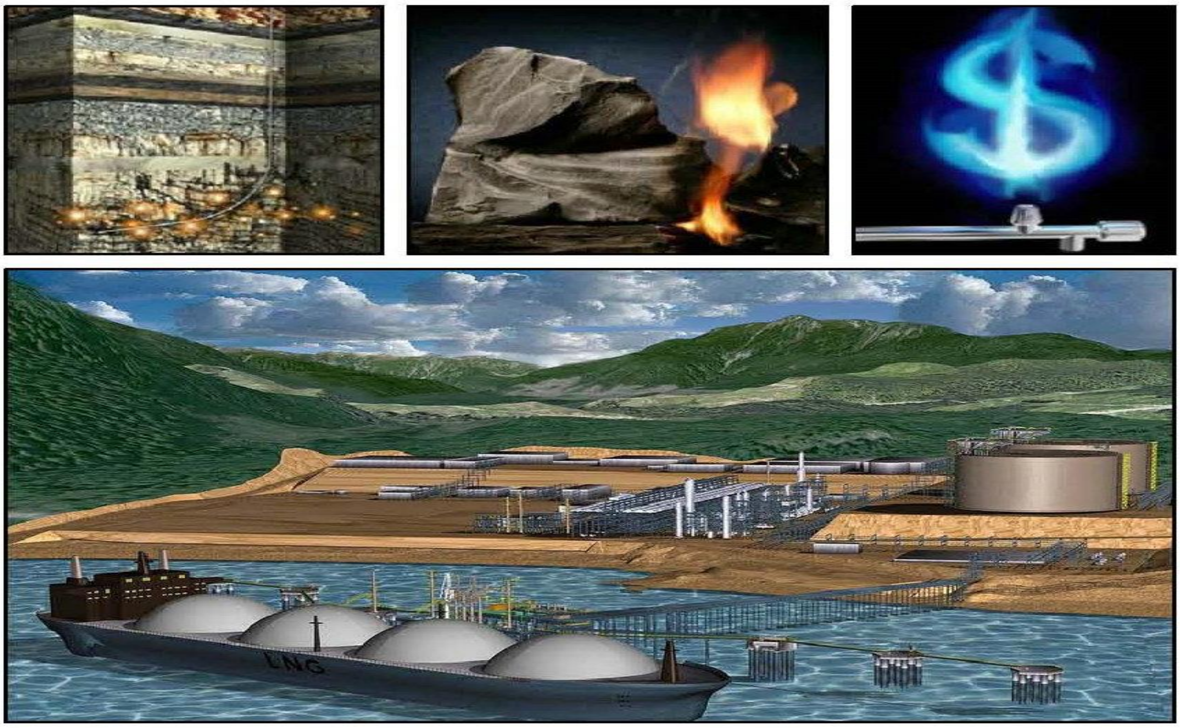
NATIONAL TECHNICAL UNIVERSITY OF ATHENS
NAVAL ARCHITECTURE AND MARINE ENGINEERING
DIVISION OF SHIP DESIGN & MARITIME TRANSPORT

Shale gas: Evolution, prospects and geopolitical implications on global energy commerce and LNG shipping



Author: Konstantinos Moutzouris [Κωνσταντίνος Μουτζούρης]
Student Registration Number: 08103029

Supervising Professor: Dimitrios V. Liridis [Δημήτριος Β. Λυρίδης]

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FRONT COVER PICTURES

Top row, left: *Hydraulic fracturing;*

Top row, middle: *Shale and shale gas burning.*

Top row, right: *Natural gas burning. Flame's symbolic shape is that of the $ sign.*

Bottom row: *Kitimat LNG terminal model; it is under construction at British Columbia, Canada. Originally planned as an import terminal (where the gas would be delivered by tanker, vaporized, then sent via pipeline to North American markets), the discovery of huge shale gas reserves in B.C. and Texas plus fundamental changes in world markets led to the owner company reversing its plans. Instead, it will now export 5 million tons of LNG per year to Asian markets. For completion in 2015;*

"Daring ideas are like chessmen moved forward.
They may be beaten, but they may start a winning game."

Johann Wolfgang von Goethe

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Prologue

Introduction

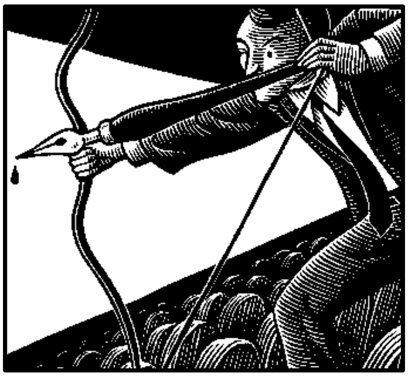
My name is Konstantinos Moutzouris and this is my pre-graduate thesis for the diploma of Naval Architecture and Marine Engineering at the National Technical University of Athens. *'Shale gas: Evolution, prospects and geopolitical implications on global energy commerce and LNG shipping'* currently held at hand by you, the reader, is a product of genuine interest and thoughtful research. My personal intrigue for the subject chosen derives from the facts synoptically presented in the paragraphs below.

The subject of energy in general is one of the greater, if not the greatest, factors in geopolitics, economy -and consequently- everyday life. Every community, country and society ever created had the instinctive pulse to discover, technically evolve and secure the energy sources that would allow it to survive, progress and prosper. The quest for energy is that of survival and creation and it is deeply rooted within mankind's nature. This quest has evolved over the centuries to end up a mishmash of complicated strategies, power-plays, conquests, technological researches and breakthroughs that ultimately define the present and quite possibly the future of humanity. Shale gas is one of the most resent and important factors discovered in the equation and as such presents great interest.

Shale gas commercial rediscovery is a breakthrough that is happening right here, right now. Apart from the interest to acquire the technological know-how of the achievement, this promising unconventional source of energy is a controversial topic followed by high expectations and equally high concerns. Will it indeed change the energy market landscape? Will it live up to the expectations currently stated or will it turn out a disappointment? If it is indeed a grand energy revolution, can we approach and comprehend the new status quo rising? Can we make accurate predictions for the near future? And what about the ecological consequences? Can they be safely predicted and encountered? All the above are questions of great importance. Some of them can be answered with the data and knowledge available nowadays, while others can be only approached without clear conclusions. In any case a reader contemplating on such a matter is a reader contemplating on the future. **I strongly believe that while we cannot always know what is waiting for us just around the corner, we can research and understand; hoping for the best while preparing for the worst, covering all scenarios imaginable in the true engineer's way.**

Finally, I would like to draw the reader's attention to the -less apparent, but equally important- final fact. This thesis does not stand only on the grounds of my mechanical engineering background. The naval architecture and marine engineering community has to seriously consider shale gas as an industry determining factor. It is part of the shift from oil to natural gas and from tankers to LNGs. I believe that liquid natural gas tankers are the way of the future and that when the dust settles and the new oil-gas equilibrium is achieved, major developments in the field will take place ('Electrical ship' is just one of the many side-thoughts that come to mind). New maritime routes are in the making, while old ones drastically change and adapt accordingly to modern demand. Shale gas is part of the momentum and it is best to be taken into account at this early stage.

Purpose of the author



'Shale gas' as a study theme presents many challenges to the researcher. On first approach, the historical background and the technical aspect of the achievement can be accurately acquired and presented. Yet, knowledge of the general 'fossil fuels' topic is prerequisite and only via a series of comparisons a concrete opinion can be formed. Moving away from the documented history of the subject and trying to shed light into its economic and ecological aspects, the search stumbles upon the characteristics of shale gas that make it so unique: It is something new, under development, hyped and highly controversial. The information available -regarding data volume, quality and accessibility- evolves by the day and is by no means final.

Above all, this thesis aims to inform the reader on all the major aspects of the shale gas revolution currently taking place. My main intention is to present the research information gathered and deemed significant, in one consistent and comprehensive volume. Background knowledge required is presented (hopefully) before the need occurs. When the topic examined is controversial all the opinions stated on the matter are taken into account and analyzed. Browsing through the paper and dealing only with facts, the reader gradually builds his awareness and opinion on the subject. I would like to take the chance and underline the fact that the nature of the report prohibits it from ever reaching 'final-definitive' status. It cannot mention, nor predict, every effect of the shale gas breakthrough. It will have successfully served its purpose, if the reader gains an overview perspective and understanding of the 'shale gale' and intends to use this paper both as a starting and reference point for further research.

Chapter I: Natural gas

1.0 Introduction to Chapter I

This thesis is dedicated to the topic of shale gas. In order to avoid any misconceptions, from this early point, it is clarified and emphatically underlined that shale gas is natural gas. It is formed from being trapped within shale formations and -for reasons to be explained- is classified under the unconventional natural gas resources category. During the past decade, shale gas has become an increasingly important source of natural gas (mainly in the U.S. of America) and is currently widely regarded as a factor with the potential to shape and change the global economy.

Naturally, Chapter I serves as an introductory approach to the general topic of natural gas. Its purpose is to familiarize the reader with the essential knowledge needed to understand and comprehend on a deeper level the following shale gas-related chapters. Focus is centered on presenting, in a brief and consistent manner, the background information about natural gas; what it is exactly, how it is formed and found in nature, its exploitation history and its main categories. Don't wanting to exceed the boundaries of a proper and interesting introduction, all common ground between general (natural gas) and sub-category (shale gas) are ad interim excluded and presented thoroughly later on as part of the shale gas analysis, our main point of interest.

Finally, I would like to state that since this chapter is about presenting bits of knowledge that have been fully established and no personal inquiry is needed, part from the selection of the information, most of the material used is derived from educational public domain sites such as www.wikipedia.org and www.naturalgas.org (all due credit attributed in the 'bibliography' section). This is the only section of the thesis that this approach is followed.

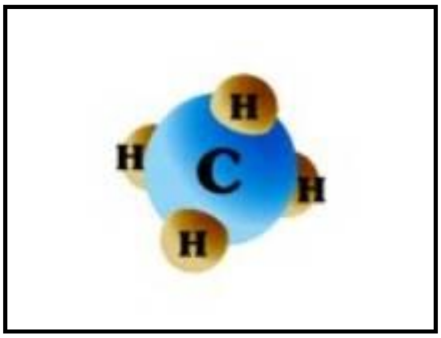
1.1 What is natural gas?

Composition

Natural gas is a combustible mixture of hydrocarbon gases. In its pure form it is colorless, shapeless, and odorless. When burned it gives off a great deal of energy. Unlike other fossil fuels, natural gas is clean burning and emits lower levels of potentially harmful byproducts into the air. While it is formed primarily of methane, it can also include ethane, propane, butane and pentane. The composition of natural gas can vary widely, but below is a chart outlining the typical makeup of natural gas before it is refined.

Methane	CH_4	70-90%
Ethane	C_2H_6	0-20%
Propane	C_3H_8	0-20%
Butane	C_4H_{10}	0-20%
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen Sulphide	H_2S	0-5%
Rare gases	A, He, Ne, Xe	Trace

In its purest form, such as the natural gas intended for home use, it is almost pure methane. Methane is a molecule made up of one carbon atom and four hydrogen atoms, and is referred to as CH_4. The distinctive 'rotten egg' smell that we often associate with natural gas is actually an odorant called mercaptan that is added to the gas before it is delivered to the end-user. Mercaptan aids in detecting any leaks.



A methane molecule, CH_4

When we say that methane is combustible, it means that it is possible to burn it. Chemically, this process consists of a reaction between methane and oxygen. When this reaction takes place, the result is carbon dioxide (CO_2), water (H_2O), and a great deal of energy. Chemists would write the following to represent the combustion of methane:

$$CH_4[g] + 2\ O_2[g] \rightarrow CO_2[g] + 2\ H_2O[l] + 891\ kJ$$

That is, one molecule of methane (the [g] referred to above means it is gaseous form) combined with two oxygen atoms, react to form a carbon dioxide molecule, two water molecules (the [l] above means that the water molecules are in liquid form, although it is usually evaporated during the reaction to give off steam) and 891 kilojoules (kJ) of energy.

Natural gas is the cleanest burning fossil fuel. Coal and oil, the other fossil fuels, are more chemically complicated than natural gas, and when combusted, they release a variety of potentially harmful chemicals into the air. Burning methane releases only carbon dioxide and water. Since natural gas is mostly methane, the combustion of natural gas releases fewer byproducts than other fossil fuels. Ethane, propane, and the other hydrocarbons commonly associated with natural gas have slightly different chemical formulas. Natural gas is considered 'dry' when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydrocarbons are present, the natural gas is 'wet'.

Measurement

Natural gas can be measured in a number of different ways. As a gas, it can be measured by the volume it takes up at normal temperatures and pressures, commonly expressed in cubic feet (cf) or meters (cm). Production and distribution companies commonly measure natural gas in thousands of cubic feet (Mcf), millions of cubic feet (MMcf), or trillions of cubic feet (Tcf). While measuring by volume is useful, natural gas can also be measured as a source of energy. Like other forms of energy, natural gas is commonly measured and expressed in British thermal units (Btu). One Btu is the amount of natural gas that will produce enough energy to heat one pound of water by one degree at normal pressure. One cubic foot of natural gas contains about 1,027 Btus.

Usage

Natural gas has many uses, residentially, commercially, and industrially. Found in reservoirs underneath the earth, it is often associated with oil deposits. Production companies search for evidence of these reservoirs by using sophisticated technology that helps to find the location of the natural gas, and drill wells in the earth where it is likely to be found. Once brought from underground, the natural gas is refined to remove impurities such as water, other gases, sand, and other compounds. Some hydrocarbons are removed and sold separately, including propane and butane. Other impurities are also removed, such as hydrogen sulfide (the refining of which can produce sulfur, which is then also sold separately). After refining, the clean natural gas is transmitted through a network of pipelines. From these pipelines, natural gas is delivered to its point of use.

The formation of natural gas

Natural gas is a fossil fuel. Like oil and coal, this means that it is, essentially, the remains of plants and animals and microorganisms that lived millions of years ago.

There are many different theories as to the origins of fossil fuels. The most widely accepted theory says that fossil fuels are formed when organic matter (such as the remains of a plant or animal) is compressed under the earth, at very high pressure for a very long time. This is referred to as *thermogenic methane*. Similar to the formation of oil, thermogenic methane is formed from organic particles that are covered in mud and other sediment. Over time, more and more sediment and mud and other debris are piled on top of the organic matter. This sediment and debris puts a great deal of pressure on the organic matter, which compresses it. This compression, combined with high temperatures found deep underneath the earth, breaks down the carbon bonds in the organic matter. As one gets deeper and deeper under the Earth's crust, the temperature gets higher and higher. At low temperatures (shallower deposits), more oil is produced relative to natural gas. At higher temperatures, however, more natural gas is created, as opposed to oil. That is why natural gas is usually associated with oil in deposits that are 1 to 2 miles below the Earth's crust. Deeper deposits, very far underground, usually contain primarily natural gas, and in many cases, pure methane.

Natural gas can also be formed through the transformation of organic matter by tiny microorganisms. This type of methane is referred to as *biogenic methane*. Methanogens, tiny methane-producing microorganisms, chemically break down organic matter to produce methane. These microorganisms are commonly found in areas near the surface of the Earth that are void of oxygen. These microorganisms also live in the intestines of most animals, including humans. Formation of methane in this manner usually takes place close to the surface of the earth, and the methane produced is usually lost into the atmosphere. In certain circumstances, however, this methane can be trapped underground, recoverable as natural gas. An example of biogenic methane is landfill gas. Waste-containing landfills produce a relatively large amount of natural gas from the decomposition of the waste materials that they contain. New technologies are allowing this gas to be harvested and used to add to the supply of natural gas.

A third way in which methane -and natural gas- may be formed is through *abiogenic* processes. Extremely deep under the Earth's crust, there exist hydrogen-rich gases and carbon molecules. As these gases gradually rise towards the surface of the Earth, they may interact with minerals that also exist underground, in the absence of oxygen. This interaction may result in a reaction, forming elements and compounds that are found in the atmosphere (including nitrogen, oxygen, carbon dioxide, argon, and water). If these gases are under very high pressure as they move toward the surface of the earth, they are likely to form methane deposits, similar to thermogenic methane.

(Main source: http://www.naturalgas.org/overview/background.asp)

1.2 A brief history of natural gas

Natural gas is nothing new. In fact, most of the natural gas that is brought out from under the ground is millions of years old. However, it was not until recently that methods for obtaining this gas, bringing it to the surface, and putting it to use were developed.

Before there was an understanding of what natural gas was, it posed somewhat of a mystery to man. Sometimes, such things as lightning strikes would ignite natural gas that was escaping from under the earth's crust. This would create a fire coming from the earth, burning the natural gas as it seeped out from underground. These fires puzzled most early civilizations, and were the root of much myth and superstition. One of the most famous of these types of flames was found in ancient Greece, on Mount Parnassus approximately 1000 B.C. . A goat herdsman came across what looked like a 'burning spring', a flame rising from a fissure in the rock. The Greeks, believing it to be of divine origin, built a temple on the flame. This temple housed a priestess who was known as the Oracle of Delphi, giving out prophecies she claimed were inspired by the flame.

These types of springs became prominent in the religions of India, Greece, and Persia. Unable to explain where these fires came from, they were often regarded as divine, or supernatural. It wasn't until about 500 B.C. that the Chinese discovered the potential to use these fires to their advantage. Finding places where gas was seeping to the surface, the Chinese formed crude pipelines out of bamboo shoots to transport the gas, where it was used to boil sea water, separating the salt and making it drinkable.

Britain was the first country to commercialize the use of natural gas. Around 1785, natural gas produced from coal was used to light houses, as well as streetlights.

Manufactured natural gas of this type (as opposed to naturally occurring gas) was first brought to the United States in 1816, when it was used to light the streets of Baltimore, Maryland. However, this manufactured gas was much less efficient, and less environmentally friendly, than modern natural gas that comes from underground.

Naturally occurring natural gas was discovered and identified in America as early as 1626, when French explorers discovered natives igniting gases that were seeping into and around Lake Erie. The American natural gas industry got its beginnings in this area. In 1859, Colonel Edwin Drake (a former railroad conductor who adopted the title 'Colonel' to impress the townspeople) dug the first well. Drake hit oil and natural gas at 69 feet below the surface of the earth.

Most in the industry characterize this well as the beginning of the natural gas industry in America. A two-inch diameter pipeline was built, running 5 and ½ miles from the well to the village of Titusville, Pennsylvania. The construction of this pipeline proved that natural gas could be brought safely and relatively easily from its underground source to be used for practical purposes.

In 1821, the first well specifically intended to obtain natural gas was dug in Fredonia, New York by William Hart. After noticing gas bubbles rising to the surface of a creek, Hart dug a 27-foot well to try and obtain a larger flow of gas to the surface. Hart is regarded by many as the 'father of natural gas' in America. Expanding on Hart's work, the Fredonia Gas Light Company was eventually formed, becoming the first American natural gas company.

During most of the 19th century, natural gas was used almost exclusively as a source of light. Without a pipeline infrastructure, it was difficult to transport the gas very far, or into homes to be used for heating or cooking. Most of the natural gas produced in this era was manufactured from coal, as opposed to being transported from a well. Near the end of the

19th century, with the rise of electricity, natural gas lights were converted to electric lights. This led producers of natural gas to look for new uses for their product.

In 1885, Robert Bunsen invented what is now known as the Bunsen burner. He managed to create a device that mixed natural gas with air in the right proportions, creating a flame that could be safely used for cooking and heating. The invention of the Bunsen burner opened up new opportunities for the use of natural gas in America, and throughout the world. The invention of temperature-regulating thermostatic devices allowed for better use of the heating potential of natural gas, allowing the temperature of the flame to be adjusted and monitored.

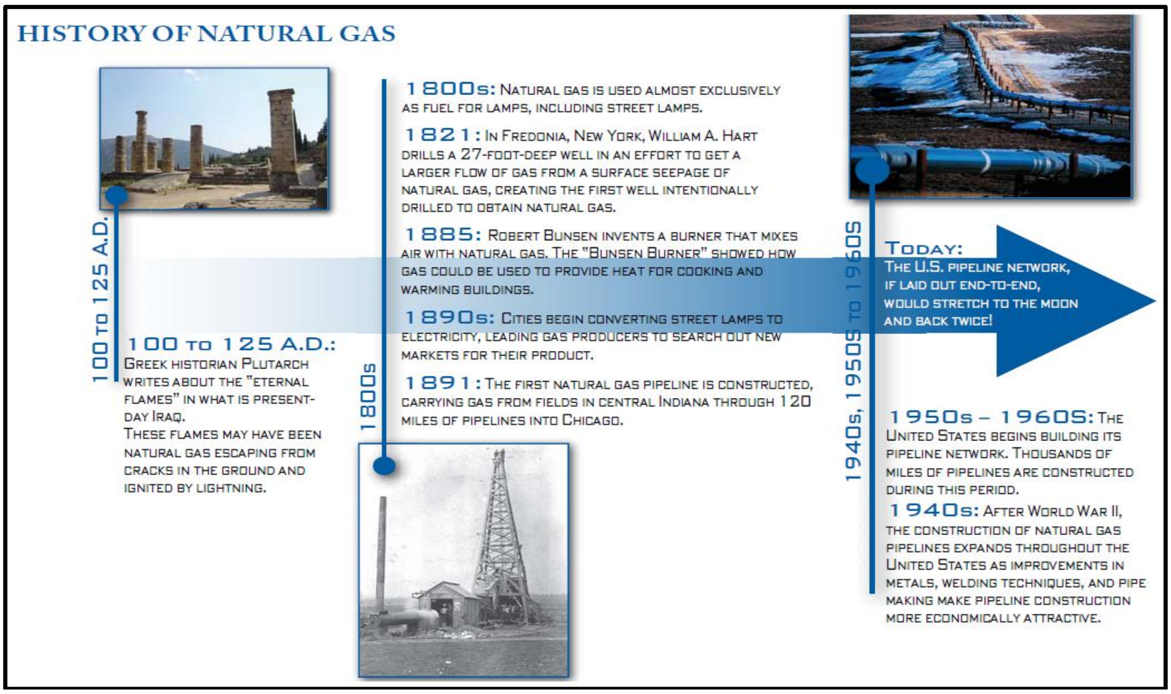
Without any way to transport it effectively, natural gas discovered pre WWII was usually just allowed to vent into the atmosphere, or burnt, when found alongside coal and oil, or simply left in the ground when found alone.

One of the first lengthy pipelines was constructed in 1891. This pipeline was 120 miles long, and carried natural gas from wells in central Indiana to the city of Chicago. However, this early pipeline was very rudimentary, and was not very efficient at transporting natural gas. It wasn't until the 1920s that any significant effort was put into building a pipeline infrastructure. After World War II, welding techniques, pipe rolling, and metallurgical advances allowed for the construction of reliable pipelines. This post-war pipeline construction boom lasted well into the '60s, and allowed for the construction of thousands of miles of pipeline in America.

Once the transportation of natural gas was possible, new uses for natural gas were discovered. These included using natural gas to heat homes and operate appliances such as water heaters and oven ranges. Industry began to use natural gas in manufacturing and processing plants. Also, natural gas was used to heat boilers and to generate electricity.

Natural gas was formerly a national or regional fuel. But the development of long-distance pipelines and the growth of liquefied natural gas (LNG) have turned natural gas into a global business.

(Main source: http://www.naturalgas.org/overview/history.asp)



1.3 Conventional and unconventional natural gas formations

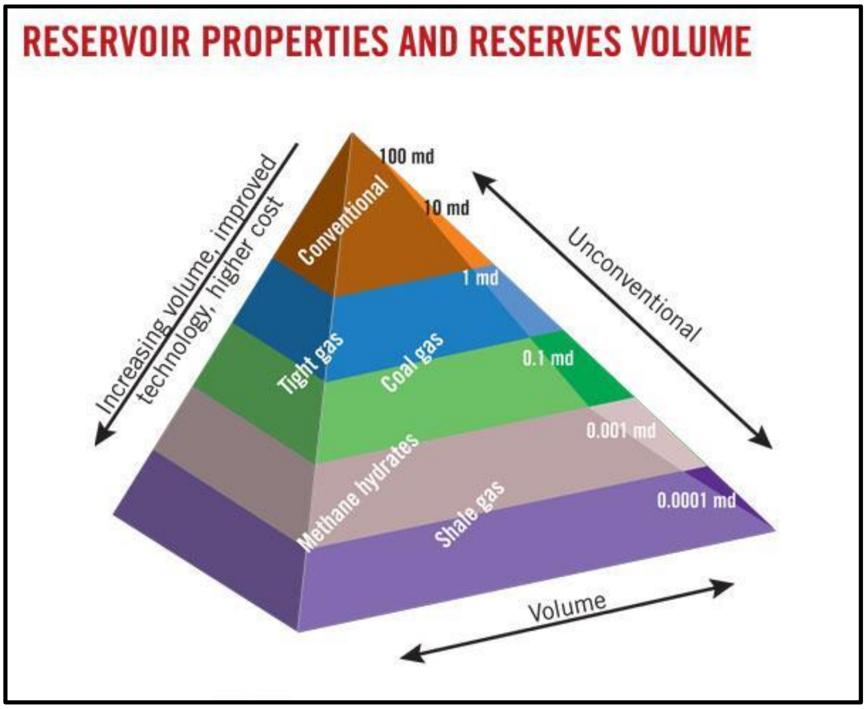
Natural gas comes from both 'conventional' (easier to produce) and 'unconventional' (more difficult to produce) geological formations. The key difference between 'conventional' and 'unconventional' natural gas is the manner, ease and cost associated with extracting the resource.

Conventional natural gas formations

Exploration for conventional gas has been almost the sole focus of the oil and gas industry since it began nearly 100 years ago. Conventional gas is typically 'free gas' trapped in multiple, relatively small, porous zones in various naturally occurring rock formations such as carbonates, sandstones, and siltstones.

Unconventional natural gas formations

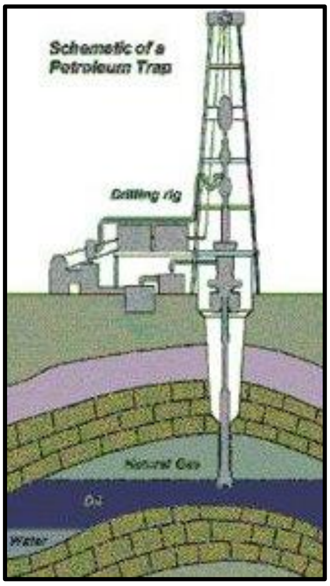
Most of the growth in supply from today's recoverable gas resources is found in unconventional formations. Unconventional natural gas is gas trapped in impermeable rock which cannot migrate to a trap and form a conventional gas deposit. Unconventional gas may be trapped in the source rock from which is generated or it has migrated to a formation of rock which has since become impermeable. Unconventional gas reservoirs include tight gas, coal bed methane, gas hydrates, and shale gas. The technological breakthroughs in horizontal drilling and fracturing have made shale and other unconventional gas supplies commercially viable.



Natural gas resource triangle

Note: A darcy (d) and millidarcy (md) are units of permeability. They are not SI units, but are widely used in petroleum engineering and geology. Like other measures of permeability, a darcy has the same units as area. A medium with a permeability of 1 darcy permits a flow of 1 cm^3/s of a fluid with viscosity 1 cP (1 mPa·s) under a pressure gradient of 1 atm/cm acting across an area of 1 cm^2.

1.3.1 Conventional natural gas

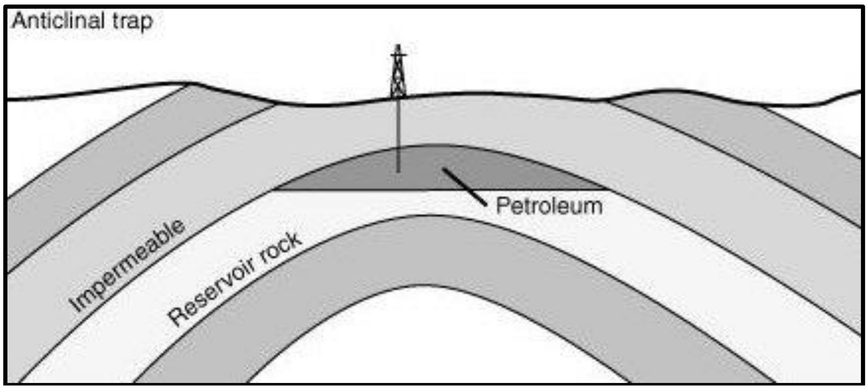


Schematic of a petroleum trap

Although there are several ways that methane, and thus natural gas, may be formed, it is usually found underneath the surface of the earth. As natural gas has a low density, once formed it will rise toward the surface of the earth through loose, shale type rock and other material. Some of this methane will simply rise to the surface and dissipate into the air. However, a great deal of this methane will rise up into geological formations that 'trap' the gas under the ground. These formations are made up of layers of porous, sedimentary rock (kind of like a sponge that soaks up and contains the gas), with a denser, impermeable layer of rock on top.

This impermeable rock traps the natural gas under the ground. If these formations are large enough, they can trap a great deal of natural gas underground, in what is known as a reservoir. There are a number of different types of these formations, but the most common is created when the impermeable sedimentary rock forms a 'dome' shape, like an umbrella that catches all of the natural gas that is floating towards the surface.

There are a number of ways that this sort of 'dome' may be formed. For instance, faults are a common location for oil and natural gas deposits to exist. A fault occurs when the normal sedimentary layers 'split' vertically, so that impermeable rock shifts down to trap natural gas in the more permeable limestone or sandstone layers. Essentially, the geological formation, which layers impermeable rock over more porous, oil and gas rich sediment, has the potential to form a reservoir. The picture below shows how natural gas and oil can be trapped under impermeable sedimentary rock, in what is known as an anticlinal formation. To successfully bring these fossil fuels to the surface, a hole must be drilled through the impermeable rock to release the fossil fuels under pressure. Note that in reservoirs that contain oil and gas, the gas, being the least dense, is found closest to the surface, with the oil beneath it, typically followed by a certain amount of water. With natural gas trapped under the earth in this fashion, it can be recovered by drilling a hole through the impermeable rock. Gas in these reservoirs is typically under pressure, allowing it to escape from the reservoir on its own.



Typical anticlinal trap

1.3.2 Unconventional natural gas

Historically, conventional natural gas deposits have been the most practical and easiest deposits to mine. However, as technology and geological knowledge advance, unconventional natural gas deposits are beginning to make up an increasingly large percent of the supply picture.

A precise answer to the question 'What exactly is unconventional gas?' is hard to find. What was unconventional yesterday may, through some technological advance or ingenious new process, become conventional tomorrow. In the broadest sense, unconventional natural gas is gas that is more difficult or less economical to extract, usually because the technology to reach it has not been developed fully, or is too expensive. For example, prior to 1978, natural gas that had been discovered buried deep underground in the Anadarko basin was virtually untouched. It simply wasn't economical or possible to extract this natural gas. It was unconventional natural gas. However, the passage of market-based rate regulation and the passage of the Natural Gas Policy Act in the U.S. provided incentives towards searching for and extracting unconventional natural gas, and also spurred investment into deep exploration and development drilling, making much of the deep gas in the basin conventionally extractable.

Therefore, what is really considered unconventional natural gas changes over time, and from deposit to deposit. The economics of extraction play a role in determining whether or not a particular deposit may be unconventional, or simply too costly to extract. Essentially, however, there are six main categories of unconventional natural gas. These are: deep gas, tight gas, gas-containing shales, coalbed methane, geopressurized zones, and Arctic and sub-sea hydrates.

Deep natural gas

Deep natural gas is typically 15,000 feet or more underground, much deeper than conventional gas deposits (which are traditionally only a few thousand feet deep at most). Deep gas has, in recent years, become more conventional. Deep drilling, exploration, and extraction techniques have substantially improved, making drilling economical. However, it is still more expensive to produce than conventional natural gas, and therefore economic conditions have to be such that it is profitable for the industry to extract from these sources.

Tight natural gas

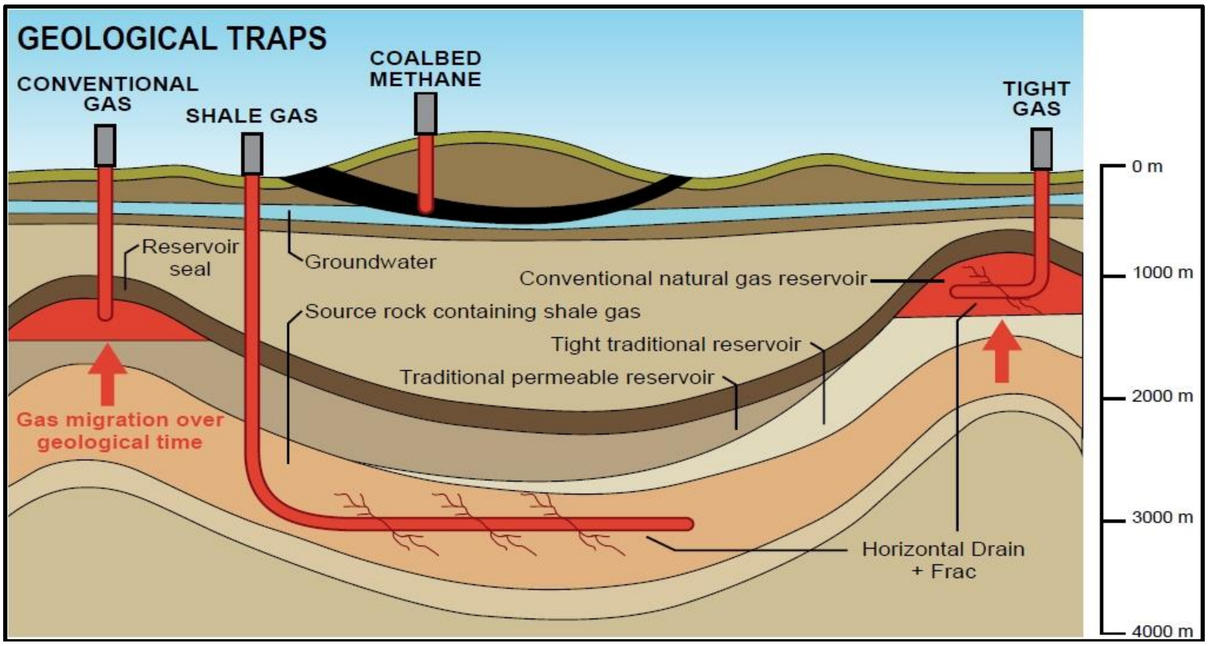
Another form of unconventional natural gas is referred to as tight gas. This is gas that is stuck in a very tight formation underground, trapped in unusually impermeable, non-porous hard rock/sandstone/limestone formation (tight sand). In a conventional natural gas deposit, once drilled, the gas can usually be extracted quite readily and easily. A great deal more effort has to be put into extracting gas from a tight formation. Several techniques exist that allow natural gas to be extracted, including fracturing and acidizing. However, these techniques are also very costly. Like all unconventional natural gas, the economic incentive must be there to incite companies to extract this costly gas instead of more easily obtainable, conventional natural gas.

Shale gas

Natural gas can also exist in shale deposits, which formed 350 million of years ago. Shale is a very fine-grained sedimentary rock, which is easily breakable into thin, parallel layers. It is a very soft rock, but it does not disintegrate when it becomes wet. These shales can contain natural gas, usually when two thick, black shale deposits 'sandwich' a thinner area of shale. Because of some of the properties of these shales, the extraction of natural gas from shale formations is more difficult and perhaps more expensive than that of conventional natural gas.

Coalbed methane

Coal, another fossil fuel, is formed underground under similar geologic conditions as natural gas and oil. These coal deposits are commonly found as seams that run underground, and are mined by digging into the seam and removing the coal. Many coal seams also contain natural gas, either within the seam itself or the surrounding rock. This coalbed methane is trapped underground, and is generally not released into the atmosphere until coal mining activities unleash it. Historically, coalbed methane has been considered a nuisance in the coal mining industry. Once a mine is built, and coal is extracted, the methane contained in the seam usually leaks out into the coal mine itself. This poses a safety threat, as too high a concentration of methane in the well creates dangerous conditions for coal miners. In the past, the methane that accumulated in a coal mine was intentionally vented into the atmosphere. Today, however, coalbed methane has become a popular unconventional form of natural gas. This methane can be extracted and injected into natural gas pipelines for resale, used as an industrial feedstock, or for heating and electricity generation. What was once a by-product of the coal industry is becoming an increasingly important source of methane and natural gas.



Schematic cross-section showing the general setting of basin centered / low permeability regional gas accumulations

Geopressurized zones

Geopressurized zones are natural underground formations that are under unusually high pressure for their depth. These areas are formed by layers of clay that are deposited and compacted very quickly on top of more porous, absorbent material such as sand or silt. Water and natural gas that are present in this clay are squeezed out by the rapid compression of the clay, and enter the more porous sand or silt deposits. The natural gas, due to the compression of the clay, is deposited in this sand or silt under very high pressure (hence the term 'geopressure'). In addition to having these properties, geopressurized zones are typically located at great depths, usually 10,000-25,000 feet below the surface of the earth. The combination of all these factors makes the extraction of natural gas in geopressurized zones quite complicated. However, of all of the unconventional sources of natural gas, geopressurized zones are estimated to hold the greatest amount of gas.

Methane hydrates

Methane hydrates are the most recent form of unconventional natural gas to be discovered and researched. These interesting formations are made up of a lattice of frozen water, which forms a sort of 'cage' around molecules of methane. These hydrates look like melting snow and were first discovered in permafrost regions of the Arctic. However, research into methane hydrates has revealed that they may be much more plentiful than first expected. In fact, the United States Geological Survey (USGS) estimates that methane hydrates may contain more organic carbon than the world's coal, oil, and conventional natural gas - combined. However, research into methane hydrates is still in its infancy. It is not known what kind of effects the extraction of methane hydrates may have on the natural carbon cycle or on the environment.

1.3.3 Conventional & unconventional gas: Differences in retrospective

Conventional natural gas	Unconventional natural gas
Accumulations in medium to highly porous reservoir with sufficient permeability to allow gas to flow to producing well	Deposits found in relatively impermeable rock formations – tight sands, shale and coal beds
Pressure regime tends to move gas towards producing well (i.e. natural flow)	To get resources out of the ground, artificial pathways (fractures) have to be created
Technology required is conventional and economically sustainable	Key technologies are unconventional and expensive (horizontal drilling and modern fracturing techniques)
Geological knowledge needed is fully acquired	Need to understand geology better
Normal number of extraction points	Need for much higher number of extraction points

(Main sources:
http://naturalgas.org/overview/unconvent_ng_resource.asp,
http://www.capp.ca/CANADAINDUSTRY/NATURALGAS/CONVENTIONAL-UNCONVENTIONAL /Pages/default.aspx
http://www.nt.gov.au/d/Minerals_Energy/index.cfm?header=What%20is%20the%20difference%20between%20Conventional%20and%20Unconventional%20Gas?)

1.4 Natural gas production and supply chain

This section provides a quick insight of the natural gas production and supply chain. The same basic principles described in the general natural gas chain apply to shale gas as well.

Note: A production chain is defined as the steps that need to be taken in order to transform raw materials into goods which can then be used by the individual consumer and/or the industry. A supply chain is a system of organizations, people, technology, activities, information and resources involved in moving a product or service from the supplier to the customer.

The process of getting natural gas out of the ground, and to its final destination to be used, is a complicated one. This section provides an overview of the processes that allow the natural gas industry to get their product out of the ground, and transform it into the natural gas intended for commercial/industrial use.

Section overview			
#	Chain type	Section	Is about
1	Production chain	Exploration	how natural gas is found and how companies decide where to drill wells
2	Production chain	Extraction	the drilling process and how natural gas is brought from its underground reservoirs to the surface
3	Production chain	Production	what happens once the well is drilled, including the processing of natural gas once it is brought out from underground
4	Supply chain	Transportation	is transported from the wellhead and processing plant, using an extensive network of pipelines
5	Supply chain	Storage	the storage of natural gas, how it is accomplished and why it is necessary
6	Supply chain	Distribution	the delivery of natural gas from the major pipelines to its final destination
7	Supply chain	Marketing	the role that natural gas marketers play in the supply chain

Chapter II: History of the shale gas innovation

2.0 Introduction to Chapter II

Chapter II is dedicated to the presentation of the shale gas history from the very begging of the commercialization efforts, through its major steps and all the way to its recent breakthrough and 'mainstream' success.

Thesis approach to the history of the shale gas revolution

The United States of America is the birthplace of the global shale gas revolution. Shale gas innovation was sought after and engineered in the USA and the country is -up to this day- the leader in the field, paving the shale development and establishment way for others to follow. All the advances that took place were made possible by technological innovations resulting from a sustained partnership between the gas industry and the American federal government. With the above in mind, the history of the -American in origin- breakthrough of shale gas commercial exploitation is approached in §2.1 from the perspective of the pioneering private sector -Mitchell Energy and Development- and in §2.2 from that of the U.S. government.

2.1 Private sector: Mitchell Energy pioneering the breakthrough

The 'father' of shale gas drilling


George Phydias Mitchell

George Phydias Mitchell (born May 21, 1919) is an American businessman, real estate developer and philanthropist from Texas. He is widely regarded as the American dream's 'rugs to riches' incarnation and -above all- credited with pioneering the economic extraction of shale gas. He is the son of a Greek goat herder, Savvas Paraskevopoulos, who had ended up in Galveston, Texas. Mitchell grew up poor and worked his way through Texas A&M University. He graduated in 1940, first in his class, in petroleum engineering (with his degree's additional emphasis on geology). After World War II, where he served as a captain in the Army Corps of Engineers, he started an independent oil and gas company, Mitchell Energy & Development Corp. in Houston. Gradually he built it into a Fortune 500 company that focused much more on natural gas than oil. Indicative of his character's determination is the way he pursued highly ambitious goals in every field he competed in: During the 1960's and 1970's (along with his oil and natural gas oriented targets and while trying to combine them, linking all his actions into one gigantic investment) he envisioned a real estate project on a scale never seen in the booming Houston area – a complete new town. He built 'The Woodlands', a 25,000-acre planned community, in 1974. In 2011 it totaled 27,000 and the population numbered 75,000. George Mitchell ranks #736/1,426 inside the Forbes 2013 Billionaires List.

Mitchel Energy & Development Corp. background (1946-1970's)

George Mitchell became a shareholder of Roxoil Drilling, an enterprise incorporated and renamed Oil Drilling in 1946. In 1949 he participated in the formation of a new wildcatting*see note partnership that also included his brother Johnny Mitchell and H. Merlyn Christie. The firm gradually bought out other Oil Drilling shareholders and attracted important investors. In 1952 the partners drilled their first well in North Texas, making one of the biggest gas strikes in industry history, with the discovery of the rich gas resources of the Boonsville field. A subsidiary of Oil Drilling was formed in 1953 and began acquiring leases and drilling in North Texas. In 1954 the company arranged to supply natural gas to the Chicago metropolitan area through the Natural Gas Pipeline Company of America. After 1955 the firm began to diversify into real estate, (an investment that would lead to the aforementioned 1974 'Woodlands'). In 1957 the firm diversified into gas processing with the construction of its GM&A gas products plant at Bridgeport, Texas. In 1959 George Mitchell became company president and chief executive officer of Oil Drilling. Around 1962 H. Merlyn Christie retired from the company and the brothers split 70-30 their shares (with George taking the ruling percentage) and renamed the enterprise Mitchell and Mitchell Gas and Oil Corporation. In 1963 the company acquired 200 miles of pipeline in Palo Pinto County from Southwestern Gas Pipeline, Incorporated. In 1971 the business was renamed Mitchell Energy and Development Corporation, and in 1972 an initial public offering was made on the American Stock Exchange. By 1974 Mitchell Energy had formed many contract-drilling subsidiaries and also purchased ten gas-processing plants.

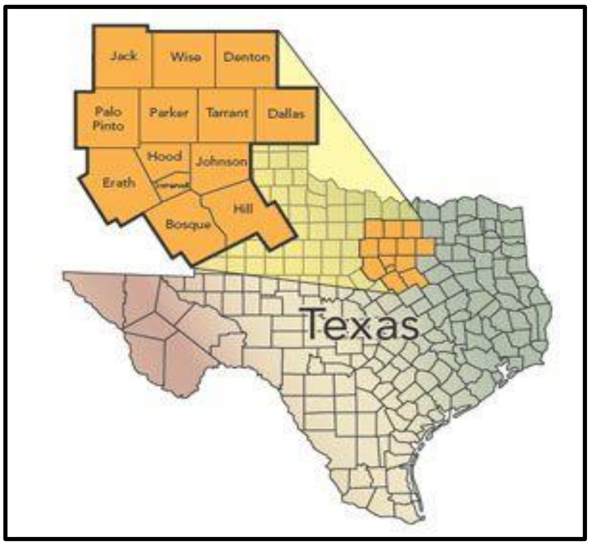
Note: A wildcatter is an American term for a person who drills wildcat wells, exploration oil wells in areas not known to be oil fields.

Foreseeing the problem

Mitchell was contracted in 1954 to deliver a substantial amount of natural gas from Texas to feed a pipeline serving Chicago. About twenty five years later, in the early 1980s, Mitchell successfully predicted the problem coming: He had noticed the reserves on which the contract depended going alarmingly down. The -not so remote- possibility of natural gas shortage would put the company in a very difficult position. This concern was amplified by the uncertain availability of suitable replacements, were the reserves in use depleted. Supplies were constrained by scarcity. Having a strong hunch, years of experience in the field and piqued by a geology report that was published around 1982, Mitchell started forming an abstract idea of the goal -virtually a cause- he we would end up stubbornly and relentlessly pursuing for the next twenty years.

Determined for success

For a very long time it had been recognized that natural gas was to be found not only in productive reservoirs but also trapped in hard, concrete-like shale rock. This shale rock served as the source rock, the 'kitchen' where the gas was created, and also as the cap that sat on top of reservoirs that prevented the gas and oil from leaking away. These were not just speculations of the geology report. It was known that the very first natural gas well in the United States, in Fredonia, New York, in 1821, drew from a shale formation. Gas could certainly be extracted from shale formations. The problem of the matter was, to its core, an economic one: It was inordinately difficult and thus very expensive to extract gas from shale. While it could be theoretically done, shale gas exploitation was considered commercially impossible.



Barnett Shale

Mitchell was determined to crack the shale code. The 'laboratory' he chose was a large region called the Barnett Shale, around Dallas and Fort Worth, Texas. Despite all efforts, the Barnett Shale proved continuously unforgiving and the project was met with disappointment and skepticism from the engineers and geologist who participated in the research. The few major companies that were also tackling the problem, discouraged by the failure to deliver, dropped out by 1997, leaving only Mitchell and a few minor independents in the Barnett region.

In the mid-1970s (and in the aftermath of OPEC's 1973 embargo) the American government issued a series of incentive programs wanting to promote national energy development. Federal policy aimed to lower the risks taken by innovative individuals and provide complementary inputs (without supplanting the private sector). Section 29, a provision in the 1980 windfall profits tax bill provided a federal tax credit for drilling for so-called unconventional natural gas. Over the years, that incentive did exactly what it was supposed to do, stimulating activity that would otherwise not have taken place. Mitchell for his part, still having to overcome incredible odds and difficulties, was aided by the government's support and persisted on acquiring the needed know-how.

Breakthrough

The introduction of 3D seismic improved the understanding of the subsurface. Still, Mitchell Energy had not yet cracked the Barnett's code. For that to happen, two key technologies –hydraulic fracturing and horizontal drilling- had to be developed, combined and applied accordingly.

Mitchell Energy had been experimenting with different methodologies for hydraulic fracturing, colloquially named 'fracking' or 'fraccing', a technique that was first used at the end of the 1940s. Natural gas is impounded in porous, low permeability shales that act like a sponge. Through the fraccing process, large amounts of water combined with sand and small amounts of chemicals are injected, under high pressure, into the shale formation. This fragments underground rock, creating pathways for the otherwise trapped natural gas to find a route and flow through to the well. By the end of 1998, the company's trial-and-error approach ultimately paid off. Mitchell finally achieved his breakthrough; by successfully adapting a fracturing technique known as LSF (light sand fraccing) he managed to break up the shale rock.

The problems did not end for Mitchell with the cracking of the code. Developing the Barnett shale would require an investment capital way too big for the (60-year-long) independent Mitchell Energy. Mitchell decided to sell the company but potential buyers, although intrigued by the interesting idea of shale exploitation, decided -after due diligence- to pass, considering it to be a commercial flop.

The Mitchell Energy crew went back to work on the shale, further developing its capabilities, deepening its understanding and producing a lot more natural gas. The sudden rising output on the Barnett Shale area was noticed in 2001 by Larry Nichols, the co-founder and CEO (-at that time-, now executive chairman) of, the also independent, Devon Energy. Devon was among the interested parties that had previously passed. With a renewed, results-reinforced, faith in hydraulic fracturing, Devon went on and acquired Mitchell Energy for $3.5 billion. Nichols said, *"We thought we could take that technology [fraccing] and combine it with horizontal drilling and be able to significantly improve the economics of the wells and drill in a lot more places"*. George Mitchell also stated, *"This transaction provides significant value while retaining a unique opportunity to participate in the exciting upside potential of Devon. Our shareholders and employees will benefit from becoming part of a larger, stronger and more diversified company".*

Devon, for its part, had strong capabilities in another technology, horizontal drilling, which had begun to emerge in the 1980s. Advances in controls and measurement allowed operators to drill down to a certain depth, and then drill on at an angle or even sideways. This would expose much more of the reservoir, permitting far greater gas recovery. Devon combined the fracturing know-how and the team it had acquired from Mitchell with its own skills in horizontal drilling. This fusion of knowledge and advances, though successful, still required experimentation; Devon started drilling a series of wells, shaping and perfecting the shale gas extraction method. Shale gas, heretofore commercially inaccessible, began to flow in significant volumes and the 'unconventional gas revolution' was finally a reality.

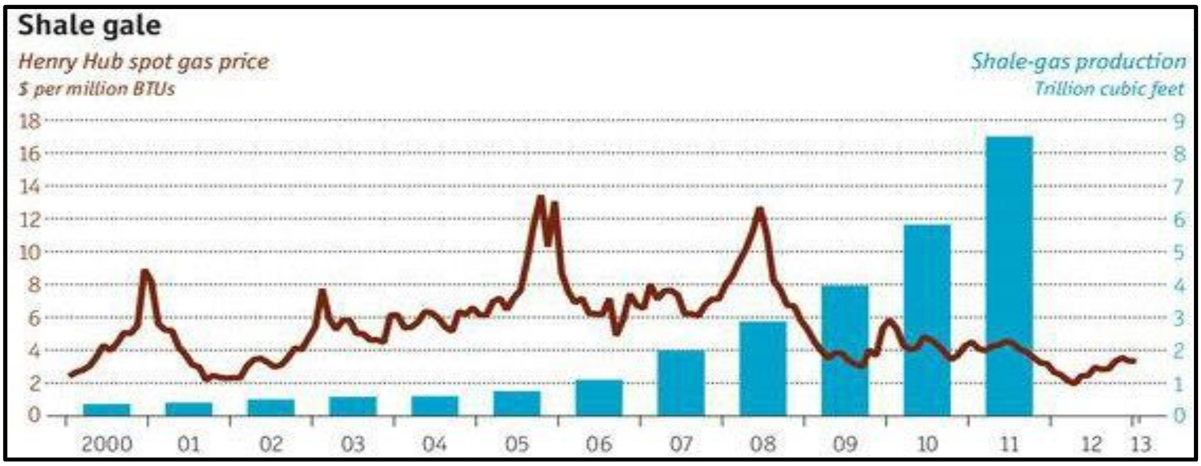
Entrepreneurial independent oil and gas companies jumped on the technology and quickly carried it to other US regions -in Louisiana and in Arkansas, and Oklahoma, and then to the 'mighty Marcellus' shale that sprawls beneath western New York and Pennsylvania down into West Virginia-.

The 'Shale gale'

By 2007, the US was expected to face a sharp decline in domestic natural gas production and the market was ready to utilize the LNG alternative solution. These predictions of gloomy numbers were all disproved. The technological breakthrough that had taken place was beginning to make its impact felt. The rest of the industry now realized that something new was happening. And that included both major oil and gas companies, which so far had been more focused on big international LNG (thought to be required to offset the anticipated shortfall in North American natural gas).

Over the next few years, the output of shale gas continued to increase. Skills were further developed. Costs gradually came down and resulted in making shale gas cheaper than conventional natural gas. In 2000 shale was just 1 percent of natural gas supply. By 2011 it was 25 percent, and within two decades it is said to have the potential to reach 50 percent. The shale gas turbulence was given a 'catchy' name, 'shale gale'.

Energy expert Daniel Yergin best summarizes the 'shale gale' impact: *"The shale gas transformed the U.S. natural gas market. Perennial shortage gave way to substantial surplus, which turned the prospects for LNG in North America upside down. Just a few years earlier, LNG had seemed destined to fill an increasing share of the U.S. market. Instead it became a marginal supply rather than a necessity. Electric utilities, remembering gas shortages and price spikes, had been reluctant to use more natural gas. But now, with the new abundance and lower prices, lower-carbon gas seemed likely to play much larger role in the generation of electric power, challenging the economics of nuclear power and displacing higher-carbon coal, the mainstay of electric generation. As a source of relatively low-priced electric power, it created a more difficult competitive environment for new wind projects. Shale gas also began to have an impact on the debate on both climate change and energy security policy. By the beginning of this decade, the rapidity and sheer scale of the shale breakthrough -and its effect on markets- qualified it as the most significant innovation in energy so far since the start of the twenty-first century. As a result of the shale revolution, North America's natural gas base, now estimated at 3,000 trillion cubic feet, could provide for current levels of consumption for over a hundred years-plus"*.



Note: The Henry Hub is a distribution hub on the US gas pipeline system in Erath, Louisiana. Due to its importance, it lends its name to the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX) and the OTC swaps traded on Intercontinental Exchange (ICE).

Environmental controversy

Shale gas has stoked environmental controversy and policy debate in the US. Demographic differences have brought the controversy to the fore: Lower-density states, such as Texas, are accustomed to energy development; they encourage it as a major source of income for the population and revenues for the state government. Eastern states, like New York and Pennsylvania, are not accustomed to drilling in their region and regard it with reservations (although Pennsylvania is experienced with coal mining and was the birthplace of the oil industry). A part of the society welcomes the jobs, royalties, and tax revenues, but another is conscious about the surface disruption and the sudden truck traffic increase.

Environmental concern is mostly centered on water: Hydraulic fracturing takes place a mile or more below drinking water aquifers and is separated from them by thick layers of impermeable rock. During the process a small amount of chemicals is being used. Critics warn that it may damage drinking water aquifers. The industry argues that it has mastered the techniques used, carrying more than 60 years of experience and expertise and that an unpredictable contamination accident is highly unlikely to occur.

The biggest fracturing issue has become not what goes down, but what comes back, the 'flow back' and the 'produced water', that surfaces out of the well over time. This water needs to be handled properly and safely disposed. Three things can be done with it. It can be injected into deep disposal wells, put through treatment facilities, or recycled back into operations. In traditional oil and gas states, the wastewater has often been re-injected. But the geology attributes differ from place to place (in Pennsylvania re-injection is not an option) and the water that cannot be recycled is put through local treatment facilities or trucked out of state. Aboveground management of the wastewater is constantly progressing. New large-scale water treatment facilities are being developed. The industry is now recycling 70 to 80 percent of the flow back. Simultaneously, there is intensive focus on innovation: Methods to reduce the amount of water used and to increase the number of drilled wells from one 'pad' (-thus reducing the surface disruption-) are constantly engineered and improved on.

A more recent concern, provoking the highest controversy, is that of 'migration', methane leaking toward the surface and into some water wells as a result of fraccing. Methane has been found in water wells in gas-producing regions, but there is no agreement on how this can happen. Some cases of methane contamination have been tied to shallow layers of methane, not the mile-deep deposits of shale gas where fraccing takes place. In other cases, water wells may have been dug through layers of naturally occurring methane without being adequately sealed. It is difficult to know for certain because of a lack of 'baseline' data (measurements of a water well's methane content before a shale gas well is drilled in the neighborhood). Gas developers are now routinely taking such measurements before drilling begins in order to establish whether methane is preexisting in water aquifers.

Events timeline

1919	George P. Mitchell was born.
1940s	Hydraulic fracturing first used at the end of the decade.
1952	Oil Drilling (Mitchell brothers and M.Christie) drills its first well in North Texas - Major gas strike & discovery of Boonsville Field.
1954	Oil Drilling contracted to supply natural gas to Chicago.
1959	G. Mitchell becomes Company President - Chief Executive Officer of Oil Drilling.
1962	Merlyn Christie leaves. Mitchell brothers acquire stocks and form Mitchell and Mitchell Gas & Oil Corporation.
1971	Company renamed and reformed into Mitchell Energy and Development Corporation.
1972	Mitchell Energy enters American Stock Exchange Market.
1973-1974	OPEC's oil embargo;
1980s	Mitchell starts researching shale gas exploitation in the begging of the decade.
	Horizontal drilling development in this decade;
	Section 29 (Provision in the windfall profits tax bill);
1998	**Mitchell succeeds in breaking up shales - LSF technique.**
2000	Shale gas is 1% of the whole US natural gas supply.
2001	Devon acquires Mitchel Energy for $3.5 bilion.
2001	Devon combines hydraulic fracturing and horizontal drilling know-how.
2011	Shale gas is 25% of the whole US natural gas supply.

2.2 US government's policy regarding shale gas

Up to this point, the shale gas breakthrough has been analyzed mainly from the scope of Mitchell Energy, the individual company that accomplished the innovation and paved the way for the rest of the private sector. Press and media often focus solely on this part of the story, for the sake of presenting the facts in a novelized and interesting way. As so often happens in reality, the truth is more complicated and there is no parthenogenesis; at least not in the manner of one man and his company conquering the odds by themselves and innovating a method from the ground up. Mitchell's brilliance, in my opinion, lies within three basic facts: he recognized the enormous hidden potential of shale gas and grabbed the opportunity as something attainable; he didn't quit despite the difficulties of the trial-and-error method followed; and finally, he sought and received all the help he could find in order to gather the scattered pieces of the 'know-how' – while shaping and improving the ones missing- and figured them out into a total. This help received was of great importance on achieving the end success and by no means diminishes his role to something less than 'the father of shale gas'.

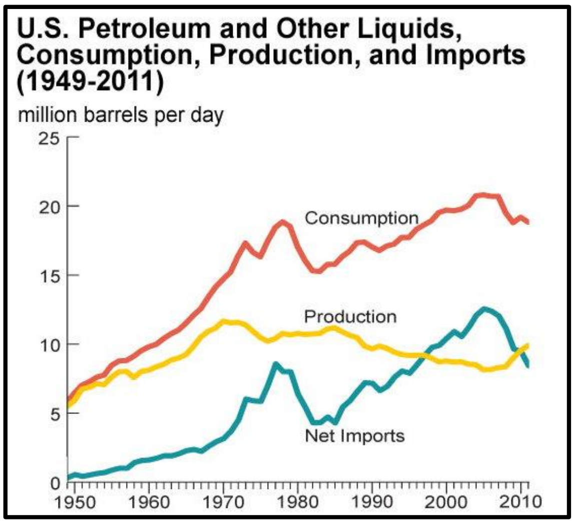
But where did this help come from? Simplifying the conditions of the time we find two main interested parties: private sector companies with the will to explore the unknown region of unconventional fossil fuels and the US government wanting to help them, for reasons explained below. So far, in §2.1, we only talked about section 29 as regards government policy towards unconventional. From my understanding, the US government had a much more strategic role in the matter: It was the coordinator of the private attempts towards answering the risky and innovative question marks spotted on the energy map; in constant interaction, sharing, organizing and exchanging knowledge, but never stepping in to replace the private sector.

Below we take a closer look at the reasons that drove the US government to form this helpful-towards-unconventional agenda, the actual help it offered and the lessons to be learnt from this successful collaboration of private-public sector.

US forming an energy strategy in the 1970s

The 1970s was a crucial, turbulent decade for the US of America and one its reverberations would ultimately continue to be felt to this day. The tension on global scale had been building up from the very start of the twentieth century and turmoil never seized to exist: massive technological progress drastically altered the ways of life and production and their energy demands; two world wars had taken place, that made very clear the link between power-security-independence and oil (Lord Curzon, British foreign secretary said after WWI, *"The allied cause had floated to victory upon a wave of oil"*); world power and reserves were redistributed accordingly by the WWII winners (causing friction between them) ; peak oil theory -the anticipation of oil running out- led to the fear of permanent oil shortage, igniting a frantic search for new supplies; OPEC *(Organization of Petroleum Exporting Countries)* was founded in 1960, aiming to secure abundance, convenience and low prices, leading to the postwar economic miracles of France, Germany, Italy and Japan. The world seemed to be entering a new era and the USA had to seriously reevaluate the strategic significance of energy (and its acquisition) to meet with the times.

The problem was that of energy self-sufficiency. The US economy leaned heavily on importing oil and that was a tactical weakness bound to be exploited by contradicting interests in control of this vital commodity. While the problem was foreseeable, action was taken after the oil crisis had broken out.



Several events combined to bring about the energy crisis of the 1970s. The first was a dramatic rise in energy consumption, with the United States consuming a huge percentage of the world's energy in proportion to its population. Domestic oil production declined at the same time, leading the country to lean heavily on foreign oil. In 1973 and again in 1977, the US was placed under an OPEC embargo for political reasons. Middle Eastern members of OPEC wished to protest American involvement in an ongoing conflict with Israel. The limited supply and heavy demand resulted in prices skyrocketing and the shock was hardly limited to the United States. On an international level, the price increases of petroleum disrupted market systems in changing competitive positions. At the macro level, economic problems consisted of both inflationary and deflationary impacts of domestic economies.

The 1970s was also an era in which environmentalism was becoming mainstream. Public opinion stopped regarding environmentalists as absurd individuals and became genuinely interested and concerned. The energy crisis, combined with more awareness in environmentalism, brought about a rise in interest in alternative sources of energy and fuel efficiency.

Politically, the US government struggled to deal with the crisis. Richard Nixon (37th President of the United States, in office January 20, 1969 – August 9, 1974) aimed at 'energy independence', a concept that was adopted as the high goal of pretty much every US government since then (often, with the broadened -Churchill's- sense of the term, meaning not only self-sufficiency but security and diversification of supply). Yet, the Watergate scandal erupted at about the same time, making it difficult for the Nixon administration to make productive policy decisions. Once Gerald Ford (38th President of the United States, in office August 9, 1974 – January 20, 1977) and later Jimmy Carter (39th President of the United States, in office January 20, 1977 – January 20, 1981) took over, they struggled to make sense of the problem. A number of government agencies, including the Department of Energy, were founded during this period in an attempt to formulate policy and shift the way in which Americans used energy.

The energy crisis was a major milestone and consequently an equally major turning point in world and US affairs alike. To fully analyze its vast and complex array of results is beyond this paper's topic and intent. Over the long term, the oil embargo changed the nature of policy in the West towards increased exploration, energy conservation, and more restrictive monetary policy to better fight inflation. **Our focus concentrates on the changes it resulted in the US unconventional shale gas field. The hunt for in-house energy development led companies to search oil and gas even in areas as difficult in exploration as Alaska. It was clear that tapping unconventional reserves was part of the solution and towards the energy independence target. The government wanting to promote domestic energy increase and help the companies in that direction adopted a massive policy plan that brought results in more than one field, among others, the shale gas one.**

1970	Libya 'squeezes' oil companies. Earth day;
1971	Tehran agreement; Shah's Persepolis celebration; Britain withdraws military force from Gulf.
1972	Club of Rome study;
1973	Yom Kippur War; Arab oil embargo (fourth postwar oil crisis); Oil price rises from $2.90 per barrel (September) to $11.65 (December). Alaskan pipeline approved. Watergate scandal widens.
1974	Arab embargo ends. Nixon resigns. International Energy Agency (IEA) founded.
1975	Automobile fuel efficiency standards established in the United States. First oil comes ashore from North Sea. South Vietnam falls to communists. Saudi, Kuwaiti and Venezuelan concessions come to an end.
1977	North Slope Alaskan oil comes to market. Buildup of Mexican production. Anwar Sadat goes to Israel.
1978	Anti-Shah demonstrations, strikes by oil workers in Iran.
1979	Shah goes into exile. Ayatollah Khomeini takes power. Three Mile Island nuclear plant accident; Iran takes hostages at U.S. embassy.
1979 - 1981	Panic sends oil from $13 to $34 a barrel (fifth postwar oil crisis).

1970-1980 Decade's major events chronology
(Note: Included out of context for better understanding and further research on the 1970s)

Shale gas difficulties in the 1970s

Shale gas extraction became commonplace in the 1990s, after approximately twenty long years of hardship, research and effort to tame its unconventional nature. It is a noteworthy fact that this –known way back from the 1820s- resource was even bypassed when drilling, in order to reach sandstone deposits that could be attained underneath it. But what were exactly the shale gas/unconventional gas conditions and prospects in the mid-1970s, when the US federal government decided to support the venture?

- Nothing was known about the geochemistry of gas shales. The knowledge base was inexistent, lacking logs or maps of the shale gas deposits and tectonic activity. There was uncertainty about the magnitude of the resource potential and the industry didn't know where to drill. Mapping techniques still delivered poor results.

As regards the technology of shale gas extraction, it was in a crude, economically not viable, state.

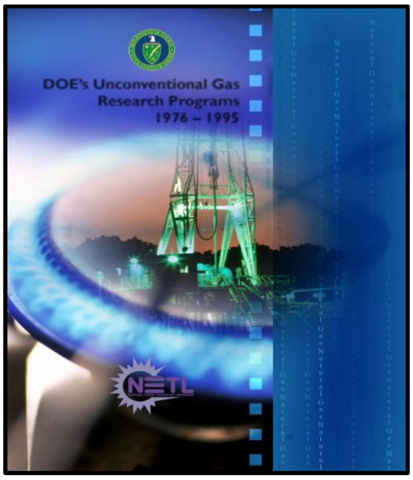
- Horizontal drilling was considered profitable only for low permeability -but not particularly deep- reservoirs and in cases where gas and water intrusion was expected.

- Hydraulic fracturing needed much more development before it could be combined into the exploitation process.

- Even the conventional drill bits of the time were unsuitable for the task.

The industry regarded unconventional as an economically and technologically impossible, full of risk and uncertainty, investment.

Significant work had to be done. The private sector taking up the task would continue to work on improving and innovating the exploration and production technologies needed, while the federal government would aid it in more than one ways: mapping the resources; coordinating and complementing industry efforts; supporting basic research and development; and promoting tax credits for unconventional gas.



"DOE's unconventional gas research programs 1976 – 1995":
An archive of important results

US government's role in the shale development: An official summary

The Breakthrough Institute is a paradigm-shifting think tank committed to modernizing environmentalism for the 21st century. On May 2012 it issued a superb and comprehensive 13-page fact sheet of the federal government's shale-involvement, titled "Where the shale gas revolution came from – Government's role in the development of hydraulic fracturing in shale". Below is included an abridged version of the paper that serves the flow of the thesis in an excellent manner: It provides a summary of the federal shale support and a narrative of the combined public-private efforts towards the innovation;

Note: Begging of abridged "Where the shale gas revolution came from"

In summary, federal investments and involvement in the development of shale gas extraction technologies spanned three decades and were comprised of:

• The Eastern Gas Shales Project, a series of public-private shale drilling demonstration projects in the 1970s;

• Collaboration with the Gas Research Institute (GRI), an industry research consortia that received partial funding and R&D*(research and development) oversight from the Federal Energy Regulatory Committee (FERC);

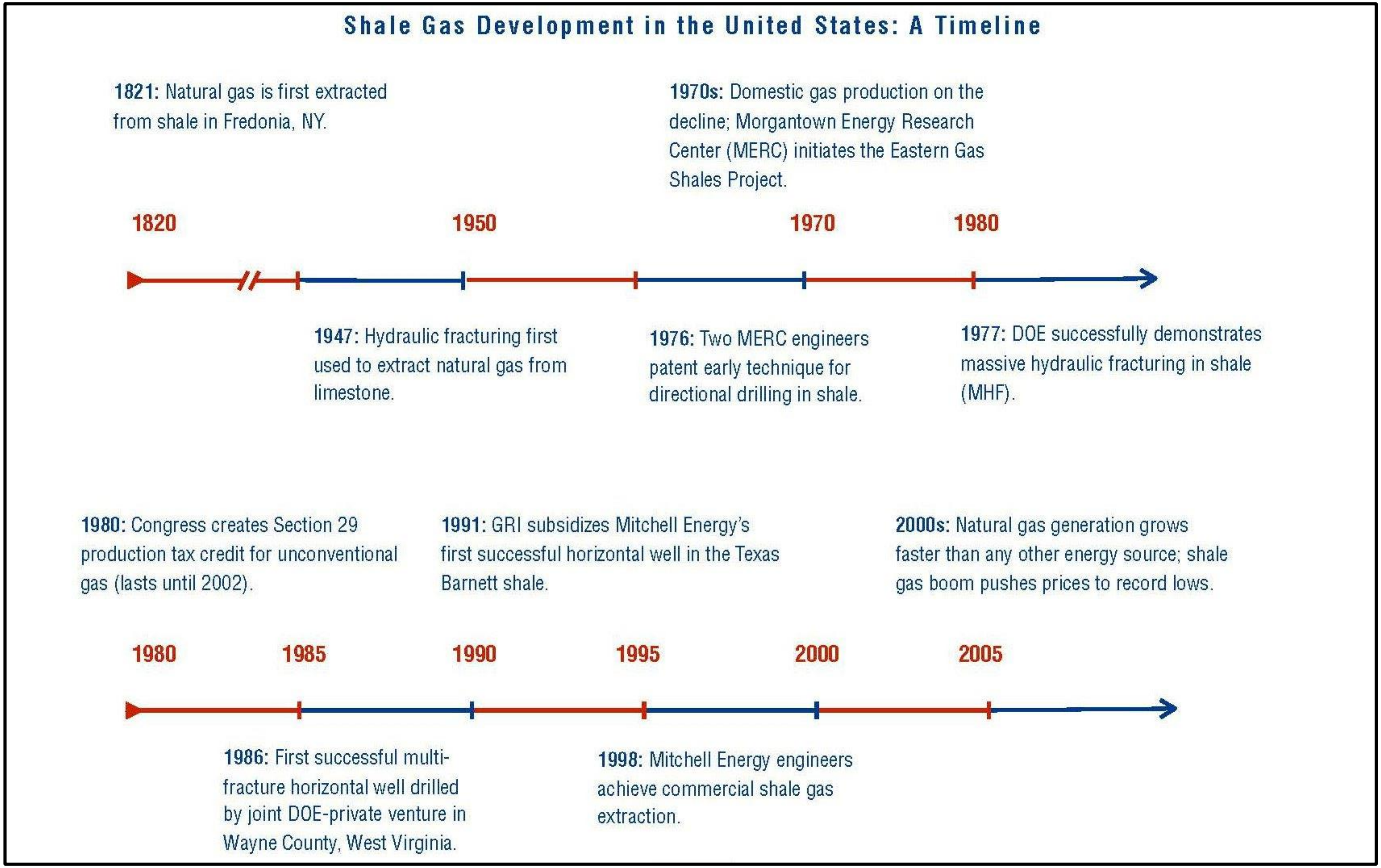
• Early shale fracturing and directional drilling technologies developed by the Energy Research & Development Administration (later the Department of Energy), the Bureau of Mines, and the Morgantown Energy Research Center (later the National Energy Technology Laboratory);

• The Section 29 production tax credit for unconventional gas, in effect from 1980-2002;

• Public subsidization and cost-sharing for demonstration projects, including the first successful multifracture horizontal drilling play in Wayne County, West Virginia in 1986, and Mitchell Energy's first horizontal well in the Texas Barnett shale in 1991;

• Three-dimensional microseismic imaging, a geologic mapping technology developed for applications in coal mines by Sandia National Laboratories.

These federal investments, coordinated in close concert with gas industry representatives, were predicated upon a single mission: the commercialization of shale gas extraction technology. As a result of these efforts carried out over the course of 30 years, shale gas went from inaccessible deposits locked in unfamiliar geologic formations to the fastest growing contributor to the nation's energy portfolio.


Shale Gas Development in the United States: A Timeline
1821: Natural gas is first extracted from shale in Fredonia, NY.
1970s: Domestic gas production on the decline; Morgantown Energy Research Center (MERC) initiates the Eastern Gas Shales Project.
1820
1950
1970
1980
1947: Hydraulic fracturing first used to extract natural gas from limestone.
1976: Two MERC engineers patent early technique for directional drilling in shale.
1977: DOE successfully demonstrates massive hydraulic fracturing in shale (MHF).
1980: Congress creates Section 29 production tax credit for unconventional gas (lasts until 2002).
1991: GRI subsidizes Mitchell Energy's first successful horizontal well in the Texas Barnett shale.
2000s: Natural gas generation grows faster than any other energy source; shale gas boom pushes prices to record lows.
1980
1985
1990
1995
2000
2005
1986: First successful multi-fracture horizontal well drilled by joint DOE-private venture in Wayne County, West Virginia.
1998: Mitchell Energy engineers achieve commercial shale gas extraction.

An industry in decline finds a new partner

Conventional natural gas production in the United States began to decline in the early 1970s. In a decade when both the Ford and Carter administrations were prioritizing fossil energy R&D during the oil crises, the natural gas industry reached out to federal research agencies for help in buffering domestic gas resource potential. The industry and federal researchers had their eyes on unconventional resource bases that stood out of reach from contemporary drilling technologies, including coalbed methane deposits, 'tight sands' natural gas, and shale gas.

While Jimmy Carter is often pointed to as the president who initiated the energy push in response to the oil crises of the early seventies, it was Republican President Gerald Ford whose administration began a concerted federal effort to seek unconventional natural gas in response to shortages. In 1976, the Morgantown Energy Research Center (MERC, now the National Energy Technology Laboratory) and the Bureau of Mines (BOM) initiated the Eastern Gas Shales Project, which established a series of demonstration partnerships with universities and private gas companies in Pennsylvania and West Virginia. That same year, two MERC engineers - Joseph Pasini III and William K. Overby, Jr. – patented an early directional shale drilling technique that allowed operators to span larger radial expanses of shale deposits. These breakthroughs would later lead to horizontal well drilling in shale, which ultimately proved a much more cost effective method for recovering large stores of natural gas.

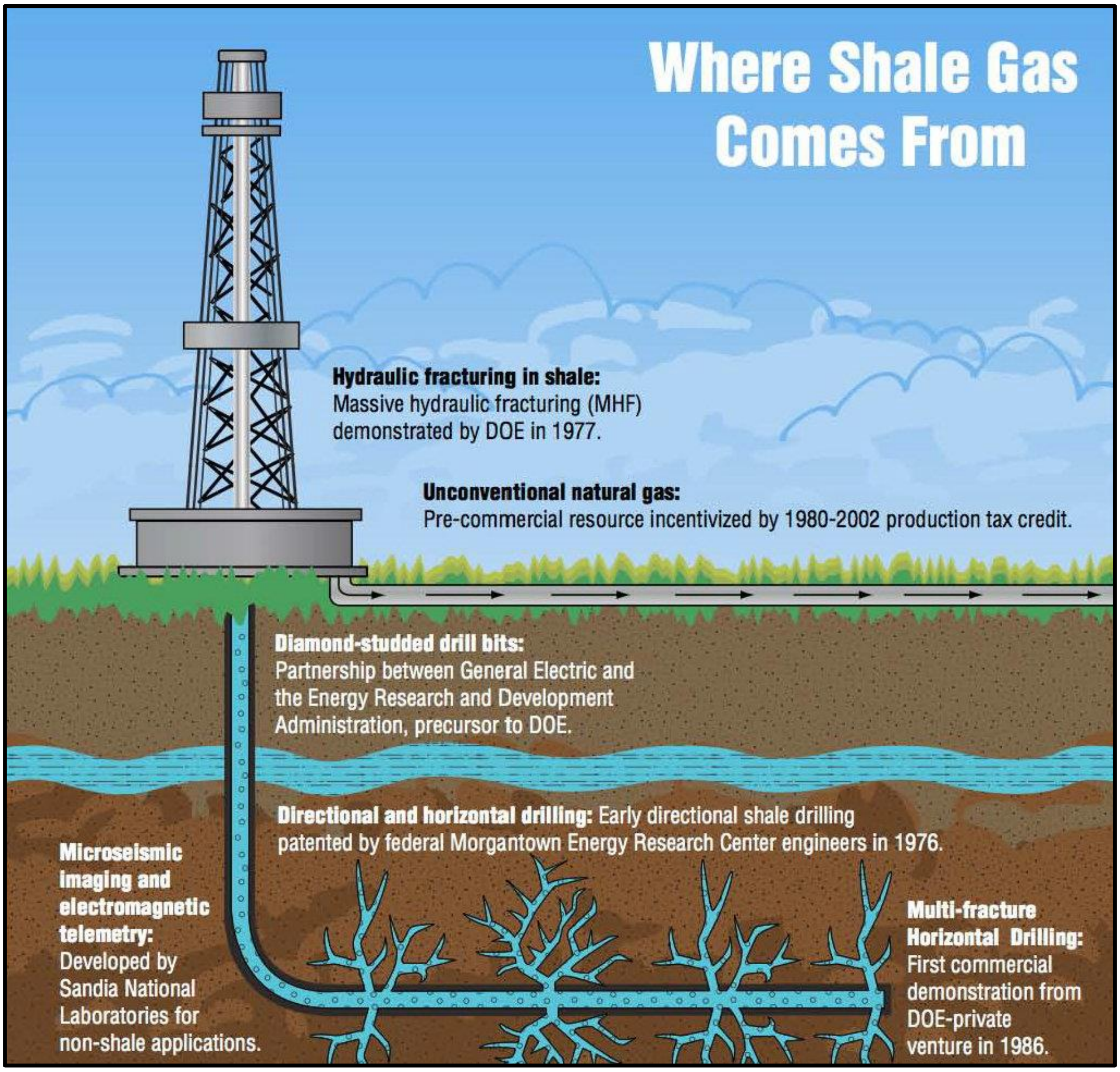
A key early innovation came from a partnership between General Electric and the Energy Research and Development Administration (ERDA, a precursor to DOE) to develop advanced drill bits. Diamond-studded bits proved more effective at drilling through shale than conventional tools. ERDA originally sought to use the diamond technology for drilling in hot dry rocks for the agency's geothermal energy program, but the more successful application came when ERDA developed drill bits for shale drilling in collaboration with the gas industry.

Federal researchers and engineers often worked very closely with natural gas companies in the development and refinement of shale gas recovery tools and techniques. The National Labs, including Sandia, Los Alamos, and Lawrence Livermore, contributed modeling, monitoring, and evaluation to the MERC-contracted demonstration projects. In 1979, the public-private efforts to drive shale gas and coalbed methane to market were formalized in the new Department of Energy's Commercialization Plan for Recovery of Natural Gas from Unconventional Sources.

Because of shale's peculiar geology, new imaging technology was necessary to map shale deposits. Three-dimensional microseismic imaging, a technology developed by Sandia National Laboratories for work in coal mines, was serendipitously imported for application in shale gas drilling. The new seismic tools and mapping software allowed drillers to visualize the shale formations and locate the natural fractures and unevenly-distributed gas deposits. Without microseismic, shale drillers were blind, and it is unlikely that either public or private fracturing R&D efforts could have proved fruitful without the critical imaging technology.

In 1980, Congress passed the Windfall Profits Tax Act, which among other things created the Section 29 production tax credit for unconventional gas, providing an incentive of $0.50 per thousand cubic feet (Mcf) of natural gas produced from unconventional resources. The tax credit expired in 2002, after Mitchell Energy had achieved commercial production from the Barnett shale. Production of unconventional gas nearly quadrupled over this period, with the production tax credit vital to the growth and maturation of this advanced energy industry.

Federal support proved essential in the early goings of the shale gas revolution. As Fred Julander, head of Julander Energy and member of the National Petroleum Council, notes, "The Department of Energy was there with research funding when no one else was interested and today we are all reaping the benefits. Early DOE R&D in tight gas sands, gas shales, and coalbed methane helped to catalyze the development of technologies that we [in the industry] are applying today."



U.S. Government's role in the shale gas exploitation effort and production

Mitchell Energy cracks the Barnett

Most of the early R&D and demonstration work was done in the Devonian and Marcellus shales, large shale formations occupying portions of Pennsylvania, Ohio, Kentucky, and West Virginia. But the final breakthroughs would come in the Barnett shale in northeast Texas. George Mitchell, a veteran of the Texas natural gas industry, wanted to apply the technologies developed in the Eastern United States to the Barnett. He and other industry representatives spent much of the 1980s advocating for DOE fossil energy research, even as Congress attempted to zero out R&D budgets as the nation enjoyed low oil prices. In the meantime, Mitchell Energy's engineers and geologists performed considerable in-house R&D, working to scale hydraulic fracturing for commercial application in shale gas recovery.

In 1986, a DOE/private venture first demonstrated a multi-stage horizontal fracture in the Devonian shale. Commercial-scale hydraulic fracture recovery, however, would not come until after Mitchell Energy's team had finished work on refining the drilling processes and inputs. Here, again, the federal government would step in to aid the private sector. In addition to innovating on top of platform technologies like MHF and directional drilling that were originally developed by the ERDA, MERC, DOE, and other federal agencies, Mitchell Energy benefitted from a direct and sustained partnership with the federal government. In the 1980s Mitchell relied on DOE mapping techniques and research to understand the complex geology of tight shale formations. In 1991, Mitchell partnered with DOE and GRI to develop tools that would effectively fracture formations in the Barnett shale, which now produces over 6 percent of all domestic natural gas. GRI's microseismic imaging data proved particularly useful throughout the 1990s when Mitchell Energy would make the final key innovations credited with 'cracking the Barnett'.

Although unconventional gas production had been growing since the early 1980s, hydraulic fracturing technology had not been perfected or scaled to the point where full commercial deployment was competitive without subsidy. Shale gas production relied on the Section 29 production tax credit and on developers like Mitchell Energy charging a premium for gas resources. Mitchell Energy invested revenues in in-house R&D throughout the 1980s and 1990s. Having successfully demonstrated multi-fracture horizontal well drilling techniques in the Barnett, engineers had to develop the optimal combination of inputs – water, sand, propants, chemical lubricants, etc. – to achieve maximum gas recovery at the lowest cost possible. In 1998, Mitchell Energy engineers, led by Nick Steinsberger, applied an innovative drilling technique called 'slick water fracturing' (or 'light sand fracking') that brought fracture job costs down to around $100,000, compared to between $250,000 and $300,000 for MHF projects. This is widely considered a milestone that pushed shale gas into full commercial competitiveness.

Mitchell Energy was bought by Devon Energy in 2002 for $3.5 billion, the same year that the Section 29 production tax credit was allowed to expire.

Note: Ending of abridged "Where the shale gas revolution came from"

Lessons learnt

The shale gas exploration history presents us with a very successful example of a private - public sector partnership; one that delivered impressive and highly innovative results and benefited both parties. There are lessons to be taught and a lot of valuable assumptions that can be drawn from such an example. Innovation does not occur on linear, nor lonely, paths.

- The federal government studied past tactical mistakes and focused in a consistent and persistent manner on a strategy - remedy. The general target was that of in-house energy promotion and that target was pursued with determination regardless the change of rule between rival political parties over the course of time.

- The federal government wisely chose to aid rather than supplant the private sector. It identified and 'nurtured' the potential bore within capable risk taking independents, such as G. Mitchell. It lowered the risks presented and provided complimentary inputs. This led to a safer private trial-and-error environment, which in return delivered additional experience and knowledge. It promoted the essential actions in order to fill in the R&D gaps the private sector (lacking the information and capital background) could not possibly attend to.

- The tasks the government undertook required both serious effort and funding along with extensive planning. The full scope of the investment's applications couldn't be predicted beforehand. So R&D and technologies developed were transferred experimentally from one research domain to another. The exceptional coordination, organization and combination of the actions and information gathered were essentially the key elements to success.

- It should be noted that success was only evident in retrospect and the US government had to wait two decades before the proof-of-concept was confirmed and translated into commercialized benefits. While the major contribution by the public sector is -post success- regarded as positive, before the breakthrough it might have been characterized as unproductive and costly. The federal government had the experience to foresee the hardships (such as long time lags not uncommon in capital-intensive industries) that would rise along the way and the patience to overcome them.

Chapter III: Technology of the shale gas extraction

3.0 Introduction to Chapter III

Chapter III is the chapter dedicated to the technology behind the shale gas exploitation: how we manage to reach the shales, how the reservoir is exposed for production and how the gas is extracted from them; and how all this is achieved in the environmentally safest way possible. In §3.1 we sum up the distinct geological characteristics of the shales, characteristics that ultimately will determine our course of action. In §3.2 an overview of the well completion process is presented in the form of slideshows. Section §3.3 is an in depth approach to all the major technologies previously mentioned.

3.1 Shale geology and shale gas in depth approach

Prior to presenting the technologies utilized in the shale gas extraction, we study the geology of the shales formation in order to understand the problems it imposed, deeming the process unattainable at first and later on 'unconventional'; better understanding of the problem leads to better understanding of the solutions applied.

Shale gas is natural gas produced by and contained in shales. In terms of chemical makeup, it is typically a dry gas primarily composed of methane (90% or more), but some formations do produce wet gas. But what exactly are these gas shales and how they came to be both the gas's source and reservoir? Up until very recently they were regarded only as source rocks and seals for gas accumulating in the sandstone and carbonate reservoirs of traditional onshore gas development. Shales are geological rock formations rich in clays, typically derived from fine sediments, deposited in fairly quiet environments at the bottom of seas or lakes, having then been buried over the course of millions of years. The naturally tabular clay grains tend to lie flat as the sediments accumulate and subsequently become compacted as a result of additional sediment deposition. This results in mud with thin laminar bedding that lithifies into thinly layered shale rock. The very fine sheet-like clay mineral grains and laminated layers of sediment result in a rock that has limited horizontal permeability and extremely limited vertical permeability. Typical unfractured shales have matrix permeabilities on the order of 0.01 to 0.00001 millidarcies. During the deposition of these very fine-grained sediments, there can also be deposition of organic matter in the form of algae-, plant-, and animal-derived organic debris. When a significant amount of organic matter has been deposited with the sediments, the shale rock can contain organic solid material called kerogen. If the rock has been heated up to sufficient temperatures during its burial history, part of the kerogen will have been transformed into oil or gas (or a mixture of both), depending on the temperature conditions in the rock. This transformation typically increases pressure within the rock, resulting in part of the oil and gas being expelled from the shale and migrating upwards into other rock formations, where it forms conventional oil and gas reservoirs. Shales are the source rock for the oil and gas found in conventional reservoirs.

Some, or occasionally all, of the oil and gas formed in the shale can remain trapped there, thus forming shale gas reservoir. Low permeability means that the gas is trapped in the shale and cannot move easily within the rock except over geologic expanses of time (millions of years). The natural layering and fracturing of shales can be seen in the outcrop that reveals the natural bedding planes, or layers, of the shale and near vertical natural fractures that can cut across the naturally horizontal bedding planes. Although the vertical fractures shown in this picture are naturally occurring, artificial fractures induced by hydraulic fracture stimulation in the deep subsurface reservoir rock would have a similar appearance.

Shale outcrop (Marcellus)

Shales are ubiquitous in sedimentary basins: they typically form about 80% of what a well will drill through. As a result, the main organic-rich shales have already been identified in most regions of the world. Their depths vary from near surface to several thousand meters underground, while their thickness varies from just a few meters to several hundred. Often, enough is known about the geological history to infer which shales are likely to contain gas (or oil, or a mixture of both). In that sense there is no real 'exploration' required for shale gas. However, the amount of gas present and particularly the amount of gas that can be recovered technically and economically cannot be known until a number of wells have been drilled and tested. The potential of a shale formation to contain economic quantities of gas can be evaluated by identifying specific source rock characteristics such as total organic carbon (TOC), thermal maturity, and kerogen analysis. Each shale formation has different geological characteristics that affect the way gas can be produced, the technologies needed and the economics of production. Different parts of the (generally large) shale deposits will also have different characteristics: small 'sweet spots' or 'core areas' may provide much better production than the rest of the play, often because of the presence of natural fractures that enhance permeability. The amount of natural gas liquids (NGLs) present in the gas can also vary considerably, with important implications for the economics of production.

Note: Information presented in §3.1 is an edited combined selection of the chapters 'Shale gas – Geology' [Modern shale gas: A primer] and 'What are shales and shale gas?' [Golden rules for a golden age of gas]. More info available in the Bibliography section.

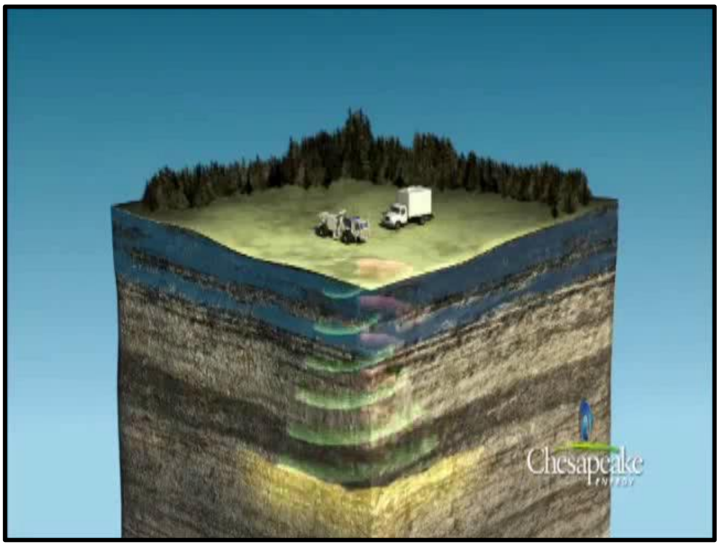
3.2 Shale gas extraction overview

Shale gas extraction is an elaborate procedure consisting of many phases. Section 3.2 aims to provide a step by step –simplified, yet complete- overview on which we will further build upon. In §3.3 all the major techniques seen here will be thoroughly analyzed and presented. The overview screenshots were created using Chesapeake Energy's commercial (youtube uploaded) video and the text following them was written down by hearing the audio commentary.

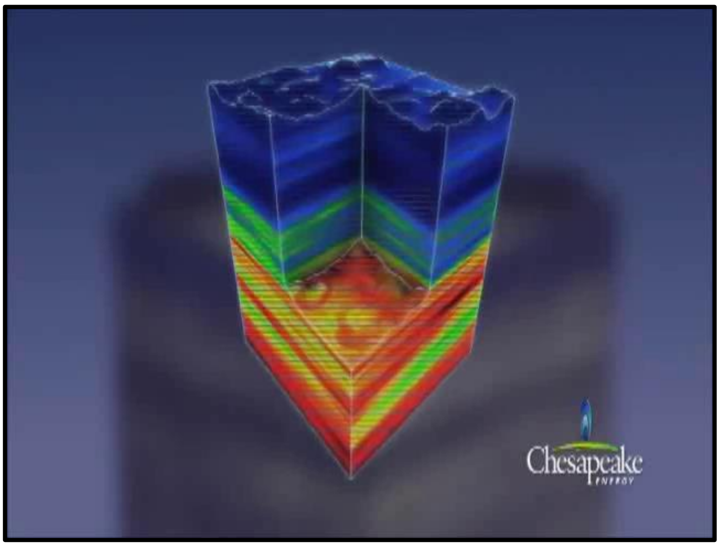
Note: The site presented is part of the Marcellus region and is being exploited by Chesapeake Energy.

<u>Locating shale gas reserves</u>

The latest technology is used to locate shale gas reserves. This includes 3D seismic imaging to explore for and produce natural gas.



3D Seismic imaging uses an energy source, such as vibrator trucks, to produce sound waves that pass through the ground and are reflected from different layers in the Earth's crust.



This information is then processed into a 3D seismic volume which gives geoscientists the ability to study natural gas reservoirs that otherwise might go undiscovered.

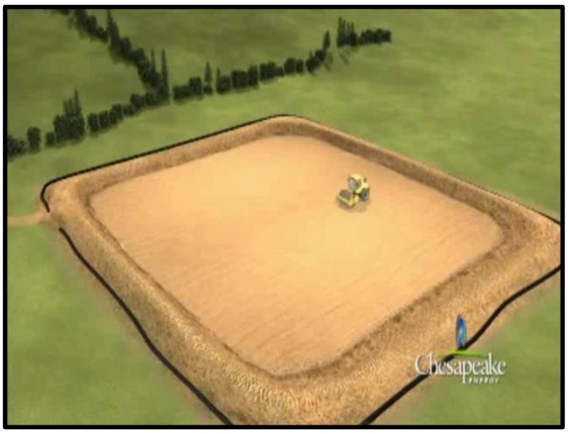
Using this technology allows us to locate and accurately drill for natural gas with reduced impact to the environment.

Installing precautionary measures

When selecting areas for natural gas production numerous factors are considered, such as access roads, existing infrastructure for natural gas transportation, power consumption, streams, wetlands and residential areas. The topography of the land and proximity of near bodies of water also play an important factor in determining the placement of the rig, the production equipment and the environmental protection measures.

Protective measures such as sediment and erosion control are carefully designed to meet the needs of each location while conforming to area regulatory requirements. When the area for a drilling and production site has been selected, preparations are made to support the process.

First, a level site must be created. Soil is stockpiled on the highest side of the site and used as a berm, similar to a dike or pond dam, to prevent water from flowing over the location. Eventually, this soil will be used for site reclamation after the well no longer produces natural gas.



Cruise installs buffers such as silt socks, reflection berms and sediment traps to eliminate the potential of sedimentation and erosion.

Once these are in place the entire location is graded to create a level site. These measures work together to insure that any potential spills will be contained on site.

After all of the dirt work is complete the cut and fill-sides of the location are hydromulched. Hydromulching is a planting process which utilizes a slurry of seeds and mulch to promote the growth of vegetation and stabilize the location with erosion control.

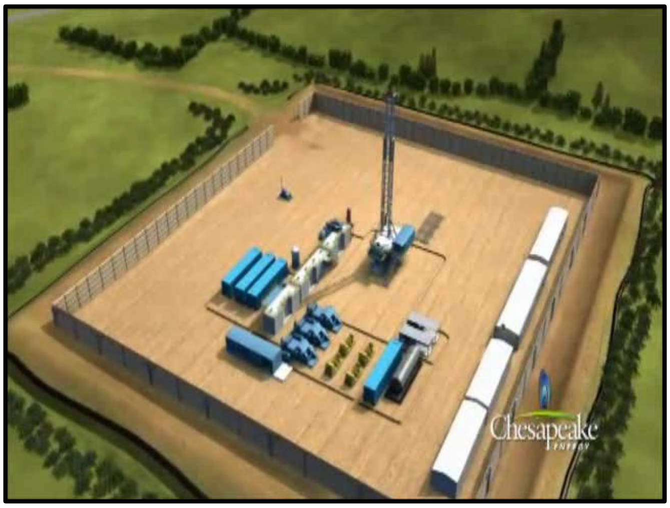
This covers environmental protection measures and best management put into place before the drilling rig is moved on to the location. Once the rig is set up additional measures are added.

Setting up the drill rig ('Rig up')

This step consists of moving in the rig, assembling the rig, installing all necessary equipment and constructing additional environmental measures. Assembling of the drilling rig is also known in the industry as a 'rig up'.

All the equipment needed to assemble the rig arrives by specialized tracks. Modern drilling rigs are constructed for quick assembly and disassembly and are highly modular.

During the rig up which takes up to five days, the process is overseen to make sure that all safety standards are met according to state regulations. The initial portion of the rig up takes place during day light hours only. Twenty-four hour operations begin once electrical equipment and light are in place, allowing rig personnel to work safely through the night.

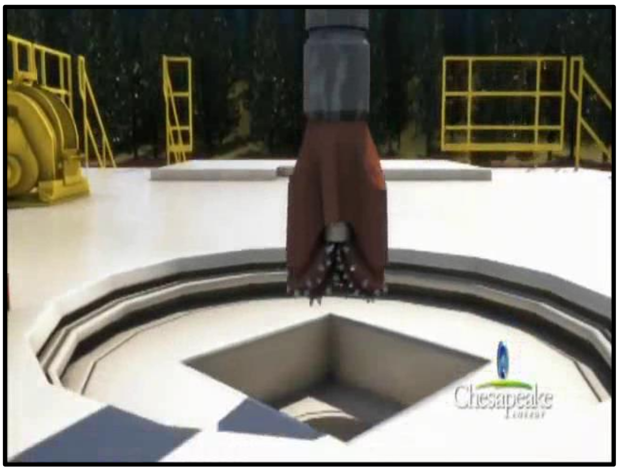


After the rig equipment is erected a trenching machine installs a trench system around the drilling rig. The trenches act as a preventative barrier in the event of an accidental spill. The surrounding area is taken into consideration. In residential areas sound walls to absorb and reflect noise are utilized. Since the rig is operated day and night, effort is made to minimize sound and noise disturbance as much as possible.

First stage of drilling

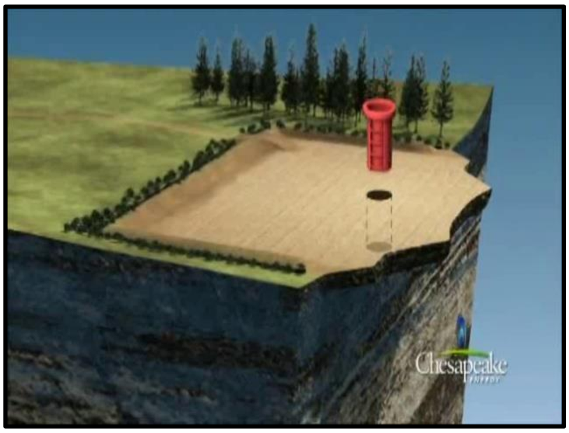
After the well site has been carefully prepared to meet environmental, health and safety standards, drilling can begin. This is an intricate operation requiring a well-planned infrastructure. A variety of processes and expert trained specialists are used to bring natural gas to the surface, while strictly adhering to all individual state regulations.

During the drilling process the rig is in constant operation twenty-four hours a day, seven days a week, for approximately twenty-one to twenty-eight days. As an added precaution in some areas, a protective mud covers two thirds out of the pad site.

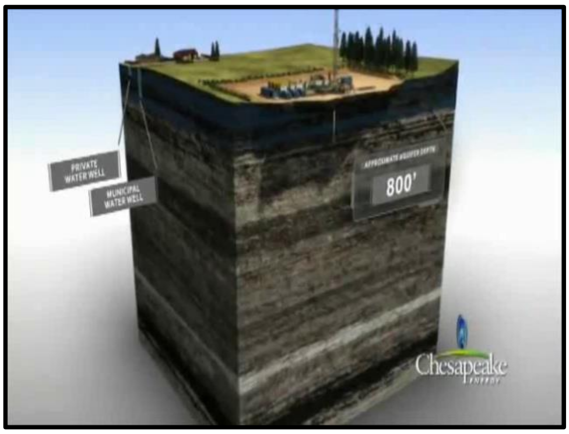


Utilizing heavy duty industrial strength drill bits a typical well is drilled in several stages, starting with a large diameter drill bit and then successively smaller drill bits as the drilling is advanced.

After drilling each portion of the well, nested steel protective casing is cemented into place. This will protect ground water and maintain the integrity of the well.



Initially and prior to moving in the drilling rig, a large diameter hole is drilled for the first fifty to eighty feet. Conductor casing is then cemented into place stabilizing the ground around the drilling rig and well head and isolating the well from most private water wells.

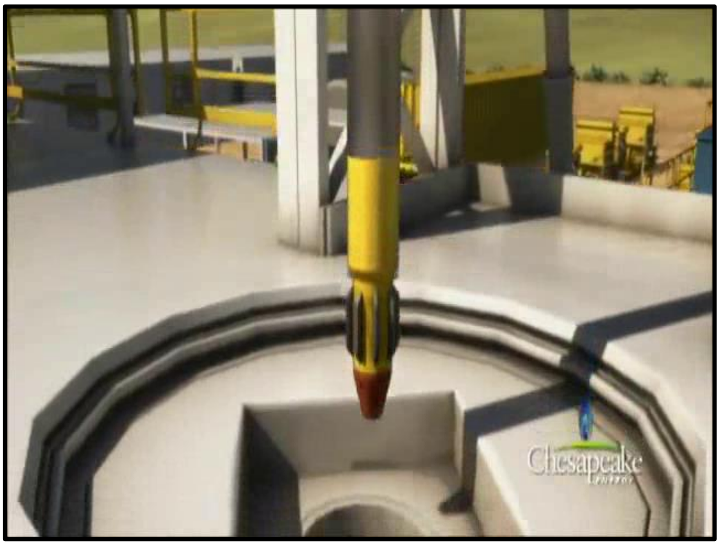


In the Marcellus area the fresh water zone extends to approximately eight hundred feet below ground.

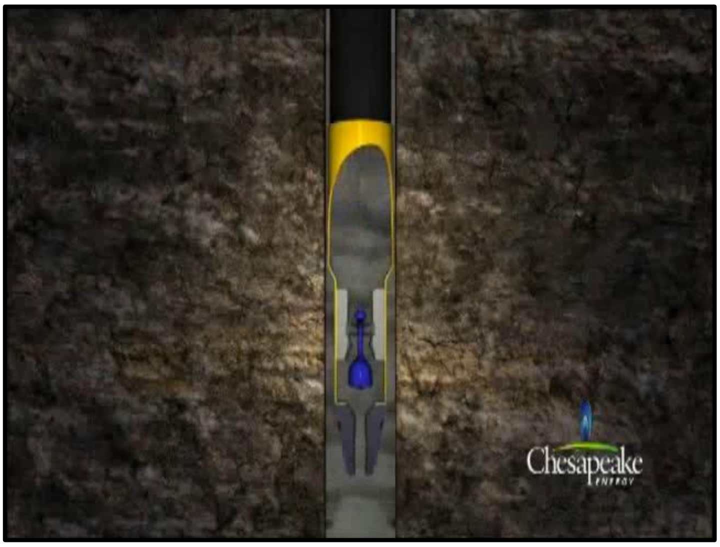
The fresh water zone consists of porous sand stone and rock stratus containing water within the porous space of the rock. Air drilling is utilized until the hole is advanced to an average of a hundred to two hundred feet below the base of the fresh water zone. This provides added protection to the fresh water zone.

A series of compressors and boosters generate the air that is used to lift the rock cuttings and fresh water into steel bins. The rock cuttings are then disposed of within state guidelines and permits. The drilling equipment is retracted to the surface and stored for the second stage of drilling.

Surface casing



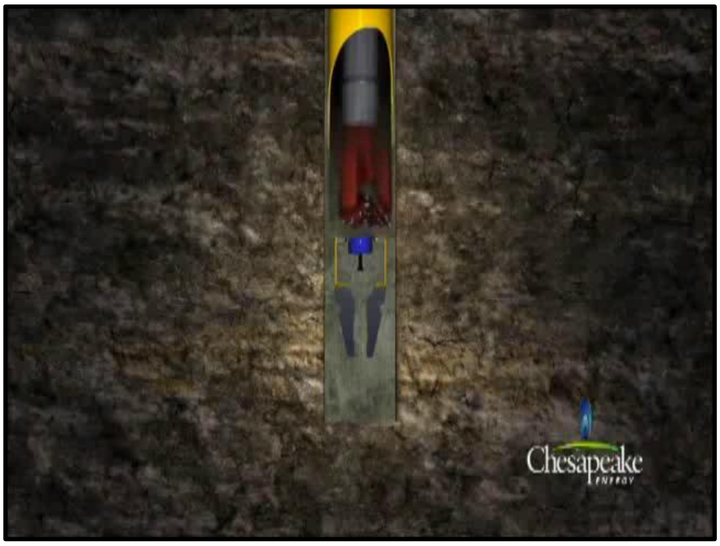
To protect the integrity of the hole and the surrounding deep fresh water zone, a second layer of steel casing, called surface casing, is installed and cemented inside the newly drilled hole and conductor casing.



Cement is pumped down through the surface casing and up along the sides of the well to provide a proper seal. This completely isolates the well from the deepest of private or municipal water wells.

A blowout preventer is installed after the surface casing has been cemented. The blowout preventer is a series of high pressure safety valves and seals attached to the top of the casing to control well pressure and prevent surface releases.

Second stage of drilling



Next, a small drilling assembly is passed down through the surface casing. At the bottom of the casing the bit drills through the flow equipment and cement continuing its journey to the natural gas target area as deep as 8,000 feet below the surface.

The drilling method employed below the surface casing uses drilling mud which is a non-hazardous mixture based on bentonite clay or synthetic thickeners. In addition to lifting the rock cuttings out of the hole, drilling mud also helps to stabilize the hole, cool the drill bit and control down hole pressure. A few hundred feet above the target shale the drilling assembly comes to a stop.

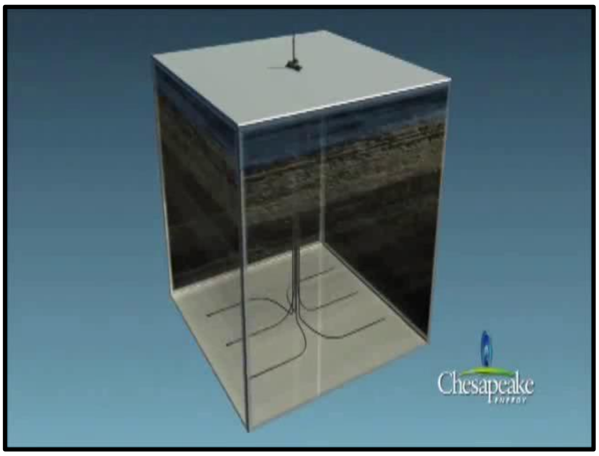
The entire string is retracted to the surface to adjust the drilling assembly and install a special drilling tool. This tool allows us to gradually turn the drill bit until a horizontal plane is reached.

Last stage of drilling: Horizontal drilling

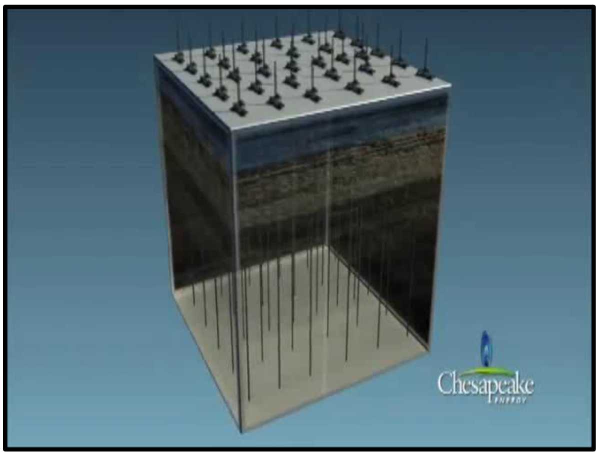
The remainder of the well is drilled in this horizontal plane, while in contact with the gas producing shale. Drilling continues horizontally through the shale at lengths greater than 4,000 feet from the point where it entered the formation. Once drilling is completed the equipment is retracted to the surface.

Horizontal drilling offers many advantages when compared to vertical drilling. Since horizontal wells contact more of the gas producing shale, fewer wells are needed to optimally develop a gas field. Multiple wells can be drilled from the same pad sites.

For example, development of a 1,280 acre tract of land using conventional vertical drilling techniques could require as many as thirty-two vertical wells, with each having its own pad site. However, one multi-pad site with horizontal wells can effectively recover the same natural gas reserves from the 1,280 acre tract of land, while reducing the overall surface disturbance by 90%.

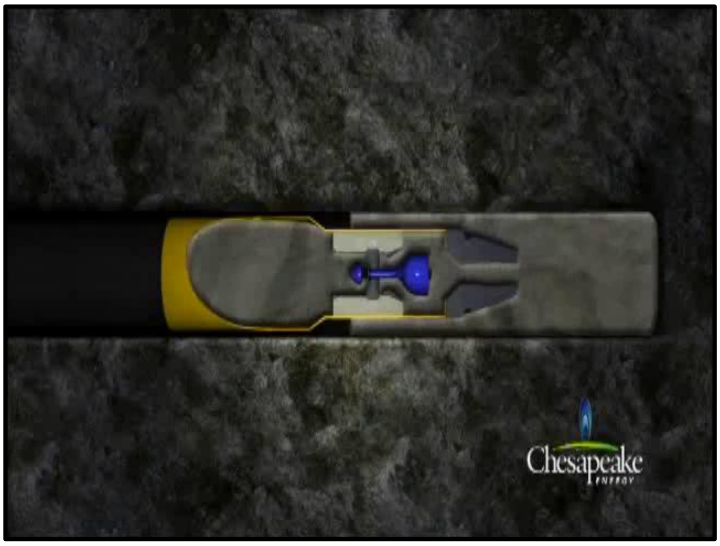


Horizontal drilling

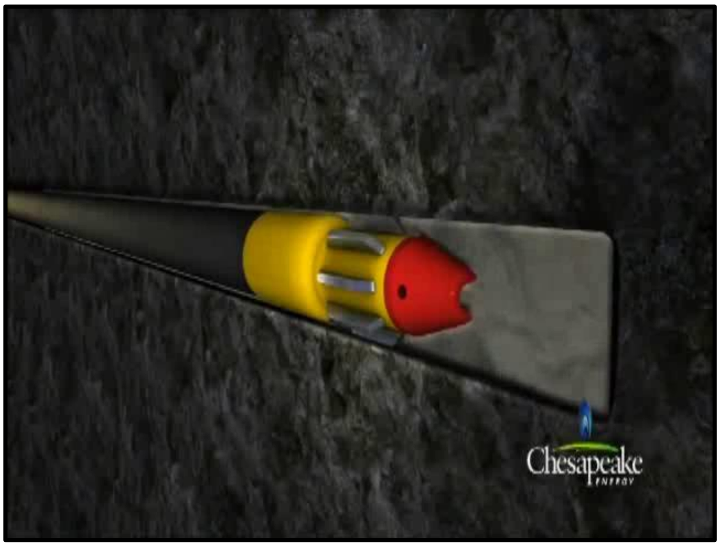


Vertical drilling

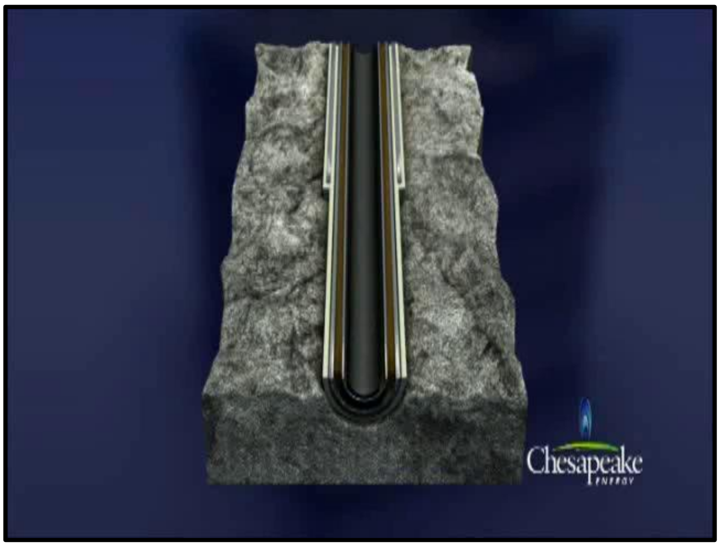
Production casing



After the equipment retraction, a smaller diameter casing, called production casing, is installed throughout the total length of the well. The production casing is cemented and secured in place by pumping cement down through the end of the casing. Depending on regional geologic conditions the cement is pumped around the outside casing wall to approximately twenty five hundred feet above the producing shale formation or to the surface.



The cement creates a seal to insure that formation fluids can only be produced via the production casing. After each layer of casing is installed the well is pressure tested to insure its integrity for continued drilling.

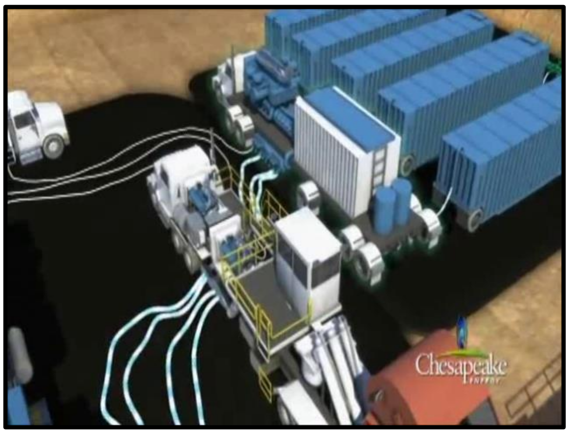


A cross-section of the well below surface reveals several protective layers. Cement, conductor casing, cement, surface casing, drilling mud, production casing and then production tubing through which the produced gas and water will flow; seven layers of protection.

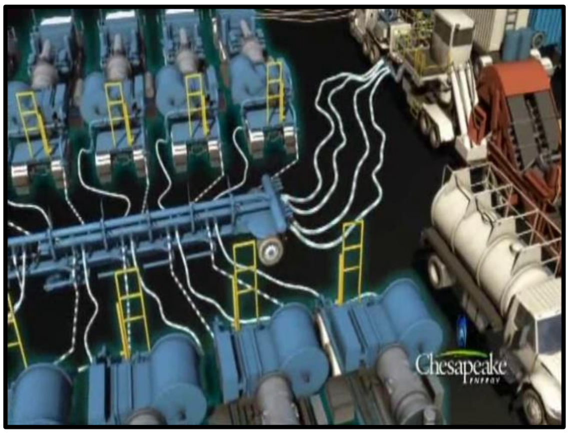
Hydraulic fracturing

In order to maximize the production potential of the well, the shale formation will be hydraulically fractured. In preparation for the fracturing process the casing will be perforated in the horizontal portion of the well, using tubing conveyed perforating guns containing explosive charges. The perforated intervals are spaced approximately fifty to eighty feet apart and create a connection between the production casing and the shale formation.

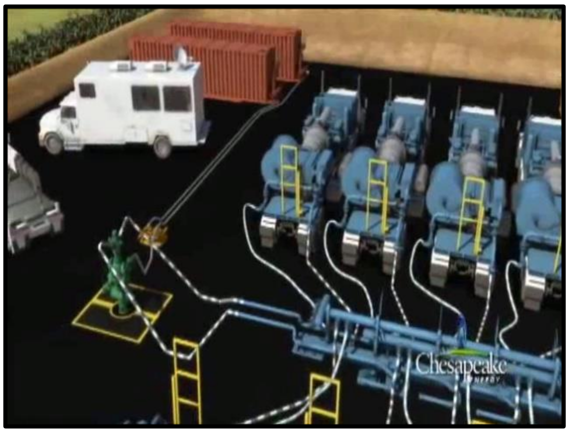
With the initial perforating complete, the tubing in perforating guns are pulled to the surface and the work over rig is replaced by hydraulic fracturing crew, consisting of a number of high pressure pumps and blending equipment. This equipment will pump a mixture of water and proppant, usually sand, through the newly created perforation and the production casing and into the shale formation.



First, water is passed from a water storage impoundment into the blue working tanks depicted on this location. The water is then pulled into a hydration unit, which provides the ability to gel the fluid before it is transferred to the blender.



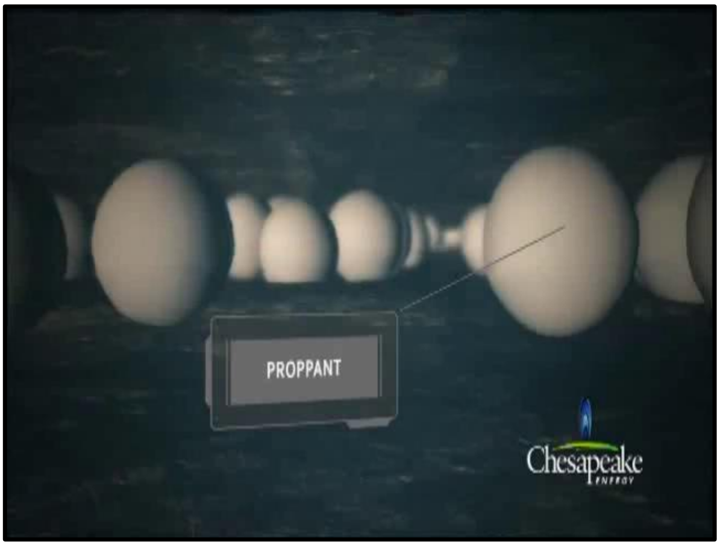
At the blender proppant and a small amount of chemicals that aid in the fracturing process are added. The blender transfers the fluid and proppant mixture to the pump trucks.



Through the low-pressure side of the manifold the fracturing pumps increase the pressure of the fluid, sending it back through the high-pressure side of the manifold, to the fractury where it enters the well. The entire fracturing process is controlled from the treatment monitoring van.

When the fracturing fluid reaches the perforations pressure builds until the shale formation fractures allowing fluid to enter into the formation.

Additional fractures are created along natural zones of the weakness in the shale. These fractures are contained within the shale formation, well below the ground.



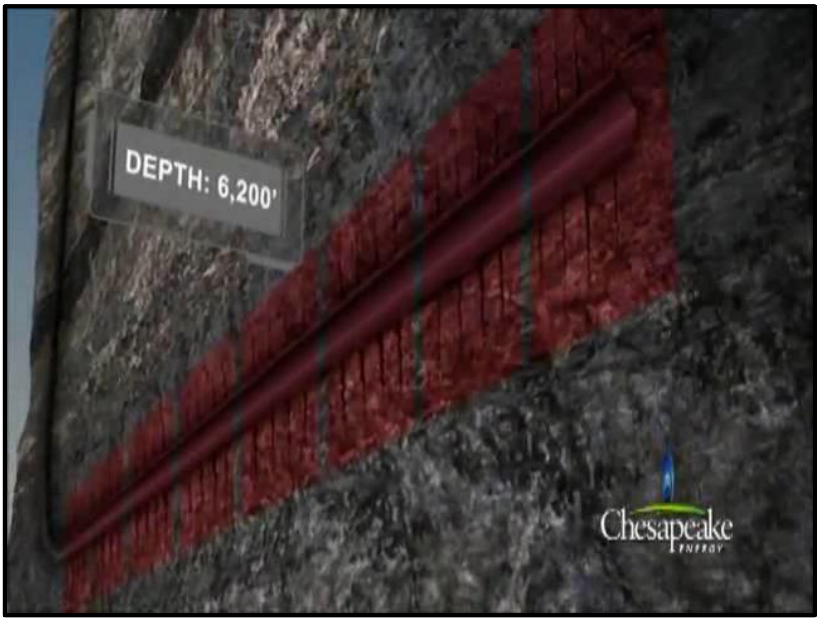
After an initial stage of fluid (called the pad) is pumped to create a fractured area, proppant is added to the fluid and is distributed throughout the newly created fracture network. At the conclusion of the fracturing treatment, the proppant allows the fractures to remain open so that the natural gas can flow into the production casing and to the surface. This completes the first of several stages in the fracturing process.

The process is repeated by lowering and pumping down an isolation plug and perforating guns into the wellbore, to complete the next stage of fracturing.

This time, the tools are conveyed into the well by a wireline unit, which allows the fracturing process to proceed much faster and more efficiently. A lubricator is used to control the pressure of the well while the operation is taking place.

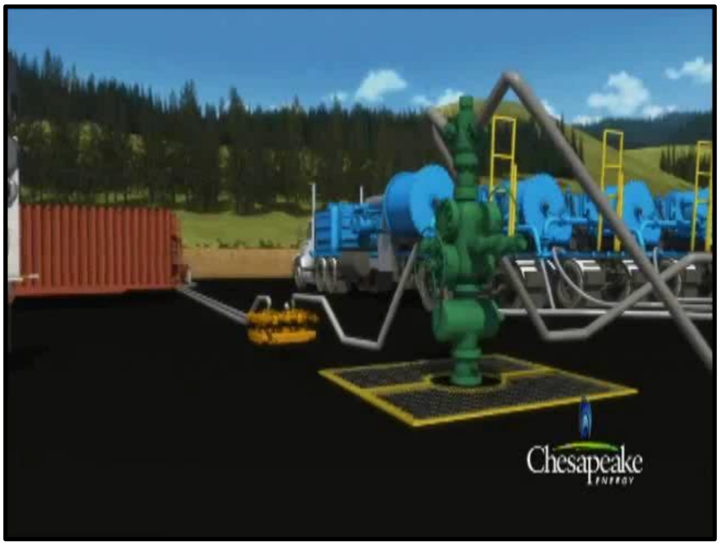
On the bottom of the perforating gun, a composite bridge plug is placed to isolate the newly fractured zone. This ensures that the subsequent fracturing treatment is contained in the current zone.

The perforating gun is again fired at roughly fifty to eighty feet intervals, creating a connection between the production casing and the shale formation. The fracturing process is then repeated until all of the stages are completed.



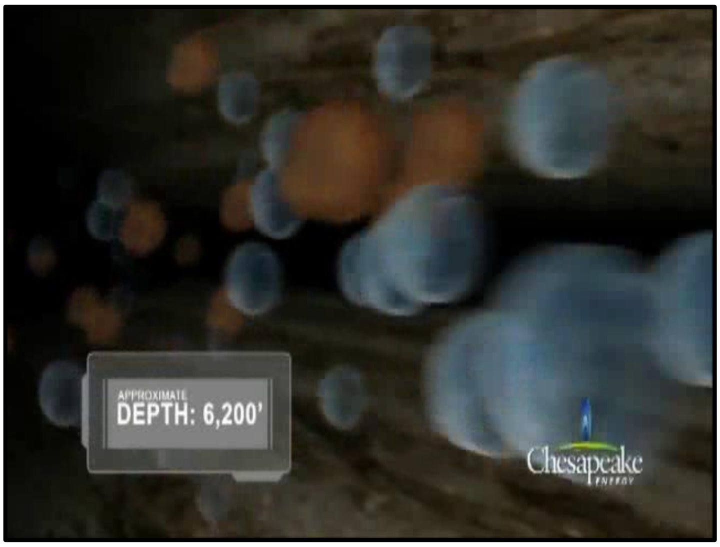
A typical shale well has approximately eight to twelve stages of fracturing.

Ending the fracturing operation



At the conclusion of the fracturing operations the isolation plugs are removed from the well and production can start. The produced fluids are diverted through a flow-back manifold into storage tanks. The fluids are then recycled or disposed of according to state and federal regulations.

After the completion of the well, it is time to start production and reclaim the site. The heavy machinery has moved onto the next well site leaving just the production tree, the separator and the production tanks.



Below the surface, at depths of more than one mile, the mixture of gas and fluid is flowing through the fractured shale. The mixture containing predominantly gas flows onto the production tubing and up through the wellbore to the surface. It is then diverted from the wellhead to the separator, which separates the fluid (and any other petroleum liquids –such as condensate and oil- that may occur) from the gas.

3.3 Detailed analysis of the major shale gas extraction techniques

Up to this point the reader has acquired the general know-how of the way shale gas is extracted from the underground formations. In this sub chapter we will examine in greater detail all the major techniques employed in the procedure. Some of these techniques (such as locating the reserves and drilling vertically) are common practice in the industry and take place in any kind of natural gas production, of both conventional and unconventional nature. They are presented here -and not in introductory Chapter I- so that the procedure is described in its entirety. On the other hand, we have the two key technologies of horizontal drilling and hydraulic fracturing that are combined and applied in order to overcome the 'unconventional' challenge presented by the shale imprisonment; their presentation is the heart and purpose of this section. Horizontal drilling is simple in concept but more complex in practice. Hydraulic fracturing is a production operation that, apart from the main task, also includes a series of elaborate sub-tasks, like isolating fractured zones and properly handling the fracturing fluids. The §3.2 slideshow overview also included a lot of necessary preparatory actions that mostly have to do with creating and securing work and environment safety. These are simple enough to not require any further explanation. Important anti-pollution and precautionary measures, like well cementing and fracturing fluids disposal, are included in the presentation and explained from the technical point of view. In Chapter IV we will expand on the 'environment protection-shale gas' topic.

Process of shale gas development

Mineral Leasing

Companies negotiate a private contract or lease that allows mineral development and compensates the mineral owners. Lease terms vary and can contain stipulations or mitigation measures pertinent to protect various resources. (Several weeks to years)

Permits

The operator must obtain a permit authorizing the drilling of a new well. Surveys, drilling plans, and other technical information are frequently required for a permit application. The approved permit may require site specific environmental protection measures. Other permits such as water withdrawal or injection permits may also be required. (Several weeks to months)

Road and Pad Construction

Once permits are received, roads are constructed to access the wellsite. Well pads are constructed to safely locate the drilling rig and associated equipment during the drilling process. Pits may be excavated to contain drilling fluids. (Several days to weeks)

Drilling and Completion

A drilling rig drills the well and multiple layers of steel pipe (called casing) are put into the hole and cemented in place to protect fresh water formations. (Weeks or months)

Hydraulic Fracturing

A specially designed fracturing fluid is pumped under high pressure into the shale formation. The fluid consists primarily of water along with a proppant (usually sand) and about 2% or less of chemical additives. This process creates fractures in rock deep underground that are "propped" open by the sand, which allows the natural gas to flow into the well. (Days)

Production

Once the well is placed on production, parts of the wellpad that are no longer needed for future operations are reclaimed. The gas is brought up the well, treated to a useable condition, and sent to market. (Interim Reclamation: days; Production: years)

Workovers

Gas production usually declines over the years. Operators may perform a workover which is an operation to clean, repair and maintain the well for the purposes of increasing or restoring production. Multiple workovers may be performed over the life of a well. (Several days to weeks)

Plugging and Abandonment/Reclamation

Once a well reaches its economic limit, it is plugged and abandoned according to State standards. The disturbed areas, including well pads and access roads, are reclaimed back to the native vegetation and contours or to conditions requested by the surface owner. (Reclamation Activity: Days; Full Restoration: Years)

3.3.1 Exploration

The first section of the shale gas production chain is that of exploration: how shale gas is found and how companies decide where to drill wells.

Generally, there are two kinds of exploration: onshore and offshore. Offshore exploitation in practice follows the shame basic principles of the onshore one, adjusting the procedure to the more difficult sea environment. Although recently there has been great talk about huge United Kingdom offshore shale reserves we will not get into the subject of neither offshore exploration nor extraction. At the moment, the sheer scale and difficulty of the project, the research required and the existence of cheaper alternatives (importing natural gas will cost less than trying to engineer a way) condemn any such attempt (though technically speaking it is realizable).

Exploration for gas shales is similar to exploration for conventional reservoirs which, for an unexplored basin, usually includes:

- review of existing information;
- aerial surveys to gather data regarding magnetic fields, gravity and radiation;
- seismic surveys to locate and define subsurface structures capable of trapping natural gas;
- exploration drilling to test subsurface structures for the presence of hydrocarbons;
- logging the wells to determine porosity, permeability and fluid composition;

<u>Exploration begging</u>

The process of exploring for natural gas deposits is characteristically an uncertain one, due to the complexity of searching for something that is thousands of feet below ground. In the case of shale gas the database of existing information provides valuable assistance; at earlier times, when their exploitation was not yet possible, shale locations found in other drillings were mapped.

Typically an exploration process starts with geologists examining the surface of an area in search of geological indications suggesting the underground existence of gas reservoirs ('anticlinal slopes' - explained in Chapter I - is a formation that often presents this likelihood). Once an area is chosen, further preliminary surface and sub-surface research is conducted including rock cutting samples gathering and analysis, detailed data collection and tests that allow for a more accurate mapping of the underground formations. Of course, permission agreements are obtained prior to accessing the site and the searching party often commits itself to inform and update the landowners and involved residents on the surveying progress.

Seismic exploration

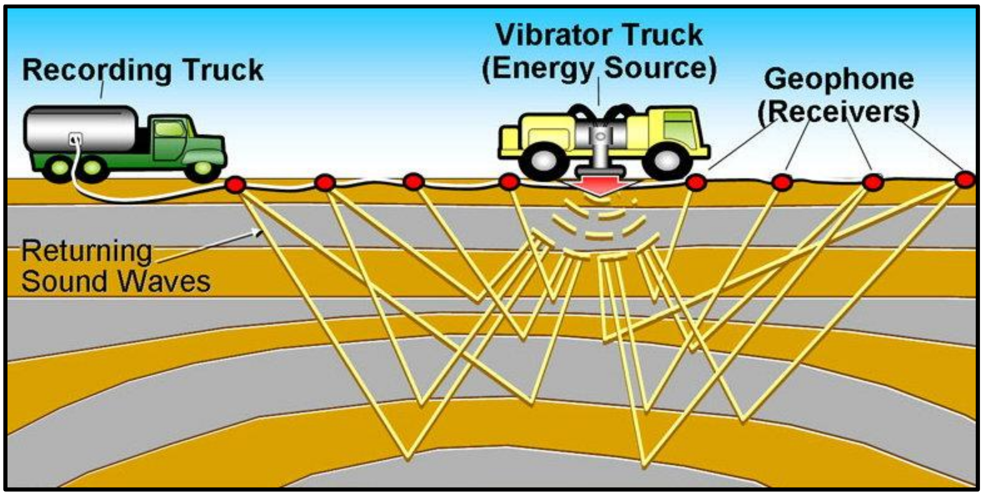
The next step of the procedure is seismic exploration: using technology applied in seismology to reveal the geology beneath and locate gas reserves. Seismology refers to the study of how energy in the form of seismic waves moves through the Earth's crust and interacts with various types of underground formations. Artificially emitted seismic waves will travel through the earth, but also be reflected back toward the source by the different underground layers. This basic concept might seem simple but in practice seismology reveals itself as a complex science. A typical survey on the field consists of the below tasks:

- Generating the needed seismic waves;

  This can be accomplished with both explosive and non-explosive ways. Technological advancements along with environmental concern have rendered the use of explosive means (par example dynamite) obsolete. When used, small charges are buried in 10 to 30 meter-deep holes that are drilled with vehicle-mounted drilling units. These activities create low-energy sound waves, are conducted at safe distances and no explosion is seen at the surface. Non-explosive technology usually consists of four to five large, heavy-wheeled or tracked vehicles carrying special equipment designed to create a large impact or series of vibrations. They move behind each other and place their vibrating plates every 25 meters to send the seismic wave through the layers of rock. Each chosen location is vibrated for about two minutes.

- Installing the geophones and recording the sound waves;

  Geophones are sensitive pieces of equipment that can pick up the reflections (echoes) of the sound waves bouncing off the underground formations. They are embedded in the ground at set distances (and removed after the survey's completion). The cable bearing the geophones stretches for several kilometers. The number of cables used depends on the desired data accuracy. In 2-D imaging a single cable is adequate. In cases where a larger volume of data is required (3-D, 4-D imaging) a number of cable lines is utilized, laid out parallel to each other to cover the area. The signal received is transmitted to specialized trucks (not the ones emitting the sound waves) where it is recorded.



Complemental and/or alternative means of exploration

The next major phase of the exploration process is the interpretation of the data collected. The correct study/selection/understanding of the information gathered and the computer assisted recreation of the underground is of maximum importance. Before getting to that though, we will sententiously exhibit the remaining exploration processes that can be incorporated to the above or alternatively used depending on the challenges presented.

- Magnetometers

  The magnetic properties of the underground can also be measured and used to generate geological data. This is accomplished with devices called magnetometers. Yet, -apart from being large and bulky- they can only be used to survey a very small area at a time.

- Gravimeters

  Another attribute that differs from one formation to another is the unique way they interact with the Earth's gravitational field. We can develop clearer insight of the underground by measuring these minute differences with very sensitive and sophisticated equipment.

- Exploratory wells

  Digging an exploratory well is the best way to understand the geological potential of an area. Apart from the main hydrocarbon search, geologists also study the rock cuttings and the fluid samples collected when drilling *(note: see 'logging').* Still, it is an expensive and time consuming process that affects the environment. It is carried out only after sufficient evidence of gas or oil existence has been obtained.

- Logging

  Prior, during and after the well drilling the whole process is studied and monitored via a series of tests conducted. This is called 'logging' and essentially is the first real contact the geologists make with the underground. There is a wide variety of more than 100 logging tests (including standard, electric, acoustic, radioactivity, density, induction, directional and nuclear). Logging helps geologists understand the underground, secure the correct carrying out of the process, adjust real-time to the requirements faced and predict difficulties. Two of the most prolific are standard and electric logging. Standard logging, already mentioned above -and as implied by its name-, is about collecting and studying core samples of the drilling. Electric logging consists of measuring the formation's resistance by running electrical current through the rock. Logging data is archived and used in further exploration of nearby or geologically-identical areas. Historical logs have proven to be of great assistance in shale gas exploration.

Data interpretation

The methods so far described present the geologists and geophysicists with a wealth of raw-data information. Collecting them in a correct manner is very important but what is even more essential is their proper interpretation: understanding and combining the data methodically into an educated, coherent model of the underground formations. Despite the amazing evolution of technology the only way of being sure that a natural gas reservoir exists is to drill an exploratory well; scientists make their best guesses as to the location of reservoirs, but these are not infallible. The use of computers ('CAEX': Computer Assisted EXploration) has revolutionized the way geological data are compiled and assembled into the aforementioned model and dramatically increased its reliability and sophistication. The main types of CAEX models are 2D, 3D and 4D imaging. They mostly rely on seismic information acquired on the field but can also take into consideration a vast library of data obtained from other sources (such as exploratory wells and logs). Types of CAEX imaging:

- Two-dimensional (2-D) seismic imaging

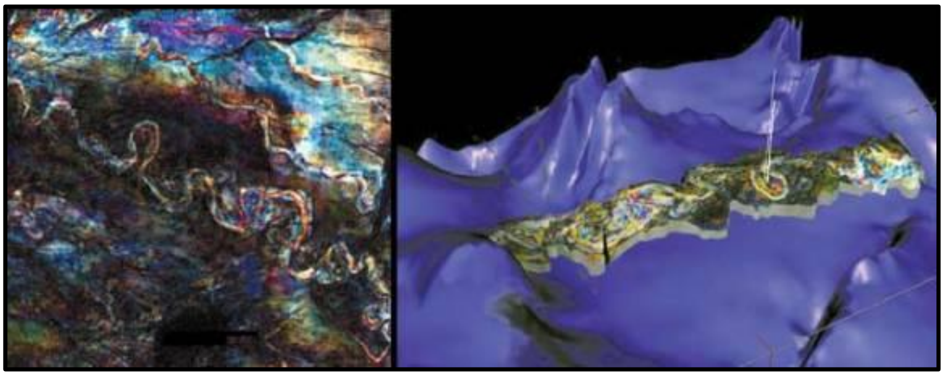
  2-D CAEX includes generating an image of subsurface geology much in the same way of normal 2-D data interpretation, but in a much more time efficient and detailed manner (due to the capabilities and power of the aiding computer). In addition, with 2-D CAEX it is possible to use color schemes to highlight geologic features that may not be apparent using traditional 2-D seismic imaging methods. Although 2-D is less complicated and detailed than 3-D, it was developed after the 3-D imaging techniques as an extension. Its simplicity makes for a faster and more economic method, so it is employed frequently in areas that are somewhat likely to contain natural gas deposits, but not likely enough to justify the full cost and time commitment required by 3-D imaging.

- Three-dimensional (3-D) seismic imaging

  The development of the 3-D computer assisted seismic imaging is a major innovation and a milestone in the scientific field of exploration. It utilizes seismic data of an area to generate a three dimensional 'picture' of the underground formations and their geologic features. This technology has been extremely useful in raising the success rate of exploration efforts even by 50 percent. Its major disadvantage is the cost needed to develop the 3-D imaging models; scanning seismically in 3-D can cost hundreds of thousands of dollars per square mile. In contrast to the simpler 2-D -that can be generated from several hundred data points only-, three dimensional images require thousands of points. This translates into a much more prolonged and expensive process, usually applied to selected areas of interest pinpointed first by a 2-D image. Most (75-80%) of modern day onshore explorations use 3-D imaging, rendering the method an industry standard.

- Four-dimensional (4-D) seismic imaging

  Expanding on the concept of 3-D seismic imaging, 4-D CAEX studies dynamically the data gathered. Whereas in 3-D we only have a static 'snapshot' of the formations underground, in 4-D we record the changes in structures and properties of underground formations over a period of time (time is considered the fourth dimension). In this way geologists can gain a better understanding of many properties of the rock, including underground fluid flow, viscosity, temperature and saturation. Although very important in the exploration process, 4-D seismic images can also be used by petroleum geologists to evaluate the properties of a reservoir, including how it is expected to deplete once petroleum extraction has begun. Using 4-D imaging on a reservoir can increase recovery rates above what can be achieved using 2-D or 3-D imaging. Where the recovery rates using these two types of images are 25 to 30 percent and 40 to 50 percent respectively, the use of 4-D imaging can result in recovery rates of 65 to 70 percent.



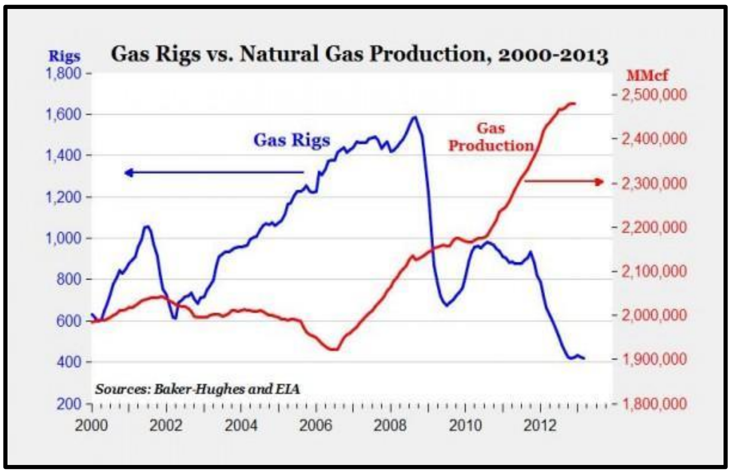
Example of 3-D seismic imaging technology

The construction of a well to access shale gas deposits is divided into two main phases: the drilling phase (3.3.2), where the hole is drilled to its target depth in sections that are secured with metal casing and cement; and the completion phase (3.3.3), where the horizontal cemented casing across the reservoir is perforated and the shales stimulated by hydraulic fracturing in order to start the production.

3.3.2 Well construction Part I: Drilling phase

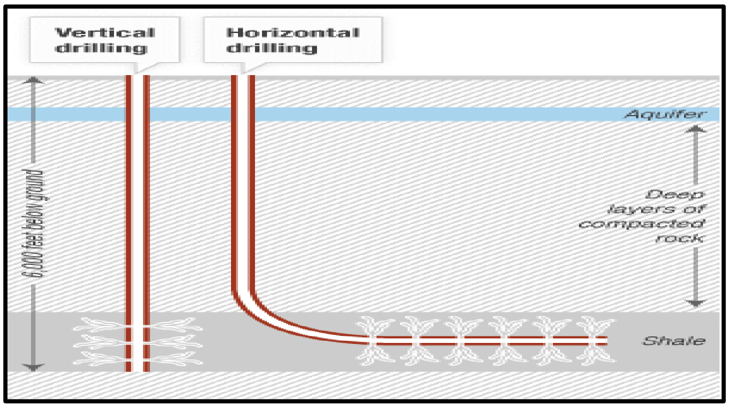
Having concluded all the necessary 3.3.1 exploration techniques, we move to choosing the optimal location of the well construction. This selection is dictated by the results of the exploration (nature of the formation to be drilled, characteristics of the subsurface geology, depth and size of the target deposit) but also takes seriously into account a range of other concerns: water availability and disposal, proximity to residential areas, existing infrastructure, regulation and potential environmental impact.

The drilling phase is the most disruptive and visible phase of the whole shale gas production process. The drilling rig site usually occupies an area of 100 m^2, where equipment is stored and drilling fluid disposal pits are created. Shale gas development requires a much greater number of wells compared to the conventional natural gas one. In order to minimize the environmental impact (by limiting the drilling footprint) and optimize development, the industry is moving towards the model of constructing multiple horizontal wells from one single pad. Multiple wells per pad drilling is not yet standard (30% of US shale and tight gas wells in 2011) but will be the norm in the years to come, due to the extremely important factor of recovery efficiency. The following IEA chart confirms these speculations:



"The US natural gas production has risen to record levels and increased by almost 17% during roughly the same period that active gas rigs dropped by 75%. In about the last five years, the amount of natural gas produce per rig has increased by more than four times"

Mark J. Perry,
Professor of economics at the
University of Michigan



Consequently, the drilling phase described here features the essential technique of horizontal drilling. When excluding it, the remaining sections also cover adequately every other (simpler, less efficient and soon to be abandoned) case.

The drilling process is broken down and presented in the following order: Vertical drilling, horizontal drilling and well casing. Vertical drilling (apparently) takes place first and horizontal follows. Well casing is conducted -as we have already seen in 3.2- simultaneously with drilling, both vertically and horizontally, but is described here in its own subchapter; the time sequence of the drilling phase is considered covered in the aforementioned section and while retaining for the most part chronological order, emphasis is primarily given on the technical aspects of every step.

Vertical drilling - Rig up

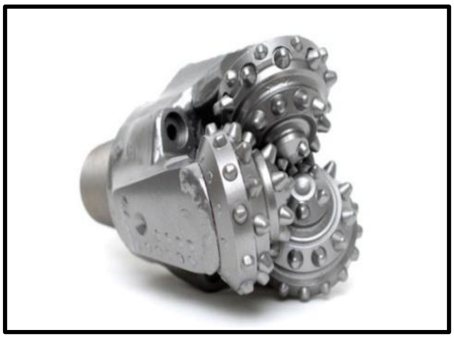
Drilling begins with the 'rig up': the location is secured and the rig is moved into site and assembled, along with all other necessary equipment. Setting up drilling in a new area might involve between 100 and 200 truck movements to deliver all the equipment (, while further truck movements will be required to deliver supplies during drilling and completion of the well). Installing the rig takes about five days.

Vertical drilling - Drilling basics

There are two main modern types of onshore drilling: The first one is called percussion, or 'cable tool' drilling, and consists of raising and dropping a heavy metal bit into the ground, effectively punching a hole down through the earth. It is usually utilized for shallow, low pressure formations and the procedure is fairly simple. The second one is rotary drilling, where a sharp, rotating metal bit is used to drill through the Earth's crust. This type of drilling is used primarily for deeper wells, which may be under high pressure. Shale gas development, as expected, employs the second more sophisticated and complex practice of rotary drilling.

The effectiveness of drilling heavily depends on choosing appropriately the drill bit type suited for the formations to be drilled. There are three types of formations: soft, medium and hard. A soft formation includes unconsolidated sands, clays, soft limestones, red beds and shale. Medium formations include calcites, dolomites, limestones, and hard shale. Hard formations include hard shale, calcites, mudstones, cherty lime stones and hard and abrasive formations. As regards drill bits per say, there exist two different types: fixed cutter and roller cone. A fixed cutter bit is one where there are no moving parts, but drilling occurs due to percussion or rotation of the drill string. Fixed cutter bits can be either polycrystalline diamond compact (PDC) or grit hot-pressed inserts (GHI). Roller cone bits can be either tungsten carbide inserts (TCI) or milled tooth (MT). The manufacturing process and composites used in each type of drill bit make them ideal for specific drilling situations. Additional enhancements can be made to any bit to increase the effectiveness for almost any drilling situation.

PDC fixed cutter



Tri-cone rotary bit

Roller cones-PDC hybrid

Vertical drilling

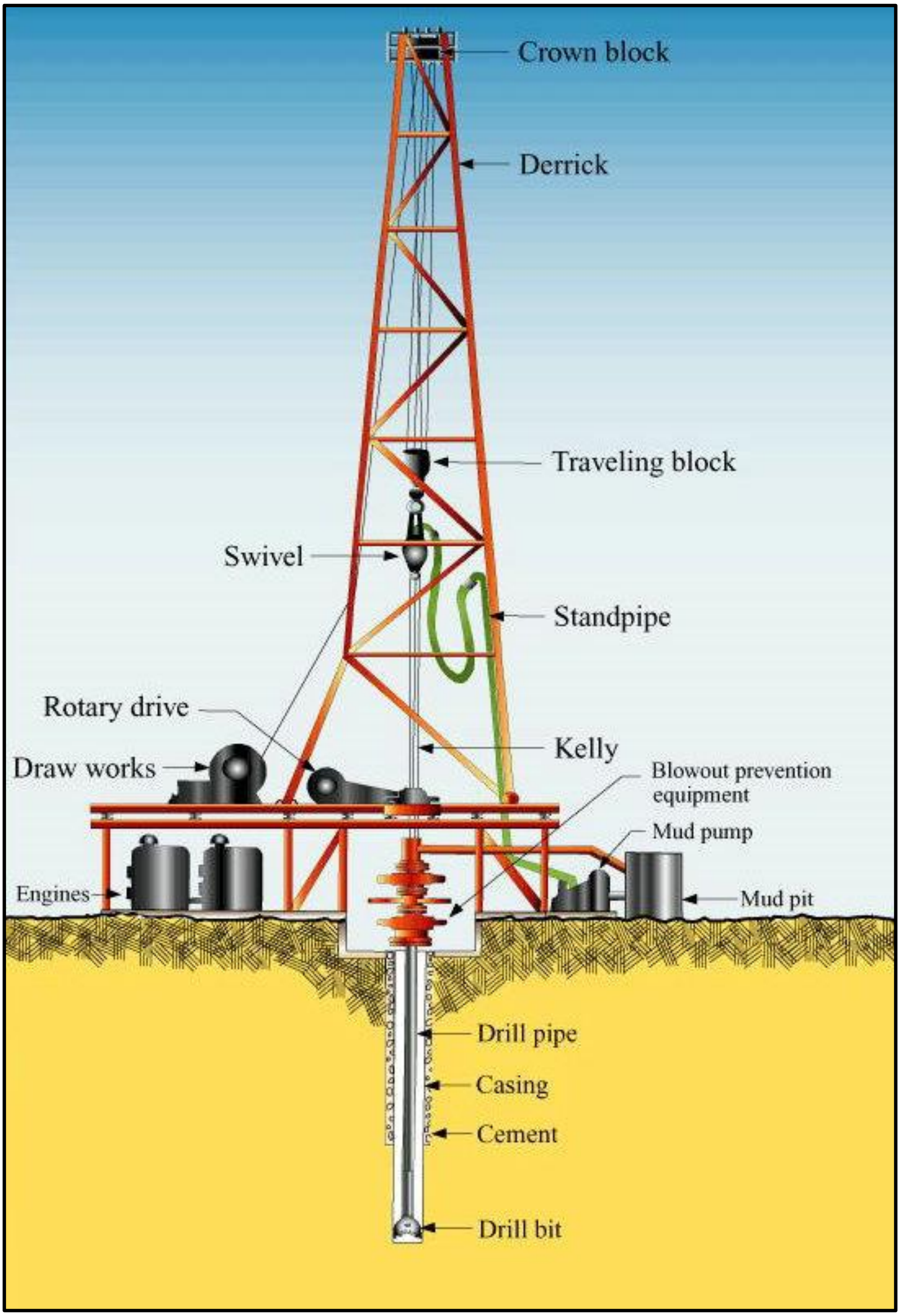
When the drilling finally begins, it is generally a 24/7 operation, creating noise and fumes from diesel generators, requiring lights and extra precautions at night time and creating a regular stream of truck movements during mobilization and demobilisation periods. Depending on the desirable depth and the formation drilled the operation can last from a few days to several months. Usually a standard drilling phase (including the later parts) takes about one month.

The drilling depth -a crucial factor of the procedure- differs depending on the location of the reservoirs. The goal is to drill vertically up to a certain critical point and then start directional drilling (requires a very large radius) until the horizontal plane of the shales is met. In Ohio and New York State the average depth of the reservoirs is 3,000 feet while in Pennsylvania it can take 10,000 feet or more to reach the shale formations.

The drilling starts off with a large diameter drill bit which is gradually replaced by smaller ones. The key to a rotary drill's speed is the relative ease of adding new sections of drill pipe/string while the drill-bit is turning. Modern drill bits studded with industrial diamonds can grind through any rock type, however, from time to time the drill string must be removed (a process termed 'tripping') to replace the worn drill bit.

If the new well, once drilled, does in fact come in contact with natural gas deposits, it is termed a 'development' or 'productive' well. At this point, with the well drilled and hydrocarbons present, the well may be completed to facilitate its production of natural gas. However, if the exploration team was incorrect in its estimation of the existence of a marketable quantity of natural gas at a well site, the well is termed a 'dry well', and production does not proceed.

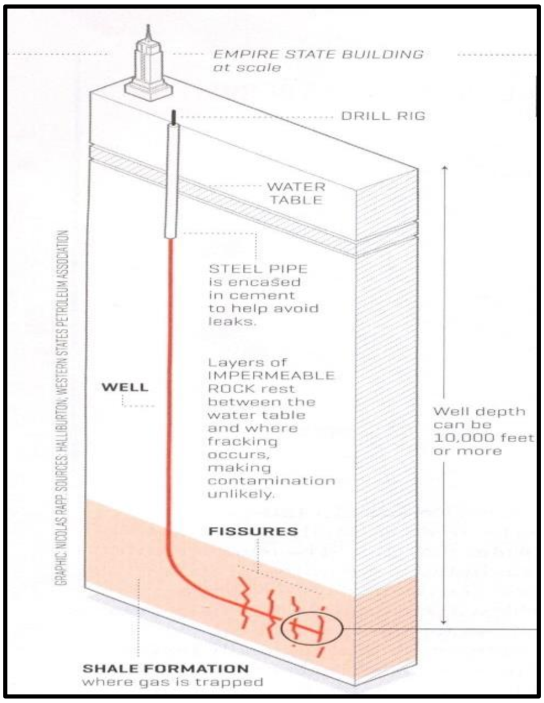
As the drill bit grinds through the rock, drilling fluid, known as 'mud', is circulated through the wellbore. Mud circulation is of maximum importance to the operation and acts on more than one levels: it lubricates the drill bit, allows pressure control, keeps the wellbore from collapsing and removes rock cuttings. The circulation is achieved with a series of compressors and blowers. This lubricating mud is mostly bentonine clay, as found in nature, enhanced for the purposes needed. It consists of a base fluid, such as water or oil, mixed with salts and solid particles to increase its density and a variety of chemical additives. It is solid when still and fluid when disturbed. This essential property keeps the drill cuttings suspended in the mud. The mud's chemistry and density must be carefully monitored and adjusted as the drilling deepens. The mud is mixed, contained and monitored (to prevent leaks) in mobile containers or -most commonly- in open pits dug into the ground and lined with impermeable material. There are parts of the operation that require several hundred tons of mud and so the demand for sufficient supplies throughout the drilling is constantly large. At the completion of the operation mud is either recycled at another drilling or is safely disposed. Rock cuttings recovered from the mud during the drilling process amount to between 100 and 500 tons per well, depending on the depth. They are also disposed of in an environmentally acceptable way, usually being stored in the pits after all mud is retrieved. The mud and the rest of the by-products of the drilling have led to environmental concerns and requests for development of eco-friendlier ways of disposal.


Crown block
Derrick
Traveling block
Swivel
Standpipe
Rotary drive
Kelly
Draw works
Blowout prevention equipment
Mud pump
Engines
Mud pit
Drill pipe
Casing
Cement
Drill bit

The drilling does not stop. When reaching a certain depth it gradually changes direction from a vertical to a horizontal plane and continues grinding in pretty much the same manner. In accordance to the way we presented the vertical drilling, talking about the actual horizontal operation, we are also going to breeze through all the noteworthy facts of this technology.

<u>Horizontal drilling - Introduction</u>

Directional drilling and horizontal drilling are terms often used interchangeably. Directional drilling refers to drilling at a slant or angle to increase contact with the resource. Horizontal is a type of directional drilling.

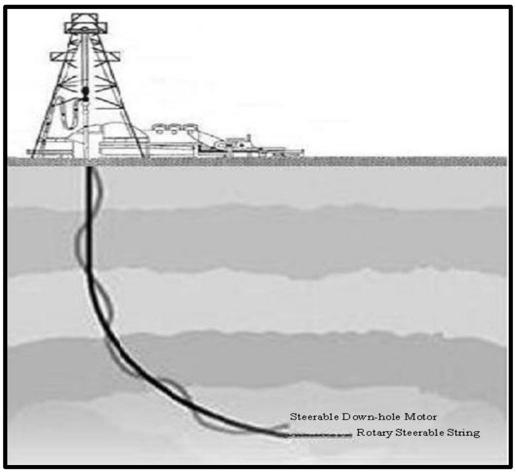


Well cross-section

Horizontal drilling is one of the two key technologies employed to make the unconventional development of shale gas realizable and commercially viable. The other is hydraulic fracturing. While both of them are essential -and their combination is the one that ultimately delivers-, the true marvel of engineering is horizontal drilling and not hydraulic fracturing. This fact is largely ignored and horizontal drilling is often considered as one more necessary sub-step of the fracking process; in truth it is the opposite. While impressive in its own right, *"the main innovations in hydraulic fracturing in recent years have been beefing up the generating horsepower to accommodate horizontal wells rather than vertical ones, and refining of the fluids used to conserve water and create better, longer lasting fractures in the target formation"* [David Blackmon, Forbes]. Hydraulic fracturing is the way we stimulate natural gas flow from the formations made accessible via horizontal drilling; sophisticated and definitively helpful, yes; solely responsible for the shale gale, no. In a vertical drilling, fracturing is conducted in a small portion of the exposed shale formation, with reduced production rates. It is proven that shale formations tend to expand horizontally and not vertically. As far as shale extraction is concerned, the horizontal approach is the way of the future; (vertical drilling in shale is still carried out mainly due to the cost of horizontal drilling). The tremendous advancements achieved through horizontal drilling, previously unimaginable, easily show its significance: *"When drilling into a hydrocarbon bearing formation 100 feet thick, vertical drilling would allow an operator to contact 100 feet of rock, which would limit your potential recovery to whatever oil or gas would flow into that length of pipe. Horizontal drilling now allows these same operators to drill and set pipe for a mile or more horizontally through this same rock formation. You are now contacting and 'fracking' 5200 feet of rock rather than 100 feet, which multiplies expected well recovery rates many times over. The technology employed is so advanced and exacting that drillers today can hit a target at the end of a drill string that is 10,000 feet vertical with a mile long horizontal section that is no more than a few inches in diameter. Drillers also use sensors to detect particularly promising rock intervals within the formation,* *and are able to move the drill string up or down, left or right as they drill through the horizontal section to target those intervals"* [David Blackmon]. Taking into account all the other -just as important- beneficial results (maximizing of well returns, tax revenues, less environmental impact) we conclude that horizontal technology is indeed a major scientific innovation. All the involved pro and against development parties in the controversy following the shale gale have focused (with help from the press) on the hydraulic fracturing process encompassing almost every drilling activity to the word 'fracking', depriving the horizontal drilling innovation of its true shine.

Horizontal drilling - Directional drilling basics

Directional drilling (or slant drilling) is the practice of drilling non-vertical wells. It can be broken down into three main groups: oilfield directional drilling, utility installation directional drilling (or H.D.D., horizontal directional drilling, directional boring) and in-seam directional drilling (coalbed methane).



Control: Steerable motor vs. rotary steerable string

Early direction drilling was achieved via placing a steel down-hole wedge that deflected the drill toward the desired target. This method lacked both control and time efficiency. Later on, the use of steerable down-hole drill motors operating on the hydraulic pressure of the circulating drilling mud improved the control over the change of direction (but control was still far from perfect). The most recent advance in drilling is the ability to direct the drill bit beyond the region immediately beneath the drill rig. Rotary steerable systems, first introduced in the 1990s, eliminated the need to slide a steerable motor. The newer tools drill directionally while continuously rotated from the surface by the drilling rig. This enables a much more complex and accurate drilling trajectory. Continuous rotation also leads to higher rates of penetration and fewer incidents of the drill-string sticking.

Directional wells are drilled for several purposes:

- Increasing the exposed section length through the reservoir by drilling at an angle;
- Drilling into the reservoir where vertical access is difficult or not possible.
- Grouping together all the wellheads on one surface location so that fewer rig moves are needed, less surface area is disturbance, and the production cost is smaller;
- Drilling 'relief wells' to relieve the pressure of a well producing without restraint;

Trivia: In 1990 Iraq accused Kuwait of stealing oil through directional drilling as a pretext to invade. At the time, technological limitations of directional drilling would have made any attempt of that kind impossible.

Horizontal drilling - Types of horizontal drilling

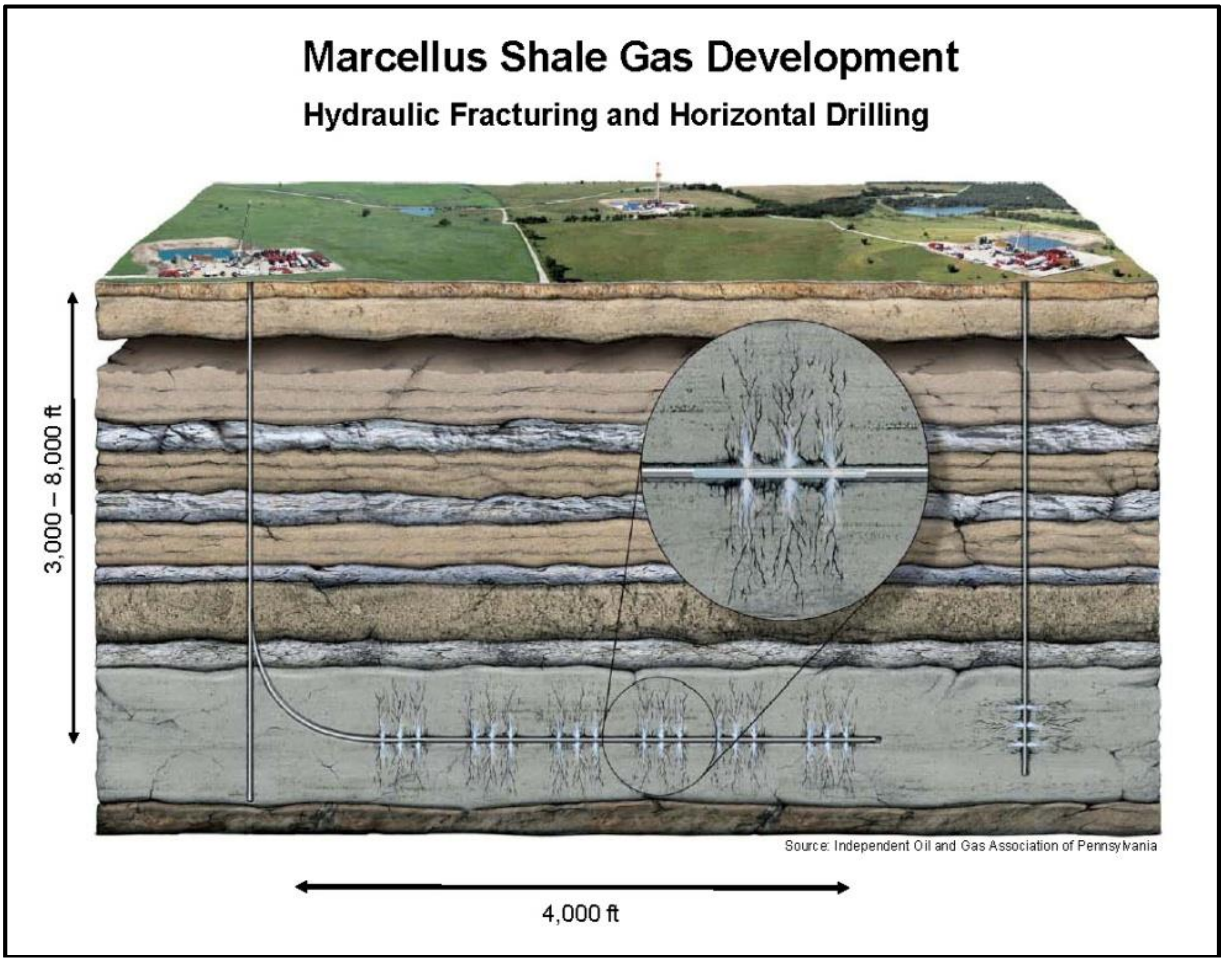
There are three main kinds of horizontally drilled wells. Their distinction is based on the radius of the curve transiting from vertical to horizontal plane.

- Short-radius wells: they typically have a curvature radius of 20 to 45 feet, being the 'sharpest turning' of the three types. Usually they are constructed in order to increase the recovery rate of already drilled and developed vertical wells (moving horizontally towards part of the reservoir until recently unreachable). They are sometimes used in the unconventional cases of tight gas and coalbed methane.

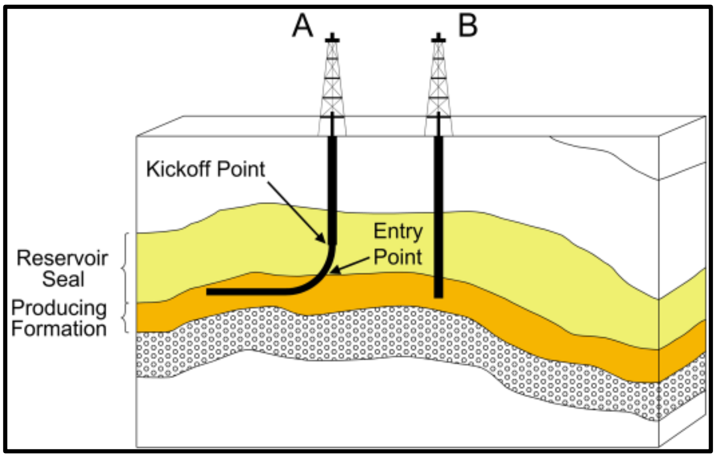
- Medium-radius wells: they typically have a curvature radius of 300 to 700 feet, with the horizontal portion of the well measuring up to 3,500 feet. These wells are useful when the drilling target is a long distance away from the drill site, or where reservoirs are spaced apart underground. Multiple completions may be used to gain access to numerous deposits at the same time. Medium-radius wells are constructed in the shale gas extraction.

- Long-radius wells: typically having a curvature radius of 1,000 to 4,500 feet the can extend a great distance horizontally and are mostly used in offshore operations.

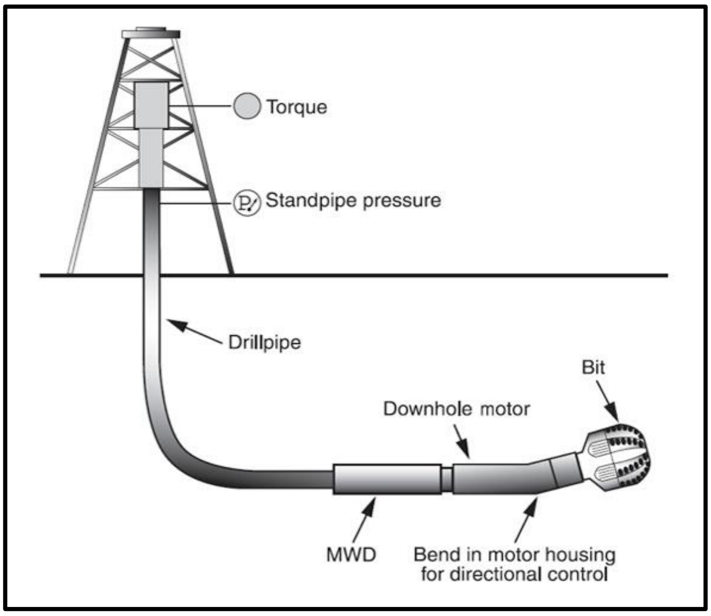
Horizontal drilling



The first step of the procedure has already taken place; a (near) vertical well has been drilled down to the kickoff point that marks the depth of the curved section's start. This kickoff point is usually fixed at 100 - 200m above the horizontal plane. It has been determined prior to the drilling by geologists who have calculated the needed radius of the curve, the point of entry to the shale formations and the location and length of the shales. The aim is to divert the wellbore from the vertical plane around a curve intersecting the reservoir at the 'entry point' with a near-horizontal inclination, and to remain within the reservoir until the desired bottom hole location is reached. When drilling beyond the kickoff point, the trajectory starts deviating from the vertical orientation with build rates of 10^o to 20^o/30m. Shale gas wells are medium-radius wells having a curvature radius of 300 to 700 feet.



There are two main modern ways (both already seen in the 'Directional drilling basics' and also analyzed in the next section) that a well can be drilled horizontally: The first is using a rotary steerable system, which bears a special device utilizing 'kick pads' in deflecting the rotating drilling assembly in a certain angle. Rotary steerable technology is the more complex option providing better control, time efficiency and results. The downside to all these is that it is also the far more expensive choice, used in cases requiring extra technological sophistication and/or shorter well construction times. The alternative option is that of the traditional down-hole drill motor type assembly that does not rotate when building angle. At the end of the drill pipe there is an actual motor, with a rotor and a stator, that is powered by the force of the drilling mud or fluid that is pumped at high pressure down the drill pipe from the rig on the surface. The drilling fluid causes the motor to turn, which in turn powers an oil well drill bit. The difference in this kind of drilling is that instead of the entire string of drill pipe turning from the surface on down to the bit, only the mud motor moves. Because the mud motor has a bend in it, the driller can leave it in a certain position and allow it to eat away at the rock while the drill pipe slides along following it. Because the driller has a readout up on the surface, displaying information from direction measuring instruments below, called MWD or LWD (measure while drilling) or (logging while drilling), he can know which way to slide the mud motor to achieve a 'build' or



Down-hole drill motor assembly

increase in inclination upward. Once the motor and bit reach a certain inclination, such as eighty degrees or more, the rig will pull out the entire section of drill pipe and mud motor and replace the mud motor with one that has less of a bend in it to drill the horizontal section of the hole. Then they will 'go to bottom' or trip in the hole with the new motor and finish drilling the well at ninety degrees. They may drill several hundred or even thousands of feet horizontally out from the original vertical well.

[Main source of the last paragraph: www.doodlebugs.hubpages.com/hub/Horizontal-Drilling--How-Directional-Drillers-Drill-Oil-Wells-Sideways]

Note: The omission of an in-depth section about rotary steerable systems, down-hole drill motors, MWD and LWD was a deliberate decision. Their basic functions and role in the horizontal drilling operation was sufficiently explained. Further analysis would have required the pausing of the 'shale technology topic' and the inclusion of a subchapter with far too many drilling related details (in order to properly explain) that would end up being off topic. For the reader that does want to deepen his knowledge on the subject I suggest these two articles:

- *'Rotary steerable system replaces slide mode for directional drilling applications'*
  [Jonny Haugen, Baker Hughes]
  www.ogj.com/articles/print/volume-96/issue-9/in-this-issue/general-interest/rotary-steerable-system-replaces-slide-mode-for-directional-drilling-applications.html

- *'Measurement While Drilling'*
  [Courtesy of Oilfield Directory]
  www.oilfielddirectory.com/oilfield/measurement_while_drilling.htm

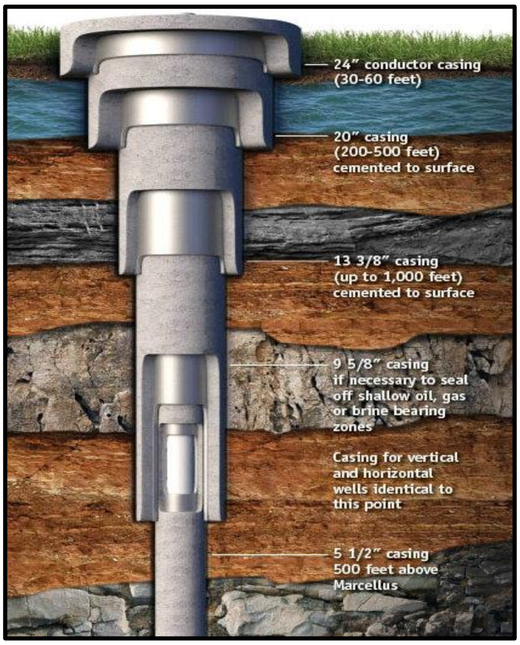
Horizontal drilling - Advantages & disadvantages (summary)

Horizontal drilling allows much greater access to the shale basins. This translates into much more available shale formations for stimulation, greater efficiency in recovery rates (2.5 to 7 times in comparison to vertical) and -in the long run- a more economical production. Its use hasn't introduced new environmental concerns. On the contrary, the reduced number of wells (when drilling multiple horizontal wells per pad) has significantly reduced surface disturbance (see also Chapter IV). Horizontal drilling has one major disadvantage: The capital investment it requires can cost more than 3 times that of a vertical well ($2.5 million as opposed to $800.000, excluding pad and infrastructure). Minor and independent developers do not have the option of acquiring the know-how and the tools needed and the scale of the investment is beyond their capacity.

During the course of the wellbore drilling, multiple well casing installations take place. In order to avoid shift of focus from the drilling to the well casing method and vice versa, this part of the drilling phase is presented isolated from the main core, in a chronologically consistent manner and with follow up information of its most important aspects.

Well casing - Introduction

From the very begging of the well construction and until the drilling stops, multiple layers of specially designed steel casing and cement are installed in the wellbore. In the 3.2 example we described one possible protective combination of layers: cement - conductor casing - cement - surface casing - mud - production casing - production tubing. The various combinations installed provide an essential multi-layer barrier; the barrier ensures that high-pressure gas from deeper down cannot escape into shallower rock formations or water aquifers and flows up exclusively through the well to be produced. It also contributes in maintaining the integrity of the ground around the wellbore and in preventing any possible drilling fluid leaks. All regulatory programs place great emphasis on securing the water zones underground.



Marcellus well casing

Well casing - Design

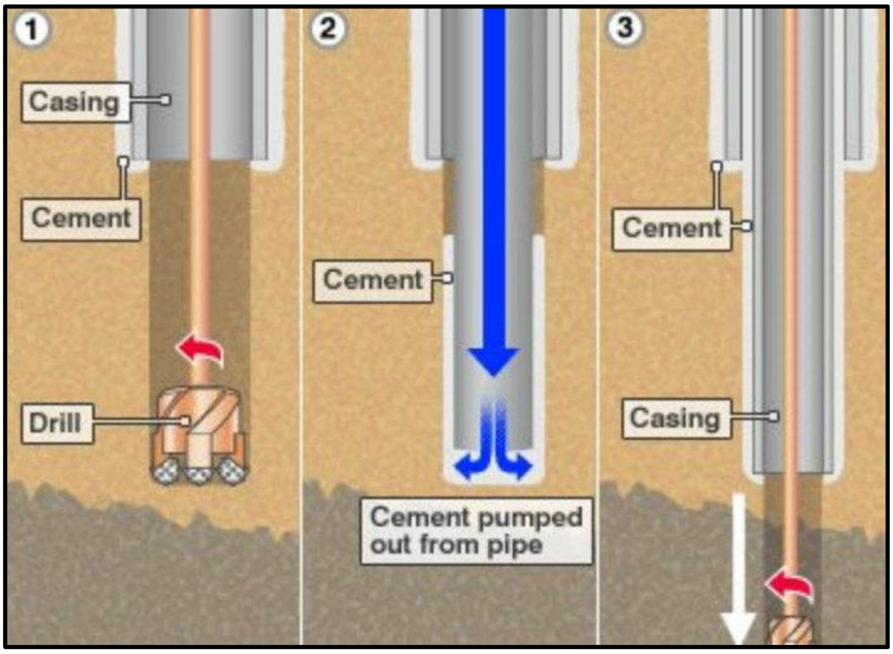
The barrier has to be designed to withstand the cycles of stress it will endure during the subsequent hydraulic fracturing, without suffering any cracks. The most important design aspects to be taken into account are:

- The drilling of the wellbore to specification (without additional twists, turns or cavities);
- The positioning of the casing in the center of the wellbore before it is cemented in place; this is achieved with centralisers placed along the casing as it is adjusted in the well.
- The correct choice of cement; the cement design needs to be studied both for its liquid properties during pumping (to ensure that it gets to the right place) and then for its mechanical strength and flexibility, so that it remains intact. Another critical factor is the settling time of the cement; if it takes too long to set may end up with reduced strength; equally, cement that sets before it has been fully pumped into place requires difficult remedial action.

Well casing and cementing

Every well casing is studied and designed accordingly prior to the installation. The number and length of the casing depend on the depth and the properties of the geology. The type of cement is also chosen according to its properties. Regulation often specifies the required depth the time that is required for cement to set.The diameter of the well hole (and the casing) depends on the size of the drill bit used. In most wells, the diameter of the well hole decreases the deeper it is drilled, leading to a type of conical shape that must be taken into account when installing casing. Casing horizontally is identical to casing vertically; naturally, the well casing intended for the more sensitive section where the transition from one direction to another is achieved is adjusted to correspond to the added requirements.

The general concept of well casing - cementing is depicted in the production casing installation diagram below:

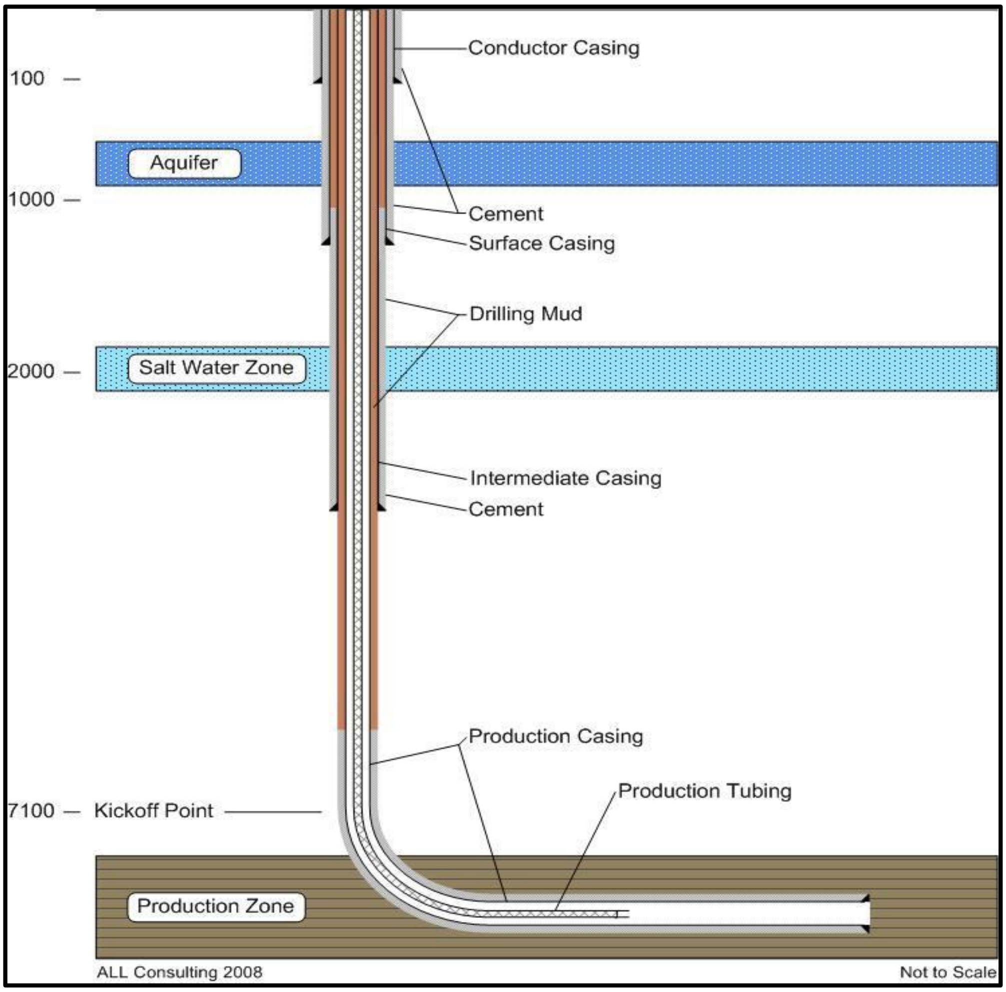


01. The conductor casing has been installed and cemented (it stops at a certain point). The drill continues digging, forming the wellbore up to the depth required by the surface casing length. The protective layers so far are: cement - conductor casing.

02. The drill stops working and is pulled out of the wellbore. Cement is pumped out from the pipe. Moving upwards, towards the surface, it fills the rock face - surface casing gap and the conductor casing - surface casing gap. The protective layers are now: cement - conductor casing - cement - surface casing.

03. The drill is once again lowered in order to form the next part of the wellbore. Intermediate and production casing will be installed in the same manner.

There are four main types of well casing used in shale gas extraction:



- Conductor casing: It is installed first, prior to the arrival of the drilling rig. Conduction casing is usually 20 to 50 feet long and its diameter measures 16 to 20 inches. The hole corresponding to its dimensions is often drilled with a small auger drill mounted on the back of a truck. The conductor casing is cemented in place to prevent the top of the well from caving in and to help in the process of circulating the drilling fluid up from the bottom of the well.

- Surface casing: It is the next type of casing to be installed. It can be anywhere from a few hundred to 2,000 feet long, and is smaller in diameter than the conductor casing. When installed, the surface casing fits inside the top of the conductor casing. The primary purpose of surface casing is to protect fresh water deposits near the surface of the well from being contaminated by leaking gas. It also serves as a conduit for drilling mud returning to the surface, and helps protect the drill hole from being damaged during drilling. As a further protection of the fresh water zones, air-rotary drilling is often used when drilling through this portion of the wellbore interval to ensure that no drilling mud comes in contact with the fresh water zone. Surface casing, like conductor casing, is cemented into place. Regulations often dictate the thickness of the cement to be used to ensure that there is little possibility of freshwater contamination.

- Intermediate casing: It is usually the longest section of casing found in a well. The primary purpose of intermediate casing is to minimize the hazards that come along with subsurface formations that may affect the well. These include abnormal underground pressure zones, underground shale, and formations that might otherwise contaminate the well, such as underground salt-water deposits. In many instances, even though there may be no evidence of an unusual underground formation, intermediate casing is run as insurance against the possibility of such a formation affecting the well. These intermediate casing areas may also be cemented into place for added protection. The borehole area below an intermediate casing may be un-cemented until just above the kickoff point for the horizontal leg. This area of wellbore is typically filled with drilling muds.

- Production casing: It is installed last and is the deepest section of casing in a well. This is the casing that provides a conduit from the surface of the well to the gas-producing shales.

  Note: Main source of 'Types of casing': www.naturalgas.org. More information in the bibliography section;

While and after the well casings are put in place, operators and regulatory agencies conduct a series of tests to ensure the mechanical integrity of the casing and the isolation of each zone. Strength of the casing and cement - casing bonding are checked.

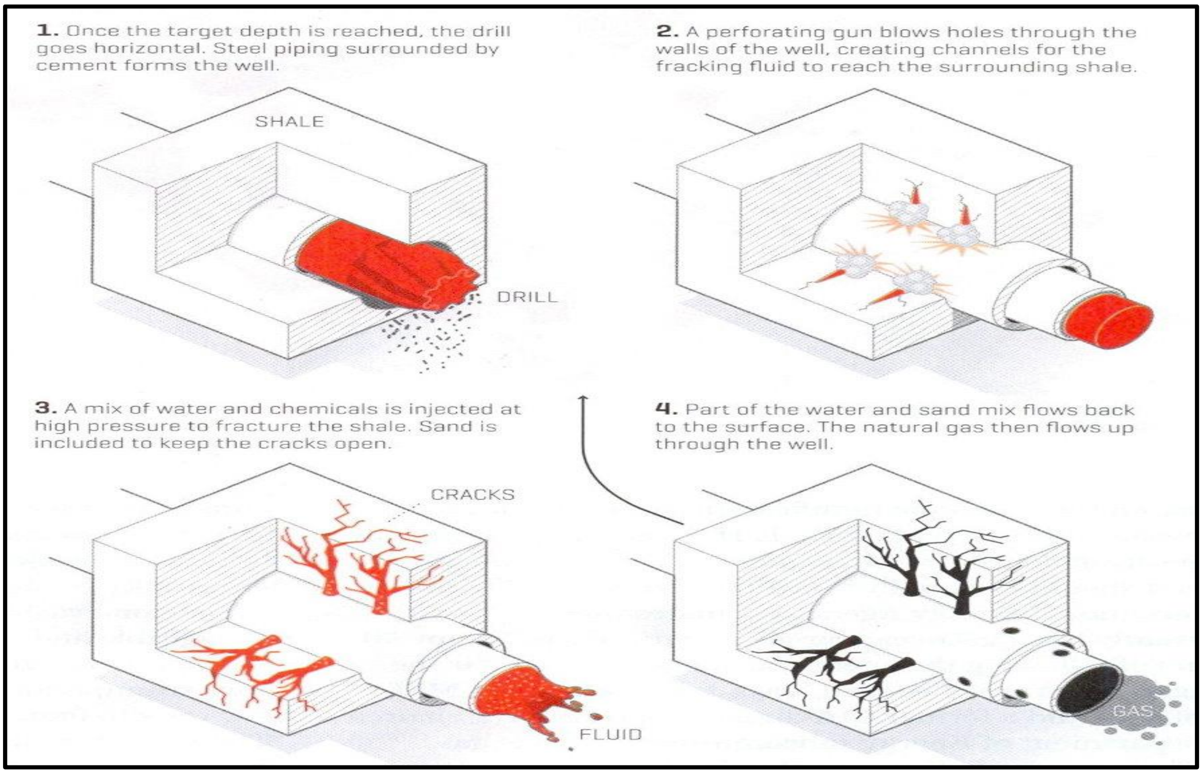
After the casing is installed, tubing is inserted inside the casing, running from the opening well at the top to the formation at the bottom. The drilling phase is now over and the completion phase is about to begin.

3.3.3 Well construction Part II: Completion phase

The well has been drilled and secured with casing, the shale formations have been reached and everything is set for the begging of the completion phase that includes the operations of hydraulic fracturing and production.

<u>Hydraulic fracturing - Introduction & method overview</u>

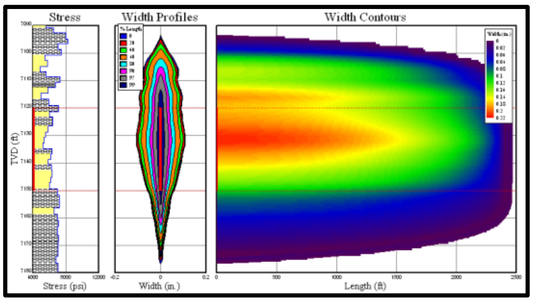
What sets apart shale gas from conventional natural gas is the fact that it is trapped in low permeability shales. Once the well has been drilled and the casing installed, the gas-bearing rock is perforated in order to establish connection between the rock and the well. The pressure of the well is lowered so that the natural gas can move from higher to lower pressure and flow into the production tubing. Low permeability of the shale formation means very low flow rates, which in turn translates into very low well revenue. In order to accelerate the flow of the gas and make the extraction economically viable, hydraulic fracturing is employed. Hydraulic fracturing involves pumping a fracturing fluid into the formation at a calculated, predetermined rate and (high) pressure to generate crevices a few millimeters wide in the target formation far below the surface. In the shale development case, the fracturing fluids are water-based fluids enhanced with additives in order to carry sand proppant into the fractures and 'prop' them open. Additional fluids are pumped in order to further develop the fractures created and to maintain the well pressure necessary to accommodate the increasing length of the opened fractures in the formation. These fractures can extend tens, or even hundreds, of meters away from the well. If the rock was to be relieved of the pressuring fluids and proppant hadn't been added and promoted inside the fractures, they would tend to close over time and production would be halted once again.



Hydraulic fracturing method overview

Hydraulic fracturing - Fracture design

The process of hydraulic fracturing starts from its design. The shale rock targeted for fracturing is studied and its properties (thickness of shale, fracturing pressure, fracture length etc.) are identified, recorded and evaluated. Every formation has inherent natural variability and the fracturing treatment has to be designed and adjusted specifically for it. Yet, the general concept behind each design stays the same. With the growth of the shale gas exploration, the industry gains experience and databases containing these formation-specific data, drawn from previous practices, are being compiled and patterned.



Hydraulic fracture stimulation model

The scientists use sophisticated and state of the art engineered processes to understand the conditions of the formation and its dynamics. They build simulation models that help them approach the behavior of the formation and maximize the effectiveness and the economy of the design. A computer model can be used to simulate hydraulic fractures. Techniques employed to study these models include micro-seismic fracture mapping and tilt-meter analysis. The model stimulation of hydraulic fracturing ensures the safe conduct of the operation in real life. The modeling programs allow modification and optimization of the fracture treatment design. They are used to predict the possible height, length and orientation of the fractures to be produced. These results are of great importance. An uncalculated extension of the fractures beyond the targeted shales and into other formations can be disastrous for the whole operation: apart from the waste of materials, time and money it can result in environment pollution (underground water contamination, gas leaking, expensive recovery programs etc.) and even to the loss of the well and its gas reserves.

Hydraulic fracturing – Fracturing stages

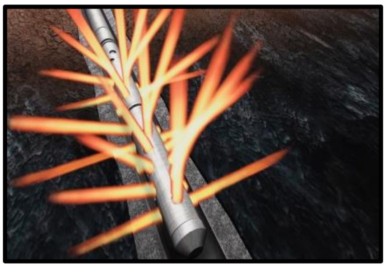
As we have already seen in §3.2, the horizontal portion of the shale well -the portion to be fractured- is divided into zones. These zones are fractured sequentially, starting from the end point of the wellbore and moving uphole. The fracturing of each zone is called a fracturing stage, or just stage. Once a stage is completed, the zone is isolated and the next stage begins. The procedure continues in the same manner until the entire horizontal length of the well is stimulated and then connected into production. This procedure is followed because of the restrictions imposed by the lateral length of the well (that can range distances from 1,000 to 5,000 feet): It is very difficult, or even impossible, to achieve and maintain the needed fracturing pressure to the entire length of the well, so isolated smaller portions have to be created. The distance of its portion depends on the well's horizontal length and pressure conditions. Staging multiple fracture treatments also allows for a very controlled process. The operator is enabled to make changes to each portion separately in order to accommodate site-specific variations (such as shale thickness, overabundance or lack of natural fractures, proximity to the end of the wellbore or other formations etc.).

Hydraulic fracturing - Initial testing and inspection

The formation has been studied and a basic design has been planned. Before performing the treatment, tests are being carried out (by both the company and regulatory agencies) to ensure the well's endurance to the hydraulic fracturing pressure and flow rates. These tests are conducted as early on as the casing installation stage and inspect the condition of the well, the casings and the cement applied (see also 'Well casing and cementing'). The multi-stage fracturing applied in the shale formations delivers repeated stress on the well and for that reason premium well construction is required. Prior to the operation all hydraulic fracturing machinery and equipment are also inspected and tested.

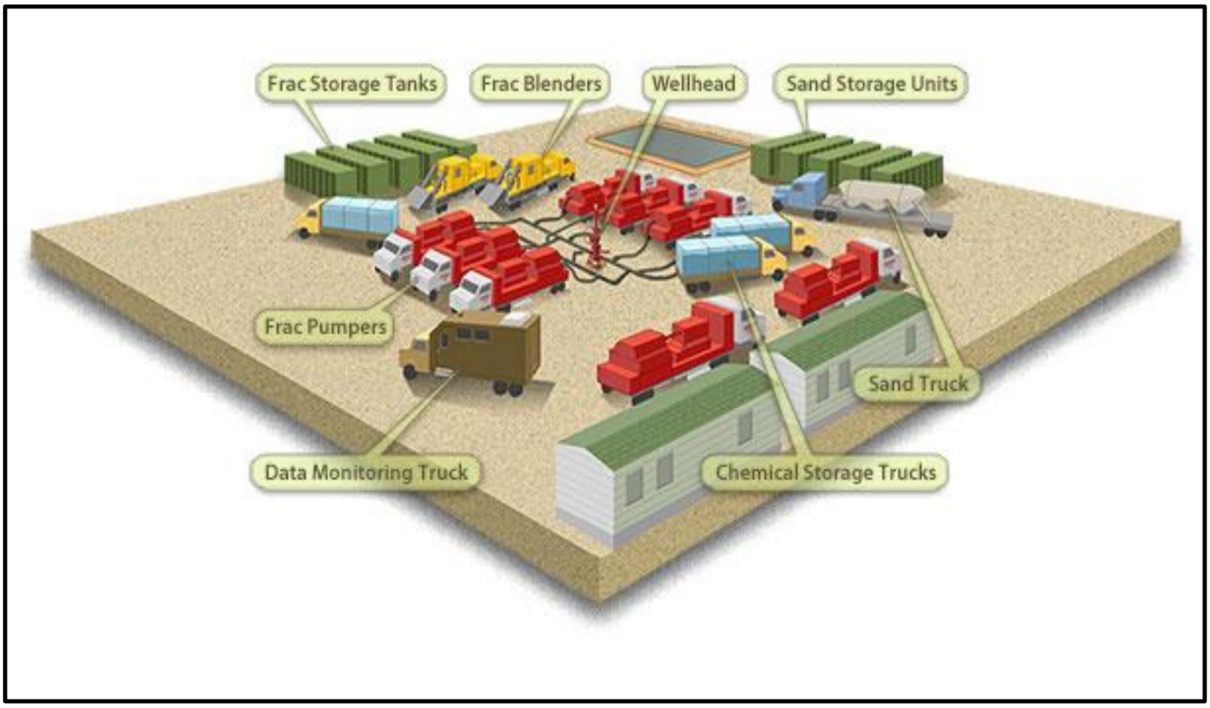
Hydraulic fracturing - Preparation

The operation begins with the perforation of the horizontal portion of the well casing, in preparation for the treatment. A tubing-conveyed perforating gun, containing explosive charges, is lowered into the well and reaches the designated location of the furthest end of the wellbore. Using electrical current the charges are set off and small fractures are created in the steel casing, the cement and the shale formation. The perforating gun is fired at roughly 50 - 80 feet intervals. The number and orientation of the perforations are pre-determined and designed to intersect the shale formation's inherent natural fractures. Production casing and shales are now in contact.



Perforating gun

With the perforation complete, the drilling rig is disassembled and the hydraulic fracturing equipment is moved into place. From now on a wireline unit is used to convey the fracturing tools into the well. The surface equipment consists of multiple pumping units (the treatment size determines their number/capacity), blending units, control units and storage units.



Hydraulic fracturing equipment

Hydraulic fracturing

Every preparation has been made and the hydraulic fracturing treatment begins. The process consists of four activities:

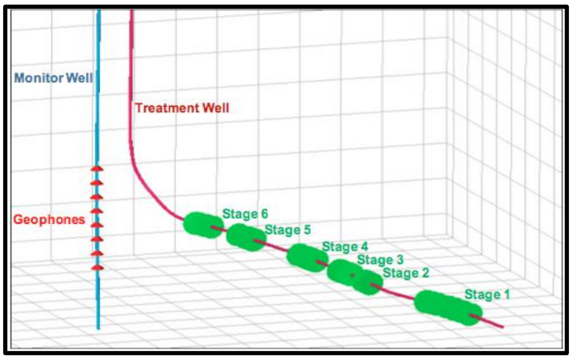
- Pumping high-pressured fracturing fluids in the perforated formation to create fractures;
- Continue pumping fracturing fluids to grow the fractures created;
- Inserting proppant slurry, as part of the fracturing fluids, in the fractures;
- Stop pumping and recover the fracturing fluids;

Initially hydraulic fracturing starts with a sub-procedure called 'acidizing'; pumping acid (HCL solution) into the wellbore to remove near-wellbore formation damage and damaging substances that may have occurred during the drilling phase.

After the acidizing, volumes of water-based fracturing fluid containing friction reducing agents, called slickwater pads, are mixed with proppant are successively pumped down the well. The initial pad does not include proppant. It is a volume of fracturing fluid large enough to fill the entire wellbore and the open formation area (double in size compared to the largest of the prop pads). It is pressured into the well to create the fractures on the perforated shale formations. Gradually the slickwater pads pumped are combined with different volumes and types of mesh sand - proppant. The first proppant sub-treatments include the pumping of large volumes of fluids with the inclusion of finer-grained proppant. Later on, the volume of fluids is reduces (to about to 60% of the original prop pad). Finer-grained proppant is used because it is capable of penetrating deeper within the fractures. In the final sub-stages coarse-grained proppant replaces finer-grained while the fluids volume further decreases to 20% of the original prop pad volume. Having grown the fractures to the desirable point, coarse-prop is used to maintain open the wider parts of these fractures. After the last sub-stage the well is flushed with freshwater to remove excess proppant from the wellbore and the fracturing equipment.

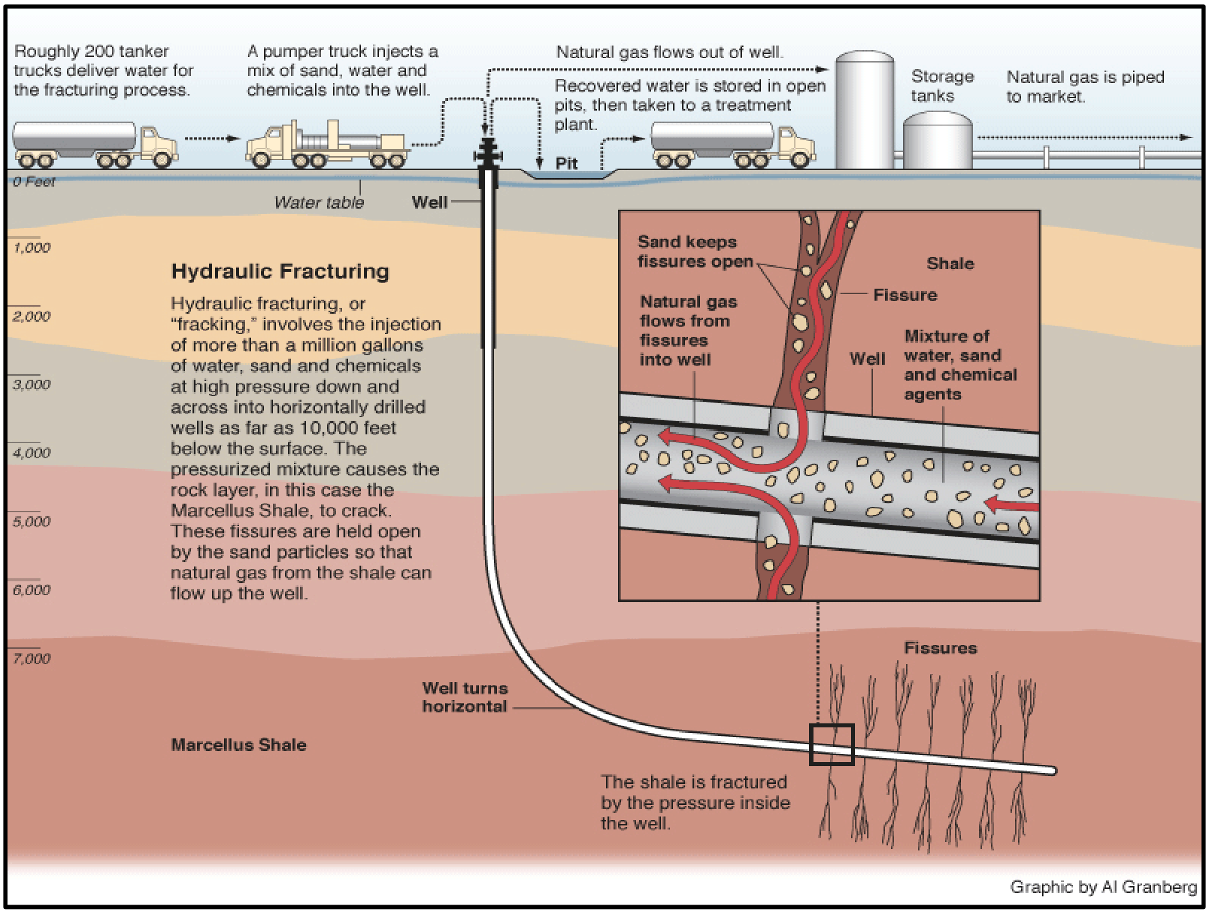
The whole hydraulic fracturing stimulation is constantly being monitored by a team of 30 - 35 fracturing specialized operators. They inspect and keep track of every aspect of the procedure including:

- The wellhead and downhole pressure;
- The pumping rates and density of the fracturing fluid slurry;
- The volumes of each additive and the water used;
- Equipment functionality;



Typical monitoring configuration

After the stimulation of a stage has been completed, a composite bridge plug is adjusted on the bottom of the perforating gun, which is then lower in the wellbore. The stimulated stage is than isolated from the remaining horizontal well and a new stage begins. At the conclusion of the operation, the plugs are removed and production can finally start.



Hydraulic fracturing operation overview

Hydraulic fracturing - Single stage example of a sequenced hydraulic fracturing treatment

The following table presents the real fracturing fluid volume statistics of the sub-stages of a single stage of a sequenced fracturing treatment in the Marcellus area (Source: Arthur et al., 2008). The first sub-stage is that of acidizing and it uses 5,000 gallons of HCl solution. The first slickwater pad isn't mixed with proppant and has a volume of 10,000 gallons. Sub-stage pads Prop1 to Prop7 are mixed with finer-grain proppant and start off at the volume of 50,000 gallons and end up with a volume of 30,000 gallons. Pads Prop8 to Prop15 have a volume of 20,000 to 10,000 gallons and include coarse-grained proppant. Finally, the flush pad requires about 13,000 gallons of freshwater. Since the flush pad is based on the total volume of the wellbore, as we move from the first to the last stage and isolate portions of the well, the volume of the flush pad required will significantly decrease. The total amount of proppant used is about 450,000 pounds. The total volume of water (slickwater pads are 99.5% water) needed is 578,000 gallons.

This example refers to a single stage of a multistage fracturing treatment (or to the simplest case of vertical shale drilling). If the whole operation consists of four stages the total amount of water needed would be about 2.2 - 2.3 millions of gallons.

Note: 42 gallons = one barrel, 5,000 gallons ≈ 120 barrels;

Hydraulic Fracture Treatment Sub-Stage	Volume (gallons)	Rate (gal/min)
Diluted Acid (15%)	5,000	500
Pad	100,000	3,000
Prop 1	50,000	3,000
Prop 2	50,000	3,000
Prop 3	40,000	3,000
Prop 4	40,000	3,000
Prop 5	40,000	3,000
Prop 6	30,000	3,000
Prop 7	30,000	3,000
Prop 8	20,000	3,000
Prop 9	20,000	3,000
Prop 10	20,000	3,000
Prop 11	20,000	3,000
Prop 12	20,000	3,000
Prop 13	20,000	3,000
Prop 14	10,000	3,000
Prop 15	10,000	3,000
Flush	13,000	3,000

Hydraulic fracturing – Water availability

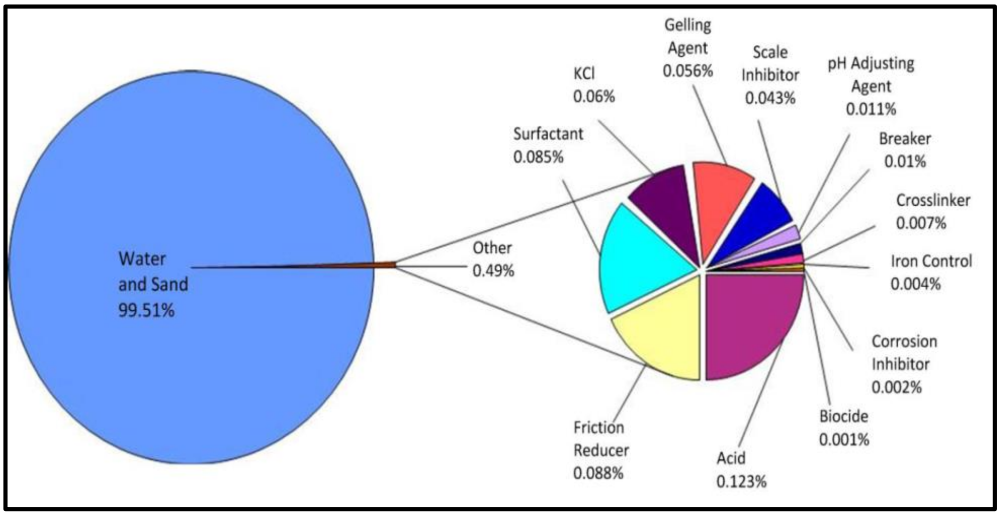
A typical shale gas hydraulic fracturing treatment requires 2.5 - 4 million gallons of water. This estimation may differ substantially, depending on the case. The water supply in demand is retrieved from nearby surface water bodies (rivers and lakes), drawn from the underground (municipal or private wells) or from stored re-used produced water.

Hydraulic fracturing - Fracturing fluids

Fracturing fluids have two main objectives: to create and promote the growth of fractures and to carry proppant (usually silica sand or ceramic beads) into them. They primarily (98 - 99.5%) consist of water. The rest very low 0.5 - 2% concentration refers to a variety of 3 to 12 chemical additives. Their exact number, type and concentration differ from case to case and depend mostly on the properties of the formation fractured, the conditions of the well and the kind of water applied. Until recently, the composition of these additives was considered a trade secret;

In shale gas fracturing the current dominant fluid is the slickwater: a mix of water-based fracturing fluids with friction-reducing additives. Reduced friction translates into higher rate and reduced pressure pumping of the fluids/proppant into the well. Other additives enhance differently the operation: Biocides prevent microorganism bio-fouling, oxygen scavengers reduce corrosion and acids remove drilling mud damage within the near-wellbore area; Special polymers are added to gelify the pad while it is being pumped in the well. Gelifying the mix equally distributes the proppant particles suspended in the fluid. Without this effect the heavier particles, under the influence of gravity, would have been distributed unequally and the mix would have ended up less efficient. Finally, there are additives that give time-dependent properties to the fluid. Some of the enhancements made to deliver the proppant in the cracks are not desirable at other stages of the process and their characteristics are designed to wear off over time (par example, gel liquefaction).

Some of the chemical additives can be hazardous in the case of their unplanned release. In 2011 a US government survey listed 2,500 hydraulic fracturing products containing 750 chemicals; 29 of these were identified as known carcinogens, regulated under safe water and/or clear air legislation. This is the reason why they are handled responsibly, according to strict regulations and long-standing industry practices.



Slickwater pad concentration

[Source: ALL Consulting based on data from a fracture operation in the Fayetteville Shale]

Additive Type	Main Compound(s)	Purpose	Common Use of Main Compound
Diluted Acid (15%)	Hydrochloric acid or muriatic acid	Help dissolve minerals and initiate cracks in the rock	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive byproducts	Disinfectant; sterilize medical and dental equipment
Breaker	Ammonium persulfate	Allows a delayed break down of the gel polymer chains	Bleaching agent in detergent and hair cosmetics, manufacture of household plastics
Corrosion Inhibitor	N,n-dimethyl formamide	Prevents the corrosion of the pipe	Used in pharmaceuticals, acrylic fibers, plastics
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases	Laundry detergents, hand soaps, and cosmetics
Friction Reducer	Polyacrylamide	Minimizes friction between the fluid and the pipe	Water treatment, soil conditioner
	Mineral oil		Make-up remover, laxatives, and candy
Gel	Guar gum or hydroxyethyl cellulose	Thickens the water in order to suspend the sand	Cosmetics, toothpaste, sauces, baked goods, ice cream
Iron Control	Citric acid	Prevents precipitation of metal oxides	Food additive, flavoring in food and beverages; Lemon Juice ~7% Citric Acid
KCl	Potassium chloride	Creates a brine carrier fluid	Low sodium table salt substitute
Oxygen Scavenger	Ammonium bisulfite	Removes oxygen from the water to protect the pipe from corrosion	Cosmetics, food and beverage processing, water treatment
pH Adjusting Agent	Sodium or potassium carbonate	Maintains the effectiveness of other components, such as crosslinkers	Washing soda, detergents, soap, water softener, glass and ceramics
Proppant	Silica, quartz sand	Allows the fractures to remain open so the gas can escape	Drinking water filtration, play sand, concrete, brick mortar
Scale Inhibitor	Ethylene glycol	Prevents scale deposits in the pipe	Automotive antifreeze, household cleansers, and de-icing agent
Surfactant	Isopropanol	Used to increase the viscosity of the fracture fluid	Glass cleaner, antiperspirant, and hair color

Representative table of the major shale hydraulic fluids additives
Source: 'Modern shale gas development in the United States: A primer'

The following table presents the major shale hydraulic fluids additives: what is their main compound/s, their purpose in the fracturing treatment and where these compounds are commonly used;

Note: Diluted acid (15%) is HCl solution comprised of 85% water and 15% acid.

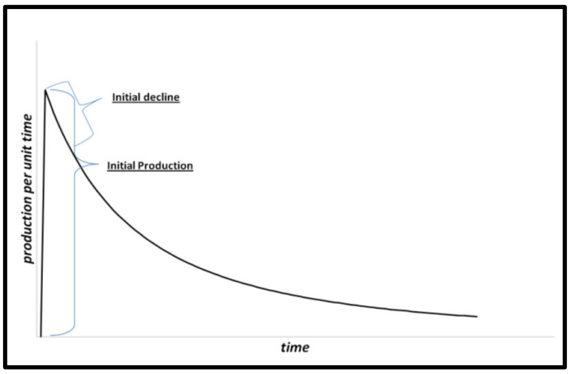
In Chapter IV we will analyze from an environmental perspective the shale gas extraction impacts (and especially those of the highly controversial hydraulic fracturing method).

Production

With the ending of the hydraulic fracturing treatment, the shale gas reservoir has been reconnected and wholly stimulated. Parts of the well pad that are no longer needed are reclaimed for operations elsewhere or stored for future use. The only things left (from a once crowded drill rig and hydraulic fracturing crew) are a production 'Christmas tree' of valves -about 1 meter high-, a separator and the production tanks. Usually, this tree facilitates production from more than one close-by wells.

Once the well is connected to the processing facilities, the gas production can finally begin. Before reaching full production, there is a transitive phase of several weeks, where excessive remaining fluids from the fracturing treatment flow back up the well mixed with hydrocarbons. Best practice during this period is to use 'green completion' methods to separate the gas from the mix, and collect - process the waste stream (up to 77% of the original flow back can be re-used). The later part is standard in the production operation, but the capturing of the natural gas at this early stage requires optional facility investments that aren't always installed due to economic reasons. The alternatives to the above are (the environmentally harmful) venting or flaring of the gas and/or fluid mix.

Once the main production is achieved, the well develops a mixture containing predominantly natural gas and a (far smaller) stream of waste and other natural occurring substances carried from the well to the surface. Natural gas is treated to a useable condition while the produced fluids are diverted into storage tanks. They are managed according to regulation, recycled or properly disposed.



The production phase is the longest phase of the well's lifecycle. A conventional well can keep on producing gas for more than 30 years. Unconventional productive life can also span that long but with deferent production rates. They typically exhibit a burst of initial production that steeply declines (after the first year the output is reduced by 50 - 75%). The well continues on to produce gas at far lower rates for a long period of years, but most recoverable gas is attained during the first few years of production.

Workovers

Workovers are maintenance operations that can be carried out multiple times over the well's production phase. Their purpose is to restore part of the production rate that declines over time. Apart from cleaning, repairing and maintenance, workovers may even include a process called re-fracturing: a further stimulation of the shale formations through a new (less intent) hydraulic fracturing process. Re-fracturing is more frequent in vertical shale wells and rare in horizontal wells.

Plugging and abandonment/reclamation

Once a well reaches its production limit, it is plugged and abandoned according to regulations. Facilities are dismantled and the land is reclaimed to its former state. The reclamation activity lasts days while full restoration demands the passing of several years. Special caution is required in long-term prevention of leaks from the well to the underground aquifers.

Chapter IV: Ecology and environmental shale gas impact

4.0 Introduction to Chapter IV

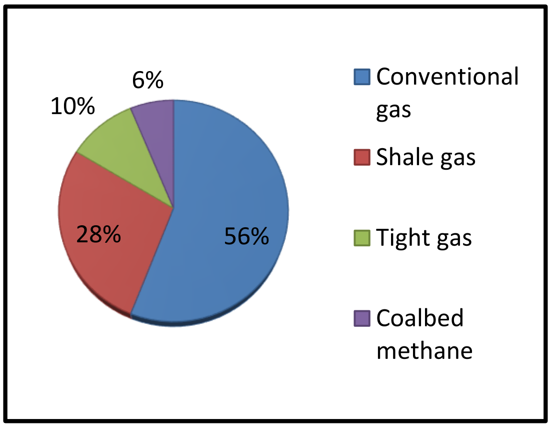
Chapter IV is dedicated to presenting in greater detail the environmental topics concerning shale gas development. Since many of the operations conducted have to do with securing the environment of the well, the reader has already established a first eco-contact on shale in Chapter III. Here it is explained why ecological shale-consideration is crucial. Moving once again along the development chain we identify the possible shale gas environmental risks and impacts and try to assess their hazardous potential. This thesis doesn't intend to present the regulatory shale system that is still in the making. In the last part of the chapter it briefly explains the complications that have risen from the legislation's delay to keep up with the establishment of mainstream shale gas production and a guideline proposed by IEA is included.

4.1 Importance of environmental consideration

The modern day energy market is in the midst of a grand structural reformation. Along with oil and coal production -that have so far been the dominant of means to satisfy energy demand-, attention is shifted towards their co-existing alternatives with promising potential. Nuclear energy and renewables are of course part of the new picture, but a great -if not the greatest- portion of the energy equation change is happening due to the development and promotion of natural gas. From heating means to industrial plants and even vessels, natural gas steadily claims larger share of the market.

The natural gas optimism is underlined -not without crucial footnote warnings- in the 2011 IEA analysis titled "Are we entering a golden age of gas?". IEA builds a positive natural gas scenario relaying on four main assumptions of high probability: an increase in natural gas use in China's rapidly growing economy; greater natural gas use in transportation; slower growth in global nuclear power capacity; and an optimistic outlook on gas supply, based primarily on the availability of additional unconventional gas (exploited at a relatively low cost). While it is too soon to make claims of confirmation, these speculations successfully catch the market momentum and the prediction of an increased natural gas role in the future global energy mix (21% to 25% by 2035, overtaking -currently second- coal), seems a very possible outcome.

But what about the footnote warnings mentioned? The title of the analysis ends with a "?", asking a question rather than delivering a statement. This reflects the continued uncertainties concerning the future of natural gas and in particular those connected with the potential for growth in the unconventional gas supply. The unconventional exploitation is a prerequisite in the natural gas boom. IEA estimates that *"the remaining technically recoverable resources of unconventional gas worldwide approach the size of remaining conventional resources (which are 420 trillion cubic meters [tcm]). Remaining technically recoverable resources of shale gas are estimated to amount to 208 tcm (, tight gas to 76 tcm and coalbed methane to 47 tcm). The economic and political significance of these unconventional resources lies not just in their size but also in their wide geographical distribution, which is in marked contrast to the concentration of conventional resources. Availability of gas from a diverse range of sources would underpin confidence in gas as a secure and reliable source of energy"*. One might assume that, since deemed unconventional, the hesitation derives from the technical and economic difficulties presented by the nature of these gas reservoirs. Challenges of this sort are existent, yet not the main cause of concern. As so often happens with technological innovation, after the breakthrough is achieved, the rest of the pieces find a way over time, to fit in and form/evolve the procedure into an optimized profitable functional way. While unconventional gas development has some distinctive features and requirements, the technologies utilized are established and have much in common with other parts of the upstream industry. The problem derives from the unconventional gas inherent higher



Natural gas recoverable reserves (IEA estimation) (compared to conventional) risk of environmental damage and adverse social impacts. Its production is an intensive industrial operation with many implications for the environment (regarding land use, surface and underground water reserves, GHG emissions etc.). Regulatory agencies were caught unprepared for the sudden unconventional rise and a coherent, adequate regulation remains to be imposed. Possible hazards and implications have generated controversy and public anxiety. Improperly addressed, concerns on the subject threaten to curb, or even stop, the development of unconventional resources.

In conclusion, natural gas -largely thanks to shale and the rest of the unconventional production- is about to enter a golden age of adequate, reliable and affordable supply. For this to happen, governments (through regulation) and the industry have to respond to both environmental and social challenges presented. They must apply the highest practical standards of production and inspection, monitoring, optimizing, successfully predicting and controlling all environmental impacts (, especially when considering the fact that there is little back track record of shale gas mainstream production). Firstly and fore mostly to secure the environment (and the production) from ignored or unexpected dangers; secondly and finally, to prove their competence and trustworthiness towards the public, thus gaining 'a social license to operate'.

Unconventional practice: Distinctive characteristics

In §4.2 we are going to focus on the main objective of this chapter: the environmental impact and risks of the shale gas development process. In order to better understand these environmental shale-related hazards, we are briefly summarizing the distinctive characteristics of unconventional and shale practices from which they derive.

Generally unconventional resources (shale gas, tight gas and coalbed methane) are more diffuse and difficult to produce. For a given volume of natural gas, an unconventional output requires an operation of a much larger scale that also results in a much larger environmental footprint. These are their distinctive characteristic leading to heavier environmental impacts and risks:

- Extracting unconventional gas requires a greater number of wells (a greater exposure to the imprisoning formation of the reservoir). This smaller recovery rate of quantity of gas/unit of land results in an intense drilling impact. With the combination of multi-horizontal drilling this effect is significantly lessened.

- Either way, development tends to extend across much larger geographic areas.

- Stimulating a functional flow for the trapped gas almost always (in shale and tight gas cases, less frequently as regards coalbed methane) results in a method of hydraulic fracturing. The associated use and release of water gives rise to a number of environmental concerns, including depletion of freshwater resources and possible contamination of surface and underground water aquifers.

- Production can result in higher airborne emissions of methane, a potent greenhouse gas (GHG). Also, taking into account the extra energy required, unconventional extraction leads to greater carbon dioxide (CO_2) emissions.

- Resources can be located in areas with little to no exploitation experience.

4.2 Environmental risks and impacts of shale gas development

Environmental risks and impacts of the shale gas development process can be classified in ten main categories:

- Risk of underground water contamination
- Risk of surface water contamination
- Water resources abstraction - Risk of depletion
- Air quality degradation
- Seismicity inducement
- Surface disturbance and land occupation
- Wildlife disturbance
- Noise
- Visual impact
- Traffic

Emphasis is primarily given in the first five categories. These concern the major shale-distinctive (unconventional-distinctive) environmental risks and impacts caused mainly due to the process of hydraulic fracturing. The remaining five categories are common in both conventional and unconventional procedures. On account that most of these impacts are conventional-natural-gas common knowledge, they are presented synoptically, from the shale development perspective.

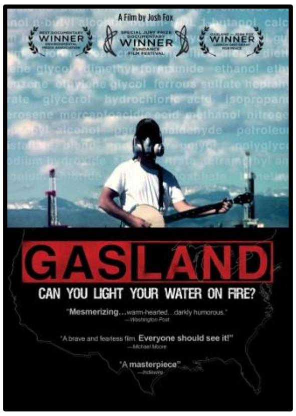
4.2.1 Shale gas (unconventional) risks and impacts

Risk of underground water contamination

Excluding the first phase of site preparation, the risk of underground water contamination is imminent during all shale gas development operations: drilling, hydraulic fracturing, well completion (flow-back), production and abandonment. The risk of water contamination, both above and belowground, has stirred the most shale-related controversy (, with GHG emissions following in the second place). The risk of underground contamination is considered high, especially during the phases of fracturing, well completion and production. Moving along the development process we are going to isolate one by one its phases and analyze the risks they present to the underground water reservoir.

During the drilling phase there is the risk of subsurface water contamination due to drilling mud, additives and naturally-occurring chemicals in the well cuttings. These cutting can come in contact with the underground water reservoir either by accidental drill penetration or by fluid - rock formation flow (going both ways). Underground contamination at this early stage is usually associated with low structural quality of the well. Design, casing and cementing defaults and defects (such as inadequate casing depth and poor cement seals) compromise the integrity of the well for its whole lifecycle.

In the hydraulic fracturing phase there are two main hazards threatening the groundwater. Firstly, there is the risk of leakage via the wellbore or through the induced fractures (both successfully created fractures and extended-beyond-the-desired-formation ones). If the wells integrity is somehow compromised, anything that goes down and comes up from the wellbore can end up in the water reservoir. This includes fracturing fluids (and their chemicals), produced water, natural gas, trace-elements and naturally occurring radioactive materials (NORMs). The second risk is that of migration through faults and pre-existing manmade structures. Careful measuring and site consideration ensures the absence of unwanted gas pathways.



Methane (natural gas) migration towards water formations is the hot topic of the shale controversy mentioned. Methane is combustible and asphyxiant and can be dangerous when reaching water aquifers. The documentary 'Gasland' shows footage of methane-contaminated water that is set on fire and strongly supports that the leakage was caused by a hydraulic fracturing process carried out in the state of Pennsylvania. The very few past incidents of methane migration proven to have been linked to fracking cannot be associated with the modern, well established practices carried out by the industry. As regards the movie, the pro-shale party strongly states that there is no proof, only debatable indications, that modern day fracking can result to methane migration. What makes the research between a potential fracking - methane migration link even more difficult is the lack of baseline comparable log data and the existence of naturally occurring methane migration into water aquifers (very common phenomenon in Pennsylvania).

Burning methane-water

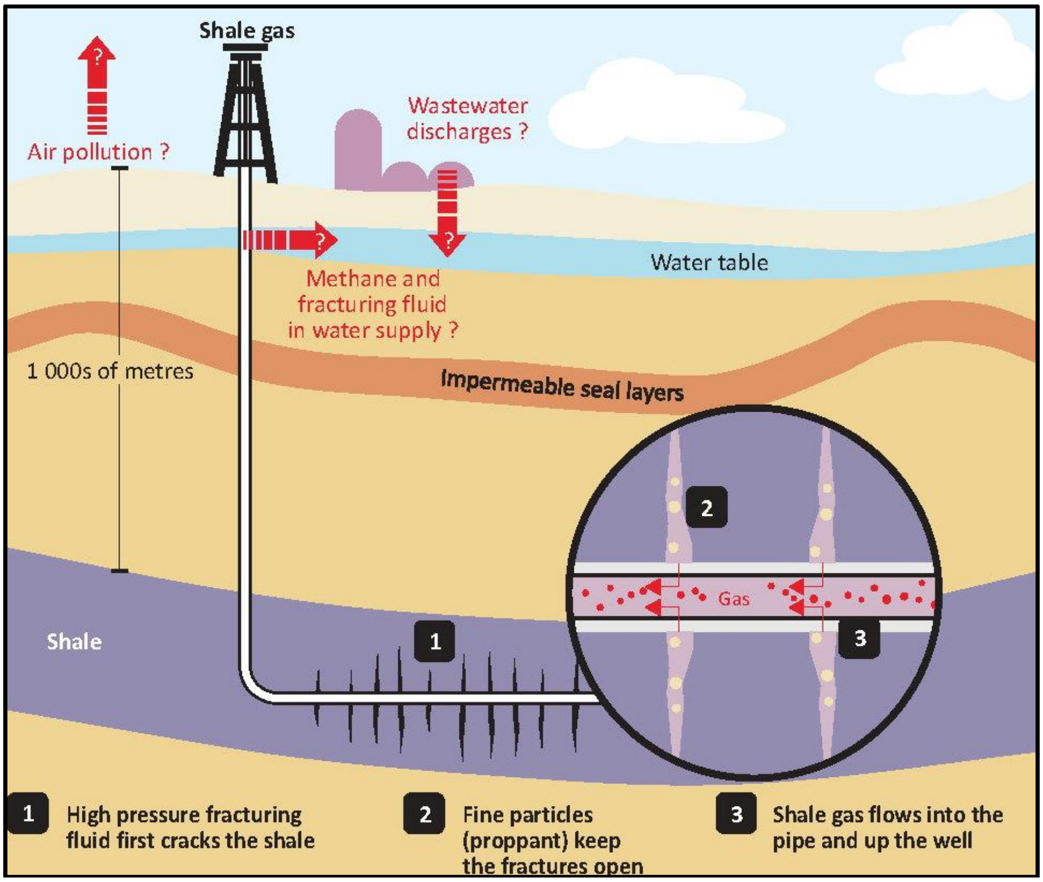
Considering the standard minimum 600m separation distance between the horizontal portion of the shale well and the underground water reservoir, the risk of methane migration is regarded as moderate. Naturally, cumulative effects of multiple well pads installation present higher risk.

The case of NORMs (radium, thorium, uranium) leakage also presents interest. NORMs emit low levels of radiation. Through the fracturing, flow-back and production operations they can be brought to the surface along with some of their decay elements. Hydraulic fracturing chemicals are mostly responsible for interacting with the formations containing them and freeing them. Long term NORM concentration in field production equipment, though taken into consideration, doesn't really present dangers, since human exposure to them is very brief. On the contrary, NORMs concentrated along with the waste in disposal pits and found in recycled fracturing fluid should definitely be taken into account and regarded as a moderate to high risk (especially in the case of multiple well pads).

During the well completion phase, flow back is disposed, stored, injected or recycled. Operators need to handle the produced water to ensure that accidents, runoff and surface spillages do not occur. If flow back is recycled the risk of introducing NORMs and other natural occurring chemical elements rises significantly.

In the phase of well abandonment, poorly controlled and logged wells may present risks in the long-term. Unrecovered fracking fluids contained within the target formations gradually dissolve or flow back in a very small volumes and over an extended time span.

Finally, potential surface water contamination in any stage of the development can result in underground contamination as well.



Schematic of some possible hydraulic fracturing hazards (including deep water contamination)

Risk of surface water contamination

From the stage of site preparation and up to production (including revisiting - refracturing of the well) there is risk of surface water contamination. This risk is considered high, mostly during the stages of hydraulic fracturing and well completion. Surface water can be contaminated by drilling mud and fluids, fracturing fluids and produced water (including fracturing fluids, NORMs and chemicals). The possible incidents that can lead to surface water pollution are:

- Bad site design - preparation (inadequate area, wrong choice of area near surface water);
- Bad design of pits;
- Ground erosion;
- Rainwater runoffs;
- Accidents of fluid carrying vehicles;
- Facility leakage (storage tanks, flow back recycling process);

Water resources abstraction - Risk of depletion

During the stages of hydraulic fracturing and well completion (and in the case of refracking in the production stage), there is a moderate risk of environmental impact to the water resources quality and quantity due to abstraction. The development process requires large amounts of water in order to carry out the hydraulic fracturing treatment. The abstracted water volume -though large- generally represents a small percentage of the total water resources of the area; however, granted that development needs it when drilling and fracking are conducted, the withdrawals are made in a relatively short period of time. Adverse effects can occur when in unsustainable locations or on periods of low flow and drought. These effects are:

- Reduced stream flow affecting overall availability;
- Change in the water attributes (oxygenation, temperature, salinity, quality, stimulated bacteria growth);
- Upwelling of lower quality water and substances from deeper deposits;
- Interplay with the water discharges resulting in higher pollutants concentration;

Air quality degradation

Shale gas exploration and production is similar in terms of air emissions to the conventional natural gas development. However, the varying composition of the produced gas, the larger scale of the development process and the fact that there is no associated oil production along with the operation, affect the end quantity (3.5% higher than conventional) and composition of the air emissions.

The development includes a variety of potential air emissions whose output and effects differ depending on the phase of the operation. A relatively low source of emissions throughout the drilling and hydraulic fracturing process is the vehicles used to transport the necessary equipment. In the drilling phase most air emissions are produced from the diesel or natural gas drilling rig engines and machinery. In the hydraulic fracturing treatment multiple diesel-powered pumps are utilized also contributing to the air pollution. In the production phase along with the emissions from the facilities, there is a much more serious and environmentally hazardous source of emissions: flaring or venting of natural gas, especially in the first transitive stage of production and in cases of natural gas located leaking. In the initial, crude flow back the stream of fracturing fluids that carries natural gas towards the surface is extensive. To direct this first natural gas into production, after separation, is a very difficult and costly procedure, much more complex than the standard procedure of the main production and requires the installation of expletory equipment. When best practices of this short aren't followed due to lack of initiative, investment capital and/or time, natural gas is vented or flared into the air. Flaring, in practice, is restricted to short periods of time during well testings, completion and workovers. Non-routine situations resulting in air pollution are potential gas leaks from the pipeline and equipment network and well blow-out accidents (4 environmental incidents of blow-outs have occurred between 2008 and 2012 in Pennsylvania, resulting in fluids and gas release).

Air quality degradation - Air emissions composition

The main categories of air emissions produced by shale gas development are:

- Nitrogen oxides, NOx; they are produced in any industrial activity that burns fossil fuels to provide the necessary power to the machinery utilized. In shale gas development, diesel or natural gas is burnt as fuel for powering the vehicles, drilling equipment, hydraulic fracturing equipment and development facilities. NOx also occur in the flaring process of natural gas.

- Volatile organic compounds, VOCs; they are emitted usually in the dehydration of the natural gas process. The production of shale gas -and generally natural gas- is a closed process that results in fewer VOCs in comparison to oil production.

- Particulate matter, PM; practical matter may occur mostly from the dust/soil of the drilling process and the exhaust byproducts of the engines and the vehicles (using diesel fuel).

- Carbon monoxide, CO; it is emitted during flaring and from the incomplete combustion of carbon-based fuels used in engines. CO emissions from the natural gas industry represent a very small part of the total.

- Sulfur dioxide, SO_2; it is formed when fuel containing sulfur is burnt. SO_2 emissions from the shale and natural gas industry are also very low in comparison to other industrial operations.

- Ozone, O_3; ozone is not directly emitted in the development process. Ground-level O_3 may be created when NOx and VOCs are combined together with sunlight.

- Methane, CH_4; methane is the principal component of natural gas. It is classified as one of the top greenhouse gases, GHG, along with CO_2. Methane is a more potent GHG but has a half-time of about 15 years, in comparison to the 150 years of CO_2. Although natural gas is confined within the production network of the well, CH_4 may be released as a fugitive emission from processing equipment; high pressure pneumatic controls and pipelines are mostly the equipment vulnerable to such leaks. The industry has strong economic incentives to limit fugitive methane emissions to the greatest degree possible and maximize production and supply volume. A series of best measurement practices (BMPs) have been developed and optimized to reduce natural gas loss. Methane emission has been one of the shale-topics generating controversy. Shale gas is promoted as an eco-friendly alternative to oil, that has lower GHG emissions in its development and use. The controversy derives from the fact that the GHG footprint of the shale gas has not been fully evaluated. It is proven that shale development produces more GHG than the standard conventional development, mainly due to the hydraulic fracturing process leaks. The shale gas GHG conversation is part of a much bigger debate: that of which fuel, oil or natural gas, contributes less in greenhouse gases emissions. The short-term effects of methane and its GHG characteristics are currently re-evaluated to determine whether the original speculations underestimated the environmental impact.

Air quality degradation - Air emissions BMPs

Air emissions BMPs focus on preventing air pollution from occurring; prevention consists of maintaining and upgrading the necessary equipment along with improving the operational practices. Pneumatic devices, such as valves and controllers, operate by measuring pressure changes through releasing small gas quantities. Optimizing their operation or replacing them with higher efficiency newer models can result in significant reduction of gas leaking. Specially constructed flash tank separators can be employed to retrieve more than 90% of the natural gas residing in the initial flow back. Workovers can restore machinery functionality lost over time, reduce fugitive emissions and raise production rates. BMPs also try to optimize the monitoring systems: IR cameras are used to identify potential gas leaks, so that they are attended to and repaired rapidly and without significant energy losses. BMPs contribute greatly to recovering natural gas that would otherwise been lost and minimize other emissions. Some of them are enforced through regulation while others are applied voluntarily by the industry.

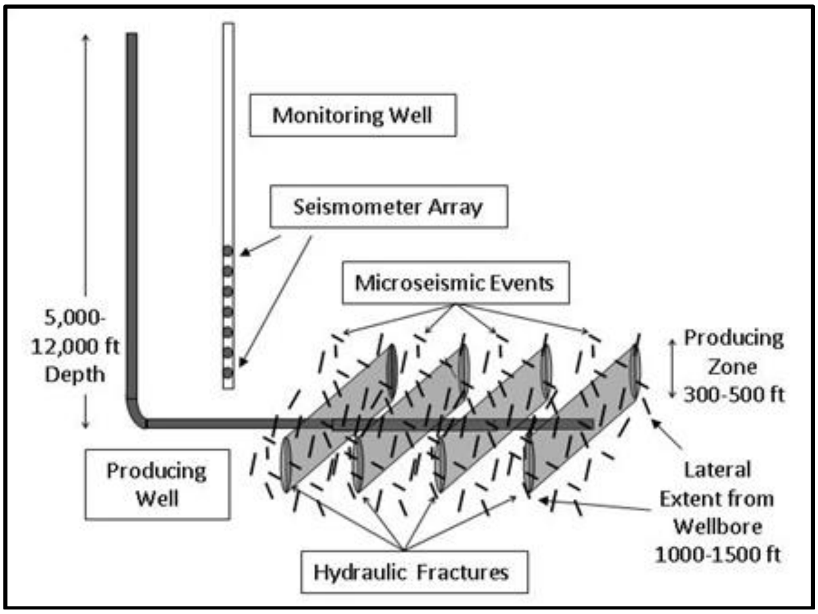
Seismicity inducement

Hydraulic fracturing has been associated with two types of seismicity inducement:

- The first type includes the micro-seismic activity stimulated by the physical process of fracking: creating cracks in the rock formations belowground results in mini-earthquakes, of very low magnitude, that cannot be felt by humans at the surface. Using very sensitive equipment (adjusted in monitoring wells or the surface) scientists record these seismic events and the data collected is used to monitor and guide the process. Larger seismic activity can occur if the fractures intersect or reactivate existing faults. In May 2011 at the Cuadrilla shale exploratory site, Blackpool UK, two earthquakes of magnitude 1.5 and 2.3 in the Richter scale were detected and all activity is still paused in order to conduct research on the event. A link between hydraulic fracturing and the earthquakes is strongly suggested.

- The second type of seismic inducement occurs when injected fracturing fluids reach existing faults in the underground; this create earthquakes of bigger magnitude that can be felt on the surface. At Youngstown, Ohio USA, several earthquakes were recorded in 2011, with average magnitude of 3.0 caused by the injection of fracturing waste water in a disposal well (a process similar to the pumping of fracturing fluids in the shale formations).

Hydraulic fracturing is not the only anthropogenic activity that can trigger small earthquakes; any activity that creates underground stresses carries such a risk. Well integrity is not expected to be affected by the low magnitude (and of low frequency) seismic fracking related events. Well casing and cementing is designed to maintain wellbore integrity in any kind of seismic event and the risk of well damage due to hydraulic fracturing induced seismicity is a very small one.



Schematic of seismic inducement Type I

4.2.2 Common risks and impacts of shale gas development

Surface disturbance and land occupation

The development process of shale gas requires a large area of operations. During the drilling and hydraulic fracturing phases the location is occupied by the drilling rig, the hydraulic fracturing treatment equipment and vehicles, the disposal pits, storage tanks etc. As seen in Chapter III, horizontal drilling can significantly reduce the surface disturbance of the well site. Near-well areas are also disturbed by access roads and pipeline routes. After well completion the occupied well pad land is reclaimed in the best possible way (never reaching full restoration). Surface disturbance throughout the whole development process is considered to impose a low to moderate risk (moderate in case of multiple well pads).

Wildlife disturbance

Shale gas development can affect wildlife and its habitat during the exploration, development, operations and abandonment phases. The sensitive equilibrium of natural biodiversity is very difficult to secure and preserve (and sometimes even understand) in almost every large-scale anthropogenic activity. Biodiversity refers to the diversity of species and ecosystems near the shale gas development area. The potential risks that can result in loss of biodiversity include:

- The removal, degradation or fragmentation of the natural habitat chosen as the well site; even at the production level, when human activity is minimized, new linear features (such as pipelines) will have been introduced to the ecosystem and will have altered its characteristics.

- The introduction of species foreign to the local ecosystems (microorganisms drilled to the surface or transferred along with the water, ground-erosion-control plants etc.);

- noise and disturbance;

- water and land pollution caused by potential contamination from fracturing fluids, produced waste or escaping underground elements;

Utilizing multi-horizontal drilling from one vertical well pad can reduce wildlife disturbance significantly. Less vertical wells don't only translate into smaller pad surface disturbance, but also to fewer roadways and utility corridors. Operations are allowed more flexibility in order to achieve optimum adjustment to the site and drilling underneath sensitive (water reservoir) formations is kept at minimum levels.

Even when all risks are considered and precautionary measures are applied, disturbance in the ecosystem of the well site is unavoidable. While it is impossible to return the entire site to its previous state after well abandonment, reclamation practices restore effectively large portions of the well's ecosystem. The risk to biodiversity loss and wildlife impact is considered moderate.

Noise

Noise impacts present temporary moderate to high risks to nearby residential areas and the natural ecosystem surrounding the well. In the phase of well construction most noise is produced by the preparation of the site and the drilling procedure. After the completion of the well there is minimal noise emission from the producing facilities contained within the well pad. As we have already seen in Chapter III, BPMs are applied in order to minimize the noise effects in the first stages of development.

Visual impact

Visual impacts of the shale gas development result from the inconsistent (in terms of material, form and function) introduction of features associated with the well site. These impacts are heavier in the phases of the 'rig up', the drilling and the fracking; yet, the visual disturbance is usually short-termed and tends to be minimal from distances beyond 1 mile. Once again, horizontal drilling lessens the visual effect, combining multiple wells to one well pad. In production phase the visual impact is very low. After well abandonment a very small portion of the equipment might not be recoverable. In multiple well installations the well pads are separated by approximately 1.5 km and the cumulative effects are still considered moderate to low. Visual impact is of course considered higher in the cases of areas of high landscape value, of close proximity to residential areas and to rural locations.

Traffic

The truck traffic in the development process presents moderate risks that can even be considered high when there are multiple well pads. Most traffic occurs in the stages of site preparation, drilling and hydraulic fracturing. Traffic impact, though temporary, has the potential to result in significant adverse effects:

- Increase of road traffic (slower traffic flows, congestion);
- Road safety degradation;
- Risk of spillages and accidents involving hazardous materials;
- Damage to regional infrastructure (roads, bridges etc.);

4.3 Shale gas legislation and proposed guideline

The analysis of shale gas legislation is beyond the limits and the intentions of the current thesis. It is a very complicated topic that is still evolving over time and varies substantially among continents and countries (and sometimes even states).

Shale gas mainstream development was not expected and initially caught off guard the US regulatory agencies. So far, a coherent, concrete and up to date regulation hasn't been imposed. Authority -and responsibility- are distributed among state and federal agencies, leading to a complex, diverse and frequently conflicting regulatory system. US federal government is ultimately responsible for developing and imposing regulations concerning water safety and management (and thus hydraulic fracturing). In many cases federal authority is delegated to states whose own regulations meet or exceed federal standards. Still, many argue that the extraction ends up an unregulated process and that federal government should have more responsibility. The industry feeling confident in its ability to extract safely shale gas and wanting to reassure public concern, asks the government for more regulation. Wanting also to secure production, it even self imposes regulations not found in the federal or state legislation, but considered best practices after years of experience.

In Europe, both the policy makers and the public remain wary of the potential environmental impact of shale gas development. While wanting to join in the shale race, governments are reluctant to support and approve shale gas development. Europe is much more densely populated than the United States and taping the new energy shale deposits would in many cases mean development near major cities. Further complications arise from lack of technical expertise, prior experience and the different regulatory systems of neighboring countries involved. Under the pressure of public opinion, France in 2011 and Bulgaria in 2012 banned fracking, while Germany (that has more than 30 years of experience in tight gas extracting) paused the topic until more research has been conducted. Shale gas is eventually going to be extracted in Europe too. Poland wants to take full advantage of the shale reservoirs it discovered and England is even considering going offshore to tap the vast share of shales it possess. Taking into account the fact that the regulatory framework hasn't been finalized in the US of America -shale gas's birthplace-, Europe will also need more time to take in all the required information, make up her mind and adjust American experience to its own standards.

The regulatory development issue is a global one. As more and more countries from all around the world (including countries from Asia and Australia, not mentioned so far) consider the possibility of shale gas development, the need for a solid legislation that will secure the environment and the gas production becomes urgent. This kind of regulation will ensure that drilling and fracking taking place so far is conducted in the optimum and safest way possible and set the practice standards for the developments to follow.

IEA, wanting to promote in the right direction shale gas environmental development, issued a world energy outlook report on unconventional gas entitled "Golden rules for a golden age of gas". In the optimum scenario of the paper, where these golden rules are applied and the conditions for mainstream shale gas development are in place, natural gas production has doubled by the year 2035, while the overall financial cost of a typical shale gas well has increased only by an estimated 7%. This set of rules acts as a guideline not only for the industry but also for the regulatory authorities aiming to correctly inspect and promote shale gas practice. Without getting into deeper detail, as regards the report's analysis, we present here the IEA Golden Rules:

Measure, disclose and engage

- Integrate engagement with local communities, residents and other stakeholders into each phase of a development starting prior to exploration; provide sufficient opportunity for comment on plans, operations and performance; listen to concerns and respond appropriately and promptly.

- Establish baselines for key environmental indicators, such as groundwater quality, prior to commencing activity, with continued monitoring during operations.

- Measure and disclose operational data on water use, on the volumes and characteristics of waste water and on methane and other air emissions, alongside full, mandatory disclosure of fracturing fluid additives and volumes.

- Minimize disruption during operations, taking a broad view of social and environmental responsibilities, and ensure that economic benefits are also felt by local communities.

Watch where you drill

- Choose well sites so as to minimize impacts on the local community, heritage, existing land use, individual livelihoods and ecology.

- Properly survey the geology of the area to make smart decisions about where to drill and where to hydraulically fracture: assess the risk that deep faults or other geological features could generate earthquakes or permit fluids to pass between geological strata.

- Monitor to ensure that hydraulic fractures do not extend beyond the gas-producing formations.

Isolate wells and prevent leaks

- Put in place robust rules on well design, construction, cementing and integrity testing as part of a general performance standard that gas bearing formations must be completely isolated from other strata penetrated by the well, in particular freshwater aquifers.

- Consider appropriate minimum-depth limitations on hydraulic fracturing to underpin public confidence that this operation takes place only well away from the water table.

- Take action to prevent and contain surface spills and leaks from wells, and to ensure that any waste fluids and solids are disposed of properly.

Treat water responsibly

- Reduce freshwater use by improving operational efficiency; reuse or recycle, wherever practicable, to reduce the burden on local water resources.

- Store and dispose of produced and waste water safely.

- Minimize use of chemical additives and promote the development and use of more environmentally benign alternatives.

Eliminate venting, minimize flaring and other emissions

- Target zero venting and minimal flaring of natural gas during well completion and seek to reduce fugitive and vented greenhouse-gas emissions during the entire productive life of a well.

- Minimize air pollution from vehicles, drilling rig engines, pump engines and compressors.

Be ready to think big

- Seek opportunities for realizing the economies of scale and coordinated development of local infrastructure that can reduce environmental impacts.

- Take into account the cumulative and regional effects of multiple drilling, production and delivery activities on the environment, notably on water use and disposal, land use, air quality, traffic and noise.

Ensure a consistently high level of environmental performance

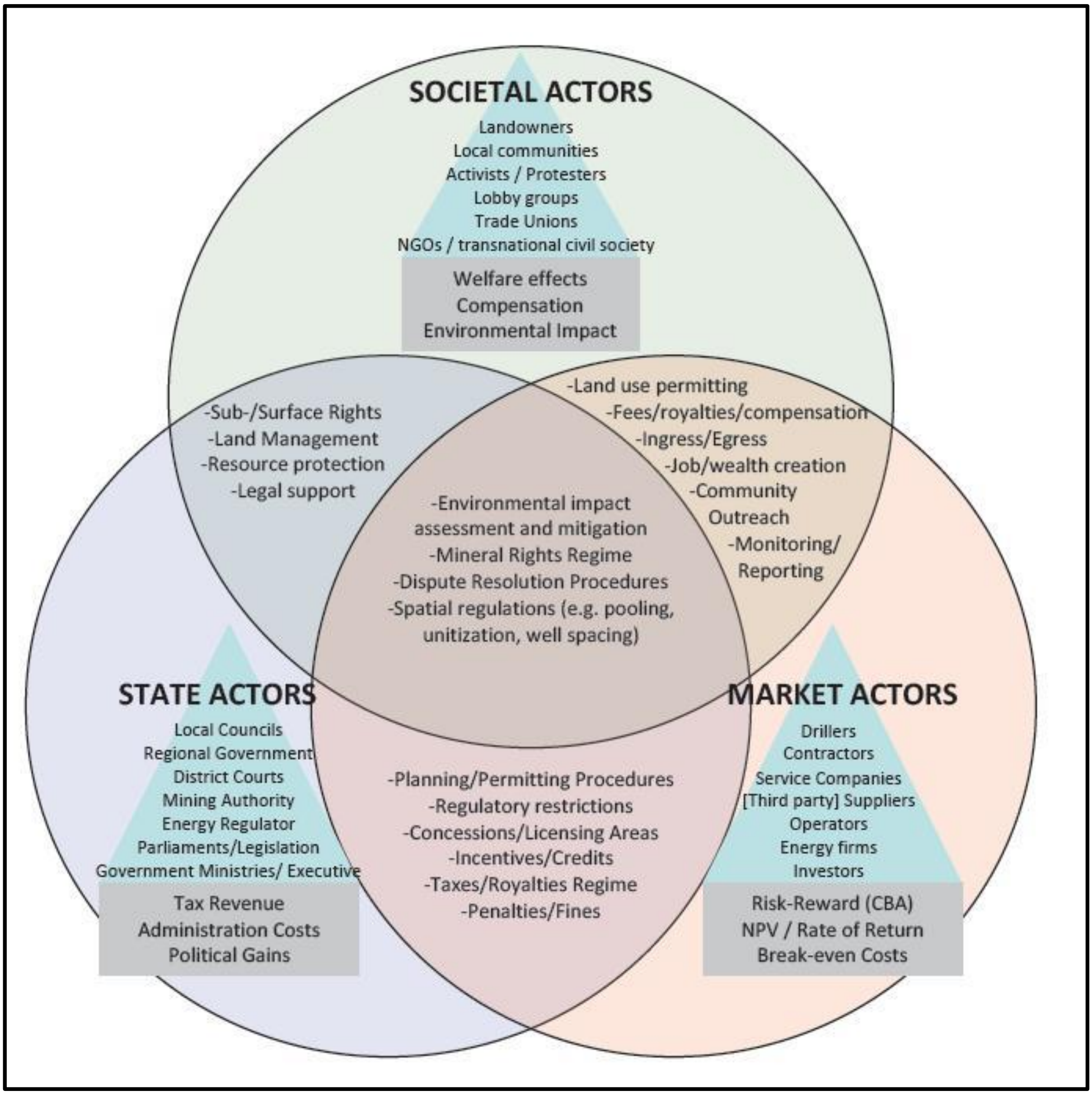
- Ensure that anticipated levels of unconventional gas output are matched by commensurate resources and political backing for robust regulatory regimes at the appropriate levels, sufficient permitting and compliance staff, and reliable public information.

- Find an appropriate balance in policy-making between prescriptive regulation and performance-based regulation in order to guarantee high operational standards while also promoting innovation and technological improvement.

- Ensure that emergency response plans are robust and match the scale of risk.

- Pursue continuous improvement of regulations and operating practices.

- Recognize the case for independent evaluation and verification of environmental performance.



Key regulatory framework elements

Chapter V: Shale gas implications on global energy commerce

5.0 Introduction to Chapter V

Summing up Chapters I through IV we have covered the information needed to understand the shale gas topic. We have defined the nature of shale gas and its distinctive unconventional characteristics; we have understood the events that took place and ultimately led to its commercial rediscovery; we have presented in full scope the ways technology is employed to overcome the unconventional obstacles of production; and finally, we have assessed the environmental risks and dangers of the exploitation process and the importance of eco-consideration. In Chapter V, the last chapter of this thesis, we are going to present the current economic implications delivered by the US shale gale, attempt a glimpse at the global post-shale future market and relate all the knowledge previously acquired to an economy perspective.

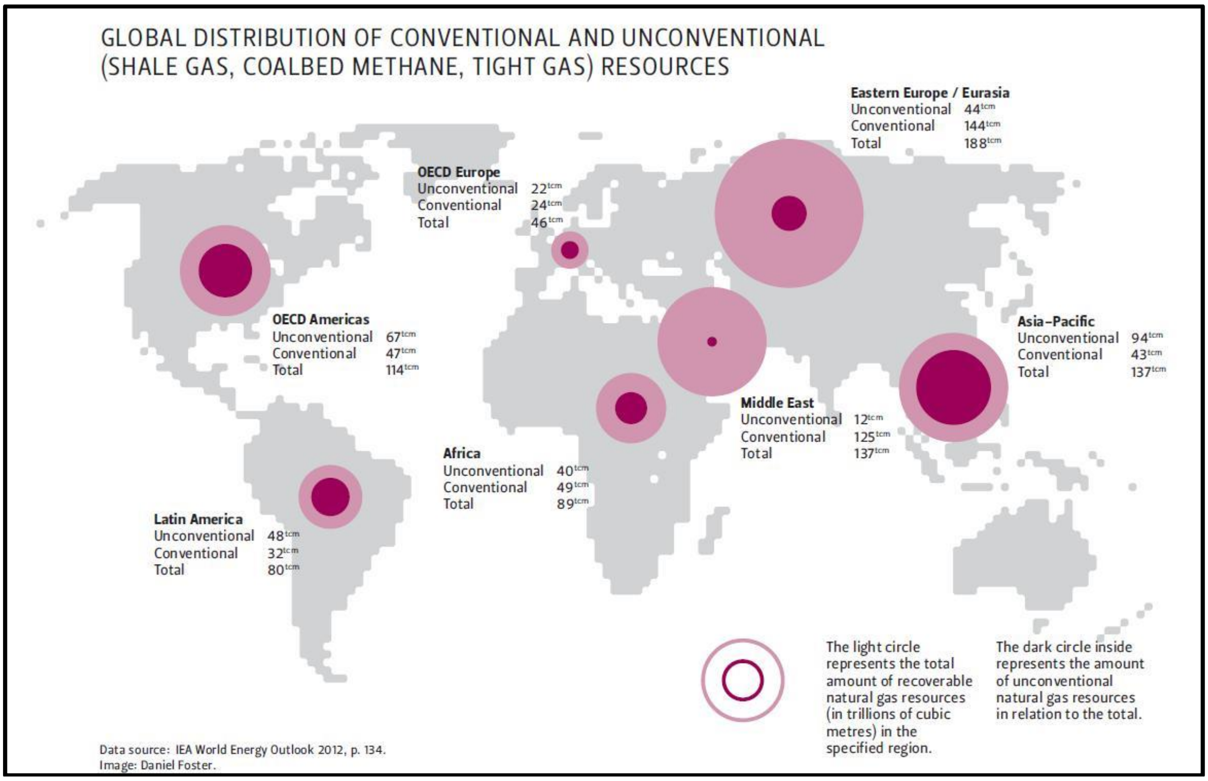
Shale gas was an unexpected source of natural gas supply. Its exploitation in North America delivered direct regional impacts along with indirect global ones. USA was assumed and anticipated by the energy market to take up the role of energy importer; instead, United States experienced a natural gas supply boom, due to shale, that ensured domestic needs and even offered the possibility of becoming an LNG exporter. World-scale changes are set in motions as more and more countries consider following the US example; the importers-exporters equilibrium and the terrestrial (pipelines) and maritime (LNG) network connecting them has already began to change, adopting to what seems to be a new age of natural gas. Noteworthy is the fact that almost all scenarios studying not only shale but natural gas in its totality conclude to the assumption that natural gas is the only fossil fuel whose demand rises definitely in the future. Key drivers that lead to this assumption are: shale and unconventional gas contribution to overall natural gas supply; post-Fukushima nuclear reevaluation and adaptation of the natural gas alternative; China's decision to promote natural gas use; growing competiveness of natural gas in comparison to the rest of the fossil fuels and finally the potentially eco-friendly -low in CO_2 emissions-character of natural gas.

This chapter does not attempt a systematic review. Shale gas production is virtually taking place solely in North America. Information on US and Canadian shale gas production is not available at this early stage and a lot of assumptions are based on estimations of high uncertainty. The rest of the world is considering the shale option but has yet to follow, so data in this case are nonexistent and -again- there is a wide range of possible outcomes. Furthermore, shale gas numerical data that have to do with the rise of supply (e.g. LNG liquefaction, regasification capacity and vessel fleet) are incorporated in the bigger natural gas 'picture' and cannot be isolated. Still, research is needed to understand and review the shifts and major trends attributable to growing shale gas production. This chapter is an econometric, exploratory survey that studies the available qualitative evidence aiming to interpret the inclination of the energy market, its future behavior and identify areas of further study as the shale gas progresses into mainstream on a global scale.

5.1 Geo-political implications of shale gas

Global shale gas resources

Shale gas development is having a steadily increasing influence on regional and world markets. Just by isolating the most notable case of US shale development and the serious country-world balance changes it brought, one can understand why it is important to think globally. Estimating the quantity, location and availability of the world's shale gas resources is a difficult task. The industry is still at a learning phase when it comes to shale outside North America. Although undoubtedly large, unconventional resources are poorly known in terms of quantity extent, judgment on possible extraction and technological adjustment to distinctive field challenges. Estimations include the very wide range of uncertainty of this early development stage. Estimating methods, subjectivity, difference in perception of basic definitions and data interoperation, combined with this uncertainty frequently lead to vague, improperly verified and contradicting results. A basic source of data and research had to be followed and IEA was deemed creditable and chosen (IEA was also the first to record unconventional data in 1995 and present them in 1997). One final point of notice must be drawn to attention before finally getting to the shale gas estimates. Our experience and understanding of the resource base grows with the development conducted. From the year 1995 and up to 2006, IEA US shale resource predictions were relatively steady and around to 7-10 tcm. In the 2006-2011 timeframe, when development turned mainstream, these estimates increased by 200% (24 tcm). So, according to IEA this is the 2012 estimate of conventional and unconventional natural gas resources global distribution:



Attention must be drawn at the difference between the terms 'resource' and 'reserve'. When talking about resources we are referring to one or more of the following:

- Original gas in place, OGIP; it is the total volume estimated to be present in a given region.

- Ultimately recoverable resource, URR; it is the sum of all gas expected to be recovered from a region over all time.

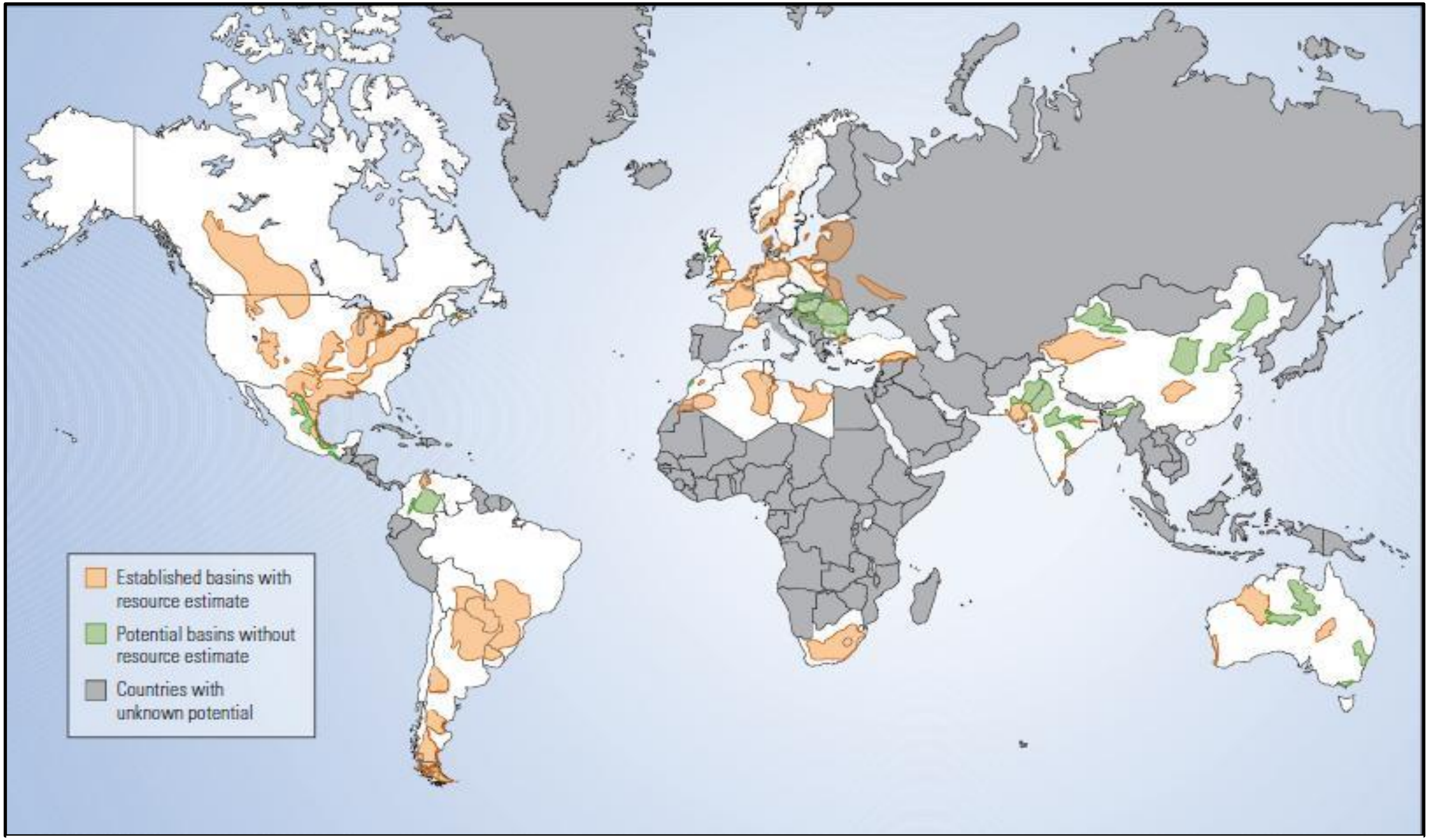
- Technically recoverable resource, TRR; it is the fraction of the gas in place that can be recovered with current technology.

- Economically recoverable resource, ERR; it is the portion of the TRR that will be economic to recover (low production rates and high cost fields are some of the economically not viable examples excluded from the ERR calculations).

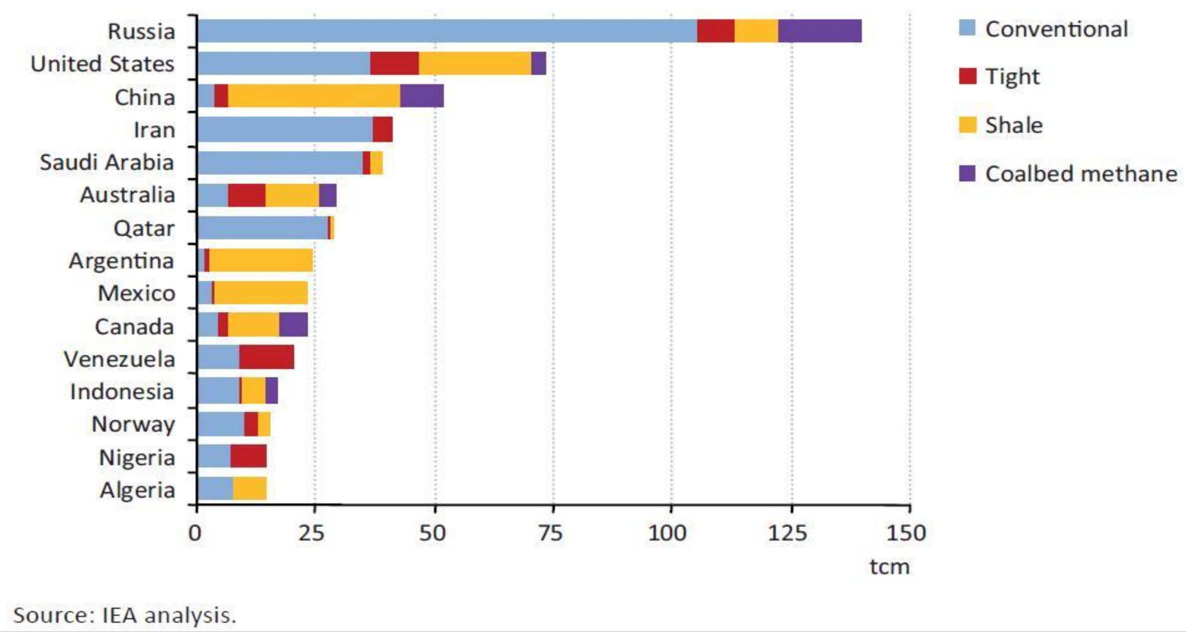
In all these categories ambiguity remains over whether the estimates include undiscovered volumes of gas (usually they do) and how they define the term 'undiscovered'. There seems to be little assumption basis about the exploitation viability of regions that have not been yet found, drilled and examined. In our case, taking into account the fact that usually shale gas plays tend to overlie conventional oil and gas wells, the potential for locating truly undiscovered resources is greater in countries with relatively little history and experience in onshore production. Furthermore, considering that extensive geological mapping of the underground has been conducted in many countries, we can (rather safely) presume that currently undiscovered fields will be overshadowed by discovered but not yet developed ones.

In the map above, IEA is referring to 'the total amount of recoverable natural gas resources', URR and in its speculations takes into account undiscovered areas.

Reserves are generally perceived and defined as those portions of URR that have been discovered and are estimated to have a specified probability (P1=90%, P2=50%, P3=10%) of being produced.



Global shale gas resources
(EIA estimation; scarcity of data led to exclusion of purple highlighted areas)



Remaining TRR in top fifteen countries (2011)

	Total		Unconventional		
	Conventional	Unconventional	Tight Gas	Shale Gas	Coalbed methane
E. Europe/Eurasia	131	43	10	12	20
Middle East	125	12	8	4	-
Asia/Pacific	35	93	20	57	16
OECD Americas	45	77	12	56	9
Africa	37	37	7	30	0
Latin America	23	48	15	33	-
OECD Europe	24	21	3	16	2
World	**421**	**331**	**76**	**208**	**47**

Source: IEA analysis.

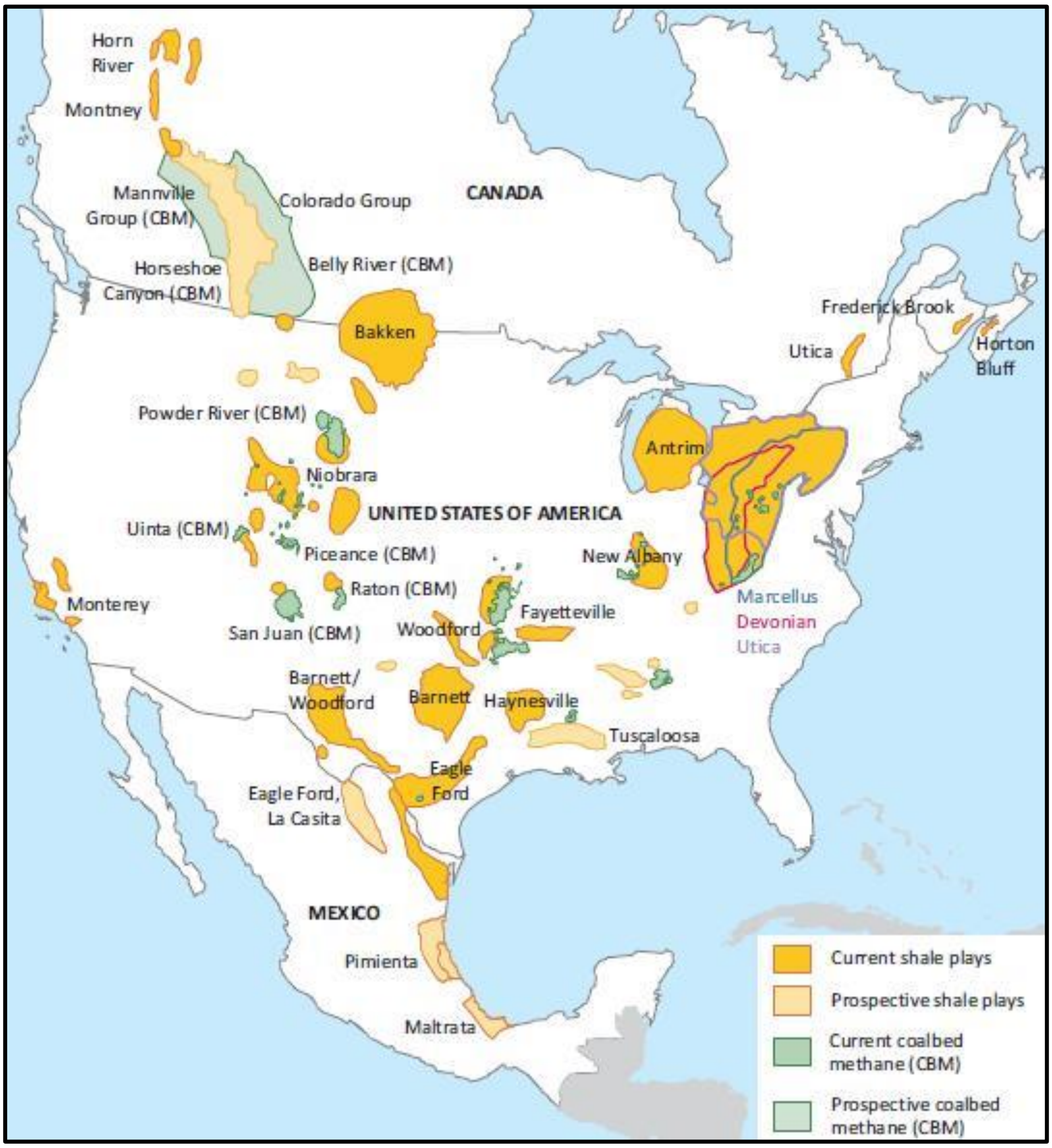
Remaining TRR by type and region (2011)

Russia and the Middle East countries (Iran-Saudi Arabia-Qatar) are the largest holders of conventional natural gas followed by the USA. Shale gas and other unconventional resources are absent in the Middle Eastern region (this has a logical explanation since the abundance of conventional gas in the area shows that the gas produced in the underground found easy access to higher formations and didn't remain trapped). Russia has the largest overall share of gas resources. The US of America almost doubles its natural gas resources when adding the unconventional ones. This is also the case with Europe. China -who has almost no conventional natural gas- has a potentially huge share of shale gas resources (though the exact number presented is debatable and the Chinese government's estimation is smaller by 20%). Australia presents a strategically important unconventional/shale gas resource.

5.1.1 Regional and country lookouts

This section is dedicated to the presentation of regional and country lookouts of all potentially major shale gas players and shale-affected parties.

America - North America



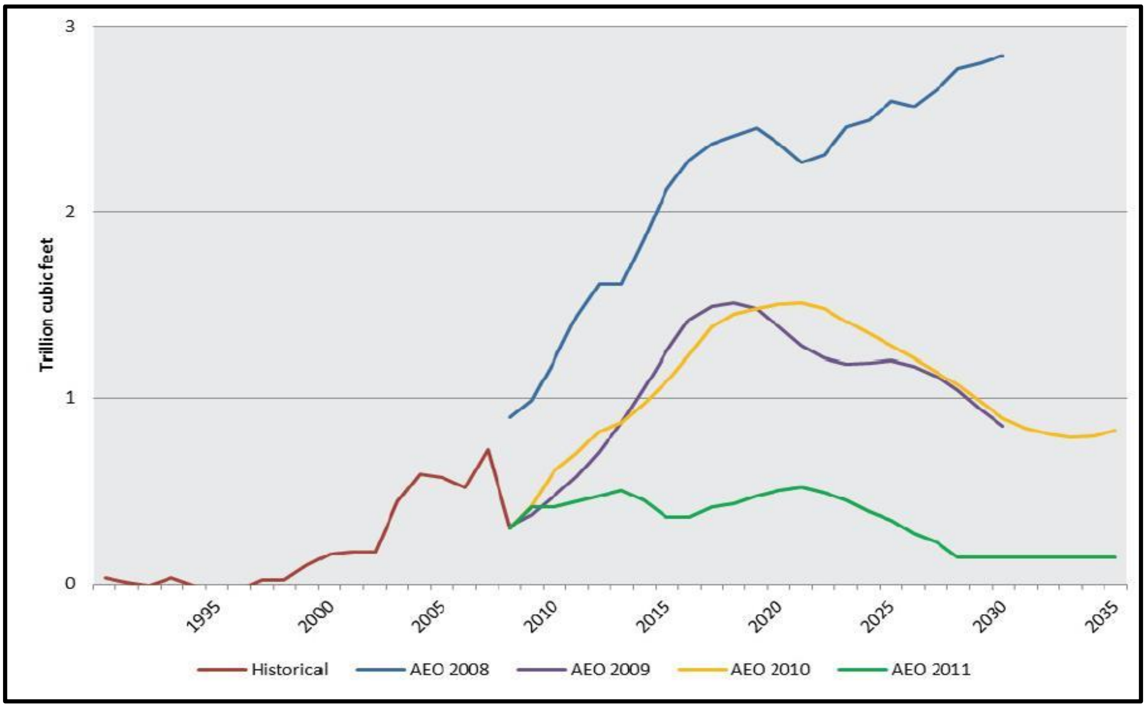
Major unconventional resources in North America

North America - United States of America

Naturally, this 'Country and regional outlook' section starts with the two countries that account virtually for all commercial production of shale gas in the world: USA and Canada. USA traditionally relied on oil, natural gas and coal that were abundant and thus less expensive. Renewable energy was -and still is- considered a secondary small-scale option in the total energy mix. In the years prior to the shale gas commercial exploitation (up until about 2006), a sharp decline in domestic energy production was anticipated and USA considered alternatives such as increasing Canada and LNG imports. Instead, there was a sudden surge of energy owed to the 'shale gale'. The unpredicted rapid commercialization of large-scale shale gas production delivered a series of major changes that affected regional and world markets.

First and foremost, shale gas potential is considered strong enough to make USA energy self-sufficient for the next 100 years. The numbers seem to partly justify this optimistic view: From 2005 to 2010, shale gas production has increased at an amazing 45%. Unconventional natural gas is now 60% of the whole natural gas production and natural gas holds more than 25% of the energy mix, surpassing second-place coal and aiming to overtake oil in the mid-term. IEA's latest forecast predicts a 0.9% shale gas growth rate for the next 25 years that will lead to 656 bcm in 2020 and 737 bcm in 2035. The Marcellus and Haynesville shale plays have been identified as two of the largest reservoirs in the world. Even original dismissive OPEC and Russia have now acknowledged the importance of the shale effect. Of course the positive results so far cannot wash away all skepticism and uncertainty; environmental impacts, implications of the new post-shale global market status quo, unpredicted implications in the US production and the fear of oversupply with not enough demand are just some of the topics under consideration.

Energy self-sufficiency resulted in complete reversal of the USA's anticipated role in the world market. It was initially expected that USA would begin to import substantial amounts of LNG. These expectations led to massive infrastructural investments that would be needed to import and process liquefied gas and regional market started to prepare itself for an LNG surge. All predictions were disproved and USA ended up importing only around to 13 bcm of LNG in 2009, while having prepared an infrastructure with nearly 150 bcm re-gasification capacity. Nowadays, USA orientates its strategy towards adjusting this grand infrastructure (along with its internal massive pipeline network) with enhanced export abilities that will direct underused LNG to other importing countries (most notably the EU).



Historical and projected net US LNG imports

The 'shale gale' has had a profound economic impact in the USA interior providing more than $118 billion in GDP. Shale development industry significantly contributed to US employment with more than 600,000 jobs (expected to reach 850,000 by the year 2015). Development has bolstered federal, state and local tax revenue. Consumer natural gas and electricity cost has been seriously reduced. Finally, cheap gas is reinforcing the trend of 'repatriation' of industry providing additional gain in other field of investment.

On the environmental side, the increase in natural gas use has lowered the US CO_2 emissions by more than 10% from the 2005 baseline. Pro-shale parties advertise this as an eco-friendly advantage of natural gas, promoting it against competing fossil fuels. Yet, serious study and re-evaluation, under the scope of long term effect, of the natural gas's GHG methane emissions have to be conducted to reach a conclusion on the subject.

The final major US shale impact, already mentioned briefly above, concerns the coal production of the country. Turn to natural gas made the coal sector adjust in two ways: Reduce col production in 2012 by 10% (100 million tons) and direct coal abundance of 25% (66 million tons) to other markets, most notably Europe.

US are the birthplace of shale gas development and its leading pioneer. The country's behavior is expected to affect patterns of trade, production and climate policies in a global scale.

<u>North America - Canada</u>

Canada is the third largest natural gas producer (following second USA and leader Russia) with an average annual production of 180 bcm. Canada has always been a traditional key supplier of natural gas to the USA. In-house needs are easily satisfied and more than 50% of production is exported towards the neighboring country.

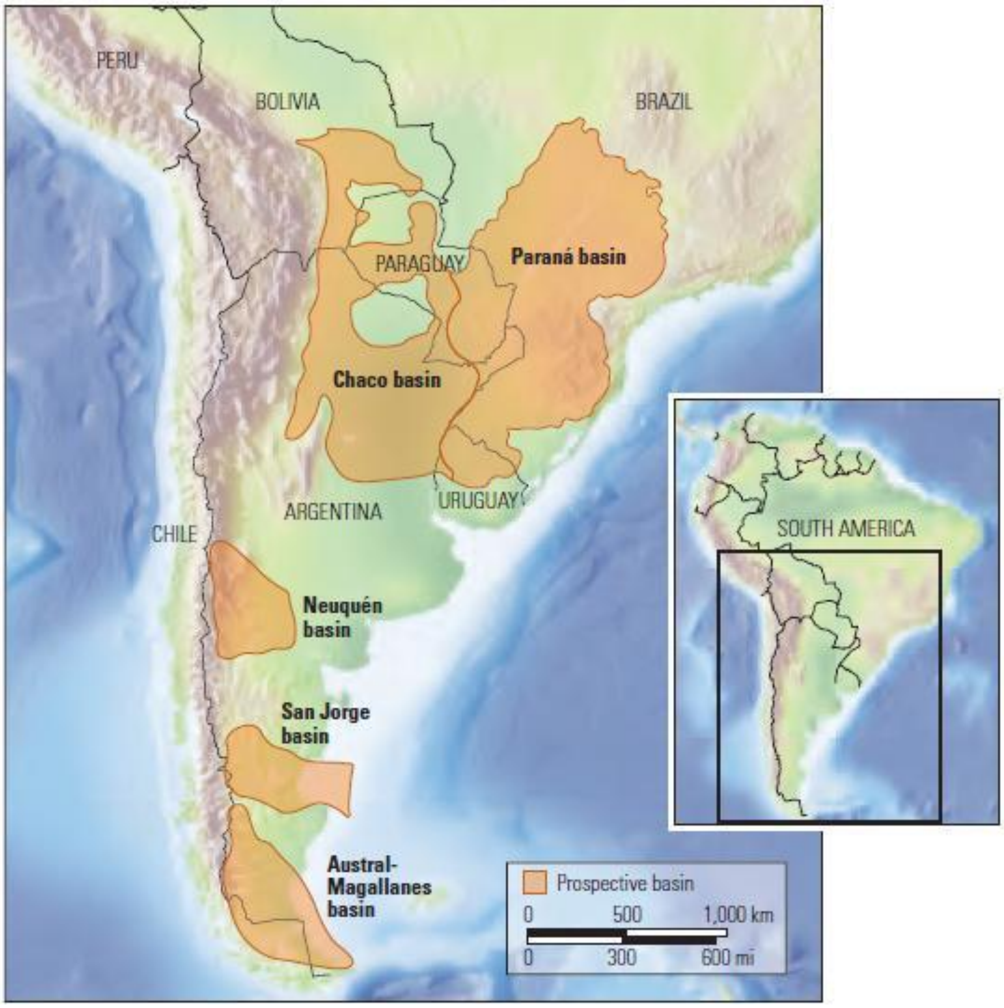
Canada is endowed with large unconventional gas resources of all three major types and while shale production is currently 3 bcm (tight is 50 bcm and coalbed 8 bcm), it is considered the unconventional with the greatest long term production potential. Conventional production is declining steadily and 80% of Canada's total remaining recoverable gas resources are unconventional (estimated 12 tcm of shale gas, 3 tcm of tight gas and 7 tcm of coalbed methane).

Adjusting to the times, Canada strives for two strategic changes: establishing and promoting shale-unconventional development and directing its extra production to new, LNG reachable importers, compensating the loss of the now energy self-sufficient USA. Large-scale commercial shale gas production has not yet started, but development explorations are carried out in Alberta (Colorado Group), British Columbia (Horn River Basin and Montney Shales), Quebec (Utica Shale) and New Brunswick (Horton Bluff Shale). A preliminary drilling testing in the Eastern providence Utica Shale suggests the possibility of a large resource; and while there is no production infrastructure in Quebec, proximity to the US market completely makes up for its lack. Generally, these resources require a relatively long lead time for their development, production and deployment as optimal technologies and the pace of development will be determined by natural gas prices. A $5 billion investment of turning the -originally intended for importing- LNG Kitimat terminal into an exporting one with all the necessary liquefaction facilities is due for completion in 2015. Canada aims at exporting to the energy thirsty Asian market (Japan, South Korea and China) but will have to compete fiercely with Australia.

North America - Mexico

In 2012 Mexico was 9th in the global oil production chart (IEA) and 16th in natural gas (CIA world factbook). It is estimated to have the fourth largest shale gas base in the world (19 tcm). While there are multiple scenarios and will for exploitation there is also serious doubt as to the viability of the venture. The largest shale play, Eagle Ford, is located in Coahuila, one of Mexico's driest states. Water reserves are needed for agricultural and other uses and fracking on a commercial scale has to overcome this crucial obstacle.

America - South America

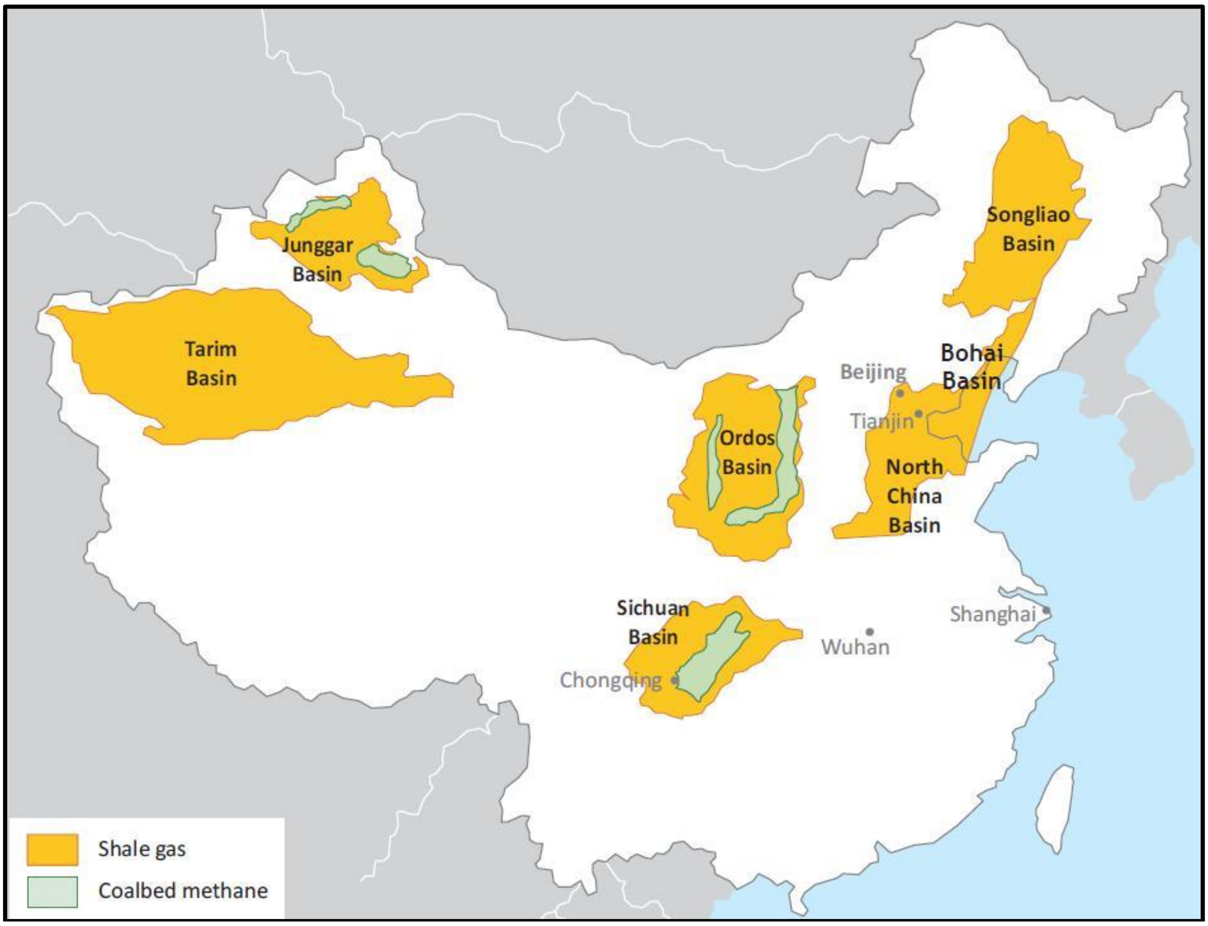


Major shale gas resources in South America

South America - Argentina

Argentina, that is currently facing economic problems, relies heavily on expensive natural gas imports from Bolivia and Qatar. Preliminary explorations in South America suggest that, along with Brazil and Colombia, it may be sitting on large shale resources (21.9 tcm TRR out of 77 tcm OGIP). Argentina is the only South America country that is seriously considering the shale gas direction and focuses on the Neuquén Basin. If, in some point in the future, the country manages to take advantage of the potentially (Mexico-level) high shale resource it would definitely strengthen its position both on the inside and outside.

Asia



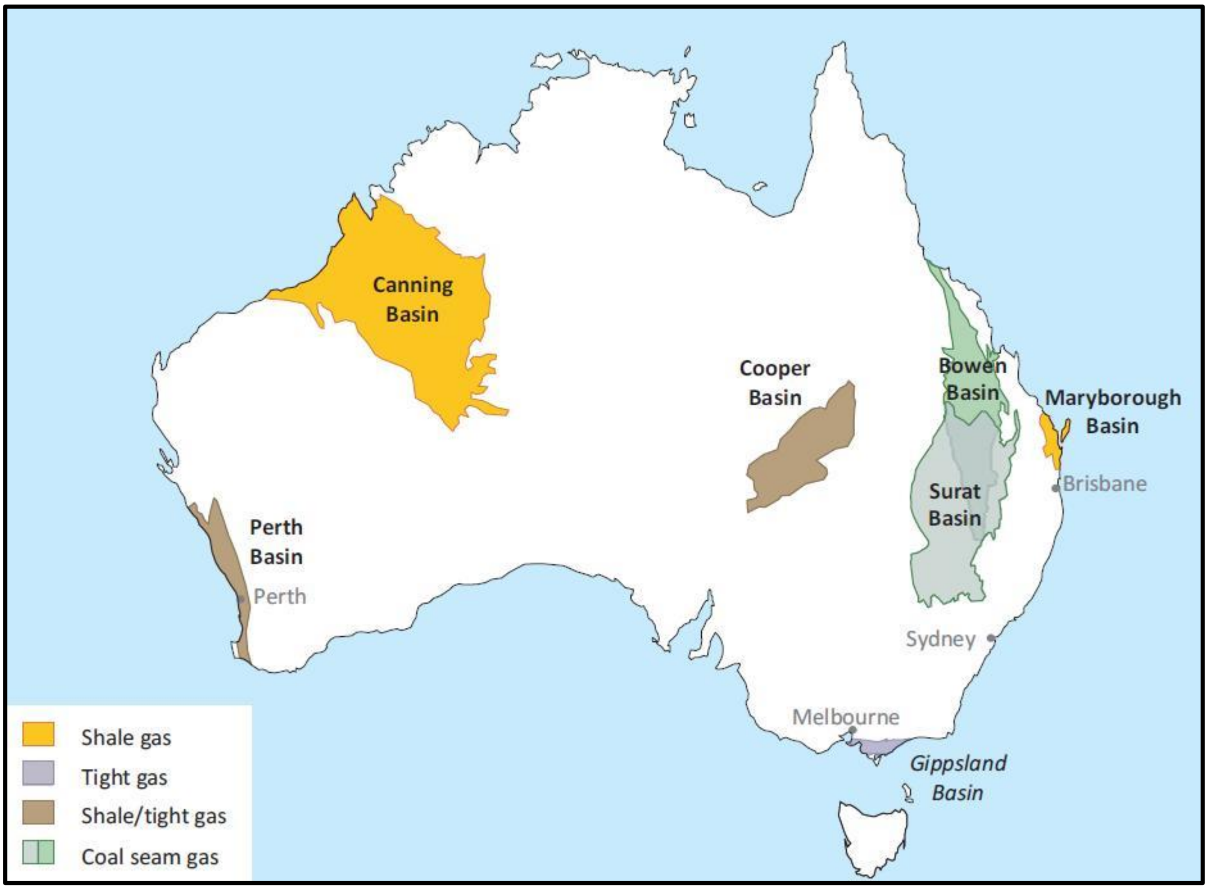
Major unconventional natural gas resources in China

Asia - China

China is the country with the rapidest growing economy in the world. It has huge energy thirst that can, by no means, be satisfied by the conventional resources of oil and gas it processes. It is thus one of the major Asian energy importers, along with South Korea and Japan. In 2010 the Chinese government began exploring shale gas production. The country is estimated to have tremendous shale resources potential (134 tcm in OGIP and 36 tcm in TRR); this is more than double the shale resources of the US and even tops combined US and Canada resources. It is also 13 times more than China's own remaining conventional URR. Coalbed methane is so far the dominant unconventional source being produced (output of 10 bcm in 2010). Yet, China has launched a shale exploration boosting program in partnership with foreign firms (most notably, PetroChina in collaboration with Shell oil) to acquire the know-how, define the potential of the shales and start production. Despite ambitions for a 6.5 bcm shale production by 2015, North American shale gas will continue to dominate for the years to come. Based on early stage exploration, China's geology presents difficulties in shale development that translate into higher cost. Kerogen quality indicates low organic content in the shale gas, meaning that for a similar to North American output more development has to be conducted. The biggest of all obstacles is the water availability - hydraulic fracturing issue. Even in areas in which water resources aren't scarce, they are reserved for agricultural and urban needs with little to no margin for use elsewhere. On the upside (at least as regards production and not environment), China's highly centralized regulatory framework places high priority on industrial and economic development and shale projects might encounter far less environmental-related halts.

China is not expected to join the shale revolution in a significant manner for the time being and will continue to rely on imports from old (Russia) and new (Australia) exporters. This weakness to follow shale from the begging is very likely to be exploited by the grown economies of the Western world that fear the rates of China's growing economy. While China continues to base its production to imported conventional energy, Europe and USA can counterbalance the overwhelming Chinese rates by utilizing the advantages shale gas offers to their markets.

Oceania



Major unconventional natural gas resources in Australia

Oceania - Australia

Australia has significant conventional and unconventional natural gas resources and an overall annual production of about 45 bcm. While the potential to become a major shale developer is moderate (to low), Australia's key position in combination with its limited domestic demand and large natural gas production makes the country a strategic player in energy world market.

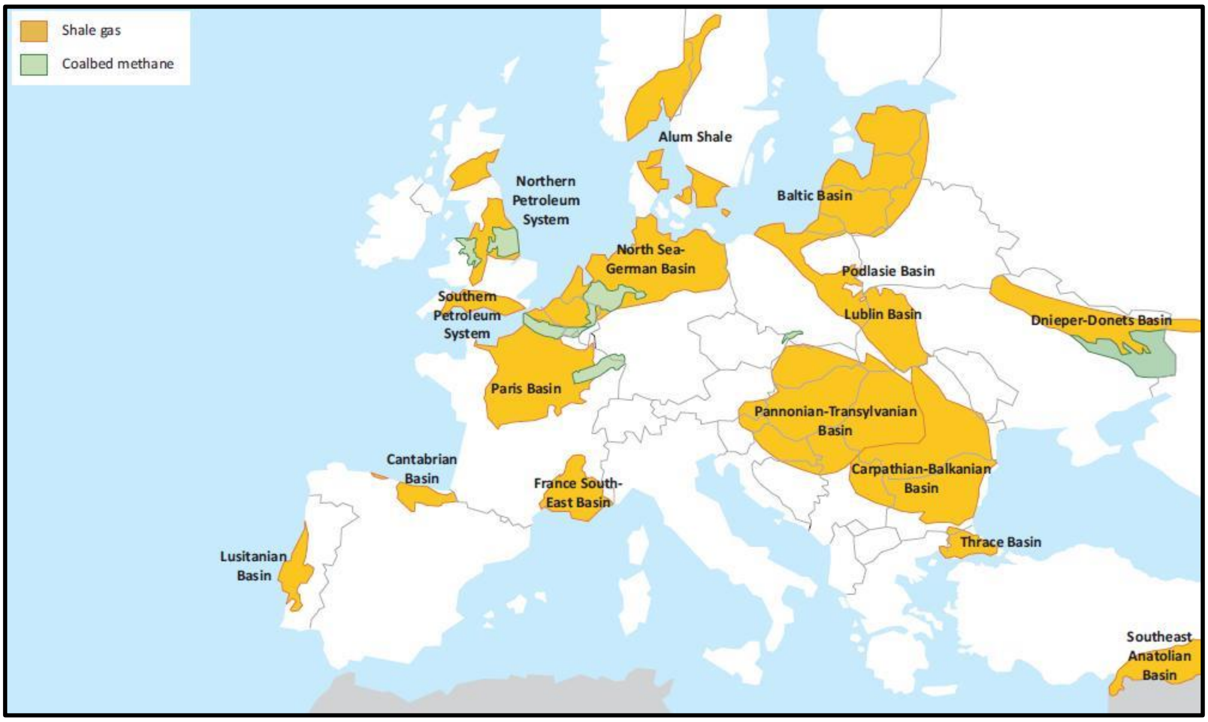
From 1996 and onwards Australia has invested in the production of coalbed methane. In 2010 output reached 5 bcm, accounting for about 15% of the country's energy consumption. Virtually all coalbed methane is produced in the Bowen and Surat basins in the Queensland and New South Wales states (Australia is divided in six states). Natural gas in-house promotion is indicated by the Queensland's government climate policy that requires 13-16% of the energy needed is gas-produced. Political and public worrying about the environmental impacts of unconventional development have somewhat slowed down production rates.

Remaining tight gas URR is estimated at about 8 tcm in the areas of Perth, Cooper and Gippsland Basins. Proximity of these locations to already existing conventional gas infrastructure makes the production more cost efficient.

Shale gas is estimated at 11 tcm and mostly found in the Cooper, Perth and Maryborough Basins. Shale exploration is in an immature infancy stage and its current economic viability is uncertain. The first vertical shale well was drilled in 2011. The reasons of shale-pessimism derive from: the very high cost of production (almost three times that of the US cost); environmental concerns about fracking; lack of infrastructure in the shale basins; lack of shale expertise; and finally very tough competition with coalbed methane.

The abundance of natural gas (owed mostly to coalbed) has led to a number of -$40 billion in total- investments in LNG exporting facilities. Four large LNG plants are under construction: Queensland Curtis (BG), Gladstone (Santos), Australia Pacific (Origin and ConocoPhillips) and -almost completed- Arrow (Shell and PetroChina). This will virtually double Australia's exporting capacity to 29 bcm. Australia aims to export to become the number one exporter to the hungry nearby importing markets of Malaysia, Taiwan, (post-nuclear) Japan, South Korea and of course China.

Europe



Major unconventional natural gas resources in Europe

In the last few years, Europe has started considering the prospects of unconventional natural gas development from its resources. At first interest was focused on coalbed methane and tight gas, but after the US 'shale gale', attention is shifted towards shale. France and Poland are estimated to have the largest shale gas resources, followed by Norway, Ukraine, Sweden, Denmark and the UK. Yet, development is somewhat doubtful for reason to be explained.

The European Union is among the three largest natural gas consumers. In 2011 -a year in which production was halted by the ongoing economic crisis- EU fell from second to third consumer's ranking with demand amounting to about 460 bcm. Demand in the long term will increase again leading to dependency on new imports. Europe possesses a well-established natural gas pipeline system and a market that encourages investments (since price is balanced, higher than US but lower than Asia).

Western Europe

In Western Europe there have been estimated sizable quantities of shale gas (and coalbed methane as well). Exploration has begun to occur in the form of joint ventures that promote know-how acquiring and lower the investment risk. Despite the optimistic outlook as regards the European shale resources, development is not considered possible any time soon, at least not in a large-scale commercial sense. Greater world competition, varying shale-initiative, complicated geopolitics, high production cost, lack of expertise and low margins consist part of the hesitation investors express. Environmental concern that has been stirred up, even before fracking reached Europe and the high population density in many of the prospective (industry-virgin so far) areas are two great boundaries development must overcome to reach commercial status. Regulation and legislation haven't been updated and adjusted to the new shale needs, resulting in further development problems.

Western Europe - France

France was expected to be one of the first European countries to jump on the shale train, along with Poland, because of the great shale resource estimations in the Paris Basin in the North of the country and the Southeast Basin. In the early 1980s high expectations conventional drilling was conducted in the Paris Basin, but the results of very low oil production were discouraging. Some geologists argue that the targeted fields weren't discovered because gas and oil in the region are still trapped in the 'unconventional' formations below. Due to strong public opposition over the potential environmental harm of fracking, a moratorium on hydraulic fracturing was issued in 2011 and two out of three development permits that had been granted by the government, were revoked (the third was altered so as to prohibit the h.f. treatment). Public concern would have been high either way, but it was further provoked by the dangers fracking could impose in the grand tourist industry near the basins and the lack of public consolation.

Western Europe - United Kingdom

The Bowland shale formation in the UK is estimated to hold as much as 5.7 tcm of RTT. It is development and investor friendly since relatively shallow (average depth of 1600m) and in certain areas rich in liquids. As we have already seen in Chapter IV, operations were suspended due to two earthquakes that might have been linked to the hydraulic fracturing treatment. It is clear that the UK government supports shale gas development. UK has been at a tough energy spot before and favors pluralism in the energy mix; were it not for the timely development of the offshore conventional reserves of the North Sea it would have faced enormous troubles in the past. Drilling processes and hydraulic fracturing treatments are to be conducted with strict monitoring to ensure the environment and the operations.

Western Europe - Sweden

The Scandinavian Alum shale doesn't include only Sweden. It extends from Norway to Estonia and from Germany to Poland. Shale oil has been produced from the basin in the past decades but, lacking overpressure and containing a high concentration of Uranium, shale gas production is proving to be a difficult process that requires technological optimization and economical investment. Shell was persistent in developing shale gas but the deposits were proven dry and due to high cost dropped out.

Western Europe - Germany

Germany has a great 20 year experience in tight gas and hydraulic fracturing methods to extract it. It has moved towards researching and developing potential shale resources with several companies (among them energy giant ExxonMobil). Despite previous experience, strong opposition against shale hydraulic fracturing has occurred. Germany, that recently abandoned nuclear energy, is determined to proceed in finding alternative domestic sources of energy.

Eastern Europe - Poland

In Eastern Europe potential shale resources are estimated mostly in Poland, Ukraine, Lithuania and Bulgaria. Bulgaria and Lithuania development is not going to happen any time soon. Bulgaria forbade hydraulic fracturing due to public demand and Lithuania has paused all operations and agreements to create a sufficient legislation framework. Ukraine is in a difficult and complicated geopolitical position as regards Russia and moving to shale is a risky choice that might not be entirely up to her to decide.

Poland is the European country that is more actively seeking to exploit its estimated 5.3 tcm shale resources and diminish expensive Russian imports. Poland has a long history in petroleum industry (one of the oldest in fact) and is seeking a way to revive domestic energy production that has declined over the past decades. It has established cooperation with field giants such as ExxonMobil and Chevron and is moving to change its regulatory framework to include the prospect of commercial shale production.

Europe - Conclusion

Shale gas development in Europe is being considered as a concept. There are many difficulties development must overcome in order to reach a mainstream status, but even if Europe succeeds, this success will be partial. A 2012 report from the European Commission states that, unlike the United States, *"Shale gas production will not make Europe self-sufficient in natural gas. The best case scenario for shale gas development in Europe is one in which declining conventional production can be replaced and import dependence maintained at a level of around 60%"*. The case of the USA differs greatly. The US shale gas boom is based on an efficient gas market, flexible pricing and large indigenous unconventional resources. But the energy market is a global one and the impacts of shale gas in Europe can be indirect and at the same time very important. Europe is dependent on energy from Russian and Middle Eastern imports. The last few years it has tried to diversify importing sources to secure energy safety and lower costs. In 2006 a major dispute between Russia and Ukraine (in the aftermath of the 'Orange revolution') disrupted Russian gas supply in the EU and showed the vulnerabilities of its importing system. One attempt is the Forth corridor (that features recently decided TAP) aiming at bringing non-Russian gas to Europe from former Soviet Union countries like Azerbaijan. Of course in-house shale production can be helpful to domestic use but, unless the current data change significantly, the impact will be regional and not European; and of course Europe is waiting to see if US will play the role of the exporter towards EU now that the first has secured self-sufficiency and has gas abundance. In this likely-to-happen scenario shale gas from Europe will not be able to compete with imported natural gas from the US. So while developing -with a lot of uncertainty- shale gas is regarded as a small scale regional production. But the new shale equilibrium works in favor of Europe in the sense of providing better importing alternatives and conditions. The 'shale gale' delivered a major impact in the LNG market, making it finally global. As regards Europe, along with domestic production it can choose to import from a very wide variety of providers: US will most probably be exporting LNG; supplies from Qatar and other producers, originally intended for US imports, will be also free; LNG will finally be affordable and provide a solid spot-priced alternative to pipelines. Russia's influence will be strongly lessened. Diversification and flexibility will lead to price drops from the traditional exporters of Middle East and Russia (that would prefer to export to nearby EU market).

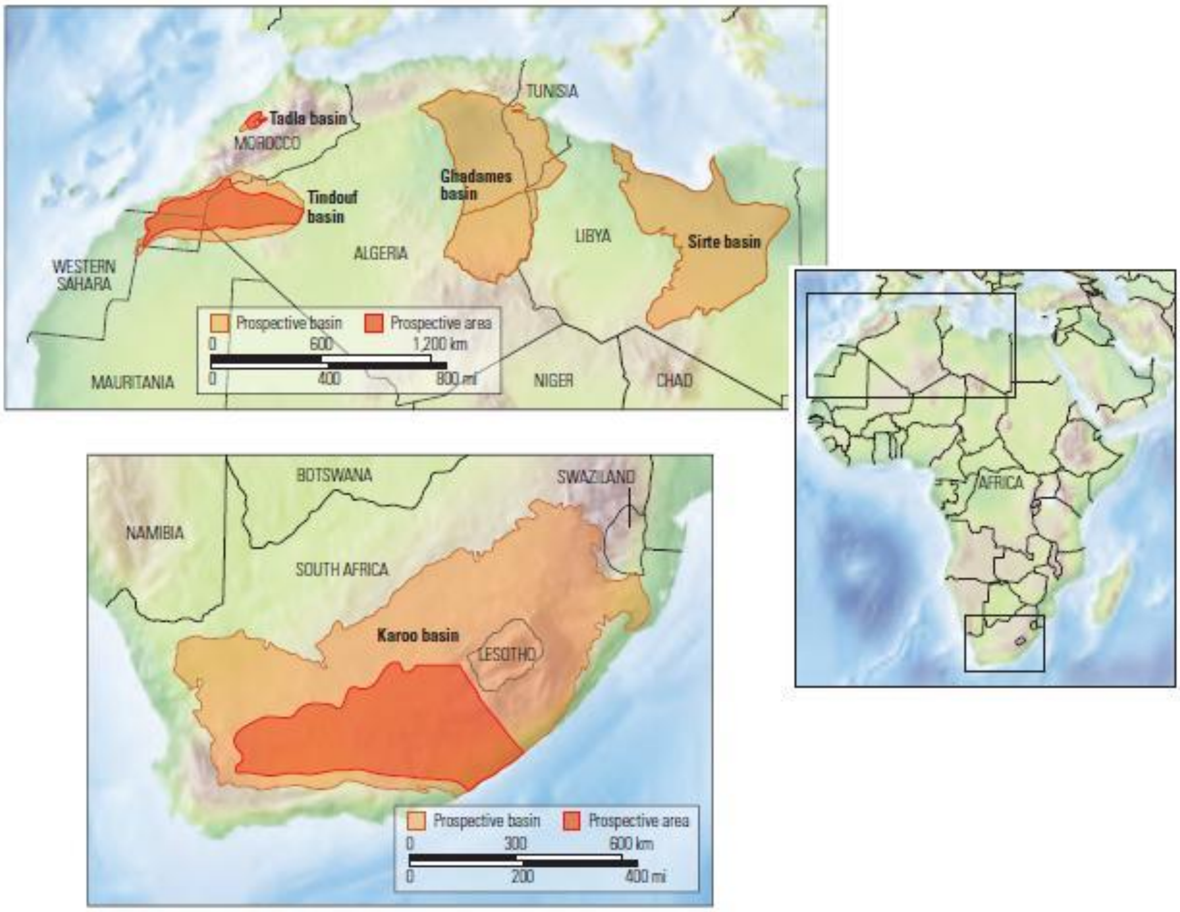
All the above are very likely to happen, but are still speculations. One should not forget the fear of political implications, ultra-low prices or overabundance in LNG that could tap the natural gas market equilibrium out of order. Yet, it is my opinion that shale directed the market towards a more fragmented and competitive order and the complex mechanism set in motion is irreversible; in the (near?) future energy importing countries, that will also utilize significant domestic resources, will be able to balance their imports with regional exporters and global players.

Eurasia - Russia

Russia is the world's top natural gas producer with an average annual production of 670 bcm. It has an estimated conventional TRR of more than 110 tcm and an unconventional of 35 tcm. It is one of the major exporters of energy in the world along with Saudi Arabia and Venezuela. The unexpected shale and unconventional development in other regions of the world affected the country greatly since the new supply and market conditions disturb Russian exports. Originally dismissive of the shale gas potential, Russia is changing its policy towards consuming importers. So far, Gazprom *see note* would provide 60% of its production relatively cheap for domestic use while selling the rest 40% abroad with a wide margin. The company would insist -especially when dealing with the EU- on longstanding arrangements, in most cases linking oil price to gas. Oil product linkage was established in the 1970s on the principle that the price of gas should generally be competitive with the prices of alternative (non-gas) fuels. Now Gazprom has succumbed to the pressure of EU (mostly LNG) diversification and tends to amend previous contacts to a more spot-purchase, short term form. Meanwhile, trying to secure basic exporting and geopolitical balances Russia is actively slowing down shale gas development in neighboring countries. Gazprom recently made an agreement with ExxonMobil exchanging cooperative development of oil in the Artic for an Exxon withdrawal from a Polish shale project. It also required technologic shale know-how from ExxonMobil. In 2013 Russia bought from Ukraine $7 billion worth of natural gas it did not need after Shell had announced a $10 billion Ukrainian shale investment. The new energy conditions are going to divert some of Russia's exports to the Asian markets.

Note: Gazprom was created in 1989 when the Ministry of Gas Industry of the Soviet Union transformed itself into a corporation. Later on it was privatized in part, but currently the Russian government holds most of the control (90%) in its hands.

Africa



Major shale gas resources in Africa

Due to the presence of untapped conventional resources in Africa, there has been little exploratory activity as regards unconventional and shale gas. The majority of the basins identified are either located in North Africa (Morocco, Algeria, Tunisia, and Libya) or South Africa (South Africa). Continental Africa remains virtually unexplored; data regarding shale gas resources are nonexistent and are likely to stay that way for the years to come. South Africa is the country that is actively pursuing shale gas production with major and independent E&P [*exploration and production] companies working in the field. The Karoo basin has been estimated to bare a significant volume of organically rich, thermally mature, dry shale gas (13.7 tcm TRR, 51.9 tcm OGIP). Energy dependent Morocco along with Algeria have also started conducting exploratory research but are still at a very early stage.

5.2 Shale gas implications on LNG shipping

The shale gas implications can be categorized in many ways: direct and indirect, current and future, probable to happen and improbable (and to what percentage), regional and global etc. When studying these implications, along with the helpful categorizations, we must keep in mind that shale gas production is part of the larger natural gas market (which in turn is part of the global energy commerce) and as such cannot be regarded as something independent and stand-alone. Shale implications interact constantly in a complicated manner with the rest of the energy market and their dynamic depends heavily on the combinations of conditions, situations and effects that can occur. In sub-chapter 5.2 we are going to try to approach the possibly emerging shale gas - LNG market implications that affect LNG shipping, taking into account the changes shale gas delivered in the geo-political strategy field presented in 5.1 and the market's current status and inclinations.

As already stated, virtually all commercial shale gas production takes place in USA and Canada. In order to assess future shale prospects and implications we choose the current shale implications as a starting point and expand upon accordingly.

The growth of US shale gas production has so far emerged as a shock to the LNG system for two main reasons:

- Firstly, it has become clear that USA became natural gas self-sufficient and didn't have to resort to LNG (or Canadian pipeline) imports. Fifty and hundred-year uncertain speculations aside, USA will not be importing significant LNG volumes over the next decade. In the first years of the shale gale a natural gas glut occurred due to the extra shale gas supply (directed towards US domestic consumption) and the unused, originally US intended, LNG volumes. The later were absorbed by the unexpected energy needs of Japan after the Fukushima incident. This fact goes to demonstrate how complicated and unpredictable the LNG market is. On a regional level, the shale gas boom has affected Canadian and Mexican energy markets and on a global one the LNG volumes and trade-flows targeted towards the USA. It must be underlined that so far no shale gas LNG exports have taken place. Even the USA exports that are considered definite to happen are expected after 2015-16. The ones that have taken place concern natural gas originally imported by the United States in anticipation of domestic energy production decline (re-exports) and not produced shale gas. This means that while shale gas will drastically affect and change the LNG market's structure globally, the rebalanced picture of the new LNG network is currently in the making and cannot be presented in detail beforehand.

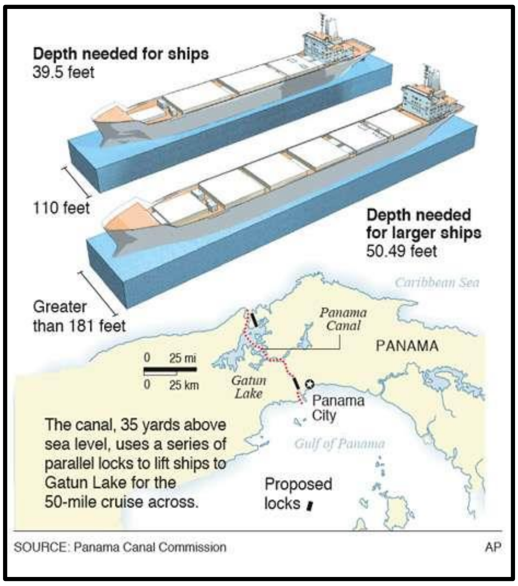
- Secondly, shale development delivered (constantly growing) uncertainty to the LNG market over whether other countries will be able to replicate the US shale boom and reduce their own need for imports while cultivating the thought of becoming (mostly regional) exports. The North American shale gas revolution has proven to be sustainable and seems robust. Yet, this is the result of a great number of factors coming together: *a prime resource base, large service sector capacity, favorable pricing, easy to market gas, clear property rights, a supportive government, etc. These conditions are largely absent in most other places - and even when some conditions are present (for example, high prices), others are not (availability of rigs, people, services or easy access to pipelines or clear sub-surface mineral rights, etc)*

[IGU World LNG report 2011]. Until now, serious exploration has taken place mostly in Poland, Australia, China and Argentina and has led to mixed results. While there is certainly potential, several more years have to pass before activity builds to a commercial level (and only after economic and geologic difficulties have been evaluated and overcome).

From the above, we can draw an outline of the ways shale gas (due to new importing-exporting equilibrium and potential extra supply) might and most probably will further affect the LNG market's structure. This outline consists of three linked but distinct braches: LNG trade-flows, LNG market structure and pricing and LNG vessel fleet.

LNG Trade-flows

The LNG trade-flows comprise a complicated network that is constantly interacting with a vast number of factors (geopolitics, economy, global & regional commerce conditions, energy security and strategy, technological innovation etc.). Setting aside shale gas production, the globalization of natural gas (analyzed in the following 'price' section), Asian rising market and eco-consideration along with recent developments are bound to drastically affect the LNG trade-flows on a global scale. While we cannot know the way shale gas is going to fit in the equation, it is definitely expected to cast its influence significantly and in more than one ways. A shining example of the difficulty in predicting the combined effects of more than one factors manifesting simultaneously that concerns shale gas is the Panama Canal expansion: In 2007 the reshaping the Canal began in order to accommodate larger vessels with shipments travelling from Asia to US without any shale consideration related to the gigantic project. After the US shale gas boom the Panama Canal expansion is sure to be central to US LNG exports anticipated after 2015. US (whose natural gas price is low in regional market) will target energy hungry Asian markets and use new-generation Panamax LNG carrier (e.g. MHI "EXTREM") travelling through the Panama Canal and cutting voyages by more than 7,500 nautical miles (8,500 miles). Thus, shale gas production in US in this case affects greatly not only trade-flows, but also LNG vessel orders and order characteristics.



LNG Trade-flows - 2012 LNG trade overview

A coherent picture of the present LNG and natural gas market is essential for any study on future shale trade-flow implications. "BP Statistical review of world energy 2013" offers all the data required for understanding the current market conditions (importers, exporters, LNG-pipeline comparison and trade-flows):

Billion cubic metres	From																					
To	US	Canada	Mexico	Bolivia	Other S. & Cent. America	Netherlands	Norway	United Kingdom	Other Europe	Kazakhstan	Russian Federation	Turkmenistan	Other Former Soviet Union	Iran	Qatar	Algeria	Libya	Other Africa	Indonesia	Myanmar	Other Asia Pacific	Total imports
US	–	83.8	†	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	**83.8**
Canada	27.5	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	**27.5**
Mexico	17.6	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	**17.6**
North America	45.1	83.8	†	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	**128.9**
Argentina	–	–	–	4.5	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	**4.5**
Brazil	–	–	–	10.1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	**10.1**
Other S. & Cent. America	–	–	–	–	2.3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	**2.3**
S. & Cent. America	–	–	–	14.6	2.3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	**16.9**
Austria	–	–	–	–	–	–	1.3	–	1.6	–	4.7	–	–	–	–	–	–	–	–	–	–	**7.6**
Belgium	–	–	–	–	–	5.2	9.0	4.6	–	–	7.3	–	–	–	–	–	–	–	–	–	–	**26.2**
Czech Republic	–	–	–	–	–	–	3.4	–	–	–	6.6	–	–	–	–	–	–	–	–	–	–	**10.0**
Finland	–	–	–	–	–	–	–	–	–	–	3.1	–	–	–	–	–	–	–	–	–	–	**3.1**
France	–	–	–	–	–	9.4	17.9	–	0.4	–	7.3	–	–	–	–	–	–	–	–	–	–	**35.0**
Germany	–	–	–	–	–	25.3	30.8	–	0.8	–	30.0	–	–	–	–	–	–	–	–	–	–	**86.8**
Greece	–	–	–	–	–	–	–	–	0.6	–	2.3	–	–	–	–	–	–	–	–	–	–	**2.9**
Hungary	–	–	–	–	–	–	–	–	1.1	–	4.8	–	–	–	–	–	–	–	–	–	–	**5.9**
Ireland	–	–	–	–	–	–	–	5.3	–	–	–	–	–	–	–	–	–	–	–	–	–	**5.3**
Italy	–	–	–	–	–	6.8	6.3	–	5.9	–	13.6	–	–	–	–	20.6	6.5	–	–	–	–	**59.7**
Netherlands	–	–	–	–	–	–	8.0	2.1	2.3	–	2.1	–	–	–	–	–	–	–	–	–	–	**14.5**
Poland	–	–	–	–	–	–	–	–	2.0	–	9.0	–	–	–	–	–	–	–	–	–	–	**10.9**
Slovakia	–	–	–	–	–	–	–	–	0.3	–	3.8	–	–	–	–	–	–	–	–	–	–	**4.1**
Spain	–	–	–	–	–	–	2.3	–	0.7	–	–	–	–	–	–	10.2	–	–	–	–	–	**13.3**
Turkey	–	–	–	–	–	–	–	–	–	–	24.5	–	2.9	7.5	–	–	–	–	–	–	–	**34.9**
United Kingdom	–	–	–	–	–	7.3	26.8	–	1.3	–	–	–	–	–	–	–	–	–	–	–	–	**35.4**
Other Europe	–	–	–	–	–	0.6	0.8	–	7.4	–	10.9	–	–	–	–	1.9	–	–	–	–	–	**21.5**
Europe	–	–	–	–	–	54.5	106.6	12.0	24.4	–	130.0	–	2.9	7.5	–	32.8	6.5	–	–	–	–	**377.2**
Belarus	–	–	–	–	–	–	–	–	–	–	18.3	–	–	–	–	–	–	–	–	–	–	**18.3**
Russian Federation	–	–	–	–	–	–	–	–	–	11.0	–	9.9	8.9	–	–	–	–	–	–	–	–	**29.8**
Ukraine	–	–	–	–	–	–	–	–	–	–	29.8	–	–	–	–	–	–	–	–	–	–	**29.8**
Other Former Soviet Union	–	–	–	–	–	–	–	–	–	0.3	7.9	0.9	3.9	0.9	–	–	–	–	–	–	–	**14.0**
Former Soviet Union	–	–	–	–	–	–	–	–	–	11.3	56.0	10.8	12.9	0.9	–	–	–	–	–	–	–	**91.9**
Iran	–	–	–	–	–	–	–	–	–	–	–	9.0	0.4	–	–	–	–	–	–	–	–	**9.4**
United Arab Emirates	–	–	–	–	–	–	–	–	–	–	–	–	–	–	17.3	–	–	–	–	–	–	**17.3**
Other Middle East	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2.0	–	–	0.6	–	–	–	**2.5**
Middle East	–	–	–	–	–	–	–	–	–	–	–	9.0	0.4	–	19.2	–	–	0.6	–	–	–	**29.2**
South Africa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	3.6	–	–	–	**3.6**
Other Africa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2.0	–	0.4	–	–	–	**2.4**
Africa	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2.0	–	4.0	–	–	–	**6.0**
Australia	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10.9	**10.9**
China	–	–	–	–	–	–	–	–	–	–	–	21.3	0.2	–	–	–	–	–	–	–	–	**21.4**
China Hong Kong SAR	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2.8	**2.8**
Malaysia	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2.3	–	–	**2.3**
Singapore	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7.9	–	1.7	**9.5**
Thailand	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	8.5	–	**8.5**
Asia Pacific	–	–	–	–	–	–	–	–	–	–	–	21.3	0.2	–	–	–	–	–	10.2	8.5	15.4	**55.5**
Total exports	**45.1**	**83.8**	**†**	**14.6**	**2.3**	**54.5**	**106.6**	**12.0**	**24.4**	**11.3**	**185.9**	**41.1**	**16.3**	**8.4**	**19.2**	**34.8**	**6.5**	**4.6**	**10.2**	**8.5**	**15.4**	**705.5**

†Less than 0.05.

Source: Includes data from Cedigaz, CISStat, IHS CERA.

Trade movements by pipeline 2012

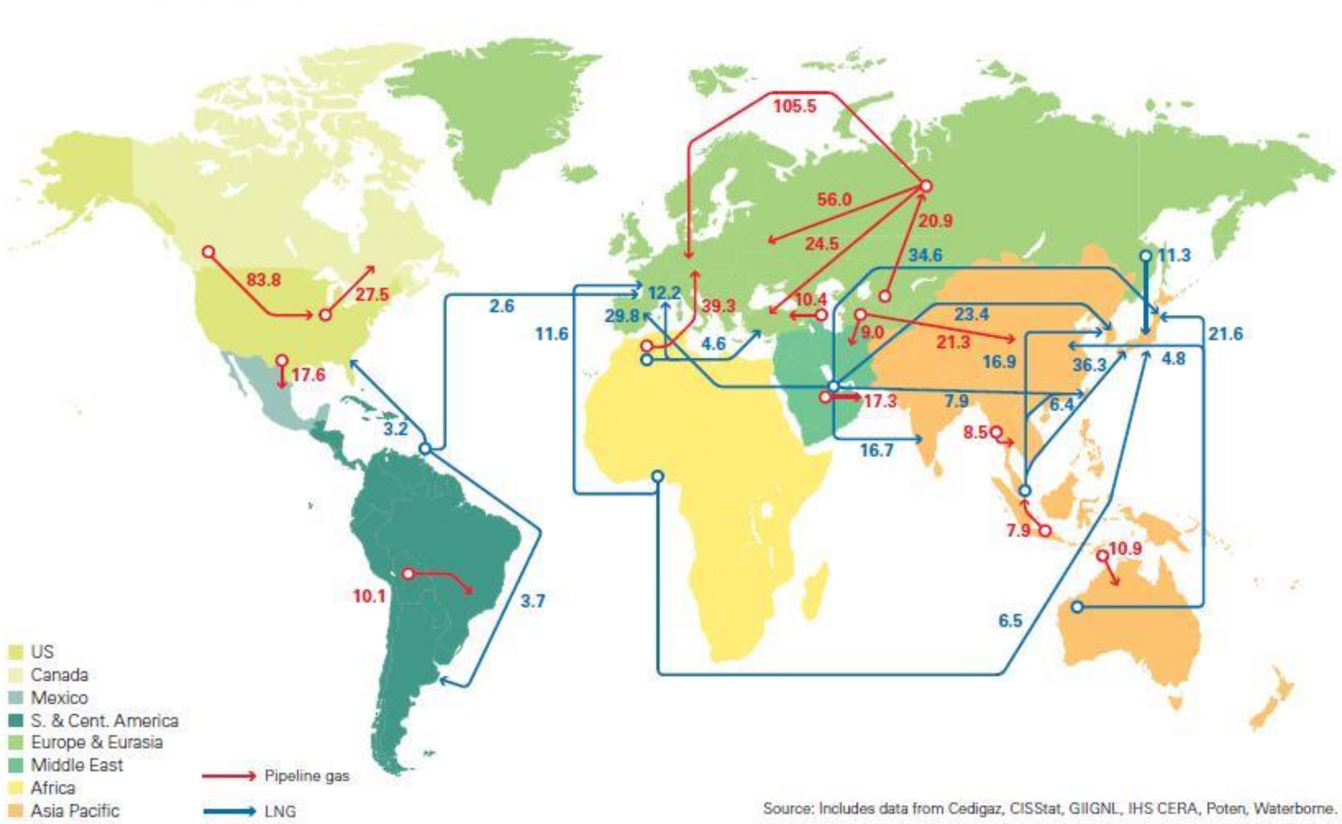
Billion cubic metres	From																			
To	US*	Brazil*	Trinidad & Tobago	Peru	Norway	Other Europe*	Russian Federation	Oman	Qatar	United Arab Emirates	Yemen	Algeria	Egypt	Equatorial Guinea	Nigeria	Australia	Brunei	Indonesia	Malaysia	Total imports
US	–	–	3.2	–	0.2	–	–	–	1.0	–	0.6	–	0.1	–	–	–	–	–	–	**4.9**
Canada	–	–	0.8	–	–	–	–	–	1.0	–	–	–	–	–	–	–	–	–	–	**1.8**
Mexico	†	–	0.2	1.2	–	–	–	–	1.7	–	0.4	–	–	–	1.1	–	–	0.3	–	**4.8**
North America	†	–	4.2	1.2	0.2	–	–	–	3.6	–	0.9	–	0.1	–	1.1	–	–	0.3	–	**11.6**
Argentina	–	0.4	3.7	–	0.2	0.7	–	–	0.1	–	–	–	0.1	–	–	–	–	–	–	**5.2**
Brazil	0.2	–	0.8	–	0.2	0.4	–	–	1.1	–	–	–	–	–	0.5	–	–	–	–	**3.2**
Chile	–	–	3.1	–	0.1	–	–	–	–	–	0.3	–	0.3	0.4	–	–	–	–	–	**4.1**
Other S. & Cent. America	–	–	2.4	–	0.1	–	–	–	0.2	–	–	–	–	–	0.1	–	–	–	–	**2.8**
S. & Cent. America	0.2	0.4	10.1	–	0.6	1.1	–	–	1.3	–	0.3	–	0.3	0.4	0.5	–	–	–	–	**15.2**
Belgium	–	–	–	–	–	–	–	–	4.5	–	–	–	–	–	–	–	–	–	–	**4.5**
France	–	–	–	–	0.2	–	–	–	1.8	–	–	4.8	0.9	–	2.7	–	–	–	–	**10.3**
Italy	–	–	–	–	0.1	0.1	–	–	5.8	–	–	1.0	0.2	–	–	–	–	–	–	**7.1**
Spain	–	–	2.5	2.6	1.7	0.7	–	–	4.3	–	–	3.6	0.7	–	5.4	–	–	–	–	**21.4**
Turkey	–	–	–	–	0.2	0.2	–	–	1.2	–	–	4.1	0.5	–	1.5	–	–	–	–	**7.7**
United Kingdom	–	–	–	–	0.2	–	–	–	13.3	–	–	0.1	†	–	†	–	–	–	–	**13.7**
Other Europe & Eurasia	0.1	–	0.2	–	0.8	0.2	–	–	0.2	–	–	0.8	0.2	0.1	2.0	–	–	–	–	**4.5**
Europe & Eurasia	0.1	–	2.6	2.6	3.1	1.1	–	–	31.1	–	–	14.4	2.4	0.1	11.6	–	–	–	–	**69.3**
Middle East	–	–	0.4	–	0.2	–	–	–	2.9	0.1	–	–	0.2	–	0.8	0.1	–	–	–	**4.6**
China	–	–	0.2	–	–	–	0.5	0.1	6.8	–	0.8	0.1	0.4	–	0.4	4.8	–	3.3	2.5	**20.0**
India	0.1	–	–	–	–	0.2	–	–	16.1	–	0.6	0.6	0.8	–	2.1	–	–	0.2	–	**20.5**
Japan	0.4	0.1	0.4	1.1	0.6	0.5	11.3	5.4	21.3	7.5	0.4	0.2	1.4	3.8	6.5	21.6	8.0	8.4	19.9	**118.8**
South Korea	–	–	1.1	–	0.1	0.2	3.0	5.7	14.2	–	3.6	–	0.8	0.5	2.5	1.1	1.1	10.3	5.6	**49.7**
Taiwan	–	–	0.1	–	0.1	0.1	–	–	7.9	–	–	–	0.3	0.2	1.6	0.3	–	2.6	3.8	**16.9**
Thailand	–	–	0.1	0.4	–	–	–	–	0.3	–	0.5	–	–	–	0.1	–	–	–	–	**1.4**
Asia Pacific	0.5	0.1	1.9	1.5	0.7	0.9	14.8	11.2	66.5	7.5	5.9	0.9	3.8	4.5	13.1	28.0	9.1	24.7	31.8	**227.2**
Total exports	**0.8**	**0.4**	**19.1**	**5.4**	**4.7**	**3.2**	**14.8**	**11.2**	**105.4**	**7.6**	**7.1**	**15.3**	**6.7**	**4.9**	**27.2**	**28.1**	**9.1**	**25.0**	**31.8**	**327.9**

†Less than 0.05.
*Includes re-exports.

Source: Includes data from GIIGNL, Poten, Waterborne.

Trade movements LNG 2012

Trade flows worldwide (billion cubic metres)



Major trade movements 2012

Gas trade in 2011 and 2012

Billion cubic metres	2011 Pipeline imports	2011 LNG imports	2011 Pipeline exports	2011 LNG exports	2012 Pipeline imports	2012 LNG imports	2012 Pipeline exports	2012 LNG exports
US	88.3	10.0	40.7	1.7	83.8	4.9	45.1	0.8
Canada	26.6	3.3	88.2	–	27.5	1.8	83.8	–
Mexico	14.1	4.0	0.1	–	17.6	4.8	†	–
Trinidad & Tobago	–	–	–	18.5	–	–	–	19.1
Other S. & Cent. America	14.8	10.6	14.8	5.2	16.9	15.2	16.9	5.8
France	32.3	15.5	2.2	–	35.0	10.3	1.2	0.2
Germany	84.0	–	11.7	–	86.8	–	12.5	–
Italy	60.8	8.7	0.1	–	59.7	7.1	0.1	–
Netherlands	15.6	0.8	50.4	–	14.5	0.8	54.5	–
Norway	–	–	95.0	4.5	–	–	106.6	4.7
Spain	12.5	24.2	0.5	0.8	13.3	21.4	0.7	1.2
Turkey	35.6	6.2	0.7	–	34.9	7.7	0.6	–
United Kingdom	28.0	24.8	16.0	0.1	35.4	13.7	12.0	–
Other Europe	100.8	10.9	10.1	0.6	97.6	8.2	9.3	1.7
Russian Federation	30.1	–	207.0	14.2	29.8	–	185.9	14.8
Ukraine	40.5	–	–	–	29.8	–	–	–
Other Former Soviet Union	35.3	–	63.0	–	32.3	–	68.8	–
Qatar	–	–	19.2	100.4	–	–	19.2	105.4
Other Middle East	32.1	4.6	9.1	28.2	29.2	4.6	8.4	25.9
Algeria	–	–	34.4	17.8	–	–	34.8	15.3
Other Africa	5.7	–	8.3	40.0	6.0	–	11.0	38.8
China	14.3	16.6	3.1	–	21.4	20.0	2.8	–
Japan	–	107.0	–	–	–	118.8	–	–
Indonesia	–	–	9.3	29.3	–	–	10.2	25.0
South Korea	–	50.6	–	–	–	49.7	–	–
Other Asia Pacific	28.6	32.1	16.3	68.7	34.1	38.8	21.0	69.0
Total World	**700.0**	**329.8**	**700.0**	**329.8**	**705.5**	**327.9**	**705.5**	**327.9**

†Less than 0.05.

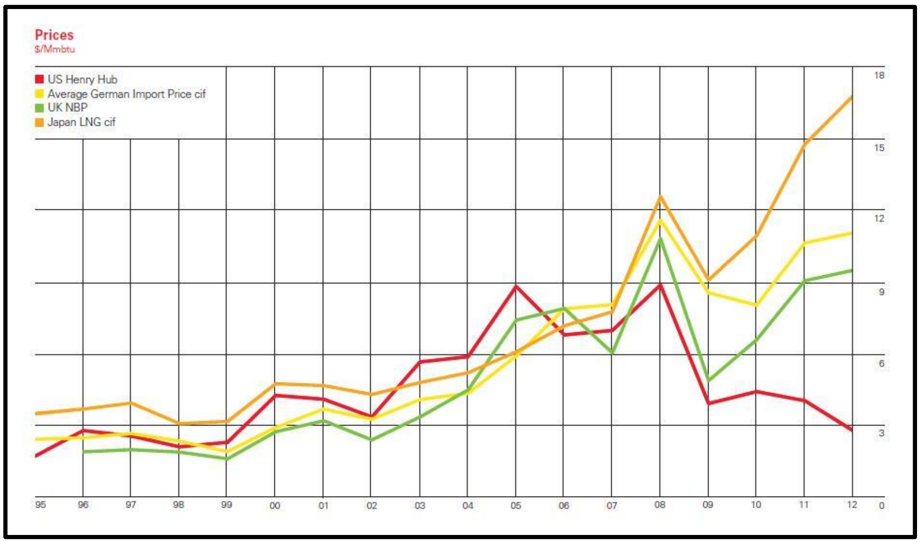
Source: Includes data from Cedigaz, CISStat, GIIGNL, IHS CERA, Poten, Waterborne.

Pipeline - LNG comparison 2011 & 2012

LNG Trade-flows - Future shale consideration

Shale gas development in other countries and regions will upset the natural gas importers-exporters balance and define new trade-flows. So far, US shale production has led to minimizing American LNG imports (10 bcm in 2011 and 5 in 2012). USA is preparing the infrastructure required for exporting abundant natural gas to mostly Asian -but also European and Latin American- markets in the near future (2015-2017).Consequently, extra North American natural gas will demand trade-flows towards Asia, Europe and Latin America while LNG flows towards North America will be diverted elsewhere. Australia will also compete in supplying the Asian markets with natural gas. Judging by the infrastructure it has invested in, it aims at becoming a strategic key player in the region and trade-flows connecting Australian natural gas with China, India, Japan and the rest of the Asian market are in the making. The US, Canadian and Australian LNG alternatives presented to the Asian market will also have an effect in Middle Eastern and African LNG trade-flows to Asia. Middle East up until now provides 55% of the needed Asian LNG supply and North Africa 37%. Two thirds of Middle Eastern LNG is supplied by LNG giant Qatar. These exporters will start considering other importing clients as an option. *Europe on the other hand has found itself in an interesting competitive buying position as the closest major LNG market to major Middle Eastern supplies i.e. the market with the lowest transportation cost compared with competing Asian or US destinations [Jensen, "LNG revolution"].*Thus, more trade-flows connecting Middle Eastern LNG to consuming Europe are also probable. Of course, other major exporting countries such as Russia will have to succumb to the market pressure and offer better and more LNG-competitive prices while also directing part of the production (through pipeline and LNG) to other new interested buyers. An interesting point is the fact that future successful development of shale gas in other regions (not expected to reach a commercial scale for the next 5-10 years) can result in regional exporters providing pipeline natural gas to nearby importers as an alternative to LNG. In this final scenario shale gas ends up promoting pipeline trade-flows against LNG.

LNG Market structure and pricing



The LNG market so far was not globally integrated. This means that depending on region, natural gas prices could vary greatly and not affect other markets. These are some of the 2011 average price ranges of natural gas per country-region:

Saudi Arabia	$00.75/MBtu
USA	$02.00/MBtu
Asia	$16.00/MBtu
EU	$09.21/MBtu

Natural gas abundance in Saudi Arabia and USA resulted in extremely low prices when compared to the energy-hungry Asian market ones. Natural gas was bought from the European Union at an US and Asia average price of about $9. Again, this price might not apply to all countries of the region.

'Global gas' was a concept unimaginable mostly due to high cost, technical difficulties and supply resources. It is one of the industry's top surprises that a series of events started to reform the natural gas structure into globalization. These events are:

- Steady development of a global LNG market;
- The shale boom boom in the United States;
- Economic recession that led to decrease of demand;

LNG trade on a global level has steadily increased over the past decade and with it, so has the world LNG liquefaction and regasification capacity. This trend will continue in the same fashion and a 200% increase (!) in annual LNG interregional gas trading is anticipated (from 590 bcm in 2008 to 1200 in 2035). In 2010 Europe accounted for 22% of the global regasification capacity; Korea and Japan for 44% and North America for 25%. With the unconventional US revolution and the shift of US role from importer to exporter, these statistics are about to drastically change. Europe is growing steadily to become the second (after Asia) largest LNG regasification-importing market overtaking the altered US one.

Europe's LNG import capacity increase was accompanied by the development of LNG liquefaction plants in Russia, Qatar, Peru and Yemen. Most notable of the above is the Qatari super-plant that adds 80 bcm to the global liquefaction capacity. A typical plant project needs 4 to 5 years for completion and has a life expectancy of at least 20 years.

The apparent mismatch between total global liquefaction and regasification (in 2010 regasification was 2.5 times bigger) is much more reasonable than it first seems. Abundance in regasification capacity translates into flexibility and security. It also means that when natural gas demand is high there will be global competition for acquiring the supply before another interested and able party.

The liquefaction capacity is further expanding by LNG plants in Angola, Algeria and Australia. Australia aims to export massive LNG volumes to Asian markets and invests on grand infrastructure that might even make it (with 70 bcm by 2015) the second largest LNG exporter next to Qatar.

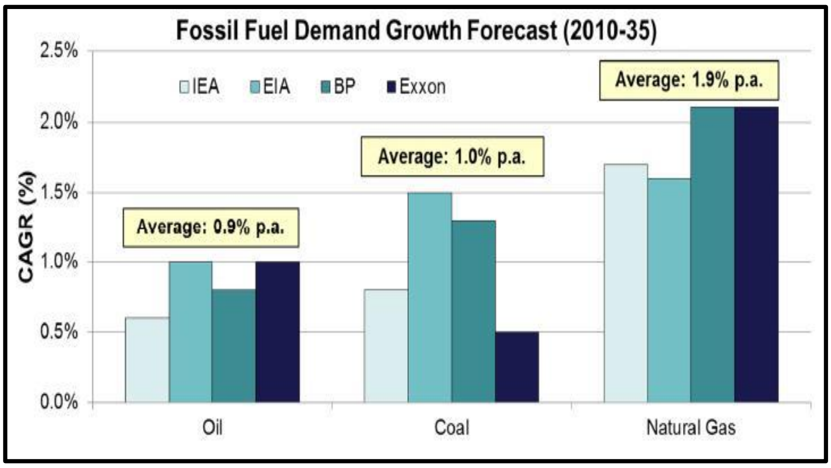
US natural gas is planned to be exported via LNG to Asian or European markets or to Canada. The last choice will result to Canadian LNG exports.

Rise in LNG infrastructure investment stands in contrast with the very few and slow progressing interregional pipeline investments. LNG can serve the need of transporting gas reserves that are discovered and developed far from major markets. It is also an investment with greater margin since it is not limited by locational specificity and customers. LNG sellers can follow the price incentive and move from low to high value markets. This is called 'arbitrage'.

LNG markets are difficult to monitor and have no price or hub references. Traditional LNG selling model is that of a long-term, take or pay contract that delivers some of the market risk to the end user. Project developers work in ventures to share the cost and risk of the operation and act as if they were shareholders in a corporation rather than independent and competitive corporate entities. This model is begging to change. Short-term, less expensive contracts are made concerning destination and quantity flexible volumes. Competition and individual drive and risk are assisted by the increasing number of uncommitted LNG carriers. While the later model still restrains significantly from becoming the norm, in the next few years the market inclines towards a hybrid between the old strict contract form and the newer, more flexible one.

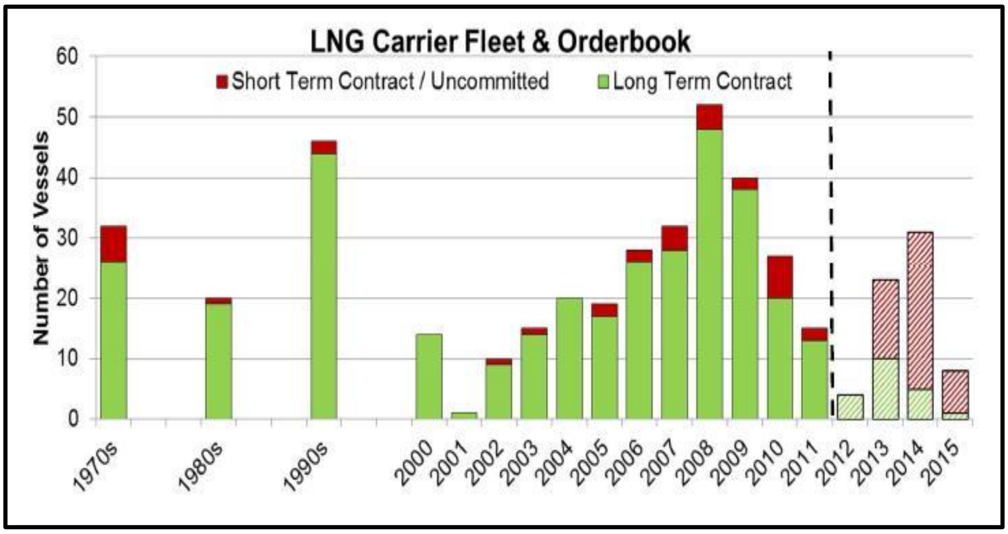
LNG vessel fleet

As explained thoroughly throughout Chapter V, the energy market is expected to enter a golden age of natural gas. In this new age LNG plays a major -if not the most important of all- role in gas transportation. After the Fukushima accident, 2011 charter rates reached historic heights. High LNG demand from China, India and the rest of the developing Asian economies will continue to grow. Newly presented arbitrage opportunities increase LNG vessel journey lengths and capacity requirements. Also, eco-consideration has led to regulation that promotes natural gas above all other fossil fuels (along with power plants and industrial production, CO_2 reducing regulations are promoting LNG as a maritime fuel as well). The shipping industry has invested heavily in LNG newbuilding orders and anticipates an LNG bloom. In this environment, shale gas hasn't upset the market's predictions in an unwanted manner. On the contrary, it seems to have reinforced and consolidated the belief that the market is entering the natural gas golden age. Shale gas has not yet been traded, but the potential is there and the effect of this discovery in the total available LNG reserves is undisputed: significant contribution of natural gas supply and new trade-flows offering spot shipping charters. Asian demand is anticipated so great that the extra supply is not feared as a factor that can reverse the tide and is regarded only from a positive perspective; LNG market will remain tight in the years to come and extra supply is essential to meet the needs of demand. Synoptically presented, current market conditions along with anticipated future ones (including shale gas exports and development in other regions) have led to the below effects as regards the LNG carrier fleet:



- More players in the global "arena" of LNG trading; moving from a commerce controlled by few (few exporters, few loading and discharging ports with the necessary infrastructure, few ship owners and operators with an LNG fleet, specific number of vessels and shipbuilding projects, limited crew and shore personnel with the relevant expertise etc) to a commerce that now involves many, providing LNG at a cost that will further help increase its global demand.

- More LNG vessels: The shipping industry has realized that there is a huge future opportunity driven by the shale gas revolution, the overall booming of natural gas demand and the interesting geopolitical dynamics. A significant investment and effort is required for someone to enter this market but investment experts support these bold moves. 2012 LNG fleet numbered 373 vessels with combined capacity of 54.5 mcm. Favorable conditions have led to the postponement of the aging (above 25 years old) vessels – about 12% of the total fleet. 63 LNG carriers are currently on order. Of those, only 18 are committed to long-term projects. The average ship capacity has also increased, reaching 150.000 cm while the future estimations expect a further growth to 170.000 cm.



Note: It must be underlined that Greek ship-owners represent a very large proportion of the new orders, accounting for about 46% while currently owning just 4% of the existing fleet. Greek LNG investment is estimated to exceed the amount of $10 bil. The major players of these investments are Yannis Aggelikousis (Maran Gas Maritime), Dinos Martinos (Thenamaris), Giorgos Prokopiou (DynaGas), Petros G. Lebanos (GasLog) and Giorgos Oikonomou (Cardiff Marine) followed by Christos Kanelakis (Alpha Tankers & Freighters) and Nikolas Tsakos (TEN) with much smaller fleets. Two out of three LNG carriers delivered in 2012 by the shipyards worldwide are Greek.

Chapter V Appendix: International Energy Agency (IEA)

Any serious attempt on studying and researching energy related topics is surely bound to come across the International Energy Agency. Granted that when writing this thesis I relied on multiple occasions on collective data, knowledge and reports gathered, carried out and provided by the IEA, the following section is dedicated to the presentation of this -essential to the field- agency.

In the aftermath of the 1973 OPEC oil embargo and at a time nowadays regarded as *"the worst crisis, and the most fractious, to afflict the Western alliance since its foundation after World War II"* [Daniel Yergin] the International Energy Treaty emerged out of a turbulent energy conference in Washington DC. The treaty established a new energy security system aiming to secure supply to the member nations, avert in-house competition, prevent a future "oil weapon" use by the exporting countries and finally, maintain functionality to the global economy. To meet these objectives -and to counterbalance the almighty OPEC- IEA was founded.

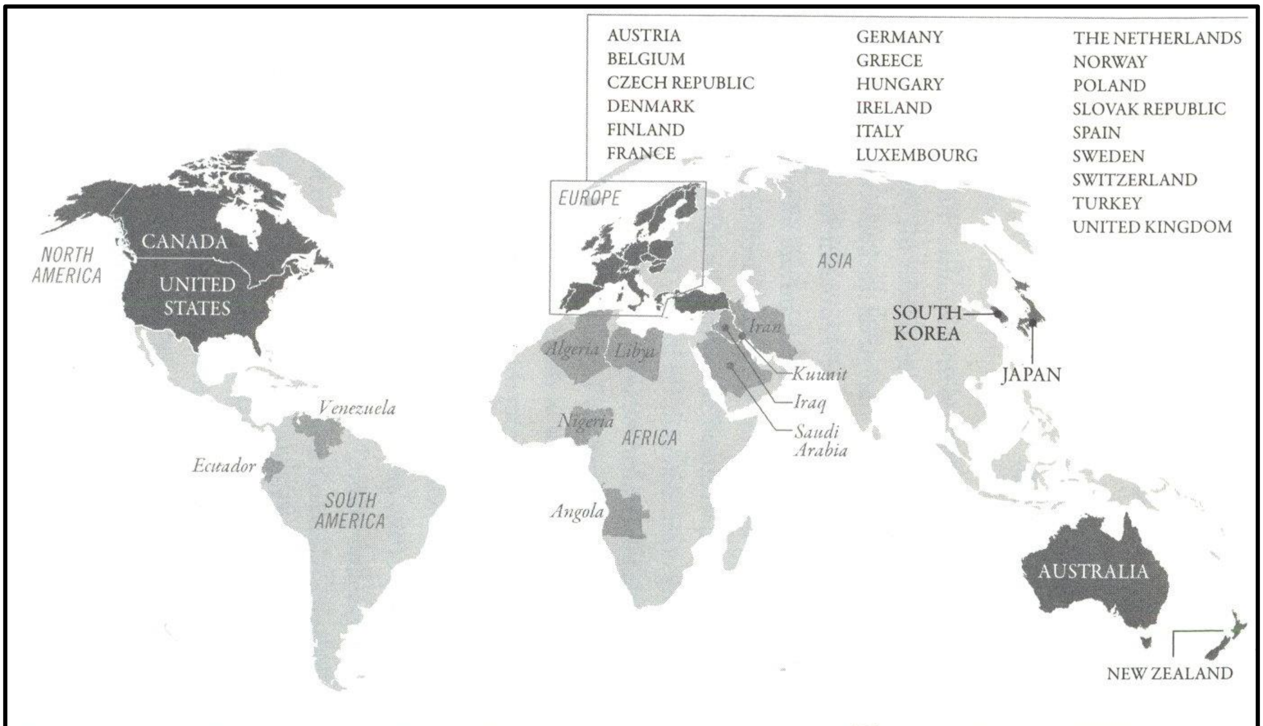
As stated i, *the International Energy Agency is an autonomous organization which works to ensure reliable, affordable and clean energy for its 28 member countries and beyond. Founded in response to the 1973/4 oil crisis, the IEA's initial role was to help countries co-ordinate a collective response to major disruptions in oil supply through the release of emergency oil stocks to the markets. While this continues to be a key aspect of its work, the IEA has evolved and expanded. It is at the heart of global dialogue on energy, providing authoritative and unbiased research, statistics, analysis and recommendations. Today, the IEA's four main areas of focus are:*

- *Energy security: Promoting diversity, efficiency and flexibility within all energy sectors;*

- *Economic development: Ensuring the stable supply of energy to IEA member countries and promoting free markets to foster economic growth and eliminate energy poverty;*

- *Environmental awareness: Enhancing international knowledge of options for tackling climate change; and*

- *Engagement worldwide: Working closely with non-member countries, especially major producers and consumers, to find solutions to shared energy and environmental concerns.*



OPEC AND THE IEA: THE BALANCING ACT

OPEC represents key oil-exporting countries; the IEA was founded to represent importing countries.

Synopsis

When I first heard about shale gas, I was intrigued by the subject and started researching on a deeper level. Most reports and articles found seemed to focus on only one, or in the best case, few of the shale gas topics (mostly on those of unconventional controversial nature like hydraulic fracturing and GHG emissions). My intention when writing this thesis was to select and gather the scattered pieces of shale information needed and put them into context, presenting all major aspects of shale gas - conventional and unconventional- into one consistent, coherent narrative.

Starting from **Chapter I**, we defined what shale gas is and understood its unconventional nature and place in the natural gas 'family'. **Chapter II** was dedicated in presenting the history behind the breakthrough of shale gas that ultimately led to its full scale US commercialization. **Chapter III** presented the technology behind shale gas development. It didn't focus only on the key techniques of horizontal drilling and hydraulic fracturing; it provided a description of the whole development procedure from start to finish, putting into shale-perspective important conventional operations that are often omitted. During development we saw the carrying out of many operations that aimed at securing the environment of the basin. In **Chapter IV** we analyzed the various environmental impacts and hazards of development and emphasized on the importance they bear for the further establishment of shale gas. Concluding the thesis, **Chapter V** provided an economical presentation of the shale gas present and future effects in geopolitics, the global energy commerce and LNG shipping.

Shale gas has already made a tremendous impact in the energy field. The unpredicted conversion of the USA from a natural gas importer to exporter has led to a domino of rapid geo-strategic economic changes that have significantly and drastically altered the world's energy market. If all (serious) environmental issues are addressed successfully in the future, shale gas will live up to its full potential; and even if it doesn't, the magnitude of its established effects is great enough to consider it a milestone in the world's energy history. It is indeed an 'unconventional' natural gas revolution.

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