GENERAL SCREENING CRITERIA FOR SHALE GAS RESERVOIRS AND PRODUCTION DATA ANALYSIS OF BARNETT SHALE

A Thesis

by

VAIBHAV PRAKASHRAO DESHPANDE

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 2008

Major Subject: Petroleum Engineering

GENERAL SCREENING CRITERIA FOR SHALE GAS RESERVOIRS AND PRODUCTION DATA ANALYSIS OF BARNETT SHALE

A Thesis

by

VAIBHAV PRAKASHRAO DESHPANDE

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

Approved by:

Chair of Committee,	David S. Schechter
Committee Members,	Stephen A. Holditch
	Luc Ikelle
Head of Department,	Stephen A. Holditch

December 2008

Major Subject: Petroleum Engineering

ABSTRACT

General Screening Criteria for Shale Gas Reservoirs and Production Data Analysis of Barnett Shale.

(December 2008)

Vaibhav Prakashrao Deshpande, B.Tech, Dr. Babasaheb Ambedkar Technological University, Lonere

Chair of Advisory Committee: Dr. David S. Schechter

Shale gas reservoirs are gaining importance in United States as conventional oil and gas resources are dwindling at a very fast pace. The purpose of this study is twofold. First aim is to help operators with simple screening criteria which can help them in making certain decisions while going after shale gas reservoirs. A guideline chart has been created with the help of available literature published so far on different shale gas basins across the US. For evaluating potential of a productive shale gas play, one has to be able to answer the following questions:

1. What are the parameters affecting the decision to drill a horizontal well or a vertical well in shale gas reservoirs?

2. Will the shale gas well flow naturally or is an artificial lift required post stimulation?

3. What are the considerations for stimulation treatment design in shale gas reservoirs?

A comprehensive analysis is presented about different properties of shale gas reservoirs and how these properties can affect the completion decisions. A decision chart presents which decision best answers the above mentioned questions.

Secondly, research focuses on production data analysis of Barnett Shale Gas reservoir. The purpose of this study is to better understand production mechanisms in Barnett shale. Barnett Shale core producing region is chosen for the study as it best represents behavior of Barnett Shale. A field wide moving domain analysis is performed over Wise, Denton and Tarrant County wells for understanding decline behavior of the field. It is found that in all of these three counties, Barnett shale field wells could be said to have established pressure communication within the reservoir. We have also studied the effect of thermal maturity (Ro %), thickness, horizontal well completion and vertical well completion on production of Barnett Shale wells. Thermal maturity is found to have more importance than thickness of shale. Areas with more thermal maturity and less shale thickness are performing better than areas with less thermal maturity and more shale thickness. An interactive tool is developed to access the production data according to the leases in the region and some suggestions are made regarding the selection of the sample for future studies on Barnett Shale.

DEDICATION

I dedicate this work to my brother-in-law Mr. Mangesh Kumthekar.

ACKNOWLEDGEMENTS

I would like to thank my committee chair, Dr. David Schechter, and my committee members, Dr. Steve Holditch and Dr. Luc Ikelle for their guidance and support throughout the course of this research.

I would also like to thank Dr. Ayers for his important input through out the course of this research.

I thank IHS Energy for providing data we needed. This would not have been a smooth journey without their help. I would also like to thank Jack Breig of Newfield Exploration for his valuable technical input and discussion during the completion of this task.

I thank the faculty and staff of the Petroleum Engineering Department; my association with them has been very rewarding in many ways.

Finally, I would like to thank my parents and my siblings for their patience, love, and support. We all did this project together. I would like to take this opportunity to thank my friends Zuher, Dipin, Romil, Angad, Moses, Tushar and all my colleagues for helping me time to time with their expertise in particular topics along the way.

TABLE OF CONTENTS

LIST OF FIGURES

FIGURE Page

LIST OF TABLES

CHAPTER I

INTRODUCTION

Traditionally, fine-grained rock units have been of interest as source rocks of hydrocarbons and as seals or cap rocks for hydrocarbon accumulations. Large volumes of hydrocarbons are known to have migrated from their sources into more porous and permeable reservoir rocks. However, shale source rock retains part of the generated hydrocarbons, thus acting as both source and potential reservoir. Natural fractures are also essential for a shale gas system to store hydrocarbons and to serve as permeable pathways for migration to the wellbore (Faraj et al[1]).

The main productive Gas Shale basins in the United States are shown in figure 1 :

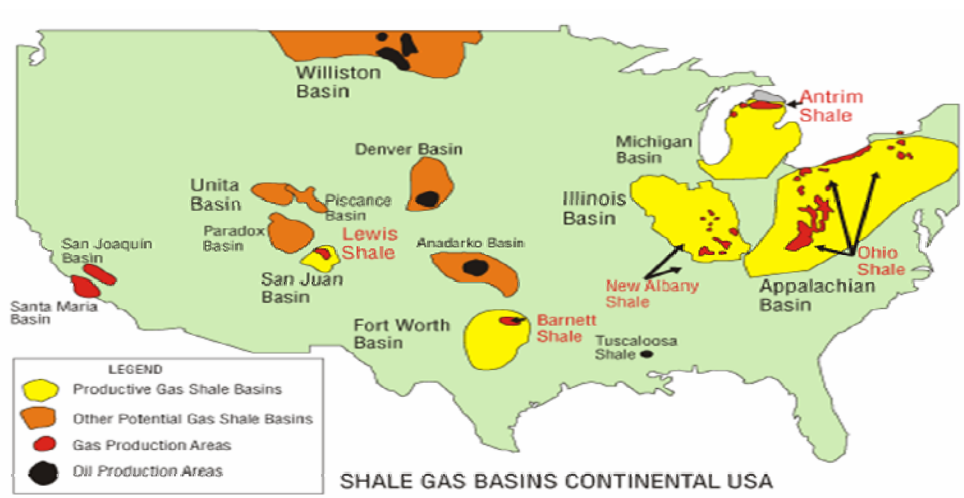


Figure 1: Gas Shale Basins in the US (Bustin[2])

The NE fields have been producing since as early as the 1820s, due to their proximity to the consumption markets. Renewed development of shale gas exploration in the US was precipitated by the enactment of the Section 29 Non-conventional Fuels Production Tax Credit, implemented to encourage unconventional gas production in the late 1970s[1]. However, exploration of the Shale gas potential basin is currently limited to the US and to a lesser extent, Canada (Western Canadian Sedimentary Basin).

This thesis follows the style of the SPE Journal.

Each shale gas basin has been studied individually so far and no attempt has been made to put together all the literature and come up with unified screening criteria on shale gas reservoirs. This type of study would be beneficial for the operators working in such type of reservoirs and help them develop quicker understanding of the type of shale gas reservoir they are dealing with.

Also worth mentioning here is importance of the Barnett Shale in Fort Worth Basin for future development of understanding of shale gas reservoirs. Barnett Shale is the largest gas producing field in Texas. Operators working in the Barnett shale are still trying to figure out what makes the Barnett Shale so productive. We have presented a detailed production data analysis of the core producing region of the field.

1.1 Production Potential

Natural gas is anticipated to become a more and more important energy supply in the next decades. Its production will try to fill the growing gap between demand and supply the oil alone cannot fill any longer.

According to most analysts (Ausubel[3]), natural gas will be the transition fluid between the current oil-based economy to a cleaner, more stable one. The latter would be based on anticipated future energy sources (one of which is believed to be hydrogen, following the global trend of decarbonization of the energy source the world witnessed for centuries as shown in figure 2) from wood, to coal, oil, and natural gas, the H/C ratio never stopped increasing[3]).

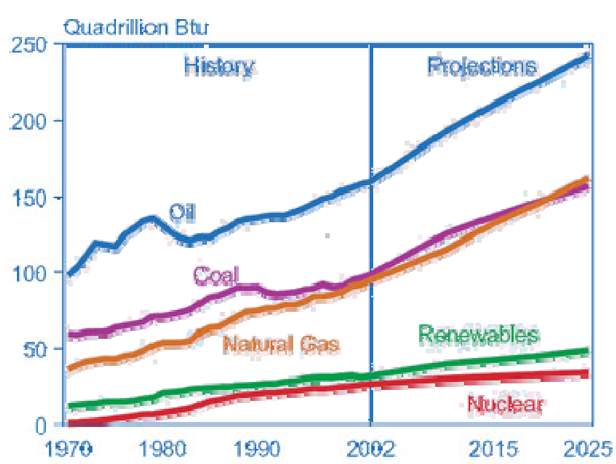


Figure 2: World Energy Production History and Forecast (EIA)

However, gas reserves are mainly located in the former Soviet Union and Middle East (Figure 3), causing fear of supply shortening to western economies amongst Western countries leaders, and a rush for new natural gas reserves in the US.

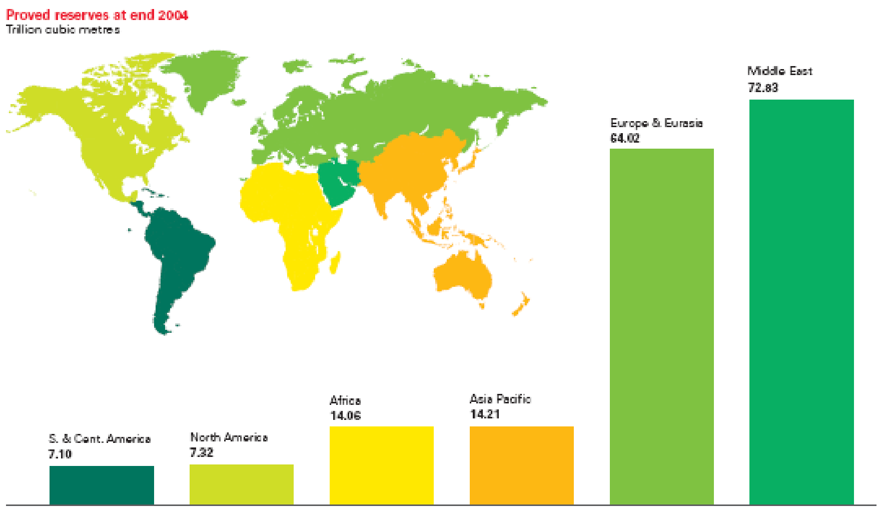


Figure 3: World Natural Gas Reserves (BP[4])

The U.S. domestic conventional gas resources being almost entirely explored and produced, gas producers had to turn to unconventional gas reservoirs, such as Tight Sands, Coal bed Methane and Shale Gas reservoirs.

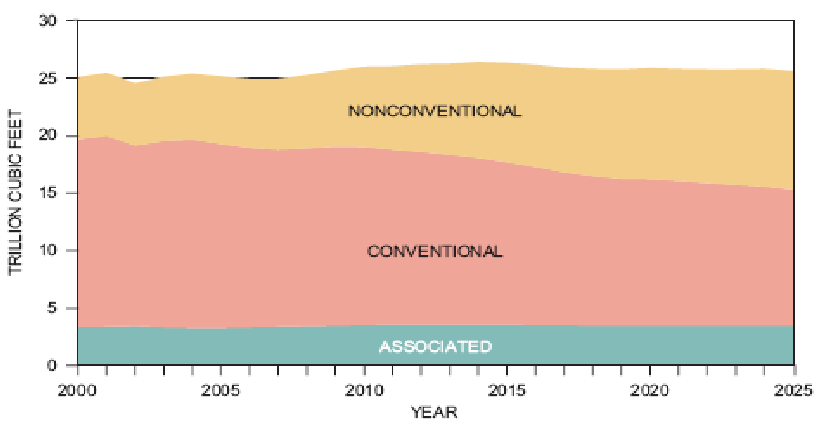


Figure 4: Gas Production Estimations for US Lower 48 and Non-Artic Canada (NPC[5])

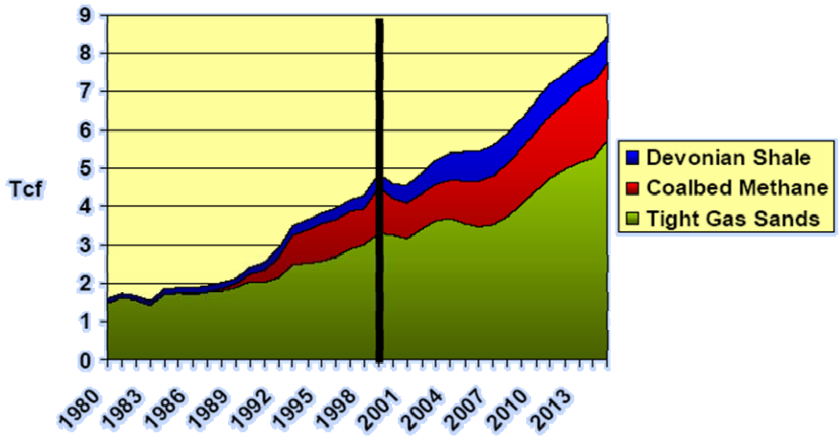


Figure 5: Unconventional Gas Production History and Forecast (Perry[6])

The part of unconventional gas in the US natural gas production will grow in the next years (Figure 4). Gas Shales (also called "fractured shales" or "Devonian shales") will play an important role in this growth, along with Tight Sands and Coal bed Methane (see Figure 5).

As we notice in Figure 6, there is an important production potential for Shale gas in the US. Gas-in-place resource estimates for the five main plays total 581 Tcf, and recoverable resource estimates range from 31 to 76 Tcf [7]. Because estimates of gas-in-place for the Barnett Shale and recoverable gas for the Lewis Shale are not available, the total U.S. gas shale resource and recoverable reserve estimates shown here should be considered conservative.

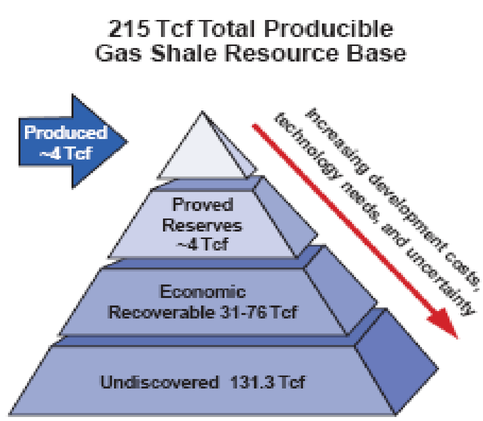


Figure 6: Gas Shale Resource Pyramid for U.S. Lower-48 States (Hill and Nelson[7])

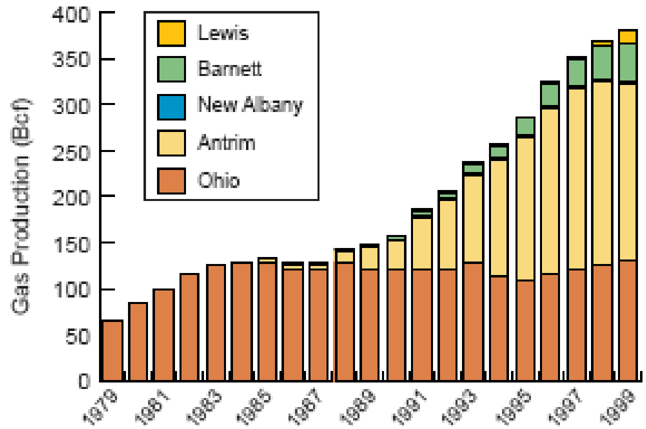


Figure 7: Annual Gas Shales Production from U.S. Basins (Hill and Nelson[7])

The Antrim Shale in Michigan, as well as the Barnett Shale in Texas and the Lewis Shale in New Mexico and Colorado have been extensively studied and produced since the tax credit period (See, Figure 7). Their exploration and production continues today, even with the end of the tax incentives, thanks to very high natural gas prices as shown in figure 8.

Figure 8: Evolution of the Natural Gas Price (Henry Hub) in \$/MMBtu Over the Last 5 Years[8]

1.2 Literature Review of Generic Geology of Major Shale Gas Producing Basins across the US

The hydrocarbon generative potential of shales and the presence of porosity and permeability to store and transmit hydrocarbons, determine the potential for shale gas production from a formation or unit of interest. It is important to understand generic geology of major shale gas basins to categorize them based on their specific properties.

1.2.1 Depositional Environment

In the special case of shale gas, the reservoir rock is the source rock. Therefore, the deposition of gas shale must occur in an anoxic environment, where organic rich material can settle without being oxidized before its burial and the generation of hydrocarbons. The Oxygen Minimum Layer (OML, see Figure 9) is a good location for the deposition and preservation of marine organic-rich sediments on the continental slope. The deeper water setting and silted basins are also good depositional systems for source rocks such as gas shales[9].

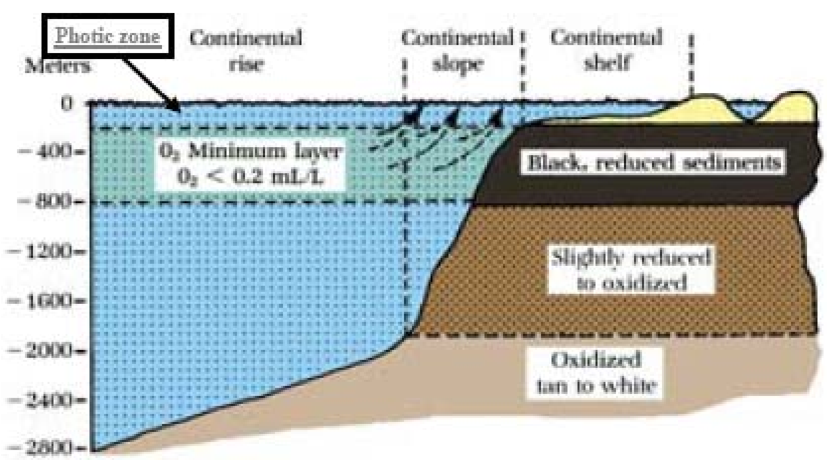


Figure 9: Location of the OML (Oxygen min. layer), (from Ayers[9])

A typical shale gas source rock would be organic-rich shale with the following characteristics (from Ayers[9]):

- Dark brown to black color

- Low porosity and permeability
- 1-10% (or more) Total Organic Content (TOC)
- Commonly well-laminated
- Gamma-ray signature usually high >140 API
- Pyrite common in rocks (anoxic muds where anaerobic bacteria have been active)
- Shales may be phosphatic

1.2.2 Accumulation

Shale gas plays are classified as "continuous" natural gas plays, i.e., accumulations that are pervasive throughout large geographic areas, offering long-lived reservoirs with attractive finding and development costs, according to the United States Geological Society[10]. Continuous accumulations differ from conventional hydrocarbon accumulations in two important ways. First, they do not occur above a base of water, and second, they commonly are not density-stratified within the reservoir as shown in Figure 10.

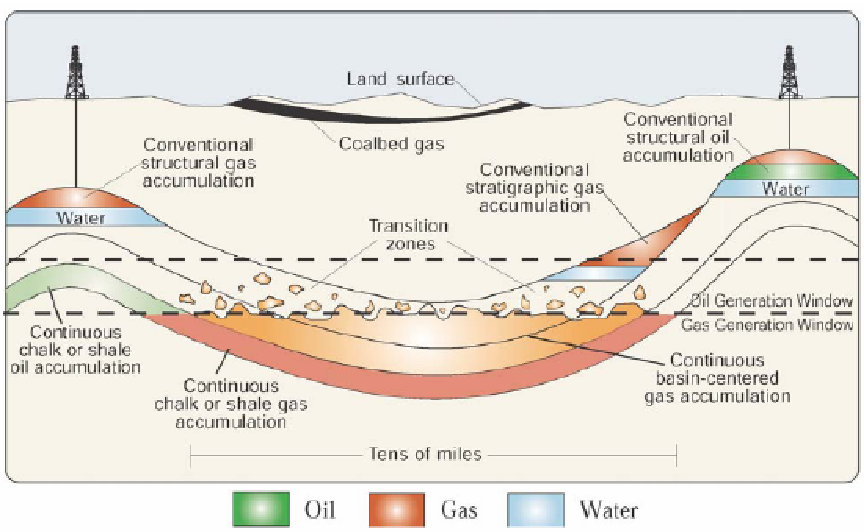


Figure 10: Generalized Diagram Showing the Area of Occurrence of Continuous Shale Gas Accumulation (from Schenk and Pollastro[11])

1.2.3 Hydrocarbon Generation

Gas originates in source rocks by two main processes:

- As biogenic gas because of the action of anaerobic micro-organisms during the early diagenetic phase of burial or recent invasion of bacteria-laden meteoric water; and
- As thermogenic gas from the thermal breakdown of kerogen at greater depths and temperatures.

Factors that control the level of methane production after sediment burial are anoxic environment, sulfate deficient environment, low temperature, abundant organic matter and sufficient space for gas storage.

Biogenic gas generally forms at depths less than 3,300 ft but can be preserved in reservoirs to depths as great as 14,850 ft (Po Basin, Northern Italy) (from Faraj et al.[1]). Biogenic methane also can form later in the rock's geologic history as the result of oxygenated ground water circulating through the rocks, usually at shallow depths of less than 1,800 ft. It is apparent that any organic-rich source shale is potential gas shale, regardless of maturity level.

A useful indicator of the provenance of the generated hydrocarbons (either biogenic or thermogenic) is the Vitrinite reflectance. According to the Schlumberger Oilfield Glossary[8], it is a measurement of the maturity of organic matter with respect to whether it has generated hydrocarbons or could be an effective source rock. The reflectivity of at least 30 individual grains of vitrinite from a rock sample is measured under a microscope. The measurement is given in units of reflectance, % Ro, with typical values ranging from 0% Ro to 3% Ro. The vitrinite reflectance value can thus help us determine whether or not the source rock was buried enough to produce hydrocarbons. Typical values of the oil generation and gas generation "windows" are the following:

- %R0 > 0.6, the rock went "through" the oil window
- %R0 > 0.78, the rock went "through" the gas window

1.2.4 Permeability and Porosity

As their intrinsic fluid storage and transmissivity (micro Darcy) characteristics are usually bad, shales must be fractured (either naturally or through stimulation) to be an economic source of gas. Storage of the gas occurs within the fractures, within matrix porosity and as an adsorbed phase on kerogen. Adsorption is the adhesion of a single layer or more of gas molecules to the internal surfaces of a coal or shale matrix. Up to 50% of the total gas within shale can be found as an adsorbed phase on kerogen[1]; thus, the total amount and type of organic matter exerts a strong influence on the adsorptive capacity of shale.

The permeability is achieved through the natural fracture systems developed from structural influences in an otherwise competent package, as well as through siltstone/sandstone laminae, which transmit fluids far better than shales.

The Nelson[12] classification ranks the gas shale reservoirs in the type 2 fractured reservoirs: the storage is mainly in the matrix and the permeability is assured by the fractures.

1.2.5 Geology of Major Shale Gas Occurrences

As seen in Figure 11, there are 5 major shale gas reservoirs in the US:

- Ohio Shale (Appalachian Basin)
- Antrim Shale (Michigan Basin)
- New Albany Shale (Illinois Basin)
- Barnett Shale (Fort Worth Basin)
- Lewis Shale (San Juan Basin)

Basin	State(s)	Major Shale-Bearing Formation or Group	Basin Area (mi²)	Total Organic Carbon (TOC)%	Thermal Maturity (%R_o)	Shale Gas-In-Place Resource (Tcf)		Estimated Recoverable Shale Gas Resource (Tcf)		Estimated Total Undiscovered Shale Gas Resource (Tcf)
Appalachian	OH, KY, NY, PA, WV, VA	Ohio Shale	160,000	0 - 4.5	0.4 - 1.3	225 - 248+	1980 & 1992 NPC Estimates	14.5 - 27.5	1980 & 1992 NPC Estimates	90.7
Michigan	MI, IN, OH	Antrim Shale	122,000	1 - 20	0.4 - 0.6	35 - 76	1980 & 1992 NPC Estimates	11 - 18.9	1992 NPC & 1995 USGS Estimates	40.6
Illinois	IL, IN, KY	New Albany Shale	53,000	1 - 25	0.4 - 1.0	86 - 160	1980 & 1992 NPC Estimates	1.9 - 19.2	1992 NPC & 1995 USGS Estimates	NA
Fort Worth	TX	Barnett Shale	4,200 ++	4.5	1.0 - 1.3	NA		3.4 - 10.0	Schmoker, 1996 Kuuskraa, 1998	NA
San Juan	CO, NM	Lewis Shale	1,100 ++	0.45 - 2.5	1.6 - 1.88	96.8	1997 Burlington Resources Estimate	NA		NA

Figure11: The 5 Major US Gas Shale Reservoirs (Hill and Nelson[7])

The first three (Ohio, Antrim, New Albany) in the U.S. were deposited during the Late Devonian period, an important marine source rock deposition period (see Figure 12).

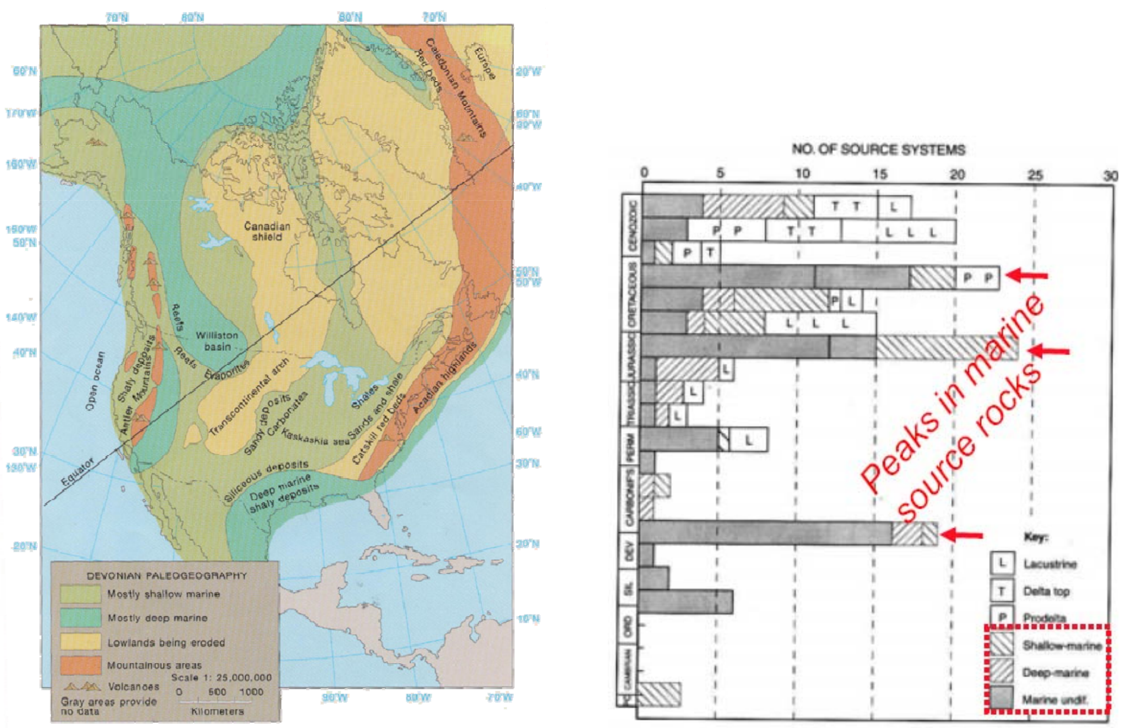


Figure 12: Left: Devonian Paleogeography of North America (from Yacobucci[13]). Right: Source Rock Depositional Environment through Time (from Ayers[9])

The Late Devonian source rocks have been described by Klemme and Ulmishek[14]. They consist of organic-rich siliceous shale, marl and limestone with dominant type II Kerogen. This association of rocks is often called the black shale facies.

The 5 main producing gas shale source rocks can be split in 3 groups according to their lithology:

- Shales having very fine sand and silt laminae and beds (similar to tight sand: e.g. Ohio Shale, Lewis Shale)
- Dark, organic-rich shales having water-filled fractures and must be depressurized (like coal bed reservoirs, e.g. Antrim Shale)
- Mixed – Shales that have characteristics of 1 or 2 above depending on location in basin (e.g. New Albany Shale)

The Figure 13 illustrates the variability in the reservoir properties of the 5 major shale gas reservoirs.

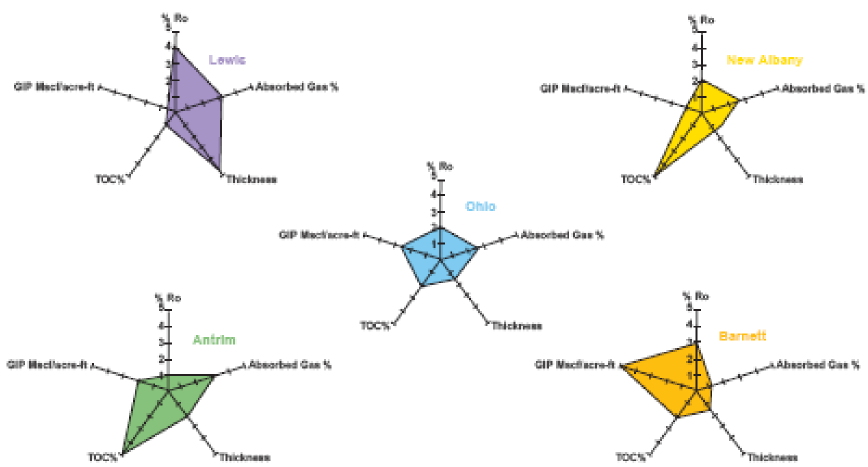


Figure 13: Gas Shale Reservoir Property Comparisons (Hill and Nelson[7])

1.2.5.1 Ohio Shale (Appalachian Basin)

The Devonian shales in the Appalachian Basin were the first produced in the 1820s. The play extends from Central Tennessee to Southwestern New-York. The Middle and Upper Devonian shale formations underlie approximately 128,000 mi^2 (331,520 km^2) and crop out around the rim of the basin. Subsurface formation thicknesses exceed 5000 ft (1524 m), and organic-rich black shales exceed 500 ft (152 m) in net thickness (Dewitt et al.[15]). As Figure 14 indicates, 3,800 ft of mixed sand, shale, and carbonate provide an adequate reservoir seal to the Devonian black shale.

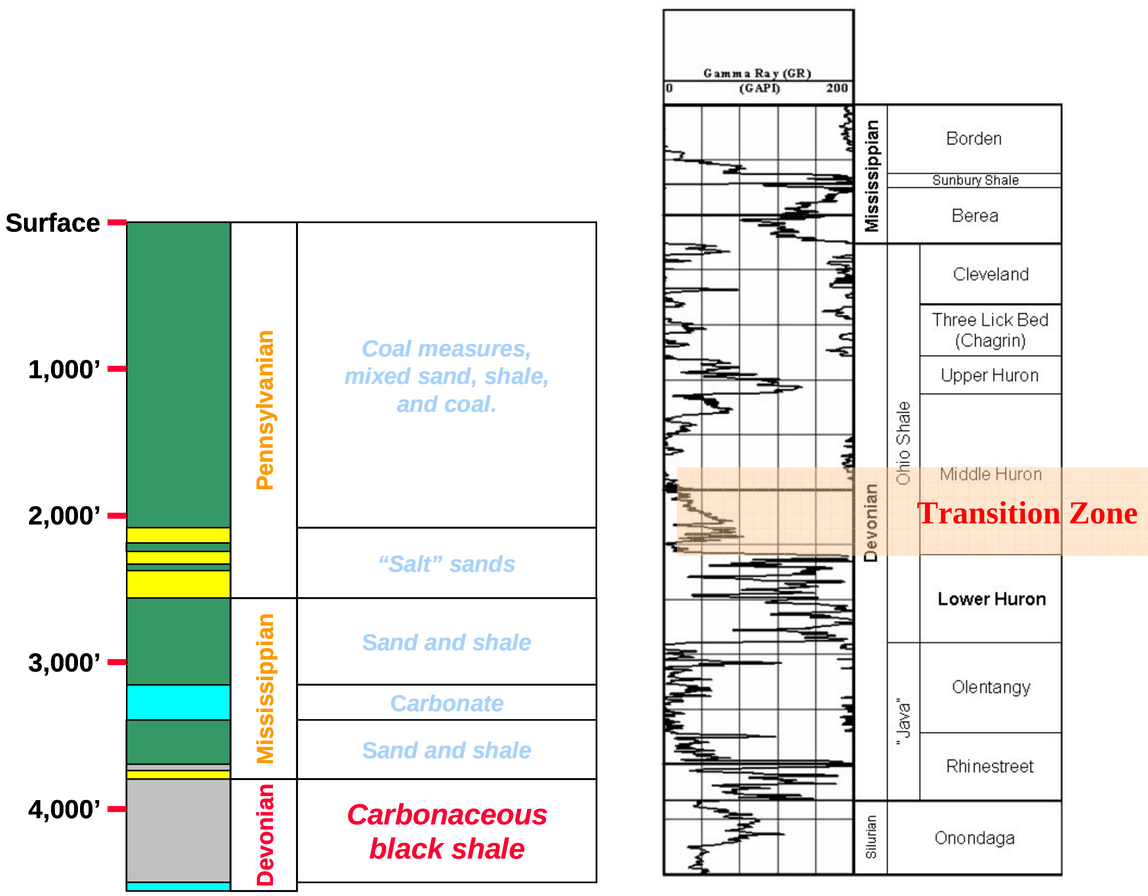


Figure 14: Left: Geologic Column for Appalachian Basin (Kentucky Geological Survey), Right: Type Geophysical Log and Devonian Shale Nomenclature (Kentucky Geological Survey)

The Ohio Shale, within the Devonian Shales, consists of two major stratigraphic intervals: the Chagrin Shale and the underlying Lower Huron Shale (Figure 14).

The Chagrin Shale consists of 700 to 900ft of gray shale (Curtis[16], Jochen and Lancaster[17]), which thins gradually from East to West. Within the lower 100 to 150 ft, a transition zone consisting of interbedded black and gray shale lithologies announces the underlying Lower Huron formation. The Lower Huron is 200 to 275 ft of dominantly black shale, with moderate amounts of gray shale and minor siltstone. Essentially all the organic matter contained in the lower Huron is thermally mature for hydrocarbon generation, based on vitrinite reflectance studies. The organic matter is predominantly type II (liquid- and gas-prone) kerogen.

According to Faraj *et al.*[1], the vitrinite reflectance of the Ohio Shale varies from 1 to 1.3 %, which indicates that the rock is thermally mature for gas generation. The gas in the Ohio Shale is consequently of thermogenic origin.

The productive capacity of these shales is a combination of gas storage and deliverability (Kubik *et al.*[18]). Gas storage is associated with both classic matrix porosity as well as gas adsorption onto clays and kerogen. Deliverability is related to matrix permeability although highly limited (10^{-9} to 10^{-7} *md*) and, more importantly, a well developed fracture system.

1.2.5.2 Antrim Shale (Michigan Basin)

The Antrim shale is black, organic rich bituminous shale the deposited during the late Devonian and early Mississippian time during a period of glacial migration in the Michigan basin, See figure 15. The shale is divided into four members, from base to top: the Norwood, Paxton, Lachine, and upper members. The upper members are overlaid by the Greenish-grey Ellsworth Shale. Typical depths for the entire Antrim shale unit range from 500 to 2,300 ft and the areal[19] extent is roughly 30,000 mi^2. The entire area is overlain by Devonian and Mississippian sediments and hundreds of feet of glacial till. The Antrim mineralogy shows the shale to be laminated with very fine grains. The composition consists mainly of illite and quartz with small quantities of organic material and pyrite.

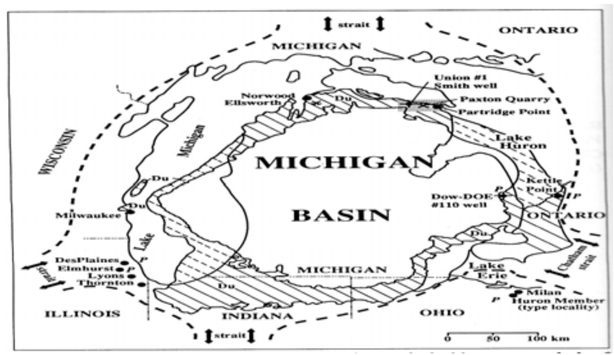


Figure 15: The Antrim Shale is found within the Michigan Basin[19]

The Antrim Shale has an organic matter up to 20 wt%, and is mainly made up of algal material. The vitrinite reflectance is in the range of 0.4 to 0.6, which leads to the conclusion that the shale is thermally immature. The shale is also shallow and there is a high concentration of methane in the composition, which would lead one to assume the gas is of a microbial origin. But, $\delta^{13}C$ values of approximately -50% would indicate a more thermogenic origin. The answer lies somewhere in-between. For shallow wells in the Antrim, the gas is of microbial origin. Deeper wells have a mix of thermogenic gas and microbial gas. The plot in Figure 16 shows how this occurs. For gas compositions with $C_1/(C_2+C_3)$ <100 the gas origin is thermogenic, and this occurs for the gas present in the Niagaran formation which under lays the Antrim Shale. Since the Antrim has so many natural fractures, it is not unreasonable to assume there is migration of gas from the Niagaran formation in to the Antrim Shale.

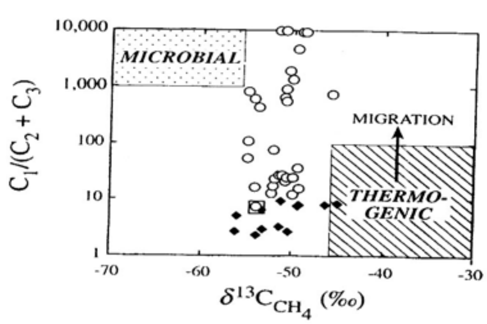


Figure 16: Migration of Deeper Gas Can Cause Gas Composition to be of Biogenic and Thermogenic Origin[20]

The Antrim shale has two main ways of storing gas: absorption and free gas in the pore volume. Figure 17 shows the adsorption isotherms taken at two different depths from the Antrim Shale, the first in the upper Lachine member, and the second from the Norwood Member. As can be seen from the graph at 500 psi, the lower Norwood member has a higher adsorption capacity (~115 scf/ton) than the Lachine member (~85 scf/ton)[21]. This is an important factor to consider when designing a fracture treatment because it would be more beneficial to have more of the proppant in the zone with the highest gas content.

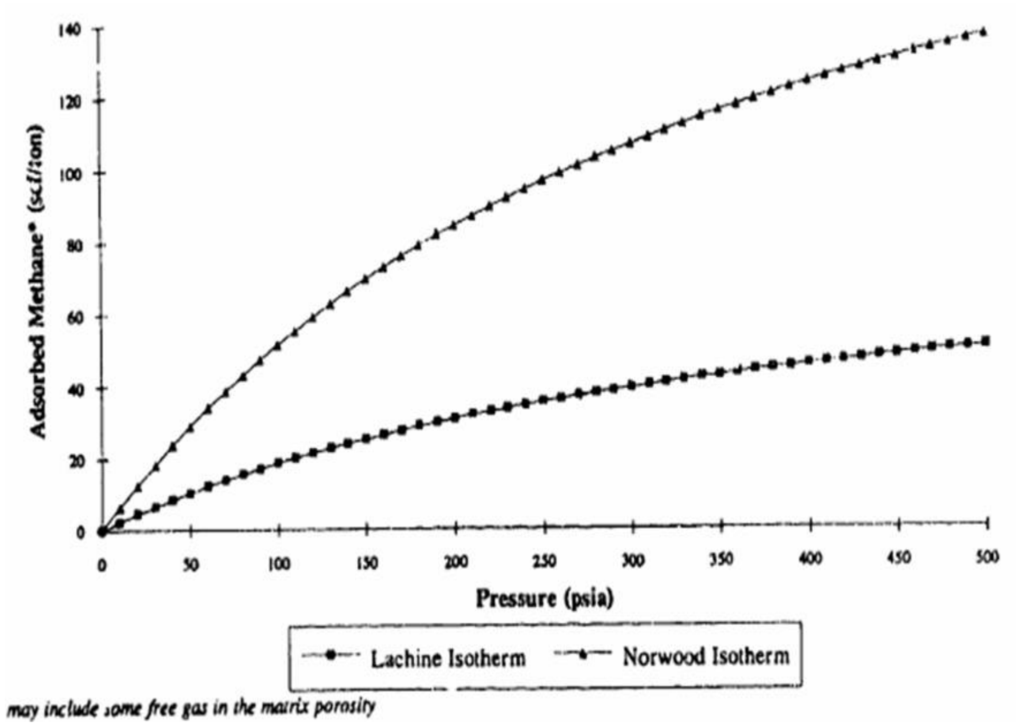


Figure 17: Adsorption Isotherms for Norwood and Lachine Members of the Antrim Shale[21]

The free gas in the pore space can account for up to 10% of the total gas in place, but it is still not clear on how dependant the free gas is on the water in place. The very low permeabilities of the matrix could create a “permeability jail” and make it impossible to remove a significant portion of the free gas.

The Antrim Shale is highly fractured for a shale reservoir. Fracture spacing can be as close as 1 to 2 ft, compared to 10 to 20 ft for the Barnett shale. These fractures can create permeability-thicknesses in the range of 50 to 5000 md-ft[21], which increases gas production. But, it also helps water flow, and thus most wells produce large amounts of water which must be disposed of.

1.2.5.3 New Albany Shale (Illinois Basin)

The New Albany Shale is organic-rich shale located over a large area in southern Indiana and Illinois and in Northern Kentucky (Zuber et al.[22]). The depth of the producing interval varies from 500 ft to 2,000 ft depth, with thicknesses of about 100 ft. A location map and representative log are reproduced thereafter. Figure 18 shows that the shale is generally broken into four stratigraphic intervals: from top to bottom, these are the Clegg Creek, Camp Run/Morgan Trail, Selmier, and Blocher intervals.

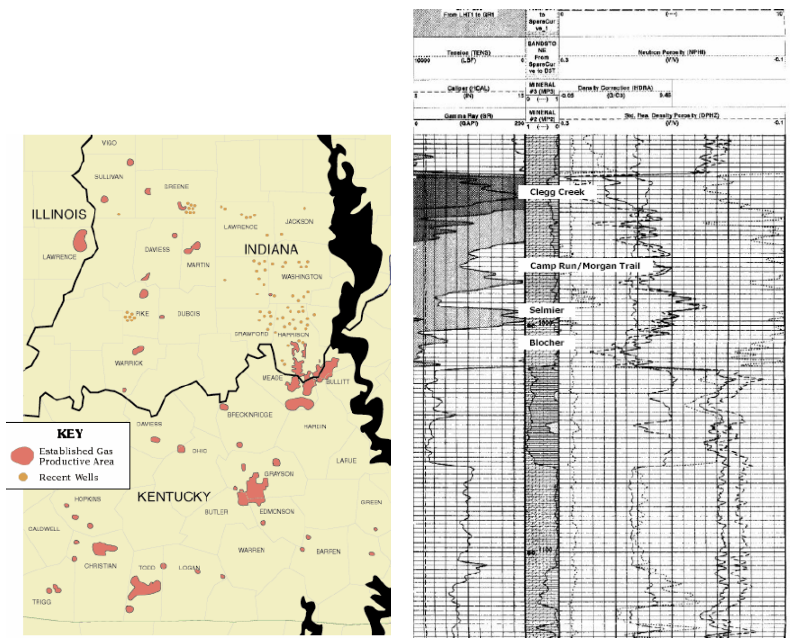


Figure 18: New Albany Shale: Left: Location Map (Indiana Geological Survey); Right: Representative Well log (Zuber et al. 2002)

As seen before, the New Albany shale can be seen as a “mixed” source rock: some parts of the basin produced thermogenic gas, and some others produced biogenic gas. This is confirmed by the vitrinite reflectance in the basin, varying from 0.6 to 1.3 according to Faraj et al.[1]. It is not known whether circulating ground waters recently generated this biogenic gas or whether it is original biogenic gas generated shortly after the time of deposition.

1.2.5.4 Barnett Shale (Fort Worth Basin)

The Fort Worth basin covers approximately 15,000 mi2 in North-Central Texas. The wedge shaped basin is centered along the north-south direction, deepening to the north and outcropping at the Liano uplift in Liano County as seen in Figure 19. The general stratigraphy of the basin is shown in Figure 20. The Cambrian Riley and Hickory formations are overlaid by the Viola-Simpson and Ellenburger groups. These two groups are very important in production from the Barnett. The Viola-Simpson limestone group is found in Tarrant and Parker counties and acts as a frac barrier between the Barnett and the Ellenburger formation. The Ellenburger formation is a very porous, karsted aquifer[22] that if fractured will produce copious amounts of highly saline water, effectively shutting down a well with water disposal cost.

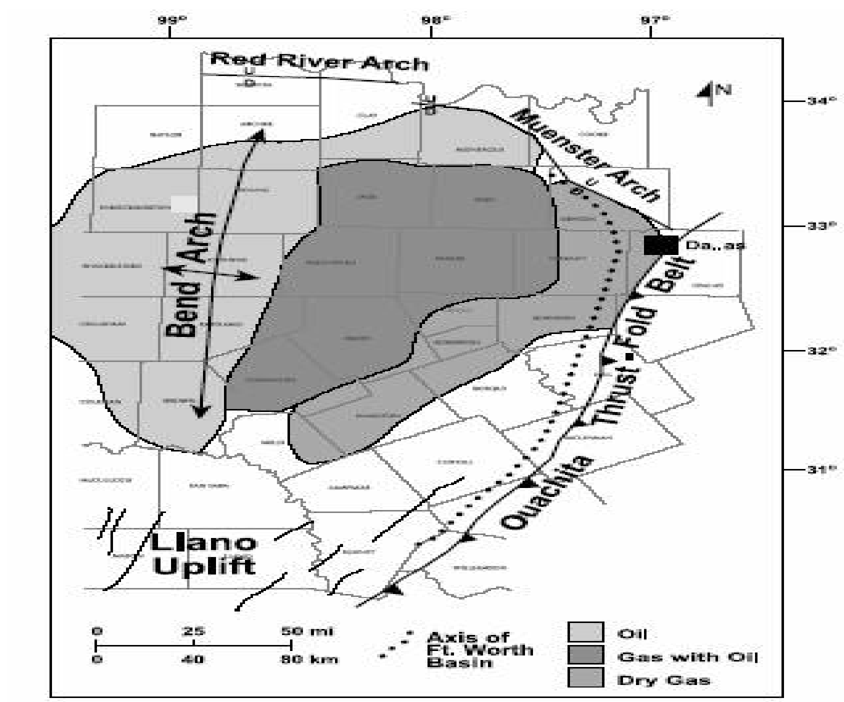


Figure 19: Structures of the Fort worth Basin[23]

Over the Viola-Simpson group lies the Mississippian age Barnett Shale. The Barnett is anywhere between 150-800 ft, and is the most productive gas shale in Texas, with 1.6 Tcf [23] produced as of September 2005, see Figure 22. Permeability ranges from 7 to 50 nanodarcies[24] and porosity from 4 to 6%.

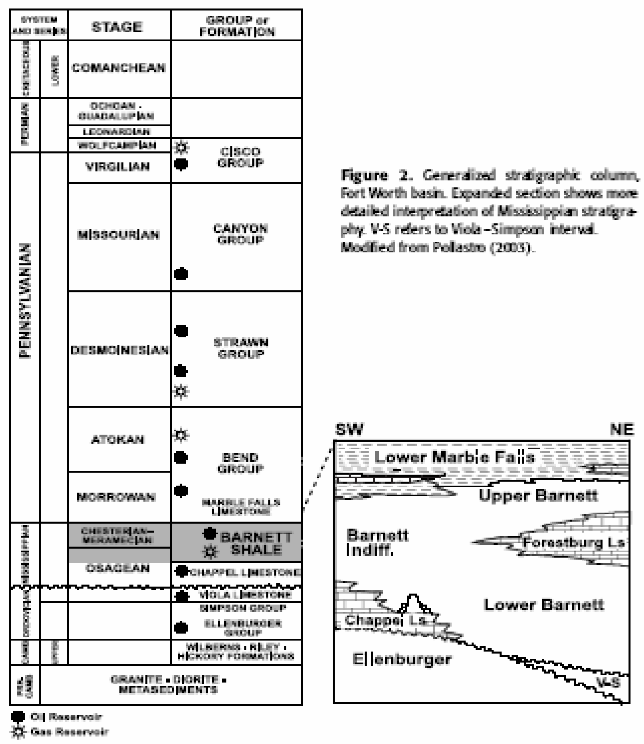


Figure 20: General Stratigraphy of the Fort worth Basin[23]

The three most important production related structures in the basin include both major and minor faulting, fracturing, and karst-related collapse features[25]. Fracturing is important to gas production because it provides a conduit for gas to flow from the pores to the wellbore, and it also increases the well's exposure to the formation. The Barnett's very complex fracture geometry often creates difficulty in estimating fracture length and exposure to the formation due to the complex geometry. The fracturing is believed to be caused by the cracking of oil into gas. This cracking can cause a ten-fold increase in the hydrocarbon volume, increasing the pressure until the formation breaks. The precipitation of calcium carbonate in the fractures can cut down on the conductivity of the fractures. This precipitation is hard to detect on logs, and can cause a well location that appears to be good on seismic into an unproductive well. This precipitation is also hard to treat with acidization due to the long distances the acid is required to travel before making a noticeable impact on production.

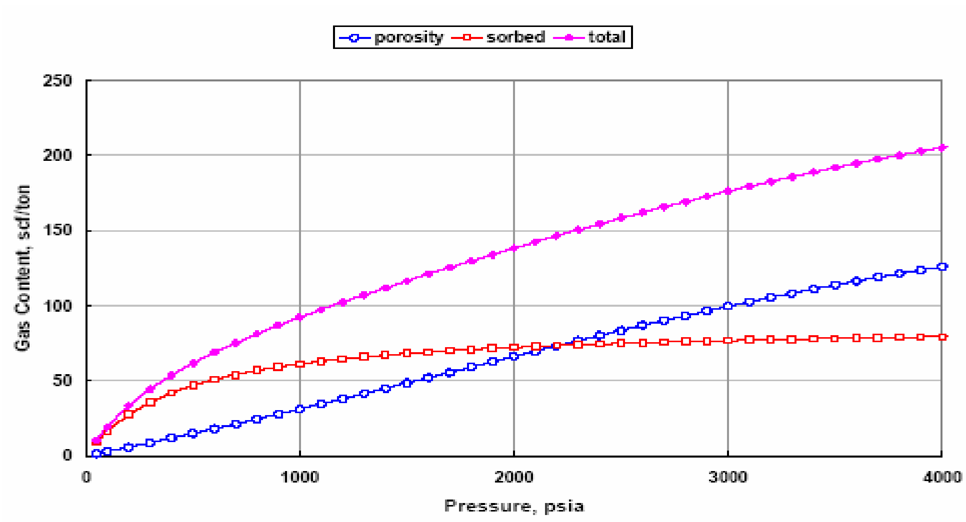


Figure 21: Gas Content of Free and Absorbed Gas[25]

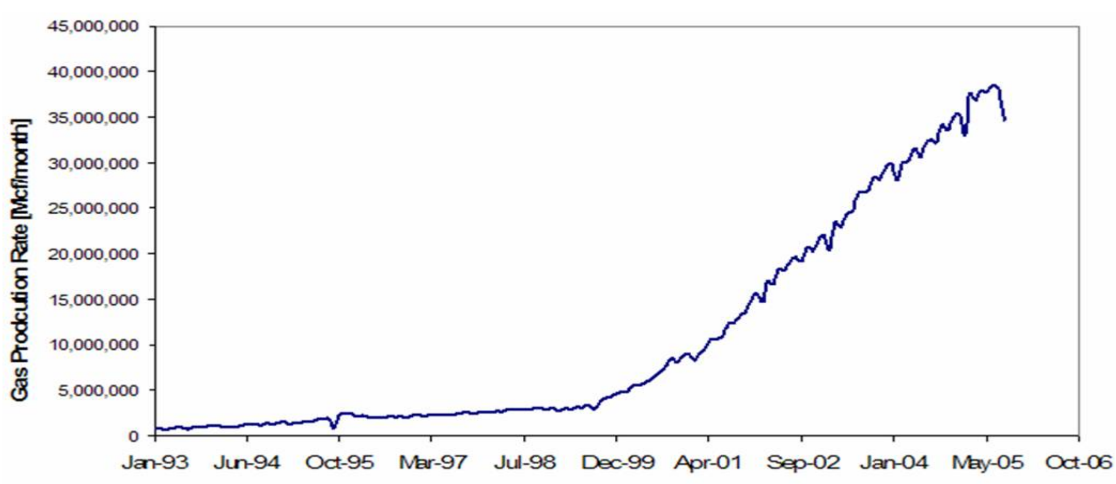


Figure 22: Gas Production Rates have Exceeded 35 Bcf/Month as of September 2005[24]

Change in gas content with pressure in the Barnett shale is shown in Fig. 21[25] with a typical reservoir pressure in the range of 3000-4000 psi. In low permeability formations, pseudo radial flow can take over 100 years to be established. Thus, most gas flow in the reservoir is a linear flow from the near fracture area towards the nearest fracture face. Faulting and karst-related collapse features are important mainly in the Ellenburger formation. By mapping these karst and faults several companies have made economic wells outside the Viola-Simpson frac barrier by drilling the wells away from any karst or faults. This keeps the water production down and the water disposal cost down.

CHAPTER II

SCREENING CRITERIA FOR SHALE GAS RESERVOIRS

Geology of 5 major shale gas basins has been presented in the previous section. We can use properties of these reservoirs to come up with unified screening criteria. This chapter discusses such properties which are particularly observed in shale gas basins. Table 1 shows different properties of shale gas reservoirs and their interdependency. Properties in the same font color are believed to depend on each other.

Table 1: Classification of Shale Gas Reservoir Properties

Basin specific Properties	General Shale gas reservoir Properties	Well Specific properties
Pressure or Depth of the Shale interval	Thermal Maturity (To Decide upon the Gas window)	Thickness of shale formation
Stress allocation within reservoir (Natural fracture orientation and severity)	Depositional Environment	Stimulation Type and frac fluid selection
Gas Storage mechanism (Adsorption, Matrix/fracture)	Low Porosity/ Permeability	Decision on drilling vertical and Horizontal well
TOC %	Naturally fractured reservoirs	Stimulation necessary for production
Mineralogy of shale (Rock texture) (Low Calcite) or (high calcite, more Clay)	Multi layered or single layered?	

Following discussion concentrates on these different shale gas reservoir specific properties. Screening criteria is devised after going through these different properties.

2.1 Influence of Clay Mineralogy

Shales consist of different types of clays. Clay may be present in sandstone either as a detrital matrix or as authigenic cement. As clays recrystallize and alter during burial, this distinction is always not easy make. The presence of clay in a reservoir obviously destroys its porosity and permeability. The mineralogy of clays is very complex but basically there are three groups to consider. These, the koilinitic, illitic and montmorillonitic clays, have different effects on reservoirs and different sources of formation[26].

Kaolinite generally occurs as well-formed, blocky crystals within the pore spaces. This crystal habit diminishes the porosity of the reservoir, but may have only a minor effect on permeability. Kaolinite is stable in the presence of acid solutions. Therefore it occurs as detrital clay in continental deposits, and as authegenic cement in sands that have been flushed by acidic waters, such as those of meteoric origin.

Illitic clay is quite different from kaolin. Authegenic illite grows as fibrous crystals, which typically occur as furlike jackets on the detrital grains. These structures often bridge over the throat passages between pores in a tangled mass. Thus illitic cement may have a very harmful effect on permeability. They are the dominant detrital clay of most marine sediments and occur as authigenic clay in sands through which alkaline connate water has moved[26].

The montmorillinitic, or smectitic, clays are formed from the alteration of volcanic glass and are found in continental or deep marine deposits. They have the ability to swell in presence of water. Reservoirs with montmorillonite are thus very susceptible to formation damage if drilled with a conventional water based mud and must therefore be drilled with an oil-based mud. When production begins, water displaces oil, causing the montmorillonitic clays to expand and destroy the permeability of the lower part of the reservoir. Kaolinite, illite and montmorillonite may all be found in shallow reservoirs, depending on the source material and the diagenetic history. With the increasing burial the kaolinites and montmorillonite alter to illite, the collapse of montmorillonite being a possible cause of overpressure, and related to the expulsion of petroleum[26].

2.2 Gas in Place

To have an economic shale play, there must be a sufficient amount of gas in place within the shale. Thus, shale must also be a hydrocarbon source that generated large volumes of either thermal or biogenic gas. To have generated such large quantities of gas, shale needs to be rich in organic matter, relatively thick and to have been exposed to source of heat in excess of usual global geothermal gradients. The presence of adsorbed gas, trapped gas and free gas in fractures contributes to the complexity of the problem.

A general equation for calculating gas in place as first estimate would be

G= 27, 878, 400 * A * h * (G.C.)

G= Gas in Place, Scf

A= Area in sq miles

H= Average Net Thickness, ft

G.C. = Gas Content Scf of gas / cubic ft of shale

1 sq mile = 27,878,400 sq ft

Looking at the above equation, one can come up with different estimates for different parameters involved. Thickness could be found by applying gamma ray cut-offs, porosity cut offs or density cut offs. Drainage area is also contentious issue here. Gas content measurement could be subject to laboratory core analysis errors.

2.3 Concentration of Organic Matter

Organic carbon concentration in the shales is important in deciding its productive potential. Among all shale basins studied here, it appears that organic carbon concentration in productive shales range anywhere between 1-10 % or more. In some reservoirs like Barnett shale, intervals with high carbon concentration exhibit higher gas in place and generally, the highest matrix porosity and the lowest clay content. It is difficult to come up with a deterministic value of TOC (%) as it often differs from basin to basin.

2.4 Thickness

Thickness of the shale gas reservoir again is a regional variable. For reservoirs like Barnett shale, average thickness was found to be 250-300 ft while Michigan shales are relatively thin and average about 30-50 ft. Same is true for oil producing Bakken shale where thickness of the productive shales is around 25-30 ft. one interesting fact, Barnett shale is relatively thin in thermally less mature areas and is relatively shallow.

2.5 Thermal Maturity

Thermal maturity of the shales is important parameter in deciding the oil window and gas window. Prospective shale must be within thermal maturity window for shale gas production. It is said that shales act as semi permeable membrane and allow only smaller molecules can pass through the sieves and larger molecules choke pore throat and can't pass through. So it is important to locate on the transition from gas to oil window as wells in the oil window are subjected to poor performance if developed as gas wells. Thermal maturity is generally represented by Vitrinite reflectance (R_0 %). Vitrinite reflectance is measured in the core analysis. Vitrinite reflectance is one of the organic geochemical indicators of petroleum maturation. The principal maceral groups in coals provide the basic Van Krevelen diagram, which depicts path of their evolution during carbonization. Paths progressively approach origin depicting 100 % carbon. The macerals are distinguished by their plan precursors. Vitrnite is one of the macerals which includes both telinite, in which woody structures are pressent and collinite, essentially structureless matrix, cement and cavity infilling. Vitrinite is not fluorescent. It is primarily humic organic material.

For shale reservoirs, generally

Ro %	0.1 to 0.5	Thermally immature
Ro %	0.6 to 1.1	Oil window
Ro%	1.2 to 2.0	Gas window

2.6 Gas Storage Mechanism

Shale gas reservoirs being low porosity, low permeability reservoirs, It is important to know how the gas is stored before producing it. There are three possibilities

1. Most of the gas (>50 %) is adsorbed on the shale matrix and remaining is stored in the matrix
2. Most of the gas is stored in matrix and fractures and adsorption is not so important phenomenon.
3. Most of the gas is stored in fractures. Matrix storage is not possible due to absolute absence of porosity and permeability.

Out of these, third possibility of gas being stored in fractures alone is not seen as yet. So is not considered here. When the gas is adsorbed on the matrix, Shale gas reservoirs can be treated as special case of CBM reservoirs. As seen in the case of Antrim shale reservoirs, dewatering of the shales is required before actual gas production. Antrim shale is fairly shallow reservoir with pressure gradient less than normal. So wells are treated at low operating pressures. In other Devonian shales like Albany shales where both phenomena are present, i.e. adsorption and matrix storage both exist, production mechanism is decided on well to well basis. Reservoirs where matrix storage is major, it is seen that these wells have high initial decline but produce for longer time, so pay out period for these wells is long but wells produce for 30-50 years as matrix gas diffuses into fractures Slowly. Stimulation treatments and horizontal well technology advancements have played an important part in development of these reservoirs.

2.7 Water Saturation

Water saturation is very difficult to measure in shale gas reservoirs. Reason being all water saturation equations developed till date are designed for non shale lithology and concept of net pay based on non-shaly zones in a reservoir. So water saturation could be measured from the core analysis more reliably in shale reservoirs.

2.8 Pressure Conditions in Shale Gas Reservoirs

Power (1967) pointed out that there are two types of water in clays: normal pore water and structured water that is bonded to the layer of montmorillonite clays (smectites). When illitic or kaolinitic clays are buried, a single phase of water emission occurs because of compaction in the first 2 km of burial. When Montmorillonite rich-muds are buried, however, two periods of water emission occur: an early phase and a second quite distinct phase when the structured water is expelled during the collapse of the montmorrilonite lattice as it changes to illite. Further work by Burst (1969) detailed the transformation of montmorillonite to illite and showed that this change occurred at an average temperature of some 100 to 110 ^{o}C, right in the middle of oil generation window. The actual depth at which this point is reached varies with the geothermal gradient, but Burst (1969) was able to show a normal distribution of normal distribution of productive depth at some 600 m above the clay dehydration level. By integrating geothermal gradient, depth, and the clay change point, it was possible to produce a fluid distribution model for the Gulf Coast area. Barker (1975) has pursued this idea[27], showing that not only water but also hydrocarbons may be attached to the clay lattice. Obviously, the hydrocarbons will be detached from the clay surface when dehydration occurs. The exact physical and chemical process whereby oil is expelled from the source rock is not clear. Clay dehydration is only one of the several causes of supernormal pressure. Inhibition of normal compaction due to rapid sedimentation, and the formation of pore-filling cements, can also cause high pore pressures. Furthermore, some major hydrocarbon provinces do not have supernormal pressures. In some presently normally pressurized basins the presence of fibrous calcite along veins and some instances, such as the wessex basin of southern England, these calcite veins contain traces of petroleum (Stonely, 1983).

2.9 Natural Fractures

Natural fracture presence is another important property for a shale gas reservoir to be economically producible. Almost all shale gas reservoirs are naturally fractured. Severity of natural fracturing differs in different reservoirs. In situ stress orientation has a profound effect on the natural fracture intensity and orientation as fracture tends to propagate perpendicular to maximum horizontal stress. Exploitation of natural fractures to the fullest depends on the stimulation treatment strategy. So reservoir simulation is carried out to see the effect of longitudinal fracture versus transverse fracture on the productivity of the well. Fracture spacing is one more variable in simulating naturally fractured reservoir which is generally an assumed value and deterministic value is highly impossible. So sensitivity study of fracture spacing and effect of longitudinal and transverse fractures is important in making reservoir management decisions[28]. If the fracture intensity is very high or a formation is much fractured then stimulation treatment should be chosen to have complex fracture geometry. On this issue will be discussed in stimulation treatment considerations.

2.10 Stimulation Treatment Considerations

Most shales contain high percentage of clay minerals. Conversely Barnett and other productive shales do not. Reason being shales with less clay and more calcite in it, tends to be brittle. We can look at this in two ways:

1. Shales with more silica in it tend to be naturally fractured and more productive.
2. Shales with more silica, less clay in it can be more easily hydraulically fractured and success of the stimulation treatment tends to be more in such shales.

Both these arguments basically point towards successfully exploiting shale gas reservoirs so we buy the argument “silica rich shale are high potential shale gas intervals”.

One can basically classify all shale gas reservoirs based on the mineralogy as follows:

- Shales with more than 50 % clays, less calcite mineralization

Slick water treatments are not favorable. Reasons explained in stimulation treatment considerations.

- Shales with less than 50 % clays, more calcite mineralization

Slick water treatments favored formation being more brittle and ease of fracturing.

Designing a fracture treatment in a shale gas reservoir depends on many issues. Main driver being economics, shale gas reservoirs are considered as a long term investment. Pay out period is long but drilling is cheaper, fast and can be produced for long time, so optimum stimulation treatment is the one which is cheapest and most effective. Slick water treatment seems to be one of the options. The ultimate goal of each completion is to expose and interconnect the maximum surface area of shale to the wellbore in the area of the reservoir. Therefore, economical completions must connect vast quantities of rock surface through fractures to generate sufficient production volumes. Knowledge of the bounding rock layers is required in design optimum completion due to the limits on bottom-hole pressure, rate and fluid volume. In the case of water bearing zones, horizontal wellbore have been utilized to contain the height growth and increase fracture complexity thereby exposing maximum surface area to the gas shales. Variations in the horizontal well technology abound as engineers experiment with the perforation cluster design, lateral length, and number of stages, pump rate, fluid type and volume, proppant selection seeking to find the optimum combination for a particular type of geology within the region[28]. As shown in Figure 23, Fluid selection depends on the mineralogy of the rock. If shale contains more than 50 % clays then rock would be less brittle. So using a slick water treatment would not be appropriate and required initiation of the fracture would be difficult. So a cross linked gel treatment is favored in such formations[29]. As natural fracture intensity and composition of the shale are closely related, fracture intensity matters when it comes to treatment design. Following flowchart should guide through the treatment design.

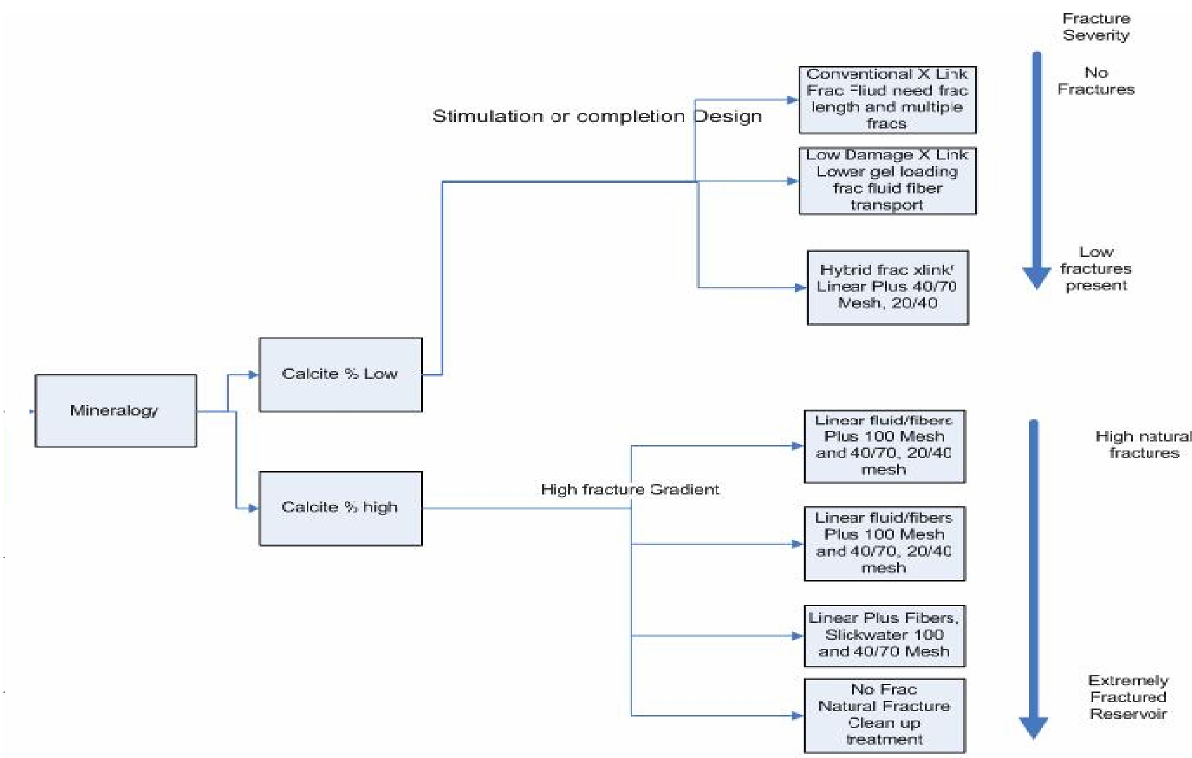


Figure 23: Stimulation Treatment Considerations

Before we proceed, it is important to know how the fracture is created and developed within the reservoir. In 1986, Blanton presented the results of laboratory and theoretical studies on the interaction between natural and hydraulic fractures. So author puts up his theory saying if a hydraulically created fracture is propagating in the direction of natural fracture, several things could happen. When the hydraulic fracture reaches a natural fracture, one possibility is, it continues across the natural fracture as if it were not there. This is unlikely to occur in all cases, because the energy at the tip of the fracture dissipates to some extent when the tip comes in contact with the pre-existing failure plain in the rock (natural fracture). For the fracture to reinitiate on the other side of the fracture, another breakdown of the rock must occur. Thus, much higher pressures would be needed for the crack to reinitiate on the other side of the fracture. One more possibility is, fracture initiates on the other side of the natural fracture but with some offset. This could occur because there may be pre existing flaw on the face of the natural fracture, which will preferentially break down first (before the rock directly across from the hydraulic fracture) due to this pre-existing weakness. This assumes that natural fracture accepts enough fluid (due to leak off and fracture opening) to allow the pressure in the fracture to increase. Offsets such as these (even on the order of a few inches) are often used to explain the existence of near wellbore tortuosity, presence of multiple fractures, and higher treating pressures, in general. Last but not the least, there is a possibility of opening or dilating of the natural fracture, as a result of the increase in the pressure. Under certain circumstances, it should be expected that a hydraulic fracture treatment opens up an existing natural fracture(s) and follow along it path (as opposed to propagating across it).

As explained briefly by Blanton[30] and expanded upon by Warpinsky[31], predicting whether a hydraulic fracture will propagate through or dilate (open) natural fractures is based on many factors. These factors include minimum and maximum stresses which control the normal stress exerted on the natural fracture, the angle of approach, the natural fracture, and the rock tensile strength, coefficient of friction along the natural fracture, and rock property anisotropy. According to Blanton, for small differences in minimum and maximum stresses it is likely that fluid and sand pumped will follow the path of the existing natural fractures. Industry rule of thumb says that for shallow depths (Less than 2000 ft) and treating pressures greater than 1 psi/ft, horizontal fracture is created limiting vertical height growth.

2.11 Basic Screening Chart Development

After studying all these properties, a basic chart encompassing all properties can be made as follows.

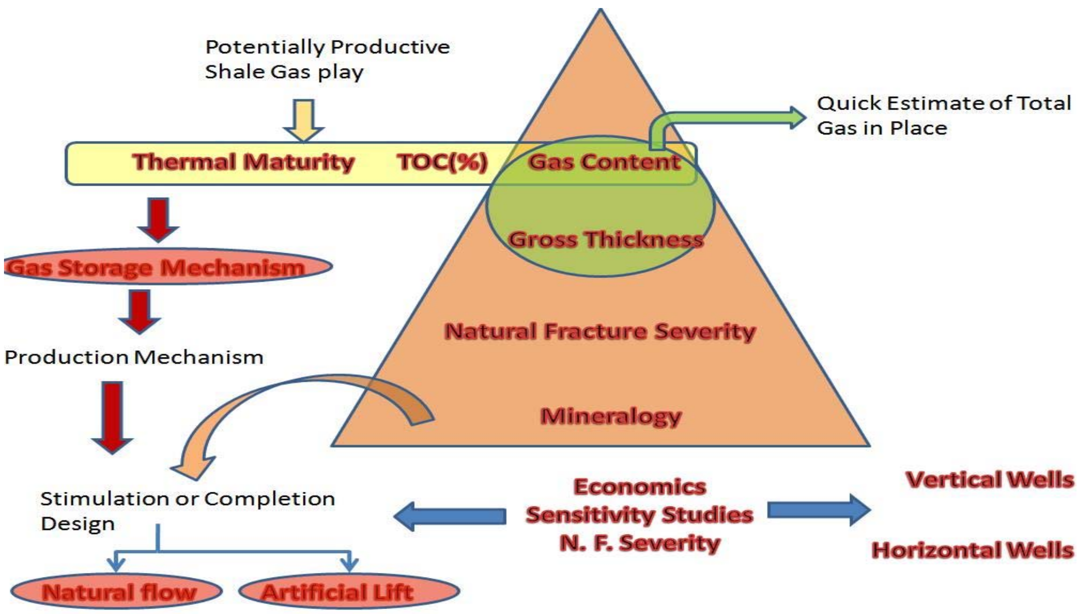


Figure 24: Basic Decision Chart for Shale Gas Reservoirs

Figure 24 shows that thermal maturity, Total Organic Content % and Gas Content Scf /ton are the most important properties which decide whether a shale gas play will be potentially productive or not, as illustrated in Figure 25. Then a gas storage mechanism decides production mechanism and how the gas will flow to the wellbore post stimulation (see, Figure 26).Stimulation techniques depend on the mineralogy of the shale. As discussed, natural fracture severity of shale depends on the amount of calcite present in it. Completion techniques are described in Figure 27. Generally horizontal wellbore is always preferred considering nature of the reservoir (Low Porosity, Low Permeability) to contact maximum reservoir area but this decision could be limited by factors like economics, availability of rigs, prior drilling pattern in the area and regulatory issues of the specific region as shown in Figure 28.

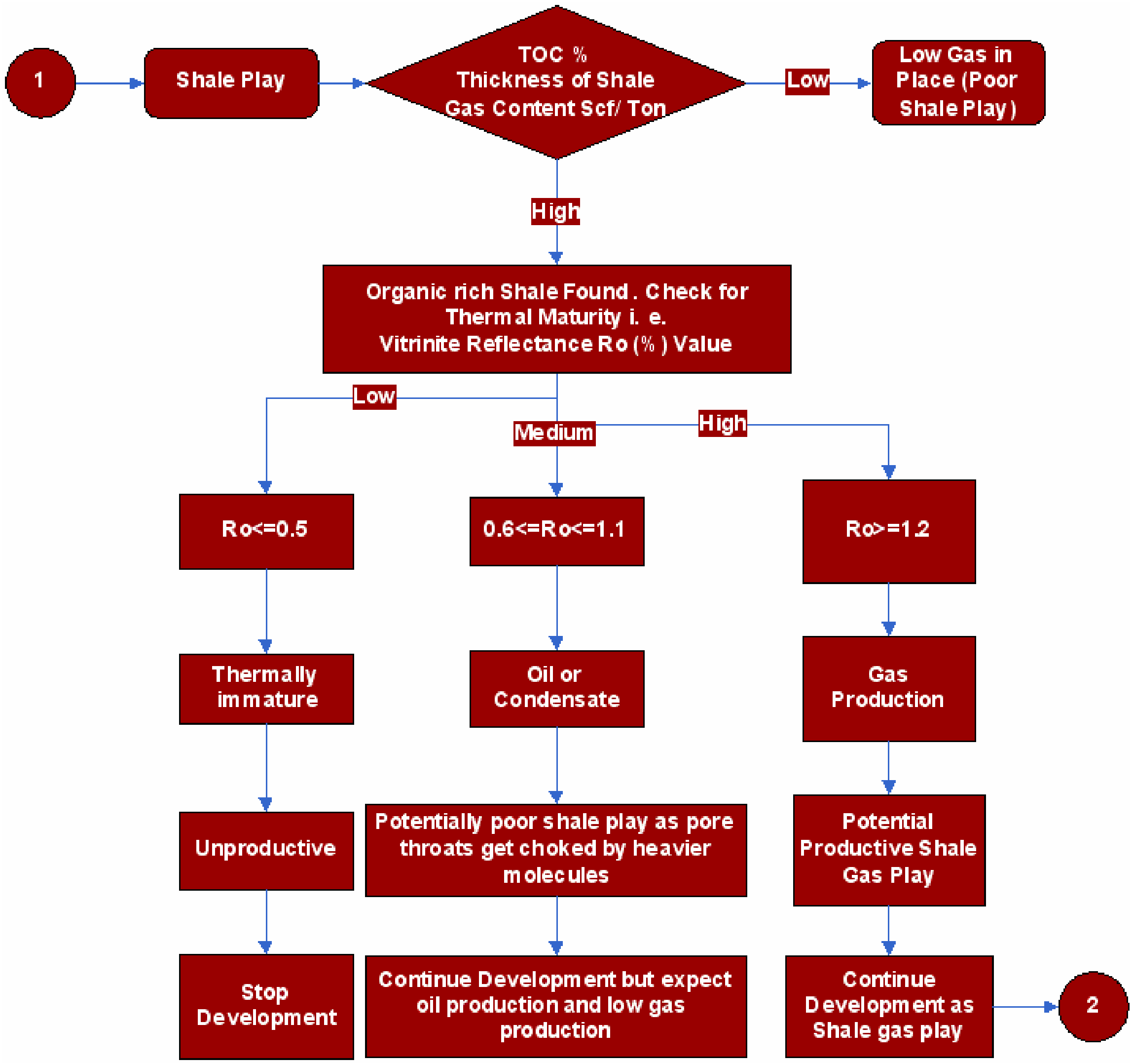


Figure 25: Screening Criteria for a Potential Productive Shale Play

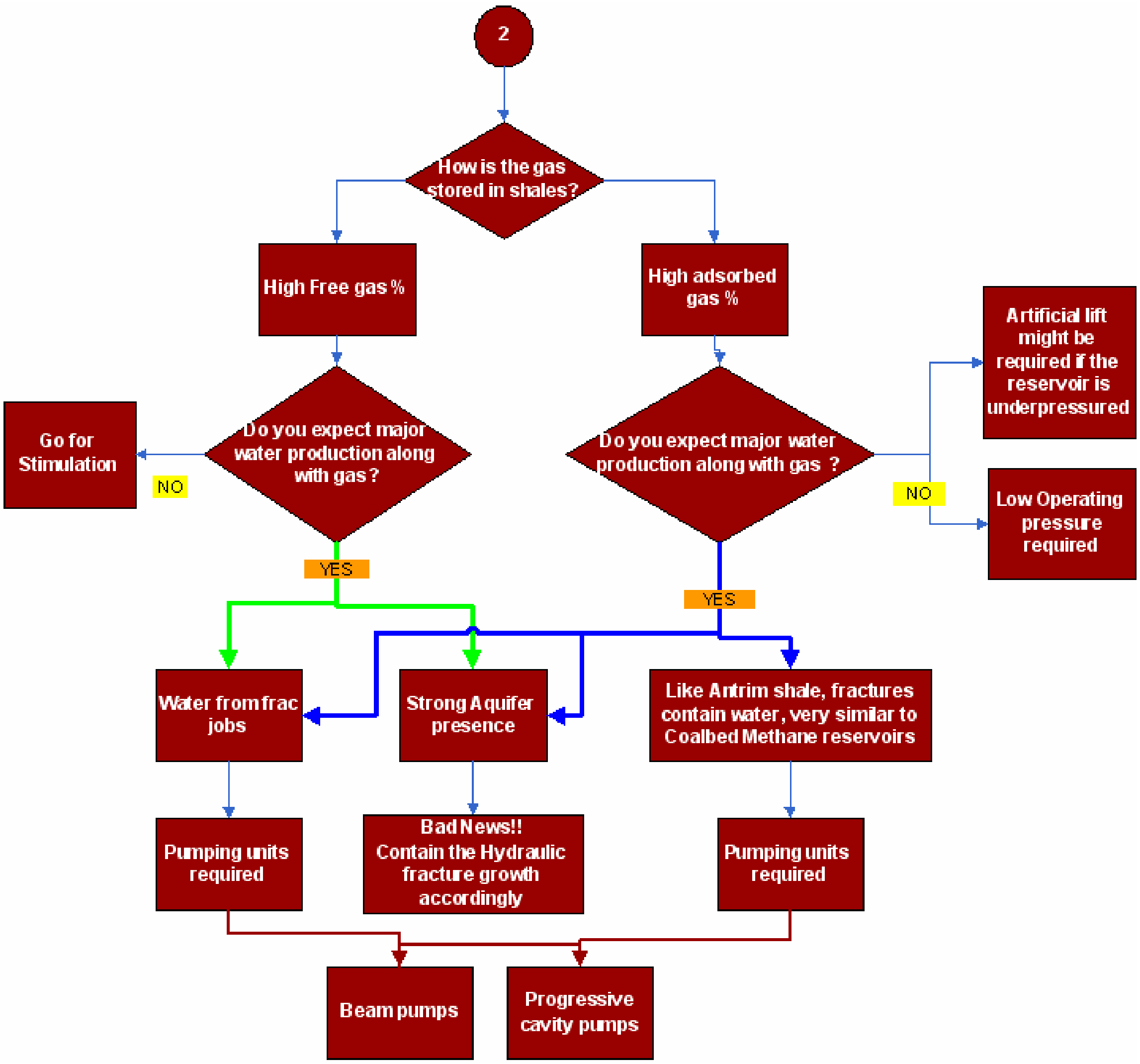


Figure 26: Screening Criteria for the Use of Pumping Units in Potentially Productive Shale Play

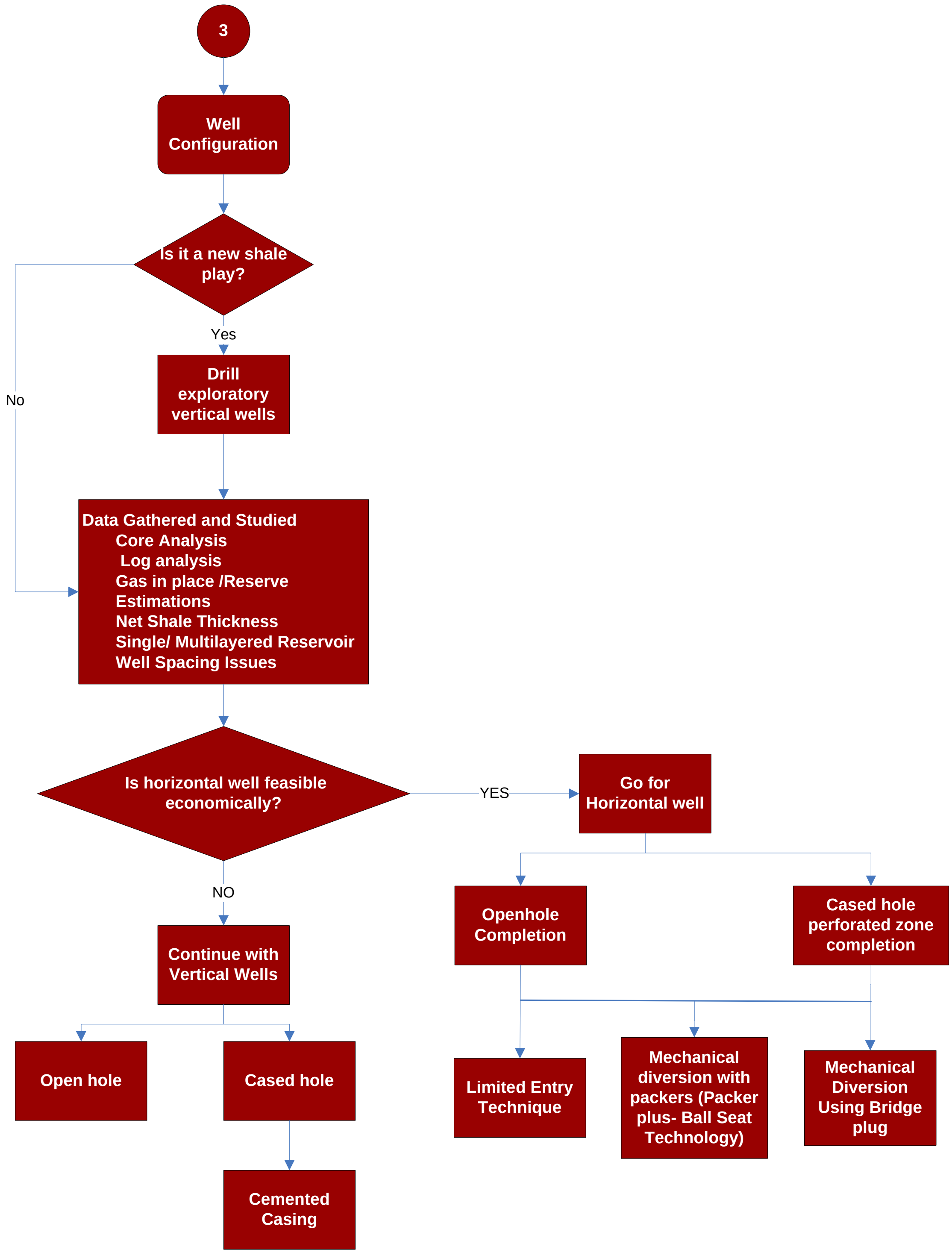


Figure 27: Screening Criteria for the Completion Strategies in Potentially Productive Shale Play

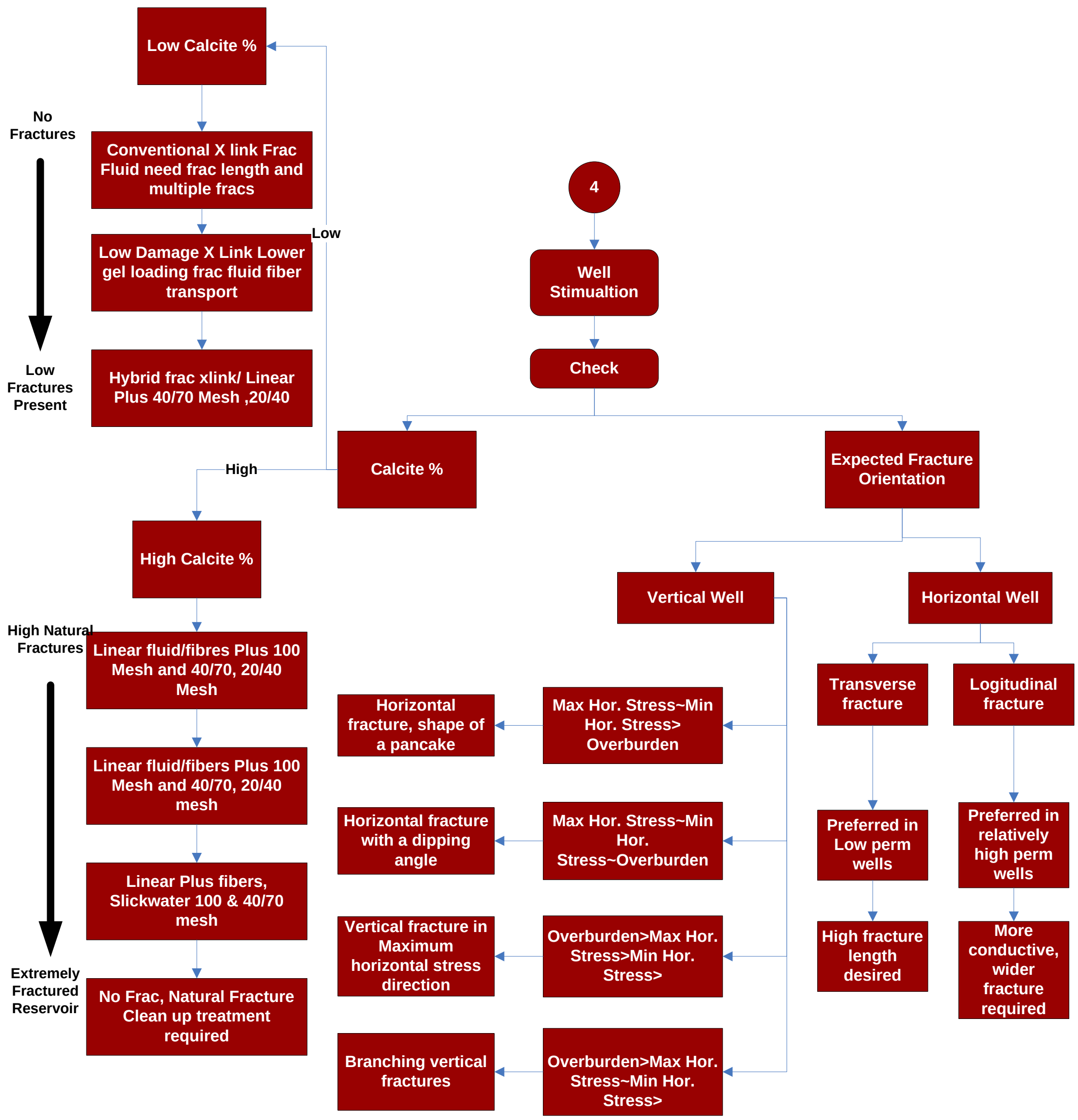


Figure 28: Screening Criteria for the Stimulation Treatment Considerations

CHAPTER III

BARNETT SHALE GAS PRODUCTION DATA ANALYSIS

3.1 Background

A lot of literature has been published on the geological and geochemical analysis of Barnett shale. But production data has been so far kept proprietary. Motivation to do this kind of study comes from the hypothesis that completion techniques in Barnett shale result in typical declines in the reservoir. So we decided to do a production data analysis of the core producing region which is most representative of the entire Barnett Shale. We have used production data from public databases available such as IHS, Drillinginfo and HPDI. April 2007 issue of AAPG Bulletin is dedicated to Barnett shale geology and geochemical issues. Schlumberger's Moving Domain Express™ software is used for the Moving domain analysis of the production data and Fekete's RTA™ is used for Decline curve analysis. Background for these two methods is presented in the following sections.

3.2 Moving Domain Analysis

Moving domain analysis takes a much broader, more statistical view of production data. It uses publicly available production and completion data to identify areas of interference between existing wells and to quantify the impact of completion and stimulation practices on well performance and drainage area. It may be used to quantify infill drilling opportunities over large areas, to evaluate completion practices and stimulation treatment sizes, and to locate areas for more in-depth, detailed engineering studies.[32]

Although moving domain analysis may be performed with publicly available production data alone, a combination of public and operator-supplied data may be required for completion or stimulation analysis. Moving domain analysis also provides an unbiased and consistent analysis across a study area. Finally, moving domain analysis is cost effective, i.e., in some cases, moving domain analysis has provided essentially the same results as much more detailed engineering studies at a small fraction of the cost in terms of both dollars and manpower.

This new technique called moving domain analysis evaluates when wells are completed, where they are located and how much they produce to determine historic productivity, evidence of depletion, effective well density, and undrained acreage and infill potential. We achieve these conclusions through a set of empirically derived approximations, comparisons and statistical analysis. Statistical tests might impose objectivity on the analysis so technique is further developed for linking this approach to conventional reservoir engineering approach.

To summarize, “Moving domain” is a set of empirically derived approximations, comparisons and statistical tests that attempt to mimic what a reservoir engineer does when faced with a single infill location evaluation. To sum it up, this technique looks at surrounding well performance, compares new wells to old wells for signs of depletion, calculates effective well density, and, once linked to a scattering of conventional estimates of drainage area provides estimate of undrained acreage and infill reserves. Typically results are in a map format with a mix of dots, bubbles and contour lines to highlight the achievements.

3.3 Bootstrap Method

The bootstrap method is a special type of Monte Carlo analysis which does not require a prior knowledge of the underlying probability distributions of the model parameters. The bootstrap method makes two assumptions. First, there is a model which predicts reservoir performance. Second, there is a field data set available where the data are independently and identically distributed. This second assumption is the same one which is normally made to justify the use of nonlinear regression.

First, a large number of synthetic data sets are generated from the original data set. Each of the synthetic data sets is the same size as the original data set, and is obtained by picking points at random from the original data set, with replacement. Each resulting synthetic data set contains only data from the original data set, with some points omitted, and other points duplicated one or more times. Second, nonlinear regression is used to obtain estimates of the decline curve parameters for each synthetic data set, and then these parameter estimates are used to forecast performance for each synthetic data set. Perhaps the biggest advantage of the bootstrap method is that it provides a probabilistic reserves estimate which is based on only rearrangements of original data. It does not require prior knowledge of the underlying distribution of the model parameters; indeed, it may be used to obtain those distributions. It allows for the model parameters to be strongly correlated as are qi, Di, and b. it also allows the model parameters to be constrained, as. For example, b is required to be between 0 & 1.

CHAPTER IV

RESULTS AND DISCUSSION

4.1 Study Area Details

Barnett shale region i.e. Denton, Tarrant and Wise counties chosen for the study are illustrated in figure 29 below[31]. Production data available is typically reported on a commingled basis for all the wells within the study area mentioned. Typical production data includes gas and water production rates vs. time and the number of wells drilled vs. time. Available data used is from the public database namely IHS and www.drillinginfo.com.

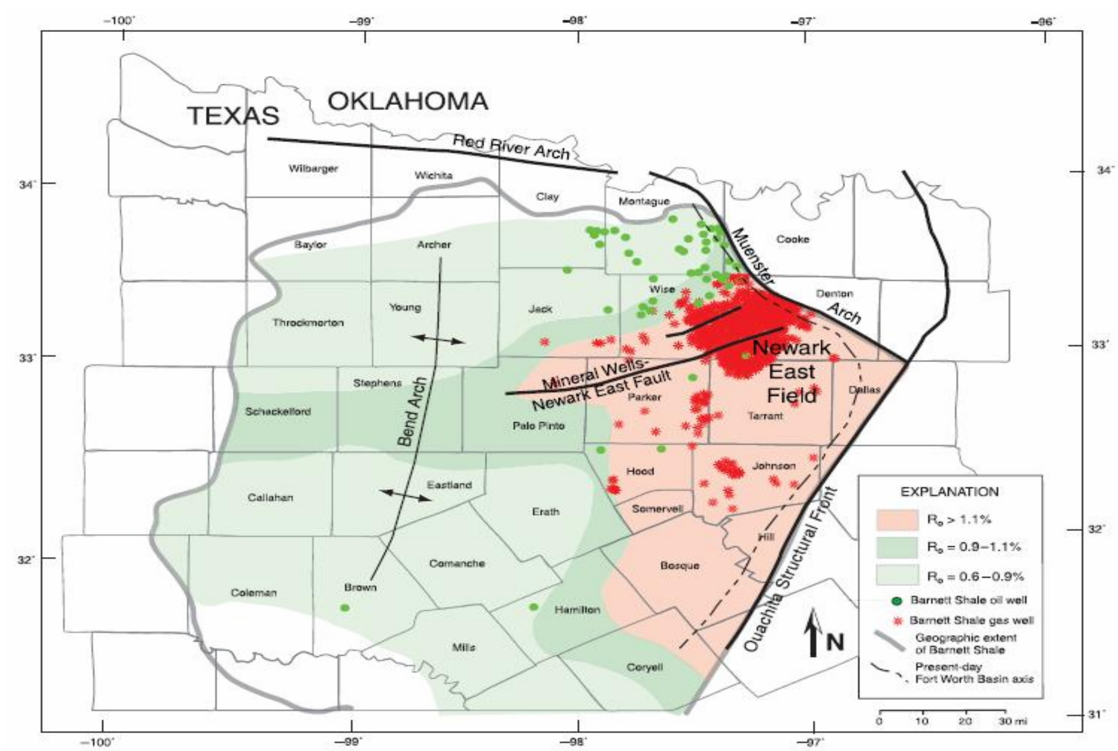


Figure 29: Barnett Shale Core Producing Region Shown in Red[33]

4.2 Study of Completions in Barnett Shale

Analysis presented here is subject to 2-3 % error per county as different databases report different number of wells. As one can see, Denton County is one of the most explored areas and can be considered as heart of Barnett shale region .Tarrant county completions activity mainly started in 2000 and most of the wells drilled by 2005 were horizontal wells as shown in Figure 30.

It is found that there are approximately 5082 active gas wells and 66 oil wells till May 2007 in core producing region of Barnett shale. Drilling took a giant leap in the years 2002-2003 (See, Figure 31) so field best 12 months production when plotted against date of first production shows a positive slope. It can be seen in figure 32, if a well is to produce 1 BCF of gas in 5 years, then it should have produced 37 MMCF of gas initially in first year. Figure 33 shows average monthly production rate for all the wells in the field over time. Average monthly production is calculated as ratio of total gas production each month over number of wells producing at that time. If the production curve is observed carefully, after 2000, production shows a steeper rise and then production goes down and becomes stable at year around 2005. This could be explained through chronology of the drilling in the field. Around 2000, horizontal wells just started getting drilled and we see a rise in the production. But production takes a dip after that probably attributable to the well interference and depletion. Later part of the curve shows production curve flattening which is really hard to analyze as there could be several reasons including wells getting drilled after 2005 may be in relatively fresher areas. One more interesting fact observed is, as majority of horizontal wells came on the production after 2000, average monthly production almost doubled. This phenomenon shows the success of horizontal wells over vertical wells. Chronology of the wells drilled in the area is presented in figure 35 below. Wise and Denton Counties had most of the early completions. It can be seen that drilling in Tarrant County started in 2002.

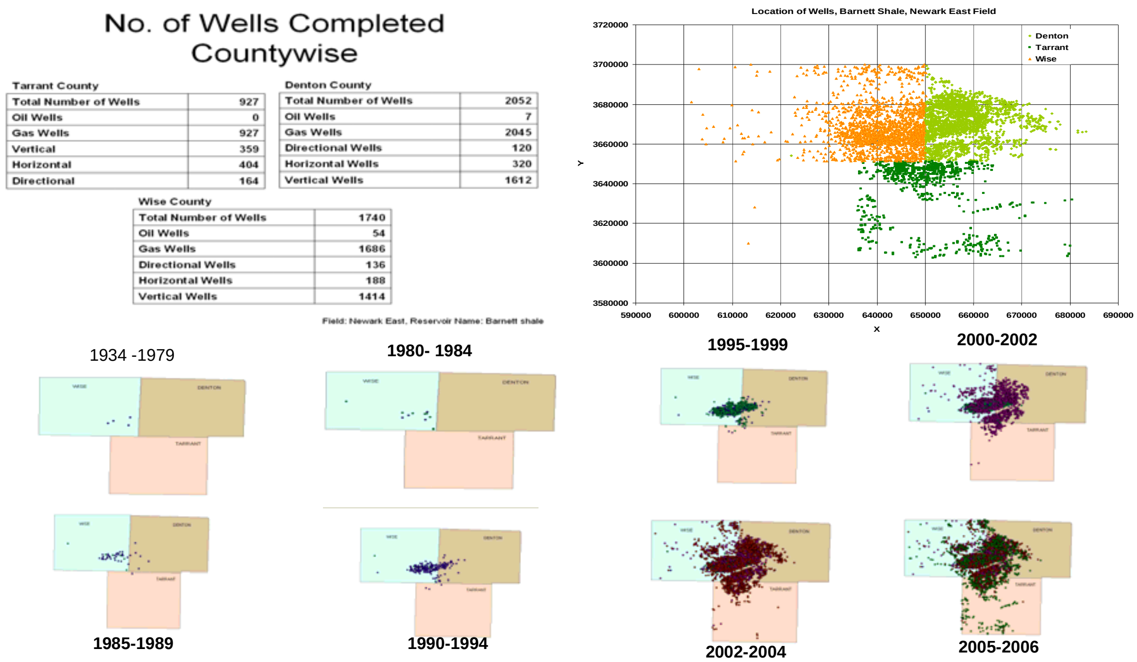


Figure 30: Overview of Three Counties and Number of Wells Drilled

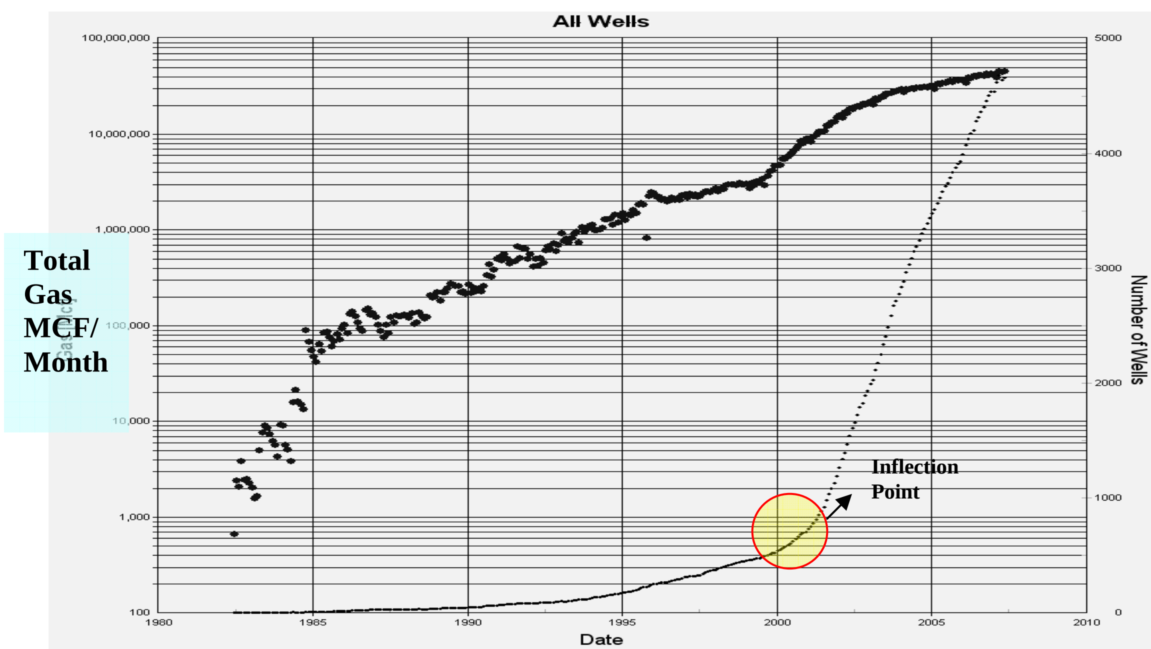


Figure 31: Number of Wells Drilled with Time and Total Gas Production of the Three Counties with Time

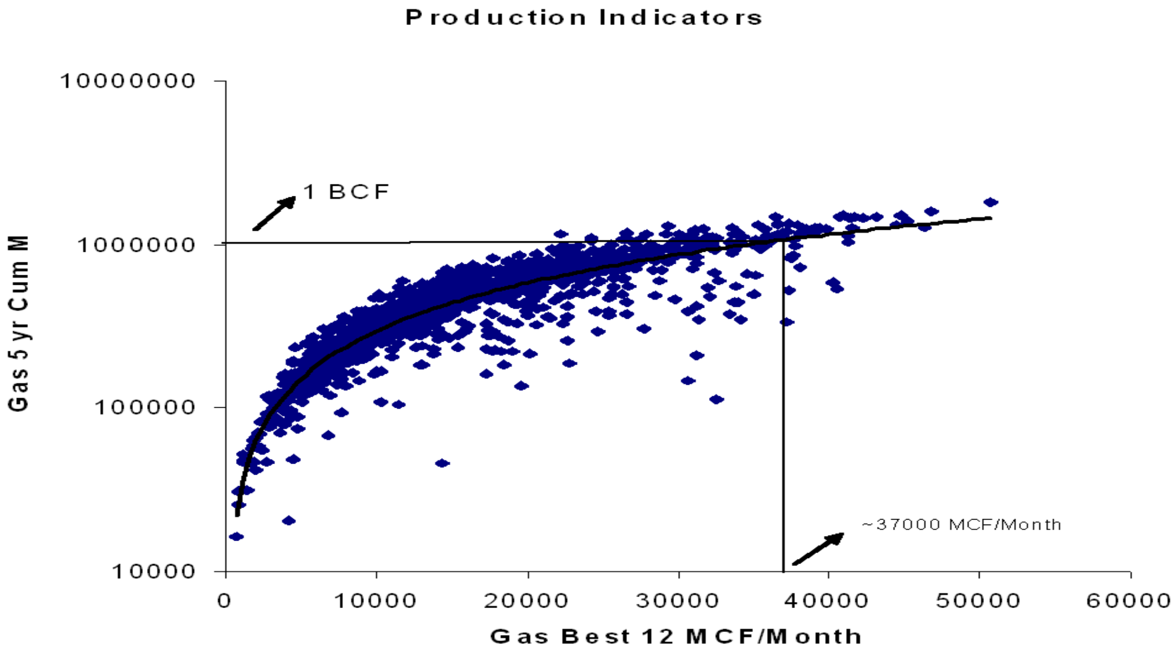


Figure 32: Gas Best 12 vs. Gas 5 yr cum Shows the Production Potential of Average Well

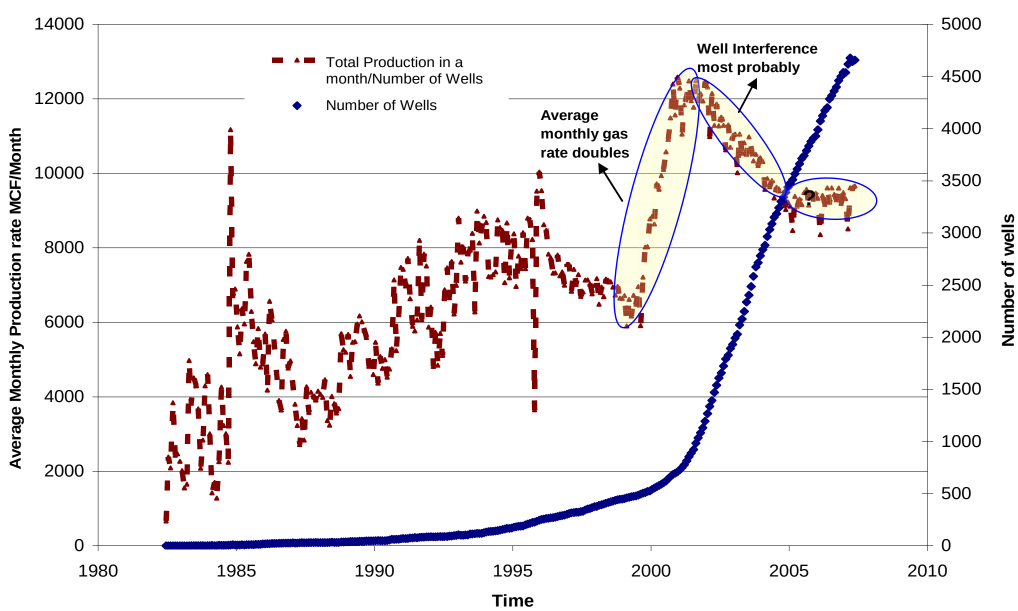


Figure 33: Zero Time Plot Barnett Shale Core Producing Region Average Monthly Gas Rate

Figure 34 below presents an interesting observation that wells completed after 2003 are largely successful and average monthly production of the wells is almost doubled. This is because of the huge rise in horizontal drilling activity in the area.

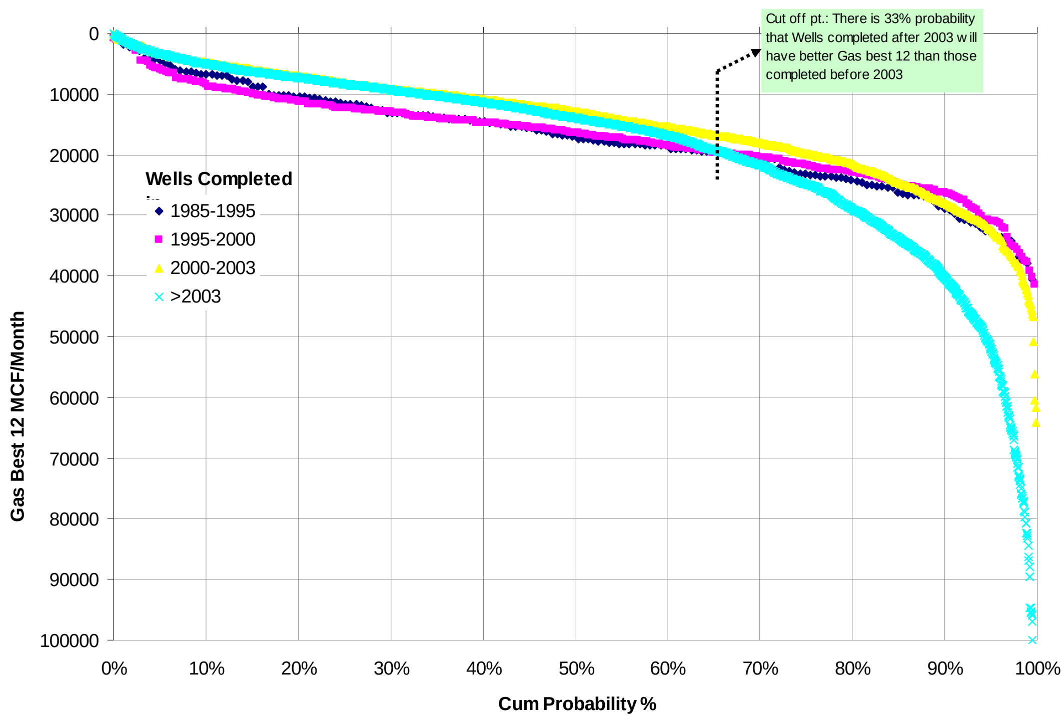


Figure 34: There is 33 % Probability That Wells Completed After 2003 Will Have Better Gas Best 12 than Those Completed Before 2003

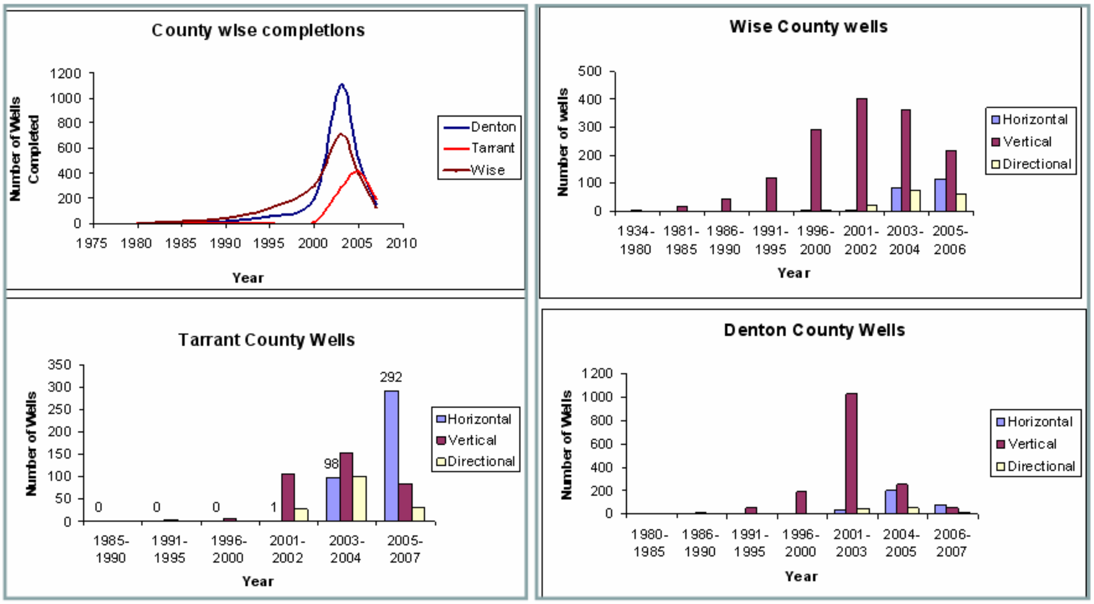


Figure 35: Number of Wells Completed in the Counties Year Wise

So moving domain analysis gives an overview of the whole field and its production potential. We can now focus on the individual counties. In figures 36 to 38, we can see how each county is producing over the years.

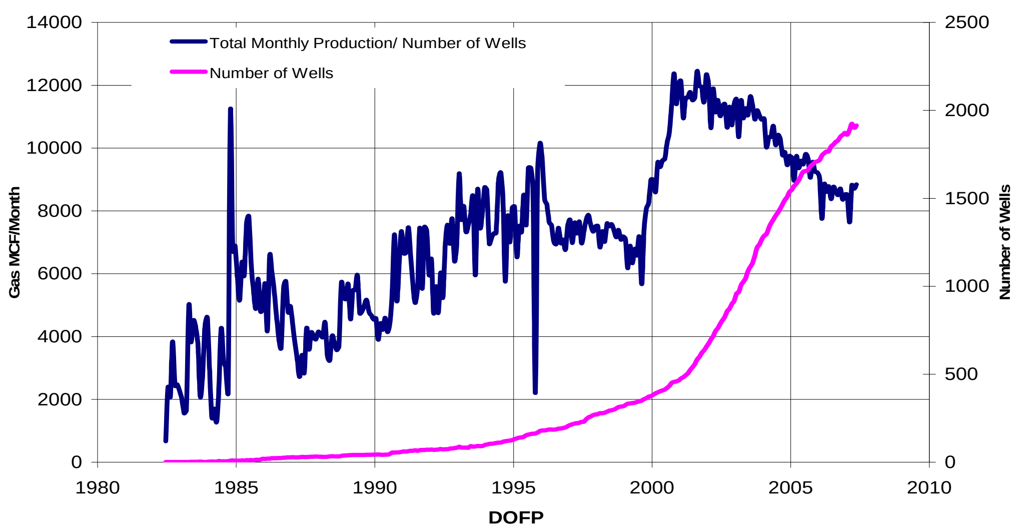


Figure 36: Wise County Average Monthly Production Field Curve

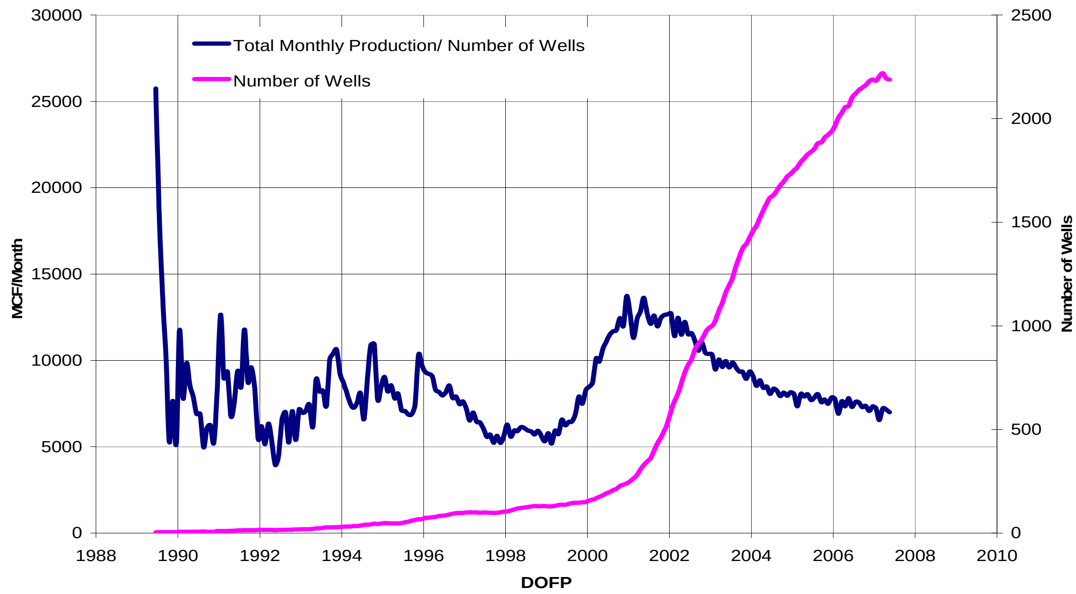


Figure 37: Denton County Average Monthly Production Field Curve

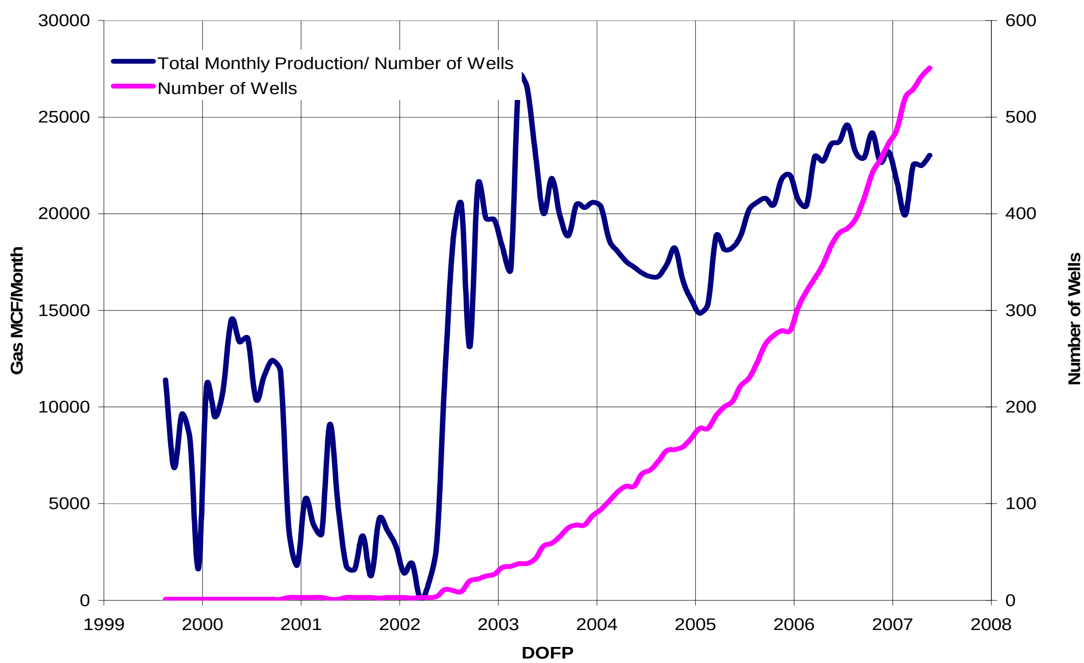


Figure 38: Tarrant County Average Monthly Field Production Curve

Above figures show that core producing region in the Barnett shale is on decline and declining steadily which means wells are showing pressure communication through this signature curve after 2001.

Left hand side of the plot is MCF/Day/per well. It is calculated as follows,

MCF/Day/Well= (Cumulative production of the Denton county as a whole with time)/ Number of wells on-line (producing) with time. Here per well average production is calculated as shown in Table 2,

Table 2: Example calculation of per well average production

Date	No. of wells producing	Field cumulative production(MMCF)	Per well avg, production
March 2005	750	120	120000/750
April 2005	755	130	130000/755
May 2005	765	150	150000/765
June 2005	800	160	160000/800

Here it can also be seen that average production in the counties is declining in a uniform manner which shows wells have established a pressure communication with each other.

4.3 Grouping of the Wells

After examining how the individual counties are behaving, behavior of particular group of wells remains to be seen. Grouping of wells is done based on thermal maturity contour map and whole Barnett shale isopach map of the core producing region. Contour map presented in “AAPG April 2007” issue dedicated to Barnett Shale is shown in Figure 39.

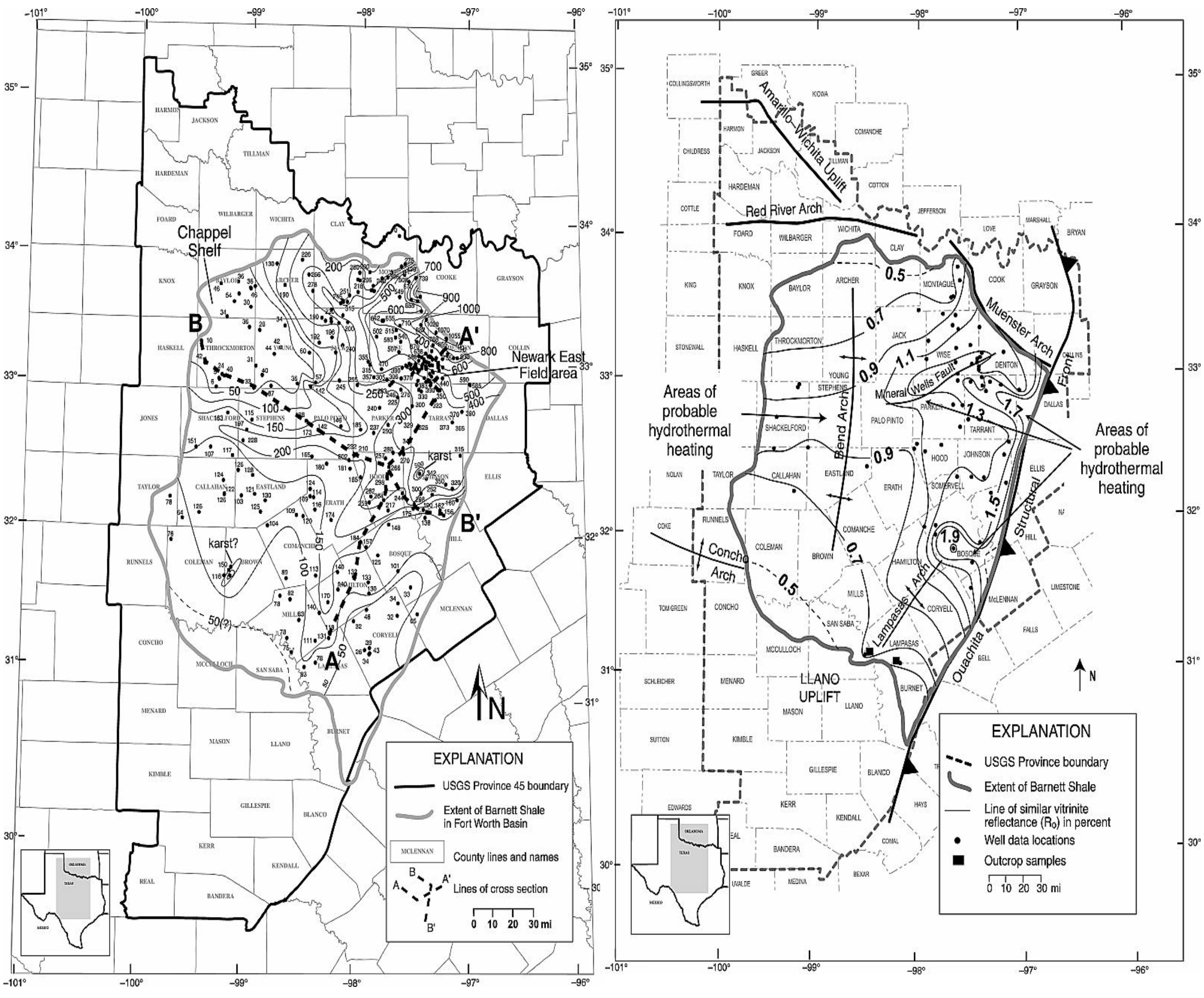


Figure 39: Left, Generalized Isopach Map of the Barnett Shale[31] from Pollastro et al Right, Equal Thermal Maturity Map for Barnett Shale[29] from Pollastro et al

We divided the entire region into 26 different parts. Every region has a different combination of thermal maturity value and thickness of shale value. Figure 40 below represents the actual divisions of the core producing region. This map was created after digitizing the original contour map from the AAPG paper mentioned above. Strategy is to see effect of thermal maturity on production of the wells. Evaluating effect of thermal maturity on individual well production profile would be rather difficult so grouping the wells is considered right strategy. Production of the wells in these regions is averaged by taking ratio of cum production of the wells and number of productive months of each well. It is interesting to see which property is affecting gas production.

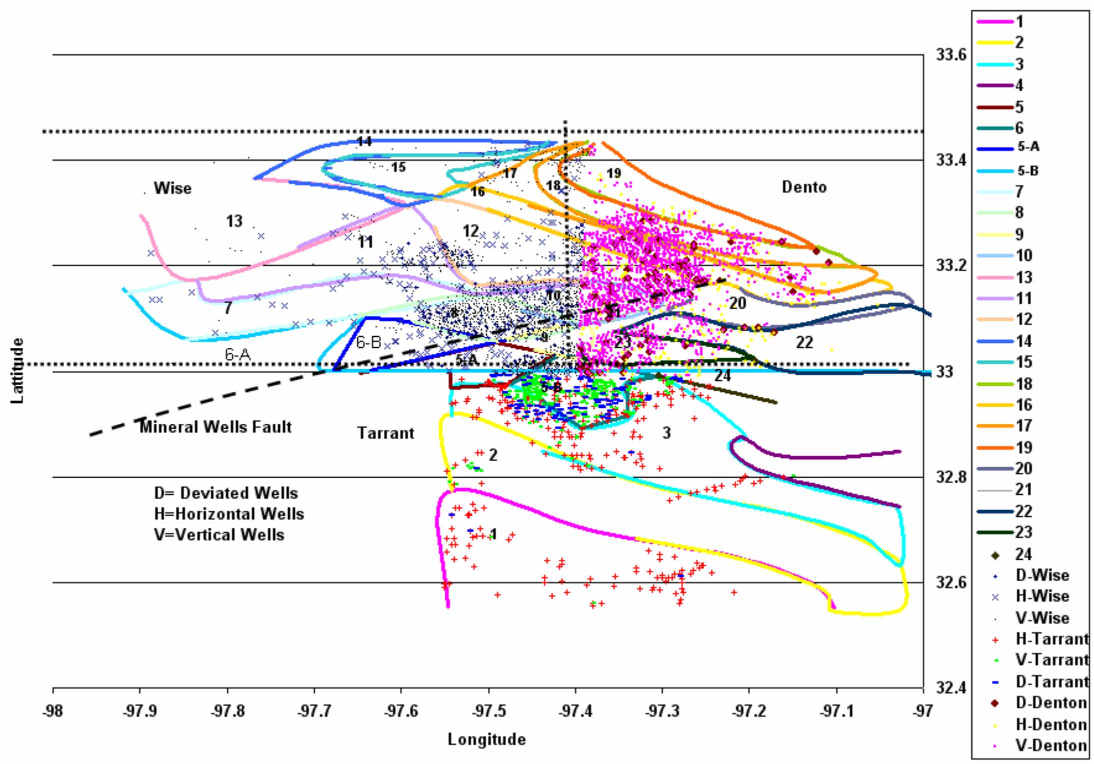


Figure 40: Grouping of Wells According to Their Thermal Maturity and Thickness

Thickness of the region varies from 325 ft to 1000 ft thick shale. Isopach map referred here takes into account upper and lower Barnett shale thickness together. Thermal maturity or vitrinite reflectance (% Ro) ranges from 1.0 to 1.8 in the region. (See Table 3)

Table 3: Details of thermal maturity and shale thickness in each region in the three counties

Region	Thermal Maturity* Ro%	Thickness ft	Maturity/Thickness	(Maturity/Thickness) *1000
1	1.2	325	0.0036923	3.692307692
7	1.2	450	0.0026667	2.666666667
11	1.2	550	0.0021818	2.181818182
12	1.2	650	0.0018462	1.846153846
16	1.2	750	0.0016	1.6
17	1.2	850	0.0014118	1.411764706
18	1.2	950	0.0012632	1.263157895
19	1.2	1000	0.0012	1.2
20	1.2	650	0.0018462	1.846153846
22	1.2	550	0.0021818	2.181818182
23	1.2	450	0.0026667	2.666666667
2	1.4	350	0.004	4
5-A	1.4	350	0.004	4
5-B	1.4	350	0.004	4
6-B	1.4	350	0.004	4
6-A	1.4	350	0.004	4
8	1.4	450	0.0031111	3.111111111
10	1.4	550	0.0025455	2.545454545
21	1.4	550	0.0025455	2.545454545
9	1.4	450	0.0031111	3.111111111
24	1.4	450	0.0031111	3.111111111
3	1.6	350	0.0045714	4.571428571
4	1.8	350	0.0051429	5.142857143
13	1	550	0.0018182	1.818181818
14	1	650	0.0015385	1.538461538
15	1	750	0.0013333	1.333333333

*= Values are averaged for simplifying purpose. Original maturity values are reported in the ranges eg. 1.1-1.3 or 1.5-1.7

4.4 Results and Discussion

Figure 41 shows effect of thermal maturity on the production. It can be inferred that thermal maturity is of greater importance than the thickness of the shale underlying.

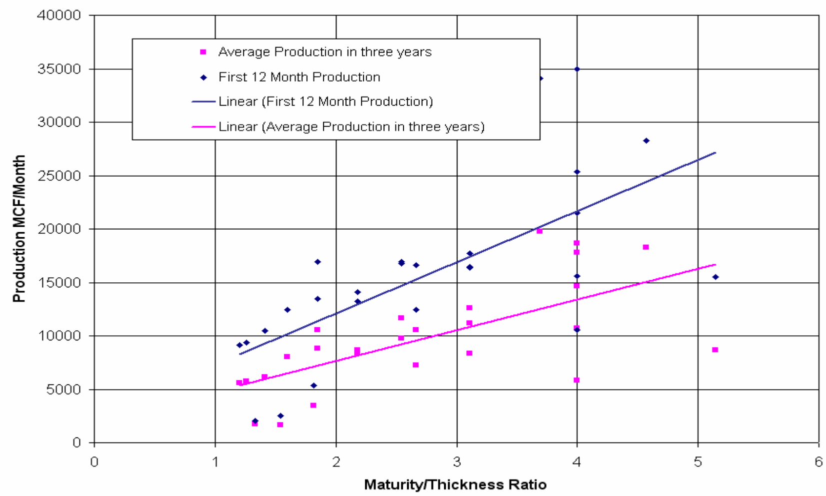


Figure 41: Effect of Thermal Maturity/Thickness Ratio on Average Production of the Well

If effect of thermal maturity is to be seen individually, it is shown in figure 42 below. We can see as thermal maturity increases there is an increase in the production. Average production values are calculated again based on cum production of the well divided by its number of productive days.

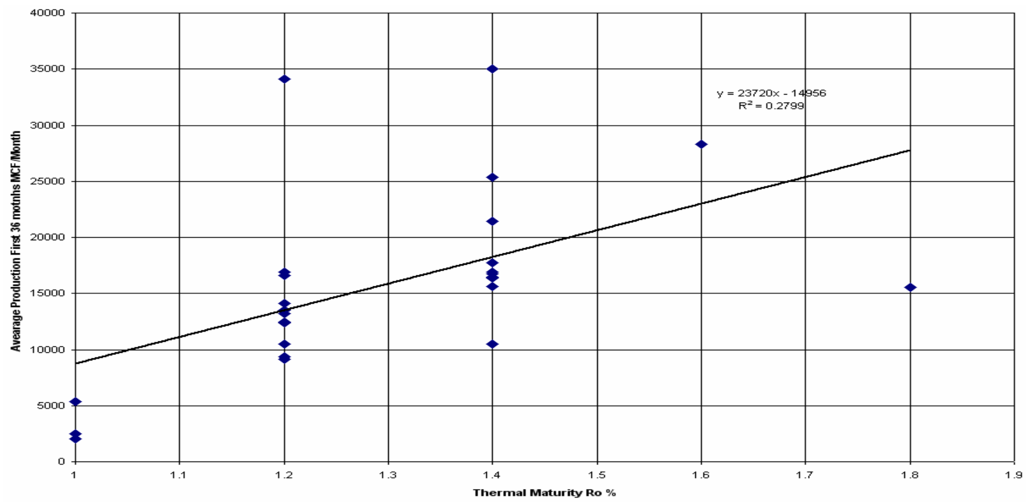


Figure 42: Increase in the Average Production of the Well is seen with Increase in the Thermal Maturity of the Region

4.5 EUR Type Curve Study of the Barnett Shale Region

This work uses bootstrap method objectively. We have grouped all wells into five categories based on their Gas best 12 values. Production data for all the wells in a particular group are averaged. For example, Wells having their gas best 12 more than 100 MMCF/Month are in one group. A sample size is selected from each and production data for all wells in the sample size are averaged out. So finally we get one production dataset representative of the whole group. Then we have run the bootstrap program to fit a decline to the dataset which gives us values of Decline analysis parameters such as Qi, De and EUR after 10 years for that particular group as shown in Table 4. So method is combination of deterministic and probabilistic method. Instead of running bootstrap method on all the wells which will be county wise grouping scheme of the EUR, one can get deterministic values of EUR for the whole Barnett shale field sample based on their production potential.

To study EUR type curves in the field, Wells were classified according to their Gas Best 12 month production into five classes from highest to lowest producers in the field(Refer, Figure 43). Groups

3, 4 and 5 were studied for a sample size of wells which were drilled between 2003 & 2004. Type curves were identified from these classes. Boot Strap method is used for predicting future rates and identifying decline curve analysis parameters. Decline analysis parameters are listed in table 3. Refrac or well shut in could result in erroneous forecast. So EUR type curves mentioned here are strictly on the basis of condition that well is produced under constant operating conditions.

After studying all the production rate- time curves for these 5 classes, average EUR[34, 35] type are plotted as shown in figure 44. A bootstrap decline analysis parameters program is used to fit the decline curve to the production data.

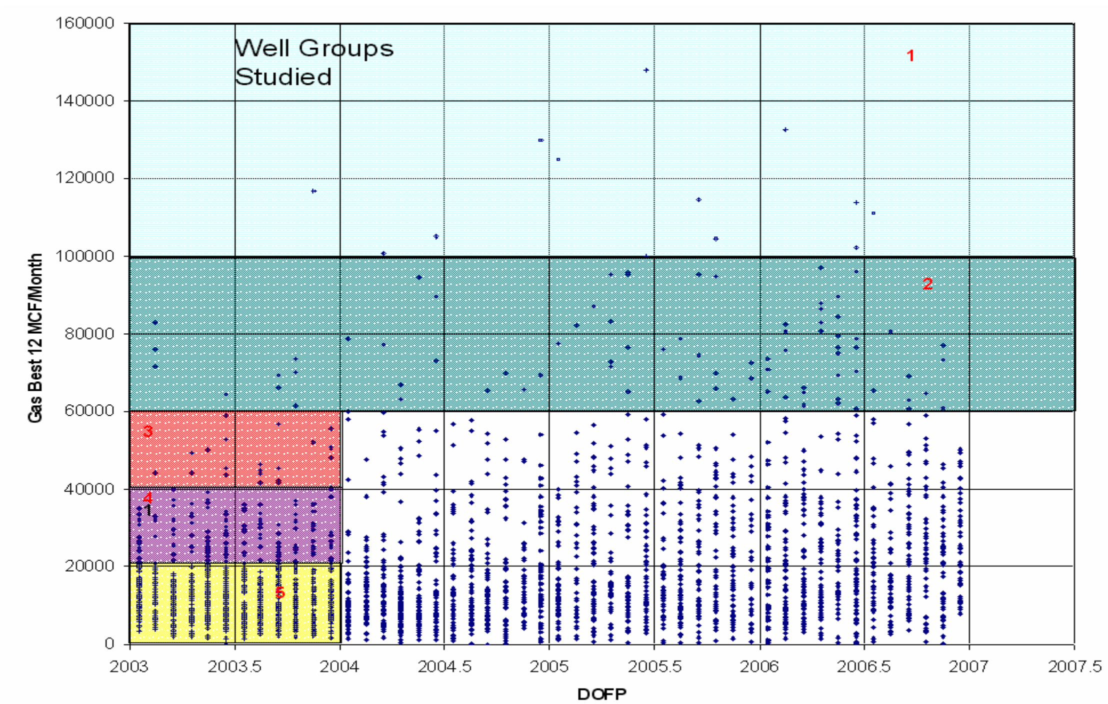


Figure 43: Grouping of Wells According to the Best 12 Month Production of the Wells

Table 4: Details of DCA Parameters for Five Groups According to their Gas Best 12 MCF/Month

Class	**Gas Best 12 (MCF/Month)**	**b**	**Effective Decline De % /year**	**Q_i MCF**	**EUR /Well* after 10 years (BCF)**
1	>100000	0.9974	7.5189	158976.1751	6.012
2	60000-10000	1.142807138	6.4616	98593.44443	3.675
3	40000-60000	1.411012775	5.7016	67846.14191	2.521
4	20000-40000	1.593	5.2287	41008.56176	1.091
5	0-20000	2	4.188	18776.93938	0.7

*= EUR is calculated using traditional harmonic decline curve method.

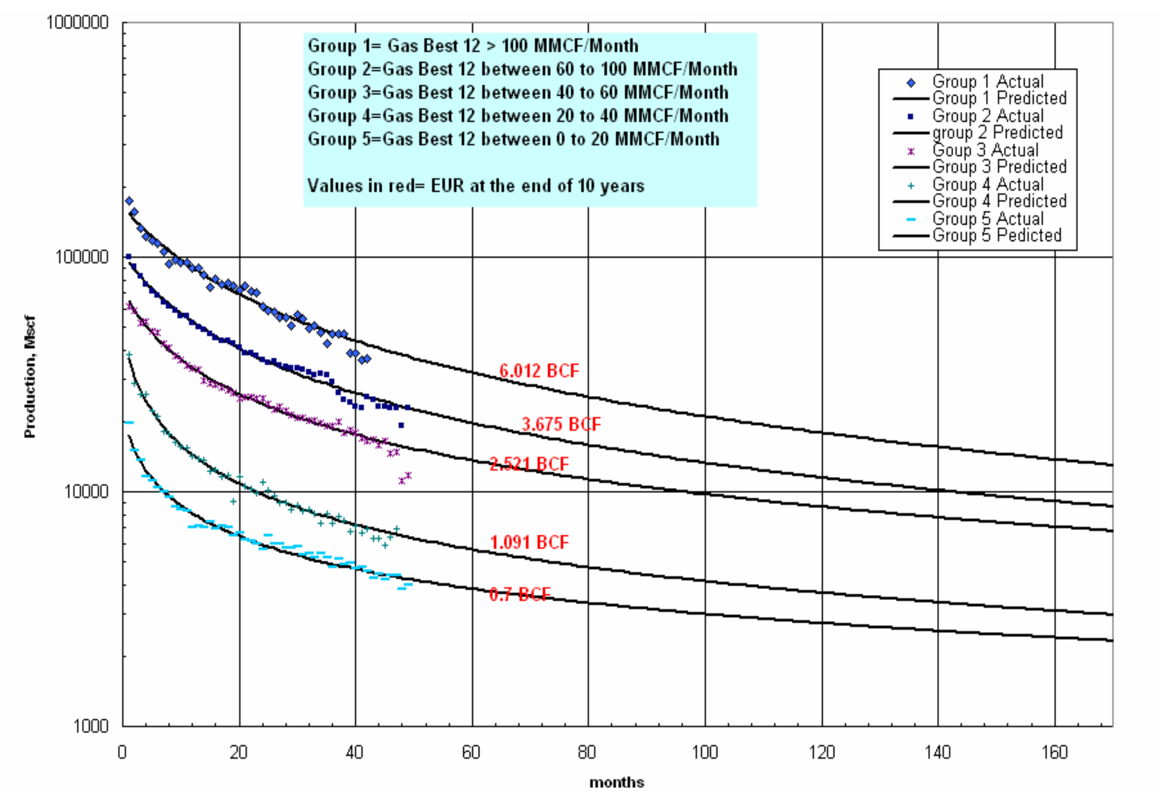


Figure 44: EUR Type Curves for Wells with Different Gas Best 12 Productions

4.6 Statistical Analysis of the Completions

Wise County completion data analysis is presented here. Scout tickets for all the wells are made available by IHS Energy. Only horizontal completions are analyzed as focus was more on optimum number of frac stages and optimum lateral length in the county.

Total Horizontal wells in Wise County= 188

Total Horizontal wells in Wise County Producing Gas= 180

Total Horizontal wells in Wise County Producing Gas analyzed= 173 (Data for 7 wells is missing in Scout tickets provided)

MCF/Day = Cum Gas Per well/ Number of producing days

Number shown here as MCF/Day is average of respective number of data points

For example, for stage 1, Average production was found to be average of MCF/Day of 78 wells.

No of wells with 1 Stage= 78

No of Wells with 2 Stages = 55

No of Wells with 3 Stages = 22

No of Wells with 4 Stages = 11

No of Wells with 5 Stages = 8

Figures 45 and 46 show a statistical analysis of lateral lengths and number of frac stages of the wells in Wise County. Lateral length is calculated using N/S- E/W offset of the wells. This analysis is strictly statistical and wells with more than 4 or 5 frac stages showing less production could be attributed to number of factors such as sample size being small or failure of treatment or wells being drilled in the depleted zones or less thermally mature zones. This analysis hints that wells with lateral length of 3000-3500 ft and 3 frac stages are better producers in Wise County.

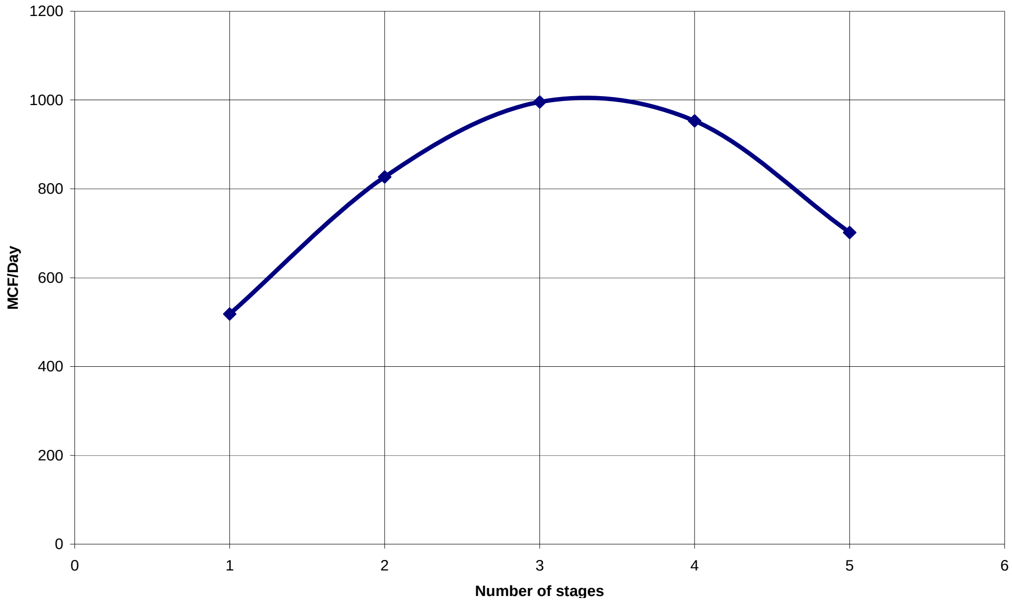


Figure 45: Lateral Length vs. Average Production of the Well in Wise County

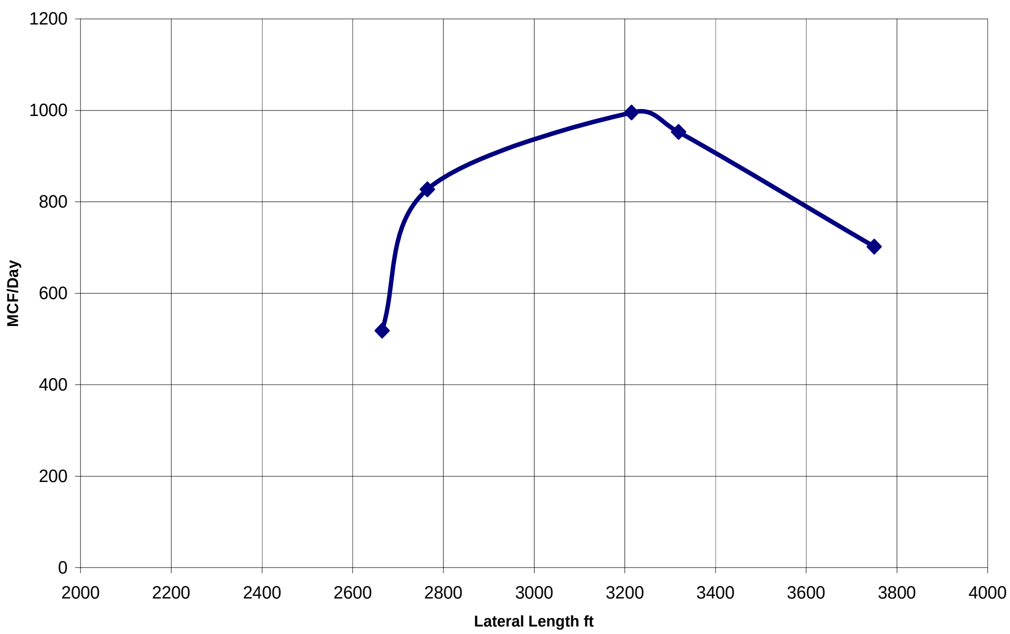


Figure 46: Number of Frac Stages vs. Average Production of the Well in Wise County

4.7 Database Development for Future Studies

Database of all Barnett shale core producing region wells is built in MS-Access. A user friendly form is built which classifies all the wells production data according to their leases. Methodology adopted here is every county has multiple numbers of leases on it. Every lease has single or multiple numbers of wells on it. This could help in future studies as leases could be studied individually and choosing sample size with minimum variations in the reservoir quality would become easier. Screenshot of the user interface is shown in Figure 47. Rate- Time Curve could be seen for all the wells on a particular lease. Also drill type of these wells could be seen on the pivot chart as shown in Figure 48. This could immensely help future studies on Barnett Shale core producing region, as wells could be studied lease wise and their production data is readily available with their completion type.

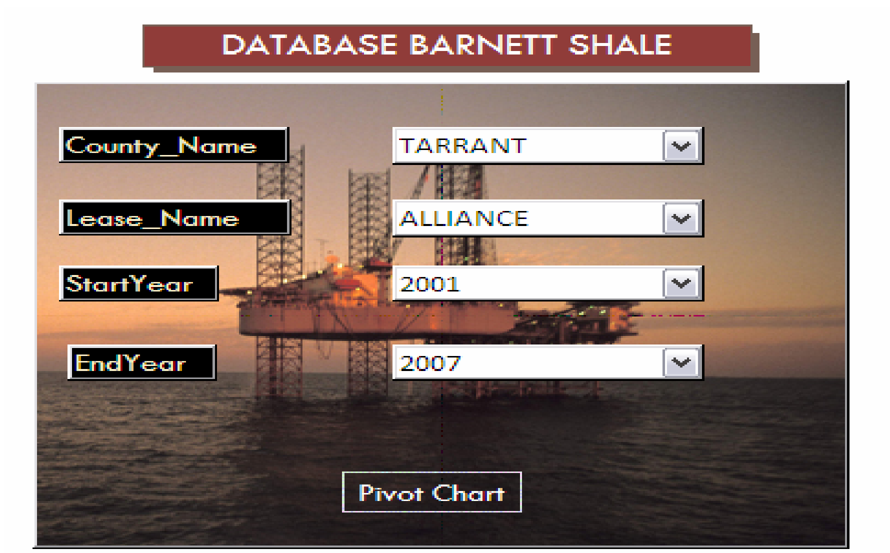


Figure 47: Example Screenshot of the Database Built in MS-Access ™

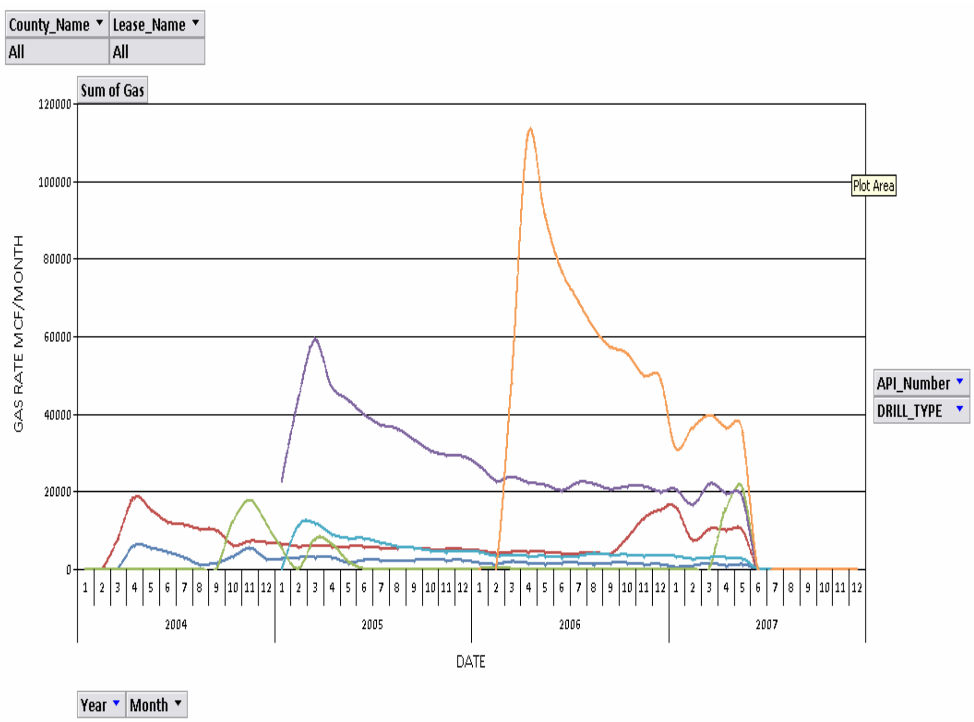


Figure 48: Sample Lease Production Graph during a Specific Period of Time

4.8 Comparison between Production Behavior of Vertical and Horizontal Wells

Using the above mentioned tool, we can compare production from wells with different completions. For example, vertical wells production can be differentiated from horizontal well which starts producing at the same time and which is on the same lease. Production behavior could be attributed to the specific completion type assuming all other reservoir properties are same. Below are some of the examples from all three different counties.

Purpose of the plots in Figures 49-51 is to show how the horizontal wells are behaving compared to vertical wells or deviated wells. Name of the lease is not disclosed for the proprietary purposes. It is observed that horizontal wells produce 3-4 times higher than the vertical wells which are on the same lease and which are completed at the same time. Reservoir properties could be directly attributed to the behavior of the wells presented here.

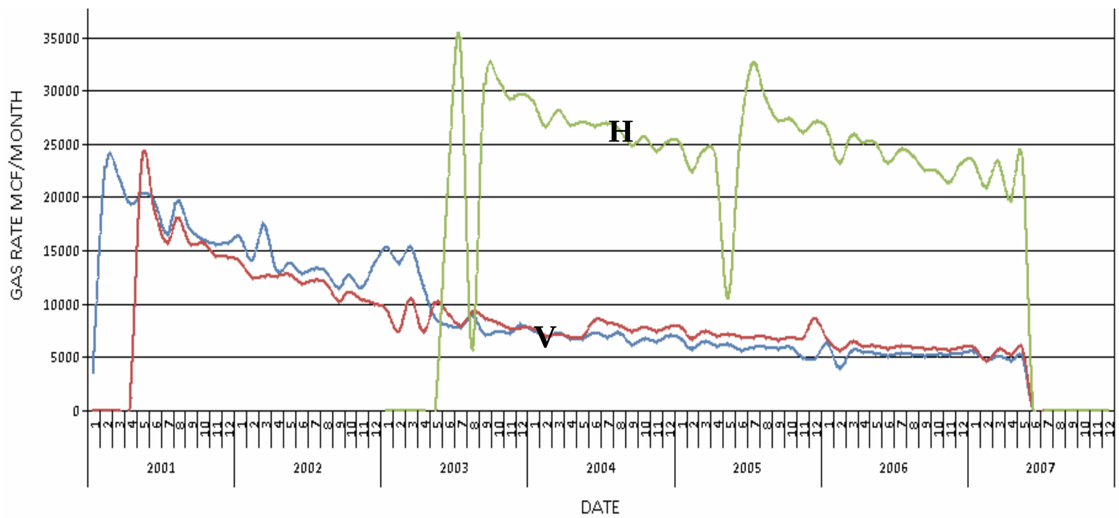


Figure 49: Sample Lease Production in Denton County during a Specific Period of Time

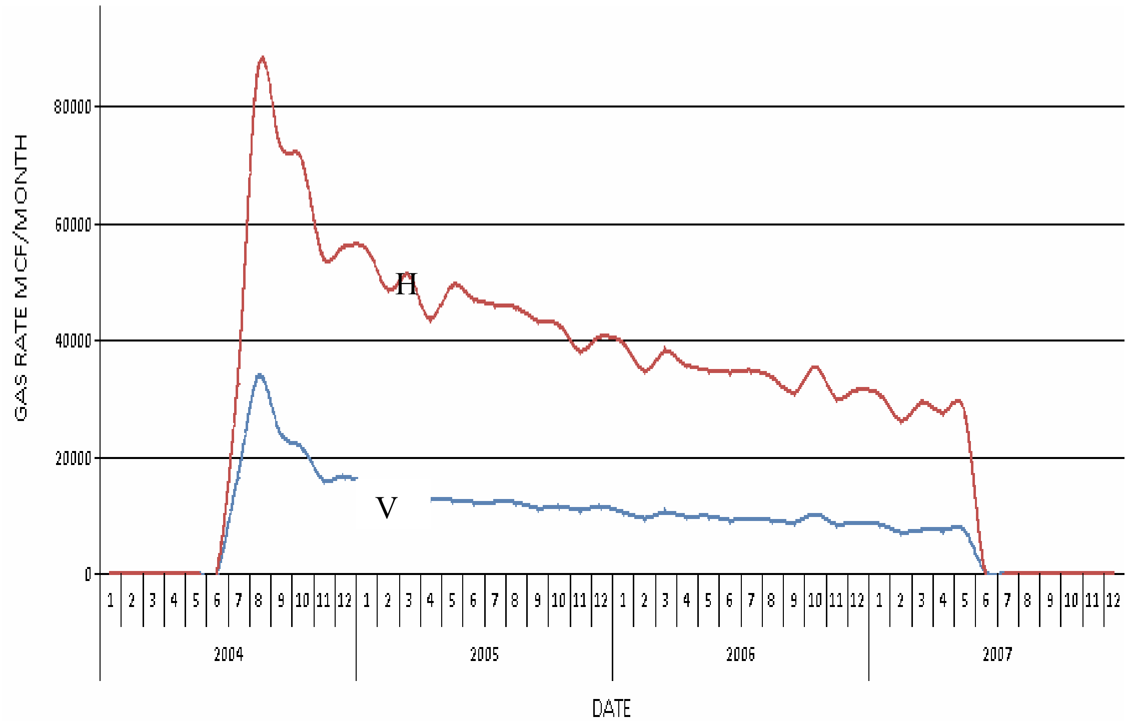


Figure 49: Continued

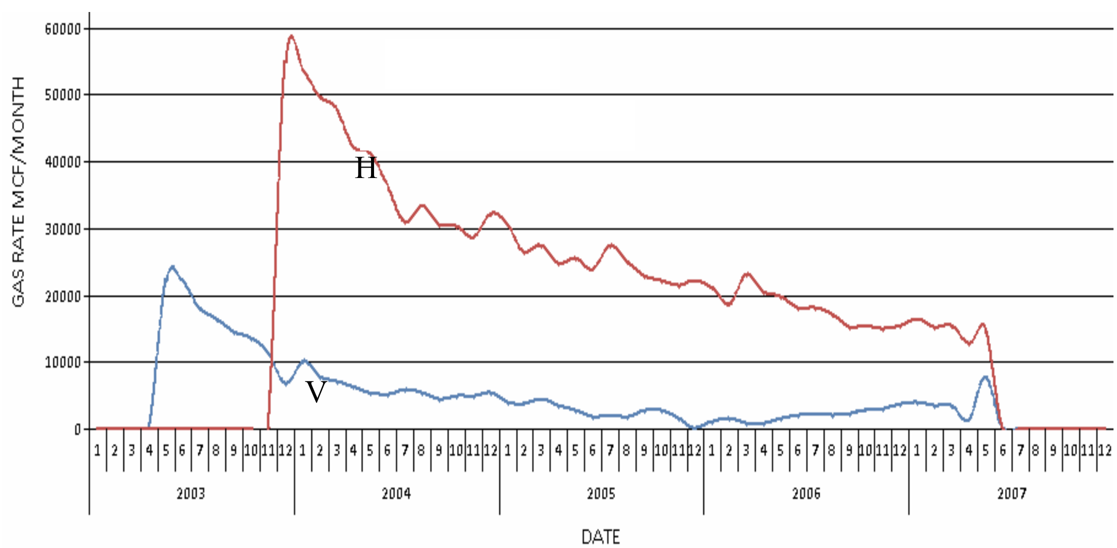


Figure 50: Sample Lease Production in Tarrant County during a Specific Period of Time

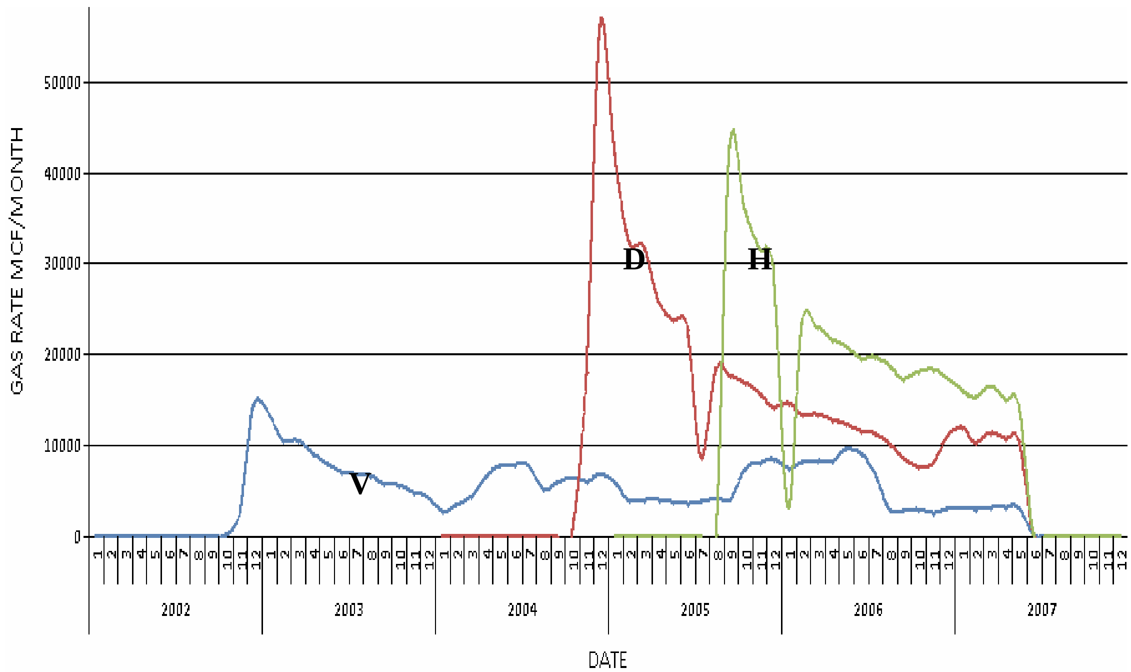


Figure 50: Continued

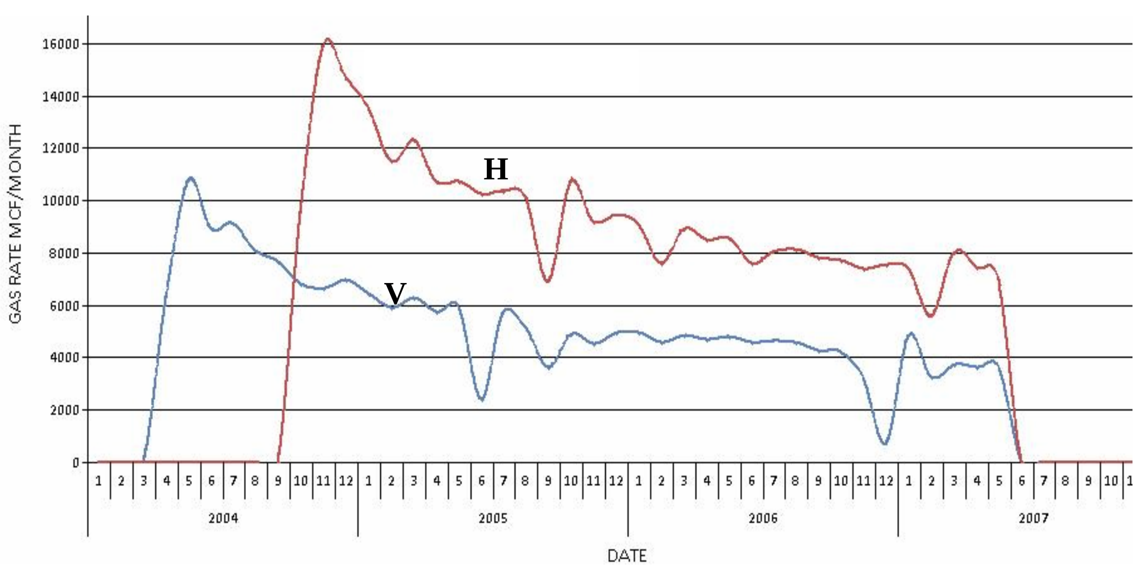


Figure 51: Sample Lease Production in Wise County during a Specific Period of Time

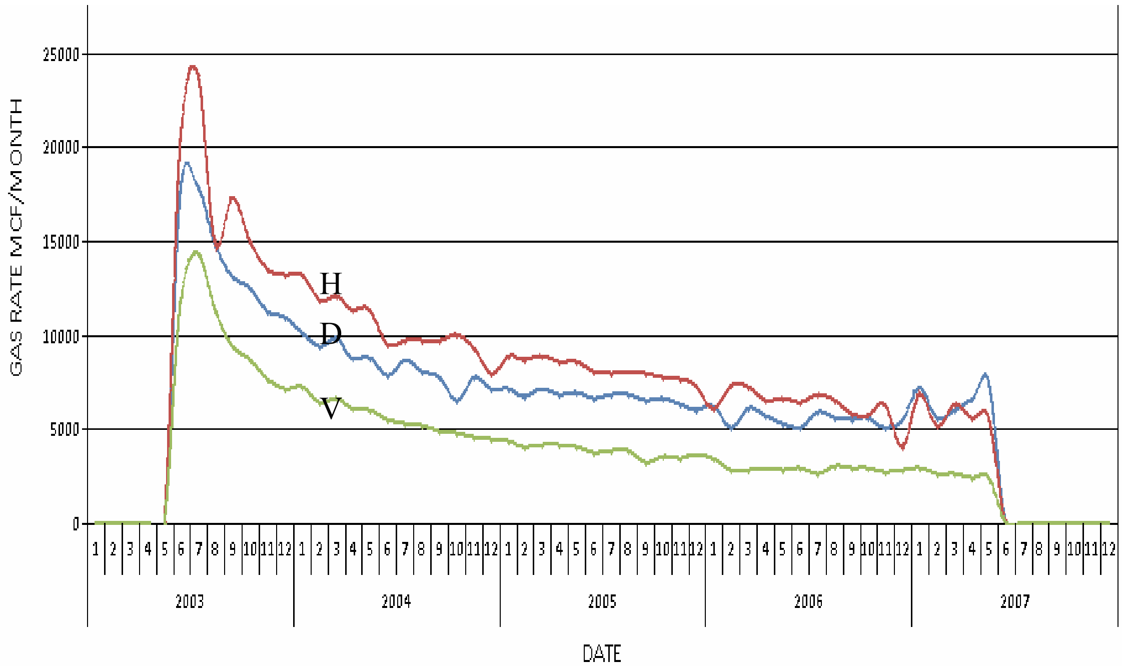


Figure 51: Continued

CHAPTER V

CONCLUSIONS/RECOMMENDATIONS

It could be concluded from the work presented here that most important properties which decide whether a shale gas play is potentially productive or not are thermal maturity (Ro %), TOC (%) range and Gas content (cubic ft/ton) of the shale. Other conclusions are as follows,

1. Shale gas reservoirs can be classified into two main groups based on their gas storage mechanisms. If adsorption is the dominant phenomenon, then shale gas reservoir behaves like a coal bed methane reservoir with large water production initially. While fracture-matrix interaction could be another type of gas storage mechanism where adsorption is secondary phenomenon.

2. Hydraulic fracturing stimulation treatment success depends on the natural fracture severity in the region, mineralogy of the shale, stress orientation in the region and available technology for isolating fractured zones.

3. Barnett shale core producing region production data is analyzed using moving domain analysis method. Horizontal wells are more successful in these counties than vertical wells.

4. When the wells were grouped according to the shale thickness and thermal maturity f the region, it is seen that thermal maturity takes precedence over thickness of the shale, which is an important finding. Effect of other properties on the production could be found using similar strategy.

5. It is observed that average production throughout the life of a horizontal well is 3-4 times the vertical well in Barnett shale formation.

6. Effect of completions on production could be studied by studying different leases separately using the database developed here.

It is recommended that,

1. Study of completions could be continued in other two counties namely, Denton and Tarrant counties which could not be covered in this thesis because of time limitations. A conclusive result could be obtained as far as lateral length and lateral stages are concerned.
2. Production of oil and water has not been given much consideration in this work as Gas is treated as primary product. Threshold of thermal maturity with which economic amount of gas could be produced is something operators in the area would be interested in knowing.
3. Decline curves in the region showing sharp declines initially and then declining at a very minimal rate could be because of the fracture offloading and matrix desorption in the later life of the well. This concept could be utilized for developing a predictive tool for Barnett shale.
4. Predictive tool development for Barnett shale will require formation evaluation and well logs must be made available for future studies. Leases mentioned in this thesis can be used as an excellent sample to further understanding of reservoir properties.
5. One more research area of interest would be modification to the currently available packer systems which can work in open hole horizontal wellbore to provide better zonal isolation during hydraulic fracturing of the horizontal wellbore. Cemented laterals are proving to be bad choice for fracturing as they might clog the natural fracture openings and restrict flow to the wellbore in low perm environment.

NOMENCLATURE

H	Horizontal Well
V	Vertical Well
D	Deviated Well
Gas DOFP	The mid-month date gas production began in decimal year format. For example, a well that began producing gas in January 1995 would have a Gas_DOFP equal to 1995 years + (1/12 – 0.5/12) months or 1995.0417. If there is no monthly gas production, the default value is equal to 0.
Gas Best 12	Average monthly gas rate during the best 12 consecutive months (examples 1 and 2). Months with zero gas production are included in the consecutive Months.

REFERENCES

1. Faraj, B., Williams, H., Addison, G., McKinstry, B.: "Gas Potential of Selected Shale Formations in the Western Canadian Sedimentary Basin," *Gas TIPS* (Winter 2004), p.21-25.
2. Bustin, R.M.: "Gas Shale Tapped for Big Pay," *AAPG Explorer*, **26**,(2) Feb. 2005, p.30.
3. Ausubel, J.H.: "Can Technology Spare the Earth?" *American Scientist* (March/April 1996), Volume 84, p. 166-178.
4. "Putting Energy in the Spotlight" *BP Statistical Review of World Energy*, (June 2005), p.5.
5. "Balancing Natural Gas Policy", *National Petroleum Council*, (September 2003), p. 34.
6. Perry, K.P.: "Unconventional Gas Focus Group", Gas Technology Institute Presentation (September 2002).
7. Hill, D.G., and Nelson, C.R.: "Gas Productive Fractured Shales: An Overview and Update," *Gas TIPS* (Summer 2000), p. 4-13.
8. Schlumberger Oilfield Glossary, "Vitrinite Reflectance", http://www.schlumberger.com, 22 October, 2006.
9. Ayers, W.B. Jr.: *PETE 612: Unconventional Reservoirs Course Notes,* Texas A&M University (Fall 2005).
10. Law, B.E.: "Basin-centered Gas Systems," *AAPG Bulletin* (November 2002), **86**, (11), p. 1891-1919.
11. Schenk, C.J., and Pollastro, R.M.: "Nat 0113-01 Gas Production in the United States," *U.S. Geological Survey Fact Sheet* (January 2002), 0113-01.
12. Nelson, R.A.: *Geologic Analysis of Naturally Fractured Reservoirs,* 2nd Edition, Gulf Publishing Co. Book Division, Houston (2001).
13. Yacobucci, M.M.: "Field Trip to the Devonian Dundee Formation, Whitehouse OH," *http://geology.bgsu.edu/Yacobucci/Geol_415_515/Whitehouse.htm*.
14. Klemme, H.D., and Ulmishek, G.F: "Effective Petroleum Source Rocks of the World: Stratigraphic Distribution and Controlling Depositional Factors" *AAPG Bulletin* (December 1991), **75**,(12),p. 1809-1851.

15. DeWitt, W. Jr., Roen, J.B., and Wallace, L.G.: "Stratigraphy of Devonian Black Shales and Associated Rocks in the Appalachian Basin," *Petroleum Geology of the Devonian and Mississippian Black Shale of Eastern North America*, *U.S. Geological Survey Bulletin 1909* (1993), p. B1–B57.

16. Curtis, J.B.: "Fractured Shale-Gas Systems," *AAPG Bulletin* (November 2002), **86**, (11), pp. 1921-1938.

17. Jochen, J.E. and Lancaster, D.E.: "Reservoir Characterization of an Eastern Kentucky Devonian Shales Well Using a Naturally Fractured, Layered Description," SPE Paper 26192, presented at the 1993 SPE Gas Technology Symposium, Calgary, Alberta, Canada, June 28-30.

18. Kubik, W., and Lowry, P.: "Fracture Identification and Characterization Using Cores, FMS, CAST, and Borehole Camera: Devonian Shale, Pike County, Kentucky," SPE Paper 25897, presented at the 1993 SPE Rocky Mountains Regional/Low Permeability Reservoirs Symposium, Denver, CO, April 12-14.

19. Gutschick, R. C., and Sandberg, C.A., 1991, Late Devonian History of the Michigan Basin, in Catacosinos, P.A., and Daniels, P.A., Jr., (eds.), *Early Sedimentary Evolution of the Michigan Basin: Geological Society of America Special Paper 256*, p. 181–202.

20. Martini, A.M., Budal, J.M., Walter, L.M., and M. Schoell: "Microbial Generation of Economic Accumulations of Methane within a Shallow Organic-rich Shale," Nature, 12 September 1996.

21. Kuuskraa, V. A., Wicks, D. E., and Thurber, J. L.; "Geologic and Reservoir Mechanisms Controlling Gas Recovery from the Antrim Shale," paper SPE 24883 presented at the 1992 SPE ATCE, Washington, D.C., October 4-7.

22. Zuber, M.D., Williamson, J.R., Hill, D.G., Sawyer, W.K., and Frantz, J.H.: "A Comprehensive Reservoir Evaluation of a Shale Gas Reservoir – The New Albany Shale," Paper SPE 77469, presented at the 2002 Annual Technical Conference and Exhibition, San Antonio, TX, September 20 – October 2.

23. Montgomery, S.L., Jarvie,D.M. , Bowker K.A., and Pollastro, R.M., "Mississippian Barnett Shale, Fort Worth Basin, North-central Texas: Gas-Shale Play with Multi–trillion Cubic Foot Potential", Paper *AAPG Bulletin*, **89**, (2) pp 155-175.

24. Texas Railroad Commission, "Production Data Query" http://webapps.rrc.state.tx.us/PDQ/, 5 December 2005.

25. Frantz, J.H., Waters G.A., and Jochen V.A.: "Evaluating Barnett Shale Production Performance Using an Integrated Approach," paper SPE 96917 presented at the 2005 SPE ATCE, Dallas, TX, October 9-12.

26. Selley Richard C., *Elements of Petroleum Geology*, Chapter 6, 2nd Edition, Academic Press, London (1998), p. 268-269.

27. Barker, C. "Aquathermal Pressurizing: Role of Temperature in Development of Abnormal Pressure Zones," paper *AAPG Bulletin,* (October 1972), **65**, (10), p. 2068-2071.

28. Hopkins, C.W., Rosen R.L., and Hill D.G.: "Characterization of an Induced Hydraulic Fracture Completion in a Naturally Fractured Antrim Shale Reservoir," paper SPE 51068 presented at the 1998 SPE Eastern Regional Meeting, Pittsburgh, Pennsylvania, November 9-11.

29. Lancaster, D.E, McKetta, S.F, Hill, R.E., Guidry, F.K., Jochen, J. E.: "Reservoir Evaluation, Completion Techniques, and Recent Results from Barnett Shale Development in the Fort Worth Basin," paper SPE 24884 presented at the 1992 SPE ATCE, Washington, D.C., October 4-7.

30. Blanton, T.L.: "Propagation of Hydraulically and Dynamically Induced Fractures in Naturally Fractured Reservoirs," paper SPE 15261 presented at the 1986 Unconventional Gas Technology Symposium, Louisville, May 18-21.

31. Warpinski R. N., Kramm R. C., Heinze R. J., and Waltman K. C.: "Comparison of Single and Dual-Array Microseismic Mapping Techniques in the Barnett Shale," paper SPE 95568 presented at the 2005 Annual Technical Conference and Exhibition, Dallas, Texas, 9-12 October.

32. Cipolla C.L., Wood M.C.: "A Statistical Approach to Infill Drilling Studies: Case History of the Ozona Canyon Sands ," paper SPE 35628 Presented at the 1996 Gas Technology Symposium, Calgary, Alberta, Canada, 28 April-1 May.

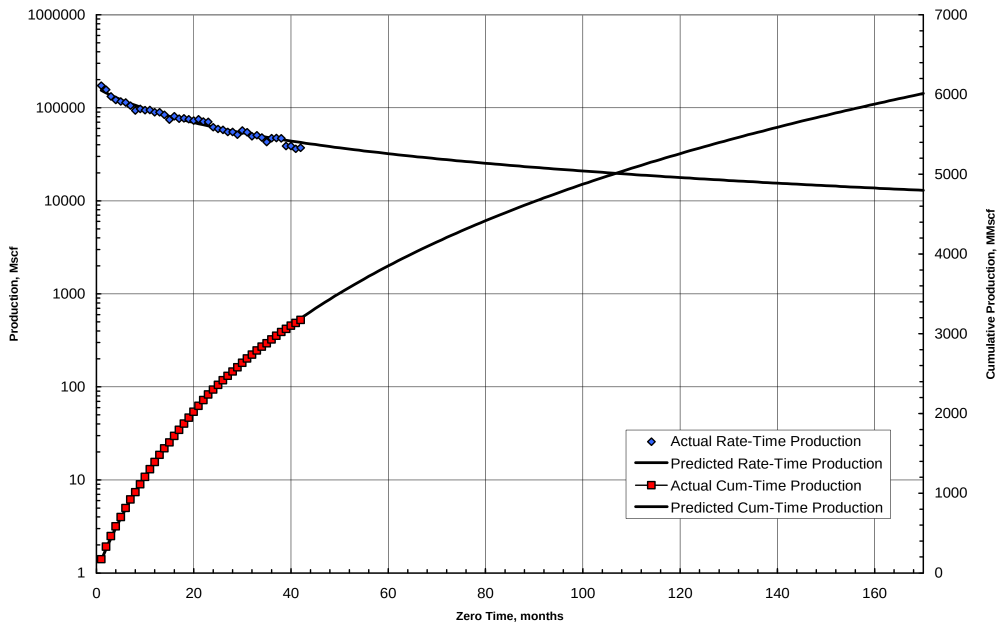
33. Pollastro R. M. et al. : "Geologic Framework of the Mississippian Barnett Shale, Barnett-Paleozoic Total Petroleum System, Bend Arch–Fort worth Basin, Texas," paper *AAPG Bulletin* (April 2007), **91**, (4), p. 405-436.

34. Arps, J.J.: "Analysis of Decline Curves," Trans., AIME, **160** (1945), 228- 247.

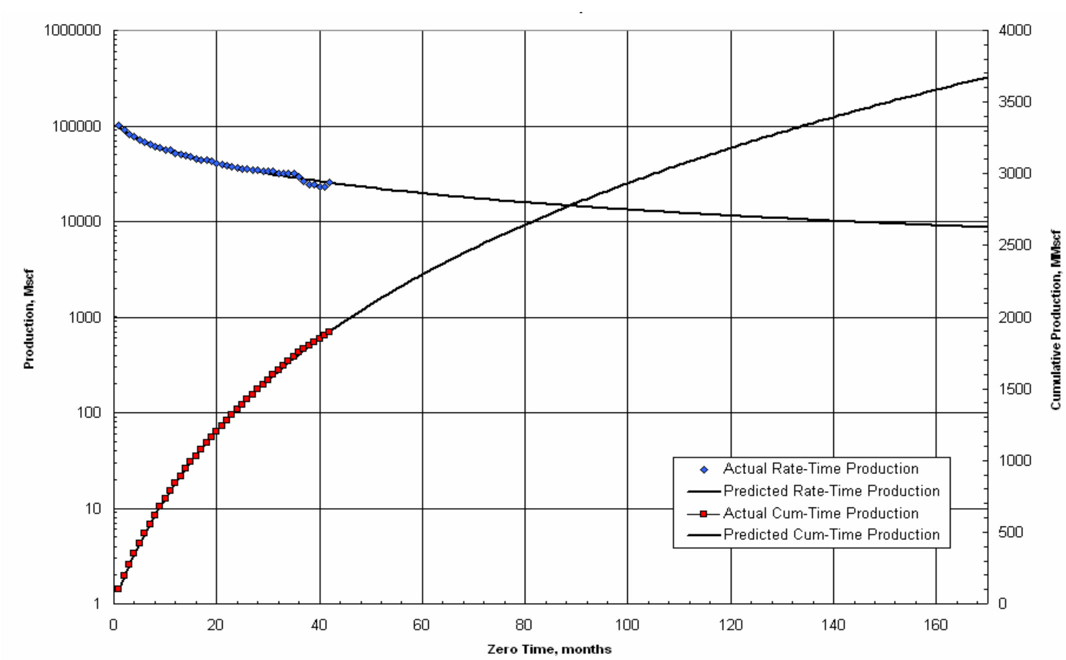
35. Fetkovitch, M.J.: "Decline Curve Analysis Using Type Curves," *Journal of Petroleum Technology* (June 1980) 1065-1077.

APPENDIX

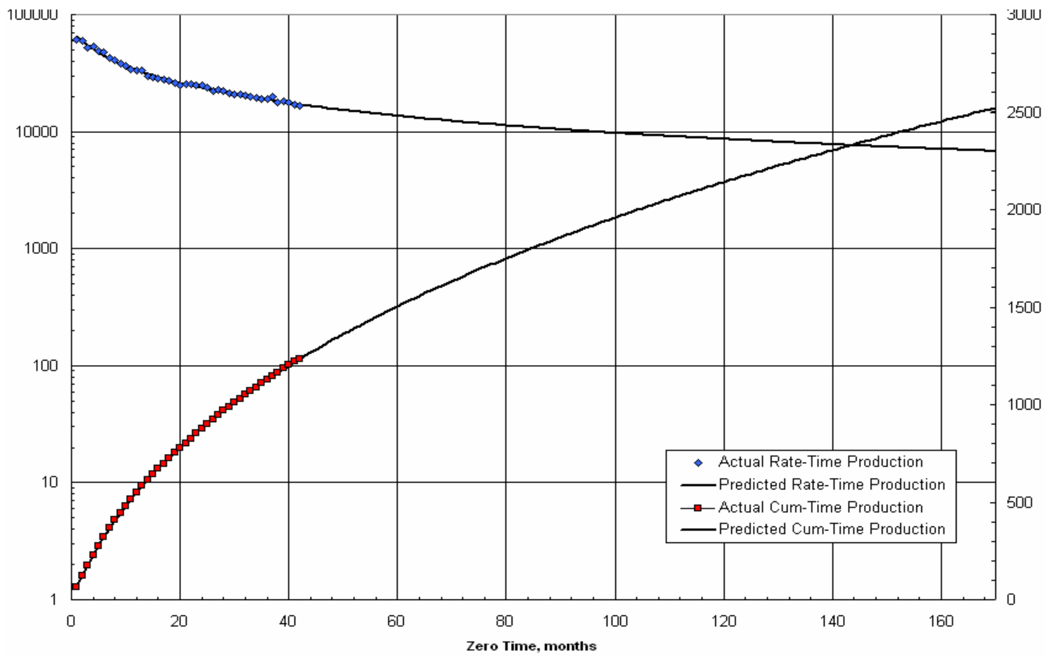
EUR TYPE CURVE STUDY BY BOOTSTRAP DECLINE ANALYSIS



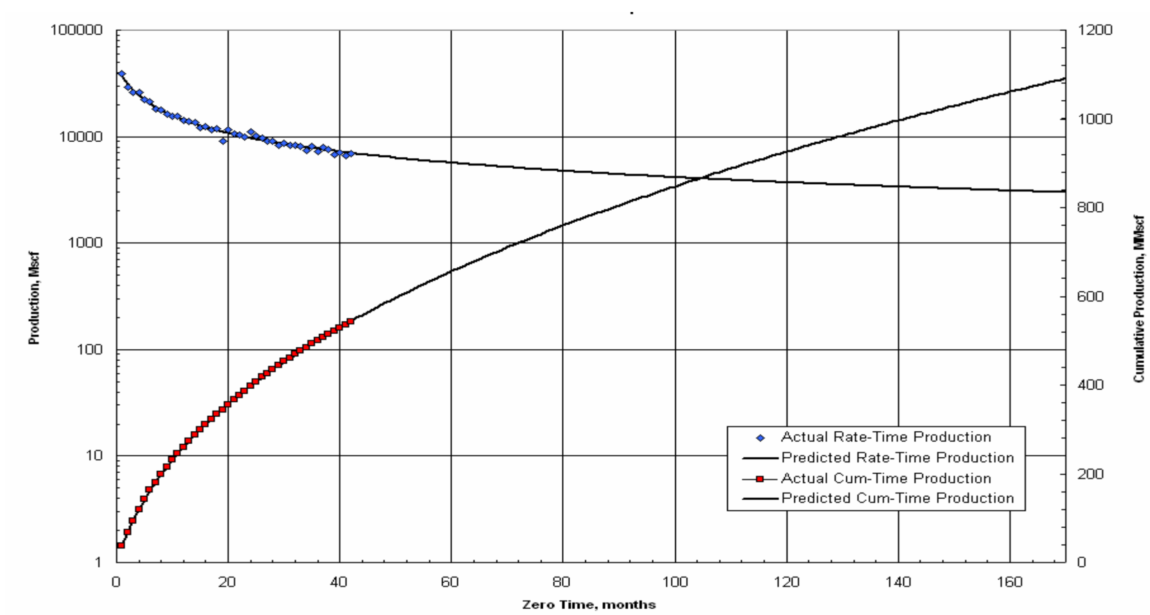
A1. Gas Best 12 Production between 0-20 MMCF/Month



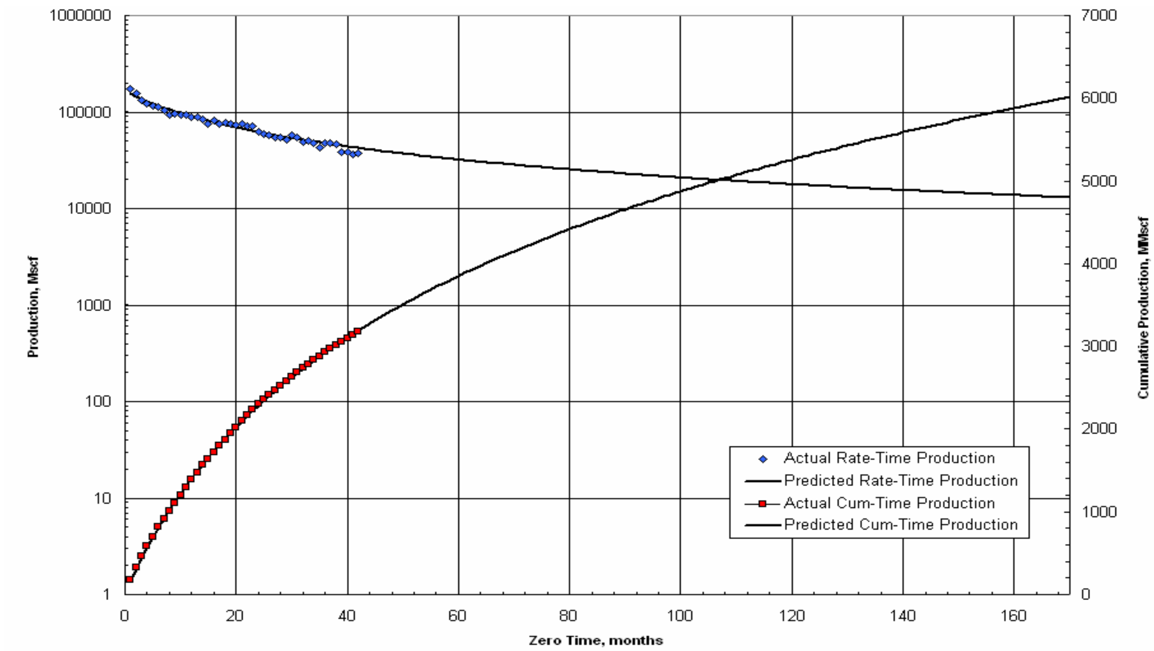
A2. Gas Best 12 Production between 20-40 MMCF/Month



A3. Gas Best 12 Production between 40-60 MMCF/Month



A4. Gas Best 12 Production between 60-100 MMCF/Month



A5.Gas Best 12 Production more than 100 MMCF/Month

VITA

Vaibhav Prakashrao Deshpande received his Bachelor of Technology degree in petroleum engineering from Dr. Babasaheb Ambedkar Technological University in India. He entered into the petroleum engineering program at Texas A&M University in the spring 2005 and received his Master of Science degree in December 2008. His research and work interests include unconventional reservoirs, reservoir characterization with a view to Formation Evaluation. Mr. Deshpande may be reached at 803, Harold Vance Department of Petroleum Engineering, 3116, TAMU, College Station, Texas, 77843-3116. His email is Vaibhav2482@gmail.com.