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Eagle Ford Shale: Evaluation of Companies and Well Productivity

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Eagle Ford Shale: Evaluation of Companies and Well Productivity

by

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Thesis

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Dedication

This work is dedicated to my wonderful father, Jose. Without his love, example, and encouragement, I would not be the person I am today. Thanks for always believing in me.

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Abstract

Eagle Ford Shale: Evaluation of Companies and Well Productivity

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The University of Texas at Austin, 2016

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Unconventional resources, particularly shale reservoirs, are a significant component in oil and gas production in the United States as they represent (as of May 2015) 48 and 58 percent, respectively, of the total oil and gas produced. However, there has been a deceleration on oil and gas production in general because of low market prices. The drastic decline in oil and gas prices that started in 2014 has companies struggling to continue their operations, resulting in negative financial outcomes for 2015 for most companies. The present work examines the financial results of three companies, EOG Resources, Pioneer Natural Resources, and Chesapeake Energy, along with their particular well productivity using the Logistic Growth model to forecast production in one of the most prolific shale plays in the United States, the Eagle Ford. This work also examines the economic feasibility of drilling new wells when oil prices are low using a discounted cash flow model for each company. The financial analysis shows that from the three companies, Pioneer Natural Resources has the best financial results; its high cash-flow-to-debt ratio, and low debt and debt-to-equity ratios make it an attractive company to invest in. In

contrast, Chesapeake has the worst results which represents high risk for investors, and EOG has moderate results that still make it a good company to invest in. The discounted cash flow model demonstrate that under the cost assumptions and estimated production used in this work, EOG gets the best results from their wells located in the Eagle Ford with break-even prices bordering the 40 $/bbl compared to the other companies with break-even prices above 87 $/bbl for Pioneer and 89 $/bbl for Chesapeake. From the discounted cash flow model, it can also be concluded that none of the companies in the analysis is expected to gain revenue from drilling new wells if oil prices are under 40 $/bbl, and that companies that are quick to respond to the low prices by reducing their drilling and completion costs can significantly improve their well economics.

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Chapter 1: Introduction

The extraction of unconventional resources from shale rocks has spurred an exponential growth of oil and gas well drilling and has changed the energy landscape not only in the United States but also worldwide. For the United States, unconventional oil production was 4.6 million barrels per day as of May 2015, which represents 48% of total U.S. oil production. Regarding natural gas, the domestic dry shale gas production was 41.5 billion standard cubic feet as of May 2015, which represents 58% of total U.S. natural gas production (U.S. EIA, 2015). This scenario has changed the country's energy portfolio, especially with the cheap supply of natural gas reducing the U.S. imports, and contributing to the national goal of being energy independent (on natural gas).

However, in the ever changing economy, oil and gas companies have experienced a recent setback because of low market prices. The drastic decline in oil and gas prices in 2014 has companies struggling to continue their operations as their financial results show net income losses by year-end 2015, which have resulted in the revaluation and sale of non-core assets to raise capital.

Despite this environment, many companies have continued to drill even with apparently adverse economic results. Questions arise when analyzing their cash flow and balance sheets such as: Is it profitable to drill under current cost structures when prices are low? What is the breakeven price? What strategies are companies using to stay afloat?

The thesis aims to answer the previous questions by analyzing financial ratios and well economics of shale formations using the Eagle Ford Shale as reference case. A multiscenario analysis is performed to understand the principal variables that improve the economics of new wells, and establish the break-even price of individual wells under the cost structures and production volumes of three companies: EOG Resources, Pioneer Natural Resources, and Chesapeake Energy.

This section is followed by seven chapters. Chapter 2 presents a brief explanation of the oil market emphasizing the complex and dynamic interactions of the variables that determine oil and gas prices. Chapter 3 describes the principal factors affecting well economics: production decline rates and costs; and their differences when evaluating wells in shale formations compared to wells in conventional reservoirs. In Chapter 4, I discuss the impact of low oil prices on companies' finances and operations, as well as strategies used by companies to minimize risk in times of uncertainty. Chapter 5 includes a description of the selected companies in the study including production and reserves volumes, and the results and analysis of the companies' financial ratios. In Chapter 6, I evaluate two different methods for the development of a production model using wells located in the Eagle Ford. Three individual production models are developed for each of the companies in the study. Chapter 7 uses the discounted cash flow (DCF) approach to determine the economic feasibility of drilling a typical well in the Eagle Ford for each company in the study. A multiscenario analysis is used to determine the break-even price for each company, as well as to perform a sensitivity analysis. Finally, Chapter 8 presents the conclusions of the study.

Chapter 2: The oil market

The price of oil has an important impact on economic activity and our lives. Of all the energy sources, oil and its products represent the largest energy expenditure compared to any other individual energy source or technology; therefore, it has a significant impact on the economy (King et al., 2015). For modern civilization, oil plays an important role because it is crucial to meet transportation needs until we find an accessible alternative fuel that aligns to our current budgets and travel time disposition (Ausubel, 2014).

The financial concerns associated with the future oil price and its relationship with a country's economy also affect other commodity markets such as other energy commodities, metals, and agriculture. For this reason, many analysts have created models to attempt forecasting oil prices; but reality has shown that the dynamics driving it are complex and many times unpredictable. In 2014 when the oil prices started declining rapidly, many industry specialists were certain that the price would not fall below 40 $/bbl or similar estimates. 2015, proved they were wrong.

In this chapter, I present a brief history of oil and natural gas prices, and some of the factors that play an important role to understand fluctuating prices.

2.1. Understanding oil and natural gas prices

Understanding the mechanisms that drive oil prices is especially important for oil companies, since a bad forecast can terribly hurt them. In 1998 when prices were around 10 $/bbl, specialists forecasted that prices would not go back up in the short term. Based on this, many companies hedged their production at 10 to 15 $/bbl (Carollo, 2012) and faced the consequences when prices started increasing in 1999, and then picked in 2001 because of the Iraq war (9/11 events) before falling again as can be seen in Figure 2.1.

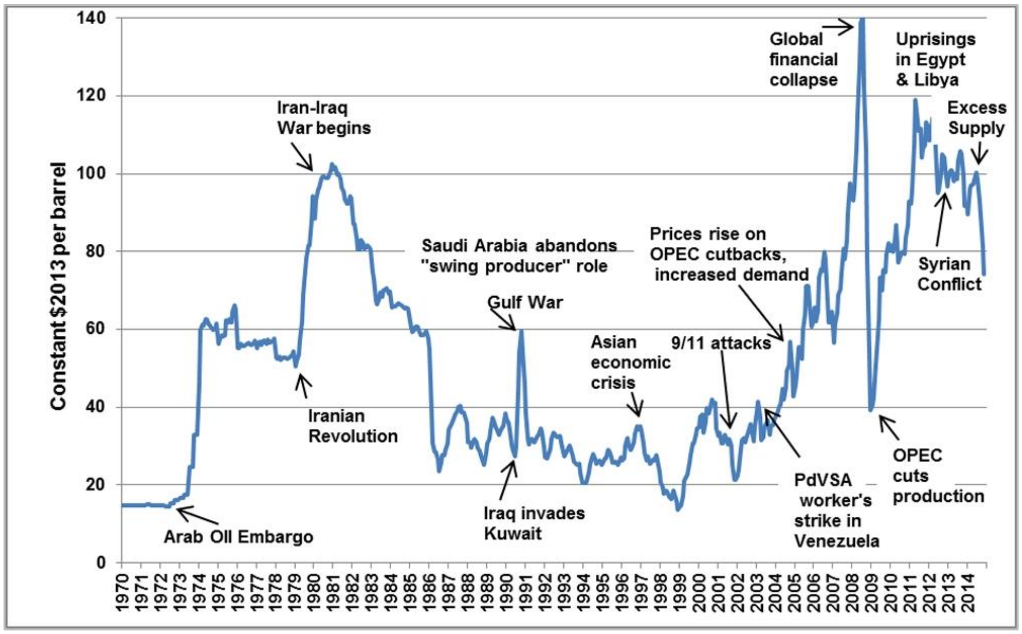


Figure 2.1. Oil prices and historical events 1970-2014 (Source: U.S. Department of Energy, 2015).

There are various modeling approaches when trying to forecast oil prices. These models attempt to predict the price behavior given different factors and their interactions. Some models include regression, time series, and artificial neural networks among others. Based on research studies, regression models are weak because they depend on forecasting other variables to forecast oil prices (De Souza e Silva at al., 2010), and time series models are not useful because oil prices exhibit a nonlinear behavior (Xie et al., 2006). Artificial neural networks and a combination of other models seem to be promising (De Souza e Silva at al., 2010); but it is difficult to include all the variables in this intricate system when the relationship between them is not completely understood.

Ultimately, oil price is determined by the economic model of supply and demand balance. However, supply and demand are affected by outside forces with many interacting factors including: geopolitical events, discoveries of new oil reserves, the financial and economic status of global economies, new energy sources and technologies, weather conditions, and decisions by oil producers including OPEC (Organization of the Petroleum Exporting Countries) and North American oil companies among others. Thus, it is very difficult to model these complex and dynamic interactions.

The demand part of the price function is largely driven by economic development around the world (Sorkhabi, 2008). Economic development translates into an increment in energy demand, especially in developing countries as they try to improve their standard of living. Countries with large populations, such as India and China, have had a rapid economic growth over the past decade and have drastically increased their demand for oil. Additionally, the demand is also affected by competition with new energy sources that at the same time is driven by an increasing concern for the environment.

On the other hand, the supply part of the price function is driven by new oil discoveries (reserves additions), spare capacity of oil fields, spare capacity or lack thereof in refineries (for petroleum products), OPEC and independent oil company decisions, and even some unpredictable events like natural disasters and geopolitical events including wars and political instability, especially in OPEC nations.

Let us discuss the OPEC's role further. OPEC manages the oil production of its member nations by setting quotas. From the world's oil production in 2015, OPEC nations produced 40% of the total, and their exports represented about 60% of the total oil traded worldwide (U.S. EIA, Feb. 9, 2016). Furthermore, geopolitical events affecting OPEC nations have historically resulted in reductions in oil production (U.S. EIA, Feb. 9, 2016).

This situation partially explains why oil prices go up when the OPEC production quotas are reduced. Other factors mentioned before also play a part in the final price.

As for natural gas, the Henry Hub is the pricing point for natural gas future contracts representing overall market conditions in the United States and used to compare the relationship between oil and natural gas prices. Supply and demand balance is still the main driver of natural gas prices; and like oil, it is also affected by reserves, production output, storage, weather, and seasonality.

One important characteristic about natural gas is that its consumption is seasonal but its production is not. This seasonality leads to higher prices during winter and lower prices during summer because of its use in heating and cooling systems. More natural gas tends to be used for heating northern U.S. cities during winter than for generating power to run air conditioning in southern U.S. cities during summer.

2.2. Oil price vs. natural gas price

The disparity between oil and natural gas prices can largely be attributed to the differences between their energy content. Natural gas is priced in dollars per million BTU and oil is priced in dollars per barrel. To be comparable, it is an industry standard to use a 5.8 to 1 ratio, given that a barrel of oil produces 5.8 million BTUs of energy.

The difference in price per BTU also resides in their physical state. Natural gas is not as easy to transport because of its gaseous state, although infrastructure deployment has increased worldwide over the past decade. On the other hand, oil is easily transportable because of its liquid form making it the No.1 energy commodity worldwide (McGuire, 2015). However, this makes oil prices more volatile given its vulnerability to events that can disrupt its transportation.

Natural gas price fluctuations generally followed those of crude oil; and substitution and competition between oil and natural gas seemed to be the link between their prices (Brown and Yucel, 2008). However, after the crisis of 2008, natural gas prices continued to follow a downward trend in contrast to oil, which slowly started to pick up in 2009 (see Figure 2.2).

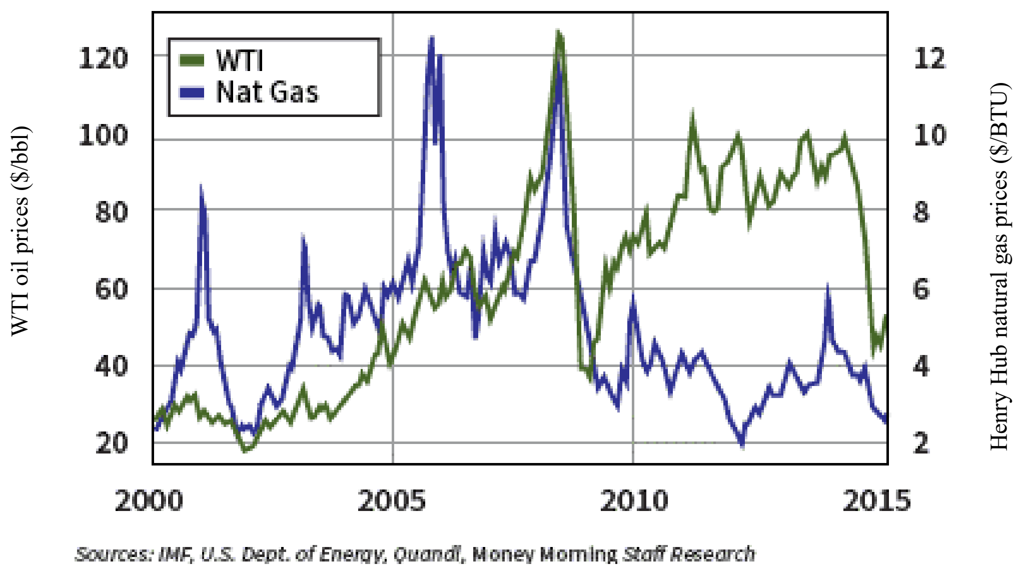


Figure 2.2. WTI oil prices and Henry Hub natural gas prices 2000-2015 **(**Source: McGuire, 2015).

Over the past decade in the U.S., advances in extraction techniques from unconventional reservoirs have allowed the production of amounts of both oil and natural gas in very significant quantities that were not previously anticipated. From Figure 2.3, it can be observed that the United States' dry gas production from shale reservoirs started increasing rapidly in 2007 when it accounted for 5% of the total production. By 2013 shale gas accounted for 40% of the total dry gas production and continues to increase. The increased in the total production of natural gas is a determining factor for the low gas prices experienced since 2008 and the disparity between oil and gas prices trends.

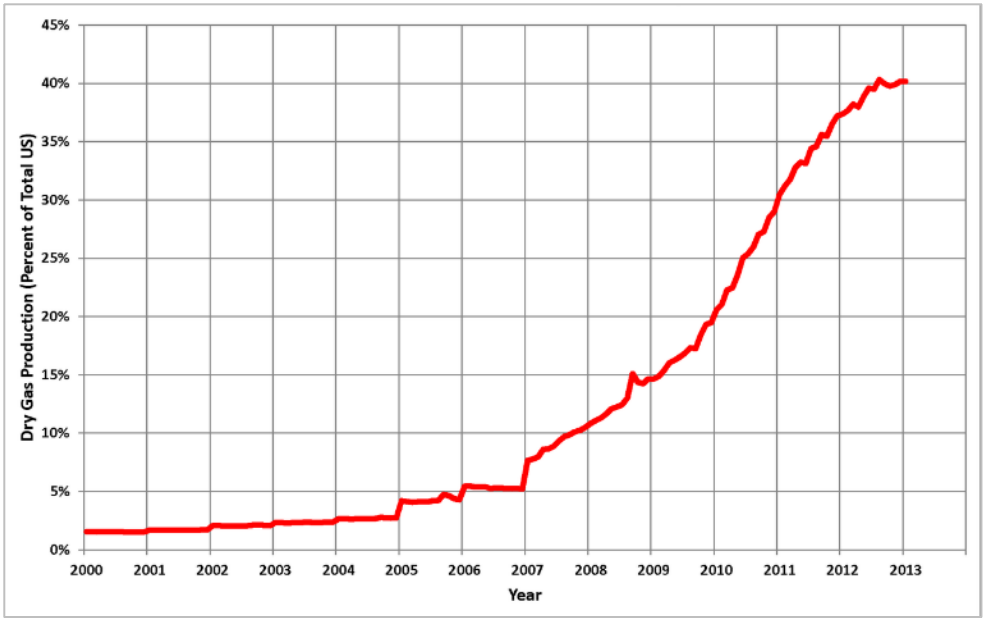


Figure 2.3. Shale gas production as a percentage of total U.S. dry gas production 2000-2013 (Source: U.S. EIA, 2013).

2.3. Oil price history

The majority of the abrupt changes in oil price can be explained both by geopolitical events and supply-demand imbalances affected by both production and consumption technologies (see Figure 2.1).

For example, the first oil shock was a result of the Yom Kippur War/Arab embargo in 1973 when the nominal price increased from 4.31 $/bbl to 10.11 $/bbl. The second oil shock increased the oil price from 15.85 $/bbl to 39.50 $/bbl; and started in 1978 due to the Iranian Revolution and picked in 1980 as a result of the Iran-Iraq War. The first abrupt price drop showed in Figure 2.1 was a result of the world's oversupply and less demand

(Carollo, 2012). In the same way, the Gulf War, Iraq War, and the financial crisis of 2008 were the primary reasons to the changes in oil price for those years.

2.3.1. The crisis of 2008

The oil price collapse of 2008 was something never seen in the history of the oil industry. Crude oil prices fell abruptly from almost 140 $/bbl to under 40 $/bbl. It was not the result of a decline in oil demand; in fact, there was an increase on the global demand of around 2 million bbls/day and a reduction in the production of about the same amount (Carollo, 2012) contradicting the law of supply and demand. This was a special case. The crash of international financial institutions was a detonator to burst the oil bubble by affecting daily trades of oil contracts on financial markets; and therefore, bringing down the price of oil (Carollo, 2012).

In this situation, the OPEC tried to remediate the situation by implementing cuts in production. However, this action did not prevent the price from continuing downwards; and confirmed that OPEC’s decisions are not always the determinant factor on the dynamics of crude oil prices (Carollo, 2012).

2.3.2. Current oil price

The drop in oil price that started in June 2014 was triggered largely by continued oversupply when demand was not growing at the same level, along with financial concerns in Europe and Asia, uncertainty in equity and non-energy commodity markets, high inventory levels of crude oil, and Iran’s compliance on the nuclear deal lifting the sanctions which will rise Iranian crude oil exports (U.S. EIA, Feb. 2016; OPEC, Aug. 2015). Since mid-2014 the price trend has been downwards with small and brief periods in the change of the overall trend as observed in Figure 2.4. The WTI price as of February 2016 is 32.15 $/bbl which represents a decrease of 69.4% compared to June 2014.

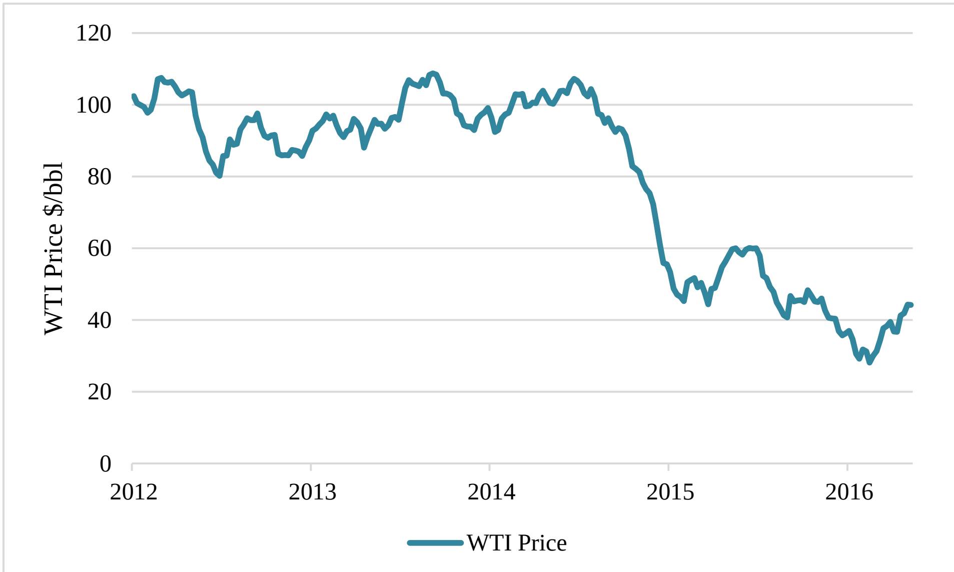


Figure 2.4. WTI Oil price history from January 2012 to May 2016 **(**Source: U.S. Energy Information Administration, May 2016).

As previously explained, there are many factors affecting prices; and in the past, OPEC has tried to help maintaining prices at a certain level. However, it is unlikely that countries such as Saudi Arabia will lower their production as a strategy to slow the development of new energy sources which have increased the production of the United States and Canada in recent years.

The current situation limits new production, which, in theory, should allow for a modest rise of oil prices because of the supply and demand law. The current global projection for oil demand predicts growth of about 1.3 million barrels per day propelled by the low oil prices encouraging transportation fuel demand and an increased demand of petrochemicals in China, Unites States, and Asia-Pacific (OPEC, Feb. 2016). However, as explained in this chapter, the dynamics to predict the future oil price are complex.

Chapter 3: Economic aspects of shale reservoirs

The economic feasibility of production from shale rocks differs from conventional reservoirs in many aspects. First, conventional reservoirs have been studied and produced for longer; and, their production forecasting can be achieved by using traditional methods, while production from shale rocks is relatively new. Therefore, there is limited experience forecasting production from shales and tight sands. This limited experience with shale production can bring great uncertainty when evaluating the economics of these reservoirs as it greatly depends on production volumes. Second, shale formations are difficult and expensive to develop. From well design to the handling of flow-back water, costs associated to shale reservoirs can affect or delay the development of a play.

In this chapter, I describe the principal factors affecting well economics: production decline rates and costs, in addition to how these vary between shale wells and wells in conventional reservoirs. Costs are divided in three categories to have a better understanding of what is included in each: capital costs, operation costs, and financing costs.

3.1. Production decline rates

The extraction of hydrocarbons from shale reservoirs is relatively new and still needs more data and experience to reduce uncertainty when drawing assumptions for these plays. Still, the limited data available from existing wells suggests that production declines more rapidly in shale wells than in conventional vertical wells (Lake et al., 2013). A shale well can reach its total production within the first five years in contrast to the projected thirty-year longevity for most conventional wells. As a result, companies must continue drilling, as well as to use re-fracturing and enhanced oil recovery techniques to maintain high production volumes and low unit costs.

Initial production of a well typically bears some correlation with the expected cumulative production during the life of the well. As technology improves and companies find and target sweet spots, initial production has seen a constant increase allowing companies to extract more oil during the initial months of production, a trend that can be observed across different plays. One example is the Eagle Ford Shale that has seen a continuous improvement in initial productivity (see Figure 3.1). The targeting of sweet spots to maximize initial production has allowed companies to be resilient despite decline rates that can reach up to 79% for the first year, like in the Niobrara Shale, or can be as low as 18% for the first year like in the Monterey-Temblor Shale. Decline rates for the first year in some Texas shale plays are: 60% for the Eagle Ford, 65% for the Barnett, and 66% for the Permian (Hughes, 2013).

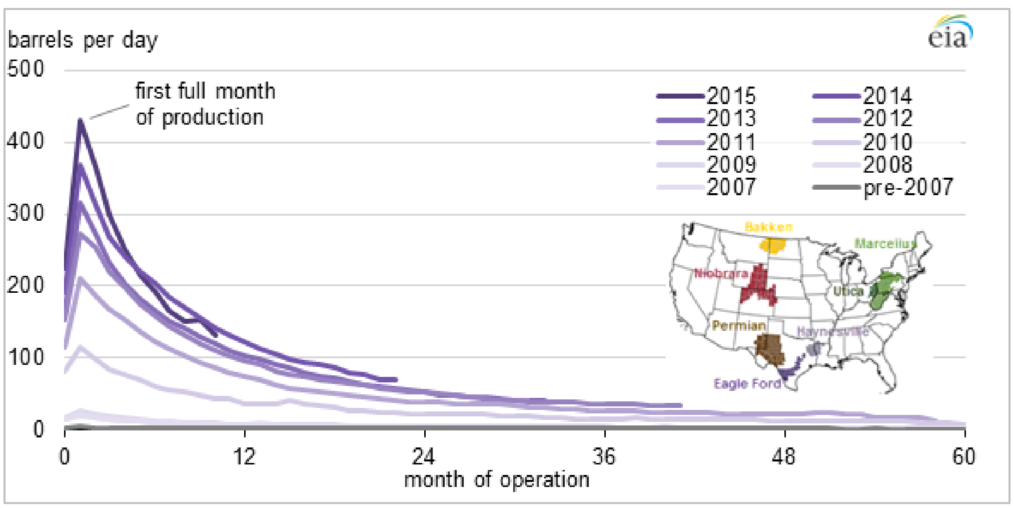


Figure 3.1. Average oil production per well in the Eagle Ford (Source: U.S. Energy Information Administration, February 2016).

3.2. Costs

The variations on costs primarily depend on the location's geology, well depth, and water management and disposal options.

3.2.1. Capital costs

Capital costs or capital expenditures (CAPEX) are funds invested by a company to start a new project or to improve the useful life of an existing capital asset. CAPEX typically consists on geological and geophysical (G&G) costs, drilling costs, tankers, facilities, pipelines, and other items. However, when analyzing the economics of shale plays, the approach is usually centered in the economic feasibility of drilling a new well or a group of wells in a certain area where the G&G costs can be omitted as shale reservoirs have little discovery risk and very few wells are unproductive (Lake et al, 2013). Additionally, economic analysis on a well by well basis in an already productive play also disregards facilities and pipelines costs because these were already considered when evaluating the initial development of the play. Under this approach, CAPEX are composed in its majority by drilling and completion costs (D&C), and to a lesser extent by abandonment costs. At the same time, D&C can be divided into intangible and tangible costs. Intangible costs are not part of the final operating well which usually include service fees, fluids, rented equipment, and expendable equipment. Tangible costs are the opposite and often include casings, equipment, and other tangibles. Abandonment costs are associated with the environmentally safe abandonment of a well and facilities at the end of its economic life.

In contrast to conventional wells, shale wells need additional operations after drilling for them to produce. These operations are those for hydraulic fracturing, a well-stimulation technique in which a hydraulically pressurized liquid (fracking fluid), that includes the blend of water with sand and chemicals, is injected into the ground in order to create fractures in shale rocks to increase the flow of hydrocarbons from a well. Depending on the depth of the geological formation, fracturing activities can take place from several hundred feet to several miles underground. Hydraulic fracturing is part of the completion cost; and it significantly contributes to the increased capital cost of putting a well into production as it accounts for the largest portion of D&C. Table 3.1 shows the typical cost breakdown for D&C in the Eagle Ford from which drilling represents 38% of the total cost and completion represents 62%.

	$ Thousands	
DRILLING		
Set Up costs	$	215.00
35 Rig days @20k/d	$	700.00
Fluids, chemicals, transportation & fuel	$	270.00
Services & rental equipment	$	540.00
Bits, expendable equipment & Misc.	$	60.00
Labor, engineering & overhead	$	70.00
Casing and other tangibles	$	190.00
Contingencies	$	240.00
Plugging and abandonment	$	100.00
Sub-total for drilling	**$**	**2,385.00**
COMPLETION		
Set up	$	35.00
Rig & daywork	$	115.00
Fluid, chemicals, transportation & fuel	$	66.00
Services & rental equipment	$	208.00
Formation Stimulation	$	2,760.00
Expendable equipment & Misc.	$	19.00
Casing and other tangibles	$	430.00
Contingencies	$	325.00
Sub-Total for completion	**$**	**3,958.00**
Total D&C budget	**$**	**6,343.00**

Table 3.1. Typical budget for a well in the Eagle Ford Shale for the year 2011 (Source: Rigzone, 2011).

Drilling and completion costs vary across and within plays depending on the geology of the area, its complexity, and well design (lateral length and fracture stages). In 2015, drilling costs ranged from 90 to 180 $/ft, and completion costs were between 400 and 800 $/ft (U.S. EIA, Mar. 2016). For the Eagle Ford Shale, these costs per foot were approximately 150 $/ft and 700 $/ft for drilling and completion respectively in the same time period (U.S. EIA, Mar. 2016).

From Table 3.1, the largest component of the completion cost is formation stimulation which refers to hydraulic fracturing; a process that uses large amounts of water. It is estimated that 2 to 4 million gallons of water per horizontal well are typically required for hydraulic fracturing. (Wang et al., 2014). This is problematic in drought prone areas such as west Texas. As a result, companies are forced to come up with better solutions for the amount of water used by changing to other fluids or by adopting techniques that allow them to re-use or recycle water. Adopting these techniques has the additional benefit of reducing costs, for some plays, compared to hauling water in or out.

Another component of hydraulic fracturing is the proppant used in the fracking fluid which keeps fractures opened allowing the flow of hydrocarbons. The proppant is typically sand, also called “frac-sand”; but artificial materials such as man-made ceramic are also used. Frac-sand prices vary depending on its quality. In the United States, the freight on board (FOB) price for the year 2015 ranged from 60 to 150 $/ton with an average of 67 $/ton (Rock Products, 2015). In the Eagle Ford Shale, proppant costs are higher due to heavy reliance on artificial proppant. Additionally, gas prone areas where pressure is high increases proppant use and completion cost (U.S. EIA, Mar. 2016)

As the industry continues to evolve, improvements in drilling and completion technologies have allowed companies to reduce times, lower total well costs, and increase well performance. Improvements in drilling technology include longer laterals, improved geo-steering, increased drilling rates, minimal casing and liner, and multi-pad drilling among others. In the same way, improvements in completion technology include number of fracturing stages, shift to hybrid fluid systems, and spacing optimization (U.S. EIA, Mar. 2016). In 2015, hydraulic fracturing costs dropped over 40% compared to 2012 despite much larger completions with more stages (U.S. EIA, Mar. 2016). Technological advances play an important part on cost reductions; but it also can be partially attributed to the low oil price environment which has resulted in a decrease of drilling activity and, consequently, a demand decrease for field services. Because of this, service companies have responded to the low demand by reducing their fees, which in the Eagle Ford Shale has contributed to a drop of 25% on average in costs (U.S. EIA, Mar. 2016). Additionally, according to the Bureau of Labor Statistics, drilling rates dipped by 19.6% from June 2014 to May 2015, the price of frac-sand declined by 12.5%, whereas the rates for support activities, which include the surveying, cementing, casing and treatment of wells only dipped by 1.4% in the same timeframe (Blum, 2015).

3.2.2. Operation costs

Operation costs (OPEX), also referred to as lease operating expenditures (LOE), occur periodically and are necessary for daily operations. These costs are usually expressed in expenditure per year or per unit of production, and typically include: utilities, maintenance, administrative and general (A&G) overhead, production costs, transportation of the product to delivery points, evacuation costs, and insurance costs (Mian, 2002).

OPEX are highly variable ranging from 9 to 24.50 $/boe[1] influenced by location, play type, well performance, and company efficiency (U.S. EIA, Mar. 2016). In the case

[1] Boe stands for barrel of oil equivalent.

of Eagle Ford's oil wells, OPEX is dominated by artificial lift and water disposal as can be observed in Figure 3.2.

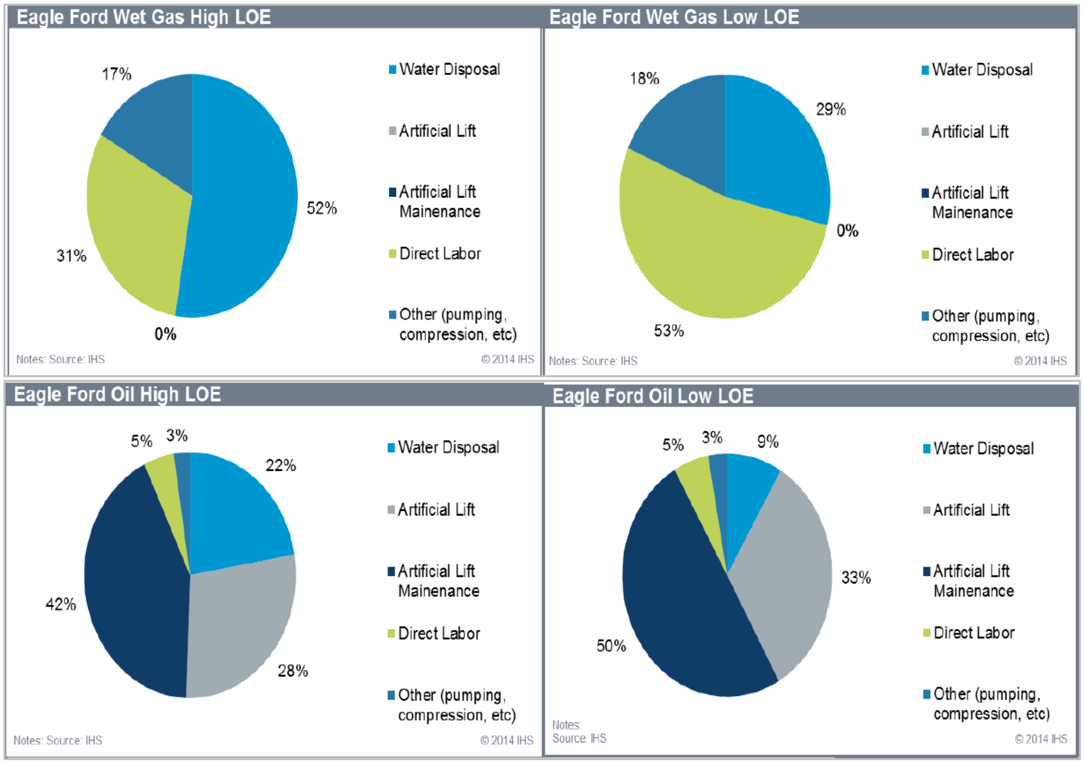


Figure 3.2. Pie charts showing the operating cost distribution for gas wells and oil wells (Source: U.S. Energy Information Administration, March 2016).

Water disposal is a major cost for some plays. It refers to the fluid that flows back to the surface after hydraulic fracturing and during the hydrocarbon extraction process. This flow-back fluid is a combination of fracking fluid and naturally occurring water that exists in the formation. The management of this flow-back water is a crucial point in the extraction process since the improper handling of these fluids poses a great risk to water and land contamination, and is therefore regulated under State guidelines.

The costs involved in the handling of flow-back water vary depending on the location of the shale play whose characteristics influence decisions such as reuse or recycling, as well as treatment and final disposal. In the United States most flow-back water is disposed through deep underground injection using Class II control wells. The availability of adequate deep-well disposal capacity can be a limiting factor like in the case of the Marcellus Shale where approximately 77.5% is sent to treatment facilities to later be discharge to surface waters, 16% is reused, and a very small percentage is injected into deep wells (Gregory et al., 2011; Rozell and Reaven, 2012). Flow-back disposal is very different in Texas where disposal wells are available. At the low cost of 1 $/bbl, injection is the preferred method of flow-back water management despite the high water production rates (Rassenfoss, 2013; Nicot et al., 2014). Reuse of flow-back water for hydraulic fracturing operations is another viable option with costs in the range of 0.60-1.80 $/bbl depending on its chemical composition (Stewart, 2015).

3.2.3. Financing costs

Financing costs are the expenses associated to securing financing for a project. Because oil and gas projects are capital-intensive, companies finance their operations either from equity financing or through borrowings and loans. The financing costs include interest payments and other costs paid to the providers of the funds. The other costs can include: amortization of discounts or premiums, finance charges applied to finance leases, and exchange differences from foreign currency borrowings (IFRS, 2012).

Each company has a financial structure used to raise capital, both debt and equity. Small companies are typically limited to their capital sources with only bank loans available for debt financing. Larger companies, particularly publicly traded, have access to more options of securitized debt or venture capital (Inkpen and Moffett, 2011). Although debt is cheaper, it is considered a burden and a risk; therefore, companies should try to raise equity to maintain an appropriate balance (Inkpen and Moffett, 2011). Depending on the capital structure of the company, the adequate proportion of debt and equity is determined.

Another important aspect when discussing financing costs is the opportunity cost which is defined as “the potential benefit lost or sacrificed when the choice of one course of action requires giving up an alternative course of action” (Mian, 2002). Companies have a portfolio of projects and they must choose the best that will give them an attractive return on their investment. When performing the economic analysis through the discounted cash flow method, the opportunity cost must be taken into consideration and is reflected in the discount rate used for the evaluation. The discount rate is the risk-adjusted cost of capital for the specific project. A company creates value for their shareholders when it invests in projects that yield results above their cost of capital (Inkpen and Moffett, 2011). Since companies usually use financing mechanisms to raise capital, they must choose a discount rate that is above their weighted average cost of capital (WACC). The WACC is the corporate hurdle, meaning the proportion of debt and equity, and depends on the capital structure of the company (Inkpen and Moffett, 2011).

Chapter 4: Impact of low oil prices

The sharp decline in oil prices is pushing companies to innovate, reduce costs, and evaluate strategies that can help them stay afloat while prices are low.

In this chapter, I discuss the impact of low oil prices on companies' finances, operations, and some strategies that can be applied when there is uncertainty in prices.

4.1. Impact on the finances

Companies require capital to sustain their operations which is raised through debt (acquiring loans or selling bonds), or through equity (selling stocks in the market). Since oil prices started declining in mid-2014, there has been an increased weakness among credits related to oil and gas exploration, production, and energy services. According to the Board of Governors of the Federal Reserve System, total loans for the oil and gas exploration and production sector were 276.5 billion dollars for the year 2015, of which 34.2 billion dollars were classified as substandard, doubtful, or loss compared to 6.9 billion dollars in 2014 (FRB, 2015). This situation is reflected in the companies' income statements. EOG Resources reported a net income loss of 4.5 billion dollars in the year 2015 when the WTI price averaged at 48 $/bbl compared to a net income gain of 2.9 billion dollars in 2014 when the WTI price averaged at 85 $/bbl (EOG Resources, Feb. 2016). Pioneer Natural Resources and Chesapeake Energy reported a net income loss of 0.3 and 14.9 billion dollars respectively in 2015 (Pioneer Natural Resources, Feb. 2016; Chesapeake Energy, Feb. 2016). When prices are low, companies become more capital-constrained and may have to get capital at higher interest rates (Ikonnikova and Gülen, 2015). Negative results push companies to increase their liquidity to meet their financial obligations which can be achieved through the sale of assets, CAPEX and OPEX reduction, debt acquisition, or equity reduction.

Companies respond to low prices by reducing expenses, mostly in these categories: number of employees (layoffs), exploration costs, drilling and completion costs, and non-core businesses (assets sale). Companies including companies and oilfield services have announced and already reduced their workforce. Schlumberger eliminated about 20,000 jobs worldwide in early 2015 and Baker Hughes plans to eliminate about 7,000 jobs in 2016 (Karkela, Jan. 2016). Companies like EOG Resources and Pioneer Natural Resources have already decreased their workforce by 240 and 343 employees respectively (EOG Resources, Feb. 2016; Pioneer Natural Resources, Feb. 2016).

Companies use different strategies to minimize risk. One of them is hedging, which is an investment position intended to offset potential losses from fluctuations in prices by agreeing to set a future price for a product. Hedging is the use of financial instruments known as “derivatives” that are commonly used by companies to protect their cash flow. However, when the uncertainty in prices is high, hedging can be counterproductive in the case prices rise above the hedging price while a contract for said price is still in place. Additionally, companies are evaluating their assets to sell the ones that do not fit their strategy in this low price environment. For example, Pioneer Natural Resources has sold its Eagle Ford Shale midstream business to increase the company’s liquidity position (Pioneer Natural Resources, May 2016). International companies are also struggling with uncertainty in prices. Companies such as Petrobras and Pemex, are also considering selling non-core businesses for the same reasons (Llanos-Small and Thornton, 2015).

4.2. Impact on the operations

In times of price uncertainty, companies are driven to adjust their production which translate into potential changes in capital budgets and input costs that result on changes in number of wells drilled and completed; the combination of water, proppant, and chemicals used for completion; and completion design (Ikonnikova and Gülen, 2015). Companies are also focusing on keeping production flowing from their existing wells and not trying to develop new areas if they do not have commitments to fulfill, forcing shale producers to delay new drilling and rely more in re-fracturing to keep production constant. Other companies are still drilling, but not completing new wells; therefore, an increase in the number of new wells does not necessarily translate to an increase in production (Allen, 2016). For example, EOG Resources reported 300 drilled uncompleted wells at year-end 2015; and they expect an oil production decline of 5% for the year 2016 (EOG Resources, Feb. 2016). The advantage of having drilled but uncompleted wells is that almost half of their cost is considered sunk by the time they start producing (Dunning, 2016). The decrease on the number of wells drilled in the United States is reflected in the decrease on the amount of active rigs in oilfields (Figure 4.1). As of December 2015, the rig count in the United States has decreased in 1,168 compared to the previous year (Baker Hughes, 2016).

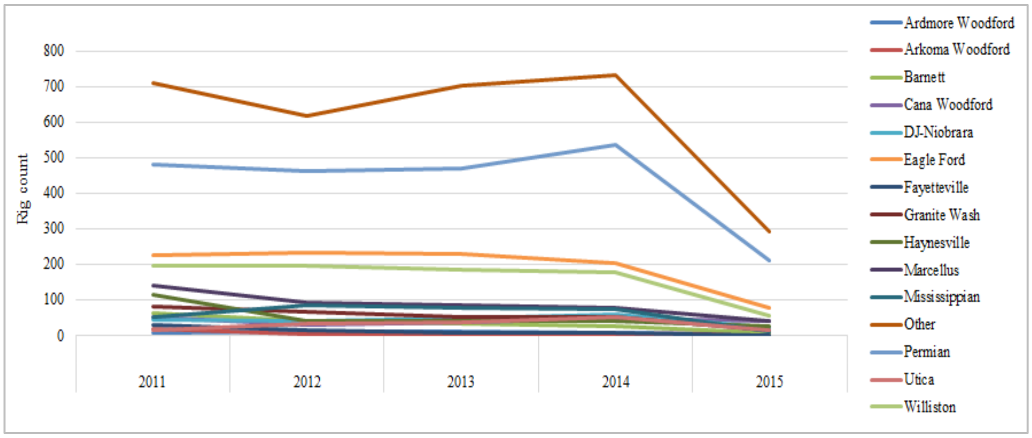


Figure 4.1. U.S. onshore rig count 2011-2015 (Source: Baker Hughes, 2016).

As experience is gained in shale reservoirs, companies pick better drilling locations which improves wells' productivity; and they also improve drilling and completion techniques which can reduce costs. Cost reduction is especially important when oil prices are low so new wells can be economically viable. Companies like EOG Resources and Pioneer Natural Resources are responding to this challenge by reducing their drilling time and completion costs which have an economic impact on service fees and well economics. Additionally, companies use infill drilling, which reduces the spacing between wells, in high-productivity areas to expand the inventory of wells and increase the field's production. The new wells drilled through an infill drilling program are cheaper to complete because they use significantly less water and proppant than original wells; but the production from the individual infill wells is lower than original wells (Ikonnikova and Gülen, 2015). Nevertheless, despite the lower per-well production, infill drilling leads to higher estimated ultimate recovery from a given field which can possibly translate into higher return on capital on a per-lease basis (Ikonnikova and Gülen, 2015).

Additionally, for shale plays that have different hydrocarbon products, diversifying their portfolio of oil and gas wells can be helpful. For example, the Eagle Ford Shale, compared to other shale reservoirs that usually contain either oil or gas, contains large quantities of oil, natural gas liquids, and natural gas. This has being beneficial in the past for South Texas companies (principally producing shale gas) since, as explained in Chapter 2, there is a disparity between oil and natural gas prices; thus, when oil prices are low, companies can switch to produce more gas if its price has not fallen as much (Tunstall, 2014). Although the real profit for companies in the Eagle Ford is still in oil production.

Chapter 5: Financial analysis

Many companies are struggling to keep operations afloat with oil prices below 50 $/bbl, which is observed in their financial results measured through the financial ratios. Financial ratios are relationships between different categories of financial data (cash, net working capital, and net fixed assets) from a company used for comparison purposes (Inkpen and Moffett, 2011). They are classified as: liquidity measurement ratios, operating performance ratios, profitability ratios, debt ratios, and investment valuation ratios.

In this chapter, I give a brief description of each of the selected companies to later explain the results for some financial ratios that are the most relevant in comparing the selected companies in regards to debt, liquidity, and cash flow from their operating activities.

For the financial analysis, I collected data from the companies' balance sheets, statements of income, statements of cash flows, and business summary which are compiled in the 10-K reports, as well as data from the annual report to shareholders. The 10-K report is an annual form required by the United States Securities and Exchange Commission (SEC) that gives a comprehensive summary of a company's financial performance. The study comprises data for a ten-year period (2005-2015) to understand the relationship between the oil price cycles and the companies' financial performance.

5.1. Selected companies

To carry out the financial, as well as the economic analysis, the selected companies must be publicly traded to obtain their financial data and investor presentations, which include operational insights required for the study. Additionally, the companies must have operations in the Eagle Ford Shale and operate their stimulated, horizontal wells with over twelve months of production data.

5.1.1. EOG Resources

EOG Resources Inc. (EOG) is based in the United States. It operates in the United States, Canada, United Kingdom, Trinidad, and China. In the United States, EOG has assets in the Eagle Ford, the location of most of its assets and in which the company is the largest crude oil producer. EOG also has assets in the Permian Basin (Leonard, Wolfcamp, and Second Bone Spring Sand plays), Barnett Shale, Marcellus Shale, the Anadarko Basin, the Rocky Mountains area, and the Upper Gulf Coast region. EOG is listed in the New York Stock Exchange and is traded under the ticker symbol "EOG".

According to EOG's Annual Report 2015, the company leads in number of wells with peak production rates greater than 1,000 barrels of oil equivalent per day, which can be confirmed by looking at the production of some of their wells in databases like those from Drillinginfo. Additionally, EOG's initiatives extends beyond drilling and completion technological advances; its in-house developers create proprietary analytical software suited to its particular needs as a company (EOG, Feb. 2016).

In 2015, EOG increased its combined domestic and international oil and condensate production by177.20 MBbld[2] compared to the results from 2014, because of the production growth in domestic plays (Figure 5.1). However, its natural gas and natural gas liquids (NGLs) production suffered a small decline (Figure 5.2, and 5.3). EOG's daily crude oil and condensate, natural gas, and natural gas liquids production from the United States only

[2] MBbld stands for thousand barrels per day.

are in Figure 5.4, Figure 5.5, and Figure 5.6 respectively. Additionally, EOG's net proved reserves declined by 471.72 MMBoe[3] (Figure 5.7).

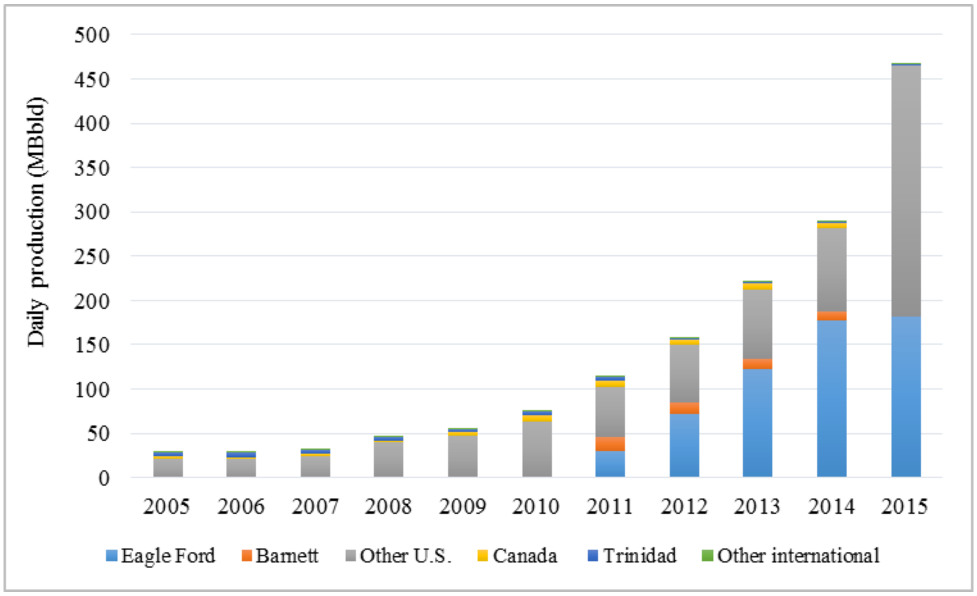


Figure 5.1. EOG's Crude oil and condensate daily production per location 2005-2015 (EOG, Feb. 2016).

[3] MMBoe stands for million barrels of oil equivalent.

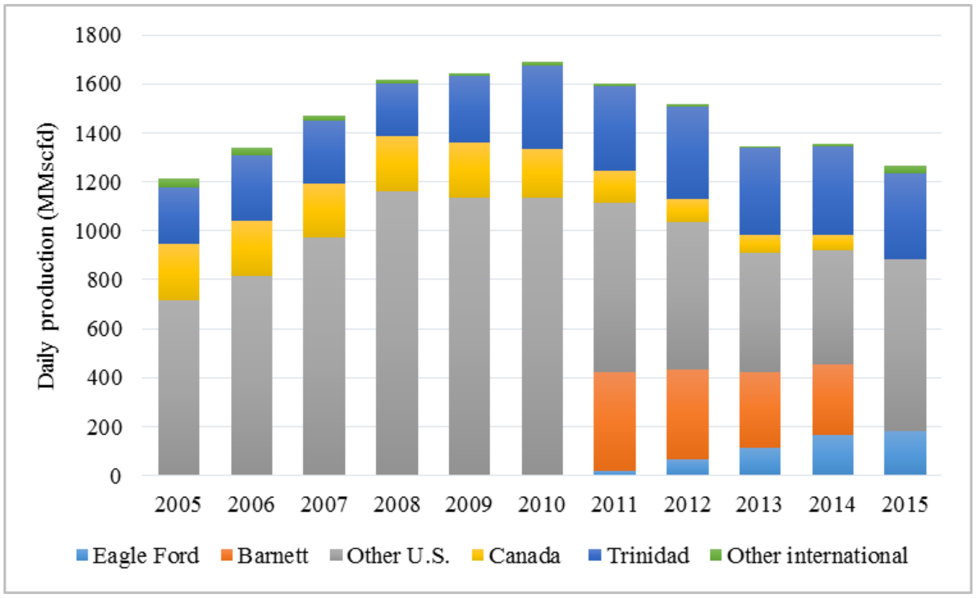


Figure 5.2. EOG's Natural gas daily production per location 2005-2015 (EOG, Feb. 2016).

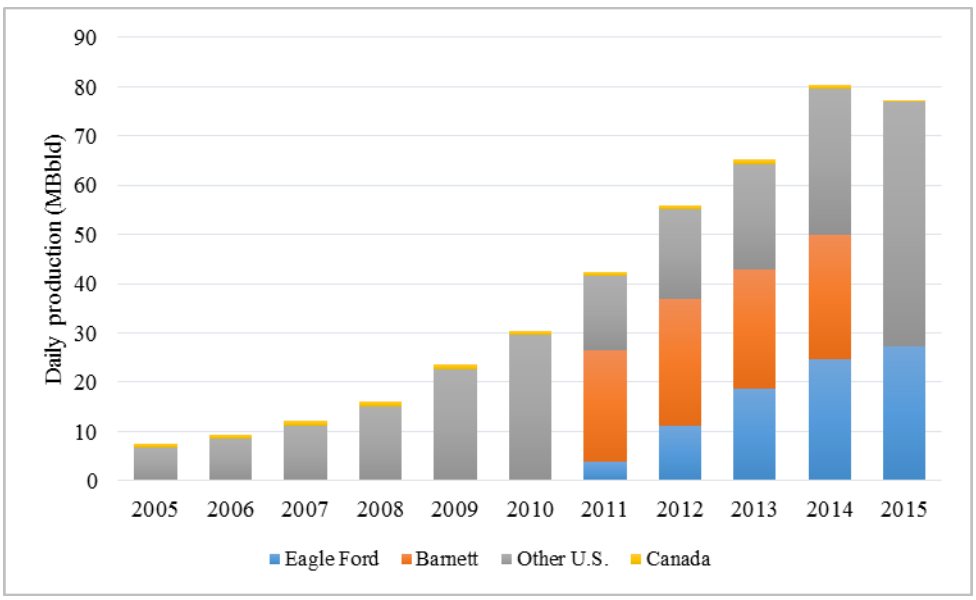


Figure 5.3. EOG's Natural gas liquids daily production per location 2005-2015 (EOG, Feb. 2016).

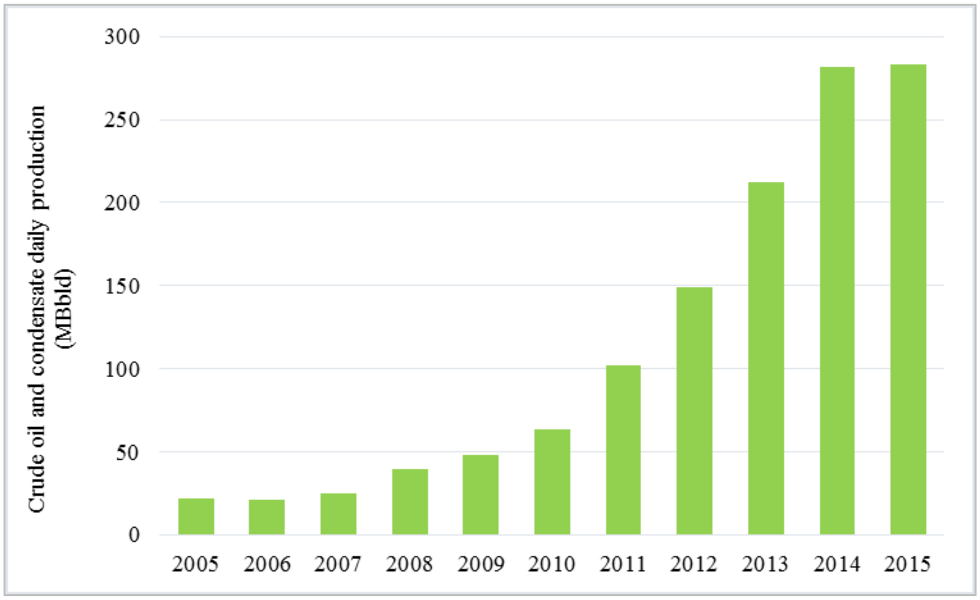


Figure 5.4. EOG's U.S. crude oil and condensate daily production 2005-2015 (EOG, Feb.2016).

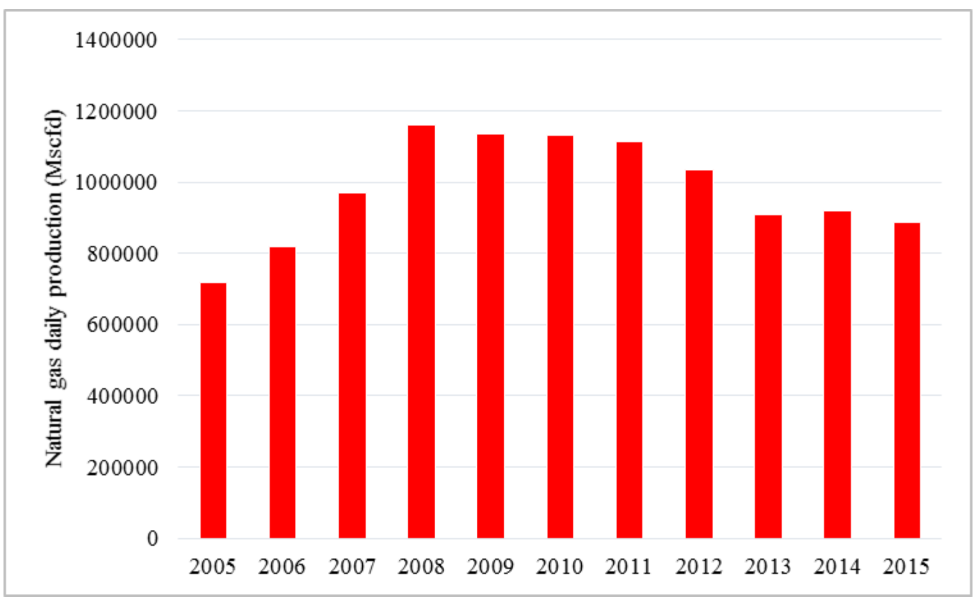


Figure 5.5. EOG's U.S. natural gas daily production 2005-2015 (EOG, Feb. 2016).

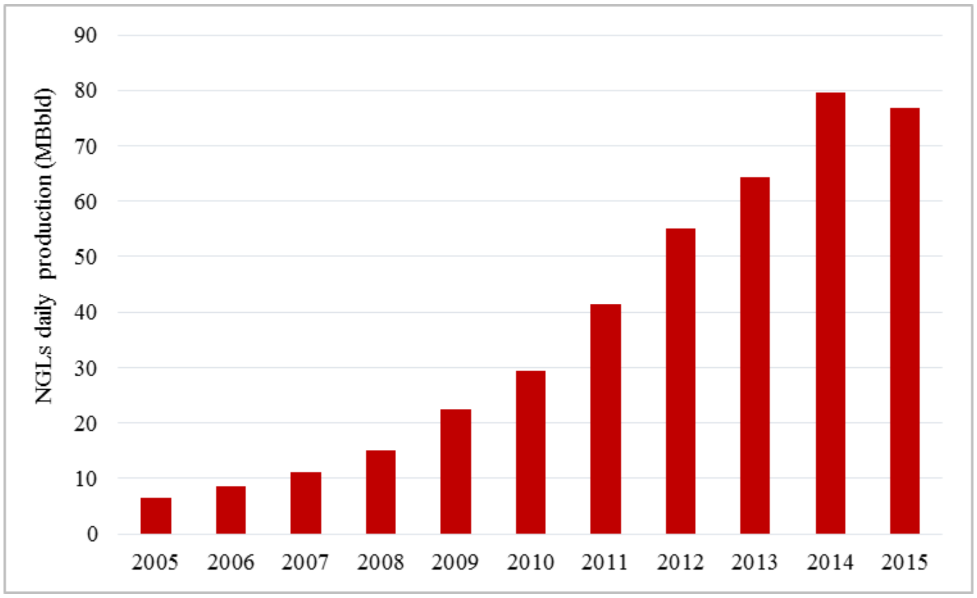


Figure 5.6. EOG's U.S. natural gas liquids daily production 2005-2015 (EOG, Feb. 2016)

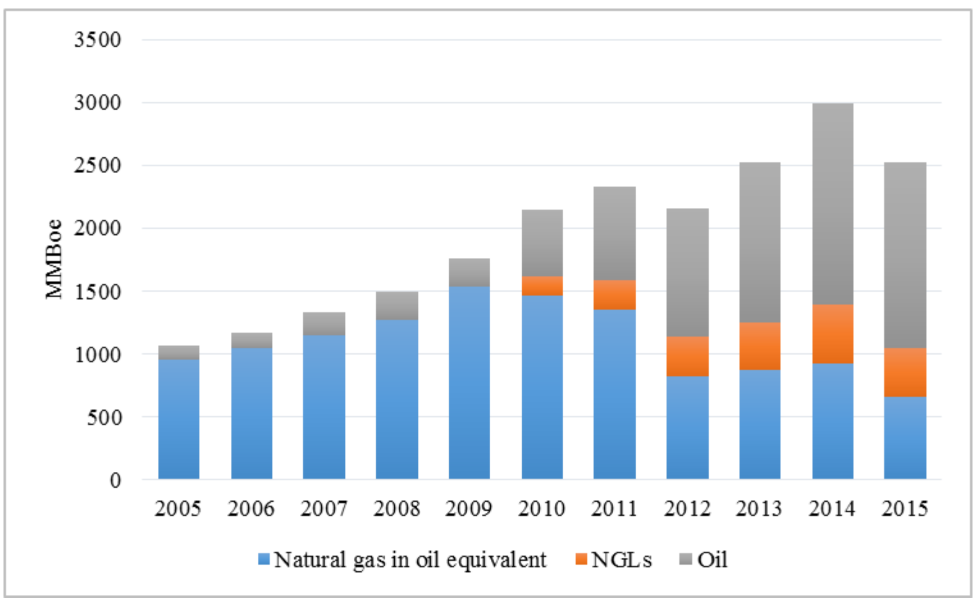


Figure 5.7. EOG's Net proved reserves of oil equivalent 2005-2015 (EOG, Feb. 2016).

5.1.2. Pioneer Natural Resources

Pioneer Natural Resources (Pioneer) is an exploration and production (E&P) company from the United States based in Texas. The company focuses its operations in the Spraberry/Wolfcamp in the Permian Basin and the Eagle Ford Shale, both in Texas. They are the largest producer in the Spraberry/Wolfcamp and a top operator in the Eagle Ford Shale. Additionally, Pioneer is a large natural gas producer in the West Panhandle gas field in Texas and in the coal bed methane-rich Raton Basin in southeastern Colorado. Before 2010, the company operated in Argentina, Canada, South Africa, and Tunisia, as well as in the United States; but since 2011, Pioneer focused its efforts to develop domestic plays. Pioneer is listed in the New York Stock Exchange traded under the ticker symbol "PXD"; and has been the second best performing E&P stock in the S&P 500 over the past five years (Pioneer, Feb. 2016).

During 2015, Pioneer placed 197 horizontal wells on production, increasing its crude oil and condensate production by 15.75 MBbld (Figure 5.8) compared to 2014. However, Pioneer’s natural gas (Figure 5.9) and NGLs (Figure 5.10) production decreased by 16.60 MMscfd and 4.60 MBbld, respectively for the same period. Pioneer’s daily crude oil and condensate, natural gas, and NGLs production from the United States from 2005 to 2015 are in Figure 5.11, 5.12, and 5.13 respectively. Additionally, Pioneer’s net proved reserves declined in 105.41 MMBoe (Figure 5.14).

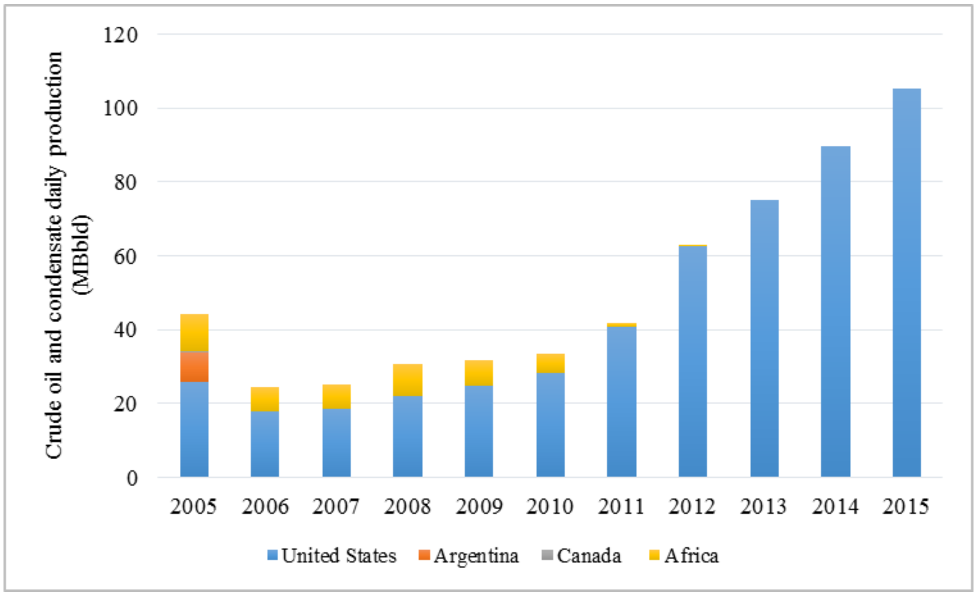


Figure 5.8. Pioneer's crude oil and condensate daily production per location 2005-2015 (Pioneer, Feb. 2016).

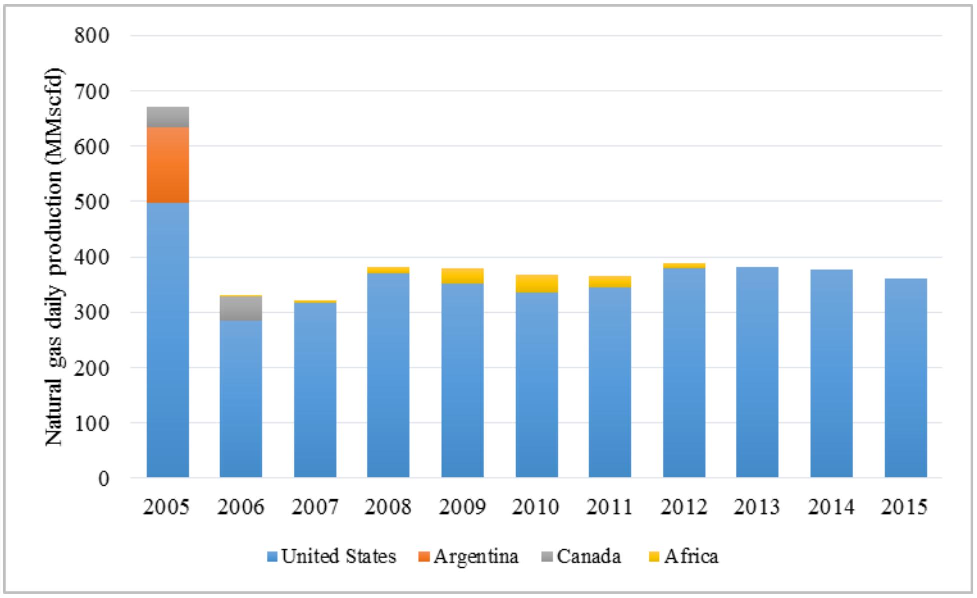


Figure 5.9. Pioneer's Natural gas daily production per location 2005-2015 (Pioneer, Feb. 2016).

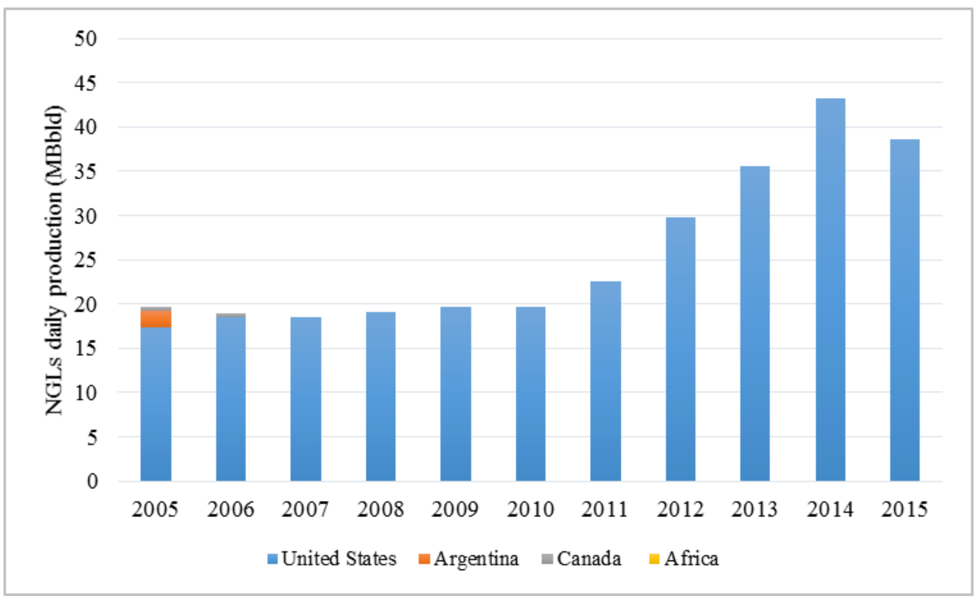


Figure 5.10. Pioneer's Natural gas liquids daily production per location 2005-2015 (Pioneer, Feb. 2016).

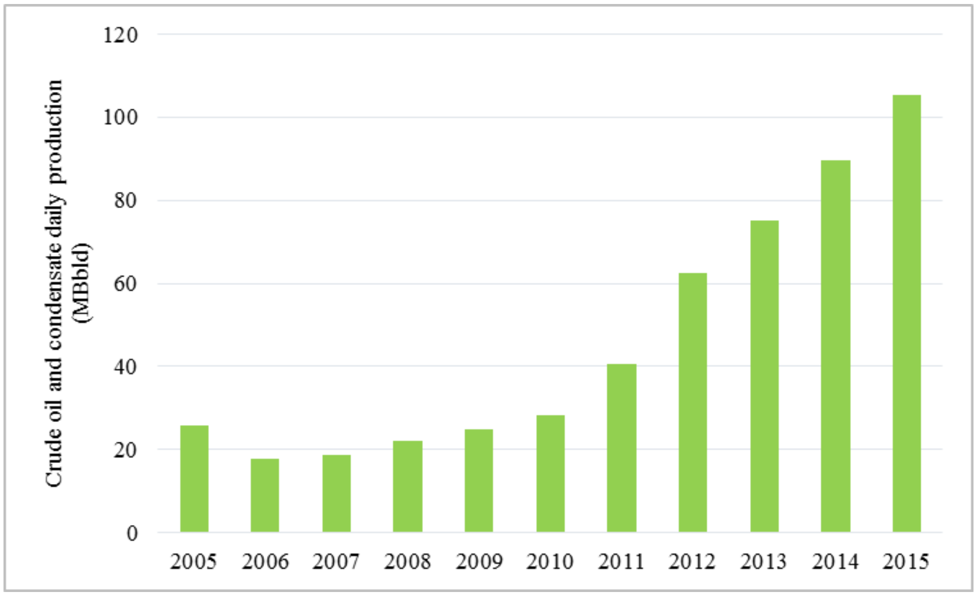


Figure 5.11. Pioneer's U.S. crude oil and condensate daily production 2005-2015 (Pioneer, Feb.2016).

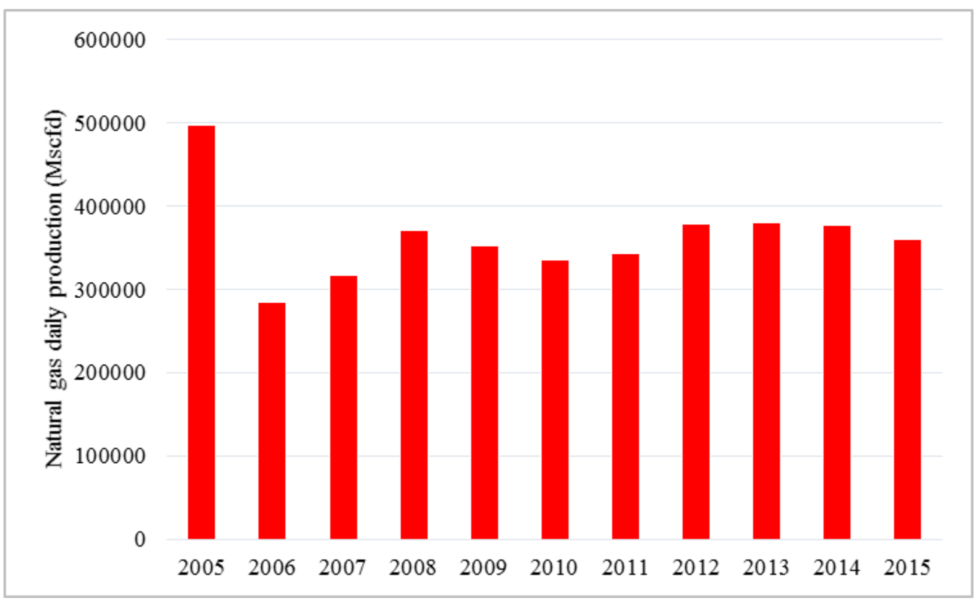


Figure 5.12. Pioneer's U.S. natural gas daily production 2005-2015 (Pioneer, Feb. 2016).

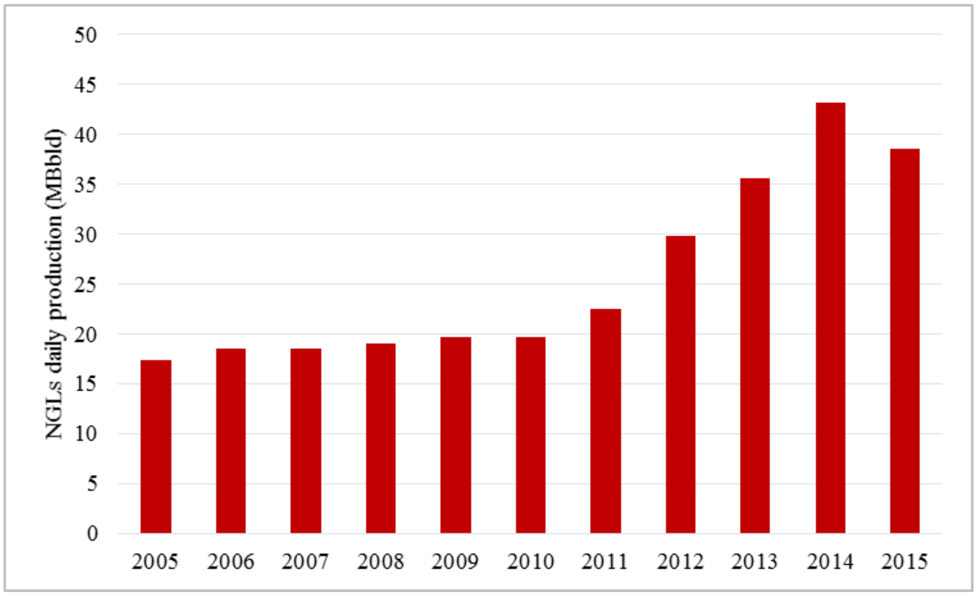


Figure 5.13. Pioneer’s U.S. natural gas liquids daily production 2005-2015 (Pioneer, Feb. 2016)

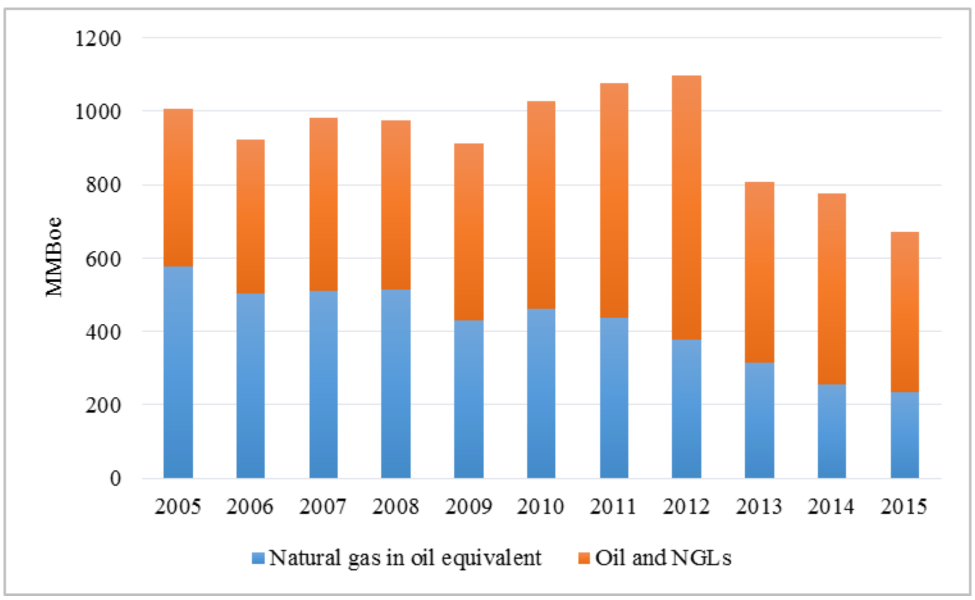


Figure 5.14. Pioneer’s Net proved reserves of oil equivalent 2005-2015 (Pioneer, Feb. 2016).

5.1.3. Chesapeake Energy

Chesapeake Energy (Chesapeake) is based in Oklahoma. Chesapeake operates in the Utica, Marcellus and Niobrara Shales on the north of the country, and on the Eagle Ford, Anadarko Basin, Haynesville, and Barnett Shale on the south. Chesapeake is listed on the New York Stock Exchange and is traded under the ticker symbol "CHK".

In 2015, Chesapeake's crude oil and condensate production decreased in 13.70 MBbld (Figure 5.15), and its natural gas production decreased in 68.49 MMscfd (Figure 5.16). Additionally, Chesapeake's net proved reserves declined by 991.90 MMBoe (Figure 5.17).

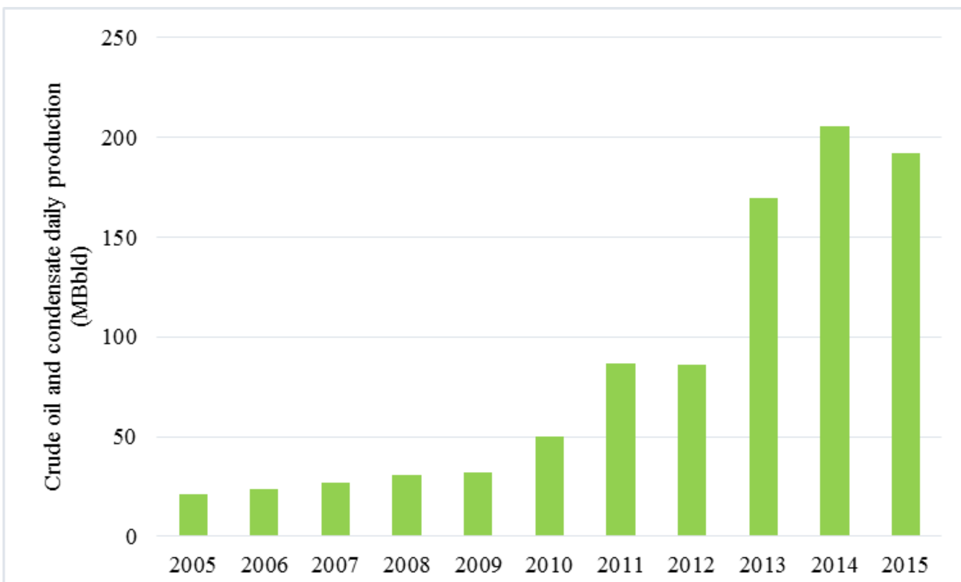


Figure 5.15. Chesapeake's U.S. crude oil and condensate daily production 2005-2015 (Chesapeake, Feb.2016).

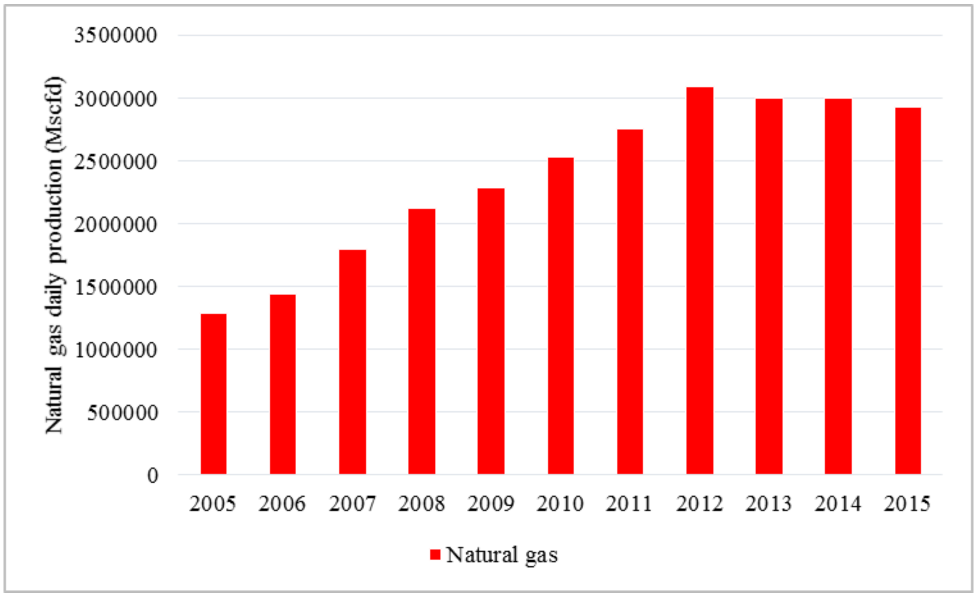


Figure 5.16. Chesapeake's U.S. natural gas daily production 2005-2015 (Chesapeake, Feb. 2016).

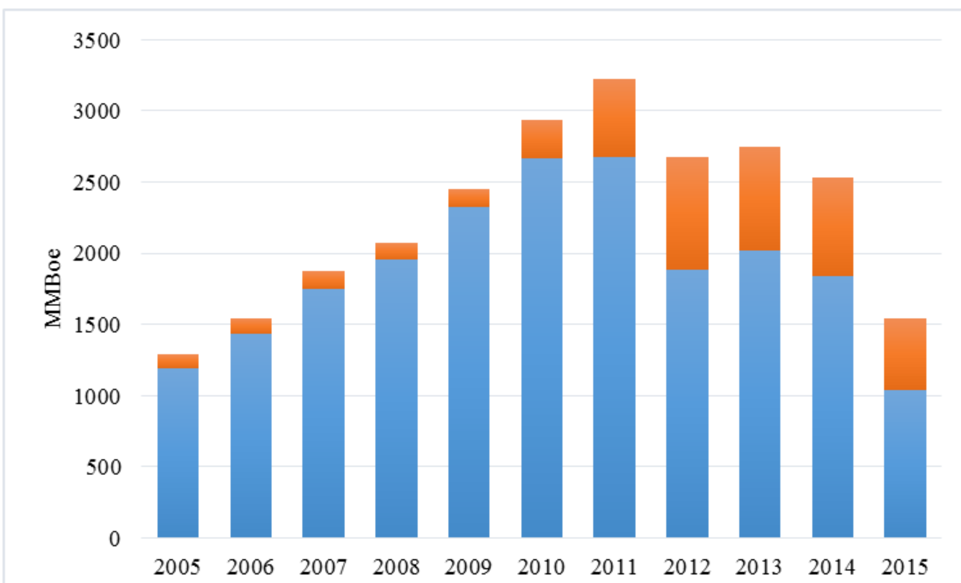


Figure 5.17. Chesapeake's net proved reserves of oil equivalent 2005-2015 (Chesapeake, Feb. 2016).

5.2. Financial ratios results

- Cash ratio

The cash ratio is an indicator of a company's liquidity. It measures the amount of cash, cash equivalents or invested funds in current assets to cover current liabilities. This ratio only takes into account the most liquid short-term assets of the company, which are those that can be easily converted to cash to pay off current obligations; thus, it ignores inventory and receivables, as there are no assurances that these can be converted to cash in a timely matter to meet current liabilities. Very few companies have enough cash to cover their current liabilities; hence, it is not necessarily bad for a company to have a cash ratio under 100%. The equation for the cash ratio is:

$$Cash\ ratio = \frac{Cash + Cash\ Equivalents + Invested\ Funds}{Current\ Liabilities} \quad [5.1]$$

The results for the cash ratio in Figure 5.18 show that throughout the 2005 and 2015 period there is no trend present for any of the three companies. However, Chesapeake’s cash ratio is low for the majority of years, meaning that its liabilities greatly exceed its cash, cash equivalents, and invested funds in current assets that can be used to pay said liabilities. For 2015, Pioneer’s cash ratio is 95%, which is a sign of financial strength, meaning that for that year, the company can pay most of its current liabilities with the amount it has in cash or the assets that can be easily converted to cash.

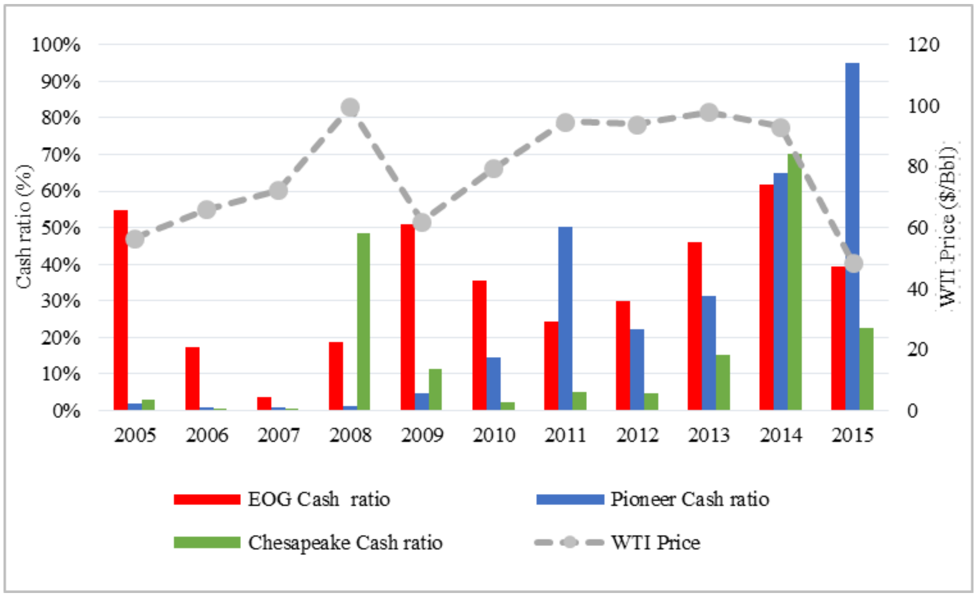


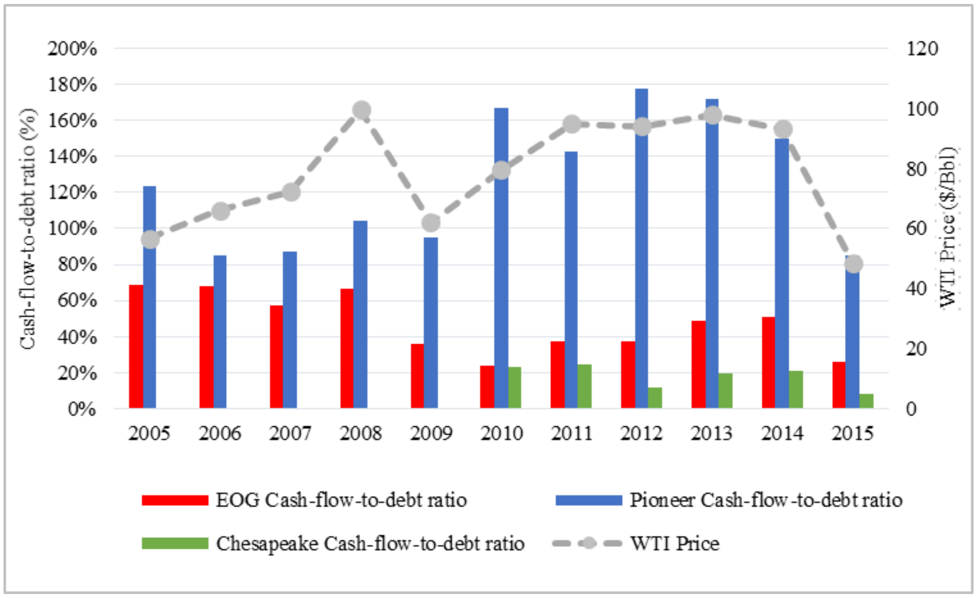
Figure 5.18. Cash ratio showing WTI Price 2005-2015.

- Cash-flow-to-debt ratio

A variation to the cash ratio is the cash-flow-to-debt ratio that is a measure of a company's ability to meet its total debt (or total liabilities) with its yearly cash flow from operations. The greater the ratio, the greater the company's ability to carry its total debt. It is defined by the equation:

$$Cash\ flow\ to\ debt\ ratio = \frac{Operating\ cash\ flow}{Total\ Liabilities} \qquad [5.2]$$

The results for the cash-flow-to-debt ratio show that EOG and Chesapeake have higher debt loads than their operating cash flows; and, on the contrary, Pioneer produces enough yearly cash flow from their operations to cover their liabilities in most years (Figure 5.19). Pioneer's performance is a sign of financial strength since it has outstanding results with a ratio >100% for the years 2005, 2008, and 2010-2014. Even in the low oil price environment of 2015, its ratio was 85% which still shows financial strength. EOG has a moderate performance throughout the 2005-2008 period; but since the crisis of 2008, its cash-flow-to-debt ratio has declined Chesapeake's results show a weak cash flow generation and too much debt.



Values for Chesapeake from 2005 to 2009 were not found.

Figure 5.19. Cash-flow-to-debt ratio showing WTI Price 2005-2015.

- Operating profit margin

This profitability ratio represents how many cents are earned for each dollar of sales. It does not take into account selling, general and administrative, or operating expenses. Positive and negative trends in this ratio are, for the most part, directly attributable to management decisions since operators have control over these expenses. The operating profit margin ratio shows whether the fixed costs are too high for the production or sales volume. High or increasing operating margin is preferred because if the operating margin is increasing, the company is earning more money per dollar of sales. The equation for the operating profit margin is:

$$Operating\ profit\ margin = \frac{Operating\ profit}{Revenues} \quad [5.3]$$

The operating profit margin for each company is in Figure 5.20. The results seem to follow the oil price trend; but they are not necessarily correlated. Even though oil prices determine in great part profit margin for oil companies, the operating profit margin is mainly determined by costs. This ratio measures how much revenue is left over after deducting operating expenses. Under the low oil price environment of 2015, the three companies show loses from their operating activities which is expected taking into account the breakeven analysis in Chapter 7. Chesapeake is the one with the largest loss per dollar of sales, which is also consistent with the analysis in Chapter 7. A low operating profit margin usually means that a company has a high financial risk, since it implies that the company struggles to pay its fixed costs that include interests on debt.

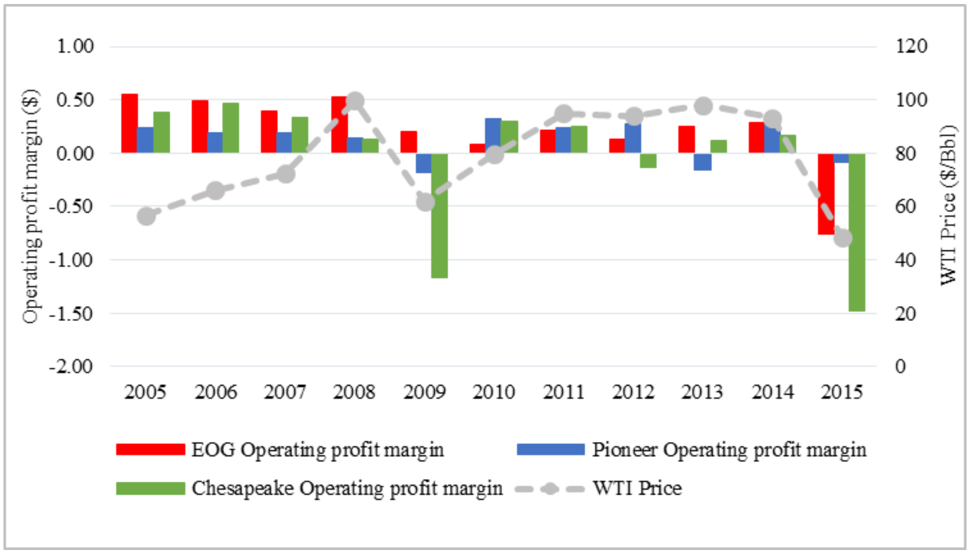


Figure 5.20. Operating profit margin showing WTI Price 2005-2015.

- Net profit margin

A variation on the operating profit margin is the net profit margin. This profitability ratio calculates the percentage of income that remains after all operating expenses, interest, taxes, and preferred stock dividends have been subtracted from the total revenue. The equation for the operating profit margin is:

$$Net\ profit\ margin = \frac{Net\ Income}{Revenues} \qquad [5.4]$$

The net profit margin results for each company is in Figure 5.21 and resembles the trend from the operating profit margin ratio.

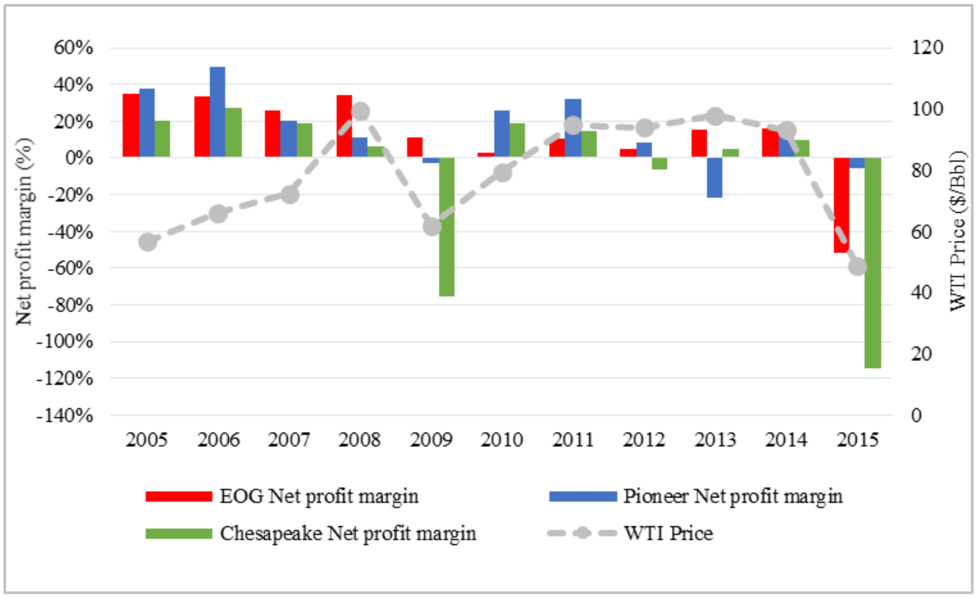


Figure 5.21. Net profit margin 2005-2015.

- Debt ratio

The debt ratio measures the amount of debt a company has on its balance sheets compared to its assets. This ratio is helpful when analyzing a company's leverage. The higher the ratio, the more debt compared to assets and the more leveraged it is which can be considered riskier. A downside to this ratio is that it is not a pure measurement of debt as it also includes operational liabilities, such as accounts payable and taxes payable; therefore, it is analyzed along with other ratios for comparison purposes. The equation for the debt ratio is:

$$Debt\ ratio = \frac{Total\ Debt}{Total\ Liabilities} \quad [5.5]$$

Figure 5.22 shows that EOG and Chesapeake have high debt ratios, and Pioneer has a low debt ratio. These results are consistent with the previously discussed cash-flow-to-debt ratio. When analyzing both ratios together, it can be concluded that Pioneer has a smaller debt load, which can be greatly covered by the cash produced from its operations. In contrast, EOG and Chesapeake have a larger debt load compared to their operating cash flows, which can be interpreted by investors as being riskier companies that struggle to meet their obligations.

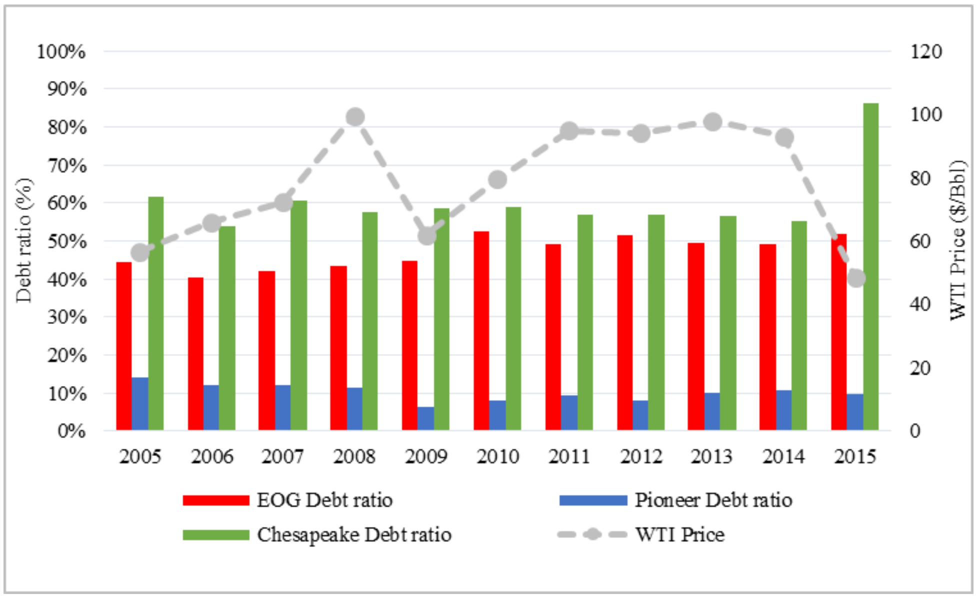


Figure 5.22. Debt ratio showing WTI Price 2005-2015.

- Debt-equity ratio

The debt-equity ratio provides a general indication of a company's relationship between equity and liabilities. This ratio can be used when evaluating a company that is applying for a loan. However, it is necessary to understand the industry in which the company operates. Oil and gas companies are capital intensive; and it is common to have debt-equity ratios above 100%. The debt-equity ratio is calculated as follows:

$$Debt - equity\ ratio = \frac{Total\ Liabilities}{Shareholder's\ Equity} \quad [5.6]$$

The results in Figure 5.23 show that EOG and Chesapeake have debt-equity ratios close to or over 100% for the 2005-2015 period. However, for 2015, Chesapeake's debt-equity ratio was 700%, which indicates that the company has been heavily taking on debt. A ratio this high is risky for the company because if the cost of the debt outweighs its return, it can lead to bankruptcy. Pioneer, on the other hand, has very low debt-equity ratios for the same period indicating that it has taken on little debt.

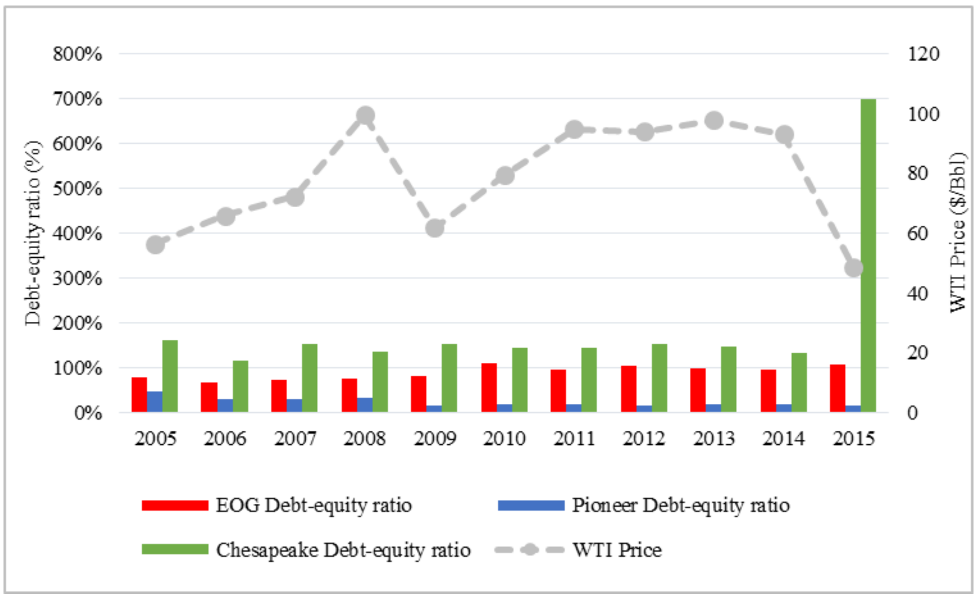


Figure 5.23. Debt-equity ratio showing WTI Price 2005-2015.

- Capitalization ratio

A company's capitalization is the term used to describe the capital structure of a company's permanent or long-term capital, which consists of both long-term debt and shareholders' equity. This ratio indicates to what extent the company is using its equity to support its operations and growth. A low level of debt and a healthy proportion of equity in a company's capital structure is an indication of financial fitness. A company considered too highly leveraged (too much debt) may find its options to rise capital restricted by its creditors, or may be impaired by high interest costs. The capitalization ratio is calculated as follows:

$$Capitalization\ ratio = \frac{Long - term\ Debt}{Long - term\ Debt + Shareholder's\ Equity} \quad [5.7]$$

There is not an established appropriate capitalization ratio; it depends on the company’s structure. Figure 5.24 shows that from 2005 to 2014, Pioneer and Chesapeake have a capitalization ratio below or close to 50%, which is moderate in the industry. However, the results for 2015 show that Chesapeake has a capitalization ratio of 83% which can make the company look at risk of insolvency if it fails to pay its debts on time. EOG has the lowest capitalization ratio among the three companies for most years during the observed period which is considered good and a sign of financial fitness as its capital structure balances its equity proportion with a low level of debt.

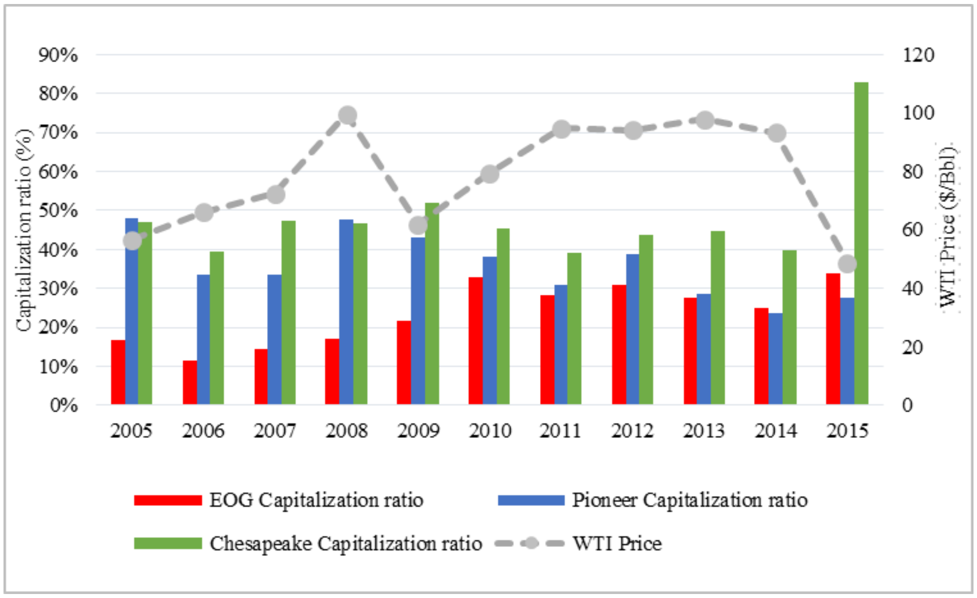


Figure 5.24. Capitalization ratio showing WTI Price 2005-2015.

Other information commonly used to complement financial data are net proved reserves and net undeveloped acres. Net proved reserves are important because by definition they are only considered as such if they can be extracted with existing technology and under existing operating conditions (most importantly price); consequently, they change. Net undeveloped acres is another important factor to consider when analyzing companies because the amount of acres available to drill directly affects operations and production. I included these two factors in the analysis plotting them against WTI price and price per share data (Figure 5.25 and 5.26) extracted from the MarketWatch website which has comprehensive financial information on publicly traded companies.

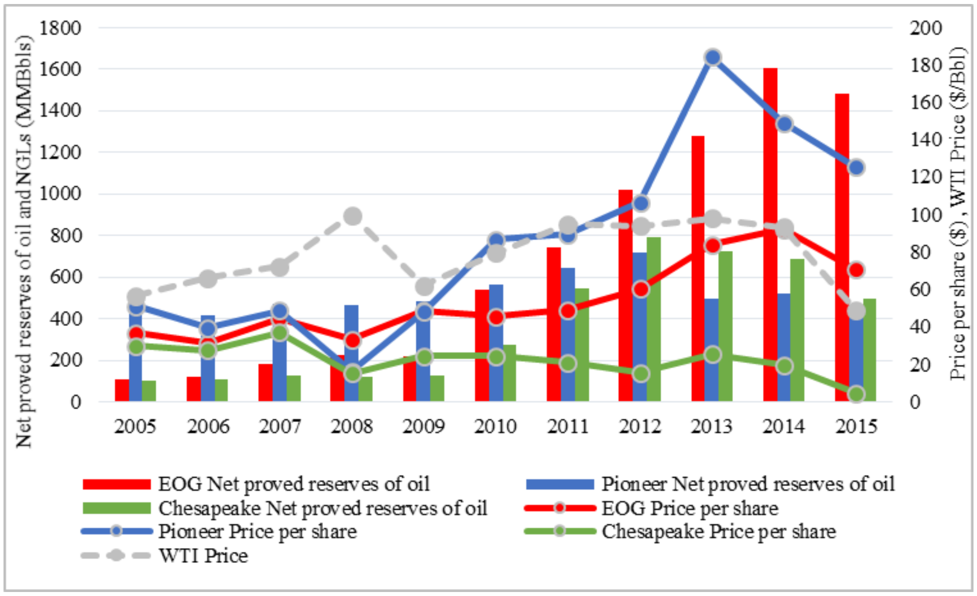


Figure 5.25. Net proved reserves of oil and NGLs vs. price per share vs. WTI price 2005-2015.

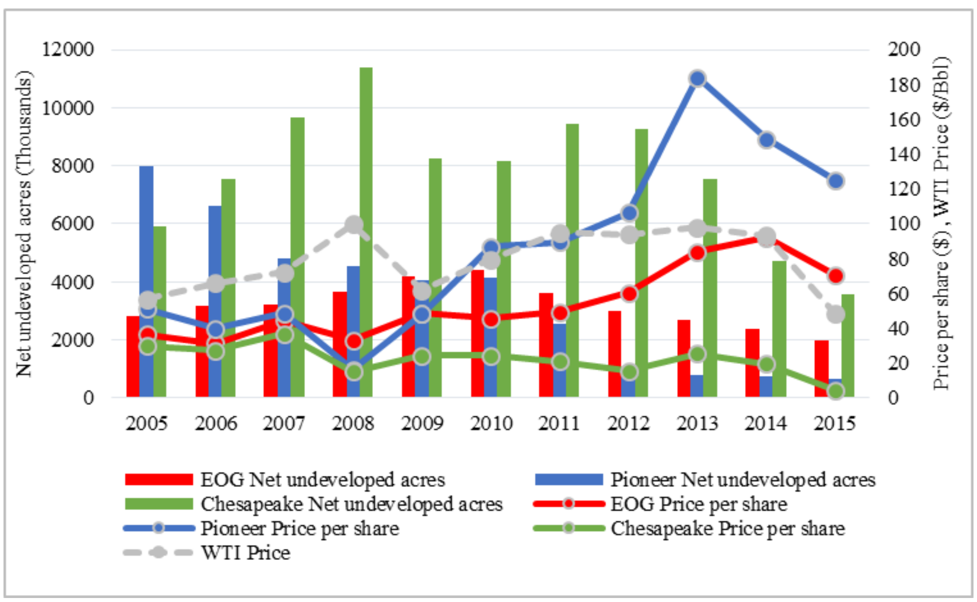


Figure 5.26. Net undeveloped acres vs. price per share vs. WTI price 2005-2015.

From the financial ratios analysis, Pioneer is the company with the best results; its high cash-flow-to-debt ratio, and low debt and debt-to-equity ratios make it an attractive company to invest in. In contrast, Chesapeake has the worst results which represents high risk for investors. The results from the companies' financial performance is reflected in their per share price. Pioneer's shares are valued higher than for EOG or Chesapeake; and Chesapeake's is valued the lowest. However, the oil price decline that started in 2014 has taken a hit to the oil and gas industry which is reflected in the negative profitability ratios at year-end 2015 for the three companies analyzed in this study (Appendix), and that are repeated for other companies across the industry.

Financial ratios are useful indicators of a company's operative performance and financial situation, as well as to analyze trends and compare companies in the same industry. Although they cannot be used to make certain predictions on a company's future and position within the industry, they provide a good notion of the areas a company needs to improve on, which is important for investors. Additionally, although Figure 5.25 and 5.26 do not show a relationship between net proved reserves or net undeveloped acres and price per share, they are still important factors to consider.

Chapter 6: Production model

Production forecasting is a crucial part of analyzing the economics of a drilling project or a single well. Production volumes will determine, in great part, the economic feasibility of drilling a new well because if production falls below a certain rate, the cost to extract the hydrocarbon is more than the income received from its production.

In this chapter, I evaluate two different methods to develop a production model and estimate future production for wells in the Eagle Ford Shale. I selected the Eagle Ford because it is the largest oil and gas development in the world based on capital invested (Eagle Ford Shale, Feb. 2016), and it is the second largest oil producer in the United States, after the Permian basin, as of March 2016 (U.S. EIA, Mar. 7, 2016). This perspective is important given the current low oil and gas prices since companies will focus on what they think are the most profitable plays.

6.1. Eagle Ford Shale

The Eagle Ford Shale, located in South-Central Texas, consists of Cretaceous sediments with an average thickness of 250 feet that extends 50 miles wide and 400 miles long covering 30 counties (Figure 6.1) (Eagle Ford Shale, 2016; U.S. EIA, May 2010; TRRC, Feb. 2016). This low permeability reservoir has a large carbonate content, which makes it relatively brittle and thus easier to stimulate through hydraulic fracturing than other plays. The importance of this shale play is its capability to produce large volumes of oil as well as natural gas. The hydrocarbons produced from the Eagle Ford range from dry gas to gas condensate to volatile oil to black oil. The well production and quality vary widely across the play. The average estimated ultimate recovery (EUR) for the Eagle Ford is 168,000 barrels per well which varies from county to county and from well to well (Figure 6.2) (U.S. EIA, 2014). The average EUR for different counties is in Table 6.1.

The proved reserves for the Eagle Ford at year-end 2014 were 5.2 billion barrels of oil, and 23.7 trillion standard cubic feet (Tscf) of natural gas (U.S. EIA, Nov. 23, 2015). These reserve estimates account for 30% and 16% of the total U.S. tight oil and shale gas reserves for 2014.

Production from the Eagle Ford has been increasing rapidly; but has seen a deceleration in 2015 (Figure 6.3) as a result of the low oil and gas prices. The average production for the year-end 2015 is 1.1 million barrels per day of oil, 5.4 trillion cubic feet of natural gas, and 0.3 million barrels per day of condensate (TRRC, Feb. 2016).

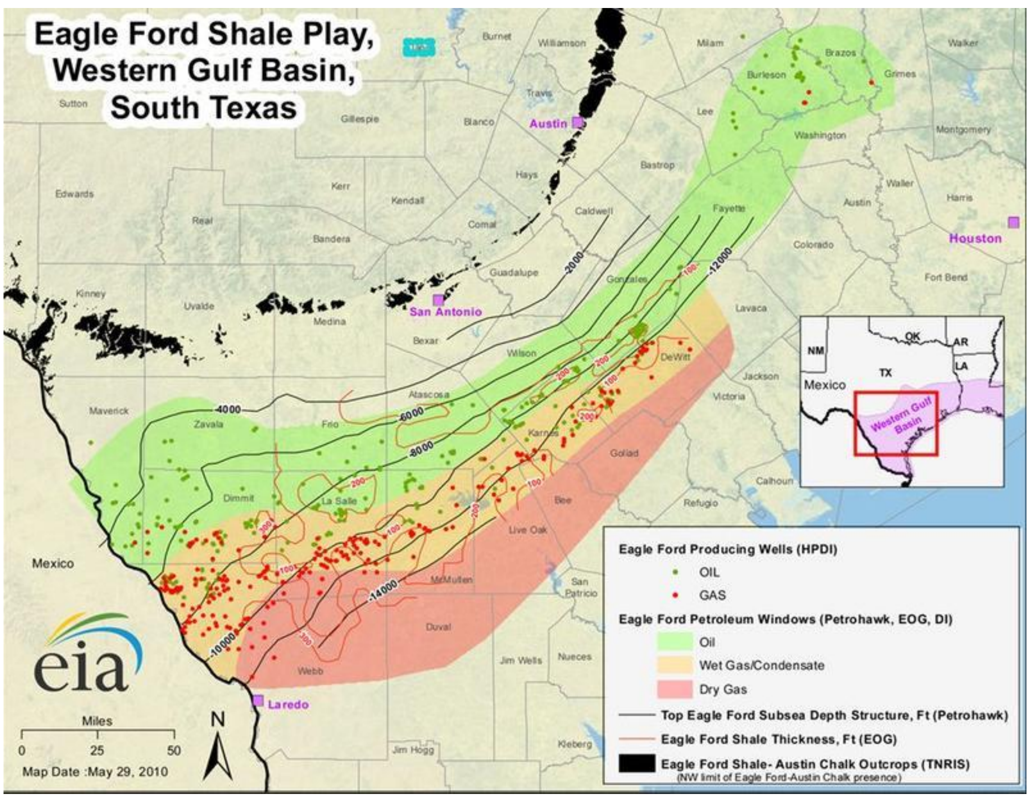


Figure 6.1. Eagle Ford map showing the different petroleum and gas windows (Source: U.S. Energy Information Administration, May 2010).

County	Average EUR (bbls/well)
Eagle Ford Shale	168,000
DeWitt	334,000
Karnes	226,000
Gonzales	198,000
LaSalle	153,000
Dimmit	137,000
McMullen	127,000
Webb	80,000
Burleson	<25,000
Maverick	<25,000

Table 6.1. Average EUR in Eagle Ford counties from wells drilled between 2008 and 2013 (Source: U.S. Energy Information Administration, 2014).

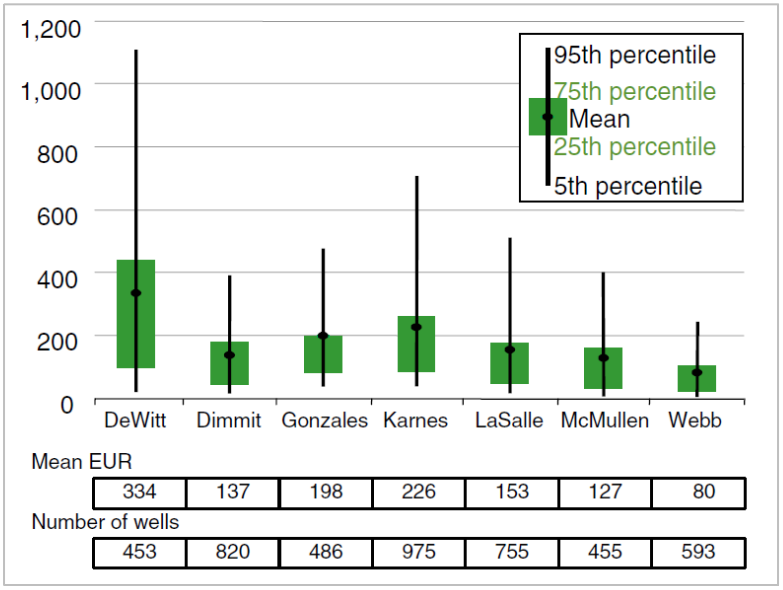


Figure 6.2. Distribution of EUR in thousand bbls per well in the Eagle Ford (Source: U.S. Energy Information Administration, 2014).

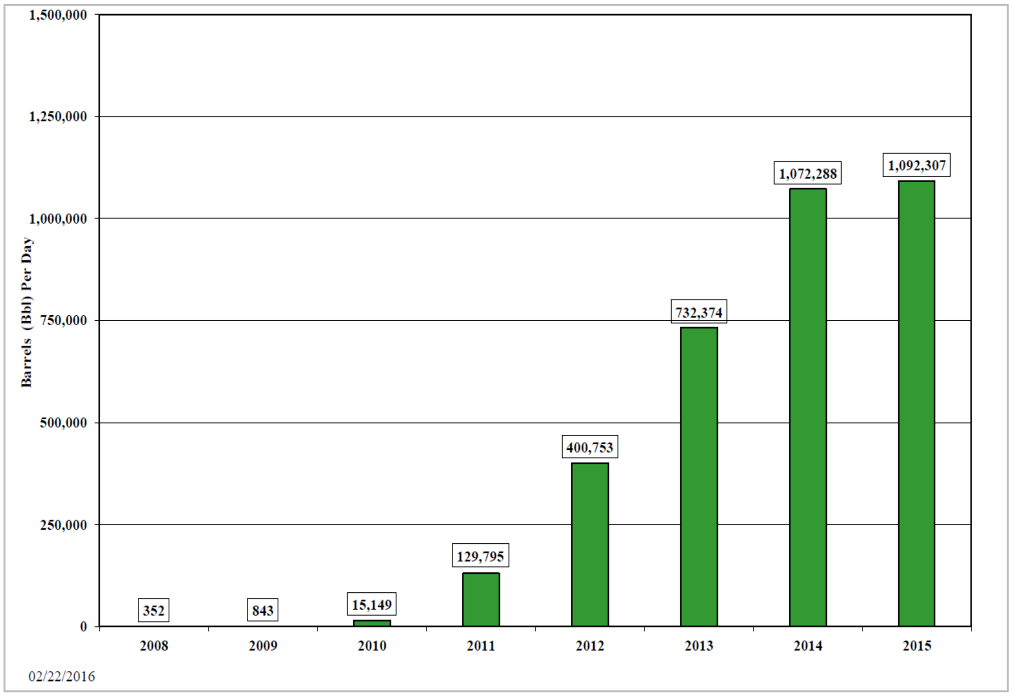


Figure 6.3. Eagle Ford oil production 2008-2015 (Source: Railroad Commission of Texas, February 2016).

Even though the Eagle Ford has experienced a decrease of 59% in drilling permits issued, from 5,613 in 2014 to 2,315 in 2015 (TRRC, Feb. 2016), it still has a substantial number of drilling rigs operating compared to other basins, which is an indication that companies will continue their operations in this play. By year-end 2015, the Eagle Ford had 77 drilling rigs on location out of a 700 total in the United States (Figure 6.4).

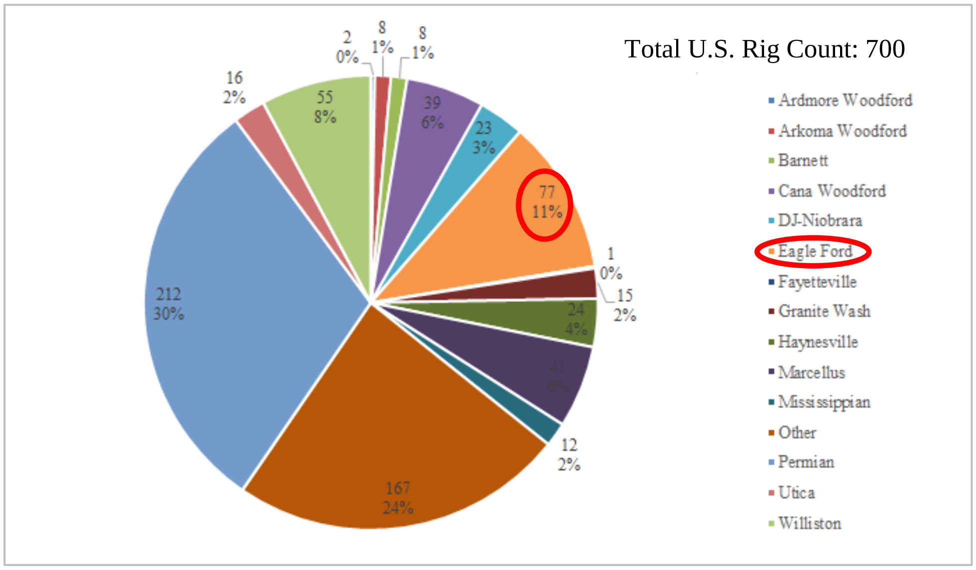


Figure 6.4. Pie chart for drilling rig count in the United States and percentage per basin at year-end 2015 (Source: Baker Hughes, 2016).

The challenge of selecting the Eagle Ford Shale for the analysis is mainly because of the short life of the play. The Eagle Ford started its play-wide development in 2008 when the first horizontal well was drilled, and it has been in continuous development since then. However, there is not long-term production performance to fully understand the decline characteristics in this play. Moreover, it also presents technical challenges when forecasting production given its low permeability and the complex fracture network resulting from multistage fracture treatments (Gong, 2013). For this reasons, the selection of the adequate decline curve analysis model is essential to create a reliable production model.

6.2. Decline curve analysis models

The volume of hydrocarbons that can be produced from a reservoir can be estimated by using production decline curve analysis, which is a traditional method for the prediction of well performance and life based on historical production data. The concept of decline curve analysis involves fitting a trend line through a well's historical production and extrapolating that line to estimate future production under the assumption that the past trend will not change under constant operational conditions (Arps, 1945).

The objective is to determine the estimated cumulative production, the project life, as well as production rates over the life of a well. It is known that production rate declines over time as cumulative production increases. Production will be terminated when the rate reaches its economic limit which is when the current income from operations equals the cost of production. The estimated cumulative production from before production starts until its economic limit is known as estimated ultimate recovery or EUR. As hydrocarbons are produced, the sum of the accumulated production from a well and its remaining reserves are equal to the EUR (Apiwatcharoenkul, 2014).

Many of the existing decline curve analysis models are based on empirical equations developed by Arps in 1945, which is still one of the preferred methods to estimate production. Arps proposed that when plotting production rate versus time, the curve generated can be expressed mathematically by the hyperbolic family of equations (Bahadori, 2012). This model was developed to analyze trends in conventional reservoirs; but unconventional reservoirs such as the Eagle Ford Shale are dominated by different characteristics, frequently resulting in an erroneous estimation of EUR compared to the actual cumulative production at the end of a well's life.

Given the current importance of unconventional reservoirs, which have boosted hydrocarbons reserves particularly in the United States, new approaches to the existing method along with new models have been developed to specifically forecast production from these shale and tight sands reservoirs. Some of this models are: Power Law

Exponential (PLE) by Ilk et al. 2008, Stretched Exponential Decline (SEPD) by Valko 2009 and Valko and Lee 2010, Duong Method by Duong 2011, and Logistic Growth model by Clark et al. 2011.

The present study analyzes the main differences between only two of the mentioned models based on the data necessary and available for each: Arps Decline Curve model and Logistic Growth model to determine the most appropriate that will later be used for the production model.

6.2.1. Arps decline curve model

Arps developed a mathematical model for three types of production decline curves: exponential, hyperbolic, and harmonic, which are observed in traditional reservoirs of different qualities. The Arps' model is based on the concept of loss-ratio and its derivative expressed as follows (Kanfar and Wattenbarger, 2012):

Loss ratio:

$$\frac{1}{D} = -\left(\frac{q}{dq/dt}\right) \qquad [6.1]$$

Derivative of loss ratio:

$$b = \left(\frac{d}{dt}\right)\left(-\frac{q}{dq/dt}\right) \qquad [6.2]$$

Where:

D = decline constant

b = hyperbolic exponent

q = production rate at time t

Production from shale reservoirs follow a hyperbolic decline curve which is characterized by extremely high initial production rates, followed by a rapid decline. This type of reservoirs are commonly analyzed using Arps' hyperbolic decline equation:

$$q = q_i(1 + bD_it)^{-\frac{1}{b}} \quad [6.3]$$

$$N_P = (\frac{q_ib}{(1-b)D_i})(q_i^{1-b} - q^{1-b}) \qquad [6.4]$$

Where:

q = production rate at time t

q_i = initial rate

D_i = initial decline constant

b = hyperbolic exponent

N_p = cumulative production at time t

In Arps' hyperbolic decline equation, b should take values between 0 and 1. However, when fitting data using this equation for low permeability reservoirs, b often takes values greater than 1. As mentioned, this method was developed to analyze trends in conventional reservoirs with boundary-dominated flow regimes; however, unconventional reservoirs like low permeability shales are dominated by long transient flow regimes (Delaihdem, 2013). This behavior results in a cumulative production that does not reach the finite dimensional boundaries, frequently causing an over estimation of EUR (Clark et al., 2011).

6.2.2. Logistic growth model

Logistic growth models are based on the concept that growth is possible only to a maximum size referred as carrying capacity at which point the growth stabilizes. The model was adapted for single wells in tight permeability reservoirs by Clark et al. (2011) from the work by Tsoularis and Wallace (2002) who used it to model biological systems. The adapted model uses a growth equation which represents cumulative oil or gas production.

The adapted equation for predicting cumulative production for a single well is expressed as:

$$N_p = \frac{Kt^n}{a+t^n} \qquad [6.5]$$

Where:

N_p = cumulative production

K = carrying capacity

a = constant

n = hyperbolic exponent

t = time period

The production rate is expressed as:

$$q(t) = \frac{Knat^{n-1}}{(a+t^n)^2} \qquad [6.6]$$

Where:

q = production rate

In the equations above the carrying capacity *K* is the amount of recoverable oil or gas when *t* approaches infinity, in other words, the EUR; and is what constrains cumulative production. The hyperbolic exponent n has the same function as b in Arps' equation as it controls the steepness of the decline. When n takes smaller values, the well will decline at a high rate for a short period of time before stabilizing; when n takes larger values the well will display a more gradual decline. If $n>1$, the model will have an inflection point where the rate increases for a short period of time before decreasing (Clark et al., 2011). The constant a is the time to the power n at which half of the carrying capacity has been produced. The larger the a value, the more stable the production will be during the life of the well (Clark et al., 2011).

In the Logistic Growth equation, the hyperbolic exponent n and the constant a are unknown. The parameter K can be obtained from volumetric calculations and will constrain the cumulative production (Clark et al., 2011). If K is known, the n and a parameters are obtained using least squares regression in Excel combined with the Solver add-in (Clark et al., 2011) by minimizing the sum of the difference between the squared historical data and squared estimated production. This initial estimated production needs preliminary n and a parameters which are later solved and replaced for the appropriate values with the Solver add-in. If K is unknown, it can also be solved using the least squares regression in Excel combined with the Solver add-in; but an initial estimation is still needed. The initial estimated value for K can be obtained from studies done in the area.

6.3. Method selection

The selection of the appropriate method to estimate production for a typical well is essential for the production and discounted cash flow model and analysis. The production model using the selected method is to estimate oil production only, given that this study is focused on the impact of low oil prices.

Based on the relatively short production history of the Eagle Ford, the Arps' model does not allow for an accurate estimation of future production. Information available for the Eagle Ford includes the historical production from horizontal wells drilled as well as the average EUR of the play as a whole and also per county. The Logistic Growth Model equations use the EUR as the carrying capacity which serves as the maximum cumulative production that a well can reach. Having the EUR information from studies or the companies themselves facilitates production forecast when using the Logistic Growth Model and solves the problem of over estimation of reserves during the life of a well (Figure 6.5).

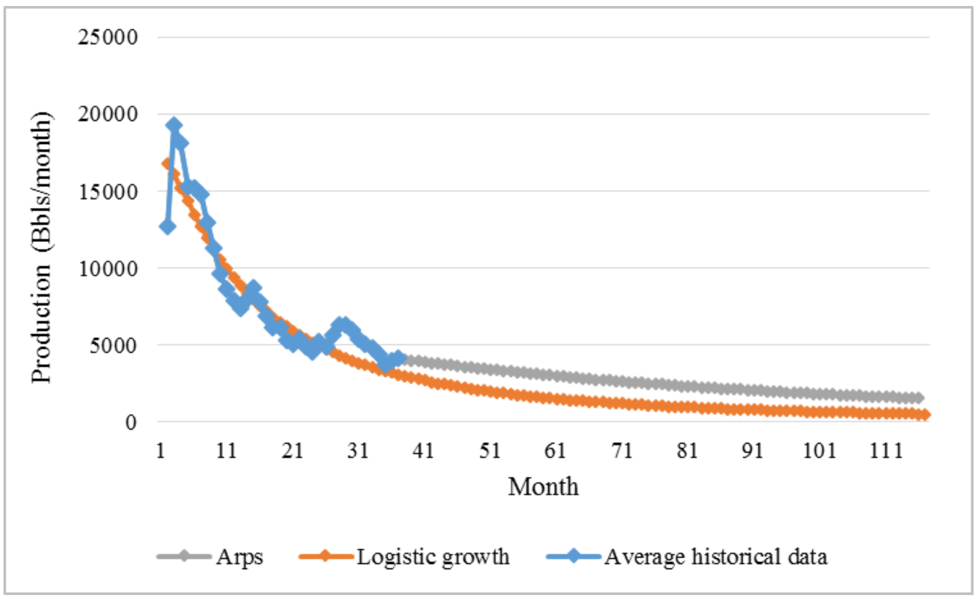


Figure 6.5. Method comparison between Arps and Logistic Growth.

Given the available information for the Eagle Ford Shale and the analysis performed between Arps and Logistic Growth methods, I decided to use the Logistic Growth for the production model as it is specifically developed for unconventional reservoirs, the necessary information to apply this method is available (EUR and historical production), and it gives a conservative answer when performing the discounted cash flow analysis.

6.4. Data preparation

I analyzed Eagle Ford historical production data from the Drillinginfo database by plotting monthly production against time. This facilitated the identification of wells that presented a reasonable hyperbolic decline curve to be considered for selection since not all profiles follow a smooth decline trend most likely because of well stimulation and re-fracturing. This criterion helps in the calculation of the *n* and *a* parameters when performing the least squares regression. Twenty wells were selected for each company that I analyze (see Chapter 7) with the following criteria:

- Reasonably smooth hyperbolic decline curve
- >12 months of production data
- Classified as oil wells
- Horizontal wells
- Drilled between 2008-2014

The majority of the selected wells produce gas along with the oil; and therefore, it is also included in the analysis. The gas forecast was estimated using the gas-oil ratio (GOR) from the historical data, not using the Logistic Growth method since there is not available EUR information for the gas that can be produced from oil wells. I plotted the GOR against time and determined the trend line to find a constant factor to multiply by the oil rate to provide a gas production estimate. The assumption for this approach is that production conditions will be constant during the life of the well and that the amount of gas produced is directly proportional to the amount of oil produced.

The production model for each company was developed for a typical well, which is the average of the selected existing wells per company. Months with a production value of zero were omitted when averaging the productions since they are because of temporary closure of the well. Averaging the production from the selected wells and omitting zero values smooths the production curve; however, it was not possible to get a completely smooth curve in all the cases.

The production model accuracy depends on the amount of production history available; for this reason, the wells selected for the model are those that have over twelve months of production at the time that the data were collected. Some important companies in the Eagle Ford did not meet this criterion, and therefore, were not included in the analysis.

6.5. Production forecast

The necessary information for the production forecast using the Logistic Growth model is historical production data and the EUR to use as the parameter K. The historical production data were obtained from the Drillinginfo database. The EUR was obtained either from the company's investor presentation or from the Annual Energy Outlook (AEO) 2014 prepared by the U.S. Energy Information Administration. However, it is also possible to solve for K to get the EUR. I compared the forecast results of each method to analyze the variation between using the given EUR and the obtained K.

To facilitate the analysis, the assumption is that the well will decline naturally without applying methods to increase production rate at a certain point. Additionally, the production forecast was terminated when the well becomes a "stripper well" at a production rate of 300 barrels per month. At this point the well becomes marginal and is reaching the end of its economic life. For the Eagle Ford, this can happen within five years of the start of production (Delaihdem, 2013). In reality, companies use enhanced oil recovery methods to extend the economic life of a well.

6.5.1. Production model 1: EOG Resources

For EOG Resources, the parameter *K* equal to 450,000 barrels of oil per well was obtained from the company's investor presentation (May 2015). The selected wells' location is in Figure 6.6.

Inputs:

K = 450,000 bbls/well

Production = Average monthly production from 20 wells with 36 months of historical data

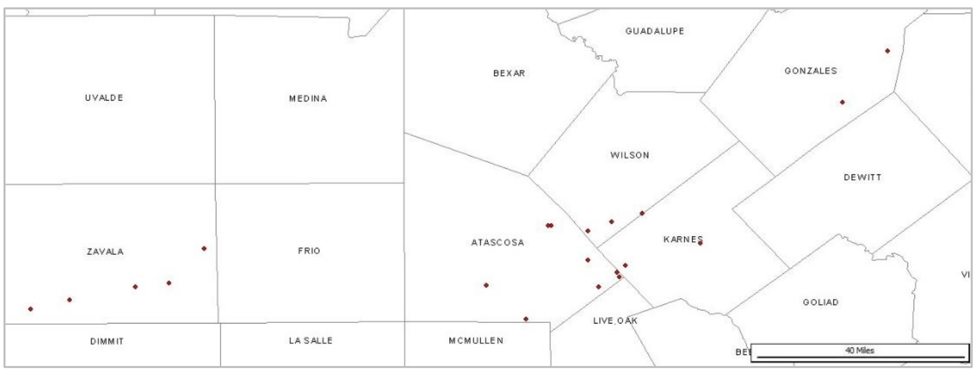


Figure 6.6. Map showing the selected EOG wells (Source: Drillinginfo, 2016)

The results for the oil forecast (per Equations 6.5 and 6.6) are as follows:

n = 1.05

a = 25.90

N_p = 398,826 bbls of oil

In this case, *n* is larger than 1. This does not mean the forecast is erroneous; it can be used to match data for wells whose initial rate is not their peak rate (Clark et al., 2011), which is true for the majority of the wells used in the analysis.

The EOG typical well becomes a stripper well in the 158th month after production starts; therefore production was terminated at this point reaching a cumulative production of 398,826 barrels of oil during its economic life as can be observed in Figure 6.7.

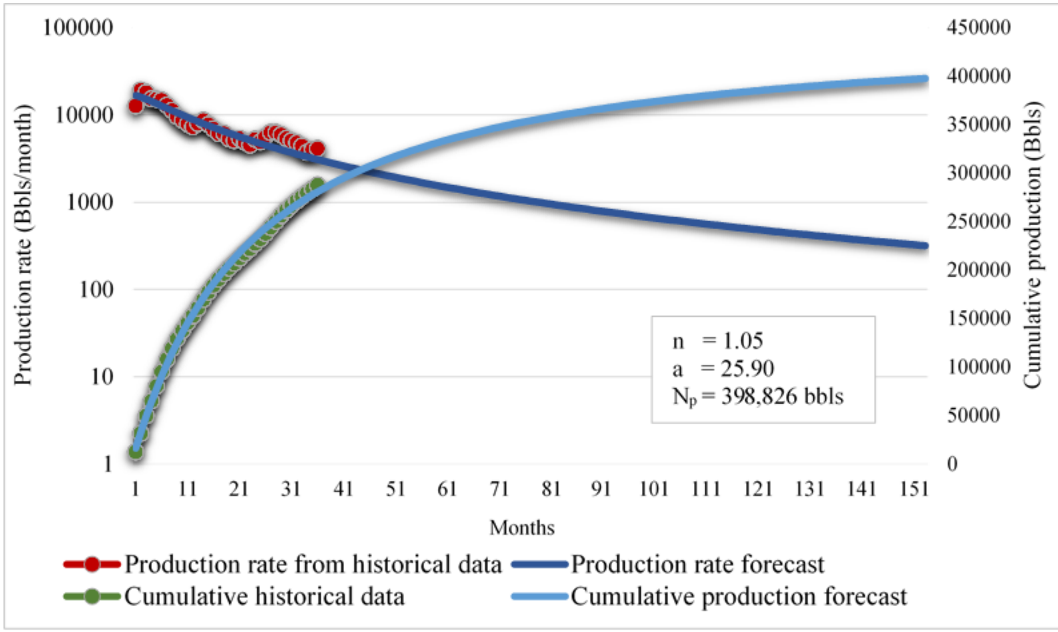


Figure 6.7. Oil production forecast from EOG's data using the Logistic growth model.

The estimated gas rate was obtained using the results from the oil production forecast multiplied by a constant value of 1.39, which is the GOR on the last month of historical data. The cumulative gas production is 431,957 Mscf (Figure 6.8).

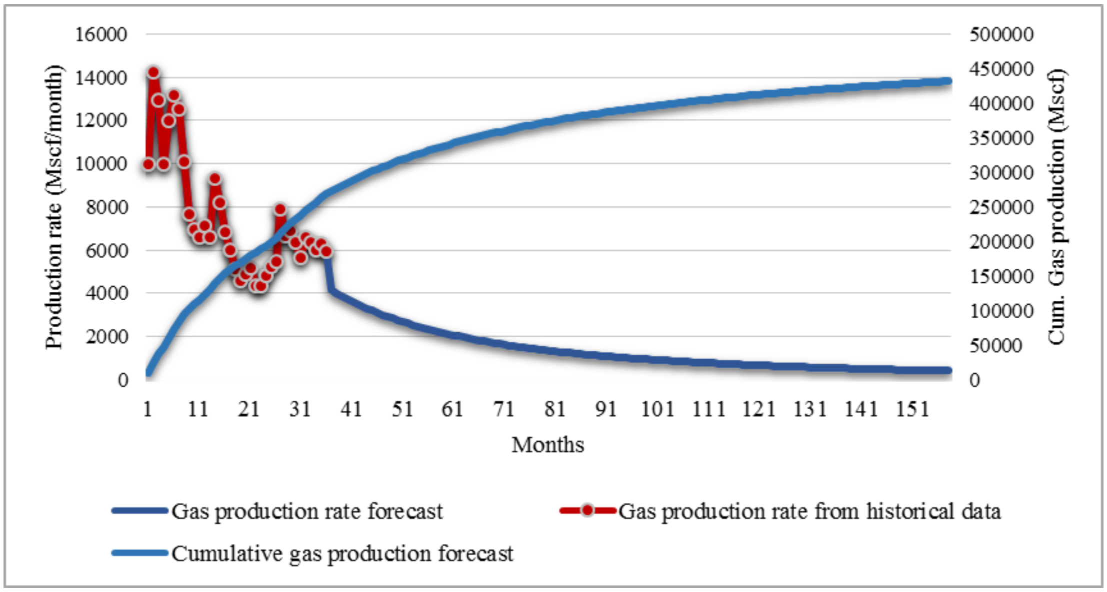
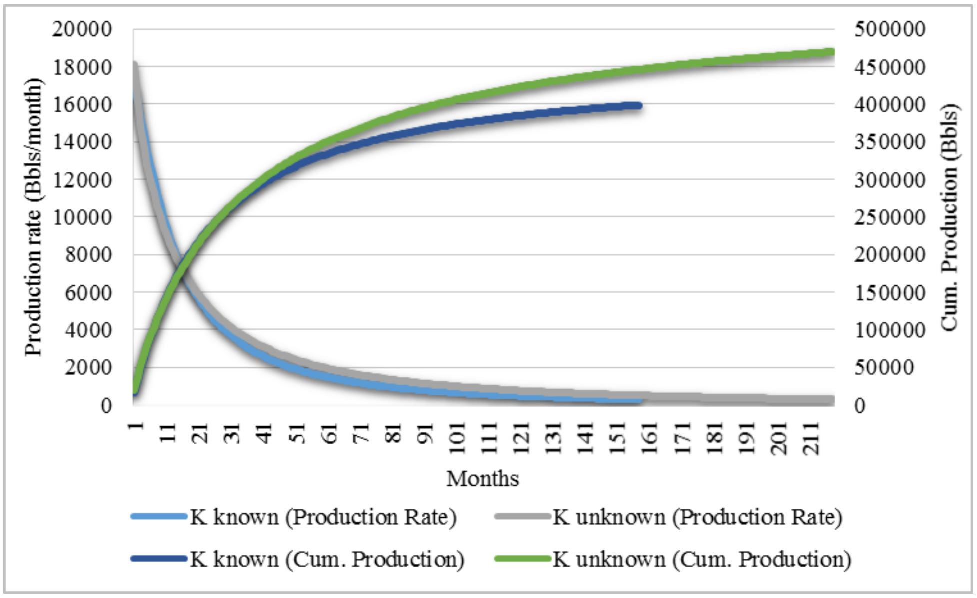


Figure 6.8. Gas production forecast from EOG's data.

When solving for *K*, the resulting value is 552,047 barrels of oil which is greater than the EUR for an average well given on the company's investor presentation; thus, cumulative production (N_p) increases by 70,527 barrels and the life of the well is extended in 60 months (Figure 6.9). The cumulative production differs from *K* because production was terminated at 300 barrels per month for the reasons previously explained. Because of the increase in production, it is assumed that gas production also increases from the previously stated assumption that gas produced is directly proportional to the amount of oil produced. The variation in cumulative production during the life of the well is significant and can have important implications in the well economics; therefore, the variation in production is further analyzed in Chapter 7.



	K known	**K unknown**
K (EUR)	450,000 bbls	552,047 bbls
n	1.05	0.93
a	25.90	26.37
N_p	398,826 bbls	469,346 bbls

Figure 6.9. Oil production forecast for EOG from two different methods: K as a known parameter (given EUR from investor presentations) and K as an unknown parameter (solved simultaneously with *n* and *a* to provide the best model curve fit to the data using Equations (6.5) and (6.6)).

6.5.2. Production model 2: Pioneer Natural Resources

In Pioneer Natural Resources' case, the parameter *K* equal to 168,000 barrels of oil per well was obtained from EIA's Annual Energy Outlook 2014 since this information was not included in the company's investor presentation. I used the average EUR for the Eagle

Ford Shale since the selected wells are located in different counties. The selected wells' location is in Figure 6.10.

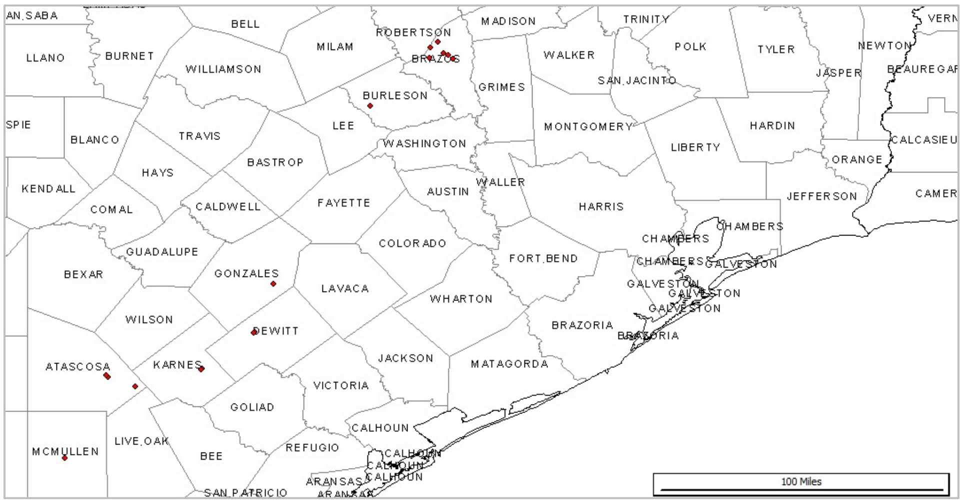


Figure 6.10. Map showing the selected Pioneer wells (Source: Drillinginfo, 2016)

Inputs for the model:

K = 168,000 bbls/well

Production = Average monthly production from 20 wells with 18 months of historical production

The results for the oil forecast (per Equations 6.5 and 6.6) are as follows:

n = 1.12

a = 10.59

N_p = 150,776 bbls of oil

The typical Pioneer well becomes a stripper well in the 57th month after production starts; therefore production was terminated at this point reaching a cumulative production of 150,776 barrels of oil during its economic life as can be observed in Figure 6.11.

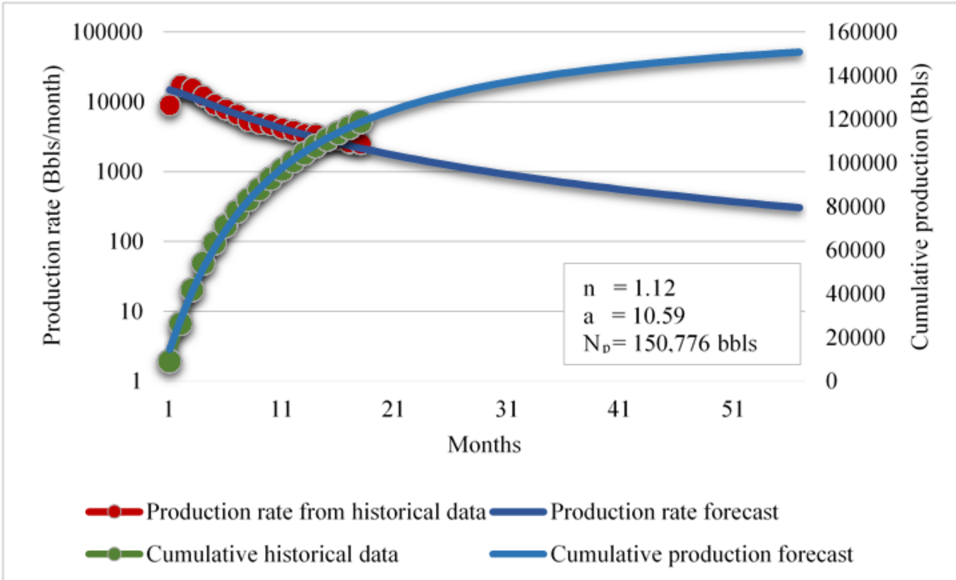


Figure 6.11. Oil production forecast from Pioneer’s data using the Logistic growth model.

The estimated gas rate was obtained using the results from the oil production forecast multiplied by a constant value of 3.00, which is the average GOR on the last month of historical data. The cumulative gas production is 432,648 Mscf (Figure 6.12).

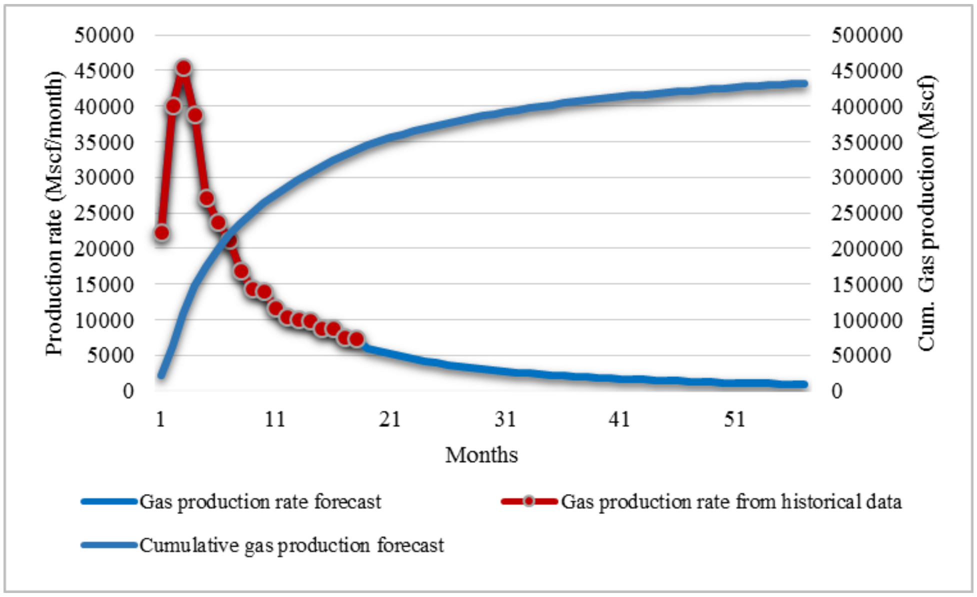
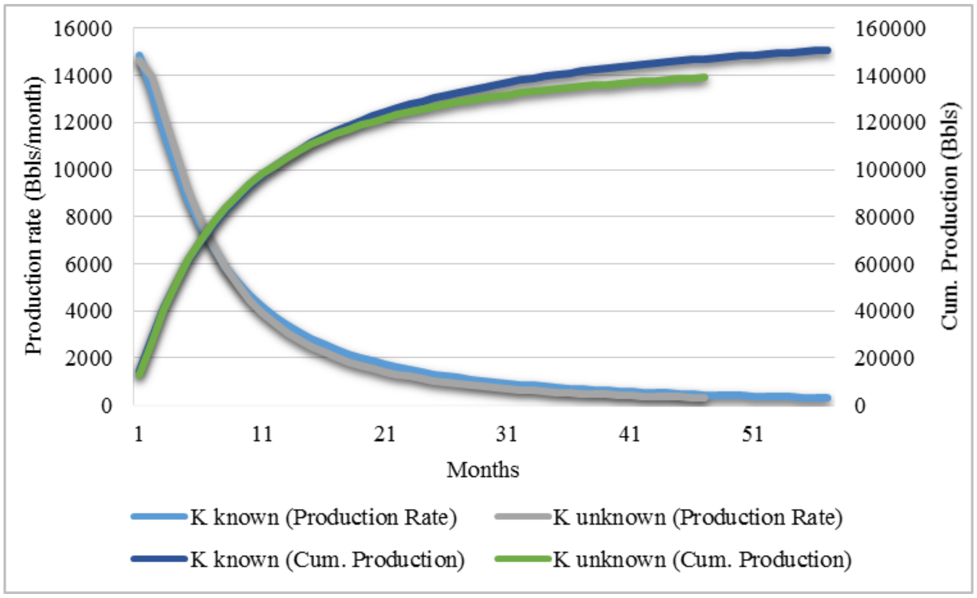


Figure 6.12. Gas production forecast from Pioneer's data.

When solving for K, the resulting value is 151,409 barrels of oil which is smaller than the average EUR for Eagle Ford from the EIA's Annual Energy Outlook 2014; consequently, cumulative production (N_p) decreases in 11,674 barrels and the life of the well is reduced in 10 months (Figure 6.13). The cumulative production differs from K because of the reasons previously explained. Because of the decrease in production, it is anticipated for gas production to decrease too. The variation in cumulative production during the life of the well could be significant when analyzing the well economics; therefore, the variation in production is further analyzed in Chapter 7.



	K known	K unknown
K (EUR)	168,000 bbls	151,409 bbls
n	1.12	1.25
a	10.59	10.84
N_p	150.776 bbls	139,102 bbls

Figure 6.13. Oil production forecast for Pioneer from two different methods: K as a known parameter (given EUR from EIA AEO 2014) and K as an unknown parameter (solved simultaneously with *n* and *a* to provide the best model curve fit to the data using Equations (6.5) and (6.6)).

6.5.3. Production model 3: Chesapeake Energy

For Chesapeake Energy, the parameter *K* equal to 168,000 barrels of oil per well was obtained from EIA's Annual Energy Outlook 2014 since this information was not in the company's investor presentation. I used the average EUR for the Eagle Ford Shale since the selected wells are located in different counties. The selected wells' location is in Figure 6.14.

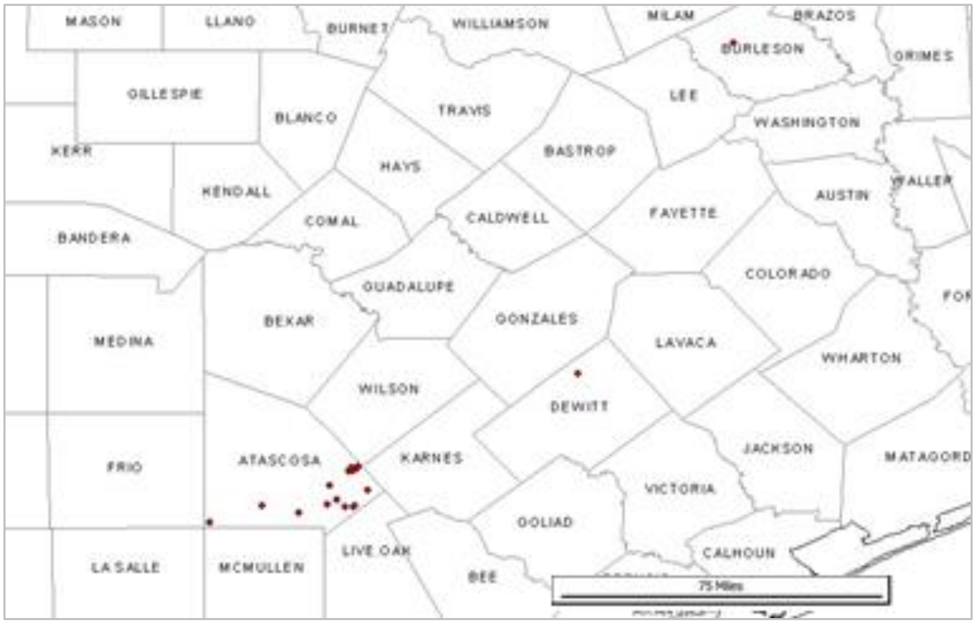


Figure 6.14. Map showing the selected Chesapeake wells (Source: Drillinginfo, 2016)

Inputs:

K = 168,000 bbls/well

Production = Average monthly production from 20 wells with 13 months of historical production The results for the oil forecast (per Equations 6.5 and 6.6) are as follows:

n = 1.22

a = 15.10

N_p = 151,906 bbls of oil

In this case, *n* is larger than 1; but as explained previously, this can be used to match data for wells whose initial rate is not their peak rate which is the case for the majority of the wells used in the analysis.

The Chesapeake typical well becomes a stripper well in the 59th month after production starts; therefore production was terminated at this point reaching a cumulative production of 151,906 barrels of oil during its economic life as can be observed in Figure 6.15.

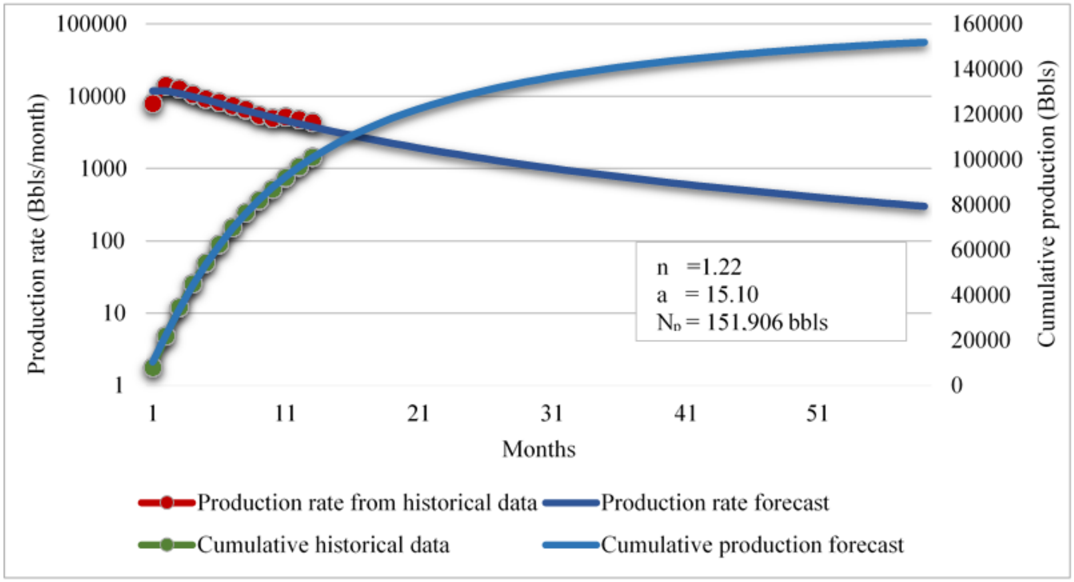


Figure 6.15. Oil production forecast from Chesapeake's data using the Logistic growth model.

The estimated gas rate was obtained using the results from the oil production forecast multiplied by a constant value of 0.90, which is the GOR on the last month of historical data. The cumulative gas production is 119,487 Mscf (Figure 6.16).

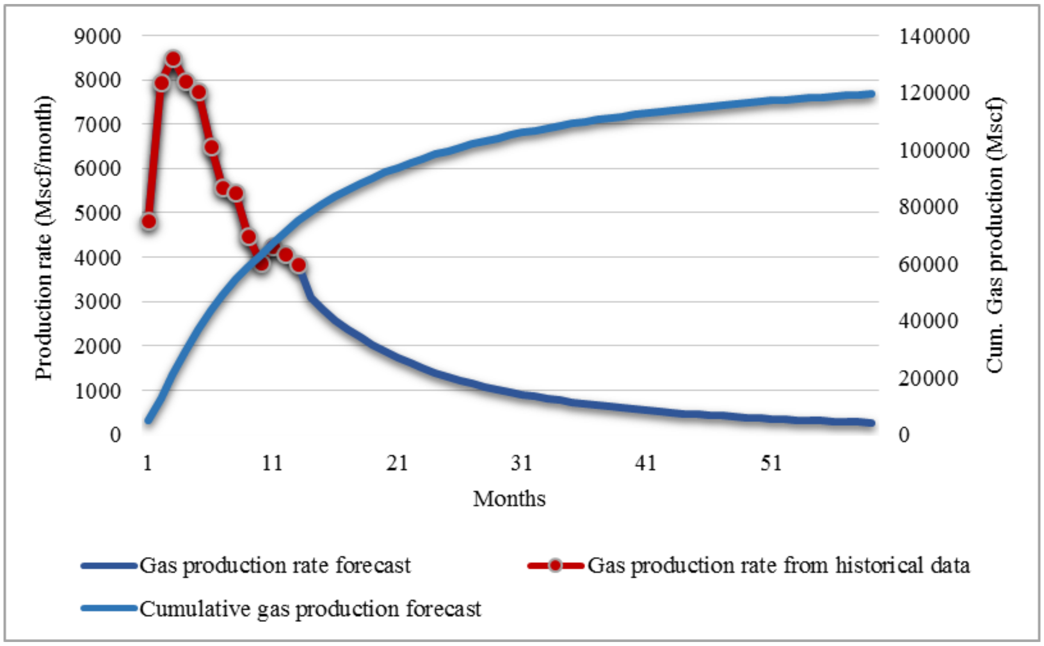
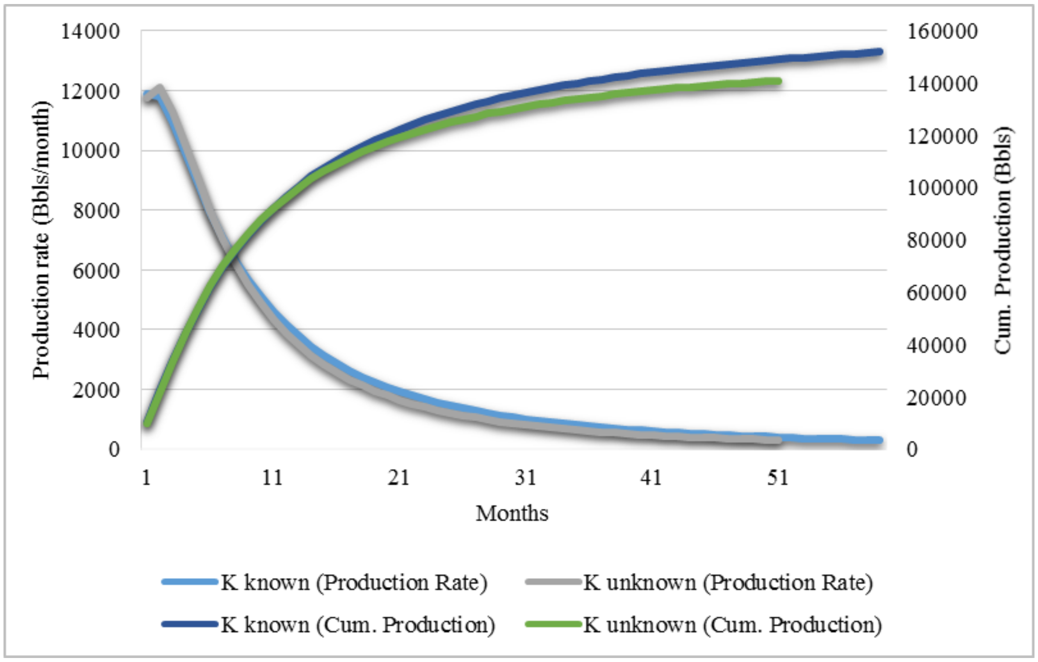


Figure 6.16. Gas production forecast from Chesapeake's data.

When solving for *K*, the resulting value is 154,153 barrels of oil which is smaller than the average EUR from the EIA's Annual Energy Outlook 2014; consequently, cumulative production (N_p) decreases in 10,817 barrels and the life of the well is reduced in 8 months (Figure 6.17). The cumulative production differs from *K* because of the reasons previously explained. Because of the decrease in production, it is anticipated for gas production to decrease too. The variation in cumulative production during the life of the well, even though does not seem as large in contrast to the other companies in the study, could be significant when analyzing the well economics; therefore, the variation in production is further analyzed in Chapter 7.



	K known	**K unknown**
K (EUR)	168,000 bbls	154,153 bbls
n	1.22	1.29
a	15.10	14.83
N_p	151,906 bbls	141,089 bbls

Figure 6.17. Oil production forecast for Chesapeake from two different methods: K as a known parameter (given EUR from EIA AEO 2014) and K as an unknown parameter (solved simultaneously with *n* and *a* to provide the best model curve fit to the data using Equations (6.5) and (6.6)).

Chapter 7: Well economics

Drilling a new well or a group of wells is a business decision, and as such, an appraisal and in-depth analysis of the investment opportunity is needed. The discounted cash flow (DCF) analysis is a widely accepted valuation method to estimate the economic feasibility or attractiveness of an investment opportunity by taking into account the time value of money.

In this chapter, I use the DCF approach as a method of economic valuation to determine the economic feasibility of drilling a typical well for the production of oil and gas for three companies in the Eagle Ford Shale by using production and costs estimates, as well as royalty, taxes, and price assumptions.

Additionally, a sensitivity analysis was developed for each company. This is a technique that indicates how much the profitability of drilling a well will change in response to changes in an input variable while others are held constant.

7.1. Discounted cash flow (DCF) model

Future and past values of money can be converted into their present value equivalent or Net Present Value (NPV) which is critical when assessing the profitability of long-term investments especially when ranking projects and economic resources are limited (Mian, 2002).

The DCF analysis uses projections for future cash flows and discounts them to the present. The purpose of determining the present value of future cash flows relies on the premise that a dollar invested today is worth more than a dollar payable in the future because of the risk of not receiving revenue from that investment (Knull et al., 2007). The objective of this method is to obtain the NPV, calculated as:

$$NPV = \sum_{t=0}^{n} \frac{CF_t}{(1+i)^t} \qquad [7.1]$$

Where:

CF = cash flow at time t

i = discount rate

n = number of periods

If the NPV is positive, it means that the expected revenues are greater than what could be gained by earning the discount rate in other options. If the NPV is equal to zero, it means that there is neither gain nor loss. If the NPV is negative, it means that the project is expected to lose money.

The key component of the equation is the discount rate *i* defined as the “risk adjusted cost of capital” (Inkpen & Moffett, 2011). The discount rate used changes with each company; but, it has to be one that yields above the weighted average cost of capital (WACC) (Inkpen & Moffett, 2011) which depends on the company’s capital structure. For analysis purposes, the DCF model developed uses the same discount rate for the three companies.

Additional to the discount rate *i*, the NPV is determined by the cash flow for each period during the life of the project. The cash flow that considers only costs, royalty, and severance tax is called cash flow before tax (CF_{BFIT}) and yields the $NPV_{BFIT.}$ The cash flow that considers depletion allowance and federal income tax is called cash flow after tax (CF_{AFIT}) and yields the NPV_{AFIT}. The depletion allowance for the model was calculated using the cost depletion method.

The cash flow before federal income tax (BFIT) for each year in the DCF model is calculated as:

$$CF_{BFIT} = [Gross\ oil * (1 - Royalty) * Price\ oil + Gross\ gas * (1 - Royalty) * Price\ gas] - Capex - Opex - [Net\ oil * Price\ oil + Net\ gas * Price\ gas] * Sev.tax \qquad [7.2]$$

Where:

Gross oil = Total oil produced (Bbls)

Gross gas = Total gas produced (Mscf)

Royalty = Fraction of the oil paid to the lessor of the land

Price of oil = Estimated selling price of oil ($/bbl)

Price of oil = Estimated selling price of gas ($/Mscf)

Capex = Capital expenditures ($)

Opex = Operating expenditures in $/boe, where 1 Mscf of gas is equivalent to 1/5.8 bbls of oil

Net oil = Gross oil minus royalty

Net gas = Gross gas minus royalty

The cash flow after federal income tax (AFIT) for each year in the DCF model is calculated as:

$$CF_{AFIT} = CF_{BFIT} - [(CF_{BFIT} - Depletion\ Allowance) * Federal\ Income\ Tax] \qquad [7.3]$$

Where:

Federal Income Tax = Corporate tax imposed on net taxable income

Depletion Allowance = Tax reduction for the recovery of capital investments

The depletion allowance used in the model is the Cost Depletion method, calculated for each year as:

$$Depletion\ Allowance = \left(\frac{Capex}{Cumulative\ production}\right) * Net\ production \qquad [7.4]$$

Where:

Cumulative Production = Estimated total production of oil and gas during the life of the well (boe)[4]

Net production = Net production of oil and gas produced in the year (boe)

7.1.1. General inputs and assumptions

The accuracy of the model depends on the accuracy of the assumptions and inputs which frequently are uncertain; therefore, two types of models were developed as part of the analysis to account for this uncertainty. The two types of models developed for each company are: a deterministic or base case model, and a probabilistic model.

A deterministic model is fully determined by the initial parameter values; it is a static model that yields only one possible result and is the reason why it is used as the base case model. A probabilistic model assumes an inherent randomness to the model inputs to account for a possible under-appreciation of the complexity and risks associated to drilling a well.

The DCF base case model is based on production, revenues, costs, royalty, and taxes projections. The production projection for each company is explained in Chapter 6; the others are explained below:

- Costs

The main components are operating expense (OPEX) and capital expenditure (CAPEX), in which the latter is formed by drilling and completion. OPEX and CAPEX were obtained from the company's 10-K reports or investor's presentations. If the

[4] Boe stands for barrels oil equivalent where 1 Mscf of gas is equivalent to 1/5.8 bbls of oil.

information was not available in these documents, the values used were obtained from similar studies done in similar shale plays and by consulting with industry specialists. Additionally, another important cost is abandonment, this information was not specified in the operators' documents consulted; thus, the input value used was obtained from similar studies in Texas shale plays.

- Royalty

A stipulated fraction of the oil and gas produced is paid to the lessor of the land either in kind or its equivalent in money. In Texas, royalties are usually negotiable, and therefore vary by lease. The base royalty used in the model is 25% which is commonly used by industry specialists when evaluating projects in the Eagle Ford (TRRC, Feb. 2016).

- Taxes

Although Texas does not levy a property tax on the value of oil and gas property or a state federal income tax, it collects tax revenues via a severance tax. In addition, companies also pay federal income tax.

Severance tax: The baseline for Texas is 4.6% on the market value of oil and condensate produced, and 7.5% on the market value of gas produced. Since the model is for wells classified as "oil wells", the severance tax used is 4.6% which applies to the oil and gas produced (gas treated as oil equivalent in boe). The 7.5% severance tax on gas production is omitted from the analysis principally from the wells classification, but also from the many tax exemptions Texas offers for high cost gas wells (Gülen et al., 2013).

Federal income tax: The federal income tax used in the model is 35%. This is a corporate tax imposed on the net taxable income (gross income less allowable tax deductions). Some allowable tax deductions include depletion, depreciation, and amortization (DD&A) which the companies can calculate by using different methods. The model developed includes a cost depletion calculation to allow for a fair comparison between the companies comprised in the present study.

- Revenues

The revenues will be dependent of the net production and market price of oil and gas. The base market price used for the model is 40 $/bbl and 2.28 $/Mscf, for oil and gas respectively.

The DCF probabilistic model is based on the values used in the base case model, but the uncertainty factor is introduced into the equation by setting probabilistic distributions for some of the inputs:

- Costs

Drilling, completion, abandonment, and OPEX were modeled using the Triangular distribution under the assumption that they can take values under and over 20% of the baseline value.

- Royalty

It was modeled using the Triangular distribution assuming it can vary 20% from the baseline value.

- Production

It was modeled using the Lognormal distribution for the initial production (production of the first year). The mean and standard deviation parameters were calculated from the historical initial production from the selected wells for each company.

- Price

Oil and natural gas real prices between the years 2000 and 2015 (in 2015 dollars) were analyzed to determine the best distribution that fitted the data which results can be observed in Figures 7.1 and 7.2. Then, the prices were modeled using the Logistic and

Triangular distribution, for oil and gas respectively. Additionally, prices were truncated at 15 $/bbl and 1 $/Mscf, for oil and gas respectively based on historical data prior to the year 2000.

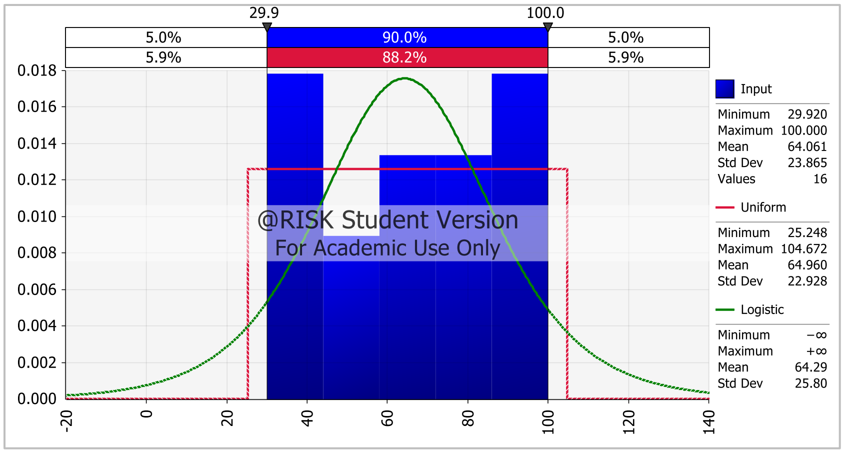


Figure 7.1. Results for the distribution fitting analysis for oil prices (Source: U.S. Energy Information Administration, 2015; Inflation Data, 2015).

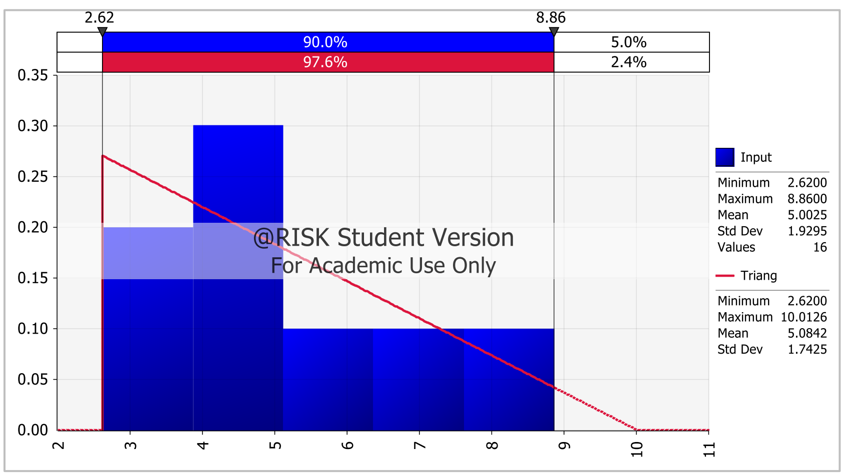


Figure 7.2. Results for the distribution fitting analysis for natural gas prices (Source: U.S. Energy Information Administration, 2015; Inflation Data, 2015).

The model was developed under the following assumptions that apply to all companies:

Assumption	Value		Description
Working interest (WI)	100	%	The company is responsible for all the costs incurred in the drilling, completion, production and abandonment of the well.
Discount rate	10	%	Commonly used in the industry to evaluate projects.
Economic limit	300	Bbls/month	Wells reaching the end of its economic life.
Royalty	25	%	Royalty for the Eagle ford between 22-28%.
Oil price	40	$/bbl	Flat during the life of the well.
Gas price	2.28	$/Mscf	Flat during the life of the well.

Table 7.1. Assumptions used in the DCF base case model for all companies.

7.2. Model description and results

The base case model was developed in Excel using the production projection results assuming a known carrying capacity *K*. However, a DCF model was also developed for the results when assuming an unknown *K* to analyze the variations between the two approaches and accuracy of the production inputs. The probabilistic model, sensitivity analysis, and distribution fitting was developed using @Risk Student Version software. The software uses probabilistic distributions that are set for the variables resulting in an ensemble of different outputs.

7.2.1. DCF model 1: EOG Resources

7.2.1.1. Base case model EOG Resources

The base case model for EOG uses input values shown in Table 7.2 that are the most likely to occur.

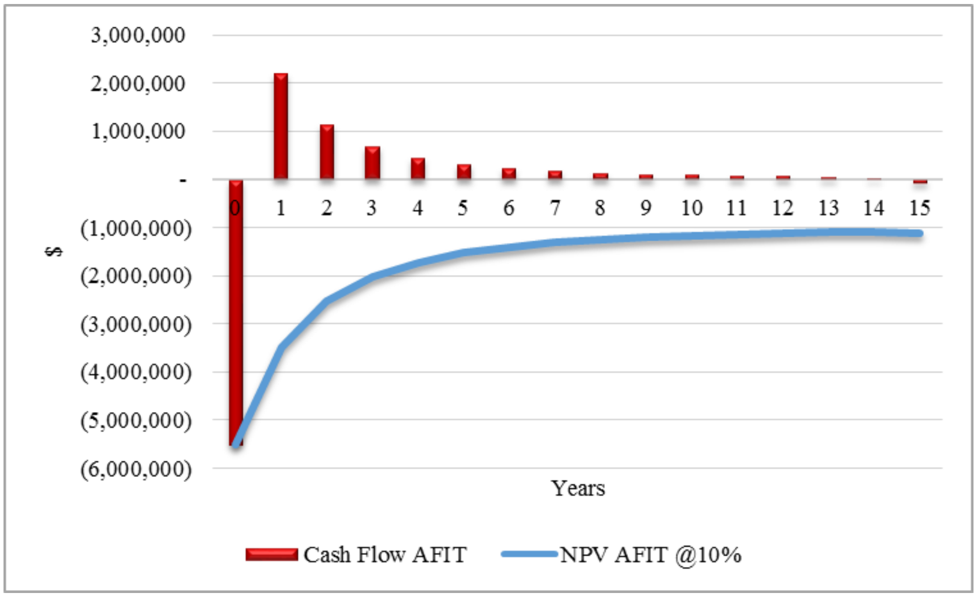
Variable	Value		Source	Description
Drilling cost (CAPEX)[5]	2,090,000	$	EOG (Investor presentation), Rigzone	Includes rig, rental equipment, services, labor, engineering, overhead, etc.
Completion cost (CAPEX)[6]	3,410,000	$	EOG (Investor presentation), Rigzone	Includes fluids, chemicals, transportation, formation stimulation, services, rental equipment, etc.
OPEX oil equivalent	12.86	$/boe	EOG Resources (10-K report)	Includes lease, well cost, transportation, and General & Administrative.
Abandonment cost	75,000	$	Gülen et al. 2013	Plug and abandon well once its economic life ends.
Severance tax	4.6	%	Railroad Commission of Texas	Baseline Texas severance tax for oil and liquids.
Federal income tax	35	%	U.S. Securities and Exchange Commission	Federal tax levied on the income of corporations.
Working interest (WI)	100	%	(Assumption)	The company is responsible for all the costs incurred in the drilling, completion, production and abandonment of the well.
Discount rate	10	%	(Assumption)	Commonly used in the industry to evaluate projects.
Economic limit	300	Bbls/month	(Assumption)	Wells reaching the end of its economic life.
Royalty	25	%	(Assumption)	Royalty for the Eagle ford between 22-28%.
Oil price	40	$/bbl	(Assumption)	Flat during the life of the well.
Gas price	2.28	$/Mscf	(Assumption)	Flat during the life of the well.

Table 7.2. Input values for the DCF base case model for EOG Resources.

The NPV at a 10% discount rate, both before and after federal income tax, obtained from the base case model under the assumptions used are negative; meaning that it is not economically viable for EOG to drill a well under the current conditions. The break-even analysis suggests that a change in the price of oil, leaving all other variables intact, would make it economically viable to drill when the oil price is over 42.00 $/bbl (BFIT) and 47.50 $/bbl (AFIT). The results for the base case model for EOG are in Figure 7.3.

[5] Drilling cost is considered to be 38% of the total D&C cost based on the article "Costs for drilling the Eagle Ford" from Rigzone website www.rigzone.com.

[6] Completion cost is considered to be 62% of the total D&C cost based on the article "Costs for drilling the Eagle Ford" from Rigzone website www.rigzone.com.



NPV $_{BFIT}$ @10%, 40$/bbl	(457,815.00)	$
NPV $_{AFIT}$ @10%, 40$/bbl	(1,116,864.86)	$
IRR $_{AFIT}$ @40$/bbl	1	%
Break-even price BFIT	42.00	$/bbl
Break-even price AFIT	47.50	$/bbl

Figure 7.3. EOG's base case cash flow after federal income tax diagram using a discount rate of 10%, 40$/bbl, 2.28$/Mscf.

From the base case model, the sensitivity analysis for a 20% change in the variables inputs show that well economics are most sensitive to the price of oil followed by OPEX. Additionally, Figure 7.4 also shows that a change of that magnitude in either variable still will not make this well economically feasible considering the NPV$_{AFIT}$.

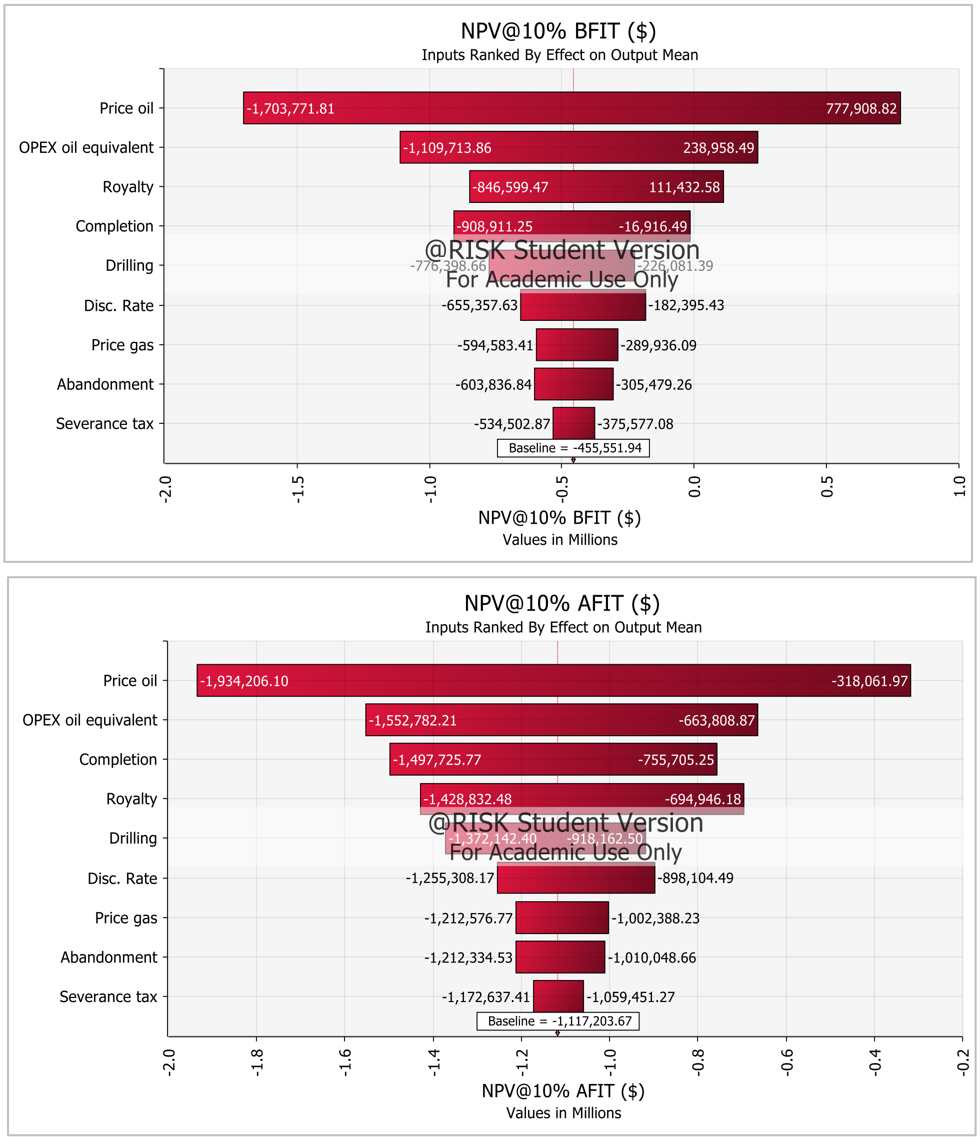
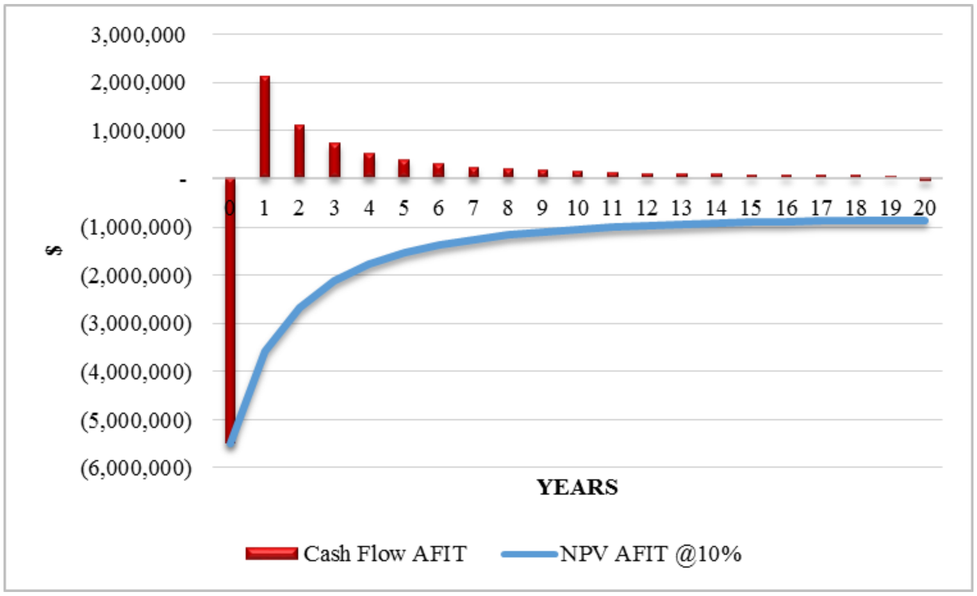


Figure 7.4. Tornado charts showing EOG's sensitivity analysis results for a 20% change in inputs for NPV_{BFIT} and NPV_{AFIT}.

As explained in Chapter 6, the production model using the Logistic Growth method can use an assumed carrying capacity *K* (expected EUR), or it can be obtained. The base case model presented above is for the expected EUR reported on the company's investor presentation. For EOG, when obtaining *K*, the total cumulative production is higher than when using the EUR reported, extending the life of the well and improving its economics. The results are in Figure 7.5.



NPV $_{BFIT}$ @10%, 40$/bbl	31,278.99	$
NPV $_{AFIT}$ @10%, 40$/bbl	(875,101.72)	$
IRR $_{AFIT}$ @40$/bbl	4	%
Break-even price BFIT	39.88	$/bbl
Break-even price AFIT	45.37	$/bbl

Figure 7.5. EOG's (K unknown) cash flow after federal income tax diagram using a discount rate of 10%, 40$/bbl, 2.28$/Mscf.

7.2.1.2. Probabilistic DCF model EOG Resources

Two probabilistic DCF models were developed: A) considers that the initial production can vary according to a range of values based on historical data; and B) disregards a possible change in initial production. The input values for scenario A are presented in Table 7.3.

Variable	Unit	Distribution	Min	Average (Mean, Most likely)	Max	Std. Dev.
Initial production	Bbls/year	Lognormal	-	154,432	-	257,042
Drilling	$	Triangular	1,672,000	2,090,000	2,508,000	-
Completion	$	Triangular	2,728,000	3,410,000	4,092,000	-
OPEX oil equivalent	$/boe	Triangular	10.8	12.86	15.43	-
Abandonment	$	Triangular	60,000	75,000	90,000	-
Price Oil[7]	$/bbl	Logistic (truncated at 15$/bbl)	15.00	64.29	-	25.8
Price Gas[8]	$/Mscf	Triangular (truncated at 1$/Mscf)	1.00	5.08	10.01	1.74
Royalty rate	%	Triangular	20%	25%	30%	-

Input values for Scenario B are the same, except Initial production is not included in the model.

Table 7.3. Input values and probabilistic distributions for each variable for the EOG Resources probabilistic model.

For scenario A, decline rates (how much production decreases from one year to the next) are assumed to stay the same as in the base case model; however, the calculated production will vary because initial production varies. Additionally, production from year twelve to year thirteen drops in 83% because the well only produces for two months during the last year. The decline rates for each year are:

7 The distribution fitting analysis yield two possible distributions for the price of oil. The model was developed using the Logistic distribution to follow the parameters from the study done by Gülen et al. 2013.

8 The results from the distribution fitting analysis yield a minimum natural gas price of 2.62 $/Mscf; however, prices prior to the year 2000 demonstrate that it is possible for prices to reach 1$/Mscf.

Year	1	2	3	4	5	6	7	8	9	10
Decline	49%	41%	35%	30%	26%	23%	21%	19%	17%	16%
Year	**11**	**12**	**13**							
Decline	15%	14%	85%							

Table 7.4. Decline rates used in the probabilistic DCF model, Scenario A.

The results from the two probabilistic models are from 100 simulations of 1000 interactions each with a mean NPV_{AFIT} of 3.2 million dollars for scenario A and 4.5 million dollars for scenario B which are shown in Figure 7.6 and Figure 7.7. From the simulation results, the chance to have a positive NPV_{AFIT} is 40.8% for scenario A and 78.7% for scenario B. A sensitivity analysis (Figure 7.8) was also performed demonstrating that initial production rate is the most significant variable when analyzing the economic feasibility of drilling a well, followed by price of oil.

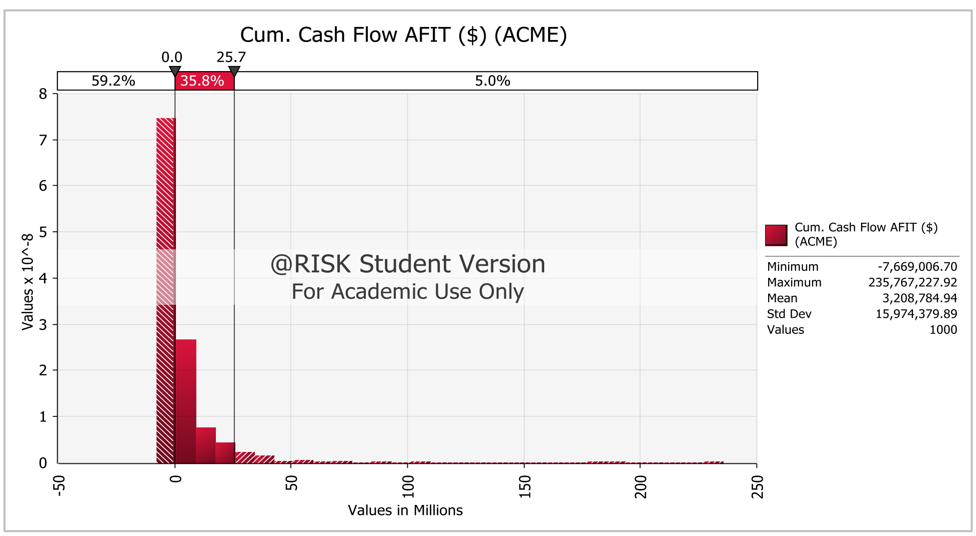


Figure 7.6. Histogram of NPV_{AFIT} (Cum. Cash Flow) results considering changes in initial production (Scenario A).

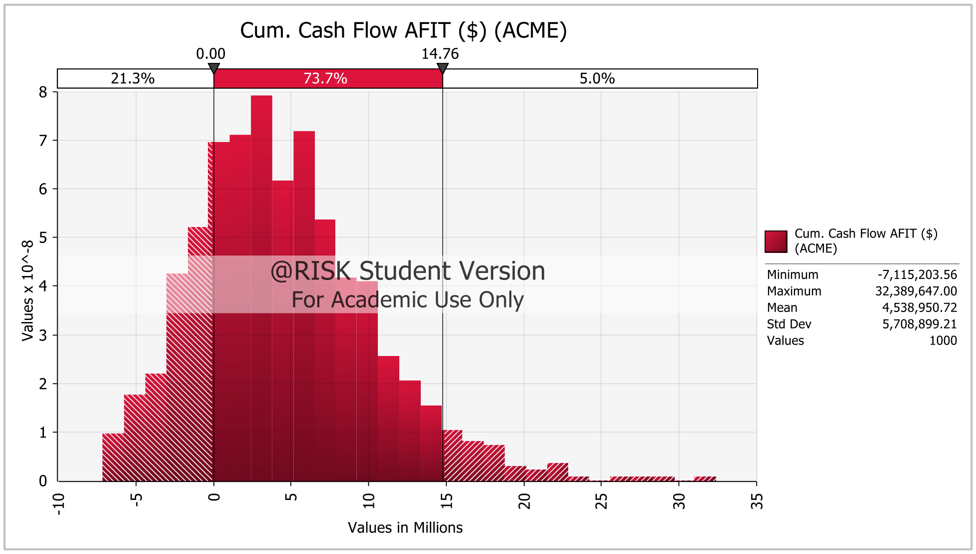


Figure 7.7. Histogram of NPV_{AFIT} (Cum. Cash Flow) results disregarding changes in initial production (Scenario B).

NPV_{AFIT} @10%

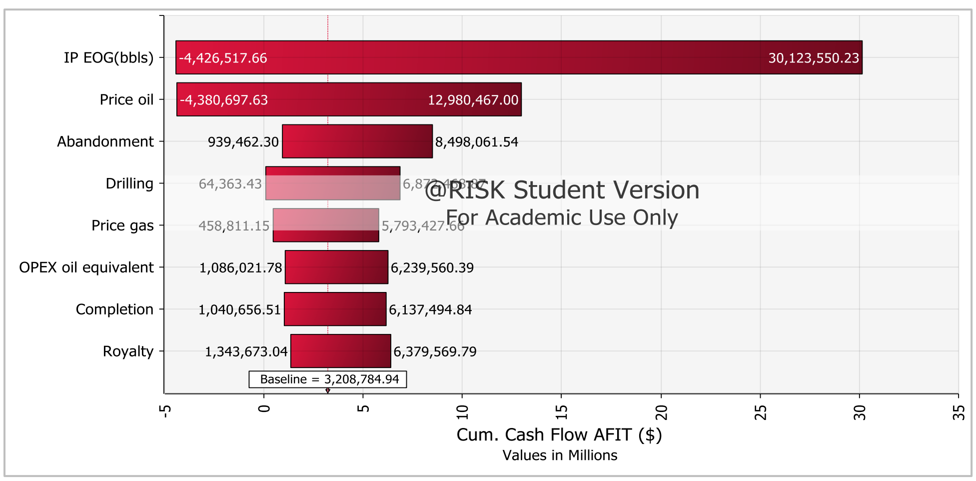


Figure 7.8. Tornado chart showing EOG's sensitivity analysis results for the probabilistic model.

7.2.2. DCF model 2: Pioneer Natural Resources

7.2.2.1. Base case model Pioneer Natural Resources

The base case model uses input values shown in Table 7.5 that are the most likely to occur.

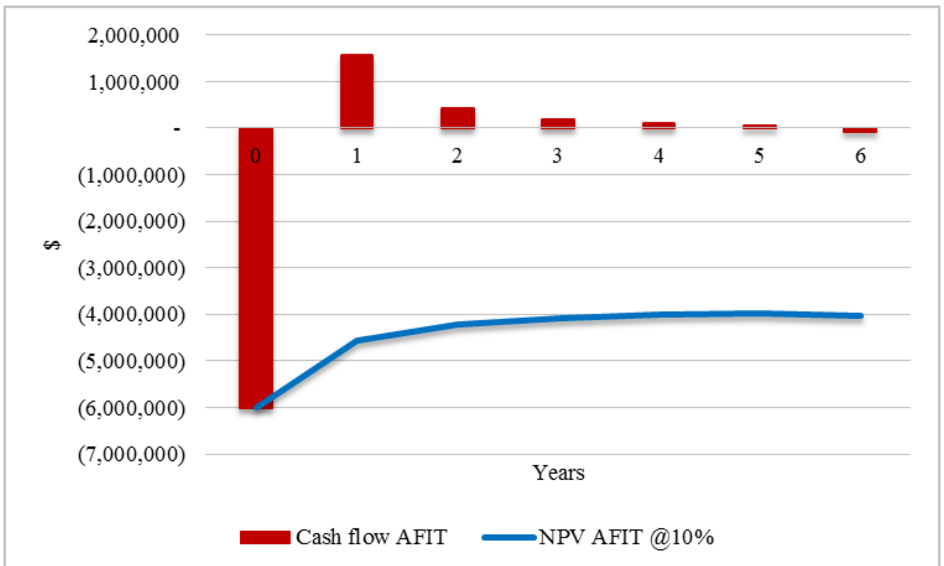
Variable	Value		Source	Description
Drilling cost (CAPEX)[9]	2,280,000	$	Berman, A., Rigzone	Includes rig, rental equipment, services, labor, engineering, overhead, etc.
Completion cost (CAPEX)[10]	3,720,000	$	Berman, A., Rigzone	Includes fluids, chemicals, transportation, formation stimulation, services, rental equipment, etc.
OPEX oil equivalent	10.4	$/boe	Pioneer Natural Resources (10-K report)	Includes lease, well cost, and transportation.
Abandonment cost	75,000	$	Gülen et al. 2013	Plug and abandon well once its economic life ends.
Severance tax	4.6	%	Railroad Commission of Texas	Baseline Texas severance tax for oil and liquids.
Federal income tax	35	%	U.S. Securities and Exchange Commission	Federal tax levied on the income of corporations.
Working interest (WI)	100	%	(Assumption)	The company is responsible for all the costs incurred in the drilling, completion, production and abandonment of the well.
Discount rate	10	%	(Assumption)	Commonly used in the industry to evaluate projects.
Economic limit	300	Bbls/month	(Assumption)	Wells reaching the end of its economic life.
Royalty	25	%	(Assumption)	Royalty for the Eagle ford between 22-28%.

Table 7.5. Input values for the DCF base case model for Pioneer Natural Resources.

[9] Drilling cost is considered to be 38% of the total D&C cost based on the article “Costs for drilling the Eagle Ford” from Rigzone website www.rigzone.com.

[10] Completion cost is considered to be 62% of the total D&C cost based on the article “Costs for drilling the Eagle Ford” from Rigzone website www.rigzone.com.

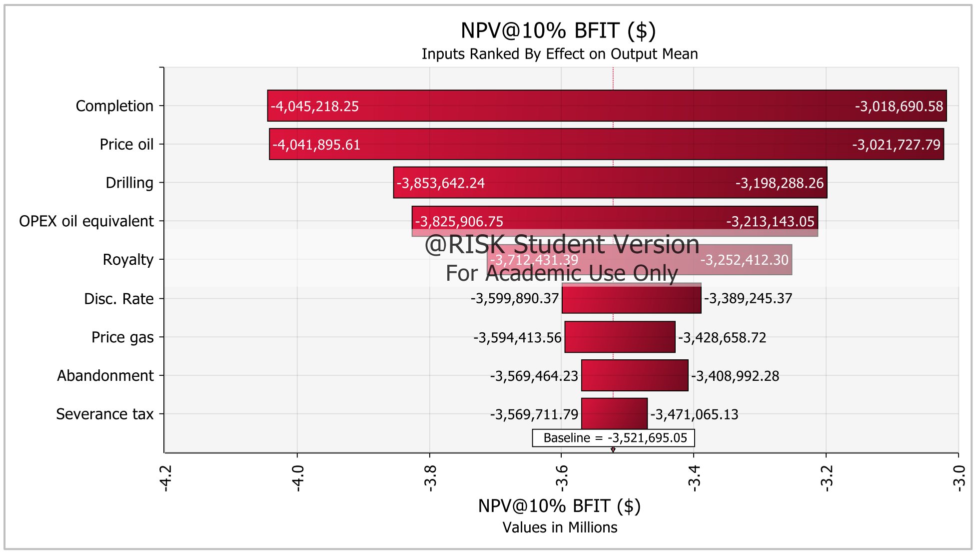
The NPV, both before and after federal income tax, obtained from the base case model under the assumptions used are negative; meaning that it is not economically viable for Pioneer to drill a well under the current conditions. The break-even analysis suggests that a change in the price of oil, leaving all other variables intact, would make it economically viable to drill when the price is over 87.54 $/bbl which differs greatly from the results for EOG. A relatively small increase in the price of oil can turn an EOG well into a profit earning project; on the contrary, prices would have to increase by 119% (compared to the baseline of 40 $/bbl) to make a Pioneer well economically feasible. The results for the base case model for Pioneer are in Figure 7.9.



NPV BFIT @10%, 40$/bbl	(3,522,175.07)	$
NPV AFIT @10%, 40$/bbl	(4,019,787.73)	$
IRR AFIT @40$/bbl	<0	%
Break-even price BFIT	75.98	$/bbl
Break-even price AFIT	87.54	$/bbl

Figure 7.9. Pioneer’s base case cash flow after federal income tax diagram using a discount rate of 10%, 40$/bbl, 2.28$/Mscf.

From the base case model, the sensitivity analysis results in Figure 7.10 show that for Pioneer, the well economics are most sensitive to price of oil and completion cost. This is expected given the results from the break-even analysis and the higher completion cots that Pioneer has compared to EOG. However, the factors affecting well economics have a different order of impact for NPV_{BFIT} and NPV_{AFIT} since the first is mostly dependent on costs to be economical, and the latter is mostly dependent of revenues since they include tax deductions.



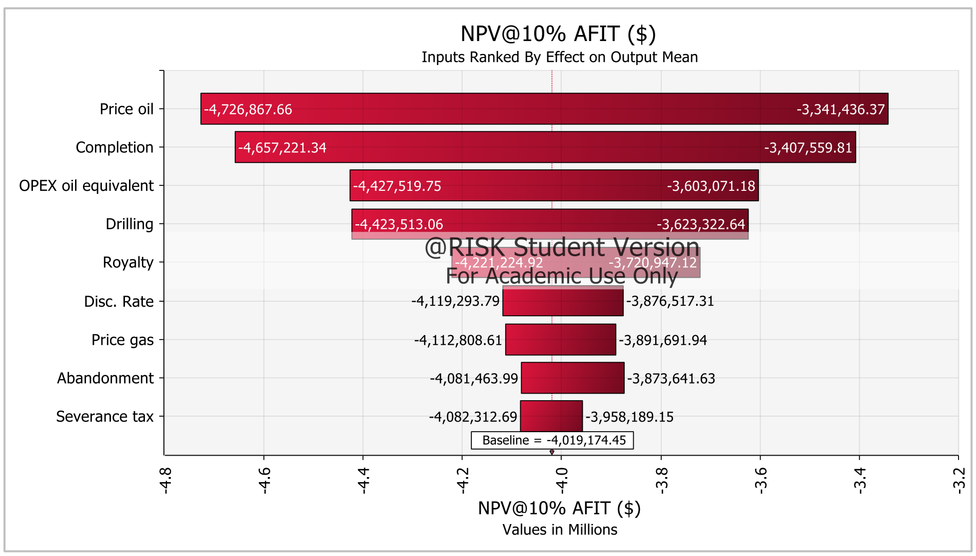
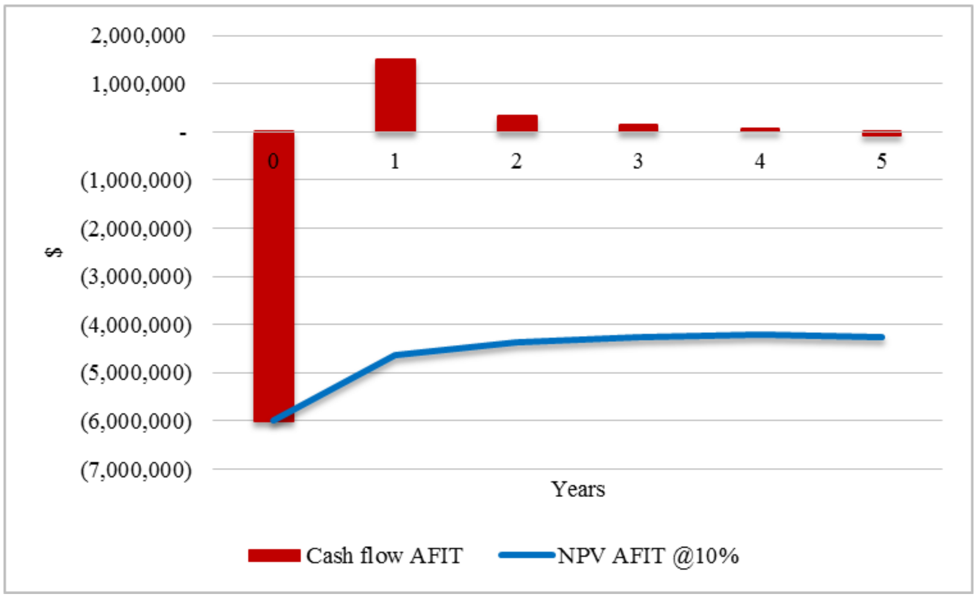


Figure 7.10. Tornado charts showing Pioneer's sensitivity analysis results for a 20% change in inputs for NPV_{BFIT} and NPV_{AFIT}.

The base case model presented above is for the expected EUR reported on the U.S. EIA Annual Energy Outlook 2014. For Pioneer, when obtaining *K*, the total cumulative production is lower than when using the EUR reported, shortening the life of the well and weakening its economics. The results are in Figure 7.11.



NPV $_{BFIT}$ @10%, 40$/bbl	(3,689,578.63)	$
NPV $_{AFIT}$ @10%, 40$/bbl	(4,263,151.64)	$
IRR $_{AFIT}$ @40$/bbl	<0	%
Break-even price BFIT	80.30	$/bbl
Break-even price AFIT	92.36	$/bbl

Figure 7.11. Pioneer's (K unknown) cash flow after federal income tax diagram using a discount rate of 10%, 40$/bbl, 2.28$/Mscf.

7.2.2.2. Probabilistic DCF model Pioneer Natural Resources

In the same way as with EOG's analysis, two probabilistic DCF models were developed: one taking into account possible changes in initial production (scenario A), and the other disregarding these possible changes (scenario B). The input values for Scenario A are presented in Table 7.6.

Variable	Unit	Distribution	Min	Average (Mean, Most likely)	Max	Std. Dev.
Initial production	Bbls/year	Lognormal	-	101,846	-	49,709
Drilling	$	Triangular	1,824,000	2,280,000	2,736,000	-
Completion	$	Triangular	2,976,000	3,720,000	4,464,000	-
OPEX oil equivalent	$/boe	Triangular	8.32	10.40	12.48	-
Abandonment	$	Triangular	60,000	75,000	90,000	
Price Oil[11]	$/bbl	Logistic (truncated at 15$/bbl)	15.00	64.29	-	25.8
Price Gas[12]	$/Mscf	Triangular	1.00	5.08	10.01	1.74
Royalty rate	%	Triangular	20%	25%	30%	-

Input values for Scenario B are the same, except Initial production is not included in the model.

Table 7.6. Input values and probabilistic distributions for each variable for the Pioneer Natural Resources probabilistic model.

[11] The distribution fitting analysis yield two possible distributions for the price of oil. The model was developed using the Logistic distribution to follow the parameters from the study done by Gülen et al. 2013.
12 The results from the distribution fitting analysis yield a minimum natural gas price of 2.62 $/Mscf; however, prices prior to the year 2000 demonstrate that it is possible for prices to reach 1$/Mscf.

For scenario A, decline rates are assumed to stay the same as in the base case model; however, the calculated production will vary because initial production varies. The decline rates for each year are:

Year	**1**	**2**	**3**	**4**
Decline	73%	57%	45%	51%

Table 7.7. Decline rates used in the probabilistic DCF model, Scenario A.

The results from the two probabilistic models are from 100 simulations of 1000 interactions each with a mean NPV_{AFIT} of -0.95 million dollars for scenario A and -0.41 million dollars for scenario B which are shown in Figure 7.12 and Figure 7.13. From the simulation results, the chance to have a positive NPV_{AFIT} is 28.9% for scenario A and 43.1% for scenario B which are much lower than for EOG. This is in part because Pioneer wells have smaller production rates and because the GOR is larger, having wells producing more gas and increasing the OPEX. A sensitivity analysis (Figure 7.14) was also performed demonstrating that price of oil is the most significant variable when analyzing the economic feasibility of drilling a well, followed by initial production rate.

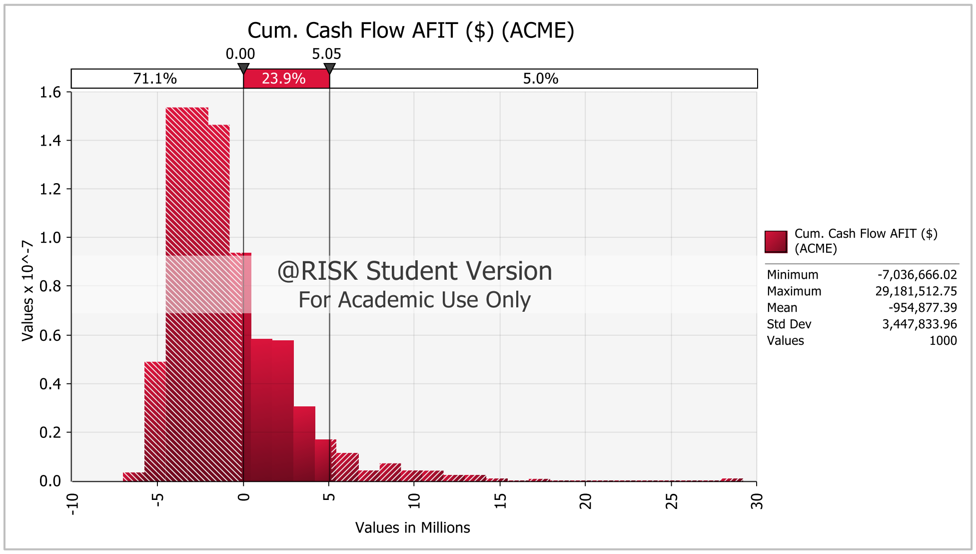


Figure 7.12. Histogram of NPV_{AFIT} (Cum. Cash Flow) results considering changes in initial production (Scenario A).

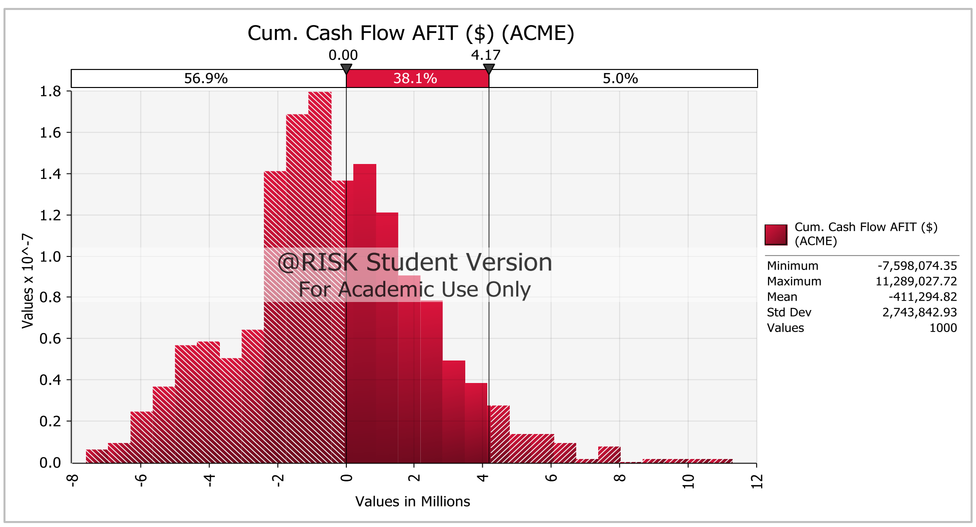


Figure 7.13. Histogram of NPV_{AFIT} (Cum. Cash Flow) results disregarding changes in initial production (Scenario B).

NPV$_{AFIT}$ @10%

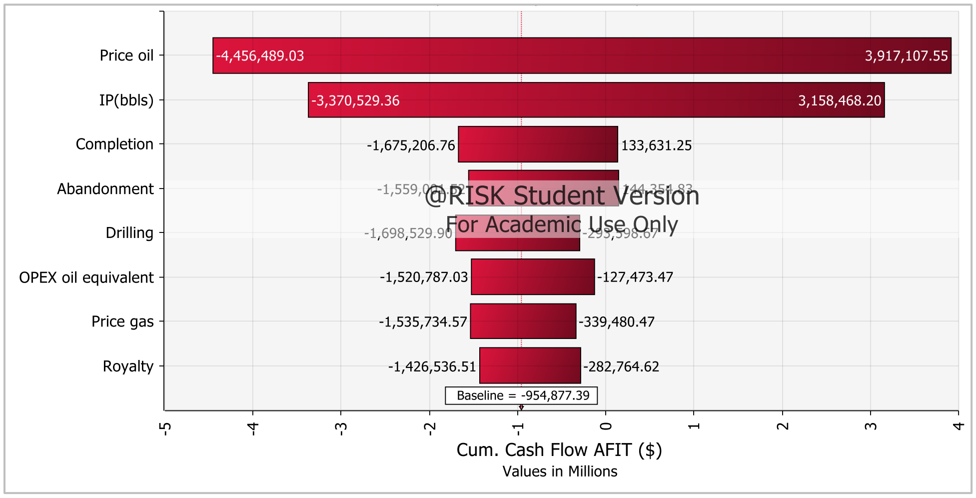


Figure 7.14. Tornado chart showing Pioneer's sensitivity analysis results for the probabilistic model.

7.2.3. DCF model 3: Chesapeake Energy

7.2.3.1. Base case model Chesapeake Energy

The base case model uses input values shown in Table 7.8:

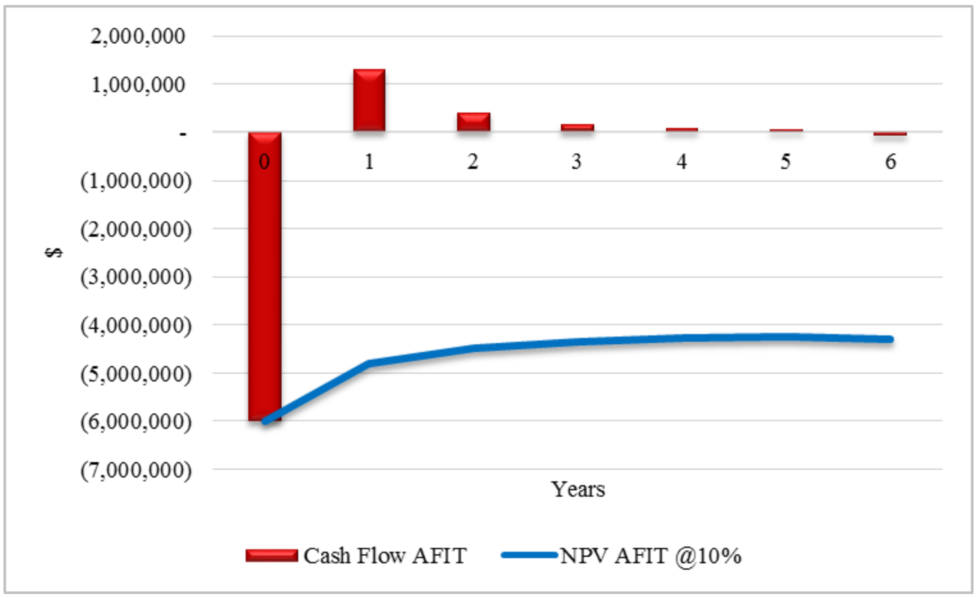
Variable	Value		Source	Description
Drilling cost (CAPEX)[13]	2,280,000	$	Berman, A., Rigzone	Includes rig, rental equipment, services, labor, engineering, overhead, etc.
Completion cost (CAPEX)[14]	3,720,000	$	Berman, A., Rigzone	Includes fluids, chemicals, transportation, formation stimulation, services, rental equipment, etc.
OPEX oil equivalent	12	$/boe	Berman, A.	Includes lease, well cost, transportation, General & Administrative.
Abandonment cost	75,000	$	Gülen et al. 2013	Plug and abandon well once its economic life ends.
Severance tax	4.6	%	Railroad Commission of Texas	Baseline Texas severance tax for oil and liquids.
Federal income tax	35	%	U.S. Securities and Exchange Commission	Federal tax levied on the income of corporations.
Working interest (WI)	100	%	(Assumption)	The company is responsible for all the costs incurred in the drilling, completion, production and abandonment of the well.
Discount rate	10	%	(Assumption)	Commonly used in the industry to evaluate projects.
Economic limit	300	Bbls/month	(Assumption)	Wells reaching the end of its economic life.
Royalty	25	%	(Assumption)	Royalty for the Eagle ford between 22-28%.

Table 7.8. Input values for the DCF base case model for Chesapeake.

[13] Drilling cost is considered to be 38% of the total D&C cost based on the article "Costs for drilling the Eagle Ford" from Rigzone website www.rigzone.com.

[14] Completion cost is considered to be 62% of the total D&C cost based on the article "Costs for drilling the Eagle Ford" from Rigzone website www.rigzone.com.

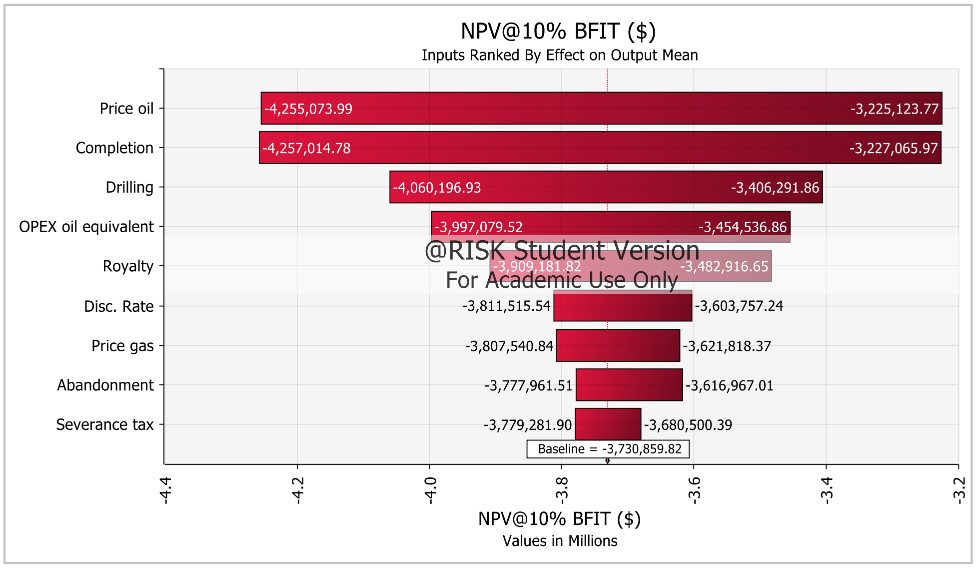
The NPV, both before and after federal income tax, obtained from the base case model under the assumptions used are negative; meaning that it is not economically viable for Chesapeake to drill a well under the current conditions. The break-even analysis suggests that a change in the price of oil, leaving all other variables intact, would make it economically viable to drill when the price is over 89.73 $/bbl given Chesapeake's costs which is not likely to occur in the short term. The results for the base case model for Chesapeake are in Figure 7.15.



NPV $_{BFIT}$ @10%, 40$/bbl	(3,731,354.49)	$
NPV $_{AFIT}$ @10%, 40$/bbl	(4,293,604.15)	$
IRR $_{AFIT}$ @40$/bbl	<0	%
Break-even price BFIT	78.06	$/bbl
Break-even price AFIT	89.73	$/bbl

Figure 7.15. Chesapeake's cash flow after federal income tax diagram using a discount rate of 10%, 40$/bbl, 2.28$/Mscf.

From the Chesapeake's base case model, the sensitivity analysis results in Figure 7.16 show that the well economics are most sensitive to completion and price of oil, followed by completion cost. In the same way as Pioneer, Chesapeake's break-even price is much higher than the baseline of 40 $/bbl; and in the current price environment, it is unlikely that prices will increase in the necessary magnitude to make a well economically feasible with Chesapeake's current costs.



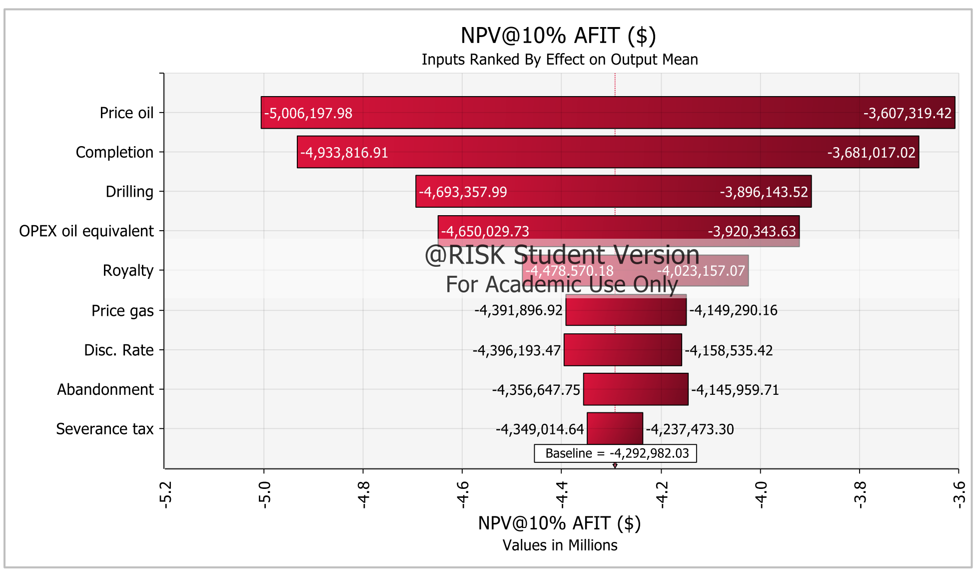
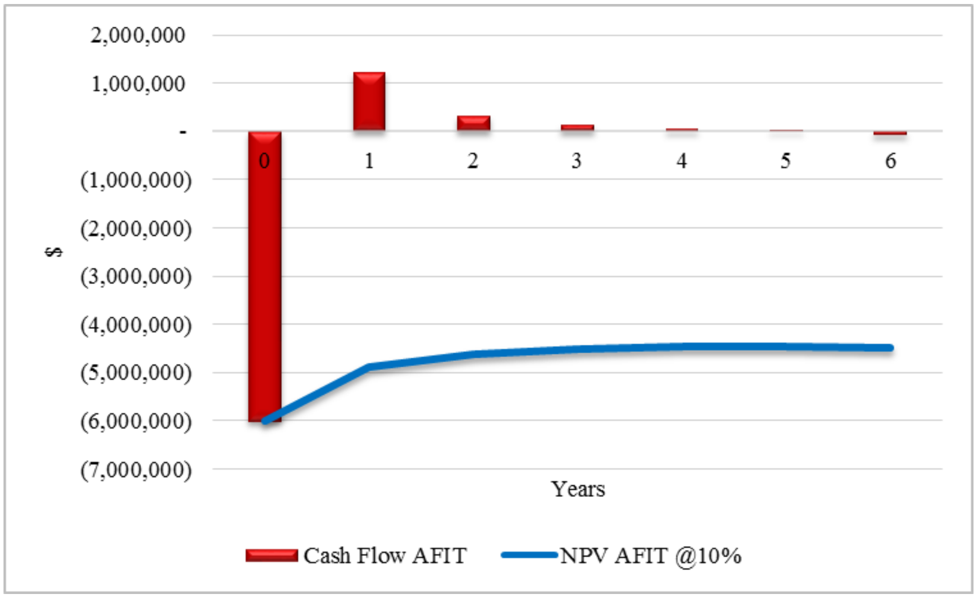


Figure 7.16. Tornado charts showing Chesapeake's sensitivity analysis results for a 20% change in inputs for NPV_{BFIT} and NPV_{AFIT}.

The base case model presented above is for the expected EUR reported on the U.S. EIA Annual Energy Outlook 2014. For Chesapeake, when obtaining *K*, the total cumulative production is lower than when using the EUR reported, shortening the life of the well and weakening its economics. The results are in Figure 7.17.



NPV BFIT @10%, 40$/bbl	(3,871,679.72)	$
NPV AFIT @10%, 40$/bbl	(4,498,646.03)	$
IRR AFIT @40$/bbl	<0	%
Break-even price BFIT	78.06	$/bbl
Break-even price AFIT	89.73	$/bbl

Figure 7.17. Chesapeake's (K unknown) cash flow after federal income tax diagram using a discount rate of 10%, 40$/bbl, 2.28$/Mscf.

7.2.3.2. Probabilistic DCF model Chesapeake Energy

Two probabilistic DCF models were developed: one taking into account possible changes in initial production (scenario A), and the other disregarding these possible changes (scenario B). The input values for Scenario A are presented in Table 7.9.

Variable	Unit	Distribution	Min	Average (Mean, Most likely)	Max	Std. Dev.
Initial production	Bbls/year	Lognormal	-	96,095	-	85,599
Drilling	$	Triangular	1,824,000	2,280,000	2,736,000	-
Completion	$	Triangular	2,976,000	3,720,000	4,464,000	-
OPEX oil equivalent	$/boe	Triangular	9.60	12.00	14.40	-
Abandonment	$	Triangular	60,000	75,000	90,000	-
Price Oil[15]	$/bbl	Logistic (truncated at 15$/bbl)	15.00	64.29	-	25.8
Price Gas[16]	$/Mscf	Triangular	1.00	5.08	10.01	1.74
Royalty rate	%	Triangular	20%	25%	30%	-

Input values for Scenario B are the same, except Initial production is not included in the model.

Table 7.9. Input values and probabilistic distributions for each variable for the Chesapeake Energy probabilistic model.

For scenario A, decline rates are assumed to stay the same as in the base case model; however, the calculated production will vary because initial production varies. The decline rates for each year are:

Year	**1**	**2**	**3**	**4**
Decline	68%	57%	46%	43%

Table 7.10. Decline rates used in the probabilistic DCF model, Scenario A.

[15] The distribution fitting analysis yield two possible distributions for the price of oil. The model was developed using the Logistic distribution to follow the parameters from the study done by Gülen et al. 2013.

16 The results from the distribution fitting analysis yield a minimum natural gas price of 2.62 $/Mscf; however, prices prior to the year 2000 demonstrate that it is possible for prices to reach 1$/Mscf.

The results from the two probabilistic models are from 100 simulations of 1000 interactions each with a mean NPV_{AFIT} of -1.5 million dollars for scenario A and -1.1 million dollars for scenario B which are shown in Figure 7.18 and Figure 7.19. From the simulation results, the chance to have a positive NPV_{AFIT} is 24.0% for scenario A and 33.7% for scenario B. A sensitivity analysis (Figure 7.20) was also performed demonstrating that initial production rate is the most significant variable when analyzing the economic feasibility of drilling a well, followed by price of oil.

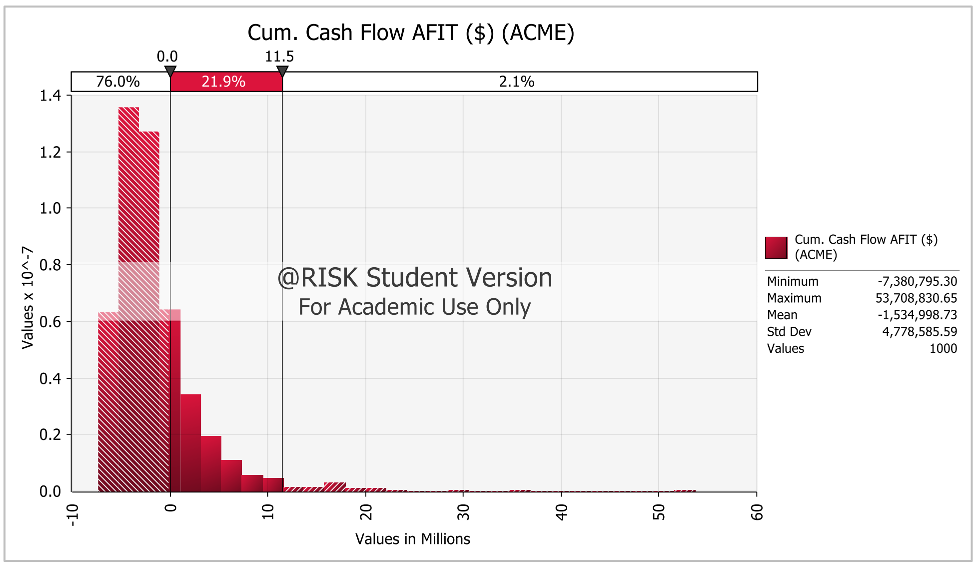


Figure 7.18. Histogram of NPV_{AFIT} (Cum. Cash Flow) results considering changes in initial production (Scenario A).

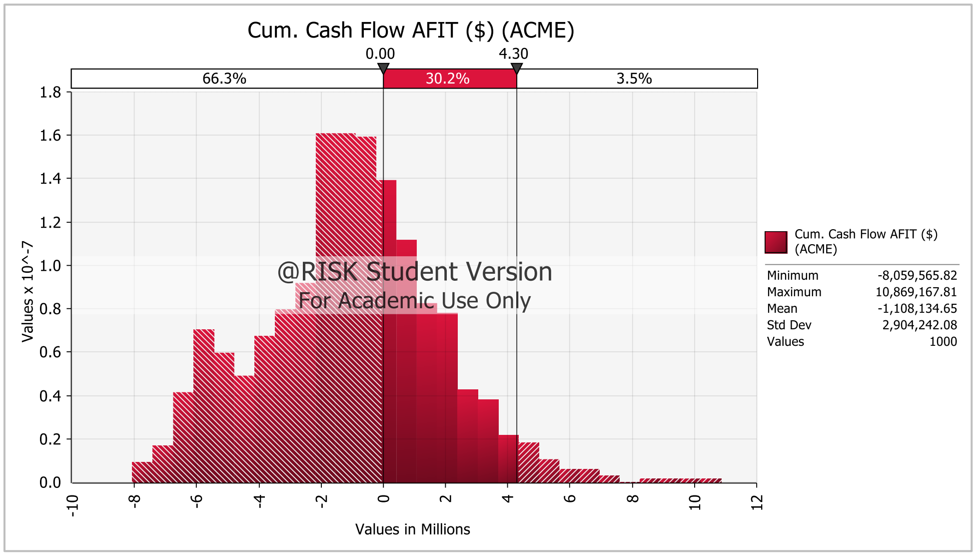


Figure 7.19. Histogram of NPV_{AFIT} (Cum. Cash Flow) results disregarding changes in initial production (Scenario B).

NPV_{AFIT} @10%

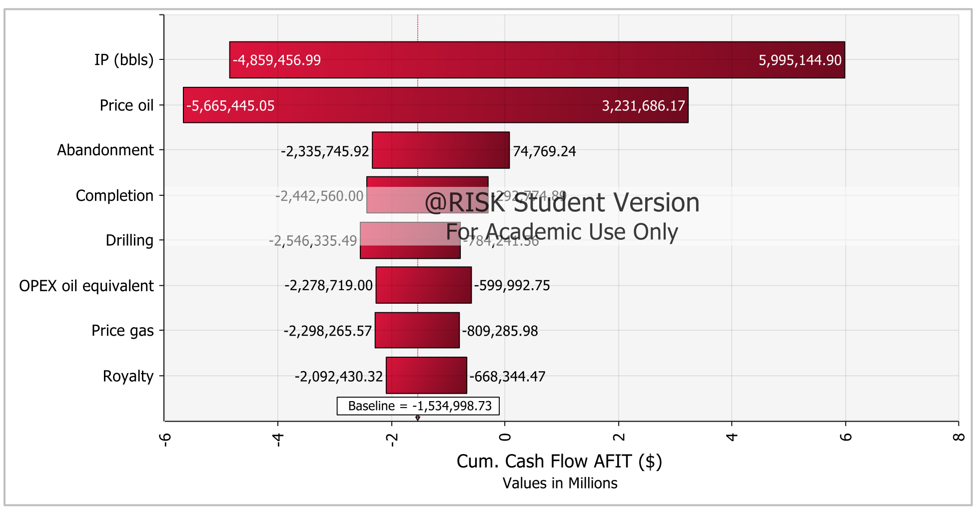


Figure 7.20. Tornado chart showing Chesapeake's sensitivity analysis results for the probabilistic model.

7.3. Summary of results

The summary results from the DCF model are in Table 7.11.

		EOG	Pioneer	Chesapeake
Base case model	NPV_{AFIT} (MM$)	-1.1	-4.0	-4.3
	NPV_{BFIT} (MM$)	-0.5	-3.5	-3.7
	Break-even price AFIT ($/bbl)	47.5	87.5	89.7
Probabilistic Scenario A	NPV_{AFIT} (MM$)	3.2	-0.9	-1.5
Probabilistic Scenario B	NPV_{AFIT} (MM$)	4.5	-0.4	-1.1

Table 7.11. Summary of results from DCF model.

Given the current oil price environment is very difficult to make money with wells that break-even at over 40 $/bbl and this is reflected in the results from the DCF models. The results show that none of the companies in the analysis is expected to gain revenue from drilling new wells at current prices (around 40 $/bbl) considering their particular costs and production rates. Given the inputs and assumptions of the probabilistic model, from the three companies, EOG is the only one that has a positive NPV. This is because EOG has been quick to respond to the low prices by reducing their drilling and completion time; therefore, reducing their CAPEX which is one of the principal determinants when evaluating new projects. Additionally, the variability in their wells' production is high; some of them can have an accumulated production of over 900,000 barrels of oil for the first year of production which helps significantly in their well economics.

Chapter 8: Conclusions

Hydrocarbons play an important role in meeting the increasing energy demand, particularly for transportation, as developing countries improve their standards of living. Therefore, the development of unconventional resources from shale reservoirs will remain a significant component in oil and gas production for meeting global energy requirements.

In contrast to wells in conventional reservoirs, wells in shale rocks need additional operations after drilling for them to produce (hydraulic fracturing). There is limited experience forecasting production from shale reservoirs which brings great uncertainty when evaluating their economics. Hydraulic fracturing composes approximately 60% of the drilling and completion costs, making them more expensive to drill than conventional reservoirs; and production varies largely within plays and from well to well.

As technology and knowledge about shale reservoirs evolves, improvements in drilling and completion have allowed companies to reduce times, lower total well costs, and increase well performance. In 2015, hydraulic fracturing costs dropped over 40% compared to 2012. Technological advances play an important part on cost reductions; but it also can be partially attributed to the low oil price environment which has resulted in a decrease of drilling activity and, consequently, a demand decrease for field services. Because of this, service companies have responded to the low demand by reducing their fees, which has helped oil and gas companies to keep their operations afloat.

Additional to the decreasing drilling activity, the wells that are being drilled are not being completed. The advantage of having drilled but uncompleted wells is that almost half of their cost is considered sunk by the time they start producing, getting a lower break-even price than newly drilled wells.

Oil and gas prices, along with production volumes, are the two most significant factors in determining the economic feasibility of drilling new wells. With break-even prices above 40 $/bbl is very difficult for companies to be profitable from drilling new wells under current cost structures; and many companies have reported negative income from operations. The selected companies analyzed in this study, Chesapeake Energy, EOG Resources, and Pioneer Natural Resources have reported a net income loss for 2015 of 14.9, 4.5, and 0.3 billion dollars respectively. Their operating profit margin and net profit margin ratios are also negative.

For companies operating plays that produce different hydrocarbons like the Eagle Ford, diversifying their portfolio of oil and gas wells has proven to be helpful in the past because of the disparity between oil and natural gas prices; thus, when oil prices are low, companies can switch to produce more gas if its price has not fallen as much. However, from 2014 to 2016, the prices of both oil and gas have dropped.

The fluctuations in hydrocarbon prices affect oil and gas companies' capital structures, forcing them to reevaluate non-core assets, lower their operation costs, adjust their production, and redefining their strategies to stay afloat when prices are low. For example, Pioneer Natural Resources has sold its Eagle Ford Shale midstream business to increase the company's liquidity.

Hedging is a strategy intended to offset potential losses from fluctuations in prices by agreeing to set a future price for a product. However, when the uncertainty in prices is high, hedging can be counterproductive in the case prices rise above the hedging price while a contract for said price is still in place. Companies benefited from having contracts hedging their production when prices started decreasing in 2014; but most companies did not negotiate new contracts because of the uncertainty and industry specialists forecasting increasing prices.

Companies try to maintain a level of liquidity to meet their financial obligations and reassure their investors. Liquidity is measured by the cash ratio. From the three companies analyzed, the results for 2015 (Table 8.1) show that Pioneer's cash ratio is 95%, which is a sign of financial strength. The results for EOG and Chesapeake are 39% and 22% respectively. Although very few companies have a high cash ratio to cover their liabilities, a low cash ratio is prejudicial on the eyes of investors, reason why companies like Chesapeake are trying to raise capital by selling shares.

	2014	**2015**	**Δ**
EOG	62%	39%	-22%
Pioneer	65%	95%	30%
Chesapeake	70%	22%	-48%

Table 8.1. Cash ratio 2014 vs. 2015.

Low oil and gas prices directly affect operating profit margins. During the previous abrupt price drop between 2008 and 2009, as well as the current price drop, companies experienced a dramatic decrease in their profit margins.

According to the financial ratios analysis, Pioneer is the company with the best results; its high cash-flow-to-debt ratio, and low debt and debt-to-equity ratios make it an attractive company to invest in. In contrast, Chesapeake has the worst results, which represents high risk for investors. The results from the companies' financial performance is reflected in their per share price. Pioneer's shares are valued higher than EOG's, and Chesapeake's are valued the lowest. For EOG, whose financial results are considered good under the current economic environment, a restructuration of their different business units can bring better results in the future.

For this study, the Eagle Ford Shale was selected to develop a production model and a discounted cash flow model for the well economics analysis. The Eagle Ford, located in Texas, is an important play because of its capability to produce large volumes of hydrocarbons that range from dry gas to gas condensate to volatile oil to black oil. Eagle Ford's proved reserves at year-end 2014 were 5.2 billion barrels of oil, and 23.7 Tscf of natural gas which accounted for 30% and 16% of the total U.S. tight oil and shale gas reserves for 2014. Although its production decelerated in 2015 because of the low prices, it still has a substantial number of drilling rigs operating compared to other basins, which is an indication that companies will continue operations in this play.

Production forecasting is a crucial part of analyzing well economics, especially in times of price uncertainty; thus, the selection of the appropriate method to estimate production is essential. Given the limited experience in forecasting production from shale reservoirs, as well as their importance in boosting hydrocarbons reserves, new forecasting methods have been developed. For the Eagle Ford, the method selected in this study is the Logistic Growth Model because of the data available and the use of the EUR as the maximum production a well can have that solves the problem of over estimation of reserves during the life of a well.

There are two approaches when using the Logistic Growth Model. One approach is to assume a maximum production (parameter K on the Logistic Growth equation) using a EUR obtained from volumetric calculations; the second approach is to find parameter K. For the analyzed companies, the variance from both approaches affects their production models. For Pioneer and Chesapeake, the expected cumulative production during the life of the well decreases 11,674 and 10,817 barrels respectively when solving for K, meaning that their wells have similar production profiles. In EOG's case, solving for K increases its cumulative production by 70,527 barrels. The difference is possibly because the wells used for the model have higher production profiles compared to other wells.

The discounted cash flow (DCF) analysis is the preferred method to estimate the economic feasibility of drilling a new well. The DCF results demonstrate that under the cost assumptions and estimated production of the model EOG gets the best results with break-even prices bordering the 40 $/bbl compared to the other companies with break-even prices above 87 $/bbl for Pioneer and 89 $/bbl for Chesapeake. From the DCF analysis, it can be concluded that EOG's high production volumes and low completion cost are the determinant factors for better well economics among the analyzed companies.

	EOG	**Pioneer**	**Chesapeake**
Base case model ($/bbl)	47.5	87.5	89.7

Table 8.2. Break-even price AFIT from the DCF base case model.

The economic analysis shows that none of the companies in the analysis is expected to gain revenue from drilling new wells if oil prices are under 40 $/bbl considering their particular costs and production rates. Given the inputs and assumptions of the probabilistic model, from the three companies, EOG is the only one that can have a positive net present value (NPV) with a small oil price increase. This is because EOG has been quick to respond to the low prices by reducing their drilling and completion time, which translate into lower costs. Additionally, the variability in their wells' production gives them an advantage if the company concentrates their development operations in sweet spots where a well's cumulative production for the first year can reach 900,000 barrels of oil.

As the selected companies in this study have significant production from the Eagle Ford but is not their principal asset (except for EOG), the integration of the financial and economic analysis would require to extend the latter for all the plays they have operations in to have a better understanding of their financial results.

Appendix

Category	Ratio	Operator	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Liquidity	Cash ratio	EOG	55%	17%	4%	19%	51%	36%	24%	30%	46%	62%	39%
		Pioneer	2%	1%	1%	1%	5%	14%	50%	22%	31%	65%	95%
		Chesapeake	3%	0%	0%	48%	11%	2%	5%	5%	15%	70%	22%
Profitability	Net profit margin	EOG	35%	33%	26%	34%	11%	3%	11%	5%	15%	16%	-52%
		Pioneer	38%	49%	20%	11%	-3%	26%	32%	8%	-22%	18%	-6%
		Chesapeake	20%	27%	19%	6%	-75%	19%	15%	-6%	5%	10%	-115%
	Operating profit margin	EOG	55%	49%	39%	53%	20%	9%	21%	13%	25%	29%	-76%
		Pioneer	23%	19%	19%	15%	-18%	32%	24%	28%	-16%	32%	-9%
		Chesapeake	38%	47%	34%	13%	-116%	30%	25%	-14%	12%	17%	-148%
	Pretax profit margin	EOG	54%	49%	38%	53%	18%	7%	19%	11%	24%	28%	-79%
		Pioneer	23%	19%	19%	15%	-18%	32%	24%	28%	-16%	32%	-9%
		Chesapeake	32%	44%	30%	10%	-121%	31%	25%	-8%	8%	15%	-150%
	EBITDA	EOG	-	-	-	-	-	-	-	16%	42%	14%	-63%
		Pioneer	-	-	-	-	-	-	-	16%	24%	17%	-62%
		Chesapeake	-	-	-	-	-	-	-	-2%	44%	6%	-81%
Debt	Debt ratio	EOG	44%	40%	42%	43%	45%	53%	49%	51%	50%	49%	52%
		Pioneer	14%	12%	12%	12%	6%	8%	9%	8%	10%	11%	10%
		Chesapeake	62%	54%	61%	58%	59%	59%	57%	57%	57%	55%	86%
	Debt-equity ratio	EOG	80%	68%	73%	77%	81%	111%	96%	106%	98%	96%	108%
		Pioneer	47%	30%	30%	33%	16%	18%	19%	18%	19%	18%	17%
		Chesapeake	161%	117%	153%	136%	154%	144%	144%	152%	148%	133%	700%
	Interest coverage ratio	EOG	3244%	4532%	3586%	7353%	964%	415%	1008%	700%	1561%	2580%	-2816%
		Pioneer	7582%	2638%	2080%	1056%	-884%	2588%	2085%	2340%	-3376%	9394%	-2339%
		Chesapeake	-	-	-	-	-	-	-	-	-	-	-
	Cash flow to debt ratio	EOG	69%	68%	57%	67%	36%	24%	38%	37%	48%	51%	26%
		Pioneer	124%	85%	87%	104%	95%	167%	143%	178%	172%	150%	85%
		Chesapeake	-	-	-	-	-	23%	25%	12%	20%	21%	8%
	Capitalization ratio	EOG	17%	12%	14%	17%	22%	33%	28%	31%	28%	25%	34%
		Pioneer	48%	33%	33%	48%	43%	38%	31%	39%	29%	24%	28%
		Chesapeake	47%	40%	47%	47%	52%	45%	39%	44%	45%	40%	83%
Operating Performance	**Fixed-asset turnover**	EOG	-	-	48%	36%	20%	21%	30%	30%	33%	38%	17%
		Pioneer	24%	24%	29%	30%	18%	33%	34%	32%	39%	53%	47%
		Chesapeake	43%	40%	31%	38%	26%	32%	34%	33%	47%	60%	55%
	Total-asset turnover	EOG	53%	46%	39%	51%	28%	31%	44%	45%	50%	55%	28%
		Pioneer	20%	20%	25%	26%	15%	27%	26%	25%	29%	37%	32%
		Chesapeake	23%	27%	23%	34%	23%	24%	28%	30%	42%	51%	44%
Investment Valuation	Earnings per share (Basic)	EOG	-	-	-	-	-	-	-	-49%	282%	32%	-255%
		Pioneer	-	-	-	-	-	-	-	-78%	-500%	204%	-129%
		Chesapeake	-	-	-	-	-	-	-	-159%	150%	164%	-1263%
	Earnings per share (Diluted)	EOG	-	-	-	-	-	-	-	-49%	281%	32%	-256%
		Pioneer	-	-	-	-	-	-	-	-78%	-511%	204%	-129%
		Chesapeake	-	-	-	-	-	-	-	-163%	150%	156%	-1300%

Table A. Comparative table showing financial ratios for EOG, Pioneer, and Chesapeake.

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