope as the last flow trend seems to match with this method. It is controlled by the  $q_{\infty}$  parameter, which accounts for the late performance, but the whole performance could not reach reasonable matching consistency. Using conventional empirical methods to estimate or predict future production trends is dangerous. Most importantly, a less-than-perfect history match process could not be reached with these methods for analyzing unconventional oil exploration. There are limitations when it comes to detailed approximation for a complex combination of flow regimes, specifically for horizontal wells with multiple fracturing stages, not to mention more complicated production decline performances like natural fractures around artificial hydraulic stimulating methods completed. Sometimes, large, laminar fracture boundary dominated flow would

appear after linear flow or stimulated reservoir volume (SRV) could also induce a boundary effect on the presentation of flow regimes because of particular structural geometry. When pressure transmits through the cross area between the inner and outer reservoir, conventional empirical methods cannot identify this special boundary dominated flow and may underestimate future recovery when analyzing this kind of well.

## 5.5 Numerically simulated production decline type-curves of horizontal wells with multiple hydraulic fractures in a homogenous reservoir

### 5.5.1 Introduction

Many type-curve plots have been developed for rate-transient analysis for conventional and unconventional reservoirs. The most classical type-curve plot is the Fetkovich semi-analytical curve set. It is formulated from analytical solutions of transient radial diffusivity equations under constant bottom-hole pressure and single liquid flow assumptions in an effort to use analytical type-curve matching. The original transient type-curve plot which defined the boundary dominated flow as a hyperbolic decline concave down stem, originating from Arps. Later on, Fetkovich (1973) provided a composite analytical/empirical composite type-curve which can be divided into two parts. Left part collapses the transient flow trends into stems with reference to different reservoir size and skin factor, while the right part combines Arps' empirical trends for boundary dominated flow description with different  $b$  values. In addition, normalized rate type-curves have been included in the interpretation to account for changing operation conditions, specifically for changes in flowing pressures. The advantage over other type-curve methods is that it does not use superposition functions to deal with time, which may bias the interpretation of the original decline trend. However, these type-curve sets

are mainly used and are technically popular for analysis of conventional production. The transient type-curve is limited to radial flow systems, confining its application to unconventional reservoirs exploited by horizontal drilling techniques. According to Fetkovich et al. (1987), type-curve matching performance could be achieved by plotting the natural logarithm of actual production data on a drawing graph with a size cycle coherent with the type-curve itself.

More recently, Blasingame has developed modern type-curve models (1994) to present pressure normalized rates featuring the theory of superposition time, which is known as material balance time, with the use of fully analytical approaches to generate constant rate type-curves featuring a single depletion stem, irrelative with any derivative mechanisms. The matching results with Blasingame type-curves include formation permeability, original fluid in place and reservoir drainage area, etc. Furthermore, this set of type-curves also includes the integral flow rate and its corresponding integral derivative functions allows more accurate compatibility than using production data alone. These integral functions have the advantage of eliminating the effect of erratic production data and changing operations.

The Agarwal-Gardner type-curve is a practical tool compiled based on the concept of constant rate production and is used in conventional dimensionless variable definitions as opposed to the graphed dimensionless variable definitions used by Blasingame. The matching results not only provide the estimation provided by Blasingame, but also fracture half-length for hydraulically fractured wells. The other advantage over Blasingame type-curve is that Agarwal-Gardner's type-curve features a transitional period between transient and boundary dominated flow. It provides production formats in

additional forms to normalized rate versus material balance and derivative plots to add accuracy in the matching process. Based on the feasibility of simulation performances of pressure transient expressions for a fractured horizontal well in a reservoir under different situations, history matching of production decline curves is held between simulation models and real production data extracted, the same as used for comparisons in forecasting and estimation with different empirical rate-time relations.

**Type-curve matching performance generated by CMG**

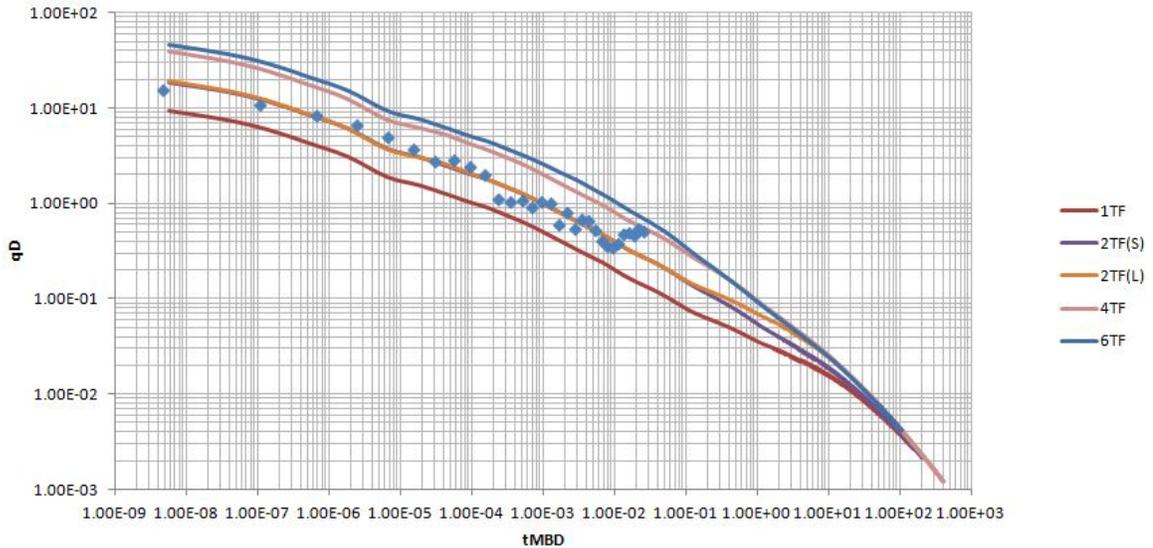


Fig. 5.11 — log-log plot of historical production matched performance for well #1(ID 191/01-33-006-09W2/00 (4414)) from type 1 with simulation type-curves

The type-curves shown in **Fig. 5.11** are formulated and generated by modeling numerical simulation featuring commercial engineering software CMG (computer modeling group). These production decline curves are the pressure transient equivalence of Scenario 3 (Chapter 3) under constant flowing bottom-hole pressure production constraints. Well-test variable dimensionless rate and dimensionless time are used for the graphic method for the x-axis and y-axis, and the dimensionless forms of production rate and time for standard well-test analysis is defined as:

$$qD = \frac{q\mu B}{Kh(P_i - P_{wf})}$$

$$tD = \frac{kt}{\phi\mu C_t A}$$

All the units used comply with international units

The simulated case shown in **Fig. 5.11** is a cased horizontal well with multiple transverse hydraulic fractures alongside the wellbore in a rectangular homogeneous reservoir. The solid red line stands for only one fracture in the middle of this horizontal well (1TF). Yellow and purple lines refer to two transverse hydraulic fractures with different spacing in which 2TF(S) is for smaller spacing and 2TF (L) is for the large spacing. The last pink and blue lines are 4 and 6 transverse fractures respectively.

The matched result of production history between well #1(ID 191/01-33-006-09W2/00 (4414)) drilling from the Bakken formation with fracturing stimulation treatment from type 1 and production decline type-curves established from simulation modeling, reached an overall consistency. The stepped transition flow from the first linear flow to the second linear period of wells from Type 1 is very hard to match with traditional type-curves.

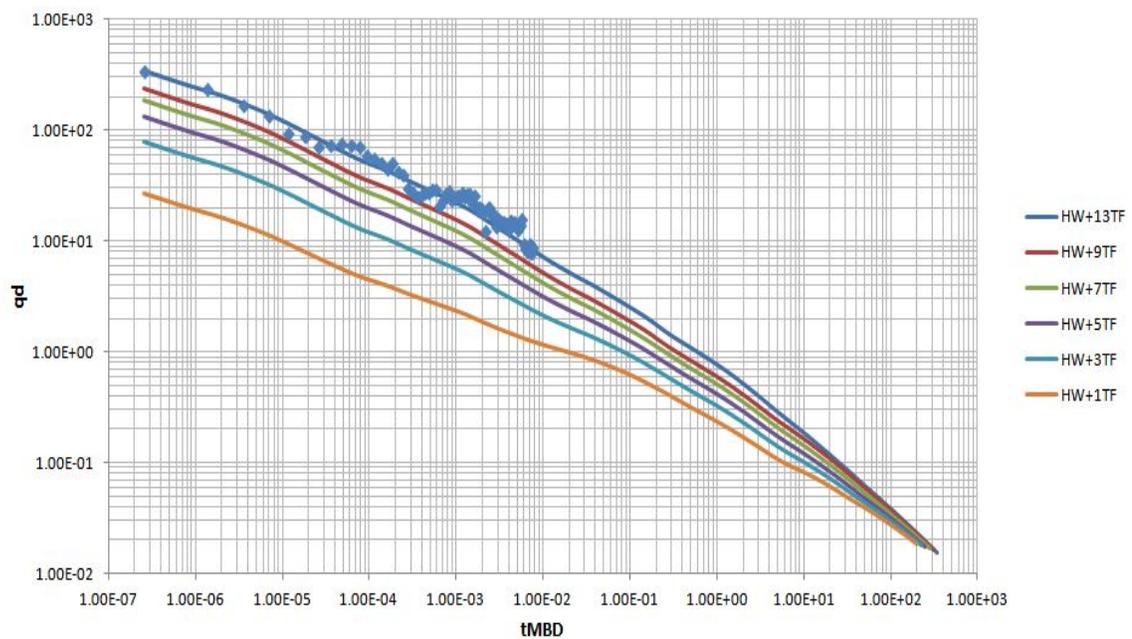


Fig. 5.12 — log-log plot of historical production matched performance for well #2 (ID 191/14-09-010-07W2/00 (4414)) from type 2 with simulation type-curves

**Fig. 5.12** shows the matching results between the example of well #2 (ID 191/14-09-010-07W2/00 (4414)) from type 2 production trend and an open-holed horizontal well intersected with various numbers of transverse fractures simulated by CMG. The production histories in type 2 all present long-time linear flow until abandonment which is a phenomenal circumstance for many wells completed with horizontal wells with the addition of artificial fractures in a low to ultra-low permeability tight or shale formation, and well 191/14-09-010-07W2/00 (4414) is the one within this type with little production turbulence and most transparency on the rate decline trend. The well has been in production for more than 8 years without any obvious long-term interruption.

The simulation cases shown in **Fig. 5.12** are the same as those illustrated in **Fig. 5.11** except for the completion variance that the horizontal well is open-holed with a horizontal wellbore length of 2559 ft. which means that the flow can happen in the fractures as well as in the horizontal well and there could be simultaneous drainage both from the fractures and matrix blocks. The number of hydraulic fractures ranges from 1 to 13, which is normal for a horizontal wellbore with a half-length of 200ft, and they are simulated by CMG. The reservoir is in a homogeneous single-porosity condition. This

long linear flow trend by this type of oil well matched on the blue curve which is a horizontal well completed with 13 transverse hydraulic fractures with a close fracture spacing of 90 ft. The decline curve analysis results could tell us the properties and characteristics of the reservoir/wellbore and the parameters of completion conditions of this type of well. Since all extracted wells from Geoscout are without pressure data and other critical operation or completion parameters, simulation modeling is a practical and convenient tool for the estimation and evaluation of interpreting well information.

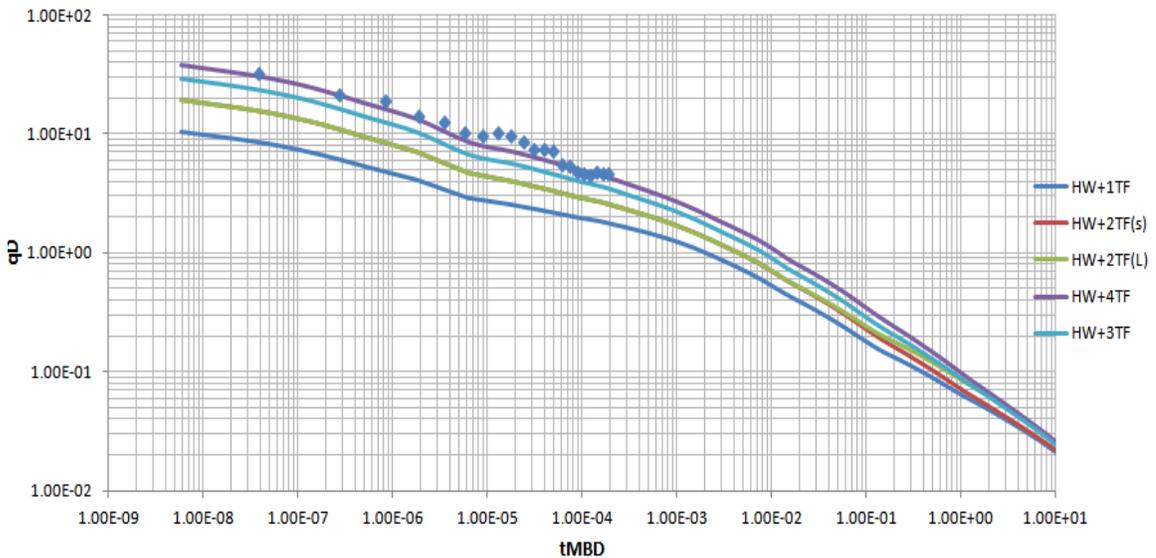


Fig. 5.13 — log-log plot of historical production matched performance for well #3 (ID 191/14-09-010-07W2/00 (4414)) from type 3 with simulation type-curves

The third type of well production trend exhibits a quarter-slope and two sets of half-slopes which are indications of bilinear and linear flows, respectively. This chosen well #3 is an active oil well producing from tight middle Bakken and is completed with a hydraulic fracturing stimulation normal to horizontal well. **Fig. 5.13** shows a history match between raw production data of this well and type-curves generated using CMG, with proper input parameters suited to tight formation characterization and adjusted by Bakken reservoir properties. These type-curves from Scenario 3 are specifically established for an open-holed horizontal well with a certain length completed with multiple hydraulic fractures with steady half-length in a single-porosity rectangular reservoir representing middle Bakken approximation. Actual production data fall on the solid purple line which stands for dimensionless forms of production type-curves for a horizontal well with a length of 300 m stimulated with four hydraulic fractures normal to the horizontal wellbore and equally spaced with 60 meters. However, the problem is that the first linear flow does not solidly match this purple line because a height gap exists within the two linear flow trends; the transition period between these two accounts for different causes contributing to two linear flow behaviors. Finding a way to explain this transition time and modeling accurately with CMG is what I am striving for. Based on the

research of many authors I speculate that these two linear flow periods could belong to inner formation linear flow and outer reservoir linear flow as a whole for multi-staged hydraulic fractures situated on a horizontal well in a rectangular reservoir. A large permeability difference between the stimulated reservoir region and outer lower permeability area could induce a delay for fluid flow through this transition zone which

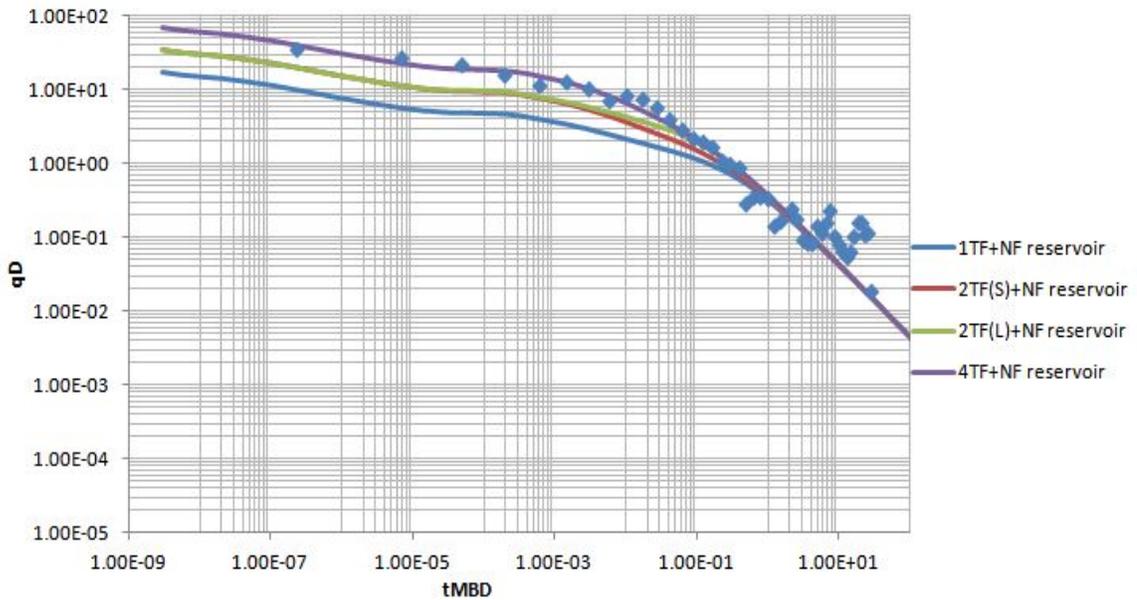


Fig. 5.14 — log-log plot of historical production matched performance for well #4 (ID 191/14-02-009-09W2/00 (4414)) from type 4 with simulation type-curves

The last type exhibits boundary dominated flow. Quarter-slope and half-slope indications for bilinear and linear flow regimes match perfectly on the solid purple line which demonstrates four hydraulically fractured horizontal wells completed in a naturally fractured reservoir. True production data show some fluctuation at late times, and boundary dominated flow can be recognized as a unit slope line, natural fractures combined with artificial hydraulic fractures complicate flow behaviors for this type of situation.

Type-curve matching for all types of decline performances demonstrated that for horizontal wells with hydraulic fracture stimulation, identification of flow regimes is always related to linear or bilinear flows which depend on the completion control implementation. To better understand flow and reservoir characteristics, detailed production information under substantial circumstances should be taken into consideration. From an overall point of view, numerical simulation is trustworthy and gives us a more clear approach to interpret production decline analysis in tight formations. A way to achieve a close-to-perfect measurement for predicting and analyzing production performance still need to get a more complete, sound simulation model.

## 5.6 Field case studies for wells from Dodsland Viking formation, Western Saskatchewan

### 5.6.1 Introduction

The Viking formation is comprised of different production pools which are mainly located in central Alberta. These pools include Redwater, Halkirk, Provost, Dodsland and Plato. All these wells were vertically drilled in the early 1960s and with the popularity of implementing hydraulically fractured horizontal wells to improve recovery economically and commercially, some pools like Dodsland are starting to use this kind of technique as a combination of horizontal well and hydraulic fractures. A large amount of hydraulic fracturing treatment is applied during the time of revolution including open-holed and cased horizontal wellbore, depending on the geological condition and stimulation effectiveness. It is necessary to make sense of the production decline responses of these stimulated horizontal wells given the various reservoir qualities, complex combinations of wellbore/fractures and primary production decline and permeability diversities based on layered reservoirs. The unconventional Viking formation extends from the north-west of Alberta which is north-east of Edmonton to the north-western corner of Saskatchewan. Water flooding is used in an effort to prevent the early decline behavior and a pattern waterflooding is implemented for prolonging the production life of these wells with hydraulic fracturing technology. Many sandstone beds could be observed from investigations in the core lab and its depositional environment is transitional to offshore marine deposition. The lithology is mainly composed of fine-to-coarse sandstone and welling-clay with the unique characteristic of interbedded conglomerate and cherty conglomeratic sandstone. Interbedded, predominantly marine-influenced sandstone and

shales make up the Viking equivalent units which are all deposited in the Western Canada foreland basin. Dodsland is located in Western Saskatchewan with a thickness of nearly 15 meters which is the target reservoir pool for production analysis in the following. The Dodsland Viking reservoir trend was initially and subsequently declined due to succeeding exploration by conventional operations, but this oil-bearing portion has emerged into another boom through the introduction of multiple-hydraulic fracturing technology with horizontal drilling to enhance contacting the surface area with the region around the wellbore/hydraulic structure.

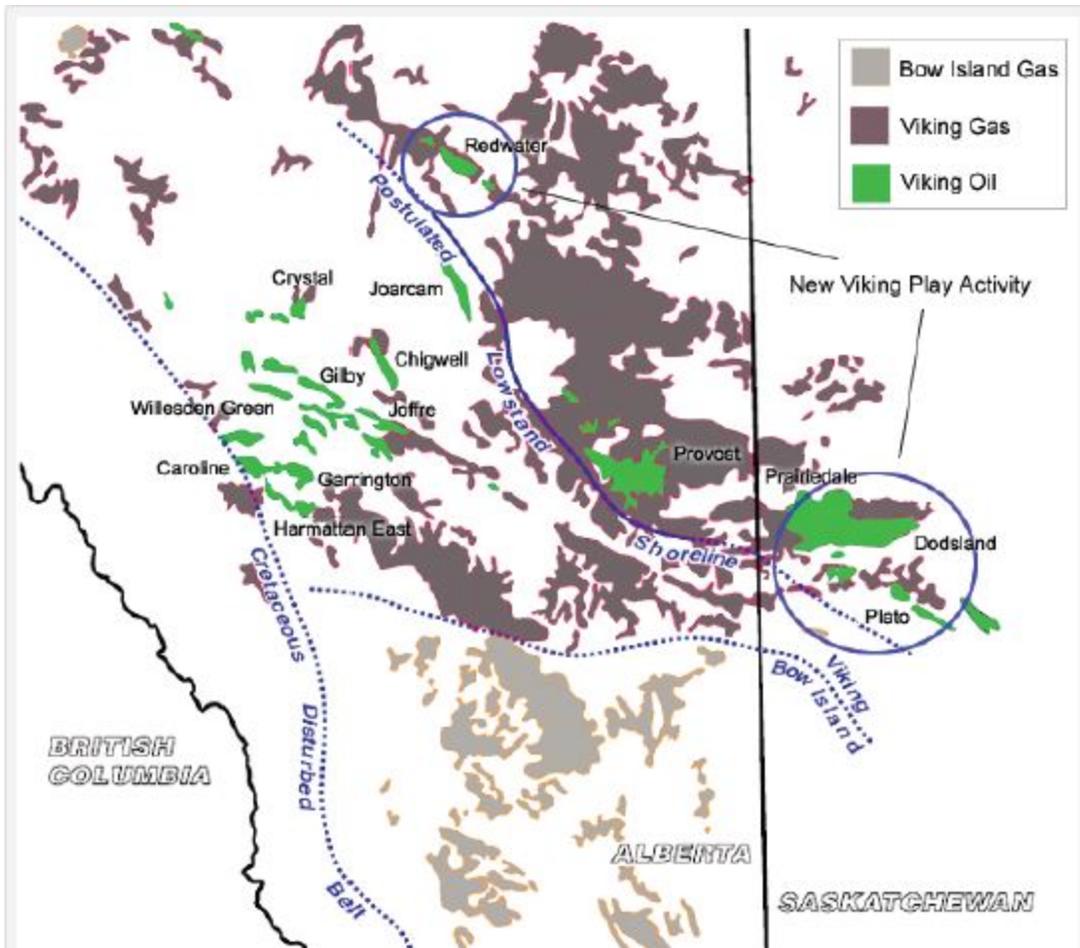


Fig. 5.15 — Viking Formation in Western Canada (Excerpted from Canadianoilstock)

### 5.6.2 Evaluation of production performances

When analyzing horizontal wells with multiple-hydraulic fractures, flow regimes are often obscured by geological information because their very long horizontal wellbores increase the contact surface area with the formation, which leads to a complex combination of wellbore/reservoir geometry. This results in complicated presentation

flow regimes due to stimulation alongside the wellbore and sometimes with the addition of a natural fracture system and transverse hydraulic fractures they generally penetrate into adjacent layers or are intercepted by components with different properties and depositional environment. Arvil C. Mogensen (2012) has done the similar decline analysis for these 7 horizontal wells.

Seven Vintage horizontal wells are selected from Dodsland Viking formation, northwestern Saskatchewan through the widely-used and mostly – accepted commercial geological software Accumap to analyze well production-decline-trend behaviors and evaluating hydraulic fracturing stimulation effectiveness. Five aforementioned Empirical decline models which were used on Bakken horizontal wells and type-curves generated by numerical simulation are compared for accessing matching performances. Fracture or formation linear flow are the dominant flow behavior through the identification of flow regimes by production decline analysis of multi-staged hydraulically fractured horizontal wells which is evidenced by **Fig. 5.17**. Long-term linear flow indicated by a definitive black dotted half-slope line followed by a transition period leading to the final unit slope shape which is a characterization of bounded flow regime.

## Oil Rate versus Material Balance Time

Reece/Pennwest Doddsland Viking Formation Oil wells, (half-slope – black dotted line,  
unit slope – green dotted line)

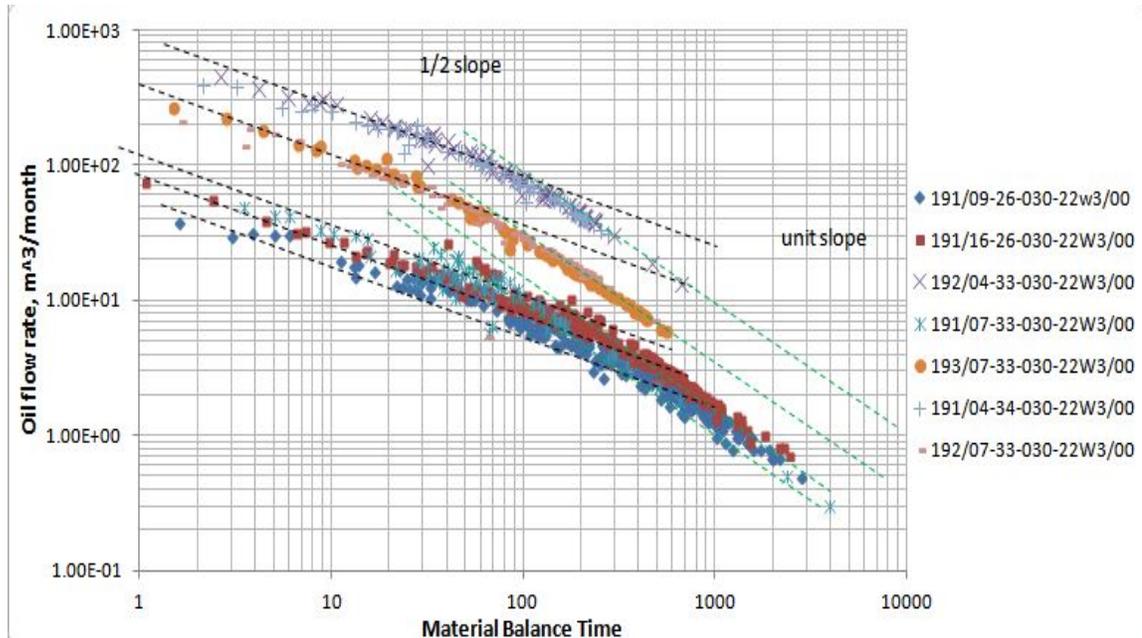


Fig. 5.16 — log-log plot of monthly oil production rate against material balance time for wells from Doddsland Viking Formation

(SPE 162813 has done the similar decline analysis for these 7 horizontal wells)

The production history of these wells is publicly achieved monthly oil production data. Diagnostic Plot **Fig. 16** featuring material balance time, a superposition function first proposed by Blasingame and Palacio (1993), which is defined as the cumulative production rate divided by the instantaneous production rate for constant compressibility

fluid. As for the case where compressibility is not a constant for production blow the bubble point, Palacio indicates that changes in compressibility only have a small influence on the signature of flow regimes so there is no need to modify or adjust the material balance time definition. This material balance time function acts like a filter tool for removing the effect of distorted production rates, and also, it has the advantage that it does not affect the early transient flow period. Almost all wells display immediate linear flow as indicative of a half-slope line followed by a late-time unit slope representing boundary dominated flow; this linear flow happens between hydraulic fractures. Radial flow does not happen for the production life. Early linear flow exhibits a duration of 60 material balance time days, which would probably be 120 days of real-time production for well 191/04-34-030-22W3/00 and well 192/04-33-030-22W3/00. The linear low period lasts approximately 40 material balance days for well 192/07-33-030-22W3/00 and well 192/07-33-030-22W3/00. The last three wells have the longest linear flow periods with nearly 300 material balance time days. Long time linear flow period demonstrate the unique geologic feature of the Viking formation because of its rectangular drainage area before fracturing treatment induced by the offshore marine depositional environment. A large number of hydraulic fracture stages could also be the reason for this long linear flow period. With more information from the operation and completion treatment, we could also make a comprehensive evaluation and assessment to analyze flow regimes.

**Fig. 5.16** also shows that the higher initial production rate, the more the oil production there is, as well as reserves. It can be seen on this plot that when two wells have the same production rate, the well with higher initial rate is shifted to the right-hand side, which is

an indication of more cumulative production as the material balance time is defined by  $Q/q$ . So, we can come to the conclusion that wells with a higher initial rate will accelerate oil production in the long run and as long as the curve shifts to the right, this well will be more productive, based on this plot. Future production forecasts is risky because some fractured horizontal wells exhibit early boundary dominated flow when SRV is felt. So the development of a detailed workflow for analyzing future production should be built.

### **5.6.3 Type-curve matching performances between analytical and numerical simulation results**

Five empirical methods were applied again for the selected well 1193/07-33-030-22W3/00. **Fig. 5.17** shows that Arps' rate-time relations could give a reasonable forecast. The transient linear flow exhibits a duration of one log cycle. The power law exponential model also gives a feasible matching result. The infinite parameter which accounts for the situation of well abandonment is assumed to be 0, the decline rate  $D_i$  is the same as the Arps definition, so based on this case, the power law exponential is theoretically identical to the expression of Arps' rate-time relation. The stretched-exponential model (SEPD) also matches well from transient linear flow until the late bounded flow regime. The last two analytical methods could not explain the flow behavior, especially for the early transient flow period. Duong's model tends to be concave down earlier without matching the intermediate-time linear trend, and would overestimate the ultimate recovery in the future from the matching plot. The last logistic growth model is the worst in predicting and matching the production decline performance because this method was originally used to analyze large population. The  $K$  parameter is assumed to be very large for analyzing the population, but when it comes to estimating the oil production situation, the

outcome is beyond feasible and we can get to the conclusion that for oil production horizontal wells with hydraulically fracturing treatment, the LGR method would probably not be suitable for analyzing production decline performance. From the whole view, it can be observed from **Fig. 5.17** that type-curve matching with the use of Arps' empirical rate-time relation slightly overestimated the ultimate recovery, as did the PLE analytical method. The SEPD solution obtain the best match. However, these analytically derived methods could not explain the flow behavior for hydraulically fractured horizontal wells perfectly due to the long time experience of transient linear flows, when the flow regimes become more complex due to complicated reservoir/wellbore combinations. How to evaluate each flow regime or the sequence of linear flow behavior is a significant problem facing modern production decline analysis with only production rate in hand.

The practice of using these existing and popular empirical rate-time relations for analyzing and forecasting production and EUR estimation specifically for tight reservoirs has been discussed and utilized for comparison with other production decline analysis methods. Performing a reasonable and dependable matching presentation is a challenging task for many researchers, especially when it comes to interpreting field cases. Since a few analytical and empirical methods have been introduced into the petroleum industry for tight /shale formation, SEPD and Duong's models are the two most mentioned practices for fractured dominated formation by professional experts in analyzing low permeability reservoirs.

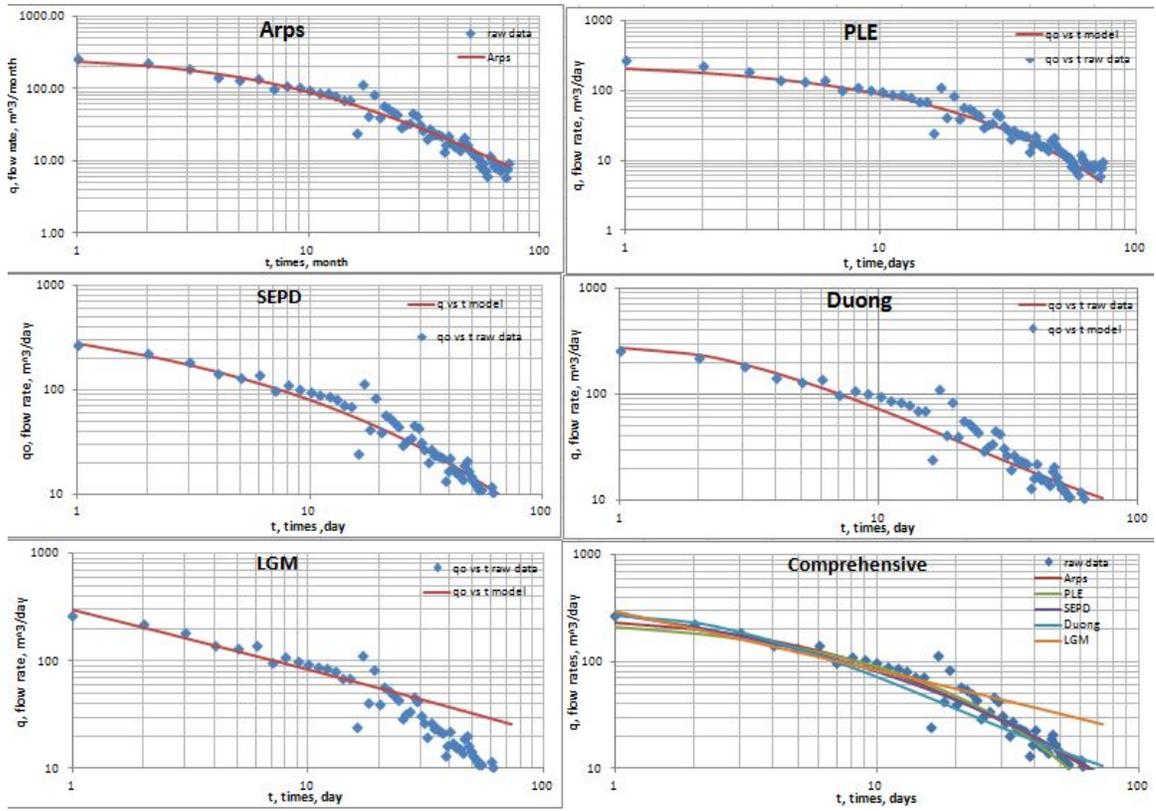


Fig. 5.17 — log-log plot of historical production matched performance for well 193/07-33-030-22W3/00 from Dodslund Viking Formation using different empirical rate-time relations

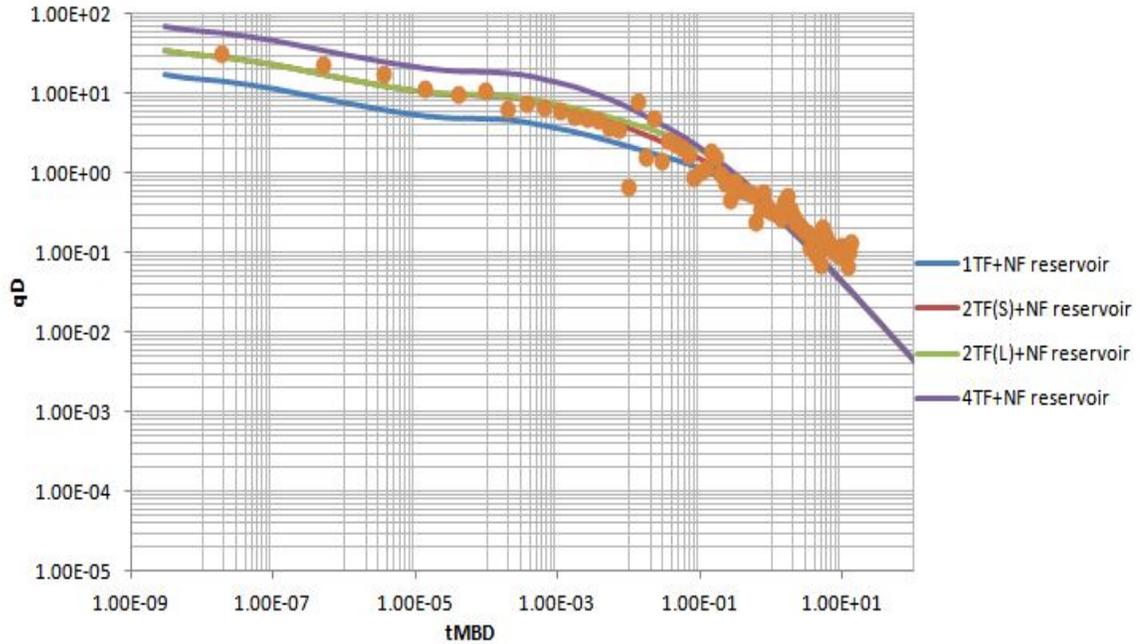


Fig. 5.18 — log-log plot of historical production matched performance for well 193/07-33-030-22W3/00 from Dodsland Viking Formation with simulation type-curves

**Fig. 5.18** shows a type-curving matching result by oil rate for well 193/07-33-030-22W3/00. Solid decline curves are generated by using the industry-accepted commercial simulator, CMG IMEX (computer Modeling Group). All these type-curves are based on the simulation cases discussed before. **Fig. 5.18** presents numerically simulated production type-curves for a transverse hydraulically fractured horizontal well completed

in a naturally fractured reservoir which is simulated by a dual-porosity model first presented by Warren and Root (1963). The actual oil production rate falls on the middle red line which is covered by the green one; they both represent two transverse fractures located along the horizontal wellbore with different fracture spacing, 60 m for the red line and 270 m for the green line, respectively. The selected oil production well is located in Dodsland and produced by Pennwest Petroleum Ltd in the Viking formation. Hydraulically fracturing stimulations are implemented for these horizontal wells, so this matching result shows us that this well might be stimulated with two hydraulic fractures with large spacing and the fracture half-length would probably be between 60m and 80m, based on the simulation input parameters. The late-time production already reaches the no-flow boundary after nearly six years of production from Jul, 2008 to Aug, 2014 in the Viking formation, western Saskatchewan. The immediate early decline was expected by many explorers because of its unique geological characteristics and thinly-laminated production zone. Comparing the matching results between the simulated production type-curves and empirical rate-time relations, the former gives a more positive result when matching performances both account for the early transient flow and the late bounded flow regimes.

Table 5.1 — Results of case studies

Case	Field	Reservoir Type	Well Type	Fracture Conductivity	Number of Fractures	Hydraulic fracture half-length
1	Viewfield Bakken	Single Porosity	Cased Horizontal Well Multi-fractured	10000 md. ft	2	200 ft
2	Viewfield Bakken	Single Porosity	Open-holed Horizontal Well Multi-fractured	1000 md.ft	13	250 ft
3	Viewfield Bakken	Single Porosity	Open-holed Horizontal Well Multi-fractured	10000 md. ft	4	300ft
4	Viewfield Bakken	Dual-porosity (Naturally fractured reservoir)	Cased Horizontal Well Multi-fractured	10000 md. ft	4	200 ft
5	Dodsland, Viking	Dual-porosity (Naturally fractured reservoir)	Cased Horizontal Well Multi-fractured	1000 md, ft	2	200 ft

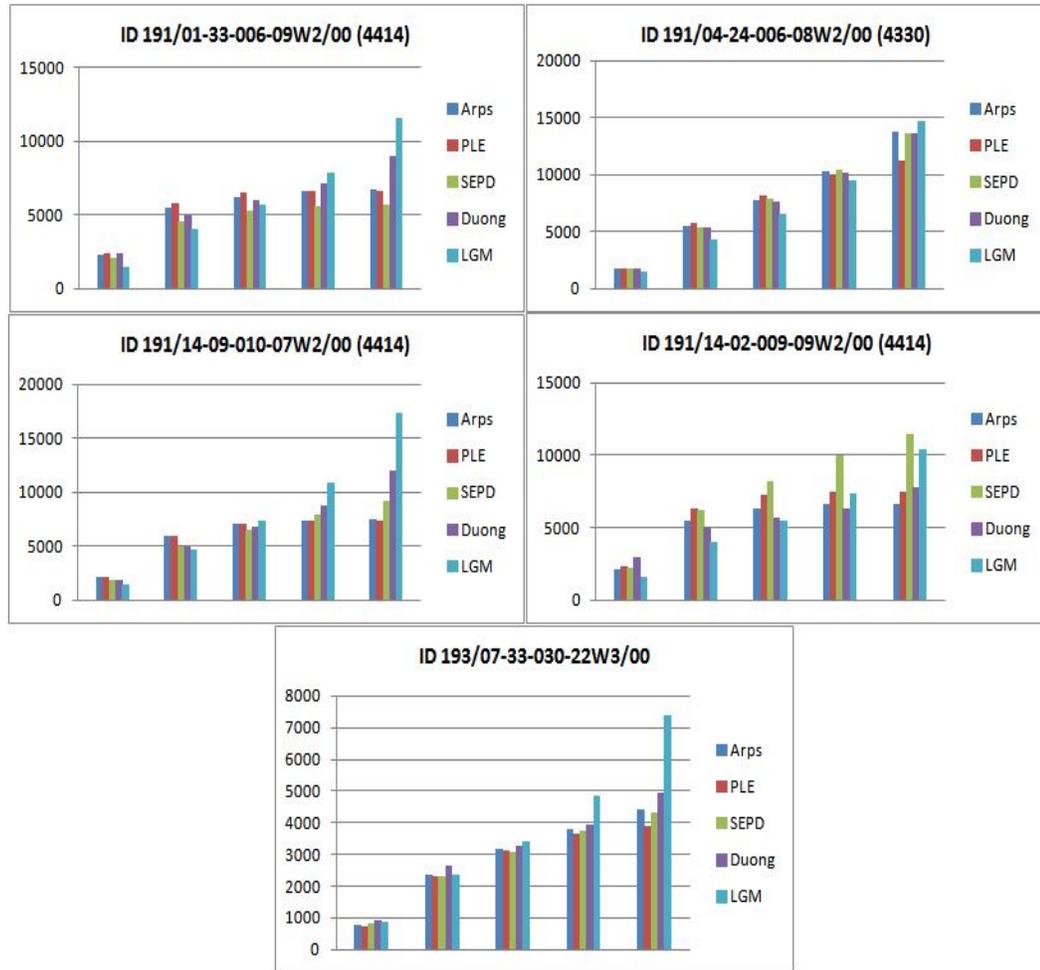


Fig. 5.19 — Expected estimated ultimate recovery prediction results from five empirical decline analyses

The calculated EUR results are summarized in **Fig. 19** based on five decline methods exited in the petroleum industry which could be used to account for the decline curve

behavior of unconventional reservoirs. From a whole point of view, the ultimate recovery was estimated on 100 days, 500 days, 1000 days, 2000 days and 5000 days which were drawn as columns marked in different colors for these expected production date. Stretched exponential decline analysis methods seems to provide the most conservative prediction results than all the other decline formulations when an approach was made to match the historic production trend, for all five selected wells no matter it's from Bakken or Viking formation, relatively high  $b$  values are used for Arps rate-time relations especially for the well with long-time linear flow trend which is from type II, Bakken formation in order to match the production data in an adequate way. Long-term transient duration and the difficulty for fitting production performances with Arps' method suggest that the target formation is very tight and use sole traditional decline curve analysis could not achieve a perfect EUR estimation and curve fitting behavior in analyzing tight reservoirs at least for Bakken and Viking formation in Western Canada sedimentary Basin. Almost for all cases, production data is fairly noisy and there is a need for filtering specifically for some wells with operational changes during the midway or end tail of production process, the goal of filtering is to remove noisy rate of the publically available monthly production data try to get a reasonable decline trend. From the type-curve matching and the addition of EUR estimation results, it's obvious that SEPD decline method could be the best analysis approach for predicting the future production and LGM analytical method is way beyond the expectations and economic limit for all typical types of decline.

## CHAPTER 6

### CONCLUSIONS AND RECOMMENDATIONS

#### 6.1 Conclusions

In this work, discussions of diagnostic plots for pressure and its corresponding derivative responses of hydraulically fractured horizontal wells in global, local and homogeneous reservoirs have been provided.

Considering the efficiency of getting the solutions computed from CMG, numerical simulation of CMG would spend several hours, even days to get to the final results of each case, we need more comprehensive and realistic analytical models to provide more robust type-curves in the future and this is definitely the trend!

Field data categorization based on various combinations of flow regimes has also provided to better understand the production trend in the targeted Bakken and Viking formation, and this can serve as a comparative standard when analyzing production data from other formation in comparing with other analytical type-curve!

The model can not only provide technical support in reservoir numerical simulation techniques, but also be applied to analyzing well stimulation performance and optimize production operation after hydraulic fracturing for unconventional tight oil reservoirs.

In simulating and representing actual reservoir model in interpreting pressure transient performance for hydraulically fractured horizontal wells in a naturally fractured or unnaturally fractured tight reservoir, CMG has a limitation not only in accurately approaching the identification of flow regimes but also the long calculating time in

getting the final solution, so we need more accurate analytical models with more fast computational speed in calculating solutions of pressure or rate transient behaviors!

## 6.2 Recommendations

It is very important to understand and analyze the production and pressure transient performance for horizontal wells with multiple hydraulic fractures in low permeability reservoirs, and a comprehensive and more mature simulation modeling process should be built, such as taking skin and wellbore storage into consideration.

Complete production type-curves can be built to explain fracture properties in the future and detailed interpretation for linear or bilinear flow should be taken into account.

It is crucial to develop and produce a more systematic procedure to analyze rate and pressure transient performances as there is a need for qualitative and quantitative information on field productions.

Estimation and evaluation of the stimulated reservoir volume and drainage area can be calculated through numerical simulation and type-curve matching.

Further experimental studies and micro-seismic mapping are suggested to characterize fracture structures in detail and to achieve more standard numerical modeling of fracture networks.

A more complete comparison between numerical modeling and analytical solutions is suggested to account for a more accurate and intact presence of production and pressure transient analysis.

## LIST OF REFERENCES

- Abdulal, H. J., Samandarli, O., & Wattenbarger, B. A. (2011, January). New Type Curves for Shale Gas Wells with Dual Porosity Model. In *Canadian Unconventional Resources Conference*. Society of Petroleum Engineers.
- Aguilera, R. (2011). Modeling fractured horizontal wells as dual porosity composite reservoirs—application to tight gas, shale gas and tight oil cases.
- Al Ahmadi, H. A., Almarzooq, A. M., & Wattenbarger, R. A. (2010, January). Application of linear flow analysis to shale gas wells-field cases. In *SPE Unconventional Gas Conference*. Society of Petroleum Engineers.
- Al-Ghamdi, A., & Ershaghi, I. (1996). Pressure transient analysis of dually fractured reservoirs. *SPE Journal*, 1(01), 93-100.
- Al Rbeawi, S. J. H., & Tiab, D. (2011, January). Transient Pressure Analysis of Horizontal Wells in a Multi-Boundary System. In *SPE Production and Operations Symposium*. Society of Petroleum Engineers.
- Asps, J. J. (1945). Analysis of decline curves. *Transactions of the American Institute of Mining, Metallurgical and Petroleum Engineers*, 160, 228-247.
- Bello, R. O. (2009). *Rate transient analysis in shale gas reservoirs with transient linear behavior* (Doctoral dissertation, Texas A&M University).
- Bello, R. O., & Wattenbarger, R. A. (2008, January). Rate transient analysis in naturally fractured shale gas reservoirs. In *CIPC/SPE Gas Technology Symposium 2008 Joint Conference*. Society of Petroleum Engineers.

- Blasingame, T. A. (2009). Decline Curve Analysis for HP/HT Gas Wells: Theory and Applications.
- Blasingame, T. A. (2012). Practical Considerations for Decline Curve Analysis in Unconventional Reservoirs—Application of Recently Developed Time-Rate Relations.
- Biryukov, D., & Kuchuk, F. J. (2012). Transient pressure behavior of reservoirs with discrete conductive faults and fractures. *Transport in porous media*, 95(1), 239-268.
- Buhidma, I. M., Habbtar, A., & Rahim, Z. (2013, May). Practical Considerations for Pressure Transient Analysis of Multi-Stage Fractured Horizontal Wells in Tight Sands. In *SPE Saudi Arabia Section Technical Symposium and Exhibition*. Society of Petroleum Engineers.
- Can, B. (2011). *Probabilistic performance forecasting for unconventional reservoirs with stretched-exponential model* (Doctoral dissertation, Texas A&M University).
- Carter, R. D., Agarwal, R. G., & Pollock, C. B. (1979). Evaluation and performance prediction of low permeability gas wells stimulated by massive hydraulic fracturing. *J. Pet. Tech*, 362-372..
- Chen, C. C., & Raghavan, R. (1997). A multiply-fractured horizontal well in a rectangular drainage region. *SPE J*, 2(4), 455-465.
- Chen, C., & Raghavan, R. (2013). On Some Characteristic Features of Fractured-Horizontal Wells and Conclusions Drawn Thereof. *SPE Reservoir Evaluation & Engineering*, 16(01), 19-28.

- Clark, A. J., Lake, L. W., & Patzek, T. W. (2011, October). Production forecasting with logistic growth models. In *Paper SPE 144790 presented at the SPE Annual Technical Conference and Exhibition, Denver, CO* (Vol. 30).
- Clarkson, C. R., Jordan, C. L., Ilk, D., & Blasingame, T. A. (2009, January). Production data analysis of fractured and horizontal CBM wells. In *SPE Eastern Regional Meeting*. Society of Petroleum Engineers.
- Clarkson, C. R., & Qanbari, F. (2014, October). A Semi-Analytical Forecasting Method for Unconventional Gas and Light Oil Wells: A Hybrid Approach for Addressing the Limitations of Existing Empirical and Analytical Methods. In *SPE Annual Technical Conference and Exhibition*. Society of Petroleum Engineers.
- Clonts, M. D., & Ramey Jr, H. J. (1986, January). Pressure transient analysis for wells with horizontal drainholes. In *SPE California Regional Meeting*. Society of Petroleum Engineers.
- Doublet, L. E., Pande, P. K., McCollum, T. J., & Blasingame, T. A. (1994). Decline curve analysis using type curves—analysis of oil well production data using material balance time: application to field cases. *paper SPE*, 28688, 10-13.
- Duong, A. N. (2010, January). An Unconventional Rate Decline Approach for Tight and Fracture-Dominated Gas Wells. In *Canadian Unconventional Resources and International Petroleum Conference*. Society of Petroleum Engineers.
- El-Banbi, A. H., & Wattenbarger, R. A. (1998, January). Analysis of linear flow in gas well production. In *SPE Gas Technology Symposium*. Society of Petroleum Engineers.
- Fetkovich, M. (1973). The isochronal testing of oil wells. *paper SPE*, 4529, 137-142.

- Fetkovich, M. J. (1980). Decline curve analysis using type curves. *Journal of Petroleum Technology*, 32(6), 1065-1077.
- Fetkovich, M. J., Vienot, M. E., Bradley, M. D., & Kiesow, U. G. (1987). Decline-Curve Analysis Using Type Curves—Case Histories. *SPE Formation Evaluation*.
- Iraj Ershaghi, S. P. E. (1986). Triple-porosity systems for representing naturally fractured reservoirs. *SPE Formation Evaluation*.
- Ilk, D., Mattar, L., & Blasingame, T. A. (2007). Production Data Analysis—Future Practices for Analysis and Interpretation. *Paper, 1101*, 2007-174.
- Jalali, Y., & Ershaghi, I. (1987, April). Pressure transient analysis of heterogeneous naturally fractured reservoirs. In *Paper SPE 16341 presented at the SPE California Regional Meeting, Ventura, California* (pp. 8-10).
- Kazemi, H. (1969). Pressure transient analysis of naturally fractured reservoirs with uniform fracture distribution. *Society of petroleum engineers Journal*, 9(04), 451-462.
- Kanfar, M., & Wattenbarger, R. (2012, October). Comparison of Empirical Decline Curve Methods for Shale Wells. In *SPE Canadian Unconventional Resources Conference*. Society of Petroleum Engineers.
- Larsen, L., & Hegre, T. M. (1991, January). Pressure-transient behavior of horizontal wells with finite-conductivity vertical fractures. In *International Arctic Technology Conference*. Society of Petroleum Engineers.
- Larsen, L., & Hegre, T. M. (1994). Pressure transient analysis of multifractured horizontal wells. *paper SPE*, 28389, 25-28.

- Lee, S. J., Kim, T. H., & Lee, K. S. (2013, June). Pressure transient characteristics of a fractured horizontal well in shale gas reservoirs. In *The Twenty-third International Offshore and Polar Engineering Conference*. International Society of Offshore and Polar Engineers.
- Lee, W. J., & Hopkins, C. W. (1994). Characterization of tight reservoirs. *Journal of Petroleum Technology*, 46(11), 956-964.
- Medeiros, F., Kurtoglu, B., Ozkan, E., & Kazemi, H. (2007, January). Pressure-transient performances of hydraulically fractured horizontal wells in locally and globally naturally fractured formations. In *International Petroleum Technology Conference*. International Petroleum Technology Conference.
- Medeiros, F., Ozkan, E., & Kazemi, H. (2008). Productivity and drainage area of fractured horizontal wells in tight gas reservoirs. *SPE Reservoir Evaluation & Engineering*, 11(05), 902-911.
- Meyer, B. R., Bazan, L. W., Jacot, R. H., & Lattibeaudiere, M. G. (2010, January). Optimization of multiple transverse hydraulic fractures in horizontal wellbores. In *SPE Unconventional Gas Conference*. Society of Petroleum Engineers.
- Mogensen, A. C., Bachman, R. C., & Singbeil, P. P. (2012, January). Case Study: Evaluation of Horizontal Well Multistage Fracturing in the Viking Oil Formation. In *SPE Canadian Unconventional Resources Conference*. Society of Petroleum Engineers.
- NoRDQuiST, J. W. (1953). Mississippian stratigraphy of northern Montana.
- Odeh, A. S., & Babu, D. K. (1990). Transient flow behavior of horizontal wells pressure drawdown and buildup analysis. *SPE Formation evaluation*, 5(01), 7-15.

- Ozkan, E., & Raghavan, R. (1991). New solutions for well-test-analysis problems: part 1—analytical considerations. *SPE Formation Evaluation*, 6(3), 359-368.
- Ozkan, E., Brown, M. L., Raghavan, R. S., & Kazemi, H. (2009, January). Comparison of fractured horizontal-well performance in conventional and unconventional reservoirs. In *SPE Western Regional Meeting*. Society of Petroleum Engineers.
- Palacio, J. C., & Blasingame, T. A. (1993). Decline curve analysis using type curves: Analysis of gas well production data. *Paper SPE*, 25909, 12-14.
- Siddiqui, S. K. (2012). *Production data analysis of tight hydrocarbon reservoirs* (Doctoral dissertation, University of Alberta).
- Valkó, P. P., & Lee, W. J. (2010, September). A better way to forecast production from unconventional gas wells. In *Paper SPE 134231 presented at the SPE Annual Technical Conference and Exhibition, Florence, Italy* (pp. 19-22).
- Warren, J. E., & Root, P. J. (1963). *The behavior of naturally fractured reservoirs*. SPE Journal.
- Yu, S. (2013, November). Best Practice of Using Empirical Methods for Production Forecast and EUR Estimation in Tight/Shale Gas Reservoirs. In *SPE Unconventional Resources Conference Canada*. Society of Petroleum Engineers.
- Yueming Cheng, S. P. E. (2011). Pressure transient characteristics of hydraulically fractured horizontal shale gas wells.
- Zhao, G. (2012, January). A simplified engineering model integrated stimulated reservoir volume (SRV) and tight formation characterization with multistage fractured horizontal wells. In *SPE Canadian Unconventional Resources Conference*. Society of Petroleum Engineers.

Zhao, G., Xiao, L., and Su, C., Chen, Z. and Hu, K.: "Model-based Type Curves for Horizontal Wells with Multi-staged Hydraulic Fractures", The 1st International Discrete Fracture Network Engineering Conference, Vancouver, Oct. 19~22, 2014.