Economic Analysis of Shale Gas Wells in the United States

by

Christopher D. Hammond

Submitted to the
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In Partial Fulfillment of the Requirements for the Degree of

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ABSTRACT

Natural gas produced from shale formations has increased dramatically in the past decade and has altered the oil and gas industry greatly. The use of horizontal drilling and hydraulic fracturing has enabled the production of a natural gas resource that was previously unrecoverable. Estimates of the size of the resource indicate that shale gas has the potential to supply decades of domestically produced natural gas. Yet there are challenges surrounding the production of shale gas that have not yet been solved. The economic viability of the shale gas resources has recently come into question. This study uses a discounted cash flow economic model to evaluate the breakeven price of natural gas wells drilled in 7 major U.S. shale formations from 2005 to 2012. The breakeven price is the wellhead gas price that produces a 10% internal rate of return.

The results of the economic analysis break down the breakeven gas price by year and shale play, along with P20 and P80 gas prices to illustrate the variability present. Derived vintage supply curves illustrate the volume of natural gas that was produced economically for a range of breakeven prices. Historic Natural Gas Futures Prices are used as a metric to determine the volumes and percentage of total yearly production that was produced at or below the Futures Price of each vintage year. From 2005 to 2008, the total production of shale gas resulted in a net profit for operators. A drop in price in 2009 resulted in a net loss for producers from 2009 to 2012. In 2012, only 26.5% of the total gas volume produced was produced at or below the 2012 Natural Gas Futures Price.

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1. Introduction

In recent years, the rapid increase in natural gas production from shale formations has had a major impact on the oil and gas industry in North America. Within the span of a decade, the rise of natural gas production from shale rocks has opened up vast natural gas resources that were previously unrecoverable. In addition, countries all over the world are paying close attention to natural gas production in the United States and considering producing natural gas from shale formations in their own countries. Despite these recent advances, there are considerable challenges that remain unsolved in the production of these unconventional resources. One prominent issue is the variability of productivity from well-to-well, even within the same shale formation, which gives rise to further challenges. For one thing, it becomes very difficult to accurately assess the amount of natural gas that can be recovered from shale formations. This poses problems for a range of stakeholders, from production companies to those trading natural gas and land resources.

This study uses an economic model and historic individual well production data to deduce a breakeven price of natural gas for each well. Aggregating these individual breakeven gas prices with corresponding gas volumes produces supply curves that show what quantities of natural gas were economically viable at various natural gas prices. Since the supply curves are derived from individual well breakeven prices, unique supply curves can be created based on different combinations of years and shale formations. In total, this study examines horizontally drilled natural gas wells from the past eight years across seven major U.S. shale gas plays. Results highlight historical trends in the economic viability of natural gas produced from shale rock formations. Most notably, as natural gas supplies rose and price dropped, producers moved to areas of shale formations that produced natural gas liquids as well as natural gas. This phenomenon has resulted in significant quantities of natural gas with a break-even price of zero dollars, which has a broad range of implications from affecting future gas prices to impacting the chemical and energy sectors. Additionally, the vintage supply curve of any given year analyzed can be compared to the natural gas price of that year to make an assertion about what volume of gas resulted in a profit for the producing companies and what volume resulted in a loss.

1.1 What is shale gas?

Natural gas, like crude oil, is formed from organic matter that becomes buried and is transformed over thousands of years under immense heat and pressure. As such, natural gas and crude oil are found deep within the earth's crust in reservoirs at high pressures. Natural gas can be found with or without crude oil, in a variety of reservoir types as Figure 1-1 illustrates below. Natural gas that is found in a reservoir also containing oil is called associated gas, while natural gas that is found without oil is called non-associated gas. Both associated gas and non-associated gas fall under the category of conventional gas resources. Conventional resources develop when organic material is turned into hydrocarbons like oil and gas in a permeable source rock. The oil and gas then migrates towards the surface until it reaches a layer of rock that is impermeable. The oil and gas collect under the impermeable layer, held in place by a buoyant force, in a permeable rock termed the reservoir rock. Conventional resources are extracted by drilling into the reservoir rock, which allows the high pressure within the rock to push the gas and/or oil to the surface where it is collected.

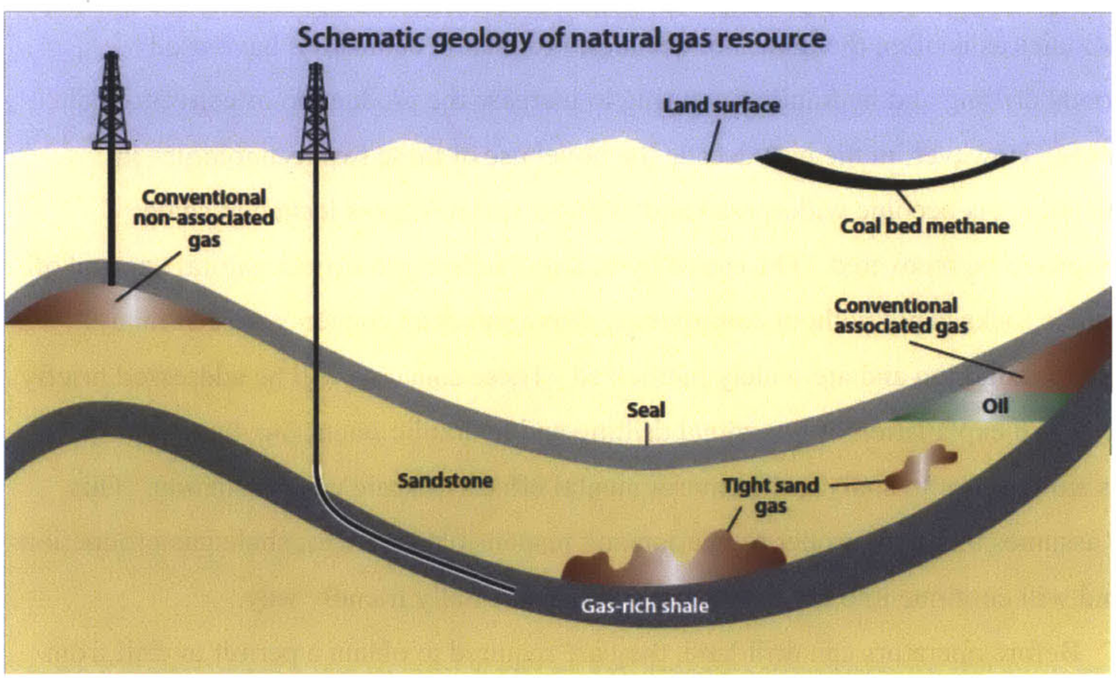


Figure 1-1: Schematic of the various types of geology of natural gas resources

Unconventional resources are found in rocks where the permeability is extremely low, so gas cannot migrate to another formation. Instead, small droplets of gas or oil are trapped within pores in the rock. One type of rock in which unconventional resources are often found is shale. The shale serves as both the source and reservoir rock in these cases. This study focuses on natural gas found in shale formations. Shales have a permeability that is on the order of 0.01 to 0.00001 millidarcies. A darcy is a unit of permeability. A medium that has a permeability of 1 darcy allows a fluid with a viscosity of 1 mPa•s to have a volumetric flow of 1 cm^3/s under a pressure gradient of 1 atm/cm acting across a 1 cm^2 area. The extremely low permeability of shale means that extracting natural gas from shale formations requires the use of distinct technologies. Hydraulic fracturing is a process that creates pathways within the shale formation to allow natural gas to flow out of the rock. The specifics regarding this technology will be discussed in the next section.

1.2 Enabling Technology

The technologies that have unlocked the expansive and previously unrecoverable shale gas and shale oil resources, horizontal drilling and hydraulic fracturing, are not new technologies as is often thought. For decades, production companies have used horizontal drilling and hydraulic fracturing to increase the production of conventional resources. However, in the past decade the novel use of these two technologies in combination has become widespread and allowed vast resources locked in shale formations to be recovered. The use of hydraulic fracturing to extract natural gas and oil from shale rocks is not without controversy. Environmental concerns arise at many stages of production and are widely publicized. These concerns will be addressed briefly following an explanation of horizontal drilling and hydraulic fracturing, but the purpose of this study is not to analyze the environmental effects of shale gas production. This study assumes that with proper regulation and responsible practices, shale gas production can and will continue into the future in an environmentally friendly way.

Before operators can drill land, they are required to obtain a permit to drill from the state in which they are drilling. Then, the first step in production of natural gas from shale rock is to drill horizontally into the shale formation. The advantage of horizontal drilling is that it greatly increases the contact area between the wellbore and the rock formation in comparison to conventional drilling, which is done vertically. To begin, a production company drills vertically down into the earth to different depths before cementing a steel tube in place to keep the well open. Typically three layers of cement and steel casing are set in place to different depths before the final production casing is run to bottom of the well. The purpose of the cement and steel casing are to separate the layers of rock and ground water above the shale formation from the shale formation itself. Figure 1-2, below, shows a representation of a typical casing and cement program. This process is not a perfect one and has led to shale gas development coming under fire for environmental issues related to groundwater contamination.

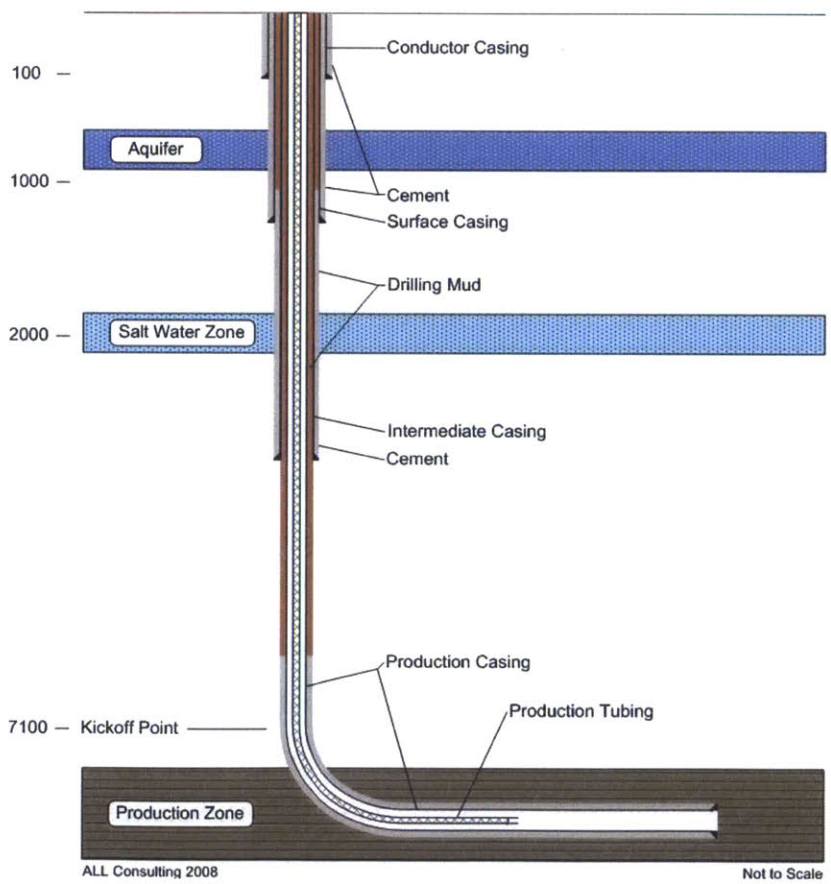


Figure 1-2: Schematic of typical casing and cement program

The wellbore is drilled vertically until it is just above the top of the shale formation. At this point, a specialized drill bit is used to turn the well at a rate of a few degrees per hundred feet until it has made a 90-degree turn and runs horizontally through the shale formation. The direction of the wellbore through the shale formation is important for hydraulic fracturing. The wellbore is aligned parallel to the direction of the least compressive stress within the shale formation. Shale formations fracture in an orientation that is perpendicular to the direction of least compressive stress because the least compressive stress is the first to be overcome, resulting in the fracturing of the rock. This means that the wellbore is perpendicular to the dominant orientation of fractures in a formation where fractures are naturally occurring [1]. A prominent benefit of horizontal drilling is the ability to drill multiple wells from a single well pad, sometimes called "pad drilling". Drilling pads are usually 3-5 acres in size, and one drill pad is typically used to drill approximately 6 wells. Pad drilling greatly reduces the time, cost, and environmental impact of drilling shale gas wells.

After the well has been drilled into the shale formation, it is ready to be hydraulically fractured. Before hydraulic fracturing, or fracking, can be done the wellbore is perforated at specific points along the horizontal section to open the bottom of the wellbore to the rock formation. In shale formations, the low permeability prevents gas from migrating. Hydraulic fracturing is the process of creating pathways in the shale for the gas to flow out. Large volumes of fluid containing roughly 99% water and sand and 1% chemicals, are pumped into the well at high pressures. This is where the direction of the wellbore within the formation becomes important. Figure 1-3 illustrates the effect of wellbore orientation on fracture propagation. The graphic in the bottom right of Figure 1-3 shows the case where the wellbore is oriented parallel to the minimum horizontal compressive stress (or conversely, perpendicular to the maximum horizontal stress). The high pressure overcomes the least compressive stress within the shale rock, opening fractures that extend dominantly in the direction perpendicular to the wellbore. This is repeated at several locations or "stages" along the wellbore, creating a large network of fractures in the shale formation that are open to the wellbore. The sand in the fracking fluid keeps the cracks in the shale open so that gas can flow for years, and the chemicals mainly lower surface tension to help increase the flow of natural gas to the surface.

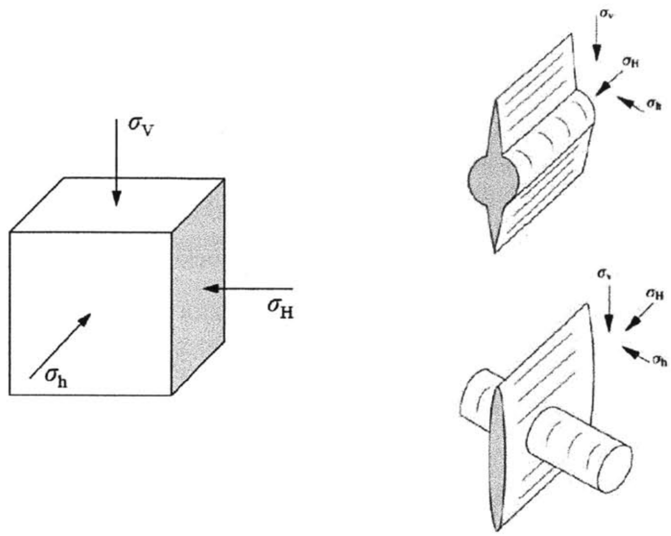


Figure 1-3: Effects of horizontal stresses, wellbore orientation on fracture propagation

The best shales for hydraulic fracturing are those that fracture in a brittle, rather than ductile, manner. Ductile shales tend to resist fracturing and deform internally, while brittle shales fracture more easily and respond well to the hydraulic fracturing process [1]. Shale gas wells tend to have a steep decline in production rate during the first year. This decline is typically about a 60% drop-off after one year and is relatively consistent in past years across shale formations. Though sophisticated seismic techniques are used to estimate the characteristics of hydraulically induced fractures, the models are not exact. For this reason and others, the production rates of natural gas wells can vary unpredictably, as will be discussed later. The development of both micro and macro scale seismic techniques could help improve the accuracy and productivity of fracking operations.

Another important technical aspect of natural gas found in shale rock formations is that not all areas produce the exact same mixture of gas and liquids, even within the same play. Natural gas is primarily composed of methane, which is the simplest and lightest possible hydrocarbon molecule consisting of four hydrogen atoms attached to a single carbon atom (CH_4). However, the geological process that turns organic matter into natural gas can lead natural gas in shale formations to contain smaller amounts of heavier hydrocarbons such as ethane (C_2H_6), propane (C_3H_8) and butane (C_4H_{10}) [2]. These heavier hydrocarbons are produced from the shale rock formation along with methane and are referred to as natural gas liquids (NGLs). Natural gas liquids are sold at a separate, higher price than natural gas which in many cases can help offset the cost of producing and selling natural gas at a low gas price, making a particular area within a shale play more lucrative. Areas that tend to produce relatively high amounts of NGLs are called liquids-rich. A ratio called the liquid-to-gas ratio is used in the industry to quantify how liquids-rich a particular area is. The ratio is just as it sounds, a ratio of barrels of oil equivalent liquids to million cubic feet of gas (boe/MMcf). The fact that NGLs fetch a considerably higher price than natural gas makes liquids-rich areas of shale plays desirable.

1.3 Environmental Risks

Though the use of horizontal drilling and hydraulic fracturing has rapidly increased in recent years, the technologies do come with environmental risks. There are even some who claim that shale gas production is currently causing considerable environmental damage. Though hydraulic fracturing is most often the process attacked as environmentally damaging because of its use of chemicals and massive volumes of water, the process of horizontal drilling is not without its own set of environmental concerns. Multiple environmental risks surround the issue of water. One issue is quite plainly the enormous amount of water that is used in each fracking operation. It is typical for a fracking operation to consume from 2 to 4 million gallons of water for a single well. Standing alone, this is a massive amount of water, but studies have shown that it is just a small portion of the water consumption in areas where shale gas is developed. Water use by shale gas ranges from less than 0.1% to 0.8% of total water use in the area of the shale play, substantially outpaced by use for livestock, irrigation, industrial/mining, and public supply [3]. Regardless, shale gas producers are continuing to improve in reusing fracking fluid that returns from the well in order to reduce overall water use. Another issue surrounding water is the occurrence of surface spills at a drilling or fracking site. There are many fluids used in the production of shale gas, with the most common being drilling mud and fracking fluid. Surface spills can occur as a result of equipment failure like pumps and hoses, or as a result of overflow of a tank or surface pit. If a large volume of fluid is spilled it could contaminate local waterways and cause further problems. A third water related environmental risk is the disposal of flow-back fluid, which is a mix of fracking fluid and formation water that is returned back up the well after the completion of a fracking operation but before production. The flow-back fluid typically has high salinity and can contain naturally occurring radioactive material (NORM) from deep within the ground. In some states the practice is to inject the flow-back fluid into an EPA regulated disposal well, while in others like Pennsylvania the fluid is taken to waste treatment plants, many of which cannot handle the high contamination levels of the flow-back fluid. The issue of disposal of flow-back fluid is an ongoing problem.

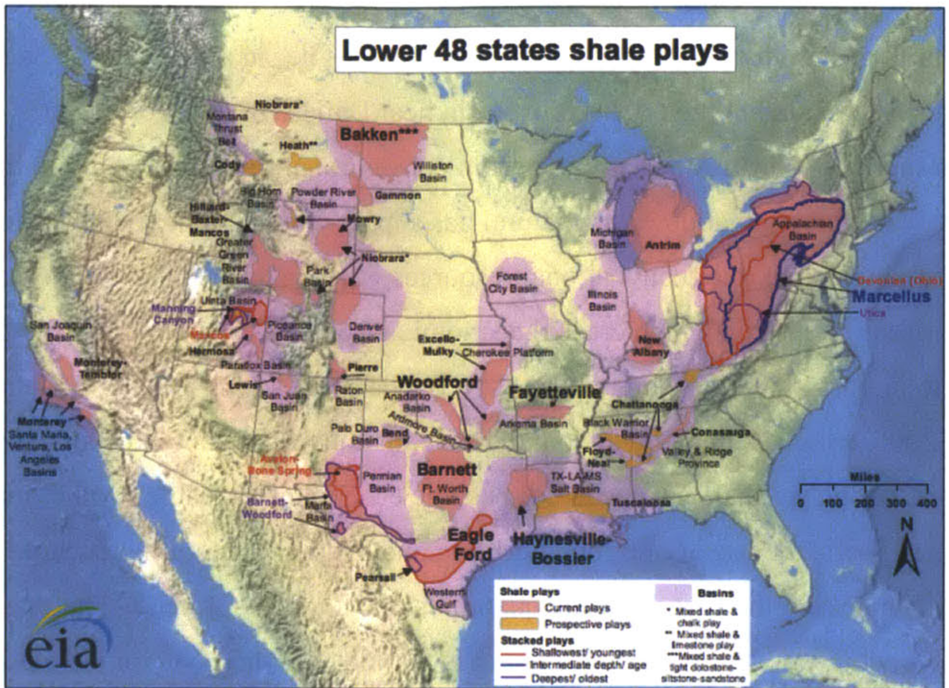
Other environmental impacts affect the communities in the shale play area more directly. Many of the shale gas plays are located in rural areas where the residents rely on the groundwater table as their supply of potable water. The most common cause of reported environmental incidents is the migration of natural gas or drilling fluids into groundwater zones, which is related to issues that occur while drilling and setting the casing that is supposed to protect the groundwater. There are a few causes for this contamination. One cause could be that the drilling fluid, or "drilling mud," is too dense and therefore pressure at the depth of the groundwater table causes the drilling mud to move into the groundwater table. Another cause could be that the wellbore enters an unexpected pocket of natural gas, and the open passageway to the groundwater table results in natural gas migrating to and contaminating the groundwater. Lastly, if the casing that protects the groundwater is poorly cemented in place it could result in an open pathway to the groundwater table by which contaminants from subsequent operations could migrate into the groundwater. Regardless of the source of contamination, if the groundwater table becomes unfit for use in an area that depends on it for its water supply, the community is greatly affected. Production companies that caused groundwater contamination in the past have had to pay to have potable water shipped to rural residents. Another way the community and local environment are affected by shale gas production is the large increase in traffic and infrastructure in the areas of drilling. Many drilling locations are inaccessible by roads, so the production company must build a road in order to transport the rig and supplies to the location. Estimates for the number of truck trips to a shale well site for both drilling and completion range from 890 for drilling and completing one well to 8,900 for two drilling rigs and completion supplies for 8 wells [3]. For the rural communities of many shale gas plays, this large increase in truck traffic disrupts their way of life. Additionally, the construction of access roads and well pads causes damage to the community and local environment.

A controversial but nonetheless important environmental concern surrounding shale gas development is the issue of harmful air emissions. It is recognized that engines for drilling rigs, pumps, mixers, trucks, and similar equipment that run on a hydrocarbon fuel will produce some level of harmful air emissions. However, these emissions are known and essentially taken as a given in the process of natural gas extraction. A less known set of emissions are what are called fugitive emissions or fugitive gas. Fugitive emissions can occur from leaks in pipes or connectors, or as a result of the use of pneumatic devices that bleed small amounts of natural gas into the atmosphere during their normal operation. Additionally, when a problem is experienced it may be necessary to release down-well pressure by flaring, or burning off natural gas that is rising from the well. All of these sources and more contribute to fugitive emissions. There is no consensus about the extent of the problem that fugitive emissions pose to the environment. Methane is a greenhouse gas that is much more harmful than CO_2, however when burned it burns the cleanest of all fossil fuels and produces roughly half of the CO_2 emissions that coal produces. Despite the fact that it burns cleaner than coal, one study, [4], asserted that because of fugitive emissions, natural gas from shale formations releases more harmful emissions than coal when the entire extraction and burning life cycle is taken into account. More recent studies refuted the previously mentioned study [5], [6]. As it stands, fugitive emissions from shale gas production pose a relatively unknown environmental risk.

1.4 The Rise of Shale Gas

Natural gas production from shale rock formations began about a decade ago in the Barnett shale located in the Fort Worth Basin near Dallas, Texas. For decades, natural gas supply in North America came from conventional resources. Around the year 2000, there was concern that domestic natural gas supply would not be sufficient to satisfy increasing demand, as conventional resources were on the decline. At the same time, gas prices were rising which created economic incentives to build infrastructure necessary to import Liquefied Natural Gas (LNG). Gas prices rose sharply in the later months of 2005, which ultimately led to the dissemination of horizontal drilling and hydraulic fracturing, as shale gas resources became economically viable for the first time. In subsequent years, the use of horizontal drilling and hydraulic fracturing became widespread, unlocking the vast domestic quantities of natural gas stored in shales. The shift to cheap, domestic gas from shale plays has left many of the LNG import stations unused. However, these LNG import terminals leave open the option of future imports, and some have proposed the idea of overhauling these import terminals for use as LNG export terminals.

With the success of horizontal drilling and hydraulic fracturing to produce natural gas from the Barnett shale beginning mainly in the year 2005, the domestic natural gas supply picture changed drastically. Soon after, production companies began drilling exploratory wells into similar shale formations around the United States. Figure 1-4 shows numerous shale formations across the lower 48 states [7]. Though these formations are widespread, many are currently undeveloped. The major shale plays currently under development and those analyzed in this study are the Barnett, the Marcellus, the Fayetteville, the Haynesville, the Eagle Ford, the Woodford, and the Bakken which is largely a shale oil formation. Figure 1-5 below shows the rapid and large increase in total U.S. shale gas production starting around 2008 and taking off in 2010, as well as which plays contributed most to this increase [7].



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Figure 1-4: Map of shale plays in the lower 48 United States

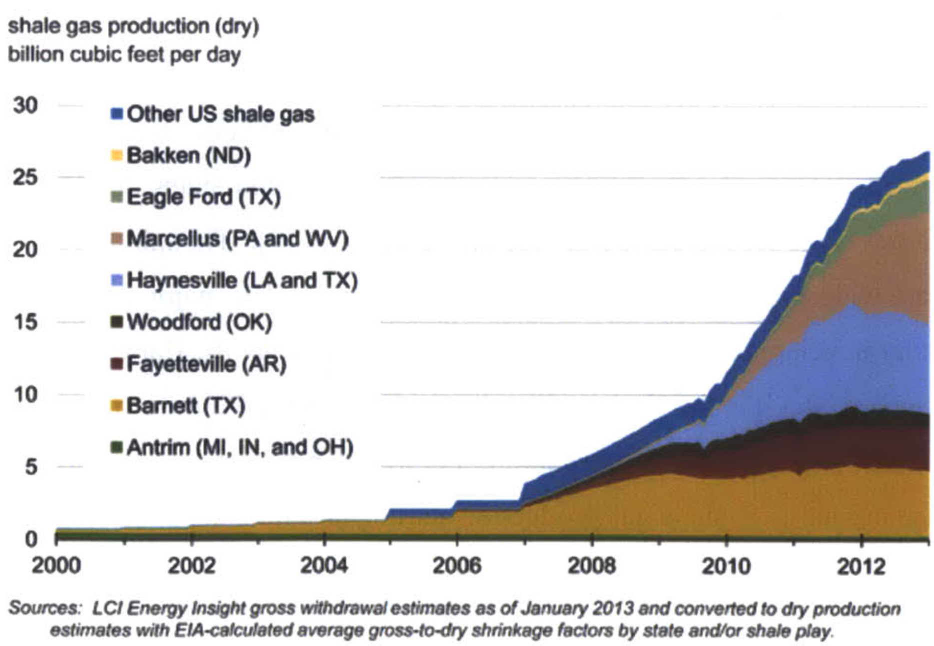


Figure 1-5: Individual shale play contribution to total U.S. shale gas production, in billion cubic feet per day (Bcf/day)

Not only has the recent natural gas production from shale formations increased dramatically, but signs point towards the continued growth of shale gas as an exploited resource. The EIA, in its Annual Energy Outlook 2013 projected a 44% increase in total natural gas production from 2011 to 2040 in the United States. By far the largest contributor to that increase in production is shale gas, which is projected to grow by 113% from 2011 to 2040. That is a growth from 7.85 trillion cubic feet (Tcf) of production in 2011 to a projected 16.70 Tcf in 2040 [7]. Figure 5 below illustrates this projected growth.

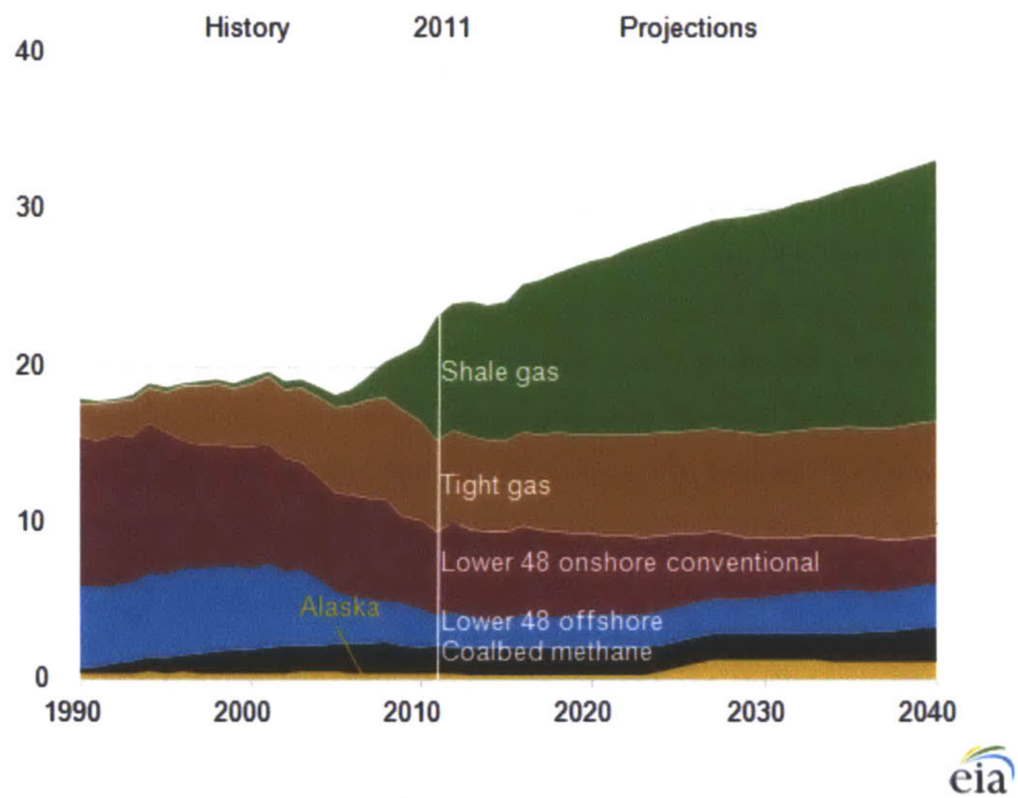


Figure 1-6: EIA Annual Energy Outlook 2013 projected contributions to total U.S. natural gas production by resource type, 1990 – 2040

The main reason that projections of future shale gas production can be so aggressive is that the resource is quite large across the lower 48 United States. While the resource is known to be large, it is difficult to estimate how large it truly is and projections can vary drastically. There are two categories of projections that are useful for understanding how much natural gas exists in the ground. The first type is estimates of proved reserves. Proved reserves are the amount of gas that is thought to exist in known gas reservoirs and estimated to eventually be recovered, given the current economic and technological conditions. Proved reserves are always smaller than the second type of projection, which is technically recoverable resources. Technically recoverable resources, sometimes just called resources, is the amount of gas that is more broadly thought to be in the ground that could be recovered given the current technological conditions. This includes proved as well as unproved plays, but ignores whether it would be economical to produce the gas. Technically recoverable resources are essentially an estimate of the amount of gas in the ground that could one day be recovered given the right economic conditions. Natural gas resources on the large scale like this are measured in trillion cubic feet, or Tcf.

Even though projections disagree, it is by and large accepted that the shale gas resource, and natural gas resources in general, are substantial. In 2011 the EIA reported that the United States has a technically recoverable shale gas resource of 862 trillion cubic feet and proved natural gas reserves of 272.5 trillion cubic feet. Even more impressive, however, is the estimate for the total amount of technically recoverable natural gas from all sources. The EIA estimates that in the United States there are 2,203 trillion cubic feet of technically recoverable natural gas. To put this in perspective, at the U.S. 2011 natural gas consumption rate of approximately 24 Tcf per year, the technically recoverable resource is enough to last about 92 years.

Nations around the world have taken notice of the new natural gas resource that hydraulic fracturing has opened up in the United States. These countries have begun to examine shale formations within their own borders in hopes of exploiting the resource in a similar fashion to the United States. Early studies of the worldwide shale gas resource have revealed that shale gas has the potential to become an immense source of natural gas in the future. A study prepared by Advanced Resources International for the EIA reported in 2011 that an initial estimate of technically recoverable shale gas resources is 6,622 Tcf. The study analyzed 32 countries around the world in addition to the United States. Notable among the results is the fact that China has a technically recoverable natural gas resource of 1,275 Tcf and Argentina has a natural gas resource of 774 Tcf. The study states that the addition of the identified shale gas resource increases the total world technically recoverable natural gas resources to 22,600 Tcf, an increase of over 40 percent [8]. Table 1-1 below summarizes findings of the study for each country analyzed. The study did not include Russia or the majority of the Middle East, which are large contributors to the overall world supply of natural gas. The study notes that its total estimate of shale gas resources is not a global estimate but rather the estimate for the 32 countries analyzed in addition to the United States. For that reason, the global shale gas resource is most likely even higher. Still, estimates like these have a high degree of uncertainty. Shale gas is largely untapped in countries outside the United States despite the enormous resource estimates. The economic, environmental, and societal impacts of shale gas production in the United States could have important implications for how the resource is exploited worldwide.

	2009 Natural Gas Market[1] (trillion cubic feet, dry basis)			Proved Natural Gas Reserves[2] (trillion cubic feet)	Technically Recoverable Shale Gas Resources (trillion cubic feet)
	Production	Consump-tion	Imports (Exports)		
Europe					
France	0.03	1.73	98%	0.2	180
Germany	0.51	3.27	84%	6.2	8
Netherlands	2.79	1.72	(62%)	49.0	17
Norway	3.65	0.16	(2,156%)	72.0	83
U.K.	2.09	3.11	33%	9.0	20
Denmark	0.30	0.16	(91%)	2.1	23
Sweden	-	0.04	100%		41
Poland	0.21	0.58	64%	5.8	187
Turkey	0.03	1.24	98%	0.2	15
Ukraine	0.72	1.56	54%	39.0	42
Lithuania	-	0.10	100%		4
Others[3]	0.48	0.95	50%	2.71	19
North America					
United States[4]	20.6	22.8	10%	272.5	862
Canada	5.63	3.01	(87%)	62.0	388
Mexico	1.77	2.15	18%	12.0	681
Asia					
China	2.93	3.08	5%	107.0	1,275
India	1.43	1.87	24%	37.9	63
Pakistan	1.36	1.36	-	29.7	51
Australia	1.67	1.09	(52%)	110.0	396
Africa					
South Africa	0.07	0.19	63%	-	485
Libya	0.56	0.21	(165%)	54.7	290
Tunisia	0.13	0.17	26%	2.3	18
Algeria	2.88	1.02	(183%)	159.0	231
Morocco	0.00	0.02	90%	0.1	11
Western Sahara	-	-		-	7
Mauritania	-	-		1.0	0
South America					
Venezuela	0.65	0.71	9%	178.9	11
Colombia	0.37	0.31	(21%)	4.0	19
Argentina	1.46	1.52	4%	13.4	774
Brazil	0.36	0.66	45%	12.9	226
Chile	0.05	0.10	52%	3.5	64
Uruguay	-	0.00	100%		21
Paraguay	-	-			62
Bolivia	0.45	0.10	(346%)	26.5	48
Total of above areas	**53.1**	**55.0**	**(3%)**	**1,274**	**6,622**
Total world	**106.5**	**106.7**	**0%**	**6,609**	

Table 1-1: Summary of shale gas resource estimates for 32 countries

1.5 Historic Natural Gas Economics

Natural gas in the United States did not historically have a smooth path to get to where it is today. The natural gas market was first developed with the help of an interstate natural gas pipeline system that supplied local distribution systems. At this point the market was subjected to cost-of-service regulation by both the Federal government and state governments, and natural gas production and use grew significantly in this framework during the 1950's, 1960's and into the 1970's. However, after the first oil embargo many energy customers attempted to switch to natural gas. The issue was that price controls and the tightly regulated natural gas market served as disincentives for domestic gas production. This led in part to the perception that U.S. gas resources were limited. From the late 1970's until the late 1980's, legislation essentially outlawed building new gas-fired power plants, lowering the demand for natural gas. However, by the mid 1990's the process of deregulation of wellhead natural gas prices that had begun in the late 1980's was complete and new technology surrounding the natural gas market came to the forefront. Highly efficient and relatively inexpensive combined cycle gas turbines were being deployed, and new upstream technologies were used to developed offshore natural gas resources. The combination of these factors led to a period where domestic gas supplies were perceived to be abundant.

At the turn of the 21st century, the situation began to change yet again. Concerns arose that domestic natural gas supplies were inadequate. Supplies of natural gas from conventional sources were in decline. Unconventional natural gas resources were too expensive and difficult to produce, and the overall confidence in gas fell sharply. The price of natural gas went through periods of significant volatility. The price volatility in the early 2000's served to accelerate the development of LNG import terminals and infrastructure, as such projects were deemed economically advantageous. In late 2005, a rapid increase in the price of natural gas finally tipped shale gas into the territory of economically viable. The high natural gas prices at the time were justification for the development, using horizontal drilling and hydraulic fracturing, of the Barnett shale. Shale gas was perceived as a profitable venture, causing many to jump into the industry. As drilling of wells in shale plays increased across the United States at the end of the decade, a glut of natural gas in the market was quick to follow, driving prices down yet again. The low prices observed led some to question whether shale gas was actually an economically viable option at all. This study hopes to shed some light on the recent economics of natural gas produced from shale formations. Figure 1-7 below shows the historical wellhead price of natural gas in dollars per thousand cubic feet ($/Mcf), helping to illustrate the erratic history of natural gas in the United States.

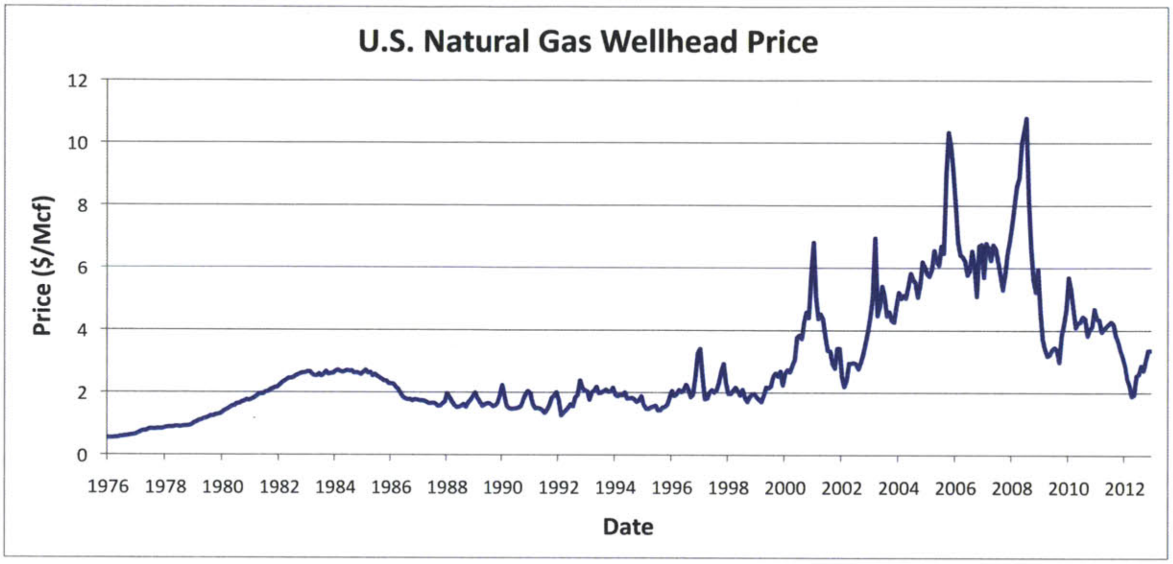


Figure 1-7: Historic U.S. natural gas wellhead price ($/Mcf)

1.6 Implications of Shale Gas Production

Low natural gas prices like those of the past year make it difficult for operators to produce shale gas at a profit. While this puts stress on the operators and may influence some to hold off on future production until prices increase, there are other sectors in the United States that stand to benefit greatly from abundant, cheap natural gas. Two prominent sectors that fit this category are the electric power sector, and the chemical manufacturing sector.

In recent years, electric power generation from natural gas has increased partly due to the low cost of the fuel. However, in addition to the currently low price, natural gas is a desirable fuel for electricity generation for a number of reasons. First, natural gas is the cleanest burning of all fossil fuels because of methane's simple, light structure. In comparison to coal, which is what has been the dominant power generation fuel for decades, natural gas produces approximately one-half of the CO_2 emissions that coal does per kilowatt-hour. The improvement of natural gas over coal is even more drastic when it comes to other harmful pollutants. Natural gas produces less nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate ash than coal, all by at least one order of magnitude difference [3]. These reduced emissions are critical to any future energy plans that call for the reduction of greenhouse gas emissions, especially in the short term. Another advantage of natural gas over coal is that power plants can be highly efficient. Natural Gas Combined Cycle (NGCC) power plants have efficiencies typically around 50-60%. When high efficiency is combined with low natural gas price, the option becomes economically advantageous. Lastly, natural gas turbines can be ramped up or down quickly to respond to changes in power demand. Even before the low gas prices of late, natural gas was used as a backup source of power that could be quickly brought online when needed. With the projected and environmentally necessary increase in renewable, albeit intermittent, power generation sources, the demand for quick responding backup power will increase. Renewable power sources like solar power and wind have the downfall of unreliability based on unpredictable factors like weather, so using natural gas turbines as a backup to ensure that power supply meets demand will most likely increase in the future. Clearly there are several benefits to natural gas as a fuel for power generation. Lower-cost natural gas translates into lower-cost power generation, and those savings can be passed on to customers as lower electricity costs.

The chemical manufacturing sector in the United States is inherently tied to the global chemical manufacturing sector. Large companies dominate the sector, and decisions regarding where to locate factories and production facilities are based on the cost of supplies in different locations. Natural gas can be used as both a feedstock and fuel source for many chemical manufacturing processes. For instance, methane is broken down to provide the hydrogen needed to produce ammonia, and natural gas can be the fuel that provides the energy to break down the methane. Ammonia is used as a fertilizer by itself and is also used as a basis for other types of fertilizer for the full range of plants and crops. Similarly, ethane from natural gas can be processed into ethylene, which is the most significant single chemical in terms of volume and value and is the basis for various product categories including plastics, adhesives, soaps, solvents, and paints, to name a few. The process of transforming ethane into these products also needs a fuel to provide the necessary energy, which natural gas can cleanly do. A PricewaterhouseCoopers (PwC) study of the impact of shale gas on domestic chemical manufacturing companies found that lower-price natural gas as a result of shale gas production results in big benefits for chemical companies. The study states that the United States could be the lowest-cost producer of ethylene, ahead of Asia and Saudi Arabia. Polyethylene, the number one plastic by volume and value, is produced from ethylene that has been converted into long-chain polymers. The PwC study found that the potential selling price of High Density Polyethylene (HDPE) could be reduced by 2.4 times because of the reduction in natural gas costs [9]. Since chemicals are used in an estimated 90% of all manufactured products, the lower chemical costs that result from lower natural gas prices can bring about lower manufacturing costs which can eventually be passed on to the customers as savings. If natural gas prices remain low, the chemical sector and its customers all benefit.

2. Current Situation and Challenges

2.1 Supply Increase, Price Decrease

At the current time natural gas production from shale formations is still quite young and developing. Performance data for modern shale gas wells cannot be older than eight years in the case of wells from 2005. Most wells, especially in younger plays have only been producing natural gas for a few years. Because of the relative novelty of shale gas as a serious portion of domestic supply, the long-term production of these wells remains to be seen. Similarly, longer-term economic, environmental, and societal effects are currently unknown. Despite this, production of natural gas from shale rocks has been and will continue to be extensively studied and analyzed because of its massive potential.

As mentioned above, shale gas production has brought a substantial volume of natural gas to the market, and this trend is likely to increase into the future. The increase in supply has outpaced demand resulting in low natural gas prices, most notably in the past two to three years. While these low prices benefit some, it puts pressure on the operators to keep costs low and production high, which might not always be possible. In fact, as the economic analysis in this study will show, many wells that have been drilled in the past resulted in a monetary loss for the operating company. With excess supply creating downward pressure on natural gas prices, some smaller operating companies may be forced out of the industry at least until prices rise back to a level that is conducive to profitable wells. For this reason among others, prices may not stay at the low level that they are currently. Yet for the time being the low gas prices pose a formidable challenge to production companies that seek to make a net profit on each of their wells.

2.2 Production Variability

Although low gas prices create an economically challenging situation for production companies, a larger challenge exists for the entire shale gas industry. As more and more wells are drilled in various plays, it has become apparent that there exists a wide, unpredictable variability in the natural gas production of shale gas wells. Different shale plays have different shale characteristics, so it is quite reasonable to expect production rates to vary from one play to another, which they do. However, it is also the case that a large variability in production rates exists within the same play. Figure 2-1 shows a histogram of the peak production (in average Mcf/day of the peak month) from all Barnett wells analyzed in this study drilled from 2005 to 2012 [10]. It can be shown that this distribution is lognormal. Table 2-1 summarizes the mean and median peak gas production of the same Barnett wells. Universally, the mean peak production rate is greater than the median peak production rate, which indicates that the distribution is skewed upwards. Also listed in Table 2-1 are the P90 and P10 peak production rates, which are the peak production rates that 90% of wells performed below and 10% of wells performed below, respectively. The spread between the P90 and P10 peak production rates is quite consistent across vintages and is bounded between 4.5 and 5.6. This ratio of approximately a factor of five difference between the top and bottom performing wells solidifies the fact that unpredictable variability can present quite a challenge. Furthermore, the variability is not spatially dependent at small distance scales. What this means is that while there are "core" areas of plays that on average contain higher producing wells, within the core or non-core areas there is an equal chance of producing a relatively high volume of gas as there is of producing a relatively low volume of gas.

Most importantly, this variability has not been linked to any characteristics of the land or operating procedures, and is thus totally unpredictable.

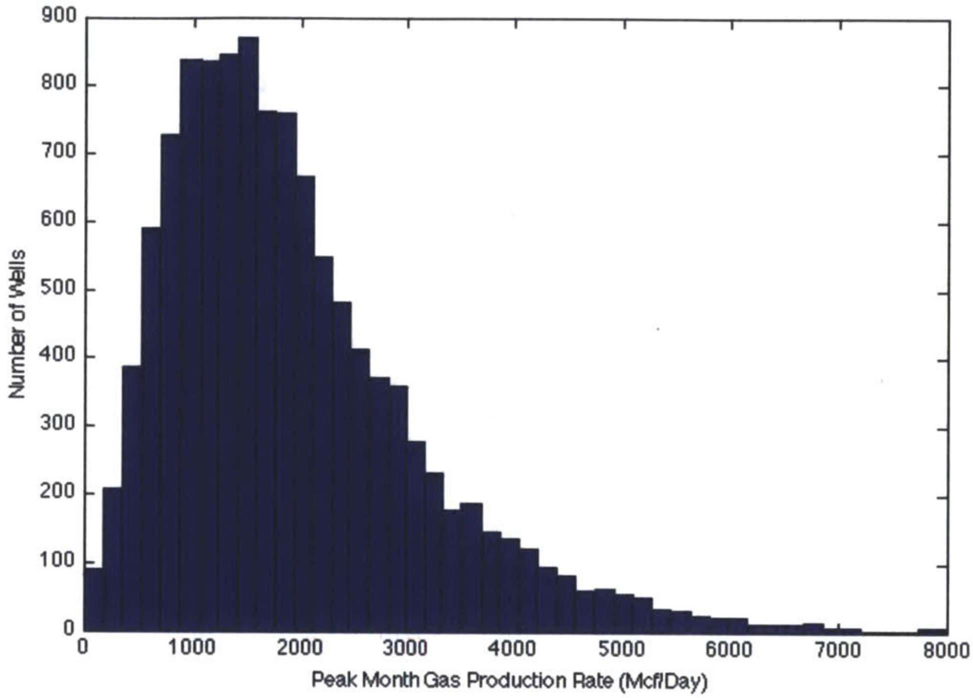


Figure 2-1: Distribution of peak gas production rate in Mcf/day for all Barnett wells analyzed in this study drilled between 2005 and 2012

Vintage	Mean	Median	P90	P10	P90-P10 Ratio
2005	1,816	1,583	3,421	616	5.6
2006	1,689	1,435	3,149	603	5.2
2007	1,794	1,553	3,262	602	5.4
2008	1,767	1,559	3,137	628	5.0
2009	2,005	1,799	3,614	723	5.0
2010	2,225	1,928	3,985	883	4.5
2011	2,383	2,095	4,358	805	5.4
2012	2,056	1,774	3,763	829	4.5

Table 2-1: Summary of peak production rate statistics in Mcf/day for all Barnett wells analyzed in this study drilled between 2005 and 2012

The unpredictable variability of shale gas wells within the same play poses an immense challenge for predicting the economics of shale gas. For one thing, high variability of individual well production translates to difficulty assessing the amount of recoverable natural gas in an area. While on a very large scale the variability could average out, producers looking to buy or lease acreage to drill are put in the tough position of attempting to assess recoverable resources. Chesapeake Energy recently ran into some problems where, among several issues, they claimed that the value of their land was higher than it actually was. With production rates varying so wildly, it is difficult to accurately assess the value of land. Similarly, production variability adds a large amount of uncertainty to operators' metrics for whether or not a shale gas project is a positive economic investment. That difficulty is exacerbated for small operating companies who might operate one rig at a time and drill ten sites in one year. With a much-reduced ability to absorb financial losses compared to large integrated oil companies, a small operating company is essentially taking a potentially very costly gamble with each well it drills as to whether the project will result in a profit. Though big production companies are taking this same gamble their large amounts of capital allow them to drill enough wells to come close to averaging out the variability, so the gamble is much riskier for small production companies.

Some have claimed that a distinction exists between conventional resource production rationale and shale gas production rationale. In a conventional exploration, development, and production process each prospective well is evaluated on an individual basis. Shale gas development has been referred to as more of a "manufacturing process" where wells are drilled on a statistical basis. Even if this contrast holds true, the "manufacturing process" of shale gas drilling occurs within an environment of high variability, and a large number of wells would need to be drilled in order for average production to come close to overall mean well productivity. With this production variability in mind, this study performs an economic analysis that essentially illustrates the varying profitability of individual wells within the current environment of high production rate variability.

3. Method for Economic Analysis

This study makes use of a discounted cash flow (DCF) model to calculate a breakeven price of shale gas wells on a full-cycle, individual well basis. Using several inputs, the model calculates the wellhead gas price that generates a 10% internal rate of return (IRR) on an individual well basis for each well analyzed. The model is programmed as a MATLAB function, which allows flexibility both in the application of the model to distinct well data sets as well as manipulation of resulting data sets for intuitive plots and graphics. The economic model includes the first 20 years of production. Steep production declines and discount rates mean that the majority of revenue for each well comes from the first few years. After breakeven prices are calculated, various types of plots can be created to illustrate and analyze the breakeven prices and associated volumes of shale gas.

There are numerous inputs for the economic model. The revenue stream is mainly defined by each well's initial production data, liquid-to-gas ratio (LGR), and the market price for natural gas liquids (NGLs). The revenue stream also depends on the decline curve parameters D and n, which will be described in more detail. Costs include the capital expenditures, operating costs, royalty and severance payments, lease costs, and taxes. The model also makes use of a 1.5% inflation rate. Explanations for the values used for these parameters in the economic model in this study are detailed below.

The wells that are analyzed in this study were drilled in the following plays: the Barnett, the Haynesville, the Fayetteville, the Eagle Ford, the Marcellus, the Woodford, and the Bakken. Well characteristic and production data was obtained from the HDPI database for these wells. After exporting the well data, additional filtering was needed to eliminate wells that were either missing data or had data misreported. For instance, wells that had zero gas production, wells that had total depths outside of the possible range for a play, and wells that had negative data values for categories that could only exist as positive values were eliminated from the data set. Also, because full-scale production began at differing times for different shale plays, the first year vintage for each play varies accordingly. All wells in the data sets were drilled horizontally and were active as of March 7, 2013. Table 3-1 below shows the years for which data was included, broken down by each play, as well as the number of wells included from that vintage for each play.

Shale play	Year 2005	2006	2007	2008	2009	2010	2011	2012	Total
Barnett	658	1180	2201	2629	1482	1635	1426	449	**11660**
Fayetteville		103	391	669	831	868	819	707	**4388**
Woodford		74	224	382	269	214	309	269	**1741**
Bakken		151	274	468	461	812	1271	1365	**4802**
Marcellus				35	216	633	1182	1239	**3305**
Haynesville				44	400	523	447	195	**1609**
Eagle Ford					59	252	651	1160	**2122**

Table 3-1: Number of wells analyzed by play and vintage year

3.1 Revenue Streams in the Economic Model

As mentioned, this study made use of a discounted cash flow model to calculate the wellhead gas price that generates a 10% IRR. The revenue flow in the model is the result of natural gas production and NGL production. In order to calculate the theoretical revenue flow from natural gas, it is necessary to determine an estimated ultimate recovery (EUR) projection for each well.

3.1.1 Decline Curves and EUR

The oil and gas industry has been estimating the ultimate recovery from wells for a long time, as it is important for asset valuation and calculation of proved reserves. However, there is no single way to calculate EUR. One common choice in the industry is to use a reservoir simulation. Unfortunately for shale gas, simulation is not a realistic option because of the lack of understanding of the physics that govern shale gas production [11], [12]. A second common option for estimating ultimate recovery is the use of a "decline curve," which involves determining a decline trend based on observed production data and projecting that trend forward to reach an EUR. This is the method employed in the economic model used in this study.

Arps carried out the initial work on the decline method [13]. The decline curve that Arps suggested was entirely empirical. Equation 1 below gives the general form of Arps' suggested decline curve.

$$q = q_i \frac{1}{(1 + bD_i t)^{(1/b)}} \tag{1}$$

In Equation 1, q is the well's instantaneous production rate, q_i is the initial production rate of the well, t is time, and b and D_i are constants. The Arps equation is widely used by analysts to establish shale gas well EURs. Despite its widespread use, the Arps equation is often flawed in a way that leads to an overestimation of EUR [12], [14], [15]. To illustrate the problem, note Figure 3-1 and Table 3-2, which respectively show the normalized production decline trend of the horizontal well vintages in the Barnett shale for 2005, 2007, 2009, and 2011 from [10], and the best-fit b and D_i parameters. All of the b parameter values are greater than 1. However, in the limit $t \rightarrow \infty$, with a b value greater than 1, the EUR also goes to infinity which is, logically, a physically impossible value. Some have used the Arps model and assumed a 30 year lifetime of the well, after which production stops [16]. However this method is also incorrect because these wells often remain in transient flow for long periods of time [17],[18], which the Arps equation does not account for. Studies have shown that if the Arps equation is used carelessly with early-life productivity data it can result in an overestimation of EUR by over 100% [14], [19].

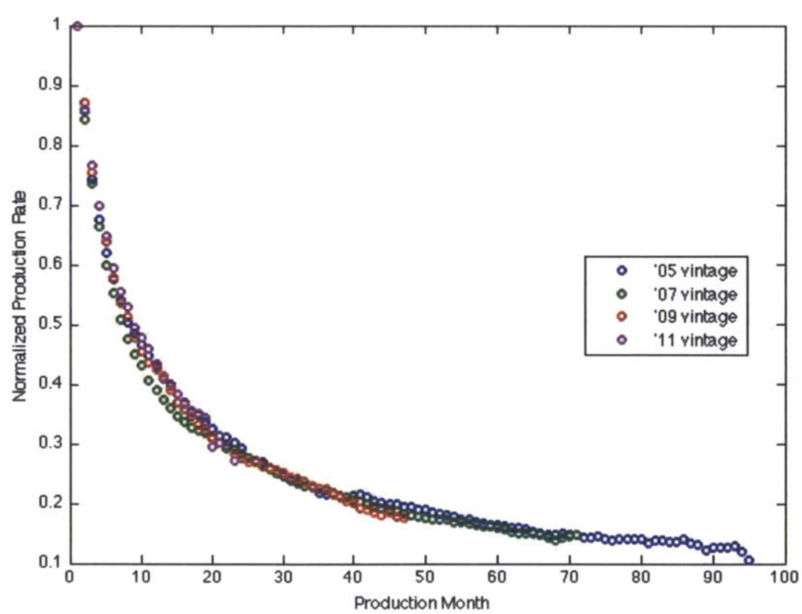


Figure 3-1: Normalized production decline curves for select Barnett vintages

Vintage	D	b
2005	0.1683	1.556
2007	0.201	1.659
2009	0.1612	1.454
2011	0.1522	1.434

Table 3-2: Arps decline curve parameters for select Barnett wells

More recently, Ilk et al [14] and Valko [20] have proposed decline curves, which are very similar. The decline curve that is employed in the economic analysis for this study is Valko's rate equation, Equation 2:

$$q = q_i \exp\left[-\left(\frac{t}{\tau}\right)^n\right] \tag{2}$$

where q is the well's instantaneous production rate, q_i is the initial production rate of the well, t is time, and τ and n are parameters derived from empirical data. Valko's decline equation accounts for transient flow, and results in finite and reasonable EURs in all situations. This model results in lower EURs than would result if Arps' equation were utilized.

In order to use Valko's "power-law exponential" decline curve, the defining parameters D (used in place of $1/\tau$) and n needed to be determined from empirical data using best-fit curve analysis. Logically, each play has slightly different vintage empirical decline curves because of natural geological variations in the shale formations and their history. Additionally, vintage decline curves from more recent years do not yet have a fully developed shape, and thus resulted in decline curve parameters that cause too aggressive of a decline. For this reason, discretion was used in choosing the decline curve parameters D and n for each play based on averages of the same parameters determined for several of the most historic vintage decline curves for each play.

In the economic model utilized in this study, the power-law exponential decline curve is used with the empirically determined parameters D and n and each individual well's peak gas production rate to create an array of theoretical gas output for each month in a 20 year period. The individual well peak production rate was taken as well data from the HDPI database, and is the amount of gas produced, in Mcf, during the well's highest productivity month, which is typically the first full calendar month that the well is producing gas. From there, a theoretical yearly production array was built out to 20 years, assuming that production started in year 0 plus 6 months. Each well's 20-year production is used in the economic model as one source of revenue flow for that particular well.

3.1.2 Determining the Correct LGR Calculation

The second contribution to a particular well's revenue flow in the economic model comes from natural gas liquids. The amount of NGL associated with each individual well is calculated based on the liquid-to-gas ratio, which itself is a calculated value in barrels of oil equivalent per million cubic feet (boe/MMcf). The well data from the HDPI database includes data on the liquid production of each well in addition to gas production data. Though not completely accurate, the model used in this study assumes that over the 20 year span examined, the production of NGLs declines according to the same decline rate as natural gas production. In reality, liquids production appears to drop off at a faster rate than gas production. Figure 3-2 illustrates this trend through a cumulative distribution function of the liquid-to-gas ratio of all wells drilled in the Barnett shale in 2006 calculated three different ways. The first method uses the one month peak gas and peak liquids production numbers to calculate the LGR. The second uses the gas and liquids volumes from the first 12 months that a well is on production, and the last uses the cumulative gas and liquids volumes from the entire time that the well has been on production. As can be seen in Figure 3-2, the cumulative distribution function of LGRs reaches 1 fastest when the cumulative gas and liquid production data is used. This means that the LGRs calculated using cumulative data are in general lower than LGRs calculated using the first twelve month data, which themselves are generally lower than the LGRs calculated using peak gas and peak liquid data. This indicates that the liquid production rate that is present during the peak month declines faster over the cumulative production life of the well than the natural gas production rate. If the gas and liquid production rates declined in equal fashion, the cumulative distribution functions of the LGR's would be identical regardless of which data is used to calculate the LGR.

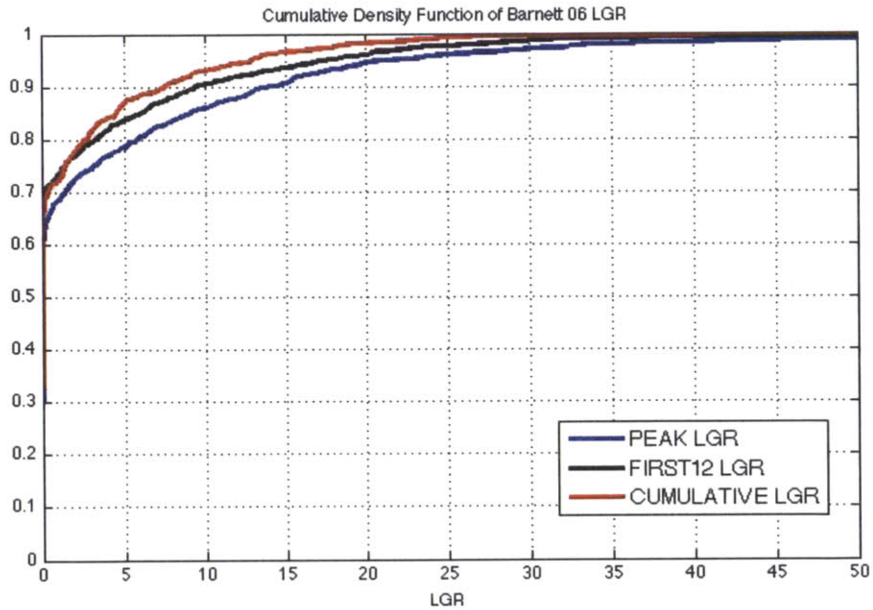


Figure 3-2: Cumulative Distribution Function of the liquids-to-gas ratio of 2006 vintage Barnett wells calculated using 3 different data sets

Although calculating the LGR using the cumulative gas and liquid production data is perhaps the most accurate, not all wells that were analyzed have the same length of production. For younger wells, the cumulative distribution functions of the LGRs calculated using cumulative production data and the first 12 month production data are rather similar, as there is less of a difference between the data sets used for the calculations because the length of production is not considerably longer than 12 months. On the other hand as pointed out above, for older wells there is a considerable difference between the LGRs calculated using cumulative data and peak month data. In order to keep consistent and comparable LGRs between vintages, the LGRs that were used in the economic model were calculated using the first 12 month natural gas and liquid production data.

3.1.3 Natural Gas Liquids Pricing

Natural gas liquids fetch a considerably higher price in the market than natural gas does. This represents a potentially lucrative revenue stream for a natural gas well beyond the revenue of the natural gas itself. Different constituents of natural gas are priced differently in the market, and like oil and natural gas prices, these prices fluctuate individually. However, the data available for this study does not include the composition of the NGL produced from gas wells, which would be quite complicated. For this reason an approximated, single price for natural gas liquids is established for use in the economic model. In this study, for each vintage of shale gas wells, the liquids price that is used is 80% of the Cushing, OK WTI Spot Price FOB for the given year. With this price as an input and the derived 20-year liquids production based on the well's LGR and production decline curve parameters, the economic model calculates a portion of revenue flow from natural gas liquids. In total, the gross revenue in the economic model comes from natural gas production and NGL production.

3.2 Costs in the Economic Model

After gross revenue is calculated, royalties and severance payments must come off of the top. One trait of royalties and severance payments is that they come from gross revenue before any other reductions, as a percentage. Another rather simple-to-calculate cost is operating costs. Operating costs are a cost per thousand cubic feet of gas produced, typically around one dollar or less. In the economic model, the operating cost accrued in a given year is based solely on the amount of gas produced in that year.

The majority of costs involved with shale gas wells come from drilling and completing (hydraulically fracturing) operations. In this economic model, drilling and completing costs were combined as a single capital expenditure value that is assumed to occur in the first year. Several factors such as shale formation depth, geological make-up of layers above the shale, machinery and supply costs, and operating practices due to regulation all affect the drilling and completion costs of a well. Logically because of the differences in the factors mentioned, the different plays analyzed had different capital expenditure values. The economic model was run for each well vintage in all of the plays with capital expenditure applied in two different ways. The first was with a fixed capital expenditure value for each well in a given play that is the same regardless of well date or more importantly well depth (the total length of the well). This is obviously a simplistic view, but little is known or published about drilling and completion costs for wells, especially in the newer plays. The second way in which capital expenditure was applied in the economic model was using a capital expenditure value for each well that depended on the well depth. A specific per-foot capital expenditure value is calculated for each play by dividing the fixed capital expenditure value by the median total well depth of 2011 vintage wells for each play. When running the economic model using this variable capital expenditure, another input is the total well depth of each well, from which a unique capital expenditure value is calculated for each well. The total depth of the well is the length of pipe from the surface, along the curve and horizontal, to the end of the well, not the vertical depth.

Fortunately for operators, drilling and completion costs as well as lease costs can be written down before taxes according to different schedules. Drilling and completion costs are written down according to United States regulations for both depreciation and intangibles. Lease costs are written down as a percentage cost depletion. This means that each year the percentage of total production that was produced in that year is the percentage of lease cost that can be written off. In the case of the economic model utilized in this study, these percentages come from the projected production based on the decline curve. An example of a depreciation, intangibles, and depletion schedule for a Barnett shale well is shown below in Table 3-3.

Barnett Shale Tax Write Down Schedule

Year	Depreciation	Intangible	Depletion
1	0.14	0.80	0.1549
2	0.25	0.04	0.1902
3	0.17	0.04	0.1291
4	0.13	0.04	0.0960
5	0.11	0.04	0.0746
6	0.10	0.04	0.0597
7	0.10	0.00	0.0488
8	0.00	0.00	0.0405
9	0.00	0.00	0.0340
10	0.00	0.00	0.0288
11	0.00	0.00	0.0246
12	0.00	0.00	0.0212
13	0.00	0.00	0.0184
14	0.00	0.00	0.0160
15	0.00	0.00	0.0140
16	0.00	0.00	0.0123
17	0.00	0.00	0.0109
18	0.00	0.00	0.0097
19	0.00	0.00	0.0086
20	0.00	0.00	0.0077

Table 3-3: Barnett shale tax write down schedule

Lease costs for the operating company depend on regulation and norms in each area. States tend to have regulation about the spacing of wells. This well spacing value is defined in terms of acres per well and differs between shale gas plays. Similarly, the typical lease cost per acre varies between plays although it is generally relatively standard across areas within the same play. Given the well spacing and the per-acre lease cost, a total lease cost for a well can be calculated. The lease costs are calculated in this straightforward manor in the economic model.

After all of these costs and tax write-offs are applied to the revenue for each well, the economic model applies taxes. The model in this study used a severance tax rate of 5%, a state tax rate of 5%, and a federal corporate tax rate of 35%. This effectively combines to become a 38.3% tax rate. As mentioned above, the inflation rate that is used in the economic model is 1.5%, and the breakeven price for each well is calculated to achieve a 10% IRR. A summary of the input values that are used for each play can be found in Table 3-4, below.

3.3 MATLAB Calculation and Optimization Scheme

The economic model described above was written as a MATLAB function. The MATLAB function allowed for great versatility in applying the model to many sets of data, as well as convenient output data that could be easily plotted and analyzed. For each well, the model finds the natural gas price that results in a net present value (NPV) of zero using a discount rate of 10%. The NPV of a well is the sum of 20 years of discounted cash flow in this model. An iterative optimization process based on the calculated NPV of each well was coded into the MATLAB function to determine the breakeven gas price of each well. First the NPV of each well is calculated based on its peak gas production and LGR, using a NGL price that is 80% of the Cushing, OK WTI Spot Price FOB and an arbitrary natural gas price. The iterative optimization scheme changes the natural gas price applied in the model with each loop so that NPV converges towards zero (within +/- $100, which results in fractions of a cent difference in gas price). In other words, if the NPV of a well is negative by a large margin, the gas price applied in that loop is below the breakeven gas price for that well. The optimization scheme uses a Newton-esque optimization process to converge to the breakeven gas price that results in an NPV of zero. Some wells with unusually low production rates tended to be outliers that resulted in unrealistically high breakeven prices. To avoid this, the function sets the maximum breakeven gas price as $25.00/Mcf, so that in the output data all of the least profitable wells have a breakeven gas price of $25.00/Mcf.

The output of the economic model MATLAB function is a two-column matrix that contains the breakeven gas price of each well in one column, as well as the corresponding volume of gas produced by each well in the second column. This output is useful for building supply curves to analyze the amount of gas that was profitable at a given gas price in a vintage year.

	Barnett	Fayetteville	Woodford	Bakken	Marcellus	Haynesville	Eagle Ford
Decline curve parameters D, n	D=0.0584 n=0.5363	D=0.5263 n=0.6133	D=0.0507 n=0.6357	D=0.0380 n=0.5885	D=0.0500 n=0.6500	D=0.0947 n=0.6828	D=0.0563 n=0.8840
Royalty Rate	0.25	0.17	0.20	0.20	0.17	0.25	0.25
Severance Tax	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Federal Tax	0.35	0.35	0.35	0.35	0.35	0.35	0.35
State Tax	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Resulting Marginal Tax	0.383	0.383	0.383	0.383	0.383	0.383	0.383
Capital Expenditure (Fixed)	$3.00 million	$3.00 million	$5.00 million	$9.00 million	$5.00 million	$8.00 million	$8.50 million
Capital Expenditure (specific per-foot)	$270/ foot	$340/ foot	$400/ foot	$450/ foot	$450/ foot	$470/ foot	$580/ foot
Operating Costs	$0.75/ Mcf	$0.75/ Mcf	$0.75/ Mcf	$0.75/ Mcf	$0.75/ Mcf	$0.75/ Mcf	$0.75/ Mcf
Well Spacing	80 acres/well	80 acres/well	160 acres/well	160 acres/well	160 acres/well	160 acres/well	160 acres/well
Lease Cost	$5,000/ acre	$3,000/ acre	$3,000/ acre	$5,000/ acre	$3,000/ acre	$5,000/ acre	$5,000/ acre
Inflation	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Discount Rate	0.10	0.10	0.10	0.10	0.10	0.10	0.10

Table 3-4: Summary of economic model input values

4. Results

4.1 Breakeven Price Distribution

Obtaining a calculated breakeven price and associated volume of gas for individual shale gas wells in different plays can lead to interesting findings. First, the resulting breakeven prices can be plotted as a cumulative distribution function, like the one shown in Figure 4-1 below for Barnett vintages from 2005 to 2012. From the cumulative distribution function, the P20, P50, and P80 breakeven prices are compiled. The P20 breakeven price represents the natural gas price at which 20% of wells have a lower breakeven price, or which 80% of wells have a higher breakeven price. Similarly, the P80 breakeven price is the natural gas price at which 80% of wells have a lower breakeven price. The P50 breakeven price, logically, is the natural gas price at which half of the wells have a lower breakeven price and half of the wells have a higher breakeven price. Table 4-1 below summarizes the P20, P50, and P80 breakeven prices of the wells analyzed, broken down by play and vintage year. Additional cumulative distribution functions for the plays analyzed are included in Appendix A.

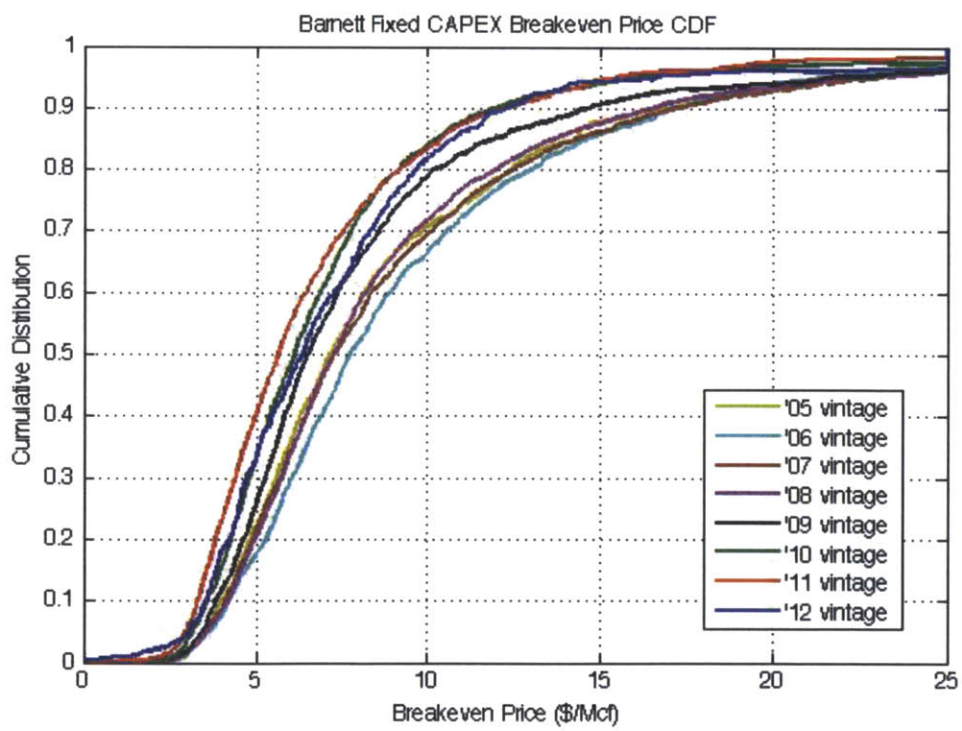


Figure 4-1: Cumulative Distribution Function of breakeven prices of vintage Barnett wells for 2005 to 2012 vintages

Year		Barnett Fixed	Barnett Variable	Fayetteville Fixed	Fayetteville Variable	Woodford Fixed	Woodford Variable	Bakken Fixed	Bakken Variable
	P20	$4.20	$4.33	$2.98	$3.06	$3.46	*	$0	$0
2012	**P50**	**$6.34**	**$6.22**	**$3.65**	**$5.73**	**$5.44**	*	**$0**	**$0**
	P80	$9.69	$9.09	$5.10	$5.02	$9.61	*	$15.99	$14.12
	P20	$3.80	$3.81	$3.13	$3.14	$3.71	*	$0	$0
2011	**P50**	**$5.64**	**$5.41**	**$3.88**	**$3.96**	**$4.99**	*	**$0**	**$0**
	P80	$9.19	$8.57	$5.61	$5.87	$7.81	*	$25.00	$25.00
	P20	$4.26	$4.18	$3.56	$3.38	$2.56	*	$0	$0
2010	**P50**	**$6.11**	**$5.79**	**$4.68**	**$4.35**	**$3.56**	*	**$0**	**$0**
	P80	$9.19	$8.66	$7.29	$6.67	$5.73	*	$14.94	$6.70
	P20	$4.62	$4.49	$3.68	$3.52	$3.11	$3.03	$0	$0
2009	**P50**	**$6.51**	**$6.18**	**$5.11**	**$4.78**	**$4.24**	**$4.43**	**$0**	**$0**
	P80	$10.17	$9.55	$7.84	$7.31	$7.24	$7.41	$25.00	$25.00
	P20	$4.97	$4.64	$4.02	$3.64	$2.55	$1.50	$0	$0
2008	**P50**	**$7.25**	**$6.59**	**$5.59**	**$4.91**	**$3.64**	**$3.49**	**$0**	**$0**
	P80	$12.01	$10.44	$8.89	$7.81	$7.21	$6.24	$25.00	$25.00
	P20	$4.88	$4.51	$4.75	$4.16	$4.99	$2.17	$0	$0
2007	**P50**	**$7.33**	**$6.50**	**$7.50**	**$6.20**	**$8.51**	**$5.15**	**$25.00**	**$25.00**
	P80	$12.48	$10.56	$13.47	$11.25	$15.22	$10.36	$25.00	$25.00
	P20	$5.29	$4.88	$5.69	$4.39	$5.22	$2.45	$3.56	$0
2006	**P50**	**$7.74**	**$7.16**	**$8.61**	**$6.47**	**$6.38**	**$5.45**	**$25.00**	**$25.00**
	P80	$13.04	$11.46	$14.05	$10.98	$9.70	$7.89	$25.00	$25.00
	P20	$4.81	$4.29						
2005	**P50**	**$7.19**	**$6.33**						
	P80	$12.46	$10.53						

Year		Marcellus Fixed	Marcellus Variable	Haynesville Fixed	Haynesville Variable	Eagle Ford Fixed	Eagle Ford Variable
	P20	$3.73	*	$5.01	$4.97	$5.40	$0.00
2012	**P50**	**$5.86**	*	**$6.03**	**$5.99**	**$8.68**	**$4.07**
	P80	$10.80	*	$7.44	$7.43	$18.49	$17.91
	P20	$2.90	*	$4.83	$4.93	$0.81	$2.46
2011	**P50**	**$4.30**	*	**$6.06**	**$6.06**	**$5.07**	**$5.07**
	P80	$7.07	*	$7.90	$7.99	$10.65	$9.95
	P20	$3.94	$2.98	$4.42	$4.35	$3.55	$3.69
2010	**P50**	**$5.63**	**$5.18**	**$5.68**	**$5.56**	**$8.27**	**$8.41**
	P80	$9.33	$9.06	$7.92	$7.54	$13.96	$13.47
	P20	$5.00	$4.85	$4.20	$4.02	$5.56	$5.40
2009	**P50**	**$7.85**	**$7.55**	**$5.84**	**$5.61**	**$7.67**	**$7.65**
	P80	$13.72	$12.57	$8.35	$7.85	$25.00	$21.17
	P20	$7.65	$6.58	$5.07	$4.69		
2008	**P50**	**$14.07**	**$11.51**	**$6.10**	**$6.07**		
	P80	$25.00	$25.00	$11.13	$10.07		

Table 4-1: Summary of breakeven gas prices ($/Mcf) for all wells, including P20, P50, P80 values

Not all of the plays and vintage years provided adequate well depth data. The Marcellus shale and Woodford shale, for example, did not provide well depth data for all of the wells drilled in more recent years. The data sets contained a large portion of zeros for total well depth. As such, when the economic analysis was carried out using the specific per-foot capital expenditure value, these wells had a calculated capital expenditure of zero. The large number of wells that fit this description strongly influenced the P20, P50, and P80 breakeven prices to the point that the numbers were wholly unrealistic and incorrect. The plays and years for which this was the case have the breakeven prices replaced with an asterisk in Table 4-1.

4.2 Supply Curves

A cumulative distribution function gives pertinent information about the variability of the breakeven prices of shale gas wells in the major plays across the last several years. While this information is illustrative of past price trends and offers some insight into the potential profitability (or lack of profitability in some cases) of shale wells, it does not provide any information about the volumes of natural gas connected to these breakeven prices. For this purpose, supply curves indicate the volume of natural gas that was produced at or below a particular breakeven price. This information is useful in a number of ways. First, it allows for a comparison to actual historic gas prices to estimate what volume of natural gas was economically produced in the past. Second, aggregate profit or loss in past years is insightful for determining just how economically sustainable shale gas is as a resource. In addition to retrospective analysis, supply curves offer a clear, functional platform from which hypothetical situations can be built by analyzing past trends in shale gas production and gas price. Supply curves can offer a basis for decisions about a broad range of issues from investment decisions to policy. The implications of these supply curves will be discussed in more depth later. Figure 4-2 shows the vintage supply curves for shale gas production from all plays examined, using the specific per-foot capital expenditure structure.

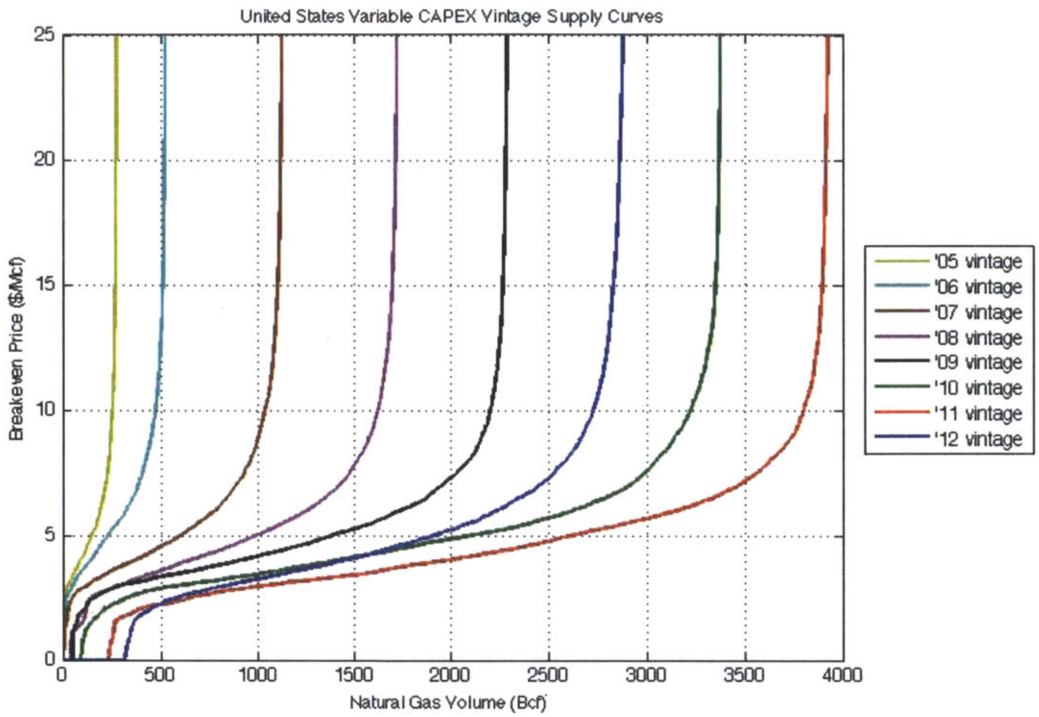


Figure 4-2: U.S. shale gas vintage supply curves, calculated using specific per-foot capital expenditure values

Both supply curves and the distribution of breakeven prices serve vital roles in analyzing past shale gas production. While supply curves offer the added benefit of connecting a volume of natural gas with the breakeven gas price that produced the volume, a detriment of supply curves is that they are not consistent across years because they partially depend on total yearly production numbers. In other words, supply curves are useful in some applications and types of analysis, while cumulative distribution functions and the variability of breakeven prices are useful in others. Supply curves are difficult to compare from year to year because there are many rapidly changing factors from year to year that influence the annual supply curve, and at the same time cumulative density functions of breakeven prices do not provide information about produced volumes of natural gas and the economic viability of those volumes.

The rapid growth of shale gas production means that the volume of shale gas produced each year differs drastically. A breakeven gas price of $5.00 in 2006 corresponds to 227.5 Bcf at a profit, while a breakeven price of $5.00 in 2009 corresponds to 1383 Bcf of gas at a profit, though the comparison is not a direct one. The truth is that the total volume of natural gas produced from shale in 2006 is significantly lower than the total volume of gas produced from shale in 2009. In addition to the difference in volumes, another factor that is at play between the two situations is the fact that operators are continually learning and adjusting their best practices. Improved operator know-how can result in lower capital expenditure for wells, which would in turn result in a lower breakeven gas price. Yet another factor that is often discussed in terms of gas production is known as the "creaming" effect. The "creaming" effect is essentially the idea that when a play is new, operators will produce the most promising (and theoretically cheapest) areas first. Once the best areas within a play are gone, it could be expected that production costs might rise, leading to a rise in breakeven price. Overall, there are several factors at play between supply curves from different years, so it can be difficult to compare vintage supply curves directly.

4.2.1 The Shift to Liquids-Rich Areas

Figure 4-3 below shows three vintage supply curves from the total United States gas production, using the specific per-foot capital expenditure calculation. There are two key features to note. The first is that between 2006 and 2012, the volume of natural gas that was produced at low breakeven costs grew dramatically. In recent years, below $5.00 per Mcf, a small change in breakeven gas price results in a substantial change in the volume of gas that can be economically produced. What this means for operators is that a small decrease in costs can have a large effect on whether or not individual wells post a profit. In Figure 4-2, the 2010 and 2011 vintage supply curves indicate that an even larger volume of gas was available at low prices than in 2012. The second important feature to notice is that in 2012, there is a large amount of essentially "free" gas. In 2012, 310.8 Bcf of natural gas was produced at a breakeven price of zero. This means that the well produced enough NGLs to cover the cost of the well, so the natural gas that was produced only increases profits. This can serve to put downward pressure on the price of natural gas. Additionally, it is important to notice that this "free" gas is a new phenomenon even in the young shale gas industry. In 2006, essentially no gas was produced at a breakeven price of zero dollars. In 2009, a small yet present amount of gas was produced at a breakeven price of zero dollars and by 2012 a substantial amount of gas was produced at a breakeven price of zero dollars. Supply curves help illustrate that as natural gas prices dropped, production moved towards liquids-rich areas.

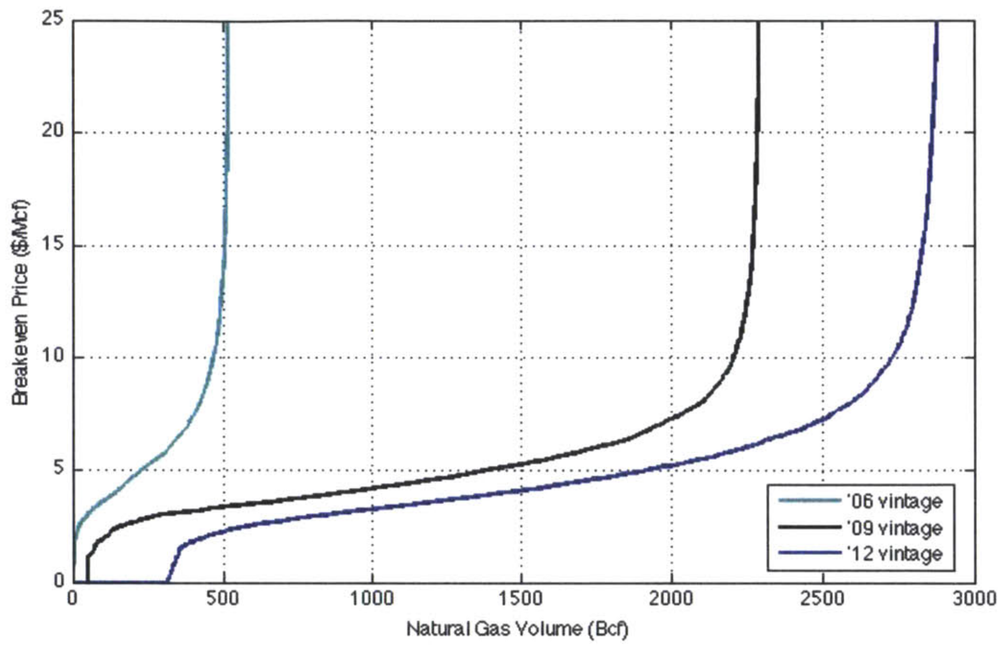


Figure 4-3: Select U.S. total shale gas supply curve vintages. The years were selected to highlight the shift towards liquids-rich shale gas production

4.2.2 Past Breakeven Volumes and Percentages

A major focus of this study was the creation of vintage supply curves to estimate the volume of natural gas that was produced economically in that corresponding year. Table 4-2 below summarizes the volumes of gas that the economic model utilized in this study predicts breakeven at the Natural Gas Futures Price of each particular vintage. The Natural Gas Futures Prices listed in the table are data taken from the EIA.

The volumes and percentages of natural gas that broke even at past Natural Gas Futures Prices are enlightening. Logically, the futures price of each year plays an important role in determining how much gas breaks even. It is no surprise that the years with the highest futures prices have the highest percentages of total yearly production that broke even. However this analysis, too, tells only a partial story of the profitability of historic shale gas wells.

		Fixed CAPEX		Variable CAPEX	
Vintage	Futures Price ($/Mcf)	Breakeven Gas Volume, Bcf	Percentage of total vintage production	Breakeven Gas Volume, Bcf	Percentage of total vintage production
2005	$9.22	235	86.5%	244	89.9%
2006	$7.14	345	66.1%	385	73.8%
2007	$7.28	820	72.6%	912	80.8%
2008	$9.10	1532	88.8%	1587	92.0%
2009	$4.25	970	42.2%	1036	45.1%
2010	$4.48	1656	48.9%	1743	51.4%
2011	$4.12	2091	53.0%	2053	52.0%
2012	$2.89	757	26.1%	770	26.5%

Table 4-2: Past volumes of natural gas, in Bcf, that broke even and the percentage of total vintage production that broke even

4.3 Aggregate Vintage Shale Gas Profitability

Of the wells that did not breakeven, some were only slightly unprofitable. On the other hand, some wells produced so little gas that hardly any of the well costs were recovered. Another way to analyze the profitability of historic wells is to compare the hypothetical revenue generated by the total volume of natural gas produced in each vintage at that year's futures gas price with the cost of producing that gas if each incremental volume of gas cost its breakeven price. For volumes of gas below the futures price, the difference between the futures price and the breakeven price of each incremental volume is value captured by the operator. For volumes above the futures price, the difference between the futures price and the breakeven price of incremental volumes is value lost by the operators. When summed, these increments of value captured and lost provide an estimation of whether the shale gas industry as a whole posted a profit or loss from each vintage year production. Figure 4-4 depicts this analysis on a supply curve, showing the breakeven price areas that create captured value for production companies, and the breakeven price areas that resulted in a value loss. The area representing the total revenue is also shown. The supply curve illustrated in Figure 4-4 is the U.S. 2010 vintage supply curve calculated using the specific per-foot capital expenditure method. The natural gas futures price for 2010, $4.48 is shown on the plot, as well as the breakeven volume of gas, 1,743 Bcf, and the total volume of gas produced, 3,389 Bcf.

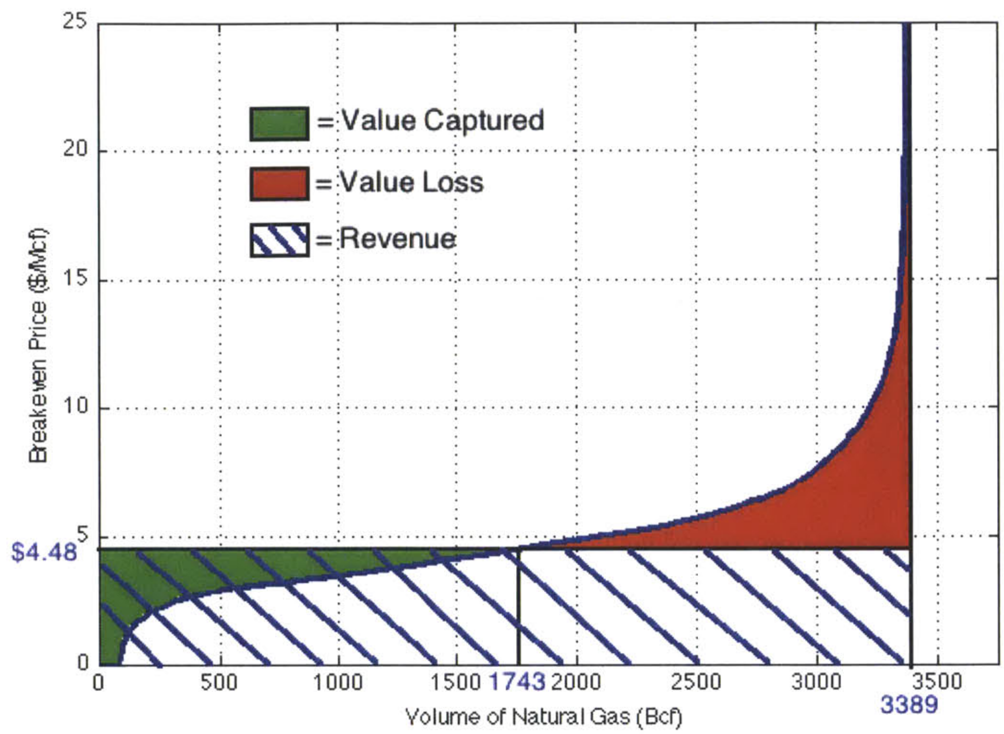


Figure 4-4: Representative regions of value captured, value loss, and revenue on the 2010 U.S. vintage supply curve, using 2010 Natural Gas Futures Price

The method described above utilizes an important simplifying assumption, which is that all of the natural gas produced in each vintage is sold at the natural gas futures price of that year. In reality, the sale price of the volumes of gas produced will fluctuate throughout the course of the vintage year, so the true revenue is not accurately depicted as the revenue box in Figure 4-4. Additionally, natural gas can be produced and then stored, rather than sold. Therefore the entire volume produced in a given year might not be sold in the year. For the sake of analysis, the assumptions used roughly approximate the true situation. Table 4-3 below shows a summary of the net difference between the hypothetical revenues and costs for each vintage year analyzed. The hypothetical revenue is the vintage futures gas price multiplied by the total gas volume produced in that year, represented by the revenue box in Figure 4-4. The hypothetical cost is roughly the integral of the supply curve for each vintage. Each well's breakeven price was multiplied by its contribution to total gas production, which resulted in a hypothetical cost for each increment of gas. These costs were summed to calculate the vintage's total hypothetical cost. The net difference is the cost subtracted from the revenue, and represents the total profit or loss for the shale gas producers in each vintage.

Vintage	Net Profit or (Loss), $ in billions	Revenue, $ in billions	Costs, $ in billions
2005	**$0.970**	$2.504	$1.533
2006	**$0.492**	$3.727	$3.235
2007	**$1.766**	$8.221	$6.455
2008	**$6.629**	$15.795	$9.167
2009	**($1.831)**	$9.771	$11.602
2010	**($1.489)**	$15.181	$16.670
2011	**($1.656)**	$16.257	$1.791
2012	**($5.239)**	$8.395	$13.633

Table 4-3: Revenue, costs, and net profit/loss for U.S. vintage shale gas production

Table 4-3 illustrates quite clearly that beginning in 2009, there has been a shift in the profitability of shale gas wells. Also, Table 4-2 above shows a distinct drop in the percentage of total yearly gas production that was produced at or below the historic futures price for the corresponding year, beginning in 2009 as well. Though there are surely several factors that affect these figures, there is no question that the sharp drop in natural gas prices between 2008 and 2009 adversely affected the profitability of shale gas wells in the United States. Figure 4-5 below presents the unmistakable shift in profitability of gas wells around 2009 in accord with the historic natural gas futures prices. Figure 4-5 seems to imply that there were two distinct periods in the brief history of shale gas in the United States. From 2005 to 2008 with gas prices in the range of $7.00 to $9.00/Mcf, shale gas production in the United States enjoyed a profitable rise in popularity. However for the next four years from 2009 to 2012, when prices were roughly halved, the production of shale gas proved to be an unprofitable industry on the whole. It also appears that if gas prices remain in the range of 2009 to 2012 prices, producers of shale gas face a tough challenge to economically produce natural gas from shale plays.

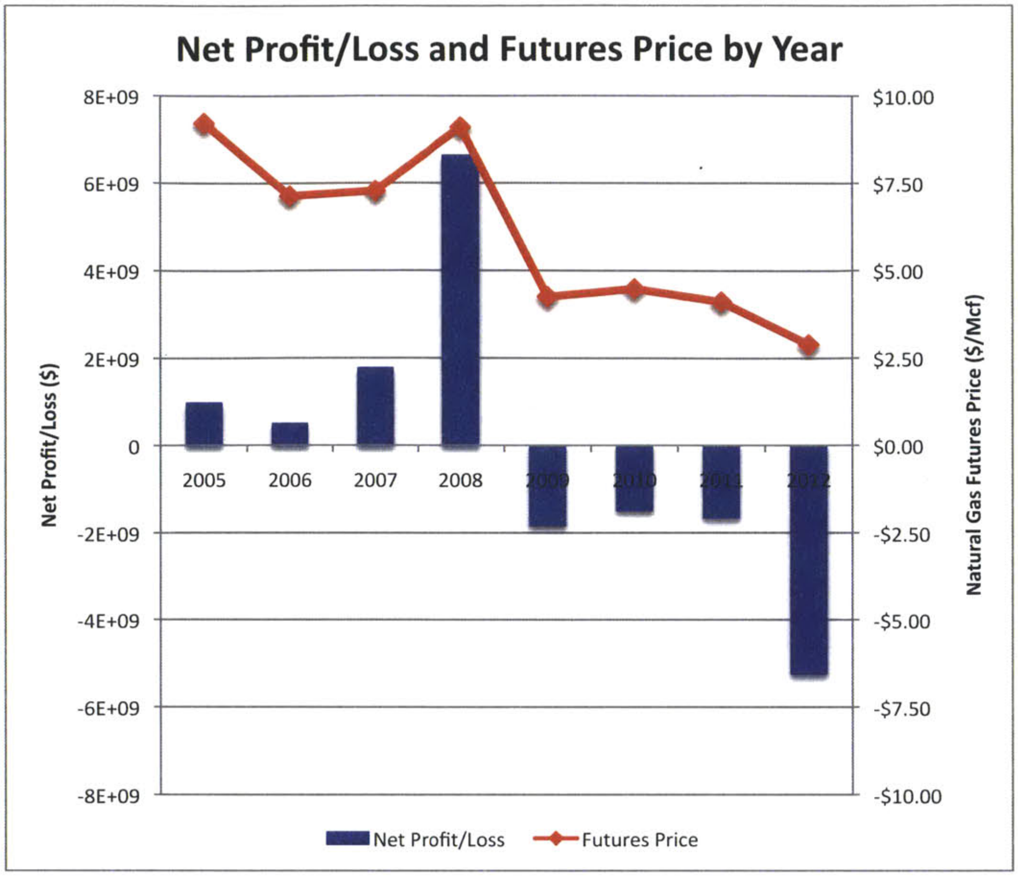


Figure 4-5: Calculated aggregate profit/loss of shale gas wells by vintage ($), with vintage Natural Gas Futures Price ($/Mcf)

5. Discussion and Implications of Analysis

5.1 Will production decline?

There is deservedly a lot of hope and excitement in the United States surrounding the prospect of shale gas production. After all, the ability to produce natural gas from shale formations has brought roughly a century's worth of new domestic natural gas resources to the United States. There is no question that shale gas will play a large and growing role in the energy picture of United States in future years. However it appears as though the young nature of the resource and its development has not yet reached equilibrium. The economic profitability of shale gas from 2005 to 2008 proves that the resource is economically viable given the right market conditions. The lucrative nature of shale gas production during those years brought many new players to the field, which in turn brought an oversupply of gas to the market and a dip in natural gas prices.

With natural gas prices at their lowest point in recent memory in 2012, the large net loss of the shale gas industry reflected the dip in prices. It is interesting to note however that 2012 was the first year since 2005 that the total production of natural gas from shale plays did not increase in comparison to the previous year. As Figure 4-2 above shows, from 2005 to 2011, the total production of shale gas increased with each consecutive year, bringing with it large volumes of gas that could be produced at low breakeven prices. 2012 saw a reversal in this trend, which is most likely due to the fact that operators realized that the majority of the wells they had been drilling would not be profitable given the market conditions. In an economically normative market, with gas prices at their current level, the volume of shale gas that is brought to market would continue to decline as it did from 2011 to 2012. It will be interesting to see whether production of shale gas remains at a lower level in the near future until gas prices rise. The analysis above also proves that if natural gas prices were to rise closer to the levels of 2005 to 2008, shale gas could provide a considerable volume of natural gas supply for the United States.

5.2 Does Shift to Liquids-Rich Areas Help?

Another trend that the analysis of the study reveals is the transition in recent years towards liquids-rich shale plays. The transition brought substantial volumes of "free" gas to the market beginning somewhat in 2009 but especially in 2011 and 2012. There are two points that can be taken away from this transition and the economic analysis above. The first is that even though these volumes of "free" gas had an effect on the net profit/loss balance of shale gas in 2011 and 2012, it was far from enough to make the overall balance positive. The operators who were able to sell gas with a breakeven price of zero dollars benefitted individually, but the profit/loss balance for the total production in these years was solidly negative. As a follow-up to this point, the transition to liquids-rich areas could result in a negative feedback situation. Operators move to liquids-rich areas in order to overcome the low gas prices in the market. However, producing liquids-rich areas and bringing "free" gas volumes to the market applies a downward pressure on natural gas prices. If the move to liquids-rich plays keeps gas prices at low levels, the incentive only increases for a further and more intense transition to liquids-rich shale production. A more intense transition in turn applies more pressure on the gas prices to keep them low. Unfortunately for the shale gas industry, this strategy of seeking liquids-rich plays for near-term profits could hinder the longer-term rise of gas prices. For shale gas to be profitable, the market conditions need to change such that gas prices rise. The transition to liquids-rich plays may actually be a bit of an obstacle to such a rise in gas prices.

5.3 Beneficiaries of Low-Price Gas

Even so, there are those who stand to benefit in the short-term future from the low gas prices in the market today. Natural gas power plants, for example, have experienced reduced fuel costs, which can be passed on to customers as lower electricity prices. Additionally, environmentalists argue that in order to lower greenhouse gas emissions in the near future, natural gas use for power generation needs to increase. The low gas prices in the current market might help push the market in the direction of increased natural gas use. However, it is important to stress that the rates of fugitive gas emissions during natural gas extraction are largely unknown. Chemical manufacturers and other manufacturing industries also stand to benefit from a large supply of low-price natural gas. Natural gas is widely used as both a fuel and feedstock in chemical manufacturing processes. The cost savings from low-price natural gas has the potential to spread to savings in many areas of the economy. Lower petrochemical costs can lower the price of many plastics, and lower fertilizer costs, derived largely from natural gas, can potentially lower food costs. The implications of low price natural gas for manufacturing have led some to claim that a new age of American manufacturing is dawning. Of course, this depends in large part on the long-term supply of cheap natural gas, which is not a certainty.

5.4 International Implications

The largest implications of shale gas production in the United States are actually outside of the country. As mentioned above, the world's shale gas resources are enormous, though the United States is the only country to date to exploit the resource at a large scale. Other countries that have a large shale gas resource, particularly China, will want to take note of whether shale gas production in the United States is successful. It is important to realize that natural gas does not have a standard price around the world, as oil does. The market for oil is global and oil prices are therefore relatively level around the world. Natural gas on the other hand is traded in spot markets around the world and is often tied to contracts. Additionally, industry regulation differs around the world, which also affects gas price. In recent years, the natural gas price in the United States has been well below the spot prices of other markets around the world [21]. As Table 1-1 above shows, China has an enormous shale gas resource. The natural gas price in China is under government control with a complicated structure that ultimately dictates the end-user price [22]. Furthermore, China's upstream natural gas sector is dominated by three national oil companies, of which the government has a 90%, 77.42%, and 70.6% share [23]. With such a strong government influence, China may be in a good position to exploit its shale gas resources without the dip in price that the unregulated United States gas market experienced.

Shale gas in the United States has become generally unprofitable in recent years as a supply glut caused a major drop in prices. What is for sure, though, is that the United States has proven that natural gas found in shale formations can be produced and can contribute large volumes of natural gas to a country's energy mix. China, with its government control, may look to increase its production of domestic shale gas. Much of China's natural gas is imported and the rate of imports is climbing due its increasing energy consumption. The large shale gas resource in China possibly offers an option for increased natural gas supply security in the longer-term. The reason that China is an important example to highlight is that China's shale gas resource is estimated to be very large, and its energy consumption is also huge and growing. The combination leads to a situation where shale gas development may become an important part of the energy mix. This is not to say that China is the only country where this applies. Whether or not China and other countries around the world decide to exploit domestic shale gas resources, the progression of the shale gas industry in the United States serves as a valuable case study from which to learn for future decisions.

5.5 Criticisms of Analysis Method

There are a few shortcomings of this study that merit acknowledgement. In general, these shortcomings are the result of a lack of data. The first issue is that industry data on true drilling and completion costs (capital expenditure) is naturally very limited. As major driver of the profitability of a well, operators are reluctant to reveal these costs. Many of the capital expenditures used for the various plays in this study were listed as targets rather than true costs, so it may be the case that actual drilling and completion costs are a bit higher than the values used. Real data for drilling and completion costs would enhance the accuracy of results, though it is unclear how large of a difference this would make. In addition, better knowledge of drilling and completions costs could be the basis for different specific cost values. For instance, wells could be characterized by specific per-foot costs that differ for the vertical and horizontal portions of the well to create an even more realistic capital expenditure structure. The capital expenditure values used in this study could stand to be improved with true drilling and completion cost data.

A second issue with data used in this study revolves around misreporting in the HDPI database from which well data was accessed. It was mentioned above that the data analyzed was filtered to reject unreasonable data values. Unfortunately, while this filtering process screens out obvious mistakes, it does not assure the accuracy of the rest of the data. Elimination of these individual instances of misreported data could improve the results, even in the slightest way. A few major instances of misreporting/ lack of data occurred in the 2010 to 2012 well depth data for the Woodford shale and the 2011 and 2012 well depth data for the Marcellus shale. In these data sets, large numbers of wells were reported to have a well depth of zero. When using the variable per-foot capital expenditure structure with this data, the capital expenditure for these wells was calculated to be zero, which is obviously incorrect. To overcome this problem, the variable capital expenditure vintage supply curves for 2010 to 2012 use the fixed capital expenditure results for the missing data sets, so that the total volume of produced gas remains accurate for both capital expenditure structures. Though the difference appears to be minute, improved data reporting would improve the accuracy of results.

6. Conclusion

The production of natural gas from shale formations has had a dramatic impact on the oil and gas industry in the United States. The combination of horizontal drilling and hydraulic fracturing has made vast quantities of previously unrecoverable natural gas in shale formations producible. Beginning in 2005 in the Barnett shale in the Fort Worth Basin of Texas, the rate of production of shale gas has grown to the point that it contributes a significant amount of natural gas to the United States' market. Shale plays across the country are now seen as future resources of natural gas. The situation is similar outside of the United States, as early estimates of global shale gas resources indicate that the total global shale gas resource could be enormous. Countries outside of the United States are considering producing their own domestic shale gas resources, and the United States' shale gas expansion serves as a good tool for analyzing the prospect of shale gas production.

Before the expansive production of shale gas, U.S. natural gas prices and supply levels had an erratic path through deregulation and periods of high price volatility. The dramatic increase in price around the year 2005 was the force that finally pushed shale gas production to become a viable resource. From that point on, the volume of natural gas supplied to the market from shale plays expanded. Despite this expansion and the development of industry know-how, a major challenge that faces shale gas producers is the seemingly unpredictable variability in production rates from shale wells. This documented variability creates difficulty for a number of stakeholders, from operators to those who trade natural gas and land resources. Another challenge is that in recent years, the increased supply of natural gas has driven prices down, creating a difficult environment for operators to produce shale gas at a profit, which is something this study investigates. Nonetheless, there are industries and sectors that stand to benefit from large volumes of low-price natural gas.

This study uses a discounted cash flow economic model to estimate some of the economic conditions surrounding shale gas development. Real well data is used for the inputs to the model, along with cost parameters typical of each play. Production data for each play was analyzed to define parameters for a power-law exponential decline curve that is used to estimate the production of each well out to 20 years. The model is programmed as a MATLAB function that finds the breakeven gas price, defined as the wellhead gas price that produces a 10% IRR. The outputs of the model are a breakeven price in dollars per thousand cubic feet as well as the volume of gas produced during the first year of production. These outputs are useful for a variety of analyses.

Cumulative density functions for each play and year were created in this study to analyze the P20, P50, and P80 breakeven wellhead gas prices. Results naturally vary by play and year. In addition, supply curves were built that show the volumes of gas that could be produced at or below a range of breakeven prices. The results were then compared to the Natural Gas Futures Price for each given year, to estimate the volume of gas that was produced economically as well as what percentage of the total gas production these volumes represented. The results of this analysis show two distinct periods within the 2005 to 2012 timeline. In the years 2005 to 2008, roughly three quarters or more of the gas produced in each year broke even at that year's Futures price. From 2009 to 2012, that portion dropped to around half of total production, even dropping as low as roughly one quarter of total production in 2012. Lastly, the total net profit or loss of the shale gas industry for each year was estimated based on simple revenue and cost assumptions. It is not surprising that the same two periods revealed by the supply curve analysis presented themselves again. From 2005 to 2008, the economic model utilized estimates that in total, shale gas producers made a profit each year. On the contrary, from 2009 to 2012, gas production resulted in a net loss. These two periods of distinct shale gas economic conditions coincide with a substantial drop in natural gas prices.

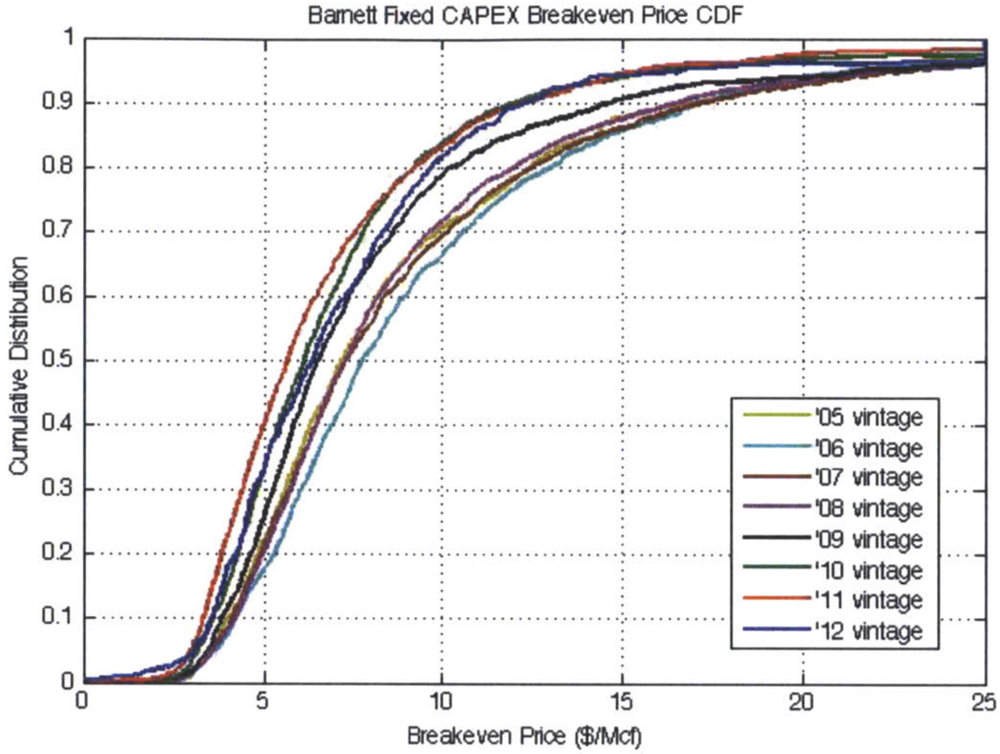
The variation in the profitability of U.S. shale gas over its short history suggests that the young industry has not yet reached equilibrium. Based on the estimated net monetary losses each year starting in 2009, it would not be surprising to see production of shale gas slow down, as it did from 2011 to 2012. This trend may continue until gas prices rise and shale gas production becomes profitable on aggregate. Another trend that was witnessed apparently as a result of the drop in shale gas profitability was a shift in production towards more liquids-rich areas. Supply curves from 2011 and 2012 show that a considerable volume of "free" gas, or gas that breaks even at zero dollars per Mcf because of the large volumes of liquids produced from the same well, was produced.

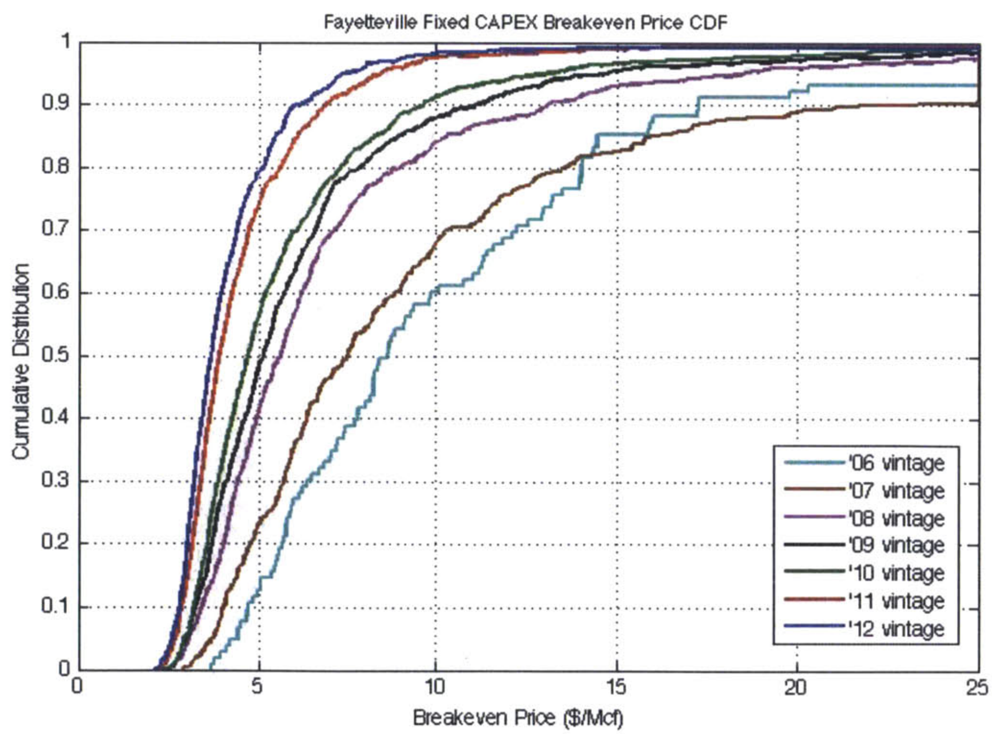
These "free" gas volumes were not present in the early years of shale gas. Unfortunately, these volumes of gas that breakeven at zero dollars per Mcf probably apply downward pressure on natural gas prices and inhibit the return of shale gas to net profitability.

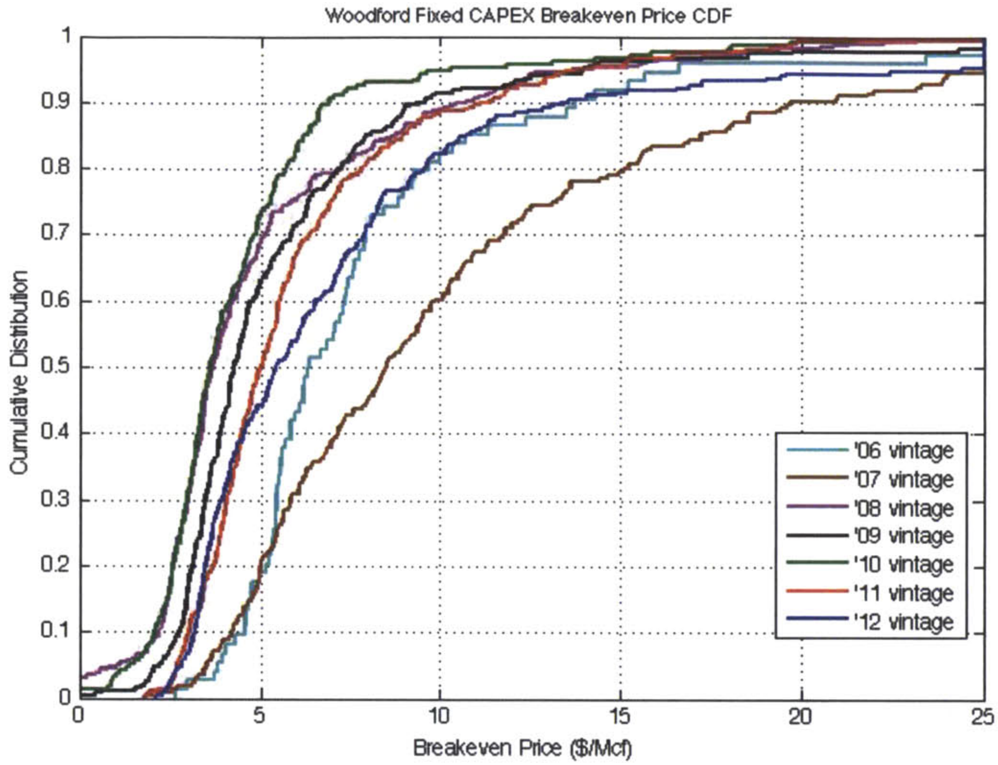
Even though shale gas production has met some challenges in recent years, there is no question that the resource is vast and presents potential gas supply for decades to come. As the years 2005 to 2008 prove, shale gas can be a profitable venture in the right economic conditions. This has implications around the world, as countries with higher natural gas prices than the United States search for a lower cost source. The fact that the United States was able to exploit shale gas resources domestically is essentially proof that the resource exists, and early estimates from around the globe paint a rosy global natural gas supply picture as a result. Though excitement over the new shale gas resource is warranted, caution must be exhibited to exploit it responsibly and economically. The shale gas resource is undoubtedly real, but still young.

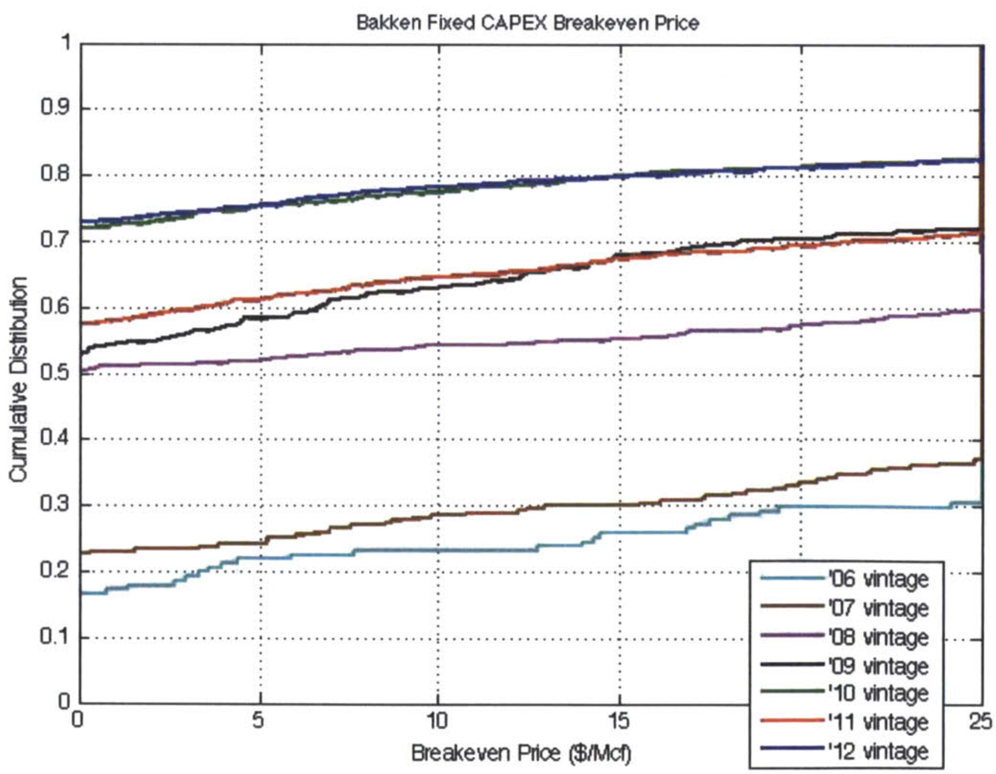
Appendices

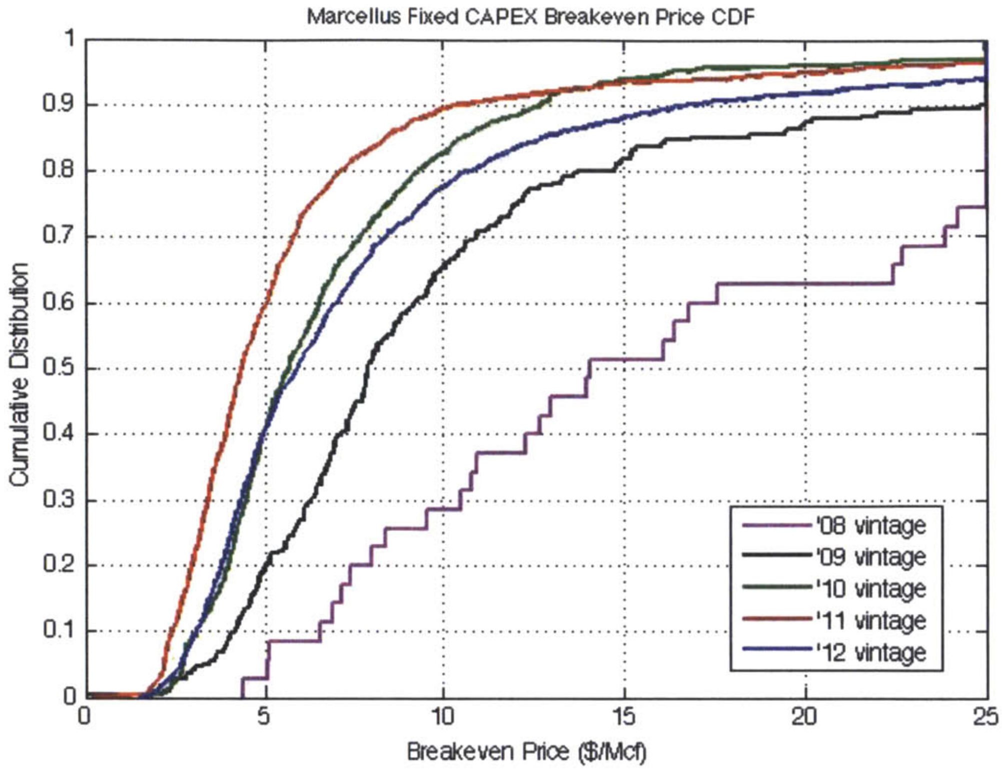
Appendix A: Breakeven Price Cumulative Distribution Functions by Play






Woodford Fixed CAPEX Breakeven Price CDF
Cumulative Distribution
Breakeven Price ($/Mcf)
'06 vintage
'07 vintage
'08 vintage
'09 vintage
'10 vintage
'11 vintage
'12 vintage


Bakken Fixed CAPEX Breakeven Price
Cumulative Distribution
Breakeven Price ($/Mcf)
'06 vintage
'07 vintage
'08 vintage
'09 vintage
'10 vintage
'11 vintage
'12 vintage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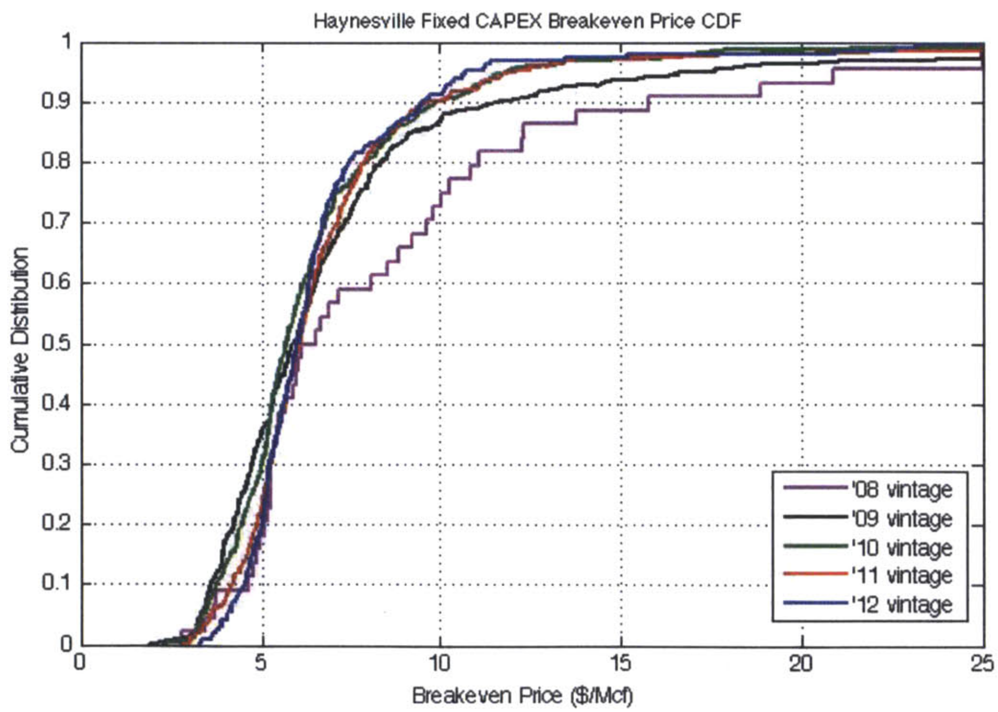
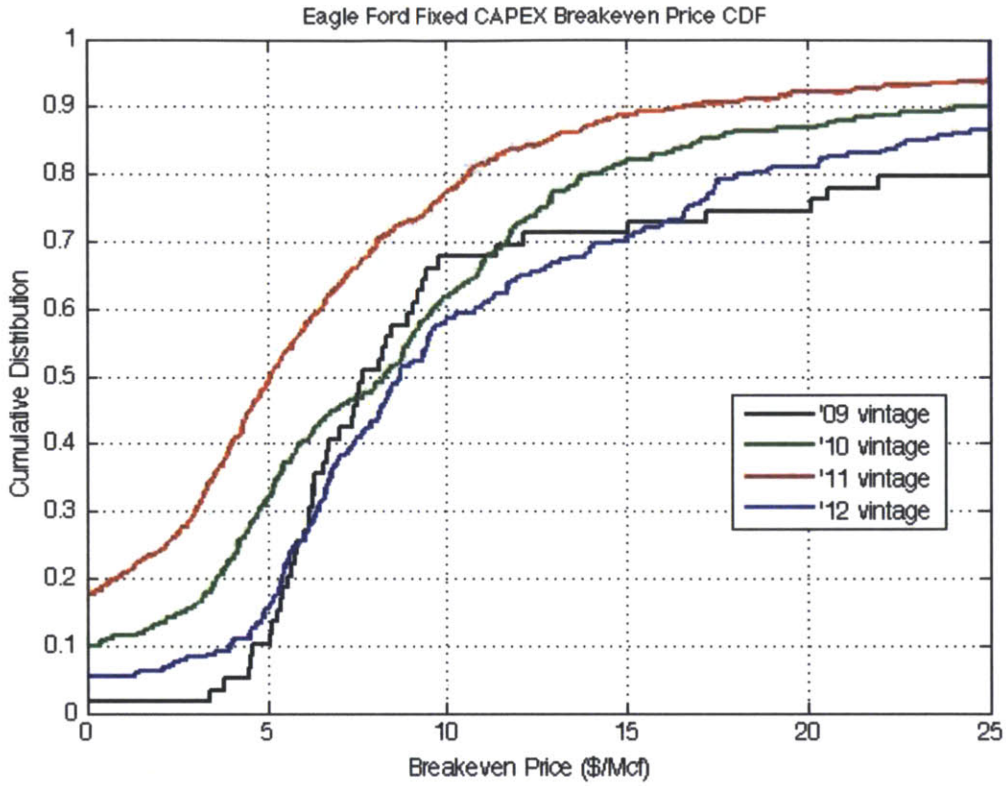
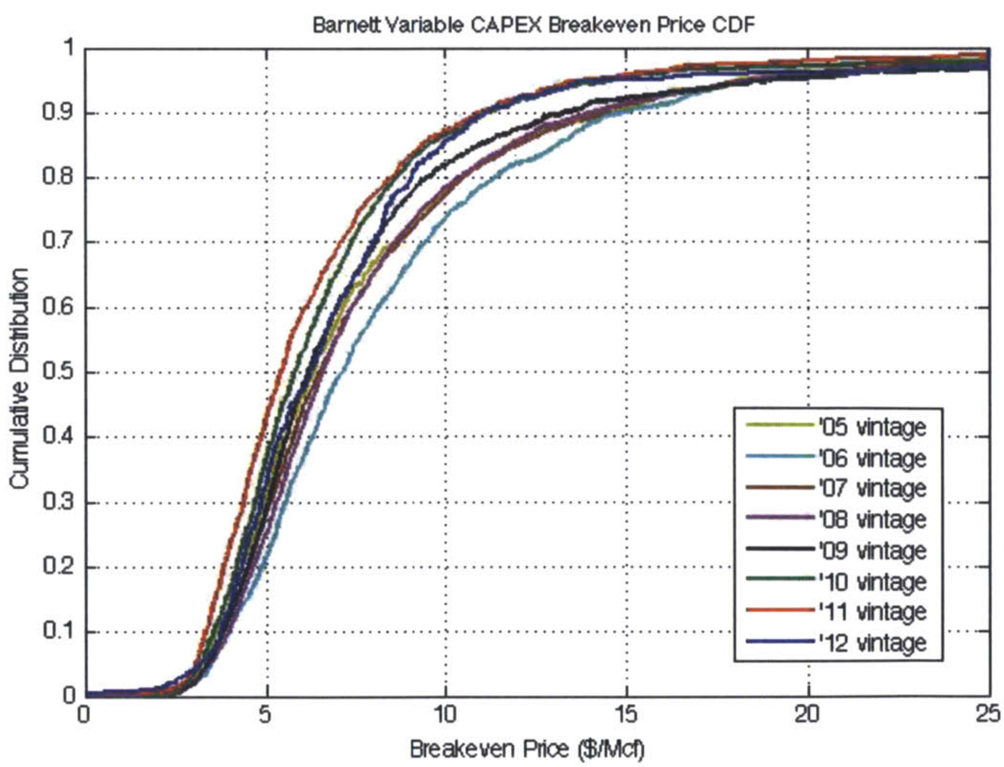
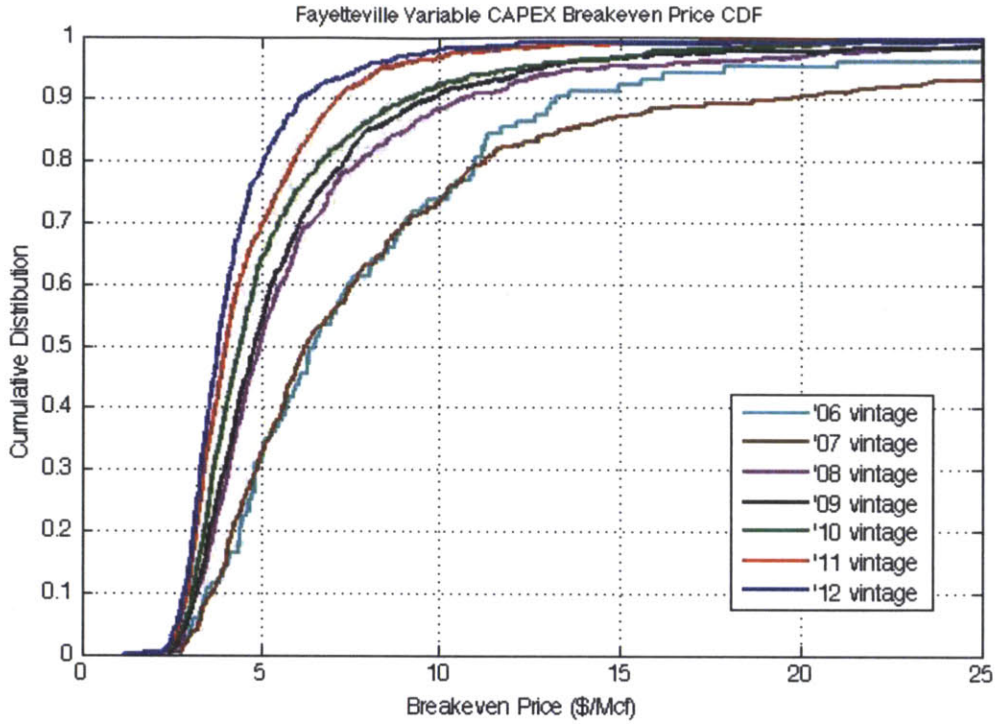
Cumulative Distribution
Breakeven Price ($/Mcf)
'08 vintage
'09 vintage
'10 vintage
'11 vintage
'12 vintage

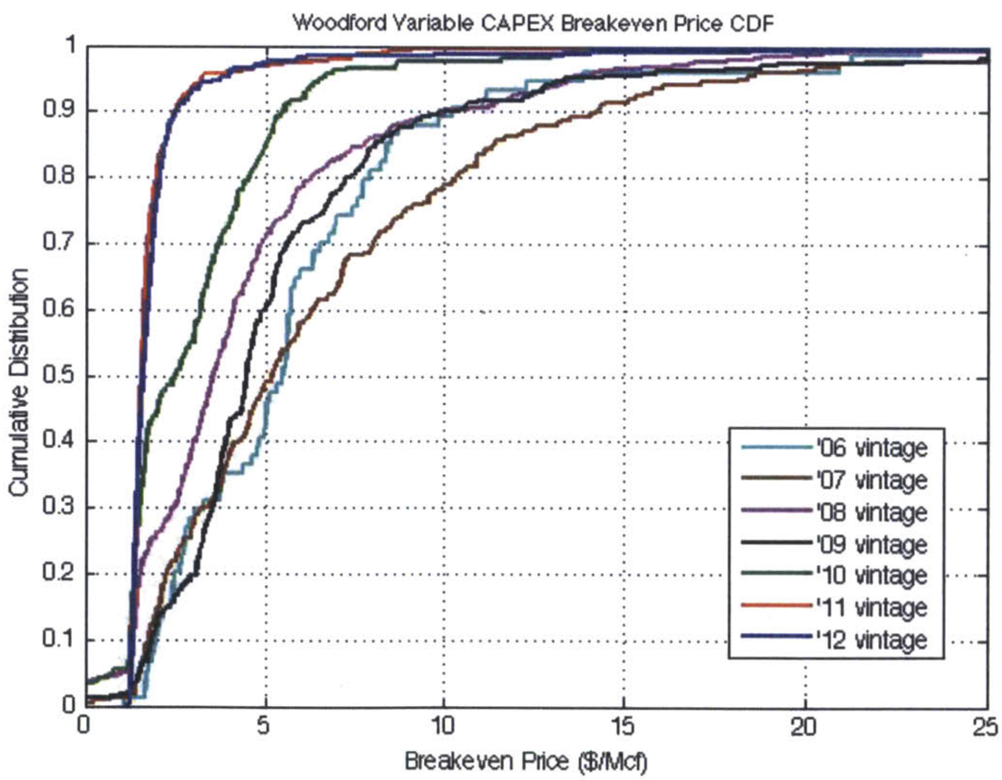

Haynesville Fixed CAPEX Breakeven Price CDF
Cumulative Distribution
Breakeven Price ($/Mcf)
'08 vintage
'09 vintage
'10 vintage
'11 vintage
'12 vintage


Eagle Ford Fixed CAPEX Breakeven Price CDF
Cumulative Distribution
Breakeven Price ($/Mcf)
'09 vintage
'10 vintage
'11 vintage
'12 vintage
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
0
5
10
15
20
25

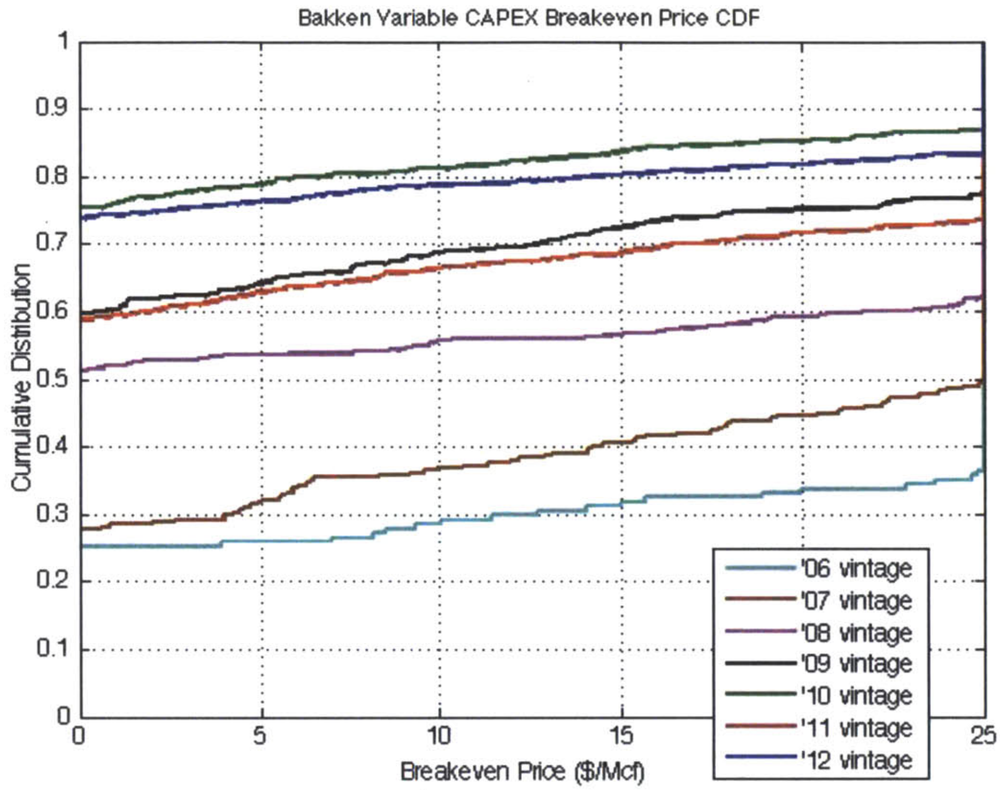

Barnett Variable CAPEX Breakeven Price CDF
Cumulative Distribution
Breakeven Price ($/Mcf)
'05 vintage
'06 vintage
'07 vintage
'08 vintage
'09 vintage
'10 vintage
'11 vintage
'12 vintage
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
0
5
10
15
20
25

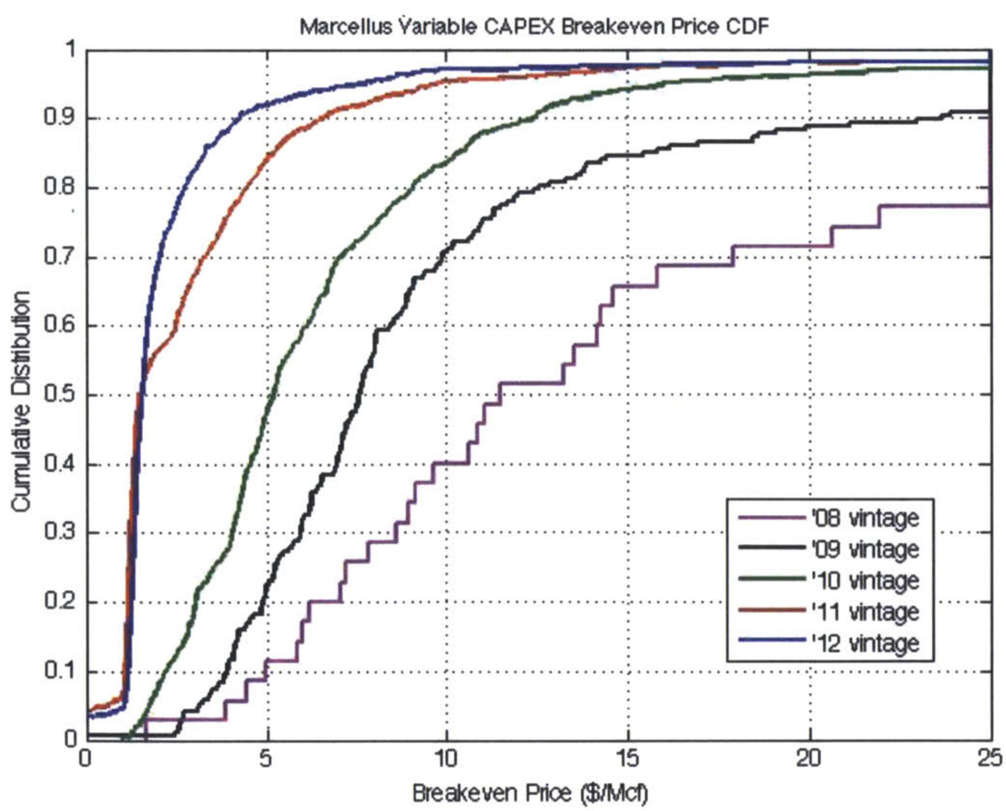


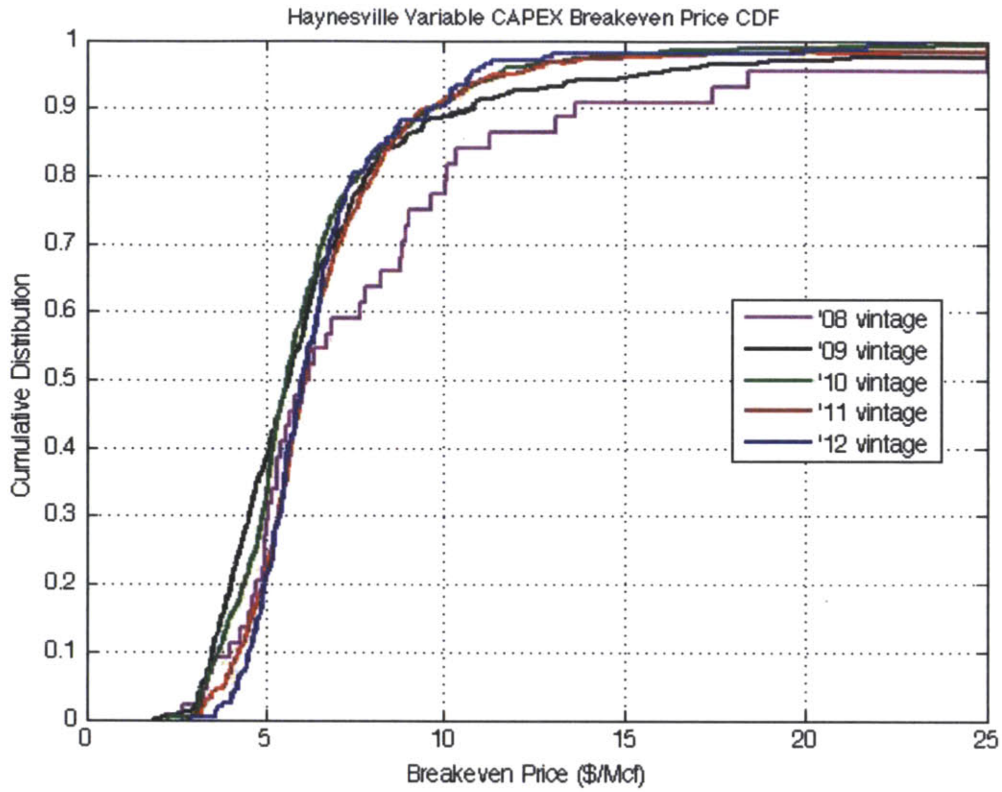
Fayetteville Variable CAPEX Breakeven Price CDF
Cumulative Distribution
Breakeven Price ($/Mcf)
'06 vintage
'07 vintage
'08 vintage
'09 vintage
'10 vintage
'11 vintage
'12 vintage

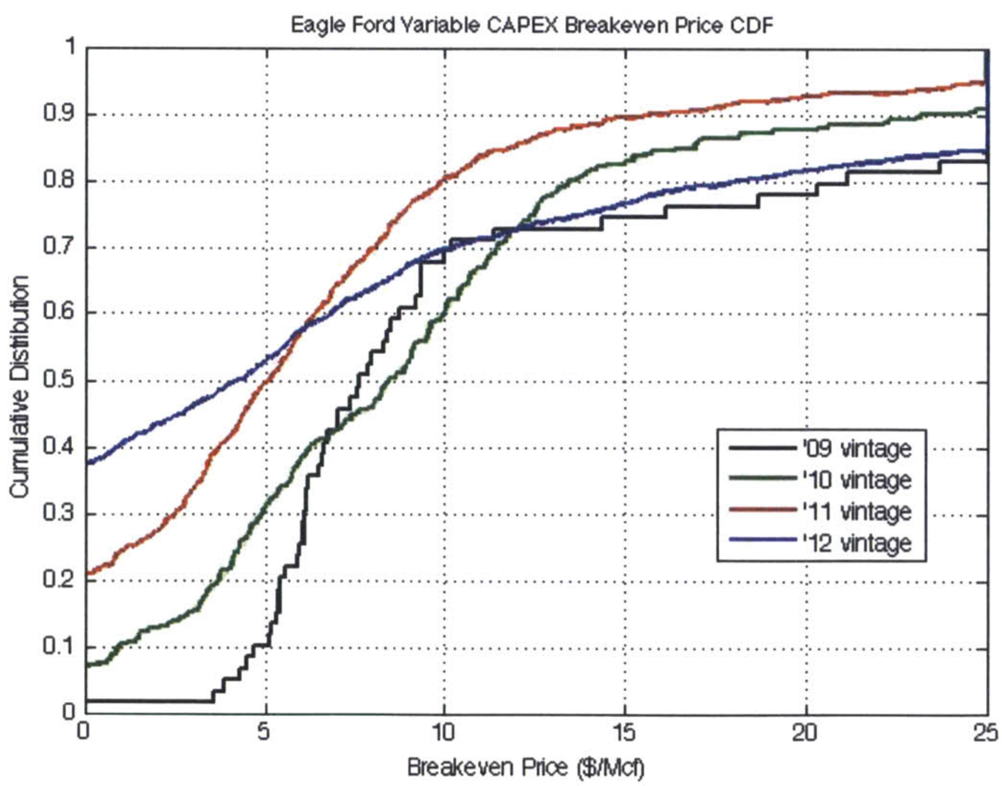


Woodford Variable CAPEX Breakeven Price CDF
Cumulative Distribution
Breakeven Price ($/Mcf)
'06 vintage
'07 vintage
'08 vintage
'09 vintage
'10 vintage
'11 vintage
'12 vintage

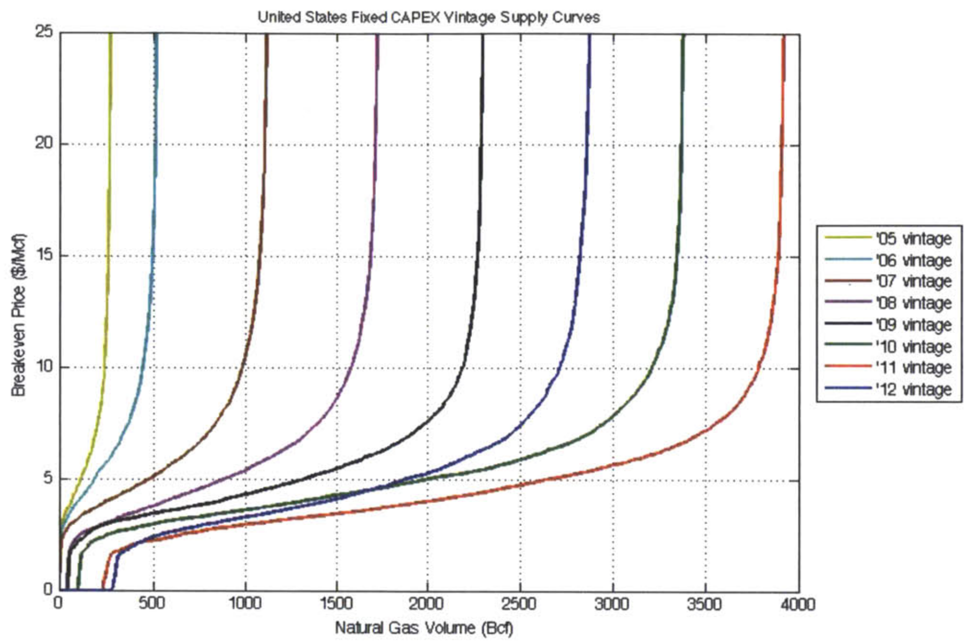

Bakken Variable CAPEX Breakeven Price CDF
Cumulative Distribution
Breakeven Price ($/Mcf)
'06 vintage
'07 vintage
'08 vintage
'09 vintage
'10 vintage
'11 vintage
'12 vintage

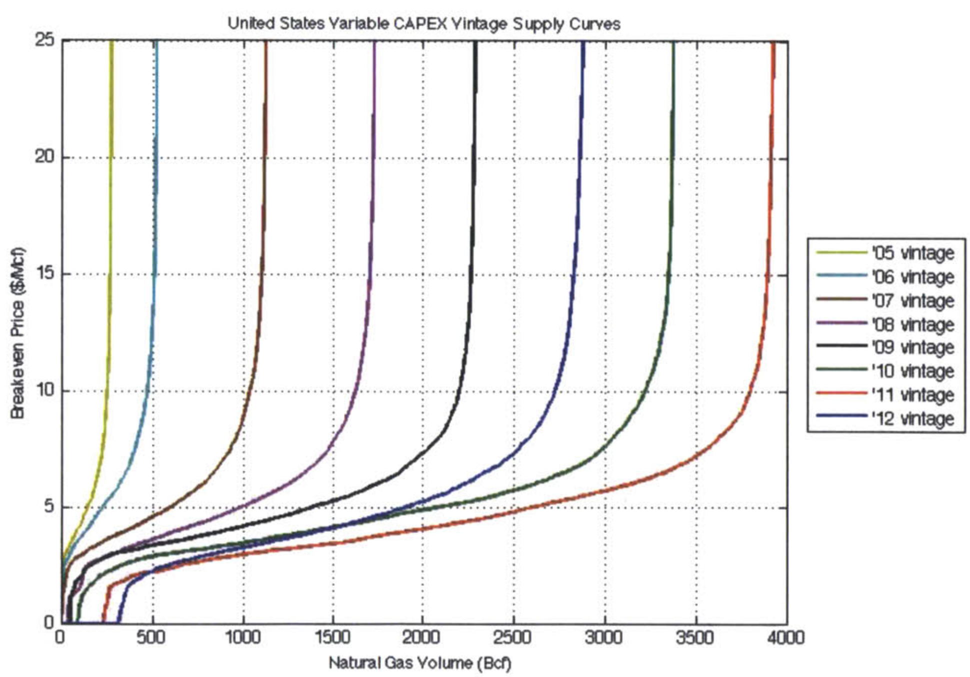

Marcellus Variable CAPEX Breakeven Price CDF
Cumulative Distribution
Breakeven Price ($/Mcf)
'08 vintage
'09 vintage
'10 vintage
'11 vintage
'12 vintage


Haynesville Variable CAPEX Breakeven Price CDF
Cumulative Distribution
Breakeven Price ($/Mcf)
'08 vintage
'09 vintage
'10 vintage
'11 vintage
'12 vintage


Eagle Ford Variable CAPEX Breakeven Price CDF
Cumulative Distribution
Breakeven Price ($/Mcf)
'09 vintage
'10 vintage
'11 vintage
'12 vintage

Appendix B: United States Vintage Supply Curves





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