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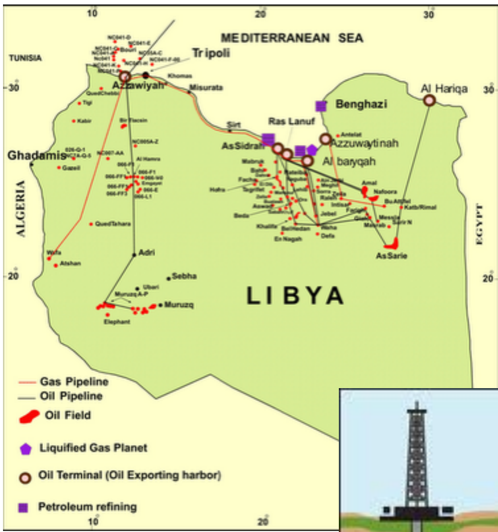
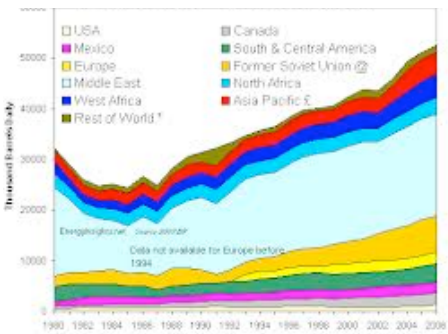
Lehrstuhl für Geologie, Geochemie und Lagerstätten des Erdöls und der Kohle (LEK)

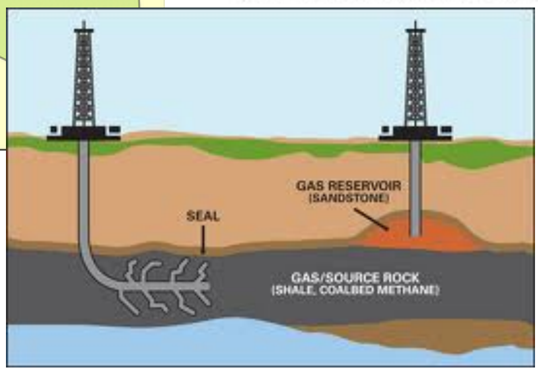
VEREDELUNG UND HANDEL FOSSILER ENERGIETRÄGER

BENEFICIATION AND TRADE OF FOSSIL FUELS

Ergebnisbericht der Studieneinheit vom WS 2011/2012







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I. Treatment, Refining and Utilization of Oil and Natural Gas

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Abstract

This chapter gives an overview on our most important energy sources – oil and natural gas. At first, general facts are outlined in the introduction to provide a realistic and comprehensive impression of the role of oil and gas in today's energy policy, economy and markets. It is followed by the overview on treatment and refining techniques of oil and natural gas as well as common classifications.

Thereby, oil can be classified by its geographical origin or its chemical components. A great number of refining techniques are required to produce the desired product from the crude oil. This text briefly presents distillation, cracking, reforming, coking and blending.

The most important steps in natural gas refining are the removal of oil and condensates, water, sulfur und CO_2 and finally, the separation of Natural Gas Liquids.

A lot of different uses of natural gas are known whereas the most important consuming sectors are the Electric Power as well as the Industrial Sector, followed by the Residential and Commercial Sector.

Crude oil can be converted into a great variety of products like different kinds of fuel and gasoline, but also fertilizers, pharmaceuticals or textiles.

Finally, some future prospects on trends, potential problems and solutions in regard to energy consumption are given.

I.1. Introduction

Petroleum and natural gas are still the most important energy sources besides coal (BGR, 2010; BMWi, 2011). The main fields of usage for natural gas and oil are fuels for different means of transport as well as fuels for power generation and heating. Reasons for this application are the high calorific values and energy densities of these fossil fuels. In Table I-1 different examples of fuels and their average heating value per unit of quantity are given. Oil-based fuels show the highest heating values per unit volume as well as per unit mass (specific). Therefore smaller volumes and quantities in comparison to other fuels contain the same amount of energy.

Table I-1: Average heating values for standard fuels, modified after (BMWi, 2011; Deutsches Institut für Normung, 1992; Deutsches Institut für Normung, 2011; Grote, 2005)

Fuel	Heating Value in MJ/m_n^3	Heating Value in kJ/kg
Lignite	8,554	9,004
Hard coal	36,120	30,116
Natural gas	35	41,375
Crude oil	36,172	42,556
Light fuel oil	47,086	42,806
Diesel	35,807	42,960

Another important application field of oil is the usage as base material for chemical production processes. A large range of products, e.g. lubricants, plastics and textiles (Total, 2010; BP, 2011c; Kratzert, 2000) is petroleum-based. A detailed overview of the extraction processes and the applications of petroleum products is given in Chapter I.2.1. Different types and qualities of oil and gas are required as “base materials” for various applications. Classifications of oil and natural gas as well as an overview of the complex procedures of treatment and refining are given in Chapter I.2. Some general facts are outlined below to provide a realistic and comprehensive impression of the role of oil and gas in today’s energy policy, economy and markets.

I.1.1. General facts - production, reserves and resources

I.1.1.1. Oil production

The total amount of oil produced until 2009 was approximately 159 Gt and thus equated the known reserves of conventional oil with approximately 161 Gt. In 2009 the estimated conventional oil reserves plus resources amounted to 260 Gt. Besides these conventional deposits the so-called unconventional deposits are gaining importance. Research activities on unconventional deposits have increased noticeably during recent years. It is assumed, that unconventional oil reserves plus resources are much larger than those for conventional oil. According to a recent study on energy resources by the BGR (2010) they could amount to approximately 375 Gt. The leading oil producing countries in 2009 were Russia (494 Mt), Saudi-Arabia (460 Mt) and the USA (325 Mt) with Saudi-Arabia and Russia also being the most important oil exporters. The German production in 2009 was 2.8 Mt and decreased to 2.5 Mt in 2010 due to limited reserves (BGR, 2010; LBEG, 2011; Pasternak, 2011).

I.1.1.2. Oil consumption

Oil accounts for approximately 35% of the worldwide primary energy consumption and thus is the most important energy source. Mineral oil consumption in 2009 was circa 3884 Mt whereof the consumption of the USA accounted for 840 Mt, of China for 390 Mt and of Japan for 200 Mt. These three countries were not only the biggest oil consumers, but also the biggest oil importers. Information about the utilization of oil can be found in Chapter I.3.1.
The consumption in Germany was approximately 104 Mt corresponding to rank eight in the list of the world's biggest oil consumers. Comparison with Germany's own production, which was about 2.8 Mt in 2010, reveals that Germany imported more than 95% of its consumed oil and thus was the sixth biggest oil importer (Figure I-1) (BGR, 2010; LBEG, 2011).

I.1.1.3. Natural gas production:

The situation for natural gas is different in that the cumulative production until 2009 reached just one third of the known reserves. An estimation of the potential of reserves plus resources is quite difficult due to the rapidly increasing importance of unconventional deposits. According to present estimations, conventional deposits amount to approximately 432 Trillion m³ ($432 \cdot 10^{12}$ m^3) and the potential of unconventional deposits exceeds that of conventional by multiple times. However, there is a high uncertainty due to the early stage of exploration and production for unconventional gas deposits. Leading gas producing countries in 2009 were the USA with 593 Billion m³ ($593 \cdot 10^9$ m³) and Russia with 584 Billion m³ ($584 \cdot 10^9$ m³). The biggest gas exporters were Russia, Norway and Canada. Germany produced 15.5 Billion m³ ($15.5 \cdot 10^9$ m³) in 2009, the production decreased to 13.6 Billion m³ ($13.6 \cdot 10^9$ m³) in 2010 due to depletion of gas fields (BGR, 2010; LBEG, 2011; Pasternak, 2011).

I.1.1.4. Natural gas consumption

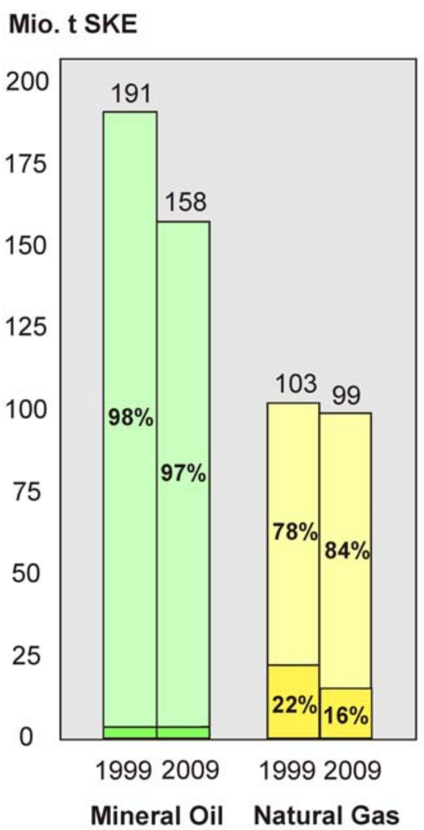

Figure I-1: Consumption of mineral oil and natural gas in Germany with percent of import and own production, modified after (BGR, 2010)

Natural gas accounts for 24% of the worldwide primary energy consumption and thus ranges on the third position of the most important energy sources, after oil and hard coal. The worldwide consumption was about 2957 Billion m³ ($2957 \cdot 10^9$ m³) in 2009, the largest portions of which were used in the USA and Russia with 647 Billion m³ ($647 \cdot 10^9$ m³) and 390 Billion ($390 \cdot 10^9$ m³) m³, respectively. Germany's consumption amounted to 92 Billion m³ ($92 \cdot 10^9$ m³) and thus Germany was the fifth biggest consumer of natural gas. As Germany's own production in 2009 was only 13.6 billion m³ ($13.6 \cdot 10^9$ m³) most amount of the consumed gas had to be imported (Figure I-1). Therefore Germany was the second largest importer of natural gas, ranging directly behind the USA (BGR, 2010; LBEG, 2011). A detailed view on the usage of gas is given in Chapter I.3.2.

Development of prices

The price development for oil and gas was similar in the past. In the time period from 1987 to 1998 the price varied between 10 USD/barrel oil equivalent (boe) and 20 USD/boe with a slightly higher price for oil. After 1998 the price increased considerably as a result of growing demand due to economic growth and an increase in technologies with high energy-intensity (BGR, 2010; BP, 2011). This trend reached its peak in 2008 and was followed by a rapid decrease due to the global economic crisis. The only exceptions were India and China, with a continuously increasing demand and consumption. After the global crisis the prices for oil and gas developed differently for the first time since the linkage of gas and oil prices, which started in the 1960ies. While the prices for oil recovered in 2009 and 2010 in response to the rebounding energy consumption driven by economic recovery (BP, 2011; BP, 2011b) the gas prices remained low and increased only slightly in 2010. This was mainly due to the rapid development of unconventional gas resources, which resulted in an excess supply of natural gas (BP, 2011; BP, 2011a). More detailed information on this topic is given in Chapter III.

I.2. Treatment and refining

Crude oil and natural gas are both mixtures of different compounds, predominantly hydrocarbons. Crude oil consists predominantly of higher molecular-weight alkanes, cycloalkanes and aromatics, and varying amounts of non-hydrocarbon species containing nitrogen, sulfur and oxygen (NSO).

Natural gas contains mainly light hydrocarbons (methane, ethane, propane and butane), but gases with high and strongly varying percentages of hydrogen sulfide, molecular nitrogen and carbon dioxide are encountered in specific geological situations. Natural gases with high sulfur or carbon dioxide contents are referred to as sour gases. More classifications for crude oil and natural gas are mentioned in the pertaining chapters.

A wide range of beneficiation and processing methods are applied to extract specific compounds or compound classes from the complex crude oil or natural gas mixtures, and purify them for further use. Some of these diverse technologies are explained in the following chapters.

I.2.1. Oil

In order to create or increase economic value, crude oil must be transformed into products that can be commercialized. Heat, pressure, catalysts and chemicals are used in the refining process to convert crude oil and other hydrocarbons into petroleum products.

The capacity of a refinery is expressed in terms of its distillation capacity, either by barrels per stream day (BPSD) or barrels per calendar day (BPCD). The main refinery processes and technical terms are summarized in Table I-2

I.2.2. Classification: different types and qualities, e.g. heavy oil and light oil

Crude oil consists of a hydrocarbon mixture, especially alkanes (paraffins), cycloalkanes (naphthenes or cycloparaffins) and aromatics (arenes), as well as smaller non-hydrocarbon fractions, e.g. oxygen, sulfur, nitrogen and metals. According to the portion of each component the oil is classified as paraffin base, naphthene base, or mixed base.

Crude oils can also be differentiated in terms of their API (American Petroleum Institute) gravity, which compares the crude with the gravity of water, and the sulfur content, which is important for further refining steps.

The API Gravity (°) = formula can be expressed as:

$$API = (141.5 / \text{Density } (g/cm^3 SG) - 131.5$$

The density is determined at 15°C and atmospheric pressure

Oils classified as light have a low density (API ° > 35) and heavy oils have a high density (API ° < 25). Crude oils basically range between 20 and 45°API ((Gary, 2001). Light oil is more in demand, since it produces a larger amount of gasoline. Crude oil is called sour if it has high sulfur content and sweet if the sulfur content is low. Low-sulfur oils are generally more valuable.

Colour, consistency and smell of crude oil depend on its geographical origin and these properties may be used to classify crude oil. The West Texas Intermediate (WTI) and Brent Crude are examples for light and sweet and therefore high-quality oils, whereas the Dubai Crude is a light and sour variety. These are also the three primary crude oil benchmarks (BP, 2011b).

I.2.2.1. Refining: techniques

Refining and beneficiation of crude oil is the third step after drilling and production. Approximately 20 % of crude can be used directly after production. The remaining portions have to pass different refining steps until the final products are obtained. Table I-2 lists the main refining steps, but only distillation, cracking, reforming and blending are described in the following parts.

Table I-2: Major steps of the crude oil refining process

Distillation:	Separation by boiling into fractions or cuts consisting of hydrocarbon compounds of similar molecular size and boiling point ranges.
Conversion:	Changing the size or structure of hydrocarbon molecules by chemical reactions.
Decomposition:	Breaking down large molecules into smaller molecules with lower boiling points through cracking and related processes. Heavy parts can be converted into lighter parts such as gasoline.
Unification:	building small molecules into larger molecules through alkylation, polymerization, and related processes.
Reforming:	Rearranging molecules into different geometric structures in isomerization, catalytic reforming, and related processes.
Blending	is the process of mixing and combining hydrocarbon fractions additives, and other components to produce finished products with specific performance properties.

I.2.2.2. Crude oil distillation

The crude oil is cleaned from water and sediments, separated from its gas phase at the production site and transported to the refinery, where the beneficiation process takes place. It is also important to desalt the crude before distillation processes to avoid problems within the pipeline systems (e.g. salt in contact with water generates acid). Therefore chloride (NaCl) contents should be below 10ppm (Gary, 2001).

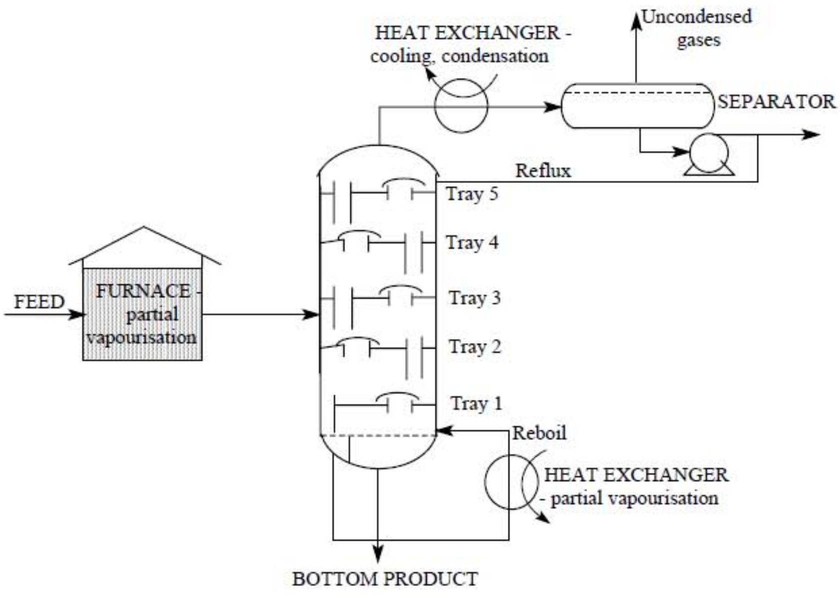

Figure I-1: Fractional distillation (Heil, 2007)

The first refining step is the distillation, which separates the crude into fractions according to the boiling point (Figure I-1). The crude is heated up to 350°-370°C in a furnace and injected into the fractionating columns, which can be up to 60 m high. These towers have different trays with vapor inlets and liquid outlets. The principal idea of distillation is to bring the different fractions of the crude into the gaseous phase and let the vapor condense partially. Volatile fractions condense and remain in the upper part of the column, whereas the heavier parts with a higher boiling point remain in the other trays according to their boiling point (Heil, 2007).

The main products of a typical crude distillation unit are as follows (Table I-3): Fuel gas (methane, ethane), wet gas (propane, butane), LSR (Light Straight Run) naphtha (gasoline), HSR (Heavy Straight Run) naphtha (kerosene), gas oils (light oils and heavy oils) and residuum. These products undergo further refinery until the final good is obtained (see Chapter I.3 Utilisation).

Modern refineries perform a first distillation with a boiling point up to 250°C (light and heavy gasoline, naphtha petroleum). This fraction is subjected to a hydro-desulfurization treatment in order to separate sulfur from the rest. The advantage of this treatment is that no further desulfurization or sweetening of this fraction is required.

Table I-3: Definitions of different crude oil fractions, after (Waddams, 1970)

Product	Boiling point range	Hydrocarbon-molecule
Gas, liquefied gas	➢ 25°C	C_1-C_4
Gasoline (naphtha)	Ca. 20-200°C	C_4-C_{12}
Petrol	Ca. 175-275°C	C_9-C_{16}
Gas-oil and diesel fuel	Ca. 200-400°C	C_{15}-C_{25}
Heating oil		C_1-C_4
Bitumen		> C_{40}

I.2.2.3. Cracking

Catalytic Cracking is a major refinery process to convert heavy oils (large alkanes, long hydrocarbon chains) into lighter oils and gasoline (smaller alkanes), for which a higher demand exists.

During cracking, the bonds in high-boiling (large alkanes) hydrocarbon molecules are cleaved to form new low-boiling (smaller alkanes) hydrocarbons. This is effected either by exposure to high temperatures and pressures (ca. 500 °C, 10 – 30 bar), called thermal cracking, or in the presence of a catalyst (catalytic cracking) at lower temperatures and pressures. In both cases the aim is to reduce the yield of heavy oils and to produce marketable low-boiling products.

In the past, mainly thermal cracking was accomplished, whereas meanwhile catalytic cracking has replaced thermal cracking completely. Reasons for this development are higher productions of gasoline and the lower output of heavy oils. Besides, catalytic cracking proceeds faster.

Coke is a byproduct generated in cracking processes, which rapidly lowers the activity of catalyst by covering its surface. Hence, the coke has to be burned off with air in a separate unit to regenerate the catalyst for its reuse.

The reactors for the cracking process can be divided into moving-bed and fluidized-bed reactors. As catalysts mostly silica-alumina combinations are used.

Catalytic cracking is often combined with hydrocracking in the presence of hydrogen. The hydrogen converts olefinic cracking products into saturated hydrocarbons. Process pressures between 100 and 150 bar pose specific requirements to the cracking unit. Otherwise hydrocracking has various advantages, e.g. a better balance between production of distillate and gasoline products (Gary, 2001; Heil, 2007; ARAL; FIZ b.).

I.2.2.4. Coking

Coking is a special form of thermal cracking. In coking units the heavy residuals of vacuum distillation and other thermal cracking processes are converted into low-boiling hydrocarbons and solid coke. Therefore high temperatures crack the heavy residuals thermally in a fractionating tower. The coke production starts delayed in the downstream coke chambers as seen in Figure I-2.

To eliminate the contained volatile matter from the coke it has to be burned off at temperatures around 1200°C. This process is called calcination.

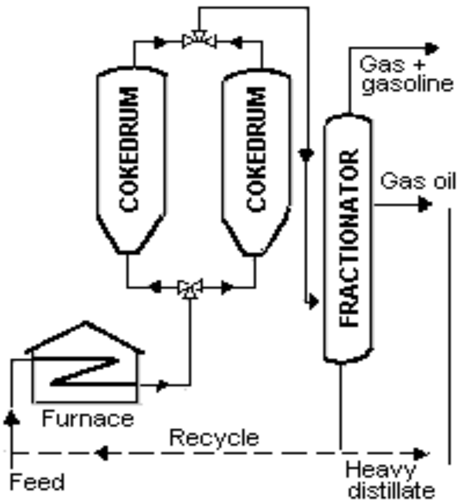

Figure I-2: Schematic of a Delayed Coking Unit (SET)

Coking can be classified in three different processes – delayed coking, fluid coking and flexicoking. The three forms of coke produced by coking, sponge coke, needle coke and shot coke are for example used as fuels. Calcinated coke is especially used in the production of electrodes.

After coking the produced low-boiling hydrocarbons are separated in a distillation unit. Subsequently the products have to be hydrogenated before using as fuels etc. (ARAL; FIZ b. ; Gary, 2001).

I.2.2.5. Reforming

Generally, reforming increases the octane number of gasoline and therefore creates hydrocarbons with a higher value. During the process there is a minor change of the feedstock's boiling point, thus reforming has another effect than cracking does. Reforming mainly means the rearrangement of hydrocarbon molecular structures to form aromatics, which have a higher octane number than olefins, paraffins or naphthenes.

The desirable reactions during reforming processes are the saturation of olefins to paraffins, the isomerization of paraffins to naphthenes and finally the conversion of naphthenes to aromatics. Undesirable reactions are e.g. the cracking of paraffins and naphthenes, because the aim of reforming is not the production of low boiling hydrocarbons. Consequently the operation conditions have to be chosen in a way, that they support the desirable reactions. Therefore bi-functional catalysts are used at which one compound supports the cyclisation and isomerization and the other compound catalyzes the dehydration. Additionally the hydrogen pressure is high to reduce cracking reactions and the production of coke.

The feed for the reforming units are often stocks with a high yield of naphthenes, which become cycling and isomerized. An important byproduct is hydrogen, further used in the hydrocracking process (Gary, 2001; FIZ b.).

I.2.2.6. Blending

The last step in the beneficiation chain is the blending of the products. Blending is the process of mixing and combining hydrocarbon fractions additives and other components to produce finished products with specific performance properties. The objective of blending is to produce high quality products at lowest costs to maximize the profit. Today blending is mostly computer-controlled. For example, naphthas can be blended into gasoline or jet fuel, depending on the demand. Almost all refinery products are blended, even asphalt (Heil, 2007).

A large variety of additives are being used to achieve the required product properties. Well-known examples are the gasoline anti-icing-additives glycol and alcohol, or Wax-Anti-Setting-Additives (WASA) in diesel fuels, which inhibit the precipitation of paraffins.

I.2.3. Gas

I.2.3.1. Classification: different types

Natural gas consists of a mixture of hydrocarbons, especially methane, ethane, propane and butane. Further, non-combustible components are molecular nitrogen, carbon dioxide and hydrogen sulfide as well as oxygen and other trace gases (NGSA, 2010).

Natural gas is classified as dry gas and wet gas containing <1.3 and >4 liters/100m³ of condensable liquids, respectively. The hydrogen sulfide content determines the characterization of gas as *sweet* (H_2S free, < 2 Vol.-% CO_2) or *sour* (> 1 Vol.-% H_2S) (Hunt, 1996). If the sulfur content is negligible, the gas can be used directly (unlike gas with high sulfur contents which has to be treated before) (Porth, 1997).

An overview of natural gas deposits with high H_2S contents can be seen in Table I-4.

As more than 40% of the world's gas reserves contain different amounts of CO_2 and H_2S, the interest in methods to exploit these types of deposits is high (Total, 2007). A problematic effect of the gases is especially corrosion of metals (within the pipes) (Total, 2007). Methods to remove CO_2 and H_2S are described below.

A lot of other, geological classifications like associated/non-associated or biogenic/thermogenic gas on can be used but will not be discussed within this text.

Table I-4: Natural Gas Deposits with high H_2S content (Hunt, 1996)

Region	***Reservoir age***	***Lithology***	***Depth [m]***	***% H_2S in total gas***
Lacq, France	Upper Jurassic and Late Cretaceous	Dolomite & Limestone	3.100-4,500	15
Pont d'As-Meillon, France	Upper Jurassic	Dolomite	4,300-5,000	6
Weser-Ems, Germany	Permian (Zechstein)	Dolomite	3,800	10
Asmari-Bandar, Shahpur, Iran	Jurassic	Limestone	3,600-4,800	26
Urals-Volga, Rus-sia	Late Carboniferous	Limestone	1,500-2,000	6
Irkutsk, Russia	Late Cambrian	Dolomite	2,540	42
Alberta, Canada	Mississippian Devonian	Limestone	3,506 3,800	13 87
South Texas	Late Cretaceous (Edwards) Upper Jurassic (Smackover)	Limestone	3,354 5,793-6,098	8 98
East Texas	Upper Jurassic (Smackover)	Limestone	3,683-3,757	14
Mississippi	Upper Jurassic (Smackover)	Limestone	5,793-6,098	78
Wyoming	Permian (Embar)	Limestone	3,049	42

I.2.3.2. Refining

After the first steps of raw natural gas exploration and extraction, which may vary in a wide range depending on the deposit type, the production starts. The extracted gas needs to be treated in order to remove water, oil, condensate and other components and thus obtain “pipeline quality”. Therefore fluids and various hydrocarbons have to be separated from the natural gas so that methane would be the principal component (NGSA, 2010). The most important steps of natural gas refining are described in the following text.

First scrubbers are installed at or near the wellhead to clean the crude gas from large particles such as sand. To avoid the formation of gas hydrates with dropping temperatures, heaters are used to ensure a constant temperature of the gas along the gathering pipe (NGSA, 2010).

The major processes to obtain "pipeline quality" dry gas are the removal of oil, condensates and water, the sulfur and carbon dioxide removal and the separation of natural gas liquids (NGL's) (NGSA, 2010). Apart from dry gas, also by-products obtained during the processing of natural gas are sold (like sulfur or higher molecular-weight hydrocarbons) (EIA, Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market, 2006).

I.2.3.3. Oil and Condensate Removal

The removal of oil and condensate, if necessary, normally takes place near the gas field. If a deposit contains associated gas, the gas-phase is usually partly dissolved in the liquid hydrocarbon phase because of the high pressure the formation is under. During oil production, these dissolved gases separate on their own from oil and condensates due to the pressure decrease. Different types of "separators" are used to achieve optimum separation of oil and gas (NGSA, 2010).

I.2.3.4. Water removal

The first step of oil and condensate removal is followed by the extraction of nearly all water within the natural gas to avoid the possible formation of hydrates. Therefore the free associated water is removed from the gas with simple separation methods near the field of recovery. The more complex elimination of water vapor is made by dehydration processes comprising absorption and adsorption processes (NGSA, 2010).

One example for an absorption process is the dehydration with glycol. Glycol has an affinity for water so it is hygroscopic. In a contactor the glycol is brought in contact with die wet natural gas absorbing the water vapor. The water-glycol-solution is transported out of the absorption tower to a special boiler where water and glycol can be separated by using their different boiling points.

An example for an adsorption process is the solid-desiccant dehydration. Therefore the wet gas passes an adsorption tower. This tower is filled with a desiccant, which adsorbs the water at its surface. To regenerate the desiccant after it is saturated, hot dry gas is used (NGSA, 2010).

I.2.3.5. Sulfur and Carbon Dioxide Removal

Another important step in the processing of natural gas is the removal of sulfur and carbon dioxide. As stated above, natural gas containing H_2S and CO_2 in larger amounts is called "sour gas". For commercial use, these components have to be removed in a sweetening process. In contrast to the techniques described above the gas is transported to large processing plants (BGR, 1997).

Hydrogen Sulfide is undesirable mostly because of its toxicity. So the significant rotten smell is a good indicator to identify H_2S already in very small concentrations. Furthermore H_2S may cause the corrosion of pipelines as well as negative environmental impacts during combustion (formation of SO_2) (NGSA, 2010).

To eliminate sulfur and carbon dioxide, an amine solution with an affinity to sulfur is used. Because of this affinity the amine solution absorbs up to 97 % of the sulfur components from the natural gas. This is also known as Girdler process. Afterwards, the sulfur can also be treated and sold. The amine solution containing H_2S and CO_2 can be regenerated to be reused in the absorption process (NGSA, 2010).

After separated from the amine solution the H_2S is fed to a Claus-Unit. In this claus unit a part of the H_2S is oxidized with air oxygen to create SO_2. This SO_2 reacts with H_2S. During the reaction between H_2S and SO_2 elementary sulfur is refined (cf. equation (1) and (2)).

$$2\ H_2S + 3\ O_2 \rightarrow 2\ SO_2 + 2\ H_2O \qquad (1)$$

$$2\ H_2S + SO_2 \rightarrow 3\ S + 2\ H_2O \qquad (2)$$

The produced elementary sulfur can also be sold (NGSA, 2010; FIZ a.).

Thereupon, the gas has to pass a Nitrogen Rejection Unit (NRJ) where another dehydration process takes place. As part of the NRJ or as a separate process the separation of methane (also called “demethaniization”) of the natural gas occurs. For both processes different methods exist (EIA, Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market, 2006; NGSA, 2010).

I.2.3.6. Separation of Natural Gas Liquids (NGL)

Natural gas liquids are mainly ethane, propane, butane and some heavier hydrocarbons. The extraction of NGL’s (natural gas liquids) quite is similar to dehydration techniques of natural gas and can be subdivided into two important processes. At first, all liquids are extracted from the gas. Then these liquids are separated into their different base components. The majority of NGL is extracted by absorption or by the cryogenic expander process (especially lighter hydrocarbons). In the absorption method, a special absorbing oil is used which dissolves the NGL’s (comparable to glycol in the dehydration process). The oil-NLG-mixture is heated up and the hydrocarbons can be captured. In the cryogenic expander process the temperature of the gas is dropped. Methane remains gaseous while the light hydrocarbons condense (NGSA, 2010).

To obtain economically valuable products, the NGL mixture, condensed from the gas phase, has to be further separated into particular hydrocarbon classes. The corresponding process is called “fractionation” and separates the compound groups according to their boiling points (beginning with ethane). The resulting NGL’s (e.g. ethane, propane or butane) are sold (NGSA, 2010).

I.3. Utilisation

I.3.1. Oil

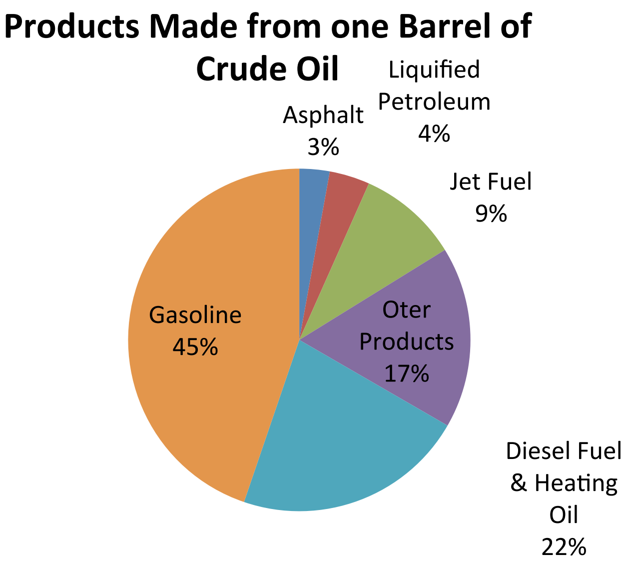

Figure I-3: Crude oil products in percentage, after (US Department of Energy)

In our industrial society, crude oil constitutes the main fuel for transportation and the most important raw material for petrochemical industry (Figure I-3). As shown in the second chapter, refinery products can be gaseous, liquid or solid (Table I-5). The main refinery processes are based on the large-quantity products such as gasoline, diesel, jet fuel, and residentially used heating oil. Another portion goes into petrochemical industry for the production of synthetic material such as plastics, textiles etc. Only 6-7% of the crude oil worldwide is used in petrochemical industry, more than 90% are burned. Economic balances are required to determine whether certain crude oil fractions are sold as they are or further processed to obtain products with a higher value.

Depending on the boiling point or respectively the number of C-atoms, different fractions of converted crude oil have a large variety of applications. Methane and ethane, occurring in small quantities in the crude, extracted and used for power generation in the refinery itself, whereas propane and butane are liquefied and commercialized as Liquefied Petroleum Gas (LPG).

Although all fractions of petroleum find uses, the greatest demand is for gasoline (Ophardt C. , 2003). One barrel of crude petroleum contains only 25-35% gasoline, but the amount of gasoline increases during cracking procedures as explained in Chapter I.2. Conventional gasoline is mostly a mixture of more than 200 different hydrocarbon liquids ranging from those containing 4 carbon atoms to those containing 11 or 12 carbon atoms.

Gasolines have variable octane numbers, mainly in the range between 65 and 75 ORZ. Octane numbers are used to indicate the resistance of a motor fuel to knock. Octane numbers are based on a scale on which isooctane is 100 (minimal knock) and heptane is 0 (bad knock) (chemistry.about.com).

Table I-5:Main Refinery products from crude oil in the last 40 Years after Gary, 2005

	1964	**1974**	**1984**	**1994**	**2003**
Gasoline	44,1	45,9	46,7	45,7	46,9
Distillate fuel oil	22,8	21,8	21,5	22,3	23,7
Resid. Fuel oil	8,2	8,7	7,1	5,7	4,2
Jet fuel	5,6	6,8	9,1	10,1	9,5
Coke	2,6	2,8	3,5	4,3	5,1
Asphalt	3,4	3,7	3,1	3,1	3,2
Liquefied gases	3,3	2,6	1,9	4,2	4,2
Total	**90,1**	**92,3**	**92,9**	**95,4**	**96,8**

Distillate fuels with a boiling range between 170 C and 400 C are applied in different areas. One operation area is the aircraft sector in which distillate fuels (mainly alkanes and aromates) are used as jet fuels in the jets engines. Distillate fuels can also be used for road vehicles, locomotives and smaller boats, called automotive diesel fuels. Because super needs a cetane number above 45, automotive diesel fuels need to be blended. For diesel fuels the cetane number is a measurement of the combustion quality during the ignition of compression. As railroad diesel fuels a cetane number of 30 is adequate for the operation in low speed engines like marine types. Furthermore in the past heavy distillate fuels were often used as power station oils, but meanwhile the demand decreases particularly because of environmental restrictions (Gary, 2001).

Residual fuel oils also known as bitumen are the residuals after vacuum distillation. Bitumen, containing up to 70 carbon atoms, are mainly used as a cover material for roads and airfield runways. Moreover it is a waterproofing material and is applied in different ranges (Gary, 2001).

By-products like sulphur are applied for the manufacture of fertilizers and coke.

Although their usage is relatively small in comparison with fuel, petrochemical industries are producing a large range of finished products, for example plastics, rubber, pharmaceutical, pigments, cleaning supplies, adhesion and many more. Rubber, pigments, plastics, fibers and detergents are the major finished products. Petrochemical products have a great impact on our lives, since one can find them in food, clothes, shelter and leisure (Ophardt C. , 2003).

The main raw materials in petrochemical industries are naphthas or respectively natural gas, which are converted into primary petrochemicals (Figure I-4).

Primary Petrochemicals include:

- olefins (ethylene, propylene and butadiene)
- aromatics (benzene, toluene, and xylenes)
- methanol

Thousands of different products can be generated with its derivates (Figure I-5) (Ophardt C. , 2003).

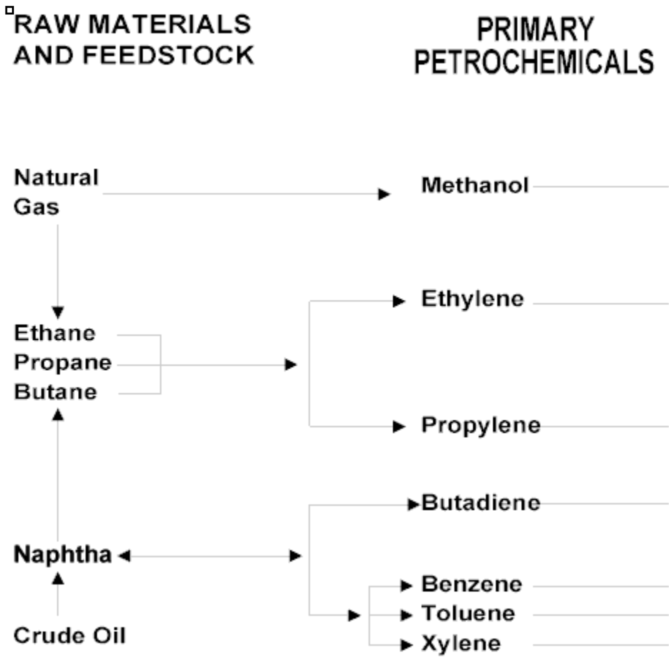

Figure I-4: Raw materials from crude oil as a source for petrochemicals (Ophardt, 2003)

According to its value, pharmaceutical, special adhesion products and pesticides are most important (Behr, 2010). These fine chemicals are produced in small amounts, they have a rather complicated molecule structure (highly branched and cycled) and various syntheses steps (4-8 steps or even more than 10) are needed to reach the desired quality. Furthermore, purity grades are usually >99 %, and fine chemicals are often substituted after (Waddams, 1970) some years, whereas other products such as acid sulfur have a much longer economic life-time (Behr, 2010).

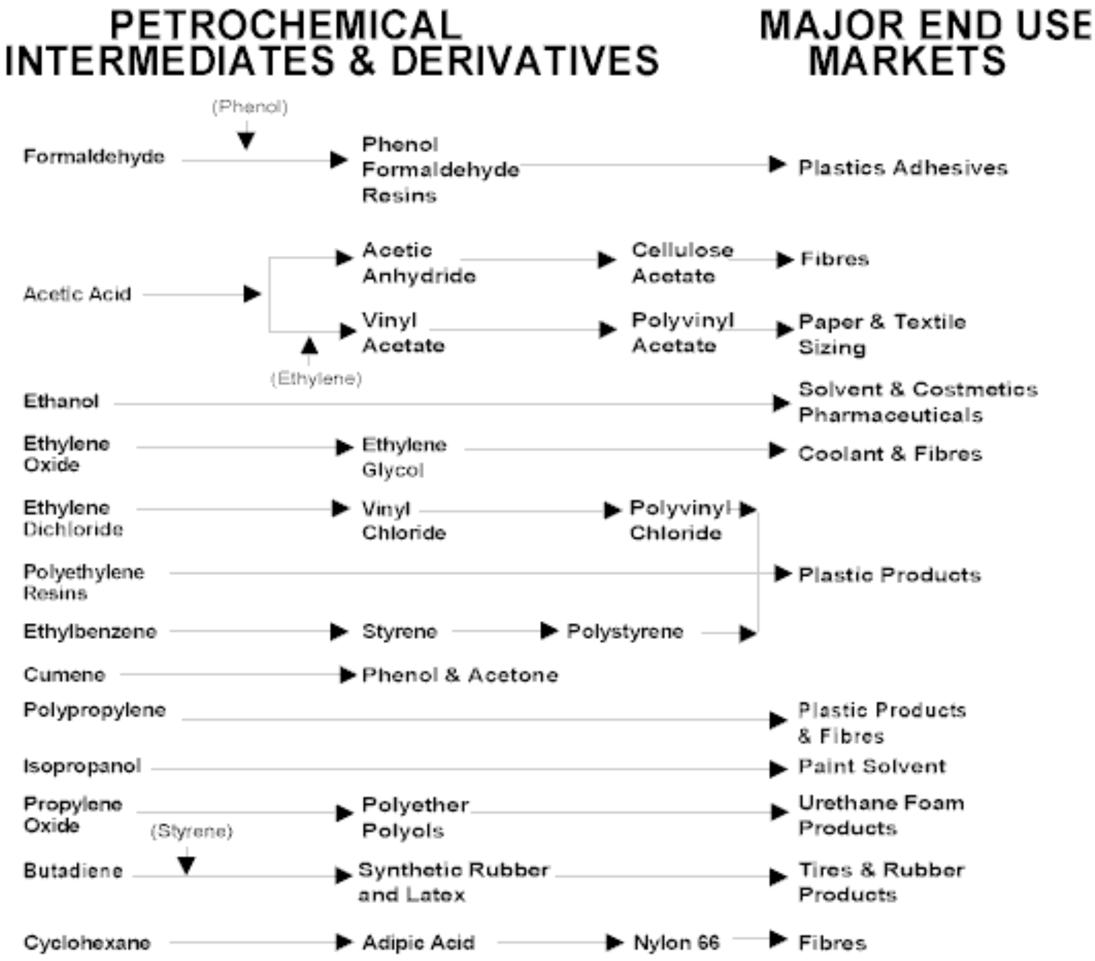

Figure I-5: Petrochemical derivates and major end use markets (Ophardt, 2003)

I.3.2. Gas

Figure I-6 gives an overview of the natural gas use by sector in 2010. The largest amount (31%) is consumed in the electric power sector, followed by the industrial, residential and commercial sector. The consumption of these four branches constitutes over 90% of the total gas use. Of lesser importance are oil and gas industry operations, pipeline fuels and vehicle fuels. The following subchapters will show some possible applications of pipeline-quality gas within the different sectors.

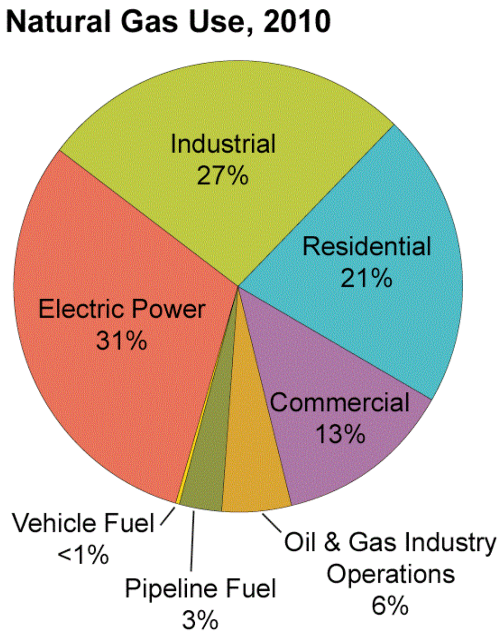

Figure I-6: Natural Gas Use 2010 by sector (EIA, Annual Energy Outlook 2011, 2011)

While long-distance pipeline systems still constitute the most important means for natural gas transport worldwide, liquefaction and transcontinental transport by ship is gaining increasing importance. The volume of “Liquefied Natural Gas” (LNG) is about 600 times smaller than the gas volume at atmospheric pressure and temperature conditions (SLO, 2006). The LNG technology permits the commercialization of natural gas resources located in remote areas without long-distance pipeline infrastructure (SLO, 2006).

But not only can the end product of nearly 100% methane be used. Also higher hydrocarbons and sulfur, which are separated during the processing, are sold. A mixture of hydrocarbons (for example ethane, propane, butane and others) is sold in thin-walled bottles for domestic cooking or as transport fuel. Pentane and higher hydrocarbons that are liquids under normal pressures may be used to produce gasoline (SLO, 2006).

Hydrogen sulfide extracted from the gas it is subjected to the “Claus process” to obtain pure sulfur. About 15% of the US sulfur production originates from the gas sector (NGSA, 2010).

I.3.2.1. Electric Power Sector

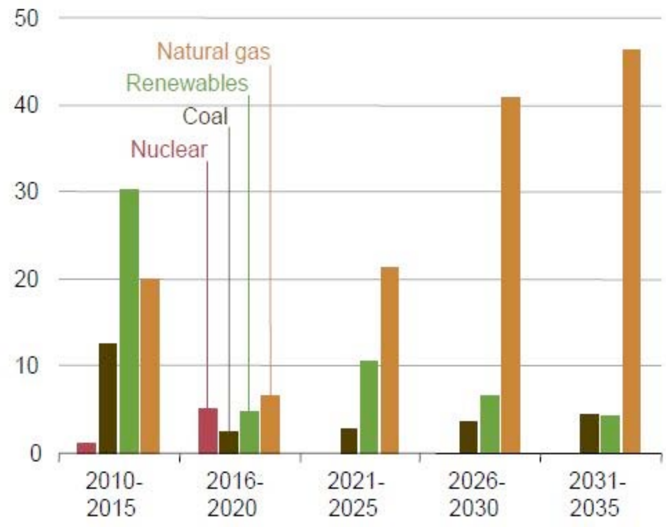

Figure I-7: Electricity generation capacity additions by fuel type in gigawatt, 2010-2035 (EIA, Natural Gas, 2011)

With new technologies and changes in environmental and economical aspects, the generation of electric power will change. The contributions of coal and nuclear power plants to electricity generation are expected to decrease substantially by 2035 (cf. Figure I-7) In consequence, natural gas utilization for electricity generation will increase, especially due to lesser environmental impacts of the power plant emissions (EIA, Annual Energy Outlook 2011, 2011).

There are different possibilities of how natural gas can be used to generate electric power. Some of them are steam generation units, gas turbines or combined-cycle units (NGSA, 2010).

I.3.2.2. Industrial Sector

The industrial sector comprises a large variety of natural gas uses with a slightly increasing tendency until 2035 (EIA, Annual Energy Outlook 2011, 2011). This multitude can be seen in Figure I-8. Gas in industrial processes is often used for heating, cooling or cooking processes. Possible applications for high-value hydrocarbons like propane or butane are as feedstock for products like pharmaceu-

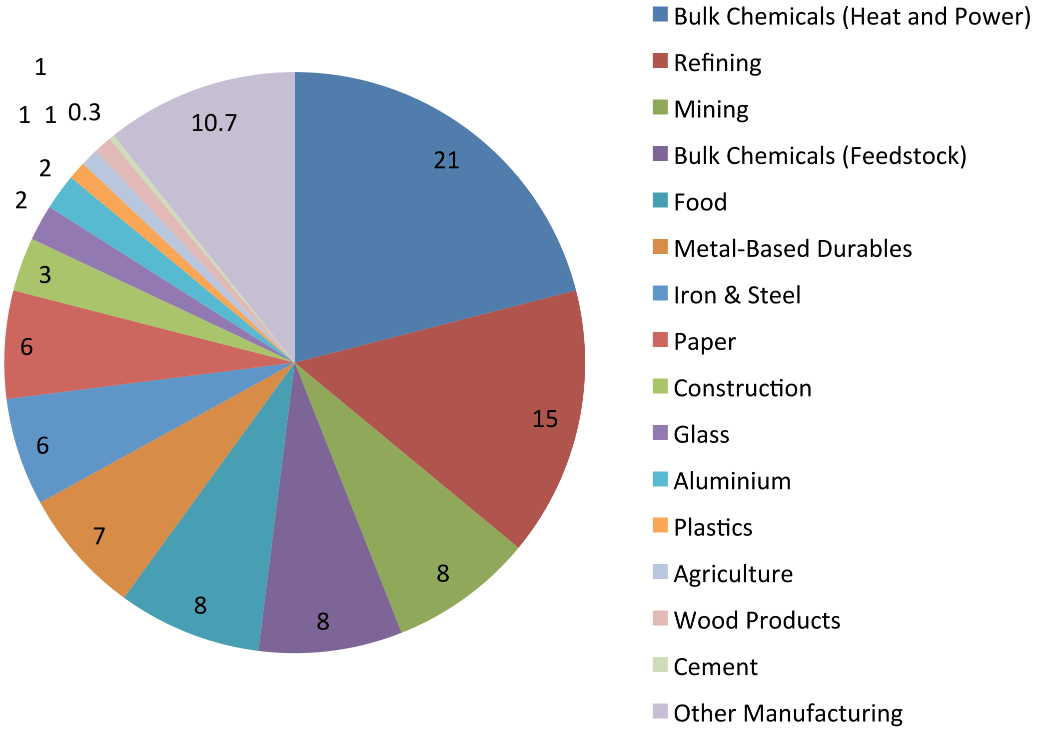

Figure I-8: Industrial Natural Gas Consumption by Subsector (2006) (Center for Climate and Energy Solutions)

tical products or fertilizers.

Often, natural gas is subjected to a steam reforming process, which leads to “synthesis gas”, a mixture of hydrogen and carbon oxides. This synthesis gas is further processed to form methanol, which is a reactant to a lot of follow-up products (NGSA, 2010).

I.3.2.3. Residential/Commercial Sector

Due to actually low prices in comparison to other conventional energy sources and rising efficiencies, the demand of natural gas in the residential sector is expected to grow until about 2015 (EIA, Annual Energy Outlook 2011, 2011). Comparable to industrial uses (but in a minor scale), heating and cooking are the main applications in the residential sector. Prospectively, another interesting use of natural gas may be the generation of electricity by means of fuel cells (NGSA, 2010).

The natural gas use in the commercial sector (public and private enterprises) is quite similar to the one of the residential sector. As mentioned above, the most important applications are heating of buildings and water as well as cooling.

I.4. Outlook/future prospects

The global energy consumption is growing rapidly due to increasing use of energy-intensive processes, technologies etc. (cf. Figure I-10). This trend is displayed in the number of world primary energy consumption, which grew by 5.6% in 2010. This was the largest increase since 1973 (BP, 2011). Directly related to this is the global situation in oil and gas consumption, which shows two major trends. On one hand there is a constant to slightly increasing trend in the developed countries, on the other hand there is a strong increasing trend in developing countries, especially in China and India (BGR, 2010; BP, 2011). According to the BGR study (2011) on energy sources, it will be no problem to guarantee the gas supply for the next decades but the situation for oil is somewhat different. The current state of knowledge is that oil reserves are limited and will meet the demand for approximately two and a half more decades. This implies a necessity for substitution or other solutions. Furthermore there is an increasing interest in environmental topics and thus sustainable development in some countries, especially in Europe.

Conceivable solutions to guarantee future energy supply are: usage of unconventional deposits, relating to the “oil problem” of limited reserves especially bituminous sands and oil shale, usage of gas hydrates and increasing usage of regenerative energies together with new energy storage concepts, e.g. “power to gas” (USGS, 2011; BGR, 2010; World Energy Council, 2010; DENA, 2011; IFM Geomar, 2005). But in the interaction of supply and demand it also possible that power saving will play a major role in the future.

However, it should be taken into account that oil is used for various other applications besides fuel, as mentioned above (Behr, 2010). For some of these applications substitute materials do not exist or they are not economically producible. Therefore it can be stated that today’s industry and economy, and thus our standard of living, are highly dependent on oil. According to Behr (2010) oil is the most important resource for the chemical industry since the middle of the 20th century. And even if this phenomenon is quite new, it is hard to imagine a world without oil. Major questions besides the maintenance of energy supply would be how to guarantee the supply with food, clothing, synthetics and even medicines – especially with a continuing growth in world population. Therefore it is likely that in the future oil will mainly be used for other purposes than fuel and that the research for substitutes will increase.

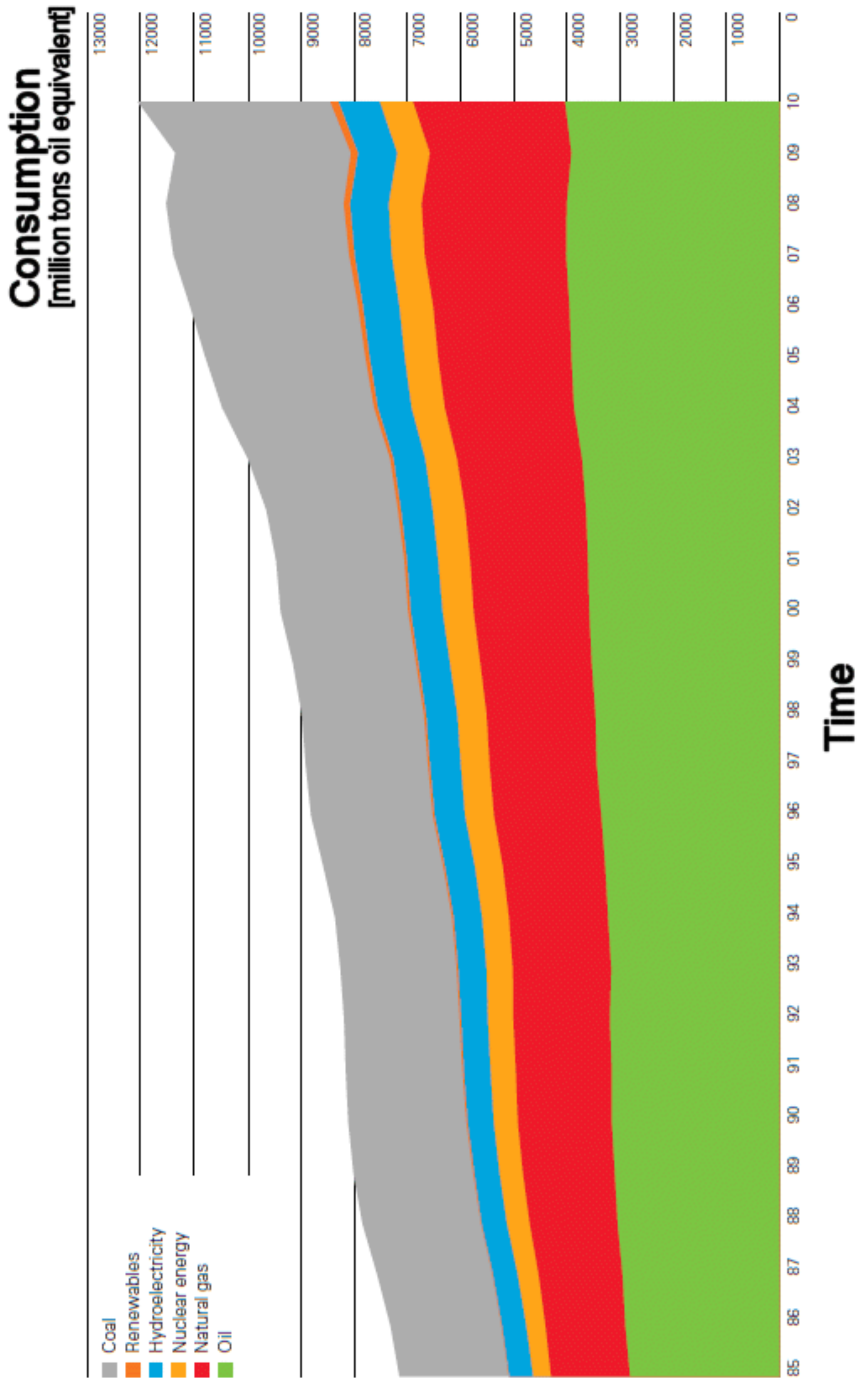

Figure I-9: World Energy Consumption, modified after (BP, 2011)

I.5. References

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I.6. List of Figures

I.7. List of Tables

II. Production and Transport Cost of Oil and Gas

Diana Chaves, David Bulmann, Markus Mueller

Abstract

This chapter deals with the total upstream costs of the oil and natural gas industry. These are the costs spent for the finding of hydrocarbon reservoirs, lifting of the fossil fuels and environmental expenditures to meet the sustainability requirements.

Finding costs comprise the exploration of the subsurface in regards to determine the location on possible hydrocarbon deposits. This includes geophysical, geochemical and geological exploration as well as drilling of explorational wells. The costs for these activities vary significantly depending on the location of the possible site of the reservoir and the environmental conditions.

Lifting costs include all activities executed to extract the hydrocarbons from the reservoir. These operations require extensive infrastructure, facilities and equipment and labor, executed by well-educated staff. Besides the extraction of the fossil fuels their transportation and the costs related to these processes have a big impact on the lifting costs, and therefore on the upstream costs in general.

The environmental expenditures are part of the producing company's sustainability efforts. These are the costs that arise when the production of a reservoir is executed as environmentally friendly as possible while still being economic. Included in these costs is the disposal of waste material, the containment of pollution and the expenditures paid to communities that are negatively affected by the company's activities.

II.1. Introduction

The goal of this chapter is to give an overview on how the costs for the production and transport of oil and gas come together, which aspects of the production have to be considered and what expenses incurred.

Production costs for hydrocarbons can be divided into three types corresponding to phases of the production process. These costs, which incur in the run up to the production, during the production phase and after the reservoir has been exploited, are called “upstream costs” (Rempel & Babies, 2009). They have a significant impact on the total costs for the end products of the hydrocarbon industry. The percentage distribution of the upstream costs on the end product, in this case oil and gas, is shown in Figure II-1.

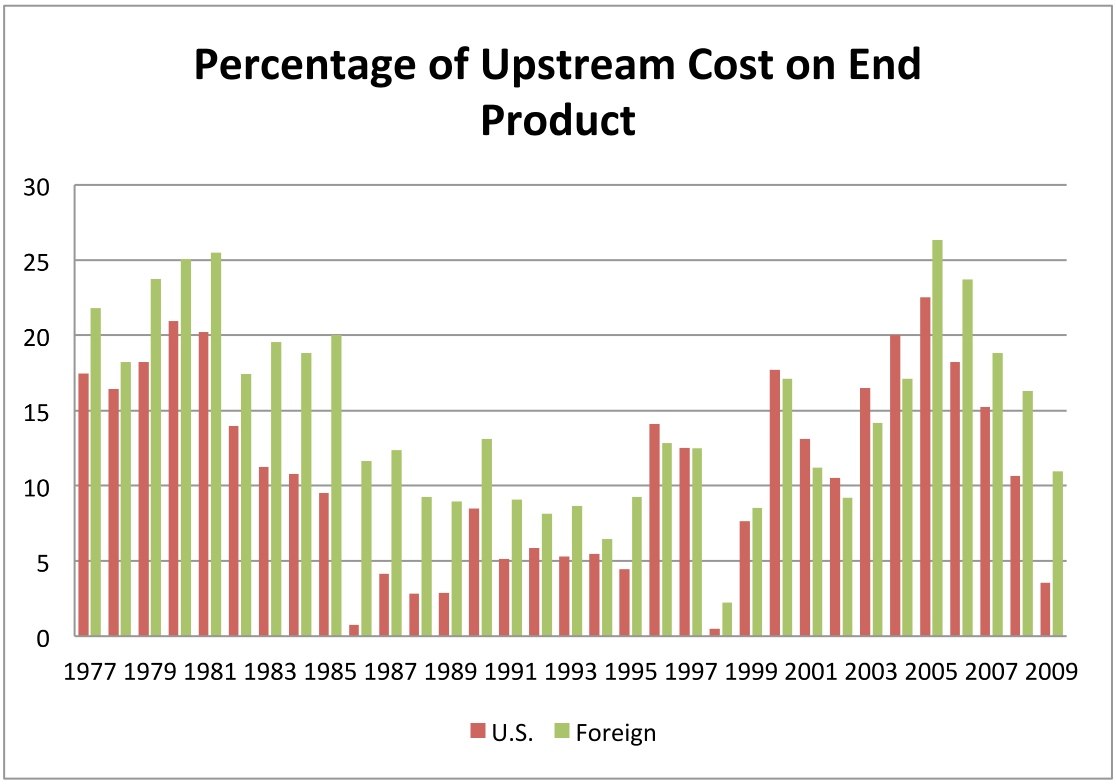

Figure II-1: Percentage of Upstream Cost on End Product (modified after EIA, 2011).

The cost types, dealing with the three mentioned fields of the production, are referred to as *finding costs*, *lifting costs* and *environmental expenditures*. Each of these can be subdivided into further more specified kinds of costs.

II.2. Finding

A great part of the initial investment costs are the expenditures for finding oil and gas reservoirs. These costs can vary significantly with the geological situation of the reservoirs and are associated with off- and onshore localization of the deposits.

The most common performance measure of these costs is “Finding Costs per BOE”. This measure is quite difficult to obtain, but it allows evaluating the efficiency of a company in adding new reserves (Wright & Gallun, 2008).

It is difficult to make a comparison between different companies, because there is no unique definition of what is included in the finding costs. Furthermore, the financial statements of companies have a typical time difference between periods when finding costs were added, and the periods in which the new reserves are actually reported. Consequently, an assessment of the Finding Costs per BOE ratio is difficult to determine (Wright & Gallun, 2008). Owing to this, there are two methods of accounting for exploration and development costs, which are currently accepted in practice. These are the *successful effort method* and the *full cost method*. Within the successful effort method the geological and geophysical (G&G) exploration costs are written off as incurred costs. However, the costs of dry exploratory wells are written off when the conclusion is made that the well is dry. Hence, only the costs for successful exploratory wells and successful dry development wells are capitalized and amortized (Wright & Gallun, 2008).

In contrast to the successful effort method, in the full cost method all costs incurred in exploration, drilling and development are capitalized and amortized. To get comparable outcomes it has to be determined which reserves should be used to correspond to the costs. Eventually finding costs can be calculated as follows:

$$\text{Finding costs}/_{BOE} = \frac{\text{G\&G exploration costs} + \text{All exploratory drilling costs}}{\text{Reserve extension \& discoveries} + \text{Revisions in previous estimates}}$$

Unfortunately, there is no unique way of calculation. Some analysts include current reserve revisions, while others exclude those (Wright & Gallun, 2008).

The following section provides an overview on the different capabilities of oil and gas exploration and their costs.

II.2.1. Exploration

In general explorational costs are part of the total upstream costs of the oil and gas industry.

To prove the potential of oil or gas reservoirs in a sedimentary basin, exploratory wells are needed. The total costs of these wells depend on environmental conditions, equipment and personnel. Furthermore, the costs also rise exponentially with increasing depth of the well (Wiley et al., 2007).

Therefore, geologists, geophysicists and geochemists must conduct a risk analysis for the exploration phase. Subsequently an analysis of the receipts and expenditure over the whole life cycle of the expected oil field must be created. Thus, the crucial point for exploration is the return on investment (Wiley et al., 2007).

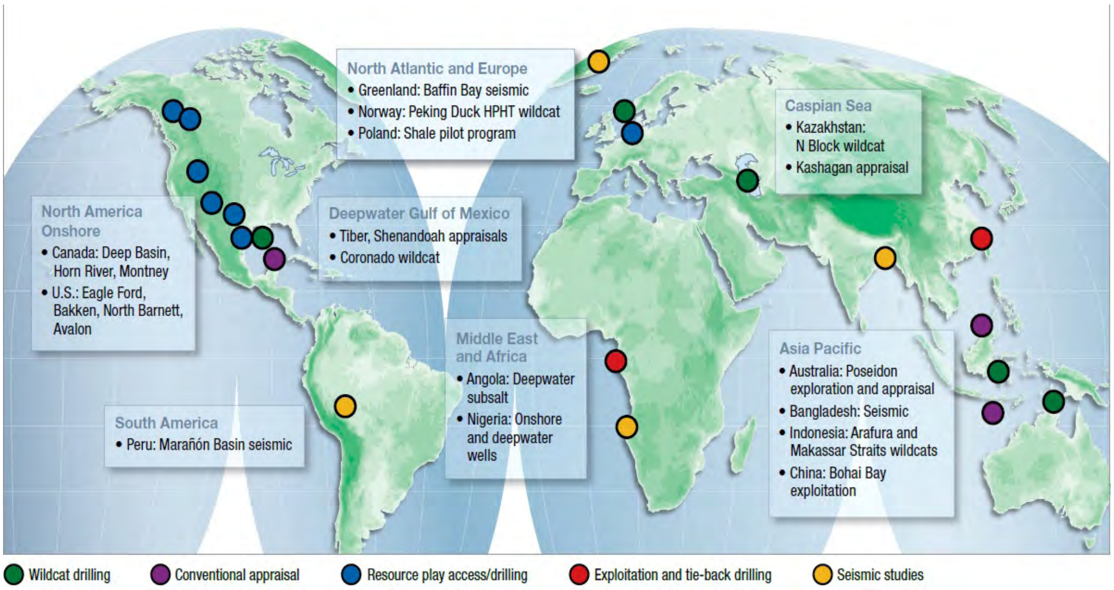

Figure II-2: Exploration and Production Worldwide Operations (ConocoPhillips, 2011)

A major player in this business worldwide is BP, which runs explorational activities in 26 countries. According to them they are the leading explorer in industry. One of the biggest competitors is the Hess Corporation, a big petrochemical company, which has exploration and production operations in about 20 countries. Another major player in this business is the Conoco Phillips Company, which is the fifth largest private sector energy corporation in the world and is one of the six supermajor vertically integrated oil companies. In other words it is one of the world's six largest publicly-owned oil and gas companies. The worldwide exploration and production operations of this company are demonstrated in Figure II-2.

Also, there is ExxonMobil. Exxon is the biggest company in the world measured by their market revenue. The daily production of Exxon totals about 3.9 Million BOE.

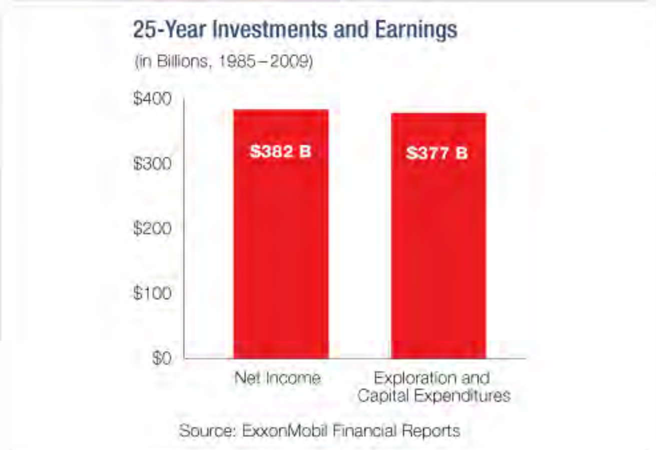

Figure II-3: 25-Year Investments and Earnings of ExxonMobil (ExxonMobil, 2010)

ExxonMobil had exploration expenditures of about $ 17 billion in 2005 and operating costs for exploration of almost $ 1 billion. Figure II-3 shows the investment and earnings of ExxonMobil in a 25 year period.

II.2.1.1. Seismic Exploration

Usually, exploration starts with the collection of seismic data. The seismic reflection method is the central element of modern exploration since the 1970s. This is mainly, because of the digital recording and collection of data, as well as the increased availability of processing and interpretation programs. Conclusions on stratigraphic sequences and geological beds can be delivered very precisely by these methods (Wiley et al., 2007).

The fundamental principle of these methods is the measurement of the transit time of artificially generated elastic waves, e.g. generated by detonation of explosive charges placed in boreholes. In addition to this method, other energy sources are also used nowadays. A good example is the vibroseis method, whereby a steel plate fixed below a truck is pressed by the weight of the truck onto the ground and transmits waves to the underground by a vibrator. The frequency of the transmitted waves can be controlled. So, four to six trucks can operate simultaneously. A great advantage of this method is the possibility to work on roads and tracks in populated areas. Therefore, this method is not only more rapid, but also cheaper than other methods (Wiley et al., 2007).

For the seismic measurements in offshore regions the airgun method is the most often used technique. Highly compressed air is suddenly released and a large number of recording vessels measure the reflected waves. This method is often self-financed by seismic companies, which sell the measurements to oil companies (Wiley et al., 2007).

An upcoming and more and more often used method in exploration is the three dimensional seismic method, which is nowadays common in characterization of proved deposits. In contrast to the line seismic method the 3D seismic uses cross lines. Geophones, which are placed with distances of 25 m, record the waves, released by explosives fired from various sides. As in the line seismic method the digital recorded results are interpreted with usual computer programs. Due to the large number of geophones, in some instances several thousands, a large number of staff is needed, up to 350 persons. This makes this method very expensive. Wiley et al. (2007) give a sample calculation, which documents the costs for 3D seismic profile per km² (see Table II-1).

Table II-1: Sample calculation 3D seismic method (Wiley et al., 2007)

Area of survey	300 km²
Surveying party size	140 employees
	32 vehicles
	1,000 tracks
Geophones	14,400
Optical-fiber cable	71,500 m
Bore holes	15,076
Drilling meterage	157,183
Scanning points	480,000
Cost	ca. $ 7.5 Mio
Cost per km²	$ 25,000

II.2.1.2. Exploration Cost Examples

To clarify the role of exploration expenditures, some graphs are shown in this section. The data of these figures have been released by the U.S. Energy Information Agency in 2011.

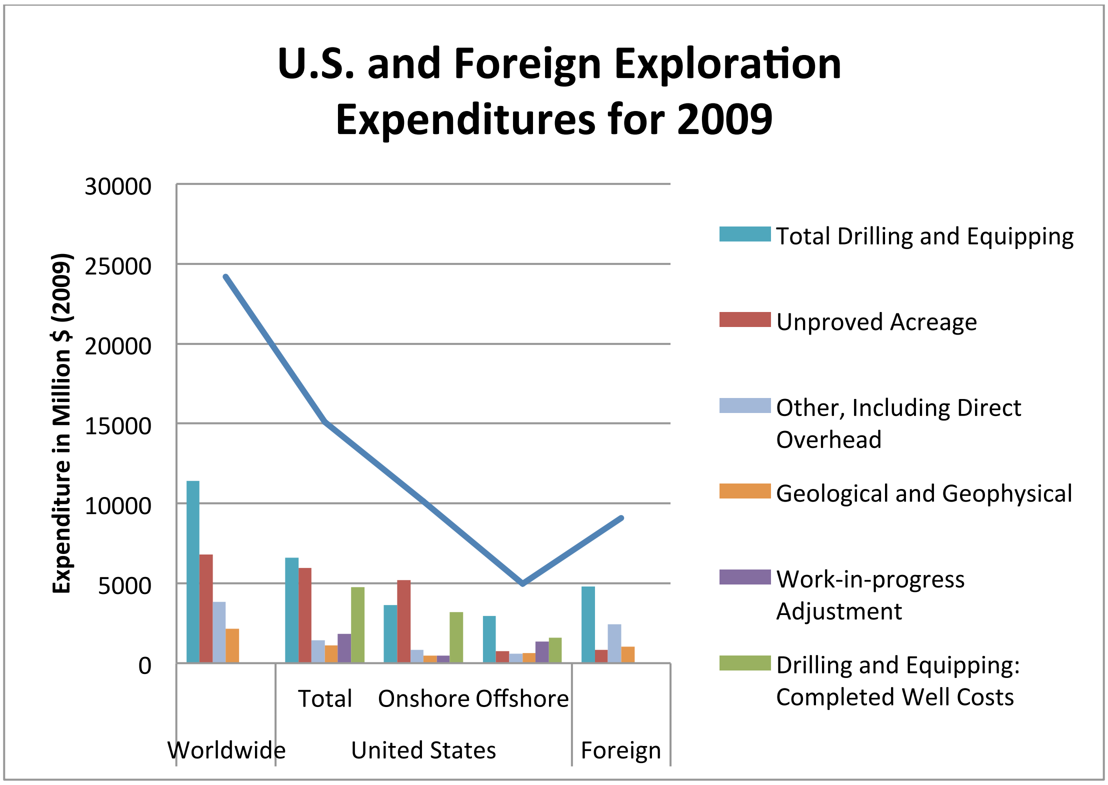

Figure II-4: Exploration Expenditures in 2009 (modified after EIA, 2011)

Figure II-4 shows the exploration expenditures in 2009 for the U.S. and foreign countries. These expenditures are subdivided into sub-categories, like drilling and equipping costs, geological and geophysical costs and unproved acreage.

The biggest cost factors in exploration are the total drilling and equipping expenditures. In 2009 the worldwide they amount to $ 11,500 million. Evidently, geological and geophysical exploration costs are marginal. Additionally, it should be noted that the U.S. expenses for exploration amount to more than half of the worldwide exploration expenditures.

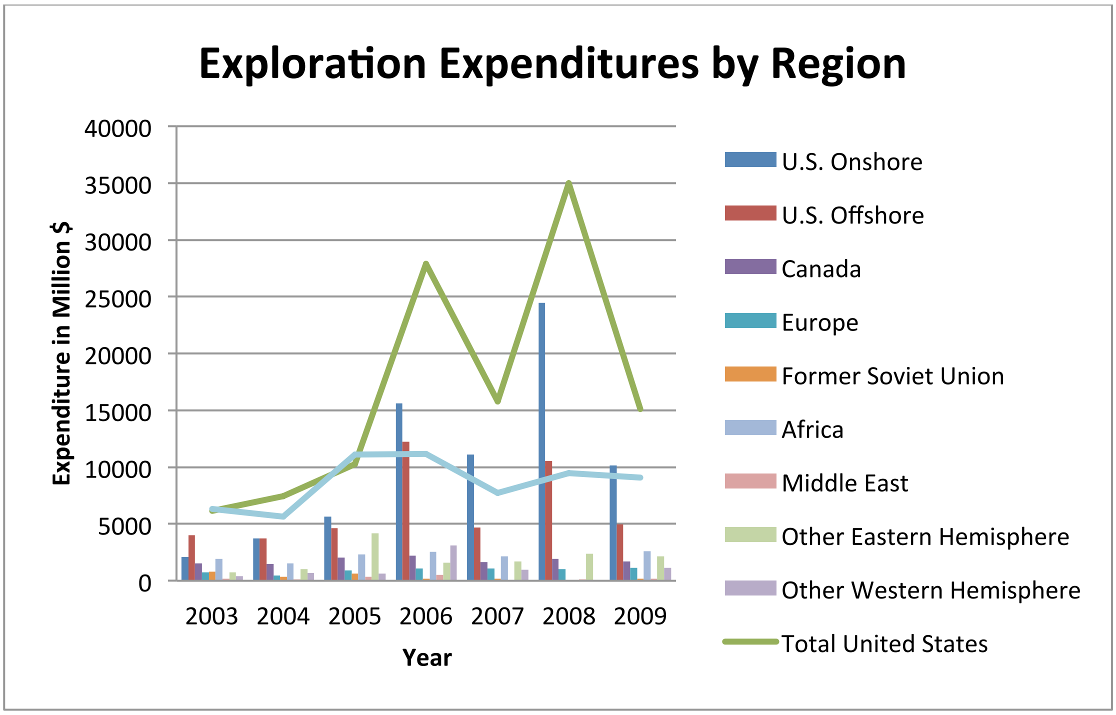

Figure II-5: Exploration Expenditures by Region (modified after EIA, 2011)

Figure II-5 shows that during the last decade U.S. onshore exploration became more important than offshore exploration. In 2003 the offshore exploration expenses surmounted the onshore exploration expenses. One year later they were balanced, but in the following years this ratio turned over. The peak of U.S. onshore exploration was in 2008 with a total expense of about $ 24,000 Million. In fact, the U.S. exploration expenditures in the period from 2006 to 2008 were exceptionally high in comparison to previous years. The peak was in 2008 with a total expense of $ 35,000 Million. On the contrary, the exploration expenditures of the other countries were relatively stable.

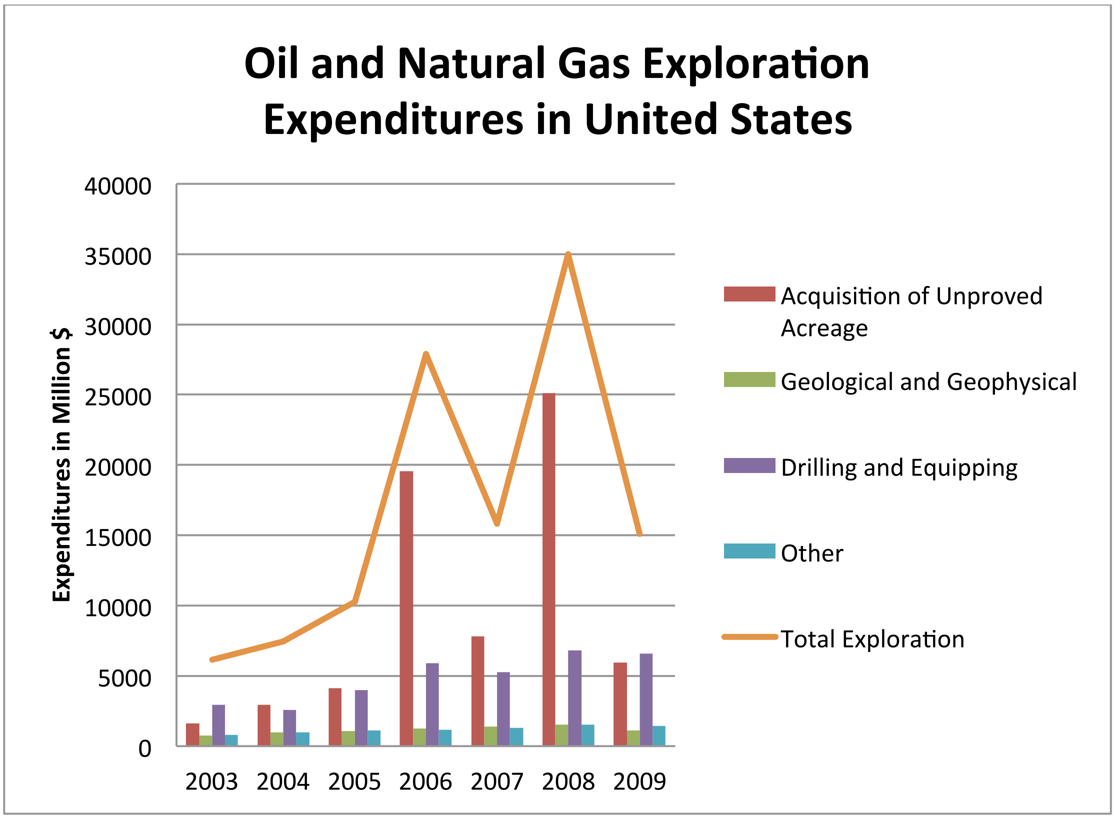

Figure II-6: Development of U.S. Oil and Gas Exploration Expenditure (modified after EIA, 2011)

Again, the trend of high exploration expenses of the U.S. exploration in the period from 2006 to 2008 is presented in Figure II-6. The main reasons for this are the dumps for the acquisition of unproved acreages. These climbed highly in 2006 and 2008 with a peak of $ 25,000 Million. This can be seen as the reason for the high exploration expenditures in this period. Besides this, the second factor is the drilling and equipping costs.

In the same way, the exploration expenditures for the non-U.S. countries had their peak in 2006, also due to intense acquisition of unproved acreage (Figure II-7). These costs dropped down quite abruptly in 2007 resulting in a decrease of total exploration expenditures. However, the costs for drilling and equipping rise steadily since 2003. One reason for this is the increasing tendency to drill in areas which are difficult to access. Even though, the expenses for geological and geophysical exploration are quite stable since 2003.

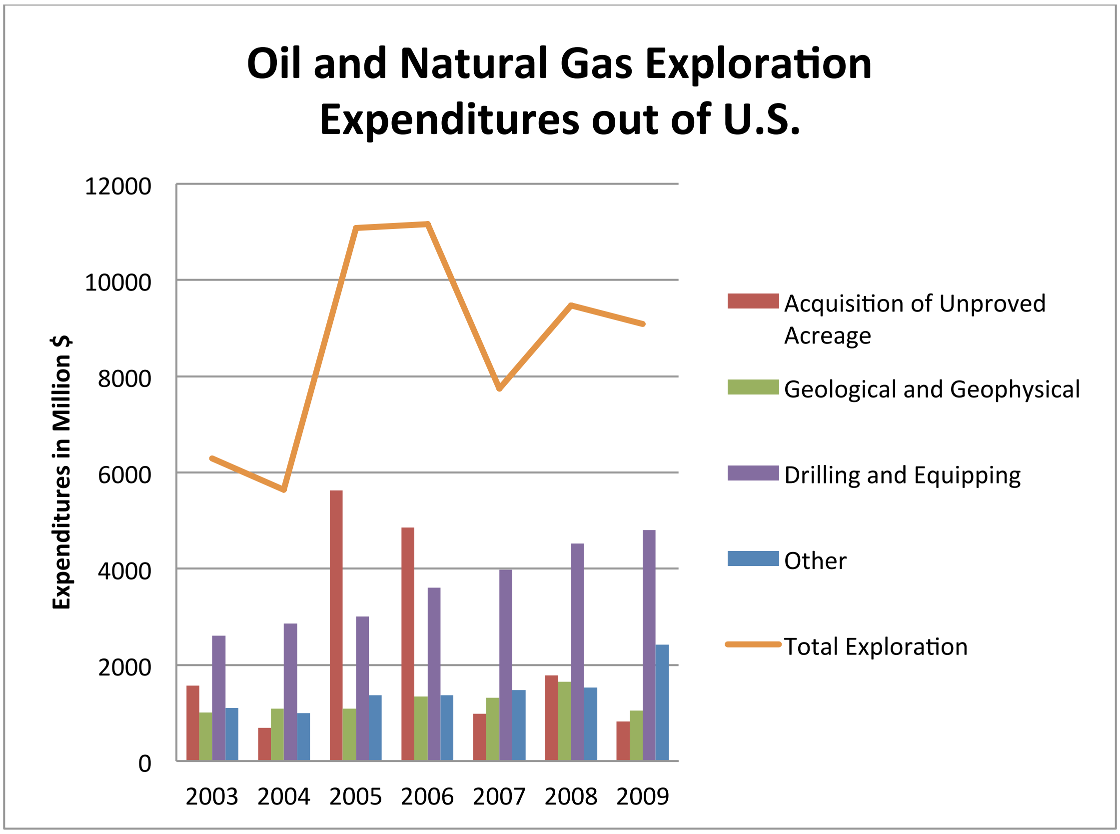

Figure II-7: Oil and Natural Gas Exploration Expenditures out of U.S. (modified after EIA, 2011)

The cost development of finding costs for the US (offshore), Africa and Europe is shown in Figure II-8. The finding costs remained stable from the early 90s till the beginning of the first decade of the 21st century followed by an abrupt rise in the period from 2001 to 2004. It is remarkable that U.S. offshore exploration costs exceed both, European and African exploration expenditures. In summary, there is a trend of rising exploration expenditures since 2001 for all three regions.

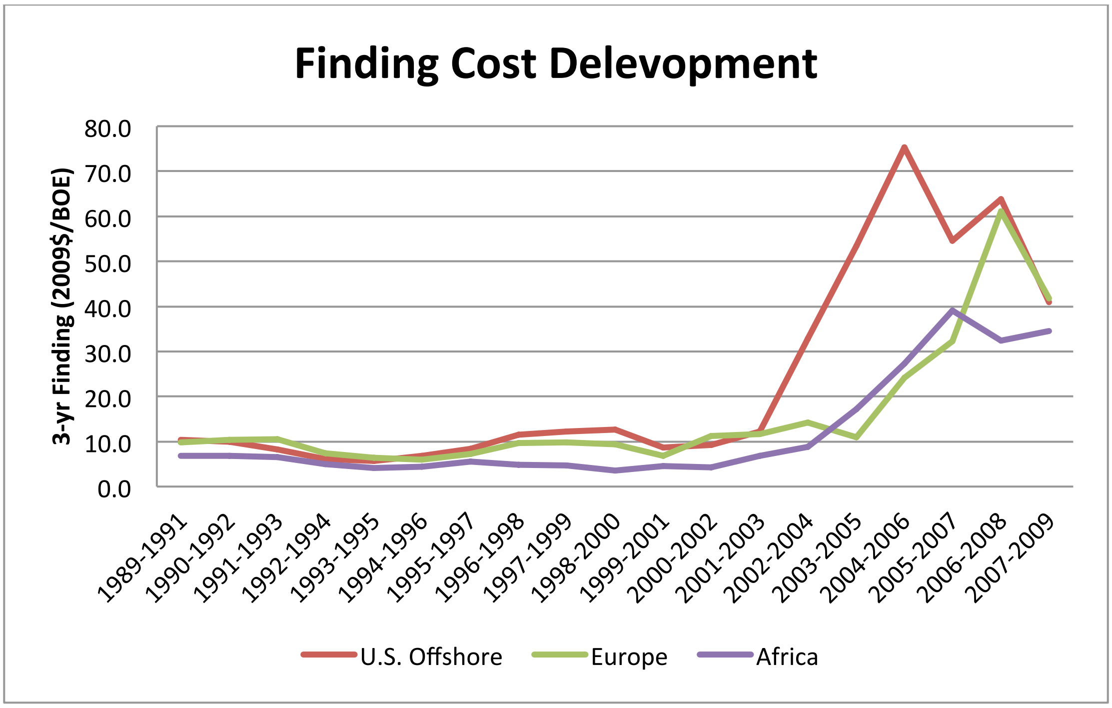

Figure II-8: Finding Cost Development (modified after EIA, 2011)

II.2.1.3. Example: Tahiti Reservoir by Chevron

Once a gas or oil reservoir is discovered, billions of additional dollars must be spent before the well can start to produce and bring revenue. Oil exploration costs in an offshore region can amount to between $ 200,000 and $ 759,000 per day per site (Mason, 2009). This is exemplified by the 'Tahiti' project of the Chevron Company. This project in the Gulf of Mexico is representative for the large investment of firms prior to the start of production. The reservoir is located 306 km off the U.S. coast, near New Orleans at a depth of 1.2 km (Chevron, 2009). The reservoir is estimated to hold 400 to 500 Million Barrels of oil and gas equivalent (Mason, 2009). Chevron envisaged a 7 year period to build the necessary infrastructure and start production, with an estimated investment of $ 4.7 billion. Taking a midterm value of 450 Mio barrels of oil equivalent, up-front development cost will amount about $ 10.44 per barrel of oil resource and $ 1.86 per 28 m² gas resources (Mason, 2009). Chevron also estimated that this project will produce for a period up to 30 years. The long time lapse between the initial investment period of 7 years and the average production period of 30 years is a characteristic feature of this kind of projects. This one represents only one of 40 projects in which Chevron's share of investment is over $ 1 billion (Chevron, 2009).

II.2.2. Field Development

As a transition stage between finding and lifting, field development is the project phase in which a reservoir is made economically producible, mainly due to the drilling of suitable production wells.

Development costs are given by the following equation:

$$Finding\ and\ Development\ costs/_{BOE} = \frac{\text{G\&G exploration costs} + \text{All exploratory and development drilling costs} + \text{proved and unproved property acquisition costs}}{All\ reserve\ additions\ (including\ revisions)}$$

This equation gives the total finding and development cost ratio for a reservoir (Modified after Wright & Gallun, 2008).

Worldwide development expenditures divided by activities, material and equipment are shown in Figure II-9.

Long term installation of infrastructure such as production rigs, pipelines, compactors and similar machines and equipment can be considered as field development as well (Rempel & Babies,2009), but are excluded from the equation given above. They are included in the equation for lifting costs, given in section II.3. Lifting.

These installations are the link to the lifting costs, where the ongoing activities require the use of different kinds of equipment and material.

Like all costs in the finding process, field development costs vary with the regional setting, associated difficulties and labor costs in the area. An overview of the development expenditures per region is given in Figure II-10.

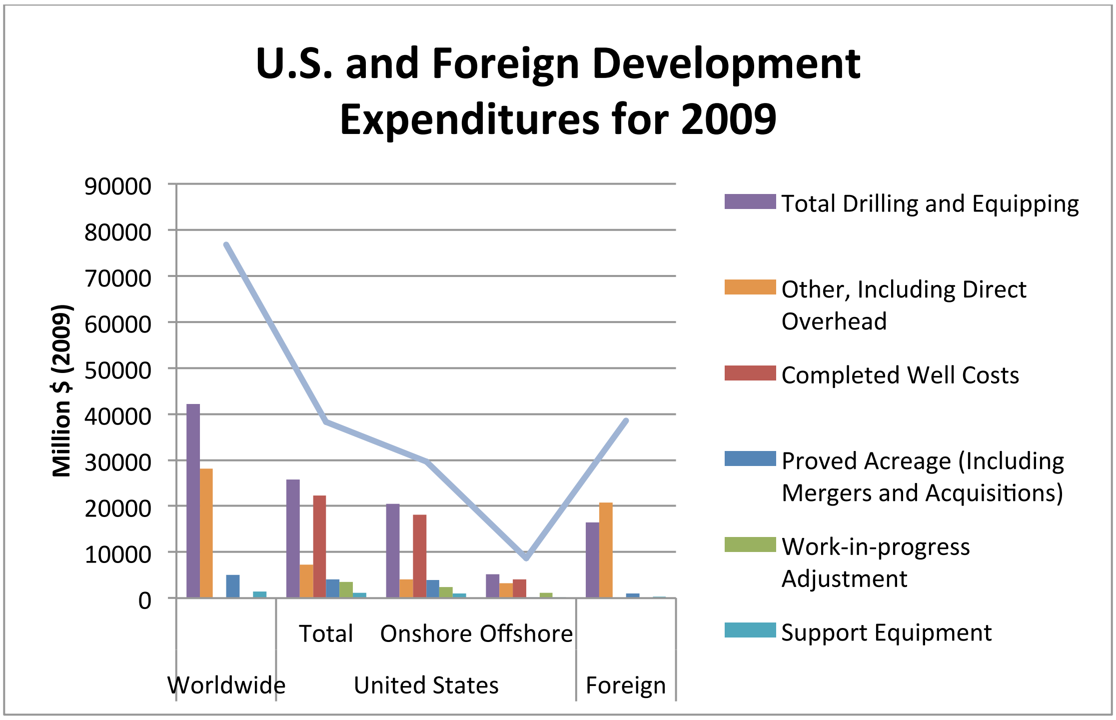

Figure II-9: U.S. and Foreign Development Expenditures for 2009 (modified after EIA, 2011)

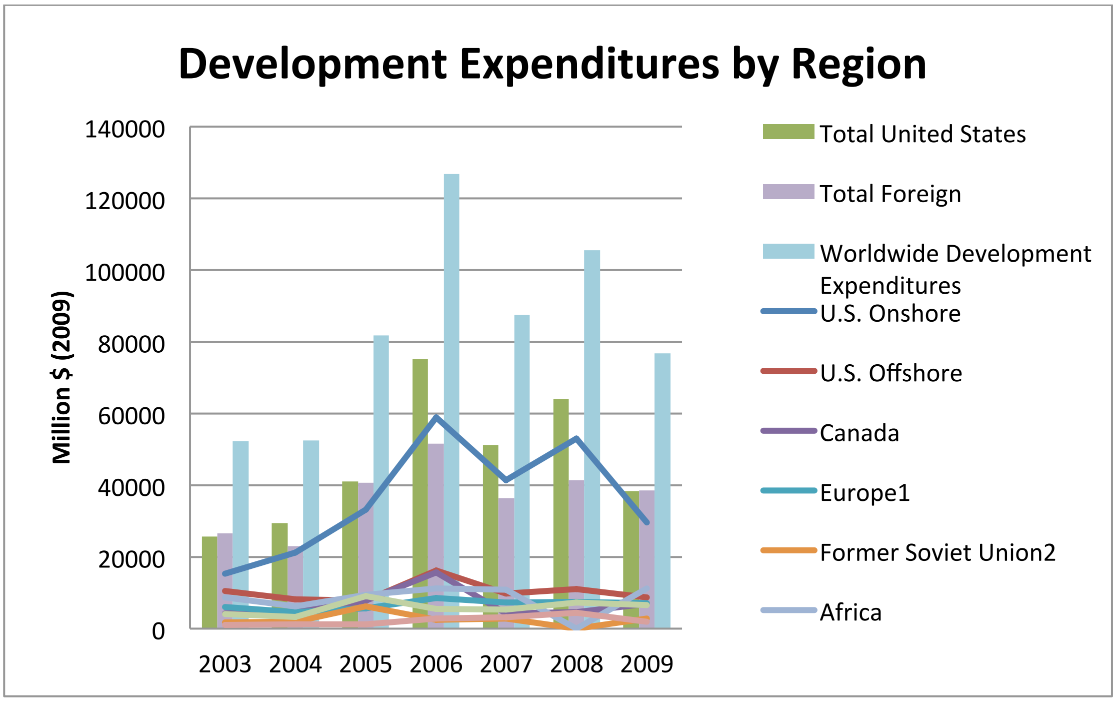

Figure II-10: Development Expenditures by Region (modified after EIA, 2011)

II.3. Lifting

Lifting includes all activities executed to extract the hydrocarbons from the reservoir. It describes the ongoing operations performed at a well after the initial explorational drilling and field development has been done. Another aspect of the lifting process is the transportation of the mined good. All of these actions require special infrastructure, facilities and equipment, besides labor, executed by well-trained workers and supervisors.

Lifting costs, as a part of the Total Upstream Costs, therefore consist of a variety of expenditures, which can be summarized as follows:

1. Transportation costs, including the handling of the hydrocarbons via ship, road, rail and pipeline
2. Labor costs, meaning the labor performed on the production site and the work executed in the transportation process
3. Costs of supervision
4. Supplies, like chemicals, drilling mud additives, etc.
5. Costs of operating the pumps
6. Electricity
7. Repairs
8. Royalties payable to the lessor
9. Taxes

All of the above-mentioned costs vary depending on the geological and geographical location of the production site and the degree of difficulty associated with the environmental surrounding. They are regulated by the demand and price for energy and the current economic situation in the region. This is especially the case for labor costs.

Royalties to the landowner, which are specified in the lease agreement, also differ by the area where production takes place and is often highly regulated by governments (Oil and Gas Industry, 1996).

For these reasons Lifting costs per Barrel of oil equivalent can be mainly distinguished by geographical position (Table II-2).

Table II-2: Costs for Producing Crude Oil and Natural Gas, 2007–2009, 2009 US Dollars per BOE (EIA, 2011).

	Lifting Costs	**Costs Finding Costs**	**Total Upstream Costs**
United States – Average	$12.18	$21.58	$33.76
On-shore	$12.73	$18.65	$31.38
Off-shore	$10.09	$41.51	$51.60
All Other Countries – Average	$9.95	$15.13	$25.08
Canada	$12.69	$12.07	$24.76
Africa	$10.31	$35.01	$45.32
Middle East	$9.89	$6.99	$16.88
Central & South America	$6.21	$20.43	$26.64

In this regard the onshore or offshore location of the production site is the next biggest factor influencing the expenses for the production. In comparison to offshore finding costs, which are much higher than onshore finding costs, offshore lifting costs, for example in the U.S., are about 20 % cheaper than onshore lifting costs (Table II-2). This is due to the different ways of transportation and the related costs, which will be dealt with in section II-3.2. Transport Costs.

To measure how efficiently the production process is working it is important to calculate the cost to production ration, which is given by the following equation:

$$Lifting\ Costs\Big/_{BOE} = \frac{Total\ annual\ lifting\ costs}{Annual\ Production\ [BOE]}$$

Where Lifting costs give the real value in a specific currency, total annual lifting costs are the entire above mentioned costs added up and annual production being the amount of hydrocarbons produced during the year (Wright & Gallun, 2008).

With this equation given it has to be brought to attention that the lifting costs per BOE are no measurement for the profitability of a company's production process, but only a calculation on how much money has to be spent to produce one BOE. To make a statement about the profitability, revenues and net income of the company's commercial operations have to be considered. If, for example, a company has a higher lifting cost per BOE ratio than its competitor, but produces a product of higher quality, it can be sold for a higher price, and therefore result in a higher profit per BOE (Wright & Gallun, 2008).

Overall lifting costs from 2003 until 2009, divided by region, are shown in Figure II-11.

Lifting can furthermore be divided into three units, which all play a crucial role in the price development of the oil and gas production. These are field development, operating and production and transport.

To give an understanding on how each of these affect the total lifting costs and to get to further grasp of the production process in general, they will be explained in the following sections.

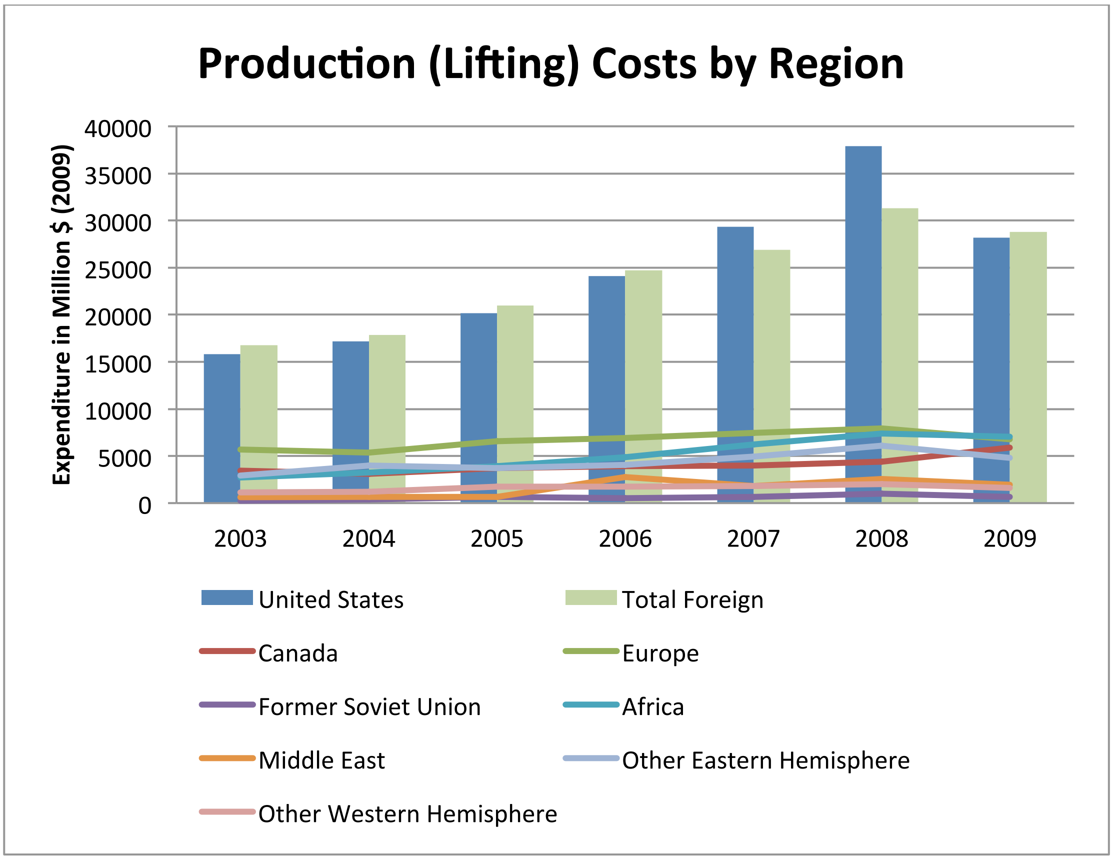

Figure II-11: Lifting Costs by Region (modified after EIA, 2011).

II.3.1. Operating and Production

After field development has been finished, the regular production of oil and natural gas can begin. This is an on-going process that lasts, depending on the capacity and content of the reservoir, 25 years on average (Karl, 2010). The costs for production and operating are again influenced by the difficulties and challenges the environmental situation poses, as well as the costs for labor that vary by region.

Table II-3: Prices for Offshore Rigs, Global Rig Fleet and Utilization (Rigzone.com, 2012)

Floating Rigs			
Rig Type	Rigs Working	Total Rig Fleet	Average Day Rate
Drillship < 4000' WD	5 rigs	8 rigs	$247,000
Drillship 4000'+ WD	44 rigs	65 rigs	$454,000
Semisub < 1500' WD	11 rigs	17 rigs	$233,000
Semisub 1500'+ WD	57 rigs	87 rigs	$303,000
Semisub 4000'+ WD	86 rigs	106 rigs	$405,000

Jackup Rigs			
Rig Type	Rigs Working	Total Rig Fleet	Average Day Rate
Jackup IC < 250' WD	31 rigs	53 rigs	$71,000
Jackup IC 250' WD	43 rigs	63 rigs	$76,000
Jackup IC 300' WD	89 rigs	134 rigs	$88,000
Jackup IC 300'+ WD	126 rigs	155 rigs	$145,000
Jackup IS < 250' WD	5 rigs	8 rigs	--
Jackup IS 250' WD	6 rigs	9 rigs	--
Jackup IS 300' WD	2 rigs	5 rigs	$60,000
Jackup IS 300'+ WD	1 rigs	3 rigs	$70,000
Jackup MC < 200' WD	3 rigs	12 rigs	$36,000
Jackup MC 200'+ WD	13 rigs	28 rigs	$51,000
Jackup MS < 200' WD	2 rigs	2 rigs	--
Jackup MS 200'+ WD	6 rigs	19 rigs	$45,000

Other Offshore Rigs			
Rig Type	Rigs Working	Total Rig Fleet	Average Day Rate
Drill Barge < 150' WD	18 rigs	39 rigs	--
Drill Barge 150'+ WD	6 rigs	9 rigs	--
Inland Barge	11 rigs	74 rigs	$52,000
Platform Rig	140 rigs	250 rigs	$36,000
Submersible	0 rigs	5 rigs	--
Tender	25 rigs	32 rigs	$131,000

As mentioned before, specific infrastructure and equipment has to be implemented to produce and transport hydrocarbons. For production two general locations can be distinguished. These are offshore and onshore production.

Costs for offshore production strongly depend on the geological setting of the reservoir and water depth. Daily rates for rigs in the deep-sea regions are significantly higher than daily rates for rigs in shallow marine environments. An average rate for a floating rig is, for example, $ 328,400 per day, while a Jackup rig, operating in shallower areas, costs $ 71,333 a day on average. Mobile drilling ships that can drill in water depth of more than 4,000 m reach the highest prices with $ 454,000 per day. A detailed list of offshore rig prices is given in Table II-3.
Another factor influencing the day rates for production rigs is the current demand for rigs per region, and the utilization of available rigs in the area of interest. If, for example, the demand for production rigs is very high in a specific region and the utilization of the rig fleet is at 90 % or more, prices for the still available 10 % can rise significantly, if the remaining rigs are suited for the planned operation.
As with offshore rigs, the prices for onshore rigs strongly depend on the geographical setting and on how deep the well needs to be drilled. While onshore operations are much cheaper than offshore operations on a daily average, the overall lifting costs are higher (Table II-2). Average onshore drilling rig day rates in the period from 1999 to 2010 for the USA are given in Figure II-12. This is due to the different ways of transportation in the offshore and onshore sector and the related costs, which will be dealt with in section II-3.2. Transportation Costs.

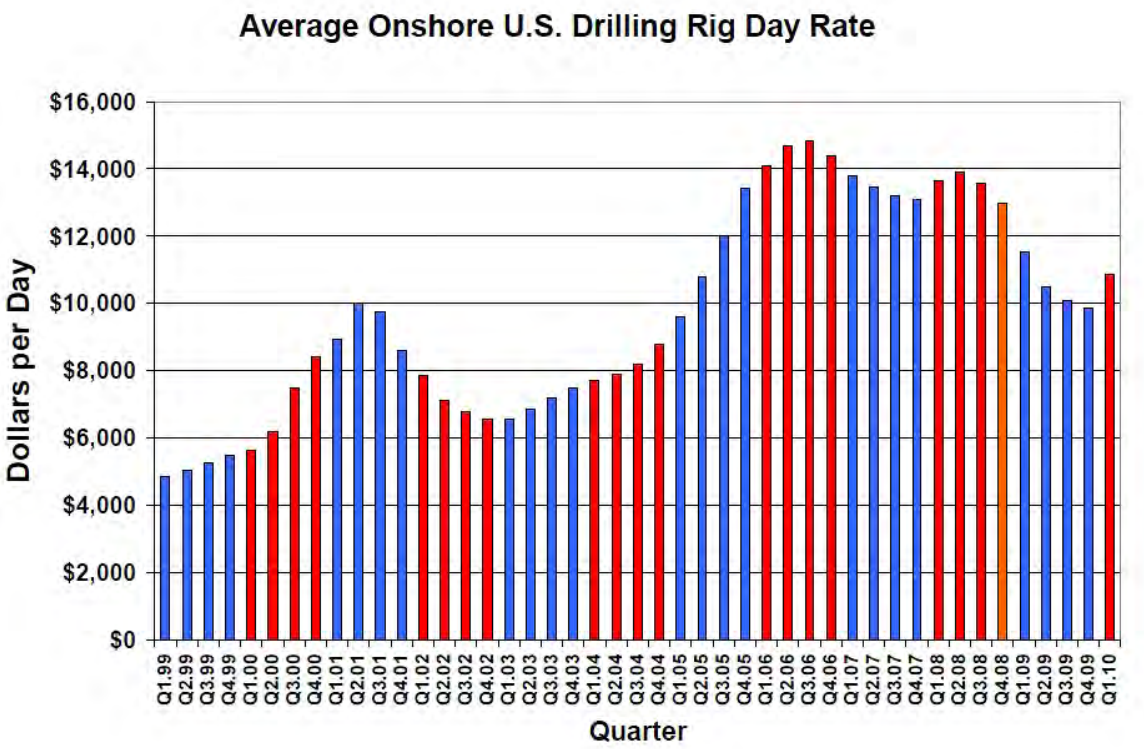

Figure II-12: Average day rate for onshore drilling rigs in the USA (Winter 2010-11 U.S. Natural Gas Production and Supply Outlook)

The infrastructure needed to transport the produced goods is one of the most important factors influencing the total lifting costs. The different transport methods will be discussed first, while the actual transportation costs and their impact on the lifting costs will be described in section II-3.2. Transportation Costs.

Offshore transportation is obviously done by ship. Another way for offshore transport is the handling of oil and gas via pipeline. In the first case storage facilities and harbor capacities have to be implemented, before economical production can be initiated. In this regard one has to distinguish the transportation of oil and gas, because there is a significant difference in the energy density between the two fossil fuels.

Pipeline transportation on the other hand, which can be done offshore and onshore alike, requires large capital investments. For a pipeline with a total length of 484.6 km and a capacity of 410,000 barrels of crude oil per day, the pipe steel costs would be $ 202,000,000 on the basis of the steel prices in 2009. This price does not include coating, transportation and other related costs, which would sum up to about $ 470,000,000, for an onshore pipeline situated in Ecuador. If all factors are taken into account, including difficulties that arise during the construction of the pipe in the Amazon region and the facilities and equipment associated with the transport process, the total construction costs add up to an estimated $ 2,033,104,087 (Masrour, et al., 2009). A detailed cost overview is listed in Table II-4.

Another example for the cost intensity of pipeline construction is the Nord Stream pipeline, which connects Russia's gas fields with Europe. It is an offshore pipeline located in the Baltic Sea and will have a transport capacity of about 150,700,000 m^3 of natural gas per day. The offshore pipeline will have a total length of 2292 km and an estimated price of about 10,2 billion $. Additionally, 1,767 km of onshore pipeline had to be constructed in Russia and Germany to connect the Nord Stream pipeline to the gas fields and the European pipeline net (Nord Stream, 2011).

If onshore transportation is not done via pipeline, movement by train and truck are the alternatives. If a railroad network is already implemented, the transport by train is much cheaper than transportation by truck, while lorries have a significant advantage, because they are more flexible when the produced reservoir is located in poorly accessible areas. Constructing railroads in mountain ranges, for example, is highly cost intensive, while trucks can gain access via rural roads.

Especially the transportation costs by truck vary depending on the region, because labor costs tend to differ from country to country.

Table II-4: Benchmark cost estimate for pipeline project in Ecuador. All estimations based on labor, material and equipment costs in 2009 (modified after Masrour, et al., 2009)

Item	2009 $
Land	$7,031,408
R.O.W.	$36,759,467
Line pipe	$469,405,754
Line pipe fittings	$42,140,936
Pipeline construction	$575,083,042
Buildings	$39,989,068
Pumping equipment	$78,587,181
Machine tools, machinery	$90,687
Other station equip.	$114,071,445
Oil tanks	$83,344,942
Delivery facilities	$26,259,183
Communications systems	$6,223,127
Office furn. and equip.	$3,045,317
Vehicles, other work equip.	$7,000,088
Other	$4,487,521
TOTAL	**$1,493,519,166**
Add Ecuador Taxes	$399,584,920
Add Line Fill	$140,000,000
GRAND TOTAL ESTIMATE FOR PROJECT	**$2,033,104,087**

II.3.2. Transport

In general transport costs are the monetary measure of how much the provider must pay to provide the transportation service. They can be subdivided into fixed costs, which are the costs to use and maintain infrastructures, and variable costs, which are the operating costs during the transportation process. Both of these are influenced by a variety of conditions, of which distance and accessibility are the most basic ones. The longer the transport distance and the more difficult a good is to access, the more energy will be spent transporting it and therefore the price for transportation will increase (Rodrigue et al., 2009).

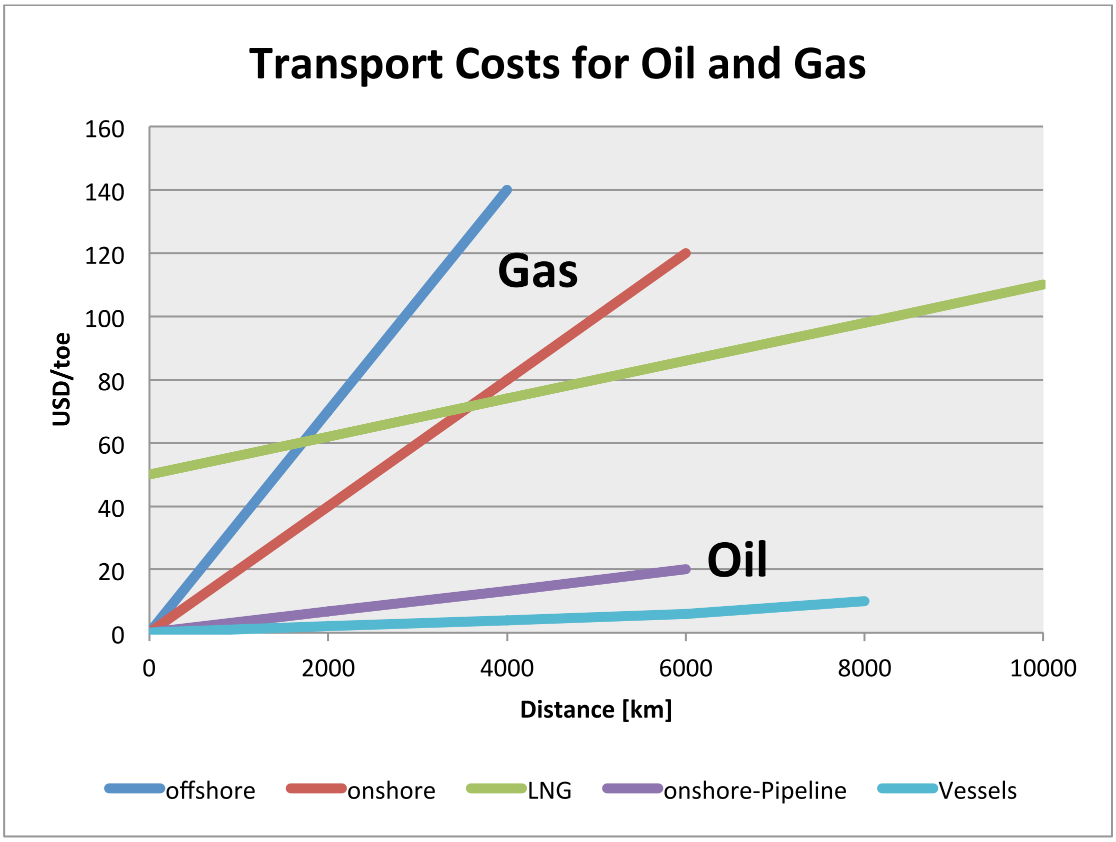

Figure II-13: Transport Costs for Oil and Gas by Distance (modified after Rempel & Babies, 2009)

Depending on the type of product, special handling is required, which increases the transportation costs according to the complexity of the activities necessary. For instance, the storage of oil is cheaper than the storage of gas, because the latter one needs to be compressed for efficient storing, which takes up an additional amount of energy. Insurance costs, which depend on the value to weight ratio and the risk associated with the movement of the product, have to be taken into account as well (Rodrigue et al., 2009).

Especially in the movement of fossil fuels the economies of scale come into play. This means that higher quantities of transported material lead to a lower transportation cost per unit. Therefore larger vessels and pipelines with larger diameters lead to lower transportation costs per BOE (Rodrigue et al., 2009).

For oil the offshore transport by ship is cheaper than the movement by pipeline, due its high energy density (Rempel et al., 2009). Long distances can be bridged with only little amounts of money spent per BOE (Figure II-13). It is therefore the most economical way for the offshore movement of crude oil.

Onshore pipelines for oil are a valuable option to truck and railway transport because the transportation costs decrease significantly once the investment for the pipeline construction is amortized.

Compared to crude oil the transportation costs for natural gas are much higher, because of the lower energy density of this fossil fuel. The costs for onshore and offshore transport via pipeline increase drastically with increasing distances, due to the high expenditures for construction and the large amount of energy needed to guarantee a steady gas flow (Figure II-13). Offshore transport of liquefied gas by vessels is an alternative to pipeline transportation, but is only useful for long-distance transport, because the liquefaction process takes up a considerable amount of energy (Rempel et al., 2009).

Depending on the diameter of the pipeline and the capacity of the LNG vessel, the break-even point for the movement of liquefied gas is reached at distances between 3000 and 4800 km for offshore transportation (Rempel et al., 2009).

II.4. Environmental expenditure

Environmental expenditures are part of the producing company's sustainability efforts. They are the costs that arise when the production of a reservoir is executed as environmentally friendly as possible while still being economic. Included in these costs is the disposal of waste material, the containment of pollution and the expenditures paid to communities that are negatively affected by the company's activities.

II.4.1. Renaturation

The exploitation and transport of oil and gas represents a major impact on the environment and the communities in the vicinity of these operations.

Communities in areas with a high population density, or in which land is owned in numerous small tracts, may be unwilling to accommodate large-scale drilling because of the disruption it would cause and the increased demands on local infrastructure, particular in transport. (WEO, 2009)

Oil and gas drilling have a large and invasive footprint on the landscape, because of the nature of drilling operations and the large number of wells needed to produce a given volume of gas. The treatment and disposal of the large quantities of water required in the fracturing process may fall foul of environmental regulations, especially where contamination of ground water is a major concern, and will in any case, represent a substantial operating cost.

Access to sufficient water may also be a barrier, although technological progress is beginning to reduce the volume required. Obtaining an environmental approval will be most difficult in ecologically sensitive areas, and the time and expenditure required for obtaining licenses and permits for drilling and related activities will complicate the development of projects. (WEO, 2009)

II.4.1.1. Greenhouse gases emissions

Hydrocarbon gases are brought to the surface during crude oil extraction. In some instances, this gas is flared or burned, either as a safety measure or as a means of disposal. Gas is flared only when alternate options to utilize the associated gas do not exist.

The use of fossil fuels releases VOCs, SO_2, NO_x, and particulates, which can contribute to air quality issues since high concentrations of these compounds can impact human health and the environment (ExxonMobil, 2012).

The reduction of CO_2 and NO_x is a major issue around the world. Therefore the laws in all continents have been increased and nowadays they are more restrictive. According to oil companies, the statistics show a reduction of greenhouse gases. For instance, BP estimated at the end of 2010 that the Greenhouse gas emissions were approximately reduced by 8 million tonnes. Note that in this report any emissions from the Deepwater Horizon incident have not been included.

ExxonMobil reports that in 2010, the air emissions of VOCs, SO_2, and NO_x decreased by 6 percent from 2009 and 36 percent from 2006 levels. By the end of 2010, the U.S. refining facilities had reduced combined NO_x and SO_2 emissions by over 70 percent as compared to the levels in 2000. Since 2006, their global chemical operations have been averaging a reduction per unit of production of 6 percent per year for VOCs and 3 percent per year for NO_x (ExxonMobil, 2012).

According to Halliburton, the global carbon-dioxide emissions in 2010 were approximately 3.88 million metric tons (the equivalent of about 60 percent of the carbon-dioxide emissions from a small, natural gas-fired power plant in the U.S) (Halliburton, 2011).

II.4.1.2. Water

Water scarcity is an increasingly pressing global issue as a result of increased industrial development, population growth and lifestyle.

According to the OECD, almost half the world's population will be living under severe water stress by 2030 if no new policies to improve freshwater management are introduced. Water pollution is also of growing global concern. (BP, 2010)

A reliable supply of water is essential for life and for developing both fossil fuel and renewable sources of energy. With competing demands for water, regulations and international standards are growing more stringent. Protecting and preserving freshwater resources involves understanding supply and demand trends at the local level, assessing potential effects on quality and quantity, and implementing steps to appropriately address challenges.

In 2010, the net consumption of fresh water by ExxonMobil operations was 2140 million barrels, representing a 1-percent reduction from 2009. The company implemented a variety of projects to reduce water consumption in 2010. For example, the Altona Refinery in Australia improved the control system in its cooling towers, resulting in a 3-percent reduction in freshwater consumption (ExxonMobil, 2010)

II.4.1.3. Social issues

The oil and gas exploitation has an impact on the communities living nearby to this kind of operations. Therefore, the companies have been forced to develop different projects which mitigate the damage and benefit them. In theory this projects cause a positive impact, because they improve the local needs and interests, for example, new education infrastructure, healthy programs, more economical opportunities, etc.

II.4.1.4. Examples

In the following sections some examples for environmental expenditures by different companies are given.

I. BP Investment

The BP direct spending on community programs in 2010 was $ 115.2 million, which included contributions of $ 22.9 million in the US, $ 36.7 million in the UK (including $ 6.5 million to UK charities, relating to $ 3.6 million for art, $ 1.3 million for community development, $ 0.8 million for education, $ 0.5 million for health and $ 0.3 million for other purposes), $ 3 million in other European countries and $ 52.6 million in the rest of the world (BP, 2010).

II. ExxonMobil Investment

In 2010, ExxonMobil Corporation provided a combined $ 199 million in cash, goods, and services worldwide. Of the total, $ 119 million supported communities in the United States and $ 80 million supported communities in other countries.
Since 2000, they have made cash grants of more than $ 83 million to help fund malaria programs across sub-Saharan Africa

III. Ecopetrol Investment

Ecopetrol S.A. is the largest company and the principal petroleum company in Colombia. Because of its size, Ecopetrol S.A. belongs to a group of the 40 largest petroleum companies in the world and is one of the four principal petroleum companies in Latin America.
Ecopetrol S.A. is responsible for the total production of crude oil and gas in Colombia obtained by means of direct and associated operations.

The operations include the extraction, collection, treatment, storage and pumping or compression of hydrocarbons.

Table II-5: Production Levels of Ecopetrol S.A. (Ecopetrol, 2010)

Production levels - Ecopetrol S.A					
Oil and gas	**2005**	**2006**	**2007**	**2008**	**2009**
Crude and gas owned by Ecopetrol (Kbpde)	376	385	399	447	520
Crude direct operation Ecopetrol (Kbpd)	138	157	151	172	198
Total crude owned by Ecopetrol (Kbpd)	311	316	327	362	426
Crude Ecopetrol + partners (Kbpd)	526	528	525	564	
Crude country (Kbpd)	526	529	531	588	671

With operations throughout the national territory, Ecopetrol has four management divisions to handle the operation of 163 production fields.

In 2009, the total daily oil production in the country was 672 barrels (kbpd), 426 kbpd of which were Ecopetrol's (including holding in direct and associated operations) (Ecopetrol, 2012).

In 2010, Ecopetrol invested $ 556,068,577 in its Environmental Management Program. This value represents a 62% increase compared to 2009 (Ecopetrol, 2010).

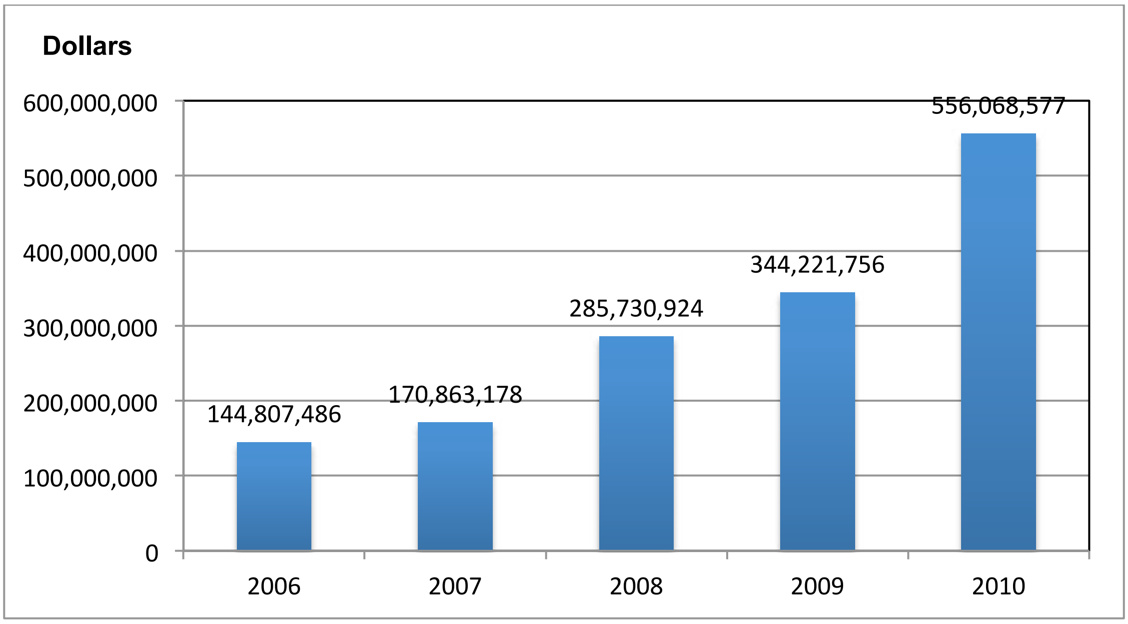

Figure II-14: Environmental Investments (Ecopetrol, 2010)

This environmental investment program includes: execution and diagnosis of environmental studies, recovery and protection of renewable natural resources, soil recovery programs and environmental protection of flora and fauna (Ecopetrol, 2010).

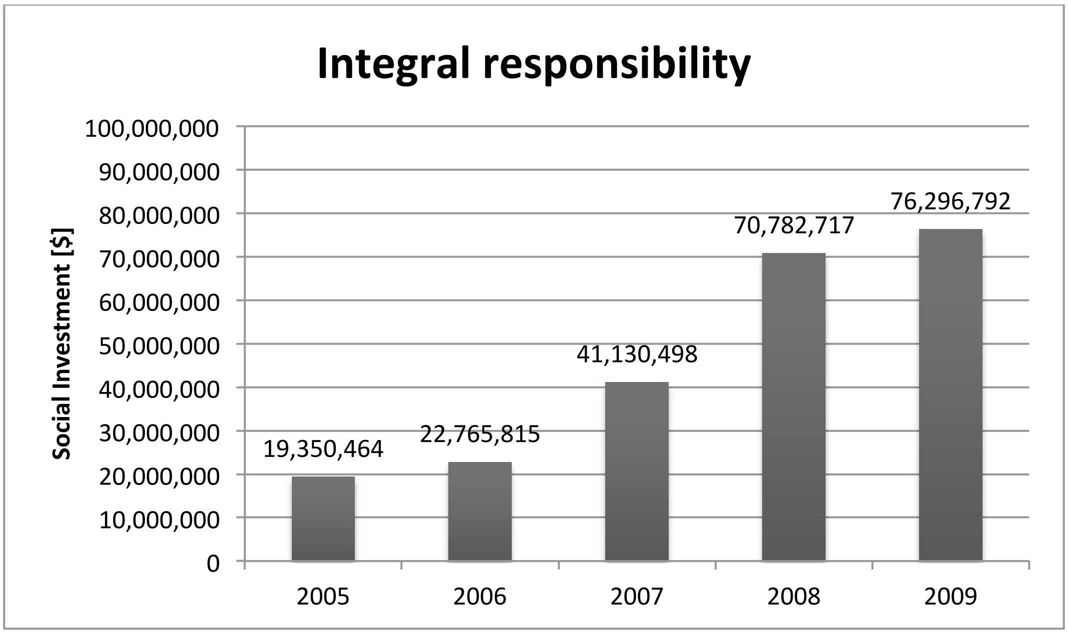

Figure II-15: Integral responsibility (Ecopetrol, 2010)

IV. GULF OF MEXICO

On the 20th of April 2010, following a well blowout in the Gulf of Mexico, an explosion and fire occurred on the semi-submersible rig Deepwater Horizon and on the 22nd of April the vessel sank. Tragically, 11 people lost their lives and 17 others were injured. Hydrocarbons continued to flow from the reservoir and up through the casing and the blowout preventer (BOP) for 87 days, causing a very significant oil spill. The well was in a water depth of 5,000 feet and 43 nautical miles offshore. (BP, 2011)

BP faced significant costs in 2010 in response to the Gulf of Mexico oil spill. The spill response costs of $ 13,628 million include amounts provided during 2010 of $ 10,883 million, of which $ 9,840 million have been expended during 2010, and $ 1,043 million remain as a provision at the 31st of December 2010.

In addition, a further $ 2,745 million of clean-up costs incurred in the year, that were not provided for. Additions to environmental provisions in 2010 in respect of the Gulf of Mexico oil spill relate to BP’s commitment to fund the $ 500-million Gulf of Mexico Research Initiative, a research program to study the impact of the incident on the marine and shoreline environment of the Gulf coast, and the estimated costs of assessing injury to natural resources. BP faces claims under the Oil Pollution Act of 1990 for natural resource damages, but the amount of such claims cannot be estimated reliably until the size, location and duration of the impact is assessed.

As of 31st December 2011, BP had paid more than $ 600 million for assessment efforts.

Additionally the BP Sustainability Reporting 2011 has voluntarily committed up to $ 1 billion to implement early restoration projects that are expected to commence in 2012.

Early restoration projects are designed to accelerate efforts to restore natural resources in the Gulf that were injured as a result of the Deepwater Horizon accident.

BP has committed to provide up to $ 1 billion to fund these projects under an agreement signed with federal and state trustees in April 2011. Priority will be assigned to projects that offer the greatest benefits to affected wildlife, habitats and recreational use (BP, 2011).

Table II-6: Key statistics 2010 (BP, 2011)

Key statistics	2010
Total pre-tax cost recognized in income statement ($million)	40,935
Total cash flow expended (pre-tax) ($million)	17,658
Total payments from $20-billion trust fund ($million)	3,023
Total number of claimants to Gulf Coast Claims Facility (GCCF)	468,869
Number of people deployed (at peak) (approximately)	48,000
Number of active response vessels deployed during the response (approximately)	6,500
Barrels of oil collected or flared (approximately)	827,000
Barrels of oily liquid skimmed from surface of sea (approximately)	828,000
Barrels of oil removed through surface burns (UAC estimate)	265,450

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II.7.1. List of Figures

II.7.2. List of Tables

III. Value Added and Price Development of Oil and Gas

Robert Luttermann, Amelie Metzmacher and Markus Schramm

The prices for oil and gas have massively risen during the past decades. On a world market with various producers, intermediaries and distributors such developments can be comprehended as economic results within a complex system. After conventional resources are depleting and the efforts for exploration and production of gas and oil rise, costs for the raw products are continuously increasing.

Due to the political, social and economic relevance there are efforts to secure the energy resources supplies. The political approaches on the other hand impact the free market economy and therefore need to be well considered and from time to time adapted.

In this article we look at the production steps, recent developments making the production of unconventional resources possible (and expensive), and the long path which oil and gas cover until they reach the final purchaser. We also discuss the relevant market mechanisms, which finally lead to the market price.

Contents

III.1. Introduction

Fossil Fuels must be located underground before they can be produced. For finding fossil fuels such as coal, oil and gas there exists a large variety of methods which usually are chosen by the certainty respectively uncertainty of knowledge about the (presumed) deposit. The better knowledge about a deposit becomes the more sophisticated the applied methods and the technology are. Before it comes to producing a new deposit the investments made usually are in the magnitude of several to hundreds of millions of dollars. Sometimes the billion dollar mark is reached before the first revenues arrive and the invested capital can be paid back. Beyond this there is a large risk to fail in finding an economic deposit. This large risk is very characteristic for the mining sector. After exploring a natural resource the production begins. Other than at coal the production of oil and gas usually does not make an end-costumer-ready product. Before that crude fuels have to be beneficiated – a costly process that must be precisely tailored to the raw resource. Between these steps there lie routes of transport, which cause costs again.

III.1.1. Cost Generation in Mining

The special situation in the mining sector has direct influence on the pricing when the product is sold on the international resource and energy market. Economically spoken quite a formidable part of the products' value has been created. First, finding it through geographical, geological and geophysical prospection requires much money. Secondly before the first drop flows or the first ton of coal is raised the mining corporation has invested in the mine and well site technology and in building infrastructure which is necessary for the exploitation of the deposit.

Another factor generating costs for the mining company are royalties. These charges are paid per unit produced. Therefore they vitally differ from other fiscal duties such as taxes, which usually are calculated on the basis of business volumes, earnings or benefits.

III.2. Oil

Oil accounted for 32.8% of the world's primary energy supply in 2009 (nn, Bundeszentrale für politische Bildung, 2011). Therefore it still is the most important fossil fuel. From the reservoir to the end user it makes a way through a long production and transportation chain. The value added lies in both – the complex processes of beneficiation and the long way of transportation through the stages until the end product reaches the end costumer.

III.2.1. Oil Exploration

Exploration is the first step of any oil business activity when one looks at the whole production chain. Looking for oil is difficult. Till this day there is no technology, which makes it possible to directly look for oil. Exploring hydrocarbons always means to look for geological structures which are known to have the ability to comprehend oil. These are so called "trap structures" which can vary strongly. After such a possible oil/gas trap has been found the only perfectly secure way to figure out if it contains what the company was looking for is drilling into the supposed reservoir and directly check.

Exploration drill holes today cost multi millions of dollars each. Especially deep sea-drilling today often results in three-digit million dollars costs.

The chance to be successful anyway usually lies somewhere around 33%. The other two thirds are not successful.

That all means that there are both large expenditures and large exploration risks to be taken into account.

In case of success there is another question: Is it economical to produce the reservoir or is it more cost-effective to charge the previous expenditures off and start another exploration project elsewhere?

III.2.2. The Three Phases of Oil Recovery

If the company decides to produce the reservoir, oil recovery begins. The used procedures are equally high tech as exploration is. Oil recovery techniques currently are intensively researched.

The oil recovery process can be divided into three phases. In the beginning of the primary phase the hydrocarbons are driven out of the reservoir by natural forces. The oil is not pumped so there is no energy spent on any process to lift the oil or gas. After recovery of a small part of the reservoir's oil this process will come to an end and it becomes necessary to spend energy on lifting the oil. So in the second part of the primary phase the oil is pumped but there are no advanced techniques used to make the oil flow beyond pumping.

After the pressure in the reservoir has been lowered to a grade which allows no more recovery just by pumping the second phase is entered. Water or natural gas is pumped into the reservoir to increase the pressure in it and make another part of the contained oil flow to the reservoir's top where it can be pumped to the surface.

This technique reaches its limits when the adhesion between the oil and the rock becomes too high and when the permeability is too low to enable the remaining oil to flow. Then another phase called tertiary recovery can be entered which is even more complex and requires further investment in the reservoir. The list of technical options either being discussed or used is a long one. In the following only the most important ones shall be introduced shortly.

The following paragraphs pursue the intention to give the reader a detailed idea of where a large part of the costs for oil go to. As men must produce more and more unfavourable reservoirs the costs for this part of the chain of adding value to the product make a larger part of the final product price than ever before. For this reason the following pages shall be dedicated to this outstandingly important link in the economic value creation chain.

III.2.2.1. Methods of Secondary and Tertiary (Enhanced) Recovery

What has been introduced above as tertiary recovery often is also referred to as so called 'Enhanced oil recovery' or 'Improved oil recovery'. The aim of an enhanced oil recovery is to improve the recovery factor. While there can be 20 to 50% of the oil recovered within primary and secondary recovery it is possible to enhance the oil recovery factor to 60% or even slightly more depending on the characteristics of the reservoir. To do so there is a broad extent of physical, chemical and biological methods and those that cannot be assigned to only one category.

III.2.2.1.1. Hydraulic Fracturing

One of the most common techniques of stimulating a well is fracturing the reservoir rock near the well. This method was first applied in 1947 at the Hugoton field in Oklahoma, USA (Hyne, 2005, p.560) and nowadays about 30% of all oil wells drilled in the USA are fractured. The most important number by which a frac job is described is the volume of fluid and proppant which is pumped into the well. A typical volume for an oil well is around 163 m³ of fluid and 31 t of proppant but there are even extremely large frac jobs where 4.000 m³ of fluid and 1.500 t of proppant are used (Hyne, 2005, p.425). The production outcome usually rises by 5 to 15%.

III.2.2.1.2. Water Flooding

Water flooding is also referred to as pressure maintenance or secondary recovery. It sometimes is also called a method of enhanced oil recovery (Leffler, W. L., 2008, p.177) whereas EOR is also used as a synonym for tertiary recovery.

Water is injected below the oil-water contact to drive the oil to the top. While the first intention usually is to increase the amount of oil recovered, as an additional function the produced water can be disposed into the reservoir space which has become available during primary recovery. Sometimes disposing polluted water can even be a major aim of water flooding of the reservoir.

There is a number of critical elements when arranging a waterflood design. According to (Leffler, W. L., 2008, p.179) these are:

- reservoir geometry
- lithology
- reservoir depth
- porosity
- permeability
- continuity of rock properties
- fluid saturations
- fluid properties and relative permeabilities
- water source and its chemistry

Many of the above parameters can be measured and controlled quite accurately while others cannot. Especially the inhomogeneity of the reservoir rock is one of the major sources of complication during water flooding. Also the efficiency of the described method is only satisfying at moderate oil gravities between 17 and 38°API. Heavier oil with higher viscosity will not be propelled enough by the water. (Leffler, W. L., 2008)

As water flooding is one of the most common and due to existing experience best controlled methods it is quite affordable today. Costs can be estimated at about 0.008 $/m^3$.

III.2.2.1.3. Steam Floods

Steam is commonly used in reservoirs containing heavy oil (8-18°API) to lower its viscosity. There are two possibilities how to organize injection and production. The first one is to do injection and production one after another through the same well. Usually steam is injected for a couple of days, then there is a “steam soak” time usually lasting between 8 and 12 hours and in a third step the oil is

produced through the same well. There are two leading effects that make this method work. First the reservoir pressure is enhanced and secondly the heavy oil has a lower viscosity after the heating process.
The second approach of using steam is injecting and producing simultaneously through different wells. The steam condenses to hot water, which pushes the oil towards the production well. Again the heat makes the oil less viscous.

III.2.2.1.4. CO_2 Injection

The CO_2 is pressed into the reservoir through an injection well. On its way through the rock it mixes with the oil and lets it swell. This way more oil is detached from the pore surface and can flow towards the production well due to the horizontal pressure gradient which is generated by the injection, too (Leffler, W. L., 2008, p.185).

Quite similar methods exist when using natural gas or nitrogen. It is essential that the gas does not react with the oil. Air cannot be used, as the oil would react with oxygen and burn (Amarnath, A., 1999).
As an alternative to injecting only gas, the gas can be mixed into water. This process, called “water alternated with gas”, is more efficient because the flood front is spread and the chance of bypasses is reduced. This process can mobilize larger quantities of oil than a gas-only process. The method requires oil of at least 22°API and needs depths of at least 800 m to make CO_2 and water mixable.
This technology allows to recover about another 20% of the original reservoir oil.

Conventional CO_2 projects used exclusively CO_2 from natural deposits for enhanced oil recovery. Since the greenhouse effect has become a sensitive issue and CO_2 sequestration is widely discussed, the demand to use carbon dioxide from hydrocarbon and coal combustion for oil recovery purposes has grown. The obvious problem is the transport of the sequestered CO_2 to the

location where it can be used for EOR. This adds another point to the already complex and cost intensive logistics of a drilling project. (Hyne, 2005)
As CO_2-injection is a more sophisticated technology and the gas logistics is more complicated, costs may be estimated at 0.02 $/m³. It is therefore more expensive than water injection (Amarnath, 1999).

III.2.2.1.5. Chemical Injection

One aim of injecting chemicals into the reservoir is to reduce the interfacial tension between the rock surface and the oil. Therefore either alkaline or caustic solutions are used. Those react with the organic acids that are also contained by natural oil reservoirs resulting in soap. This soap helps disperse the oil so it can be washed out of the rock by the solution. An alternative is the direct injection of surfactants such as petroleum sulfonates.
Another chemical approach is injecting agents, which do not affect the oil but the reservoir rock. This can be seen as a well stimulation method. Hydrochloric acid is used to dissolve calcitic rocks in order to enhance the permeability (Türksoy, 2000).

III.2.2.1.6. Microbial Injection

More recently the injection of microbes into petroleum reservoirs has been used to improve recovery. Three approaches of microbial EOR are known:

- Bacteria partially digesting long organic molecules and transforming them into shorter-chain molecules with improved flow characteristics
- Bacteria producing biosurfactants which reduce the adhernce of oil to the pore surfaces
- Bacteria emitting carbon dioxide (effect as described in paragraph 2.4 CO_2 injection) (Jack, Th.R., 1991)

It is not only challenging to find or develop the most useful microbes for the individual purpose. Another challenging aspect of microbial EOR is to provide an appropriate nutrient source after injecting them into the reservoir (Banat, 1994).

III.2.2.1.7. Application of Vibro-Energy

Both, laboratory and field tests showed that applying vibrations by vibro trucks decreases the percentage of residual oil in the pore space. The vibro-energy helps to reduce interfacial tension and increases the relative permeability to oil. This technique might especially work in combination with other methods like application of thermal energy or chemical agents. The economic point of view has not been sufficiently evaluated so far (Kouznetzov, 1998).

III.2.3. Beneficiation and Refining

For the refining of natural crude oil 658 refineries existed worldwide in 2007. Altogether they had a capacity of 85.2 million barrel per day (Dratwa, 2010 after Nakamura, 2007). Most of them are located in industrialized countries with deregulated markets. The five biggest refining companies only process 20 million barrel per day, which is less than one fourth of the worldwide capacity. This distribution of capacities indicates that there is neither a monopoly nor an oligopoly. The institutionalized market conditions promote competitive behaviour of the market actors. The institutions where price building takes place are specified and the process is transparent. Products made from mineral oil are traded at commodity future exchanges in New York and London. Especially for north-western Europe the Rotterdam spot market (Dratwa, 2010) holds the exchange function for our region.

Table 1: Comparison of the selling prices to cost prices, realized: profit-loss per 1t (in US$/t)

refinery product	Selling price	Cost price	Profit - Loss
Propane	254,60	228,41	26,19
Butane	170,91	214,44	-43,53
Propane-butane mixture	219,60	218,36	1,24
Aliphatic solvent 60/80	341,60	431,82	90,22
Aliphatic solvent (medical)	315,80	440,77	-124,97
Aliphatic solvent 65/105	341,30	348,47	-7,17
Aliphatic solvent 80/120	295,40	432,42	-137,02
Aliphatic solvent 140/200	208,60	432,42	-223,82
Benzene (aromatic)	393,60	356,42	37,18
Toluene	298,00	353,34	-55,34
Gasoline regular	356,80	256,90	99,90
Gasoline premium	400,40	266,43	133,97
Unleaded	432,40	277,66	154,74
Gasoline G-92	251,80	266,27	-14,47
Pyrolysis gasoline	226,70	247,33	-20,63
Straight-run gasoline	212,18	240,04	-27,86
Fuel gas	69,13	164,51	-95,38
Gasoline	267,30	289,94	-22,63
Propylene	465,00	191,06	273,94
Cracked gasoline	183,90	222,50	-38,60
Petroleum for lighting	228,90	243,77	-14,87
Diesel special	486,30	205,30	281,00
Jet fuel	239,40	244,20	-4,80
Diesel fuel D-1	276,70	209,41	67,29
Diesel fuel D-2	279,79	202,37	77,42
Fuel oil EL	244,10	202,07	42,03
Low sulfur fuel	209,60	184,60	25,00
Ecological oil EL	590,30	250,21	340,09
Fuel-oil medium	161,60	193,80	-32,20
Sulfur	113,40	125,59	-12,19
Bitumen	196,69	209,60	-12,91

Table 1 shows selling and cost prices for 31 different refinery products and the correspnding profits or losses. It is striking that there exist losses. The reason is that the operator of the refinery has to control the ratio of the output products and therefore must estimate how to mix the products to maximise profit.

III.2.4. Selling the Product to the End Costumer

Dratwa (2010) refers to information published by the German Mineralölwirtschaftsverband (Association of the German Petroleum Industry) stating that a vendor at a gas station earns a profit of 0.07 to 0.08 €/L. From this he has to pay his distributional and administrational costs and has to make benefit. According to information provided by Aral in 2011 the profit margin at the gas station is around 0.01 €/L. The rest of the price is made by VAT, ecological tax and upstream production and transportation costs.

III.3. Natural Gas

Gas accounted for 23.8% of the word's energy supply in 2009 (nn, Bundeszentrale für politische Bildung, 2011). Therefore after oil and coal it is the world's third most important energy resource.

While in many cases the energy resources may be interchangeable, there are utilizations where one of them offers certain advantages. For example it is relatively easy to make cars run on oil-based fuels or on gas. But as gas burns much hotter than most products refined from oil, gas is important for some industrial processes.

III.3.1. Natural Gas Exploration

Exploring gas is closely connected to oil exploration for these two fossil energy resources genetically have a lot in common. The source material can always be the same for both oil and gas and even the geological structures in which they are trapped can be the same ones. The difference lies in the diagenesis the material undergoes. Gas results from higher temperatures within the source rocks history. Often reservoirs contain both oil and gas resulting from variable conditions in the source rocks. There are sophisticated approaches to predict if a reservoir is oil- or gas-filled but if it really is bearing one or both of these can only be ensured by drilling into the prospected area.

Though producing and trading gas differs from dealing with oil. In this context the most important difference between oil and gas is the most obvious one – the aggregate state. Handling gas is much more complex and therefore only economically advantageous if the amount of gas is large enough. In contrast even smaller amounts of oil may be profitable to produce.

III.3.1.1. Two Principal Ways of Gas Transportation over Large Distances

Natural Gas is more difficult to transport to the consumer than oil. In the past decades it has been tried to keep transport distances of gas short. Currently there are major pipeline projects on the European continent for transportation of natural gas over distances of thousands of kilometers. The North Stream pipeline has been brought to operation on 8th November 2011. This pipeline has a total length of 1223 km and does not transit any territorial waters of nations not involved in the project. The North Stream pipeline is one example for the long-term strategic alignment of states to ensure future energy supply.

Another way to transport Natural Gas is liquefaction. To make natural gas liquid it is cooled down below 164°C. This process takes 15 to 20 % of the energy contained by the gas Therefore LNG (liquefied natural gas) often is an economic choice when the transport distance exceeds 2000 km or if building pipelines is no choice due to other reasons.

III.3.1.2. Structure of German Gas Supply

The German structure of the gas supply chain has grown historically. There are 6 levels which can be divided (Figure 1)

- Producers/importers
- large distance transporters (may be importers, too)
- regional suppliers
- sub-regional municipal energy suppliers
- local municipal energy suppliers
- end costumers (both private and industrial)

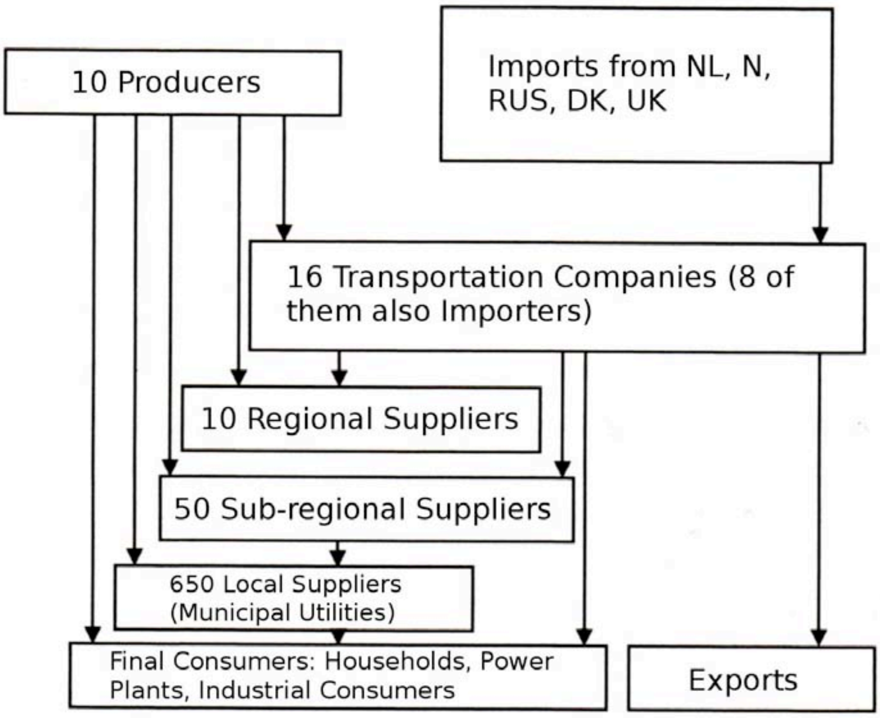

Figure 1: Historical Structure of the German Gas industry (after Schwintowski, 2006)

The historically built structure on the German gas market is very complex. There have been long-term contracts and peak supply could only be served on the more flexible spot market accepting higher prices.

Today the marked is partly liberalized and contracts can be concluded much m-ore flexible. Anyway the old actors still are the same ones. The liberalization process has only been affecting the gas market for a couple of years so there will be lots of changes in the future, too. Because the oil market cannot become that global as the oil market (as explained before in chapter III.3.1.1) we should not expect it to become that dynamic.

III.4. Price Formation

Price formation in natural resources is a very complex topic. Of course, all different steps of the value-added chain influence the final price the customer has to pay. But in the business of oil and gas there are many more factors which are of a great importance.
First, supply and demand have an effect on the price. In a simple market model with only four relevant factors (price, quantity, demand and supply) this becomes visible (see Figure 2).

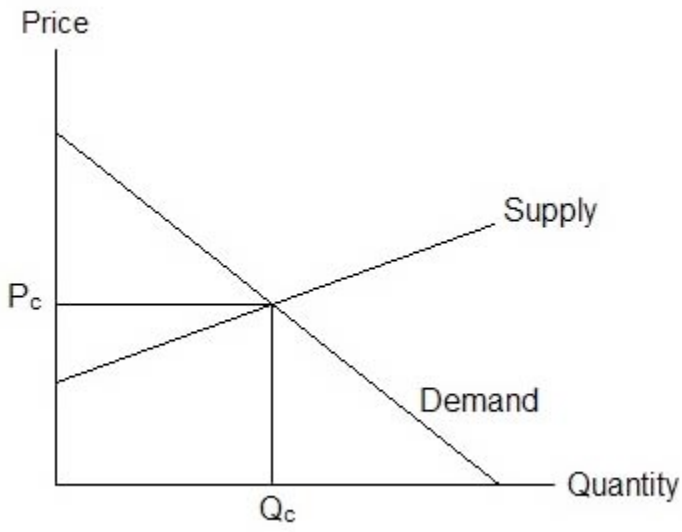

Figure 2: Supply and demand in the simple market model (after Gotsch, 2001)

If the demand increases the price will rise and this also causes an increase in supply, since this makes reserves mineable, which previously were not. However, this also works the other way round; if the supply is higher than the demand or the demand declines the price will fall. In the centre of the diagram, where the supply- and demand-lines cross, “Market Equilibrium” is reached. Here sellers and customers realize their ideas of price (P_c) and quantity (Q_c), and the maximum turnover is achieved (Friedrichs, 2011).
Price formation on good markets is more sophisticated because of decreasing and increasing supply- and demand-functions (Feess, 2000).

Moreover, for natural resources even more factors that influence price formation, e.g. political, social or ecological, have to be taken into account.

III.4.1. Oil

As described in Chapter 2, a very important factor in oil price formation is the exploration and production of the natural resource itself. Drilling costs amount to around $ 8,000 to $ 15,000 per day (Flower, 2009). This seems to be relatively cheap. But before the oil companies are able to drill they have to spend much in the preliminary work to ensure the profitability. Some of these prior work steps are, e.g. process test works, a pre-feasibility study, basic engineering, a bankable feasibility study, funding and customer contracts as well as detailed engineering and approvals.

Moreover, there are several additional costs during the actual drilling process, which lead to high costs. Some of these costs are payments for contractors, welders, engineers, supervisors, mud loggers, geologists and other scientists. Furthermore, personnel for drilling, logging, cementing, casing and other logistics has to be paid. Then the oil company has to clear all the dues with the landowner and pay taxes, fee for attorney and permit to drill the well. Eventually, costs for maintenance evolve, e.g. three shifts with personnel employed 24 hours a day, motels, restaurants, transport, water and food (Flower, 2009).

Altogether, well costs vary from a few million to billions of dollars. Of course, this depends on e.g. onshore/shelf or offshore drilling, the drilling areas (industrial countries vs. developing countries), infrastructure, etc. These costs amount to 15 to 40 % of the overall exploration costs in the case of offshore deposits and up to 80 % for onshore deposits (MWV, 1996).

Since the oil spill disaster of BP´s Deepwater Horizon, some more information has become available about the practices and calculations of the large oil companies. The economists Robert W. Hahn and Peter Passell (2009) analyzed the benefits and risks of drilling. In their analysis they look at three types of

benefits: producer revenues, lower prices to consumers and less fluctuation in oil prices.
The benefits are considered in two different scenarios: at \$ 50/barrel and \$ 100/barrel. At \$ 50 per barrel they estimate that 10 billion barrels of oil would be recoverable from the off-limits outer continental shelf. Drilling this amount would cost around \$ 166 billion. The production of one barrel offshore would reach \$ 17. In addition, there arise environmental costs (\$ 1 billion), greenhouse gas damages (\$ 1 billion), local air pollution (\$ 28 billion), traffic congestion (\$ 28 billion) and accidents (\$ 32 billion). Thus, the cumulative costs would amount to \$ 255 billion, which obviously is a huge sum. But, by summarizing the total benefits, this leads to an amount of \$ 578 billion. Eventually, the net benefits are around \$ 323 billion respectively \$ 33/barrel (Hahn & Passell, 2009).
However, these numbers become even more interesting by regarding an oil price of \$ 100/ barrel. Then, 11.5 billion barrels would be recoverable from the off-limits continental shelf. Drilling costs would rise to \$ 238 billion and offshore production to \$ 20/ barrel. Environmental costs and greenhouse gas damages would both stay at \$ 1 billion. Local air pollution would cost \$ 22 billion, traffic congestion \$ 33 billion and accidents \$ 38 billion. Hence, the cumulative costs are \$ 332 billion and the total benefits are \$ 1298 billion. Therefore, the net benefits amount to \$ 967 billion or \$ 84/barrel (Hahn & Passell, 2009).
These calculations could be also applied for gas reserves (Hahn & Passell, 2009).

III.4.1. Natural Gas

Price fixing for natural gas is quite similar to the one of crude oil, since the whole procedure of exploration and production, etc. is more or less the same. Moreover, there often exists an oil-gas price link. Arguments for this are that it helps companies to plan and calculate in a better way.

Figure 5 describes the different parts, which have influence in the final price the customer has to pay for natural gas. Due to the high similarity of natural gas and crude oil, this diagram can also be used for oil. The greatest portion, 74 %
%, is made up by import/production, transport, storage and distribution. The remaining 26 % correspond to value added taxes (14 %), natural gas tax (9 %), concession levy (2 %) and proportionate mining royalty (1 %).

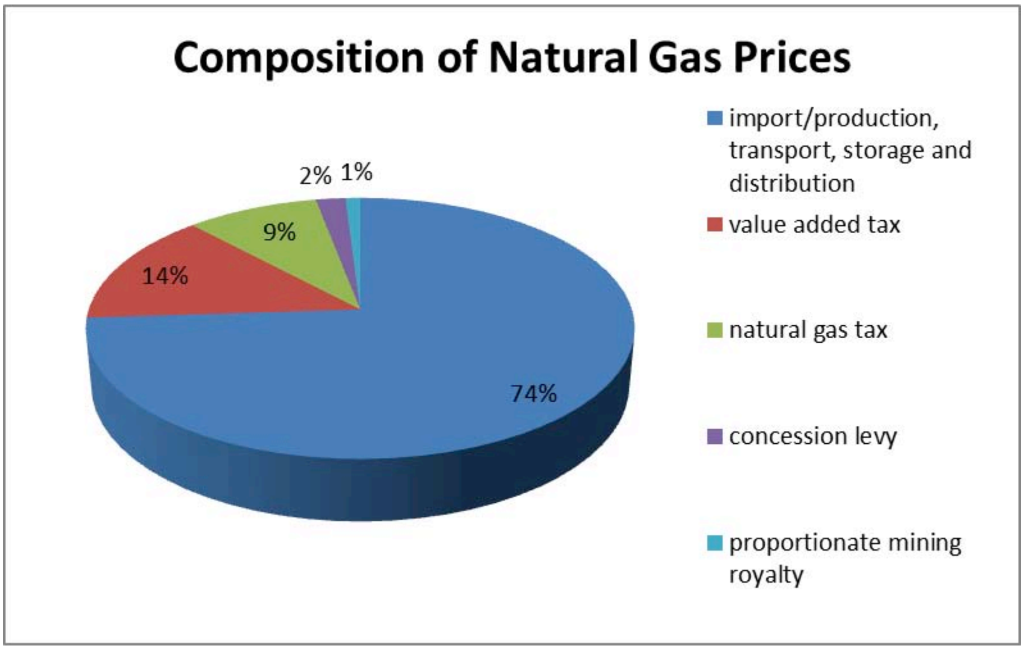

Figure 3: Composition of Natural Gas Prices (after DIE ENERGIE, 2011)

The nature of the natural gas market is similar to other competitive commodity markets: prices reflect the ability of supply to meet demand at any time. The economics of producing natural gas are relatively straightforward. Like any other commodity, the price of natural gas is largely a function of demand and supply of the product.

When demand for gas is rising, and prices rise accordingly, producers will respond by increasing their exploration and production capabilities. As a consequence, production will over time tend to increase to match the stronger demand. However, unlike many products, where production can be increased and sustained in a matter of hours or days, increases in natural gas production involve much longer lead times. It takes time to acquire leases, secure required government permits, do exploratory seismic work, drill wells and connect wells to pipelines; this can take as little as 6 months, and in some cases up to ten years. There is also uncertainty about the geologic productivity of existing wells and planned new wells. Existing wells will naturally decline at some point of their productive life and the production profile over time is not known with certainty. Thus, it takes time to adjust supplies in the face of increasing demand and rising

III.5. Price Development

After a short introduction of the oil and gas price development from 1987 to 2010 in chapter 1, this chapter describes the price development during the recent months.

III.5.1. Oil

The price development of oil is regarded at the two oil grades Brent Crude and West Texas Intermediate (WTI). As shortly introduced in chapter 1 these are both light and sweet oils and therefore can be called high quality oils. They are the most traded spreads of crude oil worldwide. Brent Crude is the most important oil grade in Europe. It is traded at the ICE in London and delivered in Rotterdam. Brent Crude is mainly produced offshore in the North Sea next to the Shetland Islands (Broker-Test, 2012 (a)).

However, WTI is the most important oil grade on the US-market and traded at the NYMEX in New York. Primarily, it is produced in the Middle West of the US. (Broker-Test, 2012 (b)).

As shown in Figure 4, Brent Crude and WTI reached nearly similar prices or WTI was a bit higher than Brent Crude. But in the last months this changed; Brent Crude is now higher than WTI. At first, this is striking, since WTI is of better quality than Brent Crude, due to its lower sulfur content (Brent Crude: 0.37 %; WTI: 0.24 %; Energy & Capital, 2012). But this is, of course, not the only factor influencing the current prices. The reason for currently higher price for Brent Crude can be found in the political and economic situations in the sales markets. As it is known, after the financial crisis in 2007, which affected Europe and the US equally, the economy in Europe is again in a process of growth. Whereas the economy in the US needed more time to recover. Hence, the demand on oil is at the moment in Europe higher, which leads the increase in price (Morrien, 2011). Another important factor for the price difference between WTI and Brent Crude are the rising stock levels of WTI in the US (Wirtschafts Blatt, 2012).

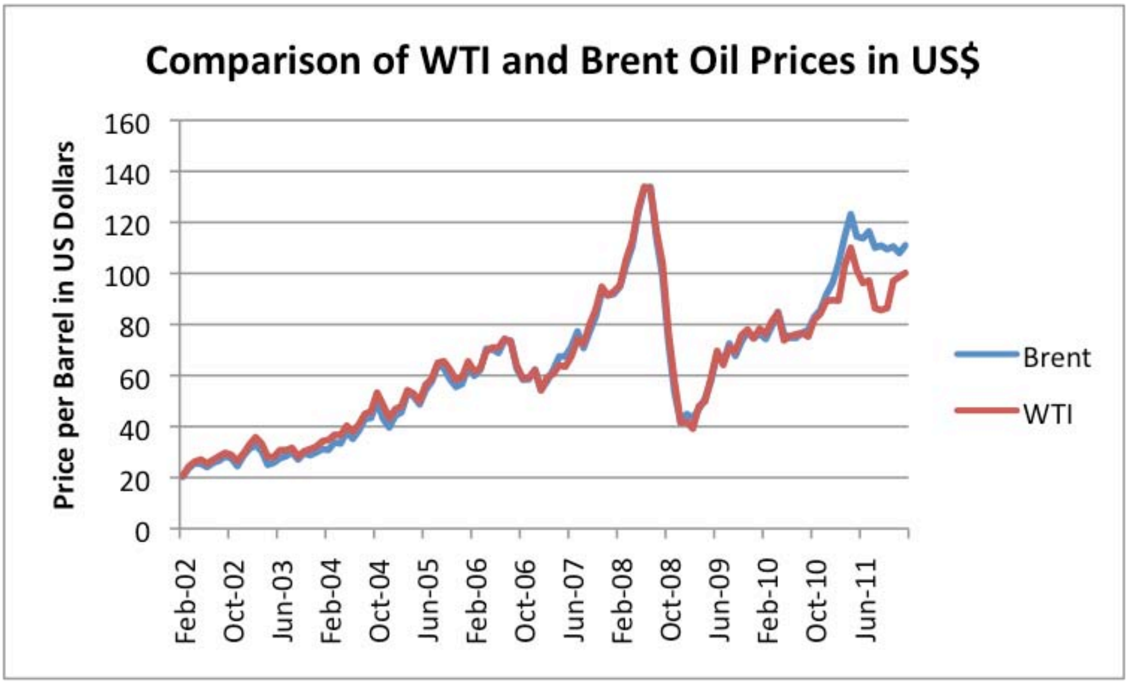

Figure 4: Comparison between WTI and Brent Crude Oil Prices in US$, Tverberg (2012)

Nevertheless, it is obvious that the prices for both oil brands have increased significantly during the last months (Figure 5 & Figure 6**Fehler! Verweisquelle konnte nicht gefunden werden.**). At the end of February 2012 they reached $ 122.5/barrel (Brent) and $ 106.28/barrel (WTI). One reason is that also speculative financial investments increased. On the one hand, this is caused by political conflicts in the Middle East like the uncertainty about Iran. This has great influence on the development of the prices, especially after the European Union (EU) adopted an oil embargo for Iran coming into effect in July 2012. As a response for the decision of the EU, Iran cancelled oil exports to Great Britain and France and uttered threats for other European countries at the end of February 2012, which obviously also resulted in increasing prices. On the other hand, increasing demands from China and India affect oil prices and intensify speculations.

Figure 5: Brent Crude in Dollar, Finanzen (2012)

Figure 6: WTI in Dollar, Finanzen (2012)

III.5.2. Natural Gas

Gas prices show a very different development than oil prices. Whereas the prices for oil indicate a clear upward trend, the prices for gas develop in the opposite direction (see Figure 7). In 2011 the prices were mostly between 3.50 and 4.75 $/MMBtu. Since the end of 2011 the prices rapidly declined to partially less than 2.50 $/MMBtu.

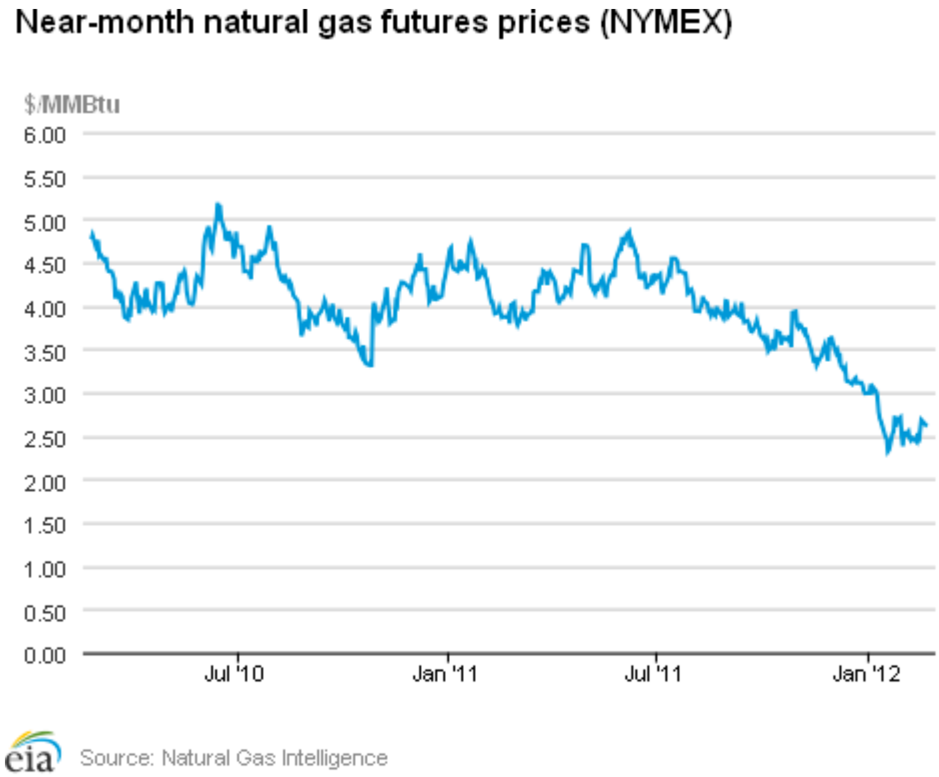

Figure 7: Natural Gas Futures Prices (NYMEX), EIA (2012)

The main reason for this different development, even despite the oil-gas-price link, is that natural gas is mainly a regional product and often produced by state monopolists. Exports are mostly combined with long-term delivery contracts, which were negotiated on a political level. In the last few years the gas market began to develop towards globalization. For instance, with the construction of liquefaction terminals to inject delivered liquefied natural gas into the local gas net. Since the prices for such terminals as well as the prices for LNG-tankers declined, the transport with ships over several thousands of kilometers is often even cheaper than the transport in pipelines. Furthermore, the governments in the US and Europe support the construction of terminals, since they help to enhance the states' negotiation position for long-term delivery contracts of natural gas (wallstreet-online, 2012).

In summary, it is very difficult to understand the reasons and influencing factors of the development of the natural gas prices.

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IV. Unconventionals: Shale Gas

Conrad Keller, Marc Petelin, Stephanie Schiffer

The potential for shale gas production in Europe has has become an issue of growing interest during recent years.
The USA have become the world’s largest gas producer due to the exploitation of unconventional natural gas (coalbed methane, tight gas and shale gas). The techniques for recovering natural gas were improved in the 1990s. Because of horizontal drilling and hydraulic fracturing, shale gas could be produced economically. The most important US reservoirs are the Barnett shale in northern Texas and the Marcellus shale, which is located in the northeast of the United States. Compared to the situation in the USA exploration and production efforts for unconventional gas are still in an early stage in Europe. Complex geological settings and higher operating costs have significant impac on well planning. Governments as well as citizens are indecisive about exploring and producing regional resources, which lead to an intensive debate in public. The Baltic basin in Poland is the most promising area for shale gas production in Europe. However, the European shale gas sector is in its infancy and it is difficult to get an analogy between the situation in the US and European countries. Economical, environmental and also legal issues will have to be considered and also the public acceptance and the high population density will be a problem. Moreover, due to insufficient data, there are still large uncertainties concerning the total gas reserves.

IV.1. Introduction

The increasing demand of energy, which comes along with improved technology and high standards of living, is still largely met by fossil fuels. Especially since the industrialization of former emerging nations the global energy market has changed. Energy is needed for mobility as well as for accommodation. In addition the traditional main producing areas for oil and natural gas have seen a political destabilization since the year 2000. These facts convinced many governments of industrial nations to become more independent of the international energy market and rely more on regional energy sources. Besides the extended research for alternative energy sources, the unconventional natural gas sources seem to be most promising. Therefore, several research cooperatives in Europe have been founded to estimate if coal bed methane, tight gas and shale gas can be developed in a similar successful manner as in the USA. Chapter IV.2 gives an impression of the historical and yet planned development.

IV.2. Development of Shale Gas Production in the USA

Since the 1990's the production of unconventional gas in the US has increased rapidly and led to the so called "shale gas revolution". This term first appeared in 2007/2008 when the US Potential Gas Committee released its report of US unproven gas resources with the highest estimates since four decades (Kuhn & Umbach, 2011). According to the EIA, today, the US owns 72 trillion m³ of technically recoverable natural gas which includes undiscovered, unproved, and unconventional natural gas. This is mostly due to the growing importance of shale gas. Just a few years ago the United States was a significant importer of gas and now it has become the world's largest gas producer (Ridley, 2011). Net imports decreased by 17.6 % between 2004 and 2009 to 79.3 billion m³. Besides, the US Department of Energy assumes a decline to 19 billion m³ in 2030, which is a further drop of 75 % (Gény, 2010). As the conventional gas reserves are decreasing steadily, unconventional gas reserves are becoming more important since the 1990s. Within the decade from 1996 to 2006 the annual US unconventional gas production doubled. Today, unconventional gas production accounts for more than a half of total US gas production (Kuhn & Umbach, 2011).

However, due to their low productivity shale formations were of little interest in the beginning and therefore remained marginal for many decades (Gény, 2010). Natural gas did not become an important commodity until after World War II. In the beginning of the 1980s, producers began looking beyond traditional sources of natural gas because of a growing market and depleting conventional reservoirs. In the 1990s the interest in coalbed methane and also shale gas grew (Frantz et al., 2005). The most important key factors, which led to the success of shale gas are the improvements in exploration, drilling and well stimulation techniques. The first attempts of hydraulic fracturing of rock to open paths and allow hydrocarbons to be extracted date back to the 1940s. The technique of horizontal drilling was already used in the oil industry in the 1970s, but experienced important improvements in the 1990s in Texas (Ridley, 2011). In 2005 a technological breakthrough was achieved in the Barnett shale in the Forth Worth Basin by combining the method of hydraulic fracturing and horizontal drilling (Gény, 2010). These improved techniques made it possible to produce shale gas economically and thus, major companies participated consequently in the market. Today the Barnett shale is the most important play in the US. It was the first shale gas play with a high productivity and a large extent. It provides 5 % of US natural gas supply (Ridley, 2011). Due to the successful activities in the Barnett shale and the attractive natural gas prizes, the industry was encouraged to intensify its activities in other shale gas plays since 2006 (EIA, 2011). Figure IV-1 shows an overview of shale gas plays in the lower 48 states of the USA. Of these the Marcellus shale has the potential to be the largest and most productive play (Ridley, 2011).

In 2009 US shale gas production accounted for 16 % of total gas production. More than 40,000 wells produced from shale gas reservoirs in 2010 (Gény, 2010). In future the importance of shale gas will increase even more. According to the EIA (2011) it is expected that shale gas production in particular will incrase to 47 % of total US gas production by 2035, while production of other unconventional gas resources, such as tight gas and coalbed methane will remain stable (see Figure IV-2). However, there are large uncertainties concerning these assumptions.

Figure IV-1: Lower 48 states shale plays (EIA, 2011b).

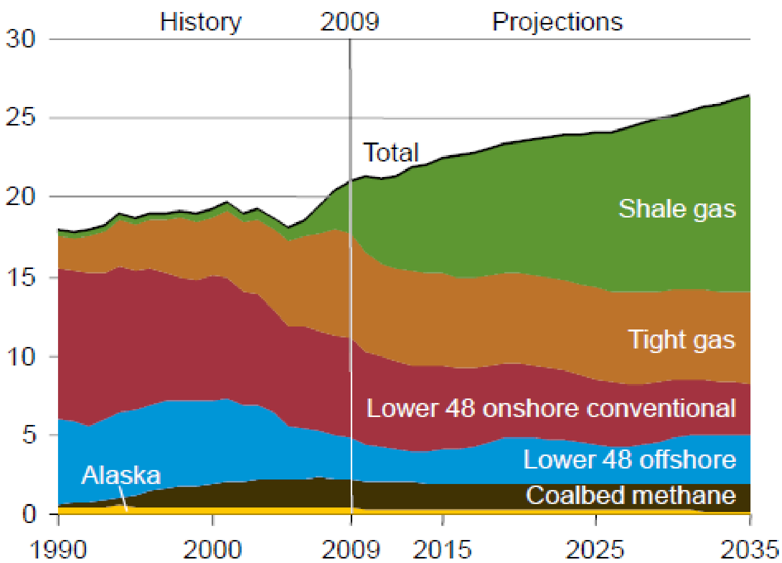

Figure IV-2: Natural gas production by source, 1990-2035 in trillion cubic feet (tcf) (EIA, 2011).

IV.3. Geology of Shale Gas Reservoirs

IV.3.1. American Gas Shales

Within the United States shale formations occur in several sedimentary basins. The two most important reservoirs for shale gas are the Barnett Shale in northern Texas and the Marcellus Shale, which extends over the states of New York and Pennsylvania (see Figure IV-1). The by far biggest amount of the US shale gas is produced here (Montgomery et al., 2005). The Barnett Shale is of special interest because many small- to medium-sized companies have invested in this gas play. Many technological innovations were developed to extract the natural gas from this shale. Furthermore, due to the intense work in this area a substantial amount of data was collected, which can be used as a basis for estimations in European shales. It is important, though, to note that each play has individual geological and physical properties, this means that any correlation between gas shale systems has to be viewed with caution.

IV.3.1.1. Barnett Shale

The Barnett Shale is located within the Fort Worth Basin in northern Texas (see Figure IV-1 and Figure IV-4). It is a Paleozoic foreland basin that developed during the Ouachita orogeny, in late Mississippian/early Pennsylvanian (Montgomery et al., 2005; Loucks et al., 2007). The Barnett Shale consists of five different lithofacies, which are black shale, lime grainstone, calcareous black shale, dolomitic black shale and phosphatic black shale. The total thickness of the basin strata is 3660 m. Of these, up to 1500 m are lower to middle Carboniferous (Mississippian) rocks and 1200-1500 m represent Carboniferous (Pennsylanian) rocks (Jarvie et al., 2007).

The best producing horizon in Barnett Shale has a mineral composition of 45 % Quartz and only 27 % clay. These rocks show a mineralogy-related brittleness, which makes them attractive for fracking operations (Bowker, 2003). Present-day TOC values range from 4-5 % at a mean VR_r value of 1.67 %. In immature outcrop samples, TOC contents may exceed 11 % on average (Jarvie et al., 2007). The shales have low porosity and low permeability. Altogether, the Barnett

Shale is a three-component system comprising source rock, reservoir rock and hydrocarbon trap in one.

At the estimated burial depths, reservoir temperatures resulted in natural gas genesis by kerogen and oil cracking (Jarvie, 2007; Killops et al., 2005). The high organic richness and thermal maturity of this formation are parameters, which lead to an estimated gas content of 4.5 m³/ton. Much of the produced gas was expelled; the rest resides in the open pore space or is sorbed in the rocks. Since a substantial portion of the natural gas contained in shale source rocks is sorbed physically on the organic matrix, the sorption capacity is of special interest. Values measured in desorption experiments from cuttings show sorbed gas contents averaging between 9.74 and 11.00 m³/m and corresponding to up to 60 % of total gas in place (Figure IV-3) (Montgomery et al., 2005).

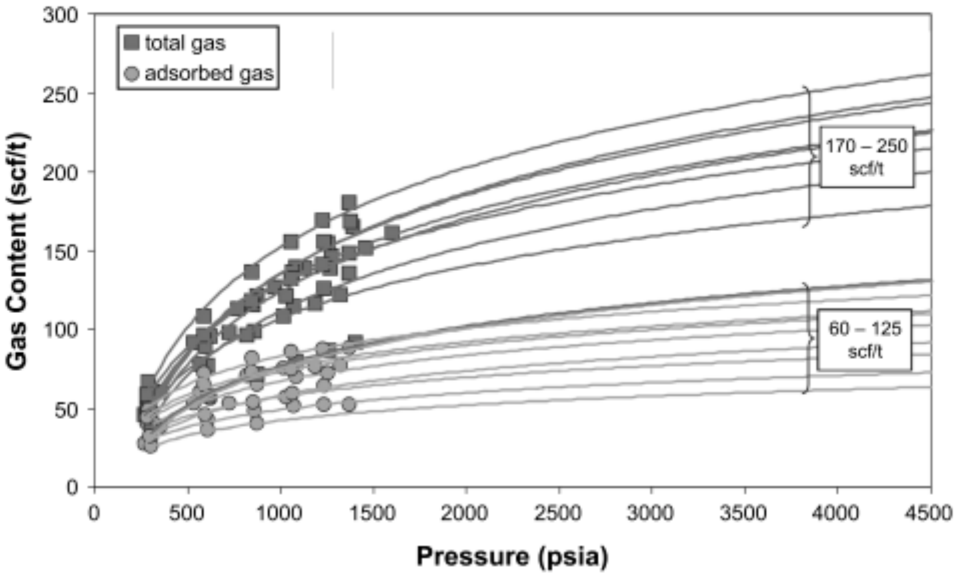

Figure IV-3: Sorption isotherms for Barnett Shale core samples recovered from the Mitchell Energy 2 T. P. Sims well, Wise County. Gas content range from 170 to 250 and from 60 to 125 scf/t (1 scf = 0.028 m³) for total and adsorbed gas, respectively, are indicated for a reservoir pressure of 3800 psi (in Montgomery et al., 2005).

IV.3.1.2. Marcellus Shale

The second example of a shale gas play is the Marcellus shale, located in the north-east of the United States (see Figure IV-1 and Figure IV-4). The Devonian Black Shales of this formation lie at depths between 910 m at the western boundary and 2745 m at the eastern side (see Figure IV-6) (Roen, 1984 and geology.com). The composition of the black shales is on average 25 % quartz, 10 % feldspar, 5-30 % various mica minerals, calcite up to 25 % and various clay minerals over 60 %. The TOC values vary between 0.5 wt. % and 20 wt. % at a mean of 4 wt. %. According to the USGS (website) the Marcellus Shale complex has a total gas in place capacity of 14,150 billion m³ of which 141 billion m³ are considered as recoverable. Between 2005 and 2007 375 wells have been permitted in the Pennsylvanian part of the Appalachian basin. The thermal maturity extends from less than 0.6 %VRr at the western thinning area to 3.0 %VRr in the east (Martin et al., 2008).

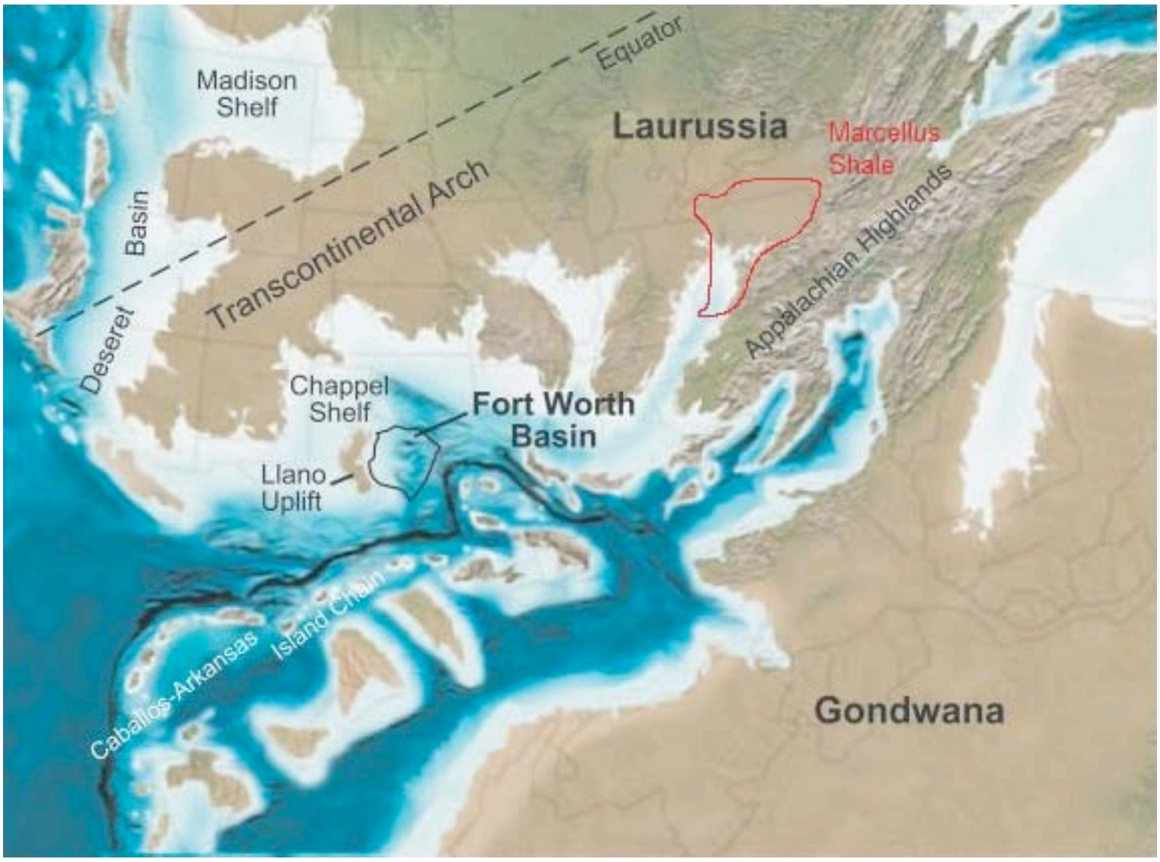

Figure IV-4: Paleogeography of the sedimentation areas of the Barnett Shale (Fort Worth Basin) and the Marcellus Shale (in red) (altered after Loucks & Ruppel, 2007).

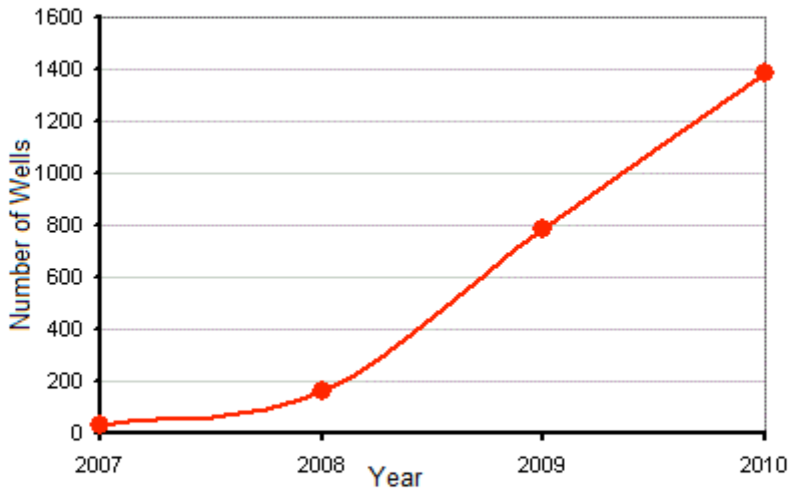

Figure IV-5: Numbers of wells drilled into the Marcellus Shale in Pennsylvania per year from 2007 to 2010 (USGS).

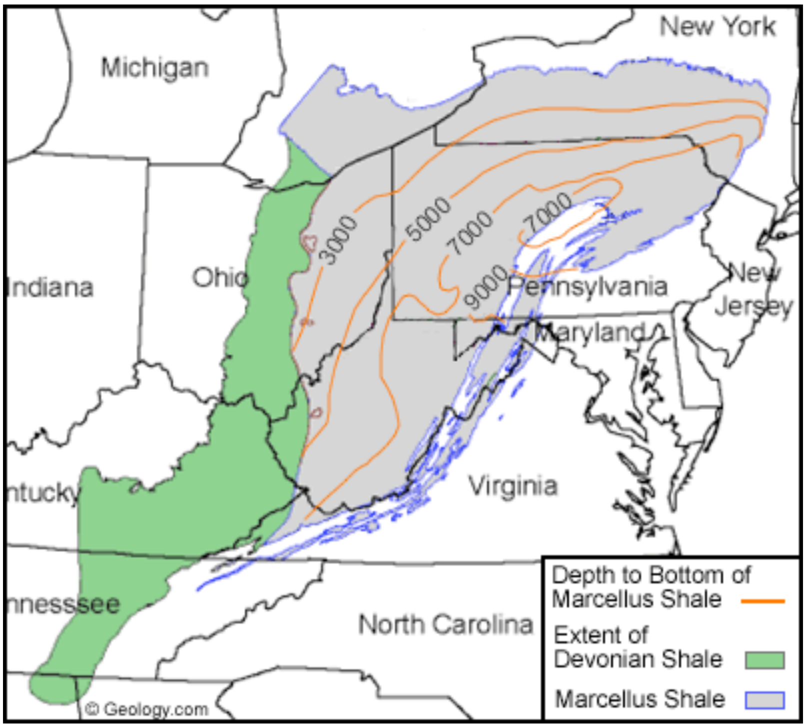

Figure IV-6: Approximate depth to base of Marcellus Shale. Units are feet below surface (geology.com).

IV.3.2. European Gas Shales

IV.3.2.1. Overview

According to BP's Statistical Review of World Energy (2010) the European gas market is the second largest gas market in the world with a demand of 473 billion m³ in 2009 although gas production and reserves in Europe are declining. This will result in increasing dependence on imports. One way to counteract this increasing dependence would be to develop new gas resources from unconventional plays. As mentioned in section IV.2, shale gas production accounted for 16 % of the US total gas production in 2009 (EIA, 2011). Compared to this situation the European shale gas sector is in its infancy. Rogner (1997) estimated the European total unconventional gas resources to amount to 35,537 billion m³ subdivided into 15,546 billion m³ from shales, 12,205 billion m³ from tight sands and the rest from CBM. Gény (2010) stated that Rogner's estimates were too low and pointed out that Rogner's work was based on the technology and understanding of 1997. Furthermore Rogner did not include Poland, Hungary, and Romania in his consideration. The lack of data concerning shales stems from the little economical interest in this type of rock before the shale gas sector emerged (Gény, 2010). The appraisal of new data has just begun, but it will take some time until enough data are collected to make more accurate estimations. The fast acquisition of data and their understanding is counteracted by the secrecy around it due to market rivalry (Gény, 2010). Another factor is that local governments are not willing to invest into data acquisition. The companies are independens and it is up to them to invest much money into long-term projects for shale gas exploration and development (Gény, 2010).

Figure IV-7: Potential shale gas plays in Europe (Kuhn & Umbach, 2011).

Exploration and development of shale gas plays in Europe encounters various specific problems. Besides the economical, environmental, and legal issues, which will be discussed in sections IV.4.3.2 and IV.4.3.3, further problems arise due to the relatively high population density in Europe. This imposes limitations on accessibility of a shale gas plays and the possibility of drilling exploration wells. More importantly, lack of public acceptance has become one of the main issues for the development of the unconventional gas sector (Kuhn & Umbach, 2011).

Figure IV-7 shows potential shale gas plays in Europe. There is a large span of geological settings in which potential plays are occurring. The north of Europe is dominated by alum shales of Cambrian and Ordovician ages. In western Europe, shales of Jurassic age are present. Shales of Carboniferous and Permian age extend from the UK aross the Netherlands and northwest Germany up to southwest Poland. In northern and eastern Poland, shales of Silurian ages have been found. The major Paleozoic potential shale gas plays are those of Cambrian and Ordovician, Carboniferous and Permian, and Silurian ages (Kuhn & Umbach, 2011). Those play areas are not readily comparable to US shale gas plays. As shown in Figure IV-1, the US plays are generally of much larger extension. It must also be taken into account that the European plays are "[...] tectonically more complex, and geological units seem to be more compartmentalized. Furthermore, shales tend to be deeper, hotter, and more pressurized. The quality of the shales is also different, with generally more clay content in Europe" (Gény, 2010). In consequence, the technological solutions which have been developed for US shale gas plays will have to be customized in order to fit the European requirements (Gény, 2010).

IV.3.2.2. Shale Gas in Poland

Among the European countries, Poland is the one with the most promising potential to produce unconventional gas (see Figure IV-8). The main focus lies on its Silurian shales (Littke et al., 2011). The Wood Mackenzie company estimated In 2009 Poland's recoverable unconventional resources were estimated to amount to 1,402 billion m³ (49.5 Tcf) (bloomberg.com). For comparison, Figure IV-9 shows another estimation of the Polish recoverable unconventional gas resources by Wilczyński (2011). The amount of 5,000 billion m³ of projected unconventional gas resources is 3.5 times higher than the estimation by Wood Mackenzie. This illustrates the huge uncertainty concerning the actual amount of unconventional gas resources in Poland.

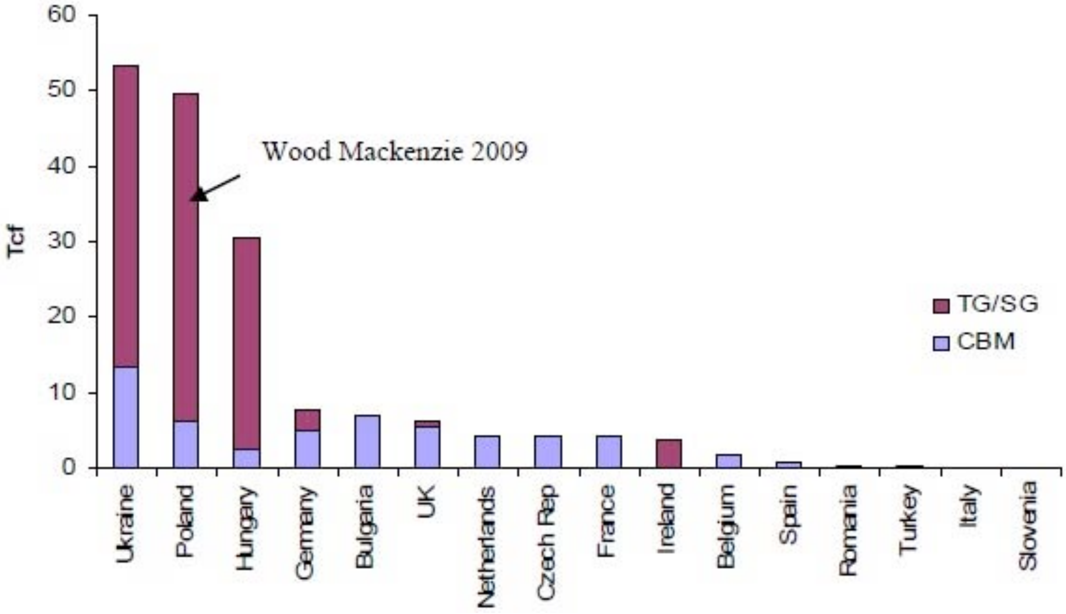

Figure IV-8: Estimates of European CBM and tight sands recoverable resources by country, (Gény, 2010).

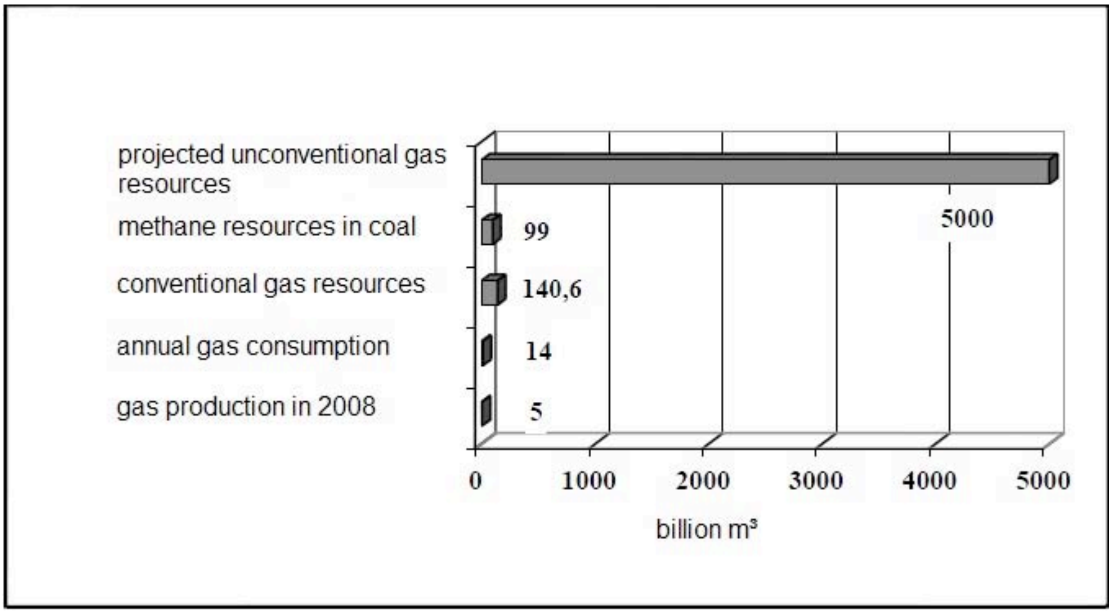

Figure IV-9: Resources, mining and natural gas consumption in Poland (after Wilczyński, 2011).

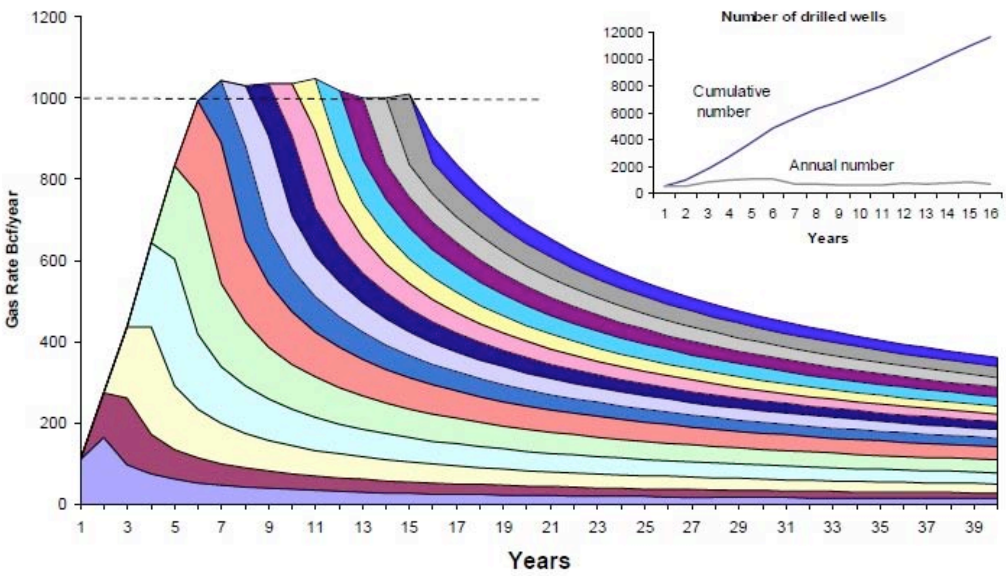

Figure IV-10: How to produce 1 Tcf of gas/year for 10 years (Gény, 2010): Each color represents the production of one well that would have to be drilled in order to produce 1 Tcf/a of shale gas for a ten year period after a five year development phase. The reason is the considerable production decline of shale gas wells.

The requirements for a production of 28.3 billion m³/a (which equals approximately 1 Tcf) in terms of the number of wells that have to be drilled are shown in Figure IV-10. Gény (2010) chose the Fayetteville shale as a US analogue to the Baltic Depression Basin because of the comparable geology. She pointed out that because of the lack of data concerning the Silurian shales it is highly hypothetical to compare those plays. Another concern she mentioned is that similar geological properties do not necessarily result in similar shale play performances. Anyhow, up to present the geological properties were the only factor on which the choice of an analogue could be based on. By assuming that the production performances of those shales are comparable, Gény (2010) estimated that in order to produce 28.3 billion m³/a after a starting period of 5 years, and sustaining this amount over a period of 10 years, a total of 11,700 wells would have to be drilled in 15 years (see Figure IV-10). It should be noted that according to Figure IV-9 a production of 28.3 billion m³/a would be slightly more than twice the annual consumption of gas in Poland. Gény (2010) stated that "[…] it is likely that the production of 1 Tcf/year of unconventional gas in Europe may not come from a single basin or country, with the possible exception of Poland, but will rather result from aggregate production across Europe." This illustrates why Poland is the only country in Europe, which is highly interested in shale gas production (Weijermars & McCredie, 2011). Besides the probably high production capability there are even more incentives to establish the unconventional resources sector in Poland. Firstly, natural gas from Polish domestic plays can be used to lower the greenhouse emissions of coal-fired power plants by increasing their performance (Weijermars & McCredie, 2011). Secondly the production of domestic gas would lower the dependence from Russian gas (Weijermars & McCredie, 2011). Therefore the Polish government has already assigned more than 70 exploration licenses for potential shale gas areas and considers assigning more. As discussed in section IV.4.2, more than 50 companies are currently involved in the exploration in Poland (Gény, 2010). It is important to realize that there are also problems, which arise concerning the production of unconventional gas. For example the assumed production of 28.3 billion m^3/a requires massive amounts of surface area. For the drilling of 1000 wells about 324 km^2 surface area are required amd additional space for infrastructure has to be considered, too (Gény, 2010). Access to the exploration area is partly limited due to environmental restrictions and a high urbanization (Gény, 2010). Furthermore water supply is a problem, as will be explained in section IV.4.3.3. Another issue is the limited number of drilling rigs, which will be addressed in section IV.4.3.2. As mentioned earlier, the public acceptance is going to play an important role. Contrary to the US, landowners in Europe only hold the surface rights, while in the US they also hold the mining rights. Therefore the landowners profit from any resources that are mined on or below their property (Gény, 2010). This is an important factor, which lowers the public acceptance in countries like Poland. The companies have to create jobs or invest in local communities increase public acceptance. A positive aspect in Poland is, that because of its coal mining history the acceptance for unconventional gas could be higher than in other European countries (Gény, 2010). The exploration and development of the Polish plays will be an important test for the entire European unconventional gas sector. If it is successful, it might reduce criticism about exploration and development of shale gas plays in the rest of Europe (Weijermars & McCredie, 2011).

IV.4. Strategy and Perspective of Shale Gas (in Europe)

IV.4.1. Political Scenarios

Whether or not unconventional hydrocarbon-resources are developed, depends particularly on public opinion and political strategies. Also, the general public attitude and political strategy might differ in understanding and approaching this topic. This section gives an overview over the different trends in Europe and Germany particularly.

As shown in section IV.2, the USA managed to change their natural gas market completely from net importer to net exporter. Attractive tax benefits encouraged small developers to intensify their efforts in Research and Development (R&D) and bonuses on land prices gave another appeal for engaging the shale gas sector. Major producers did not start to show interest in this sector until the minor companies were able to produce economically. Prospection and production in Europe would take further effort in research and development, since the European legal situation demands a higher safety and environmental standards than the United States (Gény, 2010). Fiscal support similar to the American tax system and its benefits for shale gas producers would expedite technical progress. Considering the tendency in European society to prefer environmental protection over industrial development (Diekmann & Franzen, 1999; Galeotti, 2006), it seems unlikely that there would be a similarly fast progress as observed in the USA.

Since the release of the documentary movie “Gasland” in 2010, an active, well-organised lobby has formed using the internet as a medium to influence public opinion efficiently. Abutters and environment organizations proceed against shale gas production because of the massive land use and other environmental difficulties in the US. Some residents of drilling and producing areas claim health issues, which in their opinion are caused by polluted air and ground water. The public concerns are driven by the coverage of mass media, which tend to publicize incidents without further research and questioning. An example is a spectacular scene from “Gasland” in which gas flowing out of a water tap is ignited. According to research done by the State of Colorado, this is biogenic methane from a coal-bearing aquifer and not, as suggested by the movie, thermogenic hydrocarbons that leaked from a natural gas well (State of CO, 2010).

One reason for the critical public attitude is the lack of transparency in the hydrocarbon business. To protect enterprise knowledge, and thus advantages to competitors, exploration and production are disclosed only very reluctantly. Surprised by the massive reactions that followed the first exploration activities, corporations recently started programs to improve public acceptance. An open and citizen-orientated approach is necessary to convince critics and officials as already performed in the German coal sector, where much effort is given to explain the necessity of coal mining (Milojcic, 2011). Thus, ExxonMobil created an information website which provides answers to many frequently asked questions about their drilling and producing activity in Germany. In addition the company tries to establish a connection with town councils and citizens via information events and visitor-centers in cities and on well sites.

Presently the political parties in Germany avoid taking responsibility related to E&P, especially in connection with hydraulic fracturing, which feeds multiple worst-case scenarios. Though the debate about unconventional gas is in progress, as can be followed at the website of the North Rhine-Westphalian parliament (Landtag-NRW). However, a positive outcome of such campaigns is unlikely since the emotional intensity within this debate complicates a solution-oriented discussion.

Table IV-1: Laws and legal guidelines concerning gas exploration in the EU. Distinction between Union and national laws (modified after Gény, 2010).

European Union	Liberalization and integration of energy markets	**Water:** Drinking Water Directive (1998), Water Framework Directive (2000), Groundwater Framework Directive (2006)
	Climate change and energy package: 20-20-20 Targets	**Biodiversity**: Birds Directive (1979), Habitats Directive (1992) , Natura 2000 network
	Improve security of supply	Mining Waste Directive (2006)
		Noise Directive (2002)
Member States	Mining laws and decrees, Permitting regulations (spatial planning, drilling, safety, noise, etc.)	Federal or National environmental laws, Permitting regulations (Water, EIA, etc.)
	Local E&P regulations	Local environmental regulations (water, soils, chemical use, etc.)

Gény (2010) pointed out, that political ambitions in Europe are different than in America. The US *Gas Revolution* would not have happened without the tax benefits and support on the part of authorities. In addition the US mining laws are very liberal. It is comparatively easy to get drilling permissions and land access.

In contrast the EU created and reconfirmed several environmental laws lately, which affect any drilling proposal/planning directly or indirectly (Table IV-1) EU and national laws that affect drilling programs. The general trend in politics strives towards an extensive protection of environment and environmental resources. The public awareness of environmental issues has grown during the last decade. A high level of wealth allows the majority of citizens to demand improved protection of environmental goods and sustainable strategies of development of their governments (Dieckmann & Franzen, 1999).

Another factor that complicates the acquisition of drilling licenses within the EU is that there are no legal arrangements that would adjudge a share of profits to land owners. Therefore in Europe people are less motivated to make their land available, whereas in the US royalties around 12.5 % and in some cases up to 25 % are paid (Gény, 2010; geology.com).

In Europe there are various strategic positions among the different states. For example the western European countries are relying on the conventional gas market wich is mainly supplied by imports from Arabia and the Russian Gazprom. With the Nord-Stream pipeline put in operation in 2011, Germany has now a direct supply line for natural gas from Russia. Contracts with Gazprom guarantee gas supply for at least 50 years (Nord-Stream, website). On the other hand the former USSR-States such as Ukraine strive towards independency from Russian gas imports. With this goal it is likely that these nations will develop their regional gas plays as soon as possible. Before Nord-Stream, Western Europe had to rely on pipelines that pass transit states such as Ukraine, which lead to several complications in recent years: The Ukrainian dispute of 2005 is an example for economical tension between Russia and the transit countries to Western Europe. Ukraine refused to pay higher, market oriented gas prices, which ended in a supply-stop by Gazprom. Both countries blamed each other to be responsible. This action affected the European gas market as well, so that several countries faced shortages of about 20 % of the common imports (Kazantsev, 2010). Such instabilities in politics improved the acceptance of Nord-Stream in general.

IV.4.2. Competing Companies

During the past decades the shale gas industry in the USA developed very successfully. Since 2007 the interest in European unconventional gas resources has increased strongly (Gény, 2010). The US development of the whole shale gas sector started without the participation of major oil and gas companies. Instead of those majors, smaller independent developers were responsible for the initiation of the whole sector (Gény, 2010). The majors who joined the US shale market with delay are trying to avoid this mistake on the European shale gas market and are trying to participate in this development from the very beginning (Kefferpütz, 2010). This has lead to numerous joint ventures between major US companies and European companies. For example “[...] BP is negotiating a deal with Lewis Energy for a joint venture agreement in the Eagle

Ford shale in south Texas, ExxonMobil has struck a $41 billion all-stock takeover of XTO Energy, and both Statoil and Total have increased their acreage position in the US shale market through deals with Chesapeake Energy, the second biggest natural gas producer in the US" (Kefferpütz, 2010). Contracts like these aim at a transfer of experience and know-how for the future exploration and development of European shale gas plays.

Figure IV-11 shows that as a result of the high expectations concerning the European unconventional gas potential, numerous companies have leased potential play areas. It is evident that besides the majors there are companies of every size as well as national oil and gas companies (OMV, MOL), and European groups (GdFSuez, RWE) (Gény, 2010). It should be mentioned that more than 60 % of the players are small companies, North American ones willing to bring their knowledge gained on US operations, or national ones with knowledge about local conditions (Gény, 2010). Big companies often work together with smaller players. The former contributes risk capital, while the latter one has unconventional gas expertise and is able to take fast decisions.

IV.4.3. Economic Issues

The major challenges to shale gas production in Europe are of economic and environmental nature. Compared to the conditions in the US, there are more regulations in Europe and also the production costs will be higher than in the US.

Figure IV-11: Unconventional gas competitive landscape Europe (Gény, 2010).

IV.4.3.1. Natural Gas Price Development

The natural gas price depends on several factors. Among these the costs of production, beneficiation and transport are the most important ones. Through the application of modern technology, such as hydraulic fracturing, production costs have been reduced since the 1990s. However, since 2003 they are increasing again due to higher costs for labor, material and equipment. The costs for beneficiation depend on gas composition. Lean gas, which mostly consists of methane, only needs to be dried whereas rich gases require higher efforts (see chapter I: Treatment, Refining and Utilization of Oil and Natural Gas) (BGR, 2009).

There are large differences in gas prices between regional and national markets. In the period from 2007 to the middle of 2008 the gas prices were similar on different markets, but since 2009 this trend is declining again (see Figure IV-12). In general, the natural gas prices are linked to oil prices. In continental Europe the link between oil and gas had weakened due to contract renegotiations and additional inflows of cheaper spot gas in early 2010, but prices remained relatively high in 2010 at $27/kWh. In North America oil and gas prices remain disconnected due to the continuing abundance of shale gas. This leads to low natural gas prices of about $13.5 per kWh (IEA, 2011).

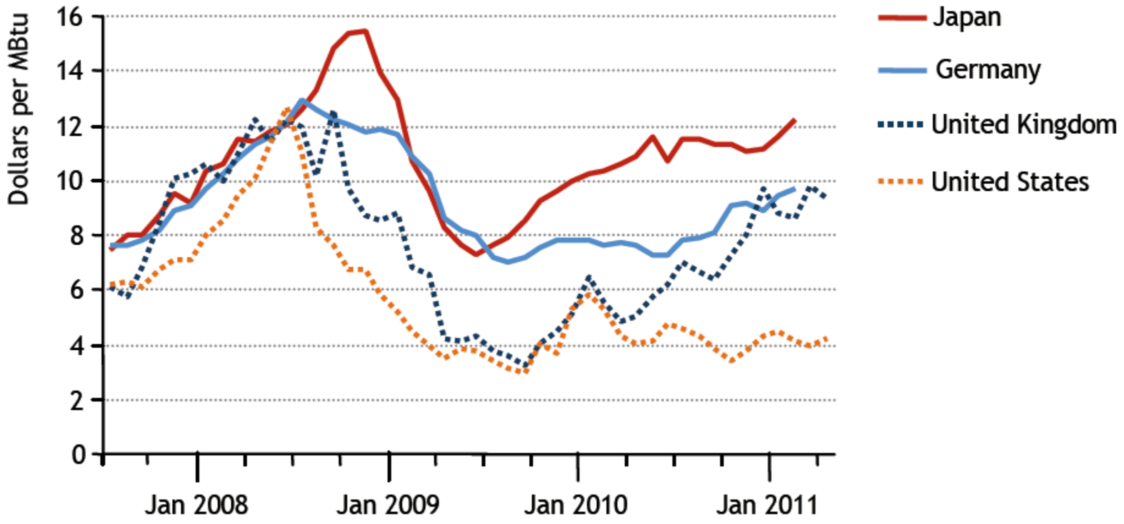

Figure IV-12: Natural gas prices in major markets, July 2007 to April 2011 (1 MBtu = 0,293 kWh) (IEA, 2011).

IV.4.3.2. Economic Problems

Production costs vary with different characteristics of the shale formation, but in general costs for shale gas wells are always higher compared to conventional wells due to horizontal drilling and hydraulic fracturing (Levell, 2010). However, the full-cycle costs for unconventional gas production are the same as for conventional gas production. Full-cycle costs are divided into four categories, which include: finding and development costs (F&D), production costs (also Lease Operating Expense) (LOE), general and administrative and interest expense. The first two factors are the most important ones, as they account for 80 % of total full-cycle costs. The F&D costs include acquiring and exploring land, drilling and well completion (D&C), which are almost 100 % of well costs.

Figure IV-13 shows the drilling and completion costs of a well in the Haynesville shale play. The total well costs of $9 million are almost equally divided into drilling and completion costs. Concerning drilling costs, directional drilling and cementing actions form the largest share (19 %), followed by rig costs (day rates) and costs for casing (both 13 %). Concerning completion costs, stimulation processes (hydraulic fracturing) account for the highest share with 33 % (Gény, 2010). In general, costs for horizontal wells are three to four times higher than costs for vertical drilling (Considine et al., 2009). The LOE costs incur after the well has been drilled. They include costs of gathering, processing and shipping the gas to a certain market point (see chapter II: Production and transport costs of oil and gas).

The major economical problem concerning shale gas production is the fact that wells from shale formations have a lower productivity than conventional wells and their production rate declines rapidly. Typically it drops between 70 and 90 % in the first year, requiring a larger number of wells to keep up production. After the first years decline rates slow down (Gény, 2010). Figure IV-14 shows the daily production rate of different wells from the Marcellus, Haynesville, Barnett and Fayetteville shale gas plays according to data released from Chesapeake Energy in 2009. The production rate declines between 68 % and 85 % during the first year and between 33 % and 38 % during the second year. This leads to a daily production of only 28,316.9 m^3 after 10 years of production.

Compared to the situation in the US, shale gas production in Europe will be substantially more expensive. This is mainly due to higher drilling and development costs and to low acceptance. According to Gény (2011) there are four main cost drivers in European countries. At first, the reservoir depth on average is 1.5 times higher than in the US, and thus more powerful rigs and more fracturing fluids have to be used. Consequently more water is consumed, while water costs are ten times higher than in the US. However, shale formations in Europe occur in a wide range of depth levels just like in the US. For example, in the Fayetteville shale gas is produced from 1,200 m depth and in Haynesville the shale formation is about 4,000 m deep. In Europe, tests are being conducted on the Alum shale in Sweden at 900 m while potential shale formations in the Baltic basin occur between 2,500 and 4,000 m (Kuhn & Umbach, 2011). Another problem will be the strict regulations in Europe concerning labor, environment and safety, leading to organizational difficulties and therefore also to a rise of expenses (Gény, 2010). Moreover, there is a lack of specialized companies and experienced staff compared to the US. For example, in January 2012 Europe accounted for only 108 drilling rigs (onshore and offshore) while in the US there were 2,003 rigs in place of which 1,953 for onshore wells (EnergyEconomist, 2012). In Europe the number of rigs is sufficient to drill the exploration wells, but most of the rigs are unsuitable for both drilling and fracking operations. This will result in 20 % higher rig rates compared to conditions in the US, where the costs were between \$20,000 and \$30,000 per day in 2010. In addition, infrastructure has to be built first before shale gas can be produced in Europe. All in all, producing costs for shale gas in Europe will be up to four times higher than in the US (Gény, 2010).

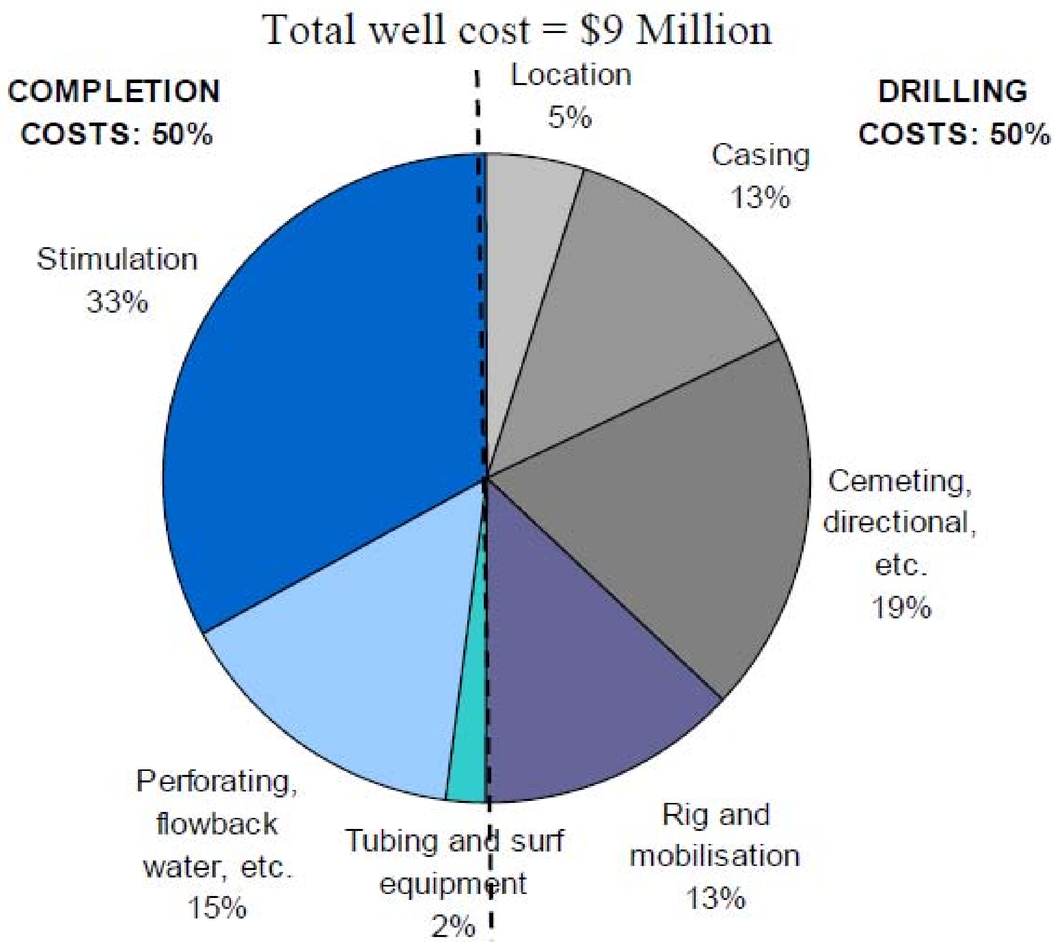

Figure IV-13: Drilling and completing costs in Haynesville (Gény, 2010).

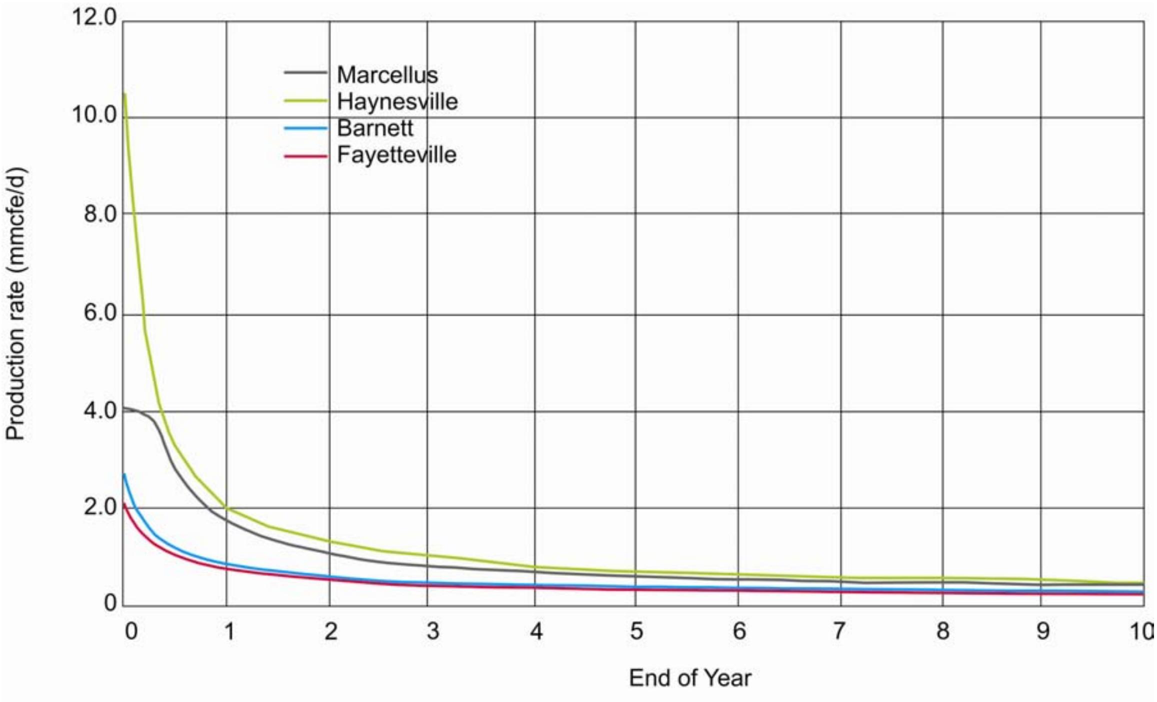

Figure IV-14: Production rate in million cubic feet of gas equivalent per day (mmcfe/d) from different wells (Chesapeake, 2009).

IV.4.3.3. Environmental Problems

In the US the debate about environmental impacts of shale gas production is rising. These concerns are also existent in European countries as there are ongoing activities in exploration. The major impacts of shale gas production are groundwater contamination due to uncontrolled fluid or gas flow, blowouts and wastewater discharge, which can also affect air and soil. Moreover the public is concerned about earthquakes triggered by the stimulation activities.

The biggest ongoing debate is about the hydraulic fracturing process due to documentary films such as “Gasland” from 2010. Hydraulic fracturing or “fracking” is used to recover natural gas and oil from deep shale formations by creating fissures or fractures.

The fracturing fluids consist mainly of water (98 %) and of different chemicals (2 %) like acid, breaker, stabilizer, friction reducer etc. In the US, companies do not have to fully disclose the composition of the used chemicals because of legal changes. In 2005 the US passed the “Clean Energy Act” which is closely oriented to the interests of oil and gas companies (Zittel, 2010). In Germany, companies such as ExxonMobil have already revealed lists of their fracking chemicals used in shale gas wells. Table IV-2 shows the composition of the fracturing fluids used in a well in Goldenstedt in 2010. The fluid mixture is classified as “weak water endangering and not harmful to the environment” (ExxonMobil, 2010). There are also chemicals, which are toxic. In general, the public is concerned that the used fluids might also include allergenic, mutagenic and carcinogenic substances.

During fracturing processes the fluid mixture is injected into the geological formation at a high pressure. When this pressure is released, about 20 to 50 % of the injected fluids, including methane, flow back to the surface. The effluent may also contain radioactive material, which comes from the rock formation such as uranium, thorium and radium, and these might contaminate drinking water resources and air (Zittel et al., 2011). Also leaks in the cement casing may lead to pollution of drinking water, when the well passes a water-bearing formation. However, this risk is also present in conventional gas wells. In Pennsylvania and upstate New York where shale gas is produced, drinking water wells show a very high methane concentration, with maxima up to 64 mg/l. In neighboring, non gas-extracting countries, the concentration was 1.1 mg/l (Zittel et al., 2011). The criticism concerning the gas contaminated water wells is growing, because it is not always known whether the methane derives from oil and gas companies producing thermogenic methane from deeper geological formations by using hydraulic fracturing, or it stems from biogenic activities. Biogenic methane is found in shallow aquifers. Recent researches on gas samples in the affected areas, which were discussed in the documentary film “Gasland”, used both stable isotope analysis of the methane and compositional analysis of the gas to differentiate between thermogenic and biogenic gas. It was shown, that some of the wells in question contain only biogenic methane and thus are not related to oil and gas activities (State of CO 2010). In addition the overburden rock, which can be thousands of meters thick, consists of impermeable clay and salt formations, which seal the reservoir. In Lower Saxony, where hydraulic fracturing is used since the 1960s, not only for oil and gas but also for geothermal wells, there are no accidents or environmental contamination known yet (Wintershall, 2012).

Another point of importance is the fact that, comparing shale gas production to conventional drilling, the water consumption is ten times higher, as there are huge amounts of water, which are used due to hydraulic fracturing (see above). A statistical research in the US shows that the typical water consumption for a horizontal well ranges between 25 and 42 m^3/m, depending on fracking fluid composition. To scale it up, for example in the Barnett shale, about 15,000 m^3 water per well is used so that in 2010 a total of 17 million m^3 was consumed (Zittel et al., 2011). Typically, operators use open pits and tanks to store the drilling fluids and also the flowback fluids which contain heavy metals, such as mercury, and also radioactive particles which come from the rock formation (see above). The problem concerning open pits is the risk of soil contamination by seeping fluids and also overflowing in case of heavy rain (Gény, 2010). In case of an overflow or leaking tubes, toxic chemicals such as methanol (see Table IV-2) are released.

Moreover it is well known that hydraulic fracturing causes microseismic events. In Arkansas, for example, the rate of small earthquakes has increased tenfold over the last years (Zittel et al., 2011). The town of Guy experienced hundreds of small but noticeable earthquakes since 2010. The largest ones had magnitudes from 4.0 and 4.3. In this region nearly 3,700 natural gas wells have been drilled and fracked in the Fayetteville shale field (Nelson, 2011). Also in Blackpool in the UK, small earthquakes with magnitudes of 1.5 and 2.3 are probably related to the drilling activities, which were stopped immediately. In this region no earthquakes were noticed before (Nonnenmacher, 2011).

Table IV-2: Selected substances used in fracturing fluids in the well Goldenstedt Z23 (underlined ingredients are toxic) (ExxonMobil, 2010).

Description	**Ingredients**	**Purpose**
Water and sand (98 %)	H_2O, SiO_2	Expands fracture/allows fractures to remain open
Acid	HCL and others	Helps dissolve minerals/initiate cracks
Breaker	Diammoniumperoxodisulphate	Allows a delayed breakdown of the gel
Clay stabilizer	<u>Tetramethylammoniumchloride</u>	Prevents formation clays from swelling
Biocide	Magnesiumchloride Magnesiumnitrate <u>5-chloro-2-methyl-2H-Isithiazol-3-One and 2-methyl-2H-Isothiazol-3-One (3:1)</u>	Eliminates bacteria etc. in the water that produces corrosive byproducts
Crosslinker	<u>Methanol</u> Inorganic borates Inorganic salts	Maintains fluid viscosity as temperature increases
Surfactant	2-butoxylethanol Propane	Used to increase the viscosity of the fracture fluids

IV.5. Discussion and Conclusion

Unconventional natural gas resources, especially shale gas, are a great opportunity for European countries to become more independent from fuel imports. Compared to the already established market for shale gas in the United States, Europe has to struggle with various difficulties. The most serious concerns are low acceptance of the E&P activities in public opinion, spatial constraings due to high population density, hig environmental protection standards and finally the comparatively high cost of labor, material and operational expenses.

While politics in Poland tend to establish regional production soon, politicians in Germany are still indecisive. Which option will be chosen henceforth relies on the development in Poland and will emerge within the next 10 to 15 years. Because of the intense emotionality that made its way into the debate in Germany, non-scientific publications and media reports should be viewed critically and with caution.

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V. Libya’s Role on the Global Petroleum Market: The Aftermath of the Arabian Revolution

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Libya has very large proven petroleum reserves of about 46 billion barrels of oil and about 1.55 trillion cubic meters of gas. Over 20 billion barrels of those estimated 46 billion have already produced since the late 50’s. The remaining petroleum potential within the major sedimentary basins of Libya is enormous. The high production rates of the 1960ies with over 3 million barrels per day were never reached again, since Gaddafis takeover in 1969. After UN sanctions were lifted in 2003, many new trading partners were acquired and a general privatization of the Libyan petroleum industry was announced. A production increase to the former peak of the 1960ies was to be reached by 2017 (NOC, 2009). The 2011 Libyan Revolution caused less damage to the petroleum industry, than expected. The production was picked up very fast and was about 1.3 million bpd in January 2011, almost as high as before the civil war. Until a stable government is established in Libya, a forecast for Libyan’s role on the global petroleum market would not be very reliable. Many international oil companies, however, seem to appreciate the changeover and trust in a positive development of the political situation in Libya.

V.1. Introduction

Since the late 1950ies Libya is a crude oil producing country and today it counts to the wealthiest countries of Africa. A production peak of over 3 million barrels a day was reached in the late 1960ies, but then production decreased rapidly, since a new government, under leadership of Muammar Gaddafi, implemented high taxes, putting the foreign oil companies under pressure. The production rate never recovered to that level. Several conflicts and subsequent trading embargos and sanctions limited the oil and gas export potential of Libya for long periods. The long-term lack of foreign exploration efforts in the past, however, may be a good opportunity for foreign exploration companies today, especially after the revolution. The former regime under Muammar Gaddafi had plans to enhance production drastically and after UN sanctions were lifted in 2003, many new trading partners were acquired and a general privatization of the Libyan petroleum industry was announced. The Arabian revolution threw over all the former production and trading plans. Again, like in 1969, the foreign oil companies had to fear for their expensively acquired concessions. The current developments reflect the growing importance of Libya's role on the global petroleum market. However, there is no doubt, that in the future Libyan oil production strongly depends on foreign exploration efforts and thus on the political stability within the country.

V.2. Overview

The following chapter provides an overview of the geography and economics of Libya with emphasis on the political history of Libya since the first petroleum discoveries and the time of Gaddafi's reign.

V.2.1. Geography

Libya is situated south of the Mediterranean Sea between Egypt and Tunisia. Other neighboring countries are Algeria in the west and Niger, Chad and Sudan in the south. Libya's coastline is with 1,770 km the longest of all African countries bordering the Mediterranean (see Fig. V-1). The majority of the 6.5 Mio habitants live in densely populated areas along the coastline, like Tripoli, the capital of Libya, Misrata, Sirte, Benghazi and Tubruq (from west to

Figure V-1: Map of Libya and its neighboring countries (CIA)

east). With an area of 1,759,540 km², Libya is the fourth largest country in Africa and the 17th largest in the world by area (CIA WORLD FACT BOOK, 2011). Most of this area, except the coastline, is extreme desert. The Libyan Desert covers more than 90% of the country and is one of the most arid places in the world, where in some places decades may pass without rain. The highest recorded naturally occurring air temperature reached on Earth (57.8 °C) was measured in a small town south west of Tripoli on 13th September 1922.

V.2.2. Political history

The first traces of oil were found in a water-well near Tripoli in 1926. Italian geologists were active since 1901, investigating and mapping the region. Four major sedimentary basins were identified. However, the first large petroleum discoveries were made in the end of the 1950's after the end of the Second World War. After gaining its independence in 1951, Libya established as a federal constitutional monarchy. Until the early 1960's, 70% of the land area of Libya was placed under license. The principal concession holders at this time were Esso, Mobil, Oasis, Amoseas, Gulf, BP, Shell, and CFP. Among smaller American companies were Libyan American, Nelson Bunker Hunt and W.R Grace. European companies were Deutsche Erdoel, Wintershall, Elwerath, CORI, Ausonia Mineraria and SNPA (HALLETT, 2002).

On 1st September 1969 the monarchy in Libya was overthrown by a military coup led by Colonel Muammar al Gaddafi. In order to take over the administration, a Revolutionary Command Council was established coupled with new ministerial appointments. The first aim of this new government was to negotiate the withdrawal of British and American forces from Libya. They made it clear that existing agreements with foreign oil companies would be honoured and that there was no intention of nationalizing the Libyan oil industry. On 30th June 1970 the last American soldiers left Libya. After negotiations about a more equitable posted price for oil produced in Libya failed, the new government imposed drastic production cuts. The alleged reason was reservoir damage due to overproduction. The next action was the nationalization of the marketing of Libyan oil products and the impoundment of a port tax in July 1970. By this strategy the government also prevented Esso from building a LNG plant. In consequence, many foreign companies reduced or even stopped their exploration efforts within Libya. However, within a short time almost all of the producing companies had been forced to agree to posted price increases of 30 cent/barrel and an increase in tax to 58%. Contrary to previous assertions, state participation in all concessions became an officially stated goal of the Gaddafi regime in 1972, requesting a 51% interest in all existing licenses. The producing companies protested, but finally had to follow the orders of the Libyan government in 1974, after several external events had led to a national estimation of the posted oil price, making all OPEC members more or less independent. While the posted price of Libyan crude oil increased from 3.45 to 4.60 $/barrel between April 1971 and September 1973, after the Yom Kippur War and the declared independence of the OPEC Gulf States in October 1973, the posted price for Libyan crude oil rapidly increased to 15.76 $/barrel in January 1974. Through these developments, the government of Libya had reached its participation targets until summer 1974. It had taken over BP, Hunt, Amoseas and Shell's holdings completely and a 50% interest or more in the concessions of Esso, Mobil, Oasis and Occidental. Furthermore it had two joint venture agreements with Aquitane and Agip. The State of Libya had taken possession of all of the available open acreage and controlled 70 % of production (HALLETT, 2002). But the victory of the government over the foreign producing companies was not without cost. Several companies withdrew completely from Libya, while most of the remaining companies reduced their exploration effort to a minimum to concentrate on production instead. The resulting inadequate level of exploration drilling has not recovered until today. With several campaigns the government tried to encourage exploration, especially by offering new concessions. The exploration history clearly reflects this important change after the takeover by Gaddafi. About 80% of Libya's presently known reserves were discovered and 50 % of all exploration wells were drilled between 1958 and 1968. Since 1968 the pace of exploration has been much slower and it has suffered from under-investment. As a result, Libya is under-explored in comparison with areas such as the North Sea, which were developed during the same period (HALLETT, 2002).

In 1977, Gaddafi officially passed power to the General People's Committees and Libya became the "Socialist People's Libyan Arab Jamahiriya". Meanwhile international critics claimed the reforms gave him virtually unlimited power. The new government structure was officially referred to as a form of direct democracy. However, election results were never published. Shortly tafter this reformation Gaddafi ordered a military strike on Egypt, to prevent the Egyptian President from signing a peace treaty with Israel and demonstrated his sole domination and this ruthless course of action. Several wars were fought and much of the country's oil revenues were spent on the purchase of arms and sponsoring paramilitary and terrorist groups around the world. After two terrorist attacks on the airports of Rome and Vienna in December 1985 the U.S. sank two Libyan ships in the Mediterranean Sea. The Berlin discotheque bombing on 5th April 1986 shocked the western world, especially the U.S. because of the specific aim of the terrorists to kill American soldiers. An intercepted message with congratulations for a well-done job from Libya to the Libyan embassy in East Berlin was followed by bombardments of Tripoli and Benghazi by U.S. forces. Libya was put under United Nation sanctions. Despite all this, within Libya also many positive developments could be recorded. The Human Development Index of Libya became the highest in Africa. Life expectancy rose from 57 years in 1977 to 77 years today. The problem of limited natural freshwater resources was solved by the world's largest water development scheme, the Great Manmade River Project. Today, the Libyan coastline is supplied by fossil groundwater, produced from deep reservoirs in the southern desert and then transported through pipelines.

During the last years of his reign, Gaddafi had the reputation of being a relative safe Western-oriented trading partner to the European Union within the Arab world. Especially the relations with Italy were very close and entangled. The United Nation sanctions were lifted in September 2003 and even the sanctions of the old enemy U.S.A. were totally removed by June 2006. In Figure V-2 a timeline of the Gaddafi regime is shown, including key events of his leadership and of the revolution in Libya in 2011.

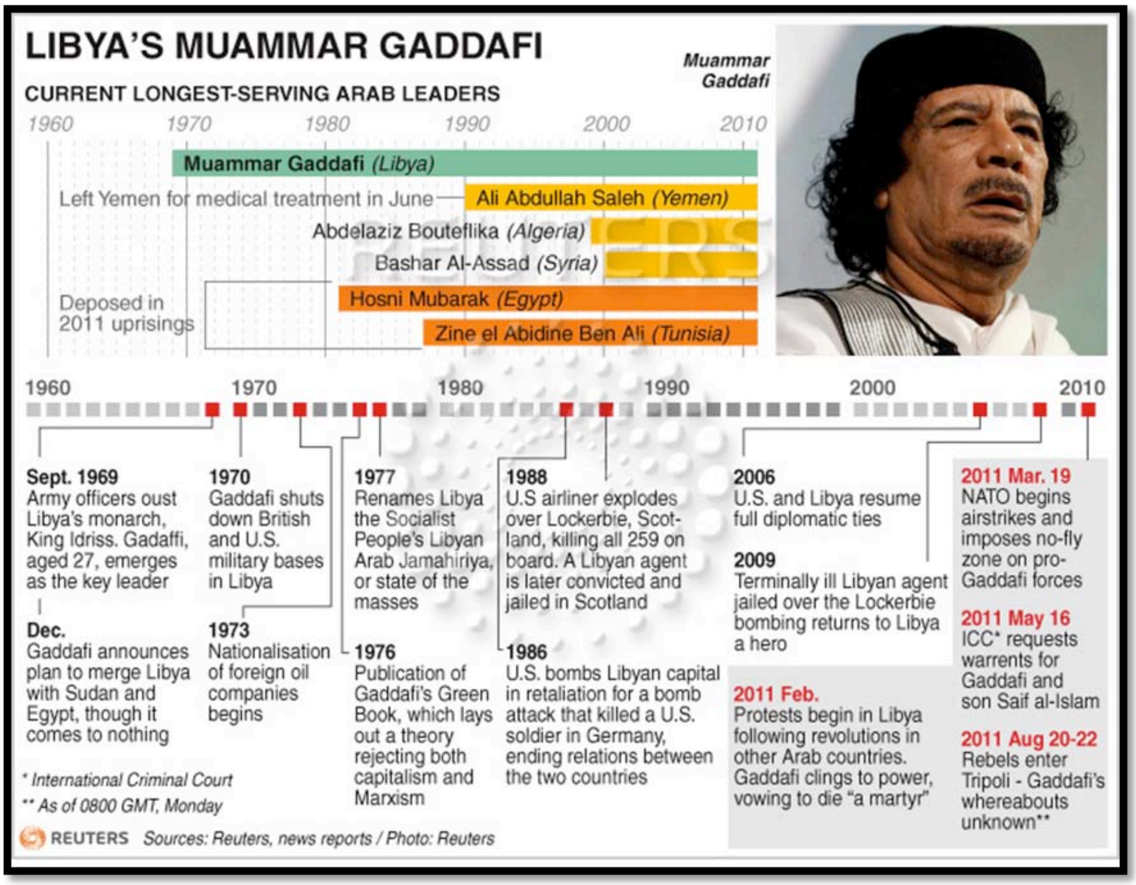


Figure V-2: Libya's Muammar Gaddafi (Reuters)

V.2.3. Economy

As outlined above, the petroleum industry has a key role in the Libyan economy. Gaddafi's influence on the national crude oil production since the beginning of his leadership can be seen in Fig. V-3.

In 2010, 95% of export earnings, 65 % of gross domestic product (GDP) and 80% of government revenues came from the oil sector (see Fig. V-6, page V-13). Other important sectors are the service and the construction sector, which together account for roughly 20% of the GDP (CIA WORLDFACTBOOK, 2011). Libya has one of the highest per capita GDP's in Africa, resulting from large revenues by the petroleum industry and a relatively small population.

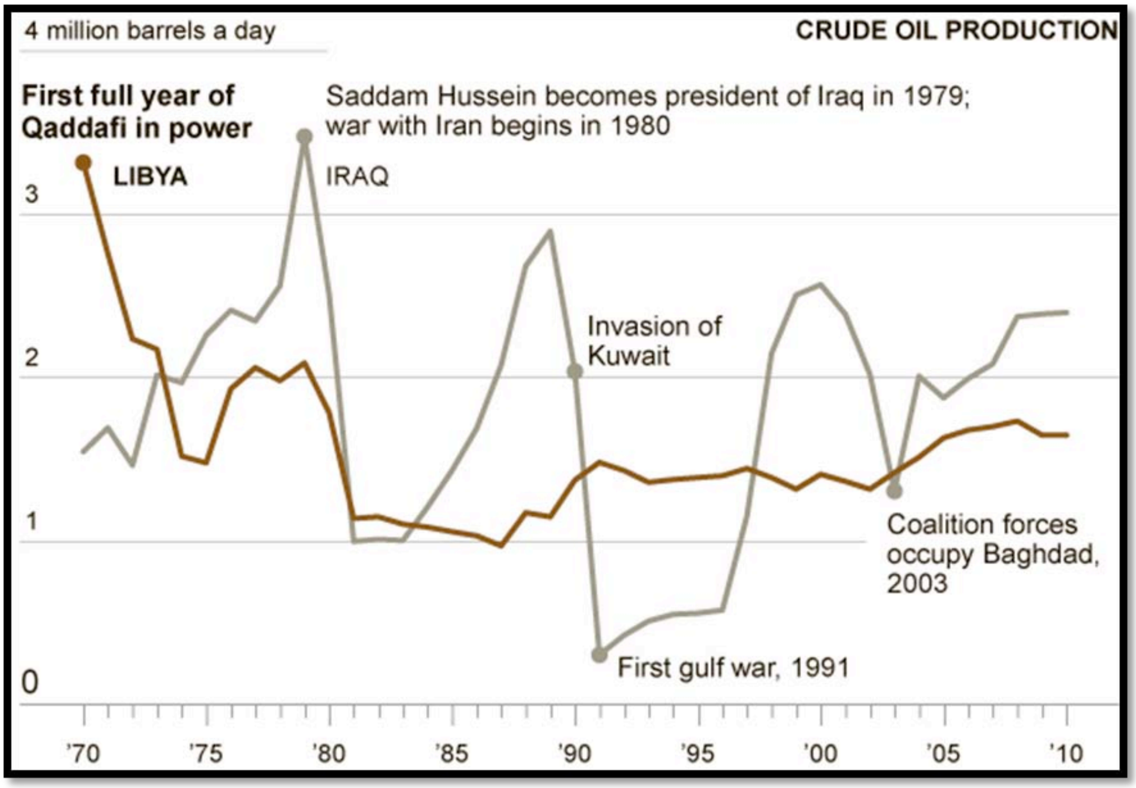


Figure V-3: Graph demonstrating the influence of the Gaddafi regime on the crude oil production in Libya (New York Times)

In the past years several economic reforms and diplomatic efforts were made to attract more direct foreign investments. The lifting of sanctions was the initial start of a broad liberalization campaign. New Libyan oil and gas licensing rounds drew high international interest, not only for European, but also for American and Asian companies. The announcement of privatization plans and the act of applying for WTO membership gave the foreign investors growing confidence. However, many of them still saw a risk of instability in the government. The National Oil Corporation (NOC) had set a goal of nearly doubling oil production to 3 Mio barrels per day by 2012. In November 2009 they announced that this target may slip to as late as 2017. These facts clearly reflect the intention of the Gaddafi regime to integrate more foreign companies into the Libyan oil industry on long term.

V.3. Petroleum Resources and Reserves

Within the sedimentary basins of Libya the 9th biggest recoverable oil reserves of the world were estimated with about 46.4 billion barrels (2010). The proven natural gas reserves were about 1.55 trillion cubic meters (rank 22) in 2011

(CIA WORLDFACTBOOK, 2011). Besides those huge known reserves, Libya is still unexplored in large parts. In order to provide an overview of Libya's petroleum systems, their potential and the actual stage of exploration, in the following chapter the geological setting of Libya is briefly presented and the most important basins are described.

V.3.1. Geological background

The North African region has undergone several deformation phases: The Pan-African Orogeny, the Infracambrian extension, the Cambrian to Carboniferous alternating extension and compression, the mainly Late Carboniferous "Hercynian" intra-plate uplift, the Late Triassic to Early Jurassic and the Early Cretaceous rifting, the Late Cretaceous-Tertiary "Alpine" compression and the Oligocene to Miocene rifting (HALLETT, 2002). Six independent basins were identified within Libya (see Fig. V-4), three of Paleozoic and three of Mesozoic to Cenozoic age.

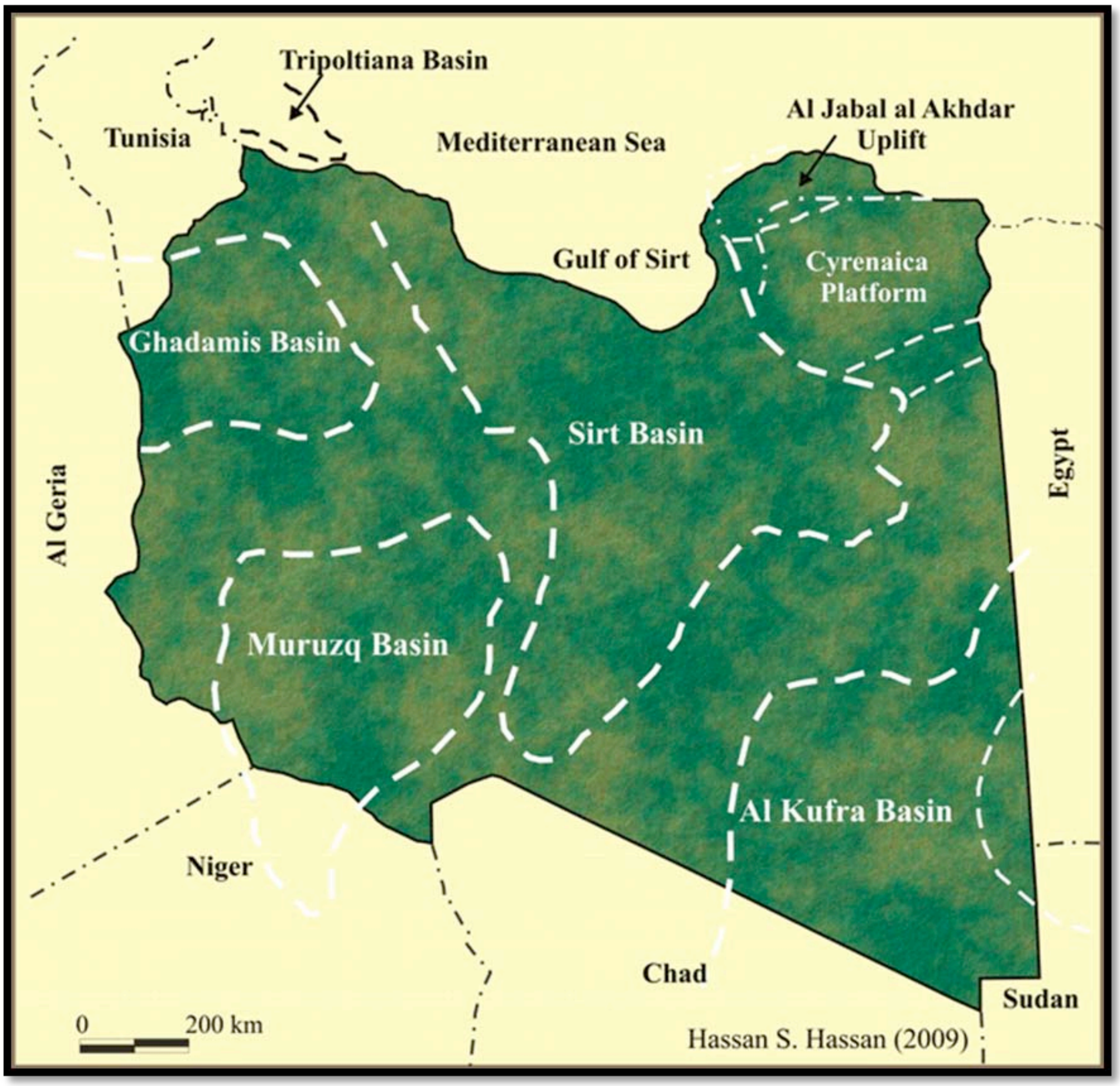


Figure V-4: Petroleum basins in Libya (HASSAN H.S., 2009)

The Paleozoic basins Ghadamis, Murzuq and Al Kufrah are intracratonic basins, the first two of which contain Silurian shaly source rocks. The Sirt Basin and the Cyrenaica Platform, as well as the offshore Tripolitana Basin are younger and have very individual settings, source and reservoir rocks. All basins are explored to a certain stage, while just within the Western basins production is running. In the Eastern basins, the Al Kufrah Basin and the Cyrenaica Platform until today no, or just a very small amount of economically producible hydrocarbons (within the Ash Shulaydimah Trough and offshore) was found (HASSAN, 2009). The most important basins regarding production and reserves are in order of importance the Sirt, the Murzuq, the Ghadamis and the Tripolitana Basin.

The youngest Libyan Basin, the **Sirt Basin**, has the largest oil reserves in Libya with about 117 billion barrels of proven oil in place and thus is the most prolific oil province in North Africa. The origin of the Sirt Basin is generally attributed to the collapse of the Sirt Arch during late Jurassic to Early Cretaceous times. During the Cretaceous the Sirt Basin was flooded rapidly and filled with clastics and, during late Cretaceous time, the organic-rich Sirt Shale, deposited with a thickness of over 250 m and in some places even up to 700 m. While Western Libya was uplifted during the Paleocene, the Sirt Basin continued subsiding and carbonate sequences were deposited. During Eocene time the Sirt Shale was buried sufficiently deep for hydrocarbon generation. Cenozoic rifting controlled the migration and distribution of hydrocarbons. Several normal faults displace different lithologies against each other. As a result, the carbonates of the Tertiary as well as Cretaceous sandstones or fractured Paleozoic and Basement rocks are the potential reservoir rocks. Oil accumulations have been found from depths of 700m to as deep as 4000m. The oils are generally sweet (0.15 to 0.66% sulphur) and have relatively low gas contents. The majority of the oils are undersaturated (HALLETT, 2002).

The intracratonic **Murzuq Basin** (Fig. V-5) contains one proven mature source rock and at least two other potential source rocks, and reserves of 5.4 billion barrels of oil in place, of which about 1.7 billion barrels are recoverable (BELAID ET AL, 2009). Gas-oil ratios are low within the Ordovician reservoir. The major source rocks, consisting of Rhuddanian hot shales, were deposited in a depression on the Ordovician surface prior to the main Silurian marine transgression. On marginal outcrops the Tanzuft shales may have a thickness of 350 to 475 m, the hot shales, however, are limited to a relatively thin interval at the base of the formation. The sediment fill of the basin is up to 3000 m. The Ordovician sandstone bears more than 50 separate oil fields across a broad region from the Murzuq Basin of SW Libya to the Ahnet Basin of central Algeria. The Silurian Tanzuft Shale is the major stratigraphic target in terms of source rocks in southern Libya and Algeria (HALLETT, 2002).

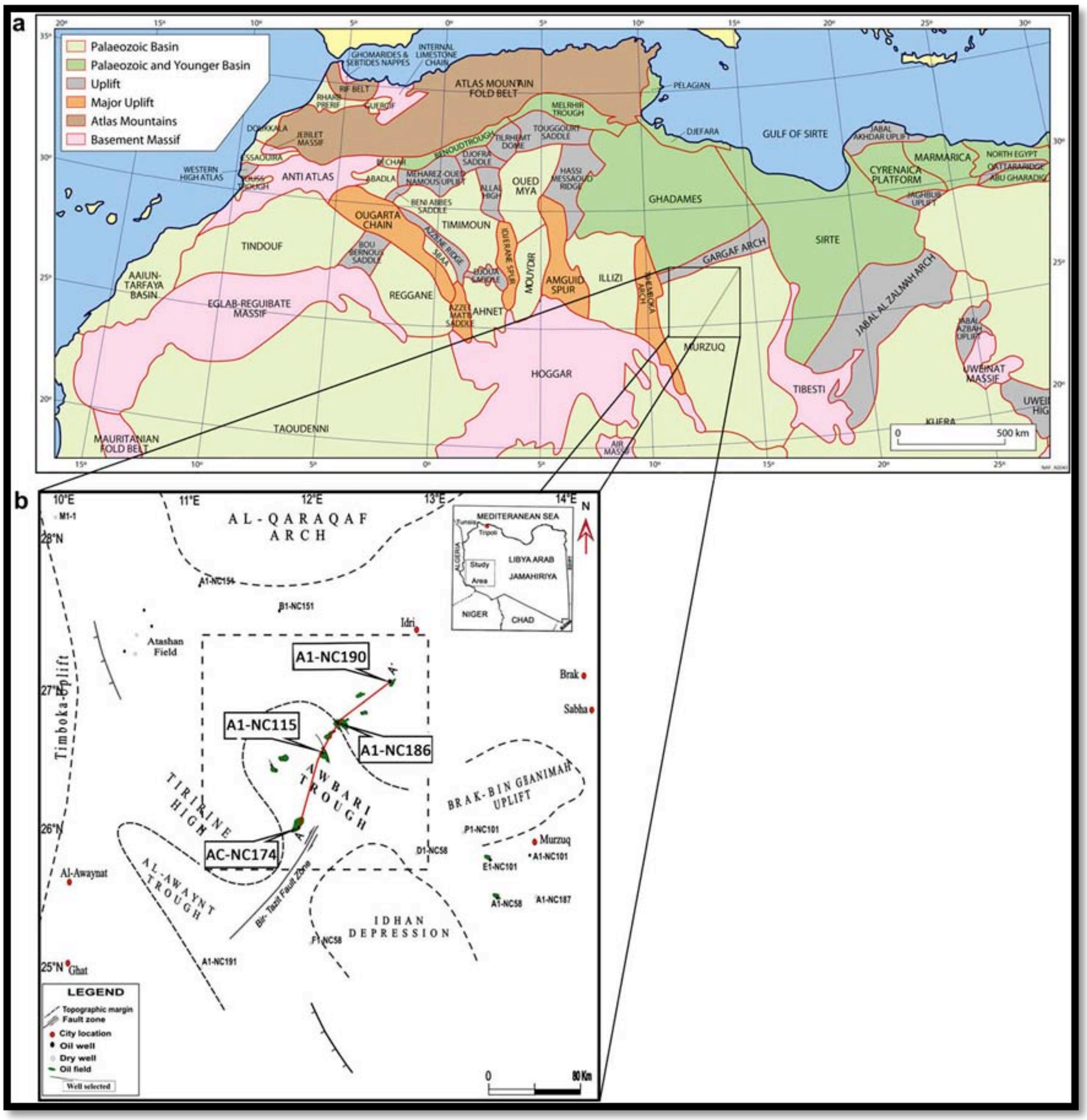


Figure V-5: Murzuq basin (BELAID et al, 2009)

The **Ghadamis Basin**, located north of the Murzuq Basin, is also charged by the Silurian Tanzuft Shale. By contrast to the Murzuq Basin, the hydrocarbon accumulations are gas-rich and many reservoirs contain gas and condensates. The basin reaches from western Libya to southern Tunisia and eastern Algeria, where its depocenter is located. During the last ten years, five to six billion barrels of recoverable oil equivalent have been discovered mostly on the Algerian side of this basin (RUSK, 2002). Here the Paleozoic and Mesozoic sedimentary rocks reach a maximum thickness of about 7000 m. The typical basin fill comprises mixed clastic and carbonate rocks. Due to the deep burial the source rocks and hydrocarbons have reached a high maturity level. The main reservoirs are the Upper Silurian Acacus and the Lower Devonian Tadrart and Kasa formation. A second potential source rock is a Middle to Upper Devonian shale. About 1 billion barrels of recoverable oil are estimated on the Libyan side of the basin.

The offshore **Tripolitana Basin** occurs to have several potential source rocks. The major source rock is believed to be organic-rich shale of Early Eocene age, known as the Jdeir in Libya and Bou Dabbous in Tunisia. Here, migration and trapping is controlled stratigraphically rather than structurally (HASSAN, 2009). The Basin is part of the Djeffara-Pelagian Basin Province (also called Pelagian Shelf basins system), which contains about 1 billion barrels of proven recoverable oil reserves and 0.48 trillion m³ of proven natural gas reserves.

The region of **Cyrenaica** in the Northeast of Libya is divided into two tectonic provinces, the Cyrenaica Plattform in the south and the Al Jabal Al Akhdar Uplift zone in the north. No major hydrocarbon discoveries have been made but there is no doubt that several potential source rocks are present in the area. Potential source rocks are certainly in the shales of the Devonian and early Carboniferous on the Cyrenaica Platform. These rocks contain thick sequences of organic-rich shales. The kerogen is mostly type III, and gas-prone. In the Al Jabal al Akhdar Trough, marine Jurassic and early Cretaceous rocks are present, containing thin shales with moderate organic content (HALLETT, 2002).

No significant quantities of hydrocarbons have been found in the **Al Kufrah Basin** up to present. This is probably due to lack of effective source rocks. Source rocks may be present in pull-apart grabens in the Infracambrian, similar to known structures in western Algeria, Saudi Arabia and Oman, but these have yet to be proved. The Tanzuft interval, which bears the hot shale source rock within the Murzuq and Ghadamis Basin, is represented by shallow-marine siltstones and shelf-deposited shales within the Al Kufra Basin. However, these never exceed 130 m in thickness (HALLETT, 2002).

There are still some poorly explored areas in Libya, both offshore and onshore, with high petroleum potential and therefore very attractive for further exploration. The last years showed how strongly dependent Libya is on the technical and scientific know-how of foreign exploration companies, in order to tap new reserves.

V.4. Libya's role on the global market

Libya produced about 1.6 mb/d of crude oil and 0.1 mb/d of NGL in January 2011, of which 1.5 mb/d were exported. Europe received over 85% of Libya's crude oil exports in 2010, while about 13% were shipped east of Suez. Figure V-6 shows all customers of Libyan crude oil in 2010. 28% of the Libyan exports went to Italy, 15% to France, 10% to Germany and 10% to Spain.

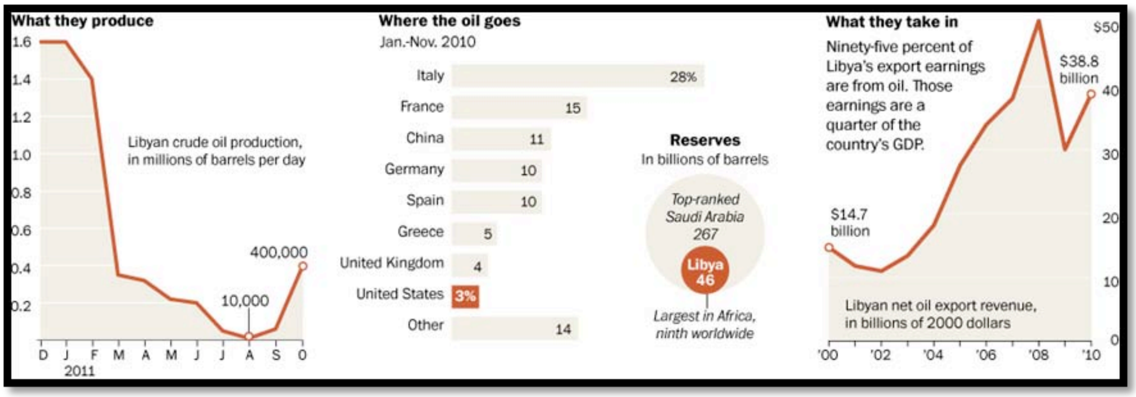
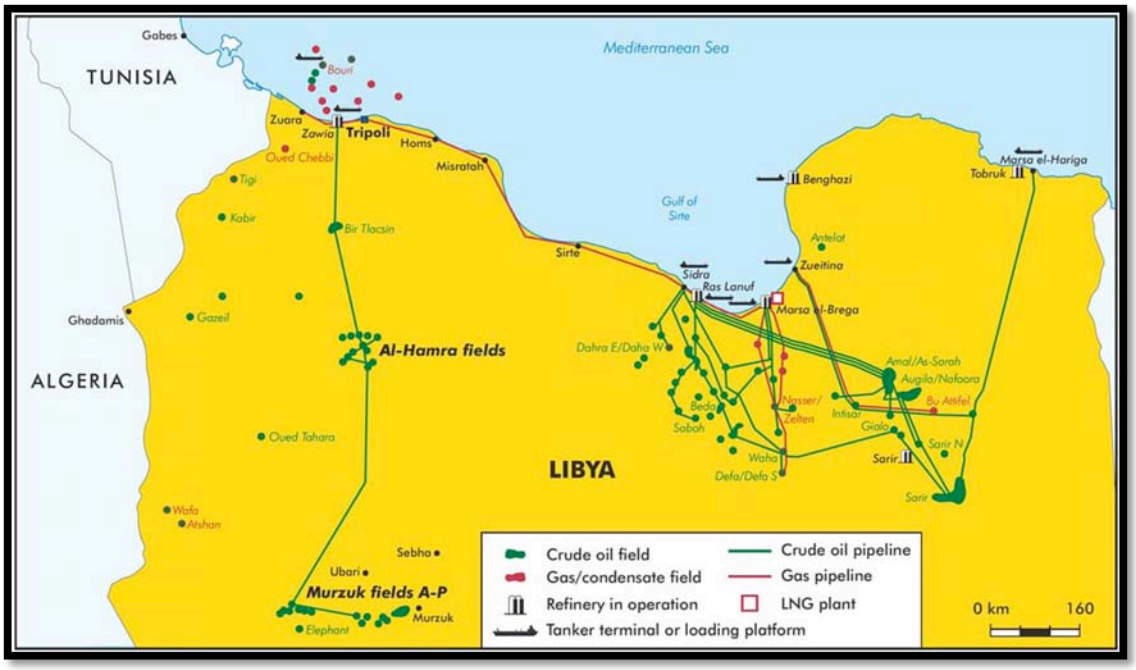


Figure V-6: Informational graph on Libya's economy (Washington Post)

These four countries account for 63% of the Libyan crude oil exports in 2010. The only important non-EU customer is the People's Republic of China with 11%. Libya has five domestic refineries, with a combined capacity of 378 kb/d, which mostly produce Jet Kerosene and Residual Fuel Oil. On average 100 kb/d of these products are exported, mostly to Europe and in particular Italy (60% of OECD imports from Libya in 2009). However, most of the Libyan oil is exported as unrefined light crude oil from six major terminals, five of which are located in Eastern Libya at the rim of the Sirt Basin (see Fig. V-7) (IEA, 2011).



<u>Figure V-7:</u> Oil infrastructure map of Libya (IEA)

The European dependency on Libyan oil is much higher than on Libyan gas, except for Italy, which imported 26 million m³ of gas per day in 2010 via the 520 km long *Greenstream* underwater pipeline, corresponding to 13 % of its total gas imports (IEA, 2011).

V.5. The "Arabian revolution"

This chapter provides background information on the "Arabian revolution" in Libya and its consequences for the petroleum industry.

V.5.1. Political

The first riots in Libya started at the beginning of 2011. It came to the government takeover by the National Transitional Council in March, after Gaddafi had tried to brutally suppress the oppositional movement. However, Gaddafi had many followers and for many months there was a fierce civil war within the entire country. By a military intervention approved by the United Nations (abstention only by China and Germany), the revolutionary forces finally were able to end the civil war, some weeks after Gaddafi's death in October.

V.5.2. Impact on petroleum production

Due to their location deep within the Libyan Desert, most Libyan oil fields suffered only minor damage during the civil war. The key oil towns along the coast, however, saw some of the fiercest fighting and have been hit hard by the conflict. The export terminals as well as several refining facilities were severely damaged. Rebel oil chief Tarhouni estimated that around 10 to 15% of Libya's oil infrastructure was damaged during the war, clearly concentrated on coastal areas (arabianoilandgas.com). By August 2011 the Libyan oil production had almost come to a total halt.

V.5.3. Impact on petroleum market

Although Libyan oil amounted to less than 2% of world demand, breakdown of its production affected prices because of its high quality and suitability for European refineries and the slim margin of spare supply in OPEC. Europe relies on Libya for oil, and Libya relies on Europe to buy it, with over 86% of exports to EU countries and Italy relying on Libya for 22% of total imports. European refineries were unable to swap heavy Saudi crude for Libyan crude, a significant reason why oil prices remained stubbornly high for much of 2011 despite Saudi's pledge to replace Libyan lost production following an OPEC meeting on 8th June 2011. The loss of Libyan exports contributed to a 20% increase of oil prices to an amount of 127.02 $ at London's commodity exchange in April 2011. Figure V-8 shows a graph of the oil price correlation with equities.

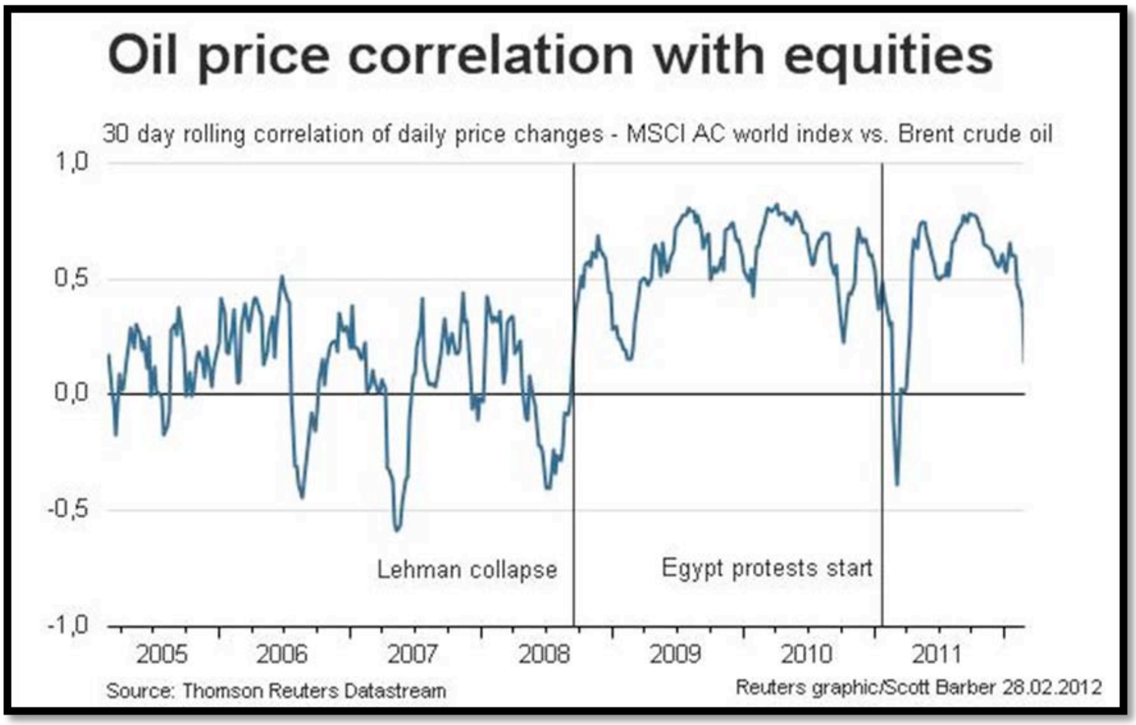


Figure V-8: Oil price correlation with equities (Reuters)

V.5.4. Recovery of the Libyan oil industry

This chapter gives an overview of the recovery of the Libyan oil industry, with a focus on European companies. In order to do so, we tried to cover the period from the ouster of Gaddafi by the National Transitional Council (NTC) in August 2011 until the end of February 2012. Because most of this information is based on news released by press and companies to the public, these data have to be taken with some degree of caution. Figure V-9 provides a overview foreign oil interests in Libya.

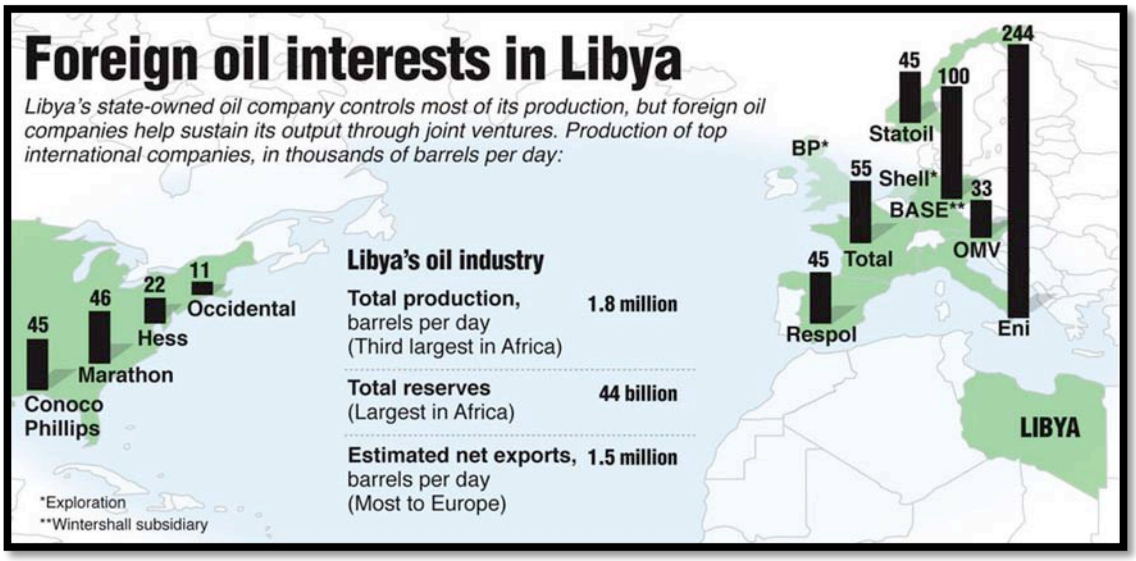


Figure V-9: Foreign oil interests in Libya (Reuters)

V.5.4.1. Outline of the recovery of the Libyan oil industry

Even before NATO ended its military actions in Libya at the end of October 2011, foreign oil producing companies returned to a couple of facilities to assess the damages. But even they admitted that it was too early to consider restoring production and export. One of the first major contributions to supporting an increase in petroleum production was the remedial maintenance of the Greenstream gas pipeline in October, which takes Libyan gas 510 km undersea from Mellitah on the North coast to Gela in Sicily. Libyan NTC military spokesman Ahmed Bani told Reuters news agency that the gas pipeline is "back and running, supplying the pump stations and the Mellitah (gas processing) refinery. Gas will start flowing to Europe." Bani did not give a timeframe for exports to begin. Furthermore Bani said that the closure had resulted in the loss of about 1 million euros per day worth of gas. In August an ENI spokesman stated that they had been in contact with the higher echelons of the rebellion since the beginning, eager not to lose their position in the market. To emphasize that effort, staff from ENI already had been sent out to take a look into a restart of oil facilities in the country's east. Italy's Foreign Minister Franco Fratini told the Italian state TV company RAI according to a Reuters report in August, that "The facilities had been made by

Italians, by (oil field service group) Saipem, and therefore it is clear that ENI will play a No. 1 role in the future…".

ENI operated in Libya since 1959 and before the war was Libya's largest foreign producer with six exploration and producing sharing agreements in force with the National Oil Company. Each of the agreements lasting to 2042 for oil and 2047 for gas, which produced 522,000 barrels of oil equivalent per day (2009) with ENI's share amounting to 244,000 barrels of oil equivalent per day, 44% of which was liquids. At about the same time a spokesman for BP told Reuters "We fully intend to return to Libya to fulfill our contract when conditions allow". BP has a 900 million US$ exploration contract in Libya but is not yet (by the end of 2011) producing any oil in the country. Like BP, its rival Shell was also exploring in Libya. Industry analysts have stated that the two companies may benefit as a result of Britain's early support of the uprising against Gaddafi. As we will pick up later, these two companies most certainly will not be the only ones taking advantage of a support of the rebel groups by certain countries during the revolution.

In the beginning of September 2011 Abdeljalil Mayouf, information manager of Libya's rebel-held Arabian Gulf Oil Company (Agoco), which operates the Sarir and Mesla fields in the east of the country, told Reuters the fields are ready for production and that security is the only concern. "When security is OK we will start. Perhaps two or three weeks after the improvement in security. In three weeks maybe.". The Sarir and Mesla fields have a total capacity of around 250,000 barrels per day or around one sixth of Libya's total pre-war capacity. Several sources report that, despite heavy fighting around oil facilities like terminals, much of the damage is minimal and production can begin within a few weeks of assurances that the country is secure. How long that will take is not known, though the chances of an insurgency akin to that in Iraq are low. The position of the majority was that a combination of rapid abandonment and war damage means the recovery of Libya's oil production is likely to come in two stages, with an initial burst of activity followed by a slow, but steady increase up to pre-war levels. This "initial burst" was corroborated by the assumption of the career network Oilcareers.com that in light of recent developments in Libya, the demand for skilled oil and gas workers will increase rapidly to get the economy working again. Meanwhile

ENI had signed a deal with the NTC to restart oil and gas operations, increase operational stability around oil infrastructures and supply refined products to the NTC to meet domestic needs. To fulfill this deal, ENI restarted production in fifteen wells in Abu-Attifel, located almost 300 km south of Benghazi. In order to reach the required volumes to fill the pipeline connecting the field to Zuetina terminal, ENI planned to reactivate additional wells in the area. The Abu-Attifel field was the first giant oil field discovered in Libya by ENI in the 1960's. Relating to the restart of the major offshore oilfield Bouri, which is located 120 kilometers north off the Libyan coast in the Mediterranean Sea and had a pre-war production capacity of 60,000 bpd, ENI stated that it will resume production more rapidly than onshore fields. TOTAL, the French multinational oil company confirmed on 23th September 2011 that they resumed production at their Al-Jurf offshore field. The operating platform is located in the Mediterranean Sea about 100 km off Libya's western coast and accounted for 40,000 bpd of TOTAL's 55,000 bpd production capacity before the war. A company spokesman further estimated that exports will be resumed "in two weeks with full production back within a week or so more". Untill the beginning of October 2011 Libyan oil production increased as more foreign oil companies made exploratory returns to the country and the National Oil Company estimated that in the nation-wide production had already hit the 350,000 barrels per day mark. By the end of October the restoration of Libya's oil production hit the landmark of 500,000 barrels per day according to the National Transitional Council (NTC). The minister for oil and finance of the NTC, Ali Tarhouni, told reporters at a news conference in Benghazi on the 23th, that "As of an hour ago we are up to 500,000 barrels per day with the Sharara field resuming operation…". The Sharara field, which is located in the Murzuq basin and operated by REPSOL, was estimated to pump roughly 70,000 bpd from its initial start-up level of 30,000 bpd, still far away from its pre-war level of 360,000 bpd. Bottlenecks at the export end are also looking to ease shortly. Nuri Berruien, Chairman of the Libyan National Oil Company, says the Es Sider terminal, which shipped approximately one third of Libya's pre-war crude exports, will be operational in around 10 weeks. Ras Lanuf - the country's largest refining facility - could restart within a few days, according to Reuters, with 300,000 barrels of crude currently stored at site and ready for processing. In October Wintershall restarted their operations in Libya, too, by sending a small group of Libyan workers to a cluster of oil fields in Sirt Basin. The company had suspended and sealed off production operations in their eight onshore oil fields around 1,000 km south-east of Tripoli in February 2011 in view of the political situation and for security reasons. Wintershall also holds a share in the offshore oil field Al Jurf in a consortium with the Libyan National Oil Corporation and TOTAL, where production already restarted a few days earlier. Wintershall has been producing crude oil in Libya since 1958 and was producing around 100,000 bpd in Libya before the unrest. With investments of more than two billion US dollars and over 150 wells, the company is one of the largest oil producers in the country.

The status of Libyan liquid hydrocarbon production by the end of October 2011 can be seen in Fig. V-10.

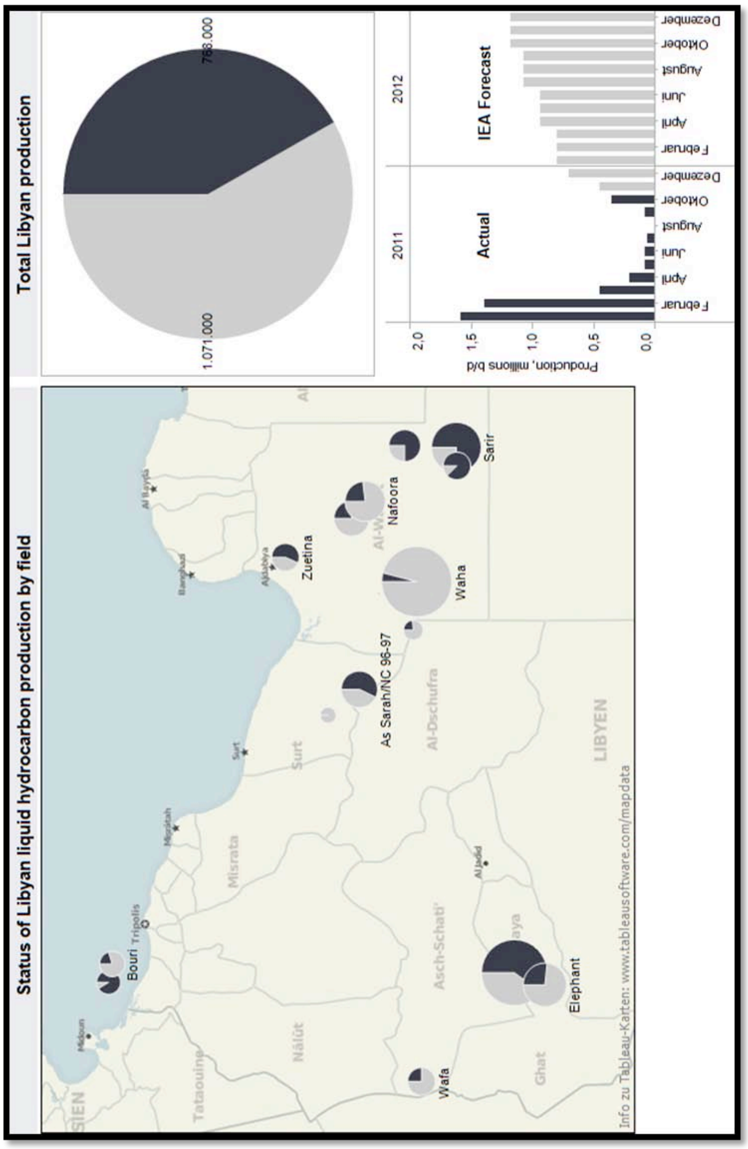


Figure V-10: Status of Libyan liquid hydrocarbon production by field in October 2011 (arabianoilandgas.com)

In November the IEA stated in its latest monthly oil market report that the restoration was on a “far faster track” than expected earlier due to a “herculean” effort by officials of the Libyan NTC and that capacity should reach 700,000 bpd by the end of 2011. Furthermore IEA gave a forecast that Libya’s production capacity will rise further to an average of 800,000 bpd in the first quarter of 2012, up from an estimate of 500,000 bpd made earlier in June 2011. Beyond this, capacity is expected to reach 930,000 bpd in the second quarter of 2012, 1.07 million bpd in the third quarter and 1.17 million bpd in the fourth quarter. “So far, the surge in volumes has come from the restart of some of Libya's key oil fields, but additional growth is likely to depend more on the state of pipelines, refineries and export terminals", the report stated. According to IEA calculations, Libyan exports of crude oil are lagging a bit behind production and amounted to an average of 180,000 bpd in October with estimates of around 200,000 to 250,000 bpd for November. Only a few weeks later, on 9th December, the prediction by the IEA was already outdated. According to the National Oil Company, Libya's production had reached a level of 840,000 barrels per day and was expected to be back on pre-war output by the end of 2012. During December 2011, TOTAL restarted its onshore operations at the Mabrouk field within the Sirt basin, which formerly had an output of 19,000 bpd. Together with the offshore production at Al Jurf field, operating already since end of September, TOTAL therefore theoretically re-established their pre-conflict output of 55,000 barrels per day in Libya. "There are still some logistical issues that need to be sorted out…" Michel Seguin, special advisor to the president of TOTAL Exploration & Production, told Reuters.

By the end of January oil output had climbed to 1.3 million barrels per day (bpd) according to Libya's National Oil Corporation. The renascent oil production took analysts by surprise, who had estimated that the country would be producing around half the current amount at this stage. Accompanied by the production rise, exports took off as well. Libya transacted 21 shipments of crude between 26th January and 1st February totalling 12.7 million barrels, reported Reuters.

The February 2012 began with the news that Libya's Arabian Gulf Oil Company (Agoco) had reached production of about 300,000 barrels a day and hoped to reach full production in April, later than previously thought because of electricity problems on some fields. Agoco's Abdeljalil Mayuf said "… the bigger Sarir and Messla fields [Sirte Basin] received new equipment which should increase production by the end of the month" and thus catch up with pre-war production of 425,000 bpd. Wintershall has boosted output in the country to three times the quantities produced in fall, but ageing pipeline infrastructure is limiting its production capacity, its CEO told Reuters on 10th February. "We started with a production of 20,000 bpd in October and we have now stabilised to an average of 60,000 bpd," Chief Executive Rainer Seele said in an interview during an energy conference. Wintershall could produce 90,000 bpd from its fields but Libya's old pipeline system is preventing the company from transporting the crude from the desert to the coast in the quantities it would want to. "We are now discussing with [Libya's] national oil company a long-term solution because the pipeline is more than 50 years 'young' and we definitely have to see whether we can find a solution there," he stated further. Conditions to do business in Libya had improved since October, he added. Back then, the international financial sanctions imposed during the war and the country's financial collapse was problematic, Seele had told Reuters previously. "It is now back to normal. We have no problems with financial transactions and sanctions are lifted." Exploring further for oil in Libya was on hold for Wintershall, Seele explained, as it would depend on what kind of economic conditions foreign oil companies would work under once stable political institutions are restored. That remained uncertain at the moment, he said. "It is a question of what framework we are going to have. We are waiting for a long-term sustainable situation in the country. How long it would take, I don't know." The chief executive no longer saw safety was as a worry. "Safety of operations is absolutely there. This is not a concern."

In the meantime further progress was achieved by Repsol whose Sharara oilfield had reached a production level of 300,000 barrels a day compared to 70,000 bpd in October 2011, NOC stated on its website.

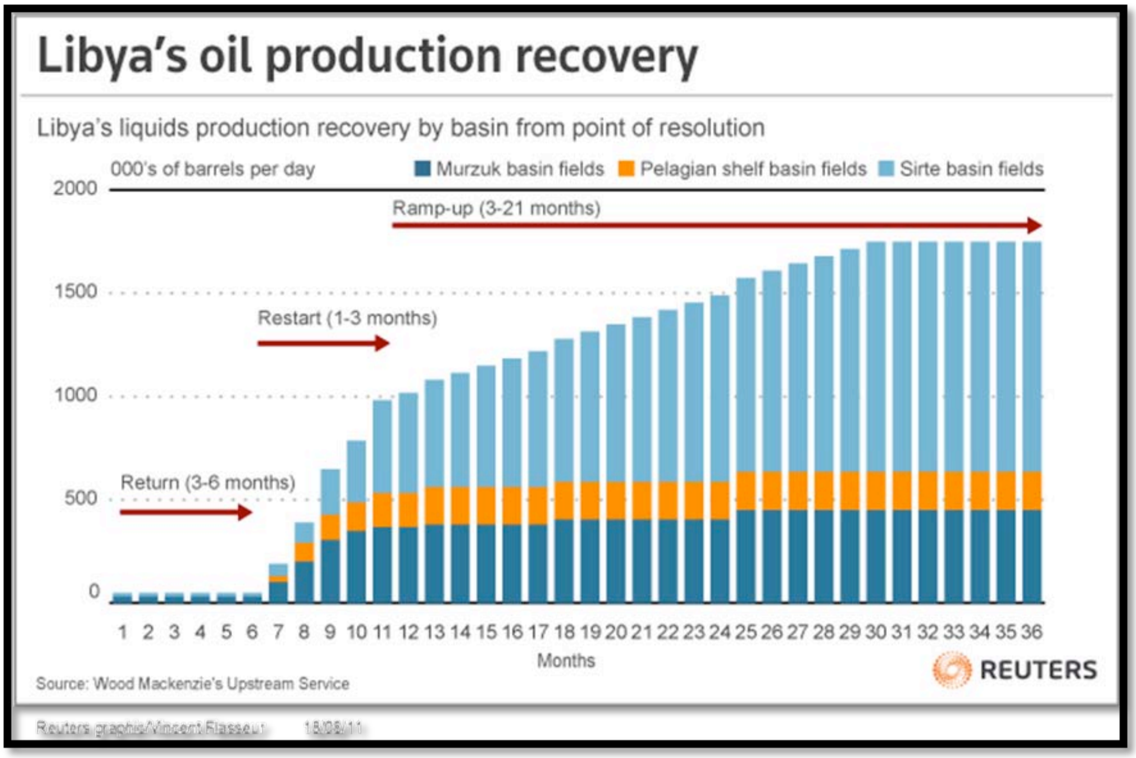
On Monday 27th February the National Oil Corporation mentioned in their monthly statement that Libya's crude output had climbed to 1.4 million barrels per day. Further it stated that oil operations activity had resumed at all fields and oil ports and the situation in the country is "secure and stable". An overview of the development of the oil production in comparison with the IEA forecasts can be seen in Table V-1 below.

Table V-1: Comparison of production forecasts and actual amount of production in Libya in million barrels per day ([1]NOC forecast Feb '12; [2]NOC forecast Nov '11)

Date	IEA forecast (June 2011/ Dec 2011)	NOC (reported values)
Begin Oct 2011		0.35
End Oct 2011		0.5
09.12.2011		0.84
End 2011	0.4 / 0.7	
End Jan 2012		1.3
End Feb '12		1.4
1st Quarter 2012	0.5 / 0.8	[1]1.5
2nd Quarter 2012	- / 0.93	
3rd Quarter 2012	0.7 / 1.07	
4th Quarter 2012	- / 1.17	[1]1.7 ([2]1.3)
2012	- / 1.4	
2014	- / 1.6	

V.5.4.2. Future trends

Considering the trends of the last months and the given forecasts, Libya's pre-war production level is expected to be reached soon. Libya's Oil Minister Abdul-Rahman Ben Yezza, while attending a meeting of the Organization of Petroleum Exporting Countries in Vienna, said on Dec. 14 "[Libya is] seeking to raise output to 2 million barrels a day in three to five years.". Reuters compiled a graphical representation (Fig. V-11) of an estimate by Wood McKenzie's Upstream Service prepared in August 2011 about the recovery by basin (Sirt Basin, Murzuq Basin and Pelagian Shelf basins field) of the Libyan oil production.



<u>Figure V-11:</u> Libya's oil production recovery (Reuters)

In early February 2012 Libya's Deputy Oil Minister Omar Shakmak stated to Reuters that oil companies were currently producing at between 60 and 90 percent of their normal output. When asked if pre-war output could be achieved before the summer, Shakmak answered: "Yes, if you consider the progress in production which has been achieved now, maybe that will be before. But if it is by June-July, we are quite satisfied." Furthermore Shakmak said a draft proposal looking to split the running of Libya's oil industry between oil production and exploration, or upstream, from oil refining or downstream activities was being looked at but it was unlikely any such change would happen under the current transitional government. "That's one of the proposals we are thinking of as a strategy, it is not in stage of activity," he said. "But I'm not expecting that will be done during this transitional period of government because most of the major changes should be done by the elected government – all the Libyan people should be involved." Officials have spoken of plans to train and unite thousands of former rebel fighters under an umbrella oilfield and installation guard. Until now, groups of fighters have stood guard at different fields in the absence of a national army. Shakmak said the plans were for a force of around 9,000. "The plan is to give a chance to the people who have taken care of the oilfields during the war against the Gaddafi regime," he said.

Not only people who supported the rebels will profit from it, countries, or respectively petroleum companies situated in these countries, will gain profit out of their support during the war. Despite the urgency to resume pre-war production, the NTC is leery of welcoming countries that did not support the revolution to what promises to be a booming reconstruction and upstream environment. "We don't have a problem with western countries like Italians, French and UK companies. But we may have some political issues with Russia, China and Brazil," Abdeljalil Mayouf, information manager at Libyan rebel oil firm Agoco, told Reuters. The three countries either disagreed with sanctions on the Gaddafi regime or discouraged the rebels from fighting Gaddafi's forces, and it is now unclear whether they will win new contracts from the state. In the case of China the prospects to take part in Libya's reconstruction look dim, following the discovery of documents itemizing the sale of 200 million $ of arms to Gaddafi after the revolutionary war broke out and UN sanctions preventing arms sales were imposed on his regime. Abdel Raham Busim, a Transitional National Council military spokesman, said documentation was still being collected and the new government was considering bringing legal action against Beijing, possibly via the UN. Qatar may benefit from Russia's, China's and Brazil's loss, having provided banking and military assistance to the rebels.

First indications of this are that the NOC announced on the 27th of February the return of exploration activity in Libya. Seismic surveys at oil concessions belonging to the Arabian Gulf Oil company have resumed, and the Arab Company for Geophysical Survey (AGESCO) has started on February 25 carrying out seismic survey operations in the Ghadames basin. A second division will start implementing an exploration programme in Sirte basin by the end of March."

V.6. Conclusion

Despite intense engagement of Libya in the OPEC, Libyan oil production decreased drastically during Gaddafi's regime (see Fig. V-3). When the "Arabian Revolution" started in Libya, the oil production soon bottomed out at

22,000 bpd in July 2011. Despite the heavy fighting, oil facilities only suffered minor damage, making security the main aspect of concern.

The recovery of the Libyan petroleum industry occurred much faster than expected by many analysts and the latest achievements in Libya give rise to expectations for a bright future for petroleum production. There will be winners and losers of the "aftermath of the Arabian revolution", the interesting question is who will occupy which role in the future.

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VI. Petroleum systems of the Caspian region

Abstract

The Caspian Sea Region has some of the world's deepest sedimentary. These basins occur both, offshore and onshore, and were formed in a wide variety of plate tectonics and sedimentary processes. In the first part of this chapter the locations of the basins, their geological framework and their potential for hydrocarbon resources are outlined with regard to the hydrocarbon potential of the Caspian region. The basins contain oil and gas resources at great depth. Production is going on in some of these basins; numerous fields have been discovered but are not producing yet.

The second part of this chapter discusses the political situation of the gas and oil market. After the collapse of the Soviet Union, the Caspian Region has received worldwide attention due to its substantial hydrocarbon reserves. People in this region are predominantly Muslims or Russian-Orthodox Christians. Russian, Persian and Turk languages are prevailing. The economies of the states depend strongly on the oil price. The development of oil and gas resources provides a unique opportunity for the Caspian Basin countries to modernize their economies and gain political independence or power. But exploration of oil and gas resources requires an advanced infrastructure and transport system for humans and equipment. The Caspian Sea is a landlocked sea and the region still suffers from the limited infrastructure from Soviet Union times. Furthermore, the Caspian countries have only little refining capacity and compared to the last years the general trend in expansion of refining capacity shows only slight growth. Politics in the Caspian politics are characterized by issues. Kazakhstan, Azerbaijan and Turkmenistan struggle for economical independence from Russia, prosperity and technical progress. Iran seeks more political influence in CEA. Geopolitics of foreign countries differ substantially from each other because of different energy developments and initial situations.

VI.1. Introduction

VI.1.1. Geography

The Caspian Sea is the largest inland body of water in the world. It contains 40 to 44 percent of the total lacustrine water of the world. It has a dimension of 1030 km in length and 435 km in width. The surface area is 371,000 km². The coastline of the Caspian Sea has a length of 7,000 km and is shared by Azerbaijan, Iran, Kazakhstan and Turkmenistan. The basin is divided in three parts: the Northern, the Middle and the Southern Caspian. The differences between these three parts of the basin are dramatic. In the North Caspian only shallow water is present with average depths up to 6 m and a total water volume of less than 1 percent. The Middle Caspian has an average depth of 190 m and a total water volume of 33 percent. The South Caspian is the deepest part of the basin with depths up to 1,025 m and holding 66 percent of the water. In the northern part, cold, freezing winters are typical, whilst the southern part has mild winters with agreeable temperatures. Over 130 rivers flow into the Caspian Sea with the Volga, the Ural and the Kura River being the largest. The largest cities around the Caspian Sea are Baku, Rasht, Aktau, Makhachkala, and Turkmenbasy.

Figure 1: Overview map of the Caspian Region with the most important cities (CIA, 2012).

VI.1.2. Climate

Due to the great north-south extension of the Caspian Sea, the region comprises several different climatic zones. The northernmost region belonging to Kazakhstan and Russia is characterized by dry and cold temperate continental climate. The southern part of the sea with Azerbaijan, Iran und Turkmenistan is mountaineous and much warmer. The average annual temperature and the mean annual precipitation are shown in Figure 2.

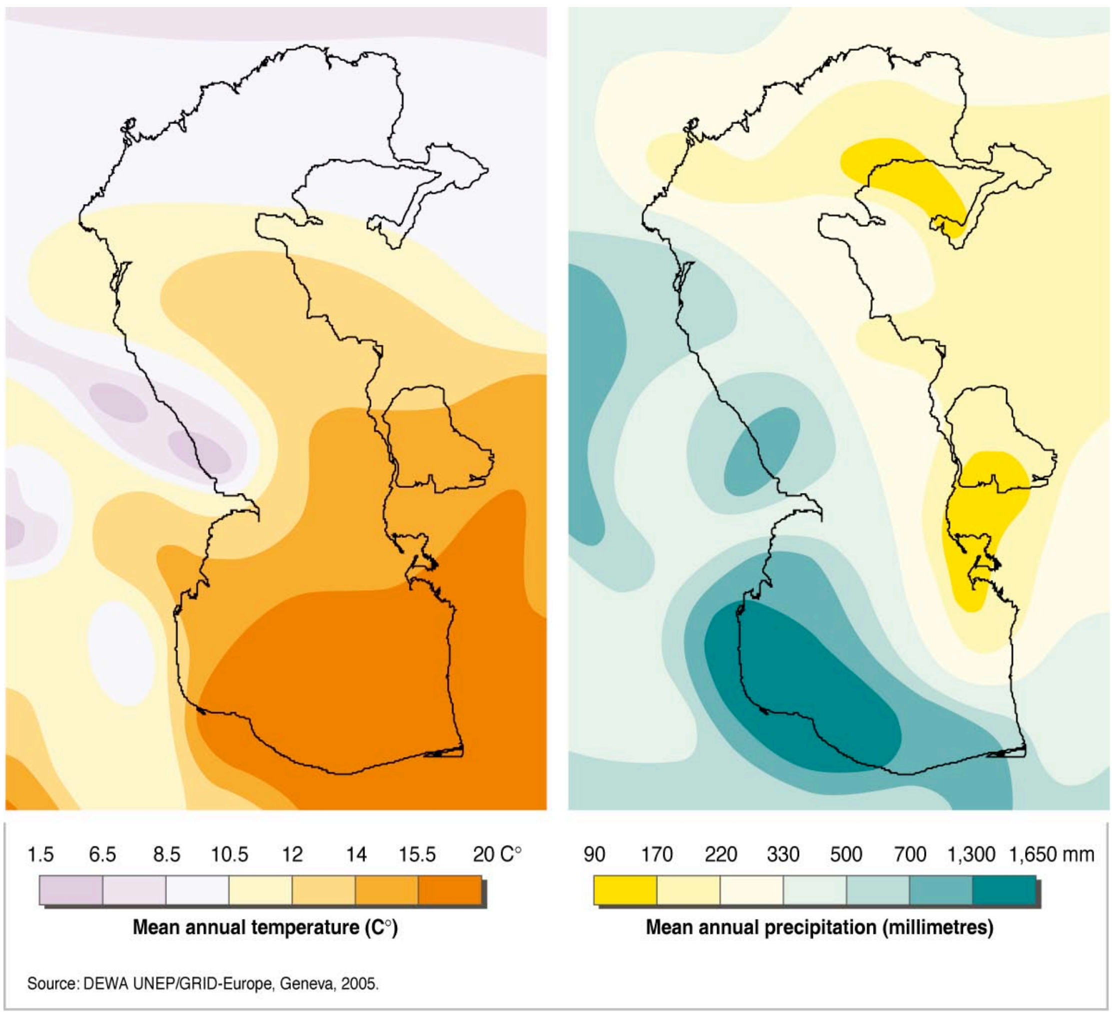

Figure 2: Mean annual temperature and precipitation in the Caspian Sea region (http://www.grida.no/)

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VI.2. Geology

VI.2.1. Basin outline

VI.2.1.1. North Caspian basin

The North Caspian basin province covers the northern part of the Caspian Sea and large parts of Kazakhstan and Russia with an area of 500,000 km². The boundaries of the basin are the Ural foldbelt and the Mugodzhary zone in the east, the Paleozoic South Emba high in the southeast, the Karpinsky foldbelt in the southwest, and a 1,500 km long north and west margin which is defined by sedimentary escarpment of the Volga-Ural basin in subsalt (see Figure 3).

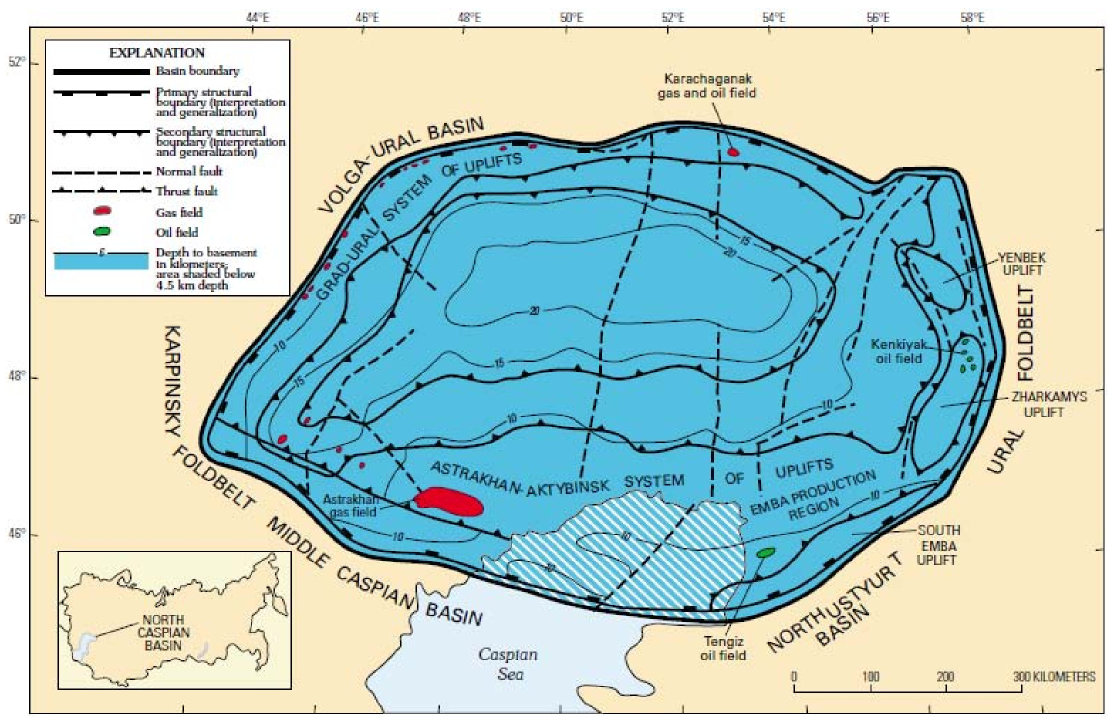


Figure 3: North Caspian basin with basin boundaries, gas fields, and major geologic and geographic features discussed in the text (Dyman, 2001).

VI.2.1.2. Middle Caspian basin

The Middle Caspian basin extends from the eastern North Caucasus region through the central part of the Caspian Sea to the depression systems in the east of the sea. The southern boundary is defined by the Great Caucasus foldbelt, Karabogaz arch and in the offshore area by Apsheron sill. The northern zone is bounded by Karnpinsky foldbelt. The boundaries of the east are defined by the Mangyshlak and Central Ustyurt system of uplifts. In the west the Stavropol arch and Mineralovod high separates the Middle Caspian basin from the Azov-Kuban basin located farther west. Most of the basin is located in Russia and Kazakhstan. Small parts of the south-western area are in Azerbaijan (see Figure 4).

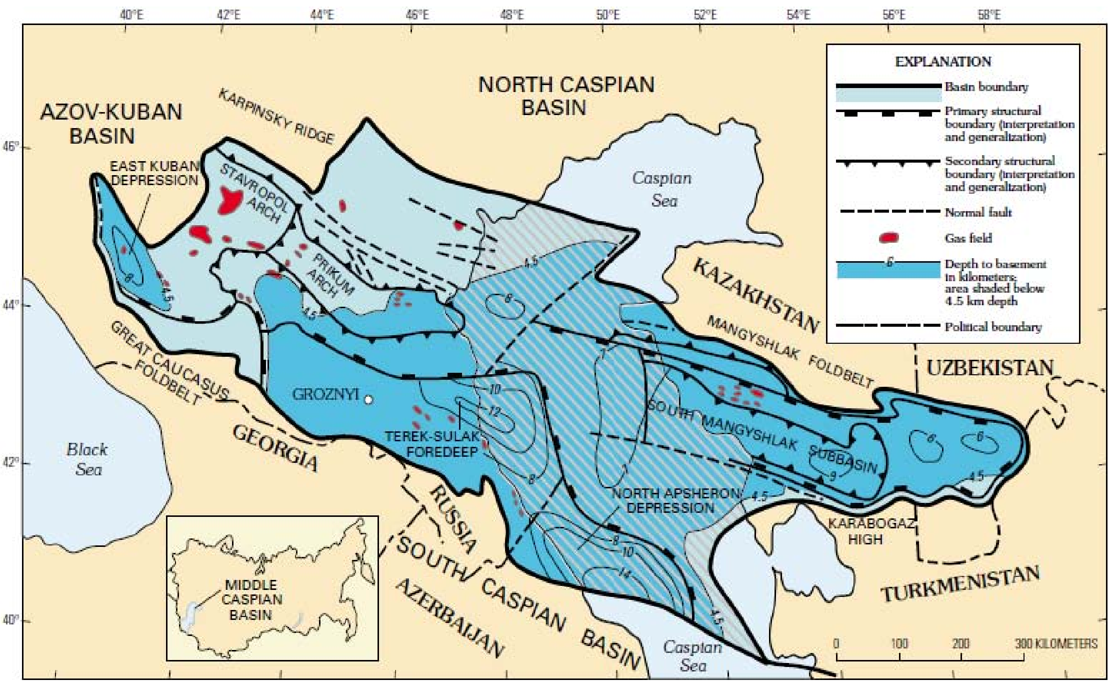


Figure 4: Middle Caspian basin showing political boundaries, gas fields, and major geologic and geographic features discussed in text. Dark shade: Portion of basin with sedimentary rocks below 4.5 km (Dyman, 2001).

VI.2.1.3. South Caspian basin

The South Caspian basin is an elongated intermontane basin stretching from western Georgia, through Azerbaijan and part of northern Iran, to western Turkmenistan. In total the basin covers an area of 360,000 km². The central portion of the basin is covered in the south Caspian Sea. Water depth here is up to 1,000 m. The northern boundary of the basin is formed by a major fault zone which links the northern margin of the Kopet-Dag foldbelt to the Greater Balkhan Massif, runs under the Caspian Sea as the Absheron-Pribalkhan Uplift zone and continues as the southern margin of Greater Caucasus foldbelt. To the south the basin is bounded by a major Alpine mountain chain, comprising the lesser Caucasus, Talysh and Alborz fold belts. The western extremity of the basin is marked by the Imereti Uplift, and a northeast-trending strike-slip fault separates the basin from the neighboring Rioni Basin. The south-east of the basin is bounded by the thrusts of the Kopet-Dag Range (see Figure 5).

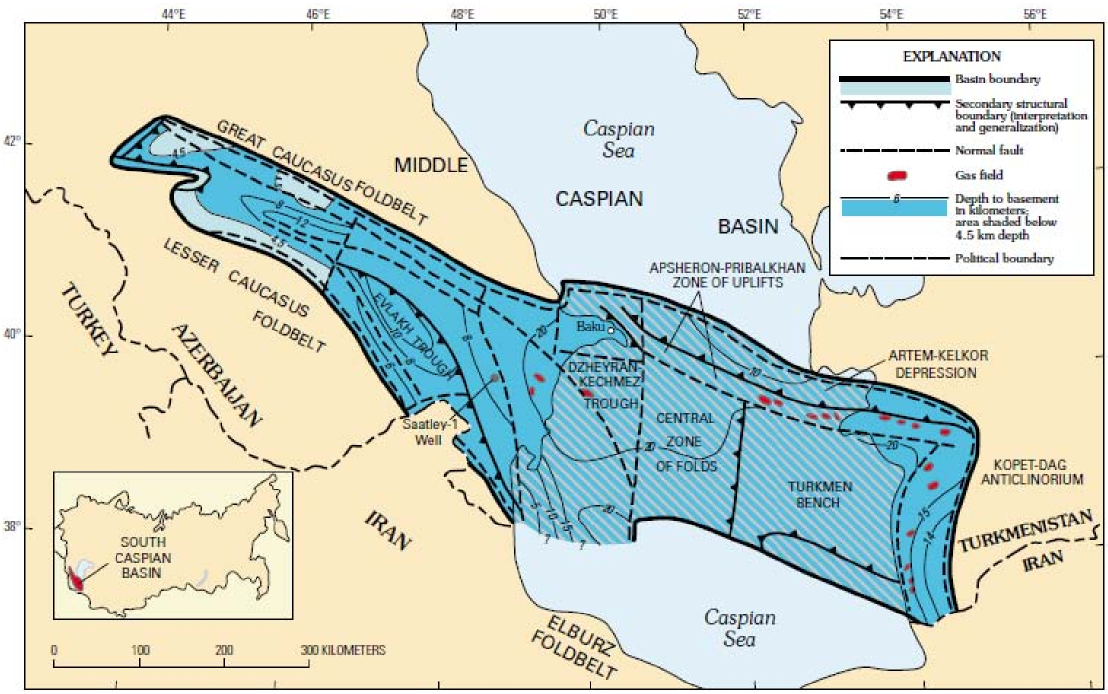


Figure 5: South Caspian basin showing political boundaries, gas fields, and major geologic and geographic features discussed in text. Dark shade: Portion of basin with sedimentary rocks below 4.5 km (Dyman, 2001).

VI.2.2. Stratigraphy and Tectonic

VI.2.2.1. North Caspian basin

The North Caspian Basin is one of the world's deepest basins with sediments of more than 20 km thickness. It is underlain by oceanic and thinned continental crust. Most geologists believe that the basin originated as a rift, but different models have also been proposed. According to one model, rifting occurred in the Riphean (Middle-Late Proterozoic), in another model the rifting is assumed to have occurred during Middle Devonian (Malushin, 1985; Zonenshain et al., 1990; Volchegursky et al., 1995). The most widely accepted model assumes that rifting took place in Early Ordovician time contemporaneously with rifting in the Urals, which resulted in the opening of the Uralian Ocean. The newly formed graben, filled with a 5 km thick sequence of clastics, is present in the northeast of the basin margin underlying the Orenburg gas field. In both areas the original rifting and formation of grabens occurred at the same time but spreading, starting in the North Caspian graben, resulted in deadlock of rifting and a subsequent compression and inversion of the Orenburg graben. Cratonic blocks, which presently form a series of arches along the south, are the result of spreading in the North Caspian basin. The east basin margins moved away from the Russian Craton and opened the oceanic crust

In the Devonian, Carboniferous and much of Early Permian time the tectonic development was characterized by continuous subsidence of the basin and deposition of carbonate and clastic sediments on its margins. In the middle of the basin this stratigraphy grades into deep-water black shales and turbidites. Hercynian deformation started in the Late Carboniferous in the Ural foldbelt and in the Early Permian in the Kapinsky foldbelt and in the South Emba high. Thick layers of Upper Carboniferous to Lower Permian orogenic molasse sediments are present on the eastern and southern margins of the basin. A continental collision separated the North Caspian deep-water oceanic basin from the Tethys Ocean. After that the basin was filled with a Kungurian evaporate sequence which is mainly composed of salt and has a thickness of 4-5 km (Komissarova, 1986; Volchegursky et al., 1995).

The orogenesis in the Urals, a rapid subsidence of the North Caspian basin and deposition of thick sedimentary layers continued during the Late Permian and Triassic time. Most sediments of this age are continental orogenetic clastic. Only in the western area some Upper Permian carbonates and evaporates and Lower and Middle Triassic marine shales and marls are present. A deformation of Hungarian salt began relatively soon after its deposition and Upper Permian to Lower Triassic sediments are dominant in several km thick layers in depressions between salt domes. The intense tectonic subsidence of the basin floor was completed in Jurassic time. A deformation of salt continues at present and some salt domes penetrate the surface (Dyman, 2001).

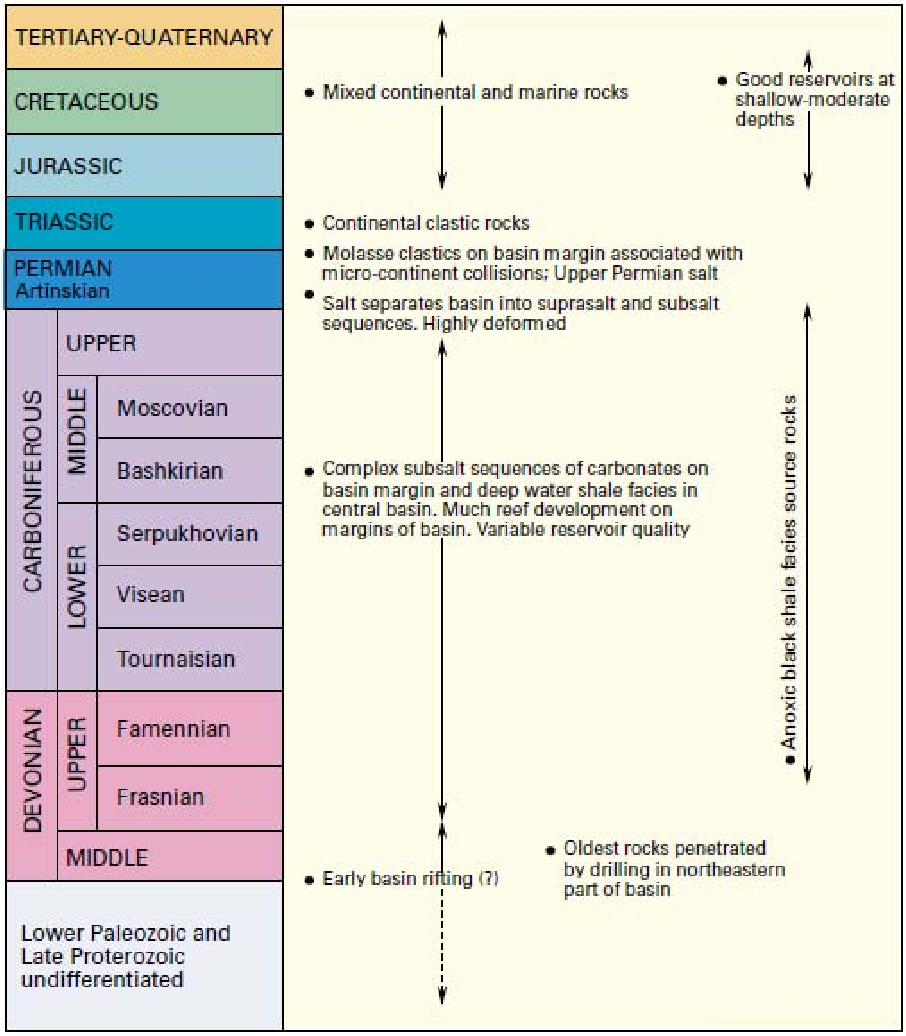


Figure 6: Major geologic events, primary source and reservoir rocks, and basin history of the North Caspian basin. Dashed line below early basin rifting event indicates that the event may extend into the Lower Paleozoic (Dyman, 2001).

VI.2.2.2. Middle Caspian basin

The Hercynian basement was rifted in Late Permian to Triassic time. Rift systems were afterwards filled with sequences of clastic and carbonate sediments with high thickness. During the Late Triassic, volcanism occurred which was followed by a Late Triassic to early Jurassic compression event. This resulted in a partial inversion of the rift grabens and erosion. A strongly deformed rift of this time represents the Mangyshlak foldbelt. From Jurassic to Eocene time, much of the western part of the basin became a passive margin. Jurassic rocks containing coals thicken southward towards the Caucasus and pinch out northwest on the Stavropol arch. The remaining passive margin is composed of Aptian to Albian clastic rocks, Upper Cretaceous carbonates and thin Paleocene to Eocene marls and calcareous shales. The Oligocene to Lower Miocene Series is about 1.6 km thick. Olistostromes indicate uplift and deformation in the Caucasus at this time. The Tertiary mainly consists of coarsening-upward orogenic clastic rocks mainly provenanced by the Caucasus. The Tertiary is 5 – 6 km thick in the narrow foredeep and thins northward (Ulmishek and Harrison, 1981). The South Mangyshlak sub-basin developed during the Jurassic through the Cenozoic. A gentle Cratonic depression was the indicator. The lithology as well of the stratigraphy in the Mesozoic to Lower Tertiary differs from those in the rest of the basin. The orogenic section is absent and only present in thin sequences above the Maykop Series (Dyman, 2001).

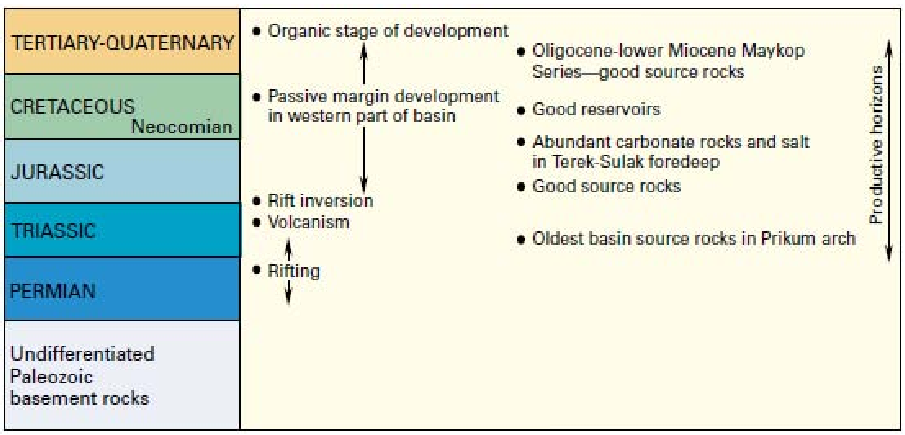


Figure 7: Major geologic events, primary source and reservoir rocks, and basin history of the Middle Caspian basin (Dyman, 2001).

VI.2.2.3. South Caspian basin

The early history of the basin is not well understood because the oldest rocks only occur at great depth. A big part of the offshore part of the basin is underlain by oceanic crust. Reconstructions of the plate tectonics indicate that the basin was formed in Late Jurassic or Early Cretaceous in conjunction with back-arc rifting of the northern margin of the Tethys Sea (Zonenshain et al., 1990). Cretaceous to Lower Tertiary formations are only known from outcrops on the basin margins. These rocks were deposited in marine deep-water depositional environment. The oldest rocks penetrated by wellbores are deep-water organic rich shales of the Oligocene to Lower Miocene Maykop Series (Begir-Zade et al., 1987). This formation is overlain by deep-water organic-rich shales and limestones of the Miocene Diatom Series. The total thickness of these layers reaches several kilometres. In the late Miocene the South Caspian basin was separated from the Tethys Sea by uplifts. The basin became a large inland lake. receiving clastic sediments. The Pliocene Productive Series with a thickness of about 5 km was deposited. During the late Pliocene the Caspian Sea and the Black Sea were connected by a marine transgression. Subsidence and sedimentation continued into Quaternary time.

During the Pliocene and Quaternary, rapid basin subsidence prevented normal compaction in the Maykop Series shales. A quick compression in the Quaternary led to plastic flow of the shales and formation of anticlines. Many anticlines contain active mud volcanoes and are associated with mud volcanoes with roots in the Maykop Series. Today's compression may be related to subduction of the South Caspian basin crust under the Middle Caspian Basin crust (Granth and Baganz, 1996).

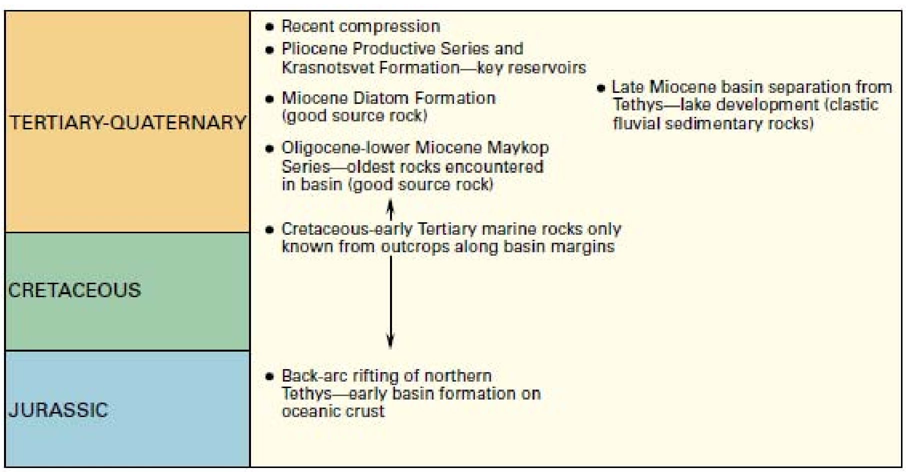


Figure 8: Major geologic events, primary source and reservoir rocks, and basin history of the South Caspian basin (Dyman, 2001).

VI.2.3. Petroleum systems

VI.2.3.1. North Caspian basin

Several oil and gas fields in the North Caspian basin have been discovered in subsalt and suprasalt sequences. The subsalt sequence contains large oil and gas reserves in the Upper Devonian through Lower Permian carbonate and clastic reservoirs in structural traps and reefs. The suprasalt sequences are mainly in Upper Permian to Tertiary clastics. Most hydrocarbons are found in Jurassic and Cretaceous reservoirs in traps near salt domes. However, only one Total Petroleum System (TPS) is presently identified within the basin. It is called the "North Caspian Paleozoic Total Petroleum System".

Source rocks

The principal petroleum source rocks in the North Caspian basin are basinal black-shale facies coeval with Upper Paleozoic carbonate platform deposits on the basin margins. The Lower Permian basinal facies of the western margin is characterized by total organic carbon (TOC) contents ranging from 1.3 to 3.2 percent and hydrogen index (HI) values betwen 300 and 400 mg HC/g TOC (Punanova et all., 1996). Lower Permian black shale of the Karachanganak reef has TOC values up to 10 percent (Maksimov and Ilyinskaya, 1989). In the Middle Carboniferous black shales in the eastern part of the basin, TOC values reach 7.8 percent (Dalyan, 1996). In the Biikzhal deep the Middle Carboniferous black shale has a TOC around 6 percent. However, only a small number of samples exist because of the great depth of the basin. The high TOC contents are typical for anoxic black shales containing type II kerogen. These are the principal source rock in Paleozoic basins all over the world (Ulmishek and Klemme, 1990).

In the southern part of the basin upward-coarsening clastics of the Upper-Devonian to Lower Carboniferous Izembet Formation have TOC contents from 0.1 to 7.8 percent. The organic is matter is of mixed terrestrial and marine sapropelic origin. The HI varies from 100 to 450 mg HC/g TOC. Most samples have type II and type III kerogen. In the suprasalt section some source rocks may

be present in the Triassic strata but geochemical data show that suprasalt oils were generated in a subsalt source and migrated upward in depressions between domes (Sobolev, 1993; Murzagaliev, 1994).
The vitrinite reflectance and geochemical data indicate that most subsalt rocks occur in the oil window or the upper part of the gas window. The geothermal gradient of the basin is relatively low because of the thick salt formations inside the basin. The principal stage of hydrocarbon generation and formation of the fields was in Late Permian to Triassic time when the salt seal was in place and thick orogenic molasse clastics were deposited (Borovikov, 1996).

Reservoir rocks

There are mainly subsalt carbonate and clastic reservoirs in the Middle Caspian basin. The reservoir properties of carbonate rocks (which are of better quality) mainly depend on diagenetic changes like leaching. The reef carbonates e.g. in the Karachaganak field have porosities from 10 to 14 percent. Porosity is mainly present as vugs. The porosity of Upper Devonian to Middle Carboniferous carbonate rocks in the Tengiz field averages 6 percent over the extensive atoll and is essentially vugular. Higher porosity values are characteristic for ring-shaped zones of the core of atoll reefs (Pavlov, 1993). The permeability of the most reservoir rocks is mainly controlled by fractures and varies widely from a few to hundreds of mD.
Several small oil reservoirs were found in sandstones of the upper part of the Upper Devonian to Lower Carboniferous Izembet formation on the eastern margin of the basin. The sandstones are poorly sorted and have a high content of carbonate cement. Porosity averages 15 percent and permeability varies up to hundreds of mD. However, due to high overpressure and great depth the reservoir quality is not good at all.
Lower Permian molasse clastics, mainly on the eastern and southern margins of the basin, also show poor reservoir quality.
The main problem of the subsalt sandstone reservoirs is the discontinuity of the sandstone bed due to rapid progradational deposition of the sequences.

The suprasalt sandstone reservoirs are the Jurassic and Cretaceous are excellent. Porosity ranges from 25 to 35 percent and permeability is very high up to 500 mD (Ulmishek, 2001).

Seal

For subsalt reservoirs the Lower Permian Kungurian evaporite sequence is an important seal rock. It covers nearly the entire basin region. Where the seal is absent, hydrocarbons migrate from subsalt to suprasalt. Upper Jurassic and Cretaceous marine shales seal the hydrocarbons of the suprasalt section.

Traps

The most common traps of the North Caspian basin are carbonate reefs in the subsalt section. Various morphological types are present. The most common are atolls and pinnacle reefs with high hydrocarbon columns. Barrier reef reservoirs are much smaller because the maximum oil/gas content is defined by the back-reef slope, which is usually no higher than 200 m. Some subsalt fields are in structural traps like anticlines, which are related to the Hercynian compression from the Urals. They were formed during Permian-Triassic time isochronic with the peak of hydrocarbon generation.

In the suprasalt section all productive traps are related to salt tectonics and are geomorphologically variable. Anticlinal uplifts and faults as well as walls of the salt dome are the most common. Modern seismic equipment has improved the ability to map structures around salt domes resulting in new types of structures being mapped (Dalyan, 1998). These are, for instance, arches in depressions and semi arches against slopes of salt domes. Most structures occur in the Upper Permian rocks (Ulmishek, 2001).

Production

Most hydrocarbon reserves of the basin are in subsalt Upper Paleozoic rocks. Three super giants, the Astrakhan, the Karachanganak and the Tengiz field produce from this series. Smaller reserves are found in supra salt sections. Several deep accumulations are found in the Lower Permian and Carboniferous reefs along the northern and western basin margins. Most of these fields are not in production because of relative small reserves. Newest reservoirs are found in Upper Devonian to Middle Carboniferous carbonate atolls overlain by Lover Permian pinnacle reef at a depth of 5.2 km. The top of the primary reservoir of the Tengiz field lies at 4 km in an Upper Devonian to Bashkirian atoll. Most of the fields in the basin are overpressured (Dyman, 2001).

VI.2.3.2. Middle Caspian Basin

The Middle Caspian basin consists of four known TPS: The South Mangyshlak system, the Terek-Caspian system, the Stavropol-Prikumsk system and the Shakapakhty system. Three of the four systems extend into the Caspian Sea where their dimension is unknown because of missing wellbore data. The main oil and gas reserves of the South Mangyshlak system are in structural traps of Middle Jurassic sandstones. Some reserves are in Triassic carbonates and clastics. Minor accumulations are known in Lower Cretaceous sandstones and fracture basement granites. In the Terek-Caspian system most reserves are in Upper Cretaceous carbonates and Middle Miocene sandstones. Hydrocarbons are trapped in anticlinal structures which are related to thrusts. The Stavropol-Prikumsk system contains large hydrocarbon reserves in sandstones of the Lower Maykop and Lower Cretaceous in anticlinal traps. Some reserves were found in Jurassic clastics and Lower Triassic carbonates. In the Shakapakhty system, hydrocarbon reservoirs can be found in Middle Jurassic clastic rocks (Ulmishek, 2001).

Source Rock

In the Middle Caspian basin only few geochemical data for source rocks exist. Most geological and geochemical data suggest that different source rock intervals are present in various parts of the basin. One source rock occurs in the Lower to Middle Triassic interval. It has TOC values ranging from 1 to 4 percent, which is not very high, and it contains mainly of Type II kerogen (Mirzoev and Dzhaparidze, 1979). This is the source of the oil in the Prikum arch and most of the oils in the South Mangyshlak system.

A second source rock occurs in the Middle Jurassic interval. The TOC content is low with values ranging from 1 to 3 percent and the origin of the carbon is marine and terrestrial matter. This source is responsible for the carbonates in the Prikum arch and some gas in the South Mangyshlak system.

A third source rock interval may be present in the Lower Maykop Series. It is composed of anoxic black shales with high TOC contents ranging from 7 to 8 percent. This source rock is mature in foredeep and slope areas but immature in the northern areas and the South Mangyshlak subbasin. Due to the existing geochemical data these source rocks generate most of the hydrocarbons in the Middle Caspian basin. The geothermal gradient in this area ranges from 38° to 41° C but in past it was substantially higher. The hydrogen index is around 250 – 270 mgHC/g TOC (Ulmishek, 2001).

Reservoir Rocks

The reservoir rocks of the Middle Caspian basin comprise nearly the entire sedimentary interval from the Triassic to the Middle Miocene. All the reservoirs are productive. Triassic rocks contain oil and gas pools in carbonate rocks and are existent in the South Mangyshlak subbasin and in the Prikum arch. Lower to Middle Jurassic sandstones contain extensive gas and oil reserves, mainly in the South Mangyshlak subbasin. Most pools are at depths of about 1.1 – 2.3 km. The sandstone reservoirs are generally characterized by high porosity and moderate to high permeability (Ulmishek and Harrison, 1981). The reservoirs in the Prikum arch area are also from the Jurassic. The sandstones occur at depths of 3 – 4 km and the porosity ranges from 12 to 18 percent, which is quite good. Permeability is usually not higher than a few tens of mD. The main parts of hydrocarbons in the Prikum arch area are in sandstones of the Aptian and Albian formation at depth up to 3 km. The porosity of these reservoirs ranges from 15 to 22 percent and the permeability from 100 to 200 mD (Maksimov, 1987).

The main reservoirs are in the Upper Cretaceous carbonates, which contain more than 50 percent of all reserves of the Middle Caspian basin. The reservoirs are controlled by fractures. Middle Miocene sandstones also form reservoirs in the basin. They occur at shallow depth and have excellent reservoir properties. Large gas reserves can be found in the Khadum horizon at the base of the Maykop Series at depths of 1.2 km or less. The porosity is very high (40 – 40 percent) and the permeability reaches values up to 1 Darcy (Maksimov, 1987).

Seals

Seals differ from region to region. In the South Mangyshlak subbasin, Upper Jurassic marine shales and carbonate beds allegorize the seal. They are more than 500 m thick but in some parts thins to 100 – 300m and effectively control the gas reserves in the Lower to Middle Jurassic reservoirs. Hydrocarbons under Triassic formations are sealed by dense carbonates and tuffs without porosity and permeability (Ulmishek, 2001).

In the Terek-Caspian system, Maykop Series shales control the accumulations of the Mesozoic sequences. The sequence is 750 to 1600 m thick and overlies most of the TPS area. It overlies directly the reservoirs of the Upper Cretaceous to Eocene Series. Accumulations of the Middle Miocene sandstones are sealed by alternating shale beds with a thickness of several tens of meters. Another excellent seal in this region is the Upper Jurassic salt formation that is only present in the west of Dagestan projection (Ulmishek, 2001).

Important seals of the Stavropol-Prikumsk system are Maykop Series shales. Oil and gas accumulations in the Mesozoic strata are sealed by various shale beds of the Upper Bajocian and Upper Aptian, which seal most of the reserves of the Prikum arch (Ulmishek, 2001).

Traps

Most of the hydrocarbon accumulations in the Middle Caspian basin are trapped within structural traps in front of the Great Caucasus fold belt in anticlines with closures up to 1005 m. Oil and gas of the Prikum arch and the Stavropol arch are trapped in isometric, low-relief anticlines over basement highs of Triassic reefs. In the South Mangyshlak subbasin mainly asymmetric anticlines underlain by thrusted Jurassic rocks are present (Popkov, 1991). In addition to these structural traps, many fields are controlled by unfractured Triassic carbonates and unfractured Lower Maykop Series shales.

Production

Most hydrocarbons of the Middle Caspian basin are found in the Middle Jurassic sandstones of the South Mangyshlak sub-basin, in Upper Cretaceous sandstones of the Prikum arch and in Oligocene sandstones of the Stavropol arch. The fields have depths up to 4572 m and mostly oil is present. Deep pools are found in Triassic carbonate rocks and Upper Cretaceous carbonates. In the Groznyi area some pools are located in the Lower Cretaceous sandstones. In the Triassic the primary reservoirs are carbonates of the Lower Triassic. Most of the pools are found in reef facies. A few pools have been drilled and are producing. In the Groznyi area Cretaceous pools are mostly not drilled and do not produce due to overpressure in this region (Dyman, 2001).

VI.2.3.3. South Caspian Basin

Three petroleum systems can be recognized within the basin: The Maykop-Productive Series system, the Eocene-Eocene system and the hypothetical Shemshak-Jurassic/Barremian system. The Maykop-Productive Series system is the main hydrocarbon system in the basin and extends from Oligocene to Quaternary. Known hydrocarbon accumulations are in onshore Azerbaijan, the offshore Baku Archipelago, onshore and offshore Apsheron-Pribalkhan Zone and onshore and offshore western Turkmenistan areas. Primary source rocks are the marine Oligocene to Lower Miocene Maykop Series and the Upper Miocene Diatom Series. Dominant hydrocarbon accumulation can be found in fluviodeltaic Productive Series and the correlative Red Bed Series.

Source rocks

Source rocks occur at great depths but are known from outcrops on the margins of the basin and from brecciae of mud volcanoes. The deep-water, anoxic shales of the Oligocene to Lower Miocene Maykop and Diatom Series vary in TOC content but are the richest in the Middle Maykop. The TOC values range up to 10 percent. Most oils are sourced from this source rock, which is slightly calcareous with an algal marine clastic facies. It contains type II and type III kerogen. Oils of this source rock are highly paraffinic and low in trace metals and sulfur contents (Frydl et al., 1996). The pristane/phytane ratios are between 1.3 – 1.6 and the vitrinite reflectance equivalents range from 0.8 to 1.0 (Abrams and Narimanov, 1997). Hydrogen Indices range from 150 to 500 mg HC/g TOC. The thickness of the source rock formations ranges from 100 m to 2800 m within the South Caspian basin. Their maximum thickness of 3500 m is located outside the basin near the Lesser Caucasus Mountains. Less important source rocks are in the Upper Cretaceous. Deep-water marine rocks with less than 1 percent TOC and Eocene algal marine rocks with 1 – 2 percent TOC are present in this series. Another potential source rock is in the Pliocene to Pleistocene strata in western Turkmenistan (Ulmishek, 2001).

Reservoir Rocks

The reservoir rocks of the Pliocene productive series are sandstones and siltstones. The reservoir properties of the sandstones depend on the paleogeographic conditions of the sedimentation. The best reservoir rocks are located on the Apsheron-Pribalkhan Peninsula near Baku. Here, quartz-rich sandstones with clastic sediments entered the basin from the paleo-Volga river. The sandstones were deposited in a deltaic and alluvial environment. At a depth of 2 to 3 km the porosity of these sandstones varies from 15 to 30 percent and the permeability varies from tens to 1,000 mD. At greater depth, porosity and permeability is reduced. The very good reservoir properties are related to a low geothermal gradient and overpressure. To the east and south of the basin the grain size decreases and clay content increases, resulting in poorer reservoir quality. In the southwest of the South Caspian basin, clastic sediments were deposited by the paleo-Kura river system. The reservoirs of there sediments have a poor quality compared to those of the Apsheron area. At a depth of 2.5 to

3 km, porosity ranges from 12 to 14 percent, and permeability only reaches tens of mD. At greater depth, reservoir quality is even worse (Ulmishek, 2001).

Seals

Seals in the South Caspian basin are formed by intraformational shales within the Pliocene reservoirs. Transgressive shales within the Productive Series and the Akchagylian and Apsheronian strata provide effective seals for Middle Pliocene reservoirs. Due to discontinuity of some thin seals the basin is kind of leaky. In Azerbaijan seals are formed by Upper Maykop, Karagan and Upper Diatom Series.

Traps

Most oil and gas fields in the South Caspian basin are controlled by structural traps. But pool outlines are also often associated with lateral stratigraphic changes. The dominant trap types are compressed anticlinal folds grouped into long zones in the onshore and shallow-shelf areas. Fold amplitudes vary from 0.3 to 3 km. Folding took place in Pliocene to Quaternary time. Many faults subdivide the folds into distinct structural blocks. Many folds have active mud volcanoes along their crest. The fold amplitudes are usually smaller in the eastern margin than in the western margin. In the central deep-water part of the South Caspian basin, gigantic anticlinal structures have been mapped by seismic surveys but have not been drilled until today (Ulmishek, 2001).

Production

Nearly all hydrocarbon reservoirs of the South Caspian basin are in clastic reservoirs of the Pliocene Productive Series. Deep drilling in this basin began in the 1950s with wells up to 4572 m. Over twenty oil pools have been discovered at depth greater than 4.5 km but only 9 fields have been drilled. Several more pools have been indicated. The deep oil and deep gas potential of the basin is believed to be very high.

Table 1: Geological data for 14 representative fields in the Caspian Region (modified after Dyman, 2001)

Country	Basin	Field Name	Tyoe	Age	Lithology	Depth	Trap
Kazakhstan	North Caspian	Karachanganak	Gas, Oil	Middle Devonian	Clastic	5630	Structural
Russia	North Caspian	Upryamovo	Gas, Oil	Lower Permian	Carbonate	5935	Structural
Kazakhstan	North Caspian	Karatobe	Oil	-	Clastic	5143	Structural
Russia	Middle Caspian	Arak-Dalatarek	Oil	Lower Cretaceous	-	4950	-
Russia	Middle Caspian	Gudermes-Vostochny	Oil	Upper Cretaceous	Carbonate	4560	Stratigraphic
Chechnya	Middle Caspian	Andreyevo	Gas, Oil	Upper Cretaceous	-	5612	-
Russia	Middle Caspian	Norolak-Arkabash	Gas	Upper Cretaceous	Carbonate	5341	Structural
Russia	Middle Caspian	Yubileynoe	Oil	Lower Triassic	Carbonate	4470	-
Azerbaijan	South Caspian	Garasu-Deniz	Gas, Oil	-	-	4710	Structural
Azerbaijan	South Caspian	Zyaya	Gas , Oil	Pliocene	Clastic	4560	Structural
Azerbaijan	South Caspian	Bakhar	Gas, Oil	-	-	4800	Structural
Azerbaijan	South Caspian	Bulla-Deniz	Gas, Oil	Pliocene	Clastic	4890	Structural
Turkmenistan	South Caspian	Barsa-Gel’mes	Gas, Oil	Pliocene	Clastic	4900	Stratigraphic
Azerbaijan	South Caspian	Yuzhnoe	Gas, Oil	Pliocene	Clastic, Carbonate	4700	-

VI.3. Geopolitical situation in the Caspian Region

VI.3.1. Countries and their Infrastructure

VI.3.1.1. History

In 1871 the giant Bibi-Etat field was discovered by the Tsardom of Russia and modern petroleum industry was established. In the late 1800‘s two combative and competing families, the Noble brothers and the Rothschild family, produced oil in the region. Russia became the largest oil-producing country until 1902 and 50% of its oil were produced in the Caspian region. After the fall of the Tsarist Empire and during Civil War, the Caspian region suffered a period of turmoil until 1920 with the beginning of Bolshevik era. From 1927 until 1974 the Caspian region experienced an increase in oil production with the Stalin regime and its Five-Year Plans. During the Second World War, Hitler tried to capture Baku but failed. The Soviet oil production became the largest of the world. 28% of the Soviet oil production came from the Caspian region. Today “the struggle over vital resources, rather than ideology or balanced-of-power politics, dominates the martial landscape” (Klare, 2008).

VI.3.1.2. Caspian Region: Population, Religion, Language, Culture

An analysis of the Caspian Region with its population and area is given in Figure 9. Azerbaijan is the smallest state of the Caspian Region but has a higher population than Turkmenistan. Thus, Azerbaijan experiences/will experience a growth in domestic demand and consumption. The Caspian region is characterized by Muslim religion and Russian-Orthodox religion. It is influenced by Russian and Persian language. There are spoken many different languages. Due to the size of the countries there are many large cities with a high population (Table 2).

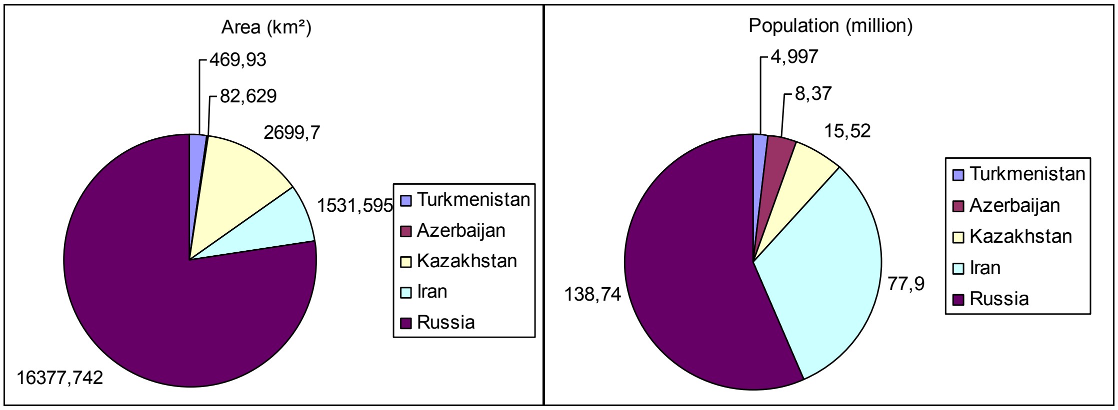


Figure 9: Population and Area (CIA World Factbook 2012

Table 2: Caspian Region: Population, Religion, Language, Culture (CIA World Factbook 2012)

Caspian Region	Population (million)	Area (km²)	Religion	Language	Cities (population, CAPITAL)
Kazakhstan	15.52	2,699,700	Muslim 47%, Russian Orthodox 44%, Protestant 2%, other 7%	Kazakh 64.4%, Russian 95%	Almaty (1.383 million); ASTANA (650,000)
Turkmenistan	4.997	469,930	Muslim 89%, Eastern Orthodox 9%	Turkmen (official) 72%, Russian 12%, Uzbek 9%	ASHGABAT (637,000)
Iran	77.9	1,531,595	Muslim (official) 98% (Shia 89%, Sunni 9%), Zoroastrian, Jewish, Christian, and Baha'i 2%	Persian (official) 53%, Azeri Turkic and Turkic dialects 18%, Kurdish 10%, Gilaki and Mazandarani 7%, Luri 6%, Balochi 2%, Arabic 2%	TEHRAN (7.19 million); Mashhad (2.6 million); Esfahan (1.7 million); Karaj (1.5 million); Tabriz (1.5 million)
Azerbaijan	8.37	82,629	93.4%, Russian Orthodox 2.5%, Armenian Orthodox 2.3%	Azerbaijani (Azeri) (official) 90.3%, Lezgi 2.2%, Russian 1.8%, Armenian 1.5%	BAKU (1.5 million)
Russia	138.74	16,377,742	Russian Orthodox 15-20%, Muslim 10-15%, Christian 2%	Russian (official)	MOSCOW (10.523 million); Saint Petersburg (4.575 million); Novosibirsk (1.397 million); Yekaterinburg (1.344 million); Nizhniy Novgorod (1.267 million)

VI.3.1.3. Economic development

In the following discussions Russia is left out because considering Russia as a whole would distort the figures relevant for the Caspian region. Separate data from the Russian part of the Caspian Basin were not available.

Kazakhstan

Kazakhstan's economy grew by more than 9% per year from 2000 to 2007. This growth was largely fuelled by the hydrocarbon and mining industries. Geographic limitations and decaying infrastructure are a special challenge to this region. At the end of 2007, the global financial crisis started and Kazakhstani banks lost capital and this caused a credit crunch. The oil and commodity prices dropped in 2008 and Kazakhstan plunged into recession. In 2010, rising commodity prices have helped revitalize Kazakhstan's economy. The economy recovered well with a growth rate of about 7 %.

Azerbaijan

From 2006 to 2008 Azerbaijan’s economy grew because of its large and growing oil exports. The economic slowdown to a growth rate of 0.2% is the result of the global financial crisis and the low oil prices. Anyway, Azerbaijan suffers less then other countries in the region.

Turkmenistan

From 1998 to 2005, Turkmenistan lacked export routes for natural gas and suffered from obligations on extensive short-term external debt. But total export rose by 15% per year from 2003 – 2008. Revenues increased due to higher international oil and gas prices.

Iran

Since the 1990s Iran tried to reduce its inefficiencies, corruption and informal market activities. Introducing the Targeted Subsidies Law (TSL), the Iranian government wants to reduce state subsidies on food and energy. But there is still a rising inflation. Iran's oil export revenue increased due to rising world oil prices and easing of the financial impact of international sanctions.

In comparison Iran has the highest gross domestic product (GDP) and Turkmenistan the highest GDP real growth rate. The GDP is composed of three sectors: services, industry and agriculture. Iran's economy has the highes number in the agricultural sector in comparison with the other countries with 11.2%. Azerbaijan has the largest industry sector with 62.7% and Turkmenistan has the highest service sector with 62.7% (Figure 10, Table 3).

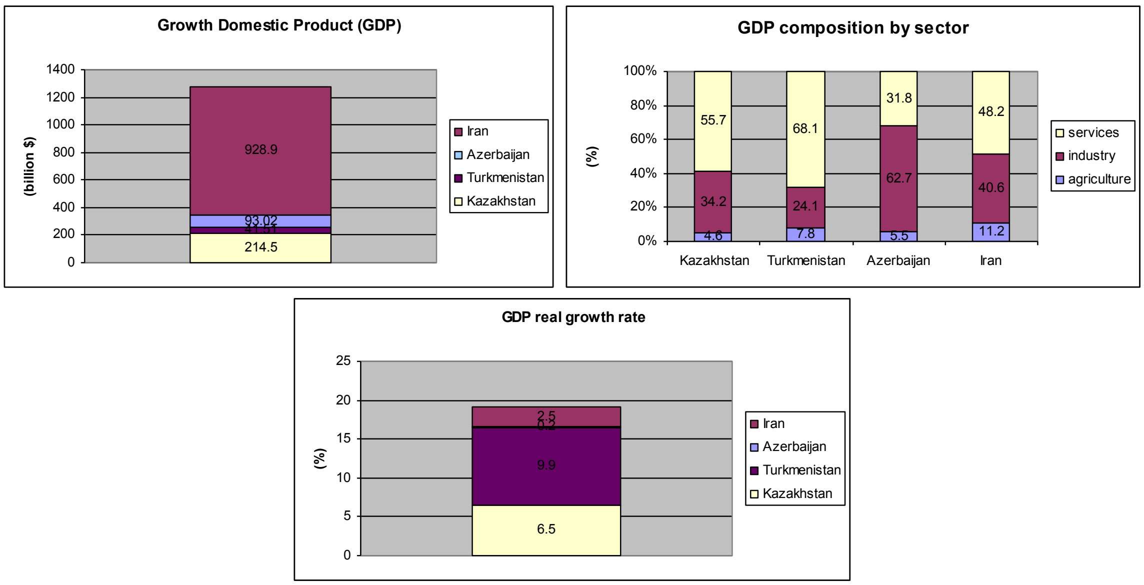


Figure 10: Gross Domestic Product (CIA World Factbook 2011)

Table 3: Gross domestic product, real growth rate and country comparison to the world (CIA World Factbook 2011)

State	Gross domestic product (purchasing power parity) (billion $)	Real growth rate (%)	Rank in world GGP list by country
Kazakhstan	214.5	6.5	53
Turkmenistan	41.51	9.9	98
Azerbaijan	93.02	0.2	76
Iran	928.9	2.5	18

VI.3.1.4. Transportation and Infrastructure

The development of oil and gas resources provides a unique opportunity for the Caspian Basin countries to modernize their economies and gain political independence or power. But exploration of oil and gas resources requires an advanced infrastructure and transport system for human and machine. In Figure 11 the number of airports with paved runways over 3,000m are illustrated, which are needed for the transportation of a high number of passengers and heavy machines. But the number of airports is not related to the Caspian Region but it gives an impression of the infrastructure available. The Caspian Sea is a landlocked sea and thus a limited use of ports and shipping of goods. Important ports for transport in the Caspian Region are in Kazakhstan: Aqtau (Shevchenko), Atyrau (Gur'yev); in Turkmenistan: Turkmenbasy; in Iran: Neka, Bandar-e-Eman Khomeyni (Persian Gulf); Assaluyeh (Persian Gulf), Bandar Abbas (Persian Gulf); in Azerbaijan: Baku and in Russia: Novorossiysk (Black Sea). The geographic maps in Figure 12 show the most important airports, ports, highways and oil and gas pipelines of the Caspian region. Furthermore, a list of oil and gas pipelines is given in Table 4 and 5.

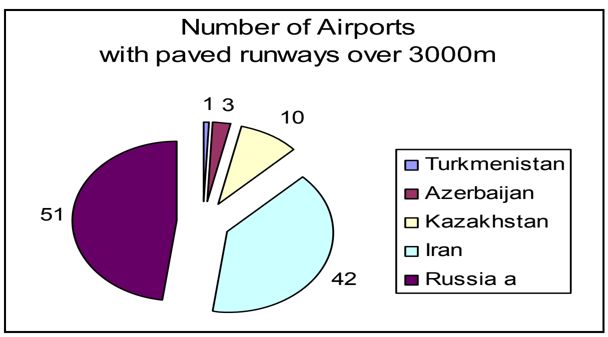


Figure 11: Airports for transportation (CIA World Factbook 2010) [a] Includes whole Russia.

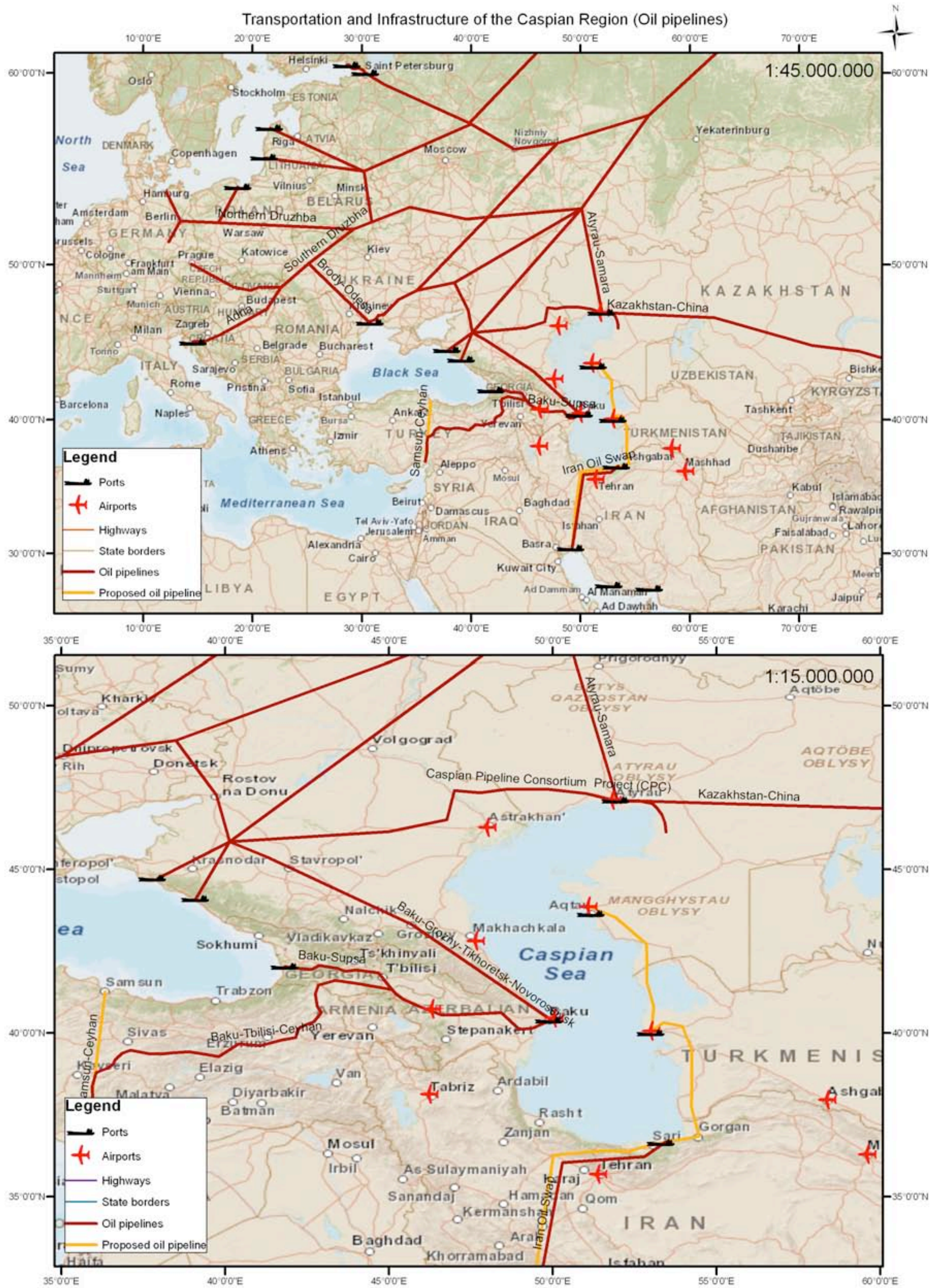
Table 4: Oil pipelines (Gelb 2005, CIA World Factbook 2012)

Oil Pipelines	Route	Lenght (kilometer)	Capacity (billion barrel / day (bbl/d))	
			2001/2002	2010/2015
Operating				
Atyrau-Samara	Atyrau, Kazakhstan to Samara, Russia	695	310,000	500,000
Baku-Novorossiysk	Baku, Azerbaijan to Novorossiysk, Russia (Black Sea) via Chechnya, Russia	1,396	100,000	300,000 (possible)
Baku-Novorossiysk	Baku, Azerbaijan to Novorossiysk, Russia (Black Sea) via Dagestan, Russia	328	120,000	360,000 (planned)
Baku-Supsa	Baku, Azerbaijan to Supsa, Geogia (Black Sea)	828	100,000	600,000 (planned)
Caspian Pipeline Consortium (CPC)	Tengiz oil field, Kazakhstan to Novorossiysk, Russia	1,577	560,000	1,340,000
Baku-Tbilisi-Ceyhan	Baku, Azerbaijan to Ceyhan, Turkey (Black Sea) via Tbilisi, Georgia	1,768	-	1,000,000
Kazakhstan-China	Aktyubinsk, Kazakhstan to Xingjiang, China	987	-	180,000 (possible)
Iran Oil Swap	Neka, Iran (Caspian Sea) to Bandar Imam Khomeini, Iran (Persian Gulf)	334	175,000	370,000
Under Construction, Planned, or Proposed				
Kazakhstan-Turkmenistan-Iran	Atyrau, Kazakhstan to Bandar Imam Khomeini, Iran (Persian Gulf) via Turkmenbasy, Turkmenistan	1,496	-	1,000,000
Samsun-Ceyhan	Samsun, Turkey to Ceyhan, Turkey	550	-	1,500,000

Table 5: Gas pipelines (Gelb 2005, CIA World Factbook 2012)

Gas Pipelines	Route	Lenght (kilometer)	Capacity (billion cubic meter / year (bcm/y))	
			2001/2002	2010/2015
Operating				
Blue Stream	Stavropol Krai, Russia to Ankara, Turkey	1,213	-	16
Central Asia	Kashgar, China to Alexandrov Gay, Russia via Okarem, Turkmenistan	2,000	90	90
Soyuz	Saratov, Russia to Kharkiv, Ukraine	2,675	32	32
South Caucasus	Baku, Azerbaijan to Erzurum, Turkey via Tbilisi, Georgia	692	-	20
Brotherhood	Urengoy, Russia to Uzhgorod, Ukraine via Pomary, Russia		100	100
Transgas	Kharkiv, Ukraine to Frankfurt, Germany and Udine, Italy	n.a.	n.a.	n.a.
Yamal Europe	Yamal, Russia to Europe	4,196	33	33
Northern Lights	Ukhta, Russia to Torzhok, Poland	7,377	51	51
Nord Stream	St. Petersburg, Russia to Greifswald, Germany	1,224	55	55
Under Construction, Planned, or Proposed				
Nabucco	Ahiboz, Turkey to Baumgarten an der March, Austria	4,042	-	31
South Stream	Novorossiysk, Russia (Black Sea) to Brindisi, Italy and Vienna, Austria	550	-	47

Transportation and Infrastructure of the Caspian Region (Oil pipelines)



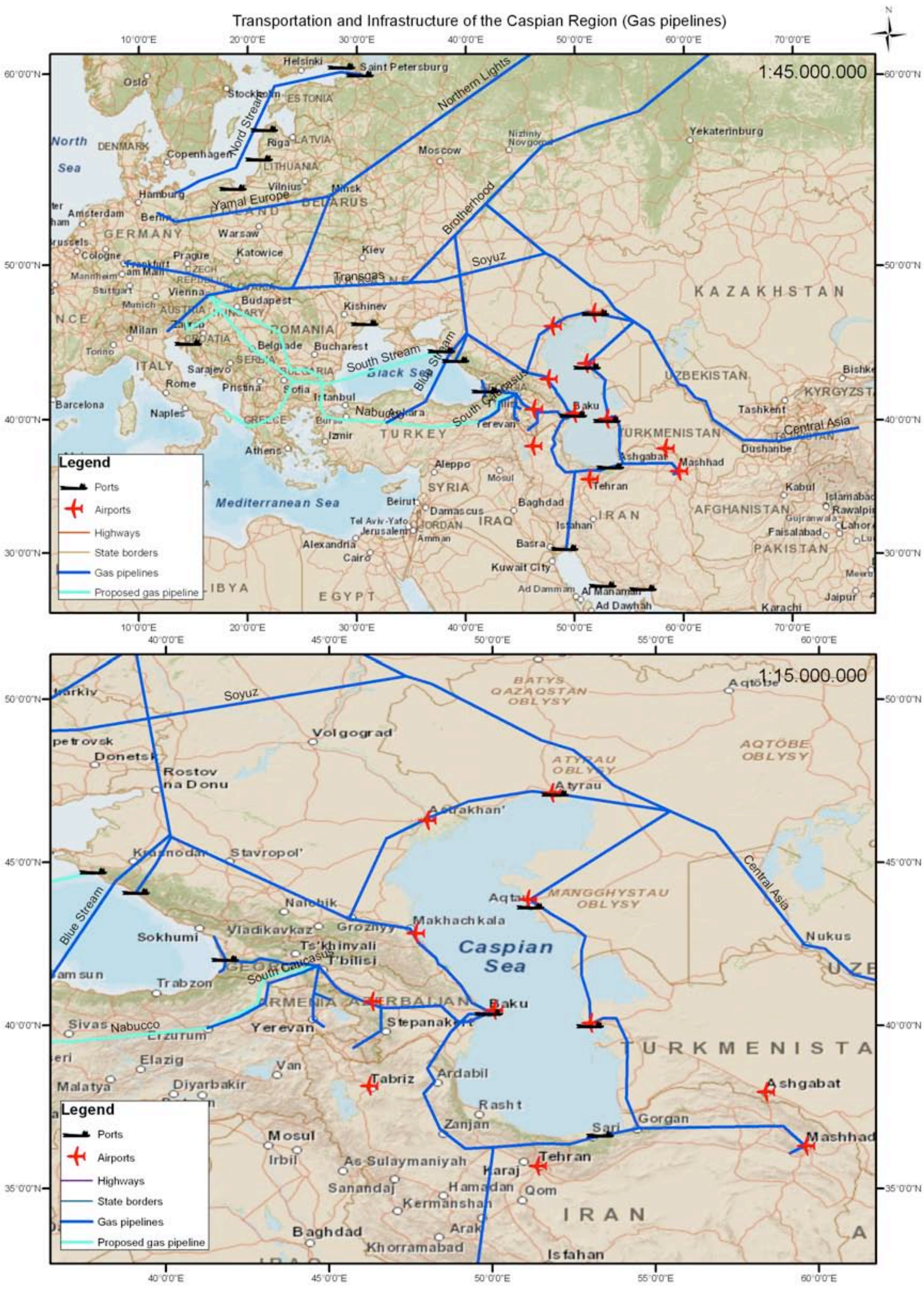


Figure 12: Gas and Oil Pipelines in the Caspian Region and Europe (Gelb 2005, CIA World Factbook 2012, created by Roeloffs)

VI.3.2. Market

VI.3.2.1. Reserves of the Caspian Basin

The Caspian reserves are distributed among Turkmenistan, Kazakhstan, Azerbaijan, Iran and Russia (Table 6). The The Caspian region has received wide attention because of the existence of substantial hydrocarbon reserves. Caspian region oil reserves amount to 233.75 bbl and 87.95 tcm of gas (EIA 2009). The Caspian reserves are distributed among Turkmenistan, Kazakhstan, Azerbaijan, Iran and Russia (Table 6).

VI.3.2.2. Production and Refining

Caspian Sea crude oil production has recovered from stagnation in the early 1990’s (Mahnkovski 2002). 3 to 4.5% of the total world crude oil production comes from the Caspian Sea region (non-Russian and Iranian sectors) (Figure 15 and Table 7). Future oil production in the Caspian region will be dominated by Kazakhstan and Azerbaijan, and will reach its peak between 2010 and 2015 (Figure 13 and 14). “Macroeconomic and demographic developments in the region will affect export potential primarily through the growth in domestic consumption” (Mahnovski 2002: p.112). For instance, Turkmenistan’s export potential will steadily decrease to 4% in 2020. Moreover, Uzbekistan has already become a net importer of crude oil, importing almost 34,430 barrels per day (bl/d) in 2010. The highest natural gas potential will come from Turkmenistan, which will secure Turkish and Far Eastern markets (Mahnovski 2002). The natural gas production and thus contribution to world supplies are higher than for oil (Gelb 2005).

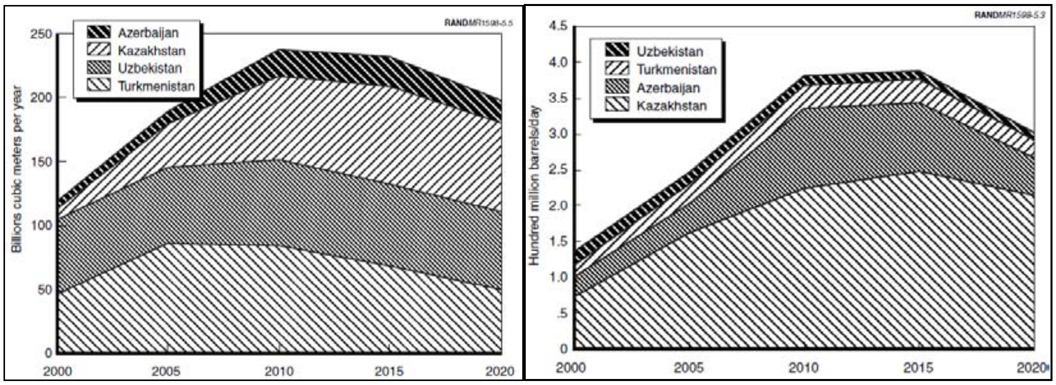


Figure 13 + 14: Caspian Crude Oil (left)and Crude Gas Production (right) Forecasts (Mahnovski 2002)

Table 6: Reserves of the Caspian Basin (EIA - Energy Information Administration)

Region	Country	Proven Reserves Oil (billion barrel (bbl)) / Gas (trillion cubic meter (tcm))					Possible Additional
		US Department of State 1997	BP (End of 2003)[f]	O & G Journal (1/1/05)[f]	Giuli (2008)	EIA 2009	EIA[a] 2005 (2006) [2003]
Caspian Sea Region	Azerbaijan	-	7 / 1.36	7 / 0.85	n.a. / 1.35 – 2.30	7 / 0.85	32 / 1.0
	Iran[b]	-	0.1 / 0[c]	n.a. /n.a.[c]	n.a. / 28.13	136.15 / 29.62	15 / 0.31
	Kazakhstan	-	9 / 1.84	9 / 1.84	-	30 / 2.41	92 / 2.49
	Russia[b]	-	1 / 1.84[c]	n.a. / n.a.	-	60 / 47.57	7 / n.a.
	Turkmenistan	-	0.5 / 2.86	0.5 / 2.01	n.a. / 2.67	0.6 / 7.50	38 / 4,50
	TOTAL	**200 / 7**	**18 / 4.81**	**16.5 / 4.7**	**-**	**233.75 / 87.95**	**184 (70 – 150) [17 – 33]/ 8.30 (8)**
Reference Areas	United States	-	31 / 5.24	22 / 5.35	-	8,162.2 / 611,76	47 / 7.67[d]
	North Sea[e]	-	15 / 3.4	15 / 3.06	-	2,868.2 / 271.59	n.a.
	Saudi Arabia	-	263 / 6.68	259 / 6.65	-	9.752,6 / 89.56	n.a.
	WORLD	-	1,148 / 175.71	1,278 / 171.03	-	84,422.4 / 3,201.446	n.a.

n.a. - Not available from sources listed below.

[a] Excludes proven reserves. Data from various sources compiled by EIA in Survey cited below.

[b] Only regions near the Caspian Sea are included.

[c] Data from EIA.

[d] Undiscovered conventional oil and gas.

[e] Includes Denmark, Germany, Netherlands, Norway, and United Kingdom.

[f] Sources:

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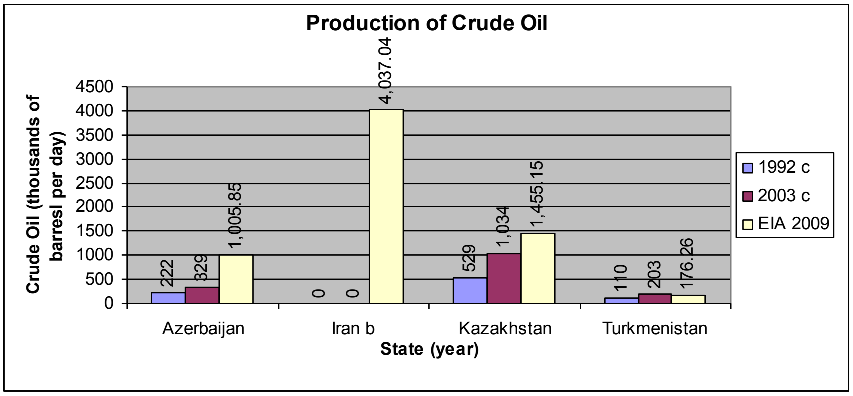

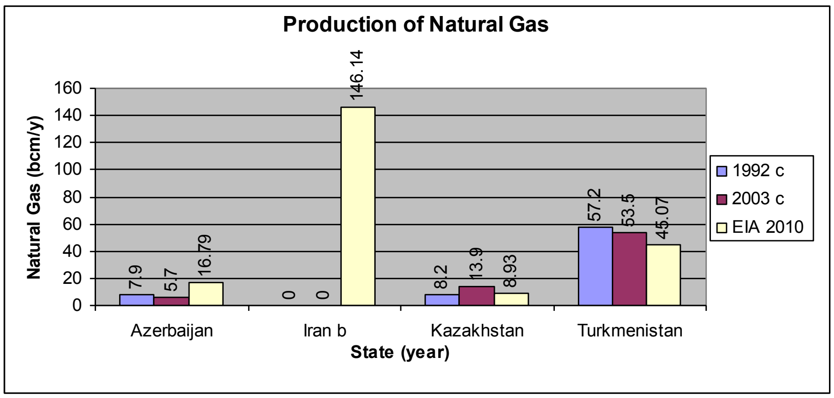

Figure 15: Production of Crude Oil and Natural Gas in the Caspian Region. Comparison of production figures of 1992, 2003 and 2919 (EIA 2009)

Table 7: Crude Oil and Natural Gas (EIA 2009/2010- Energy Information Administration)

	Crude Oil[a] (thousand of barrels per day (tbl/d))			**Natural Gas (billion cubic meter /year (bcm/y))**		
State	1992[c]	2003[c]	EIA 2009	1992[c]	2003[c]	EIA 2010
Azerbaijan	222	329	1,005.85	7.9	5.7	16.79
Iran[b]	n.a.	n.a.	4,037.04	n.a.	n.a.	146.14
Kazakhstan	529	1,034	1,455.15	8.2	13.9	8.93
Russia[b]	n.a.	n.a.	9,495.36	n.a.	n.a.	630.30
Turkmenistan	110	203	176,26	57.2	53.5	45.07
Total Caspian[d]	861[e]	1,566[e]	6,674.3	73.3[e]	73.1[e]	216.93
WORLD	73,935	76.777	82,282.0	2,044.3	2,617.4	3,369.7

n.a. - Not available from specified sources.

[a] Includes natural gas liquids.

[b] The production includes whole Russia.

[c] Sources: BP. Statistical Review of World Energy 2004, June 15, 2004; Department of Energy, Energy

[d] Excludes Russia. [e] Excludes Iran.

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The Caspian countries have only little refining capacity (Table 8 and Figure 16). The former Soviet Union (FSU) countries are suffering from their poor infrastructure. Refining capacity increased from 6.5 million barrels per day in 2011 to 6.6 million barrels per day in February 2012 (Figure 17). But compared to 2011, the general trend is constant with some fluctuation (EIA 2012). For example, “in Kazakhstan, runs rose by some 60,000 bl/d in December on rebounding runs at PetroKazakhstan’s 105,000 bl/d Shymkent refinery” (EIA Oil Market Report 2012: 51). In October the plant was shut because of an overhaul and in February the plant had problems with a fire. Generally, Caspian countries have problems with their old and not yet renewed machinery and infrastructure from Soviet Union time.

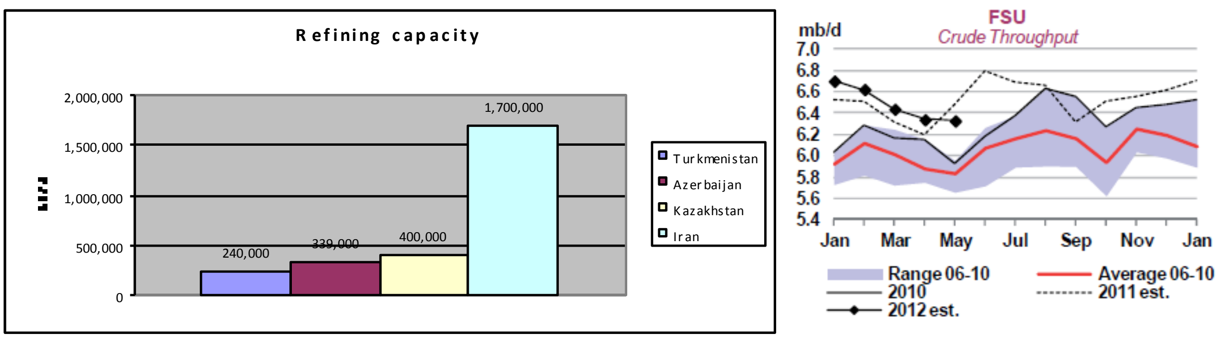


Figure 16: Refining Capacity of Caspian countries and crude throughput of FSU (EIA 2012)

Table 8: Refineries (EIA 2012)

	Number of Refineries
Turkmenistan	2
Azerbaijan	2
Kazakhstan	3
Iran	9

Global Refinery Crude Throughput[1]
(million barrels per day)

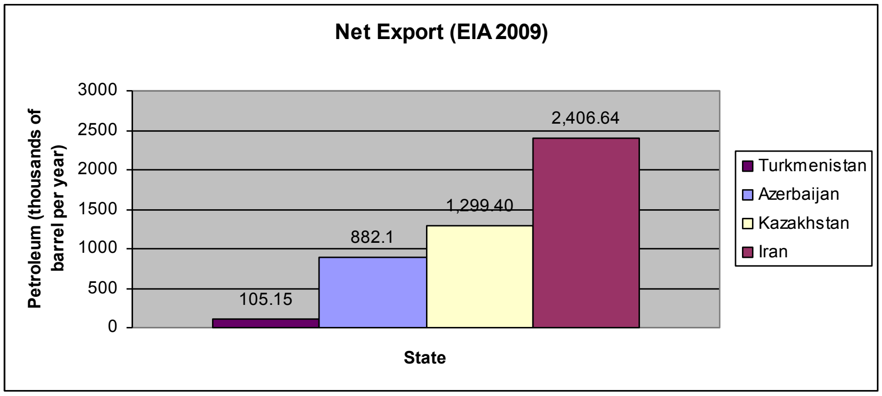
	3Q2011	Oct 11	Nov 11	Dec 11	4Q2011	Jan 12	Feb 12	Mar 12	1Q2012	Apr 12	May 12
North America	**18.3**	17.3	17.8	17.6	**17.6**	17.5	17.2	17.2	**17.3**	17.6	18.0
Europe	**12.4**	11.9	12.1	12.2	**12.1**	12.2	11.9	11.8	**11.9**	11.7	12.0
Pacific	**6.4**	6.2	6.6	6.8	**6.5**	6.9	7.0	6.6	**6.8**	6.4	6.2
Total OECD	**37.2**	**35.5**	**36.5**	**36.7**	**36.2**	**36.5**	**36.1**	**35.5**	**36.1**	**35.8**	**36.2**
FSU	**6.6**	6.5	6.6	6.6	**6.6**	6.7	6.6	6.4	**6.6**	6.3	6.3
Non-OECD Europe	**0.5**	0.5	0.6	0.6	**0.5**	0.6	0.5	0.5	**0.5**	0.5	0.6
China	**8.8**	8.7	9.2	9.2	**9.1**	9.4	9.2	9.1	**9.2**	9.3	9.1
Other Asia	**8.9**	8.5	9.1	9.1	**8.9**	9.3	9.1	9.1	**9.2**	9.0	9.3
Latin America	**5.4**	5.2	5.4	5.3	**5.3**	5.4	5.3	4.9	**5.2**	4.9	4.9
Middle East	**6.3**	6.2	6.1	6.0	**6.1**	5.9	6.0	5.7	**5.9**	5.8	6.0
Africa	**2.2**	2.2	2.2	2.3	**2.2**	2.2	2.2	2.2	**2.2**	2.2	2.2
Total Non-OECD	**38.5**	**37.8**	**39.1**	**39.2**	**38.7**	**39.4**	**38.9**	**38.2**	**38.8**	**38.2**	**38.4**
Total	**75.7**	**73.2**	**75.5**	**75.9**	**74.9**	**76.0**	**75.1**	**73.7**	**74.9**	**73.9**	**74.5**

1 Preliminary and estimated runs based on capacity, known outages, economic run cuts and global demand forecast

Figure 17: Global Refinery Crude Throughput (Oil Market Report 2012)

VI.3.2.3. Export/ Import

Gas exports from Kazakhstan amounted to 3.7 bcm/y (Giuli 2008) in 2007. In 2009 exports decreased to 0.11 bcm/y (EIA 2009). Russia imported 37.5 bcm/y from Turkmenistan (Giuli 2008) in 2006. “Most of these imports are subsequently sold to Ukraine” (Giuli 2008: p.3) and Iran. Turkmenistan exports 43.3 bcm/y (Giuli 2008) in 2007 to Iran (5.5 – 6.0 bcm/y) and Russia (37.5 bcm/y). “To this extent, Turkmenistan benefits from the high rate of exploration of its gas and the low domestic demand due to a small population and a poor industrial base” (Giuli 2008: p.3). Iran imported 5.8 bcm/y from Russia (Giuli 2008) in 2006 and exported 5.6 bcm/y to Turkey (Giuli 2008) and further 2 bbl/d (Moradi 2006) in 2005. Figure 18 gives an overview of today’s net exports.



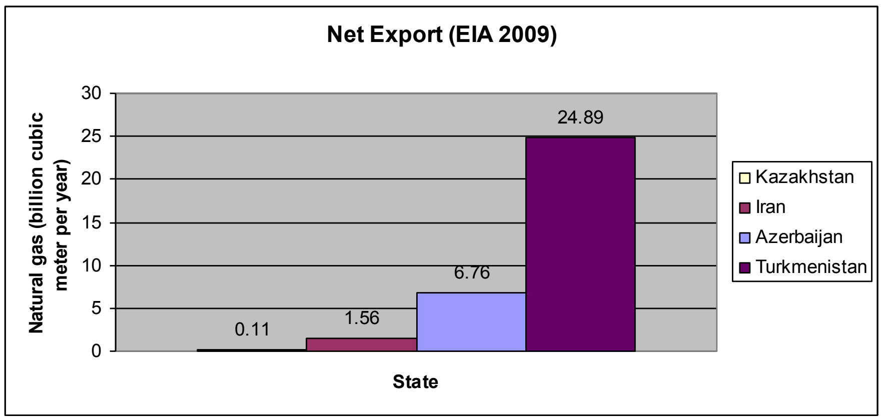


Figure 18: Net export of oil and gas from states of Caspian region (EIA 2009)

[a] Net export = total production - consumption

VI.3.2.4. Present and Prospective Markets

Caspian crude oil and natural gas is exported north and/or west. The transport to takes place via pipelines to and/or through Russia to European markets or via tanker (Black Sea, Persian Gulf) to Europe, China, India, USA and other global markets (Figure 19 and 20, Table 9). Turkmenistan will contribute 10 bcm/y of natural gas to the Nabucco pipeline. Furthermore the country will supply Russia 80 - 90 bcm/y for 30 years. Turkmenistan's domestic consumption is expected to reach 20 bcm/y. Armenia will import 2 bcm/y of natural gas for its domestic demand.

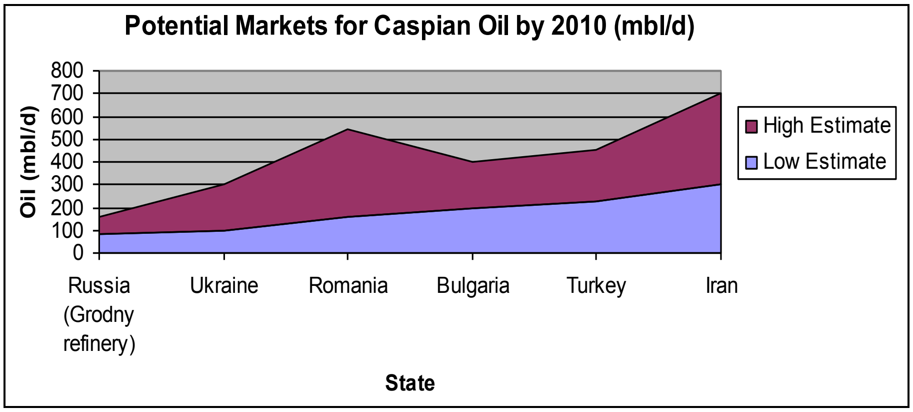
Azerbaijan will supply 20 bcm/y for the Nabucco pipeline. Its oil and natural gas production is regulated by the several contracts:

1. the "Contract of the century" was signed in 1994. This contract between AIOC (Oil companies led by the British Petroleum Company BP) and the State Company of Azerbaijan Republic, SOCAR with an initial expected

production of 80,000 barrels per day and peak production of 800,000 barrels per day. Investors are American Amoco (17%), Pennzoil (4.8%), Unocal (9.5%), Exxon (5%), Russian Lukoil (10%), Norwegian Statoil (8.5%), Japanese Itochu (7.45%), British Ramco (2%), Turkish TPAO (6.75%), Saudi Arabia's Delta (1.6%), and the Azerbaijani state oil company, SOCAR, (10%).

2. In June 1995 the Contract for Karabakh was signed which contains the production of 85-120 million tonnes of oil of the Karabakh field.
3. The Shah Deniz contract of 1996 involves Lukoil with 10% in the production.
4. In 1996 a contract was signed with US, Japanese and Saudi Arabian companies to develop the Dan Ulduzu and Ashrafi offshore fields.
5. The Contract for the Lenkoran-Talysh Deniz of 1997 involves SOCAR and French companies (Gökay 1998).
6. Iran and Turkmenistan signed a 25-year contract that provides Iran with natural gas (5 – 6 bcm/y).

Iran could contribute 30 bcm/y to the Nabucco pipeline but the USA undermines the attractiveness of Iran through sanctions. Malaysia and China are interested in an Iranian import of oil (400,000 – 500,000 bbl/d) if the US sanctions are lifted (Moradi 2006). Non-Caspian Basin states have different interests in the development of markets. Turkey will generate transit fees from shipment and pipelines over its territory. Japan already imports natural gas and India's and Pakistan's energy consumption will grow with its growing population. China's increasing economy and its oil consumption makes the Caspian region an attractive energy market.



Potential Markets for Caspian Oil by 2010 (million barrel / day)		
State	Low Estimate	High Estimate
Russia (Grodny refinery)	80	80
Ukraine	100	200
Romania	160	380
Bulgaria	200	200
Turkey	226	226
Iran	300	400
TOTAL	1,066	1,486

Figure 19: Potential markets for Caspian oil by 2010 (Planecon, 2000)

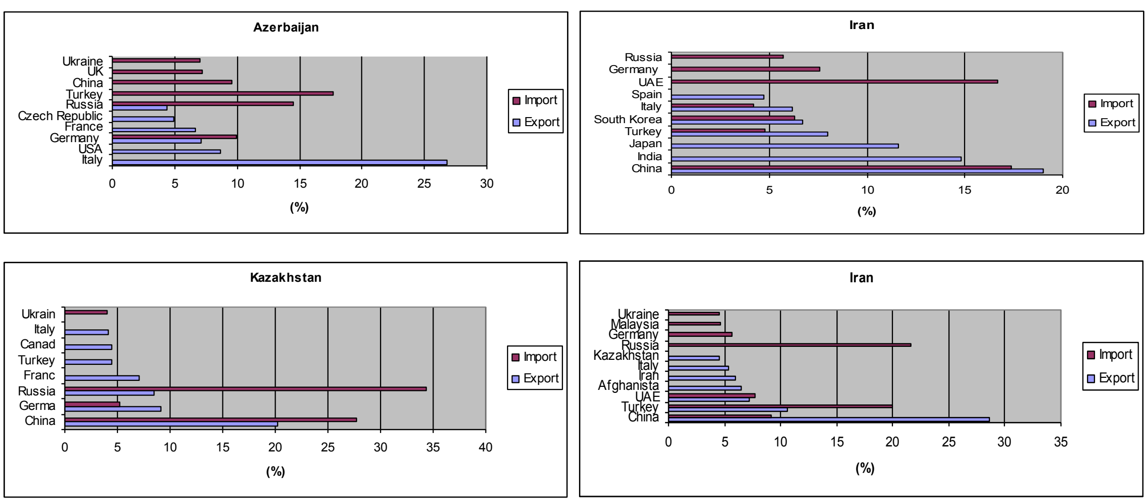


Figure 20: Oil and gas import and export from/to Caspian states (CIA World Factbook, 2010).

Table 9: Import and export commodities of the Caspian region (CIA World Factbook, 2010)

Azerbaijan		Iran		Kazakhstan		Turkmenistan	
Export	**Import**	**Export**	**Import**	**Export**	**Import**	**Export**	**Import**
oil and gas 90%	machinery	petroleum 80%	industrial supplies	oil and oil products 59%	machinery	gas and crude oil	machinery
machinery	oil products	chemical and petrochemical products	capital goods	ferrous metals 19%	metal products	petrochemicals	chemicals
cotton	foodstuffs	fruits and nuts	foodstuffs and other consumer goods	chemicals 5%	foodstuffs	textiles	foodstuffs
foodstuffs	metals	carpets	technical services	machinery 3%		cotton fiber	
	chemicals			grain, wool, meat, coal			

VI.3.3. Geopolitics

VI.3.3.1. Legal Situation

The last document regulating the Caspian Sea’s legal status was the 1940 Soviet-Iranian treaty. It awarded each signatory an "exclusive right of fishing in its coastal waters up to a limit of 10 nautical miles”. Furthermore, the parties decided that the Caspian belongs to Iran and to the Soviet Union. “However, these treaties cannot be used to define the status of the Caspian, for these documents only applied to navigation and fishing, and not to the problem of the exploration of mineral resources” (Gökay 1998:p. 3).

Since the 1991 collapse of the Soviet Union, the legal issues occupy the Caspian politics. The 1982 U.N. Convention on the Law of the Sea defines the Caspian Sea as "a special inner sea." There are four different positions with respect to the legal status of the Caspian Sea:

1. “Border Lake”
2. “Open Sea”

3. Caspian Sea divided into Economic Zones.
4. “Joint Exploration”.

The first position “Border Lake” declares that “each sector will be considered and categorised as „territorial waters“ belonging solely to the state concerned” (Gökay 1998: p.4). Based on the United Nations’ Convention on the 1982 Law of the Sea, the Caspian Sea is defined as „Open Sea“ and each state has a 12-mile territorial water limit. According to position 3, the Caspian Sea should be subdivided into economic zones, which are equidistant from points on opposing shorelines. Finally, the Caspian should be treated as a “Giant Lake”, which should be explored together (“Joint Exploration”). Russia and Iran favour the positions two and four. Azerbaijan, Kazakhstan and Turkmenistan treat the Caspian as a sea, that should be divided into sectors (Position one and three). “However, Turkmenistan insists that no development should take place on subsoil gas and oil deposits on disputed territories until a final multilateral agreement is reached” (Mahnovski 2002: p.139). The different views on the Caspian Sea cause many conflicts. For example, on July 23, 2001 a BP research operation was threatened by Iranian gunboat due to a dispute of Iran and Azerbaijan about territorial waters (Mahnovski 2002).

VI.3.3.2. Geopolitics of Caspian Basin Countries

Iran’s unique geographic position promotes it as a transit country for pipelines to the global market. Moreover, Iran seeks for more political influence in CEA. But Iran is in conflict with the USA. The USA accuses Iran of developing nuclear weapons and supporting radical Islamic groups. Furthermore, Iran has some economic problems, suffers internal political struggle and failed to introduce a democratisation process (Amineh 2003). Officially, Iran declares itself neutral in conflicts between Caspian region’s states. For its trade relations and independence Iran favours a pipeline from Baku, Azerbaijan to Neka, Iran. Iran tries to secure its domestic pipeline network.

Kazakhstan, Azerbaijan and Turkmenistan struggle for economical independence from Russia, prosperity and technical progress. “Although the CEA countries still depend on the Russian economy and military assistance, their main aim is to distance themselves from Russia" (Amineh 2003: p.4).

Russia's objective is to preserve economic, political, cultural and military influence. The control of Caspian oil and gas resources and transport are a main goal. Through regional cooperation and support, Russia tries to maintain this influence. Russia enters strategic cooperation with regional powers, like Iran and China (Amineh 2003).

VI.3.3.3. Geopolitics of Foreign Countries (European Union, USA, China)

Geopolitical interests of foreign countries in the Caspian region depend on energy developments and initial situations (Figure 21). The European Union seeks for stability on its eastern border for commerce and energy supply and supports peacekeeping activities. But Britain, France and Germany have diverging interests due to different energy developments and resources.

Stakeholders in Caspian Energy Developments

Stakeholder	Objectives	Actions
Private industry	• Maximum long-term profits • Manage risk	• Develop economically viable infrastructure • Promote government subsidies • Hedge by waiting
Energy-rich, but infrastructure-poor states (i.e., Azerbaijan, Kazakhstan, Turkmen-istan)	• Maximum revenue stream • Energy independence and political clout • Maintain power	• Attract foreign direct investment • Secure lucrative foreign markets
Energy and infrastructure-rich states (i.e., Russia, Iran)	• Maintain status quo and market power over transport	• Undermine competing projects • Upgrade existing infrastructure, lower tariffs
Pure transit states (i.e., Georgia)	• Steady revenues • Reliable and affordable supply	• Maximum transit fees without alienating project on its territory
Energy-poor neighbors (i.e., Turkey)	• Cheap, secure supply with as many routes as possible	• Support several options • Overestimate demand • Guarantee cost overruns
United States	• Promote former Soviet Union independence • Bolster non-OPEC supply • Support U.S., companies	• Support multiple pipelines through pro-U.S. countries

Figure 21: Stakeholders in the Caspian Region (Mahnovski 2002)

Britain has its own oil and gas resources. France meets its energy needs through nuclear power. Only Germany depends on significantly imports. Due to this divergence, the European Union has taken only little interest in the Caspian region. But the interest is growing, partly to reduce dependence on Russia (Amineh 2003).

The USA has three mayor interests in the Caspian region (Shaffer 2003: p.1):

1. Preserving the independence and security of the new states of the region.
2. Development of energy and transport lines on an east–west corridor.
3. Denying Iran and other potential proliferators’ sources in the new states of technology, materials and scientists which can be used to advance their WMD (Weapon of Mass Destruction) programs.

The USA’s further goal is to secure its dominant position in CEA (post-Soviet Central Eurasia). Thus their global strategy is to preserve the control and security of world oil and gas resources. Further, the US tries to break Russia’s dominating position in the Caspian region and to establish a basic infrastructure. “Since September 2001, the US has also seen the Caspian region as an important component in its anti-terrorism policy” (Shaffer 2003: 1). Moreover, they try to prevent the construction of pipelines through Russian or Iranian territory by sub-regional agreements (GUUAM) (Amineh (2003). The military aid of the US aims at supporting local powers and preparing for possible intervention (Klare 2008).

China sees the Caspian region as an energy source of future supply. It is interested in the construction of eastward pipelines to its territory. But China has an open conflict with the USA. Moreover, China is interested in Russia as the main player in CEA. China and Russia supply arms to oil and gas producers in the developing world and have started to enhance their military capacity in key energy-producing areas (Algeria, Angola, Chad, Nigeria, Zimbabwe, South Africa) to secure their energy demands (Klare 2008; Amineh 2003). They are willing to expand their influence in the Caspian region as well.

VII. Conclusion

The sedimentary basins of the Caspian Region are some of the deepest basins in the world with depths up to 20 km. They occur in offshore and onshore areas and have great dimensions. The basins were formed in a wide variety of tectonic and sedimentary processes including rift movement, foreland uplift, alluvial terrestrial sedimentation and lots of more processes. The source and reservoir rocks range in age from Proterozoic to Tertiary with major source rocks in Devonian to Permian, Cambrian and Oligocene – Lower Miocene (Maykop) age. Both, sandstone and carbonate reservoirs occur in the Caspian region. In the South Caspian basin the main reservoirs are in clastic sediments whereas the main carbonate reservoirs are located in the North Caspian basin. Future production plans, especially for the South Caspian Basin, are highly recommended. The relationship between geopolitics, economics and technology, which is the basis of oil and gas industry, is very complex. Long-term security of supply and appropriate prices are the desired future options. But increasing domestic demands in the Caspian countries, insufficient transport infrastructure and lack of confidence in the stability of the states are potential barriers for future development.

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VII. CCS and Emissions Trading

Meike Kurth, Mirjam Rahn, Christoph Wohlgemuth

VII.1. Introduction

Carbon capture and storage (CCS) may become an important method to reduce anthropogenic CO_2 emissions to the atmosphere. Since 1990 research began worldwide to search for potential storage units (sdgg Heft 74, S. 10) CO_2 emissions are estimated to triple from 20.6 Gt in 1990 to 62 Gt in the year 2050 (Baseline scenario by iea 2008). Different scenarios have estimated the CCS contribution in 2050 to CO_2 emission reduction to an average of 23% in the electricity generation and 27% in the industry sector.

VII.2. Carbon capture and storage

Carbon capture and storage has the aim to capture CO_2 from power generation or other industrial sector to store it away from the atmosphere. The CO_2 is separated from other gases and then being transported to a permanent storage facility (IPCC, 2005).

VII.2.1. Emission trading

Emissions trading, as set out in Article 17 of the Kyoto Protocol, allows countries that have emission units to spare - emissions permitted them but not "used" - to sell this excess capacity to countries that are over their targets. (United Nations)

VII.2.2. Clean development mechanism

The Clean Development Mechanism (CDM), defined in Article 12 of the Protocol, allows a country with an emission-reduction or emission-limitation commitment under the Kyoto Protocol (Annex B Party) to implement an emission-reduction project in developing countries. Such projects can earn saleable certified emission reduction (CER) credits, each equivalent to one metric ton of CO_2, which can be counted towards meeting Kyoto targets. (United Nations)

VII.2.3. Joint implementation

The mechanism known as “Joint Implementation” (JI) defined in Article 6 of the Kyoto Protocol, allows a country with an emission reduction or limitation commitment under the Kyoto Protocol (Annex B Party) to earn emission reduction units (ERUs) from an emission-reduction or emission removal project in another Annex B Party, each equivalent to one ton of CO2, which can be counted towards meeting its Kyoto target (United Nations).

VII.3. Greenhouse effect

The simple picture in Figure 1 describes the main and most important issues of the greenhouse effects we have to be aware of. The physical changes in climate will affect humans, animal, plants and the Earth as we know it today. The main CO_2 emitters as seen in figure 2 play a major role to the greenhouse effects. Lowering the emission, especially considering the different sectors regarding its necessity should be a main goal to fight the climate warming.

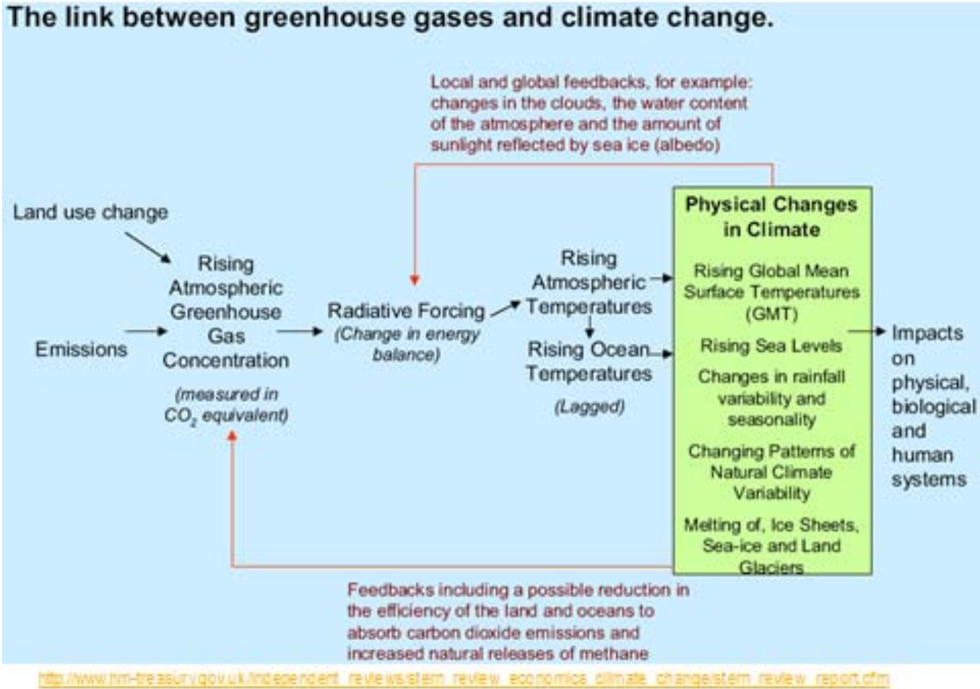

Figure VII-1: Greenhouse Effect

(http://www.hm-treasury.gov.uk/media/986/CC/sternreview_report_part1.pdf)

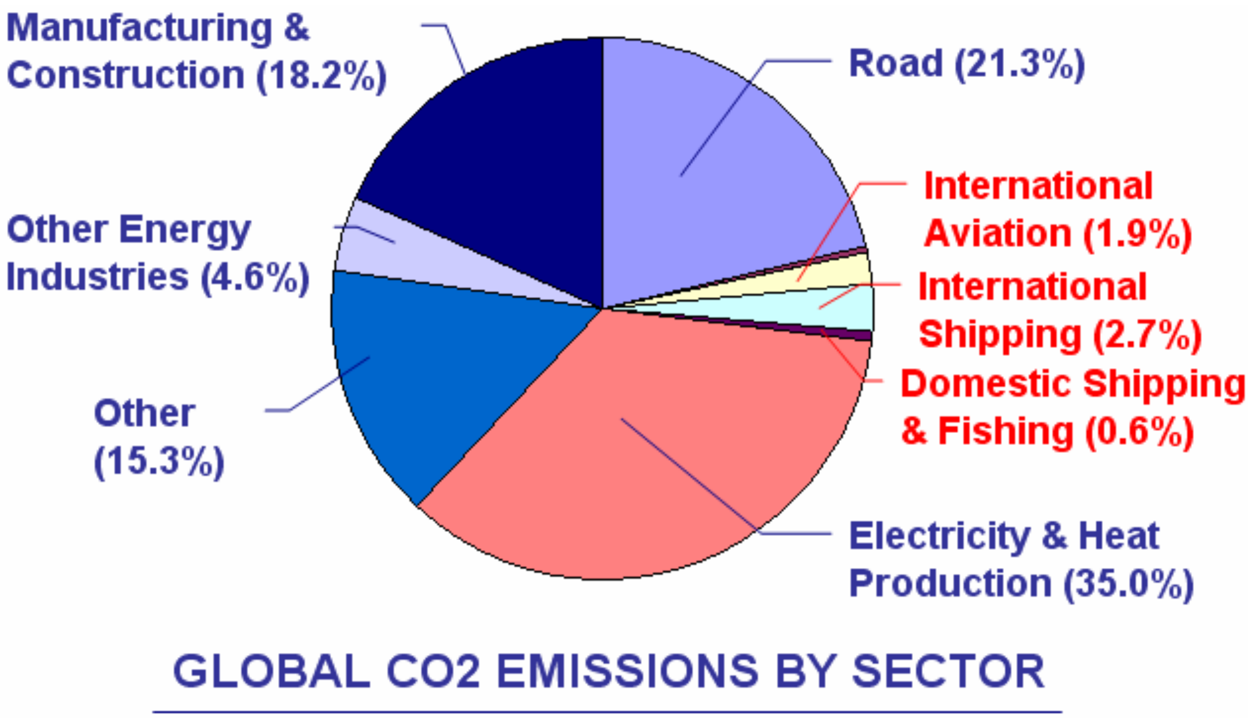

Figure VII-2: Diagram of main CO2 emitters by sector (IEA.org, 2012)

VII.3.1. Hockey stick diagram

The hockey stick diagram is a graph based on research data of the estimated temperature record of past centuries. In 1998 the scientists Michael Mann, Raymond Bradley and Malcom Hughes published a paper called "Global-scale temperature patterns and climate forcing over the past six centuries" in which the hockey stick graph was shown.

They used preserved physical evidence of the past to reconstruct earth climate conditions and its history. These evidences are called climate proxies such as gas bubble and the $\delta^{18}O$-value, which relies on fracturing during gas and liquid phases in ice-cores, with an ancient composition of the atmosphere at the time of their formation or pollen grains in sea-sediments, which show indirect the climate conditions. These temperature reconstructions produced by combined proxies are longer than instrumental records and are used to evaluate earth temperature history and ongoing trends, which lead to the discussion of global warming.

With the hockey stick diagram and the first clues to a global warming, the main author of the paper Michael Mann was a target to various attacks such as inquiry into allegations regarding research integrity, including allegations of research misconduct.

The graph was featured prominently in the 2001 Third Assessment Report of the United Nations Intergovernmental Panel on Climate Change, also known as IPCC as supporting the mainstream view of climate scientists that there had been a relatively sharp rise in temperatures during the second half of the 20th century. It became a focus of dispute for those opposed to this strengthening scientific belief. The term became famous because of the climatologist J. Mahlmann to describe the circumstance, envisaging a graph that is relatively flat to 1900 and increases afterwards.

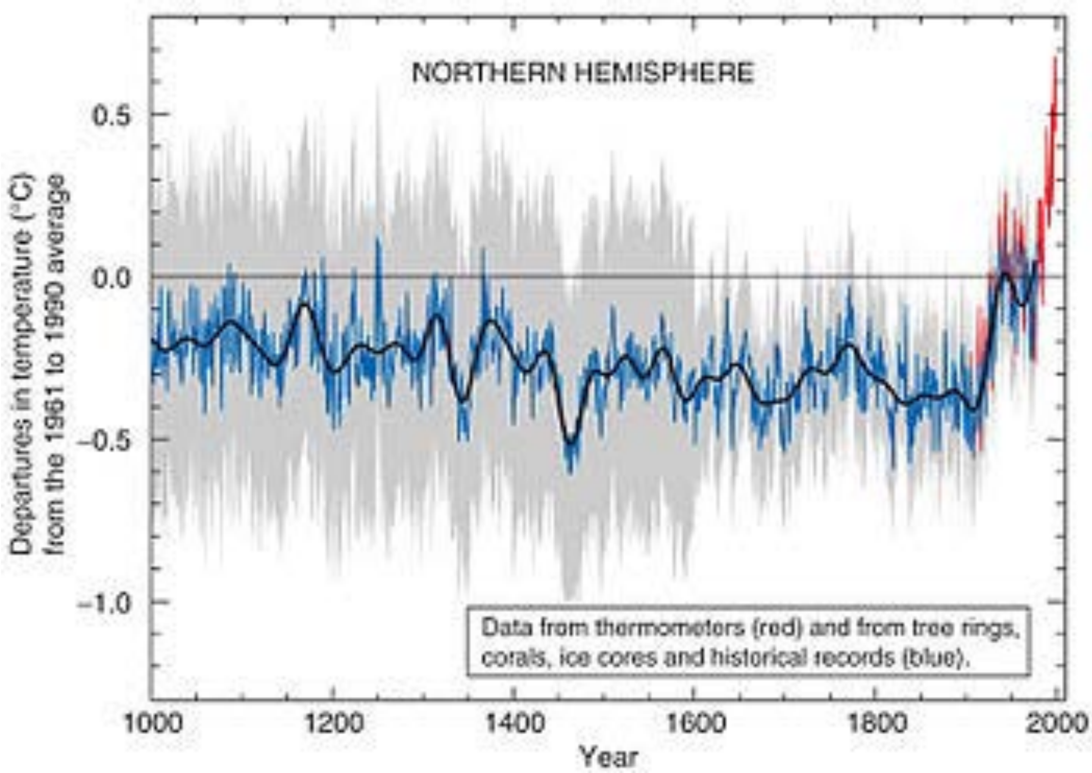

Figure 2: Hockey Stick Diagramm (IPCC, 2005)

More than twelve subsequent scientific papers, using various statistical methods and combinations of proxy records, produced reconstructions broadly similar to the original MBH hockey-stick graph, with variations in how flat the pre-20th century "shaft" appears. Almost all of them supported the IPCC conclusion that the warmest decade in 1000 years was probably that at the end of the 20th century (Pearce, 2010).

VII.3.2. Consequences (for nature)

As seen in figure 1 above in chapter VII.3.1 there are certain links between the rise of greenhouse gases and consequences for nature. First of all, the rise of atmospheric greenhouse gases such as carbon dioxide changes the radiative force. By increasing the amount of greenhouse gases into the atmosphere the less sunbeams, which – simplified - equals energy in this scenario, can reach the earth, because there is a higher rate of backscattering due to their molecular behavior of these gases. Hence, the beam which reaches Earth`s surface and usually gets reflected out of the atmosphere is trapped by the same gases. This changes the energy balance of the Earth, leads to different physical circumstances on Earth and therefore the climate change.

There are certain main problems which come along with a rise of carbon dioxide. For example the amount of CO_2 absorbed by the oceans will decrease with every degree the average water temperature rises due to various biological, chemical and physical processes. One scenario is that, carbon dioxide absorbing (micro-) organisms are likely to be damaged or lack of functioning by a higher temperature, which can lead to a acidification *(http://www.hm-treasury.gov.uk/media/986/CC/sternreview_report_part1.pdf).*

Main factors of climate change:

- Rising global mean temperature
- Rising sea level
- Changes in rainfall – variability/seasonability
- Changes of natural climate variability
- Melting of ice - ice sheet, glacier

For humans this leads to following situation. The risks of floods are increasing, especially for the people living near the coastal line and/or in lower regions/islands. Therefore, the ongoing trend, settling down at the coast comes along - even in the developed countries – with a risk. In southern Europe as well as North America heat waves are more likely to occur, which comes along with an expansion of heat-related diseases such as Malaria. But, precipitation will appear on higher latitudes.
About ¼ of all animal and plant species is in danger of extinction and this will have a great impact on humans *(IPCC, 2007).*

VII.4. Economy

VII.4.1. Costs of global warming effects

It is difficult to calculate accurately the costs of climate change but it could be said that global warming will have a major influence on global economics in the future. Therefore it is important to differentiate between developed and undeveloped countries together with the global location of the country. Hence, these different aspects will be discussed in the following. On the one hand climate change will have some positive effects for a few developed countries for moderate amounts of warming (not more than 2 or 3°C), but will become dramatically damaging at the higher temperatures that are forecasted for the second half of this century. Developed Countries located in higher latitudes such as Canada, Russia and Scandinavia could profit from climate change due to higher agricultural yields, lower winter mortality, lower heating requirements and a potential grow in tourism. This is the case due to moderate climate change. But on the other hand developed countries in lower latitudes will be more vulnerable. This is the case in regions where water is already rare, it will cause serious difficulties to provide enough abundances of water and will lead to rising costs (e.g. seawater desalination). *Schröter et al. (2005)* suggests a 2°C rise in global temperatures may lead to a 20 – 30% reduction in water ability in Southern Europe. Water availability will generally rise in higher latitude regions where rainfall becomes more intense. But regions with Mediterranean-like climates will have existing pressures on limited water resources exacerbated because of reduced rainfall and loss of snow/glacial meltwater.

Although slightly increasing temperatures have a big influence on harvest. While agriculture is only a small component of GDP in developed countries (1-2 % in USA) it is the complete difference in not developed countries e.g. Somalia which GDP accounts for 60 % to agriculture. Hence, due to the fact that agriculture is highly sensitive to climate change it could have a dramatically impact on the GDP of not developed countries which are commonly very poor. Furthermore famines will be ineluctably such as in Somalia in 2011.

In terms of energy consumption climate change has to be observed differentiated because of the different energy use due to the latitude the country is located. Thus, climate change will result decreasing heating demands in winter periods for countries located in higher latitudes, while increasing summer cooling demands. In lower latitude countries overall energy use is expected to increase dramatically due to increasing air-conditioning demands. If we look at Qatar which has the highest energy use per capita with 26.7 tons oil equivalent caused by enormous cooling demands because of the high average temperature. In the case of Italy *(www.cru.uea.ac.uk)* calculates 20% decreasing winter energy use for a warming of 3°C globally, while summer energy use increases by 30%.

The most important and most expensive aspect in terms of climate change is the increasing rate of extreme weather events such as storms, floods, droughts and heat waves (Fig 3). These events lead to significant infrastructure damages such as due to the hurricane Katrina, which was the costliest extreme weather event in known history. Since 1990 the costs are constantly increasing with annual losses of around 60 billion dollar in the 1990s (0.2 % of World GDP) to record costs of 200 billion dollar in 2005 (0.5 % of World GDP). Muir-Wood *et al.* (2006) found out based on insurance industry data that weather-related catastrophe losses have increased by 2% each year since 1970 if this trend will continue due to rising global temperatures, losses from extreme weather events could reach 0.5 to 1 % of world GDP by the middle of this century.

Example Hurricane Katrina:

As mentioned before extreme weather events occur with higher frequency and intensity due to rising temperatures. The costliest weather catastrophe on record was Hurricane Katrina in 2005 with a total of 125 billion in economic losses (1.2 % of US GDP) *(Munich Re, 2005*). As a result of the weather event about 1200 people died and over 1 million people lost their homes and had to be displaced. These enormous losses and fatalities were caused by the extreme power of the Hurricane, which were classified as Category 5 Hurricane (Categories range from 1 (small) to 5 (most severe). Most scientists agree that the Hurricane got this extreme force (peak gusts of 340 km per hour) concerning the exceptionally warm waters of the Gulf region (1-3°C above the long term average) were the Hurricane passed through on its way to Louisiana.

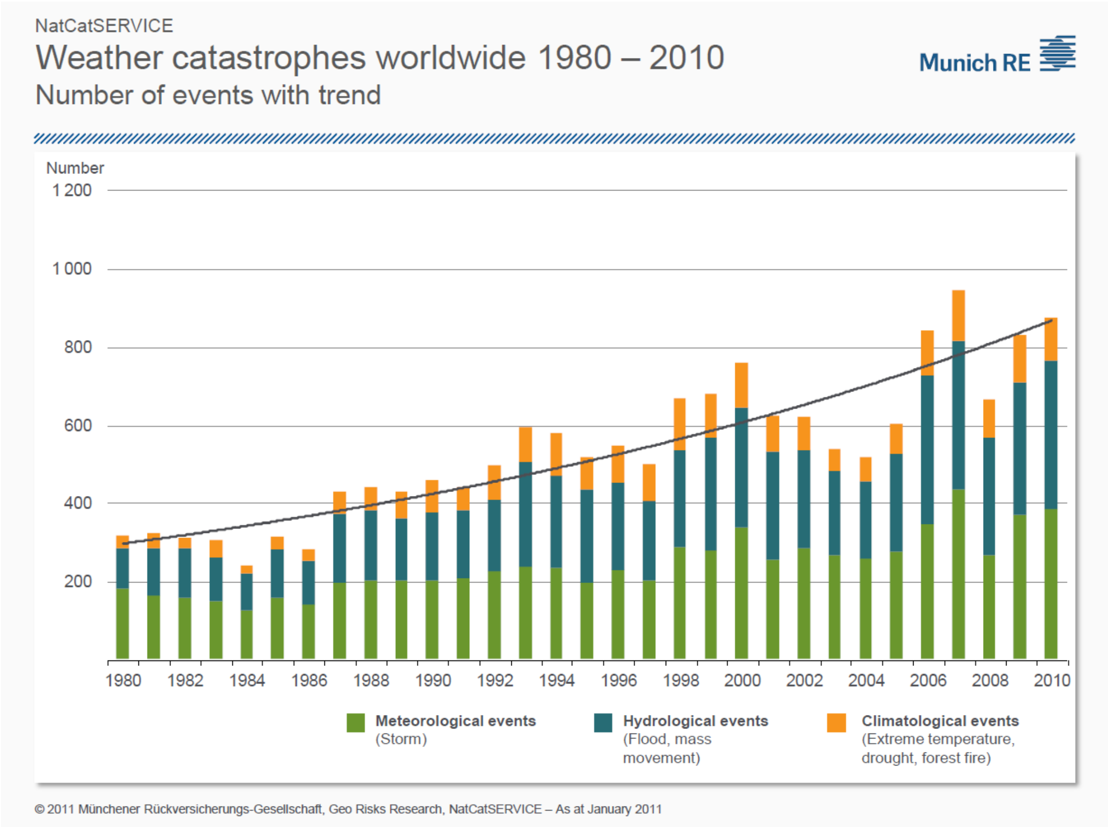

Figure 3: Weather catastrophes worldwide *(Munich Re, 2010)*

VII.4.2. Costs of avoidance of CO_2 emissions

Due to the increasing CO_2 emissions in recent years it is necessary to build new power plants which have the technology to avoid CO_2 emissions such as Carbonate Capture and Storage or new CO_2 filters to reduce sustainable greenhouse emissions and reach the targeted limits. However, power plant construction costs have significantly increased in the last five years unaffected by the technology which is used. Today total electricity generation costs including CCS technologies are about 74 to 100 % higher than for conventional steam cycles without CCS capture. This may reduce to 30 to 50 % higher costs in the longer term if the technology is matured *(IEA, 2008)*. Today electrical energy from Capture and storage power plants will cost about

150 $ per ton CO_2 mitigated. It has also be taken into account that the costs of capturing CO_2 depend on the type of power plant which is used (fig.5) including the overall efficiency and the Co2 capture energy requirements. All in all the operating costs of CCS capturing power plants increase by 50 to 100 % compared to those without the CCS technology.

Cost of electricity and CO_2 avoidance

Fuel	Power generation technology	CO_2 capture technology	\$1.1/GJ coal, \$3.9/GJ gas		\$2.2/GJ coal, \$7.8/GJ gas	
			c/kWh	\$/t CO_2 avoided	c/kWh	\$/t CO_2 avoide
Coal	Pulverised fuel	None	4.46		5.36	
		Post-combustion, Fluor	6.34	30	7.49	34
		Post combustion, MHI	6.27	28	7.40	31
		Oxy-combustion	6.63	33	7.76	36
	IGCC (Shell)	None	4.88		5.81	
		Pre-combustion, Selexol	6.52	33	7.68	39
	IGCC (GE)	None	4.55		5.60	
		Pre-combustion, Selexol	5.66	20	6.94	27
Gas	Combined cycle	None	3.70		6.23	
		Post-combustion, Fluor	5.07	44	8.03	58
		Post-combustion, MHI	4.93	39	7.76	48
		Oxy-combustion	6.84	85	9.98	102

Figure 4: Cost of Electricity (*Ram et al. 2002)*

Table SPM.3. Costs of CCS: production costs of electricity for different types of generation, without capture and for the CCS system as a whole. The cost of a full CCS system for electricity generation from a newly built, large-scale fossil fuel-based power plant depends on a number of factors, including the characteristics of both the power plant and the capture system, the specifics of the storage site, the amount of CO_2 and the required transport distance. The numbers assume experience with a large-scale plant. Gas prices are assumed to be 2.8-4.4 US\$ per gigajoule (GJ), and coal prices 1-1.5 US\$ GJ^{-1} (based on Tables 8.3 and 8.4).

Power plant system	Natural Gas Combined Cycle (US\$/kWh)	Pulverized Coal (US\$/kWh)	Integrated Gasification Combined Cycle (US\$/kWh)
Without capture (reference plant)	0.03 - 0.05	0.04 - 0.05	0.04 - 0.06
With capture and geological storage	0.04 - 0.08	0.06 - 0.10	0.05 - 0.09
With capture and EOR[17]	0.04 - 0.07	0.05 - 0.08	0.04 - 0.07

Figure 5: Cost of CCS *(IPCC,2005)*

VII.5. Emission trading

Several of “so called” flexible mechanisms were included into the Kyoto Protocol to support a cost-effective allocation to attenuate climate change. One of those flexible mechanisms is emission trading which is a market based approach to regulate carbon dioxide pollution by providing economic incentives for achieving a reduction of emissions for pollutant countries.

Initially, a regulatory agency limits the overall level of emissions, either by setting standard or allocating emissions, and then it allows countries to trade their emission allocations or surplus permits *(Rubin, 1995)*.This model takes on the successful analog instrument for SO_2 emissions established in the United States. Europe has emerged as a leader in the emissions trading industry with the EU Emission Trading System (ETS) being the world's largest single market for CO2 emission allowances accounting for approximately 98% of the global transactions for 2007. In 2010 the EU ETS covers about 11,000 power stations and industrial plants in 30 countries. The principle of emission trading is that every pollutant has an allowance (certificate) for every emitted CO_2 unit. If a country doesn't need the complete amount of units it can sell their surplus to other countries which have to cover their lack of CO_2 certificates. Due to the equilibrium of the market a price for one CO_2 unit develops which reflects the costs to reduce this amount of emissions (Fig. 6). The transactions globally for 2007 exceeded 2.1 billion tons of CO_2 worth which is approximately $50.394 billion *(IETA, 2008*). The number of allowances is reduced over time so that total emissions fall. The EU ETS plan arranges for 2020 emissions will be 21% lower than in 2005. The European Emission Trading System provides for three carbonate auctions phases. During the first trading period (2005 to 2007) the member states have the allowance to trade only very limited quantities of carbon certificates, and also during the second trading period (2008 to 2012) the major share of carbon allowances will still allocated for free. From the start of the third trading period in 2013 about half of the allowances are expected to be auctioned. The auctioning method was chosen because it is the most transparent allocation method that allows market participants to acquire the allowances concerned at the market price.

Positive aspects:

Due to the fact of different CO_2 avoidance costs between the different pollutant countries international emissions trading leads to the beneficiation of costs. Hence, by means of the EU ETS some countries were actuated to implement actions to reduce their CO_2 emissions in excess of the guidelines

of the Kyoto Protocol. This will be achieved by selling not required CO_2 units. The object of Emission Trading is to minimize the CO_2 avoidance costs to make CO_2 reduction attractive and receive the goals of the Kyoto Protocol.
Another important fact is that there is the opportunity that not only a small group of the Annex 1 Countries (Industrialized Countries) is compromised in Emission Trading but another group of not Annex 1 countries were included. These developing countries can have benefits by reducing their emissions in terms of funding, transfer of technology, development assistance and the reduction of local pollution. The most important benefits of ETS are flexibility and cost effectiveness. The ETS now operates in 30 countries (the 27 EU Member States plus Iceland, Liechtenstein and Norway). It covers CO_2 emissions from installations such as power stations, combustion plants, oil refineries and iron and steel works, as well as factories making cement, glass, lime, bricks, ceramics, pulp, paper and board.
Nitrous oxide emissions from certain processes are also covered. Between them, the installations currently in the scheme account for almost half of the EU's CO_2 emissions and 40% of its total greenhouse gas emissions.

Negative aspects:
One of the negative aspects is the opportunity for richer countries to buy one's way out of the responsibility instead of reducing their Co_2 emissions. There is the question if it is morally correct to pay the poorer countries out to defend domestic industries for example steel or electricity industries which are large scale greenhouse gas emitters.
Another negative aspect is that in the first period to many CO_2 units were allocated so that the price was too low for one CO_2 unit so that it was more profitable to buy the missing certificates instead of reducing CO_2 emissions.
Furthermore there is a problem called „trading with hot air" which means that due to the economic collapse of the USSR and the slowly growing industry these countries fall below the value of the Kyoto Protocol and could trade their certificates without doing anything to avoid their emissions. The result would

be that globally the emissions grew caused by emission trading. Hence, this is contrary to the idea of the Kyoto Protocol.

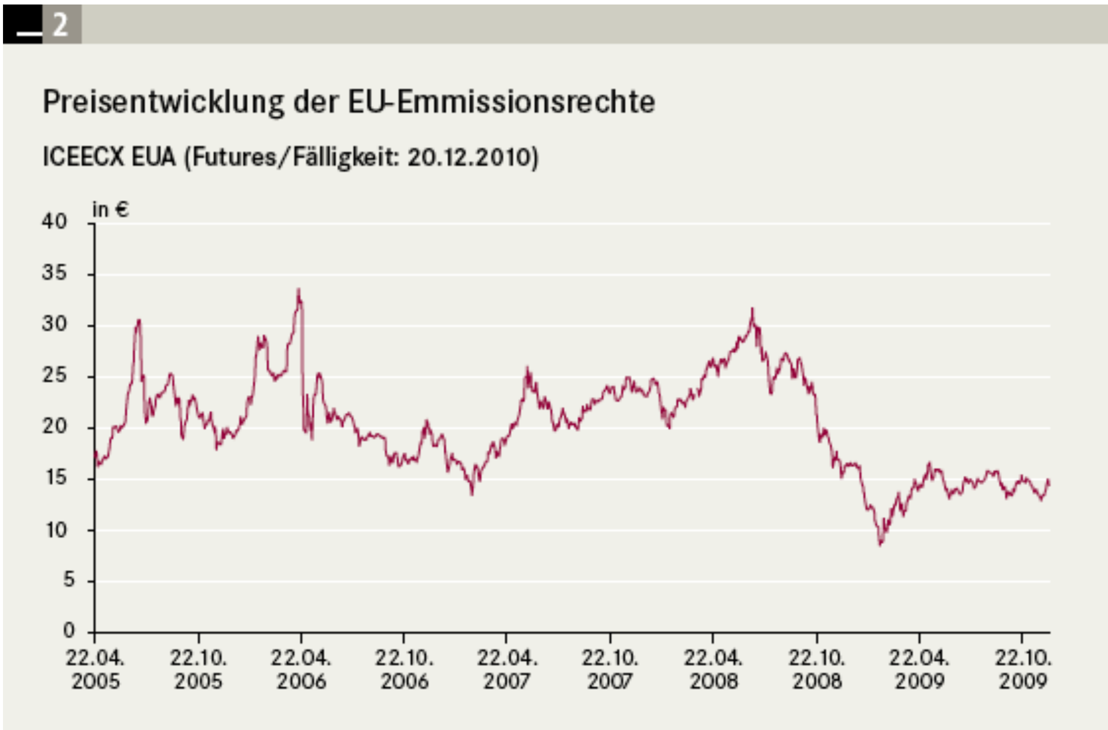

Figure 6: Price development of emissions trading in Europe *(http://www.die-bank.de/finanzmarkt/images/022010/FM_022010_01_02.gif)*

VII.6. Kyoto protocol

The Kyoto Protocol is an international agreement linked to the United Nations Framework Convention on Climate Change. The major feature of the Kyoto Protocol is that it sets binding targets for 37 industrialized countries and the European community for reducing greenhouse gas (GHG) emissions .These amount to an average of five per cent against 1990 levels over the five-year period 2008-2012.

The Kyoto Protocol was adopted in Kyoto, Japan, on 11 December 1997 and entered into force on 16 February 2005. The detailed rules for the implementation of the Protocol were adopted at COP 7 in Marrakesh in 2001, and are called the “Marrakesh Accords.”

VII.6.1. History and outcome

In 1988 a first step was made on the way to the Kyoto protocol with a semi political conference held in Toronto. This was the first time a debate was focused on global warming and regulations of CO_2 emissions were discussed. At the end of the debate the parties recommend in a first step to reduce the CO_2 emissions about 20 per cent from the 1988 level by 2005. This “Toronto target” was arbitrary, but the idea that countries should commit to meeting a target for CO_2 emission reduction was born.

In the same year the Intergovernmental Panel on Climate Change (IPCC) was founded by the UN General Assembly. The IPCC was commissioned to report about climate change, potential impacts of climate change and possibilities to avoid climate change. The IPCC’s first assessment report, published in 1990, concluded that ‘emissions resulting from human activities are substantially increasing the atmospheric concentrations of the greenhouse gases and will enhance the greenhouse effect, resulting on average in an additional warming of the Earth’s surface *(IPCC, 1990*). The report concluded that the greenhouse gases need to be reduced by 60 per cent to stabilize the CO_2 level of 1990 otherwise the global temperature would rise about 0.2 to 0.5 °C per decade in the future.

After the IPPC´s report publication some OECD Countries, the European Community and several other Countries (e.g. Japan, USA, Canada, and Australia) pledged to reduce or stabilize their CO_2 emissions by the level of 1990. Germany announced the most radical target to reduce their emissions of 25 to 30 per cent from the 1987 level by 2005. But all in all at this time there were no uniform and binding regulations.

In 1992 at the Rio Earth Summit negotiations on the Climate Change Framework ended in an agreement that was signed by more than 150 countries except the United States. But it did not commit any signatories to meeting specific targets or timetables, Article 4 of the agreement implied that developed country parties recognize ‘that the return by the end of the present decade to earlier levels of anthropogenic emissions of carbon dioxide and other greenhouse gases’ would be desirable. It also implied the aim of returning individually or jointly to their 1990 levels of these anthropogenic

Emissions. As a result of these gentle agreements it was signed by so many countries and was implemented quickly.

In 1995 the IPCC took Aerosols into account in the climate models and revised their previous publications and rectified the increase of the global mean temperature by 0.14 to 0.28 °C per decade, which is more moderate than the previous prediction. Aerosols are very small floating particles which were released by burning fossil fuels (e.g. jet blast), leading to a local cooling effect. However, there is still a conspicuous anthropogenic influence on the climate.

On the 28th of March the first United Nations Framework Convention on Climate Change was held in Berlin. This Conference was a milestone for the debate of Climate Change, because all industrialized countries agreed to negotiate CO_2 emission limits within concrete time frames (2005, 2010 and 2020), called the Berlin mandate. These quantitative ceilings were to be included in a new protocol that might be ready for signing by the end of 1997. However, there was a drop of bitterness due to the fact that developing countries were excluded to limit their CO_2 emissions, what leaded the United States later refuse to sign the Kyoto Protocol.

Outcome:

To enter into law, and therefore to become binding on the countries that are parties to it (but not other countries), the Protocol must be ratified by at least 55 countries, responsible for at least 55 per cent of the total carbon-dioxide emissions of the so-called ‘Annex I’ countries. Developing countries are excluded from the protocol. With the late ratification of Russia in 2004 the basic conditions were fulfilled, however USA that is responsible for more than 35 per cent of the whole CO_2 emissions rejected to ratify the protocol. Until today (2012) 191 countries signed and ratified the Protocol. In Figure 7 the emission reduction target of the G8 countries is compared with the real emission reduction in year 2007. Due to the fact that the Kyoto Protocol expires 2012 a succession plan has to be negotiated.

Durban outcome:

The outcome of the Durban climate conference was seen critically by several environmentalists in contrast to the members of the conference who declared the outcome as a milestone to reach a succession plan for the Kyoto Protocol including the big pollution countries USA, China and India (Fig. 9). The bottom line is that there is no binding agreement signed by the negotiating countries but a time-table for the elaboration of a succession plan until the next climate conference in Qatar in 2011. The individual reduction targets of the countries have to be included in the agreement by the end of the year 2012. Furthermore until 2015 a binding agreement has to be reached with emission targets including the big pollutants USA, China and India. But a directly legally binding is discussed controversial with no outcome so that further negotiations have to be done. The only achievement which was reached is an installation of the Green Climate fund by the year 2020 with an annual volume of 100 billion dollar provided for undeveloped countries to prepare for the climate change.

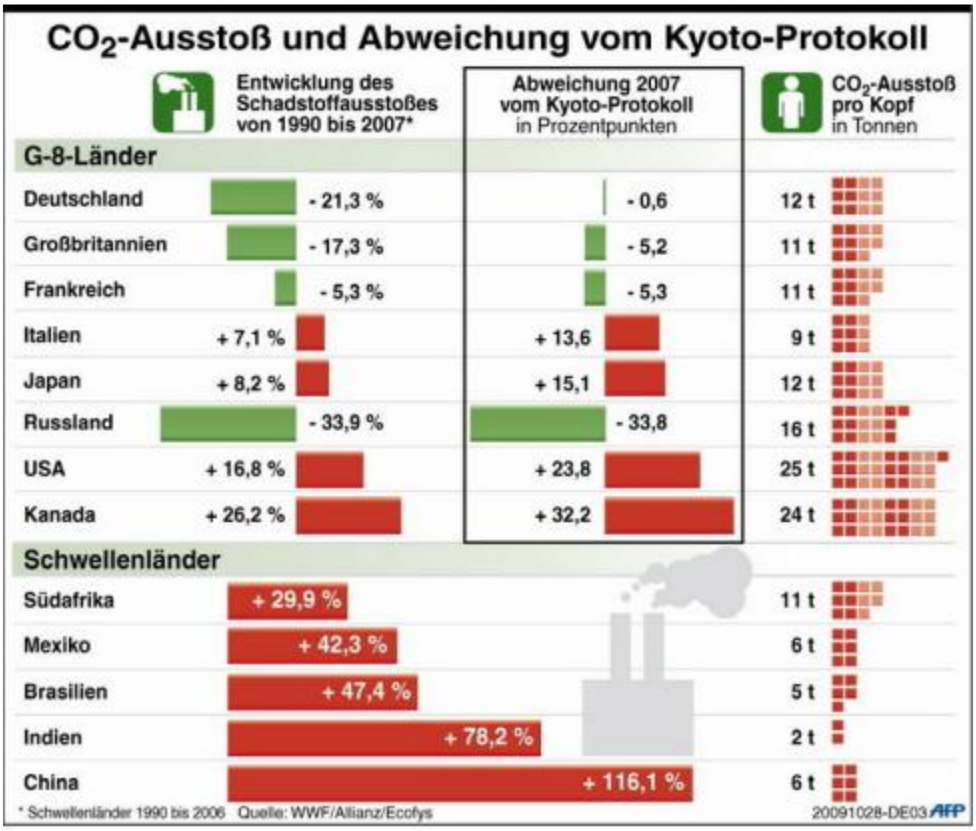

Figure 7: CO_2 Emissions and discrepancy to the Kyoto Protocol *(http://www.abendblatt.de/multimedia/archive/00238/klima23_HA_Politik__238193b.jpg)*

Table 1
Status of the Kyoto Protocol

Annex I countries	CO_2 emissions 1990 (gigagrams)	Share of Annex I 1990 emissions (%)	Kyoto target 2008–12 (% relative to 1990 or alternative base year)	Projected emissions 2000 (% relative to 1990 or alternative base year)
United States	4,957,022	36.00	93	104
European Union*	3,288,667	24.05	92	103
Austria*	59,200	0.43	92	111
Belgium*	114,410	0.84	92	n.a.
Denmark*	52,025	0.38	92	103
Finland*	53,900	0.39	92	131
France*	366,536	2.68	92	109
Germany*	1,014,155	7.42	92	90
Greece*	82,100	0.60	92	115
Ireland*	30,719	0.22	92	120
Italy*	428,941	3.14	92	113
Luxembourg*	11,343	0.08	92	67
Netherlands*	167,600	1.23	92	92
Portugal*	42,148	0.31	92	129
Spain*	227,322	1.66	92	122
Sweden*	61,256	0.45	92	104
UK*	577,012	4.22	92	102
Australia*	288,965	2.11	108	115
Canada*	462,643	3.38	94	110
Iceland	2,172	0.02	110	105
Japan*	1,155,000	8.45	94	104
New Zealand*	25,476	0.19	100	116
Norway*	35,514	0.26	101	111
Switzerland*	45,070	0.33	92	97
Liechtenstein	208	n.a.	92	118
Monaco	n.a.	n.a.	92	n.a.
Economies in Transition	3,364,259	24.60	103	81
Alternative base year	3,531,476	—	98	77
Bulgaria* 1990	82,990	0.61	107	84
1988	96,878	—	92	72
Czech Republic	165,792	1.21	92	82
Estonia	37,797	0.28	92	54
Hungary 1990	71,673	0.52	110	96
1985–7	83,676	—	94	82
Latvia	22,976	0.17	92	74
Lithuania*	n.a.	n.a.	92	n.a.
Poland* 1990	414,930	3.03	108	96
1988	478,880	—	94	83
Romania 1990	171,103	1.25	107	n.a.
1989	198,479	–	92	n.a.
Russian Federation	2,388,720	17.47	100	83
Ukraine	n.a.	n.a.	100	n.a.
Slovakia	58,278	0.43	92	84

Figure 8: Status of Kyoto Protocol *(IPCC, 2005)*

Table 1 (continued)

Annex I countries	CO_2 emissions 1990 (gigagrams)	Share of Annex I 1990 emissions (%)	Kyoto target 2008–12 (% relative to 1990 or alternative base year)	Projected emissions 2000
Croatia	n.a.	n.a.	95	n.a.
Slovenia	n.a.	n.a.	92	n.a.
Total 1990	13,675,067	100	95	98
Total base	13,842,284	—	94	97

Notes: Two Annex I countries (Belarus and Turkey) are excluded from the table, as they are not included in Annex B of the Kyoto Protocol. Four other countries (Liechtenstein, Monaco, Croatia, and Slovenia) are included in Annex B but not in Annex I. *Indicates that the country is a signatory to the Kyoto Protocol, as of 23 October 1998. CO_2 emissions exclude land-use change and forestry.
Source: All data are from the web page of the Climate Change Secretariat, http://www.unfcc.de.

Figure 9: Status of Kyoto Protocol *(BARNET S., 1998)*

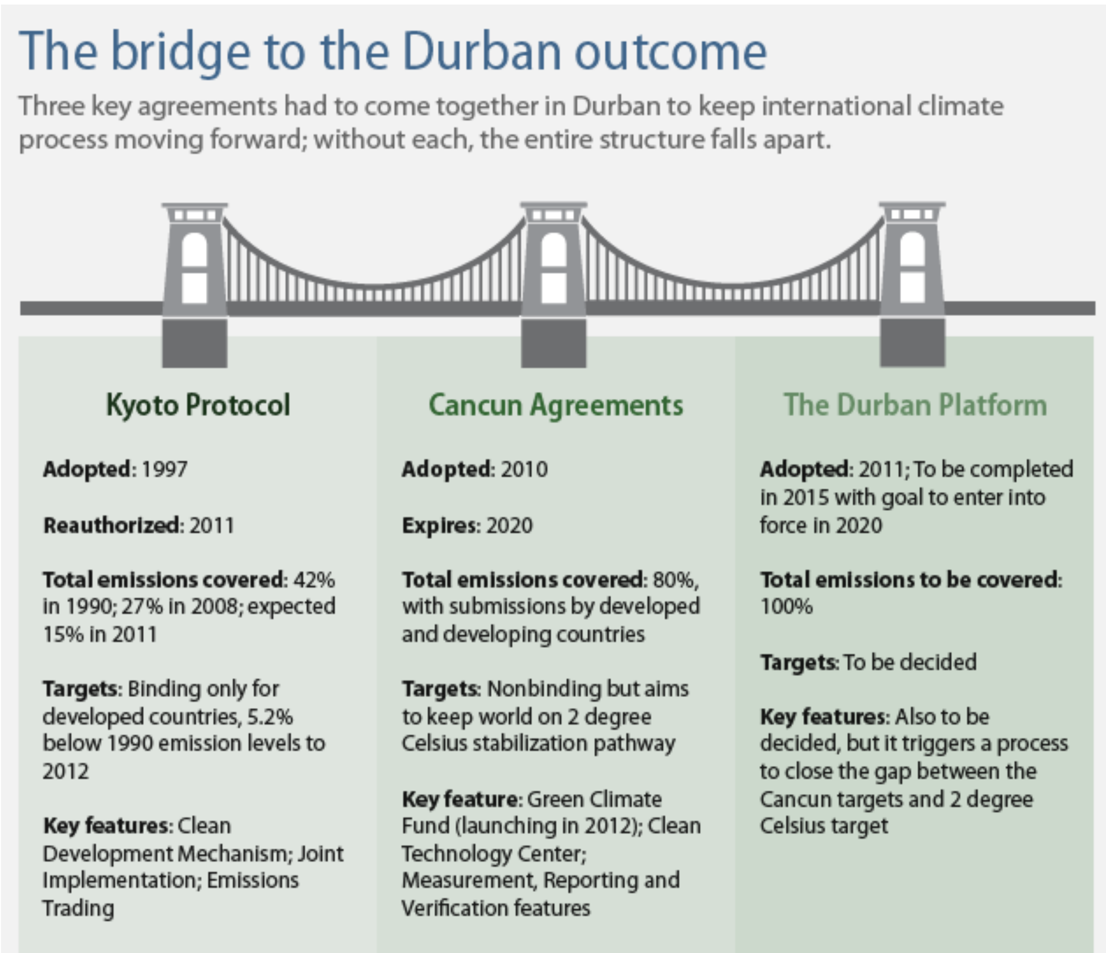

Figure 10: Bridge to Durban outcome

(http://www.americanprogress.org/issues/2011/12/img/durban_bridge.jpg)

VII.6. 2. Regulations EU and Germany

The countries, that signed the Kyoto Protocol agreed to reduce their greenhouse emissions by 5% between 2008 and 2012, in which the EU with its 15 member states committed to reduce the emissions by 8 percent. The specific reduction targets were allocated under the EU member states due to their industrial and economic growth and the technological level of its domestic industries. Therefore Germany targeted to reduce 21% of their emissions, which accounts 75% of the total allocated issue volume of the EU. To reach the targeted emission reduction the EU ETS policy was established.
The EU ETS cap is the total amount of emission allowances to be issued for a given year under the EU Emissions Trading System. Each allowance represents the right to emit one ton of CO_2. The cap for the year 2013 has been determined at 2.04 billion allowances and should decrease each year by 1.74 %.

VII.6.2.1. Implementation into national laws

The National Allocation Plans (NAPs) set out the total quantity of greenhouse gas emission allowances that Member States grant to their companies in the first (2005-2007) and the second (2008-2012) trading periods. Before the start of the first and the second trading periods, each Member State had to decide how many allowances to allocate in total for a trading period and how many each installation covered by the Emissions Trading System would receive. For the third trading period, which begins in 2013, there will no longer be any national allocation plans. Instead, the allocation will be determined directly at EU level (EU ETS).
In Germany the National Allocation Plan (NAP) was submitted to Commission on 31 March 2004 and the Nap-Act was passed by the government on 21. April 2004. The total planned budget was allocated with 499 Mt CO_2 p.a. to be equally distributed across years. The emission budget for Emissions Trade installations was set politically and is less stringent than existing voluntary agreement would have implied. The ET-sector emits about 50 per cent of total Greenhouse gas emissions and 58 per cent of CO_2 (Bundesregierung).

VII.6.3. Non EU

VII.6.3.1 E.g. Australia and USA

Emissions trading programs in the United States are comparable with these in Europe, because the U.S. sulfur dioxide cap and trade system was a role model for the EU ETS system. While the EU ETS serve the U.S. sulfur dioxide in many ways as a model, there are several significant differences in the two programs.

The first difference is that the EU ETS system is much larger than the U.S, covering 11,500 sources compared to about 3,000 for the U.S. program. Furthermore, the level of prepolicy emissions in the EU ETS is over two billion metric tons of CO_2 compared to 16 million (short) tons of CO_2 in the US program. Another difference is the dimension of the emission reduction which is regulated with 8 per cent of the 1990s stage compared to 50 per cent sulfur dioxide reduction in the US program.

But it has to be taken into account that SO_2 is a much more potent greenhouse gas which also causes acid rain compared to CO_2. Furthermore it is much easier to avoid SO_2 emission due to new filters in power plants.

In Australia the government proposed the Clean Energy Bill in February 2011 and was passed by the Lower House in October 2011 and the Upper House in November 2011. The aim of the bill is focusing on the connection of sustainable growth and carbon dioxide emissions reduction. Furthermore the bill proposes to reduce the carbon emissions by 160 million tons a year by the end of 2020. The government worked out a 4 step plan including (1) 500 worst polluting companies of the country have to pay for every ton of carbon they put into the atmosphere whereby charges are paid in fixed slabs (2) Establishment of green industries and development of clean energy sources (3) reduce carbon dioxide emissions by 160 million tons a year by 2020 and (4) use the earnings collected from the carbon taxes to cut taxes on families and increase pensions. The carbon tax will be established at the 1st July, 2012 with an initially price of 23 $ per ton.

VII.7. CCS

VII.7.1 Capture and Separation of CO_2

Capture of CO_2 can be used in different sectors, for fossil fuelled power plants, in the industrial sector, in the fuel production or the transformation sector (*IEA, 2008).* To capture CO_2 three technologies are used for industrial and power plant applications. Post-combustion capture, pre-combustion capture and oxyfuelling (see Figure 11).

While the separation of the CO_2 occurs in the post-combustion capture after power and heat is generated, the CO_2 is captured in the pre-combustion capture before the fuel is added to the power plant. The oxyfuel technique works in a cycle, the coal is burned in near pure oxygen and high concentrated flue gas is then again added to the cycle.

The CO_2 in the post-combustion technology is captured through a chemical sorbent where CO_2 and solvent create a strong bond. The technology can be applied on a total capacity of 2261GW_e of current installed oil, coal and natural gas power plants (*IPCC, 2005*).

In the pre-combustion technique fuel is processed in steam and/or air or oxygen and the product is CO and H_2, which is called synthesis gas. In a second step CO is again reacting with steam (shift reactor) and a highly concentrated mixture of CO_2 and H_2 is the result. CO_2 is then removed with the help of a physical or chemical sorbent and H_2 can be used again in other applications. Power plant system of reference are today about 4 GW_e of oil and coal based integrated gasification combined cycles (*IPCC, 2005*).

Pure Oxygen is used in the oxyfueling process. The Oxygen is taken from the air and the coal is burned in nearly pure oxygen, as a result a high concentration (70-85%) of CO_2 is the product of producing the heat and power and can be recycled (*IEA, 2008).* Oil, coal and natural gas power plants are the facilities where this technique can be used (*IPCC, 2005*).

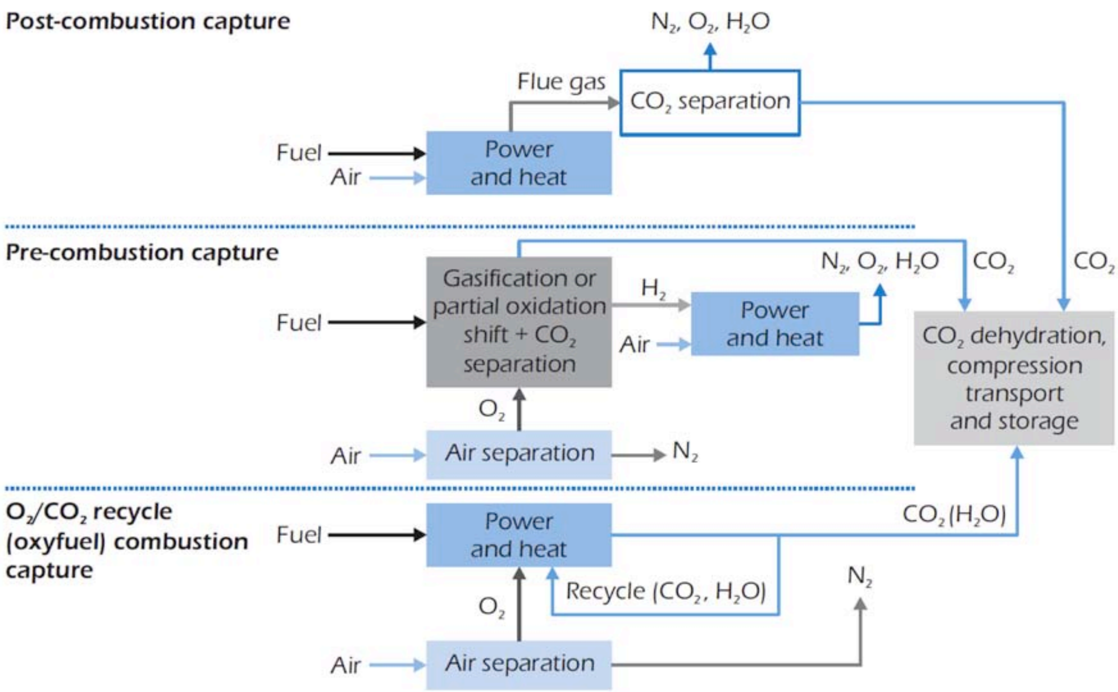

Figure 11: CO_2 capture processes (*IEA, 2008)*

These capture methods can not only be apply in new build plants investments, but also retrofitting of existing power plants is possible. This is only reasonable and economic for power plants with a high efficiency, which are most likely the recently built power plants. Another problem could be missing space for capture equipment.

New power plants can be built as “capture ready”, so that the necessary capture equipment can be installed later (IEA, 2008).

VII.7.2 Storage

VII.7.2.1 Potential storage units

Three main mechanisms for trapping CO_2 can be distinguished into physical trapping through immobilizing CO_2 in a gaseous or supercritical phase, which is used in structural traps or porous structures, or chemical trapping in water or hydrocarbons, by dissolution or ionic trapping. The CO_2 reacts with minerals (mineral trapping) or absorbs on mineral surfaces (adsorption trapping). And Hydrodynamic trapping by capturing CO_2 in extremely low velocities in intermediate *layers (IEA, 2008).*

Figure12 shows the trapping mechanisms and the timeframe for a secure storage lasting hundreds or thousands of years without major leakages.

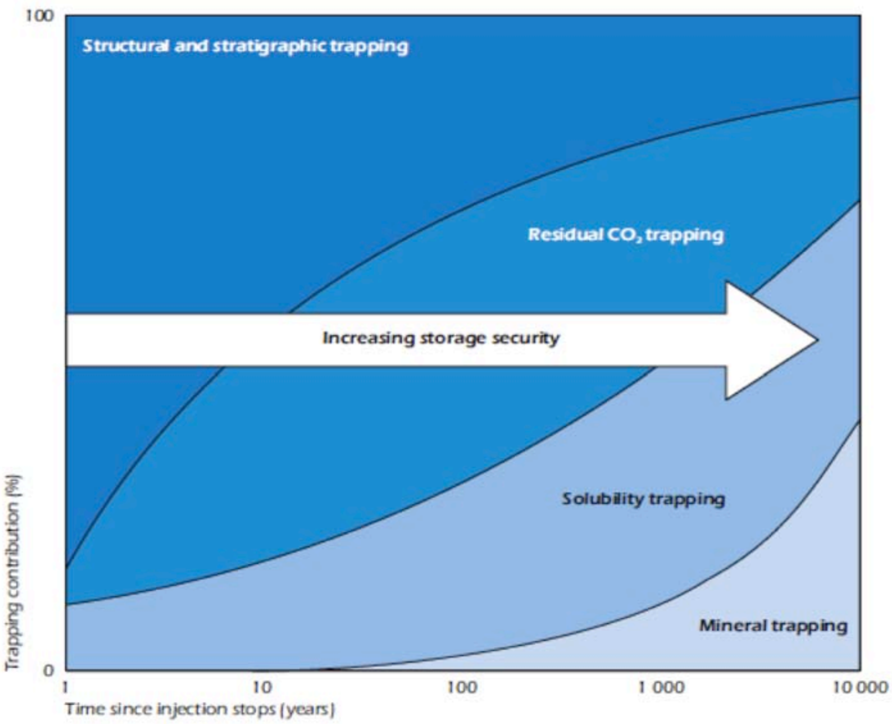

Figure 12: CO_2 trapping mechanisms and timeframes *(IEA, 2008)*

CO_2 can be stored in different geological sub-surface situations: deep saline formations, depleted oil/gas fields and unmineable coal seams. Furthermore the combination of CO_2 storage with enhanced fossil-fuel production is under consideration.

The overall criteria are a sufficient storage capacity, acceptable sealing caprock and sufficiently stable geological environment. Also, factors like basin characteristics, basin resources, industry maturity and infrastructure are important (*IPCC, 2005*).

Figure13 shows the maturity of CCS technologies. Three technologies are in the research phase, another three are in the demonstration phase, five are economically feasible under specific conditions and four are already in operation.

CCS component	CCS technology	Research phase [13]	Demonstration phase [7]	Economically feasible under specific conditions [5]	Mature market [6]
Capture	Post-combustion			X	
	Pre-combustion			X	
	Oxyfuel combustion		X		
	Industrial separation (natural gas processing, ammonia production)				X
Transportation	Pipeline				X
	Shipping			X	
Geological storage	Enhanced Oil Recovery (EOR)				X[a]
	Gas or oil fields			X	
	Saline formations			X	
	Enhanced Coal Bed Methane recovery (ECBM)		X		
Ocean storage	Direct injection (dissolution type)	X			
	Direct injection (lake type)	X			
Mineral carbonation	Natural silicate minerals	X			
	Waste materials		X		
Industrial uses of CO_2					X

Figure 13: Current maturity of CCS system components. An X indicates the highest level of maturity for each component (*IPCC, 2005*)

Depleted oil or gas fields have numerous advantages. The original oil or gas has been securely trapped in the reservoir for a long time. Furthermore, the reservoirs are well studied (geological structure and physical properties). Also infrastructure and wells are already installed and can further be used. [IPCC 200]

Enhanced oil recovery (EOR) helps to recover additional 5-40% of oil through CO_2 flooding (by injection). This technology is well studied and already in use, for example in the Rangely project in Colorado and multiple projects in Texas (*IPCC, 2005*). Saline formations are widespread and are sedimentary rocks saturated with formation water or brine. The first commercial-scale project is carried out in the North Sea (Sleipner Project) with about $1*10^6$ t of injected CO_2 into the underground (*IPCC, 2005*).

In Germany only depleted gas fields and saline formations are presently under consideration for CO_2 storage.

Sediments in the North German basin have a maximum thickness of more than 10 km and host saline aquifers that represent the largest portion of potential storage potential in Germany. Reservoir rocks are e.g. sandstones with a barrier rock of salt or claystone above the sandstone.

VII.7.2.1. Capacity

Estimations were made for the worldwide storage capacity, shown in Figure 14, but a detail description of world's sedimentary basins (Figure 15) has to be done in order to assess the economical and technical storage capacity (*IPCC, 2005*).

Geological Storage Capacity

Reservoir Type	Lower Estimate ($GtCO_2$)	Upper Estimate ($GtCO_2$)
Oil and gas fields	675*	900*
Unminable coal seams	3–15	200
Deep saline formations	1000	Uncertain, but possibly ~10^4

* Estimates are 25% larger if "undiscovered reserves" are included.

Figure 14: Geological Storage Capacity worldwide (*IPCC, 2005*)

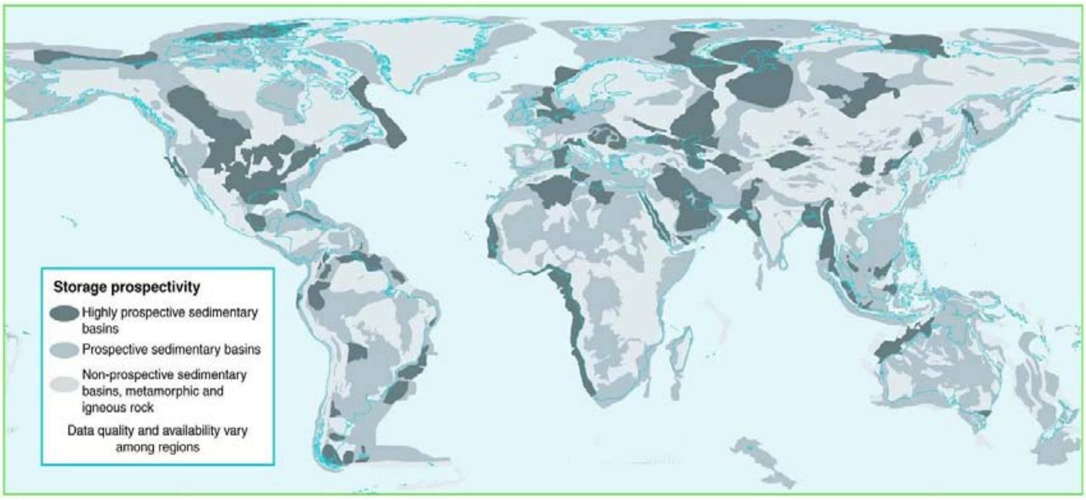

Figure 15: Prospective areas in sedimentary basins where suitable saline formations, oil or gas fields, or coal beds may be found [(*IPCC, 2005*)

Potential geological storage capacities for CO_2 in Germany are located in the Alpine foreland basin, the Upper Rhine Rift, the Saar-Nahe-Basin, the Thüringer Basin, in the Münsterländer Kreidebecken and the Fränkischen Basin (see Figure16). The North German area accounts for the largest storage capacity, due to big sediment basins with a maximum of reservoir thickness *(Knopf et al. 2010).*

A total of $12.8*10^9$ t CO_2 storage capacity in saline aquifers is estimated. This calculation is based on the North German basin, the upper Rhine Rift and the South German Alpine Foreland Basin. Other areas of Germany have not yet been studied in detail *(Knopf et al. 2010).*

Gas fields have a cumulated storage volume of $2.75*10^9$ t CO_2. The advantage of storing in depleted gas fields is the proven existence of a sealed area, because the gas was securely trapped for millions of years *(Knopf et al. 2010).*

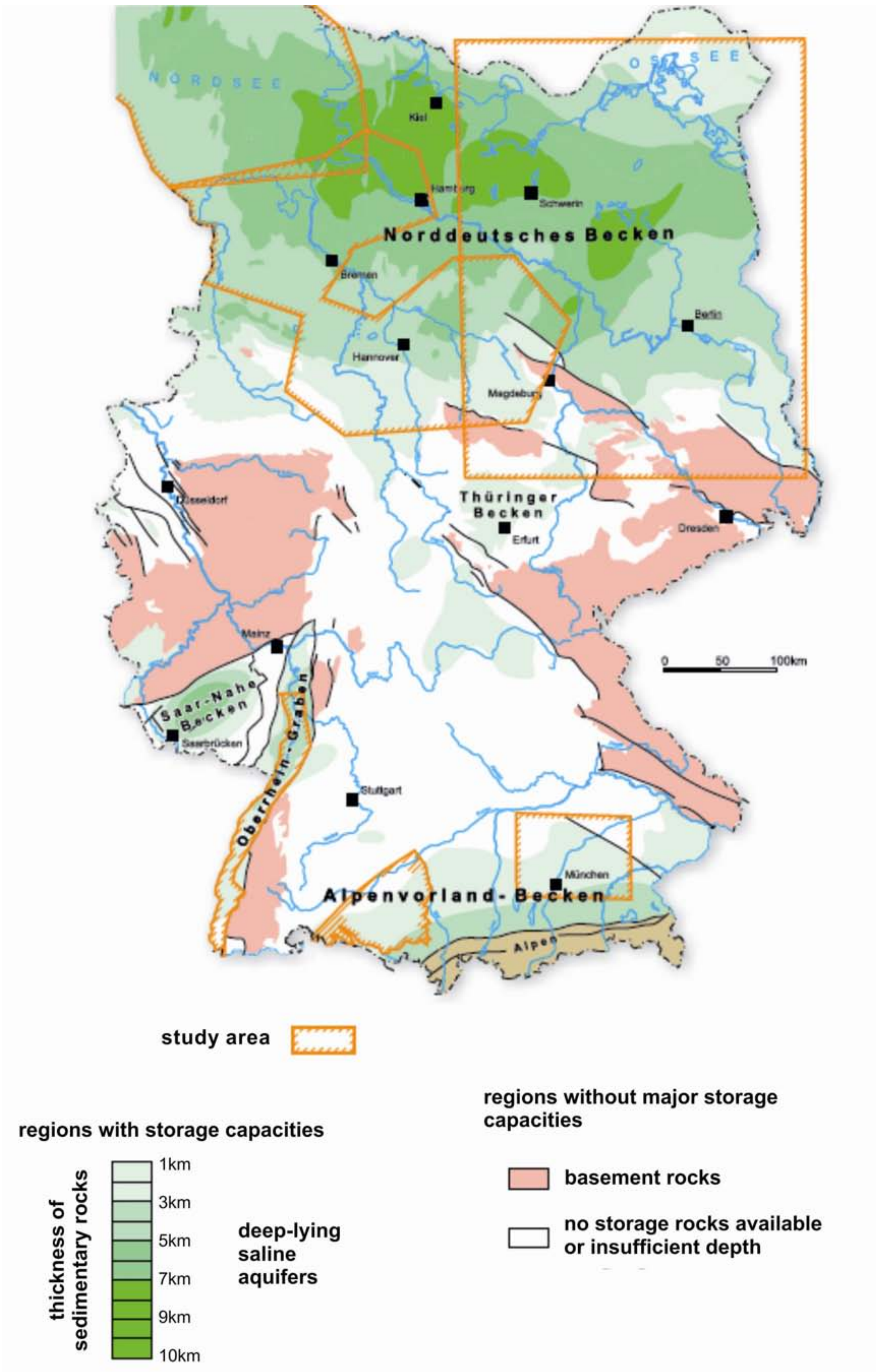
NORDSEE
OSTSEE
Kiel
Hamburg
Schwerin
Bremen
Norddeutsches Becken
Berlin
Hannover
Magdeburg
Düsseldorf
Thüringer Becken
Erfurt
Dresden
Mainz
0 50 100km
Saar-Nahe Becken
Saarbrücken
Oberrhein-Graben
Stuttgart
München
Alpenvorland-Becken
Alpen
study area
regions with storage capacities
thickness of sedimentary rocks
1km
3km
5km
7km
9km
10km
deep-lying saline aquifers
regions without major storage capacities
basement rocks
no storage rocks available or insufficient depth

Figure 1VII-3: Storage capacities in Germany. Green areas show sediment basins, which could be possible CO_2 storages. [modified after: Knopf et al. 2010]

VII.8. Recent projects

One of the biggest projects to explore and develop suitable storage sites in Germany is the storage catalogue ("Speicher-Kataster") project. The project covers the entire area of Germany and is coordinated by the Federal Institute of Geosciences and Natural Resources (BGR). The aim is to find qualified geological storage sites, like reservoir and barrier rocks. Two requirements for a storage in geological units were determined, a storage horizon with a high storage capacity and a barrier horizon with a secure and long-term seal, which can resist the reservoir pressure. Important features for a reservoir rock are thickness (>10m), depth (top at >800 m under ground level), porosity (>10%) and permeability (>10 mD). Therefore jointed and cavernous carbonates and porous sandstones are considered as the most promising potential reservoir rocks for CO_2 storage (*Reinhold et al 2011).*

A suitable barrier rock can be characterized through petrophysical, petrochemical and structural features, but also thickness (>20m) and deepness (bottom at >800 m under ground level) are of importance. Salt- and Clay-stones have a low porosity and beneficial fracture and deformation behavior and are therefore appropriate barrier rocks *(Reinhold et al 2011).*

Research in North Rhine-Westphalia showed that the regions of Weserbergland and the Osnabrück Bergland are potential units for storage and need further investigation (see Figure17). The Rotliegend and sandstone of the middle Buntsandstien could be suitable reservoir rocks. As potential barrier rocks, Zechstein and the Upper Buntsandstein have the required features. Because of insufficient data, an estimation of storage capacity and storage suitability is not yet possible *(Dölling, M. 2011)*

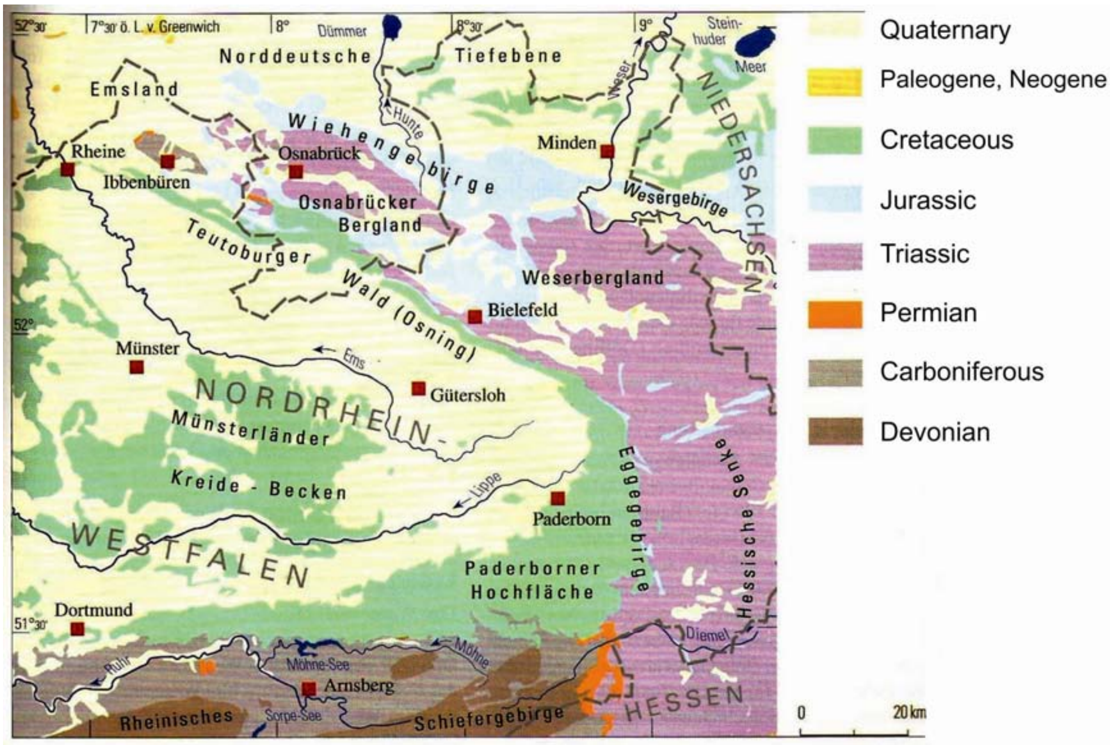

Figure 17 Geological overview map of North-Rhine Westphalia (*modified after: Dölling, M. 2011)*

Other projects include the Sleipner CCS Project in the North Sea, about 230km off the coast of Norway. The project started in 1990 and CO_2 is stored in deep saline formations. Since 1996 1 Mt CO_2 were injected per year, with costs of about USD 16 per t of CO_2 injected (*IEA, 2008).*

Also a CO_2 monitoring and storage Project started in the year 2000 and is carried out in Canada (Weyburn field). CO_2 is delivered by a Pipeline from a coal-gasification plant in North Dakota, USA. [IEA, 2008] Since the year 2000 about $18*10^6$ t CO_2 were injected into an oil reservoir for enhanced oil recovery (*Whittaker et al. 2011).*

The In Salah (Algeria) CCS Project started in 2004 with 400 t per day of injected CO_2 into saline formations underlying a gas reservoir (*IEA, 2008).*

The Snøhvit CCS Project is carried out in the Barents Sea (Norway) and CO_2 is injected into offshore geological storages since 2008 (*IEA, 2008).*

VII.9. Risks

The IPCC- Report claims certain local health, safety and environmental risks by the use of CCS Technologies. First of all there is an enormous energy requirement to capture Carbon and storage it, as pointed out in chapter VII.5.2 10-40% increase per unit of product. This requirement can increase environmental emissions such as plant-level resource requirements. A certain site-specific assessment is highly recommended and mostly necessary.

There are a high variety of risks coming along with CO_2 pipelines. These pipelines has to be build similar than this posed by hydrocarbon pipelines. This goes in hand with a lot of environmental issues and circumstances which has to be considered, such as the habitat, building codes, residents' acceptance, and geological conditions. The geological storage is another topic that has to be considered. The site selection to capture is probably the big reason for failure. CO_2 could be trapped for a certain amount of time, and although some leakage occurs upwards through the soil, well selected storage sites are likely to retain over 99% of the injected CO_2 over 1000 years. The soil would be irreparable destroyed in its abilies and as a habitant for the creatures it usually hosts. A leakage in the injection pipe can be a great risk, although it is usually protected with different kinds of valve,there is a certain risk that the pipeline cannot stand the pressure and leak.

Practical experience with transport via pipeline and sinking under pressure has the hydrocarbon industry. For example, at the oilfield “Krechba” near In Salah in the Algerian Sahara up to 1.2 CO_2 annually is injected into the gas field to enhance the oil recovery factor. Measurements via satellites discovered land uplift near the injection bores. This could mean that the injection pressure is too high, but it is also a sign, that geology reacts different than expected *(Krupp, 2010).*

The IPCC estimates 30–85% of the sequestered carbon dioxide would be retained after 500 years for depths 1000–3000 m. Mineral storage is not regarded as having any risks of leakage. The IPCC recommends that limits be set to the amount of leakage that can take place. This might rule out deep ocean storage as an option.

The condition in the deeper (with about 40 MPa) ocean has to be considered. The water – Carbon dioxide mixing is fairly low, but the formation of water-CO_2 hydrates, a kind of solid water cage that surrounds the CO_2, is favorable.
A very detailed geological history and a broad knowledge of potential Carbon dioxide storage units are indispensable required and should be utilize to decrease the risk associated with fault stability. On injection of CO_2 into the earth, the major change in pressure coming along with the injection can trigger cracks and faults as well as it can maybe break the seal. The liability of potential leaks is the largest barrier to a safe CCS-Technology *(IPCC, 2005)*

VII.10. Outlook

As discussed in this chapter there are various facts, circumstances and aspects to consider when using with Carbon Capture and Storage as well as Emissions Trading. Not yet discussed is the aspect about the range of CCS technology in Germany. As an example: When 75 Mio t CO_2 annually- as a main part of the industrial emission in Germany – is supposed to be captured in the underground, this would take a storage capacity of about 3 billion t and an operating time of 40 years. As far as Germany has potential storage capacities of about 12 billion tons – 2.75Gt in natural gas fields and 6.3 -12.8 Gt in saline aquifers – this exceeds the required storage multiple times *(Knopf et al, 2010).*
Not to underestimate for the longtime use of CCS are the enormous energy expenditures. A main electrical generating station (>600MW) has an average CO_2 emission of 5 Mt per year, but as long as CO_2 has to be captured with a density of over 90%, these 5 Mt has to be filtered out of 50 Mt flue gas. At least 10% capacity of the electrical generating stations is necessary to achieve that. This probably goes in hand with an increase of energy costs for the final consumer and therefore a lowering in acceptance *(Rochlitz, 2010*).
Beneath that, the acceptance in general public is low. First of all people located near potential storage unit do not agree to CCS “in their backyards” *(Petersen, 2010)*. Secondly, there are people and environmental scientist, who say that CCS technology is a way to create negative emissions of CO_2 to accomplish the Kyoto/ Durban protocol, but in real life it is not, because CO_2

is still generated but does not count anymore because it is captured *(Hauser, 2010).*

To sum up it has to be said, that a lot of effort, money, and scientific knowledge incorporated into CCS technology. The technology is highly accomplished. But at this point due to a lack of long-term studies, the disagreement of the residents located near a potential storage unit, the exceeding emissions over the storage capacities, and the incalculable risks to nature it is not economically useful to invest into CCS. However, further investigation and studies might lead to a supported, well-known and user friendly technology.

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VIII. Positioning of Health, Safety and Environmental (HSE) in the Oil and Gas Industry

Stefan Ginzel

Abstract: Today's oil and gas producing Industry is expected to fulfill the increasing requirements of regulations and several guidelines during every stage of hydrocarbon recovering process. The following text shows the positioning of HSE in the oil and gas industry and gives an idea about environmental impacts and HSE-management. The oil and gas producers continuously adapt to higher standards and have to include environmental aspects into their business decisions.

Environmental Impacts leads to necessity of HSE in the Oil and Gas Industry

Gas, Oil and Coal are the most used energy sources in the word. The demand of fossil fuels increased continuously over the last century and it still grows. About 90 per cent of the worldwide primary energy consumption is made out of fossil fuels (oil, gas 63% and coal 27%) (BP 2011). The oil and gas producing companies like Exxon Mobil, BP, Shell, Saudi Aramco, Gazprom etc. are in charge to ensure a constant supply for the worldwide market. To achieve that issue the oil and gas companies try to explore and recover their products under every given natural, legal and social conditions. Therefore they have to deal with reservoirs in tropical rainforests, deserts, onshore and offshore, regions with a high density of population or Siberia. As the Agenda 21 says the recovering of any kind of resource should happen under minimized environmental and social impacts. That means that it is a big challenge for the oil and gas companies to recover profitable while protecting the environment. The main environmental issues stated in the Agenda 21 are given in Table 1.

Table.1 Environmental issues in Agenda 21

- Protecting the atmosphere	*- Management of biotechnology*
- Managing land sustainability	*- Protecting and managing the oceans*
- Combating deforestation	*- Protecting and managing fresh water*
- Combating desertification and drought	*- Safer use of toxic chemicals*
- Sustainable mountain development	*- Managing hazardous wastes*
- Sustainable agriculture development	*- Managing solid wastes and sewage*
- Conservation of biological diversity	*- Managing radioactive wastes*

Agenda 21

These Issues have to be taken care of in every step of the recovering process, which leads to a high necessity of security and controlling.

The first of all stages in the hydrocarbon searching process is always the desk study of geological maps to determine potential reservoirs in sedimentary basins. Of course this stage happens without any environmental impact. After this first step the field operation starts to approve the reservoir. The most often used field survey method is the seismic exploration, which has also the first influence on the environment. The seismic exploration can be used to determine geological structures onshore and offshore. The seismic method uses sound waves, which are sent in the ground and are reflected differently depending on the kind of the variegating rock layer. The source of the sound waves is an energies releasing process which transmits acoustic waves into the ground. Some of the waves are reflected at the boundaries of the different layers, while others go deeper into the ground and are reflected later. In the next step the seismic data is interpreted in offices. Explosives like dynamite were used in the past do create an energy source in the onshore seismic exploration, but today it is more common to send vibrations made by hydraulic power into the ground (E&P 1997).

When there is a potential geological structure found, the only way to determine the amount and chemical composition of the hydrocarbons is to drill exploration boreholes. The area that is needed for an onshore exploration drilling site depends on the terrain and requires 4000- 15000 m^2 (E&P 1997). There are mobile offshore drilling units that are fixed on ships to do exploration drilling on sea. Usually drilling rigs consist of several modules (Fig.1), according to that it is easier to transport them to the exploration area.

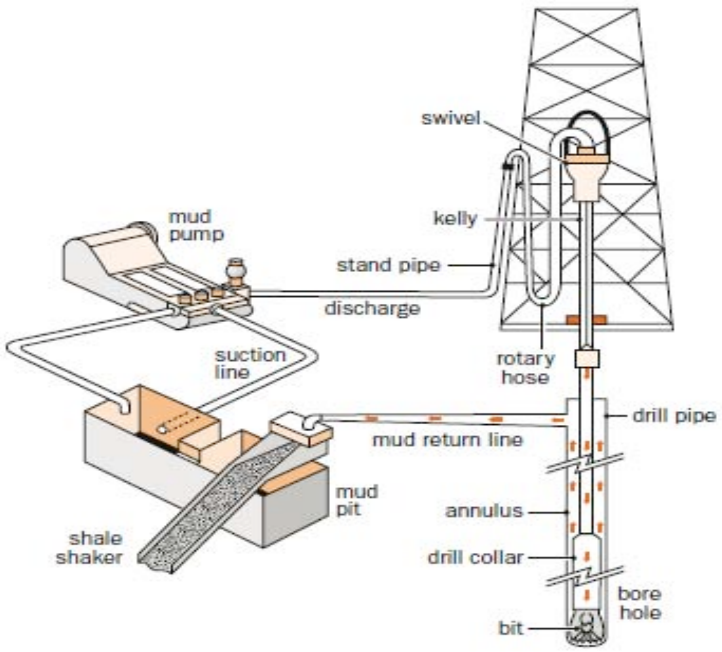

Figure 1: Drilling equipment
The main constituent parts of a drilling site are the derrick, the equipment to deal with drilling mud, to generate power, to do the cementing and tanks for water and fuel. (E&P 1997)

Besides these there are accommodations for the workforce, canteens, parking areas and other technical support like communication, machines to treat the waste and areas for storage and supply. At least it takes between one and three months for the geologists and engineers to determine key facts of a potential hydrocarbon reservoir like the flow rates, formation pressure, porosity and permeability. If the reservoir can be used to recover hydrocarbons, the equipment might be moved to other points of it to approve the data. If the reservoir does not contain the expected amount of hydrocarbons the well is being sealed with cement, so that there is no effect on the environmental rock formation. The next step would be the appraisal stage in which more exploration wells are drilled and more seismic work is done to determine the size of the reservoir and kind of hydrocarbon trap. After the appraisal of the reservoir, there has to be decided which place is suitable to drill the production well. These wells differ from drilled in the exploration by the recovering capacity for oil or gas. Furthermore the production site is build with a better and increasing infrastructure, more accommodation opportunities, waste management etc., due to the longer use. It is also possible that one well carries three or more production tubes to reach the hydrocarbons from different rock layers. In most of all cases the underground pressure lets the hydrocarbons flow to the surface. To control the flow of the fluids it is necessary to have a stabile casing and blowout preventer. The autonomous flow might stop at some point of the production, due to the viscosity of the oil, the pressure, the rock properties and the oil/gas ratio. In this case the pressure in the reservoir will be increased by water or gas injections or pumping is started. There are also other ways to increase the hydrocarbon flow, like acid treatment in limestones or hydraulic fracturing. The surface arriving fluids are separated into oil, gas and water. The water is getting cleaned before disposal and the hydrocarbons must be free of unwanted components like liquids, sulphide and carbon dioxide. The process of crude oil production and the further treatment is shown in Figure 2.

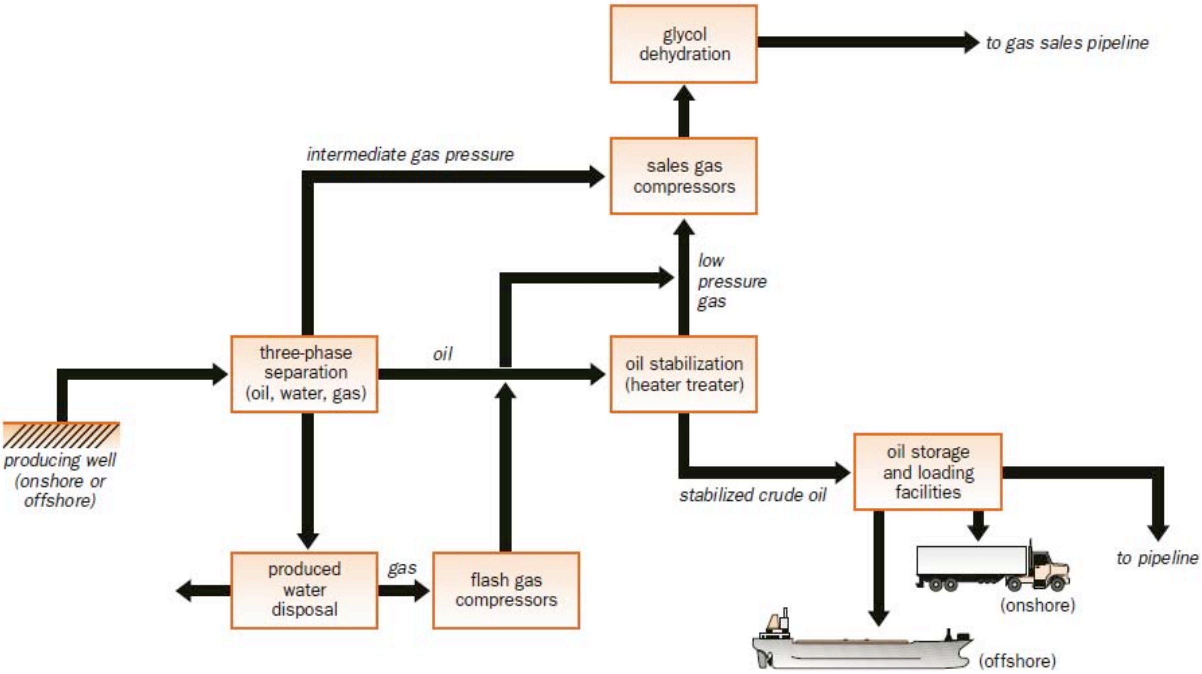

Figure 2: Process of crude oil production (E&P 1997)

In all of the producing and transporting stages potential environmental impacts are present. The evaluation of the hazards depends on the surrounding environment and the complexity of the project. The potential impacts can be categorized in effects on human (socio-economic and cultural impacts), atmospheric, aquatic and terrestrial impacts (E&P 1997).

The main impacts on human might be the result of the changed land-use. The agriculture, fishing and hunting in the area could be affected. There is also a rising population in the area, because of the created jobs that are created by the acting hydrocarbon producers, but also by the involved contractors. Furthermore there will be a higher demand for goods and services like education, healthcare, water, fuel etc., which leads to a higher import of consumer goods into the region. In many cases of hydrocarbon rich regions there were pipelines about hundred of kilometers build into an untapped ecosystem. In the case of the Chad-Cameroon Oil Pipeline the involved financial supporters paid to create new national parks in addition to balance the environmental impact (Goodland 2005). Consequently jobs arise in the national parks. Another impact could be an aesthetic one, because of unhandsome and noisy facilities and transportation infrastructure. These are not directly unhealthy affects, but they can negatively influence the quality of living in a region (OGP 2000).

The reduction of atmospheric impacts is, at least due to the CO_2 debate in the last years, a long term goal of governments and the industry worldwide. The main atmospheric emissions from the hydrocarbon production are carbon dioxide, carbon monoxide, methane, other volatile carbon gases, nitrogen oxides and dust particles. The main sources are venting, flaring, combustion and traffic (E&P 1997).

The aquatic impacts might be the result of the recovered water in the reservoir and also the water that is needed for several processes. The several operations lead to aqueous wastes from the produced water, the drilling fluids, well treatment chemicals, process, wash and drainage water, sewerage and sanitary water, spills and leakages and cooling water. The amount of aqueous waste depends on the stage of the exploration or producing process. During the whole period of exploration and production it has to be clear how to treat the polluted water and the ways of disposal. There is water-based and oil-based drilling mud and each of them has different properties influencing the environment. Ocean discharges of water-based mud leads to temporally affect on species diversity in a radius around approximately 100m around the source. If there is a discharge of oil-based mud, the organisms in a distance of 800m can be affected (E&P 1997).

Terrestrial impacts can be forced by three major forces. These are the physical disturbance as a result of construction, contamination resulting from spillage or solid wastes and indirect anthropogenic impact from social change. To build the exploration and the producing rigs the vegetation has to be removed, so the soil is prone to erosion. During the drilling of a 3000m deep well, 1000-1500 tones of cuttings are produced (E&P 1997). These has are analyzed to get more information about the reservoir, but they have also to deposited at some place. The terrestrial impacts might also influence the flora and fauna in the area. Changes in the vegetation cover leads to ecological affects. The habitat might change, because of influences on breeding areas, migration routes and food supplies (E&P 1997).

Table 2 shows a summary of the exploration and production stages and the potential impacts.

Table.2 Potential environmental impacts

Activity	Source	Potential impact	Component affected
Aerial survey	Aircraft	Noise	H/At/B
Seismic operations (onshore)	Seismic equipment Base camps Line cutting	Noise Noise/light Access/footprint Access/footprint	H/At/B H/At/B H/At/B/Aq/T H/B/Aq/T
Seismic operations (offshore)	Seismic equipment Vessel operations	Noise Emissions and discharges Interference	B At/Aq/T H
Exploration and appraisal drilling (onshore)	Roads Site preparation Camp and operations Decommissioning and aftercare	Access Footprint Discharges, Emissions, Waste Socio-economic, Cultural Footprint	H/At/B/Aq/T H/At/B/Aq/T H/At/B/Aq/T H H/BAq/T
Exploration and appraisal drilling (offshore)	Site selection Operations Decommissioning	Interactions Discharges, Emissions, Waste Footprint	H/B/Aq H/At/B/Aq/T B/Aq
Development and production (onshore)	Roads Site preparation Operations	Access Footprint Dicharges, Wastes, Emissions Socio-economic, Cultural	H/Aq/B/T H/At/Aq/B/T H/At/Aq/B/T H
Development and production (offshore)	Site selection Operations	Interactions Discharges, Emissions, Waste Socio-economic, Cultural	H/B/Aq H/At/B/Aq/T H
H=Human, socio-economic, cultural; T=Terrestrial; Aq=Aquatic; At=Atmospheric; B=Biosphere			

(E&P 1997)

HSE Management in the Oil and Gas Industry

HSE management is used to protect the environment and involved workers in projects. The protection before potential emergencies is one of the major issues HSE management programs have to deal with. The main emergencies are:

- *spillage of fuel, oil, gas*
- *blowouts*
- *explosions*
- *fires*
- *natural disasters*
- *war and sabotage*

(E&P 1997)

There are technical and environmental guidelines offering a framework to create a HSE management program. However guidelines are not always applicable, because they need to be adapted to the area, the ecosystem, the climate and other conditions. Furthermore beneath these natural conditions, there are national laws that determine the freedom of action. One of the first steps is to do an environmental impact assessment (EIA), which is a very common method, to consider every potential impact on the environment and to evaluate them. Legislations differ depending on the country and the government, but they have usually the same intention. There are general petroleum laws dealing with the contracting and planning burdens of reservoirs. There are furthermore acts describing the treatment of wastes, protection of water and air, forest protection, public and worker health and safety, handling chemicals and protection of flora and fauna. Companies should always try to adhere to the regulations, whether they are enforced or not. In order to confirm with laws and regulations it is necessary to create an infrastructure for environmental protection. This infrastructure might consist of a policy formulation to act environmental compatible, a clear response in case of emergencies, inspection and monitoring program, workforce training, logistics, transportation and communication networks and technical services and supply (OGP 2000).

Environmental management in the oil and gas industry requires general ways of acting and continuously improvement. Environmental issues should be integrated into business decisions and health, safety and environment should be integrated in on single management program (E&P 1994). The single natural components like air, water and soil have to be taken care of during the operation levels and influences have to be reduced or eliminated. The used resources should be minimal and waste production, waste re-uses and waste disposal should be complemented.
To achieve these goals it is highly recommended to integrate a Health, Security and Environment Management System (HSE-MS). It is common that HSE-MS are based on the guidelines of ISO (International Standards Organization) 9000 (standards for quality management) and on the ISO 14000 (standards for environmental management).

"ISO 9000 is the standard that provides a set of standardized requirements for a quality management system, regardless of what the user organization does, its size, or whether it is in the private, or public sector. It is the only standard in the family against which organizations can be certified – although certification is not a compulsory requirement of the standard" (www.iso.org/iso/iso_9000)

"An EMS meeting the requirements of ISO 14000 is a management tool enabling an organization of any size or type to:

- identify and control the environmental impact of its activities, products or services, and to
- improve its environmental performance continually, and to
- Implement a systematic approach to setting environmental objectives and targets, to achieving these and to demonstrating that they have been achieved." (www.iso.org/iso/iso_14000_essentials)

The following text presents a HSE-MS made by the E&P Forum that shows a way to integrate environmental issues into formal management. The E&P forum (oil industry international Exploration and Production Forum) is an association of oil companies almost 60 members worldwide, which used this management system to integrate HSE into their performance.

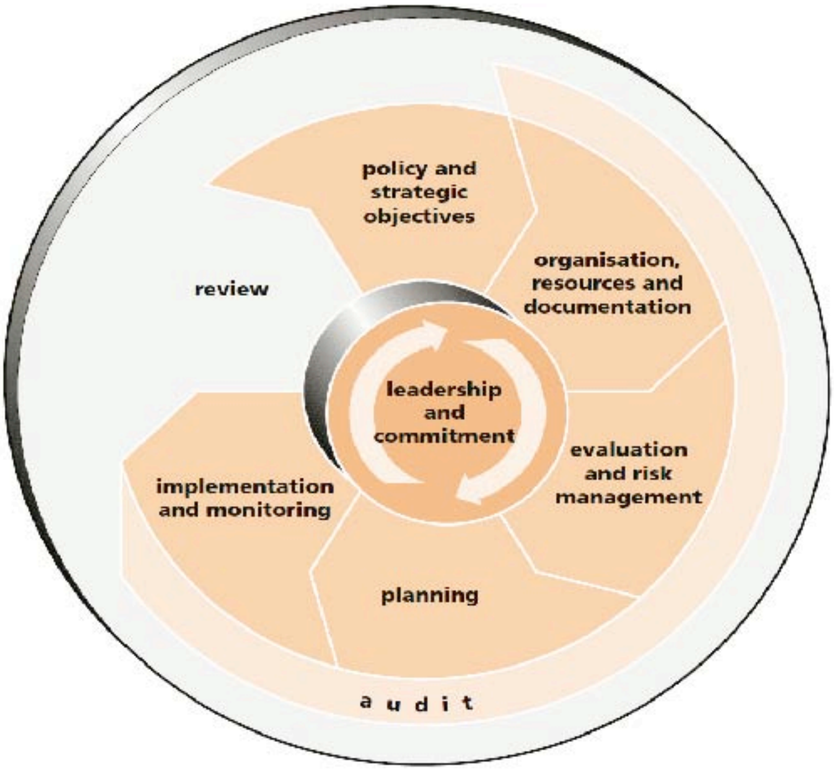

Figure 3: Model of a Health, Safety and Environmental Management System based on ISO 9000 and ISO14000 (E&P 1997)

The HSE-MS shown in Figure 3 contains the elements leadership and commitment, policy and strategic objectives, Organization, resources and documentation, Evaluation and risk management, planning, implementation and monitoring and review. The element leadership and commitment includes that the senior management communicates the policies and goal, allocates the necessary resources, ensure the participation in every stage, delegate responsibilities and ensure communication between the involved apartments. Policy and strategic objectives mean that companies have to define and document their HSE-goals. The defined policies should then be communicated to public, stakeholders, employees and partners (UNEP/IPIECA 1995). It also includes developed standards for issues and activities, which are not regulated by any kind of law.

The next element is the “Organization, resources and documentation”. Therefore the structure of organization has to be determined, which is a key element in every project. Every part of the employee has to know his authority and environmental responsibility for his sphere of control. To achieve this, company’s staff is trained contentiously. Environmental training ensures that the staffs are able to meet the individual defined role and job requirement. The environmental training teaches how to do suitable reporting, pollution prevention, usage of chemicals and waste and emergency training.

The next step in the provided HSE-MS is the evaluation and risk management. From the inception to the decommissioning of a project companies have to identify hazards and potential effects resulting from their activities. The already mentioned environmental impact assessment (EIA) offers a tool to achieve this goal. The first step of the EIA is to get information about the legislation, such as boundary values. After that the environment is analyzed to identify project effects and the quantity of impacts. The identification of hazards and their consequences might then lead to the evaluation of alternatives. All the information that are collected from the EIA becomes a part of the next step of the HSE-MS, which is the planning. The planning phase includes a detailed waste control, specified operating procedures, communication programs and monitoring. Furthermore the information from the EIA gives ideas how to integrate the environment with the project design.

In the Implementation and monitoring stage is probably the most important, because at this stage every planed operation is checked. The effectiveness of planning and operational procedure is measured and unexpected faults are exposed and eliminated.

The last point is the audit and review. It deals with the evaluation of the whole project and points out strengths and weaknesses. The goal of this last phase is to do a critical assessment in order to improve performance in other projects (E&P 1997).

Examples of HSE Applications in the Oil and Gas Industry

When it comes to the application of HSE programs in the oil and Gas industry, there are several ways to transform the ideas.
The health and working achievements include improves in working conditions. Better working conditions leads to a better performance and ability to focus on tasks. These might be the upgrades in ventilation systems for better air qualities, reduction of disturbing noises, fitness for work programs and local health facilities (Shell 2006 & BP 2004). Furthermore there are programs to support the local medical supply, such as HIV voluntary counselling and testing or blood supply programs (Shell 2006).

There is a plurality of opportunities to become safer in the daily performance. Shell launched the five forecourt safety pillars, which are communicated to the workforce from the first day in the job. The pillars include: Only authorised containers to be filled, no smoking, no using of cell phone, no straddling on motorbikes and switch of engine (Shell 2006). Seminars are being used to train the staff in such rules and they are repeated continuously.

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