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Fredrik Robelius

Giant Oil Fields – The Highway to Oil

Giant Oil Fields and Their Importance for Future Oil Production

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Abstract

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Since the 1950s, oil has been the dominant source of energy in the world. The cheap supply of oil has been the engine for economic growth in the western world. Since future oil demand is expected to increase, the question to what extent future production will be available is important.

The belief in a soon peak production of oil is fueled by increasing oil prices. However, the reliability of the oil price as a single parameter can be questioned, as earlier times of high prices have occurred without having anything to do with a lack of oil. Instead, giant oil fields, the largest oil fields in the world, can be used as a parameter.

A giant oil field contains at least 500 million barrels of recoverable oil. Only 507, or 1 % of the total number of fields, are giants. Their contribution is striking: over 60 % of the 2005 production and about 65 % of the global ultimate recoverable reserve (URR).

However, giant fields are something of the past since a majority of the largest giant fields are over 50 years old and the discovery trend of less giant fields with smaller volumes is clear. A large number of the largest giant fields are found in the countries surrounding the Persian Gulf.

The domination of giant fields in global oil production confirms a concept where they govern future production. A model, based on past annual production and URR, has been developed to forecast future production from giant fields. The results, in combination with forecasts on new field developments, heavy oil and oil sand, are used to predict future oil production.

In all scenarios, peak oil occurs at about the same time as the giant fields peak. The worst-case scenario sees a peak in 2008 and the best-case scenario, following a 1.4 % demand growth, peaks in 2018.

Keywords: giant oil fields, URR, future oil production, peak oil, forecast

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To my family

Contents

1. Introduction

The increase in the use of energy during the 20^{th} century has been enormous. In the early part of the century, coal was the dominant source of energy. The main competitor was oil because of its higher energy density. After the World War II, a shift from coal to oil has occurred, and oil is now the main energy source. The shift from coal to oil was mainly due to its use for transportation. The supply of cheap energy has spurred both economic and population growth.

Infrastructures in general and infrastructures for transportation in particular are constructed for oil, which has made the society of today very dependent on oil. Almost 40 per cent of the total energy consumption in the world stems from oil (BP, 2006). Annual global oil production is now about 4.2 billion m^3 (26 billion barrels) and with the addition of oil related liquids, total liquid productions amounts to almost 4.8 billion m^3 (30 billion barrels).

Vast amounts of oil are produced and consumed every year. A continued strong demand for oil raises the question if future oil production actually can keep pace with demand. This question had led to discussions whether the production of oil will reach a peak in the not so distant future. Or in other words, will the future supply be able to meet future demand?

1.1 Scope of Work

This thesis is part of a research project, with the aim to predict when global peak oil production will occur. The basic idea for this project is to make a survey of data for global oil reserves, production and discoveries. During the early work of the project it was decided to focus on the largest oil fields in the world, the so called giant oil fields, and their importance for the global oil production. Thus, a great deal of work has been spent on establishing databases with reliable giant oil field data (see chapter 2). In the licentiate thesis *Giant Oil Fields and their Importance for Peak Oil* (Robelius, 2005) the validity of predicting the peak by the use of giant oil fields was shown. The next step is to construct a model for future production from the giant oil fields. The modeling result, together with other forecasts, is then used to predict when peak oil will occur.

Before discussing the future oil production, an understanding of its geologic origin and entrapment is needed. How oil fields are discovered, explored and the economical considerations are discussed in chapter 3. This chapter contains some basic petroleum geology concepts, a short description of the exploration phase and some basic reservoir engineering together with fundamental production concepts to explain the producing phase.

As a coincidence, the oil price has shown an upward trend since the beginning of the project in early 2003. This has resulted in a growing coverage of oil related topics in general and the oil price in particular in the media. Almost without exceptions, there have been some media coverage on oil every day. This attention in the media shows how important oil is for the world and thus, peak oil will have far-reaching effects on the world, both with respect to geopolitics and economics. In order to understand the situation of today, when oil is such a central part of the energy mix and somewhat dictate geopolitical events, an understanding of yesterday is needed. Accordingly, in chapter 4 a brief look back to the early years of oil exploration is included as well as a description of the growth of the oil era.

Peak oil is sometimes referred to as the end of the era of cheap oil (Campbell and Laherrère, 1998). Evidence for peak oil and a discussion about it will be given in chapter 5. The important but too often forgotten concept of depletion is also discussed. The widely used, and heavily debated, Hubbert model for predicting peak oil is described as well. There have been times in history when high oil prices have led to fears of imminent shortages of oil. However, since peak oil has not yet occurred, the price might not be the best parameter for predicting the peak.

Instead, giant oil fields could be an important parameter for predicting peak oil. Chapter 6 explains what giant fields are, where they are located and how many they are. Moreover, their importance and contribution for single countries and regions as well as the world as a whole are also shown.

Any analysis of future oil production must consider contributions from present exploration, deepwater production and production from unconventional oil. Accordingly, production forecasts based on field by field analysis for deepwater fields, major new fields, oil sands from Canada and heavy oil from Venezuela are presented in chapter 7. The contribution of the oil price development and technology progress to exploration and production is also discussed and put into context. In addition, future oil demand is discussed.

The model used for the forecast of production from giant oil fields is described and discussed in chapter 8.

All pieces of the future oil production puzzle is put together in chapter 9. Accordingly, peak oil predictions based on different scenarios is presented here.

1.2 Literature Study

A wide array of publications have been used for the present report that covers the different topics regarding oil. The research can simply put be divided into two parts, where the first consisted of literature research and collection of data and the second of analyzing and using the collected information. Information from the different sources regarding oil fields have been put into one of three databases, which all are described in detail in chapter 2. However, the main texts and sources for the information is briefly described below.

The first part of the report, which deals with petroleum geology, exploration and production for oil is based on information given in the Master of Science program in Petroleum Engineering at Heriot-Watt University in Edinburgh, Scotland. The literature from the program and several other books have been used extensively. Among them, the petroleum geology book by Selley (1998) and a reservoir engineering text by Dake (2004) has been used frequently.

The Prize by Yergin (1993) is considered to be the standard text on the development of the oil era. However, to get a wider picture, sources such as O'Connor (1965) and Longhurst (1959) have also been used.

The Oil & Gas Journal (OGJ) has at least since 1930 published a yearly summary with oil production from single oil fields outside the USA. In addition, OGJ has also published a yearly summary with the production from the largest fields in the USA. The access to this information has been possible because the library of The Royal Institute of Technology (KTH) and the Royal Library hold OGJ from the 1920s and up to date. However, since the data collected by OGJ sometimes are contradictory, other sources are needed. Among them are the American Association of Petroleum Geologists (AAPG) Bulletin. The library of the Swedish Geological Survey (SGU) is the only library in Sweden that has the AAPG Bulletin from the late 1930s and up to date. A lot of information, not only regarding production, has been collected from the AAPG Bulletin, especially from the yearly development papers. These have been consulted in order to gain new information as well as trying to confirm data and numbers from OGJ. In addition, AAPG has published and still publish memoirs with a focus on giant fields. The AAPG Treatise of Petroleum Geology contain a number of books on Structural Traps, which contains detailed studies of a number of oil and gas fields. Valuable information on oil fields have also been found in the book by Tiratsoo (1984). The Arab Oil & Gas Research Center publishes every year the Arab Oil & Gas Directory (AOGD). A large number of AOGDs from 1980 and up to date has been used to collect information on the North African and Middle East oil producing nations. Many of the AOGD has been made available by the Ångström Library at Uppsala University. The International Energy Agency (IEA) has published reports that sometimes contain oil field information, especially the World Energy Outlook 2005 with its focus on the Middle East and North Africa. The International Petroleum Encyclopedia (IPE), which is published annually, contains information on the yearly developments in all oil producing countries. In addition, oil field production statistics is included. Issues from the late 1960s and up to date has been used frequently.

The Society of Petroleum Engineers (SPE) has a digital library with a large amount of technical papers. As an SPE-member, access to some of the papers are granted from their Journal of Petroleum Technology.

IHS Energy (former Petroconsultants) together with WoodMackenzie (WM) is generally considered to be the leading consulting companies with respect to data on exploration and production. Therefore, material prepared by any of them and presentations and/or articles where they are credited as sources are considered to be reliable and used to a great extent. Valuable information, especially on exploration, has been found in the IHS Energy International Oil Letter.

Other petroleum related trade journals like AAPG Explorer, Offshore, Offshore Engineer, Petroleum Review, Petroleum Economist, Upstream and World Oil have been used to get information about giant fields, information on new discoveries and field development plans. The latter is of course highly important for the debate on peak oil and future oil production. The oil field service company Schlumberger (SLB) publishes oil related news on their web site and it has been used extensively. In addition, different web sites with focus on oil and gas exploration have been consulted to get the latest from the world of exploration and production.

The Organization of Petroleum Exporting Countries (OPEC) publishes the Annual Statistical Bulletin with useful information, especially on the yearly production from the different state owned oil companies in the OPEC countries. Moreover, the compilation on both the economic and operational performance of the major international private oil companies is essential.

Company fillings, for both private and national oil companies, with the US Securities and Exchange Commission (SEC) sometimes contain useful field information, especially the form 20-F.

The US Energy Information Agency (EIA) maintain updated information not only on production from the USA but also on international production. EIA's Country Analysis Brief's must be considered essential with respect to background information on oil producing countries. In addition, EIA publish a wide array of useful reports on different oil related topics.

Presentations and reports from major oil companies, energy departments of oil producing countries and energy consulting firms have been found on the internet. For example, the Department of Trade and Industry (DTI) of UK, the Norwegian Petroleum Directorate (NPD), Nigerian National Petroleum Company (NNPC), the US Minerals

Management Service (MMS) and the Mexican state owned oil company PEMEX publish detailed information regarding their oil and gas fields.

Anders Sievertsson, former member of the research group, has made the database behind the Sievertsson Oil Depletion Model (SODM) available. In addition, people with past or present experience from the oil industry has been consulted in order to fine tune the evaluations of some of the data. Some information contained in the databases come from private communication with Jean Laherrère and Colin Campbell, both retired oil explorers and oil executives. The databases also holds some information stemming from private communication with Ray Leonard, Sr. Vice President International Exploration and Production MOL Plc.

All the gathered information has been evaluated and put into any of the databases.

1.3 Use of Units

Still, the most common units in the oil industry are the so called field units. This unit system is non-consistent, which can be compared to the consistent SI unit system. In general, SI units are used in this text. However, despite all advantages with the SI unit system, it is not used for all units. This is mainly due to the reporting on oil industry related topics mainly is in field units and it gives the reader a chance of comparing numbers with other texts.

The following units are reported in field units due to its wide acceptance as industry standard. Oil volume is measured in barrels (b), which equals 0.159 m^3. Oil production rate is measured in barrels per day (bpd). All prefixes are the standard SI unit prefixes. Thus, one million (10^6) barrels of oil is written as 1 Mb and one billion (10^9) barrels of oil as 1 Gb. Accordingly, the oil production rate 3 million barrels of oil per day is written as 3 Mbpd. Volumes of natural gas is measured in cubic foot (cf), which equals 0.0283 m^3. Oil and gas volumes are sometimes reported in barrels of oil equivalents (boe), in order to be able to compare the volume of each resource. One boe equals 5610 cf of natural gas, or 159 m^3 of natural gas. Thus if a field volume is reported in boe, and no information is given on the fluid content, it is neither possible to tell if it is an oil or gas field nor the volume of oil.

Viscosity is measured in centipoise (cp), which in SI units equals 0.001 Pascal seconds (Pa s).

It is written in the text if other field units are used.

2. Methodology

The chosen method to predict future oil production is based on a field by field analysis focusing on giant fields. Therefore, data and information on giant fields have been collected. Future production is also dependent on exploration, upcoming new field development projects and expansions in old fields. Accordingly, information on those topics have also been collected. In order to store the information, three databases have been constructed: Oil Field News (OFN), Giant Field Data (GF) and Giant Field Production (GFP).

When data or information originates from any of the databases, the database abbreviation is written in brackets at the end of the actual sentence, or at the end of a caption in a graph or a table.

2.1 Oil Field News (OFN) Database

The database contains information on more than 700 oil fields. Among the stored information are discovery year, year of production start, production levels, reserve estimates, type of oil and location. The information is updated continuously. For example, a field listed as a discovery some time ago can now be listed as a complete field development project or as an abandoned well.

The main sources are the SLB news homepage and the different trade journals.

2.2 Giant Field Data (GF) Database

The ultimate recoverable reserve (URR) is the amount which is thought to ultimately be produced from an oil field. The URR for a field which has been in production for some time is the cumulative production plus the remaining recoverable reserves. An oil field that is thought to be able to produce at least 0.5 Gb of oil is defined as a giant oil field.

Information on discovery year, year of first production cumulative production up to 2005 and different URR estimates of the giant fields are stored in this database.

The AAPG publications on giant fields are the main sources.

2.3 Giant Field Production (GFP) Database

Annual oil production for over 330 oil fields, with the earliest production data from 1925, and up to 2005 is stored in GFP. The main purpose with this database is to show production from the largest and most productive fields. Therefore, in addition to giant fields, fields that have produced over 100 000 bdp during at least a year is included as well. This inclusion is based on ideas discussed by Simmons (2002). However, it is only about 20 fields with production over 100 000 bdp that is not giant fields with respect to the reserve estimate.

The annual reports from OGJ and AAPG are the main sources, together with reports from DTI, NPD, NNPC and PEMEX.

However, despite all information gathering, production data for some years for some fields are still unknown. The first step is to work through the available sources in order to find indications on what level the production in a missing year can be. The missing years can also be assumed based on earlier and later production. If no information is found on a field expansion, it is assumed the field produced on a level close to the production level of the years before and after the missing years. Since the giant fields in most cases represent a majority of the annual production, it is possible to assume a production value based on the total annual production. The state owned oil companies in some countries have subsidiaries, which produce oil from fields in a certain area. Reports on production from these subsidiaries is also used in the assumptions. Some reports give the total cumulative production for a field at some time. If a field is in decline a gentle decline rate is assumed. In all, the combined information gives an assumed value that should be acceptable.

3. Petroleum - from Source to Production

In order to discover and produce oil and/or gas, a wide range of disciplines in sciences and engineering are used. This chapter presents a brief introduction to petroleum geology and petroleum engineering, i.e. from the geological formation to the most common production technologies.

Oil is found in subsurface reservoirs and was formed in the geological past. Unfortunately, the time scale for petroleum formation is millions of years, thus it is a finite resource. Oil fields consist of a number of reservoirs that contain the oil and/or gas.

Exploration is the term for all the different activities that are used in order to localize reservoirs with oil. If the exploration leads to a discovery, the next step is the production phase, which consists of bringing the oil and/or gas to the surface and later to the market.

The producer of crude oil sell it to refineries, which refine it to products such as gasoline and other fuels for transportation and heating.

Crude oil can be classified in many different ways dependent of the different physical and chemical properties. However, the most common way to describe oil is by its gravity. The gravity measurement is defined by the American Petroleum Institute (API). It is generally referred to as API-gravity, and is defined as follows (Dake, 2004)

$$^\circ\text{API} = \frac{141.5}{\text{Specific gravity}} - 131.5 \tag{3.1}$$

The specific gravity is defined as the density ratio of a crude oil to water at 15.6°C. Hence, oil with API-degrees less than 10 is more dense than water. Heavy oils have gravities of less than 20°API. Oils with gravities between 20°API and 30°API are called medium crudes and oil with gravities above 30°API is light crude (Corbett et al., 2000). It is higher requirements for the refineries to refine heavier oil, and there is a lack of this refining capacity, therefore it is harder to market heavier oil. In addition to crude oil, other liquids such as condensate and natural gas liquids (NGL) are also produced. Condensate is in gas phase in the reservoir but condenses to liquid at surface (Selley, 1998). NGL is produced gas with a high liquid content, so called wet gas, where the liquid part is separated from the gas at surface separators (Ahmed, 2001). In general, both condensate and NGL is included in global oil production numbers, which is about 83 Mbpd, and accounts for about 10 Mbpd.

3.1 The Origin and Migration of Oil

The oil and gas discovered today was formed between 5.3 and 570 million years ago during what is called the Phanerozoic era. The prevailing theory of the formation of petroleum is the organic theory[1], i.e. the origins of petroleum are organic matter (Selley, 1998; Hunt, 1995). In addition to time and organic matter, the formation of petroleum is dependent on heat.

3.1.1 Source Rock

Under the right circumstances sediments, such as sand and mud, will be deposited with organic matter and form so called source rocks for oil and/or gas formation. However, the organic matter must be able to mature into kerogen because it in its turn mature into oil and/or gas. Kerogen is the insoluble fraction of organic matter in sediments. Kerogen in oil bearing source rocks is almost exclusively derived from lacustrine and marine organic matter. Organic matter in gas bearing source rocks, on the other hand, can form from both land plants and from marine and lacustrine environments.

Phytoplankton, i.e. diatoms and algae, is the main producer of organic matter in lacustrine and marine environments. They fixate carbon through photosynthesis in oceans and lakes, with the highest productivity in the uppermost 50 m of the water and declining with depth as the penetration of the sunrays decreases (Selley, 1998; Hunt, 1995). In addition, high productivity is also dependent on nutrients, mainly nitrogen and phosphor (Selley, 1998). Concentrations of nutrients are commonly highest in coastal areas, where they are land derived, and in zones of up-welling. However, most of the organic matter produced is recycled through the food chain by larger organisms or oxidized by bacteria. Only a small amount, just a few per cent, of the produced organic matter actually reaches the sea floor where it can be buried and preserved (Selley, 1998). However, the organic matter on the sea floor will be degraded by the action of aerobic bacteria. Thus, the preservation of organic matter is essential for the creation of a source rock. Therefore, sedimentation environments with low or no content of oxygen should be good for preservation of organic matter (Selley, 1998). In addition, organic matter can be preserved due to rapid burial of other sediments, which prevent oxidizing (Selley, 1998).

[1] There are a few other theories, see e.g. Selley (1998).

There are three main settings that create suitable conditions for preservation of organic matter in sediments and thus, suitable conditions for the creation of source rocks (Corbett et al., 2000):

Lakes The poor turnover of the water column in some lakes allows for the accumulation of land-derived (gas prone) or algal-derived (oil prone) organic matter.

Deltas are formed when rivers meet the sea, e.g. the Nile. Most deltas are characterized by river channels with swamps and ponds in between. The organic matter can be derived from lagoonal algal concentrations or directly from plants growing on the delta plain.

Marine basins Restricted water circulation in marine basins form ideal conditions for the accumulation of thick organic-rich source rocks.

Organic matter buried at shallow depths in water bearing mudrocks undergoes bacterial decay due to low temperatures (below 60° C), that results in the formation of methane (CH_4), carbon dioxide (CO_2) and water (H_2O). The net result is the reduction of oxygen in the organic matter, which is matured into kerogen. The sediment layers containing the kerogen can be considered as immature source rocks (Tiratsoo, 1984). There is no certain number of the amount of organic materiel needed to generate a good source rock (Deffeyes, 2001). In general, a sediment with an accumulation of 5 to 20 per cent organic material generates a good source rock (Corbett et al., 2000). However, sediments containing less than 5 per cent organic matter might generate a good source rock (Leffler et al., 2003).

In general, three different types of kerogen are recognized as able to generate oil and/or gas. The origin of organic matter and the ratio between hydrogen and carbon, and the ratio between oxygen and carbon determine if oil or gas is generated (table 3.1) (Selley, 1998; Hunt, 1995). The most common and richest source rocks for oil contain type II kerogen (Hunt, 1995).

Table 3.1: *The three main types of kerogen and their properties (H=hydrogen, C=carbon, O=oxygen) (Selley, 1998; Hunt, 1995)*

Kerogen	**Organic matter**	**H/C ratio**	**O/C ratio**	**Produces**
Type I	Marine and lacustrine, mainly algal	high (1.3-1.7)	low (<0.1)	Oil
Type II	Marine, plankton and algal	medium (1-1.5)	low (0.1-0.2)	Oil & gas
Type III	Land plants	low (<1)	high (>0.2)	Gas

3.1.2 Generation of Oil (The Oil Window)

The maturation of kerogen into petroleum is dependent on temperature (Selley, 1998). At greater burial depths the temperature increases and temperatures above 60°C causes thermal degradation of the kerogen. This temperature corresponds to a burial depth of at least 2 km with a geothermal gradient of 2.6°C/100 m, which is a global average (Selley, 1998). The maturation of kerogen at temperatures above 60°C is called catagenesis and the source rock is now considered to be mature and starts to form oil (Tiratsoo, 1984). When the temperature is above 150°C, corresponding to a depth of almost 6 km, the kerogen is said to be post-mature and its ability to produce oil has almost vanished. However, if the kerogen is gas prone the production can continue up to a temperature of 250°C. At even higher temperatures and correspondingly greater depths, carbon in the form of graphite is the only remains of the kerogen. This temperature (or depth) interval where the source rock is mature is called the oil window (figure 3.1). Thus, if oil occurs in a sedimentary basin the source rock must be at a depth below 2 km but not deeper than 6 km, assuming a geothermal gradient of 2.6°C/100 m. For gas, the corresponding depth is up to 10 km. Sediments deposited in the deep sea floor setting are overall less than 1 km thick, which is too shallow (i.e. the temperature is too low) for organic matter maturation and hydrocarbon formation (Deffeyes, 2001).

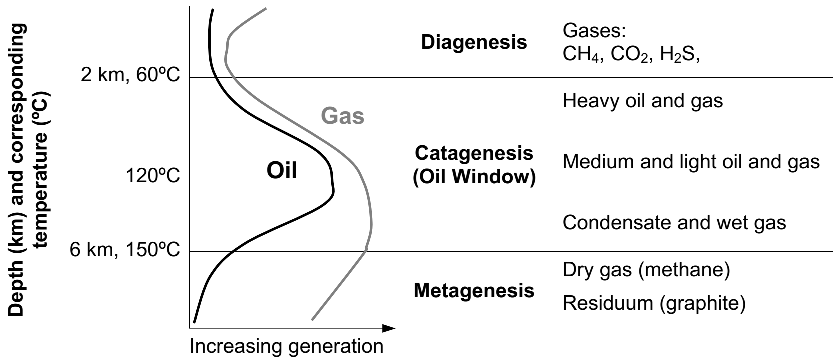


Figure 3.1: The Oil Window. The relation between depth and temperature is based on a geothermal gradient of 2.6°C/100 m , which is a global average (Selley, 1998).

3.1.3 Migration of Oil

As has been shown in section 3.1.1, oil and gas have an origin in source rocks, which are virtually impermeable mudrocks (Selley, 1998). However, both oil and gas are found in porous and permeable reservoir rocks. Thus, oil and gas migrates from the source rock to the reservoir. This process is divided into primary and secondary migration (Selley, 1998; Hunt, 1995).

Primary migration is all movement of hydrocarbons in the mature source rock, whereas secondary migration is any movement outside the source rock. This movement can occur, among other, in fractures, reservoir rocks, or in rock layers with good fluid transport capacity, so called carrier beds.

The origin of primary migration is poorly understood (Selley, 1998). The mechanisms, however, of hydrocarbon migration in a fine-grained source rock are diffusion, solution and as an oil-gas phase (Hunt, 1995). In general, it is thought that the generation of oil causes migration.

The main force of secondary migration is the buoyancy force. This is because most pores in sedimentary rocks are to some extent filled with water (Selley, 1998). A difference in density between two liquids results in buoyancy forces, i.e. the less dense liquid (oil) will move upwards in the more dense liquid (water). As long as the oil droplet is smaller than the narrowest part of the pore, the so called pore throat, the buoyancy will move the droplet upwards (Selley, 1998). If the droplet reaches a smaller pore throat, the buoyancy has to overcome the capillary entry pressure (Corbett et al., 2000). If the oil droplet can not move through the pore throat, it is trapped. However, the droplet might build up beneath the throat due to upward moving of underlying oil, and in that way increasing the pressure, and thus squeezing the droplet through the throat (Selley, 1998). This process will continue until the droplet reaches a rock layer with such small pores that the pressure from the oil column is not sufficient enough to squeeze it through. This is called a capillary seal (Selley, 1998).

3.1.4 World Source Rocks

The importance of source rocks is obvious and thus a discussion on their distribution and generation is necessary. The distribution of source rocks is uneven, both in areal and stratigraphic senses. Up to the late 1960s, it was explained by a lack of exploration in different regions and accordingly, variable exploration maturity. However, contributions in geochemistry during the last 30 years have shown that the uneven distribution of source rocks is a "fundamental fact of petroleum geology"(Klemme and Ulmishek, 1991). Research has also made it possible to match most known reserves of oil and gas to a certain source rock (Selley, 1998).

The majority of oil and gas has its origin in two stratigraphic intervals, Upper Jurassic (144–159 Million years ago (Ma)) and Middle Cretaceous (90–120 Ma) (Klemme and Ulmishek, 1991). Additionally, there are four other main producing stratigraphic intervals, Silurian, Upper Devonian, Lower Permian and Oligocene–Miocene (Klemme and Ulmishek, 1991)

A number of the largest oil fields in the world have source rocks from the Upper Jurassic and Middle Cretaceous (3.2). Oil in Ghawar, the world's largest oil field, comes from an Upper Jurassic source rock (3.2).

Table 3.2: *Some producing areas and their main source rocks with a few field examples (Klemme and Ulmishek, 1991; Tiratsoo, 1984).*

Region	**Source Rock**	**Major Field**
Arabian–Iranian	Silurian	
	Upper Jurassic	Ghawar
	Middle Cretaceous	Greater Burgan
North Sea	Upper Jurassic	Ekofisk
Gulf of Mexico	Upper Jurassic	
	Middle Cretaceous	Thunder Horse
Lake Maracaibo	Middle Cretaceous	Tia Juana

3.2 The Entrapment of Oil - Reservoirs, Traps and Seals

Oil and gas accumulate in reservoirs. The accumulation is possible only if the hydrocarbons are trapped in rocks which have a seal (Selley, 1998). If not, secondary migration will continue upwards until the hydrocarbons reach the surface, and a so called seepage can form (Tiratsoo, 1984). Thus, the entrapment of oil and gas is a prerequisite for a commercially exploitable oil accumulation. A more detailed review of reservoirs, seals and traps, can be found in Magoon and Dow (1994b) and Selley (1998).

3.2.1 The Reservoir

Any rock can act as a reservoir as long as it has pores that can both store and transmit fluids. Sedimentary rocks such as sandstones and carbonates are, however, the most common reservoir type and a vast majority of the world's known oil fields have sedimentary reservoirs (Tiratsoo, 1984).

The percentage pore volume of a rock is called porosity. The permeability of rock describes the ease with which a fluid can pass through the porous structure under a pressure drop (Selley, 1998). Porosity and permeability, which vary between reservoirs and even in the same reservoir, are the most important variables in characterizing and evaluating a reservoir (Corbett et al., 2000).

In general, porosity is divided into total and effective porosity. Total porosity is defined as the volume of void between grains in the rock and is expressed as a fraction of the total rock volume (equation 3.2).

$$\phi = \{\text{porosity}\} = \frac{\text{volume of voids}}{\text{total volume of rock}} \tag{3.2}$$

Pores with connection to other pores contributes to fluid movent in the reservoir and constitute effective porosity. The higher the porosity of a formation, the more oil can be held in a given volume of rock. The porosity changes with burial depth and usually declines with greater depths due to compaction of the sediments (Corbett et al., 2000; Selley, 1998). A reservoir with very low porosity (less than 5 per cent) has insignificant porosity, whilst excellent porosity is above 20 per cent (table 3.3).

Table 3.3: *Typical oil reservoir porosity values (Hyne, 2001).*

Porosity value [per cent]	**Classification**
0–5	insignificant
5–10	poor
10–15	fair
15–20	good
>20	excellent

Darcy's law is the basic equation describing fluid flow through a porous medium under a pressure drop (figure 3.2) and it also defines the permeability. The unit for permeability is Darcy but since the permeability in oil reservoirs generally is less than one Darcy, the millidarcy (md) is commonly used. In field units, Darcy's law is given by equation 3.3.

$$Q = 0.001127 \cdot k \frac{A}{\mu} \frac{\partial P}{\partial L} \tag{3.3}$$

where

Q = fluid flow rate (bpd)

k = permeability (md)

A = cross-sectional area to flow (square feet, ft^2)

$\frac{\partial P}{\partial L}$ = pressure gradient (pounds per square inch per feet, psi/ft)

μ = viscosity of the fluid (centipose, cp)

0.001127 = conversion factor to express the equation in field units $\left(\frac{\mathrm{s} \cdot \mathrm{b}}{\mathrm{ft}^3 \mathrm{day}}\right)$

The permeability in reservoirs is often in the interval 5–500 mD, but higher values exist (table 3.4). It is important to notice that the permeability is not necessarily the same in different directions. In general, the horizontal permeability is greater than vertical (Selley, 1998).

Diagenesis is the term for the physical and chemical processes which turn sediments into rocks. The sediments consists of different grains and their origin govern the type of rock created. Sand grains in different sizes,

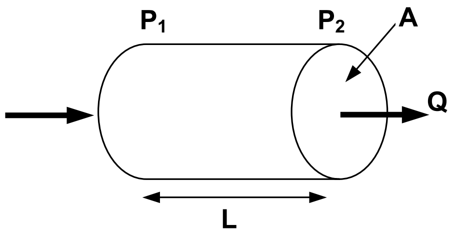


Figure 3.2: Graphical representation of Darcy's Law.

which on compaction and cementation, will turn into sandstones. Carbonate grains, on the other hand, are initially mainly composed of some form of calcium carbonate and precipitated from sea water and/or by organisms (Corbett et al., 2000). These organisms produces a wide range of particle sizes, from mud-size to large hard shells. Reefs, which are a common reservoir rock, form directly as rock and do not undergo compaction (Selley, 1998).

Table 3.4: *Typical oil reservoir permeability values (Hyne, 2001).*

Permeability value [mD]	**Classification**
1–10	poor
10–100	good
100–1000	excellent

Both types of sediments undergo the same processes of compaction and cementation, but the effects are different. Since calcium carbonate is less stable than sand grains, diagenesis has a higher effect on carbonates (Selley, 1998). Moreover, carbonate reservoirs have often large fractures, which transmit fluids well (Corbett et al., 2000).

There are four main parameters that can affect the porosity and permeability of newly deposited sands and thus, affect the sandstone (Corbett et al., 2000):

- Grain size
- Sorting
- Grain shape (roundness, sphereicity)
- Fabric (packing, grain orientation)

Grain size and sorting are determined by the depositional environment, i.e. the physical conditions when the sand ceased to be transported and started to be deposited. The grain shape is governed by the time and impact of the transportation as well as the depositional environment. The compaction and cementation of sand into sandstones is then equally important for the permeability and porosity.

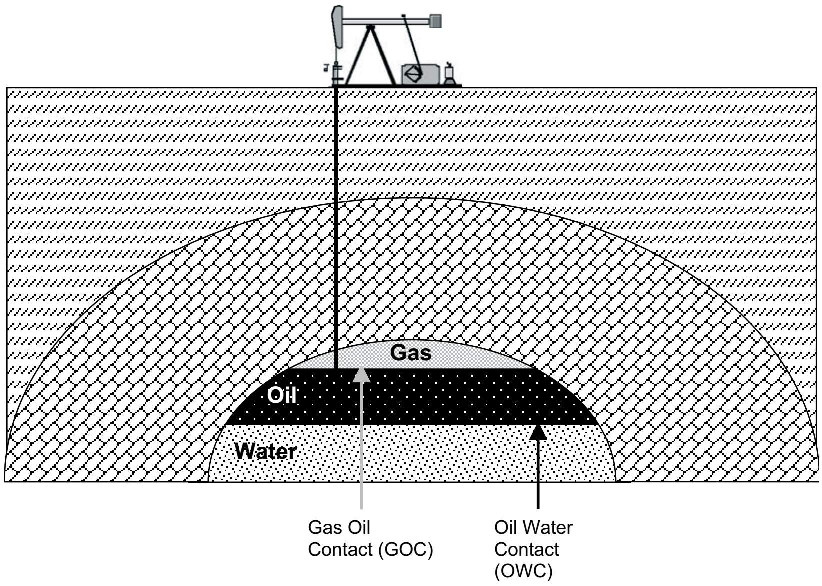


Figure 3.3: A simplified sketch of a reservoir showing the different layers due to density separation and their respective contact zones.

It is usually assumed that the fluids in a reservoir is in a state of equilibrium and that density separation has occurred, i.e. the lighter fluid is above the more dense fluids (Ahmed, 2001). Thus, a reservoir containing gas, oil and water has a gas zone on top, underlaid by an oil zone, which is above a water zone (figure 3.3). The interfaces are called gas oil contact (GOC) and oil water contact (OWC) respectively (figure 3.3)(Dake, 2004). The layer of oil between the GOC and OWC is referred to as the oil column. As a consequence of the density separation, there is virtually no oil below the OWC. Accordingly, gas is not present below the GOC. However, the pores in the oil zone are not fully filled with oil since some connate water usually exists there as well. The saturation of a fluid is measured as the fraction of a pore volume which is occupied by a certain fluid. Consequently, the sum of the saturations in a given volume is one (Ahmed, 2001).

$$S_{\text{oil}} = \{\text{oil saturation}\} = \frac{\text{oil in the pore volume}}{\text{pore volume}} \tag{3.4}$$

$$S_{\text{gas}} = \{\text{gas saturation}\} = \frac{\text{gas in the pore volume}}{\text{pore volume}} \tag{3.5}$$

$$S_{\text{water}} = \{\text{water saturation}\} = \frac{\text{water in the pore volume}}{\text{pore volume}} \tag{3.6}$$

If oil is able to flow, the oil saturation will be over a certain value, the critical oil saturation.

Another important parameter is the reservoir continuity, i.e. the lateral or vertical extension of the reservoir where the fluids are in contact with each other (Selley, 1998). For example, a reservoir can be divided into several non-communicating zones due to faulting. A good reservoir continuity will facilitate the production of the field.

3.2.2 Traps and Seals

A seal is required to prevent the hydrocarbons from migrating out of the reservoir. The reservoir and the seal, and their geometric arrangement with each other, are two fundamental components of a trap. A trap "can be defined as any geometric arrangement of rock, regardless of origin, that permits significant accumulations of oil or gas, or both, in the subsurface" according to Biddle and Wielchowsky (1994) .

The less permeable the seal, or cap rock, the more effective the seal. This is due to the high capillary entry pressure in the seal (section 3.1.3). Mudrocks are the most common seal whilst evaporites, such as salt, are the most effective ones (Selley, 1998; Biddle and Wielchowsky, 1994).

There exists several trap classifications but three main groups are generally recognized (Selley, 1998; Corbett et al., 2000).

Structural Traps The geometry is created by tectonic processes after deposition of the rock beds. Most are either fold dominated or fault dominated (figure 3.4(a)), where anticlines (figure 3.4(b)) are an example of the former. Another type is salt domes (figure 8.2(c)), which is created by masses of salt that penetrates the subsurface rock layers.

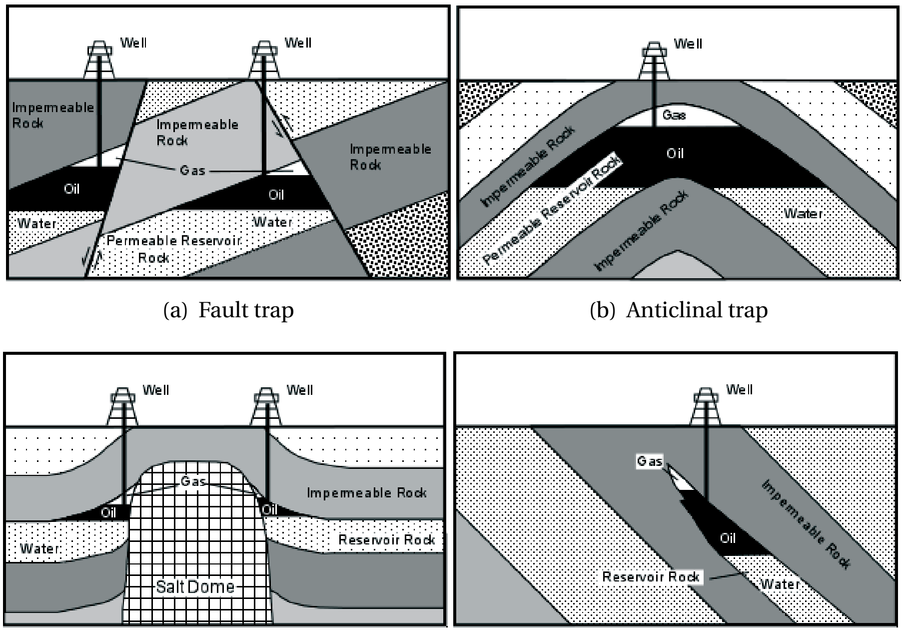
Stratigraphic Traps The trap geometry is formed by changes in the rock lithology (figure 8.2(d)).

Combination Traps Both structural and stratigraphic features in the trap configuration.

A majority of the world's largest oil fields have structural traps (Halbouty, 1970). Relatively few fields are caused solely by faulting (Selley, 1998). A recent trend in the discovery of large oil and gas fields is that fields with stratigraphic dominated traps are increasing (Halbouty, 2003)

3.2.3 Oil Fields and their Reserves

The accumulations of oil and/or gas in one or more reservoirs in the same geological feature is termed an oil field. The configuration of a few oil fields are shown in figure 3.4. In order to have an oil field there must have been an active source rock and a migration path to a reservoir, which in turn must be in a trap to accumulate the hydrocarbons. These components are parts



(a) Fault trap (b) Anticlinal trap

(c) Saltdome trap (d) Stratigraphic trap

Figure 3.4: Different types of petroleum traps. a) to c) are structural traps, while d) is a stratigraphic trap. (Source: Earth Science Australia and Prof. Stephen A. Nelson, Tulane University).

of the petroleum system and if any of the parts are missing, there would not be an oil field (Magoon and Dow, 1994a; Selley, 1998).

The size of a trap, estimated by geological and geophysical investigations, gives an early estimate of the potential volume of oil in a field before any drilling has been conducted. As more data gets available, first from drilling and then production, the estimates will be more and more accurate (Dake, 2004; Corbett et al., 2000). The total volume of oil in an oil field prior to any production is referred to as either oil originally in place (OOIP) or oil initially in place (OIIP). The latter, OIIP, will be used in this text. This is the amount of oil in the pores of one or more reservoirs making up a field (Todd and Somerville, 2000). OIIP can be calculated by use of equation 3.7.

$$\text{OIIP} = 7758 \cdot Ah\phi(1 - S_{\text{water}}) = 7758 Ah\phi S_{\text{oil}} \text{ (barrels)} \tag{3.7}$$

where

7758 = conversion factor from acre-feet to barrels

A = areal extent of the reservoir (acre)

h = average thickness of the producing formation (feet, ft)

ϕ = average porosity (%)

S_{water} = water saturation in the oil zone (%)

S_{oil} = oil saturation in the oil zone(%)

Equation 3.7 assumes both porosity and saturation to be homogenous throughout the reservoir, which is generally not the case.

However, OIIP is not the same thing as the producable amount or reserves of oil. The reserve is defined as the part of oil that can be extracted from the reservoir (Todd and Somerville, 2000).

$$\text{Reserves} = RF \cdot \text{OIIP} = RF \cdot 7758 A h \phi S_{\text{oil}} \text{ (barrels)} \tag{3.8}$$

where

$$RF = \text{recovery factor (\%)}$$

The recovery factor is a dynamic value and is an expected and estimated percentage of the total volume that can be recovered. There are numerous factors that influence the recovery factor, including the rock and fluid properties, the reservoir drive mechanism (see section 3.3.2), variations in the formation and the development process (Todd and Somerville, 2000). A global average for the recovery factor is 29 per cent (Meling, 2005).

Reserves estimations can be either deterministic or probabilistic and are based on known geological, engineering and economic data (Todd and Somerville, 2000). The estimation is deterministic if a single best estimate is used. If the estimate is based on probabilities for a range of estimates, it is a probabilistic estimate. The term proven reserves (1P) is in a deterministic estimate defined as those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions (Todd and Somerville, 2000). However, if a probabilistic estimate is used, reasonable certainty should be translated to a probability of at least 90 per cent, and this is sometimes referred to as P90 reserves (Todd and Somerville, 2000). A less certain reserve volume is probable reserves, which in the deterministic approach are more likely than not to be recoverable. Proven plus probable is usually denoted 2P or sometimes P+P. In the probabilistic method, the probable reserves plus the proven reserves will be recovered with a probability of at least 50 per cent

(P50 reserves) (Todd and Somerville, 2000). A third and the most uncertain reserve volume is possible reserves, which are less likely to be recovered. This translates to a probability of 10 per cent that the proved, probable and possible reserves will be recovered.

To conclude this section, an example is worked through. A structure with an area of 4500 acres contains three reservoirs, with a total producing thickness of 200 ft. It is assumed that the porosity and oil saturation is the same in all three reservoirs. Porosity is 30 per cent and oil saturation 78 per cent. Equation 3.7 gives an estimated OIIP of 1.63 Gb. Other fields in the surrounding area with similar geology has had a recovery factor of at least 20%, which is used. Thus, the use of equation 3.8 gives an estimate of a recoverable reserve of 0.33 Gb. Since this value is based on a conservative RF, the proven reserves is put to 0.33 Gb. The learning from other fields and the availability of effective technology made it possible to increase the RF to 27 per cent. This means an additional 0.11 Gb as probable reserves and thus a value of 0.44 Gb for proven plus probable reserves. There is also an upside to reach a RF of 31 per cent, which should yield an extra 0.07 Gb in possible reserves. Accordingly, the total reserves of proven, probable and possible leaves a number of 0.51 Gb.

3.3 Exploration and Production of Petroleum

The intent of this section is to give a brief introduction to the subject of exploration and production of hydrocarbons. The first step, exploration, is to find areas with hydrocarbon deposits. The drilling and extraction of an oil discovery comprise the production phase.

3.3.1 Exploration

Since petroleum is generated in sedimentary rocks and almost always trapped in sedimentary reservoirs, exploration for petroleum should be performed where sedimentary rocks are in abundance in the subsurface. This is the case in sedimentary basins, which are areas of the earth where the layers of sediments have accumulated in greater thickness than in adjacent areas (Selley, 1998). Thus, the first step of exploration is to establish where the sedimentary basins are, and when they are found determine if petroleum systems are present.

However, before any actual exploration take place, a permission from the resource owner must be granted. In general, the resource owner is the government in the actual country (Tweedie, 2003). Licensing is the general term for describing the process of granting exploration permission. The license should dictate the conditions and responsibilities of the resource owner and explorer, such as license area, dividing of financial benefits and ownership of the discovered oil and/or gas (Tweedie, 2003). Usually a resource owner offers a number of licenses in a so called lease sale or license round. The license area is commonly divided into several exploration blocks. A common process to allocate the blocks is through competitive bidding, i.e. an auction. Each resource owner has its own selection criteria but some of the following is usually included: extent of work programme (i.e. seismic and number of wells drilled), earlier performance and nationality (Tweedie, 2003). When the license is secured, it is time to start the exploration process, which is described below.

The early explorers who were active in the end of the 19^{th} century had to rely on their senses and luck. However, natural seepages of oil gave clues on where to drill. In addition, surface features resembled those around earlier discoveries also gave indications on drilling sites. This was the first steps toward using more scientific methods in exploration (Yergin, 1993). In the early 20^{th} century, geologists and later geophysicist were employed by the companies to study the earth's structure in order to find sedimentary rocks that could be possible reservoirs. The most widely used technique in exploration today is seismic surveys. This method utilizes sound energy that is propagated into the ground (Hyne, 2001).

The main purpose of a seismic survey, as well as other geophysical investigations, is to develop an image of the subsurface geology (Corbett et al., 2000). Either explosives or a vibroseis truck is used on to generate the sound energy. Offshore, air guns are used to generate the sound energy. The generated sound energy travel through the rocks and some of the energy is reflected from the different layers and returns to surface at varying times (Corbett et al., 2000). The incoming waves at the surface are registered by sensors. This part of the seismic survey is called acquisition. The next step is processing and interpretation which consist of the creation and interpretations of subsurface images. The acquisition data is processed in computers to produce images of the subsurface.

If the interpretation of the subsurface image shows a structure that looks promising, the next step is to decide to drill the structure or not. Drilling is required in order to determine if the structure contains oil. The drilling of a promising structure/prospect is termed exploration drilling. The first exploration well in a new prospect is usually called a new field wildcat (NFW) (Corbett et al., 2000).

The drill cuttings are examined during the drilling to see if there is any trace of oil or gas. Rock samples are collected in order to see if the rock is porous and/or permeable. Moreover, samples of the drilling mud, which is circulated, are examined to see if they contain any hydrocarbons. This is done since the drilling mud is between the drill bit and the rock formation and thus hydrocarbons from the formation can mix with it (Deffeyes, 2001). Evidence of hydrocarbons, a so called hydrocarbon show, when drilling is not a guarantee for a producible discovery. The rock might not have sufficient permeability and porosity to allow the hydrocarbons to flow, i.e. the formation is tight. When target depth, the depth where the reservoir is thought to be, is reached it is time for logging. If it is a clear show of hydrocarbons, the well is called a discovery well (figure 3.5). However, it is too early to determine if the discovery contains commercial quantities of hydrocarbons or not. It is also a premature conclusion to abandon the well as a dry hole even if there is no indication of hydrocarbons when reaching the target depth (Hyne, 2001). This is because the drilling can have damaged the formation and this can prevent any fluids in the formation to flow.

The aim of logging is to measure, among other parameters, porosity, fluid content and saturation (Hyne, 2001). This is done by the use of logging tools, which are lowered into the well on a wireline. The logging tools measure various rock properties as they are slowly pulled back to surface, where the sampling interval usually is every 0.15 m (Deffeyes, 2001). For example, one tool measures the resistivity of the pore fluids. Water, especially salt water, is a good electrical conductor but oil and gas are not. If the resistivity is high, it is an indication of oil or gas (Deffeyes, 2001). The readouts from the tools are called logs and these are then interpreted. The accuracy of logging is at its best if it is a very good reservoir with good oil or gas saturations, or if it is poor and essentially non producible (Deffeyes, 2001).

In order to collect fluid samples and to make pressure measurements, tools as the repeat formation tester (RFT) and the modular formation dynamic tester (MDT), are used. If the fluid sample contains oil and/or gas, a pressure, volume and temperature (PVT) test is performed to determine the physical and chemical properties of the fluid (Dake, 2004). Another way to collect a fluid sample and at the same time test the flow is to do a drill stem test (DST). However, the flow duration is short and might not give a definite result on the reservoir size (Dake, 2004).

If the tests are encouraging, the exploration well can be completed and put on a production test. The most common test is the pressure build-up test (Dake, 2004). The results obtained are then used to determine the reservoir pressure, formation characteristics and the size of the reservoir (Dake, 2004). In order to get the best possible picture of the field, appraisal drilling now commences (figure 3.5). This ends when the collected data is sufficient to tell if the size of the field is enough to motivate a full scale development or not (Dake, 2004).

3.3.2 Production

A company with a successful discovery, which is large enough to motivate a field development, is usually required to apply for a production license from the resource owner (Tweedie, 2003). Thus, the exploration license is converted to a production license. This usually requires a submission of

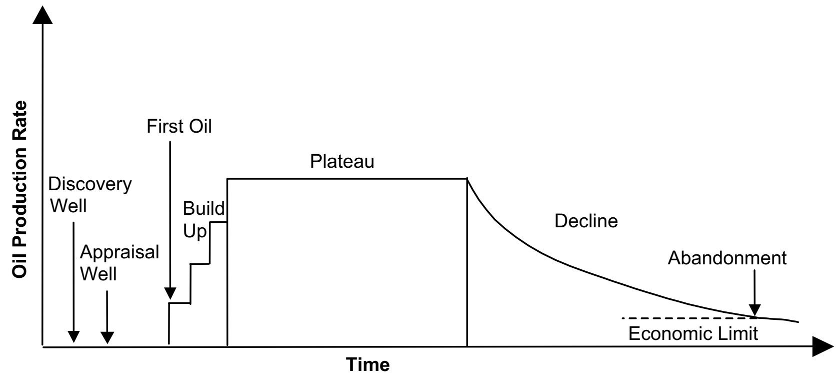


Figure 3.5: Production profile for an oil field. (After Davies (2001)).

a field development plan containing, among others, a time schedule from project start to first oil, information on production levels, field development method and environmental impact (Tweedie, 2003). When the field development plan is sanctioned by the resource owner, the work towards first oil production starts.

The period from the start of continuous production (first oil in figure 3.5) until the field abandonment, is referred to as the development and production phase (Dake, 2004). After first oil there is a build up phase with the aim of reaching the designed plateau production (figure 3.5). The production profile is to a large extent dependent on the characteristics of the reservoir and its fluids, such as pressure and permeability. Moreover, it also governs the design of the production system used to get the produced fluids from the reservoir to the surface. The production system can be divided into five parts and is illustrated in figure 3.6 (Peden, 2000):

1. Reservoir
2. Wellbore
3. Production conduit (tubing)
4. Surface installations (wellhead, Christmas tree, flowline and choke)
5. Separator

An unproduced reservoir contain fluids (oil and/or gas and/or water) in the pore space, usually at high pressure. When a well is drilled into the reservoir, the stored energy in the compressed fluids allow the fluid to flow toward the wellbore[2] (figure 3.6). As long as the pressure in the reservoir will lift the fluids to the surface, the well is natural flowing. In addition to pressure, the flow is governed by the viscosity of the oil (μ) and the properties of

[2]Some reservoirs do not flow under initial pressure and therefore supporting energy must be supplied from the beginning.

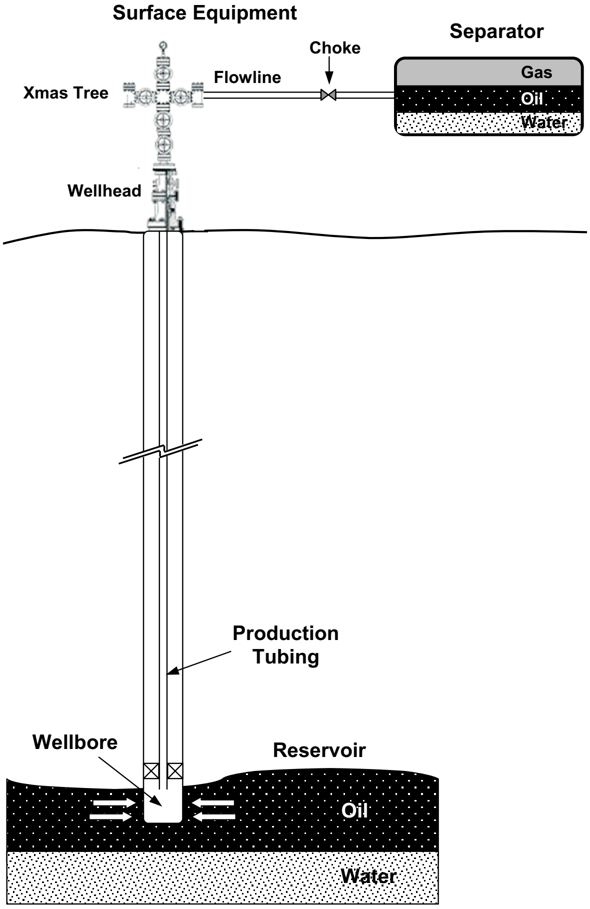


Figure 3.6: The production system. (After Peden (2000)).

the following reservoir parameters: permeability (k), porosity (ϕ), and pore compressibility (c). At some point during the production time, the pressure declines to a level where the fluids can not reach the surface. In this case, supporting energy must be supplied by some kind of pump and the well is said to be artificial lift operated. The reservoir fluids then flow through the production tubing and reaches the surface equipment (figure 3.6). The wellhead is an equipment assembly (piping, valves) placed on top of a well to safeguard against uncontrolled flow of oil and/or gas, i.e. a blow-out. On top of the wellhead is a so called Christmas tree (or Xmas tree), an assembly of pipes and valves where the produced fluids leave the well and enter the flowline. A choke (figure 3.6) is installed on the flowline to provide stable conditions before the separator. In the separator (figure 3.6), the produced fluids are separated to each phase and then stored, sold or used.

The production results in a pressure depletion process in the reservoir. This is a dynamic process and the fluid remaining in the reservoir will change both in terms of its volume, flow properties and in some cases its composition. The response of the reservoir is to compensate for the produced fluids by compaction of the reservoir rock and/or expansion of any of the fluids present in the reservoir or underlying water bearing rocks, so called aquifers (Dake, 2004; Peden, 2000). The compensation of the withdrawn fluids is the reservoir drive mechanism and it has certain typical performance characteristics in terms of (Ahmed, 2001):

- Ultimate recovery factor
- Pressure decline rate
- Gas-oil ratio (GOR)
- Water production

The recovery of oil from any of the reservoir drive mechanisms is called primary oil recovery. Secondary recovery, on the other hand, is when a fluid is injected into the reservoir in order to increase production and recovery. Below is a short description[3] of each of the reservoir drive mechanisms.

Volumetric Expansion Drive The simplest form of reservoir drive occurs when the reservoir pressure is above the oil's bubble point, the oil is undersaturated. The removal of oil from the reservoir is compensated by expansion of the oil left in place, i.e. the pressure drops. As long as the reservoir pressure is above the bubble point, the expansion of the oil is the only drive mechanism. Continued production will eventually lead the pressure to drop to a level below the bubble point. Only a small percentage of the oil in place is recovered by volumetric expansion drive (Ahmed, 2001).

Solution Gas Drive The production of a reservoir where the pressure is below the oil's bubble point will result in gas bubbles coming out of solution. As the pressure drop continues, both the gas and oil phases will expand in the reservoir which is the drive mechanism for the reservoir. Gas will come out of solution everywhere in the reservoir where the pressure is below the bubble point. However, the gas will be concentrated in low pressure areas such as close to the wellbore. A rapid decline in the reservoir pressure is usually observed. The GOR will increase rapidly as soon as the gas saturation allows free gas to move to the wellbore. If the vertical permeability is good, a secondary gas cap can be built up due to gravitational forces. The ultimate recovery factor vary from 5 to 30 per cent, which suggests that a lot of oil is left in the reservoir (Ahmed, 2001). Consequently, solution gas drive reservoirs are good candidates for secondary recovery methods.

Gas Cap Expansion Drive In a reservoir where both oil and gas zones exist, i.e. the reservoir pressure is equal to or below the bubble point of the

[3] Based on Ahmed (2001), Dake (2004), Peden (2000) and Todd and Somerville (2000).

oil, gas will migrate upwards to form a gas cap. The production will result in an expansion of the gas cap and expansion of the solution gas as it is liberated. The pressure decline will in general be slow, due to the expansion capacity of the gas cap. However, this depends on the size of the gas cap and its relative size to the oil volume. A steady increase in the GOR is usually observed. The recovery factor for a gas cap reservoir can be expected to be in the interval 20 to 40 per cent (Selley, 1998; Ahmed, 2001).

Influx Water Drive It is common that reservoirs are bounded by aquifers. Their size compared to the oil volume vary from very large to negligible. When oil is removed from the reservoir during production, the water from the aquifer moves into the pore space which previously was occupied by oil and in this way replace the oil. If the aquifer is large compared to the oil volume the pressure decline is usually very gradual. As production continues the oil-water level (OWL) will gradually rise. However, it is only in very uniform reservoirs the OWL will rise in an even way. The water will eventually reach a producing zone and cause water break-through and consequently, production of both oil and water. The fluid production is often stable but with an increasing part water and decreasing part oil during the lifetime, i.e. the water cut increases. If there is a drop in pressure, the drop is slow and thus the GOR in water drive reservoirs is usually stable. The recovery factor is very high, according to Ahmed (2001) up to 75 per cent while Selley (1998) has it to 60 per cent.

Compaction Drive The pressure depletion caused by fluid production from a reservoir will in some cases be compensated by a compaction of the reservoir due to the overburden of the overlying layers. To some limited extent, compaction is present in all reservoirs, but usually with no measurable effects (Peden, 2000). For example, the giant Ekofisk oil field in the Norwegian part of the North Sea is an example where the reservoir compaction was measured in meters (Dake, 2004).

Combination Drive The most common type of reservoir drive is a combination of the drive mechanisms mentioned above. The combination of free gas and an aquifer is most encountered (Ahmed, 2001). The response to production of oil is less predictable in a combination drive reservoir (Peden, 2000).

A well drilled into a reservoir will recover hydrocarbons in an area around it, called the drainage area. The ideal drainage area is circular with radial flow into the wellbore (figure 3.7). The drainage area will have a pressure P_{res} (Peden, 2000). On the other end of the system is the separator (figure

3.6), which has an optimal operating pressure (P_{sep}). If the oil will be able to flow from the reservoir into the wellbore, there must be a pressure drop between the reservoir and the wellbore, a drawdown ($\triangle P_{\text{res}}$).

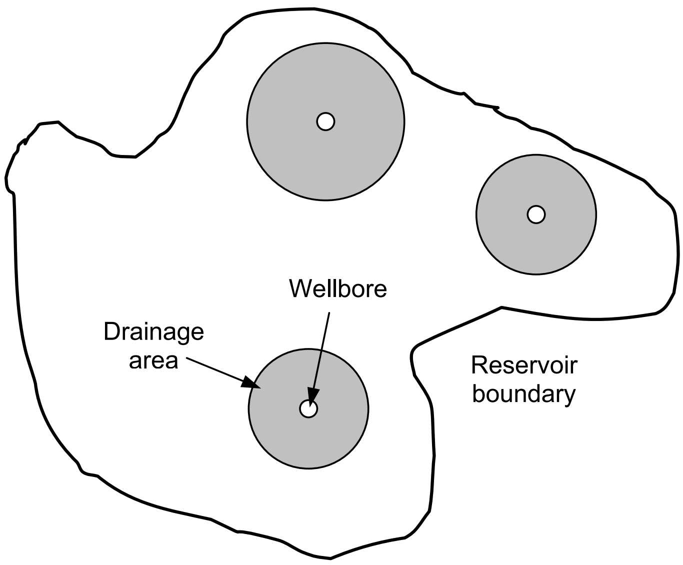


Figure 3.7: Planar view of an ideal drainage area of an oil well. (After Peden (2000)).

The lowest part of the production tubing, the downhole completion, will cause a pressure drop usually referred to as the bottomhole completion pressure ($\triangle P_{\text{bhc}}$) (Peden, 2000). When the oil is in the wellbore it has to flow up the production tubing. The pressure losses between the bottomhole and the surface is termed the vertical lift pressure ($\triangle P_{\text{vl}}$), which is attributable to pressure losses due to friction, hydrostatic head and kinetic energy losses. When at the surface, the oil has to flow through the surface installations, which yields the surface pressure loss ($\triangle P_{\text{surf}}$). To get the separator pressure, the oil then passes through the choke, where a pressure loss occurs ($\triangle P_{\text{choke}}$). The available pressure drop, which is rate dependent, from the reservoir to the separator tank is then given by (Peden, 2000):

$$(P_{\text{res}} - P_{\text{sep}}) = [\triangle P_{\text{res}} + \triangle P_{\text{bhc}} + \triangle P_{\text{vl}} + \triangle P_{\text{surf}} + \triangle P_{\text{choke}}] \tag{3.9}$$

Supporting energy must be added when the reservoir drive energy is not enough to overcome the completion and vertical lift pressure. This can be done by either inject fluids into the reservoir or providing more energy to the vertical lift process by some kind of pump. The methods can also be used in combination.

Any attempt to recover more oil from a reservoir than the recovery from the natural drive energy is called improved oil recovery (IOR). In general, IOR is divided into secondary recovery and enhanced oil recovery (EOR).

The injection of either water or gas into the reservoir is usually referred to as secondary recovery. The aim of the secondary recovery is to balance the withdrawn fluids and in that way maintain reservoir pressure. The efficiency is determined by the viscosity of the oil and the mobility between the oil and the injected fluid (Dake, 2004). EOR methods used are miscible flooding and different thermal methods, such as steam flooding.

Water Injection Water is injected into the aquifer through one or more injection wells, which typically are drilled in patterns to maximize the effect. Initially only oil[4] is produced but at some time during the production lifetime a water break through will occur and hence both production of oil and water. The water percentage of the production is called the water cut, and it will in general increase during the production.

Gas Injection The injection of gas follows the same patterns as for water injection. However, for gas injection to be efficient, the gas should be injected above the oil (Dake, 2004). In this way the injected gas creates or expands a gas cap.

Water Flooding Water is injected into the oil zone and ideally creating a vertical flood pushing the oil toward the producer.

Gas Flood Gas has a higher mobility relative to oil and will therefore channel through the oil zone. Therefore, for a gas flood to be effective, the initial injection of a fluid with the right properties is needed.

The other method, to support the vertical lift process, are referred to as artificial lift techniques (Davies, 2001). Two main types can be identified: gas lift and downhole pumping. Both types are discussed below, and the information is mainly from Davies (2001) and Peden (2000). The selection of which artificial method to apply depends on many factors, such as well and reservoir characteristics, field location, operational limitations and economics. It has been estimated that more than 90 per cent of the world's oil wells requires some kind of artificial lift in order to flow (Davies, 2001).

Gas Lift The aim is to reduce the bottomhole pressure by injecting gas into the production tubing. The gas is injected into the annulus between the production tubing and the casing. Gas entry valves at different depths at the production tubing allowing the gas inside the tubing and hence mixes with the oil. This results in a reduction of the density of the fluid above the injection point, which in turn reduce the bottomhole pressure. Gas lift is suitable for medium to high rate wells and high GOR is an advantage.

[4]Some reservoirs produce both oil and water from the start.

Electric Submersible Pumps (ESP) A multi stage centrifugal pump is installed at some depth downhole, usually as an integral part of the production tubing. ESP is good for high rate wells (<100 000 bpd), even with high water cuts, in depths up to 5 000 m. They are also suitable for highly deviated wells (<80°).

Progressing Cavity Pumps (PCP) A helical metal rotor rotating inside an helical stator is installed downhole. The rotating action is supplied by an electrical engine. The pump is suitable for pumping viscous oils. They can either pump moderate volumes (1 000 bpd) at shallow depth (~2 100 m) or small volumes (100 bpd) at greater depths (~4 600 m).

Hydraulic Downhole Pumps use a high pressure power fluid pumped from the surface which drives a downhole turbine pump or positive displacement pump. Hydraulic pumps are good both for moderate rates (100 bpd) and high rates in depths up to 5 500 m.

Rod Pumps is in general referred to as "nodding donkeys". A downhole plunger is moved up and down by a rod connected to an surface engine. Rod pumps are suitable for low rate wells in depths up to 5 000 m. The pumping depth decreases quickly as soon as the rate exceeds 100 bpd. Rod pumps are not suitable for rates above 5 000 bpd.

Despite using artificial lift methods and both secondary and enhanced recovery methods, well inflow might not be as good as expected. There are numerous reasons to this and some are described below.

Solid invasion can occur during drilling where the solids can invade the formation and block the pore throats and thus reduce permeability.

Fluid loss to formation Fluids used during drilling or completion invades the formation and increases the liquid saturation. This reduces the relative permeability for oil and thus decrease the flow.

Inorganic scale formation Changes in temperature and pressure in the reservoir and/or the production system and mixing with incompatible fluids can generate scale formation. The result is a flow reduction and increases the pressure losses.

Organic scale formation Wax precipitation occur due to the reduction of temperature in the production tubing. The reduced pressure from the reservoir and through the production system leads to precipitation of asphaltene. As with inorganic scales, organic scales will reduce the flow and increase the pressure loss.

Fines movement Small particles on water wet sand grains in the reservoir start to move when both water and oil is produced. The fines can block the pores and reduce the permeability. Hence, the flow is reduced.

Sand production At some flow rate, sand particles are removed from the reservoir and is transported with the produced fluids. Sand production can destroy both the production system as well as the reservoir. Sand production usually occurs at high flow rates.

Despite well inflow problems, oil is flowing in large volumes from wells all over the world. The global hunt for the good wells and the economical and geopolitical consequences of it is described in the next chapter.

4. The Oil Era

The aim of this chapter is to show what happened when the science of geology and techniques of exploration and production was put into practice. It starts with the early exploration in the mid 19^{th} century and continues with the evolution of the main oil producing nations. Moreover, the chapter also shows the growth of the use of oil as an energy source as well as its role in geopolitics, which has led to the situation of today when peak oil is discussed. The history of oil might have been a completely different one if it was not for the invention and development of the internal combustion engine.

Despite the fact that oil was commercially drilled for in China, Russia, Romania, Burma and Canada earlier than 1859, the modern history of oil dates back to the discovery at Oil Creek in Pennsylvania in 1859. This is due to a refining method that made it possible to extract kerosene from the oil. From then on and to the late 1890s, crude oil was refined to kerosene and used for lighting. At the end of the 19^{th} century, oil was an international commodity.

The development of the incandescent light bulb started a shift in lighting technology, from the use of kerosene to electric power. This was seen as a major threat to the oil industry but the rapid development of the automobile and the use of the internal combustion engine changed the situation. Consequently, the demand for gasoline refined from crude oil had a rapid growth. Thus, the oil industry expanded and became a truly international industry.

During the 20^{th} century the energy use in general increased and the use of oil in particular. Oil went from being a small part of the energy mix to be the most important. The shift was of such significance that security of supply became part of the national policies for the main consumer nations such as the US and the nations in Western Europe. The first world war showed the importance of oil and in the second world war, oil was a strategic goal. The economic boom of the post-war era was fueled by cheap oil, which mainly came from the Middle East. However, the resulting oil dependence and the instability of the region led to several conflicts.

4.1 The Early Years

The early years of the oil industry is dominated by the growth of different oil regions and companies. The first oil regions of the world was Pennsylvania (USA) and Baku in Russia (today Azerbaijan). Standard Oil, founded by J Rockefeller, was the dominating company that sought after world monopoly, but other companies challenged them. The riches that oil companies generated led people and companies to explore for oil in different areas of the world.

4.1.1 USA

In USA, the oil prices in the 1860s were far from stable, due to overproduction. In 1870, J. Rockefeller created the Standard Oil Company in order to consolidate the market and take control over prices. Rockefeller's idea of integration, i.e. bringing both supply and distribution functions in the same company, helped the company to reduce costs and thus, gain market shares. However, selective price cuts also helped Standard Oil to force competitors off the market (O'Connor, 1965). By 1891, Standard Oil was responsible for about 25 per cent of the production and about 85 per cent of refining in USA (Yergin, 1993).

At the end of the 19^{th} century the demand for oil was growing mainly due to the use of gasoline in automobiles. A growing use of fuel oil for boilers in factories, trains and ships further increased the demand. The focus had now shifted from where to find markets to where to find new supplies. The fields in operation in Pennsylvania showed a clear decline in production and the few fields in Ohio could not match the demand.

The first area outside the eastern part of USA to start production was California. Because of transportation problems, this production did not help to ease the soaring demand on the east coast. Instead, the main market for California oil was Asia. The discovery of oil in Spindletop in 1901 started the Texas oil boom and companies like Texaco and Gulf were established. However, the oil could not be refined into kerosene due to its bad quality, instead it was used as fuel oil in heating, power and locomotion. This was the first steps which led to a conversion from coal to oil in industrial society (Yergin, 1993).

4.1.2 Russia

The export of kerosene, from Philadelphia to London, started as early as 1861. Soon, the export expanded to the rest of Europe. One of the most promising markets was Russia, which had a primitive oil industry that was dated as far back as the beginning of 19^{th} century. The Russian oil industry was situated in Baku at the Caspian Sea, very far from the market in St. Petersburg. In 1873, the Czar opened Baku for competitive private enterprizes. The leading man of the oil industry in Baku was "the oil king of Baku" - Ludwig Nobel (O'Connor, 1965). He and his brothers, Alfred and Robert, established the Nobel Brothers Petroleum Producing Company[1]. Despite the transportation problems, kerosene from the Nobel refinery reached St. Petersburg in 1876. Their solution was to transport the oil in bulk. The Swedish-built ship Zoroaster was sent to the Caspian, and became the first successful bulk tanker (O'Connor, 1965; Yergin, 1993). A few years later this type of ships proved themselves on the Atlantic, thus a revolution in oil transport was seen (Yergin, 1993).

At first, Standard Oil dismissed the idea of Russian oil as a threat to their European market, but in 1880, when a railroad between Baku and the port Batum in the Black Sea was granted, the competition for the European market started. Still, at the end of the 19^{th} century the main player was Standard Oil.

4.1.3 Far East and Growing Competition

Oil seepages had for a long time been known on the islands Sumatra and Java of the Dutch East Indies. In 1884, the first successful well was drilled on Sumatra and in 1890, the Royal Dutch Petroleum Company[2] was established in Amsterdam. Soon, they had a considerable market around the Chinese Sea.

A promising market for the growing oil supply from Batum was the Far East, which could be reached through the Suez channel. However, the board of the channel did not allow oil transports on Suez. Eventually, the British trading company M. Samuel & Co had a new tanker design that was allowed to travel on the Suez. In 1892, the Suez channel opened for the tanker Murex from M.Samuel & Co, which transported oil from Batum. Since then, it has been the greatest income for the Suez channel (Yergin, 1993).

To the annoyance of both Standard Oil and Royal Dutch, M. Samuel & Co had established a market in the Far East. In 1897, the Samuel's renamed the company to the Shell[3] Transport and Trading Company. At the beginning of the new century the three companies - Standard Oil, Royal Dutch and Shell - were the main players of the international oil market, with Standard Oil as the leader. In order to gain control over the Far East market Standard Oil tried to buy both Shell and Royal Dutch. The head of Royal Dutch, H. Deterding later called the "Napoleon of Oil" (O'Connor, 1965), realized that the only way to beat Standard Oil was if Royal Dutch and Shell merged. And in 1907, after a few years of bad profits for Shell, the fusion was a fact and Royal Dutch/Shell (RD/S) was born.

[1] O'Connor (1965) calls it the Nobel Brothers Naphta Company
[2] Up to 1949 the name was Royal Dutch Company for the Working of Petroleum Wells in the Netherlands Indies (O'Connor, 1965).
[3] In respect of their father, a Shell merchant (Yergin, 1993).

4.1.4 Persia

Already around 500 B.C, Darius the Great excavated at least one hand-dug oil pit in Persia (O'Connor, 1965). Therefore, it is no surprise that explorers of the late 19^{th} century were interested in Persia. In 1901, W. D'Arcy was offered a petroleum concession that covered 772 320 square kilometers, which would last for 60 years. Exploration started despite the lack of roads, the problematic water supply, and tribes with uncertain intentions in the area (Longhurst, 1959). Oil was first struck in 1904 but the well soon went dry. Operations moved to the south west, a land belonging to the most powerful tribe in Persia, the Baktiharis. They demanded a percentage of the net profits to guard the concession. However, the agreement fell apart due to conflicts within the tribe (Baktihari, 2004). Drilling at the site called Masjid-i-Sulaiman commenced in 1908 and on May 26 1908 they struck oil (Longhurst, 1959). The discovery became the foundation for the creation of the Anglo-Persian Oil Company (A–P) in 1909, which later became British Petroleum (BP) (Longhurst, 1959).

4.1.5 Mexico

The construction of railroads and the need for fuel for the locomotives ignited the oil exploration in Mexico in the late 19^{th} century. Drilling started in 1901 and the first success was the Dos Bocas well number 3 in 1906, with a flow of 50 000–10 0000 bpd. However, it quickly turned out to be a disaster since the well caught fire and burned until it was almost dry, caused by bad drilling practice and a lack of security thinking (O'Connor, 1965). In 1910, the famous well Potrero del Llano number 4 was discovered with a flow of 110 000 bpd. This was probably one of the largest wells ever encountered in the world (Deffeyes, 2001; Yergin, 1993). But once again, the bad drilling practice led to an uncontrolled flow. However, the well started the Mexican oil boom in the so called Golden Lane. In hindsight it is possible to say that the drilling and production practice utilized at that time was not good enough for the enormous wells in Mexico, which led to the more or less bad production of the Golden Lane fields. The aftermath of the Mexican revolution in 1911 led oil companies to abandon Mexico and start to look further south.

4.2 World War I

In the early years of 1910 the enemies of UK had shifted, it was no longer France and Russia but Germany. In August 1914, World War I started. Before and at the outbreak of the war, planning was made with respect to railroads and horses, but during the war the focus would shift from horses to more mechanized and motorized equipment such as cars and aeroplanes.

In general, the use of oil in the war increased the mobility of the armies and a new type of warfare developed (Engdahl, 2004). Since oil was the fuel, this in turn shifted the focus towards secure oil supplies (Engdahl, 2004).

Neither France nor UK produced oil on their own ground, but both military forces became increasingly dependent on oil. This made them very vulnerable to supply disruptions. The supply was the United States, which shipped the oil to Europe in tankers. Around 80 per cent of the oil used by the allies was imported from the USA (Yergin, 1993). Consequently, the USA oil were crucial for the survival for the allies. Germany had similar problems with their oil supply, since they did not produce any large amounts of oil on their own ground. The solution for Germany was to annex the main producer of oil in Europe, Rumania. It was out of reach for the allies and soon became the main source of oil for Germany.

Germany's attacks on oil tankers were successful, and in early 1917 they sunk one per day. At this time, it looked like the allies had to apply for truce before Christmas due to a lack of oil (O'Connor, 1965). However, the allies succeeded in strengthen their supply chain of oil despite the successful German attacks on oil tankers. Moreover, Germany was denied any oil since the oil fields in Rumania was partly destroyed by the allies (Yergin, 1993). As a consequence, Germany was inferior to the allies and surrendered in November 1918. According to Lord Curzon of UK, "the Allies floated to victory on a sea of oil" (Longhurst, 1959).

4.3 Growth of the Oil Era

In the early 1920s, there was a fear of shortage of oil since USA had been overproducing during the war and, in addition, the discoveries between 1917 and 1920 had been disappointing. A director of the US Geological Survey (USGS) predicted an imminent peaking of US oil production (Yergin, 1993), which together with increased competition, pushed the US companies to start to explore overseas. This led the US companies to the Middle East, especially Mesopotamia (now Iraq), and Venezuela as well as growing competition with companies like RD/S and A–P.

The use of cars increased both in Europe and especially in the USA. By 1929, there were 23.1 million cars in the US, which were 78 per cent of the world's cars. Consequently, the demand for gasoline increased and with that the demand for oil. The competition between different companies resulted in the creation of the modern gas station (Yergin, 1993).

Part of this growth in automobile use was due to federal and sometime state support for the construction of new roads. This was a great advantage compared to other transport methods, because the streetcar companies had to pay themselves for the rail and railroads. Moreover, in secret General Motors (GM) bought more than hundred streetcar companies and shut them down. This was done in Tulsa, Montgomery, El Paso, Chicago and New York among others. Instead buses, constructed by GM, run the former streetcar lines (Schlosser, 2004). Another important factor for the increasing use of cars was the establishment of the drive-in culture in California where drive-in restaurants became common and the first drive-in bank saw day light (Schlosser, 2004).

The oil industry in Russia, which had been an important part of the global oil market before World War I, was nationalized in 1918 by the Soviet government[4] (Yergin, 1993; Grace, 2005). This reduced the oil production to 40 per cent of the 1913 level, the last pre World War I level (Grace, 2005). In addition, this meant the end for foreign oil companies, such as RD/S and Nobel, in Russia, and many of them lost all their investments (Yergin, 1993; Grace, 2005). However, the low oil production levels led to a re-opening of the oil market and Western companies with more efficient production technologies were back in Soviet in the mid 1920s (Grace, 2005). As a result, Soviet remained an important oil exporter and during the 10 year period between 1926 and 1935, 14 per cent of the oil imported by Western Europe came from Soviet (Grace, 2005).

In 1913, RD/S was the first company to get a concession in Venezuela and minor production started the same year. After World War I, their exploration and production really took off. It was a difficult task to acquire a concession in Venezuela but Standard Oil of New Jersey[5] (SONJ), Standard Oil of Indiana (SOI) and Gulf succeeded. Company geologists said at the time that major discoveries were not to be made in Venezuela (Yergin, 1993). As drilling technology improved, it turned out that Lake Maracaibo was one of the most promising oil areas in the world. Most of the fields discovered in the Lake Maracaibo turned out to be part of the giant Bolivar Coastal Complex, one of the the largest fields ever discovered. The stability in Venezuela, due to a strong dictatorship, and the profitable petroleum laws drew a lot of interest from other companies and soon Venezuela became a world leader in oil production (O'Connor, 1965).

Many countries were interested of oil exploration in Mesopotamia. In 1914, the Turkish Petroleum Company (TPC), was established to explore for oil in Mesopotamia. The owners of TPC were A-P (major share holder), RD/S, Deutsche Bank and the investor C. Gulbenkian. The latter was allocated 5 per cent on account of his merits during the negotiations for the concession and thus his famous nickname "Mr Five Percent" was born (Longhurst, 1959). The company managed to get exclusive rights to oil production in the Ottoman Empire (Yergin, 1993). However, the outbreak of World War I stopped all activity in Mesopotamia.

[4] The creation of Soviet was one result of the Russian Revolution in 1917.
[5] The main company of the newly divided Standard Oil Trust.

In 1920, the newly created state owned French company CFP got the German part of TPC. Fears of a British oil monopoly and a soon peak in US production prompted the US government to demand an open door policy for US oil interests in the Middle East (O'Connor, 1965; Yergin, 1993). Negotiations and exploration continued, both with no success. But in 1927 TPC drilled the Baba Gurgur well number 1, which was the discovery of the Kirkuk field. The field is one of the largest ever discovered. The discovery accelerated the negotiations and finally, the Near East Development Company[6] (NEDC) received half of A-P's share in TPC that soon changed name to Iraq Petroleum Company (IPC) (Longhurst, 1959). The exclusive rights owned by TPC were now expanded to include Turkey and all countries in the Middle East, except for Kuwait and Persia (now Iran) (Yergin, 1993). The concession included the Red-Line agreement, which stated that exploration for oil in the concession area could only by carried out by the IPC. The agreement shaped all future exploration in the Middle East and was also a constant source for conflict among companies and to some extent countries (Yergin, 1993).

According to the geological expertise at the time, Arabia did not have a potential for oil discoveries. Standard Oil of California (Socal) showed an interest in the Bahrain concession. Gulf tried to secure a concession in Kuwait. This upset the UK government and once again, a bitter feud between US and UK about oil rights took place. An agreement was reached for the Bahrain concession and, in 1932, Socal discovered oil. This changed the conditions, because the geology in Bahrain and the Arabian Peninsula was the same (Yergin, 1993).

Ibn Saud took control over Arabia in 1925 and in 1932 he changed the name to Saudi Arabia. In 1933, Socal won the oil concession[7] for Saudi Arabia and it would last for 60 years (O'Connor, 1965). To be able to handle a big discovery, Socal needed help with the marketing. Thus, they formed the joint venture Caltex with Texaco for managing the oil from Arabia (Yergin, 1993). In 1938, the large oil field Dammam was discovered. Ten years later, Ghawar was discovered in Saudi Arabia and it is by far the largest oil field discovered.

In 1934, after a few years of arguments and a constant pressure from the US State Department, the Kuwait Oil Company (KOC) was established (Longhurst, 1959). A-P and Gulf owned half of the shares each. However, the development within Kuwait was assured to the British (Yergin, 1993). Later the same year, KOC was granted a 75 year concession covering the whole of Kuwait. In February 1938, a month before the discovery in Saudi Arabia, oil was struck at the Greater Burgan Field. The discovery was huge, the second largest so far to be discovered, and the future for Kuwait was decided.

[6]Represented the leading US oil companies, such as SONJ, Gulf and Standard of New York.

[7]Socal created the California-Arabian Standard Oil Company (Casoc) to hold the concession (O'Connor, 1965; Yergin, 1993).

Despite the move of exploration abroad, exploration in the USA continued especially in California, Oklahoma and Texas. In 1921, oil was found at Signal Hill outside Los Angeles and by 1923, California was the largest producer in the US. During the same time warnings of an upcoming shortage of oil led to an increased interest in the Colorado Plateau oil shales. However, the costs of development were woefully underestimated and the project was abandoned. The largest oil boom ever seen in the US started with the discovery in 1930 of the East Texas field, the largest field discovered in the lower 48 states. The huge production from East Texas consequently led to a price fall, first in Texas and later nationwide. In order to avoid overproduction the Texas Railroad Commission (TRC) was permitted to regulate the production.

4.4 World War II

In contrast to World War I, both the planning for and the strategy of World War II was heavily dependent on oil. Oil installations, such as refineries and tankers, became important targets for both sides (Longhurst, 1959). Both Hitler and Churchill knew that the dependence on imported oil was a weak link in their respective nations warfare (Yergin, 1993). To reduce the oil dependence, Germany focused on the production of oil from coal, which was made by the Fisher-Tropsch method. The British concern was where to find their supply. The only place to look was to the US and to some small extent Persia.

Germany invented the Blitzkrieg, short battles with mechanized forces that would lead to victory before petroleum supply problems could develop (Yergin, 1993). The need for oil was the one of the motives behind the German invasion of Russia in 1941, where the objective was the oil fields in Baku (Yergin, 1993). By mid 1943, it was clear that the German operation in North Africa could not gain access to the Middle Eastern oil. At the same time, Germany's invasion of Russia had failed since the troops got stuck in Stalingrad, partly due to a lack of oil supplies (Yergin, 1993).

The most vulnerable link in the supply chain between US and Britain were the oil tankers, which were the main target of the German submarines. The situation was at its worst in March 1943, with an almost broken supply chain and minimal oil supply. However, the breaking of the German Enigma code and further development of the radar shifted the table and an abundant flow of oil reached Europe (Yergin, 1993).

Japan invaded China in order to capture both living space and resources. About 80 per cent of Japan's oil in the late 1930s came from the US (Yergin, 1993). But when Japan invaded Indochina, now Indonesia, in 1941, aiming for the oil fields in the Dutch East Indies, the US stopped their supply to Japan. The Japanese military saw only one solution and consequently declared war on US (Yergin, 1993). In 1941, the US was dragged into the war by the Japanese attack on Pearl Harbor (Vidal-Naquet, 1991).

The Japanese took over the drilling and development of the oil fields in Indochina, but as the war continued the Japanese were pushed back, and their fuel supply was hampered. In order to save fuel, the kamikaze mission was created: enough fuel for a one-way mission, i.e. a suicide mission (Yergin, 1993).

In Europe, the D-Day (June 6, 1944) was the beginning of the end. However, it took nine months before the war ended, when Russia captured Berlin. The Pacific war on the other hand ended in August 1945, with the dropping of the atomic bombs. The better and more secure supply of oil and refined fuel was one of the main reasons the allies finally could get the war to an end (Yergin, 1993).

4.5 The Era of Cheap Oil

The post war era is characterized by an immense growth in energy use, especially the usage of oil. The world total energy consumption increased more than three times between 1949 and 1972. During the same period the oil consumption increased by more than five times (Yergin, 1993). Since the main consumers, US and Western Europe, did not produce enough oil, they became dependent on imported oil. The increase in demand and a growing dependence on Middle East oil stimulated exploration in new areas such as Africa, Alaska and the North Sea.

In 1947, the war torn Europe faced an energy crisis due to a shortage of coal, which led to a conversion from coal to oil. Oil could be used not only in transportation such as cars, trucks and aeroplanes but also in industry boilers and power plants. Since Europe did not produce much oil of its own, it had to be imported. The need for oil in Western Europe coincided with the development of the large Middle East oil fields. About 20 per cent of the economical aid from the USA to Europe after World War II (the Marshall plan), was used to cover costs connected to oil (Yergin, 1993). The shift from a self-supported coal based economy to an oil based led to a dependence on imported oil. The USA was the first country to switch from a coal based to an oil based economy. The main reasons were the post war explosion in car use and that oil became a cheaper energy source. In 1955, almost two thirds of the world's cars were in the USA. Oil production in the USA could not match this growth in demand and the oil empire also shifted to an importer and the dependence that follows.

The shift from coal to oil as the main energy source went fast in western Europe. In 1955, 75 per cent of the total energy use came from coal while oil made up 23 per cent. The relationship was more or less the opposite in 1972 (Yergin, 1993). The strong economic growth of this period was powered by cheap oil (Yergin, 1993). The cheap oil came from the Middle East, mainly Saudi Arabia and Kuwait, whose enormous oil potential now had been established. The lucrative European market was the goal for the Arabian-American Oil Company (Aramco) that had the concessions in Arabia. Aramco consisted of the four US companies Socal, Texaco, SONJ and Socony[8]. The oil from Saudi Arabia and Kuwait reached Europe by the so called Tapline, a 1673 km long pipeline from Saudi Arabia to Lebanon (O'Connor, 1965). From there, tankers carried the oil to Europe. The oil production in the Middle East grew at an almost exponential rate from 1940 and up to the early 1970s. In 1940, the Middle East contributed with 95 Mb of the 2 150 Mb produced in total, i.e. slightly less than 5 per cent. This number increases steadily and reached 38 per cent in 1973 when 7 800 Mb of the total of 20 153 Mb were produced in the Middle East. The demand for oil in Europe increased at more or less the same rate as the production from the Middle East.

The response to this increased dependency of oil in general and Middle East oil in particular varied from nation to nation. For example in 1971, 75 per cent of the energy consumed in Sweden was imported oil and the response was to develop nuclear power (Robelius, 1997).

Oil production was an important part of the Soviet economy and before World War II, oil production had slowed down due to old and mature fields, especially in Baku (Grace, 2005). Exploration in the Volga Ural region led to the discovery of the Romashkino field in 1947, which at the time was one of the largest fields in the world. The production growth from the field from first oil in 1952 to its peak level in the early 1970s was the fuel for the expansion of the Soviet economy (Grace, 2005). Western Siberia, the world's largest swamp, was the next oil and gas province to be discovered in Soviet (Grace, 2005). The region is still the most important oil and gas producing area of Russia. The main field is Samotlor, which was discovered in 1965 and is the largest field in Russia and one of the largest in the world. In addition, Western Siberia holds the world's largest producing gas field, Urengoy. The growth of oil production in Western Siberia during the 1970s gave Soviet increased export possibilities and consequently, higher export revenues (Grace, 2005). At the end of the 1980s, Western Siberia contributed over 14 per cent of world oil production, levels only Saudi Arabia have matched.

Exploration for oil in Africa became an important issue since the (major) oil companies wanted to diversify their supply and to be less dependent on the governments in the Middle East. In the early 1950s, Algeria was still a French colony and exploration could lead to a decreased dependence in imported oil for France. The first major field was discovered in 1956 and

[8]Socal, Socony and SONJ later changed names in the following way: Socal=Chevron, Socony=Mobil and SONJ=Exxon (Yergin, 1993).

later the same year, the Hassi Messaoud field was discovered. This was the largest field to be discovered in Algeria and showed that large fields occurred in northern Africa (Tiratsoo, 1984). More discoveries followed and soon Algeria was established as a large producer. Thus, France now had its own production (Yergin, 1993).

Algeria's neighbor in the east, Libya was expected to have petroleum potential as well. The relative political stability and a relatively small distance to the European market made Libya interesting. Many of the major companies involved in the Middle East begun exploration and in 1959, SONJ drilled at a place called Zelten where they struck oil. More exploration success followed and by 1961 Libya was exporting oil. The development of the petroleum industry was quick and during the 1960s the production increased steadily to more than 1 Mbpd in 1970 (Tiratsoo, 1984).

Oil exploration in Nigeria can be dated back as far as to 1908 (Tiratsoo, 1984). World War II delayed the exploration and it was not until 1956 that the first commercial discovery was made in the main Niger Delta (Tiratsoo, 1984). During the following years a string of large fields were discovered, among them Bomu and Imo River. Production increased steadily and Nigeria was soon a main producer of Africa.

In the late 1950s, exploration in Alaska took off with a few big discoveries (Tiratsoo, 1984). In 1968, the largest field so far discovered in North America (excluding Mexico), Prudhoe Bay, was discovered (Yergin, 1993; Tiratsoo, 1984).

The exploration in the North Sea started with the discovery of the Groningen gas field in Northern Netherlands in 1959. This led to the following application: "Phillips Petroleum Co. is interested in obtaining from the Norwegian government an oil and gas concession covering the lands lying beneath the territorial waters of Norway plus that portion of the continental shelf lying beneath the North Sea which may now or in the future belong to or be under the jurisdiction of Norway" (Nyland, 2004). This concession was not granted. In 1965, the first discoveries in the North Sea were made, but they were gas. However, in 1969 Phillips discovered the large Ekofisk (Norway) field. The harsh conditions in the North Sea combined with the deep water made it difficult to drill. Development of drilling and production technologies was very quick and this was necessary for the continuation of the North Sea exploration. During the early 1970s large fields such as Brent (UK), Forties (UK) and Stattfjord (Norway) were discovered. By this, Europe had finally been able to reduce the import dependence.

4.6 Control of Oil

The increased importance of oil is reflected by the political attempts to secure oil supplies and also the invention of policies to protect private companies. However, the governments in the consuming countries were not alone in the attempts to take control over the oil. Also, the producing countries wanted a larger influence.

During the wartime oil shortages in 1917–18 it became evident to the UK how important the oil was. Mesopotamia was the only place with promising oil prospects the British could gain control over. This became a war aim for the British and it was accomplished at the San Remo conference in 1920, where the division of the Middle East took place and the UK secured Mesopotamia (O'Connor, 1965; Yergin, 1993).

As early as 1907, the later to be US President, W. Wilson wrote that concessions held by American interests was to be protected by the US government, even if other nations sovereignty would be harmed (O'Connor, 1965). The US State Department issued the open door policy in 1897, which aimed at equal access for American capital and business. It also made it possible for the US State Department to put pressure on other governments regarding oil concessions. This was used in order to get US companies access to oil in Iraq when the San Remo agreement excluded the USA from all participation in oil exploration.

Future oil supplies became a strategic question at the end of World War I. This was also the case at the end of World War II. At this time, the increased demand in the USA could soon not be met by domestic production. This could lead to serious implications for the national security (Yergin, 1993). USA and UK agreed on that the petroleum matter in the Middle East must be settled before the end of the war in order to have stability. An intensive exchange of telegrams concerning oil between US president F.D. Roosevelt and UK prime minister Churchill showed the importance of oil in world politics (Yergin, 1993). As a result, Roosevelt suggested that they should share Iraq and Kuwait and the USA could have Saudi Arabia whilst the UK had Persia (Yergin, 1993). Moreover, both met with king Ibn Saud to discuss oil and the future of Saudi Arabia (O'Connor, 1965).

The oil production from the 1930s and onwards were dominated by the companies SONJ, RD/S and Anglo-Iranian Oil Company[9] (A–I). These were in different ways interlocked to Socony, Socal, Gulf and Texaco in different projects. Together, these seven companies controlled the production in Iran, Iraq, Kuwait, Saudi Arabia and Venezuela and thus, more or less the entire world oil market (O'Connor, 1965). In 1960, together with the French state owned company CFP they controlled around 90 per cent of the oil traded in the world (O'Connor, 1965). The companies kept the control of the oil for a period of time, but the producing nations started to object and questioning this order. New deals, national oil companies, and even expropriation would come in the post-war era.

[9]The Anglo-Persian Oil Company changed name to Anglo-Iranian Oil Company in 1935 (Longhurst, 1959).

First time a state owned oil company was mentioned was probably in Mexico in 1914 (O'Connor, 1965). But nothing really happened until L. Cárdenas took office and in March 1938 he signed the expropriation order. The state oil company Petróeos Mexicanos (Pemex) was established to control and continue the production. RD/S and SONJ turned to their respective governments asking for help to restore their properties. Instead, the governments of US, UK and Mexico reached an agreement where the companies were compensated for the loss. Thus, the first state owned company did survive and this also sent a message not only to the companies holding concessions around the world but also to other producing countries.

In the 1930s and 1940s, voices were raised in Venezuela to take back the oil, or at least get better revenues from the companies. After the expropriation in Mexico, either the companies or the US and UK governments could afford loosing the Venezuelan oil. The solution was a fifty–fifty deal based on the companies net revenues, which meant a large increase in income for the producing nations. One of the reasons the industry accepted this was that no one would question how they got over the concessions. These had in most cases been acquired illegally (O'Connor, 1965).

The news about the deal in Venezuela spread and in late 1950, Saudi Arabia made an agreement with Aramco on a fifty–fifty deal. The same deal was discussed in Iran as well, but it was not enough to stop a nationalization of the oil industry. As a response, the UK government, which owned 51 per cent of A–I, wanted to declare war on Iran. Instead, a trade embargo was imposed and no oil was transported from Iran due to a threat from the UK government to tanker owners. Oil operations in Iran ceased as well as exports of oil. Negotiations occurred resulting in the National Iranian Oil Company (NIOC) now owned the oil in the ground but a new consortia of SONJ, Socony, Socal, Gulf, Texaco, RD/S, BP[10] and CFP operated the fields (O'Connor, 1965; Yergin, 1993).

During the Arab Oil Congress in Egypt 1959, A. Tariki of Saudi Arabia and P. Alfonzo of Venezuela met. They shared the idea of a coordination of the production in order to control the price level. This would also guarantee the income for their nations. The two organized a meeting where representatives from Kuwait, Iran and Iraq were present. In 1960, SONJ decided to cut the posted price[11] without discussing it with the producing nations. This was the final straw, which resulted in the establishment of the Organization of Petroleum Exporting Countries (OPEC). The intentions of OPEC was to defend and restore the price. Moreover, they had plans of a system for regulation of the production from each member country. The five founding members of OPEC controlled more than 80 per cent of the exported oil.

[10]Anglo–Iranian Oil Company (A–I) changed their name to British Petroleum (BP) in 1954 (Longhurst, 1959).

[11]The income for the producing nations, i.e. taxes and royalties, was computed on the posted price.

However, the companies did not take OPEC serious in the beginning (Yergin, 1993).

In 1967, during the six-day war OPEC tried to impose an oil embargo on parts of the Western world, but without effect due to larger tankers and a spare capacity in the US (Yergin, 1993). However, it proved to the companies that OPEC might be a force in the future. This was clearly demonstrated during the oil crisis in 1973, when the OPEC countries embargoed large part of the Western world with an immense increase in the oil price as a result (Yergin, 1993). Moreover, the 1970s was the time when the OPEC members nationalized their oil industries, e.g. Kuwait in 1975 and Venezuela in 1976 (Yergin, 1993). By this, the major companies lost large parts of their reserves and production and had to explore in other areas and develop technologies to produce oil in more harsh environments. Thus, the power and control of oil had shifted, from the major companies to the producers and OPEC in particular.

Before the oil crisis, the Club of Rome in their book *Limits to growth* started to discuss the future of oil as an energy source. The oil crisis and the rising oil prices during the rest of the 1970s strengthened their view. But by 1986, the oil price had collapsed and this left OPEC much weakened. This led to a view that oil supply was no longer a problem. Still, the demand for oil has increased during times of both low and high prices. The future demand is predicted to grow by 1.4–1.7 per cent per year up to 2030 (EIA, 2006; IEA, 2006). Geopolitics with a focus on oil is again on the agenda, where for example US troops are placed in many Caspian Sea countries, which are believed to have large oil reserves (Klare, 2002). In the South China Sea, the Spratly Islands are a seed of conflict because of the petroleum resources thought to be there (Dahlby, 1998; Klare, 2002). The war in Iraq and oil is a heavily debated topic, but oil is one important parameter (Englund, 2004). In early 2006, a dispute on gas prices between Russia and Ukraine led to a cut off on exports from the Russian company Gazprom, which is state controlled (Friedman, 2006; Jovene, 2006). The cut off also effected parts of Europe and this led to discussions on energy security and the role of energy as a political weapon (Jovene, 2006). The more or less same situation took place early January 2007, when an oil pipeline between Russia and Belarus was closed. Late 2006 and early 2007 has also shown examples on increased nationalization, for example Sakhalin projects in eastern Russia and Orinoco heavy oil production in Venezuela (Wertheim, 2007).

In summary, the oil era has left the consuming nations with a dependence on producing nations, which political stability can be questioned, and put oil geopolitics on the agenda. Moreover, the transportation network is built for vehicles powered by refined oil products. Around two thirds of the oil consumed in the USA is used for transportation (BP, 2005). In Europe, the number is around 50 per cent. The economic growth in China has been fueled by oil and their continued economic growth is expected to require more oil (EIA, 2005). Thus, oil is needed and will be an important part of the future world and the question to what extent it will be available is of the uttermost importance.

5. The Peak Oil Debate

Uncertainties about the future oil supply have been a part of the oil business since its beginning in the 1850s. So far, the answer has been new areas for exploration and improved technology. For example, in 1865 when the oil production in Pennsylvania started to decline, at that time the only source for US production, successful exploration was carried out in Ohio. However, the oil found in Ohio was high in sulphur, i.e. sour and thus smelled very bad, which made it harder to market. By the work of an innovative chemist a way to refine it and get rid of the smell was found (Yergin, 1993).

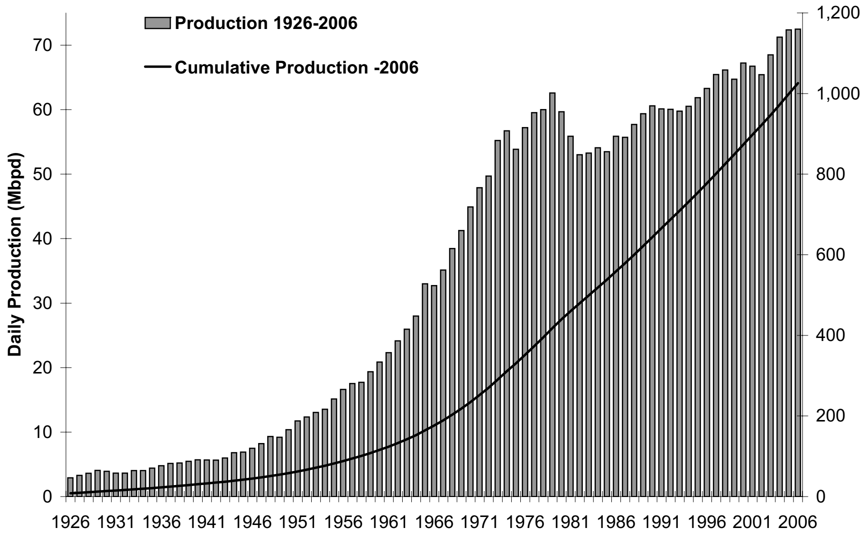


Figure 5.1: World oil production, both daily production in million barrels per day (Mbpd) and cumulative production in billion barrels (Gb), from 1926 to 2006 (GFP). Note that production only include crude oil, i.e other liquids such as condensate and NGL are excluded.

When the demand for oil grew during the 20^{th} century, new areas were explored (see chapter 4). This has continued up to our days and global oil production shows a clear upward trend (figure 5.1). Since oil is a finite resource and generated predominately during two brief geological epochs (see chapter 3), increasing oil production can not go on forever.

A drop in the price of oil during the 1990s seemed to prove that oil would be cheap and abundant for years to come. However, not everyone agreed on this and Scientific America published an article called *The End of Cheap Oil* by Campbell and Laherrère (1998). This article put the question of future oil supply on the agenda once again and predicted that global oil production would reach a peak level and thereafter decline. Later, this issue was to be called the peak oil theory. Following this article, numerous articles were published to either confirm eg Aleklett and Campbell (2003) or debunk eg Söderholm (2003) the peak oil theory. The debate really took off after a series of articles in Oil & Gas Journal during the summer of 2003 (Williams, 2003a). Accordingly, the following sections will examine and describe the issues regarding peak oil.

5.1 Definition of Peak Oil

There are a few basic questions regarding peak oil that should be addressed. The questions are as follows:

- What is peak oil
- Is peak oil a new subject
- Will there be a global peak oil

The use of the phrase peak oil is fairly new and was invented by Colin Campbell in 2001 and is defined as:

> "The term Peak Oil refers the maximum rate of the production of oil in any area under consideration, recognising that it is a finite natural resource, subject to depletion."

In practice, the maximum rate of production in a certain area is reached when production from new fields is not enough to offset declining production from old fields. If this occur on a global scale, global oil production starts to decrease and global peak oil has been reached. Accordingly, an increase in, or even a steady, demand for oil can no longer be met by the production. Thus, global oil production have a peak level which it can not exceed (figure 5.2). Please note the forecast values and projected demand are not actual projections but just drawn to illustrate the concept of peak oil. However, peak production can also be caused by a drop and decline in demand. It is also important to distinguish between running out of oil and peak oil. After the peak, oil production will continue for a long time, but in a declining manner. Moreover, it is still a lot of oil left to produce. Running out of oil, on the other hand, means that there is little or no oil left to produce.

The frequent mentions and debates over peak oil suggests that it is a fairly new topic. On the contrary, it is pretty old. The topic of a future global peak production of oil was first discussed in 1949 by M. King Hubbert, a geophysicist employed by Shell Oil (Hubbert, 1949). He developed a method, based on a bell curve, that he used to model the annual production and ul-

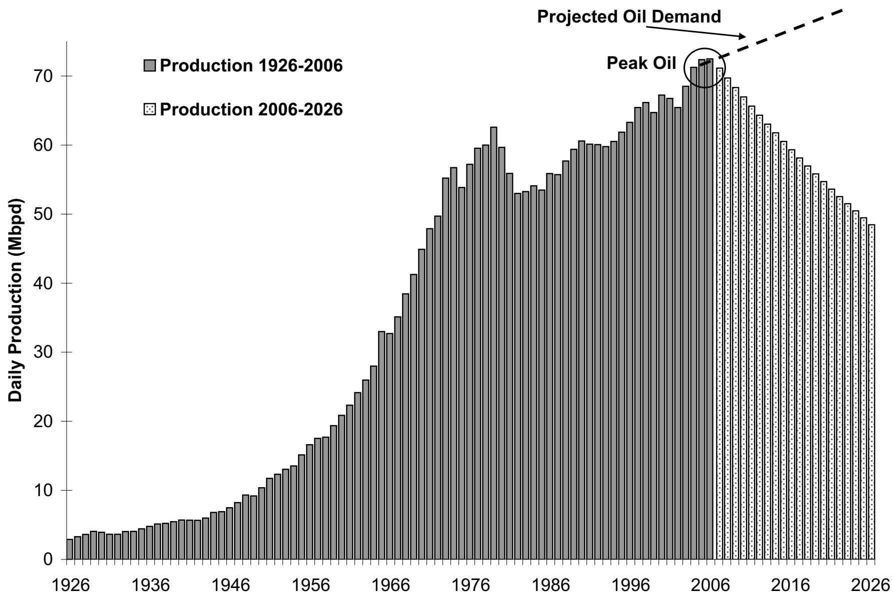


Figure 5.2: World daily oil production in million barrels per day (Mbpd), from 1926 to 2006, and projections for future production. Please note the projections are no actual forecasts but included just to illustrate the concept of peak oil.

timate recovery of oil and gas in the world and the USA. His method and the bell curve is usually referred to as the Hubbert model and the Hubbert curve, respectively. This will be discussed in further detail in section 5.2.

In 1956, Hubbert predicted, using the bell curve and two different estimates of ultimate recovery of oil in the USA, that the oil production of the lower 48 states of the USA would have a peak between 1965 and 1972 (Hubbert, 1956). This prediction turned out to be true, since oil production in the USA peaked in 1970. Modified versions of his theory have been used by Campbell and Laherrère (1998), Ivanhoe (1996) and Deffeyes (2001) to name a few. However, the Hubbert model is heavily debated, see for example Lynch (2003).

The oldest and most mature, i.e. most well explored, oil production area of the world is the lower 48 states of the USA. The latest oil region discovered is the North Sea, where United Kingdom and Norway have the lion share of the production. The first wells drilled in the North Sea were drilled in 1963 and the first giant oil field discovery was the Norwegian Ekofisk in 1969.

Oil production in the USA, including Alaska, shows a clear peak in 1970 (figure 5.3). The increase in USA's production in 1976 is due to the opening of the Alaska pipeline. At that time the pipeline mainly contained oil produced from Prudhoe Bay, which is the largest field discovered in the USA (Halbouty, 2003).

The double peak in UK production (figure 5.3) needs an explanation. The first peak, which occurred in 1985–6, and the following drastic drop in UK production is not due to a lack of prospects but the tragic Piper Alpha disaster and its consequences (DTI, 2004; Westwood, 2004).

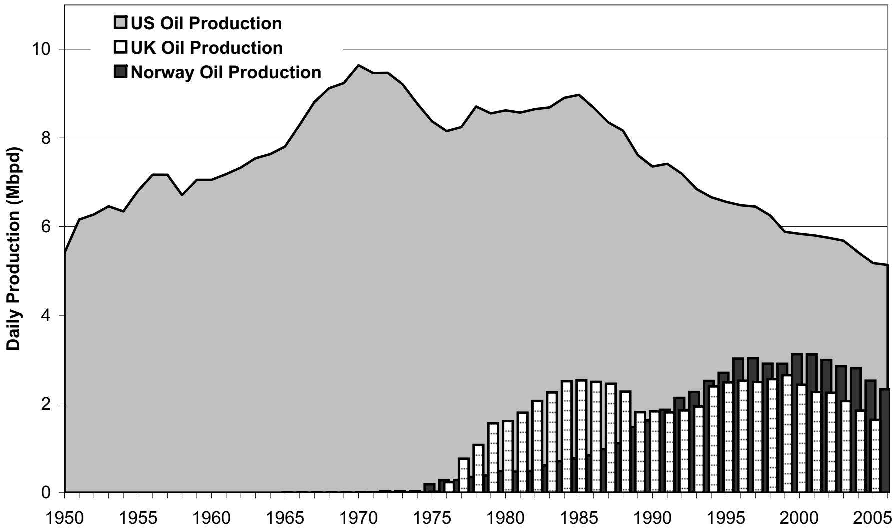


Figure 5.3: Oil production between 1950 and 2006, in million barrels per day (Mbpd), from USA (including Alaska), UK and Norway.

On July 6 1988, a massive explosion of leaking condensate[1] led to large oil fires at the North Sea platform Piper Alpha. The fires led to further massive explosions and the accident claimed the lives of 167 people (Vielvoye, 1990).

Obviously, safety issues became high priority and the installation of new equipment and routines restricted production for a few years time (DTI, 2004). However, the drop in production from 1999 and onwards are due to declining production from the oil fields in combination with both lesser and smaller discoveries. This is true even if not only crude oil is considered but all liquids are included (BP, 2005).

The oil production from the Norwegian part of North Sea as well as production from the Norwegian Sea peaked in 2000 (figure 5.3), but total liquids production peaked in 2001 (BP, 2005).

Thus, the most mature oil area, i.e. the USA, and the latest big oil region discovered, the North Sea, are both in decline and have passed their respective peak. The conclusion is that all oil regions, mature as well as newer ones, will peak and then decline. For both regions, this has taken place despite a strong demand for oil and a high oil price. Thus, high production rates were motivated but apparently not possible. This is by itself not ev-

[1]Condensate is in gas phase in the reservoir but condenses to liquid at surface (Selley, 1998).

idence for a soon global peak in oil production but it clearly points to a global peak oil, somewhere in the not so distant future.

5.2 The Hubbert Model

5.2.1 Theory of the Hubbert Model

The best known depletion model for a finite natural resource is the Hubbert model. The model with respect to oil considers three factors: oil discovery rate, oil production rate and the size of the oil reserve at any time. The idea is that for a new region, where it is assumed there is no constraints on exploration, the first discoveries are small and the discovery rate low. During exploration both the size of the discoveries and the rate then grow because of better knowledge of the region. Later during the exploration the rate of discoveries decreases as well as the size of the discoveries. Accordingly, the cumulative value of all discoveries (V_D) will be represented by an S-shaped graph (figure 5.4).

An important fact is that the oil must be discovered before it can be produced. Therefore, the oil production will lag the discoveries with respect to time. The cumulative production (V_P) will have a similar behavior as the the cumulative discovery (figure 5.4). Moreover, this also assumes that the oil will be produced without any constraints.

Since there is a time lag between discovery and production, there will be an amount of oil available, which is the reserve (V_R). The size of the reserve at any time is given by equation 5.1 and shown in figure 5.4.

$$V_R = V_D - V_P \tag{5.1}$$

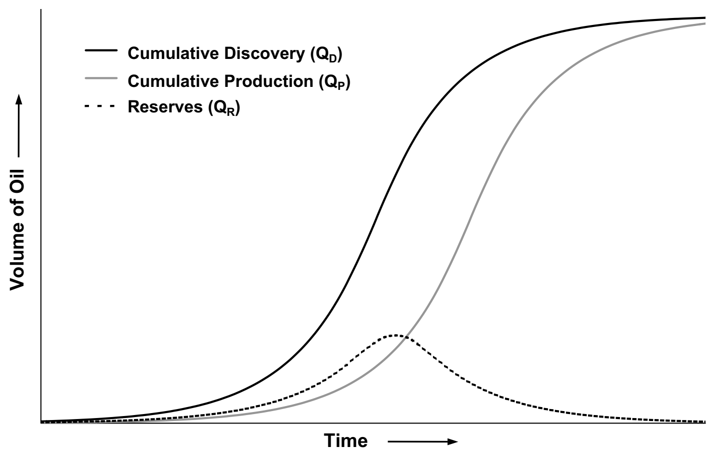


Figure 5.4: Theoretical shape of the Hubbert curve, which is a model for the exploration and discovery of oil versus time.

The time rate of change for both cumulative discoveries and production will have similar shapes, but once again shifted by a time lag. The time rate of change is the slope of the curve, which is the derivative of the curve. This gives a discovery rate and a production rate. Taking the derivative of equation 5.1 gives the rate of reserve change (equation 5.2), and is shown in figure 5.5.

$$\frac{dV_{\mathrm{R}}}{dt} = \frac{dV_{\mathrm{D}}}{dt} - \frac{dV_{\mathrm{P}}}{dt} \tag{5.2}$$

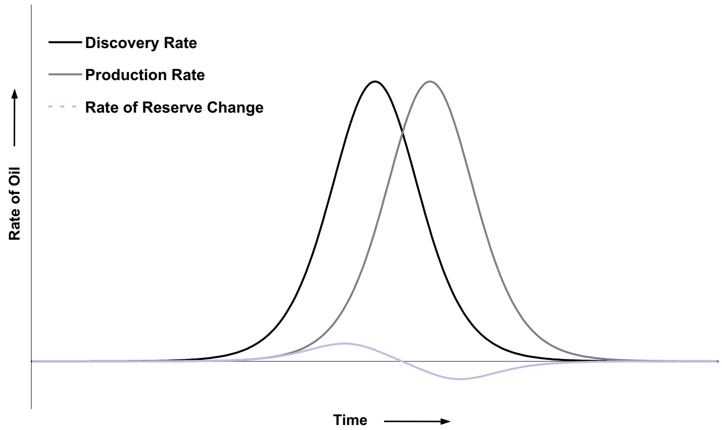


Figure 5.5: Theoretical shape of the Hubbert curve, when rate is used instead of volume. (Compare with figure 5.4.)

This graph shows two important times: the time when $\frac{dV_{\mathrm{R}}}{dt}$ is at maximum and the time when $\frac{dV_{\mathrm{R}}}{dt}$ equals zero. The former is called the inflection point. The latter time occurs halfway between the peak of the discovery rate and the peak of production rate. This observation can be used to determine in advance the time for peak production. Two parameters are needed: the lag time (Δt) between discovery and production, and the time when $\frac{dV_{\mathrm{R}}}{dt}$ equals zero (t_0). The peak in production will then occur at $t_{\mathrm{m}} = t_0 + \frac{\Delta t}{2}$. However, this prediction assumes that there is a good correlation between discoveries and production as well as there are no constraints on either one.

The S-shaped curve (figure 5.4) can mathematically be described by the logistic curve, which was first formulated by Verhulst in 1845 and used in population studies (Laherrère, 2000). This curve can also be used to model cumulative production of oil and it is described by equation 5.3 (Laherrère, 2000).

$$V_{\mathrm{P}}(t) = \frac{U}{1 + e^{a(t - t_{\mathrm{m}})}} \tag{5.3}$$

where

$V_P(t)$ = Cumulative oil production at time t

U = Ultimate recovery

t = time

t_m = the midpoint (or peak time)

a = a factor describing the slope

However, the curve (figure 5.5) for annual production is more convenient to use since it illustrates the peak in a clear way. As mentioned above, the derivative of the cumulative production curve is the production rate. Accordingly, the production rate is then the derivative with respect to time of equation 5.3, which is expressed in equation 5.4.

$$P = \frac{dV_P}{dt} = \frac{aU}{2 + 2\cosh a(t - t_m)} = \frac{2P_m}{1 + \cosh a(t - t_m)} \tag{5.4}$$

where

P = Annual oil production

$P_m = \frac{aU}{4}$ = Peak production

The mathematical treatment of the Hubbert curve is not discussed in Hubbert's work (Deffeyes, 2001; Laherrère, 2000), but equation 5.4 is the Hubbert curve according to Laherrère (2000).

Another widely used function to describe the annual production is the Gaussian, or the normal, function. The parameters used in a Gaussian function describing annual oil production are: ultimate recovery (U), the midpoint (t_m) and the standard deviation (σ).

$$P = \frac{dV_P}{dt} = P_m e^{-\frac{(t-t_m)^2}{2\sigma^2}} \tag{5.5}$$

5.2.2 Applications of the Hubbert Model

The main application of the Hubbert model is to predict future oil production from known historical data. This is done by constructing Hubbert curves by using either the logistic or Gaussian equation and adjusting the parameters so the curve fits as good as possible with the actual data. The reliability of the prediction is depending on the status of depletion and there are three different situations (Laherrère, 2000).

Post production peak In this case, both P_m and t_m is known. Only a needs to be calculated. This gives the most reliable prediction.

Pre production peak but post inflection If the inflection point, i.e. when the production increase has a maximum, has been reached it is possible to calculate P_m and t_m. This prediction is less reliable than the prediction when peak production has occurred as well.

Pre production peak and pre inflection Predictions can not be made by use of production data. Instead, reserve data can be used in two different ways. First, annual discovery data can be used if assuming a good correlation between discovery and production (figure 5.5). However, if discoveries have not yet reached its peak, the prediction is very unreliable. The second method is based on using ultimate recovery estimates. The peak will occur at the mid-point of depletion, which is reached when half of the ultimate recovery is produced. However, this assumes a single exploration cycle (figure 5.5).

The lower 48 states of the USA can be modeled by equation 5.4, which yields a good fit to the actual data (figure 5.6). This is usually taken as a validation of the model, but it is important to note that restrictions on exploration and production were relatively few. Thus, the assumptions for the theoretical model was fulfilled. A similar study on global production, again

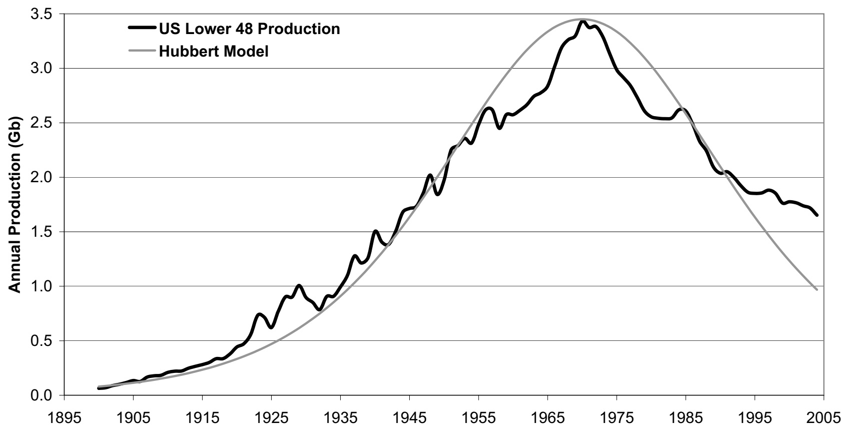


Figure 5.6: Hubbert model of the annual oil production in billion of barrels (Gb) of the lower 48 states of the USA, compared with actual production.

using equation 5.4, shows a good fit up to 1973 (figure 5.7). However, from there on, when the Organization of Petroleum Exporting Countries (OPEC) restrained production, a clear discrepancy is shown between the model and the reality and hence, the conditions for the model is no longer fulfilled. By the use of more than one discovery cycle, it is possible to construct more advanced Hubbert models, which shows a good fit to the actual global production curve (Laherrère, 2000).

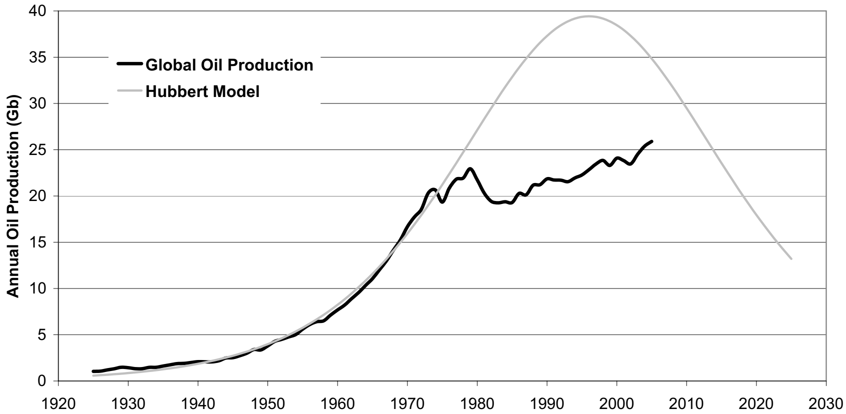


Figure 5.7: Hubbert model for annual global oil production in billion of barrels (Gb). The curve was constructed in order to fit production up to 1973, when OPEC reductions were put in place.

5.3 Oil Production Rate versus Oil Reserves

As simple as it may seem, the understanding of the difference between production rate and reserves is imperative. This is especially true for an analysis of future oil production. Moreover, the concept of depletion is another topic that needs to be addressed.

The oil production rate is unique for each individual oil field and depends on the nature of the oil, reservoir characteristics, reservoir pressure, the number of wells, and the volume of oil in the reservoir. As discussed previously (chapter 3), the flow of an oil well can be helped by installation of artificial lift or secondary recovery.

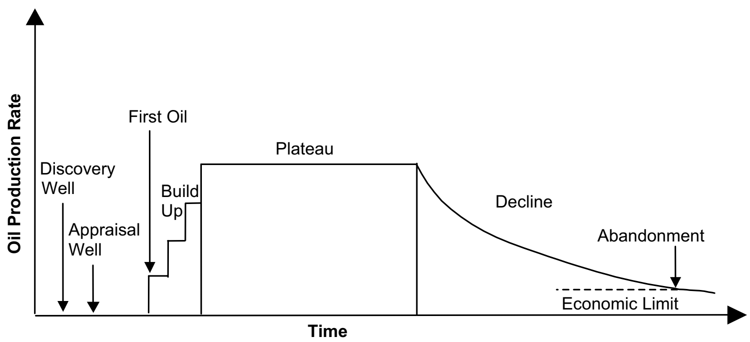


Figure 5.8: Production profile of an oil field. After Davies (2001).

Depletion must be taken into account when discussing the production rate and reserves of an oil field. Volumetric depletion of an oil field is simply the tapping of oil, and it begins as soon as the first barrel of oil is produced. The reserve to production ratio is a common way of expressing the remaining lifetime of an oil reserve. However, dividing proven reserves by current production does not provide a valid measure of the sustainability of an oil field. First, it assumes that production will remain constant at the current level, which is not the case (figure 5.8). Second, it assumes that the last barrel of oil can be produced as quickly in the future as it is currently. These assumptions ignores the concept of resource depletion and is therefore misleading. The crucial point is that proven reserves do not tell everything about the future production capabilities. For example, the Beryl field in the UK part of the North Sea has an estimated remaining reserve of around 200 Mb. The Alpine field in Alaska has more or less the same reserve estimate. However, the expected production from the fields is far from alike, Beryl produces around 25 000 bpd while the production from Alpine is close to 120 000 bpd. The difference in production rate between the fields is due to both volumetric and pressure depletion, the lifetime of the field and where in its production profile the field is (figure 5.8). In this example, Beryl is an old field far down in its decline phase, which means the production rate will continue to decline. Alpine, on the other hand, is still in its build-up phase and will soon reach its plateau production. When a field has reached its decline phase, the easy and inexpensive production has ended. In most cases, the decline will be permanent. What can be done is various attempts to slow down the decline and hence reduce the slope of the decline phase. Future oil production from Angola will probably be around 14 Gb (Sandrea and Barkindo, 2007), and future contribution from the North Sea (Denmark, Norway and U.K) will be in the same range (Radler, 2006). However, future production rates from them are not at all similar: production rates from Angola is expected to grow rapidly while North Sea production is forecasted to decline. Thus, large oil reserves are not enough to tell if future production will decline or grow. Maturity and eventual additions of new fields must be included.

5.4 The Reserve Issue - Backdating and Replacement

Since the dawn of the petroleum industry, oil has been produced and new discoveries have been made. The difference between the cumulative volume discovered and the cumulative production is the oil reserve. Each year, the world produces a volume of oil and discovers another volume of oil. Positive reserve replacement and net additions to reserves during a certain period occur if the discovered volume of oil is greater than the produced volume of oil. On the other hand, the reserve is decreasing when the produced volume exceeds the discovered volume. This connection is of course true on a global scale as well as for a small oil company. The global reserve is one parameter to study in order to determine future oil production. Accordingly, the question if the global reserve is growing or declining is important. This question seems to have an obvious answer, but it is a heavily debated topic. Therefore, an account of the following items is needed.

- What is included in the reserve estimate
- In what way with respect to uncertainty is the reservoir measured
- Which reserve booking method has been used
- Is the reserve estimate from the public domain or an industry source

The crucial point is to be conscious of different inclusions in the estimates of the reserves. Especially if, for instance, oil sands from Canada and/or Orinoco Belt heavy oil from Venezuela are included or not. The resource base of both are very large, but it is still only a small portion that is developed.

It is also important to note what kind of reserve estimate it is: proven reserves (1P) or proven plus probable (2P). As has been shown in chapter 3, proven reserves indicate either the volume that most likely will be produced, or with a probability of 90 per cent. Probable reserves are either more likely than not to be recovered, or at least with a 50 per cent probability. Obviously, proven plus probable reserves is the more optimistic estimate and should be greater than the proven reserves.

When an oil field is discovered an estimate of the recoverable volume is made. This estimate contain estimates of proven, probable and possible reserves. The size estimate will develop during time to be a more and more accurate estimate of the recoverable volume. In this development of the reserve estimate, field extensions are included, revisions of earlier estimates and the availability to new technologies to improve the oil recovery. These items are generally referred to as reserve growth. This means that the estimated recoverable volume of oil can grow during time. This can be a bit confusing since a better understanding of a field and its reservoirs can be interpreted as a new discovery. In order to overcome this confusion backdating is used, which means that all subsequent reserve growth is dated to the year of the original discovery. This method shows in a plain way the discovery of a field and the reserve development over time. In addition, the contributions from discoveries of new fields are evident.

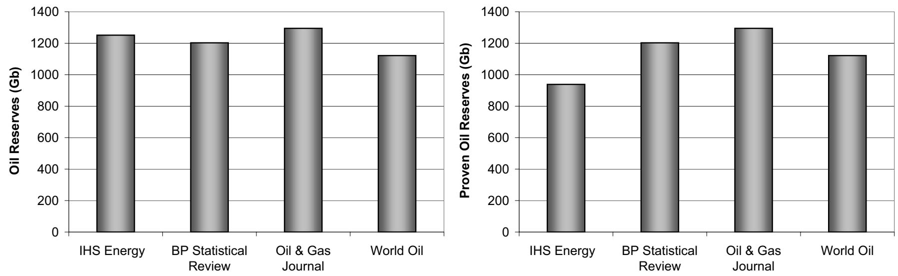
The most widely used public reserve databases are BP Statistical Review of World Energy (BP) and Oil & Gas Journal Worldwide Report (OGJ). Others are World Oil and OPEC Annual Statistical Bulletin. The BP estimate, which “not necessarily represent BP’s view of proved reserves by country" (BP, 2005), is to a large extent based on the data from OGJ. Therefore, a closer look at OGJ reserve estimate is motivated.

In some cases the public data might even be intentionally misleading. This is raised by the dubious reserve reporting from some of the countries associated with the OPEC in the mid-1980s (table 5.1).

National oil companies (NOC) were established in the main OPEC countries during the 1970s due to the expropriation of the holdings of foreign companies. In 1985 Kuwait reported an almost 50 per cent increase of their reserves (table 5.1). Since the size of the reserves was a parameter in the calculation of a country's export quota this would increase the production quota of Kuwait and hence larger oil export revenues. A few years later, in 1987, Venezuela doubled its reserves, probably by including long-known reserves of heavy oil. This led Abu Dhabi, Dubai, Iran, and Iraq to huge increases of their reserves in order to protect their quotas. A few years later, Saudi Arabia followed with an increase of almost 50 per cent. In total, the increase from 1986 to 1991 amounted to 306 Gb. Some increase of the reserve estimates, however, was called for, because the inherited estimates from foreign companies were too low. But no great discoveries were reported during the years of revisions (Hemer and Lyle, 1985; Hemer and Gohrbrandt, 1986, 1987; Hemer et al., 1988; Hemer and Phillips, 1989, 1990). However, the reserve growth in the giant fields in the the countries represented in table 5.1 from 1981 to 1996 was some 108 Gb (Klett and Schmoker, 2003). The difference between the revisions and the reserve growth is a staggering 198 Gb, which equates to 15 fields of the size of Prudhoe Bay in Alaska. The lack of reported new discoveries together with the difference between reserve growth and revisions implies that the revisions were too large. Moreover, all of the main OPEC countries have produced large quantities of oil from 1986 and up to date, but most of the reported reserves are unchanged (table 5.1). In addition, during the 1990s just a few great discoveries with a combined ultimate recoverable reserves (URR) of about 13 Gb have been reported (Halbouty, 2003). For example, since 1986, Dubai has produced some 2 Gb from four fields and despite no reporting of new discoveries, the reserve estimate is still 4 Gb (OFN). The reserve number for Abu Dhabi is very interesting when comparing it to the URR of their giant fields, which dominate the production. The most optimistic estimate of the URR of the giant fields in Abu Dhabi is 72 Gb, i.e. 20 Gb less than the reported reserves (GF). In addition, since 1988, almost 12 Gb has been produced.

A further look on the reserve estimates reveals that 65 countries out of 98 has unchanged reserve numbers in the end of 2004 as in the end of 2005. For the last five years, 37 reserve estimates have remained unchanged while 25 have not changed in the last ten years. It is therefore reasonable to conclude that publicly available reserve estimates are not reliable. Thus, the use of public reserve estimates as an indicator of future production must be cautious.

Instead, by using industry sources relying on backdated reserves a more accurate picture of the reserve and discovery picture appears. A comparison between reserve estimates available in the public domain and industry sources shows a striking similarity that the reserves are around 1200 Gb (figure 5.9(a)). However, the three public estimates are based on proven reserves, while the industry source is based on 2P reserves, except for the US and Canada where proven reserves are used. A “ball park figure" for converting 2P to 1P is that 1P is 0.75 of 2P (Mearns, 2006). Thus, the industry source gives a considerable less reserve estimate than the estimates available in the public domain (figure 5.9(b)).



(a) 2P industry source reserve estimate compared with 1P public reserve estimates.

(b) 1P industry source reserve estimate compared with 1P public reserve estimates

Figure 5.9: A comparison between reserves estimates, in billion barrels (Gb), from industry sources and public available sources. *Source: Based on data from IHS Energy, BP, Oil & Gas Journal and World Oil.*

Annual new field discoveries have been less, with a few exceptions, than produced volumes the last 25 years (figure 5.10). However, by adding reserve growth the yearly discoveries have exceeded produced volumes in most years.

It is important to note that this indicates a lack of finding new fields and that reserve growth mainly is for old large discoveries, which is obvious when comparing annul discoveries as reported in 1994 and 2005 (figure 5.11). Moreover, the future contribution of reserve growth from old mature fields should be decreasing since the use of new technologies, especially 3D seismic, is disappearing (Rech and Sanière, 2003). The discovery trend of finding less volumes in new fields rises another concern: the resource base for future reserve growth is decreasing.

Moreover, the use of the latest technologies in exploration, especially 3D seismic, should also give a more accurate estimate of the recoverable volume much earlier on. This, too, should point to less growth in newer fields. The available amount of data is not sufficient to determine if there exists a clear trend. However, the drastic drop in reserve growth in the latest years is alarming (figure 5.12). Moreover, the exploration result during 2005, a year with the highest oil price in over 20 years, was everything else than encouraging: 11.5 Gb in new fields and 9 Gb in reserve additions. Almost 10 Gb less than the produced volume (figure 5.12).

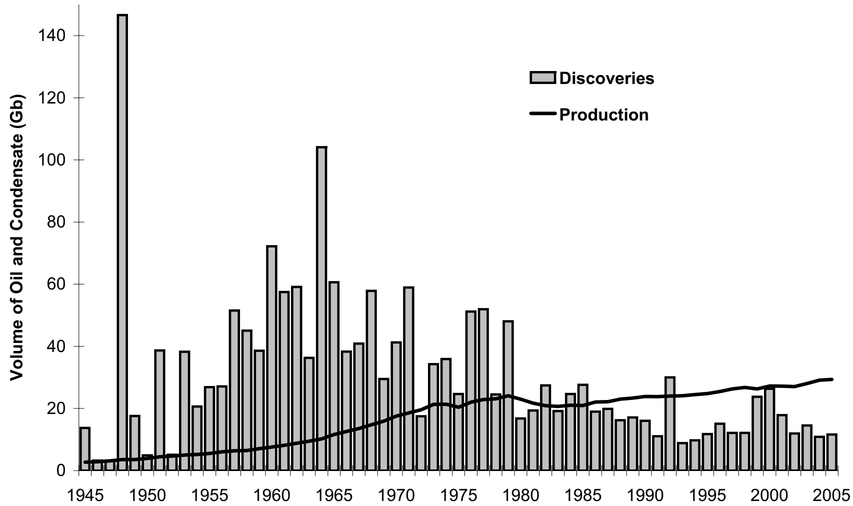


Figure 5.10: Global annual discoveries of both oil and condensate, and oil production in billion of barrels (Gb). *Source: Based on data from IHS Energy, ASPO and Oil & Gas Journal.*

5.5 Have We Heard All This Before?

The recent spikes in the oil price, where the price was above 73 dollar per barrel in all of July and August 2006, might imply that the peak of global oil production is here. Or, have we heard all this before? There have been times before when oil crises led to high oil prices and the belief in running out of oil. So far, none of the crises have shown to be a peak. Thus, a sense of caution is needed when addressing the subject.

Up to 1993, there have been six post-war oil crises (Yergin, 1993). Including the war in Iraq in 2003, the number of oil crises is seven. They are briefly described below.

Nationalization of Anglo-Iranian Oil Co. (A-I), 1951 Iran wanted a better deal on the oil revenues from A-I but UK refused. This conflict together with the news of a fifty–fifty deal between Saudi Arabia and Aramco, led to a demand of a nationalization of A-I, which later was carried out. The UK government wanted to declare war on Iran, but instead a trade embargo was imposed. Moreover, no oil was transported from Iran due to a threat the UK government imposed on tanker owners. Oil operations in Iran ceased as well as exports of oil.

Suez Crisis, 1956 UK, France and Israel attacked Egypt when it nationalized the Suez canal. As an answer, Egypt closed the canal and stopped the pumping stations on the Iraq Petroleum Company pipeline in Syria. The combined effect meant that 75 per cent of Western Europe's

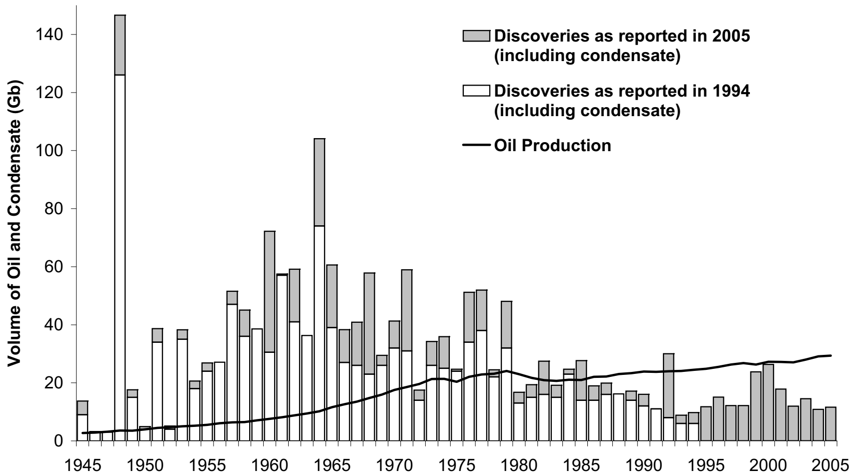


Figure 5.11: Global annual discoveries of both oil and condensate, as reported in 1994 and 2005, together with oil production in billion of barrels (Gb) The difference reported discoveries is the reserve growth. *Source: Based on data from IHS Energy, ASPO and Oil & Gas Journal.*

oil supply was interrupted. Moreover, Saudi Arabia instituted an oil embargo on UK (Yergin, 1993).

Six-day War, 1967 Israel attacked Egypt and Jordan as a reaction to Egyptian and other Arab states military mobilization. Arab oil ministers decided to impose an oil embargo on Israel friendly states such as US and UK. This was the first time the so-called "oil weapon" was used. The Suez canal and the pipelines from Iraq and Saudi Arabia to the Mediterranean was closed. Almost half of Western Europe's need for oil was now shut off. However, spare capacity, especially in the USA, and the development of large supertankers made it possible to export oil to Europe.

Yom Kippur War, 1973 In October, Egypt and Syria attacked Israel. When USA and other countries supported Israel, OPEC answered with an increase of the oil price. The continued supply support from the USA to Israel came as a reaction to the supply support from USSR to Syria. However, OPEC decided to use the oil weapon again and imposed an oil embargo on the USA, i.e. stopped all shipments of oil to the USA. This time there was no spare capacity in the USA and the price of oil sky rocketed.

Iranian Revolution and Price Panic, 1979-81 The events leading to the overthrown of the ruler of Iran (the Shah) included strikes at the oil fields and in December 1979 the Iranian exports had ceased

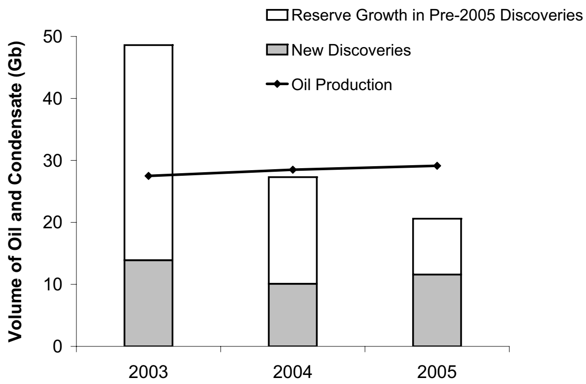


Figure 5.12: Global annual discoveries and reserve growth of both oil and condensate, from 2003 to 2005 together with oil production in billion of barrels (Gb). *Source: Based on data from IHS Energy and Oil & Gas Journal.*

altogether. The shortage in combination with a rush to build oil inventories led to an increase of the price.

UN Iraq Embargo, 1990 Kuwait produced more than its quota assigned by OPEC, which annoyed their neighbor Iraq. Moreover, an invasion of Kuwait would lead Iraq to be the dominant oil power of the world. In order to prevent an invasion the UN imposed an embargo on oil from Iraq. However, the invasion became reality and the combined effect of the embargo and the disruption of Kuwait oil led to an increase of the oil price.

War in Iraq, 2003 It was thought, mainly by the USA, that Iraq had developed weapons of mass destruction (Englund, 2004). Iraq, led by S. Hussein, was therefore considered a threat to world peace and in March an USA led invasion was started. The disruption in oil production led to an increase of the oil price.

The seven crises and their impact on the oil price is shown in figure 5.13. However, note that the price is a yearly average and thus do not reflect short-term spikes in the price.

All the above crises had a few common factors. Firstly, the geographic factor, all crises are related to the Middle East and the Western World's dependence on their oil. Secondly, the oil did not reach the market due to the fact that some oil producing countries deliberately closed the valves of their oil fields and ceased their exports. Thirdly, parts of the media and some governments reacted to the crises with panic and claimed that the world is running out of oil.

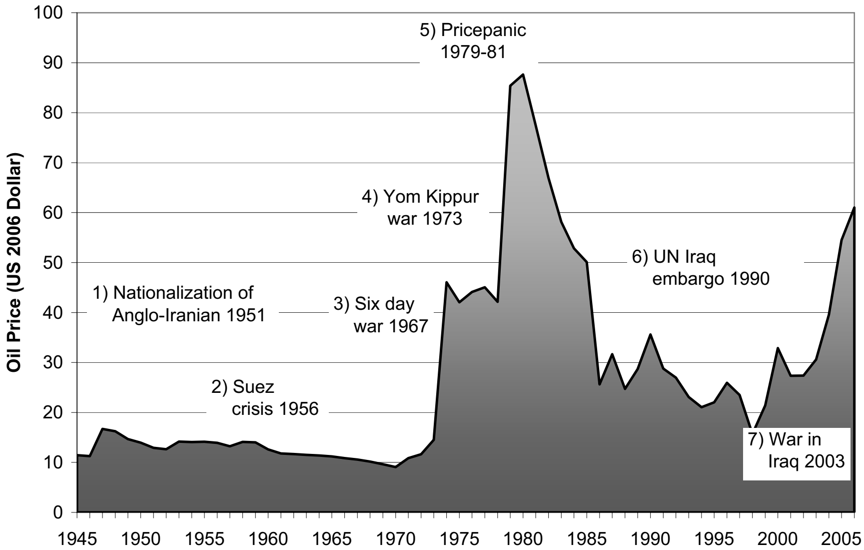


Figure 5.13: Oil price in 2006 US Dollar (i.e. inflation adjusted oil price) and the seven post-war oil crises.

Clearly, it is easy to reject the notion of a global peak oil today with respect to those earlier crises, but there is one big difference: no one is deliberately closing any valves today, on the contrary, all valves are open and production is more or less maximized. However, another question that should be asked is to what extent the oil price is a valid parameter for predicting a future peak oil. Another more important parameter for future oil production and predictions of a peak oil is the giant oil fields, i.e. the largest oil fields in the world.

Table 5.1: *OPEC Reserve Revisions where numbers in bold indicate the year of revision. Note the almost unchanged values for the last 15 to 17 years (Sievertsson, 2003; Williams, 2003c; Radler, 2006).*

Year	**Abu Dhabi [Gb]**	**Dubai [Gb]**	**Iran [Gb]**	**Iraq [Gb]**	**Kuwait [Gb]**	**Neutral Zone [Gb]**	**Saudi Arabia [Gb]**	**Venezuela [Gb]**
1980	28	1.4	58	31	65	6	163	18
1981	29	1.4	58	30	66	6	165	18
1982	31	1.4	57	30	65	6	165	20
1983	31	1.4	55	41	64	6	162	22
1984	30	1.4	51	43	64	6	166	25
1985	31	1.4	49	45	***90***	5	169	26
1986	30	1.4	48	44	*90*	5	169	26
1987	31	1.4	49	47	*92*	5	167	25
1988	***92***	***4***	***93***	***100***	*92*	5	167	***56***
1989	*92*	*4*	*93*	*100*	*92*	5	170	*58*
1990	*92*	*4*	*93*	*100*	*92*	5	***258***	*59*
1991	*92*	*4*	*93*	*100*	*95*	5	*258*	*59*
1992	*92*	*4*	*93*	*100*	*94*	5	*258*	*63*
1993	*92*	*4*	*93*	*100*	*94*	5	*259*	*63*
1994	*92*	*4*	*89*	*100*	*94*	5	*259*	*65*
1995	*92*	*4*	*88*	*100*	*94*	5	*259*	*65*
1996	*92*	*4*	*93*	*112*	*94*	5	*259*	*65*
1997	*92*	*4*	*93*	*113*	*94*	5	*259*	*72*
1998	*92*	*4*	*90*	*113*	*94*	5	*259*	*73*
1999	*92*	*4*	*90*	*113*	*94*	5	*261*	*73*
2000	*92*	*4*	*90*	*113*	*94*	5	*259*	*78*
2001	*92*	*4*	*90*	*113*	*94*	5	*259*	*78*
2002	*92*	*4*	*90*	*113*	*94*	5	*259*	*78*
2003	*92*	*4*	*126*	*115*	*97*	5	*259*	*78*
2004	*92*	*4*	*126*	*115*	*99*	5	*259*	*78*
2005	*92*	*4*	*132*	*115*	*102*	5	*264*	*80*

6. Giant Oil Fields - The Important Parameter

The largest oil fields of the world are called giant fields. The definition of a giant oil field is an oil field which will ultimately produce more than 500 Mb or 0.5 Gb. The first was discovered in Peru in 1868 and one of the latest was discovered in 2003 in the deep-water outside Brazil (GF). Ghawar, which is the largest oil field in the world, is situated in Saudi Arabia. The aim of this chapter is to show the importance of giant fields for the global oil production, both of today and for the future.

In the study of the giant oilfields, the size measurement is important, and the chosen one is ultimate recoverable reserves (URR). Previously, URR was defined as the cumulative production plus the recoverable reserves. Recoverable reserves is a dynamic value and consequently, so is URR. However, in order to minimize the dynamic aspect of URR, proven plus probable (2P) reserves are used.

The amount of recoverable oil in oil fields vary from thousands of barrels to gigabarrels (Gb). In the US, the term giant was originally defined as an accumulation that contained at least 0.1 Gb of recoverable oil (Tiratsoo, 1984). However, in some parts of the world this amount of recoverable oil was not enough to justify field development, due to long distances from markets and local political factors. This led to an evolution of a larger international standard for giant fields of 0.5 Gb of recoverable oil reserves (Tiratsoo, 1984). As mentioned above, this is the definition used here. In the oil business, giant fields or large fields are called elephants. Oil fields with an estimated recoverable reserve greater than 0.1 Gb of oil are usually called major fields or significant discoveries.

6.1 Giant Fields Compared to Other Fields

An article by Ivanhoe and Leckie (1993) in Oil & Gas Journal reported the total amount of oil fields in the world to almost 42 000, of which 31 385 are in the USA. According to the latest Oil & Gas Journal worldwide production survey, the total number of oil fields in the USA is 34 969 (Radler, 2006). The number of fields outside the USA is estimated to 12 500, which is in good accordance with the number 12 465 given by IHS Energy (Chew, 2005). Thus, the total number of oil fields in the world is estimated to 47 500.

The number of giant fields is very small compared to the total number of oil fields. Of the estimated 47 500 fields, only 507 are considered to be giant oil fields, i.e. just above 1 per cent (GF) (figure 6.1).

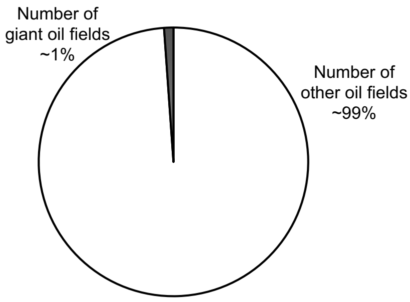


Figure 6.1: The number of giant oil fields compared to the total number of oil fields. Based on 2005 data (GF).

About 100 of the 507 discovered giant fields are found offshore, of which 27 in deepwater. Although 507 giant oil fields are reported as discoveries, some 430 of them are in production, or at least have been in production for some time. Between 2007 and 2012, 17 giant fields will be developed and ten of them are deepwater giant fields. The rest of the reported giant fields, some 50 fields, might be under evaluation. However, information is lacking for this last group of fields and some of them might be producing or may actually not be giants. Their share of total URR is rather low, about 45 Gb.

The total URR of the world is a highly discussed topic, as seen in chapter 5, with a lot of different views. Different estimates for the last ten years are in the range of 1750 to 2850 Gb (Andrews and Udall, 2003). One reason for the difference is what is included in the estimate, where for example, some include oil sands while others only include conventional oil. Moreover, the estimates include the estimated producible reserves of yet to find fields, which is expected to be discovered in the near future. Obviously, this part of the estimate is uncertain and a lot of the controversy revolves around this. An average of the estimates done during the last ten years gives an URR value of 2250 Gb. A similar value is obtained by adding the around 1000 Gb already produced to the IHS Energy estimated remaining 2P reserve of 1200 Gb (see section 5.4). The URR of the 507 giant oil fields is estimated to be between 1350 and 1150 Gb (GF). Thus, if using 2250 Gb as a global value of URR, the giant fields represent about 65 per cent of the global URR (figure 6.2).

Total oil production in 2005, excluding oil from oil sands, Orinoco heavy oil, condensate and NGL, was almost 72 Mbpd. The production of the hundred largest, with respect to URR, giant fields is estimated to be around 32 Mbpd, which corresponds to about 45 per cent of the total volume of oil produced (GFP) (figure 6.3).

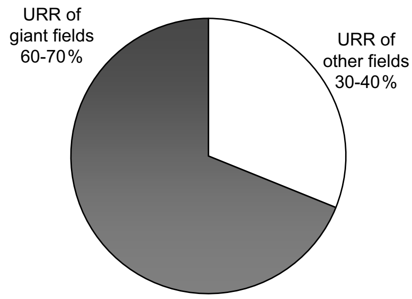


Figure 6.2: The URR of giant oil fields compared with URR in other oil fields. Based on 2005 data (GF).

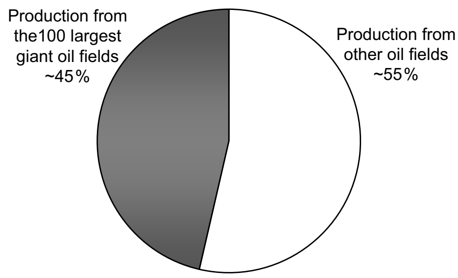


Figure 6.3: The production of the hundred largest giant oil fields compared with total oil production. Based on 2005 data (GFP).

Clearly, the giant fields, which are only a small portion of the world's total oil fields, are important with respect both to URR and production. Thus, the importance of the giant fields on a global scale is established. However, there are a few further questions regarding the giant fields that need to be discussed.

6.2 Size and Location of the Giant Fields

Discoveries of giant fields have been done on all continents, with the exception of Antarctica (Mann et al., 2003). However, as with all other oil fields the distribution of giant fields is very uneven. The largest number of giant fields is located in Russia, where 70 of the 507 have been discovered. In the USA (including Alaska), which is the most explored area of the world, 53 giant fields have been discovered. However, both the USA and Russia are very large areas and the concentration of giant fields are consequently not that high. The Persian Gulf, on the other hand, has the most dense population of giant fields on an area which is less than one tenth of the area of the USA. The Persian Gulf area, which includes the countries United Arab Emirates[1] (UAE), Saudi Arabia, Kuwait, the Neutral Zone between Saudi Arabia and Kuwait, Iraq, and Iran holds 144 or 28 per cent of the giant fields (figure 6.4). All of these countries are members of the Organization of Petroleum

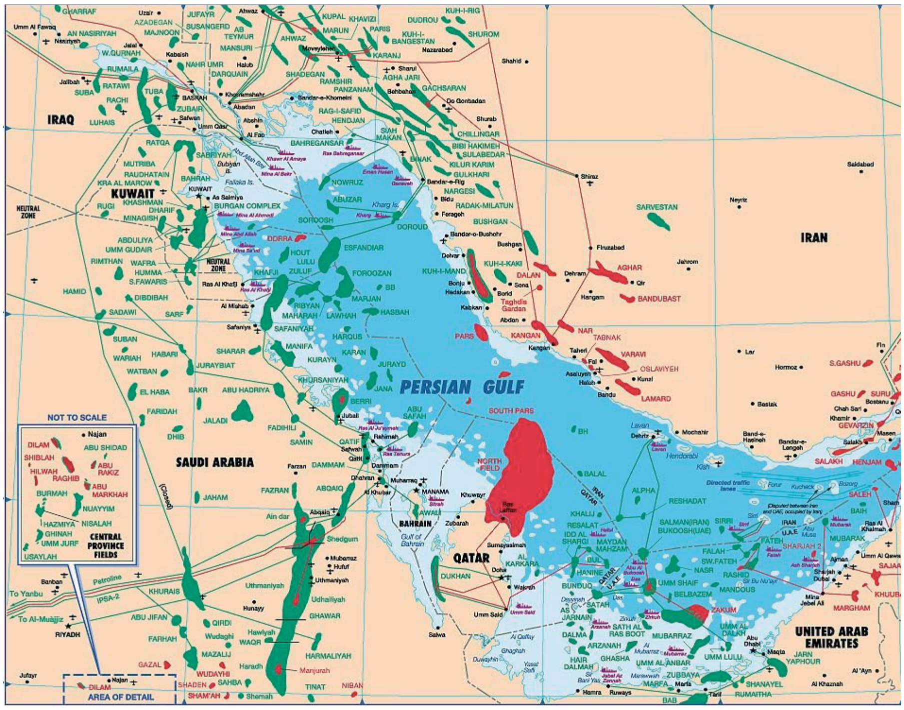


Figure 6.4: Oil and gas fields of the Persian Gulf area, where green represents oil fields and red gas fields (Source: World Oil, August 2000. Used with the kind permission from Gulf Publishing).

Exporting Countries (OPEC). If the giant fields in the remaining countries[2] of OPEC are included, OPEC holds 232 or 46 per cent of the total number of giant fields.

The largest oil fields discovered are also concentrated to the Persian Gulf area (table 6.1). Only five of the 20 largest fields are outside the Persian Gulf area, and four of them are outside OPEC nations (table 6.1). The five non-Persian Gulf fields are the Bolivar Coastal Complex in Lake Maracaibo in Venezuela, Cantarell Complex in Mexico, Samotlar and Romashkino in Russia, and Daqing in China. The largest field in the North Sea is Norway's Statfjord, with an estimated URR of 3.6 Gb. In comparison to the giants in the Persian Gulf area, it is still quite a small field.

The largest field in the world is Ghawar of Saudi Arabia, which has an URR of up to 100 Gb of oil. Some estimates even put the URR at 150 Gb

[1]Abu Dhabi is by far the largest oil producer of the 7 emirates making up the United Arab Emirates.

[2]Algeria, Indonesia, Libya, Nigeria, Qatar and Venezuela. Angola is a pending member of OPEC but excluded in this calculation.

Table 6.1: *The 20 largest oil fields in the world with respect to URR (GF).*

Field name	**Country**	**Discovery year**	**Production start**	**Range of URR [Gb]**
Ghawar	Saudi Arabia	1948	1951	66–150
Greater Burgan	Kuwait	1938	1945	32–75
Safaniya	Saudi Arabia	1951	1957	21–55
Rumaila North & South	Iraq	1953	1955	19–30
Bolivar Coastal	Venezuela	1917	1917	14–30
Samotlor	Russia	1961	1964	28
Kirkuk	Iraq	1927	1934	15–25
Berri	Saudi Arabia	1964	1967	10–25
Manifa	Saudi Arabia	1957	1964	11–23
Shaybah	Saudi Arabia	1968	1998	7–22
Zakum	Abu Dhabi	1964	1967	17–21
Cantarell	Mexico	1976	1979	11–20
Zuluf	Saudi Arabia	1965	1973	11–20
Abqaiq	Saudi Arabia	1941	1946	13–19
East Baghdad	Iraq	1979	1989	11–19
Daqing	China	1959	1962	13–18
Romashkino	Russia	1948	1949	17
Khurais	Saudi Arabia	1957	1963	13–19
Ahwaz	Iran	1958	1959	13–15
Gashsaran	Iran	1928	1939	12–14

(OFN). The field was discovered in 1948 and brought on stream in 1951. During 1980, the field produced almost 5.6 Mbpd, which is its peak production (GFP). However, since 1991 and up to date, the daily production from Ghawar has been around 5 Mbpd (GFP). At the end of 2005, the field had produced over 60 Gb. In comparison, the total production from the North Sea to 2005 is almost 43 Gb. Moreover, Ghawar is still producing at plateau level while the North Sea is in steep decline (GFP). However, the future production potential of Ghawar and its reserves is a somewhat disputed topic, where Simmons (2005) claims the field is close to be depleted and soon will enter an irreversible decline.

The next field in size is Greater Burgan of Kuwait, which was discovered in 1938. Indisputably, Greater Burgan together with Ghawar are the two largest oil fields discovered in the world. First production occurred in 1946, and its production history is also impressive, with a peak level of 2.4 Mbpd in 1972 (GFP). However, the peak was due to production constraints implied by OPEC (Brennan, 1990). There is also a controversy around the future of the Greater Burgan field. Future production has generally been assumed to be above 2 Mbpd, but the optimal rate should instead be 1.7 Mbpd (Cordahi and Critchlow, 2005). The URR of the field might only be 46 Gb, according to internal Kuwait Oil Company documents, instead of the often cited number of 60 Gb (Weekly, 2006).

Safaniya, in Saudi Arabia, is the largest offshore field in the world. Production started in 1957, six years after the discovery of the field. In the early 1980s, Safaniyah produced over 1.5 Mbpd. The field produces heavy oil and since it is not as valuable as light oil, production has been constrained. The field capacity, however, is thought to be around 2 Mbpd (OFN).

The Bolivar Coastal Complex in Venezuela consists of a number of fields, which all are situated in and around the Lake Maracaibo. The largest producers are Tia Juana, Lagunillas and Bachaquero. They were discovered between 1926 and 1930, and production started almost immediately from discovery.

Another giant offshore field is the Cantarell field of Mexico, which was discovered in 1976. Production at Cantarell was around 1 Mbpd from 1982 to 1993, when a decline set in (GFP). In order to halt this, a massive nitrogen injection program was launched, resulting in a steady increase with production exceeding 2 Mbpd in both 2003 and 2004. However, the production increase, according to the operator PEMEX, was not due the nitrogen injection program but could instead be traced to the drilling of a large amount of wells with wider production tubing (Shields, 2002). Early reports suggested production levels around 2 Mbpd for a few more years, but the field is now in decline with some 14 per cent annually and production in 2007 is thought to be about 1.5 Mbpd, down from 1.8 Mbpd in 2006 (Harrup, 2004, 2005, 2007).

Russia's largest field, Samotlar, was discovered in Western Siberia in 1961 and oil production commenced in 1964. The production rose quickly and reached a peak of over 3 Mbpd in 1980, a level which only Ghawar has surpassed (GFP). From the mid 1980s, the production dropped drastically and reached a low point of about 0.3 Mbpd in 2001. The drop was partly due to the collapse of the Soviet Union. Efforts during the latest years has helped reach the production level to almost 1 Mbpd and this level is thought to be prolonged for a few more years (Donnelly, 2006).

From the size distribution of the giant fields, it is evident that the super sized giant fields are scarce (figure 6.5). The smaller giants are, on the other hand, more plentiful.

6.3 Geologic Settings of Giant Oil Fields

The geological settings for the giant fields are of course varying. However, a few trends can be highlighted. The dominant trap setting is structural, over 400 of the fields have this setting. Of these fields, more than half have

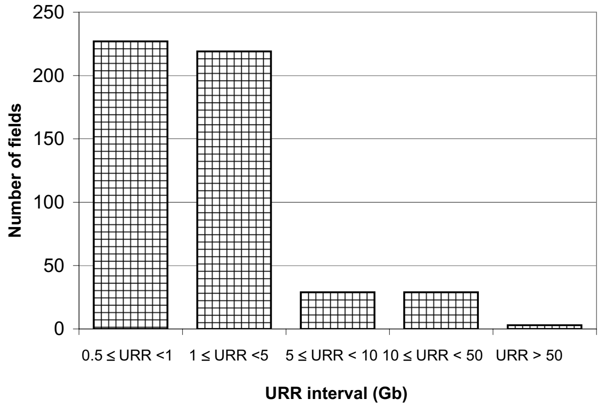


Figure 6.5: Size distribution of the giant fields (GF).

some kind of anticlinal structure. Some 270 fields have reservoirs made up by sandstones, which is the dominating type of reservoirs.

The notable geological feature of some of the largest giant fields are the domination of anticlinal traps and that all reservoirs are of sedimentary rocks, where sandstones is the major one (table 6.2).

6.4 Discovery and Discovery trends of Giant Oil Fields

The discovery year, and hence the age, of the largest fields reveals an interesting fact, the fields are all old (table 6.1). The youngest of the largest is East Baghdad, which was discovered in 1979. Half of the fields are more than 50 years old. This indicates that the discovery of large giant fields is something of the past.

Further indications of this is given by the discovery trend of giant oil fields, which shows a clear peak in the 1960s (figure 6.6).Both the number of fields discovered and the URR discovered was the highest during the 1960s, and it has proved to be the most prolific decade for giant field discoveries. The observed trend is that from 1970 and forward, the discovery rate of giant oil fields has decreased. This is true with respect both to number of fields discovered and the URR. In the 1960s, the average size was almost 4.4 Gb per field compared to 1.9 Gb per field in the 1970s and 1.3 Gb per field in the 1980s. This dropped even further in the 1990s, down to 1.2 Gb per field. However, the average size of the giant fields discovered so far during the 2000s is 1.5 Gb per field. This is mainly due to the discovery in 2000 of the giant Kashagan field in Kazaksthan, with an estimated URR of 13 Gb (OFN).

Table 6.2: *Geological features of some giant oil fields (Halbouty, 2003).*

Field name	Trap	Reservoir	Reservoir Age
Ghawar	Structural (Anticline)	Calcarenite Limestone	Late Jurassic
Greater Burgan	Structural	Sandstone	Early Cretaceous
Safaniya	Structural (Anticline)	Sandstone	Early Cretaceous
Bolivar Coastal	Combination of structural and stratigraphic	Sandstone	Eocene-Miocene
Berri	Structural (Anticline)	Calcarenite Limestone	Late Jurassic
Rumaila N & S	Structural (Anticline)	Sandstone	Cretaceous
Zakum	Structural (Anticline)	Limestone	Early Cretaceous
Cantarell	Structural (Anticline)	Dolomitic Breccia	Paleocene
Manifa	Structural (Anticline)	Calcarenite	-
Kirkuk	Structural (Anticline)	Carbonate	Oligocene
Statfjord	Structural	Sandstone	Middle Jurassic
Prudhoe Bay	Combination of structural and stratigraphic	Sandstone	Triassic

Between 2000 and 2006, 14 giant fields were discovered (table 6.3). When it comes to size, Kashagan is clearly in a league of its own. However, the Kashagan structure was identified by Russian geologist's during the Soviet era but it was never drilled and western companies had tried to get drilling permission long before 2000 (Moody-Stuart, 2004). The size of the other fields, however, is small with URR of around 0.5 Gb. Not only are the size of the fields decreasing, but not a single giant field discovery have been reported since 2003 (table 6.3). However, the Brazilian deepwater discovery 1-RJS-628A, drilled in 2006, might contain over 1 Gboe and thus, it is not clear if it is an oil or gas field (Explorer, 2007). The Vladimir Filanovsky discovery, drilled in 2006 by Russian company Lukoil, in the Caspian Sea has shown very promising test results and early estimates indicate a giant oil field in the size of 0.6 Mb (OFN).

Looking at the settings of the discovered fields, offshore fields dominate. Due to to the development of production technology there has been a shift in the discovery of giant fields to deepwater areas. Of the fourteen fields discovered, eleven are offshore and of them eight are in deepwater.

6.5 Production from Giant Fields

The ability to sustain very high production rates for long times explains the significant contribution from giant oil fields to global oil production (figure 6.3). This ability highlights the importance of the giant oil fields and it is also

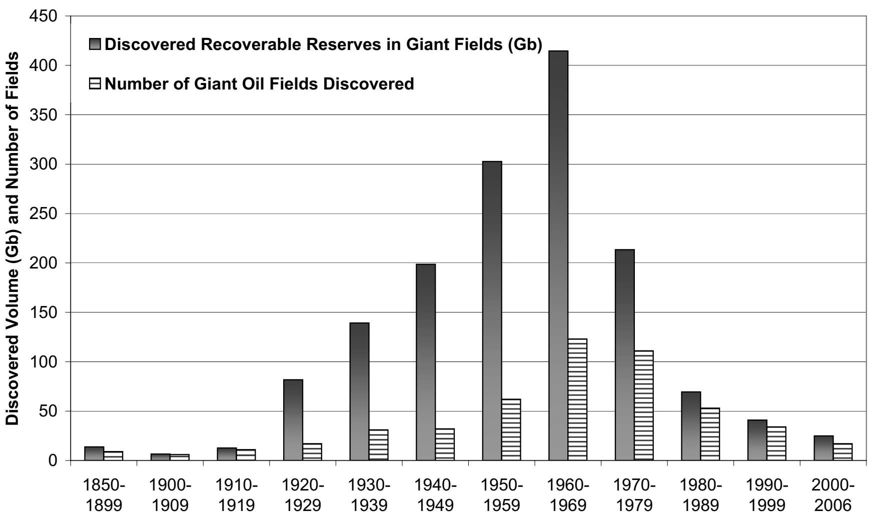


Figure 6.6: Discovery of giant oil fields per decade,with respect to number and URR. The most optimistic URR estimates has been used (GF)

a crucial fact to bear in mind when analyzing future oil production. A comparison between the two Norwegian oil fields Gyda and Statfjord further accentuate the importance of oil production from giant oil fields. Although the Gyda field, with an URR of 0.21 Gb, is a large field it is small compared to Statfjord's URR of 3.6 Gb. The size difference is also evident when comparing the production rates from the fields: Gyda's peak level was around 50 000 bpd while Statfjord has produced in excess of 500 000 bpd. The combined production from five fields, brought on stream at the same time, of the size of Gyda is dwarfed by the Statfjord production (figure 6.7). Thus, even if a large amount of small fields are discovered and brought on stream, it is not enough to compensate production from giant oil fields. In the context of the declining discovery trend of giant oil fields, this indicates a peak governed by the giant oil fields.

The importance of giant oil fields and production capacity has been highlighted by Simmons (2002). The definition used for giant fields in Simmons (2002) is a field with a daily production exceeding 0.1 Mbpd. This definition has been adopted and the database with giant field production (GFP) includes, in addition to giant field production, production data on oil fields with at least one year of production over 0.1 Mbpd. From 1930 and to 2005, only 21 fields have produced in excess of 0.1 Mbpd without being giant oil fields with respect to URR (GFP). Thus, the importance of the giant oil fields with respect to production capacity is further accentuated. Historically, giant oil fields have been the major contributor to world oil production and in 2005, the total contribution from 312 giant fields and 21 fields with production exceeding 0.1 Mbpd included the in GFP database was 61 per cent

Table 6.3: *The giant fields discovered from 2000 to 2006 (GF,OFN).*

Field name	**Country**	**Discovery year**	**Range of URR [Gb]**
Kashagan	Kazakhstan	2000	10
Yadavaran*	Iran	2001	1.5
Bongo SW	Nigeria	2001	1.4
Akpo	Nigeria	2001	1.1
Cachalote	Brazil	2002	0.4–0.8
ESS-121	Brazil	2003	0.45–0.7
Takhman	Saudi Arabia	2002	0.7
ESS-130	Brazil	2003	0.6
Jubarte	Brazil	2002	0.6
Palogue	Sudan	2003	0.4–0.6
Golfinho	Brazil	2003	0.45–0.6
Buzzard	UK (North Sea)	2001	0.5
Tahiti	US (Gulf of Mexico)	2002	0.5
Usan	Nigeria	2002	0.5

*Formerly known as Khusk.

(figure 6.8). The importance of giant oil fields to the oil production of each of the continents on the globe is described in the following sections. If not otherwise stated, all information in the following sections are from the GF and GFP databases. Moreover, all figures are exclusively for crude oil and thus, excluding contributions from condensate and NGL.

6.5.1 Giant Oil Fields of Africa

The rapid growth of African oil production in the late 1950s and early 1960s is due to giant oil fields in Algeria, Libya and Nigeria (figure 6.9). In 1970, the giant oil fields peaked at a combined level of close to 5 Mbpd. The giant oil field production is based on 56 fields, where 51 are giants with respect to URR. Three of the four included deepwater fields are giants. By far, the largest giant oil field in Africa is Hassi Messaoud of Algeria. However, no field in Africa has produced in excess of 1 Mbpd, the closest are Hassi Messaoud and Libya's Nasser (previously known as Zelten), which both have produced around 0.6 Mbpd for short periods of time.

Since Algeria, Libya and Nigeria, the historic main producers of Africa, are members of OPEC, their production has been subject to quota restrictions. However, the rise in production from 2000 and forward is mainly due to higher production quotas for the OPEC members and the start up of the deepwater giant oil fields in Angola.

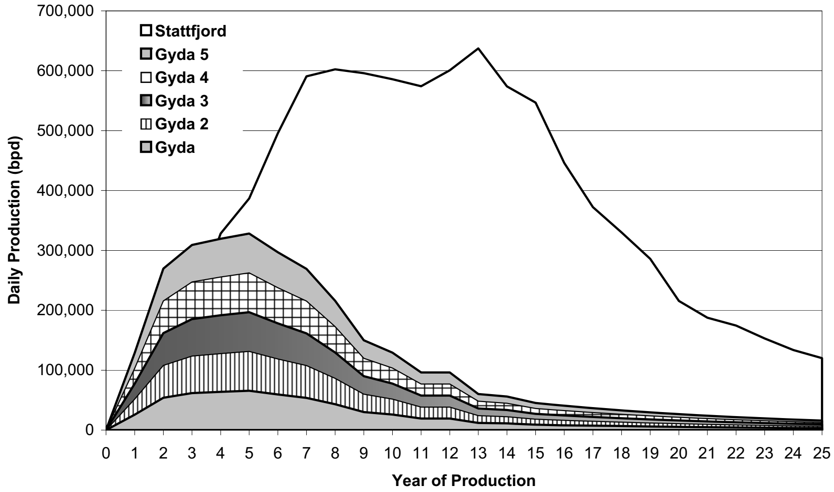


Figure 6.7: Production, in barrels per day (bpd), from the Norwegian fields Statfjord and Gyda compared. For illustrative purposes, five fields the size of Gyda are supposed to be brought on stream at the same time as Statfjord.

6.5.2 Giant Oil Fields of Asia

The oil production in Asia is dominated by China and Indonesia and the growth from their giant fields is the reason to the strong growth in production seen in the early 1970s (figure 6.10). Although the giant oil fields peaked at over 4 Mbpd in 1995, total production has continued to grow but in a slow manner. Still, the production from 31 fields, whereas 25 are giants, contribute to a little less than half of the total production. The dominating giant in Asia is the Daqing complex in China, which is one of the few exclusive fields with production in excess of 1 Mbpd. The largest fields in Indonesia are Minas and Duri and the peak production of about 0.42 Mbpd for Minas in 1973 is the highest production from a single field in Indonesia.

6.5.3 Giant Oil Fields of Eurasia

Russia is the dominant producer of the Eurasia[3]. The Romashikino field was responsible for the steady increase starting in the 1950s and it reached a peak level of over 1.6 Mbpd in the early 1970s. At this time, Russia's largest field, Samotlor, started its production growth, which ended in 1983 at about 3.4 Mbpd. Although younger fields such as Priobskoye and Sporyshevskoye produce at rates between 0.2 and 0.5 Mbpd, Samotlor still is the top producer with production levels reaching 1 Mbpd. Only 28 fields, of which 27 are giants, contribute with some 45 per cent of the total Eurasia production (figure 6.11).

[3]The countries/regions making up the former Soviet Union.

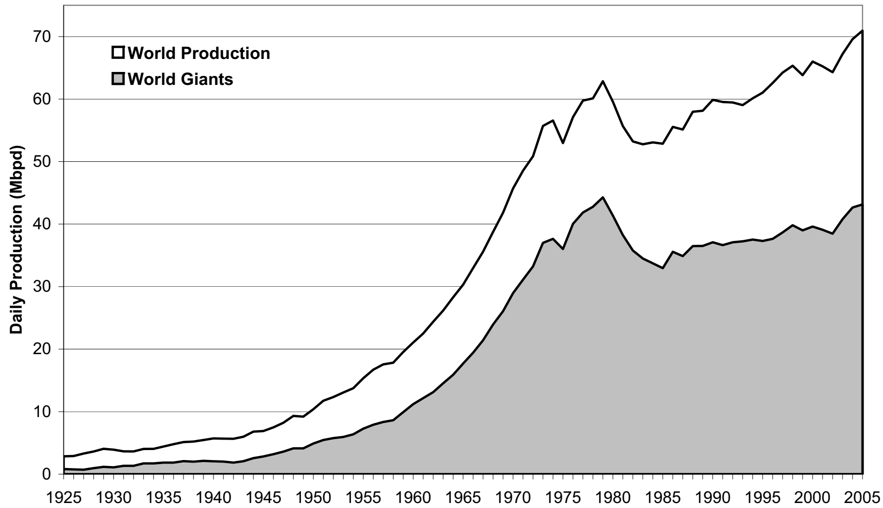


Figure 6.8: World oil production, excluding condensate and NGLs, in million barrels per day (Mbpd), and the contribution from 312 giant fields and 21 fields with production exceeding 0.1 Mbpd for at least one year (GFP).

6.5.4 Giant Oil Fields of Europe

The North Sea, with Norway and U.K as dominant producers, accounts for approximately 90 per cent of the oil produced in Europe. Of the about 230 oil fields producing in the North Sea, only 28 are giants and five more fields have produced in excess of 0.1 Mbpd (figure 6.12). However, the contribution from the 33 fields are close to half of the total production. The Piper Alpha disaster (section 5.1) explains the drop in the oil production in the late 1980s. Although European oil production was sustained a few more years after the giant's peak at 3.5 Mpbd in 1996, a drastic decline since 2000 is apparent (figure 6.12).

The 13 giant fields of the U.K reached their peak as early as 1984, at a level of almost 2 Mbpd. The Forties field, which is the largest U.K field, had a plateau level of more than 0.5 Mbpd in the late 1970s. Since then, production has been in decline and it reached a low point of 42 000 bpd in 2003. A reassessment of the field has allowed production to reach 65 000 bpd during 2005.

The Norwegian oil production has been dominated by the 13 giant fields, which peaked in 1997 at a daily production level of 2.4 Mbpd. The largest giant field in the Norwegian part of the the North Sea is Statfjord, which was discovered in 1975.

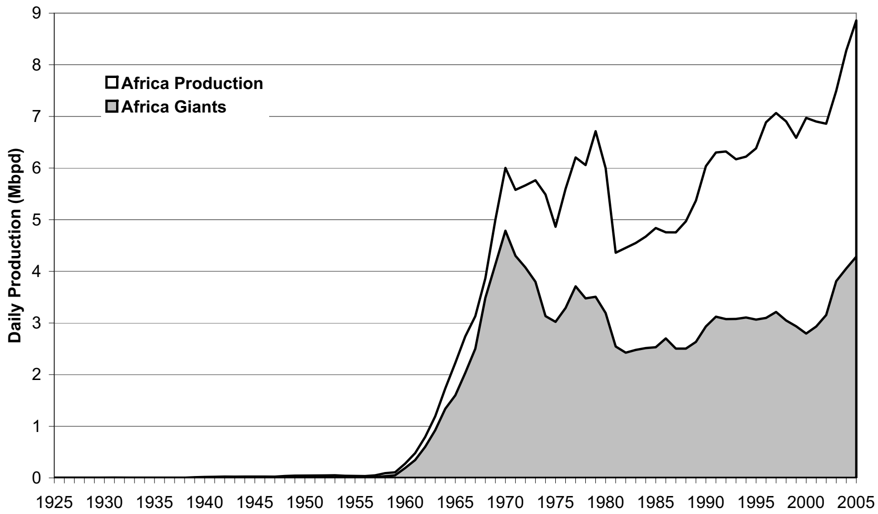


Figure 6.9: Africa oil production, excluding condensate and NGLs, in million barrels per day (Mbpd), and the contribution from 51 giant fields and 5 fields with production exceeding 0.1 Mbpd for at least one year (GFP).

6.5.5 Giant Oil Fields of the Middle East

The dominance of giant fields in the Middle Eastern oil production is total (figure 6.13). In 2005, 79 giant fields out of the global total of 47 500 fields contributed to about a quarter of the global oil production. The Middle East holds the largest fields discovered as well as the largest amount of fields that have produced in excess of 1 Mbpd. Except the giants in Saudi Arabia and Kuwait previously described, only Iran and Iraq have fields where the production has exceeded 1 Mbpd. Among them are the Iranian fields Ahwaz, Agha Jari, and Marun, while Iraq have Kirkuk and Rumaila[4]. Besides the common factor of production rates above 1 Mbpd the fields have been on production between 40 and 74 years. In addition to those countries Abu Dhabi has a number of large fields, most notably the onshore field Bu Hasa and the offshore field Zakuum. Since 1950, the onshore field Dukhan has been the mainstay of Qatar's oil production.

6.5.6 Giant Oil Field of North America

USA has been and still is the main producer of oil in North America, despite the USA peak in 1970. However, the growth in production from the mid 1970s was pushed by production from Prudhoe Bay in Alaska and especially the Mexican offshore giant fields, with Cantarell in the lead. Those two fields are the only ones in North America where production has ex-

[4]Rumaila is divided into a north and south part and it is the combined production that have been above 1 Mbpd.

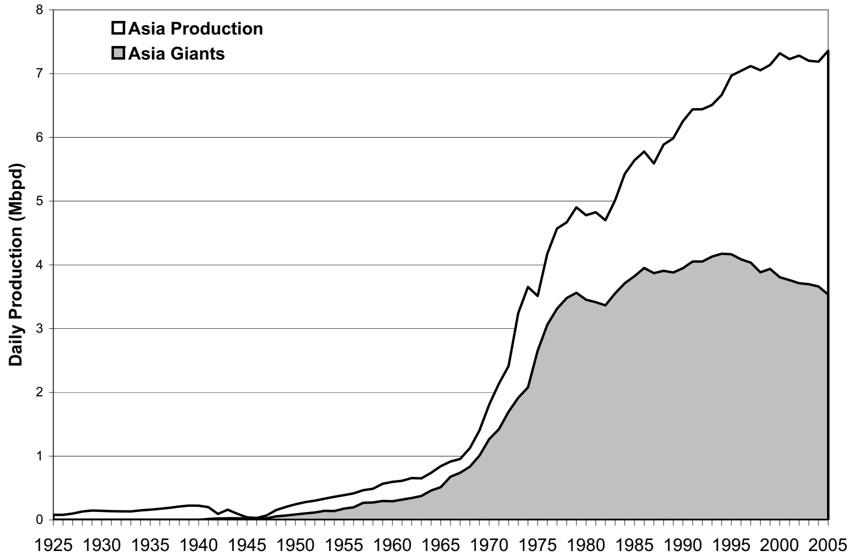


Figure 6.10: Asian oil production, excluding condensate and NGLs, in million barrels per day (Mbpd), and the contribution from 25 giant fields and 6 fields with production exceeding 0.1 Mbpd for at least one year (GFP).

ceeded 1 Mbpd. However, both fields have the common factor of being past their prime and now being in decline. The number of giant fields in North America is 68 and of them, 47 has been discovered in the USA. The production includes four other fields that have produced in excess of 0.1 Mbpd. Those 72 fields, out of over 36 000 fields, produces 48 per cent of the total North American production (figure 6.14). However, the 72 fields peaked in 1983 at a level of more than 6 Mbpd and the year after the total production peaked as well (figure 6.14).

6.5.7 Giant Oil Field of South America

Historically, the dominant producer in South America has been Venezuela. This is still true, but nowadays Brazil contributes with a large part as well. The contribution from Brazil is mainly from six deep water giant oil fields, of which Roncador is the largest deep water oil field in the world with an URR of 2.6 Gb. Besides the Bolivar Coastal complex, the fields El Furrial and Mulata are major contributors to Venezuelan production. Although no single field has produced above 1 Mbpd in South America, Lagunillas has been close with 0.95 Mbpd in the mid-1960s. However, Lagunillas is one of the fields of the Bolivar Coastal complex and the production from the complex has exceeded 1 Mbpd. Another prolific producer is the Cupiagua-Cuisiana field in Colombia, which produced 0.43 Mbpd at its peak in 1999. The 34 giant fields included contributes to more than 50 per cent of South American production.

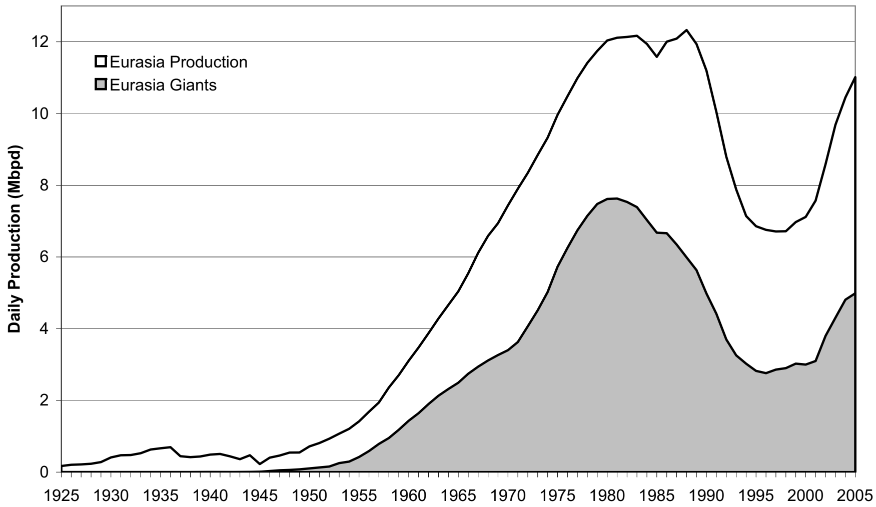


Figure 6.11: Eurasian oil production, excluding condensate and NGLs, in million barrels per day (Mbpd), and the contribution from 27 giant fields and 1 fields with production exceeding 0.1 Mbpd for at least one year (GFP).

6.5.8 Contribution from the Largest Giant Oil Fields

The dominance of just a few very large giant oil fields in world oil production (figure 6.16) in combination with the declining discovery trend of giant oil fields strongly suggests a concept of peak oil governed by giant oil fields, which is further accentuated by the peaks in both Europe and North America. Furthermore, it justifies the modeling of future oil production from giant oil fields. However, before the future of giant oil fields are examined, the contribution from other sources such as deepwater oil production and Canadian oil sands must be studied, and in what way technology and the price of oil influence future oil production.

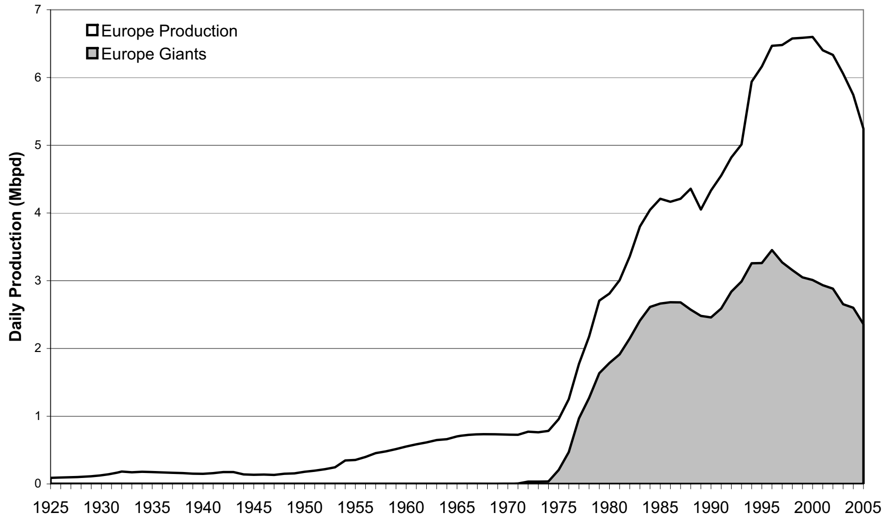


Figure 6.12: European oil production, excluding condensate and NGLs, in million barrels per day (Mbpd), and the contribution from 28 giant fields and 5 fields with production exceeding 0.1 Mbpd for at least one year (GFP).

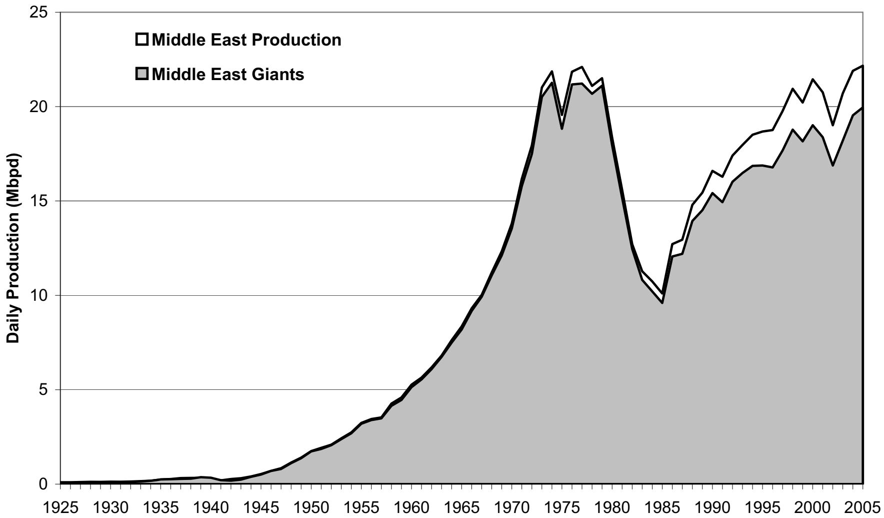


Figure 6.13: Middle East oil production, excluding condensate and NGLs, in million barrels per day (Mbpd), and the contribution from 79 giant fields (GFP).

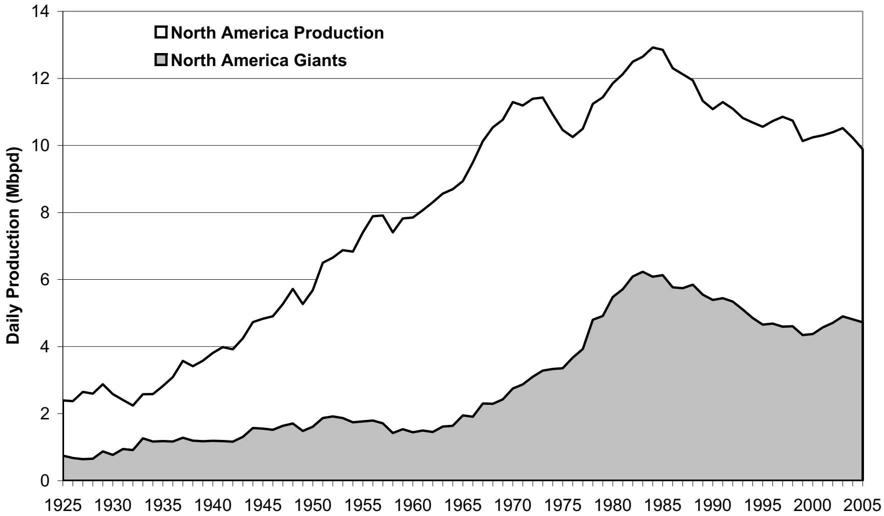


Figure 6.14: North American oil production, excluding condensate and NGLs, in million barrels per day (Mbpd), and the contribution from 68 giant fields and 4 fields with production exceeding 0.1 Mbpd for at least one year (GFP).

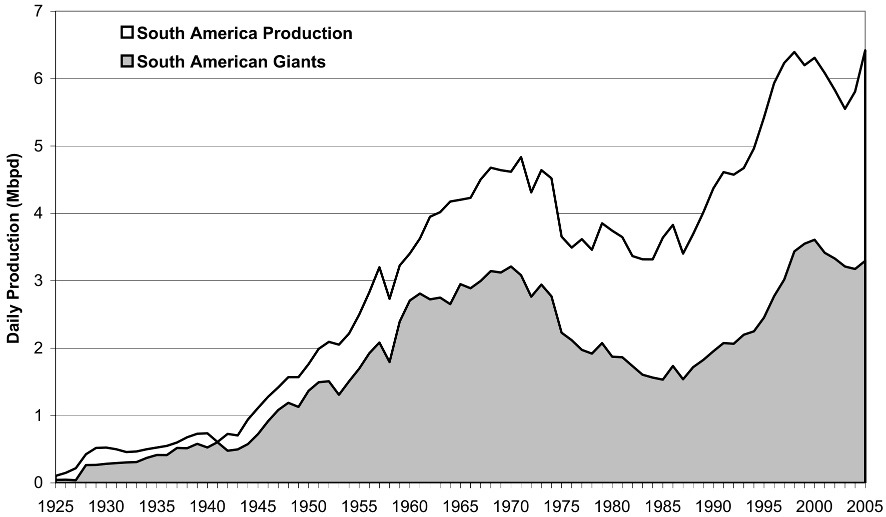


Figure 6.15: South American oil production, excluding condensate and NGLs, in million barrels per day (Mbpd), and the contribution from 34 giant fields (GFP).

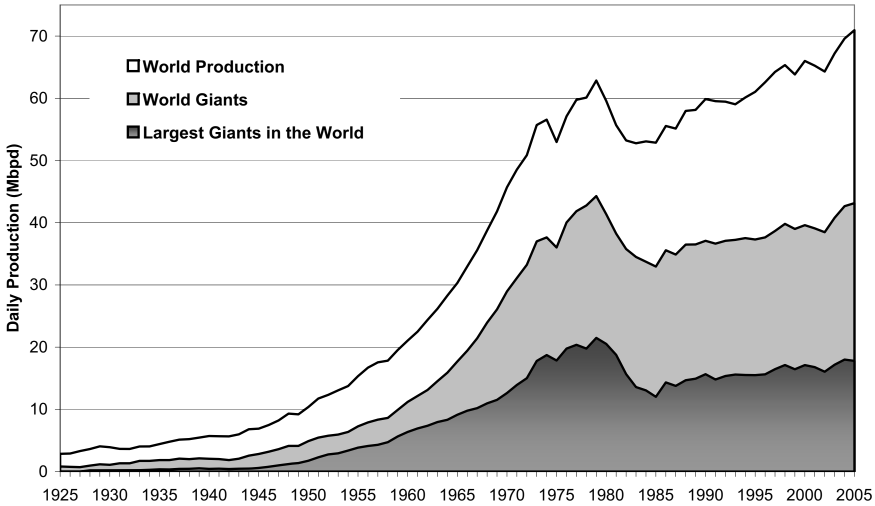


Figure 6.16: World oil production, excluding condensate and NGLs, in million barrels per day (Mbpd), and the contribution from 312 giant fields and 21 fields with production exceeding 0.1 Mbpd for at least one year. In addition, the contribution from the largest fields is included (GFP).

7. Contributions to Future Oil Production

The average increase in oil demand from 1994 to 2006 calculated from International Energy Agency (IEA) Oil Market Reports was 1.74 per cent. But in later reports, IEA claims that signs of demand destruction, due to sustained high prices, are visible and accordingly, lower the future oil demand growth estimate to 2030 to 1.3 per cent (IEA, 2006). However, the annual growth estimate in the World Energy Outlook (IEA, 2006) reference case up to 2015 is 1.7 per cent, which is in line with calculated historic values. Another widely cited report on future energy demand is the International Energy Outlook published by the Energy Information Agency (EIA) in the USA. Their reference case scenario for demand growth in oil from 2003 to 2030 is 1.4 per cent per annum (EIA, 2006). The low and high demand cases forecast annual oil demand growth of 1.0 per cent and 2.0 per cent, respectively. At the same time, maturing oil fields show a yearly decline between 3 and 8 per cent. Starting out from 2005 production, including all liquids, there will be a growing gap between supply and demand (figure 7.1). Filling this gap is one of the toughest challenges the global oil industry is facing. First, production from new fields must compensate for declining production in existing mature fields. By this, previous production levels will be reached. Second, those new fields must then increase the production level even further to reach the corresponding level of the growing demand.

Declining production in regions with growing demand exerts an ever greater pressure on the exporting countries. This in turn makes it even more difficult to fill the gap. The main sources generally cited to fill the gap is deepwater oil production, oil sands from Canada and heavy oil from Venezuela, and production increases from Saudi Arabia. In addition, major new field projects and the effect of a higher oil price on exploration and production will help to fill the gap. These sources are all described below, with an emphasis on oil sands, deepwater oil production, and major new projects. Information gathering and field forecasts of the two latter have been a part of the research and the forecasts are presented below as well. All the forecasts are made from a supply perspective and come from single projects.

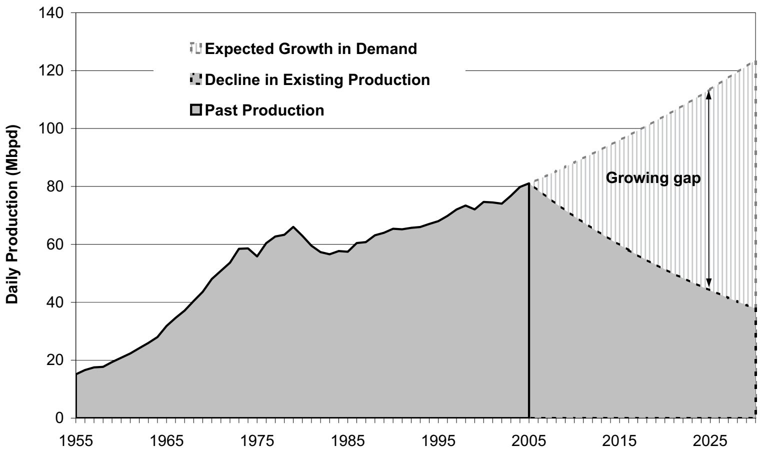


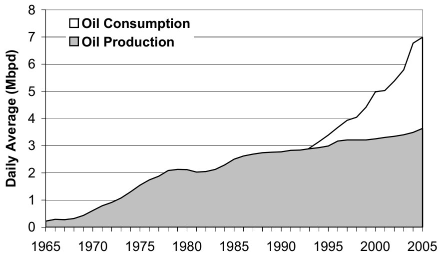
Figure 7.1: Historic oil production, together with expected growth in demand and decline in existing production, in million barrels per day (Mbpd).The annual demand growth is 1.7 per cent and production declines with 3 per cent annually.

7.1 Major Oil Consumers and Their Production

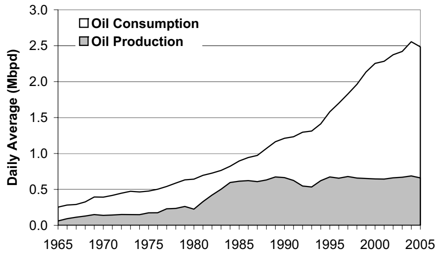
The quite sudden increase of oil prices starting in 2002 is partly due to a rapid growth in oil demand from China and India (figure 7.2(a) and 7.2(b)). China turned from a net exporter into a net importer. At the same time the demand for oil continued to rise, despite high prices, in the two major consumption regions: the USA and Europe (figure 7.2(d) and 7.2(c)). In addition, the production from both regions continued to decline. This illustrates that even if both the USA and Europe succeed in keeping the demand constant, there will be a net increase due to the declining domestic production. In other words, the import of oil must increase with the same amount of oil that is lost due to declining oil production. The present consumption levels in both China and India are estimated to continue to grow, with 3 to 4 per cent annually to 2030 (IEA WEO). However, both countries are close to their respective peak production and no new large discoveries have been reported or large new fields are on development. Consequently, in the best case their import level will be held constant but an increase in import is more probable. Thus, their consumption will add to the pressure of the exporting countries, which in 2030, might need to export some 30 Mbpd more than today (Aleklett, 2006). The extra production of 30 Mbpd translates to three new oil regions of the size of Saudi Arabia.

7.2 Deepwater Oil Production

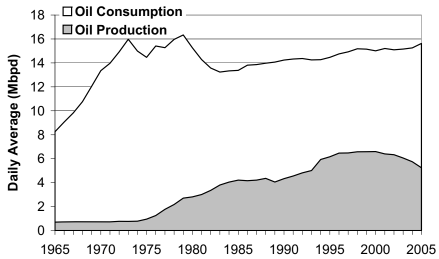
The development of offshore technology for exploration and production of petroleum at ever greater depths is a true landmark for technology. The first



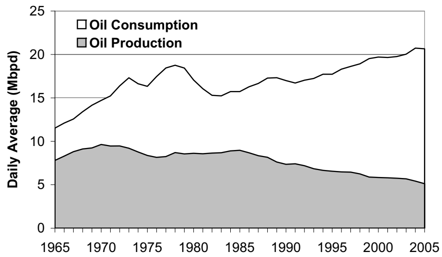
(a) China Oil Production and Consumption



(b) India Oil Production and Consumption



(c) Europe Oil Production and Consumption



(d) USA Oil Production and Consumption

Figure 7.2: Oil production and consumption in four major consumption regions/countries a) China b) India c) Europe) d) USA.

offshore drilling took place in water depths of 11 m in Summerland, California in 1897 (Leffler et al., 2003). Petrobras discovered Marlim Sul 100 years later in over 1 700 m of water offshore Brazil. However, while development of technology continues, there is a geological limit to deepwater production as exploration continues further out from the continental shelf and onto the oceanic crust, with thinner layers of sediment (Shirley, 2004). The limiting factor is the oil window and accordingly the lack of oil and/or gas generation in sediment layers buried in less than 2 000 m depth (see chapter 3).

Exploration in deepwater, water depthes exceeding 500 m, has so far mainly been conducted in three regions, which accordingly hold the most discovered resources: the US Gulf of Mexico, Brazil and West Africa (Pettingill and Weimer, 2002). Angola and Nigeria are the dominant players in West Africa deepwater exploration and production. On a global level, at the end of 2005 over 48 Gb have been discovered (figure 7.3) (OFN).

The exploration really took off in the mid 1980s (figure 7.3), mainly because advances in seismic reflection imaging led to a reduction in the geological risk involved with deepwater exploration (Pettingill and Weimer, 2002). This is further illustrated by the increase in success rates[1] in deepwater exploration. The global average has been about 30 per cent since 1985, while before 1985 the average was less than 10 per cent

[1] Percentage of a number of wells drilled that discovered oil and/or gas.

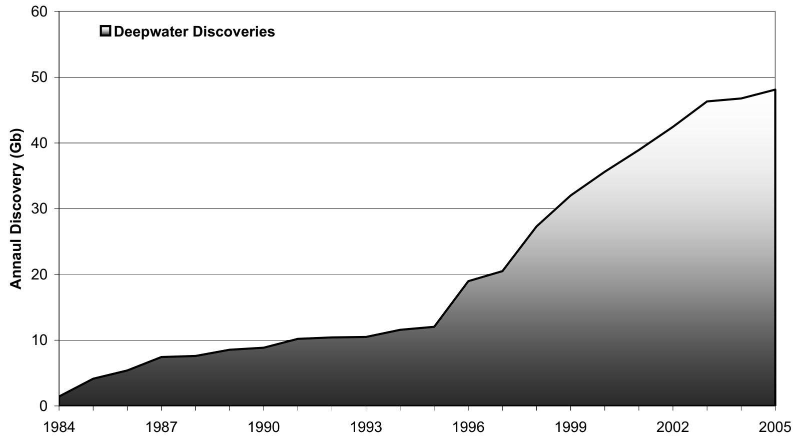


Figure 7.3: Cumulative global deepwater discovery in billion barrels (Gb) (OFN).

(Pettingill and Weimer, 2002). Exploration licenses for deepwater areas in Angola and Nigeria were awarded in the early 1990s with subsequent start of exploration (McLennan and Williams, 2005). Success rates were high, almost 50 per cent, and yielded many large discoveries (figure 7.3) (Pettingill and Weimer, 2002). The yearly contribution from deepwater shows a peak in discovery in 1998 and many of the largest fields were discovered early on (figure 7.4). So far, 27 giant oil fields have been discovered in deepwater, where the largest is Roncador in Brazil with a URR of more than 3 Gb (table 7.1). The size of the discovered deepwater giants are small compared to the largest giants discovered (table 6.1). However, large areas with deepwater potential are still lightly explored and some observers estimate the future potential to be as much as already discovered, thus a total resource base of some 90 Gb (Sandrea, 2004).

Offshore exploration and production follows the same steps as outlined in chapter 3. Since offshore environments in general are more harsh and the water itself causes difficulties, the equipment used is both more advanced and more expensive. Seismic acquisition is acquired by specially designed ships. The general classification of offshore drilling rigs is mobile offshore drilling unit (MODU) (Hyne, 2001). Three different types of MODU:s are widely used: jackup, semisubmersible and drillship. They are all used for drilling and well testing. After finishing drilling at one site, they move, either by their own engines or are towed, to a new drill site. Jackups have a lower hull and upper hull, where the upper contains the drilling rig. At the site of drilling, the lower hull is flooded and then lowered to the seafloor. The upper hull is raised. Water depths up to around 100 m are suitable for jackups (Hyne, 2001). For greater depths, either semisubmersibles or drillships are used. A semisubmersible is a drilling rig with large pontoons guaranteeing

Table 7.1: *Deepwater giant oil fields discovered to 2005 (GF, OFN).*

Field name	**Country**	**Discovery year**	**Range of URR [Gb]**
Roncador	Brazil	1996	3.2
Marlim Sul	Brazil	1987	2.5
Marlim	Brazil	1985	2.4
Albacora	Brazil	1984	1.4
Barracuda	Brazil	1989	1.2
Thunder Horse	US Gulf of Mexico	1999	1.0
Dalia	Angola	1997	0.9
Girassol	Angola	1996	0.9
Bonga	Nigeria	1996	0.7
Akpo	Nigeria	2000	0.6
Papa Terra	Brazil	2002	0.5
Cachalote	Brazil	2002	0.4–0.8
Agbami	Nigeria	1998	0.7
Hungo (Kizomba A)	Angola	1998	0.7
Albacora East	Brazil	1993	0.6
Jubarte	Brazil	2002	0.5
Mars	US GoM	1993	0.7
1-ESS-121	Brazil	2003	0.7
1-ESS-130	Brazil	2003	0.6
Erha	Nigeria	1999	0.6
Atlantis	US GoM	2001	0.6
Golfinho	Brazil	2003	0.6
Usan	Nigeria	2002	0.5
Kissanje (Kizomba B)	Angola	1998	0.5
Bonga SW–Aparo	Nigeria	2001	0.5
Mad Dog	US GoM	1998	0.5
Tahiti	US GoM	2002	0.5

the flotation. When used in shallow water a semisubmersible is anchored to the bottom. At greater depths, a semisubmersible uses dynamic positioning. Drilling in water depths of up to 3 000 m can be accomplished by a semi-submersible. For even greater depths, drillships are used. They as well use dynamic positioning. Drillships have drilled in water depths greater than 10 000 m.

The mid 1970s, in the US Gulf of Mexico, saw the first wells drilled in water depths exceeding 200 m. This depth was at that time considered deep water. Fixed steel platforms (figure 7.5) were then used as production units but as water depths became deeper, other production units were required. Today, when drilling and production in depths of more than 2 000 m is common, a variety of different production systems are in use. In

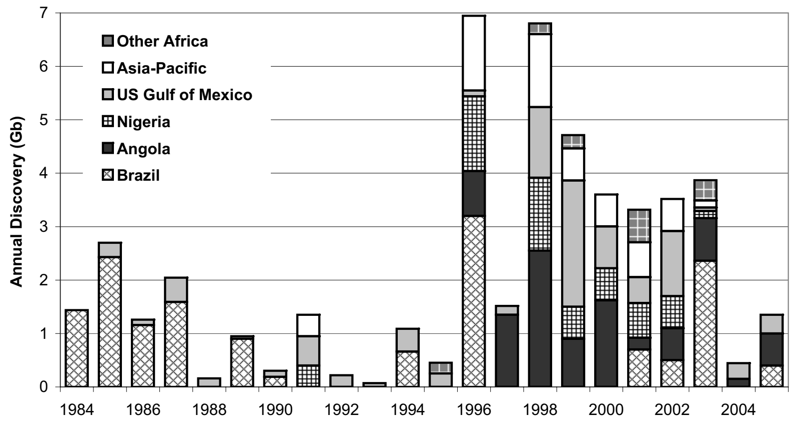


Figure 7.4: Annual global deepwater discovery in billion barrels (Gb) (OFN).

general, two different systems can be distinguished: bottom supported units and floating units (Leffler et al., 2003). The first group contains fixed platforms and compliant towers (figure 7.5). In the second group, Spar-platforms, semisubmersible, Tension leg platforms (TLP), and floating production storing and offloading (FPSOs) are found (figure 7.5). In addition, subsea systems are used to connect smaller oil fields to existing infrastructures (figure 7.5). Thus, a number of small fields, not large enough to motivate its own platform, can be brought together to one common platform.

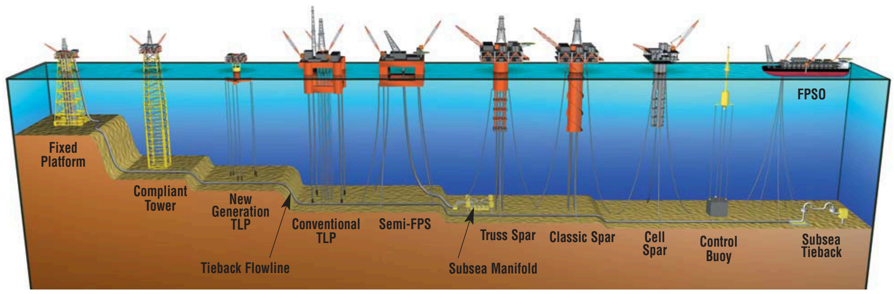


Figure 7.5: Different deepwater production systems. The semi-FPS (Floating Production System) corresponds to the semisubmersible in the text. *Source: Part of the 2005 Deepwater Solutions & Records For Concept Selection Poster. Used with the kind permission of Mustang Engineering.*

Water depth is the first parameter to consider when choosing any of the above production systems, where fixed units can be used in water depths up to 1 000 m and floating units can be used in greater water depths (figure 7.5).

A common development is to install a production unit to exploit a certain field and other, most often smaller, fields will be tied back at a later time to the production unit when there is free capacity on it. In other words, when the production from the main field start to decline it is possible to keep the plateau production with additional fields. The developments in Angola of Girassol, BBLT, Greater Plutonio and Kizomba are all examples of this development scheme. The Girassol field came on stream in 2001 and in 2003 the Jasmine was field connected. The Rosa field is supposed to be connected during 2007 to prolong the plateau production. This development scheme also simplifies the forecasting since the production capacity of the production units are known and with a high probability will not change over time.

The deepwater production forecast is based mainly on data from the oil field news (OFN) database, some information stems from the other two databases (GF and GFP). The forecast can be said to contain a number of production hubs with a fixed production limit. Included projects are listed in Appendix A. Below is a short description of the assumptions for the main parameters in the deepwater forecast. The assumption of prolonged plateau levels with resulting drastic decline rates has been confirmed from attended presentations at the 18^{th} World Petroleum Congress 2005. Moreover, IEA assumes high decline rates in their different forecasts of Angola deepwater production (IEA, 2006a).

First oil Fields are assumed to start production at the time given in the latest available sources.

Production If not otherwise stated, fields are assumed to ramp up to plateau/peak production rapidly. First year production is calculated from when during the year the field is supposed to go on stream. Eventual later tie-backs are assumed to come on stream at the time given and to keep the plateau level until decline sets in.

Plateau/peak level Any information on plateau/peak level is used. If no such information exists an estimate based on the production capacity of the production unit is made. The peak level is assumed to be constant until the decline phase sets in.

Decline The decline phase sets in when prior production plus production during decline exceeds the best reserve estimate with 10 per cent. The decline is assumed to be about 20 per cent annually, and this illustrates the operators' will to keep the fields at plateau levels as long as possible.

Reserves Numbers on proven plus probable reserves are used whenever the information is available. If information on oil in place is given, the most optimistic estimate of the recovery factor from the operator is used. Eventual upsides on reserves are included. In an attempt to account for future reserve growth in a field, total production from a field exceeds the best reserve estimate with some ten per cent.

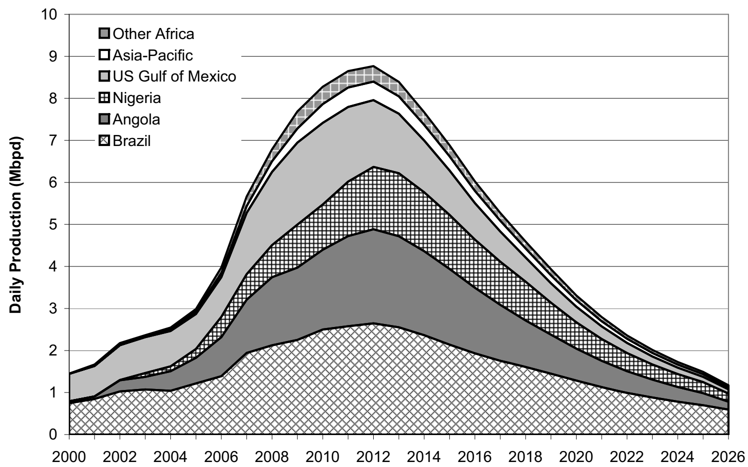


Figure 7.6: Deepwater production forecast, in million barrels per day (Mbpd) based on OFN.

The deepwater forecast, including over 170 fields, shows a steep rise in production up to 2012 and thereafter a steep decline. The forecast includes a number of development projects not yet sanctioned and with no actual development plans. This might result in a less steep increase and a less steep decline. Brazilian production is mainly based on their five large giant fields (table 7.1), and they govern the future of Brazilian deepwater production. The recent discoveries of oil in Angola deepwater indicates later tie-backs and thus a bit longer plateau period. The growth in US Gulf of Mexico is largely due to the production start in 2008 of the two giant fields Thunder Horse and Tahiti. Since the largest discovered deepwater giants already are on stream, or will be on stream before 2010, the reliability of the deepwater forecast is considered to be good.

7.3 Oil Sands in Canada and the Orinoco Belt in Venezuela

The resource base in Alberta in Canada and the Orinoco belt in Venezuela is usually referred to as unconventional oils. In a historic context, conventional drilling and production methods could not be used to produce the oil and hence the term unconventional. The main reasons for this is the density (low API gravity) and high viscosity of the oil. Oil is generally defined as heavy if the API gravity is below 20°API. Some heavy oils are even more dense than water, since they have densities below 10°API. Heavy oil fields occurs all over the world, such as Kern River, California, Captain in the U.K part of the North Sea and Duri in Indonesia. However, the two by far largest accumulations of heavy oil are Alberta and Orinoco. Oil from Orinoco is usually called heavy oils while the extracted fluid from the oil sands in Alberta is referred to as bitumen. Furthermore, the main difference between the bitumen in Alberta and the heavy oil in Orinoco lays in the viscosity: bitumen is non-mobile at reservoir conditions while heavy oil is mobile at reservoir conditions. However, the similarity of the produced oils from both regions are the need for upgrading to an oil suitable for ordinary refineries (Williams, 2003b; Söderbergh et al., 2006).

In general, geochemists agree on that all generated oil is light and thus movable. During migration and subsequent trapping, oil can be degraded of the lighter hydrocarbon chains and thus become heavy oil, or even bitumen (Curtis et al., 2002). Degradation is more probable near the surface in shallow reservoirs. Typically, heavy oil reservoirs are in younger geological formations and thus more shallow. However, it is still not completely understood what the sources for the oils in both Alberta and Orinoco are, but it is agreed that they derive from heavily biodegraded marine oils (Alboundwarej et al., 2006).

Depending on the depth of the deposit and viscosity of the oil, different production methods are employed. In general, two different types can be distinguished: cold production, which do not utilize heat, and thermally assisted recovery methods. Open mining is a cold production method utilized for shallow oils. This is only economical for the shallow oil sands in Alberta due to to the large volume and surface access (Alboundwarej et al., 2006). In cases where the oil is moveable ordinary production methods can be used. The aim with the thermal recovery methods is to heat the bitumen in order to reduce the viscosity and hence increase the mobility. The heat must be sufficient to make the oil flow. The methods used in each region is described in more detail in each section, respectively.

7.3.1 Oil sands in Alberta

The province of Alberta in the south western part of Canada holds the entire resource base of Canadian oil sands. To further distinguish, the oil sands are in three areas: Athabasca, Cold Lake and Peace River (Söderbergh et al., 2006) (figure 7.7). A typical oil sand consists of up to 80 per cent of sand, silt and clay assembled in a porous rock. The actual resource extracted from oil sands is bitumen. The gravity of bitumen is around 9°API and the viscosity can be as high as 1 000 000 cp (Hinkle and Batzle, 2006). The bitumen is upgraded to a synthetic crude oil (SCO) suitable for conventional refineries. This is accomplished by addition of hydrogen or rejection of carbon,

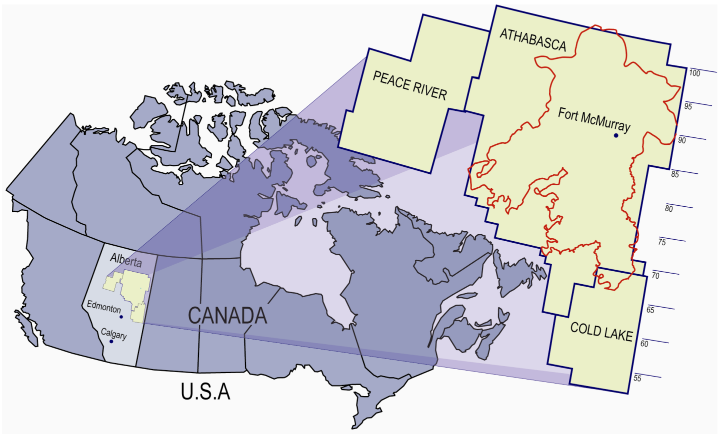


Figure 7.7: Alberta's three oil sands areas. *Source: Alberta Energy Utilities Board (EUB)*

or both, to the bitumen. A more comprehensive review of the Canadian oil sand industry is given by Söderbergh (2005).

The oil sands of Alberta holds large volumes of oil, 1 700 Gb is estimated to have been original in place (table 7.2).

Table 7.2: *Reserves of oil sands in Alberta. All values in Gigabarrel (Gb) (Söderbergh et al., 2006)*

	Oil initial in place	**Initial established reserves**	**Remaining established reserves**
Mineable	110	35.2	32.1
In Situ	1590	143.6	142.2
Total	1700	178.8	174.3

There are two main technologies of extracting bitumen from oil sands: open mining and in situ thermal production. Open mining requires the removal of an overburden in order to reach the oil sands. At current economic considerations, the thickness of the overburden can be up to 75 m. Bitumen is then separated from the oil sand. Some 20 per cent of the reserves are deposited shallow enough to be mined. In general, the open mining process is closer related to the mining industry than the oil industry. Hence, open mining faces the same environmental challenges as mining for other economic rocks, such as large amounts of waste. When the overburden is too thick for strip mining, in situ extraction methods have to be applied. In addition to thermal recovery methods, attempts to dissolve the bitumen by injection of solvents are performed. However, solvent injection methods are not yet mature enough for field applications. Accordingly, thermal methods are used and the most widely used is steam injection, which often is referred to as cyclic steam stimulation (CSS) or "Huff and Puff". Wells are alternately used for injection and production. First, hot steam is injected through a well into the reservoir. Second, the well is closed while the reservoir absorbs the heat, the so called soak phase. Third, the well is put on production and the now heated (and mobile) bitumen can flow and is then pumped to the surface. This method is very energy intensive, with a steam to oil ratio of 3:1-4:1, or in other words; 3-4 barrels of water is required to generate one barrel of bitumen. The recovery is low, due to stimulation only around the wellbore, and between 20-25 per cent is recovered.

Another method is steam assisted gravity drainage (SAGD), which already is in use in some operations despite it is not fully developed. In SAGD methods, two horizontal wells are used and they are horizontally separated from one another by around 5 m. The horizontal length can be up to 1 000 m. The hot steam is continuously injected into the injector well, which is the upper of the two. The heated bitumen flows, caused by gravity, towards the lower producer well and is then pumped to the surface. The energy intensity is less for SAGD, with a steam to oil ratio of 2.5:1 to 3.0:1. The larger volume of oil sand exposed to heat improves the recovery, which can be between 40-60 per cent.

One big hurdle in the expansion of in situ production is the need for natural gas. As an industry rule of thumb it takes 1 000 cubic feet of natural gas to produce one barrel of bitumen. In addition some 400 cubic feet of gas is needed to upgrade one barrel of bitumen to one barrel of SCO (Söderbergh et al., 2006). Thus, 1 400 cubic feet of natural gas is required to convert bitumen to one barrel of SCO. The remaining established in situ reserves from table 7.2 is 142.2 Gb. They require almost 200 000 billion cubic feet of natural gas to be exploited. At the end of 2006, according to Oil & Gas Journal, the proven natural gas reserve of Canada is almost 58 000 billion cubic feet, which is only 29 per cent of the total requirement (Radler, 2006). In addition, the utilization of natural gas for bitumen extraction is not the only use of natural gas in Canada. However, this argument do not take into account any technological advances in bitumen extraction but even a 50 per cent reduction in the need for natural gas can not resolve the situation. Present and forecasted projects use technologies as SAGD for extraction of in situ bitumen (Söderbergh et al., 2006). Hence, the bitumen is made moveable by heating and this requires energy, which is a fundamental law of physics. Thus the argument shows the need for energy and natural gas is not enough to extract all in situ bitumen. One proposed solution is to construct nuclear power plants and use the generated steam for bitumen extraction, an idea supported by the Natural Resource Minister (Rogers, 2007; Williams, 2003b). However, everyone that has followed the debate of the future of nuclear energy knows this will not happen overnight. Another way to overcome the natural gas hurdle is to burn residue fuel in a large scale. However, this generates acceleration of carbon dioxide emissions, which do not comply with the Canadian commitments to the Kyoto protocol (Söderbergh et al., 2006).

The forecast for oil production from oil sands in Canada is based on the one given by Söderbergh et al. (2006), where further details regarding the forecast can be found. A detailed study of all upcoming projects up to 2018, both mining and in situ, has been performed. The mining part consists of eight projects, while the in situ part considers 12 projects. All in situ projects are based on SAGD. After 2018, the in situ projects are assumed to show a linear growth trend reaching 4.5 Mbpd in 2050. The study of the mining projects shows that they will reach a plateau around 2020 of some 2.2 Mbpd and then start to decline in 2040. Moreover, all obstacles are assumed to be overcome and accordingly, the forecast must be judged to be optimistic. The total production from oil sands will increase rapidly up to 2011 and thereafter a less rapid growth up to 2040, when the peak production occur at close to 6 Mbpd (figure).

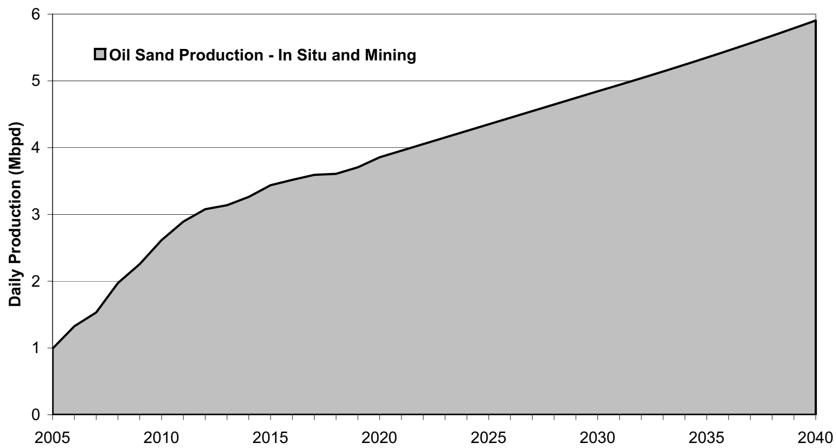


Figure 7.8: Oil production, in million barrels per day (Mbpd), from oil sands in Alberta, Canada. Note both in situ and mining is included in the graph.

7.3.2 Heavy Oil from the Orinoco Belt, Venezuela

The first detailed study of the Orinoco belt (figure 7.9) was carried out in 1968, despite a first discovery well of 7°API in 1935 (Curtis et al., 2002). The Venezuela state oil company Petróleos de Venezuela S.A. (PDVSA) tried various thermal recovery methods but the projects were mothballed in the late 1980s due to high costs of heating. However, in the mid 1990s, four new projects were started in co-operation with international oil companies such as ExxonMobil, Statoil and Total. These projects are Petrozuata, Sincor, Cerro Negro and Hamaca, where Petrozuata was the first to come online in 1997 (Curtis et al., 2002). The heavy oils in the mentioned projects have gravities around 8°API and are transported by pipeline to the upgrade facilities in José, 200 km north of the Orinoco belt (figure 7.9). In addition to the heavy oil produced by the four projects the PDVSA subsidiary Bitumenes Orinoco SA produces a product called orimulsion, which is an emulsion of heavy oil with water and a surfactant (Williams, 2003b). Orimulsion is marketed as a boiler fuel for power generation, but its future seems to be somewhat unclear (Moritis, 2005).

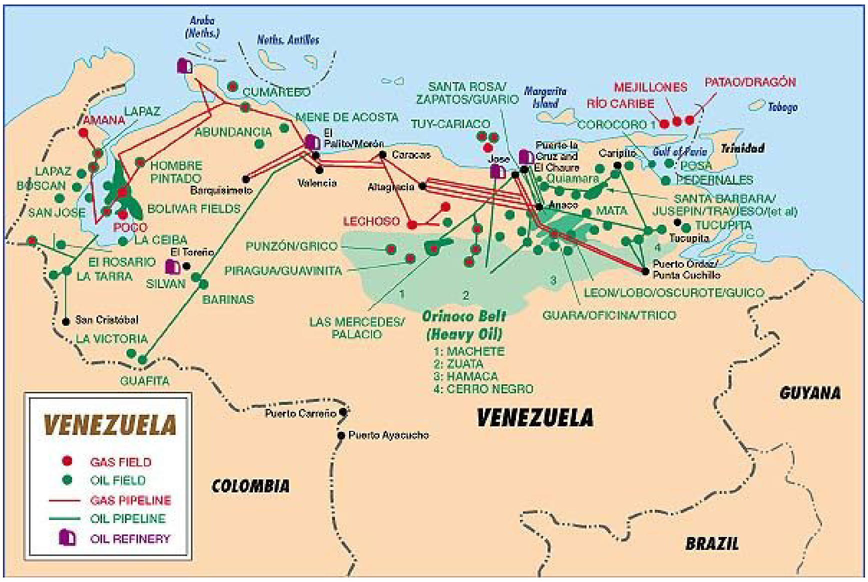


Figure 7.9: The Orinoco belt of heavy oil in Venezuela. Note the Bolivar giant field complex at the Lake Maracaibo. *Source: World Oil, August 2000. Used with the kind permission from Gulf Publishing.*

The estimated oil in place is 1 360 Gb (table 7.3) and the latest recovery estimate by PDVSA approaches 20 per cent which gives a reserve of 236 Gb. The gravity of the oil varies between 8 and 10°API, while the viscosity can vary from 1 000 to 5 000 centipoise (Hinkle and Batzle, 2006). The reservoir conditions are good, especially the permeability which can be as high as 15 000 mD, and the porosity is around 30 per cent (Hinkle and Batzle, 2006).

The prerequisite for the use of cold production methods in Orinoco is the less viscous and mobile oil at reservoir conditions compared to bitumen in Alberta. The main recovery method in the Orinoco belt is varying horizontal well techniques supported by electrical semisubmersible pumps or progressive cavity pumps (described in chapter 3). In order to reduce viscosity, a dilution of very light oil called naphtha (47°API) is injected into the reservoir (Curtis et al., 2002). The development of horizontal drilling techniques and increased cost effectiveness of both drilling and pumps has made it possible to recover the heavy oil without using costly thermal meth-

Table 7.3: *Reserves in Orinoco Belt. All values in gigabarrel (Gb) (Moritis, 2005)*

Area*	**Oil in place**	**Established reserves**	**New Reserve certification**
Carabobo (Cerro Negro)	227	15	N/A
Ayacucho (Hamaca)	87	6	N/A
Junin (Zuata)	557	15	N/A
Boyacá (Machete)	489	1	N/A
Total	**1360**	**37**	**236**

*Names in brackets are the old names for the areas.

ods (Curtis et al., 2002). However, thermal methods are also used to some extent (Alboundwarej et al., 2006).

The production profile for the Orinoco fields is to ramp up to a plateau and then keep it there for a long time. The aim for the four main projects in Orinoco is to keep the level at 0.6 Mbpd for 35 years, a view shared by PDVSA (Curtis et al., 2002; Moritis, 2005). This level is used as the base for the forecast of future Orinoco production (figure 7.10). From 2009, a new block will add a production of 0.12 Mbpd and in 2010 another new block plus additional production from the first new block will add 0.35 Mbpd extra. This leaves the total production including an assumed Orimulsion production of 0.10 Mbpd at 1.2 Mbpd in 2012. This ramp up of production follows the PDVSA plan as reported by Moritis (2005) in Oil & Gas Journal. As of today no development plans for the new projects exist but seven international, both private and state owned, companies are studying new regions. After reserve certification of the new regions, development negotiations with PDVSA will commence (Moritis, 2005). However, since the resource base is large it is assumed an extra expansion starting in 2015 which eventually will reach 1 Mbpd in 2020. The expansion will continue and total production reaches 2.4 Mbpd in 2025. This increase is simply a doubling of the PDVSA estimated production in 2012. However, these projects assumes a reduction in time from start up to full production, ten years instead of 15. Recent turmoil and fiscal regimes in Venezuela do not lend a lot of credibility to this scenario (Wertheim, 2007). Nevertheless, it is included to show the future potential of the Orinoco Belt.

7.4 Production increase from Saudi Arabia

Many publications with forecasts of future oil production has a gap between future production and demand. A common solution to fill the gap is production from Saudi Arabia. There seem to have been a general consensus among forecasters on a more or less unlimited production capacity from Saudi Arabia, with production levels up to 20Mbpd (EIA, 2005, 2006;

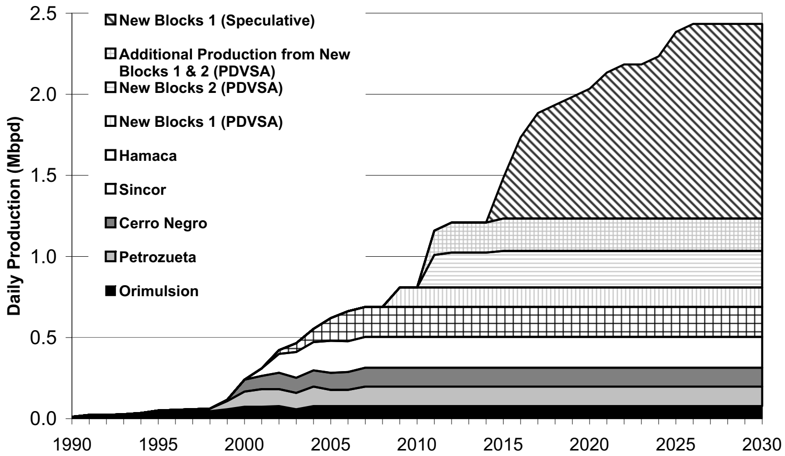


Figure 7.10: Production from the Orinoco belt in million barrels per day (Mbpd), both historic and a forecast up to 2030. Note it is only the Hamaca, Cerro Negro, Petrozueta and Sincor that is actually on production.

IEA, 2005). Peculiar enough, this consensus has developed despite no such information from neither Saudi Aramco nor Saudi Arabian officials. Permanent increases in production rates together with ever increasing reserves have simply been taken for granted. Indeed, the reserves of Saudi Arabia are large, the largest in the world. However, to refer to the discussion in chapter 5, the official Saudi Arabian proven reserve number is listed at around 260 Gb and have been more or less unchanged the latest 16 years. This is despite a total production of 48 Gb during the last 16 years. Moreover, new field discoveries during the same time amount to less than 10 Gb (OFN, GF). Thus, a simple calculation reveal a proven reserve of around 220 Gb. This number includes the debated increase from 170 Gb to 258 Gb in 1990. A look at the URR for the giant fields of Saudi Arabia reveals a number between 230 and 361 Gb (GF). A majority of this difference can be found in the URR estimates of the largest fields: Ghawar, Safaniya, Berri, Shaybah, Abqaiq and Zuluf. Cumulative Saudi Arabian production excluding the neutral zone is some 103 Gb. This leaves a volume between 127 and 258 Gb left of the original URR. By assuming the URR to the 2P reserves, the higher number is consistent with the official number. The only difference being the official number is proven reserves instead of 2P. Moreover, assuming the top 25 per cent is probable reserves leaves the high end estimate of Saudi Arabia proven reserves at 194 Gb and the low end at 95 Gb. Still, the lower value is a very large reserve but undeniable much less than the official value of 260 Gb. Unfortunately, as Simmons (2005) has argued, neither Saudi Aramco nor the official Saudi Arabian oil ministry has released any detailed field by field data to prove either the reserve estimate of 260 Gb or 95 Gb right.

As a response to Simmons work, two representatives from Saudi Aramco presented their view on the criticism on the Saudi reserve at a meeting in Washington D.C. The presentation by Baqi and Saleri (2004) showed for the first time since the early 1980s details on production from single fields. Furthermore, the presentation includes a forecast on future production from Saudi Arabia. The forecast shows two views, one of sustained production at a 10 Mbpd level and the other at 12 Mbpd. Thus, far away from other forecasts of 20 Mbpd. Moreover, Dr S. I. Al-Husseini, retired executive from Saudi Aramco E & P, called the expectations of 20 Mbpd production from Saudi Arabia unrealistic, instead he referred to future plateau levels of 10 and 12 Mbpd (Mortished and Duncan, 2004; Al-Husseini, 2004).

7.5 Major Oil Field Developments on the Horizon

Future development of oil fields is an essential part of future oil production and therefore important to study. Those fields will help to fill the gap between old declining fields and rising demand. The forecast, based on information from OFN database, of future production from new field developments includes all major developments but excludes deepwater, which is studied by its own. As of today it covers over 80 fields, which came on stream during 2005 or will come on stream as late as 2013. In addition, some field extensions in non-giant fields that came on stream prior to 2005 are included. Included fields are listed in Appendix B.

There are several parameters involved in a forecast and below is the assumptions for the main ones outlined. In general, the forecast is based on info given no later than early 2007. Moreover, each field is studied individually and thus specific information regarding a fields production profile can be available. Such information is used in the first place and therefore, discrepancies from the outline can occur.

First oil Fields are assumed to start production at that time given in the latest available sources.

Production If not otherwise stated, fields are assumed to ramp up to plateau/peak production rapidly. First year production is calculated from when during the year the field is supposed to go on stream. Eventual later production stages are assumed to go on stream at the time given and to reach the new production level during a year.

Plateau/peak level Available information on plateau/peak level is used. If no such information exists an estimate based on the production capacity of the production unit is made. The level is assumed to be kept at a constant level until the decline phase sets in.

Decline The decline phase sets in when prior production plus production during decline exceeds the best reserve estimate with 10 per cent. Small offshore fields are assumed to have a drastic annual declines of 15–20 per cent. This is due to the operators' will to have a quick return on investment. This also keeps the fields at plateau for a longer time. Larger fields, both offshore and onshore, is assumed to have a more gently decline, around 10 per cent annually.

Reserves Numbers on proven plus probable reserves is used whenever the information is available. If information on oil in place is given, the most optimistic estimate of the recovery factor from the operator is used. Eventual upsides on reserves are included. In an attempt to account for future reserve growth in a field, total production from a field exceeds the best reserve estimate with some ten per cent.

The forecast shows a peak level of over 5 Mbpd in 2011–12, which is followed by a gentle decline. The gentle decline is completely governed by production from the giant Kashagan field in Kazakhstan, which is assumed to come on stream in 2009. Its production rate from 2016 is assumed at 1.2 Mbpd, which is over a fourth of the total production. However, the development of this field has been plagued by delays and its production start might well be later. In any case, its dominance in the production forecast further accentuates the importance of large giant oil fields for future production.

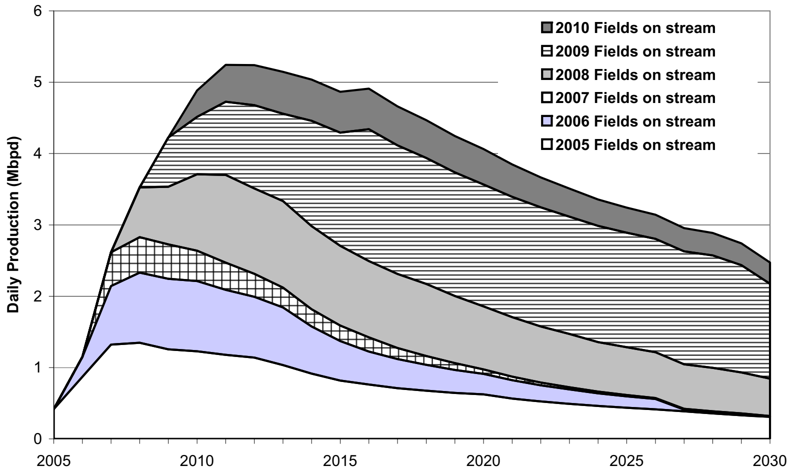


Figure 7.11: Production forecast, in million barrels per day (Mbpd) for new field developments.

7.6 The Role of Technology

Technical breakthroughs and innovations have been a part of the oil industry since its beginning some 150 years ago, where deepwater exploration and production, and extended reach drilling are late examples of this development. High technology solutions are a prerequisite for production in deepwater offshore Angola and Brazil, two countries hosting large volumes of oil. The Sakhalin 1 project at the Sakhalin Island in the Russian Far East probably holds the current record for extended reach drilling, where an onshore rig has drilled into a reservoir almost 10 km from shore (Boschee, 2005). In addition, part of the drilling was conducted under severe winter conditions with temperatures below minus 30°C. The Sakhalin 1 project, consisting of three fields, went on stream in 2005 and the total recoverable volume of oil is estimated to almost 2.3 Gb (OFN).

However, the technological success involved with state of the art technology and exploration in remote areas has in many cases less impressive consequences: cost overruns and start up delays. In terms of cost overruns, the Sakhalin 2 project, which will develop 1 Gb of oil offshore Sakhalin Island, must be considered to be the worst. The original budget of 10 billion dollars is now doubled to 20 billion dollars (Means, 2006). There is also reports on cost overruns of 5 billion dollars at the Sakhalin 2 project, but the operator of Sakhalin 2, ExxonMobil, has not confirmed this (Means, 2006). The Sakhalin projects and the Kashagan field development in the Caspian Sea has problems with both ice and cost overruns as common factors. The Kashagan field is probably the largest field discovered in the past 30 years with an URR of 13 Gb and recent reports indicates at an even larger URR (Murgida, 2007). The field is developed by a consortia consisting of companies such as ExxonMobil, Royal Dutch/Shell, Total and ENI. The original plan had production start up to 2005, but technical problems has delayed start up to at least 2009. Full field development envisages peak production of at least 1.2 Mbpd, which is scheduled to be reached in 2016. In addition to the delays, costs will soar to at least 15 billion dollars from the budget of 10 billion dollars. It should also be noted that the delays in the development has taken place while the price of oil has been increasing.

The largest deepwater field discovered in Nigeria is Bonga, with an estimated URR of 0.7 Gb. The original plan was to put it on stream in 2003 but due to technical problems, the start up was delayed first to 2004 and then to 2005. Production commenced in late November 2005 at a cost of 3.6 billion dollar, which is more than 30 per cent above the planned budget. The 1998 discovery of the giant Thunder Horse field is so far the largest US Gulf of Mexico deepwater field, with an estimated URR of just below 1 Gb. However, the field development has been afflicted by difficulties involved with the semisubmersible production unit, which is the largest offshore platform ever built, and the extensive subsea facilities. The difficulties has resulted in cost overruns of more than one billion dollar and a three year start up delay, where the latest production start date is late 2008. Atlantis, another US Gulf of Mexico giant deepwater field, has had problems of similar characteristics as Thunder Horse.

However, despite delays and cost overruns, the question is in what way the latest technologies have contributed to new field discoveries, since their role in reserve growth is both important and confirmed (see chapter 5). The URR of the Thunder Horse field is estimated to almost 1 Gb and so far the largest US Gulf of Mexico deepwater field. The less impressive technologies used in 1930 was enough to discover the East Texas field containing almost 6 Gb. The discoveries made in Texas during the ten year period between 1926 and 1936 amounts to almost 20 Gb. A comparison with the total discoveries made in Angola deepwater from 1994 and up to 2005 shows a result of about 10 Gb, almost half the amount discovered in Texas 60 years ago. Obviously, the difference is not due to a lack of technology.

Today, national oil companies (NOC) are the largest oil companies with respect to reserves and production. NOCs of the large Persian Gulf producers such as Abu Dhabi, Kuwait and Saudi Arabia, which together produce almost 20 per cent of global production, the latest technology is the rule instead of the exception (Al-Husseini, 2004; UAE, 2005). The oil field development practices utilizing the latest exploration and production technologies have without a doubt been a crucial part in keeping up the impressive production numbers from those countries' mature super giant oil fields. However, Simmons (2005) claims that a possible result of the latest production technologies is a rapid production followed by very high decline rates. This might imply a future drastic drop in production instead of slow and gentle from the above mentioned countries. This behavior has been observed at Yibal, the largest giant oil field in Oman (GFP, GF). However, this is not proving that a similar situation will occur in Abu Dhabi, Kuwait and Saudi Arabia, merely an indication of what can happen.

The oil industry has developed new technologies, allowing discovery and production of oil in even deeper waters, in even harsher environments but in even smaller quantities. This illustrates that technology by its own merits do not discover large volumes of oil but it must be applied on good and large prospects, and they have clearly been lacking, as shown with field examples above and the discovery trend of giant field discoveries (chapter 6).

7.7 Oil Price versus Exploration and Production

Times of high prices will spur investments in exploration and production and therefore increase both production and reserves. Accordingly, prices will go down to a normal level. This is how it should work if oil was just another commodity and followed the theories of supply and demand. But during the history, the connection between large discoveries with associated high production and high prices is missing (figure 7.12) .

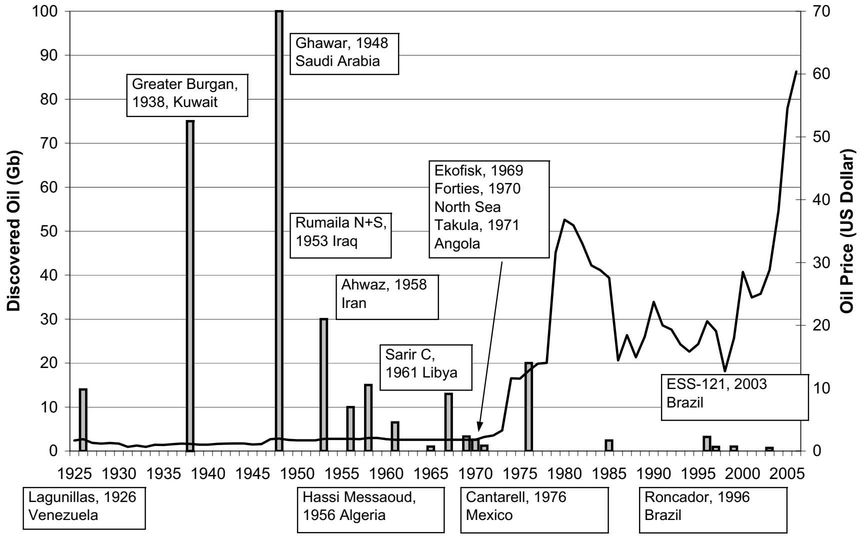


Figure 7.12: The largest oil fields, in billion barrels (Gb) for a number of major oil producing countries, and the oil price. Note that the fields between 1985 and 1999 are the largest deepwater fields. ESS-121 is the latest confirmed giant discovery. Takula is the largest field discovered in Angola, including deepwater fields (GF).

When it comes to exploration, a good prospect is a good prospect irrespective of the price. This is illustrated by the three deepwater giant oil fields Thunder Horse (US Gulf of Mexico), Rosa (Angola) and Hungo-part of Kizomba A (Angola), which were discovered in 1998 when oil prices were at a low point. A less promising and/or more difficult prospect can be more interesting during times of high prices. This is because the high risk involved with drilling the prospect is balanced by the higher reward if it is a discovery. A basin with no petroleum system or a region with too thin layers of sediments will never turn into a good prospect even if the price increases tenfold, see for example Sweden[2].

Production wise, a large field will be developed even in times of low prices since they in general have a high production rate (see Kizomba A example below).

The conclusion is that the potential revenues generated by an oil field decide if a field will be developed or not. A large oil field will generate enough revenue to motivate a development even in times of very low oil prices.

[2]It can be argued that Sweden has large volumes of oil shale and therefore can be an oil producer. However, oil shales are not yet mature source rocks and oil production in a conventional way will not take place. But if progress in shale oil production nears commercialization, Sweden might be an shale oil producer in the future again. If patient, the oil shale might mature into source rocks some million years down the line and generate petroleum.

Consequently, a smaller field will need higher oil prices to generate enough revenue to motivate the development. Thus, times with high oil prices will unlock marginal fields that was uneconomical at lower oil prices. In addition, the high price can attract companies to try untested technologies, which can help in developing marginal fields.

The time lag from the opening of a license round through exploration and development to the time of first oil is also a factor to consider. As an example, the different stages involved in putting ExxonMobil's prolific deepwater Kizomba A on stream is described. In 1991, Angola offered a number of exploration blocks, both onshore and offshore. Among them were the deepwater block 15, which ExxonMobil was pursuing, with water depths above 1 000 m (OGJ, 1993). A provisional award was given to Exxon and its co-ventures in 1993 and in August 1994, the rights to explore the block was acquired (OGJ, 1994; Boles and Mayhall, 2006). The exploration commitments included both seismic surveys and drilling of a number of wells. Seismic surveys were then conducted and the first structure, in more than 1 000 m of water, was drilled in 1997. The first discovery was drilled at Kissanje number 1 in early 1998. Three more discoveries were made in 1998, among them Hungo (Boles and Mayhall, 2006). Further work, including appraisal drilling, during 1999 and 2000 resulted in the development plan for Kizomba A, consisting of the Hungo and the Chocalho discoveries. In 2001, the Kizomba A project was sanctioned and the development plan aimed at first oil in 2004. August 9, 2004 saw the first production from Kizomba A and production was soon ramped up to its plateau level of 200 000 bpd. During all this process from 1991 to first oil in 2004, the oil price in nominal terms has been both low and high (figure 7.13).

The four largest private oil companies are ExxonMobil, Chevron (including Texaco), BP and Royal Dutch/Shell. These companies, the supermajors, have the latest technologies both when it comes to exploration and production. Moreover, they present annual reports with detailed information. In sum, by studying the ten year period from 1995 to 2005 with respect to oil production, oil reserve additions, oil price, and investments in exploration and production should give a decent picture of the impact of both low prices and high on exploration and production.

In the annual reports five items are listed as reserve additions:

Revisions An earlier estimate is revised, either downward or upward, due to better understanding of the reservoirs.

Improved recovery New recovery methods enables more oil to be recovered from a field.

Extensions and New Discoveries Extensions are new discoveries within a field while new discoveries denotes a new field.

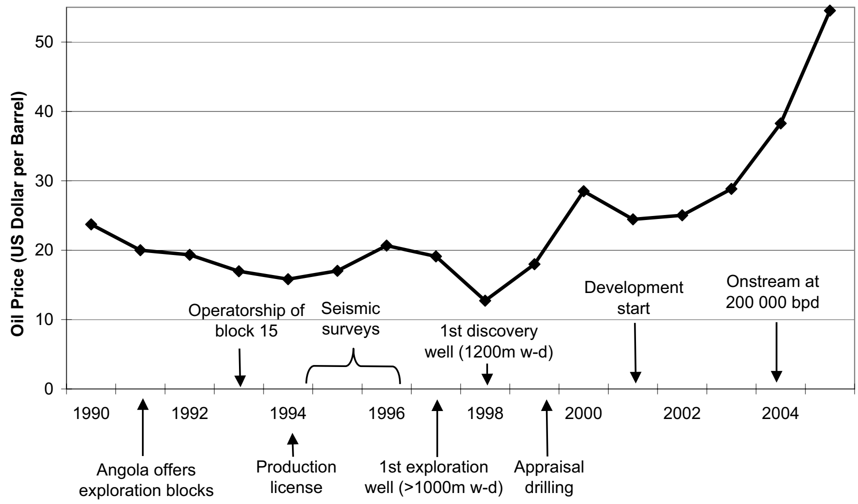


Figure 7.13: Kizomba A development.

Purchase Fields purchased from other companies.

Sales Fields sold to other companies.

Neither purchase nor sales are included in the following analysis because it does not add or remove any new oil. Revisions, improved recovery and, extensions and discoveries add or remove oil by the drillbit and/or by the knowledge from new technology.

Capital and expenditure (CAPEX) on exploration and production show the amount of money invested in exploration and production. Unfortunately, the data does not differ between oil and gas and accordingly, CAPEX data is for both. However, oil is still the primary target because the higher revenues connected to it and the relative easiness it can be transported from a discovery site to the market (Tweedie, 2003). The CAPEX from these companies in relation to the nominal oil price over time illustrates the effect of the price on CAPEX over time (figure 7.14). From a low of 24 billion dollar in 2000, the CAPEX has grown to 44 billion dollars in 2005 (figure 7.14).

The result of the increase in CAPEX with respect to oil reserve additions shows a clear downward trend (figure 7.15). The total drop is driven by the lack of success in adding more oil from extensions and new discoveries. Additions from improved recovery has been almost constant from 2001. Moreover, despite the highest oil price during the time period, reserve revisions were negative in 2005, i.e. earlier reserve revisions were too optimistic.

Since 1997 the four companies have together produced about 8.6 Mbpd each year. This is despite an increase in the oil price from the low in 1998 of less than 13 dollar per barrel to over 50 dollar per barrel in 2005. From 1997, with the exemption of 1999, and up to 2002, the reserve additions

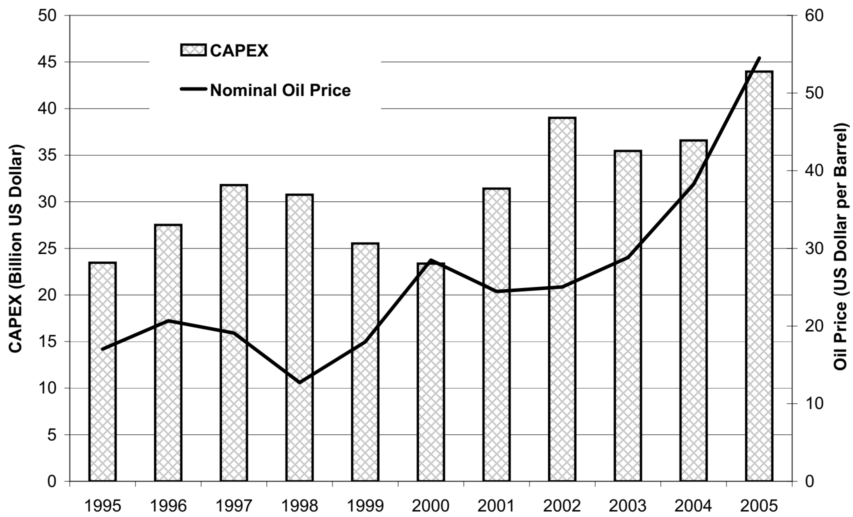


Figure 7.14: The nominal oil price in relation to CAPEX for the supermajors, i.e. BP, Chevron(Texaco), ExxonMobil and Royal Dutch/Shell.

were larger than the produced volumes of oil (figure 7.16). But when the price started to increase in 2003, the reserve additions dropped below the produced volumes. Thus, reserve replacement is negative and the companies produces from old discoveries, just as the world as a whole (chapter 5).

To summarize, the four largest private oil companies have not succeeded in increasing neither production nor reserves despite an increase of the oil price and increased investments in exploration and production.

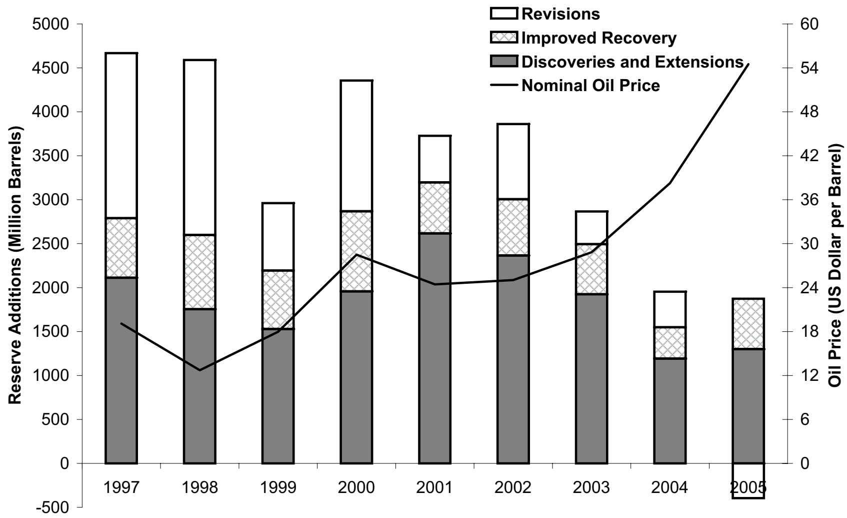


Figure 7.15: Annual oil reserve additions, in million barrels, for BP, Chevron, ExxonMobil and Royal Dutch/Shell, i.e the supermajors. Note that revisions in 2005 was negative.

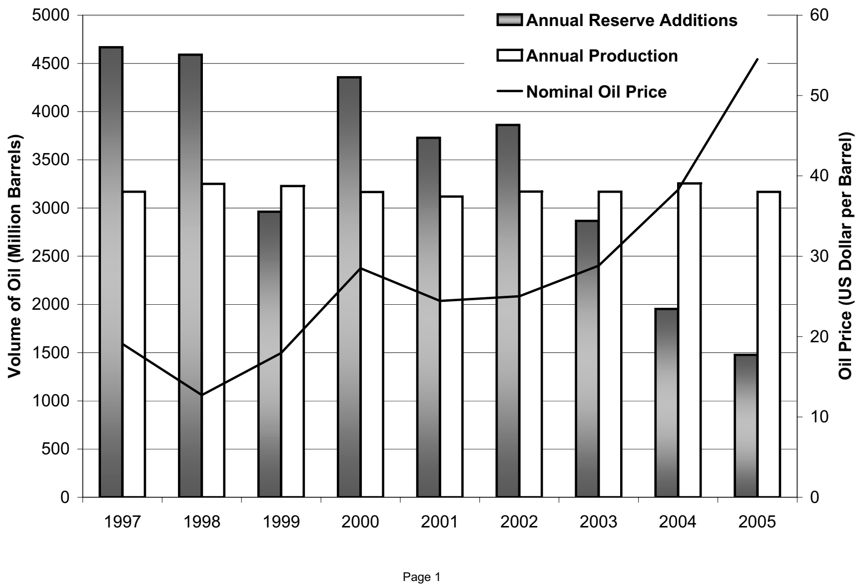


Figure 7.16: Annual oil reserve additions and oil production for the four largest private oil companies, BP, Chevron, ExxonMobil and Royal Dutch/Shell.

8. Modeling of Future Production from Giant Oil Fields

Any model is an attempt, under a set of assumptions, to describe the reality in a good as possible way. The aim with this model is to predict future production from giant oil fields. For this work, the number of fields to be modeled is the over 330 contained in the GFP database. Thus, the question is in what way to treat each field. Either with a detailed mathematical description including error estimates for each field or in a generalized manner with a number of different outcomes. A model based on a detailed mathematical description for each field would suffer from the inherent uncertainty in oil production data as well as relying on assumed production data. Therefore, a more general model is applied, with a number of outcomes. In this way, different future production situations will be simulated and the range between the outcomes will serve as an error estimate.

For each field, there are three known variables, which are total past production, present production level and the ultimate recoverable reserve (URR). These variables together with the general production profile (see section 3.3) are the components of the model. The production profile is divided into four parts (figure 8.1), and listed below.

1. Past production, which is known, to 2005 and is denoted A.
2. Prolonged plateau level continuing from the 2005 production level, which is called B.
3. Decline production, which is denoted C.
4. Tail End Production$C$.

The variables A, B and C, which are measured in barrels, are related to URR (equation 8.1).

$$A + B + C = \mathrm{URR} \tag{8.1}$$

However, if A+C exceeds URR in 2005, the prolonged plateau phase, B, is omitted and the decline phase, C, starts in 2006.

Tail end production is not included in the URR, but is assumed to be a bonus production, representing reserve growth in the field. Thus, the total field production will be URR plus tail end production.

Studying of a number of production profiles for giant oil fields reveal a most often visible plateau production followed by a decline phase. Moreover, the decline phase usually shows an exponential decline. The decline of

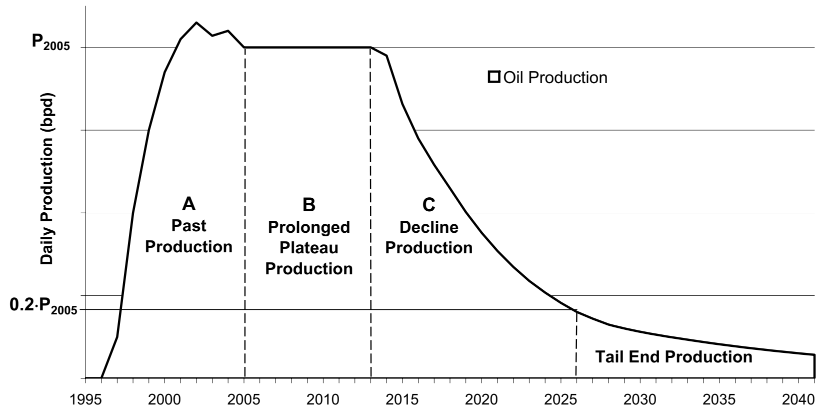


Figure 8.1: The production profiles and the relationships of the components of the model.

values declining exponentially will appear as a straight line in a plot where the value axis is logarithmic. The plotting of the production profile for a number of large giant fields, where the value axis is logarithmic, shows the decline phase as a straight line and thus an exponential decline (figure 8.2). All the fields plotted have complete data sets, i.e. no assumed production data. In addition, none of the fields have been under production restrictions and accordingly, it is reasonable to assume the production has been maximized. Moreover, both state owned companies and major private oil companies are represented as operators of the fields.

Thus, the exponential decline rate is assumed to be valid for all studied giant fields. This assumption makes it possible to calculate a decline rate from a field by the use of equation 8.2.

$$P_P \cdot (1-x)^n = P_n \tag{8.2}$$

where

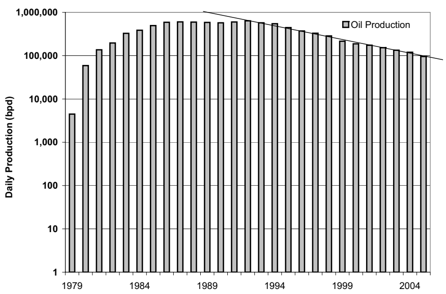
P_P = production rate at plateau level

x = decline rate (%)

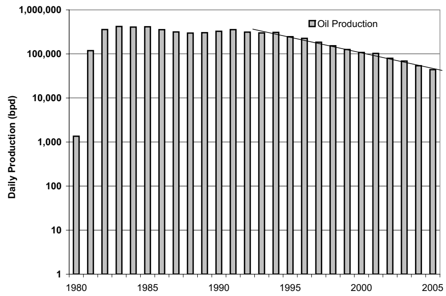
n = number of years in decline phase

P_n = production rate at time n

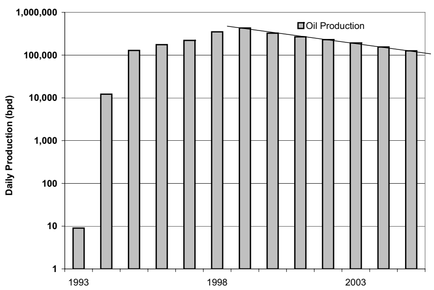
A logarithmic analysis has been performed on some 20 fields in order to get a range of decline rates. The analysis shows that three decline rates, 6, 10 and 16 per cent, are justified to use in the model in order to cover varying field production situations. The decline in production is assumed to start from the 2005 production level (figure 8.1). The decline phase is assumed to end when the production level is 20 per cent of the production level in 2005 (figure 8.1). Thus, a start and end level of the decline phase is known.



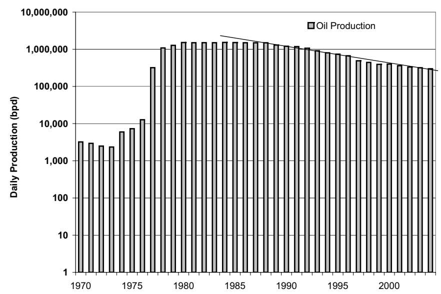
(a) Statfjord (Statoil, Norway)



(b) Abaktun (PEMEX, Mexico)



(c) Cupiagua-Cuisiana (BP, Colombia)



(d) Prudhoe Bay (BP, Alaska)

Figure 8.2: Logarithmic presentation of a number of giant fields. The straight line in each plot highlights the decline. Operator and country is given in brackets for each field.

Since the decline rates are also known, it is possible to calculate the number of years the decline phase goes on for each decline rate (equation 8.3).

$$n = \frac{\ln\left(\frac{0.2 \cdot P_{2005}}{P_{2005}}\right)}{\ln(1-x)} = \frac{\ln 0.2}{\ln(1-x)} = \frac{-1.61}{\ln(1-x)} \tag{8.3}$$

The assumption of the production levels for both the start and the end of the decline phase combined with the time span for the decline phase makes it possible to calculate the produced volume during the decline phase. The production C under the decline phase is calculated by the integration of equation 8.2. The total production during the decline phase is given by equation 8.4, which is a close approximation of the integration of equation 8.2.

$$C = P_{2005} \cdot \frac{(1-x)^n - 1}{x-1} \cdot 365 \tag{8.4}$$

The factor 365 in equation 8.4 is included in order to convert P_{2005} from bpd to barrels.

Three out of four variables in equation 8.1 are now known. Accordingly, the last variable, which is B, can now be calculated. Since three different values of C are given for each field, three different values of B is calculated. Consequently, the decline phase of each field will set in at three different points in time.

8.1 Model Implementation and Modifications

The model is set up using a spreadsheet program, where two spread sheets are used for each field. The first contains all equations and the three decline rates and the second plots the production graph with the three different outcomes. Historic production together with the best URR estimate are then put into the model. For each year after 2005, B is calculated and as long as the condition $A + B + C \leq$URR is fulfilled, the production level in 2005 is used. As soon as $A + B + C \leq$URR no longer is true, the decline phase sets in. However, some modifications to the $A + B + C \leq$URR condition and each decline rate has been done, as described below.

16 per cent decline rate It is assumed the decline rate stabilizes at seven per cent, when the production level is less than 20 per cent of the 2005 production level.

10 per cent decline rate It is assumed the decline rate stabilizes at five per cent, when the production level is less than 20 per cent of the 2005 production level.

6 per cent decline rate represents a case with reserve growth and successful implementation of decline reducing technologies, resulting in a 10 per cent increase in the original URR. However, when more than 10 per cent of the original URR is produced, the decline enters a more steep rate of 15 per cent.

If no information is given on future expansion plans for a field, 2005 production level is assumed to continue as a plateau level. Or, if A+C exceeds URR, the decline starts in 2006. On the other hand, if expansions plans are available they are assumed to be put on line in time.

The production from the giant fields in a country is added to give the total contribution from the giant fields. However, each of the three different decline rate outcome is added and thus, a country have three future production outcomes. But to show a wider range, two different production outcomes are showed, a low end and a high end. The low end is the minimum value for each year and the high end is the maximum value of each year.

8.2 Advantages and Disadvantages

In the model, each field has both a long and gentle decline, and a steep decline. This is a clear advantage since it is not known if a field will have a long and gentle decline or a steep decline. 2005 was a year with record oil prices and therefore should production been at a max. This is further strengthen by the notion that OPEC produced at full capacity. No consideration is taken to future production constraints implied by OPEC, for example, which is a lack. The dominant variable is the URR and a large change in it will cause changes to the point in time when the decline sets in. The available 2006 production data for single fields compared to the production from the model, shows that the model generates a bit more optimistic value. However, comparing nations, the low end estimate seems to be closer to the actual value. Thus, based on a far from complete data set, the indications are the model is generating a bit optimistic values.

8.3 Illustrative Examples

A number of graphs from the model is presented below in order to illustrate the different generated future production.

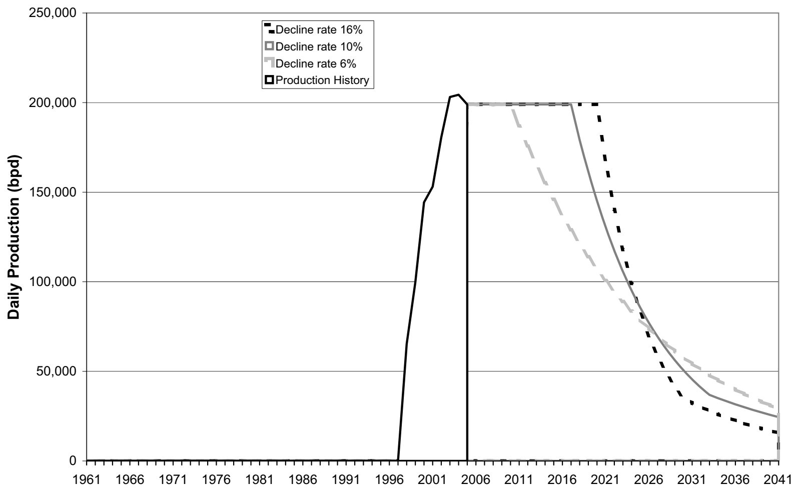


Figure 8.3: Hibernia, Canada, future oil production in barrels per day (bpd).

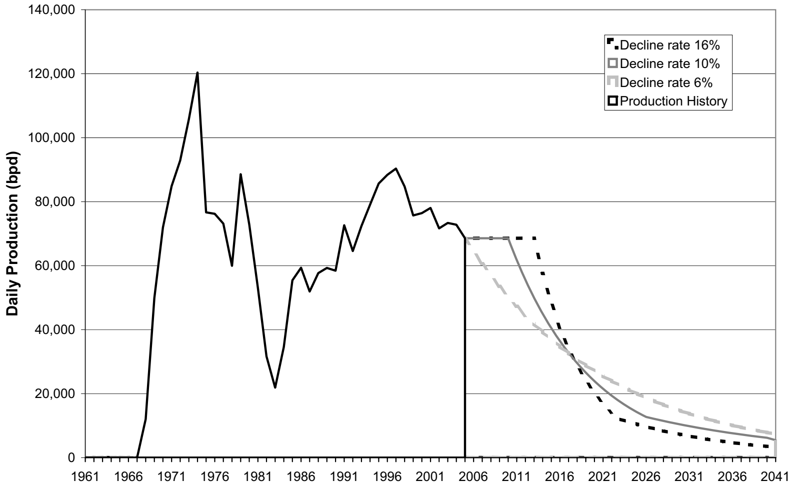


Figure 8.4: Meren, Nigeria, future oil production in barrels per day (bpd).

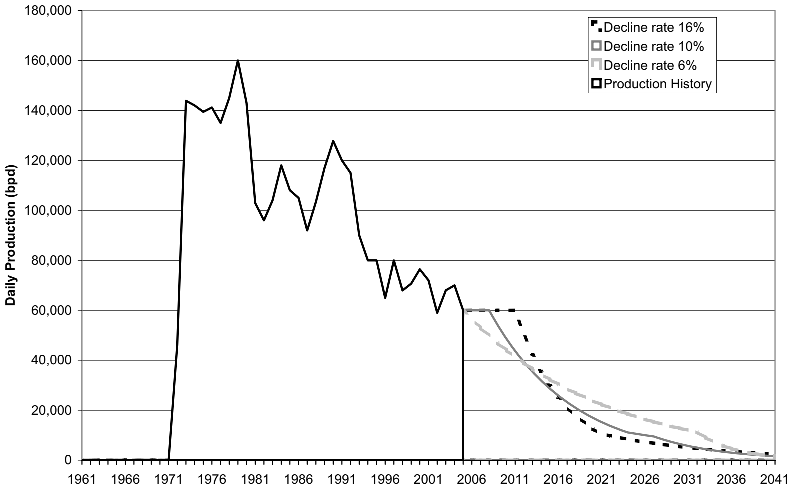


Figure 8.5: Bul Hanine, Qatar, future oil production in barrels per day (bpd).

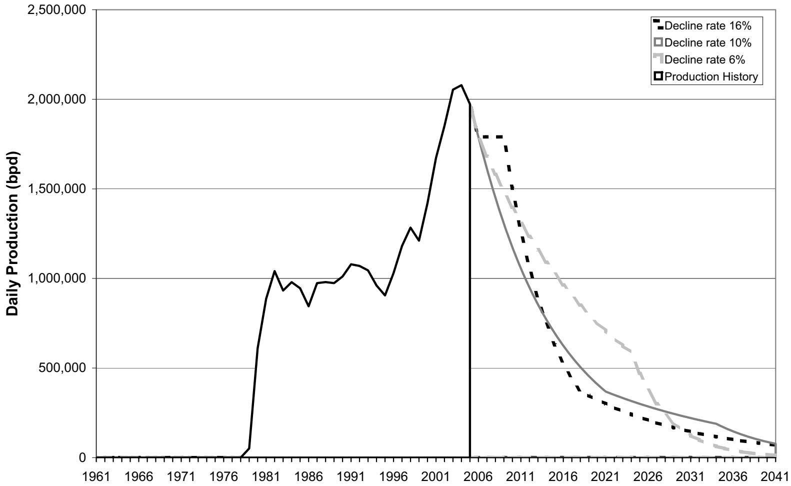


Figure 8.6: Cantarell, Mexico, future oil production in barrels per day (bpd).

9. Future Oil Production

In order to forecast future oil production, the results of the modeling of the giant oil fields contained in the GFP database have been combined with the production forecasts of deepwater oil, major new fields, Orinoco and oil sands, as described in chapter 7. In addition, historic production and assumed future production of both NGL, condensate and processing gains[1] are included in a strive to reach a comprehensive picture of global liquid production. The US Energy Information Agency (EIA) provides historic data, from 1980 and forward, for NGL, condensate and processing gains and this data is used in the forecasts.

For the model, the following values are given for 2005: crude oil production 70.3 Mbpd, oil sand 0.99 Mbpd, Orinocco 0.62 Mbpd and NGL plus other liquids 10.2 Mbpd. Thus, total liquid production in 2005 was 82.1 Mbpd.

Instead of trying to predict a single best estimate of future production, the forecast is divided into four scenarios:

1. Worst Case
2. Standard Case - Low End
3. Standard Case - High End
4. Best Case

9.1 Scenario Assumptions

All four different scenarios have a few basic assumptions in common. First, they all include the major new field development forecast with no constraints. Second, the optimistic Orinoco heavy oil production forecast is included. Third, the full forecast for future production from oil sands is included. Fourth, future production of NGL, condensate and processing gains is assumed to reach 12 Mbpd in 2011 and then be constant at that level. Fifth, the deepwater oil production forecast is included in all cases.

The difference between total oil production, excluding all of the aforementioned forecasts, and giant oil field production is termed other fields. This represents all fields not included in the GFP. The decline in production from other fields is in general thought to be between 3 and 8 per cent,

[1] Refineries add other liquid streams to the oil during refining and the result is a net increase in liquid volume produced, called processing gains.

as discussed in chapter 7. The decline rate in other fields is different from scenario to scenario.

A description of the main assumptions for each scenario is in the following subsections.

9.1.1 Standard Case

There are several on-going projects to expand production from major giant oil fields. Some of the projects are well under way and will increase the production from the field, while others are just in the planning stages. Based on data from OFN, a number of expansion projects are included in the standard case. The major ones are listed below (table). Moreover, oil production from Iraq, which in 2006 was estimated to 1.9 Mbpd, is assumed to grow quite rapidly to 2.5 Mbpd in 2011. This growth is only from old fields, which are assumed to undergo substantial work over programs and thus reach pre-war production levels.

The low end scenario is based on the lowest annual value from the giant field model. Other fields are assumed to have a decline rate of five per cent.

The high end scenario, on the other hand, uses the highest annual value generated by the giant field model. In this case, the decline rate of other fields are assumed to be three per cent.

9.1.2 Worst Case

The worst case scenario illustrates the situation if the low end URR estimates of the largest field is used, resulting in a shorter plateau phase. In addition, some of the large expansion projects are assumed to fail. The latter is most notable in Iraq, and the aim is to forecast a situation of continued war, which interfere with field rehabilitation. Except the listed fields (table 9.2), all the assumptions from the standard case is included (table 9.3).

The fields chosen for the worst case scenario are very large giant oil fields with high production levels, but where the URR numbers are uncertain. Accordingly, most of these fields are in OPEC countries around the Persian Gulf.

The annual decline rate in other fields in the worst case scenario is consequently the highest and is assumed to be seven per cent.

9.1.3 Best Case

The aim with this scenario is to illustrate a situation when all major expansion project, which so far has proved to be delayed or more difficult than first thought, actually succeeds. A number of the large undeveloped field in Iraq is assumed to be brought on stream. The start of these projects will occur between 2008–10 and the development times and production levels

Table 9.1: *Major field expansions,given in thousand barrels per day (kbpd), included in the standard case. Field production is assumed to be increased gradually.*

Field	**Country**	**Peak Level [kbpd]**	**Year of Peak**	**Comments**
Hassi Messaoud	Algeria	575	2009	
Rhoude El Baguel	Algeria	50	2009	BP failed to increase levels above 40 kbpd.
Elephant	Libya	150	2007	
Bombay High	India	290	2007	Low 2005 production due to an accident.
Priobskoye	Russia	500	2010	Production growth has been very slow the last year
Tengiz	Kazakhstan	550	2010	Difficulties with sour gas injection delays the expansion
Al Shaheen	Qatar	500	2009	Full field expansion
Greater Burgan	Kuwait	1700	2008	60 Gb is used as URR
Doroud	Iran	215	2007	Iran offshore re-development
Soroosh	Iran	100	2007	Iran offshore re-development
Aboozar	Iran	200	2006	Iran offshore re-development
Agha Jari	Iran	300	2010	Delays and still no contract signed
Shaybah	Saudi Arabia	950	2011	0.75 Mbpd reached in 2009
Khursaniyah	Saudi Arabia	500	2009	Re-development of an old field
Khurais	Saudi Arabia	1100	2011	Re-development of an old field
Manifa	Saudi Arabia	1000	2014	Re-development of an old field
Ghawar	Saudi Arabia			105 Gb is used as URR
Rumaila N+S	Iraq	1250	2009	
West Qurnah	Iraq	250	2010	
Kirkuk	Iraq	400	2010	
KMZ	Mexico	800	2010	

Table 9.2: *The URR in gigabarrel (Gb) used in the worst case scenario.*

Field	**Country**	**Low end URR [Gb]**
Greater Burgan	Kuwait	46
Abqaiq	Saudi Arabia	12
Berri	Saudi Arabia	9
Ghawar	Saudi Arabia	66
Safaniyah	Saudi Arabia	21
Zuluf	Saudi Arabia	11
Rumaila N+S	Iraq	19
West Qurnah	Iraq	9
Zubair	Iraq	7
Gachsaran	Iran	12
Ahwaz	Iran	10
Agha Jari	Iran	10

used are the ones found in different sources, most notably AOGD (see chapter 1). Moreover, the high end estimate of 150 Gb in URR for Ghawar is used.

Production from other fields are assumed to decline with a modest 1.5 per cent.

9.2 Results

The emphasis in this study is on the giant oil fields and accordingly, the results from the giant field modeling is presented alone (figure 9.1). Notably from either case is the rather short period of time until the commence of declining production. Although the production in either case reaches a bit above 40 Mbpd the peak production of the giants occurred already in 1979 at almost 44 Mbpd.

Given the assumptions in the worst case scenario, declining production started already in 2006. In the low end estimate of the standard case, production starts to decline in 2012 after a plateau production of about 40 Mbpd. The impact of the expansion projects is more marked in the high end estimate of the standard case, resulting in increasing production levels. However, production is in decline after 2011. Even higher peak production and a further postponed peak is observed in the best case scenario, which mainly is due to the start ups of the undeveloped giant fields in Iraq. Undoubtedly, those Iraqi fields are very large and have great potential, but their production only offsets the giant oil field peak to 2014.

The next step is to add all other production forecasts to the giant production forecasts in order to forecast total future production. In order to see the relative importance of the different forecasts, the high end standard case is

Table 9.3: *Major field expansions, given in thousand barrels per day (kbpd) included in the best case scenario. Field production is assumed to be increased gradually.*

Field	**Country**	**Peak Level [kbpd]**	**Year of Peak**	**Comments**
Tengiz	Kazakhstan	825	2012	
Northern fields	Kuwait	900	2013	Much delayed project finally in progress
Majnoon	Iraq	1000	2018	Gradual expansion, reaching 600 kbpd 2012
West Qurnah	Iraq	550	2015	
Halfayah	Iraq	250	2014	Re-development of old field
Nahr-Umr	Iraq	500	2017	Re-development of old field
Nasiryah	Iraq	300	2016	Re-development of old field
Zakum Upper	Abu Dhabi	700	2013	Low pressure and poor porosity reservoir
Ratawi	Iraq	200	2013	Re-development of old field
Tuba	Iraq	180	2015	Re-development of old field

shown (figure 9.2). Although contributions from new field developments and deepwater is large, production from the 333 giant oil fields still dominates. Besides production from other fields and giant fields, NGL is the single largest contributor. Despite optimistic production forecasts of the undoubtedly large resources of Orinoco and Alberta, their contribution is not enough to offset peak oil.

Notably, in all scenarios, future oil production is governed by the the giant fields and when they starts to decline the rest of the liquids follows at the same time or a few years later (figure 9.3).

The main difference in the different scenarios is the peak production level, where the worst case scenario peaks at just above 83 Mbpd in 2008 while the best case scenario reaches a peak level of 94 Mbpd in 2013 (figure 9.4). Thus the time span is only 5 years but the production level span is 11 Mbpd.

9.2.1 Demand Adjusted Production

Future demand is of course important to consider in a study on future oil production. The International Energy Agency (IEA) forecasts demand in 2007 to be around 1.7 per cent. Demand is assumed to continue with this rate, according to IEA WEO 2006, up 10 2015. EIA, on the other hand, forecasts future demand to be 1.4 per cent. Both the high end standard case and the best case scenario can keep pace with the demand growth suggested by IEA, even with some spare capacity, up to 2012 and 2013, respectively (fig-

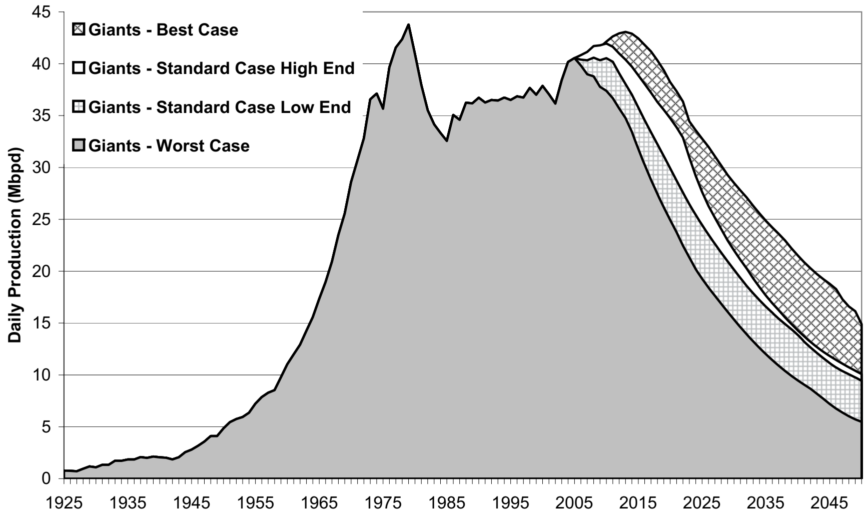


Figure 9.1: Future oil production from giant oil fields, in million barrels per day (Mbpd).

ure 9.5). In a way to illustrate the best possible situation, the best case oil production is assumed to follow an annual demand increase of 1.4 per cent. Thus, this offsets the peak with a few more years, to 2018 (figure 9.5), but at the price with no spare capacity.

9.3 Discussion

To sum up the results, the main observation is the dominance of the giants and their governing of the peak production. The analysis is based on annual production data for 333 giant oil fields and thus the reliability of the data is of main importance. Besides some of the production data from the Persian Gulf producers, the production data should be reliable. However, the production data for most of the Persian Gulf countries are reliable up to at least the mid 1980s. Subsequent production data is less reliable although the impact of this should be minimized by the use of the most optimistic URR and three different decline rates. In addition, a large number of production expansions are included and assumed to be completed in time and reach the planned production level. Thus, future production from the fields in the model should be somewhere in the range resulting from the model. Accordingly, the peak of the giant oil fields should occur in the range given by the four different scenarios.

The production from the giant fields Kashagan and Azedegan is dominant in the upcoming developments forecasts and since no other development project of their size is on the horizon, the forecast should be reliable. In light of recent events in Venezuela, the production forecast for heavy

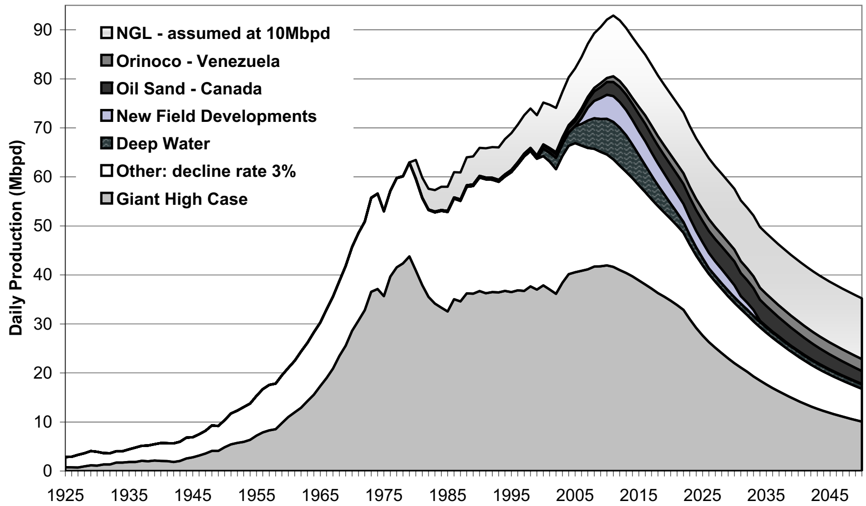
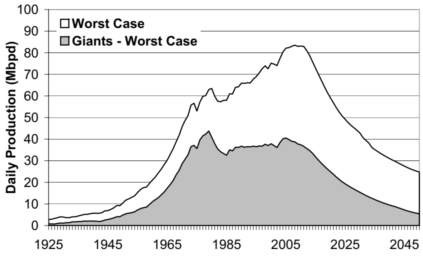


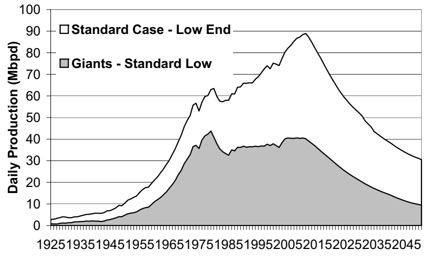
Figure 9.2: Global liquids production per liquid stream in million barrels per day (Mbpd).

oil from Orinoco must be considered unreliable. However, the potential is there and a rising oil price might shift the situation towards a larger expansion program. Although political stability is in place in Canada, the oil sands industry is not without its own hurdles, most notably the natural gas situation and environmental concerns. Despite this, all projects are assumed to get approval and produce according to plans.

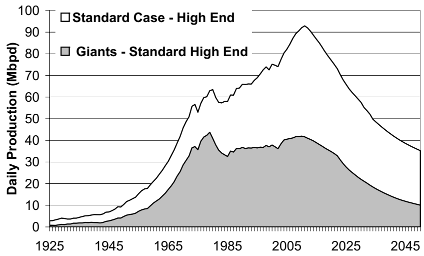
A comparison with oil production forecasts from the IEA and EIA reveals an extreme difference in future production levels. Production in IEAs reference case continues to increase to 2030, which is the last reported year, and at that time the level is 116 Mbpd. In the analysis by EIA, future oil production is projected to increase to a level of 123 Mbpd, which is reached in 2030. In contrast the most optimistic result, which is the demand adjusted best case scenario, from the analysis performed here shows a peak in 2018 at a level of 93 Mbpd (figure 9.5). Although only speculative, the analysis of IEA and EIA might not fully integrate the role of the giant oil fields in future oil production.



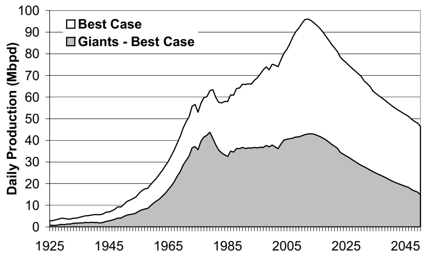
(a) Worst case scenario



(b) Standard case – low



(c) Standard case – high



(d) Best case scenario

Figure 9.3: Future oil production, in million barrels per day (Mbpd), for each scenario and the contribution from the giant fields.

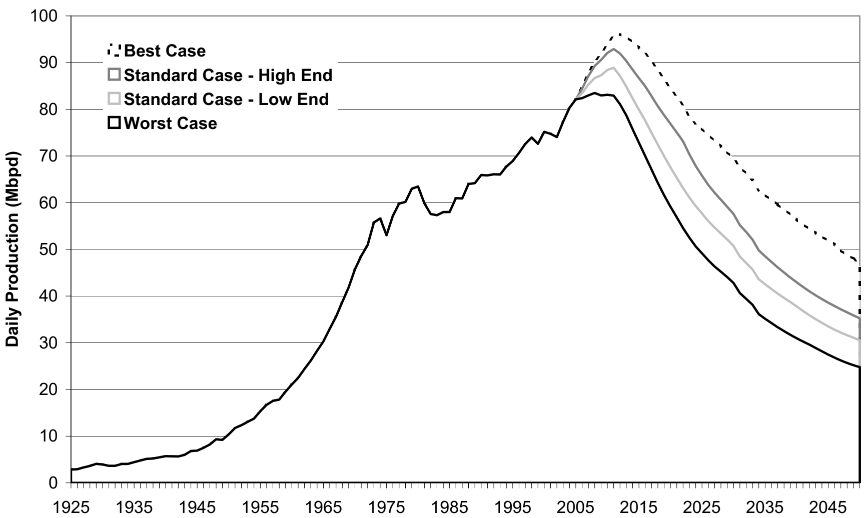


Figure 9.4: Global liquids production, in million barrels per day (Mbpd), in the four different scenarios.

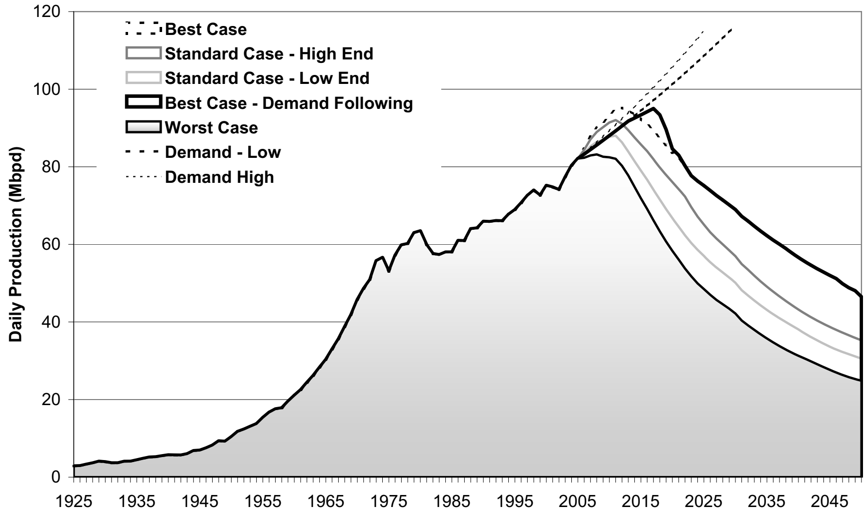


Figure 9.5: Global liquids production in million barrels per day (Mbpd) for all scenarios, with the best case scenario adjusted to fit an annual demand growth of 1.4 per cent.

10. Conclusion

The society of today is dependent on energy and the main energy source is petroleum, mainly because its use for transportation. The origin of petroleum is geological and it was formed in the Phanerozoic era, between 5.3 and 570 million years ago. The timescale for formation of petroleum is millions of years and it is therefore a finite resource. In order to have an oil field, it is a necessity that all components of the petroleum system are or have been present.

The 20^{th} century has been a century of exploration of new areas and developments of new technology to be used in both exploration and production. It was also the century when the main consumers became importers and thus dependent on oil producing nations. The importance of oil for the major consuming nations such as the USA and Western Europe, and the dependence on imported oil made security of supply a main issue on the political agenda. Future demand of oil is expected to increase annually by 1.4–1.7 per cent and therefore, the question to what extent oil will be available is of the uttermost importance.

Peak oil, when global production reaches its maximum production and then starts to decline, has been a heavily debated topic the last few years. Especially in the context of future demand growth for oil. However, the evidence for peak oil is obvious since the most mature oil region, the lower 48 states of the USA, peaked in 1970. In addition, the latest oil region discovered, the North Sea, peaked in 2001. Both regions continue to decline despite strong demand and high oil prices, which motivates high production rates. Moreover, high prices tends to spur the idea of a soon peak oil. However, earlier oil crises have led to high oil prices before but the peak has not yet occurred. Some of the earlier crises were caused by the producers deliberately halted the oil production and did not export any oil. Since there will be a peak in the future, the validity of the oil price as the single parameter for peak oil prediction must be questioned. Instead, giant oil fields, i.e. the largest fields on the globe, can be used as a peak parameter.

Although the number of giant oil fields is very limited, only 507 out of some 47 500, their contribution is far from limited. About 65 per cent of the global ultimate recoverable reserves (URR) is found in them. Historically, giant fields have been the main contributor to global oil production and in 2005, their share was over 60 per cent. Thus, giant oil fields are and will continue to be important for global oil production. However, the largest giant fields are old and many of them have been producing oil for over 50 years. The greatest number of giant fields were discovered during the 1960s. This decade also proved to be the time when the largest URR in giant fields were discovered. Since then, both the number of giant fields discovered and the reserves discovered in giant fields have been declining. Although indications of two possible giant field discoveries during 2006, the last confirmed giant oil field discovery was in 2003. At a first look, the importance of this might not be obvious, but the crucial point is the oil production rate in giant fields compared to smaller fields. In general, giant oil fields can sustain a high oil production rate for a long time. Even a large amount of small fields might not be enough to offset declining production from a giant field. This is the case with Norway, where the giant fields peaked a few years before the total production peaked. On a larger scale, the same is true for both Europe and North America. Consequently, this in combination with the declining discovery trend, strongly suggests a concept of peak oil governed by giant oil fields. Furthermore, this motivates the construction of a model to forecast future production from giant fields in order to predict the peak oil.

Forecasts, based on field by field analysis, for major new field developments, deepwater oil production, heavy oil from Orinoco in Venezuela and oil sands in Canada have been made since their role in future oil production must be considered. In addition, impacts on future production on both the oil price and the development of technology have been put into context. Despite the advanced technology involved in deepwater exploration, the contribution to large discoveries is missing. For example, the East Texas field discovered in 1930 is six times larger than the largest US Gulf of Mexico field, Thunder Horse. The advanced technology must be applied on good prospects, in order to discover large fields. The declining trend in giant field discoveries suggests the good prospects are already drilled. Studying the four largest private oil companies and their effort in exploration and production during a 10 year period of both high and low prices should indicate the role of the oil price. Although their investments in exploration and production has increased, the companies have not succeeded in increasing neither production nor reserves despite an increase of the oil price. On the contrary, from 2003, reserve additions have decreased below annual production and the companies have produced oil from old discoveries, a situation which also applies on the global scale.

The giant oil field model is based on past annual production, URR and three different assumed decline rates. The results from the modeling of 333 giant fields are used in combination with the other forecasts in order to predict future oil production. Four different scenarios have been modeled and peak oil governed by the giant oil fields is a common result for the scenarios. The worst case scenario shows a peak in 2008, while the best case peaks in 2013 although at a higher production level. The production in the best case scenario increases more rapidly than a future demand growth of 1.4 per cent. Therefore the production can be adjusted to follow the demand growth, resulting in a postponed peak oil to 2018. Thus, global peak oil will occur in the ten year span between 2008 and 2018.

Acknowledgements

It's a long way to the oil, unless you have my supervisor Kjell Aleklett. He came up with the idea for this project and he is also responsible for convincing Lundin Petroleum that funding the project was a good idea. Four years ago, I was sitting in your less tidy office when you tried to convince me of peak oil by the use of some graphs with curves on and the advantages of being a PhD student. Apparently, I swallowed it all and I have now produced a PhD thesis with a large amount of graphs showing some curves and trying to convince people of... Thank you very much for guidance, ideas and support! The internship with Lundin Petroleum is greatly appreciated.

My office mate, Bengt, and I have had a whole lotta oil discussions during the years, which I have enjoyed greatly. A big thank you for your precise and exact recommendations on the text, and for letting me listen to my music at the office. Now you are in control of the loudspeakers!

Our group, Uppsala Hydrocarbon Depletion Study Group (UHDSG), has now grown and it includes present members and a former member. Keep up the good *work*, Anders, Aram, Bengt, Kristofer and Mikael. Oil ain't a bad place to be!

Colin Campbell and Jean Laherrère deserves credit for supplying useful information, good ideas and fantastic stories from their experience of the oilage.

My research has taken me to the most remote, the least explored and most dusty areas of a number of libraries. The very helpful staff at the SGU library, the Ångström library and last but not least the staff at Biblioteksdepån in Bålsta are all remembered. Part of the research material has been available thanks to the scholarship from AIM.

This report is unique in that it is the first, but probably not last, report ever to be Wilmanized by Christofer Willman. The report is definitely neither the first nor the last that will be scrutinized by the (in)famous proofreader Hans (T-H) Ericsson. The result of their work was much more work for me but a much better report. If you by any chance will find anything wrong, despite all their work, it is my sole responsibility and I am the only one to blame. Both gentlemen share my interest in country music and guitars, which I greatly appreciate. In addition, I wouldn't be the drummer I am without Willman. My knowledge in long forgotten Swedish words and proverbial saying is all due to Mr Kliché – a word when you need it! Thanks a bunch and keep on truckin'!

Annica and Inger, the ones who actually run the department, have always been very helpful and supportive. Thank you and I really appreciate it!

The coffee breaks are always energizing and fun and it's because all of the great colleagues, Tobbe (what he doesn't know about music is not worth to know), Staffan (skavfötters!), Otas, Anni, Punk-Henke, Emma, Sophie, Henrik, Lotta, Karen, Kajsa, Karin and Richard. The lunch break walk is a quite new tradition I hope you keep up with.

Bengt Karlsson is not forgotten for taking time and discuss various topics regarding databases.

There is a rumor of a new worldwide Uppsala tour called Let there be oil with the department band Ib–Karinz... It's been great fun to be a member of the band and I really appreciate that you put up with my sonic boom guitar attacks and not so cool moves! Thank you very much Ib, Karin, Karin, Wild Thing Tord, Ane, Henrik, Willman Animal, Kristoffer, Kjell and Joahn.

My friends outside the department are of course remembered, Johan, the leading advocate of the advantages of having a cell phone switched on, Clabbe, Maria, Micke, Eva, Danny W-W, Johanna, Rille, Bobbo, Åsa, Niklas, Joakim, Classe, Helena, Krull, Bengan, Maria, Ecke, Markus and Camilla. The president of SGS, Pablo Chimienti, will never be forgotten. The support from Marit is also remembered.

The support from my family Sylvi, Ola and my brother Anders is greatly acknowledged. I have enjoyed both great and not so great games of scrabble, fun discussions, great input to my research and fantastic musical jams to highlight just a few things.

During this work, I have obviously been oilstruck and I also wish to continue to be an oilseeker. Thus, don't be surprised if I will be back in oil, sooner or later.

Finally, I would like to raise my cold 2.8 Pure in a toast for all of your support and say[1]

For those about to oil - I salute you!

[1] Not a single mention of AC/DC? Ha! Try and find all the song and album titles where one word is changed to oil. The winner will get a cream bun with almond paste, topped with liquorice, and a 2.8 Pure. Good Luck!

Motorvägen till olja – svensk sammanfattning

Syftet med föreliggande avhandlig är att försöka bedöma den framtida oljeproduktionen och att göra en uppskattning när den når sin topp. Grundtanken har varit att med hjälp av studier av de globala oljereserverna, historisk produktion och nya fyndigheter göra en prognos över framtida oljeproduktion. I ett tidigt skede av arbetet beslutades att fokus skulle läggas på de största oljefälten, de så kallade gigantfälten.

Starten för den moderna oljeindustrin sätts ofta till 1859 när oljeborrning påbörjades i Oil Creek, Pennsylvania i USA. Innan den bensindriva motorn hade slagit igenom i början på 1900-talet raffinerades olja främst till fotogen och användes för belysning. Första världskriget visade betydelsen av olja i krigssammanhang och säkra oljeresurser blev ett strategiskt mål för länder som bland annat USA och Storbritannien. De första tecknen på massbilism syntes i USA under mellankrigstiden och detta ledde till ett ökat beroende av olja. Efterkrigstiden har präglats av ett växande oljeberoende, där de största konsumenterna importerar allt mer från de största exportörerna, det vill säga länderna runt Persiska viken. Importbehovet blev påtagligt under 1970-talets oljekriser när OPEC-medlemmarna slutade att sälja olja till importländerna.

Idag står oljan för runt 40 procent av världens energitillförsel, som domineras av fossila bränslen. Det råder inget tvivel om oljans betydelse för både världsekonomin och den globala energiförsörjningen. Detta gör att frågan om hur länge till oljeproduktionen kan motsvara efterfrågan är synnerligen viktig. Den globala oljeproduktionen uppgick 2006 till cirka 72 miljoner fat per dag (Mf/d). Till detta ska läggas ytterligare drygt 10 Mf/d från bland annat kondensat och vätskor utvunna från naturgas (NGL). Något felaktigt brukar totalsumman, i detta fall drygt 82 Mf/d, användas som ett mått på den globala oljeproduktionen, när siffran i själva verket redovisar den totala produktionen av oljerelaterade vätskor. Världens största oljefält, så kallade gigantfält, är dominerande i den globala oljeproduktionen. Dessa fält har därför valts ut för en djupare analys, slutsatserna från analysen används sedan för att göra en prognos för framtidens oljeproduktion. En stor del av arbetet har gått ut på att samla in information om gigantfält och denna har lagrats i två databaser: gigantfältsdata (GF) och gigantfältsproduktion (GFP). Information om tillskott från prospektering har lagrats i en tredje databas, oljefältsnyheter

(OFN). Informationen från dessa databaser har sedan använts för att göra prognoser för framtidens oljeproduktion.

Geologiska förutsättningar

Den olja som pumpas upp idag bildades för mer än 150 miljoner år sedan. Organiskt material, främst alger och plankton, kan under rätt omständigheter ombildas till kerogen som i sin tur kan mogna till olja vid rätt temperatur. Den bergart där kerogenet finns kallas för moderbergart. Den viktigaste parametern för oljebildning är temperatur och kerogen börjar generera olja vid ca 60 grader. Detta motsvarar att moderbergarten är belägen på ett djup av ungefär 2 km. Moderbergarten kan inte längre generera olja om temperaturen överstiger 150 grader, vilket motsvara ett djup på cirka 6 km.

Prospektering och utvinning

Den olja som pumpas upp idag bildades för mer än 150 miljoner år sedan. Organiskt material, främst alger och plankton, kan under rätt omständigheter ombildas till kerogen som i sin tur kan mogna till olja vid rätt temperatur. Den bergart där kerogenet finns kallas för moderbergart. Den viktigaste parametern för oljebildning är temperatur och kerogen börjar generera olja vid ca 60 grader. Detta motsvarar att moderbergarten är belägen på ett djup av ungefär 2 km. Moderbergarten kan inte längre generera olja om temperaturen överstiger 150 grader, vilket motsvara ett djup på cirka 6 km.

Om det finns olja i strukturen är nästa steg att avgöra om volymen olja är tillräcklig för att motivera en storskalig utvinning. Loggning och vätskeprov används i en första bedömning och om dessa är lovande kan brunnen även få flöda under en begränsad tid, en så kallad provpumpning. Flödes- och tryckändringar registreras och utifrån dessa kan sedan en volymsbedömning göras. För att säkerställa hur stort oljefältet är kan ett antal utvärderingsbrunnar borras på andra ställen i strukturen. Resultaten från alla utförda tester används sedan för att avgöra vilken typ av utvinningsmetod som är lämpligast.

I början av utvinningen är reservoartrycket oftast tillräckligt för att pressa oljan till ytan, men det avtar i allmänhet efter hand och då måste oljan pumpas till ytan. Dessutom kan grundvatten tränga in i brunnen vilket försvårar hanteringen vid ytan eftersom två vätskor ska hanteras. Någon gång under utvinningen kommer pumpkostnaden överstiga försäljningsförtjänsten och då stängs fältet.

Gigantiska oljefält

Ett oljefält som bedöms kunna producera minst 500 miljoner fat (URR) olja definieras som ett gigantfält. Av de cirka 47500 oljefält som finns i världen är det endast 507 som är gigantfält. Den totala mängden olja som finns är en omdiskuterad fråga, men ett medelvärde av ett antal undersökningar är 2250 miljarder fat. Gigantfältens del överstiger hälften av den volymen. Produktionsmässigt är gigantfälten också dominerande, de 100 största fälten pumpade upp nära nog hälften av all olja under 2005. De allra största fälten finns i mellanöstern, och främst i länderna runt Persiska viken (figure 10.1). Ghawar, som ligger i Saudiarabien, är världens största oljefält. Från sin produktionsstart 1951 och fram till 2005 har fältet producerat över 60 miljarder fat. Detta kan jämföras med den totala produktionen från Nordsjön som uppgår till närmare 43 miljarder fat. Nordsjöns produktion är i kraftigt avtagande medan Ghawars produktion fortfarande ligger på en platånivå runt 5 Mfpd. Kuwait har det näst största fältet, Greater Burgan. De allra största gigantfälten hittades för över 50 år sedan och olja har pumpats från dem nästan lika länge. Sedan 1970-talet har allt färre gigantfält med allt mindre volymer upptäckts. Inga gigantfält har hittats sedan 2003. Gigantfältens förmåga att hålla en hög produktionstakt under en lång tid förklarar deras dominans i världsproduktionen. Produktionen från ett stort antal mindre oljefält räcker inte till för att kompensera för avtagande produktion i ett gigantfält. Detta är väldigt tydligt i Norge, där de 13 gigantfälten nådde sin topp 1997 och bara tre år senare vände den totala produktionen i Norge, som nu är i brant avtagande.

Den totala oljeproduktionen i Europa och Nordamerika började avta strax efter att gigantfältens produktion hade börjat avta. Detta är en tydlig signal om att gigantfälten även kommer att avgöra när den globala produktionstoppen inträffar, en tes som ytterligare stärks av produktionsdata från över 330 gigantfält i GFP vilket visar deras dominans i den globala oljeproduktionen (figur 10.1). En modell har upprättats i syfte att göra prognoser för framtida produktion från gigantfälten.

Tillskott från prospektering och teknikutveckling

Även om upptäckterna av nya gigantfält lyser med sin frånvaro upptäcks det varje år ett antal oljefält och produktionstillskotten från dessa måste beaktas i en prognos över framtidens oljeproduktion. Tillskotten från mer svårproducerad olja, som främst finns i Kanada och Venezuela, måste också tas med i prognosen.

Prognosen för nya tillskott är uppdelad i två delar, där den ena innefattar produktion från djupvattenoljefält medan den andra delen innehåller övriga fält. Oljefält som hittas i vattendjup över 500 m

Table 10.1: *De 20 största oljefälten i världen, med avseende på URR (GF).*

Fältnamn	**Land**	**Upptäcktsår**	**Produktionsstart**	**URR [Gb]**
Ghawar	Saudiarabien	1948	1951	66–150
Greater Burgan	Kuwait	1938	1945	32–75
Safaniya	Saudiarabien	1951	1957	21–55
Rumaila North & South	Irak	1953	1955	19–30
Bolivar Coastal	Venezuela	1917	1917	14–30
Samotlor	Ryssland	1961	1964	28
Kirkuk	Irak	1927	1934	15–25
Berri	Saudiarabien	1964	1967	10–25
Manifa	Saudiarabien	1957	1964	11–23
Shaybah	Saudiarabien	1968	1998	7–22
Zakum	Abu Dhabi	1964	1967	17–21
Cantarell	Mexico	1976	1979	11–20
Zuluf	Saudiarabien	1965	1973	11–20
Abqaiq	Saudiarabien	1941	1946	13–19
East Baghdad	Irak	1979	1989	11–19
Daqing	Kina	1959	1962	13–18
Romashkino	Ryssland	1948	1949	17
Khurais	Saudiarabien	1957	1963	13–19
Ahwaz	Iran	1958	1959	13–15
Gashsaran	Iran	1928	1939	12–14

kallas för djupvattenfält[2]. Djupvattenproduktion är tekniskt avancerad oljeproduktion och därför dyrare än oljeproduktion på grundare vatten eller på land. Västafrika, främst Angola och Nigeria, Brasilien och USA:s del av den Mexikanska golfen dominerar djupvattenproduktionen. Eftersom ett djupvattenfält kräver stora investeringar är bolagen måna om att snabbt få tillbaka de investerade pengarna och detta resulterar i höga produktionstakter från djupvattenfälten. Detta i sin tur leder till kraftigt avtagande produktion i fältens slutskede. Denna produktionsmetod ligger som grund för prognosmodellen för djupvattenfält. Prognosen för djupvattenfält, vilken innefattar över 100 fält, visar en kraftig produktionsökning de närmaste åren med en topp på nästan 9 Mf/d runt 2012 och därefter börjar produktionen avta.

Prognosen för övriga fält baseras på 75 fält men avtagandetakten är inte lika hög i dessa fält. Resultatet visar en kraftig ökning fram till 2011 men därefter avtar produktionen, dock relativt långsamt. Detta beror mycket på de två gigantfälten Kashagan (Kazakhstan) och Azedegan (Iran) som förutsätts producera stora volymer under lång tid.

[2]Definitionen i den Mexikanska golfen i USA är 350 m (=1000 fot)

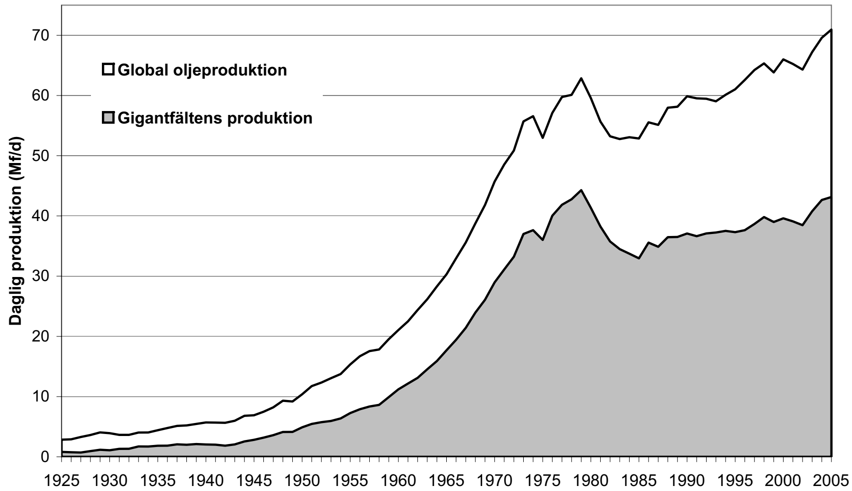


Figure 10.1: Global oljeproduktion, uteslutande både kondensat och NGLs, i miljarder fat per dag (Mf/d), och bidraget från 312 gigantfält och 21 fält som någon gång har producerat över 100 000 f/d (GFP).

I Alberta i Kanada och i Orinocobältet i Venezuela finns stora mängder trögflytande olja. I Alberta finns oljan, kallad bitumen, i stora lager av oljesand. De ytliga lagren av denna bryts med gruvliknande metoder, medan bitumen från djupare lager utvinns med mer ordinära oljepumpningsmetoder. Orinocobältets olja är mindre trögflytande än bitumen och den brukar kallas för tungolja. Likheterna mellan tungolja och bitumen är att utvinningen är svårare och dyrare än för vanlig olja. Dessutom måste den utvunna oljan uppgraderas innan den kan skickas till ett raffinaderi för vidare förädling. Prognosen för produktion av tungolja och bitumen bygger på alla annonserade projekt, även sådana som ännu inte har fått klartecken för genomförande. Trots den rådande situationen i Venezuela antas att annonserade projekt genomförs. För att visa på Orinocobältets potential har ytterligare ett antal projekt lagts in. Dessa får dock anses ha låg sannolikhet, vilket gör att prognosen är optimistisk.

Tekniskt avancerad borrning och produktion, som djupvattenproduktion, är betydelsefull. Det viktiga är dock i vilken grad de upptäckta volymerna bidrar till den framtida produktionen. Den totala volymen djupvattenolja upptäckt i Angola mellan 1994 och 2005 uppgår till cirka 10 miljarder fat. Den långt mindre avancerade tekniken som fanns tillgänglig på 1920-talet var tillräcklig för att hitta nära nog 20 miljarder fat i Texas mellan 1926 och 1936.

De fyra största privata oljebolagen har ökat sina investeringar i prospektering och produktion i takt med det ökande oljepriset, men de har inte lyckats att öka produktion de senaste 10 åren. De har dessutom efter 2002 misslyckats med att ersätta producerade volymer olja med nya oljefyndigheter och 2005 ersatte de mindre än hälften av den producerade oljan.

Framtidens oljeproduktion

Baserat på de varierande uppgifter som finns om gigantfältens storlek och genomförandet av framtida expansionsprojekt av de befintliga gigantfälten har fyra olika produktionsscenarier tagits fram. I det sämsta fallet har de lägsta URR-siffrorna för de stora fälten runt persiska viken använts medan det bästa fallet innefattar en relativt snabb start för stora fält som finns i främst Irak.

Resultatet från modellen tillsammans med de övriga prognoserna visar att gigantfälten styr produktionstoppen och att den inträffar strax efter att gigantfälten har passerat sin topp (figur 10.2). Sammantaget visar resultatet att tidsspannet för produktionstoppens inträffande inte är särkilt stort utan endast fem år, någon gång mellan 2008 och 2013 (figure 10.3). Den årliga globala efterfrågeökningen på olja prognostiseras till 1,4-1,7 procent. Om produktionen i det bästa fallet anpassas till en ökning på 1,4 procent kan oljetoppen skjutas fram ytterligare några år och inträffa först 2018.

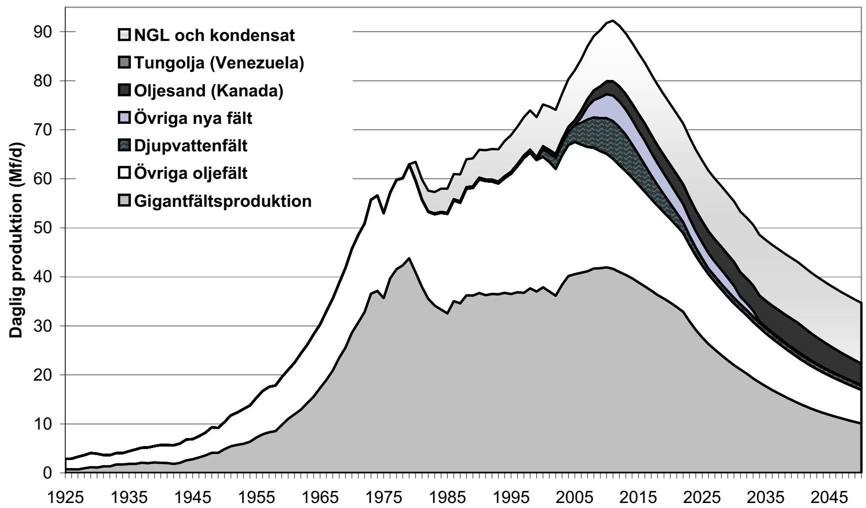


Figure 10.2: Global produktion, i miljoner fat per dag (Mf/d), av oljerelaterade vätskor uppdelad i vätskeslag. Prognosen bygger på standardfallet – högt utfall (GFP).

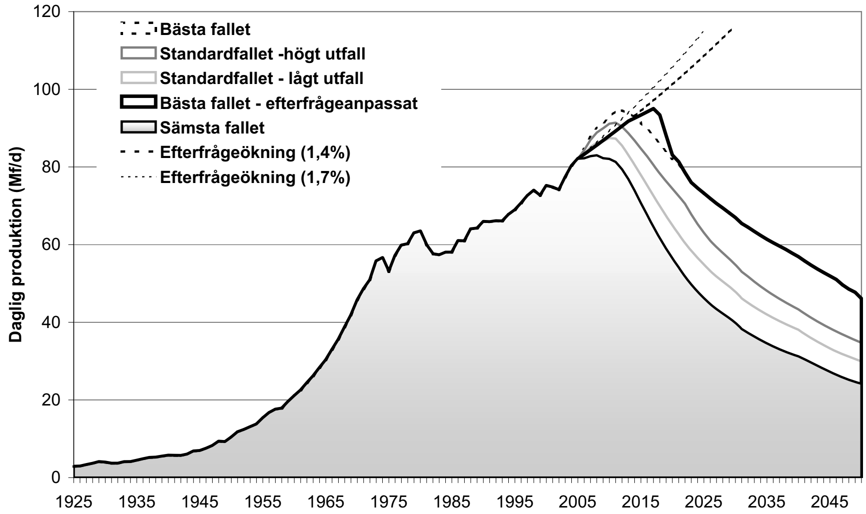


Figure 10.3: Global produktion, i miljoner fat per dag (Mf/d), av oljerelaterade vätskor de fyra olika fallen. Det bästa fallet är anpassat för att följa en årlig efterfrågeökning på 1.4 procent .

Appendix A Projects Included in Deepwater Oil Production Forecast

The following tables list the projects included in the deepwater oil production forecast. Many of the projects in Angola consists of a number of fields, but in most cases it is only the project name listed.

The fields are categorized in five reserve groups:

Reserve Group I URR ≥ 2 Gb

Reserve Group II 1 ≤ URR < 2 Gb

Reserve Group III 0.5 ≤ URR < 1 Gb

Reserve Group IV 0.1 ≤ URR < 0.5 Gb

Reserve Group V URR < 0.1 Gb

Table 2: *Deepwater projects in Angola (OFN).*

Field name	First Oil	Peak Level [kbpd]	Peak Year	Reserve Group
Angola				
Bl 14 Kuito	1999	66	2002	IV
Bl 14 Tombua-Landana	2006	100	2010	IV
Bl 14 BBLT	2006	195	2008	IV
Bl 15 Kizomba A	2004	250	2006	II
Bl 15 Kizomba B	2005	250	2007	II
Bl 15 Kizomba C	2008	200	2009	III
Bl 15 Xikomba	2003	80	2004	IV
Bl 17 Pazflor	2011	200	2012	III
Bl 17 Dalia	2006	225	2008	III
Bl 17 Girassol, Jasmine +Rosa	2001	250	2004	II
Bl 17 CLOV	2011	130	2012	III
Bl 18 Greater Plutonio	2007	220	2008	III
Bl 18 WEST	2012	100	2013	IV
Bl 31 NE	2010	150	2011	III
Bl 31 SE	2011	150	2012	III
Bl 32	2010	90	2011	III
Bl 04 Jimbao	2008	45	2008	V

Table 3: *Deepwater projects in Nigeria (OFN).*

Field name	First Oil	Peak Level kbpd	Peak Year	Reserve Group
Abo	2003	30	2005	IV
Agbami	2008	250	2009	III
Akpo	2008	175	2009	III
Bolia + Chota	2011	60	2012	IV
Bonga & Bonga NW	2005	225	2006	II
Erha/Erha N	2006	200	2007	III
Usan-Ukat	2011	150	2012	III
Yoho	2002	150	2006	IV
Bonga SW-Aparo	2010	125	2011	IV
Bosi	2009	120	2012	IV
Egina, Egina S + Preowei	2012	150	2013	III
Ngolo	2012	50	2013	IV
Nsiko	2011	75	2012	IV

Table 4: *Deepwater projects in other Africa (OFN).*

Field name	First Oil	Peak Level [kbpd]	Peak Year	Reserve Group
Congo–Brazzaville				
Moho-Bilondo	2008	90	2009	IV
Azurite Marine	2009	35	2010	V
Cote D'Ivoire/Ivory Coast				
Baobab	2005	60	2006	IV
Eq Guinea				
NPG-Okume complex*	2007	60	2007	IV
Ceiba	2000	48	2002	IV
Mauritania				
Chinguetti + Tevet	2006	75	2007	V
Tiof	2008	100	2010	IV

Table 5: *Deepwater projects in Asia–Pacific (OFN).*

Field name	First Oil	Peak Level [kbpd]	Peak Year	Reserve Group
Australia				
Enfiled	2006	100	2007	IV
Stybarrow + Eskdale	2008	70	2009	IV
Indonesia				
West Seno	2003	60	2005	IV
Gehem-Ranggas	2010	40	2011	IV
Merah Besar	2011	20	2012	V
Aton	2008	20	2009	V
Hijau Besar	2009	25	2010	V
Janaka North	2009	15	2010	V
Putih Besar	2012	20	2013	V
Malaysia				
Kikeh	2008	120	2010	IV
Gumusut+Kakap	2010	100	2011	IV

Table 6: *Deepwater projects in Brazil (OFN, GF).*

Field name	**First Oil**	**Peak Level [kbpd]**	**Peak Year**	**Reserve Group**
Albacora	2000	145	2002	II
Albacora East	2000	180	2007	III
Barracuda	1997	150	2006	II
Bijupira-Salema	2003	65	2004	IV
Cachlotea	2012	100	2013	III
Caratinga	2005	135	2006	IV
Espadarte	2001	110	2007	IV
Frade	2008	90	2010	IV
Golfhino	2006	180	2008	III
Jubarte I	2003	50	2007	IV
Jubarte II	2010	180	2010	III
Marimba Leste	1998	35	2000	IV
Marlim	1991	590	2002	I
Marlim Eastb	2000	175	2010	IV
Marlim Sulc	1994	430	2011	I
Papa Terra	2012	175	2014	III
Piranema	2006	35	2009	IV
Roncadord	1999	350	2007	I
Parque de Conchas BC-10	2011	90	2012	IV
Urugua (Pole BS-500)	2012	100	2013	IV
Voador	1998	20	2000	V
ESS-130	2008	100	2009	III
Peregrino	2010	40	2011	IV

Table 7: *Deepwater projects in the US Gulf of Mexico. Note, condensate is excluded from production in most fields, resulting in a lower liquid production (OFN).*

Field name	**First Oil**	**Peak Level [kbpd]**	**Peak Year**	**Reserve Group**
Mars-Ursa	1996	268	2004	II
Holstein	2004	75	2007	IV
Auger	1994	72	1997	IV
Cognac	1979	70	1983	IV
King/Horn Mt	2002	79	2003	IV
Troika	1997	96	1999	IV
Pompano	1994	49	1998	IV
Medusa	2003	35	2006	IV
Bullwinkle	1989	50	1992	IV
Genesis	1999	50	2001	IV
Brutus	2001	55	2002	IV
Petronius	2000	53	2003	IV
Ram-Powell	1997	46	1999	V
Front Runner	2004	35	2007	IV
Baldpate	1998	31	2000	V
Magnolia	2004	35	2007	V
Amberjack	1991	19	1993	V
Neptune	1997	24	1999	V
Lena	1984	24	1987	V
Kepler	2004	46	2005	V
Nansen	2001	22	2004	V
Hoover	2000	44	2002	V
Europa	2000	28	2000	V
Gunnison	2004	25	2007	V
Crosby	2002	40	2002	V
Morpeth	1998	21	1999	V
Salsa	1999	6	2001	V
Jolliet	1989	11	1991	V
Boomvang	2001	30	2003	V
Angus	1999	29	2000	V
Allegheny	1999	17	2000	V
Typhoon	2000	28	2002	V
Marco Polo	2004	15	2006	V
Devil's Tower	2004	13	2007	V
Oregano	2001	17	2002	V
Apen	2002	23	2003	V
Arnold	1998	13	1999	V
Ariel	2004	26	2005	V
Marlin	2001	4	2001	V

Table 8: *Deepwater projects in the US Gulf of Mexico. Note, condensate is excluded from production in most fields, resulting in a lower liquid production (OFN).*

Field name	**First Oil**	**Peak Level [kbpd]**	**Peak Year**	**Reserve Group**
Boris	2002	15	2004	V
Diana	2000	14	2001	V
Macaroni	1999	7	2000	V
Rocky	1996	4	1996	V
Pompano I	1994	49	1999	IV
Tahoe/SW Tahoe	2002	2	2002	V
Madison	2002	7	2003	V
Nile	2005	3	2007	V
Llano	1998	36	2005	V
Fourier	2003	17	2004	V
Matterhorn	2003	10	2004	V
Marshall	2001	5	2002	V
Mica	2001	4	2001	V
Manta Ray	1999	3	2000	V
Boomvang East	2002	0.5	2004	V
Cooper	1996	7	1997	V
Pilsner	1987	2	1987	V
Boomvang West	2001	0.5	2002	V
K2	2005	35	2007	V
King Kong	2002	5	2006	V
Swordfish	2005	1	2005	V
N/A 2	2004	1	2005	V
N/A 3	1995	2	1996	V
N/A 4	2001	0.5	2004	V
Allegheny S	2006	10	2006	V
Anduin	2007	13	2008	V
Atlantis	2007	180	2008	III
Balboa	2006	4	2006	V
Blind Faith	2008	35	2008	V
Cascade	2009	75	2009	IV
Chinook	2009	50	2009	IV
Clipper	2009	12	2009	V
Constitution	2006	40	2006	IV
Deimos	2007	30	2007	IV
Entrada	2007	35	2007	IV
Genghis Khan	2007	25	2007	V
Goldfinger	2005	15	2005	V
Gomez	2006	20	2006	V

Table 9: *Deepwater projects in the US Gulf of Mexico. Note, condensate is excluded from production in most fields, resulting in a lower liquid production (OFN).*

Field name	**First Oil**	**Peak Level [kbpd]**	**Peak Year**	**Reserve Group**
Great White	2010	100	2010	IV
Lorien	2006	15	2006	V
Mad Dog	2005	100	2007	IV
Neptune	2008	50	2007	IV
Perseus	2005	4	2005	V
Puma	2007	75	2007	IV
Shenzi	2008	75	2008	IV
St Malo	2010	50	2010	IV
Tahiti	2008	100	2008	III
Thunder Hawk	2008	50	2009	IV
Thunder Horse	2008	225	2009	II
Ticonderonga	2006	20	2006	V
Venus	2007	20	2007	V

Appendix B Fields Included in New Field Development Forecast

The following tables list all the fields included in the new field development forecast. Some fields are developed together with other fields and might therefore not be listed in the year the field goes on–stream.

The fields are categorized in five reserve groups:

Reserve Group I URR ≥ 2 Gb

Reserve Group II 1 ≤ URR < 2 Gb

Reserve Group III 0.5 ≤ URR < 1 Gb

Reserve Group IV 0.1 ≤ URR < 0.5 Gb

Reserve Group V URR < 0.1 Gb

Table 10: *Fields on–stream before 2005 (OFN).*

Field name	**Country**	**Discovery**	**Peak Level [kbpd]**	**Peak Year**	**Reserve Group**
Doba fields	Chad		225	2005	II
Block NC 186	Libya	2000	100	2009	IV
Menzel Ledjmat North	Algeria	1996	40	2008	IV

Table 11: *Fields on–stream in 2005 (OFN).*

Field name	**Country**	**Discovery**	**Peak Level [kbpd]**	**Peak Year**	**Reserve Group**
Block 0 Sanha-Bomboco	Angola	1987	90		IV
Mutiner-Exeter	Australia	1997	100	2006	IV
Wollybutt- Scallybutt	Australia		19	2005	V
ACG - Azeri, Central (ACG)	Azerbaijan	1987	340	2008	II
White Rose	Canada	1984	100	2006	IV
Caofeidian (CFD)	China		60	2007	IV
Darkhovian ph1	Iran	1965	160	2007	II
Okwori	Nigeria		0	2006	V
Kristin	Norway	1997	50	2007	IV
Huayari	Peru	2005	10	2006	V
Sakhalin 1 (Chayvo field)	Russia	1979	250	2007	II
Salym fields	Russia		125	2010	II
Jasmine	Thailand		20	2006	V
Greater Angostura	Trinidad and Tobago	1999	50	2007	IV
Clair Phase I	UK (North Sea)	1977	60	2007	IV
Farragon	UK (North Sea)		20	2006	V
Hiswah (Malik block 9)	Yemen		15	2006	V
Ust-Vakh	Russia	2000	75	2009	IV

Table 12: *Fields on–stream in 2006 (OFN).*

Field name	**Country**	**Discovery**	**Peak Level [kbpd]**	**Peak Year**	**Reserve Group**
Cliff Head	Australia	2001			V
ACG - Azeri, East	Azerbaijan	1987	240	2009	II
ACG - Azeri, West	Azerbaijan	1987	300	2008	II
Sinai	Egypt	2005	8	2007	V
DeRuyter	Netherlands		17	2007	V
Nda - included in Okwori (2005)	Nigeria	2004			V
Fram East	Norway	1992	45	2007	V
Ringhorne East	Norway	2003	15	2007	V
Brenda	UK (North Sea)	1990	35	2007	IV
Buzzard	UK (North Sea)	2001	180	2007	III
Al-Nilam ST1 (S2 block)	Yemen	2005			V
Mabruk Expansion	Libya	1959	50	2006	IV

Table 13: *Fields on–stream in 2007 (OFN).*

Field name	**Country**	**Discovery**	**Peak Level [kbpd]**	**Peak Year**	**Reserve Group**
Puffin	Australia	1975	25	2007	V
Saqqara	Egypt	2003	45	2007	V
Avouma	Gabon		12	2007	V
Oyong	Indonesia	2001	6	2008	V
Tui Area	New Zealand	2002	25	2007	V
Bilabri	Nigeria	2006	25	2007	V
Alvheim	Norway	1998	75	2008	IV
Vilje	Norway	2003	25	2008	V
Volve	Norway	1993	50	2008	V
Blane	UK (North Sea)	1989	15	2007	V
Callanish	UK (North Sea)		25	2007	V
Chestnut	UK (North Sea)	1986	8	2008	V
Dumbarton (Donan)	UK (North Sea)		38	2007	V
Enoch	UK (North Sea)		10	2007	V
Ettrick	UK (North Sea)	1981	30	2007	V
Tweedsmuir & Tweedsmuir South	UK (North Sea)	2002	50	2007	V
Corocoro	Venezuela	1999	120	2011	IV
Song Doc	Vietnam	2003	50	2007	IV

Table 14: *Fields on–stream in 2008 (OFN).*

Field name	**Country**	**Discovery**	**Peak Level [kbpd]**	**Peak Year**	**Reserve Group**
Vincent	Australia	1998	80	2008	V
Pyrenees complex	Australia		100	2008	IV
Theo	Australia	2006	15	2008	V
Montara Complex	Australia		25	2008	V
ACG - Guneshli DW	Azerbaijan	1979	300	2010	II
Jeruk	Indonesia	2004	50	2008	IV
Khest	Iran	1994	20	2008	III
Maari	New Zealand	1983	35	2008	V
Volund (Hamsun early name)	Norway	1994	40	2008	V
Verkhnechonsk	Russia (E Sib)	1978	200	2013	II
Ooguruk	US (Alaska)	2005	20	2009	V
Vankor	Russia (E Sib)	1988	280	2011	I
Prirazlomnoye	Russia	1989	155	2011	IV
Talakanskoye	Russia	1984	120	2010	III
Block 208 El Merk Fields	Algeria	1993	100	2008	IV

Table 15: *Fields on–stream in 2009 (OFN).*

Field name	**Country**	**Discovery**	**Peak Level [kbpd]**	**Peak Year**	**Reserve Group**
Olowi	Gabon		20	2009	V
Aishwariya (N-A-1) (NF)	India	2004	15	2009	V
Bhagyam (NF)	India	2004	40	2009	IV
Mangala (NF)	India	2004	100	2009	IV
Banyu Urip (Cepu block)	Indonesia		165	2010	IV
Jambaran (Cepu block)	Indonesia		10	2009	V
Azadegan	Iran	1999	260	2013	I
Kashagan	Kazaksthan	2000	1,200	2016	I
Dana (Block SK 305 Sarawak)	Malaysia	2006	20	2009	V
Tyrihans	Norway	1983	82	2009	IV
Liberty	US (Alaska)		50	2009	IV
Uvatskoye Fields	Russia		60	2010	IV
Nuayyim	Saudi Arabia		75	2010	III

Table 16: *Fields on–stream in 2010 and later (OFN).*

Field name	**Country**	**Discovery**	**Peak Level [kbpd]**	**Peak Year**	**Reserve Group**
Hebron complex	Canada		150	2011	III
Anaran block	Iran	2004	100	2010	II
Skarv	Norway	1998	75	2010	V
Bolshehetskiy	Russia		170	2013	III
Dolginskoye	Russia (Barent)	2000	135	2011	II

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