Investigating the effect of skin on the optimization of Coal Bed Methane (CBM) production

By

Raja Hamizah binti Raja Bongsu
A project dissertation submitted to the
Petroleum Engineering Programme
Universiti Teknologi PETRONAS
in partial fulfilment of the requirement for the
BACHELOR OF ENGINEERING (Hons)
(PETROLEUM ENGINEERING)

Approved by,

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(Mr Saleem Qadir Tunio)

UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK

CERTIFICATION OF APPROVAL

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CERTIFICATION OF ORIGINALITY

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

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RAJA HAMIZAH BINTI RAJA BONGSU

ABSTRACT

Coal Bed Methane (CBM) gas reservoirs have gained increasing attention from the last decades as future alternative energy source. Among the countries that commercially extracted methane from coal beds are USA, Australia, China, India and Canada. Coal is consists of almost pure carbon, and hence the reservoir characteristics is fundamentally different from conventional reservoir. Few studies have been conducted to predict production behaviour of CBM wells in different conditions; gas slippage effect and matrix shrinkage factor. The gas production mechanism from coal seam is significantly different from that of a conventional reservoir. Thorough research need to be conducted to investigate the behaviour of CBM reservoirs. This project will focus on the production behaviour when the formation is damaged or has been stimulated. Mathematical formulation is used in evaluating the skin effect to the well production. It is expected to have different production profiles with different skin values.

ACKNOWLEDGEMENT

Foremost, I would like to express my gratitude to my supervisor, Mr Saleem Q. Tunio for his constant guidance throughout the 2 semester of the study and all of his patience and motivation. His guidance has helped me in all of the time of research and writing the final report. I could not imagine a better advisor and mentor for this research and study. Besides my supervisor, I also would like to express my thanks to my other class mate for their encouragement, comments and insightful opinions. Last but not least, a bunch of thanks to my close friends, fellow classmate, family and my parent for their continuing support physically and spiritually throughout the research and my life.

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CHAPTER 1

INTRODUCTION

1.1 Background of Study

With the decline in the production and increase in demand of fossil fuel, economically producing gas from unconventional sources is a great challenge today.. Coal Bed Methane (CBM) is a form of natural gas extracted from coal beds. Coal bed methane is more attractive than conventional reservoir because it generally has a very high percentage of methane recoverable making the gas produced can be used as direct replacement for conventional natural gas in pipeline network. Therefore it is important to develop CBM production to fulfil the future fuel's demand. In order to develop CBM, further studies are essential because the properties of coal seam are different with the conventional reservoir. Among the differences between CBM and conventional reservoir are coal bed reservoir properties, gas storage mechanisms, gas-transport phenomenon, and water disposal.

There are many countries including Spain, France, Poland, Australia, Canada, Great Britain, Germany, Zimbabwe and Russia that conducted research on CBM after the initial success in United States. Few models/numerical simulations have been developed to predict the production behaviour of CBM wells in various conditions like gas slippage effects and matrix shrinkage factor. This paper will focus on the study of the skin effects to CBM wells. Several fields with sufficient published data will be chosen to analyse the positive or negative skin effect to the reservoir. Positive skin indicates extra flow resistance near the wellbore whereas a negative skin indicates flow enhancement near the wellbore. As for an example, the production well in San Juan Basin has -1.97 value of skin. It indicates that the reservoir is well stimulated. The production performance of this well will be analysed and will be compared with positive skin value. The positive skin value in a well showed that the well has formation damage.

Formation damage is an undesirable operational and economic problem that can occur during the various phases of hydrocarbon recovery including production, drilling, hydraulic fracturing and workover operation. For CBM wells, formation damage is likely to happen during drilling operation and hydraulic fracturing. The drilling fluid or hydraulic fluids induced to the formation are highly potential to plug or clog the cleats that act as pathway for the methane to be desorbed. In order to optimize the well's production, it is extremely important to study the skin effect in reservoir production. This is conducted to evaluate the effectiveness of drilling operation and stimulation treatments on the production performance.

1.2 Problem Statement

The world is currently looking for an alternative future resource and Coal Bed Methane is viewed as one of the future natural gas resource. However, there hasn't much research regarding the production of CBM field. Thorough research should be done to determine the effect of skin towards production rate in unconventional well.

1.3 Objective

The objectives of this project are as follow:

To study the effect of skin formation on the production of coal bed methane reservoirs.

1.4 Scope of Study

This project will study the effect of skin during drilling and hydraulic fracturing operation to the optimization of CBM production. This study is important in well's development plan so that mitigation plan can be constructed earlier in order to achieve maximum production with economical operation.

The fields chosen in this simulation study were taken from published data and fields:

i) San Juan Basin

ii) Powder River Basin, Wyoming, USA

iii) Horsehoe Basin

iv) Appalachian Basin

CHAPTER 2

LITERATURE REVIEW

2.1 The Need of Alternative Energy

Continued growths of industry and world population require more energy. The United States and other industrialized countries such as Chine, Germany and Russia are taking initiatives to explore for energy source to:

(i) substitute gasoline and diesel vehicular fuels

(ii) supply clean fuels for power plants[1]

J. T Thomson and T.T.Leshchyshyn stated that the CBM production in Alberta, Canada has grown dramatically from only $8.6x10^3 m^3/day$ at the early January 2003, to $3198x10^3 m^3/day$ at the beginning of January 2005 [2]. This showed that CBM development has increased rapidly over the past few years. Further world development will increase natural gas energy consumption in the future than only 23.66% in the figure below. The factors such as supply and environmental problems with oil, environmental problems with coal, safety problems with nuclear power and limited alternative sources may cause the shift in usage toward natural gas.

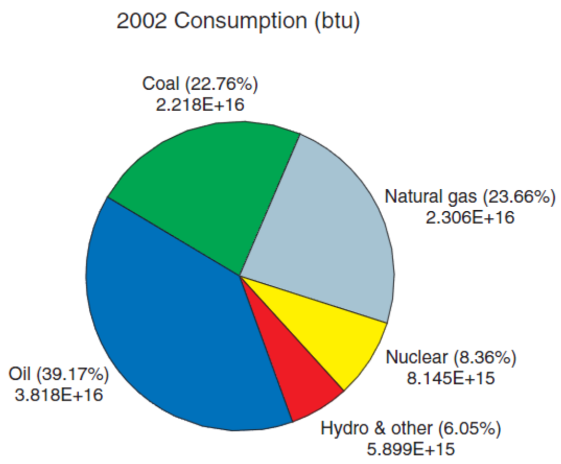


Figure 1: Mix of Energy Use [1]

Coal bed methane is one of the unconventional reservoirs that are highly potential to be developed as future alternative energy source. According to Ahmed and McKinney (2005), the term coal in coal bed methane (CBM) refers to sedimentary rocks that contain more than 50% by weight and more than 70% by volume of organic materials consisting mainly of carbon, hydrogen and oxygen in addition to inherent moisture. CBM consists of over 90-95% methane that developed during the coalification process.

2.2 Formation of Methane in Coal Seam

Coalification process is the transformation of plant debris into continuous products as expressed below:

peat →lignite → subbituminous coal→bituminous coal→ anthracite

The products changes in an order of increasing percentages of carbon and decreasing percentages of oxygen and hydrogen. (Francis,1961).

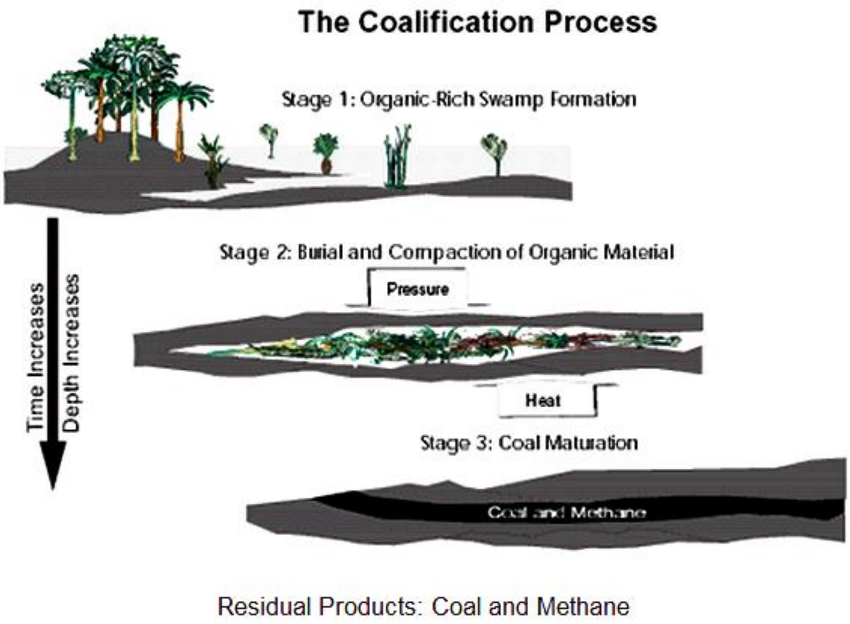


Figure 2: Coalification process [4]

The process starts when plant matters falls and accumulates at the bottom of swamp, and then anaerobic bacteria reacted to decompose them[5]. This reaction usually occurs within few meters from the surface. The decaying material produces peat[6]. By time, the increasing pressure compressed peat and form almost impermeable layer. In order to survive, the aerobic bacteria used oxygen in the original peat. When the oxygen has been used up, the aerobic bacteria die and completed the first stage of decaying process.

In the second stage, the decaying process starts by anaerobic bacteria. During this process, the anaerobic bacteria extracts oxygen from organic molecules of vegetal matter and results in high concentration of hydrogen. Part of this hydrogen is liberated as methane and the rest is absorbed by humic colloids. As time passed, the rising temperature and pressure encourage the generation of hydrocarbon. Thermal breaking of free lipid hydrocarbon fraction and breaking of the kerogen fraction of coal produces methane gas. [7]

Methane gas is formed in two ways; biological process and thermogenic process. Biogenic methane is produced by anaerobic bacteria in the early stage of coalification. On the other hand, thermogenic methane is produced at temperatures of 120-150$^{\circ}C$[8]. The rank and depth of coal determine the amount of methane stored in coal. The higher the coal rank and deeper the coal seam, the greater its capacity to produce and keep methane gas.[9]

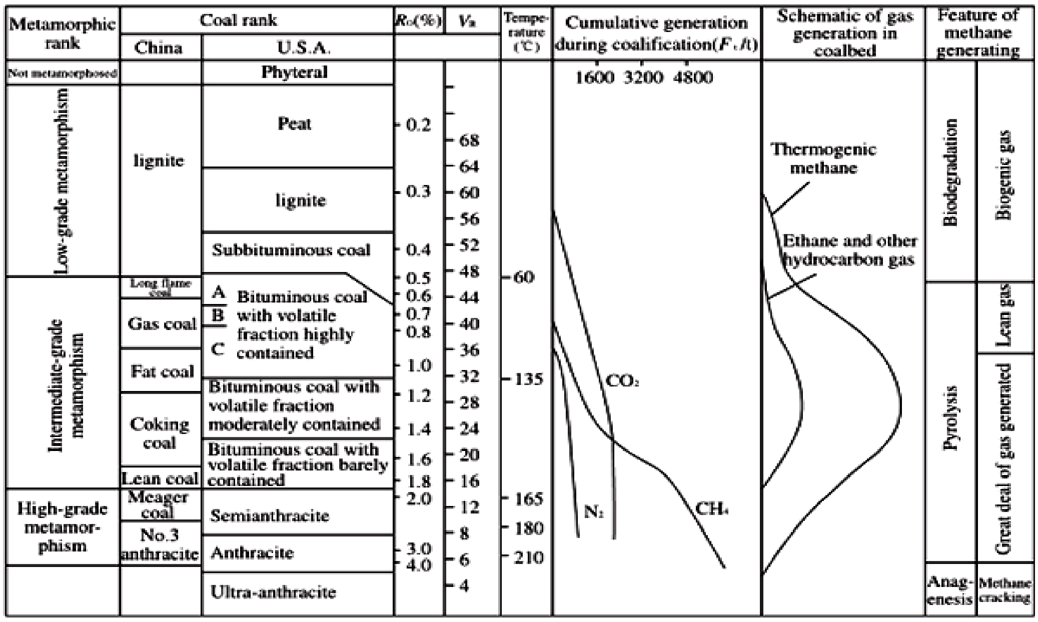


Figure 3: Methane generation in different stages of coalification [9].

2.3 Geologic Parameters of Coal

The physical and chemical properties of coal are different from seam to seam and over a short distance within a seam. Coal can be classified by three fundamental characteristics as illustrated by figure below which are Rank, Type and Grade.

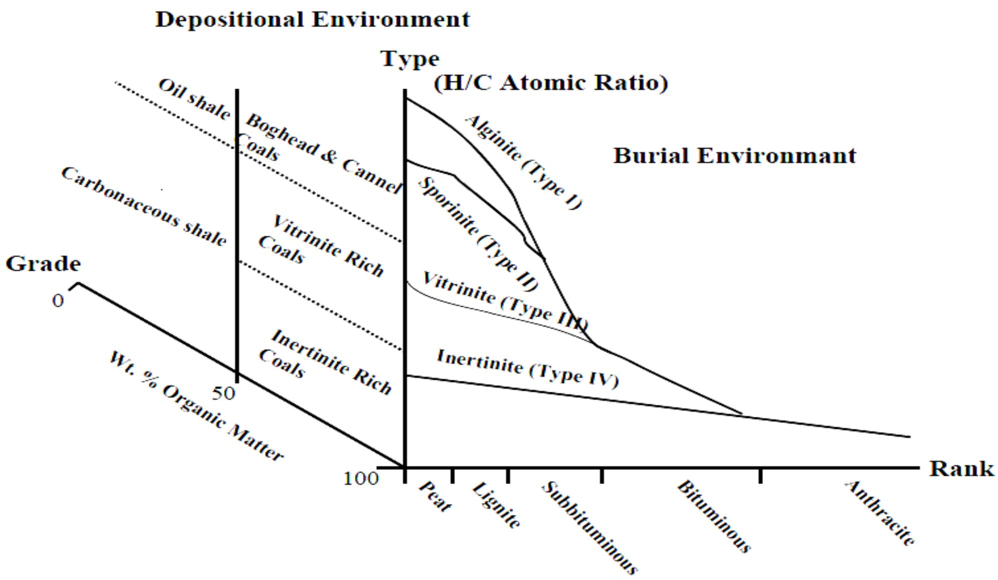


Figure 4: Coal as classified by three different characteristics[10]

Rank is defined as the degree of metamorphism or level of coalification. This is related to the temperature it has been exposed. Tim Moore(2011) stated that the higher rank of the coal, the more methane it is able to hold. Additionally, rank also important in determining gas content, permeability, and mechanical and physical properties of coal.[11]

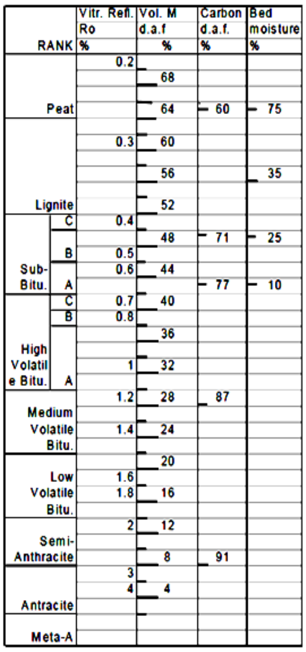


Figure 5 : Coal Rank [11]

Type of coal represents the relative proportions of various organic constituents (macerals) components. It reflects the nature of plant debris from which the original peat was derived and the level of degradation they were exposed before burial. On the other hand, the grade of coal usually refers to its level of purity, that is, what are the relative amounts of organic and inorganic materials present within a particular coal . Therefore, a high grade coal would be relatively free of 14 mineral matter, and hence a high organic content .[12]

2.4 Coalbed Structure

Unlike the conventional reservoir which has randomly-spaced fractures, CBM has uniformly-spaced fractures. Generally, the coal reservoir is a system that comprised of fractures and matrix. The following showed the microscopic view of coal structure: [13]

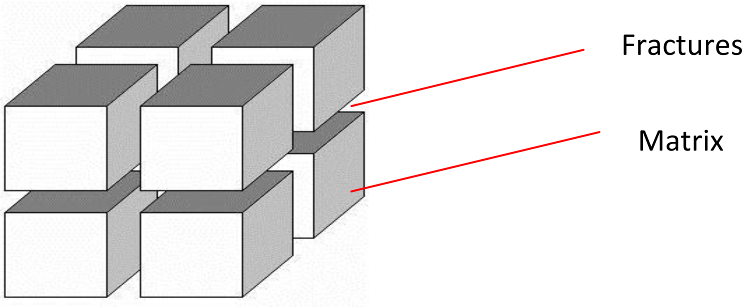


Figure 6: Fractures represented by Spaces while coal matrix represented by blocks[11]

2.3.1 Fractures

Coal is naturally fractured which also better known as cleats. There are two major orthogonal joint systems: face cleats and butt cleats. The primary channel for flow in coal is the face cleats while the butt cleats typically will terminates against the face cleat. This phenomenon indicates that butt cleats were formed later in geological time. [10] The Figure 5 as follow illustrates the face cleat and butt cleat.

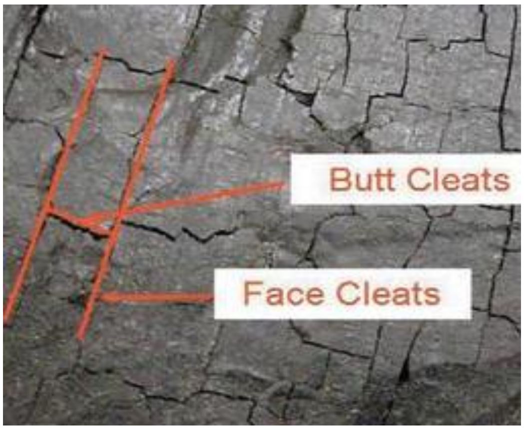


Figure 7: Face Cleat and Butt [11]

Cleats network plays important role in the production of methane gas from coal beds. This is because cleats provide the permeability for fluid to flow to the surface. Hence, in order to produce optimum gas at economic rates, coal must have extensive cleats system. [12]

2.3.2 Coal Matrix

The coal matrix consists of a network of different pore sizes. The smallest pores situated within the matrix and the pore sizes becoming bigger towards the surface of the coal. The larger pores provide path for the desorbed gas to diffuse to the cleat system, while the microspores of the coal matrix are the prime place for gas adsorption [8]. Based on International Union of Pure and Applied Chemistry (IUPAC) classification (1994), pores are classified into macropores (>50nm), transient or mesopores (between 2 and 50 nm) and micropores (< 2nm). The figure below shows macropores and micropores[10]:

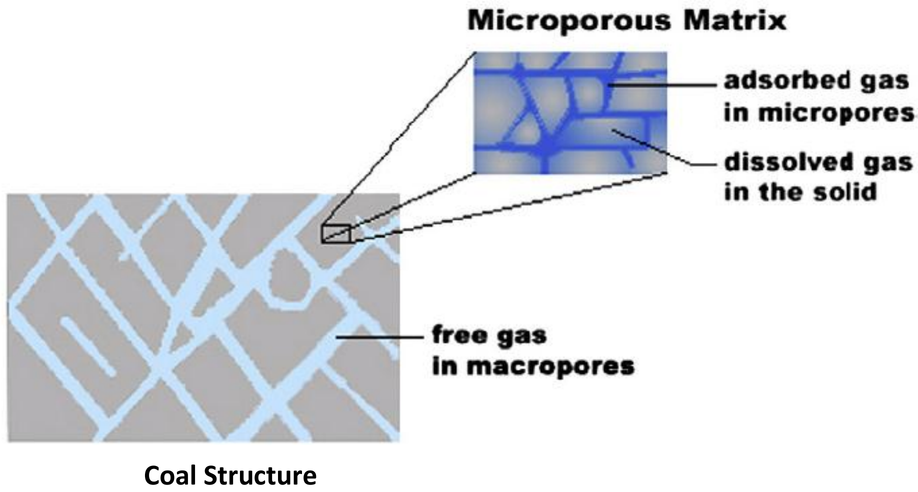


Figure 8: The figure illustrates macro and micro-pores containing gas in free, adsorbed and dissolved states [10]

Coalbed gas is kept in coals in few different ways:

1) physical adsorption upon internal surfaces(in micropores)
2) absorption into molecular structure of coal
3) as free gas in voids, cleats and fractures
4) as a solute in groundwater exist in the coal seam [1].

2.3.3 Gas Storage Mechanism

The gas being stored in coal bed methane is different from conventional reservoir. In the typical reservoir, gas is compressed by the pressure in the formation. The expansion of gas provides path for the gas to be produced. For CBM, the gas is stored within the coal matrix by a process known as adsorption. [1]

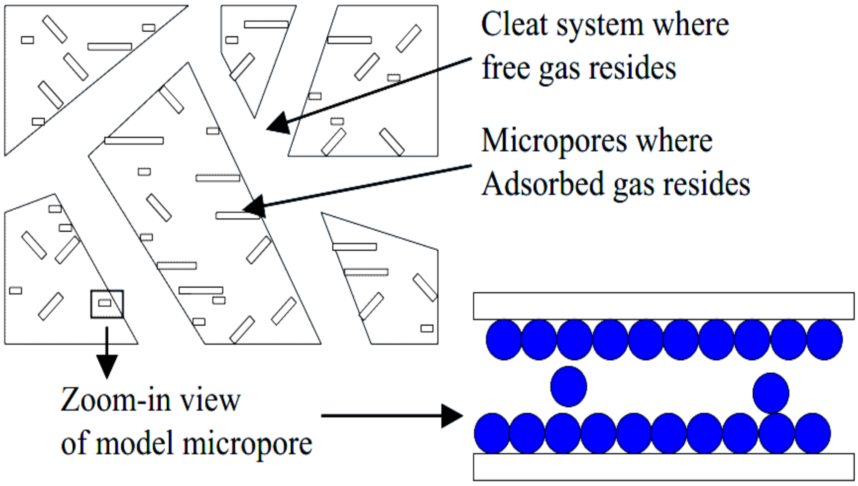


Figure 9: Coalbed Adsorption Phenomenon [1]

In adsorption, the gas molecules stick to the surface of the coal and create a film layer on the surface of adsorbent [1]. When the reservoir pressure is reduced, gas is detached from the coal surface and flows through the cleats to the surface to be produced [2]. This process also known as desorption.

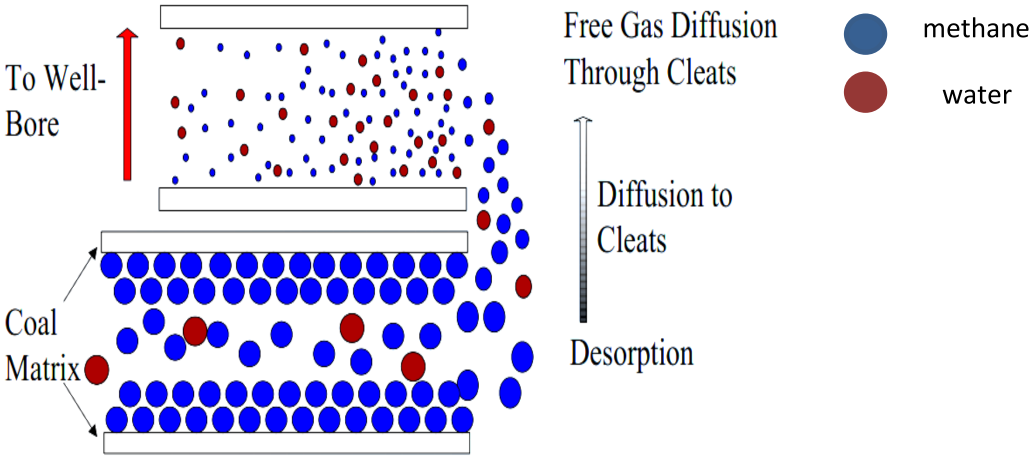


Figure 10: Methane flows to the cleats [1]

The figure above illustrates that when the water is produced, cleat pressure also will be decreased. As the pressure reduced, methane will desorb from matrix to cleats and flow to wellbore [2]. Figure 7 is a schematic diagram that shows the process of gas extraction from coal reservoir. When coal seam gas reached the surface, any water in the gas will be separated and sent for re-injection or being discharged, while the gas is compressed and sent by pipeline to customers.[13]

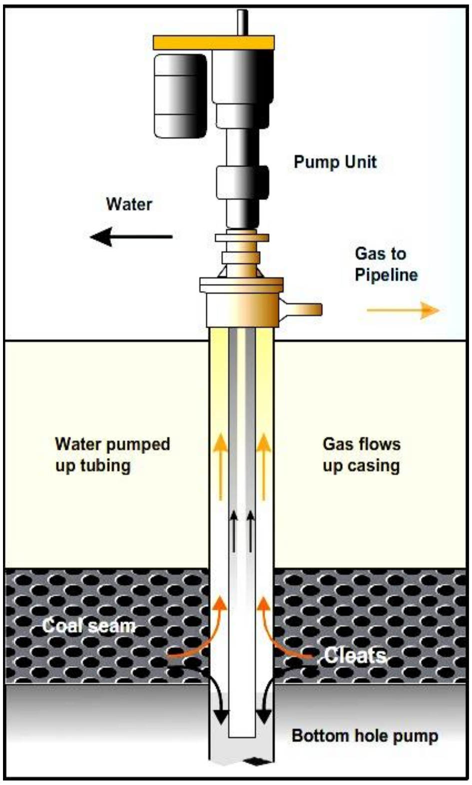


Figure 11: Schematic diagram of coal seam gas extraction [13]

2.3.4 Gas Production Performance

Coal bed methane is a dual porosity system where the gas is stored by the adsorption of the in the coal matrix. This in turn causes the pressure volume relationship is described by sorption isotherm which relates the gas storage capacity of a coal to pressure. The typical sorption isotherm is shown in Figure 5. The common relationship between gas storage capacity and pressure can be described by an equation presented by Langmuir:

$$G_s = \frac{V_L P}{P_L + P}$$

Equation 1: Relationship between gas storage capacity and pressure (Langmuir Equation)

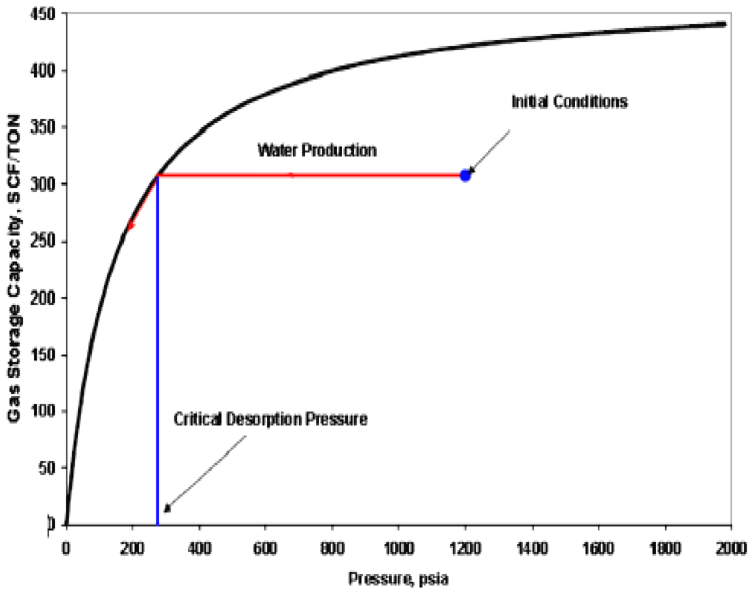


Figure 12: An example of Langmuir Isotherm[26]

The production performance in CBM has small differences with conventional reservoir. In conventional gas reservoirs; gas is stored in the small pores within the rock. Hydrocarbon will be produced when there is pressure difference between the formation and the wellbore. Gas production in conventional reservoir is highest at the early time and slowly decreases as time increases. This is because as time passed and gas being produced, the reservoir pressure decreases and water production rate will increase.

As for CBM production, at the initial stage large volume of water will be produced from coal seam. This is essential because most CBM wells are naturally water saturated. The water was liberated during coalification process and resides in the principal cleat network. Therefore it is eminent to remove the water first in order to allow gas to flow out easily through the fracture systems. When water pressure decreases, the gas molecules detach or “desorb” from the coal and flow to the surface through the wellbore. During the stable phase, water production is drastically decreased and the gas production rate will be increased. The water relative permeability decreased and the gas relative permeability increased. The gas production become stabilized and starts to undergo a normal decline trend. After that, during decline stage, the well is considered dewatered, so the water production is negligible. Gas production is slowly decreased. The figure below illustrates the difference of production performance between conventional reservoir and coal seam.

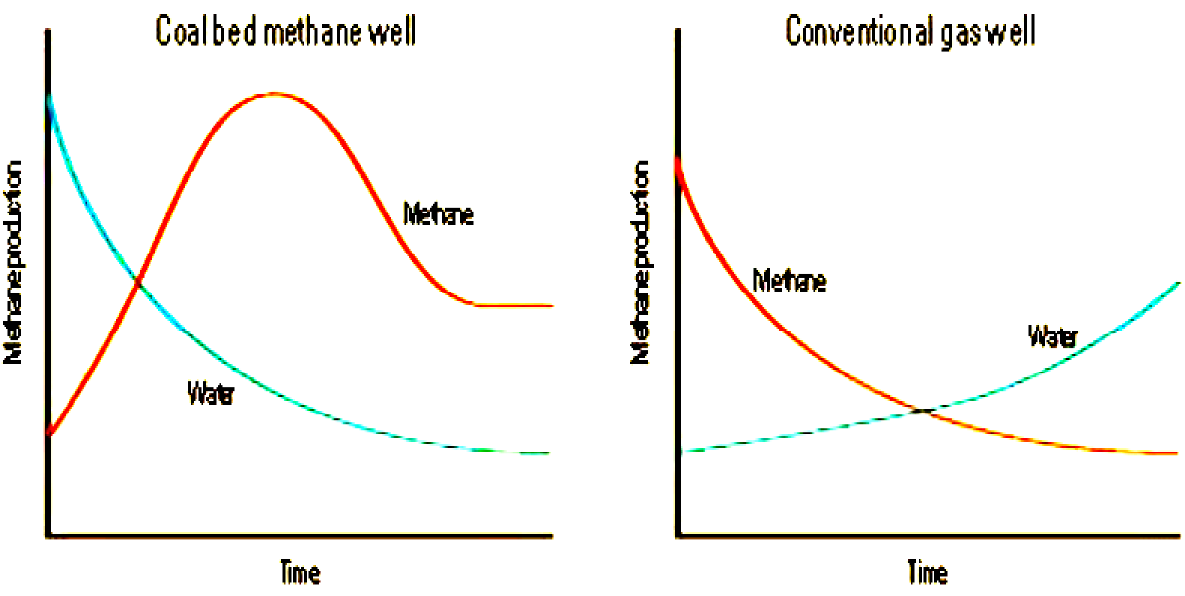


Figure 13: Production Curve for CBM and Conventional Gas Well [14]

The difference between CBM and Conventional reservoir can be summarized as below:

Table 1: Comparison of CBM and Conventional Gas Reservoirs Characteristics

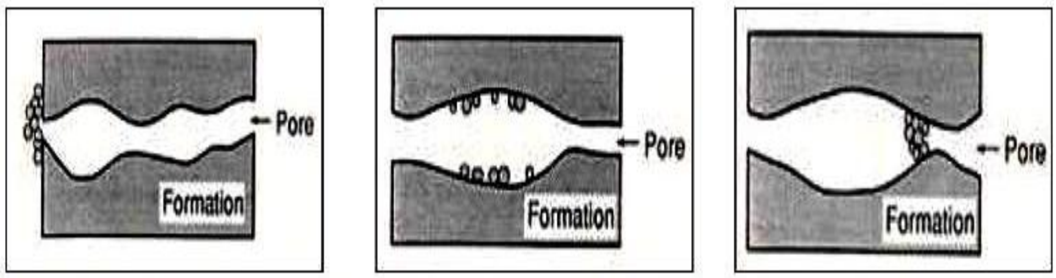
Characteristic	**Conventional**	**CBM**
Gas Generation	Gas is generated in the source rock and then migrates into the reservoir	Gas is generated and remains trapped in the coal
Structure	Randomly-spaced fractures	Uniformly spaced cleats
Gas Storage Mechanism	Compression	Adsorption
Transport Mechanism	Pressure Gradient (Darcy's Law)	Concentration Gradient (Fick's Law) and Pressure Gradient (Darcy's Law)
Production Performance	Gas rate starts high and then decreases. Little or no water initially. GWR decreases with time	Gas rate increases with time then declines. Initially the production is mainly water. GWR increases with time.
Mechanical Properties	Young Modules ~10^6 Pore Compressibility ~10^{-6}	Young Modules ~10^5 Pore Compressibility ~10^{-4}

2.4 Formation Damage in Unconventional Reservoir

Formation damage is defined as the impairment of the permeability of petroleum bearing formation by different adverse process. According to Amaefule et al. (1998)" Formation damage is an expensive headache to the oil and gas industry". In order to achieve efficient exploitation of hydrocarbon reservoirs, formation damage assessment, control and mitigation are among the crucial issues need to be resolved (Energy Highlights, 1990).

Formation damage is caused by physic-chemical, chemical and, hydrodynamic, thermal interactions of porous formation, particles, and fluids and mechanical deformation of formation under stress and fluid shear. These processes are created during the drilling, production, workover and hydraulic fracturing operations. Formation damage caused reduction in permeability and thus reduce well performance. Amaefule et al. (1998) categorized the factors affecting formation damage as following:

i) Invasion of foreign fluids, such as water and chemicals used during stimulation job, drilling mud invasion, and workover fluids
ii) Intrusion of foreign particles and mobilization of indigenous particles including sand, mud fines bacteria and debris



Cake formation by large particles | Surface deposition of adhering particles | Plugging by deposting particles

Figure 14 : Illustration represent three different types of deposits [16]

iii) Operation conditions like well flow rates and wellbore pressures and temperatures
iv) Formation fluids and porous matrix properties[17]

The graph below shows pressure profile and skin. Initially, the before workover, the skin value is negative. Later on, after some workover job performed and some formation damage created, the skin value becomes positive and this dropped the pressure at the wellbore.

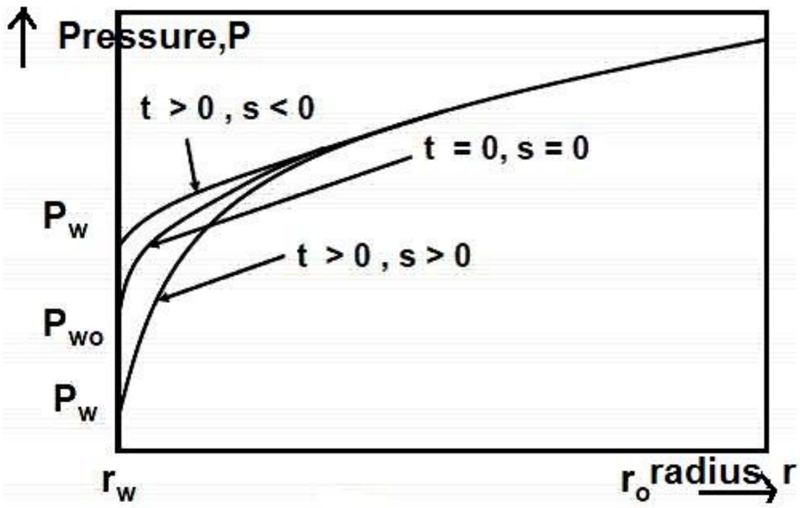


Figure 15: Pressure Profile [16]

This equation is used in order to quantify the effect of skin on production:

$$\text{Qg} = \frac{kh\ (P_r - P_{wf})}{141.2\mu B\left[ln\frac{r_e}{r_w} + S\right]}$$

Equation 2: skin effects on gas flow rates [16]

Based on the equation it shows that when the skin value is greater, the well's production will be decreased.

2.4.1 Formation Damage in Coal Reservoirs

Formation damage in CBM reservoir has small difference compared to petroleum reservoirs because of different reservoir characteristics. Damage of the coal seams is likely to occur during these two phases:

a) Drilling operation:

Among the problems encountered during drilling operation are:

i) Coal-rock that is in banding structure, can easily developed cracks and micro-cracks and hence make the coal to be unconsolidated and brittle. When the coal reservoir being drilled, an excess of drilling fluids were penetrated into the cracks and lessen the consolidating force between the coal-rock further. Consequently this will result in coal-rock to be fractured and collapsed.

ii) Clay mineral and illite content which is prone to hydrates, cracks and slough are higher in coal seam compared to conventional reservoir which cause the borehole become more unstable.

iii) The fractures structure of coals needs the use of light weight drilling muds in order to minimize formation damage. A column of cement which has greater density than drilling mud will exert hydrostatic pressure on the formation. Typically this pressure forces cement into cleats and then plugged the fractures that were presumed to provide channels for methane to flow into the wellbore [1].

iv) Cleats are wide open to allow the invasion of slurry and filtrates during drilling operation.[18]

b) Hydraulic fracturing

In achieving higher production, coal bed methane reservoirs often stimulated by hydraulic fracturing. A fracture is created in the coal seam to connect the wellbore to the coalbed joint/ cleat system. In order to create this fracture, a thick, water-based fluid is pumped into the coal seam with rising rate. After the fracture has been created, proppant-laden gelled fluids, which normally contain polymers, surfactants, friction reducers and other chemicals, are injected to hold the fracture open.

Unfortunately, performing this stimulation job has resulted reduction in formation's permeability due to filtrate invasion. There are two types of permeability damage: matrix selling and cleats plugging. Matrix swelling happened when the components in the coal, such as smectite, illite, kaolinite, calcite and chlorite are affected by water based fracturing fluids. Besides, matrix plugging occurred whenever the gelled fluids injected plugged the cleats and thus hindered well production. [2]

2.4.2 Method To Measure Skin

The extend of formation damage in CBM can be measured by using:

1) Diagnostic Fracture Injection Test (DFIT)

   This method is performed by injecting fluid above the fracture gradient to estimate the reservoir breakdown and closure pressure

2) Injection Fall-off Test (IFT)

   This test is able to be performed in either open or cased-hole. [27]

CHAPTER 3

METHODOLOGY

3.1 Project Flow Chart

The project flow chart is as shown below:

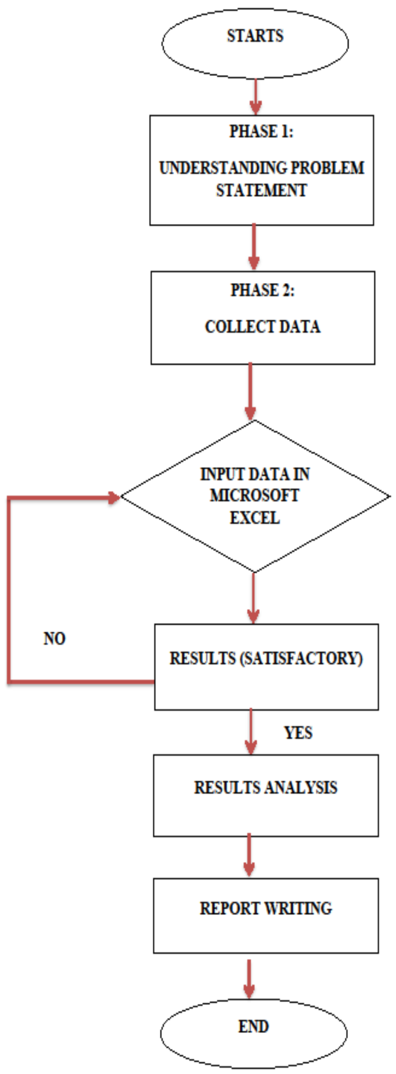


Figure 16: The methodology flow chart diagram

A mathematical formulation was involved in this study. As coal bed methane produced 95% methane, it was assumed that the well is gas well. As stated by Tarek Ahmad in Reservoir Engineering Handbook, determination of flow capacity of gas well requires a relationship between the inflow gas rate and the bottomhole pressure. This inflow performance relationship can be established by using Darcy's equation. In vertical gas well, the differential form of Darcy's equation for compressible fluid under the pseudo-steady state flow condition is as below:

$$J = \frac{k_h * \mathrm{h}}{1422 * T[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + S]}$$

Equation 3: Productivity Index[19]

The equation is used for 3 distinct pressure regions:

i) high pressure region : > 3000psi
ii) intermediate pressure region :2000-3000psi
iii) low pressure region : < 2000 psi

As coal seam pressure is generally between 500-600 psi which is falls under classification of low pressure region, Golan and Whitson (1986) in Reservoir Engineering Handbook by Tarek Ahmad implemented Equation 4 to predict productivity index:

$$J = \frac{k\mathrm{h}}{1422T(\mu_g * z)_{avg}[\ln\left(\frac{Re}{Rw}\right) - 0.75 + S]}$$

Eqn 4: Productivity Index for low pressure region [19]

In evaluating the productivity index, production data of 4 basins from published papers are used and they are mentioned as follows:

i) Powder River Basin

Powder River Basin is located in northeastern Wyoming and southeastern Montana. It is an elongated basin of 25,800 miles, approximately 75 percent of which is in Wyoming. Based on Powder River Coalbed Information Council, it is believed that fifty percent of Powder River Basin has potential for coalbed methane production. Annual production volume was estimated at 147 Bcf in 2000 in 2002, wells in the Powder River Basin produced about 823 Mcf per day of coalbed methane.[20]

Coalbeds in this region are intermixed at varying depths with sandstone, mudstone, conglomerate, limestone, and shale. Mostly the potentially productive coal zones range from 450 feet to over 6500 feet below ground (Montgomery,1999). A recent estimate of coalbed methane reserves is in the Powder River Basin range from 7 trillion to 40 Tcf (Montgomery, 1999; PRCMIC, 2000). The coal rank is from lignite to subbituminous.

Table 2: Reservoir properties of Powder River Basin

Data used for simulation in published paper [20]

Coal Thickness	130 ft
Coal Porosity	0.05 %
Coal Permeability	300 md
Coal Density	1,800 ton/acre-ft
Average depth	750 ft
Langmuir Volume	75 scf/ton
Langmuir Pressure	350 psia
Gas Content	37 scf/ton
Gas gravity	0.55
Initial pressure	365 psia
Producing Bottomhole Pressure	50 psia
Reservoir Temperature	75$^{\circ}F$
Initial Water Production Rate	500 bpd

Confining Layer Thickness	30 ft
Confining Layer Permeability	0 to 0.03 md
Well Spacing	40,80 to 160 acres

ii) San Juan Basin

The San Juan basin measures roughly 100 miles long north to south and 90 miles wide. It covers an area of about 7500 miles of Colorado-New Mexico.The Continental Divide inclines north to south along the east side of basin. The major coal-bearing unit in San Juan Basin is known as Fruitland Formation. Total thickness of all coalbeds ranges from 20 to over 80 feet throughout the San Juan Basin, compared to 5 to 15 feet in eastern basin. The coalbed methane wells in San Juan Basin range from 550 to 4000 feet in depth. It is well-known that San Juan Basin is the most productive coalbed methane basin in North America. In 1996, coalbed methane production there averaged about 800 000 cubic feet per day per well and contributes to over 800 billion cubic feet (Bcf) for that year (Stevens et al., 1996). The coal rank is bituminous.

Table 3 : Reservoir properties of San Juan Basin

Data used for simulation in published paper [21]:

Thickness	50ft
Bulk Density	1.33 g/cm^3
Cleat porosity	0.5%
Gas gravity	0.544
Absolute Permeability	50 md
Initial Reservoir Pressure	150 psia
Reservoir Temperature	67$°F$
Formation Compressibility	$1 * 10^{-4}$
Langmuir Volume	155psi^{-1} scf/ton, in-situ
Langmuir Pressure	547 psia
Drainage Area	160 Acres
Flowing Bottomhole Pressure	25 psia

iii) Appalachian Basin

Appalachian Basin is divided into two main part: Northern Appalachian Basin and Central Appalachian Basin. The Northern Appalachian Basin occupies 43000-44000 sq miles of West Virginia, Pennsylvania, Ohio, Kentucky and Maryland, whereas Central Appalachian Basin extends portion of West Virginia, Virginia, Kentucky and Tennesse.. Coal is mined as deep as 2,500 feet in Central Basin, deeper than in Northern Appalachian basin. The production of methane in Central Appalachian basin is about 52.9 Bcf of gas in 2000 while for Northern part the total production is 1.41 Bcf in 2000[22]. The coal rank is in the range of high volatile A bituminous to low volatile bituminous.

Table 4: Reservoir properties of Appalachian Basin

Data used for simulation in published paper [22]

Reservoir Area	40 acres
Thickness	10 ft
Matrix Porosity	0.5%
Fracture porosity	2%
Matrix Permeability	0.01 md
Fracture Permeability	10 md
Fracture Spacing	0.2 ft
Initial Pressure	600 psia
Temperature	113$°F$
Langmuir Pressure	675.6 psia
Langmuir Volume	475 scf/ton
Bottomhole pressure	50 Psia

iv) Horsehoe Canyon

Horsehoe Canyon is situated 17 km southwest of Drumheller, Alberta, Canada on Highway 9. It is the first commercial production of CBM in Alberta. The basin covers an area at least 90 x 300 miles with an estimated initial gas in-place of 147.0 TCF. In 2012, there are more than 7000 producing wells in Horsehoe canyon, with initial production rates across the trend averaging 100 Mcf/d. The coal rank is subbituminous C rank to high volatile bituminous B. These coals tends to have low gas contents (but are fully saturated with methane), poorly developed cleating, low permeability and low pressure.

Table 5: Reservoir Properties of Horsehoe Canyon

Data used for simulation in published paper [23]

Reservoir Area	40 acres
Thickness	170 ft
Matrix Porosity	0.5%
Fracture porosity	2%
Matrix Permeability	0.01 md
Fracture Permeability	40 md
Fracture Spacing	0.2 ft
Initial Pressure	525 psia
Temperature	62°F
Langmuir Pressure	675.6 psia
Langmuir Volume	475 scf/ton
Bottomhole pressure	360 psia

The reservoir properties from published papers were used in order to calculate the productivity index using Equation 4 in conducting the analysis, assuming the value of skin factor in the range of -5 to +5. On the other hand, the value of compressibility factor or z factor used in was based on 2 methods: assumption and calculation. The assumed values of z factor are 0.8, 0.85, 0.9 and 0.95. To increase the accuracy of the analysis, calculation was made to determine the z factor by assuming that the well producing pure natural gas. This is because coal bed methane is generally produced very high content of methane gas, which is about 95%. Hence, the assumption used in this study is the well producing pure gas,methane. The compressibility chart is used to establish z factor for each basin.

$$T_{pr} = \frac{T}{T_{pc}}$$

Equation 3: Pseudo-reduced temperature, Tpr [19]

$$P_{pr} = \frac{P}{P_{pc}}$$

Equation 4: Pseudo-reduced Pressure, Ppr [19]

After calculating T_{pr} and P_{pr} , the value for compressibility factor, z is determined by referring to the compressibility in Figure 16.

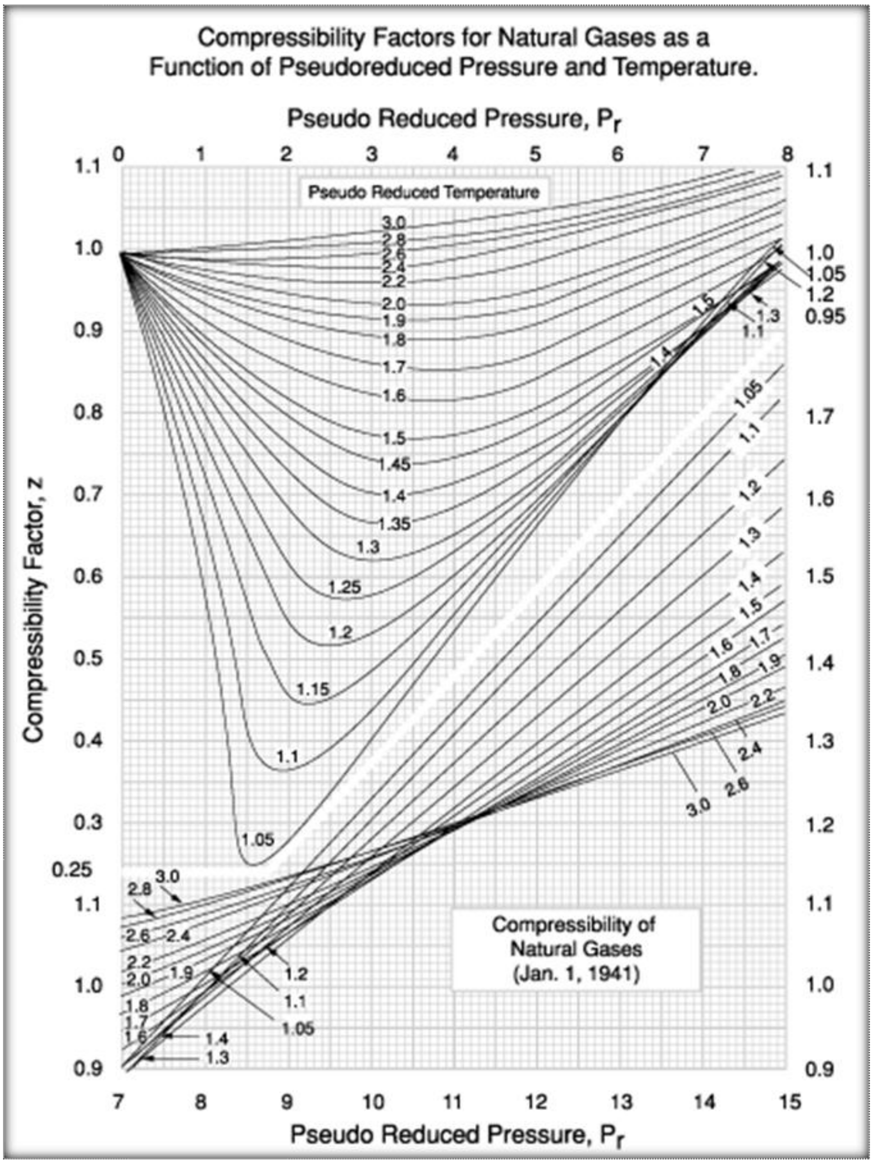


Figure 17: Compressibility Chart [19]

The viscosity for the gas of different field was determined by referring to the graph below:

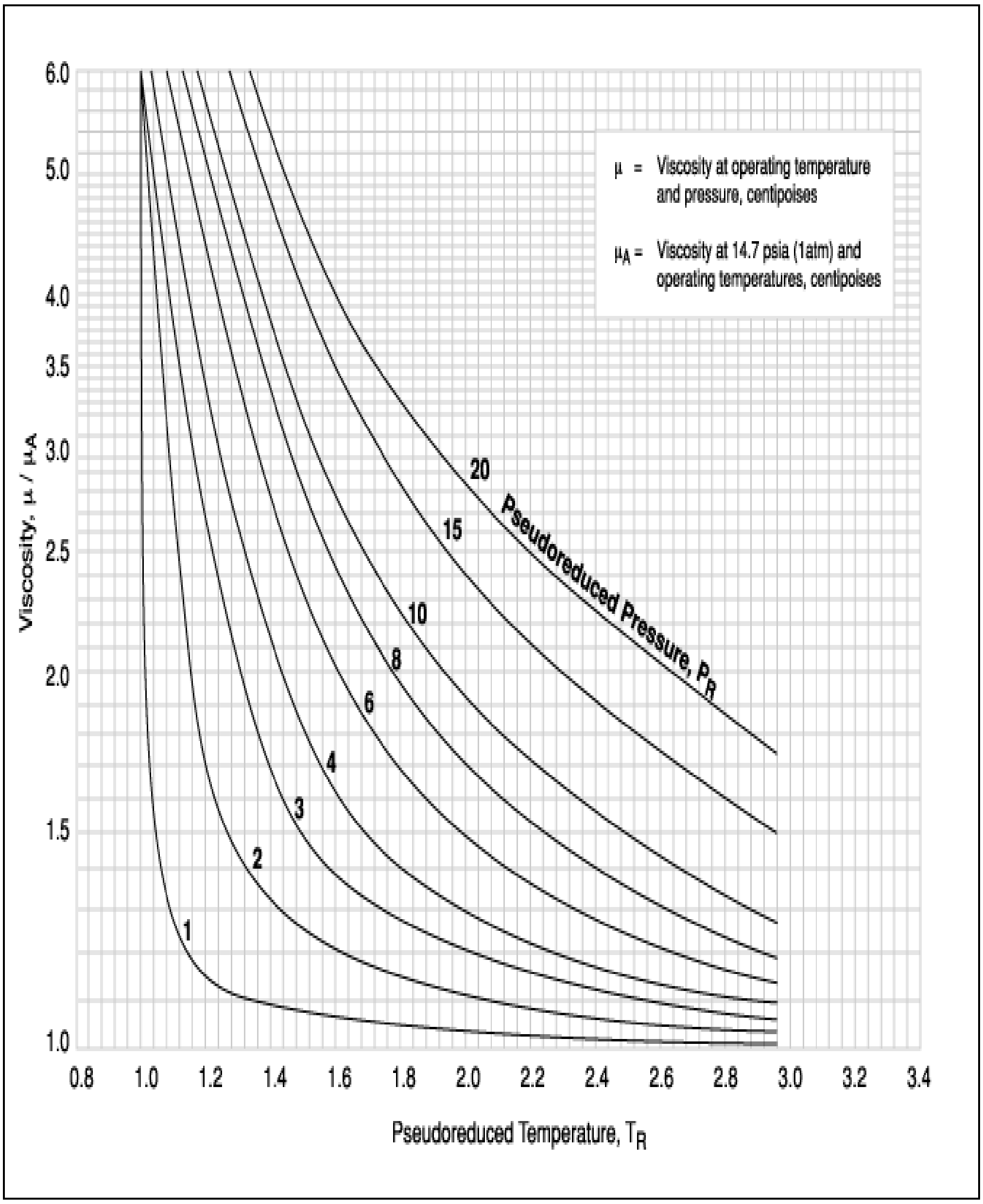


Figure 18 : Viscosity Chart [19]

3.2 Gantt Chart

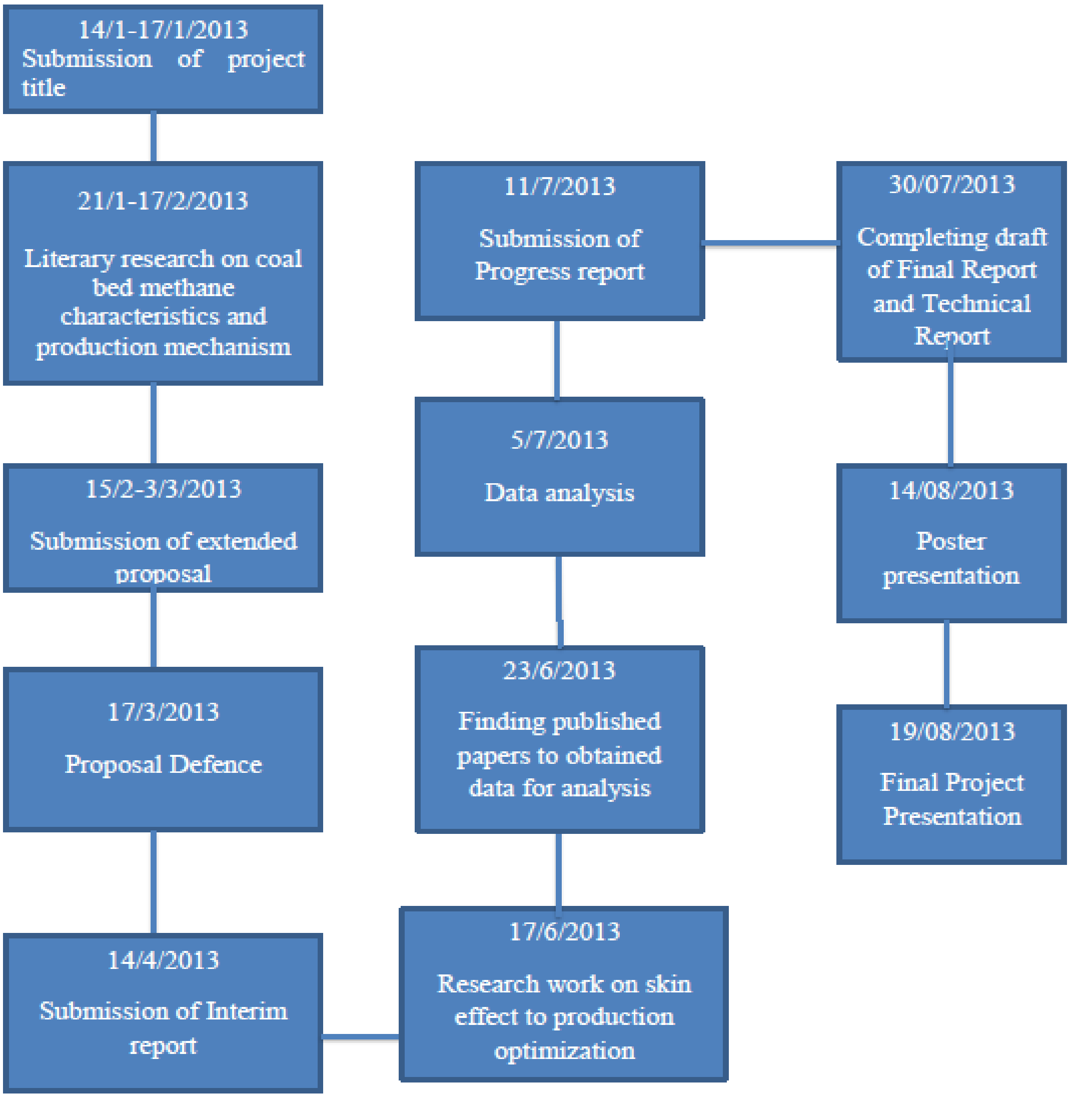
Table 6: Gantt Chart for FYP 1

N0	DETAILS/WEEK	1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	FYP 1 BRIEFING														
2	TOPIC SELECTION														
3	PRELIMINARY RESEARCH														
4	EXTENDED PROPOSAL REPORT SUBMISSION														
5	PROPOSAL DEFENCE (ORAL PRESENTATION)														
7	PROJECT WORK CONTINUES: IN DEPTH SUDIES ON COAL BED METHANE AND THE SKIN EFFECTS IN PRODUCTION OPTIMIZATION														
8	FAMILIRIAZATION WITH ECLIPSE AND FEKETE SOFTWARE														
9	PREPARATION FOR INTERIM REPORT														
10	DRAFT OF INTERIM REPORT SUBMISSION														

Table 7: Project Gantt Chart for FYP II

NO	DETAIL/WEEK	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	PROJECT WORK CONTINUES															
2	SUBMISSION OF PROGRESS REPORT															
3	PROJECT WORK CONTINUES															
4	PRE-SEDEX															
5	SUBMISSION OF DRAFT REPORT															
6	SUBMISSION OF DISSERTATION (SOFT BOUND)															
7	SUBMISSION OF TECHNICAL PAPER															
8	ORAL PRESENTATION															
9	SUBMISSION OF PROJECT DISSERTATION (HARD BOUND)															

3.3 Key Milestone



3.4 Tools

The tools used in this research are:

i. Microsoft excel
ii. Published research papers

CHAPTER 4

RESULTS AND DISCUSSION

The figure below showed the results of the skin value to the productivity Index computed by using the equation 3 and Equation 4 as stated before. The calculation is then repeated for every field:

$$J = \frac{k_h * \mathrm{h}}{1422 * T[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + S]}$$

Equation 3: Productivity Index [19]

$$J = \frac{k\mathrm{h}}{1422T(\mu_g * z)_{avg}[\ln\left(\frac{Re}{Rw}\right) - 0.75 + S]}$$

Equation 4: Productivity Index for low pressure region [19]

Case 1: Powder River Basin

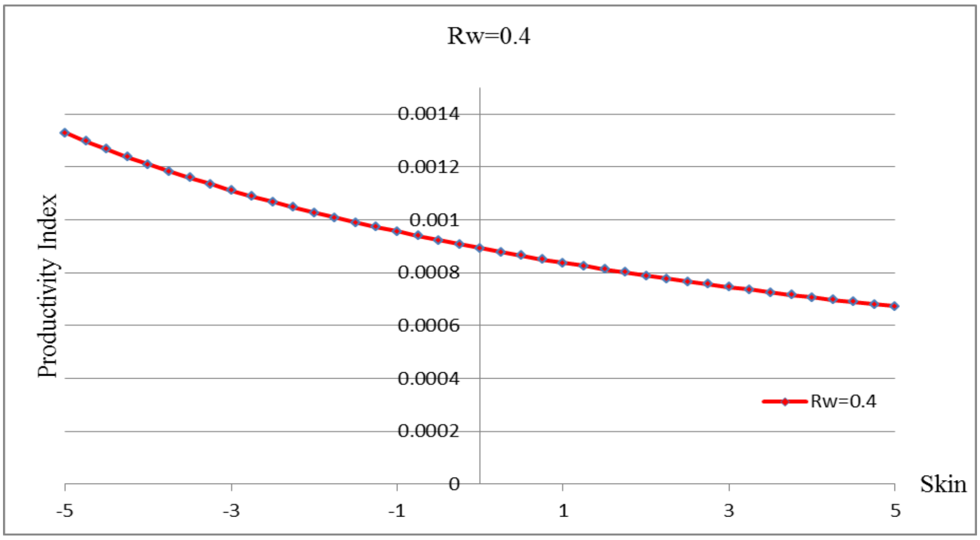


Figure 19: Productivity Index vs Skin for Rw=0.4

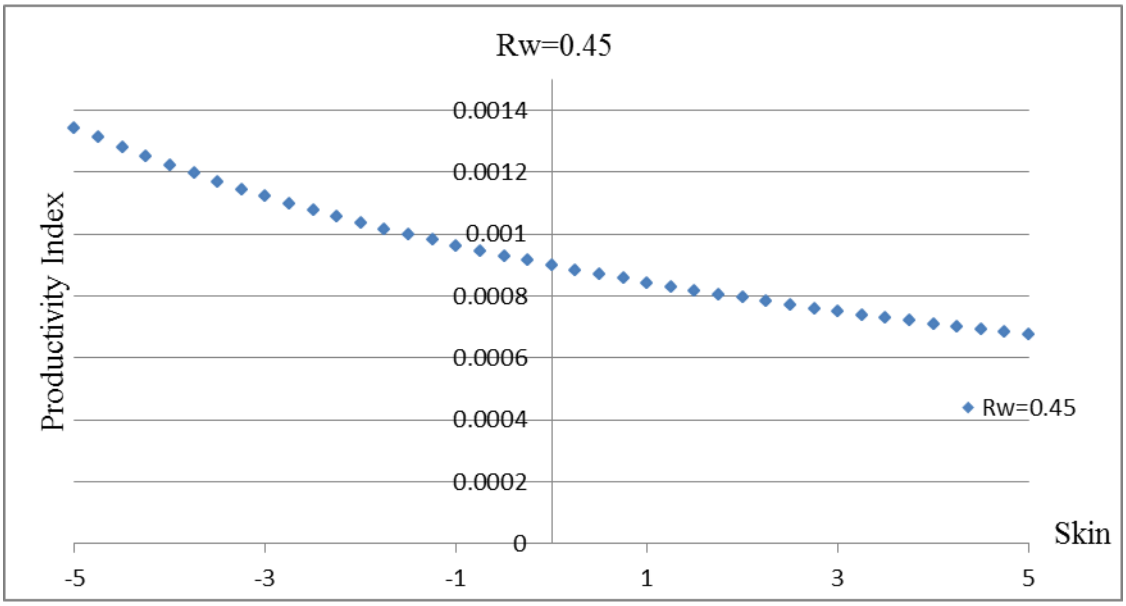


Figure 20 : Productivity Index vs Skin for Rw=0.45

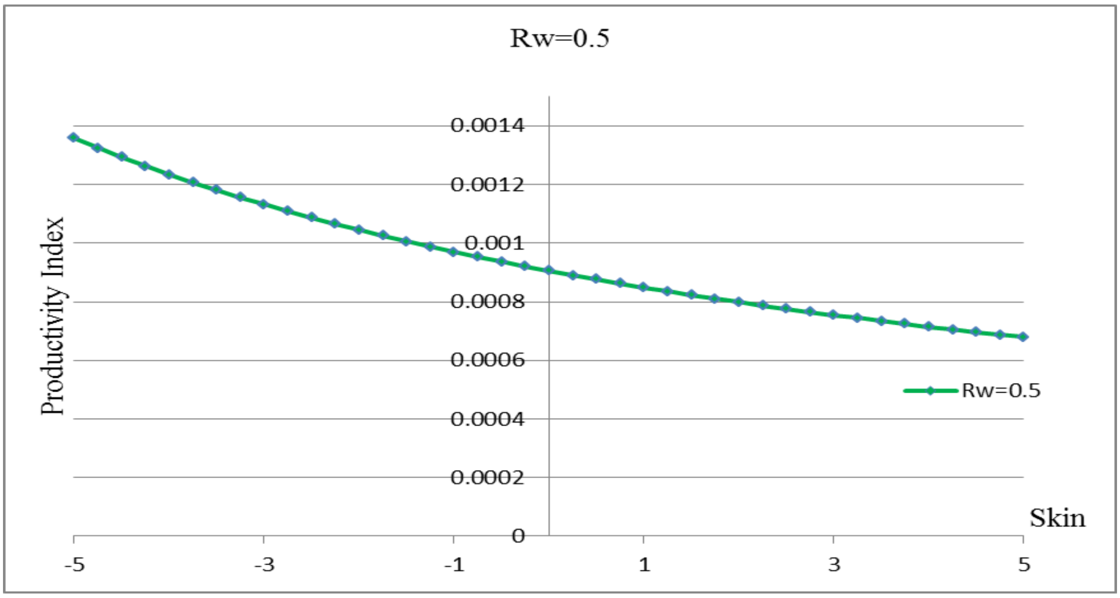


Figure 21: Productivity Index vs Skin with Rw=0.5

The above charts showed that when the wellbore radius changes in Powder River basin from 0.4 to 0.5, the productivity index does not indicate much change. The productivity index ranges from 0.00065 to 0.0014. It can be clearly seen from the graph that as the skin value increases the production rate decreases. The coal rank for Powder River basin is sub-bituminous.

Using Equation 4 by assuming the z value from 0.8-0.9, the figure below show the trends of productivity index changes as skin value increases:

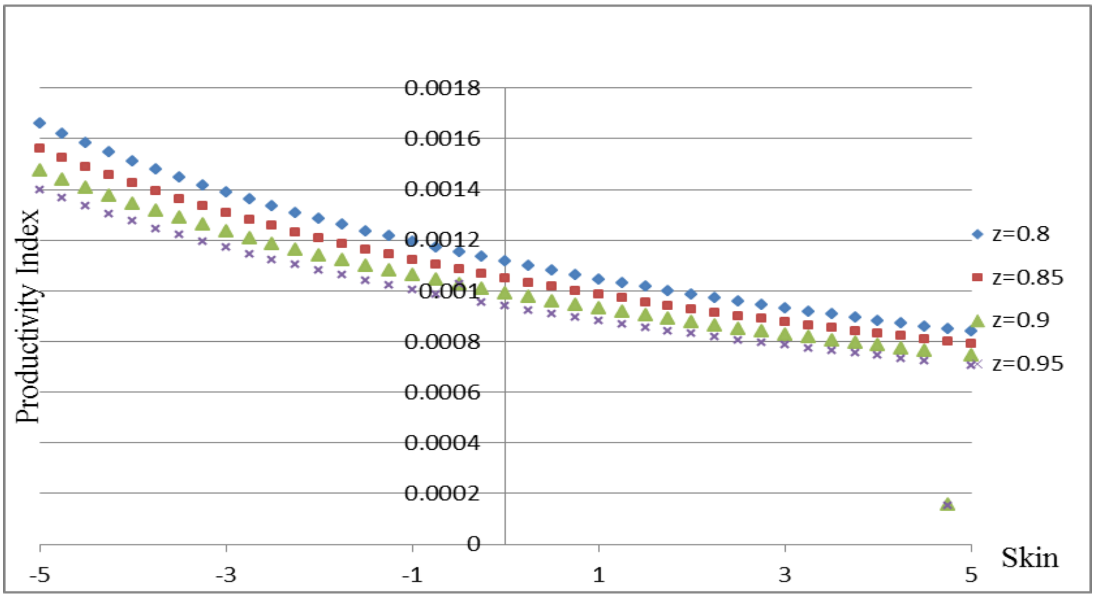


Figure 22: Productivity Index vs Skin with Rw=0.4

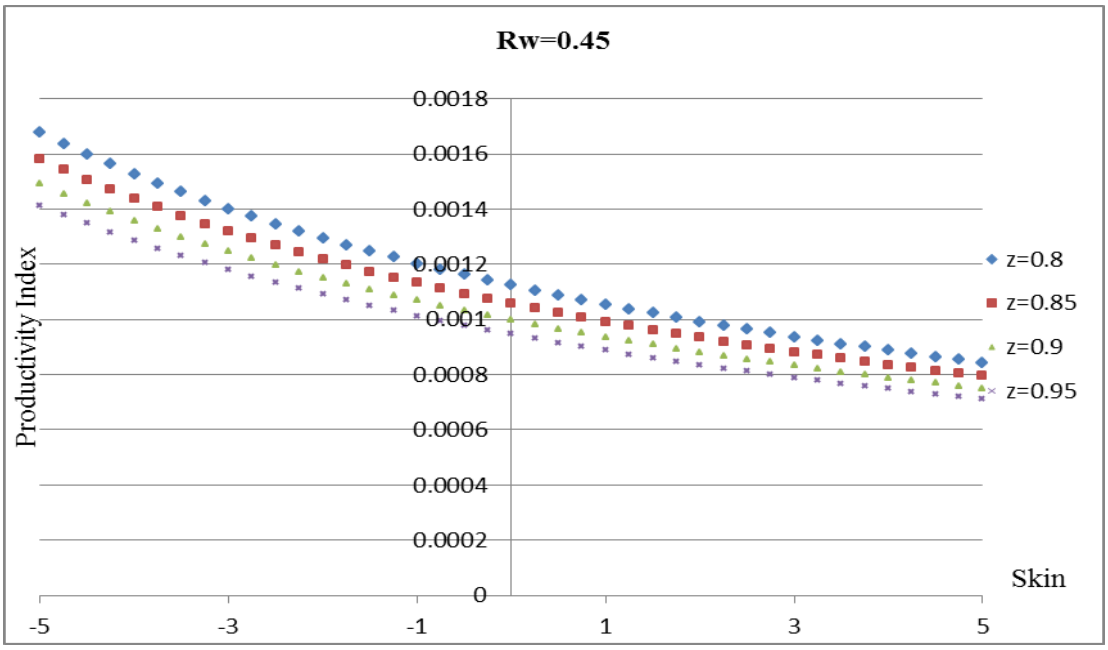


Figure 23: Productivity index vs Skin with Rw=0.45

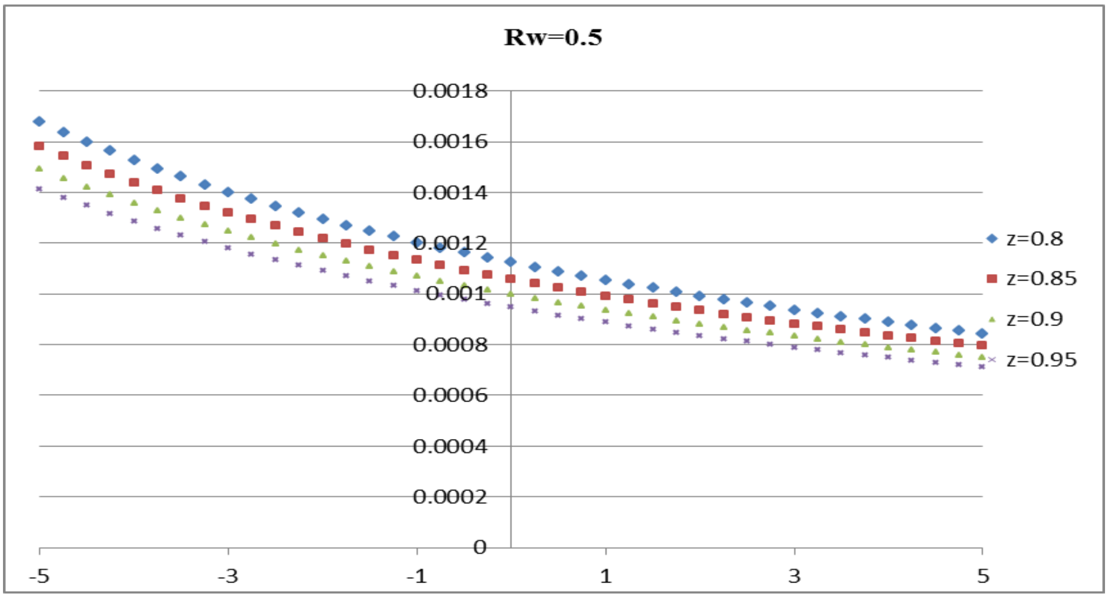


Figure 24: Productivity Index vs Skin with Rw=0.5

From the figures below, the changes in z value factor does affect the production of gas from CBM well. As the Z values increases, the productivity index decreases.

Case 2: San Juan Basin

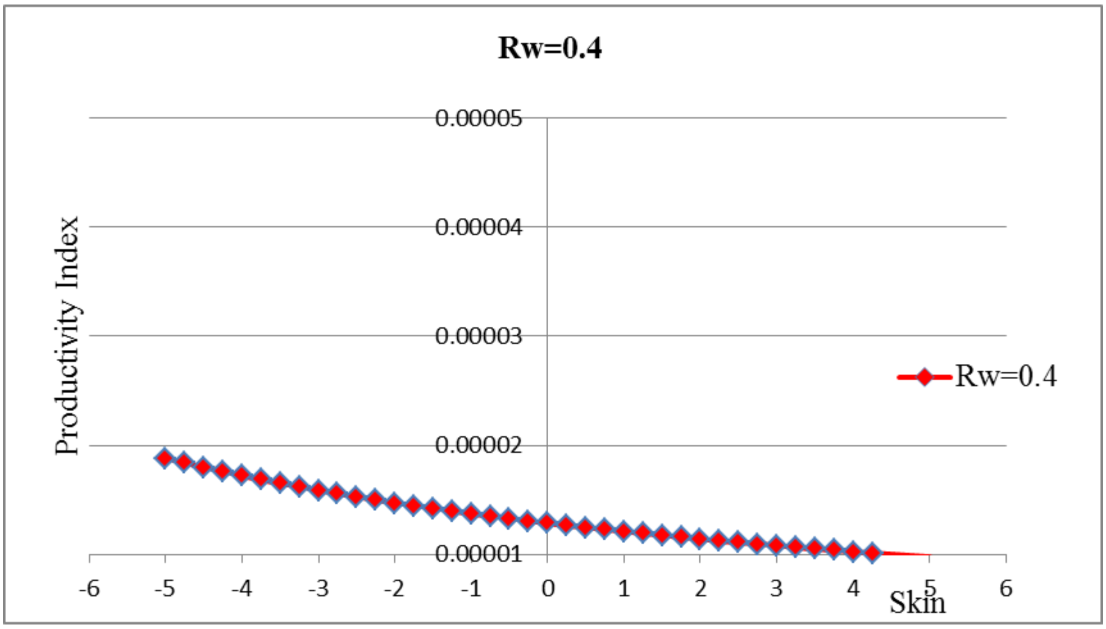


Figure 25 : Productivity Index vs Skin with Rw=0.4

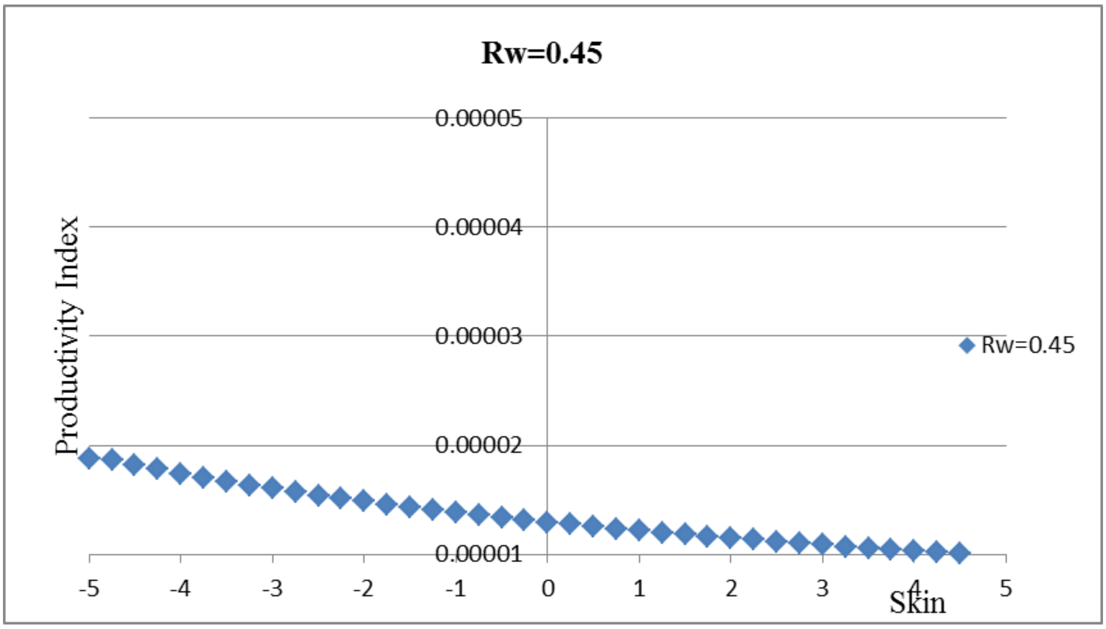


Figure 26: Productivity Index Vs Skin with Rw=0.45

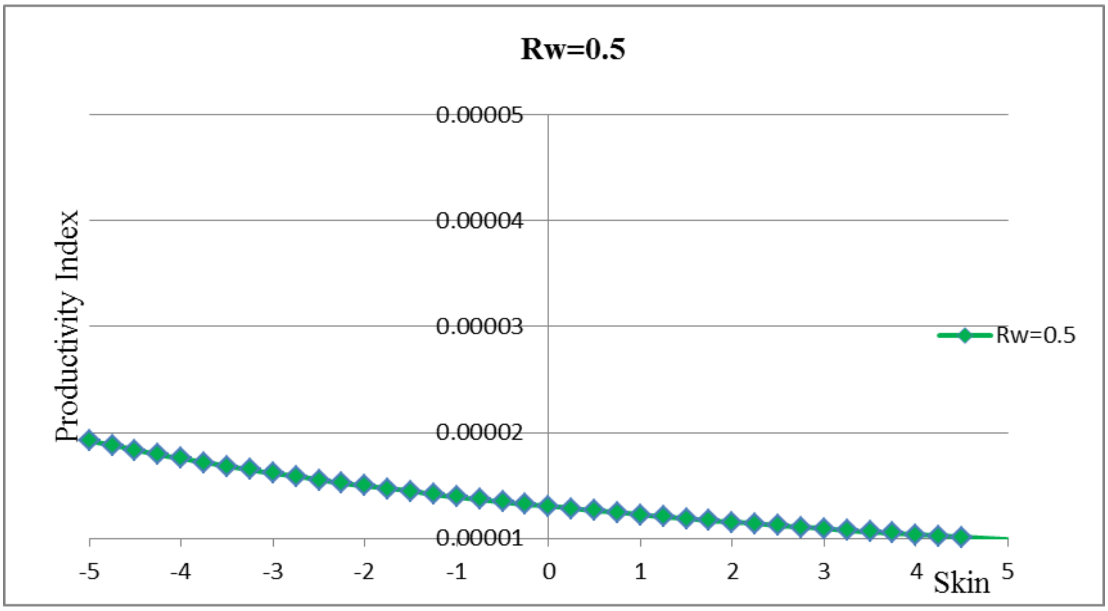


Figure 27: Productivity Index vs Skin with Rw=0.5

Using Equation 3, the productivity index for San Juan Basin is lower as compared to Powder River Basin. The productivity index for San Juan field ranging from 0.000013 to 0.00002. The figures shows the same trends as previous field, as skin value is higher, the productivity index decreases.

The figure below shows the productivity index vs skin value for San Juan Ban by using Equation 4.

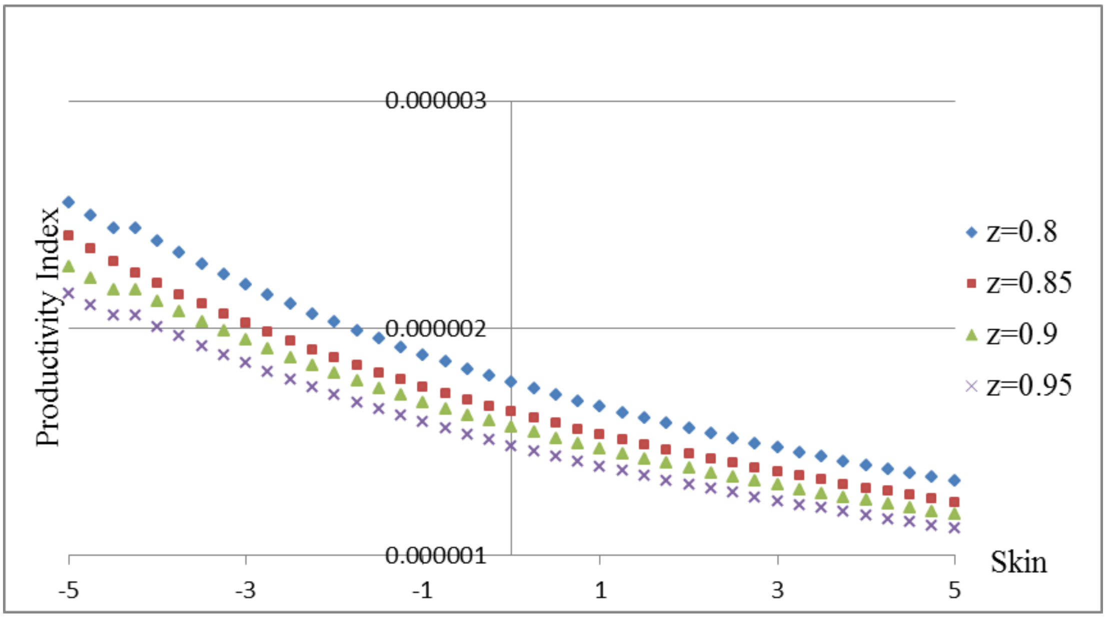


Figure 28: Productivity Index vs Skin with Rw=0.4

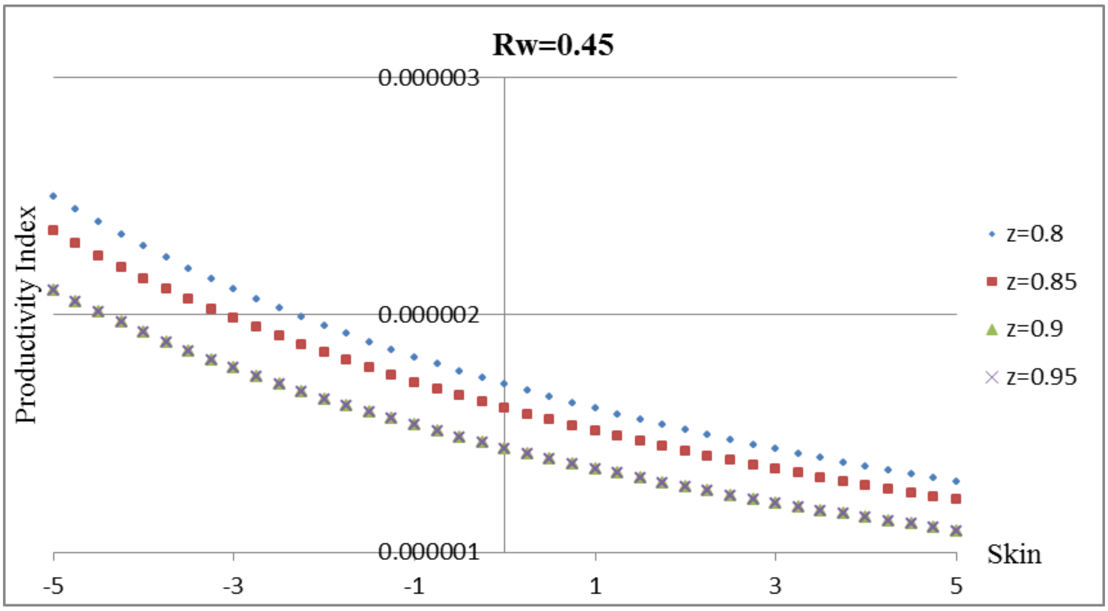


Figure 29: Productivity Index vs Skin with Rw=0.45

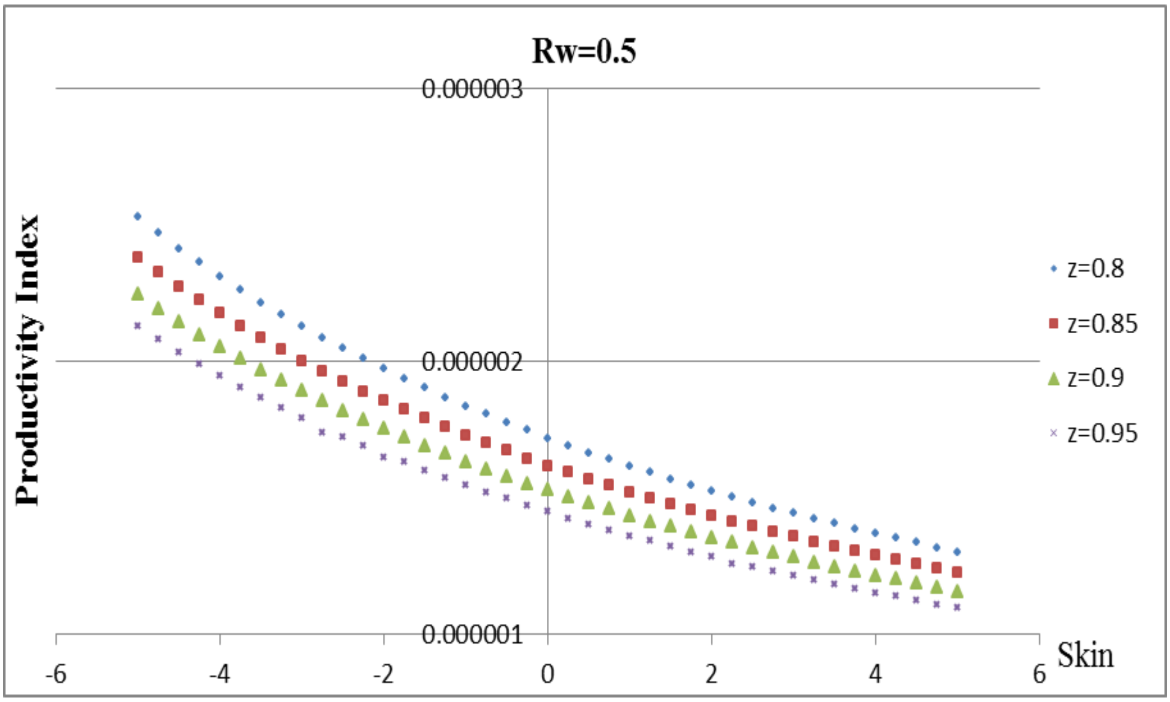


Figure 30: Productivity vs Skin with Rw=0.5

The productivity index for San Juan Basin by using Equation 4 is around 0.000001 to 0.0000025. As compared to Powder River basin, the productivity index for San Juan basin is lower. The coal rank is from High Volatile to Low Volatile Bituminous.

Case 3: Appalachian Basin

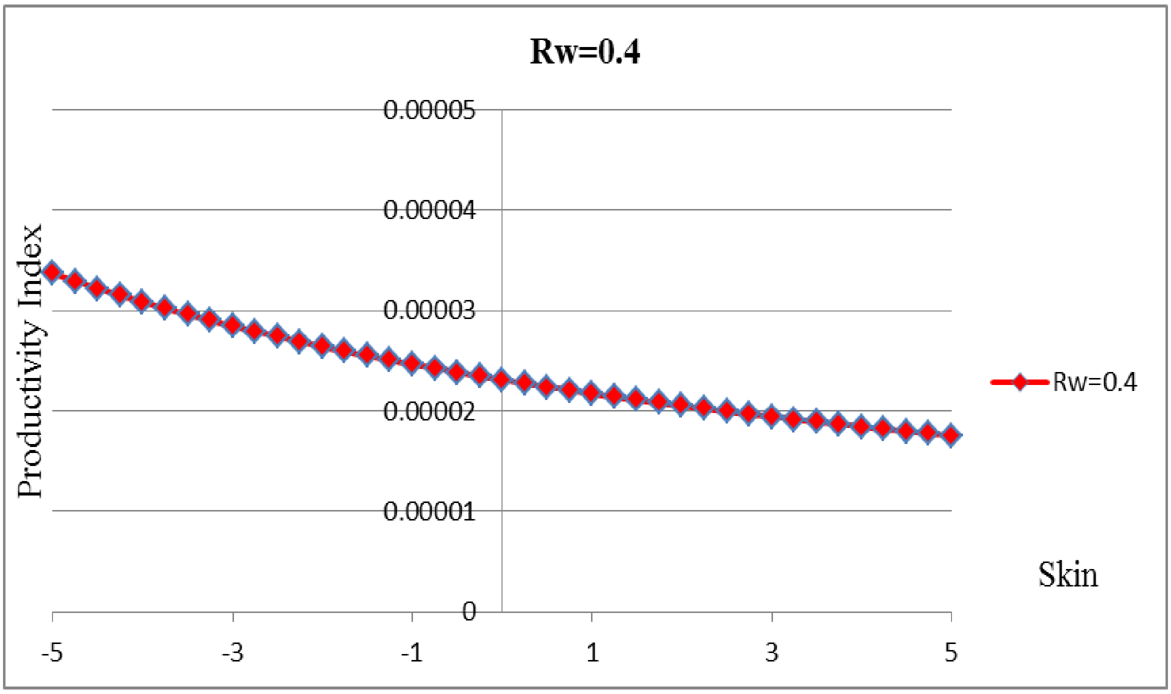


Figure 31: Productivity Index vs Skin with Rw=0.4

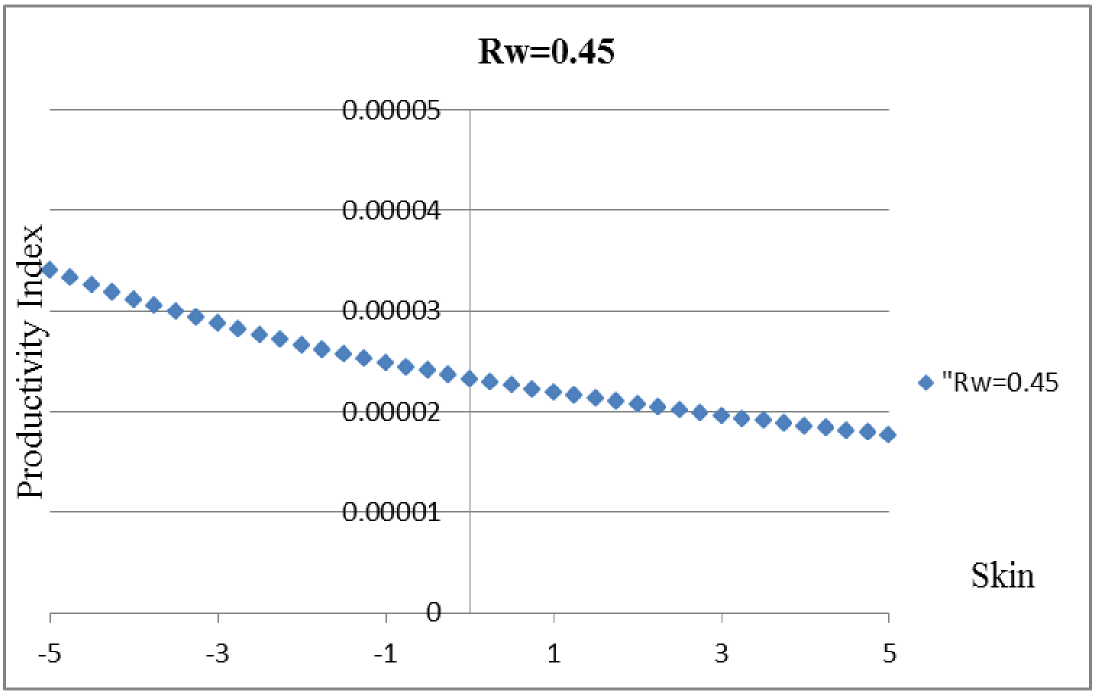


Figure 32: Productivity Index vs Skin with Rw = 0.45

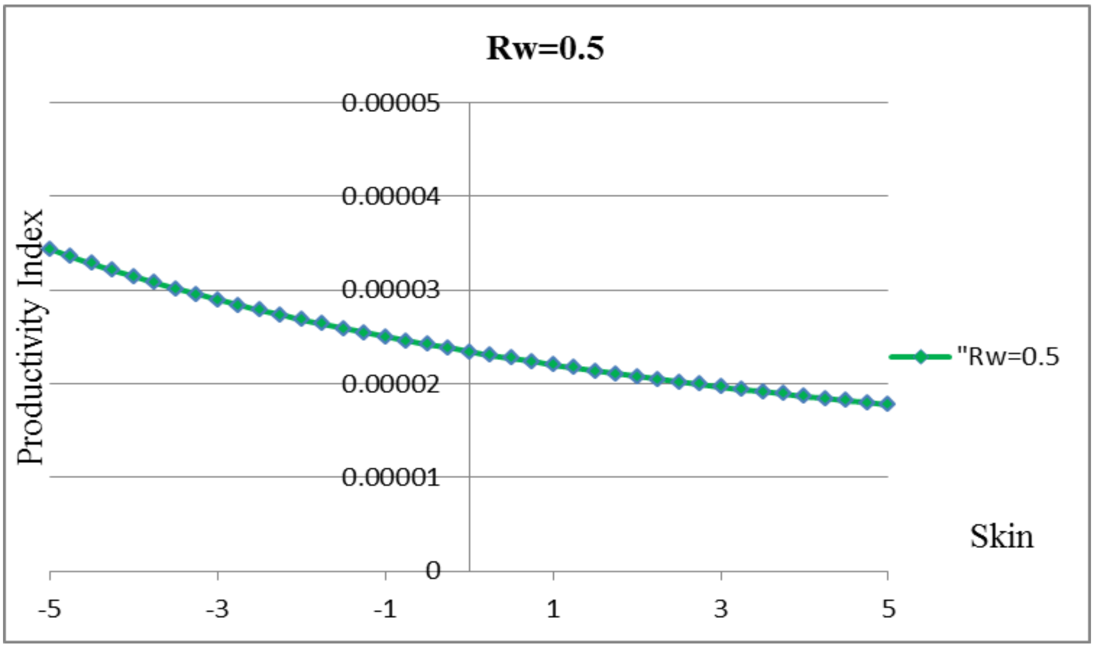


Figure 33: Productivity Index vs Skin with Rw=0.5

By using Equation 3, the productivity index of Appalachian basin is between 0.000018 to 0.000035.

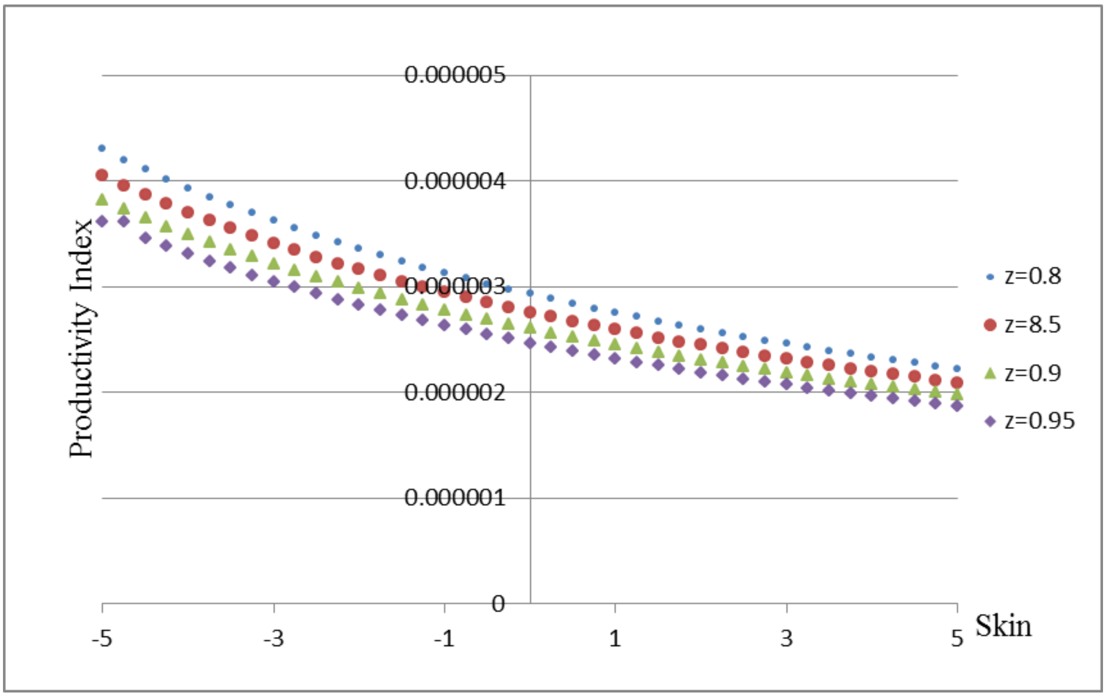


Figure 34: Productivity Index vs Skin with Rw= 0.4

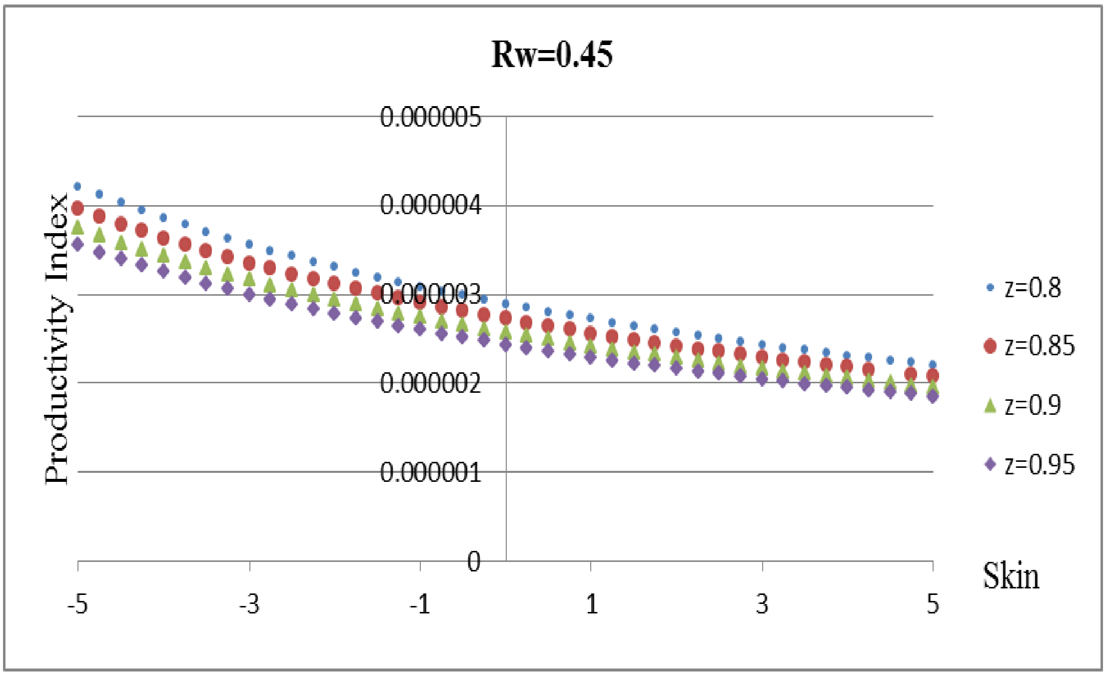


Figure 35: Productivity Index vs Skin with Rw=0.45

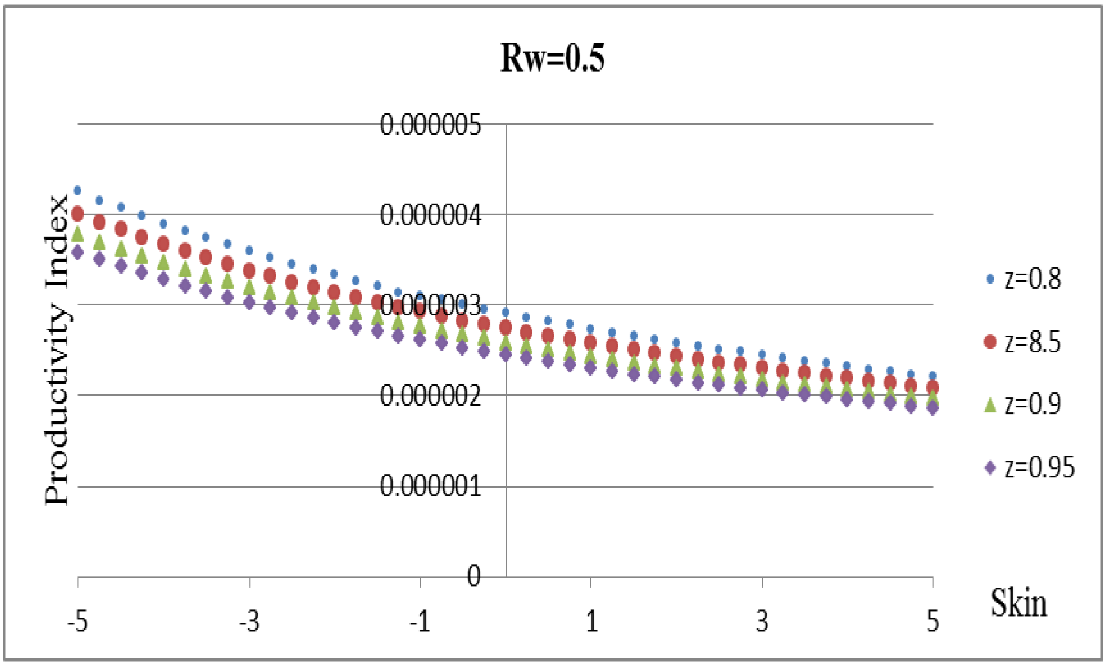


Figure 36: Productivity Index vs Skin with Rw=0.5

By using Equation 4, the productivity index is between 0.0000019-0.0000042. The difference in Z value does not show any significant effect on productivity index because the value difference is only 0.0000005. The coal rank is from High Volatile A to High Volatile B bituminous.

Case 4: Horsehoe Canyon

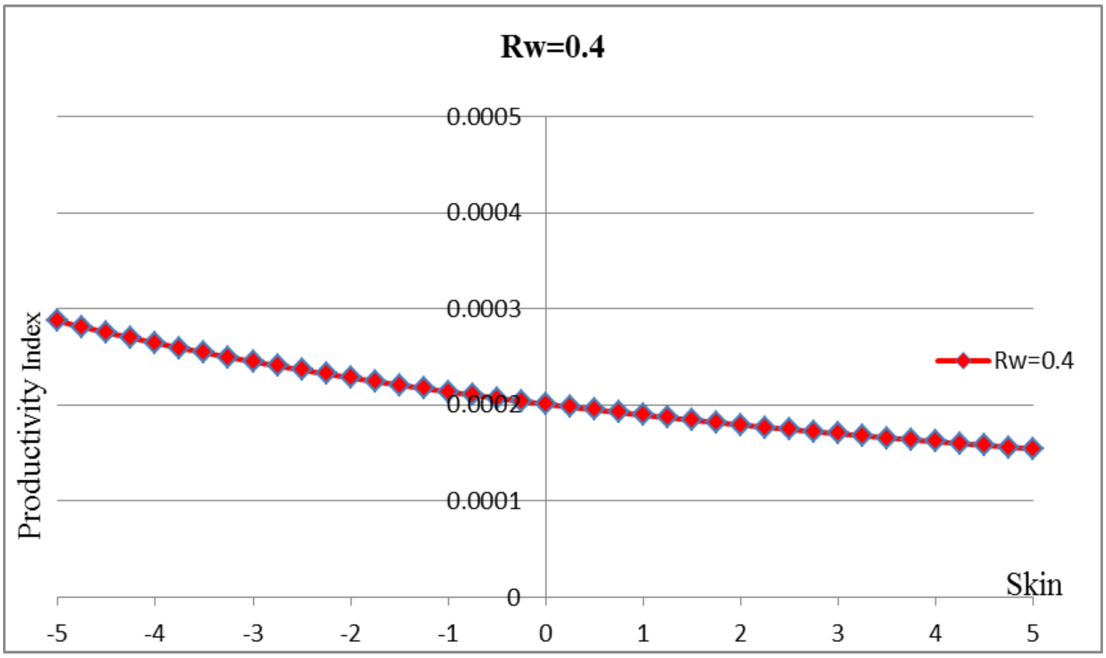


Figure 37: Productivity Index vs Skin with Rw=0.4

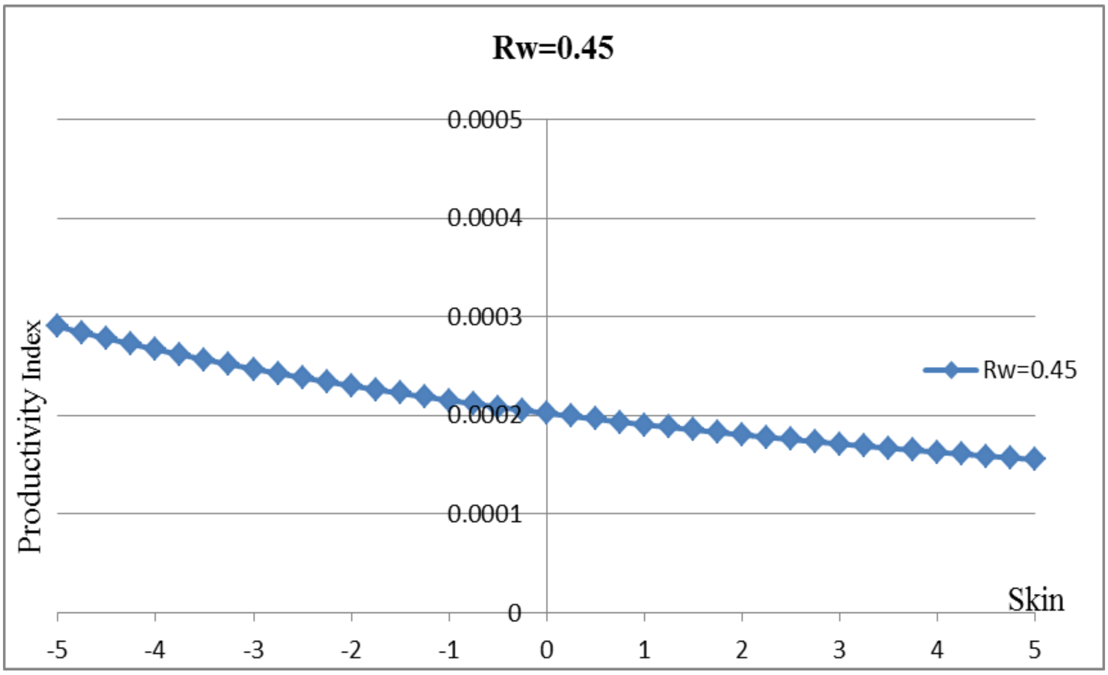


Figure 38: Productivity Index vs Skin with Rw=0.45

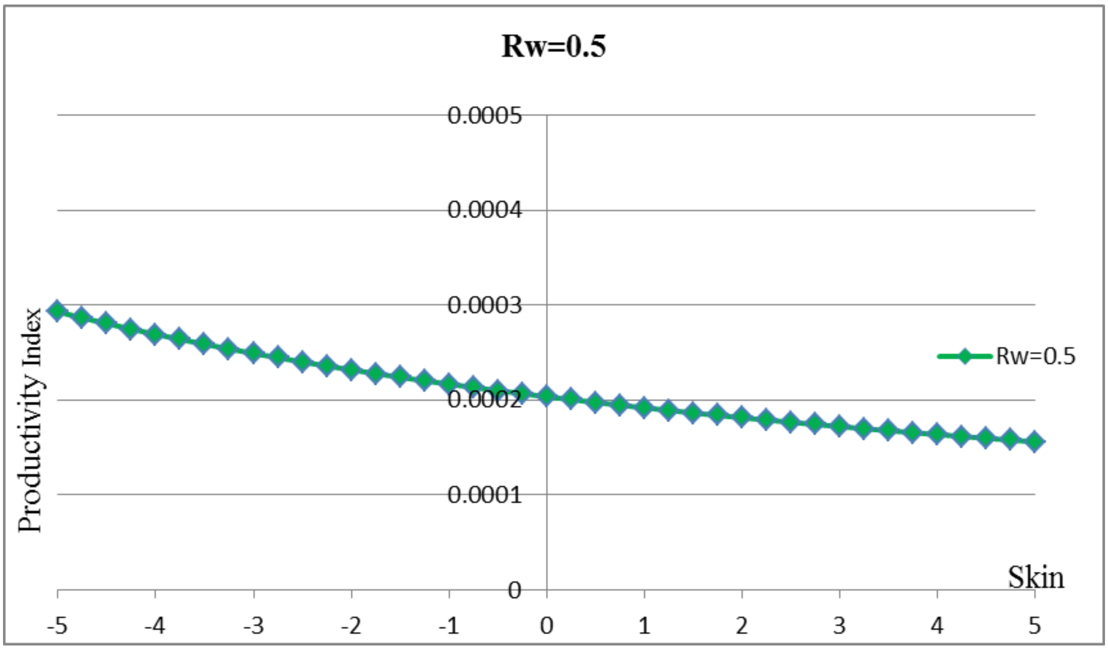


Figure 39: Productivity Index vs Skin with Rw=0.5

By using equation 3, the productivity Index for Horsehoe Canyon is ranging from 0.00017 to 0.0003. The productivity index vs skin shows similar trends as previous field, as the skin value increases the value of productivity index increases.

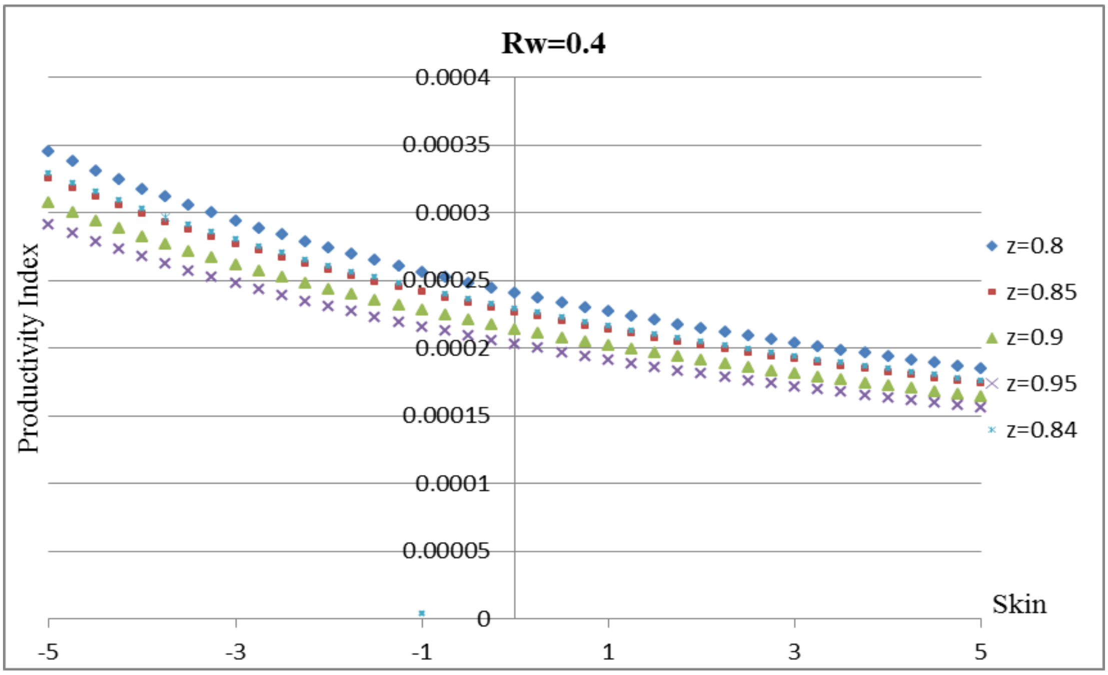


Figure 40: Productivity Index vs Skin with Rw=0.4

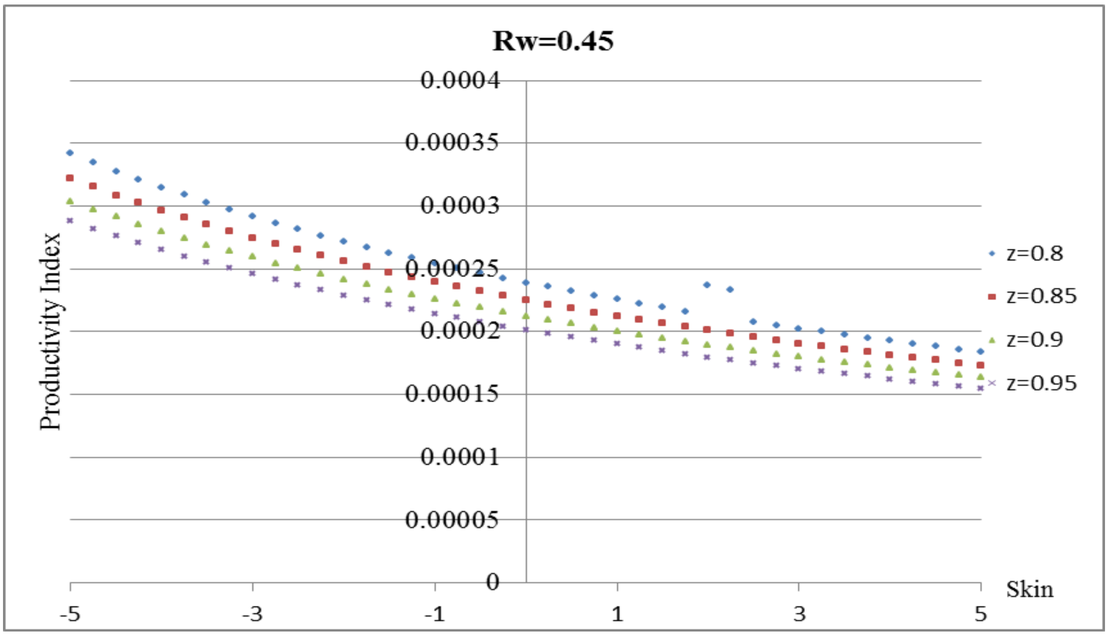


Figure 41: Productivity Index vs Skin with Rw=0.45

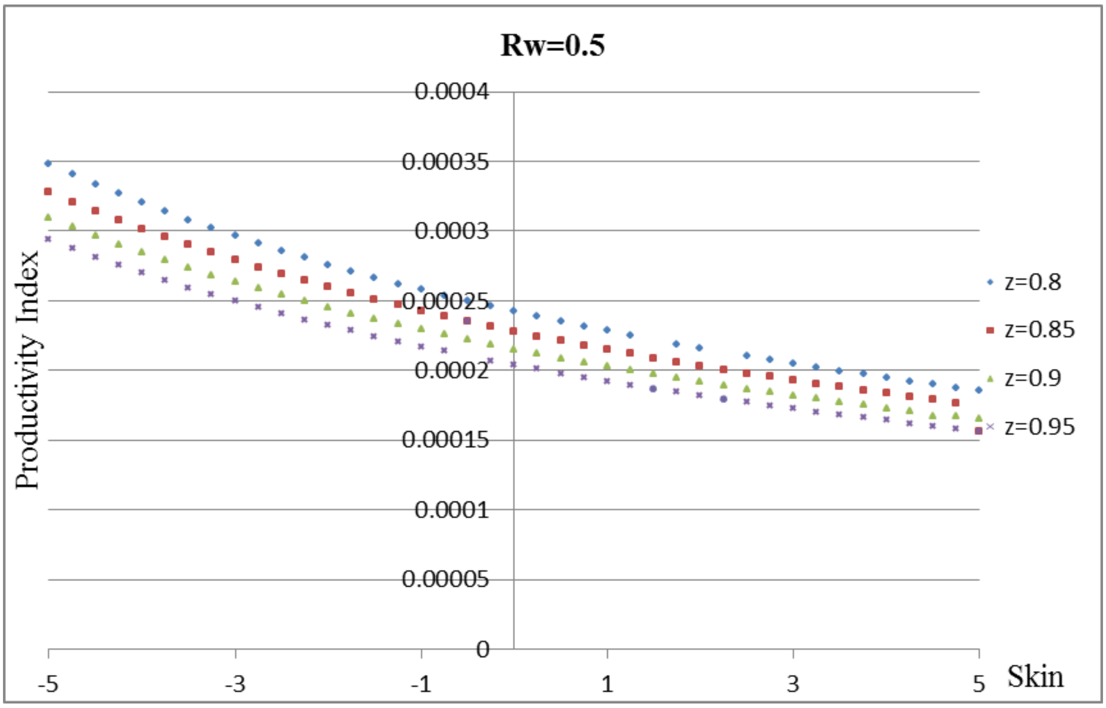


Figure 42: Productivity Index vs Skin with Rw=0.5

By using Equation 4, the above Productivity Index vs Skin profiles were resulted. The productivity Index are ranging from 0.00015 to 0.00035. The coal rank for Horsehoe Canyon is subbituminous to medium volatile bituminous.

Generally, from the graphs resulted above similar trends for Powder River basin, San Juan, Horsehoe and Appalachian basin. It can be seen that the productivity index for every field is very low. The coal rank play a major factor in determining the gas holding capacity. The more mature a coal, the more gas it can hold. In addition, higher coal rank also indicates that the fractures in the coal are wider, hence the coal bed is able to produce higher production rate. However, this theory is also depends on the basin because different basin may have different coal type, grade and botanically inherent microstructures. From the basin chosen, the coal rank is from subbituminous to bituminous. As for an example, for San Juan basin the coal rank is High Volatile to Low Volatile Bituminous and the highest Productivity Index is 0.000055. As for Horsehoe Canyon, the coal rank is subbituminous to medium volatile bituminous and the highest productivity Index is 0.013. Although the coal rank of San Juan Basin is higher than Horsehoe Basin, the productivity Index of Horsehoe Basin is greater. This is because the gas holding capacity is related with coal rank is not universal, but within the coal basin only.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

After a thorough research on skin effects to the production rates of gas in CBM wells, it can be concluded that:

i) The greater the skin value, the lower the productivity index. This happened because during drilling phase, the cements and drilling mud plug the cleat system. During hydraulic fracturing process, the gelled fluids used also can plug the structures which restricts the gas to flow to the surface. In addition, the matrix swelling phenomenon also damage the matrix CBM.

ii) The production rate of CBM well is very low due to its extremely low permeability. In order to achieve economic production rates, such reservoirs required some stimulation such as bon dioxide or nitrogen gas injection.

iii) The coal rank plays a main factor in determining the gas storage capacity in coal seam. Generally, higher rank of a coal able to hold more gas. In addition, the greater coal rank indicates that the coal bed methane has greater fractures which CBM to produce higher rate of gas production.

Among the recommendations that can be made as follow up to this project:

i) Simulation using Fekete or Dot.CBM should be run in order to compare the results between using simulation software and Microsoft Excel

ii) Further studies should be conducted to study the production performance of coal bed methane and the other factors that can also affect its productivity index.

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APPENDICES

NOMENCLATURE

1. Q_g = gas flow rate, Mscf/day

1. K = permeability, md
2. Pr = average reservoir real gas pseudo-pressure, psi^2/cp
3. T = temperature, $°R$
4. r_e = drainage radius
5. r_w = wellbore radius
6. J = productivity index
7. Tpr = pseudo-reduced temperatue
8. Tpc = pseudo-critical temperatue
9. Ppr = pseudo reduced pressure
10. Ppc = pseudo-critical temperature