A TECHNICAL AND ECONOMIC STUDY OF COMPLETION TECHNIQUES IN FIVE EMERGING U.S. GAS SHALE PLAYS

A Thesis

by

ARCHNA AGRAWAL

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2009

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Stephen A. Holditch
Committee Members,	Walter B. Ayers
	Maria A. Barrufet
Head of Department,	Stephen A. Holditch

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ABSTRACT

A Technical and Economic Study of Completion Techniques in Five Emerging U.S. Gas Shale Plays. (December 2009)

Archna Agrawal, B.S., The University of Texas at Austin
Chair of Advisory Committee: Dr. Stephen A. Holditch

With the increased demand for energy and the declining conventional hydrocarbons worldwide, energy companies, both majors and independents, are turning to unconventional resources to produce the hydrocarbons required to meet market demand. From coalbed methane to low permeability (tight) gas reservoirs and gas shales, energy companies are making substantial progress in developing the technologies required to bring these unconventional reserves to the market. A common misconception is that there are not enough domestic oil and gas reserves to fuel our economy. The United States imports most of the oil used for transportation fuel and several TCF of natural gas annually. However, there is a very large resource of natural gas in unconventional reservoirs, with over 2,200 TCF of gas in place in just the gas shale formations that have been identified in the energy arena (Navigant Study 2008). There are still major gas shale plays and basins that have not been explored and are waiting to be evaluated and developed. The natural gas in shales and other unconventional reservoirs can be used to generate electricity, or it can be turned into liquids and used by the transportation industry. It is also misconstrued that gas shales are relatively new in our industry and something of the future. The first commercially viable gas shale well was drilled in the early 1920s in Pennsylvania, before the famous oil well drilled by Colonel Drake.

The objectives of this study are to (1) complete literature review to establish which geologic parameters affect completion techniques in five emerging gas shales: the

Antrium, the Barnett, the Haynesville, the Marcellus, and the Woodford; (2) identify the different completion methods; (3) create an economic model for the completion techniques discussed; (4) develop a sensitivity analysis on various economic parameters to determine optimal completion strategy; and (5) create completion flowcharts.

Based on the literature review I have done for several gas shale basins, I have identified seven pertinent geologic parameters that influence completion practices. These are depositional environment, total organic content (TOC), average gas content, shale mineralogy, shale thickness, and reservoir pressure. Next, I identified different completion and simulation trends in the industry for the different shale plays.

The results from this study show that although there are some stark differences between depths (i.e. the Antrim Shale and the Haynesville Shale), shale plays are very similar in all other geologic properties. Interestingly, even with a large range for the different geological parameters, the completion methods did not drastically differ indicating that even if the properties do not fall within the range presented in this paper does not automatically rule them out for further evaluation in other plays. In addition to the evaluation of geologic properties, this study looked at drilling cost and the production profile for each play. Due to the volatility of the energy industry, economic sensitivity was completed on the price, capital, and operating cost to see what affect it would have on the play. From the analysis done, it is concluded that horizontal drilling in almost any economic environment is economic except for one scenario for the Woodford Shale. Therefore, gas shales plays should still be invested in even in lower price environments and companies should try to take advantage of the lower cost environments that occur during these times. With continual development of new drilling and completion techniques, these plays will become more competitive and can light the path for exploration of new shale plays worldwide.

DEDICATION

To God who has put so many wonderful people on my path and to my family, friends, and teachers who have been there to help me get to where I am today.

ACKNOWLEDGEMENTS

I would first like to thank my family for their support in completing my thesis. I would also like to thank my friends both professionally and personally that have helped me by pointing me in the right direction for this thesis, as well as helping me edit my thesis. Lastly, I want to thank and acknowledge my mentors and teachers—even if they didn't have the title.

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CHAPTER I

INTRODUCTION

1.1 Natural Gas Price, Internal Demand, and Production Review

The economy in North America has become dependent on natural gas. The versatility of natural gas as an energy source allows consumers to use it for heating, electricity generation, industrial processes, and even for transportation. Natural gas and crude oil prices were relatively flat for the past 20 years, then spiking to never before seen levels starting in the year 2000 (**Fig. 1.1**).

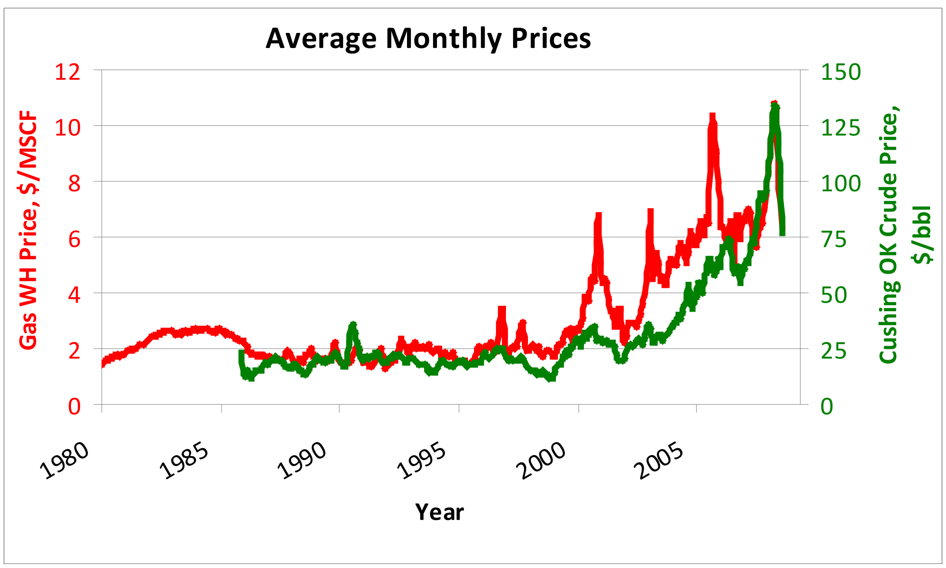

Fig. 1.1—Spike in natural gas and oil prices began in 2000 (EIA 2008)

Mostly due to the low price for natural gas, consumption started to increase steadily beginning 1985. In the year 2000, when price of natural gas began to trend upwards, the consumption of natural gas in the U.S. stabilized and remained relatively flat (**Fig. 1.2)**.

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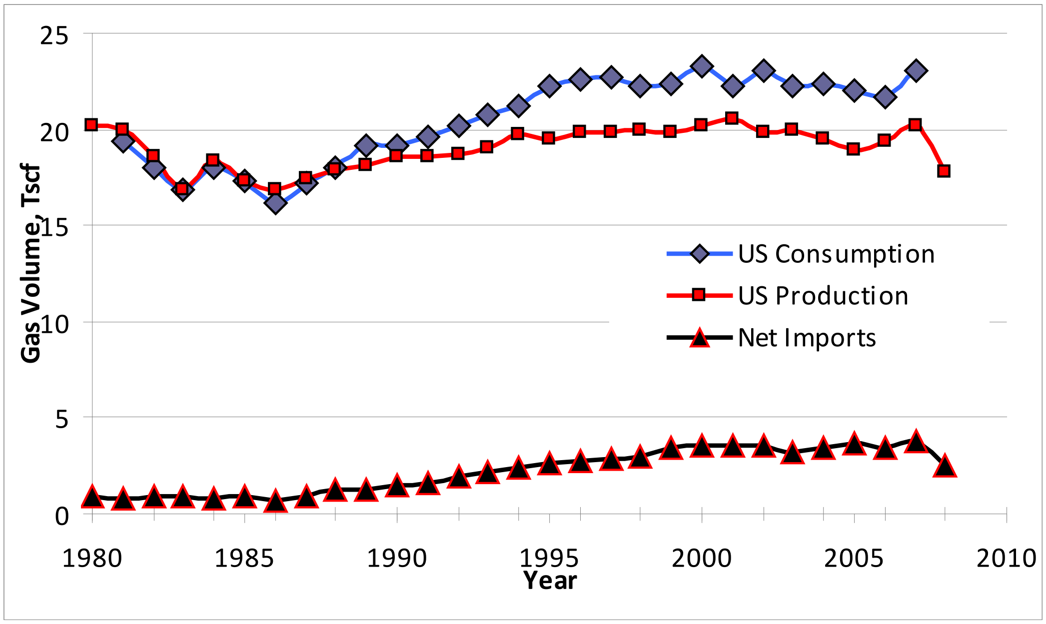

Fig. 1.2—Consumption is higher than production in 1986 (EIA 2008)

It is important to note in Fig. 1.2 that consumption of natural gas in the U.S. has exceeded production (including Alaska) since 1989. Not surprisingly, natural gas imports into the U.S. began to increase in 1989 and became an important component in meeting the natural gas demand. Imports from the U.S. mainly came from Canadian gas fields, and from LNG projects, and as of 2007, imports made up 16% of the total supply.

The remarkable facet of this stabilized natural gas production, which has been around 20 TCF per year since 1994, is that no major conventional gas fields have been discovered in the U.S. since 1994. Existing gas wells will tend to decline at annual rates of 10-20% per year, yet that overall production behavior as shown in Fig. 1.2 shows essentially no decline. The primary reason is that unconventional gas reservoirs have been continuously developed during the past few decades. Increased production from unconventional gas fields has been paramount for maintaining a flat production profile while conventional natural gas fields continue to decline.

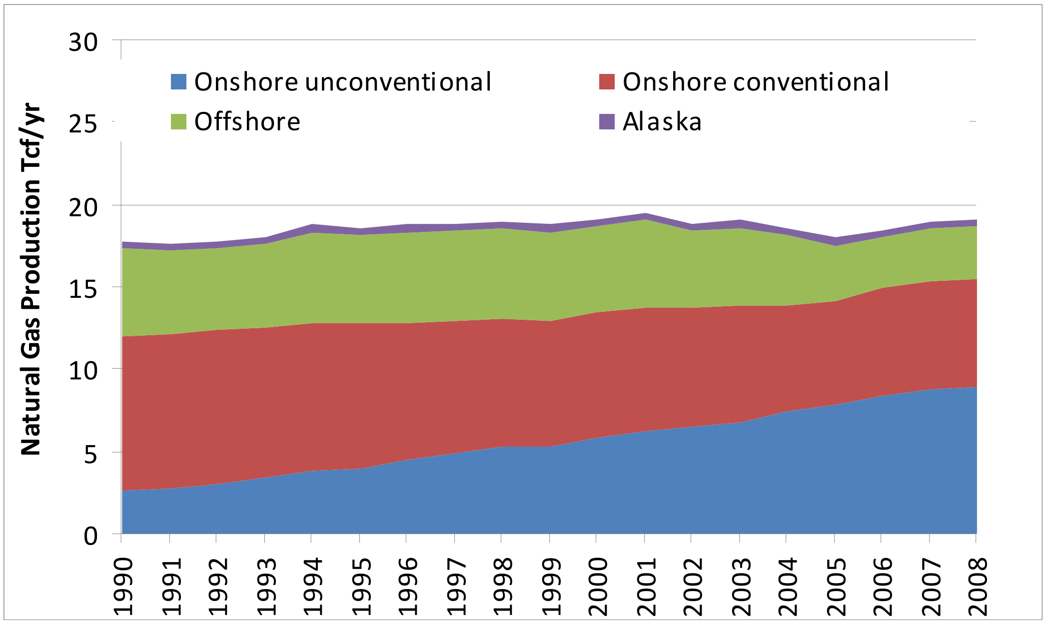

Fig. 1.3—Share of production from unconventional gas fields (EIA 2008)

It is evident that the gradual shift from gas production from conventional fields to gas production from unconventional fields (**Fig. 1.3**) has taken place during a time of relative gas price stability. Therefore, I concluded that the improvements and cost reduction of important technologies, such as horizontal drilling and hydraulic fracturing, helped make unconventional gas fields more economically appealing.

1.2 Role of Unconventional Gas Production

Unconventional gas reservoirs are classified as tight gas sands, coalbed methane (CBM), or gas shales. Even though Devonian Shale reservoirs in the Appalachian Basin have been producing since the 1920s, there was little effort to produce unconventional reservoirs until the 1970's when prices for natural gas began increasing, resulting in a valid economic reason to look at such reservoirs. As gas production from conventional reservoirs has declined in recent decades, many companies launched sizeable projects to characterize and develop unconventional resources. Beginning in the 1970's, the natural gas industry began serious development of tight gas sand reservoirs in a number of basins in North America. After tight gas sands became more attractive and somewhat routine in many basins, the industry began looking closely at producing gas from coal seams. Natural gas production from coal reservoirs required overcoming challenges in reservoir characterization, project economics, and water handling. After a lot of work on CBM reservoirs, the industry next turned its attention to producing gas from gas shale reservoirs. The technology advances and knowledge obtained from the development of tight gas sands and CBM fields helped unlock the potential of gas shales. The main difficulties of developing gas shale fields include drilling long horizontal and multilateral wells, massive transverse hydraulic fractures, and gaining an understanding in reservoir characterization. The yearly production of unconventional gas fields since 1998 is shown below **(Fig. 1.4)**.

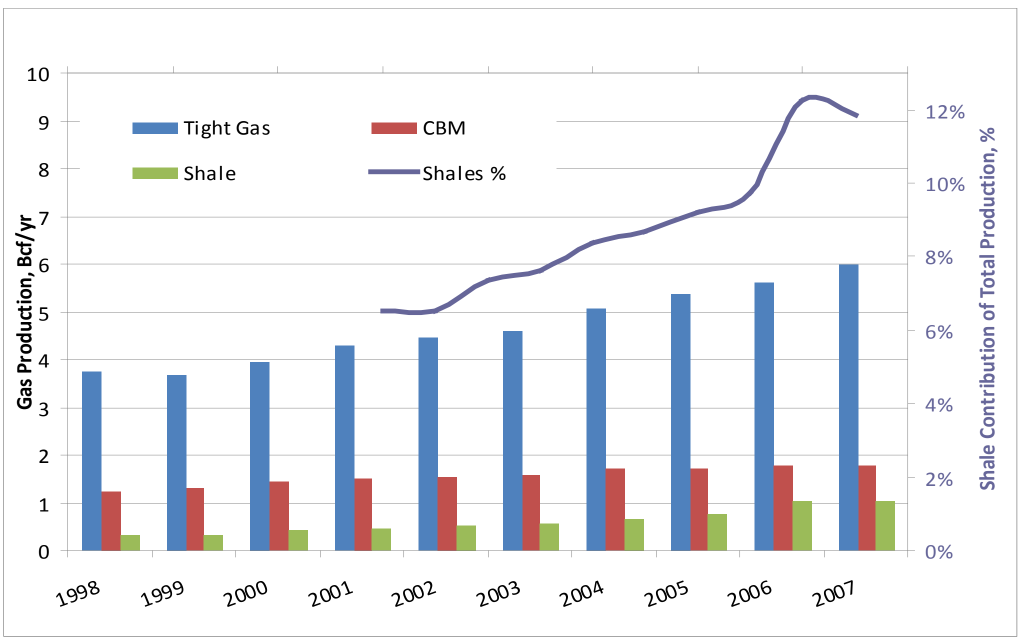

Fig. 1.4—Tight gas sands lead in yearly gas production (Navigant Study 2008)

Fig. 1.4 shows the percentage of unconventional gas production attributed to gas shales. Gas shale contributions continued to increase in the U.S., but almost doubled from 1998 when gas shales were making 6.5% of the unconventional gas in the U.S. to about 11.8% in 2007.

The gravitation of the gas industry towards unconventional gas resources is best explained by the resource triangle (**Fig. 1.5)**. The effort to increase gas reserves in an environment with high gas prices requires companies to look for fields of lesser quality.

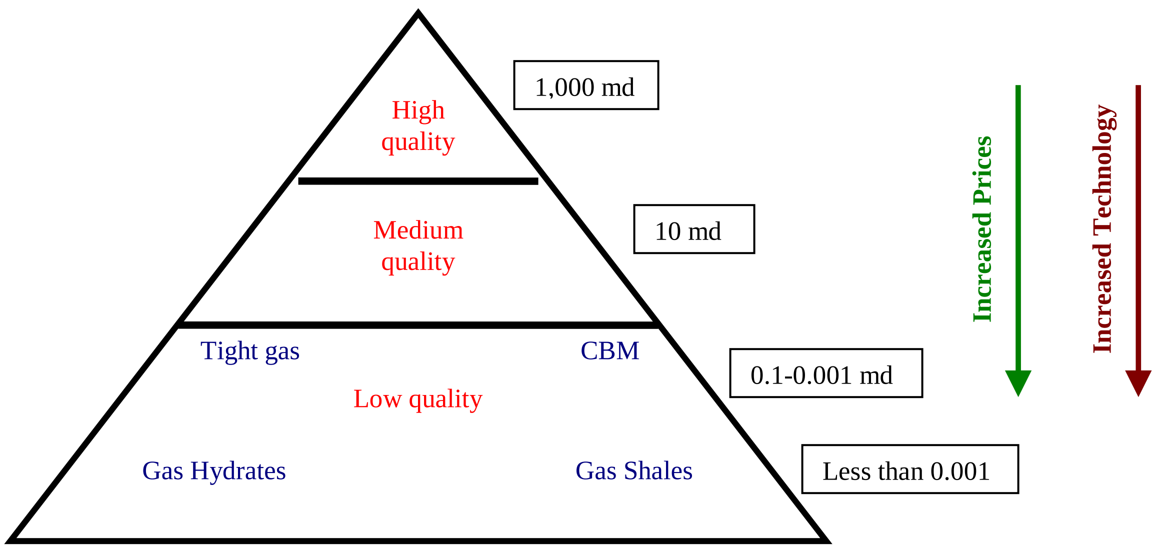

Fig. 1.5: Resource Triangle--The tip of the triangle represents a small number of high quality gas fields while at the base there is a greater number of lower quality gas fields (Holditch 2006)

Holditch (2006) uses the resource triangle to demonstrate the value and importance of unconventional reservoirs. At the apex of the triangle are the high quality gas reservoirs. These reservoirs are few and do not represent the majority of total value of gas in place (resources), but the appeal for producers is that when a conventional gas field is discovered, its development is rather straightforward. Taking a step lower into the resource triangle, the triangle illustrates the medium quality reservoirs. There are more medium quality reservoirs than high quality reservoirs scattered around the world. In fact, the field size distribution of all gas reservoirs will be log-normally distributed. At the wider base of the triangle, the triangle displays the low quality reservoirs, which is the portion of the resource triangle where unconventional gas is represented. Unconventional gas reservoirs are characterized as low permeability, low quality reservoirs. However, the low quality reservoirs at the base of the triangle contain extremely large volumes of gas in place when compared to the high quality reservoirs at the apex of the resource triangle. Gas shales are unconventional reservoirs and fall into the low quality category. Another point to be noted is from top to bottom of the triangle, from high to low quality; it requires both high gas prices and ever improving technology to produce these resources economically.

With higher natural gas prices in the United States since 2000, a steady domestic demand for natural gas, and dwindling production from conventional fields in the U.S., the natural gas industry has been steadily moving into unconventional gas fields to provide the gas demanded in the market. Since 2000, the year when gas prices began to rise, proved reserves began to increase for the first time in over 30 years (**Fig. 1.6**).

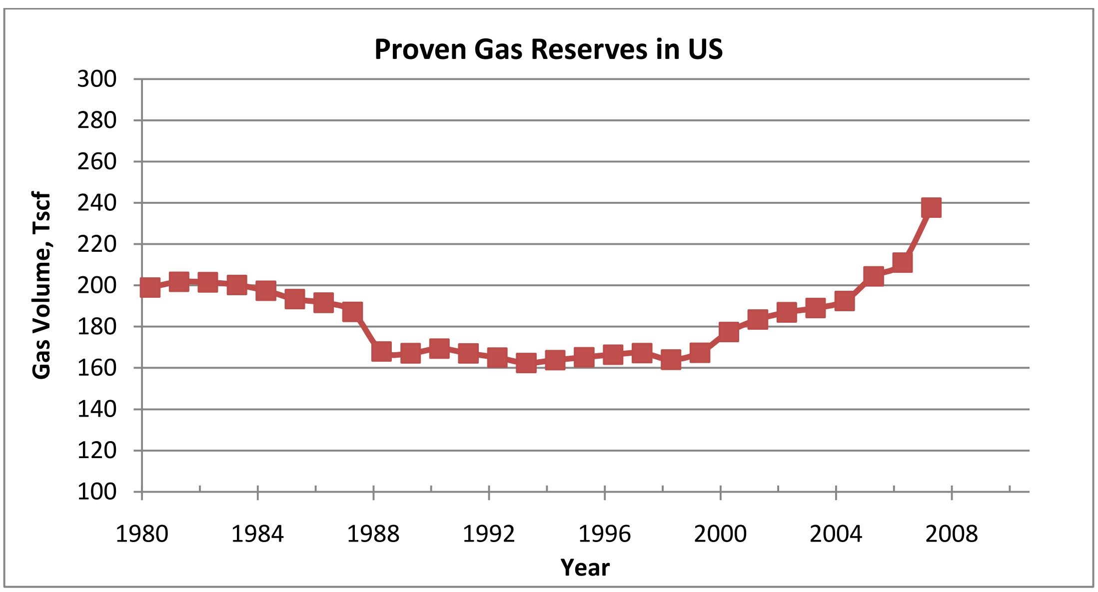

Fig. 1.6—Higher gas prices and improved technology have affected reserves (EIA 2008)

It can be observed that gas shales have become an important source of natural gas production in the United States. Importantly, most of this production has come from the Barnett shale in the Fort Worth area, yet several other important gas shales have been under development during the past 5 years or so, and these additional plays will soon add significant production to the national gas pipeline grid. These other gas shale plays like the Woodford, Haynesville, Fayetville, and Bakken are in very early stages of development when compared to the Barnett and Antrim shales. Given sufficient gas prices, however, it is expected these gas shale plays will experience similar levels of development as the Barnett shale. The exponential production growth of the total shale gas production with the Barnett shale supplying most of the production is shown below **(Fig. 1.7)**.

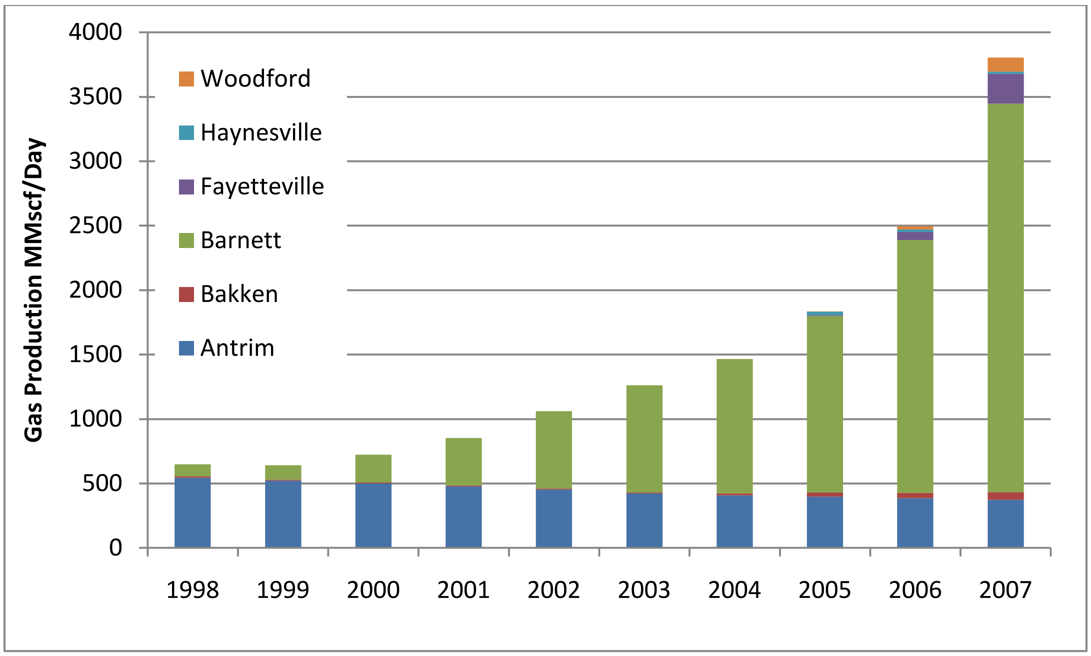

Fig. 1.7—Total gas shale production trend since 2000 (Navigant Study 2008)

1.3 Current View of Gas Shale Plays

Although gas shales are now a very important strategic play for many companies, the industry is still having difficulty determining what is the optimum drilling and completion techniques for wells drilled in the various shale reservoirs. The industry seems to optimize development in each different play by trial and error. Instead the industry needs to develop predictive models to help determine the optimum drilling, completion and stimulation options as functions of the shale reservoir properties and economic conditions. In short, the industry needs to determine best practices for various shale scenarios. Another reason that compilation of knowledge and data transfer are so imperative is that our workforce is aging, and within the next 10 to 15 years, nearly half of the employees working in the oil and gas industry will reach retirement age; hence, without proper documentation, much of the knowledge needed to develop unconventional gas reservoirs will retire with these employees.

As companies continue to increase their activity in gas shale reservoirs, it will be important to decide how to best drill and complete these wells since the technology and understanding are immature. Thus, there can be a steep learning curve for new companies or new shale plays that can delay many projects and lost profit due to development mistakes. The largest uncertainties and the highest cost in most shale plays are the drilling, completion and stimulation methods that should be used in any development program. Currently, companies use trial and error to determine what works best for each shale basin.

In gas shale reservoirs as in most unconventional reservoirs, the reservoir characteristics can vary substantially both vertically and areally. However, despite these variations, shale reservoirs in different basins can be evaluated compared and best practices should be somewhat transferable. If engineers and geologists look for differences and similarities in reservoir and geologic properties, then it should be possible to use best practices to design the drilling and completion operations to optimize gas recovery and economics. Most reservoir engineers working in gas shale development do not have the time to do a thorough study of industry-wide activity to help determine what is working in other areas and what is not. However, if such information is made available, shale gas development could potentially escalate and help the U.S. to meet its energy demand as well as help the development of international gas shale fields.

A compilation of lessons learned and best practices can be found in the oil and gas literature. Using this information, we can develop flow charts/diagrams to allow the application of best practices in new or even existing gas shale plays. This study will help engineers and geologist better understand which drilling and completion practices are successful in plays similar to theirs as well as to determine which completion technique is best in a given economic environment.

1.4 Research Objectives

Gas shales are now a very important part of the current industry activity and of the many facets being scrutinized, the most important one is how to economically and effectively drill and complete these wells safely, while maximizing the value of each well. There are several factors that need to be explored to determine how to optimally complete and produce from any specific gas shale formation. Depositional environment, TOC, gas content, shale mineralogy, shale thickness, and reservoir pressure are the main properties that affect how the shale will produce and what technology works in each play. Once these factors are known and coupled with the price environment, it is easier to decide which completion technique is most suitable, whether it is vertical or horizontal well. Once that decision has been made on what type of well needs to be drilled, the completions and stimulation procedures becomes crucial to the success.

The objective of my research has been to (1) review literature to establish which geologic parameters are most important in deciding the optimum completion techniques in five emerging gas shales in the United States: the Antrim Shale, the Barnett Shale, the Haynesville Shale, the Marcellus Shale, and the Woodford Shale; (2) identify different completion ideologies for each respective gas shale basins, (3) create an economic model for each completion technique discussed, (4) develop a sensitivity analysis on prices to determine which completion strategy is optimal, and (5) offer my findings in the form of flowcharts on which completion designs should be selected based on given geologic parameters as well as price environment.

CHAPTER II
GAS SHALE PROPERTIES

2.1 Overview of Gas Shale Systems

Due to the success of producing large volumes of gas from the Barnett Shale and now the Haynesville Shale, the petroleum industry has switched gears from looking at shales as a source rock to analyzing shales as possible gas reservoirs.. Most believe that gas shale systems are vastly different from other unconventional plays because of the nature of producing from a source rock; thus, making it difficult to determine optimum drilling, completion and stimulation methods for these reservoirs. Since these source rocks are also reservoir rocks, the environment during deposition must have been anoxic, meaning that organic rich material could settle with minimal oxygen contact; therefore, allowing the material to later generate hydrocarbons. As shale is buried, there are two main processes that the shale undergoes to generate gas. Biogenic gas can be formed through the action of anaerobic micro-organisms or thermal gas through the thermal breakdown of kerogen. With the use of vitrinite reflectance (VR) and core analysis, the origin of the gas can be determined as either biogenic or thermal. Gas shale rocks that are organic-rich are usually dark color (brown/black) with high TOC content (can be higher than 10%), and high gamma ray signatures (greater than 140 API units). The porosity and permeability of these organic shales will be a function of compaction during burial history.

Most producing gas shales will produce gas that is stored in one of two places: free gas in the pores and natural fractures, and gas that has been adsorbed to the organic material in the shale. Free gas is the same as the gas that is in the pores and natural fractures found in most formations. Adsorbed gas is the gas that is attached to the surface of the organic matter and is only released as the pressure in the reservoir declines. Tests must be run using cores in a laboratory to determine how much gas will be desorbed from the surface of the shale as the reservoir pressure declines. Once known, the volume of desorbed gas production can be easily modeled and predicted.

The main geologic parameters we must know to determine the quality of a gas shale reservoir are depositional environment, total organic carbon (TOC), average gas content, shale mineralogy, thickness, and reservoir pressure. The depositional environment is very important for determining a commercially viable shale gas reservoir because this affects how the hydrocarbons are formed, establish if hydrocarbons are even present, and determine what type of hydrocarbons might exist in the shale. TOC is another factor to evaluate because it is indicative of the quantity of organic material available for the formation of hydrocarbons, it can be directly proportional to the yield of gas, and it allows evaluation of organic matter transformation.

The average gas content is important since this is indicative of what is in place and it can be used to forecast what is recoverable. In general, shales with high values of gas content also have higher values of gas permeability. Obviously, a more porous and permeable shale will contain more gas and will allow its production at higher gas flow rates. Shale mineralogy is vital to the success of any gas shale play. If there is a high clay content, the shale will be more difficult to fracture treat and more difficult ot keep a fracture propped open over time. If a shale contains more quartz, the shale will be more brittle, it will fracture treat easier and it will be easier to keep a hydraulic fracture propped open.

Thickness is another parameter that is important to the commercial gas shales. It is difficult to produce from shales that are less than 50 feet because of the area of contact and there might not be much gas in place. Most of the thinner shales tend to be uneconomic. Likewise, if a shale is too thick, it can become more difficult to determine the best layers to produce from and the effectiveness of horizontal drilling is reduced in thick formations, unless large fracture treatments are pumped or multiple horizontal holes are drilled. Reservoir pressure also plays a key in determining the gas in place and gas recovery of the gas shale. In gas shales with high pressure gradients, the shale may have never been compacted and it is likely the porosity and permeability of gas shales with high pressure gradients will be better than low pressure gas shales, all things being equal.

The geologic parameters described above will be discussed for five emerging gas shale basins—Michigan Basin (Antrim Shale), the Fort Worth Basin (Barnett Shale), the North Louisiana Salt Basin (Haynesville Shale), the Appalachian Basin (Marcellus Shale), and the Arkoma Basin (Woodford Shale).

2.2 Review of Gas Shale Geologic Parameters

2.1.1 Antrim Shale

The Antrim Shale is a gas shale where production occurs mainly along a belt that crosses the northern part of the Michigan Basin (**Fig. 2.1**) that has been producing since the early 1940s (Goodman and Maness 2008). Even with such an early discovery, the Antrim shale did not become active (economic) until the 1980s. Goodman and Maness (2008) indicate that as of 2008, the Antrim shale formation has produced over 2.6 TCF of gas from almost 10,000 wells. Based on the U.S. Shale Gas study done by Halliburton (2009), the estimated gas-in-place is anywhere from 35 to 76 TCF. The typical depth that this formation is encountered in the basin is between 500’ to 2,000’ and extends aerially approximately 30,000 sq miles (Goodman and Maness 2008).

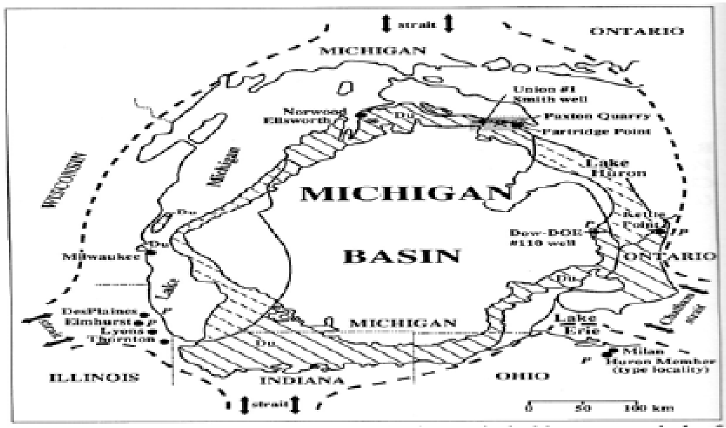

Fig. 2.1—Antrim shale located in Michigan Basin (Ferguson, Riestenberg, and Kuuskraa 2007)

Through the use of Vitrinite Reflectance (VR) and core analysis, it was concluded that the Antrim shale produces biogenic gas as opposed to thermogenic gas (Goodman and Maness 2008). From the Antrim shale outcrop, it is black in color, organic rich, brittle, radioactive, and contains bitumen (Kuuskraa and Wicks 1992). Due to the radioactivity in the shale, the shale is easily spotted on a gamma ray log (**Fig. 2.2**).

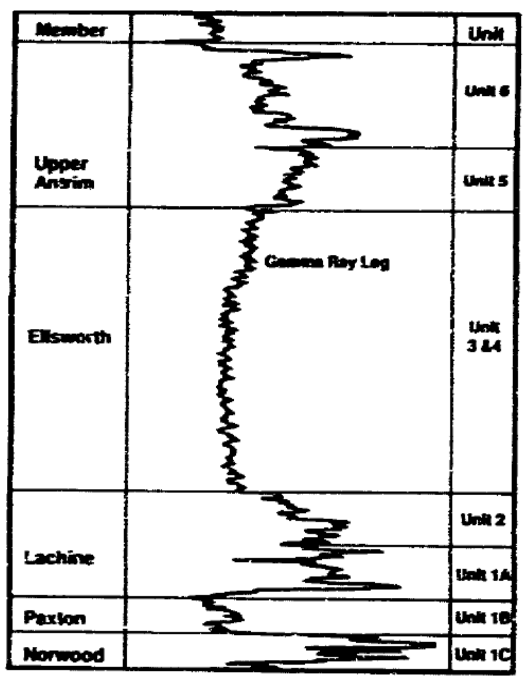

Fig. 2.2—Gamma ray log of Antrim shale (Kuuskraa and Wicks 1992)

Understanding the potential recovery of the Antrim shale is difficult due to three main factors according to Kuuskraa and Wicks (1992). The first is that this shale produces a substantial amount of water along with the gas production, similar to many coalbed methane reservoirs. The presence of this water complicates the system since it behaves as a two-phase system. Second, since there is such a large amount of adsorbed gas and the system of storage, release and diffusion of gas in shales is poorly understood. Third, the Antrim is a naturally fractured formation. It is difficult to identify the "sweet spots" in this basin because there is difficulty in determining where the highly fractured areas exist (Matthews 1989).

Depositional Environment

According to R.D. Matthews (1989), the stratigraphy in the Michigan Basin, the Antrim shale was deposited in the late Devonian and early Mississippian time period in the Michigan basin. This shale was generated as part of a large Devonian-Mississippian "Black-Shale Sea" which deposited this organic rich formation from the Transcontinental Arch found in the west to the Appalachians found in the east. When the Antrim shale began depositing in the Michigan Basin, it was deposited as a shale-sand sequence. In modern day, it is observed that moving from the center of the basin to the margins, the shale rises but then truncates under a cover of glacial drift on land or under the lake sediment deposits of the Great Lakes. Since there is an absence of the Devonian-Mississippian shales across the basin margins, it is conclusive that extensive erosion took place throughout much of the continental interior during the late Devonian period. Also, there is evidence that the removal of the Palezoic rocks that were once present in the Michigan basin are found in the elevated organic maturity of the rocks now present in the basin (Matthews 1989).

Kuuskraa and Wicks (1992) discuss how during its deposition and the burial history, four distinct layers, as seen in Fig. 2.2, were formed which are considered the Antrim shale: Upper Antrim, Lachine, Paxton, and Norwood on the bottom. The Upper Antrim is made up of several different unit formations. Traditionally, the Upper Antrim is picked at the top of the first black shale beneath the Bedford formation. The Ellsworth shale occurs between the upper Antrim section and the lower Antrim section that compose the Antrim Shale. The Ellsworth is gray to greenish gray; distinguishing itself from the Antrim members. The Lachine is marked by an increase in the gamma ray log. The top of the Paxton can be identified by a sharp decrease in the gamma ray log and the top of the Norwood is distinguished by the sharp increase on the gamma ray log. By these deflection differences in the gamma ray, it is easy to see where the different layers are in a new well or using it to correlate between wells. Fig. 2.2 also depicts these attributes of the different stratigraphic members of the Antrim Shale.

TOC

The organic content in the Antrim shale can be as high as 20%. Matthews indicates that most of this organic material is algal, meaning that hydrocarbons in place come from mostly plant material instead of animal. Some of the plant materials encountered in this shale are tree branches, Callixylon newberyi, Tasmanite spores, etc. Also, there are some fish scales found and other small animal fossils impressions are present in the shale (Matthews 1989).

Gas Content

The total average porosity found throughout the Antrim shale is approximately 9% but can range from 3% to 10%. Of that 9%, the average gas porosity is from 2% to 6%. This porosity only takes into account the free-gas that is available in the pores and not the adsorbed gas. Since the Antrim shale is shallow compared to other producing shale gas reservoirs, it is important to know the amount of absorbed gas since that will probably be liberated when the well begins production and the reservoir pressure decreases. About 60% to 70% of the gas in this gas shale system is adsorbed indicated by Kuuskraa and Wicks (1992). Gas content is important in determining how much cubic feet of gas is in place per ton of rock. Phasis Consulting (2008) states that for the

Antrim Shale, the gas content ranges from 40 scf/ton to 100 scf/ton, depending on the location of the one well in different portions of the basin. Since there is such a large range in the gas content, the EUR varies quite a bit in the Antrim. Through core analysis, pressure transient testing, and well testing, Pickering (2009) believes that the estimated ultimate recovery (EUR) could be as low as 20% to as high at 60%. If the recovery factor actually gets high enough to 60%, it can be deduced that operators will produce adsorbed gas that will be released.

Shale Mineralogy

The mineralogy of the Antrim shale, as stated by Matthews (1989), is rather uniform and contains both quartz and clay. The Antrim Shale has unusually high quartz content compared to many other shales making it ideal as a reservoir rock. Antrim can have up to 50% to 60% quartz in its mineralogy. This is almost twice the amount than other source rock shales in the U.S. The next abundant mineral in this shale is illite which makes about 20% to 35% of the shale. Remaining minerals found in the various quantities are kaolinite, chlorite, and pyrite. Calcite and dolomite may be present in the form of limestone nodules and lenses in the lower half of the shale as thick as 5 feet. About 0.2 to 0.8% of bitumen is found in this shale as well.

Thickness and Reservoir Pressure

The shale thickness increases to the northwest and to the east. An isopach map of the entire Antrim Shale found in the Michigan basin (**Fig. 2.3)** is shown below.

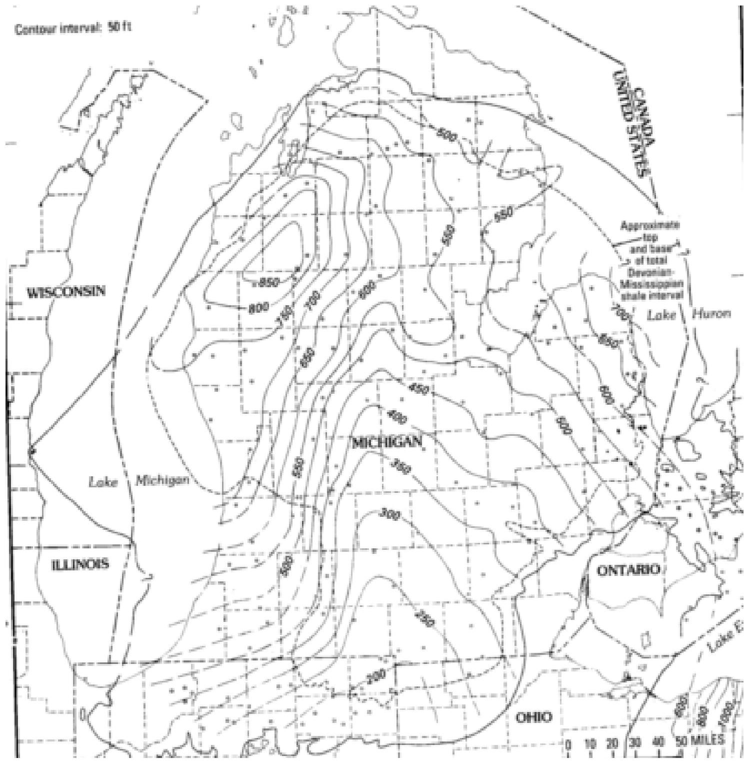

Fig. 2.3—Antrim shale isopach map (Matthews 1989)

The Antrim shale is found at depths anywhere from 500 feet to 2,000 feet depending on which location of the basin is being studied. The deeper depths (>1,500 feet) are located at the center of the basin and get shallower towards the margins. The gross thickness of the Antrim shale ranges between 200 feet to 850 feet. Of the gross thickness, 70-120 feet is considered to be net pay yielding a high net-to-gross ratio (Phasis Consulting 2008).

The average reservoir pressure in the Antrim Shale relayed by Hayden and Pursell (2009) is approximately 400 psi at 1,150 feet, yielding a pressure gradient of 0.35 psi/ft to 0.38 psi/ft. This is lower than normal hydrostatic pressure but because of low pipeline pressures, the industry still produces the Antrim shale economically. One thing to note is that since the pressure is now below hydrostatic pressure, there are some wells that must be producing adsorbed gas in addition to free gas in the pore volume. Most of the wells are on artificial lift to remove water from the wellbore.

2.1.2 Barnett Shale

The Barnett Shale is the most active gas shale in the U.S. and is located in the Fort Worth Basin. Natalie Givens and Hank Zhao (2008) reveal the history of not only the Barnett Shale but also some geologic information of the Fort Worth Basin. The Fort Worth basin covers roughly 15,000 square miles of North Texas (**Fig. 2.4)**. Of the 15,000 square miles, the Barnett shale covers approximately 5,000 square miles and has depths ranging from 6,500' to 8,500' deep.

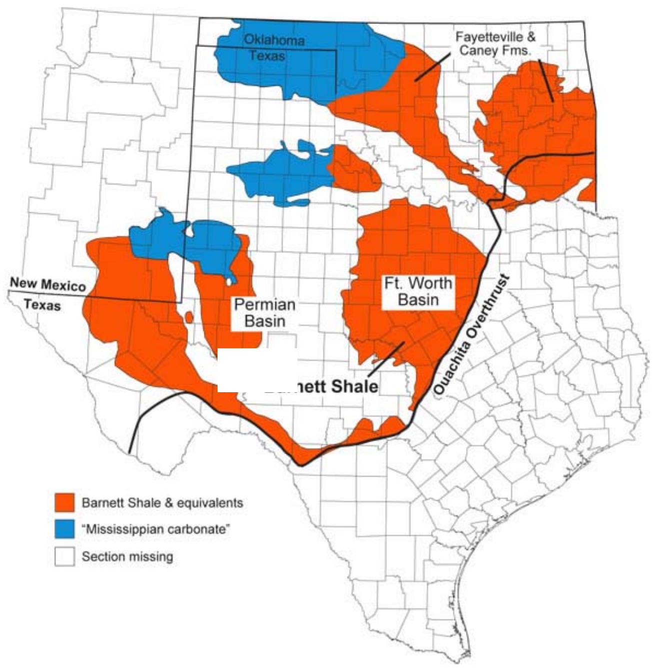

Fig. 2.4—Barnett shale located in the Fort Worth Basin (Givens and Zhao 2008)

The first Barnett well was drilled in 1981 in Wise County, but not much additional drilling activity occurred in the 1980's (Brackett 2006). Marc Airhart (2007) states that the reason for the Barnett drilling program take off in the late 1990's was due to higher prices for natural gas as well as improvements in drilling technology. Based on data that was published (Pickering 2009), production and rig count increase is shown below (**Fig. 2.5)**. According to Brackett (2008) as of July 2008, the Barnett has produced about 4.5 TCF of gas. The estimated gas-in-place is between 25 TCF and 30 TCF (NKNT 2008). The Barnett Shale is also present in other basins such as the Permian Basin; however, an overwhelming majority of the wells have been drilled in the Fort Worth Basin. Completion techniques found most economic in the Barnett Shale can be used in the other basins where the Barnett Shale exists under similar geologic conditions. However, the areal extent is so large that there is no guarantee that the Barnett Shale in Oklahoma will be similar to the Barnett Shale in the Ft. Worth Basin or the Barnett Shale in West Texas. It is important to look at all the shale properties before determining an analogy.

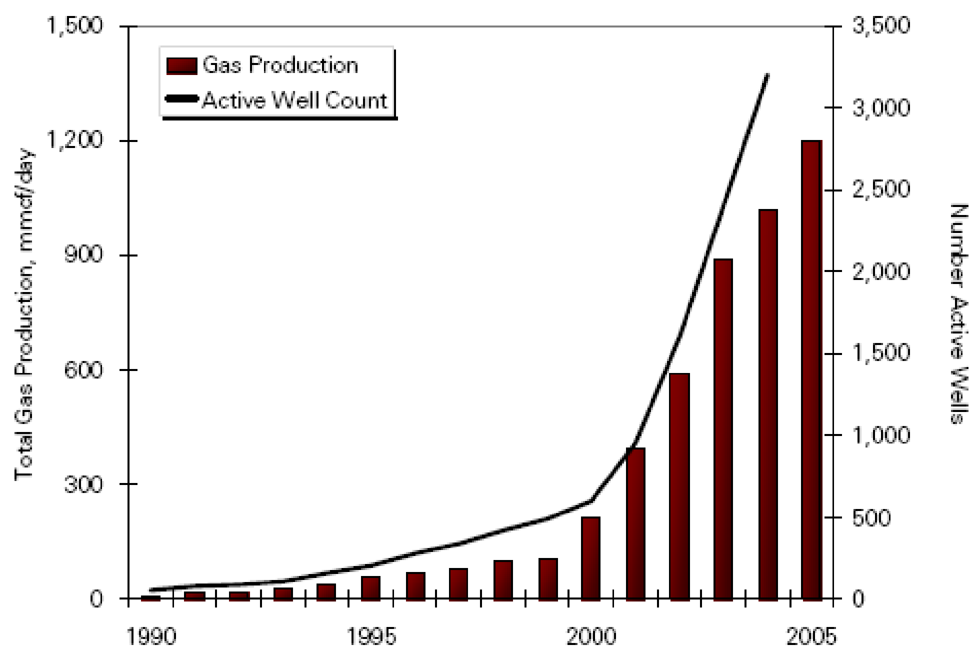

Fig. 2.5—Yearly production curve for the Barnett shale (Pickering 2009)

Although the Fort Worth Basin is very large, most of the wells have so far been drilled in and around the Newark East field **(Fig. 2.6)**. The Newark field is bounded by the Muenster arch to the north and east, the Ouachita Structural Front to the east and south. The Barnett shale outcrops at the Llano uplift located in central Texas. There are small faults that go through the field shown in Fig 2.6 (Source Rocks as Reservoirs 2008). Currently, the Newark East field is the largest shale-gas field in the world.

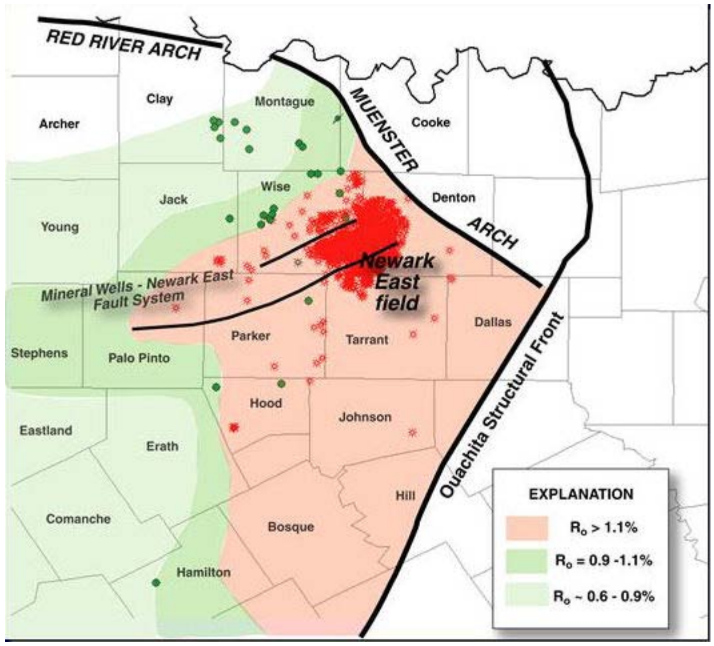

Fig. 2.6—Newark East field location in the basin and the thermal maturity of the Ft. Worth Basin (Source Rocks as Reservoirs 2008)

Through the use of VR and core analysis, it is concluded (Jarvie 2004) that the Barnett shale is capable of producing either gas or oil depending on where you drill the well. This thesis will discuss only the gas component, which is the primary hydrocarbon produced from the Barnett Shale in the Ft. Worth Basin. Pickering (2009) states that the Barnett produces thermogenic gas as opposed to biogenic gas created in the Antrim shale. The Barnett shale has original organic richness and hydrocarbon generation capability, primary and secondary cracking of kerogen, retention of gas by adsorption, and porosity due to decomposition of organic matter. The Barnett shale is black, organic rich, siliceous, and very hard (Jarvie, Hill, Ruble, and Pollastro 2007). A typical Barnett Shale well log is provided below **(Fig. 2.7)**.

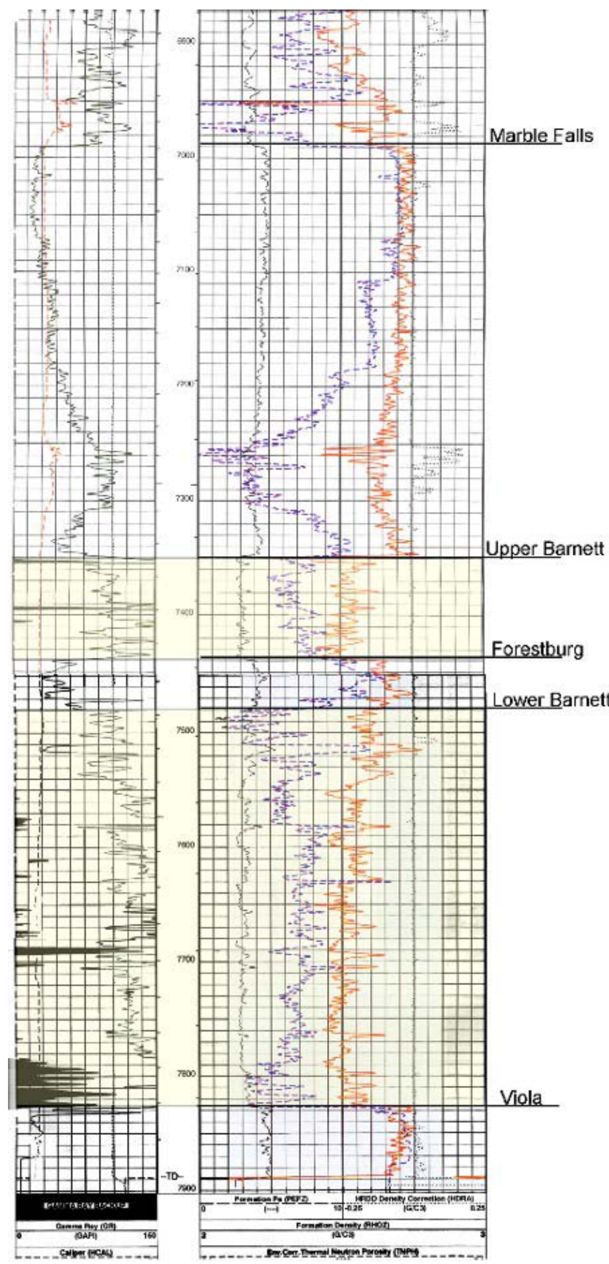

Fig. 2.7—Type log of the Barnett shale (Givens and Zhao 2008)

Givens and Zhao (2008) discuss that to truly understand the potential gas recovery from the Barnett shale is difficult because of three factors. The first is that this shale has a variety of minerals in the shale, and the shale has layers with varying lithology. This makes it difficult to correlate reservoir parameters regionally. Second, to understand the distribution of hydrocarbons in this basin, it is also important to understand the faulting and fracturing that occurs throughout the area. Knowledge of the faults and fractures provides the necessary channels for gas flow and migration. Since the Barnett shale has a very intricate and multifaceted fracture system, it is often tricky to determine fracture length and how well the wellbore is connected to the reservoir. The third factor is the regional faulting and underlying Ellenberger karsting.

Depositional Environment

Givens and Zhao (2008) as well as Lancaster et al (1992) state the depositional environment of the Barnett shale which consists of sedimentary rocks that were deposited during the late Mississippian time period where a marine transgression took place that originated by the closing of the Iapetus Ocean Basin. The Oklahoma aulacogen, which the Barnett shale is deposited on, subsided as a result of the middle or late Mississippian collision of the North American plate with the South American plate. As the Pennsylvanian age came to an end, the Ouachita Thrust belt began to infringe upon the Barnett shale sediments and created the foreland basin along the front of the thrust **(Fig. 2.8)**.

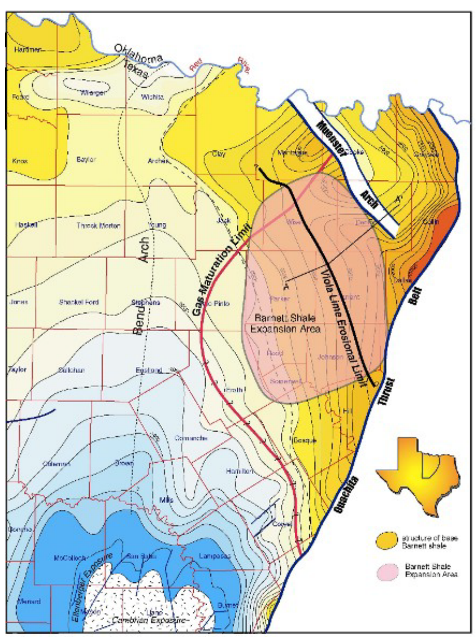

Fig. 2.8—Extent and boundaries of the Fort Worth Basin (Givens and Zhao 2008)

In modern day, the Barnett thickens north and east and is thickest just south of the Muenster Arch. This increased thickness is due to the interstratifications of the shales, limy shales, and the lime beds that were unevenly deposited over the basin. The Barnett shale rests directly on top of the Ordovician Viola Limestone or Ellenberger Limestone. Before the Barnett shale sediments were deposited, the Viola began eroding and pinched out exposing the Ellenberger formation **(Fig. 2.9)**. A major unconformity is present between the Ellenberger/Viola and the Barnett on top of the Precambrian crystalline Llano Uplift (Pickering 2009).

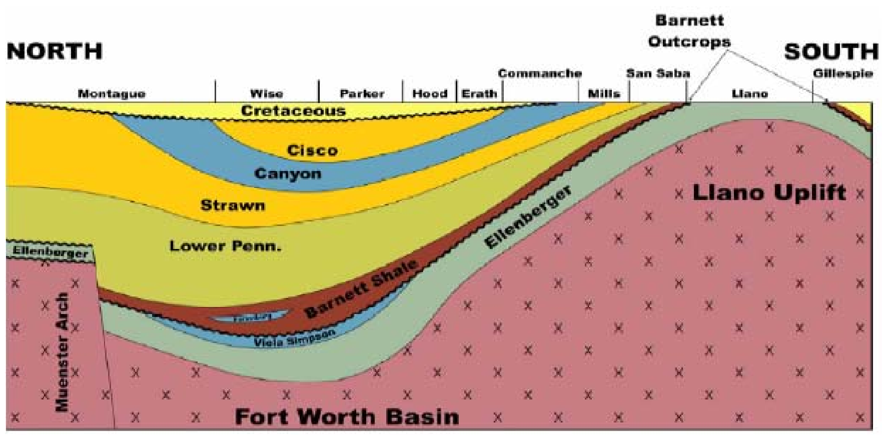

Fig. 2.9—North-South cross section of the Fort Worth Basin (Pickering 2009)

During deposition and the burial process, two distinct layers (**Fig. 2.10)** formed, which are considered the Barnett shale: the upper and lower Barnett. These two layers are very distinct in the northeastern part of the basin, in which the Forestburg limestone separates the shale into the two zones. The upper Barnett is uniform in thickness at about 60-70 ft throughout the entire northeastern basin. On the other hand, the lower Barnett ranges in thickness from over 600 feet in the northeast portion near the Muenster arch to less than 50 feet near the Bend arch in the western part of the basin. In the remaining area of the basin, there is no identifiable difference between the upper and lower Barnett Shale as discussed by Loucks and Ruppel (2007).

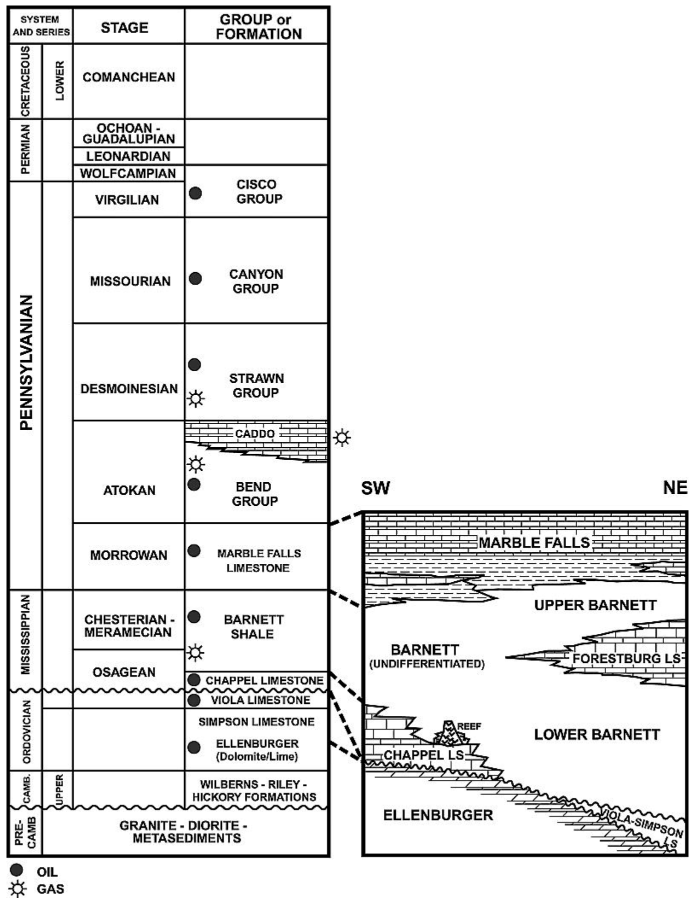

Fig. 2.10—Stratigraphic column of the Fort Worth Basin (Givens and Zhao 2008)

TOC

The organic material present in the Barnett shale can be as high as 12%, but on average it is about 4.5%. Loucks and Ruppel (2007) investigated the mineral make up of the Barnett shale. The thinner grains contain accumulations of silty biomicrite, fossiliferous silty shale, and fossiliferous intraclast conglomerates containing abundant phosphate clasts. The coarser material found contains skeletal components derived from an assorted group of marine invertebrates that include brachiopods, sponges, pelecypods, gastropods, cephalopods, conodonts, and echinoderms. Other species found in the Barnett are crinoids, burrows, benthic foraminifera, filibranch mollusks, bryozoans, ophiuroids, agglutinate foraminifera, and radiolarians. This shows that plant and animal matter form the Barnett shale and depending on which part of the basin is being studied, the organic matter changes (Hickey and Henk 2007).

Gas Content

The total average porosity of the Barnett shale is anywhere from 3% to 8% with an average of 5%. Of that 5%, the average gas porosity is roughly 2% to 6%. This porosity only takes into account the free-gas that is available in the pores and not the adsorbed gas. Nearly 70% to 85% of the gas in the Barnett Shale is found in the free state (Hayden and Pursell 2009). About 15% to 30% of the gas in this gas shale system is adsorbed, which is not considered too much gas since there are such low recovery factors in the Barnett. Since there is less gas that is adsorbed, the gas content for the Barnett is higher than many other shale plays. It is not uncommon to find a gas content anywhere from 300 to 350 scf/ton in the Barnett shale, which can yield high EURs. From core analysis, pressure transient testing, and well testing, the industry believes that the EUR is 10-20% (Hayden and Pursell 2009).

Shale Mineralogy

Hickey and Henk (2007) report in their paper that although the Barnett is sometimes called a homogenous black shale, it contains an assortment of organic-rich lithofacies. Some of the most common lithofacies are siliceous, calcareous, or phosphatic composition. The Barnett shale has a high quartz content that makes up approximately 40% to 45% of the formation. The next most abundant mineral type is clay, which comprises 20% to 40% of the formation. In addition, pyrite content may be as high as 5%. Remaining minerals, found in the various quantities, are feldspar, calcite, dolomite, siderite, and ankerite.

Thickness and Reservoir Pressure

The Barnett shale thickness increases towards the Muenster Arch which is located to the east-northeast of the Fort Worth Basin (**Fig. 2.11)**.

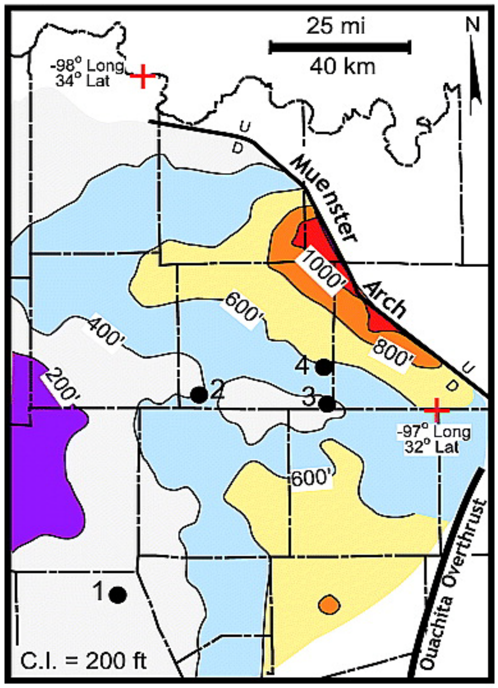

Fig. 2.11—Barnett shale isopach map (Loucks and Ruppel 2007)

Barnett shale gas production occurs at depths of 6,500 feet to 8,500 feet, depending on location in the basin. The gross thickness of the Barnett shale varies from 200 feet to more than 1,000 feet, and the net thickness is approximately 100 feet to 600 feet (Pickering 2009). The upper Barnett is uniform in thickness which is about 60-70 ft in the northeastern basin and the lower Barnett ranges in thickness from more than 600 feet in the northeast portion near the Muenster arch to less than 50 feet near the Bend arch found in the western part of the basin (Loucks and Ruppel 2007).

According to Hayden and Pursell (2009), the original reservoir pressure in the Barnett Shale Basin is 3,000 psi to 4,000 psi, yielding a pressure gradient of approximately 0.42 psi/ft to 0.46 psi/ft. The variation of the reservoir pressure is due to the depth. At shallower depths, the pressure is lower, and it is imperative to ensure there are no surface pressure issues to prevent long-term production delays (i.e. pipeline pressures, pipeline capacity constraints, etc).

2.1.3 Haynesville Shale

The Haynesville Shale is a gas shale that is present in many different basins in the southeastern United States (**Fig. 2.12)**, but most of the recent drilling success has been in the North Louisiana Salt Basin (Goddard, Mancini, Talukar, and Horn 2009). This shale is also referred to the Shreveport shale, because most of the activity is in or around the Shreveport area.

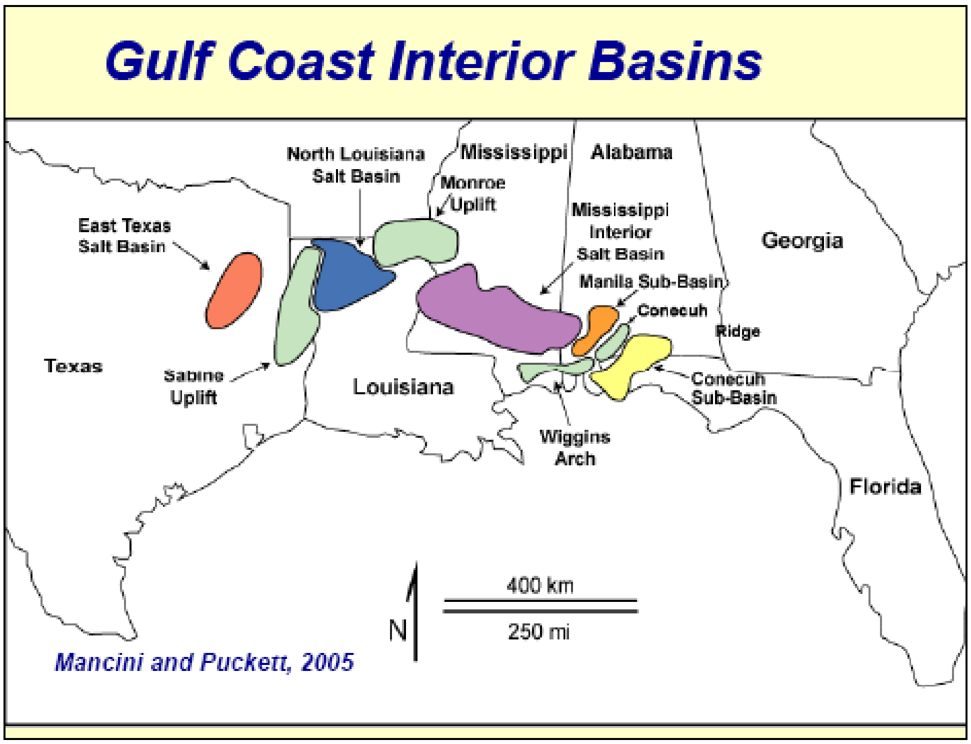

Fig. 2.12—Haynesville shale located across the southeast U.S. (Goddard, Mancini, Talukar, and Horn 2009)

According to Durham (2007), the first Haynesville well was drilled in 1905, but the play did not receive much attention until EnCana Oil & Gas drilled in January 2006. Samson Contour drilled the next Haynesville well in June 2007. After the success of the vertical Haynesville well, the first horizontal well was permitted and drilled by Chesapeake in August 2007 which ignited not only interest in the oil industry but a plethora of land acquisition and trades. The production from the Haynesville shale, shown by Drilling

Info (2008), has exponentially increased in a matter of months once horizontal wells started to be drilled **(Fig. 2.13)**.

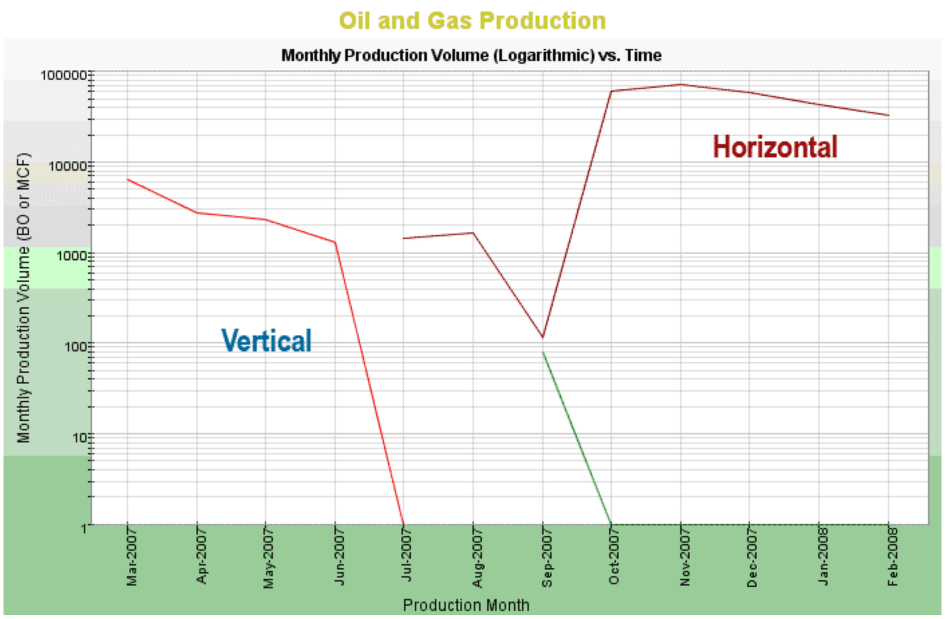

Fig. 2.13—Haynesville shale production (DrillingInfo 2008)

Currently, this Haynesville shale is producing 25 MMCF/D from the North Louisiana Salt Basin and from the whole play, which includes Texas and Louisiana areas, the Haynesville produces approximately 40 MMCF/D based on data collected in December 2008 (Goddard et al 2009). Since this is a new play, there is still some uncertainty to how much gas is in place but current estimates suggest that there is anywhere from 250 to 320 TCF. The typical depth that this formation is encountered in the basin is between 9,000’ to 16,500’ and extends aerially approximately 9,000 sq miles. A common phenomenon seen is that the Haynesville shale gets deeper as the field dips toward the Gulf of Mexico (Goddard et al 2009).

Through the use of gas samples taken, it was concluded that the Haynesville shale produces thermogenic gas like the Barnett does in East Texas. The Haynesville shale is grey black to blackish green color shale that contains muddy fine-grained sandstone, laminated fine-grained sandstone, sandy mudstone, and silty mudstone. These characteristics can be seen in the type log for the Haynesville Shale **(Fig. 2.14)**. Fig 2.14 illustrates that the typically the Hayesville shale will have a high gamma ray count that is about 135 API unit (Goddard et al 2009).

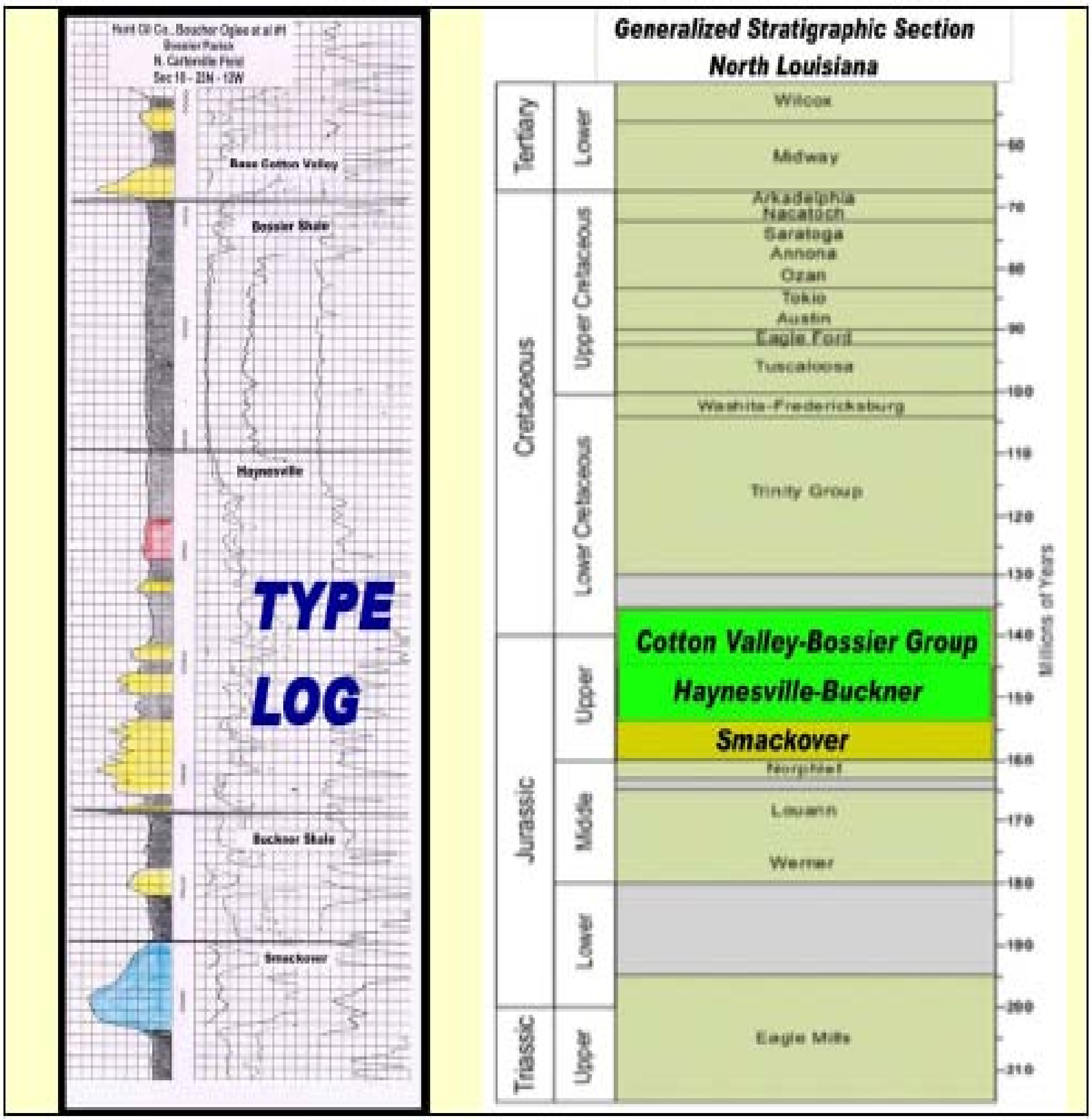

Fig. 2.14—Type log of the Haynesville shale (Goddard, Mancini, Talukar, and Horn 2009)

The Haynesville is a fascinating play due to the size of the play itself. As shown previously (Fig. 2.12), this play spans throughout Louisiana, Alabama, Mississippi, and Texas. Many shale plays seems to be isolated to one basin or at the very least one state where it is considered productive, but the Haynesville is found to be productive throughout the southeastern portion of the United States. My research will focus on the Haynesville in the North Louisiana Salt Basin, since that is where most of the publicized activity is but it is worthy to note that Texas and Mississippi are both undergoing large development because of the blanket deposit of the Hayneville Shale. Like most thick, black shales, the Haynesville was deposited in a deep water marine environment so it will cover a very large areal extent. The potential gas recovery of Haynesville is still unknown, but with the help of new technology, most believe the Haynesville Shale has enormous potential. There are some difficulties in producing the Haynesville that include it being very deep (>12,000 ft), lack of public data on production and geology, and aerial extent because it is a very new play area. Depth is a concern in this play since this formation can be found at depths ranging from 9000 ft to 16,500 ft. However, the Haynesville in many areas is overpressured and very permeable, so it can be produce even at such depths. It should be recognized that there will be limitations in well design, data collections, and completions due to the costs to develop the deep Haynesville; however, with recent advances in drilling and completion technologies, operators are developing the Haynesville at depths of 12,000+ ft.

Depositional Environment

Joseph Magner and John Wren (2008) indicate that the Haynesville shale was deposited during the upper Jurassic (Kimmeridgan) Period which took place approximately 150 million years ago. During the deposition of the Haynesville shale, the majority of the sediments found as part of the make-up of the shale flowed in from the north and northeast rivers that were present at the time. In fact, there are still traces of the three rivers found through drilling and use of seismic. Also, several geologic structures have been identified that show that a lagoon could have been present at the time of the

Haynesville deposition and that carbonate shoals surrounded the deposition of the organic matter into the basin. Most of the deposition of the very fine grained sand to silt sequence took place across the marine slope and the basin environment over an extended period of time which is the reason the Haynesville shale is thick and blanketed over such a large area. The Bossier shale sits on top of the Haynesville shale and there is still some debate as to whether or not it is considered as part of the Haynesville shale. The Bossier shale has similar roots in deposition as the Haynesville shale and in fact the Haynesville shale is sometimes referred to as the Lower Bossier shale. Above the Bossier and Haynesville shale lays a thick sand formation called the Cotton Valley Group which is continuous as well, providing an effective seal and prevention of any gas leaks.

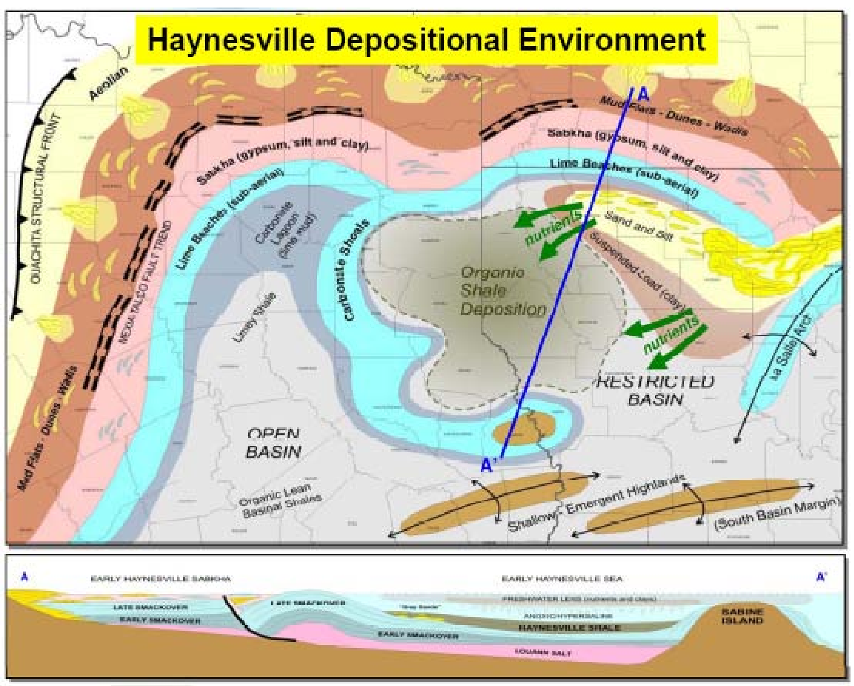

Fig. 2.15—Haynesville shale depositional environment (Revels and Gilbert 2009)

A picture that depicts the depositional environment for the Haynesville shale is shown above **(Fig. 2.15)**. This is just one interpretation of what the depositional environment appeared during the Jurassic period in this area. As industry knowledge expands through seismic interpretation, drilling, etc., this interpretation will more than likely evolve.

TOC

The organic material that is present in the Haynesville is approximately 2.83% but can range anywhere from 0.5 to 4% (Goddard et. al 2009). It is uncommon to find the lower end of the spectrum but there are reports that it could be that low. Most of this organic material in the Haynesville is terrestrial plant debris Type III kerogen. Large fossils fragments such as textularid-type foraminifera tend to collect together and can occupy anywhere from 2 to 10% of the rock volume. Filaments of organic material have been found as well in samples gathered throughout the basin (Magner and Wren 2008).

Gas Content

The total porosity throughout the Haynesville shale ranges from 6 - 15%. In many of the producing areas, the porosity averages 12%. Of that 12%, the average gas porosity is roughly 5% to 11% (Magner and Wren 2008). This porosity only takes into account the free-gas that is available in the pores and natural fractures, but does not include the adsorbed gas. The adsorbed gas in this play ranges from 20% to 30% of the total gas in place. Due to the high pressures and depth of the Haynesville shale, there is a small possibility that the adsorbed gas will be tapped into with current technology. The Haynesville has similar if not better gas content than the Barnett which has made this play very successful in the past few years. The gas content is anywhere from 350 scf/ton to 475 scf/ton throughout the North Salt Louisiana Basin. Since the Haynesville shale is deep, the free gas will be the only gas that will produce with present day technology. Therefore, recovery factors are based just on the volumes of free gas production not adsorbed gas production. Given that the Haynesville play is emerging and there is not established long-term production from these wells, there are theories on EURs for these wells based on knowledge compiled from other plays. Many gas shale plays have 1 to 0.7 ratio between initial production (IP) and EUR. For example, if a well has an IP of 2

MMCF/D then rule of thumb is that the EUR will be approximately 1.4 BCF. Therefore, EURs for each well, the industry is looking at an average EUR for each wellbore to be 2 to 8 BCF in horizontal completions and 0.5 BCF in vertical completions. In most Haynesville wells, the initial decline rate is very high and falls in the range of 50-80% (Goodard et al 2009). Through core analysis and well testing, the industry believes that the EUR for the Haynesville shale in the North Louisiana Basin is 34 TCF which is 13.6% recovery factor. With the development of new technology, the recovery factor could increase to 3-30% in the future.

Shale Mineralogy

Goddard et al (2009) reported that the mineralogy of the Haynesville shale contains both quartz and mudstones, which is mostly clay. The Haynesville has a good percentage of quartz content that is about 28% to 33%. The amount of quartz varies throughout the Haynesville contributing to areas known as “sweet spots” of the play. The next abundant material is clay minerals which range from 25% to 33% of the mineralogy. Remaining minerals found in the various quantities are calcite, dolomite, siderite, feldspar, and pyrite.

Thickness and Reservoir Pressure

The thickness of the Haynesville shale is relatively uniform throughout the North Louisiana Salt Basin with minor thinning and thickening. Studies are still underway to ensure proper characterization of the Haynesville shale (Hutchinson 2009). An isopach map of Southern Star Energy’s interpretation of the Haynesville shale trend as well as highlights key players and production rates that are transpiring throughout not only the North Louisiana Salt Basin but also other areas where the Haynesville is gaining momentum is depicted below **(Fig. 2.16)**.

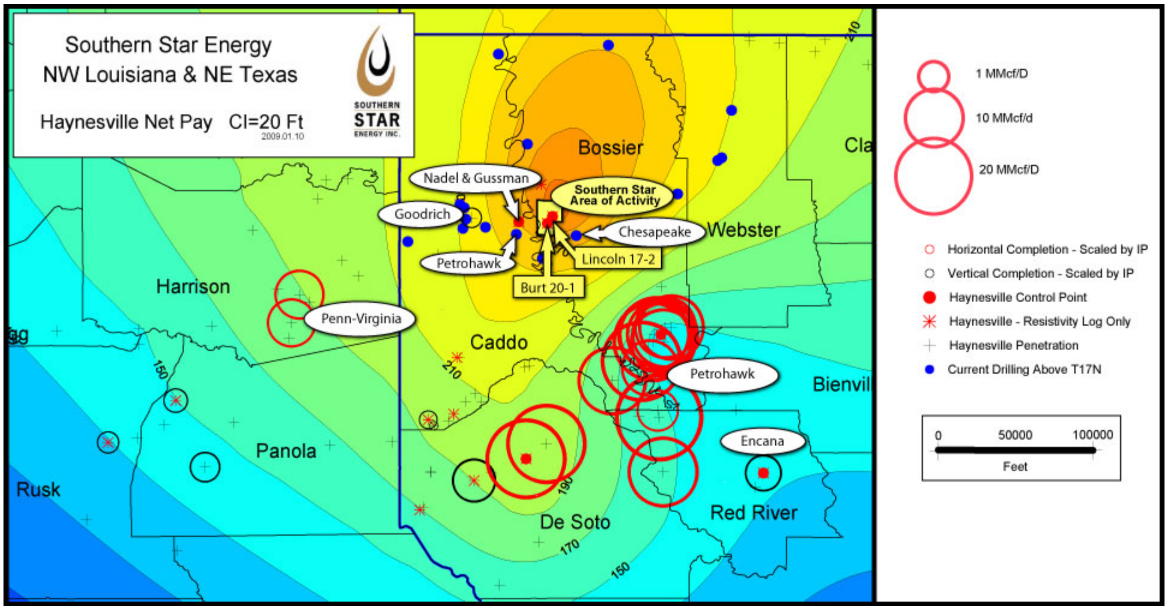

Fig. 2.16—Haynesville shale isopach: trend and activity map (Hutchinson 2009)

The Haynesville shale occurs at depths anywhere from 9,500 feet to 16,500 feet depending on where you are located in the North Louisiana Salt Basin. The gross thickness of the Haynesville shale is on average about 270 feet. Of the 270 feet, 100-200 feet is considered to be net pay showing a high net-to-gross ratio (Hutchinson 2009; Magner and Wren 2008).

Average Haynesville reservoir pressure in the North Louisiana Salt Basin is approximately 8,000 psi to 10,000 psi, yielding a pressure gradient of 0.7 psi/ft to 0.92 psi/ft (Goodard et al 2009; Chesapeake 2008). These are pressure gradients that are 1.5 to 2.0 times the normal gradient. Due to the depth of the burial in this basin and the overpressured shale, this area produces dry gas.

2.1.4 Marcellus Shale

The Marcellus Shale is a gas shale found throughout the Allegheny Plateau region of the northern Appalachian Basin (**Fig. 2.17**). This shale runs across the southern portion and Finger Lakes regions of New York, northern and western Pennsylvania, eastern Ohio, western Maryland, and throughout most of West Virginia (Bertola 2009). The Marcellus shale was first completed in the 1980's with foam fracture stimulation but really kicked off in 2000, and currently there are 14,000 wells currently producing from the Marcellus Shale[74]. The estimated gas-in-place is about 1,300 to 1,900 TCF with about 350 to 500 TCF recoverable which could be a low estimate because of the recent activity in this area. The typical depth that this formation is encountered in the basin is between 1,500ft to 8,500 ft—of that the producing depth is usually 4,000 ft to 8,500 ft (Chesapeake 2009)—and extends aerially approximately 54,000 sq miles and covers over 15 to 20 counties (Brackett 2008).

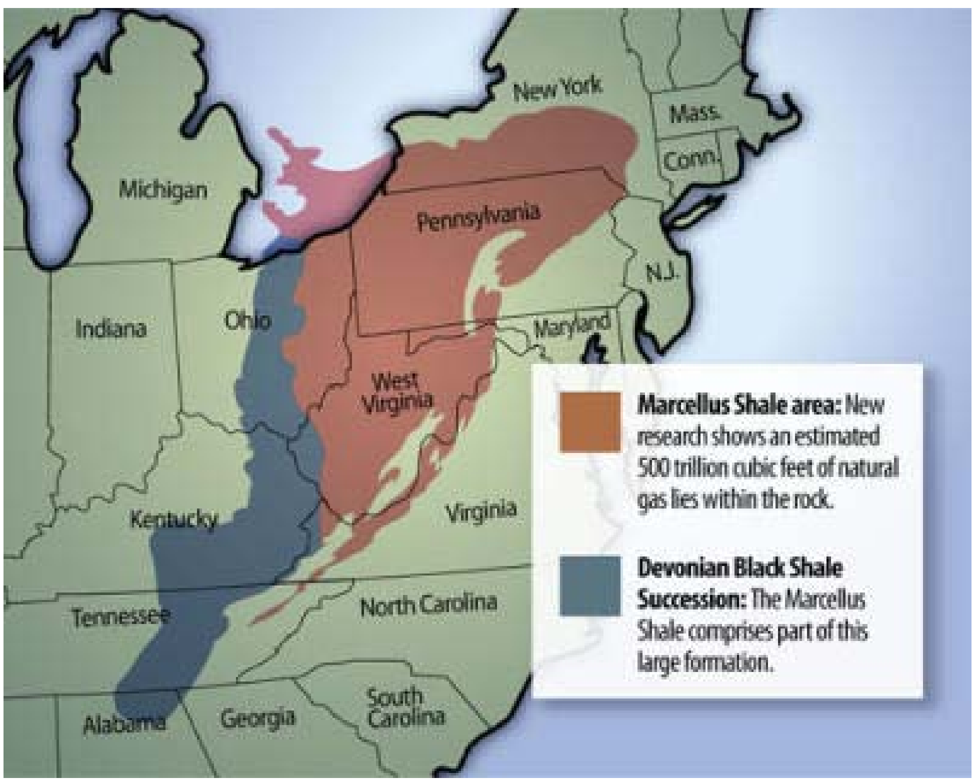

Fig. 2.17—Marcellus shale located in Appalachian Basin (Bertola 2009)

Through the use of core analysis, it was concluded that the Marcellus shale produces thermogenic gas such as the Barnett shale. The Marcellus shale if seen in an outcrop is a black, carbonaceous shale that is interbedded with limestone beds that are well developed (geology.com 2009). Also, this shale contains bitumen but is too old to contain any bituminous coal.

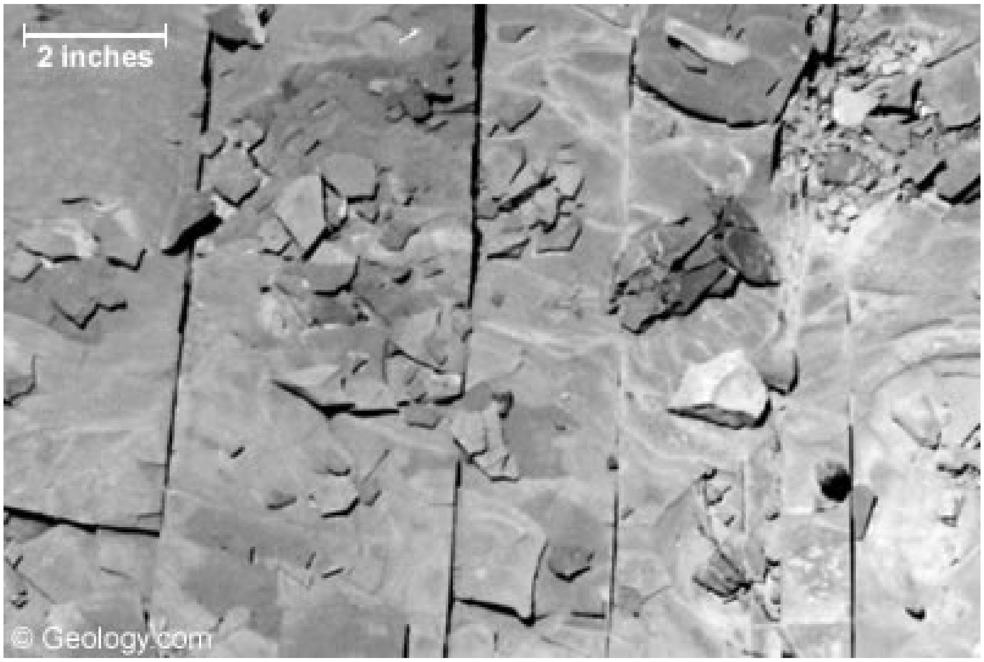

Fig. 2.18—Marcellus shale outcrop (geology.com 2009)

The Marcellus shale is highly fractured and fracture can be created easily in the outcrops that have been seen throughout the Northeast states (Marcellus Shale – Applachian Basin Natural Gas Play 2009) **(Fig. 2.18)**. Due to the radioactivity in the shale, the Marcellus shale make a strong positive deflection on gamma ray curve allowing it to be easily spotted on a gamma ray log **(Fig. 2.19)**. Terry Engelder (2009) states that this deflection is even more prominent if the shale lies directly on top of carbonate rocks. It is vital to the development of this shale because of the different depths, thickness, and extent of the Marcellus shale throughout the Appalachian Basin. The Marcellus shale sits under a disconformity and if not for this strong deflection it could be misconstrued for another formation. Also, because of the varying thickness throughout the basin this gamma ray signature helps determine gross thickness as one moves from state to state.

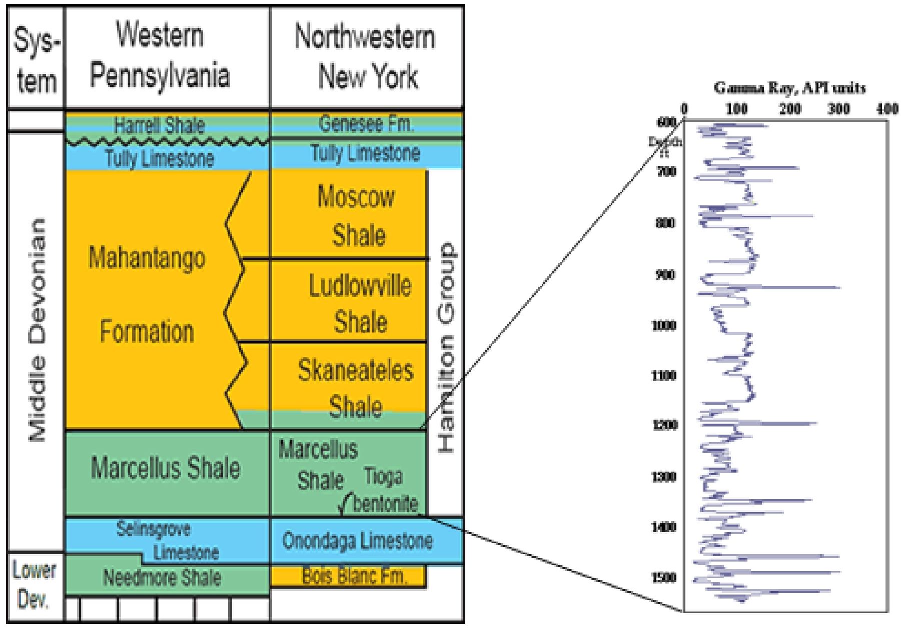

Fig. 2.19—Gamma ray log of Marcellus shale (geology.com 2009; Engelder 2009)

Developing and comprehending the potential of the Marcellus is difficult mainly because of the fractured characteristic of the shale. This reservoir is very brittle and falls apart very easily as seen in the outcrops. Another potential hurdle to overcome is the lack of oilfield infrastructure in place in the NE United States. This area is slowly growing its infrastructure such as roadways to sites, pipeline, plants, etc. but it is a slow process. With more studies coupled with industry knowledge, the Marcellus shale can not only have a vital impact on the financial health of the companies vested in the play but also on the oil and gas economy.

Depositional Environment

As mentioned above, the Marcellus shale is a radioactive, carbonaceous black shale that was deposited during the Middle Devonian period, in the Paleozoic era. Deposition of the Marcellus shale took place when the Acadian Mountains were jutting upwards, and the black and gray shales of the Hamilton Group sediments began collecting into the sea as a result of the mountains eroding (Martin 2009). More sediments fragments were carried into the Appalachian Basin **(Fig. 2.20)**, by ancient rivers that meandered to the ocean. While deposition was taking place, the Appalachian Basin was hundreds of miles away (Barrett 2009; Mazzullo 1973).

Fig. 2.20—Depositional environment of the Marcellus shale (Blakey 2009)

This shale was formed by relatively deep, sediment starved, and oxygen deficient, trough that formed comparable to the mountain chain. This deposition produced a transgressive black shale, because it was deposited in deepening condition when the basin floor dropped due to the rising of the mountain (Patrick 2004). The dark shale facies of this shale materialized from flysch, which was a mud deposited in the deep water. According to Aurthur and Sageman (2005), the Marcellus shale has two composite depositional sequences that are found through studies done. One is the general coarsening upward cycle and continues to the base of the overlying formations and second is the short-term oscillations in the basin depth which is depicted by the interbedding of lighter shales and limestones in the shale.

Thomas Grasso (1968) writes that the Marcellus shale is a member of the Hamilton Group, which consists of black and dark gray shales that were deposited during the Middle Devonian period. Other shales that make up the Hamilton group include the

Skaneateles, the Ludlowville, and the Moscow shales. All three of these formations have similar characteristics as the Marcellus shale in which limestone beds are found within the main shale reservoir. The Marcellus shale consists of three distinct non-shale layers imbedded within that appear in different regions of the Appalachian Basin: Cherry Valley Limestone, Purcell Limestone, and Tioga Ash Bed **(Fig. 2.21)**.

<table>
<tr><td colspan="2" rowspan="4">Oakta Creek shale</td><td rowspan="3">Cardiff dark gray shale</td><td>Pecksport shale</td><td>(Mt. Marion Fm.)</td></tr>
<tr><td colspan="2">Solsville shale and sandstone</td></tr>
<tr><td>Bridgewater shale</td><td>Otsego</td></tr>
<tr><td colspan="2">Chittenango black shale</td><td>Berne</td></tr>
<tr><td colspan="4">Cherry Valley limestone</td><td rowspan="2">Stony Hollow shale & limestone</td></tr>
<tr><td rowspan="2">(Seneca Mb.) (Onondaga Fm.)</td><td colspan="3">Union Springs shale and limestone</td></tr>
<tr><td colspan="2">(Onondaga Fm.)</td><td colspan="2">Union Springs shale and limestone</td></tr>
</table>

Fig. 2.21—Members of the Marcellus shale (Grasso 1968)

Authors Broadhead (1989), Witt et. al (1989) indicate that the Cherry Valley Limestone is found throughout the New York, Pennsylvania, and West Virginia. This limestone merges with the Union Springs and the Oatka Creek, which are two other members found within the Marcellus shale, under Lake Erie. The Cherry Valley is composed of skeletal limestones which shaly intervals between its lower massive limestone layer and the upper limestone layer. In central Pennsylvania, Maryland, and West Virginia, the Purcell Limestone is found within the Marcellus shale. Where the Purcell Limestone is found, the Marcellus shale is comprised of gray silty sand and mudrock with abundant limestone nodules and barite nodules dispersed throughout. The Purcell Limestone is about 50 to 100 feet of inter-bedded calcitic shale and limestone. The Purcell is equivalent to the Cherry Valley Limestone found in New York. Lastly, the Tioga Ash Bed is found at the base of the Marcellus shale in much of the northern part of the Appalachian Basin. Although there was much speculation that the Tioga Ash Bed was one ash fall but over time and research it now encompasses three definite ash falls (Witt et al 1989). These beds are used for correlation purposes throughout the basin for location of not only the Marcellus but for other formations. Other layers found within the Marcellus shale but do not make up much of the shale are the Bakoven Shale, Cardiff Shale, Chittenango Shale, and the Solsville Sandstone (Broadhead 1989).

TOC

The organic material that is present in the Marcellus shale ranges from 0.3 to 11% throughout the basin according to Martin (2009). Most of the organic material that creates the shale is land plants, such as trunks of confier trees, that were present during deposition but there are fossilized organisms present. MacFarlane (1875) indicated that the Marcellus contains the oldest known diverse set of thin-shelled mollusks. Also, found is an extent shelled marine animal similar to a squid called goniatites. Other species found in the Marcellus include brachiopods called Spinocyrtia, crinoids, seas lilies which are plant-like animals, limonite, gastropods, and bivalves (Schneider 1894; Burns 1991; Pabian and Strimple 1976).

Gas Content

The total average porosity found throughout the Marcellus shale is approximately 9% to 13% with an average of 11%. Of that 11%, the average gas porosity is roughly 3 to 6%. About 20 to 40% of the gas in this gas shale system is adsorbed gas. The Marcellus shale has a wide range of gas content that differs throughout the different states and even within a state. The gas content ranges from 275scf/ton to 325scf/ton (Phasis Consulting 2008). The different values are due to adsorbed gas, thermal maturity, and depth. Through studies done and industry proven trends, the EUR is about 2 to 4.6 BCF per well. Using this recovery for a Marcellus well, has led to the development of vertical wells on 40 acre spacing and horizontal wells on 80 acre spacing (DeWitt 2008).

Shale Mineralogy

Hosterman (1989) looked at the mineralogy of the Marcellus shale and determined that this shale is heterogeneous throughout the basin since it covers most of the northeast U.S.; therefore, the composition is based on what is most commonly found throughout this area but it is important to remember that these percentages may vary from outcrop to outcrop. The Marcellus shale has about 18% to 24% quartz present in the bedrock. This quartz percentage is lower than what has been discussed in this paper on the other plays due to the sheer amount of calcite present in the Marcellus shale—25%. The other major mineral present other than clay is pyrite, which makes up 5% of the mineralogy. The clay minerals make up 40% to 60% of the mineralogy; one of the highest percentages in what is considered a "commercial" gas shale play. The minerals that make up the bulk of this bedrock are chlorite (15%), illite (70%), and illite-smectite. In some samples that have been captured show traces of illite-chlorite. Also present is uranium which make this shale radioactive; hence, making it easier to identify in well logs.

Thickness and Reservoir Pressure

Due to the extensive magnitude of the Marcellus Shale, the thickness of the formation fluctuates throughout the basin (Brackett 2006). An isopach map of the entire Marcellus Shale found in the Appalachian Basin **(Fig. 2.22)**.

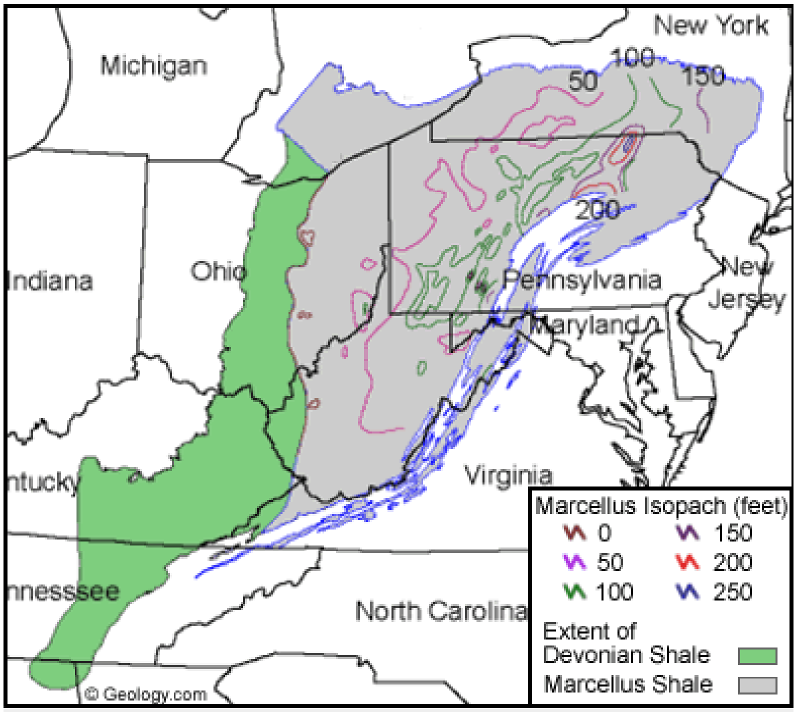

Fig. 2.22—Marcellus shale isopach map (Brackett 2006)

The Marcellus shale can be encountered at 900 feet thick in New Jersey to less than 40 feet near Canada. To the east, the Marcellus shale is approximately 200 feet thick in West Virginia. To the north of West Virginia, the shale is 800 feet thick in eastern Pennsylvania and thins to the west to about 50 feet along the Ohio River. The reason for this thinning is due to the decrease in the grain size in the clastic deposits since the sediments entered on the eastern flank of the basin during deposition (De Witt et al 1989). The Marcellus shale pinches out at the Cincinnati Arch.

Average reservoir pressure that is found in the Appalachian Basin for the Marcellus varies with depth from about 1,600 psi to 5,000 psi, yield a pressure gradient between 0.42 psi/ft to 0.70 psi/ft. The Marcellus shale pressure gradient ranges anywhere from below the hydrostatic gradient to 1.5x the hydrostatic; therefore, it is imperative to understand pressures and depths to ensure successful drilling and completions (Chesapeake 2009).

2.1.5 Woodford Shale

The Woodford Shale is a shale deposited during the Late Devonian/Early Mississippian age which is now found throughout Oklahoma and Arkansas (Comer 2008). Although this is true, the focus of this paper is on the Arkoma Basin. Comer (2008) acknowledges the fact that besides the Arkoma Basin, the other major basins that the Woodford is found are in the Ardmore Basin and the Anadarko Basin **(Fig. 2.23)**.

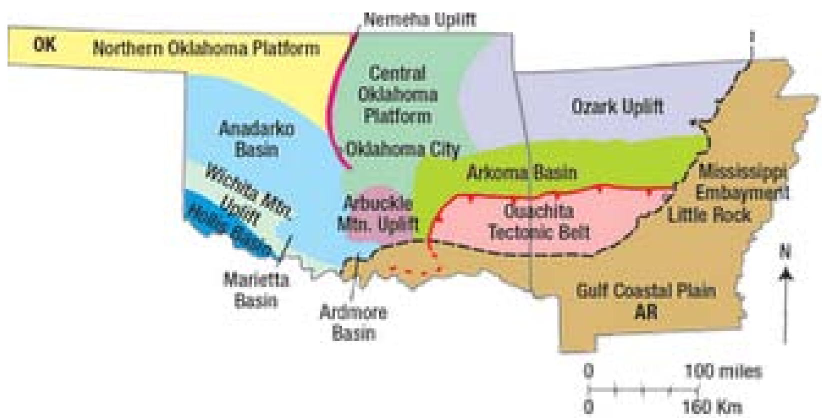

Fig. 2.23—Oklahoma basins (Comer 2008)

Many of the operators that are producing the Woodford in Ardmore Basin are reporting oil/condensate production with minimal gas associated with the liquids. There are about 10-15 wells that have been drilled in this basin and it seems to be due to the fact that it is liquid production instead of gas causing most operators to shy away from it since liquids seems to lock up the system rather quickly; with that said, the Ardmore basin is still getting a lot of attention (Ardmore Basin Woodford gas plan takes off 2008). On the other hand, in the Anadarko Basin, most production is gas but there are limitations due to depth. Most of the Woodford Shale major production comes from depths anywhere from 7,000 feet to 18,000 feet. Even with depth challenges, operators are slowly moving into this area and getting wellbores down. One such example is Marathon who had a press release in January 2009 stating their first success Woodford Horizontal in a new area of the Anadarko Basin that yielded a normalized IP of about 5.2 MMCFD (yahoo finance 2009). Even with the recent success in the Anadarko Basin, there is only a 50 to

60 wells drilled there. In contrast to the Ardmore Basin and the Anadarko Basin, the Arkoma Basin contains over 150 wells producing from the Woodford Shale. As mentioned above, the Woodford shale is located in the Arkoma Basin which covers the southeastern section of Oklahoma. The Arkoma Basin covers the southeastern portion of Oklahoma and western portion of Arkansas **(Fig. 2.23)**. Charles Wickstrom (2008) discussed in depth his learnings for the Woodford shale at the 2008 AAPG conference held in San Antonio, TX. The Woodford Shale was first completed in the 1939 but this play did not gain momentum until 2003 with the use of new completion techniques and the increase in gas prices. Prior to the boom in 2003, there was only about 24 wells producing in the Woodford shale throughout the entire state. Initial IPs at that time for the Woodford wells ranged from 0 to 200 MCF/D. After 2003, production rates took off almost exponential as seen in Fig. 2.24. By early 2008, there were over 750 Woodford wells in production with most wells being drilled in Hughes, Coal, Pittsburg, and McIntosh counties, which are located on the western side of the basin. The major players in the Woodford are Newfield, Devon, Continental and Chesapeake. The current estimated gas-in-place for the Woodford is roughly 45 TCF to 60 TCF. The typical depths that the Woodford is encountered at in the Arkoma Basin are between 6,000 to 11,000 feet and extend aerially nearly 1,500 square miles (Coffey 2007).

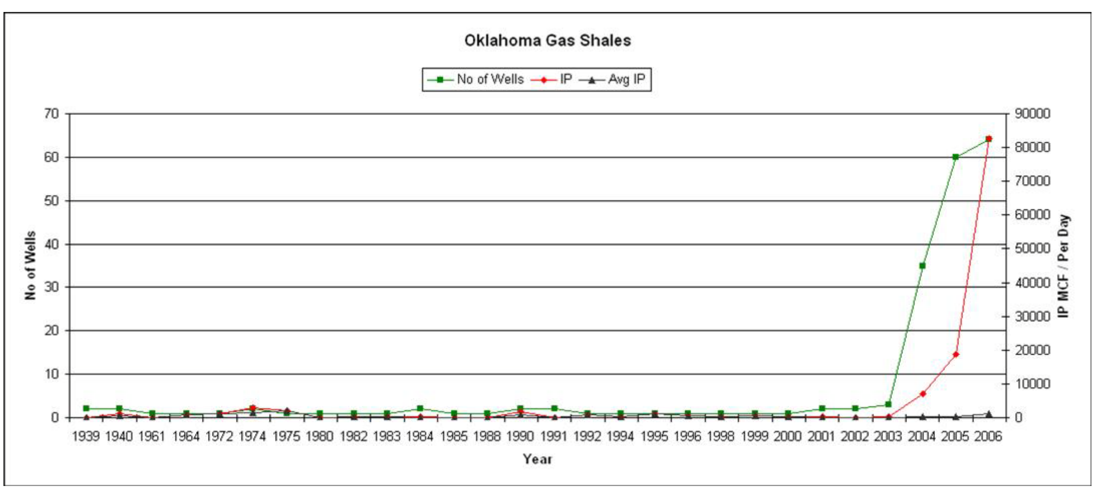

Fig. 2.24—Number of wells and IP rates for the Woodford shale in Oklahoma (Wickstrom 2008)

Through the use of core analysis coupled with VR, it is known that the Woodford shale produces thermogenic methane and biogenic gas (in the cherty portion of the Woodford) such as the Antrim shale (Andrews 2007). The Woodford is a brittle grey to black shale that is found throughout the basin. Cardott (2007) indicates in the outcrop of the Woodford shale shown below the most distinguishing feature is the natural fractures **(Fig. 2.25)**. In the Woodford outcrop, there are three sets of natural factures that are observed. The first set is roughly parallel to the dip direction of the bedding plane. The second set is parallel to the dip of the bedding and the third set is oblique to the strike and fold axis of the formation.

Fig. 2.25—Woodford shale outcrop (Cardott 2007)

The Woodford shale is easily recognized on well logs due to the radioactivity of the shale as well as the placement of the formation between two carbonates **(Fig. 2.26)**. The Woodford is characterized by relatively low sonic, resistivity, and neutron-induced radiation signatures (Cardott 2007; Comer 2008). The Woodford overlies a regional unconformity which can be observed on well logs. The Woodford shale is broken into three units—upper, middle, and lower. The lower unit, which sits on top of the unconformity, has the lowest radioactivity; thus, containing more carbonate, silt and sand. The middle unit has the highest radioactivity; it also contains the most organic content and pyrite. The upper unit's radioactivity falls between the middle and lower unit. This unit consists of black shale with few spores and mostly parallel laminae[14, 17].

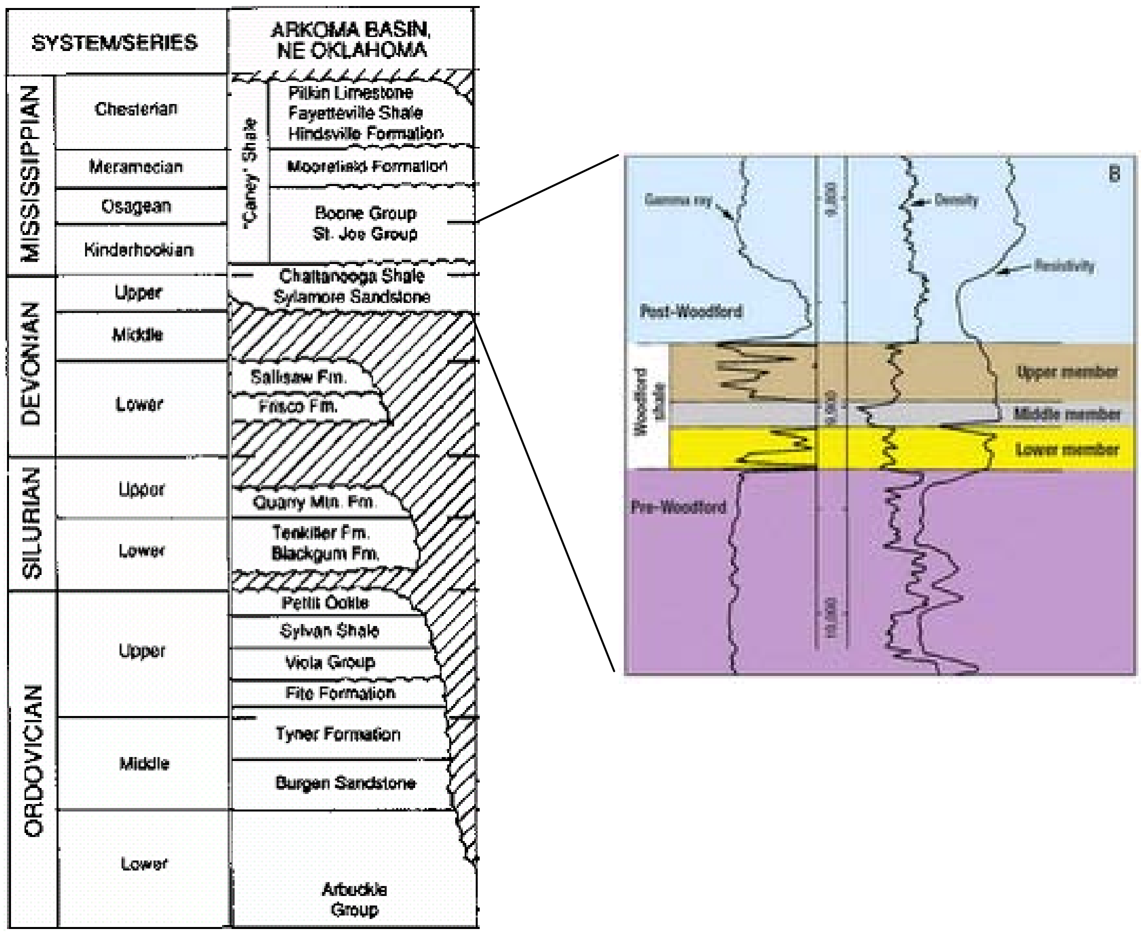

Fig. 2.26—Gamma ray log of Woodford shale (Cardott 2007 and Comer 2008)

Developing the Woodford does have its challenges due to several factors (Cemen, Ataman, Puckette, and Boardman 2007). The first pertinent challenge is the natural fracture contribution. There is little knowledge on how the fracture system is contributes to the overall performance of the play as well as the number of fractures one might encounter when drilling. One thing that is known is the Woodford is a highly fractured reservoir that causes the rock to be very brittle. The next vital challenge that operators face according to Coffey (2007) is the vast spread of drilling depths that the Woodford is encountered. It is much easier to develop a gas shale play that is shallow (~6,000 feet) than it is when it is deep (~11,000 feet). Operators are overcoming these challenges with the development of new drilling and completion technologies to not only unlock the way to develop this reservoir but also do to it economically.

Depositional Environment

As mentioned earlier by Comer (1997), the Woodford shale was deposited during the Late Devonian/Early Mississippi age. During this time, the southern midcontinent lay along the western margin of the North America in what was considered warm and dry tropics which is confirmed by the hypersalinity found within the cracks of the present-day Woodford. The deposits that formed the Woodford shale began to be deposited into the epeiric seas when the sea level began to rise, drowning the marine embayment that was present at the time. The seal level continued to rise and cover the sub-aerial, eroded, and dissected terrain that consisted of Ordovician to Middle Devonian carbonate rocks.

Comer (1997) also discussed the three members that make up the Woodford shale—upper, middle, and lower units. The upper unit is chertier than the other two formations but it is not as radioactive as the middle member. On the other hand, the middle unit is widespread than the other two regionally but it is also the one that contains the most organic content. The lower unit is known for the abundance of other lithofacies such as carbonates.

TOC

The organic material that is present in the Woodford shale can be as high as 20%. This is a very high TOC; in fact, it is higher than even the Barnett shale, which was the frontier play into the modern day gas shale arena. The average TOC for the Woodford in the Arkoma Basin ranges from 3% to 10% (Cardott 2007). Most of the organic material found in the Woodford shale is marine since this was once deposited on an embayment. The fossils discovered in the Woodford shale are conodonts, ammonoids, fish debris, shark debris, and radiolarians. One of the most fascinating findings in the Woodford is that the formation is the oldest rock in Oklahoma that contains wood from the progymnosperm Archaeopteries. This wood was transported to the depositional area using rivers that were present at that time (Andrews 2007).

Gas Content

The total average porosity found throughout the Woodford shale can range from 7.5% to 14% with an average porosity of 10%. Of that 10%, the average gas filled porosity is anywhere from 3% to 6.5% (Andrews 2007). This range is comparable to what is seen in the Barnett and the Marcellus Shale, slightly higher than the Antrim Shale, and is lower than what is being observed in the Haynesville Shale. The Woodford shale has about 20 to 40% adsorbed gas. According to Phasis Consulting (2008), the gas content in the Woodford shale ranges from 60 scf/ton to 115 scf/ton due to the depth and the thermal maturity seen in the Arkoma basin. This has led to much debate as to what is the correct well spacing should be for the Woodford Shale in the Arkoma Basin. Langford (2009) discusses that when this play was being developed, most companies drilled on 80 acre spacing; however, recently there has been indication that 40 acre spacing is possible since there has not been much depletion observed when companies have drilled infill wells. The average recovery from these wells range from less that 1 BCF to 6 BCF, depending on whether an operator drills vertically or horizontally.

Shale Mineralogy

Cardott (2007) discussed how the mineralogy of the Woodford shale is very similar to the other shales discussed earlier. The major mineral found in the Woodford is quartz which makes up anywhere from 55 to 87% of the formation. The next most abundant mineral found is illite which can be found in quantities ranging from 8 to 34% of the mineralogy. The mineral that is next abundant in the Woodford is kaolin which is present at about 3 to 7%. Plagioclase feldspar is found in the Woodford up to 7%. Other minerals present are dolomite (0-3%), apatite (0-1%), and pyrite (0-1%).

Thickness and Reservoir Pressure

The Woodford shale ranges in thickness from 50 to 220 feet throughout the Arkoma Basin with an average net pay of 100 to 150 feet. An isopach map of the Woodford Shale found in the Arkoma Basin **(Fig. 2.27)**.

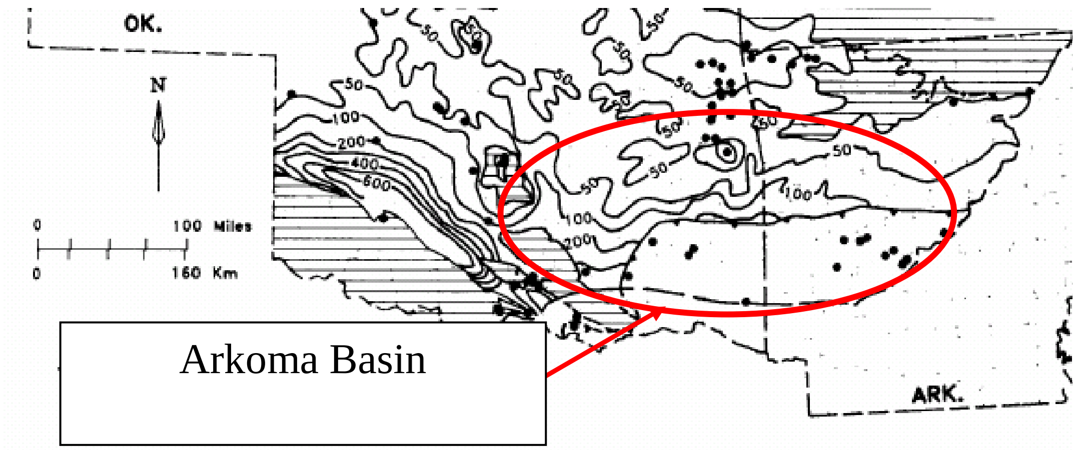

Fig. 2.27—Woodford shale isopach map (Cardott 2007)

The Woodford shale is the thinnest in the center of the Arkoma Basin. As one moves to the outskirts of the basin, the Woodford begins to thicken. There is a also a regional thickening to the southwest of the basin. The Woodford shales juts up against Ouachita Fold Belt that is seen on the south of the Arkoma Basin (Cardott 2007).

Average reservoir pressure that is found in the Arkoma Basin for the Woodford shale varies with the depth from about 3,100 psi to 5,800 psi yielding a pressure gradient between 0.48 psi/ft to 0.55 psi/ft (Langford 2009). Like the Haynesville shale and other gas shale plays, the Woodford is considered an over-pressured reservoir since the pressure gradient of the Woodford shale is higher than the hydrostatic gradient; therefore it is vital to the success of this play to understand pressures and the depths the Woodford will be encountered at to ensure successful drilling and completions.

2.3 Summary of Gas Shale Geological Parameters

Many of the geological parameters for the fives shale plays analysed above are similar. Displayed below are the ranges for the geological parameters discussed earlier for all five plays to help compare each play against one another **(Table 2.1)**.

Table 2.1—Summary of Key Properties from Five Shale Gas Basins

Property	Antrim Shale	Barnett Shale	Haynesville Shale	Marcellus Shale	Woodford Shale
Basin	Michigan	Fort Worth	North Louisiana Salt	Appalachian	Arkoma
Fairway Depth, ft	500 to 2,000	6,500 to 8,500	9,000 to 16,500	4,000 to 8,500	6,000 to 11,000
Thickness, ft	200 to 850 (net - 70 to 120)	200 to 1,000 (net - 100 to 600)	270 (net - 100 to 200)	40 to 900 (varies between states)	50 to 220 (net pay - 100 to 150)
TOC, %	up to 20	up to 12 (average - 4.5)	0.5 to 4	0.3 to 11	up to 20 (average 3 to 10)
Total Porosity, %	3 to 10	3 to 8	6 to 15	9 to 13	7.5 to 14
Gas-Filled Porosity, %	2 to 6	2 to 6	5 to 11	3 to 6	3 to 6.5
Gas Content (scf/ton)	40 to 100	300 to 350	350 to 475	275 to 325	60 to 115
Quartz Content, %	50 to 60	40 to 45	28 to 33	18 to 24	55 to 87
Clay Content, %	20 to 35	20 to 40	25 to 33	40 to 60	8 to 34
Reservoir Pressure, psi	400 TO 1,150	3,000 to 4,000	8,000 to 10,000	1,600 to 5,000	3,100 to 5,800
Reservoir Pressure Gradient, psi/ft	0.33 to 0.38	0.42 to 0.46	0.7 to 0.92	0.42 to 0.7	0.48 to 0.55
Adsorbed Gas, %	60 to 70	15 to 30	20 to 30	20 to 40	20 to 40
Well Spacing, acre as of 1/1/09	40 to 160	80 to 160	40 to 160	40 to 80	40 to 80
Gas-In-Place, TCF as of 1/1/09	35 to 76	25 to 30	250 to 320	1,300 to 1,900	45 to 60

The information in Table 2.1 helps an operator who is looking at the viability of a new prospective gas shale basin that has not been tested and at least see how it stacks up against these five plays before investing a considerable amount of capital to determine if this is something to pursue. With this said, this does not mean that if an operator finds a range outside the ones discussed above that it is not a feasible play; all this does it help gain confidence that this is the right play to invest in. As stated, with the remarkable amount of technological advances that are taken place in the oil and gas industry, plays that fall short of what is considered economic right now will most likely be unlocked in the future.

CHAPTER III
COMPLETION AND STIMULATION METHODS

3.1 Overview of Completion Techniques

For gas shale plays, as with most plays, there is a learning curve that operators must undergo before drilling and well completions operations can be optimized.. There have been many failures and uneconomic wells drilled and completed in every gas shale play, but as technology improves and we gain more experience, the success ratio and quality of the well completions continues to improve. Failures can include anything from losing a wellbore to ending up with a sub-economical well. This objective of my research is to review the literature to determine the best practices for drilling, completing and stimulating wells in all of the important gas shale plays. Then using the geologic and reservoir characteristics of each gas shale play, I have established guidelines, in the form of flow charts, the help operators obtain a first estimate of how to drill, complete and stimulate the next well in a gas shale play. By establishing these guidelines, it will be easy to transition on how these technologies can be applied in other basins/plays that were not discussed here. These other basins/plays can be either in North America or anywhere in the world where such gas shales exist.

3.2 Vertical Completions

In essentially every shale gas play, the first wells drilled, completed and tested were vertical wells. In the Haynesville, most vertical wells have been drilled to the Haynesville for data acquisition purposes but never produced long-term. In the future, we expect virtually all gas shale plays will be developed using horizontal or even multilateral wells.

3.2.1 Antrim Shale

The Antrim shale was one of the first shale gas productions in the United States, coming online in 1926 (Blakey 2009). Prior to the Antrim, many Devonian Shale wells had been drilled in the Appalachian Basin One of the main differences between the Antrim Shale and the other shales discussed in this thesis is the amount of water that is produced from the Antrim. On average, the Antrim Shale produces about 110 BW/D along with the gas. Goodman and Maness (2008) discuss the history of the completion for the Antrim Shale as well as what fracture stimulations methods have been used in the past as well as present. The first wells in the Antrim Shale were drilled to the Lachine member of the Antrim shale and completed open hole. The wells were not drilled deeper into the Traverse because it was believed that the water production was coming from the Traverse zone. As more data was collected, it was determined that the water was actually in the shale fractures and it was determined that drilling the Traverse zone was acceptable and added reserves. Most wells are fracture stimulated with a multistage treatment that has an average number of fractures anywhere from two stages up to five stages. The most common stimulation design used now by operators is a N_2 foam that carries about 25,000 to 50,000 lbs of 20/40 sand into the fracture (Goodman and Maness 2008). With this completion design, the well cost for the Antrim ranges from $200,000 to $700,000 for drilling and completions (Phasis Consulting 2008). Drake (2007) illustrates the average vertical performance of the vertical wells producing from the Antrim which is also shown below **(Fig. 3.1)**. Fig. 3.1 shows what the typical production rate is for one well. Not shown below is the water production discussed above which is approximately 110 barrels per day.

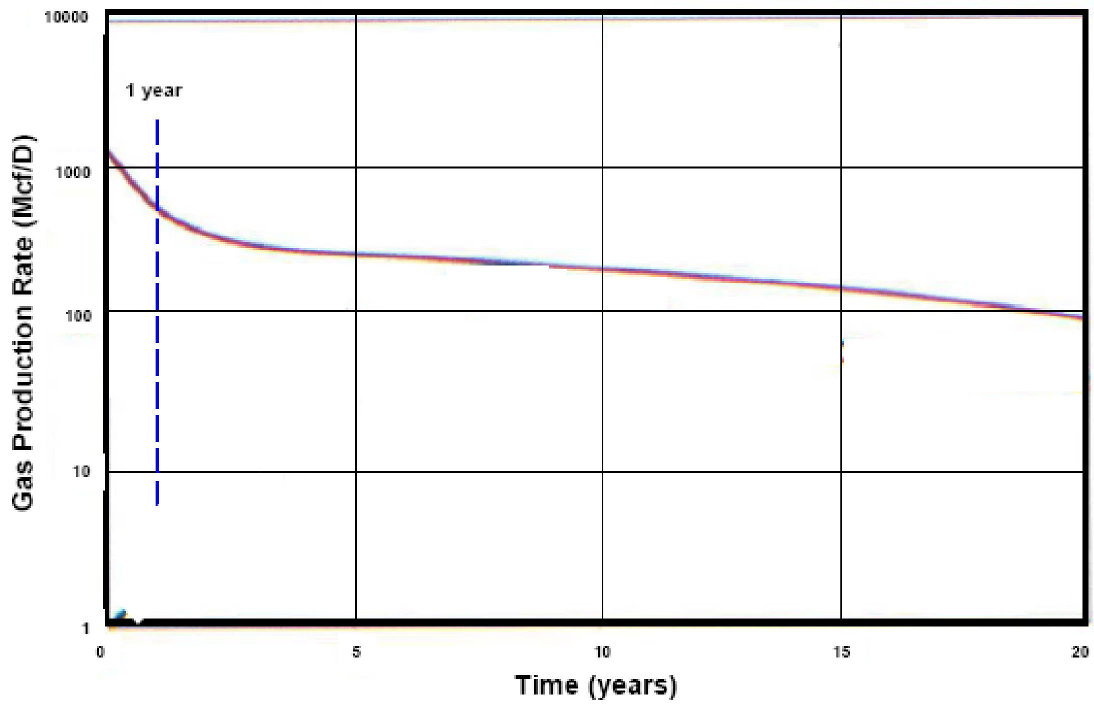

Fig. 3.1—Antrim shale vertical well performance (Drake 2007)

3.2.2 Barnett Shale

D. Martineau (2003) described the evolution of the Barnett shale in which he states that the Barnett Shale had only 100 vertical wells completed during the 80s. During this time frame, the vertical wells were fracture treated with around 200,000 gallons (gals) of cross-linked gel fluid and approximately 300,000 lbs of sand, which was usually 20/40 mesh. With this fracture treatment design, the IP for most of these wells were anywhere from 600 MCF/D to 700 MCF/D on average. Martineau (2003) goes on to say that near the end of the decade, the size of the average fracture treatment increased to 1,000,000 gals of cross-linked gel fluid and 1,000,000 lbs of sand which resulted in IPs of about twice those achieved with the smaller fracture treatments. In the 90s, there were over 2,000 wells drilled in the Barnett Shale. This was mainly due to the fact that changes were made in the fracture stimulation designs. Many operators switched from cross-linked gel to slick water fracture fluid as well as reduced the proppant amount to

100,000 lbs with no change in well deliverability but a cost reduction of 30% (Martineau 2003).

As drilling activity picked up in the Barnett, many operators focused their attention on improving productivity by improving the fracture treatments. Operators started fracturing with N_2 and eventually moved to fracturing with 123,000 gals of CO_2 foam and 188,000 lbs of Ottawa sand. The most successful stimulation treatment and widely used since the early 2000s is 31,000 gals of slick water and about 95,000 lbs of 20/40 Ottawa sand (Lancaster et. al 1992). With this new completion design, the average well cost for the Barnett is approximately $ 1 MM (Pickering 2009). The average vertical performance of the vertical wells from 1999 to 2003 is depicted below **(Fig. 3.2)**.

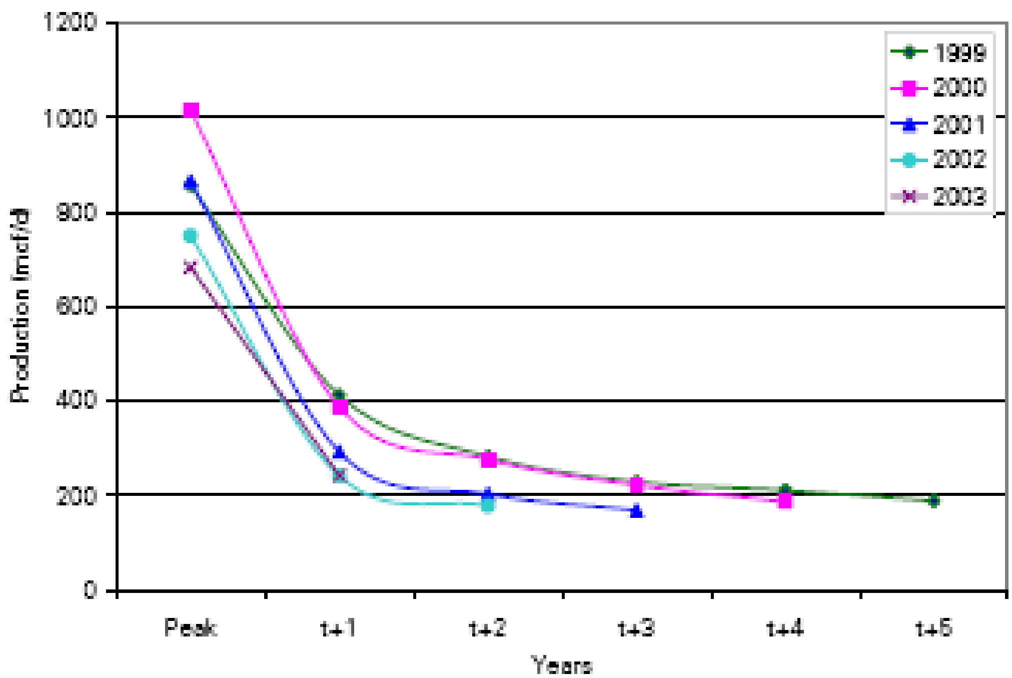

Fig. 3.2—Barnett shale vertical well performance (Pickering 2009)

The figure above (Pickering 2009) shows that although there is not a lot of change in the decline profile for wells drilled in the five consecutive years for the Barnett but there is a change in IPs. 2000 had the best IP and decline profile among all of the other years shown. The reason for the lower IPs after 2000 is due to depletion seen in the reservoir as well as the smaller fracture treatments. Although it seems to be less prolific from the graph, the cost savings for drilling this way actually allows more wells to be drilled (tighter well spacing) and higher field recoveries.

3.2.3 Marcellus Shale

When the Marcellus Shale was discovered to be productive, all the wellbores that penetrated this shale were vertical. For the Marcellus shale, there are three schools of thought concerning the effectiveness on completing and stimulating the formation—straight N_2, N_2 foam stimulation, or a slick water fracture treatment (Sumi 2008). Sumi (2008) continues to address when and where these different schools of thought were used. In 1997, the first slick water fracture treatment was tested. This fracture stimulation treatment used about 800,000 gals of water along with 250,000 lbs of 20/40 mesh sand. Water fracture treatments are most commonly used in deeper, high-pressure shales, while N_2 foam treatments are commonly pumped in shallower shales and lower reservoir pressure shales. Therefore, most companies have moved to N_2 foam fracture treatments in the Marcellus Shale since the clean-up after the stimulation is better and there is less chance of killing the well due to the large volumes of water pumped during the water fracture treatment.

Many operators still juggle between slick water fracture techniques and using a N_2 foam to treat the Marcellus wellbores. Operators are trending towards using slick water fracture treatments because of the cost reduction but if a well is drilled in an area that has lower bottomhole pressure than expected, companies move to a N_2 foam (Myers 2008). Most wells will be completed with a three to four stage treatment to maximize coverage of the reservoir in contact with the wellbore. With the use of N_2 foam fracture treamtent, the average EUR is about 0.4 BCF to 1 BCF per well which costs about \$800,000 to \$1.0 MM to drill and complete (Sumi 2008). Miller (2008) depicts the average vertical performance of the vertical wells is shown below **(Fig. 3.3)**.

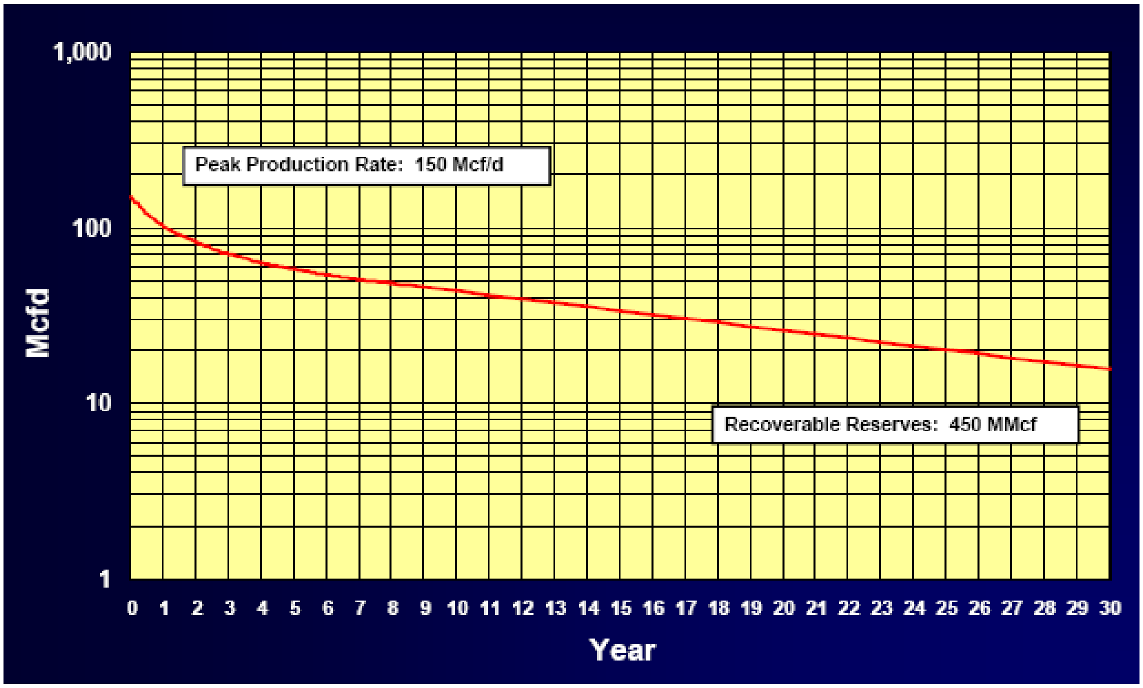

Fig. 3.3—Marcellus shale vertical well performance (Miller 2008)

3.2.4 Woodford Shale

Vertical Woodford Shale wells have been completed over the years, but the caveat is that these wells have been commingled with other reservoirs such as the Hunton limestone. In the late 1990s, Newfield Exploration began to drill Woodford vertical wells. From the late 1990s to 2006, about 100 wells have been drilled, with 60% of them drilled by Newfield (Oil and Gas Investor 2006). Most of these wells were completed with cemented casing and then perforated with 3 to 4 clusters throughout the interval. Some companies fracture treated all the perforations together; however, most wells were stimulated with 3 to 4 stage fracture treatments. The most common stimulation design used by operators drilling vertical Woodford wells has been slick water treatment. A slick water treatment is the lowest cost method to complete these vertical wells. Usually, about 100,000 gals of slick water would be used to transport anywhere from 40,000 to 50,000 lbs of either 20/40, 40/70 or 100 mesh sand per stage.

In general, the average EUR has been about 1.35 BCF per well. The cost of the vertical wells was about $2.0 MM to drill and complete. Andrews (2007) illustrates the average well performance of the vertical wells for the Woodford Shale is shown below **(Fig. 3.4)**.

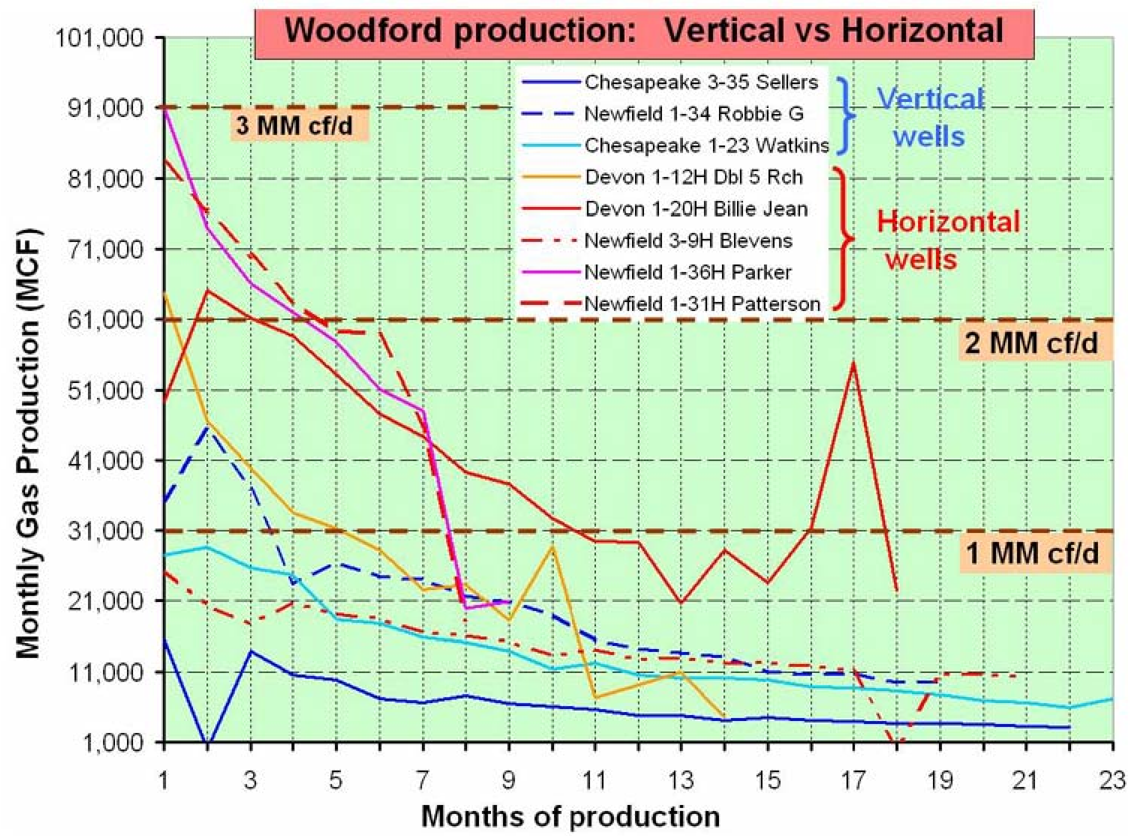

Fig. 3.4—Woodford shale production performance: horizontal vs. vertical (Andrews 2007)

3.3 Horizontal Completions

Since 2000, many operators initiated new horizontal drilling and completion designs to improve the productivity of gas shale wells. Upon reviewing the costs to drill and complete vertical wells in plays like the Barnett Shale and the Woodford Shale and factoring in the EURs from most wells, the industry turned to the use of horizontal drilling technology to improve gas flow rates and gas recovery. As is now clear, one of the greatest improvements in gas shale basins is the use of horizontal drilling. In the horizontal gas shale wells, the biggest challenge has been to determine the best way to complete the horizontal well. There are still studies done throughout the industry to understand where to land the lateral in the formation and what size casing to use, etc. As a rule of thumb, most operators will land the lateral in the middle of the formation or relatively close to the middle of the formation.

For example, the Woodford, Barnett and most of the Marcellus shale wellbores are landed in the middle, while the Haynesville is landed closer to the bottom of the formation or about 55% to 60% from the top (Chesapeake 2008; Wickstrom 2008). There is not much of a difference in placement techniques but most operators believe that the fractures stimulations grow throughout the entire interval if the horizontal hole in the middle. With the use of microseismic technology, many operators confirmed height growth during the fracture treatment is sufficient to connect the entire shale to the horizontal well, provided the shale is not too thick. The optimal result that can be achieved using microseismic is to see seismic activity following the path of the perforations that the fracture treatment is trying to stimulate without too much overlap with the treatment before or the one that will be pumped afterwards; therefore, the entire lateral has some seismic activity without too much overlay. It is imperative to understand that if there is a significant change in the rock mechanical strengths in the reservoir, the landing of the lateral in the middle of the section might not be the most optimal position.

3.3.1 Antrim Shale

Of the five basins gas shale plays discussed in this thesis, the only play that does not wells widely use horizontal wells is the Antrim shale. There are three main factors that have led to this outcome. First, the cost to drill these wells is considered minimal; the Antrim shale vertical wells cost about $350,000 to drill and complete because the formation is shallow. Usually horizontal wells cost about 2 times more to drill than vertical wells. Second, the reservoir pressure in the Antrim Shale is low (400 psi) so there could be issues with wellbore stability. It is possible horizontal wells could be drilled more often in the Antrim Shale in the future; however, for now, virtually all wells are vertical. Finally, the water production is a factor as well. Since the Antrim shale has such a high water production, the wells would be difficult to operate long-term. Many of the wells would not be able to lift the water effectively; thus, the laterals would water out very early in the life of the well.

3.3.2 Barnett Shale

In 2002, development of the Barnett Shale with horizontal wells increased substantially. Many operators shifted their focus to drilling horizontal wells and steered away from drilling vertical wells. In the early stages of horizontal drilling in the Barnett Shale, operators looked at both cemented and uncemented laterals. Uncemented laterals soon phased out due to the fact that shorter laterals were required thus leading to less number of frac stages and fracture stimulations in the uncemented lateral were difficult to design and understand. As such, most wells are now completed with cemented laterals to maintain better control on where the hydraulic fractures are created. As drilling horizontals became increasingly common, many operators moved up the learning curve on fracture stimulation rather quickly due to information shares, conferences, and relationships with service companies.

Schein (2008) describes the general design for a Barnett horizontal has been to drill a 3000 – 4000 ft lateral and then place a fracture treatment every 500 ft or so down the lateral. As such, it is common to pump 6 to 10 fracture treatment stages in any one wellbore. For the total well, it would not be uncommon to pump 1,000,000 gallons of slick water carrying 300,000 lbs of sand in each stage. The sand is normally 20/40, 40/70 or 100 mesh. Generally, a 4-1/2” or 5-1/2” casing is run-in-hole in lateral potion of the well so that average pump rate is anywhere from 40 to 120 BPM. Also, many operators are now adding friction reducer to keep the rate up higher as well as biocide (prevent corrosion-causing bacteria) and scale (prevent build-up of calcium carbonate) inhibitors to avert anything that will reduce short-term and long-term productivity. In a lot of treatments, some gel is added to the slick water to increase viscosity so that all the sand can be pumped away (Lancaster et al 1992). There have been some attempts to do simu-fracture treatments on the Barnett Shale wells. The simu-fracture treatments are where at least two laterals drilled next to each other are fracture stimulated at the same time. Data is still being gathered on this fracture treatment in the Barnett shale. Pickering (2009) shows the typical performance of a Barnett horizontal that has been fracture treated with four stages and the optimal fracture design is shown below **(Fig. 3.5)**.

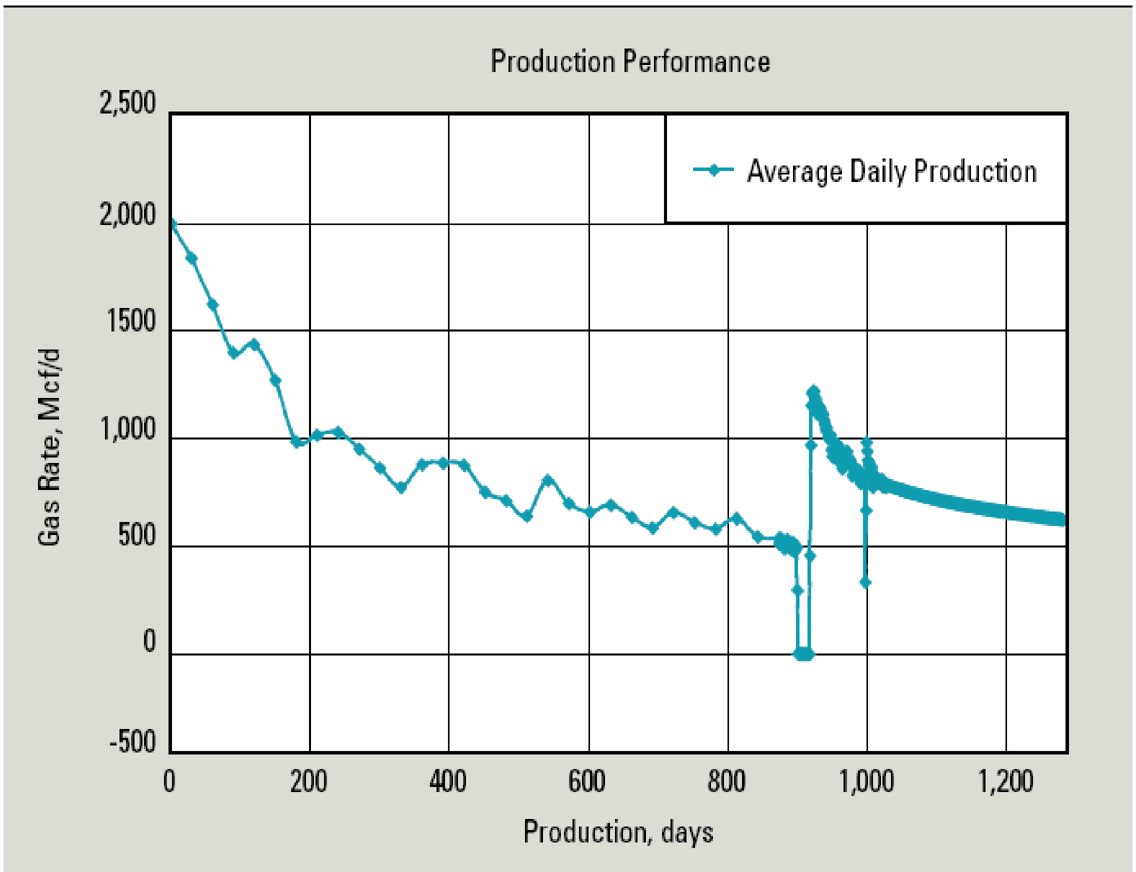

Fig. 3.5—Barnett shale horizontal well performance (Pickering 2009)

3.3.3 Haynesville Shale

Most Haynesville shale wells are horizontal completions and not vertical wellbores. Vertical pilot holes are drilled to gather data, such as cores and logs, and then plugged back to kick off a horizontal leg. Most of the Haynesville laterals are between 4,000 and 4,600 feet in length which allows more fracture stages in each wellbore. The fracture stimulation is designed with about cluster perforations about 300 to 350 feet from one another and then each cluster perforation is fracture treated separately. Most of the Haynesville horizontals have about 10 to 12 fracture stages per well. Typically, these wells are fracture stimulated down cased, cemented liners that are either 4-½ or 5-½ casing to allow high enough treating pressure to pump the fracture job away without having to fight too much friction in the process. Each stage is treated with about 8,000 to 12,000 bbls of slick water which carries approximately 300,000 lbs of proppant into the formation. However, in practice, much of the “so-called” slick water actually contains gel to increase the fluid viscosity to open the fractures to allow for the propping agent to be pumped into the fracture. The proppant that is pumped into the reservoir is a combination of Hydro Prop, Ceramic, or Resin-Coated Sand and most operators generally used 20/40 or 40/70.

So far, typical horizontal wells in the Haynesville Shale IP anywhere from 5 to 20 MMCF/D but they have very steep decline rates (Hutchinson 2009). Industry is predicting these wells will recover 4.5 to 8.5 BCF per well. The cost to drill and complete these wells is roughly $6.9 to $ 11 million (Chesapeake 2009). Many operators are now moving to closer perforation clusters such as 60 to 100 feet so that they can contact more of the reservoir when they fracture stimulate this wellbores which may be a mistake since these might cause narrower fractures instead of broader ones. Kapichinske and Sharp (2008) portray the typical performance of a Haynesville horizontal well which is shown below **(Fig. 3.6)**.

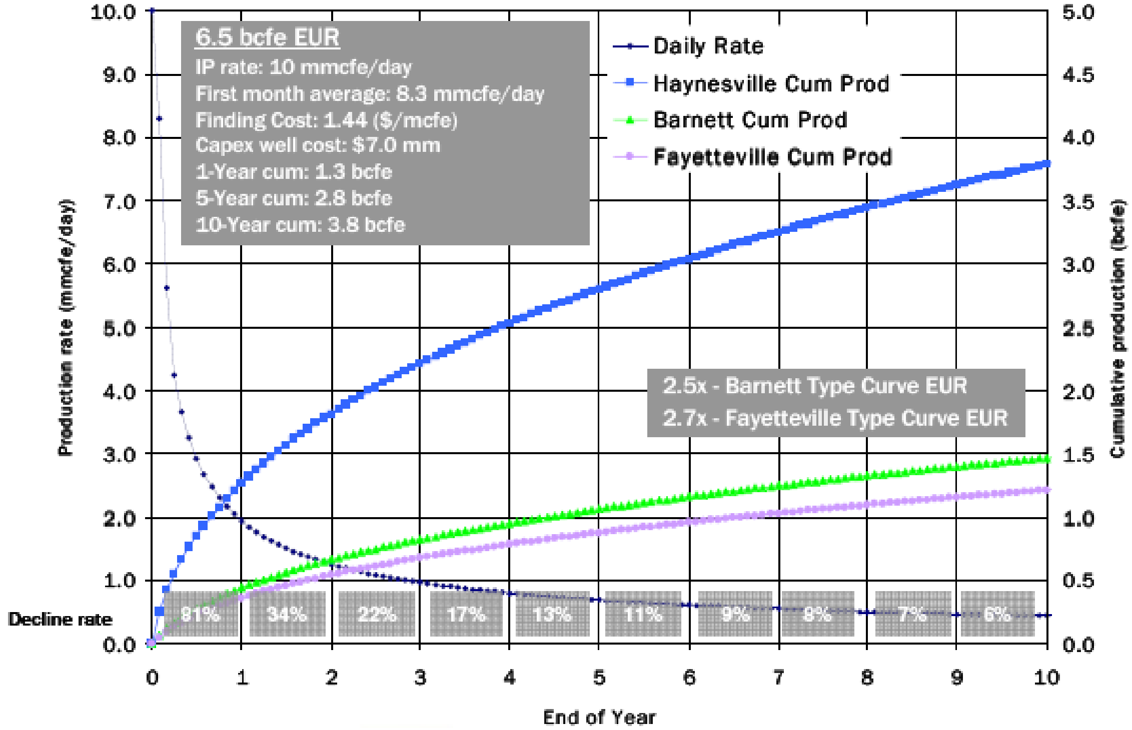

Fig. 3.6—Haynesville shale horizontal well performance (Kapchinske and Sharp 2008)

3.3.4 Marcellus Shale

The Marcellus shale play now uses horizontal drilling to develop the reservoir because the horizontal wells can be used to intersect the vertical fracture network. Many companies realized that they could recover more reserves by connecting to more fractures using horizontal wellbores. The reason that the horizontal laterals could connect to more fractures is due to the fact that the wellbore is now perpendicular to the fracture system. In the 1980s, many operators drilled horizontal wells and were technically successful but did not produce commercial quantities of gas. The main reason for the economic failure was because of the high cost of fracture stimulation and the limitations to fracture technology during that time (Miller 2008). With the improvements that have been made in fracture technology in the past 10 years, horizontal drilling can now be used successfully in the Marcellus Shale. Even with horizontal drilling being the preference, there are still many facets of horizontal drilling that are being tested in the Marcellus Shale.

The biggest issue is whether to drill these wells open hole or to case and cement these wells. Most operators have moved to cased and cement because of issues with mechanically separating the fracture stages. Even with the decision to used cemented hole completions, there are still problems with fracture initiation caused by stress anisotropy (Gottschling 2007). Arthur et al (2008) states that to reduce the fracture treatment breakdown pressures, operators are experimenting with the phasing of the perforations, using HCl acid first to open the perforations before situating, and re-perforating if there is difficulty pumping into the formation. The laterals for Marcellus Shale wells typically range from 2,000 to 4,500 feet in length depending on the number of frac stages that will be completed (DeWitt 2008). As discussed earlier, there are three schools of thoughts on the fracture fluid used in these wells – straight N_2, N_2 foam, or slick water. Gottschling (2007) discusses how most horizontal wellbores are stimulated using large foam fracture treatments where about 5 to 10 MMCF of nitrogen is pumped transporting anywhere from 728,000 lbs to over 1.8 million lbs of sand in a well that will be completed with 4 to 10 stages. The sand that is usually used in this type of stimulation treatment is 100 mesh or a 20/40 sand.

The Marcellus Shale wells IP anywhere from 1 MMCF/D to 4.3 MMCF/D. Most companies believe a horizontal well in the Marcellus Shale will eventually recover anywhere from 1 to 4.5 BCF per well. The costs to drill and complete a Marcellus Shale well are generally \$3 to \$4 million (Sumi 2008). The Marcellus shale has almost a one-to-one ratio between IP and recoverable reserves; if a well IP's ar 1 MMCF/D then more than like it will recover somewhere around 1 BCF from the well. As the industry moves to optimizing these fracturing methods, some companies are looking at using CO_2 to help assist in the flowback after the fracture treatment is completed. CO_2 is water soluble which will allow a higher water recovery percentage; thus, helping recover fluid in low bottom-hole pressure wells[20]. DeWitt (2008) shows what a typical Marcellus horizontal well performance looks like in the figure below **(Fig. 3.7)**.

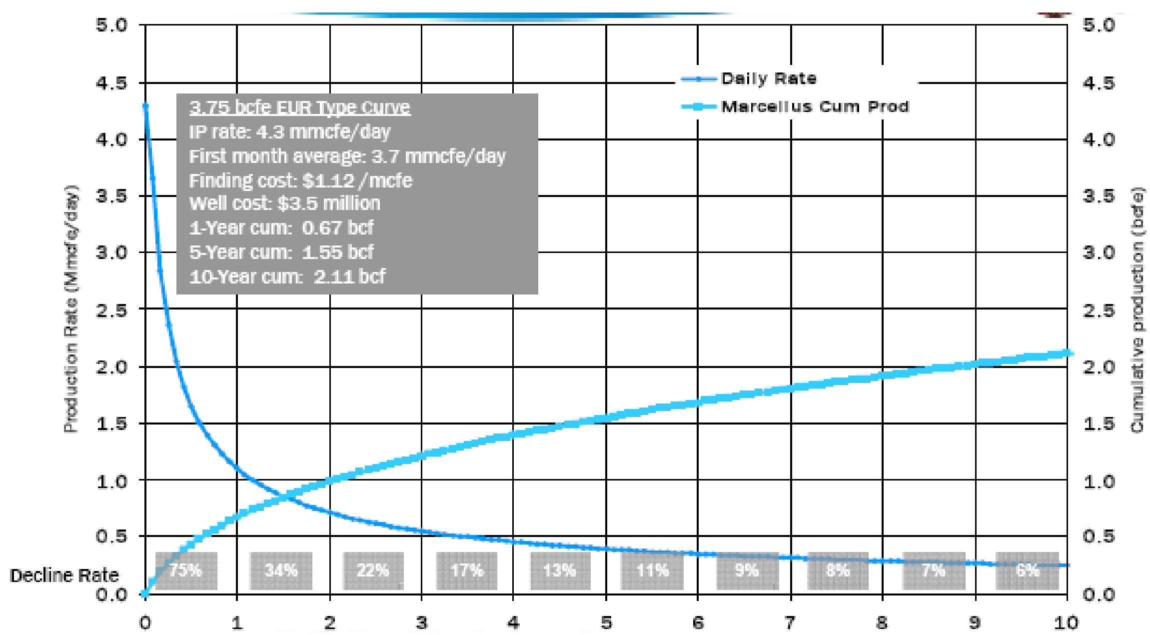

Fig. 3.7—Marcellus shale horizontal well performance (DeWitt 2008)

3.3.5 Woodford Shale

According to Wickstrom (2008), in 2004 the Woodford Shale horizontal program started to take off but did not gain much momentum until 2006 when over 130 Woodford horizontal wells were completed. As with other shale plays, there is a learning curve that is leading to better completions in the Woodford Shale (Coffey 2007). It is now common practice to find cased, cemented laterals in this play and the laterals range anywhere from 2,500 to 4,000 feet long. There is a difference between these two lengths in not only cost but EURs due to the number of fracs. The 2,500 feet lateral lengths tend to only allow five stage fracs which yields an average of about 2.5 BCF per well that is recovered over the life of that well. In the 4,000 feet laterals, operators can execute eight to nine stage treatments which can yield recoveries of 6 BCF on average. From this information, many deduce that it is beneficial to drill the longer laterals but that depends on the price environment since the shorter laterals cost about $4.75 MM to drill and complete while the longer laterals cost about $ 7.75 MM to drill and complete (Wickstrom 2008).

Wickstrom (2008) states that a common practice in the Arkoma Woodford is to perforate 300' sections at a time and then acidize the perforations with 15% HCl before fracing the formation. Each stage pumps approximately 18,000 bbls of slick water and 200,000 lbs of sand (100 mesh, 40/70 Ottawa or 20/40 Ottawa). Generally, a 5-1/2" casing is run-in-hole in lateral potion of the well so that average pump rate is anywhere from 60 to 95 BPM and an average treating pressure of about 5,600 to 5,800 psi. The typical performance of a 4,000 ft lateral Woodford horizontal well is seen in Fig. 3.4. Similar to the Barnett shale, many operators are moving to simu-fracture treatments in the Woodford shale. Also, some operators have done zipper fracture stimulations. In a zipper fracture, two laterals are next to each other and starting from the toe of each lateral one fracture stage is done in well one and then the same stage is done on well two. Then the operator goes up to the next stage in well one and then stimulates the second stage in well two. The operator continues going back and forth between the two wells until both wells are stimulated from toe to heel. The reason for this is that there have been some studies done indicating that this method helps stimulate more of the reservoir. There is not enough data to indicate if this is true or false yet.

CHAPTER IV
ECONOMIC MODEL OF COMPLETION TECHNIQUES

4.1 Gas Price Discussion

The price of natural gas is vital to the economic success of gas shale plays in the U.S. From 1983 – 2000, the average annual price of natural gas was fairly steady from about \$2 to \$3/mcf of gas. Since 2000, the price of natural gas has been very volatile and has varied from \$3 to \$8 per mcf of gas on average. **(Fig. 4.1)**. However, since the price decline late 2008 to early 2009, operators have stepped back from drilling these plays to see what the market prices will do. There is still a lot of uncertainty as to what the natural gas price will stabilize at—making many major operators hesitant when it comes investing large amount of money in gas shale plays.

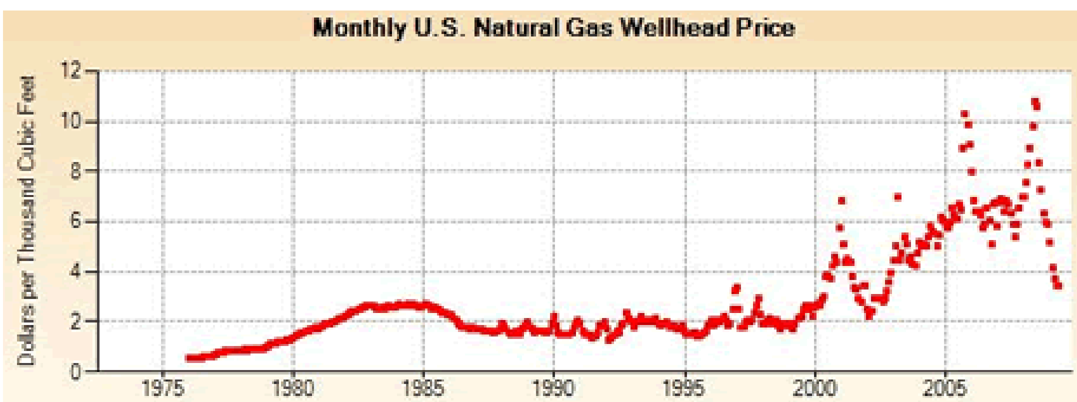

Fig. 4.1—Natural gas wellhead prices (geology.com 2009)

There is a direct relationship between gas prices and the development of gas shale play activities. When the prices increase, the activity in the gas shale basins increases. In this thesis, we have looked at the impact price has on the development in gas shale basins to determine what is the best completion design to use (horizontal versus vertical) in different price environments since this is an important analysis that needs to be done in unconventional gas shale basins.

4.2 Completion Cost and Variations

As gas prices and revenue decline, the cost of services such as drilling rig, mud, and stimulation services decline as well. These cost changes affect the overall economics of a project. Therefore, most operators will re-run their economics using different price and cost scenarios to determine the hurdle prices for gas required to move forward with project. One thing to note is that service companies tend to lag behind significant increases or decreases in gas price. However, when operators began reducing drilling projects and the rig count declines, the cost of services always decline also as competition increases. As such, when running economic scenarios, the gas prices and F&D costs are relatable.

4.3 Shale Economic Parameters

Economics were run on each of the different shale gas plays described in this thesis for two types of completions—vertical and horizontal. The reason for doing this analysis is to observe which completion method is best under different economic environments. For economic purposes, all evaluation start dates will be January 2009. Also, it is important to note that production begins one month after the fracture treatments are completed. This simulates the flowed back period to recover load water, and the time to set up facilities for each location. In addition to this, there are always a couple of days to a week delay between when the rig moves on location to stimulate because of two main reasons. The first reason is that the engineer and the geologist need to decide where to perforate and where to fracture stimulate the wellbore. Second is the time to design the fracture stimulation procedure and line up the services.

For the base case, $7/MMBTU was used since this was the typical gas price for much of 2008[86]. The capital for each shale play and completion type will be discussed in the following sections. Since gas shale reservoirs take on a hyperbolic decline rate, the b-value for the cases will be 2.3. This is higher than 1.0 which is the typical upper limit for hyperbolic decline (harmonic), but there is evidence in the industry that a b-value can be higher than 1 and that this is indicative of wells that have multipay reservoirs, multiporosity sytems, or are tight gas reservoirs. Also, the economics will be run on a 30 year life of the wellbore instead of economic limits, since each operator will have a different hurdle rate because the economic limit depends on operating expenses and lifting costs. In this calculation, the operating expense will be held constant at $5,000/Well/Month. Since this is a model for gas shale plays, the working interest (WI) is 100% and the net revenue interest (NRI) is 87.5% to represent the typical 1/8th royalty.

4.3.1 Antrim Shale

For the Antrim Shale, the drilling time from rig down to rig up is about 7 days. Once the rig is moved off location, there are a couple of days delay until the stimulation treatment can be lined up and then one day to stimulate the well. For the economics of the study, the rig will move on to location on January 1st and will be off location 3rd week of January. The well will come on March 1st and start producing to the sales line. The total drilling and completion cost for typical Antrim Shale gas well is about $350,000. The lifiting cost and the water disposal cost will be included in the operating expense and not in the initial drilling cost. With the completion techniques currently used in this play, the average IP is about 125 MCF/D with the 1st two years declining at about 35%. After the second year, decline stabilizes to 9% for the next 28 years **(Table 4.1)**. The average recovery at that time is about 0.44 BCF per well (Goodman and Maness 2008).

Table 4.1—Summary of Yearly Decline Rates for a Typical Antrim Vertical Well (Goodman and Maness 2008)

Year	1	2	3
Decline Rate (%)	35	35	9

4.3.2 Barnett Shale

Vertical Completion

The drilling time for a Barnett Shale vertical well, from rig up to rig down, is about 15 days. Once the rig is moved off location, several days are required before stimulation and then one day to stimulate the well. For this study, we assume the rig will moves on to location on January 1st and will be off location last week of January. The well will come on March 1st and start producing to the sales line. The total drilling and completion costs for a typical vertical Barnett Shale is about $1,000,000 as discussed earlier. According to Hayden and Pursell (2005), with the completion techniques currently used in Barnett Shale, the average IP is about 650 MCF/D with a 1st year decline of about 60%. The second year declines at a shallower rate of 30% and the third year at about 15%. After the third year, the well has a steady decline rate of 10% for the next 26 years **(Table 4.2)**. The average recovery at that time for the vertical wellbore is about 0.77 BCF per well depending on where you are located in the Fort Worth Basin.

Table 4.2—Summary of Yearly Decline Rates for a Typical Barnett Vertical Well (Hayden and Pursell 2005)

Year	1	2	3	4
Decline Rate (%)	60	30	15	10

Horizontal Completion

For the horizontal Barnett Shale wells, the drilling time is about 27 days. Once the rig is moved off location, there is a about a week delay before stimulation and then three to four days to stimulate the wellbore. For the economics done for this study, the rig will move on to location on January 1st and will be off location last week of January. The well will come on production to sales on April 1st and start producing to the sales line. The total drilling and completion costs for a typical horizontal Barnett Shale are about $2,000,000 as discussed earlier. With the completion techniques used right now in this play, the average IP is about 1,520 MCF/D with a 1st year decline of about 56%. The second year declines at a rate of 26% and the third year at about 15%. After the third year, the well has a steady decline rate of 11% for the next 26 years **(Table 4.3)**. The average recovery at that time is about 2.47 BCF per well (Hayden and Pursell 2005).

Table 4.3—Summary of Yearly Decline Rates for a Typical Barnett Horizontal Well (Hayden and Pursell 2005)

Year	1	2	3	4
Decline Rate (%)	56	26	15	11

4.3.3 Haynesville Shale

For the horizontal Haynesville Shale wells, the drilling time is about 50 days. Once the rig is moved off location, there is a about a two week delay to stimulation and then a four to five days to stimulate the wellbore. For the economics of the study, the rig will move on to location on January 1st and will move off location last week of February. The well will come on production to sales on May 1st. Kapchinske and Sharp (2008) indicated that the total drilling and completion cost for typical Haynesville Shale gas well is about $7,500,000 as discussed earlier. With the completion techniques used right now in this play, the average IP is about 6,000 MCF/D with a 1st year decline of about 81%. For the next 7 years the decline rate will get shallower until it reaches its final decline rate in year 9, which is 7%. Starting the second year, the decline rate decreases from 34% to 8% in seven years **(Table 4.4)**. The average recovery at that time is about 4.21 BCF per well.

Table 4.4—Summary of Yearly Decline Rates for a Haynesville Horizontal Well (Kapchinske and Sharp 2008)

Year	1	2	3	4	5	6	7	8
Decline Rate (%)	81	34	22	17	13	11	9	8

4.3.4 Marcellus Shale

Vertical Completion

For the Marcellus Shale, the drilling time for a vertical well is similar to that of the Barnett Shale—15 days. Once the rig is moved off location, there is a couple of days delay before stimulation and then one day to stimulate the wellbore. For the economics done for this study, the rig will move on to location on January 1st and will be off location last week of January. The well will come on March 1st and start producing to the sales line. The total drilling and completion cost for a typical vertical Marcellus Shale is about $800,000 as discussed earlier. With the completion techniques used right now in this play, the average IP is about 150 MCF/D with a 1st year decline of about 30%. After the first year, the well has about a steady decline rate of 7% for the next 29 years **(Table 4.5)**. The average recovery at that time is about 0.68 BCF per well (Drake 2007).

Table 4.5—Summary of Yearly Decline Rates for a Typical Marcellus Vertical Well (Drake 2007)

Year	1	2
Decline Rate (%)	30	7

Horizontal Completion

For the horizontal Marcellus wells, the drilling time is about 27 days. Once the rig is moved off location, there is a about a week delay before stimulation and then three to four days to stimulate the wellbore. For the economics done for this study, the rig will move on to location on January 1st and will be off location last week of January. The well will come on production to sales on April 1st. The total drilling and completion cost for a typical horizontal Marcellus Shale is about $3,500,000 as discussed earlier. With the completion techniques used right now in this play, the average IP is about 3,700 MCF/D with a 1st year decline of about 75%. For the next 9 years the decline rate will get shallower until it reaches its final decline rate in year 10, which is 6%. Similar to the Haynesville shale, the Marcellus horizontal starts the second year, to decline gradually from 34% to 7% in eight years **(Table 4.6)**. The average recovery at that time is about 3.67 BCF per well (DeWitt 2008).

Table 4.6—Summary of Yearly Decline Rates for a Marcellus Horizontal Well (DeWitt 2008)

Year	1	2	3	4	5	6	7	8	9
Decline Rate (%)	81	34	22	17	13	11	9	8	7

4.3.5 Woodford Shale

Vertical Completion

For the Woodford Shale, the drilling time for a vertical well is about 30 days. Once the rig is moved off location, there is a about a couple of days delay before stimulation and then one day to stimulate the wellbore. For the economics done for this study, the rig will move on to location on January 1st and will be off location last week of January. The well will come on March 1st and start producing to the sales line. The total drilling and completion cost for a typical vertical Woodford Shale is about $2,000,000 as discussed earlier. With the completion techniques used right now in this play, the average IP is about 1,000 MCF/D with a 1st year decline of about 65%. The second year declines at a shallower rate of 29% and the third year at about 18%. After the third year, the well has about a steady decline rate of 12% for the next 26 years **(Table 4.7)**. The average recovery at that time is about 1.39 BCF per well.

Table 4.7—Summary of Yearly Decline Rates for a Typical Woodford Vertical Well (Coffey 2007)

Year	1	2	3	4
Decline Rate (%)	65	29	18	12

Horizontal Completion

For the horizontal Woodford Shale wells, the drilling time is similar to the Haynesville Shale—50 days. Once the rig is moved off location, there is a about a two week delay before stimulation and then a four to five days to stimulate the wellbore. For the economics done for this study, the rig will move on to location on January 1st and will be off location last week of January. The well will come on production to sales on May 1st and start producing to the sales line. The total drill and complete cost for a typical horizontal Woodford Shale is about $7,750,000 as discussed earlier. Langford (2008) showed that with the completion techniques used right now in this play, the average IP is about 4,500 MCF/D with a 1st year decline of about 62%. For the next 4 years, the decline rate will get shallower until it reaches its final decline rate in year 6, which is 7%. Similar to the Haynesville and Marcellus shales, the Woodford horizontal starts the second year, to decline gradually from 28% to 7% in five years **(Table 4.8)**. The average recovery at that time is about 4.82 BCF per well.

Table 4.8—Summary of Yearly Decline Rates for a Woodford Horizontal Well (Langford 2008)

Year	1	2	3	4	5	6
Decline Rate (%)	62	28	18	13	11	7

4.4 Sensitivity Analysis Considerations

To understand what really impacts the overall economics of each of the different gas shale basins, several components were analyzed. The various elements that were explored in this study were the operating cost, the capital cost, and the gas price. Operating cost varied from $1,000/Well/Month to $7,000/Well/Month. The lower limit was picked because most independents do not have as high operating cost as those of major energy companies. The higher end of the operating cost is due to issues with produced water, such as the Antrim shale water production, plus any gas plant purification expenses incurred for high CO_2 content. The capital cost varied from 30% below the base case to 30% above the base case. The reason for this variation is because just as the market fluctuates with gas prices so do the cost of goods and services. For example, in 2008 there was a shortage of steel in the U.S. making it difficult to obtain steel pipe for casing and tubing which ultimately led to higher steel prices. Lastly, as discussed previously, the price was modified to as low as $3.50/mcf, which is what is being seen in the market today, to as high as $12/mcf since that was a high that the market reached to in July 2008. With the use of these sensitivities, it should help operators working not only in these basins but basins similar to this decide whether to drill horizontal wells, switch to vertical wells, or just to hold off until the market is in a position to make these plays economic.

CHAPTER V
DISCUSSION AND RESULTS

5.1 Economic Results

Petroleum economic analyze were completed on each of the shale gas plays discussed as well as sensitivity analysis using Merak PEEP, Schlumberger's economic evaluation software. To determine which results were the best completion design (vertical or horizontal) for each scenario, the discounted profit to investment ratio (DP/I) was the main factor that would compare the different scenarios. To calculate DP/I, the net cash flow discounted at 10% is divided by the discounted investment; therefore, a DP/I of 1.0 is equal to a net present value (NPV) of 0 at 10%, which will be indicative of a hurdle ratio. Other economic parameters looked at were NPV at a 10% discount rate, rate of return (ROR) and payout of the capital. Using the economic parameters discussed in Chapter IV, each shale gas play was evaluated. The table below summarizes the DP/I for each of the different formation and completion type with varying capital spend, EUR, and operating cost **(Table 5.1)**. This table represents the best case scenario, although unrealistic in most instances, for each play.

Table 5.1—Summary of Best Case Scenario for Each Shale Gas Basin

Play	Completion Type	DP/I	NPV @ 10% ($)	ROR (%)	Payout (mo)	Gas Price ($/MCF)	Capital Spend ($)	Operating Cost ($)
Antrim	Vertical	4.86	946,000	136.7	12.1	12	245,000	1,000
Barnett	Vertical	3.98	2,089,000	175.4	10	12	700,000	1,000
Barnett	Horizontal	5.48	6,276,000	218.5	9.2	12	1,400,000	1,000
Haynesville	Horizontal	3.02	10,613,000	118	11.7	12	5,250,000	1,000
Marcellus	Vertical	3.39	1,338,000	66.9	21	12	560,000	1,000
Marcellus	Horizontal	5.36	10,681,000	358.8	7	12	2,450,000	1,000
Woodford	Vertical	3.38	3,328,000	113.2	12.5	12	1,400,000	1,000
Woodford	Horizontal	3.54	13,772,000	159.9	10.2	12	5,425,000	1,000

At a $12 gas price, all plays regardless of completion type, will on average produce economic results. The DP/I ranges anywhere from 3.02 for a Haynesville horizontal to 5.48 for a Barnett horizontal well. Also, when looking at the type of completions, it seems that all the horizontal completion types are more profitable than the vertical completions based on not only DP/I but also when looking at NPV, ROR, and payout. Since the best case scenario is rarely present when evaluating these shale plays, this investigation looked at other scenarios more commonly found in the industry. Again, It is important to note that the chances of all the independent variables occurring at the optimal value is probably unrealistic.

For the base case scenario calculations, the gas price was set at $7/mcf, capital was the average of what is seen at that price, and operating cost was $5,000/Well/Month. Each of the parameters was varied independently while the other two were held at the base case to evaluate the three parameters.

5.1.1 Antrim Shale

The Antrim Shale is a shallow play compared to all the other four plays; therefore, drilling costs are relatively low. For the first component that was varied—gas prices, the Antrim shale was not economic at the $3.50/mcf but was economic at the base case of $7/mcf. The table below shows the DP/I, NPV @ 10%, ROR, and the payout for the three values of gas price **(Table 5.2)**.

Table 5.2—Gas Price Sensitivity on the Antrim Shale Gas Play

	Low Gas Price ($3.50/mcf)	Base Gas Price ($7.00/mcf)	High Gas Price ($12.00/mcf)
DP/I	0.44	1.17	2.55
NPV @ 10% ($)	(196,000)	61,000	541,000
ROR (%)	0.0	17.3	62.9
Payout (months)	0.0	48.1	20.2

From this investigation, it is apparent that unless gas prices are close to $7.00/mcf with everything else held constant, the Antrim shale does not reach the hurdle ratio; thus, it is not recommended to drill this play unless drilling and completion costs can be reduced.

As mentioned earlier, the capital spent foe each type of well in each play was also analyzed to see what impact that has on the economical viability of developing the shale. The gas price and operating costs were held constant at $7.00/mcf and 1,000/Well/Month respectively. As expected, the capital did affect the DP/I as well as the NPV. If the cost increases by 30%, the well was not economic but when the investment decreased by 30%, this well was economic **(Table 5.3)**.

Table 5.3—Capital Spend Sensitivity on the Antrim Shale Gas Play

	Low Capital ($245,000)	Base Capital ($350,000)	High Capital ($455,000)
DP/I	1.54	1.17	0.97
NPV @ 10% ($)	133,000	61,000	(11,000)
ROR (%)	33.5	17.3	9.0
Payout (months)	30.8	48.1	68.2

It can be concluded that the capital cost does not affect the overall project as much as the gas price did, but it is important to keep in mind capital costs when deciding which vendor to use for the drilling and completion of these wells.

The last component explored in terms of impact on the financial viability of the Antrim shale was the operating cost. When all other factors were held constant at the base case and the operating cost fluctuated between 1,000 up to $7,000/Well/Month, the higher operating cost was uneconomic while the other two other scenarios were economic. The economic results with these adjustments are portrayed below **(Table 5.4)**.

Table 5.4—Operating Cost Sensitivity on the Antrim Shale Gas Play

	Low Operating Cost ($1,000/Well/Month)	Base Operating Cost ($5,000/Well/Month)	High Operating Cost ($7,000/Well/Month)
DP/I	2.07	1.17	0.86
NPV @ 10% ($)	374,000	61,000	(49,000)
ROR (%)	37.6	17.3	1.9
Payout (months)	31.5	48.1	79.5

For the Antrim shale, it seems that the operating monthly cost had a larger influence than the capital spent. The reason for this is because the costs to drill these wells are so low; therefore, the change from 1,000/Well/Month to $7,000/Well/Month will have a larger impact on the overall economics for the Antrim Shale. From this sensitivity analysis, it is concluded that the gas price has the largest impact, followed by the operating cost and then the capital spend for the Antrim Shale. From this study, it is evident that horizontal wells have not been drilled in the Antrim shale since vertical wells are marginal even at the base case.

Since the reserves for each well can vary, it is important to look at what affect this has on the overall economics of the play. A summary of how the DP/I changes with reserves and each of the parameters discussed above is shown below **(Fig. 5.1)**.

Antrim Shale Vertical -- DP/I Per Well			
Capital Expenditure = $245,000			
Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
($/mcf)	0.25	0.45	0.6
$ 3.50	0.83	1.39	1.88
$ 7.00	1.68	2.79	3.79
$ 12.00	2.9	4.8	6.51

Antrim Shale Vertical -- DP/I Per Well			
Capital Expenditure = $350,000			
Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
($/mcf)	0.25	0.45	0.6
$ 3.50	0.68	1.06	1.41
$ 7.00	1.27	2.05	2.75
$ 12.00	2.12	3.46	4.65

Antrim Shale Vertical -- DP/I Per Well			
Capital Expenditure = $455,000			
Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.25	0.45	0.6
$ 3.50	0.59	0.89	1.16
$ 7.00	1.05	1.65	2.19
$ 12.00	1.7	2.73	3.65

Antrim Shale Vertical -- DP/I Per Well			
Capital Expenditure = $245,000			
Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
($/mcf)	0.25	0.45	0.6
$ 3.50	0.38	0.5	0.79
$ 7.00	0.73	1.53	2.47
$ 12.00	1.67	3.47	5.18

Antrim Shale Vertical -- DP/I Per Well			
Capital Expenditure = $350,000			
Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
($/mcf)	0.25	0.45	0.6
$ 3.50	0.36	0.44	0.65
$ 7.00	0.61	1.17	1.82
$ 12.00	1.26	2.52	3.72

Antrim Shale Vertical -- DP/I Per Well			
Capital Expenditure = $455,000			
Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.25	0.45	0.6
$ 3.50	0.36	0.41	0.57
$ 7.00	0.54	0.97	1.47
$ 12.00	1.05	2.01	2.93

Antrim Shale Vertical -- DP/I Per Well			
Capital Expenditure = $245,000			
Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
($/mcf)	0.25	0.45	0.6
$ 3.50	0.33	0.39	0.53
$ 7.00	0.55	1.09	1.9
$ 12.00	1.27	2.84	4.51

Antrim Shale Vertical -- DP/I Per Well			
Capital Expenditure = $350,000			
Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
($/mcf)	0.25	0.45	0.6
$ 3.50	0.33	0.37	0.47
$ 7.00	0.48	0.86	1.43
$ 12.00	0.98	2.08	3.25

Antrim Shale Vertical -- DP/I Per Well			
Capital Expenditure = $455,000			
Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.25	0.45	0.6
$ 3.50	0.33	0.36	0.43
$ 7.00	0.44	0.73	1.17
$ 12.00	0.83	1.67	2.57

Fig. 5.1--Summary of Antrim shale economics

In Fig. 5.1, the boxes that are highlighted in red are those that have a DP/I less than 1, which means that at that particular gas price, capital spend, operating expense, and EUR, the well is not economic; therefore, a bad investment if the well is looked at individually. The boxes that are yellow represent a DP/I greater than 1 but less than 1.2. This represents wells that have marginal returns. The boxes that are green are those that have a DP/I greater than 1.2 but less than 3 showing that it was a good investment. The parameters that lead to a DP/I greater than 3 are shaded as blue, which show conditions that are considered a "slam dunk" to drill and complete.

5.1.2 Barnett Shale

The Barnett Shale is currently the largest gas field in the U.S. Many operators have drilled vertical and horizontal wells during the 2000's and with the higher gas prices; it is evident that most operators are now drilling horizontal wells to develop their acreage. From the analysis, I have evaluated if there are situations that one would switch back to vertical completions or if the drilling should stop completely due to unacceptable economics.

Vertical Completion

The Barnett Shale vertical completions were looked at separately from the horizontal wells since there are operators that drill vertical wells before switching to horizontal wells. In the horizontal section, there will be a comparison of the results seen in the vertical wells to those found in the horizontal wells. I first looked at the effect of gas price. A Barnett vertical well will not be economic at the $3.50/mcf, but was economic at the higher price environments. The table below shows the DP/I, NPV @ 10%, ROR, and the payout at each of the different gas price values **(Table 5.5)**.

Table 5.5—Gas Price Sensitivity on the Vertical Barnett Shale Gas Play

	Low Gas Price ($3.50/mcf)	Base Gas Price ($7.00/mcf)	High Gas Price ($12.00/mcf)
DP/I	0.75	1.48	2.57
NPV @ 10% ($)	(249,000)	484,000	1,569,000
ROR (%)	0.0	32.1	88.1
Payout (months)	0.0	31.3	14.7

From this study on price variation, is apparent that a price of anything above $5/mcf will met the hurdle ration of 1.0 for DP/I. Also, a very interesting observation is that the DP/I for the high gas price is almost 75% greater than the $7/mcf and that with the higher gas price the NPV is over $1.5 MM. On the other hand, if the gas price is low then it is not recommended to drill a vertical Barnett well unless there is a drastic drop in drilling and completion costs.

As mentioned earlier, the capital spend was also analyzed to see what impact it has on the economical viability of the project. With constant gas price of $7.00/mcf and the operating cost at a fixed cost of 1,000/Well/Month, the capital did cause a swing in the DP/I as well as the NPV. For the vertical completions in the Barnett Shale, no matter if the cost went up by 30% or went down, a well in this play is still a very good investment **(Table 5.6)**.

Table 5.6—Capital Spend Sensitivity on the Vertical Barnett Shale Gas Play

	Low Capital ($700,000)	Base Capital ($1,000,000)	High Capital ($1,300,000)
DP/I	1.99	1.48	1.21
NPV @ 10% ($)	690,000	484,000	227,000
ROR (%)	59.5	32.1	19.3
Payout (months)	19.3	31.3	44.6

It can be deduced that the capital cost does not have a negative impact unless the cost increase is significantly higher than 30%. As a result, the engineer looking at drilling vertical wells should not focus too much on the capital cost if the other components such as price and operating cost are similar to the base case unless it is significantly over 30% incremental increase than the base.

The last component explored in terms of impact on the financial viability of the vertical wells in the Barnett shale was the operating cost. When all other factors were held constant at the base case and the operating cost fluctuated between $1,000 to $7,000/Well/Month. As with the capital spend, there was no case that did not meet the hurdle ration of 1.0. The table below shows the economic results with these adjustments **(Table 5.7)**.

Table 5.7—Operating Cost Sensitivity on the Vertical Barnett Shale Gas Play

	Low Operating Cost ($1,000/Well/Month)	Base Operating Cost ($5,000/Well/Month)	High Operating Cost ($7,000/Well/Month)
DP/I	1.78	1.48	1.36
NPV @ 10% ($)	776,000	484,000	359,000
ROR (%)	39.8	32.1	27.9
Payout (months)	27.5	31.3	33.5

From the analysis done on the vertical Barnett shale, it seems that unless there is a significant increase (above 30%) in capital spend or a significant increase (over $7,000/Well/Month) in operating cost it is an economic prospect at prices higher than $5/mcf.

Since the reserves for each well can vary, it is important to look at what affect this has on the overall economics of the play. The figure below depicts how the DP/I changes with reserves and each of the parameters discussed above **(Fig. 5.2)**.

Barnett Shale Vertical -- DP/I Per Well			
Capital Expenditure = $700,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.5	0.77	1
$ 3.50	0.91	1.29	1.63
$ 7.00	1.61	2.38	3.06
$ 12.00	2.62	3.94	5.1

Barnett Shale Vertical -- DP/I Per Well			
Capital Expenditure = $1,000,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.5	0.77	1
$ 3.50	0.73	1	1.23
$ 7.00	1.22	1.76	2.23
$ 12.00	1.93	2.85	3.66

Barnett Shale Vertical -- DP/I Per Well			
Capital Expenditure = $1,300,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.5	0.77	1
$ 3.50	0.63	0.84	1.02
$ 7.00	1.01	1.43	1.79
$ 12.00	1.56	2.27	2.89

Barnett Shale Vertical -- DP/I Per Well			
Capital Expenditure = $700,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.5	0.77	1
$ 3.50	0.6	0.94	1.25
$ 7.00	1.23	1.97	2.63
$ 12.00	2.21	3.5	4.65

Barnett Shale Vertical -- DP/I Per Well			
Capital Expenditure = $1,000,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.5	0.77	1
$ 3.50	0.52	0.75	0.97
$ 7.00	0.96	1.47	1.93
$ 12.00	1.64	2.55	3.35

Barnett Shale Vertical -- DP/I Per Well			
Capital Expenditure = $1,300,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.5	0.77	1
$ 3.50	0.47	0.65	0.82
$ 7.00	0.81	1.21	1.56
$ 12.00	1.33	2.03	2.65

Barnett Shale Vertical -- DP/I Per Well			
Capital Expenditure = $700,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.5	0.77	1
$ 3.50	0.51	0.8	1.1
$ 7.00	1.08	1.79	2.44
$ 12.00	2.02	3.3	4.44

Barnett Shale Vertical -- DP/I Per Well			
Capital Expenditure = $1,000,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.5	0.77	1
$ 3.50	0.45	0.66	0.86
$ 7.00	0.85	1.35	1.8
$ 12.00	1.51	2.41	3.2

Barnett Shale Vertical -- DP/I Per Well			
Capital Expenditure = $1,300,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.5	0.77	1
$ 3.50	0.42	0.58	0.73
$ 7.00	0.73	1.11	1.46
$ 12.00	1.23	1.92	2.53

Fig. 5.2—Summary of vertical completions in the Barnett shale economics

In Fig. 5.2, the boxes that are highlighted in red are those that have a DP/I less than 1, which means that at that particular gas price, capital spend, operating expense, and EUR, the well is not economic; therefore, a bad investment if the well is looked at individually. The boxes that are yellow represent a DP/I greater than 1 but less than 1.2. This represents wells that have marginal returns. The boxes that are green are those that have a DP/I greater than 1.2 but less than 3 showing that it was a good investment. The parameters that lead to a DP/I greater than 3 are shaded as blue, which show conditions that are considered a "slam dunk" to drill and complete.

Horizontal Completion

The Barnett Shale horizontal completions have become the most common practice in this play replacing conventional vertical wells. For the first component that was varied—gas prices, the Barnett vertical well was not economic at the $3.50/mcf, but was very economic at the higher price environments. The table below shows DP/I, NPV @ 10%, ROR, and the payout at each of the different price decks **(Table 5.8)**.

Table 5.8—Gas Price Sensitivity on the Horizontal Barnett Shale Gas Play

	Low Gas Price ($3.50/mcf)	Base Gas Price ($7.00/mcf)	High Gas Price ($12.00/mcf)
DP/I	1.18	2.25	3.77
NPV @ 10% ($)	363,000	2,498,000	5,548,000
ROR (%)	15.7	52.3	121.3
Payout (months)	56.4	22.2	12.3

From this study on price variation, is apparent that a price of anything above $3.50/mcf will met the hurdle ration of 1.0. Unlike the vertical completions, the horizontal wells will payout even in the lower price environment and are much more lucrative at the base and high gas prices. Similar to the vertical completions, the DP/I for the high gas price is almost 75% greater than the $7/mcf and that with the higher gas price the NPV is over

$5.5 MM. At all the different price environments, it would be a good investment to drill a horizontal Barnett well.

As mentioned earlier, the capital spend was also analyzed to see what impact that has on the economical viability of the project. With constant gas price of $7.00/mcf and the operating cost fixed at 1,000/Well/Month, the capital did cause a change in the DP/I as well as the NPV. For the horizontal completions in the Barnett Shale, no matter if the cost went up by 30% or went down, this play is still a very good investment **(Table 5.9)**.

Table 5.9—Capital Spend Sensitivity on the Horizontal Barnett Shale Gas Play

	Low Capital ($700,000)	Base Capital ($2,000,000)	High Capital ($2,600,000)
DP/I	3.08	2.25	1.80
NPV @ 10% ($)	2,911,000	2,498,000	2,084,000
ROR (%)	89.3	52.3	35.3
Payout (months)	15.0	22.2	30.4

As seen in the vertical completions, it is concluded that the capital costs do not have a negative impact unless the cost increase is double the original cost of $2MM. As a result, the engineer looking at drilling horizontal wells should control capital costs but small cost overruns will not cause the project to be uneconomic if the well is successful and recovers 6.5 BCF or more in 30 years. Even at the 30% increase cost, the NPV for a well is still over $2MM which is close to paying out 200% of the well cost to drill. If looking at these wells compared to the vertical wells, it is easily seen that it is better to drill horizontal wells because of the high NPV and the high DP/I. The only time horizontal drilling would not be advised is in a capital constrained environment or when gas prices are very low.

The last component explored in terms of impact on the financial viability of the horizontal wells in the Barnett shale was the operating cost. When all other factors were held constant at the base case and the operating cost fluctuated between $1,000 to $7,000/Well/Month. As with the capital spend, there was no case that did not meet the hurdle ration of 1.0. In fact, all of the scenarios were over 50% ROR as well as an NPV over $2 MM, which is better than the vertical Barnett shale wells **(Table 5.10).**

Table 5.10—Operating Cost Sensitivity on the Horizontal Barnett Shale Gas Play

	Low Operating Cost ($1,000/Well/Month)	Base Operating Cost ($5,000/Well/Month)	High Operating Cost ($7,000/Well/Month)
DP/I	2.41	2.25	2.17
NPV @ 10% ($)	2,812,000	2,498,000	2,340,000
ROR (%)	55.7	52.3	50.6
Payout (months)	21.4	22.2	22.6

From the sensitivity analysis done on the horizontal Barnett shale, it seems unless there are significant extremes that are unfavorable in each of the three parameters, there is no reason not to drill these wells. Compared to the vertical completions, it is evident that with the improvement in technology the higher value of the project is in horizontal drilling and not vertical drilling.

Since the reserves for each well can vary, it is important to look at what affect this has on the overall economics of the play. The figure below depicts how the DP/I changes with reserves and each of the parameters discussed above **(Fig. 5.3)**.

Barnett Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $1,400,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	2.47	3.9
$ 3.50	1.5	1.76	2.64
$ 7.00	2.74	3.27	5.01
$ 12.00	4.5	5.42	8.41

Barnett Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $2,000,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	2.47	3.9
$ 3.50	1.14	1.33	1.94
$ 7.00	2.01	2.38	3.6
$ 12.00	3.25	3.89	5.98

Barnett Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $2,600,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	2.47	3.9
$ 3.50	0.95	1.09	1.56
$ 7.00	1.62	1.91	2.84
$ 12.00	2.57	3.06	4.67

Barnett Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $1,400,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	2.47	3.9
$ 3.50	1.28	1.54	2.41
$ 7.00	2.51	3.05	4.79
$ 12.00	4.28	5.2	8.19

Barnett Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $2,000,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	2.47	3.9
$ 3.50	0.99	1.17	1.78
$ 7.00	1.85	2.23	3.45
$ 12.00	3.09	3.73	5.83

Barnett Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $2,600,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	2.47	3.9
$ 3.50	0.83	0.98	1.44
$ 7.00	1.5	1.79	2.73
$ 12.00	2.45	2.95	4.55

Barnett Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $1,400,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	2.47	3.9
$ 3.50	1.16	1.43	2.3
$ 7.00	2.4	2.94	4.68
$ 12.00	4.17	5.09	8.08

Barnett Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $2,000,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	2.47	3.9
$ 3.50	0.91	1.1	1.71
$ 7.00	1.78	2.15	3.37
$ 12.00	3.01	3.66	5.75

Barnett Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $2,600,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	2.47	3.9
$ 3.50	0.77	0.92	1.39
$ 7.00	1.44	1.73	2.67
$ 12.00	2.39	2.89	4.5

Fig. 5.3—Summary of horizontal completions in the Barnett shale economics

In Fig. 5.3, the boxes that are highlighted in red are those that have a DP/I less than 1, which means that at that particular gas price, capital spend, operating expense, and EUR, the well is not economic; therefore, a bad investment if the well is looked at individually. The boxes that are yellow represent a DP/I greater than 1 but less than 1.2. This represents wells that have marginal returns. The boxes that are green are those that have a DP/I greater than 1.2 but less than 3 showing that it was a good investment. The parameters that lead to a DP/I greater than 3 are shaded as blue, which show conditions that are considered a "slam dunk" to drill and complete.

5.1.3 Haynesville Shale

The Haynesville Shale is a play that has been developed with horizontal wells from the beginning with is only for the past couple of years. For the first component that was varied—gas prices, the Haynesville shale was not economic at the $3.50/mcf and was barely economic at the base case of $7/mcf. The table below portrays the DP/I, NPV @ 10%, ROR, and the payout at each of the different price decks **(Table 5.11)**.

Table 5.11—Gas Price Sensitivity on the Haynesville Shale Gas Play

	Low Gas Price ($3.50/mcf)	Base Gas Price ($7.00/mcf)	High Gas Price ($12.00/mcf)
DP/I	0.77	1.34	2.16
NPV @ 10% ($)	(1,729,000)	2,579,000	8,733,000
ROR (%)	2.8	22.0	61.0
Payout (months)	187.9	42.3	18.5

From this study, it is apparent that unless gas prices are higher than $5.00/mcf with everything else held constant, the Haynesville shale does not reach the hurdle ratio; thus, it is not recommended to drill this play at low natural gas prices unless drilling and completion costs can be reduced.

As mentioned earlier, the capital spend was also analyzed to see the impact on the economical viability of the project. Constant gas price of $7.00/mcf and fixed the operating cost at 1,000/Well/Month, caused a swing in the DP/I as well as the NPV. Regardless if the cost went up by 30% or down by 30%, this play was still a good investment. The table below summarizes the effect that capital spend has on the overall economics of the shale gas play **(Table 5.12)**.

Table 5.12—Capital Spend Sensitivity on the Haynesville Shale Gas Play

	Low Capital ($5,250,000)	Base Capital ($7,500,000)	High Capital ($9,750,000)
DP/I	1.79	1.34	1.11
NPV @ 10% ($)	4,130,000	2,579,000	1,028,000
ROR (%)	41.7	22.0	13.4
Payout (months)	24.9	42.3	62.8

It can be deduced that the capital cost does not have such a severe impact on this project as the gas price did, but it is important to keep in mind the capital cost when deciding which vendor to use for the drilling and completion of these wells since these wells are so expensive to drill.

The last component explored in terms of impact on the financial viability of the Haynesville shale was the operating cost. When all other factors were held constant at the base case and the operating cost fluctuated between 1,000/Well/Month up to $7,000/Well/Month. Again, the swing in operating cost did not make an impact on the economic health of this project **(Table 5.13)**.

Table 5.13—Operating Cost Sensitivity on the Haynesville Shale Gas Play

	Low Operating Cost ($1,000/Well/Month)	Base Operating Cost ($5,000/Well/Month)	High Operating Cost ($7,000/Well/Month)
DP/I	1.39	1.34	1.32
NPV @ 10% ($)	2,908,000	2,579,000	2,415,000
ROR (%)	23.1	22.0	21.4
Payout (months)	41.1	42.3	42.9

For the Haynesville shale, it is evident that the operating cost does not have much of a negative effect which would make it uneconomic. One thing to note is that NPV at 10% is over $2MM even though the DP/I are not that high. The reason for this is the large investment made in the drilling and completion of the well unlike ones that have been looked at so far. From this inspection, it is seems that as long as gas prices are relatively high (over $5.00/mcf), the Haynesville is a good play to partake in.

Since the reserves for each well can vary, it is important to look at what affect this has on the overall economics of the play. The figure below shows how the DP/I changes with reserves and each of the parameters discussed above **(Fig. 5.4)**.

Haynesville Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $5,250,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3	4.21	7
$ 3.50	0.82	1.02	1.5
$ 7.00	1.39	1.84	2.85
$ 12.00	2.22	2.99	4.78

Haynesville Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $7,500,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3	4.21	7
$ 3.50	0.66	0.81	1.15
$ 7.00	1.07	1.38	2.09
$ 12.00	1.65	2.19	3.44

Haynesville Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $9,750,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3	4.21	7
$ 3.50	0.58	0.7	0.95
$ 7.00	0.89	1.13	1.68
$ 12.00	1.34	1.76	2.72

Haynesville Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $5,250,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3	4.21	7
$ 3.50	0.75	0.96	1.44
$ 7.00	1.33	1.77	2.79
$ 12.00	2.16	2.93	4.72

Haynesville Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $7,500,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3	4.21	7
$ 3.50	0.62	0.77	1.1
$ 7.00	1.03	1.34	2.05
$ 12.00	1.6	2.15	3.4

Haynesville Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $9,750,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3	4.21	7
$ 3.50	0.55	0.66	0.92
$ 7.00	0.86	1.1	1.65
$ 12.00	1.31	1.72	2.69

Haynesville Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $5,250,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3	4.21	7
$ 3.50	0.72	0.93	1.41
$ 7.00	1.3	1.74	2.76
$ 12.00	2.13	2.9	4.69

Haynesville Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $7,500,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3	4.21	7
$ 3.50	0.6	0.75	1.08
$ 7.00	1	1.31	2.03
$ 12.00	1.58	2.13	3.38

Haynesville Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $9,750,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3	4.21	7
$ 3.50	0.53	0.65	0.9
$ 7.00	0.85	1.08	1.63
$ 12.00	1.29	1.71	2.67

Fig. 5.4—Summary of Haynesville shale economics

In Fig. 5.4, the boxes that are highlighted in red are those that have a DP/I less than 1, which means that at that particular gas price, capital spend, operating expense, and EUR, the well is not economic; therefore, a bad investment if the well is looked at individually. The boxes that are yellow represent a DP/I greater than 1 but less than 1.2. This represents wells that have marginal returns. The boxes that are green are those that have a DP/I greater than 1.2 but less than 3 showing that it was a good investment. The parameters that lead to a DP/I greater than 3 are shaded as blue, which show conditions that are considered a "slam dunk" to drill and complete.

5.1.4 Marcellus Shale

Vertical Completion

The Marcellus Shale vertical completions were looked at separately from the horizontal wells since there are operators that drilled vertical wells for a long time before switching to horizontal wells. In the horizontal section, there will be a comparison of the results seen in the vertical wells to that found in the horizontal wells. For the first component that was varied—gas prices, the Marcellus vertical well was not economic at the $3.50/mcf, barely met the hurdle ratio at the base price, but was lucrative at the higher price environment. The table below shows the DP/I, NPV @ 10%, ROR, and the payout at each of the different price decks **(Table 5.14)**.

Table 5.14—Gas Price Sensitivity on the Vertical Marcellus Shale Gas Play

	Low Gas Price ($3.50/mcf)	Base Gas Price ($7.00/mcf)	High Gas Price ($12.00/mcf)
DP/I	0.46	1.08	2.05
NPV @ 10% ($)	(435,000)	66,000	842,000
ROR (%)	0.0	12.2	35.6
Payout (months)	0.0	71.7	33.9

From this examination on price variation, is apparent that a price of anything below $7.00/mcf would not met the hurdle ratio of 1.0. Also, a very interesting observation is that the DP/I for the high gas price is almost double that of the $7/mcf. On the other hand, if the gas price is low then it is not recommended to drill a vertical Marcellus well unless there is a drastic drop in completion and operating costs.

As mentioned earlier, the capital spend was also analyzed to see what impact that has on the economical viability of the project. When keep the gas price constant at $7.00/mcf and the operating cost at a fixed cost of 1,000/Well/Month, the capital did cause a swing in the DP/I as well as the NPV. For the vertical completions in the Marcellus Shale, if the prices went up by 30%, the well would not meet the hurdle ratio but if it went down 30% it is a better investment by about 30%. A summary of the overall economics for the different capital spend is shown below **(Table 5.15)**.

Table 5.15—Capital Spend Sensitivity on the Vertical Marcellus Shale Gas Play

	Low Capital ($560,000)	Base Capital ($800,000)	High Capital ($1,040,000)
DP/I	1.41	1.08	0.90
NPV @ 10% ($)	231,000	66,000	(99,000)
ROR (%)	21.3	12.2	7.4
Payout (months)	48.6	71.7	101.1

From this analysis, it is concluded that if the capital is as high as 30%, then vertical Marcellus wells are not economic. The NPV is negative as well as the hurdle ratio is less than 1.0.

The last component explored in terms of impact on the financial viability of the vertical wells in the Marcellus shale was the operating cost. When all other factors were held constant at the base case and the operating cost fluctuated between 1,000/Well/Month up to $7,000/Well/Month. As with the capital spend, if the operating cost got too high, then the case did not meet the hurdle ratio of 1.0. Looking at the results of this sensitivity it is seen that the operating cost has a big impact on the economics of a vertical Marcellus well on both the positive and negative side. If the operating costs are lowered to 1/5 of the base operating cost, there is a high upside to the economics but if there are a lot of operating costs for a field then this is no longer an economical prospect if drilled vertically **(Table 5.16)**.

Table 5.16—Operating Cost Sensitivity on the Vertical Marcellus Shale Gas Play

	Low Operating Cost ($1,000/Well/Month)	Base Operating Cost ($5,000/Well/Month)	High Operating Cost ($7,000/Well/Month)
DP/I	1.49	1.08	0.89
NPV @ 10% ($)	396,000	66,000	(88,000)
ROR (%)	20.7	12.2	6.2
Payout (months)	53.4	71.7	93.0

Unless there are high gas prices, low capital and low operating cost, the vertical Marcellus wells are marginally economic if at all. Therefore, when looking at vertical completions, the operator should spend more time finding the right vendors to use and to drill in high market environments; otherwise, it will be a dismal project.

Since the reserves for each well can vary, it is important to look at what affect this has on the overall economics of the play. Shown below is a summary of how the DP/I changes with reserves and each of the parameters discussed above **(Fig. 5.5)**.

Marcellus Shale Vertical -- DP/I Per Well			
Capital Expenditure = $560,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.4	0.68	1
$ 3.50	0.67	1.02	1.43
$ 7.00	1.24	1.98	2.84
$ 12.00	2.05	3.35	4.86

Marcellus Shale Vertical -- DP/I Per Well			
Capital Expenditure = $800,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.4	0.68	1
$ 3.50	0.57	0.81	1.1
$ 7.00	0.96	1.48	2.08
$ 12.00	1.53	2.44	3.49

Marcellus Shale Vertical -- DP/I Per Well			
Capital Expenditure = $1,040,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.4	0.68	1
$ 3.50	0.51	0.7	0.91
$ 7.00	0.81	1.21	1.67
$ 12.00	1.25	1.95	2.76

Marcellus Shale Vertical -- DP/I Per Well			
Capital Expenditure = $560,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.4	0.68	1
$ 3.50	0.35	0.52	0.87
$ 7.00	0.69	1.4	2.26
$ 12.00	1.47	2.77	4.28

Marcellus Shale Vertical -- DP/I Per Well			
Capital Expenditure = $800,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.4	0.68	1
$ 3.50	0.34	0.46	0.7
$ 7.00	0.58	1.08	1.68
$ 12.00	1.12	2.03	3.09

Marcellus Shale Vertical -- DP/I Per Well			
Capital Expenditure = $1,040,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.4	0.68	1
$ 3.50	0.34	0.42	0.61
$ 7.00	0.52	0.9	1.36
$ 12.00	0.93	1.64	2.45

Marcellus Shale Vertical -- DP/I Per Well			
Capital Expenditure = $560,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.4	0.68	1
$ 3.50	0.33	0.39	0.65
$ 7.00	0.51	1.13	1.97
$ 12.00	1.19	2.48	3.99

Marcellus Shale Vertical -- DP/I Per Well			
Capital Expenditure = $800,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.4	0.68	1
$ 3.50	0.33	0.37	0.55
$ 7.00	0.45	0.89	1.47
$ 12.00	0.93	1.83	2.88

Marcellus Shale Vertical -- DP/I Per Well			
Capital Expenditure = $1,040,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	0.4	0.68	1
$ 3.50	0.32	0.36	0.49
$ 7.00	0.42	0.75	1.21
$ 12.00	0.79	1.48	2.29

Fig. 5.5—Summary of vertical completions in the Marcellus shale economics

In the figure above, the boxes that are highlighted in red are those that have a DP/I less than 1, which means that at that particular gas price, capital spend, operating expense, and EUR, the well is not economic; therefore, a bad investment if the well is looked at individually. The boxes that are yellow represent a DP/I greater than 1 but less than 1.2. This represents wells that have marginal returns. The boxes that are green are those that have a DP/I greater than 1.2 but less than 3, showing that it was a good investment. The parameters that lead to a DP/I greater than 3 are shaded as blue, which show conditions that are considered a "slam dunk" to drill and complete.

Horizontal Completion

The Marcellus Shale horizontal completions have become the most common practice in this play replacing conventional vertical wells. For the first component that was varied—gas prices. As seen above, the Marcellus vertical well was not economic at the $3.50/mcf, but when drilling horizontally even at the lower price this project is still viable. The table below portrays the DP/I, NPV @ 10%, ROR, and the payout at each of the different price decks **(Table 5.17)**.

Table 5.17—Gas Price Sensitivity on the Horizontal Marcellus Shale Gas Play

	Low Gas Price ($3.50/mcf)	Base Gas Price ($7.00/mcf)	High Gas Price ($12.00/mcf)
DP/I	1.15	2.22	3.75
NPV @ 10% ($)	527,000	4,275,000	9,628,000
ROR (%)	15.3	63.7	176.3
Payout (months)	54.7	18.0	9.7

From this study on price variation, is apparent that a price of anything above $3.50/mcf will met the hurdle ratio of 1.0. Unlike, the vertical completions, the horizontal wells will payout even in the lower price environment and are much more lucrative at the base and high gas prices. Similar to the vertical completions, the DP/I for the high gas price is almost 50% greater than the $7/mcf and that with the higher gas price the NPV is close to $10 MM. At all the different price environments, it would be a good investment to drill a horizontal Marcellus well.

As mentioned earlier, the capital spend was also analyzed to see what impact that has on the economical viability of the project. When keep the gas price constant at $7.00/mcf and the operating cost at a fixed cost of 1,000/Well/Month, the capital did cause a swing in the DP/I as well as the NPV. For the horizontal completions in the Marcellus Shale, no matter if the cost went up by 30% or went down, this play is still a very good investment. The summary of how the capital spend affects the overall economics of the shale gas play is shown below **(Table 5.18)**.

Table 5.18—Capital Spend Sensitivity on the Horizontal Marcellus Shale Gas Play

	Low Capital ($2,450,000)	Base Capital ($3,500,000)	High Capital ($4,550,000)
DP/I	3.04	2.22	1.78
NPV @ 10% ($)	4,998,000	4,275,000	3,551,000
ROR (%)	119.2	63.7	40.5
Payout (months)	11.7	18.0	25.7

Unlike the vertical completions, it is observed that the capital cost does not have a negative impact unless the cost increase is double the original cost of $ 3.5 MM. As a result, the engineer looking at drilling horizontal wells should not focus too much on the capital cost if the other components such as price and operating cost are similar to the base case unless it is significantly over 30% incremental increase than the base. In fact, even at the 30% increase cost, the NPV for a well is still over $ 3.5 MM which is 200% payout of the well cost to drill. In fact, at the lower capital spend the well would pay out in less than 1 year. If looking at these wells compared to the vertical wells, it is easily seen that it is better to drill horizontal wells because of the high NPV and the high DP/I. The only time horizontal drilling would not be advised is in a capital constrained environment.

The last component explored in terms of impact on the financial viability of the horizontal wells in the Woodford shale was the operating cost. When all other factors were held constant at the base case and the operating cost fluctuated between 1,000/Well/Month up to $7,000/Well/Month. As with the capital spend, there was no case that did not meet the hurdle ration of 1.0. In fact, all of the scenarios had over a 60% ROR as well as an NPV at 10% over $4 MM, which is better than the vertical Marcellus shale wellbores **(Table 5.19)**.

Table 5.19—Operating Cost Sensitivity on the Horizontal Marcellus Shale Gas Play

	Low Operating Cost ($1,000/Well/Month)	Base Operating Cost ($5,000/Well/Month)	High Operating Cost ($7,000/Well/Month)
DP/I	2.32	2.22	2.17
NPV @ 10% ($)	4,604,000	4,275,000	4,110,000
ROR (%)	66.0	63.7	62.6
Payout (months)	17.7	18.0	18.2

So, from all the sensitivity analysis done on the horizontal Marcellus shale, it seems unless there are significant extremes that are unfavorable in each of the three parameters, there is no reason not to drill this play horizontally. Compared to the vertical completions, it is evident that with the improvement in technology the value of the project is in horizontal drilling and not vertical drilling.

Since the reserves for each well can vary, it is important to look at what affect this has on the overall economics of the play. The figure below portrays how the DP/I changes with reserves and each of the parameters discussed above **(Fig. 5.6)**.

Marcellus Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $2,450,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	3.67	4.6
$ 3.50	1.02	1.63	1.98
$ 7.00	1.85	3.15	3.88
$ 12.00	3.03	5.31	6.6

Marcellus Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $3,500,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	3.67	4.6
$ 3.50	0.81	1.24	1.48
$ 7.00	1.39	2.3	2.81
$ 12.00	2.22	3.81	4.71

Marcellus Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $4,550,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	3.67	4.6
$ 3.50	0.69	1.02	1.21
$ 7.00	1.14	1.84	2.23
$ 12.00	1.78	3	3.7

Marcellus Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $2,450,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	3.67	4.6
$ 3.50	0.89	1.5	1.85
$ 7.00	1.72	3.01	3.75
$ 12.00	2.9	5.17	6.46

Marcellus Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $3,500,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	3.67	4.6
$ 3.50	0.72	1.14	1.39
$ 7.00	1.3	2.2	2.72
$ 12.00	2.12	3.72	4.62

Marcellus Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $4,550,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	3.67	4.6
$ 3.50	0.62	0.95	1.14
$ 7.00	1.07	1.77	2.16
$ 12.00	1.71	2.93	3.62

Marcellus Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $2,450,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	3.67	4.6
$ 3.50	0.83	1.43	1.78
$ 7.00	1.67	2.95	3.68
$ 12.00	2.83	5.11	6.4

Marcellus Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $3,500,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	3.67	4.6
$ 3.50	0.67	1.1	1.34
$ 7.00	1.25	2.16	2.67
$ 12.00	2.08	3.67	4.57

Marcellus Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $4,550,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	2	3.67	4.6
$ 3.50	0.59	0.92	1.1
$ 7.00	1.03	1.73	2.13
$ 12.00	1.67	2.89	3.59

Fig. 5.6—Summary of horizontal completions in the Marcellus shale economics

In Fig. 5.6, the boxes that are highlighted in red are those that have a DP/I less than 1, which means that at that particular gas price, capital spend, operating expense, and EUR, the well is not economic; therefore, a bad investment if the well is looked at individually. The boxes that are yellow represent a DP/I greater than 1 but less than 1.2. This represents wells that have marginal returns. The boxes that are green are those that have a DP/I greater than 1.2 but less than 3 showing that it was a good investment. The parameters that lead to a DP/I greater than 3 are shaded as blue, which show conditions that are considered a "slam dunk" to drill and complete.

5.1.5 Woodford Shale

Vertical Completion

The Woodford Shale vertical completions were looked at separately from the horizontal wells since there are operators that drilled vertical wells for a long time before switching over to horizontal wells. In the horizontal section, there will be a comparison of the results seen in the vertical wells to that found in the horizontal wells. For the first component that was varied—gas prices, the Woodford vertical well was not economic at the $3.50/mcf, but was a good investment at the base price and higher. The table below depicts the DP/I, NPV @ 10%, ROR, and the payout at each of the different price decks **(Table 5.20)**.

Table 5.20—Gas Price Sensitivity on the Vertical Woodford Shale Gas Play

	Low Gas Price ($3.50/mcf)	Base Gas Price ($7.00/mcf)	High Gas Price ($12.00/mcf)
DP/I	0.70	1.35	2.29
NPV @ 10% ($)	(609,000)	704,000	2,585,000
ROR (%)	0.0	21.6	59.2
Payout (months)	0.0	44.0	19.7

From this study on price variation, is apparent that a price of anything close to the $3.50/mcf would not met the hurdle ratio of 1.0. Also, a very interesting observation is that the NPV at 10% for the high gas price is almost double is close to $2.6 MM showing that price has a very big impact on the success of drilling vertical Woodford wells. With that in mind, if the gas price is low then it is not recommended to drill a vertical Woodford well unless there is a drastic drop in completion costs and operating costs.

As mentioned earlier, the capital spend was also analyzed to see what impact that has on the economical viability of the project. With gas price constant at $7.00/mcf and the operating cost fixed at 1,000/Well/Month, the capital did cause a swing in the DP/I as well as the NPV. For the vertical completions in the Woodford Shale, it did not matter if the price went up by 30% or went down 30% it still met the hurdle ratio of 1.0 Below is the summary of how the capital spend affect the overall economics on the Woodford shale vertical wells **(Table 5.21)**.

Table 5.21—Capital Spend Sensitivity on the Vertical Woodford Shale Gas Play

	Low Capital ($1,400,000)	Base Capital ($2,000,000)	High Capital ($2,600,000)
DP/I	1.80	1.35	1.11
NPV @ 10% ($)	1,118,000	704,000	291,000
ROR (%)	39.5	21.6	13.5
Payout (months)	26.9	44.0	63.4

From this analysis, it is concluded that if the capital get any higher that a 30% incremental, then drilling vertical wells through the Woodford shale might not be the best decision if looking at the economic parameters unless gas prices are high and the operating costs are lower.

The last component explored in terms of impact on the financial viability of the vertical wells in the Woodford shale was the operating cost. When all other factors were held constant at the base case and the operating cost fluctuated between 1,000/Well/Month up to $7,000/Well/Month. As with the capital spend, there was no case that did not meet the hurdle ratio of 1.0 **(Table 5.22)**.

Table 5.22—Operating Cost Sensitivity on the Vertical Woodford Shale Gas Play

	Low Operating Cost ($1,000/Well/Month)	Base Operating Cost ($5,000/Well/Month)	High Operating Cost ($7,000/Well/Month)
DP/I	1.52	1.35	1.27
NPV @ 10% ($)	1,033,000	704,000	540,000
ROR (%)	25.5	21.6	19.5
Payout (months)	39.9	44.0	46.4

Unless there are high gas prices, the vertical Woodford wells are marginally economic. Therefore, when looking at vertical completions, the operator should hold off on drilling vertical Woodford wells until the market is high and looks to stay that high for the foreseeable future.

Since the reserves for each well can vary, it is important to look at what affect this has on the overall economics of the play. Shown below is how the DP/I changes with reserves and each of the parameters discussed above **(Fig. 5.7)**.

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $1,400,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.85	1.09	1.45
$ 7.00	1.52	2.02	2.78
$ 12.00	2.48	3.34	4.69

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $2,000,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.69	0.85	1.11
$ 7.00	1.16	1.51	2.04
$ 12.00	1.83	2.43	3.37

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $2,600,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.6	0.73	0.92
$ 7.00	0.96	1.23	1.64
$ 12.00	1.48	1.95	2.67

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $1,400,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.64	0.86	1.22
$ 7.00	1.29	1.78	2.55
$ 12.00	2.25	3.11	4.46

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $2,000,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.54	0.69	0.95
$ 7.00	1	1.34	1.88
$ 12.00	1.67	2.27	3.21

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $2,600,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.49	0.61	0.8
$ 7.00	0.84	1.11	1.52
$ 12.00	1.35	1.82	2.54

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $1,400,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.56	0.76	1.1
$ 7.00	1.18	1.67	2.43
$ 12.00	2.13	3	4.34

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $2,000,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.49	0.63	0.87
$ 7.00	0.92	1.26	1.8
$ 12.00	1.59	2.19	3.13

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $2,600,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.45	0.55	0.74
$ 7.00	0.78	1.04	1.46
$ 12.00	1.29	1.76	2.48

Fig. 5.7—Summary of vertical completions in the Woodford shale economics

In the figure above, the boxes that are highlighted in red are those that have a DP/I less than 1, which means that at that particular gas price, capital spend, operating expense, and EUR, the well is not economic; therefore, a bad investment if the well is looked at individually. The boxes that are yellow represent a DP/I greater than 1 but less than 1.2. This represents wells that have marginal returns. The boxes that are green are those that have a DP/I greater than 1.2 but less than 3 showing that it was a good investment. The parameters that lead to a DP/I greater than 3 are shaded as blue, which show conditions that are considered a "slam dunk" to drill and complete.

Horizontal Completion

The Woodford Shale horizontal completions have become the most common practice in this play replacing conventional vertical wells. As seen above, the Woodford vertical well are not economic at the $3.50/mcf and the same is true when drilling horizontally. The table below shows the DP/I, NPV @ 10%, ROR, and the payout at each of the different price decks **(Table 5.23)**.

Table 5.23—Gas Price Sensitivity on the Horizontal Woodford Shale Gas Play

	Low Gas Price ($3.50/mcf)	Base Gas Price ($7.00/mcf)	High Gas Price ($12.00/mcf)
DP/I	0.87	1.55	2.53
NPV @ 10% ($)	(1,001,000)	4,293,000	11,855,000
ROR (%)	5.8	31.1	84.1
Payout (months)	116.6	31.0	14.7

From this study on price variation, it is clear that a price of anything close to $3.50/mcf would not meet the hurdle ratio of 1.0. With this said, it would be better not to drill a vertical or a horizontal well at the lower price since neither of them are economic. Similar to the vertical completions, the NPV at 10% for the high gas price is almost $12 MM. At the higher price environments, it would be a good investment to drill a horizontal Woodford well instead of the vertical wells.

As mentioned earlier, the capital spend was also analyzed to see what impact that has on the economical viability of the project. With constant gas price at $7.00/mcf and the operating cost fixed at 1,000/Well/Month, the capital did cause a swing in the DP/I as well as the NPV. For the horizontal completions in the Horizontal Shale, no matter if the cost went up by 30% or went down, this play is still a very good investment. A summary of how the capital spend affects the overall economics for a Woodford horizontal well is shown below **(Table 5.24)**.

Table 5.24—Capital Spend Sensitivity on the Horizontal Woodford Shale Gas Play

	Low Capital ($5,425,000)	Base Capital ($7,750,000)	High Capital ($10,075,000)
DP/I	2.09	1.55	1.27
NPV @ 10% ($)	5,895,000	4,293,000	2,690,000
ROR (%)	58.1	31.1	19.3
Payout (months)	19.1	31.0	45.8

Similar to vertical completions, it is observed that the capital cost does not have a negative impact unless the cost increase is much higher than 30% of the cost of $ 7.75 MM. As a result, the engineer looking at drilling horizontal wells should not focus too much on the capital cost if the other components such as price and operating cost are similar to the base case unless it is significantly over 30% incremental increase than the base. In fact, even at the 30% increase cost, the NPV for a well is still over $ 3.5 MM which is 200% payout of the well cost to drill. In fact, at the lower capital spend the well would pay out in less than 1 year. If looking at these wells compared to the vertical wells, it is easily seen that it is better to drill horizontal wells because of the high NPV and the high DP/I. The only time horizontal drilling would not be advised is in a capital constrained environment.

The last component explored in terms of impact on the financial viability of the horizontal wells in the Woodford shale was the operating cost. When all other factors were held constant at the base case and the operating cost fluctuated between $1,000 to $7,000/Well/Month. As with the capital spend, there was no case that did not meet the hurdle ratio of 1.0. In fact, all of the scenarios were over 30% ROR as well as an NPV over $4 MM, which is better than the vertical Woodford shale wellbores **(Table 5.25)**.

Table 5.25—Operating Cost Sensitivity on the Horizontal Woodford Shale Gas Play

	Low Operating Cost ($1,000/Well/Month)	Base Operating Cost ($5,000/Well/Month)	High Operating Cost ($7,000/Well/Month)
DP/I	1.59	1.55	1.53
NPV @ 10% ($)	4,607,000	4,293,000	4,136,000
ROR (%)	32.2	31.1	30.6
Payout (months)	30.4	31.0	31.3

So, from all the sensitivity analysis done on both the vertical and horizontal Woodford shale, it seems that as long as the gas price is a little above $3.50/mcf, the wells will be economic. Unless there is a capital constraint preventing an operator from drilling a horizontal well, there is no reason not to drill this play horizontally. Compared to the vertical completions, it is evident that with the improvement in technology the value of the project is in horizontal drilling and not vertical drilling.

Since the reserves for each well can vary, it is important to look at what affect this has on the overall economics of the play. The figure below depicts how the DP/I changes with reserves and each of the parameters discussed above **(Fig. 5.8)**.

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $5,425,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.91	1.16	1.38
$ 7.00	1.6	2.13	2.58
$ 12.00	2.58	3.51	4.31

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $7,750,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.73	0.91	1.06
$ 7.00	1.21	1.58	1.9
$ 12.00	1.9	2.55	3.11

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $10,075,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.64	0.77	0.89
$ 7.00	1.01	1.29	1.54
$ 12.00	1.53	2.03	2.46

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $5,425,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.86	1.11	1.32
$ 7.00	1.54	2.07	2.53
$ 12.00	2.52	3.45	4.25

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $7,750,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.69	0.87	1.02
$ 7.00	1.17	1.54	1.86
$ 12.00	1.86	2.51	3.07

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $10,075,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.61	0.74	0.86
$ 7.00	0.97	1.26	1.51
$ 12.00	1.5	2	2.43

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $5,425,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.83	1.08	1.29
$ 7.00	1.51	2.04	2.5
$ 12.00	2.49	3.42	4.22

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $7,750,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.67	0.85	1
$ 7.00	1.15	1.52	1.84
$ 12.00	1.84	2.49	3.05

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $10,075,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.59	0.72	0.84
$ 7.00	0.96	1.24	1.49
$ 12.00	1.49	1.99	2.42

Fig. 5.8—Summary of horizontal completions in the Woodford shale economics

In Fig. 5.8, the boxes that are highlighted in red are those that have a DP/I less than 1, which means that at that particular gas price, capital spend, operating expense, and EUR, the well is not economic; therefore, a bad investment if the well is looked at individually. The boxes that are yellow represent a DP/I greater than 1 but less than 1.2. This represents wells that have marginal returns. The boxes that are green are those that have a DP/I greater than 1.2 but less than 3, showing that it was a good investment. The parameters that lead to a DP/I greater than 3 are shaded as blue, which show conditions that are considered a "slam dunk" to drill and complete.

5.2 Completions Flowcharts

From the extensive literature review done on each of the five gas shale basin discussed above, a completion flow chart was created to determine the best completion method for a gas shale play similar to these ones **(Fig. 5.9)**.

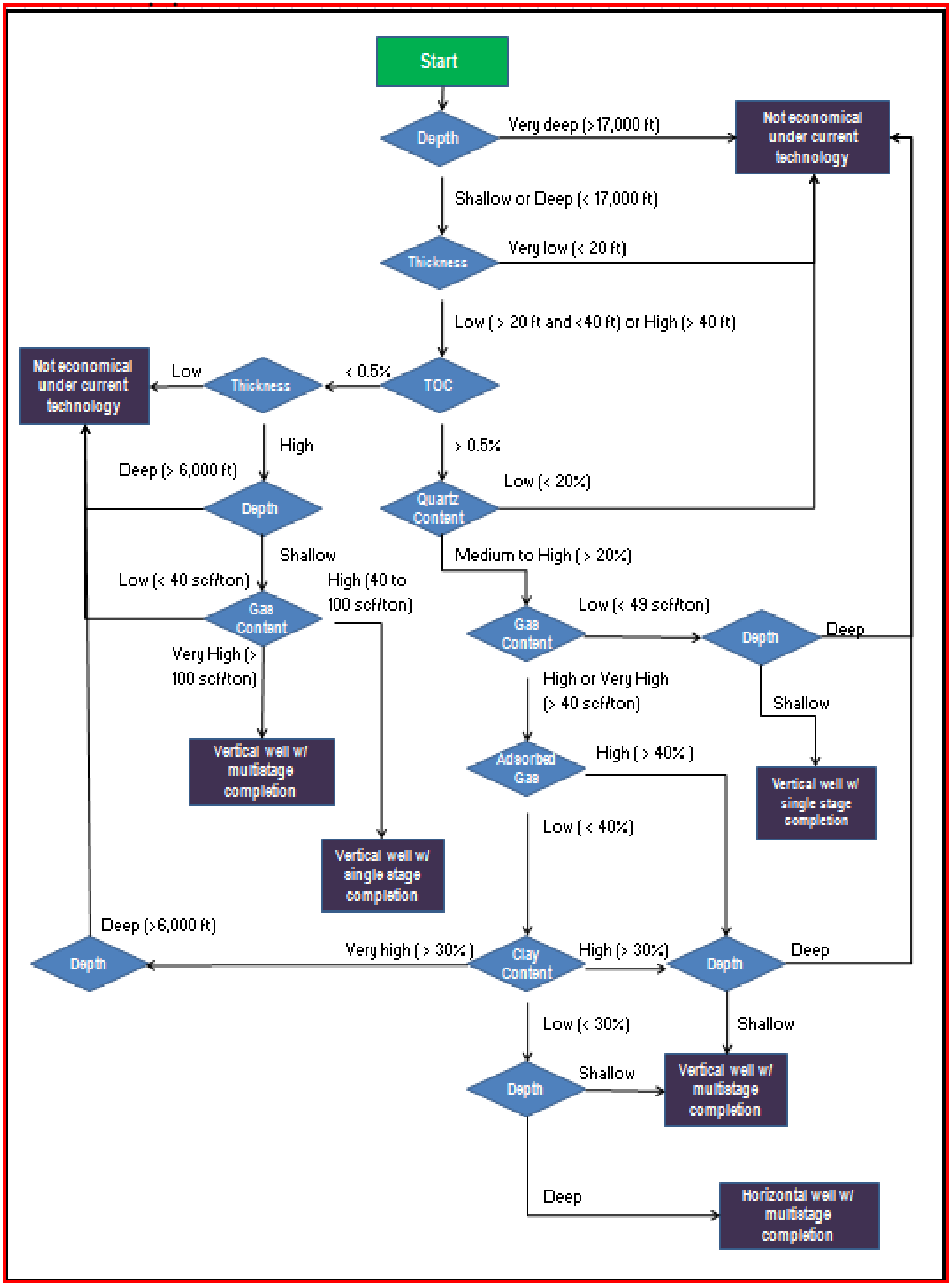

Fig. 5.9—Flow chart for selecting well orientation and completion type

Also, a flow chart was created in which completion fluids were chosen depending on parameters found in the reservoir **(Fig. 5.10).**

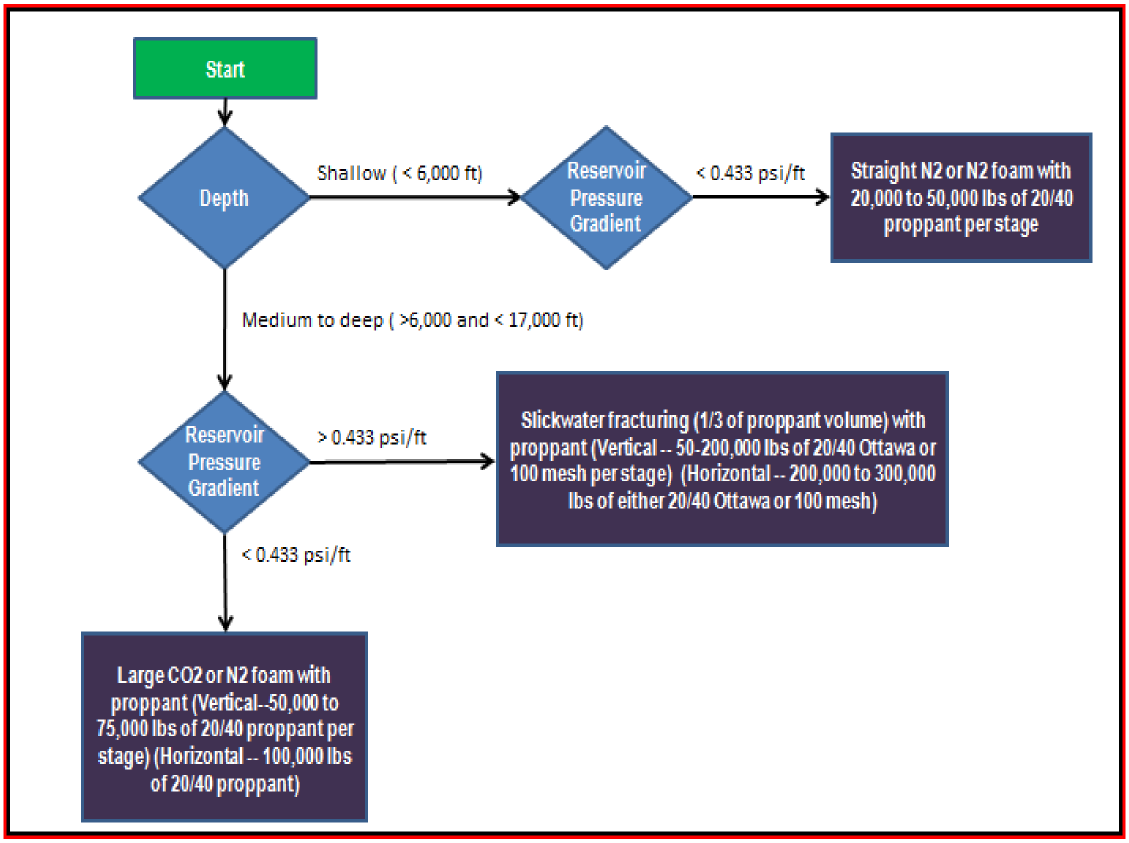

Fig. 5.10—Flow chart for selecting fracturing fluids

The cutoffs for each of the different parameters were based on what was seen in the industry in terms of completions types and fluid types used in each of the different plays. With the advancement in technology, the cutoffs will change in the future, but for right now these are what are seen to be realistic numbers for each of the different definitions.

From these two flow charts shown above coupled with the economic parameters discussed, a simple excel program was built to help operators quickly decide if they should be evaluating a potential prospect given the properties they have as well as completion suggestions if it is a recommended project. In the examples shown below, the solid black arrows dictate the decisions made to arrive to the completion and fluid selection. The dotted lines indicate decisions that were not used.

These flow charts help when looking at different basins throughout not the world. Below are examples for the five shale plays discussed (**Fig. 5.11 to Fig. 5.20)**.

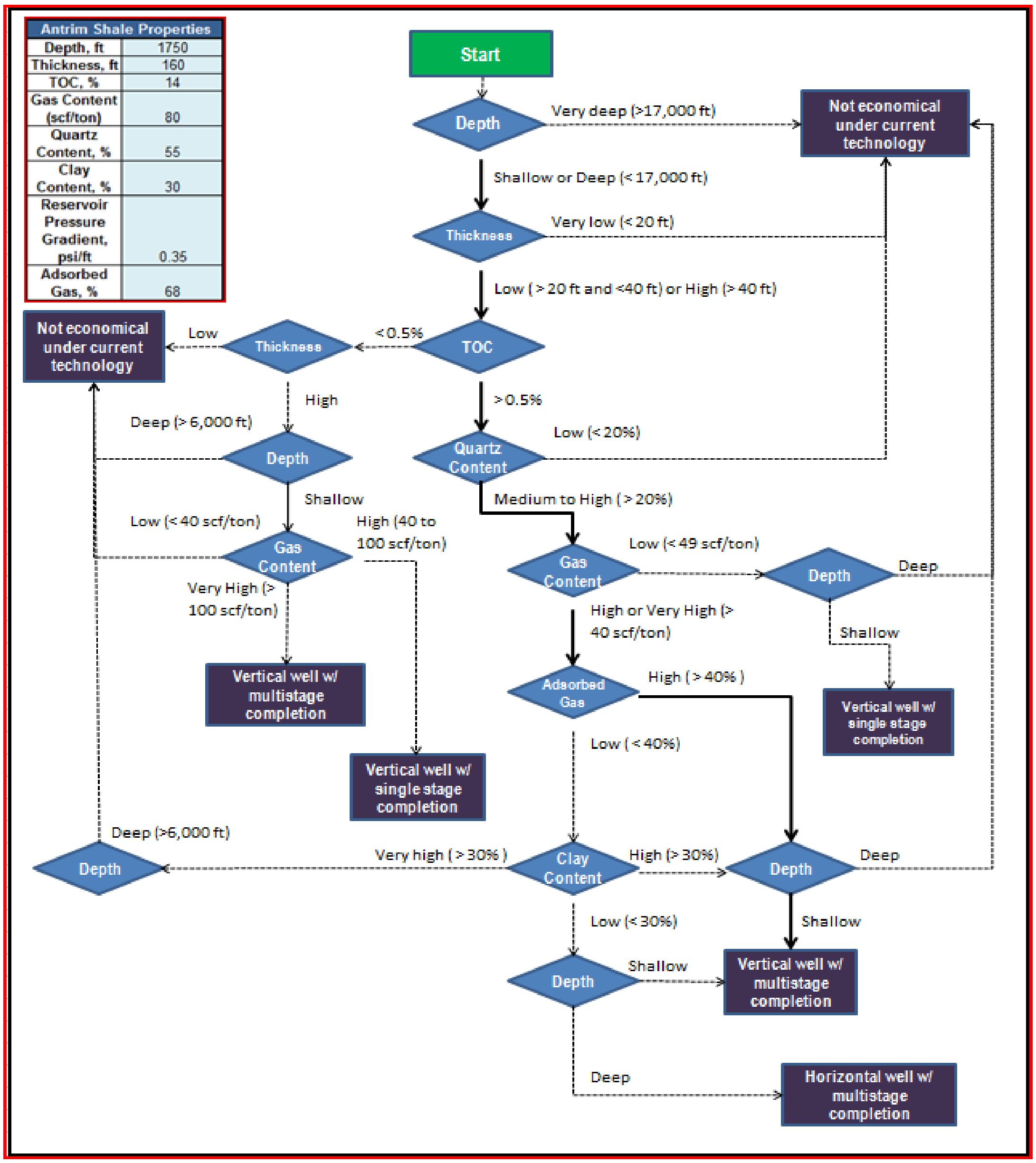

Fig. 5.11—Flow chart for Antrim shale example

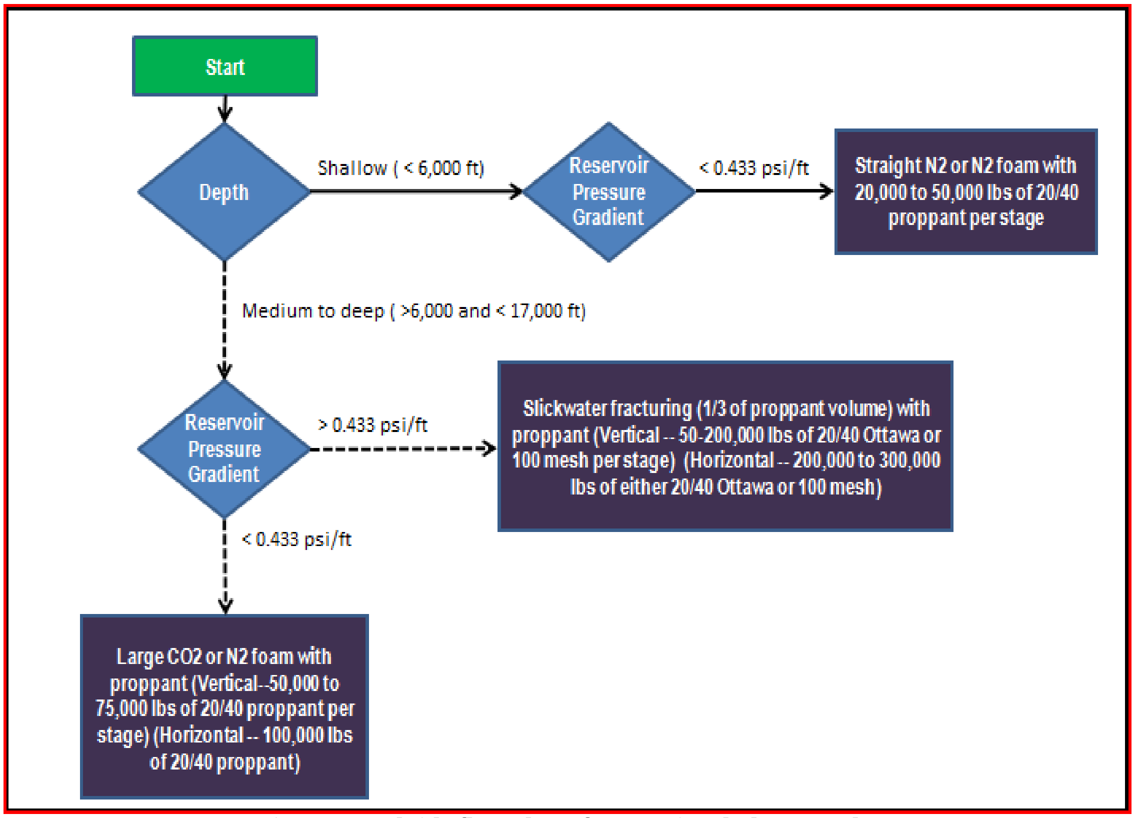

Fig. 5.12—Fluids flow chart for Antrim shale example

Now taking these properties into the flow charts created as seen above, it can be seen that the best way to complete the Antrim shale is using vertical wells with multistage completion. The best completion fluid is to use either straight nitrogen or a nitrogen foam.

Looking at the next example—the Barnett shale. The example shows the different properties necessary for the flow chart. Looking at Fig. 5.13 and 5.14, it is seen that the with the parameter values given the best way to complete this well is with a horizontal well that has multiple fracture stimulations through the lateral part of the wellbore. The best fluid design to use is slickwater with sand that is anywhere from 20/40 to 100 mesh.

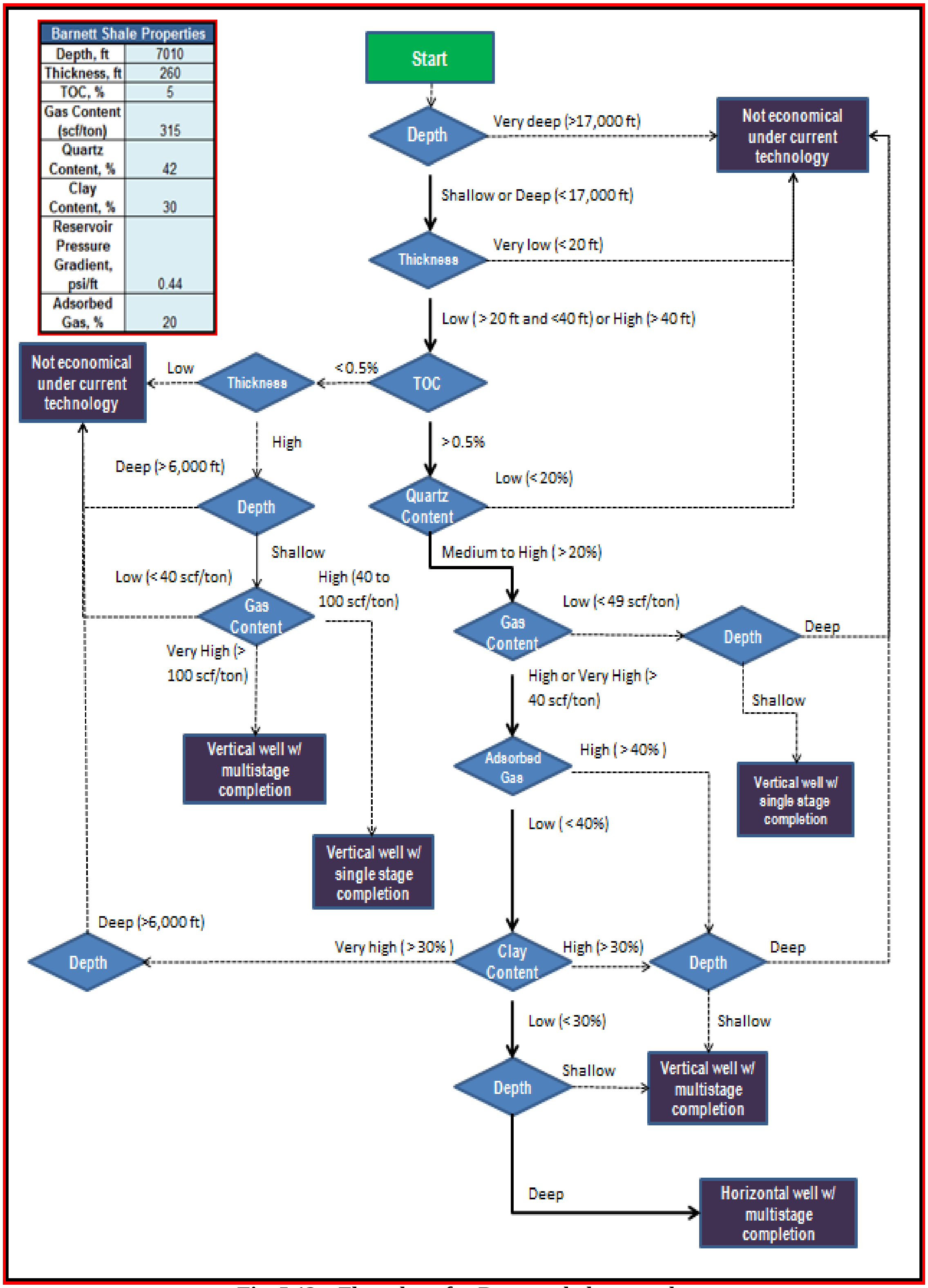

Fig. 5.13—Flow chart for Barnett shale example

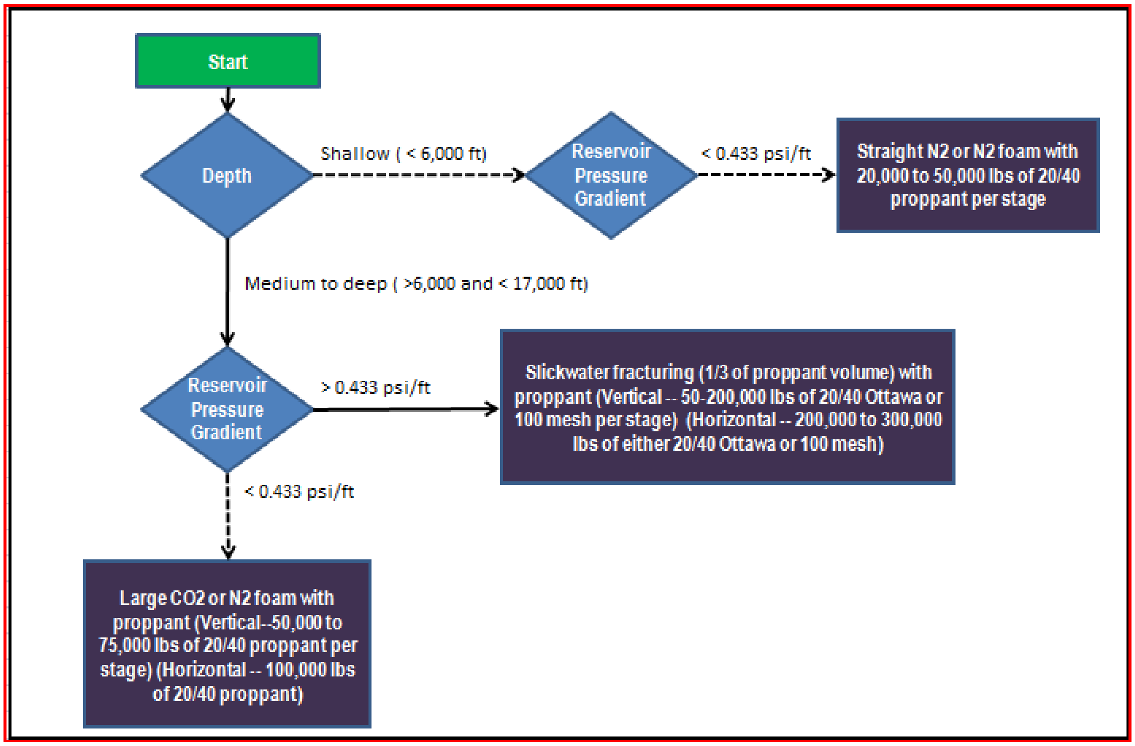

Fig. 5.14—Fluids flow chart for Barnett shale example

Now the next play looked at was the Haynesville shale. This is important to see if the flow chart gives the same results as what is being seen in the industry since the industry has not developed this play on vertical wells at all. The parameters that were used in the example are seen below.

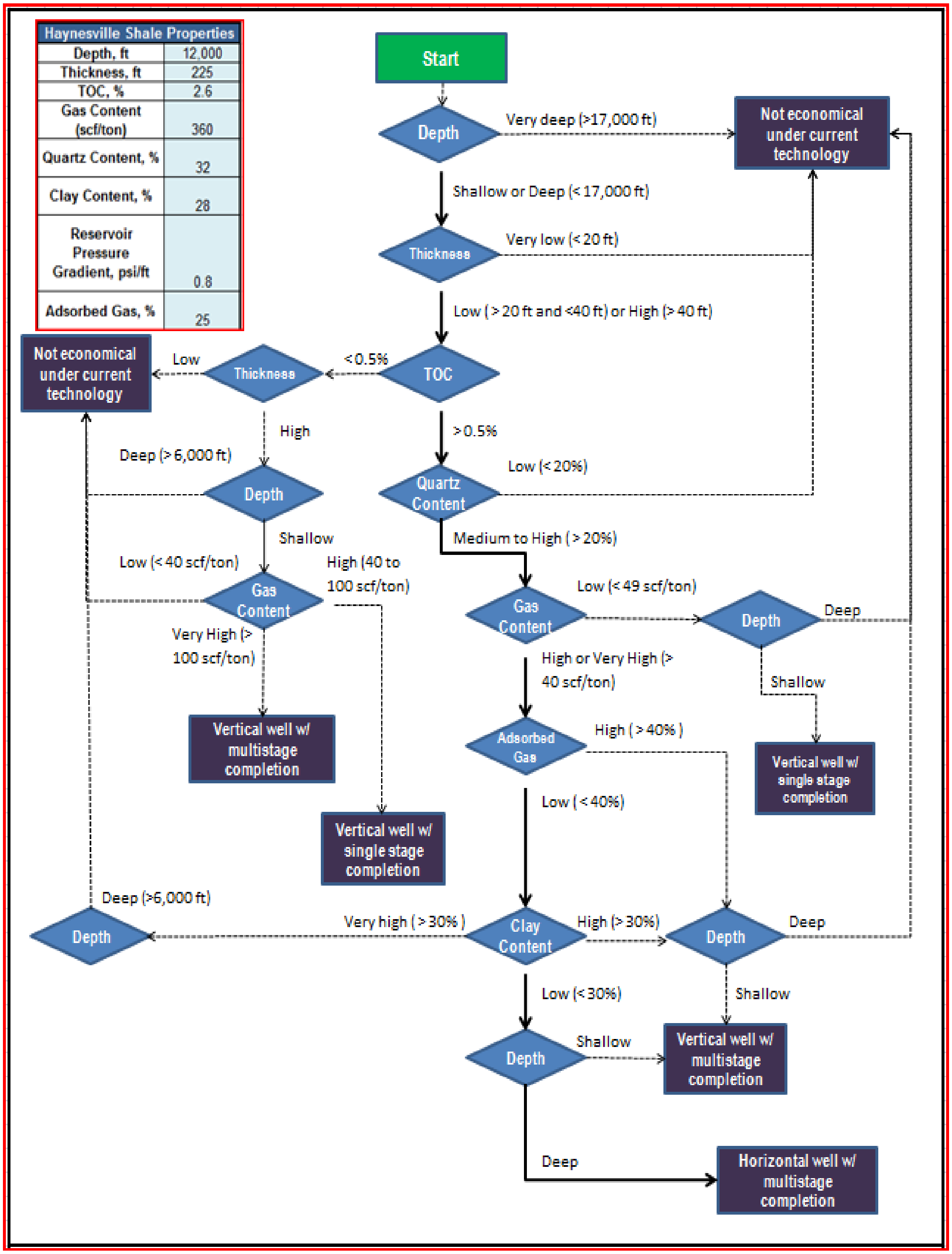

Fig. 5.15—Flow chart for Haynesville shale example

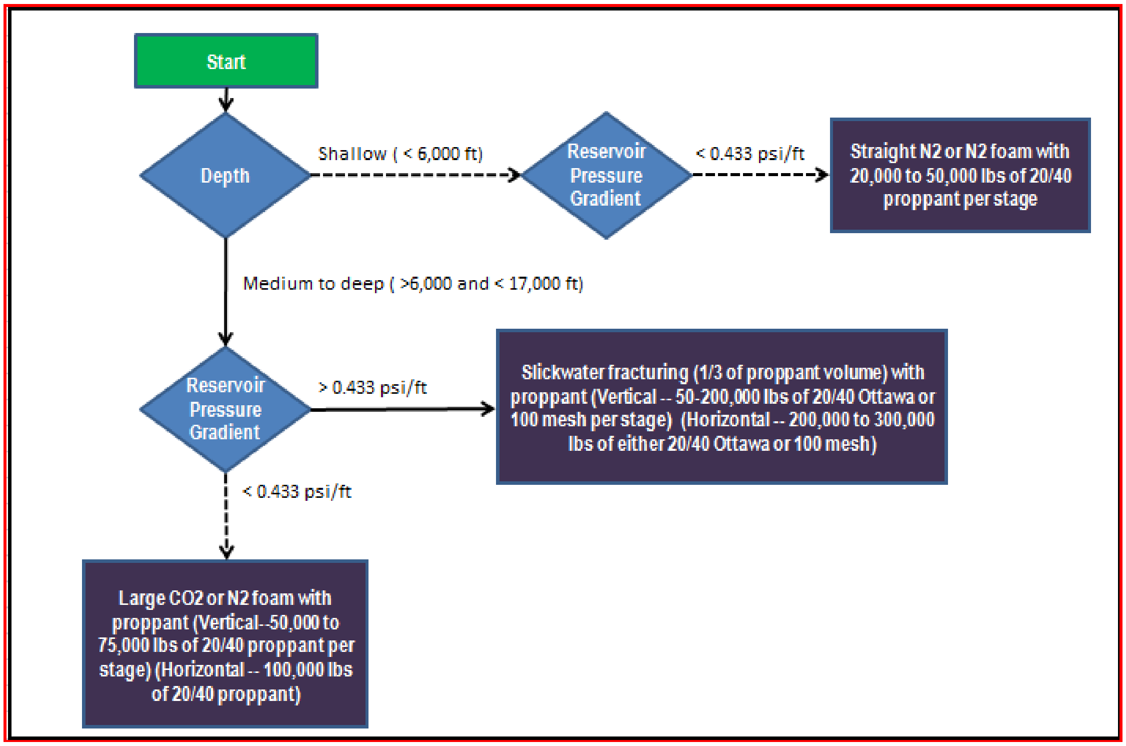

Fig. 5.16—Fluids flow chart for Haynesville shale example

From the two figures shown above, it seems that the chart recommends horizontal completions with multistage fracture treatment. In each stage, it is seen that slickwater is the optimal fluid use in the current environment.

The Marcellus shale is one that is complex because of the wide range of values that can be encountered through the play area. For this paper, only one example was looked at which can be considered the more complex place to complete since the formation is encountered at a deeper depth but the reservoir pressure gradient is less than the hydrostatic gradient.

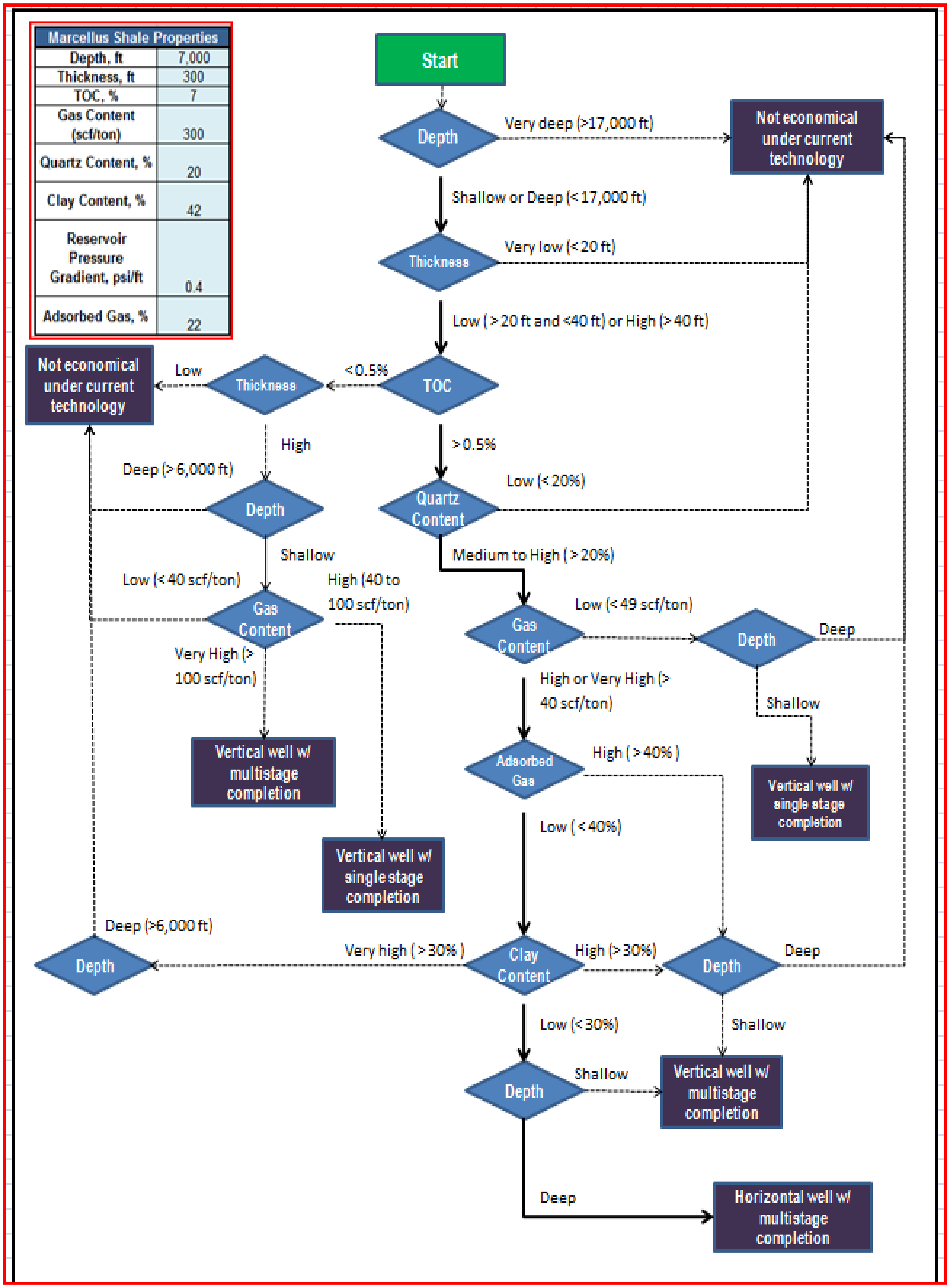

Fig. 5.17—Flow chart for Marcellus shale example

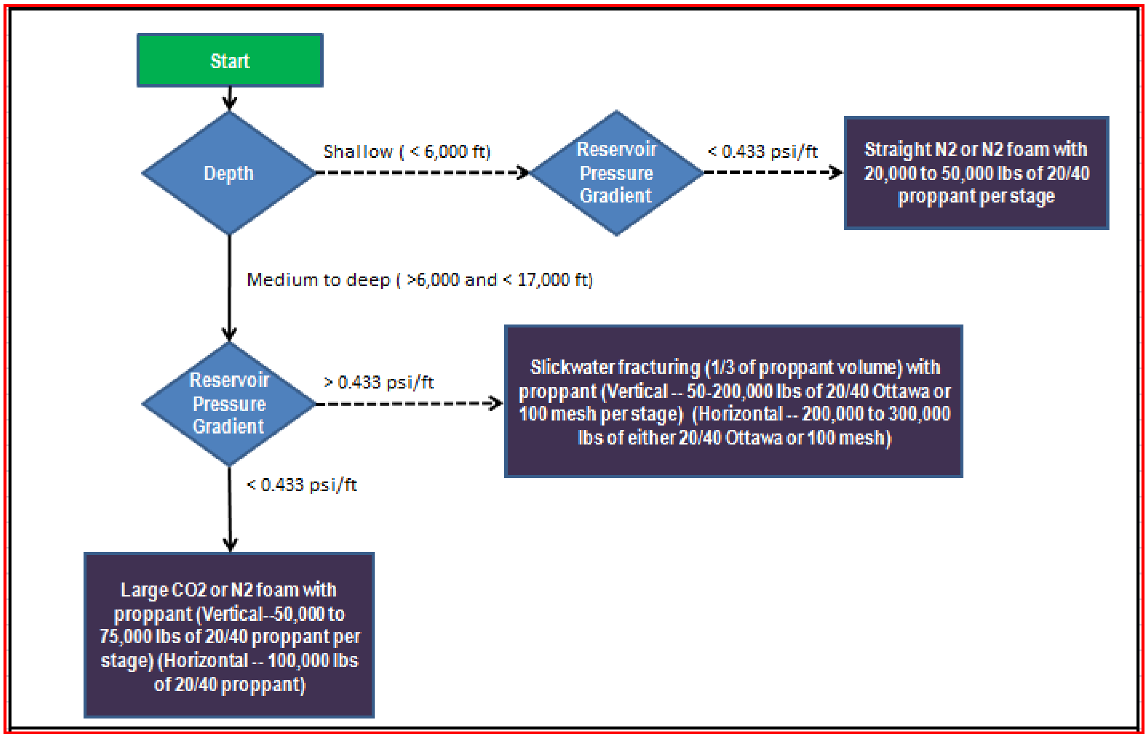

Fig. 5.18—Fluids flow chart for Marcellus shale example

From the figures above, it is concluded that with the properties described above the best way to complete this well is to use horizontal technology with multiple fracture treatments in the well. Also, the best way to fracture treat this well is to use a CO_2 fracture stimulation or nitrogen foam treatment. As stated above, the reason for this is the reservoir pressure gradient is less than the hydrostatic gradient. Therefore, if too much water is used to fracture stimulated the well, it could hinder production since the reservoir pressure will not be strong enough to pump the water out of the well.

The last example that was analyzed was for the Woodford shale. Just like the Marcellus this play is complex because of the wide range of values that can be encountered through the play. For this paper, the properties for one well were looked at through the flow chart.

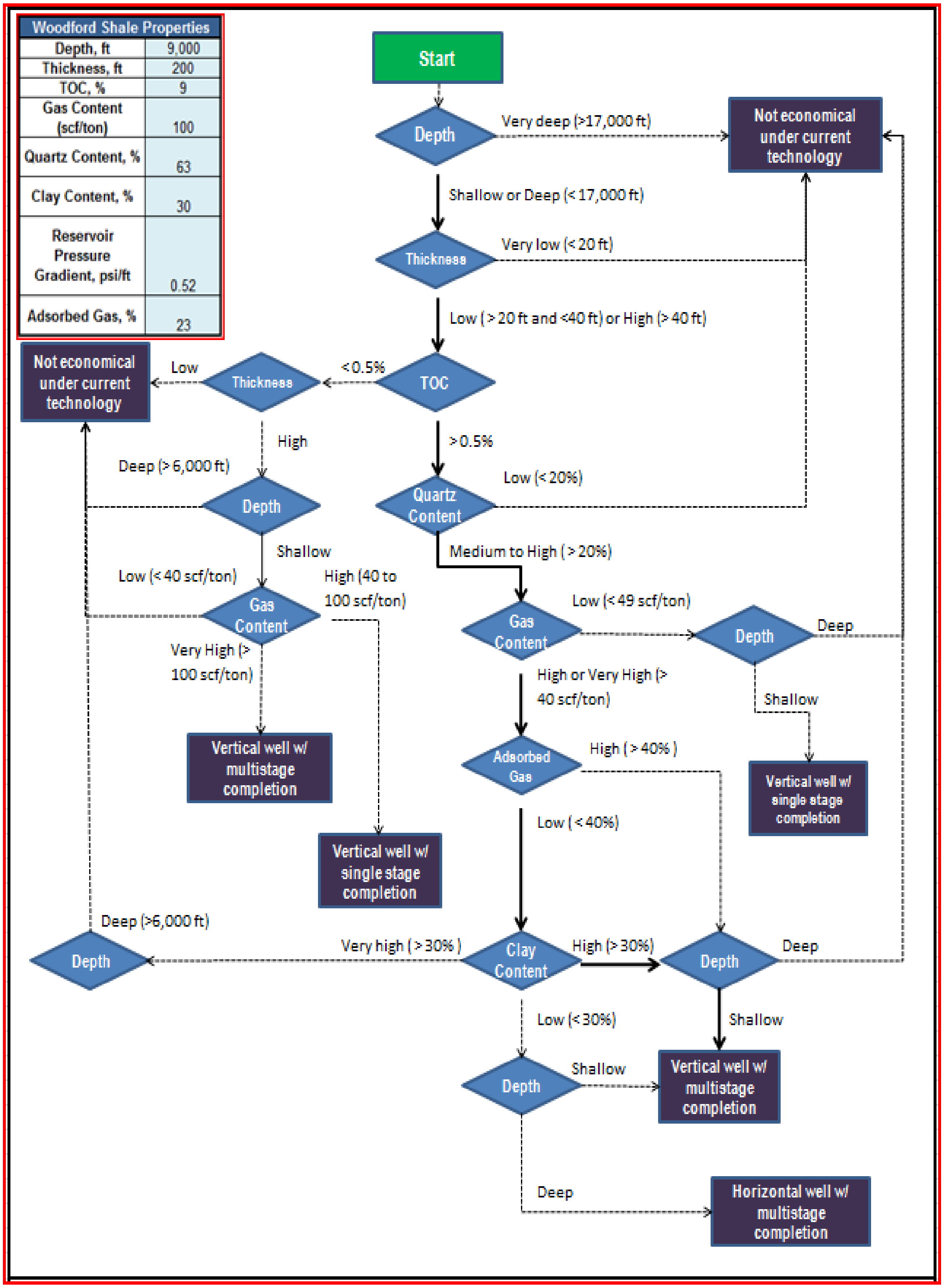

Fig. 5.19—Flow chart for Woodford shale example

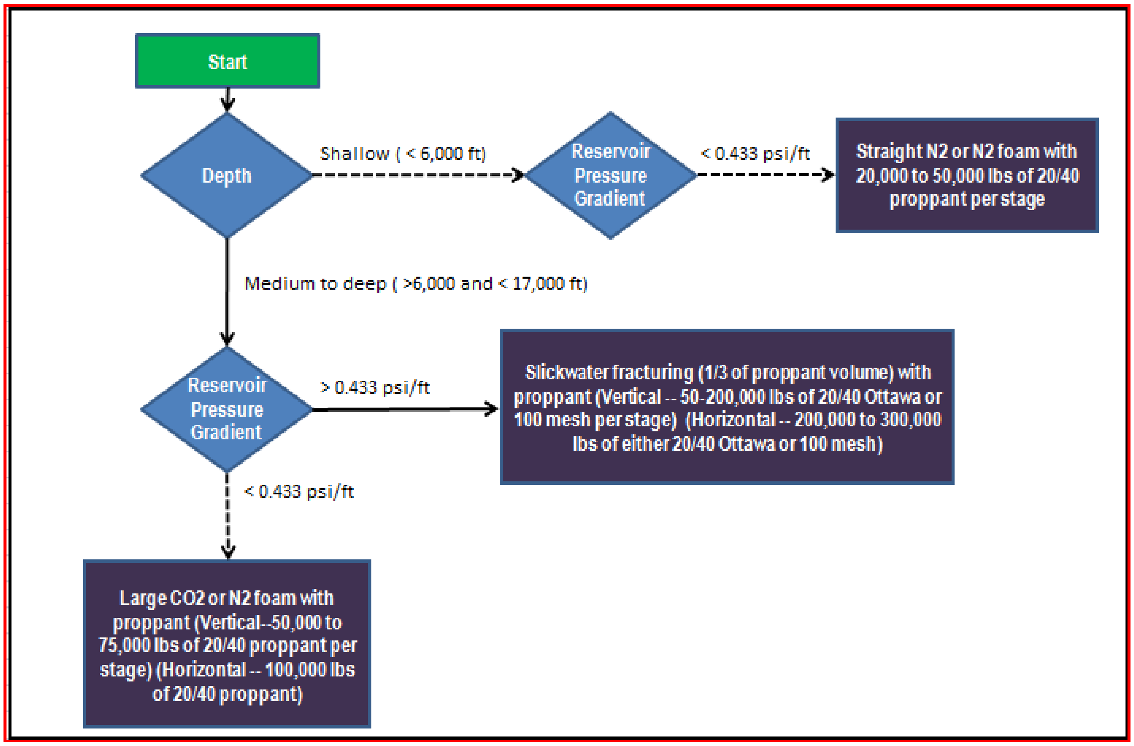

Fig. 5.20--Fluids flow chart for Woodford shale example

From the figures above, it is concluded that with the properties described in this example, the optimal design is horizontal drilling with multiple fracture stages in the stimulation. In addition to this, the best fluid to use in the treatment is slickwater.

CHAPTER VI
CONCLUSIONS

On the results of the research done the following conclusions are reached:

- A systematic evaluation of completion techniques in gas shale is important to the energy industry because gas shale plays will be an important global resource for the 21st century. With our conventional reservoirs dwindling, it is important to find new technology and techniques to economically extract oil and gas from unconventional avenues. The need for this has sparked interest in what makes up a commercially viable gas shale play.
- Through the geologic analysis of the Antrim Shale, Barnett Shale, Haynesville Shale, Marcellus Shale, and Woodford shale, this paper looks at the similarities as well as the difference in the key parameters. From the literature review, the key geologic parameters include depositional environment, depth, TOC, gas content, clay content, quartz content, shale mineralogy, adsorbed gas percentage, pressure gradient, and thickness.
- Table 1 shown above summarizes the geological parameters that are found for the five shales evaluated. Although there were some stark difference, i.e depth between the Haynesville and the Antrim shales, the shale plays were very similar in terms of other geologic properties.
- Also, these geologic parameters that differ did change completion designs, showing that even if the parameters of other plays not discussed fall out of the range shown that does not make them uneconomic.
- A flow chart was created in this thesis is a flow chart that can help users determine completion method and fracture fluid types needed for an effective completion as a function of geological gas shale properties. From this flow chart, a simple excel program was created for quick analysis on what is the ideal well type (vertical or horizontal) and completion fluids to use if given certain geologic parameters discussed in this paper.

- Completion techniques were looked at for the very fact that the geologic parameters were not all the same. With the learning curve that the industry has climbed over the years, there are some things that were not tested because of the economic viability, such as horizontal Antrim shale wells.
- Completions is key to the success of many of the gas shale plays and with new developments in this arena and becoming more cost efficient, gas shale plays will take off even faster than they are right now.
- Since the energy industry is volatile, economic sensitivity was done on the price, capital, and operating cost to see what affect it would have on these five plays. Of all the observations done, it seems that horizontal drilling in almost every environment tested is economic except the Woodford shale in which there was one scenario that wasn't economic.
- With development in newer technology, these plays will become more competitive with other conventional plays in differing economic environments but this should not stop operators from testing different shale plays not only in the U.S. but throughout the globe since this could one day become one of the primary resources for gas production.

NOMENCLATURE

BBLS	Barrels
BCF	Billion cubic feet
BPM	Barrel per minute
BWP/D	Barrels of water per day
CBM	Coalbed Methane
CO_2	Carbon Dioxide
DP/I	Discount profit to investment ratio
EUR	Estimated Ultimate Recovery
Gals	Gallons
IP	Initial Production
LBS	Pounds
MM	Million
MCF/D	Gas Rate units, thousand cubic feet per day
MMCF/D	Gas Rate units, million cubic feet per day
N_2	Nitrogen
NPV	Net Present Value
NRI	Net Revenue Interest
ROR	Rate of Return
TCF	Trillion cubic feet
TOC	Total Organic Content
U.S.	United States
VR	Vitrinite Reflectance
WI	Working Interest

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VITA

Name:	Archna Agrawal
Address:	Harold Vance Department of Petroleum Engineering Texas A&M University 3116 TAMU – 507 Richardson Building College Station, TX 77843-3116 c/o Dr. Stephen A. Holditch
Email Address:	archna.agrawal@chevron.com

Education:	B.S., Petroleum Engineering, The University of Texas at Austin, Austin, Texas 2005 M.S., Petroleum Engineering, Texas A&M University, College Station, Texas 2009