TECHNOLOGY AND ECONOMICS AFFECTING UNCONVENTIONAL RESERVOIR DEVELOPMENT

A Thesis

by

CECILIA PATRICIA FLORES CAMPERO

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

MASTER OF SCIENCE

December 2008

Major Subject: Petroleum Engineering

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Approved by:

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

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ABSTRACT

Technology and Economics Affecting Unconventional Reservoir Development.
(December 2008)
Cecilia Patricia Flores Campero, B.Eng., Universidad de Oriente, Venezuela
Chair of Advisory Committee: Dr. Stephen A. Holditch

Worldwide, unconventional resources are important sources of oil and gas when most conventional resources are declining and demand for hydrocarbons is growing. The Masters' (1979) concept of the energy resource triangle suggest that the exploitation of unconventional reservoirs is particularly sensitive to both technology and commodity price parameters.

In the United States, production from unconventional reservoirs has been stimulated by a combination of Federal tax credits, technical development programs -supported by government agencies and private organizations- and high commodity prices. In this work, the effect of technology and different economic events for selected unconventional oil and gas plays in the United States was evaluated according to the concept of the Resource Triangle Theory (RTT).

Studies conducted in the Austin Chalk -our textbook case- and other seven unconventional plays in the United States have supported the RTT concept that high prices and better technologies do result in more drilling activity and more oil and gas production from unconventional reservoirs. For instance, two approaches were employed to support RTT concept: Correlation study and Forecasting graphs.

On the first one, correlations of commodity prices and technology with drilling activity demonstrated that periods of high commodity prices coincide with increase in unconventional producing wells approximately 75% from selected plays in this study.

The second one shows that high prices and technological advances also translate into additional oil and gas production and reserves. This behavior was observed through the analysis of a series of decline production curves using a VBA program in Excel that compute oil and gas production volumes and their corresponding economic values under specific conditions. The results indicated that maximum value of approximately $50 billion oil plus gas would have been possible using conventional hydraulic fracturing technology only. Moreover, subsequent episodes of high commodity allow the introduction of new technologies that have boosted even more oil and gas production from the plays. Great examples are the use of horizontal and multilateral wells which has opened up additional areas for development, such as the Barnett Shale and the Bakken Shale. Using horizontal wells has also revived older plays, such as the Austin Chalk. The combination of horizontal well technology and water fracturing technology has led to a dramatic increase in the development of both oil and gas from shale reservoirs. Current production schemes suggest that the plays could produce an additional of $320 billion when producing at rates higher than 5 BOE/day.

Our results confirm the concept of the resource triangle that natural gas and oil resources can be produced from low quality resources when either product prices increase or when better technology is available. The seven oil and gas plays studied in this research are demonstrative examples.

DEDICATION

First of all, I dedicate this thesis to God for giving me the strength and will.
To my Mother Manuela, for her enormous support, for being my best example and for all her love and prayers.
To my brother Manuel and my sisters Lourdes and Cristina, for their courage and unconditional love. To my niece Ariadna, the future.
To my Father, who I loved so much. Rest in peace Daddy.

ACKNOWLEDGMENTS

I would like to express my sincere gratitude and appreciation to the following people who greatly contributed in no small measure to this work:

Dr. Stephen A. Holditch, head of the Petroleum Engineering Department, who served as the chair of my graduate committee. His advice, knowledge and support guided me to the completion of this work; I am very proud I had the opportunity to work in his group.

Thanks also to Dr. Walter Ayers for his support, knowledge and sense of humor, and Dr. Wayne Ahr for serving as members of my graduate committee; the Crisman Research Institute, for funding my research; the aggie family, especially Wilson Aliaga for our great conversations and support to complete my programming; all my officemates and classmates for their friendship and continuous support; and finally to Texas A&M University for the quality education I received and for being a home to me.

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CHAPTER I
INTRODUCTION

The exploitation of unconventional reservoirs in the United States (US) has been a sustained practice for more that 50 years (Holditch, 2006). Today, we have a large production database that allows us the opportunity to analyze the impact of political, economical, and technological events on the development of unconventional oil and gas reservoirs. The development of these reservoirs in the US has shown a strong correlation between prices and technology achievements.

The development of the oil industry began in the United States with success of the first well by Drake in Pennsylvania in the late 1800s. Later, in the 20th century, along with the invention of the combustion engine to power automobiles and airplanes, the US developed into a great industrial power based on oil. Major discoveries were found in East Texas in 1930s, and even larger reserves discovered in the Middle East, Iraq and Saudi Arabia ensured the supply of energy to the largest oil consumer nation, the US.

When World War II ended in 1945, oil had replaced coal as the principal source of energy. Worldwide, the oil production growth reached 3 billion barrels per year in 1947, 7.7 billion barrels per year in 1960, and 20.3 billion barrels at the end of 1973. The oil market continued growing with sustained supply and low, stable oil prices until the two oil crises in 1973 and 1979. The Yom Kippur War and the Iranian Revolution shocked oil-dependant economies as oil prices increased from $3.29 per barrel in 1973 to $36.83 per barrel in 1980 (Spangar, 1996). Subsequently, other events such as the natural gas shortage in the 1980s, and the economic growth in developing countries demanding more energy led to more development activity in unconventional reservoirs.

This thesis follows the style of *SPE Production & Facilities*.

During this study, we reviewed eight (8) different unconventional formations in the US to understand the impact of oil and gas prices and technology on the development of unconventional reservoirs. We demonstrated that political-economical events contributed to increasing production volumes by up to 5 times and technologies have increased production up to 12 times in some formations. The impact of technologies and political-economical events have a greater influence in unconventional reservoir management since these type of resources are more sensitive to increases in recovery and reductions in the finding and development costs.

1.1 The Resource Triangle Theory

The Resource Triangle Theory (RTT) suggests that natural resources are distributed in a log-normal manner **(Fig. 1.1)**. According to this theory, introduced by Masters (1979), oil and gas resources range from small, high-quality to large, low-quality accumulations distributed as in a log-normal fashion; as such, small volumes of high-quality resources are located near the apex of the triangle and much larger volumes of low-quality resources occur near the base. This theory also proposes that huge, low-quality deposits may be developed as commodity prices increase and better technologies become available. Low-quality deposits are commonly known as unconventional resources and high-quality deposits are grouped in the conventional resources category.

A conventional reservoir has rock properties such as high permeability that, combined with natural energy, will yield high production rates and rapid payout of the investment. In contrast, unconventional reservoirs must be stimulated to improve rock or fluid properties so that the wells can be produced at economic flow rates. In general, these poor reservoir conditions are associated with low permeability or high oil gravities, either of which will cause the wells to produce al low flow rates.

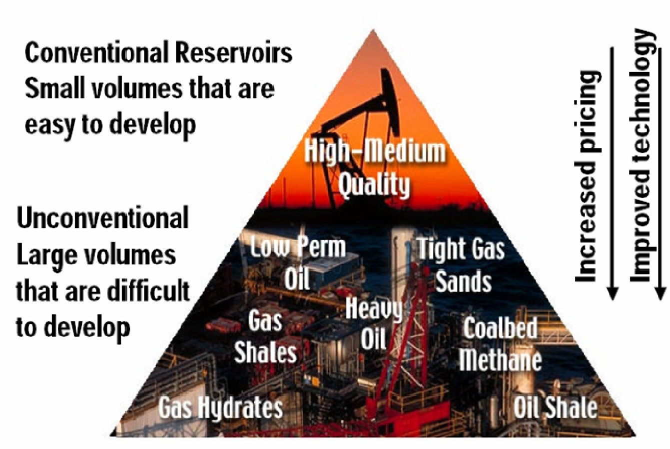


Fig. 1.1—Improved technology and high price parameters characterizing unconventional reservoirs are more sensitive to certain type of resources such as oil shales and gas hydrates (from NPC, 2007a).

1.2 Unconventional Resources (UCR)

As depicted in the RTT, the unconventional resources include tight gas sands, oil and gas shales, heavy oil, coal seams and low permeability oil formations. In the United States, unconventional discoveries are recorded as early as the 1800s; however, their commercial production was reached during the 20th century.

Heavy oil was commercially produced in the early 1900s from the San Joaquin basin in California. Production from shales and tight gas sands began in the 1950s and 1960s from the Appalachian and San Juan basins in the eastern and western US, and gas from coalbed methane were commercially produced in the 1970s. All types of unconventional resources have been produced in the US; however, in some cases, their development has been limited to pilot testing and research projects, such as the oil shales in Colorado.

Unconventional production in the US has been accelerated in response to a combination of federal tax credits, technical development programs supported by government agencies and private organizations, and high commodity prices (Reeves et al., 2007). These efforts have led to successful commercial projects as several Devonian-Mississippian gas shales in the US and other attempts that can be classified more as research projects such the oil shales of the Green River formation in Colorado.

In 1917, the construction of the first oil-shale retort brought the idea of potential oil production from the Green River oil shale formation to the attention of the industry **(Fig. 1.2)**. After World War I, the oil supply was scarce, and oil production from shales had already been tested; however, exploitation of the Green River oil shale formation in Colorado was delayed because of huge discoveries of conventional oil found in East Texas in 1930. Between the 1930s and 1960s, the ample supply of conventional oil removed incentives to produce oil from oil shales. In 1967, the US Department of the Interior began several research projects to find commercial ways to produce the Green River oil shales. Along with this initiative, the oil crisis during the 1970s fostered oil-shale activities in several areas in Colorado, Utah and Wyoming without commercial success. In the early 1980s, with high oil prices, Unocal Oil Company built an oil-shale plant to retort oil from the Green River oil shale formation. Production reached 5,900 BOPD. Although the oil price collapsed in 1986, Unocal produced more than 600,000 bbl by the end of 1987, and between 1988 and 1989, its cumulative production reached 1 million bbl. The plant and its operations were shut down in 1990 under to unfavorable economic conditions (Spangar, 1996).

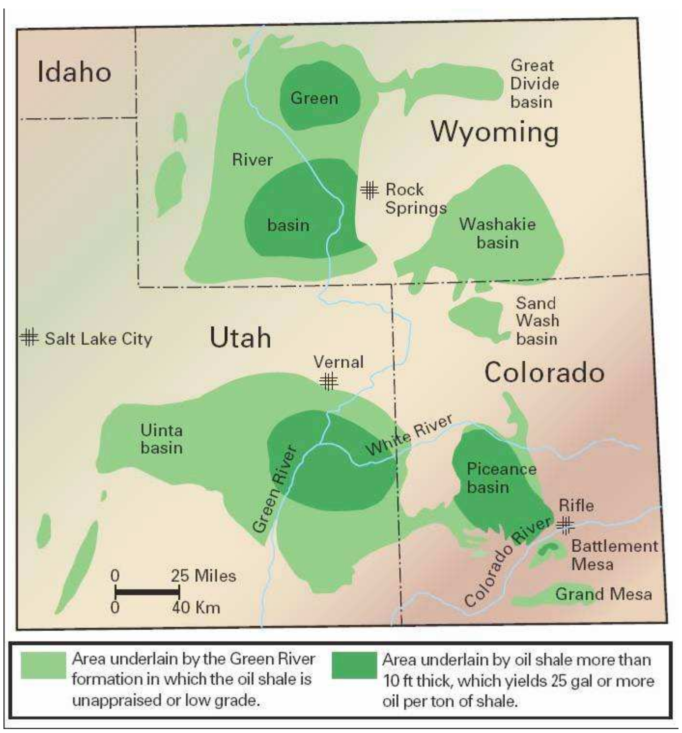


Fig. 1.2—Oil shale resources in the Green River formation are giant accumulations waiting for economical exploitation (From NPC, 2007b).

The Devonian-Mississippian black shale deposits in the eastern and northern United States are other low-quality reservoirs with a long history of production. Production from the fractured shales in the Bakken formation **(Fig. 1.3)** started in the early 1960s, and since then, technologies such as horizontal drilling and hydraulic fracturing, along with high commodity prices, have supported its development. Beginning in the late 1980s, the use of horizontal drilling made possible the first oil production peak in 1991 and the most recent peak in 2007.

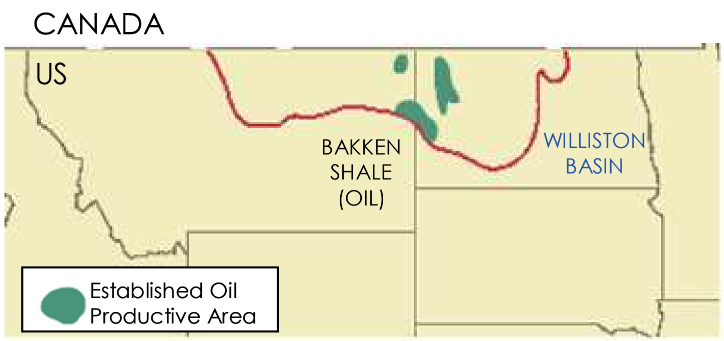


Fig. 1.3—The productive Bakken Shale formation of the Williston basin is located in the northern United States (after Hill and Nelson, 2000).

Through the years, operators and service companies have gained valuable knowledge from previous research and practical experience. Reeves et al (2007) concluded that improvements in drilling technologies reduced the drilling time by 50% and increased the estimated ultimate recovery (EUR) per well as much as 60% in tight gas sand reservoirs. These advances in technology that helped to reduce drilling costs and increase the EUR per well have encourage companies to invest in unconventional reservoirs. At the end of 2004, unconventional gas reservoirs contributed 40% of the total US gas production **(Fig. 1.4)**.

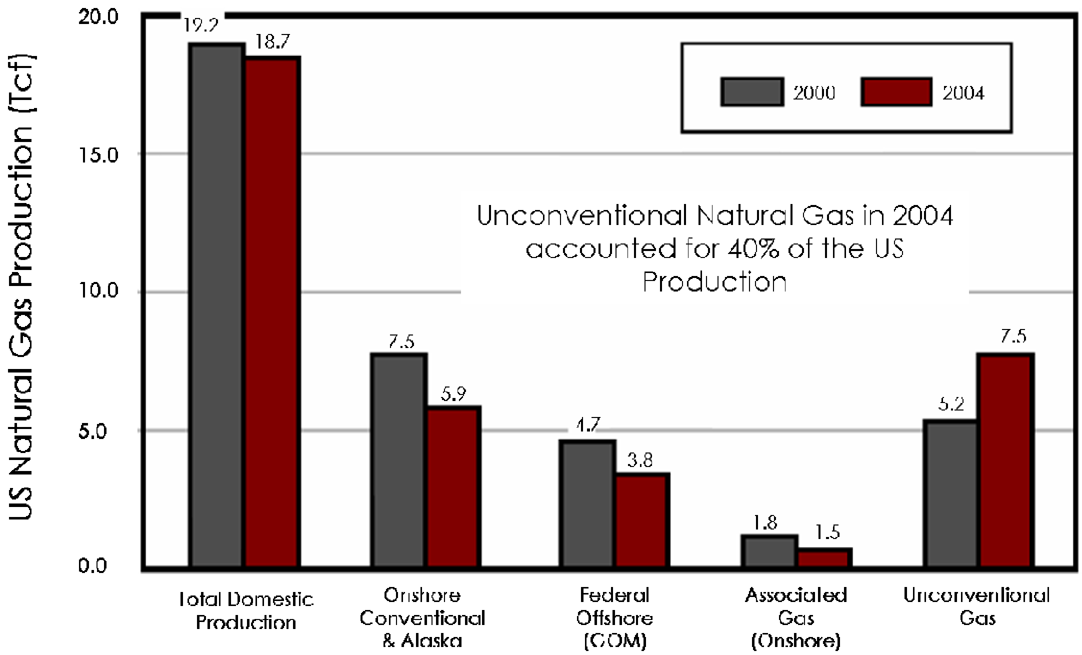


Fig. 1.4—The overall US natural gas production decreased from 2000 to 2004; however, unconventional gas production increased, accounting for 40% of the total gas produced in 2004 (from Kuuskraa, 2006).

1.3 Federal Tax Credits and the Importance of the Section 29 Legislation

Section 29 of the Internal Revenue Code for Non-Conventional Fuel Credits was established by the US Congress through the Crude Oil Windfall Profit Tax Act of 1980 to promote production of domestic hydrocarbons and reduce dependence upon imported oil after the oil crises experienced during the 1970s (Hass and Goulding, 1992).

Currently redesignated to IRS Section 45J and IRS Section 45K, Section 29 is a production-based tax credit that originally applied to qualified fuels from wells drilled or facilities placed in service between January 1, 1980, and December 31, 1992. The code specified the following as qualified fuels: (1) oil produced from shale and tar sands; (2) natural gas produced from geopressurized brine, Devonian shale, coal seams, tight formations, or biomass; (3) liquid, gaseous, or solid synthetic fuels produced from coal liquefaction and pressurization; (4) fuel from qualified processed wood; and (5) steam from solid agricultural byproducts.

The value of the Section 29 credit is determined by a formula which varies with the price of oil and the inflation (EIA, 2007). The Section 29 credit was a major stimulus to developing unconventional and high-cost gas resources. From 1980 through 1992, operators accelerated drilling from unconventional areas in Texas, Alabama, Colorado, New Mexico, and the Appalachian region. The Devonian shales increased their annual contribution from 70 Bcf to 250 Bcf between the years of 1986 to 1991 (Haas and Goulding, 1992). The tax credits also supported research projects finding suitable technologies for better drilling, and production practices for the specific plays, such as the Antrim Shale **(Fig. 1.5)**. The US government, through the Department of Energy (DOE), has been encouraging unconventional initiatives for more than 35 years through different R&D projects.

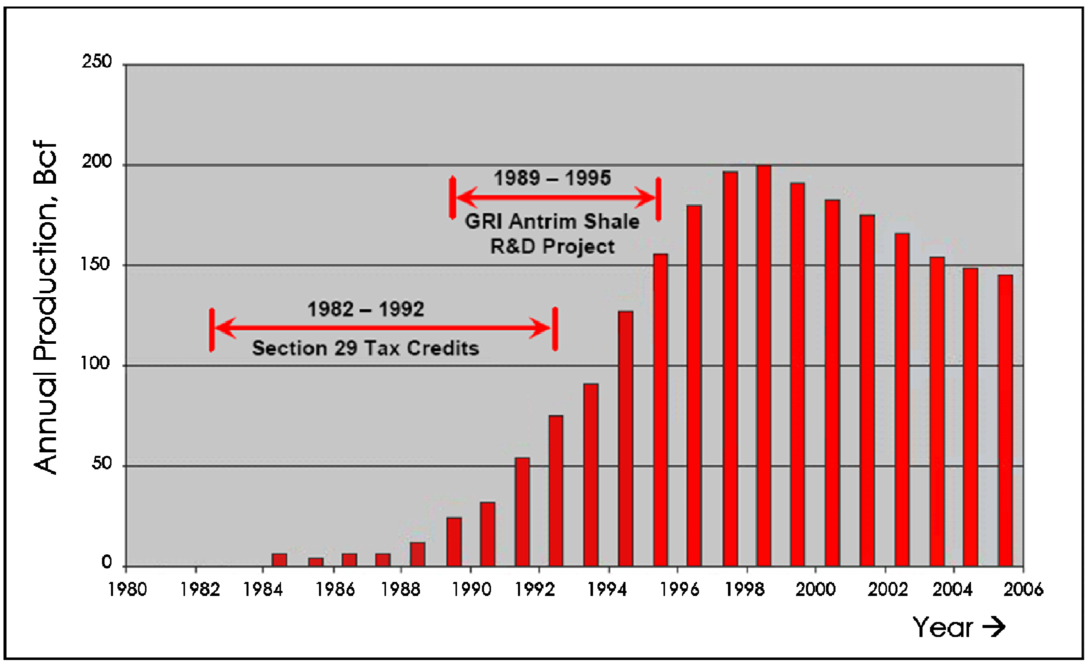


Fig. 1.5—Gas production from the Antrim shale formation in the eastern US was favored by the tax credits under the Crude Oil Windfall Profit Tax Act of 1980 (from Reeves et al., 2007).

The Antrim shale in the Michigan basin experienced a combination of reduced drilling costs, and better completion and stimulation methods that led to higher production rates (Fig. 5). R&D projects helped to develop confidence that the industry could develop and produce unconventional reservoirs economically.

1.4 US Energy Consumption by Source According to Technology Developments

In the long view of American history **(Fig. 1.6)**, wood served as the pre-eminent form of energy for about half of US history. Around 1885, coal surpassed wood usage; however, the tremendous and rapid expansion of coal was overtaken by petroleum (oil) in the middle of the 20th century. Natural gas also experienced a rapid development into the second half of the 20th century, and coal began to expand again. Late in the 20th century another form of energy, nuclear electric power, was developed and made significant contributions (EIA, 2007).

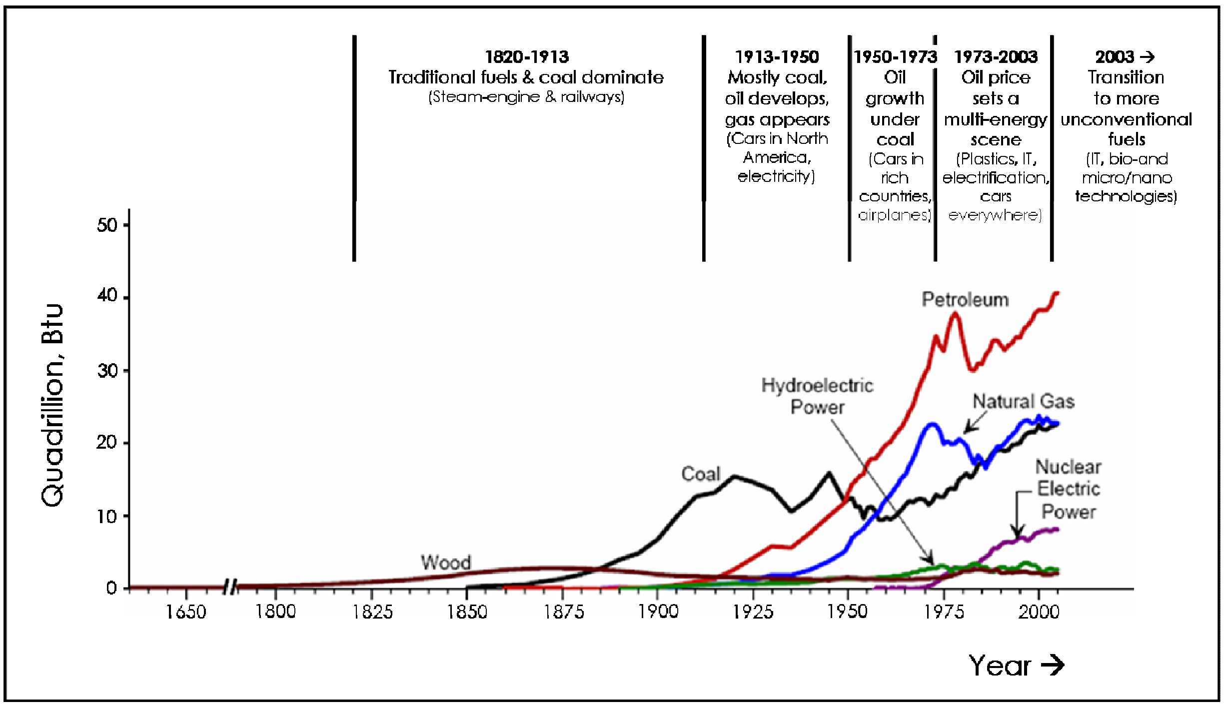


Fig. 1.6—The chronology of the US energy consumption by source and its relation with technological developments worldwide (after WEC and EIA, 2007).

The changes in US energy history were possible as new forms of energy in nature were available, accessible, affordable, and made economic by specific technological developments. Important developments in technology during the 20th century were possible thanks to hydrocarbons supporting the use of combustion engines and the generation of electrical power. During the early 20th century, the mass production of the car increased the use of oil and reduced the use of coal during the second half of the century. In 2006, two-thirds of the oil consumed in the US went to the transportation sector.

The growing demand for oil, as a result of higher per capita incomes in developing countries like China, India, Brazil, and Russia, and the recent demands for cleaner energies have created a recent multi energy scene that involves fossil fuels (petroleum, natural gas, and coal), renewable resources, and moderate generation from nuclear electric power, and the competition for energy has driven prices higher. Today, the dynamic of the worldwide energy share has benefited the production of oil and gas from unconventional sources in the US.

1.5 Technological Advancements Driving Up Production from Unconventional Resources

Unconventional reservoirs by definition cannot be produced at economic flow rates unless the wells are stimulated by massive stimulation treatments or special recovery processes and technologies, such as steam injection. Technology and the continuous search for improvement have made possible production of large oil and gas accumulations overlooked in the past for being difficult to evaluate and costly to produce (Reeves et al., 2007). In 2003, the National Petroleum Council (NPC) identified new technologies as one of the essential factors affecting natural gas prices and production volumes (RPSEA, 2005).

Fig. 1.7 shows the US government research and development (R&D) funding in recent years. Although oil and natural gas prices have grown recently, government spending on oil and gas research has been decreasing. In the early 1980s, small oil and natural gas companies preferred to buy new technology. Historically, independent companies have spent little on R&D. Even major oil and gas producing companies cut back on R&D spending during the 1990s. As such service companies had to fill the gap. The oilfields service companies have been major drivers in technology development during the past 20 years (NPC, 2007c).

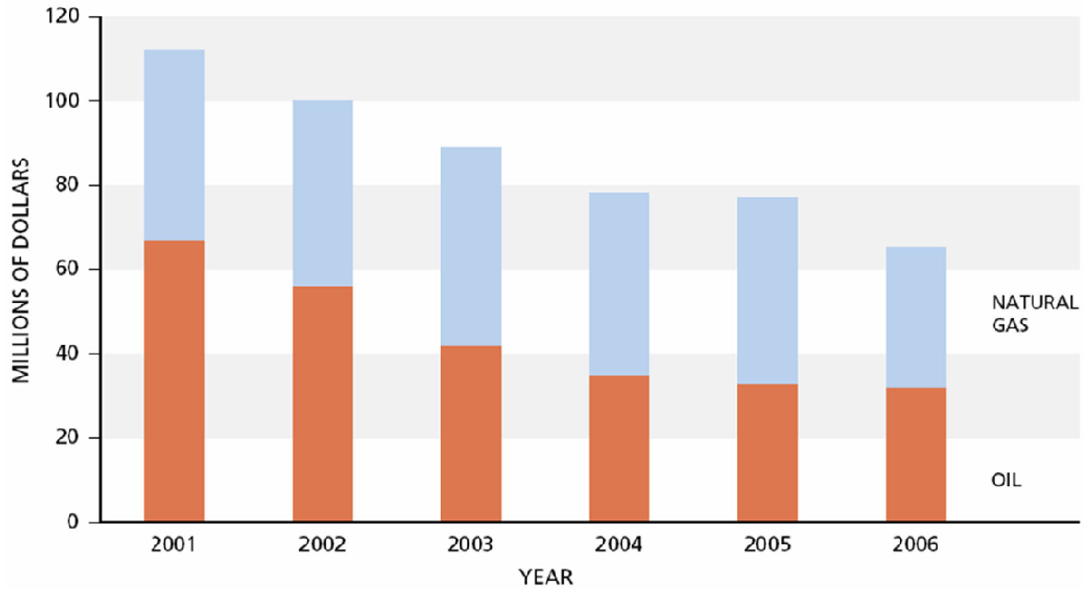
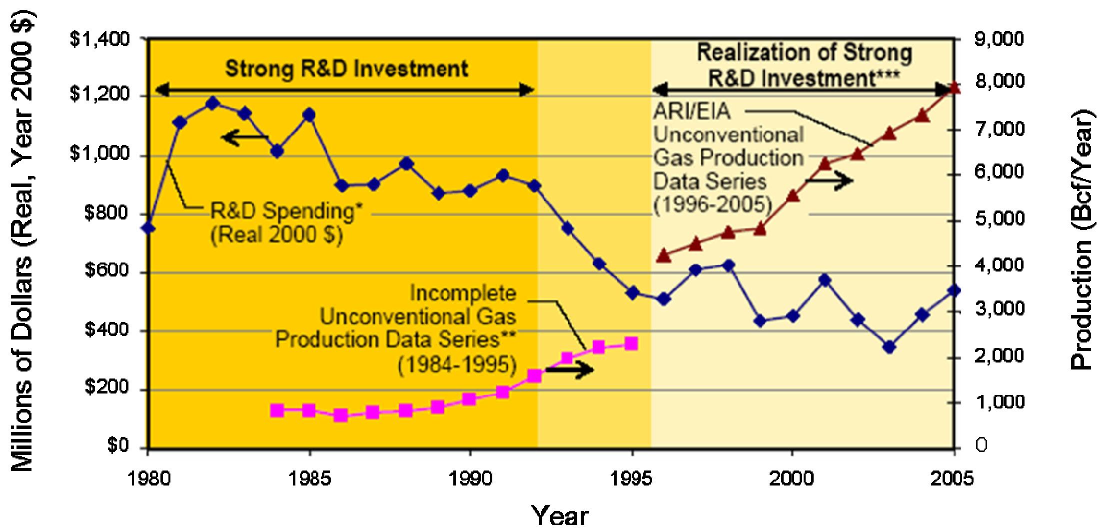


Fig. 1.7—Oil and natural gas R&D funds provided by the US government (from NPC, 2007c).

An example of R&D investment's output is shown by Revees et al (2007). **Fig. 1.8** illustrates the R&D spending and its influence on unconventional gas production from 1980 to 2005 using data from 29 major US-based energy producing companies.

During the 1980s and the early 1990s, a strong level of R&D investment helped to develop technologies for unconventional gas development. Subsequently, during part of the early 1990s, the R&D investment was stimulated by "cost share" projects sponsored by the Gas Research Institute (GRI) and the Department of Energy (DOE). The Multi-Well Experiment was an important project that helped to define the foundations for hydraulic fracturing diagnostic technology. During the mid-1990s, gas production increased at commercial scale as the results of the realization of R&D investments when technology passed from conception to commercial adaptation. Revees et al., mention the importance of high gas prices during the 2000s to ensure advancements in technology and gas production.



*Source (EIA 2007)
**Does not include data from 6 major unconventional gas basins.
***Assumes 16 year lag from technology concept to widespread commercial adoption (based on NPC, 2007)
Source: Advanced Resources International, 2007

Fig. 1.8—Investments in oil and gas recovery R&D and unconventional gas production. Data from 29 major US-based energy producing companies (from Revees et al., 2007).

The efforts by operators, private organizations, and government agencies working together proved successful. GRI, the Energy Information Administration (EIA), the National Petroleum Council (NPC), the United States Geological Survey (USGS) and others supported directly or indirectly by the Department of Energy (DOE) led to new specialize well drilling, completion, and stimulation technologies, improving the productivity of unconventional oil and gas wells. The unconventional oil and gas industry has benefited from technologies because of the 29 tax credits on for non conventional fuel production in the 1980s and early 1990s. Following the expiration of the tax credits in 1992, drilling budgets decreased and R7D spending continued to decline in real terms (Fig. 1.8). New alliances between the DOE and universities and industry, and more recently the Energy Policy Act of 2005 passed by the US Congress, will be necessary to ensure continuous support for advances in technology.

1.6 Research Objectives

The objective of this research is to evaluate the effect of technology and distinct economic events on selected unconventional oil and gas plays in the United States to evaluate the concept of the Resource Triangle Theory (RTT).

Studies conducted in the Austin Chalk play, as the pilot area, and other unconventional plays have supported the RTT concept that high prices and better technologies do result in more drilling activity and more oil and gas production from unconventional reservoirs (UCRs).

Worldwide, unconventional resources represent an important source of oil and gas in times when most conventional resources are declining and demand for hydrocarbons is growing. Production from unconventional reservoirs in the United States has been stimulated by a combination of federal tax credits, technical development programs supported by government agencies and private organizations, and high commodity prices.

Our research includes different types of UCR sources –tight sands, shales, CBM, and heavy oils– present in the United States to quantify the impact of new technologies and prices on field development activity. The analysis of produced volumes and additional recovery will help us to identify the impact of certain technologies or a period of high commodity prices on the development of UCRs.

CHAPTER II
METHODOLOGY

The primary purpose of this research has been to evaluate the effects of technology and commodity prices on production performance for selected unconventional oil and gas plays in the United States. We used the parameters of technology and oil and gas prices to verify and quantify the concept of the Resource Triangle Theory (RTT).

We identified several stimulation technologies from the literature, built a production database, and developed a computer program to help us evaluate the effect of a certain technology or/and a period of high commodity price affecting each of the selected plays.

In this research, we have performed the following tasks:

1. Performed a literature review to (a) identify episodes of fluctuations in commodity price and major technological breakthroughs in the oil industry affecting the development of UCR and (b) select cases of study considering data availability in different type of UCR.
2. Identified the different stimulation technologies used to produce each of selected cases. We classified the different stimulation technologies according to the type of UCR.
3. Identified the use of Arp's hyperbolic function as the appropriate method to estimate ultimate recovery (EUR) from unconventional reservoirs.
4. Built an Excel database to compile all required production (oil, gas, and water production rates, drilled and active wells) and economic (nominal oil and gas prices, consumer index price) data needed to compute EUR and revenues.
5. Developed a program, using the VBA programming language, to perform a series of decline curve analyses to compute the EUR. The program includes the value of the revenue adjusted by inflation at year 2006.
6. Quantified the impact of technology breakthroughs and periods of high commodity price in each of the selected cases of study in terms of both EUR and revenues. We compared all the selected cases against our pilot example (the Austin Chalk formation).

2.1 Literature Search / Documentation

The literature review formed an important part of this research effort. The review was divided into two parts. The first part was to identify the most important events historically driving the oil and gas prices and the technology breakthroughs making production from UCR reservoirs possible. The second part of the review considered the use of information available in the literature and production databases to select representative cases of study.

We obtained most of the information from sources such as papers from the SPE elibrary, AAPG, USGS and DOE, and production/drilling data from HPDI database and IHS Energy.

2.2 Stimulation Technologies

The literature search identified the different technologies used to stimulate production in each of the selected cases of study. We found six relevant technologies adding value to the final recovery (EUR). We chose the hydraulic fracturing technology as the base case since it is the common stimulation method present in each of the selected formations **(Table 2.1).**

TABLE 2.1—STIMULATION METHODS IN SELECTED FORMATIONS IN THE UNITED STATES

Formation	UCR type	Acidizing	Hydraulic Fracturing	Steam Injection	Horizontal Drilling	Improved Waterfracs	Multi-laterals
Austin Chalk (AC)	Low Perm. (Carbonates)	•	•		•	•	•
Antrim (AS)	Gas Shales		•			•	
Barnett (BS)			•		•	•	
Lewis (LS)			•			•	
Bakken (BKS)	Oil Shales		•		•	•	
Cotton Valley (CVG)	Tight Gas Sands		•			•	
Mesaverde (MVG)			•			•	

2.3 Excel Database / VBA Programming

The Excel database includes production data from the eight selected cases for this study (Austin Chalk, Antrim Shale, Barnett Shale, Lewis Shale, Bakken Shale, Cotton Valley Group, Mesaverde Group, and Kern River formations) as well as the economic parameters such as consumer price index (CPI) and nominal commodity prices. We created a VBA program in Excel to compute EUR and revenues through two procedures.

The first procedure includes the use of Arp's hyperbolic equation to obtain the best history match, and then forecasting the oil and gas production rates **(Fig. 2.1)**. The input parameters are the constant initial rate (Qi) and the initial decline rate (Di), and the production rate versus time. The input parameters in the program are used to find the best production history matching by testing different values of the hyperbolic exponent (b) in a given range from 0 to 1 value. The best match is attained when the difference of error between the historical and calculated production rate reach its minimum value. The best b value is plugged into the hyperbolic equation to forecast oil and gas production rates until the economic limit is reached. The economic limit for both oil and gas was arbitrarily selected to 5 STB/d and 15 MSCF/d, respectively. The output data are the estimated ultimate recover (EUR), the remaining reserves (RR), and the abandonment time (tA).

The second procedure computes the revenues associated to the volumes of oil and gas produced as output data from the first procedure. The nominal price of oil and gas with time (EIA, 2007; BP, 2007) is adjusted for inflation using the consumer price index (CPI). The CPI was obtained from the Bureau of Labor Statistics (BLS) of the US Department of Labor. The adjusted values of oil and gas are used to compute revenues comparable on the same basis. The program is able to adjust prices and compute revenues at money of year 2006.

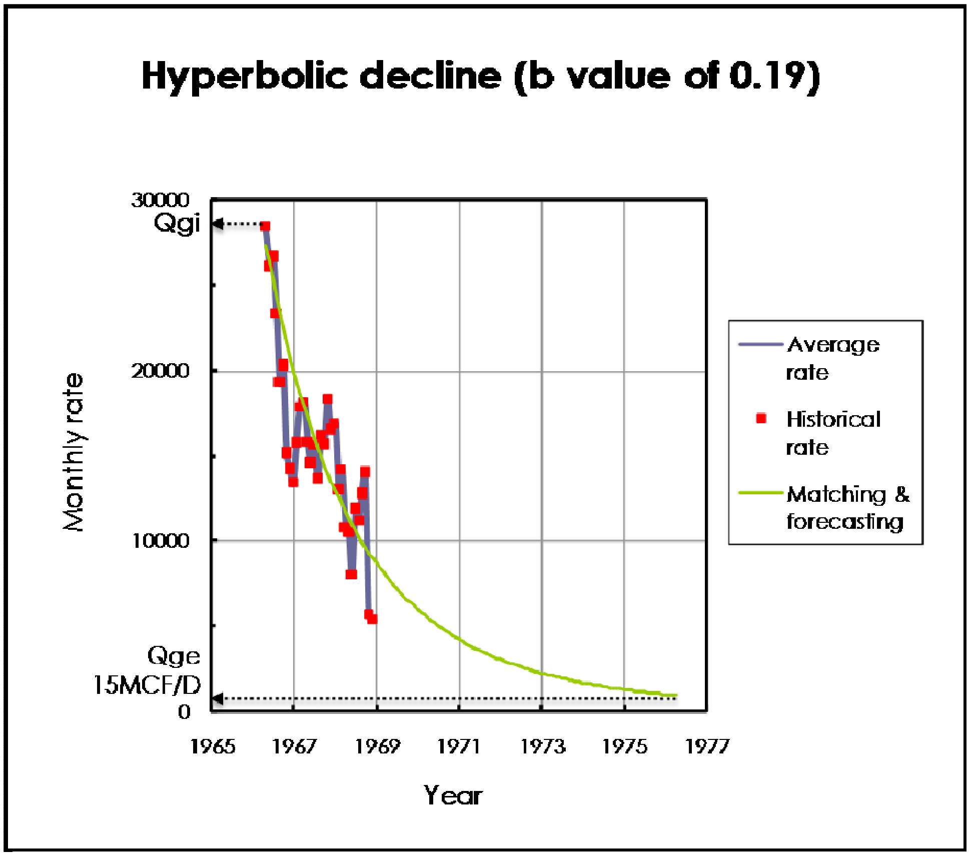


Fig. 2.1—History matching and forecasting for a natural gas producer reservoir as example. The initial decline rate (Di) of 4% and the initial rate (Qgi) of 28,439 Mcf/mo yield a value of ‘b’ exponent of 0.19. The economic limit (Qge) of 15 Mcf/day is reached after seven years of production.

The VBA program (Appendix A) quickly performs a series of decline curve analyses (DCA) to have as much history matching and production forecasting as we required for evaluating the changes of EUR under different scenarios of technology or/and price. The steps followed in this study are summarized in **Fig. 2.2**.

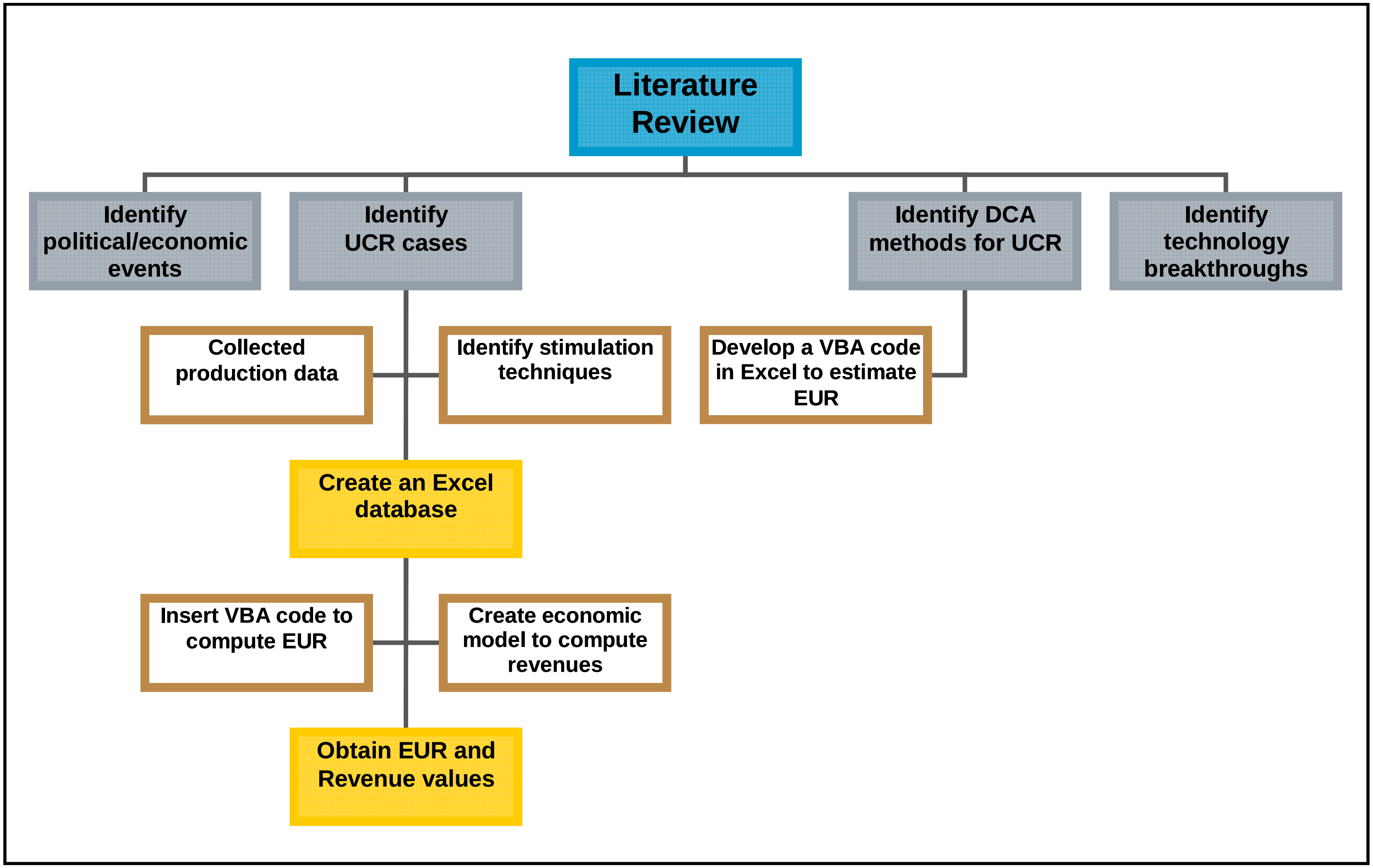


Fig. 2.2—Methodology used to define ultimate recovery (EUR) and revenues adjusted for inflation after any episode of technological advances or/and higher prices.

CHAPTER III

EVENTS AFFECTING PRODUCTION FROM UNCONVENTIONAL RESERVOIRS

Political, economical, or social events are, among other parameters, responsible for oil price fluctuations **(Fig. 3.1)**. In the case of unconventional reservoirs, the oil and gas price fluctuations are very important. Historically, periods of high prices have benefited the exploitation of unconventional reservoirs since these types of reservoirs require stimulation methods to produce. The link between periods of high price and developments in unconventional reservoirs illustrated by Masters' triangle concept is the core. Thus, it is important to review the major events affecting oil and gas prices during the past 40-50 years.

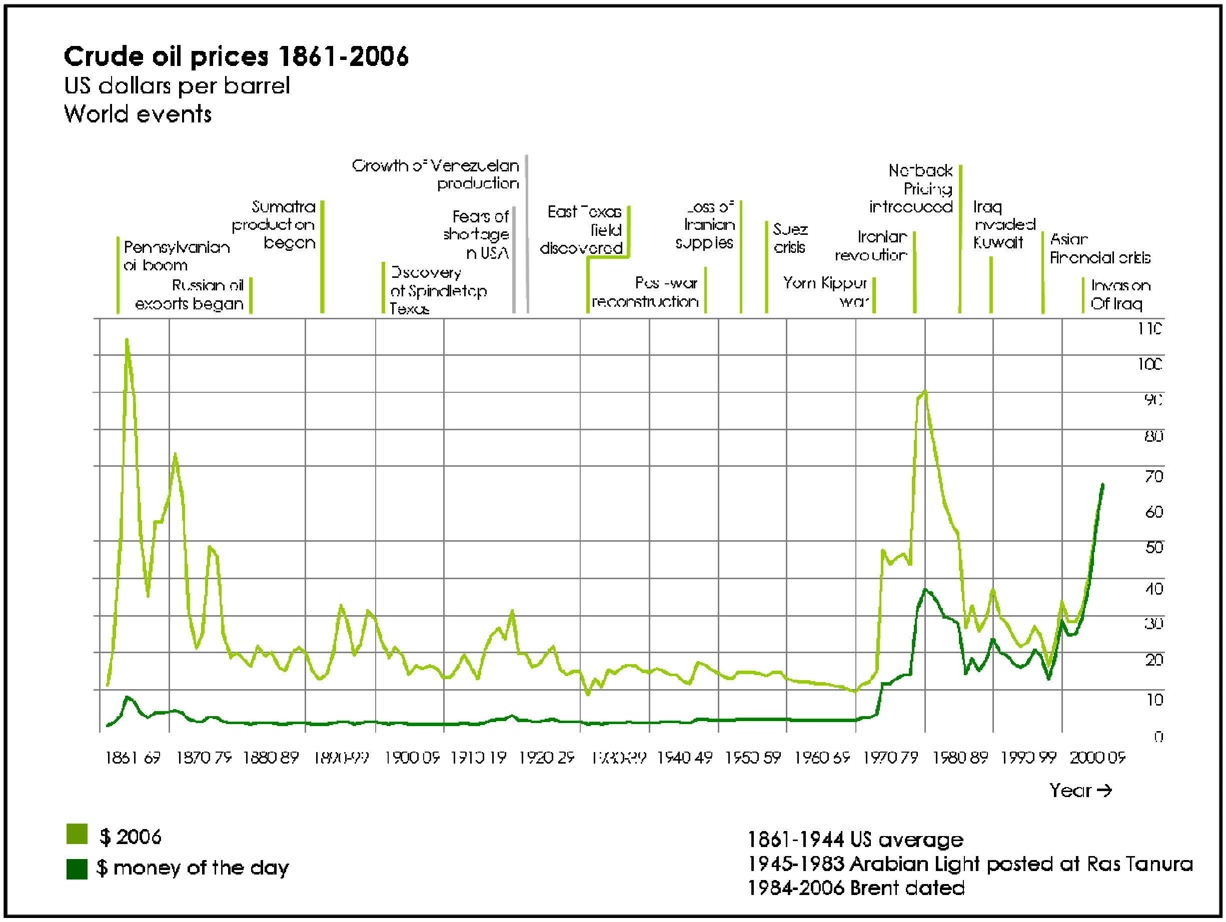


Fig. 3.1—Major critical petroleum-related events were greatly responsible for the oil price fluctuations during the period of 1861-2006 (from BP, 2007).

Traditionally, commodity prices have been the result of the supply and demand in the markets. On occasion, organizations such as the Texas Railroad Commission or OPEC have restricted production to try to affect prices. The efforts to control the market were first dominated by the actions of the Standard Oil Trust (1870s-1911), later by the Texas Railroad Commission (1928-41 and 1948-59), the Federal government (1942-47), and more recently by the OPEC cartel (since its foundation in 1960).

BP (2007) highlights the major critical petroleum-related events from 1861 to 2006 to explain the fluctuations in oil prices (Fig. 3.1). Data available in both the money of the day (nominal terms) and the money in 2006 dollars after considering inflation (real terms) allow us to compare the value of the barrel of oil at different times.

Fig. 3.1 shows that the Pennsylvanian oil boom in the 1860s saw prices reaching a peak of $104.35 per barrel (in real terms) until the oil boom began in Texas with the discovery of Spindletop (1901) and East Texas (1930) fields. The boom in Texas originated a period of stable low prices sustained by product availability (briefly described below). In 1931, the oil prices fall to a low of $8.66 per barrel (real) continuing relatively stable until the oil crises in the Middle East during the 1970s. The Yom Kippur war (1973), the Iranian revolution (1978-79), and the Iraq invasion of Kuwait (1991-92) caused spikes of $14.99 per barrel (real), $88.13 per barrel (real) and $29.71 per barrel (real), respectively. The Asian financial crisis saw prices fall in 1998 to $16.22 per barrel (real) but in 2006 prices quadrupled, reaching $65.14 per barrel. The high price tendency has continued until today with prices around $74 per barrel in 2007 (nominal), an equivalent to $70 per barrel considering prices at 2006. What follows is a brief description of significant events affecting oil prices since 1861.

3.1 Oil Commodity Prices

- **1861-1950 Period (the product-availability period).** This period is mainly marked by the US discoveries ensuring abundant product supply and low prices in a small market. The discovery of Spindletop field in Texas in 1901, the growth of production in Venezuela in the 1920s, and the reserves added by the discovery of the East Texas oil fields in the 1930s secured the energy supply for most of the 20th Century. During this period, domestic production was enough to fulfill the country's energy needs. Indeed, the US was a net exporter of oil until 1944, and net imports were slightly different from zero until 1949 (Spangar, 1996).

The product availability period from 1861 to 1950 is characterized on average, by low, stable prices below $2 bbl (nominal) that remained until 1957, except for peaks observed in 1876-77 and 1919-20 when fears of shortage increased oil prices.

- **1973 Oil Crises (The Yom Kippur War).** In 1973, several Arab nations, angered at US support of Israel in the 1973 Arab-Israeli War, instituted an oil embargo against the United States and Holland. The Arab-Israeli Yom Kippur War was accompanied by decreases in OPEC production by 25%. The minimal global excess production capacity available outside OPEC created a short-term oil shortage and prices increased. World crude oil prices in 1974 had quadrupled from the 1973 average to about $12 per barrel (nominal), and OPEC was firmly in control of the world oil market.

  From 1973 to 1975, when OPEC restored output to pre-embargo levels, consumers were paying approximately 57% more for regular gasoline and 91% more for home heating oil (EIA, 2007). The Arab oil embargo stimulated exploration and production operations in non-OPEC countries, prolonged the productive life of marginal wells, and made secondary and tertiary production techniques profitable.

- **1979 Oil Crises (The Iranian Revolution).** The Iranian Revolution began in the late 1978 and resulted in a drop of 3.9 million bbl/D of crude oil production from Iran from 1978 to 1981. Saudi Arabia and other OPEC nations increased production to offset the decline, and the overall loss in production was about 4%; however, fears of shortage increased the oil prices.

In 1980, after the revolution, Iraq invaded Iran, causing a reduction in oil production of 6.5 million bbl/D less than in 1979, and also a worldwide crude oil reduction of 10%. By 1981, OPEC production declined to 22.8 million bbl/D, 7.0 million bbl/D below its level for 1978. In 1981, crude oil prices almost tripled from the 1978 value of $14 bbl (nominal).

From 1980 to 1985, limitations on production by OPEC kept prices high, at an average of $32 bbl (nominal). Also, high prices reduced the demand for oil. For example, cars became smaller, using less gasoline and many around the world began to look at ways to reduce energy consumption. The decrease in oil consumption also made oil production from Saudi Arabia decrease from 9.9 million bbl/D in 1980 to 3.4 million bbl/D in 1985.

- **1986 Oil Price Collapse.** In 1986, Saudi Arabia and other OPEC countries increased oil production to regain market share. The overproduction in 1986 caused an oil glut that reduced the prices by 47% compared to 1985. The decrease in prices provoked an increase in oil consumption that eventually led oil exporters such as Mexico, Nigeria, and Venezuela expanded to increase production capacity.

  The collapse of crude oil prices in 1986 reversed the upward trend in US production of the first half of the decade. Many high-cost wells, which became productive after the oil crisis of 1978-1980, became unprofitable in 1986 and were shut in. Domestic crude oil production began decreasing in 1986.

- **1990 Persian Gulf Crisis (Iraq invaded Kuwait).** The Iraqi invasion of Kuwait in 1990 caused crude oil prices to increase suddenly and sharply. The United Nations (UN) limited the oil purchases from these countries, increasing prices more. Between July and September 1990, the world price of crude oil increased from $16 per barrel to $36 per barrel. However, this crisis ended as soon as UN troops began seeing military successes in Iraq. Concerns about long-term supply problems vanished and oil prices dropped again.

- **1997 Asian Financial Crisis:** The Asian financial crisis occurred in 1997 when Asian economies shrank and their demand for oil declined. The OPEC cartel declined to cut its production quotas and oil prices dropped in 1998 ($12.72 bbl at nominal price).

After the oil price collapse in 1986, the global economy expanded at a faster pace in 1987 and 1988. Low petroleum prices stimulated the growth in industrial production, and the conservation measures instituted during crisis times were discontinued. The US decline in domestic production beginning in 1970 resulted in an increase in crude oil imports **(Fig. 3.2)**.

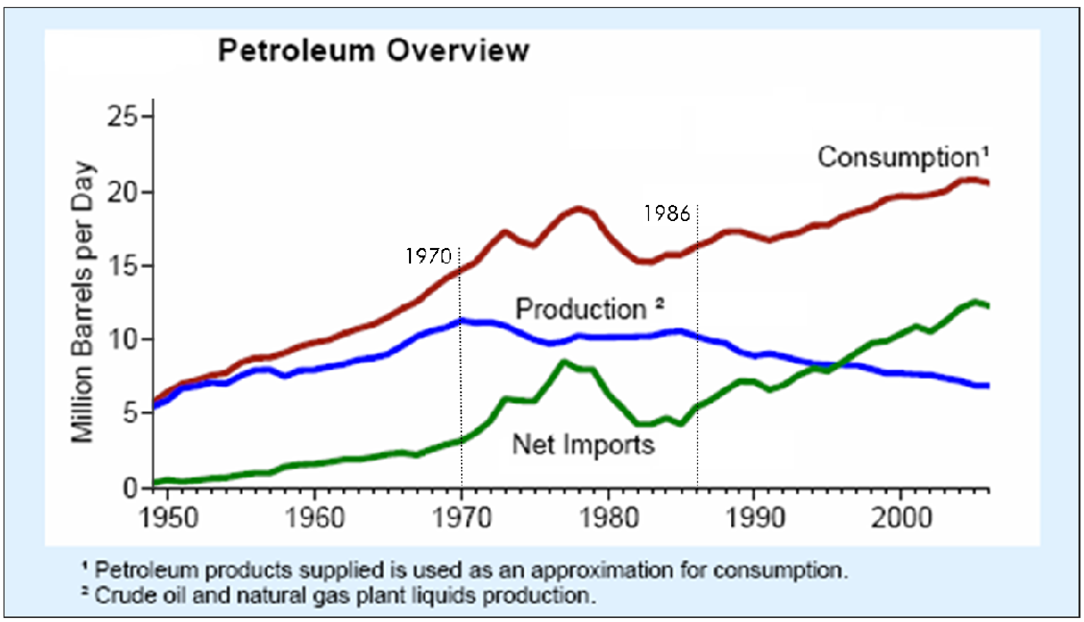


Fig. 3.2—US petroleum production peaked at 11.3 million barrels per day in 1970. Low prices in 1986 increased consumption and net imports. By 1996, net imports exceeded production. In 2006, production was 6.9 million barrels per day, and net imports were 12.3 million barrels per day (from EIA, 2007).

From 1985 to 2000, US consumption of oil climbed from 15.7 million barrels per day to 19.5 million barrels per day. Most of this oil came from OPEC, whose share of total US crude oil imports rose from 41% in 1985 to 60% in 1990, before dropping to 46% in 1995-1997. Since 1998, the OPEC share has continued to increase, reaching 51% in 2000.

Observe a sustained decrease in US oil production after the 1986 price drop (Fig. 3.1). Oil company investments began shifting to foreign oil exploration and production after the 1986 price drop since new fields in many parts of the world are generally much larger than in the United States and average production costs are lower. Changes in policy in the former Soviet Union since 1991 have increased US investment there, and recent moves toward foreign investments in Mexico have attracted American exploration and production companies (EIA, 2007). Currently, the OPEC cartel control on prices is not as powerful as in the 1970s, considering the discovery and development of large oil reserves in the Gulf of Mexico and the North Sea, the opening up of Russia, and the market modernization in terms of foreign trading. Also, with less excess capacity OPEC does not have the flexibility it once had over the supply of oil.

3.2 Natural Gas Commodity Prices

Natural gas, once considered an associated product of oil wells, became a tradable commodity after the US deregulation process in the mid 1990s. In 1981, one-fifth of gas produced in the US was associated gas from oil wells (Spangar, 1996). Similar to oil, the consumption of natural gas has steadily increased since 1986 as gas prices decreased. Controversially, natural gas consumption in the US began to outpace production after domestic operators could not find attractive to produce at these low prices.

The growth of natural gas imports in the US required to satisfy the domestic demand is illustrated in **Fig. 3.3.** In 2005, US natural gas consumption reached 22.2 Tcf, down 1% from 2004. The historical peak in US natural gas consumption occurred in 2000 when 23.3 Tcf was consumed (EIA, 2007). By 2006, the US had to import around 16% of the consumed gas to meet the requirements for fuel in the country.

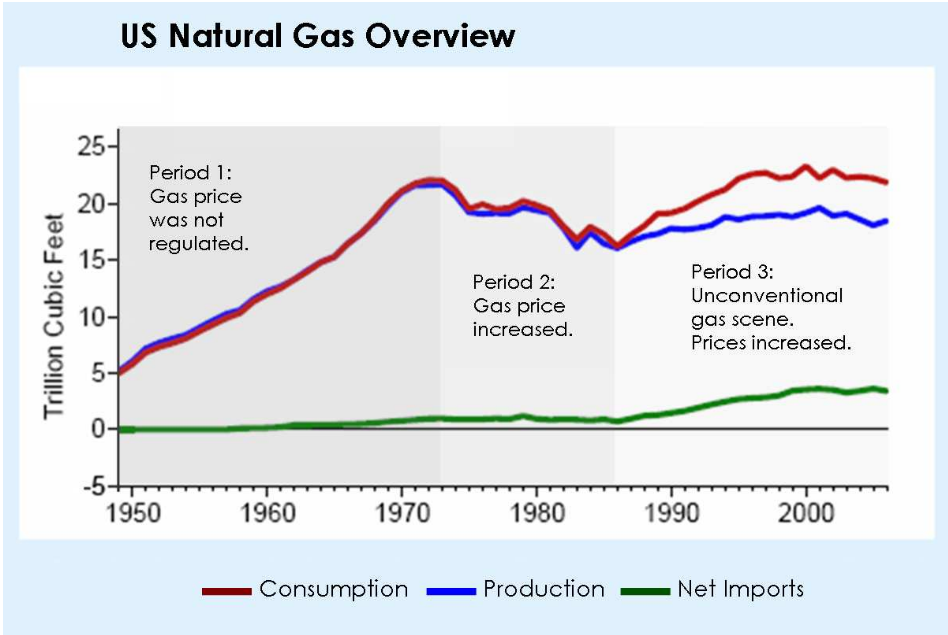


Fig. 3.3—Natural gas overview during the period of 1950 to 2006 (from EIA, 2007).

The interstate US natural gas market experienced controls and regulations by the Federal government until the early 1990s. The full decontrol of interstate in 1993 opened the market and gas became a tradable commodity. **Fig. 3.4** illustrates the historical milestones for the US natural gas industry.

Historically, natural gas prices can be analyzed in three periods: when gas prices were not regulated (1950s to early 1970s), during government regulations since the early 1970s and after deregulation in the early 1990s. In 1938, the US Congress through the Natural Gas Act (NGA) implemented principles and regulations to protect gas as a public interest. The regulations drove the prices for more than 20 years.

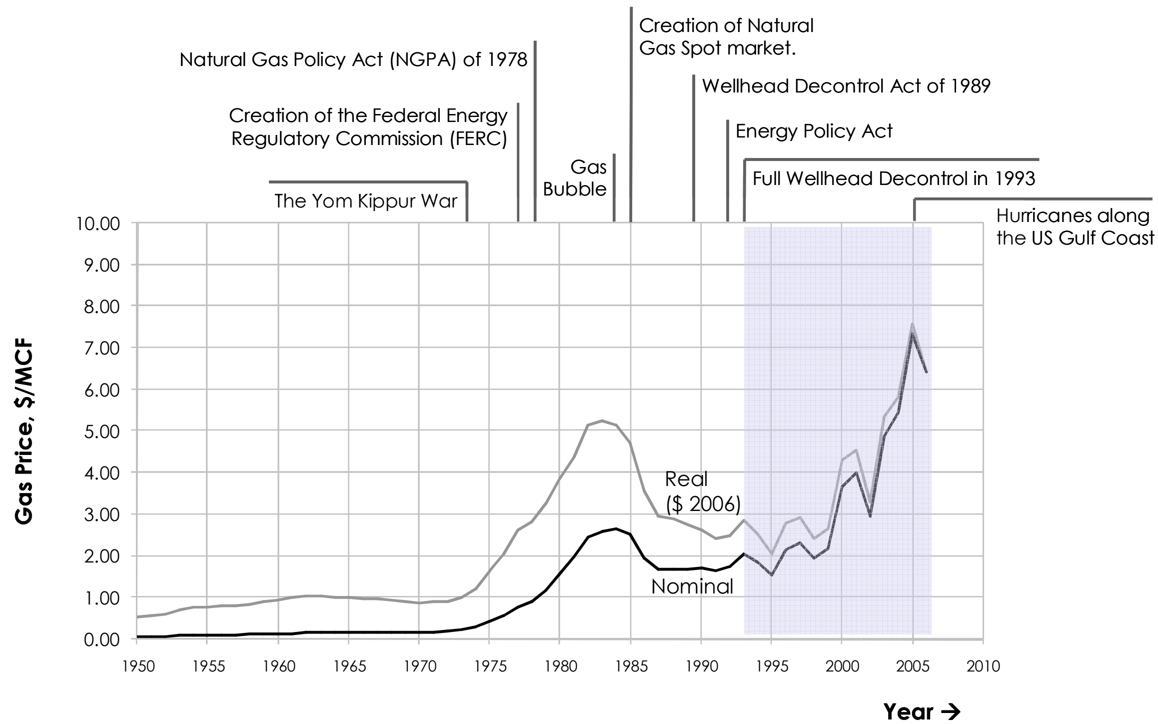


Fig. 3.4—Historical milestones for the US natural gas industry and its impact on gas prices during the period 1950-2006 (after EIA, 2007).

The NGA created the Federal Power Commission (FPC), known later as the Federal Energy Regulatory Commission (FERC), to control almost all aspects of the interstate natural gas industry (transportation, storage, and gas value). The wellhead prices imposed by FERC during the 1960s were low, shrinking operators' interest for new exploration; however, reserves continued growing until the end of 1967 (Spangar, 1996). Reserves eventually decreased and a shortage in gas supply, FERC regulations, and the oil crisis provoked by the Yom Kippur war increased the gas prices during the 1970s. The oil crisis encouraged the use of alternative fuels but new regulations by FERC in 1978 reserved gas for households. During this period the wellhead prices increased more than 260% from \$0.89 Tcf (real) in 1970 to \$3.28 Tcf (real) in 1979.

In 1978, Congress passed the Natural Gas Policy Act (NGPA) to reform wellhead prices by partially deregulating them, foster competition and support exploration and production activities. During the mid 1980s, the new FERC policies stimulated production; higher prices reduced demand, creating a surplus of gas (gas bubble) in the 1980s. The wellhead price peaked at $5.24 Tcf (real) in 1983 and the gas bubble effect provoked decreases in prices over 50% by the end of 1991 (Fig. 3.3).

The process of deregulation started with the Wellhead Decontrol Act of 1989 and was completed in 1993 with the separation of transportation, storage and merchant services. The FERC removed all the price regulations for natural gas production, and gas became a tradable commodity. Since deregulation started, prices have been steadily growing until disruptions in natural gas supply caused by hurricanes along the US gulf coast in 2005. As a result of these disruptions, natural gas price reached $7.56 Tcf (real) in many spots by the end of 2005, an increase of 270% compared to gas prices in 1995. Fluctuation in prices reflected the uncertainty over supplies. Today, most of the US unconventional gas activity is oriented to satisfy the nation's demand.

Table 3.1 summarizes the oil industry major events and technologies since the discovery of the rotary drilling in the 1930s. The effects of each event identified in Table 3.1 are linked to the fluctuations of oil prices affecting the development of unconventional reservoirs.

TABLE 3.1—OIL INDUSTRY MAJOR EVENTS SINCE THE DISCOVERY OF ROTARY DRILLING

Period	Global Event	Effect
1930s	Rotary drilling. Acidizing.	Rotary drills become standard technique (1930s). Acidizing is born (1932). Openhole completion, nitroglycerine fracture development.
1950s	Hydraulic fracturing.	Development of hydraulic fracturing (1949) and widespread use in the 1950s.
1973	The Yom Kippur war.	1st Oil Crisis: Arab Oil Embargo (1973). Oil price increment from \$3 (1973) to \$12 (1974) per barrel. Better hydraulic fracturing technologies.
1978	The Iranian revolution.	2nd Oil Crisis: Oil price increment from \$14 (1978) to \$36 (1981) per barrel. Seismic technology to locate fractures, sweet spots.
1980s	Horizontal drilling developments.	Horizontal wells and water treatment fractures. First horizontal well in the Austin Chalk, Texas (1985) Oil price Collapse (1986) reduces prices from \$37 (1980) to \$14 (1986) per barrel.
1990s	Better technology.	3D seismic horizontal drilling and better hydraulic fracturing technology improve flow rates and recoveries.
2000s	Oil price increase and multilaterals.	Oil price increment from \$29 (2000) to \$65 (2006) per barrel to \$120 (2008) and the widespread use of multilateral drilling improves well performance. Continued improvements in stimulation.

CHAPTER IV
TECHNOLOGY BREAKTHROUGHS

Technologies to overcome high drilling costs in complex areas and improve recovery in mature areas are used in tight gas sandstones (TGS), gas shales (GS), coalbed methane (CBM), and other types of unconventional resources (UCR) to increase production at the lowest possible cost. A common factor in all the UCR wells is the fact that they need to be stimulated after completion to achieve commercial production flow rates. Hydraulic fracturing in the 1950s, horizontal and extended reach wells, multilaterals and seismic advances in the 1990s, better reservoir characterization, and better information technology (IT) to process higher volumes of data coming from seismic have contributed to developing UCR **(Table 3.1)**.

4.1 Acidizing

The main purpose of acidizing is to enhance the permeability of the reservoir near the wellbore and, thereby, the productivity of the well. Originally, acidizing was limited to carbonate formations to dissolve the rock itself; however, special acid formulations were later developed to stimulate sandstone formations as well.

4.1.1 History of Development

The use of acids was first attempted in 1895 to stimulate or improve oil production from carbonate reservoirs. Several well treatments were conducted, but severe corrosion problems in the well casing and other metal equipment failure forced the technique to be discontinued. The next efforts to use acid occurred between 1925 and 1930. These efforts consisted of using hydrochloric acid (HCl) to dissolve scale in wells in the Glenpool field of Oklahoma and to increase production from the Jefferson limestone in Kentucky. No success was reported and acidizing was again abandoned until the development of arsenic inhibitors during the 1930s (Williams et al., 1979).

Arsenic inhibitors to protect the metal well equipment from HCl corrosion revitalized the interest in the acidizing technique. Williams et al., (1979) refer to this period as the modern era of acidizing. In 1932, the Pure Oil Company in cooperation with the Dow Chemical Company, which developed an effective acid corrosion inhibitor for mineral acids (Rae and di Lullo, 2003), stimulated a well in Michigan with positive results. The test used HCl acid to stimulate a limestone included an arsenic acid inhibitor to reduce corrosion in the tubing. By 1934, acidizing was commonly used to stimulate carbonate reservoirs. Acidizing and shooting with nitroglycerin were the only two known methods for well stimulation until fracturing was developed in 1948.

During the 1930s, acidizing was also tested with mixed results in sandstones by injecting mixtures of HCl and hydrofluoric (HF) acids. In the 1960s, when the chemical interaction between HF and sandstones were better understood (Rae and di Lullo, 2003) and better additives were developed, the results from sandstone acidizing treatment were improved.

4.1.2 Applications

The primary goal of an acid treatment is to increase the flow rate from the well by removing near wellbore damage. There are three fundamental acidizing techniques: (1) acid washing, (2) matrix acidizing, and (3) acid fracturing.

(1) **Acid Washing** or wellbore cleanup aims to remove any acid-soluble scales that may be present in the wellbore or in the perforations. Acid washing can be used to dissolve inorganic scales such as metal carbonates, sulfates, sulfides in the wellbore, debris, fines, solids and material that precipitated out from the crude oil during production and plugged perforations and the near-wellbore.

(2) **Matrix Acidizing** is applied to remove near well bore damage and to improve formation permeability near the well bore by dissolving acid-soluble solids or removing products that coat the rocks. Acid is injected into the formation pore space (intergrannular, vugular, or frac-

ture) below the hydraulic fracturing pressure. The acid dissolves products near the wellbore that are restricting flow, thus connecting the wellbore with the undamaged portion of the reservoir **(Fig. 4.1)**.

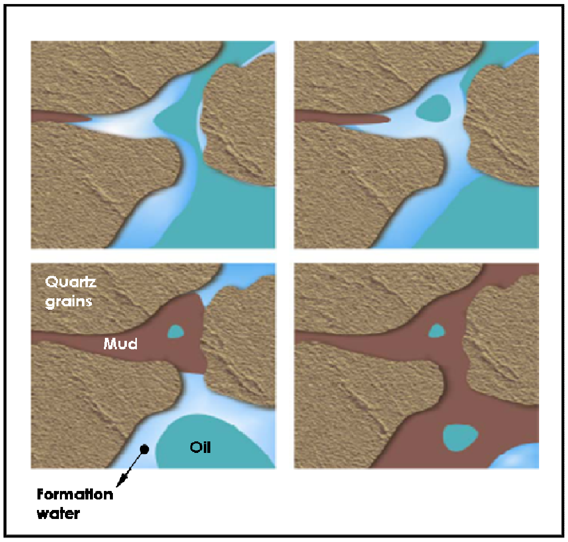


Fig. 4.1—Formation damage after drilling fluid invasion. Observe how the mud displaced the formation water and clog the pores (from Sengul and Remisio, 2002).

Removal of severe plugging materials in carbonates or sandstones near the wellbore zone can increase the well productivity.

Matrix acidizing in carbonates normally uses hydrochloric acid (HCl) followed by a sufficient after flush of water or hydrocarbon to clear all spent acid from the wellbore. A corrosion inhibitor must be added to the acid to protect the steel casing, tubing and packers from corrosion.

Hydrochloric acid, pumped at pressures below the fracture pressure, reacts with the carbonate minerals (calcite or dolomite) to dissolve the carbonates. The acid will flow preferentially into the highest permeability regions (largest pores, vugs, or natural fractures), creating pathways that are known as wormholes. The wormholes are large, highly conductive flow channels that create a high-permeability network **(Fig. 4.2)**. The creation of wormholes is related to the rate of chemical reaction of the acid with the rock; high reaction rates tend to create longer wormholes.

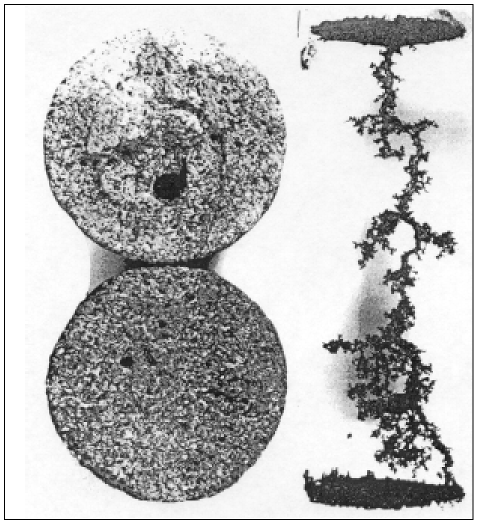


Fig. 4.2—Formation of wormholes in carbonates (From Sengul and Remisio, 2002).

Economides et al., (1994) suggested that weak acid concentrations should be used for perforation cleanup and perforating fluid, and high acid concentrations for matrix treatments. All models of wormhole propagation predict deeper penetration for higher acid concentrations.

Matrix acidizing in sandstones to remove damage is often treated with a mixture of hydrofluoric and hydrochloric (HF-HCl) acids at low injection rates to prevent fracturing. The HF-HCl mixture, commonly refers as mud acid, is used to dissolve the clays found in drilling mud and to react with minerals naturally present in sandstones, including silica and feldspar.

A typical acidizing treatment in sandstones includes three fluids: the preflush, the HF-HCl mixture, and the postflush. The preflush volume is usually a weak HCl that contains a corrosion inhibitor and other additives injected at 50 gal/ft into the formation. Next, the injection of 50 to 200 gal/ft of HF-HCl mixture will follow. In the mixture, the HF reacts with clays, and drilling mud or cement filtrate to improve the near-wellbore permeability, while the HCl will remain inert, controlling the pH to low values and preventing precipitation of HF reaction products. Finally, a postflush of diesel, brine, or HCl displaces the HF-HCl from the wellbore.

In some cases, the optimum acid selection would require analyses in a laboratory because the responses of cores to different acid concentrations will be different depending upon the specific mineralogy of the core. **Fig. 4.3** shows that although some of these formations have approximately the same acid (HF-HCI) solubility, permeability, and porosity, the response to acid is different. Initial reduction in permeability is a common occurrence observed with many formation core flow tests. It is attributed to sloughing particles (clays, silica, fines, etc.) that apparently bridge in the flow channels and restrict flow, before their further reaction with the acid. An inadequate acid volume treatment could lead to a restricted permeability in a formation, if the bridging is severe.

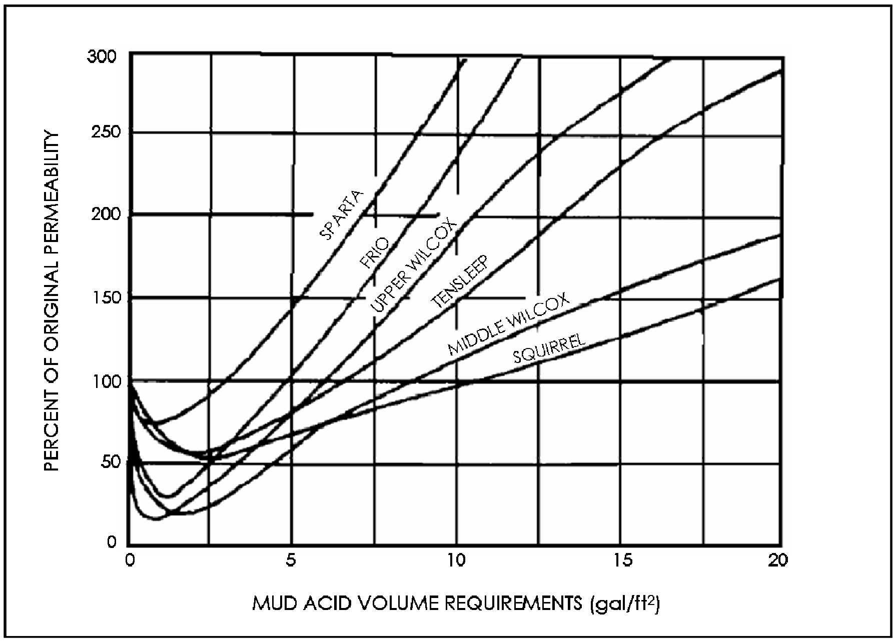
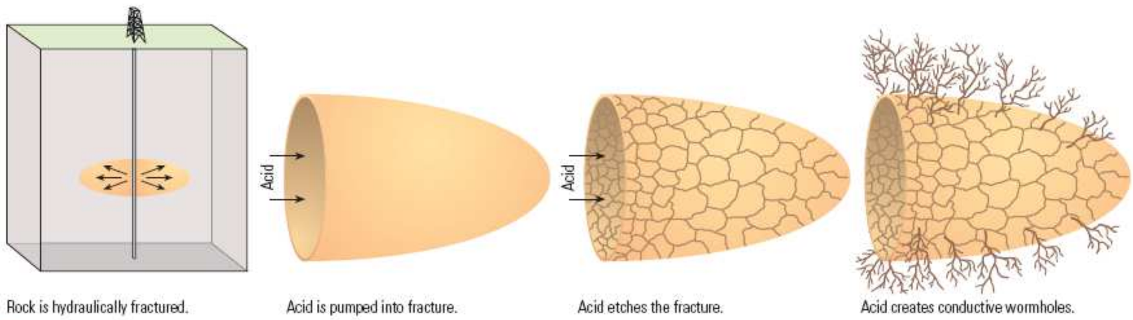


Fig. 4.3—Response of cores from producing formations to mud acid (from Coulter et al., 1962).

(3) **Acid Fracturing** is used to achieve productivity or injectivity beyond the natural capabilities of the reservoir (Coulter et al., 1962). The technique, used only in carbonates, aims to create a fracture conductivity zone pumping usually HCl at a pressure above the formation fracturing pressure. Ideally, the flowing acid tends to etch the fracture faces in a nonuniform pattern, forming conductive channels that remain open without a propping agent after the fracture

closes **(Fig. 4.4)**. Acid fracturing is only applied in carbonate formations to either bypass damage around the wellbore or alter the flow pattern in the reservoir.



^ Acid fracturing in carbonate reservoirs. During an acid-fracturing job, a viscous pad is first pumped at pressures above the fracture-initiation pressure and fractures the rock (*left and second from left*). Next, an acid stage is pumped to differentially etch the hydraulic fracture (*second from right*). The acid also creates conductive wormholes at or near the fracture surfaces, further aiding stimulation (*right*). After the acid-fracturing operation, the fracture closes but retains conductivity because of the etching and wormhole creation.

Fig. 4.4—Acid fracturing process in carbonate reservoirs (from Al-Anzi et al., 2003/2004).

4.2 Hydraulic Fracturing

Hydraulic fracturing is a stimulation treatment performed to increase the productivity of a well by changing the flow pattern in the formation. Hydraulic fracturing typically aims to improve well productivity from low-permeability formations. More recently treatments have considered wells producing from high-permeability formations with sanding problems or high damage by drilling fluids.

The fracturing process consists of pumping of fluid (liquid or gel) into the formation at a pressure sufficiently high to cause tensile failure of the rock, fracture initiation pressure or breakdown sufficient to open the rock, injection of additional fluid to extend the opening and propagate the fracture, and placement of an effective proppant agent to prevent the fracture from closure **(Fig. 4.5)**.

A successful treatment will create a path of considerably higher permeability (five to six orders of magnitude) than the original reservoir permeability. The path will connect production from the formation to the well. Average widths of a propped hydraulic fracture are on the order of 0.25 inches or less, with effective lengths up to 3,000 ft., tip to tip (Economides et al., 1994). The direction of the maximum normal stress component and the reservoir's properties will define the type of the induced fracture (longitudinal or transversal).

Propping agents, such as quartz sand, ceramic beads, or resin-coated sand, are particles that are mixed with the treatment fluid to prop open the fracture after the pumping operation ceases. Some of the factors involved in the selection of propping agents include density, strength, shape, size, susceptibility to erosion, susceptibility to embedment, and conductivity.

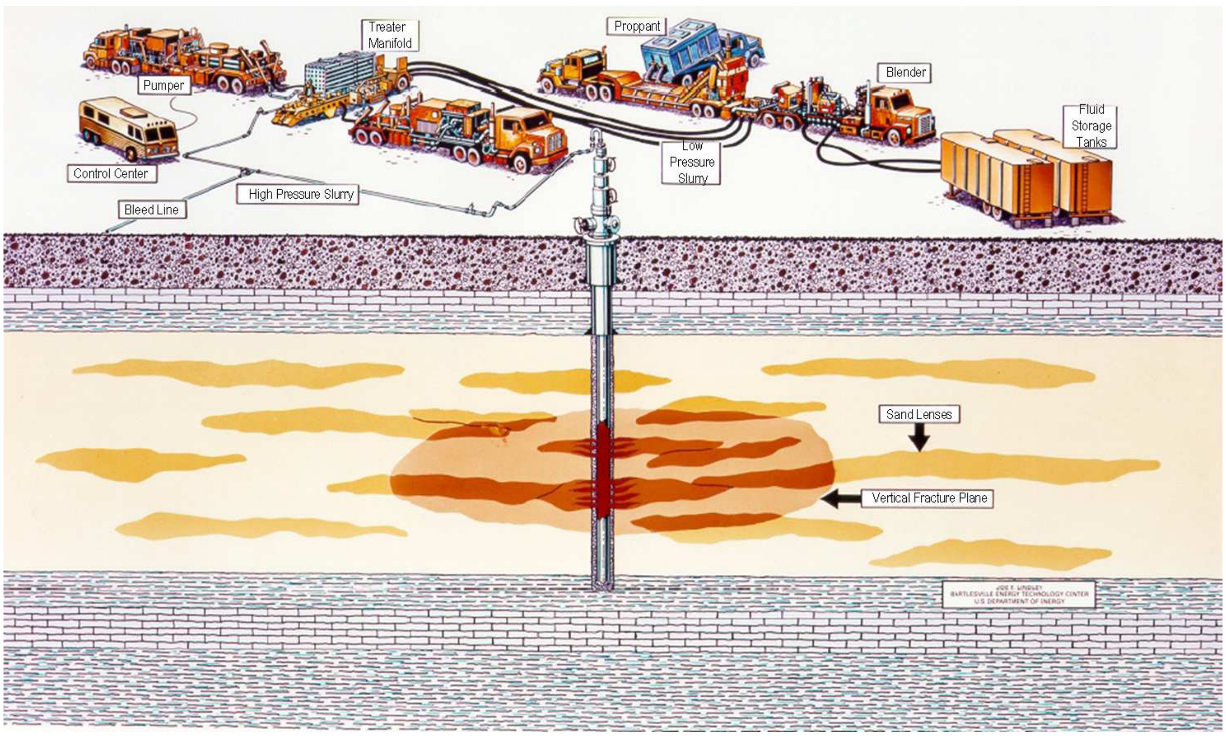


Fig. 4.5—The hydraulic fracturing stimulation process includes several steps. A viscous fluid containing a proppant is injected under high pressure until the desired fracturing is achieved. The pressure is then released, allowing the fluid to return to the well. The proppant remains within the fractures to prevent closing.

4.2.1 History of Development

The first fracturing experimental treatments in the US were performed in carbonates in the Hugoton gas field in western Kansas in 1947. The test, with no propping agents, did not report increases in the well production. Operators did not trust the technique until fracturing in the Woodbine sands in the East Texas proved successful (Economides and Nolte, 2000). The treatment in the Woodbine sands consisted of 23 bbl of gelled lease crude, 160 lbm of 16-mesh sand at 0.15 ppa, and 24 bbl of breaker (Economides and Nolte, 2000). In 1949, hydraulic fracturing was a stimulation method commercially available.

During the 1950s, the technique of hydraulic fracturing proliferated due to its success in increasing oil and gas flow rates. By the end of 1955, the industry was pumping 3,000 fracture treatments per month. The 1960s and the early 1970s was a period characterized by the understanding and the optimization of the technique. In the late 1970s, the increase in natural gas prices stimulated the development of tight gas sands and other unconventional reservoirs where massive hydraulic fracturing (MHF) treatments could be used to improve flow rates. The period saw the development of more viscous fluids able to carry higher concentrations (5 to 6 lb/gal) of proppants (Holditch and Tschirhart, 2005). The service companies continues to design sophisticated fluids (crosslinked gels) and harder materials (bauxite and lower density ceramics), as well as large-volume pumping equipment and proppant handling capacity. Operators in the US developed large-scale hydraulic fracturing technology that boosted gas production from tight-gas reservoirs by 10-fold or more (Stevens et al., 1998).

The 1980s were characterized by the need to better control the outcomes of a fracturing treatment with real-time engineering and monitoring processes. Cross-linked polymer fluids allowed the industry to pump treatments carrying as much as 10 to 12 lb/gal of proppant (Holditch and Tschirhart, 2005). The purpose of more proppants was to create long, conductive fractures needed to optimize production. First attempts to fracture stimulate horizontal wells occurred during the late 1980s. The 1990s were marked by better fracturing technologies and better fracture design models.

As explained by Holditch and Tschirhart (2005), some cross-linked treatments in low temperature reservoirs did not effectively stimulate TGSs, probably due to gel clean-up failures. As such, operators began experimenting with less expensive techniques such as the slick-water fracturing technique that used high volumes of water and low concentrations of proppant. Initial results seemed to indicate that slick water fracs would provide stimulation, but at a lower cost than cross-linked gel treatments. Other technological advances, such as the coiled tubing fracturing technique, allows for treating of multiple zones with one trip in the hole instead of pulling out every time to go to the next zone.

4.2.2. Applications

Hydraulic fracturing is a successful technique in almost all low to moderate permeability formations. Sand, limestone, dolomitic limestone, dolomite, conglomerates, granite washes, hard or brittle shale, anhydrite, chert, and various silicates can be stimulated by hydraulic fracturing. **(Fig. 4.6)**.

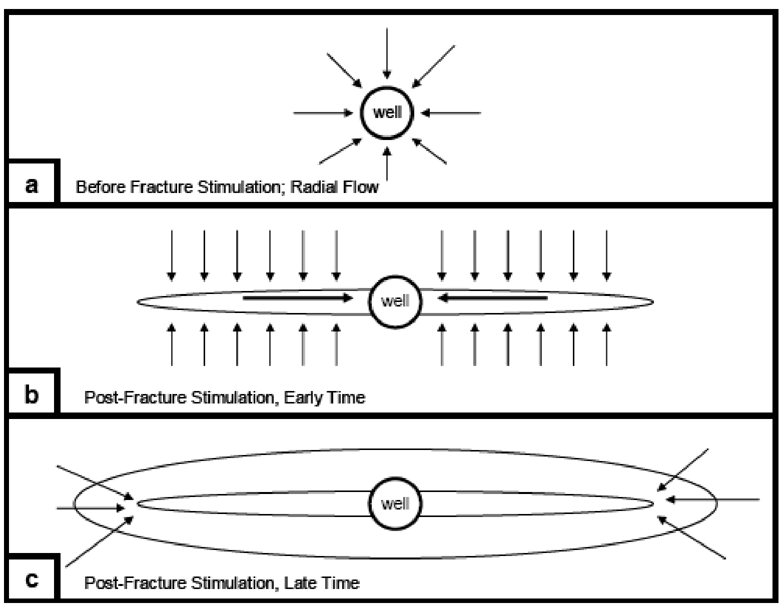


Fig. 4.6—Comparison of flow streamlines for fractured and non fractured wells (from Holditch and Tschirhart, 2005).

4.3 Waterfracture Treatments

Mayerhofer and Meehan (1998) defined “waterfracs” as fracture treatments that use a polymer-free fracturing fluid or a very low polymer concentration composed of water, clay stabilizers, surfactants and friction reducer with low proppant concentrations to reduce costs.

The success of waterfracture treatments or slickwater fracturing (LSF) in formations like the Austin Chalk or the Barnett Shale has been attributed to the waterfracture treatments ability to open existing natural fractures. As water imbibes into the matrix blocks, it expels the oil or gas into the natural fractures (Tschirhart, 2005). Furthermore, the fracture growth in naturally fractured reservoirs is usually different from the conventional concept that fracture stimulation predominately creates two single fracture wings extending from the well **(Fig. 4.7a)**. Instead, waterfracture treatments create large fracture networks that increase the surface area of the fractures. The concept of multiple fractures has been supported by fracture mapping (micro-seismic and tiltmeter) experiments. **Fig. 4.7** shows the difference between a simple conventional fracture geometry and a complex fracture network expected from stimulating a formation like the Barnett Shale (Tschirhart, 2005).

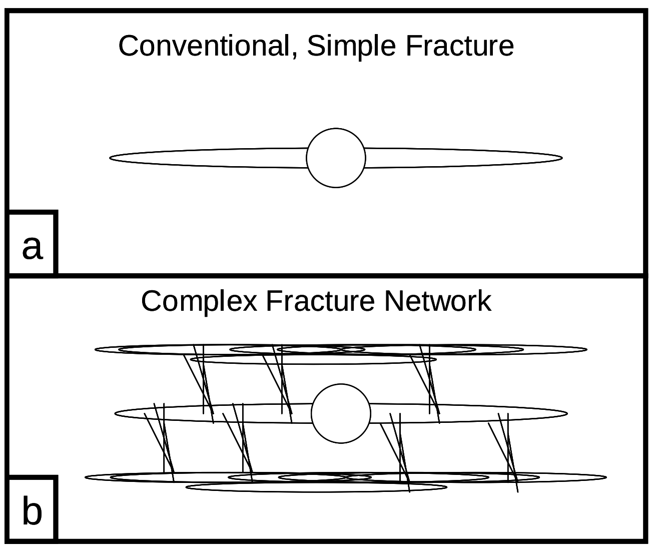


Fig. 4.7–Conventional and complex fracture growth systems (from Tschirhart, 2005).

4.4 Horizontal Drilling Technology

According to the Energy Information Administration (EIA) Office of Oil and Gas, US Department of Energy, a “unified” definition of horizontal drilling does not exist. Based on different sources, the Department of Energy, defines horizontal drilling as “the process of drilling and completing, for production, a well that begins as a vertical or inclined linear bore which extends from the surface to a subsurface location just above the target oil or gas reservoir called the kickoff point, then bears off on an arc to intersect the reservoir at the entry point, and, thereafter, continues at a near-horizontal attitude tangent to the arc, to substantially or entirely remain within the reservoir until the desired bottom hole location is reached." Shelkholesiami et al., (1991) define a horizontal well as the result of a drilling and completion technique in which the wellbore remains in a high-angle trajectory roughly parallel to the formation, thereby exposing significantly more pay to production than would be exposed by a vertical wellbore.

Horizontal wells came to play an important role in enhancing the productivity of the wells in the reservoir and subsequently the recovery factor. Usually, horizontal wells will reach areas not contacted by verticals and will solve problems associated with thin zones, fractured reservoirs, water and gas coning, gas reservoirs, waterflooding, heavy oil production, thermal processes and CO_2 flooding.

4.4.1 History of Development

Horizontal drilling activities have been documented as early as 1927; however, the first recorded true horizontal oil well was completed in 1929, near Texon, Texas. Later, a horizontal well of 500 ft was drilled in the heavy oil field of Franklin, Pennsylvania. After World War II, horizontal drilling benefited from jet perforating, casing the drilled hole, and the perforation or targeted intervals (EIA, 1993).

By the early 1980s with oil prices around $35 and improvements in downhole drilling motors and downhole telemetry equipment, horizontal drilling was commercially viable. Literature review suggests (EIA, 1993; Joshi, 2003) three different horizontal drilling stages depending on both technology and prices: *early 1980s, late 1980s-early 1990s, late 1990s-today.*

During the early 1980s, the development stage of horizontal drilling, many test wells were drilled in Europe and the US. In Europe, Elf Aquitaine tested the technique to produce heavy oil from a carbonate reservoir in the Rospo Mare oilfield, located offshore Italy in the Mediterranean Sea. Also, Elf drilled other wells in the Lacq Superieur and Castera Lou oil fields in southwestern France. Experiments in the US at the same time were carried out to reduce gas coning in the Abo Reef in New Mexico; to intersect fractures in carbonate reservoirs in Oklahoma, Kansas, and Texas; and to minimize water and gas coning into the Sadlerochit reservoir in Alaska's Prudhoe Bay field.

In the late 1980s-early 1990s, the growth of horizontal drilling or the acceptance of the technique in the industry was marked by important drilling campaigns worldwide, with North America having the greatest number of drilled wells. Many efforts to reduce costs used medium radius technology. In 1990, worldwide, more than 1,000 horizontal wells were drilled and more than 80% of them targeted the Upper Cretaceous Austin Chalk formation in Texas (EIA, 1993). Noticeable impact on the production of crude oil in certain regions was reported, and in the mid-1990s, crude oil production from horizontal wells in Texas had reached more than 70,000 BOPD.

From the late 1990s to today, many new technologies have been developed to improve horizontal drilling practices. Cost reductions, re-entry wells, coiled tubing drilling, improvements in drilling monitoring, logging while drilling (LWD), measurement while drilling (MWD), and geo-steering to drill straight horizontal holes, as well as formation damage reduction and under-balanced drilling are examples of recent stages of horizontal drilling improvements.

4.4.2 Well Configurations

The radius of the arc described by the wellbore as it passes from the vertical to the horizontal defines the horizontal well classification. In all cases, the classification will be related to both the technology involved and the application or the purpose of the well. Some authors (EIA, 1993; Fritz et al., 1991) consider four horizontal methods: short radius, ultrashort radius, medium radius, and long radius. Joshi (2003) added one more configuration, intermediate short radius, based on the arc of curvature. **Table 4.1**, after Joshi (2003), constitutes a summary of these five different configurations. In general, the required horizontal displacement, length of the horizontal section, position of the kickoff point, and completion limitations are considered when selecting a radius of curvature.

TABLE 4.1—HORIZONTAL DRILLING TECHNIQUES (after Joshi, 2003)

Type	Radius of curvature, R (ft)	Build rate (°/foot drilled)	Length (ft)	Applications
Ultra-short radius (a)	1-2 ft	45°-60°/ft drilled	100-200 ft	Commonly used when re-entering existing vertical well (Sidetrack).
Short radius (b)	20-70 ft	150°-350°/100 ft drilled	100-800 ft	Commonly used when re-entering existing vertical well (Sidetrack). Favorable in small lease blocks.
Intermediate short radius (c)	120-150 ft		1,000 ft	Commonly used when re-entering existing vertical well (Sidetrack).
Medium radius (d)	300-800 ft	6°-30°/100 ft drilled	1,000-4,000 ft	Favorable for more complex completion methods in leases as small as 20 acres. Used when re-entering existing vertical well (Sidetrack).
Long radius (e)	>1,000 ft	Up to 6°/100 ft drilled	1,000-4,000 ft	Favorable for leases of more than 160 acres. Usually new well.

4.4.3 Completion Techniques

The appropriate completion scheme will be controlled by taking into account the existing conditions from the drilling to the abandonment of the well to achieve borehole stability and sand control. Joshi (2003) defined four completion schemes for horizontal wells to illustrate those conditions: (1) openhole wells, (2) slotted liner completions, (3) liners with partial isolations, and (4) cased-hole cemented completions.

For openhole wells, the formation type represents the major limitation, and stimulation process become very difficult to perform if wells are unstable. In the case of slotted liner completions, the purpose is to control the hole collapse and at the same time insert different tools such as coiled tubing (Fritz et al., 1991). Three types of liners have been used: perforated liners (holes drilled in the liner), slotted liners (slots of various width and depth are milled along the liner), and prepacked liners. The gravel pack is an option to help to control sand production using slotted liners. The option of liner with partial isolations allows certain types of isolation for stimulation or production control along the well. Finally, cased-hole completions allow cementing and perforation of the liner. Cased-hole completion will be very useful to stimulate wells, such as medium and long radius wells, that have been exposed to drilling fluids for long periods of time and wells that have been drilled in tight formations or low permeability formations.

Short radius wells are limited to openhole or slotted liners. Although in the past the slotted liner completion scheme was a problem to stimulate a well, technological advances such as liquid fracs (acid or water fracs) have become a solution. In fact, today most of the wells in the US are liquid frac. On the other hand, medium to long radius wells have more flexibility since they can support all possible completion types.

4.5 Multilateral Wells

A multilateral well consist of several wells drilled off a single borehole (parent well) to the surface. Multilaterals can produce several horizontal or even vertical sections from a common borehole. The advantage of multiple wells drilled from a single main well is that they eliminate costly rig days and reduce environmental foot print by initiating several new wells from the same surface location.

Some of the earliest development toward horizontal and multilateral drilling took place during the early 1940s when John Eastman and John Zublin drilled between four and eight laterals in the same formation in various directions around the wellbore to increase the productivity of oil wells in California. However, the recognized father of multilateral technology is Alexander Grigoryan. “In 1949, Grigoryan proposed branching the borehole in the productive zone to increase surface exposure” In 1953, Grigoryan completed the world’s first truly multilateral well in Bashkiria field (former USRR). The well with nine producing laterals and a maximum horizontal reach from kickoff point of 136 m (446.1 ft) produced 17 times more oil per day than any other well in the field. The Soviets drilled an additional 110 multilateral wells in their oil fields during the next 27 years.

Multilateral techniques range from simple to complicated configurations. Multilaterals have been classified into six levels depending on the sophistication of the junction. The Technological Advancement of Multilaterals (TAML) organization classifies the level of a multilateral junction by its composition and hydraulic integrity, as illustrated in **Fig. 4.8**. Levels 1 and 2 are the most simple (they do not guarantee mechanical and hydraulic integrity), levels 3 and 4 guarantee only mechanical integrity, and levels 5 and 6 deliver both mechanical and hydraulic integrity.

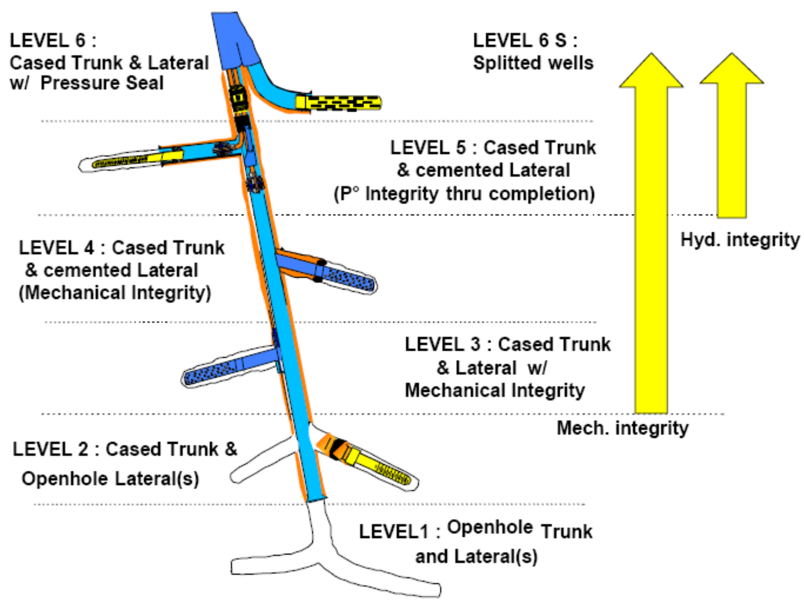


Fig. 4.8—Multilateral complexity levels one to six represent progressive levels of mechanical and hydraulic integrity (from Charlez and Bréant, 1999).

According to Charlez and Bréant (1999), the most common applications of multilaterals include exploration delineation, increasing well productivity and reserves, and revitalizing a depleted mature field. Typical uses of multilateral wells include naturally fractured carbonates such as the Austin Chalk play in Texas and heavy oil reservoirs such as the Orinoco Belt in Venezuela and similar heavy oil reservoirs in Alberta, Canada. The use of multilateral wells in naturally fractured reservoirs increases the probability of productivity improvement by intersecting several fractures and draining them efficiently. The heavy oil deposits in Venezuela benefit from multilaterals increasing contacted area during thermal processes (such as steam injection).

4.6 Steam Injection

Steam injection includes cyclic steam stimulation (CSS) and steamflooding. In areas with low-gravity crude, steam is used to heat and reduce the viscosity of the oil to allow the oil to move more easily to the wellbore.

In the 1960s, operators began to inject steam to reduce the heavy oil viscosity and increase recovery. In CSS, steam is injected into a well for a time period from several days to several weeks. The heat is allowed to soak into the formation surrounding the well for an additional time (weeks), and the oil is produced (possibly up to a year) until the rate drops below an economic limit. The steamflood technique may follow CSS to sweep oil between wells. Steam is injected in one well and oil is produced in another well, for example in a 5-spot pattern. Steamflooding operations have produced recovery factors of over 70%, such as in the Duri field in Indonesia and in several fields in the San Joaquin Valley in California.

The NPC (2007d) explains CSS in three phases: injection, soaking and production. First, high-temperature/high-pressure (HT/HP) steam is injected for up to one month. Second, the formation is allowed to soak for one or two weeks while heat diffuses to decrease oil viscosity. Third, heavy oil is pumped out of the well (artificial lift is required) until an economic rate **(Fig. 4.9)**. The production phase may take up to a year. Then the cycle is repeated, as many as

15 times, until production can no longer be recovered. Typical recovery factors for CSS are 20% to 35% with steam-to-oil ratios (SOR) of 3:5 (NPC, 2007d).

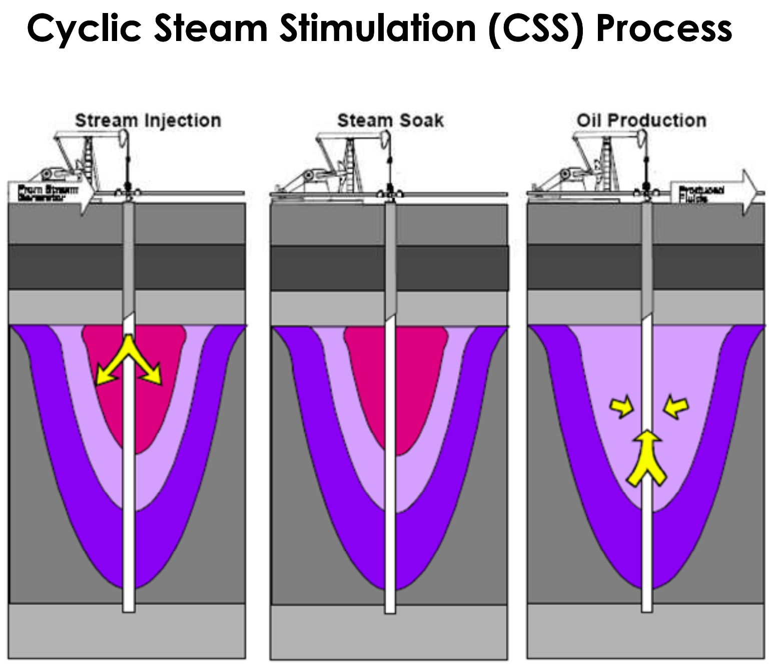


Fig. 4.9—Three steps are required to decrease oil viscosity in the reservoir allowing the well to produce. During cyclic steam stimulation (CSS), the well will be first an injector (steam-injection step) and later the producer after the soaking period (from Stevens et al., 1999).

The *steamflood* technique may follow CSS to recover the heavy oil between wells. Steamflooding usually is arranged in patterns. A common configuration is a five-spot pattern with four producing wells surrounding a central steam-injection well. The well spacing can be less than 2 acres for a field in steamflood. The steam heats the oil to lower its viscosity and provides pressure to drive the heavy oil toward the producing wells **(Fig. 4.10)**. Most steamflood operations consider well steam-stimulation at the beginning of the flood. CSS is the beginning phase of a steamflood, and in some cases even the steamflood injection wells are put on production for one or two CSS cycles to help increase initial project production and payout the high steamflood capital and operating costs (NPC, 2007d).

CSS and steamfloods are used in United States, Western Canada, Indonesia, Oman, and China. In the US, California's Kern River production rose from less than 20,000 barrels per day in the late 1950s before CSS to over 120,000 barrels per day by 1980 after the introduction of CSS. The world's largest steamflood, the Duri field in Indonesia, produces 230,000 BOPD with an estimated ultimate recovery factor of 70% in some locations.

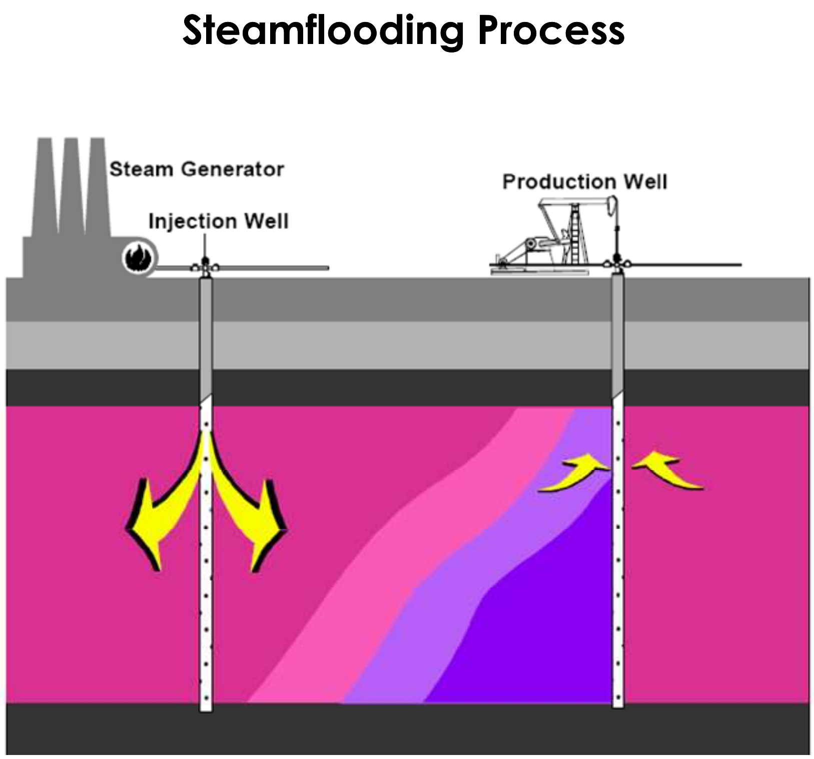


Fig. 4.10—The steamflooding technique usually is anteceded by a CSS process and characterized by a continuous steam injection process (from Stevens et al., 1999).

CHAPTER V
SELECTED CASES IN THE UNITED STATES

Unconventional reservoirs in the US have been developing for more than 50 years. For the purpose of this study, we have selected eight formations from different types of unconventional reservoirs as illustrated by Masters' Resource Triangle Theory (RTT).

Fig. 5.1 indicates the location of the selected formations and their associated basin systems. In red shading are the shale formations (Lewis, Bakken, Barnett and Antrim), and in grey the sandstones (Kern River, Mesaverde and Cotton Valley) and carbonate formations (Austin Chalk formation). For the purpose of this study, we have divided the formations into two groups: natural gas producers and oil producers.

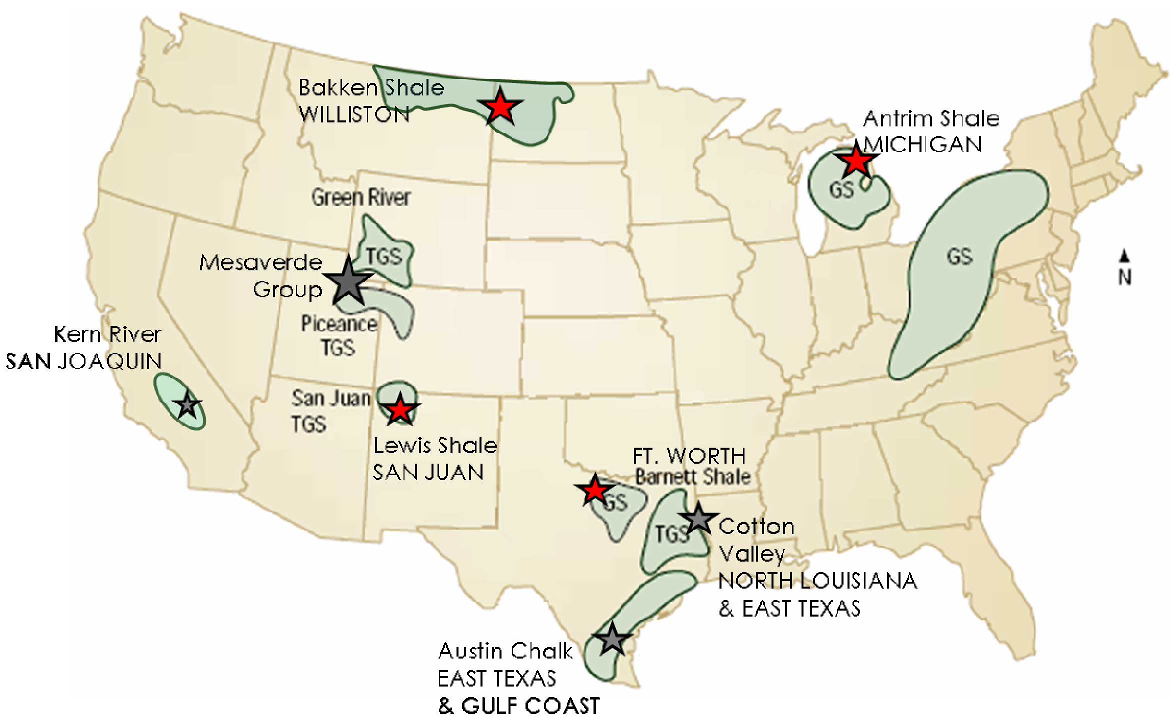


Fig. 5.1—Selected cases and their location in the United States territory. Red shading indicates the shale formations and in grey indicates the sandstones and carbonate formations under study.

5.1 Oil and Heavy Oil Producing Formations

TABLE 5.1—OIL AND HEAVY OIL FORMATIONS					
UCR	Formation	Np*, MMSTB	Oil*, MMBOE	Basin	States
Low Permeability Oil (LPO)	Austin Chalk (1955♦)	961	1,786	East Texas, Gulf Coast	TX, LA
Oil Shale (OS)	Bakken Shale (1961♦)	85	101	Williston	ND, MT
Heavy Oil (HO)	Kern River (1977♦)	42	42	San Joaquin	CA
* Cumulative Oil (Np) and Oil Equivalent (million BOE) values at Dec. 2006 from HPDI database ♦ Production data available from this date.					

5.1.1 Low-Permeability Oil (Chalk Reservoirs)

According to Fritz et al., (1991), “Although classified as a carbonate, chalk is actually between a limestone and a source rock in that it is a pelagic unit.” Schlumberger’s glossary oilfield (2008) defines chalk as “a porous marine limestone composed of fine-grained remains of microorganisms with calcite shells, coccolithophores”. Chalks are characterized by high porosity (up to 80%, but diagenesis and pore-water chemistry can reduce this porosity to less than 1%), low permeability (less than 1 md), and soft matrix (composed mainly of calcite). This combination of high porosity and low permeability requires stimulation methods to make a chalk reservoir commercially producible.

5.1.1.1 Austin Chalk Formation

The Austin Chalk formation extends from Laredo Texas through eastern Louisiana **(Fig. 5.2)** and it is the largest low permeability carbonate play in the US territory (RPSEA, 2005). The Cretaceous Austin Chalk formation depth goes from less than 1,000 ft to greater than 15,000 ft in areas of east Texas and Louisiana (Kyte and Meehan, 1998). The porosity ranges from 2% (deeper gas reservoirs) to more than 15% (shallowest oil reservoirs) with permeability values from microdarcies to hundreds of millidarcies. Productive thickness ranges from less than 50 ft to more than 800 ft. Fig. 5.2 shows the three main producing fields in Texas, the Pearsall, Giddings, and Brookeland fields.

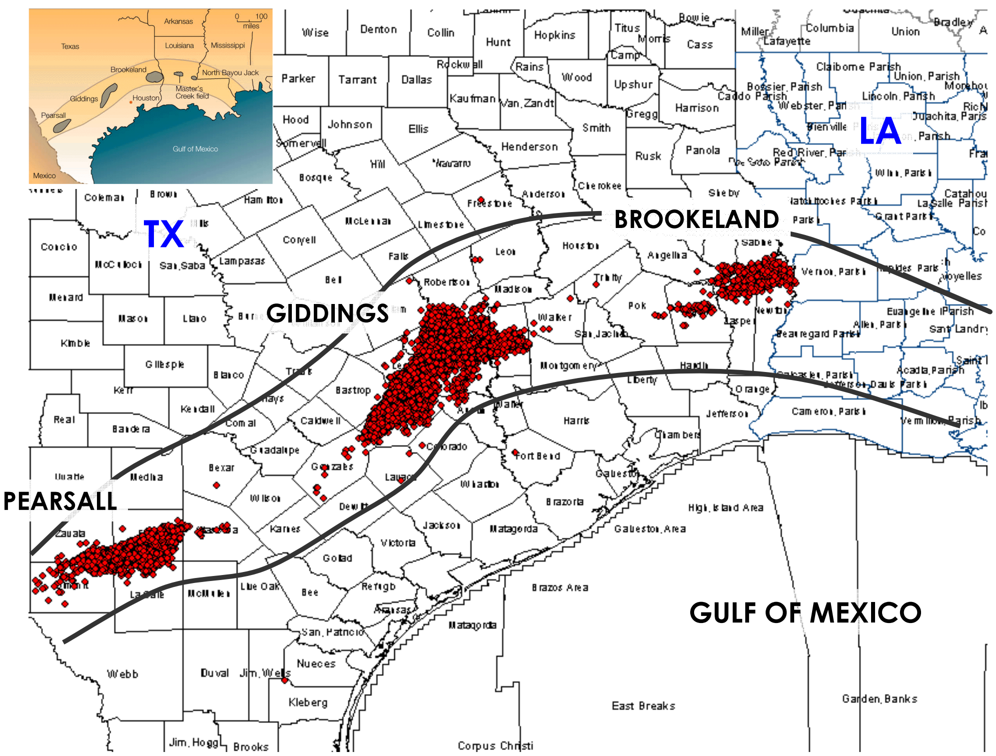


Fig. 5.2—The Austin Chalk formation is the largest carbonate play in the United States, extending from Mexico to Mississippi. The map shows the three major producer fields (HPDI, 2007).

The Austin Chalk formation has been a niche for stimulation technologies in the United States. From acidizing to horizontal drilling, the Chalk represents an excellent example of how technologies for low-permeability reservoirs can lead to increase drilling activity and increased oil and gas production.

5.1.1.1.1 Production History

The development of the Austin Chalk formation had been the result of increasing oil prices coupled with improved stimulation techniques (Rose et al., 1992). They recognized five periods of production that began with its discovery in 1933 **(Fig. 5.3)** mention that:

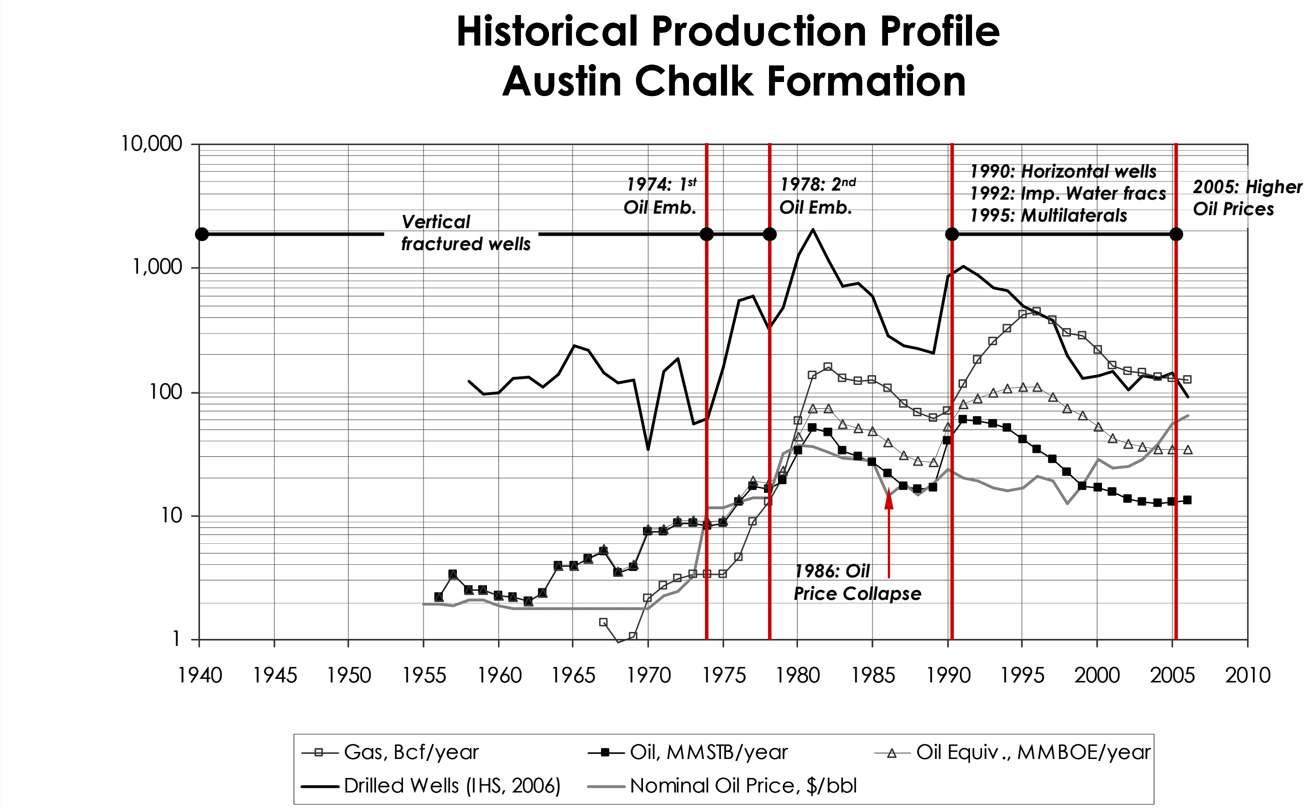
- Early activity or the first period of development in the Austin Chalk formation was mainly in the Pearsall field. Approximately 30 wells were drilled between 1933 and 1941.
- The second period took place from 1948 to 1956, when 99 wells were drilled and the selling price of oil went from $1.50 to $2.44 per barrel (nominal).
- The third period of development beginning in 1974 was characterized by oil prices moving towards $10 per barrel.
- The fourth period occurred in the early 1980s when oil prices were over $30 per barrel.
- The fifth period began in the late 1980s with the use of horizontal drilling completions, further stimulated by the increase in prices after the collapse of oil prices in the mid 1980s. Oil prices went from $15 per barrel in 1988 to $24 per barrel in 1990.

Discovered in the early 1930s, the early Austin Chalk wells were first stimulated by shooting nitroglycerin. Later acidizing was used to provide additional stimulation but drilling activity declined because the low reserves per well caused the average well to be marginal. The development of hydraulic fracturing in the late 1940s restarted activities between 1948 and 1956 (Hill et al., 1978). Hydraulic fracturing was successful in stimulating the Austin Chalk, but at the low oil prices in the 1950s, the play was still marginal and drilling activity slowly declined.

In the 1970s, a better understanding of the naturally fractured system present in the formation explained the different values of productivity index along the Chalk and improved the results of stimulation treatments. However, the real reason that activity in the Austin Chalk increased rapidly in the 1970s was the rapid increase in the price of oil.

During the mid 1980s, horizontal drilling was introduced in the Austin Chalk. The late 1980s marked the beginning of an intense water fracturing treatment program that, along with horizontal drilling, increased production. By year-end 1991, the play reached the maximum oil rate of 60 million STB/year, increasing 1988 oil production by almost four-fold.

Historically, oil and gas production has peaked twice. In 1981, after the oil crises in the Middle East, the formation reached a maximum rate of 74 million BOE/year (52 million STB/year and 135 Bcf/year) from more than 5,000 producing wells. The second peak reached its maximum value of 110 million BOE/year (41 million STB/year and 418 Bcf/year) in 1995 mainly as the result of an intense horizontal drilling activity, an increase of almost 50% compared to the first oil peak **(Fig. 5.3)**.



1948-1956: Second period of development. 99 wells were drilled. Oil prices from $1.50 to $2.44 per barrel (nominal) (Rose, Austin and Pike, 1992).

1974: Third period of development. More than 500 wells drilled at the end of 1976. Oil prices moved toward $10.0 per barrel (nominal) (Rose, Austin and Pike, 1992).

1980s: Four period of development. Oil prices were over $30.0 per barrel (nominal).

Late 1908s: Fifth period of development. First horizontal wells drilled in Pearsall field (Kyte and Meehan, 1996). In 1988, Horizontal drilling activity began in the Giddings field. Production in 1990 increased in Giddings field to 26.4 MBO/D, extreme active drilling increased production in June 1993 to 81 MBO/D and 365 MMCF/D (Meehan, 1995). In 1986, water fracturing began in Giddings.

1992: 427 horizontal wells were producing in Giddings (Meehan, 1995).

1993: As of September 1993; there were 2,834 producing wells in Giddings field. Horizontal wells constitute 29% of this total with 816 wells contributing with more than 70% of field production (Meehan, 1995).

Fig. 5.3—The development of the Austin Chalk is driven by the fluctuations of oil price (data from HPDI and IHS, 2007).

Oil and gas production from the Austin Chalk is available since 1955 (HPDI, 2007). Fig. 5.3 provides an overview of the history of production in the trend.

The main producer fields in the Austin Chalk formation are Giddings, Pearsall, and Brookeland, but there are many other smaller fields. The Giddings has accumulated to date (2007) 51% of the total oil produced and 84% of the total gas, as shown in **Table 5.2**.

TABLE 5.2—PRODUCTION COMPARISON AMONG THE MOST PROLIFIC FIELDS IN THE AUSTIN CHALK FORMATION (data from HPDI, December 2007).

FIELD	Cum. Oil, MMSTB	Cum. Gas, Tcf	Cum. Oil Equiv., million BOE	Cum. Water, MMSTB	Active wells
Giddings	516	4.3	1,228	296	2,461
Pearsall	150	0.1	167	512	265
Brookeland	42	0.4	115	58	218
Other fields	304	284	351	5,540	1,898
TOTAL	1,012	5.1	1, 861	6,406	4,842

Much of the Austin Chalk development can be attributed to the success of hydraulic fracturing, that create a permeability system of near-vertical fractures that run parallel to the structural strike and connect the low- permeability matrix with the wellbore. A horizontal well will encounter fracture swarms otherwise not producible by vertical wells **(Fig. 5.4)**.

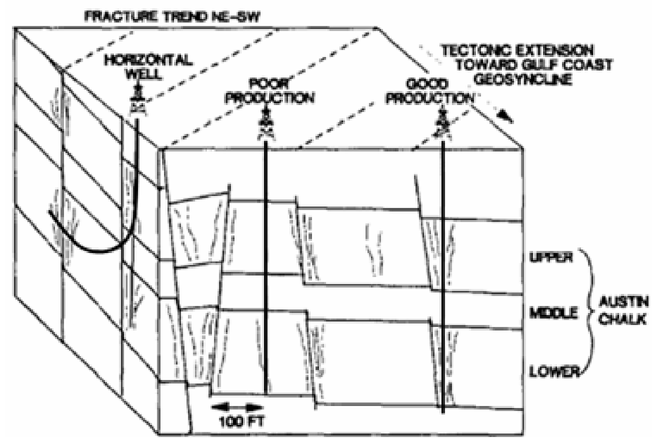


Fig. 5.4—The geological model of Giddings field shows normal faulting and horst and graben structures as characteristic patterns of Austin Chalk structural style. Production benefits from horizontal wells by connecting fractures along the reservoir to the well (from Kuich, 1989).

From the 1930s to the middle 1980s, the productivity of the wellbore drilled into the fracture system faced many uncertainties. A well must be able to intercept the natural fracture system to economically produce from the Chalk (Rose et al., 1992). Usually, the productivity of a well drilled into the natural fracture system will successfully increase its productivity after the fracturing treatment. The use of horizontal drilling increased the possibility to encounter more natural fractures achieving better production rates.

5.1.2 Oil Shale

5.1.2.1 Bakken Shale Formation

The Bakken formation in the Williston basin covers parts of the states of Montana and North and South Dakota in the US, and the provinces of Manitoba and Saskatchewan in Canada. Deposited during the Upper Devonian and Lower Mississippian periods, the Bakken formation can vary in depth from a few thousand ft in Canada to more than 10,000 feet in the deeper areas in North Dakota. This study only includes the US production available in our database (HPDI, 2007) as depicted in **Fig. 5.5**.

The upper Devonian lower Mississippian Age Bakken shale is a naturally fractured formation that is both a source and a reservoir rock. The Bakken shale consists of three sub intervals, the Upper Bakken Shale, the Middle Bakken member, and the Lower Bakken Shale. The Upper and Lower Bakken intervals are similar black shales with an average thickness of 15 ft and 30 ft, respectively. In general, the Upper Shale has higher total organic carbon content (TOC) than the Lower Shale; however, in areas like the Richland County in Montana, TOC values may reach 40% (Wiley et al., 2004). The Middle Bakken, a dolomitic shaley siltstone, is the main productive interval. Located above the Bakken shale is the Lodgepole (dense lime), and below is the Three Forks sand.

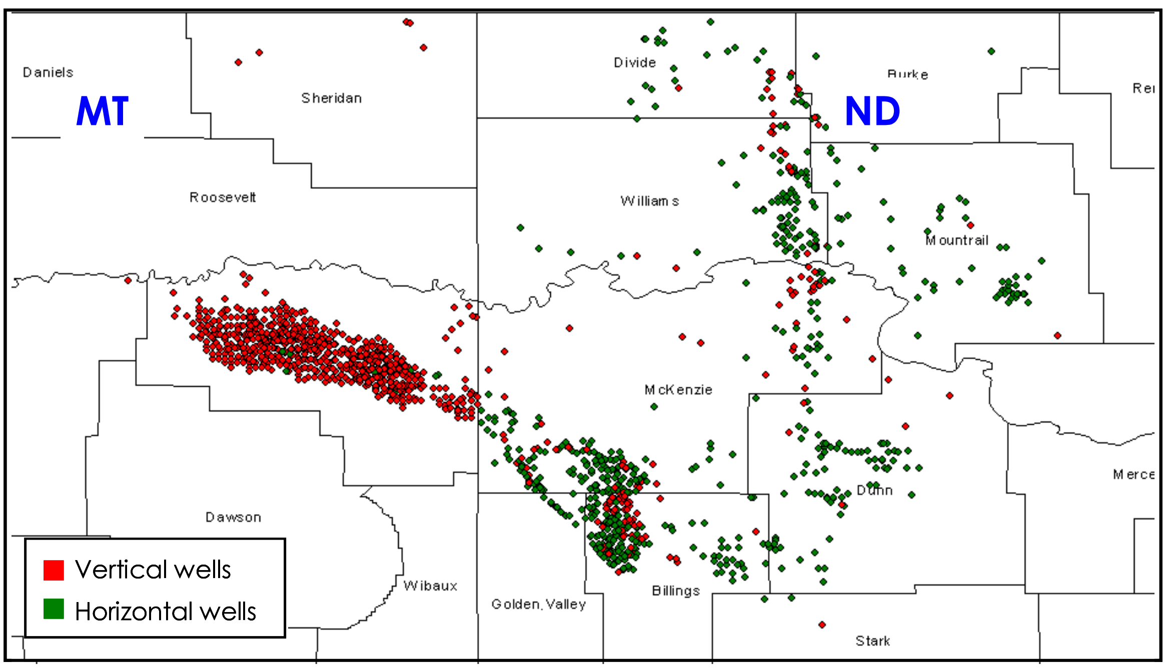


Fig. 5.5—The Bakken Shale in North Dakota (ND) and Montana (MT) has experienced two horizontal campaigns since production started in 1953. According to the HPDI database, by year-end 2007 about 30% of the total oil production came from horizontal completions.

The Middle Bakken member is an oil-wet reservoir with oil saturations ranging from 75 to 90%. The interbedded siltstones and sandstones of the Middle Bakken are found at depths of 9,500 to 11,000 ft and produce sweet oil of 44 °API. The thickness ranges from 40ft to75ft. Porosity ranges from 4 to 10%, and permeabilities will vary depending on the field area from 0.05 md to 0.5 md.

5.1.2.1.1 Production History

Oil production from the Bakken shale started in 1953 and included only production from a few vertical wells. From 1953 to 1987, the production from the shale came from less than 100 vertical wells accumulating almost 6 Million STB of oil and 5.4 Bcf of gas. The production from vertical wells during this period contributed 5.4% of the total oil produced by year-end 2007. The Bakken can be seen as an oil play that increased production after horizontal drilling revitalized the play in the late 1980s.

The first horizontal well in the Bakken was completed in September 1987 by Meridian Oil Inc. in Richland County, North Dakota. At the beginning, horizontal wells on the order of 1,000 long were drilled. These horizontal wells were not stimulated until improvements in technology during the 1990s allowed operators to drill and stimulate longer wells (average of 3,000 to 4,000 ft). The early success of horizontal drilling made possible a second period that is currently developing.

The production history of the Bakken in Montana and North Dakota can be divided into three phases: 1) early development using vertical well production prior to 1987, 2) the first cycle of horizontal well production up to the early 2000s, and 3) recent development through the second cycle of horizontal production, which has had a huge impact credited to improvements in technology in the 1990s (ability to drill longer horizontal and multilateral wells from a single vertical wellbore and improvements in hydraulic fracturing technology). **Table 5.3** shows information from these three phases. The proportion of horizontal wells (including the use of multilateral wells) as a percentage of the total producing wells has increased from zero percent in 1980 to 20% in 1988 and 67% in 1998 according to our database (HPDI, 2007).

More recent values from our database recorded about a 30% decrease in number of horizontal wells; although the values look lower than expected, we can assume that better technologies probably allow drilling longer laterals to reduce the final number of horizontal wellbores. Note that total number of horizontal wells has continued increasing (Table 5.3).

TABLE 5.3—DRILLING ACTIVITY IN THE BAKKEN SHALE			
PHASES	1961-1987	1987-2001	2001-2007
	Vertical, fractured wells. Stable to high prices.	Low to high prices; more drilling activity increased well number by over 100 including horizontals.	Increasing prices, more drilling activity with better technology to stimulate horizontal wells. Improved waterfracs.
Cumulative Oil, MMSTB/period	5.9	26.8	77.5
Horizontal wells' contribution to production		1988: 32%; 1998: 71%; 2007: 30%	

Early development of the Bakken shale using hydraulic fracturing to stimulate vertical wells used propping agents concentrations per treatment. However, the play was not really important until the first horizontal well was completed in 1987. At the beginning, the use of horizontal wells increased the gas production but it was limited by the lack of stimulation treatments until improvements in technology during the 1990s made possible to drill and stimulate longer horizontal and multilateral wells possible.

Only an approximately 6% of total accumulated oil by year-end 2007 was produced during the period of vertical well development from 1961-1987 (Table 5.3). Since 1987, the Bakken has experienced the benefits of horizontal drilling while facing the challenges of stimulating the laterals. During the last four years the Bakken has produced almost 60% of the total oil accumulated since 1961.

Fig. 5.6 shows that the Bakken shale produced from less than 10 wells during almost 20 years. By 1980, after the second oil embargo raised oil prices, Bakken rig activity increased the number of producing well from 12 in 1980 to 87 in 1987, and the oil production grew by a factor of 9. Oil rates from 1980 to 1987 went from 0.11 million STB/year to 1.01 million STB/year. After horizontal drilling began, the Bakken shale experienced its first oil peak of 4.4 million STB/year in 1991, when 230 wells were producing. The 1990s was marked by great decline in production, and by year-end 2000 the oil rate decreased to 0.77 million STB/year; however, production during the 2000s has been revitalized by the second horizontal drilling campaign that increased rates to 21.29 million STB/year in 2006. By 2007, the Bakken shale had produced a total of 110 million STB oil and 118 Bcf gas.

According to the PTTC (2000), the horizontal wells in the Bakken shale have decreased drilling costs by 26%. The cost of drilling a horizontal well is about 1.5 times the cost of drilling a vertical well, but the horizontal will be able to drain an area that would require two vertical wells. Economically the payout of a horizontal well is around 1 to 2 years instead of 3 to 4 years for vertical wells.

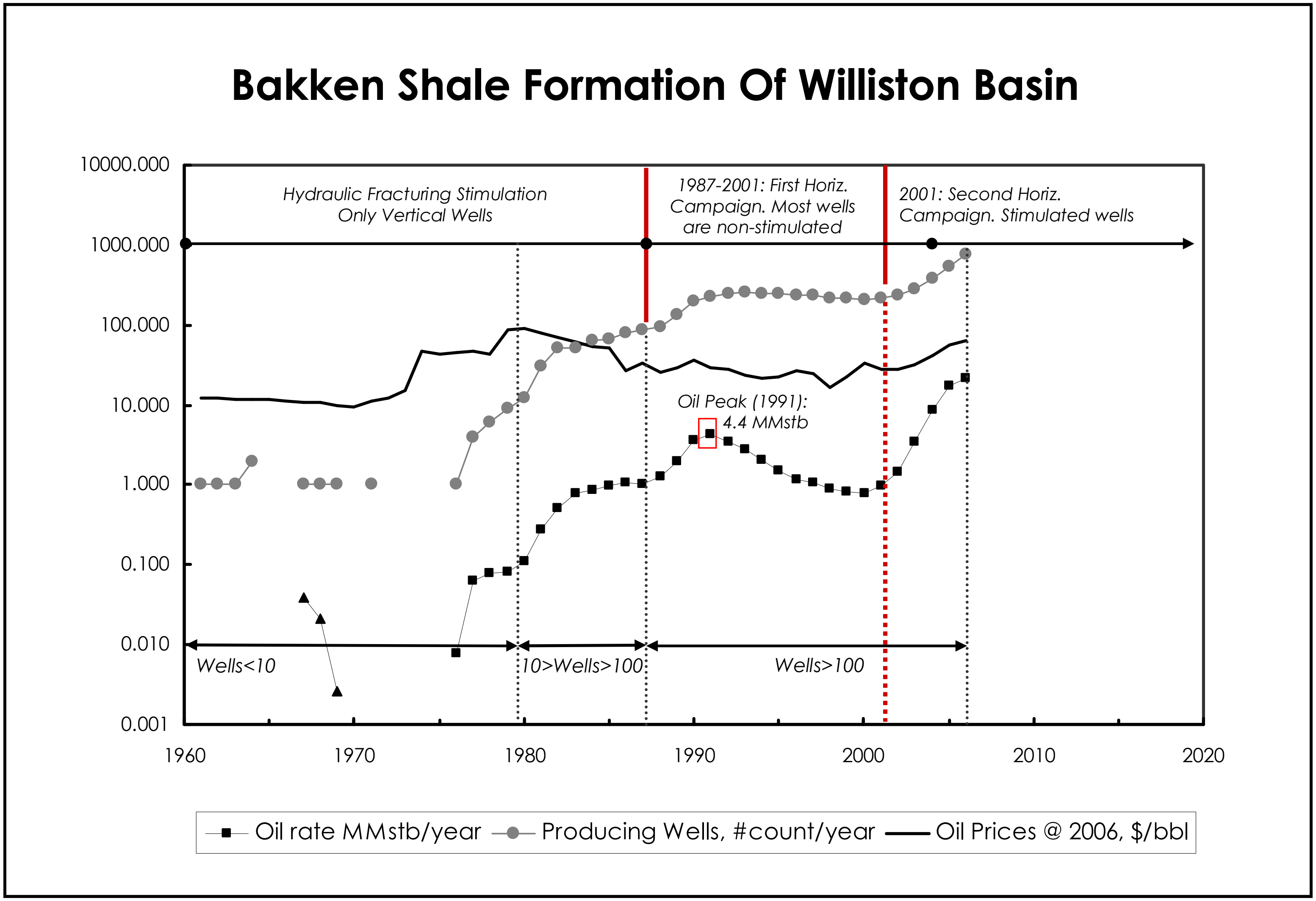


Fig. 5.6—The Bakken Shale formation of Williston basin in North Dakota and Montana has been producing since 1953. The shale has accumulated 95% of 2007 produced oil since the start of horizontal drilling in 1987.

5.1.3 Heavy Oil

Heavy oil is generally accepted to have API gravity ranging from 10 to 20°. At API gravities less than 10°, it is called extra heavy oil and bitumen. It is produced commercially in many areas; more than one-half of the United States EOR (Enhanced Oil Recovery) production is heavy oil. The predominant production technique is steamflooding because heavy oil's high viscosity is very effectively reduced by heating, and is produced mainly in Venezuela and Canada (Stosur, 1999).

5.1.3.1 Kern River Formation

The giant Kern River field in California produces heavy oil of 13°API from the Miocene to Pleistocene Age Kern River formation **(Fig. 5.7)**.

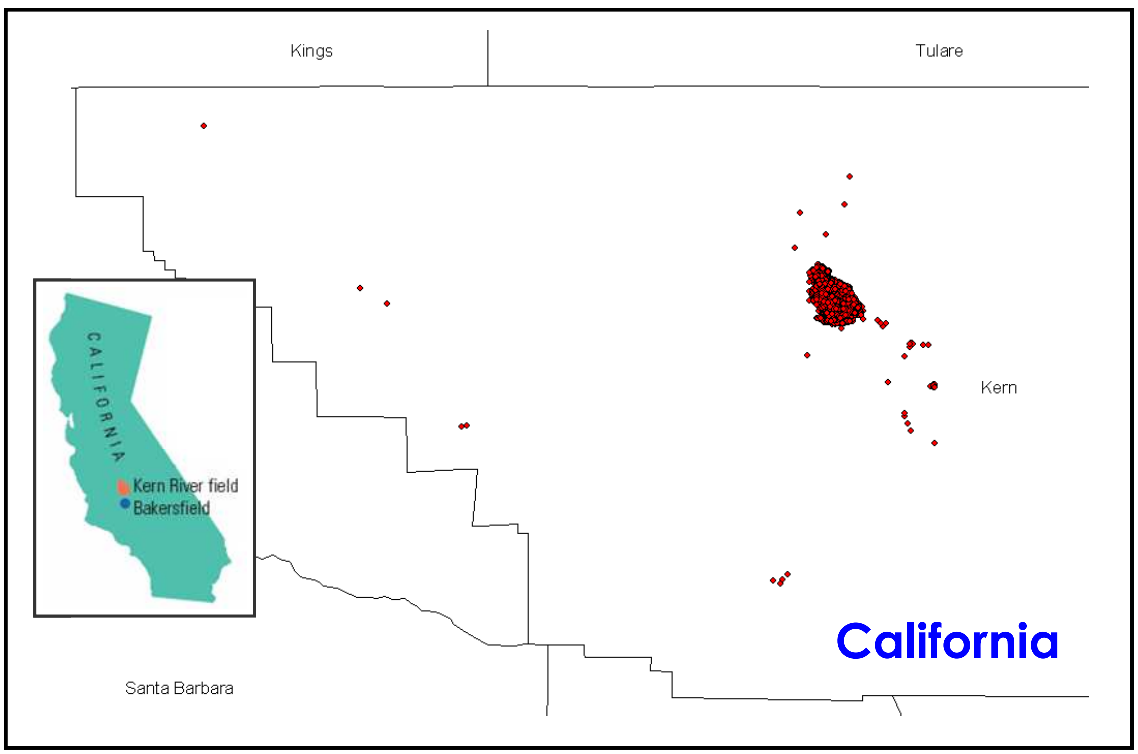


Fig. 5.7—The Kern River formation from California produces from more than 15,000 wells.

The sands of the Kern River formation in the San Joaquin basin have an average porosity of 31% and permeability ranging from 1 to 10 darcies. Cold-production techniques yielded low primary recovery until the introduction of steam injection in the 1960s. Currently, steamflooding is the dominant method of stimulation used to produce Kern River heavy oils. Operating ratios of injected steam to enhanced oil recovery of 2.47 bbl steam/bbl oil –the most critical technical/economical variable– are considered efficient (Stevens et al. 1999). Since 1986, the production decline has been controlled by significant reduction in operating costs, continued technological advances, and notably improved reservoir characterization.

The Kern River was not included in the final analysis in this study since this play has mainly produced by a single technique (steamflooding technique). We proposed additional work to identify another heavy oil example in the world in order to compare different production scenarios under different technologies through the life of the reservoirs.

5.2 Natural Gas Producing Formations

The Cotton Valley Group, the Mesaverde Group, the Antrim Shale, the Barnett Shale and the Lewis Shale are the natural gas producing formations in this study. According to the RTT, the selected natural gas producing formations can be classified as tight gas sand (TGS) reservoirs and gas shale (GS) reservoirs. **Table 5.4** provides details about the formations we have studied and the cumulative gas and oil equivalent volumes at year-end of 2006.

TABLE 5.4—SELECTED NATURAL GAS FORMATIONS					
UCR	Formation	Gp*, Tcf	Oil Equiv.*, million BOE	Basin	States
Tight Gas Sands (TGS)	Cotton Valley (1962♦)	4.36	759	Arkla, East Texas	TX, LA
	Mesaverde (1951♦)	12.25	2,091	San Juan	CO, NM
Gas Shales (GS)	Antrim Shale (1982♦)	2.27	379	Michigan	MI
	Barnett Shale (1982♦)	2.54	431	Fort Worth	MT, ND, SD
	Lewis Shale (1957♦)	0.87	159	San Juan	NM, CO

* Cumulative Gas (Gp) and Oil Equivalent values at Dec. 2006 from HPDI database.
♦ Production data available from this date.

Note that the TGS of the Mesaverde Group and the Cotton Valley Group have produced almost 17 Tcf of natural gas while the GS of the Antrim, Barnett, and Lewis formations have produced around 6 Tcf of natural gas by year-end 2006. In general, commercial production from most of the GS started later in time compared to production coming from the TGS formations.

5.2.1 Tight Gas Sands (TGS)

Tight gas sands are formations with an expected average permeability of 0.1 md or less that will not be economically viable to produce without the aid of massive stimulation treatments. The low permeability prevents a tight gas reservoir from draining much of its gas over its economic lifetime. As a result, producing tight gas reservoirs economically requires commingling as many zones as possible and fracture stimulating every zone, creating long fractures in each zone.

The low permeability is primarily attributed to the fine-grained nature of the sediments and diagenesis caused by compaction, and infilling of pore spaces by carbonate or silicate cements precipitated from water within the reservoir. Gas production rates from TGS reservoirs are low because of the poor permeability; however, the reservoirs are generally known for containing significant volumes of natural gas (Centre for Energy, 2008). Wells completed in TGS reservoirs experience relatively high decline rates during initial production, and then stabilize at low decline rates. Most hydraulically fractured tight gas wells can be matched using a hyperbolic decline curve model.

According to the Centre for Energy (2008), the production of gas from tight gas sands are found everywhere there is production from conventional reservoirs, in the deeper portions of hydrocarbon-bearing basins. Currently, natural gas is being produced from tight sands in Canada, the United States, Australia, and Argentina.

Stevens et al., (1998) recognize the Appalachian basin as the birthplace for tight gas development in the United States. Today tight gas remains the principal target in this mature region. Haines et al., (2006) lists the Cotton Valley of East Texas; the Mersaverde in New Mexico's San Juan Basin; the Canyon Sands in the Permian basin of West Texas; the Wasatch in Utah's Uinta Basin; the South Texas Wilcox/Lobo play, and the Lance, Dakota and Frontier formations in Wyoming's Green River basin as the major tight gas plays in the United States.

5.2.1.1 The Tight Sands of Cotton Valley Group

In 1980, the Federal Energy Regulatory Commission (FERC) officially classified low-permeability Cotton Valley sandstones of the East Texas and North Louisiana basins as tight gas sands, qualifying them for additional price incentives or tax credits **(Fig. 5.8)**. In combination with development of improved stimulation technology during the 1990s and price deregulation through the Natural Gas Policy Act (NGPA) of 1978, the drilling for gas in low-permeability Cotton Valley sandstones has increased dramatically (Bartberger et al., 2002).

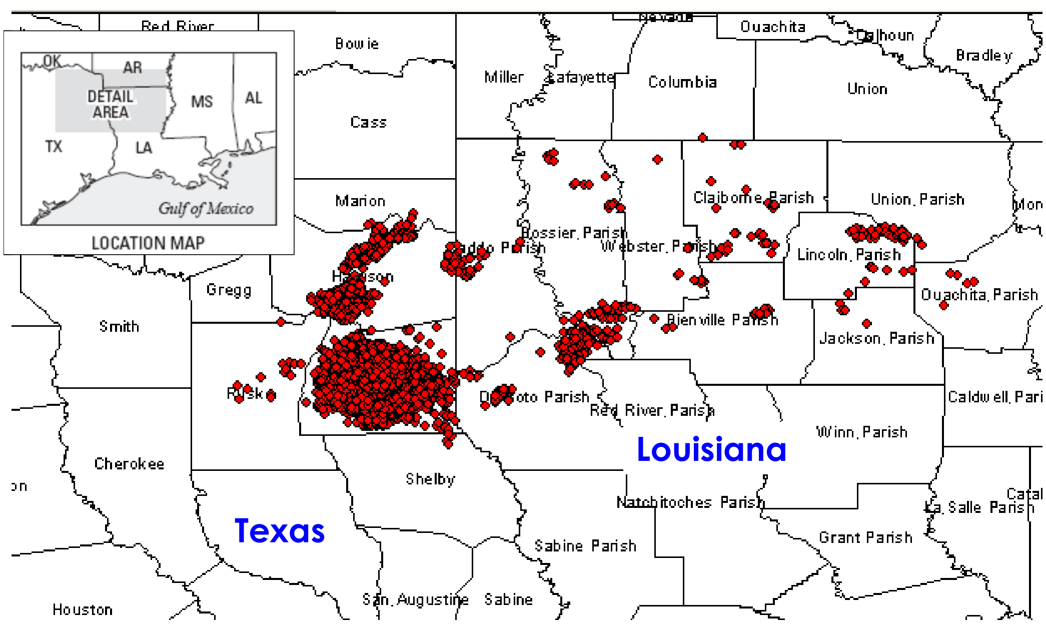


Fig. 5.8—The tight sands of the Cotton Valley Group of the East Texas and North Louisiana basins (HPDI, 2007).

The tight sands of the Cotton Valley, also referred to as massive sandstones to the south and extending westward across the Sabine uplift into eastern Texas, exhibit porosities from 6 to 10%, and average permeabilities less than 0.1 md. Cotton Valley sands occur at depths from about 8,400 to 10,500 ft or more. Reservoir temperature in these sands ranges from 225 to 275°F. Depending upon the area, Upper Cotton Valley deposits or Lower Cotton Valley or a combination may be deposited on top of the Bossier Shale, which serves as the sealing member. The Cotton Valley Sandstone is a consolidated, fine-grained sandstone with well-sorted quartz particles and varying amounts of feldspars (Bartberger et al., 2002).

Hydraulic fracturing has helped to increase the productivity of the wells in the Cotton Valley sands. The USGS (Bartberger et al., 2002) reported the average flow rate prior to stimulation is usually 50 Mcf/day with post-stimulation flow rates generally in the range of 500 to 2,500 Mcf/day; however, rates as high as 10,000 Mcf/day and 11,700 Mcf/day have been reported from Bethany field and Carthage field, respectively. The best reservoir potential has been identified from the Taylor sandstone member in the lower part of the Cotton Valley interval by Wescott (Bartberger et al., 2002). Tindall et al. in 1981 reported that Taylor sandstones in the Oak Hill field supply more than the 80% of the gas production while the sandstones in the middle and upper Cotton Valley section contribute some gas but most of the water production (Bartberger et al., 2002). Most of the drilling for tight Cotton Valley sandstones has occurred in northeastern Texas.

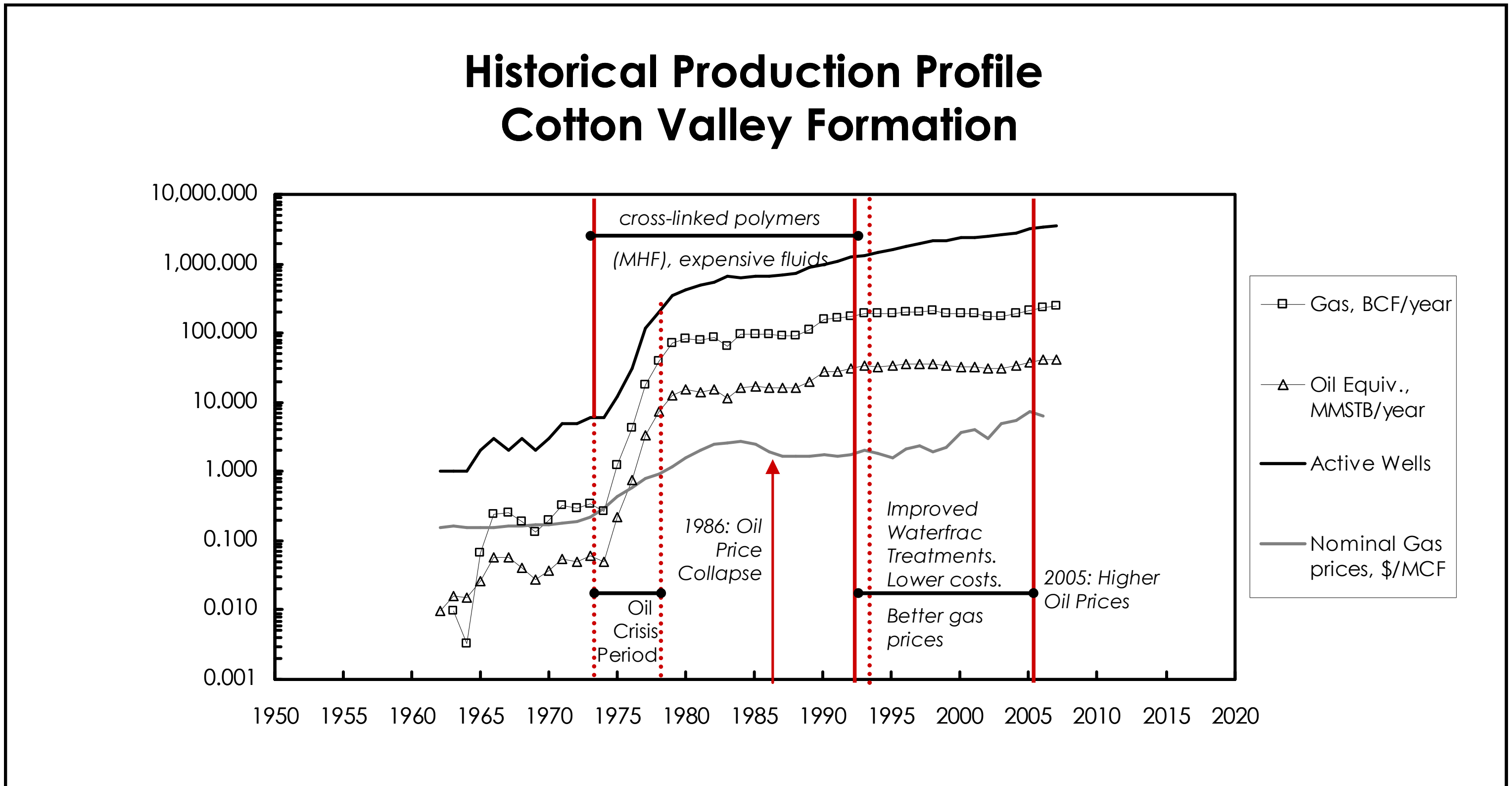
5.2.1.1.1 Production History

The development of the Cotton Valley has been encouraged because of improvements in hydraulic fracturing technology. The first Cotton Valley wells in east Texas were drilled in the late 1950s. Jennings et al. in 2006 reported that hydraulic fracturing stimulations began in the 1960s using linear water-based fluids gelled with guar gum; however, only marginal success was achieved since the fracturing treatments faced challenges such as well depths, formation temperatures, and fracture closure pressures difficult to overcome at that time (Bartberger et al., 2002). The average gas rates were less than 500 Mcf/day and the low gas prices made production not commercial (Fig. 5.9).

During the 1970s, wells in the Cotton Valley sandstones became commercial because of technical advances in hydraulic fracturing techniques and significantly higher gas prices during the 1970s. In 1972, Texaco successfully increased the rate of production from one well in Cotton Valley sandstones in the Bethany field on the Sabine uplift in eastern Texas, from 500 Mcf/day to a sustained rate of 2,500 Mcf/day through hydraulic fracturing (Bartberger et al., 2002). The high gas prices reached during the period of 1973-1978 caused an increase in rig activity and therefore in gas production from plays such as the Cotton Valley. Gas production from Cotton Valley sandstones, from the Carthage field in eastern Texas, increased from 2.2 Bcf in 1976 to 70.9 Bcf in 1980 (Bartberger et al., 2002). The production from the entire Cotton Valley tight sands during the same period increased by 21-fold with expensive massive hydraulic fracturing (MHF) and cross-linked gelled treatments (Fig. 5.9).

In 1980, the Federal Energy Regulatory Commission (FERC) officially classified low-permeability Cotton Valley sandstones as tight gas sands, qualifying them for additional price incentives. In the early 1990s, the use of limited amounts of propping agents in the fracturing fluid offered lower treatment costs, less fracture damage, and the possibility to increase productivity. Lower treatment costs using water and friction reducers, high injection rates, and minimal amounts of 40/70 sand as proppant became known as waterfracs. Lower-cost waterfrac stimulations and gas price deregulation through the Natural Gas Policy Act (NGPA) of 1978 supported the intense drilling activity in the low-permeability Cotton Valley sandstones (Bartberger et al., 2002).

Data from 1962 to 2007 shows the cumulative gas and condensate from the tight gas sands of the Cotton Valley **(Table 5.5)**. Note that more than the 80% of the oil and gas produced from the Cotton Valley has been produced from the Carthage field, the largest field in the area. The TGS of the Cotton Valley group have produced 4.5 Tcf of gas and 34 million STB of condensate at year-end 2007.



1960s: Gas prices were very low and gas production from low-permeability sandstones to the south in Louisiana and to the west in northwestern Louisiana and eastern Texas flowed gas at rates less than 1,000 MCFD was considered not commercial.

1970s: Gas prices increased after the oil crisis events. Advances in stimulation techniques such as massive hydraulic fracturing (MHF) helped to develop the play. At Carthage field in eastern Texas production increased from 2.2 BCF of gas in 1976 to 70.9 BCF of gas in 1980.

1980s: Officially classified as low-permeability reservoir, the Cotton Valley sandstones qualified for additional price incentives. For example at Carthage field, production increased from 2.2 BCF of gas in 1976 to 70.9 BCF of gas in 1980.

1990s: Operators went back to water fracture stimulation treatments (waterfrac or slickwater). Similar results in gas production made operators prefer low cost waterfrac treatments over expensive cross-linked gelled treatments (Jennings, A.R., Westerman, C.W., Tadlock, D.W., Westerman, R. and Anderson, M., 2005). Full Wellhead Decontrol in 1993 resulted in better gas prices.

Fig. 5.9—Tight sands of Cotton Valley had benefited from high prices during the 1970s oil crisis. Production rates in 1980 grew dramatically by 21 times compared to rates at the end of year 1976.

TABLE 5.5—CUMULATIVE PRODUCTION FROM THE TIGHT GAS SANDS OF COTTON VALLEY GROUP (data from HPDI, December 2007).

	Cum. Gas, Tcf	Cum. Oil, MMSTB	Cum. Water, MMSTB	Cum. Oil Equiv., MMBOE	Active wells
Carthage field	3.8	27	345	658	2,835
All fields	4.5	34	399	787	3,599

5.2.1.2 Mesaverde Group in the San Juan Basin

The naturally fractured Mesaverde formation of San Juan basin, located in northern New Mexico and southern Colorado, as shown in **Fig. 5.10**, was the first western US basin producing gas from tight sand formations (Stevens et al., 1998).

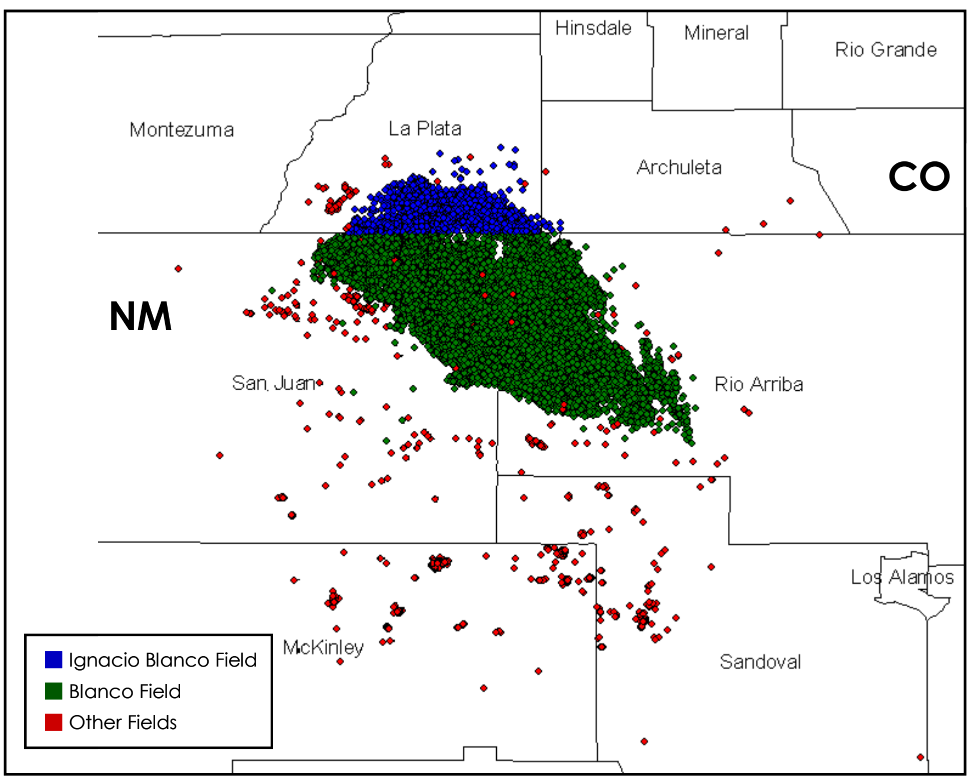


Fig. 5.10—The tight sands of Mesaverde Group in the San Juan basin produces mostly from the Blanco field in New Mexico and the Ignacio Blanco field in Colorado (HPDI, 2007).

The Mesaverde Group reservoirs were the most important producing reservoirs in the San Juan basin region. Economic gas production from Mesaverde is dependent on the presence of natural fractures that enhance the overall permeability from 0.01 to 1.4 md. Matrix permeability in the formation is between 0.001 and 0.1 md. Natural fractures are present in most of the gas reservoirs, but it is only when natural fractures form an interconnected network that their effect on fluid flow becomes important. The production from the tight sands of the Mesaverde Group represents an important source to increase the ultimate recovery from the basin since the prolific Fruitland coal started to decline in the late 1990s.

The Mesaverde Group was deposited in the Upper Cretaceous period and is present throughout many of the Rocky Mountain basins. The Mesaverde Group consists of three major tight formations, the Cliffhouse, Menefee, and Point Lookout sandstones from top to bottom; and it is bounded by the overlying Lewis Shale and the underlying Mancos Shale. The Mesaverde is typically 600 to 800 ft in gross thickness. The mid-point depth of the Mesaverde formation ranges from 5,000 to 5,500 ft.

The principal gas reservoirs in the Mesaverde interval are the Point Lookout and Cliff House marine sandstones. The Point Lookout is the most prolific interval. Smaller amounts of dry, nonassociated gas are produced from thin, lenticular channel sandstone reservoirs and thin coal beds of the Menefee. In the Mesaverde, the Blanco Mesaverde and Ignacio Blanco fields account for almost half of the total nonassociated gas and condensate production from the San Juan Basin. Within these two fields porosity averages about 10% and permeability less than 2 md; total pay thickness is 20 to 200 ft. Smaller Mesaverde fields have porosities ranging from 14 to 28% and permeabilities from 2 to 400 md, with 6 to 25 ft of pay thickness.

5.2.1.2.1 Production History

Although the Mesaverde in the San Juan basin was discovered in 1927, production data for this study was only available since 1951 (HPDI, 2007). Having accumulated a total of 12.5 Tcf gas and 49.3 million STB of or condensate by 2007, the Mesaverde Group is the largest producer of natural gas from the selected cases for this study. The Blanco Mesaverde and Ignacio Blanco fields are the main producers from the Mesaverde.

The Blanco Mesaverde reservoir was discovered in 1927, growing in response to pipeline capacity, decreased well spacing, and price increases. Extensive development took place on 320-acre spacing during the 1950s the early drilling helped to define the areas of high initial gas flow rate potential and the areas with thick net pay. A 160-acre infill development program was approved in 1974 for the Blanco Mesaverde reservoir and in 1979 for the Ignacio Blanco Mesaverde reservoir. Prior to January 1975, approximately 2,000 wells were producing on the 320-acre spacing. By 1997, pilot tests were initiated to determine the feasibility of reducing spacing to 80 acres. A simulation study revealed the significance of permeability anisotropy to the location of infill wells (Engler, T.W., and Brister, B., 2004).

Mesaverde development has been the result of improvements in hydraulic fracturing treatments and reservoir characterization to improve infill drilling strategies. **Fig. 5.11** shows three different periods of well activity since 1951. The first two (1951-1973 and 1974-1991) are characterized by a sharp positive slope followed by stabilization while the third period is still developing. During the 1950s, the number of wells increased from 99 wells in 1951 to 1,785 wells in 1959. The 1960s and 1970s showed an increased in well number less than 10%, from 2,182 wells in 1964 to 2,345 wells in 1974. The second period started in 1974. The mid-late 1970s marked by the oil and gas price increases from 1973 to 1978 led to an increase in the number of wells by almost 80%, from 2,345 wells in 1974 to 4,157 wells in 1982, followed by a stable period of growth in wells number around 5%, from 4,157 wells in 1982 to 4,348 wells in 1992. The oil and gas price increases the use of MHF techniques both led to more drilling activity in the 1970s.

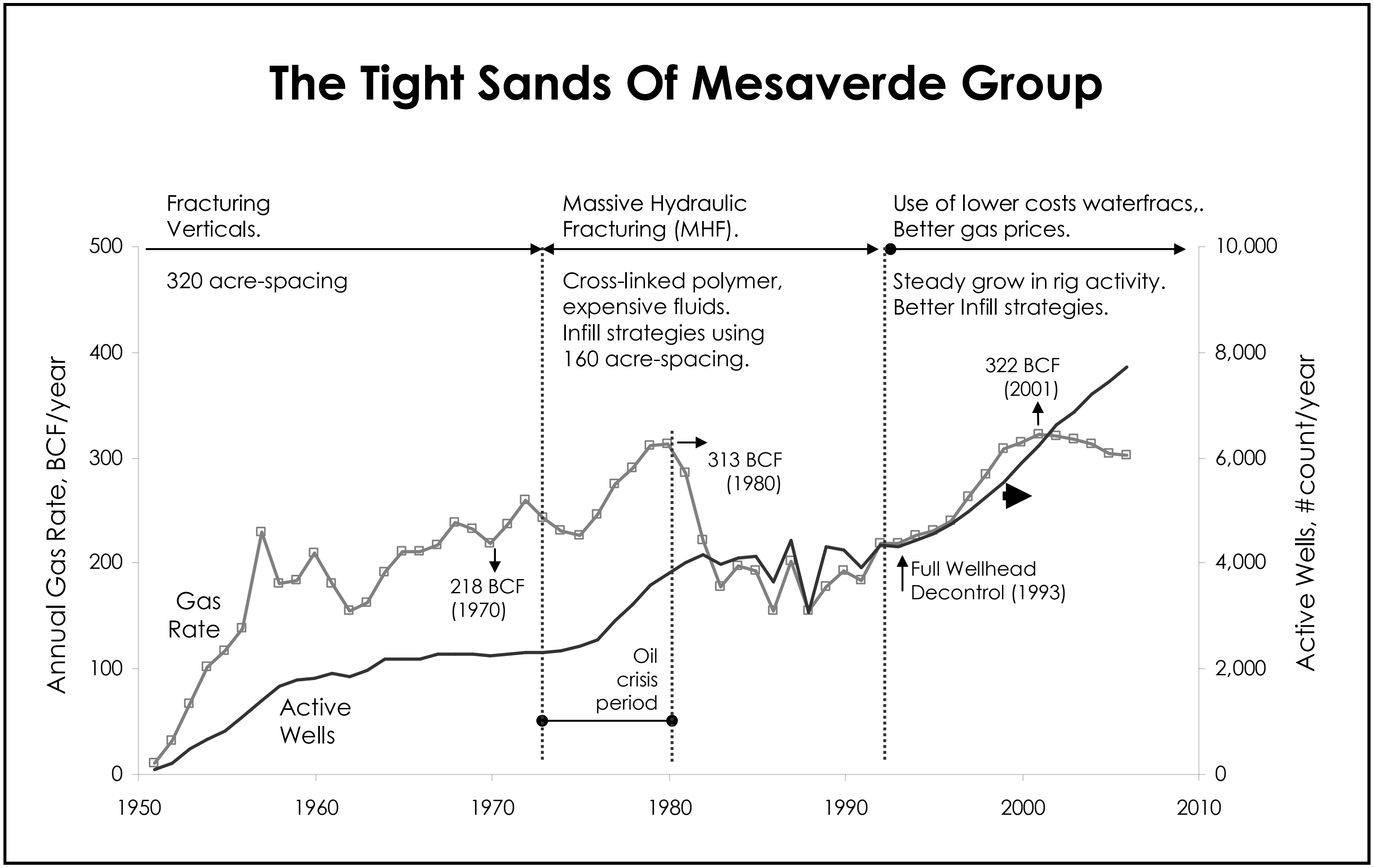


Fig. 5.11—The tight sands of the Mesaverde Group of San Juan basin are very prolific. Gas production has peaked three times since production started in 1951. Declining production suggests a new form of technology or better characterization model to increase wells productivity and final recovery.

The Mesaverde formation has experienced a steady growth in well activity after gas price deregulation in 1993. The most recent period has been characterized by stable growth and the use of better hydraulic fracturing technologies. From1992 to 2007, the play has grown almost 80% from 4,348 wells in 1992 to 7,768 wells in 2007.

Cumulative gas production to date from the Mesaverde formation is greater than 12 Tcf. At year-end of 2007 more than 7,700 completions yielded 295 Bcf/year. So far production rates in the Mesaverde have been increased by adding more wells and infill drilling on tighter well spacing.

During the 1950s the gas rate increased 21 times from 11 Bcf in 1951 to 229 Bcf in 1957, when the play reached its first peak. The following two decades, the 1960s and 1970s, are characterized by two positive slopes, the first from 1962 to 1972, when production grew almost 72%; and the second from 1975 to 1980, when production went from 226 Bcf to 313 Bcf, an increase of almost 40%. Mesaverde reached its second peak in 1980 when gas rates reached 313 Bcf/year. In 2001, gas production reached its peak of 322 Bcf/year, increasing the 1992 rate by 47%. Since 2001 the play has been declining. Ault et al., (1997) have reported that the Mesaverde in the San Juan basin is close to its maximum production with an estimated ultimate recovery (EUR) of 13 Tcf of natural gas.

5.2.2 Gas Shales

Shale is a very fine grain sedimentary rock that has low permeability. Unlike conventional gas sands or carbonates, shale can be both the source rock and the reservoir rock in a gas reservoir. Typically, the methane in organic shales was created in the rock itself. Gas from shales can be biogenic or thermogenic in origin. Thermogenic gas forms when organic matter left in the rock breaks down under rising temperature; the generated gas is then adsorbed onto the organic material, expelled through leaks in the shale, or captured within pores of the shale. In some shallow shale formation, an influx of water and the presence of bacteria will cause the generation of biogenic gas.

The presence of natural fractures in the shale formation may allow the gas to migrate in the shale and eventually be produced in a wellbore. If large fracture swarms are encountered in a shale gas reservoir, the recovery of gas can be enough to make the project economically possible. Usually, however, the shale must be hydraulically fracture treated to both create new fractures in the rock and link up the existing natural fractures to the hydraulic fracture and eventually the well bore. The only place for the gas to flow is either through natural fractures in the rock or through fractures created by injecting high rates of fluids and proppant into the formation under high pressure. In 2000, 28,000 shale gas wells were producing in the United States, with a combined production of more than 700 Bcf/year. Given the recent activity in Texas, Oklahoma and Arkansas, there are many more gas shale wells producing today (2008).

5.2.2.1 Antrim Shale Formation

The organic-rich marine shale of Devonian age in the Michigan basin known as the Antrim Shale formation is located in the eastern United States **(Fig. 5.12)**.

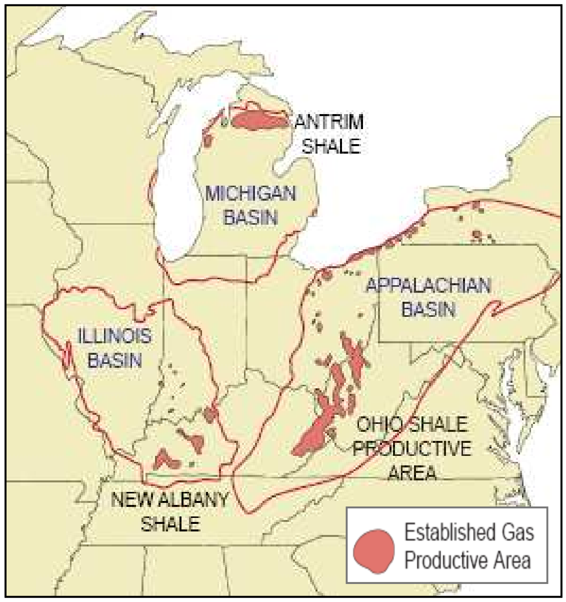


Fig. 5.12—Antrim Shale of the Michigan basin in the eastern United States was the most active natural gas producer during the 1990s (after Hill and Nelson, 2000).

The Devonian Antrim Shale has been commercially productive since 1982. The Antrim Shale was the most active natural gas play in the country during the 1990s. Antrim is a water-saturated naturally fractured shale that needs to be dewatered to produce natural gas. The Antrim, as a common source and reservoir rock as any other productive shales, produces natural gas of biogenic or microbial origin as the result of metabolic activity by methanogenic bacteria. Strong evidence of bacterial methanogenesis has been identified by deuterium isotopic compositions (δD) of methane and coproduced formation waters (Curtis, 2002). The origin of this biogenic gas is also linked to the Antrim's shallow productive depths between 400 and 2,200 ft. A typical production profile in the Antrim will show low gas flow rates at the beginning of production, follow by a peak and a slow decline. The fracture system in the Antrim is a key parameter to produce gas; however, hydraulic fracturing stimulations are needed to keep the fractures open and to connect the matrix to the wellbore for the longest time possible.

The Antrim has been divided into two main zones, the Upper and the Lower members. Typically, the wells are completed in the Lower Antrim, and production comes from the two black-shale intervals, the Lachine and the Norwood. The Lachine layer is thicker (80 to 120 ft) than the Norwood (10 to 30 ft) and both are separated by the gray Paxton shale (20 to 50 ft). The total organic carbon (TOC) content in Lachine and Norwood ranges from 0.5 to 24% by weight. The remaining Paxton unit, a mixture of lime, mudstone, and gray shale lithologies, contains values of TOC between 0.3 to 8% by weight.

5.2.2.1.1 Production History

The Antrim Shale has produced gas since the 1940s; however, the activity increased sharply in 1982 **(Fig. 5.13)**. Hydraulic fracturing technology and better understanding of the production mechanisms, along with Federal-tax credits, have helped to develop this unconventional reservoir. During the 1990s, the Antrim was the most active gas shale play in the US. By the end of year 1992, more than 1,200 wells had been drilled in this play; later in 1998, 454 wells were drilled in the shale; and the following year of 1999, the 75% of the total wells drilled in the Michigan basin targeted the Antrim play. According to Hill and Nelson (2000) the 55% of the total annual natural gas production from shales by the end of 1996 came from the Antrim shale in Michigan.

Between 1982 and 2006, the Antrim formation has produced a total of 2.27 Tcf of gas. The 9,184 wells producing at the end of 2006 are the result of intensive drilling campaigns in the play to stop the production decline. Production data shows that although drilling has continued, gas production continues declining since it peaked in 1998 (Fig. 5.13).

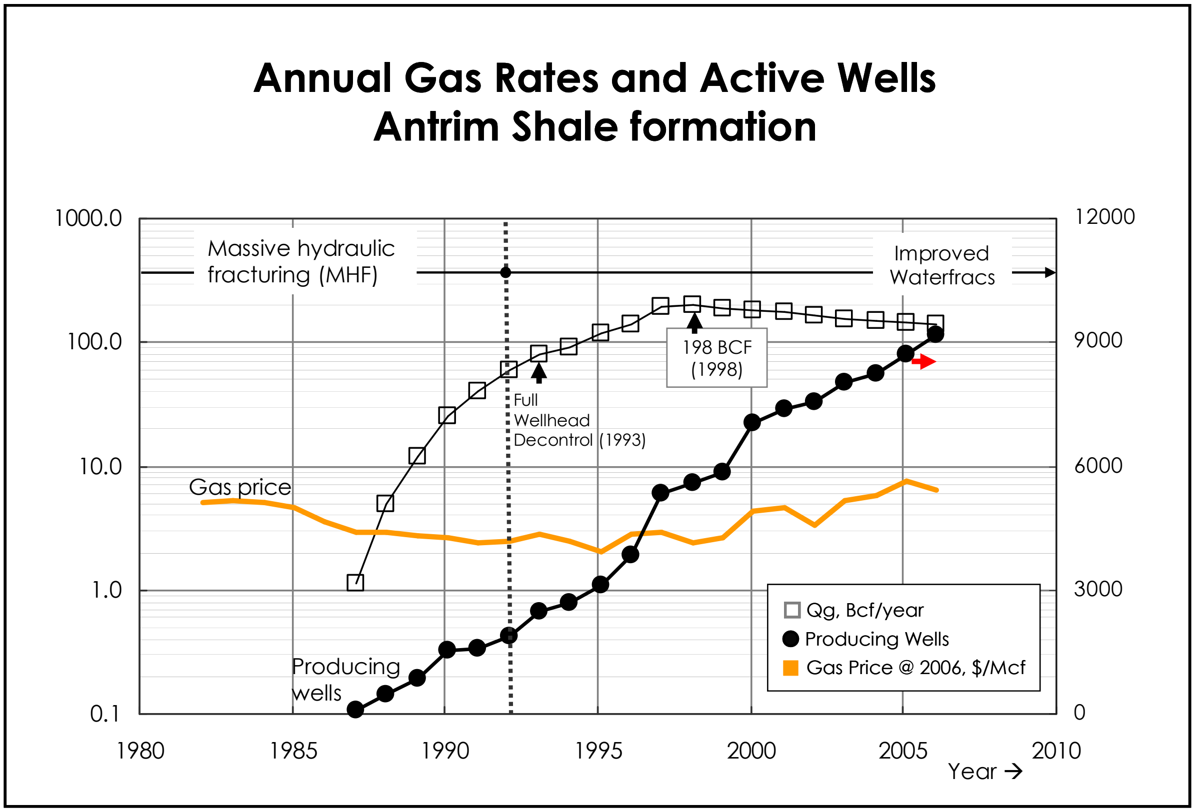


Fig. 5.13—Production in the Antrim Shale is declining since 1998 although the play has experienced a great increase in number of producing wells.

5.2.2.2 Barnett Shale Formation

The Barnett Shale formation, located in north central Texas, occurs in a 38-county area of the Fort Worth Basin. The main producing areas are north and south of Fort Worth, Texas as shown in **Fig. 5.14**. Currently, the Barnett is the most active drilling play in the United States. The first well was completed in 1981; however, the play has grown dramatically in recent years with more than 2,000 wells drilled from 2000 to 2005. The Barnett Shale in the Fort Worth basin has been the most active gas field in the US since 2000.

Important increases in gas production have been fostered by higher natural gas prices, better understanding of gas shale systems, and the use of technologies such as horizontal drilling and better stimulation technology. Hydraulic fracturing in horizontal wells results in production increases of two to three times that in vertical wells for the first 180 days (NPC, 2007d).

Wells usually start off with a rapid decline of about 50% in the first year, stabilize, and then follow a slow decline to the end of their lives.

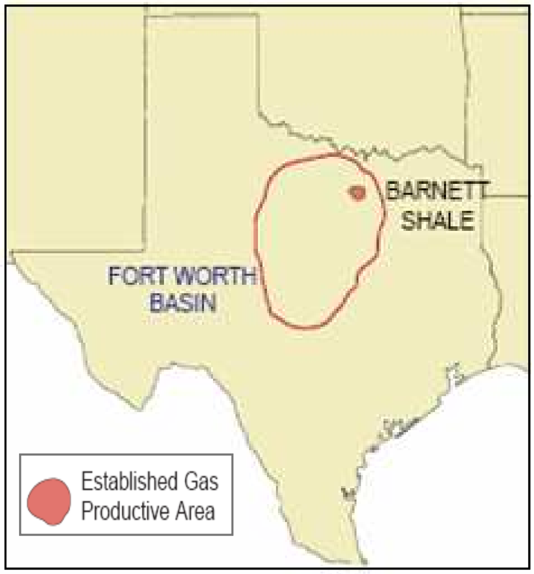


Fig. 5.14—The Barnett Shale of the Fort Worth basin is today the most prolific gas shale play in United States (after Hill and Nelson, 2000).

The Barnett shale is an organic-rich, petroliferous black shale of middle-late Mississippian age that serves as source, seal, and reservoir to the natural gas accumulations in the Fort Worth basin of north-central Texas. The Barnett lies above the Ordovician Age Viola Limestone/Ellenburger group and is overlain by the Pennsylvanian Age Marble Falls Limestone, both of which when present enable induced fractures to be confined during well completion and recovery method implementations in the Barnett.

The Shale is divided into the Upper and Lower Barnett intervals, which are respectively 150 ft and 300 ft thick. The two shale members are separated by the Forestburg Limestone that is about 10 to 20 ft thick. The Lower Barnett is the primary productive interval. Gas of thermogenic origin is produced from the Barnett from greater depths compared to other gas-shale plays in the US. The productive interval thickness in Barnett ranges from 100 to 750 ft at an average depth of 6,500 to 8,500 ft. The shale is characterized by very low permeability in the micro to nanodarcy range (0.0007 to 0.005mD) and low porosity in the 4 to 6% range (Fisher et al., 2004).

The Newark East Barnett Shale Field located within the Fort Worth Basin of North Texas has now developed into the largest gas field within the state of Texas. In December 2007, the field was producing more than 3 Bcf/day of gas, with an annual production growth substantially higher than 20%. Technically recoverable gas resource estimates for the Barnett Shale range from 3.4 Tcf to 10 Tcf (Pollastro et al., 2003). Wells in the Newark East field, the main producing play in the area, typically produce from depths of 7,500 ft at rates ranging from 0.5 to more than 4 MMcf/day with estimated ultimate recoveries per well range from 0.75 to as high as 7.0 Bcf (Montgomery et al., 2005).

5.2.2.2.1 Production History

We have identified three periods of development in the Barnett Shale. The recent period from 2000 to 2006 has been the most prolific and it has accumulated 2.5 Tcf of gas.

The first Barnett Shale well, the C.W. Slay#1, was completed by Mitchell Energy & Development Company (today Devon Energy) in 1981 in south eastern Wise County in Texas (Hill and Nelson, 2000). Initial production came from the Newark East field in Wise and Denton Counties, Texas. In 1997, AFE Oil and Gas Consultants added new areas in the south of the Newark East field, with discoveries in Dallas and Tarrant Counties in Texas.

Fig. 5.15 shows the current distribution of vertical, horizontal, and deviated wells producing from Barnett shale (HPDI, 2007). Note the Wise-Denton County area which is the core area of production in the Barnett. Gas production from the Barnett Shale is mainly centered in the Newark East field in the Wise-Denton County area which produces more than the 99% of the total gas in the Barnett Shale formation.

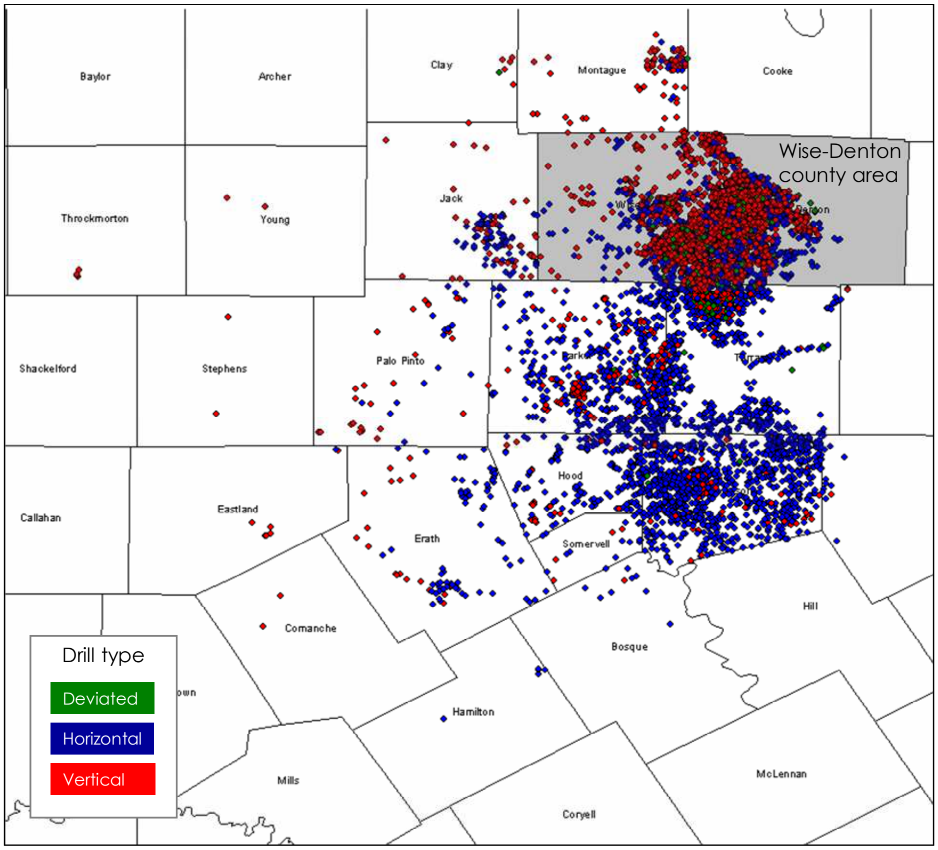


Fig. 5.15—The Barnett shale in Texas has mainly grown to the south of the core area of Wise and Denton Counties. The distribution by type of well shows intense horizontal drilling activity (HPDI, 2007).

The Newark East gas field, located in the Fort Worth Basin, Texas, is defined by a thermogenic gas producer from low-porosity and low-permeability Barnett Shale. Annual production from the Newark East field grew from less than 1 Bcf from 19 wells in 1985 to 20 Bcf from 244 wells in 1995. After the expansion of the play in 1997, production grew significantly. By 2005, annual production reached 498 Bcf from 4,564 wells (HPDI, 2007).

The periods of development in Barnett shale are characterized by the evolution of technology and high gas prices. Technology and prices have driven production from the Barnett Shale **(Fig. 5.16)**. Well stimulation techniques in the Barnett shale have also evolved throughout the history of the play.

In the early 1980s, moderate fracture stimulations with typical values of 300,000 gals of fluid and 300,000 lbs of proppant (sand) were used to stimulate vertical wells in the Barnett shale. MHF treatments then began to be implemented and this later went on to evolve into water fracturing or light sand fracturing (LSF) treatments. Through early 1997, LSF was applied to tight sands for Cotton Valley sand the application was also tried in the Barnett shale where MHF completion costs were very high. In 1998, the Mitchell Energy & Development Company found that using a new stimulation technique that employed water as the fracturing fluid and required significantly less proppant reduced the stimulation treatment cost by 60% (Hill and Nelson, 2000). The most recently introduced technique has been the use of Ultra Light Weight proppant (ULW). Integrated fracture mapping technologies have been also applied to optimize stimulation. These fracture diagnostic technologies are based on the use of tiltmeters (surface and downhole) as well as microseismic mapping to evaluate fracture placement effectiveness and orientation.

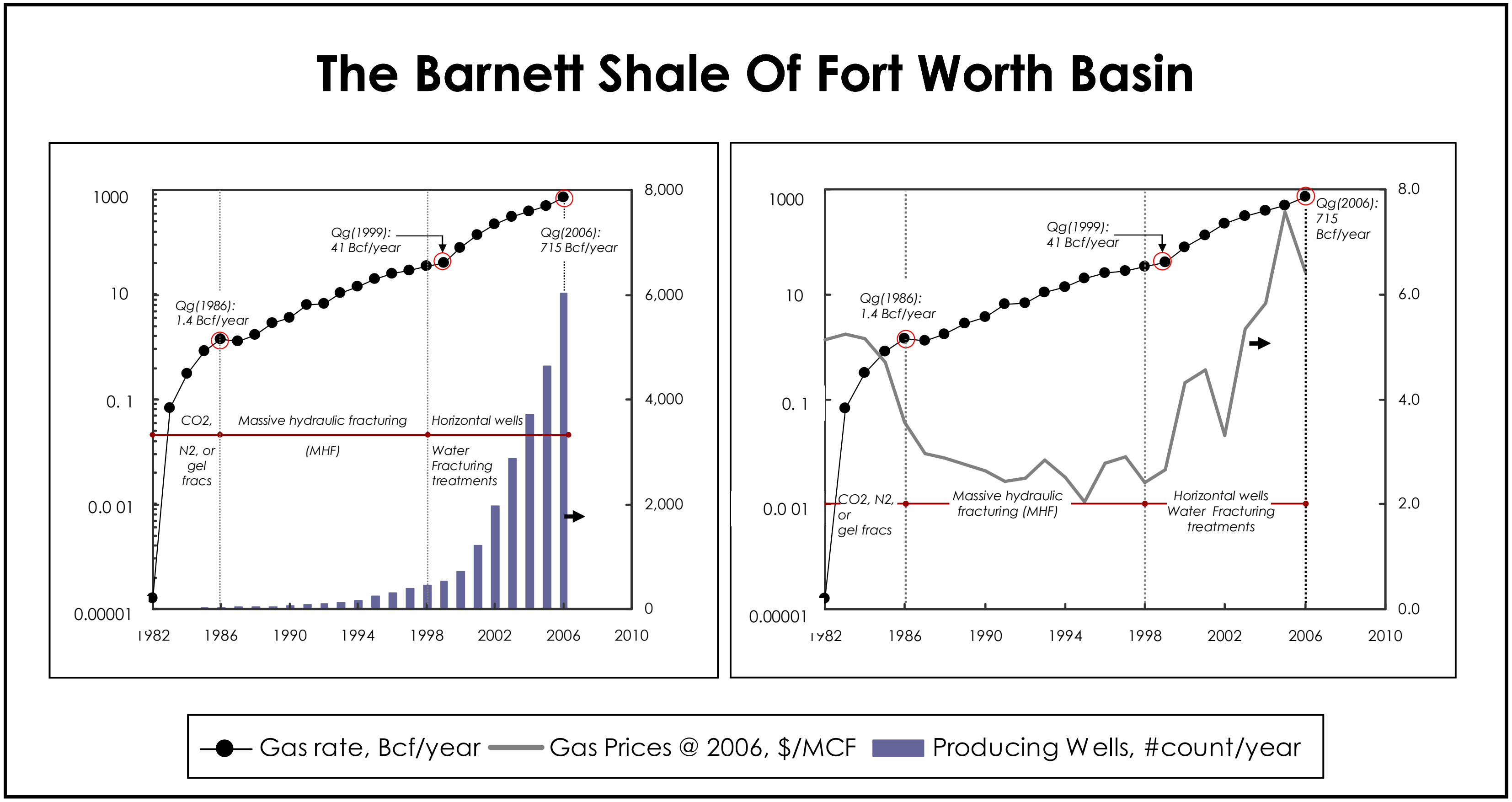


Fig. 5.16—The Barnett shale in the Fort Worth basin in Texas has been producing since 1982; however, well activity and production rates remained low during the 1980s but picked up during the mid 1980s with the use of MHF techniques. Barnett reached gas production rates greater than 1 Bcf in 1986. The MHF period increased 1986 rates by almost 30 times producing up to 41 Bcf at year-end 1999. Recently, the use of horizontals increased rates by more than 700 Bcf/year.

Technology and prices have driven production from the Barnett Shale. Starting production in 1982, the Barnett Shale of Fort Worth basin experienced a period of decrease in gas prices during the 1980s when the oil crises of 1986 reduced gas prices as low as \$1.67/Mcf of gas in 1987. A reduction of 32% compared to gas prices in 1982. Well activity remained low during the 1980s as well as production rates that started to peak up during the mid 1980s with the use of MHF techniques and more stable prices around the \$2/Mcf of gas. Barnett reached gas production rates greater than 1 Bcf in 1986. The MHF period increased 1986 rates by almost 30 times producing up to 41 Bcf at year-end 1999. However, it is the use of horizontal wells that has greatly increased rates. During the 2000s, gas prices have growth dramatically; as a result, increases in gas prices have increased the number of producing wells as shown in Fig. 5.16. From 2000 to 2005, when more than 2,000 wells were drilled, the gas production rate increased by more than 6 times going from 79 Bcf/year to 501 Bcf/year.

Table 5.6 summarizes the three different periods of development historically observed in the Barnett Shale. The impact of these three periods is reported in terms of produced gas.

TABLE 5.6—DRILLING ACTIVITY IN THE BARNETT SHALE

PERIOD	1982-1990	1991-1999	2000-2006
	Decrease in prices. Fracturing vertical wells	Stable prices, low drilling activity, massive hydraulic fracturing (MHF)	Increase in prices, high drilling activity with mainly horizontal wells. Improved waterfracs.
Produced Gas, Bcf/period	12	187	2,341
Drilled Activity	Wells<100	100<wells<1,000	Wells>1,000
Horizontal wells' contribution		Production from horizontals less than 1%	2003: 5.0% 2004: 20.3% 2005: 45.0% 2006: 66.0%

By year-end 2006, more than the 90% of the total gas produced from Barnett came from the 2000-2006 period of development when prices and technology supported more drilling and the increased use of horizontal wells. The majority of the horizontal wells in Barnett have been drilled since 2002.

Technology advances in Barnett Shale have progressively increased the EUR per well **(Fig. 5.17)**. The estimated ultimate recovery (EUR) for Barnett Shale wells ranges from about 1.0 to 3.0 Bcf/well depending on whether a well is vertical or horizontal although a reasonable average is about 1.75 Bcf/well. The EUR of gas from horizontal wells drilled in the core producing areas (counties with the highest production to date) has been reported between 2.5–3.5 Bcf of gas (Jarvie et al, 2007).

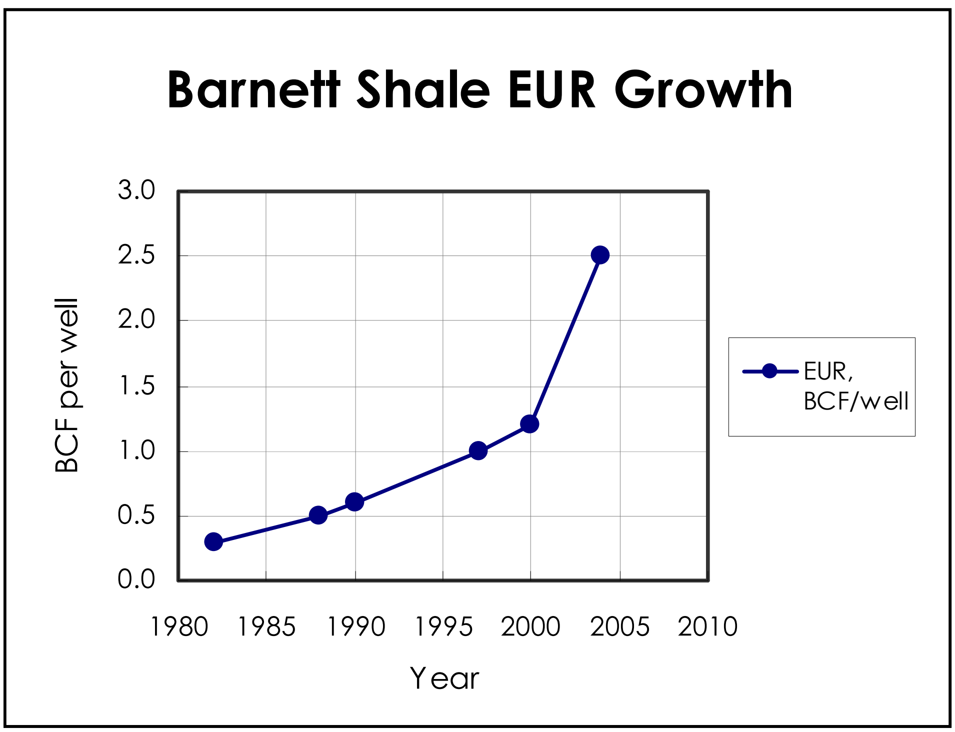


Fig. 5.17—Technology advances in Barnett Shale have progressively increased the EUR per well (From Quicksilver, 2005).

Pollastro et al (2003) reported the historical changes of EUR per well at Newark East field as follows: (1) 0.3-0.5 Bcf before year-end 1990; (2) 0.6-1.0 Bcf between 1990 and 1997; (2) 0.8-1.2 Bcf between 1998 and 2000; and (4) 1.25 Bcf more recently experienced by Devon energy as the mean EUR value for Newark East Barnett gas wells.

5.2.2.3 Lewis Shale Formation

The Cretaceous Lewis Shale of the central San Juan basin of Colorado and New Mexico is primarily a quartz-rich, sandy mudstone with total organic carbon (TOC) content ranging from about 0.5 to 2.5% **(Fig. 5.18)**.

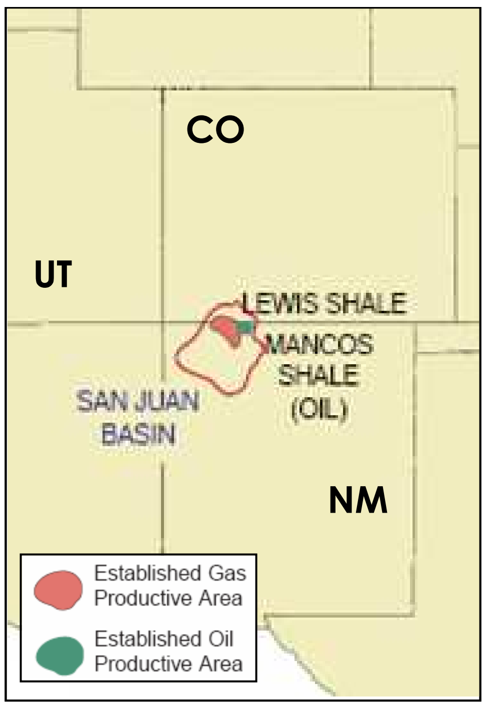


Fig. 5.18—The Lewis Shale of the San Juan basin in the western US (after Hill and Nelson, 2000).

The Lewis Shale porosity ranges from 2 to 8% with water saturation values ranging from 50 to 80%. From 1950 to 1990, only a few completions were reported from the Lewis; however, the late 1990s marked the startup of this shale gas formation. Operators target the shale as either a secondary completion zone in new wells or a recompletion zone in existing wellbores to support the decline in gas production from the prolific Fruitland Coal during the late

1990s. Production from conventional reservoirs such as the Mesaverde (MVG), Dakota (DK) sandstones, and Lewis and Manco shales represent important source to increase the ultimate recovery from the basin.

The Lewis Shale is 1,000 to 1,500 ft thick and lies above the Mesaverde formation and below the Pictured Cliffs formation. The Lewis has been divided into four geologic members, the Ute/Huerfanito Bentonite, Navajo City/Chacra, Otero/First Bench, and Otero/Second Bench. Similar to the underlying Mesaverde formation, the Lewis is naturally fractured. Although geologically different, the Lewis Shale is often considered to be part of the Mesaverde Group, given that in most of the cases it produces commingled with these reservoirs.

The common practice in completing the Lewis involves perforating the casing of existing wells, hydraulically fracturing the shale, and commingling Lewis production with existing Mesaverde or Dakota production. The commingling strategy makes the Lewis Shale extremely economic with an incremental cost of only about $0.30/Mcf (Dube at al., 2000). However, quantifying the incremental production rates, reserves and corresponding value from the Lewis as a reservoir is difficult.

In 1998 Burlington Resources characterized the Lewis Shale across the basin after observing production increases from commingled wells. Focusing its study on the Navajo City and the First and Second Otero members, Burlington estimated that average daily Lewis production from these areas would likely range between 100 and 130 Mcf/day initially, with average estimated ultimate recoveries between 0.3 and 0.5 Bcf per well (Dube et al., 2000). Hill and Nelson (2000) estimated production averages of about 100 to 200 Mcf/day of gas, exhibiting stabilized annual decline rates of about 6% with very little water or condensate production. The projected economic recoverable reserves go around 0.05 to 2.0 Bcf of gas per well. Lewis in San Juan contains considerable behind-pipe reserves indicate a value of shale gas-in-place resource of 97 Tcf and data from Hill and Nelson in 2000 show a range of recovery factor from 5 to 15% (Curtis, 2002).

Lewis production is achieved by hydraulic fracturing treatments. Stimulation fluids used to perform these fracturing treatments include slickwater, linear gel, crosslinked gel, liquid CO_2, foamed ClearFRAC (trade name of Schlumberger), foamed linear gel, and foamed crosslinked gel; and fracture treatment jobs sizes of proppant range from over 400,000 lb of sand to only about 50,000 lb (Teufel et al., 2004). Most of the wells (280) have been hydraulically fractured with foamed linear or foamed crosslinked gels and only a few with slickwater, straight linear gel, CO_2, or ClearFRAC.

We considered the Lewis as a study case for this project because it represents a challenge since its development has not been address directly; however, Lewis in San Juan basin contains considerable behind-pipe reserves that are attractive to produce economically.

5.2.2.3.1 Production History

The development of the Lewis Shale has been the result of commingled production with sandstone intervals to sustain the decline of the prolific Fruitland Coal of the San Juan basin. The gas production rates of the Lewis have supported production from the San Juan basin and encouraged producers to develop the Shale. Currently, the Lewis is considered a developing play with sustained well activity **(Fig. 5.19)**.

Historically, the Cretaceous shales of the Lewis formation were rarely completed in the San Juan Basin. From 1950 through 1990, only 16 wells that encountered extensive natural fracture systems while drilling for deeper Mesaverde and Dakota objectives were completed and produced from the shale (Dube et al., 2000). Production rates from those 16 wells ranged from one to 10 Mcf/day/well, and ultimate recoveries ranged from five to 70 Bcf. In 1991, BR began adding the Lewis to existing Mesaverde completions in specific areas. Through 1997 approximately 101 Lewis completions had been made in existing and new wells, commingled with Mesaverde or Dakota production. Actual data used for this study coincide with the fact that the 1990s was the startup of Lewis shale development.

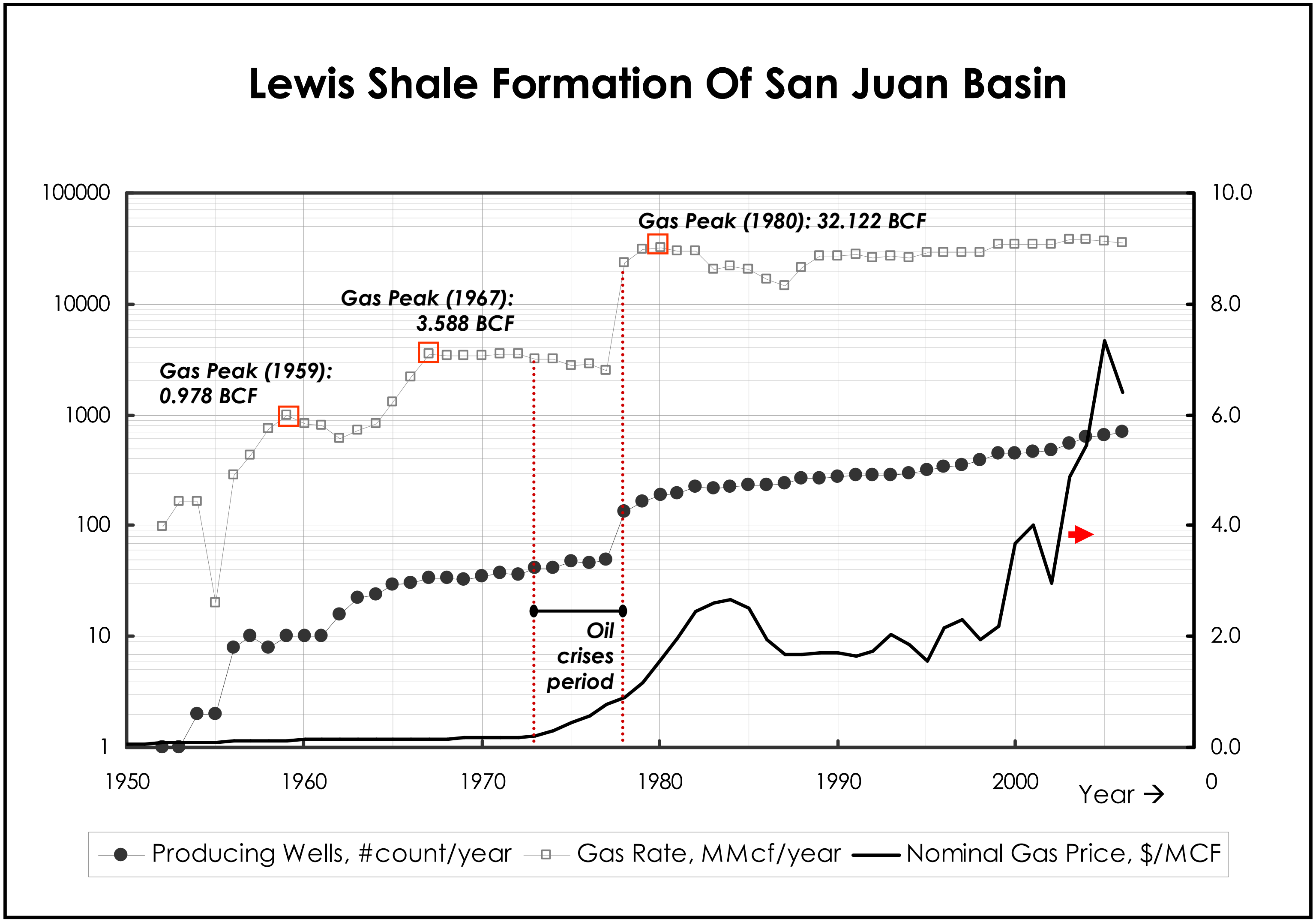


Fig. 5.19—Production profile showing the three times when gas production from the Lewis shale peaked (1959, 1967, and 1980). Production peaks that occurred before 1980 are the result of increases in well number supported by hydraulic fracturing technology, while the third peak is derived from high prices during the oil crises. The Lewis is currently a developing shale play.

Data available in our database (HPDI, 2007) indicate four periods of development since production started in 1952 (Fig. 5.19). Production data also show that the previous three periods peaked in 1959, 1967, and 1980, respectively. Production peaks that occurred before 1980 are the result of increases in well number supported by hydraulic fracturing technology while the third peak is derived from high prices during the oil crises. The Lewis is currently a developing shale play.

The play experienced its first gas peak in 1959 (0.978 Bcf/year) when on average 10 wells were producing. A second peak observed in 1967 is basically attributed to an increment in well number from 16 (1962) to 34 wells (1967). During these periods the gas production increased by almost six-fold. From 1967 to 1977 and regardless increasing number of wells from 34 to 50, the gas rate declined to 2.52 Bcf/year by the end of 1977, a reduction of almost 30%. The following year was marked by the second oil embargo, which helped speed up production when gas prices went up. Gas production in 1978 increased about 10-fold compared to the previous year. At the end of 1978, the gas rate reached 23.87 Bcf/year as the number of producing wells increased around 3 times.

In 1980, the Lewis saw its third production peak when 32.12 Bcf/year of gas was produced. The effect of oversupply of gas in the mid 1980s decreased gas prices, and production went as low as 14.52 Bcf/year by 1987. From 1980 to 1987 production declined by 55%. The late 1980s brought better gas prices and increases in production. From 1987 to 1988 production increased by two-fold after increasing in well number by a factor of 1.7.

The formation has experienced more activity when operators realized that significant behind-pipe reserves can be produced from the Lewis. Well activity has increased from 236 producing wells in 1987 to 355 in 1997 to 688 at the end of 2006. The cumulative gas increased by 246% from 1987 to 2006. Cumulative gas of 869 Bcf (2006) has brought in revenues of $3,261 million. In terms of oil, the shale has produced 14 million STB, and produced gas accounts for almost 160 million BOE.

CHAPTER VI
ANALYSIS METHODS

In this work, we have used production data from entire formations or plays to forecast the estimated ultimate recovery of gas or oil for a variety of situations. These situations can be defined by a change in either technology or oil and gas prices. Whenever, there is a technology breakthrough or a sudden change in product prices, the situation changes.

We then took our estimates of ultimate recovery and correlated these estimates with factors that could possibly change the situation. Thus, our work encompasses both production forecasting and the correlation of those forecasts to events at the time that altered the situation.

The Spearman's Rank Correlation Coefficient technique helped to determine the dependence between the active wells, the rig count, and the commodity price variables. The decline curve analyses allowed us to estimate the increase in production from different scenarios or situations of high price or technology assuming hypothetically that no subsequent changes would have happened.

6.1 Spearman's Rank Correlation Coefficient (Dependence between Variables)

Spearman's Rank Correlation Coefficient (SRCC) is a technique that can be used to summarize the strength and direction (negative or positive) of an association between variables. An association between variables means that the value of one variable can be predicted, to some extent, by the value of the other. A correlation is a special kind of association where the relation between the values of the variables is linear; however, data reliability is related to the size of the sample. As you collect and analyze more data you collect, the results should be more reliable.

SRCC is used to test for correlations between data sets based on relative rankings of elements in data sets, rather than on values of the elements. In this way SRCC ranges from values of -1.0 (perfect negative correlation) to +1.0 (perfect positive correlation), the value 0 (zero) being that of indifference or no correlation at all. The plus or minus sign of the correlation value determines the trend of the dependent value given an independent value. However, the strength of the relationship is measured through the absolute value or magnitude of the number. That is to say, the closer the absolute value is to 1, the stronger the relationship (whether it is positive or negative).

For a set of variable pairs, the SRCC gives the strength of the association between the variables. **Fig. 6.1** shows the most typical arrangements observed once the two sets of data are plotted: the example in plot (a) shows a total linear positive dependence; an increase or decrease in the value of the independent variable will have the similar effect on the dependent variable. The example in plot (b) refers to total but nonlinear negative dependence. Plot (c) shows a diffused positive dependence pattern; this type of correlation can be either positive or negative but, as the figure shows, the correlation will not be as perfect or direct as desired, while plot (d) shows a plot of uncorrelated variables, meaning the variables are completely independent.

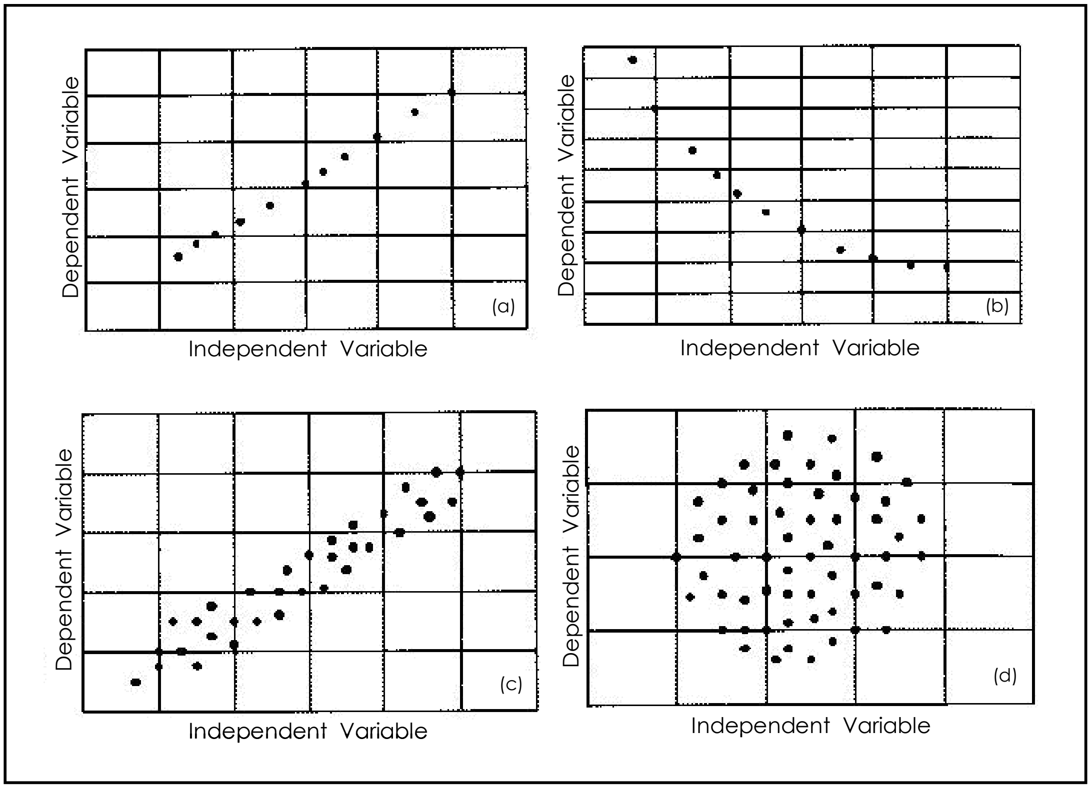


Fig. 6.1—Scatter diagrams showing typical correlations between two variables (from Mian, 2002b).

The square of the size of the correlation coefficient is the fraction of the variance of the one variable that can be explained from the variance of the other variable. The relation between the variables is called the regression line which is defined as the best fitting straight line through all value pairs. The relationship between dependent and independent variables can be quantified by fitting a linear trend line in the scatter plot. Establishing a simple linear regression, an equation for the trend line can be worked out in the form of:

$$Y = a + bX \text{ , } \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{ (1)}$$

where **a** is the Y intercept of the line, and **b** is the slope of the trend line, defined as:

$$b = \frac{\sum_{i=1}^{n}(X_i - \overline{X})(Y_i - \overline{Y})}{\sum_{i=1}^{n}(X_i - \overline{X})^2} \quad \text{.. (2)}$$

The graphical representation of dependence gives us a good qualitative assessment between two data variables; however, to reach any conclusions it is necessary to establish a quantitative relationship between the variables. This allows us to have a certain value on how strong the relationship is between the analyzed variables. The correlation coefficient (rXY) is a numerical summary measure, given by the following equation:

$$r_{XY} = \frac{\dfrac{\sum_{i=1}^{n}(X_i - \overline{X})(Y_i - \overline{Y})}{(n-1)}}{s_X s_Y} \quad \text{... (3)}$$

where **Sx** is the standard deviation of the X variable (independent),

Sy is the standard deviation of the Y variable (dependent),

$\overline{X}$ is the average (mean) of the independent variable,

$\overline{Y}$ is the average (mean) of the dependent variable, and,

n = number of elements in data sets.

6.1.1 Using Excel to Compute the Correlation Coefficient

SRCC can be calculated using standard statistical software such as Microsoft Excel. A typical way of showing the graphical correlation between variables is through a scatter diagram. A scatter diagram plots one variable in a function to the other on a Cartesian plot. The independent variable is typically placed in the x-axis while the dependent variable becomes the y-axis.

Excel has a convenient function to quickly compute the correlation coefficient. The Excel built-in function CORREL returns the correlation coefficient of the cells in RANGE1 and the cells in RANGE2

=CORREL(RANGE1, RANGE2)

The correlation factor analysis has helped us to examine the relationship between oil and gas prices and the number of operational drilling rigs or producing wells at any given time. Our hypothesis suggests that, based on the basic economic principles of supply and demand, as product prices rise supply should increase in response to the new economic incentives to produce more oil and gas. We expect a positive correlation between oil prices and active drilling rigs. The more profitable a barrel of crude oil will be to the supplier, the more drilling the supplier will engage in, contracting drilling rigs to create producing wells. We would expect a time lag associated with this correlation because of the contractual nature of drilling rigs; that is to say, once a company has leased a drilling rig, they will use it to the fullest until the end of the lease time. We developed our hypothesis from the apparent relationship among certain factors. The determination of the correlation factor can help quantify the extent to which these assumptions are true or not true.

6.1.2 Estimation of Time Lag between Correlations

The time lag is the difference of time that can be expected between the moment the value of the independent variable (oil and gas price) changes and the moment it actually impacts the dependent variable (active drilling rigs or producing wells). This can be estimated by shifting the data series of the dependent variable with respect to time while maintaining the independent variable fixed. The number of notches in the time scale that the series need to be moved to find a match between dependent and independent variables will yield a time lag estimate in years.

6.2 Decline Curve Analysis

The production decline curve analysis method is based on the relationship between the production characteristics of a reservoir and the amount of oil and gas that has been produced. The reservoir's bottomhole pressure (BHP) decreases as petroleum is produced. As a result, the reservoir's production rate will also decrease.

Decline curve analysis assumes that all estimates of ultimate recovery by extrapolation of a performance trend fundamentally follow a predictable pattern. Decline curve analysis helps us to determine the remaining productive life (reserves) of a reservoir. The decline curve analysis depends on the well's past performance. Therefore, finding the curve that approximates the past production history of the well is fundamental to have a reliable prediction.

Mian (2002a) cited two conditions required to properly perform a decline curve analysis. These were (1) sufficient past production performance available to make a reasonable match of the performance, and therefore, prediction of future behavior, and (2) production history that is based on capacity production with no operational changes. It is assumed that the well will continue to be operated in the same manner in the future.

There are three types of decline analysis commonly used in industry: exponential, hyperbolic and harmonic. Hyperbolic decline analysis is the common type for tight formations, and it is especially used in tight gas formations. The hyperbolic decline curve has a concave upward shape when plotted on semilog coordinates, and the curvature is defined by the exponent b, which is constant with time. Equations used to calculate hyperbolic declines are characterized by three parameters at a specified time, t_o, in the production life; the parameters are: production rate, q_o, nominal decline rate, D_o, and hyperbolic exponent, b. Equations to interpret hyperbolic decline curves are shown in **Table 6.1**.

TABLE 6.1—EQUATIONS TO PREDICT PRODUCTION USING THE HYPERBOLIC FUNCTION	
Cumulative Oil	$\Delta Np = \dfrac{q_i^{\,b}}{(1-b)a_i\left[q_i^{(1-b)} - q_o^{(1-b)}\right]}$
Abandonment Time	$t = \dfrac{\left(\dfrac{q_i}{q_o}\right)^b - 1}{ba_i}$
Production Rate	$q_{ot} = q_i\left(1 + ba_i t_o\right)^{-1/b}$
Decline rate	$d = \dfrac{q_i - q_o}{q_i}$
Hyperbolic exponent	b

Normally, the *b* value ranges between 0 (exponential decline) and 1.0 (harmonic decline); however, for fractured formations and low permeability, such as the Austin Chalk formation, values of *b* larger than 1.0 may be calculated. Mian (2002a) recommends checking the *b* value to avoid "unrealistic low decline rate late in the well life." Several methods are available to evaluate the hyperbolic exponent *b*; however, the most commonly used are the French curve method, shifting the curve on a log-log graph, and type-curve fitting. We developed a program to compute the *b* value and forecast production assuming the conservative scenario. We defined the value of *b* in a range from 0 to 1.

6.3 Economic Analysis

The economic model used in this study considers the calculation of revenues for every production case. We used the Consumer Price Index (CPI) to adjust the values of these revenues for inflation.

The Bureau of Labor Statistics of the US Department of Labor defines the CPI as a measure of the average change over time in the prices paid by urban consumers for a market basket of consumer goods and services. The major uses of the CPI are as an economic indicator, as a deflator of other economic series, and as a means of adjusting dollar values.

The CPI and its components are used to adjust other economic series for price changes and to translate these series into inflation-free dollars. In our case, the series adjusted by the CPI include the nominal price of oil and gas at different dates. We included the CPI and its components as a procedure within our VBA program (the second procedure) to adjust nominal oil and gas price series (from 1950 to 2006). Translating these price series into inflation-free dollars allowed comparison of price changes over time.

CHAPTER VII
RESULTS

7.1 Performed Analyses

We have used the Spearman's rank correlation coefficient technique to find dependence between the active wells, the rig count, and the commodity price variables. We have used decline curve analyses to estimate the increase of production from different scenarios of high price or technology, assuming hypothetically that subsequent changes would not have happened.

The two analyses in this study were used to identify the effect of increasing prices and new technologies, evaluating their effect in terms of EUR, productivity and revenue. The correlations indicated how periods of high oil and gas price have historically increased the number of drilled wells and thus the number of producing wells in a given formation. The study of production forecasting provided quantitative information about additional oil and gas reserves and revenues after evaluating periods of high prices or technology breakthroughs.

In this study, the Austin Chalk formation in Texas is our textbook case. The Austin Chalk is a low-permeability formation that clearly shows how changes in product prices and technology increased its production and its reserves since the play was discovered in the 1930s. Based on previous experience from the Austin Chalk formation, we identified major political/economical events and breakthrough technologies historically affecting the development of the Austin Chalk and other selected formations in the US. We demonstrated with examples that the development of unconventional formations follows the Resource Triangle Theory; that is, the increasing in reserves from unconventional plays is strongly correlatable to changes in prices and technologies.

Table 7.1 shows, in chronological order, the major discoveries in technology and different events affecting the oil industry since the development of rotary drilling.

TABLE 7.1—OIL INDUSTRY MAJOR EVENTS SINCE THE DISCOVERY OF ROTARY DRILLING		
Period	Global Event	Effect
1930s	Rotary drilling. Acidizing.	Development of rotary drilling (1930). Acidizing is born (1932). Openhole completion, nitroglycerine fracture development.
1950s	Hydraulic fracturing.	Development of hydraulic fracturing (1949) and widespread use in the 1950s.
1973	The Yom Kippur war.	1st Arab Oil Embargo (1973). Oil price increase from $3.3 (1973) to $12.8 (1976) per barrel. Better hydraulic fracturing technologies.
1978	The Iranian Revolution.	2nd Arab Oil Embargo (1978). Oil price increase from $14 (1978) to $36 (1981) per barrel. Seismic technology to locate fractures, sweet spots.
1980s	Horizontal drilling development.	Horizontal wells and water treatment fractures. First horizontal well in the Austin Chalk, Texas (1985). Oil price collapse (1986) reduces prices from $36.8 (1980) to $14.4 (1986) per barrel.
1990s	Better technologies development.	3D seismic horizontal drilling and better hydraulic fracturing technology improve flow rates and recoveries.
2000s	Oil price increase. Multilaterals.	Oil price increment from $28.5 (2000) to $65 (2006) per barrel to $120 (2008). Widespread use of multilateral drilling improves well performance. Continued improvements in stimulation.

Acidizing technology was the most widely used stimulation method for low productivity formations during the 1930s until the hydraulic fracturing technology was invented in the 1950s (Table 7.1). Critical events such as the Yom Kippur War in 1973 and the Iranian Revolution in 1978 created oil shortages which resulted in large increases in oil prices. The development of horizontal drilling in the mid 1980s, the use of better technologies in the 1990s, and the recent period of high prices during great energy demand of the 2000s are also included in Table 7.1.

Fig. 7.1 shows the evolution of technologies through time and the fluctuation in oil prices from 1920 to 2006 as the result of political and economical events.

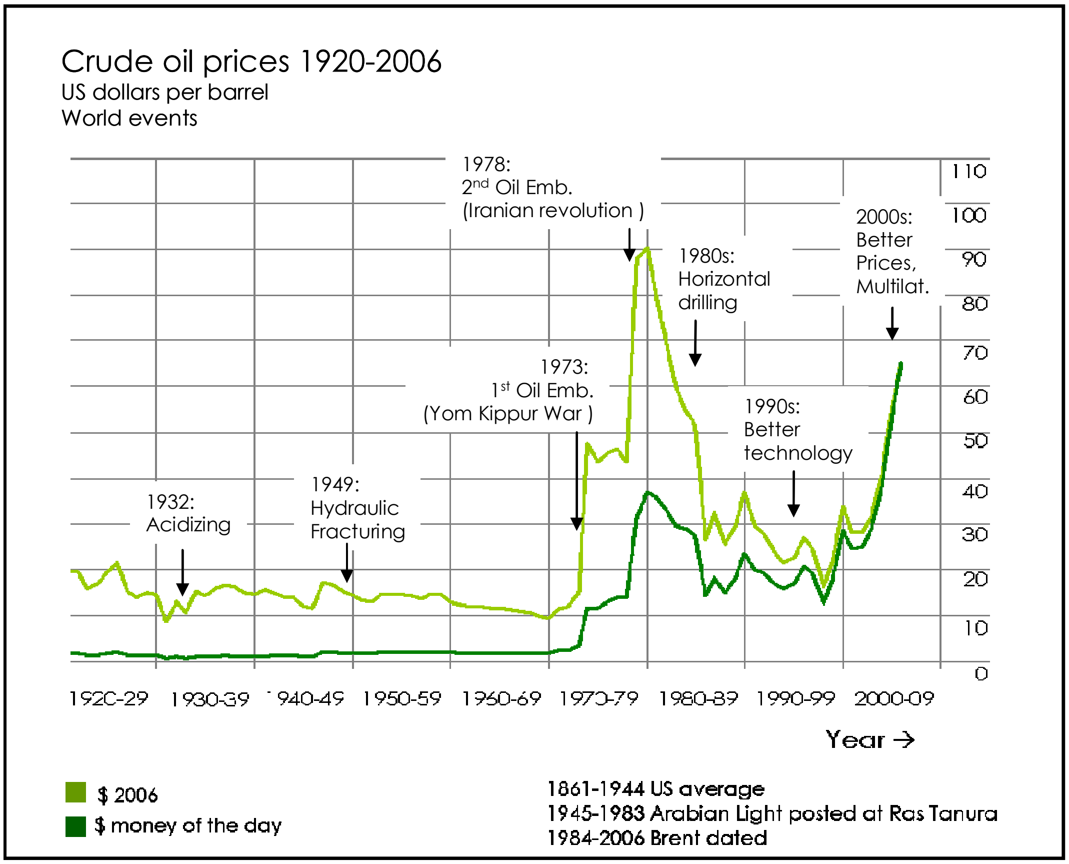


Fig. 7.1—Technological and economic events considered in this study in chronological order. Better technologies in the 1990s are supported by prices greater than $30 per barrel.

The Texas oil boom during the 1930s allowed a period of stable to low oil prices sustained by product availability. Fig.7.1 shows how in 1931, the oil prices fell to a low of $8.66 per barrel (real, $2006), continuing relatively stably until the oil crises in the Middle East during the 1970s. The Yom Kippur war (1973) and the Iranian revolution (1978-79) caused spikes of $14.99 per barrel and $88.13 per barrel, respectively. On the contrary, the Asian financial crisis provoked a decreased in prices in 1998 to $16.22 per barrel; however, the oil price quadrupled by the end of 2006, reaching $65.14 per barrel. The high price tendency has continued until today with prices above $70 per barrel in 2007.

7.2 Cases of Study

Our textbook case, the Austin Chalk formation, started to produce in 1933 but was not considered a commercial play until the 1950s. **Fig. 7.2** shows the selected cases of study according to their initial production date available in the HPDI database (2007).

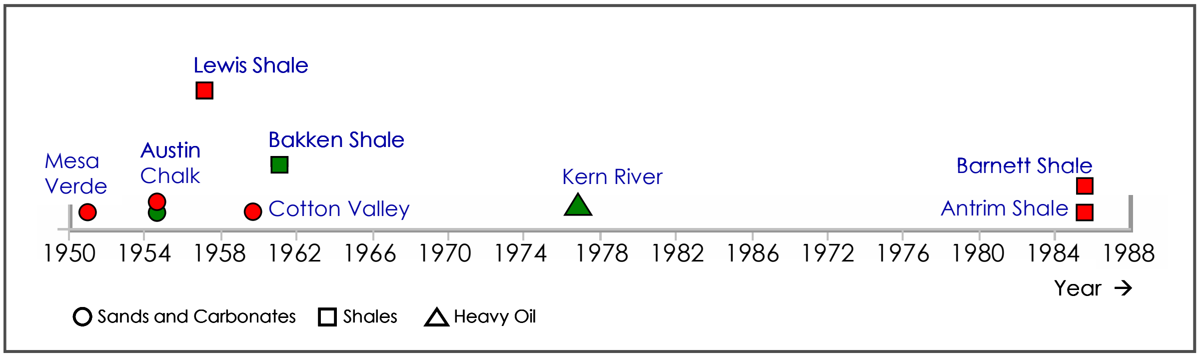


Fig. 7.2—Start of commercial production for selected cases in the United States (from HPDI, 2007).

In the HPDI database, production data from the Cotton Valley in East Texas and North Louisiana, the Mesaverde Group and Lewis Shale in the San Juan basin, the Austin Chalk in Texas, and the Bakken Shale in the northern US was available since the 1950s. Production data are available from the Kern River field in California since the 1970s, while the Antrim Shale in the Eastern US and the Barnett Shale in Texas have data available since 1982.

As mentioned previously, commercial oil and gas production from unconventional formations requires some type of stimulation technology. Our review indicates, in general, six different stimulation methods to produce oil and gas from the selected formations. **Table 7.2** shows the different stimulation techniques used to produce oil and gas from the selected cases in this study. The textbook case, the Austin Chalk formation, has gone through different stimulation methods such as acidizing, fracturing, horizontal wells, and multilaterals. Also note that hydraulic fracturing is the common stimulation technology for all the formations but the Kern River in California, which has been producing from steam injection.

TABLE 7.2—STIMULATION METHODS IN SELECTED FORMATIONS IN THE UNITED STATES

Formation	UCR type	Acidizing	Hydraulic Fracturing	Steam Injection	Horizontal Drilling	Improved Waterfracs	Multi-laterals
Austin Chalk (AC)	Low Permeability (Carbonates)	●	●		●	●	●
Antrim (AS)	Gas Shales		●			●	
Barnett (BS)	Gas Shales		●		●	●	
Lewis (LS)	Gas Shales		●			●	
Bakken (BKS)	Oil Shales		●		●	●	
Cotton Valley (CVG)	Tight Gas Sands		●			●	
Mesaverde (MVG)	Tight Gas Sands		●			●	
Kern River (KR)	Heavy Oil			●			

Tables 7.1 and 7.2 were used in this study as input information to define how certain technologies or prices have influenced the development of the formation. Thus, we observed that the Barnett and the Antrim shale formations have followed different development patterns although these two plays started to produce at the same time. Horizontal drilling in the Barnett has sped up well productivity while the Antrim has produced only from vertical wells.

7.3 Study of Correlation (Dependence between Variables)

Traditionally, rig count records in the US have been considered a primary measure of the health of the oil and gas industry (Inikori et al., 2001). Rig count data from Baker Hughes (2008) shows that, among other parameters, the number of drilled wells engaged in the US strongly depends on oil prices **(Fig. 7.3)**. US rig count data were used to exemplify the importance of prices in the development of gas and oil reservoirs.

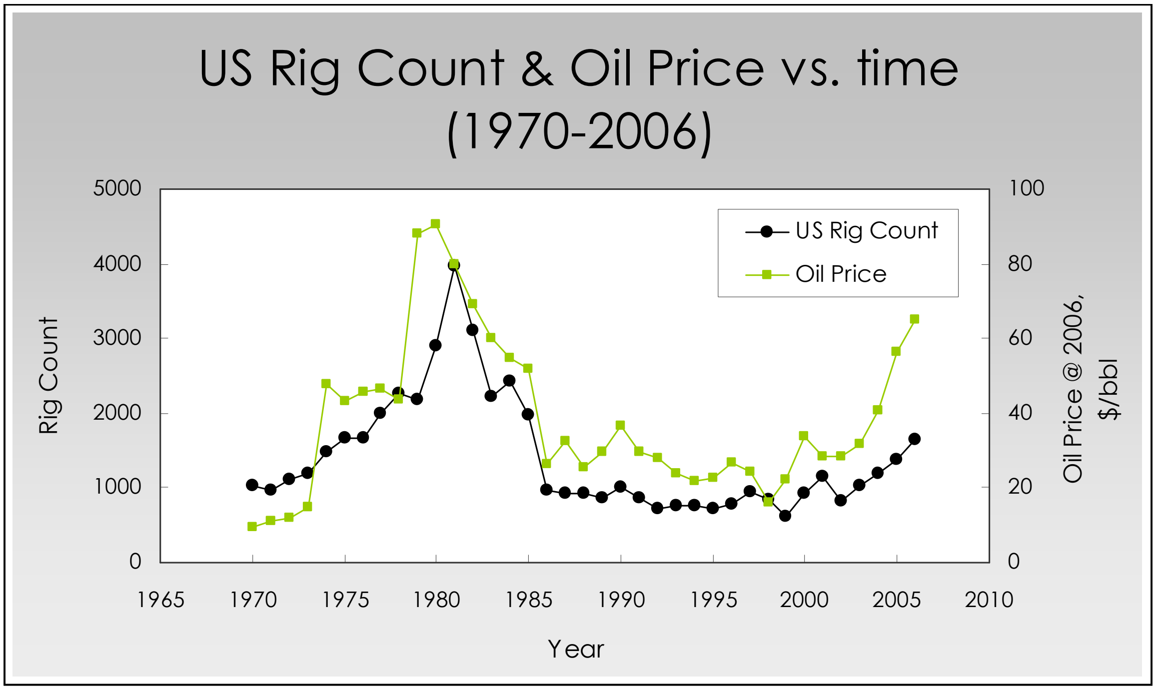


Fig. 7.3—Rig count records in the US from 1970 to 2006 show strong dependence on variable oil price. Increase in oil prices translates into increases in rig activity (data from Baker Hughes, 2008).

The US rig count data have been historically related to oil prices. **Fig 7.4** shows a strong Spearman's rank correlation coefficient (SRCC) of 0.7 between the oil price and the rig count. The SRCC indicates that 70% of the wells drilled from 1970 to 2006 depended on the variable oil price.

The strong linear correlation of 0.7 supports the hypothesis that as oil prices increase, rigs currently operating will also increase. Also, the correlation suggests that on average, for every dollar increase in the oil price, the number of drilled wells increases on average by 31.

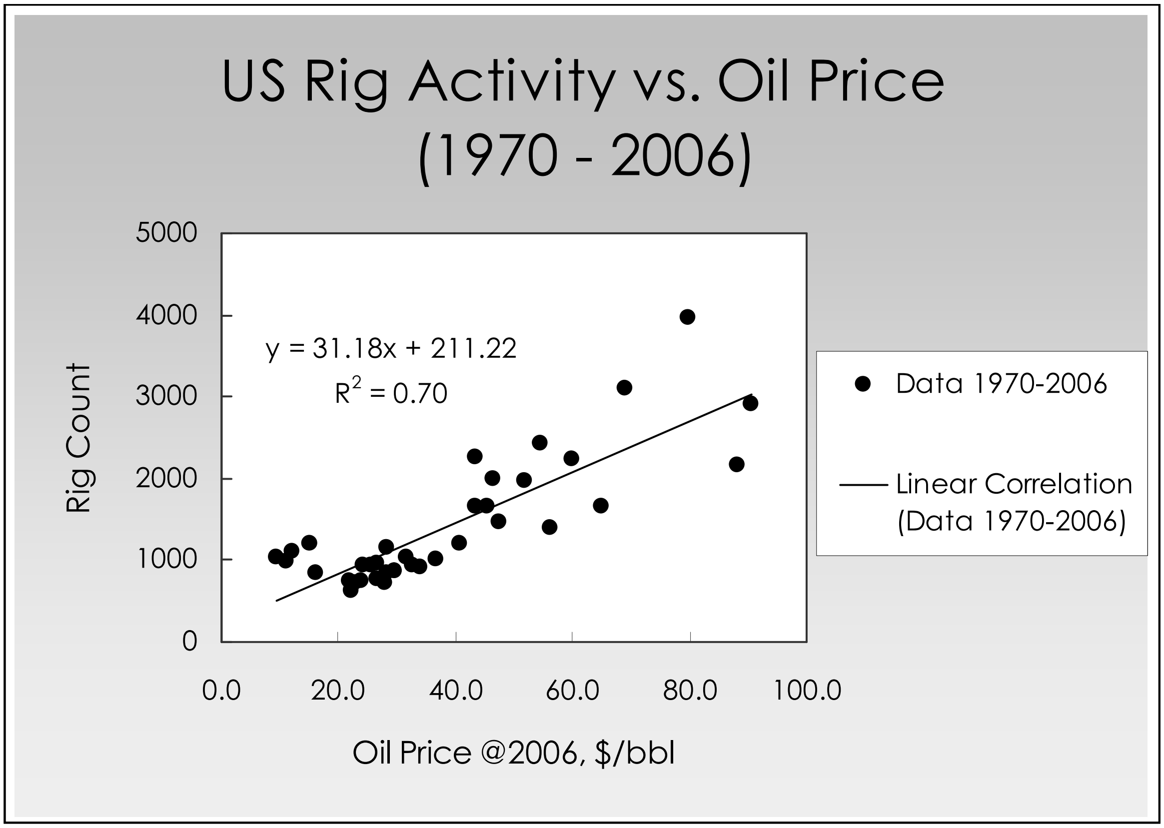


Fig. 7.4—Rig count records in the US show a relatively strong linear correlation of 0.7 with the variable oil price (data from Baker Hughes, 2008)

Oil price fluctuations from 1970 to 2006 have been the result of events such as the oil crises of the 1970s, the depression of oil prices in the mid 1980s, and more recently the increases in prices since the late 1990s **(Fig. 7.5)**.

Two events during the 1970s, the Yom Kippur war in 1973 and the Iranian Revolution in 1978, produced shortages of oil production during the 1970s that increased the price of oil. During the 1970s, a period of high prices, the price of oil went from $14.49 per barrel in 1973 to $88.13 per barrel in 1979 (real terms, $2006), an increase of almost 6 times. These two events in the 1970s were responsible for high oil prices, and an upward trend from 1970 to 1979.

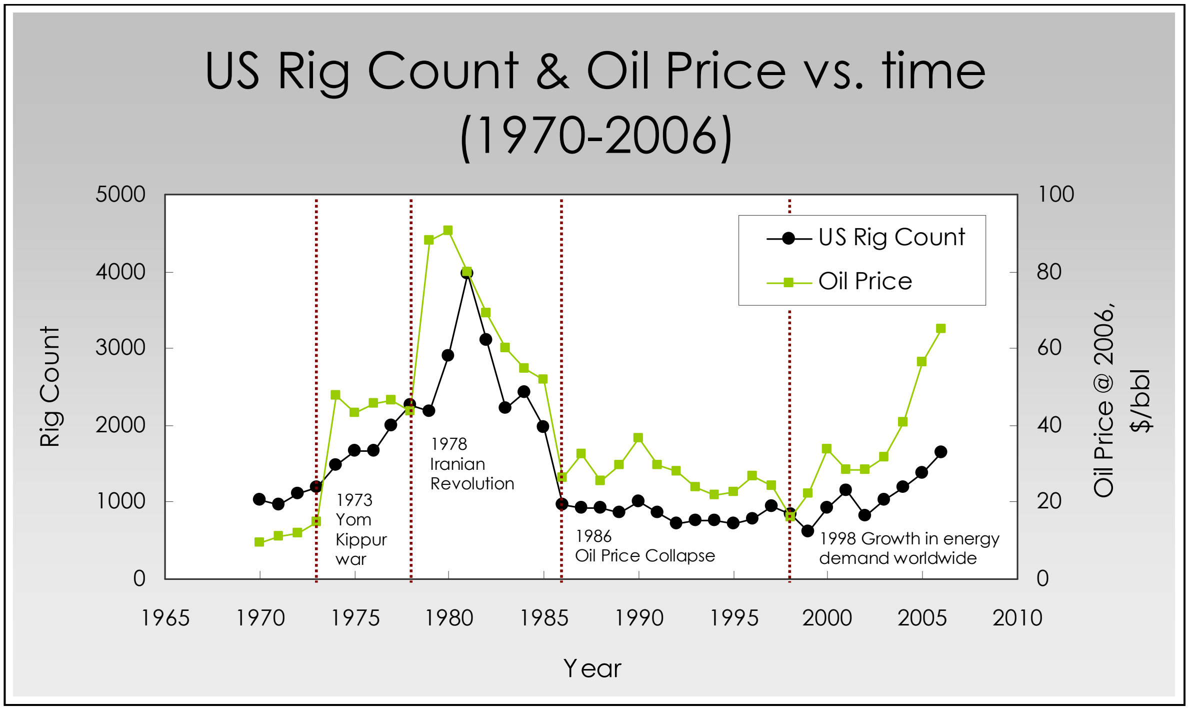


Fig. 7.5—Worldwide political/economical events have affected the price of oil and influenced the US rig count records from 1970 to 2006 (data from Baker Hughes, 2008).

In 1980, after the Iranian revolution, Iraq invaded Iran, causing a worldwide crude oil reduction of 10% in production compared to 1979. In 1981, OPEC reduced its oil production, increasing oil market prices. From 1980 to 1985, prices remained high until a reduction in consumption forced oil prices to decrease; this period is characterized by a downward trend of relatively high oil prices that lasted until 1986.

Overproduction of oil in 1986 reduced oil prices by 47% compared to 1985. The oil price collapse of 1986 created a greater demand for energy, increasing again the consumption of oil worldwide. From 1986 to 1997, the oil price profile went from stable to low. The next period, from 1998 to 2006, is marked by an upward trend characterized by the growth of developing countries and greater market activity.

Table 7.3 distinguishes the tendency of five periods of oil price change from 1950 to 2006. Available rig count data between 1970 and 2006 were correlated with oil prices based on the observed periods.

TABLE 7.3—OIL PRICE TENDENCY CHANGES AND THE US RIG COUNT ACTIVITY

Period	Event	Tendency	US Rate of growth (rig count/$)	SRCC (rig count vs. oil price)
I (Up to 1969)	Product availability.	Stable to low prices.	316	0.75
II (1970-1979)	The Yom Kippur war and Iranian Revolution created the 1970s oil crises.	High prices, upward trend.	16	0.67
III (1980-1985)	OPEC production cut's kept prices high.	High prices, downward trend.	34	0.52
IV (1986-1997)	Consumption decrease caused the oil price collapse of 1986. Prices kept stable until demand for oil regained market.	Stable to low prices.	14	0.35
V (1998-2006)	Consumption increased. More demand for energy from devel-oping countries.	High prices, upward trend.	18	0.83

In general, periods of low oil price coincide with decreased rig activity, whereas periods of high price with times of greater rig activity. US rig count data from 1970 to 2006 shows better correlation factors for periods of high commodity prices compared to periods of low commodity prices. Note that periods of high oil price, from 1970 to 1979 and from 1998 to 2006, exhibit an upward trend and strong SRCC of 0.67 and 0.83, respectively.

For instance, during Period IV of low oil prices, for every dollar added to the oil price, the number of rigs added to the active list was 14 on average; a reduction of 60% in rig count regarding previous Period III of high oil prices when the rate of growth in rig count went from 34 to 14 rigs. Data shows that periods of high price for US rig count versus oil price in Fig. 7.6 have exhibited increments of rig count up to 113%.

According to the correlation between US rig activity and oil prices in **Fig. 7.6**, the greatest increment in number of wells occurred during Period III, when on average, for every dollar added to the oil price, 34 rigs were added. On the contrary, only 14 rigs were added in Period IV when oil prices went on average from stable to low. Fig. 7.6 shows graphically the correlation between rig count and oil prices for the established periods in Table 7.3.

The rate of growth of rig count in each period indicated in Table 7.3 is given by the slope of the linear function between the variables rig count and oil price. Data in Fig. 7.6 shows that on average, the number of active rigs for every dollar added to the price of oil in the early 1980s doubled the number of active rigs in the 1970s. Baker Hughes (2008) data indicates that rig count records in the US from 1970 to 2006 show different trends during high or low commodity price periods.

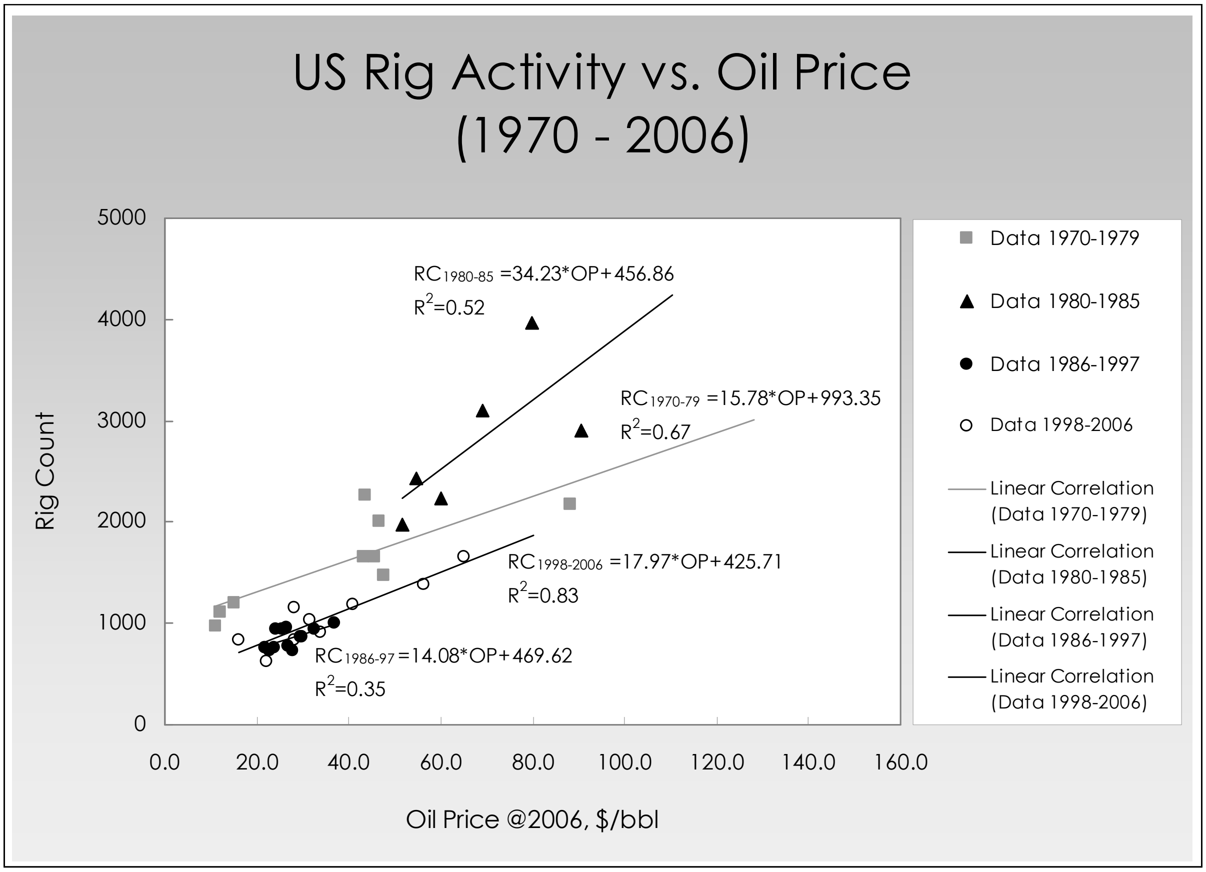


Fig. 7.6—Rig count records in the US from 1970 to 2006 show different trends according to their rate of increases or decrease during high or low commodity price periods (data from Baker Hughes, 2008).

Rig count versus oil price data in Fig 7.6 show a positive trend for each of the four dataset. On average, the number of active rigs in the early 1980s doubled the number of active rigs in the 1970s for every dollar added to the price of oil.

7.3.1 Oil Producing Formations

Table 7.4 shows the periods of oil price changes until year end 2006. Periods of stable to low prices are supported by enough product supply or decrease of consumption rates. On the contrary, high prices are the result of increase in the demand for oil or periods of product shortage.

TABLE 7.4—OIL PRICE TENDENCY CHANGES

Period	Event	Tendency
(I) Up to 1969	Product availability.	Stable to low prices.
(II) 1970-79	The Yom Kippur war and Iranian Revolution created the 1970s oil crises.	High prices, upward trend.
(II) 1980-85	OPEC production cut's kept prices high.	High prices, downward trend.
(IV) 1986-97	Consumption decrease caused the oil price collapse of 1986. Prices kept stable until demand for oil regained market.	Stable to low prices.
(V) 1998-06	Consumption increased. More demand for energy from developing countries.	High prices, upward trend.

7.3.1.1 Austin Chalk Formation

As depicted by the resource triangle, prices and technologies are important parameters that control the development of unconventional reservoirs. Annual wells drilled and oil price data between 1950 and 2000 from the Austin Chalk formation in Texas show, in general, that as oil prices increase, the wells drilled count also increases **(Fig. 7.7)**. Since 2000, the increase in oil price has not affected the number of wells drilled.

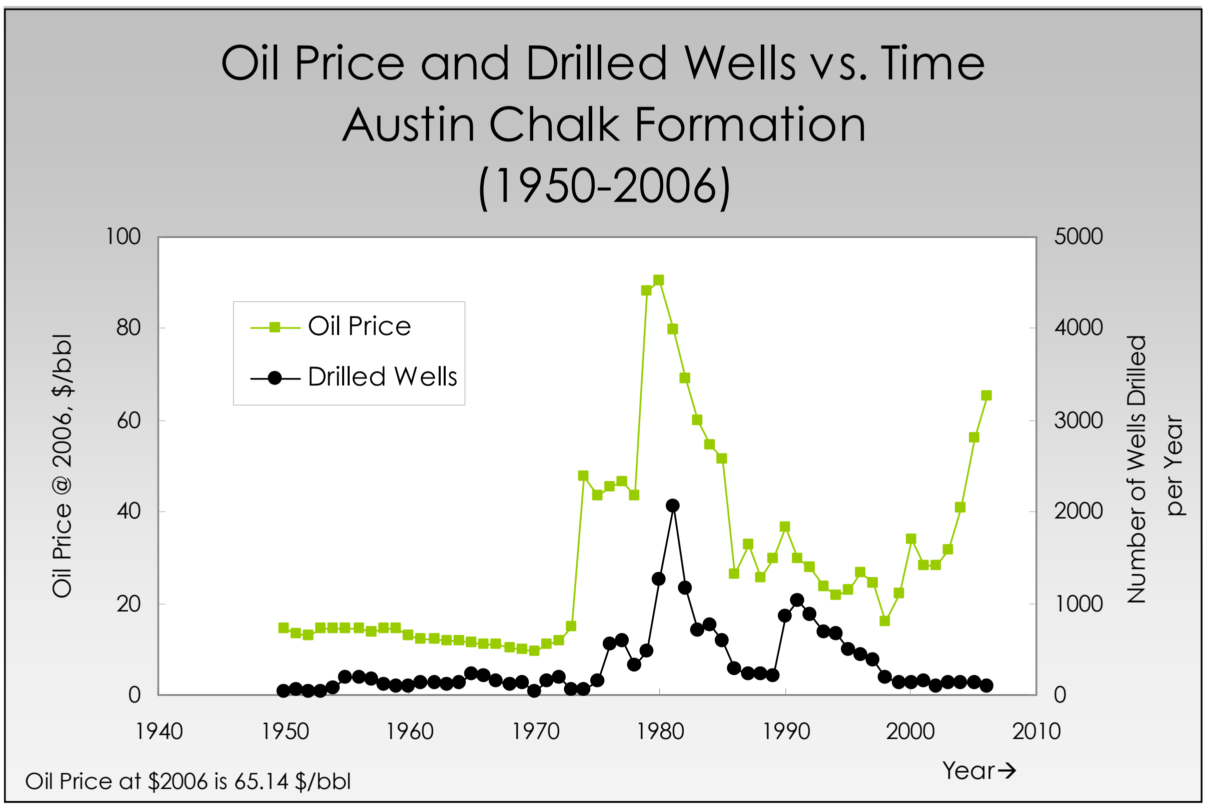


Fig. 7.7—Historical drilled wells records from the Austin Chalk formation between 1950 and 2006 show great dependence on the oil price variable (data from Baker Hughes, 2008).

Wells drilled data available from the Austin Chalk formation between 1950 and 2006 show that after the oil crises in the 1970s, the price of oil increased from $12/bbl (real, $2006) in 1972 to $90/bbl in 1980; during this period, the number of wells drilled sharply increased. The number of wells drilled in 1981 was 60 times greater than the number of wells drilled in 1970. In 1981, a historical record of 2,068 new wells was registered.

The oil price collapse of 1986 reduced the number of wells drilled in the Austin Chalk formation. At the end of 1989, the number of wells drilled went down to 206. Increases in oil price and technologies such as horizontal drilling and water fracture treatments revitalized the Austin Chalk during the early 1990s when oil prices were around $25/bbl; the number of wells drilled in 1991 was greater than 1,000 (Fig. 7.7).

Although oil prices have increased sharply since 1998, the rig activity in the Austin Chalk has shown a stable to low trend with small variations in the number of wells drilled. According to Holditch (2008), drilling activity in the Austin Chalk has been limited because the main productive areas have been drilled and produced. There is not much room left for infill drilling. As a result, there is an inverse relation between the number of wells drilled and the oil prices after year 1998 (Fig. 7.7).

The Austin Chalk wells drilled data plotted versus the oil price in $2006 shows a diffused positive dependence pattern **(Fig. 7.8a)**. This pattern means that other factors, such as technology breakthroughs, are also important in the Austin Chalk.

The SRCC of 0.41 between the wells drilled and the oil price data indicates that 41% of the wells drilled from 1950 to 2006 depended on the variable oil price. Data in Fig. 7.8a suggest that approximately 12 additional wells were added when the price of oil increased by one dollar. **Fig. 7.8b** shows the shadow area in Fig. 7.8a; the correlation improves to 0.75.

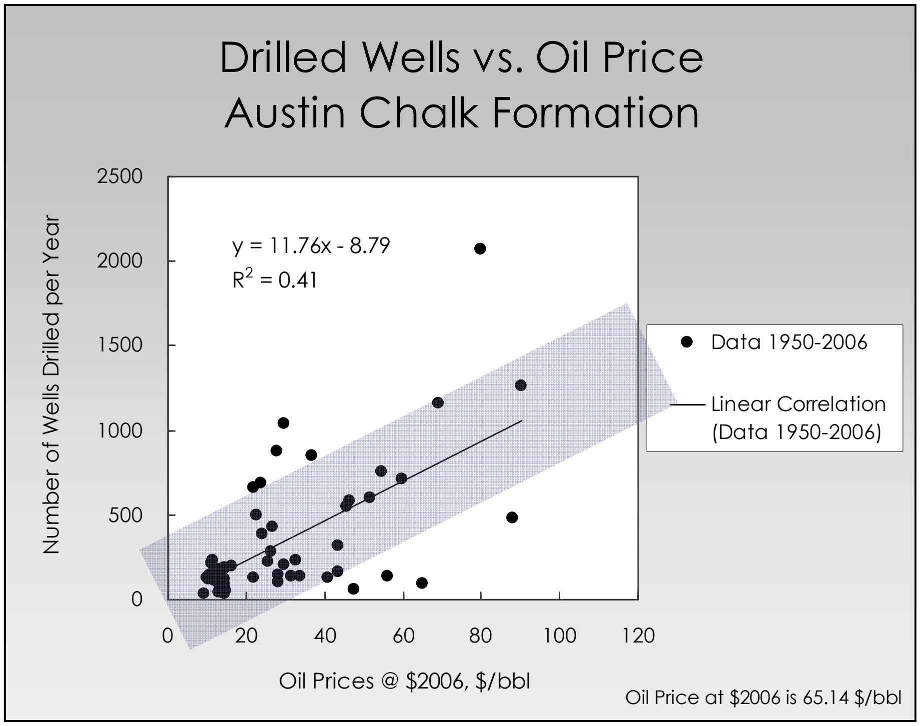


Fig. 7.8a—Austin Chalk wells drilled data shows that 41% of the wells between 1950 and 2006 depended on oil prices. Shaded area includes data from the main trend (data from Baker Hughes, 2008).

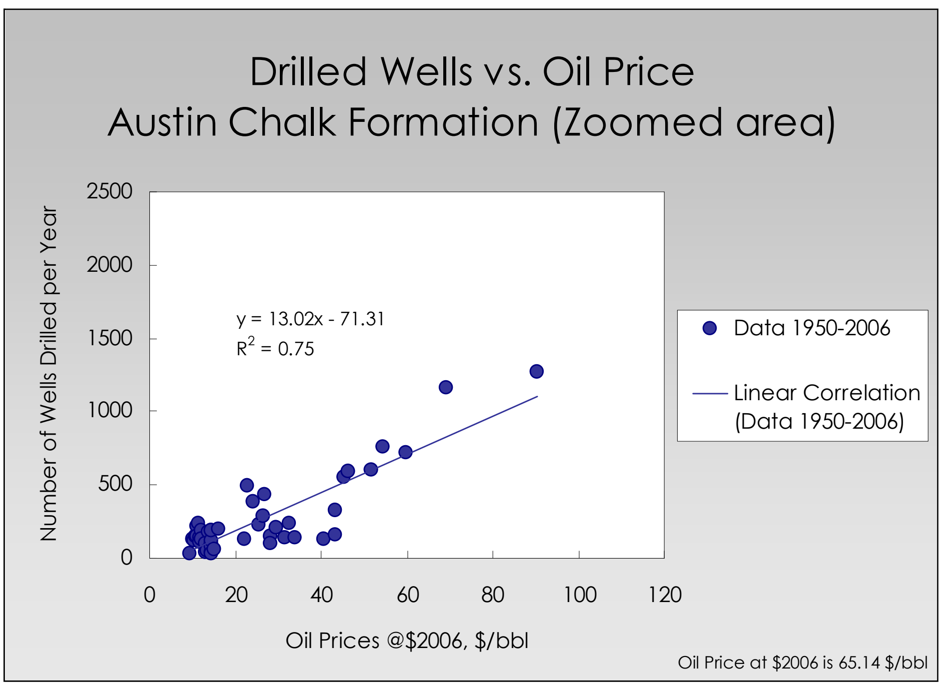


Fig. 7.8b—Shaded data in Fig. 7.8a improves the SRCC correlation value up to 75%. The variability in number of wells drilled between 1950 and 2006 can be explained with the variability of oil prices (data from Baker Hughes, 2008).

Fig. 7.9 shows the strength of the oil price and the number of wells drilled correlation for different periods of historical oil price fluctuation. Data from 1950 to 1979, Periods I to II, show the strongest SRCC of 0.8; followed by data from 1980 to 1997, Periods III to IV, with an SRCC of 0.54; and a last period from 1998 to 2006, Period V, with an SRCC of 0.33.

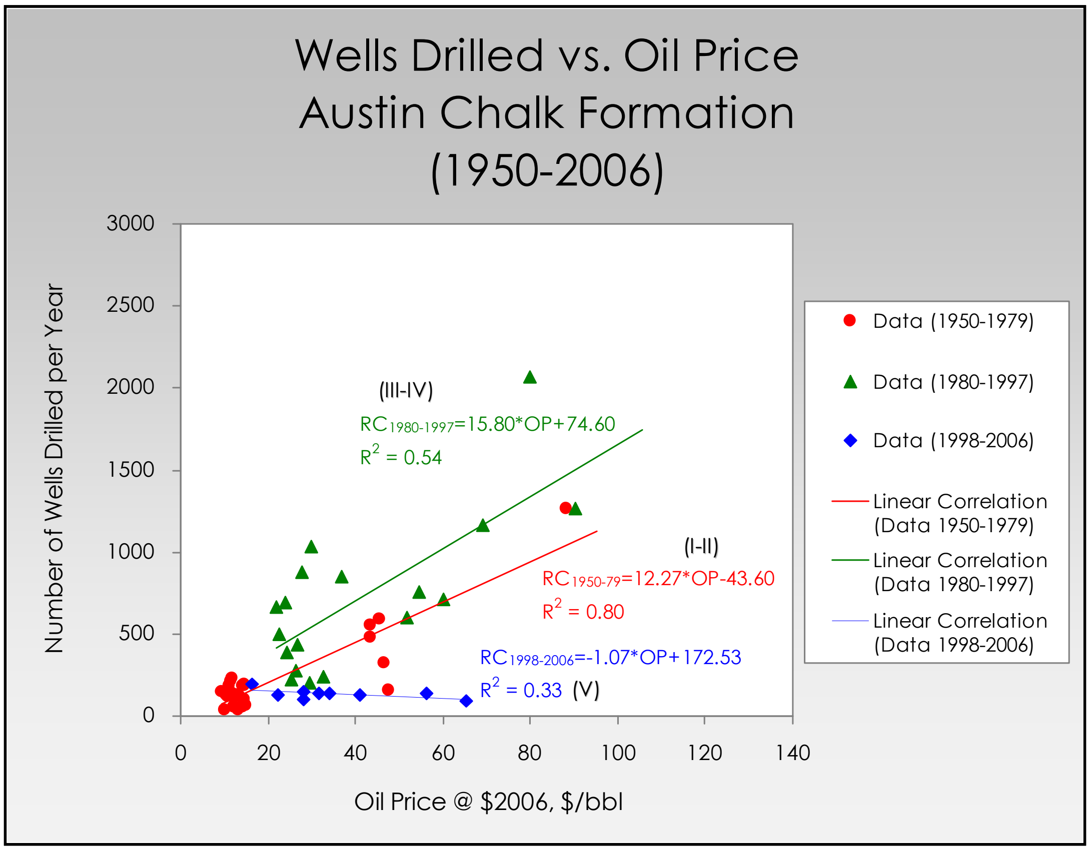


Fig. 7.9—A strong positive correlation was observed for the Austin Chalk data between 1950 and 1997. Recent data, from 1998 to 2006, show a decrease in number of drilled wells although the oil prices were increasing.

The relationship between the oil prices and the drilled wells is reasonably proportional when observing data during Periods I to IV. On the contrary, data from Period V show an increase in oil prices while the number of drilled wells decreases (Fig. 7.9). Again, there is not much infill drilling opportunity in the Austin Chalk fields; thus the number of wells drilled has not increased in the 2000s.

Please observe that Periods I to II, data from 1950 to 1979, show that on average for every dollar added to the oil price, the number of wells drilled increased by 12. Similarly, Periods III to IV, data from 1980 to 1997, show an increase in number of wells drilled around 16; however, Period V, from 1998 to 2006, shows that for every dollar added to the oil price, the number of wells drilled goes around one well on average; the rate of growth of the number of wells drilled decreased by 91% from Periods III to IV to Period V.

7.3.1.1.1 Relation between the Variables Rig Count and Producing Wells

We have observed how periods of high commodity price encourage higher rig activity in the Austin Chalk. In general, the variable wells drilled will exhibit a higher growth during periods of high commodity price, while during periods of low commodity price; the variable wells drilled will either stabilize or decrease **(Fig. 7.10)**.

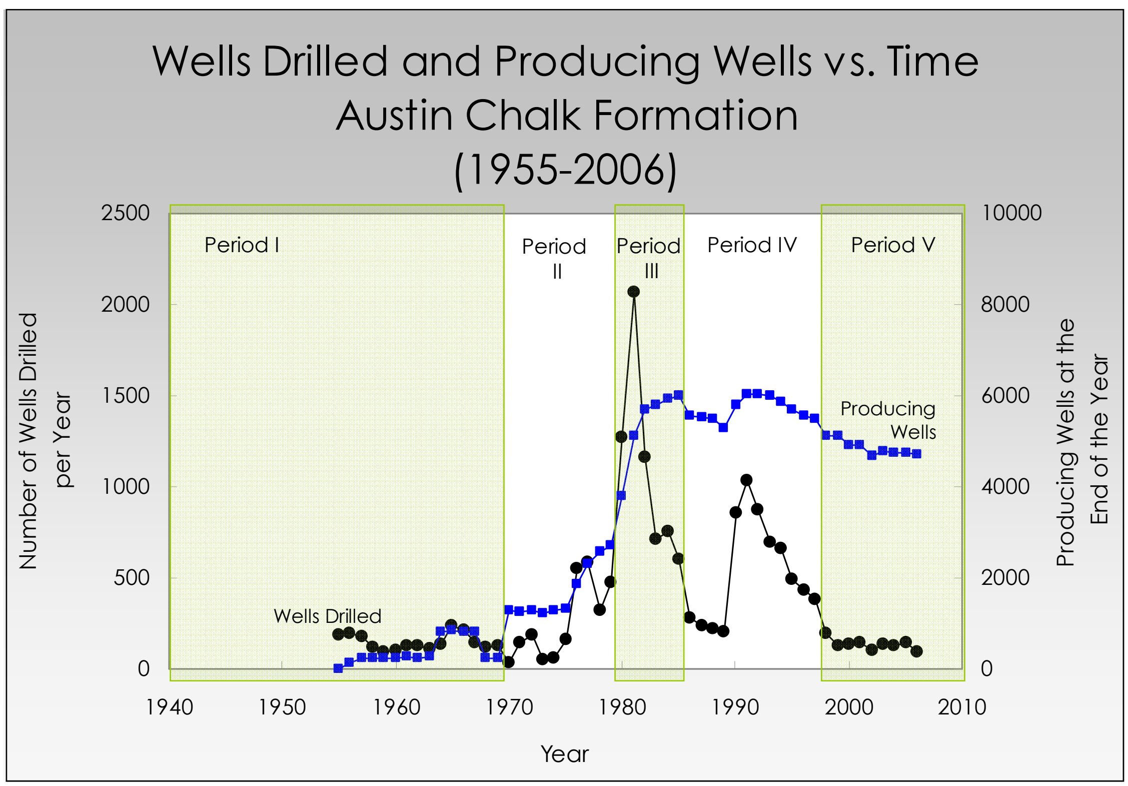


Fig. 7.10—The Austin Chalk formation drilling activity has been driving the number of producing (active) wells in the play.

Wells drilled data from our textbook case, the Austin Chalk formation, is shown in Fig. 7.10. We studied the correlation between the rig count data and the number of producing (active) wells with time. We found that data describing the wells drilled and the number of producing wells from 1950 to 2006 from the Austin Chalk formation follows a similar trend when plotted against time, as shown in Fig. 7.10.

In general, the number of producing (active) wells will always increase with time whether prices increase or decrease. In the Austin Chalk, periods of high drilling activity have increased the number of producing wells while periods of low drilling activity have shown a slight decrease in the number of producing wells; we have used the rate of growth of producing (active) wells to illustrate this tendency. **Fig. 7.11** shows the variation of the number of wells drilled as oil prices increases or decreases. Data from 1950 to 2006 illustrate that the variation in number of wells drilled.

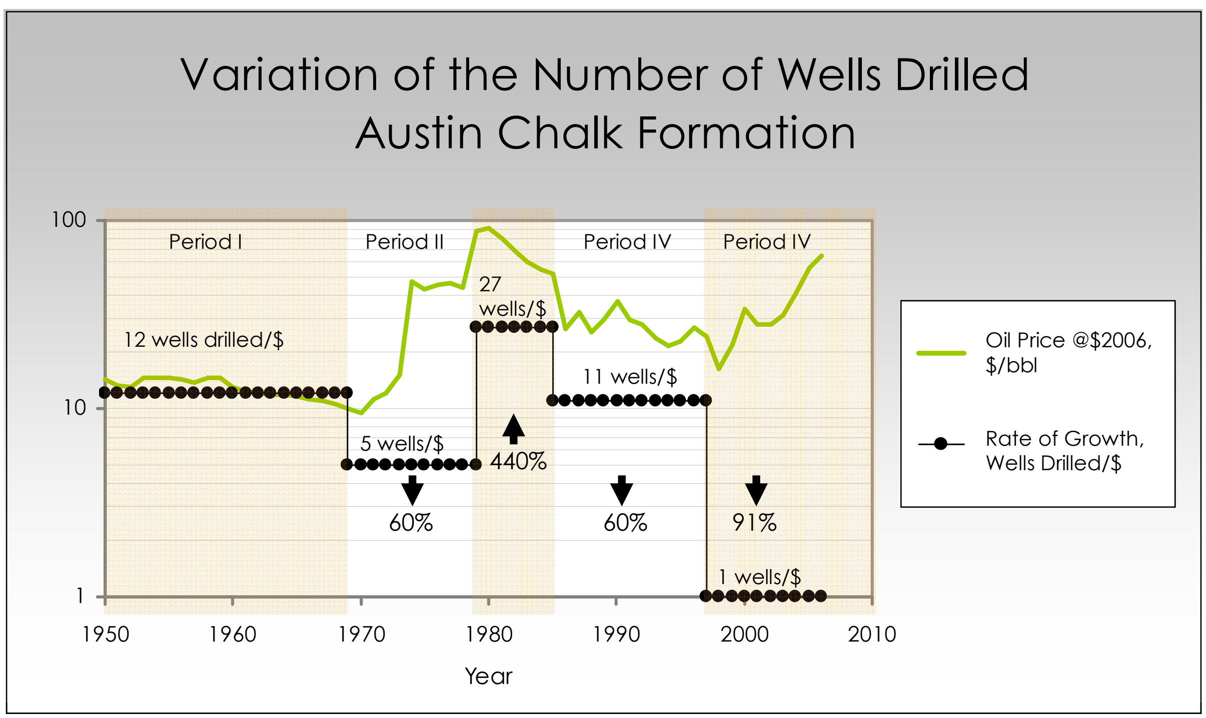


Fig. 7.11—The rate of increase in the number of wells drilled is a measure of the oil price market. Sharp changes in oil prices provoke great rate of increase, whereas stable price periods level off the rate of growth in the number of wells.

Periods I to IV show a similar tendency of decrease/increase in rate of growth for the number of wells drilled and the number of producing (active) wells. On the contrary, Period V follows a different pattern since the drilling activity during this period decreased although oil prices increased, producing a reduction in the rate of growth for the number of producing wells.

The variation of the number of producing (active) wells with time is observed in Fig. 7.11. Please note how the rate of growth of the number of producing (active) wells sharply increases or decreases as oil prices sharply increase or decrease. Data from Periods II to V show that the increase in oil price has increased the rate of growth of producing (active) wells around 170% while decreasing oil price has decreased the rate of growth around 100%. Also, please observe the peaks in the price of oil (Periods II, III, and IV) show higher values in the rate of growth of the number of producing wells.

The variation in the number of wells drilled with time is presented in Fig. 7.11. The rate of growth for in drilling activity decreases on average 60% during periods of stable to low oil prices, Period IV, and increases about 440% for periods of high oil prices, Period III, from data between 1950 and 2006.

7.3.1.2 Bakken Shale

The Bakken Shale of the Williston basin was initially developed using vertical wells but operators have recently turned to horizontal wells with spectacular success. **Fig. 7.12** shows the correlation between producing wells and oil prices for data available since 1961.

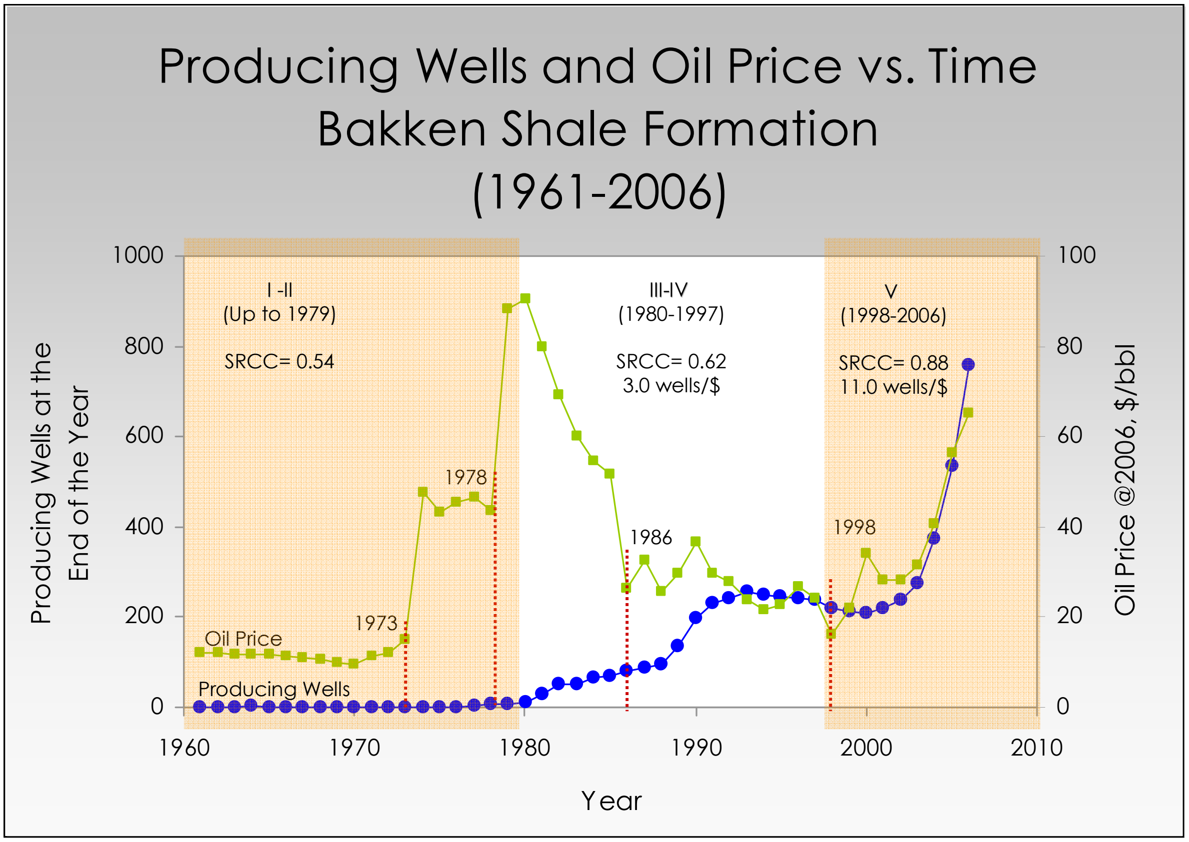


Fig. 7.12—Historical data from the Bakken Shale formation show similar tendency between producing wells and oil prices for data available since the late 1990s.

The number of producing wells for the Bakken Shale formation (BKS) of Williston basin from 1961 to 1988 was less than 100. Periods IV and V (from 1986 to 2006) showed greater activity in the Bakken Shale with production from more than 100 wells and the application of horizontal drilling.

The graph of producing wells versus oil price for the Bakken Shale, from 1961 to 2006 shows no correlation **(Fig. 7.13)**. However, since 2000, the activity in the Bakken Shale has increased rapidly due to both the use of horizontal wells and higher oil prices.

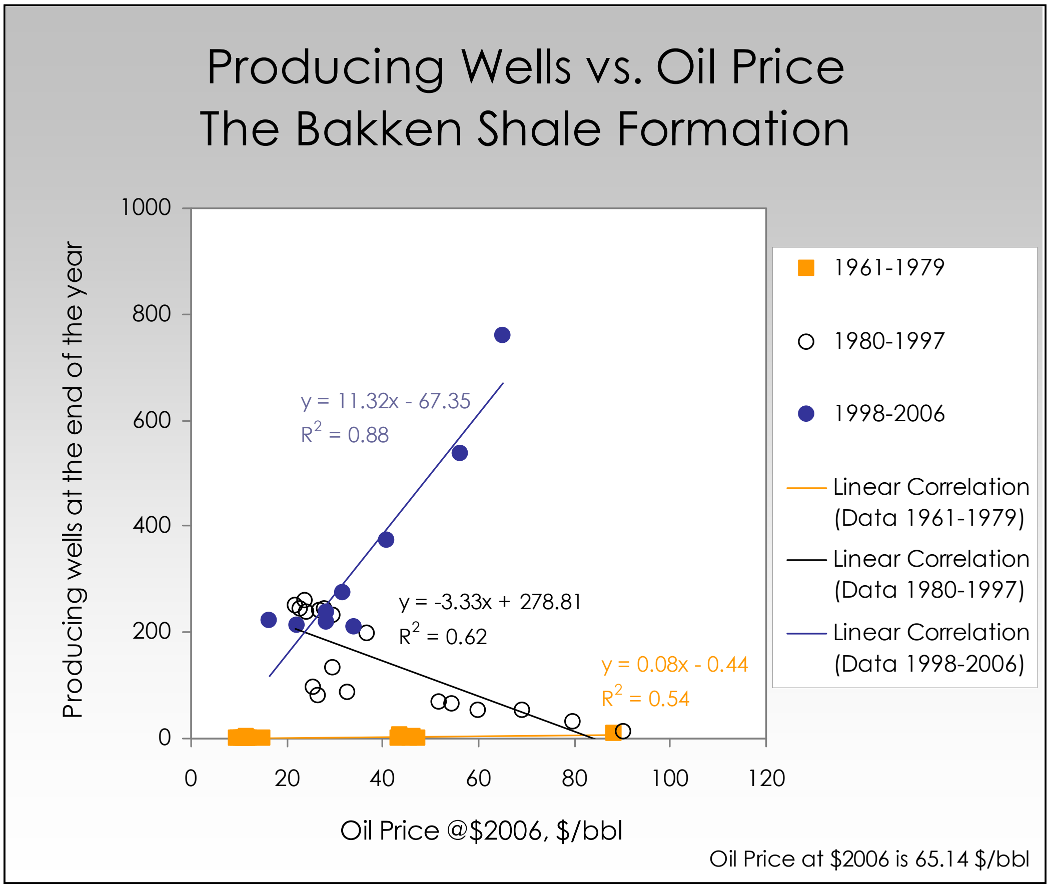


Fig. 7.13—Producing wells and oil price data from the Bakken Shale formation showing three different patterns and better correlation since the 1980s.

Producing well data since 1986 show more well activity in the play with a stronger correlation factor between the number of active wells and oil prices (Period V). Horizontal drilling in the Bakken Shale started during Period V, increasing the rate of growth in number of producing wells by more than 270% for every dollar added to the oil price.

7.3.2 Natural Gas Producing Formations

Based on the historical US gas price data, we identified four periods of correlation for natural gas formations **(Table 7.5)**.

TABLE 7.5— GAS PRICE TENDENCY CHANGES

Period	Event	Tendency
I (Up to 1969)	Product availability.	Stable to low prices.
II (1970-83)	The Yom Kippur war and Iranian Revolution created the 1970s oil crises and intrastate gas prices increased.	High prices, up-ward trend.
III (1984-92)	OPEC production cut's kept prices high, plus there was excess gas supply.	High prices, downward trend.
IV (1993-2006)	Full gas price deregulation allowed gas to behave as a tradable commodity. Gas supply bubble is eliminated. More market demand for natural gas.	High prices, up-ward trend.

The following cases in this section are natural gas producing formations with Table 7.5 as input data to analyze periods of high or low price tendency and its influence over the variation of the number of producing wells during the development of the tight gas sand formations of the Cotton Valley and Mesaverde groups and the gas shale formations of the Antrim, Barnett, and Lewis shales.

7.3.2.1 Cotton Valley Group

The tight sands of the Cotton Valley Group had substantial development after the oil crises in the 1970s and more recently in the 2000s with stable to high gas prices. From 1973 to 1978, the number of producing wells dramatically increased by more than 340% **(Fig. 7.14)**.

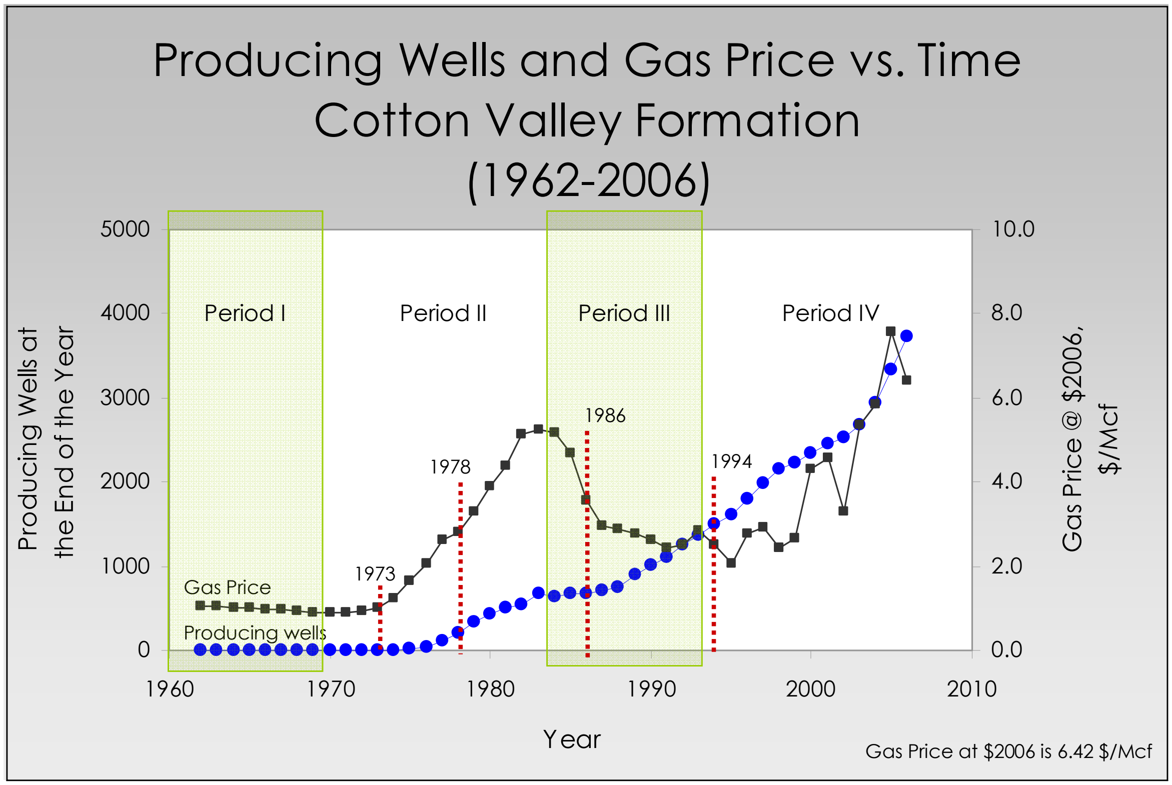


Fig. 7.14—Cotton Valley correlation factors between parameters "total wells drilled per year" and "commodity prices" show better results during the period 1958-1995 during the oil crises and the oil price collapse events.

Although drilling rig activity decreased in the US during period III, the number of producing wells from the tight sands of the CVG continued increasing around 10% per year until the early 1990s. The reason more Cotton Valley wells were drilled in the late 1980s and early 1990s was that these wells were classified as tight gas and they could earn federal income tax credits for every Mcf produced. Thus, like high prices and better technology, tax incentives also result in more wells being drilled to produce gas from the lower portion of the resource triangle.

The general SRCC of 0.49 between producing wells and gas price data from the Cotton Valley indicates that 49% of the producing wells from 1962 to 2006 depended on the variable gas price. Data also suggest that around 434 new producing wells were added when the price of gas increased by one dollar. **Fig. 7.15** shows the producing well data versus the price of gas in 2006 dollars between 1962 and 2006 from the tight sands of the Cotton Valley Group.

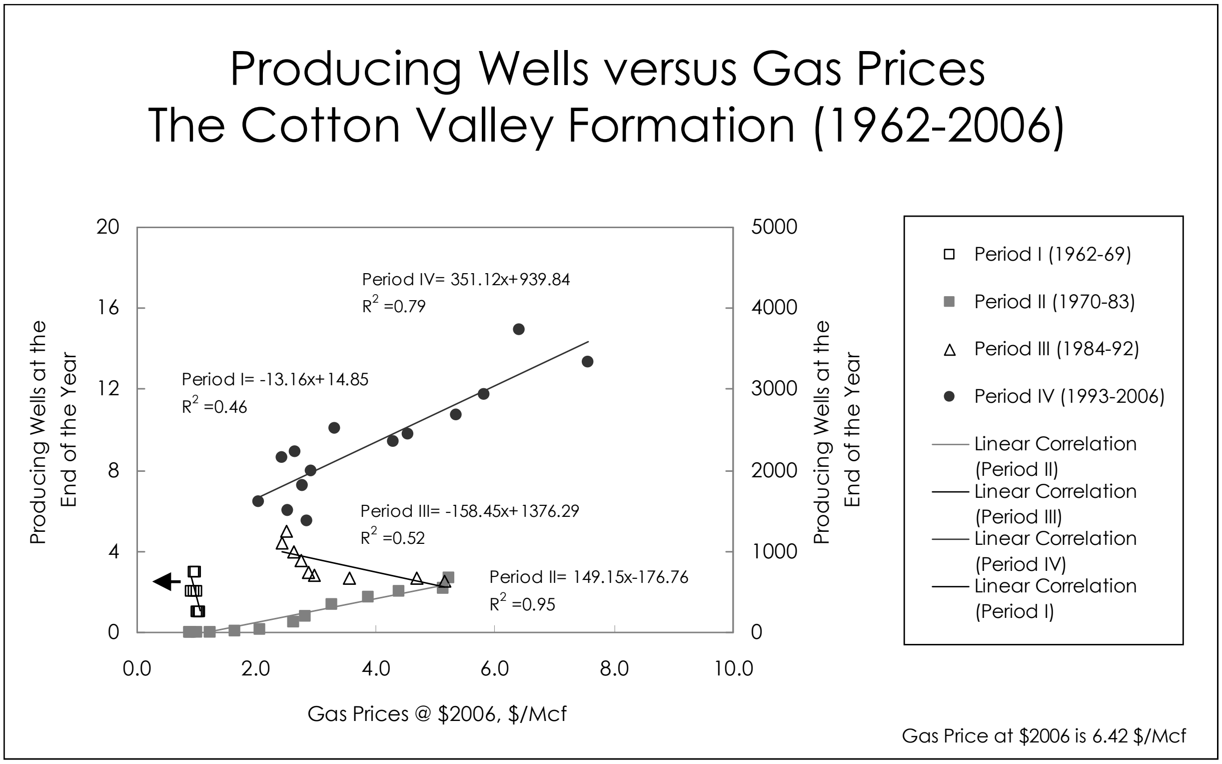


Fig. 7.15—Historical data from the Cotton Valley Group shows that, in general, 49% of the wells depend on the gas price variable.

In the Cotton Valley Group, periods of high commodity price are characterized by a strong SRCC factor. The data, in Fig. 7.15, show an SRCC factor of 0.95 during the oil crises period (II) and a value of 0.79 during the recent period of high gas prices (IV). Also, the Cotton Valley Group play data shows that the growth of producing wells have been driven by fluctuations in gas price since commercial production started in 1962 **(Table 7.6)**.

TABLE 7.6—CORRELATION FACTORS FOR THE COTTON VALLEY GROUP

	Period		SRCC (Producing Wells vs. Gas Price @ $2006)	Annual Growth of Producing Wells (wells/yr)
I	Up to 1969: Stable low prices		0.46	1
II	High prices	1970-1974	0.95	1
		1975-1983		87
III	Low prices	1984-1988	0.52	25
		1989-1992		118
IV	High prices	1993-2002	0.79	134
		2003-2006		355

High gas prices reached during the oil crises period (II) increased the growth in producing wells in 1046% and also gas production increased by 21-fold with the use of MHF treatments. In the 1990s, better fracture treatment technology, higher gas prices, and federal income tax credits fostered intense drilling activity in the play and the rate of growth of producing (active) wells continued increasing.

Data in table 7.6 indicate that the growth of producing wells have been driven by fluctuations in gas prices. For instance, during period II the Cotton Valley play was reporting a rate of growth in number of producing wells of 1.0 well/yr, on average; however, after prices peaked up in 1974, the rate of growth sharply increased by 87 wells/yr, on average. On the contrary, note that period III when prices went down, the rate of growth in number of producing wells decreased around 25 wells/year, until prices stabilized in the early 1990s and the rate of growth increased reaching around 118 wells/yr.

Fig. 7.16 shows the variation of the rate of growth of the number of producing wells through time and the fluctuations in gas price. As reference, we have also included the percentage of variation of the rate of growth.

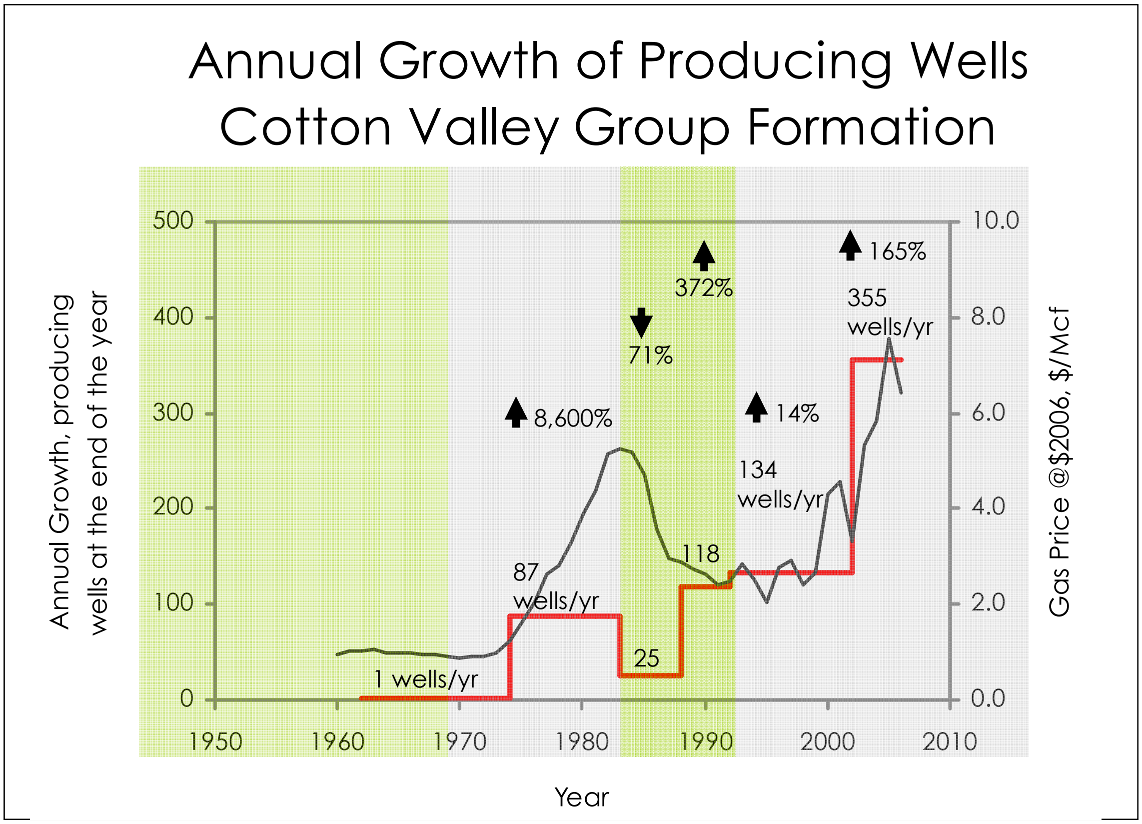


Fig. 7.16—Historical data from the Cotton Valley Group shows great dependence between the growth in number of producing wells and gas prices.

Please observe the major changes in rate of growth of the number of wells with time from the 1960s to the 1970s, and after full gas price deregulation in 1993. During the 1970s, Period II, the rate of growth was 8,600% and more recently, Period IV, up to a maximum of 165%. On average, after year-end 1988, the Cotton Valley play has been experienced increases in the number of producing wells; Fig. 7.16 shows these values.

Gas prices have impacted the rig activity in the tight sands of the Cotton Valley Group (CVG); however, the second episode, from 1993 to 2006, saw the most activity doubling the rate of growth in number of producing wells on average for every dollar added to the gas price. Period III, from 1985 to 1993, was characterized by a reduction in gas price to values lower than $2/Mcf (nominal price).

7.3.2.2 Mesaverde Group

The tight sands of the Mesaverde, the major producer of gas in the San Juan basin, have been under development since 1951. Historically, the rig activity in the Mesaverde has closely followed the fluctuations of commodity price. The growth of producing wells from 1951 to 2006 in **Fig. 7.17** illustrates this fact.

It can be observed that high gas prices during the 1970s caused an increase in the number of producing wells in the play until that the collapse in prices in the 1980s stabilized this growth. During the 1990s, after the US government deregulated gas prices and the federal income tax credits for tight gas sand was enacted, the number of wells drilled to the Mesaverde formation began to increase substantially.

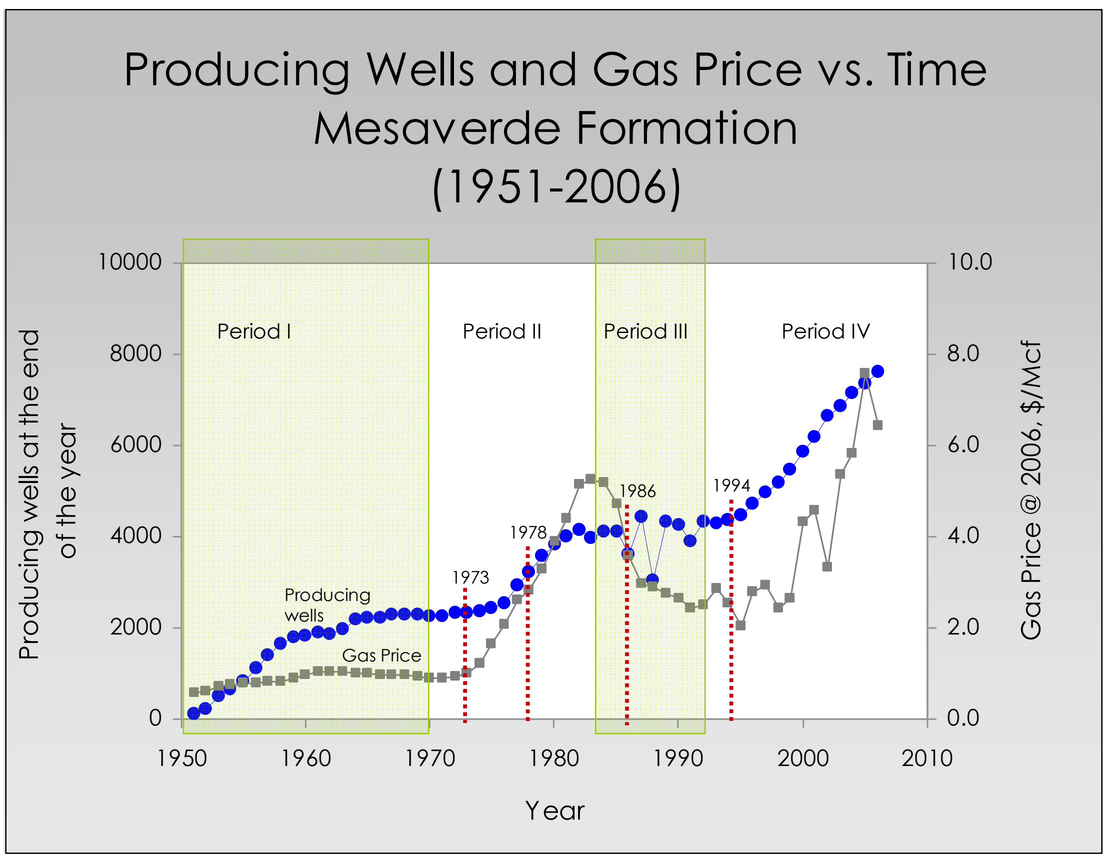


Fig. 7.17—Historical data from the Mesaverde Group show similar tendency between producing wells and gas prices.

The increase of gas prices during the 1970s supported the development of massive hydraulic fracturing (MHF) techniques in the play. The combination of higher gas prices and better stimulation technology increased the number of producing well from 2,317 in 1973 to 3,580 in 1979. The 1980s is, in most of the period, a decade marked by stabilization in well activity and production as well; the number of producing wells on average was around 4,000 (Fig. 7.17).

More recently, the formation has experienced a steady growth in the number of producing wells, especially after the gas price deregulation in 1993. Since the 1990s, the number of producing wells has grown almost 40%, increasing from 4,283 producing wells in 1993 to 7,605 wells in 2006.

Fig 7.18 shows the correlation between the number of producing wells and the fluctuation of the gas price adjusted for inflation in 2006 dollars. In general, a strong SRCC of 0.73 is observed. The correlation also suggests that for every dollar added to the price of gas, more than 900 wells came to production.

Table 7.7 shows the historical relationship between the gas price and the number of producing wells since production started in the early 1950s for the gas price correlation periods in Table 7.4. Data show an SRCC factor greater than 0.9 during the oil crises (II) period and a value of 0.8 during the recent period of high gas prices (IV). The analysis also shows no correlation at all between 1984 and 1992 (III) when the growth of producing wells in the play leveled off during low gas prices.

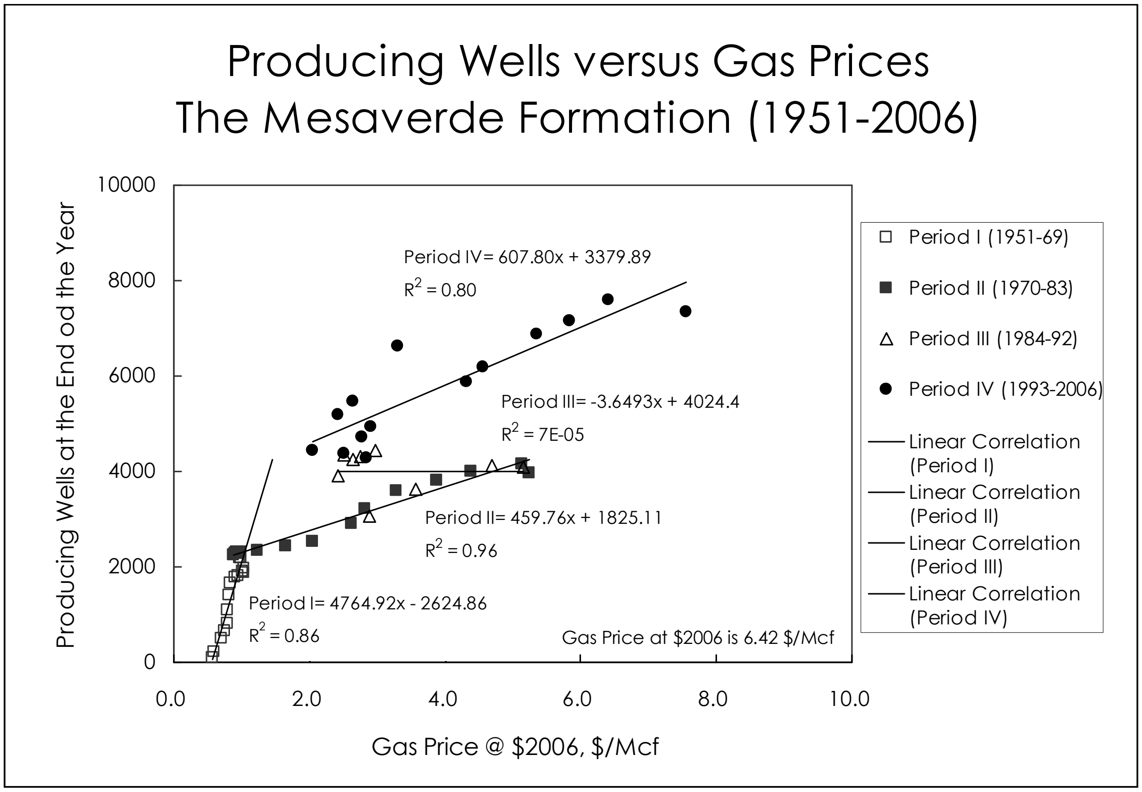


Fig. 7.18—Historical data from the Mesaverde Group suggest that, on average, more than 900 were open to production for every dollar added to the gas price.

The correlation analysis shows the variation of the rate of growth for producing wells in **Fig 7.19**. The greatest increase in rate of growth during Period IV increased the number of producing wells by 122 times.

TABLE 7.7—CORRELATION FACTORS FOR THE MESAVERDE GROUP

	Period	SRCC (Producing Wells vs. Gas Price @ $2006)	Annual Growth of Producing Wells (wells/yr)
I	Up to 1969: Stable low prices	0.86	4,762
II	1970-1983: High prices	0.96	462
III	1984-1992: Low prices	No Correlation	5
IV	1993-2006: High prices	0.80	11

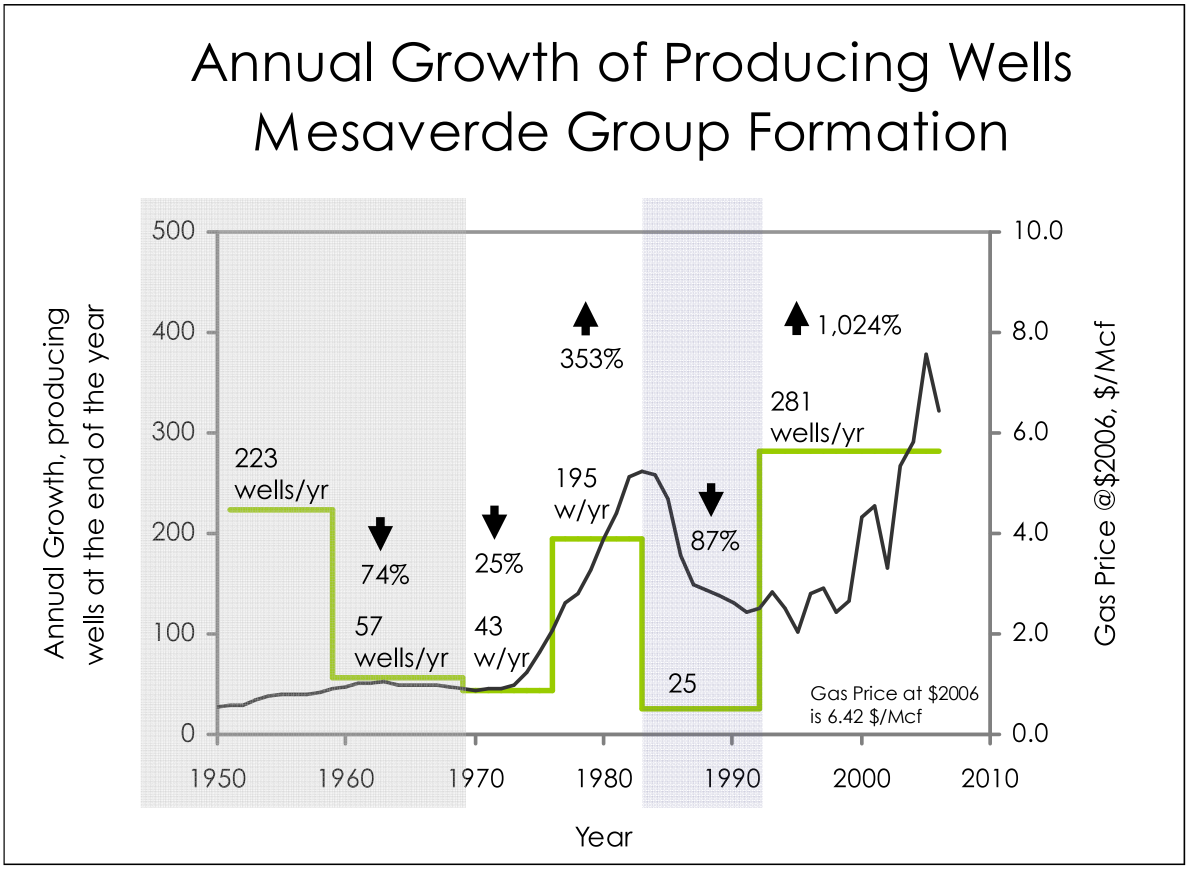


Fig. 7.19—Strong SRCC factor for the Mesaverde formation indicating the dynamic of gas price fluctuations affecting rig activity in the play since the 1950s.

7.3.2.3 Antrim Shale

From 1982 to 2006, the Antrim Shale formation of the Michigan basin has produced more than 2 Tcf of gas. The SRCC analysis shows two tendencies when plotting the number of producing wells and the gas price since production from the Antrim Shale (Periods III and IV) started in 1982 **(Fig. 7.20)**.

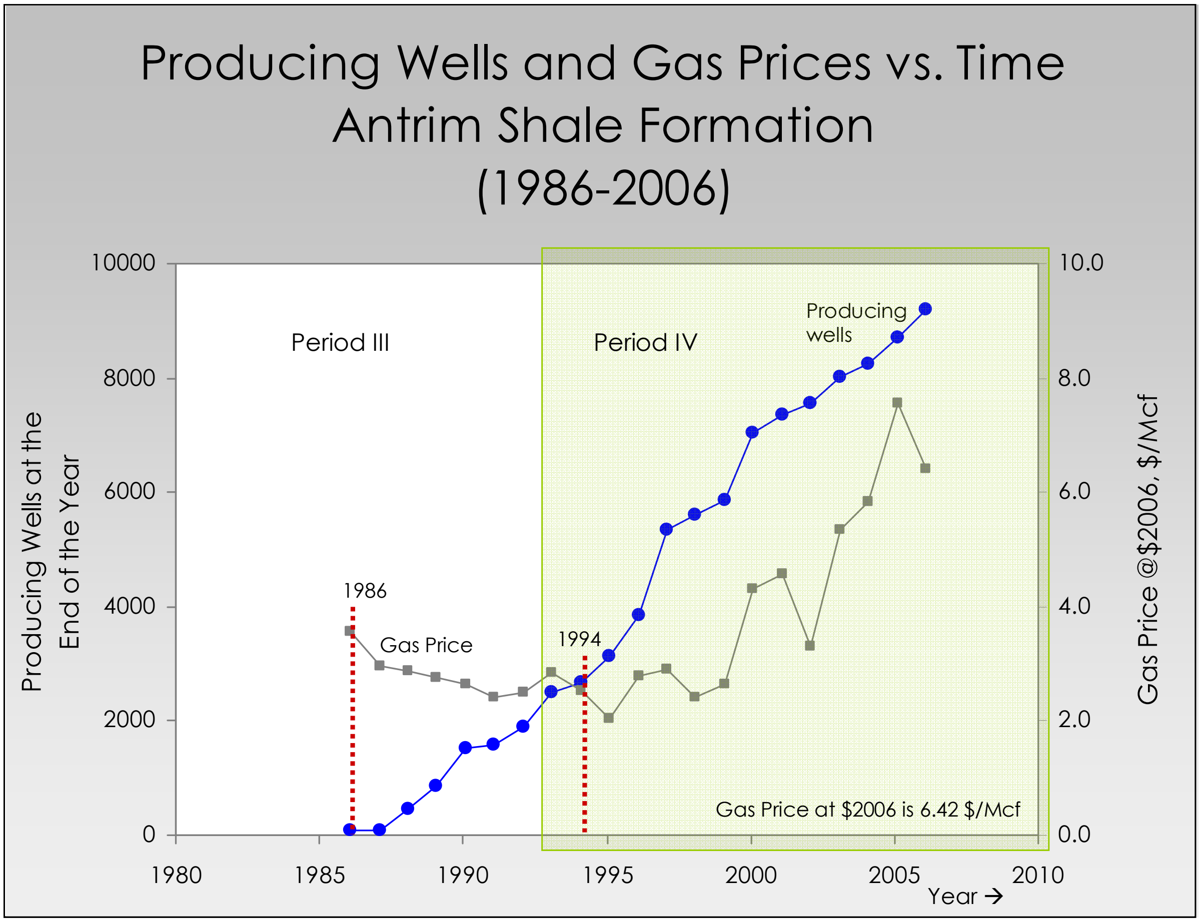


Fig. 7.20—Historical data from the Antrim Shale formation shows two tendencies of correlation between producing wells and annual fluctuations in gas prices.

The number of producing wells in the Antrim Shale from 1986 to 1993 (Period III) increased although gas prices were decreasing. The Antrim Shale was being developed due to both improvements in technology fostered by the Gas Research Institute and the federal income tax credits for producing gas from shales.

Period III for the Antrim Shale exhibits an SRCC of 0.69. Haas and Goulding (1992) noted that Section 29 credits stimulated the development of unconventional and high-cost gas resources like the Antrim Shale. From 1980 through 1992, when gas prices remained low, operators accelerated drilling from unconventional plays in the US and drilling activities in the Antrim Shale experienced great demand. On the contrary, from 1993 to 2006 or Period IV, a stronger and positive SRCC was observed, reaching on average a value of 0.72. The drilling activity during the 1990s was a sustained activity; more than 400 wells were drilled in 1998, and the following year about 75% of the wells drilled in the Michigan basin targeted the Antrim Shale play.

According to our review, the stimulation treatments performed in the Antrim Shale followed two stages with the use of MHF during the 1980s and early 1990s, and the use of light sand fracturing (LSF) treatments or waterfracs from the mid 1990s to the present. All these treatments have been performed in vertical wells. Horizontal wells have not been used in the Antrim.

7.3.2.4 Barnett Shale

The Barnett Shale has been one of the most prolific gas producing formations in the US in 2008. Historical data show that gas production has increased almost 10 times after operators began drilling horizontal wells, began applying better characterization technologies using microseismic, and using waterfracture stimulation treatments in the horizontal wells. The use of these technologies has increased the recovery factor per well through time from the Shale as reported in Chapter V (Fig. 5.14).

We have identified two different methods of stimulation that have been used in the Barnett Shale. MHF treatments (1991-1999) were used mostly in vertical wells and water fracture treatments (2000-2006) have mainly been applied to horizontal wells. **Fig. 7.21** shows the effect of technologies and gas price deregulation increasing activity in the play.

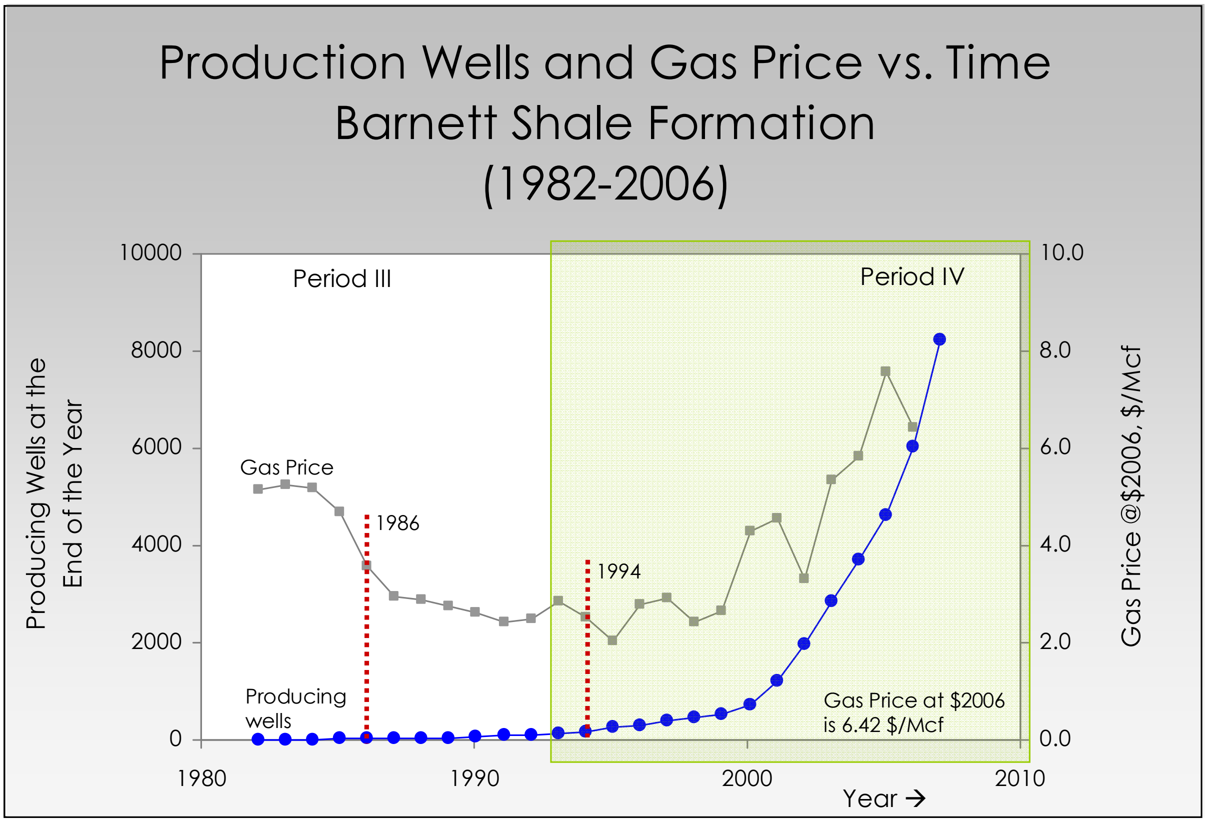


Fig. 7.21—Historical data from the Barnett Shale show the effect of technologies and higher gas prices after deregulation increasing well activity in the play.

Data from the Barnett Shale, Periods III and IV, show an overall SRCC of 0.52 **(Fig 7.22)**. Note that producing wells data after gas price deregulation in 1993 is affected by increases in gas prices since the 1990s and the evolution of stimulation technologies. Prices and better technologies have been driving the rig activity in the Barnett Shale and therefore increasing the number of producing wells as depicted in **Fig. 7.23**.

Fig. 7.23 shows a stronger and positive SRCC factor of 0.82 when plotting the number of producing wells at the end of the year and the gas price for Period IV.

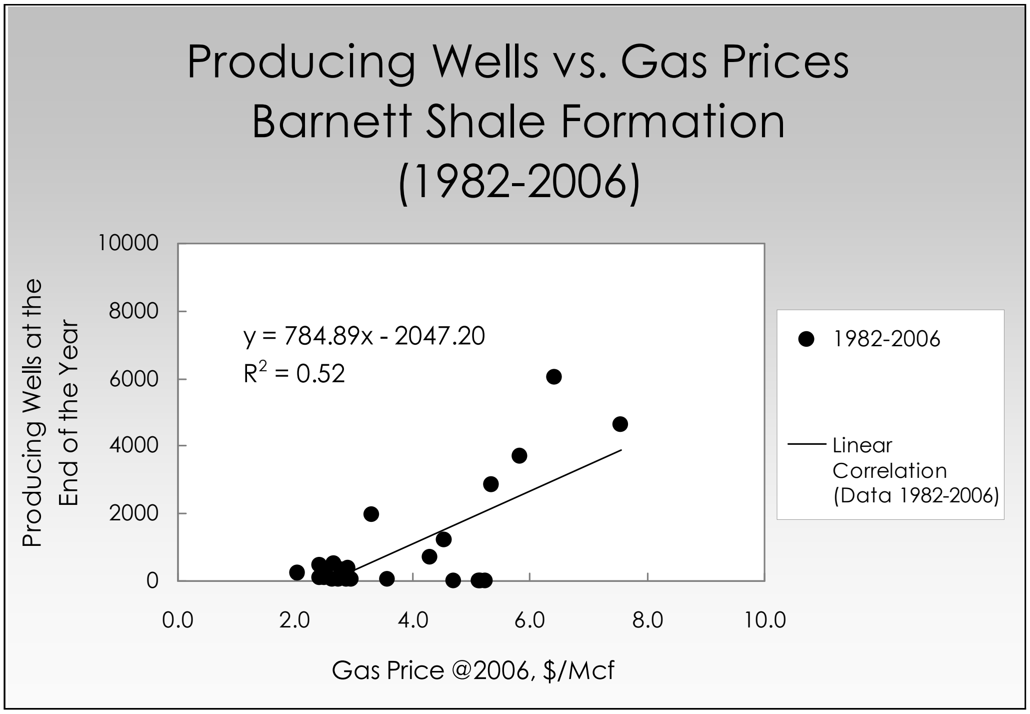


Fig. 7.22—Historical data from the Barnett Shale show how prices and the use of improved methods of stimulation have been driving the well activity in the play.

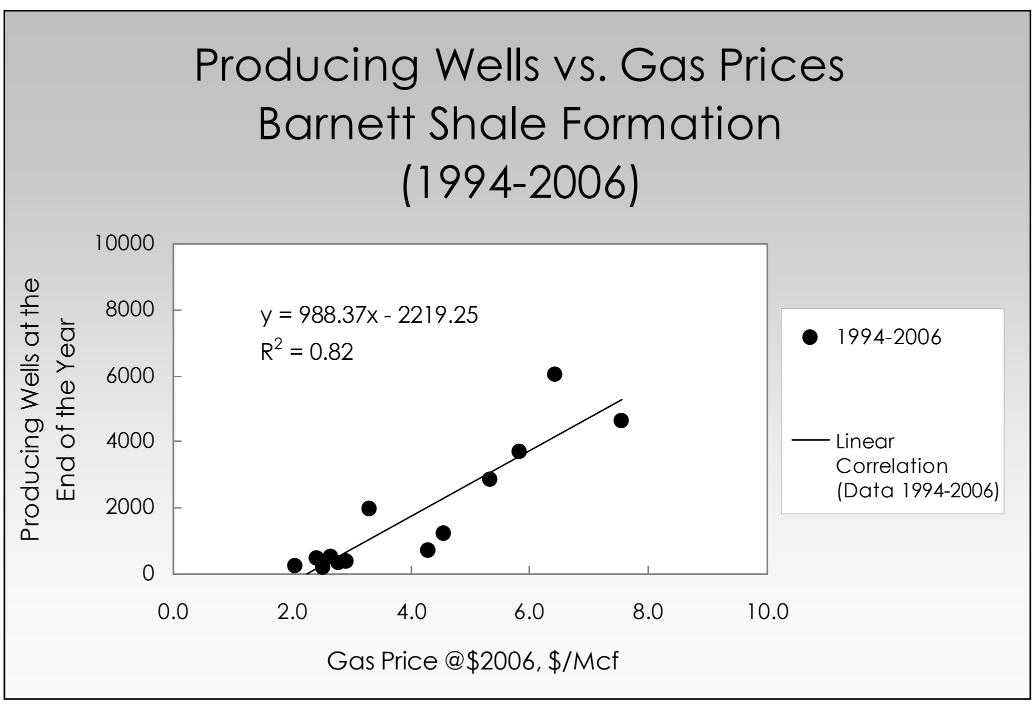


Fig. 7.23—Historical data from the Barnett Shale formation from 1994 to 2006 showing how technology and better gas prices support rig activity.

7.3.2.5 Lewis Shale

The variation in the number of producing wells for the Lewis Shale formation and its relation with gas price fluctuations is shown in **Fig. 7.24**.

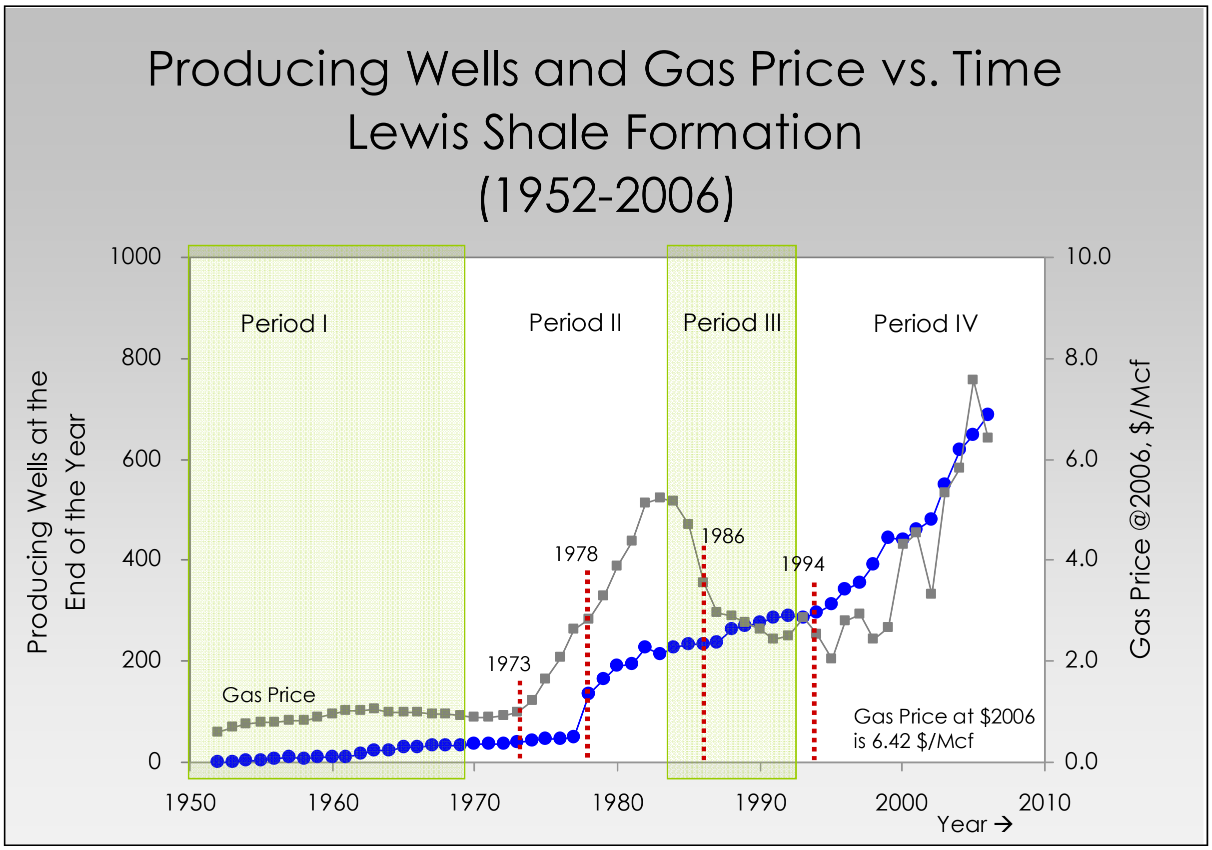


Fig. 7.24—Historical data from the Lewis Shale formation greater well activity since the late 1970s.

The correlation coefficient between the number of producing wells and gas price variables was calculated for the distinct periods since production from the Lewis Shale started in 1952. Historically, data from the Lewis Shale show that the play was not very active until after 1978 when the prices for natural gas increased. Historical data show that many of the producing wells in the Lewis Shale have been usually commingled with gas sandstone formations in the San Juan basin. As such, data from wells completed only in the Lewis Shale are not easily attainable.

A general correlation for the Lewis Shale of the San Juan basin shows a strong correlation of 0.7 between the producing wells and the gas prices in 2006 dollars. On average, around 92 wells are incorporated to production for every dollar added to the price of gas; however, a careful analysis of the data suggests four different patterns **(Fig. 7.25)**. Please, observe that gas prices not always drive the change in number of producing wells. Data from period's I-II and periods III-IV follow a similar tendency.

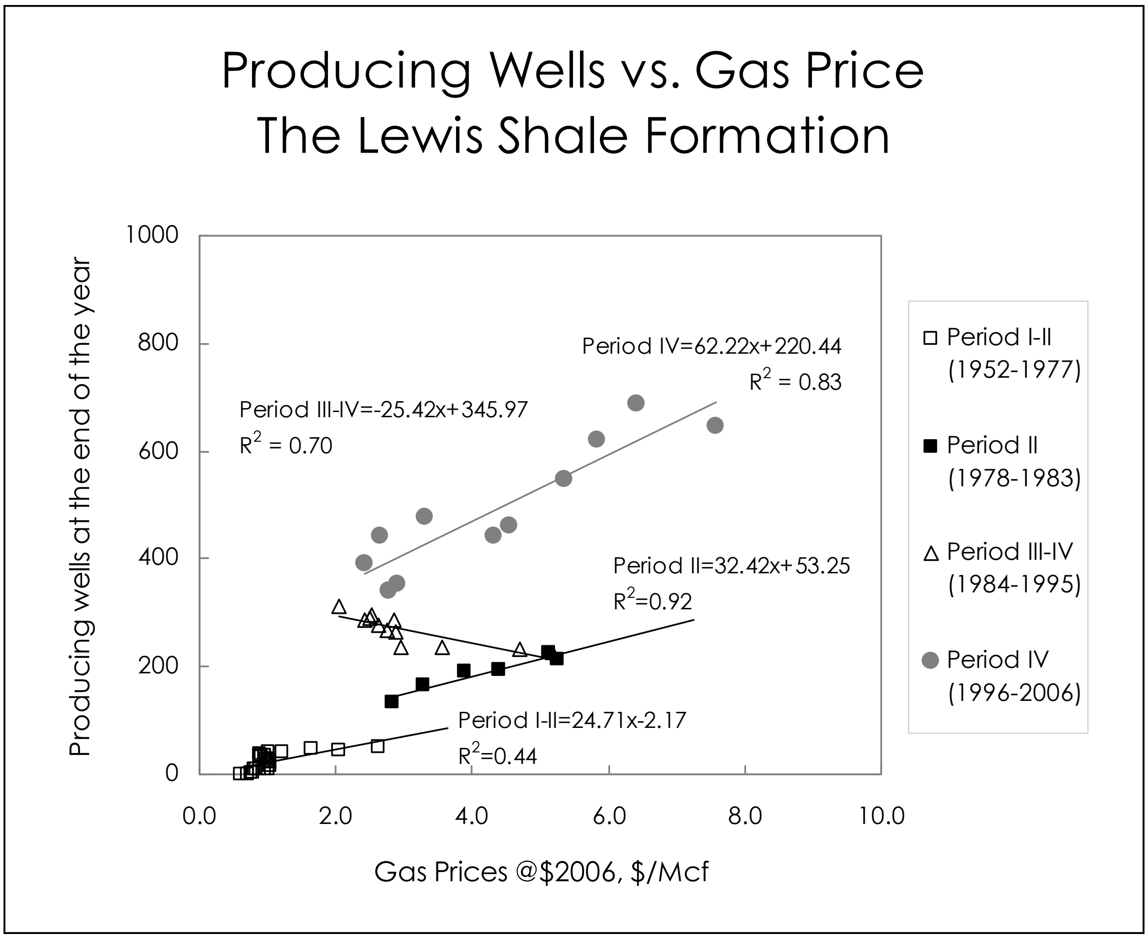


Fig. 7.25—Historical data from the Lewis Shale show positive tendencies of correlation between producing wells and annual fluctuations in gas price during periods of high gas prices. Data from 1984 to 1995 (Periods III-IV) is characterized by number of producing wells leveling off.

Fig. 7.26 shows the variation of number of producing wells for the defined four periods of gas price fluctuation. At the beginning of production with low stable prices from 1952 to 1970

(Period I), the growth of the play was very slow with less than 35 wells producing at the end of 1969. During Period I, the rate of growth in well number of 2 is probably marked for commingled completion strategies with sandstones present in the San Juan basin.

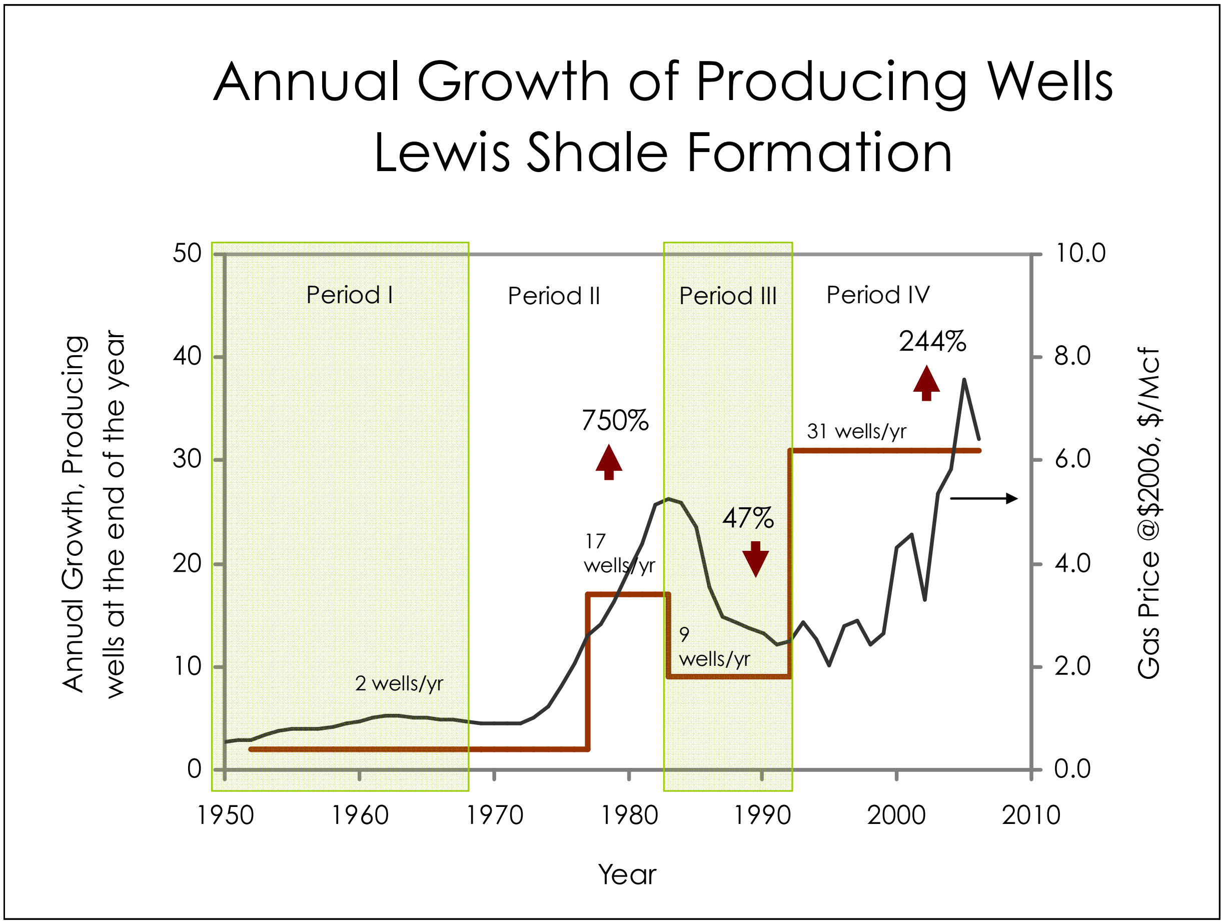


Fig. 7.26—Historical data from the Lewis Shale showing the variation in rate of growth in producing wells since 1952.

During the 1970s when gas prices went from \$0.89/Mcf (adjusted at 2006 dollars) in 1970 to \$3.28/Mcf in 1979, the number of producing wells in the Lewis shale increased almost eight-fold. The 1970s period (II) of high prices encouraged high well activity resulting in a strong SRCC factor of 0.94. The period from 1984 to 1992 (III) is characterized by a decrease in prices after the oil price collapse in the mid 1980s; however, since the Lewis shale continued its drilling activity, the SRCC factor shows a value of 0.68. More recently, from 1993 to

2006 period (IV), the Lewis Shale has experienced a sustained growth in number of wells supported by high gas prices; the number of producing wells increased around 31 wells/year, on average. Please, note in period IV, the SRCC correlation was 0.84 and the increase of the rate of growth in number of producing wells was 2.4 times (Fig. 7.26).

7.4 Forecasting Graphs

We developed a software to perform a series of decline curve analyses (DCA) required to evaluate the changes of Estimated Ultimate Recovery (EUR) under different scenarios of technology or/and price. Unconventional wells in low-permeability formations are always stimulated to increase productivity to commercial levels. Hydraulic fracturing is the most common stimulation treatment for the low-permeability formations and it is a common technology in each of our cases of study. We also consider that horizontal well bores are a form of formation stimulation.

7.4.1 Austin Chalk

As described in Chapter V, the Austin Chalk has experienced different periods of development that have been labeled as events in our study. The impacts of each of these events as defined in Table 7.2 are quantified in this section of my thesis to show how different technologies and periods of high commodity price have historically altered the production of the Chalk since 1955.

Fig. 7.27 shows the DCA results for the combined oil and gas production in Barrels of Oil Equivalent (BOE) using an economic limit of 5 BOE/day as well as the cumulative revenues at the end of each event. For convenience, we labeled the recognized periods of development in the Austin Chalk as acidizing, fracturing, oil crises, and new technologies. Five recognized events have affected the recovery in the Austin Chalk formation through time and the results from the decline curve analyses suggest that more than 500 million BOE could be produced over the next 30 years.

Cumulative values of combined oil and gas production in **Table 7.8** show the effect of different periods of production that have occurred in the Chalk. Acidizing and hydraulic fracturing treatments contributed 77 million BOE until the first oil embargo in 1973 doubled the number of producing wells and the production from these wells. The second oil embargo quadrupled the number of producing wells by year-end 1999, increasing the oil and gas production eight-fold compared to the fracturing event.

The results of the decline curve analyses performed for the Austin Chalk are also reported in Table 7.8. The estimated ultimate recovery (EUR), remaining reserves (RR), and gross revenues (adjusted for inflation at year-end 2006) by period were calculated.

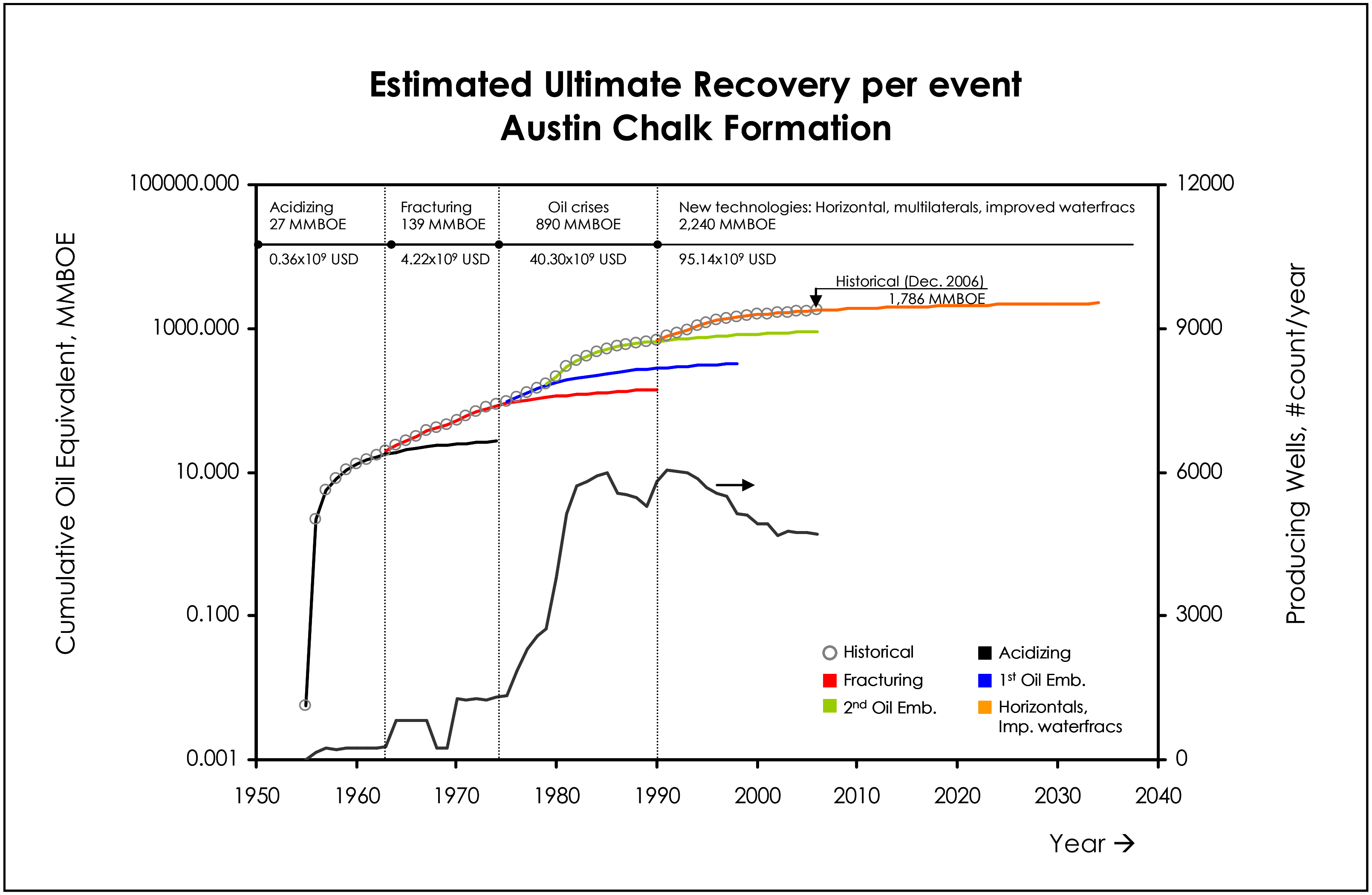


Fig. 7.27—Five recognized events have affected the recovery in the Austin Chalk formation through time. Decline curve analyses suggest that more than 500 million BOE could be produced over the next 30 years.

TABLE 7.8—OIL EQUIVALENT ESTIMATES FOR THE AUSTIN CHALK FORMATION								
EVENT	PERIOD	Cum., MMBOE	Producing Wells	Reserves, MMBOE	EUR, MMBOE	ΔEUR, MMBOE	Cum. Gross Revenues.	ΔGross Revenue
ACIDIZING	1955-1960	13	252	14	27	-	0.36	-
FRACTURING	1960-1974	77	1,237	62	139	112	4.22	3.9
1st OIL EMB.	1974-1979	147	2,593	170	317	178	12.76	8.5
2nd OIL EMB.	1978-1990	641	5,279	249	890	573	40.30	27.5
NEW TECH.	1990-2005	1,718	4,729	522	2,240	1,350	95.14	54.8
Gross revenues in billion dollars at $2006								

The two oil embargoes that occurred in 1973 and 1978 led to the higher oil prices and had a large effect on drilling in the Austin Chalk. Before the two oil crises occurred in the 1970s, production had increased by a factor of 6 when hydraulic fracturing was introduced but the absolutely value was relatively small. We computed that if the two oil crises had not occurred during the 1970s, the Austin Chalk formation would have reached a maximum recovery value of only 139 million BOE. The increased activity during the two oil crises raised the value of ultimate recovery by more than 6 times, reaching 890 million BOE for an economic limit of 5 BOE/day.

More recently, the use of new technologies such as horizontal and multilateral drilling, along with improved fracture treatment technology has increased production by more than 3 times. The new technology period or period of current development could result in a maximum value of 2,240 million BOE in ultimate recovery if no other technology is implemented or better characterization studies do not help to increase the value of recovery factor from the producing reservoirs in the Austin Chalk in the future. Our forecast predicted current remaining reserves of 523 million BOE recoverable in a 30-year span when producing at rates higher than 5 BOE/day.

If we considered the hydraulic fracturing case in the Austin Chalk, with no effects from the two oil crises, we could have expected an EUR of 139 million BOE. When the two oil crises increased prices above $30/bbl, EUR went to 890 million BOE, an increase of more than 6 times the earlier estimate. The additional production would translate to $36 billion in gross revenues considering a value of $65/bbl after year 2006.

The period following the two oil crises is labeled as new technology because of the improvements mainly in fracturing technology and horizontal drilling. The historical cumulative production at the end of this period is 1,786 million BOE and represents the coupling of improvements in technology with stable to high commodity prices. Our forecast shows a EUR value of 2,240 million BOE producible in a span of 30 years (Table 7.8). This value represents an incremental volume of 1,350 million BOE or 16 times more oil and gas production than expected from the fracturing alone. This greater volume would increase the gross revenue by $90.92 billion calculated in 2006 dollars and assuming the price of oil at $65.14/bbl after year 2006.

7.4.2 Bakken Shale

The forecasting analysis performed for the Bakken Shale (BKS) shows the effect of the different development periods since commercial production started in 1961. Please observe in **Fig. 7.28** that the Bakken Shale is a developing play that was reactivated by horizontal drilling activity in the 2000s.

The Bakken Shale is characterized by two periods of horizontal drilling, the nonstimulated period from 1988 to 2002 and the stimulated period from 2002 to date. Historical data in Fig. 7.28 shows the growth in producing wells and production from this play.

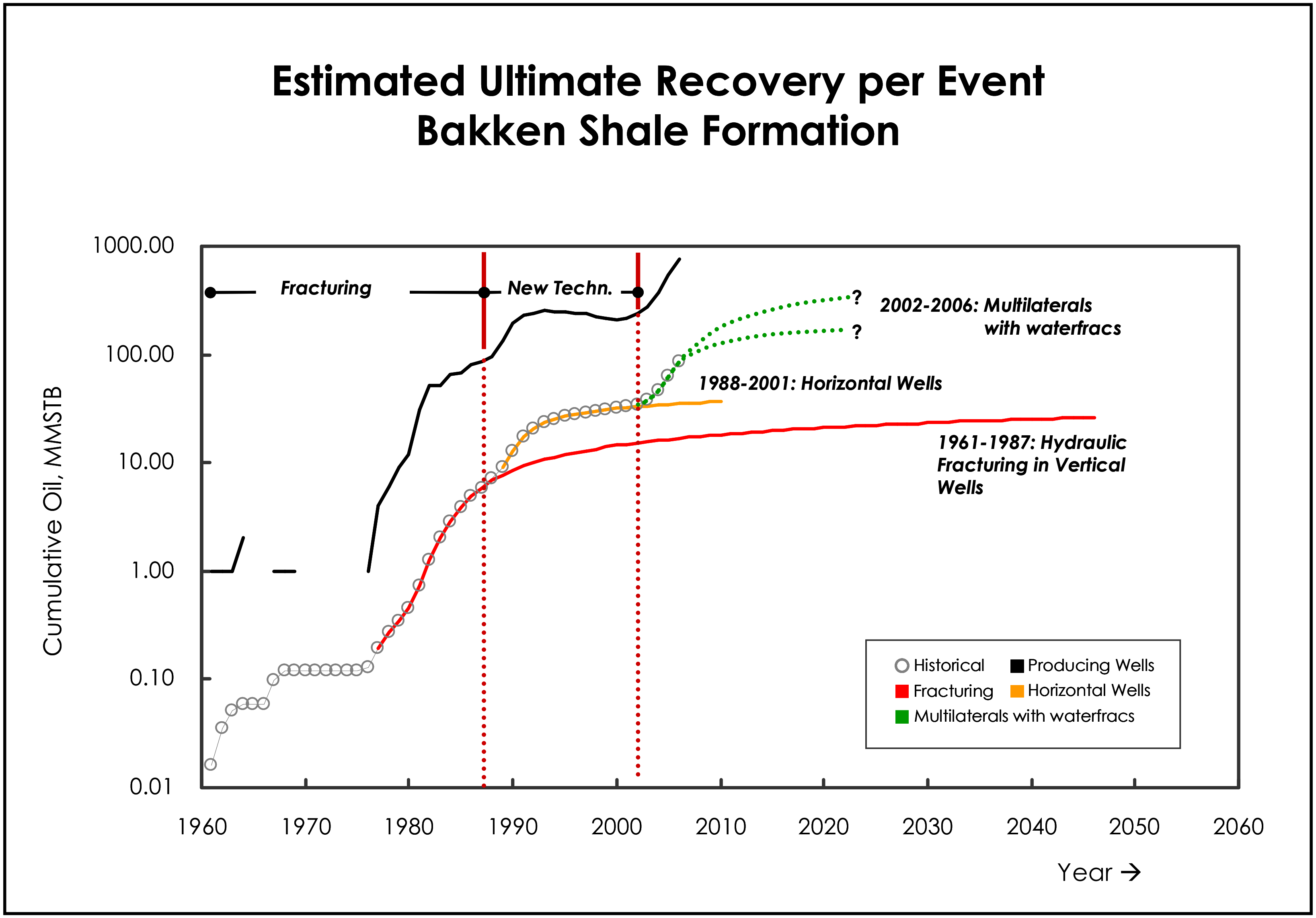


Fig. 7.28—The Bakken Shale formation of the Williston basin was revitalized by the use of stimulated horizontal wells.

The forecasting results were computed in both barrels of oil and barrels of oil equivalent and they are summarized in **Table 7.9** and **Table 7.10.** Forecasting results indicate the impact of horizontal drilling technology during the 1990s in terms of estimated ultimate recovery (EUR) and gross revenues calculated in 2006 dollars and assuming the price of oil at $65.14/bbl after year 2006.

TABLE 7.9—OIL ESTIMATES FOR THE BAKKEN SHALE FORMATION

EVENT	Cum., MMSTB	Producing wells	Reserves, MMSTB	EUR, MMSTB	ΔEUR, MMSTB	Cum. Gross Revenue	ΔGross Revenue
Fractured Vertical Wells (1961-1988)	6.3	88	20	26	-	1.23	-
Nonstimulated Horizontals (1988-2002)	32	212	4	37	11	1.25	0.02

Gross revenues in billion dollars at $2006

As depicted in Table 7.9, the cumulative oil during the fracturing activity from 1961 to 1988 is 6.3 million STB. The introduction of horizontal wells increased the cumulative value five-fold; however, the results in Table 7.9 only show the figures from nonstimulated, horizontal wells. Chapter V explained in detail the performance of horizontal wells drilled after year 2002. **Table 7.10** shows the DCA results for the produced oil and gas in terms of oil equivalent as a reference since the BKS is mainly an oil producer.

TABLE 7.10—OIL EQUIVALENT ESTIMATES FOR THE BAKKEN SHALE FORMATION							
EVENT	Cum., MMBOE	Producing wells	Reserves, MMBOE	EUR, MMBOE	ΔEUR, MMBOE	Cum. Gross Revenue	ΔGross Revenue
Fracturing Verticals Wells (1961-1988)	7.11	88	24.51	32	-	1.50	-
Nonstimulated Horizontals (1988-2002)	41.4	212	10.05	52	20	1.80	0.3
Gross revenues in billion dollars at $2006							

Our analysis shows the results for the base case, hydraulic fracturing vertical wells, and the results for the first horizontal drilling campaign of nonstimulated wells only. The Bakken play is developing so that the forecasting analysis for the more recent period of 2002-2006 is not available. The DCA shows that if no horizontal drilling had occurred in the Bakken, the maximum recovery would have been 26 million STB; in other words, under this scenario the Bakken would have produced only 30% of the historical cumulative oil reported by year-end 2006. The results of the DCA for oil production from the nonstimulated horizontal wells shot EUR to 37 million STB, an increase of 42% compared to the base case.

Current data published in 2008, indicate another increase in drilling activity for the Bakken Shale occurring as a result of improvements in horizontal well technology and increasing oil prices. In Fig. 7.28, it is clear that the production from the Bakken Shale will increase substantially during the next 5-10 years.

7.4.3 Cotton Valley

Cumulative values of produced gas from the Cotton Valley are reported in **Table 7.11** and show the effect of different events or production scenarios that occurred in the shale since 1962. The DCA results as well as the cumulative gross revenues in Table 7.11 were computed at an economic limit of 15 Mcf/day.

TABLE 7.11—NATURAL GAS ESTIMATES IN THE COTTON VALLEY GROUP

EVENT		PERIOD	Cum. Gas, Bcf	Reserves, Bcf	EUR, Bcf	ΔEUR, Bcf	Cum. Gross Revenues	ΔGross Revenue
FRACTURING		1962-1970	0.91	0.50	1.40	-	0.002	-
OIL CRISES	1st Oil Emb.	1970-1975	2.33	1.16	3.49	2.09	0.006	0.004
	2nd Oil Emb.	1975-1990	1,009	604	1,613	1,610	6.0	5.9
NEW TECH.		1990-2007	4,040	1,593	5,633	4,020	25.0	19.0

Gross revenues in billion dollars at $2006

Historical data show how the first fracturing treatments performed during the 1960s contributed around 1.0 Bcf until oil and gas shortage problems derived from the first embargo in the Middle East increased gas prices from $0.17/Mcf in 1970 to $0.30/Mcf in 1974. The increase in gas prices doubled both the number of producing wells and the production in the Cotton Valley. The cumulative gas reached the 2.33 Bcf by year-end 1974.

The second embargo had a greater impact and by the end of 1980 the Cotton Valley Group had produced more than 200 Bcf of gas from 400 wells. Gas prices in 1990 reached $1.71/Mcf and the play accumulated its first Tcf of gas, producing from more than 1,000 wells.

More recently the use of lower-cost water fracturing treatments, labeled as new technology in Table 7.11, starting in the early 1990s have increased gas production by drilling more wells. The use of new technologies tripled the cumulative gas reached in the 1990s and the play reached 3.0 Tcf in 2000. The rate of gas production from 1990 to 1998 has increased by 33% to 40% from 2000 to 2006. **Fig. 7.29** shows the results of the DCA for the natural gas production.

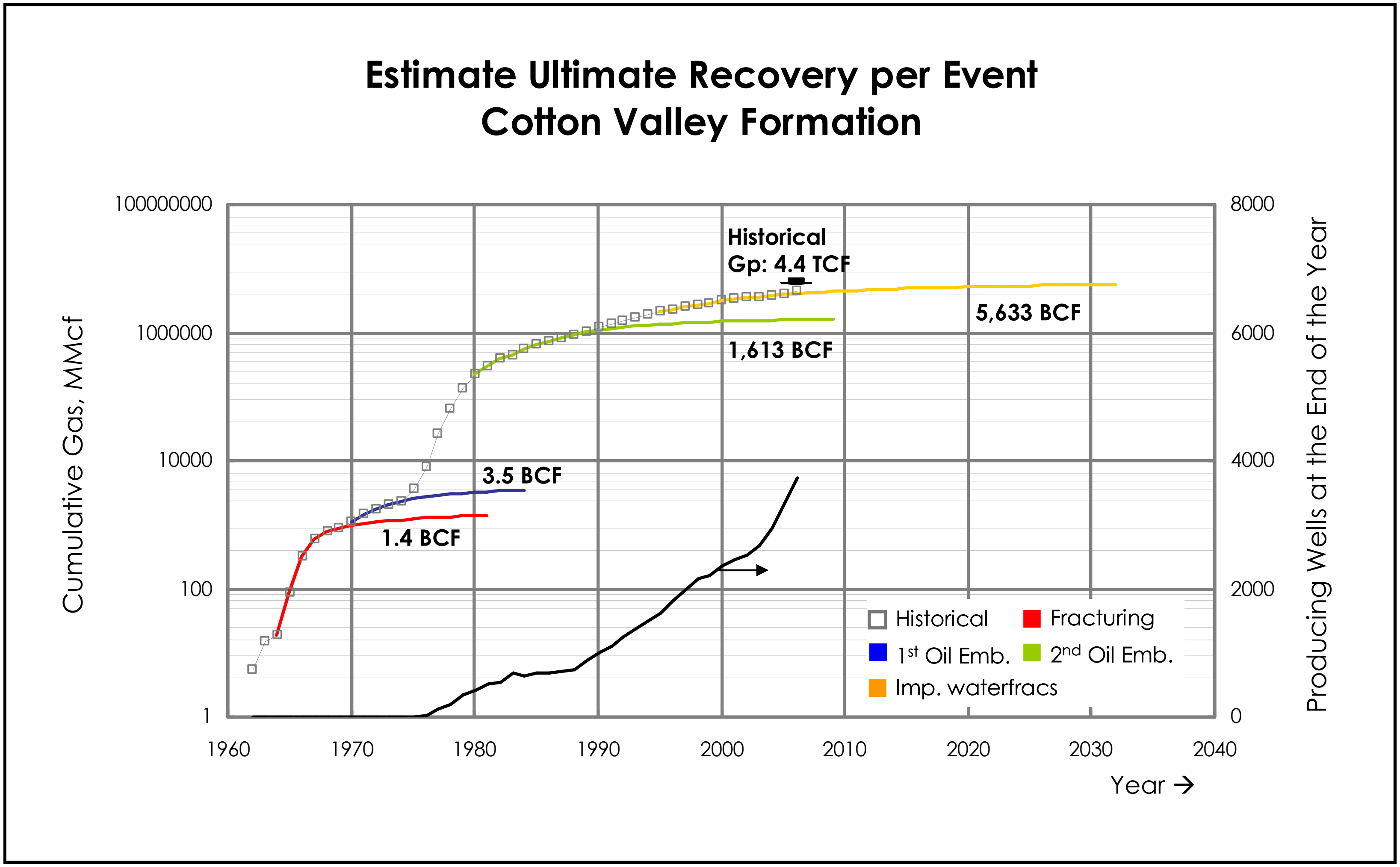


Fig. 7.29—The new technology period, the period of current development, could recover up to 6.0 Tcf if no other technology such as horizontal drilling is implemented for the tight sands of the Cotton Valley Group.

Fig. 7.29 shows the results of the DCA for the natural gas production. For convenience, we have labeled the recognized periods of development in the Cotton Valley as fracturing, first and second oil embargoes, and new technologies.

Please note in Fig 7.29 that the increase in natural gas prices that occurred in the 1970s increased production by a factor of 1,000. The increase in drilling was caused by a cycle of high gas prices until the mid-1980s when the well activity reached a plateau. In the 1990s and 2000s, more drilling occurred due to higher gas prices and the use of better fracturing technology.

The use of better fracturing technology defines the period of new technology in the play. The new technologies evolved with improvements in hydraulic fracturing techniques that have reduced costs and increased well activity. We found that if no new technologies had been implemented, the tight sands of the Cotton Valley Group could only have reached a EUR of 1.6 Tcf, or around 40% of the historical cumulative gas by year-end 2006.

Our forecasting shows that the new technology period could result in an EUR of 5.6 Tcf if no other technology such as horizontal drilling is implemented in the play or better characterization studies do not reveal ways to increase the value of the recovery factor (RF) in the reservoirs of the Cotton Valley Group. We found an additional 2.0 Tcf recoverable in a 24-year span, using an abandonment rate of 15 Mcf/day. This volume would increase revenue by $25 billion calculated in 2006 dollars and assuming the price of gas at $6.42/Mcf after year 2006.

7.4.4 Mesaverde Group

We have identified three periods of development in the Mesaverde Group formation of San Juan basin driven by the combination of advances in hydraulic fracturing treatments and reservoir characterization to improve infill drilling strategies. The three periods were characterized by the use of conventional hydraulic fracturing technologies in 320-acre spacing, the use of MHF during the oil crises period in 160-acre spacing, and the use of batter fracturing technology after the gas wellhead decontrol process was completed and gas prices started to increase. The third period is currently developing and is focused on searching for better infill strategies to improve the final recovery factor from the producing wells.

Cumulative values of produced gas in **Table 7.12** show the effect of different periods of production that occurred in the MVG. Fracturing treatments (the base case) performed during the first 20 years of exploitation contributed about 4.0 Tcf. When the oil crises in the Middle East increased stable low gas prices from $0.17/Mcf in 1970 to $1.18/Mcf in 1979, the number of producing wells in the Mesaverde increased by 60% and made possible the production of an additional 2.0 Tcf of gas. New technologies such as the use of better fracturing treatments and better characterization models to increase recovery factors in the reservoirs since the 1990s have been responsible for the production of about 4.0 Tcf of gas. The technological breakthroughs have been supported by increases in the commodity price; the price of gas by year-end 2006 increased 144% compared to its value in 1990.

The DCA results for the natural gas indicate the impact of new technologies increasing the final recovery from the reservoirs (Table 7.12). Initial fracturing treatments performed in the wells have produced around 4.0 Tcf of gas. Observe that if the oil crises had not occurred during the 1970s, the Mesaverde Group would have reached an EUR value of only 6.0 Tcf of gas, a volume that represents half the cumulative production to date from the Mesaverde Group formation. The oil crises period produced 8.0 Tcf of gas, and our forecast analysis showed that with no changes in production conditions at the end of the period, the Mesaverde Group would have reached a maximum value of 9.0 Tcf of gas, an addition of 45% more gas than the fracturing event alone. The search for better hydraulic fracturing treatments and better infill drilling strategies characterize the new technologies period.

TABLE 7.12—NATURAL GAS ESTIMATES FOR THE MESAVERDE GROUP									
EVENT		PERIOD	Cum. Gas, Bcf	Producing Wells	Reserves, Bcf	EUR, Bcf	ΔEUR, Bcf	Cum. Gross Revenues	ΔGross Revenue
FRACTURING		1951-1973	3,786	2,306	2,374	6,160	-	10	-
OIL CRISES	1st Oil Emb.	1976-1980	5,290	3,148	2,431	7,721	1,561	15	5
	2nd Oil Emb.	1978-1991	8,010	3,766	894	8,904	1,183	19	4
NEW TECH.		1992-2006	11,954	7,352	3,220	15,174	6,270	53	34
Gross revenues in billion dollars at $2006									

Our DCA model in **Fig. 7.30** indicated that the Mesaverde play could reach a maximum EUR of 15 Tcf if no other technology is implemented after year-end 2006. The EUR value for the new technology period is 246% greater than the calculated EUR value for the fracturing period from 1951 to 1973 as indicated in Table 7.12.

If we considered hydraulic fracturing treatments occurred from 1951 to 1973 as the base case with no effects from the oil crises, we could have expected a total revenue of $10 billion; however, when the gas prices increased above $1.0/Mcf, EUR reached around 9.0 Tcf, an increase of 1.4 times the earlier estimate. The increase of gas prices during the 1970s almost doubled the calculated gross revenues; our calculations showed a maximum of $20 billion at year- end of 1991.

The new technology period, currently developing, shows that the tight sands of the Mesaverde Group in the San Juan basin could recover more than 3.0 Tcf of gas and generate an additional of $19 billion in a 20-year span using an abandonment rate of 15Mcf/day.

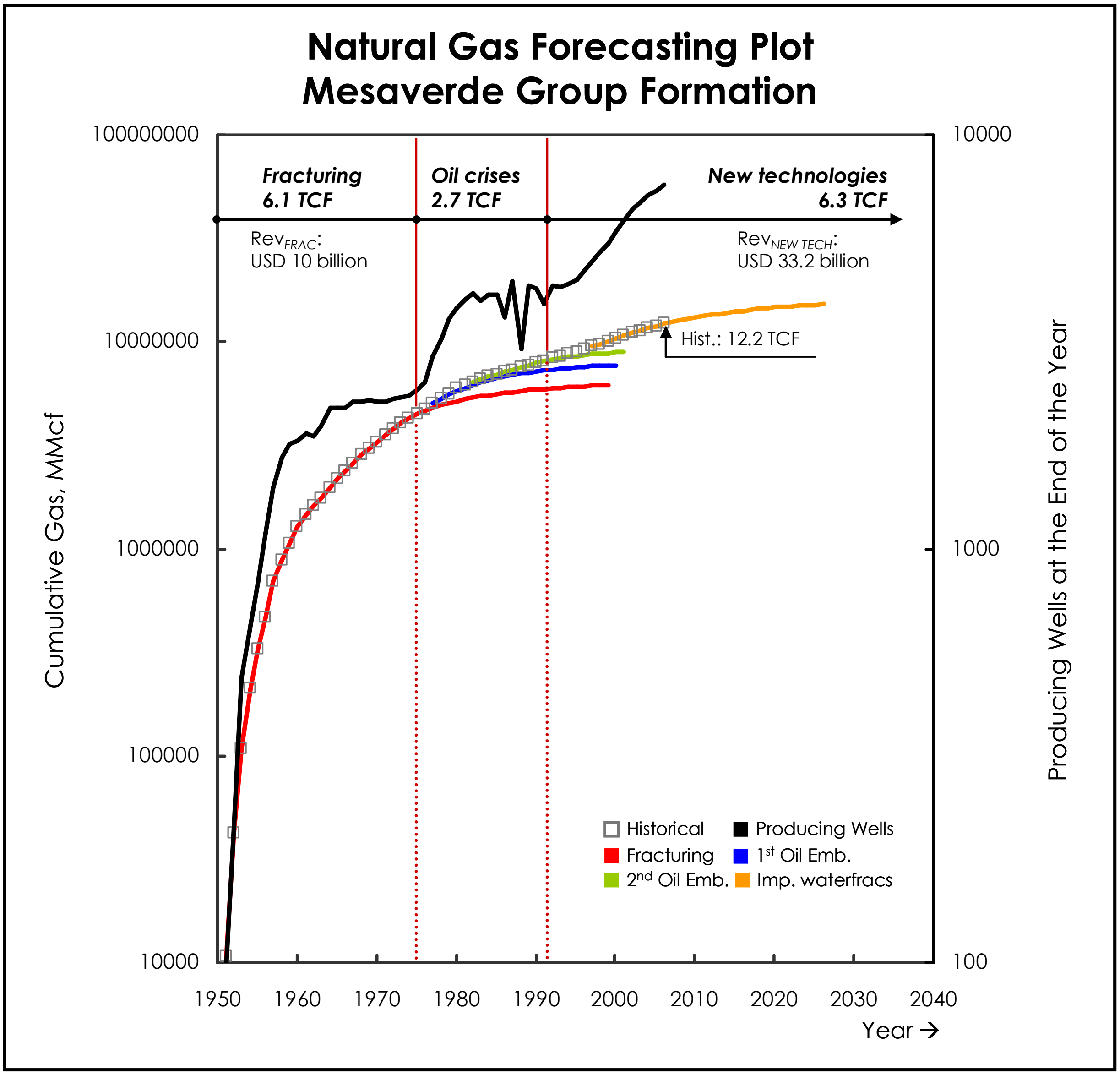


Fig. 7.30—An additional of more than 3 Tcf of natural gas could be recovered from the Mesaverde Group in the San Juan basin and generate almost $20 billion in gross revenues in a 20-year span.

Ault et al., (1997) estimated a EUR for the Mesaverde Group in the San Juan basin of 13 Tcf of natural gas. By year-end 2007 the play had reached 12.5 Tcf while operators continued developing the play, increasing the number of producer wells. The cumulative gas at the end of 2006 and the results of this study suggest that the value of EUR proposed by Ault et al., (1997) could be underestimated. At year-end 2007, more than 7,700 completions yielded 295 Bcf of gas.

7.4.5 Antrim Shale

The Antrim Shale formation of the Michigan basin which began commercial production in 1982 has been developed by using massive hydraulic fracturing during the 1980s and early 1990s and lower-cost treatments since the mid 1990s.

The values of estimated ultimate recovery (EUR), remaining reserves (RR), and gross revenues (adjusted for inflation at year-end 2006) by period were obtained using the decline curve analyses technique provided by the VBA code **(Fig. 7.31)**. For convenience, we have labeled the massive hydraulic fracturing (MHF) as the fracturing event and the use of light sand fracturing (LSF) or waterfracs as the new technology event.

Our analyses showed that if the use of waterfracs had not occurred during the mid 1990s, the Antrim Shale would have reached an EUR of 2.6 Tcf and corresponding revenues of $12 billion at $6.42/Mcf after 2006. The use of improved waterfracs or LSF treatments in the Antrim Shale fostered rig activity increasing the number of producing wells about 3 times by lowering costs of completion in the wells. Fig. 7.31 shows that the Antrim Shale of the Michigan basin has increased cumulative gas production five-fold after the use of waterfracs started in the mid 1990s. Squares in the plot represent the historical data while the red and the orange lines are the forecasting of gas for the fracturing and the new technology events, respectively.

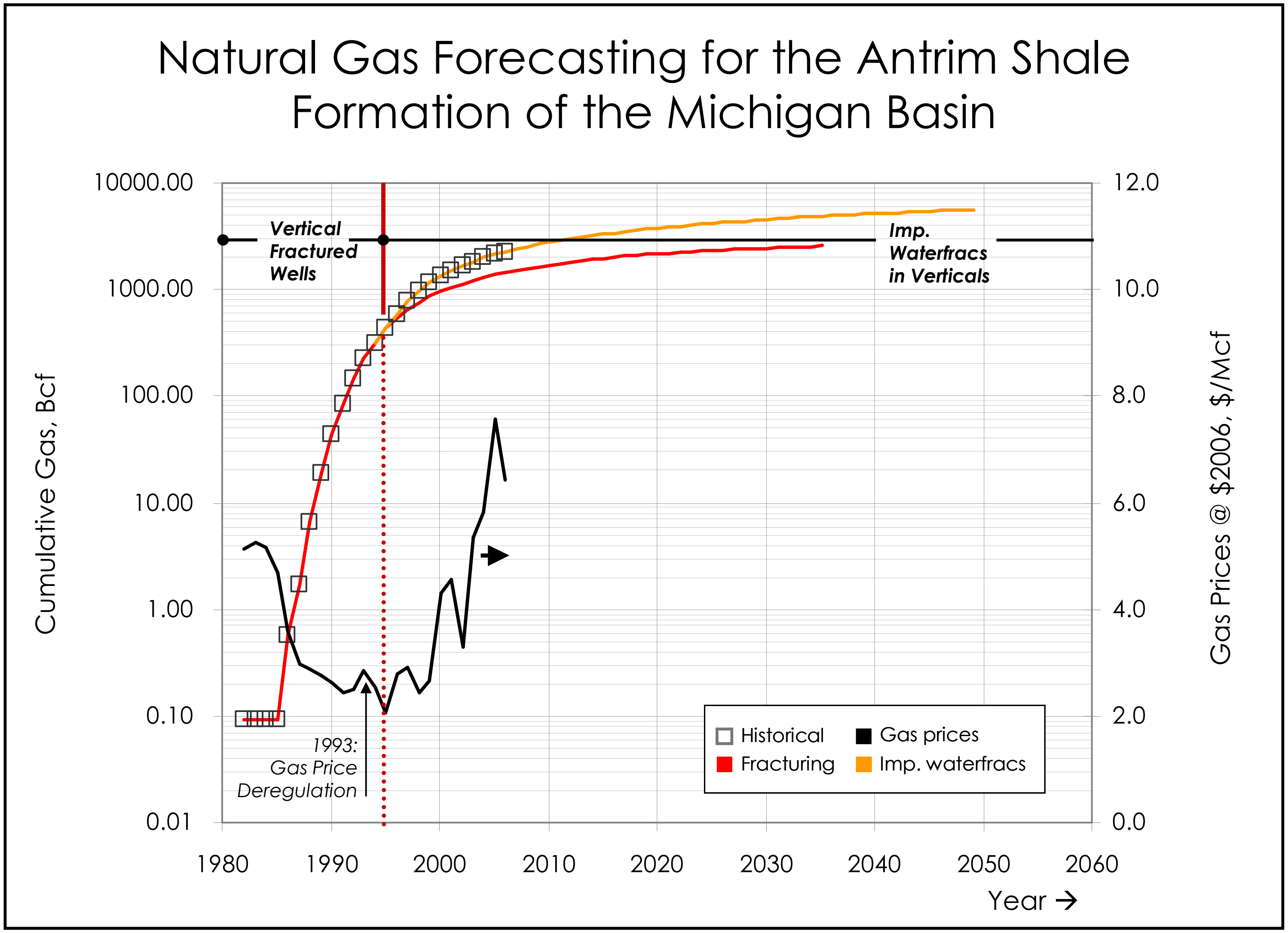


Fig. 7.31—The Antrim Shale of the Michigan basin has increased cumulative gas production five-fold after the use of waterfracs started in the mid 1990s. Squares represent the historical data while the red and the orange lines are the forecasting of gas for the fracturing and the new technology events, respectively. The black line represents the historical gas price.

If we considered fracturing as a base case with no effects from the use of lower-costs waterfracs or LSF, we could have expected an EUR of 2.5 Tcf, but the use of better fracturing technology coupled with increasing gas prices after the gas price deregulation in 1993 increased EUR to almost 6 Tcf. The additional production using better fracturing technology would translate to $31 billion, an increase of 2.5 times the earlier revenue. The RR for the latest period would be produced in a 40-year span when producing at rates higher than 15 Mcf/day (Fig. 7.31).

For convenience, we have labeled the MHF as the fracturing event and the use of better fracturing technology as the new technology event. **Tables 7.13** and **7.14** show the results for the natural gas and the oil equivalent after the DCA analysis.

TABLE 7.13—NATURAL GAS ESTIMATES FOR THE ANTRIM SHALE

EVENT	PERIOD	Cum. Gas, Bcf	Producing Wells	Reserves, Bcf	EUR, Bcf	ΔEUR, Bcf	Cum. Gross Revenues	ΔGross Revenue
FRACTURING	1982-1996	422	3,362	2,137	2,559	-	12.4	-
NEW TECH.	1997-2007	2,271	9,184	3,367	5,638	3,079	30.5	18.1

Gross revenues in billion dollars at $2006

TABLE 7.14— OIL EQUIVALENT ESTIMATES FOR THE ANTRIM SHALE

EVENT	PERIOD	Cum., MMBOE	Producing Wells	Reserves, MMBOE	EUR, MMBOE	ΔEUR, MMBOE	Cum. Gross Revenues	ΔGross Revenue
FRACTURING	1982-1996	72	3,127	301	373	-	15.9	-
NEW TECH.	1996-2007	379	9,184	203	582	209	25.0	9.1

Gross revenues in billion dollars at $2006

The impacts of these two events are quantified in this section to show the improvements in recovery factors when using better technologies supported by better commodity prices such as the case of the new technology period from 1997 to 2007.

Cumulative values of produced oil and gas in Tables 7.13 and 7.14 show the effect of these two periods of production in the Antrim Shale since 1982. MHF treatments contributed 422 Bcf from more than 3,000 wells until the introduction of new stimulation technology in the mid 1990s, which increased the gas production five-fold, producing from more than 9,000 wells. Table 7.14 shows the corresponding values for oil and gas production in terms of oil equivalent as reference.

7.4.6 Barnett Shale

Natural gas production data from 1991 to 2006 in **Fig. 7.32** indicate that the Barnett Shale of the Fort Worth basin has experienced the use of two different methods of stimulation, the MHF treatments used mostly in vertical wells (1982-1999), and the use of water fracturing technology in both vertical and horizontal wells (2000-2006).

From 1982 to 1999, gas production was achieved using mostly MHF treatments to stimulate vertical wells completed mostly in the lower member present in the Barnett Shale formation. Our DCA study showed that MHF treatments would have produced a maximum of 390 Bcf of gas if the use of horizontal wells and water fracture treatments had not been implemented (Fig. 7.32). Historically, the developing Barnett Shale has increased gas production by almost 8 times after operators introduced water fracture treatments, horizontal wells and better characterization technologies.

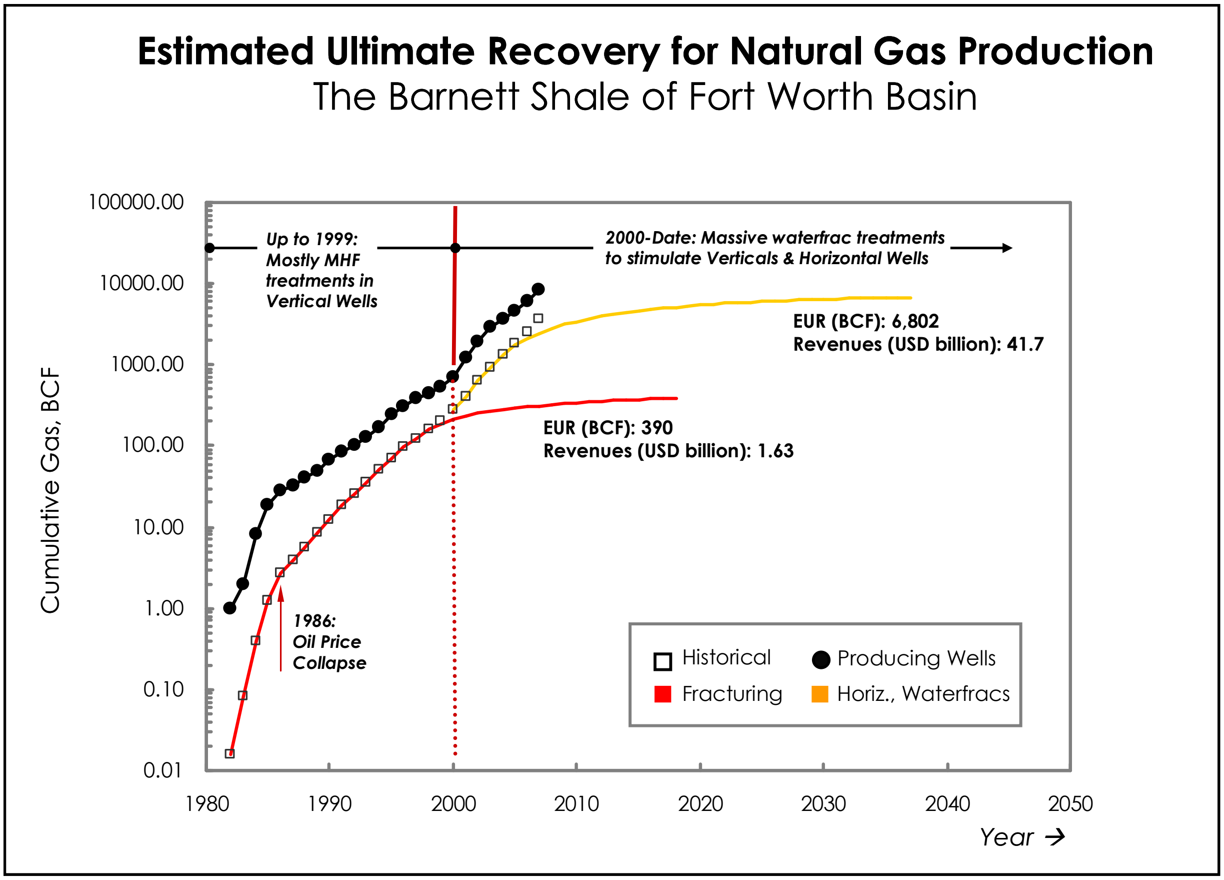


Fig. 7.32—The developing Barnett Shale has historically increased gas production by almost 8 times when operators introduced LSF treatments, horizontal wells, and better characterization technologies.

Considering the use of stimulated vertical wells (initial phase of production), we could have expected an EUR of 390 Bcf, but the introduction of horizontal drilling (second phase of production) shot EUR to almost 7.0 Tcf, an increase of more than 17 times the earlier estimate. The additional production would translate into $42 billion at $6.42/Mcf after year 2006 (Fig. 7.32).

The second phase of production started in 2000 and has been characterized by intense drilling activity including the use of waterfracture treatments as common stimulation method and the use of horizontal wells to increase the effectiveness of the fracturing by contacting more reservoir area to the wellbore. The use of stimulated horizontal wells could recover a maximum EUR of about 7.0 Tcf. Our forecast predicted a final RR of about 6.0 Tcf recoverable in 30-year span when producing at rates higher than 15Mcf/day.

Table 7.15 summarized the DCA estimations for the natural gas production from the Barnett Shale formation.

TABLE 7.15—NATURAL GAS ESTIMATES FOR THE BARNETT SHALE

EVENT	PERIOD	Cum. Gas, Bcf	Producing Wells	Reserves, Bcf	EUR, Bcf	ΔEUR, Bcf	Cum. Gross Revenues	ΔGross Revenue
FRACTURING (MHF in verticals)	1982-1999	170	476	220	390	-	1.6	
NEW TECHNOLOGY (Waterfracs in Vertical and Horizontal Wells)	1999-2005	1, 394	3,820	5,802	6,802	6,412	41.7	40.1

Gross revenues in billion dollars at $2006

Table 7.16 shows the calculations done for gas and oil produced from the BS in terms of oil equivalent.

TABLE 7.16—OIL EQUIVALENT ESTIMATES FOR THE BARNETT SHALE

EVENT	PERIOD	Cum., MMBOE	Producing Wells	Reserves, MMBOE	EUR, MMBOE	ΔEUR, MMBOE
FRACTURING (MHF in verticals)	1982-1999	28	476	39	67	-
NEW TECHNOLOGY (Waterfracs in Verticals and Horizontal Wells)	1999-2005	232	3,820	902	1,134	1,067

Please observe in **Fig. 7.33** the average gas flow rate versus time, showing the increase of the gas rate values since production started in 1982. On average, daily gas production rates per well reached the 200 Mcf/day during the 1980s to 300 Mcf/day during the 1990s to more than 400 Mcf/day during the 2000s.

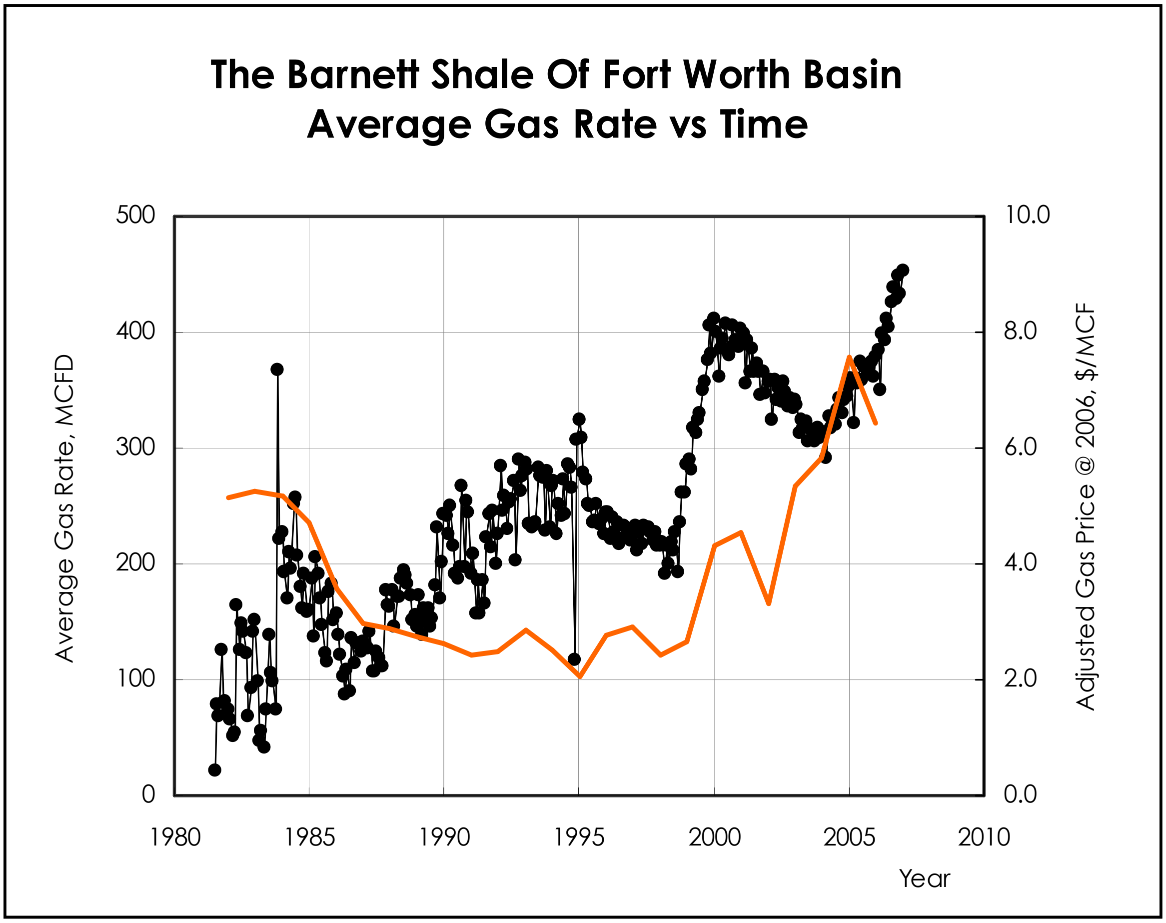


Fig. 7.33—The average gas rate shows that the production of an average well has increased with time. Maximum rates during the 1980s reached 200 Mcf/D, increasing to 300 Mcf/D during the 1990s and more than 400 Mcf/D during the 2000s.

7.4.7 Lewis Shale

We have identified four periods of development in the Lewis Shale characterized by stable growth (1952-1964), intense growth (1964-1978), intense growth and stabilization (1977-1987), and intense stable growth (1987-2007) in terms of either number of producing wells or production. For convenience, we have labeled these periods as fracturing, first oil embargo, second oil embargo, and new technologies.

Fig. 7.34 shows the amount of gas produced during major events that occurred in the Lewis Shale and the history of producing wells from 1952 to 2006. Note the big impact in number of wells during the oil crises period trying to stabilize towards the year 1990; however, better prices and technologies after this period allow a steady growth in number of wells and production. The historical cumulative gas clearly shows these changes; Fig. 7.34 includes the results from the DCA performed to the natural gas case.

Considering fracturing as a base case in the Lewis Shale formation, with no effects from the higher gas prices of the 1970s, we could have expected an EUR of 10 Bcf. However, the oil crises period during the 1970s increased gas prices and fostered rig activity as shown in Fig 7.34, increasing the EUR to more than 400 Bcf (only half of the total gas produced by year-end 2007). The new technology event characterized by the use of waterfracture treatments could produce 1.6 Tcf, which translates into $7 billion in revenues.

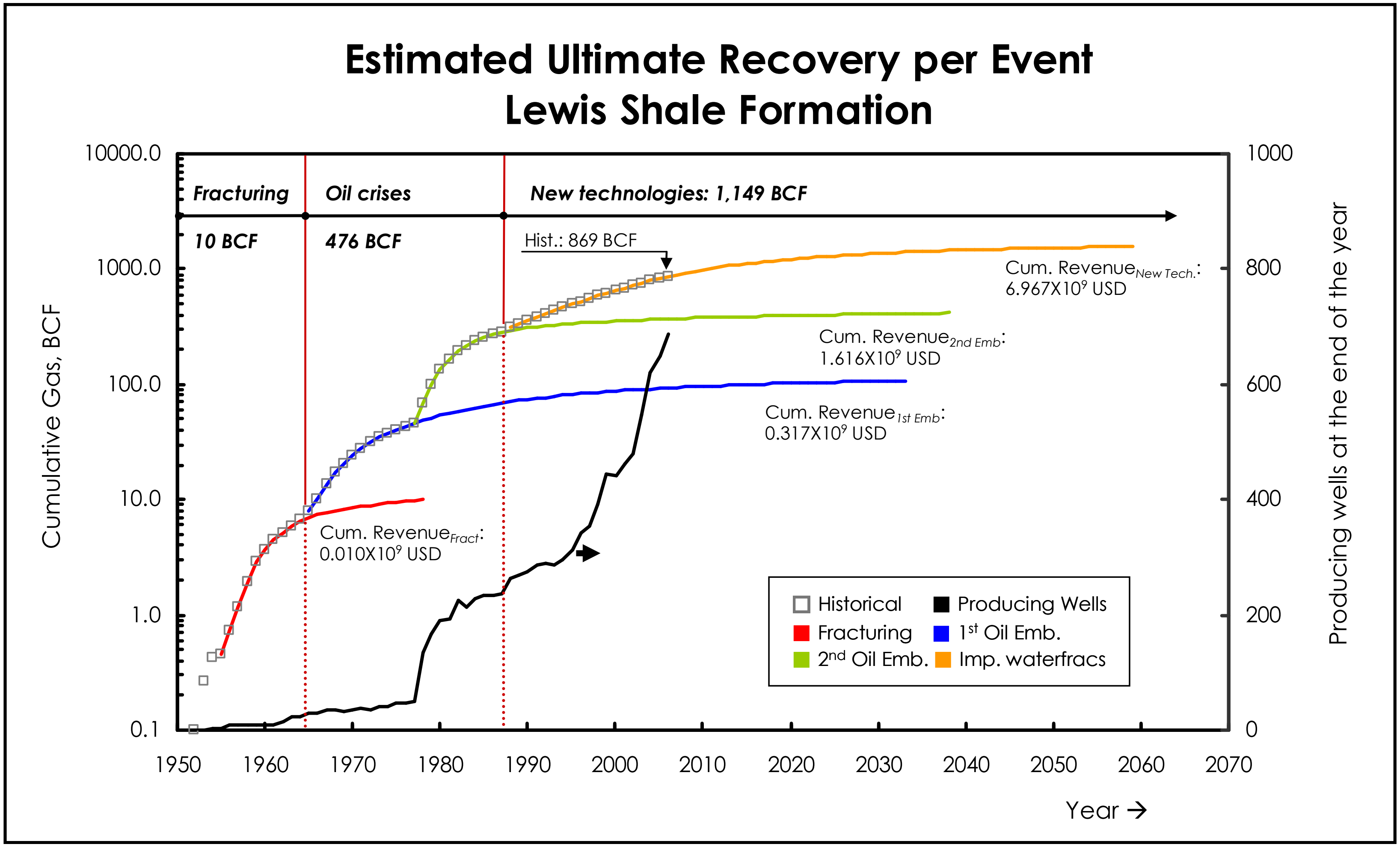


Fig. 7.34—Aggressive growth in number of wells during the oil crises period stabilized towards the year 1990; however, better prices and technologies after this period have sustained the steady growth in number of wells as well as gas production.

Table 7.17 shows the results from the DCA technique for the natural gas. The forecasting analysis for the Lewis Shale shows the effect of different development periods since 1952. We have estimated an EUR of 1.6 Tcf to be produced in a 50-year span if no other technology is implemented in the play. Currently, the Lewis Shale of the San Juan basin produces from more than 600 stimulated vertical wells.

TABLE 7.17—NATURAL GAS ESTIMATES FOR THE LEWIS SHALE

EVENT	Period	Cum. Gas, Bcf	Produc. wells	Reserves, Bcf	EUR, Bcf	ΔEUR, Bcf	Cum. Gross Revenues	ΔGross Revenue
Fracturing	1952-64	6	27	4	10	-	0.01	-
1st OIL EMB.	1964-78	46	52	61	107	97	0.32	0.31
2nd OIL EMB.	1977-87	284	180	132	416	309	1.62	1.3
New Tech.	1987-07	867	652	699	1,565	1,149	6.97	5.4

Gross revenues in billion dollars at $2006

Based on the shale gas-in-place value of 97 Tcf estimated by BR (1997) and the EUR computed in this study, we found a maximum recovery factor of 1.6% and an average EUR of 2.4 Bcf/well. Data from the literature suggest a range of EUR per well from 0.05 to 2.0 Bcf/gas per well and higher ranges of recovery factors for the Lewis between 5 and 15%. The Lewis shale is considered a developing play, so our EUR calculated for the last event, new technologies, could be underestimated.

The oil equivalent results in **Table 7.18** are reported as reference since Lewis Shale is basically a natural gas producer play.

TABLE 7.18—OIL EQUIVALENT ESTIMATES FOR THE LEWIS SHALE

EVENT	Period	Cum., MMBOE	Producing wells	MMBOE			Cum. Gross Revenues	ΔGross Revenue
				Reserves	EUR	ΔEUR		
Fracturing	1952-64	1.0	17	0.4	1.5	-	0.019	-
1st Oil Emb.	1963-78	11	50	7	18	16.5	0.553	0.53
2nd Oil Emb.	1977-87	55	225	19	71	53	3.535	2.98

Gross revenues in billion dollars at $2006

CHAPTER VIII
DISCUSSION OF RESULTS

8.1 The Spearman's Rank Correlation Coefficient – The Study of Correlation

We used the Spearman's Rank Correlation Coefficient (SRCC) to measure dependence between the variables, commodity price, rig count, and producing wells. The correlation study indicated that periods of high commodity prices have supported the growth in drilling activity in the country and vice versa.

US rig count data since 1970 indicated that periods of high commodity price caused the rate of growth of active rigs to increase by 113%. In contrast, we observed from US rig count data that periods of low commodity price reduced the rate of growth of the number of active rigs around 60%.

Periods of high commodity price encourage higher rig activity in the oil and gas reservoirs. In general, the variable rig count will be linearly proportional to the commodity price; in other words, rig activity shows higher growth during periods of high commodity price while during periods of low commodity price the variable rig count will either stabilized or decrease.

For the case of producing (active) wells, greater rig activity will always increase the number of producing (active) wells while periods of low rig activity have slightly increase the number of producing (active) wells. We used the rate of growth of producing (active) wells to illustrate this tendency; in general, we observed that the rate of growth of the number of producing (active) wells, similarly to the rig count, will sharply increase or decrease as oil prices sharply increase or decrease.

8.1.1 Producing Wells versus Commodity Prices.

Fig. 8.1 shows the dependence between gas prices and producing wells for the selected unconventional formations in this study during periods of high gas price.

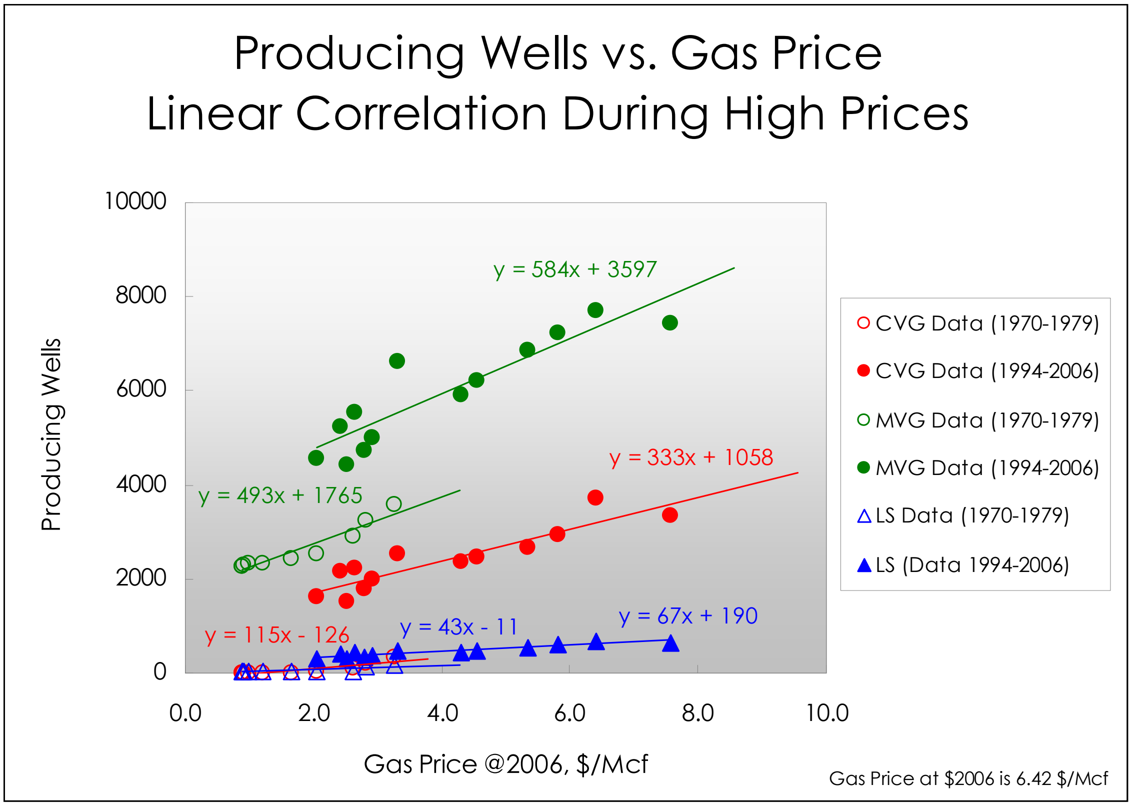


Fig. 8.1—Number of producing wells increases linearly with commodity price for selected gas formations.

Fig 8.1 shows data for the periods of high gas prices. In general, the selected formations in this study showed strong SRCC factors; however, the cases could vary as much as 30%. On average, the tight gas sands of Cotton Valley (CVG) and Mesaverde Group (MVG) and the shales of the Lewis formation (LS) showed SRCC values greater than 0.9.

Fig. 8.2 shows producing wells data after the US full deregulation of gas prices in 1993, the plays with higher rate of growth in producing wells were the Barnett (BS) and the Antrim shales (AS) followed by the tight sand formations of Mesaverde Group (MVG) and Cotton Valley Group (CVG).

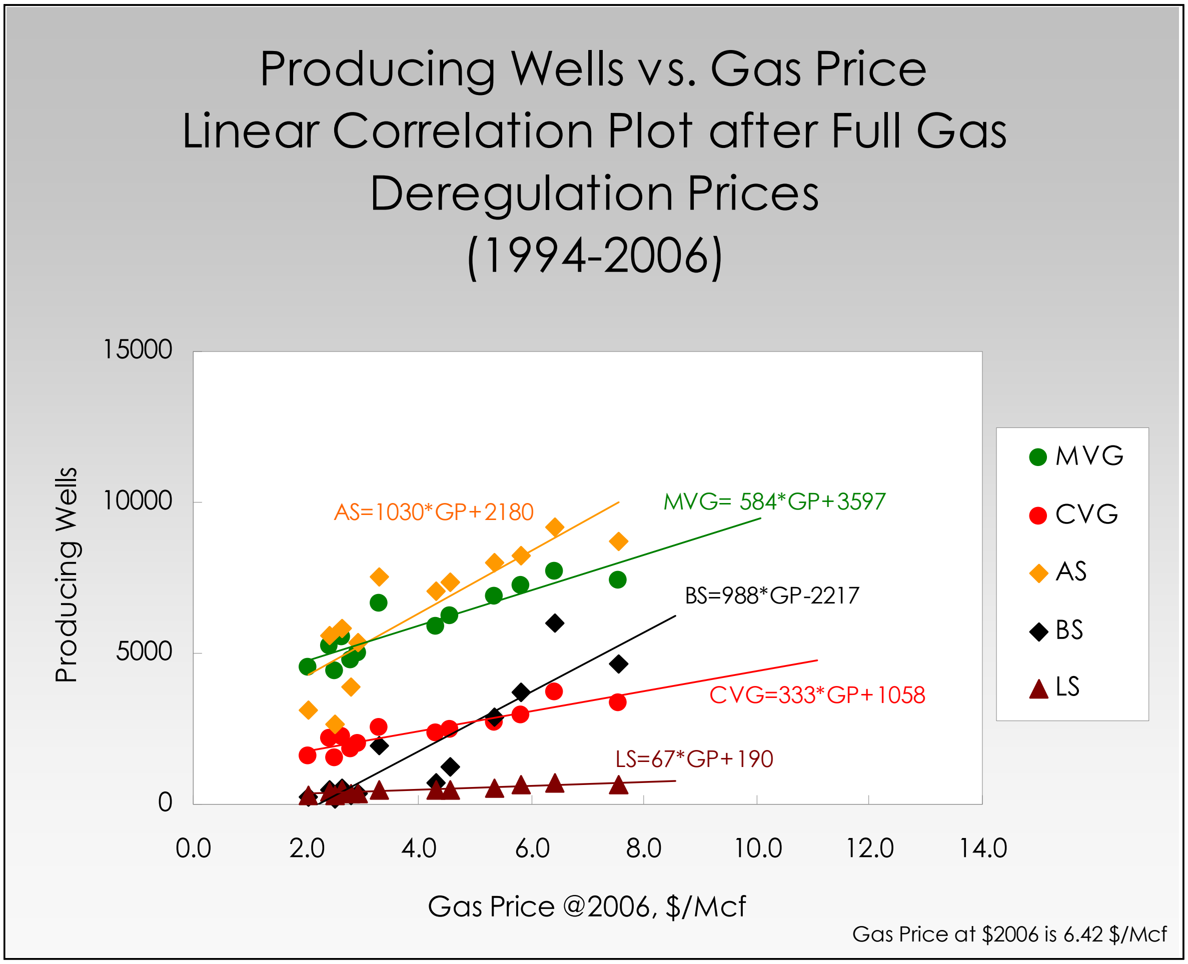


Fig. 8.2—Higher values for the rate of growth in producing well number was observed in the gas shales followed by the tight sand formations when gas price became deregulated in 1993.

Fig. 8.2 shows on average the rate of growth for every dollar added to the price of gas after the gas price deregulation in 1993; the gas shales of Antrim (AS) and Barnett (BS) show a rate of growth around 1,000 producing wells followed by the tight sands of Mesaverde Group (MVG) and Cotton Valley Group (CVG) with a growth rate between 300 and 500 producing wells. The Lewis Shale (LS) of San Juan basin has the slowest rate of growth with less than 100 producing wells.

Without question high oil prices cause an increase in rig activity; however, we have recognized that rig activity not only follows periods of high commodity prices but also limitations inherent to geographic spacing to locate more wells such as the case of the Austin Chalk formation. In general, data for oil producing wells show a proportional linear correlation with positive tendency for periods of high oil prices **(Fig. 8.3)**.

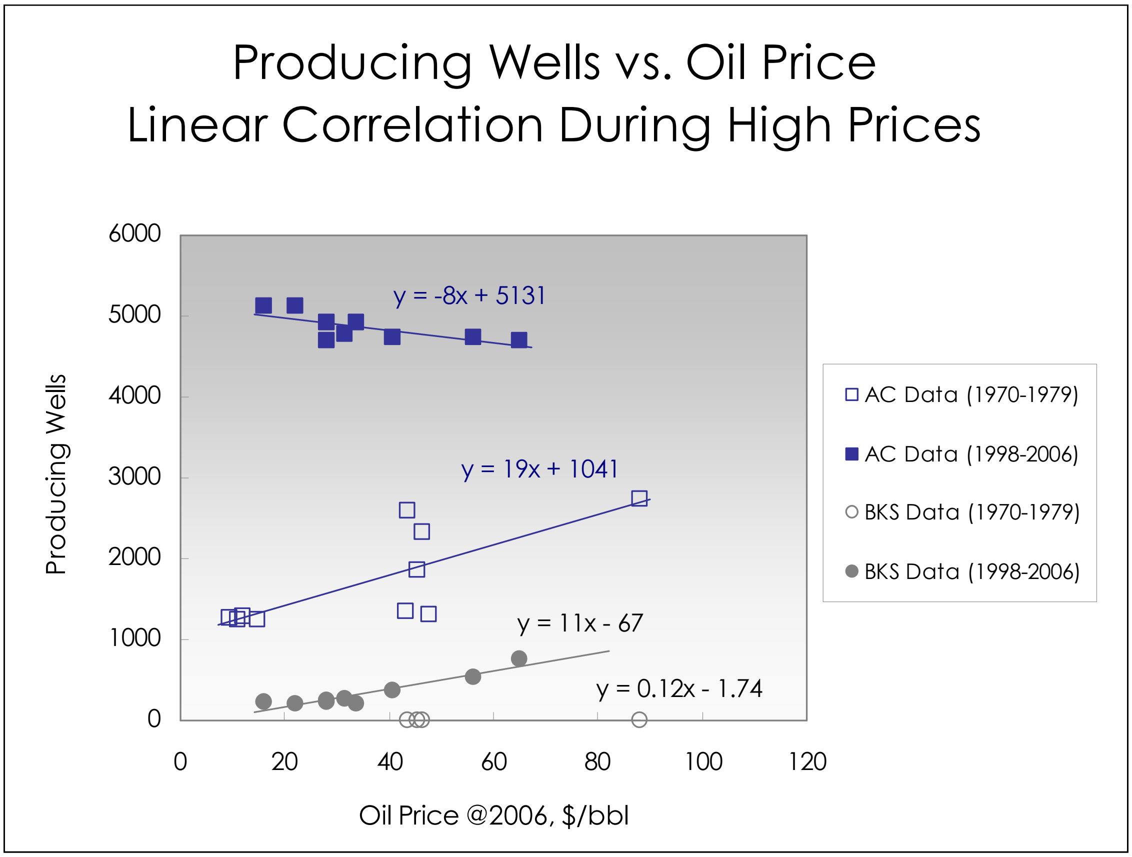


Fig. 8.3—The rate of growth in the number of producing wells was usually higher for the Austin Chalk until spacing problems reduced the rig activity in the play.

8.1.2 Rate of Growth of Producing Wells versus Commodity Prices

The correlation study indicated that periods of high commodity prices have supported the increase in well activity while periods of low commodity prices diminish this tendency.

Production data from 1950 to 2006 show the variation of the number of producing (active) wells with time for the tight sands and the gas shale formations cases of study in this research. **Fig. 8.4** shows the variation of the number of producing (active) wells with time for the tight sands of Cotton Valley Group and Mesaverde Group.

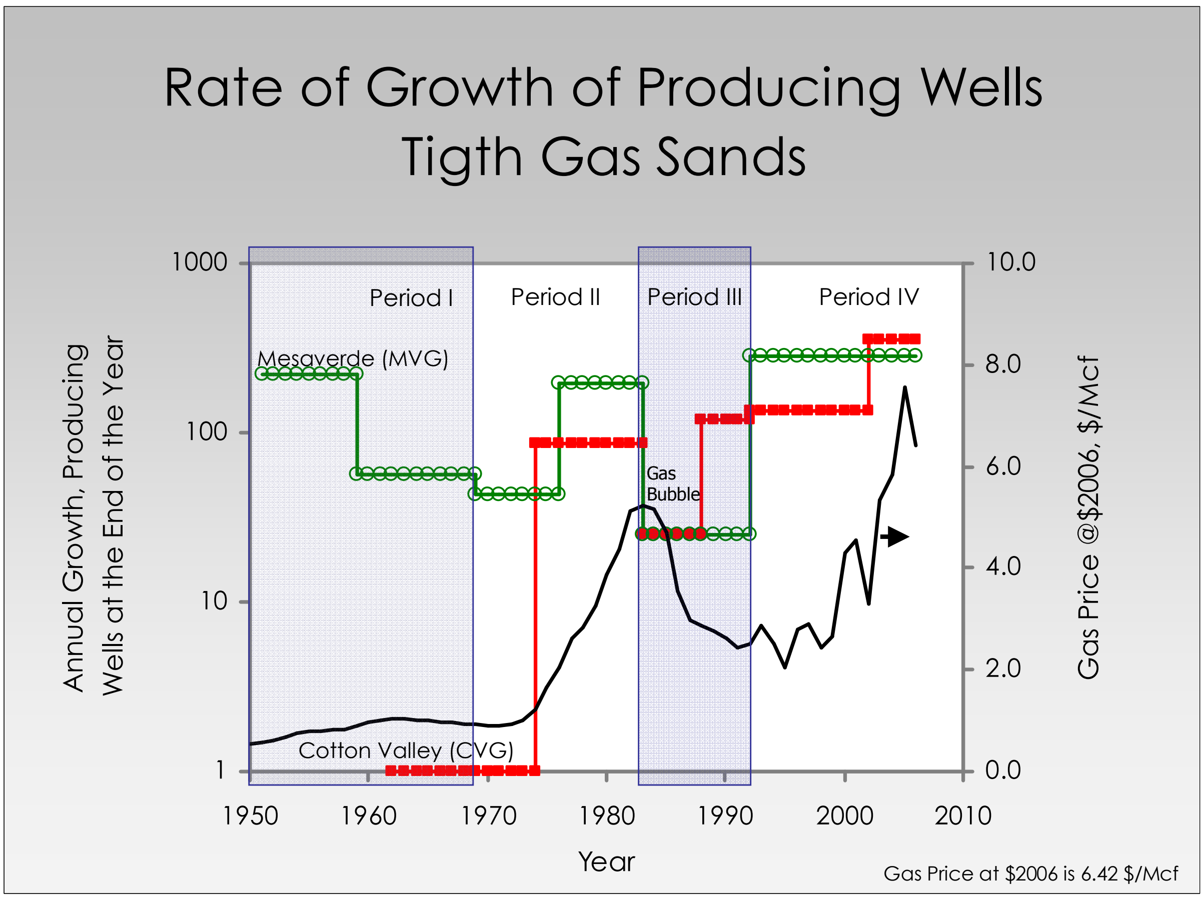


Fig. 8.4—The variation of the number of producing (active) wells with time for the tight sands of Cotton Valley (CVG) and the Mesaverde Group (MVG) is driving, in general, by gas price fluctuations.

The variation of the number of producing (active) wells for the Cotton Valley Group data from 1962 to 2006 with time shows, in general, how periods of high commodity prices result in greater increments in the number of wells for every dollar added to the commodity price. On the contrary, periods of low prices produce lower increments in the number of producing wells. Please observe that the rate of growth of producing wells for periods of high prices was as much as 8,600% while during periods of low prices the growth in number of wells decreased by 25% (Fig. 8.4).

Fig. 8.5 shows the variation of the number of producing (active) wells with time for the gas shale formations. The three cases include the Antrim, Barnett and Lewis Shale.

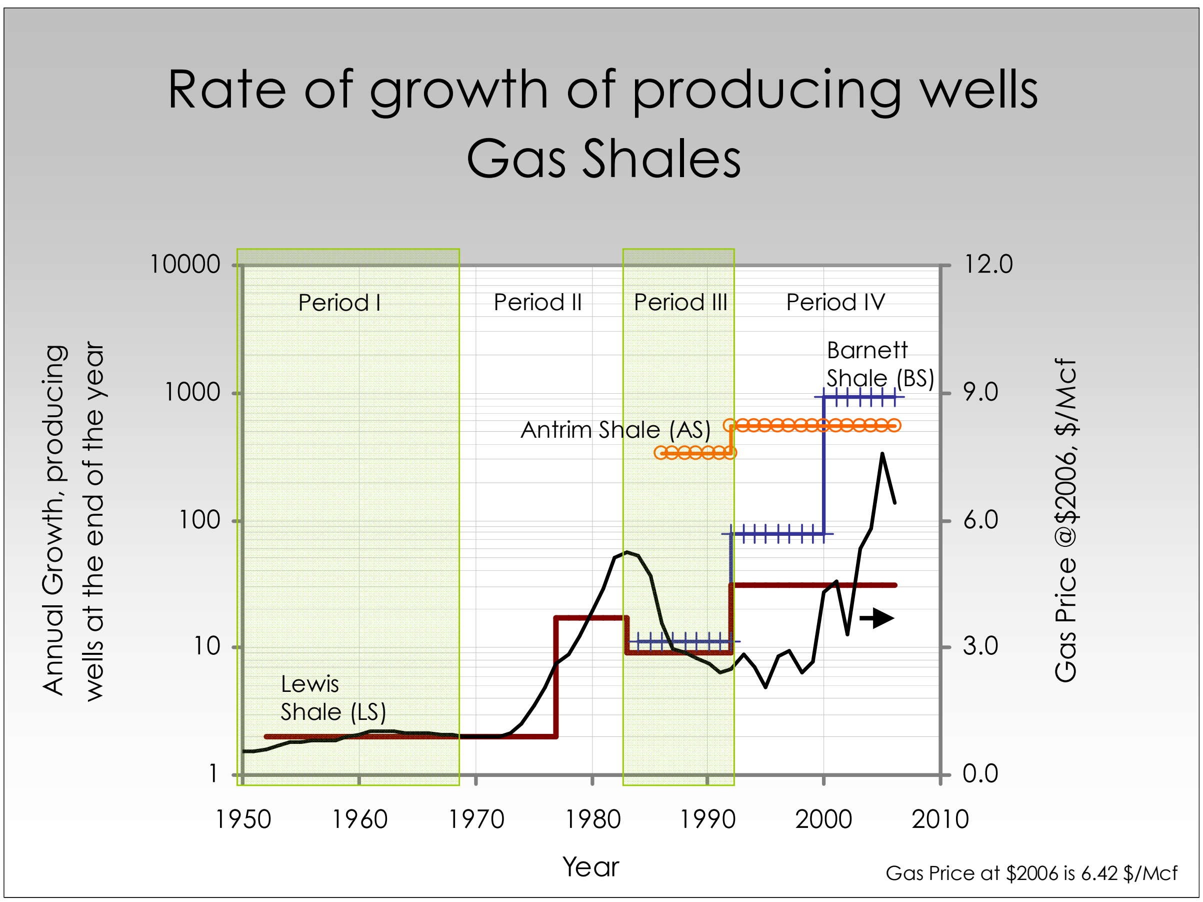


Fig. 8.5—Variation of the number of producing wells with time for the gas shales has been affected not only by prices but also by technology, especially for the Lewis Shale (LS) and the Barnett Shale (BS).

The rate of growth of producing wells for the Lewis Shale formation from 1952 to 2006 shows greater increments in the number of wells for periods of high prices while slighter increments during periods of low prices (Fig. 8.5). Periods of high commodity prices contributed with increments in the rate of growth of producing wells up to 1,100% while periods of low commodity prices decreased the rate of growth of producing wells by 47%.

Fig. 8.6 shows the variation of the number of producing (active) wells with time for the oil producing formations of Austin Chalk and Bakken Shale.

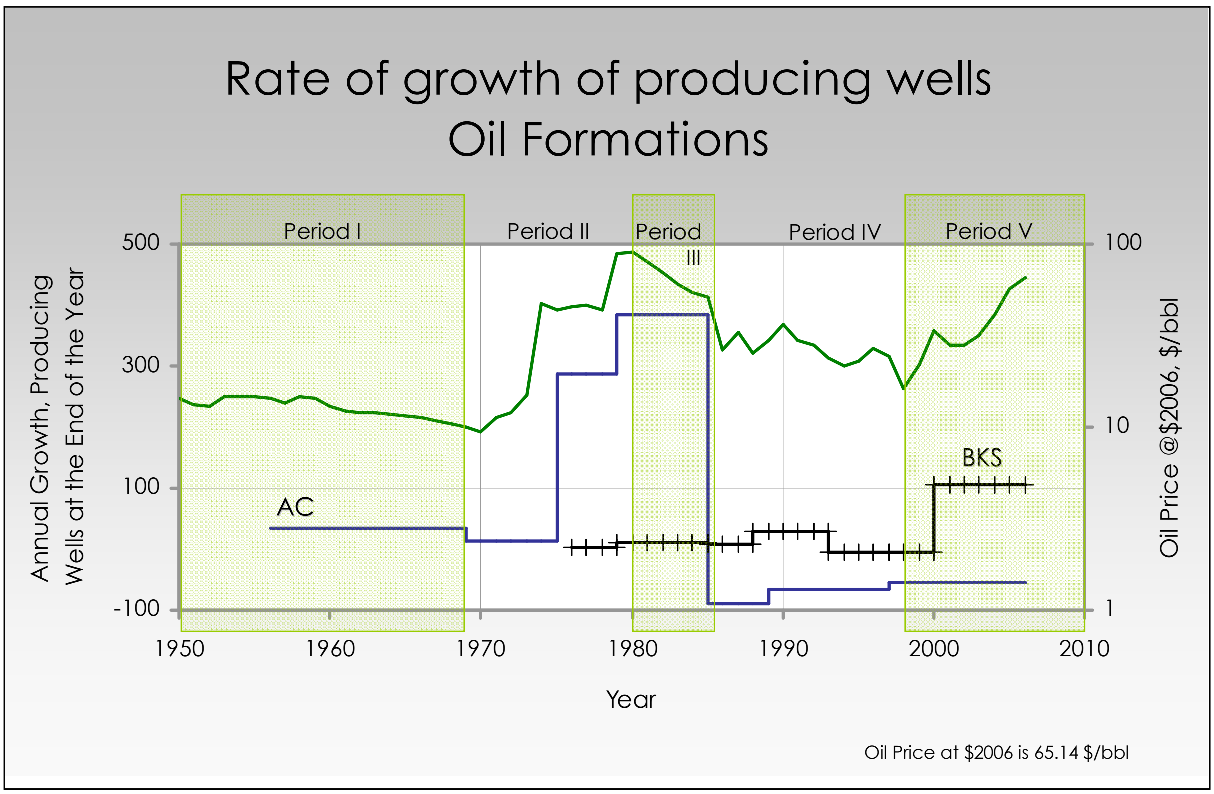


Fig. 8.6—Variation of the number of producing (active) wells with time for the oil formations of Austin Chalk (AC) and the Bakken Shale (BKS).

For the Austin Chalk formation in Fig 8.6, data shown that periods of high commodity prices increased the rate of growth of producing wells by 180% while periods of low prices decreased the rate of growth of producing wells by almost 100%. The Bakken Shale case shows similar tendencies.

8.2 Decline Analysis Study-Forecasting Graphs

We used Arp's equations to evaluate production performance under different scenarios and compute the estimated ultimate recovery (EUR), the remaining reserves (RR) and the remaining time of production (tR) in every case. Hydraulic fracturing technology in vertical wells represents the base case for almost all the cases of study labeled for our convenience as "fracturing".

Our study compared the effect of increasing prices during the oil crises of the 1970s and the effect of breakthrough technologies in the 1990s against the fracturing case. The EUR analysis considered an economic limit rate of 15 Mcf/day and 5 STB/day for gas and oil, respectively. The results of the DCA analyses for all the cases of study are compiled in Appendix B.

Historical data have showed how is possible to move progressively develop resources from the bottom of the Resource Triangle as technology improves and product prices increase. We found that the Austin Chalk, Cotton Valley, and Mesaverde formations increased their production when the oil crises caused prices to increase from $3.29/bbl in 1973 to $36.83/bbl in 1980. Well activity in these formations increased by 26-fold, by the end of 1981. Production grew 313 times compared to pre-oil crises periods. The Austin Chalk increased gas production from 3.4 Bcf/year in 1973 to 135 Bcf/year in 1981; the Cotton Valley went from 0.27 Bcf/year in 1974 to 84.6 Bcf/year in 1980; and production from the tight sands of the Mesaverde rose from 218 Bcf/year in 1970 to 313 Bcf/year in 1980.

The forecasting analysis allowed us to quantify the impact of periods of high commodity price or better technologies over production in the selected plays. We consider the selected formations in this study, in general, good examples to quantify the RTT; however, our EUR values could be underestimated since the Barnett Shale formation has not peaked yet.

During this study, we evaluated how production was affected by three major events: the use of conventional technologies (1950-1969), the increase in drilling activity caused by the oil crises (1973-1978), and the use of new technologies (late 1990s to date). In general, we can relate these three major events to timeframes; however, some of the plays such as the Barnett shale and the Antrim shale have been developed as the result of better technologies and experiences in other plays.

The use of conventional technologies mainly refers to the use of hydraulic fracturing fluids with low concentrations of propping agents and the use of vertical wells as a unique drilling type of well. The well drilling activity during the 1970s is referred to a period of high prices and the evolution of the hydraulic fracturing technology; this period was characterized by the development and use of more viscous fluids able to carry higher concentrations of proppants.

The use of new technologies includes the use of horizontal wells, the improvements of hydraulic fracturing technology and the ability to stimulate horizontal wells, as well as better characterization models to optimize spacing in the reservoirs, the use of multilaterals and the better understanding of the production mechanisms in shales and tight gas sands.

8.2.1. The Estimated Ultimate Recovery (EUR)

Observing that the recovery factor (RF) and estimated ultimate recovery (EUR) can behave as proportional variables; an increase in the value of EUR will normally increase the RF in the reservoir.

Assuming that the value of the original oil in place (OOIP) and the original gas in place (OGIP) remain constant over time, we considered two options: (1) the RF remains constant over time, and (2) the RF increases over time. For the first option, there is either no use of technology to increase the value of ultimate recovery (EUR) or the technology is just accelerating production but not really affecting the value of EUR. The second option assumes that the use of technology successfully increase the value of both EUR and RF. We found the recovery per well (EUR/well) as a good variable to measure the effect of technology or prices through time.

Our results show how different production scenarios through time (events) have changed the average value of EUR per well. **Fig. 8.7** shows the change in EUR per well in selected natural gas formations in our study. In most cases, the play has gone through a process of acceleration in production with slight changes or no changes in the value of recovery factor (RF).

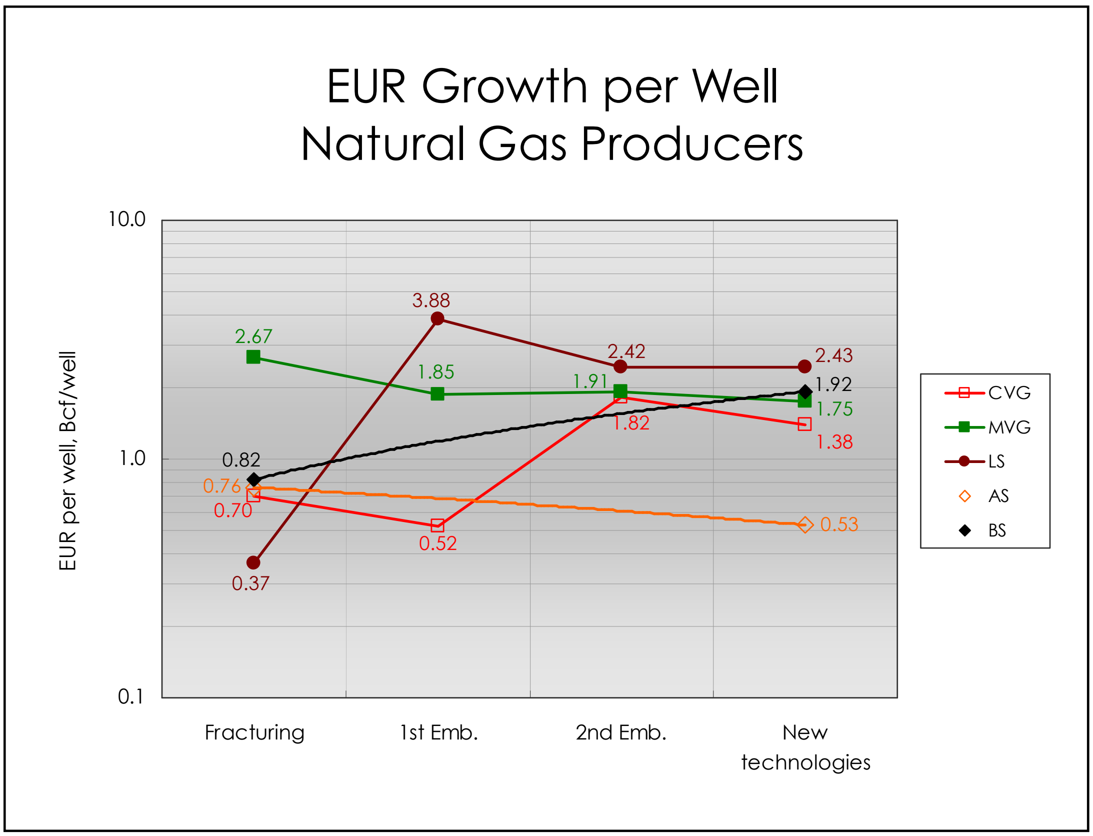


Fig. 8.7—EUR growth per well in selected natural gas formations has gone through a process of acceleration in production with slight changes or no changes in the value of the recovery factor (RF).

Fig. 8.7 shows the tendency of five natural gas producing formations in our study. The tight sands of the Cotton Valley Group (CVG) and the Mesaverde Group (MVG) have followed a similar tendency marked by periods of decrease and increase; however, the MVG has shown greater recovery values per well than the CVG formation. A decrease of EUR per well for the MVG and the CVG during the first oil embargo is the result of an intense drilling activity. On average, this study reports that the tight sands on CVG and MVG have recoveries around 2.4 Bcf/well. Note that the tight gas sands of CVG and MVG have mainly accelerated production while the recovery factor kept stable.

The wells producing from gas shale formations are characterized by initial recoveries around 0.8 Bcf/well. Please note that the recovery per well in the Barnett Shale (BS) has significantly benefited from drilling horizontal wells, increasing the EUR/well by more than 2 times the earlier value, and therefore, its recovery factor value. On the contrary, the Antrim Shale (AS) has only experience an acceleration in recovery per well.

Fig 8.8 shows the recovery per well in million BOE per well calculated for the textbook case of Austin Chalk formation. Our estimates were performed assuming that 1Mcf gas is equivalent to 6 bbl of oil.

Please observe that the value of EUR per well for our the textbook case, the Austin Chalk (AC) formation, has continuously increased over time as events such as hydraulic fracturing, oil embargoes, or new technologies came into play to increase productivity from this low permeability play.

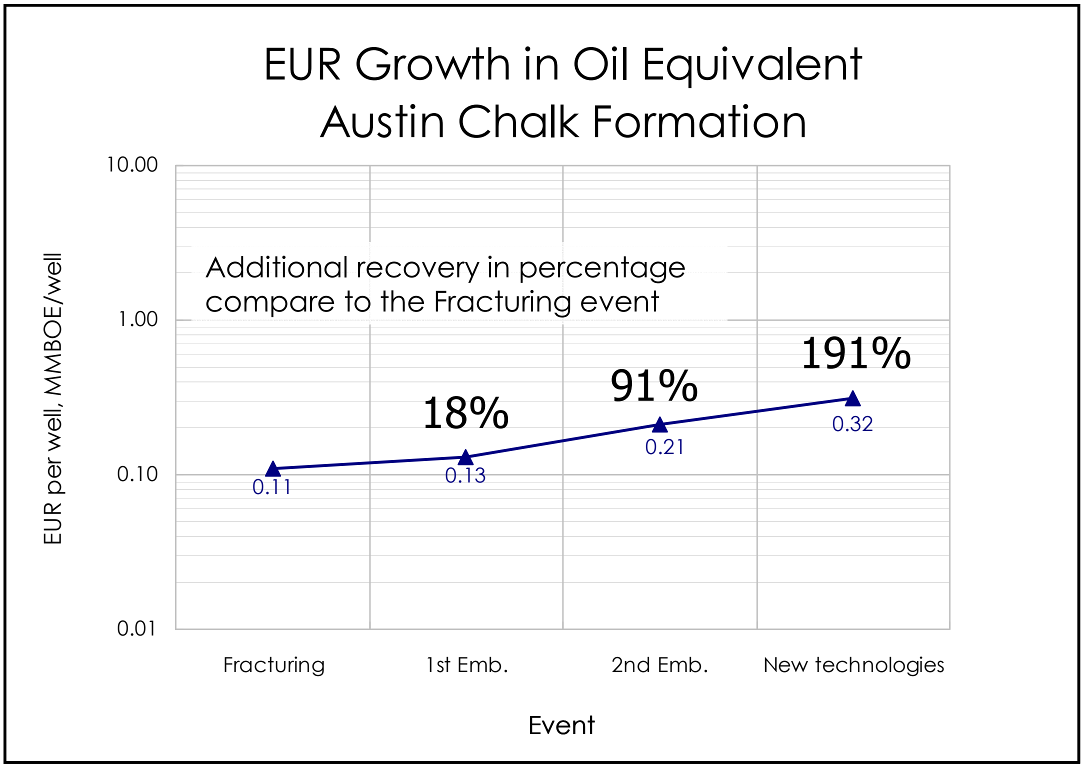


Fig. 8.8—EUR growth per well in the Austin Chalk Formation has gone through a process of acceleration with the advent of better prices and technologies since fracturing was used as the unique stimulation technique.

The Austin Chalk (AC) play shows the growth of EUR per well since the 1950s when hydraulic fracturing became a commonplace technique. Although data from the AC shows values of well recovery on average lower than 0.11 MMBOE/well, the play is the only formation showing a clear upward tendency since hydraulic fracturing was adopted as stimulation technology in the play.

Note that the Austin Chalk (AC) formation has increased well recovery in more than 190% since the fracturing event. In general, the data show that the value of EUR per well in the Austin Chalk (AC) have increased significantly through time. The effect of technology and price has helped to increase the recovery factor from the AC formation through time.

8.2.2. Well Potential

The analysis performed on the production of gas coming from the Cotton Valley Group (CVG), Mesaverde Group (MVG), and Lewis Shale (LS) has been to evaluate the effects of (1) hydraulic fracturing; (2) the first oil embargo; (3) the second oil embargo; and (4) new technologies such as horizontal and multilateral drilling, and new fracturing technologies.

Fig. 8.9 shows the estimated values of natural gas production rate (Mcf/day) calculated for the four events.

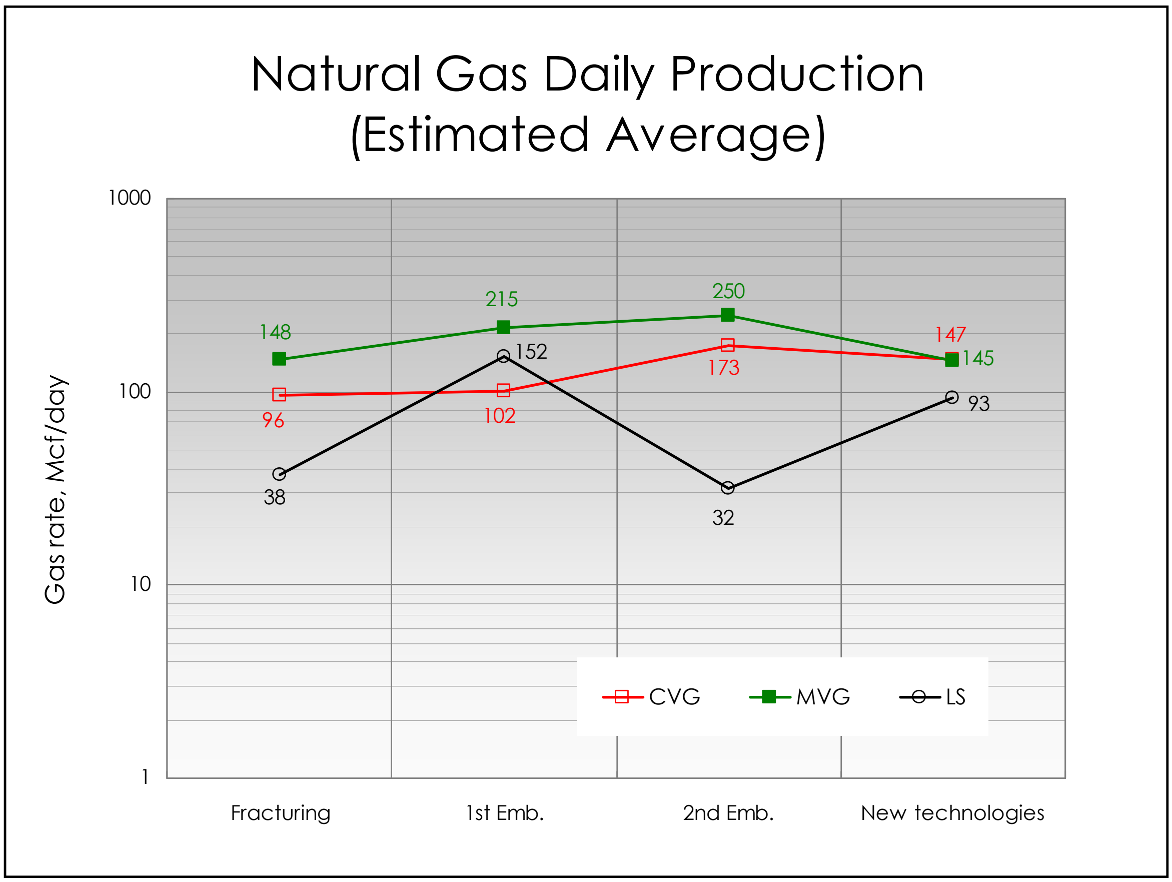


Fig. 8.9—Well potentials from tight sands (CVG and MVG) are the greatest values, followed by the shale formations (LS).

Note in Fig. 8.9 that the tight sand formations of CVG and MVG show gas rates around 145 Mcf/day followed by the gas shale formation of LS with 93 Mcf/day.

8.2.3. Horizontal Wells

Only three formations in this study have significant production from horizontal wells: the Austin Chalk (AC), the Barnett Shale (BS), and the Bakken Shale (BKS). The oil and gas plays of the AC and BS have benefited substantially from the use of horizontal technology.

Fig 8.10 shows that after the use of horizontal wells were implemented the recovery per well reached values greater than 0.3 MMBOE/well. The Bakken Shale experienced an opposite behavior when operators could not stimulated horizontal wells.

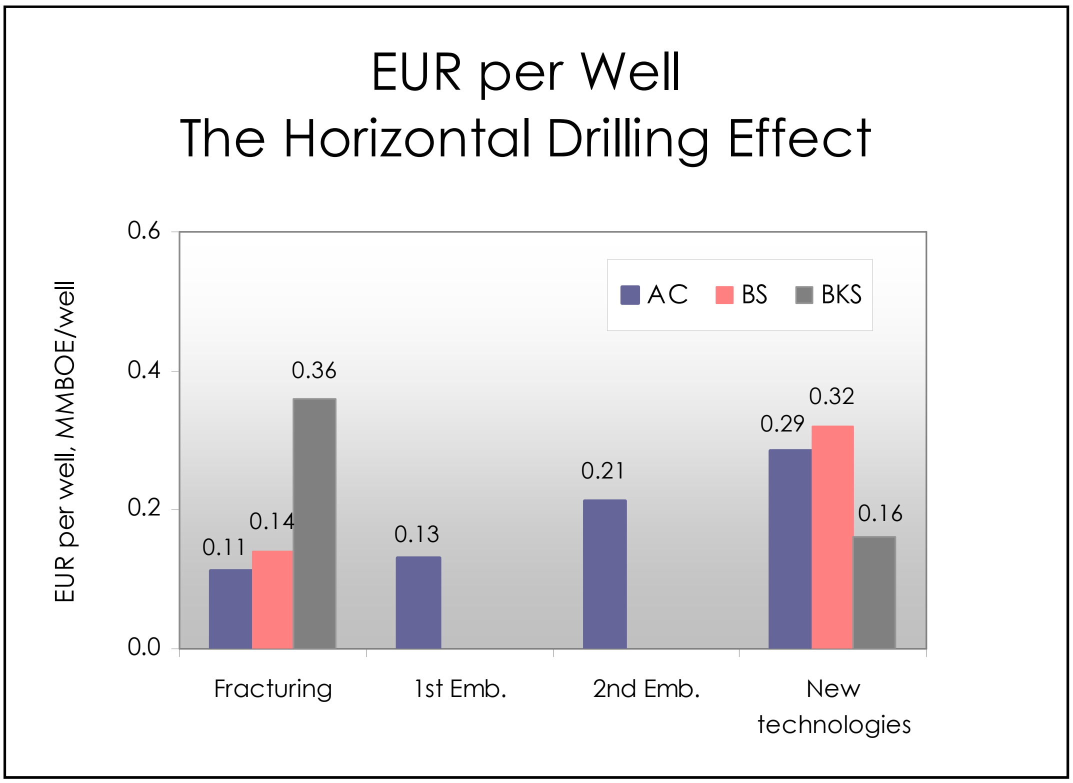


Fig. 8.10—EUR per well in the AC and the BS has growth through time, benefiting form the use of horizontal wells which at least doubled the recovery per well in both plays.

The Barnett Shale (BS) had a dramatic increase in production since horizontal drilling started. In 2006, the use of horizontal drilling sped up production by a factor of 2.3 compared to production in 1999. The Barnett shale is today a developing play; therefore, our estimates in this study are considered conservative estimates.

The Austin Chalk (AC) formation anteceded the Barnett Shale (BS) drilling its first horizontal well in the late 1980s. Increase in prices after the collapse of oil prices in the mid 1980s along with the use of horizontal drilling completions stimulated production from the AC. Results in Fig. 8.10 shows that horizontal drilling sped up production by a factor of 2.6 compared to the use of only verticals hydraulic fracturing stimulated (the fracturing event).

The horizontal drilling in the Bakken Shale (BKS) formation shows in **Fig. 8.11** a decrease of 56% in terms of recovery per well (MMBOE/well). The Bakken Shale of the Williston basin is an oil producer where stimulation of horizontal wells did not began until the early 2000s. Data in Fig 8.11 show this effect on EUR values per well.

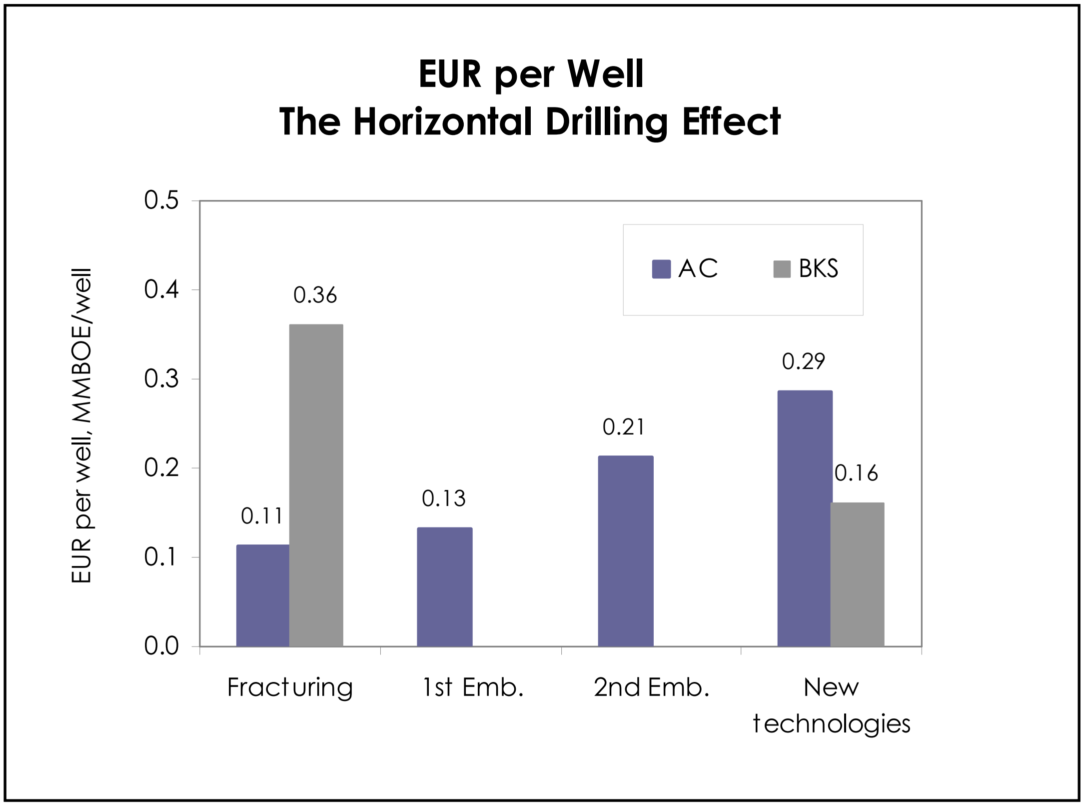


Fig. 8.11—In contrast to the Bakken Shale (BKS), the EUR per well in the Austin Chalk has grown through time. In fact, the use of nonstimulated horizontals in the Bakken Shale has reduced the recovery per well by 50%.

CHAPTER IX
CONCLUSIONS

In response to higher commodity prices, oil and gas rig activity will always increase. We can evaluate both rig activity and the number of producing wells to evaluate the effects of higher commodity prices.

1. Our results confirm the concept of the resource triangle that natural gas and oil resources are distributed log normally in nature and we can produce more oil and natural gas from the low quality resources when either product prices increase or when better technology is available to drill and produce these low quality reservoirs.

2. Our analyses clearly show that periods of high commodity prices support the increase in drilling rig activity.

3. The increase in oil and gas prices during the 1970s led to both an increase in rig count and the development of new technologies, such as massive hydraulic fracturing.

4. The use of horizontal and multi-lateral wells has opened up additional areas for development, such as the Barnett Shale and the Bakken Shale. Using horizontal wells has also revived older plays, such as the Austin Chalk.

5. The combination of horizontal well technology and water fracturing technology has led to a dramatic increase in the development of both oil and gas from shale reservoirs.

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APPENDIX A

VBA CODE — FORECASTING AND REVENUES CALCULATION CODE

```
SUB HYPERBOLICFIT_DI()

DIM NEWWB AS WORKSHEET
DIM ACHART AS CHART
DIM ANEWSERIES AS SERIES

'===================================================
CURRENT_WORKBOOK = APPLICATION.ACTIVEWORKBOOK.NAME
PATH = APPLICATION.ACTIVEWORKBOOK.PATH
WORKBOOKS(CURRENT_WORKBOOK).SHEETS("DATA").ACTIVATE
'===================================================
INIROW_T = 7
INICOL_T = 1
INIROW_QB = 7
INICOL_QB = 2
INIROW_QAV = 7
INICOL_QAV = 3
INIROW_FORC = 7
INICOL_FORC = 4
NUMPAR = 100
DELTA_B = 1 / NUMPAR
'===================================================
LIMIT = CELLS(9, 7)
NUMWELLS = CELLS(10, 7)
MLR = LIMIT * NUMWELLS * 30.4
QINI = CELLS(INIROW_QAV, INICOL_QAV)

DI = CELLS(11, 7)

ERROR_MIN = 0

  'D_II = ((QINI - QEND) / DROW_HH) / (0.5 * (QINI + QEND))
  FOR II = 1 TO NUMPAR
    B_II = II * DELTA_B
    SUMA = 0
```

```
        DROW = 0
        DO
            'T_JJ = ROUND(CELLS(INIROW_T + DROW, INICOL_T), 0)
            T_JJ = DROW + 1
            QB_JJ = CELLS(INIROW_QB + DROW, INICOL_QB)
            QBF = QINI * (1 + DI * B_II * T_JJ) ^ (-1 / B_II)
            SUMA = SUMA + (QBF - QB_JJ) ^ 2
            DROW = DROW + 1
        LOOP UNTIL CELLS(INIROW_QB + DROW, INICOL_QB) = ""
        IF II = 1 THEN
            NUMDATHIST = DROW
        END IF
        IF II = 1 OR SQR(SUMA) < ERROR_MIN THEN
            ERROR_MIN = SQR(SUMA)
            BI = B_II
        END IF
    NEXT

CELLS(19, 7) = MLR 'MONTHLY LIMIT RATE
CELLS(20, 7) = DI
CELLS(21, 7) = QINI
CELLS(22, 7) = BI
'==================================================
DROW = 0
QGE = MLR
'QGE = 3180
QGE_II = 2 * QGE
DO
    IF NUMDATHIST - 1 < DROW THEN
        MYMONTH = MONTH(CELLS(INIROW_FORC + DROW - 1, INICOL_T))
        MYYEAR = YEAR(CELLS(INIROW_FORC + DROW - 1, INICOL_T))
        IF MYMONTH < 12 THEN
            MYMONTH = MYMONTH + 1
        ELSE
            'IF MYYEAR = 2000 THEN
```

```
            '    WW = 1
            'END IF
            MYMONTH = 1
            MYYEAR = MYYEAR + 1
        END IF
        'MYDATE_STRING = LTRIM(STR(MYMONTH)) + "/1/" + LTRIM(STR(MYYEAR))
        MYDATE_STRING = LTRIM(STR(MYMONTH)) + "/" + LTRIM(STR(MYYEAR))
        MYDATE = DATEVALUE(MYDATE_STRING)
        'CELLS(INIROW_T + DROW, INICOL_T) = FORMAT(MYDATE, "MMM D YY")
        CELLS(INIROW_T + DROW, INICOL_T) = FORMAT(MYDATE, "MMMM YY")
    END IF
    'T_II = ROUND(CELLS(INIROW_T + DROW, INICOL_T), 0)
    T_II = DROW + 1
    QGE_II = QINI * (1 + DI * BI * T_II) ^ (-1 / BI)
    IF QGE_II >= QGE THEN
        CELLS(INIROW_FORC + DROW, INICOL_FORC) = QGE_II
        DROW = DROW + 1
    END IF
LOOP UNTIL QGE_II < QGE
NUMDATFORC = DROW
'===================================================
'GRAPHICS
'===================================================
NUMCURVES = 3
CHART_NAME = "FORECASTING"
XLABEL_CHART = "TIME"
YLABEL_CHART = "G"
TITLETEXT = "FORECASTING"
NUMDATAVG = NUMDATHIST

FOR II = 1 TO NUMCURVES
    SELECT CASE II
        CASE 1
          LTEXT_II = "HISTORIC DATA"
          NUMDAT_II = NUMDATHIST
```

```
        '--------------------------
        INIROW_X_II = INIROW_T
        INICOL_X_II = INICOL_T
        '--------------------------
        INIROW_Y_II = INIROW_QB
        INICOL_Y_II = INICOL_QB
        'INICOL_Y_II = INICOL_QB
        '--------------------------
    CASE 2
        LTEXT_II = "AVG DATA"
        NUMDAT_II = NUMDATAVG
        '--------------------------
        INIROW_X_II = INIROW_T
        INICOL_X_II = INICOL_T
        '--------------------------
        INIROW_Y_II = INIROW_QAV
        'INICOL_Y_II = INICOL_QAV - 1
        INICOL_Y_II = INICOL_QAV
        '--------------------------
    CASE 3
        LTEXT_II = "FORECASTING"
        NUMDAT_II = NUMDATFORC
        '--------------------------
        INIROW_X_II = INIROW_T
        INICOL_X_II = INICOL_T
        '--------------------------
        INIROW_Y_II = INIROW_FORC
        'INICOL_Y_II = INICOL_FORC - 1
        INICOL_Y_II = INICOL_FORC
        '--------------------------
END SELECT
'-------------------------------------
ENDROW_X_II = INIROW_X_II + NUMDAT_II - 1
ENDCOL_X_II = INICOL_X_II
'-------------------------------------
```

```
ENDROW_Y_II = INIROW_Y_II + NUMDAT_II - 1
ENDCOL_Y_II = INICOL_Y_II
'-------------------------------------
IF II = 1 THEN
   SET ACHART = CHARTS.ADD
   ACHART.NAME = CHART_NAME
ELSE
   WORKBOOKS(CURRENT_WORKBOOK).SHEETS(ACHART.NAME).ACTIVATE
END IF
WITH ACHART

      .CHARTTYPE = XLXYSCATTERLINES

      XRANGE = "=DATA!R" + LTRIM(STR(INIROW_X_II)) + "C" + LTRIM(STR(INICOL_X_II)) + _
      ":" + "R" + LTRIM(STR(ENDROW_X_II)) + "C" + LTRIM(STR(ENDCOL_X_II))
      YRANGE = "=DATA!R" + LTRIM(STR(INIROW_Y_II)) + "C" + LTRIM(STR(INICOL_Y_II)) + _
      ":" + "R" + LTRIM(STR(ENDROW_Y_II)) + "C" + LTRIM(STR(ENDCOL_Y_II))

      SET ANEWSERIES = .SERIESCOLLECTION.NEWSERIES
      'ANEWSERIES.CHARTTYPE = XLXYSCATTERLINES
      SELECT CASE II
         CASE 1
            ANEWSERIES.MARKERSIZE = 7
         CASE 2
            ANEWSERIES.MARKERSIZE = 1.5
         CASE 3
            ANEWSERIES.MARKERSIZE = 1.5
      END SELECT

      WITH .AXES(XLCATEGORY)
         .MINIMUMSCALE = SHEETS("DATA").CELLS(12, 7)
      END WITH

      ANEWSERIES.XVALUES = XRANGE
      ANEWSERIES.VALUES = YRANGE
```

```
        ANEWSERIES.NAME = LTEXT_II

        .AXES(XLCATEGORY, XLPRIMARY).HASTITLE = TRUE
        .AXES(XLCATEGORY, XLPRIMARY).AXISTITLE.CHARACTERS.TEXT = XLABEL_CHART
        .AXES(XLVALUE, XLPRIMARY).HASTITLE = TRUE
        .AXES(XLVALUE, XLPRIMARY).AXISTITLE.CHARACTERS.TEXT = YLABEL_CHART
        .HASTITLE = TRUE
        .CHARTTITLE.TEXT = TITLETEXT
        ACTIVECHART.HASLEGEND = TRUE

    END WITH
NEXT
'=====================================================
'GENERATING THE REVENUE
WORKBOOKS(CURRENT_WORKBOOK).SHEETS("DATA").ACTIVATE
INIROW = INIROW_T
INICOL = 11
INIROW_PRICE = 29
INICOL_PRICE = 7
DX_II = 0
QG = 0
FOR II = 1 TO NUMDATFORC
    MYDATE = CELLS(INIROW_T + II - 1, INICOL_T)
    MYMONTH = MONTH(MYDATE)
    QG_II = CELLS(INIROW_FORC + II - 1, INICOL_FORC)
    QG = QG + QG_II
    IF II = 1 THEN
        IF MYMONTH >= 1 AND MYMONTH < 12 THEN
            INIDATE = MYDATE
        ELSEIF MYMONTH = 12 THEN
            INIDATE = MYDATE
            ENDDATE = INIDATE
            CELLS(INIROW + DX_II, INICOL) = FORMAT(INIDATE, "MMMM YY")
            CELLS(INIROW + DX_II, INICOL + 1) = FORMAT(ENDDATE, "MMMM YY")
            CELLS(INIROW + DX_II, INICOL + 2) = CELLS(INIROW_PRICE + DX_II, INICOL_PRICE)
```

```
      CELLS(INIROW + DX_II, INICOL + 3) = QG
      CELLS(INIROW + DX_II, INICOL + 4) = QG * CELLS(INIROW_PRICE + DX_II, INICOL_PRICE)
      DX_II = DX_II + 1
      QG = 0
    END IF
  ELSE
    IF MYMONTH = 1 THEN
      INIDATE = MYDATE
    ELSEIF MYMONTH = 12 OR II = NUMDATFORC THEN
      ENDDATE = MYDATE
      CELLS(INIROW + DX_II, INICOL) = FORMAT(INIDATE, "MMMM YY")
      CELLS(INIROW + DX_II, INICOL + 1) = FORMAT(ENDDATE, "MMMM YY")
      CELLS(INIROW + DX_II, INICOL + 2) = CELLS(INIROW_PRICE + DX_II, INICOL_PRICE)
      CELLS(INIROW + DX_II, INICOL + 3) = QG
      CELLS(INIROW + DX_II, INICOL + 4) = QG * CELLS(INIROW_PRICE + DX_II, INICOL_PRICE)
      DX_II = DX_II + 1
      QG = 0
    END IF
  END IF
NEXT

'==================================================

END SUB
```

APPENDIX B

DCA FIGURES FOR THE SELECTED FORMATIONS

TABLE B1— NATURAL GAS ESTIMATIONS FOR THE AUSTIN CHALK FORMATION OF THE EAST TEXAS

	EVENT	HISTORICAL				FORECAST			AVERAGE		
		Period		Cum., Bcf	Wells	EUR, Bcf	RR, Bcf	tR, years	Recovery, Bcf/well	Well Potential	
		from	to							MMcf/year	Mcf/day
AC - Austin Chalk Natural Gas Figures	Fract.	1955	1974	11	1,288	11	0.00		0.01	0.49	1.34
	1st Emb.	1973	1979	48	2,593	48	0.00		0.03	4.69	13
	2nd Emb.	1978	1990	1,114	5,279	1,221	107	3	0.44	29	80
	Stimulated horiz.	1992	2000	3,881	5,114	6,449	2,568	32	1.02	26	70

TABLE B2— OIL EQUIVALENT ESTIMATIONS FOR THE AUSTIN CHALK FORMATION OF THE EAST TEXAS

	EVENT	HISTORICAL				FORECAST			AVERAGE		
		Period		Cum., MMBOE	Wells	EUR, MMBOE	RR, MMBOE	tR, years	Recovery, MMBOE/well	Well Potential	
		from	to							BOE/year	BOE/day
AC - Austin Chalk Oil Equivalent Figures	Fract.	1955	1974	77	1,237	139	62.0	16	0.11	3,211	9
	1st Emb.	1974	1979	147	2,593	317	170	19	0.13	5,470	15
	2nd Emb.	1978	1990	641	5,279	890	249	16	0.21	7,619	21
	Stimulated Horiz.	1990	2005	1718	4,729	2240	522	30	0.29	6,344	17

TABLE B3— NATURAL GAS ESTIMATIONS FOR THE COTTON VALLEY FORMATION OF THE EAST TEXAS AND LOUISIANA BASINS

CVG - Cotton Valley Group Natural Gas Figures	EVENT	HISTORICAL				FORECAST			AVERAGE		
		Period		Cum., Bcf	Wells	EUR, Bcf	RR, Bcf	tR, years	Recovery, Bcf/well	Well Potential	
		from	to							MMcf/year	Mcf/day
	Fract.	1962	1970	0.91	2	1.40	0.50	12	0.70	35	96
	1st Emb.	1970	1975	2.33	6	3.49	1.16	10	0.52	35	95
	2nd Emb.	1975	1990	1,009	890	1,613	604	20	1.82	52	143
	Imp. waterfracs	1990	2007	4,040	3,793	5,633	1,593	26	1.38	33	90

TABLE B4— OIL EQUIVALENT ESTIMATIONS FOR THE COTTON VALLEY FORMATION OF THE EAST TEXAS AND LOUISIANA BASINS

CVG - Cotton Valley Group Oil Equivalent Figures	EVENT	HISTORICAL				FORECAST			AVERAGE		
		Period		Cum., MMBOE	Wells	EUR, MMBOE	RR, MMBOE	tR, years	Recovery, MMBOE/well	Well Potential	
		from	to							BOE/year	BOE/day
	Fract.	1962	1970	0.25	2	0.33	0.08	9	0.16	9,588	26
	1st Emb.	1970	1975	0.50	6	0.65	0.15	7	0.08	6,750	18
	2nd Emb.	1976	1990	177	890	238	61	13	0.27	9,961	27
	Imp. waterfracs	1991	2007	709	3,731	947	238	22	0.25	6,559	18

TABLE B5— NATURAL GAS ESTIMATIONS FOR THE MESAVERDE FORMATION OF THE SAN JUAN BASIN

	EVENT	HISTORICAL				FORECAST			AVERAGE		
		Period		Cum., Bcf	Wells	EUR, Bcf	RR, Bcf	tR, years	Recovery, Bcf/well	Well Potential	
		from	to							MMcf/year	Mcf/day
MVG - Mesaverde Natural Gas Figures	Fract.	1951	1973	3,786	2,306	6,160	2,374	27	2.67	55	149
	1st Emb.	1976	1980	5,290	3,148	7,721	2,431	21	1.85	74	203
	2nd Emb.	1978	1991	8,010	3,766	8,904	894	11	1.91	80	219
	Imp. waterfracs	1992	2006	11,954	7,352	15,174	3,220	21	1.75	50	137

TABLE B6— OIL EQUIVALENT ESTIMATIONS FOR THE MESAVERDE FORMATION OF THE SAN JUAN BASIN

	EVENT	HISTORICAL				FORECAST			AVERAGE		
		Period		Cum., MMBOE	Wells	EUR, MMBOE	RR, MMBOE	tR, years	Recovery, MMBOE/well	Well Potential	
		from	to							BOE/year	BOE/day
MVG - Mesaverde Oil Equivalent Figures	Fract.	1951	1975	752	2,343	1,012	260	19	0.432	10,045	28
	1st Emb.	1976	1980	946	3,130	1,245	299	17	0.30	14,098	39
	2nd Emb.	1980	1990	1,334	3,523	1,501	167	14	0.65	27,142	74
	Imp. waterfracs	1990	2006	2,040	7,352	3,132	1092	45	0.43	6,983	19

TABLE B7— NATURAL GAS ESTIMATIONS FOR THE LEWIS SHALE FORMATION OF THE SAN JUAN BASIN

	EVENT	HISTORICAL				FORECAST			AVERAGE		
		Period		Cum., Bcf	Wells	EUR, Bcf	RR, Bcf	tR, years	Recovery, Bcf/well	Well Potential	
		from	to							MMcf/year	Mcf/day
LS - Lewis Shale Natural Gas Figures	Fract.	1952	1964	6	27	10	4	15	0.37	14	37
	1st Emb.	1964	1978	46	52	107	61	56	3.88	55	152
	2nd Emb.	1977	1987	284	180	416	132	52	2.42	39	107
	Imp. waterfracs	1987	2007	867	652	1,565	699	53	2.43	33	91

TABLE B8— OIL EQUIVALENT ESTIMATIONS FOR THE LEWIS SHALE FORMATION OF THE SAN JUAN BASIN

	EVENT	HISTORICAL				FORECAST			AVERAGE		
		Period		Cum., MMBOE	Wells	EUR, MMBOE	RR, MMBOE	tR, years	Recovery, MMBOE/well	Well Potential	
		from	to							BOE/year	BOE/day
LS - Lewis Shale Oil Equivalent Figures	Fract.	1952	1964	1.09	17	1.5	0.4	8	0.088	4,412	12
	1st Emb.	1963	1978	10.67	50	18	7	32	0.50	10,638	29
	2nd Emb.	1977	1987	51.6	225	70.7	19	22	0.30	9,411	26

TABLE B9—NATURAL GAS ESTIMATIONS FOR THE ANTRIM SHALE FORMATION OF THE MICHIGAN BASIN

	EVENT	HISTORICAL				FORECAST			AVERAGE		
		Period		Cum., Bcf	Wells	EUR, Bcf	RR, Bcf	tR, years	Recovery, Bcf/well	Well Potential	
		from	to							MMcf/year	Mcf/day
AS - Antrim Shale Natural Gas Figures	Fractured vertical wells	1982	1996	422	3362	2559	2137	40	0.76	14	39
	Imp. Waterfracs	1997	2007	2271	9184	5638	3367	43	0.53	10	27

TABLE B10—OIL EQUIVALENT ESTIMATIONS FOR THE ANTRIM SHALE FORMATION OF THE MICHIGAN BASIN

	EVENT	HISTORICAL				FORECAST			AVERAGE		
		Period		Cum., MMBOE	Wells	EUR, MMBOE	RR, MMBOE	tR, years	Recovery, MMBOE/well	Well Potential	
		from	to							BOE/year	BOE/day
AS - Antrim Shale Oil Equivalent Figures	Fractured vertical wells	1982	1996	72	3127	373	301	27	0.12	2,909	8
	Imp. Waterfracs	1996	2007	379	9184	582	203.50	11	0.03	1,568	4

TABLE B11— NATURAL GAS ESTIMATIONS FOR THE BARNETT SHALE FORMATION OF THE FORT WORTH BASIN

	EVENT	HISTORICAL				FORECAST			AVERAGE		
		Period		Cum., Bcf	Wells	EUR, Bcf	RR, Bcf	tR, years	Recovery, Bcf/well	Well Potential	
		from	to							MMcf/year	Mcf/day
BS - Barnett Shale Natural Gas Figures	Fractured vertical wells	1982	1999	170	476	390	220	20	0.82	22	61
	Stimulated horizontals	1999	2005	1394	3820	6802	5408.00	33	1.92	49	135

TABLE B12— OIL EQUIVALENT ESTIMATIONS FOR THE BARNETT SHALE FORMATION OF THE FORT WORTH BASIN

	EVENT	HISTORICAL				FORECAST			AVERAGE		
		Period		Cum., MMBOE	Wells	EUR, MMBOE	RR, MMBOE	tR, years	Recovery, MMBOE/well	Well Potential	
		from	to							BOE/year	BOE/day
BS - Barnett Shale Oil Equivalent Figures	Fractured vertical wells	1982	1999	28	476	67	39	20	0.14	3,804	10
	Stimulated horizontals	1999	2005	232	3820	1134	902	33	0.32	8,182	22

TABLE B13— OIL ESTIMATIONS FOR THE BAKKEN SHALE FORMATION OF THE WILLISTON BASIN

	EVENT	HISTORICAL				FORECAST			AVERAGE		
		Period		Cum., MMSTB	Wells	EUR, MMSTB	RR, MMSTB	tR, years	Recovery, MMSTB/well	Well Potential	
		from	to							STB/year	STB/day
BKS - Bakken Shale Oil Figures	Fractured vertical wells	1961	1988	6.3	88	26	20	59	0.30	5,977	16
	Non-stimulated horizontal wells	1988	2002	32.5	212	37	4	9	0.09	3,717	10

TABLE B14— OIL EQUIVALENT ESTIMATIONS FOR THE BAKKEN SHALE FORMATION OF THE WILLISTON BASIN

	EVENT	HISTORICAL				FORECAST			AVERAGE		
		Period		Cum., MMBOE	Wells	EUR, MMBOE	RR, MMBOE	tR, years	Recovery, MMBOE/well	Well Potential	
		from	to							BOE/year	BOE/day
BKS - Bakken Shale Oil Equivalent Figures	Fractured vertical wells	1961	1988	7.10	88	32	25	68	0.36	7,182	20
	Non-stimulated horizontal wells	1988	2002	42.01	212	52	9	16	0.16	5,349	15

APPENDIX C

GLOSSARY

Arab Oil Embargo of 1973: In 1973, several Arab nations, angered at US support of Israel in the 1973 Arab-Israeli War, instituted an oil embargo against the United States and Holland. The Arab oil embargo came at a time of declining domestic crude oil production, rising demand, and increasing imports. The embargo was accompanied by decreased OPEC production, and with minimal global excess production capacity available outside OPEC, created short-term shortages and price increases. When Arab production was restored and the embargo lifted six months later, world crude oil prices in 1974 had quadrupled from the 1973 average to about $12 per barrel, and OPEC was firmly in control of the world oil market.

Brent Crude Oil: Brent Blend is actually a combination of crude oil from 15 different oil fields in the Brent and Ninian systems located in the North Sea. Its API gravity is 38.3 degrees (making it a “light” crude oil, but not quite as “light” as WTI), while it contains about 0.37 percent of sulfur (making it a “sweet” crude oil, but again slightly less “sweet” than WTI). Brent blend is ideal for making gasoline and middle distillates, both of which are consumed in large quantities in Northwest Europe, where Brent blend crude oil is typically refined. However, if the arbitrage between Brent and other crude oils, including WTI, is favorable for export, Brent has been known to be refined in the United States (typically the East Coast or the Gulf Coast) or the Mediterranean region. Brent blend, like WTI, production is also on the decline, but it remains the major benchmark for other crude oils in Europe or Africa. For example, prices for other crude oils in these two continents are often priced as a differential to Brent, i.e., Brent minus $0.50. Brent blend is generally priced at about a $4 per-barrel premium to the OPEC Basket price or about a $1 to $2 per-barrel discount to WTI, although on a daily basis the pricing relationships can vary greatly (EIA, 2007).

Carbon dioxide (CO2): A non-toxic gas produced from decaying materials, respiration of plant and animal life, and combustion of organic matter, including fossil fuels; carbon dioxide is the most common greenhouse gas produced by human activities (www.centreforenergy.com, 2008).

Cubic foot (Natural Gas): The amount of natural gas contained at standard temperature and pressure (60 degrees Fahrenheit and 14.73 pounds standard per square inch) in a cube whose edges are one foot long.

Crude oil price collapse of 1986: Faced with declining world oil demand and increasing non-OPEC production, OPEC cut output significantly in the first half of the 1980s to defend its official price. Saudi Arabia, which played the role of swing producer in the cartel, bore most of the production cuts. Saudi Arabia crude oil product, which peaked at over 10 million barrels per day for the period October 1980 through August 1981, fell to just 2.3 million barrels per day by August 1985. In late 1985, Saudi Arabia abandoned its swing-producer role, increased production, and aggressively moved to increase market share. Saudi Arabia tried a netback-pricing concept, which tied crude oil prices to the value of refined petroleum products. This reversed traditional economic relationships by guaranteeing specific margins to refiners, thereby transferring risk from the crude oil purchaser to the producer. In response, other OPEC members also increased production and offered netback-pricing arrangements to maintain market share and to offset declining revenues. These actions resulted in a glut of crude oil in world markets, and crude oil prices fell sharply in early 1986.

Estimated Ultimate Recovery (EUR): Also called ‘‘ultimate resource’’ and ‘‘resource base,’’ and defined as the total amount of the material expected to be produced during its lifetime; it is the sum of the amount of the material already produced (cumulative production), the current reserves, and the amount expected to be discovered and produced in the future.

The Energy Policy Act of 2005: is a statute that was passed by the United States Congress on July 29, 2005 and signed into law by President George W. Bush on August 8, 2005 at Sandia National Laboratories in Albuquerque, New Mexico. The Act, described by proponents as an attempt to combat growing energy problems, provides tax incentives and loan guarantees for energy production of various types.

Federal Energy Regulatory Commission (FERC): The Federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, petroleum pipeline rates, and natural gas pipeline certification. FERC is an independent regulatory agency within the Department of Energy and is the successor to the Federal Power Commission.

Federal Power Commission (FPC): The predecessor agency of the Federal Energy Regulatory Commission. The Federal Power Commission was created by an Act of Congress under the Federal Water Power Act on June 10, 1920. It was charged originally with regulating the electric power and natural gas industries. It was abolished on September 30, 1977, when the Department of Energy was created. Its functions were divided between the Department of Energy and the Federal Energy Regulatory Commission, an independent regulatory agency.

Henry Hub Spot: The Henry Hub is the largest centralized point for natural gas spot and futures trading in the United States. The New York Mercantile Exchange (NYMEX) uses the Henry Hub as the point of delivery for its natural gas futures contract. The NYMEX gas futures contract began trading on April 3, 1990 and is currently traded 72 months into the future. NYMEX deliveries at the Henry Hub are treated in the same way as cash-market transactions.

Inflation: Process by which general prices increase and money loses value.

Iranian Revolution of 1978-1979: The Iranian Revolution, which began in late 1978, resulted in a drop of 3.9 million barrels per day of crude oil production from Iran from 1978 to 1981. World supplies appeared to be tight, although much of this lost production was offset initially by increases in output from other OPEC members, particularly from Iran's Persian Gulf neighbors. In 1980, the Iran-Iraq War began, and many Persian Gulf countries reduced output as well. OPEC crude oil prices increased to unprecedented levels between 1979 and 1981. By 1981, OPEC production declined to 22.8 million barrels per day, 7.0 million barrels per day below its level for 1978.

Natural Gas: A gaseous mixture of hydrocarbon compounds, primarily methane, used as a fuel for electricity generation and in a variety of ways in buildings, and as raw material input and fuel for industrial processes.

NGA (The Natural Gas Act of 1938): was the first instance of direct Federal regulation of the natural gas industry. Concern about the exercise of market power by interstate pipeline companies prompted the NGA, which gave the Federal Power Commission (FPC) (subsequently the Federal Energy Regulatory Commission (FERC)) the authority to set "just and reasonable rates" for the transmission or sale of natural gas in interstate commerce

NGPA (Natural Gas Policy Act of 1978): From 1938 to 1978, the Federal government regulated only the interstate natural gas market. The Natural Gas Policy Act of 1978 (NGPA) granted the Federal Energy Regulatory Commission (FERC) authority over intrastate as well as interstate natural gas production. The NGPA established price ceilings for wellhead first sales of gas that vary with the applicable gas category and gradually increase over time. Second, it established a three-stage elimination of price ceilings for certain categories: the price ceilings for certain "old" intrastate gas were eliminated in 1979, for certain "old" interstate gas and "new" gas in 1985, and for certain other "new" gas in 1987.

Nominal Price: The price paid for a product or service at the time of the transaction. Nominal prices are those that have not been adjusted to remove the effect of changes in the purchasing power of the dollar; they reflect buying power in the year in which the transaction occurred.

OPEC: The Organization of the Petroleum Exporting Countries (OPEC) is a large group of countries made up of Algeria, Angola, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, Venezuela, and Ecuador (rejoined OPEC in 2007). The OPEC was founded in Bagdad in1960 to unify and coordinate members' petroleum policies. OPEC headquarters are located in Vienna since 1965.

Pelagic: Referring to open water marine habitats free of direct influence of the shore or ocean bottom. Pelagic organisms are generally free-swimming (nektonic) or floating (planktonic).

Pelagic Sediment: An ocean sediment that accumulates far enough from land that detrital materials are a minor component. These sediments are largely composed of the tiny shell debris of radiolarians and foraminifera.

Rig count: The rig count is one of the primary measures of the health of the exploration segment of the oil and gas industry. The Rotary Rig Count is the average number of drilling rigs actively exploring for oil and gas. Drilling an oil or gas well is a capital investment in the expectation of returns from the production of crude oil or natural gas (Baker Hughes, 2008).

Rotary Drilling: Rotary drilling was developed in the late 1800s and became commonplace by the early 1900s. In rotary drilling, a bit is attached to a drill string which consists of joints of drill pipe. The drill string is rotated at the surface. The bit turns and breaks up the formation. A fluid is circulated to lift the drill cuttings back to the surface. The rotary drilling rig consists of the derrick, drill string, draw works, rotary table, kelly, drill collars and bits, mud systems, engines, and various other parts (Baker Hughes, 2008).

Spindletop: Spindletop is a salt dome oil field located in south Beaumont, Texas in the United States. On January 10, 1901, a well at Spindletop struck oil ("came in"), marking the birthdate of the modern petroleum industry. At 100,000 barrels (16,000 m^3) of oil a day, the gusher tripled US oil production overnight, ensuring the second industrial revolution would be fueled not by wood and coal but by oil and its byproducts. Some of the companies chartered to exploit the wealth of Spindletop are some of today's largest and well known corporations such as Chevron Corporation.

Stripper well: A term used to describe wells that produce natural gas or oil at very low rates – less than 10 barrels per day of oil or less thank 60 thousand cubic ft per day of gas (NETL, 2007).

WTI crude oil: West Texas Intermediate (WTI) crude oil is of very high quality and is excellent for refining a larger portion of gasoline. Its API gravity is 39.6 degrees (making it a "light" crude oil), and it contains only about 0.24 percent of sulfur (making a "sweet" crude oil). This combination of characteristics, combined with its location, makes it an ideal crude oil to be refined in the United States, the largest gasoline consuming country in the world. Most WTI crude oil gets refined in the Midwest region of the country, with some more refined within the Gulf Coast region. Although the production of WTI crude oil is on the decline, it still is the major benchmark of crude oil in the Americas. WTI is generally priced at about a $5 to $6/bbl premium to the OPEC Basket price and about $1 to $2/bbl premium to Brent, although on a daily basis the pricing relationships between these can vary greatly (EIA, 2007).

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