

**DEVELOPMENT OF GAS PRODUCTION TYPE CURVES FOR HORIZONTAL  
WELLS IN COALBED METHANE RESERVOIRS**

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# **ABSTRACT**

## **DEVELOPMENT OF GAS PRODUCTION TYPE CURVES FOR HORIZONTAL WELLS IN COALBED METHANE RESERVOIRS**

**Allen Ekahnzok Nfonsam**

Coalbed methane is an unconventional gas resource that consists of methane production from coal seams. The unique difference between CBM and conventional gas reservoirs is that it is a dual-porosity system characterized by complex interaction of the coal matrix and cleat system that are coupled through the desorption process. Coalbed methane reservoir performance is controlled by a complex set of reservoir, geologic, completion and operation parameters. To date there are very little tools to help with predicting the performance of CBM wells.

The purpose of this research was to develop a simple and reliable tool to help with gas production predictions for horizontal coalbed methane wells that are located in the Northern Appalachian Basin. Upon completion, a unique set of type curves were developed, that will allow for independent producers to evaluate the future production of their wells. A correlation for the peak gas rate was also developed in order to forecast production if no production data is available.

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# 1 INTRODUCTION

Since 1983, the coalbed methane industry in the United States grew from a little known, high cost operation to a competitive main line natural gas resource. CBM proven reserves in the United States have increased from 3.7Tcf in 1989 to 18.75Tcf in 2003 and currently account for over 10 percent of the estimated total US natural gas reserves. Production decline curves are usually used to forecast the recovery factor, future revenues, and well performance. The conventional decline curve methods cannot be used to predict CBM production behavior due to complex nature of CBM production. Production from CBM reservoir is controlled by a complex set of reservoir, geologic, completion and operation parameters and the inter-relationships between these parameters.(Aminian et al 2004) The dual porosity (macropores and micropores) of coal makes mathematical modeling of CBM reservoirs very challenging. The micropores, known as the matrix are considered the primary-porosity system and the macropores; commonly known as the cleat system are considered the secondary porosity system. (Remner D.J., et al., 1986).

The cleat constitutes the natural fractures in all coal seams while the matrix contains majority of the gas. In most of the CBM reservoirs, water settles in the cleat system and saturates it. The water provides the reservoir pressure that holds gas in the adsorbed state. Production of gas is controlled by a three step process – desorption of gas from the coal matrix, diffusion to the cleat system, and flow through fractures.

The dewatering process consists of producing water to lower the pressure so that the methane can be desorbed from the coal and diffuse into the macropores. The free gas saturation in the macropores increases as gas continues to be desorbed, ultimately resulting in the transportation of the gas through the fractures in the macropore system.

The water production declines throughout the life of the CBM reservoir and reaches a minimum after the peak gas rate has been reached. At this point, the behavior of CBM reservoir becomes similar to conventional reservoirs.

Horizontal wells are drilled parallel to the reservoir bedding plane. The importance of a horizontal well in a CBM reservoir is to enhance reservoir contact and thereby enhance well productivity. A long horizontal well provides a large contact area and therefore enhances well injectivity, which is highly desirable for enhanced oil recovery (EOR) applications. (Joshi S.D 1991). Also, the direction of the borehole can be controlled with respect to the principal permeability directions of the coal seam. Horizontal well completion scheme can either be open hole, slotted liner, a liner with external casing packers or cased hole with perforations. However, the major demerit of horizontal wells is that, only one pay zone can be drained per horizontal well. Horizontal wells costs are 1.4 to 3 times more than vertical wells.

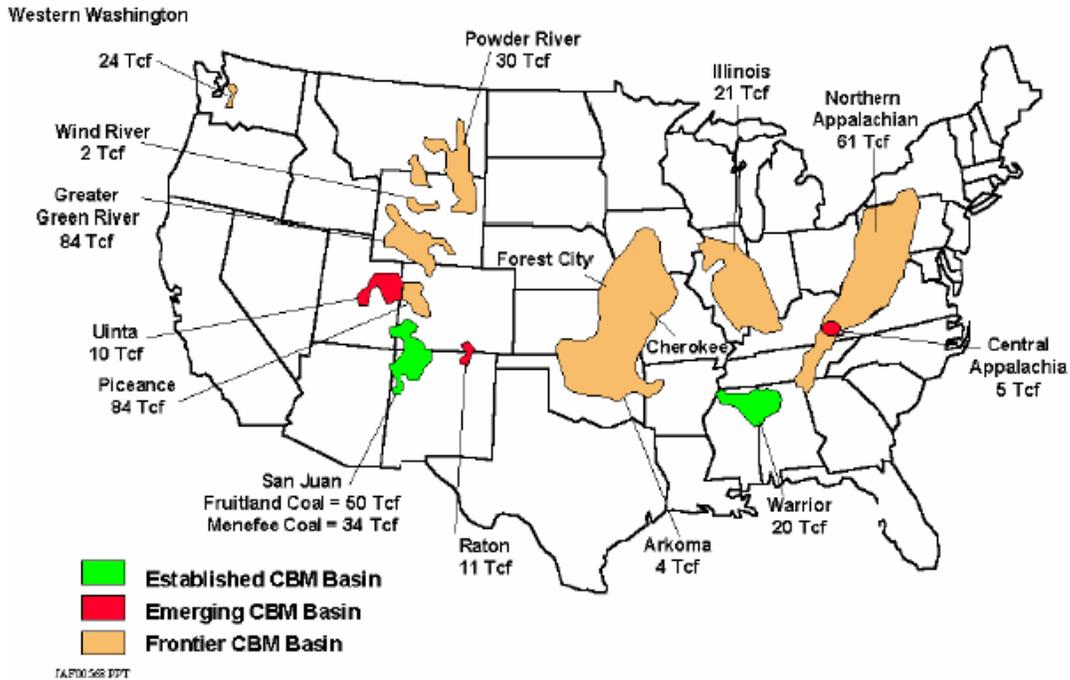
## 2 LITERATURE REVIEW

### *2.1 Coalbed Methane*

Coalbed methane is an unconventional gas resource that started growing since 1983. It was not until 1983 when the industry recognized the potential of coalbed methane as a source of low-cost gas. The US Bureau of Mines aggressively pursued research to find ways to remove methane from coal seams before mining them after the disastrous coal mine explosion in Farmington, West Virginia, in 1968. By 1971, the Bureau and Amoco Production Company conducted some experiment on wells in two of the major basins in the US (Warrior Basin and San Juan Basin).

After a successful gas production of 1Mcf/d with hydraulic stimulation treatment, the US Department of Energy (DOE) initiated its coalbed methane research program in the early 1980s. It took some time and effort to understand the production mechanism of the CBM reservoirs. The completion techniques had to be developed in order to produce gas from coal seams. The coalbed gas accounts for 7 percent of the total annual US dry gas production and 11.7 percent of estimated total gas recoverable US natural gas resource base. The total estimated gas in U.S. is about 400Tcf (Hunt, A. M., and Steele D. J., 1992). The major coalbed methane resources are located in 13 large basins (Figure 2.1): Western Washington, Wind River, Greater Green River, Uinta, Piceance, San Juan, Raton Mesa, Arkoma, Warrior, Central Appalachian, Northern Appalachian, Illinois and Power River. The two most productive basins are Black Warrior in Alabama with an estimated gas resource of 20Tcf and the San Juan in northern New Mexico with an estimated gas reserve of 88Tcf. The fast growth in coalbed methane production has required significant efforts in improving technology and understanding the difference between gas production from conventional sandstone and from coal.

Coal is unusual because it serves both as the source rock and the reservoir. To thoroughly evaluate and develop a CBM prospect, you first must understand the internal structure and character of the coal and the strata surrounding the reservoir.



Source: Advanced Resources, International

**Figure 2-1 Major US Coalbed Methane Basins**

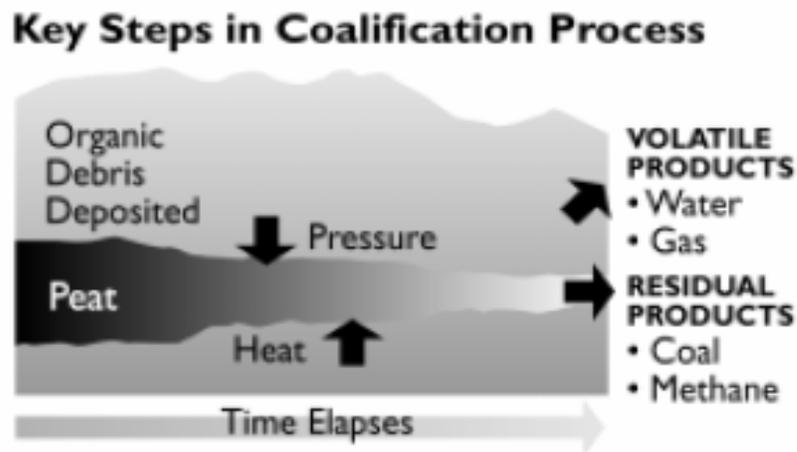
CBM consists of methane production from the coal seams. Coal is a material rich in carbon that has been formed by the chemical and thermal alteration of organic matter. As organic material is buried, compressed, and dewatered, Peat is formed. Peat is a dark brown residuum produced by the partial decomposition and disintegration of plants that grow in marshes and swamps. As peat is buried more deeply, pressure and heat progressively drive off water and volatiles. Peat is then transformed into coal as the carbon content of the fossil organic material increases through devolatilization. This process by which the vegetal matter is transformed progressively through peat, lignite, sub-bituminous, bituminous to anthracite is called coalification. Methane and other gases are produced by anaerobic fermentation, bacterial and fungal alteration and finally by coalification. Figure 2.2 illustrates the major steps and products during coalification process. Coal by definition is a heterogeneous mixture of natural components, mineral matter, water, and methane. Their relative proportions are important influences on the value of coal. Generally, methane represents the larger portion of generated gases and it is produced by two processes: biogenic and thermogenic.

a) The biogenic methane is formed by microbial decomposition of the organic material at temperatures below 50 °C in the early stages.

b) The thermogenic gas generation occurs at temperatures above 50°C.

As temperature increases, the depth of burial and coal rank also increases with time. This time-temperature relationship (also termed as “time-depth of burial”) determines the coal rank that directly controls the volume of methane, carbon dioxide and nitrogen generated. Other hydrocarbon gases such as Ethane, propane, and butane are also produced in smaller amount. However, the analysis of gas produced from coalbed either in wells or during desorption testing shows that, with a few exceptions, these gases contain an excess of 95% methane, trace of very minor amounts of higher hydrocarbons (ethane, propane, etc.), and less than 3% each of nitrogen and carbon dioxide.( Rightmire et al 1984).

Methane is a by-product generated from coalification (Figure 2.2). During this process the amount of methane produced greatly exceeds the capacity of the coal to hold the gas. Some of the gas is naturally released as its burial depth decrease and the remaining gas is stored in the coal seam. In that manner, the coal can hold two to three times as much gas in place as the same volume of a conventional sand reservoir (Kuuskraa, V. and Brandenburg C, 1989). Thus, this storage system places the coal as a very attractive source and reservoir rock for gas production.



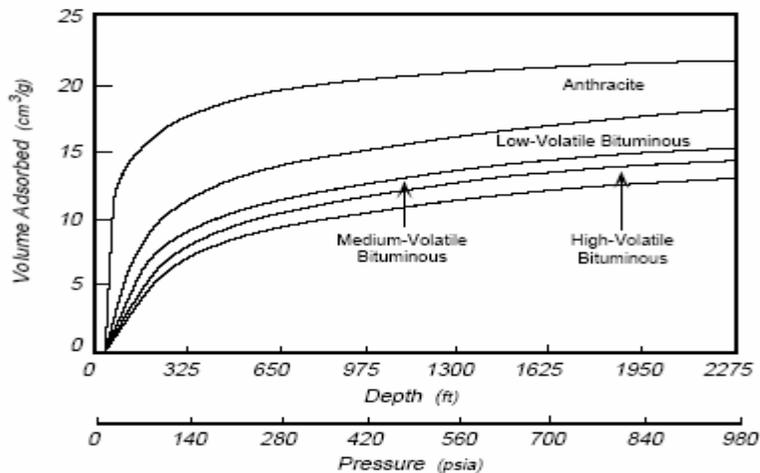
**Figure 2-2 Coalification Process**

### 2.1.1 Physical Properties in CBM Reservoirs.

**Coal Rank:** is deeply associated to CBM reservoirs since the generation of gases in the subsurface occurred during the coalification process. The methane, carbon dioxide and other volatile components of coal are considerate by-products of this process. The three levels of coal rank are:

- (i) Lignite, brownish-black in which the alteration of vegetal material has proceeded further than in peat, but not so far as brown coal.
- (ii) Bituminous; a soft coal which burn freely with a flame. It yields volatile matter with heat.
- (iii) Anthracite, a hard black lustrous coal with more than 92% fixed carbon (dry, mineral matter-free). It is also called hard coal and its permeability is usually very low.

Usually, coal rank is directly proportional to depth because coal is very sensitive to temperature, pressure, and depth of burial (Figure 2.3). Coals at the same depth do not have the same rank. Typically the gas content increases with the hardness of the coal, but the natural permeability also decreases. As a result, the most commercial coal ranks are in a range between sub-bituminous to semi-anthracite because they usually provide optimum gas content and sufficient permeability for gas production.



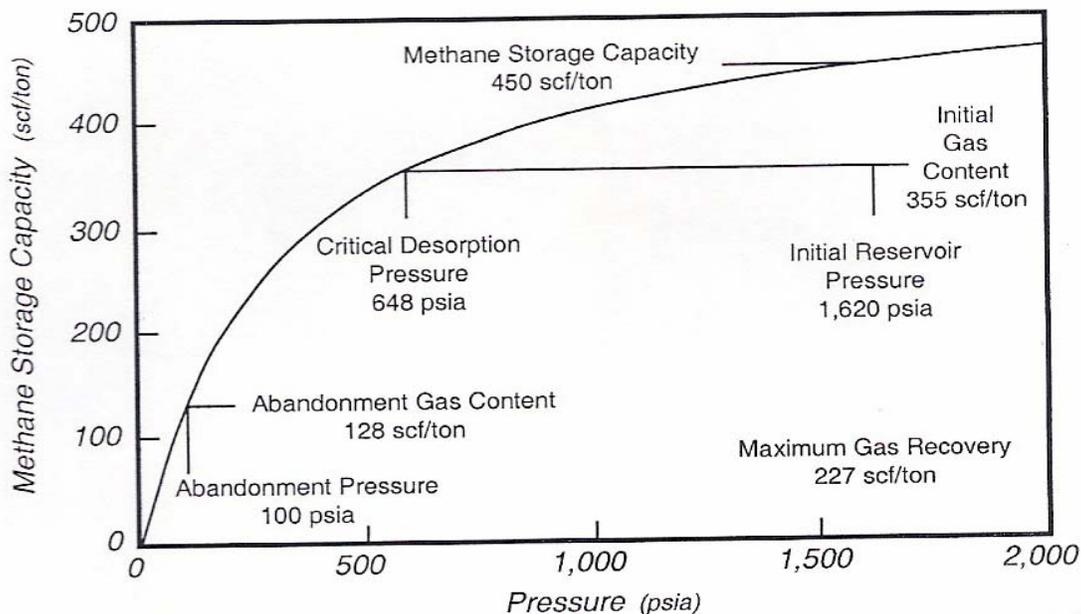
**Figure 2-3 Typical Desorption Isotherms as a Function of Coal Rank (adapted from Eddy, 1982)**

**Maceral Composition** is defined as the organic microscopic constituents of coals, analogous to minerals for rocks. There are three major groups of macerals:

- (i) The vitrinite group, which is derived from various decomposed woody tissues,
- (ii) The exinite group from spore and pollen coats, cuticles, resins and other fatty secretions and
- (iii) The inertinite group derived mainly from partial carbonization of the various plant tissues in the peat swamp stage (Rightmire et al., 1984).

**Vitrinite Reflectance** indicates the degree of metamorphism or coalification. It is mostly performed on vitrinite. It could be highly affected by the mineral matter content of the coal which tends to depress the vitrinite reflectance. Vitrinite exhibit a wide range of reflectance in the coalification series. (Rightmire et al., 1984)

**Adsorption Isotherm** is a plot that shows the ability of the coal to adsorb the gas with respect to pressure (Figure 2.4). The adsorptive capacity of coal depends on various parameters with pressure representing one of the most critical variables for producing gas. As the pressure decreases the coal will desorb more volume of gas. Higher coal ranks with larger surface areas have the highest adsorption capacity.



**Figure 2-4 Relationships between the Sorption Isotherm Curve and Gas Content and the Influence on Recovery**

**Porosity** is the portion of the total coal volume that can be occupied by water, helium, or a similar molecule. Coal pores are classified by size in macropores ( $>500\text{\AA}$ ), mesopores (20 to 500  $\text{\AA}$ ) and micropores (8 to 20  $\text{\AA}$ ). Macro-porosity includes cracks, cleats, fissures, voids in fusinite, etc. Pore volume and pore size both decrease with rank through low-volatile bituminous coals. The macropore spaces (fractures) in the coal are occupied mostly by water and some “free gas”. Also, some gas can be dissolved in the water moving within the pores of the coal. The micropore structure usually has a very low flow capacity with less permeability (in microdarcy range), whereas coal cleats have a much greater flow capacity with higher permeability (millidarcy range). Therefore, coals are considered as materials with dual porosity system.

**Permeability** which is the ability of a material (generally an earth material) to transmit fluids through a porous medium when subjected to pressure, represents one of the most important and crucial properties to produce gas at an economical rate. In the United States, absolute permeabilities can range from 0.1 to 250md. In coalbed methane, there are two major fluids flowing in the interconnected cleat network which result in a two phase flow regime. In this case, effective and absolute permeability take place in order to differentiate two fluid flows in the porous media. The effective permeability is referred to each individual fluid. The effective permeability of individual flowing phase is always less than the absolute permeability of the porous media, and the sum of the effective permeabilities of all flowing phases is less than or equal to the absolute permeability.

Relative permeability is defined as the ratio of effective to absolute permeability. After gas production starts, (long-time production of CBM) a two-phase condition is initiated. At that point relative permeability controls the behavior of the reservoir. Permeability is affected by several parameters such as time-depth burial, fracture spacing, cleat system, effective stress in coals and, coal shrinkage. The fluids in the coals (water and gases) flow through the coal cleat system and other fractures. The cleat is referred to as the natural system of vertical fractures that were formed during the coalification process. Their orientation is controlled by tectonic stresses at the time of fracture formation. The cleat system typically is formed for two or more sets of sub-parallel fractures oriented nearly perpendicular to the bedding.

The face cleat is related to the dominant set of fractures. The orientation of the face cleats is a result of the tectonic forces. They are formed parallel to the maximum compressive stress. Butt cleats are more discontinuous and non-planar than face cleats. Butt cleats are usually perpendicular to the face cleats. The cleat system usually creates permeability anisotropy; with greater permeability in the face cleat direction.

In coals, permeability is very pronounced and stress-dependent. Horizontal stress perpendicular to the face cleat can close the face cleat openings and cause low permeability. When the stress conditions are low, natural fractures can be opened and provide permeability for flow through rock strata. Cleat spacing also influences coalbed permeability greatly. The spacing of face cleat fractures may range from one tenth of an inch to several inches. It is influenced by coal rank, petrographic composition, mineral matter content, bed thickness, and tectonic history. Permeability can be higher in Medium-Volatile Bituminous than in semi-anthracite. In anthracite and semi-anthracite coals the permeability can be low to nonexistent because of the destruction of the cleat.

Furthermore, mineral fillings in cleat may also affect the permeability in the coals.

Common minerals like calcite, pyrite, gypsum, kaolinite, and illite can fill the cleats, thus lowering the permeability values of the coals. If a large proportion of the cleats are filled, absolute permeability may be extremely low. Therefore, knowing the major properties and its effects in coalbed methane reservoirs is an important procedure in describing how the methane is stored in the coal, released and the flowing characteristics. Basically there are two basic concepts in the understanding of CBM; these are the methane storage and the methane flow.

### **2.1.2 Methane Gas Storage in Coal Reservoirs**

Methane is held in coal in one of the following three ways:

- (a) As adsorbed molecules on the organic surfaces,
- (b) As free gas within the pores or fractures and
- (c) Dissolved in solution within the coalbed (Rightmire, et al., 1984).

However, the most amount of methane in coal exists as a monomolecular layer adsorbed on the internal surfaces of the coal surface and there is just a small amount of free gas in the cleat system of a coal seam. Since coals have a very large internal surface area and

the methane's molecules are tightly packed in the monomolecular layer, the total quantity of gas can be adsorbed. Adsorption process is directly influenced by pressure, temperature and coal rank. As pressure and coal rank increase (larger burial depth) and temperature decreases, the methane capacity of coal increases. So, deeper coal seams will generally store larger amounts of methane than shallower coals seams of similar rank (Figure 2.3).

In addition, as coal rank increases the coal's capacity of adsorption also increases.

The quantity of methane generated as coal progresses from peat to anthracite is greater than the capacity of the coal seams ability to absorb it. The amount of methane (and other gases) produced during coalification generally exceeds the retention capacity of the coal, and the excess methane often migrates into the surrounding strata (Boyer et al 1990). For example, the highest gas content measured for anthracite coal in the US is 21.6 cubic meters per metric ton, only 12 percent of the total theoretical amount of methane generated during coalification. This fact can be explained mainly because the pressure holding the methane is much less today than the pressure when the gas was generated and, the amount of gas generated usually exceeds the capacity of adsorption of the coal seam.

The relationship between pressure and adsorbed capacity of coals is best described using a Langmuir isotherm (Figure 2.4). Generally, the coal's capacity of adsorption gas varies non-linearly as a function of pressure. Desorption isotherm shows how the adsorbed gas concentration in the coal matrix changes as a function of the free gas pressure in the coal cleat system. Therefore, it represents the association between the flow in the matrix system and the flow in the cleat system. This non-linear relationship can be described based on an equation originally presented by Langmuir:

$$C_m = \frac{V_L P}{P_L + P} (0.031 \rho_b) \dots\dots\dots (2.1)$$

Where;  $C_m$  = matrix gas concentration. Scf/ft<sup>3</sup>

$V_L$  = Dry, ash-free langmuir volume constant Scf/ton.

$P$  = Pressure in fracture system Psia.

$P_L$  = Langmuir pressure constant

$\rho_b$  = Bulk density g/cm<sup>3</sup>

The other byproduct of coalification process that takes an important place in analyzing coalbed methane is water. Water can be stored in coals in two ways:

- (a) As bound water in the coal matrix and
- (b) As free water in the coal cleat system.

Matrix bound water is not mobile and has not shown any significant influence in methane recovery from coal. However, the free water held in the cleat system represents one of the critical parameter in methane production. The free water is mobile at high water saturations (greater than 30%). Many coal deposits are active aquifer systems and are 100 % water saturated in the cleat system. Those that are not aquifers may not be totally water saturated. Typical irreducible water saturation for a well cleated coal is in the range of 20 to 50 % of the interconnected cleat volume.

### **2.1.3 Gas Transport Mechanisms in Coal Reservoirs**

As mentioned earlier, Production of gas is controlled by a three step process – desorption of gas from the coal matrix, diffusion to the cleat system, and flow through fractures.

The majority amount methane is stored in coal basically by adsorption in the matrix.

However, as pressure in the coal is lowered, the main fluid that flows in the cleat system is water and small quantities of free gas and some dissolved gas in the water. After the coal is dewatered, the methane is released (desorption stages-process) from the surface of the coal. Desorption is the process by which methane molecules detach from the micropore surfaces of the coal matrix and enter the cleat system where they exist as free gas. After desorbing from the coal surface, the methane flow in the matrix starts moving to the cleat system by different gas concentration gradients in both zones (diffusion). In other words, progressively the cleat system experiences low methane concentration that activates the gas adsorbed in the matrix to move from the higher gas concentration to the lower one. Diffusion is a process in which flow occurs via random molecular motion from an area of high concentration to an area of lower concentration. The diffusion process in the micropore system is described by the equation derived from Fick's Law

(equation 2.2). Using this equation the rate of flow from a matrix element into the cleat system can be calculated. It assumes the matrix elements are perfect cylinders.

$$q_{gm} = \frac{8\pi DV_m}{S_f^2} (C_m - C(p)) \dots\dots\dots (2.2)$$

Where;  $q_{gm}$  = gas production rate from the coal matrix. Scf/day.

D = diffusion coefficient ft<sup>2</sup>/day.

$V_m$  = matrix volume ft<sup>3</sup>

$S_f$  = Fracture or Cleat spacing ft

$C_m$  = matrix gas concentration scf/ft<sup>3</sup>

$C(p)$  = Equilibrium concentration at matrix-cleat boundary scf/ft<sup>3</sup>

Sorption time, ( $\tau$ , days), is referred to as the time required for methane molecules to desorb off of the coal surface and diffuse through the coal into the cleat system. In coal, this time can vary from less than one day to over 300 days depending on coal composition, rank, and cleat spacing (Boyer et al., 1990). Sorption time can be calculated using the following equation,

$$\tau = \frac{S_f^2}{8\pi D} \dots\dots\dots (2.3)$$

The methane flow in the coals starts with lowering the pressure in order to produce the free gas and water from the natural system and to desorb methane from the cleat surface. The variation in concentration is compensated by releasing gas from the matrix by diffusion. Desorption is controlled by pressure gradients while diffusion is controlled by concentration gradient. Once the gas reaches a cleat or fracture, the flow of methane through the coal can be describe using Darcy’s Law. Darcy’s Law is applied to reservoirs with the simultaneous flow of more than one fluid by including the effective permeability to each flowing phase. The relative permeability of each fluid (gas and water) should be well known in order to get accurate results.

**2.1.4 Coalbed methane production**

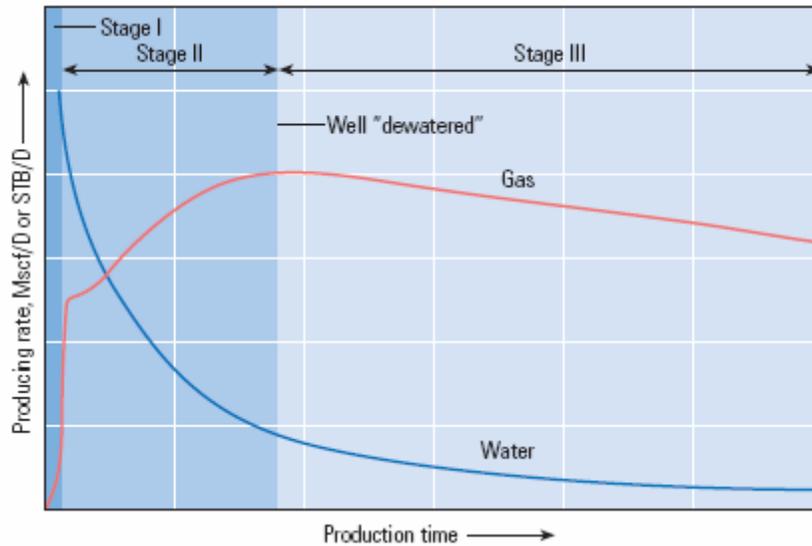
Coalbed methane production passes through three phases during the life-time of the reservoir. This behavior differs significantly from the normal decline curve of

conventional gas wells. The production profile of coalbed methane well is shown in (Figure 2.5).

During phase I, CBM wells experience a constant water production with a very low or negligible decline in gas production and decline in flowing bottomhole pressure. Initially, most CBM wells are naturally water saturated because water liberation occurs during the coalification process. The water is occupying the principal cleat network. There is the need of removing the water from the major fractures system in order to produce gas. Ideally, water production will relieve the hydraulic pressure on the coal in order to start the production by desorption of the gas from the coal. This process is known as dewatering. The number of days of this dewatering process and the amount of produced water can vary widely. Their impact deals with the economics of gas production. In this sense, they are very difficult to estimate and their influence in the economics very hard to predict. However, it seems that they are controlled by the physical properties of the coal. The major physical properties that affect the efficiency of the dewatering process are: (a) permeability, (b) adsorbed gas content, (c) relative permeability and capillary pressure curves, (d) diffusion coefficient and, (e) desorption isotherm. At the end of this first phase, the well has reached its minimum flowing bottomhole pressure.

Phase II is described by a dramatic decrease in the water production and increase of the gas production rate. The water relative permeability decreases and the gas relative permeability increases. Outer boundary effects become significant and gas desorption rates change dynamically. The limit between phase II and III is determined when the peak gas rate is reached. The gas production has stabilized and starts to experience a typical decline trend.

During phase III, the well is considered to be dewatered, so the water production is in the low level or negligible. The water and gas relative permeabilities do not change extensively. The pseudo-steady state exists for the rest of producing life.

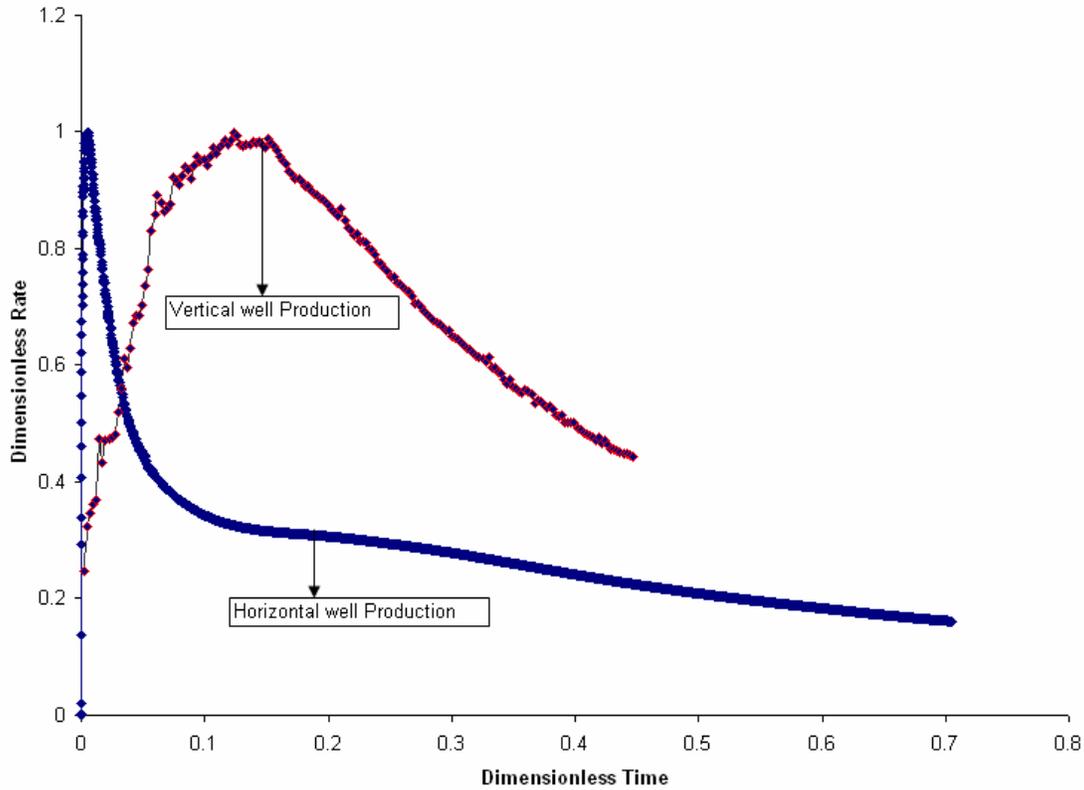


**Figure 2-5 Typical Coalbed Methane Production Profiles for Gas and Water Rates: Three Phases of Producing Life**

## ***2.2 Horizontal Wells in Coalbed Methane***

Horizontal wells in coalbed methane are a relatively new idea and many of the drilling projects that have been proposed using this technology are still in their infancy.

One of the principal benefits of horizontal well technology is that the direction of the borehole can be controlled with respect to the principal permeability directions of the coal seam. Therefore, in coalbed methane reservoirs, a more effective production technique may be a horizontal borehole placed perpendicular to the maximum permeability direction. This would result in improved access to the reservoir through the natural fracture network and enhance the rate of water production, accelerating the gas desorption process. A production profile for a horizontal CBM well is shown in Figure 2.6. The production profile for horizontal CBM wells varies from that of a vertical CBM well. Since the horizontal well is drilled perpendicular to the maximum permeability direction there is more accessibility for the water to flow into the wellbore, thus allowing the dewatering process to be accelerated. From a comparison of Figure 2.6 and Figure 2.5 one can notice that Stage 1, which is the Dewatering stage, occurs in a shorter time frame. When considering whether or not to drill horizontal wells, three properties are noted; (a) Coal thickness; (b) natural fractures; (c) anisotropic permeability.



**Figure 2-6 CBM Horizontal and Vertical Well Production**

### ***2.3 Type Curves for Coalbed Methane Reservoirs.***

Analysis of CBM reservoirs and their production performance can be very challenging. The conventional decline curve analysis cannot be utilized due to the complex production mechanism in CBM reservoirs. (Aminian et al 2005). A set of type curves has been proposed for vertical CBM wells. The type curves were developed as follows:

- 1) A basic reservoir model to predict gas production profiles for a CBM reservoir was developed.
- 2) A unique set of gas production type curves for CBM wells was developed.
- 3) The impact of various reservoir parameters on the type curves was investigated.
- 4) A correlation between  $q_{\max D}$  and the various reservoir parameters was developed.

## Reservoir Model Description

A two-dimensional Cartesian base model was developed for an under-saturated CBM reservoir with a well located at the center of the drainage area. The reservoir simulation software used in this study was GEM developed by the Computer Modeling Group (CMG). GEM is CMGs advanced general equation of state, compositional, dual porosity reservoir simulator. Gem includes options for gas sorption in the matrix, gas diffusion through the matrix, two- phase flow through the natural fracture system. The reservoir parameters used to develop the base model are summarized in Table 2.1. A set of published relative permeability was used in the model. The simulation runs were made by varying several of the key parameters over the range ranges provided in Table 2.1.

**Table 2-1 Values and Ranges of Parameters used in the CBM Base Model**

PARAMETERS	BASE MODEL VALUE	RANGE
Model	Dual Porosity	-
Shape Factor Formulation	Gilman and Kazemi	-
Matrix-Fracture Transfer Model	Pseudo-capillary pressure with corrections	-
Model Geometry	2D-Cartesian	-
Grid Size	100ft x 100ft	-
Reservoir Area	40 acres	40, 80, 160 acres
Thickness	10ft	5-15ft
Matrix Porosity	0.5%	-
Fracture Porosity	2%	1-5%
Matrix Water Saturation	0.5%	-
Initial Fracture Water Saturation	100%	70-100%
Matrix Permeability	0.01md	-
Fracture Permeability	10md	5-20md
Fracture Spacing	0.2ft	0.1-1ft
Initial Pressure	600psia	300-600psia
Temperature	113°F	-
Langmuir Pressure ( $P_L$ )	675.6psia	
Langmuir Volume ( $V_L$ )	475SCF/ton	
Coal Sorption Time	50days	10-300
Critical Desorption Pressure	300psia	300-600psia
Rock Density	89.63lb/ft <sup>3</sup>	-
Skin Factor	0	-4 to +4
Bottom Hole Pressure (Constant)	50psia	50, 75, 100psia

## Type Curve Development

A set of dimensionless rate and time equation was defined.

$$q_D = \frac{q}{q_{peak}} \text{ ----- (2.4)}$$

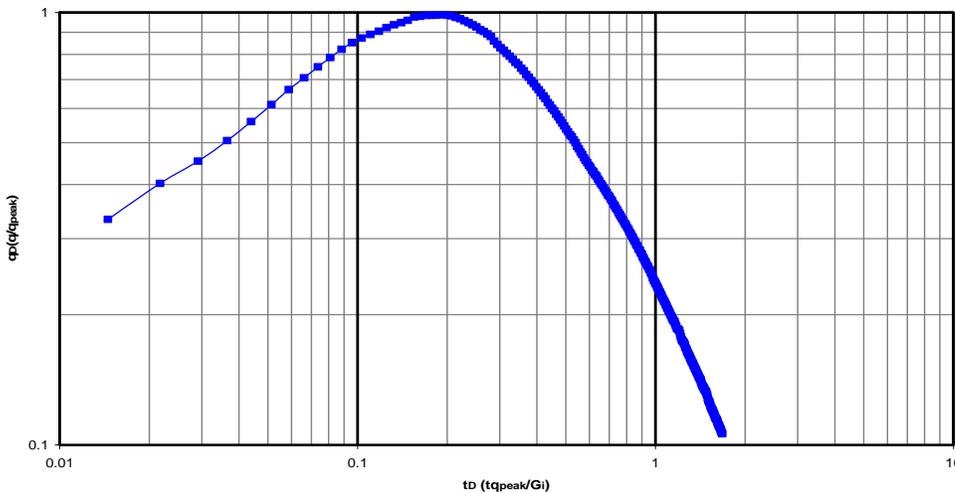
$$t_D = \frac{q_{peak}}{G_i} \times t \text{ ----- (2.5)}$$

In the above equations,  $q_{peak}$  represents the maximum or peak gas rate and  $G_i$  is the initial gas in place which can be calculated by using the following equation:

$$G_i = 43560Ah\rho G_C \text{ ----- (2.6)}$$

Where,  $G_C = \frac{V_L \times P}{P_L + P}$  is the gas content of coal in SCF/ton and  $\rho$  is the coal bulk density.

The base model gas production history was converted to dimensionless rate and time using the above definitions and the results were plotted on both Cartesian and log-log scale. Figure 2.7 illustrated the type curve developed in this study.



**Figure 2-7 Type Curve for Vertical CBM production (Aminian K, 2004)**

### Impact of Reservoir Parameters

In order to establish the uniqueness of the type curves, the impact of the key reservoir parameters was investigated. The following eight parameters caused insignificant (less than 5%) deviation from the original type curves: fracture permeability, fracture porosity, fracture initial pressure, coal thickness, drainage area, skin factor, sorption time and initial gas content of coal. Flowing bottom hole pressure appeared to have some impact on gas production type curves particularly in the latter parts of the production history.

### Correlation Between $q_{(peak)D}$ and the various reservoir parameters

The type curves can be used to predict gas rates for evaluation of a CBM prospect. It is necessary to estimate  $q_{peak}$  and  $G_i$  from available formation properties. A variation of  $q_{peak}$  with various parameters was investigated to develop a correlation. A dimensionless group for  $q_{peak}$  was developed to minimize the impact of obvious parameters and simplify the development of the correlation. The dimensionless peak gas rate is defined as:

$$q_{(peak)D} = \frac{(q_{peak})_g \times 1422 \mu z T \left[ \ln \left( \frac{r_e}{r_w} \right) - 0.75 + s \right]}{kh(P_c^2 - P_{wf}^2)} \quad \text{----- (2.7)}$$

In the above equation  $P_c$  is the critical gas desorption pressure which is the pressure at which gas desorption from coal matrix into cleat system begins. Gas viscosity and z-factor in equation 2.7 should be estimated at  $P_c$ . Cleat porosity, skin factor, Langmuir pressure and volume constants, and the critical gas desorption pressure were found to influence  $q_{(peak)D}$ . A linear multiple regression analysis was performed to develop the following correlation ( $R^2 = 0.86$ ):

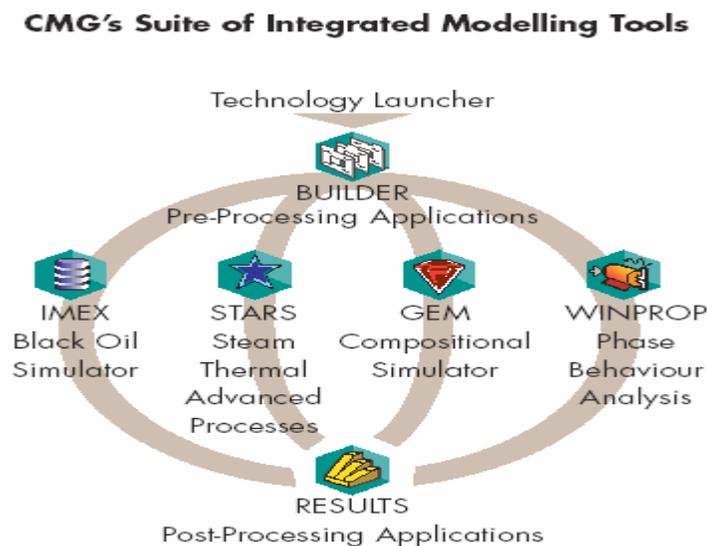
$$q_{(peak)D} = 4.20S - 21.47\phi_f - 0.024P_c + 0.084V_L + 0.01P_L + 108.78$$

### 2.4 CMG Simulator

CMG (Computer Modeling Group) model is a computer software for reservoir simulation capable to determine reservoir capacities in order to maximize potential recovery. CMG is conformed by six basic applications. BUILDER; Preprocessing Applications, IMEX;

Black Oil Simulator, STARS, Steam Thermal Advanced Processes, GEM; Generalized Equation-of-State Model Compositional Reservoir Simulator, WINPROP; Phase Behavior Analysis, and RESULTS; Post-processing Applications.

Although the applications that are included in the simulation software are designed for specific specs they can be modified slightly to handle the task at hand. The applications used in this study with CBM horizontal well production are BUILDER, GEM and RESULTS.



**Figure 2-8 CMG's modeling tools**

BUILDER is an application used in the preparation of reservoir simulation models. It makes the design and preparation of reservoir models faster and more efficient. It does this by helping engineers navigate the often complex processes involved in preparing a model. BUILDER provides a Windows interface which organizes data in an easy way for engineers. For engineers with little previous experience in modeling, it can be an excellent training tool by guiding them through the process of preparing a simulation model and enabling them to concentrate on the reservoir recovery process and not in the keyword syntax. BUILDER presents two modules which are: (a) Gridbuilder, and (b) ModelBuilder. The Gridbuilder is used to create simulation grids and rock property data for IMEX, GEM, and STARS. It allows the user to easily create and edit grids, positioning them with respect to geological maps and then interpolating geological

structures and rock properties. The grid can be displayed in a variety of 2D and 3D views to allow quick checking of the grid correctness and conformance. The ModelBuilder is also Windows-based software that helps the user to prepare input data for the simulators. It presents an easy-to-use visual interfaces as wells as support for direct editing of the data set information within the program itself. It has an automatic error checking and data validation options.

GEM is CMG's fully compositional simulator used to model any type of reservoir where the importance of the fluid composition and their interactions are essential to the understanding of the recovery process. It is an essential engineering tool for modeling very complex reservoirs with complicated phase behavior interactions which impact directly on the recovery mechanisms employed to optimize the recovery. Specifically CMG has made some modification to the code in order to be able to use it for CBM reservoirs. In this study, this modified version of GEM was the simulator used to modeling the CBM performance.

RESULTS; the post-processing application, is a CMG's set designed for visualizing and reporting simulator output. This application is able to prepare 2D and 3D plots, generate various informative graphs, and prepare tables of required information to be included in a study report. It can generate quick and easy export to spreadsheets (EXCEL) for economic analysis, and specialized software. RESULTS, is currently compose of two modules: (a) Results Graph and 3D, and (b) Result Report.

Results Graph is a 2D graph of well production and injection data from simulator runs and from common historical production data sources. It is controlled and defined by the user to provide all the options that the user needs to better understand the reservoir.

Results is a module that produces high quality scaled 2D and 3D views of all grid based simulator data and links the displayed wells directly to the graphing capabilities of Results Graph. It allows the user control over the display both in location and time. It can be accessed directly through Results Graph and vice versa by opening different windows at the same time. In this way, the user has the complete vision of the plots to better understanding the performance of the reservoir. Results Report produces user-definable tabular reports of virtually any type of data generated during a reservoir simulation run,

including well data, reservoir or sector totals and averages, and reservoir grid property data. It also can be used to compare data from different simulation runs and to generate ASCII files to input to economic analysis applications or spreadsheets of the user choice.

### 3 OBJECTIVE AND METHODOLOGY

The objective of this research was to develop a simple and reliable tool to predict the performance of horizontal wells in order to evaluate the economic feasibility and to maximize potential recovery. To achieve the objective, a methodology consisting of the following steps was employed:

1. A practical reservoir model producing through a horizontal well in the Northern Appalachian Basin was developed.
2. A set of type curves was developed using dimensionless groups.
3. The impact of various reservoir parameters on production performance was investigated.
4. A correlation between the dimensionless peak gas rate ( $q_{(\text{peak})D}$ ) and various parameters was developed.

#### ***3.1 Development of the Reservoir Model for the Northern Appalachian Basin***

Before the simulation study was performed, an intensive literature review was conducted to identify the range of parameters to be used in the base model for the parametric study. Once the basic parameters were determined, the model was built using BUILDER. Table 3.1 shows the input parameters used for the base model.

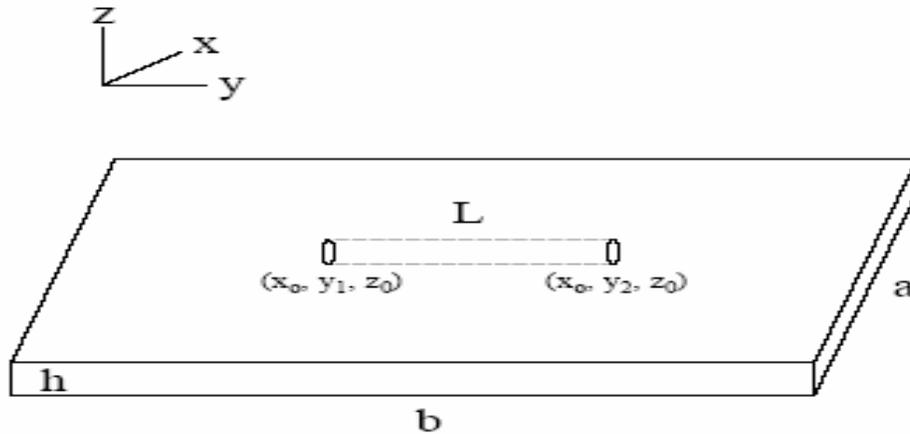
For this base model and for all the cases that has been run the reservoir will be rectangular but the ratio of width to length of the well will not change as the area increases. The permeabilities are different for all  $i$ ,  $j$  and  $k$  ( $k_x$ ,  $k_y$  and  $k_z$ ) directions. As a result of coal being permeability anisotropic, the horizontal well was drilled perpendicular to the direction with the highest permeability, that is, in  $i$ - direction (Figure 3.1). The permeability values for each direction were changed at a constant ratio of 1:3 and 1:10 (1/3 of the maximum permeability;  $i = 10\text{md}$ ,  $j = 3.3\text{md}$  and,  $k = 1\text{md}$ ).

The simulation that was run incorporated a variable permeability range from 5 to 20md in i-direction. The 20md is considered to be an extreme case for the northern Appalachian basin, but was incorporated in order to fully demonstrate the effect on the type curves.

**Table 3-1 Input Parameters for the Base Model**

INPUT PARAMETERS	Horizontal CMB MODEL	
		VALUE
Period of Production		25 years
Porosity Model	Dual Porosity Model	-
Shape Factor Calculations	Gilman and Kazemi Style Formulations	-
Matrix-Fracture Transfer Calculations	Pseudo-capillary pressure model with corrections	-
Grid	Cartesian	26 x 54 x 1
	K direction	Down
Grid's Size		100ft x 100ft
Reservoir Area		320 ac
Grid Properties	Grid top	1200 ft
	Grid thickness	10 ft
	Porosity Matrix	0.5%
	Porosity Fracture	2%
	Permeability Matrix	0.01 md (i,j,k)
	Permeability Fracture	10 md i, 3.3 md j, 1 md k
	Fracture spacing	0.2 ft
Rock Compressibility	Matrix and Fracture: Reference Pressure	1100 psi
	Rock Compressibility	$1 \times 10^{-6}$ 1/psia
EOS Model	Peng – Robinson	
Library Components	Methane	CH <sub>4</sub>
Constant reservoir temperature		113 F
Rock-Fluid Data - Grid Properties	Maximal Adsorbed mass (CH <sub>4</sub> )	Matrix: 0.2845 Fracture: 0
	Langmuir Adsorption Constant (CH <sub>4</sub> )	Matrix: 1.48 E-03 Fracture: 0
	Rock Density	Matrix: 89.63 lb/ft <sup>3</sup> Fracture: 89.63 lb/ft <sup>3</sup>
	Coal Sorption Time (CH <sub>4</sub> )	Matrix: 50 days Fracture: 50 days
Initial Conditions - Grid Properties	Water Saturation	Matrix: 0.005 Fracture: 1
	Pressure	Critical desorption Pressure: 300 psia Fracture: 600 psia
	Gas Composition (CH <sub>4</sub> )	Matrix: 1 Fracture: 0
Constraints	Minimum Bottom Hole Pressure	50 psia
	Maximum Gas Rate	350,000 ft <sup>3</sup> /day
Well Length		1100 ft

A set of published relative permeability was used in the model. The simulation runs were made by varying several of the key parameters over the ranges provided in Table 3.2



**Figure 3-1 Horizontal well in a box-shaped drainage volume (Babu and Odeh, 1989).**

The horizontal well length is changed for all the different areas and this change is based on a ratio of 11:38, 15:38, and 30:38. Table 3.2 summarizes the parameters and their ranges.

**Table 3-2 Parameters range varied during simulations**

<i>Variable</i>	<i>Range</i>	<i>Values used</i>			
Fracture permeability $i_{j,k}$ (md)	5-20	5i, 1.7j, 1k	10i, 3.3j, 1k	15i, 5j, 1.67k	20i, 6.7j, 2k
Fracture porosity (%)	1.5 - 3	1.5, 2, 2.5, 3			
Area (ac)	160-320	160, 240, 320			
Thickness (ft)	5 - 20	5, 10, 15, 20			
Critical desorption Pressure (psi)	300 - 600	300, 400, 500, 600			
Initial Fracture Pressure (psi)	300 - 600	300, 400, 500, 600,			
Flowing Bottomhole Pressure (psi)	50-100	50, 75, 100			
Changing the Ratio of Well Length to Area	1100-4300 ft	Ratio	11:38	15:38	30:38
		160 ac	1100	1500	3000
		240 ac	1300	1800	3600
		320 ac	1600	2100	4300

The same procedure in developing type curves for vertical wells was applied for horizontal wells.

**3.2 Impact of Reservoir Parameters**

In order to establish the uniqueness of the type curves, the impact of the key reservoir parameters was investigated. The following seven parameters caused insignificant (less than 5%) deviation from the original type curves: fracture porosity, fracture initial pressure, coal thickness, drainage area, critical desorption pressure, flowing bottom hole pressure, Langmuir volume. Fracture permeability and Langmuir Pressure appeared to have some impact on gas production type curves.

**3.3 Development of a Generalized Correlation between Dimensionless peak Gas Rate and various reservoir parameters.**

The development of a generalized correlation for dimensionless peak gas rate in horizontal wells follows the same procedure as in vertical wells as discussed earlier.

The following equation defines the dimensionless peak gas rate for horizontal wells in CBM reservoirs.

$$q_{(peak)D} = \frac{(q_{peak})_g \times 1422 \mu z T \left[ \ln \left( \frac{r_{eh}}{r_w} \right) - 0.75 + s \right]}{kh(P_c^2 - P_{wf}^2)} \dots\dots\dots (3.1)$$

In equation 3.1,  $P_c$  is the critical gas desorption pressure which is the pressure at which gas desorption from coal matrix into cleat system begins. Gas viscosity and z-factor in equation 3.6 should be estimated at  $P_c$ . The use of this dimensionless group minimized the impact of permeability, thickness, and drainage area.

A linear multiple regression analysis was performed to develop the correlation. To achieve the best fit, reservoir parameters with significant impact on  $q_{(peak)D}$  were correlated in various combinations.. In the first combination, critical desorption pressure, porosity, Langmuir volume and Langmuir Pressure were correlated with an  $R^2$  value of 0.7267

In the second set of combination, thickness (h), Permeability (k), skin factor (s), critical desorption pressure, porosity and Langmuir volume were correlated with an  $R^2$  value of 0.8643.

In the last set of combination, thickness (h), Permeability (k), skin factor (s), critical desorption pressure, porosity, Langmuir volume and Langmuir Pressure were correlated with an  $R^2$  value of 0.91558 .

### 3.4 Verification

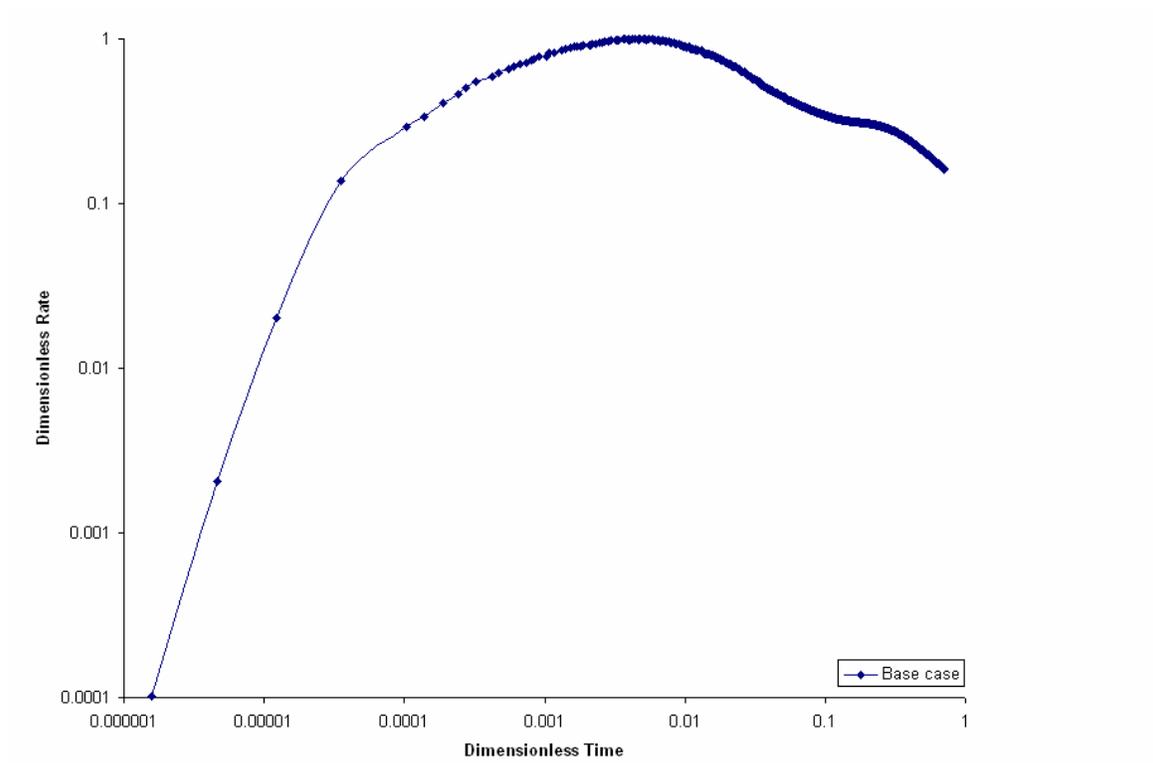
To evaluate the reliability of the gas production type curves and the correlations for  $q_{(peak)D}$ , a case study was performed . A set of reservoir characteristics as summarized in Table 3.3 were used as input into the CBM reservoir simulator to generate the production histories. These production histories were used to compare against the prediction from type curves using the gas peak rate.

**Table 3-3 Input data for the Case Study**

<b>PARAMETERS</b>	<b>VALUES</b>
Fracture permeability	8i, 2.7j, 1k
Fracture porosity (%)	1.7
Area (ac)	320
Thickness (ft)	12
Critical desorption Pressure (psi)	350
Initial Fracture Pressure (psi)	650
Flowing Bottomhole Pressure (psi)	80
Langmuir Pressure	675.6
Langmuir Volume	476
Maximum Error	7%

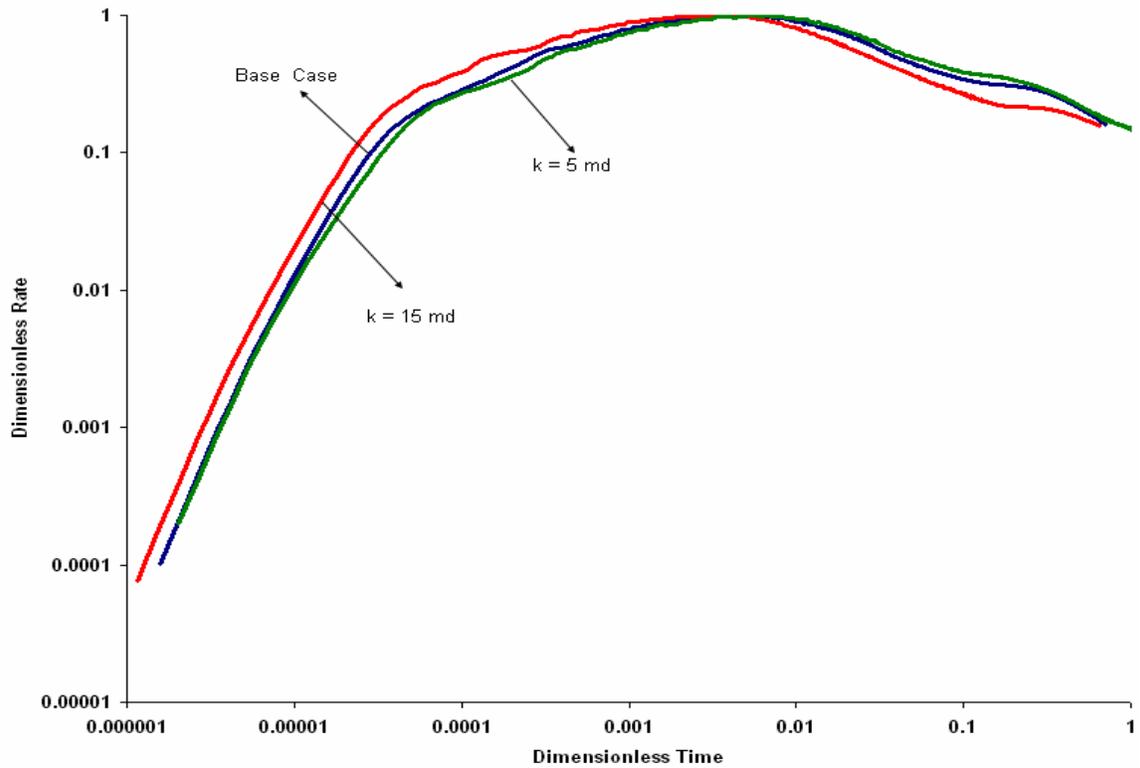
## 4 RESULTS AND DISCUSSION

The CBM production prediction tool developed in this study can serve as a quick and reliable tool for production performance, prediction and production data analysis. The results of the impact of the various parameters are shown below. Figure 4.1 shows the type curve for the base model.



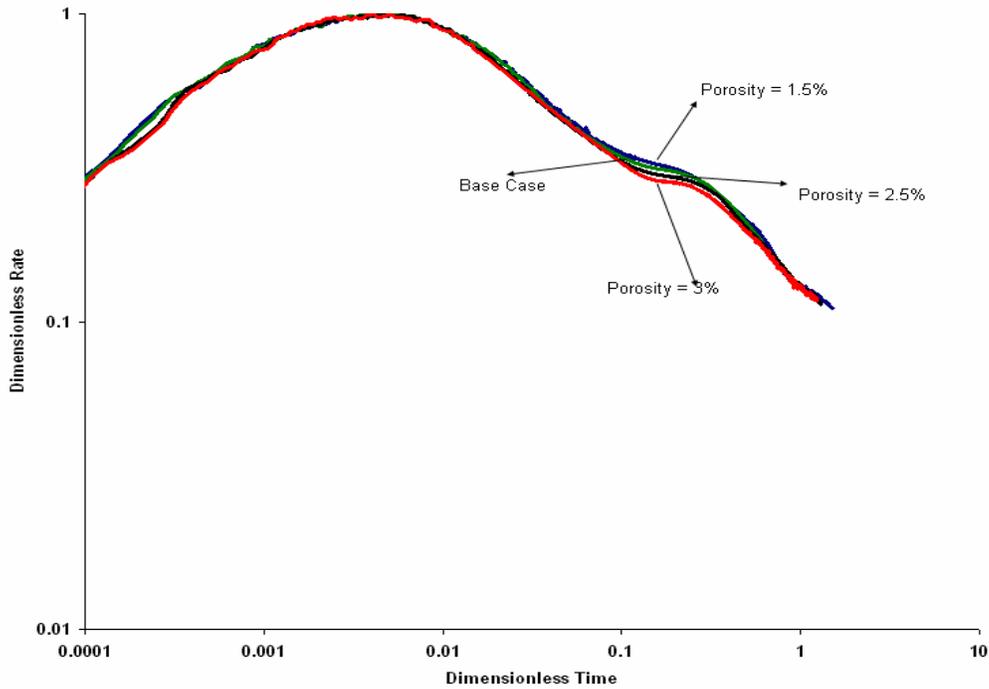
**Figure 4-1 Type Curve for the base model**

Figure 4.2 shows the impact of permeability in log-log scale. The curves for permeability converge at a later stage of the reservoir.



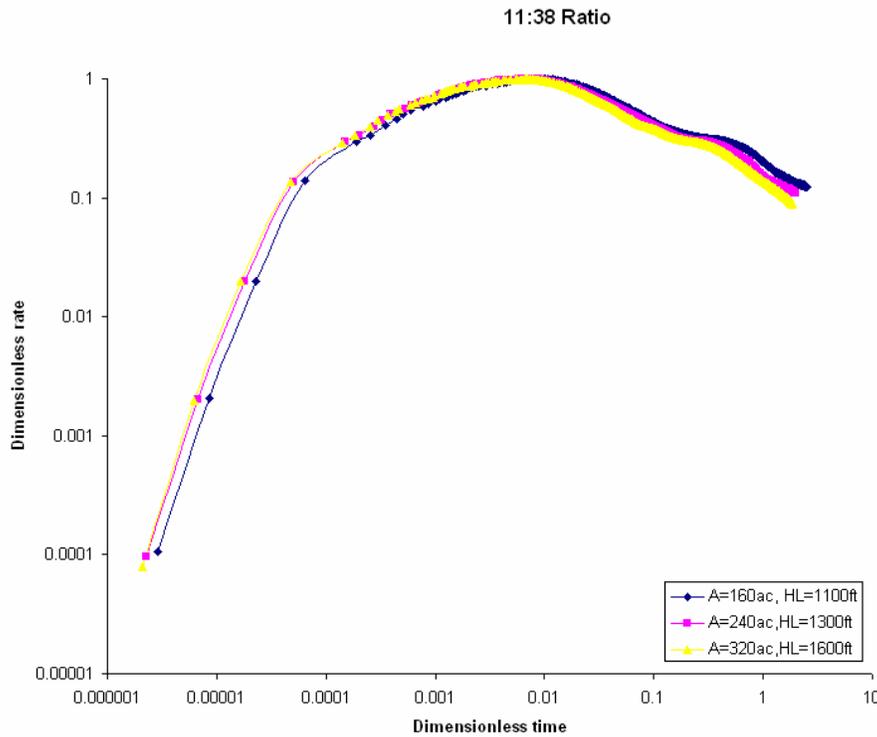
**Figure 4-2 Effect of permeability on the shape of the Type Curves Log-log scale.**

The second set of simulations took into account the effect of porosity on the production from horizontal CBM wells. The porosity varied from 1.5% to 3%. Figure 4.3 illustrates the effect of porosity in log-log scale.



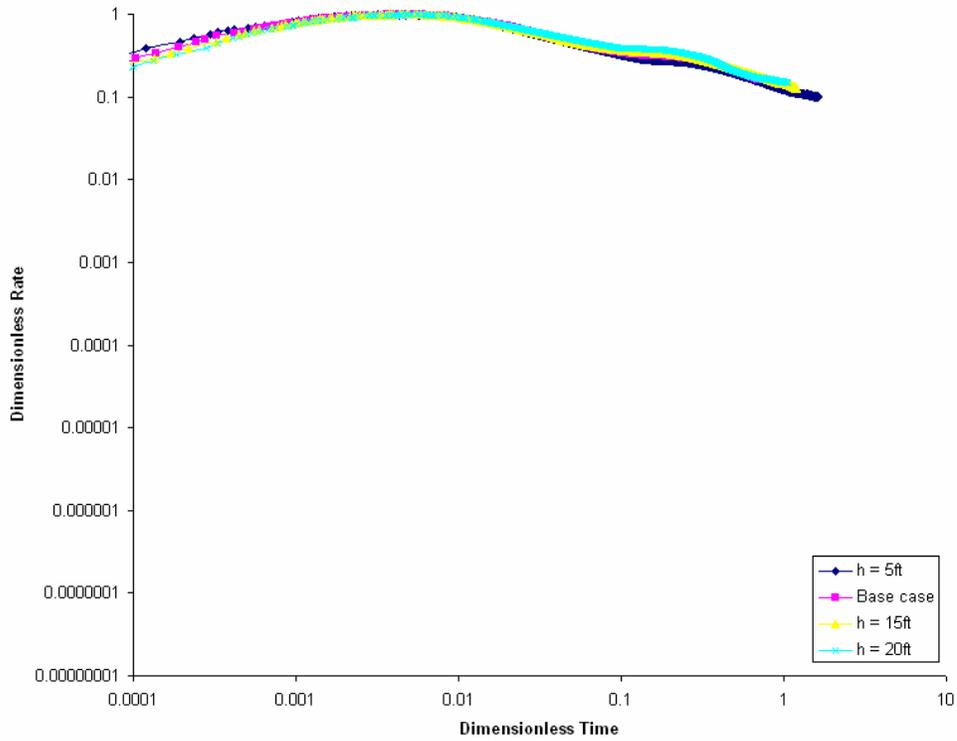
**Figure 4-3 Effect of porosity on the shape of the Type Curves in log-log scale**

In the third set of simulations, the horizontal length is changed for all the different areas and this change is based on a constant ratio as given on table 3.2. Figure 4.4 shows the results in log-log scale.



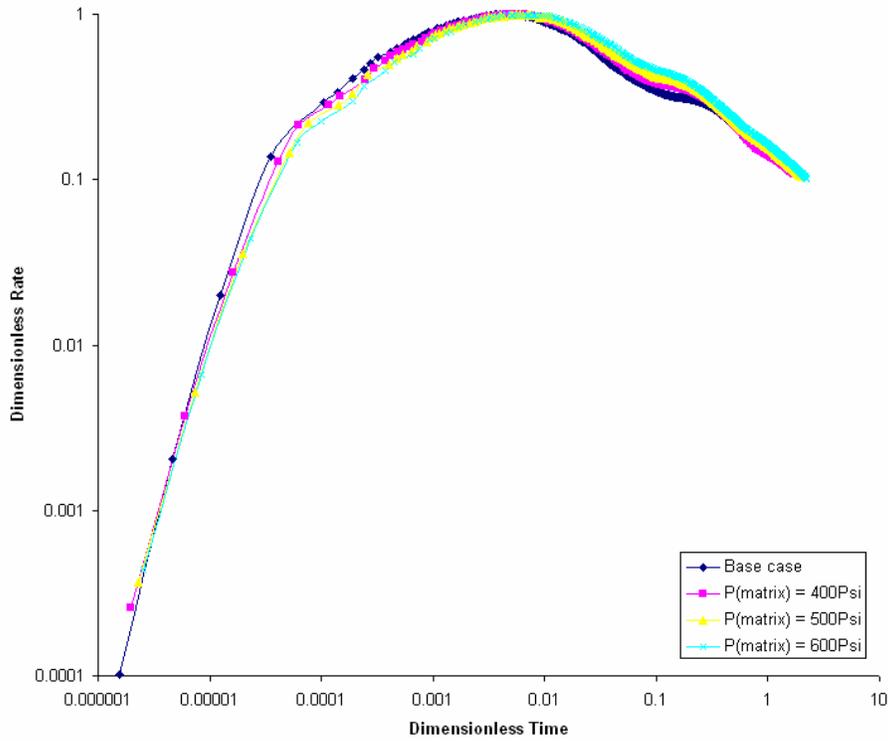
**Figure 4-4 Effect of the Horizontal length to Area Ratio on the shape of the Type Curves in log-log scale.**

The fourth set of simulations was performed to evaluate the influence of coal thickness in CBM reservoirs performance. Figure 4.5 illustrates the comparison between the various cases.



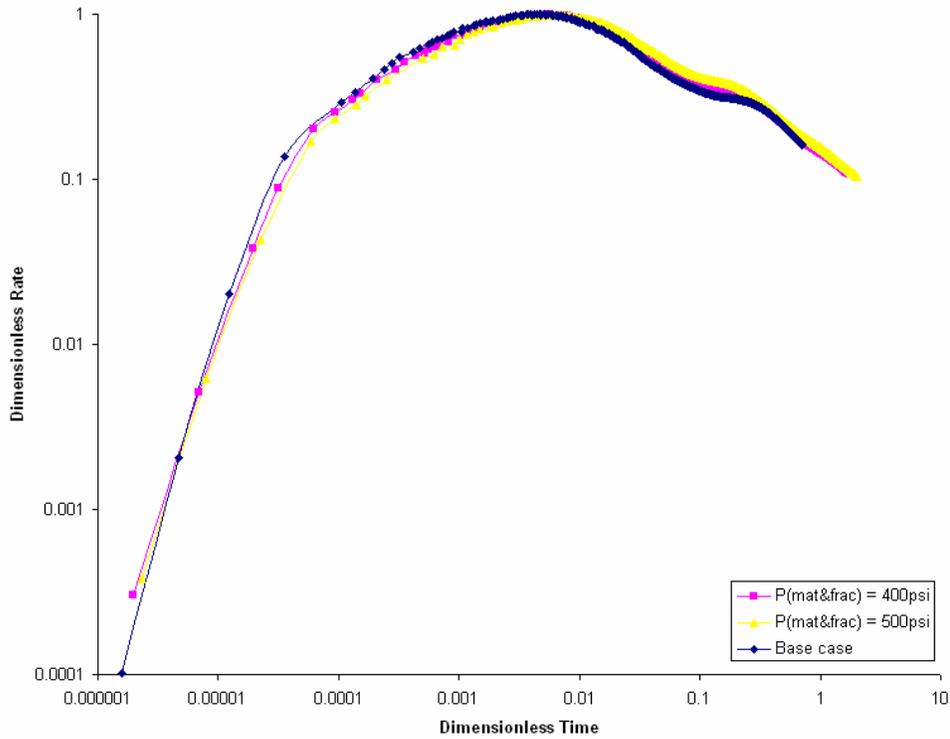
**Figure 4-5 Effect of thickness on the shape of the Type Curves in log-log scale**

The fifth set of simulations includes the variation of the critical desorption pressure. The impact of the pressure in the CBM production is considered critical and it needs to be tested to evaluate the behavior of the gas depletion. The critical desorption pressure varied in a range of 300 to 600psi. Figure 4.6 illustrates the influence of critical desorption pressure on the gas production performance in a log-log scale



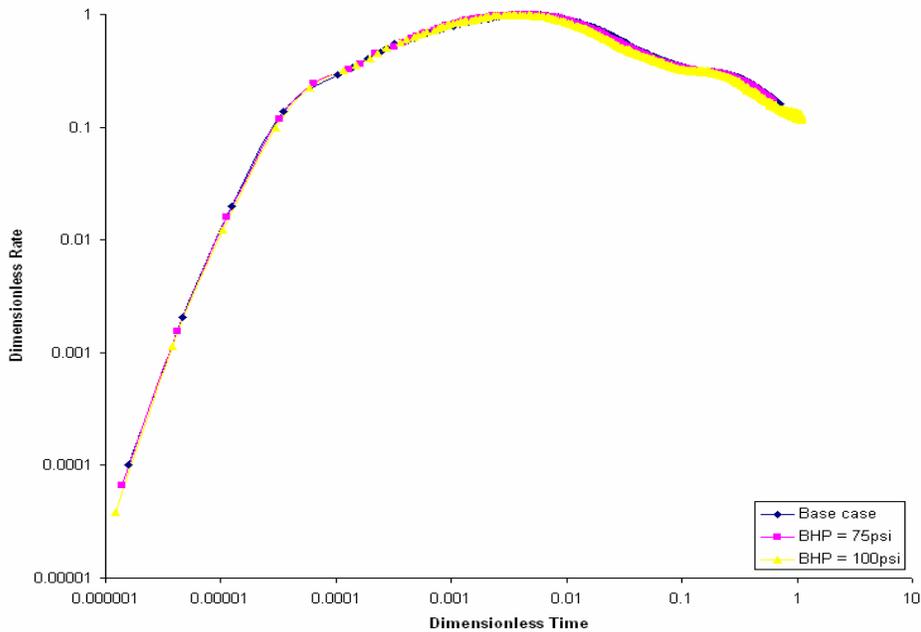
**Figure 4-6 Effect of Critical desorption pressure on the shape of the Type Curves in log-log scale.**

The sixth set of simulations corresponds to the variation of both initial desorption and fracture pressure by the same value. Simulations were performed testing these properties from 300 to 500psi. The impact of the initial fracture pressure on the gas production behavior is not as significant as initial desorption pressure because most of the gas is stored in the coal matrix and it is not flowing as a free gas in the fractures of the coal. Figure 4.7 shows the variation of the production for the different pressures in log-log scale.



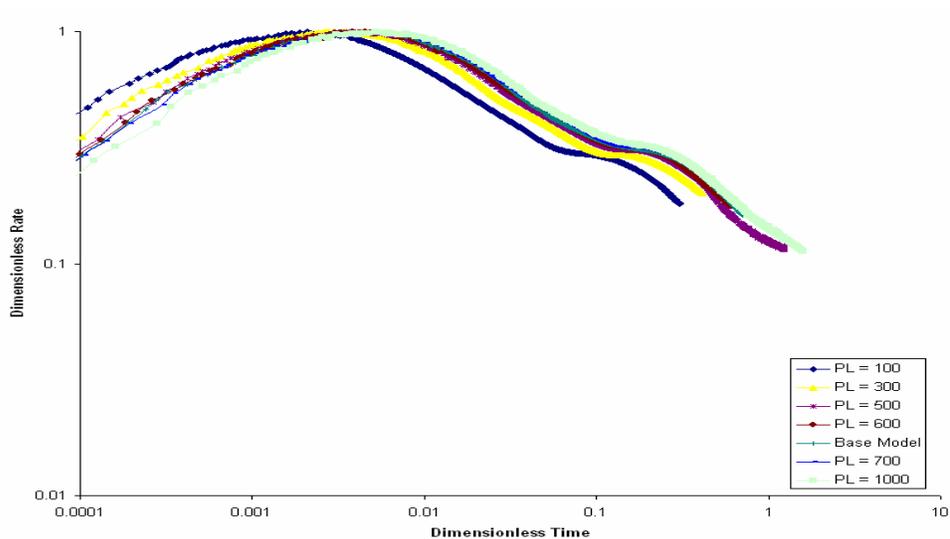
**Figure 4-7 Effect of changing both initial fracture and critical desorption pressure on the shape of the Type Curves log-log scale.**

The seventh set of simulations took into account the flowing BHP (Bottomhole Pressure). The BHP was changed to different values to determine its impact on the set of dimensionless equations. The BHP was run on values ranging from 50-100 psi. Figure 4.8 shows the behavior in log-log scale.



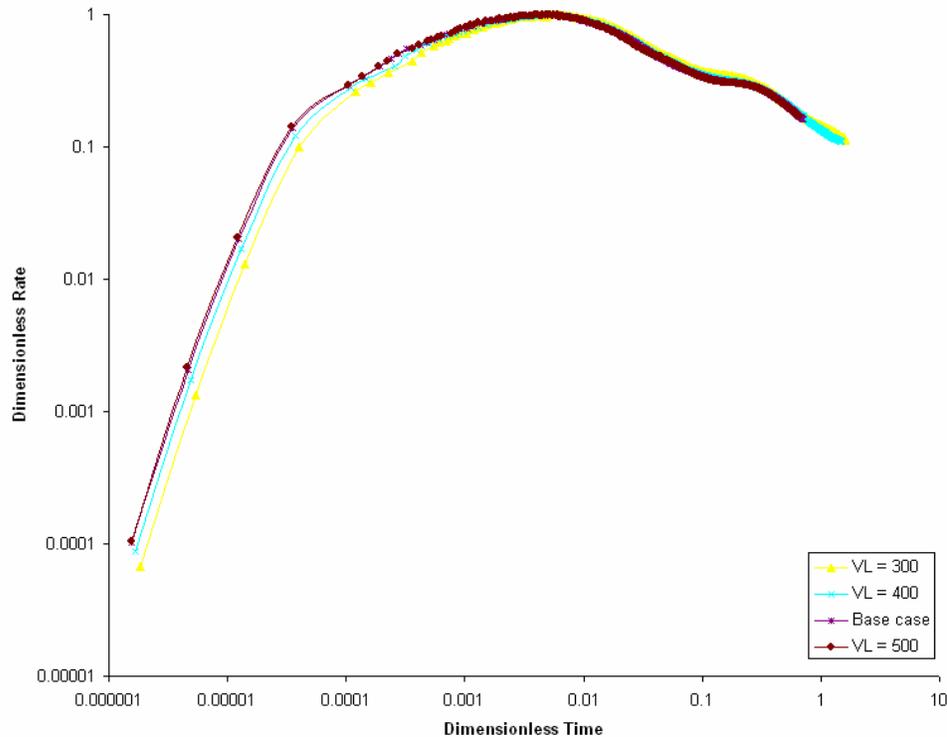
**Figure 4-8 Effect of Flowing BHP on the shape of the Type Curves in log-log scale.**

The eight set of simulations considers the influence of Langmuir pressure on the CBM gas production behavior. In this study, several Langmuir pressure were used. Figure 4.9 shows the behavior in log-log scale.



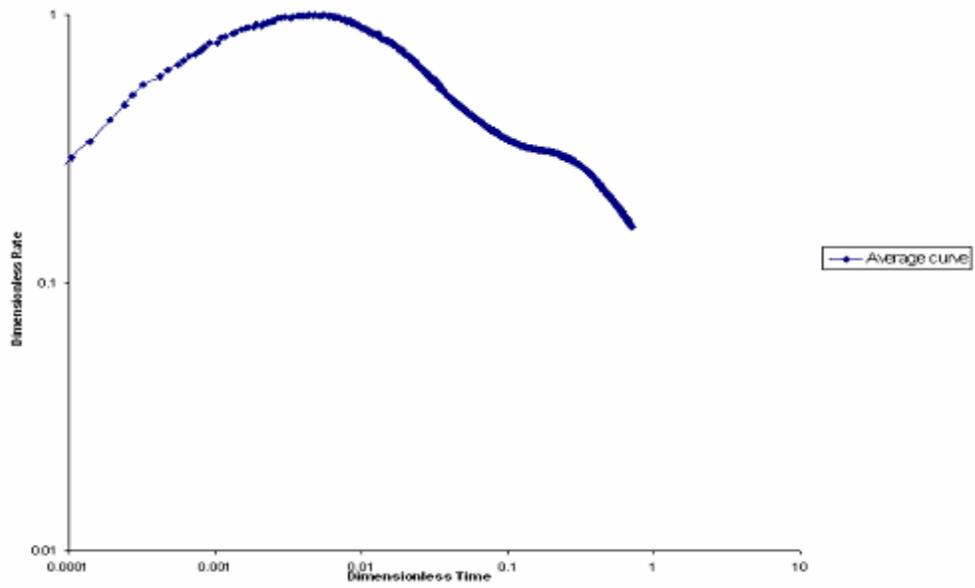
**Figure 4-9 Effect of Langmuir Pressure on the shape of the Type Curves in log-log scale.**

The ninth set of simulations considers the influence of Langmuir volume on the CBM gas production behavior. Figure 4.10 shows the behavior in log-log scale

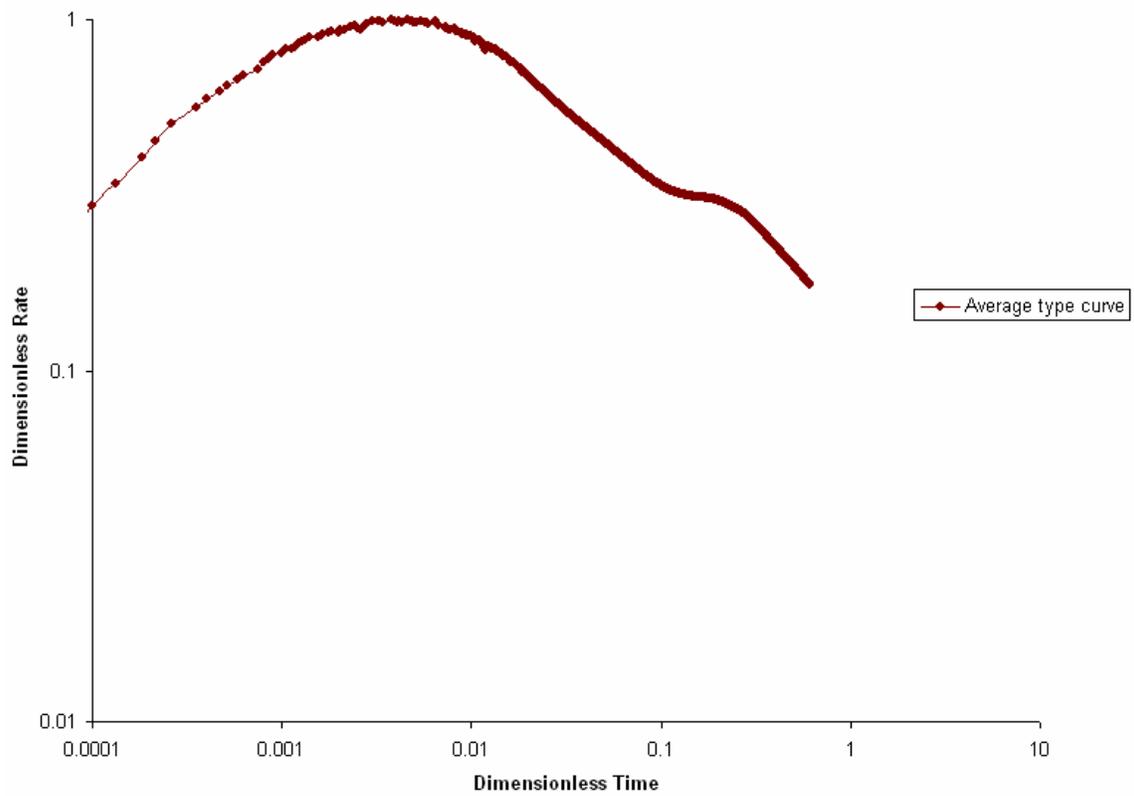


**Figure 4-10 Effect of Langmuir Volume on the shape of the Type Curves in log-log scale.**

After all the parameters have been changed and an evaluation of their impact on the dimensionless equations has been made, average type curves were developed for permeability and langmuir pressure since they have a significant impact on the shape of the type curve. Some further tests can be utilized in order to determine the error involved with using this tool compared to actual production. The average type curves are shown below in Figure 4.11 and 4.12.



**Figure 4-11 Average Type Curve for Permeability.**



**Figure 4-12 Average Type Curve for Langmuir Pressure**

From the multiple regression analysis that was done ( $R^2 = 0.91558$ ) the following equation gives the correlation for the peak production rate of the gas.

$$q_{(peak)D} = 0.3029 \times V_L - 0.1017 \times P_L - 28.1496 \times \varphi - 0.2801 \times M_p - 8.7249 \times K - 5.0955 \times h + 415.846$$

By using the above equation, and doing a reverse calculation of equation 3.1, the peak gas rate for any case in a coal bed methane (CBM) reservoir can be calculated.

With production type curves, an assumption that future production can easily be determined with some thought and a few calculations can be made. In order to estimate the future production from gas wells in which no production data is available a new equation had to be adopted and a value for  $q_{peak}$  could be calculated just from knowing a few parameters.

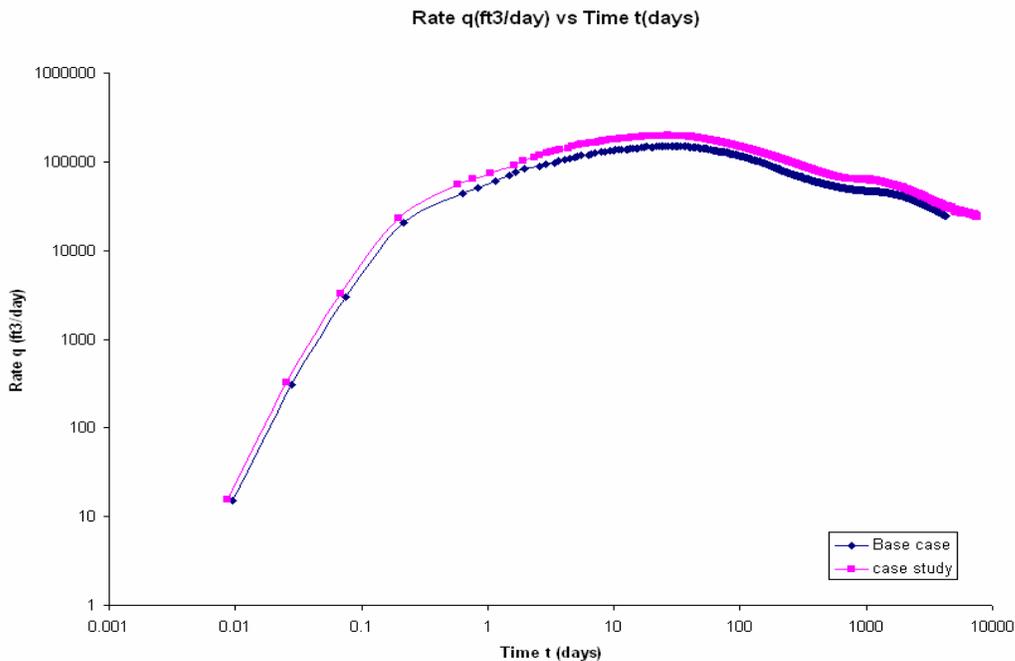


Figure 4-13 Comparison of the Predicted Gas Production on log – log scale.

From the results, the predicted production rates from the type curves closely match those from simulator.  $q_{(Peak)D}$  value was calculated for the case study by using the correlation equation developed and then the value of  $q_{(peak)g}$  was computed by using the calculated value of  $q_{(peak)D}$  in equation 3.1. The comparison of the calculated and estimated value of  $q_{(peak)g}$  for the case study, gave a maximum error of 7 percent and this leads to conclusion that the correlation developed for  $q_{(peak)D}$  can provide reliable results.

## 5 CONCLUSIONS AND RECOMMENDATIONS

The main focus of this research was to develop a set of type curves that could be used by the independent producers to evaluate and predict production data. The research took into account all geological and reservoir data to determine the impacts of each on the production. Based on the results, the following conclusions and recommendations were made.

1. Average production type curves were developed, that allowed for the analysis and prediction of future production.
2. The effects of nine (9) formation and operational parameters; permeability, porosity, thickness, critical desorption pressure, fracture pressure, flowing bottomhole pressure, and a ratio of horizontal length to area, Langmuir pressure and volume were studied to evaluate their impact on the type curve.
3. Permeability and Langmuir pressure ( $P_L$ ) were found to significantly impact the type curve.
4. A reliable correlation for predicting the peak gas rate was developed that allowed the type curve to be used as a tool for predicting production.
5. The comparison of the model prediction and type curve prediction indicated an error of 7 percent which is within reasonable engineering tolerance.

The impact of relative permeability needs to be studied in order to develop other type curves that could be used in different areas with different relative permeability data.

This research can be helpful in the development and implementation of new technology and growth in non-conventional gas reservoirs in the Northern Appalachian Basin. The results can lead to an easy to use tool for the independent producer to predict the future production of their wells. Since relative permeability is an important parameter for the gas production from CBM wells, it is recommended that a detail study of this variable be carried out.

## 6 NOMENCLATURE

$V_L$  = Dry-ash-free Langmuir volume constant, SCF/ton.

$P_L$  = Langmuir pressure constant, psia.

$\rho$  = density, g/cm<sup>3</sup>.

$t$  = time, days.

$t_D$  = dimensionless time.

$k$  = permeability, md.

$\mu_i$  = viscosity at initial condition, cp.

$\phi$  = porosity, %

$C_{ti}$  = total initial compressibility.

$A$  = area.

$P_i$  or  $P_c$  = pressure at initial conditions.

$P_{wf}$  = flowing bottomhole pressure.

$h$  = thickness.

$z$  = compressibility factor.

$q_{peak}$  or  $q_{maxD}$  = peak gas rate, cf/day.

$q$  = gas rate, SCF/D.

$q_D$  = dimensionless gas rate.

$G_i$  = initial gas in place, SCF.

$G_C$  = gas content.

$k_x$  = permeability in x direction, md

$k_y$  = permeability in y direction, md

$r_w$  = radius of wellbore, ft

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## APPENDIX

**Table 0-1  $G_c$  and  $G_i$  calculations for various PL and VL.**

$\frac{x}{453} \times 379 \times 2000 = V_L$			$x = \frac{1}{P_L}$	
<b>V<sub>L</sub></b>	<b>x</b>		<b>P<sub>L</sub></b>	<b>x</b>
100	0.0598		100	1.00E-02
200	0.1195		200	5.00E-03
300	0.1793		300	3.33E-03
400	0.2391		400	2.50E-03
476	0.2845		500	2.00E-03
500	0.2988		600	1.67E-03
600	0.3586		675.6	1.48E-03
700	0.4183		700	1.43E-03
800	0.4781		800	1.25E-03
900	0.5379		900	1.11E-03
1000	0.5976		1000	1.00E-03

<b>h= 10ft.</b> $G_c = \frac{V_L \times P}{P_L + P}$					$G_i = \frac{43560Ah\ell_c G_c}{2000}$					
<b>V<sub>L</sub></b>	<b>P</b>	<b>P<sub>L</sub></b>	<b>G<sub>c</sub></b>	<b>G<sub>i</sub></b>		<b>V<sub>L</sub></b>	<b>P</b>	<b>P<sub>L</sub></b>	<b>G<sub>c</sub></b>	<b>G<sub>i</sub></b>
100	300	675.6	30.75	192092635		476	300	100	357	2230126335
200	300	675.6	61.5	384185269		476	300	200	285.6	1784101068
300	300	675.6	92.25	576277904		476	300	300	238	1486750890
400	300	675.6	123.0	768370539		476	300	400	204	1274357906
476	300	675.6	146.37	914360941		476	300	500	178.5	1115063168
500	300	675.6	153.75	960463173		476	300	600	158.67	991167260
600	300	675.6	184.50	1152555808		476	300	675.6	146.37	914360941
700	300	675.6	215.25	1344648443		476	300	700	142.8	892050534
800	300	675.6	246.00	1536741077		476	300	800	129.81	810955031
900	300	675.6	276.75	1728833712		476	300	900	119	743375445
1000	300	675.6	307.50	1920926347		476	300	1000	109.8	686192719