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UKERC Review of Evidence for Global Oil Depletion

Technical Report 7: Comparison of global oil supply forecasts

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This document has been prepared to enable results of on-going work to be made available rapidly. It has not been subject to review and approval, and does not have the authority of a full Research Report.

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Responsibility for the contents of this report, and for the errors that undoubtedly remain, lies with the authors. Corrections and comments are welcome.

Preface

This report has been produced by the UK Energy Research Centre's Technology and Policy Assessment (TPA) function.

The TPA was set up to address key controversies in the energy field through comprehensive assessments of the current state of knowledge. It aims to provide authoritative reports that set high standards for rigour and transparency, while explaining results in a way that is useful to policymakers.

This report forms part of the TPA's assessment of evidence for **near-term physical constraints on global oil supply**. The subject of this assessment was chosen after consultation with energy sector stakeholders and upon the recommendation of the TPA Advisory Group, which is comprised of independent experts from government, academia and the private sector. The assessment addresses the following question:

What evidence is there to support the proposition that the global supply of 'conventional oil' will be constrained by physical depletion before 2030?

The results of the project are summarised in a *Main Report*, supported by the following *Technical Reports*:

1. Data sources and issues
2. Definition and interpretation of reserve estimates
3. Nature and importance of reserves growth
4. Decline rates and depletion rates
5. Methods for estimating ultimately recoverable resources
6. Methods for forecasting future oil supply
7. Comparison of global supply forecasts

The assessment was led by the Sussex Energy Group (SEG) at the University of Sussex, with contributions from the Centre for Energy Policy and Technology at Imperial College, the Energy and Resources Group at the University of California (Berkeley) and a number of independent consultants. The assessment was overseen by a panel of experts and is very wide ranging, reviewing more than 500 studies and reports from around the world.

Technical Report 7: Comparison of global oil supply forecasts compares and evaluates fourteen contemporary forecasts of global oil supply, as well as summarizing the lessons learnt from earlier forecasts. It identifies the methodologies and assumptions that are used, assesses the strengths and weaknesses of the associated models and draws attention to the difference between forecasts that see global conventional oil reaching a resource-limited production peak before the year 2030 and those that forecast no such peak. In particular, it highlights the importance of the explicit or implicit assumptions regarding the URR of conventional oil and the aggregate post-peak production decline rate and draws some conclusions on the risk of a near-term peak global production. A full summary of the reviewed forecasts is contained in a separate Annex.

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Executive Summary

This report provides a detailed comparison and evaluation of fourteen contemporary forecasts of global oil supply. The forecasts are based upon mathematical models of various levels of complexity, embodying a wide range of modelling approaches and assumptions. In addition, the views of two oil companies on the likely adequacy of future oil supply are also summarised.

Following an introduction, Section 2 defines the key terms used, and discusses briefly the types of data available in this area, the issue of data reliability, and some of the common misconceptions that surround this topic.

Section 3 looks at a number of historical forecasts of global oil production in order to set out the broader picture of how much was known in the past about future oil supply. The main conclusion is that most of the early 'peaking' forecasts did not take into account the demand responses to the oil price shocks of the 1970s. Had these been factored in, these models mostly would have predicted the peak for the global production of conventional oil as occurring around 2005 - 2010. The importance of these early peaking forecasts has been largely overlooked until recently.

Section 4 is the heart of the report. Here the contemporary forecasts are summarised and compared, and the strengths and weaknesses of the associated models and assumptions outlined.

Nine of the forecasts predict that a maximum will be reached in the global production of oil before 2030. This maximum is '*resource-limited'* in the sense that it is set primarily, not by the *volume* of known and anticipated resources but by the physical limits on the *rate* that oil can be extracted. Such forecasts are termed 'peaking forecasts'. Five other forecasts do not see a peak in global oil production before 2030, although two foresee reaching a plateau and hold therefore that global production can rise in line with demand up to that date. Because the forecast demand increases are fairly steady, these forecasts are termed 'quasi-linear'. The two views also hold that there is no foreseeable peak.

The most important difference between the peaking and the quasi-linear forecasts lies in how much production they anticipate from conventional oil fields over the period to 2030. Conventional oil is the primary focus of this study, although the assumptions and forecasts for other liquids are also examined.

A second important difference between these two classes of forecast is the types of non-conventional oil and substitute liquids that they include. Liquid fuels can be derived from a variety of sources, including: oil sands, very heavy oils (such as from the Orinoco basin in Venezuela), oil processed from 'oil shale', liquefied gases produced during the production of natural gas (NGLs), liquids produced by the conversion of gas or coal (GTLs and CTLs), and biofuels. Naturally, models which include these other sources of liquids, or which take a more optimistic view on their rate of production, are less likely to see a peak in total liquids production than those that exclude them, or estimate lower production rates over the medium term. Where possible, we have clarified which types of liquids each forecast includes.

The difference between the forecasts in terms of the production of conventional oil arises from several reasons. In part this is because the quasi-linear forecasts typically assume a higher value for the total amount of conventional oil that can be recovered (termed the ‘ultimately recoverable resource’, URR) than do the peaking forecasts. But the quasi-linear forecasts also tend to assume, sometimes explicitly but more often implicitly, that when the decline in the global production of conventional oil does occur, this will be at a higher rate than that assumed by most peaking forecasts. This is an important idea, and is illustrated graphically. In addition, some of the quasi-linear forecasts make what appear to be optimistic assumptions about the rate that the assumed URR of conventional oil can be accessed, and this is also discussed.

Section 5 summarises our conclusions. The main ones are:

- On the current evidence, a peak in the global production of conventional oil before 2030 appears very likely and a peak before 2020 appears probable.

- A peak before 2030 is likely also for global “all-oil” production (covering conventional oil, NGLs, heavy oils, and oil from tar sands).

- Less well understood is the rate that alternative liquid fuels might be brought on-stream, where these include oil from shale, GTLs, CTLs, and biofuels. More research is required in this area.

Overall, despite notable improvements in the last few years, both in the general understanding of the topic, and in detailed modeling (especially of decline rates), there remain many disagreements and misconceptions. We hope that this report may help dispel some of these and shed light on the reasons for others. We judge that more modeling effort and discussion is needed by all involved.

The Annex sets out the details of the forecasts, models and views examined in this report. For the quantitative forecasts, these descriptions follow a common format. We have aimed to have the descriptions seen and approved by the creators of the models in question. This has been possible for thirteen of the fourteen models, but for neither of the two views.

1. Introduction

There is a clear dichotomy in forecasts of the world's oil supply. This dichotomy has existed for several decades, growing more obvious, until now there is a gulf between those who believe that there are no insurmountable oil supply difficulties before 2030, and those who believe that the world is near, at, or has even passed, the peak of oil supply.

This report seeks to shed light on this dichotomy by conducting a detailed comparison of fourteen current forecasts and two 'views' of the future of global oil supply. This survey forms part of a broader assessment of the evidence for global oil depletion, carried out by the Technology and Policy Assessment (TPA) function of the UK Energy Research Centre.

The specific objectives of this report are to:

- Identify the most prominent forecasts of global oil supply that have been produced by different individuals and groups over the last five years.
- Summarise and compare the methodological approaches used by these studies, and highlight both their similarities and differences, and any particular strengths and weaknesses.
- Summarise and compare the major results of each study, including the future shape of the global production cycle and the apparent sensitivity of the results to key assumptions.
- Highlight factors contributing to the differing results and, where possible, assess their relative importance.
- Summarise and compare the key assumptions used by each of the 'bottom-up' studies, including factors such as the coverage of different hydrocarbons, the ultimately recoverable resources (URR) in different countries and regions, the rates at which new resources will be discovered and developed and the decline rates for different regions and types of field.
- Establish, as far as possible, the relative importance of these assumptions for the results obtained by these studies.
- Draw broad conclusions on the risk of a near-term peak in global oil supply.
- Identify priorities for further research in this area.

To conduct such a comparison, it is necessary to be clear about the meaning of different terms. Hence Section 2 of the report begins by defining key terms used, and discussing the types of data available in this area. It also discusses the reliability of these data and some of the common misconceptions that surround this topic.

Section 3 examines a number of past forecasts of global oil production in order to set out the broader picture of how much was known in the past about future oil supply. The main conclusion is that most of the early 'peaking' forecasts did not take into account the demand responses to the oil price shocks of the 1970s. Had this been factored in, these models mostly would have predicted the peak for the global production of conventional oil as occurring around 2005 - 2010. The importance of these early peaking forecasts has been largely overlooked.

In Section 4, the fourteen contemporary forecasts are summarised and compared, and their strengths and weaknesses outlined. Attention is drawn to the difference between the nine forecasts that see global conventional oil reaching a resource-limited production peak before the year 2030 and the five forecasts that predict no such peak. To help understand this difference, an approach is introduced to contrast explicitly the key assumptions of the forecasts, where these are sometimes implicit. This approach places each forecast in a parameter space defined by the assumed or implied ultimately recoverable resource (URR) for conventional oil, and by the assumed or implied post-peak production decline rate. In such a space, a judgement can be made as to the likelihood of the values chosen or required for each forecast.

This section also discusses whether some of the 'quasi-linear' forecasts make excessively optimistic assumptions about the rate at which the assumed URR of conventional oil can be accessed.

Section 5 summarises the conclusions. The most important ones are that:

a) Despite wide differences in methodology, there is some evidence of a convergence in supply forecasts.

b) The differences can be linked primarily to the assumed or implied values for the global URR for conventional oil and/or the aggregate rate of decline in production following the peak. All other differences are either comparatively minor or are components of these two parameters.

c) In our view, the balance of current evidence suggests that a peak in conventional oil supply before 2030 is very likely and peak before 2020 is probable.

A detailed summary of each of the forecasts and models reviewed is contained in the Annex.

1 Definitions, data sources and limitations

1.1 Definitions

In discussing the peak of global oil production, there is often considerable confusion about the meaning of different terms. This is frequently because there is no standard definition of these terms which means they may be given different interpretations by different authors. In the case of reserves, for example, the lack of clarity in distinguishing between 'proved reserves' and 'proved plus probable' reserves has driven much of the disagreement over this topic (Bentley, *et al.*, 2007). To a lesser extent, uncertainty about what is included in 'oil', and in particularly 'conventional oil', has also contributed to the different views on peaking. For this reason, the definitions used in this report are summarised and clarified below.

Note that some special usages are introduced in this report in an attempt to add clarity to the analyses. These are highlighted at the end of this section.

API gravity: The API is the American Petroleum Institute. API gravity, measured in degrees, is the oil-industry measure of *crude oil* specific gravity. By definition, API gravity = (141.5/specific gravity at 60°F) – 131.5. The API gravity rises as the specific gravity falls. Definitions vary, but light oil is often taken as > 31° API, medium oil as 22.5-31° API, heavy oil as 10-22.5° API, and extra-heavy oil as <10° API. Heavy oils are typically extremely viscous, and may not flow under normal conditions.

Barrel: The usual measure of oil, = 42 US gallons = 158.76 litres. One cubic metre = about 6.3 barrels (b). The weight of a barrel of oil depends upon the *API gravity* of the oil. One tonne of medium gravity oil is about 7.3 barrels but heavy oil can be 6.0 barrels per tonne and light oil as much as 8.0. The abbreviation used here is b, but bbl is very commonly used. The associated abbreviations used in this report are:

b/d:	barrels per day
kb	thousand barrels
mb	million barrels
Gb	billion barrels

Basin: A depression in the earth's crust, subsequently filled by a mass of sedimentary or volcanic rock. The subsidence and burial within a basin of sediments containing organic matter results in the generation of *petroleum*.

Biofuel: Synthetic fuels made from biomass (the term strictly includes gaseous as well as liquid fuels, but is used here only for liquids). The commonest liquids are ethanol, produced by fermentation of sugar or starch, and plant oils, extracted from various seeds, nuts or algae. *Cellulosic ethanol* is produced using cellulose as a feedstock.

Boe: The barrel of oil equivalent (boe) is a unit of energy measure corresponding to the standardised gross heat content of a barrel of oil (6.1178×10^9 J or ~1700kWh). This is commonly used to combine oil and gas data into a single measure. However, heat content may either be measured on a gross or net basis, with the 7-9% difference between the two corresponding to the heat that could be released by condensing the water generated during combustion. Unfortunately, when data are reported on a heat content basis, it is not always clear which definition is being used.

‘Bottom-up’ models: Those models of global oil production which extrapolate future production from smaller units, typically individual fields or countries. These individual forecasts are then compiled to form a global model. In contrast, ‘top-down’ models typically estimate certain total global parameters for oil, such as global *URR* and *decline* rates, and then extrapolate future production from these estimates.

Cellulosic ethanol: see *biofuel*. Cellulose can be a waste product of agriculture and forestry, making it a cheap biofuel feedstock that may not displace food crops, although making ethanol from cellulose may compete with the use of cellulose as a solid fuel.

Condensate: The extraction of natural gas may yield a product which is liquid at surface temperature and pressure, referred to as condensate, or lease condensate. Condensate is usually removed to avoid its condensation within natural gas pipelines. Condensate from ‘associated’ gas at oil wells is typically remixed with the crude oil stream and hence is rarely recorded separately in the production data. Condensate separated from ‘non-associated’ natural gas from gas wells may either be recorded separately or included in the data for *natural gas liquids* (NGLs).

Conventional oil: Since there is no consensus on this term it can be a major source of confusion. The definition proposed herein meets two needs: to encompass the separate categories of oil as used by some models, and to differentiate conventional oil from the *non-conventional* oils, which may have quite different characteristic rates of production and *production cycles*. Conventional oil is therefore taken in this report to <u>include</u> *crude oil*, *condensate* and *NGLs*, and to <u>exclude</u> *oil sands*, oil shale and extra-heavy oil (*non-conventional oils*). Some authors also exclude NGLs because these are used more as chemical feedstock or as liquefied gas than as transport fuels, and the report notes where this is the case.

Crude oil: Naturally occurring liquid hydrocarbon oil, produced by natural processes underground at elevated temperatures and pressures, from organic materials originally incorporated in sedimentary rocks. It may occur associated with *natural gas*. Crude oil is generally classed as light, medium or heavy (see *API gravity*), and as sweet or sour depending on how much sulphur is present. Light oil is more valuable than heavy oil, because it produces the highest yield of gasoline and other fuels when refined.

CTL: Coal-to-liquids, is the term used for synthetic liquid fuels made from coal.

Cumulative discoveries: An estimate of the total quantity of oil that has been discovered in a region from when the first discovery was made to the present day. This represents the sum of cumulative production and declared reserves.

Cumulative production: The total quantity of oil that has been produced from a field or region from when production began to the present day.

Decline: This ambiguous term is a frequent source of confusion. Decline refers to the reduction over time in the production of oil from a well, a field, a group of fields or a region. Production from a well or field normally builds to a peak or plateau, after which it generally declines steadily, largely due to pressure loss. The rate of decline can be 'natural', set simply by the physics of the reservoir and the production system, or it can be 'managed', which may mean restricting the flow from the field, but more usually means slowing the rate of decline by applying additional investment for *EOR*, reservoir management and/or production equipment.

Decline in a region is more complex, as there may be fields in the region still in the 'ramp-up' or plateau phases, and new fields yet to be brought on stream, as well as existing fields already in decline. If production from the whole region is in decline, we call this here the regional 'aggregate decline', or total production decline. The term 'average decline', when applied to a group of fields or region, should be viewed with caution, as the author may intend either the average of only those fields already in decline, or the average production from all fields in the region, including those ramping up and yet to come on stream.

Depletion: Depletion is the drawing down by production of a resource, assumed to be fixed. When specified as a percentage, depletion is the portion of the estimated *ultimately recoverable resource* which has been produced.

Depletion rate: the annual rate at which the *remaining recoverable resources* are being produced. It is defined as the ratio of annual production to some estimate of remaining recoverable resources. For an individual field the latter may be proved reserves or proved and probable reserves, while for a region it may also include the yet-to-find (*YTF*). When defined in relation to proved reserves, the depletion rate is the inverse of the commonly used 'reserve to production (R/P) ratio'. Also sometimes called the 'out-take rate' or the 'draw-down rate'.

Discovery: This general term is more specifically interpreted as the rate of discovery, or the amount of oil discovered over a specified period of time. Regional or global oil discovery is commonly quantified in billion barrels per year. Estimates of the rate of discovery are greatly complicated by the phenomenon of *reserves growth*.

Energy intensity: Taken here to refer to primary energy demand on a heat equivalent basis per unit of real GDP (Gross Domestic Product).

EOR: Enhanced Oil Recovery, also sometimes called tertiary recovery. Under primary oil recovery, oil flows naturally to the surface because of the pressure in the reservoir. During secondary recovery, pumps must be used, and/or reservoir pressure must be increased by injecting water or gas. Tertiary recovery / EOR techniques are intended to raise pressure again, to prevent water flow, to reduce oil viscosity, or to access isolated sections of the reservoir. EOR typically adds something to the reservoir, such as gas, solvents, chemicals, microbes, directional boreholes or heat. Note that the definitions of secondary, tertiary and enhanced oil recovery vary by authority.

EROI: Energy Return On Investment. The direct and indirect energy consumption required to find and exploit oil resources is significant and growing. It includes, for example, the energy involved in mining and smelting iron ore into steel, the energy used in activities such as drilling, pumping, refining and transport, and the energy consumed by the work-force involved. For very small or hard to access deposits, it is possible that this energy consumption may exceed the amount of energy recovered from the petroleum. In principle, this could set a limit on the development on such resources. But the practical limit will depend upon the relative mix of different energy carriers (which have different market prices) and the extent to which markets adequately reflect these direct and indirect energy costs.

Fallow field: In this report, a fallow field is defined as one that has been discovered but is not presently scheduled for development.

GTL: Gas-to-liquids, is the term used for synthetic liquid fuels made from natural gas.

Hydrocarbon: Any molecular species consisting entirely of carbon and hydrogen atoms. *Petroleum* is primarily a mixture of hydrocarbon molecules, but it may also contain small amounts of impurities such as oxygen, nitrogen, sulphur and vanadium.

Liquids: This report uses liquids as an all-encompassing term for liquid hydrocarbon and related fuels, including *conventional oil, non-conventional oil, biofuels* and *synfuels.* The term excludes hydrogen.

Model: A model, in the context of this report, is a set of concepts, typically expressed in mathematical form, which explains selected observations and permits predictions or forecasts to be made.

Natural gas: Natural gas is primarily methane, but may include varying amounts of ethane, propane, butane and pentane. These heavier molecules are removed as *NGLs* (see below) before use by consumers. There are also often contaminant gases such as nitrogen, carbon dioxide, helium, or hydrogen sulphide. Gas produced independently is referred to as 'non-associated' while gas produced during the production of crude oil is referred to as 'associated'.

NGLs: Natural gas liquids. These are hydrocarbon gases heavier than methane which are found in *natural gas*. They are all gaseous at room temperature and pressure. They are primarily used as chemical feedstock and liquefied gas fuels, rather than transport fuels, but many analysts include NGLs as a component of *conventional oil*. The Norwegian Petroleum Directorate defines NGLs to include propylene and butylene (components of liquefied petroleum gas - LPG) and other heavy molecules from natural gas processing.

Non-conventional oil: In this report, we take non-conventional oil to include extra heavy oil, *oil sands* and oil shales. The definition excludes, *biofuels* and *synfuels*.

Oil: In this report we take oil to include both conventional oil and non-conventional oil. It therefore includes *crude oil*, *condensate, NGLs*, extra heavy oil (high viscosity), *oil sands* and oil shales. We specifically exclude *biofuels* and synthetic fuels (*synfuels*) made from coal or gas.

Oil sand (also bitumen sand): Sandstone impregnated with immobile heavy or extra-heavy oil. 'Immobile' means that this oil will not normally flow, being too viscous. It is produced either by open-cast mining or by steam injection (such as SAGD – Steam Assisted Gravity Drainage) to reduce the viscosity. The resulting bitumen may be marketed directly or upgraded to a synthetic crude oil (*syncrude*) for further refining.

Peak oil: The point of the highest annual production of oil from a region. A production peak can occur for several reasons, but in this report 'peak oil' is taken to reflect the point at which the rate of production begins to fall due to physical depletion of the resource. However, the physical determinants of peak oil are invariably mediated by technical, economic and political factors which can make the physical origins of a production peak difficult to establish.

Petroleum: Literally 'rock oil', petroleum is the general name for all naturally occurring hydrocarbon species, including gases, liquids and solids (bitumen).

Plateau production: For a field, this is the period of maximum production, when the field produces oil at a relatively uniform rate. The precise peak will occur somewhere during this time. Plateau production is generally set by the capacity of the surface facilities, and any tendency to over-produce is restrained. The pressure in the field will start to decline almost immediately, but the early stages of the consequent production decline can be offset by reducing the restraints, until all wells are operating at full but declining capacity. The field then comes 'off plateau', sometimes quite abruptly.

Play: A conceptual or actual set of geological conditions which may result in an oil deposit. A play will generally specify the proposed source rock in which oil was generated, the porous and permeable migration pathway through which the oil may have moved (generally upwards) to the reservoir, a porous and permeable reservoir rock in which it may have accumulated, a seal (an impermeable layer of rock) overlying the reservoir, and finally a structure which produces a high point in the reservoir, where the oil may have accumulated, being unable to migrate further upwards.

Production: This general term may be more specifically interpreted as the *rate of production*, or the amount of oil produced over a specified period of time. Regional or global oil production is commonly measured in million barrels per day, or billion barrels per year

Production cycle: A graph of the rate of production against time elapsed. Also termed production profile.

Regular oil: This term is used by Campbell to refer to the sub-set of *conventional oil* which excludes heavy oil, *NGLs*, and oil from polar and deep-water fields.

Remaining recoverable resources: The economically recoverable resources that have yet to be produced from a field or region. Defined as the sum of *reserves*, anticipated future *reserves growth* and anticipated *yet-to-find*. Put another way, the yet to produce is given by the URR minus the cumulative production. As with reserves, remaining recoverable resources may be estimated to differing levels of confidence. Some authors use the alternative term ‘ yet to produce’.

Reserve: That oil which is discovered and is available for production. Reserves are commonly categorised into three probability rankings. These are variously described as Proved, Probable and Possible; 1P, 2P and 3P (where: 1P = proved; 2P = proved + probable; and 3P = proved + probable + possible); or P90, P50 and P10 (i.e. as having a 90%, 50% and 10% probability of being achieved). There is no direct correlation between these rankings, although 2P ‘proved plus probable’ is often taken as being fairly close to P50. Estimates of proved reserves need to be handled with great caution since then probabilistic interpretation can vary widely depending on the dataset being used and the countries to which they refer.

Reserves growth: Estimates of the size of individual fields often increase over time as a result of improved recovery factors, the physical expansion of fields, the discovery of new reservoirs within fields, the re-evaluation of estimates in the light of production experience, improved fiscal regimes and other factors. This process is generally referred to as ‘reserves growth’ although it would be more accurately described as ‘cumulative discovery growth’ since it is the estimates of cumulative discovery (i.e. cumulative production plus declared reserves) that grows, rather than the reserves themselves (indeed, reserves may reduce in size while cumulative discovery to continue to grow). A significant proportion of the observed reserves growth may result from conservative reporting of the size of newly discovered fields, or from regulations specifying what can be defined as ‘proved’ reserves.

Resource: This term has been used ambiguously in the literature. By definition, an oil resource is an accumulation which, under justifiable technical and economic conditions, might become economically extractable. If there are no reasonable prospects for eventual economic extraction, the oil is not strictly a resource. However, the term is also sometimes used to mean reserves, and most frequently to mean the total oil-in-place in a region, whether discovered or not, or recoverable or not. In this report we use the latter definition.

Resource-limited: This term is used here to describe the case where the rate of oil production from a region is limited by the physical depletion of the resource, as opposed to being restricted by choice (e.g. to abide by a quota); see *Peak oil*.

R/P ratio: R/P ratio = Reserves divided by annual production. Arithmetically, it states how many years the current reserves would last at current production rates. It must be remembered that for conventional oil the production rates from current reserves cannot be held constant for this length of time under any realistic circumstances (see *decline*).

Syncrude: Syncrude Canada Ltd. is a Canadian company which produces a synthetic crude oil, also often loosely referred to as syncrude, from the bitumen in

Canadian *oil sands*. Syncrude can be handled, pumped, piped and refined much as conventional *crude oil*.

Synfuels: We use the term synfuel, or synthetic fuel, to cover liquid fuels made from coal (*CTL*) or gas (*GTL*).

Top-down models: See *bottom-up models*.

URR: Ultimate Recoverable Resource. The estimated amount of oil that is considered to be technically and economically recoverable from a region over its full production cycle (i.e., from when production begins to when it finally ends). The URR is given by the sum of cumulative production, the declared reserves at known fields, the anticipated future growth of those reserves and the estimated YTF. In principle, estimates of URR imply associated assumptions about technical and economic conditions, with improved technology and higher prices leading to higher estimates.

YTF: Yet-to-find oil is the quantity of oil which it is thought remains to be discovered. Most authors (and this report) restrict YTF to the recoverable fraction of undiscovered oil, but some do not, and care should be taken.

Yet-to-produce: The estimated amount of economically recoverable oil that remains to be produced from a region. It is given by the sum of declared reserves at known fields, the anticipated future growth of those reserves and the estimated YTF. Put another way, the yet to produce is given by the URR minus the cumulative production. Some authors use the alternative term 'remaining resources'.

The terms given special usage in this report are therefore as follows:

- ***Conventional oil*: Natural crude oil, condensate and NGLs. It <u>excludes</u> oil sands, oil shales, extra-heavy oil, biofuels and synfuels.**

- ***Non-conventional oil*: Extra extra-heavy oil, oil sands and oil shales. It <u>excludes</u> biofuels and synfuels. Non-conventional oil is sometimes referred to as unconventional oil.**

- ***All-Oil*: The combination of conventional oil and non-conventional oil.**

- ***Liquids*: All liquid hydrocarbon and alcohol fuels, and so includes oil, biofuels and synfuels. It excludes hydrogen.**

- ***Resource*: Total oil-in-place in a region, whether discovered or not, or recoverable or not.**

- ***Decline rate*: This term must distinguish between natural, managed, and aggregate decline. The latter term can include existing fields which are ramping-up or on plateau, plus new fields yet to come on stream.**

1.2 Data sources and key measures

This section discusses the key data required for oil supply forecasting, the sources of these data and some relevant measures derived from the data.

When the rate of oil production in a region is plotted against time, the area under the curve is the quantity of oil that has been produced in the region. When this curve is plotted over the full production cycle, from when production begins to when it finally ends, the area under the curve represents the ultimately recoverable resource (URR). Such curves are frequently assumed (and often observed) to rise to a single peak and then to decline. However, production cycles with plateaus or with two or more peaks are also observed.

The production cycle for conventional oil supply is thus constrained by the slopes of the curve and the area under the curve; or in other words by the growth and decline of supply and the URR. But while the basic shape of the curve is constrained by geology, it can be modified to varying degrees by politics, economics and technology.

Key variables relevant to production cycle are therefore the past and present oil production rates (which determine the slope upwards), the field or regional production decline rates (which influence the slope downwards), and the estimated URR. At any point in time, the latter represents the sum of cumulative production, declared reserves, anticipated reserves growth and the estimated yet-to-find resources (YTF).

There are relatively few primary sources of data on production and reserves. While production data are generally more reliable and widely available than reserves data, they are by no means free of inconsistencies. Relatively little data are available in the public domain on decline rates and reserves growth, while both YTF and the URR have to be estimated by a variety of means (see *Technical Report 5*). The differences between supply forecasts usually result from very different assumptions - whether explicit or implicit - about these fundamental variables.

Models of oil supply may or may not be combined with models of oil demand. The latter, in turn, may either be modelled at a very aggregate level or broken down into individual regions and fuel end-uses. At a minimum, detailed demand modelling requires data and assumptions about population growth, gross domestic product (GDP), energy intensity, oil prices and price elasticities. These parameters may be derived from various data sources, econometric studies, opinion and modelling.

1.2.1 Annual oil production

There are several primary sources of data on oil production, but at the global and national level, none of these agree. The sources include:

- Commercial databases. The databases of IHS Energy are perhaps the single most comprehensive sources of data, listing past and present production and reserves for almost all fields in the world, but the cost of a subscription restricts access to the largest companies and organisations. Other commercial databases are available (e.g. Wood Mackenzie's 'PathFinder') and are cheaper but generally not as comprehensive. IHS also supplies an aggregate, country level database ('PEPS') which is available at lower cost.

- The *BP Statistical Review of World Energy* is a free annual publication each June that gives national totals for petroleum consumption, production and reserves. It is a compilation of data from primary official sources and third-party data.

- The *Oil and Gas Journal* (OGJ) provides an annual table in December of national reserves and production data. Some production data are listed by field.

- IEA (International Energy Agency) and the US EIA (Energy Information Administration) both provide free on-line monthly estimates of national oil production[1]. IEA data are also reported in *World Oil* magazine[2].

Table 1.1 illustrates some of the variability between common sources of global oil production data. Most of this variation arises from using different primary data sources and from the inclusion or exclusion of different liquids, including in particular condensate and NGL production. Lesser effects may arise from produced petroleum being burned directly during production, from bitumen production, or from oil upgrading and refining that result in refinery gains or losses. See *Technical Report 1* of this UKERC study for more information on data sources and associated issues.

Table 1.1 Comparisons of data for annual average daily global oil production (million b/d)

Source	2005	2006	2007
Oil & Gas Journal	72.4	72.6	72.2
BP	81.3	81.7	81.5
EIA	84.6	84.5	84.4
IEA[3]	84.4	85.1	85.5

1.2.2 Oil reserves and resources

Despite a number of official definitions for reserves and resources (see *Technical Report 2* of this study), there is unfortunately still a great deal of ambiguity about these terms. In general, a reserve is a petroleum deposit that is thought to be commercial now or in the future under reasonably likely circumstances. A resource is taken in this report as the total amount of physical petroleum in place, whether discovered or not, and whether recoverable or not.

Reserves are generally expressed as: proved, probable and possible; 1P, 2P and 3P (where 1P means proved, 2P means proved plus probable, and 3P means proved plus probable plus possible); or P90, P50 and P10 (indicating a 90%, 50% and 10% probability of reaching or exceeding this value).

IHS Energy again provides the most comprehensive global database of field-by-field estimates of 1P, 2P and 3P reserves, drawn from a wide range of sources including their own private sources, but other commercial databases also have useful data. *Oil and Gas Journal* and *World Oil* publish reported proved (i.e. 1P) reserves data, which are generally supplied on a country by country basis by national authorities.

[1] http://omrpublic.iea.org/supplysearch.asp ; http://www.eia.doe.gov/ipm/supply.html
[2] http://www.worldoil.com/INFOCENTER/STATISTICS_DETAIL.asp?Statfile=_worldoilproduction
[3] Averaged from monthly data in IEA Monthly Oil Market Reports http://omrpublic.iea.org/

Unfortunately there is no consistency in the definition of proved reserves as used by these authorities. Official primary data are also collated and re-published by BP (*op. cit.*). The latter publication is widely cited as a source, but it is not a primary source, and its reserves data need to be used with caution.

An error is sometimes made in the assessment of reserves when statistical estimates of individual field reserves are summed to give a regional or country total, or when country totals are summed to give a world total. P50 values can be added directly to obtain a correct overall value, but P90 (or P10) data, for example, must be added using a probability distribution as recently highlighted by Pike (2008)[4] (see *Technical Report 1*).

There is particular uncertainty about both the definition and the reliability of national data from OPEC Middle Eastern states. Large upward revisions to the declared reserves started in 1985, when the OPEC production quotas were being negotiated. The quotas were based, in part, on the proved reserves of each state. The IEA also notes, "*…They [OPEC declared reserves] were driven by negotiations at that time over production quotas and have little to do with the discovery of new reserves or physical appraisal work on discovered fields*." The remarkable increases of 1986-1987 were then followed by an equally remarkable lack of variation since that time, despite ongoing production.

Countries with the greatest reserves have no incentive to publish correct data or supporting data, or to allow an independent audit. Should we accept that Saudi Arabia has really replaced each year as many barrels as it has produced, so that their claimed reserves are unchanged? Moreover, how can we assess other OPEC reserves? OPEC's reported reserves are now variously regarded by different analysts as true 1P reserves, or as 2P reserves, as original oil-in-place, or as original proved reserves-in-place. This uncertainty results from the absence of reliable, audited data and reflects concerns about the potential distortions designed to raise the national production quota.

Data concerning reserves growth come primarily from studies of US fields. While there are some data for other regions, the topic is difficult to investigate owing to a lack of suitable field-level databases containing historic assessments of past production and remaining reserves. Reserves growth is analysed in detail in *Technical Report 3* of this UKERC study, and is also discussed further below.

1.2.3 Yet-to-Find (YTF) and Ultimately Recoverable Resource (URR)

The most comprehensive and commonly cited, country-by-country, global YTF assessments are those published by the US Geological Survey (USGS) *World Petroleum Assessments,* with the assessment published in 2000 being the most recent, reflecting data up to 1995 (USGS, 2000). This forecast gives a mean value of 724 Gb of undiscovered oil resources (excluding NGLs) having "*…the potential to be added to reserves in the next 30 years"* (i.e. between end-1995 and 2025), implying an average discovery rate (ex-NGLs) over this period of about 24 Gb/year. This

[4] However, that Pike's main contention, that global proved reserves are underestimated for this reason may not be correct. This is because published estimates of proved reserves do not always correspond to P90 reserves. For example, in some OPEC countries the official proved reserves exceed the proved plus probable ('2P') estimates held in industry datasets. Moreover, the published global value for proved reserves is close to the IHS Energy figure for global 2P reserves.

conclusion has been criticised for undue optimism, and a subsequent review by the USGS in 2005 revealed that only 11% of their forecast YTF outside the US had subsequently been discovered, after the passage of 27% of the assessed time frame (Klett, *et al.*, 2005). However, this may be an underestimate of the actual volume of discoveries because it does not allow for future reserves growth at those fields. Also, exploration has been restricted over this period in a number of areas, most notably in Iraq.[5] [6] [7]

The URR, or the ultimate recoverable resource of oil, could be estimated from the sum of cumulative production, known reserves (2P or P50 as appropriate) and the YTF. But this estimate is complicated by economic considerations, because the future price that the market is prepared to pay for oil will affect whether or not some marginally economic fields contribute to the URR. It is further complicated by 'reserves growth' at known fields, since many fields - at least historically - have been found to produce more oil than their originally declared reserves. While estimates of the URR for a region should, in principle, allow for future reserves growth, there is very little data on this issue – at least for regions outside the US. Also, most data refers to the growth in 1P reserves and hence may not provide a reliable indicator of the growth in 2P reserves.

The USGS 2000 assessment was the first of their assessments to apply reserves growth on a global scale. It used the historical experience with reserves growth in US oil fields to estimate future reserves growth in fields outside the US. This process was estimated to have the potential to contribute 730 Gb to global reserve additions (including NGLs) between end-1995 and 2025, or almost as much as new discoveries over that period.

While the US data applied to field size estimates based upon 1P reserves, the USGS data for the rest of the world incorporated field size estimates based upon 2P reserves. Hence, the experience with the former may not be applicable to the latter. The USGS approach was widely criticised, on the grounds that US reserves are defined very restrictively by US company law. Only reserves "*...supported by either actual production or conclusive formation test"* [8] may be declared proved for any field. Critics have argued that although large reserves could often be known very early during exploration and development, on good geological and technical grounds, only those parts of the field within production range of a well could be included in official reserves statistics. As more wells were drilled, so more reserves were declared, and the 'reserves growth' appeared. But the same process may not apply elsewhere in the world.

While these criticisms of the USGS approach appear reasonable, a subsequent evaluation of the USGS forecasts suggests that their reserves growth assumptions are proving fairly accurate (Klett, *et al.*, 2005). This study found that 28% of the USGS estimate of reserves growth potential had been realised in 27% of the forecast time horizon (1995-2025). Further evidence in favour of the USGS assumptions is

[5] The USGS report in 2000 estimated that mean YTF as of 1995 comprised 649 Gb oil and 207 Gb NGL from outside the US, and 76 Gb oil and 8 Gb NGLs from within the US. In 2005 the USGS reported that up to end 2003, 69 Gb of oil had been discovered outside the US, a finding rate of 1.4% p.a.. If this finding rate applies to all oil categories, then we calculate that as of end 2008, the remaining global mean YTF according to the USGS would be 603 Gb oil and 179 Gb NGLs.

[6] See *Technical Report 5* of this study for a detailed discussion of the USGS assessment.

[7] Latest (end-2007) IHS Energy data indicate that about 21% of the USGS year-2000 assessment global mean YTF of 940 Gb (incl. NGLs) has been discovered in 12 years (40%) of the 30-year period from 1996.

[8] http://www.sec.gov/divisions/corpfin/guidance/cfoilgasinterps.htm

presented in *Technical Report 3* of this study. However, the global total for reserves growth is strongly influenced by reserves growth in those countries where the reserves data is least reliable.

There is no doubt that in many fields new technology has improved, and will further improve, recovery factors, making more oil accessible. No-one disputes the reality of reserves growth caused by technology (essentially EOR), and while the ultimate potential of such technology remains uncertain, it could significantly increase the global URR. However, this increased recovery is often obtained relatively late in a field's life when the rate of production is comparatively low. Hence, the extent to which the deployment of technology can significantly affect the date of global peak production remains an open question.

1.2.4 Reserve to production (R/P) ratios

R/P is the ratio of current reserves (however defined) to the current annual production rate. It is frequently interpreted as the number of years of supply that remains at current production rates. The *BP Statistical Review of World Energy publishes* annual country-by-country estimates, based upon proved reserves.

R/P ratios are often cited as evidence of sufficient supply. An R/P ratio that stays the same for some years has often been taken as evidence that new discoveries are only being converted into proved reserves as and when required, hence there is no shortage. Equally, the global R/P ratio of 41 years has often been quoted as evidence that the world has large reserves and cannot therefore have a looming supply problem.

Emphatically, the R/P ratio does not indicate that the current annual supply can be maintained for the number of years indicated, because production from every conventional oil field declines after reaching a peak or plateau. Regrettably this is often forgotten, ignored or unknown. Despite their widespread use, R/P ratios are not a reliable indicator of future production.

R/P ratios and their changes provide no guidance to what is going on within a region, in part because two unrelated variables are involved. Mature provinces often reach a relatively stable R/P ratio, and it surprises some observers to realise that this happens while both reserves and production are falling. This is shown in Figure 1.1, where the US, UK and Norway show flat or slightly rising R/P ratios since 2000, despite declining reserves and production in every case.

Simple numerical modelling suggests that provinces will generally approach a condition where production, reserves and new discoveries steadily decline, and R/P remains almost constant. If the annual production in a region is a fixed percentage of the existing reserves, and no new discoveries are made, then the R/P ratio and the production decline rate remain constant while reserves and production fall by the same proportion each year.

Figure 1.1 Proved reserve to production ratios in post-peak regions

Source: BP (2008)
Note: The US peaked in 1970, the UK in 1999 and Norway in 2001.

Even when new discoveries are still being made, at an exponentially declining rate each year, the R/P ratio still remains almost constant, although at a slightly higher level than before. In this case the aggregate production decline rate is significantly less than the average field decline rate, which is an important point. To illustrate: suppose that production is 10% of the remaining reserves each year, and the discovery rate always falls by 10% annually. In this case, the R/P ratio is almost constant, at slightly over 10, and the aggregate annual production decline rate of the province is less than 8% for some fifty years, despite the field decline rate of 10% p.a.

1.2.5 Decline rates

Oil field decline is the phenomenon whereby the production rate of a field drops after reaching a maximum, typically before 30% of the original estimate of 2P reserves has been produced (IEA, 2008). When sufficient fields in a region, country or the whole world have started to decline, then the total production is generally irreversibly set on a downward trend, unless enough new fields can be discovered to bring sufficient new production on line. Decline is not the same as depletion, which is the rate at which reserves are drawn down by production.

Decline is a physical phenomenon, which occurs primarily because pressure in the field falls as oil is removed. The remaining oil flows ever more slowly, being under less pressure. There are other physical effects too, such as water breakthrough, where brine beneath the oil reaches the borehole and starts to be produced, reducing the oil flow rate. These effects are generally not reversible, although sometimes they can be delayed or reversed temporarily. ‘Natural’ decline refers to a field without subsequent investment and intervention, and ‘managed’ decline to a field which is either partially shut in, or - more normally - where extra investment has been made to raise production, typically by applying enhanced oil recovery (EOR) techniques.

The rate at which total global conventional oil production will decline after the peak is a fundamental parameter (either as an input or as an output) in global supply forecasts and in estimates of the timing of peak production. It is a complex sum of the average, production-weighted decline rate of current fields, including any secondary and tertiary recovery programmes, offset by the production from fields that are in the build-up or plateau phase and the amount of new production coming on-stream each year. A review is provided in *Technical Report 4* of this UKERC study.

The IEA has written an excellent review using current data from about 800 major fields in *World Energy Outlook 2008* (Chapter 10), which is recommended reading. This includes many new analyses, and the calculation of average decline rates for various types of field. The IEA concludes that the average observed decline rate of the 800 fields, weighted by production, is 5.1% p.a. after the peak, and 5.8% p.a. after the plateau phase[9] – with decline rates being faster in the smaller fields and in the offshore fields. This represents a mix of 'managed' and 'natural' decline. Extrapolating these data to the whole world, the IEA estimates the global average decline rate of post-peak fields to be 6.7% p.a.

Cambridge Energy Research Associates (CERA) published a private study of decline rates in 2007[10], also using a database of some 800 fields. These fields account for about two-thirds of current global production and half of global 2P conventional oil reserves. Only 41% of the fields, by production volume, are past plateau. CERA concluded that the aggregate observed production decline of the whole group is some 4.5% p.a., and reported that this rate is not increasing. CERA found average decline rates for those fields actually in decline of 6% p.a. (onshore) and 10% p.a. (off-shore).

Höök and Aleklett (2008) of the 'Uppsala Group' have studied the decline rates of the Norwegian suite of offshore oil, condensate and NGL-producing fields. They found that the giant fields, defined as either 0.5 Gb of URR or production exceeding 100,000 barrels/day for more than one year, have a mean exponential decline rate of 13.4% p.a., or 13.8% p.a. when weighted by peak production rate. The smaller oil fields decline at 21.3% p.a. (18.1% weighted by peak production rate), condensate fields by 35.5% p.a. (37.7% weighted by peak production) and NGL by 19.5% p.a. (15.6% weighted by peak production).

We are unable to judge the accuracy of the field decline rates calculated by the IEA and CERA (and also those by OPEC and the Uppsala group). A complete record of annual production data for each field is required, and we understand that the IHS database is incomplete in this regard for the large Middle Eastern OPEC fields. It may be that these analysts have access to confidential data. However, the average rate of decline, together with the anticipated changes in this rate, is a crucial variable for future global oil supply.

1.2.6 Economic data and assumptions

Economic data and assumptions tend to be unique to each forecaster. Not every forecast methodology requires accurate economic data as an input and the required data will depend upon whether only oil supply is being modelled, or both oil supply and oil demand.

[9] Defined as production greater than 80% of peak production.
[10] http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=9203

The relationships between price and demand, and price and supply are complex and may be represented at varying levels of detail. Forecasts of price have recently been thrown into some disarray by the sharp price increase and collapse seen in 2008. Forecasts of future global oil demand usually make reference to United Nations or other forecasts of global population growth, together with the expected growth of GDP per capita and the primary energy consumption per unit of GDP, or energy intensity. The latter has decreased over time in developed countries, but an increasing proportion of primary energy demand has been accounted for by oil and, more recently, natural gas. Personal transport is the dominant end-use sector and there is scope for very large increases in global oil demand as both population and prosperity increase in less developed countries.

Since our primary focus is oil supply, the determinants of oil demand will not be discussed in detail in this report. While several of the models reviewed include detailed modelling of energy demand, many do not model demand at all and simply make exogenous assumptions about the rate of demand growth. This leads to projections of a ‘supply gap’, when the *modelled* supply appears insufficient to meet the *assumed* demand. But in practice, supply constraints will induce higher prices and consequently both demand reduction and the substitution of conventional oil by other fuels. What is at issue is whether these price signals are likely to encourage a relatively smooth transition to more efficient end-uses and alternative fuels or, as appears quite possible, lead to economic recession and supply shortages. This in turn will depend in part upon whether the oil market signals an impending supply peak in a timely manner and/or whether policy makers anticipate the future supply difficulties and therefore take action sufficiently far in advance and on the scale required.

In principle, the ultimate economic limit for bringing an oil field on-stream should be reached when the fully built-up energy cost of supplying the final oil product to the consumer is equal to that obtained from the oil, referred to as the EROI (Energy Return On Investment) limit. The fully built-up energy costs will include, for example, the energy used to mine and smelt ore for steel, and for drilling, exploration, pumping, transport and shipping, refining and marketing. At that limit, which may change with time, fields which are small, remote or otherwise marginal may not be economically produced at any oil price. The EROI limit will depend upon the relative market prices of the relevant energy carriers and may also change over time - for example, if new infrastructure is available such as access to a platform or pipeline. EROI considerations (and as importantly, net-energy rate limits[11]) to the introduction of new types of oil, new recovery techniques, and new energy sources would benefit from a rigorous economic study.

1.3 Limitations of the study

This study is limited by its remit to focus on forecasts of conventional oil supply. By ‘conventional oil’ this study means naturally flowing oil, condensates and NGLs. However, many of the models studied also include bitumen and synthetic crudes from the Canadian oil sands, very heavy oil from the Orinoco and elsewhere, and oil from shales, although the latter is usually expected to be insignificant in the forecast period. Some forecasts also include synfuels from coal and gas, and biofuels. Where possible,

[11] The net-energy rate limit refers to the amount of available energy which must initially be diverted to the creation of a new energy supply. If this is too great, then the new energy supply effectively *reduces* the available energy supply for some time.

data for non-conventional oil and other liquids have been deducted from the oil totals to allow analysis of the forecasts for conventional oil.

This study does not create another forecast, but instead analyses and compares contemporary forecasts and the models used to produce them. We have indicated where, in our view, certain models are more or less likely to prove provide reliable forecasts, but no single model has been preferred. Users are encouraged to see for themselves how, where and why models differ, to select appropriate values of the principal parameters, and to choose or create a model which best honours those parameters and data.

Note that as far as possible, our reviews of contemporary forecasts have been offered back to the creators for discussion and approval.

We are conscious of two additional limitations. First, in the time available, we have not gone into the fine detail of the models, so the comparisons are made at a relatively high level.[12] We highlight therefore general aspects of each model, rather than make definitive statements on their accuracy or completeness. However, given the importance of the topic, and the interest in dialogue shown by all the modellers contacted, we hope there may be opportunities in future where the models can be discussed and compared in more depth.

The second limitation is that some important models are not included; in some cases because the modellers were not, or could not, be contacted; or else because the modellers chose not to collaborate for commercial or other reasons.[13]. While we regret the absence of these models, we do not consider that their omission materially affects our overall conclusions.

Nevertheless, as set out in the Acknowledgements, we have been very pleased with the overall cooperation of modellers from around the world, and we hope we have done their models at least partial justice. We are of course keen to receive further feedback, to make corrections where needed, and to provide amplification, or to alter our judgements, where the case can be made.

[12] In several cases, there is insufficient information available to conduct a more detailed comparison.
[13] These include models created by PFC Energy, Cambridge Energy Research Associates (CERA), the World Energy Council, some oil companies, and financial institutions.

2 Summary of historical forecasts of global oil production

Oil is essentially a finite resource. The rate at which oil is created today, by natural processes within the earth, has been estimated at about 3 million barrels each year (Miller, 1992), which is equivalent to three quarters of an hour's production by the oil industry. The production of oil *must* therefore at some point reach a maximum and start to decline, although whether that decline comes about because the industry cannot produce it any faster, or because demand for oil has fallen away, is a separate question.

The inevitability of an eventual peak in conventional oil production has long been recognised, and attempts have been made to forecast the event for almost as long. To those who come new to the subject, much of today's argument may still seem to be an echo of doubtful relevance from decades ago. Nevertheless, even today there is no consensus around some of the issues that were first debated fifty years ago. A clear understanding of these issues remains critical to forming a dispassionate view on the future of oil supply. This section provides a historical review which attempts to explain these arguments.

Much of this synopsis of oil supply forecasts between 1956 and 2005 is sourced from Bentley and Boyle (2008), to which the reader is referred for more detail. The strengths and weaknesses of the modelling approaches used are discussed in detail in *Technical Reports 5* and *6* of this study.

We summarise first some notable forecasts of a peak in global oil production, before considering some 'non-peaking' forecasts.

2.1 Peaking forecasts

2.1.1 Peaking forecasts 1956 - 2005

Table 2.1 lists some of the forecasts for a peak in global oil production, made since Hubbert's first global forecast in 1956. The assumptions made by various authors have necessarily been simplified in order to tabulate the results. 'URR' is the ultimate recoverable resource, in billions of barrels (Gb), although the precise coverage of liquids varies from one forecast to another. The expected date of the global peak of production moves forward from around the year 2000 in forecasts made up to 1990, to as late as 2020 in some later cases.

Table 2.1 Selected forecasts of global oil production, made between 1956 and 2005, which gave a date for the peak

Date	Author	Liquids covered	URR (Gb)	Forecast date of global peak
1956	Hubbert	Conventional oil	1250	“about the year 2000” [at 35 mb/d]
1969	Hubbert	Conventional oil	1350 2100	1990 [at 65 mb/d] 2000 [at 100 mb/d]
1972	ESSO	Probably conventional oil	2100	“increasingly scarce from ~2000.”
1972	Report: UN Conference	Probably conventional oil	2500	“likely peak by 2000.”
1974	SPRU, UK	Probably conventional oil	1800-2480	No prediction
1976	UK DoE	Probably conventional oil	n/a	“about 2000”
1977	Hubbert	Conventional oil	2000	1996 if unconstrained logistic; plateau to 2035 if production flat.
1977	Ehrlich et al.	Conventional oil	1900	2000
1978	WEC / IFP	Probably conventional oil	1803	No prediction
1979	Shell	Probably conventional oil	n/a	“plateau within the next 25 years.”
1979	BP	Probably conventional oil	n/a	Peak (non-communist world): 1985
1981	World Bank	Probably conventional oil	1900	“plateau ~ turn of the century.”
1992	Meadows et al.	Probably conventional oil	1800-2500	No prediction
1995	Petroconsultants	Conventional oil excluding NGLs	1800	About 2005
1996	Ivanhoe	Conventional oil	~ 2000	About 2010
1997	Edwards	Probably conventional oil	2836	2020
1997	Laherrère	All liquids	2700	No prediction
1998	IEA	Conventional oil	2300 (reference case)	2014
1999	USGS	Probably conventional oil	~ 2000	2010
2000	Bartlett	Probably conventional oil	2000 and 3000	2004 and 2019

2002	BGR	Conventional and non-conv. oil	2670 (conventional)	2017 (all oil)
2003	Deffeyes	All oil		~ 2005
2003	Bauquis	All liquids	3000	2020
2003	Campbell - Uppsala	All hydrocarbons		2015
2003	Laherrère	All liquids	3000	
2003	Energyfiles Ltd.	All liquids	Conventional: 2338	2016
2003	Energyfiles Ltd.	All hydrocarbons		2020
2003	Bahktiari	Probably conventional oil		2006 - 2007
2004	Miller	Conventional & non-conventional oil		2025
2004	PFC Energy	Conventional & non-conventional oil		2018
2005	Deffeyes	All oil		2005

Source: Bentley and Boyle (2008)

We start this brief description of past forecasts by outlining the work of M.K. Hubbert (see also *Technical Reports 5 and 6*). Hubbert was among the first to look quantitatively at oil peaking in a region; emphasising the importance of discovery rate, estimates of the URR, and the fitting of curves to historical data.

In 1956, Hubbert forecast a peak date for US production, using two industry estimates for that country's URR (Hubbert, 1956). He extended the historic US production curve to follow a symmetrical (i.e. bell-shaped) curve with a smooth roll-over at the top, choosing curves such that the area under these curves matched his estimates of the US URR. The curves had no particular mathematical form, and he did not claim that the production cycle had to be symmetrical. However, given the constraints of historical production and the assumed URR, he observed that "…. it became impossible to draw this curve very differently from the way it is shown." Famously his upper estimate of the peak of US production – "about 1970" – was subsequently proved correct. His companion forecast for the world was illustrated by an asymmetric curve, whose decline did *not* mirror its growth (Hubbert, 1956).

Because of challenges to Hubbert's assumed value of the URR in the United States, primarily by a group within the USGS, in 1962, Hubbert (1962) again forecast the peak of US oil production, but this time using the first differential of the logistic curve (also bell-shaped) to estimate the peak. This curve is symmetrical, and it was (and still is) a relatively good fit to US production data. It also has the advantage that a plot of (production/cumulative production) against (cumulative production) tends to a straight line. By extrapolating this line, the regional URR can be estimated from the intersection with the abscissa. Regrettably, the symmetrical 'Hubbert' curve fixed in others' minds the incorrect idea that it not only forecast the date and height of peak, but also the post-peak production rate.

Hubbert also separately derived URR estimates by fitting a curve to historical data on cumulative discoveries and extrapolating this to identify the asymptote. Any reported increases in field size due to reserves growth were back-dated to the original date of discovery (see *Technical Reports 1 and 5)*. Other modelling approaches followed in 1967 and 1969, including examining this back-dating of discovery data, and using this to forecast future reserves growth; and estimating the URR from the decreasing rate of discovery per foot drilled ('yield per effort'). Hubbert used logistic curves to estimate the timing of the global peak for two estimates of the global URR - 1350 Gb and 2100 Gb. In 1969, he estimated that global oil production would peak at 100 million b/d in 2000, using an updated estimate for the of global URR, of 2100 Gb (Hubbert, 1969).

Hubbert's mathematical model of production was therefore based on the first differential of the logistic curve, initially applying this to the US rather than to the whole world. This curve provided a convenient fit to production in many cases, although there is no basis for supposing that production *must* follow such a curve and Hubbert never claimed that it would. Each field has its own production cycle which is rarely logistic in form, and the logistic curve is likely to be applicable only to the sum of production from a number of fields.

The logistic curve can be used in a variety of ways, one of which is fitting to past production and an estimate of URR and projecting this curve forward to estimate future production. In this usage, the centre point of the curve yields an estimate for the date and height of the production peak, with production declining once 50% of the URR has been produced.

In 1982, Hubbert provided a comprehensive overview of his various techniques (Hubbert, 1982). He was clearly aware of the limitations of the logistic curve as a forecast of future production. He emphasised that a region's production need not be symmetrical or have a single maximum. He went on to say, "*For large areas, such as the entire United States or the world ... the irregularities of small areas tend to cancel ... and the curve becomes a smooth curve with only a single principal maximum,*" but he noted that this curve need not be symmetric. His estimate of the US production peak used conservative, proved reserves, which were "*not intended to represent the ultimate amount of oil that known fields will produce."* These clear caveats were often forgotten by later followers as well as critics. Hubbert also showed that although increases in the oil price had increased the rates of drilling and discovery, they had not affected the long-term decline in discovery per foot drilled.[14]

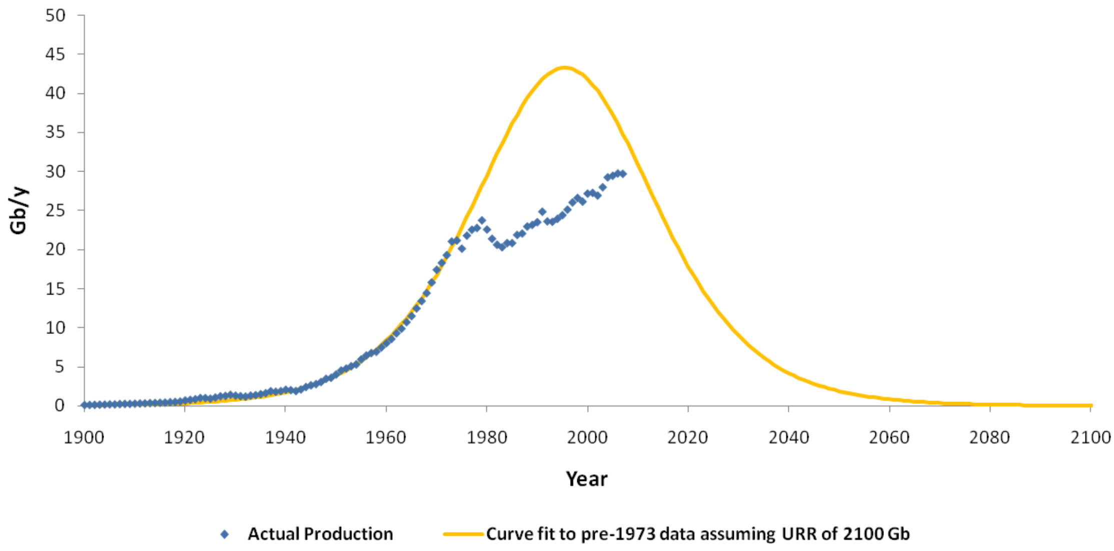
As an example of the understanding of the oil peak in the 1970s, we can quote the landmark environmental report to the United Nations in 1972 by Ward and Dubois. This said: "One of the most quoted estimates for usable reserves [global URR of oil] is some 2500 billion barrels. This sounds very large, but the increase in demand foreseen over the next three decades makes it likely that peak production will have been reached by the year 2000. Thereafter it will decline." (Ward and Dubois, 1972).

In the event, the simple model of production following the logistic curve did not occur. Following the first global oil shock, growth in oil production dropped below the logistic curve in 1973, and fell more sharply in 1978. From the mid-1980s, world oil production started once again to grow, but now at a much lower rate than the

[14] However, changes in oil prices were subsequently shown to have had a significant influence on the short-term trends (Cleveland and Kaufmann, 1991).

original logistic fit. As a result, global oil production did not peak in roughly 2000 as had been indicated. This is illustrated in Figure 2.1.

Figure 2.1:Pre-1973 forecast using logistic curve compared to actual global production



We continue this brief survey of peaking forecasts by looking at some other past forecasts that have been influential.

In 1979, H.R. Warman at BP predicted that world oil production outside communist areas would peak about 1985.[15] This was often later cited as proof of the inability of 'fixed resource' models to forecast oil production. However, Warman's forecast rate for production of non-communist conventional oil (ex-NGLs) appears reasonable, based upon the assumed size of the resource base. The main problem, as with other forecasts at the time, was that Warman did not factor in the demand reduction and fuel substitution that resulted from the 1970's price shocks. Using Warman's resource base, as indicated by the area under his predicted production curve, and accounting for the 1970's demand destruction, gives an adjusted date for the peak of non-communist conventional oil production (ex-NGLs) as around the year 2000.

In another development, B. Grossling of the USGS presented the view that abundant oil remained to be discovered globally, because many fewer wells had been drilled in much of the world compared to the US.[16] At the time, L.F. Ivanhoe disagreed with this view as it did not match his experience of the other factors (including primarily each region's intrinsic 'oiliness') that control discovery. Later, Ivanhoe (1996) combined USGS discovery data with the claim that the shape of the production curve very broadly mirrors the earlier discovery curve, to forecast that the production of global conventional oil would peak around 2010. Ivanhoe's approach highlights the link between 2P discovery & subsequent production, but the claim that these cycles taken a broadly similar shape is only poorly supported by the empirical evidence (see Nehring (2006a; b; c) and *Technical Report 5*).

In 1991, C.J. Campbell produced a comprehensive global study of future production by country, though this was often limited to using the publicly available proved

[15] "*Oil Crisis ... Again?*". BP, 1979.

[16] This argument has been used on a number of occasions, including recently by Mills (2008).

reserves data available at that time (Campbell, 1991). In 1995, Campbell and J.H. Laherrère, working for Petroconsultants (later, IHS Energy), published the first comprehensive country by country analysis, based on industry data and extensive geological knowledge (Campbell and Laherrère, 1995). They used 2P (~ P50) estimates of reserves, and employed several statistical methods for estimating the YTF, and hence the URR. Production from countries which had passed their peak was then extrapolated into the future at the existing depletion rate. For countries not yet at peak, future production was modelled with an assumed growth rate until cumulative production reached 50% of the national URR, and thereafter was again extrapolated at the then existing depletion rate. For the major swing producers of the Middle East, separate models were created under assumed conditions.

K. S. Deffeyes, in his 2001 book *Hubbert's Peak*, applied logistic curve linearisation to world oil production data and concluded that production "*will probably reach a peak sometime during this decade*". Deffeyes later updated this plot and put the global peak in 2005 (Deffeyes, 2005). Since global production departed from the symmetric logistic curve in 1975, a forecast based on upon this curve is bound to be inaccurate. Nevertheless, the timing of peak production may not be especially sensitive to the assumed shape of the production cycle.

In 2003, P-R. Bauquis assumed a global URR (including NGLs) of 3000 Gb to forecast that global liquids production would peak about 2020, at a rate of 95 mb/d, while in the following year Bakhtiari (2004) and colleagues at the National Iranian Oil Company used conservative Saudi and Russian reserves estimates to conclude that world oil production would peak by 2006-07, at about 81 mb/d.

In 2005, the consultancy PFC Energy presented a base-case forecast for 'all-oil' production at the Energy Institute, London. This forecast the global oil peak, including NGLs and non-conventional oil, as occurring in 2018. The company used back-dated 2P reserves data from a number of sources, including IHS Energy, to arrive at 'best judgment' values. They paid particular attention to the reserves data for the FSU and Middle East. 'Yet-to-find' oil was assessed from extrapolated field-size distribution curves, bearing in mind commercial thresholds (see *Technical Report 5*). Oil production was forecast by country or region, but extensive use was made of individual field modeling. Sensitivity analysis was used to describe ranges on reserve size, future improvements in recovery factor, and changes in oil price. PFC's approach is more detailed than that of Campbell and Deffeyes, and while they forecast a later date of peak production, the difference is not especially large. We were unable to include a detailed review of this model in this report, but it deserves serious consideration.

2.1.2 The evolution of peaking forecasts

Oil peaking is driven by the fact that the larger fields in a region tend to be discovered and go into production first, and then at some point begin to decline (Bentley, *et al.*, 2000). Once the rate of discovery has slowed sufficiently, the production from the later, smaller fields becomes insufficient to offset the decline of the earlier, larger fields. The aggregate production from the whole region must then decline, regardless of the quantity of reserves that remain. Moreover, the primary determinant of future production, once discovery has slowed, is thus the quantity of oil already discovered, not that which may be found subsequently, unless unusually substantial.

Authors such as Hubbert (and more recently, Meling) have argued that changes in oil price and technology have relatively limited effects on future production. For this reason, given the closeness of the predicted peak, 'peak modellers' are often more concerned by the accuracy of FSU and Middle East reserves data, than by potential price or technology developments. Note, however, that it was mainly because price and technology were usually *not* explicitly considered in peaking models that these models were often dismissed in some quarters as of little value.

There has been a clear evolution over time of the methods used for peaking forecasts. The early forecasts were generally top-down assessments, based on an estimated global URR and an assumed future production cycle, such as Hubbert's logistic curve. Few analysts now adhere to a symmetrical, bell-shaped production curve. This is correct, as there is no natural physical reason why the production of a resource should follow such a curve and little empirical evidence that it does (Brandt, 2007). As Hubbert himself observed, his use of the logistic curve was a mathematical convenience, not the result of a belief in its absolute rectitude. Some contemporary models now use other methods to estimate the global or regional URR and combine this with assumptions about, the rate of production from existing reserves, field decline rates, and the aggregate global rate of post-peak production decline. Other models use a bottom-up, field-by-field approach which extrapolates and sums individual field production profiles.

Many recent peaking forecasts therefore do not estimate the global URR at all, but simply sum the expected production from known and anticipated fields. The global URR is then an output of these models rather than an input, although it is still a useful reference parameter. This approach is quite appropriate if the oil peak is so close that virtually all the fields that will determine it are already discovered, and most of these are already in production. In terms of the URR, modern models include all conventional oil, regardless of its location and any physical or political difficulties that arise. The only cut-off that would be applied, usually implicitly but sometimes explicitly, is economic: very small fields in remote locations may not be made viable at any oil price if they exceed the EROI limit (energy return on investment). There is also much more attention now being paid to the slope of the post-peak decline in gross global production. The importance of quantifying field and regional decline rates has only been widely realised in the past few years.

2.2 Non-peaking forecasts

Historically, the opposite view to peak oil was that oil production would not decline below demand for the foreseeable future (usually, in more recent forecasts, meaning by 2020 or 2030). Table 2.2 summarises some of the more recent of these 'non-peaking' forecasts.

Some of these forecasts make explicit assessments about the geological resources available, while others do not. Many of them variously mix 1P and 2P reserves data, calculate future reserves growth on the basis of 1P historical experience in the US, accept at face value OPEC's declared reserves, or rely upon the USGS 2000 assessment of the size of global resources. Each of these assumptions has been a focus of dispute.

Table 2.2: Selected forecasts of global oil production that forecast no peak before 2030

Date	Author	Hydrocarbon	Ultimate (Gb)	Forecast date of peak (by study end-date)	World prodn. mb/d 2020	World prodn. mb/d 2030
1998	WEC/IIASA-A2	Cv. oil		No peak	90	100
2000	IEA: *WEO 2000*	Cv. oil (+N)	3345	No peak	103	n/a
2001	US DoE EIA	Cv. oil	3303	2016 / 2037	Various	
2002	US DoE	Ditto		No peak	109	n/a
2002	Shell Scenario	Cv. & Ncv. oil	~4000	Plateau: 2025 - 2040	100	105
2003	'WETO' study	Cv. oil (+N)	4500	No peak	102	120
2004	ExxonMobil	Cv. & Ncv. oil		No peak	114	118
2005	IEA: *WEO 2005*					
	Reference Sc.	Ditto		No peak	105	115
	Deferred Invest.	Ditto		No peak	100	105
2007	IEA: *WEO 2007*					
	Reference Sc.	Ditto		No peak	-	116

Source: Bentley and Boyle (2008)
Note: Note: Cv: conventional; Ncv.: non-conventional; +N: plus NGLs

2.2.1 Resource based forecasts

The IEA first recognised the possibility of global oil peaking in 1998, raising quite a reaction at the time. But in its *World Energy Outlook 2000* the IEA changed back to supporting its earlier non-peaking view (Table 2.2). The USGS 2000 assessment of the global URR was used to support this forecast, but without addressing whether this resource, if it exists, could be discovered and produced at the required rate. In its *World Energy Outlook 2008*, the IEA significantly modified its opinion following a detailed review of the decline rates of currently producing fields.[17] It now believes that the investment required to meet the demand for conventional oil up to 2030 is "daunting", and that the conventional oil supply will have levelled off (i.e. reached a plateau) by 2030.

Shell scenarios pre-dating their current forecasts were based on a URR of 4000 Gb, which included 600 Gb of "scope for further recovery" and 1000 Gb of non-conventional oil. These scenarios thus implicitly envisaged avoiding a liquids supply peak by a smooth transfer away from conventional oil.

[17] See the description of the IEA's model in Annex 1.

In 2003, the US EIA used a simple calculation, based on the USGS 2000 mean assessment of global URR (ex NGLs), to estimate that peak is likely to occur beyond 2030 (Wood, *et al.*, 2003). They assumed that production growth continued at about 2% per year until the global ratio of remaining recoverable resources to annual production reached 10 years.[18] Beyond that point, production was assumed to decline at a rate which kept this ratio equal to 10 years – which implied a very rapid post-peak decline (~10%/year). Peak dates from 2021 to 2112 were considered to be possible, based on the assumptions made. The study did not address either the rate of discovery or the likelihood of large reserves growth outside the US.

An EU study, 'WETO', published in 2003, assumed a global URR of 4500 Gb of conventional oil, where this was based on the USGS 2000 data (which included reserves growth) plus assumptions for significant additional reserves growth (CEC, 2003). Production was tied to price-dependent reserves/production ratios, i.e., a certain proportion of reserves would be produced annually at a given price. The study did not consider whether 4500 Gb was a realistic estimate of URR, and it ignored the constraints on how production in regions can evolve. The WETO study concluded that sufficient reserves exist to satisfy projected demand to 2030.

2.2.2 Non resource based forecasts

There was (and still is) a second group of opinions and analyses which ruled out any need to examine the oil resource base at all. These assumed that economic forces will ensure that supplies meet the market demand and encourage a relatively smooth transition to greater end-use efficiency and substitute fuels. While it is true that supply will always meet demand at some price, this could be the problem rather than the solution. The real questions are whether the resulting price will be so high as to reduce economic activity; and whether the rate of rise will be sufficiently slow and predictable to allow economies to adjust, or sufficiently rapid and unpredictable to cause disruption and shortages. Assessing the relative probability of these scenarios involves judgements about the future of conventional oil production, the behaviour of oil markets, the technical and economic potential for demand reduction and substitute fuels and (most importantly) the lead times required to displace a significant portion of current consumption. Each of these requires analysis and modelling.

2.2.3 Arguments against peaking

Before leaving this section on past forecasts, we discuss here briefly a number of the arguments that have been employed against forecasts of an early peak in global oil supply. Proponents of such arguments have, at various times, included political scientists, geographers and economists (e.g. Michael Lynch (1998; 1999; 2003), Morris Adelman, Paul Stevens, Campbell Watkins, Peter Odell); independent consultancies (e.g. CERA); international organisations (e.g. OPEC and, until recently, the IEA); government departments and agencies (e.g. US EIA the UK's Department of Trade and Industry); and some Independent Oil Companies (e.g. BP, Exxon and ENI). In general these criticisms are not focused on specific models, but instead point to more general flaws in peaking forecasts. The commonest criticisms which are raised, and the counter-arguments which are generally employed, are summarized below:

[18] This assumption derives from US experience, where for most of the last 100 years the proved reserves-to-production ratio has equalled ~10 years.

- *All forecasts of a global peak have so far been proved wrong*. This statement has, to some extent, been addressed above. It is partly informed by the forecasts from Campbell, Deffeyes and others that have given premature dates for the global peak. But it must be remembered that pessimistic supply forecasts will, by definition, be proved wrong by the historical record much sooner than optimistic forecasts and that the latter have frequently proved wrong as well.[19] In general, the poor record of long-term energy supply forecasting at both the regional and global level suggests the need for humility (Craig, *et al.*, 2002). This argument is also misleading because it ignores forecasts of a production peak at some future date which have yet to be proved right or wrong. All forecasts for a future peak, or indeed for a future without a peak, remain to be tested.

- *Global proved reserves are adequate to support sufficient production.* This assertion implicitly links future production capacity directly to global proved reserves by pointing to a current global R/P (reserves to production) ratio of some 40 years.[20] Analysis, however, shows that the peak will not be driven by a shortage of reserves but by the declining rate of output from fields which have passed their peak. The proposal that future rates of supply are assured maintained by some arbitrary R/P ratio is demonstrably false. The R/P ratio can in fact rise while both reserves and production fall - for example in UK, US and Norway between 2000 and 2007 (see Figure 1.1).

- *New fields are still being discovered, and proved reserves continue to rise almost every year. "It is thus a fact that the world is running into oil rather than out of it."*[21]*)*. This is a fundamental misconception. An oil discovery does not change the URR, but only moves that resource from the YTF category to the already-discovered category. To the extent that forecasts of a production peak rely upon assumptions about the URR or YTF, new discoveries will have no effect on the forecast. The only exception would be discoveries that were much larger than anticipated on the basis of the estimated YTF. Even then, such resources would need to be brought into production very rapidly to counteract the decline of most of the world's fields, which is currently estimated to be at least 3.0 mb/d each year (IEA, 2008). Peaking will occur while the world still has large oil reserves, caused by the difficulty of increasing the *rate* of production.

- *Middle Eastern OPEC and ex-Soviet Union countries have huge, easily exploited reserves.* The counter-argument is that this may not be as true as supposed. The large rises in reported official reserves, and their subsequent lack of change despite years of production, have caused several analysts to doubt the accuracy of OPEC's declared reserves (Simmons, 2005). In addition, there may not be sufficient incentive for these countries to install

[19] For example, in 1971 the National Petroleum Council used Delphi techniques to predict that US oil production would reach 13.4 mb/d in 1985 if prices reached $12 - $19. Actual production was 3.9 mb/d with a higher price level. Similarly, in 1974 Adelman et al (MIT energy Lab 1974) used a model by Erikson and Spann (1971) to forecast that US production would reach 19 mb/d in 1980 if nominal prices reach $12-$19. Actual production was 3.7 mb/d with a higher price level.

[20] For example stated by Lord Browne and Peter Davies, BP Chief Executive and BP Chief Economist respectively, June 2004 http://www.energybulletin.net/node/761

[21] http://www.guardian.co.uk/commentisfree/2008/feb/15/oil.climatechange

new production capacity at the rate forecast by many models and the growing internal demand in these countries may restrict the growth in export capacity (Gately, 2004).

- *The global URR of conventional oil (including NGLs) has been estimated at 3345 Gb by the USGS (2000), therefore there is no shortage of oil from reserves growth and that yet to be found.* This estimate was significantly higher than most previous estimates of 1800-2500 Gb, and remains controversial. Even if correct, the resource needs to be added to reserves at a timely rate if it is to affect the date of peak. But in practice, the rate of new discoveries, at least, appears to be significantly less than forecast by the USGS (Klett, *et al.*, 2005). The additional argument, that any ‘supply gap’ will be plugged by regions not assessed in the USGS year-2000 study, plus the fact that smaller fields will become increasingly economically attractive (Aguilera, *et al.*, 2009), requires demonstration that their cumulative volume is significant, and that - in the case of very small fields - they can be produced at an economic and energy profit.

- *The URR is not a constant but a variable, which grows due to changes in technology, infrastructure and economics*. Such changes have occurred, and many early peaking costs were too restricted in their view of URR. However, most modern models appear to take a more inclusive view of the various components of the URR, and allow for its possible growth.

- *Resource scarcity encourages substitution and improved end-use efficiency*. This argument suggests that market forces will replace oil with alternatives if shortages arise. Analysts note the size of the potential resource of non-conventional liquids, and the possibilities of electric-powered and other vehicles. But account needs to be taken of the costs and lead times required to displace conventional oil consumption. Substitution will certainly occur, but oil is essential as a transport fuel and at present there do not appear to be substitutes that come close in terms of cost, availability and utility. Undoubtedly there are alternative sources of *energy*, but it is not sufficient to assert their sufficiency, future practicality and timely application in substituting for oil: these aspects must be demonstrated.

- *Markets will reduce demand*. As noted earlier, markets must indeed reduce the demand if the peak is passed, by raising the price. But given the long life-times of energy-using capital stock, and the scale of investment required to replace that stock, the rate of efficiency improvements may not match the rate of production decline. As a result, demand reduction may be achieved through reducing what we currently regard as essential consumption. It is possible that the market solution to peak oil will be a forced and price-rationed reduction in the activities which consume oil.

3 Comparison of contemporary forecasts of global oil production

3.1 Introduction

There is a clear dichotomy in forecasts of the world's oil supply. This dichotomy has existed for several decades, growing more acutely obvious, until now there is a gulf between those who believe that there are no insurmountable supply difficulties before 2030, and those who believe that the world is near, at, or has even passed, the peak of oil supply. The year 2030 is an arbitrary date, close enough to be significant while distant enough to inform policy decisions, and a date which most forecasts reach.

The question is, how can such different results be generated? Which forecasts will finally prove more accurate, and more appropriate for steering policy decisions today? The answers lie in the way models are built, the quality of the data used, and the assumptions that have to be made. Within this section we examine a number of well-known contemporary forecasts, together with the models used to produce them, and describe the different methodologies, data and assumptions involved. We hope that this analysis may start the process of reconciling the divergent and strongly-held opinions of the forecasting community.

To some extent, fundamentally opposed views on the future of oil supply tend to follow the academic disciplines of geology and economics. The view that supply problems and a peak in oil supply are relatively imminent is commonly associated with the geological community, while the opposing view is promoted by many economists. Each side bases these views on the orthodoxies of their own discipline, sometimes in greater or lesser ignorance of the other. The resulting difference in forecasts has led to frequent misunderstandings and disputes. Both disciplines have essential and genuine contributions to make, and neither has a monopoly on truth. Each must also recognise and honour the valid arguments of the other, which constrain what may, and what may not, happen.

No forecast can be identified as correct until the event has happened. The world's endowment of oil, and hence the timing of the inevitable peak and decline of oil supply, have been described as being unknown and unknowable, and perhaps therefore by implication not worth studying, but such thinking is disingenuous. As when considering our own death, we may not know the future with perfect accuracy, but we can assess some useful limits and likely ranges of values. We cannot indicate the probable accuracy of any forecast, but we can suggest some relative probabilities, and indicate the relative reliability of the assumptions underlying them.

This report is primarily about *conventional oil* supply (i.e. crude oil and condensate and NGLs), whereas some of the models we describe forecast liquid fuels supply. The full range of liquid fuels includes non-conventional oil from tar sands and oil shales, synthetic fuels produced from coal or natural gas, and biofuels produced from plant or animal matter. The degree to which any decline in conventional oil supplies would even matter is in part a question of the contribution to be made by these alternative liquids. To turn that around, the progress we may need to make in developing alternative fuels is defined by the future of conventional oil (as opposed to liquids) supply. It is conceivable that the eventual decline in oil supply might be driven by declining demand, and the onset of alternative fuel supplies, rather than by lack of supply.

3.2 Discussion of the forecasts

The forecasts reviewed in this study are summarised in Table 3.1 which indicates the range of liquids covered by the model, whether oil demand is modelled explicitly and the general approach to modelling oil supply. A more detailed comparison is provided in Table 3.2.

Table 3.1: The models reviewed in this study

Category	Model	Liquids covered	Detailed demand modelling?	Supply modelling method	Conventional oil peak forecast before 2030?
International	IEA	All-liquids	Yes	Bottom-up; incremental supply constrained only by investment	No
	OPEC	All-liquids	Yes	Top-down	No
National	US EIA	All-liquids	Yes	Top-down, some individual country forecasts	No
	BGR (2006)	Conventional oil	No	Mid-point peaking	Yes
Oil companies	Shell	All-liquids	Yes	Bottom-up by field or country, demand constrained	Yes, but due to falling demand
	Meling (Statoil Hydro)	All-oil	No	Bottom-up by country	Yes
	Total	All-oil	No	Bottom-up by field or basin	Yes
	Exxon Mobil	All-liquids	Yes	Top-down[22]	No
Consultancies	Energyfiles	All-oil	No	Bottom-up by field or basin	Yes
	LBST	All-oil	No	Bottom-up by field or region, Hubbert-style curve for pre-peak countries	Yes
	Peak Oil Consulting	All-oil and GTL and biofuels,	No	Top-down for current production, bottom-up for new production	Yes

[22] Exxon provides very little modelling detail.

Universities and individuals	Colin Campbell	All-oil	No	Bottom-up by country, mid-point peaking, constant post-peak depletion rate	Yes
	University of Uppsala	All-oil	No	Bottom-up for giant fields, top-down for other sources	Yes
	Richard Miller	All-oil but excluding NGLs and some condensate	No	Bottom-up by field	Yes

Detailed descriptions of these models and the associated forecasts are provided in the Annex. In this section, we consider some general principles and assumptions, focusing primarily on the modelling of conventional oil supply. We start with a general observation of certain modelling flaws and then consider the fundamental components any forecast of conventional oil supply. We then introduce a diagram to help compare and contrast the different forecasts. Using this diagram, we highlight one of the primary reasons why the forecasts vary.

Table 3.2: A synopsis of the principal parameters used by the models and views studied here

Model	Liquids covered	URR (Gb)	Global YTF (Gb)	Production in 2030 (mb/d)[23]	Global Reserves growth (Gb)	Decline rates (% p.a.)	Oil Demand Growth (% p.a.)	Date of Peak	Economics / Politics
International									
IEA	All liquids	Conventional + NGLs: 3577 Gb. - Non-conventional oil sands and extra-heavy oil: 1000 - 2000 Gb. - All potentially recoverable oil resources: 6500 Gb. - All resources including CTL and GTL: 9000 Gb.	Conv. oil: 778 Gb Conv.+ NGLs: 805 Gb	106.4 mb/d of all liquids, excl. biofuels.	Conv.+ NGLs: 402 Gb	Studied in detail. World average post-peak field decline 6.7% p.a.; world post-peak decline of super-giants 3.4% p.a.; world post-plateau decline of super-giants 3.0-4.9% p.a.; in restricted dataset, decline of OPEC post-peak fields is 3.1% p.a., and of non-OPEC fields is 7.1% p.a., world average 5.1%	Average of 1.3% p.a. to 2015; Avg. of 0.8% p.a. 2015 - 2030.	No peak. Conventional oil “levels off” towards 2030, non-conventional oil keeps rising.	Concerns over adequate investment.
OPEC	All liquids	Conventional + NGLs: 3345 Gb. (This is USGS-2000 figure; OPEC judges as conservative.)	Not given: Implicitly follows USGS except for specific countries (see comment on URR.)	113.6 mb/d of all liquids	Tacitly accepts USGS growth model	Natural or observed field decline rate 4-5% p.a.	We calculate 1.14% p.a. after 2012	No peak although some countries peak. Supply: 113.6 mb/d by 2030 (of which: Conv. ex. NGLs: 82 mb/d; CTL plus GTL: 3.7 mb/d; biofuels: 3.5 mb/d.)	

[23] Includes refinery gains where these are distinguished (typically 2-3 mb/d)

National									
US EIA	All liquids	Not given	Not given	112.5 mb/d of all liquids; 109.8 mb/d excl. biofuels	Not quantified	Not given	1.16%	No peak. (Mentioned for some countries.)	
BGR (2006)	Conv. oil	Conventional + NGLs: 2979 Gb.	Conv.+ NGLs: 632 Gb.	Not given	Not quantified	Not given	Not given	~ 2020	
Oil companies									
Shell	All liquids	Modelled in-house but not given	Modelled in-house but not given	85.6 mb/d of all-oil (“Scramble”) 91.4 mb/d of all-oil (“Blueprints”)	The eventual ultimate recovery factor is assumed to be greater than today’s, but not given	Modelled in-house but not given	No growth after 2020 (Blueprints) or decline after 2020 (Scramble)	No peak for all liquids. *“By 2015, growth in … easily accessible oil and gas will not match projected rate of demand growth.*” - Peak for all-oil:: ~ 2030 (*Blueprints*); ~ 2020 (*Scramble*).	Two scenarios suggested for two different global political paths, “Scramble” and “Blueprints”
Meling (StatoilHydro)	All oil	Conv. + NGLS: Unstated, but probably 3149 Gb	Conv.+NGLS: 309 Gb.	94.1 mb/d of all-oil	520 Gb.	We calculate aggregate post-peak decline of 2.6% p.a.	1.6% p.a.	Base case: 2028. Supply fails to match demand by 2011.	
Total	All oil	Not stated	200 - 370 Gb.	93.1 mb/d of all-oil	Expressed as raising the mean global recovery factor by 5%	We calculate aggregate post-peak decline of 0.2% p.a	1.4% p.a.	2020	
ExxonMobil	All liquids	Not stated but implicitly follows the USGS (3345 Gb incl. NGLs)	Not given	105.2 mb/d of all-oil	Not given	Not given	About 1.4% p.a.	No peak Supply in 2030 includes (mb/d): - OPEC crude: 45-50 - Oil sands: >4	

								- OPEC condensates >3 - GTL: 1 - CTL: small. - Biofuels: 3	
ENI - view	All oil	Not stated	Not stated	Not stated	Not stated	Not stated	Not stated	No peak	
BP - view	All oil	Not stated	At least 300-400 Gb	95-105 mb/d is achievable and sustainable	Reserves growth: Up to 700 Gb	Cites CERA estimate that current mean decline of producing fields is 4.5% p.a.	Not stated	Eventual peak acknowledged but no date or height given	
Consultancies									
Energyfiles	All oil	2685 Gb	250 Gb.	78.6 mb/d for all-oil excl. refinery gains	Not stated but incorporated in model method'lgy	Aggregate global production decline 2% p.a. by 2022, 3% p.a. by 2029. Field decline 5-30% depending on size and location	1.8% p.a.	2017 (Assuming 1% p.a. demand growth.).	
LBST	All oil	1840 Gb	Not given	39.4 mb/d for all-oil	Not given	We calculate an aggregate post-peak decline rate of 3.5-4.0% p.a.	Not given	2006	
Peak Oil Consulting	All oil, GTL, biofuels	Not estimated	Not estimated	65 mb/d, all-oil	Not given	Currently 4.5% from existing producing fields. Aggregate post-peak decline is 2.0% p.a. by 2025 and 2.3% p.a. by 2030	Not used	2011-2013	
Universities & Individuals									
Campbell	All oil	2425 Gb, all-oil, produced by 2100	114 Gb for 'regular'	57.0 mb/d, all-oil	Not stated; assumed to be small in	We calculate an aggregate post-peak decline rate of	Not stated	2008	

			oil (excl. polar, deep-water, tar sands & NGLs)		terms of impact on peak	2.1% p.a.			
U. of Uppsala	All oil	Not stated	Not used	67.1 mb/d, all-oil	"Contributes little"	Field decline rates of 6-16% p.a.	Not modelled	2008-2018	
Miller	All oil; excl. some cond't & all NGLs	2800 Gb	227 Gb	91.5 mb/d, all-oil, excl. NGLs	0.2% p.a. cumulative increment in production	Aggregate post-peak production decline of 3.3% p.a. by 2025	Not modelled	2013-2017 (2019 given unlimited investment)	

3.2.1 Common weaknesses in oil supply forecasting

This study finds three common, generic failings in contemporary oil supply forecasts.

1. Many authors do not clearly identify all the assumptions that were made in constructing their forecast. This applies to both the 'quasi-linear' and the 'peaking' forecasts (see below for definitions of these terms). Some authors identify certain assumptions but not all, although the assumptions can sometimes be deduced. Many modellers also make certain assertions without supporting evidence. Any assertion should either be backed by evidence, or identified as an assumption.

2. Few modellers who forecast a production peak also acknowledge that this peak may not be the only critical point. As important as any peak will be any occasion when supply constraints lead to damagingly high oil prices, perhaps as a result of reductions in amount of oil available for export. There is no *a priori* reason why this should not occur markedly earlier than the peak itself.

3. Some forecasters do not use a model as such, but argue from economic principles. Such arguments are difficult to analyse rigorously, and we have not seen any useful historical precedents for the current situation in terms of liquid fuel supply.[24] We therefore take the view that any forecast with merit must indicate actual sources, quantities and production rates of oil or alternative liquids. Further, these sources, quantities and rates must be modelled, or at least shown to be viable, rather than simply asserted.

3.2.2 Fundamentals of conventional oil supply forecasts

All forecasts of *conventional* oil production, when put into graphical form, consist of three fundamental components, namely the types of oil included, the area beneath the curve which represents the URR, and the shape of curve itself. Since conventional oil is a finite resource, all viable production forecasts must rise with time to a peak or plateau, then fall away - eventually to zero. Even the models which forecast quasi-linear production growth up to 2030 must at some future date show a peak and a decline.

The curve itself can be divided into a growth phase and a decline phase, and perhaps a plateau phase. Fundamentally, the height and/or date of the peak can *only* be changed by changing either the area under the curve, or the shape of the curve. At this level, all the differences between the various forecasts described below can be viewed as changes in the URR, the growth rate and/or the decline rate, or the shape of the peak or plateau.

Some modelling techniques use the URR and/or the shape of the curve as input assumptions, while others generate one or both of these as outputs. But both types of model can be assessed according to whether these parameters are thought to be realistic.

[24] The transition from wood fuel to coal, or the peak and decline in coal usage in some countries such as the UK are often cited precedents for the current situation with liquid fuels. But given the closeness of the oil peak as calculated by many models, and the current absence of economically viable replacement fuels in sufficient quantity, these examples may not provide good parallels.

3.2.3 Types of oil

There is a range of liquids which may be included or excluded by the various models.

- All models include light and medium crude oil.
- Most models include heavy oil.
- Most models include condensates obtained directly from gas fields or from gas processing.
- Some models include NGLs, or natural gas liquids. These are perhaps unique in being little used as, or in the production of, transport fuel. The inclusion or exclusion of NGLs is a major source of differences between the various forecasts of global oil production.
- Two models (Campbell and the University of Uppsala) differentiate between conventional oil in 'conventional' places – the so-called regular oil – and conventional oil in deep-water or polar areas.
- Some models include Canadian oil sand production, which consists of bitumen extracted from oil sands (which may be reformed into synthetic crude). There are also potentially commercial liquids which can be recovered from bituminous shales.
- A few models include synthetic liquid fuels (synfuels), referred to as CTL (coal-to-liquids) and GTL (gas-to-liquids), derived from coal and gas respectively.
- A few models include biofuels, which comprise alcohols, derived from the conversion of plant sugars and starches (and potentially cellulose), and oils, derived from various oil-bearing seeds.

The inclusion of synfuels and biofuels in a model, as oil substitutes, calls into question the basic constraint of resource size (URR) as set out above. There is only a finite quantity of conventional and non-conventional oil, and its limits can be deduced within some level of probability. However, the limits of coal and natural gas, and the proportions which could be diverted from other uses to make synfuels, are far less clear. The potential volumes of biogenic gas that could be generated and used for making GTL, or of plant matter that could be grown and processed for biofuels, are also difficult to constrain. As Shell notes, oil for transport may eventually be substituted in part by electricity, although we must leave aside the question of how that electricity is generated. Substitution in both supply and demand is therefore inextricably linked to the duration of oil supply (where, again, oil as used in this report means conventional and non-conventional oil; and excludes synfuels and biofuels).

Forecasting the timing and degree of such substitution is an important topic, but is outside the remit of this study. The possible substitutions involve relatively new technologies, at least on the scale envisaged, but are these generally understood. Economists, in conjunction with scientists and engineers, need to model the speed, cost and impact of their development.

3.2.4 The area under the curve

The forecasts reviewed either assume or imply a very wide range of estimates for the global URR for conventional oil (see Table 3.2). The models which forecast a peak before 2030 estimate the URR of conventional oil to be in the range 1840 - 3150 Gb. The two models which forecast no such peak and also provide estimates of URR, suggest URR values of 3350 - 3500 Gb (but it is shown later that the other 'non-peaking' forecasts, under certain assumptions, may be compatible with a lower URR). Note that most modellers do not see URR as a true 'ultimate' figure, but as the volume that will be recoverable out to a fairly distant date.

The IEA estimates the total URR of all-oil (i.e. conventional oil, extra-heavy oil, oil sands and oil shales) to be around 6500 Gb. The inclusion of CTLs and GTLs raises this to around 9000 Gb. Total has a similar opinion while CERA[25] estimates the all-oil URR to be 4821 Gb.

Until the USGS global assessment in 2000, most estimates of the URR for conventional oil were in the range 1800-2300 Gb. The USGS (2000) mean estimate of the global URR for conventional oil (i.e. crude oil plus condensate and NGLs) was 3345 Gb.[26] This was a 47% increase on the previous USGS estimate and derived in part from the inclusion of reserves growth for the first time, and also from a significant increase in the estimated size of NGL resources. The global yet-to-find estimate for crude oil (i.e. excluding NGLs) was largely unchanged. This USGS estimate was among a new range of estimates of the conventional oil URR which now regularly exceed 3000 Gb, sometimes by a wide margin. The validity of these new estimates is discussed elsewhere in this report, and also in *Technical Report 5*.

Below we explain our approach for comparing the forecasts covered in this study. We focus on a URR that *excludes* tar sands and shales, synthetic oils and biofuels, thus restricting the URR to conventional oil as defined in this report (i.e., crude oil, condensate and NGLs). This is despite the fact that most models *include* production from Canadian tar sands. This restriction may seem arbitrary, because - as is generally recognised - 'the fuel tank does not care where its fuel came from'. But in practice, many authors of the models discussed below specify such a URR (or a close approximation), and our reasons for adopting this restriction are as follows:

- Outside Canada, the time scale for green-field oil sands projects is widely acknowledged to be too great for a significant contribution by 2030. Within Canada, various estimates put the maximum tar-sand output by 2030 to be around 6 - 7 million b/d (Söderbergh, *et al.*, 2007). It is therefore difficult to see great contributions from non-Canadian deposits.

- The URR for oil sands can be estimated independently, and uses somewhat different criteria than conventional oil.

- There are practical limitations on oil sand and shale developments, imposed both by the requirements for input energy and water, and by the political issues stemming from the pollution and environmental degradation that accrue. The URR of non-conventional oil may not be simply tapped at will.

[25] http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=8444

[26] Total oil, comprising conventional undiscovered, reserves growth, remaining reserves and cumulative production, is 362 Gb for the US (including NGLs), 2659 Gb for the Rest of World (excluding NGLs), and 324 Gb of NGLs from Rest of World. Cumulative production: US = 171 Gb, Rest of World = 539 Gb, NGLs = 7 Gb.

- Oil shales are barely commercially produced today except in Estonia, and are unlikely to contribute significantly at a global level before 2030. They are energy-intensive to extract, and their production currently creates significantly more CO_2 than does conventional oil.

- The constraints upon, and possibilities for, biofuels are of a different nature to those upon non-conventional oil.

- CTLs and GTLs are forecast to provide a relatively small contribution to total liquids fuel supply by 2030 (see, e.g. OPEC and IEA forecasts).

With these constraints, the URR for conventional oil is amenable to estimation. It can be sub-divided into five distinct components:

- Cumulative production
- Reserves (ready for or already in production)
- Fallow fields (discovered but undeveloped)
- Future reserves growth
- Yet-to-Find

These are discussed in turn below.

Box 3.1 The relevance of energy return on investment (EROI) to the ultimately recoverable resources of conventional oil

Estimating any URR is an exercise in economics as well as in geology and engineering. There is no doubt that cheaper, better technology has made more oil and other liquid fuels, both conventional and non-conventional, available for exploitation, and that this process will continue. What is less clear, and what the economic component of all the models rarely address, is where the limits may lie.

One limit is the EROI – the energy return on investment. When the total built-up energy cost, which includes steel, man-power, drilling, pumping, refining and transport costs, exceeds the energy yield of the oil involved, a field may never be economic to produce at any oil price. Calculations of the EROI must take into account the different 'quality' of fuels as reflected in their differing market price. For example, projects which convert a less valuable energy source, such as nuclear energy, into a more valuable liquid fuel may have a negative EROI on a simple thermal equivalent basis, but may nevertheless be economic. EROI is also variable with time, as energy expenditure may be reducible as circumstances and technology change. For example, the laying of a pipeline may decrease the energy investment required to exploit small, nearby fields which previously had a negative EROI.

A comparative study of the fully built up energy and cash cost of producing oil from various sources would help to clarify this question. As an example, the oil price required to sustain a new oil-sand development in Canada is presently widely suggested as $70-$80/barrel.[27] Brent crude first reached such a price in May 2007, yet oil sands have been profitably mined for several decades. This implies that the marginal production cost has risen in line with the oil price. This may indicate that EROI for new oil-sands projects is smaller than generally expected, and that marginal projects may remain marginal at higher oil prices since input costs rise in line those prices.

Another critical but unanswered question is how much oil could be produced globally without crossing this EROI limit? If higher prices made smaller conventional fields economic, would their combined volume be significant? In general, accurate estimates of the EROI of different liquid fuels are few and far between. There is a need for a careful, quantitative assessment of the effects of both EROI and the oil price upon the URR, separated into conventional oil, oil sands and oil shales.

3.2.4.1 Cumulative production

Global cumulative production has been estimated by various authorities, but it does not constitute a significant source of difference between the forecasts. We support a value of some 1150 Gb of all-oil (mostly conventional) produced by the end of 2008.

3.2.4.2 Global reserves

The size of global reserves has been fiercely debated for some years. Different authors choose (and sometimes, wrongly, mix) different definitions of reserve, and include different types of liquids. Doubt has been cast upon the declared reserves of OPEC countries, particularly the Middle East states of Saudi Arabia, Iraq, Iran, Abu Dhabi and Kuwait. The reserve estimates of these countries have not been

[27] e.g. $70-80/b is needed to source new deepwater and oil sands projects (Maersk CEO Nils Andersen, reported 13 January 2009 http://www.reuters.com/article/rbssIndustryMaterialsUtilitiesNews/idUSSP40098720090113 ; New oil-sands developments need at least $80/b oil to break even (CattleNetwork, 18 December 2008 http://www.cattlenetwork.com/Content.asp?ContentID=277650); Production costs of $40-80/b (Investors Chronicle 13 January 2009); $70/b production cost (Times Online article, 5 January 2009 http://business.timesonline.co.uk/tol/business/industry_sectors/natural_resources/article5447053.ece)

independently audited, which matters a great deal because they hold nearly 60% of the global total. In fact the reserves of these countries are the most important variable influencing the global URR.

The issue concerns the reliability of the data. At various times between 1983 and 1990, these five states, among others, recorded large sudden rises in their declared reserves, rises which were not known to be supported by either new discoveries or published and audited re-assessments. The widespread belief is that this was a political act, to increase each country's share of the OPEC production quota. The new values subsequently appeared almost immutable. For example, Saudi Arabia has produced 1% - 1.5% of its reserves base every year for the past 18 years, but without any significant change in that reserves base. Saudi Aramco staff and spokesmen have sometimes attributed the reserves increase to a re-assessment of the recovery factor. For example, in April 2008, Saudi Aramco announced a goal of raising recovery from 50% to 70% by 2020, which would represent an extra 14 years of production at 10 million b/d from the current declared reserves of 260 Gb[28]. Such increases in the recovery factor would certainly support the official size of the reserves, and would perhaps justify their lack of annual change. While such recovery factors have occasionally been achieved elsewhere, they are not known to be demonstrated for these fields. This does not mean that the OPEC reserves data are necessarily wrong; it means that we are uncertain, and that modellers can choose how best to interpret these observations.

As mentioned earlier, a potential error can occur if 1P reserve estimates for individual fields or regions are added arithmetically to produce regional, national or global 1P totals. But the size of this error depends on the probabilistic interpretation of the relevant data and in practice, published 1P data are rarely if ever '90% probable'. If available, 2P data provides a much better basis for supply forecasting (see *Technical Report 1 and 2).*

3.2.4.3 Fallow fields

We define fallow fields as those which are discovered but not currently scheduled for development. Some will be commercially viable and eventually developed, but others may be permanently non-commercial and never exploited, because they are too isolated, too small or too complex. Our concern is that these fields are nevertheless discoveries which are included in the industry dataset estimates of global reserves.

We are not aware of any systematic identification of which fallow fields are non-commercial. The IEA (2008) reports that 257 Gb of conventional oil reserves exist in known but undeveloped fields, distributed roughly evenly between OPEC and non-OPEC countries. However, these are not divided into economic and non-economic. BP recently analysed IHS data[29] and found that at least 231 Gb of discovered 2P reserves had not been developed by the end of 2007 (although some were in development), or 17% of the 2007 total. 135 Gb of this was discovered more than 10 years ago, 104 Gb more than 20 years ago, and 64 Gb more than 30 years ago.

Old discoveries are continually being developed, but we do not know how many more will be viable. This issue is indirectly highlighted in Miller's model, which estimates the future production which would be possible by the rapid development of all

[28] http://nextbigfuture.com/2008/04/saudi-arabias-state-future-oil-goals.html
[29] This analysis excluded US and Canada onshore (R. Miller, pers. comm.)

reserves, including those in fallow fields. This results in an improbable excess of production capacity over forecast demand for over a decade.

3.2.4.4 Reserves growth

The USGS(2000) have defined reserves growth as:

"……. the increases in estimated sizes of fields that typically occur through time as oil and gas fields are developed and produced ... This increase is generally considered to be proportional to the total size of the field. Reserves growth is a major component — perhaps the major component — of remaining U.S. oil and natural-gas resources."

Reserves growth is perhaps more accurately described as 'growth in initial reserves', since it is the estimate of cumulative discovery (i.e. cumulative production plus current reserves) that is growing, rather than just the current reserves.

The USGS assessment in 2000 was the first of their assessments to apply future reserves growth to global data. The estimated P50 (mean) value of reserves growth world-wide was 612 Gb over the 30 years from 1995. This surprised many commentators, as it was comparable to the reserve additions anticipated from new discoveries over that period. Put into annual terms, the average quantity of reserves growth (~20 Gb/year) would amount to two thirds of current annual production (~30 Gb/year).

The criticisms levelled at the USGS estimate for reserves growth were recognised by the USGS at the time, and so far the USGS has apparently been proved correct. In 2005, Klett *et al*. (2005) calculated the extent of reserves growth outside the US during the eight years following 1995 (the base year of the study). They found that, according to IHS data, 171 Gb, or 28% of the expected growth over 30 years, had occurred, in 27% of the 30-year time frame. More recent data also support this trend (see *Technical Report 3*). But a number of factors and unique revisions, in addition to technical recovery gains, can generate such apparent reserves growth, and it cannot automatically be assumed either that such growth was real, or that it will continue in the future.

The IEA (2008) assesses that the average global recovery factor might, at some point after 2030, reach 50%, from its current 35%. This, they conclude, would effectively raise global remaining recoverable resources by 1200 Gb. There is insufficient detail to be certain whether the problem of retro-fitting new technology to existing fields is addressed, but it may not always be economic to install expensive EOR technology into small, old or abandoned fields.

Overall, reserves growth, however, is a serious issue which cannot be ignored. It may be described by different authors as reserves growth, as EOR and enhanced recovery, or as growth due to improved technology. It can be included in models either within the URR (i.e. an increased volume) or as an addition to annual production (an increased rate).

3.2.4.5 YTF: Yet-to-Find

YTF is an equally contentious issue. In 2000, the USGS estimated that 939 Gb of conventional oil remained globally to be discovered (732 Gb of oil, and 207 Gb of

NGLs).[30] This was considered to be accessible in the foreseeable future using existing technology, not a forecast of what would actually be found in the following 30 years. The estimate was considerably higher than most contemporary estimates, which were typically around 200-300 Gb. A subsequent USGS review (op. cit.) found that only 11% of the non-US YTF had been discovered after 27% of the assessment period. Although some took this as evidence that the USGS had overestimated the YTF, the 11% figure may underestimate actual discoveries over this period as it does not allow for future reserves growth in the newly discovered fields. Also, exploration was restricted in a number of the most promising areas (e.g. Iraq).

The observed finding rate of the non-US YTF equates to 1.4% of the USGS estimate per year. If applied globally, this would suggest that remaining global YTF at the end of 2008 comprised 603 Gb of oil and 179 Gb of NGLs.

3.2.4.6 URR: sensitivity

We estimate here the general sensitivity of the size of the global URR of conventional oil to the size of the uncertainties in the five components listed above. The greatest sensitivity is shown by the data for the yet-to-find, reserves, and reserves growth; where the ranges of estimates are all of similar magnitude. Uncertainty on the quantity of oil in fallow fields has a smaller effect; and that on past production little effect.

- *Past production: Little sensitivity:*There is little scope for large variations in historical production. CERA [31] for example has estimated 1080 Gb produced as of November 2006, which is close to our estimate of 1150 Gb as of December 2008, based upon Campbell's historical data and BP *Statistical Review* recent production data.
- *Fallow Fields: About 150 Gb of reserves may not be developable:* This estimate is based upon BP's review of IHS data discussed above.
- *Reserves Growth: About 450 Gb of reserves growth may occur:* This estimate is based upon the USGS mean estimate of 730 Gb, of which they report 171 Gb realised by end-2003, or 21.4 Gb/y. If we estimate a further 107 Gb of growth to have occurred in the following 5 years, then by January 2009, some 452 Gb of growth may yet remain to be realised. This could be a conservative estimate since the USGS study was confined to the period up to 2025. However, the range of uncertainty in the USGS reserves growth estimate was very large: namely between 229 Gb at P95 to 1230 Gb at P5.
- *Yet-to-Find: The range between low and high estimates is some 670 Gb:* Some models do not estimate YTF, referring instead to the global URR. Direct estimates include (in order): Campbell 114 Gb of 'regular' oil; Miller 227 Gb conventional oil; Energyfiles 250 Gb; Total 200-370 Gb (probably of conventional oil); Meling 309 Gb of conventional oil including NGLs; BP implicitly 300-400 Gb; BGR 623 Gb including NGLs; IEA 805 Gb including

[30] http://pubs.usgs.gov/dds/dds-060/ESpt4.html#Table
[31] http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=8444

NGLs; USGS 939 Gb in 1995 (we suggest an estimated 782 Gb as of end 2008 [32]).

Reserves: The range of estimates is some 600 Gb: The IEA's *WEO 2008* gives a review of the conventional estimates of the proved (1P) reserves, which range from 1120 Gb in *World Oil* to 1332 Gb in *Oil and Gas Journal*. The *Oil and Gas Journal* estimate includes 173 Gb of Canadian oil sands. The BP *Statistical Review*, which is often cited, lists reported proved global reserves of 1238 Gb. This is not an independent estimate, but sums official and public source data, and includes 21 Gb from Canadian oil sands projects under active development. For proved plus probable (2P) reserves, IHS estimates some 1241 Gb, which would imply that 1P reserves are smaller. The smallest estimate is that of Campbell,[33] which discounts part of the OPEC and FSU 2P reserves, and also excludes polar, deepwater, very heavy oil and NGLs, to reach a figure of 734 Gb for the 2P reserves of 'regular' oil. CERA implicitly accepts 'proved reserves', although without defining the term, of 1200 Gb.[34] They may, in fact, be referring to 2P reserves.

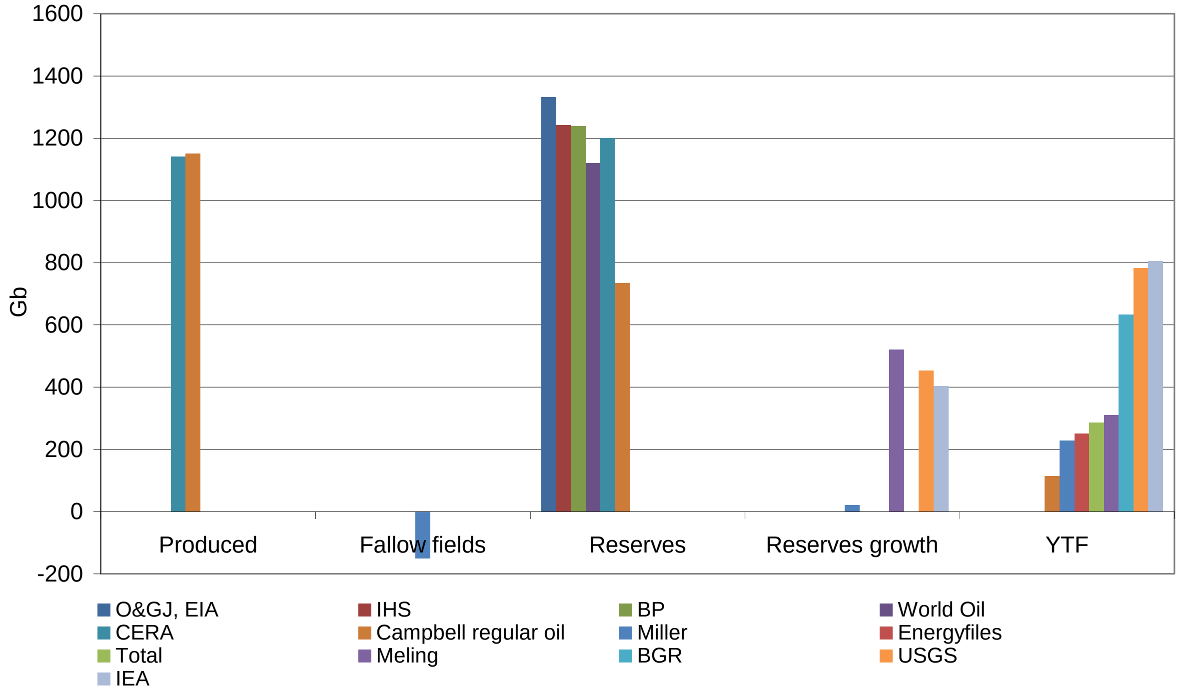
In conclusion, the models differ largely in their assumptions for reserves growth and YTF. Taken together, these give an uncertainty of 1100 Gb in the assumed global URR of conventional oil. If Campbell's low estimate is excluded, the different assumptions for global reserves contribute an uncertainty of some 210 Gb while the uncertainties over fallow fields contribute approximately 100 Gb. The smallest (mean) URR estimate is 1840 Gb (LBST) while the largest is 3577 Gb (IEA).

[32] The USGS (2000) estimated that mean YTF as of 1995 comprised 649 Gb oil and 207 Gb NGL from outside the US, and 76 Gb oil and 8 Gb NGLs from within the US. In 2005 the USGS reported that up to end 2003, 69 Gb of oil had been discovered outside the US, a finding rate of 1.4% p.a.. If this finding rate applies to all oil categories, then we calculate that as of end 2008, the remaining global mean YTF according to the USGS would be 603 Gb oil and 179 Gb NGLs, total 782 Gb

[33] http://www.aspo-ireland.org/contentFiles/newsletterPDFs/newsletter95_200811.pdf.

[34] Comprising: 662 Gb "OPEC Middle East", 378 Gb "Other Conventional", 50 Gb "Deepwater" and 110 Gb "Arctic" http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=8444

Figure 3.1 Constituents and range of uncertainty in the model assumptions for the global URR of conventional oil



Notes:

- Compares the assumptions of eight of the models, together with reserve estimates from various sources that are used by the models
- Some authors assume zero reserves growth while others anticipate growth but do not quantify it.
- Miller argues that a significant portion of the fallow fields will not be developed.
- 'Produced' column for 'Campbell regular oil' sums Campbell's production data to 1980 and BP (2008) data thereafter. This largely reflects global 'all-oil' production as the bulk of 'non-regular' oil has been produced since 1980.

3.2.5 The form of the curve

All supply forecasts can be divided into a growth phase, a peak with or without a plateau, and a decline phase. The forecast is rarely symmetric. Those forecasts with a significant phase of supply growth – the Campbell model essentially has none – either extrapolate supply to follow the forecast demand, or ignore demand to forecast the maximum possible oil production capacity (Miller's model). Simple models extrapolate historical demand trends while more sophisticated models model energy demand using assumptions about population growth, GDP growth, the secular change in energy intensity and other variables. But despite these differences, the rate of demand growth up to the peak (or up to 2030 if no peak is anticipated) is relatively similar in all of the forecasts (e.g. ~1.3%/year).

The form of the peak itself can be relatively sharp (e.g. Peak Oil Consulting) or drawn out into a plateau. It is fair to say that most commentators and modellers verbally expect the form of the peak of oil production to be an undulating plateau, and equally fair to say that no-one has produced a quantitative model of such a plateau. Such a model would necessarily include the feedbacks between supply and demand.

The assumed form, and gradient, of the post-peak decline are fundamental. The decline rate (either field or aggregate decline) is sometimes an output parameter but often an input parameter, in which case the form generally used is exponential, with a fixed rate of decline year on year (see *Technical Report 4*). While usually no *a priori* evidence is provided that exponential decline is the correct function, it serves as an approximation. In practice, decline is likely to be a more complex function than this, because of the different components which it includes. Some care in defining the decline rate is therefore required.

The post-peak decline in global oil production will be the net effect of (i) the average decline of post-peak fields, (ii) the zero decline of fields which are at plateau, and (iii) the contribution of fields which are just coming on stream, are in development, or indeed have yet to be discovered. Some good data are now becoming available on the average decline rate of post-peak fields (CERA, 2008; Höök, *et al.*, 2009; IEA, 2008), despite the five-or even ten-fold range in decline rates found between large on-shore fields and small off-shore fields. More serious perhaps is the lack of data about the fields which are on a plateau. We are not aware of any quantitative estimate of how many fields or how much production falls into this category.

3.3 Overview and comparison of the forecasts

3.3.1 Graphical comparison

Figure 3.2 presents global forecasts from thirteen of models reviewed in this study.[35] Most of the forecasts cover all-oil, but the precise coverage of liquids varies from one model to another. A common production history from 1990 to 2007 is provided using BP *Statistical Review* data for the annual global production of all-oil.

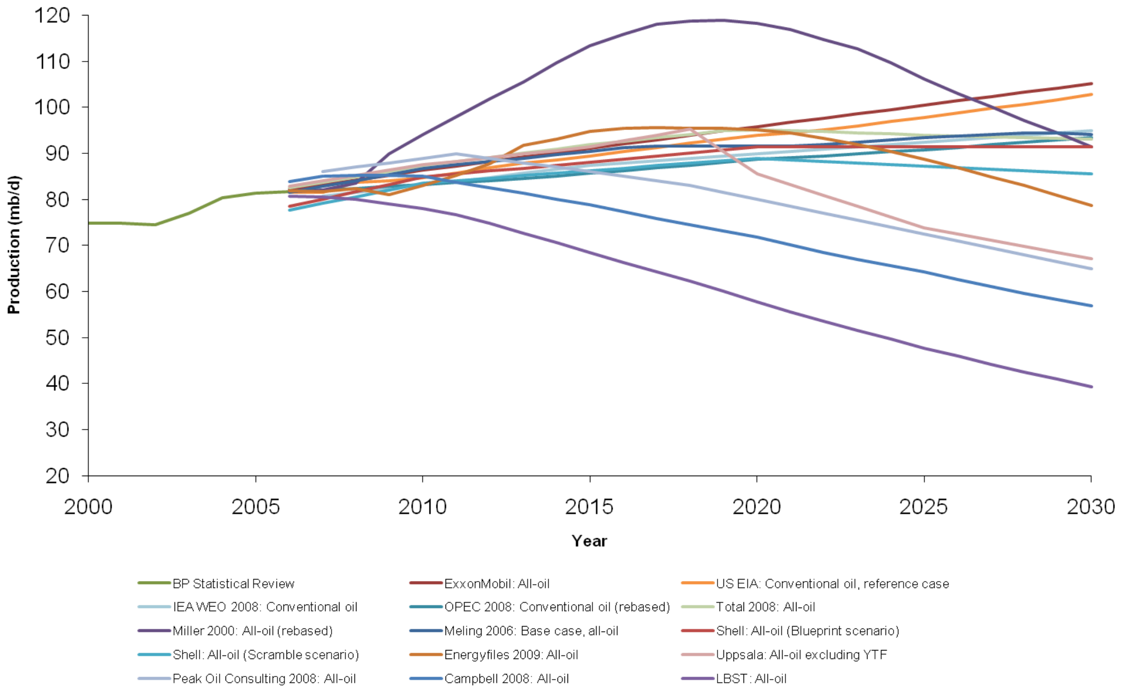
In cases where modellers provide alternative forecasts, only their 'base case' models are shown on this Figure, with the exception of Shell, which shows two 'scenarios'. OPEC's conventional-oil forecast, and Miller's model, which both exclude NGLs, have been re-based here for plotting such that their forecasts match the BP *Statistical Review* value for oil production in 2007, which does include NGLs. Growth in NGL supply means that this re-basing may lead to an over- or under-estimate by 2030 of perhaps 2 million b/d, which for our purposes is not significant.

The first striking observation from Figure 3.2 is the sheer range. The highest estimated production for 2030 is almost three times the lowest, with the range of forecast peak dates ranging from the immediate past to the indefinite future. It may seem surprising that authoritative studies can reach such different conclusions on such a crucial question.

One immediate cause of this range is that models include or exclude different components; and in particular, synthetic fuels derived from coal and gas, and biofuels. This cannot be avoided, and the different assumptions are identified in the discussion below where appropriate. But even when only 'all-oil' is considered (solid lines on the plot), the production range by 2030 is over two and a half times.

[35] BGR has published its modelling technique, but has not, we believe, recently published a detailed forecast.

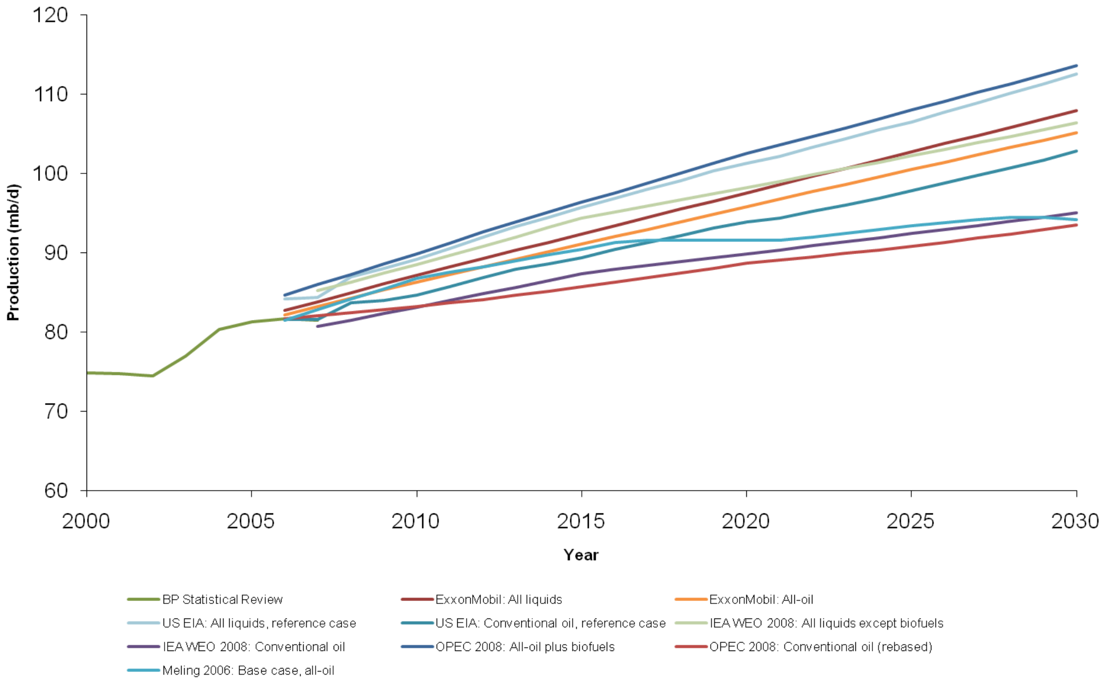
Figure 3.2 Comparison of thirteen forecasts of all-oil production to 2030



Note:
- Annual global production from 2000 to 2007 taken from BP (2008).
- Forecasts refer to all-oil as far as possible, but coverage of liquids does not always coincide.
- The OPEC and Miller forecasts exclude NGLs. These forecasts have been ‘re-based’ here to match the BP production figure for 2007. Since the estimated production of NGLs is assumed to remain fixed until 2030, these forecasts may be downwardly biased.

There are two basic groups of model results in Figure 3.2. The first group (amplified in Figure 3.3) indicates an approximately linear growth to 2030, such that if the modellers foresee a peak it is beyond the end of their forecasts. These ‘quasi-linear’ forecasts are those from the IEA, US EIA, OPEC and ExxonMobil (and the views of ENI and BP are in broad agreement). For these four models, two forecasts are shown - ‘all-oil’ and ‘all liquids’. These models generally forecast oil demand and then allocate sources of supply to fill this demand.

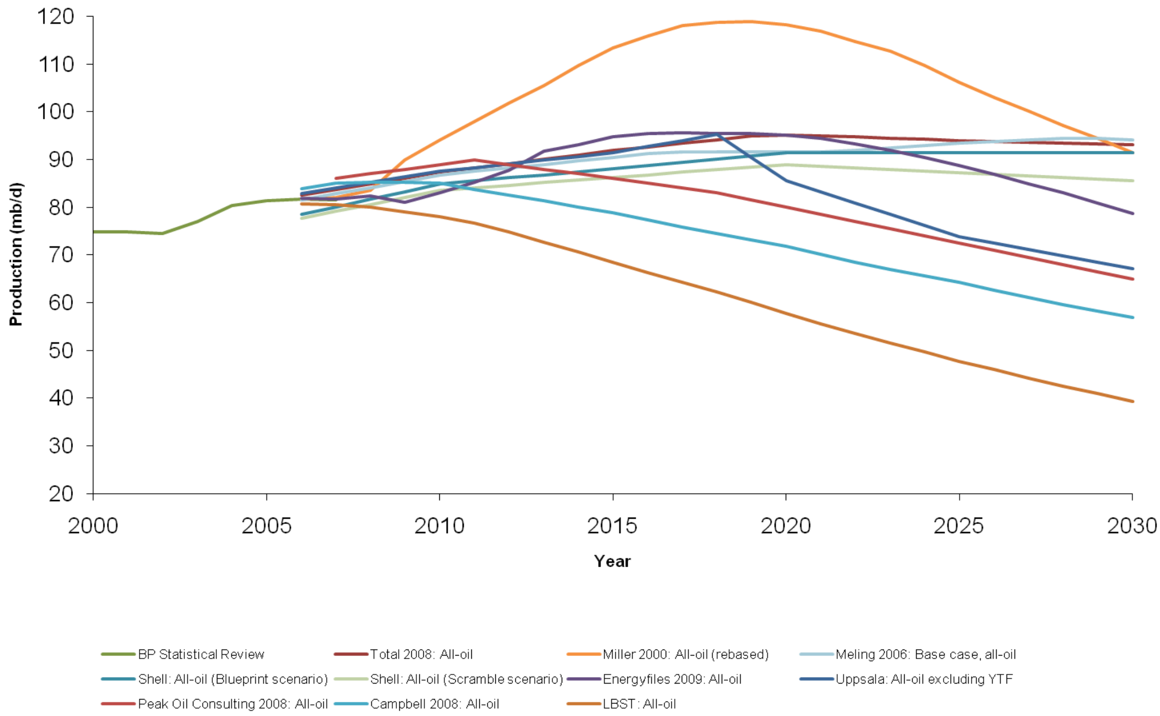
Figure 3.3 'Quasi-linear' forecasts of all-oil and all-liquids to 2030



The second group of forecasts (Figure 3.4) indicates some form of peak in all-oil production before 2030, followed by a decline. The LBST, Campbell, Peak Oil Consulting, Uppsala, Energyfiles and Total forecasts initially forecast demand rising approximately linearly before falling away due to resource limits. Meling's model, as noted, peaks late but does not meet forecast demand beyond 2011. Miller's model is specifically not a forecast of actual production, but of the maximum that could possibly be achieved, regardless of cost, were all fallow fields and new discoveries to be developed immediately. Consequently this model shows an initial rise of potential capacity beyond demand, before falling away.

The annual rate of post-peak decline of global oil production (the 'aggregate' decline) is variously forecast to be about 0.2% (Total); rapid initial decline which levels off to just under 2% (Uppsala); 2.1% (Campbell); 2.0% in 2025 rising to 2.3% in 2030 (Peak Oil Consulting); 2.0% in 2022 rising to 3.0% in 2029 (Energyfiles); 0.4% in 2030 rising to 2.6% (Meling); 3.3% from 2025 (Miller); and 3.5-4.0% (LBST). The URR of these peaking models is variously defined, but as a guide ranges from 1840 Gb (LBST) to 2800 Gb (Miller) and 3149 Gb (Meling).

Figure 3.4 'Peaking' forecasts of all-oil production to 2030



3.3.2 Isolating the key parameters

In this section we introduce a fairly simply approach for comparing the key assumptions (explicit or implicit) in the different forecasts reviewed, so as to help explain why they differ, and to assist in forming judgements on the merits of each.

The fundamental variables of oil production forecasts have been identified above as: the rate of production increased prior to the peak; the rate of production decline following the peak; the area under the curve (the URR); and the shape at peak (peak vs. plateau). The interplay between the three key variables of URR, peak date and the global post-peak production decline rate is shown in Figure 3.5. Here all the other parameters (slope up to peak, shape of peak, and starting production volume and level) have been fixed at reasonable values, matching values typical of most of the models studied. Specifically, in Figure 3.5**Error! Reference source not found.** we have assumed that:

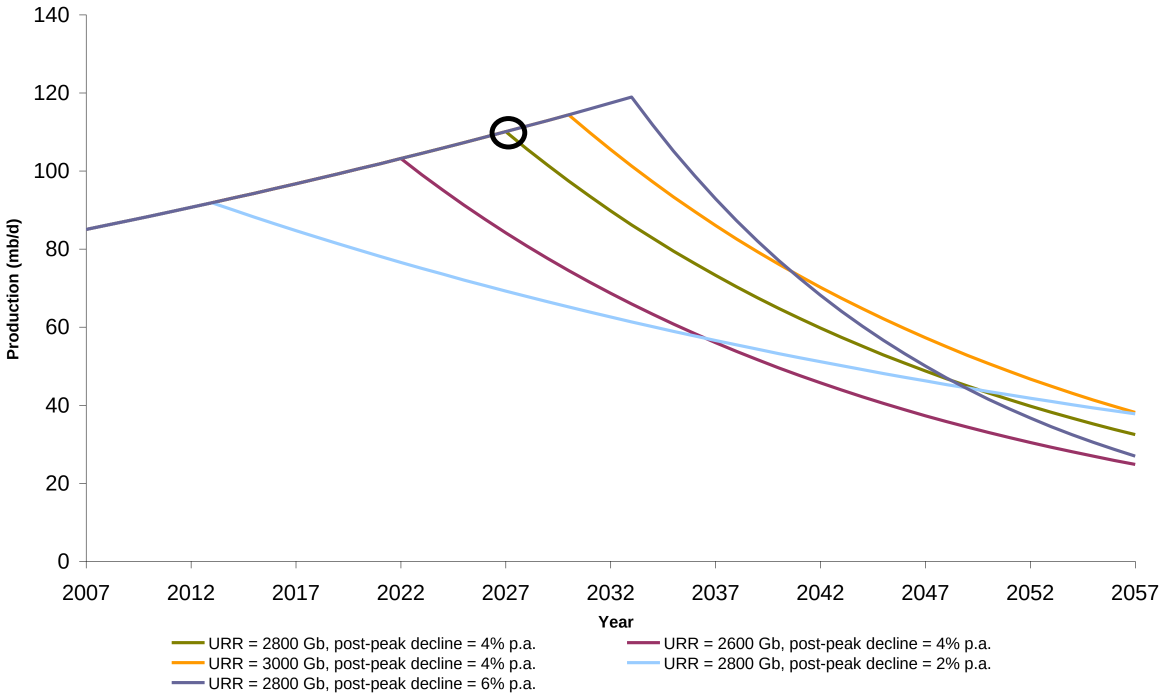
- Production climbs exponentially to a peak and then declines exponentially at a different rate, producing a sharp peak (this production cycle is unlikely in practice, but serves as a simple approximation). [36]
- Production continues for 100 years after peak, and the cumulative production by then is the effective URR. Figure 3.5 shows URRs of 2600, 2800 and 3000 Gb.

[36] The curve may be interpreted as initially steady growth in demand which is met with a combination of the existing but declining supply, new supply, and spare capacity coming on-line. The peak occurs when the last spare capacity has been committed, including any shut-in OPEC supply. The subsequent decline in global conventional oil production happens relatively suddenly because spare capacity can no longer be brought on line ("nothing left in the bank"). Consequently a relatively sharp change occurs as a discontinuity in the overall supply, even though demand, existing supply and new supply from new discoveries are changing smoothly.

- The growth rate to peak is 1.3%/year
- The decline from peak is shown for values of 2%, 4% and 6%/year
- Production in 2007 is 85 mb/d and cumulative production by end 2007 is 1150 Gb.

The assumption of a 1.3%/year growth rate up to the peak is particularly important since (other things being equal) a faster rate of demand growth should lead to an earlier peak and *vice versa*. The 1.3% assumption is consistent with the assumed or modeled growth rates in the majority of the forecasts, but these were developed prior to the global economic recession of 2008. The recession has reduced global oil demand which could delay the peak in a similar manner to the oil shocks of the 1970s. At the same time, the recession has led to the cancellation or delay of many upstream investment projects which could lead to near-term supply constraints when demand recovers (IEA, 2009).

Figure 3.5 The effect on the date of peak of varying the URR and the post-peak aggregate decline rate

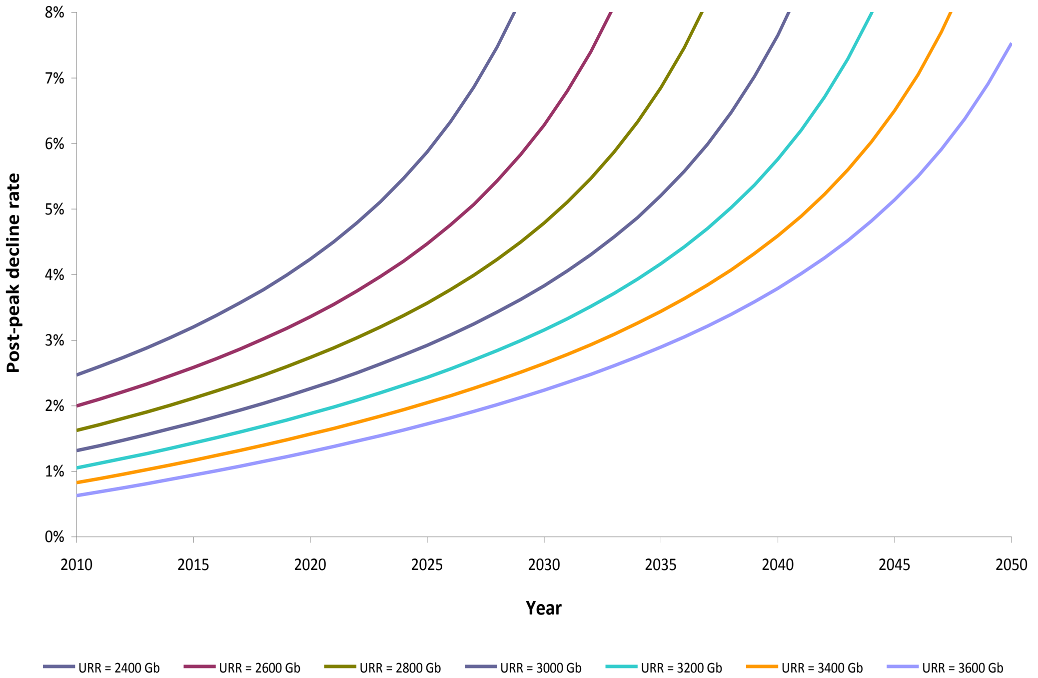


Note: The circled point, for example, indicates the date of the production peak (in 2027) that results from an assumed growth rate of 1.3%/year, a URR of 2800 Gb and a decline rate of 4%/year For a given growth rate and URR, a slower aggregate decline forces an earlier peak and vice-versa.

Rather than plot all the models reviewed on graphs like Figure 3.5, the graph can be re-formulated to focus on the three key parameters of interest: the URR, the post-peak aggregate decline rate, and the date of peak.

This is done in Figure 3.6, which is a plot in the co-ordinates of post-peak decline rate against peak year, and where potential URR values are shown by an array of iso-lines. The key property brought out by this graph is that once values are assumed for any two of these parameters, the value of the third is determined. For example, the circled point shows that if the URR is 2800 Gb and the post-peak production decline rate is 4% p.a., then the peak must occur in about 2027 (the case shown in Figure 3.5).

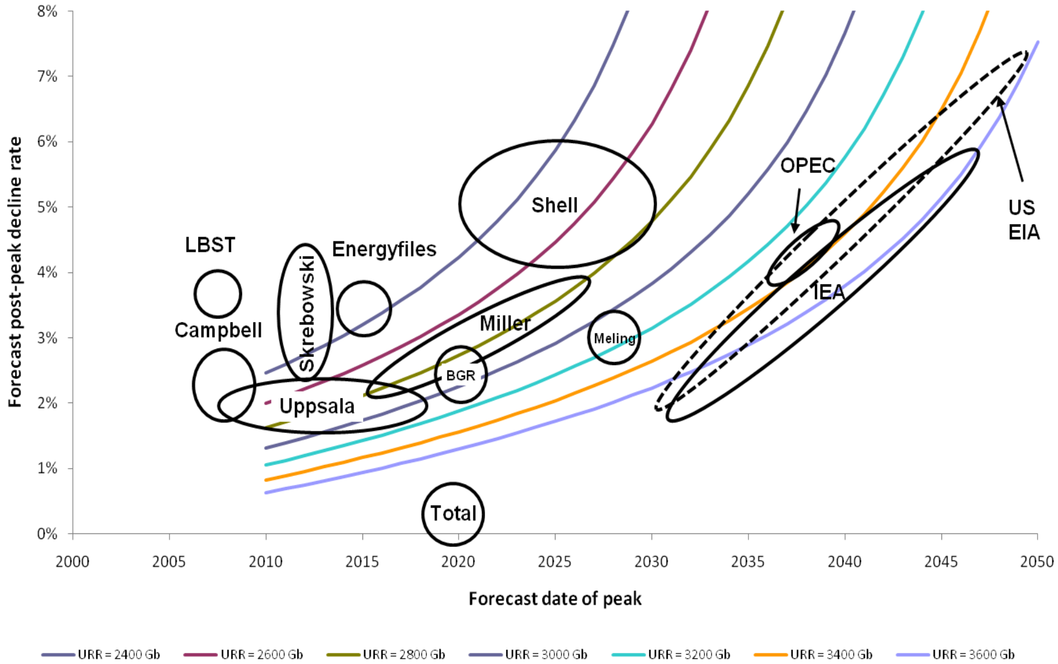
Figure 3.6: Solutions of peak year and post-peak production aggregate decline rate for various values of URR (for assumptions see text).



Thus any forecast which specifies two of the three parameters can be plotted in this space. Even where a forecast provides only one parameter, then by making reasonable assumptions the forecast can also to be put in this space, albeit in the form of a region, the constraints of which are set by the assumptions made. Figure 3.6 therefore forms a framework which enables us to compare and contrast almost any forecast.

Figure 3.6 may now be populated with data from the four reviewed, to create Figure 3.7. Thirteen models are depicted as ellipses, which broadly define the area which we judge the models to occupy in this space (the Exxon forecasts provides insufficient information to allow it to be located). The assumptions which have had to be made in order to construct these ellipses are described below. As far as possible, the production and URR values for each model are limited to *conventional oil* (which includes NGLs), plus current oil sands production. The initial assumptions that we have made in constructing Figure 3.7, such as 1.3% growth rate and a pure exponential growth and decline, do not exactly match each forecast in detail, but the overall picture remains sufficiently robust to be useful. Figure 3.7 thus shows which models give what sorts of results, and why this happens.

Figure 3.7 Mapping global supply forecasts according to the implied URR of conventional oil, the date of peak production and the post-peak aggregate decline rate.



Note: Iso-lines represent the assumed or implied global URR of conventional oil. Assumes rate of increase of production prior to the peak is 1.3%/year. Mapping of individual forecasts onto this graph involves some judgment. Conventional oil on this plot includes crude oil, condensate and NGLs, but in some cases may also include production from currently operating and planned oil sands production as this is difficult to separate out. Excluded is oil from oil sands plants not yet planned, oil from shale, and other liquids (GTLs, CTLs and biofuels). Note that Total specifically includes extra-heavy oil in its model

3.3.3 Locating the peaking forecasts

The end-date of most of the forecasts studied is 2030. On Figure 3.7, the 'quasi-linear' forecasts appear to the right of the 2030 line, while the 'peaking forecasts' appear to the left of the 2030 line.

The peaking forecasts are relatively easy to locate on Figure 3.7. All of these forecasts are marked by low decline rates, whether as an input or an output. These are sometimes the cause and sometimes the effect of an early peak. Apart from Total, it is primarily the different assumptions for the URR that accounts for the differences in the forecast date of peak within this group. Our specific assumptions are as follows:

- Campbell's model explicitly peaks in 2008 with a URR of 2450 Gb. We show this as a small ellipse. The post-peak production aggregate decline rate is about 2%/year, which is the lowest of all the models except for Total, and is one reason why Campbell's model produces an early peak. Campbell's model is a bottom-up forecast at a country level, so it is not really amenable to arbitrarily raising production, delaying the peak and increasing the post-peak decline: any increase would have to be assigned to a particular field or country, contrary to the data. The decline rate, based upon depletion rates, is also an output of his model, not an input, so it cannot be adjusted without evidence. Nevertheless, if production rates could be raised, with a consequent increase in the post-peak production decline rate, this model's forecasts would fall comfortably within those of other models.

- Peak Oil Consulting's model lies somewhat different to the others. It focuses on near-term production up to 2016. This is tightly constrained by the lead time of major projects, because those which will come on-stream within this period must already be committed. The URR is not required or stated in this bottom-up model. The model is bottom-up by project for new production, with a simple decline assumption for current production. The peak is 2011-2013 and the field decline rate is expected to be 4.5% (so the aggregate global production decline rate will be less). We show this model as an ellipse centred on 2012, with a global post-peak oil production decline rate of 2.5% - 4.5% p.a. The effective URR would appear to be one of the smallest among these models, perhaps less than 2200 Gb.

- The Energyfiles bottom-up model peaks in 2015 with a URR of 2338 Gb. The aggregate post-peak production decline rate is not mentioned, but field post-peak decline rates of 5% - 30% p.a. are noted. We show this model as a small ellipse, and it indicates a post-peak global oil production decline rate of around 3.5% p.a.

- Miller's bottom-up model is unique in estimating the absolute maximum production that might be achieved, without being constrained to match demand. The URR is 2800 Gb and the peak is around 2018. Because this is the maximum possible production, the potential excess before 2018, if it is ever producible (which Miller doubts but cannot demonstrate), would in practice be deferred. This is shown as a rotated ellipse, centred on 2800 Gb and ranging between 2015 and 2027.

- The BGR model has very little information except a URR of just under 3000 Gb and a peak in 2020. The implied decline rate must therefore be about 2.5% p.a.

- Total forecasts a peak of all oil at 2020. Neither the decline rate nor the URR is stated, but we calculate the post-peak aggregate decline from their data to be 0.2% p.a. We have placed a circle at this point, but note that the implied URR is at least 4500 Gb. Total estimates that original conventional oil in place is 6500 Gb, with a further 2800-3600 Gb of heavy oil, so this URR may correctly reflect Total's assumptions. Alternatively, the aggregate decline rate may steepen after 2030.

- Uppsala estimates a peak between 2008 and 2018. They do not state a URR (their model excludes all consideration of YTF), nor an aggregate post-peak production decline rate. Their forecast indicates an initial rapid aggregate decline which finally levels off to just under 2% p.a.. Their model is shown as an elongated ellipse.

- Meling's model has a peak in 2028 and a URR of about 3150 Gb. This is shown as a small circle. The implied aggregate global production decline rate is about 3.0% p.a.

- The LBST model uses the smallest explicit value of the URR (1840 Gb), and estimates that peak occurred in 2006. The aggregate post-peak decline rate is between 3.5 and 4% p.a. This model is shown as a small circle almost centred at these values, although it is actually off-scale for the date.

All the peaking models are marked by low rates of post-peak aggregate oil production decline, whether this decline rate is an input parameter or an output. Low decline rates are sometimes the cause and sometimes the effect of an early peak. Apart from the Total model, it is primarily the range of URR that accounts for the range in the forecast peak date.

3.3.4 Locating the quasi-linear forecasts

The quasi-linear forecasts are more difficult to locate, since the relevant information is not always provided. However, some bounds may be placed upon the aggregate post-peak decline rate. This should be less than the managed decline rate of post-peak fields because there will always be some new fields coming on stream. Taking the IEA's production-weighted estimate for 2007, this gives an upper bound of ~6.7%/year (although this is expected to increase). Lower aggregate decline rates imply larger estimates of the global URR. Furthermore, the difference between the managed decline rate of post-peak fields and the aggregate decline rate of total production needs to be met by incremental production from new projects. These could be either new discoveries, EOR projects at existing fields or the development of fallow fields. The volume of new resources that needs to be added each year will depend upon the rate at which they can be produced which is subject to physical, engineering economic constraints. Taken together, these considerations constrain the minimum decline rate that can be considered reasonable, although precisely what that should be is open to debate. We consider that decline rates of less than 2.5%/year would be difficult to justify beyond 2030.

Our specific assumptions are as follows:

- The IEA forecast reaches a plateau by 2030 of un-stated duration and assumes a URR of 3577 Gb. A peak date at ~2030 requires an aggregate decline rate of <2.5%/year which is less than the decline rate of the super-giant fields and seems difficult to reconcile with the IEA's estimate of a global average managed field decline rate of 8.5%/year by 2030.[37] But if the peak were delayed, the decline rate would need to be higher or the URR larger. We show this forecast as a narrow, slanted ellipse, centred on 3600 Gb and extending between a peak year of 2030 and a maximum decline rate of 6%/year.
- The US EIA forecast does not quantify the conventional oil URR and post-peak aggregate decline rate. However, an article published by the US EIA in 2003 assumed an aggregate decline rate of 10%/year and endorsed the USGS estimates of the global URR (Wood, *et al.*, 2003).[38] Here we use 8% as the upper limit for

[37] The difference of some 6% (and rising) of global production in 2030, or 2.1 Gb/year, would have to be found from reserves growth and new discoveries. If these resources were to be produced at an average depletion rate of 5%/year, then ~41 Gb would need to be added each year to maintain an aggregate decline rate of 2.5%/year. The rate of reserve additions would need to be higher if (as seems likely) the depletion rate was lower. These assumptions seem very optimistic.

[38] Wood *et al*. assume production declines exponentially at a depletion rate of 10%/year. With exponential decline, the decline rate is equal to the depletion rate (Section 3.4). While they justify the 10% figure with reference to US

the decline rate and a mean estimate of ~3600 Gb for the URR. In EIA's reference scenario, conventional production reaches 102.8 mb/d in 2030 and no peak is forecast. In the high price scenario conventional supply has passed peak by 2030, partly as a result of non-conventional fuels becoming more competitive. We therefore show this forecast as narrow, slanted ellipse, centred on 3600 Gb and extending between a peak year of 2030 and a maximum decline rate of 8%/year.

- It is not possible to accurately decompose the OPEC forecast into its component liquids. If we estimate OPEC NGL production at 7 mb/d by 2030, the forecast implies production of some 100 mb/d of conventional oil in 2030. The URR is stated as 3345 Gb, and OPEC estimates the global aggregate production decline rate to be 4-5%/year, but lower in OPEC states which may dominate future production. We show this forecast as a narrow, slanted ellipse, centred on 3345 Gb and extending between an aggregate 4-5% decline rate.
- ExxonMobil's forecast reaches 116 mb/d by 2030, the highest of all those reviewed. This includes some 105 mb/d of conventional oil. No other robust data are quoted, and there is no consideration of post-peak decline. In the absence of estimates for the peak year and URR, the location of this forecast on Figure 7.7 is relatively unconstrained. We therefore omit it from the diagram.

All these quasi-linear models, to greater or lesser degrees, first estimate future demand before forecasting supply. The latter is normally met first through conventional oil, generally followed by non-conventional oils (extra-heavy oil, oil sands outside Canada, and oil shale), biofuels and synfuels – typically using assumptions about marginal cost. There is nothing inherently wrong in such an approach, although a target demand could potentially introduce a bias into the supply estimates. However, there may be questions about some of the specific assumptions made:

- The forecasts of supply from the Canadian oil sands are potentially optimistic. The IEA estimates that Canadian oil sand production will rise from today's <1.5 million b/d to 5.9 million b/d by 2030, while Meling estimates some 7.5 million b/d. We estimate the sum of all current and currently proposed Canadian oil-sands projects to be 6.7 million b/d in 2030, but it seems unlikely that this will actually occur, particularly in light of the currently unfolding financial crisis. Concerns also include inadequate water and energy supplies, CO_2 emissions and environmental degradation. Also, the cost of new oil-sands projects has been rising in line with the oil price, so that new projects may be somewhat more marginal, at any oil price, than expected.

- The assumption of rapid biofuels development may be optimistic, as a high supply of current-technology biofuels would both remove sugar and starch from food-streams, and require large changes in land use. A significant contribution from biofuels may require the commercial development of cellulose-to-alcohol technology.

experience, this is invalid since the US depletion rate is measured with respect to proved reserves while the EIA depletion rate is applied to the USGS (2000) estimate of remaining recoverable resources (i.e. URR minus cumulative production). As a result, the assumed depletion rate is much larger than experienced in the US and other oil-producing regions.

- Synfuel production raises issues of high capital cost, feedstock cost, security, and CO_2 emissions. These factors can be modelled, but introduce significant uncertainties and constraints.

Without the reliance on all-liquids which marks all the quasi-linear models, these models would need to assume either a higher URR for conventional oil or a more rapid post-peak decline rate in order to meet their forecast demand.

Only Shell avoids the fundamental choice between high decline rates and high URR, which it does with a judicious mix of fuels and a move towards reducing demand, by assuming the wide-scale introduction of electric vehicles. In this model, liquid fuel supply may then decline steeply, but the demand for it also falls. Although this begs the question of how the electricity might be generated, Shell's model relieves the pressure on producing liquid fuels.

3.3.5 Comparison of individual country forecasts

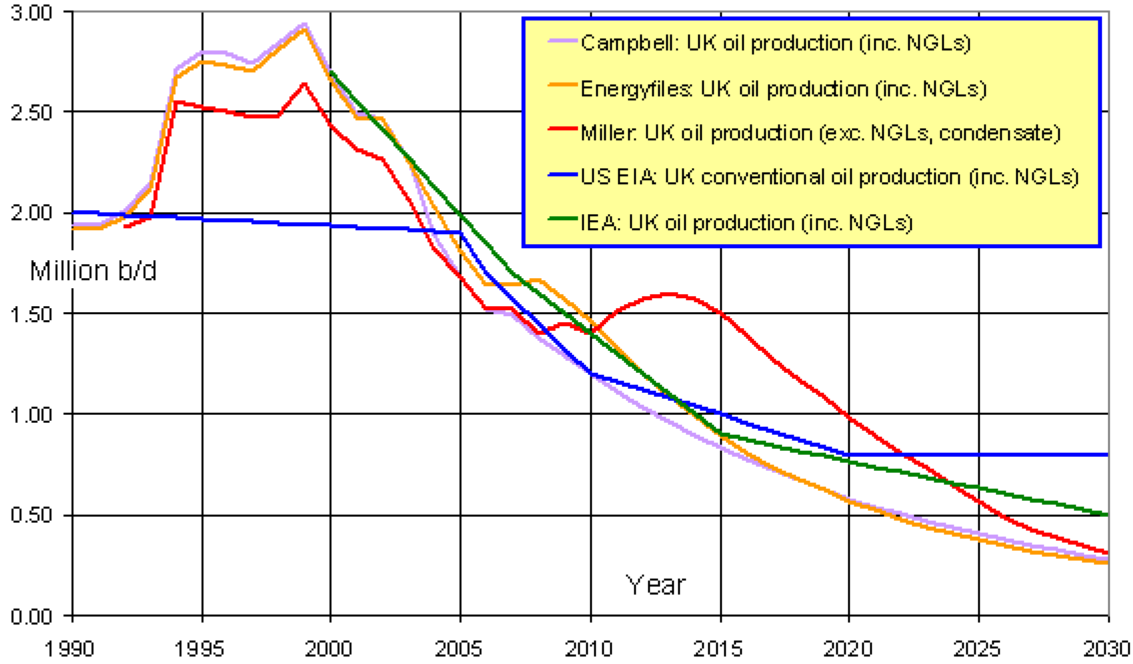
All contributors to this study were requested, if possible, to supply individual country forecasts for the United Kingdom, the United States, Saudi Arabia and Brazil. These countries were chosen to highlight the differences between the assumptions used in the various models. In practice only five modellers provided these data, and a sixth for Brazil, but the results remain illuminating. More detailed forecasts for each country can be found in the Annex.

3.3.5.1 United Kingdom

Figure 3.8 shows forecasts for the United Kingdom. This country was chosen as possessing perhaps the most detailed and widely available data, published by BERR (ex-DTI);[39] all models therefore have an 'equal start'. Note that the US EIA gives no data points between 1990 and 2005.

[39] See https://www.og.berr.gov.uk/pprs/pprsindex.htm and related web pages

Figure 3.8: Five forecasts of UK oil production to 2030. (The US EIA gives no data points between 1990 and 2005)



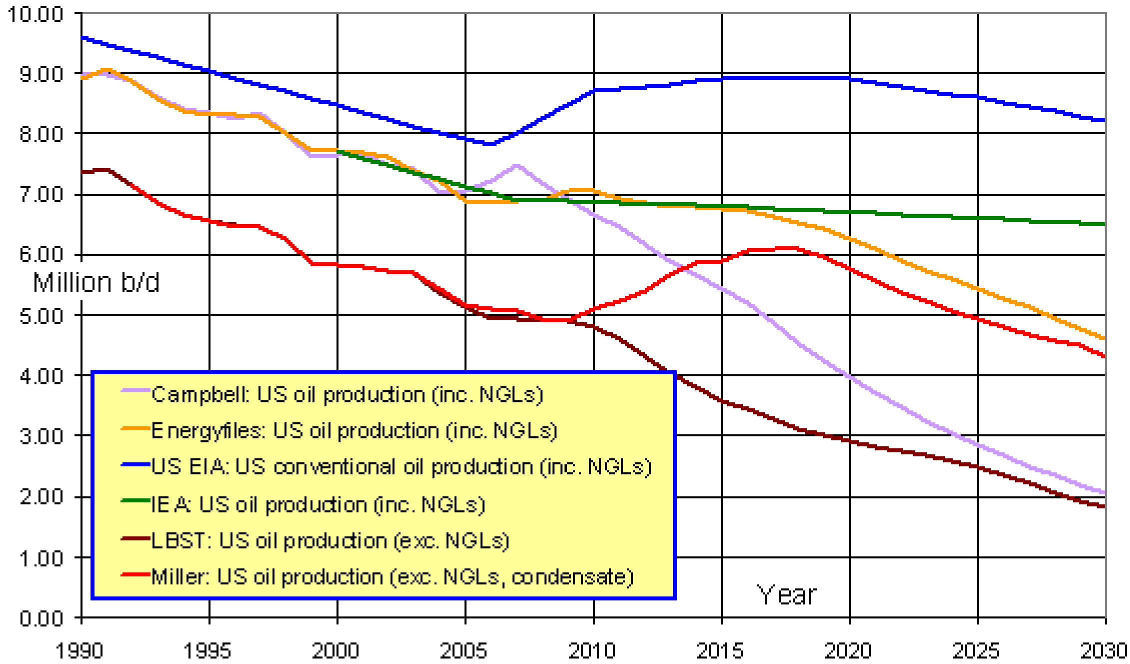
The influence of excluding NGLs and condensate is obvious from Miller's plot, as these components represent a significant portion of UK output between 1990 and 2008. Miller also shows the potential influence of the large number of UK fallow fields, mostly discovered before 2000, and ranging from 15 to 120 million barrels of nominally recoverable reserves, totalling 1.28 billion barrels in all. Their rapid development would lead to a production hump from 2010 which no other model indicates. This hump is very unlikely to occur in 2010, but it may indicate a future resource.

Otherwise, the forecasts are quite similar. Except for the US EIA, the range between the lowest and highest forecast by 2030 is almost 100%, but this is only 250 kb/d. The models vary fundamentally only by a slight variation in the forecast aggregate production decline rate and therefore in the assumed URR. It is unclear why the US EIA forecast levels off.

3.3.5.2 United States

Figure 3.9 is for the United States. Data for US onshore fields are not freely available, but data for the offshore are published. Here the differences between the forecasts are quite significant. Note that the Miller and LBST forecasts exclude NGLs.

Figure 3.9: Six forecasts of US oil production to 2030



By 2030, the US EIA (from their 2007 report) expects four times the US production level that Campbell forecasts. This might be ascribed to their inclusion of production from Artic National Wildlife Refuge (ANWR) which may be omitted by Campbell. Alternatively this might reflect a difference in view on the prospects of YTF in deepwater, or an expectation by the US EIA of substantial reserves growth, or a significant quantity of NGLs and condensate from new gas production. The sharp rise up to 2010, forecast by the US EIA in 2008, was shown in its 2007 forecast, but occurred one year earlier. The Campbell and LBST forecasts may differ only by the NGL component, which is excluded here by LBST. Miller shows a very significant potential rise under his unconstrained investment assumption, from undeveloped Gulf of Mexico discoveries and ANWR, and perhaps a more generous YTF assumption than others.

The evolution of US production in the next 5 years will provide an interesting test of these models, because of the diversity of these forecasts and the politically relatively unconstrained nature of US oil production.

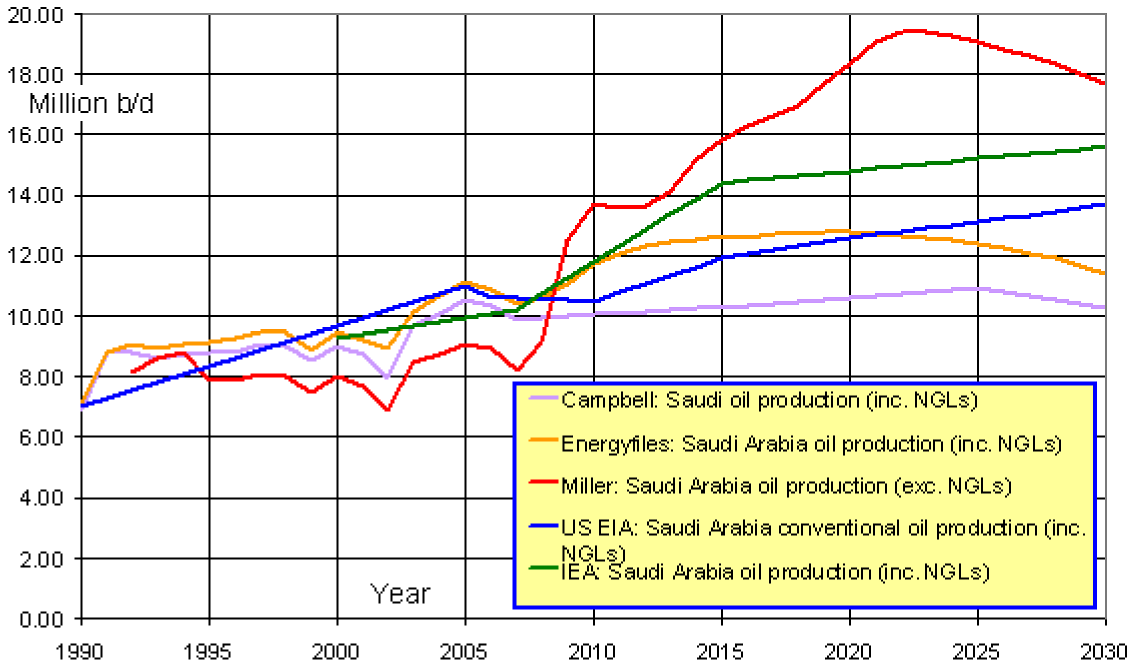
3.3.5.3 Saudi Arabia

Figure 3.10 shows the models for Saudi Arabia. This country is critical to the world's future oil supply because of Saudi Arabia's huge reserves and the existing infrastructure necessary to enable these reserves to be produced. It is, however, among the least well documented of countries. As has been described previously, there is no agreement among analysts, or between analysts and the Saudi authorities, on individual field production rates, their remaining reserves, the YTF, the closeness to peak of the super-giant fields or the managed field decline rates that can be expected post-peak.

Miller's forecast here is by far the highest. By 2010 he assumes production increases commencing from the large old fields. YTF is estimated to start coming on-stream as early as 2012 because of the dense existing infrastructure. Known fallow fields and recent discoveries are brought on-stream between 2012 and 2021. The result is a production peak of 19.5 million b/d in 2022/2023. By contrast, the US IEA and the IEA forecasts are considerably lower, not because they conclude that Saudi Arabia cannot achieve high production rates, but because they constrain production according to expected demand; Miller's model is not demand-constrained.

The Campbell and Energyfiles models produce similar, low forecasts which go into aggregate production decline before 2030. Campbell considers the Saudi reserves to be over-estimated and his model suggests the lowest Saudi URR. The range on 2030 production is under a factor of two, but represents some 8 million b/d.

Figure 3.10: Five forecasts of Saudi Arabian oil production to 2030



3.3.5.4 Brazil

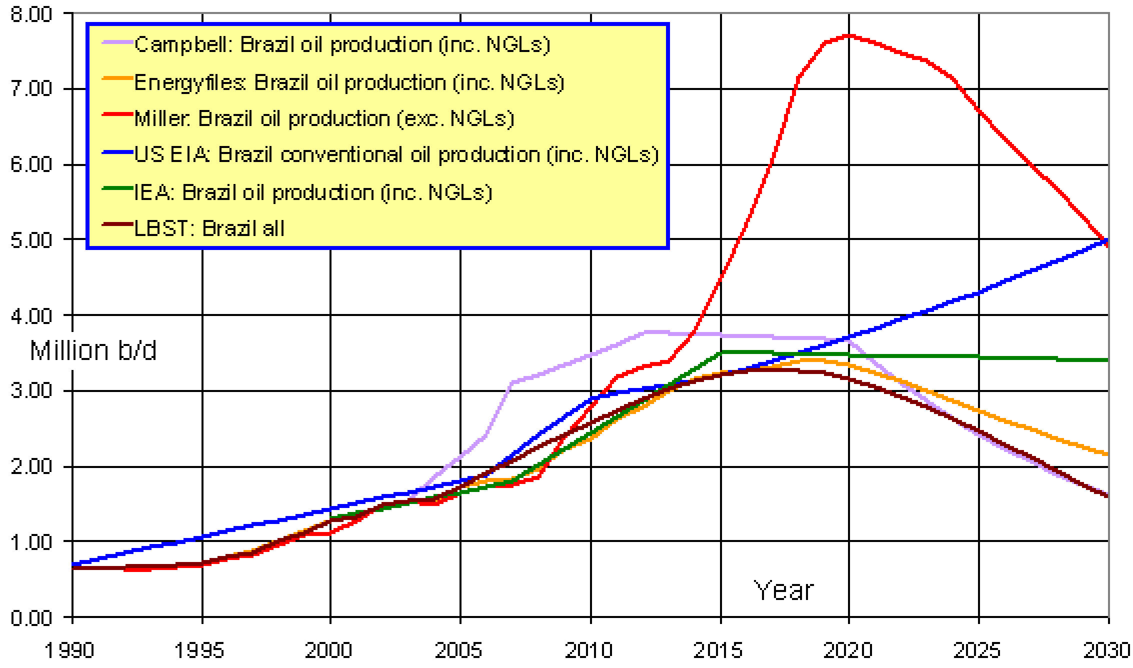
Brazil has recently made a series of eight large discoveries in a new sub-salt, deep-water play. This event was cited as evidence by some analysts that new fields are still being discovered to replace production from old fields, that global reserves are keeping pace with consumption, and that the URR cannot be meaningfully assessed. Other analysts observed that these fields are simply part of Brazil's previously estimated YTF and have no effect on the estimated URR. Brazil has a fast development programme in place to begin production from the largest discovery so far, Tupi.

As usual, Miller's forecast includes the rapid development of the large number of known but undeveloped fallow fields, totalling at least 6 billion barrels of nominally recoverable reserves excluding the new sub-salt play, which with current fields would result in a peak of 5.5 million b/d by 2019. Adding YTF brings the peak to more than 7.5 million b/d by 2020. This is twice the production level of any other model in this time period. The US EIA forecasts almost linear growth to beyond 2030, reaching Miller's forecast at that time; all other models have peaked by 2020. Campbell's forecast is indistinguishable from most others after a higher than usual forecast until

2015. The LBST and Energyfiles forecasts both show almost symmetrical growth and decline to their respective peaks.

The Figure shows that the different forecasts probably involve quite different assumptions about the URR for Brazil. The areas beneath the curves appear significantly different. Miller's URR is perhaps twice the size of any but the US EIA, yet every field in his model has been reported and the recoverable reserves estimated.

Figure 3.11: Six forecasts of Brazil oil production to 2030



3.4 Summary of model parameters and forecasts

3.4.1 URR and decline rates

We now turn from forecasts by country, to more general analysis of the global forecasts shown in Figure 3.7. As mentioned previously, for conventional oil production (but including here current and planned production from the Canadian oil sands), all models must find a balance between the principal variables of URR, the global post-peak rate of decline, and the timing of the peak.

This analysis indicates that the two groups of forecasts differ largely in their assumed or implied URR, but the post-peak aggregate decline rate also plays an important role. It is the combination of these two parameters which determines whether or not a model forecasts a peak before 2030. Lower decline rates imply more optimistic assumptions for the global URR, but if this is set to more conservative levels the required decline rate appears both inconsistent with the current evidence (IEA, 2008) and disturbingly high in terms of its likely effects upon society. For example, a 6%/year decline rate implies the loss of two thirds of conventional oil production within 20 years. Both OPEC and the IEA discuss relatively high decline rates, but only in general terms, and it is unclear how much (or even whether) the post-peak global production decline rate is considered by ExxonMobil or the US EIA.

If the decline rates are lower than we have assumed, then the quasi-linear forecasts require significantly higher values for the global URR - for example, 3000 to >3600 Gb at an aggregate production decline rate of 3%/year. In our judgement, such URR estimates for conventional oil are optimistic. This is especially the case given the USGS' review of its year-2000 assessment (Klett, *et al.*, 2005), and the uncertainties surrounding reserves and YTF in the Middle East OPEC states.

We have not found a conclusive argument in favour of either relatively high or relatively low global aggregate post-peak oil production decline rates. These rates have been estimated by authors in several fundamentally different ways:

- OPEC and the IEA measure or estimate[40] actual field decline rates, adjust these for their expectations of EOR, apply them in some form to all the world's fields, and partially offset this resulting global decline rate from existing fields with a model of steadily dropping discovery and production from new fields.

- Some quasi-linear models appear to estimate URR, and assert that any peak will come after a specified date. This implicitly defines what the minimum decline rate must be, although this may not be explicitly discussed

- Some models measure the depletion rate of an area (i.e. the proportion of either reserves or the estimated yet-to-produce that is produced each year), and use this to support models of how overall production rates will evolve and decline as the discovery rate declines.

- The detailed, field-by-field bottom-up models, such as Miller and Energyfiles, extrapolate the historical decline rates of post-peak fields in a region to all pre-peak and estimated yet-to-find fields. In these models, the aggregate decline in production is an output, not an input.

Overall, the key idea we present here is that the plausibility of any forecast of conventional oil production can be viewed in terms of the plausibility of the assumed or required values for the global URR and the post-peak aggregate decline rate. The remaining details of model construction are, in our view, only of second-order importance. Hence, forecasters should focus upon obtaining the data which constrain these two basic parameters. We confidently expect a rapid improvement in the understanding of decline at every scale, building upon the recent studies by the IEA (2008) and others. As exploration proceeds, a greater consensus may also emerge on the likely range of the global conventional oil URR.

Finally, it has been emphasised correctly that URR is a variable which is influenced by oil price and other factors. Improvements in the URR estimates will require modeling of how the URR for both conventional and non-conventional oil varies with technology, price, and other variables. But if the conventional oil peak is as close as some of these forecasts suggest, general assertions of the sufficiency of the oil resource must be discounted.

[40] We are unable to judge the accuracy of the field decline rates reported by OPEC, CERA and the IEA. A complete record of annual production data for each field is required, and we understand that the IHS database is incomplete in this regard for the large Middle Eastern OPEC fields. It may be that these analysts have access to confidential data.

3.4.2 Implications of the comparison of forecasts

Contrary to initial impressions, there is a tangible convergence appearing among most of the forecasts, however the models are constructed. This may seem surprising, given the polarised debate, and the fact that the quasi-linear models not only show no peak in conventional oil production before 2030, but often make no mention of a peak. But as the above analysis has shown, although the range of modeling procedures is very wide, the range of dates for the final peak arises primarily from differences in the assumed or implied URR and/or the post-peak aggregate decline rate of conventional oil. All other differences are either comparatively minor or are components of these two parameters. Even some of the quasi-linear models are starting to foresee a leveling off of supply (IEA, and the US EIA high-price scenario). We hope that this convergence will continue as better constraints become available, allowing a progressively broader consensus around a narrower range of peak dates.

We add as a caveat that the two basic model groups also differ by the inclusion and exclusion, respectively, of non-conventional liquids (i.e. CTLs, GTLs and biofuels), although these have been removed from the conventional oil analysis above to the extent possible. A forecast of a peak in conventional oil supply within a quasi-linear model does not constitute therefore a forecast of peak in liquid fuel supply.

Therefore uncertainties and associated risks revolve around not only the expected conventional oil URR and its forecast post-peak production decline rate, but also the cost and availability of alternative fuels and the rate at which they can substitute for conventional production. This study was restricted to the conventional oil components (including current Canadian oil sands production), but many non-conventional liquids are already a reality, they will become more important with time, and (to paraphrase others) a fuel tank does not need to know where its fuel comes from. The models of non-conventional oil and non-fossil liquid fuels require a separate study - although it is worth noting that on current evidence we are doubtful of large potential from some of these resources.

The context for comparing forecasts is that the peak in conventional oil production must occur eventually. It will occur long before most people expect it, because it must happen while there are still apparently ample oil reserves, and while new discoveries are still being made. It will occur not because the world is “running out of oil”, but because almost all supply will by then be coming from fields that have passed their peak of production. Hubbert’s original model was illustrated by a symmetrical production curve, which automatically placed the peak of production when still half of the URR remained. Hubbert himself did not claim that such perfect symmetry would actually occur, but the general concept, that the peak will happen while reserves are still considerable, remains true.

The lower the post-peak aggregate decline rate, the sooner the peak may occur, and the larger the remaining URR at the time. The longer the peak can be deferred, the greater will be the eventual decline rate and the probability of accompanying economic shocks. In such a case, if alternative fuels or substitutes for oil’s uses were not forthcoming at a quantity and price that was tolerable, then oil-consuming activities would be seriously impacted.

Since few of the models devote equal attention to oil supply and oil demand, they generally do not fully capture the complex interaction between the two. Most of the models make exogenous assumptions about the rate of demand growth. This can lead to a scenario in which the supply fails to match demand, which can happen before the final peak. Arguably such a point was reached, temporarily, in 2008, contributing to the sudden record oil prices that developed. It may also be that the demand was inflated by the activities of speculators, and that supply was less constrained than it appeared; Saudi Arabia, for example, consistently stating that it had extra supplies ready, but no buyers. Factors such as refinery capacity and the mix of different crude qualities also played a role; for example, it seems likely that the demand in 2008 was specifically for light sweet crude, while the spare supply comprised heavier and/or sour crudes which require specially-configured refineries. This illustrates the complexities of the oil market, and the multiple sources of uncertainty in any supply forecast.

In the short term we have some confidence in the Peak Oil Consulting's model, simply because the short-term is well understood and difficult to alter in light of the lead time required for major new projects. This is not to exclude other models which include a similar short-term approach, but the Peak Oil Consulting model is clear and explicit. In the longer term, we are inclined to prefer the bottom-up models, which record and extrapolate what is actually happening in the world's fields and which require fewer exogenous assumptions. A downside of these models is their substantial data requirements, and reliance upon proprietary databases that are not open to third-party scrutiny. In addition, unexpected events more often tend to increase reserves and supply than otherwise, which can contribute a pessimistic bias to the resulting supply forecasts.

For medium to long-term forecasting, we prefer models where the URR is an output rather than an input since this is an appropriate validity check upon any forecast. Past rates of discovery should guide forecasts of future discovery. Combined geological and statistical assessments of the conventional oil YTF are preferred to *a priori* estimates of the URR, as long as no potentially petroliferous region is arbitrarily excluded from the YTF for technical, economic or political reasons. We feel that the current balance of evidence favours a URR of < 3000 Gb of conventional oil plus Canadian oil sand production, and a relatively modest post-peak production decline rate of <4% p.a. for the first years after peak.

This implies that a peak of conventional oil production before 2030 is very likely, and a peak before 2020 is probable. To reach a different conclusion, it would be necessary to argue for either a significantly larger global URR and/or a more rapid post-peak decline rate (which has implications of its own). However, there are a number of caveats to this conclusion, including the following:

- As the IEA's recent analyses have shown, by 2030 actively managed fields may be declining at 8% p.a. or more. The difference between the average field decline rate and the aggregate global production decline rate lies in the succession of new discoveries that are still being made (as YTF is converted into reserves), together with the scope for reducing decline rate through enhanced recovery. The global aggregate production decline rate will very slowly converge on the average field decline rate as discoveries dwindle. This may take decades to occur, but nevertheless is the eventual outcome.

- Most of the models reviewed here are unable to capture the complex interactions between supply and demand. One potential consequence of such interactions is to turn a sharp peak into a 'bumpy plateau', as rising oil prices reduce demand and contribute to short-term supply surplus. Also, factors such as economic recession could reduce the average rate of demand growth below the 1.3% p.a. assumed here and thereby contribute to a later peak.

- Similarly, most of the models give priority to the physical factors influencing all supply. In practice, factors such as investment constraints and resource nationalism could obstruct potential supply growth over the short to medium term, and thereby change the long-term supply forecast. Similarly, global export capacity may grow slower (or decline faster) than global supply owing to growing demand in the exporting countries (which is itself a consequence of population and income growth and subsidised fuel prices).

3.5 The impacts of rates of discovery and reserves growth on the timing of peak production

Another key question raised by this review of the models is to ask how realistic - in terms of impact on the date of peak - are the large values for the conventional oil URR, explicit or implicit, in the quasi-linear models, given the current rates of discovery and reserves growth. This is a complex issue to which we cannot do full justice here. Instead we present a few simple ways of looking at the issue.

3.5.1 Mid-point peaking

The simplest approach is to fall back on the rule of thumb that production in a region peaks when 50% of the URR has been produced. With current global cumulative production of conventional oil plus NGLs standing at around 1150 Gb, current production (ex-tar sands) as perhaps 82 mb/d, and an assumed production growth rate set here as 1.3% p.a., we can then see when the mid-point of any given URR will be reached. If we take the frequently used USGS year-2000 assessment global figure (including NGLs) of 3345 Gb, then the date of 'mid-point' peak is the year 2024. This is significantly before 2030, and sounds a cautionary note to the predictions of the quasi-linear models.

3.5.2 PFC Energy's '60%' rule

PFC Energy has suggested an empirical rule that production peaks in many regions when cumulative production reaches 60% of the 2P oil discovered. To apply this rule for global forecasting we need to know the annual rate of reserve additions from new discoveries and reserves growth.

Data on new discoveries is reasonably solid. Discovery of conventional oil (including NGLs) has fallen steadily from its peak average rate of around 60 Gb/yr. in the mid-1960s to about 15 Gb/yr. when averaged over the last 5 years; roughly half the current annual rate of production.

On reserves growth, as explained elsewhere in this report, the data are far less certain. One can obtain an estimate for this in three ways:

- A gross estimate results if one takes the current total of discovered conventional oil (again including NGLs) as about 2400 Gb, and the standard (though uncertain) estimate for global recovery factor, of around 35%. Combining these gives oil-in-place for fields already discovered as perhaps 6850 Gb. One then needs to assess a realistic future global recovery factor, and the time needed to achieve this. Suppose this is 50% recovery achievable in 50 years from now. This would put the average annual reserves growth from current fields at about 20 Gb/yr.

- A better way, in principle, is to chart the increases in reserves as reported in industry databases. The USGS used this method to calculate that the global reserves reported by IHS Energy were apparently seeing 'reserves growth' of 40 Gb/yr. The more recent study in this UKERC report finds a figure for current apparent reserves growth nearer 30 Gb/yr. But for both these numbers a large uncertainty attaches, as changes in reporting parameters, and the inclusion of previously omitted fields in the database, also make for changes in aggregate discovery totals.

- Probably the only proper way to assess the scope for reserves growth is in the manner used by the Norwegian government; detailed analysis of reservoirs as a function of potential technology and expenditure. To our knowledge, no such study has been attempted for global data.

It is then left to take a range, for example values of 0, 10 & 20 Gb/y, to cover this uncertainty.

To apply the PFC Energy rule needs the current cumulative global production of conventional oil including NGLs of 1150 Gb, and the 2P discovery of just under 2400 Gb. The ratio of cumulative production to discovery today is therefore about 48%.

Projecting forward both production and discovery (including in this case that from new fields and from reserves growth in existing fields) shows when the 60% threshold will be reached. Taking the new field discovery of 15 Gb/yr as fixed (i.e., it sees no further decline) and the range given above for reserves growth, then the expected dates of peak are:

Annual reserves growth:	0 Gb/yr.	Date of peak:	2020
	10		2024
	20		2029

Note that such a simplistic rule takes no direct account of diminishing new field sizes, or the way their production accumulates over time.

3.5.3 The bottom-up models

Because both the mid-point peaking rule and the 60% rule are very approximate they should be used with considerable caution. Far better is to carry out detailed modelling of production expected from existing fields, and those to be discovered, under realistic assumptions of field production cycles, the extent of fallow-field production, the likely discovery rate, and likely reserves gains anticipated from technology improvements. This of course is exactly what the by-field bottom up models do. While the specific assumptions in these models can be questioned, the fact that all of these find the global oil peak as occurring before 2030 adds a further note of caution to the quasi-linear results.

The general point is that a high URR cannot be asserted in isolation. It must take into account the current total discovered, and be combined with the expected oil resulting from realistic data on the future discovery rate, and from anticipated changes in reservoir technology and possible increases in oil price.

4 Conclusions

Based on the above analysis, we draw the following conclusions:

1. The supply of conventional oil must eventually peak, because it is effectively finite. The peak will occur either when supply cannot grow despite industry's best efforts, or when demand falls substantially as a result of either alternative fuels or other means to achieve what oil achieves. The second scenario seems unlikely at present.

2. The peaking mechanism is poorly understood by the world at large, and even by many analysts and forecasters. It is not driven by a lack of conventional oil resources and reserves, but by the declining rate at which liquids flow from fields which have passed their maximum output. Peak will occur when new production cannot be brought on line fast enough to offset this decline in existing fields. As decline in individual fields has generally commenced by the time only 30% of the initial 2P reserves have been produced, it follows that global reserves will still be considerable when the world peak occurs, possibly as high as 50% of the URR.

3. In our view, the balance of current evidence indicates that a peak in conventional oil supply before 2030 is very likely. It is probable that the peak will be reached before 2020, and quite possible that it will occur in the next 5 years, although in the short term, the current global economic climate will play a crucial and unpredictable role in both reducing demand and postponing future supply projects. The peak will be preceded by a failure of supply growth to match historical rates of demand growth.

4. When forecasts made over the past ten years are reviewed together, a steady convergence becomes apparent. Some analysts who historically foresaw no meaningful supply problems now predict reaching a plateau for conventional oil at least in the late 2020s, while the date of peak in most peaking models has extended outwards, to a range between imminent and 2015.

5. The long-range supply models differ widely in their methodology. However, the primary source of the different results is their explicit or implicit assumptions about the URR for conventional oil and the aggregate post-peak rate of decline. To put it another way, most models would give quite similar results if they used or implied similar values for these parameters. Constraining these parameters may contribute more to improving supply forecasts than devising new models.

6. The greatest single uncertainty and sensitivity in estimates of the URR is the size of the YTF and its rate of discovery. The second greatest sensitivity is the estimate of 2P (Proved + Probable) global reserves, including the question of fallow fields which may never be economic to develop. The third is reserves growth, which is taken in this context to include all forms of enhanced, secondary and tertiary oil recovery. Each of these is likely to remain the subject of considerable controversy.

7. The short term future of oil production capacity, to about 2016, is relatively inflexible, because the projects which will raise supply are already committed. Good short-term models for any region can be constructed using widely available public data. The chief uncertainty is the possibility of projects being postponed in the current economic turmoil.

8. Medium- and long-term forecasts become progressively more uncertain owing to the multiple physical, technical, economic and political factors that influence oil supply and demand. Such forecasts are best produced with the help of global, detailed and independent data from on the 2P reserves and historical annual production of individual fields (IHS Energy is the most complete data source). Without such data, the statistics published by national authorities cannot be verified and accurate trends for field decline, basin decline, national decline and reserves changes cannot be established.

9. Many criticisms of peaking models have little evidential basis and lack scientific rigour. Other criticisms are justified, such as any assertion of strict symmetry in the production cycle, or the exclusion of some potential YTF, on technological grounds, but they only apply to a subset of models. A third group of criticisms reflect differences of opinion on parameters such as the URR or the capacity of OPEC to expand production. Future research and modelling should avoid the more basic errors and seek greater consensus on the remaining areas of difference.

10. Some important questions and poorly constrained parameters need further research. These include (i) the effect of oil prices and other factors on the estimated URR; (ii) the constraints imposed by the EROI for different liquid and field types; and (iii) the potential rate of development of alternative and substitute fuels, taking into consideration cost, net energy, net energy rate limits, investment requirements, pollution and other factors. Like Hirsch *et al* (2005) we are concerned at the time and cost that will be required to ameliorate any peak. Although substitution does not directly bear upon forecasting the date of peak, it is a necessary consideration for meaningful planning and policy making.

11. This study has been restricted to analysis of conventional oil supply, but many models also considered non-conventional oils and other alternative liquids. Some also considered new technologies that avoid the use of liquid fuels. Such alternatives and replacements will increase, but their future rate of increase, sustainability, cost and use are even less certain than the future supply of conventional oil. These topics require urgent investigation if the challenge of peak oil is to be addressed.

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