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Production Analysis of Marcellus Shale

Hossein Belyadi

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

Master of Science

in

Petroleum and Natural Gas Engineering

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Morgantown, West Virginia

2011

Abstract

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Hossein Belyadi

The purpose of this thesis was to analyze the production potential of Marcellus shale using actual field data. By using real field production data for 9 vertical and 3 horizontal wells it was possible to predict and understand the cause and effect relationship between the specific reservoir parameters and the overall production outlook of the reservoir in the long run. Using an assumed base model and narrowing each parameter down to match historically to the actual field data the forecast of the reservoir behavior was attained. The main model relied upon in this thesis was the Dual Porosity Model, which was used to analyze the real field production data using Eclipse. In addition to history matching, another goal of this thesis was to understand the effect of each parameter on the production curve so as to further the predictability of these variables. Over five hundred runs have been performed to establish the history matching in order to document the specific effect of each parameter on the production data using Eclipse. The recorded history match results for each well can permit the prediction of the future forecast for the reservoir. Lastly, based on the final parameters that were used to historically match the real field data, two models were created and run to differentiate the reserves and recovery factor for both vertical and horizontal wells.

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Table of Contents

Abstract	ii
Acknowledgments	iii
Table of Contents	iv
List of Figures	v
List of Tables	vii
List of Symbols/ Nomenclatures	viii
Introduction.....	1
Literature Review.....	3
Methodology	23
Results and Discussions.....	31
Conclusion	44
References.....	45
Appendix.....	48
Curriculum Vitae	108

List of Figures

Figure 1. United States Shale Gas Plays (EIA, 2008).....	4
Figure 2. Stratigraphy of the Marcellus Shale (NETL, 2010).....	5
Figure 3. Marcellus Shale Thickness (NETL, 2010)	6
Figure 4. Marcellus Shale Pressure Regime (NETL, 2010).....	8
Figure 5. Thermal Maturity of the Marcellus (NETL, 2010).....	9
Figure 6. Depth to the bottom of the Marcellus (Geology, 2008).....	10
Figure 7. Horizontal Drilling (Geology, 2008)	11
Figure 8. Marcellus Shale Hydraulic Fracturing (Hydraulic Fracturing, 2011)	15
Figure 9. Actual Reservoir Vs Model Reservoir (Root, The behavior of naturally fractured reservoirs, 1963)	18
Figure 10. Interporosity Flow Coefficient (Root, 1963)	20
Figure 11. Log Cycle Separation (Root, 1963)	21
Figure 12. Storativity Illustration (Root, 1963)	22
Figure 13. History Matching for Vertical #2	33
Figure 14. Final Match for Vertical #2	34
Figure 15. History Matching for Horizontal #1	36
Figure 16. Final Match for Horizontal #1	36
Figure 17. Horizontal Model #1 Illustration	37
Figure 18. Final Production Rate Behavior for Vertical Model.....	40
Figure 19. Final Cumulative Production Behavior for Vertical Model	40
Figure 20. Final Production Rate Behavior for Horizontal Model	42
Figure 21. Final Cumulative Production Behavior for Horizontal Model	43

List of Tables

Table 1. Basic Model Parameter	26
Table 2. Initial and final values of the parameters for vertical #2	32
Table 3. Initial and final values of the parameters for horizontal #1	35
Table 4. Final Parameters for Horizontal and Vertical Wells	38
Table 5. Final Vertical Parameters.....	39
Table 6. Recovery Factor for Final Vertical Model.....	41
Table 7. Final Horizontal Parameters	42
Table 8. Recovery Factor for Final Horizontal Model.....	43

List of Symbols/ Nomenclatures

K = formation permeability, md

K_f = natural fracture permeability, md

ϕ_f = natural fracture porosity, fraction

K_m = matrix permeability, md

ϕ_m = matrix porosity, fraction

X_f = fracture half length, ft

K_{hf} = hydraulic fracture permeability, md

ϕ_{hf} = hydraulic fracture porosity, %

W_{hf} = hydraulic fracture width, in

P_L =Langmuir pressure, psia

V_L = Langmuir volume, SCF/ton

T = temperature, °F

F_{CD} = dimensionless fracture conductivity

λ = interporosity flow coefficient

w = storativity

OGIP= original gas in place, MSCF

RF= recovery factor, %

EUR= estimated ultimate recovery, MSCF

h = thickness, ft

r_e = drainage radius, ft

r_w = wellbore radius, ft

P_{wf} = bottom hole pressure

A = area, acreage

Chapter 1

Introduction

Marcellus shale is a giant field in the Appalachians that is believed to have trillions of cubic feet of gas in place; however the percentage of this gas that can be recovered is controversial with varying estimates. It is very important to understand how much gas can be recovered over the life of the play. This amount is referred to as Estimated Ultimate Recovery (EUR). The production data available from different vertical and horizontal wells only indicates the short-term production recovery and reservoir simulation can be used to understand the long-term production recovery for both vertical and horizontal wells. This thesis will be a new study on the production analysis of the Marcellus Shale using reservoir simulation and history matching techniques.

There is not an abundance of public information regarding the Marcellus Shale production in the long run. This thesis focuses on analyzing the Marcellus Shale production for both vertical and horizontal wells after 30 years and historically matches the real field data in order to forecast the future behavior of the reservoirs long run production. Marcellus shale is a new discovery and the production data available from the Marcellus is typically for a few years. As a result, it is essential to build various models using the dual porosity system in reservoir simulation in order to understand and forecast the behavior of the reservoir after so many years.

Range Resources started drilling for Marcellus shale with the first well being drilled in 2003 in Washington County, Pennsylvania. They have discovered a promising flow of natural gas. Furthermore, using horizontal drilling and hydraulic fracturing, it was discovered that the

flow of natural gas can be significantly increased. Resulting from these discoveries, the first Marcellus gas production began in 2005. (Geology, 2008)

Shale gas is present across much of the lower forty eight States. The most active shales to date are the Barnett Shale, the Haynesville/Bossier Shale, the Antrim Shale, the Fayetteville Shale, the Marcellus Shale, and the New Albany Shale. Each of these gas shale basins is different and each has an exclusive set of exploration criteria. Because of these differences, the development of shale gas resources in each of these areas faces potentially unique challenges. As new technologies are developed, shale gas plays once believed to have limited economic feasibility are now being re-evaluated. (NETL, 2010)

The combination of hydraulic fracture treatments and horizontal well completions has been very important in facilitating the development of shale gas reservoirs. Before the successful development of these two technologies, shale gas resources in many basins had been disregarded because of low production rate. The low natural permeability of shale had been the limiting factor to the production of shale gas resources because it only allows small volumes of gas to flow naturally to a wellbore. For gas shales to be economically produced, these restrictions must be overcome. The combination of reduced economics and low permeability of gas shale formations historically caused operators to bypass these formations and focus on other resources. (NETL, 2010)

Chapter 2

Literature Review

2.1. Marcellus Shale:

Marcellus shale has been one of the most important developments in the past few years. Having a good understand of what this gigantesque gas reservoir can do to shape the future of natural gas industry is essential in today's U.S. economy. Marcellus shale is rich black organic shale with low density that occurs in West Virginia, Pennsylvania, and New York. In addition, small areas of Maryland, Kentucky, Tennessee, and Virginia are also affected by the Marcellus Shale. A few years ago, it was very hard to believe that Marcellus Shale could be productive and economical because of its low permeability structure; however with recent advances in specialized horizontal drilling and hydraulic fracturing technologies, it is now known as the largest potential gas field in the U.S. (Geology, 2008)

Figure 1 is a visual illustration of the location of these shale gas plays and Marcellus Shale in the U.S.

2.2. Marcellus Shale Stratigraphy:

Marcellus is bounded by the Hamilton group shale and below by limestone of the Tristate group. Figure 2 illustrates that Marcellus is located in the lower middle Devonian shale.

2.3. Characteristics of Productive Marcellus Shale in West Virginia:

- 1) Net thickness of organic rich Marcellus Shale > 30 feet;
- 2) Pressure gradient of 0.40 psi/ft;
- 3) Thermal maturation > 1.25% vitrinite reflectance (R_o);
- 4) Depth > 5000 ft

Figure 1. United States Shale Gas Plays (EIA, 2008)

2.3.1. Net thickness of organic rich Marcellus Shale > 30 feet:

Average thickness of Marcellus in West Virginia is estimated to be 10ft to 100 ft. Since this thesis is going to use vertical and horizontal wells in West Virginia counties, it is imperative to understand the thickness variation across the states. The thickness of Marcellus Shale is different across the state but it is known to be the thickest in the northeast central counties and thin to zero in the Southwest. Figure 3 is a map that illustrates the thickness of the Marcellus across the West Virginia counties. (NETL, 2010)

Period		Group/Unit	
Penn		Pottsville	
Miss		Pocono	
Devonian	Upper	Conewango	
		Conneaut	
		Canadaway	
		West Falls	
		Sonyea	
		Genesee	
	Middle	Tully	
		Hamilton Group	Moscow
			Ludlowville
			Skaneateles
			Marcellus
		Onandaga	
	Lower	Tristates	
		Helderberg	

Figure 2. Stratigraphy of the Marcellus Shale (NETL, 2010)

2.3.2. Pressure gradient of 0.40 psi/ft:

Marcellus exhibits different pressure regimes in West Virginia. Typically it is under-pressure to the Southwest and even though not a lot of data is available, it has been determined that the Marcellus is potentially over pressured to the Northeast with a transitional area in between. Figure 4 shows these pressure regimes with a question mark indicating the uncertainty associated with the normal to over pressured area. It is understandable that the highest ultimate recoveries will be from the normal to over pressured areas. The presence of these separate pressure regimes indicates different approaches to well stimulation. (NETL, 2010)

Figure 3. Marcellus Shale Thickness (NETL, 2010)

Figure 4 is an illustration of pressure distribution in West Virginia counties.

2.3.3. Thermal maturation > 1.25% vitrinite reflectance (R_o):

It is essential to understanding the meaning of each of the above terms, which are used in the Petroleum industry to classify the highest production potential of Marcellus Shale. Thermal maturity refers to a measure of the heat-induced process of converting organic matter to oil or natural gas can be distinguished by several factors and it should be converted to the universal standard vitrinite reflectance (R_o). In addition, vitrinite reflectance is a measurement of the maturity of organic matter with respect to whether it has generated hydrocarbons or could be an

effective source rock. The measurement of the thermal maturity of organic matter was developed to rank the maturity of coals and now it is being used in other rocks. Rock units are heterogeneous. The gas in the Marcellus Shale is apparently the result of its contained organic content. Thinking about the highest production potential of a shale rock, it can be determined that the more organic material in the rock, the greater is the ability to yield gas. It can be distinguished that the area with the highest production potential can be the areas with highest content of organic matter and highest level of thickness. (NETL, 2010)

Based on the 2010 NETL report, the most profitable shale formations have R_o values of greater than 1.2%. Shale with R_o less than that will likely produce more oil than gas. It can be seen in Figure 5 that thermal maturity is greatest toward the East in West Virginia. Figure 5 is the thermal maturity for West Virginia's counties. (NETL, 2010)

2.3.4. Depth >5000 ft

The estimated depth of Marcellus Shale is between 3,000 ft to 9,000 ft. Figure 6 shows the depth to the bottom of the Marcellus Shale in the Marcellus Shale's regions. (Geology, 2008)

2.4. Horizontal Drilling:

Within the last 2 to 3 decades horizontal drilling is one of the newest and most formative technological advancements in the Petroleum Industry. Horizontal drilling increases productivity compared to vertical well productivity. For example when drilling for a vertical well with a thickness of 100 ft the contact area is only 100 ft. However, in horizontal wells this contact can be held for thousands and thousands of feet. Some horizontal wells in the Marcellus Shale have initial flows that suggest that they are capable of yielding millions of cubic feet of gas per day, making them the most productive gas wells in the Eastern United States. In addition to the

productivity increase, horizontal wells improve the overall cost-effectiveness depending on the reservoir. While the cost factor for a horizontal well may be as much as two or three times that of a vertical well the production factor can be enhanced making it attractive as a new method for drilling. To have an idea of the effectiveness of horizontal drilling, the U.S. department of energy indicates that using horizontal drilling can lead to an increase in reserves in place by about 2% of the original gas in place. (Horizontal Drilling, 2008)

Figure 4. Marcellus Shale Pressure Regime (NETL, 2010)

Figure 5. Thermal Maturity of the Marcellus (NETL, 2010)

Figure 7 is an illustration of horizontal drilling with some hydraulic fracturing zones.

Figure 6. Depth to the bottom of the Marcellus (Geology, 2008)

2.5. Hydraulic Fracturing:

Hydraulic fracturing is one of the first necessary steps and costs in shale gas horizontal or vertical reservoirs. Fracing allows for the exploitation of the natural gas and oil from rock formations deep below the earth's surface. At deep formations, there may not be enough porosity and permeability to permit natural gas and oil to flow from the rock into the wellbore at economic rates. For example, conductive fractures in the rock are essential to produce gas from shale reservoirs because of the extremely low natural permeability of shale which is usually in the scale of microdarcy or nanodarcy. The fracture provides a conductive path connecting a larger area of the reservoir to the well, thus increasing the area from which natural gas and liquids can be recovered from the given formation. (Hydraulic Fracture, 2010)

Figure 7. Horizontal Drilling (Geology, 2008)

A hydraulic fracture is created by pumping fracturing fluid into the wellbore at a specific velocity to increase the downhole pressure to a value in excess of the fracture gradient of the formation rock. This applied pressure causes the formation to crack (i.e. fracture), allowing the fracture fluid to enter and extend the crack farther into the formation. This fracture that is created by pumping millions of gallons of fluids can be closed after the injection procedure is completed, so to maintain this fracture open after the injection stops, a solid proppant is added to the fracture fluid. The propped hydraulic fracture then becomes a high permeability conduit through which the formation fluid can flow to the well. (Hydraulic Fracture, 2010)

Drilling a well always involved applying downhole pressure to a rotating drill bit. This drilling action produces rock chips and fine rock particles that are highly possible to enter crack

and pore space at the wellbore wall, resulting in damage to the permeability at the end of the wellbore. This damage reduces flow into the wellbore from the surrounding rock formations. Hydraulic fracturing can be used to diminish this damage as well. (Hydraulic Fracture, 2010)

As previously mentioned, hydraulic fracture stimulation is commonly used in low permeability wells. It is estimated that 90% of the natural gas wells in the U.S. are hydraulically fractured to produce gas at economic rate. It is very clear that hydraulic fracturing is one of the most important costs in drilling a well in the U.S. since vast group of the formations are shale. With the Marcellus Shale development in the Appalachians, majority of petroleum companies are hiring entry level and experienced engineers to help fasten the procedure of hydraulically fracturing of all the wells. (Hydraulic Fracture, 2010)

As previously mentioned, there are many different applications for hydraulic fracturing such as:

- 1) Increase the flow rate of oil and/or gas from low permeability reservoirs
- 2) Increase the flow rate of oil and/or gas from wells that have been damaged
- 3) Connect the natural fractures and/or cleats in a formation to the wellbore
- 4) Decrease the pressure drop around the well to minimize sand production
- 5) Decrease the pressure drop around the wells to minimize problems with asphaltine and/or paraffin deposition
- 6) Increase the drainage area or the amount of formation in contact with the wellbore
- 7) Connect the full vertical scope of a reservoir to a slanted or horizontal well. (DOE, 2004)

There could be other uses of hydraulic fracturing, but majority of the frac jobs are pumped because of the seven above reasons. A low permeability reservoir means it has high resistance to fluid flow. In many formations, chemical or physical processes alter a reservoir rock over geologic time. Sometimes, these diagenetic processes restrict the openings in the rock and reduce the ability of fluid to flow through the rock. Low permeability rocks are typically excellent candidates for stimulation by hydraulic fracturing. (DOE, 2004)

2.5.1. Dimensionless fracture conductivity:

Dimensionless fracture conductivity is one important calculation in reservoir stimulation. Calculating this parameter will allow the engineers in charge to make a better decision as to what zones to stimulate and finally accurately calculate the economical analysis for that particular frac job. To determine the optimum fracture conductivity, the design engineer should use the dimensionless fracture conductivity shown as equation 1. (DOE, 2004)

$$F_{CD} = \frac{k_f \times w_f}{k \times X_f} \dots\dots\dots 1$$

Where w_f is the fracture width (ft), k_f is the proppant permeability (md), k is the formation permeability (md), and X_f is the fracture half length (ft). The engineer needs to design the treatment to create a fracture wide enough and pump proppant at high concentration to achieve high conductivity required to optimize the treatment. There are two types of fractures. The first one is called the high (infinite conductivity) and this occurs when $F_{CD} > 100$ and in this type of fracture, no appreciable pressure loss can be found in the fracture. The second type of fracture is called low (finite) conductivity and this type of fracture occurs when $F_{CD} < 100$. (DOE, 2004)

2.5.2. Main risk in hydraulic fracturing:

One of the main risks in hydraulic fracturing is that money is spent, but for whatever reason, the well does not produce at the desired flow rates or it does not recover the expected cumulative recovery. On a lot of occasions, mechanical problems with the well or the surface equipment cause the treatment to fail. On the other hand, the reservoir does not respond as expected. (DOE, 2004)

2.5.3. Typical hydraulic fracturing procedure:

- 1) Set the bridge plug below the target interval
- 2) Perforate target interval
- 3) Perform fracture treatment
 - Pad stage (no proppant): pad is used to initiate or propagate fracture, develop adequate width and provide sacrificial fluid for leak off.
 - Slurry stage (fracturing fluid + proppant): the goal is to inject slurry with constant proppant concentration through the entire fracture length at the end of the pumping. We can achieve that by increasing the maximum proppant concentration. Please note that during the leak off (fluid), our fracture is going to get dehydrated.
 - Flush stage: Slurry is flushed to perforation.
- 4) Repeat the step at the next location
- 5) Drill out plugs
- 6) Set production tubing (Hydraulic Fracture, 2010)

Figure 8 is a visual demonstration of the Marcellus Shale hydraulic fracturing.

Figure 8. Marcellus Shale Hydraulic Fracturing (Hydraulic Fracturing, 2011)

2.5.4. Horizontal well fracturing:

Transverse Fractures:

- 1) More suitable for low permeability reservoirs
- 2) Can achieve greater contact with reservoirs and higher productivity
- 3) Have higher risk of screen out due to tortuosity
- 4) Have convergence flow around the wellbore in fracture (Hydraulic Fracture, 2010)

Longitudinal Fracture:

- 1) More suitable for high permeability reservoirs
- 2) More suitable for cases with significant convergence flow effect
- 3) Productivity equivalent to a very long fracture
- 4) Minimum convergence flow effect

For example, for Marcellus Shale, it is very important to do transverse fracture because of low permeability shale formation. (Hydraulic Fracture, 2010)

2.6. Dual Porosity Model:

For many years it was assumed that for the purpose of making engineering studies, two parameters were sufficient to describe the single phase flow properties of a producing formation (the absolute permeability and the effective porosity). More recently, it was recognized that at least one additional parameter was required to illustrate the behavior of a porous system containing regions which contributed significantly to the pore volume but contributed negligibly to the flow capacity. Microscopically, these regions could be “dead end” or storage pores or macroscopically, they could be discrete volumes of low permeability matrix rock combined with natural fissures in a reservoir. These two classes of porosity can be described as follows,

- 1) **Primary porosity:** is intergranular and controlled by deposition and lithification. It is highly interconnected and typically can be correlated with permeability since it is largely dependent on the geometry, size distribution, and spatial distribution of the grains. The void systems of sand, sandstones, and oolitic limestones are typical of this type. (Root, The behavior of naturally fractured reservoirs, 1963)

- 2) **Secondary porosity:** is controlled by fracturing, jointing and/or solution in circular water although it may be modified by in-filling as a result of precipitation. It is not highly interconnected and cannot be correlated with permeability. Joints or fissures which occur in massive, extensive formations composed of shale, siltstone, schist, limestone or dolomite are generally vertical and they are recognized to tensional failures during mechanical deformation. Shrinkage cracks are the result of a chemical process (dolomitization) and do not appear to have any preferred orientation. (Root, The behavior of naturally fractured reservoirs, 1963)

In most general case, both classes of porosity are present and the internal void volume of the rock is intermediate in nature, i.e, an independent system of secondary porosity is superimposed on the primary system. When modeling the dual porosity, all matrix blocks are homogenous, and they have the same size.

As can be seen in Figure 9, Matrix porosity contains bigger part of the reservoir while the natural fracture porosity has smaller porosity in the system. In real life, the distribution of natural fracture is not the same throughout the reservoir, however as previously mentioned dual porosity model assumes that all the matrix blocks are homogeneous and have the same size. Fracture porosity is basically what percent of the bulk volume is naturally fractured.(Aminian, 2011)

Figure 9 is a visual representation of how matrix and fracture porosity are distributed in the reservoir.

In dual porosity reservoir, fluids exist in two interconnected systems.

- 1) The rock matrix, which usually provides the bulk of the reservoir volume
- 2) The highly permeable rock fractures

Figure 9. Actual Reservoir Vs Model Reservoir (Root, The behavior of naturally fractured reservoirs, 1963)

If the matrix blocks are linked only through the fracture system, this conventionally could be regarded as a dual porosity single permeability system, since fluid flow through the reservoir takes place only in the fracture network with matrix blocks acting as sources. If there is a possibility of flow directly between neighboring matrix blocks, this is conventionally considered to be a dual porosity dual permeability system. It should be noted that dual porosity dual permeability runs are computationally more expensive than dual porosity single permeability runs. To model such systems, two simulation cells are associated with each block in the geometric grid, representing the matrix and fracture volumes of the cell. In ECLIPSE the porosity, permeability, depth etc. of these may be independently defined (Schlumberger, 2009)

Typically, natural fractures have a lower porosity compared to matrix and as a result, they are capable of storing relatively small fraction of reservoir hydrocarbons. In dual porosity systems, the natural fractures have much higher permeability than the matrix. When the well begins to

flow, fluid travels from high permeability natural fractures to wellbore and is quickly produced. Once the natural fractures have been drained, the large volumes of hydrocarbon contained within the bulk of your reservoir (refers to as matrix) starts to flow. These hydrocarbons flow to natural fractures and then transported to the wellbore via these fractures. (Root, 1963)

2.6.1. Interporosity flow coefficient:

Interporosity flow coefficient refers to the ability of the matrix to flow into fissures and can be calculated using equation 2. (Aminian, 2011)

$$\lambda = \alpha \times r_w^2 \times \frac{k_m}{k_f} \dots\dots\dots 2$$

$$\alpha = \frac{n(n+2)}{r_m^2}$$

$$r_m = \frac{\text{Volume of Matrix Block}}{\text{Surface Area of Matrix Block}}$$

As shown in figure 10, as the interporosity flow coefficient decreases, the transition between the two semi-log straight lines is delayed. This indicates the larger fracture permeability in a comparison to the matrix and basically the more natural fractures will have to drain before the contribution from the matrix becomes significant. . (Root, 1963)

There are two types of interporosity flow which are used to model dual porosity system,

- 1) Pseudo-steady state interporosity flow: This is the most common dual porosity used. This type of interporosity flow considers the presence of minerals in the fissure network that reduces the flow from matrix to fissures. The restricted interporosity flow is also called

the pseudo steady state interporosity flow model, or Warren and Root model. (Root, 1963)

- 2) Transient interporosity flow: this type of interporosity flow considers no flow restriction at the matrix-fissure interface and matrix blocks response starts earlier. The unrestricted interporosity flow model is also called transient interporosity flow model. Some dual porosity systems are considered to have transient interporosity flow with an interporosity skin rather than the more popular pseudo-steady state interporosity flow. This is a distributed parameter model and assumes that the flow between the two porosities is a transient mode and that a positive skin exists at the interface between the two porosities. If this skin is large, then the transient model becomes equivalent to the pseudo-steady state. . (Root, 1963)

Figure 10. Interporosity Flow Coefficient (Root, 1963)

2.6.2. The storativity ratio:

The storativity ratio expresses the contribution of fissured system to total storativity and can be calculated using the equation 3. (Aminian, 2011)

$$w = \frac{(\phi \times V \times C \times t) f}{(\phi \times V \times C \times t) f + (\phi \times V \times C \times t) m} \dots \dots \dots 3$$

Fissured Formations: $w = 10^{-3}$ to 10^{-2}

Multilayered Formations: $w = 10^{-1}$

This parameter essentially represents the time separation in log cycles between the two semi-log straight lines as shown in Figure 11.

Figure 11. Log Cycle Separation (Root, 1963)

A storativity of 1 is a single porosity system with all of the reserves inside the fractures and a storativity approaching 0 is a single porosity reservoir with all the reserves in the matrix. So, as the storativity ratio decreases, a greater portion of reserves are contained in the matrix and the longer it takes for the matrix and fracture system to reach a state of equilibrium. Figure 13 illustrates this concept.

Figure 12. Storativity Illustration (Root, 1963)

Chapter 3

Methodology

The purpose of this thesis is to analyze the production potential of Marcellus shale using actual field data. Since Marcellus shale has not been producing for a long period of time and has been only recently recoverable, this thesis will focus on the future performance of the Marcellus Shale formations for both vertical and horizontal wells for the next 30 years using history matching. In order to achieve the above objective the followings steps have been taken:

- 1) Gathering vertical and horizontal production data**
- 2) Production data plot**
- 3) Development of base model**
- 4) History matching**
- 5) Development of final vertical and horizontal models**
- 6) Estimation of the recovery for horizontal and vertical wells**

3.1. Gathering vertical and horizontal production data:

This step is gathering production data for vertical and horizontal Marcellus Shale that has a reasonable decline curve. In this step, the West Virginia Geological Survey is used to gather all of the necessary production data for the Marcellus Shale formation. There are hundreds of vertical wells illustrated on their website; however a minority of the wells are located in the Marcellus Shale zones. The production rate for some of the formations appeared to be low. One of the reasons for such a low production could be that these wells were not hydraulically fractured when this information was recorded. In addition, some wells have a low production history. For instance, the production starts in January and ends in April. This amount of

production time (e.g. 4 months) is not enough data to be used for an accurate history matching and as a result they will not be used. After plotting some of the vertical wells they appear to have an abundance of fluctuations. This can be for a number of reasons including changing bottom hole pressures, equipment problems, and so forth. For this particular thesis 9 vertical wells that have the longest and smoothest production history are selected.

There are approximately 51 horizontal Marcellus Shale wells available in the West Virginia Geological Survey. The production data for majority of these horizontal wells are either unavailable or incomplete with too many fluctuations. After analyzing the data of these 51 wells only 3 had a long enough production history to be used for this thesis. Thus 3 horizontal wells with longest and smoothest production data are selected to work on.

The completion data for some of the vertical and horizontal wells are provided. However, the logging data is missing for the majority of the vertical and horizontal wells with the smoothest and longest production history. Gathering this information is the most tedious step that needs to be done. **(APPENDIX B)**

3.2. Production Data Plot:

As the reservoir is being produced the pressure decreases and gas production rate declines as a function of time. In this step the production plot for each vertical and horizontal well is plotted to demonstrate the rate at which each well is declining. Typically the production plots used in this thesis are from 1 to 3 years for both vertical and horizontal wells. **(APPENDIX C)**

3.3. Creation of base model:

Using the literature (SPE papers, Field representatives, etc.) a base model for vertical and horizontal wells is established. A base model is an essential part of this thesis because it will be used to build the shale model for vertical and horizontal wells. A dual porosity model is used for all of the runs since this is an unconventional shale performance analysis. In the model definition two phases (gas and water) are used with 1) the employment of non-equilibrium initialization, 2) the included shale properties, and 3) the instant adsorption model. This model is run for 30 years not only to have an understanding of the early and late part of each parameter, but also to predict the future behavior of the reservoir for the next 30 years.

5 layers of production for the Marcellus shale have been assumed for all the runs to see the impact of the natural fracture, matrix permeability, and porosity as much as possible in the production results. In addition, the length and width of the reservoir depends on the drainage area, which is assumed based on the real field production data from vertical and horizontal wells. Furthermore, thicknesses of the reservoir are available for some of the vertical and horizontal wells using the “Pay Zone” data from the West Virginia Geological Survey Website. For the wells with thicknesses that are not provided, the Marcellus Shale thickness map in West Virginia is used to estimate the thickness. After going through multiple SPE papers, natural fracture porosity and permeability parameters have been defined. Since all the real field production data available for the vertical and horizontal wells have about 1 to 3 years of production history and the production duration is very short, hydraulic fracture porosity will not have much impact on the initial production for vertical wells. Please note that the natural fracture and matrix permeability in z direction are 1/10 of the x and y direction because of overburden and

compaction pressure which cause the permeability in z direction to be 1/10 lower than x and y directions.

Table 1. Basic Model Parameter

Basic Model Parameters	
Reservoir Parameters	
Depth, ft	7000
Thickness, ft	75
Rock Properties	
Porosity type	Dual
Fracture Porosity, fraction	0.005
Matrix porosity, fraction	0.05
Fracture perm, l, j, k, md	0.002, 0.002, 0.0002
Matrix perm, l, j, k, md	0.0002, 0.0002, 0.0002
Coal Compress, 1/psia	1×10^{-5}
Density, lb/ft ³	100
Initial Conditions	
Reservoir pressure, psia	3500
Water saturation, fraction	0.15
Hydraulic Fractures Properties	
Half length, ft	500
Width, in	0.01
Top of Fracture, ft	7000
Bottom of Fracture, ft	7075
porosity, fraction	0.2
Well Production Controls	
P_{wf} , psia	500
Fluid Properties	
Standard Pressure, psia	14.7
Standard Temperature, °F	60
Reference Temperature, °F	120
Adsorption	
Gas Diffusion Coefficient, ft ² /day	1
Sorption Time, day	62
Langmuir Pressure, psia	635
Langmuir Concentration, MSCF/ton	0.08899

The Initial Reservoir Condition is based upon the Total Vertical Depth which is about 7000 ft for the Marcellus shale around counties selected for this project. Based on the depth the initial reservoir pressure can be estimated using the hydrostatic pressure relationship. In addition, the water saturation is set to be 15% for all simulation runs.

Hydraulic fracture properties are assumed after discussing the issue with different companies exploring hydraulic fracturing and also based on the literature review of different SPE papers. More than anything else the hydraulic fracture properties usually impact the initial production. For example changing the permeability of the hydraulic fracture of any of the wells would yield a significant change in the initial production.

Bottom hole pressure production control mode is necessary in reservoir simulation because below that pressure all simulation runs will be terminated. The above value is a typical minimum bottom hole pressure and most companies usually drain the reservoir to 500 psia after so many years of production.

Finally the fluid properties are created for the base model. In a shale reservoir there are two types of gas. The first type of gas is called the free gas which can be obtained in a conventional reservoir as well as an unconventional reservoir. Free gas exists in the reservoir in the gaseous phase rather than in a solution. As soon as the formation pressure drops below the bubble point the gas is evolved. The gas is referred to as free gas while it is in the reservoir. The second type of gas, which separates the shale formation from other conventional reservoirs, is sorbed gas. The gas accumulates on the surface of a solid material such as reservoir rock grains or more pertinently organic particles in a shale reservoir. Measuring the adsorbed gas and

interstitial gas (**i.e.** gas contained in formation pores) allows for the calculation of the gas in place in a given reservoir. (Schlumberegr, 2011)

Langmuir Concentration refers to the gas content in the reservoir. Its unit of measurement for the unconventional gas in place calculation is SCF/U.S. Langmuir pressure constant (P_L) represents the pressure at which the gas storage capacity equals one half of the maximum storage capacity (V_L). Finally, sorption time is the time required to desorb 63.2% of the initial gas volume. (Aminian, Fundamental Concept of Coalbed Methane)

By inputting all of the above adsorption parameters into the model the simulation can calculate the gas content (SCF/TON), and finally initial gas in place using Equation 4.

3.3.1. Gas in place calculation for unconventional shale formations:

Gas in place can be calculated using equation 4 which contains free gas and sorbed gas.

$$G_{i, \text{free}} + G_{i, \text{sorbed}} = Ah \left[\frac{43560 \times \phi \times (1 - S_w)}{B_{gi}} \right] + 1.359 \times A \times h \times \rho_c \times G_c \dots\dots\dots 4$$

$G_{i, \text{free}}$ = free gas in place at initial reservoir condition, MSCF

$G_{i, \text{sorbed}}$ = sorbed gas in place, MCF

A = reservoir drainage area, acres

h = reservoir net thickness

ϕ = effective fracture porosity, fraction

S_w = initial water saturation in the fracture, fraction

B_{gi} = gas formation volume factor at P_i , ft^3/Mscf

A= reservoir drainage area, acres

h=reservoir net thickness

G_c = Ave in-situ gas content, SCF/ton

P_c = average coal density, g/cc

3.4.History Matching:

By varying parameters including the reservoir drainage area, natural fracture permeability, natural fracture porosity, fracture half length, hydraulic fracture permeability, hydraulic fracture porosity, number of fractures, and flowing bottom hole pressure, each vertical and horizontal well is historically matched. In this part of the project reservoir simulation is used to create 9 models for vertical wells and 3 models for horizontal wells based on the base model parameters illustrated in Table 1. Various parameters need to be altered in each specific model in order to historically match the real field production data for vertical and horizontal wells. More than 500 runs have been performed using Eclipse in order to match each and every well as accurately as possible. In this step the impact of each mentioned parameter on the production curve is recorded to have a better understanding of the dual porosity system and shale formations.

3.5.Creation of final vertical and horizontal models:

Various parameters are used for each vertical and horizontal model. This step is one of the most important steps of the thesis because the final models for both vertical and horizontal wells are going to be built based on all of the designed vertical and horizontal models. For instance, each vertical model created has a different natural fracture permeability. After arranging all of the natural fracture permeabilities and formatting them as a table, the most commonly used

natural fracture permeability is identified and used for the vertical model. For instance, If the most commonly used natural fracture permeability for all the 9 vertical wells is 0.002md, then this permeability is used when creating the final vertical model. The rest of the parameters for the final vertical and horizontal models are found using the same procedure.

3.6.Estimation of the recovery for horizontal and vertical wells:

Finally, one vertical and one horizontal model with the most frequently repeated parameters is run in Eclipse to yield the final results for this thesis and to distinguish the future behavior of the reservoir for the next thirty years. These results include the recoverable reserves and recovery factor for both horizontal and vertical wells after thirty years. In addition, the results can be used to compare the productivity of vertical Marcellus Shale with horizontal Marcellus Shale.

Chapter 4

Results and Discussions

There are 9 vertical and 3 horizontal wells studied in this thesis. I have illustrated 1 vertical and 1 horizontal well that have been historically matched in this thesis. The first well illustrated below is vertical and the second well is horizontal. Both wells are located in Upshur County. The rest of the wells are illustrated in **Appendix D** with explanation for each history match.

4.1. Vertical #2:

The second well studied in this thesis is located in Upshur County. The acreage for this well is assumed to be 80 acres and the thickness was obtained from the completion data as 47 ft. In addition, a square reservoir is assumed for this reservoir with dimensions of 1867×1867 (ft²). Both the initial and final parameters used for getting a match are listed in Table 2.

To get a match natural fracture permeability had to be increased from 0.002 md to 0.004 md in order for the curve to shift upward. By increasing the natural fracture permeability, the entire decline curve shifts upward. In addition, natural fracture porosity had to be increased as well (from 0.005 to 0.009) in order to increase the numbers of natural fractures that exist in the dual porosity model and as a result increasing the initial production. It was observed that when altering the natural fracture porosity it does not have huge impact on the production decline curve and its little impact is only visible at the beginning of the production.

Table 2. Initial and final values of the parameters for vertical #2

Initial values of the parameters			Final values of the parameters after the match		
Area	120	acres	Area	80	acres
Top of fracture	7053	ft	Top of fracture	7053	ft
Bottom of fracture	7100	ft	Bottom of fracture	7100	ft
Thickness	47	ft	Thickness	47	ft
Fracture porosity	0.005	fraction	Fracture porosity	0.009	fraction
Matrix porosity	0.05	fraction	Matrix porosity	0.05	fraction
Fracture permeability	0.002	md	Fracture permeability	0.004	md
Dimensions	2286*2286	ft ²	Dimensions	1867*1867	ft ²
Matrix permeability	0.0002	md	Matrix permeability	0.0002	md
Rock Density	100	lb/ft ³	Rock Density	100	lb/ft ³
Pressure	3500	psia	Pressure	3500	psia
S _w	15	%	S _w	15	%
Hydraulic Fracture			Hydraulic Fracture		
Half length	500	ft	Half length	500	ft
permeability	20000	md	permeability	20000	md
porosity	20	%	porosity	20	%
width	0.01	inch	width	0.01	inch

The area of the squared reservoir was decreased from 120 acres to 80 acres. Since real field production data for this specific well was initially high compared with other vertical wells, a higher acreage was assumed for this reservoir to increase the recoverable reserve. However, after reducing the acreage down to 80 acres (which is a common acreage for vertical wells), it was determined that the recoverable reserves does not reduce by much compared to the 120 acres. Therefore assigning a higher drainage area for this well because of higher production data is not accurate. By reducing the acreage the recoverable reserve does not change much, which means assigning 80 acres would be sufficient for the reservoir to be drained. Furthermore, if 120 acres is chosen for this particular well it will decrease the recovery factor by a huge amount since the initial gas in place will be drastically increased. This change in recovery factor is not accurate

and cannot be done. Figure 14 illustrates the procedure that caused a match for the second vertical well.

Figure 13. History Matching for Vertical #2

Please note that performing other runs and changing parameters could be used to come up with a match. However, the above match is only one way of getting the match with approximate parameters from the Marcellus Shale in West Virginia. After running different simulation runs Figure 14 is the match for the second vertical well.

4.2. Horizontal #1:

The first horizontal well studied for this thesis is located in Upshur County. The acreage for this well is assumed to be 220 acres and the thickness was obtained from the thickness map of Upshur County as 75 ft. In addition, a rectangular reservoir is assumed for this reservoir with dimensions of 4800*2000 (ft^2). The length of the horizontal segment of this reservoir is 3499 ft is provided in the well data section of West Virginia Geological Survey website. Both initial and final parameters used for getting a match are listed in Table 3.

Figure 14. Final Match for Vertical #2

As can be seen in Table 3, the fracture permeability is reduced to 0.001 md compared to the base model which was 0.002 md. Also, numbers of stages (numbers of hydraulic fractures) have increased to meet the criteria. 500 ft equally fractured spacing is assumed for this reservoir. Fracture half length is reduced from 500 ft to 300 ft in order for the production decline curve to go down. In addition, the model assumes an extraordinary amount of hydrocarbon in the natural fracture when having multiple numbers of hydraulic fractures. Thus in order for the model to adjust accurately it is imperative to reduce the hydraulic fracture permeability and porosity to 10,000 md and 10%. In this scenario the model assumes reasonable amount of gas in the natural fractures and the initial production curve goes down after changing the hydraulic fracture permeability and porosity.

Finally, for this specific well the production decline trend has increased after 7 months of production instead of having a normal decline trend. This indicates a change in minimum bottom hole pressure, which can cause this increase in production. As a result to adjust for this change

minimum bottom hole pressure is assumed to be 800 psia for 7 months and after that it has been reduced to 400 psia to account for an increase in production.

Table 3. Initial and final values of the parameters for horizontal #1

Initial values of the parameters		
Horizontal length	3499	ft
acreage	220	acres
Top of fracture	7000	ft
Bottom of fracture	7075	ft
Thickness	75	ft
Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.002	md
Dimensions	4800*2000	ft^2
Matrix perm	0.0002	md
Rock Density	100	lb/ft^3
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture	Seven	Stages
Half length	500	ft
permeability	20,000	md
porosity	20	%
width	0.01	inch
Bottom Hole Pressure		
P_{wf}	500	psia

Final values of the parameters after the match		
Horizontal length	3499	ft
acreage	220	acres
Top of fracture	7000	ft
Bottom of fracture	7075	ft
Thickness	75	ft
Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.001	md
Dimensions	4800*2000	ft^2
Matrix perm	0.0002	md
Rock Density	100	lb/ft^3
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture	Seven	Stages
Half length	300	ft
permeability	10,000	md
porosity	10	%
width	0.01	inch
Bottom Hole Pressure		
P_{wf} (01/01/1981)	800	psia
P_{wf} (07/01/1981)	400	psia

Figure 15 is a visual illustration of having different reservoir and hydraulic fracture parameters. Figure 15 demonstrates that using incremental pressure is essential to get a match for this case since after about 210 days the production decline increases. In addition, natural fracture permeability is reduced to 0.001 md to meet the real field data requirements.

Figure 15. History Matching for Horizontal #1

Figure 16 is the match that was obtained for the first horizontal well.

Figure 16. Final Match for Horizontal #1

As can be seen in Figure 17 the model is assumed to be horizontal with seven stages of hydraulic fracturing. The horizontal well is assumed to be in the middle of reservoir which means it was placed in the y-direction and half of the reservoir width. The green color in the model indicates that it was successfully perforated and hydraulically fractured.

Figure 18 is a visual representation of the model.

Figure 17. Horizontal Model #1 Illustration

4.3. Final Vertical and Horizontal Model Selection:

One of the objectives of this thesis is to come up with a final model for one vertical and one horizontal well based on the previous studied vertical and horizontal wells. The vertical and horizontal well parameters developed can be used for real field application. After building the new vertical and horizontal models these two models can be run in order to understand the recovery factor and reserves for both the vertical and horizontal wells after 30 years.

Table 4 shows the final parameters for all of the vertical and horizontal wells used to history match.

Well #	Horizontal L (ft)	County	Area (acres)	Dimensions (ft^2)
Vertical #1	None	Upshur	80	1867*1867
Vertical #2	None	Upshur	80	1867*1867
Vertical #3	None	Upshur	80	1867*1867
Vertical #4	None	Doddridge	80	1867*1867
Vertical #5	None	Harrison	80	1867*1867
Vertical #6	None	Upshur	40	1320*1320
Vertical #7	None	Doddridge	80	1867*1867
Vertical #8	None	Doddridge	40	1320*1320
Vertical #9	None	Doddridge	80	1867*1867
Horizontal #1	3500	Upshur	220	4800*2000
Horizontal #2	1812	Upshur	151	3624*1812
Horizontal #3	2727	Marshall	216	4700*2000

Well #	Thickness (ft)	Natural fracture por	Natural fracture K (md)	Pwf (psia)
Vertical #1	50	0.005	0.002	500
Vertical #2	47	0.009	0.004	500
Vertical #3	57	0.005	0.002	500
Vertical #4	38	0.005	0.002	500
Vertical #5	80	0.005	0.001	500
Vertical #6	80	0.005	0.0006	500
Vertical #7	50	0.005	0.001	500
Vertical #8	47	0.003	0.002	700
Vertical #9	50	0.005	0.003	500
Horizontal #1	75	0.005	0.001	800 to 400
Horizontal #2	75	0.005	0.002	800 to 600
Horizontal #3	60	0.005	0.004	400

Well #	Hydraulic Fracture Properties				
	K (md)	Porosity (%)	width (in)	half length (ft)	# of fracs
Vertical #1	20000	20	0.01	500	1
Vertical #2	20000	20	0.01	500	1
Vertical #3	20000	20	0.01	500	1
Vertical #4	12000	20	0.01	500	1
Vertical #5	13000	20	0.01	500	1
Vertical #6	15000	20	0.01	500	1
Vertical #7	10000	20	0.01	500	1
Vertical #8	10000	20	0.01	200	1
Vertical #9	20000	20	0.01	500	1
Horizontal #1	10000	10	0.01	300	7
Horizontal #2	10000	10	0.01	350	4
Horizontal #3	20000	20	0.01	500	6

Table 4. Final Parameters for Horizontal and Vertical Wells

4.4. Final Vertical Model:

Using carefully selected parameters from the 9 vertical wells and 3 horizontal wells (Table 4) two models have been created. The first final model is a vertical well. It is based on the most repetitive parameters used for each of the 9 vertical wells. For example, an 80 acre reservoir has been used most frequently for the 9 vertical wells studied in this thesis. As a result an 80 acre reservoir parameter has been used to create for this final vertical model. All the parameters for the final vertical model have been selected using the same selection process. Table 5 illustrates the parameters for the final vertical model.

Table 5. Final Vertical Parameters

Final Vertical Model		
Area	80	acres
Top of fracture	7000	ft
Bottom of fracture	7055	ft
Thickness	55	ft
Fracture porosity	0.005	
Matrix porosity	0.05	
Fracture permeability	0.002	md
Dimensions	1867*1867	ft^2
Matrix permeability	0.0002	md
Rock Density	100	lb/ft^3
Initial Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	10,000	md
porosity	20	%
width	0.01	inch
Minimum Pwf	500	psia

After running the above vertical model, decline curve, cumulative production, and initial gas in place can be obtained.

Figure 18. Final Production Rate Behavior for Vertical Model

Figure 19. Final Cumulative Production Behavior for Vertical Model

In addition, recovery factor after 10, 20, and 30 years can be calculated and is shown in Table 6.

Table 6. Recovery Factor for Final Vertical Model

Time (years)	EUR (MSCF)	IGIP (MSCF)	RF
10.02	433,171.25	2,101,226.80	20.62
20.00	675,268.69	2,101,226.80	32.14
29.91	860,898.88	2,101,226.80	40.97

Therefore, after 30 years on average, vertical wells produce 860,898.88 MSCF with about 41% recovery.

4.5. Final Horizontal Model:

The same analysis can be done for horizontal wells. After reviewing all of the horizontal wells studied in this thesis, the parameters in Table 7 have been chosen to be run in Eclipse.

After running the parameters shown in Table 7, the production curve and cumulative production in Figure 20 and 21 are obtained.

Table 7. Final Horizontal Parameters

Horizontal Model		
Horizontal length	3500	ft
Area	216	acres
Top of fracture	7000	ft
Bottom of fracture	7075	ft
Thickness	75	ft
Fracture porosity	0.005	
Matrix porosity	0.05	
Fracture perm	0.002	md
Dimensions	4700*2000	ft^2
Matrix perm	0.0002	md
Rock Density	100	lb/ft^3
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	10,000	md
porosity	20	%
width	0.01	inch
# of stages	7	stages

Figure 20. Final Production Rate Behavior for Horizontal Model

Figure 21. Final Cumulative Production Behavior for Horizontal Model

In addition, recovery factor after 10, 20, and 30 years can be calculated,

Table 8. Recovery Factor for Final Horizontal Model

Time (years)	EUR (MSCF)	IGIP (MSCF)	RF
10.015059	3,311,735.30	7,722,280.00	42.89
20.004107	4,316,199.50	7,722,280.00	55.89
29.913757	4,947,622.00	7,722,280.00	64.07

So, after 30 years, on average, horizontal wells produce 4,947,622.00 MSCF with approximately 64% recovery.

Chapter 5

Conclusions

The objective of this thesis is to predict the future performance of the reservoir for both vertical and horizontal wells using the real field data. 9 vertical and 3 horizontal wells have been studied to better understand the importance of each parameter in the model generated in Eclipse. Some conclusions that can be made from this thesis are:

- 1) Natural fracture permeability has a significant impact on the production;
- 2) Natural fracture porosity has little impact on the initial production of the reservoir;
- 3) Hydraulic fracture properties are essential in increasing the production. First of all, the fracture half-length has a significant effect on the production. The fracture half-length primarily impacts the early production. Hydraulic fracture permeability only affects the initial production and it has no impact on the later part of the production. Finally, hydraulic fracture porosity's impact occurs during later production period as numbers of hydraulic fracturing stages increases;
- 4) After analyzing the production history from 9 vertical wells, the suggested parameters for vertical wells in Marcellus Shale are listed in Table 5.
- 5) After studying and exploring 3 horizontal wells the suggested parameters for horizontal wells in Marcellus shale are listed in Table 7.
- 6) When comparing the recoverable reserve per acreage horizontal wells produce approximately **22,905.66 MSCF/acre** while vertical wells produce **10,761.24 MSCF/acre** after 30 years;
- 7) The recoverable reserve for horizontal well is approximately **4.9 BCF** while the recoverable reserve for vertical wells is nearly **0.86 BCF** after 30 years.

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Appendix A

Appendix A demonstrates the Schlumberger Eclipse software used to Model the Marcellus shale. To achieve this goal, a coal bed methane template was used to enter the shale properties for all the cases that have been shown throughout this thesis. A sequential procedure to run the software is shown below.

(Figure A-1. Eclipse launcher main screen)

Figure A-1 is the Eclipse Launcher which is used in order to open the template tab. Once here, the “office” tab should be selected. Then “Startup Directory” would appear and the user can choose the location of files to be saved. As shown in the below image, in this example, 2009.1 version of the software is used to run the model. All the runs were made in 2009.1 Model.

(Figure A-2. Eclipse launcher main screen)

Once office window is open, the user must select “File” and then “New Project.” If the file has been saved before, then “Open Project” tab can be used instead (Figure A-3).

(Figure A-3. Eclipse office screen)

Once the new project is selected, the file name is entered and saved in the directory. Please notice that the file name has a default extension type of “.off” for the office program (Figure A-4)

(Figure A-4. Eclipse file directory screen)

Once eclipse office is launched and the specific file is selected, a template case can be added. This feature will allow the user to select from different types of reservoirs and casing. Then “Add Template Case” is selected and that will let the user select “Template Model” (Figure A-5).

(Figure A-5. Eclipse add template case screen)

Figure A-6 shows four template cases available in the program. These cases contain “Single Well Radial”, “Completion Modeling Tool”, “Coal Bed Methane”, and “CO2 Sequestration.” In addition to the “Template Model”, name and unit of the case can be selected as well.

Based on discussions with programming experts, the use of parameters in the coal bed methane template was recommended to correctly model shale gas reservoir. This is because shale has the two forms of flow, both the conventional “free” gas and as adsorbed gas. Field units and the coal bed methane template were selected from this project. (T.Schweizer, 2009)

(Figure A-6. Eclipse template model selection screen)

Once the coal bed methane template is chosen, the model can be edited after completing each required data. If there is any missing data in any section of the template, it would not let the user continue to the next page until the mentioned data is corrected. It is very important to enter the stimulation and reporting data. For all the runs, the starting time is entered to be January 1, 1981, and the ending time is entered to be January 1, 2010. Furthermore, the report interval is 31 days for the total stimulation time of 29 years. For the model parameters section, “Dry Gas” phase has been selected for the “Single Porosity Model” and “Dry Gas” and “Water” for the “Dual Porosity Model.” In addition, for the “Dual Porosity Model” the following parameters have been chosen:

- 1) Model employs non-equilibrium initialization
- 2) Coal defined on unit weight basis with ash and moisture content
- 3) Include Shale Properties
- 4) Instant Adsorption Model
- 5) Use Compositional Model

Dual Porosity Model:

The screenshot displays the 'Coal Bed Methane Modeling Tool - ECLIPSE Office' interface. On the left, a 'Workflow' pane lists various sections: Model Definition (selected), Reservoir Description, Wells, Production, Fluid Properties, Simulation Controls, and Economics. Below this are buttons for 'Generate Model', 'Run ECLIPSE', and 'View Results'. The main workspace is divided into two primary sections: 'Simulation Length and Reporting' and 'Model Parameters'. The 'Simulation Length and Reporting' section contains input fields for 'Start Day' (1), 'Start Month' (JAN), 'Start Year' (1980), 'End Day' (1), 'End Month' (JAN), 'End Year' (2009), and 'Report Interval' (31 day). The 'Model Parameters' section features a 'Phases' dropdown menu set to 'Gas & Water', a series of checkboxes for various model options (most are checked), and a 'Gas Injection' section with radio buttons for 'None', 'CO2', 'N2', and 'General'. At the bottom of the main workspace are 'Apply' and 'Help' buttons.

(Figure A-7. Eclipse model definition screen)

After completing “Model Definition” section, the next section that should be completed is called “Reservoir Description.” There are five different tabs in this section and in sequence they

are called, “Layer”, “Rock Properties”, “Non-Equilibrium Initial Condition”, “Aquifer”, and “Fractures.”

Under the layer name, each layer is called Layer+ number of the layer. Each Run that has been generated used certain amount of layers. For the most part, there is either 1 layer of 75 ft or 5 layers of 15 ft which adds up to 75 ft. The rock name is simply called reservoir. For “Top Depth Left Face” and “Top Depth Right Face” values in feet were taken from specific location with an approximate depth of 7000 ft and zero horizontal displacement due to the small size of the modeled reservoir. Different types of reservoir acreages have been chosen depending on the location and drainage area of each specific horizontal or vertical well. For horizontal wells, a rectangular reservoir is assumed whereas for vertical wells, a square reservoir is generated.

Below is just a visual illustration for the value imputed for one random well. In the below example, the drainage area is assumed to be $4000 \times 1000 / 43560 = 92$ acres and as previously mentioned, this drainage area can be different depending on location and lithology of each specific well.

Coal Bed Methane Modeling Tool - ECLIPSE Office

File Help

Workflow

- Model Definition
- Reservoir Description
- Wells
- Production
- Fluid Properties
- Simulation Controls
- Economics

Generate Model

Run ECLIPSE

View Results

Layers

Row	Layer Name	Rock Name	Top Depth Left Face (ft)	Top Depth Right F (ft)	Horiz. Disp. (ft)	Thickness (ft)	Length (ft)	Width (ft)	+
1	layer1	RESERVOIR	7000	7000	0	15	4000	1000	▲
2	layer2	RESERVOIR	7015	7015	0	15	4000	1000	
3	layer3	RESERVOIR	7030	7030	0	15	4000	1000	
4	layer4	RESERVOIR	7045	7045	0	15	4000	1000	
5	layer5	RESERVOIR	7060	7060	0	15	4000	1000	
6									
7									
8									

Apply Help

(Figure A-8. Reservoir description for layers screen)

The “Layers” tab is followed by the “Rock Properties” on the reservoir description workflow.

For “Single Porosity Model,” specific porosity is entered and by default the z direction porosity is $1/10^{\text{th}}$ of the x and y direction because of overburden pressure and compaction stress in the z direction which causes the porosity to be less in that direction.

For “Dual Porosity Model,” since matrix porosity is bigger than fracture porosity, the matrix porosity is entered as 0.05 and fracture porosity is 0.005. In addition, fracture permeability varies for each well and does not stay constant for all the runs.

Single Porosity Model:

The screenshot displays the 'Coal Bed Methane Modeling Tool - ECLIPSE Office' window. The interface includes a menu bar (File, Help), a workflow tree on the left, and a main panel with tabs for Layers, Rock Properties, Initial Conditions, Aquifers, and Fractures. The 'Rock Properties' tab is active, showing a table for defining properties for individual coal types. The table has columns for Row, Rock Name, Fracture Porosity, Bulk X-dir Perm. (mD), Bulk Y-dir Perm. (mD), Bulk Z-dir Perm. (mD), and Coal Compress. (/psi). The first row is labeled 'RESERVOIR' and contains values: 0.05, 0.001, 0.001, and 0.0001. The remaining rows are empty. Navigation buttons like '<< Previous Page' and 'Next Page >>' are visible above the table. At the bottom, there are 'Apply' and 'Help' buttons.

Workflow

- Model Definition
- Reservoir Description
- Wells
- Production
- Fluid Properties
- Simulation Controls
- Economics

Generate Model

Run ECLIPSE

View Results

Layers | **Rock Properties** | Initial Conditions | Aquifers | Fractures

<< Previous Page | Next Page >>

Rock Properties

Define properties for individual coal types.

Row	Rock Name	Fracture Porosity	Bulk X-dir Perm. (mD)	Bulk Y-dir Perm. (mD)	Bulk Z-dir Perm. (mD)	Coal Compress. (/psi)
1	RESERVOIR	0.05	0.001	0.001	0.0001	1E-6
2						
3						
4						
5						
6						
7						

Apply | Help

(Figure A-9. Reservoir description for rock properties screen)

Dual Porosity Model:

Coal Bed Methane Modeling Tool - ECLIPSE Office

File Help

Workflow

- Model Definition
- Reservoir Description
- Wells
- Production
- Fluid Properties
- Simulation Controls
- Economics

Generate Model

Run ECLIPSE

View Results

Layers Rock Properties Non-Equilibrium Initial Conditions Aquifers Fractures

<< Previous Page Next Page >>

Rock Properties

Define properties for individual coal types.

Row	Rock Name	Fracture Poro	Bulk X-dir Per (mD)	Bulk Y-dir Per (mD)	Bulk Z-dir Per (mD)	Matrix Porosit (mD)	Matrix Perm. x (mD)	Matrix Perm. y (mD)	Matrix Perm. z (mD)	Matrix-Frac. Sigma (/ft ²)	Coal Compres (/psi)	Rock Density (lb./ft. ³)
1	RESERVOIR	0.005	0.002	0.002	0.0002	0.05	0.0002	0.0002	2E-5	0.0073000029	1E-6	100
2												
3												
4												
5												
6												

Apply Help

Enter the coal type name

(Figure A-9. Reservoir description for rock properties screen)

Figure A-10 shows the non-equilibrium initial conditions section of the reservoir description. Only two data values are inputted for the initial reservoir pressure and water saturation.

(Figure A-10. Reservoir description for initial condition screen)

The next section of the reservoir description is called aquifer has not been used in this thesis but it is included to show a complete description of properties in the reservoir.

(Figure A-11. Reservoir description for aquifer screen)

Figure A-12 shows the fractures tab for reservoir description. Number of hydraulic fractures varies depending on the well. Usually for the vertical wells, one hydraulic fracture is used to generate the history matching, however for horizontal wells up to 7 fractures have been defined in the model to see the their impact on the initial production data.

X center refers to the segment of the horizontal section that needs to be fractured and Y center is the location of the horizontal well which is the in the middle of the specific formation. For example, if the width of the reservoir (which was defined in the layers section) is 2000 ft, Y center will be 1000 ft. Half length, fracture width, fracture porosity, and fracture permeability can be defined for any particular well.

(Figure A-12. Reservoir description for fractures screen)

Next section is to place the vertical and horizontal well and define a hole diameter. In this particular horizontal case, the vertical well starts from 1000 ft and it extends up to the middle of the reservoir's width (which is 1000 ft since the reservoir width is 2000 ft). In addition the productive formation starts from 7000 and goes up to 7075ft since the thickness of the reservoir for this particular well is 75 ft.

(Figure A-13. Wells for deviation survey screen)

Now to add the horizontal well to this model, right click on the Marcellus and then add lateral

(Figure A-14. Wells for deviation survey screen)

At the stage, the midpoint of the horizontal can be entered as thickness/2= 75/2=37.5 ft.

(Figure A-15. Wells for deviation survey of lateral well screen)

After defining measured depth of first point of the lateral section, it is possible to build the horizontal segment of the model. An x-axis show where the horizontal well starts and up to what point it extends. For example, in this case since the length of the horizontal segment is about 3500 ft, we would like to start the horizontal well from 1000 ft from the reservoir and extend it all the way to 4500 ft (1000+3500). In addition y-axis indicates the location of the horizontal well along the y-axis. For instance, if the location is chosen to be in the center of the reservoir, since the width of this particular reservoir is 2000 ft, half of this width can be chosen as the y-axis. So, the y-axis in this particular case is defined as 1000 ft. The below figure illustrates the horizontal segment of the reservoir,

(Figure A-16. Wells for deviation survey of lateral well screen)

Now it is time to define a minimum bottom hole pressure for the reservoir. Different reservoirs behave differently and it is a subjective topic to decide where to stop all the simulation

run. For majority of vertical and horizontal wells in this thesis, the minimum bottom hole pressure is defined as 500 psia and this number can vary. For this particular well, the minimum bottom hole pressure is assumed to be 500 as well. The below figure shows the control mode as BHP (bottom hole pressure) and the target as previously mentioned is set to be 500 psia.

The screenshot shows a dialog box titled "Production Well Schedule Data". It has three tabs: "Well Controls", "Limits", and "Economic Limits". The "Well Controls" tab is selected. Inside this tab, there are four input fields: "Start Date" with a dropdown menu showing "SQS", "Open/Shut Flag" with a dropdown menu showing "Open", "Control Mode" with a dropdown menu showing "BHP", and "Target" with a text box containing "500" and a unit dropdown menu showing "psia". At the bottom of the dialog box, there are three buttons: "OK", "Cancel", and "Help".

(Figure A-17. Production for well control screen)

Now the lateral section of the Marcellus shale needs to be perforated in order to produce from the well. If this stage is not defined in the model, the model will not run and it will give error. Figures A-18 and A-19 illustrates the steps that need to be taken to perforate the lateral section,

(Figure A-18. Production for Marcellus perforation screen)

Perforation

Perforation Name: Perforation 1

Perforation properties:

Start Date: SOS

Start MD: 37.5 ft

Stop MD: 3537.5 ft

Skin Factor: 0

Well Bore Diameter: 0.5 ft

OK Cancel Help

(Figure A-19. Production for Marcellus perforation screen)

Fluid properties need to be entered into the model for the model to have a good understand of how the fluid movies within the porous media. Since this model is assumed to be 100 methane, 1 is imputed for C1 in the model. In addition, standard pressure, reference pressure, and reference temperature are defined in the model as well,

Coal Bed Methane Modeling Tool - ECLIPSE Office

File Help

Workflow

- Model Definition
- Reservoir Description
- Wells
- Production
- Fluid Properties
- Simulation Controls
- Economics

Generate Model

Run ECLIPSE

View Results

Define and create named properties:
Each named region of the model will be assigned the corresponding named properties. If no such named property has been defined the region will be assigned the default RESERVOIR properties.

Properties for fluid: RESERVOIR Properties for rock: RESERVOIR

<< Prev Property Next Property >>

PVT Composition Rel. Perm. Coal Bed Methane Advanced

Standard Pressure: 14.7 psia

Standard Temperature: 60 F

Reference Temperature: 120 F

No	Component	Fraction
1	N2	0
2	CO2	0
3	H2S	0
4	C1	1
5	C2	0
6	C3	0
7	iC4	0
8	nC4	0
9	iC5	0
10	nC5	0
11	C6	0
12	C7+	0

(Figure A-20. Fluid properties for PVT composition screen)

Since shale reservoir has both free and sorbed gas, Langmuir data needs to be entered for the model to be valid. The below parameters have been defined for all vertical and horizontal wells,

Coal Bed Methane Modeling Tool - ECLIPSE Office

File Help

Workflow

- Model Definition
- Reservoir Description
- Wells
- Production
- Fluid Properties
- Simulation Controls
- Economics

Generate Model

Run ECLIPSE

View Results

Define and create named properties:
Each named region of the model will be assigned the corresponding named properties. If no such named property has been defined the region will be assigned the default RESERVOIR properties.

Properties for fluid: RESERVOIR Properties for rock: RESERVOIR

<< Prev Property Next Property >>

PVT Composition Rel. Perm. Coal Bed Methane Advanced

Sub-division Geometry

- Linear
- Radial
- Spherical

Number of subdivisions: 1

Outer ring vol. ratio: 0.1

No	Comp	Langmuir Press. (psia)	Langmuir Conc. (Mscf /USTon (daf))	Sorption Time (day)	Re-adsorption Coef
1	N2	0	0	0	1
2	CO2	0	0	0	1
3	H2S	0	0	0	1
4	C1	635	0.088989999	62	1
5	C2	0	0	0	1
6	C3	0	0	0	1
7	iC4	0	0	0	1
8	nC4	0	0	0	1
9	iC5	0	0	0	1
10	nC5	0	0	0	1
11	C6	0	0	0	1
12	C7+	0	0	0	1

(Figure A-21. Fluid properties for coal bed methane screen)

Finally, the model in Eclipse can be run by clicking on “RUN ECLIPSE”. Depending on the PC speed, the model may take up to days for complicated horizontal wells with different numbers of stages. After the model is run successfully, “View Results” can be selected to analyze the model.

Appendix B

Vertical wells:

Vertical 1		Vertical 2		Vertical 3		Vertical 4		Vertical 5	
Time(M)	q (MCF/Month)	Time(M)	q (MCF/Month)	Time(M)	q (MCF/Month)	Time(M)	q (MCF/Month)	Time(M)	q (MCF/Month)
1	16982	1	21724	1	18793	1	10693	1	18674
2	11873	2	16537	2	14983	2	7925	2	14996
3	9935	3	15038	3	12148	3	7177	3	13800
4	8199	4	12858	4	10053	4	7076	4	12728
5	8617	5	10376	5	9935	5	5267	5	10121
6	7537	6	10853	6	8917	6	5543	6	8731
7	6622	7	10311	7	7744	7	4500	7	9117
8	6702	8	9597	8	7437	8	4133	8	7498
9	6338	9	8894	9	6688	9	4273	9	3345
10	5853	10	8741	10	6437	10	3960	10	12193
11	5190	11	8043	11	6783	11	3903	11	3054
12	5662	12	8032	12	5624	12	4369	12	9900
13	5564	13	6945	13	6014	13	2953	13	5000
14	5236	14	6901	14	5733	14	3367	14	5024
15	4904	15	7049	15	5565	15	3458	15	5174
16	5182	16	6564	16	4617	16	2517	16	5983
17	5121	17	6623	17	5087	17	3086	17	5834
18	4619	18	6092	18	5637	18	2985	18	5184
19	4416	19	6441	19	5453			19	4154
20	4792	20	6596	20	5325			20	5197
21	4668	21	6332	21	4831			21	5040
22	4778	22	6139	22	4659			22	4876
23	4260	23	5977					23	5076
24	4599	24	6078					24	4806
25	4464							25	4869
26	4272								
27	4350								
28	4071								
29	4056								

Table B-1. Production data for vertical wells

Vertical 6		Vertical 7		Vertical 8		Vertical 9	
Time(M)	q (MCF/Month)	Time(M)	q (MCF/Month)	Time(M)	q (MCF/Month)	Time(M)	q (MCF/Month)
1	17650	1	11046	1	4322	1	14187
2	11955	2	7641	2	3980	2	14892
3	8880	3	6009	3	3766	3	13217
4	7468	4	6083	4	2314	4	11888
5	6233	5	8918	5	3388	5	13308
6	5683	6	6410	6	2770	6	8286
7	4991	7	6305	7	3097	7	9436
8	5008	8	5114	8	2700	8	8792
9	4771	9	4669	9	2183	9	9721
10	4236	10	5011	10	2689	10	8711
11	4547	11	4288	11	2718	11	7866
12	4150	12	3884	12	2757	12	8135
13	4059	13	3979	13	2209	13	7056
14	3573	14	2917	14	2589	14	8357
15	3771	15	3205	15	2582		
16	3902	16	3320	16	2489		
17	3720	17	2523	17	2464		
18	3768	18	2826	18	2300		
19	3473	19	3369	19	2311		
20	3552						
21	3497						
22	3028						
23	3318						
24	3140						
25	3192						
26	3061						
27	3109						
28	3099						
29	2816						
30	2794						
31	2441						
32	2574						

Table B-2. Production data for vertical wells

Horizontal wells:

Horizontal 1		Horizontal 2		Horizontal 3	
Time (M)	q(Mscf/Month)	Time (M)	q(Mscf/Month)	Time (M)	q(Mscf/Month)
1	58056	1	44888	1	156342
2	53757	2	38747	2	143525
3	47962	3	36641	3	123918
4	43370	4	32207	4	116830
5	42172	5	30926	5	98102
6	39718	6	28869	6	88543
7	34057	7	24773	7	60454
8	36048	8	26040	8	46030
9	33385	9	23876	9	58339
10	32712	10	24049	10	52154
11	32507	11	22355	11	48045
12	31938	12	22628	12	41601
13	31091	13	21671	13	41623
14	29312	14	20383	14	2362
15	28978	15	20220	15	18652
16	27224	16	18870	16	16549
17	28059	17	19271	17	11246

Table B-3. Production data for horizontal wells

Owner and Completion Information for vertical and horizontal wells:

Vertical #1:

Owner Information:

API	CMP_DT	SUFFIX	STATUS	FARM	WELL_NUM	CO_NUM	LEASE	LEASE_NUM	MINERAL_OWN	OPERATOR
4709703021	11/17/2000	Original Loc	Completed	Dale L Winfree et ux		624326			Dale L Winfree et ux	Columbia Natural Resources, Inc. (CNR)
4709703021	7/19/2007	Worked Over	Completed	Dale L Winfree et ux		624326		3055097	Dale L Winfree et ux	Chesapeake Appalachia, LLC

Completion Information:

API	CMP_DT	SPUD_DT	ELEV	DATUM	FIELD	DEEPEST_FM	DEEPEST_FMT	INITIAL_CLASS	FINAL_CLASS	TYPE	RIG	CMP_MTHD	TD
4709703021	11/17/2000	9/28/2000	1680	Ground Level	Cave Run	Helderberg	Oriskany	Development Well	Development Well	Gas	Rotary	Acid+Frac	7407
4709703021	7/19/2007	7/5/2007	1680	Ground Level	Cave Run	Helderberg	Marcellus Sh	Development Well	Development Well	Gas	Rotary	Fractured	7326

Vertical #2:

API	COUNTY	PERMIT	TAX_DISTRICT	QUAD_75	QUAD_15	LAT_DD	LOH_DD	UTME	UTMH
4709703444	Upshur	3444	Banks	Rock Cave	Crawford	38.838856	-80.328083	558314.5	4299108.9

Pay/Show/Water Information:

API	CMP_DT	ACTIVITY	PRODUCT	DEPTH_TOP	FM_TOP	DEPTH_BOT	FM_BOT	G_BEF	G_AFT	O_BEF	O_AFT	WATER_QNTY
4709703444	11/19/2007	Pay	Gas	7053	Marcellus Sh	7100	Marcellus Sh					

Vertical #3:

API	COUNTY	PERMIT	TAX_DISTRICT	QUAD_75	QUAD_15	LAT_DD	LOH_DD	UTME	UTMH
4709703414	Upshur	3414	Banks	Rock Cave	Crawford	38.830969	-80.324845	558602	4298235.8

Pay/Show/Water Information:

API	CMP_DT	ACTIVITY	PRODUCT	DEPTH_TOP	FM_TOP	DEPTH_BOT	FM_BOT	G_BEF	G_AFT	O_BEF	O_AFT	WATER_QNTY
4709703414	3/12/2008	Pay	Gas	6994	Marcellus Sh	7051	Marcellus Sh					

Vertical #4:

API	COUNTY	PERMIT	TAX_DISTRICT	QUAD_75	QUAD_15	LAT_DD	LOH_DD	UTME	UTMH
4701705646	Doddridge	5646	McClellan	Salem	Centerpoint	39.353768	-80.579963	536190	4356120

Completion Information:

API	CMP_DT	SPUD_DT	ELEV	DATUM	FIELD	DEEPEST_FM	DEEPEST_FMT	INITIAL_CLASS	FINAL_CLASS	TYPE	RIG	CMP_MTHD	TVD
4701705646	6/12/2008	6/5/2008	1211	Ground Level	Smtn-Flnt-Sdla	Onondaga Ls	Marcellus Sh	Development Well	Development Well	Gas	Rotary	Fractured	7375

Pay/Show/Water Information:

API	CMP_DT	ACTIVITY	PRODUCT	DEPTH_TOP	FM_TOP	DEPTH_BOT	FM_BOT	G_BEF	G_AFT	O_BEF	O_AFT	WATER_QNTY
4701705646	6/12/2008	Water	Fresh Water			115						
4701705646	6/12/2008	Pay	Gas	7324	Marcellus Sh	7362	Marcellus Sh					

Vertical #5:

API	COUNTY	PERMIT	TAX_DISTRICT	QUAD_75	QUAD_15	LAT_DD	LOH_DD	UTME	UTMH
4703304929	Harrison	4929	Tenmile	Salem	Centerpoint	39.287693	-80.589498	535401.8	4348783.3

Completion Information:

API	CMP_DT	SPUD_DT	ELEV	DATUM	FIELD	DEEPEST_FM	DEEPEST_FMT	INITIAL_CLASS	FINAL_CLASS	TYPE	RIG	CMP_MTHD	TVD
4703304929	12/3/2007	11/1/2007	1107	Ground Level	Onondaga Ls	Marcellus Sh	unclassified	unclassified	not available	unknown	unknown	unknown	7400

Vertical #6:

API	COUNTY	PERMIT	TAX_DISTRICT	QUAD_75	QUAD_15	LAT_DD	LOH_DD	UTME	UTMH
4709703020	Upshur	3020	Banks	Rock Cave	Crawford	38.844935	-80.340372	557243.1	4299775.7

Completion Information:

API	CMP_DT	SPUD_DT	ELEV	DATUM	FIELD	DEEPEST_FM	DEEPEST_FMT	INITIAL_CLASS	FINAL_CLASS	TYPE	RIG	CMP_MTHD	TVD
4709703020	12/26/2000	10/19/2000	1806	Ground Level	Cave Run	Helderberg	Oriskany	Outpost (Extension) Test	Outpost (Extension) Well	Gas	Rotary	Acid+Frac	7586
4709703020	12/19/2006	12/8/2006	1806	Ground Level		Marcellus Sh	Marcellus Sh	unclassified	unclassified	not available	unknown	unknown	7126

Vertical #7:

API	COUNTY	PERMIT	TAX_DISTRICT	QUAD_75	QUAD_15	LAT_DD	LOH_DD	UTME	UTMH
4701705553	Doddridge	5553	McClellan	Salem	Centerpoint	39.356669	-80.574734	536639	4356444

Completion Information:

API	CMP_DT	SPUD_DT	ELEV	DATUM	FIELD	DEEPEST_FM	DEEPEST_FMT	INITIAL_CLASS	FINAL_CLASS	TYPE	RIG	CMP_MTHD	TVD
4701705553	2/24/2008	2/17/2008	852	Ground Level		Onondaga Ls	Marcellus Sh	unclassified	unclassified	not available	unknown	unknown	7035

Vertical #8:

API	COUNTY	PERMIT	TAX_DISTRICT	QUAD_75	QUAD_15	LAT_DD	LOH_DD	UTME	UTMH
4701705657	Doddridge	5657	Grant	Smithburg	Centerpoint	39.296585	-80.63322	531627.2	4349753.9

Completion Information:

API	CMP_DT	SPUD_DT	ELEV	DATUM	FIELD	DEEPEST_FM	DEEPEST_FMT	INITIAL_CLASS	FINAL_CLASS	TYPE	RIG	CMP_MTHD	TVD
4701705657	5/14/2008	5/7/2008	932	Ground Level	Smtn-Flnt-Sdla	Onondaga Ls	Marcellus Sh	Development Well	Development Well	Gas	Rotary	Fractured	6920

Pay/Show/Water Information:

API	CMP_DT	ACTIVITY	PRODUCT	DEPTH_TOP	FM_TOP	DEPTH_BOT	FM_BOT	G_BEf	G_AFT	O_BEf	O_AFT	WATER_QNTY
4701705657	5/14/2008	Water	Fresh Water			45						
4701705657	5/14/2008	Pay	Gas	6870	Marcellus Sh	6916	Marcellus Sh					

Vertical #9:

API	COUNTY	PERMIT	TAX_DISTRICT	QUAD_75	QUAD_15	LAT_DD	LOH_DD	UTME	UTMH
4701705712	Doddridge	5712	McClellan	Folsom	Centerpoint	39.428269	-80.552361	538527.1	4364399.4

Completion Information:

API	CMP_DT	SPUD_DT	ELEV	DATUM	FIELD	DEEPEST_FM	DEEPEST_FMT	INITIAL_CLASS	FINAL_CLASS	TYPE	RIG	CMP_MTHD	TVD
4701705712	8/21/2008	8/10/2008	1110	Ground Level		Onondaga Ls	Marcellus Sh	unclassified	unclassified	not available	unknown	unknown	7233

Pay/Show/Water Information:

API	CMP_DT	ACTIVITY	PRODUCT	DEPTH_TOP	FM_TOP	DEPTH_BOT	FM_BOT	G_BEf	G_AFT	O_BEf	O_AFT	WATER_QNTY
4701705712	8/21/2008	Pay	Gas	7016	Marcellus Sh	7212	Marcellus Sh					

Horizontal #1:

API	COUNTY	PERMIT	TAX_DISTRICT	QUAD_75	QUAD_15	LAT_DD	LOH_DD	UTME	UTMH
4709703527	Upshur	3527	Meade	Rock Cave	Crawford	38.820683	-80.289272	561698.6	4297117.8

Completion Information:

API	CMP_DT	SPUD_DT	ELEV	DATUM	FIELD	DEEPEST_FM	DEEPEST_FMT	INITIAL_CLASS	FINAL_CLASS	TYPE	RIG	CMP_MTHD	TVD	TMD
4709703527	7/31/2008	5/26/2008	1978	Ground Level	Marcellus Sh	Marcellus Sh	unclassified	unclassified	not available	unknown	unknown	unknown	7177	10676

Horizontal #2:

API	COUNTY	PERMIT	TAX_DISTRICT	QUAD_75	QUAD_15	LAT_DD	LOH_DD	UTME	UTMH
4709703516	Upshur	3516	Banks	Rock Cave	Crawford	38.820817	-80.331143	558063.6	4297105.2

Completion Information:

API	CMP_DT	SPUD_DT	ELEV	DATUM	FIELD	DEEPEST_FM	DEEPEST_FMT	INITIAL_CLASS	FINAL_CLASS	TYPE	RIG	CMP_MTHD	TVD	TMD
4709703516	7/23/2008	4/29/2008	1978	Ground Level	Cave Run	Marcellus Sh	Marcellus Sh	Development Well	Development Well	Gas	Rotary	Acid+Frac	7249	9061

Horizontal #3:

API	COUNTY	PERMIT	TAX_DISTRICT	QUAD_75	QUAD_15	LAT_DD	LOH_DD	UTME	UTMH
4705101092	Marshall	1092	Liberty	Wileyville	Littleton	39.734912	-80.644665	530448.3	4398396.1

Completion Information:

API	CMP_DT	SPUD_DT	ELEV	DATUM	FIELD	DEEPEST_FM	DEEPEST_FMT	INITIAL_CLASS	FINAL_CLASS	TYPE	RIG	CMP_MTHD	TVD	TMD
4705101092	4/6/2008	3/14/2008	1404	Ground Level	Marcellus Sh	Marcellus Sh	unclassified	unclassified	not available	unknown	unknown	unknown	7178	9905

Appendix C

Vertical #1:

Figure C-1. Decline Curve for Vertical 1

Vertical #2:

Figure C-2. Decline Curve for Vertical 2

Vertical #3:

Figure C-3. Decline Curve for Vertical 3

Vertical #4:

Figure C-4. Decline Curve for Vertical 4

Vertical #5:

Figure C-5. Decline Curve for Vertical 5

Vertical #6:

Figure C-6. Decline Curve for Vertical 6

Vertical #7:

Figure C-7. Decline Curve for Vertical 7

Vertical #8:

Figure C-8. Decline Curve for Vertical 8

Vertical #9:

Figure C-9. Decline Curve for Vertical 9

Horizontal #1:

Figure C-10. Decline Curve for Horizontal #1

Horizontal #2:

Figure C-11. Decline Curve for Horizontal #2

Horizontal #3:

Figure C-12. Decline Curve for Horizontal #3

Appendix D

Vertical #1:

First vertical well studied for this thesis is located in Upshur County. An 80 acres area was assumed for this well with the dimensions of 1867*1867 (ft²). The thickness of this well was given in the completion data as 50 ft. Both initial and final parameters used for getting a match are listed below,

Initial parameters used		
Thickness	50	ft
Area	80	acres
Top of fracture	6890	ft
Bottom of fracture	6940	ft
Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.002	md
Dimensiosn	1867*1867	ft ²
Matrix perm	0.0002	md
Rock Density	100	lb/ft ³
Initial Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	20000	md
porosity	20	%
Width	0.01	inch

Final parameters for the match		
Thickness	50	ft
Area	80	acres
Top of fracture	6890	ft
Bottom of fracture	6940	ft
Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.002	md
Dimensiosn	1867*1867	ft ²
Matrix perm	0.0002	md
Rock Density	100	lb/ft ³
Initial Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	20000	md
porosity	20	%
Width	0.01	inch

As can be seen above, natural fracture permeability was assumed to be 0.002md. In addition, hydraulic fracture permeability is assumed to be 20000md. Hydraulic fracture porosity does not have much impact on the initial production because there is only one stage of hydraulic fracturing that is being used for this well. Water saturation was assumed to be the same for all the vertical and horizontal wells. Since the depth of the studied Marcellus Shale wells are in

between 6700-7200 ft, the initial pressure is assumed to be 3500 psia for all the wells. Historically matching the real field data using Eclipse for this particular well did not have any issues because the parameters that were used were identical to the base model. The above base model that was discussed earlier has been obtained after studying the Marcellus Shale parameters for months and talking to different operating and service companies regarding the chosen values. After using the above parameters, the below match was obtained,

Figure 22. Final Match for Vertical #1

Vertical #3:

The third well studied for this thesis is also located in Upshur County. The acreage for this well is assumed to be 80 acres and the thickness was obtained from the completion data as 57 ft. In addition, a square reservoir is assumed for this reservoir with the dimensions of 1867*1867 (ft²). Both initial and final parameters used for getting a match are listed below,

Initial parameters used		
Area	80	acres
Top of fracture	6994	ft
Bottom of fracture	7051	ft
Thickness	57	ft
Fracture por	0.005	fraction
Matrix por	0.05	fraction
Fracture perm	0.001	md
Dimensiosn	1867*1867	ft ²
Matrix perm	0.0002	md
Rock Density	100	lb/ft ³
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	20000	md
porosity	20	%
width	0.01	inch

Final parameters for the match		
Area	80	acres
Top of fracture	6994	ft
Bottom of fracture	7051	ft
Thickness	57	ft
Fracture por	0.005	fraction
Matrix por	0.05	fraction
Fracture perm	0.002	md
Dimensiosn	1867*1867	ft ²
Matrix perm	0.0002	md
Rock Density	100	lb/ft ³
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	20000	md
porosity	20	%
width	0.01	inch

To historically match this well, natural fracture permeability had to be changed because it has a great impact on the production decline curve by brining the curve up and down. Below is a visual illustration of what happens when natural fracture permeability changes from 0.001 to different permeabilities.

Figure 23. History Matching for Vertical #3

As can be seen in the above plot, when natural fracture permeability changes from 0.001md to 0.002 md; the entire production decline curve moves up. This is an indication of the importance of natural fracture permeability in dual porosity model and unconventional reservoirs. Below plot is the final match for the third vertical well which can be seen in the above plot as well.

Figure 24. Final Match for Vertical #3

Vertical #4:

The forth well studied for this thesis is located in Doddridge County. The acreage for this well is assumed to be 80 acres and the thickness was obtained from the completion data as 38 ft. In addition, a square reservoir is assumed for this reservoir with dimensions of 1867*1867 (ft²). Both initial and final parameters used for getting a match are listed below,

Initial parameters used		
Area	80	acres
Top of fracture	7324	ft
Bottom of fracture	7362	ft
Thickness	38	ft
Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.002	md
Dimensions	1867*1867	ft ²
Matrix perm	0.0002	md
Rock Density	100	lb/ft ³

Final parameters for the match		
Area	80	acres
Top of fracture	7324	ft
Bottom of fracture	7362	ft
Thickness	38	ft
Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.002	md
Dimensions	1867*1867	ft ²
Matrix perm	0.0002	md
Rock Density	100	lb/ft ³

Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	20,000	md
porosity	20	%
width	0.01	inch

Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	12,000	md
porosity	20	%
width	0.01	inch

To historically match this well, hydraulic fracture permeability was reduced from 20,000 md to 12,000 md in order to bring the production decline curve down. The below plot shows how changing hydraulic fracture permeability would change the initial production behavior,

Figure 25. History Matching for Vertical #4

As can be seen in the above plot, when the hydraulic fracture permeability is 20,000 md, the initial production starts approximately at 430 MSCF/DAY; however when it was reduced to 12,000md, the initial production was declined to approximately 360 MSCF/DAY which is

almost the same as initial real field data. This indicates that hydraulic fracture permeability has most of its impact on the initial production. Finally, the match for the forth horizontal well is shown below,

Figure 26. Final Match for Vertical #4

Vertical #5:

The fifth vertical well studied for this thesis is located in Harrison County. The acreage for this well is assumed to be 80 acres and the thickness was obtained from the completion data as 60 ft. In addition, a square reservoir is assumed for this reservoir with dimensions of 1867*1867 (ft²). Both initial and final parameters used for getting a match are listed below,

Final parameters for the match		
Area	80	acres
Top of fracture	7320	ft
Bottom of fracture	7400	ft
Thickness (assumption)	80	ft

Final parameters for the match		
Area	80	acres
Top of fracture	7320	ft
Bottom of fracture	7400	ft
Thickness (assumption)	80	ft

Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.002	md
Dimensions	1867*186 7	ft^2
Matrix perm	0.0002	md
Rock Density	100	lb/ft^ 3
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	20,000	md
porosity	20	%
width	0.01	inch

Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.001	md
Dimensions	1867*186 7	ft^2
Matrix perm	0.0002	md
Rock Density	100	lb/ft^ 3
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	13,000	md
porosity	20	%
width	0.01	inch

To historically match this well, hydraulic fracture permeability was changed from 20,000 md to 13,000 md in order to bring the initial values down. In addition, natural fracture permeability was decreased from 0.002md to 0.001 md to bring the entire production decline curve down. The below plot shows how changing hydraulic fracture permeability changes the initial production behavior,

Figure 27. History Matching for Vertical #5

As can be seen in the above plot, when hydraulic fracture permeability changes from 20,000 md to 13,000, the initial production decreases to have a close match to the real field data. Finally, the match for this well is achieved by having 13,000 md as the hydraulic fracture permeability and 0.001md as natural fracture permeability as shown below,

Figure 28. Final Match for Vertical #5

Vertical #6:

The sixth vertical well studied for this thesis is located in Upshur County. The acreage for this well is assumed to be 40 acres and the thickness was obtained from the Upshur County thickness map as 80 ft. In addition, a square reservoir is assumed for this reservoir with dimensions of 1320*1320 (ft²). Both initial and final parameters used for getting a match are listed below,

Initial parameters used		
Area	80	acres
Top of fracture	7050	ft
Bottom of fracture	7130	ft
Thickness	80	ft
Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.002	md
Dimensions	1867*1867	ft ²

Final parameters for the match		
Area	40	acres
Top of fracture	7050	ft
Bottom of fracture	7130	ft
Thickness	80	ft
Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.0006	md
Dimensions	1320*1320	ft ²

Matrix perm	0.0002	md
Rock Density	100	lb/ft ³
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	20,000	md
porosity	20	%
width	0.01	inch

Matrix perm	0.0002	md
Rock Density	100	lb/ft ³
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	15,000	md
porosity	20	%
width	0.01	inch

To get a match for this well, variety of parameters had to be altered. First of all, natural fracture permeability had to be reduced from 0.002md to 0.0006md which is very low for typical unconventional reservoir; however that was the only way to get a match. In order to try other parameters for a match, natural fracture porosity was reduced to different values but unfortunately it does not have as much impact as natural fracture permeability. The next parameter that was changed to reduce the initial production down was the hydraulic fracture permeability. Hydraulic fracture permeability was reduced from 20,000 md to 15,000md. Furthermore, as can be seen in the below plot, when natural fracture porosity was changed from 0.004 to 0.003, there were only little impact on the initial production and as a result, it does not have much impact on the later part of the production curve.

Acreage was assumed to be 40 acres for this wells since 80 acres would be a large drainage area for such a low natural fracture permeability. When reducing the drainage area from 80 acres to 40 acres, recoverable reserves did not decrease significantly which indicates assigning 80 acres for this particular well is exaggerating and this well can be assumed to be 40 acres.

Figure 29. History Matching for Vertical #6

Final parameters that were used for the match are $k_f=0.0006\text{md}$, and natural fracture permeability= 15,000 md as shown in the below plot,

Figure 30. Final Match for Vertical #6

Vertical #7:

The seventh vertical well studied for this thesis is located in Doddridge County. The acreage for this well is assumed to be 80 acres and the thickness was obtained from the Doddridge County thickness map as 50 ft. In addition, a square reservoir is assumed for this reservoir with dimensions of 1867×1867 (ft²). Both initial and final parameters used for getting a match are listed below,

Initial parameters used		
Area	80	acres
Top of fracture	6985	ft
Bottom of fracture	7035	ft
Thickness	50	ft
Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.002	md

Final parameters for the match		
Area	80	acres
Top of fracture	6985	ft
Bottom of fracture	7035	ft
Thickness	50	ft
Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.001	md

Dimensions	1867*186 7	ft^2
Matrix perm	0.0002	md
Rock Density	100	lb/ft^ 3
Pressure	3500	psia
Sw	15	%

Hydraulic Fracture

Half length	500	ft
permeability	20,000	md
porosity	20	%
width	0.01	inch

Dimensions	1867*186 7	ft^2
Matrix perm	0.0002	md
Rock Density	100	lb/ft^ 3
Pressure	3500	psia
Sw	15	%

Hydraulic Fracture

Half length	500	ft
permeability	10,000	md
porosity	20	%
width	0.01	inch

To get a match for this case, natural fracture permeability is decreased from 0.002 md to 0.001md. In addition, the hydraulic fracture permeability is reduced to 10,000 md in order to match the real field decline curve. These changes can be seen in the below plot,

Figure 31. History Matching for Vertical #7

As can be seen in the above plot when natural fracture permeability is decreased, the entire curve shifts downward and when the hydraulic fracture permeability is decreased, the initial production is decreased as well. Below is the final match that was obtained from the seventh vertical well,

Figure 32. Final Match for Vertical #7

Vertical #8:

The eighth vertical well that was studied for this thesis is located in Doddridge County. The acreage for this well is assumed to be 40 acres and the thickness was obtained from the completion data as 47 ft. In addition, a square reservoir is assumed for this reservoir with dimensions of 1320*1320 (ft²). Both initial and final parameters used for getting a match are listed below,

Initial parameters used		
Area	80	acres
Top of fracture	6870	ft
Bottom of fracture	6916	ft
Thickness	46	ft
Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.002	md
Dimensions	1867*1867	ft ²
Matrix perm	0.0002	md
Rock Density	100	lb/ft ³
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	20000	md
porosity	20	%
width	0.01	inch
Minimum pressure	500	psia

Final parameters for the match		
Area	40	acres
Top of fracture	6870	ft
Bottom of fracture	6916	ft
Thickness	46	ft
Fracture por	0.003	
Matrix por	0.05	
Fracture perm	0.002	md
Dimensions	1320*1320	ft ²
Matrix perm	0.0002	md
Rock Density	100	lb/ft ³
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	200	ft
permeability	10000	md
porosity	20	%
width	0.01	inch
Minimum pressure	700	psia

This particular vertical well is producing at low average monthly rate compared to the other vertical wells studies thus far. As a result, majority of parameters are assumed to be low in order to get a good match for the production decline curve. First of all, natural fracture permeability is remained constant as the base model (0.002 md); however fracture half length which used to be 500 ft for majority of the vertical wells is brought down to 200 ft. In addition, hydraulic fracture permeability is assumed to be 10,000 md, and minimum bottom hole pressure is set to be 700 psia.

Reducing the fracture half length from 500 ft to 200 ft will essentially reduce the production in general. This means the entire decline curves shift downward by reducing the fracture half length. The dual porosity model in Eclipse assumes that the fracture half length

which is entered in the model is the **propped fracture half length** and as a result altering this fracture half length has a huge impact on the production capability of the reservoir.

Minimum bottom hole pressure is typically defined in reservoir simulation to emphasize the importance of having enough pressure downhole in order for the diffusion to take place. For majority of the vertical wells studies up to now, the minimum bottom hole pressure is set as a constant pressure to be 500 psia; however for this particular well since the production decline curve is pretty low, the minimum bottom hole pressure was increases to 700 psia in order for the reservoir to produce less.

The last thing that was changed in order to reduce the production decline curve was decreasing the natural fracture porosity from 0.005 to 0.003. Although this has some impact on the initial production curve, typically it does not have any significant impact on the later part of the curve.

Finally the area that was assumed for this well is 40 acres because of the low production data. As previously mentioned, having a larger drainage area will not impact the recoverable reserve by much. The below two tables demonstrate the difference between 40 acres and 80 acres,

40 acres			
Time (years)	EUR (MSCF)	IGIP (MSCF)	RF
10.015059	208,071.53	846,513.63	24.57982041
20.004107	323,958.31	846,513.63	38.26970985
29.913757	406,782.31	846,513.63	48.05384055

80 acres			
Time (years)	EUR (MSCF)	IGIP (MSCF)	RF
10.015059	214,505.05	1,693,985.60	12.66274341
20.002737	351,957.06	1,693,985.60	20.77686257
29.913757	466,500.91	1,693,985.60	27.53865853

As can be seen in the above table, when drainage area was reduced from 80 acres to 40 acres, the EUR (estimated ultimate recovery) did not modify significantly after 30 years but the initial gas in place has decreased extensively. This big decrease in IGIP has caused the RF to be completely different when using 40 acres or 80 acres. As a result, the drainage area of 40 acres has been chosen for this well because the well does not have more capacity to produce even with a larger drainage area.

The below plot shows the impact of reducing the fracture half length from 400 ft to 300 ft,

Figure 33. History Matching for Vertical #8

As can be seen in the above plot, when every parameter stays constant and only fracture half length changes from 400 ft to 300 ft, the curve shifts downward and this change in production can be associated with the change in natural fracture permeability since both parameters have similar impact on the production decline curve. Although fracture half length that was used for this well is 200 ft, the above illustration is just to show the impact of changing fracture half length. Below is the match obtained from the eight vertical well with the indicated parameters in the plot,

Figure 34. Final Match for Vertical #8

Vertical #9:

The ninth vertical well that was studied for this thesis is located in Doddridge County. The acreage for this well is assumed to be 80 acres and the thickness was obtained from the thickness map of Doddridge County as 50 ft. In addition, a square reservoir is assumed for this reservoir with dimensions of 1867*1867 (ft²). Both initial and final parameters used for getting a match are listed below,

Initial parameters used		
Area	120	acres
Top of fracture	7183	ft
Bottom of fracture	7233	ft
Thickness	50	ft
Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.002	md
Dimensions	2286*2286	ft^2
Matrix perm	0.0002	md
Rock Density	100	lb/ft^3
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	20000	md
porosity	20	%
width	0.01	inch
Minimum pressure	500	psia

Final parameters for the match		
Area	80	acres
Top of fracture	7183	ft
Bottom of fracture	7233	ft
Thickness	50	ft
Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.003	md
Dimensions	1867*1867	ft^2
Matrix perm	0.0002	md
Rock Density	100	lb/ft^3
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture		
Half length	500	ft
permeability	20000	md
porosity	20	%
width	0.01	inch
Minimum pressure	500	psia

For this specific well, natural fracture permeability has increased from 0.002 md to 0.003 md to account for big production data. Moreover, the drainage area was examined for both 80 and 120 acres to distinguish if having a larger drainage area makes a huge impact on the recoverable reserve or not. As explained for the previous well, it turned out that 80 acres would be a more reasonable number compared to 120 acres because the recoverable reserved from 80 acres is almost the same as 120 acres. As a result, 80 acres was chosen for this well as well. Below is an illustration of different natural fracture permeability values.

Figure 35. History Matching for Vertical #9

Finally the match for this well is obtained from $k_f = 0.003 \text{ md } 20,000 \text{ md}$ of hydraulic fracture permeability.

Figure 36. Final Match for Vertical #9

Horizontal #2:

The second horizontal well studied for this thesis is located in Upshur County. The acreage for this well is assumed to be 151 acres and the thickness was obtained from the thickness map of Upshur County as 75 ft. In addition, a rectangular reservoir is assumed for this reservoir with dimensions of 3624*1812 (ft²). The length of the horizontal segment of this reservoir is 1812 ft is provided in the well data section of Geological Survey website. Both initial and final parameters used for getting a match are listed below,

Initial parameters used		
Horizontal length	1812	ft
acreage	151	acres
Top of fracture	7000	ft
Bottom of fracture	7075	ft
Thickness	75	ft

Final parameters for the match		
Horizontal length	1812	ft
acreage	151	acres
Top of fracture	7000	ft
Bottom of fracture	7075	ft
Thickness	75	ft

Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.001	md
Dimensions	3624*1812	ft^2
Matrix perm	0.0002	md
Rock Density	100	lb/ft^3
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture: Four fracs		
Half length	500	ft
permeability	20,000	md
porosity	20	%
width	0.01	inch
Production Data		
Minimum pressure	500	psia

Fracture por	0.005	
Matrix por	0.05	
Fracture perm	0.002	md
Dimensions	3624*1812	ft^2
Matrix perm	0.0002	md
Rock Density	100	lb/ft^3
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture: Four fracs		
Half length	350	ft
permeability	10,000	md
porosity	10	%
width	0.01	inch
Production Data		
Pwf (01/01/1981)	800	psia
Pwf (08/01/1981)	600	psia

Natural fracture permeability is increased from 0.001md to 0.002 md to increase the production decline curve. Hydraulic fracture parameters are very important in getting a match for horizontal wells because of the number of stages that can be used. Four stages were used for this model and it is shown below,

Figure 37. Horizontal #2

Fracture half length, porosity, and permeability have all been reduced to meet the condition of the real field data. In addition, this horizontal well act similar to the first horizontal well studied in this research and incremental pressure should be used to account for significant increase in production after 8 months. As a result, the minimum bottom hole pressure has decreased from 800 to 600 psia to account for this change. Below is a plot of change in fracture half length with 4 stages,

Figure 38. History Matching for Horizontal #2

Finally, the final match is plotted below with $k_f= 0.002\text{md}$ and $X_f= 350 \text{ft}$,

Figure 39. Final Match for Horizontal #2

Horizontal #3:

The third horizontal well studied for this thesis is located in Marshall County. The acreage for this well is assumed to be 216 acres and the thickness was obtained from the thickness map of Upshur County as 75 ft. In addition, a rectangular reservoir is assumed for this reservoir with dimensions of 4700*2000 (ft²). The length of the horizontal segment of this reservoir is 2727 ft is provided in the well data section of Geological Survey website. Both initial and final parameters used for getting a match are listed below,

Initial parameters used		
Horizontal length	2727	ft
acreage	216	acres
Top of fracture	7118	ft
Bottom of fracture	7130	ft
Thickness	60	ft
Fracture por	0.005	
Matrix por	0.05	

Final parameters for the match		
Horizontal length	2727	ft
acreage	216	acres
Top of fracture	7118	ft
Bottom of fracture	7130	ft
Thickness	60	ft
Fracture por	0.005	
Matrix por	0.05	

Fracture perm	0.002	md
Dimensions	4700*2000	ft^2
Matrix perm	0.0002	md
Rock Density	100	lb/ft^3
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture: Six fracs		
Half length	500	ft
permeability	20,000	md
porosity	20	%
width	0.01	inch
Production Data		
Minimum pressure	500	psia

Fracture perm	0.004	md
Dimensions	4700*2000	ft^2
Matrix perm	0.0002	md
Rock Density	100	lb/ft^3
Pressure	3500	psia
Sw	15	%
Hydraulic Fracture: Six fracs		
Half length	500	ft
permeability	20,000	md
porosity	20	%
width	0.01	inch
Production Data		
Minimum pressure	400	psia

To get a match for the last horizontal well, natural fracture permeability is increased from 0.002md to 0.004 md. In addition, the minimum bottom hole pressure is brought down to 400 psia in order to produce more from the reservoir. Below is the third horizontal well with 6 stages. As can be seen in the below graph, the fractures are equally spaced and the spacing between fractures are approximately 390 ft.

Figure 40. Horizontal #3

Below is the plot that illustrates the procedure with different parameters used to get a match,

Figure 41. History Matching for Horizontal #3

And finally the final match for the third horizontal well is as follows,

Figure 42. Final Match for Horizontal #3

Curriculum Vitae

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Education

West Virginia University- Morgantown, WV, Expected Graduation Date: August 2011

- College of Engineering and Mineral Resources: **Master of Science**
- Department of Petroleum and Natural Gas Engineering
- GPA: 4.00/4.00

West Virginia University- Morgantown, WV, May 2010

- College of Engineering and Mineral Resources: **Bachelor of Science**
- Department of Petroleum and Natural Gas Engineering
- Major GPA: 3.89/4.00, Cumulative GPA: 3.57/4.00

Work Experience

Research Assistantship- Morgantown, WV

August 2010 – Present

Graduate Research Assistant

- Marcellus Shale Characteristics Analysis
- Production Data Analysis and History Matching Using Real Field Data
- Prediction of Future Reservoir Behavior
- Natural Fracture Spacing in Shale Gas Reservoir

Summer Internship- Morgantown, WV

May 2010 – August 2010

Marcellus Shale Research

- Marcellus Shale Development & Reservoir Modeling in Gas Shale
- Comparison Between Single Porosity Model and Dual Porosity Model in Shale Reservoir
- Stimulation Effectiveness and Flow Regime in Shale Reservoir

Health Science & Technology Academy- Morgantown, WV

Summer 2009

HSTA Mentor

- Tutored high school students in Algebra, Trigonometry, Pre-Calculus, and Calculus
- Prepared high school students for public speaking

Engineering Computer Lab Manager

- Provided technical support when system malfunctions
- Implemented software and hardware upgrades

Projects

Engineering Bridge Project, Drill String Designing Analysis, Initial Oil and Gas in Place Using Material Balance, Well Design Using Natural Flow and Stimulation Treatment Methods, Aquifer Reservoir Treatment, Top Down Intelligence Reservoir Modeling, Drilling Fluid for HP/HT Zones, Shale Gas Horizontal Well Hydraulic Fracturing Design, Two Phase Z-factor Analysis, Gas Condensate Reservoir Development and Optimization, Sandstone Reservoir Development Using Reservoir Simulation

Honors and Awards

- Outstanding Graduate Student for Academic Achievement (2010-2011)
- Halliburton Award Recipient for Academic Excellence (2009-2010)
- Obtained Dean's List every academic year and President's List for the last two years
- Recipient of the West Virginia University's highly competitive Merit Scholarship (2007-2008)

Skills and Certifications

- Well Control Certificate from Wild Well Control Co. (September 2009)
- Fluent speaking, reading, and writing in **English, French, Persian, and Arabic**
- Proficient using Microsoft Office Suite, Adobe and HTML, MS Windows, IPDA, Eclipse, Computer Group Modeling (CMG), Mfrac (hydraulic fracturing software)

Activities and Interests

- **Recruiter**, Society of Petroleum Engineers, 2010-2011
- **Vice president**, American Association of Drilling Engineers, 2008-2009
- **Vice President**, Persian Student Association, 2007-2009