Depletion and Decline Curve Analysis in Crude Oil Production

Licentiate thesis

Mikael Höök

Global Energy Systems
Department for Physics and Astronomy, Uppsala University

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Abstract

Oil is the black blood that runs through the veins of the modern global energy system. While being the dominant source of energy, oil has also brought wealth and power to the western world. Future supply for oil is unsure or even expected to decrease due to limitations imposed by peak oil.

Energy is fundamental to all parts of society. The enormous growth and development of society in the last two-hundred years has been driven by rapid increase in the extraction of fossil fuels. In the foreseeable future, the majority of energy will still come from fossil fuels. Consequently, reliable methods for forecasting their production, especially crude oil, are crucial.

Forecasting crude oil production can be done in many different ways, but in order to provide realistic outlooks, one must be mindful of the physical laws that affect extraction of hydrocarbons from a reservoir. Decline curve analysis is a long established tool for developing future outlooks for oil production from an individual well or an entire oilfield. Depletion has a fundamental role in the extraction of finite resources and is one of the driving mechanisms for oil flows within a reservoir. Depletion rate also can be connected to decline curves. Consequently, depletion analysis is a useful tool for analysis and forecasting crude oil production. Based on comprehensive databases with reserve and production data for hundreds of oil fields, it has been possible to identify typical behaviours and properties.

Using a combination of depletion and decline rate analysis gives a better tool for describing future oil production on a field-by-field level. Reliable and reasonable forecasts are essential for planning and necessary in order to understand likely future world oil production.

nam et ipsa scientia potestas est

List of Papers

This thesis is based on the following papers, which are referred to in the text by their Roman numerals.

I Höök, M., Aleklett, K. (2008) A decline rate study of Norwegian Oil Production. *Energy Policy*, 36(11):4262–4271

II Höök, M. Söderbergh, B., Jakobsson, K., Aleklett, K. (2009) The evolution of giant oil field production behaviour. *Natural Resources Research*, 18(1):39-56

III Höök, M., Hirsch, R., Aleklett, K. (2009) Giant oil field decline rates and their influence on world oil production. Energy Policy, 37(6):2262-2272

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Authors comments regarding the papers

All three papers are published in scientific journals, subjected to a peer-review process with one or more reviewers. Papers I and III are published in Energy Policy, Elsevier's authoritative journal addressing those issues of energy supply, demand and utilization that confront decision makers, managers, consultants, politicians, planners and researchers. The scope of Energy Policy embraces economics, planning, politics, pricing, forecasting, investment, conservation, substitution and environment.

Paper II is published in Natural Resources Research, an international journal of the International Association of Mathematical Geosciences and American Association of Petroleum Geologists – Energy Minerals Division devoted to promoting quantitative approaches to mineral resource exploration, assessment, extraction and utilization. Natural Resources Research publishes peer-reviewed, quantitative geoscientific studies on the search for and development of natural resources, including associated environmental, economical, and risk-related aspects. Natural Resources Research reports cover a wide variety of resources, including coal, water, vegetation, and heavy oil.

Contents

Abbreviations

AAPG	American Association of Petroleum Geologists, international association of professional geologists working in the petroleum or energy minerals fields
API	American Petroleum Institute, U.S. trade organisation for oil and gas industry
BGR	Bundesanstalt für Geowissenschaften und Rohstoffe, the German Federal Institute for Geosciences and Natural Resources
bpd	barrels per day [b/d], common unit for measuring production
DAP	Depletion At Peak, the depletion rate of remaining reserves that occur when the onset of decline is reached for a field
CERA	Cambridge Energy Research Associates, consulting firm specialized in advising companies and governments on energy markets, geopolitics, industry trends and strategy
EIA	Energy Information Administration, independent statistical agency within the U.S. Department of Energy devoted to providing policy-independent data, forecasts and analysis
EUR	Estimated Ultimate Recovery, synonym to URR
Gb	Gigabarrels, equivalent to one billion barrels
IEA	International Energy Agency, intergovernmental energy organization founded by the Organisation for Economic Co-operation and Development (OECD)-countries
NGL	Natural Gas Liquids, liquid side products from natural gas processing
NGPL	Natural Gas Plant Liquids, same as NGL
NPD	Norwegian Petroleum Directorate
OIP	Oil In Place, all oil present in an underground structure
OIIP	Oil Initially In Place, synonym to OIP and OOIP
OOIP	Oil Originally In Place, synonym to OIP and OIIP
OPEC	Organization of Petroleum Exporting Countries, an intergovernmental organisation of the worlds' dominating oil exporting countries
RF	Recovery Factor, the recoverable percentage of OIP
RPR	Reserve-to-Production Ratio, quotient of remaining reserves and production used to describe how long the reserves will last with current production rate
SPE	Society of Petroleum Engineers, professional organisation engineers, scientists, managers and educators in the oil and gas exploration and production industry
URR	Ultimate Recoverable Resources, the upper limit for cumulative production
USGS	United States Geological Survey, scientific agency in the U.S. government devoted to geosciences and natural resources

1. Introduction

Oil is the black blood that runs through the veins of the modern global energy system. In some senses, oil can be seen as the black soul of our industrialized/mechanized society and the trademark of a Western lifestyle. Its combustion brings energy in immense amounts and can drive a wide array of machines, tools and processes. Oil can also be broken down and used as a feedstock in a wide range of chemical processes, providing everything from medicines to plastics. It brings wealth and political influence to those who control it. In essence, oil is a substance of power, in the truest sense of the word. The aim of this thesis is to investigate fundamental properties and behaviour of crude oil production and examine some model approaches for creating realistic outlooks for the future.

1.1 Thesis disposition

The text is composed as follows:

Chapter 2: Theoretical background

The naturalistic approach to science and observations of reality is based on the position that the universe obeys rules and laws of natural origin. This chapter described the methodology as well as the basic classification schemes relevant for crude oil.

Chapter 3: Geological overview and reservoir properties

Crude oil is a result of geological processes. Chapter 3 aims to give a brief overview of petroleum formation theory as well as the development of modern petroleum geology. Oil and gas reservoirs are the basic units in any production unit. Reservoirs and their intrinsic properties are very important for petroleum production. This chapter will provide an overview of different fundamental reservoir concepts as well as their physics.

Chapter 4: Oil production modelling

Reliable modelling of oil production is essential for forecasting and planning in all fields connected to oil. This chapter will give an overview of basic modelling approaches and give some theoretical background for the studies done in the papers.

Chapter 5: Summary and conclusions

By combining different modelling approaches with physical properties of the reservoir, a more realistic production outlook can be created. Consequently, this chapter summarizes the modelling part and puts it in a greater perspective.

1.2 Introduction to papers

This thesis is built around three papers on crude oil forecasting and behaviour of oil fields where my role has been as lead author. These are included in this thesis and briefly introduced below.

Paper I: A decline rate study of Norwegian oil production
Norway has been one of the two major producers in the North Sea as well as the world's third largest oil exporter. The Norwegian Petroleum Directorate makes all relevant data officially available, thus making Norway an ideal country for testing models or analysing historical trends. The oil category was broken down into its subparts and analyzed individually on a field-by-field level. The modelling also included estimates of undiscovered volumes as well as the inclusion of new field developments. In total, a comprehensive analysis of all parts affecting future oil production was investigated and used to provide a realistic forecast. A short discussion of the Norwegian oil fund was also done along with a remark about the strategic long-term thinking that is needed to wisely handle the wealth from oil production.

Paper II: The evolution of giant oil field production behaviour
Giant oil fields are by far the most important contributor to world oil supply. This paper used a comprehensive database with more than 300 giant fields in order to determine typical decline rates, depletion rates and other interesting parameters. The evolution of those parameters was studied to get an impression of how they changed with introduction of new technology and changes in production strategies. This also provides a reasonable basis for estimating how future behaviour might unfold. Furthermore, the analysis also uncovered a strong correlation between depletion rate and decline rate, indicating that high extraction rate of the recoverable volumes will result in rapid decline. Potential differences between land and offshore production and OPEC/non-OPEC production were also investigated. The production peak in the world's giant oil fields was also found to occur well before half of the ultimate reserves had been produced.

Paper III: Giant oil field decline rates and their influence on world oil production
This paper can be seen as a sister-study to Paper II and focused primarily on decline rates of giant oil fields and how they influence the global production. Over the years, many analysts have tried to estimate a typical decline in existing oil production and this paper performed such a study based on giant oil field data. The results were also compared with other major studies. Studies on mean and aggregate decline rate of the giant oil field population were also performed.

2. Theoretical background

Crude oil, also known as petroleum, is a wide ranging term that includes many substances and forms of liquids. The word *petroleum* derives from the Greek words *petra*, meaning rock, and *oleum*, denoting oil, which combined literally means *rock-oil*. This term was first used by the German mineralogist Georgius Agricola (1546a) in the treatise *De Natura Fossilium*.

The ancient Greek word *naphtha* was often used to describe any petroleum or pitch-like substance and in older texts was often used as a synonym for petroleum, but this has now been phased out in English language. However, some languages, such as Russian or Arabic, still use variants of naphtha as the word for petroleum.

This work will focus on oil, but much of the geology, physical laws and extraction techniques can also be applied to natural gas production. However, coal is also an important fossil fuel in the global energy system, but behaves differently due to physical differences. Even so, some discussions and methods from crude oil analysis may be relevant for investigation of coal or other energy sources.

2.1 Methodology

The naturalistic approach to science and observations of reality is based upon the position that the universe obeys certain rules and laws of natural origin. It forms the philosophical foundation of natural science, including all forms of physics. Natural science is also the basis of applied sciences, where the scientific method and knowledge is used to solve practical problems; sciences such as engineering and technology are closely related to the applied sciences. Resource physics and the study of global energy systems, such as petroleum, are examples of the application of engineering science and applied physics to characterize and describe the utilization of resources for energy production in society.

An important part of any form of oil production modelling and hydrocarbon extraction forecasting is to uncover mathematical models for the physical behaviour of the production processes. The mathematical principles of the behaviour are always important and useful. The cause of the behaviour can sometimes be satisfyingly explained by natural laws, but unfortunately not always. This dilemma is perhaps best captured by a quotation about the theory of gravity from Isaac Newton (1726):

> "I have not as yet been able to discover the reason for these properties of gravity from phenomena, and I do not feign hypotheses. For whatever is not deduced from the phenomena must be called a hypothesis; and hypotheses, whether metaphysical or physical, or based on occult qualities, or mechanical, have no place in experimental philosophy. In this philosophy particular propositions are inferred from the phenomena, and afterwards rendered general by induction."

Resource physics and analysis of global energy systems involves pure physics to a high degree, but there are also elements of economic or political nature that affect the situation. Ultimately, physics will dominate and determine the limitations, since neither economical incentives nor political motives are able to bend or break the natural laws that govern reality.

Much of the work, presented here, is just statistical or data analysis in order to identify trends or certain behaviours in time series of resource data. Locating and obtaining good data is essential and sometimes quite challenging. Petroleum related trade journals and statistical yearbooks from various oil companies have shown to be an important source of production data.

Much of the giant oil field data was compiled by my previous colleague Fredrik Robelius in his thesis (Robelius, 2007). In many ways, my work on giant fields may be seen as a more detailed analysis of his material. Furthermore, Robelius' databases have now been updated and will be developed even more in the future, as new data and information become available. Closer description of the data and details on the exact methodology, used in each study, can be found in papers I, II and III.

2.2 Oil classification

Petroleum can be divided into many subclasses and categories, depending on the intrinsic properties of specific oils. Some oils are heavy or even extra-heavy, implying that they have high density and do not flow easily. Others are sour, which means they contain significant amounts of sulphur. Some oils are classified as non-conventional (also called unconventional), denoting that they are not extracted from subsurface reservoirs like conventional oil, and instead they are derived from tar sand processing, oil shales or even synthetically produced from coal liquefaction.

Oil can also include condensate, which is gaseous in the reservoir but condensates to liquid at the surface, and natural gas liquids (NGL), corresponding to the heavier hydrocarbon types in natural gas. The Norwegian Petroleum Directorate (NPD) defines NGL as a mixture of ethane, propane, butane, isobutane and naphtha (NPD, 2008). NGL is a valuable by-product from natural gas processing and is not produced directly at the field, but rather at centralized gas treatment plants (I). In fact, U.S. Department of Energy and Energy Information Administration (EIA) even called NGL for *Natural Gas Plant Liquids* (NGPL).

The term *crude oil*, sometimes just referred to as *crude*, normally excludes unconventional oil, NGL and extra-heavy oil. Although, it should be noted that many countries or organisations have their own set of definitions that may differ from one another. For instance, NPD does not include condensate in their crude oil category, while the Energy Information Administration (EIA) treats it as crude oil.

Many different classifications can be applied to crude oil, depending on the different physical or chemical properties. However, the most common way is to describe oil by its density, often better known as *gravity number*. The American Petroleum Institute (API) defines the gravity number according to equation 2.2.1 (Dake, 2004).

$$°API = \frac{141.5}{specific\ gravity} - 131.5 \qquad (2.2.1)$$

Specific gravity is often defined as ratio of densities for crude oil and water at 15.6 °C, although slight deviations from this may use other reference points, such as 0°C, 20°C or the maximum volumetric mass of water which is at 3.98°C. API gravity ranges from 0-60°, where dense oils have low values and highly viscous oils have high values. Condensates typically have API gravities over 45° and Canadian tar sands from the Athabasca can be found in the range of 6 -10° (Peters et al., 2005). Oil with less than 10 °API is denser than water and may be called extra-heavy oil or natural bitumen (USGS, 2006), depending on viscosity. Heavy oils have gravities of less than 20°API, but more than 10°API (USGS, 2006). Medium crudes can be found between 20°API and 30°API. Light crudes have more than 30°API (Robelius, 2007).

Generalized approximate relationships between API gravity and gas-oil ratio, reservoir depth, percentage sulphur and trace metal content are described by Tissot and Welte (1984). The API gravity classification is a simple system and worked well, as long as there was one dominating quality type of crude oil in use. As new oil fields were brought into production and new crude oil blends entered the market, the simple gravity classification scheme was insufficient to fully measure the quality of crude oil. Even so, the API system is still in use for certain crude oils and products (Speight, 1999).

An improvement in classification can be performed by including the content of various important pollutants, especially sulphur. The sourness of crude oil refers to the sulphur content. The Society of Petroleum Engineers (SPE) defines sour crude oil as *oil containing free sulphur or other sulphur compounds whose total sulphur content is in excess of 1 percent* (SPE, 2009). Crude oils with low sulphur content are commonly called “sweet”.

It is more complicated to refine heavy and sour crude oils, and consequently, they are worth less on the market compared to the light and sweet crude oils. Heavy crude needs more processing to yield high quality products due to their low API-gravity, high viscosity, high initial boiling point, high carbon residue and low hydrogen content (Nygren, 2008). The most valuable oil is the light and sweet crude oil.

3. The formation of oil

The genesis of petroleum and how it is created is an important topic. Peters et al. (2005) point out the importance of the underlying oil formation theory for oil exploration. Tsatskin and Balaban (2008) even claim that the peak oil debate is underpinned by a biogenic paradigm of oil formation. However, Bardi (2004) concluded that abiotic oil formation is irrelevant to the peak oil debate unless it occurs at extremely rapid rates, much faster than conventional oil creation theory would dictate. The rate of formation compared to extraction is essential for future production outlooks and as long as the extraction process is significantly faster than the creation process, then fossil fuels must be categorized as non-renewable and subject to depletion, regardless of their biogenic or abiotic origin.

Large oil companies, such as BP and Statoil, organizations like American Association of Petroleum Geologists (AAPG) and governmental bodies like Energy Information Administration (EIA) or German Federal Institute of Geosciences and Natural Resources (BGR) and similar establishments all agree on the non-renewable properties of fossil fuels. Consequently, it is commonly accepted that fossil fuels are finite. In agreement with Bardi (2004), one should conclude that the question of a biogenic or abiotic origin of oil and other hydrocarbons is irrelevant to the peak oil debate, unless the theory states that hydrocarbons can be created fast enough to replenish reservoirs and formations as they are depleted.

A comprehensive overview of the development of petroleum geology and hydrocarbon genesis is essential for a deeper understanding of oil and the future challenges awaiting a hydrocarbon dependent society. Although, the origin of oil has little importance for the challenge of peak oil, it is still relevant for understanding future possibilities and the prospects for hydrocarbon exploration.

3.1 Development of oil formation theories

Petroleum and other hydrocarbons have been known to mankind since the dawn of civilization. Often it was treated as a curiosity without any serious use to society, although significant utilization was undertaken in some parts of the world prior to industrialization. The *eternal fires* of Kirkuk, consisting of burning oil seepages, and the use of oil and natural bitumen in ancient Middle East has been studied by Beydoun (1997). The Roman Empire has been known to use coal for household heating in Britannia (Dearne and Branigan, 1995). The dreaded *Greek fire*, an early incendiary weapon used by the Byzantine Empire, is believed to have been partly based on petroleum or naphtha (Partington and Hall, 1999). In many places all over the world, where oil seepages occurred, local inhabitants drilled or dug surface wells and shafts to increase flow rate for collection purposes (Hunt, 1979), marking the early pioneering spirit of petroleum utilization.

The ancient Greeks were familiar with the existence of petroleum and some of their famous natural philosophers made attempts to discuss its origin. Based on an elemental theory, Aristotle thought that ores, minerals and hydrocarbons were the result of exhalations from deep within the earth (Walters, 2006). His followers suggested that the foul smell that was typical for many forms of petroleum indicated that it was related to sulphur in some way. Overall, few remarks to petroleum can be found in classical literature. Roger Bacon (1258) made remarks about the inability of Aristotle and other Greek natural philosophers to adequately explain the origin of petroleum in his treatise *Opus Tertium*.

It was not until the Renaissance that the first real theories about the origin of hydrocarbons were developed. Georgius Agricola (1546b) expanded on Aristotle's ideas about exhalations from deep underground and proposed that bitumen is a condensate of sulphur in his manuscript *De Natura eorum, quae Effluunt ex Terra*. Andreas Libavius proposed that bitumen was formed from resins of ancient trees in his text *Alchemia* from 1597 (Walters, 2006). This may be seen as the first stages of the abiotic and the biogenic theories about the origin of oil.

The Russian universal genius Lomonosov proposed and demonstrated the idea that petroleum and natural bitumen originates from transformation of coal and plant remnants due to subsurface heat and pressure in his book *On the Strata of the Earth* from 1763 (Peters et al., 2005). Already by 18th century, fossil evidence had indicated that coal and peat was related and that both originate from preserved vegetation remains. Today, it is commonly accepted that coal has a biogenic origin and the modern coal geology can be read in Thomas (2002).

However, the origin of petroleum was still an unsettled discussion that continued to occupy scientists' thoughts. More detailed hypotheses and different versions of the biogenic origin of petroleum were created during the 19th century and claimed that oil originated directly from organic remains or was created in a distillation process (Dott, 1969). Hunt (1863), Lesqueraux (1866) and Newberry (1873) studied Palaeozoic rocks in North America and found that they originated from ancient marine sediments.

Meanwhile, the first seeds of the modern abiotic oil formation theory were planted in Europe. A French chemist, Berthelot, described how hydrocarbon compounds could be created from the acid dissolution of steel (Walters, 2006). In Russia, the famous scientist Mendeleev (1877; 1902) proposed that petroleum was created in the depths of the Earth from chemical reactions between water and iron carbides in the hot upper mantle. This theory was largely ignored and its supporters dwindled under the mounting evidence of biogenic petroleum creation at this time.

The beginning of the 20th century marks the development of modern petroleum geology. Early European studies of organic-rich rocks supported the biogenic origin of oil (Pompeckj, 1901; Schubert, 1915). Similar studies by the US Geological Survey (USGS) showed that Californian oil originated from organic-rich shales (Arnold and Anderson, 1907; Clarke, 1916). Engler (1913) showed a connection between thermal properties in the ground and petroleum, when he managed to produce hydrocarbons by heating organic matter. White (1915) introduced the carbon-ratio theory, which implies that petroleum occurrence is limited by the thermal history of a region. Snider (1934) implied that organic matter seemed to be almost universally buried in argillaceous mud and to a lesser extent in calcareous muds and marls, while coarse sands, gravels and very pure calcareous deposits generally lacked organic content.

The birth of more advanced chemical analysis led to many new discoveries and shed new light on the origin of petroleum. Treibs (1934; 1936) established a link between chlorophyll in living organisms and porphyrin pigments, a class of nitrogen compounds that originates from mainly chlorophylls, in petroleum, shale and coal. Oakwood et al. (1952) showed that oils retain fractions that are optically active, just like biological matter, and this was later confirmed by Whitehead (1971). Eglinton and Calvin (1967) showed that oil contains many chemical fossils and biomarkers, besides porphyrins, that could be traced to biological predecessors. Tissot and Welte (1978) expanded the analysis with geochemical fossils, allowing further comparison of structurally similar organic compounds in sediments and oil with their precursors in living organisms. A more comprehensive overview of the development of petroleum chemistry can be found in Hunt et al. (2002).

Introduction of mass spectroscopy allowed new types of analyses. Stable carbon isotope compositions in oil were found to be in line with biogenic origin (Craig, 1953). Silverman and Epstein (1958) applied carbon isotope studies to both petroleum and sedimentary organic materials, further enhancing their biogenic origin. Fuex (1977) summarizes the application of stable isotope analysis in petroleum exploration.

Geological field studies provided important knowledge and valuable information relevant to petroleum genesis. Hydrocarbons were found to be abundant in ancient marine shales and limestones, whilst they were uniformly absent in recent muds from a variety of environment (Erdman et al., 1958). Forsman and Hunt (1958) studied rock samples from a wide variety of ages, lithologies, environments and depositions, arriving at the conclusion that the absolute concentration of hydrocarbons was greater in ancient rocks than in younger sediments. The findings showed the important role of kerogen in petroleum generation (Abelson, 1963; Durand, 1980). Philippi (1965) discovered that hydrocarbon yield from source rocks increases with time and temperature. From these studies came the understanding of the geologic zone of intense oil generation, now more known as the *oil window* (Hunt et al, 2002).

Winters and Williams (1969) and Jobson et al. (1972) showed how microorganisms could alter petroleum and cause biodegradation, resulting in heavy oil. Demaison (1977) points of the importance of this process and relates it to the discovered quantities of heavy oil prior to 1980.

Starting in 1950s, Kudryavtsev (1951) and other subsequent Soviet publications proposed a modernised version of Mendeleev's theory, relying on thermodynamic equilibrium for chemical reactions which only allows spontaneous formation of methane at high temperature and pressure, comparable to those of the upper mantle region. This theory has been criticized for ignoring the fact that all life is in thermodynamic disequilibrium with its environment (Walters, 2006).

Astronomers have been frequent proposers of abiotic petroleum theory in recent times. Carbonaceous chondrites and other planetary bodies, including asteroids, comets, and moons, have been shown to contain hydrocarbons and other organic compounds while no biological life is present (Cronin et al. 1988). Hoyle (1955) theorized that since the Earth was formed from similar materials, there should be vast amounts of abiotic oil residing somewhere. The most well-known promotion of recent abiotic theory is the works of Thomas Gold (1985; 1999).

In 1980s, Gold managed to convince the Swedish government to test the abiotic theory, by drilling ultra deep boreholes near in the granite formations of an old impact crater, the Siljan Ring, in northern Sweden. The drillings became a huge disappointment and failed to locate any recoverable amounts of abiotic hydrocarbons. Evidence of even trace amounts of abiotic hydrocarbons has been deemed controversial (Kerr, 1990). In fact, no commercial quantities of abiotic oil have been found to date (Walters, 2006). Nor has any oil ever been reported along major faults in continental shield areas where sedimentary rocks are not present (Peters et al., 2005). Golds works have also been strongly criticized by Laherrere (2004) and Glasby (2006).

In reality, *the truth of the borehole* speaks louder than any theory, since it provides actual production flows. Needless to say, the drilling done in line with the biogenic theory of oil formation has resulted in a vast amount of oil that has been of benefit to mankind since the beginning of the oil era. The Siljan Ring drillings, the most serious attempt to test the abiotic oil formation theory, failed to locate any abiotic oil, as the oily black paste that was found was shown to be derived from the mud, lubricants and organic additatives of the drilling process (Jeffrey and Kaplan, 1989; Castano, 1993).

To summarize, modern petroleum geology does not deny the existence of commercial amounts of abiotic oil. Studies have even managed to discover or produce some abiotic oil in numerous cases (for example Sherwood et al., 1993; McCollom and Seewald, 2001; Potter et al., 2001; McCollom, 2003). However, globally significant amounts of abiotic oil in the crust can be ruled out (Sherwood et al., 2002). The abiotic theory of oil creation can be summarized as a question: *if abiotic petroleum exists in large amounts, where is it?*

Petroleum geology and exploration is an empirical and pragmatic field, which has largely evolved by trial and error. Geologists and oil companies have learned where to drill and where not to drill, and thus, developed a theoretical model that works and corresponds with reality. That model is consistent with the biogenic theory of oil creation, which can be read in more detail in AAPG (1994), Hunt (1995) or Selley (1998). A less comprehensive introduction to the creation of oil, suitable for a non-geologist, can be found in Robelius (2007).

3.2 Oil field formation

Oil and gas fields are the basic units in any oil and gas production unit. In order to find an oil or gas field, a complete petroleum system with all its necessary elements, must first have been formed. The essential elements are source rock, reservoir rock, seal rock, and overburden rock, and the required processes include trap formation and the generation-migration-accumulation of petroleum. All essential elements must be properly placed in time and space such that the processes required for forming a petroleum accumulation can occur. If any of the conditions are unfulfilled, there will not be any petroleum field (AAPG, 1994). A brief introduction to some of the necessary elements will follow.

A suitable source rock, containing organic material, must be present somewhere relatively close to the reservoir. Without a source rock, no petroleum can be formed. The source rock must be buried to a suitable depth and once sufficient thermal energy has been passed on to the organic matter to break chemical bonds, the petroleum produced will be expelled and starts its mitigation towards the surface (Walters, 2006). If a source rock is not buried deep enough, the heat will not be enough to cause a chemical transformation of organic matter into petroleum. Oil shale, consisting of sedimentary rocks with significant organic content that yields substantial amounts of petroleum and gas upon destructive distillation (Dyni, 2005), can be seen as an ideal source rock, which never entered the oil window where it could produce petroleum.

A field consists of one or several subsurface reservoirs, where hydrocarbons are located. Hydrocarbon reservoirs are not subterranean ponds or pools of oil, just waiting to be extracted as people often believe. In reality, hydrocarbons reside in the microscopic pore space of rocks, which are tiny void areas within the internal structure of the rocks. The situation is somewhat similar to a sponge soaked with water. If no suitable reservoir rock is present, there is no place that hydrocarbons can gather and form a commercially extractable accumulation. The basic properties of reservoirs are described in next section.

A tight and impermeable layer, commonly called *seal* or *cap rock*, must be present in order to trap hydrocarbons and prevent further mitigation (Selley, 1998). Otherwise, upward movement will continue, due to buoyancy, until the hydrocarbons reach the surface, where they will be broken down and destroyed by microorganisms. Entrapment is an absolute necessity for any commercially exploitable oil or gas accumulation (Robelius, 2007). If the seal is imperfect, small amounts can mitigate to the surface and form oil seepages (Tiratsoo, 1984). In the early days of petroleum exploration, oil seepages were an important tool for locating reservoirs. In fact, several important oil fields, such as the Mexican giant Cantarell, were found as a result of oil seepages.

There are many types of seals capable of generating a wide array of petroleum traps. A trap can be described "*as any geometric arrangement of rock, regardless of origin, that permits significant accumulations of oil or gas, or both, in the subsurface*" according to Bidde and Wielchowsky (1994). Low permeability materials and rocks make ideal seals, due to high capillary entry pressure. Mudrocks are the most common seals, while salt and other evaporates are the most effective ones (Selley, 1998). Structural traps, caused by tectonic processes after the deposition of the rock beds, are the most common seal among the world's largest oil fields (AAPG, 1970). Stratigraphic traps, caused by changes in rock lithology, and combination traps, consisting of both structural and stratigraphic traps, are the other two main types of petroleum traps.

3.3 Reservoir fundamentals

The term *porosity* refers to the percentage of pore volume compared to the total bulk volume of a rock. A high porosity means that the rock can contain more oil per volume unit. A simplified picture of this can be seen in figure 3.1. Greater burial depth generally leads to a compaction of the sediments, which results in a decreased porosity (Selley, 1998).

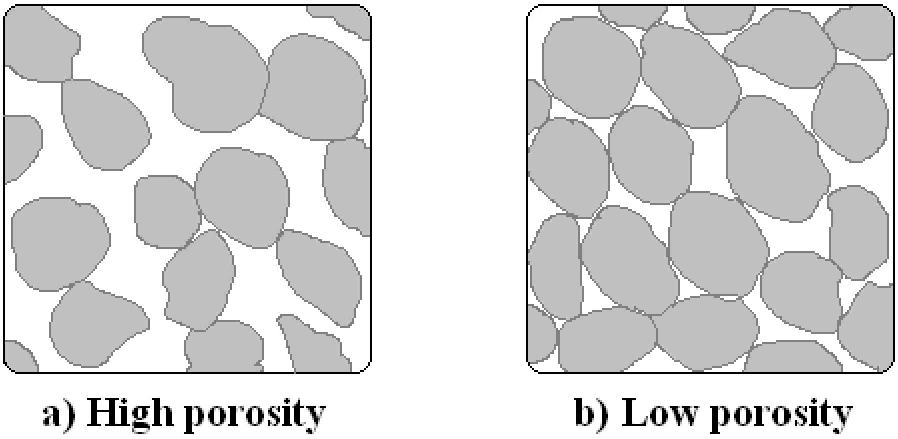

Figure 3.1: Simplified examples of materials with high and low porosity. Rocks with high porosity, such as sandstones, make ideal reservoirs as the pores both can store a large amount of oil as well as allow fluid flows. Compact granite and other low porosity rocks are unsuitable reservoirs.

Any type of rock can be a reservoir as long as the pore space is large enough to store fluids and connected well enough to effectively allow flows. However, sedimentary rocks such as sandstones and carbonates are the most frequently occurring reservoir types and sedimentary reservoirs dominates the worlds known oil fields (Tiratsoo, 1984). Porosities of more than 15% are deemed good or even excellent for oil reservoirs (Hyne, 2001).

Oil, gas and water saturation levels are important factors and refer to the percentage of the pore volume that is occupied by oil or gas. An oil saturation level of 20% means that 20% of the pore volume is occupied by oil, while the rest is gas or water. Closer discussion on this can be found in Dake (2004). If oil is supposed to be able to flow, the oil saturation must be over a certain value, often referred to as the *critical oil saturation* (Robelius, 2007).

A main driving force of secondary mitigation from the source rock to the reservoir is the buoyancy force. Most sedimentary rocks have their pores filled with water to some extent in normal circumstances (Selley, 1998). Oil is less dense than water and the difference in density will cause a buoyancy force, driving the oil upwards in the water. The principle goes back to Ancient Greek and Archimedes' classical treatise *On Floating Bodies*. The situation is also similar to that of a hot air balloon. As long as the oil droplet is smaller than the narrowest part of the rock pore, commonly called the pore throat, it will continue to move upwards (Selley, 1998).

Throughout development of the reservoir, the pore content might be change due to production or other parameters affecting the reservoir. Usually water is replacing the extracted oil as shown in figure 3.2. It should also be noted that rock properties seldom are known in all locations of the reservoir. Porosity and other properties are estimated between wells by geostatistical modelling and naturally result in some uncertainties.

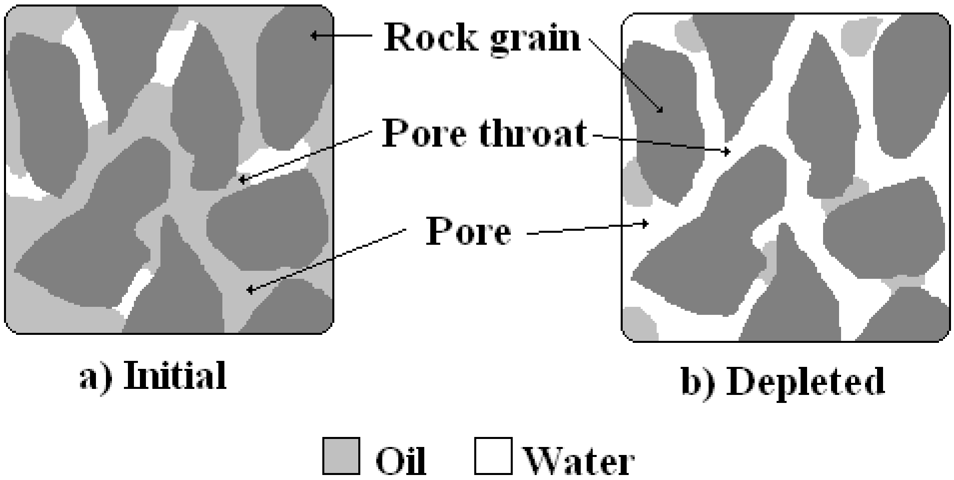

Figure 3.2: Microscopic picture of a typical reservoir rock. The fluid distribution is showne in a) the initial stage, i.e. after discovery and b) after depletion due to oil production. Oil is being replaced by water in the pore space during th reservoir life cycle. Adapted from Satter et al. (2008)

Pores have two purposes in a reservoir. The first role is as a storage space for oil and other hydrocarbons, the second role is as a transmission network for fluid flows. Consequently, it is necessary that the pores are connected in order to allow movement of the hydrocarbons within the reservoir. This was first investigated by French engineer Henry Darcy in 1850s, who studies fluid flows through a bed of packed sand. He derived a phenomenological expression to describe the behaviour and this is today known as Darcy's law (Equation 3.3.1). Darcy's law is analogous to Fourier's heat conduction law or Fick's law of diffusion. Alternatively, Darcy's law can be derived from the Navier-Stokes equations (Neuman, 1977). The ability of a rock to permit fluid movement is called permeability, usually denoted k.

$$q = \frac{kA}{\mu}\frac{\partial P}{\partial L} \qquad (3.3.1)$$

where
q = volumetric flow rate,
k = permeability,
A = cross-sectional area,
μ = fluid viscosity, and
∂P/∂L = pressure drop over the length of the flow path.

Permeability can differ in different directions, and generally horizontal permeability is greater than vertical (Selley, 1998). Pumice stone, well-known for floating on water, can have porosities of up to 90% but lacks any permeability at all due to highly isolated pores (Dandekar, 2006). Consequently, it makes pumice a bad reservoir rock. The reverse can also be true, as low-porosity rocks such as microfractured carbonate can allow unimpeded flows in the fractures. Good reservoirs are dependent on both porosity and permeability. In general, reservoir rocks do not demonstrate any solid theoretical relationship between these properties, making practical relationships and empirical surveys important.

Fractures, cracks and rifts can transmit fluids well, thus partially bypassing permeability problems caused by the pore structure, and this have been known to have a major influence on reservoir flows in certain reservoirs. This is also a property that can be affected with suitable technology. For example, fracturing techniques are used to enhance production in many Danish chalk reservoirs with low permeability. A more complete overview of reservoir rocks and their fluid properties can be found in Dandekar (2006).

3.4 Reserves in oil fields

All oil and gas fields represent a limited geological structure, and consequently, they have an upper limit of how much hydrocarbons they contain. The size of the trap and reservoir, which can be defined by geological and geophysical methods, gives an estimate of the potential volume of oil in the field, before the drilling has begun. As borehole data and production data becomes available, the reserve estimate will tend towards increasing accuracy (Dake, 2004).

The total volume of oil in a field is commonly referred to as either *oil initially in place* (OIIP) or *oil originally in place* (OOIP) or sometimes just *oil in place* (OIP). This is equivalent to the total amount of oil residing in the pores of one or more reservoirs making up a field (Robelius, 2007). It is relatively straightforward to calculate OIIP if the areal extent and thickness of the reservoir is known together with the average porosity and saturation levels (Robelius, 2007). In practice, OIIP estimates gets more complicated since both porosity and saturation varies throughout the reservoir.

Conventional oil fields only capture a tiny amount of all the oil that is generated from the source-rocks in a petroleum system and it should be remembered that there are other types of oil-bearing formations as well. For instance, the Elm Coulee field and the Bakken formation in Northern USA can be described as a "continuous-type" reservoir, which means that the hydrocarbons have not accumulated in a discrete reservoir with limited areal extent (EIA, 2006). Oil in place for unconventional formations can vary enormously depending on conditions or assumptions made in the estimation process.

Far from all the oil in place can be recovered from a given reservoir. The recoverable amount of the oil in place is classified as the *reserve* (Equation 3.4.1). The *recovery factor* (RF) is a dynamic value, representing the estimated percentage of the total oil in place volume that can be recovered. RF depends on numerous parameters, such as rock and fluid properties, reservoir drive mechanism and production technology, variations in the formation and the development process (Robelius, 2007). In some modern reservoir simulators it is not necessary to use OIIP or RF at all in order to estimate reserves.

$$Reserve = \ Recovery\ Factor * Oil\ in\ Place \tag{3.4.1}$$

The recoverable percentage of the OIIP can vary from less than 10% to more than 80% depending on individual reservoir properties and recovery methods, but the global average is as low as around 20% (Miller, 1995). Meling (2005) estimates the global average recovery factor to 29%, which is expected to be improved to 38% with new technologies. Laherrere (2003) writes that improved recovery factors due to technical progress cannot be justified with available data from individual oil fields or global data sets. However, technology can bring significant increases in recoverable volumes in more unconventional oil formations.

Initially, oil is recovered through the energy that is occurring naturally in the reservoir (buoyancy energy, pressure energy, etc.), for instance via gas drive or water drive mechanisms. This can be called the primary recovery method and usually 10-30% of the oil in place can be recovered this way (Kjärstad and Johnsson, 2009). Differences from field to field can occur, since individual reservoir properties can greatly influence recovery success.

Secondary recovery methods utilize injection of water and/or gas to maintain pressure, thus feeding additional energy to the reservoir. About 30-50% of the oil in place can be recovered by use of primary and secondary recovery methods (IHS, 2007, Kjärstad and Johnsson, 2009). Today, almost 100% of all oil fields suitable for secondary recovery methods are using it (IHS, 2007). In other words, the easiest measures to increase recovery have already been done.

Tertiary recovery methods, or enhanced oil recovery (EOR), include more complex methods, such as injection of polymer solutions, surfactants, microbes, nitrogen or carbon dioxide, capable of influencing rock and fluid properties. Only a small fraction of the world's oil fields are using EOR (IHS, 2007), which may be due to high costs and requirements of advanced technology.

In the end, recovered volume cannot be larger than the oil in place. Also, recovery will be limited by the natural laws governing reservoir flows. For example, flows will naturally cease when reservoir pressure nears a pressure balance with the surface. Saturation levels, porosity and other parameters will also eventually resist further manipulation. This is strikingly paraphrased in a line from Star Trek chief engineer Scotty (2266):

"I can't change the laws of physics!"

3.5 Ultimate recovery and reserve classifications

To avoid issues with reserve growth and dynamic reserve figures in calculations, it is often convenient to use some form of estimated *ultimate recovery* of hydrocarbons from the field. The increase of recoverable volumes that reserve growth it brings can still occur in practice, and should be properly handled. Typically, real reserve growth can be covered by increasing the URR estimate as new data becomes available. In summary, it is easier to do calculations with static reserve values, instead of dynamic ones.

This is often called *ultimate recoverable resources* (URR), *estimated ultimate recovery* (EUR), or *ultimate reserves*. This figure represents to total recovery from a field, which is past production plus reserves, where reserves is defined arbitrary depending on confidence interval (UK BERR, 2008).

As always, there are many reserve classification systems in use in the world. Some countries use their own systems, such as the Russian petroleum classification "*A+B+C*" scheme. One classification systems can often be roughly translated to another, making it less complicated to obtain internationally comparable estimates. The industry has developed a system based on proved, probable and possible reserves and this system is often the most convenient to use since it is internationally established.

1P is the short form for proved reserves and may be defined as *reserves which on the available evidence are virtually certain to be technically and commercially producible, i.e. have a better than 90% chance of being produced* (UK BERR, 2008). As an alternative but not fully equivalent notation, one can sometimes see P90 which would refer to a reserve with 90% probability of being recovered. Similar notation may also be used to form reserves with an arbitrary probability of existing. However, other countries or organizations may use different probabilities or the vague, arbitrary phrase "reasonable certainty" for defining 1P reserves.

Probable reserves are *reserves which are not yet proven, but which are estimated to have a better than 50% chance of being technically and commercially producible* (UK BERR, 2008). Proved plus probable reserves are usually called *2P*, but sometimes *P+P*. In order to minimize the dynamic aspects of URR, Robelius (2007) used 2P reserve figures. The importance of using 2P reserves has also been stated by Bentley et al. (2007).

Possible reserves are *reserves which at present cannot be regarded as probable, but which are estimated to have a significant but less than 50% chance of being technically and commercially producible* (UK BERR, 2008). Combining proved reserves, probable reserves and possible reserves yields *3P*.

Bentley et al. (2007) have responded to Watkins (2006), showing that his conclusions were flawed since he only used 1P reserves. Watkins (2006) came to the conclusion that oil was more plentiful now than 30 years ago, but if he had been using 2P data instead, a very different picture with an imminent resource-limited production peak would have emerged. Bentley et al. (2007) is highly recommended as a more comprehensive study of reserve definitions and their influence on forecasts.

Reserve classification systems are generally a labyrinth of delicate definitions and probability measures. Failure to understand the complexity, misinterpretations or political motives may easily lead to a false picture of what can actually be recovered. Campbell (2008) takes USGS assessment of petroleum reserves in the un-drilled East Greenland as an example of how a probabilistic approach may be used in a questionable way. According to Campbell (2008), USGS states that there is a 95% probability of finding more than zero, namely at least one barrel, and a 5% probability of finding more than 112 billion barrels, which together delivers a mean value (as the mean of the P95 and P5 reserves) of 47 billion barrels, which is later reported as the reserves in official assessments.

Former Total petroleum geologist Jean Laherrere often says that publishing reserve figures is a largely political act (for example: Laherrere, 2005; Laherrere, 2006). Campbell (2008) also agrees with this picture, attributing economic incentives and the need to deliver satisfactory financial records as a driving force for obscuring technical data and geological estimates.

3.6 Production fundamentals

Once a reservoir has been located, the actual *extraction* of its hydrocarbon content can begin. The extraction process is often referred to as *production*, although one may think that extraction is a more suitable word since the hydrocarbons are removed from the reservoir. A good introductory description of production methods and various technical components can be found in Robelius (2007).

3.7 Reservoir flow relations

Within the reservoir, the flow of fluids is the governing factor for the extraction process. In order to be produced, the hydrocarbon fluids must reach the production wells and consequently, the rock properties affecting fluid mobility will have a major influence on the amount that can be extracted and also on how fast it can be extracted.

Viscosity, gravity drainage and capillary effects are the main forces governing the flow (Satter et al., 2008). Viscous forces dominate the behaviour of fluids, both produced and injected, in a reservoir. Under viscous conditions, flow rates are laminar and proportional to the pressure gradient that exists in the reservoir (Satter et al., 2008). However, there are examples of tilted reservoirs and dipping formations, where gravity drainage is the prime driving force.

Capillary forces are a result of surface tension between the fluid phase and the pore walls, something that can form sealing conditions if the capillary entry pressure is high. Gravity and capillary forces act in the opposite directions and can be used to determine the initial distribution and saturation of oil, gas and water in any hydrocarbon-bearing porous structure (Satter et al., 2008). The movement of fluids in a reservoir depends on the following factors:

- Depletion (leading to a decrease in reservoir pressure)
- Compressibility of the rock/fluid system
- Dissolution of the gas phase into the liquid
- Formation slope
- Capillary rise through microscopic pores
- Additional energy provided from aquifer or gas cap
- External fluid injection
- Thermal, miscible or similar of manipulation of fluid properties

In most reservoirs, more than one factor is responsible for the flow of fluids and closer discussion on this can be found in Satter et al. (2008). Some parameters can be affected by man-made measures, while others cannot. The slope of the hydrocarbon-bearing formation is an example of a flow parameter that is fixed, while external fluid injection is dynamic and dependent on installed technology and production strategy.

Compressibility determines how much the reservoir can be compacted, which is similar to squeezing a sponge in order to get more fluid out. It is a function of a number of parameters, including the type of minerals that make up the rock mass, the degree of sorting, the degree of mineral decomposition or alteration, cementation and especially porosity (Nagel, 2001). Highly compactable reservoirs usually have reservoir porosity greater than 30% (Nagel, 2001).

Compaction has been known to cause a significant increase in the available drive energy for hydrocarbon recovery. In the Norwegian giant field Valhall, compaction has been claimed to make up 50% of the total drive energy (Cook et al., 1997). The Norwegian Ekofisk field is estimated to recover an additional 243 to 280 million barrels as a result of increased reservoir compaction (Sulak et al. 1991; Sylte et al. 1999). In the Bolivar Coastal oil fields in Venezuela, compaction drive has been estimated to constitute as much as 70% of the total drive energy (Escojido, 1981) and if steam flooding is used, compaction drive contribution can reach 80% of the total energy for the same region (Finol and Sancevic, 1995).

Compaction can also lead to *subsidence*, which is the sinking of the ground level above the reservoir. Wilimington and Ekofisk oil fields are both well known examples both due to the magnitude of the subsidence as well as the cost of remediation (Nagel, 2001). Lake Maracaibo and the nearby Bolivar Coastal Region are other examples of how reservoir depletion has caused severe subsidence and flooding and similar effects are true for the giant Groningen gas field, where a subsidence of only a few decimetres poses a significant threat since large portions of the Netherlands are below sea level and protected by dikes (Nagel, 2001).

Water-injection can solve subsidence problems and has also been shown to be a cost effective way to control compaction (Piece, 1970). However, injecting water might take the edge off subsidence issues but this also leads to the loss of compaction drive, a significant energy for driving hydrocarbon flows in the reservoir. All together this shows how various flow factors can balance each other. An increase in one of the driving forces can lead to a decrease in another and vice versa. All together, reservoir flows are a complex problem, with many interdependent variables.

4. Oil production modelling

The production of an oil field tends to pass through a number of stages. This can be described by an idealized production curve. A version of this curve can be seen in Figure 4.1. After the discovery well, an appraisal well is drilled to determine the development potential of the reservoir. Further development follows and the first oil production marks the beginning of the build-up phase. Later the field enters a plateau phase, where the full installed extraction capacity is used, before finally arriving at the onset of decline, which ends in abandonment once the economical limit is reached.

For many fields, especially smaller ones, the plateau phase can be very short and resemble more to a sharp peak, while large fields can stay several decades at the plateau production level. The life time of a field and the shape of the production curve are often related to the kind of hydrocarbon that is produced.

For instance: condensate flows very easily and can be extracted almost all at once, which results in high decline rates (I). NGL is a by product of natural gas, hence following the gas production curve intimately (I). Comprehensive studies of the life times and time scale of various stages have been performed in paper II.

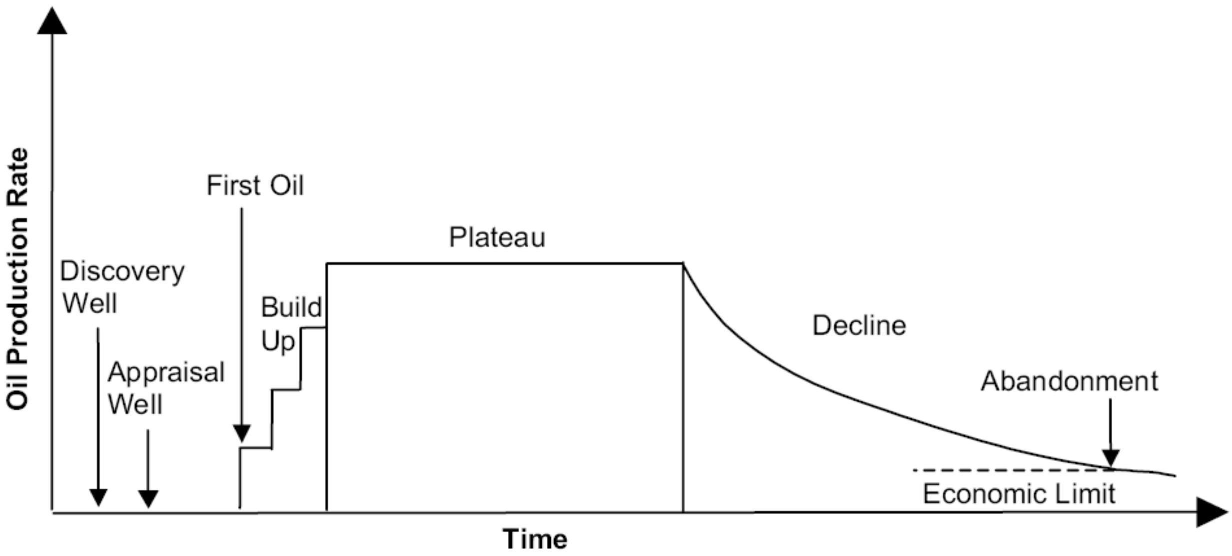

Figure 4.1. A theoretical production curve, describing the various stages of maturity. Source: Robelius (2007).

Fluid flows in porous media can be simulated to high levels of complexity or simplicity, largely depending on details in the flow model. These types of flow processes generally lead to complicated behaviour and mathematical models must include statistical analysis, fractal and/or stochastic procedures (Ramiréz, 2008).

Many reservoir simulation models are dependent on various numerical models. One example is the ECLIPSE oil and gas simulator from Schlumberger Information Solutions (2009), which uses an implicit three dimensional finite difference approach to solve material and energy balance equations in multiphase fluid system with up to four components in a subsurface reservoir with complex geometry. Traditionally finite difference methods dominate, but finite elements and streamlined numerical models are also used. Recently even more advanced computational techniques, such as neural networks and fuzzy logic (Zellou and Ouenes, 2007) or algebraic multigrids (Stüben et al., 2007), have been utilized to model reservoir flows.

Combining the reservoir flow models with drilling and development plans along with economic investment models for the field can result in accurate descriptions of actual production and how it changes over time. However, precise prediction of fluid flows usually requires detailed data and knowledge of many important reservoir properties and parameters, such as permeability, pressure and similar. Drilling plans and details around installations and development schemes are also seldom openly available. In practical cases, much of the necessary data for accurate modelling is rarely available for outsiders, since oil companies and producers do not release it. Consequently, simplified models have been developed by various researchers and engineers to mitigate this shortcoming.

Some examples of simplified models for production forecasting are depletion rate analysis and the utilization of decline curves, which are applicable to individual fields. Decline rate and depletion rate analysis is the main focus for this work. Decline curve analysis has a long history and has been used for more than 50 years within the oil and gas industry. In a similar fashion, depletion is strongly linked to the fundamental reservoir flow relations and analysis of the depletion rate is therefore a sound approach.

Peak oil discussions are often connected to the Hubbert curve, which aims to depict the collective behaviour of a large number of fields. A significant number of models and methods for creating future outlooks on a global or regional scale are available (Bentley and Boyle, 2007), but they cannot be used for single fields. Due to this constraint, further discussion of these modelling approaches will not be pursued.

4.1 Decline rate analysis

The decline rate refers to the decrease in petroleum extraction over time. In many cases the decline rate is calculated on annual basis, yielding the change in produced volume from one year to another. See equation 4.1.1 for a general definition. It should be noted that the decline rate can be positive in some cases, representing an increasing production.

$$\textit{Decline rate}_n = \frac{\textit{Production}_n - \textit{Production}_{n-1}}{\textit{Production}_{n-1}} \tag{4.1.1}$$

Decline might be caused by politics, malfunctions, sabotage, depletion and other factors. The driving force behind decline can be political or socioeconomic, representing man-made restrictions on the utilization of a reservoir. Decline can also be driven by natural forces, such as depletion of recoverable volumes within a reservoir and the resulting decline in reservoir pressure that diminish the flow rates. In reality, decline is often driven by several factors.

Politics-driven decline usually disappears once the political tensions have been resolved, and this was clearly seen after the oil crises of the 1970s when Middle East resumed their oil export to the western countries. In a similar way, economics-driven decline might be seen in fields where lack of payments, service, modernization and investments has reduced the production flow. Also in this case, decline usually disappears once more investments have been made or the economic situation returned to normal.

Depletion-driven decline occurs when the recoverable resources become exhausted and the production flow is reduces due to the physical limitations of the reservoir. Depletion-driven decline is different from other forms of decline and much harder to compensate for, since it can only be alleviated by expanding the recoverable reserves of the reservoir, which will ultimately be limited by the physical extent of the formation, permeability or other geological parameters.

Depletion is a key factor for the fluid flows within the reservoir and its connection to flow fundamentals makes it an important parameter for understanding oil production. In order to conceptually understand how depletion affects fluid flows, a simplified example can be considered. In gas fields, the ideal gas law and related special cases are often useful and pedagogic tools. One should also remember that behaviour of real gases deviates from ideal gases, notably at high pressures and temperatures. However, this can be handles with gas deviation factors (Satter et al., 2008).

Boyle's Law, first formulated by Robert Boyle (1662), describes the inverse proportionality of the absolute pressure and volume of a gas, if the temperature is kept constant within an isolated system (Equation 4.1.2). This is often applicable in gas reservoirs, since they are reasonable isolated and in thermal equilibrium with the surrounding bedrock, resulting in constant temperature.

$$\textit{Pressure} * \textit{Volume} = \textit{Constant} \tag{4.1.2}$$

The law can also be rewritten into a relationship between pressures and volumes before and after a certain isothermal change

$$p_1 v_1 = p_2 v_2 \tag{4.1.3}$$

where
p_1, p_2 = pressure of gas at state 1 respectively 2, and
v_1, v_2 = specific volume of gas at state 1 respectively 2.

Gas extraction removes mass without changing the volume of gas in the different states, i.e. $v_1 = v_2$. As a result, pressure must fall in order to maintain the balance. From Darcy's law (Equation 3.3.1) it follows that decreasing pressure leads to decreased flow rates, if all other things are equal. Consequently, extraction of gas from a reservoir will result in declining production with time, in other words a depletion-driven decline.

The situation becomes more complicated with oil extraction or other forms of production strategies, but the general situation is the same as in the simplified gas reservoir case. In fields where production strategy is to maintain reservoir pressure, for instance by water or gas injection, the extracted volumes of oil and water will remain relatively constant through the life of the field, in agreement with the material balance equation (Satter et al., 2008). However, the oil production will ultimately fall and water production increase as more and more injected water begins to diffuse into the production wells. As the reservoir depletes, the well will eventually produce too much water to be economically viable, despite the fact that reservoir pressure might still be high. The ratio of water compared to the volume of total liquids produced is referred to as *water cut*. In mature fields the water cut can reach very high levels, up to 90% and more has been recorded in parts of China (Pang, 2008). American oil fields in Kern Bluff and Mount Poso areas reports water cut of over 99% (California Department of Conservation, 2007).

To summarize, it is necessary to differentiate politics and economics from physical factors affecting decline rates. This is perhaps best shown with a few real life examples based on simple exponential decline functions (Figures 4.2 and 4.3). Curve fitting can be improved dramatically when data points disturbed by sudden political or economical events are ignored.

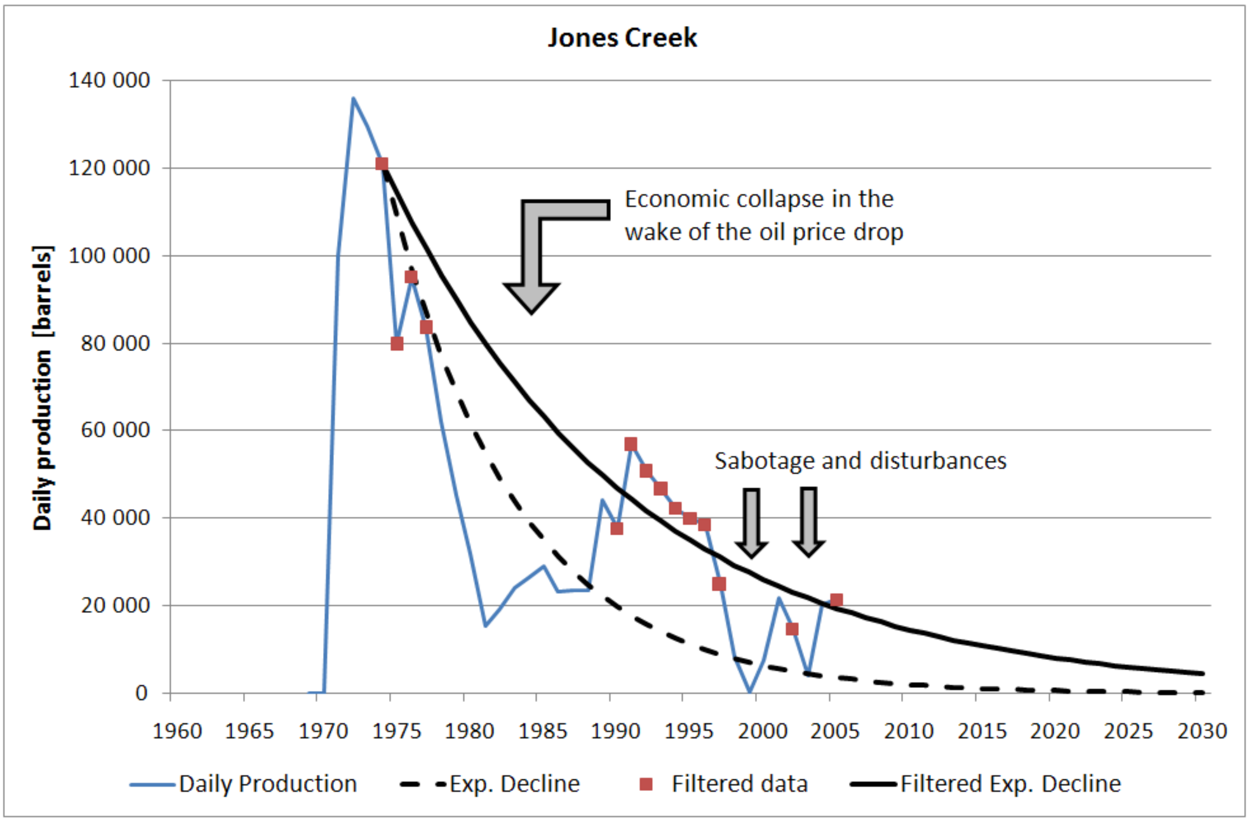

Figure 4.2: Jones Creek, a giant oil field in Africa, shows several production disturbances caused by the economic collapse of the Nigerian economy in the wake of the oil price drop in the 1980s along with sabotage and rebel attacks. In order to obtain a reasonable fit for a decline curve one must filter out some unnatural drops in production due to socioeconomic factors.

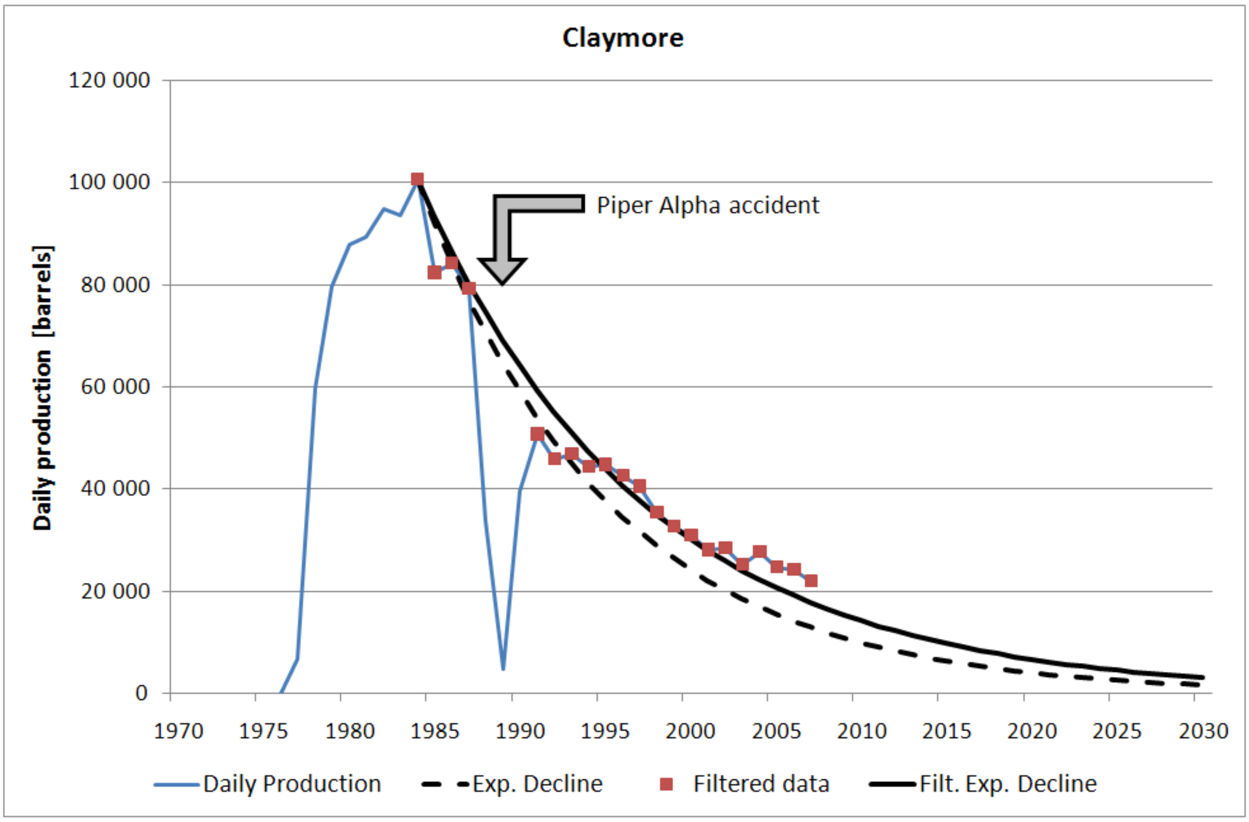

Figure 4.3: Claymore, a UK offshore giant, shows a sudden drop in the production as a result of the Piper Alpha accident. The repercussions of the incident held back much production until new safety regulations were in place. The dashed line show a decline curve fit if the Piper Alpha disturbance was included and gives a hint of how a sudden dramatic event can affect the reliability of the fit.

4.1.1 Decline curves

Arps (1945) created the foundation of decline curve analysis by proposing simple mathematical curves, i.e. exponential, harmonic or hyperbolic, as a tool for creating a reasonable outlook for the production of an oil well once it has reached the onset of decline. His original approach has later been developed further and is still used as a benchmark for industry for analysis and interpretation of production data due to its simplicity (II, III).

It should also be noted that there is a strong connection between the physical models for reservoir flows and empirical simplifications based on decline curves. The exponential curve, introduced by Arps (1945), is actually the analytical long-term solution to flow equation of a well with constant bottomhole flowing pressure (Hurst, 1934; van Everdingen and Hurst, 1949). The biggest advantage of decline curve analysis is that it is virtually independent of the size and shape of the reservoir or the actual drive-mechanism (Doublet, 1994), thus avoiding the need for detailed reservoir or production data. The only data requirement for decline curve analysis and extrapolation is production data, which is relatively easy to obtain for a large number of fields.

Decline curves of various forms can be used to create reasonable outlooks for fluid production of a single well or an entire field. However, it should be emphasized that in many field cases a single curve is not sufficient to obtain a good fit and it may be necessary to use a combination of curves to obtain good agreement (Haavardsson & Huseby, 2007). The importance of individual fields diminishes as the total number of studied fields becomes large and generalized field behaviour can be identified (II, III). In such cases, a simple decline curve can successfully be used to forecast total production from a large set of fields, as under- and overestimations for individual fields cancel out each other in the long run. Consequently, decline rate analysis and decline curves can be a convenient tool for identifying long-term trends and projecting reasonable production behaviour into the future.

The Arps decline curves are simplistic and focused on obtaining expressions with mathematical tractability that could be utilized in a simple and straightforward manner. In the models, it is assumed that the declining production starts a given time t_0, with initial production rate of r_0 and the initial cumulative production Q_0. The production rate at time $t \geq t_0$ is denoted by $q(t)$ and the corresponding cumulative production at the same time is defined by the integral $Q(t) = \int_{t_0}^{t} q(u)du$.

The simplest decline curves are characterized by three parameters, the initial production rate $r_0 > 0$, the decline rate $\lambda > 0$ and the shape parameter$\beta \in [0,1]$. If the production is allowed to continue without end and the integral $Q(t) = \int_{t_0}^{t} q(u)du$ converges as $t \to \infty$ it is possible to calculate the ultimate cumulative production of the decline phase, which can be summed with Q_0 to give the fields URR. Normally production is stopped when the economic/energetic limit is reached, i.e. when keeping the equipment running requires more money and/or energy than it yields. This cut-off point can be denoted $r_c < r_0$ and is found by solving $q(t) = r_c$ with respect to t, where the solution occurs at t_{cut}. By inserting t_{cut} as the upper limit for $Q(t)$, one can now calculate the technically recoverable volume, denoted by V_{rec}.

The key properties of the Arps exponential and harmonic decline curves can be seen in Table 4.1. The generalized hyperbolic case is described in Table 4.2. Note that the exponential and harmonic curves only are special cases of general hyperbolic decline. Modification of the shape parameter β can alter the shape of the production rate function and be used to determine what kind of decline curve that is suitable for fitting against empirical data. The value of the decline parameter λ governs how steep the decrease in production will be.

The exponential decline curve is by far most convenient to work with and still agrees well with actual data. Hyperbolic and harmonic decline curves involve more complicated functions and are, consequently, less practical to utilize. The disadvantage of the exponential decline curve is that it sometimes tends to underestimate production far out in the tail part of the production curve, as decline often flattens out towards a more harmonic and hyperbolic behaviour in that region.

An example of the application of decline curves can be made from the UK offshore giant field Thistle (Figure 4.3). The field peaked at a production level of around 123 000 barrels per day in 1982 and has been in decline since, currently the daily output is only a few thousand barrels. No significant disturbances have occurred since production started.

Table 4.1. Key properties of Arps exponential and harmonic decline curves

	Exponential	**Harmonic**
β	$\beta = 0$	$\beta = 1$
$q(t)$	$r_0 \exp\left(-\lambda(t-t_0)\right)$	$r_0\left[\exp\left(-\lambda(t-t_0)\right)\right]^{-1}$
$Q(t)$	$Q_0 + \frac{r_0}{\lambda}\left(1 - \exp\left(-\lambda(t-t_0)\right)\right)$	$Q_0 + \frac{r_0}{\lambda}\ln\left(1+\lambda(t-t_0)\right)$
URR	$Q_0 + \frac{r_0}{\lambda}$	*Not defined*
t_{cut}	$t_0 + \frac{1}{\lambda}\ln\left(\frac{r_0}{r_c}\right)$	$t_0 + \frac{1}{\lambda}\left[\frac{r_0}{r_c} - 1\right]$
V_{rec}	$Q_0 + \frac{r_0 - r_c}{\lambda}$	$Q_0 + \frac{r_0}{\lambda}\ln\left(\frac{r_0}{r_c}\right)$

Table 4.2. Key properties of Arps generalized hyperbolic decline curve

	Hyperbolic
β	$\beta \in [0,1]$
$q(t)$	$r_0[1+\lambda\beta(t-t_0)]^{-1/\beta}$
$Q(t)$	$Q_0 + \frac{r_0}{\lambda(1-\beta)}\left[1 - \left(1+\lambda\beta(t-t_0)^{1-\frac{1}{\beta}}\right)\right]$
URR	$Q_0 + \frac{r_0}{\lambda(1-\beta)}$
t_{cut}	$t_0 + \frac{1}{\lambda\beta}\left[\left(\frac{r_0}{r_c}\right)^{\beta} - 1\right]$
V_{rec}	$Q_0 + \frac{r_0}{\lambda(\beta-1)}\left[\left(\frac{r_0}{r_c}\right)^{\beta-1} - 1\right]$

An exponential decline curve fit to decline phase of the fields gives an average annual decline rate of -15.3% and cumulative production up to 1982 was 0.13 Gb. Using the relations of the Arps exponential decline curve we find that the field's URR becomes 0.46 Gb, which is near the official URR estimate of 0.51 Gb based on unspecified methodology. The cumulative production up to 2008 was 0.41 Gb, indicating that there are still some oil left to produce, but the low production rate will probably lead to abandonment in before all recoverable oil has been extracted.

A constant decline rate also makes it possible to plot annual against cumulative production and identify a linear trend, which can be extrapolated to estimate ultimate production (Figure 4.4). This is often a simple and straight-forward way of using production data for predicting future production. However, it has a drawback in terms of comprehensibility for the viewer. In other words, it is hard to grasp the temporal scale as the graph does not have time on any of the axes.

In a similar way it is possible to use decline curves to check agreement with official reserve estimates based on geological methods in any field where decline curves can be applied. This can also be utilized to create an URR estimate of a field where only production data is known. Decline curve analysis offers many opportunities and possibilities, provided that the field has reached the onset of decline so the methodology can be applied.

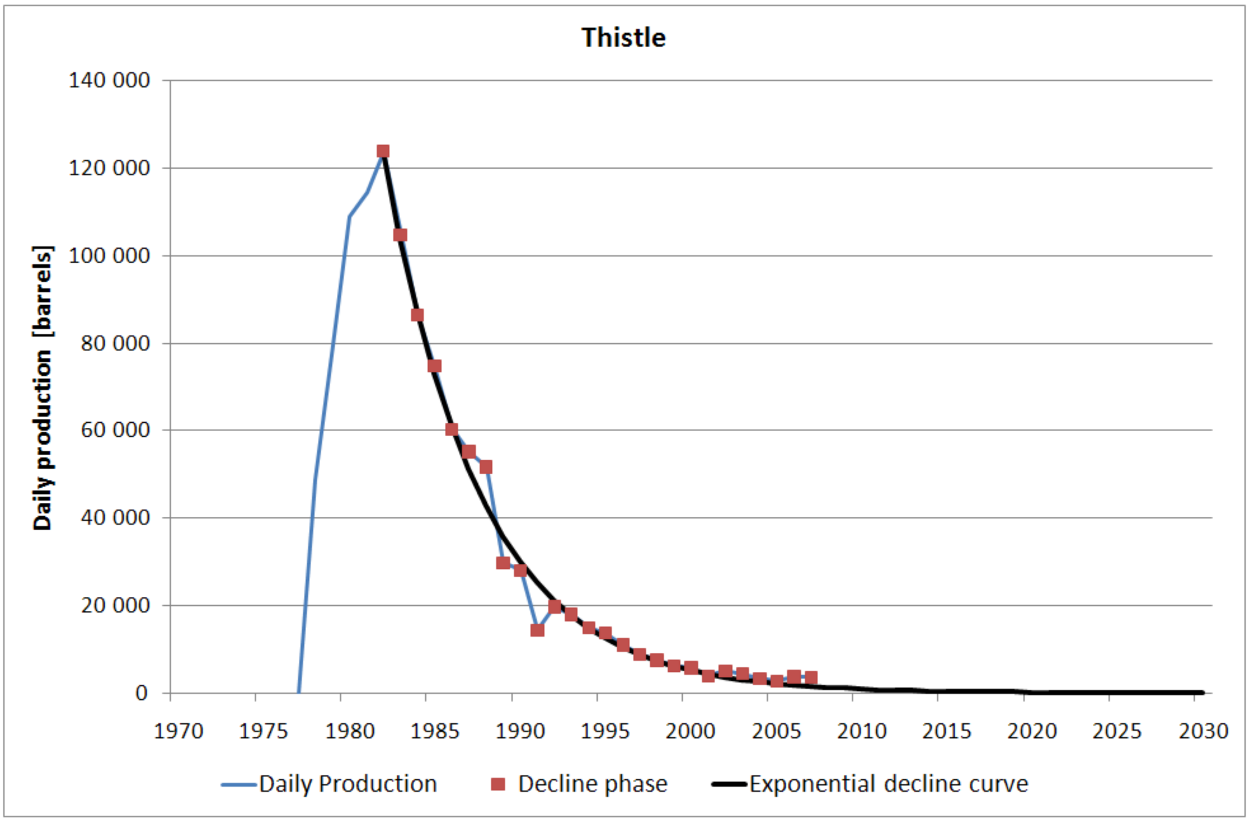

Figure 4.3: The historical production of the UK offshore giant Thistle together with a fitted exponential decline curve. The agreement is good and no data points need to be excluded in order to obtain a reasonable fit.

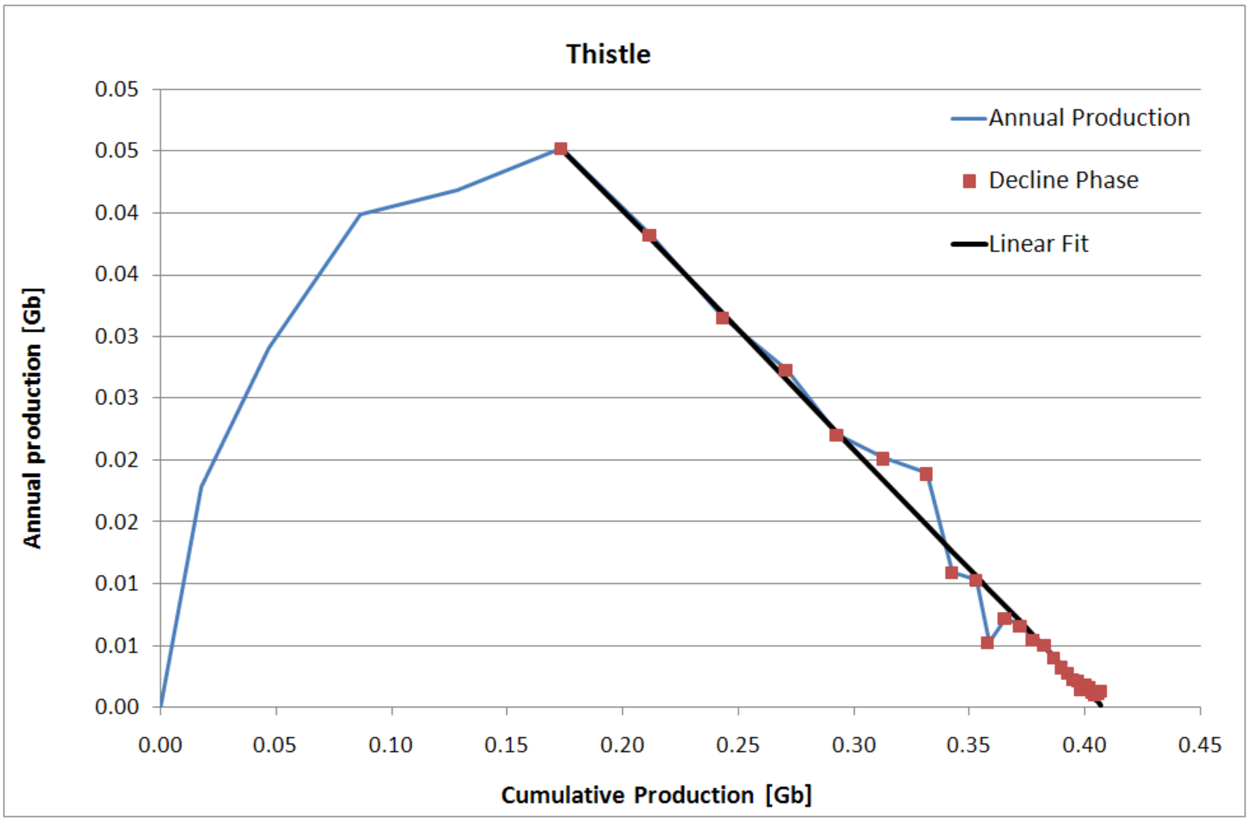

Figure 4.4: The historical production of the UK offshore giant Thistle plotted in a different way. A linear trend can be found in the decline phase and extrapolated to give a hint about future ultimate production.

4.2 Depletion rate analysis

The decline rate is only connected to production flows, while depletion rate bridges the gap between recoverable reserves in the ground and extracted volumes (II). Depletion can be defined in a number of different ways, accordingly, it is necessary to establish a good nomenclature to avoid misunderstanding and confusion.

Just as in decline curve analysis, the production rate at time $t \geq t_0$ is by denoted by $q(t)$ and the corresponding cumulative production at the same time is defined by the integral $Q_t = \int_{t_0}^{t} q(u)du$. Initially present reserves are called $\mathrm{R_0}$ and may be estimated using any form of reserve category, but 2P is frequently used. Usually it is convenient to work with URR or some other relatively static reserve number, since the problems of reserve growth and changes in reserve estimates over time is avoided which greatly simplifies calculations. The remaining reserve at time t may thus be designated $\mathrm{R_r}$ and defined in Equation 4.2.1.

$$\mathrm{R_r} = \mathrm{R_0} - \mathrm{Q_t} \qquad (4.2.1)$$

The most fundamental property when it comes to depletion is the so called depletion level D_t which refers to the produced share of the initially present reserves (Equation 4.2.2). This is frequently used by various organizations, such as IEA (2008) or Saudi-Aramco (2004) to describe depletion in fields. Typical depletion levels for the onset of decline have been studied in paper II.

$$D_t = \frac{Q_t}{R_0} \qquad (4.2.2)$$

From the definition of depletion level a form of depletion rate can be created by differentiating the production with respect to time. This leads to the *depletion rate of initial reserves* and may be denoted as d_t (Equation 4.2.3).

$$d_t = \frac{q_t}{R_0} \qquad (4.2.3)$$

Often it is much more meaningful to work with remaining reserves, as reservoir behaviour can change with extraction of recoverable hydrocarbons. Depletion is a driving factor for reservoir flows and this makes the remaining reserves a more useful parameter than initially present recoverable volumes. This argument leads to the definition of a *depletion rate of remaining reserves*, denoted $d_{\delta t}$ (Equation 4.2.4). This depletion rate measure is more useful than the depletion of initial reserves, thus depletion rate will from now on refer to $d_{\delta t}$ unless otherwise specified.

$$d_{\delta t} = \frac{q_t}{R_r} = \frac{q_t}{R_0 - Q_t} \qquad (4.2.4)$$

The depletion rate can also be seen as the inverse of the reserve-to-production ratio (RPR) as described by equation 4.2.5. An RP-ratio of 10 would, for example, correspond to a depletion rate of remaining reserves at 10%. This simple connection is not generally well-known, but can bridge the gap between the commonly used RPR from resource statistics and the depletion rate modelling of resource extraction.

$$RPR_n = \frac{R_r}{q_t} = \frac{R_0 - Q_t}{q_t} = \frac{1}{d_{\delta t}} \qquad (4.2.5)$$

Prior to the onset of decline, the depletion rate generally increases with increasing extraction. This is easy to understand from the definition, as increased extraction means that the remaining reserve gets smaller and smaller, thus more depleted. The depletion rate behaviour in the decline phase is another chapter and needs to be investigated in a more detailed manner.

For exponential decline phase it follows that the depletion rate equals the decline rate. Using the relations for production, cumulative production and URR for Arps exponential curve (Table 4.1) and inserting them into the definition of the depletion rate (Equation 4.2.5) gives:

$$d_{\delta t} = \frac{r_0 \exp\left(-\lambda(t-t_0)\right)}{\left(Q_0 + \frac{r_0}{\lambda}\right) - \left(Q_0 + \frac{r_0}{\lambda}\left(1 - \exp\left(-\lambda(t-t_0)\right)\right)\right)} \tag{4.2.5}$$

This can now be simplified into:

$$d_{\delta t} = \frac{\lambda * \exp\left(-\lambda(t-t_0)\right)}{\exp\left(-\lambda(t-t_0)\right)} = \lambda \tag{4.2.6}$$

In other words the depletion rate equals the decline rate in an idealized exponential decline curve (Figure 4.5). Consequently, knowing depletion rates also makes it possible to determine likely decline rates, at least for depletion-driven decline resulting from reservoir flow relations. However, it should also be remembered that decline is a property that also is affected by non-physical parameters, such as investments, accidents and politics. Depletion rate analysis can only provide a suggestion of reasonable decline rates for analyzed fields.

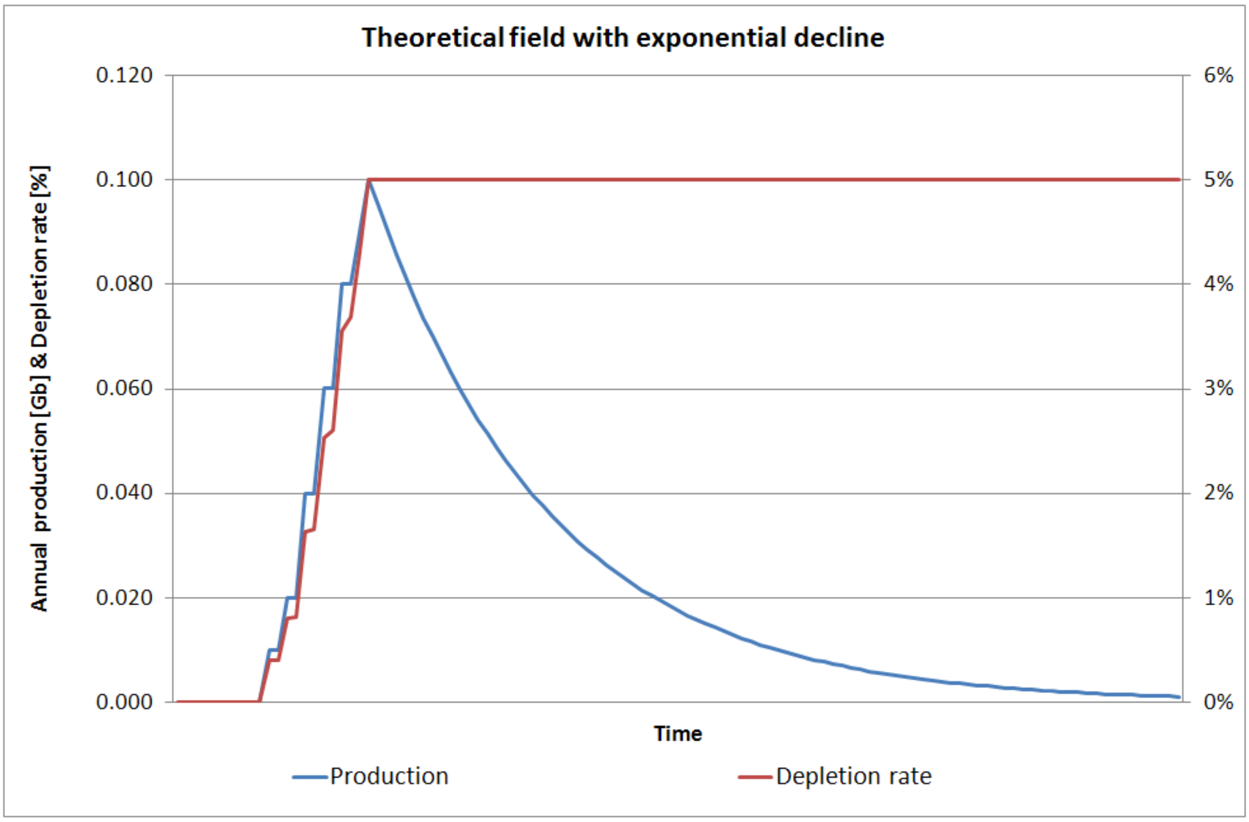

Figure 4.5. Theoretical production profile for a field with a perfect 5% exponential decline. The URR becomes 2.61 Gb using the Arps URR-function, with 0.51 Gb being extracted in the build-up phase. Once the exponential decline begins, the depletion rate of remaining reserves becomes constant.

It should also be mentioned that exponential behaviour is a simplified form of decline and that the general situation tends to be hyperbolic in nature. This makes it interesting to study how depletion rates behave in the hyperbolic decline situation. Combining the definition of the depletion rate (Equation 4.2.4) and the functions for production, URR and cumulative production in the hyperbolic case (Table 4.2) gives:

$$d_{\delta t} = \frac{r_0[1+\lambda\beta(t-t_0)]^{-1/\beta}}{\left(Q_0 + \frac{r_0}{\lambda(1-\beta)}\right) - \left(Q_0 + \frac{r_0[1-(1+\lambda\beta(t-t_0))^{1-1/\beta}]}{\lambda(1-\beta)}\right)} \tag{4.2.7}$$

Simplifying yield a depletion rate which is decreasing with time:

$$d_{\delta t} = \frac{\lambda(1-\beta)}{1+\lambda\beta(t-t_0)} \tag{4.2.8}$$

The hyperbolic depletion rate also approaches zero as time increases, since the depletion rate function is strictly decreasing as $t \rightarrow \infty$. This is a very interesting property as it implies that a *maximum depletion rate* must be reached before the field reaches the onset of decline in the general case. Typically the maximum depletion rate occurs just before the onset of decline, provided that the URR estimate is accurate. This is illustrated in Figure 4.6.

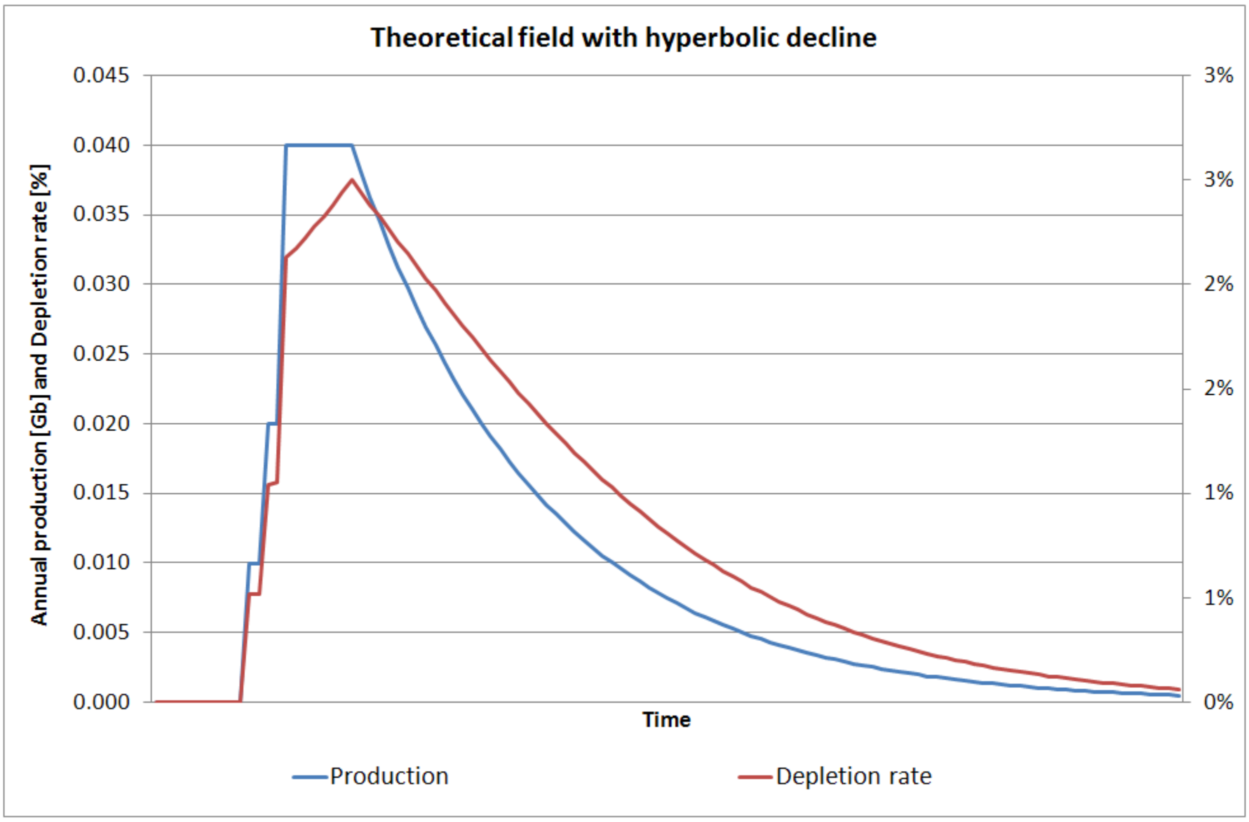

Figure 4.6. Theoretical field with hyperbolic decline behaviour. The depletion rate reaches a maximum value when the onset of decline is reached, before slowly decreasing asymptotically towards zero with decreasing production.

The existence of a maximum depletion rate for individual fields also indicates the existence of a maximum depletion rate on a regional or global scale. Over recent decades various models and studies, which all use some limit for the depletion rate or the RPR of a resource, have been made by Flower (1978), Wood et al. (2004) and Campbell and Heapes (2008). The fundamentals behind this approach have been analyzed in more detailed by Jakobsson et al. (2008), which also coined the name *maximum depletion rate modelling* to describe this type of forecasting methodology.

The *depletion-at-peak* (DAP) parameter is the depletion rate of remaining reserves that occurs when the production peaks or the point at which production lastingly leaves the plateau phase. Closer discussion and examples of this can be found in paper II. This is often the highest depletion rate that occurs in the entire production profile, provided that the URR estimate is reasonably accurate and realistic. DAP may also be seen as the point in time when depletion-caused decline in reservoir pressure and/or flows will begin to dominate over other factors, thus forcing the field into a stage of predominantly depletion-driven decline.

Figure 4.7 shows a narrow distribution of DAP-values for the world offshore giant fields, and more details on this can be seen in paper II. North Sea dwarf fields from Norway, Denmark and the UK also cluster around some reasonable DAP-values (Figure 4.8). All this put together shows that only a narrow band of depletion rates are possible before a hydrocarbon field begins to decline. Consequently, depletion rate analysis can be used to estimate when the onset of decline will come.

Depletion rates also put a constraint on the amount of hydrocarbons that can be extracted as a function of time and it connects production level to a required reserve base. Empirical studies shows that depletion forces oil giant fields into the decline phase when around 5-15% of the remaining reserve is extracted annually (II). Similar limitations are also likely to exist for smaller oil fields, but this has not been investigated in detail yet.

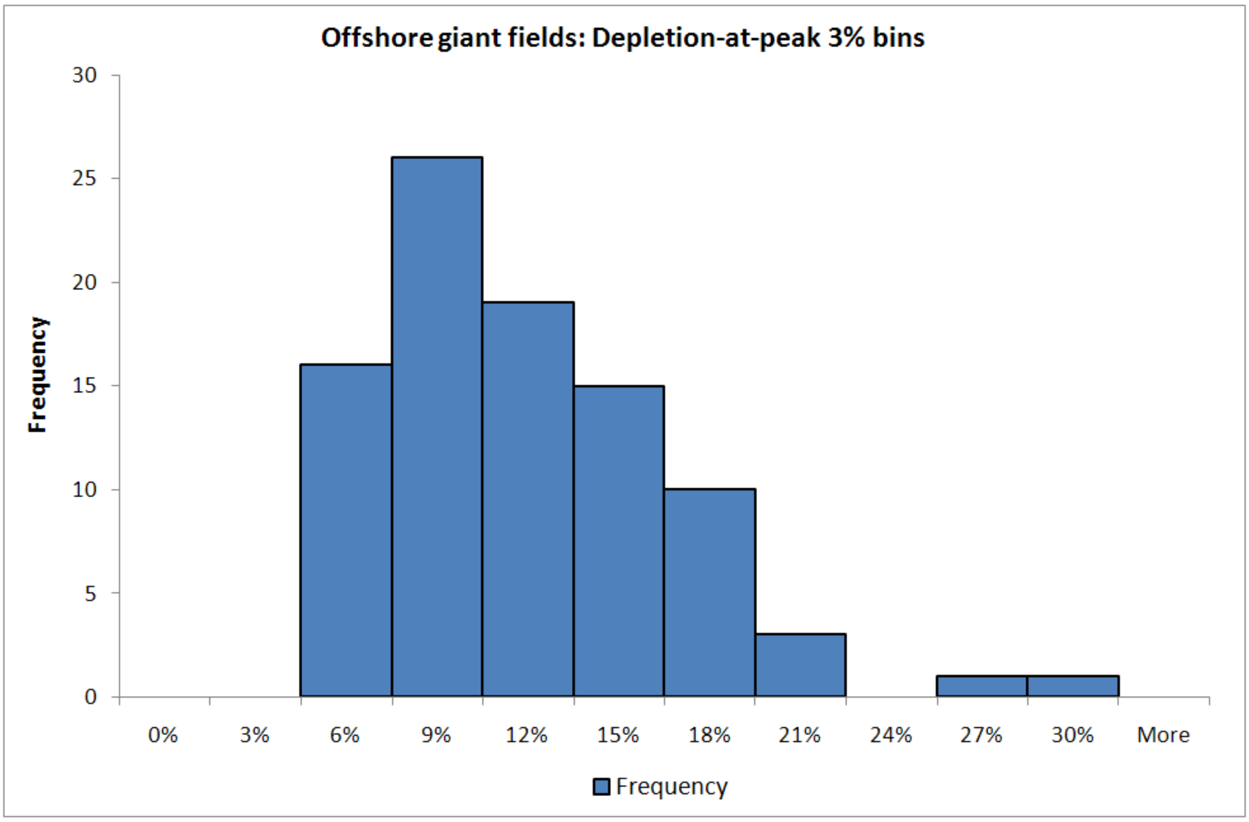

Figure 4.7. Distribution of DAP-values for the world's giant offshore fields that has reached the onset of decline. The histogram is somewhat skewed and resembles an exponential distribution. Higher depletion rates than 20% virtually never occur and are likely results from an underestimated URR.

Depletion rate analysis is somewhat similar to decline rate study, but require more data in order to be utilized. The advantage of depletion rate analysis is that it can also describe more phases of an oil field's life and give some hints of future behaviour of fields that are currently on plateau production or in build-up phase. The most important property of the depletion rate is that it is strongly connected to the reservoir flow relations, as the extraction of recoverable volumes causes a decrease in reservoir pressure which influences fluid flow driving forces. Compressibility, gas dissolution, fluid injection and other key flow factors are seldom accessible, so depletion generally becomes the only available parameter connected to the fundamental flow relations. Analysis of large oil field sets have found strong correlations between decline and depletion (II), which is hardly surprising given the importance of depletion as a driving force for reservoir flows.

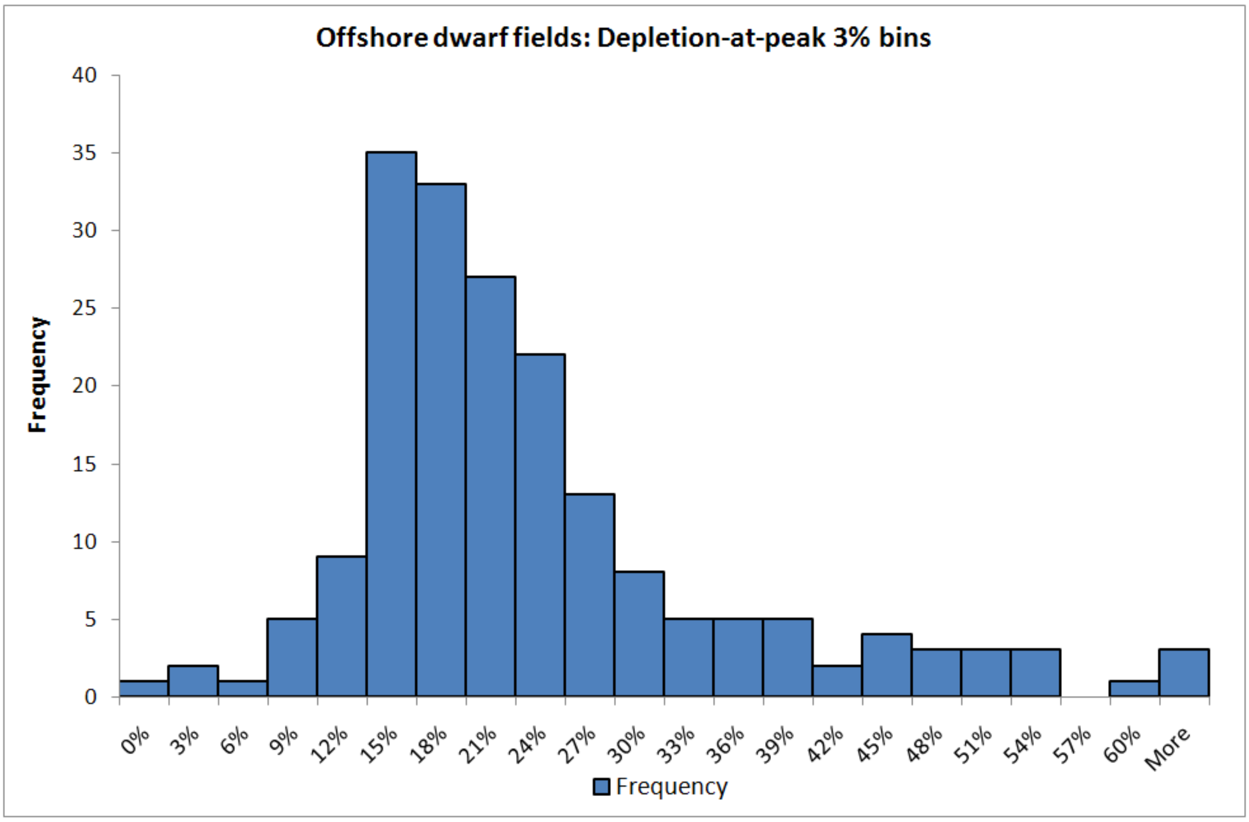

Figure 4.8. Distribution of DAP-values for the North Sea dwarf offshore fields that has reached the onset of decline. The histogram is strikingly similar to the giant offshore case. Depletion rates higher than 30% likely results from underestimated URR values.

The existence of a maximum depletion rate interval for oil fields, at least empirically, seems unlikely to be exceeded without entering the decline phase, is perhaps the most vital discovery. This connects production level to a needed reserve base, and also puts a limitation on how fast the recoverable volumes a field can be extracted in any realistic case, if production is expected to behave in agreement with hundreds of analyzed oil fields (II).

The depletion rate limitation for individual fields must also be present for an oil producing area, since it is made up from a number of fields. From suitable URR-estimates and production data it is possible to create depletion rate curves for regions and analyze the behaviour on a region scale. Looking at both the UK and Norway gives a good overview of how depletion rate analysis also can be applied to regional oil production (Figure 4.9 and 4.10).

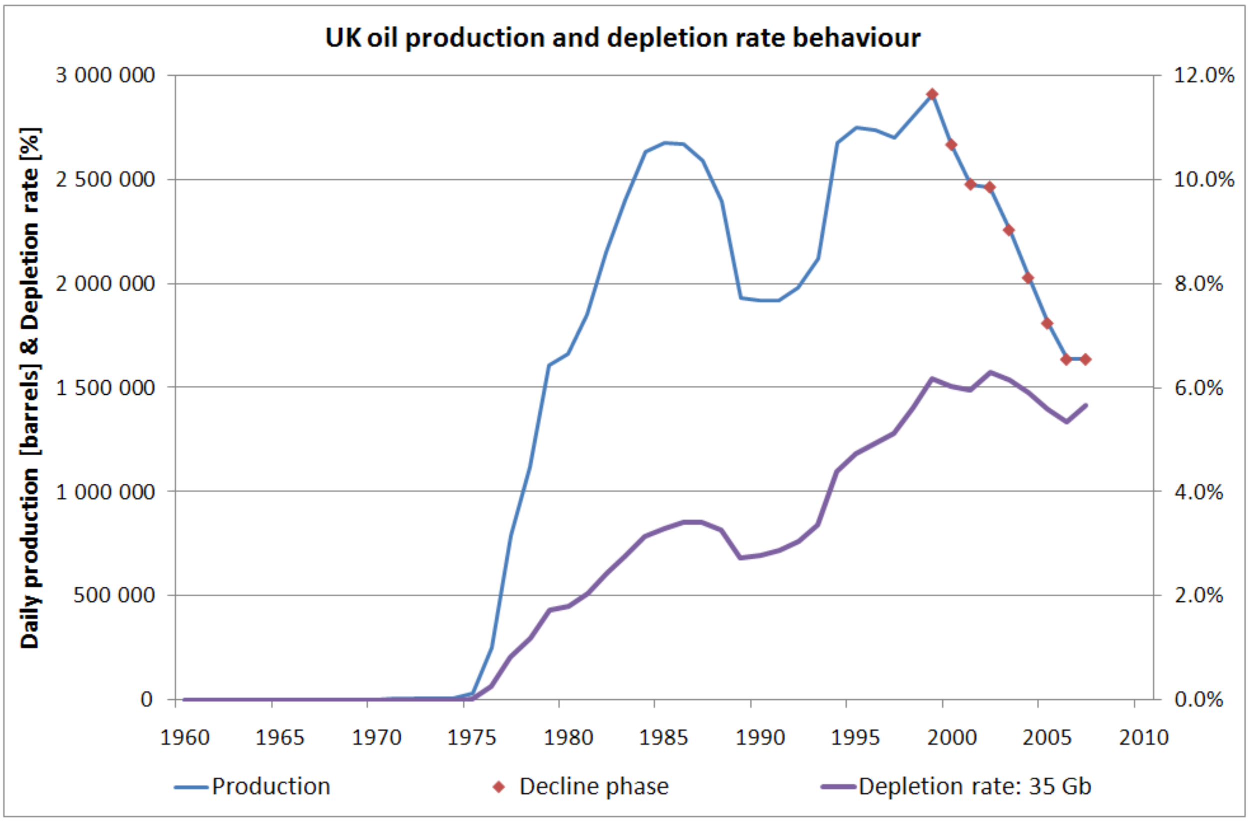

Figure 4.9. UK oil production increased dramatically after the discovery of North Sea oil. The production peaked in 1999 and has been declining ever since. Based on an assumed URR of 35 Gb, which is optimistic compared to Campbell (2008), the depletion rate was around 6% in 1999. In summary, the regional depletion behaviour is looking similar to that of an individual oil field.

However, this needs to be analyzed in more detail to uncover the similarities and differences between depletion rate behaviour on regional scale and in individual fields. Furthermore, Jakobsson et al. (2009) has already taken some of the first steps in investigating the foundations of this type of forecasting methodology.

Individual field properties will definitively affect the regional behaviour to some extent and therefore a field-by-field study of depletion may be beneficial to all forms of regional depletion models (II). Regarding field behaviour, it can be mathematically shown that a roughly bell-shaped production curve for a certain region will appear if the individual field profile is triangular, but this needs to be generalized for arbitrary production curves (Stark, 2008).

Depletion rate analysis is not limited just to oil and natural gas, as it also can be a vital tool for coal production analysis and forecasting. In fact, depletion is an important factor for all forms of finite resource extraction. However, the problem of defining an URR can be more challenging for coal or metal ores. Despite this, there have been attempts to establish URR estimates for coal comparable with the URR-concept in crude oil analysis (Höök and Aleklett, 2009). Using such an estimate for the U.S. anthracite, the highest ranking coal that almost only occurs in Pennsylvania, results in a picture similar to crude oil production (Figure 4.11).

Regional modelling has also includes a wide array of different growth curves and even multi-cycling curve fitting. The regional picture often becomes more complex and opens up for many more modelling options. More discussion on this is sadly beyond the scope of this thesis.

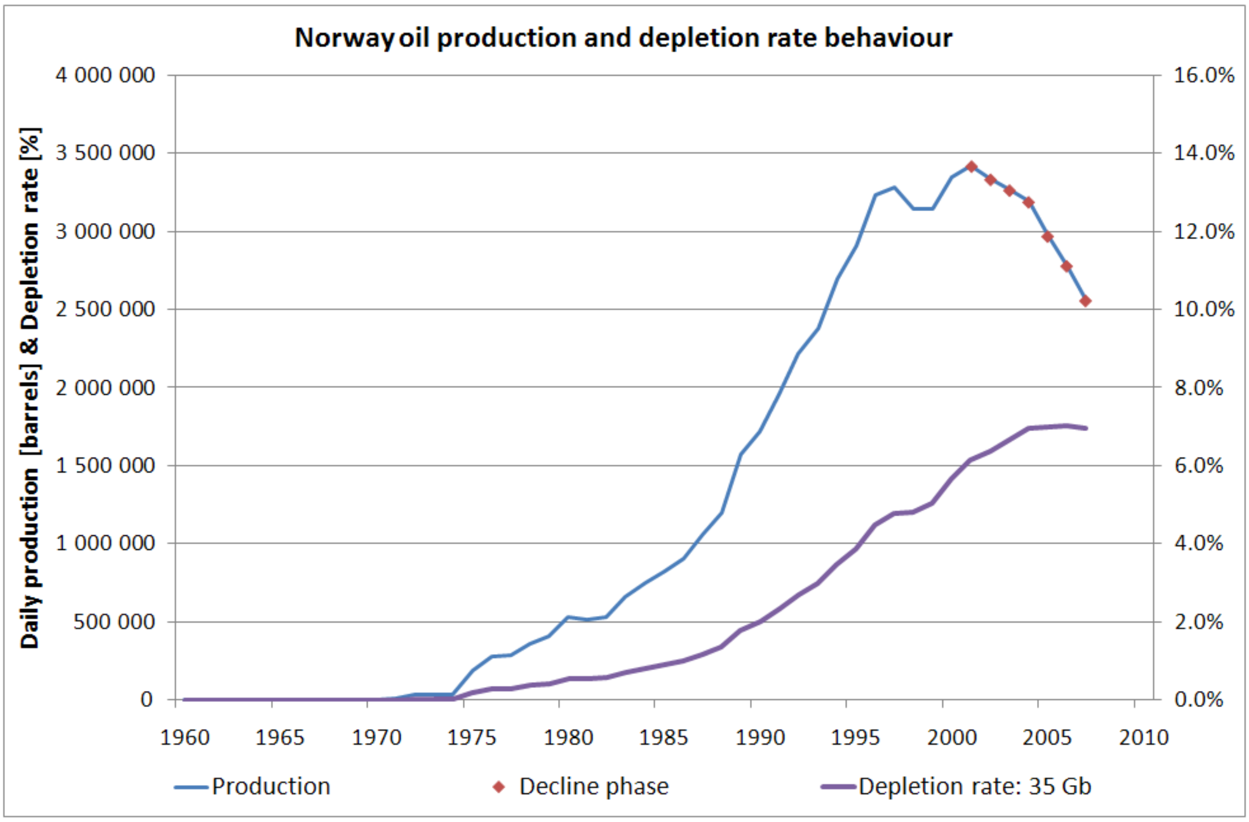

Figure 4.10. The Norwegian oil production peaked in 2001 at a depletion rate of 7%. The depletion rate has been constant despite a 30% production drop in 6 years.

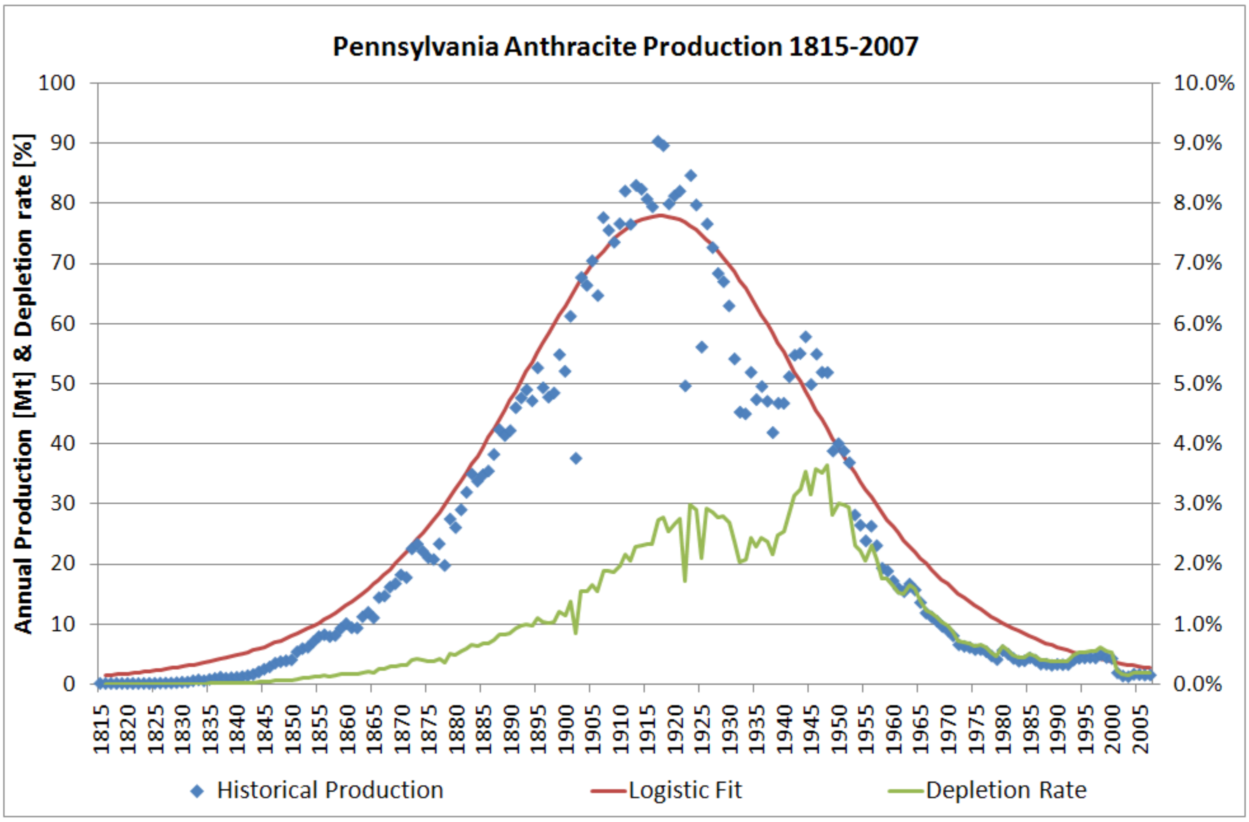

Figure 4.11. Pennsylvania anthracite production from 1800 to present and the corresponding depletion rate behaviour. The peak occurs at roughly 3% depletion rate, which never was exceeded during the entire production curve. Depletion rate analysis could also be a useful tool for coal production analysis, but this needs to be investigated in more detail.

4.3 Combining decline and depletion rate analysis

Using a combination of depletion and decline rate analysis gives a better tool for describing future oil production on a field-by-field level. The most important ability is perhaps the possibility to give an estimate of when the onset of decline will be reached. Much of the world oil production comes from old giant oil fields (III), which have been on plateau for many decades. Robelius (2007) found that the peak of the giants will determine the peak of the world oil production. Good understanding of these fields and their future behaviour is vital for the global oil supply in the future.

The depletion rate analysis and the DAP parameter can successfully be used to determine approximately when the peak of an individual field will be reached and can also give an indication of likely decline rates for the post-plateau phase (II). In order to illustrate this concept and method, a number of examples will be made.

Prudhoe Bay, the largest oil field ever discovered in the US, is a good example due to its well-behaved production curve (Figure 4.12). The field reached the onset of decline in 1988, after 8 years on a plateau production of 1.5 Mb/d. Based on the official URR-estimate of 13 Gb (Robelius, 2007), plateau was reached at a depletion rate of 4.5% and continued until depletion rate increased to 7.2% before the onset of decline. This agrees very well with the typical DAP-values of other giant oil fields (II).

Decline in Prudhoe Bay has followed an exponential curve almost perfectly with 10% annual decrease in production level. The decline curve indicates a somewhat lower URR of only 11 Gb, compared to the official estimate. Using 11 Gb as an URR gives an DAP of 9.7%, which also is well within the interval of reasonable depletion rates for giant fields (II) as well as resulting in an virtually constant depletion rate as expected from a exponential decline.

Secondly, a 9.7% depletion rate also agrees well with the observed decline rate and could serve as a good explanation for the rapid decline that followed, given the strong empirical correlation between depletion and decline (II) and the theoretical arguments for depletion as a driving force for decline. This also hints that the official URR estimate may be exaggerated or include amounts that require special recovery methods.

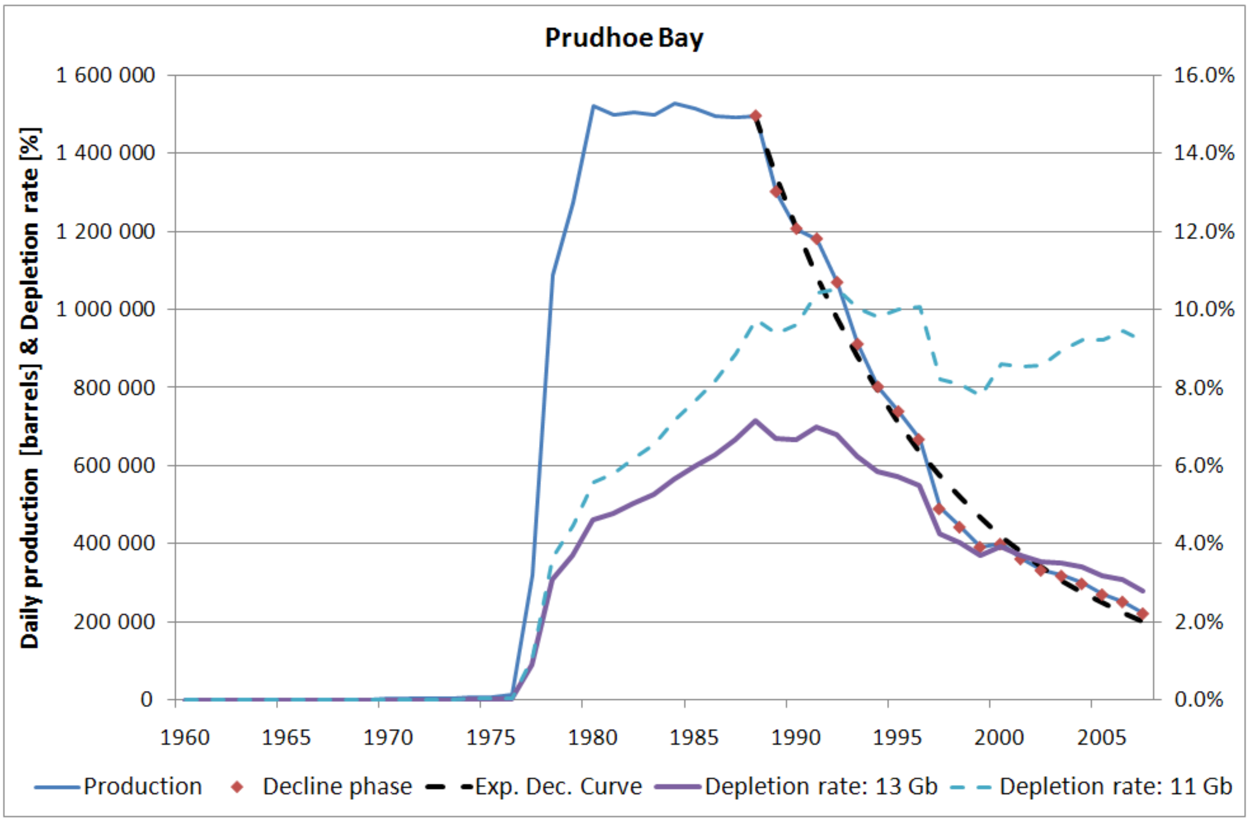

Figure 4.12. Depletion rate behaviour of the US supergiant field Prudhoe Bay. The depletion rate reaches its maximum value when the onset of decline is reached. Both the official URR and the one derived from the production curve fall within a reasonable interval.

Another suitable example is the offshore giant field Cantarell, the crown jewel of Mexican petroleum industry (Figure 4.13). The field started its production in 1979 and remained at a production output of roughly 1 Mb/d until late 1990s when nitrogen injection and new drillings increased production dramatically. The peak production was reached in 2004 before entering a steep decline. The field is claimed to contain 20 Gb according to the best official estimates (Robelius, 2007) and this gives an depletion-at-peak of 7.7%, agrees well with the behaviour of other giant fields (II).

The annual decline rate since 2004 has been 11%, and agrees well with an Arps exponential curve. The decline rate indicates a URR of 18 Gb, using relations from Table 4.1. This lower URR gives a higher DAP-value of 9.65%, which better agrees with the observed decline rate just as in the case of Prudhoe Bay.

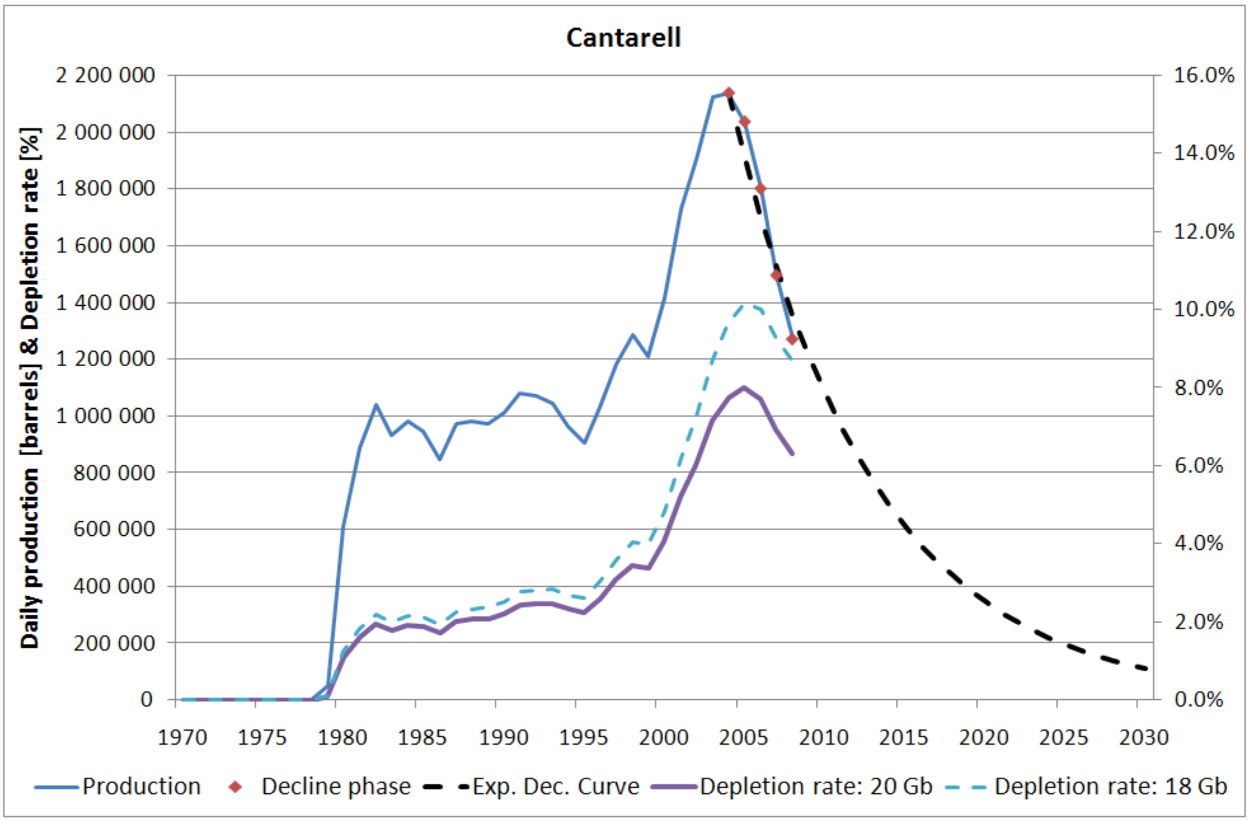

Figure 4.13.Depletion rate behaviour of the Mexican offshore giant Cantarell. After installation of nitrogen injection systems, production soared to nearly 2.2 Mb/d before entering a steep decline.

More examples can be made from Norwegian fields. The giant field Jotun contains 0.15 Gb of oil according to the official numbers (NPD, 2008) and reached its peak production of 123 000 b/d in 2000 at a depletion rate of 34.6%, which would indicate that it would entering a steep decline in the near time. The average annual decline since 2000 has been -29%.

A hyperbolic decline curve, with $\lambda = 0.50$ and $\beta = 0.19$, gives better agree with the historical data in this case (Figure 4.14). Calculating the URR from the decline curve yields 0.16 Gb, which is roughly equal to the official estimate and results in a similar DAP-value. Already from the first years of production, a future steep decline could be indicated from URR values using depletion rate analysis.

The UK offshore giant Beryl had a long plateau production for 16 years and could be seen as a useful example of how depletion rates can be used to predict the onset of decline. As production remained constant, depletion rate increased until it reached sufficiently high values to initiate a depletion-driven decline (Figure 4.15). The increasing depletion rate can be seen as increasing workload needed to keep production levels constant.

The official URR estimate is 0.94 Gb and gives a resulting DAP-value of 9.8%. Using decline curve fitting gives an URR-estimate of 0.86 Gb, which corresponds to a DAP-value of 12.6%. The average annual decline of the field has been 13% and this agrees reasonably well with both DAP-estimates.

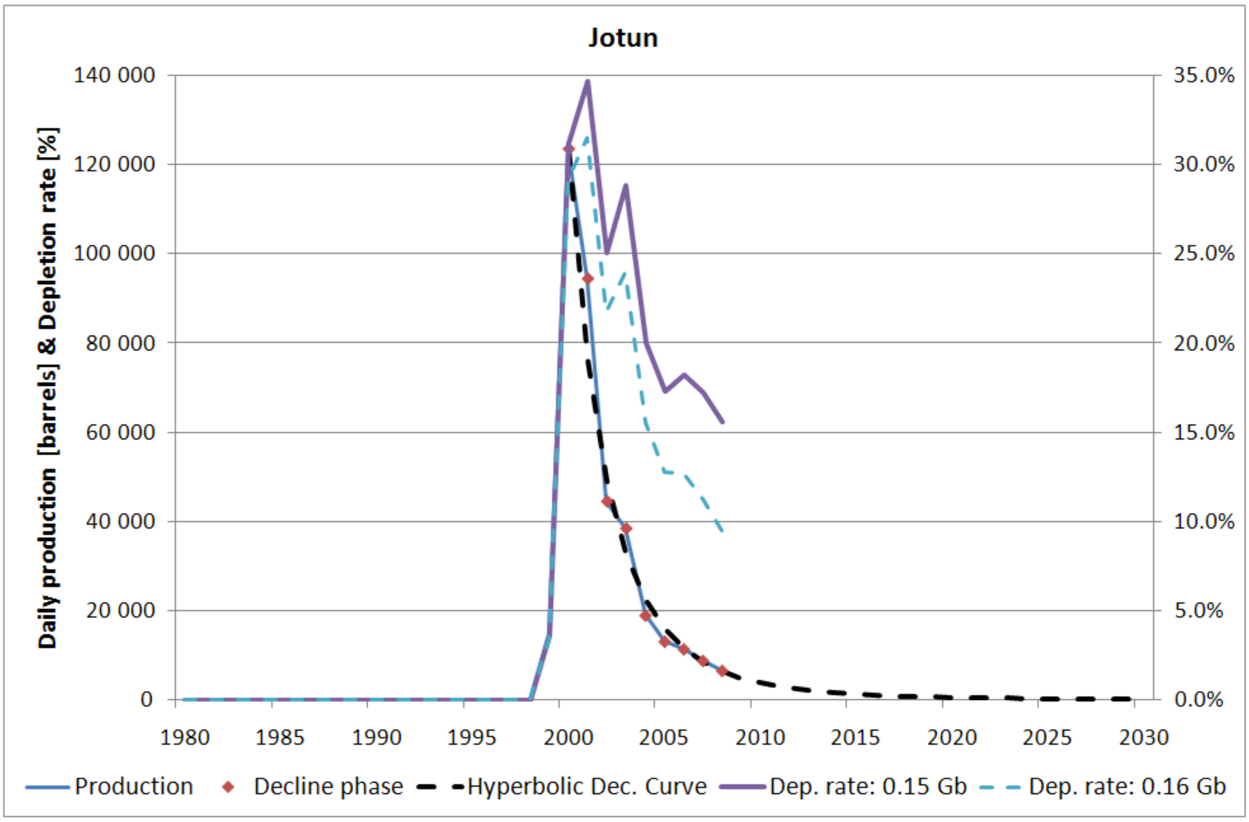

Figure 4.14. Depletion rate behaviour of the Norwegian offshore giant Jotun. After an initially high depletion rate, a rapid decline followed. Already from the first years the crash of the production could be foresighted. After peak production depletion rate falls as expected from a hyperbolic decline.

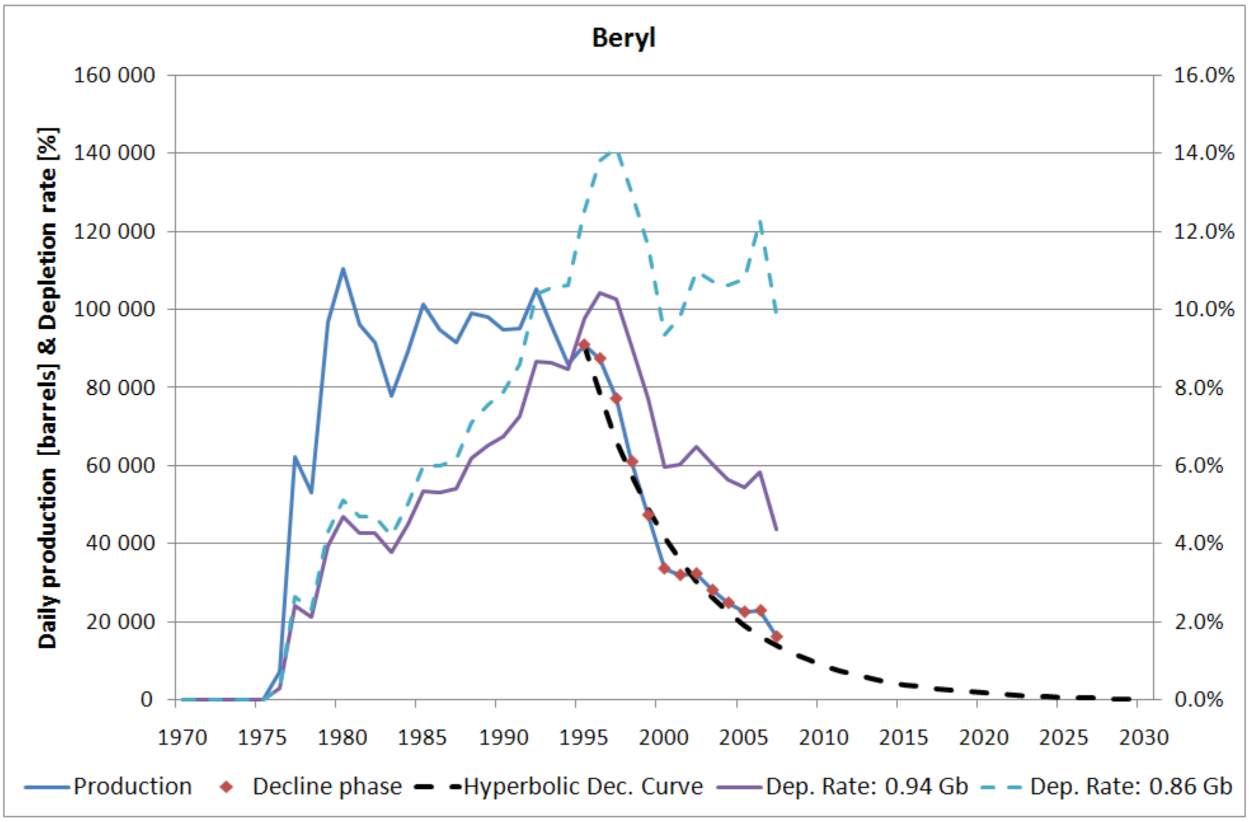

Figure 4.15. Depletion rate behaviour of the UK giant field Beryl. The field entered a plateau production at a depletion rate of 4%, which increased until the onset of decline was reached at a depletion rate of 10-12%, depending on URR estimate.

5. Conclusions and outlook

Forecasting crude oil production can be done in many different ways, but in order to provide realistic outlooks, one must be mindful of the physical laws that affect extraction of hydrocarbons from a reservoir. Decline curve analysis is a long established tool for developing future outlooks for oil production from an individual well or an entire oilfield. The approach was used in the case of Norway (I) and similar studies of other countries.

Depletion has a fundamental role in the extraction of finite resources and is one of the driving mechanisms for oil flows within a reservoir. Depletion rate also can be connected to decline curves. Consequently, depletion analysis is a useful tool for analysis and forecasting crude oil production (II). Field-by-field modelling is important, given the dominance of giants on both a national level (I) and in global oil supply (III). It is important in the study of the phenomenological and empirical behaviour of oil fields and production schemes and can be useful in general models for creating realistic outlooks.

Based on comprehensive databases with reserve and production data for hundreds of oil fields, it has been possible to identify typical behaviours and properties. This has lead to establishment of typical decline rates (III), as well as characteristic depletion levels and depletion rates at the onset of decline (II). These results are beneficial both as reasonable observed values for other forecasters, as well as for analysts connecting theory and reality.

In paper I, it was concluded that the observed rapid decline rates found should be taken very seriously, as they imply that oil production can decline rapidly in a region. Dwarf oil fields, NGL and condensate were found to decline even faster. In particular, condensate can have an annual decline rates up to 40%. Typical decline rates over 15 % can be found for these subclasses.

Decline rate studies of the world's giants were found to be in good agreement with organizations such as CERA and IEA (III). Small differences did exist, but the general picture was the same. Consequently, paper III may be seen as an academic counterpart of similar industry studies.

The overall conclusion is that the struggle to keep up world oil production will be harder and harder, marking the onset of peak oil and a future decrease in world oil supply.

Technology is an important part of oil supply considerations. All three papers include technology to some extent, but paper II may be seen as the most comprehensive study of how the introduction of new technology and production strategies has changed oil field behaviour. All three papers indicated that new technology generally has lead to more rapid decline, after the plateau phase. The spectacular declines of the Cantarell (Luhnow, 2007) and Yibal (Gerth and Labaton, 2004) fields may be early warning signs of things to come.

Paper II showed the difference between various subgroups of worlds giant oil fields. Offshore fields behave differently from onshore production. Accordingly, it is necessary to treat the subgroups separately. Comprehensive studies of each subgroup and how their behaviours have evolved over time were performed and can be used to extrapolate future trends.

In summary, this thesis and the papers it is built upon have developed a useful approach for future modelling. Reliable and reasonable forecasts are essential for planning and necessary in order to understand likely future world oil production. Energy is fundamental to all parts of society. The enormous growth and development of society in the last two-hundred years has been driven by rapid increase in the extraction of fossil fuels. In the foreseeable future, the majority of energy will still come from fossil fuels. Consequently, reliable methods for forecasting their production, especially crude oil, are crucial.

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Paper I: A decline rate study of Norwegian oil production

Mikael Höök, Kjell Aleklett

Abstract. Norway has been a very important oil exporter for the world and an important supplier for Europe. Oil was first discovered in the North Sea in late 1960s and the rapid expansion of Norwegian oil production lead to the low oil prices in the beginning of the 1990s. In 2001 Norway reached its peak production and began to decline.

The Norwegian oil production can be broken up into four subclasses; giant oil fields, smaller oil fields, natural gas liquids and condensate. The production of each subclass was analyzed to find typical behaviour and decline rates. The typical decline rates of giant oil fields were found to be -13% annually. The other subclasses decline equally fast or even faster, especially condensate with typical decline rates of -40% annually. The conclusion from the forecast is that Norway will have dramatically reduced export volume of oil by 2030.

Key words: Future Norwegian oil production, peak oil, decline rate, field-by-field analysis, oil production policy

Introduction

Norway and the United Kingdom own the largest share of the North Sea oil and have been the driving forces behind the North Sea oil production.

Particularly interesting is Norway as its domestic consumption of oil is only around 200 000 barrels per day and therefore much of its production can be exported. In fact it is also the world's third largest oil exporter (Aleklett, 2006). The United Kingdom by comparison is a net oil importer and its future production will not be as important for the rest of the world as that of Norway.

North Sea oil was discovered in the 1960s, and the first commercial production started in early 1970s. The oil crisis of 1973 made the North Sea very attractive as it could offset supply cuts by the political will of OPEC nations.

The programme for the development of new technologies got an enormous budget, 11 billion dollars more than the US had spent on the moon landing project (Time, 1975). The North Sea became the world leading region for production and offshore technology.

All the new technologies that were introduced led to increased production and in the 1990s oil was flowing. In the end of the 1990s some even stated that the world was drowning in oil and the oil price was heading towards 5 US$/barrel (Economist, 1999).

But suddenly the shock came and the situation changed dramatically. In 1999 the United Kingdom reached its maximum oil production and started to decline. In 2001 Norway peaked at a production of 3.4 million barrels per day (Mbpd) and has been in decline since then. Norwegian oil production in 2007 had fallen to 2.6 Mbpd, 25% less than the peak production. In 2008 Norway cut down its oil production forecast from 2.5 Mbpd to 2.4 Mbpd, explaining this by maturing fields on the Norwegian continental shelf (Oil & Gas Journal, 2008).

Aim of this study

Norway is a major oil exporter and the decline of Norwegian oil will affect all who are dependent on its export. A realistic forecast for the future Norwegian oil production is therefore important. This article will present such a forecast.

Oil production can be divided into crude oil, condensate and natural gas liquids (NGL). This study will present a field-by-field analysis of all Norwegian oil, condensate and NGL production. As the Norwegian Petroleum Directorate makes all field-related data available, Norway is ideal for a detailed field-by-field study.

Extrapolation and estimates of the amounts of oil that remain to be discovered will also be made to provide a reasonable picture of the impact from undiscovered reserves based on the continuation of historical trends.

Methodology

All fields will be analyzed separately to determine their depletion rate, decline rate, cumulative production and much more. The official data from the Norwegian Petroleum Directorate (NPD) is used. The total oil production is divided into four subclasses. This is to better display the different behaviour and properties of the different oil types and field sizes.

The first subclass is crude oil from giant oil fields, which are fields with more than 0,5 Gb of ultimately recoverable resources (URR) or a production of more than 100 000 barrels per day (bpd) for more than one year. The definition used here follows the established results from other studies (Simmons, 2002; Robelius, 2007).

Crude oil from smaller oil fields, which are fields not large enough to be classified as giants, will be the second subclass. These fields will be called dwarf oil fields in this study. It should however be noted that there is no clear border between giants and dwarfs. The largest dwarfs also might actually be just below giants, but on the larger scale most oil fields will be small or significantly smaller compared to the giants and therefore the term “dwarf” is chosen to illustrate the concept.

Finally all condensate and all natural gas liquids (NGL) constitute the last two subclasses. This is a result of NPDs statistics, where they are displayed as separate categories.

The past production is taken from NPDs statistics and goes back to the beginning of the Norwegian oil production in early 1970s. The URR and discovery year of all fields are also taken from official NPD material.

The overall aim is to analyze the production behaviour of Norwegian crude oil, condensate and NGL. From this a possible future production profile will be created, where the historical experience is applied to future development.

Distribution of oil

The Norwegian share of the North Sea stretches from the central parts of the North Sea all along the coast up to the Barents Sea. The North Sea and the Norwegian Sea have been the most important areas for production. The Barents Sea is the current frontier region.

All abandoned and currently producing giant and dwarf oil fields, condensate and NGL fields together contain 29.9 Gb of oil (NPD, 2007). The bulk, namely 74%, is concentrated to giant oil fields.

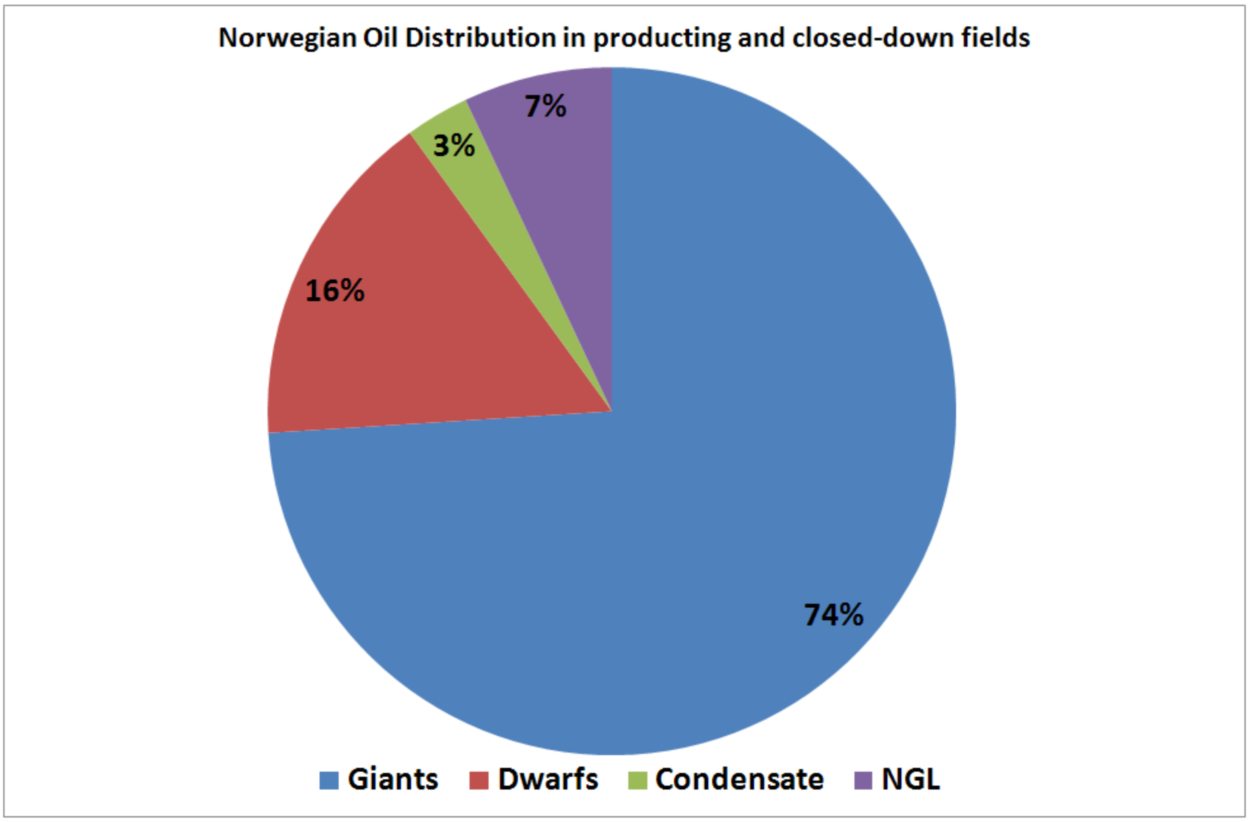

Figure 1. Distribution of oil from all closed-down and currently producing fields. Most of the oil can be found in giant oil fields, such as Ekofisk and Statfjord. Only a smaller share is found in dwarf oil fields, such as Gyda and Albuskjell. It should also be noted that any NGL and Condensate within giant oil fields are included in the Condensate and NGL classes.

The historical oil production of Norway shows the extreme importance of the giant oil fields. In fact nearly all Norwegian oil production has come from giant oil fields and it was only in the middle of the 1990s, that smaller crude oil fields, condensate and NGL started to contribute significantly to the total production.

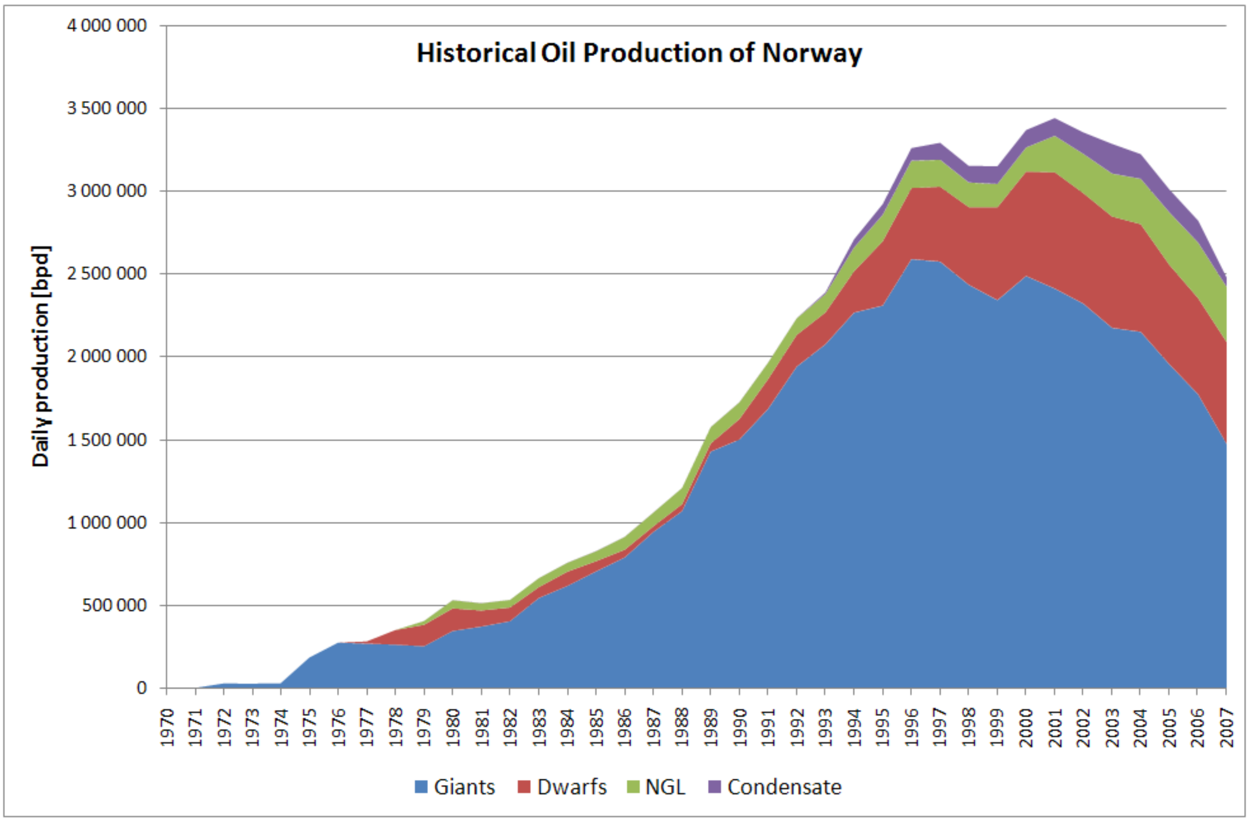

Figure 2. Historical oil production divided into subclasses. Most of all Norwegian oil production has been from giant oil fields. Since the peak production around 2000 none of the other classes managed to compensate for the decline from the giants. It should also be noted that any condensate and NGL production from giant oil fields are included in the Condensate and NGL classes.

Norwegian oil output peaked in 2001 and has been in decline since then. This coincides quite well with a plateau production, from 1996 to 2000, from the giant oil fields. Rapid development of dwarf oil fields and increased production of mainly NGL managed to offset a part of the decline from giants, but when more and more giant oil field started to decline the trend became irreversible and the total Norwegian oil production peaked.

It is clear that giant oil fields, which is a small number of fields, have been of great importance for Norway and will continue to be so for the nearest decades. The importance of giant oil fields has also been shown on a global scale (Robelius, 2007).

Norwegian giant oil fields

In total Norway have found 17 giant oil fields containing a total of 22.1 Gb crude oil. Some of these fields also contain significant amounts of condensate or NGL but this is treated separately. Statfjord and Ekofisk are by far the largest of the giants, each with more than 3 billion barrels of ultimately recoverable reserves.

By year 2007 only five of the giants were producing more than 100 000 barrels per day, and Ekofisk, producing around 207 000 bpd, had the highest production of them.

Table 1.The Norwegian giant oil fields. The largest of them were discovered in the 1970s. Jotun, the last of them, was discovered in 1994 and is minute compared to Statfjord. The peak year corresponds to the top production or the end of plateau production depending on actual production profile of the field.

Field name	URR [Gb]	Discovery year	First Oil	Top / Plateau prod. [bpd]	Peak year	Average decline [%]
Statfjord	3.557	1974	1979	573,908	1995	– 14.4
Ekofisk	3.349	1969	1971	284,694	2004	– 9.3
Oseberg	2.231	1979	1986	501,917	1996	– 14.7
Gullfaks	2.230	1978	1986	529,778	1994	– 12.5
Snorre	1.472	1979	1992	234,329	2003	– 13.0
Troll	1.467	1979	1990	358,791	2003	– 19.6
Valhall	1.300	1969	1982	91,508	1999	– 5.8
Heidrun	1.132	1985	1995	231,886	1997	– 7.7
Draugen	0.881	1984	1993	204,361	2001	– 16.5
Norne	0.857	1991	1997	194,679	2001	– 16.1
Eldfisk	0.808	1970	1979	101,243	1980	– 3.9
Grane	0.755	1991	2003	217,347	2006	– 12.2
Åsgard	0.690	1981	1999	143,372	2001	– 9.8
Ula	0.503	1976	1986	126,590	1992	– 14.2
Balder	0.387	1967	1991	120,348	2005	– 13.9
Brage	0.350	1980	1993	101,131	1997	– 14.6
Jotun	0.158	1994	2000	123,482	2000	– 29.6

The decline in production of the Norwegian giants has been high. The average decline rate is around -13% per year. Some fields, such as Jotun and Troll, have declined much faster. Eldfisk and Valhall, both with a modest production for a field of their size, have the lowest decline rates mostly because of their chalk reservoirs with low recovery rate.

Since the giant oil fields are producing so large volumes, compared to smaller oil fields, it would require an excessive amount of small oil fields to compensate or dampen the effect from the declining giants.

The important fact is that once giant oil fields go into decline it is fast. The typical decline rates for the Norwegian giants are well above -10% per year. The average decline rate of all giant fields is -13.4 % and if weighted against the peak production of every individual field it will be -13.8 %. This high decline rate will have a significant impact on the total oil production due to the large contribution from giant oil fields.

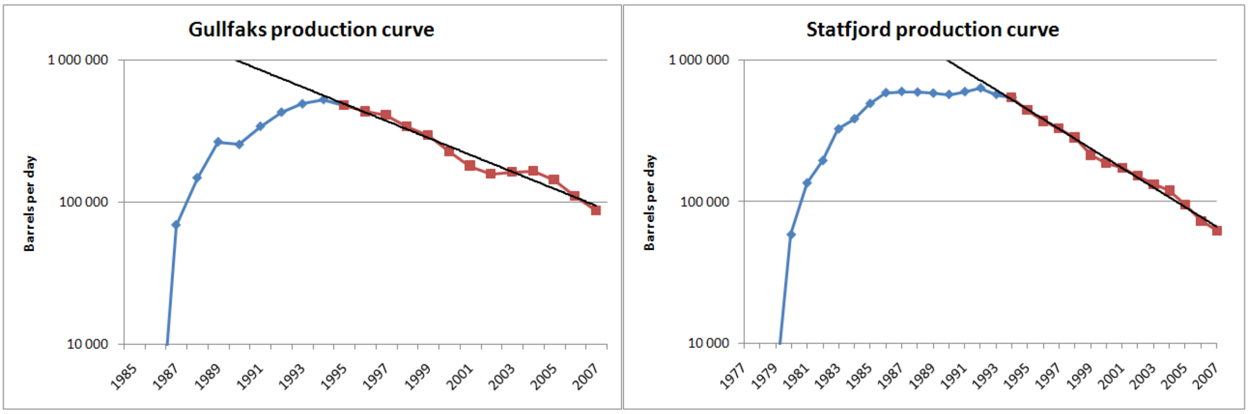

Figure 3.The production profiles of the two giant fields Gullfaks and Statfjord in a logarithmic plot with a fitted line to show the virtually constant decline. The annual decline in the post peak section varies from -23% to +3% for Gullfaks, but the average decline becomes -12.5% and the median value is -13.0%. For Statfjord the annual decline varies from -24 to -4%, with an average decline of -14.4% and a median value of -13.2%.

This result is also important for the world oil production. As pointed out by other studies a small number of giant oil field accounts for the majority of the world's oil production (Robelius, 2007). The future behaviour of these giants will be of the uttermost importance for the future oil production. By looking at the aggregate decline rate of the Norwegian giant oil fields some light can be shed on the future behaviour of the entire worlds giant oil fields as a group.

Clearly it can be seen that the aggregate decline rate is not constant, but increases with time as more and more old field falls into decline and no new fields are brought into production. This is a clear and fundamental difference compared to a recent study on aggregate decline rates, claiming that it will be constant (Cambridge Energy Research Associates, 2007).

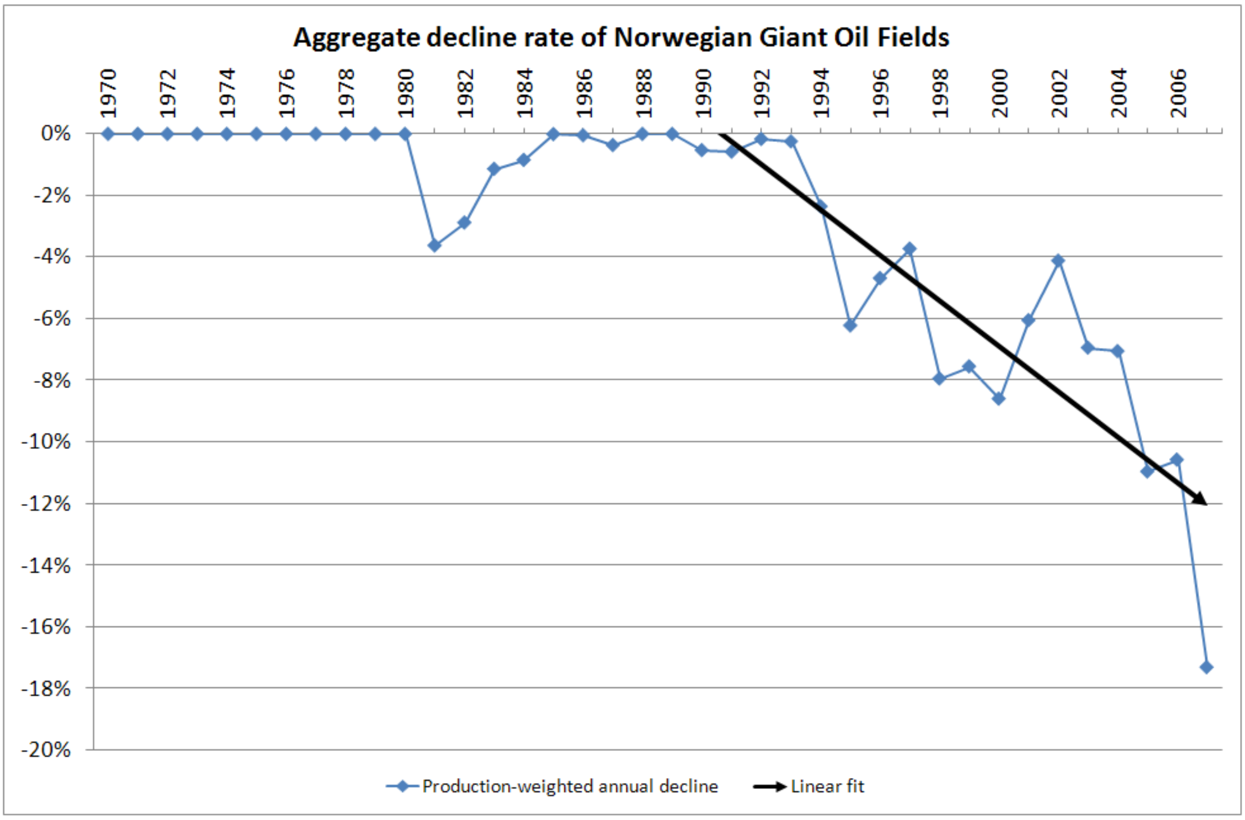

Figure 4. Aggregate decline rate of Norwegian giant oil fields. The annual decline rates of each field were weighted using the annual production to construct the aggregate decline rate of the giant oil field group. The giant oil fields started to decline in 1991 and since then the aggregate decline rate have been growing by roughly 1% annually. As no new giant oil fields were brought into production the aggregate decline rates slowly approaches the decline rate of individual giant oil fields. Only by adding new fields can the aggregate decline rate be held low.

Norwegian dwarf oil fields

Norway has a significant number of smaller oil fields, in total 41 in production or closed-down. Together they account for 4.71 Gb of crude oil in URR, but compared to the giants they are small in both reserves and total production.

A total of eight fields have been abandoned, once all recoverable oil has been extracted. Vest Ekofisk and Albuskjell are the two largest of these closed-down fields with URRs of 0.077 Gb and 0.047 Gb respectively. They peaked at a production of 66 000 bpd respectively 25 000 bpd. The remaining 34 dwarf fields are still in production. Kristin is currently the largest producer at 73 000 bpd, but most of the dwarfs lie at a much lower production.

The typical life span, namely the time the field is increasing its production or remaining on plateau, of a dwarf field is also much shorter than for a giant oil field. Therefore a very large number of dwarfs are needed to replace just one giant. This was also pointed out by others (Robelius, 2007).

Table 2. The Norwegian dwarf oil fields. The largest of them are almost giants while the smallest only contains a few million barrels of oil. The peak year corresponds to the top production or the end of plateau production depending on actual production profile of the field. NPY stands for "No Peak Yet" and implies that the field yet haven't reached the decline phase of its life.

Field name	URR [Gb]	Discovery year	First oil	Top/Plateau prod. [bpd]	Peak year	Average decline [%]
Tordis	0.406	1987	1994	70,914	2003	– 6.9
Vigdis	0.358	1986	1997	88,030	1999	– 4.8
Vesslefrikk	0.353	1981	1990	70,107	1996	– 11.2
Oseberg Sör	0.309	1984	2000	70,136	2006	– 22.1
Gullfaks Sör	0.301	1978	1995	NPY	NPY	NPY
Statfjord Nord	0.265	1977	1995	68,885	2000	– 15.0
Gyda	0.243	1980	1990	65,622	1994	– 12.5
Oseberg Öst	0.235	1981	1999	65,699	2001	– 27.2
Statfjord Öst	0.235	1976	1994	72,985	1998	– 12.3
Kristin	0.212	1997	2006	NPY	NPY	NPY
Visund	0.175	1986	1999	NPY	NPY	NPY
Njord	0.151	1986	1997	67,567	2000	– 15.9
Tor	0.150	1970	1978	77,993	1979	– 6.4
Fram	0.132	1992	2003	50,622	2004	– 23.6
Kvitebjörn	0.113	1994	1990	NPY	NPY	NPY
Yme	0.099	1987	1994	33,941	1998	– 44.4
Varg	0.095	1984	1998	29,943	2000	– 7.3
Murchison	0.086	1979	1981	49,328	1984	– 10.4
Sygna	0.080	1996	2000	43,936	2001	– 26.2
Vest Ekofisk	0.077	1970	1977	66,291	1978	– 20.3
Embla	0.071	1988	1993	24,397	1994	– 11.5
Urd	0.066	2000	2005	35,232	2006	– 58.6
Hod	0.065	1972	1990	26,297	1991	– 13.3
Heimdal	0.057	1972	1990	NPY	NPY	NPY
Tambar	0.054	1983	2001	29,749	2002	– 13.9
Glitne	0.052	1995	2001	37,172	2002	– 25.6
Albuskjell	0.047	1972	1979	24,575	1981	– 19.7
Ringhorne Öst	0.040	2003	2006	NPY	NPY	NPY
Fröj	0.035	1987	1995	30,643	1996	– 37.0
Edda	0.031	1972	1979	21,716	1980	– 6.5
Huldra	0.031	1982	2001	20,378	2003	– 37.7
Mikkel	0.029	1987	2006	NPY	NPY	NPY
Gimle	0.028	2004	2005	NPY	NPY	NPY
Tommeliten Gamma	0.025	1978	1988	13,526	1989	– 22.3
Tune	0.020	1996	2002	19,631	2003	– 37.2
Cod	0.018	1968	1977	8,013	1980	– 14.5
Skirne	0.013	1990	2004	5,116	2005	– 15.2
Vale	0.011	1991	2002	NPY	NPY	NPY
Lille-Frigg	0.009	1975	1994	7,527	1995	– 45.0
Blane	0.005	1989	2007	NPY	NPY	NPY
Mime	0.003	1982	1990	2,797	1991	– 36.1
Enoch	0.002	1972	1979	NPY	NPY	NPY

The mean decline of the Norwegian dwarf oil fields is -21.3% and if weighted against the peak production of individual fields it will be -18.1 %. The historical data thereby shows that small oil fields declines faster than giants. Dwarf oil fields that have not reached their peak yet are assumed to decline with the average mean decline rate once they end their plateau phase.

Condensate production

Condensate corresponds to the heaviest components of natural gas and is partially liquid at normal pressures and temperatures. Norway has a total of 17 fields producing condensate with a combined URR of 0.868 Gb. Often the condensate is associated gas in oil fields and in many cases the production is low. Sleipner Öst has the largest recoverable volumes of condensate with an URR of 0.22 Gb, and it peaked in 1999 at a production of 53 000 bpd.

A total of 35 new fields with recoverable amounts of condensate, some are PDO-approved while others are in the early planning stages, are expected to come online in the future. Many of them only contain a few million barrels. The total URR from all the new condensate fields will be 0.35 Gb.

The decline rates of condensate production are very high. The mean decline from all Norwegian condensate is -35.5% and it becomes -37.7% when weighted against the peak production of individual fields. This shows that condensate production basically disappears after a few years.

Natural Gas Liquids (NGL)

The Norwegian Petroleum Directorate classifies NGL as butane + ethane + isobutane + propane + LPG + gasoline + NGL mix. NGL is a valuable by-product from natural gas processing and is hence not produced directly at the field, but rather at centralized gas treatment plants. In total 45 Norwegian fields have been producing NGL. The total URR of NGL is 2.1 Gb with an additional 0.24 Gb from new field developments.

The NGL-production more than doubled from 2000 to 2007. To a great extent the production increase came from giant fields, such as Åsgard and Oseberg, which had compensated less crude oil production with increased amounts of NGL.

The mean decline of Norwegian NGL is -19.5% annually, but this is slightly lowered to -15.6% when weighted against peak production of NGL fields. The conclusion from this is that NGL declines slower than condensate, but the reason for this are the modest production levels as NGL falls out naturally as a by-product.

Table 2. *Statistics for Norwegian condensate producing fields. Most of them are very small in terms of ultimately recoverable reserves. NPY stands for "No Peak Yet" and implies that the field yet haven't reached the decline phase of its life.*

Field name	URR [Gb]	Discovery year	First Oil	Top/Plateau prod. [bpd]	Peak Year	Average decline [%]
Sleipner Öst	0.220	1981	1993	53,938	1999	– 20.8
Sleipner Vest	0.186	1974	1996	44,659	2001	– 5.2
Ormen Lange	0.139	1997	2007	NPY	NPY	NPY
Snöhvit	0.114	1984	2007	NPY	NPY	NPY
Åsgard	0.110	1981	2000	74,593	2003	– 19.4
Sigyn	0.035	1982	2003	16,982	2005	– 16.8
Troll	0.028	1979	1999	26,057	2003	– 70.3
Kristin	0.013	1997	2005	32,768	2006	– 100,0
Mikkel	0.013	1987	2003	13,100	2005	– 30.0
Frigg	0.003	1971	1977	835	1981	– 14.2
Odin	0.002	1974	1984	401	1992	– 63.2
Statfjord	0.001	1974	2004	1,161	2004	– 28.4
Fröj	0.001	1987	1977	470	1981	– 69.3
Lille-Frigg	0.001	1975	1994	111	1996	– 44.6
Nordöst Frigg	0.001	1974	1983	200	1990	– 47.3
Öst Frigg	0.001	1973	1988	212	1992	– 46.5
Murchison	0.000	1976	1983	8	1984	– 8.3

Table 4. *Data for Norwegian NGL producing fields. Just as for condensate most of the fields are small in both terms of URR and production.*

Field name	URR [Gb]	Discovery year	First oil	Top/Plateau Prod. [bpd]	Peak year	Average decline [%]
Statfjord	0.225	1974	1985	30,329	1996	– 2.3
Sleipner Öst	0.221	1981	1995	44,311	1999	– 14.1
Åsgard	0.213	1981	2000	NPY	NPY	NPY
Ekofisk	0.194	1969	1971	21,252	1991	– 3.6
Troll	0.162	1979	1998	NPY	NPY	NPY
Norne	0.128	1991	2001	4,173	2005	– 13.4
Sleipner Vest	0.128	1974	1996	26,940	2002	– 7.7
Oseberg	0.092	1979	2000	NPY	NPY	NPY
Snorre	0.068	1979	1992	18,806	2001	– 28.4
Eldfisk	0.064	1970	1979	11,223	1989	– 5.9
Gullfaks Sör	0.064	1972	1990	NPY	NPY	NPY
Valhall	0.053	1969	1982	7,533	1990	– 3.6
Gullfaks	0.044	1980	1990	9,005	1994	– 0.5
Kristin	0.042	1997	2005	NPY	NPY	NPY
Ula	0.041	1976	1986	10,383	1993	– 12.2
Visund	0.041	1986	2005	NPY	NPY	NPY
Mikkel	0.036	1987	2003	NPY	NPY	NPY
Draugen	0.035	1984	2000	14,731	2001	– 13.9
Sigyn	0.034	1982	2003	13,212	2005	– 12.5
Gyda	0.031	1980	1990	8,285	1994	– 12.8
Gungne	0.028	1982	1996	8,174	2003	– 9.8
Tordis	0.024	1987	1994	6,407	2002	– 23.1
Statfjord Öst	0.023	1976	1978	5,801	2005	– 12.6
Vest Ekofisk	0.021	1970	1979	7,020	1980	– 13.4
Vigdis	0.021	1986	2003	NPY	NPY	NPY
Brage	0.020	1980	1993	3,915	1998	– 2.6
Tor	0.020	1970	1979	5,114	1983	– 8.1
Kvitebjörn	0.019	1982	1990	16,273	2006	– 82.8
Vesslefrikk	0.018	1981	1990	5,061	1996	– 12.0
Albuskjell	0.017	1972	1979	5,090	1983	– 17.3
Heidrun	0.013	1985	2001	3,225	2004	– 20.1
Statfjord Nord	0.012	1977	1995	3,986	2005	– 43.2
Tommeliten Gamma	0.009	1978	1998	3,687	1990	– 15.8
Embla	0.009	1988	1993	1,933	1994	– 6.5
Cod	0.008	1968	1979	2,519	1983	– 13.2
Fram	0.008	1992	2007	NPY	NPY	NPY
Murchison	0.006	1979	1983	3,926	1984	– 30.2
Hod	0.005	1972	1990	1,760	1991	– 16.0
Blane	0.004	1989	2007	NPY	NPY	NPY
Edda	0.003	1972	1979	1,699	1980	– 9.7
Tambar	0.003	1983	2001	1,752	2002	– 11.8
Tune	0.003	1996	2002	925	2004	– 24.8
Huldra	0.002	1975	2001	1,040	2002	– 22.6
Gimle	0.001	2004	2005	431	2005	– 80.4
Mime	0.000	1982	1990	228	1991	– 40.2
Urd	0.000	2000	2005	366	2006	– 53.9

New field developments

A number of new dwarfs are expected to come into production in the near future. The Norwegian Petroleum Directorate lists all undeveloped fields according to how far the development plan has come.

In total eight dwarf fields have got their plan for production and operation (PDO) approved and are expected to come on stream in a few years. Alvheim and Tyrihans are the two largest of these fields, both containing around 0.2 Gb of oil.

Ten new dwarfs are in the planning stage, and will be expected to come online between 2012 and 2018. A total of 13 new dwarfs is classified as “development likely but not clarified”. These are assumed to come online after 2017. Six new oil discoveries from 2007 will also included in the new field developments.

The production from new fields developments are modelled by assuming that each new field will follow a similar production profile as some of the old fields. This means for instance that the new Volve field, with and URR of 0.092 Gb, will behave approximately as the old Varg field, with and URR of 0.095 Gb.

This is of course a crude simplification as the geology and other properties of the fields might be very different, but it provides a reasonable assumption for the future production profiles. This might also be an optimistic assumption, as the older fields generally were less complicated to develop than the fields that will be brought into production in the future.

A number of new fields that will be producing condensate and NGL are also expected to be brought on-stream in the future. These are modelled in the same way as the dwarf oil fields.

Undiscovered oil

Norway has maintained an active exploration programme licensing the more attractive areas first. The discoveries are published by the Norwegian Petroleum Directorate and the trends are clear. To summarize one can say that the Norwegian continental shelf is a mature region, where most of the fields and promising structures already have been found. Few uncharted regions remain and the geology is generally understood to a large extent.

The peak of giant oil field discovery was in the early 1980s and there have been no new giant found since 1994. The undiscovered amounts of oil in both giant and dwarf fields, condensate and NGL were estimated using a logarithmic extrapolation technique of the historical discovery trends in both URR and number of fields. This method is similar to the one used in another study (Aleklett, 2006).

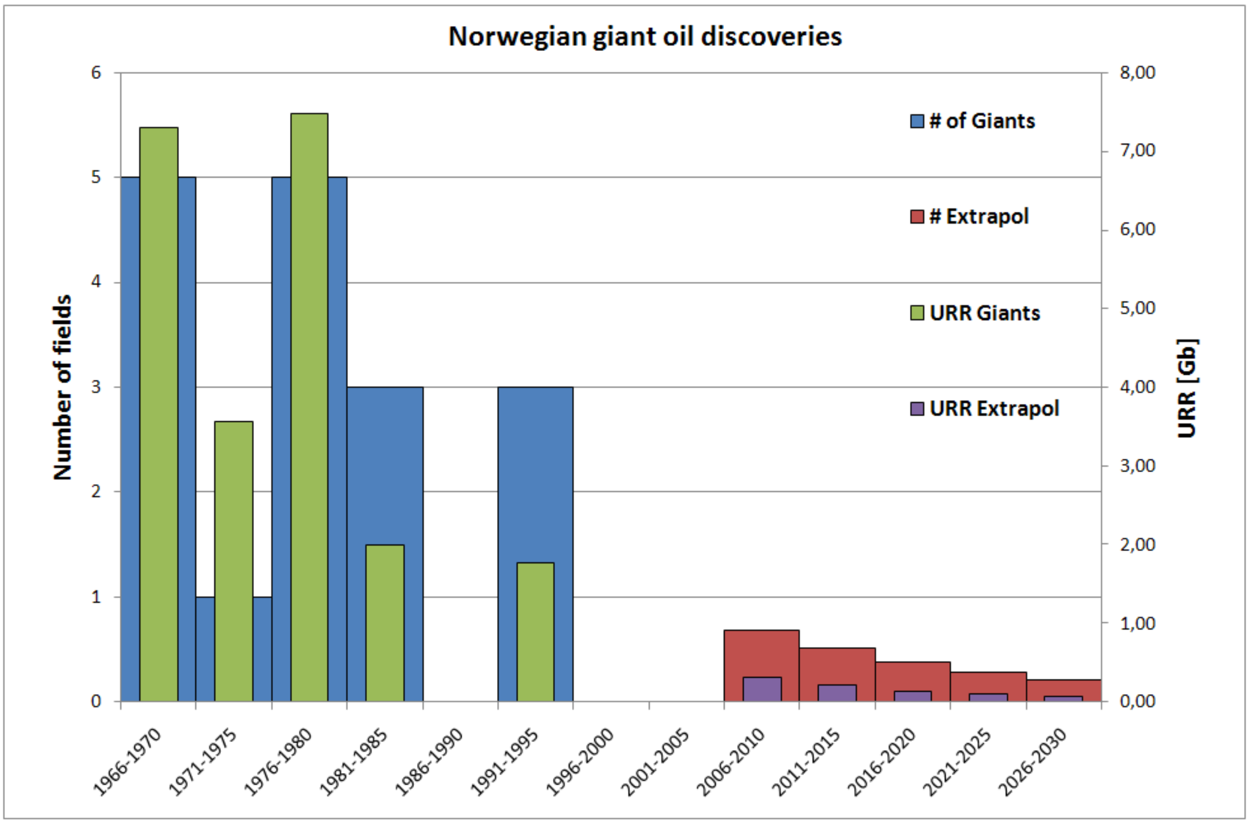

Figure 5. Extrapolation of the undiscovered amounts of giant oil fields in Norway with respect to both URR and number of fields.

In total about 2 Gb of undiscovered oil is included in this study. This makes the ultimately recoverable reserve for Norway in this study close to 35 Gb by 2030. Different assessments of the Norwegian URR have been performed by various studies. Both parabolic fractal evaluation and creaming curves were found to yield an URR of 36 Gb of oil (Laherrere, 2008). Other assessments have yielded an URR of around 33 Gb (Campbell, 2008). So the URR value of Norway here is well in line with other studies.

The Norwegian Petroleum Directorate gives an estimate based on a probability distribution and also explicitly mentions the uncertainty in all estimates of undiscovered resources. A total of 4 Gb is assumed with P90 and 16.6 Gb with P10, this gives a mean value of 9.6 Gb (Norwegian Petroleum Directorate, 2007). Somewhat optimistic compared to other studies.

The discovery of dwarf oil fields peaked in the 1990s and has been in decline since then, despite new exploration efforts and introduction of new technology. Discovery of condensate also reached its maximum level in 1990s. NGL discoveries peaked around the same time as condensate and dwarf oil fields.

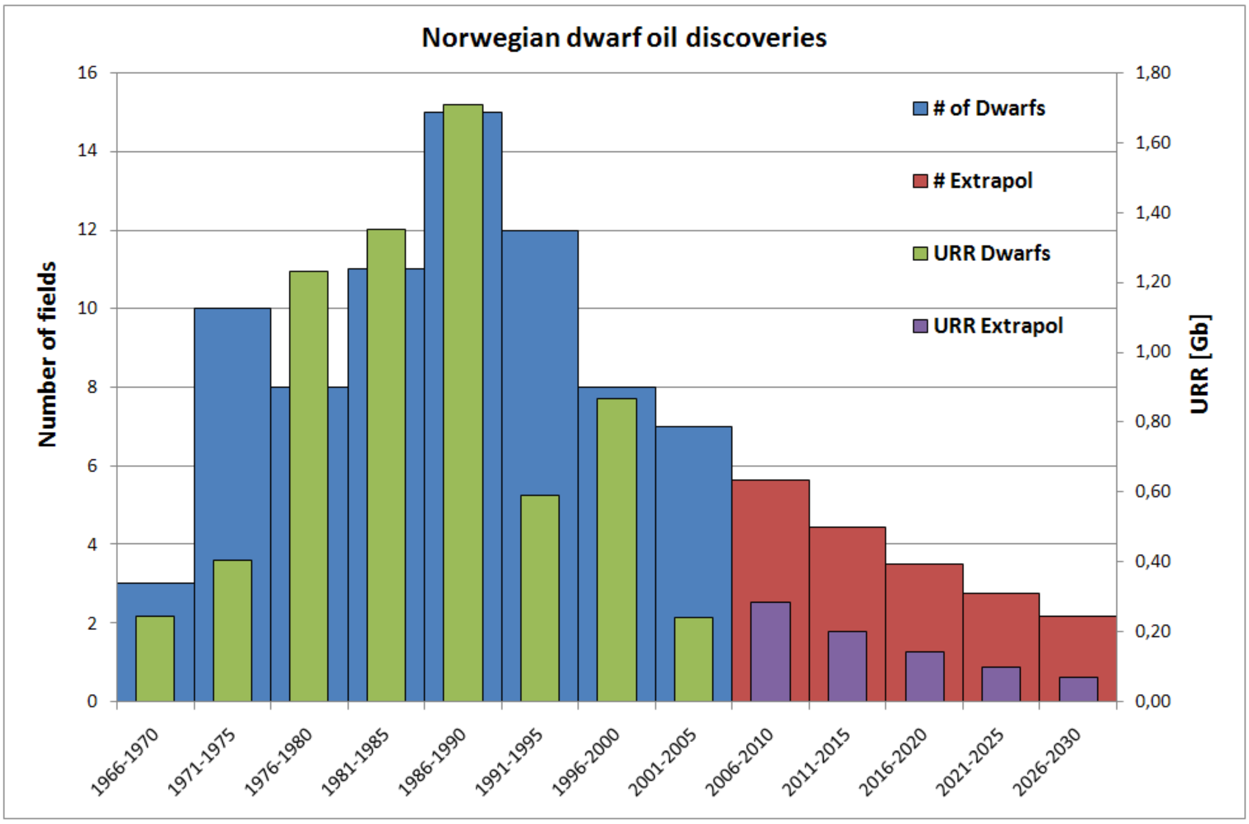

Figure 6. Extrapolation of the undiscovered amounts of dwarf oil fields in Norway with respect to both URR and number of fields.

The extrapolated discovery values of URR and number of fields are transformed to a reasonable number of fields with suitable size. The undiscovered fields are assumed to be brought into production with similar delay, between discoveries to first oil production, as already existing fields. This delay is typically 5 to 10 years. Most of the undiscovered fields will therefore come online around 2020.

The production from the undiscovered fields is modelled in the same way as the new field developments and thus assumed to follow the behaviour of already existing fields of similar size.

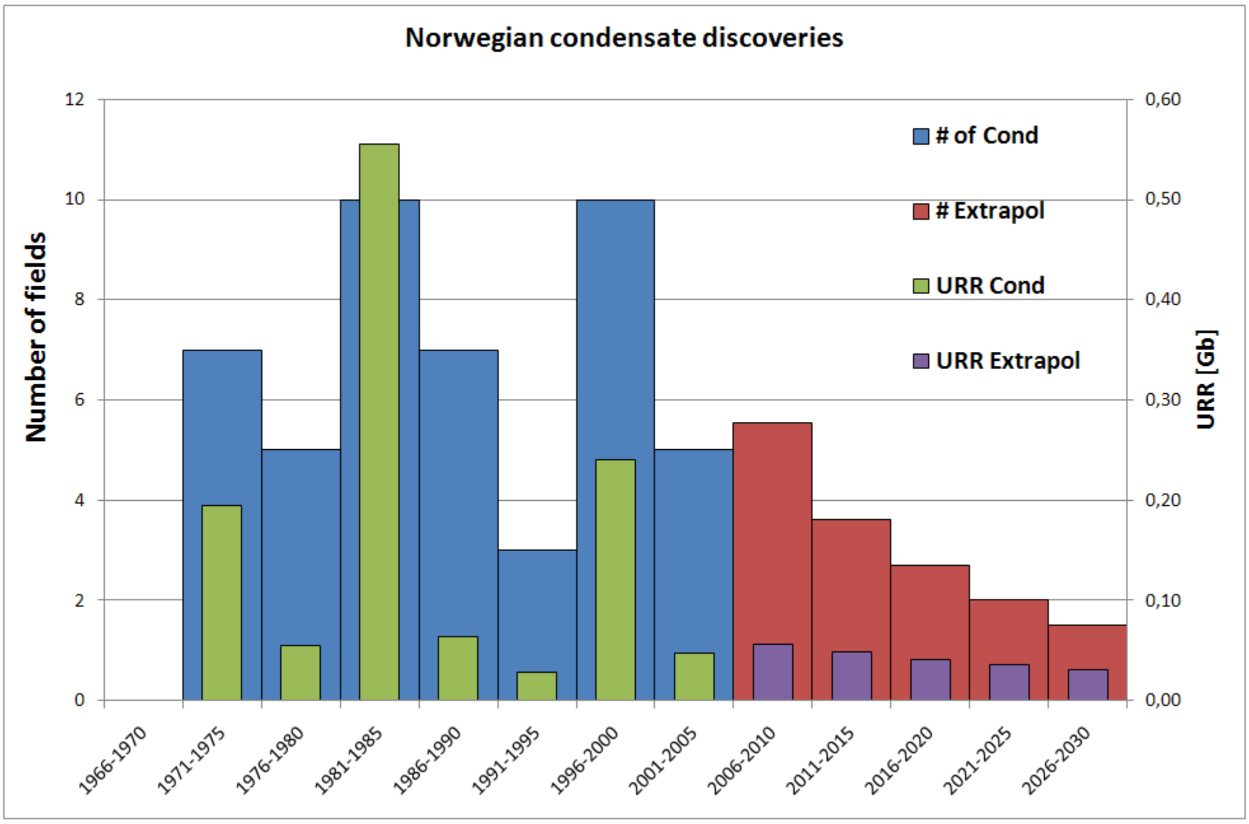

Figure 7. Extrapolation of the undiscovered amounts of condensate in Norway with respect to both URR and number of fields.

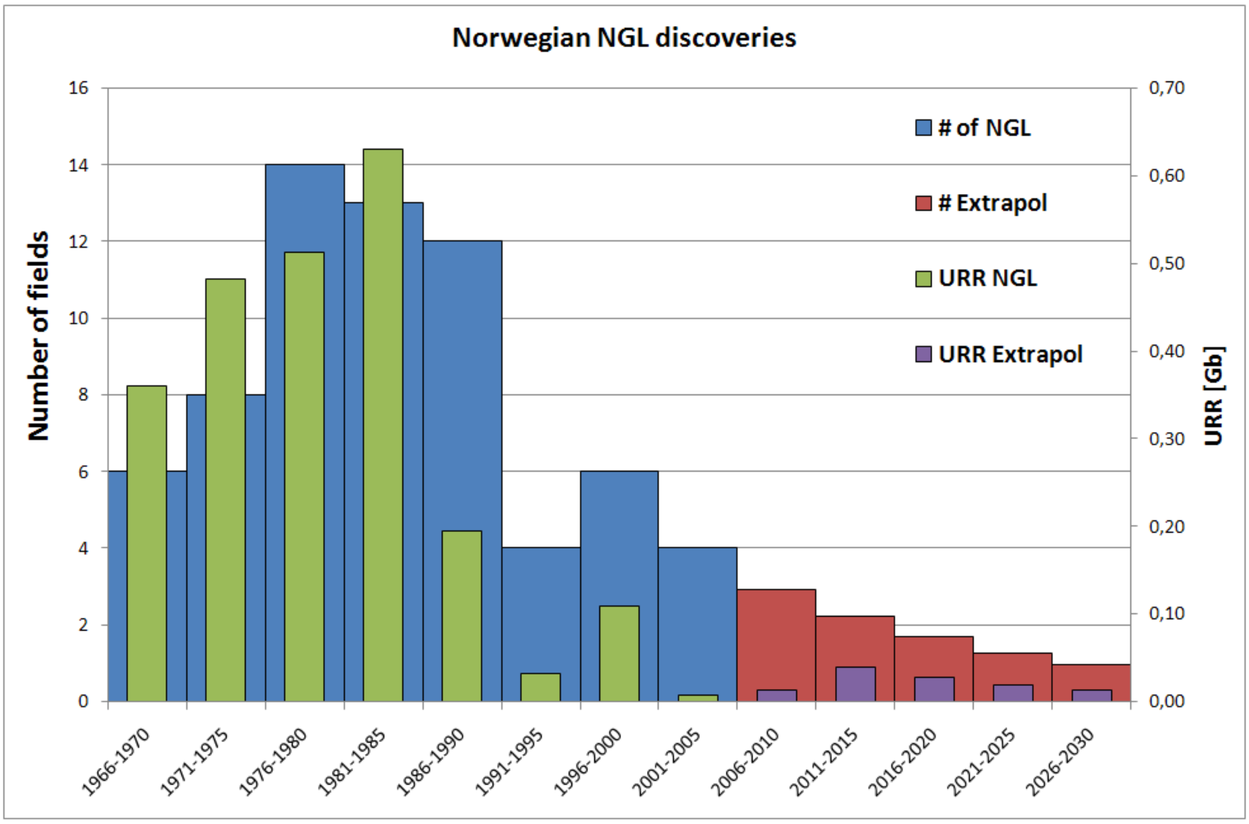

Figure 8. Extrapolation of the undiscovered amounts of NGL in Norway with respect to both URR and number of fields.

Forecast

The future oil production of Norway is forecast by a field-by-field analysis. All fields in decline phase are expected to continue their decline with typical decline rates for their subclass.

Production from new field developments is assumed to start according to official statements. In some cases no official start-up dates are available and for these fields typical delays between discovery to first oil. The production profiles of both undiscovered fields and new field developments are assumed to mimic the behaviour of already existing fields of similar size.

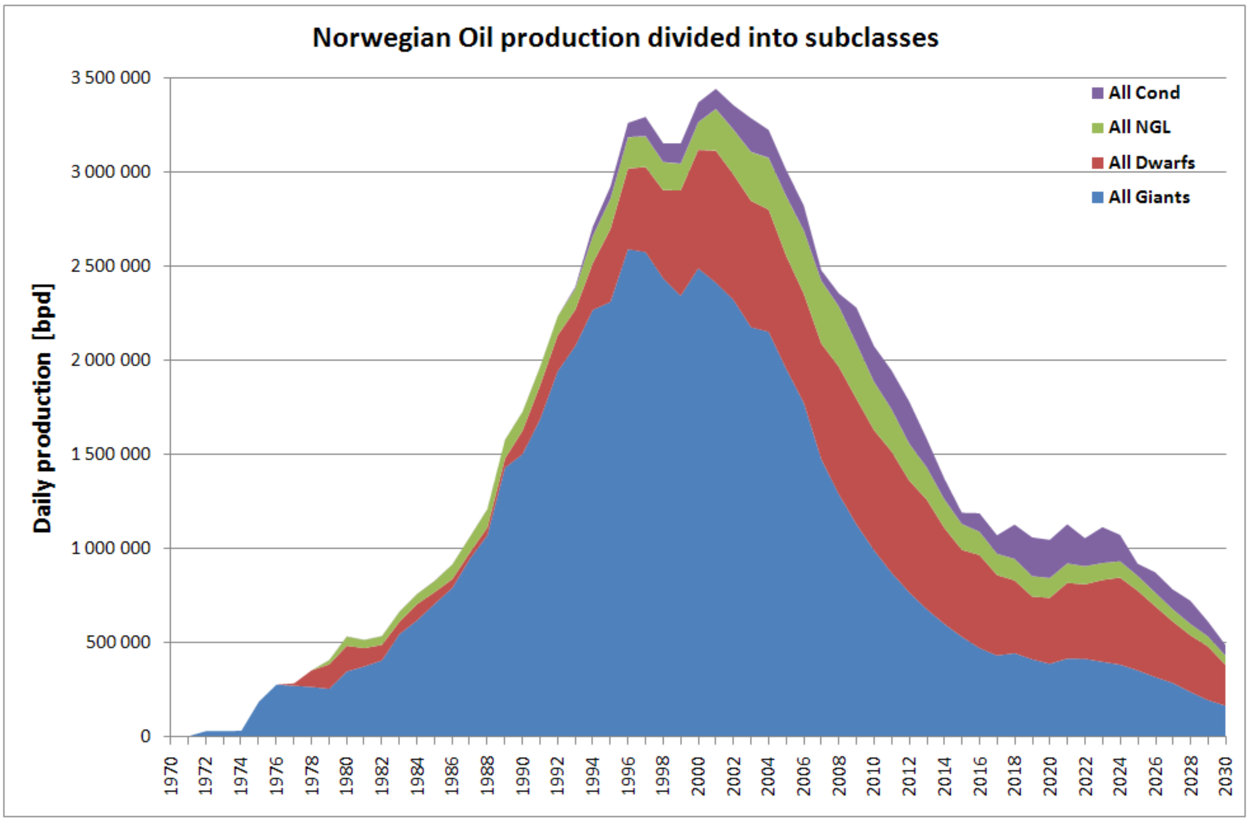

Figure 9: Future Norwegian oil production divided into subclasses. Giant oil fields will continue to be very important, but their share will diminish with time. NGL and condensate will remain as minor contributors even in the future.

The future Norwegian oil production will be very dependent on undiscovered fields. The current fields that can be found in different categories within the new field developments are all quite small and will be unable to do anything else than slightly decrease the overall decline of oil production. The most important factor the future Norwegian production is the development of the giant oil fields and how fast they decline.

Much hope must be placed on the Barents Sea. This region is less than fully explored so it might offer a few more new giants, especially when it comes to gas. However the geology of the Barents Sea is generally unfavourable. Partly this is due to the large vertical movements of the crust under the weight of the fluctuating ice caps during the previous ice ages that had pushed source-rocks below the oil window and destroyed seal integrity.

Finding more oil fields and bringing them into production is essential to dampen the decline from existing fields. Unless new discoveries are made Norway will barely be self-supplying with oil by 2030.

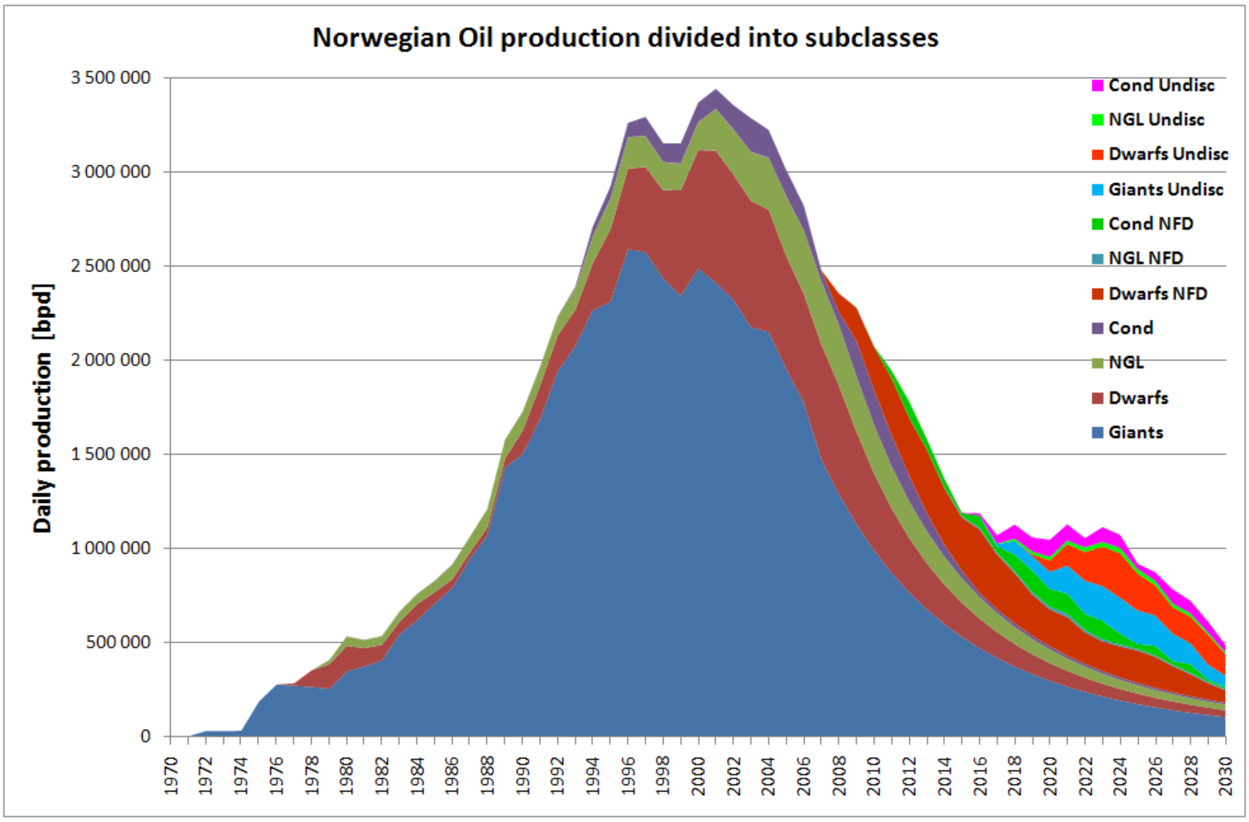

Figure 10: A possible future oil production of Norway divided into more subparts. Undiscovered giants, dwarfs and condensate will be able to decrease the decline for a moment before the decline starts again. High hopes must therefore be placed on the not fully explored the Barents Sea. Discoveries of new giant fields and new dwarf fields are essential for the future of Norwegian oil production.

In this forecast the total oil production of Norway will be around 500 000 barrels per day in 2030. By including enhanced oil recovery (EOR) it will probably be possible to increase this a bit. A more comprehensive field-by-field study of proposed projects and future potentials are needed to provide a more reasonable picture.

By assuming a 10% increase in overall recovery from EOR an additional 3.5 Gb of oil can be squeezed out from the Norwegian continental shelf. If this assumed to be evenly distributed over the next decades the total oil production might be 100 000 bpd or even more than in the forecast above. However a more detailed study is needed to determine the potential and future impact from EOR in Norway.

In 2008 the domestic Norwegian oil consumption was 226 175 barrels per day. By applying a 1% annual increase in the oil consumption, which is reasonable for a continued economic growth, the domestic oil consumption in 2030 will be 281 524 bpd.

By subtracting the domestic consumption from the total production a rough estimate of the export can be found. Only around 200 000 bpd will be available for export in this case. This is a dramatic decrease from today's export volume well over 2 Mbpd.

The oil fund of Norway

The Norwegian government has been wise in understanding that the oil will run out with time and that the wealth it brings must be saved for future generations. This has been done by investing the revenue from oil export in a fund originally referred to as *the petroleum fund of Norway*. In 2006 the name was changed to The Government Pension Fund.

The fund is managed by the Norwegian Central Bank and follows a set of guidelines, including ethical norms for investments, set up by the Norwegian Ministry of Finance. The funds capital is invested in bonds and equities in accordance to the guidelines. Since 1998 the fund has been allowed to invest 50% of its portfolio in the international stock market.

Also the Norwegian government have been very reluctant to use petroleum revenues in the state budget, based on the belief that increased spending will lead to higher inflation and perhaps even an overheated economy. Looking back at history this have been a wise strategy have in many ways managed keep Norway free from “the Dutch disease”, that struck the Netherlands after their discovery of natural gas in the 1960s (The Economist, 1977).

The oil fund is now the largest pension fund in the world with a total value of over 2000 billion Norwegian crowns, which corresponds to over 400 billion US dollars. The fund owns more than 1% of the entire European stock market (International Herald Tribune, 2008).

The financial turmoil has recently taken a serious toll of the oil fund and some analysts estimate the total losses over the first quarter of 2008 to more than 100 billion Norwegian crowns (Aftenposten, 2008), (Dagbladet, 2008). Further instability can potentially cause even more losses. In the light of peak oil and the stagnant world oil production the future development of the stock market should be re-examined. Historically the economic growth of the world has been tightly linked to increased oil consumption. Strong reaction in prices and economic upheaval are possible when the reaches peak production (Hirsch, 2008; Deutsche Bank, 2004).

Others point out that the access to cheap fossil energy has built up the enormous wealth of the modern world, and when cheap and abundant largely oil-based energy no longer exists tomorrows economic expansion will not occur (Campbell, 2006). What will happen to the stock markets after peak oil is hard to determine, but value papers, bonds and equities risk following the world economy downwards when oil production no longer can satisfy demand or soar to new record price levels.

The peak production of Norway coincided with very low oil prices in the end of 1990s and beginning of 2000s. The export also peaked around the same time, effectively meaning that Norway sold its precious oil at the worst possible time.

In 2006 the oil production had dropped 20% from the peak level of 2001 and on the same time the revenues from oil export had more than doubled. In retrospect, Norway might have profited more if it had postponed some of its production to maximize future revenues from oil export.

When looking into the future in the light of a coming global peak in the oil production, it is only reasonable to assume that oil prices will continue to remain at a high level and perhaps even increase to new record levels. A more long-term strategic thinking when it comes to oil production will be needed to wisely handle the natural wealth from the oil resource. Saudi-Arabia recently declared their intentions to leave some oil finds untapped to preserve oil wealth for future generations (Reuters, 2008). So it might be a good idea to re-evaluate the production policy and think more about what kind of investments that is best to secure wealth for the future Norwegian generations.

To conclude one can say that maximizing production in the short term might not be the best choice for the future. A production profile that is more kept back and saves oil for the future can be better choice for Norway. After all oil in the ground is a physical asset with a real value while bonds and equities are financial assets, with a value only valid within the system that created them. A barrel of oil contains 6.12 GJ of energy and that has a value independent of speculation, financial instabilities and similar.

Conclusion

The Norwegian oil production has been dominated by giant oil fields, both in production and in terms of URR. Dwarf oil fields, NGL and condensate only account for minor shares of the total oil supply.

Based on the historical production profiles of Norwegian fields typical decline rates were found for all subclasses. Giant oil fields decline slower than the other subclasses, but still at a decline rate of more than -10 % annually. The aggregate decline rate of the giant oil fields was found to increase with time, thus challenging the conclusion of the recent CERA-study (Cambridge Energy Research Associates, 2007).

Dwarf oil fields, NGL and condensate were found to decline even faster, in particular condensate with an annual decline rate of almost -40%. Decline rates well over -15 % can be found for these subclasses.

The rapid decline rates found should be taken very seriously, as they imply that oil production could go down very fast in a region. The role of technology is an important factor here, as much production technology have been aimed at prolonging plateau production or increasing depletion, which results in a rapid decline. The new fields that will be brought on-stream in the near future are small and will not be able to compensate for the decline of the old giant fields.

The conclusion from the forecast is that Norway will barely be an oil exporter by 2030, with only a few hundred thousand barrels of oil available for export in the best case. This will have dramatic consequences for the Norwegian economy and for the world, as Norway presently is the world third largest oil exporter.

By using Norway, which openly displays all its production data, a comprehensive and detailed picture of the actual production behaviour can be created. This is of great importance to better understand the future behaviour of other regions and how fast the decline will be after the moment when the world reached peak oil.

Regarding the future the current oil production policy should be re-assessed. With the increasing oil shortage imposed by peak oil and the risk of an unstable financial market the current investment might not be the optimal. Keeping oil in the ground and having a more moderate oil production policy may be a better way of ensuring the future wealth of the Norwegian people.

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Paper II: The evolution of giant oil field production behaviour

Mikael Höök, Bengt Söderbergh, Kristofer Jakobsson, and Kjell Aleklett

Abstract. The giant oil fields of the world are only a small fraction of the total number of fields, but their importance is huge. Over 50% of the world oil production came from giants by 2005 and more than haft of the worlds ultimate reserves are found in giants. Based on this it is reasonable to assume that the future development of the giant oil fields will have a significant impact on the world oil supply.

In order to better understand the giant fields and their future behaviour one must first understand their history. This study has used a comprehensive database on giant oil fields in order to determine their typical parameters, such as the average decline rate and life-times of giants. The evolution of giant oil field behaviour has been investigated to better understand future behaviour. One conclusion is that new technology and production methods have generally lead to high depletion rate and rapid decline. The historical trend points towards high decline rates of fields currently on plateau production.

The peak production generally occurs before half the ultimate reserves have been produced in giant oil fields. A strong correlation between depletion-at-peak and average decline rate is also found, verifying that high depletion rate leads to rapid decline. Our result also implies that depletion analysis can be used to rule out unrealistic production expectations from a known reserve, or to connect an estimated production level to a needed reserve base.

Key words. Giant oil fields, field behaviour, peak oil, depletion

Introduction

There are two main ways of defining a giant oil field. One system is based on ultimately recoverable resources (URR), defining a giant as a field with a URR more than 0.5 Gb. The American Association of Petroleum Geologists (AAPG) follows this definition and has published a series of memoires about giant oil fields and their geology (AAPG, 1970; 1980; 1992; 2003; 2005). Other later studies have used basically the same definition system (Nehring, 1978; Robelius, 2007).

The other system is to use production level, where a giant is a field producing more than 100 000 barrels per day (bpd) for more than one year (Simmons, 2002). Based on this definition of giant oil fields, also fields with production over 100 000 bpd have been included in the data set used in this study, even though they are not giants with respect to URR. It should however be noted that there are only about 20 such fields in total. A more detailed discussion of the giant field data used in this study can be found in the thesis by Robelius (2007).

However, the discovery of giant fields is a thing of the past since a majority of the largest giant fields are over 50 years old and the discovery trend is clearly for fewer giant fields with smaller volumes (Figure 1). The production by subclass can be seen in Figure 2. Understanding of how each subclass behaves is essential for understanding and accurately depicts future oil production.

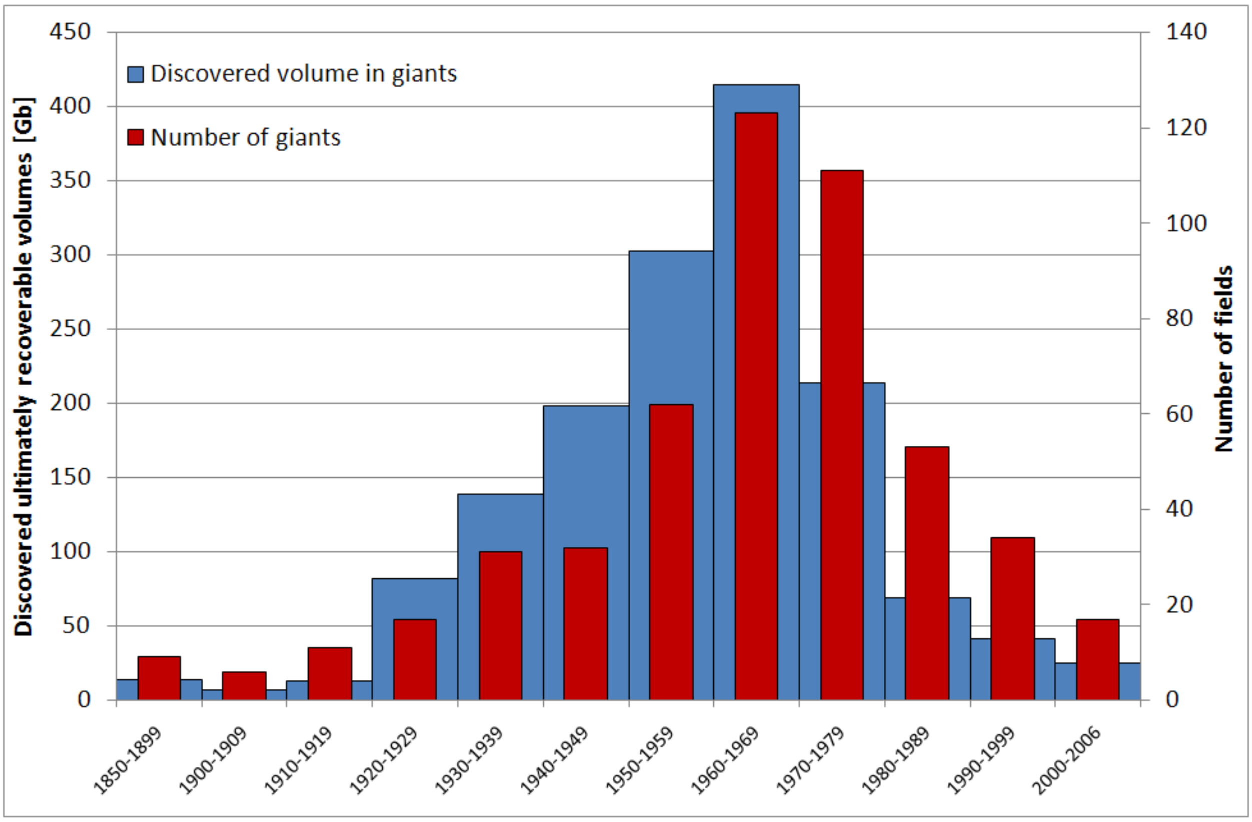

Figure 1. Discovery trend for giant oil fields. The discovered volume refers to the backdated ultimately recoverable resources. Modified from Robelius (2007)

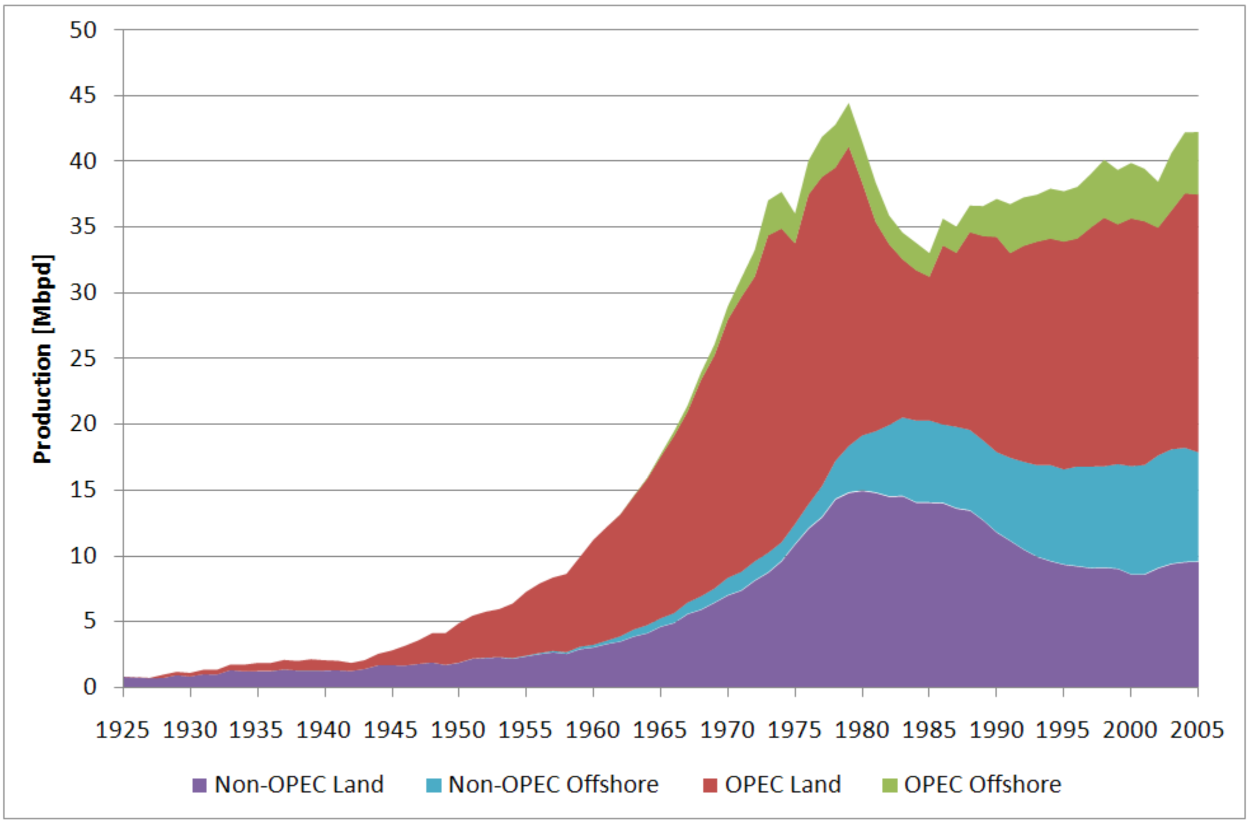

Figure 2. The history of oil production from the world's giant oil fields. The rapid expansion of oil production from the 1950s to the 1980s chiefly came from increased production from Middle East giants. The Non-OPEC nation fields peaked in the 1980s and have been in decline since then. The small upturn after 2000 coincides with the revival of Russian oil production after the fall of the Soviet Union.

Giant oilfield data

The data for this study has been taken from the giant oil field database compiled by Robelius (2007). AAPG was the main source for information about discovery year, year of first oil production, URR and cumulative production (AAPG, 1970; 1980; 1992; 2003; 2005). Other sources such as James (2000), the UK department of Trade & Industry (DTI), IHS, the Norwegian Petroleum Directorate (NPD), Arab Oil & Gas Directory (1980-2008) have also been used in the data compilation. In order to minimize the dynamic aspect of URR estimates, proven plus probable (2P) reserves has been used (Robelius, 2007). The need to use 2P reserves is justified by Bentley et al. (2007).

Production data were obtained from petroleum related trade journals like AAPG Explorer, Offshore, Offshore Engineer, Petroleum Review, Petroleum Economist, Upstream and World Oil. Other sources included statistical yearbooks from NPD, DTI, Petróleos Mexicanos (PEMEX), Nigerian National Petroleum Company (NNPC) and similar sources. Closer description of the database and how it was compiled can be found in Robelius (2007).

Aim of this study

This study will use the production profiles of over 300 giant oil fields to determine their typical production behaviour. The approach is statistical analysis based on production data for individual fields to find the average values of giant oil fields. The fields will be divided into various subgroups to better reflect their different properties and driving forces.

Production behaviour parameters, such as decline and depletion rate, will be investigated in order to show differences in behaviour among the subgroups. We also intend to show that depletion can be a useful parameter for predicting the onset of decline. Also the impact from technology can be revealed by studying how these parameters have evolved over time within the giant oil field population. This is meant as a wider investigation of the results earlier obtained by Gowdy and Juliá (2007).

Finally some brief remarks of how the derived values and parameters can be used to model future oil production from giant fields will be made. Depletion rates are used in oil production forecasts (Mäkivierikko, 2007; Campbell and Heapes, 2008). A closer investigation of depletion on a field-by-field basis may therefore benefit depletion modelling.

The produced share of the ultimate reserves when the peak occurs is also a heavily debated topic. Hubbert (1956) originally stated that the peak would occur when approximately half the resource had been consumed. Campbell and Laherrere (1998) later agreed, while others disagreed (Lynch, 2004). By studying giant oil fields and the produced shares of URR at peak, the discussion can be brought down to a field-level and made clearer.

The decline analysis has been used to model decline in existing production in many cases. This study also uses a larger data set than Robelius (2007) in order to determine a reasonable decline rates for giant oilfields. The derived parameters for may also be used to better model how each subgroup behaves, i.e. better reflecting the differences between onshore and offshore production or between OPEC and non-OPEC fields. The findings will also be compared with the results of the field-by-field analyses performed by Cambridge Energy Research Associates (CERA, 2007) and International Energy Agency (IEA, 2008).

Methodology and definitions

The giant fields can sometimes be very well-behaved and follow a theoretical production profile quite closely (Figure 3). In some fields, production has been influenced by wars, sabotage and temporary shut-downs for political reasons. These fields are generally harder to analyze, as they do not display similarly clear trends or stages. Many fields within OPEC have been partly shut down for a few years, or even mothballed during long periods.

The production profile of a giant field generally has a long plateau phase, thus no clear "*peak*" can be found. Hirsch (2008) defined a 4% fluctuation band in order to define a plateau and the end of that stage has been used as the "*peak year*" in this study. However, some fields do have a clear and distinct peak in their production curves, especially smaller giants.

The decline rate, the average annual decrease in production after the plateau phase ends, is carefully analyzed. An average annual decline rate, corresponding to an exponential decline curve model, was fitted to actual production data for the post-peak region, using least square methods. The exponential decline curve model was first proposed by Arps (1945). Further development of this method was done by Fetkovich (1980) and Mueller et al. (1981).

Due to the simplicity of Arps empirical approach, the basic relations has remained as a benchmark for industry for analysis and interpretation of production data. Although, one should note that the empirical relations has also been shown to be the physical long-term solutions for various cases, such as the exponential decline curve is the physical solution to the constant pressure case (Hurst, 1934; van Everdingen and Hurst, 1949). The advantage of the decline curve analysis is that it is virtually independent of the size and shape of the reservoir or the actual drive-mechanism (Doublet, 1994), avoiding the need for more detailed reservoir or production data.

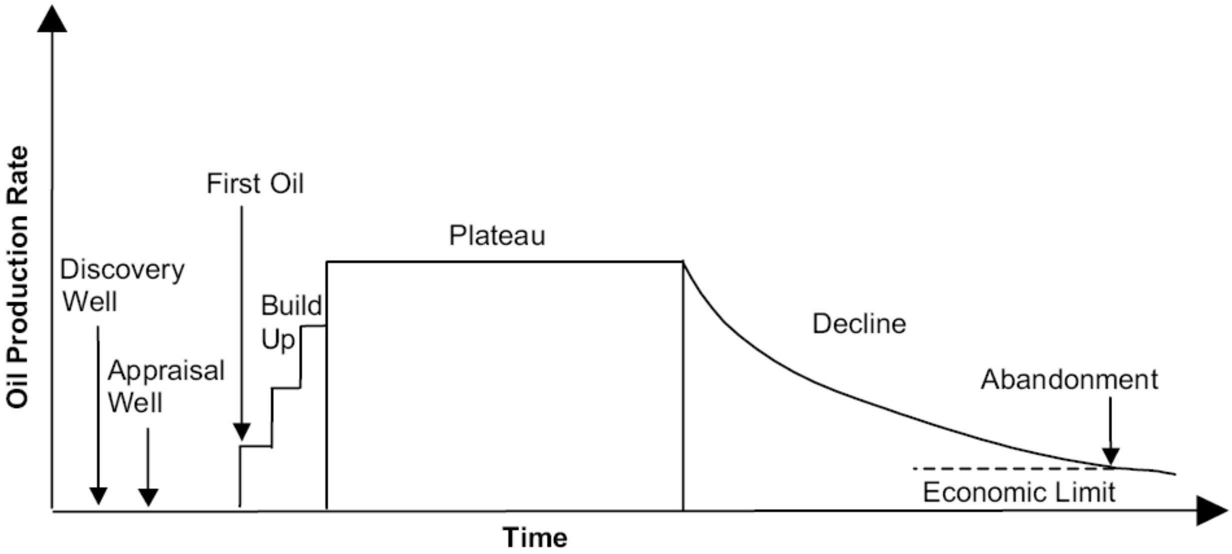

Figure 3. Theoretical production profile of an oilfield, describing various stages of development in an idealized case. Adapted from Feygin and Ryzhik (2001) and Robelius (2007)

The exponential decline model has been shown to be in good agreement with actual field data, both for describing the past and forecasting the future (Höök and Aleklett, 2008). From the exponential decline model it naturally follows that fields show no major change in their decline behaviour over time, consequently there is no need to divide the decline phase into several stages. Despite this, other studies have chosen to split the decline phase into three substages (CERA, 2007; IEA, 2008). For a closer study of the decline rates of giant oil fields and what it means for future oil production a separate study has been performed (Höök et al., 2008).

The depletion rate, i.e. the amount of the remaining ultimate reserves that is extracted each year, is also analyzed. This parameter is calculated using URR and historical production data. The depletion rate when the field peaks or ends its plateau phase is here called *depletion-at-peak* and corresponds to the percentage of remaining reserve that is produced when the onset of decline starts. This parameter is essential for the maximum depletion rate model, which has been discussed in detail by others (Jakobsson et al., 2008). The decline rate, in comparison, is only derived from production data. Consequently, depletion can be seen as a parameter capable of bridging the gap between production and geology.

The cumulative amount of the URR that has been produced at the onset of decline, here called "*Cum.Prod/URR-at-peak*", is also investigated. This parameter is derived from the historical production data and the URR estimate. It is useful for determining how much of the URR can be produced from a field before it will begin to decline. Figure 4, 5, 6 and 7 illustrate the concept with *depletion-at-peak* and C*um.Prod/URR-at-peak*, both on a theoretical and empirical basis.

Naturally there is some uncertainty in the URR estimates, and this will influence both depletion rate and the share of URR produced at peak, as they are derived from both URR and production data. Hundreds of URR estimates for different giant oil fields have been compiled for this study. However, in many cases only one URR estimate per field was found and had to be used. Closer discussion of the spread in URR estimates can be found in Robelius (2007). A higher URR value will yield lower depletion and share of URR produced at peak, while a lower URR value will result in the opposite.

Also the time between discovery to first oil, called "*discovery-to-first oil*", and from first oil to onset of decline, here called "*first oil-to-decline*" is determined for each field. These two parameters show how long it has taken from discovery to start of commercial oil production and for how long a field was in build-up or plateau phase before it started to decline. They can be calculated using the discovery year, year of first oil production and the peak year. These parameters provide information about the life time of a giant oil field.

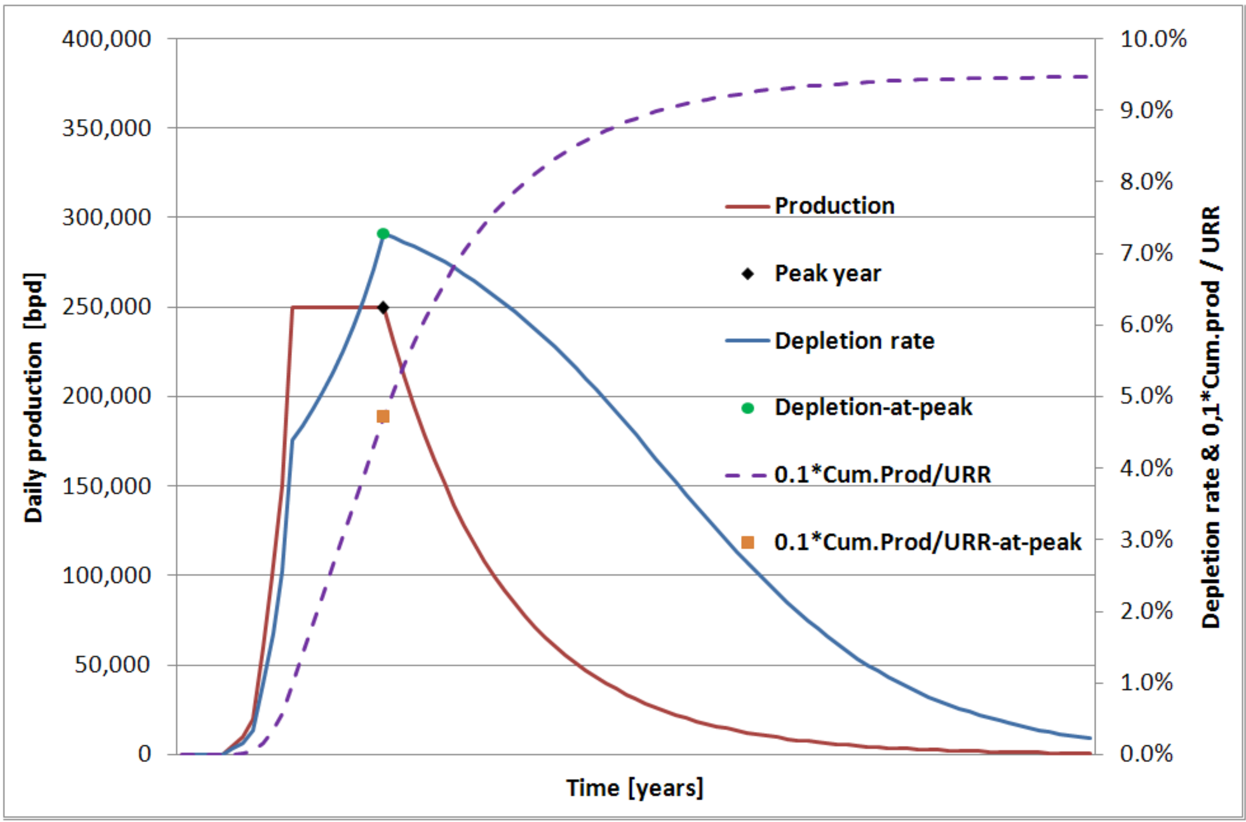

Figure 4. A theoretical production profile of a giant oil field is used to show how the depletion rate and the produced share of the URR evolve as the field passes through various stages of its life. When the plateau ends the "peak" occurs and the depletion-at-peak and Cum-prod/URR-at-peak can be found. The Cum.Prod/URR-at-peak is expressed in percent and has been scaled with a factor 10 to fit in the same axis as depletion rate.

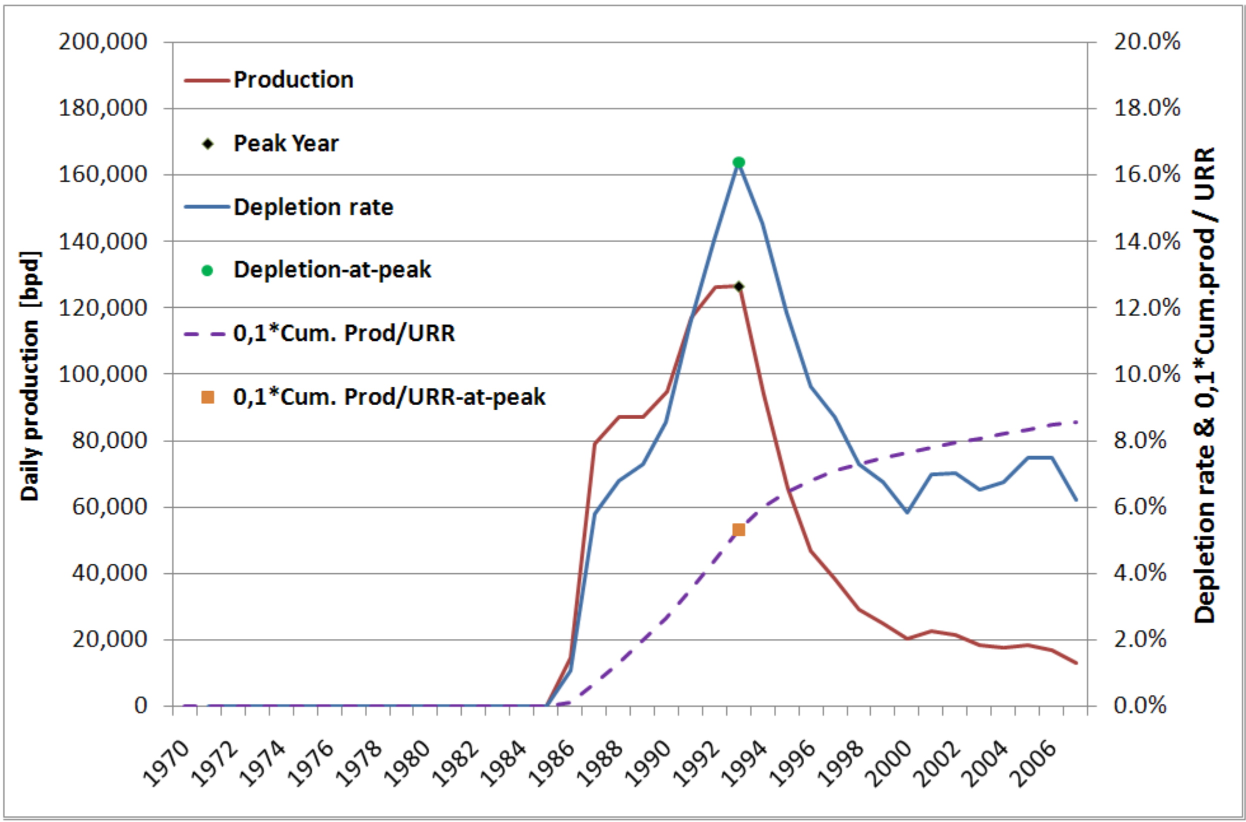

Figure 5. The actual production profile of the Norwegian giant oilfield Ula. The peak occurred in 1993 at a depletion rate of 16.4% with 53% of the URR produced, which is quite representative of many offshore giant fields in the North Sea region.

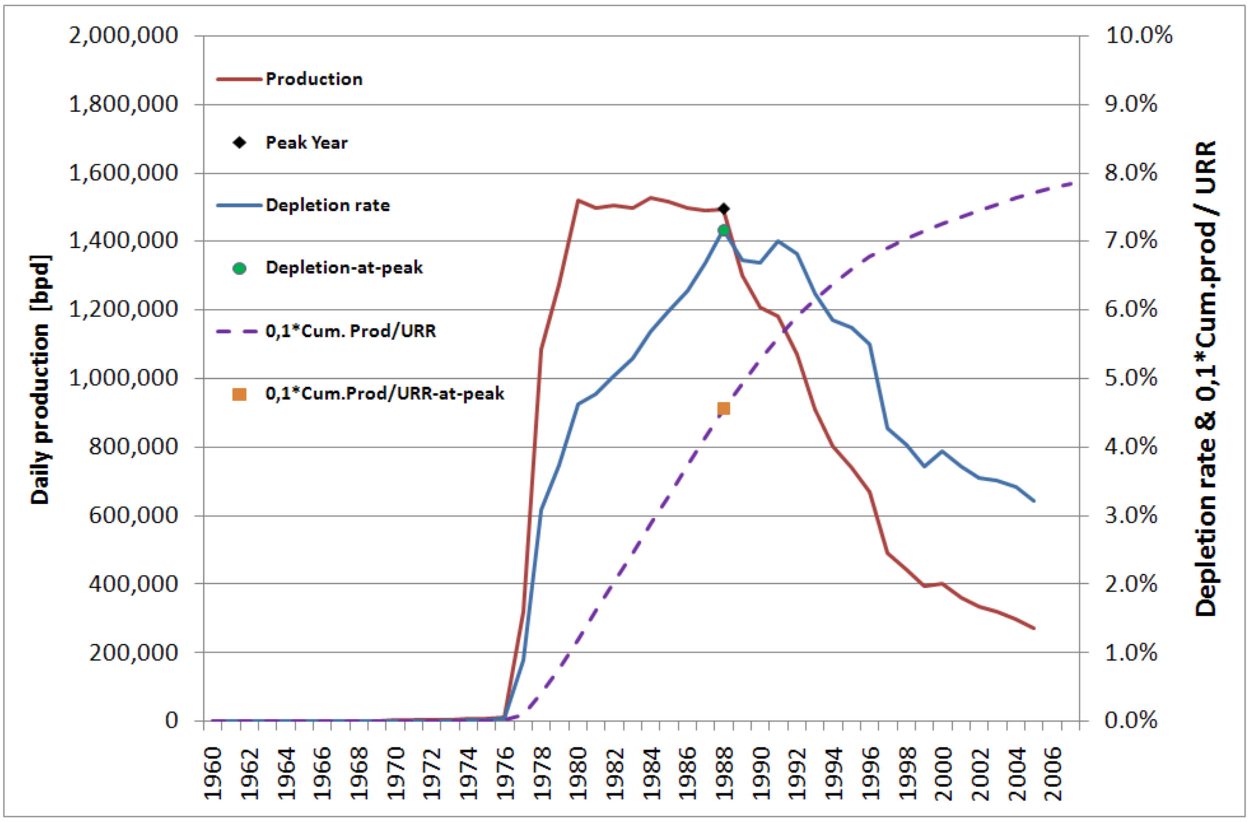

Figure 6. The famous giant oilfield Prudhoe Bay in the USA. The peak happened in 1988 at a depletion rate of 7.2% with 46% of the URR produced.

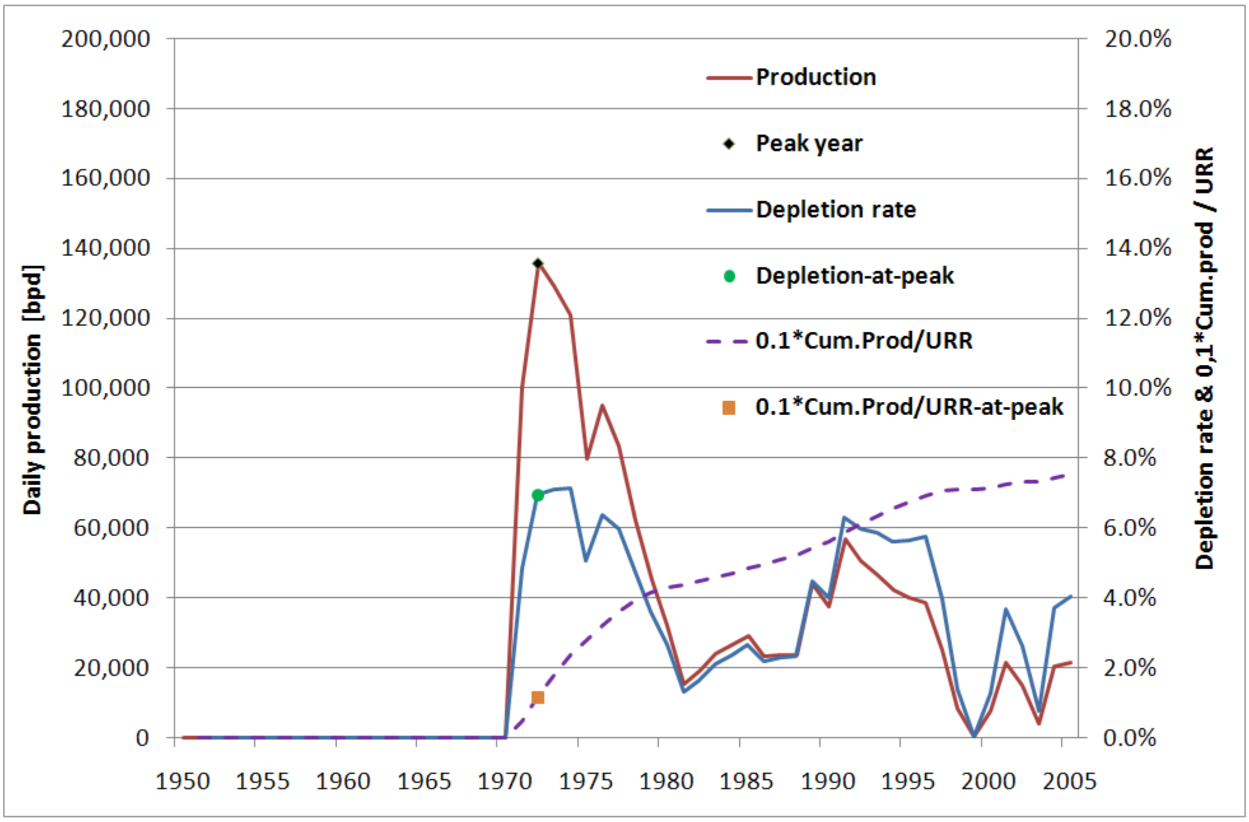

Figure 7. The production curve of the Nigerian giant field Jones Creek. This field peaked at a depletion rate of 7.0% with only 11.5% of the URR produced. Major disturbances, due to civil war, sabotage and rebel attacks, have greatly influenced production.

Characteristic behaviour

The first and most necessary division one must do is to split the giant fields into two subclasses, land-based and offshore fields. Because of the financial and practical differences between these two types of installations, this division is needed to establish a comprehensive picture of how each subclass behaves. A further division into OPEC-fields and non-OPEC fields has also been made. This is to reflect better the potentially different behaviour of giants with no political restrictions on production and those limited by quota systems. There is a significant difference in the actual production strategy between the quota-restricted fields in OPEC and those fields outside that organization's control.

This study covers 331 giant oil fields, with a combined URR of over 1100 Gb, based on the most optimistic URR estimations available in the database. The estimates for some fields vary significantly in some cases. For example, URR-estimates for Ghawar range from 66-150 Gb. Closer discussion of the URR estimates can be found in Robelius (2007).

A total of 214 (~65%) fields are land-based, while 117 (~35%) are offshore installations. 261 fields (~79%) have been classified as post-plateau and in decline and of these 170 (~65%) are land-based and 91 (~35%) are offshore. OPEC controls or has controlled 143 (~43%) of the fields. Gabon are no a longer member of OPEC, but was formerly a part of the organisation; consequently their fields are therefore classified as OPEC-fields because they have been subjected to the quota system. Same applies to Ecuador, which suspended its OPEC membership in 1992 and rejoined in 2007. In total the OPEC class includes 104 (~73%) fields on land and 39 offshore (~27%). Outside OPEC, 190 fields have been studied with 110 fields (~58%) onshore and 78 (~42%) offshore. The North Sea, Russia and the US can perhaps be seen as the most important regions within the non-OPEC group.

Based on their production curves some parameters can be calculated for each field. The number of fields is also large enough to provide reasonable statistics and form a sound mean value of the giant oil fields as a group. These values were also weighted against the peak/plateau production to provide an alternative view. Table 1 shows the values of all analyzed giant fields, regardless of their geographical location or which nation controls them. It should be noted that such a wide group is likely to miss the details and differences between, for instance, land and offshore fields.

The mean value was calculated as the arithmetic mean. The median value was defined as the common median, i.e. the value that separated the lower half of the population from the upper half. The standard deviation was defined as in Equation 1. The production-weighted average was defined as Equation 2. The reason for weighting against the peak/plateau production level was to find a suitable way of giving greater weight to fields which play a larger role in the production. This means that a 1 Mbpd field will be regarded as more important than a 100 000 bpd field. We believe that this weighting is better than using the cumulative production, since high production flows matter more to the oil market than modest flows under longer times. However, no weighting method can be seen as optimal, our choice will also be a complement to IEA (2008), which weighted against cumulative production.

$$\sigma = \sqrt{\frac{\sum(x-\bar{x})^2}{(n-1)}} \qquad \text{(Equation 1)}$$

where n = sample size, $\bar{x}$ = arithmetic mean of sample

$$\text{PW-decline} = \frac{\sum D_i * P_i}{\sum P_i} \qquad \text{(Equation 2)}$$

Where D_i = decline for individual fields according to the exponential decline curve model, and P_i = peak or plateau production level of individual fields.

From Table 1 it can be seen that there is a significant spread in the data and simple calculations, without taking the special properties of various subgroups into account, does not give very trustworthy numbers. Figure 8, 9, 10 and 11 gives a better example of the spread in some of the data.

Table 1. *Characteristic parameters of giant fields. Fields that have not yet reached their decline phase (as of 2005) are excluded. In total the post-plateau behaviour of 261 giant oil fields, distributed all over the world, is summarized here.*

All giant fields	Mean	Median	Prod. weight	Std. dev.
Depletion-at-peak	8.1%	7.2%	7.2%	4.3%
Decline rate	-6.5%	-5.3%	-5.5%	4.9%
Cum. Prod./URR-at-peak	38.6%	38.3%	36.8%	16.9%
Discovery-to-First Oil	5.2 years	3.0 years	4.2 years	5.7 years
First Oil-to-Decline	17.7 years	13.0 years	18.7 years	16.1 years

An analysis of giant oil fields divided into onshore and offshore fields yields the results displayed in Table 2. Both land and offshore fields enter the decline phase when about 40% of the URR have been produced, but offshore fields tend to extract the oil at a higher rate than land-based fields. This also explains why the average lifetimes of offshore fields are shorter than for land-fields and why they decline faster. Unsurprisingly, one can also, see that offshore fields require more time from discovery to the start of commercial oil production. All this is logical due to the higher investments required for offshore installations.

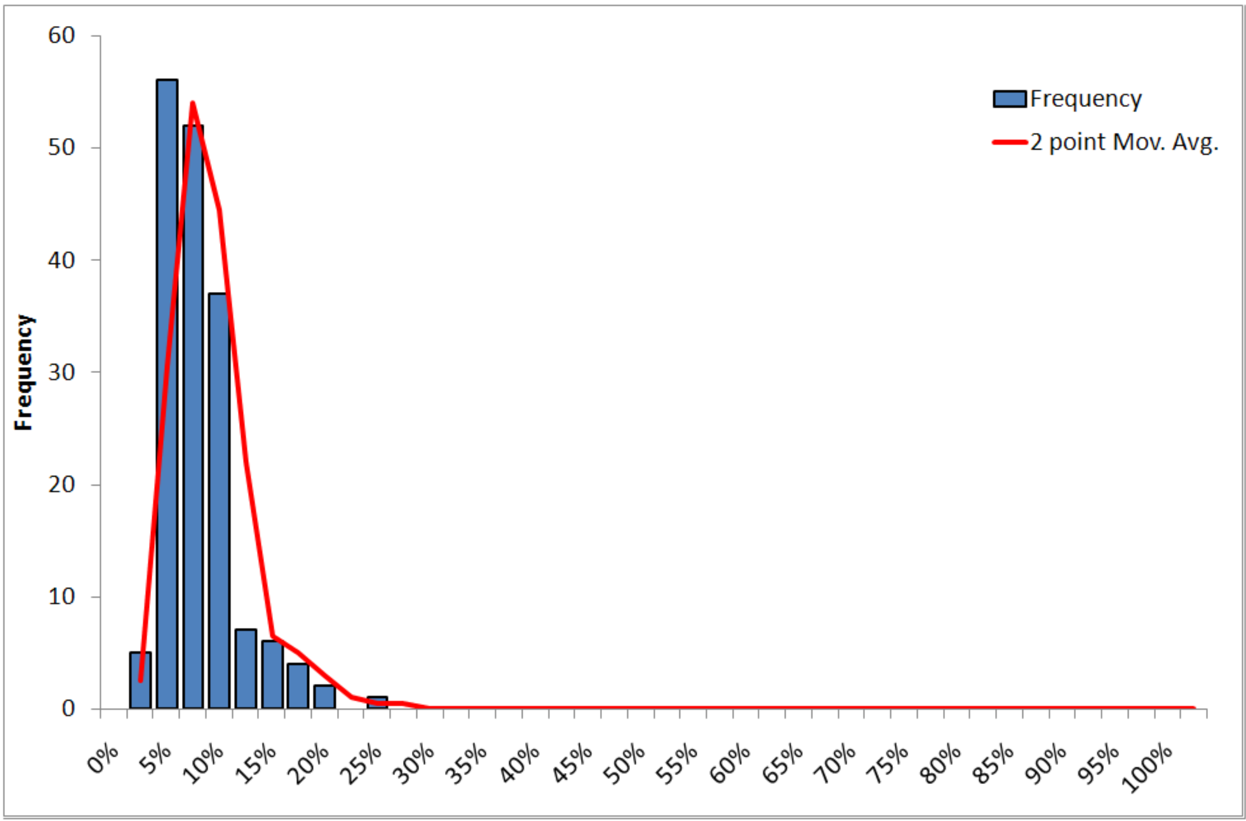

Figure 8. Histogram of the depletion-at-peak of the 170 post-plateau giant fields located on land. A small spread occurs, but the vast majority is centered in the 5-10% interval. Despite the fact that all the studied field are widely different, in terms of reservoirs, production strategies and much more, the actual difference in behavior seems small.

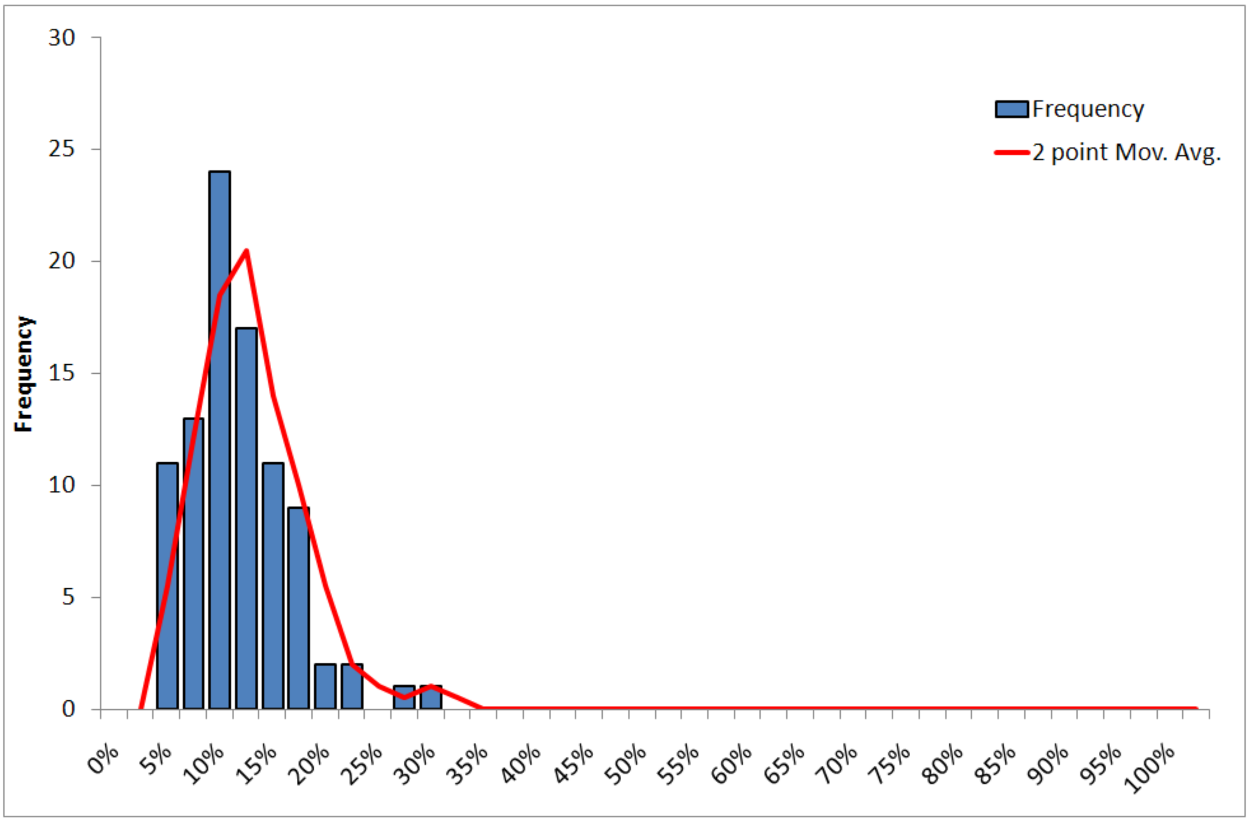

Figure 9. Histogram of the depletion-at-peak of the 91 post-plateau giant fields located offshore. The spread is somewhat larger than for land fields, but once again the majority is located in a relatively narrow interval.

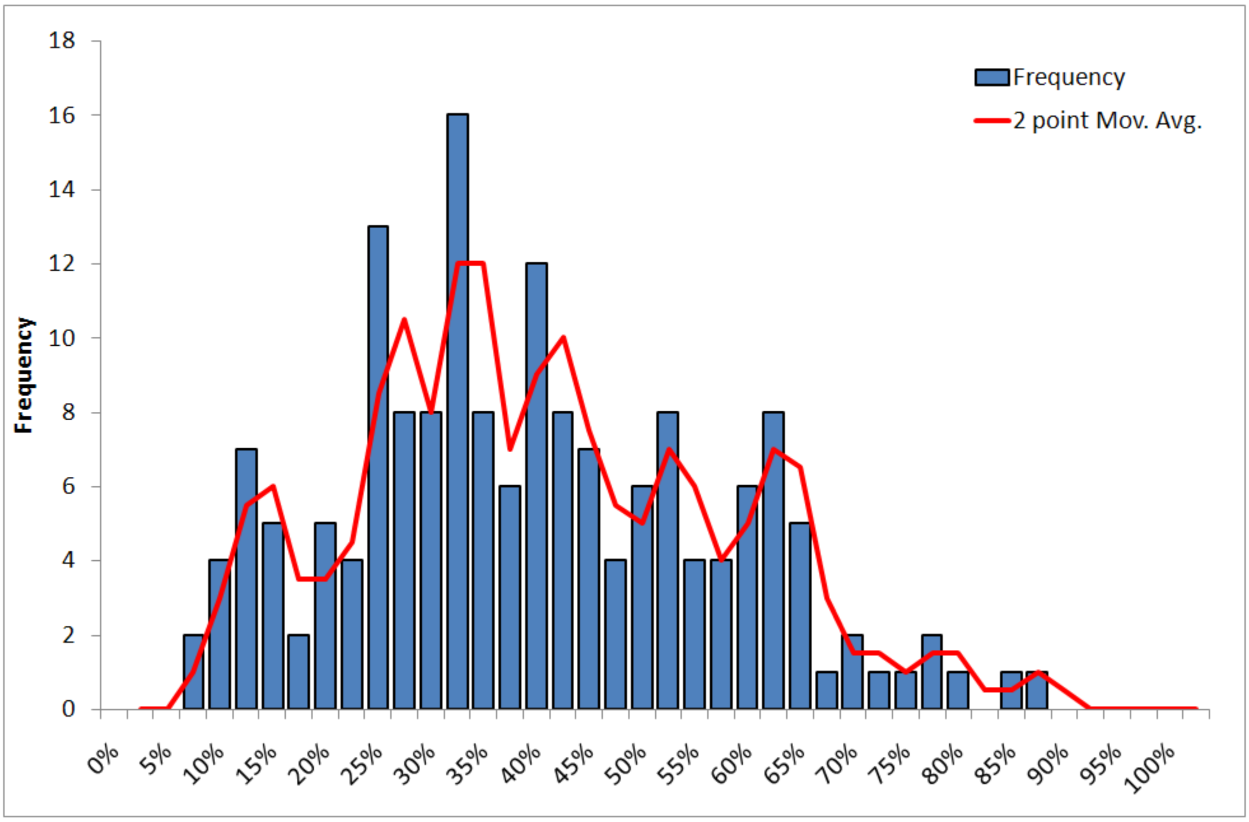

Figure 10. Histograms of the share of URR produced at the onset of decline for giant oil fields located on land. The fields with over 55% of URR produced at peak are almost solely the American giants that were revived during the oil crisis in the 1970-1980s.

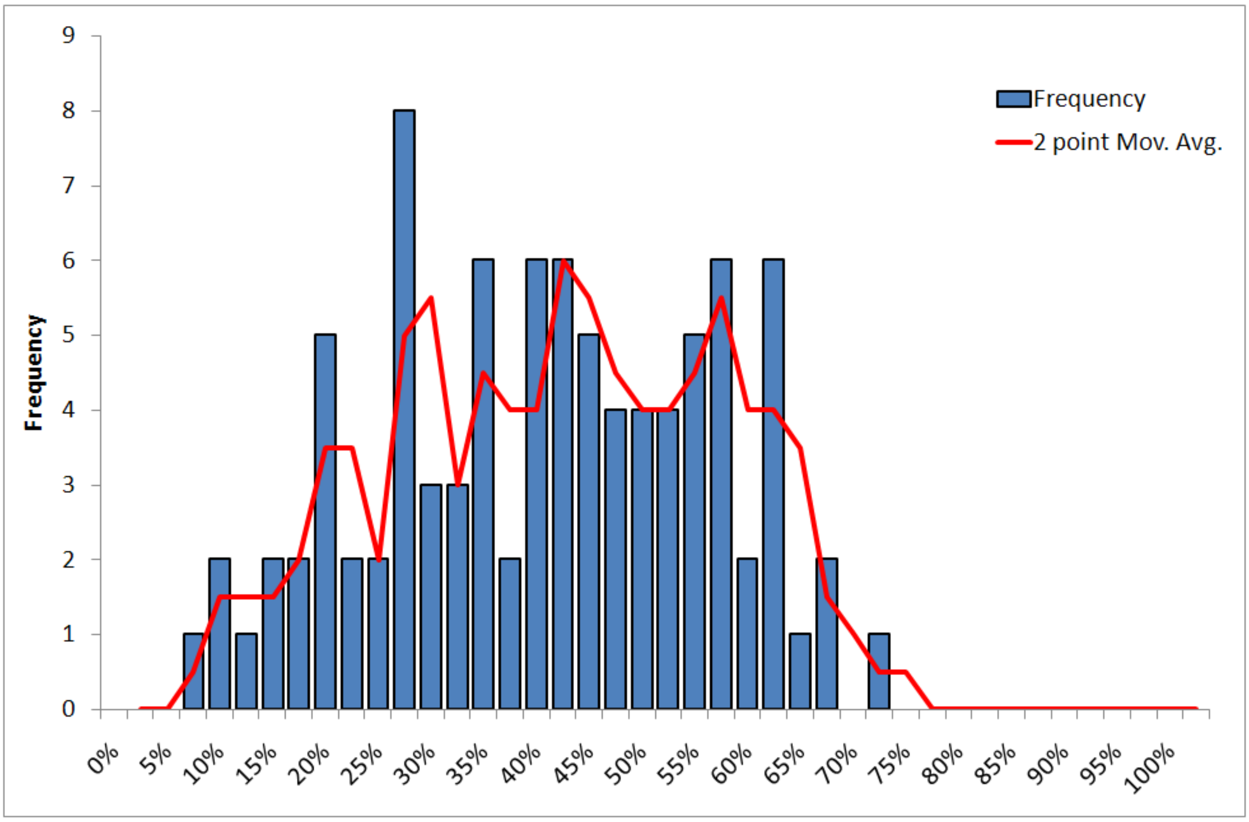

Figure 11. Histograms of the share of URR produced at the onset of decline for giant oil fields located offshore.

Table 2. Characteristic behaviour of land and offshore fields. The land group include 170 post-plateau fields and the offshore group 91 post-plateau fields. Fields that have not yet ended their plateau phase or are in build-up phase are excluded (as of 2005).

Land Fields	Mean	Median	Prod. Weight	Std. Dev.
Depletion-at-peak	6.8%	6.1%	5.8%	3.5%
Decline rate	-4.9%	-4.4%	-3.9%	3.5%
Cum. Prod./URR-at-peak	38.1%	36.2%	34.1%	17.5%
Discovery-to-First Oil	4.6 years	3.0 years	3.7 years	5.4 years
First Oil-to-Decline	21.4 years	16.0 years	21.0 years	17.9 years
Offshore Fields	**Mean**	**Median**	**Prod. Weight**	**Std. Dev.**
Depletion-at-peak	10.4%	9.4%	11.0%	4.8%
Decline rate	-9.4%	-9.0%	-9.7%	5.8%
Cum. Prod /URR-at-peak	39.4%	40.3%	44.0%	15.7%
Discovery-to-First Oil	6.3 years	5.0 years	5.3 years	6.0 years
First Oil-to-Decline	10.8 years	8.0 years	12.4 years	8.3 years

From Table 2 it can be seen that the actual difference in behaviour for land and offshore fields is significant. This division also reduces the dispersion in the data and yields a more reliable result.

The results of the non-OPEC fields can be seen in Table 3. Once again the high depletion, high decline rates and short lifetimes of offshore fields compared to land fields can be seen. The average decline rate of all non-OPEC giant fields is above 7%, indicating that non-OPEC production will be dropping relatively fast, especially in offshore regions.

Many of the low decline rates can be found in fields from the USA that peaked prior to the 1970s. In fact, most of the non-OPEC land group is dominated by the USA and its giant fields. The non-OPEC offshore group is mostly dominated by giant fields in the North Sea. Many fields, both giant fields and smaller ones, in the North Sea show a high decline rate (Höök and Aleklett, 2008; Zittel, 2001).

Table 3. Characteristic behaviour of non-OPEC fields. In total 164 fields are analysed, of which 67 fields are offshore and 97 are located on land. Fields that have not yet ended their plateau phase or are in build-up phase are excluded (as of 2005). In total 87% of all giants outside OPEC can be classified as post-plateau, this corresponds to having 83% of all the URR in giant oil fields outside OPEC located in post-plateau fields.

All Non-OPEC fields	Mean	Median	Prod. weight	Std. Dev.
Depletion-at-peak	9.1%	8.0%	8.7%	4,7%
Decline rate	-7.5%	-6.3%	-7.1%	5,0%
Cum. Prod./URR-at-peak	42.2%	41.4%	40.7%	16,7%
Discovery-to-First Oil	5.0 years	3.0 years	3.8 years	5,1 years
First Oil-to-Decline	19.1 years	14.0 years	17.9 years	17,6 years
Non-OPEC land	**Mean**	**Median**	**Prod. weight**	**Std. Dev.**
Depletion-at-peak	7.5%	6.5%	6.8%	3,7%
Decline rate	-5.7%	-4.7%	-5.2%	3,6%
Cum. Prod./URR-at-peak	42.8%	40.5%	37.4%	18,0%
Discovery-to-First Oil	4.0 years	2.0 years	2.6 years	4,9 years
First Oil-to-Decline	25.0 years	19.0 years	21.2 years	19,7 years
Non-OPEC offshore	**Mean**	**Median**	**Prod. weight**	**Std. Dev.**
Depletion-at-peak	11.5%	10.6%	11.8%	4,9%
Decline rate	-10.0%	-9.4%	-10.3%	5,6%
Cum. Prod./URR-at-peak	41.3%	41.6%	46.2%	14,7%
Discovery-to-First Oil	6.3 years	5.0 years	5.7 years	5,2 years
First Oil-to-Decline	10.4 years	9.0 years	12.6 years	8,0 years

Table 4. Characteristic behaviour of OPEC-fields. In total 97 fields, of which 24 fields are offshore and 73 are located on land. Fields that have not yet ended their plateau phase or are in build-up phase are excluded (as of 2005). In total 67% of all OPEC giant fields can be classified as post-plateau, which corresponds to having 48% of all URR in OPEC giants in post-plateau fields.

All OPEC fields	Mean	Median	Prod. weight	Std. Dev.
Depletion-at-peak	6.3%	5.9%	5.3%	2,8%
Decline rate	-4.8%	-4.1%	-3.4%	4,2%
Cum. Prod./URR-at-peak	32.4%	31.6%	31.5%	15,3%
Discovery-to-First Oil	5.6 years	3.0 years	4.7 years	6,3 years
First Oil-to-Decline	15.6 years	12.0 years	19.8 years	13,1 years
OPEC land	**Mean**	**Median**	**Prod. weight**	**Std. Dev.**
Depletion-at-peak	5.9%	5.4%	4.9%	2,7%
Decline rate	-3.8%	-3.8%	-2.8%	2,8%
Cum. Prod./URR-at-peak	31.8%	31.2%	31.0%	14,6%
Discovery-to-First Oil	5.3 years	3.0 years	4.8 years	6,3 years
First Oil-to-Decline	16.7 years	12.5 years	20.8 years	13,9 years
OPEC offshore	**Mean**	**Median**	**Prod. weight**	**Std. Dev.**
Depletion-at-peak	7.5%	7.7%	7.5%	2,8%
Decline rate	-7.7%	-6.1%	-7.5%	6,1%
Cum. Prod./URR-at-peak	34.1%	33.8%	34.8%	17,6%
Discovery-to-First Oil	6.4 years	4.0 years	3.9 years	7,5 years
First Oil-to-Decline	12.0 years	7.0 years	12.0 years	9,3 years

In comparison to the non-OPEC group one can see that the OPEC group generally has lower depletion rates and decline rates, as seen in Table 4. One quite intriguing detail is that OPEC fields tend to exit the plateau phase at a lower percentage of the URR as produced volumes. This is in many ways an explanation for the lower decline rate. Instead of a prolonged plateau, a longer decline phase with less annual decrease has generally been favoured as a production strategy compared to the non-OPEC fields.

Both land and offshore fields within OPEC tend to have much softer decline rates than their non-OPEC counterparts. The general conclusion from this is that the OPEC quota system has been quite efficient in restricting production levels and maintaining the longevity of fields rather than extracting the oil faster, with the accompanying high decline rates.

Evolution of the field behaviour

Many of the giant fields are old and had their plateau phases before much of the modern technology utilized today was implemented and standardized. Therefore it can be useful to study the evolution of field behaviour and how this has changed over time, due to the introduction of new technology and production methods.

The year that a field left plateau production will be used to form subgroups. For instance if a field started to decline sometime between 1950-1959 it will be sorted into the 1950s group and so on. The same subdivisions as previously will be used here to present a comprehensive picture of how the behaviour has changed from group to group. It should however be noted that in some cases the available statistics are poor, especially in the 2000s due to the low number of fields that started to decline in this decade.

Results for land and offshore fields can be seen in Tables 5 and 6 respectively. The trends are clear and a tendency towards higher depletion, decline rate and share of URR produced when the plateau phase is over can be seen for the giant oil fields. Also the time from first commercial oil production to the onset of decline has considerably increased, as has the proportion of URR produced before a field enters the decline phase. All this can be summarized as a generally prolonged plateau phase compared to further back in time.

One can therefore conclude that average decline rates for the giant oil fields as a group are increasing with time, even though individual field decline rates are constant once the field has left plateau production. This is in agreement with CERA (2007). The important conclusion CERA fails to draw from the historical trends in oil field behaviour is that the fields that are declining now or will begin to decline in the near term will do so with an average decline rate generally higher than the fields that left plateau level earlier in history.

New technology and the introduction of new production methods have greatly altered decline behaviour and the typical parameters for the 1960s are not valid today. Effectively this means also that one must apply a generally higher decline rate to the giant fields in the future. The low average value of -6% annually is not representative for the giant fields that are about to leave the plateau level in the near and medium term. Prolonged plateau level and increased depletion, made possible by new technology, result in a generally higher decline rate. New technology has made it possible to extract oil from fields faster and to keep flow rates high for an extended period of time, but once production starts to fall it falls more rapidly. This is in good agreement with another study on technology and exhaustion (Gowdy and Juliá, 2007).

The land and offshore division is useful to show the general behaviour of giant oil field, but it does not distinguish between fields subjected to the OPEC quota-system with its political restrictions and those producing under more “free market”-conditions. It is especially evident in Table 5 that some unusual behaviour occurred during the 1970s and 1980s. This is very likely connected to the oil crises at that time and the large number of OPEC-controlled land fields that behaved unnaturally for political reasons.

By applying the OPEC and non-OPEC division one can better see how the differences in behaviour have evolved for the two groups (Table 7 and 8). Especially in the OPEC-group the oil crisis in the 1970s can clearly be seen, with a large number of fields starting to decline prematurely at a small percentage of the URR produced compared to those non-OPEC fields that reached the onset of decline in the same decade. This also means that the OPEC fields peaked at lower depletion values, hence showing low average decline rates.

Table 5. Evolution of the behaviour of land-based giant fields. The decade that the fields left plateau production is used to form the different subgroups. The standard deviation is given based on the sample.

# fields	Depletion-at-peak	Mean	Median	Prod. weight	Std. Dev.
23	Pre 1960	6,2%	4,7%	6,6%	3,3%
19	1960s	7,3%	6,8%	8,7%	2,5%
72	1970s	6,4%	5,6%	4,9%	3,4%
25	1980s	6,3%	6,1%	5,6%	1,9%
28	1990s	7,8%	7,0%	6,9%	4,5%
4	2000s	11,6%	11,0%	12,1%	4,8%
# fields	**Average Field Decline**	**Mean**	**Median**	**Prod. weight**	**Std. Dev.**
23	Pre 1960	-4,2%	-4,4%	-4,2%	1,6%
19	1960s	-5,1%	-5,5%	-5,9%	3,0%
72	1970s	-4,2%	-3,9%	-3,0%	3,1%
25	1980s	-4,4%	-4,1%	-3,9%	2,6%
28	1990s	-6,9%	-5,6%	-5,6%	4,8%
4	2000s	-10,7%	-9,8%	-10,1%	3,5%
# fields	**Cum./URR at Peak**	**Mean**	**Median**	**Prod. weight**	**Std. Dev.**
23	Pre 1960	37,5%	36,1%	31,1%	13,9%
19	1960s	35,1%	30,0%	34,0%	18,4%
72	1970s	36,3%	34,2%	31,1%	19,3%
25	1980s	37,2%	31,6%	33,6%	14,7%
28	1990s	44,9%	40,2%	44,7%	16,4%
4	2000s	46,2%	45,2%	46,5%	15,7%
# fields	**Discovery-to-First Oil**	**Mean**	**Median**	**Prod. weight**	**Std. Dev.**
23	Pre 1960	2,4	1,0	2,3	3,3
19	1960s	1,7	1,5	2,0	1,6
72	1970s	4,1	3,0	4,4	4,6
25	1980s	4,7	2,0	3,2	6,2
28	1990s	5,2	3,0	3,9	5,7
4	2000s	1,5	1,5	1,5	1,7

# fields	First Oil-to-Decline	Mean	Median	Prod. weight	Std. Dev.
23	Pre 1960	18,2	17,0	38,3	10,4
19	1960s	17,0	8,0	12,4	19,4
72	1970s	19,9	14,0	19,8	15,6
25	1980s	23,6	16,0	22,1	18,8
28	1990s	27,8	21,5	28,9	24,2
4	2000s	26,3	25,5	25,9	23,5

Table 6. Evolution of the behaviour of offshore giant fields. The decade that the fields left plateau production is used to form the different subgroups.

# fields	Depletion-at-peak	Mean	Median	Prod. weight	Std. Dev.
0	Pre 1960	-	-	-	-
2	1960s	5,3%	5,3%	5,9%	2,4%
17	1970s	7,7%	7,9%	8,1%	3,0%
16	1980s	9,8%	9,9%	10,5%	3,4%
35	1990s	10,9%	9,6%	11,2%	5,2%
19	2000s	13,0%	12,3%	12,4%	5,0%

# fields	Average Field Decline	Mean	Median	Prod. weight	Std. Dev.
0	Pre 1960	-	-	-	-
2	1960s	-2,8%	-2,8%	-3,7%	3,3%
17	1970s	-5,9%	-6,1%	-6,3%	3,5%
16	1980s	-7,9%	-7,5%	-8,9%	4,1%
35	1990s	-10,4%	-11,4%	-10,6%	6,6%
19	2000s	-12,5%	-12,6%	-10,8%	5,1%

# fields	Cum./URR at Peak	Mean	Median	Prod. weight	Std. Dev.
0	Pre 1960	-		-	-
2	1960s	29,8%	29,8%	33,4%	13,7%
17	1970s	29,1%	25,1%	28,5%	14,9%
16	1980s	39,3%	39,6%	40,4%	12,5%
35	1990s	43,8%	44,8%	46,3%	14,9%
19	2000s	41,2%	40,4%	49,8%	17,3%

# fields	Discovery-to-First Oil	Mean	Median	Prod. weight	Std. Dev.
0	Pre 1960	-	-	-	-
2	1960s	3,5	3,5	3,0	2,1
17	1970s	3,8	3,0	3,2	1,9
16	1980s	3,9	3,5	3,8	2,8
35	1990s	5,7	5,0	5,2	3,9
19	2000s	9,4	7,5	6,9	7,1
# fields	First Oil-to-Decline	Mean	Median	Prod. weight	Std. Dev.
0	Pre 1960	-	-	-	-
2	1960s	13,0	13,0	14,1	4,2
17	1970s	9,2	7,0	7,4	8,5
16	1980s	8,3	8,0	8,1	4,3
35	1990s	12,4	11,0	13,0	9,2
19	2000s	11,0	8,0	15,8	9,2

Table 7. *Evolution of the behaviour of non-OPEC giant fields. The decade that the fields left plateau production is used to form the different subgroups.*

# fields	Depletion-at-peak	Mean	Median	Prod. weight	Std. Dev.
13	Pre 1960	6,4%	4,3%	6,9%	4,2%
12	1960s	6,3%	6,5%	6,8%	1,7%
46	1970s	7,9%	6,8%	7,5%	4,0%
33	1980s	8,2%	7,2%	8,2%	3,1%
40	1990s	10,9%	9,5%	10,1%	5,6%
20	2000s	13,3%	12,4%	12,3%	4,9%
# fields	Average field decline	Mean	Median	Prod. weight	Std. Dev.
13	Pre 1960	-4,2%	-3,8%	-4,3%	1,7%
12	1960s	-4,9%	-4,9%	-6,0%	2,5%
46	1970s	-5,8%	-4,7%	-4,9%	3,1%
33	1980s	-6,3%	-5,3%	-4,6%	3,6%
40	1990s	-10,2%	-9,5%	-6,5%	6,6%

20	2000s	-11,7%	-11,8%	-9,9%	4,3%
# fields	Cum./URR at Peak	Mean	Median	Prod. weight	Std. Dev.
13	Pre 1960	37,3%	31,9%	28,2%	16,0%
12	1960s	40,9%	42,8%	37,8%	18,0%
46	1970s	42,8%	43,9%	38,5%	20,6%
33	1980s	38,4%	37,7%	33,3%	14,3%
40	1990s	45,6%	44,8%	46,8%	14,9%
20	2000s	44,3%	43,6%	53,2%	15,6%
# fields	Discovery-to-First Oil	Mean	Median	Prod. weight	Std. Dev.
13	Pre 1960	2,3	0,0	1,7	3,8
12	1960s	2,1	2,0	2,4	1,9
46	1970s	3,2	2,5	2,5	3,0
33	1980s	4,5	3,0	2,3	5,6
40	1990s	6,1	5,5	4,2	4,9
20	2000s	8,6	6,0	0,9	7,4
# fields	First Oil-to-Decline	Mean	Median	Prod. weight	Std. Dev.
13	Pre 1960	18,3	16,0	12,1	11,6
12	1960s	23,9	18,0	20,0	20,8
46	1970s	22,8	23,5	21,9	16,0
33	1980s	17,1	9,0	18,1	17,2
40	1990s	18,0	12,0	29,8	21,7
20	2000s	13,5	11,0	36,2	12,3

Table 8. *Evolution of the behaviour of OPEC giant fields. The decade that the fields left plateau production is used to form the different subgroups.*

# fields	Depletion-at-peak	Mean	Median	Prod. weight	Std. Dev.
10	Pre 1960	5,8%	5,5%	6,1%	1,8%
8	1960s	8,3%	7,9%	10,2%	3,1%
43	1970s	5,3%	4,9%	4,2%	2,1%
8	1980s	5,5%	5,2%	3,4%	2,3%
24	1990s	7,3%	7,1%	6,3%	3,0%
4	2000s	10,2%	8,3%	14,1%	4,6%
# fields	Average field decline	Mean	Median	Prod. weight	Std. Dev.
10	Pre 1960	-4,3%	-4,7%	-4,0%	1,5%
8	1960s	-4,9%	-5,5%	-5,9%	3,9%
43	1970s	-3,2%	-3,1%	-2,2%	2,6%
8	1980s	-3,7%	-4,1%	-1,9%	3,2%
24	1990s	-6,6%	-5,7%	-4,0%	4,5%
4	2000s	-14,7%	-12,2%	-10,2%	7,5%
# fields	Cum./URR at Peak	Mean	Median	Prod. weight	Std. Dev.
10	Pre 1960	37,7%	36,9%	36,1%	11,4%
8	1960s	25,1%	24,4%	30,5%	13,4%
43	1970s	26,5%	24,1%	28,2%	13,0%
8	1980s	36,7%	35,1%	34,6%	12,1%
24	1990s	42,0%	42,8%	41,1%	16,3%
4	2000s	30,7%	28,9%	40,6%	20,4%
# fields	Discovery-to-First Oil	Mean	Median	Prod. weight	Std. Dev.
10	Pre 1960	2,6	1,5	3,4	2,6
8	1960s	1,6	1,5	1,7	1,2
43	1970s	4,9	3,0	5,2	5,3
8	1980s	3,9	4,5	6,2	2,6
24	1990s	4,3	3,0	3,5	4,2
4	2000s	5,5	4,5	2,1	5,6

# fields	First Oil-to-Decline	Mean	Median	Prod. weight	Std. Dev.
10	Pre 1960	18,1	17,0	17,2	9,1
8	1960s	5,6	4,5	5,4	3,9
43	1970s	12,8	7,0	19,0	12,6
8	1980s	20,0	16,0	34,1	15,0
24	1990s	21,1	21,5	27,4	13,3
4	2000s	14,0	5,5	17,0	20,1

Discussion

The historical evolution of depletion-at-peak values for giant fields is of great interest, as depletion-at-peak can be used to make crude estimates of when a field will enter the decline phase. When a field is in plateau production it is possible to estimate when onset of decline will occur, using depletion analysis. The narrow spread in depletion-at-peak for giant oil fields (Figure 8), provides a reasonable ground for estimating the peak years of giant fields currently in build-up or plateau phase. A production peak occurring at too low depletion rate can therefore be regarded as a production disturbance, due to non-geological reasons, rather than the onset of depletion-driven decline. This is obvious in the case of many Middle East fields that peaked in the 1970s, in the wake of the oil crises at that time.

The depletion-at-peak may also be used to control URR-estimates using production curves. If a field is reasonably well-behaved and has reached the onset of decline, one can assume that approximately the same depletion-at-peak was reached as for similar giants. For field on plateau level, one can assume that the depletion rate must be lower than the typical depletion-at-peak levels, otherwise the field would have begun to decline. This can be used to rule out some URR estimates. The enormous Cantarell field of Mexico is estimated to contain ultimate reserves of 11-20 Gb (Robelius, 2007), corresponding to depletion-at-peak values of 66.2-7.5%. It is only the depletion-at-peak values between 5-15% that are reasonable, if Cantarell is assumed to behave similar as other giant oilfields (Figure 8), so the URR-estimates giving depletion levels outside this interval may be regarded as unrealistic. Consequently, depletion connects production output to reserve base, since only some depletion rates are possible for a given reserve base without reaching a peak production.

Alternatively the depletion-at-peak can be used as a reasonable value for the maximum depletion rate in a maximum depletion rate model in order to forecast future oil production (Jakobsson et al., 2008). Understanding depletion and its impact on decline is also vital for determining how the future will unfold. The depletion rate of a region is limited by the depletion rates of the individual fields that make up the region. Further studies of the connection between depletion rates of oil fields and regions should be undertaken to better establish the actual relationship. Depletion models have been used by Campbell and Sivertsson (2003), Mäkivierikko (2007), Campbell and Heapes (2008). It is our hope that the derived depletion behaviour of giant oil fields can benefit depletion modelling of future oil production. Field-by-field analysis shows a narrow distribution of depletion rates in giant oil fields, justifying the use of depletion as a tool for production forecasting.

The produced share of URR at the onset of decline can also be used in the same way to make crude estimates of when a field will reach the onset of decline. On average, about 40% of the URR has been produced for the world's giant oil fields when they leave plateau production and enter the decline phase. Looking at the cumulative production and URR it is then possible to estimate how long a field can remain on plateau production.

As an example consider Ghawar, the world's largest oil field. By 2005 its cumulative production was around 61 Gb and we will make the optimistic assumption of a URR of 150 Gb. Assuming that the production was constant at around 5 Mbpd for 2006 and 2007 the produced share of URR by end of 2007 was 43%. This is in line with the 48% of reserves produced as stated by Saudi-Aramco (2004). This is just about the typical share of URR produced at the onset of decline and can be seen as an indication that the peaking of Ghawar is not very far away. As Ghawar is already subject to extensive water-injection and other secondary measures a high decline rate seems likely once the onset of decline begins. As Simmons (2005) pointed out, “Twilight in the Desert” is likely not far in the future.

Prolonging plateau production and increasing production levels is equivalent to increasing the depletion of the field. Most of the world’s giants have also reached maturity and many of these fields are subject to measures to increase recovery (Babadagli, 2007). Drilling of new wells and installation of more equipment can delay the actual onset of decline for some years, but once that oil field starts to decline the decline is faster. Studies have shown that production technology seldom increases the ultimate recovery, rather, only masks increasing resource exhaustion by increasing the depletion rate (Gowdy and Juliá, 2007).

A strong correlation between depletion-at-peak and average decline rate is also found. The correlation coefficient is calculated to be 0.74. Unsurprisingly, this can be seen as verification of the ironic nature of depletion of finite resources such as oil: “*the better you do the job; the sooner it ends”.*

Conclusions

The characteristic behaviour of giant oil fields has been carefully examined in this study to establish statistically reasonable parameters. With a large database covering the world’s giant oil fields that were responsible for well over 50% of total oil output in 2005, it has been possible to characterise the typical behaviour of giant oil fields.

The evolution of the parameters has shown that fields leaving plateau production in the future will decline more rapidly than fields from further back in history. A larger share of the URR will also be produced before the field reaches the onset of decline. The increased depletion of the fields, made possible by new technologies, can be seen as the main explanation for this.

The non-OPEC group contains mostly giant oil fields that have reached decline phase. In total 87% of all giant oil fields in this group can be classified as post-plateau and 84% of the non-OPEC giant oil field URR is located in declining fields. Most of the non-OPEC fields have already shown the typical behaviour for this group and the small share that remain to show this behaviour will have a relatively small impact on the world supply situation.

Regarding OPEC, more than 50% of all URR in their giant fields is also located in fields that have not yet reached the onset of decline. They still have plenty of oil left in fields that have not begun to decline, so the future production strategy and the resulting decline rates of OPEC giant oil fields will be very influential on the future world oil supply. The prolonged plateau production and higher depletion of those fields will mean that their decline will be fast once they leave their plateau phases.

From our study of the evolution of field behaviour, one can see that the average values found in Table 1 are not applicable to the giant fields that are about to leave the plateau stage in the near and medium term. More reasonable values can be obtained by treating the different subgroups separately (Table 2, 3 and 4) and combining them with the historical trends in giant oilfield behaviour. When it comes to the average decline rates of giant oilfields, our results end up in the same range as CERA (2007) and IEA (2008). This is discussed in more detail in Höök et al. (2008). Our results may also be useful in all forms of decline modelling of oil production.

Calculating general mean values of all giants, regardless of when in time they reached the onset of decline, is interesting, but do not properly reflect the behavioural changes imposed by new technology and production methods. Therefore those mean values should not be used as representative values for future decline in fields that will leave their plateau levels in the near or medium term future. To find realistic values for fields that are about to reach the onset of decline the effects of technology must be included. With the introduction of new technology and production methods the behaviour has changed dramatically over the decades. Prolonged plateau production with its corresponding high decline rates has been favoured compared to the behaviour of the 1960s and before. Based on the historical trend in giant oilfield behaviour it is reasonable to assume that future fields will decline and be depleted faster than fields from before.

The introduction of new technology and production methods has greatly enhanced depletion and made it possible to extend plateau production and prevent the onset of decline for some time, but once the decline starts its rate is higher. In many ways the use of technology to extend plateau production will disguise increasing scarcity, as earlier pointed out by Gowdy and Juliá (2007). Production management may therefore chose between a relatively shorter plateau phase and gentle decline or a longer plateau stage with generally higher decline.

Furthermore, we propose depletion as a useful parameter to bridge the gap between production and geology. Depletion analysis can be used to rule out unrealistic production expectations from a known reserve, or to connect an estimated production level to a needed reserve base. Depletion analysis can also rule out unreasonable URR estimates for individual oilfields or be utilized to obtain basic estimates of the URR from production figures. The narrow spread in depletion-at-peak provides a solid ground for depletion modeling of oil production (Figure 8). From a physical point of view, it is the extent of depletion that is the governing factor of giant oil field behavior. As expected, we also found a strong correlation between depletion and decline.

Finally we can conclude that the peak usually occurs before half the ultimate reserves have been produced in giant oil fields. From a large field-by-field analysis of the largest contributing group to the world oil production, it cannot be claimed that the peak would occur after more than half of the ultimate reserves have been produced. This result brings strength to the original assumption by Hubbert (1956), but more comprehensive analysis of the connection between individual fields and regions are encouraged to better illuminate this topic.

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Paper III: Giant oil field decline rates and their influence on world oil production

Mikael Höök, Robert Hirsch, Kjell Aleklett

Abstract. The most important contributors to the world's total oil production are the giant oil fields. Using a comprehensive database of giant oil field production, the average decline rates of the world's giant oil fields are estimated. Separating subclasses was necessary, since there are large differences between land and offshore fields, as well as between non-OPEC and OPEC fields. The evolution of decline rates over past decades includes the impact of new technologies and production techniques and clearly shows that the average decline rate for individual giant fields is increasing with time. These factors have significant implications for the future, since the most important world oil production base – giant fields – will decline more rapidly in the future, according to our findings. Our conclusion is that the world faces an increasing oil supply challenge, as the decline in existing production is not only high now but will be increasing in the future.

Key words. Giant oil fields, decline rates, peak oil, future oil production

Introduction

It is well known that oil production from many oil fields worldwide is in decline and that more fields transition into decline each year. In roughly mid 2004, total world oil production ceased to expand. Instead, new production has only succeeded in keeping world oil production relatively flat (Figure 1).

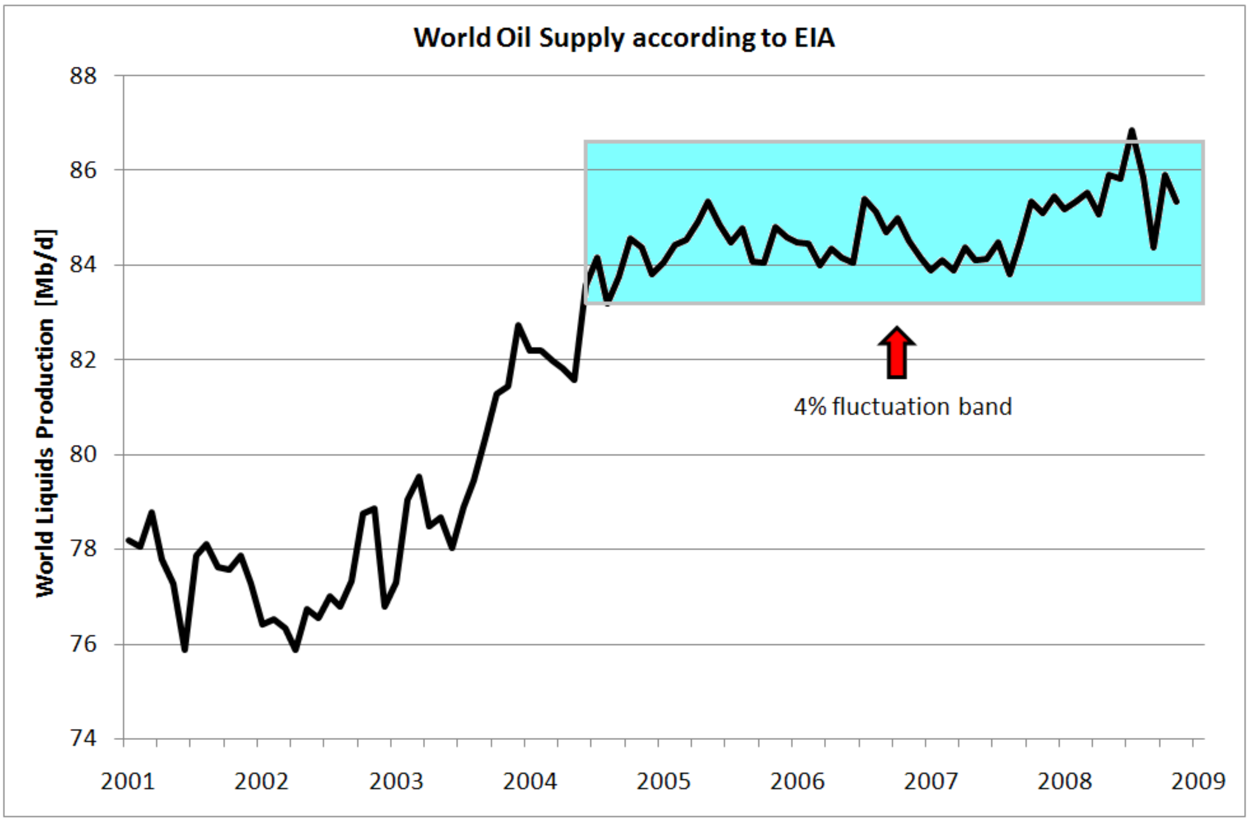

Figure 1. World liquid fuels production from January 2001 to November 2008. Since mid-2004, production has stayed within a 4% fluctuation band, which indicates that new production has only been able to offset the decline in existing production. Source: EIA (2009)

A recent analysis by Cambridge Energy Research Associates estimated that the weighted decline of production from all existing world oil fields was roughly 4.5% in 2006 (CERA, 2007), which is in line with the 4-6% range estimated by ExxonMobil (2004). However, Andrew Gould, CEO of Schlumberger, stated that *an accurate average decline rate is hard to estimate, but an overall figure of 8% is not an unreasonable assumption* (Schlumberger, 2005). T. Boone Pickens (2008), agreed with Gould in recent testimony before the US Senate Committee on Energy and Natural Resources. Duroc-Danner (2009) gives a blended average decline rate for oil and gas today of about 6%. The International Energy Agency (IEA) came to the conclusion that the average production-weighted decline rate worldwide was 6.7% for post-peak fields (IEA, 2008), which means that the overall decline rate would be less, since many fields are not yet in decline.

In this study we estimate world decline rate behaviors based on the Uppsala University giant oil field database, described in detail by Robelius (2007). Given the dominance of the giant oil fields, understanding giant oil field behavior provides important insights into likely future total world oil production.

Giant oil fields and world production

Giant oil fields are the world's largest. There are two ways to define a giant oil field. One is based on ultimately recoverable resources (URR), and the second is based on maximum oil production level. The URR definition considers giants to have more than 0.5 Gb of ultimately recoverable resources. The production definition assumes a production of more than 100,000 barrels per day (b/d) for more than one year (Simmons, 2002). In this analysis we consider the worlds conventional oil fields, regardless of location, e.g. shallow or deep water, the Arctic, etc. Conventional oil fields refer to reservoirs that dominantly allow oil to be recovered as a free-flowing dark to light-coloured liquid (Speight, 2007). Consequently, heavier crude oils that require special production methods are excluded.

The American Association of Petroleum Geologists (AAPG) has published a series of memoires about giant oil fields and their geology (see for instance AAPG, 1970; 1980; 1992; 2003; 2005). Other studies have used essentially the same definition system (Nehring, 1978; Robelius, 2007). Giant fields covered by both the AAPG and the Simmons definitions were used in this study.

Using our definition of giant oil fields, we find that roughly 500 (about one percent of the total number of world oil fields) are classified as giants. Their contribution to world oil production was over 60 % in 2005, with the 20 largest fields alone responsible for nearly 25% (Figure 2). Giant fields represent roughly 65 % of the global ultimate recoverable conventional oil resources (Robelius, 2007). Many studies have pointed out the importance of giant oil fields, for instance Campbell (1991), Hirsch (2008), Meng and Bentley (2008).

Individual oilfields can be operated in various ways. Important field operating options and planning models have been described (Palsson et al, 2003; Ortíz-Gómez et al, 2002; Barnes et al, 2002). For specific fields, much is dependent on specific reservoir characteristics, investments, production strategies, and technology use, as a function of time.

The overall production from giant fields is declining, because a majority of the largest giant fields are over 50 years old, and fewer and fewer new giants have been discovered since the decade of the 1960s (Figure 3). The average contribution from an individual giant oilfield to world production is less than 1%. Thus, with few exceptions, e.g., Ghawar, the contribution from a single field is generally small compared to the total. On this basis, our approach is to estimate collective behaviors.

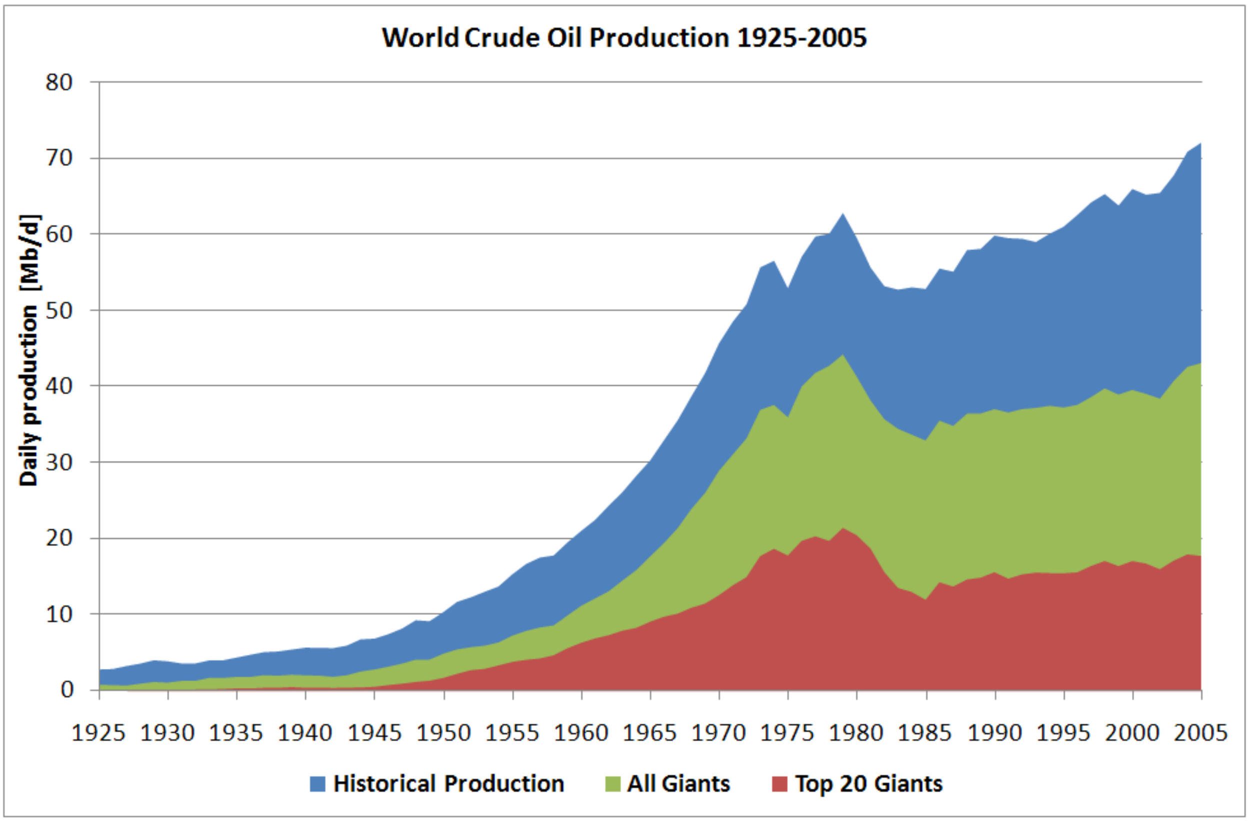

Figure 2. World crude oil production from 1925 to 2005. The dominance of the giant oil fields can clearly be seen. Modified from Robelius (2007)

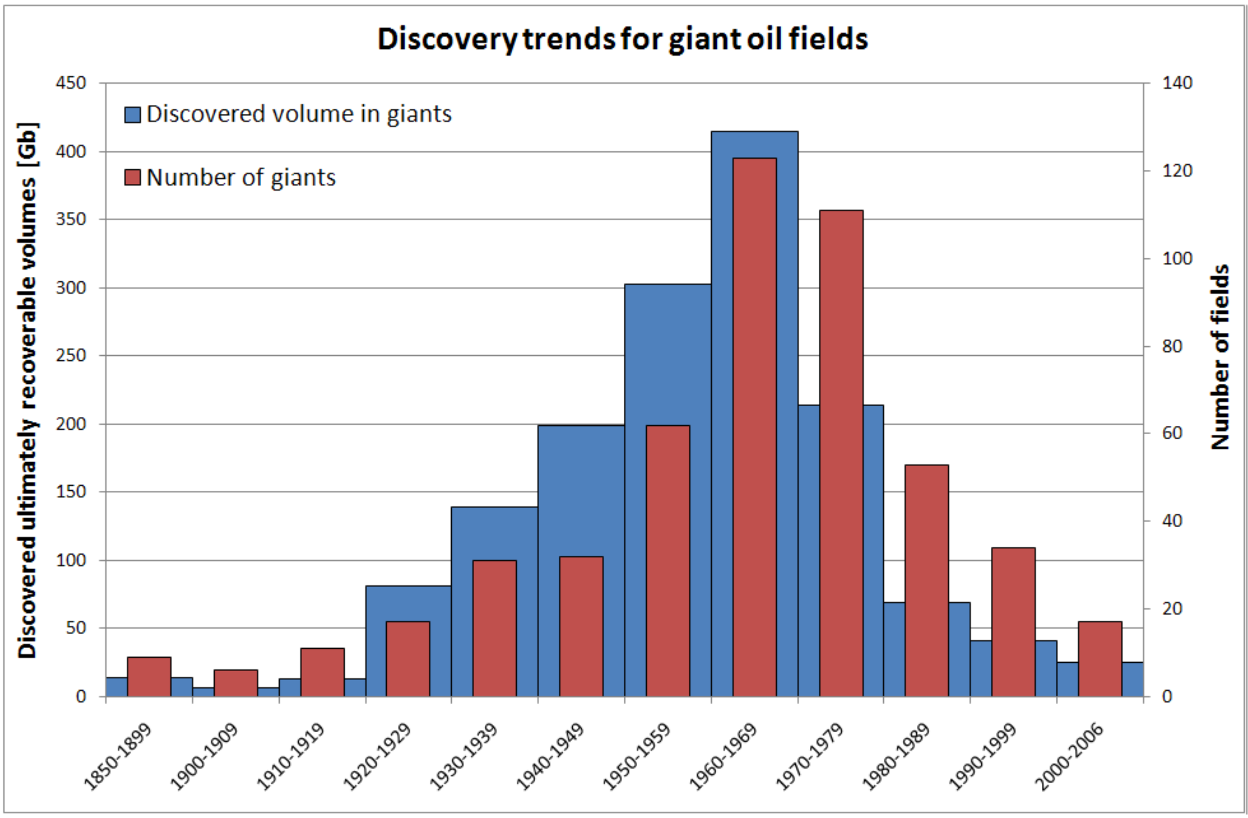

Figure 3. Discovery trends for giant oil fields in both number and annual discovered volume, based on the most optimistic, backdated URR values. Modified from Robelius (2007)

Giant field data

The data used in this analysis was taken from the giant oil field database compiled by Robelius (2007). AAPG publications on giant oil fields were the main source of information on year of discovery, year of first production, URR, and cumulative production. Production data were obtained from annual reports in Oil & Gas Journal and various AAPG development papers and project reports. Other sources included statistical yearbooks from the Norwegian Petroleum Directorate, PEMEX, the UK department of Trade & Industry and similar sources.

Fields with production over 100,000 b/d were included in our analysis, but they numbered only 20 fields in our total. A more detailed discussion of the giant field data can be found in Robelius (2007). This study uses the same data set as Höök et al. (2009) and a better description of the data set together with complementary results can be found therein.

Decline curve analysis

Production profiles of giant fields generally have a long plateau phase, rather than the sharp “peak” often seen in smaller fields. The end of the plateau phase is the point where production enters the decline phase. We adopted the end-of-plateau as the point where production lastingly leaves a 4% fluctuation band, as Hirsch (2008) postulated in a prior study.

In this analysis the exponential decline model, originally developed by Arps (1945), was used to model field behaviors and to forecast future production. One advantage of the decline curve analysis is that it generally applies independent of the size and shape of the reservoir or the actual drive-mechanism (Doublet, 1994), avoiding the need for more detailed reservoir data. This approach is the same used by CERA (2007). Accordingly, each field is assumed to have a constant decline rate, and the production for an individual oil field fluctuates around some average value over time. Examples of how well this approximation agrees with actual production in a few cases are shown in Figures 4 and 5.

In some cases, wars, sabotage and politically motivated shut downs are evident, making these fields more difficult to describe in a simple manner. Many OPEC fields have been on a plateau for a very long time, and some were even mothballed for various periods. Non-conforming fields, such as Eldfisk, Ekofisk and some fields in Nigeria, were treated separately, and production disturbances such as guerrilla attacks or accidents were disregarded (Figure 5).

Decline curves can be made much more detailed and complicated (hyperbolic etc.), so the simple exponential model used here should be seen as a simplified model for future outlooks. One disadvantage of the exponential decline curve is that it tends to underestimate tail production, which usually flattens out to a harmonic decline. However, the production levels far out in the tail region are generally very low compared to the plateau level, so this approximation is a minor problem for the model. In the near and medium term future the exponential decline curve is a suitable tool for realistic outlooks.

Some fields can also show complex behaviour with several exponential decline phases or even production collapses, where the decline can be doubled in the end stage of the field life. In other cases introduction of new technology can revive the field and significantly dampen the decline temporarily. This is the case in some Russian fields, which were reworked after the fall of the Soviet Union. However, Höök et al. (2009) found that such events are likely to result in higher decline rates later on, compensating the temporal decrease in decline rate.

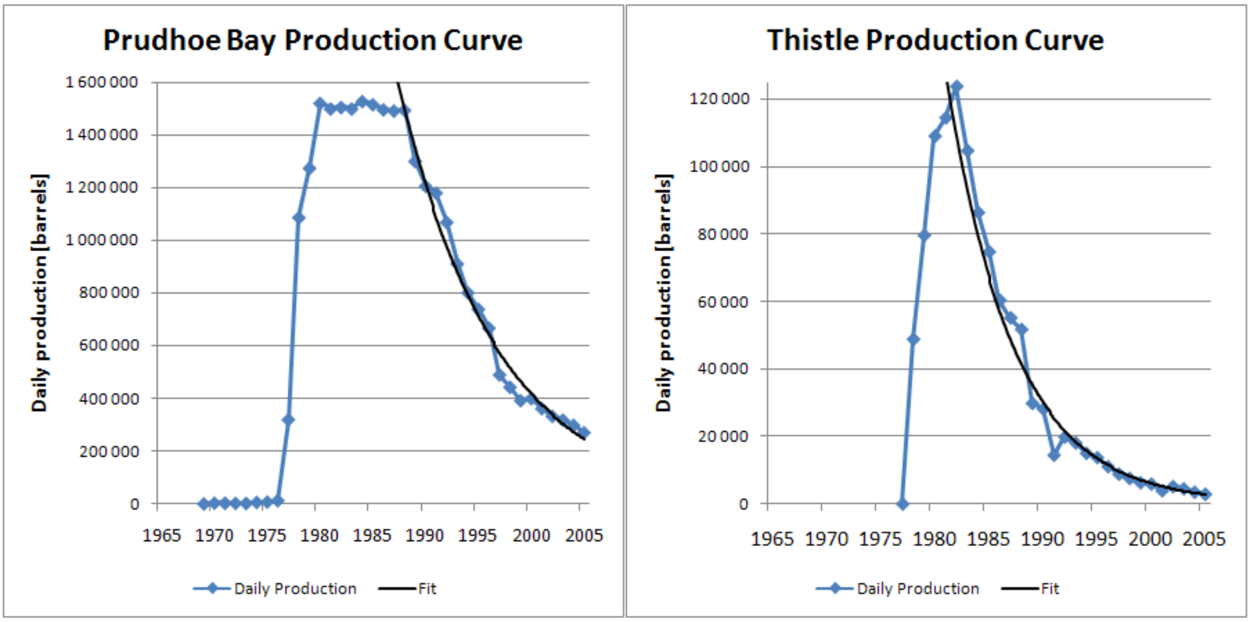

Figure 4. The production curves of the land-based US giant Prudhoe Bay and the giant UK Thistle offshore field. The approximately exponential average decline rate is clearly seen in these two well-behaved fields.

Modelling future field behaviour is done by extrapolating the historical production data with an exponential decline curve. This does not take dramatic deviations into account and assumes that declines will continue approximately exponentially. This leads to a somewhat optimistic extrapolation. The decline rate of a field is affected by introduction of new technology, investments, changes in strategies and other factors affecting production. Studying decline rates and their development gives some hints about the effects of technology and field investments.

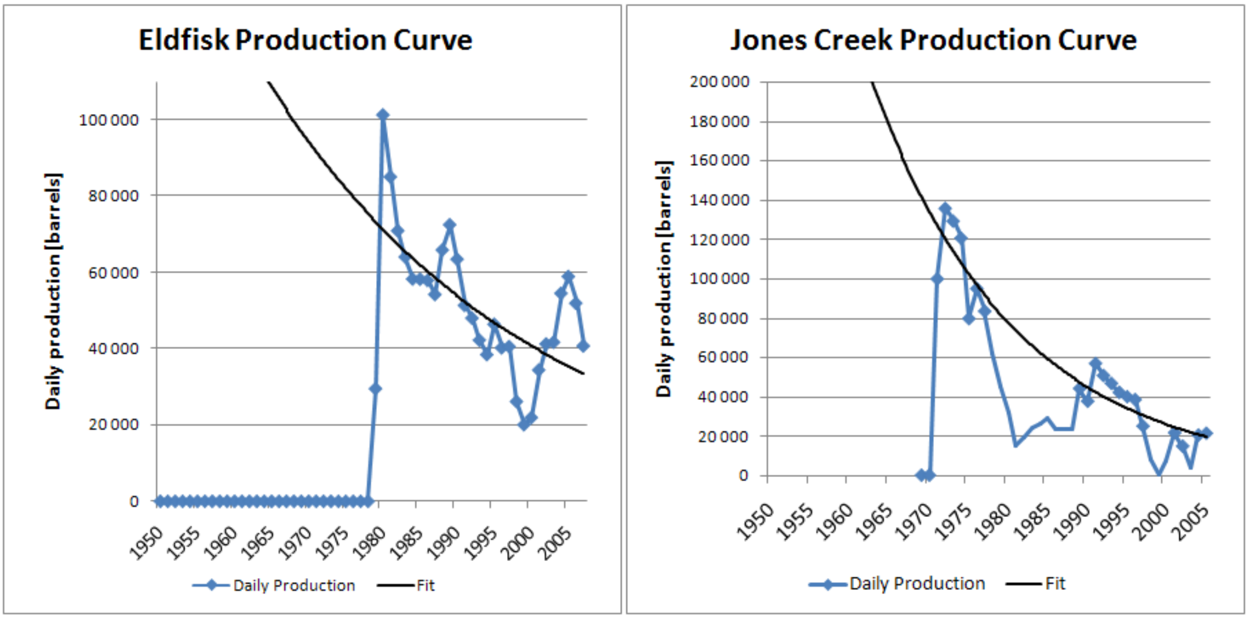

Figure 5. The exponential decline curve fits reasonably well with the production of the Norway giant Eldfisk, where pressure depletion has caused major reservoir compaction and subsidence problems. The Nigerian Jones Creek, which has been severely disturbed by wars, rebel attacks and sabotage, provides a good fit with the model if disturbed data points are disregarded. In both these cases the production curve has been fluctuating around an approximately exponential decline curve.

Average decline rate

The Uppsala giant field database includes 331 giant oil fields with a combined estimated URR of over 1130 Gb, using estimates adopted by Robelius (2007). 214 fields are land-based (about 65% of the total), while 117 are offshore installations (about 35%). To calculate the decline rate of giants that were in decline as of the end of 2005, we considered only the 261 fields classified as post-plateau and in decline. Of these, 170 were land-based and 91 offshore. IEA (2008) gives an average depletion factor, defined as cumulative production divided by initial 2P reserves, of 48% for their super-giants and giants. Höök et al. (2009) found that most giant fields leave the plateau phase and reach the onset of decline when around 40% of the URR has been produced, and combined with IEA's average depletion factor, it is not surprising that the majority of the fields are categorized as in decline.

Because the number of fields is so large, our approach provided reasonable statistics and reasonable mean, median and production weighted values for the giant oil fields as a group. The production weighted values were created by weighting the decline rate against the peak or plateau production level for each field, thus giving greater importance to fields with high production. The production weighted decline is lower than the mean value, because fields with high production levels often tend to be larger and decline slower than the rest. More details can be found in Höök et al. (2009).

The statistical uncertainty is difficult to estimate, since production data contains political influences, differences in definitions, reporting practice and many other parameters, making conventional statistical error estimate hard to apply. A histogram showing the distribution of the decline rates for all the post plateau fields considered in this analysis is shown in Figure 6.

A traditional statistical analysis based on the assumption that production data measures approximately the same thing, results in standard deviations of around 5% and may be seen as a rough attempt to put a number on the inaccuracy (Höök et al., 2009). In comparison, neither IEA (2008) nor CERA (2007) provides any uncertainty estimates and hence it is hard to judge the statistical variations in their results. This study makes no attempt to provide detailed analysis of the uncertainty; rather, it only concludes that the results are accompanied with significant uncertainty. Two significant digits will be used here, to make comparisons with CERA (2007) and IEA (2008) easier, despite the fact that the results of Höök et al. (2009) indicate that only one digit should be utilized because of the significant uncertainties in many of the underlying reserves estimates and production figures.

In Table 1 an average annual decline rate for the world's giant oil fields is seen to be roughly -6.5%, which is in line with the average observed decline rate worldwide of -6.5% and the -5.8% production-weighted average annual decline rate obtained by IEA (2008). The agreement with the 5.8% production-weighted annual decline for large fields obtained by CERA (2007) is good. However, it should also be noted that the weighting methods and field size classifications are slightly different.

CERA (2007) did not treat giant oil fields in the same way as this study. Instead their study was performed on a set of "*large fields*", classified as fields with more than 300 million barrels of originally present 2P reserves of oil and condensate. In total, their dataset represent 1155 billion barrels of original 2P reserves in place, accounting for approximately half the current annual global production. Consequently, their dataset is deemed approximately equal to the data set used in this study. When it comes to production-weighting, CERA (2007) takes each field's latest oil and condensate production into account for the averaging.

IEA (2008) uses a similar classification in their study. IEA classify "*super-giants*" as fields with more than 5 Gb of initial 2P reserves, "*giants*" contain more than 500 million barrels of initial 2P reserves, and "*large fields*" contain initial reserves of more than 100 million barrels. In IEA (2008), super-giants are treated as a subclass, while this study includes them in the giant category. In total, IEA covers 317 super-giant and giant fields, which makes their data set similar to ours. Their production-weighting is done by using the cumulative production of each field in the averaging.

Table 1. Characteristic parameters for all 261 post peak giant fields covered by this study. Fields that had not reached the decline phase as of the end of 2005 were excluded.

	Mean	Median	Prod. weight
Decline rate	-6.5%	-5.3%	-5.5%

Because of financial and practical differences between land-based and offshore fields, a division is needed to establish a comprehensive picture of how each subclass behaves. A further division into OPEC-fields and non-OPEC fields was also made to better reflect the potentially different behaviours of giants managed with no political restrictions on production and those sometimes limited by quota systems.

OPEC controls or formerly controlled 143 of the fields in our database. Gabon is no longer a part of OPEC, but used to be a member; consequently, their fields were classified as OPEC-fields because they were previously subjected to the quota system. Ecuador suspended their OPEC-membership, but recently rejoined the organization. In total, OPEC has 104 land and 39 offshore fields in our database. Outside of OPEC, 190 fields were considered with 110 fields onshore and 78 offshore. The North Sea, Russia and the US were the most important regions within the non-OPEC group.

An analysis of giant oil fields divided into onshore and offshore fields yields the results in Table 2. Land-based fields decline much slower than offshore fields, as expected and in agreement with both IEA (2008) and CERA (2007). The reason for this difference is generally the higher production capabilities built into offshore installations in order to repay expensive investments as soon as possible. Also, a significant number of land-based fields started to decline far back in time, before the introduction of modern production techniques such as water injection and other pressure managing methods. In comparison, there were virtually no deepwater offshore fields before 1970.

The offshore group can be even further divided into shelf and deepwater fields, where deepwater fields tend to decline faster and shelf fields somewhat slower. This separation was made and discussed by IEA (2008). Interestingly, IEA (2008) did not find lithology to be a dominating factor for field behaviour, while field size and OPEC-control seemed to be key factors in determining decline.

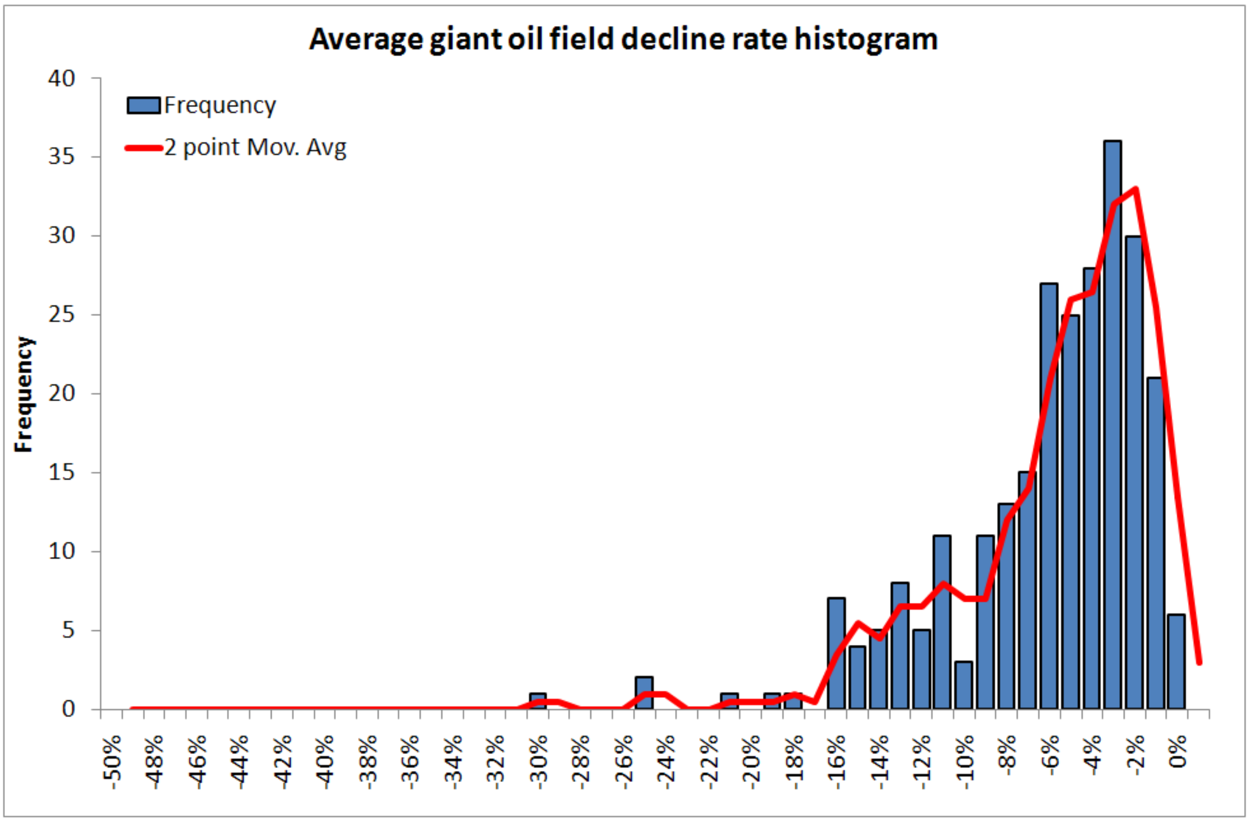

Figure 6. Histogram of the decline rate distribution of the 261 post plateau giant fields as of the end of 2005. About 65% are onshore and 35% offshore. Significant differences occur between different subgroups. The offshore fields cluster together around -10% and the land fields around -4%. OPEC fields tend to decline slower than non-OPEC fields.

Table 2. Characteristic decline rates of land and offshore fields. Fields that had not ended their plateau phase or were in build-up phase as of the end of 2005 were excluded.

# fields	Field Type	Mean	Median	Prod. weight
170	Land fields	-4.9%	-4.4%	-3.9%
91	Offshore fields	-9.4%	-9.0%	-9.7%

The results for the non-OPEC fields are shown in Table 3. Once again the high decline of offshore fields compared to land fields can be seen. The average decline of all non-OPEC giant fields is above 7%, indicating that non-OPEC production is dropping relatively rapidly.

Many of the low decline rates can be found in fields in the US that peaked prior to 1970s. In fact most of the non-OPEC land group is dominated by the US giant fields. The non-OPEC offshore group is dominated by giant fields in the North Sea. Many fields, both giant fields and smaller ones, in the North Sea, show a high decline rate, for instance in Norway and the UK (Zittel, 2001; Höök and Aleklett, 2008).

In comparison to the non-OPEC group, the OPEC group generally displays lower decline rates (Table 3). One quite intriguing detail is that OPEC fields tend to exit the plateau phase at a lower percentage of their URR volumes. This is an explanation for the lower decline rate. Instead of a prolonged plateau, a longer decline phase with less annual decrease has generally been favoured as a production strategy compared to non-OPEC. This is examined in greater detail in another study (Höök et al, 2009). An alternative explanation is that OPEC URR estimates are exaggerated, as claimed by former Aramco vice-president Sadad al Husseini (2007).

Both land and offshore fields within OPEC tend to have lower declines than their non-OPEC counterparts in good agreement with the findings of IEA (2008) and CERA (2007). The conclusion is that the OPEC quota system has been quite efficient at moderating production and maintaining the longevity of fields, instead of extracting oil rapidly with an accompanying high decline rate.

Table 3. Characteristic decline rates of OPEC-fields and Non-OPEC. Fields that had not ended their plateau phase or were in build-up phase as of the end of 2005 were excluded. In total 87% of all giants outside OPEC were classified as post-plateau, which corresponds to having 83% of all the URR in giant oil fields outside OPEC in post-plateau. In total 67% of all OPEC giant fields can be classified as post-plateau, which corresponds to 48% of all URR in OPEC giants in post-plateau.

# fields	Group	Mean	Median	Prod. weight
97	All OPEC fields	-4.8%	-4.1%	-3.4%
73	OPEC land	-3.8%	-3.8%	-2.8%
24	OPEC offshore	-7.7%	-6.1%	-7.5%
164	All Non-OPEC fields	-7.5%	-6.3%	-7.1%
97	Non-OPEC land	-5.7%	-4.7%	-5.2%
67	Non-OPEC offshore	-10.0%	-9.4%	-10.3%

Evolution of decline rate in time

It is useful to consider the historical evolution of field decline rates, since many giant fields are old and passed into decline before much of modern oil field technology was developed and implemented. The year that fields left plateau production was used to form subgroups, e.g., if a field started to decline in 1950-1959, it is included in the 1950s group and so on. This approach is different from IEA (2008), which used the year of first oil production to form subgroups in their study of decline rate evolution. We believe that the year of the onset of production decline is of greater importance because it better reflects the impacts of improved technology and alternate production strategies.

The results are shown in Tables 4, 5, 6, 7, 8 and 9. For all offshore fields (Table 4), a clear trend towards higher decline rates over time was found. For all land-based fields (Table 5), the trend is not as clear but is directionally similar. Separating OPEC and non-OPEC fields reveals larger differences. Data for the decade of the 2000s are limited because less declining field data was available as of the end of 2005.

Table 4. Evolution of the decline rate of offshore giant fields. The decade that the fields left plateau production was used to form the subgroups.

# fields	Time period	Mean	Median	Prod. weight
0	Pre 1960	-	-	-
2	1960s	-2.8%	-2.8%	-3.7%
17	1970s	-6.0%	-6.1%	-6.3%
16	1980s	-7.9%	-7.5%	-8.9%
35	1990s	-10.4%	-11.4%	-10.6%
19	2000s	-12.5%	-12.6%	-10.8%

The non-OPEC land group shows an inclination towards somewhat higher decline rates (Table 6). The increasing decline rate trend for non-OPEC offshore giant oil fields is much clearer (Table 7). The trends for the land-based fields deviate in the 1970s and 1980s, which is probably due to the twin oil crises that occurred during those decades. For the OPEC group, a tendency towards lower decline rates is observed and can be explained by the fact that fields were taken from their plateau phase for political reasons, resulting in subsequent less steep decline rates.

Table 5. Evolution of the decline rate of land-based giant oil fields. The decade that the fields left plateau production was used to form the subgroups.

# fields	Time period	Mean	Median	Prod. weight
23	Pre 1960	-4.2%	-4.4%	-4.2%
18	1960s	-5.1%	-5.5%	-6.0%
72	1970s	-4.2%	-3.9%	-3.0%
25	1980s	-4.4%	-4.1%	-3.9%
28	1990s	-6.9%	-5.6%	-5.6%
4	2000s	-10.7%	-9.9%	-10.1%

Table 6. Evolution of the decline rate of non-OPEC land-based giant fields. The decade that the fields left plateau production was used to form the subgroups.

# fields	Time period	Mean	Median	Prod. weight
13	Pre 1960	-4,2%	-3,8%	-4,3%
10	1960s	-5,3%	-5,4%	-6,0%
36	1970s	-5,5%	-4,7%	-4,9%
20	1980s	-4,8%	-4,1%	-4,6%
16	1990s	-8,2%	-6,3%	-6,5%
2	2000s	-11,5%	-11,5%	-9,9%

Table 7. Evolution of the decline rate of non-OPEC offshore giant fields. The decade that the fields left plateau production was used to form the subgroups.

# fields	Time period	Mean	Median	Prod. weight
0	Pre 1960	-	-	-
2	1960s	-2,8%	-2,8%	-3,7%
10	1970s	-6,8%	-6,5%	-7,9%
13	1980s	-8,5%	-7,5%	-9,3%
24	1990s	-11,5%	-12,1%	-11,5%
18	2000s	-11,7%	-11,8%	-10,3%

Table 8. *Evolution of the decline rate of OPEC land-based giant fields. The decade that the fields left plateau production was used to form the subgroups.*

# fields	Time period	Mean	Median	Prod. weight
10	Pre 1960	-4,3%	-4,7%	-4,0%
8	1960s	-4,9%	-5,5%	-5,9%
36	1970s	-2,9%	-3,0%	-2,2%
5	1980s	-2,8%	-3,0%	-1,9%
12	1990s	-5,1%	-5,1%	-4,0%
2	2000s	-9,8%	-9,8%	-10,2%

Table 9. Evolution of the decline rate of OPEC offshore giant fields. The decade that the fields left plateau production was used to form the subgroups.

# fields	Time period	Mean	Median	Prod. weight
0	Pre 1960	-	-	-
0	1960s	-	-	-
7	1970s	-4,7%	-3,9%	-4,3%
3	1980s	-5,2%	-6,3%	-6,2%
12	1990s	-8,2%	-7,0%	-7,9%
2	2000s	-19,6%	-19,6%	-20,8%

From this data, it is evident that average decline rates for giant oil fields as a group are increasing with time, even though individual field decline rates are essentially constant once a field has reached the onset of decline. This is in agreement with CERA (2007). However, CERA failed to note that fields that are declining now, or will begin to decline in the near term, will do so with an average decline rate generally higher than the fields that left their plateau levels in earlier years. Our results show this trend in line with the findings of IEA (2008), where the higher decline rates as a function of time were clearly evident. Unfortunately, their study did not provide a great deal of related detail.

The important conclusion is that higher decline rates must be applied to giant fields that enter decline in the future. Prolonged plateau levels and increased depletion made possible by new and improved technology result in a generally higher decline rates. Detailed case studies of giant oilfields suggest that technology can extend the plateau phase, but at the expense of more pronounced declines in later years (Gowdy and Juliá, 2007). Our findings verify their conclusion.

Since a large number of important giants are subject to enhanced production methods, such as waterflooding, gas injection, fracturing or other measures, it is reasonable to expect relatively higher declines after those fields depart their plateau phase. Comprehensive discussion on development of mature oilfields and a few examples of utilization in giant fields can be found in Babadagli (2007). The collapse of production from the Cantarell field in Mexico, which was extensively subjected to technologies aimed at increasing production, meant that the field declined even faster than the government’s pessimistic scenarios (Luhnow, 2007).

Future trends in giant field decline rates

As more giant fields go into decline in the future, the average decline rates for all giants will increase. This situation is shown in simple terms in Figure 7. We have no reason to doubt that the giant field discovery trend shown in Figure 3 will continue, since large fields are harder to miss than small fields.

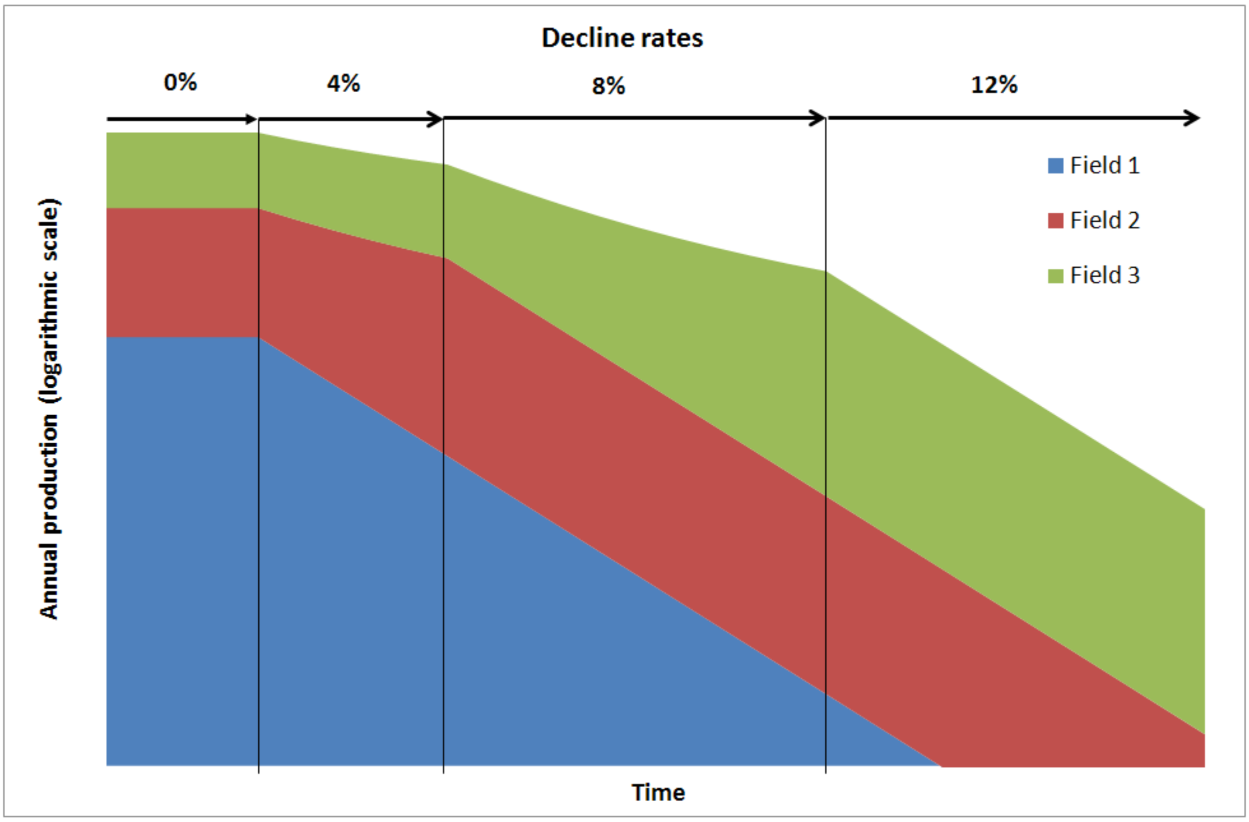

Figure 7. The decline rate of existing oil production within total world oil production will increase with time. This is because more fields go into decline as time goes on. To illustrate, consider three identical oil fields that start to decline at three different times, each with a 12% decline rate, similar to the average 13% found typical for Norway. In this example, the overall decline rate starts at zero and progressively increases.

Since the 1970s, the share of giant oilfields in decline has increased, showing the overall maturity and lack of new fields brought into production. Many giants have been in production for many decades without reaching the onset of decline, but sooner or later they will eventually do so. By 2030 one can expect 80% of total giant oilfield production to come from fields in decline, if one extrapolates the trend since 1985 (Fig. 8). The share could be even higher when important OPEC "super giants", such as Ghawar or Safaniyah, leave the plateau phase in the intervening years.

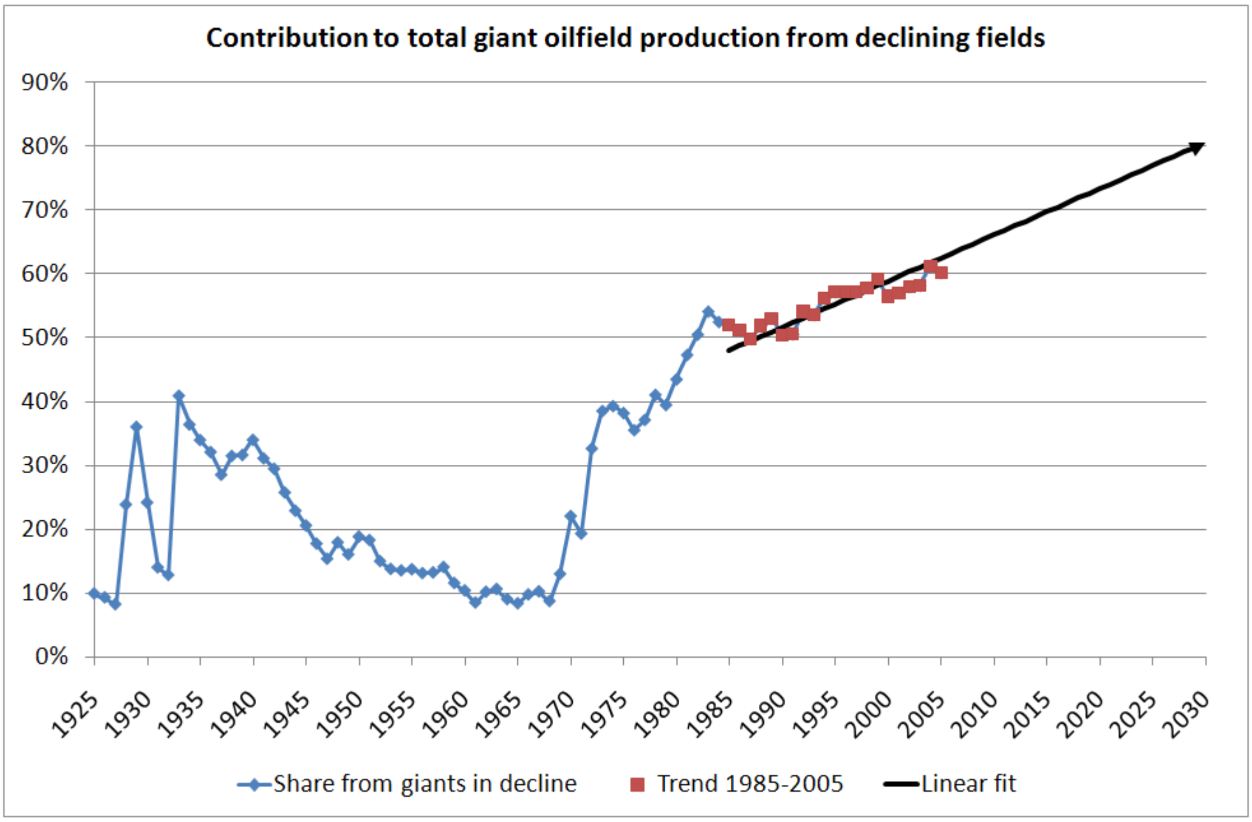

Figure 8. Contribution to total giant oilfield production from fields that have reached the onset of decline. In the 1920s oil was chiefly extracted in the US and when their giants started to decline, new giants fields all over the world were brought into production, which reduced the share from the declining fields. In the 1970s, production from many fields was interrupted for political reasons. Since 1985, the share from declining fields has been steadily increasing, despite the overall lack of political restrictions and turmoil. If extrapolated, this trend shows that over 80% of total giant oilfield production will come from fields in decline by 2030. However, the linear fit is only temporary and should be used with care if extrapolated far into the future.

Based on the Norwegian experience, a good picture of how giant oilfield decline rates might behave was constructed. Using the same data as Höök and Aleklett (2008), a picture of the relation between the average and the production-weighted decline rate can be made. Norwegian oil production has been generally free-market managed using advanced technology. Production increases and stable production were treated as a 0 % decline rate, because we were interested in the decrease in production and including increases would obscure fundamental decline trends. A single field in build-up phase can massively increase production and compensate for the production losses in several declining fields. Our aim was to show the underlying overall decline in production that must be compensated by production additions. Norwegian data shows how both average and production-weighted decline can converge over time (Figure 9).

Analysis of our 331 giant field dataset going back in time showed that the world average decline rate was near 0% until roughly 1960, when overall decline began to increase, as more and more giant oil fields left the plateau phase. Thereafter, production from new giants failed to compensate for the declines of existing giant production. The average decline rate of the giant oilfields was found to increase by around 0.15% per year. Extrapolating the 1960-2005 trend yielded an average decline rate of nearly 10% by 2030 (Figure 10). This giant field trend should have a strong influence on the future global decline rate in oil production.

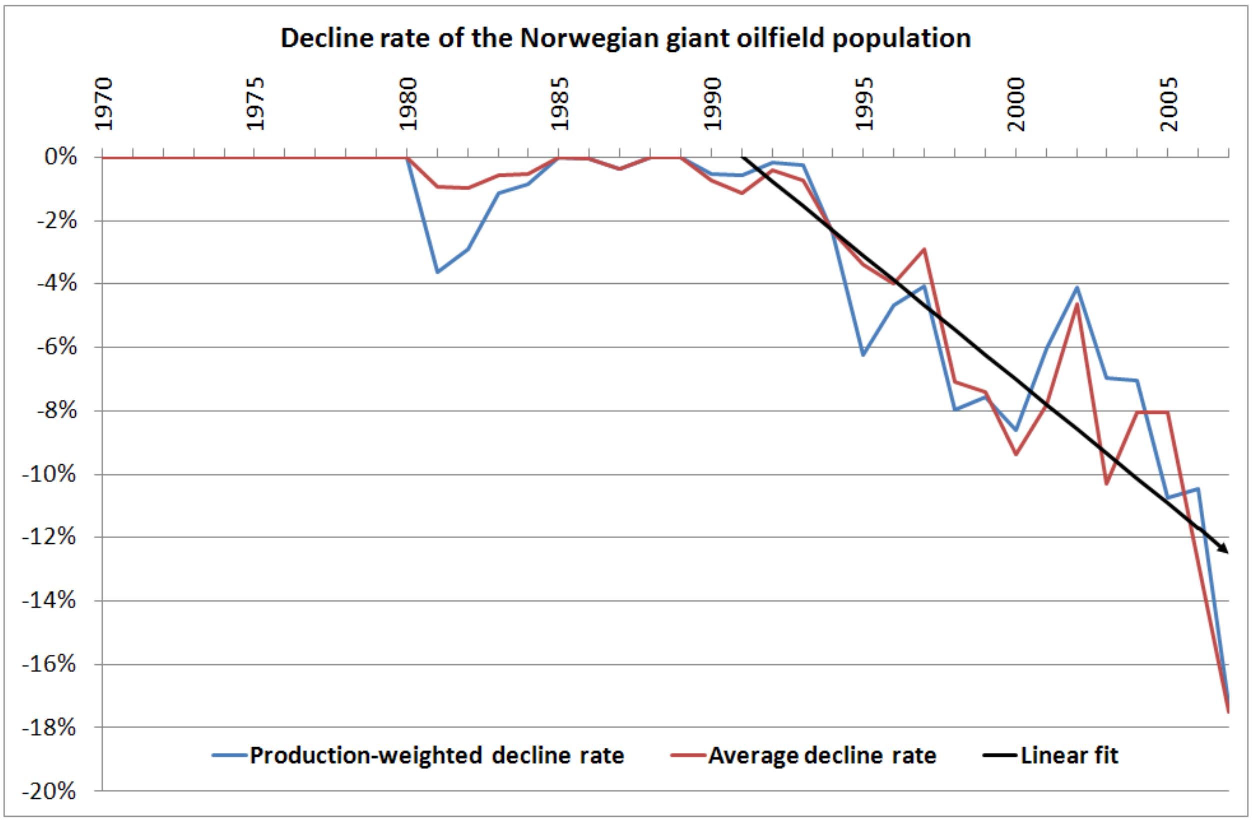

Figure 9. The decline of the Norwegian giant oilfields. Ultimately the onset of national decline could not be prevented and decline rates soared. Both the average and the production-weighted decline values agree well. Norway is an example of how technology can temporarily maintain production at the expense of a rapid future decline rate.

The production-weighted decline rate has been behaving somewhat differently, especially since 1985, compared to the average decline rate. The reason for this change is the introduction of new technologies, most notably horizontal drilling and fracturing techniques, in many major fields in former Soviet Union and the Middle East. Using new technologies, it was possible to halt the decline in many giants and keep production stable for some time. Eventually the average and the production-weighted declines must follow each other. The currently stable production-weighted decline cannot be expected to continue far into the future, once technology-enhanced fields reach the final onset of decline.

A limit for the average decline rate of the giant oil fields occur when all the fields in the population have reached the onset of decline. In other words the average decline rate cannot increase monotonously, but will sooner or later reach a limit. In the case of Norway, where all the giant fields now are in decline, the transition towards the decline rate limit was roughly linear (Figure 9) and similar behavior is expected globally. In the case of the world, OPEC and Non-OPEC, the limit of average decline rate is not known, but will be reached when all the giants have reached the onset of decline.

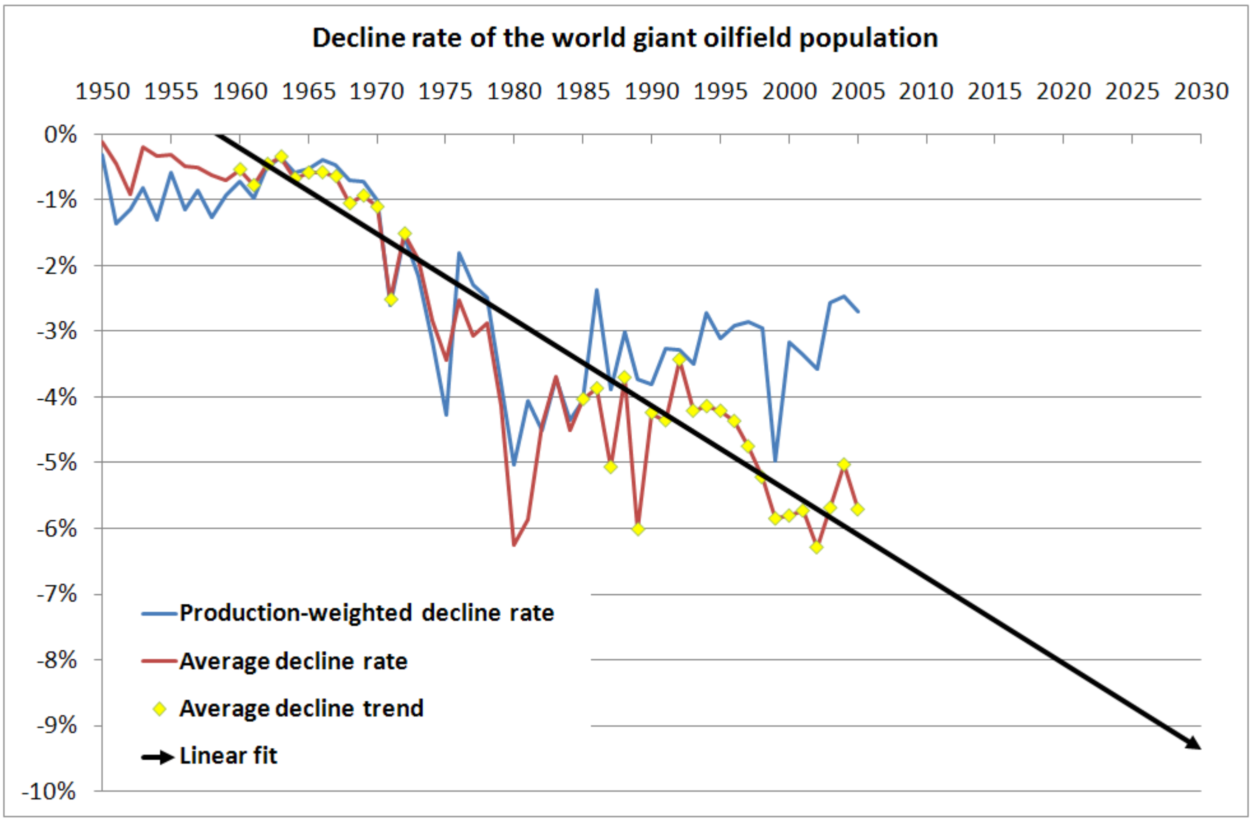

Figure 10. The decline rate of the world's giant oilfields. The trend toward an increasing average decline rate is very clear and explained by an ever decreasing volumes of newly discovered and declining production from new giant fields. The time period 1973-1982 was disregarded since production was deliberately reduced during that period by OPEC. The divergence between the two decline rates after 1985 is caused by the introduction of new technology and the revival of giant fields in primarily Middle East and Russia.

Separating non-OPEC and OPEC giant field production yields the trends seen in Figures 11 and 12. In the non-OPEC case, the 2030 decline rate is roughly 11%, while the OPEC 2030 rate is roughly 8%. Sooner or later the production-weighted decline rate must catch up with the average decline rate, but exactly how soon and how fast this development will happen is hard to forecast. Currently, the world may have a false sense of security, temporarily created by decline-delaying technology introduction in underdeveloped fields. When fewer giants can be momentarily revived, the production-weighted decline must eventually begin to increase.

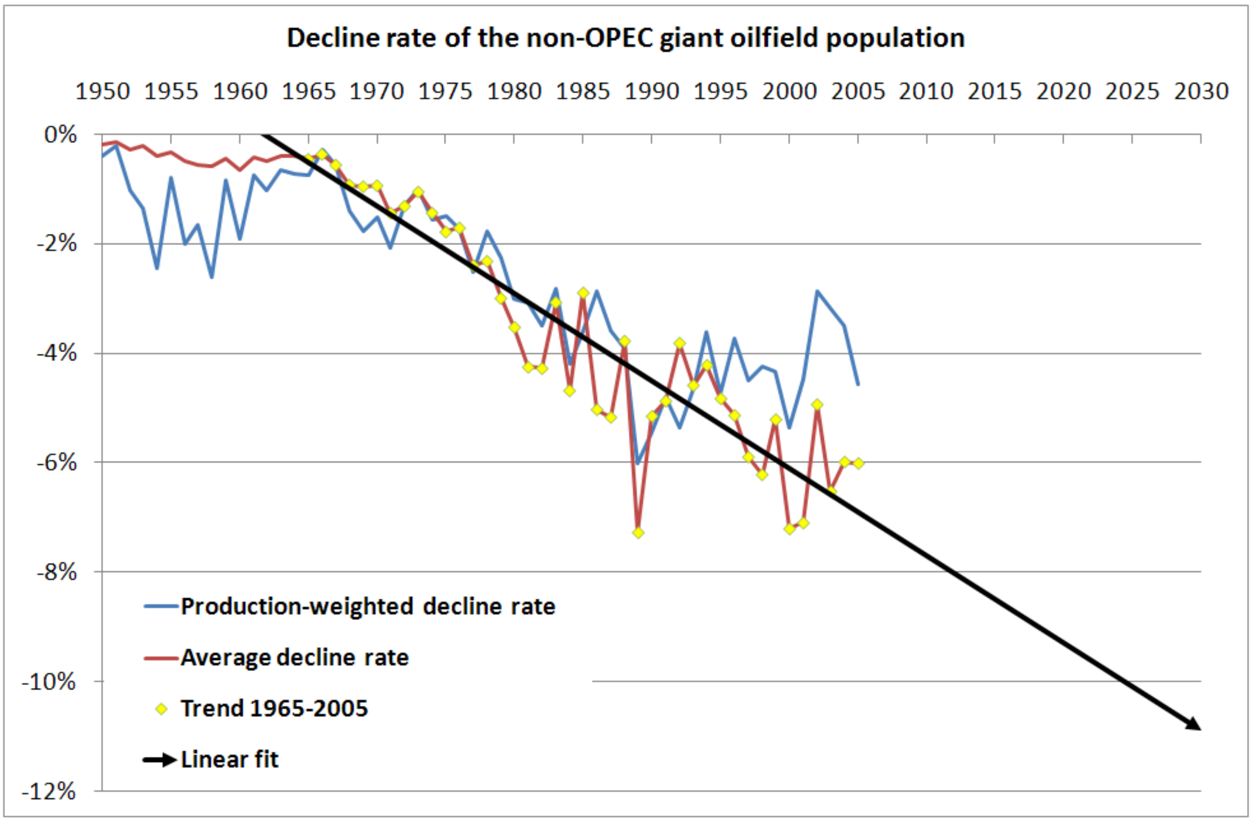

Figure 11. Decline rate of the non-OPEC giant fields. The average decline rate started to grow in 1965 and has been increasing as more and more giants reached the onset of decline. The deviation after 1995 was caused by the fall of the Soviet Union and the introduction of new technologies that managed to temporarily revive Russian giants.

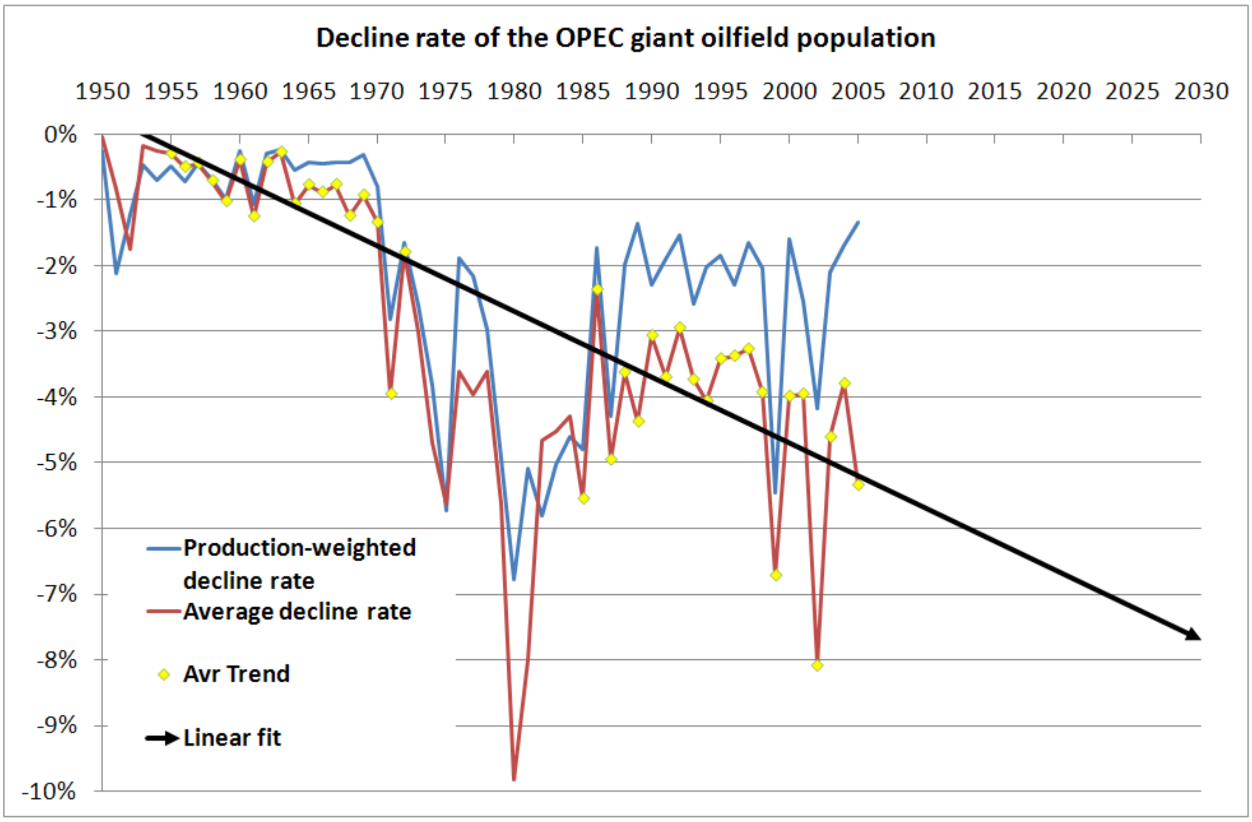

Figure 12. The decline of the OPEC giant fields. The trend in average decline broke from near zero in the 1950s and grew more slowly that in the non-OPEC case. This is likely the result of the OPEC quota system. During the period 1973-1985 significant production capacity was withheld deliberately or otherwise unavailable for short periods, so related data points were excluded. The production-weighted decline rate has been virtually constant since 1985.

Future global production

Without good data on a large fraction of the world's oil fields, an accurate estimate of future global oil production cannot be developed. While various databases exist, all include approximations and estimates, so none are fully definitive. Nevertheless, a number of factors can provide insights into what might evolve. First, the world's giant oil fields are the dominating contributors to total world oil production. Second, it is found that the decline of smaller fields is equal to or greater than those of the giants (see for instance IEA, 2008; CERA, 2007). A detailed study of Norwegian fields showed that giants declined at an average of 13%, while the small fields, condensate, and NGL declined at 20% or more (Höök and Aleklett, 2008).

A small field requires fewer wells to fully develop; hence it is more easily depleted. A large field requires many more wells, often widely separated, so it is typically depleted more slowly. High depletion rates, which are common in small fields, have been shown to strongly correlate with high decline rates (Höök et al., 2009). Thus, giant oil field decline rates are useful for estimating the likely average world decline. Accordingly, we believe that the decline in existing production, both for giants and other fields, will be at least 6.5% or 5.5% if production-weighted. The findings of Höök et al. (2009) indicate that the decline rates are only significant in the first digit. Consequently, we use 6% for our production outlook to reflect uncertainty. The average and the production-weighted values will ultimately coincide, as they did in Norway (Figure 9).

As a comparison, in a field-by-field study of predominantly giant fields, IEA (2008) derived an average decline rate worldwide for all oil fields of 6.7%. IEA (2008) stated that field size was a large determinant of field decline behaviour, noting that large fields decline relatively slower than small fields. This reasoning also supports their expected increases in future decline rates, as the world moves towards generally smaller oilfields. In their published forecast, they used a decline of 4.1% for fields in production for reasons they did not explain.

The exact annual increase in world average decline rate is difficult to estimate and requires a more comprehensive database than was available to us. Accordingly, the value of -0.15% per year derived here should be taken as a rough estimate. The important point, however, is that the average decline rate in existing production is clearly increasing with time. Also, the contribution from declining fields is increasing (Figure 8). Consequently, "*we must run faster and faster just to stand still*"

Using our 6% production-weighted average decline and extrapolation of the contribution from declining fields (Figure 8), one can create a future outlook for world crude oil production. By incorporating the increasing average decline, another possible future can be envisioned. The difference between using a constant decline rate and a growing decline is as much as 7 Mb/d by 2030 (Figure 13).

There are significant uncertainties regarding future oil production from our study and similar works. Nevertheless, reasonable future decline rates can be estimated. Our outlook and the forecast for fields in production from IEA (2008) agree reasonably well (Figure 13). While there is a few million barrels per day of difference, the overall picture is similar. However, IEA (2008) seems to lean more towards the optimistic case and a more comprehensive study of their oil forecast is recommended.

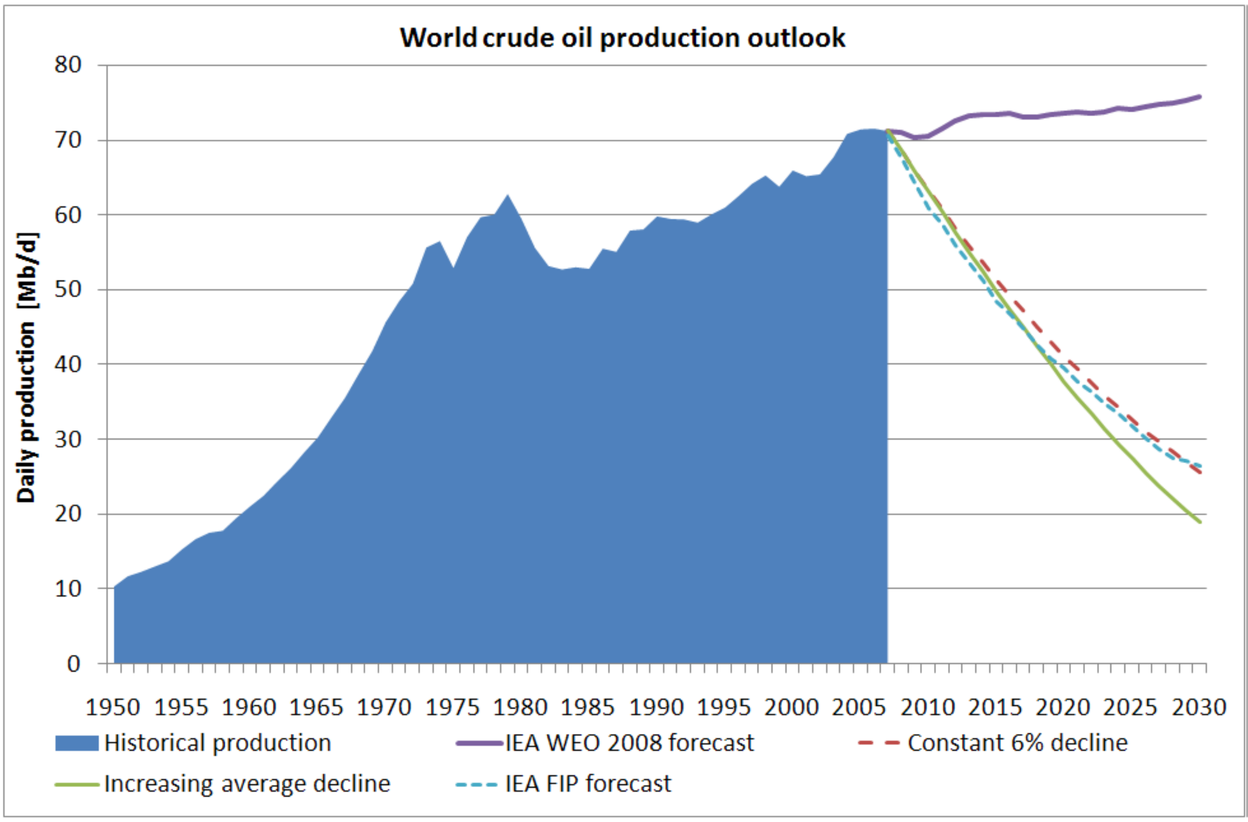

Figure 13. The historical world oil production along with crude oil forecast the reference scenario from IEA World Energy Outlook 2008. A constant decline rate of existing production of 6%, combined with an increasing share of fields in decline, is displayed as one possibility. Our other scenario is a case with increasing average decline. The IEA WEO 2008 forecast for fields in production (FIP) is compared to our own estimates of reasonable decline rates and the contribution from declining fields. The IEA forecast is reasonable in the near-term, but towards 2030, it seems optimistically biased. Using a constant decline rate compared to an increasing rate can mean as much as 7 Mb/d of production capacity by 2030.

Conclusions

Based on a comprehensive database of giant oil field production data, we estimated the average decline rates of the world's giant oil fields that are beyond their plateau phase. Since there are large differences between land and offshore fields and non-OPEC and OPEC fields, separation into different subclasses was necessary. In order to obtain a realistic forecast of future giant field decline rates, the subclasses were treated separately to better reflect their different behaviours.

Thus, our average total decline rate for post-plateau giant fields of 6.5% and CERA's overall 6.3% are in good agreement, and our 5.5% production-weighted giant field decline rate compares reasonably with IEA's 6.5% and CERA's 5.8% (Table 10).

Table 10. Comparison of our findings with the results from IEA (2008) and CERA (2007). It should be noted that the weighting methods differ and the studies used somewhat different data sets and definitions. In some cases a value for comparison was not available.

Parameter	This study	IEA	CERA
Average decline [%]			
Total	6.5	n.a	6.3
Land	4.9	n.a	5.3
Offshore	9.4	n.a	7.5
Non-OPEC	7.5	n.a	6.4
OPEC	4.8	n.a	5.4
Production-weighted decline [%]			
Total	5.5	6.5	5.8
Land	3.9	5.6	n.a
Offshore	9.7	8.6	n.a
Non-OPEC	7.1	7.4	n.a
OPEC	3.4	4.8	n.a

Offshore fields decline faster than land fields, and OPEC fields decline slower than non-OPEC fields. There are small differences in the data sets and definitions between the studies, but the results from these three studies can be considered approximately equivalent.

The evolution of decline rates over time includes the impact of new technologies and production techniques and clearly shows that average decline rates are increasing. This verifies the results of Gowdy and Julia (2007). Furthermore, prolonged plateau levels come at the cost of higher subsequent decline rates. This conclusion is in line with the findings of IEA (2008) regarding trends in average decline.

The trends in average decline rate and production-weighted decline rate indicate that technology transfer, primarily to the Middle East, was able to dampen the decline in many highly productive fields (Figures 10, 11 and 12). This cannot continue, and ultimately, production-weighted decline must approach the average decline rate, as in the case of Norway (Figure 9). How the production-weighted decline will behave in the future is difficult to estimate, but an increase appears inevitable.

Future decline rates of giant fields that have not yet left the plateau phase can be expected to be higher than those that are now in decline. This is in line with a recent statement about a decline of 10% in mature fields from Petrobras downstream director Paulo Roberto Costa (2008). The crash of the Cantarell field in

Mexico and the experiences of the North Sea giants are a vivid example of what can happen to other giant oilfields in the future.

These findings have large implications for the future, since the most important world oil production base – giant oilfields – will decline more rapidly. In the extreme, a potential 10% annual decline in Ghawar would be very challenging to compensate and would create severe problems for Saudi-Arabia and the world. The future behaviour of the remaining giants, especially in OPEC, will be a key factor in future oil supply.

Based on the decline behaviour of giants, decline rate estimates for world oil production are possible because of the large influence of the giants. Many studies have shown that smaller fields, condensate, and NGL will decline at least as fast or faster than giant oilfields, once the onset of decline is reached (CERA, 2007; Höök and Aleklett, 2008; IEA, 2008). Consequently, we believe that there is a strong basis for believing that giant oilfields can be used to set a floor for future decline rate assumptions.

In conclusion, this analysis shows that the average decline rate of the giant oil fields have been increasing with time, reflecting the fact that more and more fields enter the decline phase and fewer and fewer new giant fields are being found. The increase is in part due to new technologies that have been able to temporarily maintain production at the expense of subsequent more rapid decline. Growing average decline rates have also been noted by IEA (2008). The difference between using a constant decline in existing production and an increasing decline rate is significant and could mean as much of a difference of 7 Mb/d by 2030 (Figure 13).

By 2030 the production from fields currently on stream could have decreased by over 50% in agreement with IEA (2008). The struggle to maintain production and compensate for the decline in existing production will become harder and harder. Our conclusion is that the world will face an increasing oil supply challenge, as the decline in existing production is not only high but also increasing.

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