

CRUDE OIL
THE SUPPLY OUTLOOK

Report to the Energy Watch Group

October 2007

EWG-Series No 3/2007

ABOUT ENERGY WATCH GROUP

This is the third of a series of papers by the Energy Watch Group which are addressed to investigate future energy supply and demand patterns.

The Energy Watch Group consists of independent scientists and experts who investigate sustainable concepts for global energy supply. The group has been initiated by the German Member of Parliament Hans-Josef Fell.

Homepage:

www.energywatchgroup.org

Responsibility for this report:

Dr. Werner Zittel, Ludwig-Bölkow-Systemtechnik GmbH
Jörg Schindler, Ludwig-Bölkow-Systemtechnik GmbH

This report is sponsored by Ludwig-Bölkow-Stiftung, Ottobrunn, Germany

Ottobrunn, October 2007

CONTENT

- About Energy Watch Group..... 2
- Introduction 18
- Scope and methodology 20
 - Types of oil..... 20
 - Conventional oil 20
 - Natural gas liquids (NGL)..... 21
 - Tar sands 21
 - Oil shales 21
 - Scope and methodology 22
 - Differences in scope and methodology to other studies..... 23
- Assessment of future oil supply 25
 - Basic concepts – understanding the future of oil 25
 - Reserves 25
 - Discoveries 33
 - Estimates of the ultimate recovery 37
 - Production patterns..... 38
 - Peak oil is now 43
 - The position of the IEA and industry 48
- Scenario of future oil supply 51
 - Regional scenarios..... 51
 - Middle East 52
 - OECD North America..... 54
 - Transition Economies..... 59
 - Africa..... 60
 - Latin America..... 62
 - OECD Europe 63
 - China 64
 - East Asia..... 65
 - South Asia 66
 - OECD Pacific..... 67
 - World scenario 67
 - EWG scenario 67
 - Comparison of EWG scenario results with other projections 68

Conclusions 71

Annex 72

 Annex 1: US oil production in Alaska and the Gulf of Mexico 72

 Alaska..... 72

 Gulf of Mexico..... 73

 Annex 2: Critique of Oil Supply Projections by USGS, EIA and IEA..... 75

 US Geological Survey (USGS)..... 75

 The US “Energy Information Administration” (EIA)..... 79

 The International Energy Agency (IEA)..... 81

 Final remark 91

 Annex 3: Non-conventional oil 92

 Canadian tar sands and oil shales – hope or nightmare..... 92

 Annex 4: International oil companies 97

Literature 100

EXECUTIVE SUMMARY / KEY FINDINGS

Scope

The main purpose of this paper is to project the future availability of crude oil up to 2030. Since crude oil is the most important energy carrier at a global scale and since all kinds of transport rely heavily on oil, the future availability of crude oil is of paramount interest. At present, widely diverging projections exist in parallel which would require completely different actions by politics, business and individuals.

The scope of these projections is similar to that of the World Energy Outlook by the International Energy Agency (IEA). However, no assumptions or projections regarding the oil price are made.

In this paper a scenario for the possible global oil supply is derived by aggregating projections for ten world regions. In order to facilitate a comparison, the definition of the world regions follow the definition used by the International Energy Agency (IEA):

- OECD North America, including Canada, Mexico and the USA.
- OECD Europe, including Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, The Netherlands, Norway, Poland, Slovak Republic, Spain, Sweden, Switzerland, Turkey and the UK.
- OECD Pacific, including
 - OECD Oceania with Australia and New Zealand,
 - OECD Asia with Japan and Korea.
- Transition Economies, including Albania, Armenia, Azerbaijan, Belarus, Bosnia-Herzegovina, Bulgaria, Croatia, Estonia, Yugoslavia, Macedonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Romania, Russia, Slovenia, Tajikistan, Turkmenistan, Ukraine, Uzbekistan, Cyprus and Malta.
- China, including China and Hong Kong.
- East Asia, including Afghanistan, Bhutan, Brunei, Chinese Taipei, Fiji, Polynesia, Indonesia, Kiribati, The Democratic Republic of Korea, Malaysia, Maldives, Myanmar, New Caledonia, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Island, Thailand, Vietnam and Vanuatu.
- South Asia, including Bangladesh, India, Nepal, Pakistan and Sri Lanka.

- Latin America, including Antigua and Barbuda, Argentina, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Dominican Republic, Ecuador, El Salvador, French Guyana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, St. Kitts-Nevis-Antigua, Saint Lucia, St. Vincent Grenadines and Suriname, Trinidad and Tobago, Uruguay and Venezuela.
- Middle East, including Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, the United Arab Emirates, Yemen, and the neutral zone between Saudi Arabia and Iraq.
- Africa, including Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, the Central African Republic, Chad, Congo, the Democratic Republic of Congo, Côte d'Ivoire, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Niger, Nigeria, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan, Swaziland, the United Republic of Tanzania, Togo, Tunisia, Uganda, Zambia and Zimbabwe.

However, the scenario results presented in this paper are very different to the scenarios presented by the IEA in their periodic editions of the World Energy Outlook (WEO) where continuing growth of oil supply and as a consequence a continuation of business as usual for decades to come is deemed possible.

Methodology

The analysis in this paper does not primarily rely on reserve data which are difficult to assess and to verify and in the past frequently have turned out to be unreliable. The history of discoveries is a better indicator though the individual data are of varying quality. Rather the analysis is based primarily on production data which can be observed more easily and are also more reliable. Historical discovery and production patterns allow to project future discoveries and – where peak production has already been reached – future production patterns.

The analysis is based on an industry database for past production data and partly also for reserve data for certain regions. As reserve data vary widely and as there is no audited reference, the authors have in some cases made their own reserve estimates based on various sources and own assessments. Generally, future production in regions which are already in decline can be predicted fairly accurately relying solely on past production data.

The projections are based also on the observation of industry behaviour and on “soft” indicators (for instance, the recent turn about in the communication by the IEA and a remarkable quote by King Abdullah of Saudi Arabia).

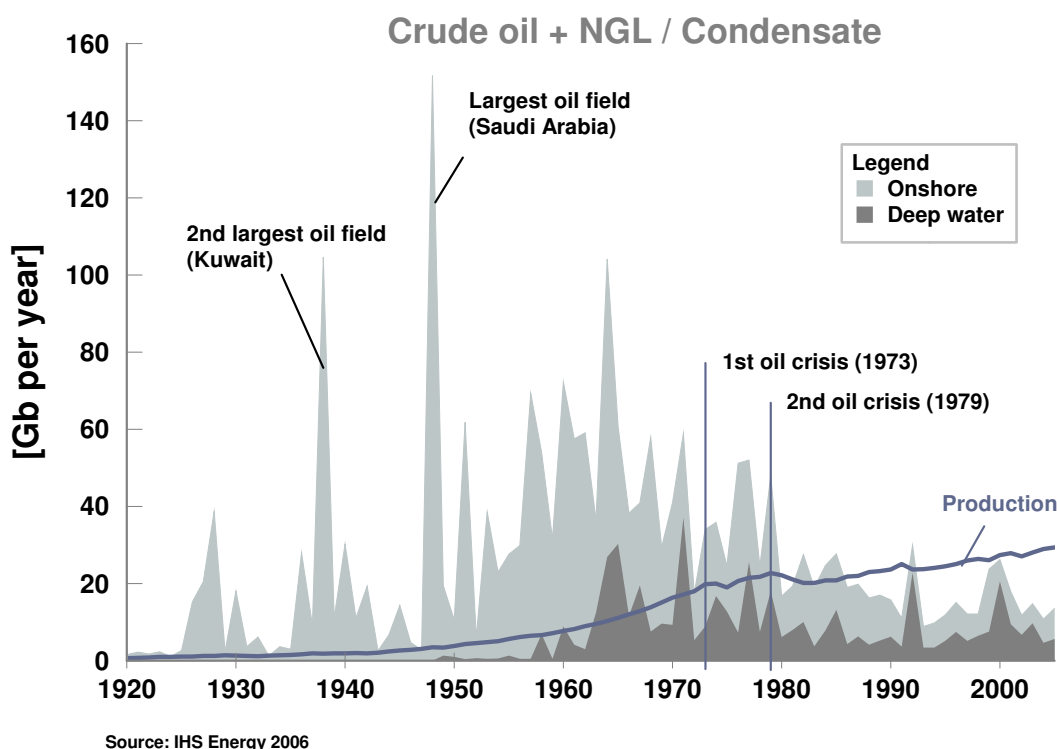
Understanding the future of oil

Only oil that has been found before can be produced. Therefore, the peak of discoveries which took place a long time ago in the 1960s, will some day have to be followed by a peak of production. After peak oil, the global availability of oil will decline year after year. There are strong indications that world oil production is near peak.

The growing discrepancy between oil discoveries and production is shown in Figure 1.

In the period 1960 to 1970 the average size of new discoveries was 527 Mb per New Field Wildcat. This size has declined to 20 Mb per New Field Wildcat over the period 2000 to 2005.

Figure 1: History of oil discoveries (proved + probable) and production



Remaining world oil reserves are estimated to amount to 1,255 Gb according to the industry database [IHS 2006]. There are good reasons to modify these figures for some regions and key countries, leading to a corresponding EWG estimate of 854 Gb. These modifications are explained in the chapters describing the detailed scenarios. The resulting reserve figures are given in in the following Figure 2 and in Table 1 (there described as EWG estimates and shown together with the IHS data). The greatest difference are the reserve numbers for the Middle East. According to IHS, the Middle East possesses 677 Gb of oil reserves, whereas the EWG estimate is 362 Gb.

Figure 2: World oil reserves (EWG assessment)

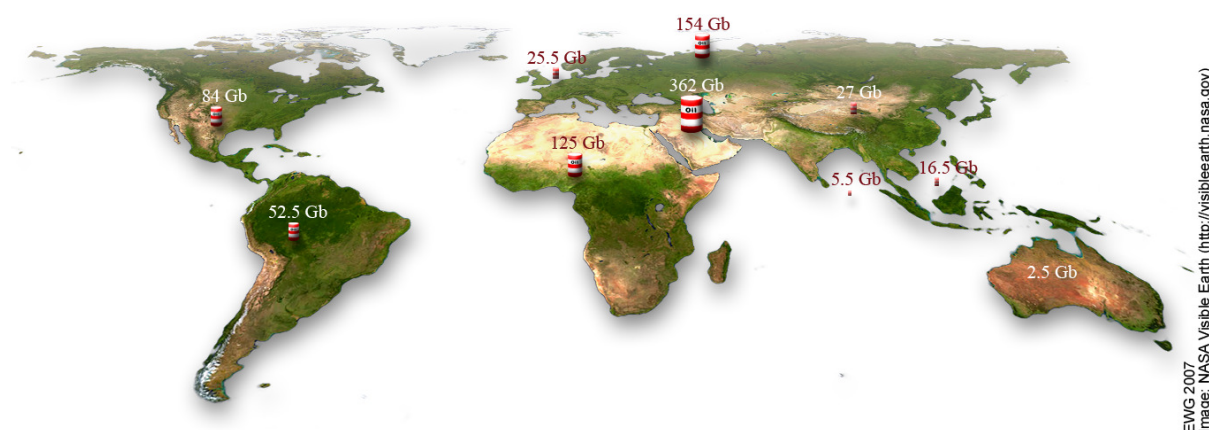
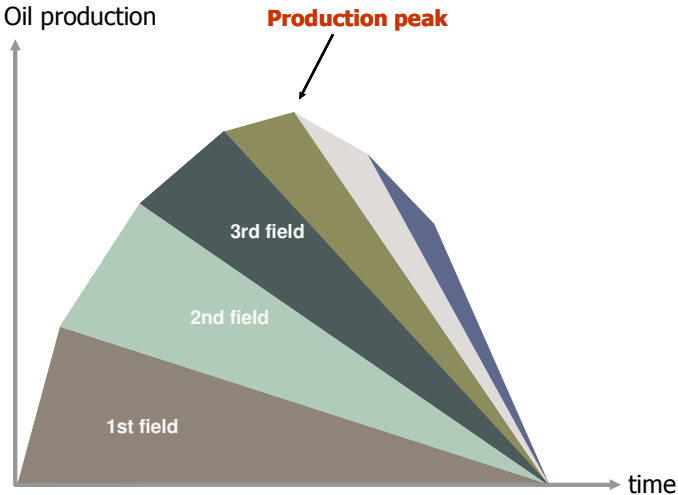


Table 1: Oil reserves and annual oil production in different regions and key countries

Region	Remaining reserves		Production 2005		Consumption 2005 [Gb/yr]
	EWG [Gb]	IHS [Gb]	onshore [Gb/yr]	offshore [Gb/yr]	
OECD North America	84	67.6	3.20	1.71	9.13
Canada	17	15.3	0.89	0.12	0.82
USA	41	31.9	1.93	0.59	7.59
Mexico	26	20.4	0.36	1.00	0.72
OECD Europe	25.5	23.5	0.1	1.94	5.72
Norway	11	11.6	0	1.13	0.08
UK	8	7.8	0.01	0.70	0.65
OECD Pacific	2.5	5.1	0.025	0.18	3.18
Australia	2.4	4.8	0.02	0.17	0.31
Transition Economies	154	190.6	4.1	0.18	2.02
Russian Federation	105	128	3.4	0.13	1.00
Azerbaijan	9.2	14	0.01	0.15	0.04
Kazakhstan	33	39	0.47	0	0.08
China	27	25.5	1.1	0.22	2.55
South Asia	5.5	5.9	0.11	0.16	0.96
East Asia	16.5	24.1	0.3	0.65	1.75
Indonesia	6.8	8.6	0.27	0.11	0.43
Latin America	52.5	129	2.0	0.61	1.74
Brazil	13.2	24	0.075	0.55	0.75
Venezuela	21.9	89	1.17	0	0.20
Middle East	362	678.5	6.97	1.97	2.09
Kuwait	35	51	0.96	0	0.11
Iran	43.5	134	1.19	0.24	0.59
Iraq	41	99	0.67	0	
Saudi Arabia	181	286	2.85	0.86	0.69
UAE	39	57	0.46	0.45	0.14
Africa	125	104.9	2.03	1.53	1.01
Algeria	14	13.5	0.72	0	0.09
Angola	19	14.5	0.01	0.45	
Libya	33	27	0.61	0.02	
Nigeria	42	36	0.39	0.52	
World	854	1,255	19.94	9.15	30.3

In every oil province the big fields will be developed first and only afterwards the smaller ones. As soon as the first big fields of a region have passed their production peak, an increasing number of new and generally smaller fields have to be developed in order to compensate the decline of the production base. From there on, it becomes increasingly difficult to sustain the rate of the production growth. A race begins which can be described as follows: More and more large oil fields show declining production rates. The resulting gap has to be filled by bringing into production a larger number of smaller fields. However, these smaller fields reach their peak much faster and then contribute to the overall production decline. As a consequence, the region's production profile which results from the aggregation of the production profiles of the individual fields, becomes more and more “skewed”, the aggregate decline of the producing fields becomes steeper and steeper. This decline has to be compensated for by the ever faster connection of more and more ever smaller fields, see Figure 20.

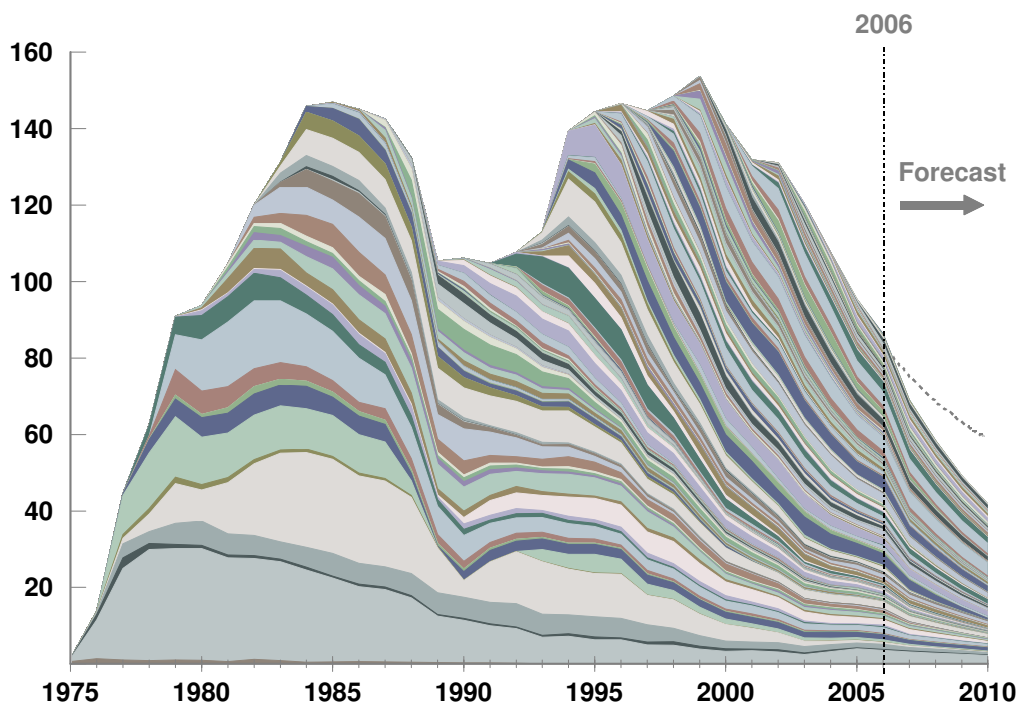
Figure 3: Typical production pattern for an oil region



So, the production pattern over time of an oil province can be characterised as follows: To increase the supply of oil will become more and more difficult, the growth rate will slow down and costs will increase until the point is reached where the industry is not anymore able to bring into production a sufficient number of new fields quick enough. At that point, production will stagnate temporarily and then eventually start to decline.

This pattern can be observed when looking at the oil production in the UK.

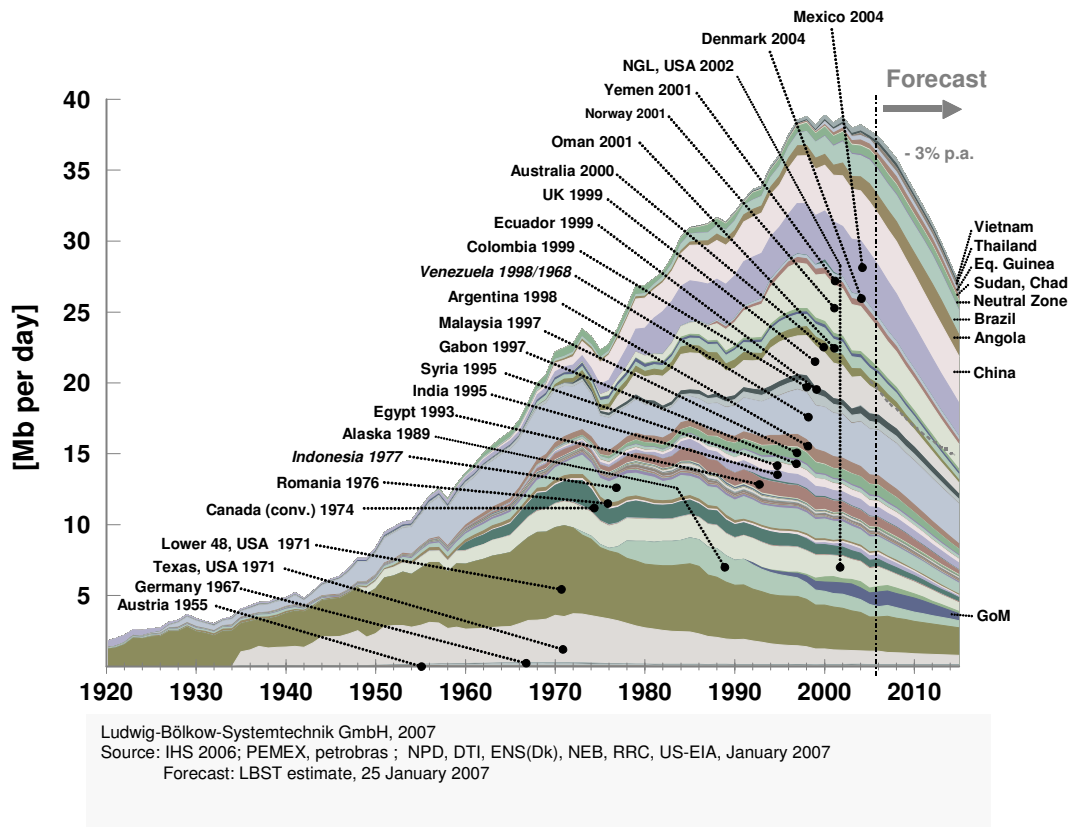
Figure 4: Oil production in the United Kingdom



Source: DTI, May 2007; Forecast: LBST

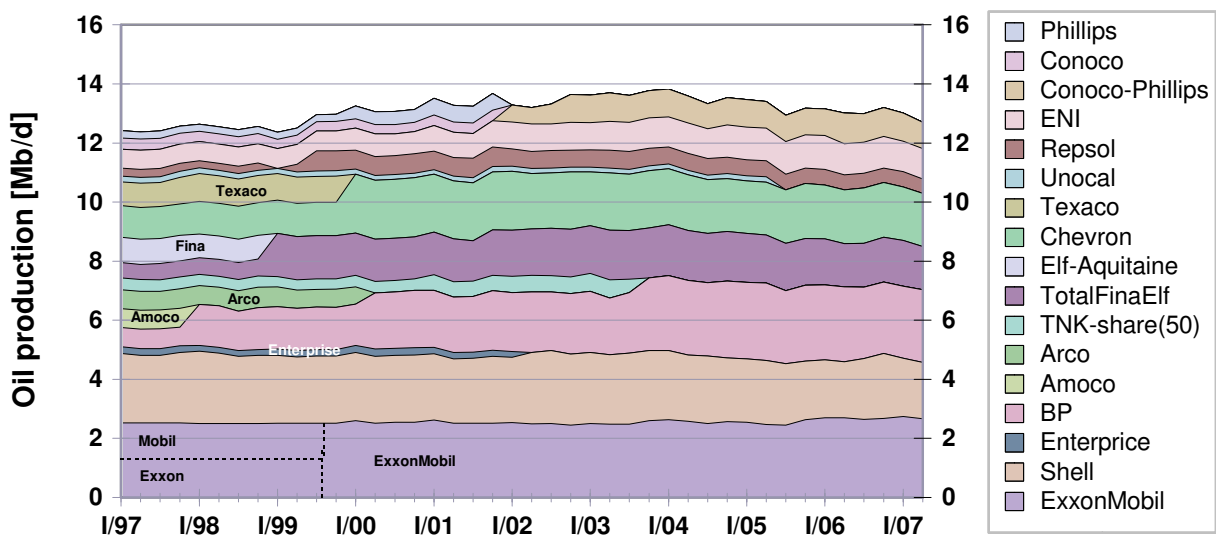
Oil production in regions having passed their peak can be forecasted with some certainty for the next years. The following Figure 5 shows the production pattern of the countries outside OPEC (only Angola is included which has recently joined OPEC) and outside the former Soviet Union. Countries with a year behind their name are countries past peak, stating the year of peak production. On the top of the graph are the few countries in this group which have not reached peak yet. If it is assumed that the remaining regions with growth potential (especially Angola, Brazil and the Gulf of Mexico) will expand their production by the year 2010 (in accordance with the forecasts of the companies operating in these regions), total oil production of this group of countries, however, will continue to decline by about 3% per year, see Figure 5.

Figure 5: Oil producing countries past peak



The difficulties of expanding oil production can also be demonstrated by looking at the performance of the big international oil companies. In aggregate, they were not able to increase their production in the last ten years, despite an unprecedented rise in oil prices.

Figure 6: Oil production of the oil majors from 1997 to 2007



Key findings

- “Peak oil is now”.

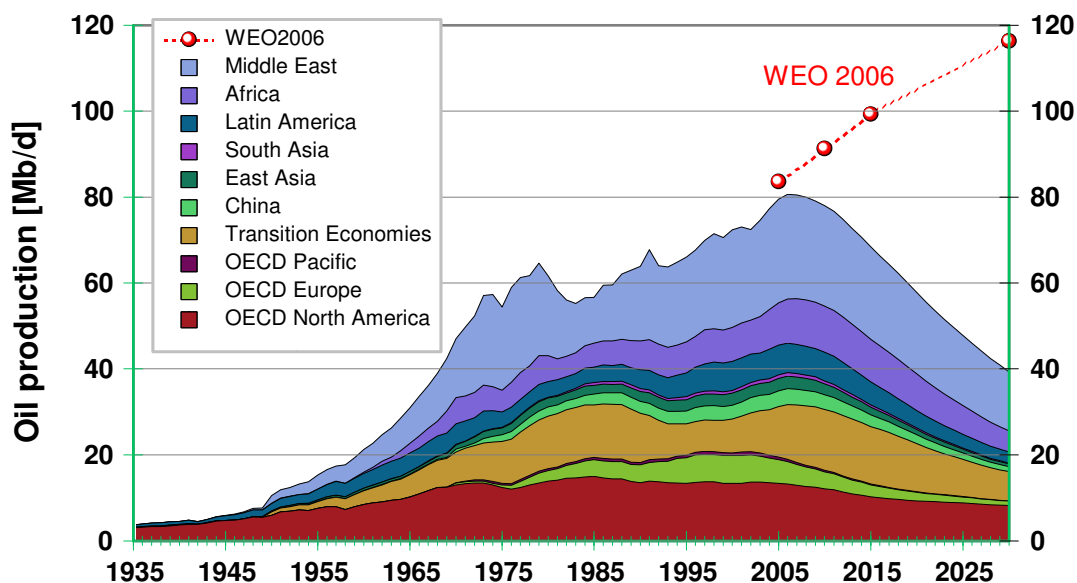
For quite some time, a hot debate is going on regarding peak oil. Institutions close to the energy industry, like CERA, are engaging in a campaign trying to “debunk” the “peak oil theory”. This paper is one of many by authors inside and outside ASPO (the Organisation for the Study of Peak Oil) showing that peak oil is anything but a “theory”, it is real and we are witnessing it already.

According to the scenario projections in this study, the peak of world oil production was in 2006.

The timing of the peak in this study is by a few years earlier than seen by other authors (like e.g. Campbell, ASPO, and Skrebowski) who are also well aware of the imminent oil peak. One reason for the difference is a more pessimistic assessment of the potential of future additions to oil production, especially from offshore oil and from deep sea oil due to the observed delays in announced field developments. Another reason are earlier and greater declines projected for key producing regions, especially in the Middle East.

- The most important finding is the steep decline of the oil supply after peak. This result – together with the timing of the peak – is obviously in sharp contrast to the projections by the IEA. But the decline is also more pronounced compared with the more moderate projections by ASPO. Yet, this result conforms very well with the recent findings of Robelius in his doctoral thesis. This is all the more remarkable because a different methodology and different data sources have been used.
- The global scenario for the future oil supply is shown in the following Figure 7.

Figure 7: Oil production world summary



The projections for the global oil supply are as follows:

- 2006: 81 Mb/d
- 2020: 58 Mb/d (IEA: 105¹ Mb/d)
- 2030: 39 Mb/d (IEA: 116² Mb/d)

The difference to the projections of the IEA could hardly be more dramatic.

- A regional analysis shows that, apart from Africa, all other regions show declining productions by 2020 compared to 2005.
By 2030, all regions show significant declines compared to 2005.

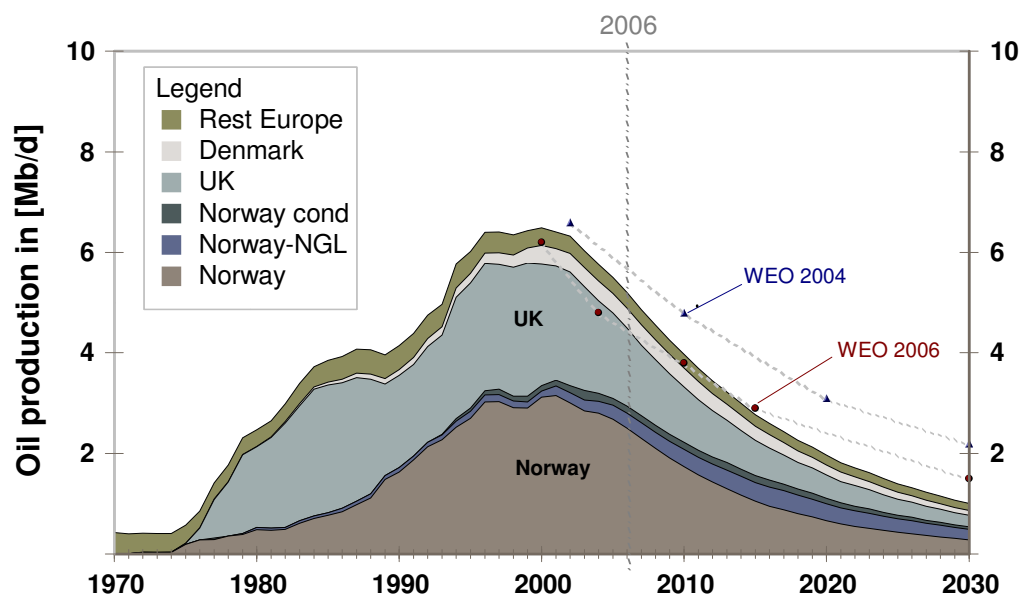
¹ Since IEA gives data only for 2015 and 2030, those for 2020 are interpolated; these data include processing gains

² Since IEA gives data only for 2015 and 2030, those for 2020 are interpolated; these data include processing gains

Three examples for regional results¹ for key producing regions are given next.

OECD Europe

Figure 8: Oil production in OECD Europe



The projections for the oil supply in OECD Europe are as follows:

- 2006: 5.2 Mb/d
- 2020: 2 Mb/d (IEA: 3.3² Mb/d)
- 2030: 1 Mb/d (IEA: 2.6³ Mb/d)

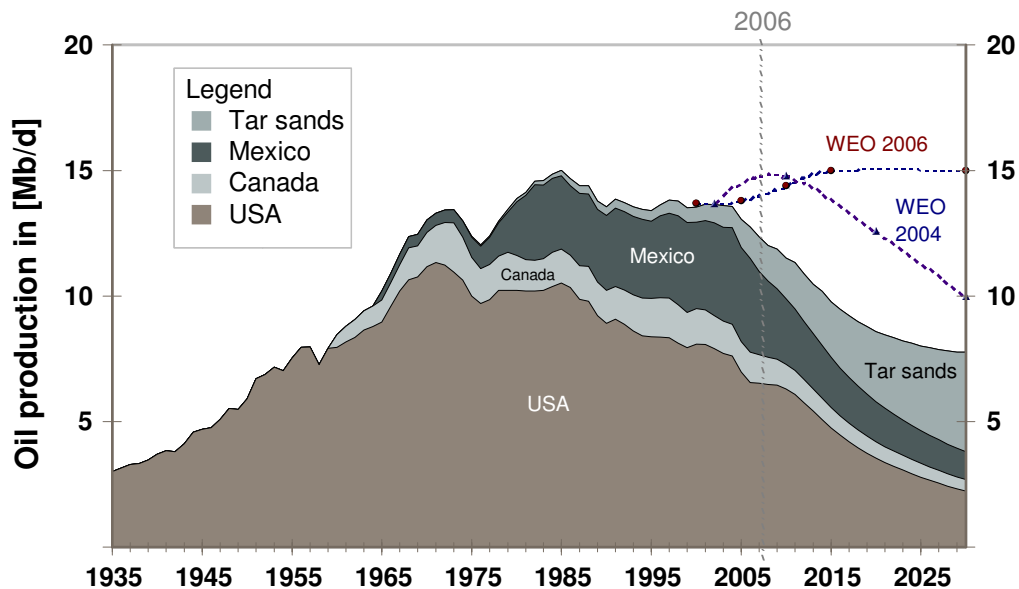
¹ Since IEA gives data only for 2015 and 2030, those for 2020 are interpolated

² For this comparison 2.3 Mb/d crude oil and 25% of OECD NGL are added

³ For this comparison 1.5 Mb/d crude oil and 25% of OECD NGL are added

OECD North America

Figure 9: Oil production in OECD North America



The projections for the oil supply in OECD North America are as follows:

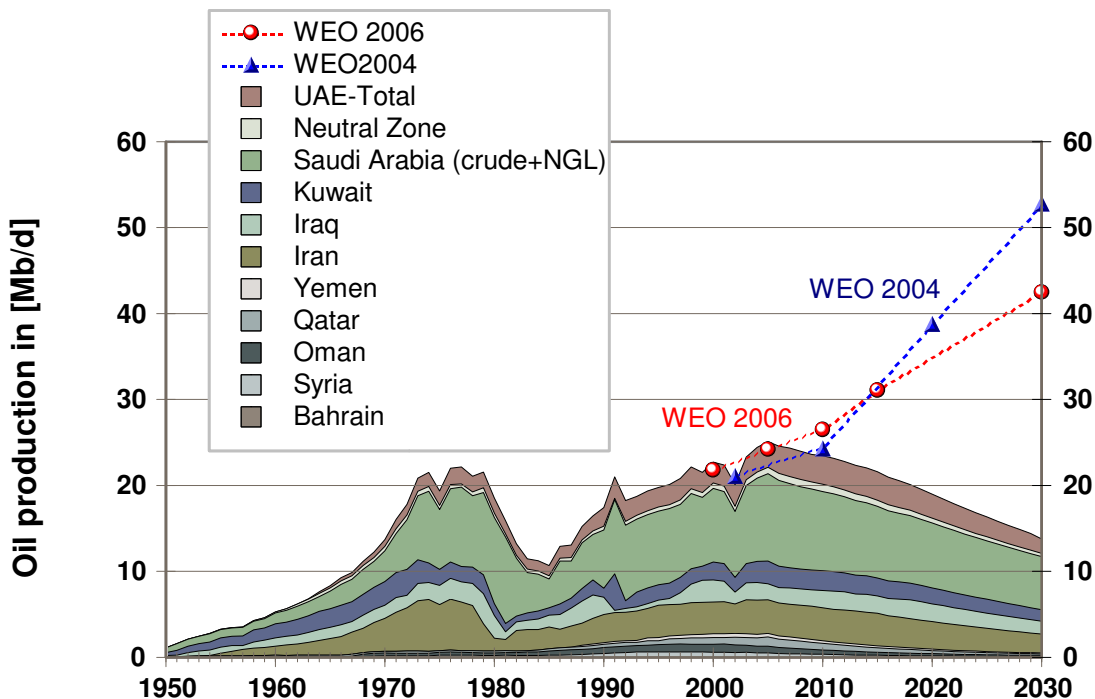
- 2006: 13.2 Mb/d
- 2020: 9.3 Mb/d (IEA: 15.9¹ Mb/d)
- 2030: 8.2 Mb/d (IEA: 15.9² Mb/d)

¹ For this comparison 8.6 Mb/d crude oil, Canadian tar sand and 75% of OECD NGL are added

² For this comparison 7.8 Mb/d crude oil, Canadian tar sand and 75% of OECD NGL are added

Middle East

Figure 10: Oil production in the Middle East



The projections for the oil supply in the Middle East are as follows:

- 2006: 24.3 Mb/d
- 2020: 19 Mb/d (IEA: 32.3¹ Mb/d)
- 2030: 13.8 Mb/d (IEA: 39.6² Mb/d)

This is the region where the assessment in this study deviates most from the projections by the IEA.

Conclusion

The major result from this analysis is that world oil production has peaked in 2006. Production will start to decline at a rate of several percent per year. By 2020, and even more by 2030, global oil supply will be dramatically lower. This will create a supply gap which can hardly be closed by growing contributions from other fossil, nuclear or alternative energy sources in this time frame.

¹ 28.3 Mb/d crude oil and 4 Mb/d NGL
² 34.5 Mb/d crude oil and 5.1 Mb/d NGL

The world is at the beginning of a structural change of its economic system. This change will be triggered by declining fossil fuel supplies and will influence almost all aspects of our daily life.

Climate change will also force humankind to change energy consumption patterns by reducing significantly the burning of fossil fuels. Global warming is a very serious problem. However, the focus of this paper is on the aspects of resource depletion as these are much less transparent to the public.

The now beginning transition period probably has its own rules which are valid only during this phase. Things might happen which we never experienced before and which we may never experience again once this transition period has ended. Our way of dealing with energy issues probably will have to change fundamentally.

The International Energy Agency, anyway until recently, denies that such a fundamental change of our energy supply is likely to happen in the near or medium term future. The message by the IEA, namely that business as usual will also be possible in future, sends a false signal to politicians, industry and consumers – not to forget the media.

INTRODUCTION

Crude oil is the most important energy source in a global perspective. About 35 percent of the world's primary energy consumption is supplied by oil, followed by coal with 25 percent and natural gas with 21 percent [WEO 2006]. Transport relies to well over 90 percent on oil, be it transport on roads, by ships or by aircrafts. Therefore, the economy and the lifestyle of industrialised societies relies heavily on the sufficient supply of oil, moreover, probably also on the supply of cheap oil.

Economic growth in the past was accompanied by a growing oil consumption. But in recent years the growth of the supply of oil has been slowing and production has now practically reached a plateau. This is happening despite historically high oil prices. It is very likely that the world has now practically reached peak oil production and that world oil production will soon start to decline at initially probably increasing rates.

Because of the importance of oil as an energy source, and because of the difficulties of substituting oil by other fossil or renewable energy sources, peak oil will be a singular turning point. This will have consequences and repercussions for virtually every aspect of life in industrialised societies. Because the changes will be so fundamental, the whole topic is not popular. Colin Campbell put it this way: "Everybody hates this topic but the oil industry hates it more than anybody else."

However, as facts cannot be ignored indefinitely, also the public perception is changing. The possibility of peak oil is more frequently referenced in the media, though it is still regularly and ritually dismissed as being only a "theory". This is a signal that the conventional ways of explaining what is actually happening are obviously failing. The oil industry is now admitting to the fact that the "era of easy oil" has ended. And the International Energy Agency, in stark contrast to past messages, is now warning of an imminent "oil crunch" in a few years time.

The purpose of this paper is to give some background information for understanding the concepts and data relevant for the assessment of the future supply of oil. This is the basis for detailed projections of future world oil supply up to the year 2030. These projections are performed for the ten world regions as defined by the International Energy Agency (IEA) and then are aggregated into a global scenario.

The scenario results are set into perspective by comparing them with selected prominent studies by other institutions and authors. The scenario described in this paper is painting a completely different picture of the future than the IEA. It is much more in line with the projections by ASPO (Campbell) and by Robelius [Robelius 2007]. The differences are partly due to different methodological approaches (which are described in this paper) but are also due to inherent differences, ambiguities and uncertainties in the databases to which the different authors have access to and which cannot be resolved for the time being..

Last but not least, future developments will be affected by so many different factors like geology (frequently referred to as “below ground” factors) and economics and politics (“above ground factors”) that the setup of scenarios is as much an art than a science. However, it appears that “geology” is now dominating economics and politics so that geological limits now define the upper limit of the future possible supply, whereas economic and political factors can only further constrain this boundary. The bandwidth of uncertainty is rapidly getting narrower.

Outline of the paper

In an introductory chapter, the scope of the study is defined and methodological questions regarding the projection of the future supply of oil are discussed. Some aspects are dealt with in greater detail in the Annex.

In the chapter “Assessment of the future oil supply” basic aspects are discussed which are necessary for a better understanding of the reasoning behind the scenario projections. This covers the concept of reserves, discussing definitions, reporting practices, data sources and reliability of data. Of equal importance is the history of the development of discoveries and production in different regions and countries. The analysis of these developments shows patterns which are relevant for the projection of future supplies.

In the chapter “Scenario of future oil supply” detailed results are presented for ten world regions and at a global level. The results are compared with prominent projections by the IEA, ASPO and Robelius. Differences and the reason for them are discussed.

SCOPE AND METHODOLOGY

Types of oil

Oil was created in the geological past by cracking biological hydrocarbon molecules into smaller hydrocarbon molecules. For this process a closed environment, proper source material, long time periods and high temperatures were necessary. When generated, oil was movable (liquid) and escaped from the source rock. In most cases oil escaped to the surface or dissipated somewhere in the ground in very low concentrations. Only when an impermeable rock layer was on top of the source rocks the oil followed the layer until it was trapped below a cap. These traps formed the oil fields with high oil concentrations.

However, the proper combination of all these parameters was rare in the geological past. Today the process of the generation of oil in source rocks and its move to oil fields is well understood by geologists. Therefore, the areas with potential hydrocarbon accumulations are well known and huge surprises can almost be excluded as the world is sufficiently explored.

In the supply projections in this study conventional oil, natural gas liquids (NGL) and oil produced from tar sands are considered.

Conventional oil

There are different classification schemes: based on economic and/or geological criteria.

The economic definition of conventional oil: *Conventional oil is oil which can be produced with current technology under present economic conditions.* The problem with this definition is that (1) it is not very precise, and (2) it describes a moving target. For instance, what were economic conditions e.g. in the former USSR as opposed to Russia now?

Then there are geological classifications, e.g. the one used by ASPO/Campbell. This classification is based on the viscosity of the oil (measured in °API) and on other properties:

- *Conventional oil is crude oil having a viscosity above 17°API*
- *Non-conventional oil:*
 - *heavy oil between 10-17°API*
 - *extra heavy oil below 10°API (tar sands belong to this category)*
 - *oil shale*
 - *deepsea oil below 500 meter water depth*
 - *polar oil north or south of the arctic/antarctic circle*
 - *condensate*

There is also a pragmatic definition which is widely used:

- *Conventional oil is:*
 - *crude oil > 17°API*

- *heavy oil between 10-17°API*
- *all deep sea oil at any depth*
- *polar oil*
- *condensate*
- *Non-conventional oil is:*
 - *NGL*
 - *extra heavy oil below 10°API*
 - *synthetic crude oil (SCO) and bitumen from tar sands*
 - *oil shale*

In this study “crude oil” is considered as consisting of “conventional oil” and “non-conventional oil”. “Conventional oil” includes oil >10°API, deepsea oil, polar oil and condensate as well as NGL (since many statistics do not distinguish between crude oil and NGL). SCO and bitumen from tar sands are treated explicitly as “non-conventional oil”. Oil shales are not considered.

Natural gas liquids (NGL)

Natural gas liquids are liquid hydrocarbons being part of the production of natural gas and which are separated at the well.

Tar sands

Tar sands are oil traps which are not deep enough below the surface to allow the generation of conventional oil. The oil was not heated enough to continue the process of cracking in order to get rid of the complex chain-molecules which are responsible for the high viscosity. The hydrocarbons have the characteristics of bitumen, they are close to the surface and are mixed with large amounts of sand. In the best regions in Canada the bitumen containing layer has an oil concentration of about 15-20 percent. The production method of choice is open pit mining. The tar sand is mined, flooded with water in order to separate the sand from the lighter oil, and then processed in special refineries to get rid of the high sulphur content (usually between 3-5 percent) and other particulates. This process needs huge amounts of energy and water. Only oil deposits in deep layers below 75 m are mined in-situ.

Oil production from tar sands in Canada is dealt with in greater detail in the Annex.

Oil shales

Oil shales contain only kerogene and not oil. Kerogene is an intermediate product on the way from biological hydrocarbon cracking to oil formation. The oil shale layer was not hot enough to complete the oil generation. For the final step the kerogene must be heated up to 500 °C and combine with additional hydrogen to complete the oil formation. This final process must be performed in the refinery and needs huge amounts of energy which usually were provided by the environment during oil formation.

The kerogene is still in the source rock and could not accumulate in oil fields. The ratio of kerogene to waste material is very low, making the mining of oil shales unattractive. This holds even more as the shale material contains other ingredients which expose the miners and the environment or health risks (e.g. from hydrosulphide).

Oil shales are not regarded as being a reasonable energy source at large scale. The main reason for this is that the energy balance for extracting the oil is too poor. In combination with environmental and economic aspects it is very unlikely that oil shale mining will ever be performed at large scale, though at some places it is used already today in small quantities.

Scope and methodology

The principal aim of this study is to project future world oil supply up to 2030. These projections are done for the ten world regions as they are defined by the IEA. This enables comparisons with IEA projections also on a regional level so that differences will be more explicit.

Basis for the regional production scenarios are the following data for each country: historical discovery and production patterns, remaining reserves and also known field development projects of the oil industry. The history of discoveries allows to project future discoveries. The analysis of production profiles allows - for countries where peak production has already been reached - to project future production patterns.

The main datasource for the analysis is the IHS database. However, for the USA, Canada, UK, Denmark and Norway detailed government statistics are used with field by field data. (For the UK and Norway a first analysis was carried out in 2001 in "Analysis of UK Oil Production", see article at www.energyshortage.com. For the analysis of the oil production in the Gulf of Mexico the statistics of MMS are used.) Production data for Saudi Arabia, Mexico and Brazil are taken from company statistics.

Furthermore, for some important regions the IHS data on remaining reserves have been replaced by own assessments based on other sources. This has been done especially for USA, Canada, Mexico, Brazil, Middle East countries, and Russia. Also, IHS states proved reserves as "remaining reserves" whereas in this study proved and probable reserves are used wherever possible and available.

For key countries details are discussed on the basis of production profiles that are derived from the individual field production data. For regions (and fields) already in decline the future production profile is derived from a plot of annual production versus cumulative production. Due to physical reasons (e.g. declining field pressure during extraction), the decline of the production profile is approximately linear in such plots (decline is exponential over time, but linear in this plot). From the steepness of the decline the ultimate amount of recoverable oil

can be estimated quite accurately. This is a common method widely used in the oil and natural gas industry.

Only for regions where the necessary detailed information was not available, production profiles are estimated from the known largest fields and by assuming a logistic growth concept.

Oil production from tar sands in Canada is projected from announced industry projects and projections of the NEB (National Energy Board) of Alberta.

Accordingly, the projections constitute a quantitative assessment based on various data and sources. There is no single rigid algorithm based on a defined set of numbers valid for all countries and regions. The projections are a result of the judgement of the authors based on the data and information available. This element of seeming arbitrariness is not avoidable in view of the deficiencies of the available data.

This quantitative exercise is necessary to get a better idea of the supply in the next two decades. But the result is not to be interpreted as an exact forecast but rather as an indication of a probable range and should therefore be ultimately interpreted qualitatively. In a way, the qualitative results and interpretations are more important and more relevant (and also more robust) than the exact numbers.

Results will be compared with projections performed by IEA, ASPO and Robelius (to take just some prominent examples from the many projections now available).

Differences in scope and methodology to other studies

ASPO

The methodology used for the ASPO projections is somewhat different. Types of oil considered are conventional oil (onshore), tar sands and heavy oil, offshore and deep offshore oil, polar oil. To each of these oil types a special production profile is attributed based on the already produced amounts and on the ultimate recoverable resource (URR). For instance, deep sea oil is extracted fast with a steep production increase and showing after peak a steep decline (5-12%) while many onshore projects are produced with a much slower decline profile (3-5%). The time horizon of the projections extends to the year 2100.

ASPO scenarios are based on a reserve assessment and Hubbert curves (this is more of a top-down approach).

Data sources are own data bases which are derived from various open and disclosed sources.

The projections are work in progress and are revised whenever better data are available.

Robelius

Robelius in his doctoral thesis [Robelius 2007] addresses the question: when is peak oil? The methodology used by Robelius is based on an analysis of reserves and production profiles of giant oil fields. Additionally, conventional oil production from smaller fields is dealt with in an aggregate manner. Also projections for unconventional oil are made (tar sands in Canada and heavy oil in Venezuela). The same types of oil are considered as in this paper.

Giant fields are defined as having an ultimate recoverable reserve (URR) of 0.5 Gb or more or have produced more than 100,000 b/d for at least a year. There are, according to Robelius, 507 such fields (i.e. about 1 percent of all known fields) which cover 60-70 percent of known reserves and about 45 percent of current world production (all numbers for 2005). The performance of these fields will determine future oil supply and will therefore also determine the timing of peak oil. An extensive and comprehensive research was undertaken by Robelius to gather relevant data for all giant fields from all available data sources. Accordingly, this database certainly contains the best and most reliable data as far as giant oil fields are concerned.

Results are presented in a range of scenarios. In the work of Robelius the regional distribution of global oil supply was not the primary focus.

International Energy Agency (IEA)

The IEA regularly projects the future world energy supply in its World Energy Outlook. The time horizon for the projections is 2030. The projections are detailed for ten world regions and also for different energy sources.

The principal approach of the IEA is to project future oil demand based on an economic model. Then the oil supply is supposed to equal demand. The possible growth of oil supply is taken for granted based on reserve estimates by the US Geological Survey (USGS) and on supply scenarios by the US Energy Information Agency (EIA). A critique of this approach is given in the Annex.

ASSESSMENT OF FUTURE OIL SUPPLY

Basic concepts – understanding the future of oil

In this subchapter a few basic concepts are introduced in order to better understand the patterns which govern the future availability of oil. These considerations are the basis for the supply scenarios in subsequent chapters.

First, the concept of reserves is explained and how it is used by different players. Then, the history of discoveries and the history of oil production is shortly described. Typical patterns of oil production over time and the influence of technology are discussed.

Only oil that has been found before can be produced. Therefore, the peak of discoveries which took place a long time ago in the 1960s, will some day have to be followed by a peak of production. After peak oil, the global availability of oil will decline year after year. There are strong indications that world oil production is near peak.

Reserves

Reserve definitions

The definition of reserves is in theory quite clear and not controversial. The standard definitions as they are e.g. stated in Wikipedia [Wikipedia 2007] are as follows:

“Oil reserves are primarily a measure of geological and economic risk - of the probability of oil existing and being producible under current economic conditions using current technology. The three categories of reserves generally used are proven, probable, and possible reserves.

Proven Reserves - defined as oil and gas "Reasonably Certain" to be producible using current technology at current prices, with current commercial terms and government consent, also known in the industry as 1P. Some industry specialists refer to this as P90, i.e., having a 90% certainty of being produced. Proven reserves are further subdivided into "Proven Developed" (PD) and "Proven Undeveloped" (PUD). PD reserves are reserves that can be produced with existing wells and perforations, or from additional reservoirs where minimal additional investment (operating expense) is required. PUD reserves require additional capital investment (drilling new wells, installing gas compression, etc.) to bring the oil and gas to the surface.

Probable Reserves - defined as oil and gas "Reasonably Probable" of being produced using current or likely technology at current prices, with current commercial terms and government consent. Some Industry specialists refer to this as P50, i.e., having a 50% certainty of being produced. This is also known in the industry as 2P or Proven plus probable.

Possible Reserves - i.e., "having a chance of being developed under favourable circumstances". Some Industry specialists refer to this as P10, i.e., having a 10% certainty of being produced. This is also known in the industry as 3P or Proven plus probable plus possible."

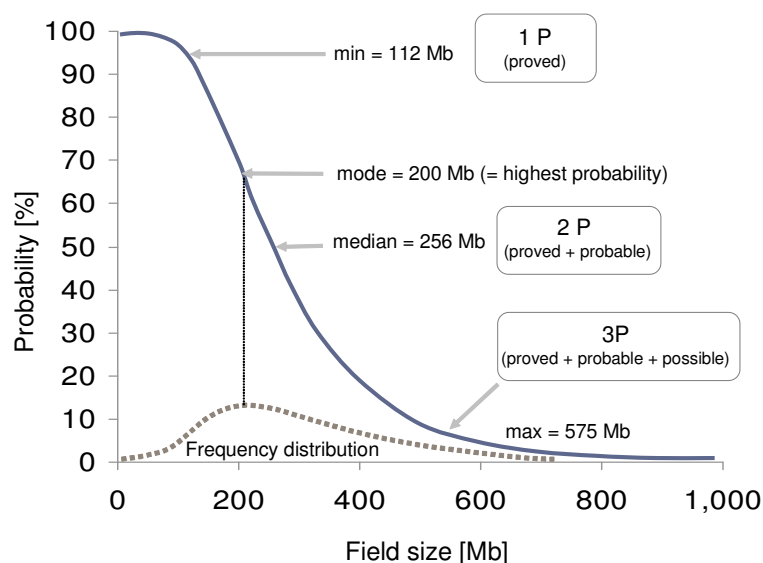
In the actual practice of the industry things are not so clear anymore. In many cases it is not clear how the data are derived. Especially in statistics on global oil reserves there is no transparent or audited procedure. For instance, the statistics published by the Oil & Gas Journal [OGJ 2007] refer to proved reserves but they rely solely on the reporting of oil producing countries. The data of the Oil & Gas Journal are also the basis for the reserve statistics published annually by BP [BP 2006].

In contrast to most of the public domain statistics which refer to proven reserves, industry databases, e.g. by IHS Energy [IHS Energy 2006], use proved and probable (or P50) reserves.

Ideally, for every oilfield discovered a probabilistic analysis is carried out taking account of the following parameters: area, thickness of the oil containing structures, porosity of the structure, oil content in the rock, estimated recovery factor, etc. From these data a probabilistic distribution is generated as shown in the following Figure 11.

In the example illustrated in the figure the field has a size of at least 130 Mb with 90% probability (P90). Most probable, however, the size is 200 Mb with a 30% chance of being smaller and a 70% chance of being larger. With 50% probability the field has a size of at least 250 Mb, having an equal chance of being smaller or larger than estimated. With 5% probability the field size exceeds 575 Mb. Though this definition seems to be quite exact, in reality in many cases it is rather unclear on which definition the estimate is based on and with which certainty the probability distribution matches the reality.

Figure 11: Normal distribution for the assessment of the recoverable oil in a specific oilfield [Petroconsultants 1995]



Reserve assessment and reporting

When analysing oil statistics one has to look at the definitions used. Some statistics only refer to conventional oil defined as oil having a density of $>20^{\circ}$ API. Some statistics also include natural gas liquids (NGL), a byproduct from the production of natural gas. In other statistics also heavy oil with a density below 20° API is considered and in some cases also unconventional oil – like tar sands – is included.

Oil companies operating in the USA are obliged to adhere to the strict reporting rules set by the Securities and Exchange Commission (SEC) which require the reporting of proved reserves. Internally, companies mostly will use proved and probable (P50) reserves. For instance, BP internally estimated the size of the Prudhoe Bay field in Alaska (the biggest field in the USA) at 15 Gb in 1970 before the start of production there. Yet, according to SEC rules, only 9 Gb were reported. Today, the real size of the field is probably between 13 and 14 Gb.

The United States Geological Survey (USGS) use their own definitions. For instance, heavy oil is regarded as being a conventional reserve. The assessment of reserves also is independent of economic or technological considerations and is carried out according to the “McKelvey-classification”. Therefore, reserve data by the USGS [USGS 2005] are much higher than those of other institutions. [Campbell 1995], [Campbell 1997]

The different reporting methods of different institutions account for most of the differences in published reserve data.

Since proved reserves always are much smaller than the initially anticipated proved and probable reserves, over time a re-evaluation of proved reserves is taking place because in the course of producing an oilfield probable reserves are converted into proved reserves. This practice creates the illusion of growing reserves despite growing consumption.

On the other hand, when proved and probable reserves are used, once the yearly consumption exceeds the yearly reserve additions, total reserves will start to decline.

Just a remark relating to the finiteness of fossil energy resources: The term “reserve growth” is a somewhat misleading metaphor. In reality, of course, each barrel of oil burnt irreversibly reduces the original reserves on earth. Just our knowledge of remaining reserves is subject to change. An upward revision of our knowledge of reserves does not increase the actual amount of reserves.

Differentiation between discoveries and re-evaluations

One of the prominent statistics in the public domain is the BP Statistical Review of World Energy [BP 2006]. The oil reserve statistics refer to proven reserves and their development is shown in the following Figure 12.

Figure 12: Development of proved reserves of oil worldwide according to public domain statistics

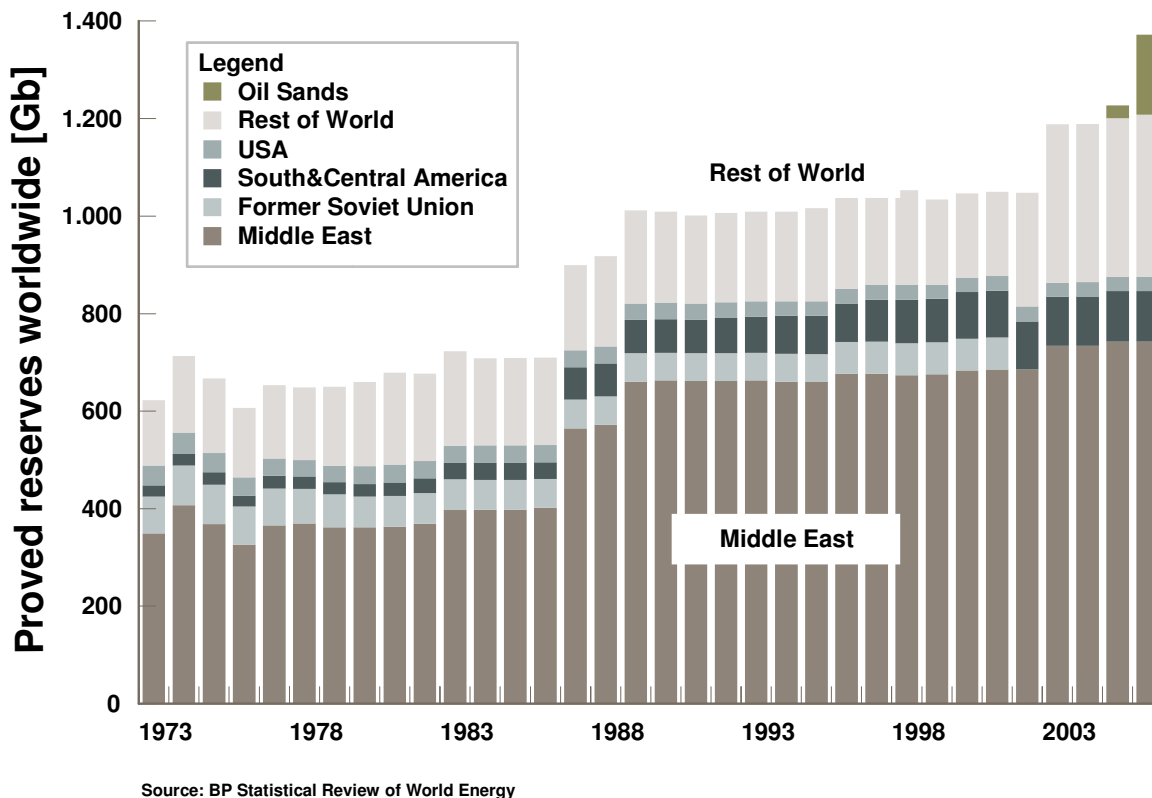
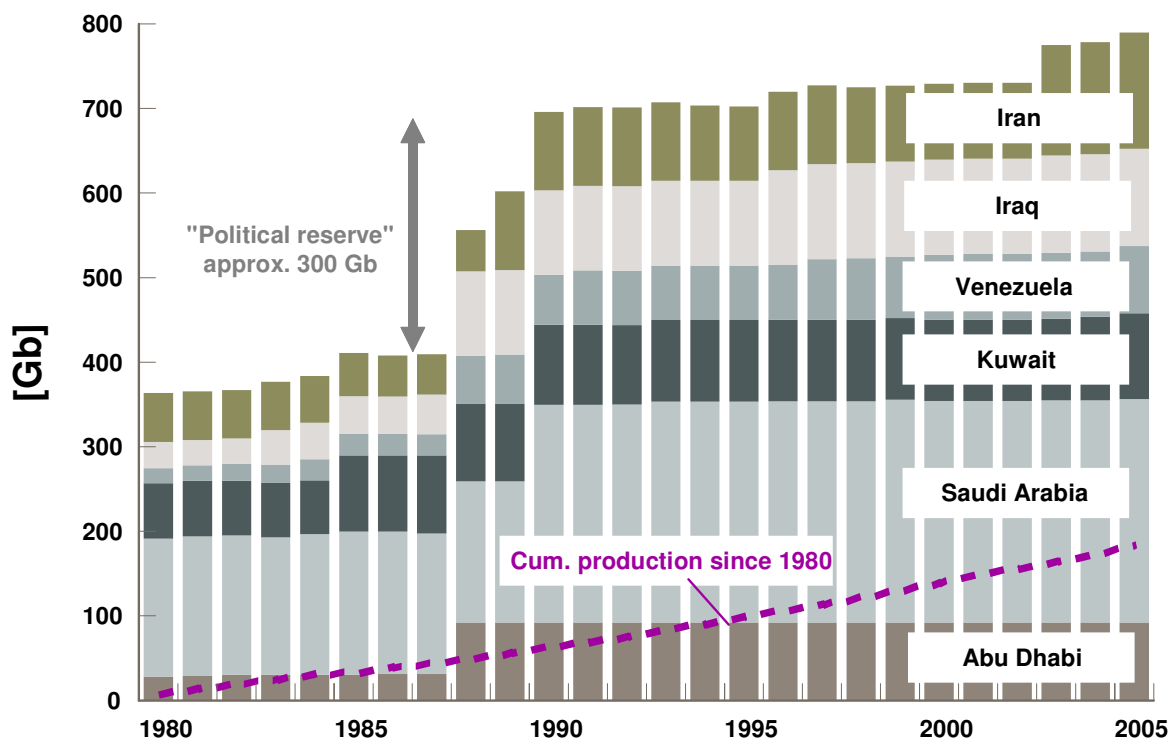


Figure 12 shows an overall growth of proved reserves during the last decades (from 600 Gb in 1973 to about 1,400 Gb in 2006). Since consumption of oil also has increased considerably in this period, this is widely seen as a strong indication that a supply problem is not imminent.

The significant rise of proved reserves in the past has occurred within a few years (1987 – 1989) and is confined to few countries. In this period reserves increased by 40% from 700 Gb to more than 1,000 Gb, all due to increases in OPEC countries. the latest increases in 2006 by 163.5 Gb (sic!) account for Canadian tar sands. The details are shown in Figure 13.

Figure 13: Development of proved reserves of oil in OPEC countries according to public domain statistics



Source: BP Statistical Review of World Energy

All major OPEC oil producing countries increased their reserves considerably, despite the fact that there were no new corresponding discoveries reported in this period. The reason given for the re-evaluation of reserves was that the reserve assessments in the past were too low. To a certain extent this may well be justified since before the nationalisation of the oil industry in these countries, private companies perhaps had a tendency to underreport reserves for financial and political reasons.

But there were also other reasons. OPEC production quotas are set according to reserves and also other factors. Therefore, there was an incentive for each country to defend their quota by keeping up with reserves. It is not transparent what the real reserves of OPEC are, especially since reserves have not been adjusted since then in spite of significant production. However, critical observers speak of “political reserves” in this context.

Reported reserves at any point in time are the result of:

- Reserves (as reported at the start of last period)
- + Re-evaluation of existing reserves (in last period)
- + New discoveries (in last period)
- Production (in last period)

= Reserves (as of to date)

In the published statistics the individual elements of the above described reserve calculation are in most cases not transparent. Without this information, it is very difficult to assess the quality of the reserve data.

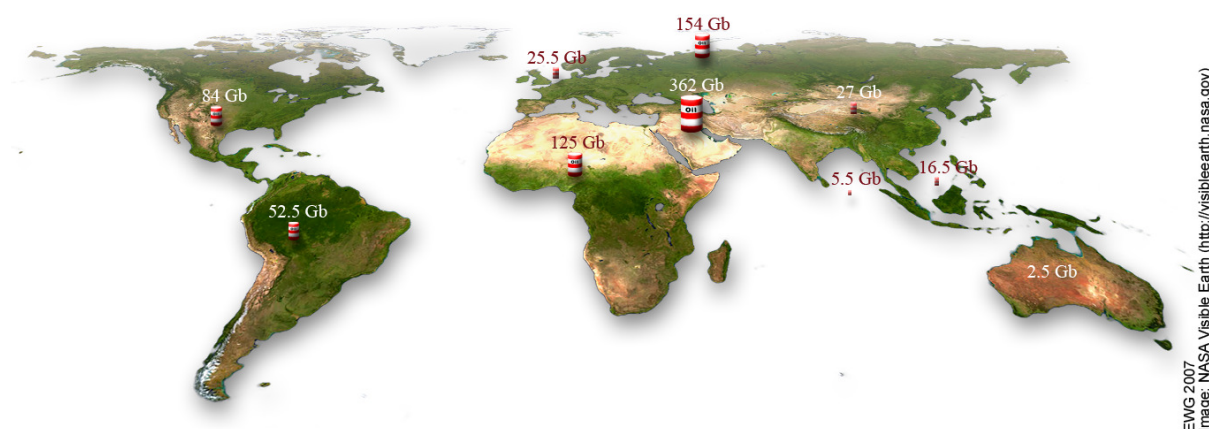
Field revisions are due to an initial underreporting of reserves. This guarantees that year by year proved reserves are increasing, thus hiding the real situation regarding new discoveries. This is common practice for the reporting of reserves by private oil companies. During the lifetime of a producing field the initially estimated proved reserve is re-evaluated several times and is finally very close to the value that in the beginning was internally known as the P50 reserve.

Also, with the help of these systematic upward revisions, years with disappointing exploration success can be hidden, and the produced quantities smoothly replaced in the company statistics. This accounts for the fact that oil reserves have almost continuously increased for more than 40 years, though each year large quantities were removed by production. The reserve figures used in financial contexts and shareholder meetings are completely different from those that address the question of how much oil has already been found and how much oil will still be found.

The main reason, however, for the apparently unchanged world reserves year after year is the reporting practice of state owned companies. More than 70 countries have reported unchanged reserves for many years, despite substantial production.

World oil reserves are estimated to amount to 1,255 Gb according to the industry database [IHS 2006]. There are good reasons to modify these figures for some regions and key countries, leading to a corresponding EWG estimate of 854 Gb. These modifications are explained in the chapters describing the detailed scenarios. The resulting reserve figures are given in Figure 14 and in Table 2 (there described as EWG estimates and shown together with the IHS data). The greatest differences are the reserve numbers for the Middle East. According to IHS, the Middle East possesses 677 Gb of oil reserves, whereas the EWG estimate is 362 Gb.

Due to ongoing but declining discoveries and reassessments of older (already discovered), fields the reserve figures will slightly change from year to year. In balance with the annual consumption of about 30 Gb/yr at present, these figures will steadily decline. In Table 2 for each region also the consumption in 2005 is presented [IHS Energy 2006], [BP 2006].

Figure 14: World oil reserves (EWG assessment)**Table 2: Oil reserves and annual oil production in different regions and key countries**

Region	Remaining reserves		Production 2005		Consumption 2005 [Gb/yr]
	EWG [Gb]	IHS [Gb]	onshore [Gb/yr]	offshore [Gb/yr]	
OECD North America	84	67.6	3.20	1.71	9.13
Canada	17	15.3	0.89	0.12	0.82
USA	41	31.9	1.93	0.59	7.59
Mexico	26	20.4	0.36	1.00	0.72
OECD Europe	25.5	23.5	0.1	1.94	5.72
Norway	11	11.6	0	1.13	0.08
UK	8	7.8	0.01	0.70	0.65
OECD Pacific	2.5	5.1	0.025	0.18	3.18
Australia	2.4	4.8	0.02	0.17	0.31
Transition Economies	154	190.6	4.1	0.18	2.02
Russian Federation	105	128	3.4	0.13	1.00
Azerbaijan	9.2	14	0.01	0.15	0.04
Kazakhstan	33	39	0.47	0	0.08
China	27	25.5	1.1	0.22	2.55
South Asia	5.5	5.9	0.11	0.16	0.96
East Asia	16.5	24.1	0.3	0.65	1.75
Indonesia	6.8	8.6	0.27	0.11	0.43
Latin America	52.5	129	2.0	0.61	1.74
Brazil	13.2	24	0.075	0.55	0.75
Venezuela	21.9	89	1.17	0	0.20
Middle East	362	678.5	6.97	1.97	2.09
Kuwait	35	51	0.96	0	0.11
Iran	43.5	134	1.19	0.24	0.59
Iraq	41	99	0.67	0	
Saudi Arabia	181	286	2.85	0.86	0.69
UAE	39	57	0.46	0.45	0.14
Africa	125	104.9	2.03	1.53	1.01
Algeria	14	13.5	0.72	0	0.09
Angola	19	14.5	0.01	0.45	
Libya	33	27	0.61	0.02	
Nigeria	42	36	0.39	0.52	
World	854	1,255	19.94	9.15	30.3

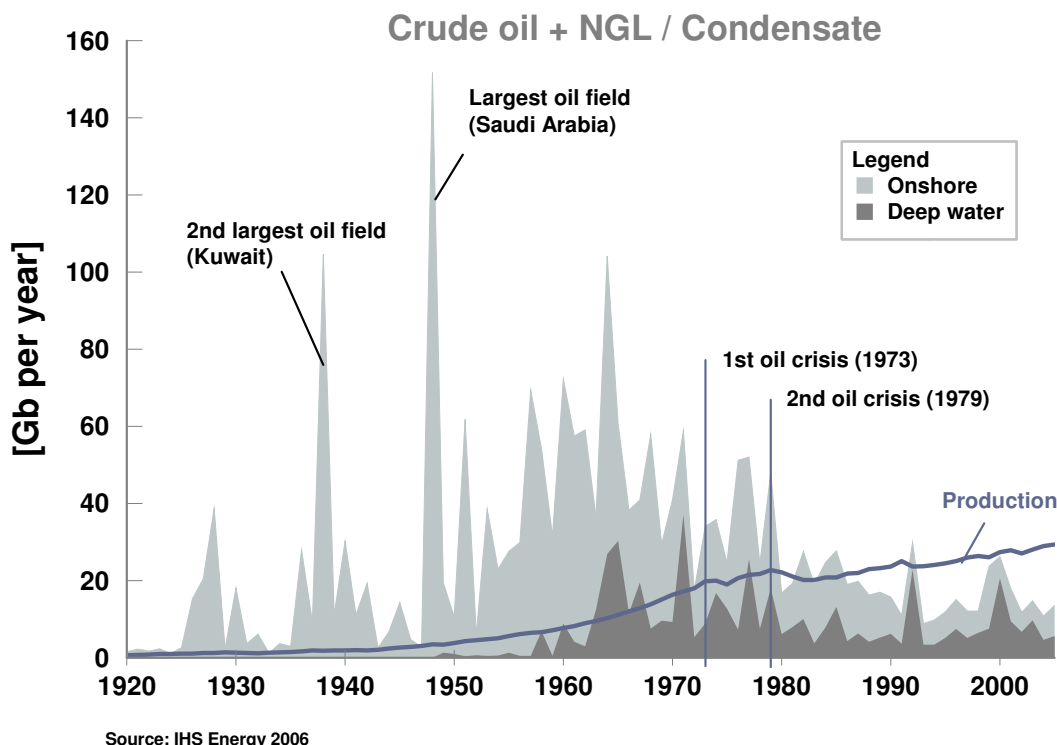
Reserves of crude oil are an important factor in determining future production possibilities. However, they are but one factor and other determinants are equally important. Many assessments which rely solely on reserve data tend to overlook relevant facts. Apart from that, reserve data for many major oil producing regions are not very reliable.

Discoveries

When trying to assess the amount of oil which can be expected to be still discovered in future (“yet to find”), the statistics on proved reserves discussed above are obviously not very helpful. The same is true for the assessment of future production potentials. For these purposes an analysis of past discoveries (measured as proved + probable reserves) and production profiles is far better suited.

Figure 15 shows the annual oil discoveries since 1920 and also the annual production rates [IHS Energy 2006]. Past discoveries are stated according to best current knowledge (and not as the reserve assessments at the time of discovery) – a method described as “backdating of reserves”. Therefore, the graph shows what “really” was found at the time and not what people thought what they had found at the time.

Figure 15: History of oil discoveries (proved + probable) and production



Since about 1980, annual production exceeds annual new discoveries. This is obviously not sustainable. The peak of discoveries must eventually be followed by a peak of production.

Table 3: Summary of worldwide oil discoveries

Period	Average oil discoveries [Gb/yr]	
	onshore	offshore
2004/2005	7	5
2002/2003	5	8
2000/2001	7	10
1990-1999	8	7.1
1980-1989	14	6.9
1970-1979	24	14.8
1960-1969	42	13.4
1950-1959	31	1.2
1940-1949	26	0.3

Figure 15 shows the long-term trend in discoveries: The big oilfields were found rather early – in 1938 the world’s second largest field, Burgan (32-75 Gb), was found in Kuwait, in 1948 the world’s largest field with 66-150 Gb, Ghawar, was discovered in Saudi Arabia [Robelius 2007]. Today, more than 43,000 oilfields are known, but the two largest fields contain already about 8% of all the oil found to date. Later on, with better exploration technology, many more fields have been discovered in many parts of the world. The maximum of discoveries was in the 1960s. However, the average size of new discoveries was declining with time. Higher oil prices in the wake of the oil price crises in the 1970s could not reverse this trend. One important lesson can be learnt: there is no empirical relation between oil price and the rate of discoveries (contrary to the assumptions of many economists).

At the end of the 1990s, there was a new increase in discoveries due to exploration successes in the deep offshore regions in the Gulf of Mexico, off Brazil and off Angola and the discovery of the field Kashagan with 6-10 Gb in the Caspian Sea. Meanwhile, deep sea exploration seems to have peaked already and discoveries are declining again.

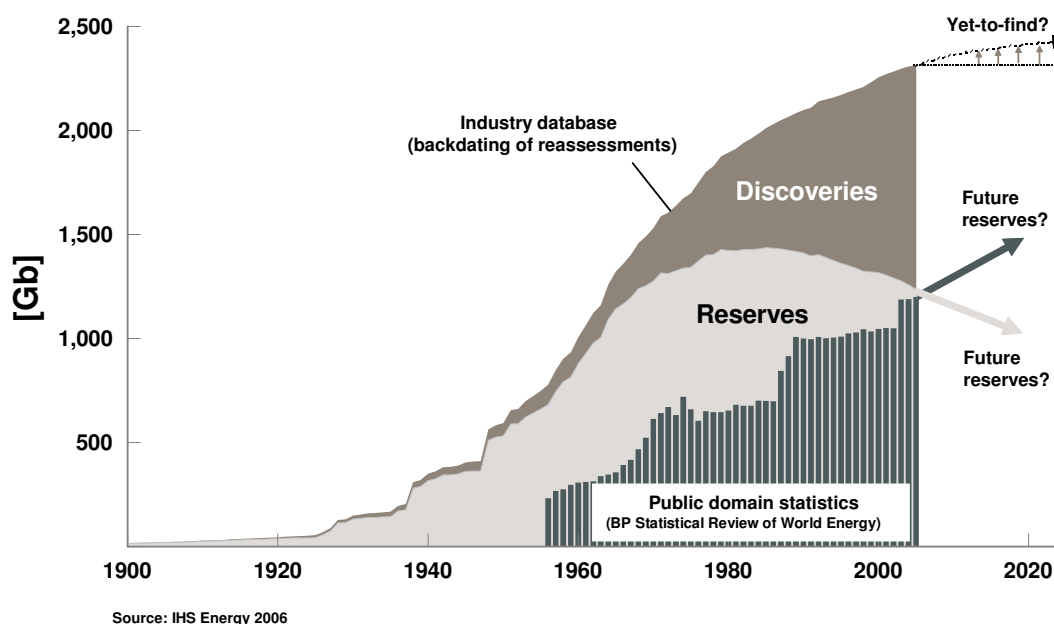
The difference between the history of proved reserves (the preferred view by “economists”) and the history of proved + probable reserves (the preferred view by “geologists”) is shown in Figure 16. The different views show opposing trends: Proved reserves look as if they can stay constant or even grow in future, whereas proved + probable reserves are steadily approaching a limit with the possibility of perhaps 200 – 300 Gb “yet to find” eventually.

A possible criticism of the cumulative curve showing proved + probable reserves is the fact that re-evaluations of past discoveries are included, but possible future re-evaluations are not accounted for. Therefore, future reserve assessments might lead to an upward shift of the

curve. This criticism is valid, but it will not affect the estimate of the yet-to-find amount of oil and it will not affect possible future production profiles much.

When subtracting the cumulative production from the cumulative proved + probable reserves, one gets the history of remaining reserves. Remaining reserves (proved + probable) are decreasing since about 1980. Even when assuming constant future consumption, remaining reserves will decrease faster in future because of declining new discoveries.

Figure 16: History of proved reserves, proved + probable reserves, production and remaining proved + probable reserves



Discrepancies between public domain statistics (e.g. BP) – which attribute reserve reassessments to the year of the reassessment – and industry data bases (e.g. IHS Energy) – which backdate reassessments – are a major reason for the differences in the assessment of future oil discoveries and also production between conventional forecasts (e.g. by IEA) and the approach presented in this paper. The relevance for production forecasts is the fact that reserve reassessments usually are done for producing fields. However, these reassessments do not influence the production pattern of the field and, especially when production is already declining, the decline is not affected by upward revisions of reserves.

Future production growth mainly can only be the result of the development of yet undeveloped discoveries. Therefore, the distinction of reassessments of reserves and new discoveries is so important.

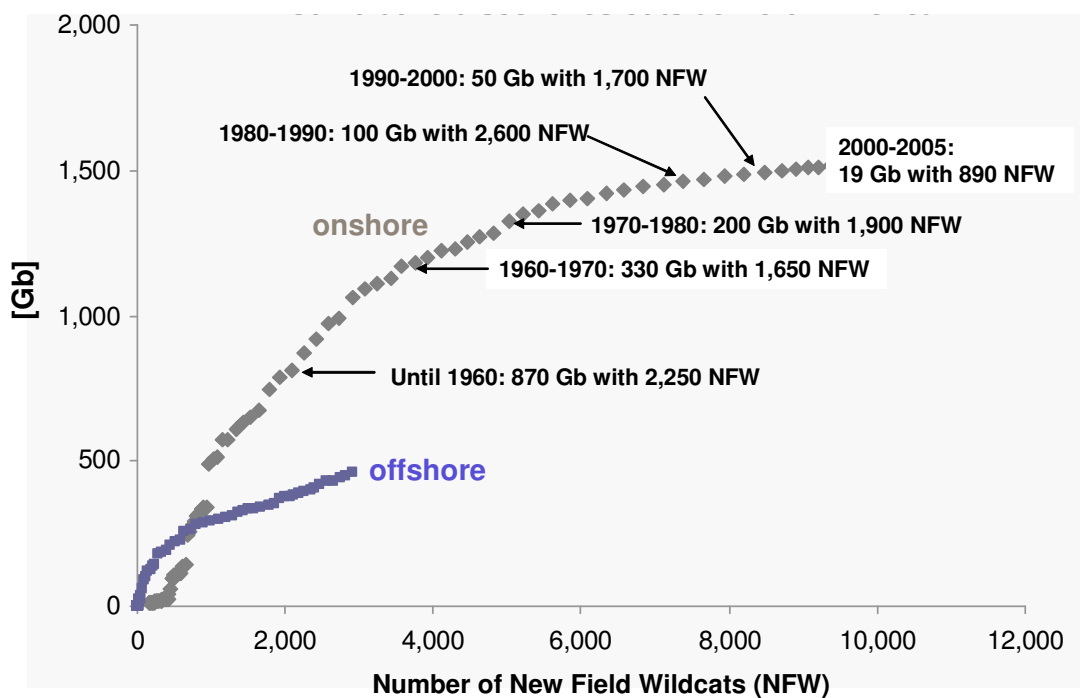
Discovery patterns and estimated ultimate recovery (EUR)

There is another reason why the difference between proved and proved + probable reserves is important. Upward revisions of field sizes usually are made when the production of the field is past peak. This pattern is also true for regions and countries. An example is the case of the

reserve estimates for the US, which are reassessed each year resulting in almost constant oil reserves over many years, though each year oil is removed by production. Despite these reassessments, the US oil production has been in decline for 30 years. These re-evaluations, therefore, do not affect the timing of the aggregate peak production of a region, a country or, for that matter, of the world.

The derived historical pattern of discoveries displays a trend that helps to extrapolate into the future and to assess the prospects for future discoveries in a given basin in coming years. Such an analysis is essential for the geologists’ decision as to where it is still worth looking for oil and where not. In nearly all oil provinces, the same pattern can be observed: Large discoveries are made early and with minimal effort. In later years the size of individual and annual discoveries gets smaller and smaller. Ever more boreholes have to be drilled to add new discoveries to the resources. The cumulative discoveries over the years saturate and approach an asymptotic value, which might be seen as the estimated ultimate potential for the oil recovery of a region. This pattern is called “creaming curve” and is shown in Figure 17.

Figure 17: Oil discoveries and drilling activity outside North America



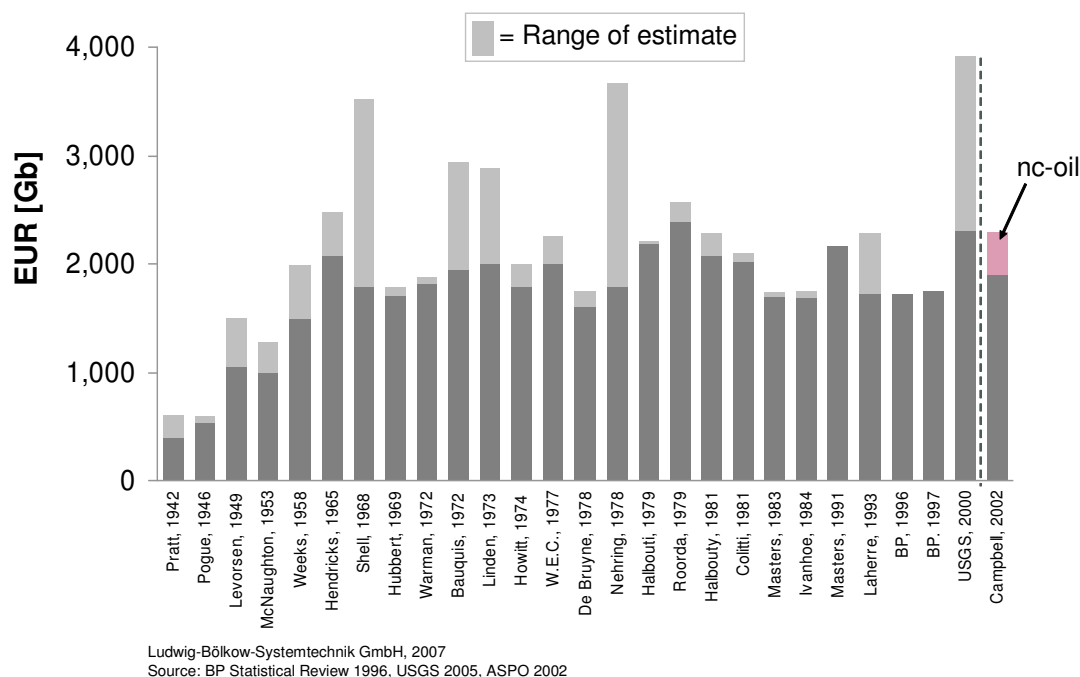
Ludwig-Bölkow-Systemtechnik GmbH, 2007
Source: IHS Energy 2006

In the period 1960 to 1970 the average size of new discoveries was 527 Mb per New Field Wildcat. This size has declined to 20 Mb per New Field Wildcat over the period 2000 to 2005. From that figure the effort to add new oil to reserves can be calculated by estimating the probable number of necessary wildcats and the associated costs.

Estimates of the ultimate recovery

The following Figure 18 shows historic estimates of the „estimated ultimate recovery“ (EUR) of oil [BP 2006], [USGS 2005], [ASPO 2002]. This is the total amount of oil geologists deem to be recovered eventually, i.e. the sum of past and future oil production.

Figure 18: Estimates of ultimate oil recovery (EUR)

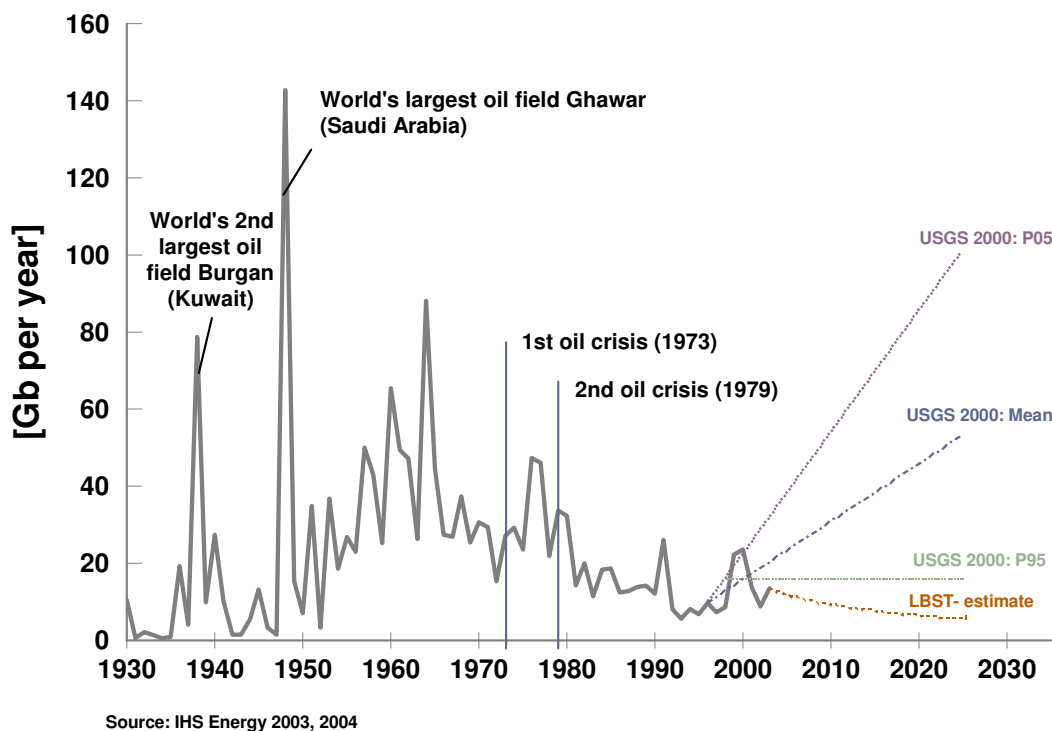


At the end of the 1940s, estimates of EUR of some hundred Gb were very moderate. With the exploration successes in the following years also the estimates of the EUR were rising. Since about the end of the 1960s the EUR estimates remained more or less constant. This is not very surprising since after the peak of discoveries the estimates became much better.

The data for BP 1996 and BP 1997 only cover past production and past discoveries, but not an estimate of the amount “yet-to-find” [BP 1996], [BP 1997].

Remarkable are the estimates by the US Geological Survey (USGS) published in 2000 [USGS 2000]. The lower estimate with a supposed probability of 95% states an EUR of approx. 2,300 Gb, well in the range of the other estimates. However, the upper estimate with a supposed probability of 5% gives an EUR of about 4,000 Gb which is way beyond all other estimates. This scenario would require a complete reversal of the trend in discoveries observed in the last decades. This is illustrated in Figure 19.

Figure 19: World oil (and NGL) discoveries and USGS projections for “yet-to-find”



Even the P95 estimate looks at being rather optimistic. The other two USGS scenarios are just fantasy.

The method how the mean value is derived is based on two extreme cases: How much oil will be found with 95% probability, and how much oil will be found with 5% probability. Applying statistical mathematics on these two cases to generate a new value yields a spurious “mean” value which obviously is biased by the 5% value. The USGS mean value has nothing to do with a P50 estimate (or best estimate) as has been described earlier on. In papers and reports referring to the USGS study, mostly only this mean value is used, not addressing the underlying assumptions. A detailed discussion can be found in Annex 2.

Production patterns

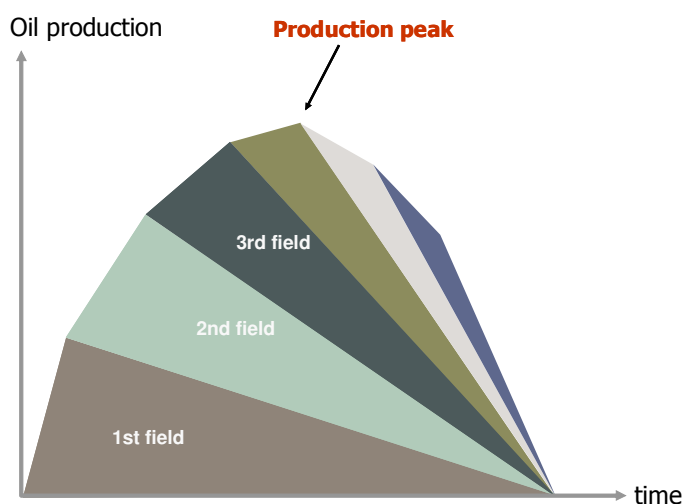
The general pattern

The different phases of oil production can be described schematically by the following pattern: In the early phase of the search for oil, the easily accessible oil fields are found and developed. With increasing experience the locations of new oil fields are detected in a more systematic way. This leads to a boom in which more and more new fields are developed, initially in the primary regions, later on all over the world. Those regions which are more difficult to access, are explored and developed only when sufficient new oil can not be found anymore in the easily accessible regions. As nobody will look for oil without also wanting to

produce it, in general, shortly after the finding of new promising fields their development will follow.

In every oil province the big fields will be developed first and only afterwards the smaller ones. As soon as the first big fields of a region have passed their production peak, an increasing number of new and generally smaller fields have to be developed in order to compensate the decline of the production base. From there on, it becomes increasingly difficult to sustain the rate of the production growth. A race begins which can be described as follows: More and more large oil fields show declining production rates. The resulting gap has to be filled by bringing into production a larger number of smaller fields. However, these smaller fields reach their peak much faster and then contribute to the overall production decline. As a consequence, the region's production profile which results from the aggregation of the production profiles of the individual fields, becomes more and more “skewed”, the aggregate decline of the producing fields becomes steeper and steeper. This decline has to be compensated for by the ever faster connection of more and more ever smaller fields, see Figure 20.

Figure 20: Typical production pattern for an oil region



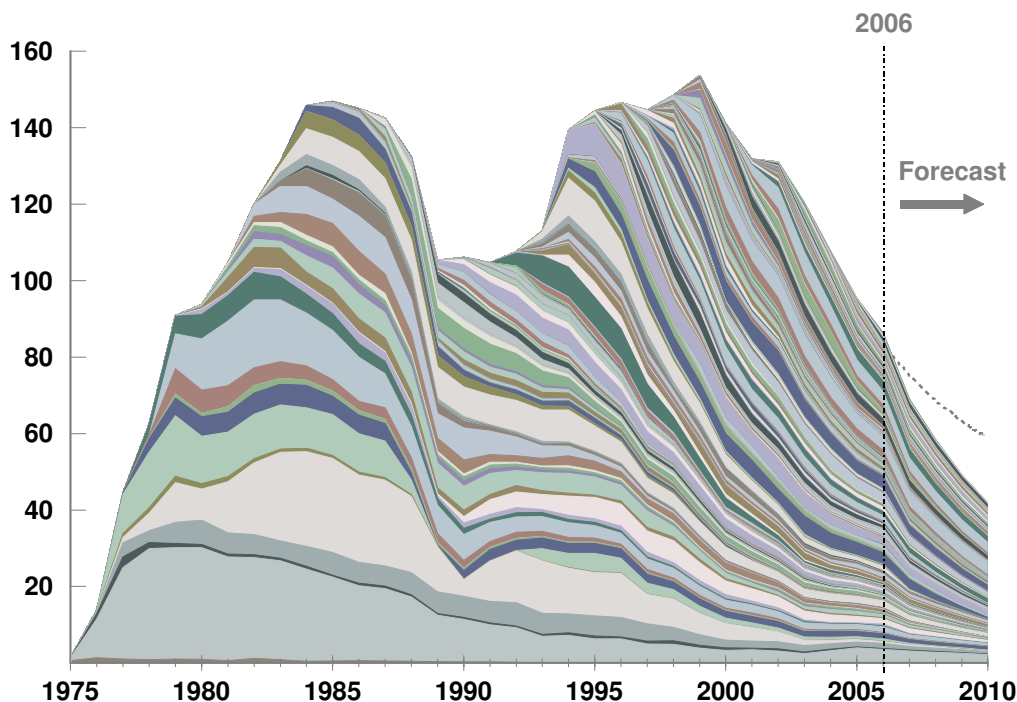
So, the production pattern over time of an oil province can be characterised as follows: To increase the supply of oil will become more and more difficult, the growth rate will slow down and costs will increase until the point is reached where the industry is not anymore able to bring into production a sufficient number of new fields quick enough. At that point, production will stagnate temporarily and then eventually start to decline.

This pattern can be observed very well in many oil provinces. But in some regions this general pattern was not prevalent, either because the timely development of a “favourable” region was not possible for political reasons, or because of the existence of huge surplus capacities so that production was held back for longer periods of time (this being the case in many OPEC countries). However, the more existing surplus capacities were reduced, the closer the production profile follows the described pattern.

Production in key regions

Figure 21 shows the oil production in the United Kingdom. It is a good illustration of the production pattern described above. Similar patterns can be shown for many regions in the world.

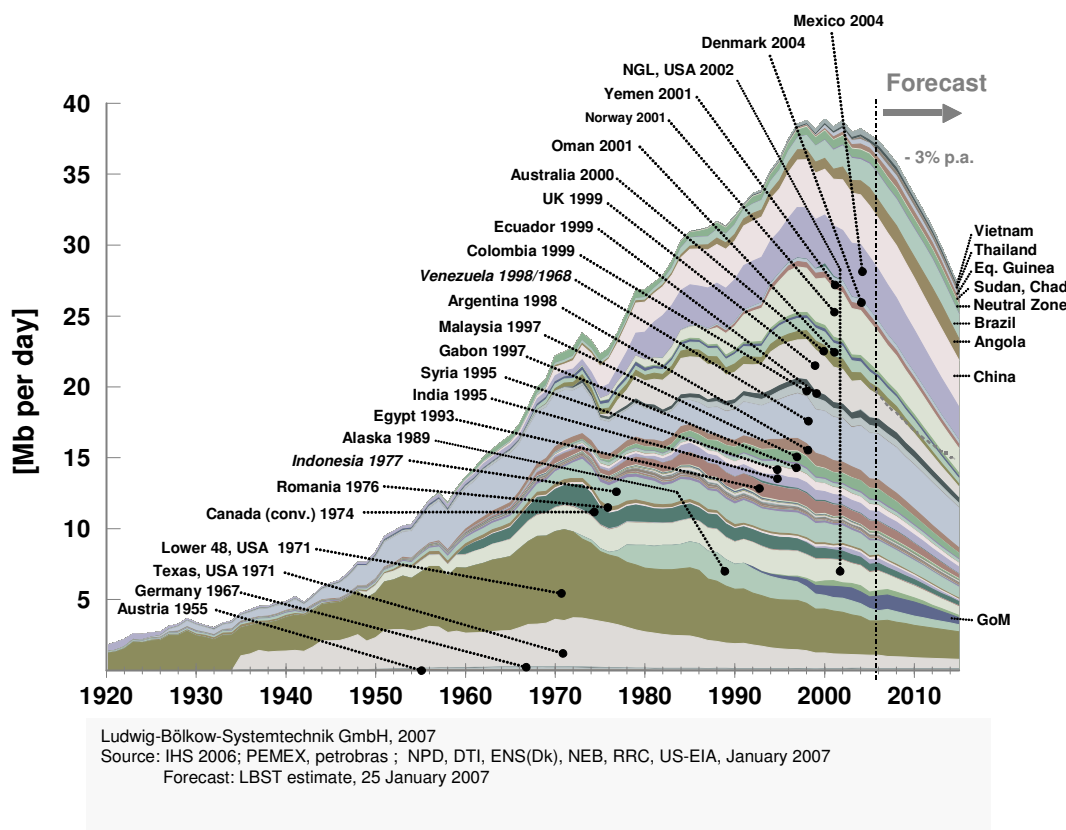
Figure 21: Oil production in the United Kingdom



Source: DTI, May 2007; Forecast: LBST

Oil production in regions having passed their peak can be forecasted with some certainty for the next years. If it is assumed that the remaining regions with growth potential (especially Angola, Brazil and the Gulf of Mexico) will expand their production by the year 2010 (in accordance with the forecasts of the companies operating in these regions), total oil production of this group of countries, however, will continue to decline by about 3% per year, see Figure 22.

Figure 22: Oil producing countries past peak



The influence of technology

With increasing production the pressure of an oil field diminishes and the water levels rise, and after some time the production rate begins to decline. This trend can be controlled to a certain extent so that the decline in production rate is delayed or reduced: by injecting gas or water into the reservoir in order to increase the pressure, by heating the oil or by injecting chemicals in order to reduce the viscosity of the oil.

These methods are known as „enhanced oil recovery” (EOR) and are widely applied in ageing fields. These measures are often cited as a reason for being optimistic regarding future oil production rates. However, for various reasons one should not overestimate the influence of these measures:

- EOR measures have already been applied for more than 30 years, and these measures are accounted for in production forecasts. There will not be any sudden changes in the future.
- EOR measures are mainly applied after peak production when the pressure level is low. These measures cannot reverse a decline into an upward production profile for any substantial period of time.

A prominent example is the production at the field Prudhoe Bay in Alaska, the largest field in the US. This field has been produced with the best technology available in the industry and every possible new measure was applied to avoid the decline (which was not possible) and to enhance production after peak (which was successful). Today, more water is extracted from the wells than oil, water that was injected into the field to increase the pressure.

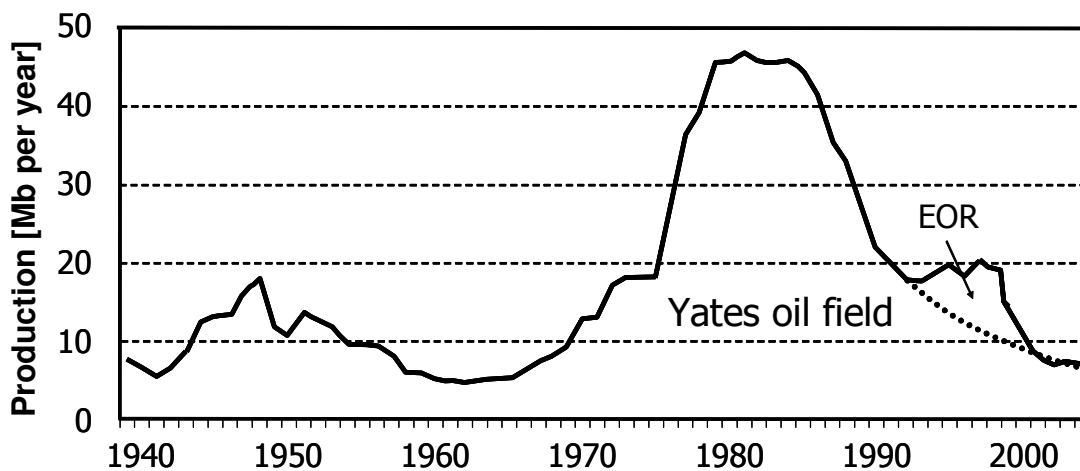
The already discussed production profile of UK fields also proves that total production is in steep decline, despite the fact that in some old fields the production rate could be increased to a small extent due to EOR measures and that permanently new (small) fields are added to the production base.

EOR measures are most effective in certain fields with complex geology which exhibit a low recovery factor.

Usually these measures increase the production rate for a short period of time, but increase the decline after a certain point in time – the oil is extracted faster, but the overall oil recovery is not increased.

To illustrate this further, the influence of EOR measures at one of the largest US fields is shown in Figure 23. The Yates field, which was discovered in 1926 in Texas, has produced since 1929. Since peak production in 1970 the production rate has declined by more than 75%. In 1993 hot steam and chemicals were injected to enhance the production rate. This measure was successful for about four years. Afterwards the decline was even steeper, exceeding 25% per year instead of 8.4% as before. Today, the production rate is even below the level it would be at without these measures. To assess the overall influence of this measure, out of the 1.4 billion barrels of oil that have been produced since 1929, only 40 million are due to enhanced oil recovery – an increase of about 3%.

Figure 23: Oil production at Yates field



Source: LBST analysis with data by Texas Railroad Commission

The use of technology, as discussed, will not change the overall picture. The decline of the oil production in the USA since 1970 could not be avoided. And, just to give a recent example, also not the production decline in the North Sea since 2000.

The use of “aggressive” production methods aimed at producing fields at a maximum rate possibly poses a problem regarding the future global oil supply. Once the inevitable decline sets in, decline rates probably will be much higher than without the prior use of these methods. The decline rates in offshore regions past peak set an ominous example.

Performance of International Oil Companies

Looking at the operation of major international oil companies over the period of the last 10 years, two developments are striking:

- the wave of mergers, and
- the inability of these companies to substantially raise their aggregate production.

This is shown in detail in Annex 4.

Peak oil is now

Indications of an imminent peak are discussed in this chapter. But let it be said that the question of the exact timing of peak oil is less important than many people think. There is sufficient certainty that world oil production is not going to rise significantly anymore and that world oil production soon will definitely start to decline.

Production in countries outside OPEC and Former Soviet Union (FSU)

On a global level, the development of different oil regions took place at different times and at varying speeds. Therefore, today we are able to identify production regions being in different maturity stages and with this empirical evidence we can validate with many examples the simple considerations which were described in the previous paragraph.

Looking at the countries outside of the Former Soviet Union and OPEC, it can be noticed that their total production increased until about the year 2000, but since then total production has been declining. A detailed analysis of the individual countries within this group shows that most of them have already reached their production peaks and that only a very limited number of countries will still be able to expand production, particularly Brazil and Angola.

Responsible for the stagnation of the oil production in this group of countries was the peaking of the oil production in the North Sea which occurred in 2000 (1999 in Great Britain, 2001 in Norway). Global onshore oil production had reached a plateau much earlier and has been declining since the mid 1990ies. This decline could be balanced by the fast development of offshore fields which now account for almost 50% of the production of all countries in this group. The North Sea alone has a share of almost 40% of the total offshore production within

this group. The peaking of the North Sea was decisive because the production decline could not be compensated anymore by a timely connection of new fields in the remaining regions – it was only possible to maintain the plateau for a few years.

There is a growing supply gap developing in coming years in the countries outside OPEC and the FSU. This gap will have to be compensated by a rising supply coming from OPEC and/or the FSU. The chances of this happening are marginal. This will be discussed in the following analysis and in the chapter describing supply scenarios for world regions.

Also, a steady degradation of the quality of the oil produced can be observed in almost all regions having passed peak and poses an additional challenge for the existing downstream infrastructures: refineries have to operate with oil of decreasing quality. The share of lesser oil qualities is steadily increasing – this will additionally drive upwards the prices for the remaining good oil grades.

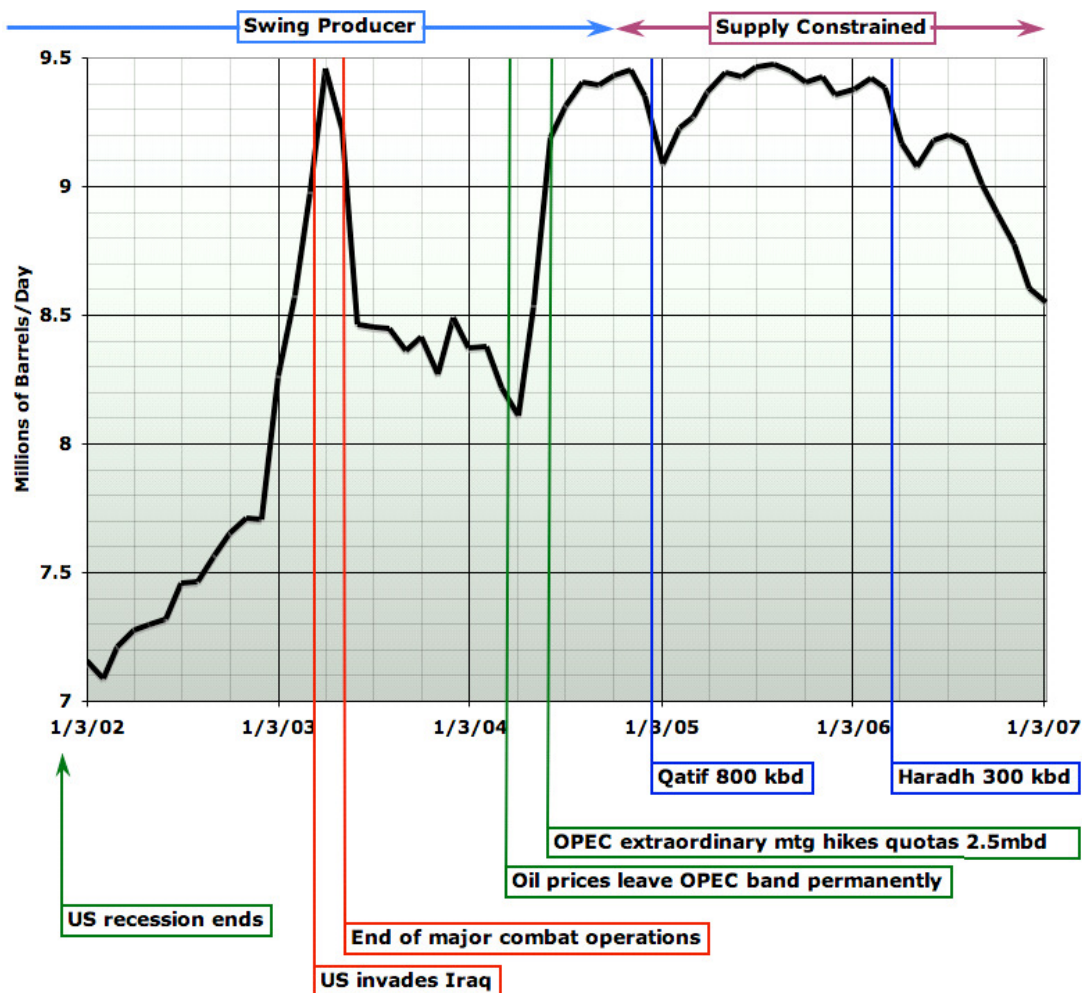
Saudi Arabia in decline?

One of the big questions still waiting for an answer is the state of the oil production in the Kingdom of Saudi Arabia (KSA). Most likely, this issue will decide the timing of world peak oil. Production in the KSA has declined since December 2005 by about 1 Mb/d as can be seen from the graph in Figure 24 taken from a post by Stuart Staniford at www.theoildrum.com on May 19, 2007 [Staniford 2007]. Data sources are [EIA 2007], [IEA 2007], [JODI 2007] and [OEPC 2007]. One possible interpretation is that Ghawar, the world's largest field, is now in terminal decline. In this case Saudi Arabia, and as a consequence also OPEC as a whole, would have lost its capacity of being a swing producer. Because of the secrecy surrounding the oil production in the KSA, only the future will show whether the current decline in production is voluntary or not.

Saudi Arabia has said it would be able to raise production in coming years to 12 Mb/d, and, if necessary, even to 15 Mb/d. This seems very ambitious but is well below the projections of the US EIA and the IEA which both assume a production of about 20 Mb/d in 2030. Our assessment is that the KSA will not be able to increase its production significantly for any meaningful period of time.

Recently, there has been a significant statement by King Abdullah of Saudi Arabia which perhaps can remove the remaining uncertainties: "The oil boom is over and will not return," Abdullah told his subjects. "All of us must get used to a different lifestyle." [Christian Science Monitor, Aug 15, 2007]

Figure 24: Saudi Arabian oil production, Jan 2002-Jan 2007, average of four different sources. Annotations show important events causally influencing production, including all documented mega projects for new supply in the time period. Graph is not zero-scaled to better show changes [Staniford 2007]



World’s biggest fields in decline

Crucial for the further development was the production peak of Cantarell in Mexico, the world’s biggest offshore field and one of the four top producing fields in the world. This field, discovered in 1978, even today contributes one half to the Mexican oil production. It has reached a plateau for some years and started to decline in 2005. The field then declined dramatically from 2 Mb/d in January 2006 to 1.5 Mb/d in December 2006, and double digit year over year decline rates are expected in the coming years.

With Cantarell, now 3 of the 4 biggest producing fields are in decline: the others being Daquin in China and Burgan in Kuwait. The status of Ghawar in Saudi Arabia is not known for sure – but the field is very likely also in decline now.

Once production in the largest fields is declining, it gets more and more difficult to keep up overall production (as has been pointed out before).

Peak oil based on an analysis of giant oilfields

A very comprehensive analysis of the future oil production potential based on the analysis of the world's giant oilfields has been carried out by Robelius [Robelius 2007]. According to his analysis, peak oil will happen somewhere between 2008 and 2018, depending on several circumstances. With regard to recent experiences in the industry which has seen delays in many major projects, the earlier dates are more likely than the later ones.

High oil prices

The growth of production has come to a standstill and production now is more or less on a plateau.

This has happened despite historically high oil prices. Prices started their rise in 2000, this was when the North Sea reached peak production. Also about that time, all producing regions outside OPEC and outside the countries of the Former Soviet Union reached their aggregate peak. It is not very likely that this was a random coincidence.

In the public debate, however, the price rises were attributed to all sorts of causes: speculation, political tensions in oil producing regions, greed of oil companies, strikes, hurricanes, rising demand in China and India, etc. Yet, global supply reaching a limit is still not considered as being a possible cause.

It is noteworthy how the perception of the level of oil prices has changed in recent years. Five years ago, an oil price above \$60 per barrel was unthinkable. Today, oil prices below \$60 are regarded as being “cheap”.

The pricing behaviour of OPEC has also changed in the period since 2000. At first, OPEC pledged to defend a price corridor of \$22-28 per barrel in order to defend the stability of the world economy. After this had failed and prices moved above \$40, OPEC talked less and less about a target price and eventually quietly dropped the price band. OPEC had learnt that the world economy will not break down with higher oil prices. And the world is learning that OPEC is not any more in a position to control the maximum price of oil by increasing its output (by the way, probably nobody is anymore able to do this). Recently, OPEC spokesmen have described an oil price of \$60 per barrel as being “fair”.

Was peak oil already in 2005?

In the history of oil production, which is now extending over more than 150 years, we can identify some fundamental trends:

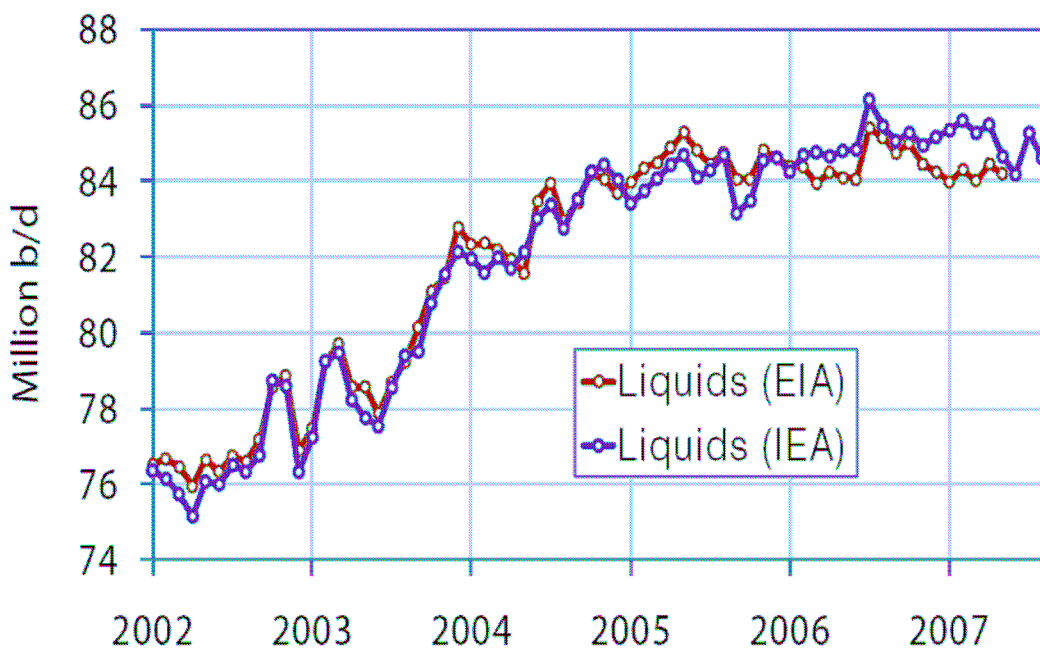
- The world's largest oil fields were all discovered more than 50 years ago.

- Since the 1960s, annual oil discoveries tend to decrease.
- Since 1980, annual consumption has exceeded annual new discoveries.
- Till this day more than 47,500 oil fields have been found, but the 400 largest oil fields (1 percent) contain more than 75 percent of all oil ever discovered.

The historical maximum of oil discoveries after some time has to be followed by a maximum of oil production (the “peak”).

Oil production (for crude and condensate) already shows a peak in May 2005 as can be seen in Figure 25 [The Oil Drum 2007]. Probably, the world oil production has peaked already, but we cannot be sure yet. However, with every month passing without showing higher production levels, the probability increases that the peak already can be seen in the “rear mirror” (as Matthew Simmons likes to express it). The regional EWG scenarios presented later in this paper endorse this view.

Figure 25: Production of crude oil and condensates



Source: Energy Information Administration, International Energy Agency

The position of the IEA and industry

International Energy Agency

In its World Energy Outlook 2004, the International Energy Agency (IEA) projected world oil production until 2030. This projection (shown in the following figure) assumes a growth in production to 120 Mb/d.

Figure 26: WEO 2004 production profile between 1971 – 2030 (figure 3.20 in the original report) [WEO 2004]

The light blue area shows the expected decline of existing production capacities assumed at amounting to approx. 6% per year.

The dark blue area is based on the projected development of existing reserves which are assumed to contain between 1,050 – 1,150 Gb of oil, depending on the data source. However, these reserves include about 350 Gb of so called “political reserves” in OPEC countries which are at least questionable. If these political reserves are subtracted, future production volumes must be much smaller than anticipated as the projected cumulative production between 2002 and 2030 amounts to 650 Gb, leaving zero remaining reserves by 2030. Therefore, the shown production profile from known reserves seems not to be realistic.

The green area shows the expected production growth due to enhanced oil recovery measures. However, enhanced oil recovery measures are in operation for more than 25 years and are not an innovation to enhance future production. Experience shows that these measures are most successful in geologically complex fields with low extraction rates. These fields are not the average and, at world level, the influence of enhanced oil recovery is much smaller than sketched here.

The yellow area shows the production from non-conventional oil fields, predominantly from Canadian tar sands. The production from these fields cannot be increased fast and therefore cannot substitute for the more rapidly declining production at other places. This assessment is consensus.

Finally, the red area indicates production from new discoveries yet to be made. The basis for this projection is the mean value of possible discoveries as outlined in the USGS study ‘World Petroleum Assessment 2000’ [USGS 2000]. As is shown in Annex 2: Critique of Oil Supply Projections by USGS, EIA and IEA, the authors of this study regard this projection as being completely unrealistic.

At a first glance, this graph seems to describe a positive vision of the future, yet careful reading of the report leads to a contrary impression. The following statements are extracted from the report to illustrate this point. They should be kept in mind when analysing the graph:

- „By 2030, most oil production worldwide will come from capacity that is yet to be built.“ (WEO 2004, p.103)
- „The rate at which remaining ultimate resources can be converted to reserves, and the cost of doing so, is, however, very uncertain.“ (WEO 2004, p. 95)
- „The reliability and accuracy of reserve estimates is of growing concern for all who are involved in the oil industry.“ (WEO 2004, p. 104)
- „In the low resource case, conventional production peaks around 2015.“ (WEO 2004, p. 102)

Though the 2006 report does not address these problems again, the changes of production profiles from report to report indicate that the projections have been continuously revised downward.

Concerning oil, the present report puts the focus more on the aspect that higher prices might result in more discoveries helping to satisfy the forecasted rising demand.

In summary, the projections by the IEA are not a very reliable basis for planning the future. The caveats in the report suggest that the future might be completely different, and even peak oil might be round the corner. This view is backed by recent interviews and statements by Fatih Birol (chief economist) and Claude Mandil (executive director) of the IEA in which they gave blunt warnings of an impending “energy crunch” in a few years time (e.g. in: *Le Monde*, 27.06.2007).

Oil industry

In general, the communications by the big energy agencies (most prominently IEA and US EIA) and by the oil industry all assume unabated growth of oil production in the foreseeable future. (But the recent shifting of the IEA position should be noted.)

Major turning points in the past, like the peaking of Prudhoe Bay, the peaking of the North Sea and most recently Cantarell, were not foreseen, and were in some cases even denied for years after the event. This casts some doubt on the quality of the forecasts of these institutions and the industry.

Within the oil industry there is one notable exception, namely the communication by Chevron at www.WillYouJoinUs.com. Chevron states that “the era of easy oil is over” and points out that 33 of the 48 largest oil producing countries have already passed peak [Chevron 2007].

Meanwhile, the debate on peak oil is getting hotter. Institutions close to the energy industry like CERA (Cambridge Energy Research Associates) are engaging in a campaign trying to “debunk” the “peak oil theory” [CERA 2006]. This has to be seen as a sign of considerable nervousness in view of historically high oil prices and a stagnating world oil production in the last two years. The concept of peak oil and the reasoning behind it is in important respects misrepresented by CERA and the arguments put forward do not stand up to a critical scrutiny

(see Skrebovsky for a prominent example of a rebuttal [Skrebowski 2006]). Also the authors at CERA are not prepared to lay open their sources and to enter into a direct and public discussion.

SCENARIO OF FUTURE OIL SUPPLY

Regional scenarios

This subchapter discusses the domestic oil production in the ten world regions as defined by the IEA and selected key countries in some detail.

The IEA in its World Energy Outlook classifies the world into the following ten regions:

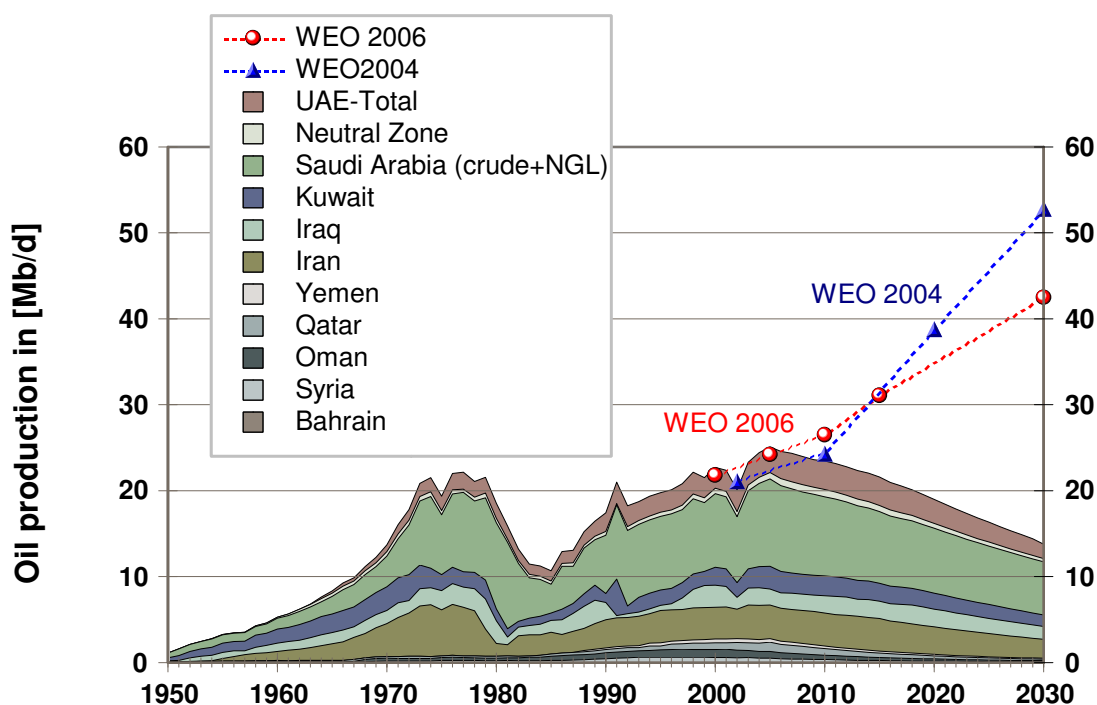
- **OECD North America**, including Canada, Mexico and the USA.
- **OECD Europe**, including Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, The Netherlands, Norway, Poland, Slovak Republic, Spain, Sweden, Switzerland, Turkey and the UK.
- **OECD Pacific**, including
 - OECD Oceania with Australia and New Zealand,
 - OECD Asia with Japan and Korea.
- **Transition Economies**, including Albania, Armenia, Azerbaijan, Belarus, Bosnia-Herzegovina, Bulgaria, Croatia, Estonia, Yugoslavia, Macedonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Romania, Russia, Slovenia, Tajikistan, Turkmenistan, Ukraine, Uzbekistan, Cyprus and Malta.
- **China**, including China and Hong Kong.
- **East Asia**, including Afghanistan, Bhutan, Brunei, Chinese Taipei, Fiji, Polynesia, Indonesia, Kiribati, The Democratic Republic of Korea, Malaysia, Maldives, Myanmar, New Caledonia, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Island, Thailand, Vietnam and Vanuatu.
- **South Asia**, including Bangladesh, India, Nepal, Pakistan and Sri Lanka.
- **Latin America**, including Antigua and Barbuda, Argentina, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Dominic. Republic, Ecuador, El Salvador, French Guyana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, St. Kitts-Nevis-Antigua, Saint Lucia, St. Vincent Grenadines and Suriname, Trinidad and Tobago, Uruguay and Venezuela.
- **Middle East**, including Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, the United Arab Emirates, Yemen, and the neutral zone between Saudi Arabia and Iraq.

- **Africa**, including Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, the Central African Republic, Chad, Congo, the Democratic Republic of Congo, Côte d'Ivoire, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Niger, Nigeria, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan, Swaziland, the United Republic of Tanzania, Togo, Tunisia, Uganda, Zambia and Zimbabwe.

Middle East

Although the Middle East region is the world's largest oil producer, oil production is expected to decline in this region in the near future. Figure 27 shows the oil production profile between 1950 and 2006 and the extrapolation up to 2030. The figure also shows the forecasts by the International Energy Agency (IEA) in its World Energy Outlook (WEO) [WEO 2004], [WEO 2006].

Figure 27: Oil production in the Middle East



The problem of assessing the realistic reserves of the Middle Eastern (ME) oil producing countries is reflected in Table 4. While the Oil&Gas Journal and BP mainly rely on published 'official' figures (which are often inflated), the estimates by Campbell and Bakhtiari are based on detailed evidence (see: *ASPO Newsletter*, 63, March 2006). Bakhtiari, who until his recent retirement worked for the National Iranian Oil Company, is one of the most reliable experts on Middle East oil reserves.

Table 4: Remaining proven oil reserves for ‘ME Five’, according to various estimates

Country	Oil & Gas Journal [a]	BP Statistical Review [b]	Campbell [c]	Bakhtiari [d]	IHS	EWG
Iran	132.5	132.5	69	35-45	134.0	44
Iraq	115.0	115.0	61	80 - 100	99.0	41
Kuwait	101.5	99.0	54	45 - 55	51.6	35
Saudi Arabia	264.3	262.7	159	120 - 140	286.0	181
U.A.E	97.7	97.8	44	40 - 50	56.6	39
TOTAL	711.0	707.0	387	320 - 390	627.2	340

Sources: [a] *O&GJ*, 19 December 2005 (for 1 January 2006); [b] BP, June 2005 (until end of 2004); [c] *ASPO Newsletter*, 62, February 2006; [d] Bakhtiari, February 2006.

In the Middle East region, Saudi Arabia (apart from Iraq) is the only country that is widely supposed to be able to increase its oil production significantly. In assessing the future production potential of Saudi Arabia, Ghawar, the world’s largest oil field, plays a key role. This field was discovered in 1948 and has now been producing oil for more than 50 years. It is a fact that more water is pumped into the field than oil is extracted, and it seems quite possible that the production rate will decline in the near future. Anyway, it is certain that Ghawar cannot contribute to an expansion of the Saudi Arabian production.

There is an ongoing debate whether Saudi Arabia will at all be able to increase its production significantly. This debate was initiated in early 2004 by Matthew R. Simmons, an American investment banker from Houston [Simmons 2004]. Simmons very much doubts the possibility of a significant growth of production. His assessment is based on a comprehensive in-depth analysis of technical papers in the public domain addressing the problems of oil production in Saudi Arabia, and on a great number of interviews with engineers working on site and also a visit to the oil fields in Saudi Arabia [Simmons 2005].

Simmons has provoked comments by Abdul-Baqi and Nansen Saleri, senior executives of the state-owned company Saudi Aramco. But their comments have rather fuelled existing fears instead of assuring the world. First, it was admitted that the big old oil fields are in decline, and that by now the Abqaiq field is depleted by 73%, and Ghawar by 48%. Moreover, it was indirectly confirmed that the proven reserves do not amount to 262 Gb, as is widely assumed. The proven reserves amount to only 130 Gb while another 130 Gb have been counted as reserves already because it is regarded probable that they can be developed eventually. If one would apply the same criteria which are common practice with western companies, then Saudi Aramco’s statement of proven reserves should be devalued by 50%. This was confirmed indirectly by another Saudi Aramco executive. (In the light of this debate the EWG estimate of reserves amounting to about 180 Gb seems to be rather conservative.)

Furthermore, Saudi Aramco executives tried to counter the fears of Simmons by stating that a production of 10 Mb/day could be upheld until 2042. In doing this they had to assume that the above mentioned reserves of 260 Gb are proved reserves (which they definitely are not).

Saudi Aramco went on to state that in case of a more aggressive development of the remaining reserves, production could be increased to 12 Mb/day by 2016 and then could be maintained constant until 2033. But even this scenario put forward by the Saudis is hardly reassuring in view of the projections by the International Energy Agency (IEA) which assume that in the longer term an additional 20 Mb/day are supposed to come from those regions.

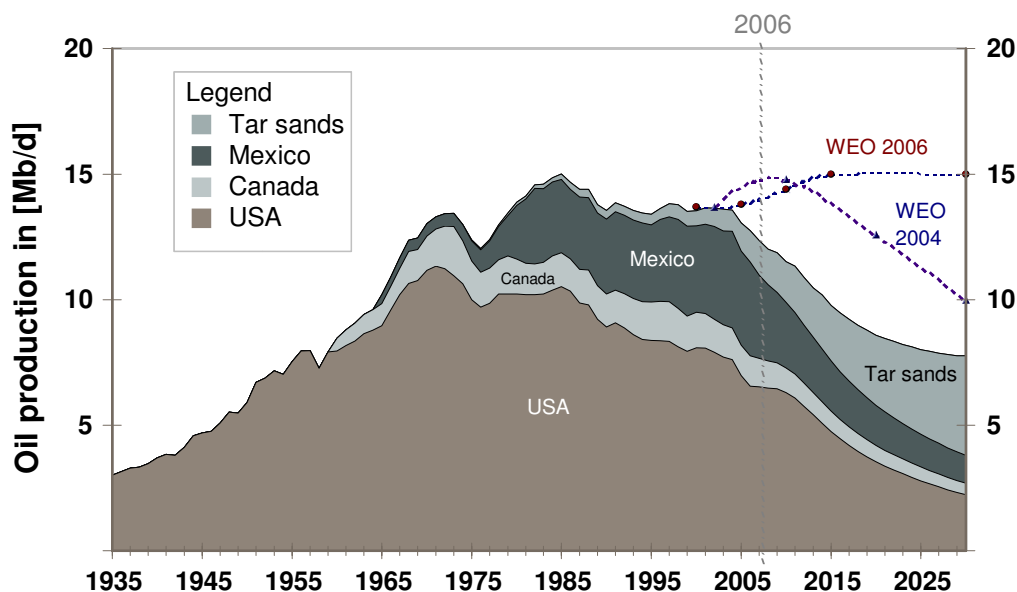
The EWG scenario of the future production is only partly based on the estimate of remaining reserves which are very uncertain as has been pointed out. Equally important are additional facts, like information regarding the production share of giant fields, the production share onshore / offshore, the rising sulfur content in the oil produced, and also political and economic long term goals, and as a result, production targets by individual nations.

The scenario presented here assumes that (1) an increase of production is not in the long term interest of the Middle Eastern countries, (2) the giant fields in the region have peaked or are about to peak and (3) production therefore will decline in the coming years. Saudi oil production is projected to decline by 2 percent per year.

OECD North America

Oil production in OECD North America peaked in 1984 (the peak in the USA was in 1970, but production in Canada and Mexico was still rising in the following years thus compensating the US decline). It is believed that total conventional oil production will decline until 2030 by about 80%. When the rising contribution from non-conventional Canadian tar sands is included, this decline will be lowered to 50%. Figure 28 summarises the different regional contributions to the total oil production in OECD North America. Also included in the figure are production profiles used by the International Energy Agency in WEO 2004 and WEO 2006.

Figure 28: Oil production in OECD North America



USA

Forty years ago, the USA were the world's largest oil producer, contributing almost 50% to world oil production. However, since 1970 the conventional production is in decline. The development of Alaska with the by far largest oil field in the USA (Prudhoe Bay) could stop this decline for a few years, until this region also passed peak production. Offshore oil from the continental shelf is produced since 1949, but turned into decline around 1995.

Since about 1980, deep water areas in the Gulf of Mexico are explored. This led to the discovery of various large fields. However, these fields were only developed in the late 1990s and early 2000. These fields are developed so fast that peak production often occurs within the first year of production. In 2001, an early peak of production in the Gulf of Mexico was reached. The present production volume is a factor of two below the forecasts made in 2002. The region with its exposure to hurricanes is difficult to produce and costs are high, therefore, current production is trailing far behind the original plans. It is not even clear whether present total production can still be increased. Probably around 2010 at the latest, the production in the Gulf of Mexico will turn into decline. For more details on Alaska and the Gulf of Mexico see Annex 1.

There is a final frontier left in the USA, the Arctic National Wildlife Refuge (ANWR). The discussion whether this environmentally sensitive area should be opened to oil exploration is repeated almost every year in the US senate. But even in case the ANWR should be developed, according to data by the USGS this might add another 5-6 Gb of oil reserves. These might be developed with first oil flows about 5 years after the start of the development and production then will peak about 10 years later. In the scenario presented here, such a

production profile for the ANWR is also included. At best, this production might compensate for the additional decline of the Gulf of Mexico deepwater production, but it never can compensate for the decline in the mature fields in the USA. Natural gas liquids contribute with about 2 Mb/d to the US oil production. Also included in the figure is the production profile according to WEO 2006 for crude oil (excluding NGLs).

Figure 29: Oil production in the USA

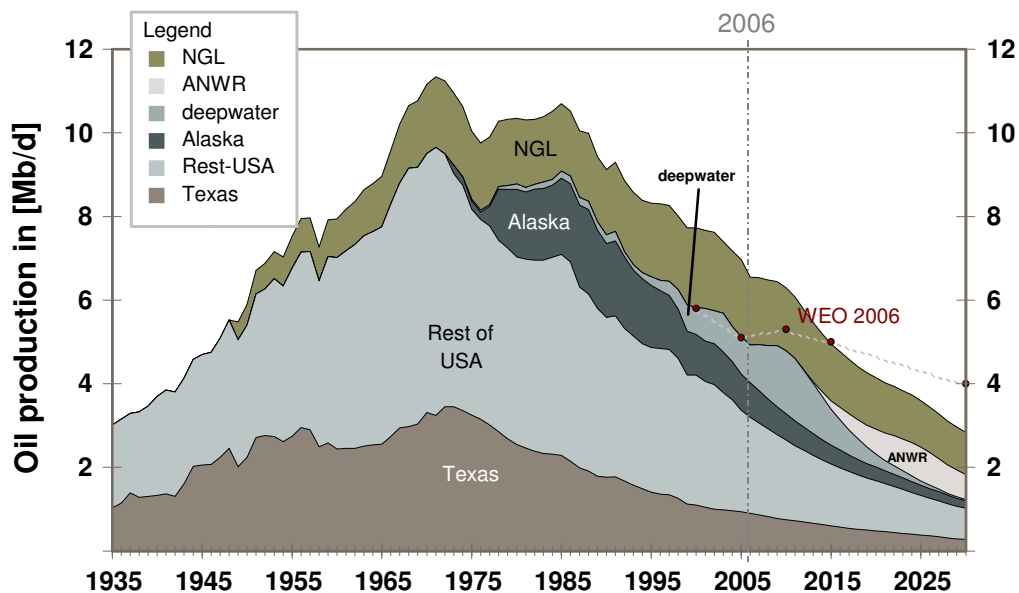
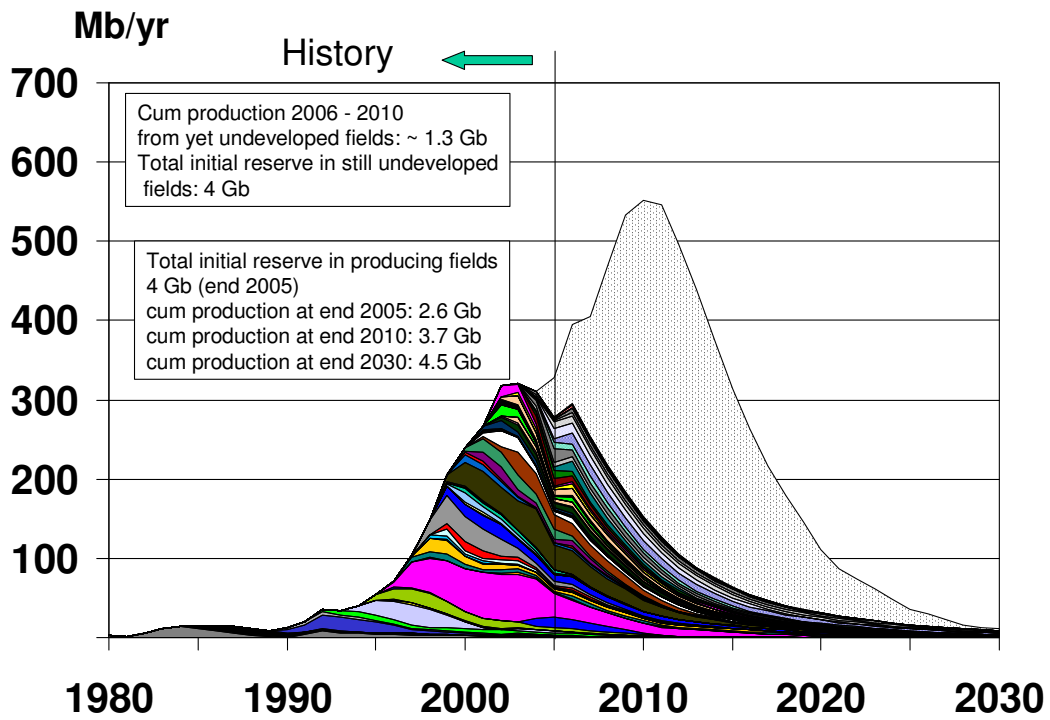


Figure 30 provides some details of the Gulf of Mexico deepwater development. All producing fields are shown individually. The steep production decline which sometimes starts already in the first year puts a huge pressure on future developments. Any delay of new field developments will result in an overall production decline and the originally estimated peak production will be lower. The steep production decline in 2005 is due to severe damages by the hurricanes Rita and Katrina. The sketched future production profile with peak production around 2011 might be optimistic in view of these problems. For a more detailed analysis of the oil production in the Gulf of Mexico see Annex 1.

Figure 30. Field by field analysis of the oil production in the Gulf of Mexico



Source: History: MMS 2006; Forecast LBST 2006

Canada

In Canada conventional oil production (including heavy oil) peaked in 1973. Offshore oil production started at the end of the 1990s with rising contributions, sufficient to compensate the decline of onshore oil until about 2003. However, the known discoveries are too small to continue this trend. Now the beginning decline of the offshore production adds to the decline of the onshore production. Figure 31 shows some details of the oil production in Canada.

Figure 31: Oil production in Canada

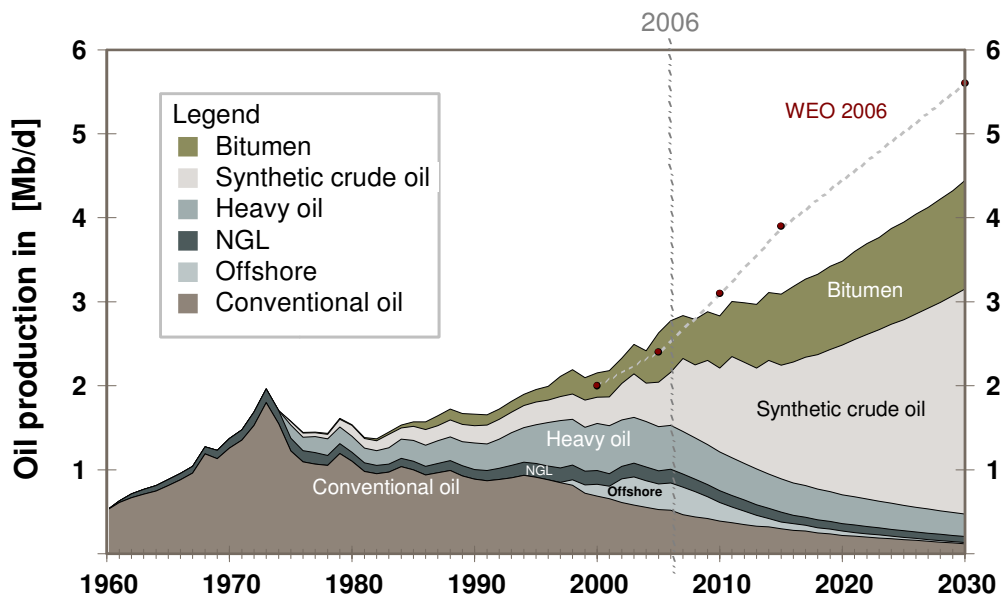


Figure 31 shows the contributions from the different regions and sources, especially from non-conventional tar sands. Production of natural gas liquids (NGL) roughly parallels the natural gas production. However, its contribution is too small to have a significant influence. Also, heavy oil production from Alberta and Saskatchewan contributes since 1973 with rising shares.

Finally, non-conventional synthetic crude oil and bitumen from tar sands are produced since 1967 with steadily rising contributions. By 2030, almost 90% of all Canadian oil will come from this source. The projections for tar sands is based on studies and forecasts by the Canadian National Energy Board for the time horizon up to 2025, the further extrapolation to 2030 is by the authors of this study.

Mexico is the third country belonging to OECD North America according to the IEA classification. By far the largest contribution comes from the offshore field Cantarell which contains about 12 – 15 Gb of oil. Its production started to decline already in 1994. However, with huge investments in nitrogen injection plants and additional production wells the field’s production could be increased again for a few years. In 2004 Cantarell contributed more than 50% to the total oil output since other fields are already in decline since some years. The production projection is based on the assumption that Cantarell started to decline in 2006 at a

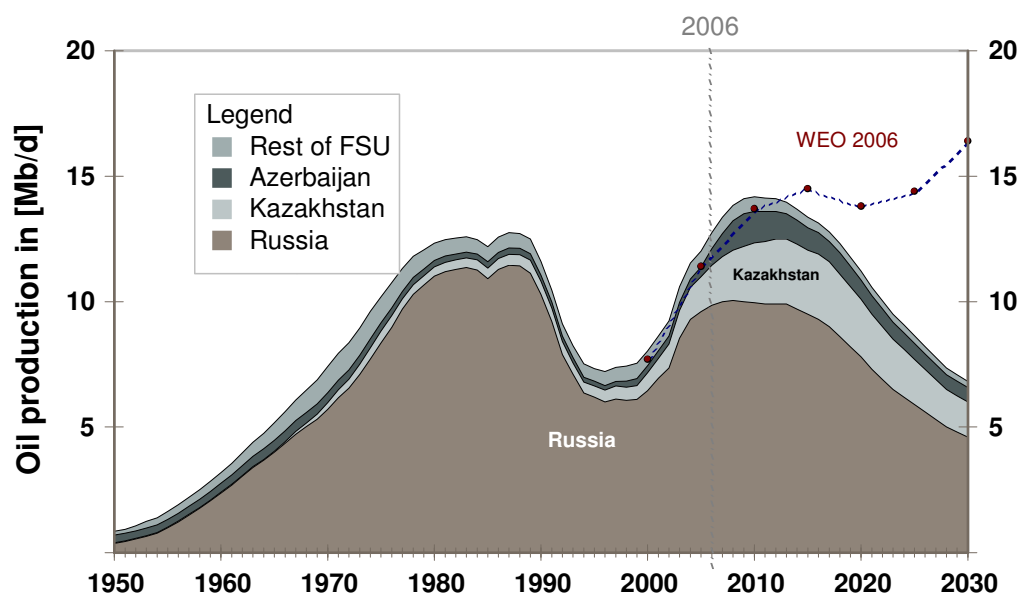
rate of 10% per year and that the contribution from other fields can be held at the present level. In this case, total production will decline by 70% by 2030.

Transition Economies

The Transition countries are among the important oil producing and exporting countries, dominated by the large fields in Russia, and there especially in Siberia. At the end of the 1980s the production declined by 40% within five years. This decline was caused by the decline of the largest producing fields while new fields were not developed in the years of the economic transformation. By around 1995, new economic structures had been established and the known remaining fields were developed with the help of foreign investment. However, remaining opportunities are becoming smaller and therefore the fast revival of the Russian oil production is slowing down, leading to a second production peak probably around 2010.

The production peak at the end of the 1980s had been forecasted by western geologists based on the depletion patterns of the largest oil fields [Masters 1990]. However, the following production collapse during the economic break down turned out to be much steeper than expected. After the liberalisation of the oil market, Russian companies were able to stop this decline and to increase production levels again – at double-digit rates in some years during the last 5 years - with the help of international cooperation and investments.

Figure 32: Oil production in Transition Economies



The two other important oil regions of the Former Soviet Union are Azerbaijan and Kazakhstan. Several discoveries between 1995 and 2000 led to the expectation that the development of large fields (e.g. Tengiz, Kashagan, Azeri, Chirag, Guneshli) can maintain the present production increase up to 2010 to 2015 before the unavoidable decline starts (see Figure 32).

Azerbaijan is the oldest industrial oil region of the world. Today, we can expect an expansion of production only in the offshore areas. Especially the field complex Azeri-Chirag-Guneshli has to be mentioned. Once fully developed, this field probably will reach its maximum in 2008 or 2009 with a production rate of 1 Mb/day. Soon thereafter the production rate will decline very fast to almost negligible amounts within 10-15 years. The total production of this region, however, will increase by a smaller amount as some oil is already produced from Azeri-Chirag-Guneshli today and as the production from other fields will drop noticeably in coming years.

For some years Kazakhstan was considered to be a potential counterbalance to Saudi Arabia. We now know that these expectations were exaggerated. They were nurtured by speculations by the US federal agency EIA which estimated the oil and gas reserves in the Caspian Sea region to amount to up to 300 Gb of oil equivalent. Realistically, only about 45 Gb of oil are likely to be recoverable, about half of this amount is located in already developed fields.

High expectations regarding their future production potential are concentrated on three fields: Tengiz, Kamchagarak and Kashagan. Tengiz and Kamchagarak are already producing oil for some years. All three fields contain oil with a high sulphur content, the development of which jeopardises the environment and is very expensive. In Tengiz alone, more than 4,500 tons of sulphur are separated from the produced oil each day and stored in the surrounding area polluting the environment. Plans for a production extension are delayed due to high costs and difficult geological conditions.

In 2000, Kashagan, the largest of the three big oil fields, was discovered. Production schedules had to be revised many times. Original targets for production to start in 2006 are now deferred to 2010. Difficult environmental conditions in the Caspian Sea, a high sulphur content of the oil, and extremely high deposit pressures of more than 1000 bar make the field difficult and expensive to develop. It is certainly no coincidence that two of the big companies involved in the discovery of the field (BP and Statoil) have withdrawn from the consortium which develops the field.

Azerbaijan and Kazakhstan will, in the best case, be able to double their production rate by 2015, from 1.3 Mb/d to about 2.5 Mb/d.

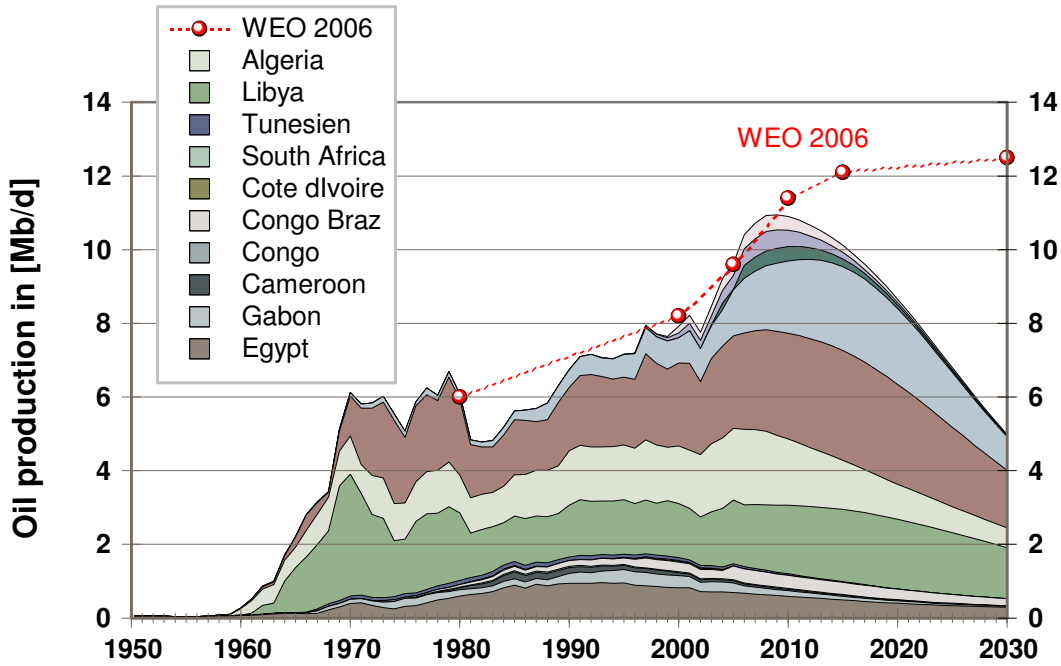
Africa

Oil production can be increased in Angola, Libya and Nigeria. Oil production is expected to decline in Africa after 2010. In almost all African countries the oil production will peak between 2010 and 2015. The main reason is the slow rate of new fields coming on stream. The remaining reserves allow for a production profile as shown in Figure 33. It should be

noted that the remaining reserves for Africa assumed here (125 Gb) are higher than the reserves stated by IHS (102 Gb).

Figure 33 shows also the forecasts by the IEA in the WEO 2006. The IEA projection obviously implies reserve estimates which must be higher by far.

Figure 33: Oil production in Africa



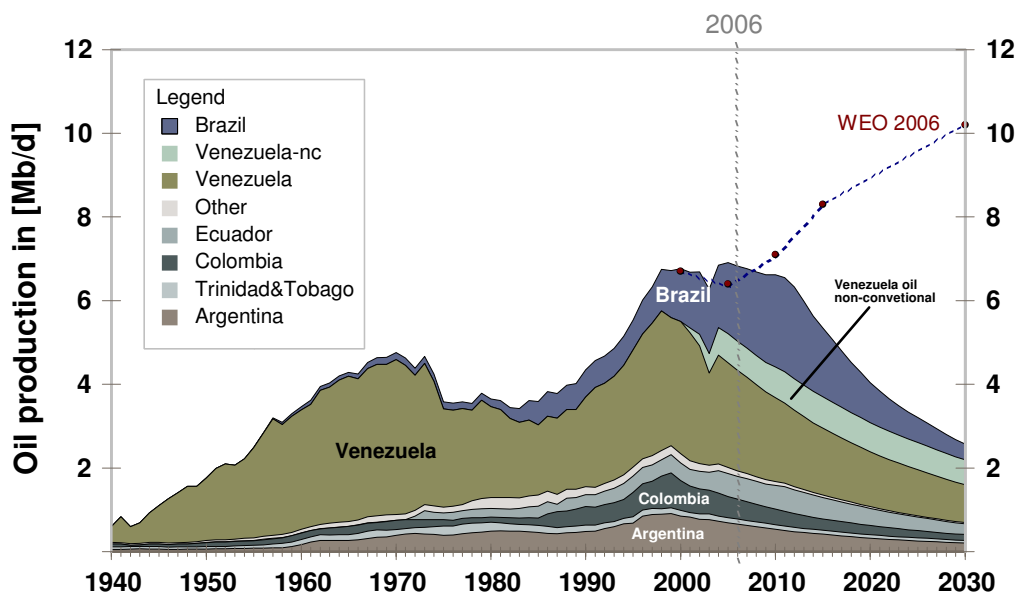
Latin America

As indicated in Figure 34, oil production in Latin America will most likely decline in future. Oil production in Venezuela, being the largest oil producer in Latin America, started to decline after 1970 but picked up again in the mid 1980s. Now a peak has been reached in 2000, since when production is declining. Even with increased non-conventional oil production, Venezuela will not be able to maintain its present production rate.

Since the 1980s, Brazil, the second largest oil supplier in Latin America, has increased its oil production up to 1.5 Mb/d. Peak production of around 2.2 Mb/d is expected to be reached by the end of this decade.

Figure 34 also shows the IEA forecast for the future oil production in Latin America.

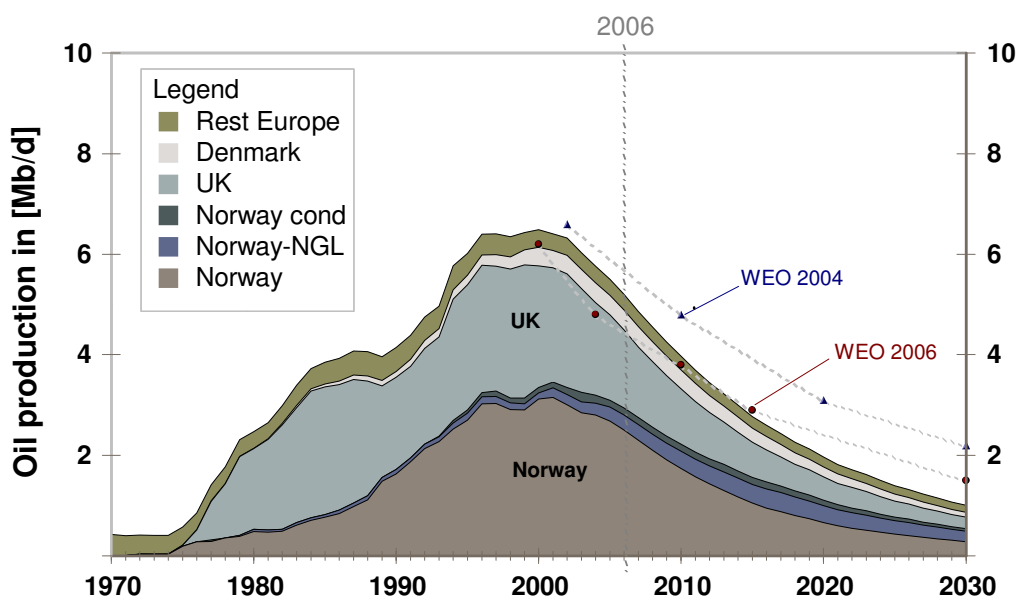
Figure 34: Oil production in Latin America



OECD Europe

Oil production in OECD Europe has peaked around 2000, see Figure 35. This was already confirmed in the IEA reports WEO 2004, and WEO 2006. Probably production in 2015 will be down by about 50% compared to 2005 production. The peak of European oil production in 2000 marked a turning point insofar as the largest oil province found in the last 50 years experienced peak. At peak level, the region contributed about 40% to the world offshore production – the only area where production still is growing. However, this peak reduced the global growth rate and coincided with the peak of the oil production outside former Soviet Union countries and outside OPEC countries.

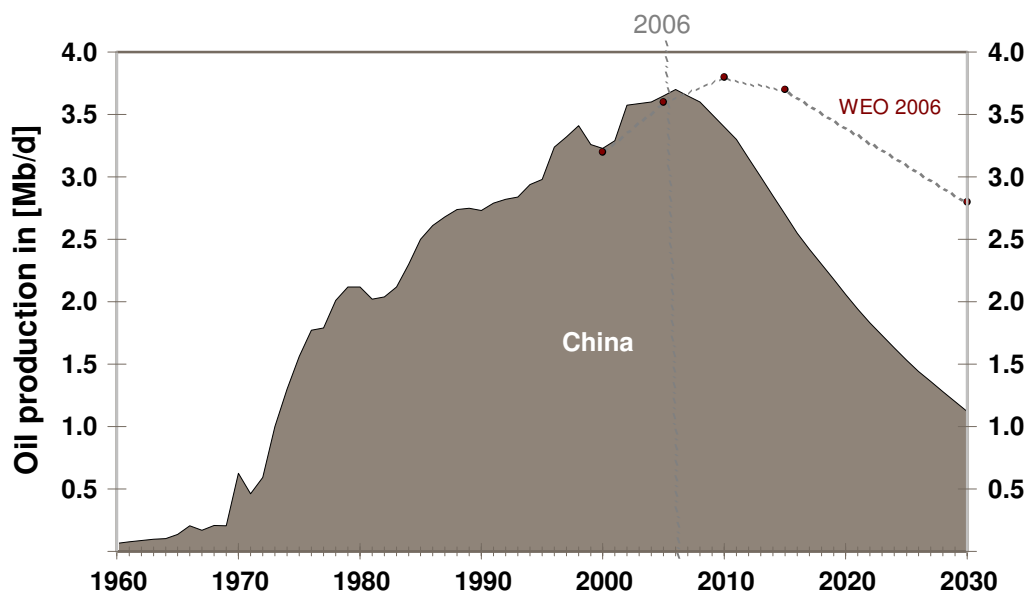
Figure 35: Oil production in OECD Europe



China

Daqing is the largest oil field in China and already in decline. Today, this field produces about 1 Mb/d. To compensate this decline, China has been increasing its efforts to develop offshore oil production. As shown in Figure 36, it is expected that oil production in China will peak before 2010 and then decline by around 5% per year on average until 2030. Also, the IEA in its WEO 2006 expects oil production in China to peak by the beginning of the next decade.

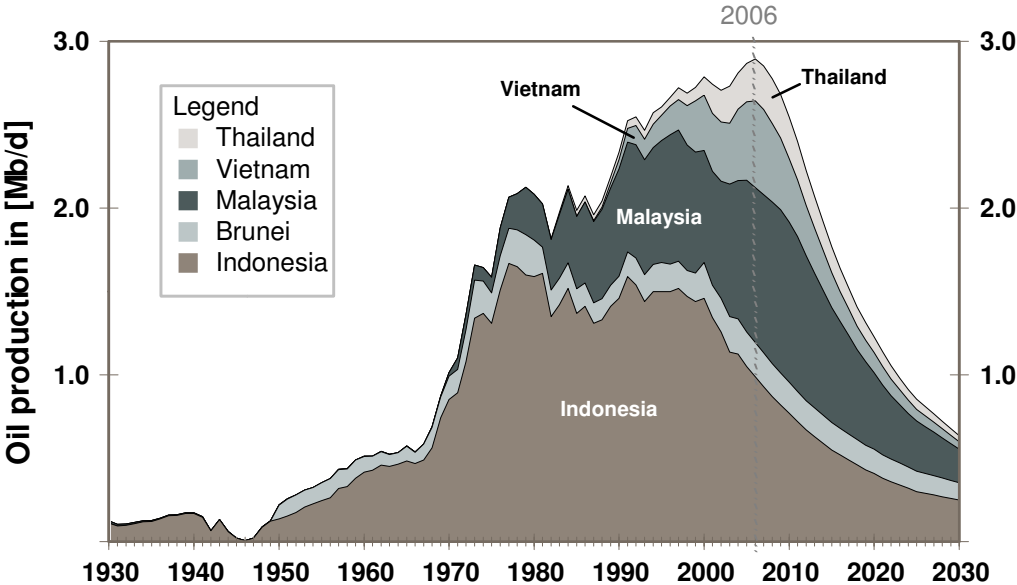
Figure 36: Oil production in China



East Asia

Oil production in East Asia is expected to peak before 2010. In Indonesia, the largest producer in the region, production has been declining since 1990 by around 30%. Production in Malaysia, the second largest producer in the region, is close to peak. It is expected that oil production in Malaysia, Vietnam and Thailand will peak before 2010. Figure 37 shows that a sharp fall of oil production in East Asia is projected until 2030.

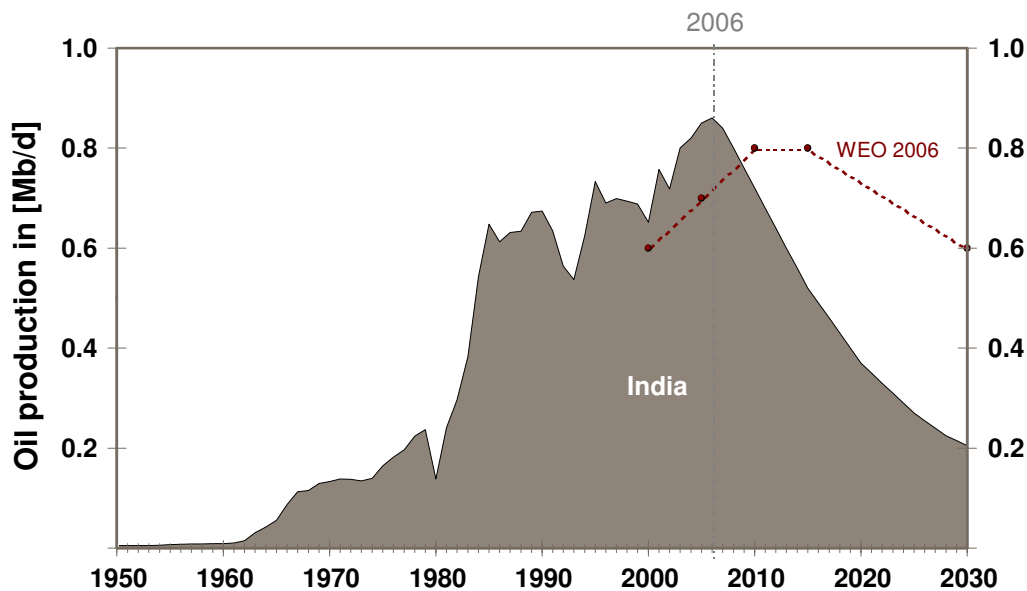
Figure 37: Oil production in East Asia



South Asia

India is the only oil producing country in South Asia. The scenario assumes that South Asia reached peak oil production in 2006 which will be followed by a steep decline. As indicated in Figure 38, IEA assumes oil production to peak some time before 2020.

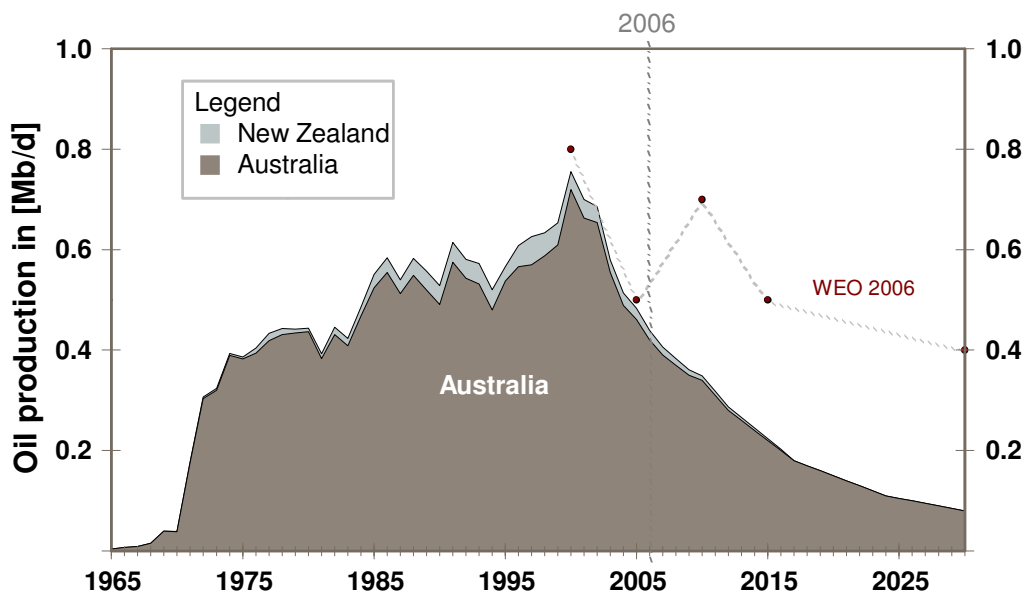
Figure 38: Oil production in South Asia



OECD Pacific

Almost all oil of the region comes from Australia which experienced peak production in 2000, followed by decline rates of around 10% per year (see Figure 39). Such steep decline rates are typical when aggressive modern extraction methods like horizontal drilling or early gas or water injection are applied. The recent decline since 2000 is well acknowledged. The IEA assumes that it will be possible to increase production again to almost the peak level of 2000, at least for a short time period. This assumption is based on the expectation of very fast developments of the deepwater discoveries made in recent years. However, this projection seems to ignore the ongoing decline of the production base which will have an ever greater effect with progressing time.

Figure 39: Oil production in OECD Pacific



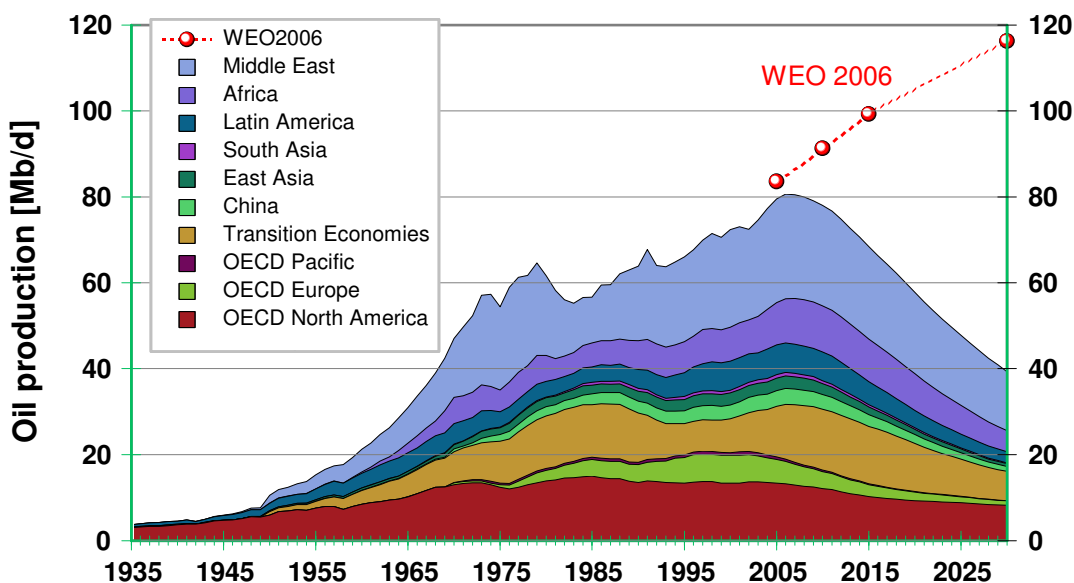
World scenario

EWG scenario

World oil production between 1935 and 2005 and the extrapolation up to 2030 as projected by the authors is sketched in Figure 40. This includes natural gas liquids (NGL) and oil from tar sands.

According to this scenario, peak oil occurred in 2006 with a peak production of 81 Mb/d.

Figure 40: Oil production world summary



According to the scenario calculations, oil production will decline by about 50% until 2030. This is equivalent to an average annual decline rate of 3%, well in line with the US experience where oil production from the lower 48 states declined by 2-3% per year.

However, it must be noted that this is a moderate assumption as today a large fraction of the oil is produced offshore. Offshore fields are produced by very aggressive modern extraction methods, e.g. injection of water, gas, heat and surfactants – in order to increase the pressure and decrease the viscosity – and horizontal drilling – in order to extract the oil faster. These methods allow the faster extraction of the oil for a limited time. The horizontal wells allow to extract more oil per time, but as soon as the water level reaches the horizontal well, oil production switches to water production almost within several months. These production methods lead to decline rates after peak of 10% per year or even more (e.g. 14% per year in Cantarell (Mexico), 8-10% in Alaska, UK and Norway, more than 10% in Oman and possibly 10% or more in Ghawar, the world's largest oil field in Saudi Arabia).

Comparison of EWG scenario results with other projections

World Energy Outlook by the IEA

The EWG scenario is compared with the reference scenario by the International Energy Agency (IEA) in its latest World Energy Outlook [WEO 2006] as shown in **figure**.

The global projections for the oil supply are as follows:

- 2006 81 Mb/d

- 2020 EWG: 58 Mb/d (IEA: 105¹ Mb/d)
- 2030 EWG: 39 Mb/d (IEA: 116² Mb/d)

The differences to the projections by the IEA could hardly be more dramatic.

The alternative policy scenario by the IEA results in a slightly reduced production (about 10%) but does not really deviate from the general trend of the referenc scenario which more or less extrapolates the development observed from 1980 to 2005.

The WEO foresees no peaking of oil production in the period up to 2030.

The difference is of course due to the different methodologies and assumptions (for a more detailed dicussion regarding the differences see Annex 2).

ASPO scenario

The EWG scenario results differ also from the ASPO projections. Taking the estimates of the ASPO newsletter #80, August 2007:

- Peak oil will be reached around 2011 at about 90 Mb/d (against 81 Mb/d in 2006 in the EWG scenario).
- Production in 2020 will be at 75 Mb/d (against 58 Mb/d in the EWG scenario).
- Production in 2030 will be at 65 Mb/d (against 39 Mb/d in the EWG scenario).

The difference in the timing of peak is perhaps not really important. More important is the higher volume of peak production assumed by ASPO. However, the differences in decline rates and production levels after peak are quite significant. They are – apart from the higher level of the peak - mainly due to a different assessment of oil production in the Middle East in the coming decades (ASPO expects production in the Middle East to decline by about 10% after peak until 2030 whereas EWG expects a decline of more than 40%).

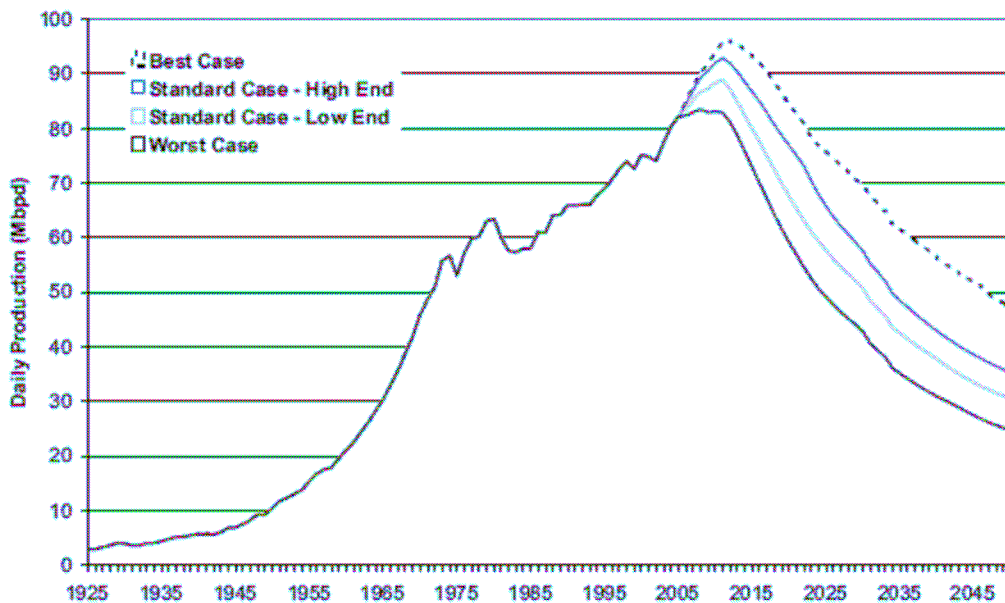
Robelius scenarios

Robelius has four basic scenarios ranging from worst case to best case, and a demand adjusted scenario for the best case [Robelius 2007]. In the basic scenarios peak occurs between 2008 and 2013 with peak production ranging from 83 to 94 Mb/d. The demand adjusted best case scenario has a peak in 2018 at 94 Mb/d.

¹ Since IEA gives data only for 2015 and 2030, data for 2020 are interpolated; data include processing gains

² Since IEA gives data only for 2015 and 2030, data for 2020 are interpolated; data include processing gains

Figure 41: Results for the Robelius basic scenarios ([Robelius2007] p. 132)



All scenarios show a steep decline of production after peak:

- In the worst case, production at peak remains on a plateau for a few years and then declines to 60 Mb/d by 2020, and to 43 Mb/d by 2030.
- In the basic best case, production declines to 85 Mb/d by 2020, and to 70 Mb/d by 2030 (the decline from peak production of 94 Mb/d in 2013 to 70 Mb/d in 2030 occurs in the span of 17 years).

Again, it seems that this decline pattern is a significant result, though this aspect is not elaborated in the study. This steep decline after peak is perhaps even more important than the exact timing of peak oil.

The results for the worst case scenario are very close to the results of the EWG scenario. Looking at current developments, at the moment it seems that these scenarios probably are the most realistic.

CONCLUSIONS

The major result from this analysis is that world oil production has peaked in 2006. Production will start to decline at a rate of several percent per year. By 2020, and even more by 2030, global oil supply will be dramatically lower. This will create a supply gap which can hardly be closed by growing contributions from other fossil, nuclear or alternative energy sources in this time frame.

The world is at the beginning of a structural change of its economic system. This change will be triggered by declining fossil fuel supplies and will influence almost all aspects of our daily life.

Climate change will also force humankind to change energy consumption patterns by reducing significantly the burning of fossil fuels. Global warming is a very serious problem. However, the focus of this paper is on the aspects of resource depletion as these are much less transparent to the public.

The now beginning transition period probably has its own rules which are valid only during this phase. Things might happen which we never experienced before and which we may never experience again once this transition period has ended. Our way of dealing with energy issues probably will have to change fundamentally.

The International Energy Agency, anyway until recently, denies that such a fundamental change of our energy supply is likely to happen in the near or medium term future. The message by the IEA, namely that business as usual will also be possible in future, sends a false signal to politicians, industry and consumers – not to forget the media.

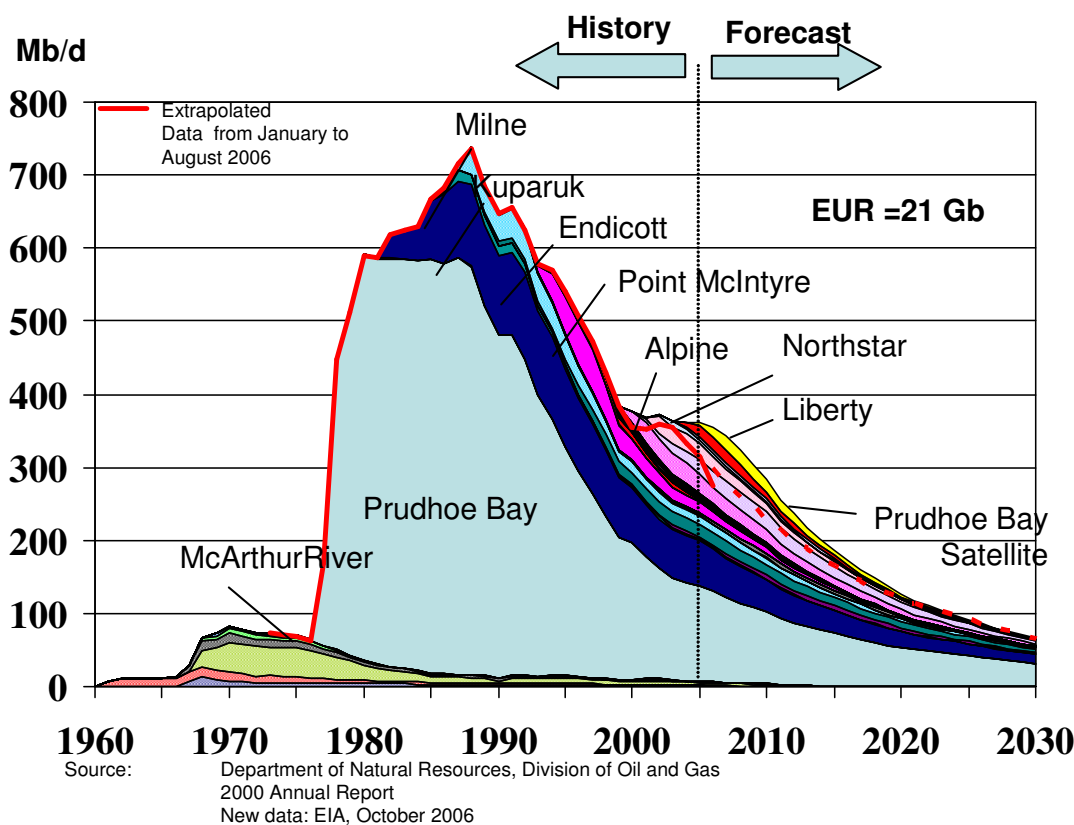
ANNEX

Annex 1: US oil production in Alaska and the Gulf of Mexico

Alaska

Figure 42 shows the field by field production history of the crude oil production in Alaska. The forecast is based on the assumption that beyond peak production the production rate declines with declining field pressure. This results in a linear decline rate when the annual production is plotted against the cumulative production.

Figure 42: Field by field analysis of the oil production in Alaska



The forecast until 2010 is prepared by the Department of Natural Resources in 2000. The extrapolation until 2030 is by LBST.

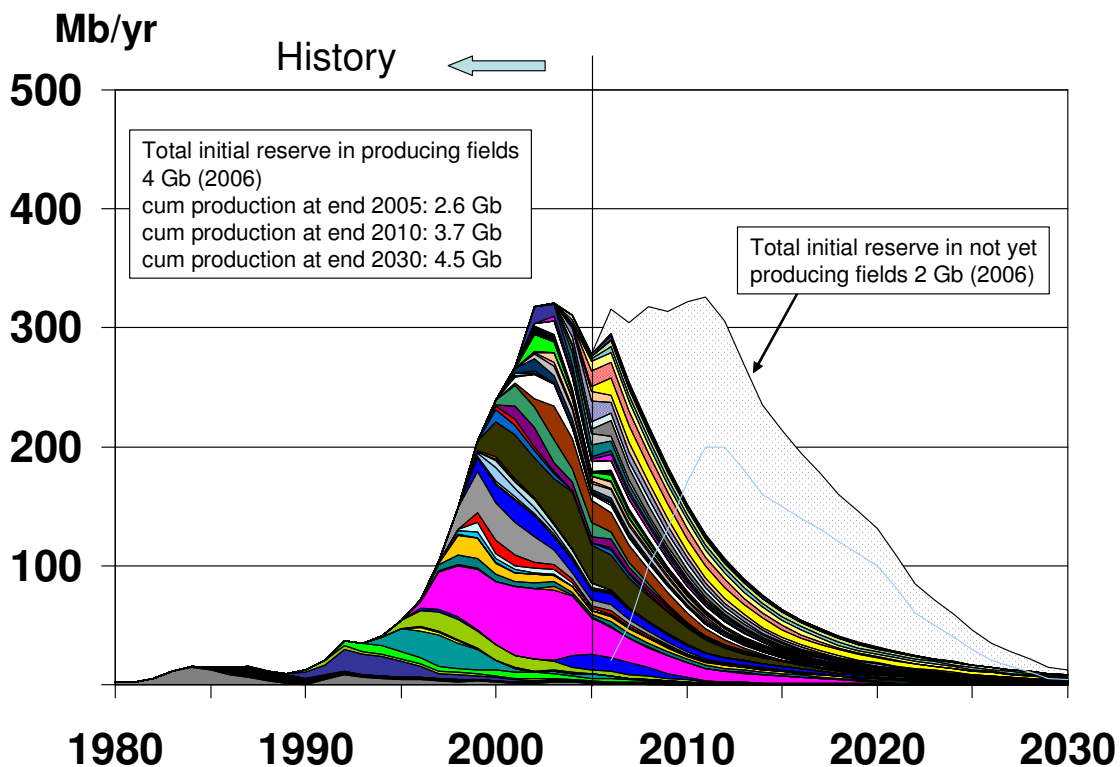
Since 1989 the decline of the oil fields in Alaska adds to the decline rate of the lower 48 states. However, since around 1990 deep water fields in the Gulf of Mexico were developed which help to compensate declining oil production elsewhere - at least partially. However, these fields are developed rapidly. Since oil is scarce, these fields are brought to their peak production rates as fast as possible, sometimes even within or slightly after the first year of connection.

Gulf of Mexico

The Figure 43 shows the production profiles of the connected deep water fields in the Gulf of Mexico. These fields enter into decline very fast. According to a forecast by the Minerals and Mines Service (MMS) in 2002, production from the Gulf of Mexico (outer continental shelf) was expected to be between 2 and 2.47 Mb/day by the end 2006. But actually, in 2002 production peaked and turned into steady decline since then. At end 2005 the production was at 1.27 Mb/day, production from wells below 1000 feet water depth even less. These fields are displayed in the following graphics, exhibiting the field by field development. Many fields reached peak production much faster than anticipated before. Partly this is due to severe damages to some oil platforms after the hurricanes Ivan, Katrina and Rita. The dotted area includes the estimated production profile of all known but not yet developed fields. These fields are expected to contain about 3.5 Gb, which together with the oil in already developed fields adds to about 5 Gb of total reserves. This is by far more than the proven reserves of 3.5 Gb at end 2004. If some key fields developed in time the present production decline might be reserves and turned into a peak around 2010. But a considerable increase of the production to 2 Mb/day seems almost impossible. When the development of these fields is delayed due to technical problems, peak production might be even lower.

The development of Thunderhorse North which was expected to contribute with 250 kb/day from late 2006 on is already in delay and will not be completed before 2008.

Figure 43: Field by field analysis of the oil production in the Gulf of Mexico



Source: History: MMS 2005; Forecast LBST 2005

Recently developed fields peak very fast and enter into decline sometimes even after the first year of connection [MMS 2006]. This figure is based on the field production data and expected field developments as published.

Annex 2: Critique of Oil Supply Projections by USGS, EIA and IEA

US Geological Survey (USGS)

The latest survey of resources is the “US Geological Survey World Petroleum Assessment 2000” and was published in June 2000 [USGS 2000a].

In the executive summary of the resource survey 2000 the following phrases deserve attention: purpose of the study is “... to assess resources ... which have the potential to be added to reserves within a 30-year timeframe (1995-2025)...” [USGS 2000a]. It is stated explicitly that those oil findings can be expected in the time between 1995 and 2025. Until today, one third of this time span has elapsed, so that now we are able to compare the estimates of the study with reality.

Moreover the wording “to assess resources... which have the potential to be added to reserves” is so vague that its exact interpretation is left to the reader.

In brief the results of the survey can be summed up as follows:

- Outside of the USA up to 334 Gb of oil can be found between 1995 and 2025 at a probability of 95%, and 1107 Gb at a probability of 5%. By using extensive Monte-Carlo simulations a “mean” value of 649 Gb is calculated.
- Furthermore between 95 Gb (5% probability) and 378 Gb (95% probability) of natural gas liquids (NGLs) can be found.
- In contrast to previous analyses a new factor - called “reserve growth” - is introduced. The factor for the reserve growth is calculated from the experience in the USA during the last decades, extrapolated for the next 30 years and then applied on the rest of the world.

This method of adjusting reserves by a growth factor must be criticised in two respects:

The upward revision of reserves in the past is caused in most cases by an initial underestimation of the size of the old and large fields. These fields were so large that it wasn't necessary for their efficient development to determine their exact size. And some of these fields are so old (up to 100 years and more) so that the methods of reserve estimation at the time of discovery were very simple and unprecise.

Today, the growth of reserves tends to be much smaller, partly because newly found fields are so small that a precise estimate is needed, but also because modern exploration methods are much more precise than in the past. Nowadays it happens quite often that reserves also have to be adjusted downwards instead of upwards (as lately the example of Shell has shown).

The second point of critique refers to the fact that – as is known to all experts - the growth of reserves in the USA in the past was much higher than elsewhere. This is a direct consequence of the regulations by the Securities Exchange Commission (SEC), which for financial reasons call for very conservative evaluations at the beginning of the development of an oil field. This US practice leads to systematic underestimations.

For these reasons this marked reserve growth in the past was only observed in the USA and can not be extrapolated into the next 30 years, nor even less can this pattern be applied to the whole world.

But apart from this important aspect, it seems very strange that a scientific geological institute makes estimates of the geological potential of oil findings and then additionally applies a growth factor which only reflects the economic rules of “reserve reporting”. It is obvious that the reporting of reserves can only extend within the boundaries of the geologically possible. The USGS study mixes different categories of reserve evaluation which are not compatible. The results can not be regarded as scientifically sound and are all but reliable.

To arrive at a global picture, US data have to be added to the world’s oil resources outside the US. For this purpose the USGS draws on its own analysis of the US from 1996 [USGS 1996]. The aggregate results of the USGS study are shown in the following Table 5.

Table 5: USGS estimate of potential oil findings between 1995 and 2025 and reserve growth in already found fields [USGS 2000a]

Discoveries	5% Probability	Mean	95% Probability
Crude oil (outside USA)	1107	649	334
NGL (outside USA)	378	207	95
Crude+NGL (USA)	104	83	66
Total	1589	939	495
Reserve growth			
Crude oil (outside USA)	1031	612	192
NGL (outside USA)	71	42	13
Crude+NGL (USA)	(76)	(76)	76
Total	1178	730	281

Moreover, the study quotes figures of proven reserves and cumulative production from other statistics. It is particularly interesting that the USGS takes the values for non-US countries

from the industry database (formerly Petroconsultants, today IHS-Energy). This very database, however, is also used by Campbell and others for their analyses.

Table 6: Cumulative production by 01/01/1996 and proved reserves, as quoted in the USGS study [USGS 2000a]

	Crude+NGL (USA)	Crude (outside USA)	NGL (outside USA)	Total
Cum. production	171 Gb	539 Gb	7 Gb	717 Gb
Reserves	32 Gb	859 Gb	68 Gb	959 Gb

Using these figures the USGS calculates the total potential of past and future world oil production (Estimated Ultimate Recovery – EUR) to be: 3,012 Gb being the mean value, 2,269 Gb with a probability of 95% and 3,919 Gb with a probability of 5%. In addition, the total amount of liquified natural gas outside of the US is estimated to be in the range of 183 to 324 Gb. For the US the NGLs are already accounted for in the table above.

To give an insight into the methodology of the analysis, two regions will be examined in greater detail: the Falkland Islands and the basin of the Greenlandic Sea.

The USGS study identifies as the region with the largest potential of oil discovery the sea area east of Greenland which is estimated to contain as much oil as the North Sea. In this region certain geological analogies exist to the shelf ridge off Middle Norway, but only certain analogies... With a probability of 95% no oil at all will be found, according to the USGS, with a probability of 5% 117 Gb will be found. Based on these estimates, it is calculated via complex mathematical models that probably 47 Gb of oil could be found in the region. (Incidentally in the shelf off Middle Norway 10 Gb have yet been found after many years of intensive exploration – with the significant contribution of Colin Campbell.)

Until today there hasn't been any single exploration drilling in the Greenlandic Sea. It will be interesting to see which oil company will take the risk to drill in an area where oil is expected to be found with a probability of 5%.

For to the Falkland Islands, the potential for “undiscovered” oil is estimated to be 5,8 Gb. This number was calculated as the mean value assuming that at 95% probability no oil at all will be found and with a probability of 5% about 17 Gb will be found.

In contrast to this estimate, the sobering reality is described in the following quotation of Marshall DeLuca in OFFSHORE, one year before the completion of the USGS study [De Lucia 1999]:

“The most recent frontier project was the offshore Falkland Islands area. This exploration project has turned out to be a disappointment – thus far. The operators have tried six wells in the area ... and have encountered some oil shows, but did not strike anything close to

commercial levels. It has been estimated that the group will need a discovery with at least 140 Mb of oil to justify development of the Falklands. With the harsh environment of the Falklands, well costs are currently estimated at between \$25 and \$30 million per well. The FOSA drilling program is now complete, and the operators are evaluating well data. No plans for the future have been announced.”

So far no single oil field containing approximately 140 Mb has been found. Where to look for the 5,800 Mb of which the USGS assumes that they can be found?

As the study indicates, the time frame 1995 to 2025 for the new discoveries of oil, one can easily calculate how much oil per year on average should be found.

Table 7: Calculation of average discoveries per year until 2025 based on USGS assumptions

Probability	Discoveries (crude+NGL)		Reserve growth		Total
	1995-2025	Gb/yr	1995-2025	Gb/yr	Gb/yr
95%	495 Gb	16.5	281 Gb	9.4	25.9
Mean	939 Gb	31.3	730 Gb	24.3	55.6
5%	1589 Gb	53.0	1178 Gb	39.3	92.3

Just taking this table, the lack of realism of the study becomes apparent. If we take seriously the values indicated as “mean”, this would mean that every year 55 Gb of new oil would have to be added to the reserves, originating either from new discoveries or from reassessments of existing fields. In fact, however, reported reserves have been staying roughly constant. Currently discoveries and reassessments correspond approximately with annual consumption - which amounted to about 29.5 Gb in 2005. Hence, the USGS study assumes that in future on average this value will be at least twice as high than in the past.

As a matter of fact, between end of 1995 and end of 2005 in total only 146 Gb were discovered and 312 Gb were added by reassessing existing fields¹. According to the USGS projections (“mean”), however, in this period 313 Gb should have been found and 243 Gb should have been added due to reassessments, whereas the amounts to be expected with a probability of 95% did materialize. After one third of the forecasting period has now passed, the real development lags far behind the USGS projections. In order to achieve the “mean” projections even roughly, in future much more oil than ever before has to be found. This

¹ Discoveries are taken from the industry data base of IHS Energy. These provide data of crude oil and NGL/condensates. The upgradings were calculated from reserve figures shown by the BP Statistical Review of World Energy, by accounting cumulative production in this period and the IHS designated findings.

seems to be the most unlikely of all possible future developments! There is not a single indication that the USGS estimates, apart from the 95% probability values, have anything to do with reality.

The US “Energy Information Administration” (EIA)

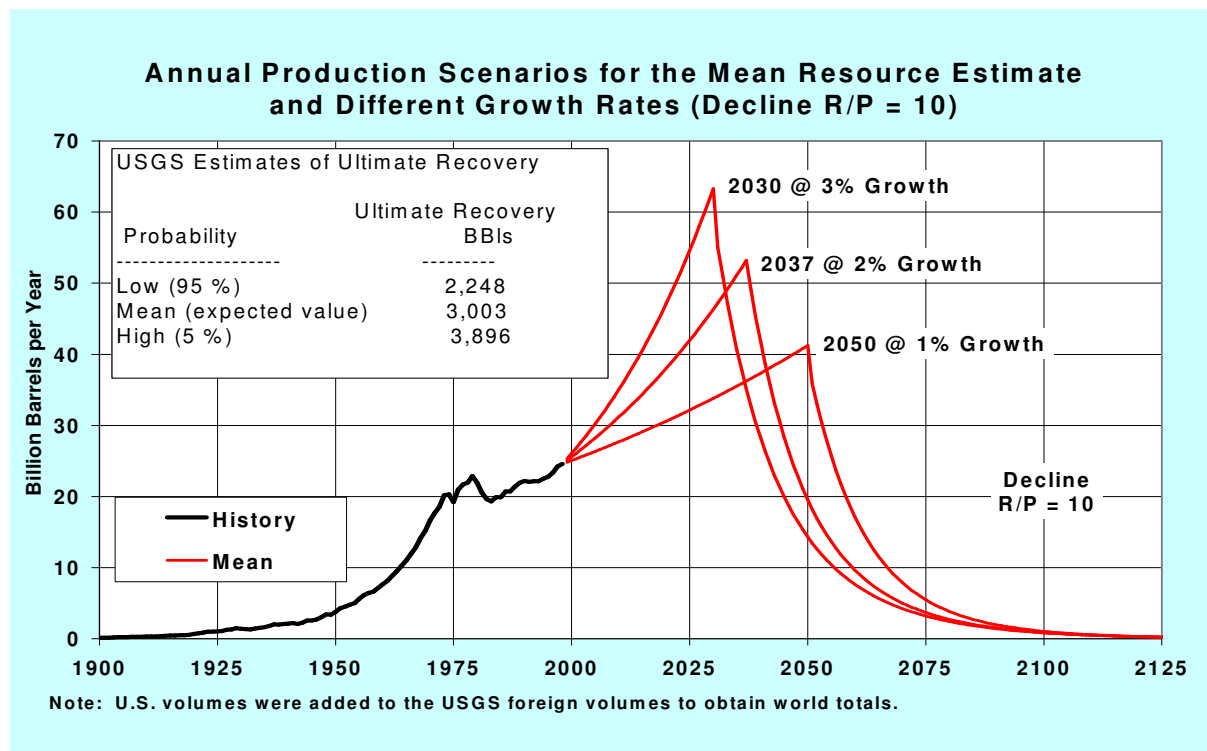
The Energy Information Administration, which belongs to the US Department of Energy, publishes many energy statistics and analyses which draw worldwide attention.

The publication of the USGS resource study discussed above was used as a basis by the EIA to forecast the world's oil production. As an example for many analyses of EIA the study “Long Term World Energy Supply” will be examined in greater detail [EIA 2000].

Based on the resource data of the USGS study different supply scenarios until 2010 and beyond are outlined. In the summary it is pointed out that all 12 analyzed scenarios see the production peak, depending on different assumptions, between 2021 and 2112. Also included, but not mentioned in the text of the summary is the chart “Annual Production Scenarios with 2 Percent Growth Rates and Different Decline Methods” which shows the peak in the year 2016 based on 2% decline after peak and an EUR of 3003 Gb.

Moreover, the only realistic - from our point of view - scenario is not mentioned. This is a scenario based on the USGS resource figures at 95% probability (2,248 Gb) and assuming a production increase of 2% per year until the peak is reached and thereafter a production decline of 2% per year. In this scenario the peak would already be reached before 2010, consistent with the claim of the “pessimists”. Instead of this the pessimistic scenario formulated in the EIA presentation is based on the USGS “mean” with a total oil production potential of 3,003 Gb.

Figure 44: Annual Production Scenarios for the Mean Resource Estimate and the Different Growth Rates (Decline R/P = 10) [EIA 2000]



The methodological approach for the construction of the “Annual Production Scenarios for the Mean Resource Estimate and the Different Growth Rates (Decline R/P = 10)” is strange. First of all: Why is there a production curve based on the “Mean” case of the USGS study and not also one for the “Low” case (with a probability of 95 %)? Later in the study for the most part only graphs are shown which are based on the USGS “High” values with a probability of 5%. However, as already mentioned, if we calculate the production profile with a growth rate of 2% before and a decline rate of 2% after the maximum based on the “Low” case, then production would peak before 2010 – fully consistent with the estimates of the “Pessimists”.

Assuming the peak of production takes place very late in time obviously leads to very unrealistic “catastrophic scenarios”: a long period of growth is necessarily followed by a steep decline, i.e. a total break down of oil production within a few years after the peak.

This steep production decline is generated by assuming a constant reserve/production ratio of 10 years (R/P = 10). It is argued that such a constant R/P–ratio was observed empirically in the US after production peaked in 1971.

In fact, production each year declined at an average rate of 2%, but reserves were also adjusted each year in such a way that the R/P-ratio was almost unchanged. (This is a consequence of the concept of “reserve growth”: Even though reserves were adjusted downwards each year, they were adjusted by less than the actual production of the year in question.)

A consistent calculation would have to be in line with the observed 2% decline rate of the production. EIA, however, uses the constant R/P=10 ratio based on the final EUR as basis which results in a 10% annual decline rate. But the real praxis was to arrive at R/P=10 by annually upward revising EUR.

However, much more important is another criticism. How realistic are the future production scenarios as described by EIA? These scenarios are quite implausible as already today most of the regions in the world have either reached or passed their production peak. Once more and more regions experience a shift from growing to declining production it is getting increasingly difficult for the ever fewer remaining countries to compensate for this decline, let alone to add to total production. For instance, if we take the scenario with the peak in 2030 (based on a yearly production growth of 3%), this curve tells us the following: In the last 50 years the world has managed to increase global production per year from about 5 Gb by about 20 Gb to 25 Gb; in little more than half of this period it is thought to be possible to increase yearly production by about twice that amount from 25 Gb to 65 Gb – by another 40 Gb! This is incredible.

In view of the remaining production potentials it is much more likely that global oil production will never be able to exceed the 30 Gb level significantly, and not for longer than a few years if at all.

The International Energy Agency (IEA)

The IEA was founded by the OECD nations after the oil shocks in the 1970s as a counterweight to OPEC. Since that time the IEA is regarded as the “energy watchdog” of the western world and is supposed to help to avoid future crises. Until 2004 the IEA published the “World Energy Outlook” (WEO) every two years, since then every year. The WEO forecasts the development of the coming two decades. These reports are considered by many people to be something like a “bible”. The IEA also publishes monthly reports covering the current situation of the oil markets.

IEA methodology

The usual basis for demand and supply forecasts is the World Energy Outlook (WEO) biannually prepared by the International Energy Agency (IEA). The 2004 edition of the WEO will be reviewed in this chapter, contrasting results from the 1998 edition with those of the 2004 report which is very close to the 2005 update.

The World Energy Outlook classifies the world into the following ten regions:

- OECD North America, including Canada, Mexico and the USA
- OECD Europe, including Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, The

Netherlands, Norway, Poland, Slovak Republic, Spain, Sweden, Switzerland, Turkey and the UK

- OECD Pacific, including
 - OECD Oceania with Australia and New Zealand
 - OECD Asia with Japan and Korea
- Transition Economies, including Albania, Armenia, Azerbaijan, Belarus, Bosnia-Herzegovina, Bulgaria, Croatia, Estonia, Yugoslavia, Macedonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Romania, Russia, Slovenia, Tajikistan, Turkmenistan, Ukraine, Uzbekistan, Cyprus and Malta
- China, including China and Hong Kong
- East Asia, including Afghanistan, Bhutan, Brunei, Chinese Taipei, Fiji, Polynesia, Indonesia, Kiribati, The Democratic Republic of Korea, Malaysia, Maldives, Myanmar, New Caledonia, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Island, Thailand, Vietnam and Vanuatu,
- South Asia, including Bangladesh, India, Nepal, Pakistan and Sri Lanka
- Latin America, including Antigua and Barbuda, Argentina, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Dominican Republic, Ecuador, El Salvador, French Guyana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, St. Kitts-Nevis-Antigua, Saint Lucia, St. Vincent Grenadines and Suriname, Trinidad and Tobago, Uruguay and Venezuela
- Middle East, including Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, the United Arab Emirates, Yemen, and the neutral zone between Saudi Arabia and Iraq
- Africa, including Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, the Central African Republic, Chad, Congo, the Democratic Republic of Congo, Côte d'Ivoire, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Niger, Nigeria, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan, Swaziland, the United Republic of Tanzania, Togo, Tunisia, Uganda, Zambia and Zimbabwe.

The International Energy Agency's WEOs are demand based forecasts. Based on economic developments and geopolitical assumptions the energy demand is forecasted.

Resource restrictions are not included as natural resources per definition are regarded as being cost free and practically "unlimited". Only costs for extraction, conditioning, transport and distribution enter into the calculations. A possible resource restriction could enter into these calculations only via rising extraction costs. But these are not adequately modelled. In reality, extraction costs even of a single producing oil or gas field rise year over year, simply due to

rising efforts (e.g. water injection, additional wells) and shrinking production volumes (e.g. the oil to water share of the extracted volume is declining continuously).

Based on these demand forecasts, another chapter deals with the supply situation. In almost every IEA report, the question is never raised if the projected demand could be met with an adequate supply. All these forecasts are usually based on “business as usual” scenarios not projecting disruptions on the supply side.

The energy projections are based on a complex World Energy Model (WEM). In short, the model contains the three modules “final energy demand”, “power generation and refinery”, and “fossil fuel supply”. According to the model philosophy, the scenario calculations are demand oriented. This means that starting point for the scenario calculations are basic assumptions regarding population growth, economic growth and fuel prices.

These assumptions are used to calculate the economic activity and the corresponding final energy demand. From the sector specific demand for heat, electricity and fuels the energy consumption of the power generation and the whole transformation sector (refineries) is calculated. These calculations end up in total primary energy supplies for each region.

In almost independent sections the primary energy supply from various fuels is calculated.

- Economic growth assumption

Gross domestic product grew between 1971 – 2004 at an average rate of 3.2% per year.

The basic assumption for the energy projections is that this growth will continue over the next 20 to 30 years. The 2004 report [WEO 2004] used an average growth rate of 3.2% per year between 2002 and 2030. This is slightly higher than in the previous [WEO 2002] report (3%), but considerably lower than in the [WEO 1998] report (3.8%). The report of 2005 is again based on an economic growth rate of about 3.2%. The latest report [WEO 2006] assumes an average growth rate of 3.4% over the next 25 years.

- Population growth assumption

The second assumption on which the forecasts are based on, is the future population growth. Around 1980 the world population grew with a maximum rate of about 1.85% per year. The present growth rate is about 1.2%. This rate is projected to decline further to about 1% between 2000 and 2030. This assumption is not changed in WEO 2002, 2004, 2005 and 2006, though in former reports (WEO 1998) this rate was assumed to stay higher at 1.2% per year.

- Oil price assumption

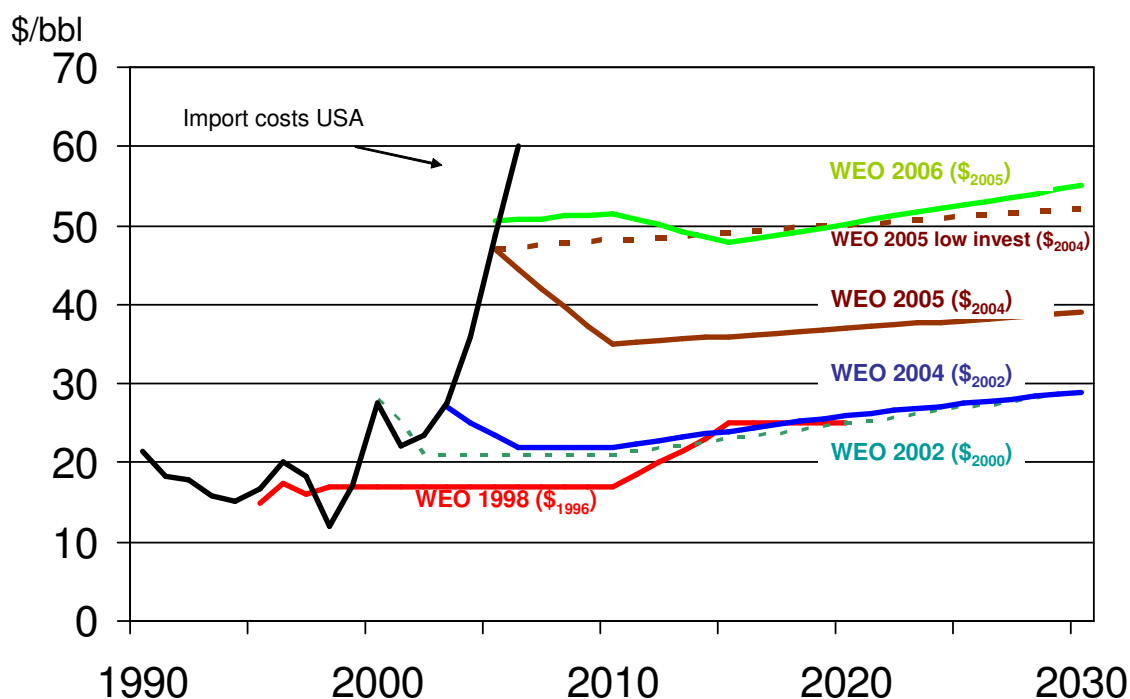
Figure 45 illustrates the changing oil price assumptions. In the 1998 edition a slight increase to 25\$/bbl in 2015-2020 was assumed, as sketched with the red line in the figure (WEO 1998). Real prices, however, started to rise in 2000. But this influenced the 2002 report only

marginally: A decline from 27\$/bbl down to 22\$/bbl was expected for 2003 followed by a moderate increase to 25\$/bbl by 2020 (as in the previous study) and to 29\$/bbl by 2030 (dashed line). However, prices remained high. The 2004 report still expected declining oil prices for the near future to around 22\$/bbl with a modest increase to 29\$/bbl by 2030 (blue line). Continuing high oil prices presumably forced the International Energy Agency to deviate from its biannual publication rhythm and to publish late in 2005 an additional report (WEO 2005). The major differences to the preceding report are higher oil price projections.

The latest price developments are marked in the figure with the bold dark line. In 2005 IEA import prices for crude oil averaged at about 50\$/bbl – USA with 48.8\$/bbl at the low end and UK with 53.8\$/bbl at the high end –, and the present trend indicates a price of about 60\$/bbl in 2006.

The explanations for the price development are quite simple: according to the IEA, today's high oil prices will foster the investment of oil companies into upstream activities. This will result in an expanded supply which in turn will reduce prices. This was the justification for the price decline around 2010 in the WEO 2005 report. The 2006 report delays the response time until 2015 and calculates only with a modest decline by then which will be followed by a price increase of 10% above today's oil price by 2030.

Figure 45: IEA crude oil import price projections according to WEO 1998 (red line), WEO 2002 (dashed line) and WEO 2004 (blue line). The black line shows the historic development of the IEA crude oil import prices.



The big differences between projected and observed crude oil prices make the price projections very doubtful. Since these projections, however, influence the energy demand forecasts, these must also be regarded with caution. According to an independent report of the

International Energy Agency, each price increase by \$10/bbl might result in a drop of GDP by about 0.5%. Therefore, a 30\$/bbl price increase, as already experienced since the publication of the WEO 2004 might result in an economic slow down of ~1.5%. This in turn could dampen the energy consumption correspondingly.

The whole methodological approach is questionable. The modelling is based on the following sequence:

- Make assumptions for the future development of GDP, population and oil prices up to 2030.
- Calculate from the level of economic activities the corresponding final energy demand.
- Calculate the primary energy demand required for the final energy demand.
- Match the projected primary energy demand with a corresponding supply.
- Provide arguments to show that the projected supply increases are feasible.

In reality, however, restrictions on the supply side determine the availability of energy, energy prices, and of course, economic development and GDP growth. Therefore, once there are limits on the supply side, this modelling sequence must be reversed: The available supply determines the possible energy demand which in turn is closely linked to the possible economic growth. The IEA model is only adequate if there are – for all practical reasons - no supply restrictions, i.e. when the peaking of a finite energy source is still far in the future.

Discussion of various IEA reports

The “IEA World Energy Outlook 1998” did forecast that world oil demand will increase by 50% to 120 Mb/day by 2020. It was correctly seen that production outside of OPEC would reach its maximum in the year 2000 and soon after would start to decline. Almost 20% or 17 Mb/day of the total consumption in 2020 was explicitly defined as “not yet identified unconventional oil” – a hidden warning which could be translated to “the IEA has no idea of where this oil is going to come from”. This study did also discuss the different views on the future production potential by dedicating 5 pages to a review of the “Pessimists” position.

The following report „IEA World Energy Outlook 2000“ was already influenced by the USGS Resource Assessment 2000. This influence can also be seen in the later report „IEA world Energy Outlook 2002“ [WEO 2002]. While the 1998 report still discussed the different views later reports simply ignored differing views.

The “IEA world Energy Outlook 2000” and “IEA world Energy Outlook 2002” have an almost opposite message compared with the report of 1998. According to the 2002 report world oil demand will reach the level of 120 Mb/day by 2030 instead of by 2020. But the hint

at “yet unidentified sources” in the 1998 report has been dropped. Quite the reverse, based on the USGS study, now almost any production rate is considered to be possible. Even the production of non-OPEC states, which according to the 1998 report was supposed to decline to 27 Mb/day by 2020, is expected to grow from 43 Mb/day in 2000 to 46 Mb/day in 2020.

Table 8: Aggregate figures of table 3.5 in “The world Energy Outlook 2002” [WEO 2002]

	Amount of Oil	IEA Comment
Remaining reserves	959 Gb	Reserves are effective 1/1/96
Undiscovered resources	939 Gb	Resources effective 1/1/2000 are mean estimates
Total production to date	718 Gb	
2001 Production	75.8 Mb/day	

The stated sources are USGS (2000) and IEA databases.

In fact, all figures except those for the current production are derived from the USGS 2000 study. However, in the USGS study all data refer to January 1st 1996 including still undiscovered resources and total production to date. This is a first methodical error. It would have been correct to adjust all figures in the IEA table to the new base year 2000, i.e. to extrapolate the remaining reserves to 2000, to reduce the findings still to be obtained and to adjust the historic production (after all, 132 Gb have to be added in the period from 1996 to 2000).

Moreover, the figures are not consistent as the following examples show.

Table 9: Daily production in 2000 and 2030 as well as reserves and undiscovered in selected countries, according to the report “IEA World Energy Outlook 2002”, cumulative production between 1996 and 2030 calculated from these figures, and real discoveries between 1996 and 2005

	Production		Cum. Production 1996-2030 (Gb)	Reserves 1995 (Gb)	Undiscovered 1996-2025 (Gb)	Discoveries 1996-2005 (Gb)
	2000 (Mb/d)	2030 (Mb/d)				
Indonesia	1.4	1.7	19.5	10	10	2.6
China	3.2	2.1	35	25	17	8.0
Brasil	1.3	3.9	29	9	55	6.3
UK	3.3	1.1	27	13	7	1.9
Norway	3.4	1.4	32	16	23	2.5
Mexico	3.5	2.7	44	22	23	1.1

The first two columns show the daily production in 2000 and 2030 according to the assumptions in [WEO 2002]. The study gives also intermediate values which allow to calculate the total production over the period 1996 to 2030 (column “Cum. production 1996 – 2030”). In this calculation the year 1995 has to be taken as the base since the assumed reserve data in this study (column “Reserves 1995”) and expected discoveries (column “Undiscovered 1995-2025”) refer to this year. For comparison, the real discoveries made in these countries between 1996 and 2005 are listed in the last column “Discoveries 1996-2005”. These are the discoveries after a third of the forecasting period.

It is obvious that the production forecast by the IEA cannot be attained by Indonesia, UK and Mexico, even if we accept the optimistic assumptions regarding discoveries, since the assumed reserves are not sufficient.

When we compare the real discoveries between 1996 and 2005 with the expected discoveries between 1996 and 2025, the rate of expected discoveries for all these states except for Indonesia and China is in total contrast to the observed development. Particularly striking are the discrepancies for Brazil, Norway and Mexico – there after all more than 100 Gb were expected to be found until 2025, but in fact only 10 Gb were discovered between 1996 and 2005.

If we assume that the present discovery rates can be held constant over the remaining forecasting period (which is very optimistic, because according to past experience discoveries decrease with time), then in every country (maybe except for China) production would be down to zero in 2030.

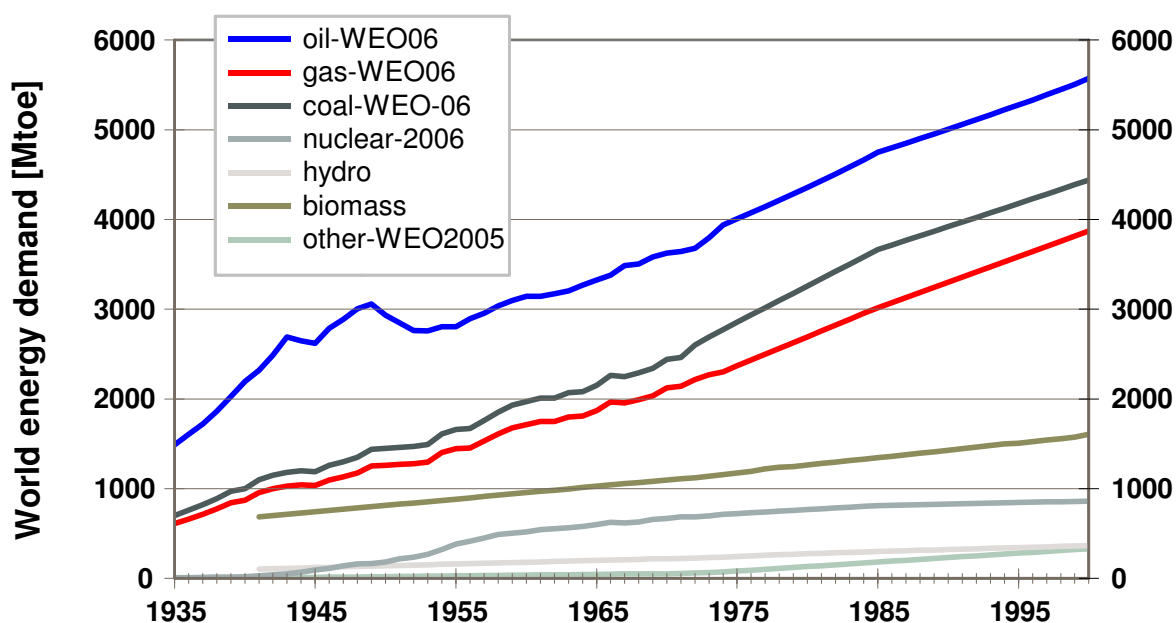
Also in Germany, the Bundesanstalt für Geowissenschaften und Rohstoffe (i.e. the German federal agency for earth sciences and raw materials) has dealt critically with the scenarios of the IEA and comes to the conclusion [BGR 2002]: “The forecasts of EIA and IEA assume a continuous growth in oil consumption, without assessing sufficiently the real supply of oil and the production potential.”

Comment on the "World Energy Outlook 2005"

Breaking the usual biannual rhythm, the IEA in October 2005 published the report “World Energy Outlook 2005” [WEO 2005], covering the period until 2030. The reason for this unexpected publication probably was the unprecedented rise of oil prices during the preceding year causing growing public concern.

In its „reference scenario“ the IEA report describes the most probable development of energy markets until 2030. In addition, two alternative scenarios are considered, a “low investment scenario” (if investment in upstream activities is much lower than expected) and an “alternative scenario” (if policy measures are introduced to cut energy demand). For details see the following Figure.

Figure 46: Development of oil, gas and coal demand and the use of wind, solar and geothermal energy (=other) in accordance to the reference scenario of the “World Energy Outlook 2005”



These scenarios include also renewable energy. Solar, wind and geothermal energy will increase their contribution in the reference case until 2030 and will reach a share of 2% of primary energy supply. The “alternative scenario” will increase this contribution by 30% above the reference case and reaches a share of 2.6% for the renewable energies.

In face of the expected growing demand for oil and gas until 2030 the IEA raises the question where the necessary additional upstream capacity could come from. The IEA sees the potential for a considerable increase of oil production capacity in the Middle East and in North Africa. According to the IEA, these countries still hold large reserves which are sufficient to match the expected future demand. But there is a caveat: the known reserves are sufficient only by their absolute size, in order to sustain growth huge additional reserves must be added in the coming years -otherwise world oil production will peak before 2030. Translated into plain language that is to say that, contrary to the initial statement, known reserves in these countries are not a sufficient basis for the projected production increases. Nevertheless, the impression is given that the projected capacity increases are feasible. The alternative scenario discusses the option of reducing the demand growth by political measures. This is seen by the IEA as being possible and desirable, however the effect on the demand is minimal leading only to a reduction of less than 10%.

According to the IEA, energy consumption in the oil and gas producing countries in the Middle East and North Africa will rise as a consequence of the growing population. However, this additional demand pressure is expected to be an incentive to extend production capacities.

This then will also lead to an increase of the net export capacity of these countries - a conclusion which probably will not be shared by many.

A necessary precondition for expanding the production in these countries are increased investments in exploration and production. According to the report, a doubling of present budgets is necessary.

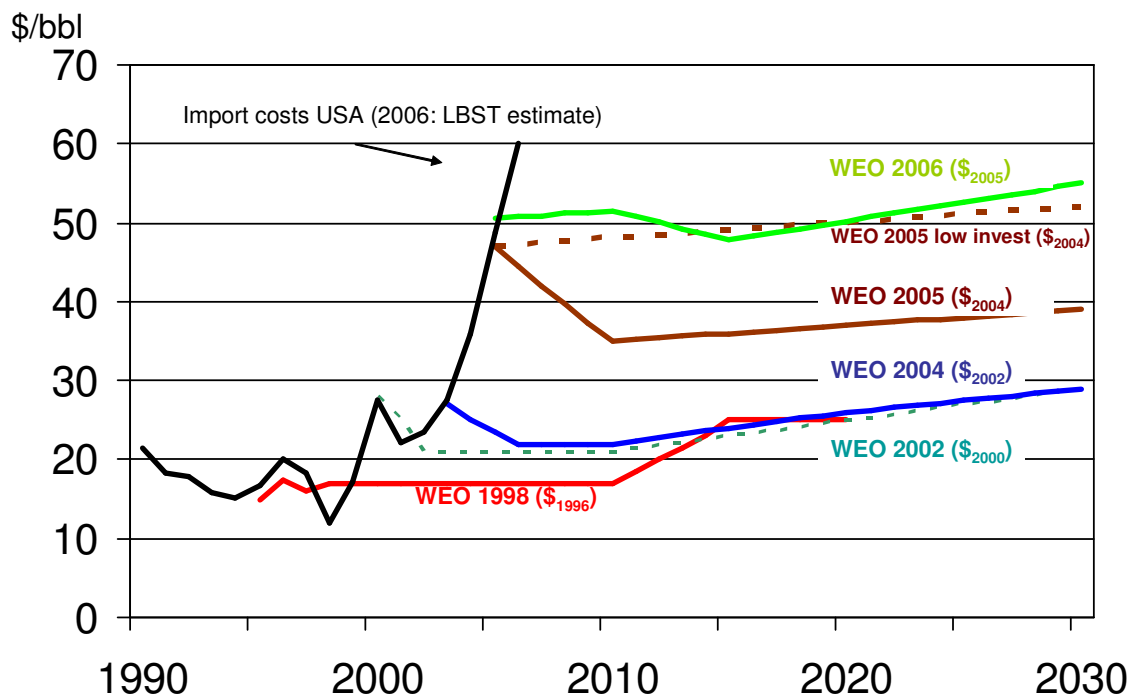
After describing the conditions for supply extensions, the IEA addresses possible problems. It could turn out that the countries in question are either not able or not willing to increase their investments. In this case it would be necessary to open these countries for foreign investments.

A second problem mentioned by the IEA is that all scenario calculations and conclusions are based on data which are completely unreliable: “Uncertainties about just how big reserves are and the true costs of developing them are casting shadows over the oil market outlook and heightening fears of higher costs and prices in future.”

Rather unexpectedly at this point, the IEA casts doubts on the feasibility of growing oil supplies in future. However, instead of addressing the problem of lacking or uncertain reserves, the IEA concentrates on the problem of insufficient investments.

The IEA puts much effort into arguing that production extensions effected by huge investments are in the interest of the oil producing countries in the Middle East and North Africa. It is argued that higher investments will result in higher overall income for these countries. This result is achieved by assuming different oil prices for the alternative cases of big and small capacity extensions (see Figure 47). The assumed price levels leading to this result are far below present oil market prices and are completely arbitrary. Obviously, the IEA intends to convince the OPEC that huge investments in oil exploration and production are in their best own interest.

Figure 47: Forecast of oil import prices according to various editions of the World Energy Outlook (stated in real prices for the quoted base years)



It remains to be seen whether these arguments will convince the OPEC countries. One should be sceptical, however, in view of the experiences the OPEC countries made in the last years in which they saw prices rise far beyond the “automatic price band” of \$22-\$28, a development which did not lead to a shrinking of oil demand and had no dramatic effects on the world economy, contrary to the predictions of western sources. By the way, presently nobody seems to be able to increase supplies to control crude oil prices.

The key messages of the World Energy Outlook 2005 are:

- The oil reserves of the world are sufficient to supply a considerable demand growth until 2030. Only the necessary investments for the increases of exploration and production must be ensured. If this can be achieved there will be no “peak oil” problem before 2030.
- The main difference to the preceding reports is the expectation of a considerable increase in oil import prices until 2030. From the chosen wording it can be concluded that the IEA regards not the “reference scenario” as the most probable, but the “low investment” scenario which projects an increase of oil import prices up to \$52/barrel by 2030.
- Renewable energies will not reach a significant market share within the next 25 years.

The negligible role attributed to renewable energies by the IEA even in the long term is an obvious attempt to influence the energy policy of governments, a position which meets strong criticism especially in Europe. Why does the IEA not investigate what effect an investment

level as proposed for the oil industry would have when applied to renewable energies? The answer points to the interests to which the IEA seems to be obliged.

Fundamental and - according to our opinion - much more important questions are not addressed by the [WEO 2005], especially:

- Are oil production extensions in the Middle East countries and North Africa really possible even when the investment is doubled? This is rather doubtful with regard to the size structure, the age, and the depletion status of the producing fields.
- Is it really in the long term interest of oil producing and consuming countries still to increase the production? This would result in a higher maximum production which will necessarily be followed by a steeper decline. Because the ultimate recoverable amount is a fixed quantity only the production profile over time can be influenced. The inevitable transition from oil to renewable energies will not be made easier and the energy problems will be exacerbated.

Final remark

The projections presented by USGS, EIA and IEA regarding the future availability of oil give reason to grave concerns because the comforting messages of these studies unfortunately are not based on valid arguments.

These studies ignore future limitations in the supply of oil which are meanwhile apparent, and by doing this they send misleading political signals.

It should also be noted how these studies build on each other. The supporting ground floor has been built by the USGS 2000 study: it describes, how much oil the world has at its disposal - it just needs to be found. On this the EIA has built a first floor which describes the future production potential. The result is that in fact any conceivable future growth of production will be possible - with growth rates exceeding everything that could be observed in the past. On top of this, the IEA constructs a second floor: the predicted growth in oil demand for the next decades will not be restricted by any limits of supply. This is a house of cards.

Annex 3: Non-conventional oil

Canadian tar sands and oil shales – hope or nightmare

It is the hope of many people, that non-conventional oil might substitute conventional oil. To the degree that conventional oil is getting scarce and more expensive, the production of non-conventional oil should be extended to assure a smooth substitution in the supply of high-quality oil for fuel, chemistry and heating purposes.

Indeed, many economists adhere to this point of view and so does the oil industry. For many observers the increase of the oil reserves in 2002 is evidence of this development. At that time the world oil reserves were upgraded by about 16% by ExxonMobil in their statistics publication. The comparative production costs of non-conventional tar sands, it was said, meanwhile justify the transfer of these resources, well known since decades, into the category of “proven reserves”. This inclusion of the Canadian tar sands into the oil reserves was followed in Germany by the Minerölwirtschaftsverband, the association of the German oil industry. A few years later, in 2007, also the BP Statistical Review of World Energy followed suit.

How realistic is this approach? There are indeed huge resources of non-conventional oil. Especially tar sands in Canada, heavy oil in Venezuela and oil shales in many other places in the world.

Oil shales will not be discussed here in detail (for a more comprehensive discussion see e.g. Blending in www.energiekrise.de/forum). Just two aspects should be mentioned:

- In California, oil shales are exploited since more than 100 years. In Germany, oil shales were produced at the Schwäbische Alb during World War II for military purposes. Then, production was conducted under inhuman conditions employing forced labour – but oil was hardly extracted.
- A supposedly promising project for the production of oil shales was started in Australia a few years ago by the Canadian Oil Company Syncrude which produces oil from tar sands. Meanwhile Syncrude has retreated from the Australian project (and has – instead? – invested in the construction of wind parks in Canada).

More realistic is the upscaling of the oil production from tar sands in Canada. About 40 Gb of bitumen from tar sands are regarded as recoverable (at present costs and using known technologies). Tar sands in Canada are produced at increasing rates since about 40 years. About two thirds of the produced bitumen are processed into so called synthetic crude oil.

Tar sand formations originate from organic sediment layers which were not transformed into liquid oil in the geological past, as these formations were not isolated enough and also were

not sufficiently heated at great depth. In geological and chemical terms tar sands constitute a precursor to crude oil. The organic substances were preserved in the form of bitumen admixed with lots of sand.

The most extensive bitumen reservoir is located in Athabaska. A thick layer, measuring up to several ten meters and extending over about 77,000 square kilometres, contains 20 percent bitumen at best.

The bitumen is produced in conventional open pit mines. First, the covering upper layer containing no bitumen has to be removed. In some areas close to the Athabaska river this cover layer is just 10 – 20 meters thick. These easily accessible areas have been tapped first by the companies Suncor and Syncrude in the late 1960s.

But in most cases the cover layer is considerably thicker where open pit mining would be far too expensive. Therefore, those bitumen deposits have to be produced with so called “in-situ” processes. This is achieved by heating the mixture of bitumen and sand in the deposit up to a temperature where the bitumen gets liquid. Then the liquid bitumen can be pumped to the surface. Today, about 10,000 barrels of bitumen per day are produced with “in-situ” processes in pilot plants. (for more details on on-situ production processes see [Busby 2004]. In-situ production is expected to have a maximum share of about 10 percent of total bitumen production from tar sands even by 2015. The following analyses up to the year 2015 are therefore limited to open pit mining.

After the cover layer is removed, the tar sand is extracted with shovel excavators and transported by huge trucks to conveyor belts.

By adding great amounts of water the tar sand is transformed into a liquid mixture before it is transported with conveyor belts to subsequent conditioning stages. In the liquid mixture the sand settles at the bottom whereas the lighter bitumen accumulates at the surface and is separated for further cleaning and conditioning. Canadian tar sands contain on average about 2-3 percent sulphur. Today, in the separation process 2,000 to 3,000 tons of sulphur are produced daily and are in part converted to plaster. A third of the cleaned bitumen is transported to the USA for further processing. Two thirds are further processed in so called “upgraders” close to the mining sites. There the hydrocarbon molecules of the bitumen are split up and with hydrogen from natural gas are processed into synthetic crude oil.

The described processes are complex, expensive and damage the environment. A report by the Canadian National Energy Board from May 2004 states the following facts:

- For each cubic meter of bitumen produced about 2 to 4 cubic meters of fresh water are required even though some purification and recycling of the water is already done. (Note: Today nearly ¼ of the entire fresh water of the Alberta province is used for the extraction of oil-sands.)

- Today, about 4 percent of the West Canadian gas production is used for the extraction and further processing of bitumen to synthetic crude oil. (Note: The use of natural gas for the oil production from tar sands competes with the direct marketing of natural gas. The natural gas used by the tar sands industry often is derived from wells at or close to bitumen containing layers. The Canadian Energy Board decided that some natural gas fields may not be tapped because otherwise the pressure of the gas deposit would get too low and would endanger future in-situ extraction of the bitumen deposits in the area of the natural gas fields. This is a first visible consequence of the competing natural gas uses.)
- The emissions resulting from the mining of bitumen and processing it to synthetic crude oil are indicated to be per cubic meter of synthetic crude oil 741 kg of CO₂ and 50 kg of CO₂-equivalent of which 42 kg are caused by methane emissions and 8 kg by N₂O emissions. (Note: Related to the energy content, emissions per kWh of synthetic crude oil amount to about 82 g of CO₂. At least another 30 g of CO₂ per kWh have to be added for the processing of the synthetic crude oil into fuel. The combustion of the fuel in a vehicle results in emissions of about 270 g CO₂ per kWh leading to total emissions for fuel production and use of about 380 g CO₂ per kWh. This is as much as the combustion of coal releases and nearly twice as much as is released by the extraction, transport and combustion of natural gas.)

About 1.2 Mb/day of bitumen were produced in Canada in 2006. About 60 percent of this amount will be processed to synthetic crude oil and the remaining bitumen is mainly sold to refineries in the USA. Extending the tar sand production capacities needs big investments and is time-consuming. In the latest oil sands report of the National Energy Board, Canada, it is assumed that the production rate probably will be raised to 3 Mb/day by 2015 with an uncertainty range of between 1.9 Mb/day to 4.4 Mb/day [NEB 2006]. This evaluation is based on the analysis of existing, already started, approved and disclosed projects. The latest update of these projects is summarized in Table 10 according to [Dunbar 2007]. The capacity of the expected new projects until 2015 adds up to 2 Mb/day and would equal about 2 percent of the world oil production. However, the real production might be 10-20 percent below the capacity extensions.

The development of tar sands follows the same pattern as the production of conventional oil - the easy prospects are developed first, but the production rate remains almost constant for several decades.

Table 10: Expected Capacity extensions until 2015 if all projects under construction, approved, disclosed, filed an application or announced will start their operation in time [Dunbar 2007]

Status	Bitumen Upgrading [kb/d]		Mining [kb/d]	In-Situ [kb/d]	Total [kb/d]
	Input	Output			
Operation	885	768	863	520	1,383
Construction	467	407	158	90	248
Approved					
<=2015	550	459	840	409	1,249
>2015				180	180
Disclosed					
<=2015	573	509	220	345	565
>2015	382	376	200	80	280
Application					
<=2015	492	432	164	260	424
>2015	50	45	50	0	50
Announced					
<=2015	628	533	331	825	1,156
>2015	445	377	262	334	596
Total under operation, construction, approved or disclosed until 2015		2,143	2,081	1,364	3,445
Total until 2015 (incl. application, announced)		3,108	2,576	2,449	5,025

Despite the increasing tar-sand production, total Canadian oil production will just rise by about 10-20 percent until 2015 due to the declining production of conventional oil.

Summary of the production assessment for Canadian tar-sands:

- Until 2015, the Canadian tar sand extraction will probably increase by about 1.9 Mb/day up to 3 Mb/day. This will increase total Canadian oil production only by about 10-20 percent.
- Therefore, CO₂ emissions will rise significantly and amount up to 100 million tons/year in 2015.
- About 10 percent of today's natural gas production in Western Canada will be used for the extraction and the processing of the tar sands. As natural gas production in Western Canada has already peaked, the share of natural gas production will presumably be about 20 – 30 percent in 2015. Due to increasing gas prices the tar sand production will rise.
- By 2015 the consumption of fresh water will be about 300 – 500 million m³ per year. This is equivalent to a river with a flowing speed of two meters per second, with a cross section of 10 – 15 m² (at two meters water depth and 5 – 7.5 m width) just for the tar sand production.

- Because of the demonstrated limitations it is not likely that unconventional oil sources in Canada will compensate for the future decline in worldwide conventional oil production. It is much more probable that the further expansion of the production capacities will encounter similar difficulties as observed in the conventional oil production.

The automobile industry might perceive higher greenhouse gas emissions of fuels from non-conventional oil sources as a nightmare.

Annex 4: International oil companies

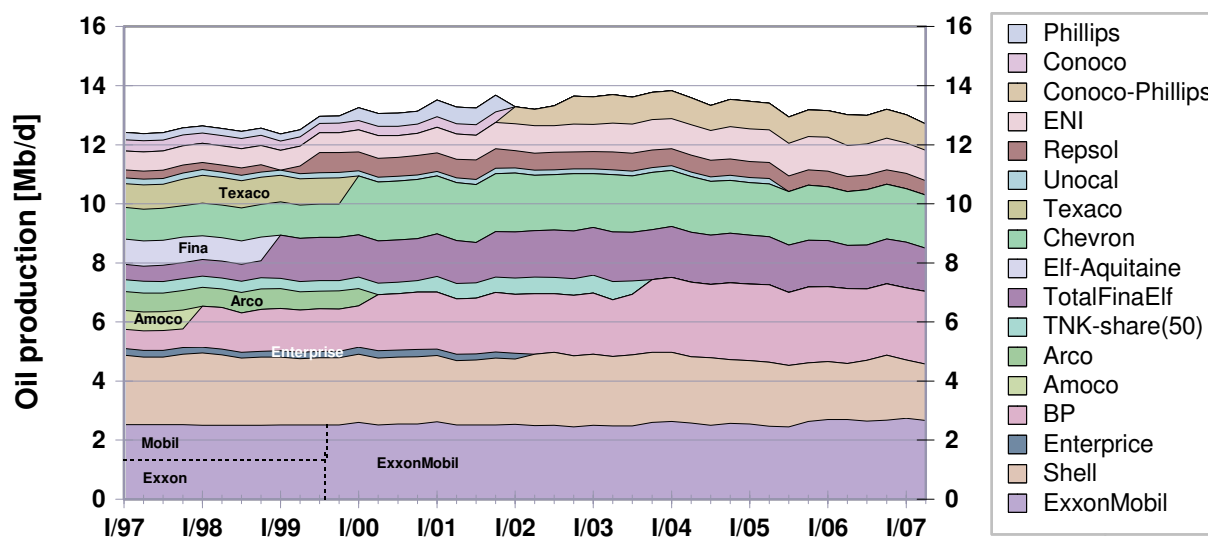
In this annex the production performance and the financial behaviour of major international oil companies in recent years is analysed.

Looking at the operation of major international oil companies over the period of the last 10 years, two developments are striking:

- the wave of mergers, and
- the inability of these companies to substantially raise their aggregate production.

This can be seen in Figure 48.

Figure 48: Oil production of the oil majors from 1997 to 2007



The mergers were necessary to compensate for declining production in individual companies.

Rising expenditures, especially for production, just led to a not very marked peak in 2004 of aggregate production, but production has declined since then. The repeated announcements of the super majors since 2000 to increase their production significantly never did materialise.

Recently, the “lacking access“ to more promising oil regions has been blamed by the international oil companies for their disappointing performance regarding production volumes.

It seems that the fact that most of the oil has already been found is also accepted by most oil companies. This can be inferred by analysing their annual budgets for exploration and production which are listed for ExxonMobil, BP, Shell and Eni in the following Table 11. Over the last seven years the exploration expenses were reduced by between 30 to 50%. But the expenses for maintaining the production, in most cases increased considerably. Expenses for production also include the acquisition cost for acquiring other companies with their

production capacities. Therefore, this analysis leads to the conclusion that companies prefer to expand their production by mergers and acquisitions instead of by exploring new fields.

Table 11: Company expenses for exploration and production as well as annual production for large western oil companies as published in their annual reports [source: quarterly company reports]

	1998	1999	2000	2001	2002	2003	2004	2005
ExxonMobil								
Expenses for exploration [bn\$]	2.2	1.9	1.5	1.7	1.3	1.017	1.119	0.969
Expenses for production [bn\$]	13.3	11.4	9.7	10.6	12.7	10.971	10.596	13.501
Production [Mboe/day]	4.272	4.235	4.277	4.255	4.238	4.203	4.215	4.066
BP								
Expenses for exploration [bn\$]	0.921	0.548	0.599	0.48	0.644	0.542	0.637	0.684
Expenses for production [bn\$]	5.302	3.646	5.784	8.381	9.055	14.828	10.556	9.553
Production [Mboe/day]	3.05	3.107	3.24	3.419	3.519	3.606	3.997	4.014
Shell								
Expenses for exploration [bn\$]	1.595	1.062	0.753	0.857	0.915	1.059	1.123	0.815
Expenses for production [bn\$]	4.879	3.075	3.048	6.018	12.231	7.070	7.264	10.043
Production [Mboe/day]	3.709	3.634	3.69	3,773	3.997	3.905	3.772	3.518
Eni								
Expenses for exploration [bn\$]	0.755	0.636	0.811	0.757	0.902	0.712	0.543	0.656
Expenses for production [bn\$]	2.127	2.632	2.728	3.519	4.713	4.969	4.378	4.308
Production [Mboe/day]	1.038	1.064	1.187	1.369	0.921	0.981	1.624	1.737

This is also shown in Figure 49 for the three largest private western oil companies ExxonMobil, BP and Shell.

This is even better illustrated by the example of Shell which ten years ago was the largest private western oil company (see Figure 50). Production has declined since 1998 by 20% despite the fact that the expenses for E&P have quadrupled, that a medium size company (Enterprise) was added to the production base and that first production from Canadian tar sands started in 2003.

Figure 49: Exploration and production expenditures of super major and buy back of shares

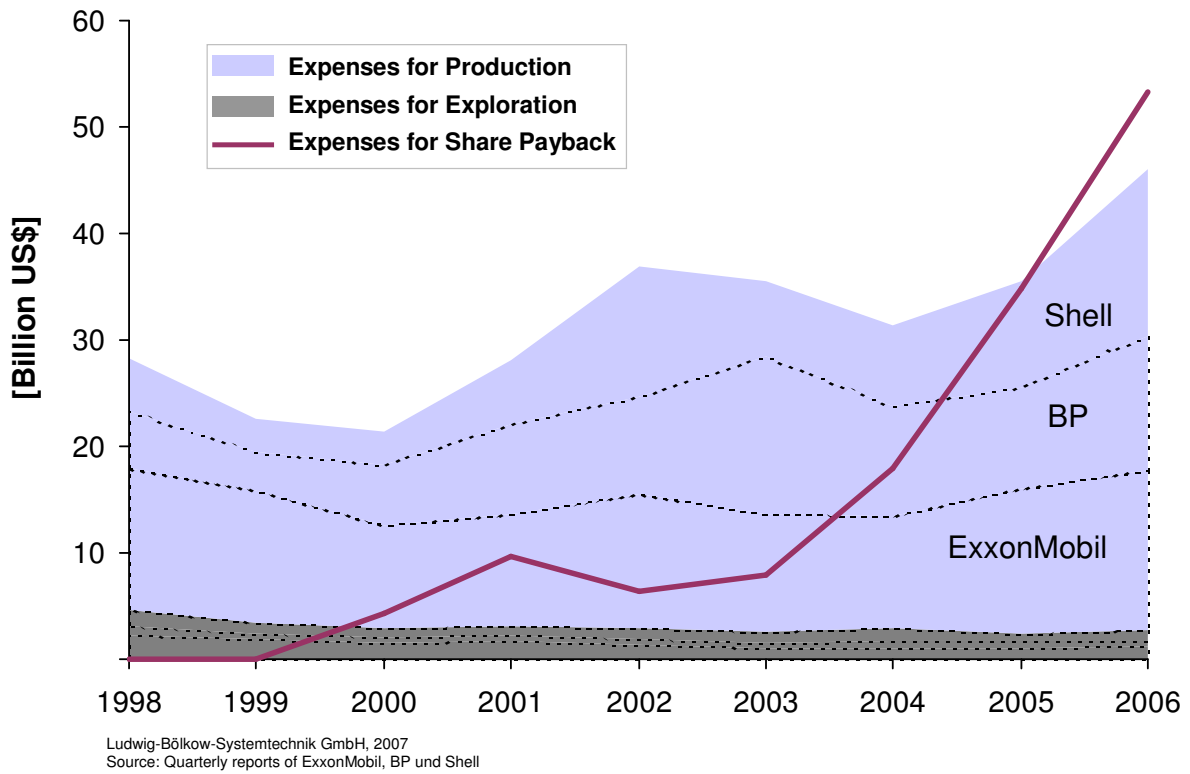
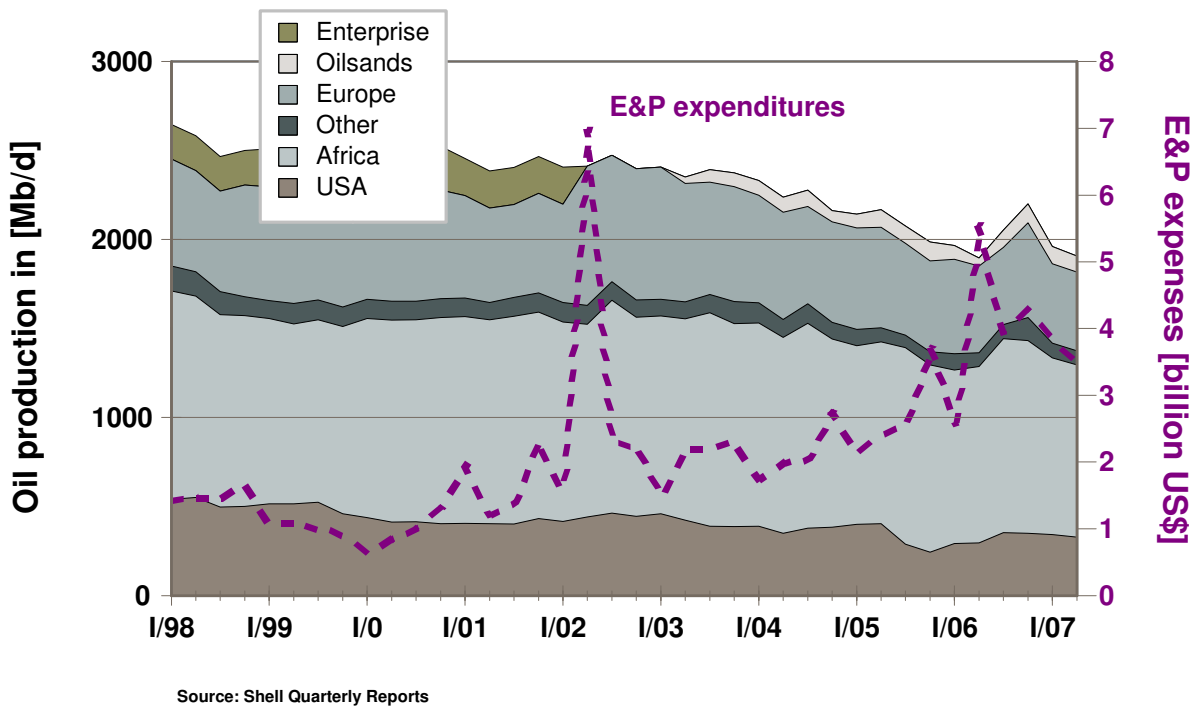


Figure 50: Shell – oil production and exploration and production (E&P) expenditures



LITERATURE

- [Bakhtiari 2004] Samsam Bakhtiari „World oil production capacity model suggest output peak by 2006-07“, Oil & Gas Journal. April 26th, 2004
- [BGR 2002] Reserven, Ressourcen und Verfügbarkeit von Energierohstoffen 2002, Bundesanstalt für Geowissenschaften und Rohstoffe, Hannover 2003, p. 104.
- [BP 2004] BP Statistical Review of World Energy 2004, (www.bp.com)
- [BP 2006] BP Statistical Review of World Energy
- [Busby 2004] John Busby, “Canadian Tarsands”, ASPO Newsletter No 37, December 2004
- [Campbell 1998] C.Campbell, J. Laherrere, The imminent Peak of World Oil Supply, Scientific American March 1998
- [CERA 2006] CERA (Cambridge Energy Research Associates), “Why the ‘Peak Oil’ Theory Falls Down – Myths, Legends, and the Future of Oil Resources”, Cambridge Mass., November 2006
- [De Lucia 1999] Marshall De Lucia, Offshore, April 1999, p. 40-42
- [Dunbar 2007] R.B. Dunbar, “Existing and Proposed Canadian Commerical Oil Sand Projects”, Strategy West Inc. June 2007, www.strategywest.com
- [EIA 2000] US-EIA Presentation : Long Term World Oil Supply, (http://www.eia.doe.gov/pub/oil_gas/petroleum/presentations/2000/long_term_supply/index.htm)
- [EIA 2004] US Annual Energy Outlook 2004, Energy Information Administration, (<http://www.eia.doe.gov/oiaf/aeo/index.html>)
- [IHS 2006] Petroleum Exploration and Production Statistics (PEPS), IHS Energy, Geneva and London 2006
- [Masters 1990] C.D. Masters, D.H. Root, E.D. Attanasi, World Oil and Gas Resources – Future Production Realities, US Geological Survey, in Ann. Rev. Energy 1990, vol. 15, p. 23-51
- [NEB 2006] Canada's Oil Sands, Opportunities and Challenges to 2015: An Update, An Energy Market Assessment, June 2006, National Energy Board, Canada, (www.neb.ca)
- [Petroconsultants 1995] C.J. Campbell, J.H. Laherrere, “The World’s Oil Supply 1930-2050”, Petroconsultants (ed.) Geneva 1995

- [Robelius 2007] Fredrik Robelius, “Giant Oilfields – The Highway to Oil], Uppsala, 2007
- [Simmons 2004] M. R. Outlook 1998”, Paris, 1998
- [WEO 2000] International Energy Agency, “World Energy Outlook 2000”, Paris, 2000
- [WEO 2002] International Energy Agency, “World Energy Outlook 2002”, Paris, 2002
- [WEO 2004] International Energy Agency, “World Energy Outlook 2004”, Paris, 2004
- [WEO 2005] International Energy Agency, “World Energy Simmons, “The Saudi Arabian Oil Miracle”, presentation at the Center for Strategic and International Studies (CSIS), Washington, 24 February, 2004
- [Simmons 2005] M. R. Simmons, “Twilight In The Desert – The Coming Saudi Oil Shock And The World Economy”, John Wiley & Sons, 2005
- [Skrebowski 2006] Chris Skrebowski, “Open letter to Peter Jackson of CERA”, Oil Depletion Analysis Center (ODAC), 21 Dec 2006
- [Söderberg 2007] A Crash Program Scenario for the Canadian Oil Sands Industry, B. Söderberg, F. Robelius, K. Aleklett, Energy Policy, volume 35, issue 3, march 2007, pp 1931-1947
- [Staniford 2007] Stuart Staniford, “A Nosedive towards the Desert”, [www.theoil Drum.com/ node/2331](http://www.theoil Drum.com/node/2331)
- [USGS 1996] D.L. Gautier, G.L. Dolton, K.I. Takahashi, K.L. Varnes, eds. 1996, „National assessment of United States oil and gas resources---Results, methodology , and supporting data: U.S. Geological Survey Digital Data Series DDS-30, Release 2
- [USGS 2000a] USGS World Petroleum Assessment 2000; (www.usgs.gov)
- [USGS 2000b] „USGS Reassesses the Potential World Petroleum Resources: Oil estimates up, gas down“, USGS press release and US-DoE from March 22nd, 2000
- [WEO 1998] International Energy Agency, “World Energy Outlook 2005”, Paris, 2005
- [WEO 2006] International Energy Agency, “World Energy Outlook 2006”, Paris, 2006