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Global Oil Depletion:

An assessment of the evidence for a near-term peak in global oil production

Global Oil Depletion: An assessment of the evidence for a near-term peak in global oil production

A report produced by the Technology and Policy Assessment function of the UK Energy Research Centre

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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 summarises the main conclusions from the TPA's assessment of evidence for global oil depletion. 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 Synthesis Report presents the main findings of this assessment. More detailed results are contained in seven in-depth *Technical Reports* which are available to download from the UKERC website:

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

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- Roger Bentley, Department of Cybernetics, University of Reading (*Technical Report 7*)
- Godfrey Boyle, Director, EERU, The Open University (*Technical Report 7*)
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About UKERC

The UK Energy Research Centre's mission is to be the UK's pre-eminent centre of research and source of authoritative information and leadership on sustainable energy systems. It undertakes world-class research addressing the whole-systems aspects of energy supply and use while developing and maintaining the means to enable cohesive research in energy. UKERC is funded by the UK Research Councils.

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The above individuals represent a range of views on the risks of global oil depletion and none are responsible for the content of this report.

Executive Summary

Abundant supplies of cheap liquid fuels form the foundation of modern industrial economies and at present the vast majority of these fuels are obtained from ‘conventional’ oil. But a growing number of commentators are forecasting a near-term peak and subsequent terminal decline in the production of conventional oil as a result of the physical depletion of the resource. This is anticipated to lead to substantial economic dislocation, with alternative sources being unable to ‘fill the gap’ on the timescale required. In contrast, other commentators argue that liquid fuels production will be sufficient to meet global demand well into the 21st century, as rising oil prices stimulate exploration and discovery, the enhanced recovery of conventional oil and the development of ‘non-conventional’ resources such as oil sands. The first group claims that physical depletion will have a dominant influence on future oil supply, while the latter emphasise how depletion can be mitigated by investment and new technology. A concern for both is whether the relevant organisations will have the incentive and ability to invest.

Despite much popular attention, the growing debate on ‘peak oil’ has had relatively little influence on energy and climate policy. Most governments exhibit little concern about oil depletion, several oil companies have been publicly dismissive and the majority of energy analysts remain sceptical. But beginning in 2003, a combination of strong demand growth, rising prices, declining production in key regions and ominous warnings from market analysts has increased concerns about oil security. While the global economic recession has brought oil prices down from their record high of July 2008, the International Energy Agency (IEA) is warning of a near-term ‘supply crunch’ owing to the cancellation and delay of many upstream investment projects. An increasing number of commentators are warning that the age of cheap oil is coming to an end.

Without sufficient investment in demand reduction and substitute sources of energy, a decline in the production of conventional oil could have a major impact on the global economy. In addition, the transition away from conventional oil will have important economic, environmental and security implications which need to be anticipated if the appropriate investments are to be made. While the timing of a future peak (or plateau) in conventional oil production has been a focus of debate, what appears equally important is the rate at which production may be expected to decline following the peak and hence the rate at which demand reduction and alternative sources of supply may be required. In addition, there are uncertainties over the extent to which the market may be relied upon to signal oil depletion in a sufficiently timely fashion.

Overview

This report 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 report is based upon a thorough review of the current state of knowledge on oil depletion, supplemented by data analysis and guided by an Expert Group. A total of seven supporting reports have been produced and are available to download from the UKERC website. This synthesis report clarifies the concepts and definitions relevant to the ‘peak oil’ debate, identifies the strengths and weaknesses of different methods for estimating the size of oil resources and for forecasting future supply, highlights the degree of uncertainty associated with key issues, compares contemporary forecasts of oil supply and assesses the risk of a near-term peak in oil production.

The report focuses on ‘conventional oil’, defined here to include crude oil, condensate and natural gas liquids (NGLs) and to exclude liquid fuels derived from oil sands, oil shale, coal, natural gas and biomass. Conventional oil is anticipated to provide the bulk of the global supply of liquid fuels in the period to 2030 and its resource base is comparatively depleted. A peak in conventional oil production will only be associated with a peak in liquid fuels supply if ‘non-conventional’ sources are unable to substitute in a sufficiently timely fashion. While the economic potential of non-conventional fuels is of critical importance, it is beyond the scope of this report.

The report also focuses on the broadly ‘physical’ factors that may restrict the rate at which conventional oil can be produced, including the production profile of individual fields and the distribution of resources between different sizes of field. While these are invariably mediated by economic, technical and political factors, the extent to which increased investment can overcome these physical constraints is contested. Global oil supply is also influenced by a much wider range of economic, political and geopolitical factors (e.g. resource nationalism) and several of these may pose a significant challenge to energy security, even in the absence of ‘below-ground’ constraints. What is disputed, however, is whether physical depletion is *also* likely to constrain global production in the near-term, even if economic and political conditions prove more favourable. In practice, these ‘above ground’ and ‘below ground’ risks are interdependent and difficult to separate. Nevertheless, this report focuses primarily on the latter since they are the focus of the peak oil debate.

The report does not investigate the potential consequences of supply shortages or the feasibility of different approaches to mitigating such shortages, although both are priorities for future research.

Key conclusions

The main conclusions of the report are as follows:

1. **The mechanisms leading to a ‘peaking’ of conventional oil production are well understood and provide identifiable constraints on its future supply at both the regional and global level.**
   - Oil supply is determined by a complex and interdependent mix of ‘above-ground’ and ‘below-ground’ factors and little is to be gained by emphasising one set of variables over the other. Nevertheless, fundamental features of the conventional oil resource make it inevitable that production in a region will rise to a peak or plateau and ultimately decline. These features include the production profile of individual fields, the concentration of resources in a small number of large fields and the tendency to discover and produce these fields relatively early. This process can be modelled and the peaking of conventional oil production can be observed in an increasing number of regions around the world.
   - Given the complex mix of geological, technical, economic and political factors that affect conventional oil production, anticipating a forthcoming peak is far from straightforward. However, supply forecasting becomes more reliable once access is available to the appropriate data and the range of ‘possible futures’ becomes more

constrained once the resource is substantially depleted. This is increasingly the case at the global level.

2. **Despite large uncertainties in the available data, sufficient information is available to allow the status and risk of global oil depletion to be adequately assessed.**
   - Publicly available data sources are poorly suited to studying oil depletion and their limitations are insufficiently appreciated. The databases available from commercial sources are better in this regard, but are also expensive, confidential and not necessarily reliable for all regions. In the absence of audited reserve estimates, supply forecasts must rely upon assumptions whose level of confidence is inversely proportional to their importance – being lowest for those countries that hold the majority of the world's reserves.
   - Data uncertainties are compounded by errors in interpretation and the slow progress towards standardisation in reserve reporting. For example, it is statistically incorrect to simply add the estimates of 'proved' reserves from different oil fields to obtain a regional total. Doing so may lead to an underestimation of reserves at the regional and global level which could potentially offset any overestimation of those reserves by key producing countries. Hence, the debate on oil depletion would benefit from improved understanding of the nature and limitations of the available data.

3. **There is potential for improving consensus on important and long-standing controversies such as the source and magnitude of 'reserves growth'.**
   - The distribution of conventional oil resources between different sizes of field is increasingly well understood. Although there are around 70,000 oil fields in the world, approximately 25 fields account for one quarter of the global production of crude oil, 100 fields account for half of production and up to 500 fields account for two thirds of cumulative discoveries. Most of these 'giant' fields are relatively old, many are well past their peak of production, most of the rest will begin to decline within the next decade or so and few new giant fields are expected to be found. The remaining reserves at these fields, their future production profile and the potential for reserve growth are therefore of critical importance for future supply.
   - Estimates of the recoverable resources of individual fields are commonly observed to grow over time as a result of improved geological knowledge, better technology, changes in economic conditions and revisions to initially conservative estimates of recoverable reserves. This process appears to have added more to global reserves over the past decade than the discovery of new fields and it seems likely to continue to do so in the future. While the contribution of different factors varies widely between different fields and regions, 'reserve growth' does not appear to be primarily the result of conservative reporting.
   - Reserve growth tends to be greater for larger, older and onshore fields, so as global production shifts towards newer, smaller and offshore fields the rate of reserve growth may decrease in both percentage and absolute terms. At the same time, higher oil prices may stimulate the more widespread use of enhanced oil recovery techniques. The suitability of these techniques for different sizes and types of field and the rate at which they may be applied remain key areas of uncertainty.
   - The oil industry must continually invest to replace the decline in production from existing fields. The average rate of decline from fields that are past their peak of

production is at least 6.5%/year globally, while the corresponding rate of decline from all currently-producing fields is at least 4%/year. This implies that approximately 3 mb/d of new capacity must be added each year, simply to maintain production at current levels - equivalent to a new Saudi Arabia coming on stream every three years.

- Decline rates are on an upward trend as more giant fields enter decline, as production shifts towards smaller, younger and offshore fields and as changing production methods lead to more rapid post-peak decline. As a result, more than two thirds of current crude oil production capacity may need to be replaced by 2030, simply to prevent production from falling. At best, this is likely to prove extremely challenging.

- Oil reserves cannot be produced at arbitrarily high rates. There are physical, engineering and economic constraints upon both the rate of depletion of a field or region and the pattern of production over time. For example, the annual production from a region has rarely exceeded 5% of the remaining recoverable resources and most regions have reached their peak well before half of their recoverable resources have been produced. Supply forecasts that assume or imply significant departures from this historical experience are likely to require careful justification.

4. **Methods for estimating resource size and forecasting future supply have important limitations that need to be acknowledged.**
   - The ultimately recoverable resources (URR) of a region depend upon economic and technical factors as much as geology and can only be estimated to a reasonable degree of confidence when exploration is well advanced. Although widely criticised, simple ‘curve-fitting’ techniques for estimating URR have an important role to play when field-level data is not available and also have much in common with more sophisticated methods such as ‘discovery process modelling’. But they are best applied to well-explored and geologically homogeneous areas with a consistent exploration history. Since many regions do not meet these criteria, errors are likely to result.

   - Many analysts have paid insufficient attention to the limitations of curve-fitting techniques, such as the sensitivity of the estimates to the choice of functional form, the frequent neglect of future reserve growth and the inability to anticipate future cycles of production or discovery. This has led to underestimates of regional and global URR and has contributed to excessively pessimistic forecasts of future supply.

   - Methods of forecasting future oil supply vary widely in terms of their theoretical basis, their inclusion of different variables and their level of aggregation and complexity. Each approach has its strengths and weaknesses and no single approach should be favoured in all circumstances. Bottom-up models using field or project data provide a fairly reliable basis for near to medium-term forecasts, but many existing models are hampered by their reliance on proprietary datasets, lack of transparency, neglect of economic variables and requirement for multiple assumptions. Sensitivity testing and the presentation of uncertainties remain the exception rather than the rule.

   - The timing of a global peak (or plateau) in conventional oil production may be estimated to within decadal accuracy assuming a particular value for the global URR and no significant disruptions to the oil market. But given the potential for political, economic, or technological disruptions, no model can provide estimates of great precision. Increasing model complexity does little to address this problem and is subject to rapidly diminishing returns.

5. **Large resources of conventional oil may be available, but these are unlikely to be accessed quickly and may make little difference to the timing of the global peak.**
    - Although estimates of the global URR of conventional oil have been trending upwards for the last 50 years, the most recent estimates from the US Geological Survey (USGS) represent a substantial departure from the historical trend. Contemporary estimates now fall within the range 2000-4300 billion barrels (Gb), compared to cumulative production through to 2007 of 1128 Gb. This wide range leads to a corresponding uncertainty in global supply forecasts. But despite their apparent optimism, assertions that the USGS estimates are 'discredited' are at best premature. Global reserve growth appears to be matching the USGS assumptions and although the rate of new discoveries is lower than implied by the USGS, the size of these discoveries may have been underestimated and there are continuing restrictions on exploration in some of the most promising areas.
    - The timing of the global peak for conventional oil production is relatively insensitive to assumptions about the size of the global resource. For a wide range of assumptions about the global URR of conventional oil and the shape of the future production cycle, the date of peak production can be estimated to lie between 2009 and 2031. Although this range appears wide in the light of forecasts of an imminent peak, it may be a relatively narrow window in terms of the lead time to develop substitute fuels. In this model, increasing the global URR by one billion barrels delays the date of peak production by only a few days (for comparison, the cumulative production from the UK is approximately 24 Gb). Delaying the peak beyond 2030 requires optimistic assumptions about the size of the recoverable resource combined with a slow rate of demand growth prior to the peak and/or a relatively steep decline in production following the peak. These considerations constrain the range of plausible global supply forecasts.
    - Although more optimistic estimates of the global URR of conventional oil appear plausible, much of this is located in smaller fields in less accessible locations. If (as seems likely) these resources can only be produced relatively slowly at high cost, supply constraints may inhibit demand growth at a relatively early stage. Demand growth may also be constrained if the national oil companies that control much of these resources lack the incentive or ability to invest.
6. **The risks presented by global oil depletion deserve much more serious attention by the research and policy communities.**
    - Much existing research focuses upon the economic and political threats to oil supply security and fails to either assess or to effectively integrate the risks presented by physical depletion. This has meant that the probability and consequences of different outcomes has not been adequately assessed.
    - The short term future of oil production capacity, to about 2016, is relatively inflexible, because the projects which will raise supply are already committed. Reasonable short-term forecasts for any region can be constructed using widely available public data. The primary issue for the short term is the cancellation and delay of these projects as a result of the 2008 economic recession and the consequent risk of supply shortages when demand recovers.
    - For medium to long-term forecasting, the number and scale of uncertainties multiply making precise forecasts of the timing of peak production unwarranted. Nevertheless,

we consider that forecasts that delay the peak of conventional oil production until after 2030 rest upon several assumptions that are at best optimistic and at worst implausible. Such forecasts need to either demonstrate how these assumptions can be met or why the constraints identified in this report do not apply. On the basis of current evidence we suggest that a peak of conventional oil production before 2030 appears likely and there is a significant risk of a peak before 2020. Given the lead times required to both develop substitute fuels and improve energy efficiency, this risk needs to be given serious consideration.

Policy implications

The evaluation of different mitigation options is beyond the scope of this report. However, three general comments may be made.

- First, it seems likely that mitigation will prove challenging owing to both the scale of investment required and the associated lead times. For example, a report for the US Department of Energy argues that large-scale programmes of substitution and demand reduction need to be initiated at least 20 years before the peak if serious shortfalls in liquid fuels supply are to be avoided (Hirsch, *et al.*, 2005). While this report overlooks many important mitigation options (e.g. public transport, electric vehicles) it also assumes a relatively modest post-peak decline rate (2%/year) and ignores environmental constraints. Hence, even 2030 may not be a distant date in terms of developing an appropriate policy response.
- Second, although many mitigation options are consistent with climate policy, the economic impact of oil depletion could create strong incentives to exploit high-carbon non-conventional fuels which could undermine efforts to prevent dangerous climate change. For example, converting one quarter of the world's proved coal reserves into liquid fuels would result in emissions of around 2600 billion tonnes of carbon dioxide (CO_2), with less than half of these emissions being potentially avoidable through carbon capture and storage. This compares to recommendations that total future emissions should be less than 1800 billion tonnes if the most likely global warming is to be kept to 2^oC (Allen, *et al.*, 2009). Hence, early investment in low-carbon alternatives to conventional oil is of considerable importance.
- Third, investment in large-scale mitigation efforts will be inhibited by oil price uncertainty and volatility and seems unlikely to occur without significant policy support. This investment can be encouraged by measures comparable to those being established within national climate programmes. But greater and more rapid change than is currently envisaged could potentially be required. For this to become politically feasible requires both improved understanding and much greater awareness of the risks presented by global oil depletion.

Glossary

All-liquids	Collective term used to include *crude oil, condensate, NGLs, CTLs, GTLs* and *biofuels.*
All-oil	Collective term used to include *crude oil, condensate* and *NGLs.*
API Gravity	The American Petroleum Institutes standardised measure of *crude oil* density. API gravity is measured in degrees. Definitions vary, but light oil is often taken as > 30° API, medium oil as 20-30° API, heavy oil as 10-20° API, and extra-heavy oil as <10° API.
BERR	UK Department for Business, Enterprise and Regulatory Reform. The relevant responsibilities of this department are now taken over by *DECC*.
Biofuels	Synthetic fuels made from biomass (such as corn or vegetable oil), commonly refers to bio-ethanol and bio-diesel.
Condensate	Very light oil which condenses from natural gas at surface temperatures and pressures. Produced at natural gas wells and gas processing plants. Includes pentanes (C_5) and heavier hydrocarbons.
Conventional Oil	Taken in this report to include *crude oil*, *condensate* and *NGLs*, and to exclude *oil sands*, shale oil and *extra-heavy oil* (non-conventional oils).
Crude Oil	A mixture of hydrocarbons that exist in liquid phase in natural underground reservoirs and which remain liquid at atmospheric temperature and pressure.
CTLs	Coal-To-Liquids. Synthetic liquid fuel derived through the gasification of coal followed by a Fischer-Tropsch process.
Cumulative Discoveries	Total discoveries in the field or region at a particular point in time. Given by the sum of *cumulative production* and *reserves.*
Cumulative Production	Total production from a field or region since production began
Decline Rate	Annual rate at which oil production from a well, *field* or region declines. When applied to a region, it is important to distinguish between the overall decline rate which includes fields that have yet to pass their peak of production, and the post-peak decline rate which refers to the subset of fields that are in decline. Aggregate estimates of decline rates are usually weighted by production.
Depletion	The portion of the estimated *ultimately recoverable resource* which has been produced.
Depletion Rate	The annual rate at which the *recoverable resources* of a *field* or region are being produced. Defined as the ratio of annual production to some estimate of recoverable resources. If the latter is *proved reserves,* the depletion rate is the inverse of the *R/P ratio.*

Discovery	Either: a) the economically recoverable resources contained in fields that are newly discovered within a particular time period; or b) the change in cumulative discoveries from one period to the next. These measures may not be the same owing to the phenomenon of *reserve growth*.
Discovery Cycle	A graph of discovery against time, from when discovery begins to when it ends. An alternative term is discovery profile.
DECC	UK Department of Energy and Climate Change.
EIA	US Department of Energy's Energy Information Administration.
EOR	Enhanced Oil Recovery, also called tertiary recovery. Typically involves the introduction of gas, solvents, chemicals, microbes, directional boreholes or heat into a *reservoir* to change the properties of the oil and increase the *recovery factor*.
EROI	Energy Return On Investment. A measure of the ratio of energy expended in oil exploration and production to energy recoverable from the produced fuel.
Extra-heavy oil	*Crude oil* having an API gravity less than 10°. Because of its high viscosity, extra-heavy oil has to be produced using steam injection.
Fallow Field	An oil field that has been discovered but is not presently scheduled for development.
Field	An area consisting of a single *reservoir* or multiple reservoirs, all related to a single geological structure. Fields may either be discovered, under development, producing or abandoned and the number of wells in a producing field may range from one to thousands.
FSU	Former Soviet Union.
GTL	Gas-to-liquids. Synthetic fuel derived from the liquifaction of methane using the Fischer-Tropsch process.
Heavy Oil	Commonly defined as *crude oil* having a API gravity less than 20°. Oil with API gravity less than 10° is often referred to as 'extra heavy'. This definition is not consistent, however, with Venezuela including oil up to 22° as heavy, and Canada using 25°.
Hydrocarbons	Any molecule consisting entirely of carbon and hydrogen atoms. *Petroleum* is primarily a mixture of hydrocarbon molecules, but it may also contain small amounts of, for example, oxygen, nitrogen, sulphur, vanadium etc.
IEA	International Energy Agency.
IOCs	International Oil Companies.
MMS	US Department of the Interior Minerals Management Service.
Natural Gas	Methane found naturally occurring in reservoir rock.
NGLs	Natural Gas Liquids. Light hydrocarbons found associated with *natural gas* that are either liquid at normal temperatures and pressures, or can be relatively easily turned into a liquid with the

	application of moderate pressure.
NOCs	National Oil Companies (i.e. State owned).
OGJ	Oil and Gas Journal
OOIP	Original Oil In Place. Total quantity of oil contained within a reservoir, field or region before production begins.
Oil Sands	Sandstone impregnated with heavy or extra-heavy oil that can be mined and processed to produce *syncrude*.
OPEC	Organisation of Petroleum Exporting Countries.
Peak	The highest annual *production* of oil from a field or region.
Petroleum	General name for all naturally occurring *hydrocarbon* species, including gases, liquids and solids (bitumen).
Petroleum Basin	A single area of subsidence which filled up with either sedimentary or volcanic rocks and which is known or expected to contain hydrocarbons. Sedimentary basins are the primary source of petroleum, as a result of organic carbon being progressively buried, heated and compressed.
Plateau	Period surrounding production *peak* where annual production is higher than a specified percentage of peak production.
Play	An area for petroleum exploration, containing a collection of petroleum *prospects* which share certain common geological attributes and lie within some well-defined geographic boundary.
Primary Recovery	The recovery of oil under its own natural pressure.
Production	Quantity of oil recovered from a field or region over a specified period of time. Also termed rate of production, or rate of change of cumulative production. Normally measured on a daily (mb/d) or annual (Gb/year) basis.
Production Cycle	A graph of production against time, from when production begins to when it ends. An alternative term is production profile.
Prospect	A geological anomaly that has some probability of containing pools of recoverable *hydrocarbons* and is considered to be a suitable target for exploration.
Proved (1P) Reserves	The quantity of oil in known fields which is considered to have a <u>high</u> probability (e.g. >90%) of being economically recovered.
Proved and probable (2P) Reserves	The quantity of oil in known fields which is considered to have a <u>medium</u> probability (e.g. >50%) of being economically recovered.
Proved, probable and possible (3P) Reserves	The quantity of oil in known fields which is considered to have a <u>low</u> probability (e.g. >10%) of being economically recovered.
Province	An area with common geological properties relevant to petroleum formation. May contain a single or several petroleum *basins*. A province is the largest entity defined solely on the basis of geological considerations that is relevant for resource assessment.

Recovery Factor	The percentage of *original oil in place* that can be recovered with current or anticipated technology.
Refinery Gains	The difference between the volumetric output of refinery products and the volumetric input of crude oil. Attributed to the production of products which, on average, have a lower specific gravity than the crude oil which was refined.
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 *reserve growth* and anticipated *yet-to-find*. May be estimated to differing levels of confidence.
Reserves	Those quantities of oil in known fields which are considered to be technically possible and economically feasible to extract under defined conditions. May be estimated to different levels of confidence, such as *proved reserves* (1P); *proved and probable reserves* (2P); or *proved, probable and possible reserves* (3P).
Reserve Growth	The phenomenon by which many fields ultimately produce more oil than was initially estimated as reserves.
Reservoir (or 'pool')	A subsurface accumulation of oil and/or gas which is physically separated from other reservoirs and which has a single natural pressure system. A single *field* may contain many reservoirs.
Resource	The total quantity of *hydrocarbons* estimated to exist in a region, including those in known fields which are not considered economically feasible to extract as well as those in undiscovered fields.
R/P Ratio	Ratio of some measure of oil *reserves* to annual oil *production*. Normally defined with respect to *proved reserves*.
SEC	US Securities and Exchange Commission.
Secondary Recovery	The recovery of oil using water or gas injection to maintain pressure.
Supply	Volume of produced oil that reaches the market. May be slightly different from production since oil may be stored as strategic reserves or lost through accident.
Syncrude	Synthetic crude oil made from the bitumen in Canadian *oil sands*. Syncrude can be handled, pumped, piped and refined much as conventional *crude oil*.
Synfuels	Liquid fuels made from coal (*CTL*) or gas (*GTL*).
UAE	United Arab Emirates.
URR	Ultimately Recoverable Resource. The amount of oil that is estimated to be economically extractable from a field or region over all time – from when production begins to when it finally ends. An alternative term is estimated ultimate recovery (EUR).
WEO	IEA World Energy Outlook.
YTF	Yet-To-Find. The amount of economically recoverable oil that is

expected to be discovered in a region in a relevant time frame.

Units

b	Barrels. 42 US Gallons or 158.76 litres
kb	Thousand barrels
mb	Million barrels
mb/d	Million barrels per day
Gb	Billion barrels
boe	Barrel of oil equivalent (6.1 GJ)
m^3	Cubic meters
t	Tonnes

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1 Introduction

The UKERC Technology and Policy Assessment (TPA) function was set up to address key controversies in the energy field through comprehensive assessments of the current state of knowledge. It aims to provide rigorous and authoritative reports, while explaining results in a way that is useful to policymakers. This report 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?

1.1 Depletion of oil resources and 'peak oil'

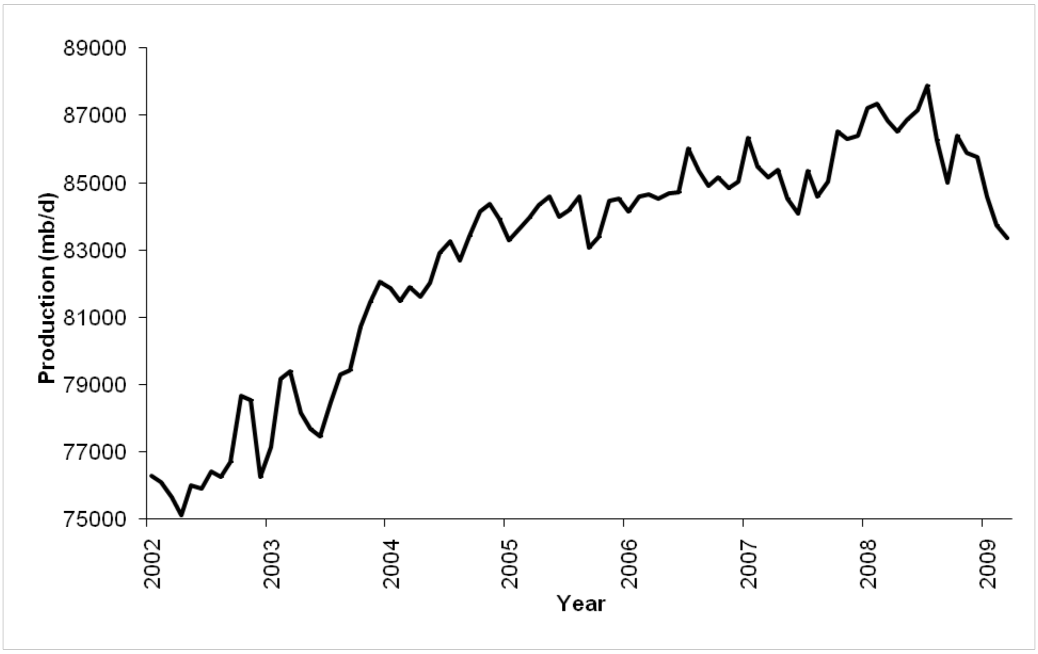
The debate over oil depletion is polarised and contentious. On one side, 'pessimists' forecast an imminent peak and subsequent terminal decline in the global production of conventional oil (Campbell, 1997; Deffeyes, 2005; Zittel and Schindler, 2007). This is expected to lead to substantial economic dislocation, with alternative and non-conventional sources being unable to 'fill the gap' on the timescale required. On the other side are 'optimists' who believe that liquid fuels production will be sufficient to meet global demand well into the 21st century, as rising oil prices stimulate new discovery, the enhanced recovery of conventional oil and the development of non-conventional resources such as oil sands (Adelman, 2003; CERA, 2005; Mills, 2008; Odell, 2004). Pessimists claim that geological factors will largely determine future oil supply, while optimists emphasise the importance of investment and new technology. Similarly, pessimists claim that there is no precedent for the current global situation while optimists point to the long history of failed predictions of the 'end of oil' (Lynch, 1998). Some middle ground is provided by commentators who argue that production will be limited by investment, with OPEC nations having little incentive to expand capacity fast enough to avoid significant increases in price (Gately, 2004).

The growing popular debate on 'peak oil' has had relatively little influence on conventional policy discourse. For example, the UK government rarely mentions the issue in official publications and "…..does not feel the need to hold contingency plans specifically for the eventuality of crude oil supplies peaking between now and 2020." (BERR, 2008). But beginning in 2003, a combination of strong demand growth (especially in China, India and the Middle East), rising prices, declining production in key regions and ominous warnings from market analysts has increased concerns about oil security. A milestone was the 2008 World Energy Outlook (WEO) from the International Energy Agency (IEA) which included a detailed examination of the accelerating decline in production from existing fields. In its reference scenario, the IEA estimated that 64 million barrels/day (mb/d) of new capacity would need to be put into production before 2030, equivalent to six times the current output of Saudi Arabia or 20 mb/d more than had been achieved over the preceding 23 years. While this scenario did not envisage a peak in the production of conventional oil before 2030, the IEA expressed serious concerns about whether the required investment would be forthcoming.

The supply outlook has changed since the publication of the 2008 WEO, with the worsening economic recession leading to a major reduction in global oil demand (Figure 1.1), tumbling oil prices (from \$150/barrel in July 2008 to \$40/barrel in January 2009) and the cancellation or delay of many upstream projects. Given the long lead time on those projects, the likely result is constrained supply over the next five years and the risk of shortfalls and price spikes when demand recovers (IEA, 2009a). But while the short-term outlook has changed, the dispute about resource depletion and peak oil remains unresolved. Most governments exhibit little concern about physical depletion, several oil companies have been publicly dismissive and the majority of energy analysts remain sceptical. As a consequence, the general level of understanding of this topic remains fairly poor.

The debate is nevertheless important because without sufficient investment in demand reduction and substitute sources of energy, a decline in the global production of conventional oil could have major economic impacts. If global export capacity declines more rapidly than global production, the economic impacts in importing countries could be magnified (Rubin and Buchanan, 2007). In addition, the transition from conventional oil to substitute sources of energy is likely to have major economic, environmental and security implications, which need to be anticipated if required investments are to be made. While the timing of a future peak (or plateau) in conventional oil production has been a focus of debate, what appears equally important is the rate at which production may be expected to decline following the peak and hence the rate at which demand reduction and alternative sources of supply may be required. In addition, there are uncertainties over the extent to which the market may be relied upon to signal oil depletion in a sufficiently timely fashion (Kaufmann and Shiers, 2008; Reynolds, 1999b).

Figure 1.1 World total liquids production - January 2002 to March 2009

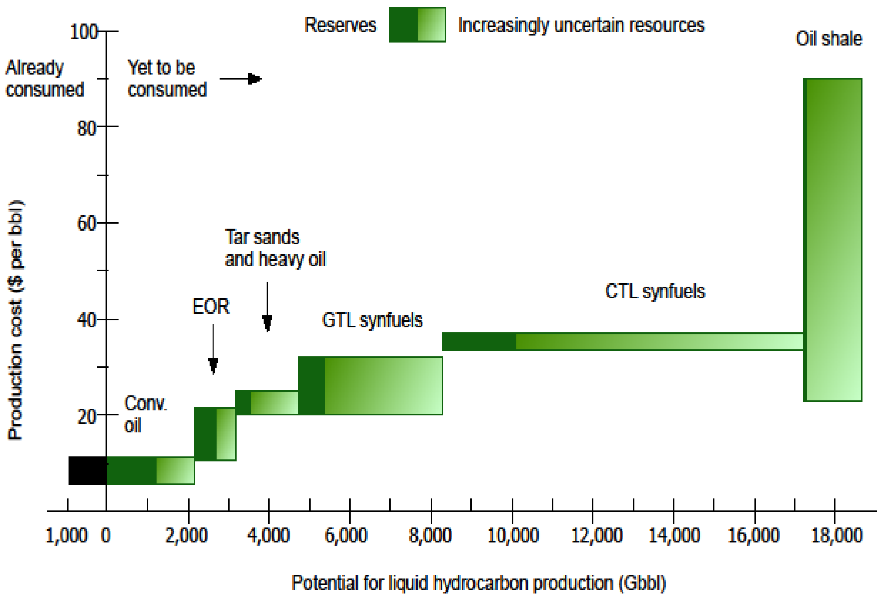


Source: IEA
Note: Includes crude oil, condensate, natual gas liquids, refinery gains, oil sands, heavy oil, oil shales, coal-based and natural gas-based oil substitutes and methane-based blending components.

1.2 Are we running out of oil?

Concerns about global oil depletion are often characterised as concerns about 'running out'. The image is one of a tank being slowly drained and eventually running dry, which implies that the main concern is precisely when this will occur. But as Figure 1.2 demonstrates, there is very little risk of 'running out' of liquid fuels in the foreseeable future, even without considering the potential for biofuels or for replacing liquid fuels with electricity. To date, the world has used less than half of its endowment of conventional oil and the resource base of non-conventional fuels is very much larger.

Figure 1.2 The global resource base of potential liquid hydrocarbon fuels



Source: Farrell and Brandt (2006).
Note: Global resources of fossil hydrocarbons that could be converted to liquid fuels. EOR is enhanced oil recovery, GTL and CTL are gas-and coal-derived synthetic liquid fuels. The CTL and GTL quantities are theoretical maxima because they assume all gas and coal are used as feedstock for liquid fuels and none for other purposes. The lightly shaded portions of the graph represent less certain resources. Results are based on conversion efficiencies of current technologies available in the open literature. Gas hydrates are ignored due to a lack of reliable data.

But the absolute size of the hydrocarbon resource is neither the only constraint on future oil supply, nor the most important. At least four other factors are relevant. First, the remaining resources are frequently more expensive to locate, extract, transport and/or refine than those which have been used to date, which implies that the era of cheap oil may have come to an end. Second, the exploitation of many of these resources will have severe environmental consequences, including landscape destruction, water abstraction and carbon emissions, which could constrain their use for liquid fuels. Third, compared to conventional oil, the exploitation of non-conventional resources generally requires more energy consumption at all stages of the processing chain, with the result that the *net energy* available for productive uses in society is likely to be reduced (Box 1.1). Finally, the *rate* of production of the remaining resources could be relatively low as a result of their physical properties and/or location, together with the scale of investment that is required. And this last point is the key to the peak oil debate: it is not so much the size of the resource, but the *rate of production* of that resource and the reasons why that rate must eventually decline.

In 2008, the global production of liquid fuels[1] averaged 82.3 million barrels per day (mb/d), or approximately one thousand barrels a second (a barrel is 159 litres). The IEA forecasts this increasing to 103.8 mb/d by 2030 (an increase of 26%), largely as a result of income growth in the developing world and the expanding demand for personal automotive transport – with the global car fleet projected to more than double. But despite this being a significant downward revision of previous IEA forecasts,[2] many analysts question whether 100mb/d is achievable, or if so, whether it can be sustained for any length of time.

Box 1.1 Net energy and the future supply of liquid fuels

Oil production is normally measured by volume (barrels) or energy content (GJ). But this neglects the energy that is required to find the resource, extract it from the ground, transport it to the refinery and produce the oil products. This includes both the direct consumption of energy at each stage – for example, in pumping water into a well – and the energy that is required to produce and maintain the relevant capital equipment such as drilling rigs. The energy return on investment (EROI) is a measure of the net energy gain from the production of oil and other resources, once the energy used in extraction and processing has been taken into account.

The energy costs of oil production have increased over time as a consequence of accessing smaller fields in more difficult locations (e.g. deepwater) and shifting to non-conventional sources. For example, Cleveland (1992a; 2005) estimates that the thermal equivalent EROI for petroleum extraction in the US oil production fell from around 100:1 in 1930 to around 20:1 in the mid-1990s, while Gagnon *et al.* (2009) estimate that the EROI for global oil and gas production fell from 26:1 in 1992 to 18:1 in 2006. The energy costs of converting crude oil to road fuels lowers this further to around 10:1. However, the EROI for conventional oil is much greater than that for the majority of substitute fuels.

Estimates of EROI vary with the method and system boundary adopted and should take into account the ‘quality’ of energy carriers as reflected in their market price (Cleveland, *et al.*, 2000; Kaufmann, 1994). Projects which convert a less valuable energy carrier, such as coal, into a more valuable liquid fuel may make financial sense even though they result in a net loss of energy (Gilliand, 1975). EROI also varies with time: for example, the laying of a pipeline may reduce the energy required to exploit small, nearby fields.

Changes in the aggregate EROI for liquid fuels are difficult to estimate and are ignored by most energy analysts who prefer to measure scarcity on the basis of price or cost. But the anticipated decline in the net energy available to society has important implications that should not be overlooked (Hall, *et al.*, 2009; 2008).

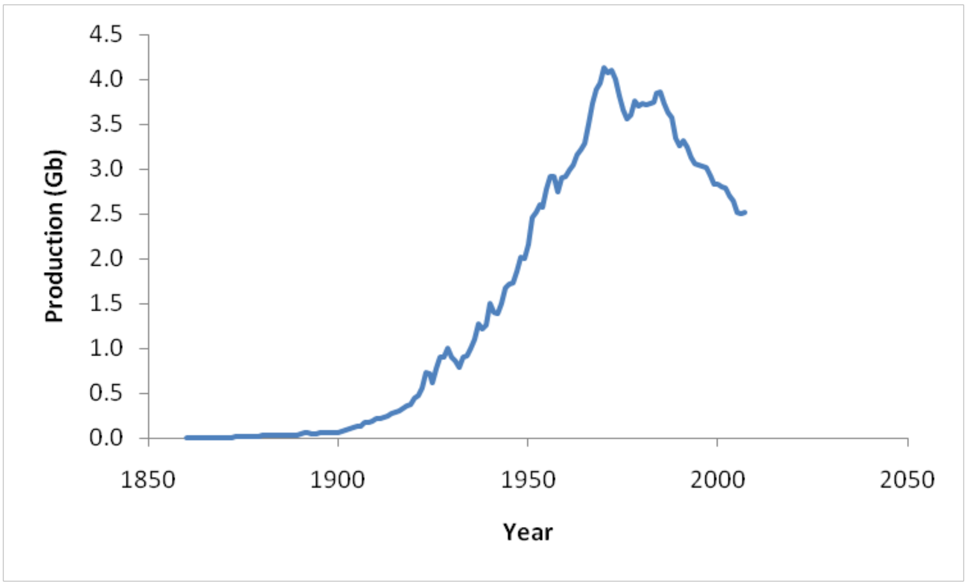
1.3 Mechanisms of oil peaking

The rate of production of a resource is influenced by the physical features of that resource, the technology available to exploit the resource and the various economic and political factors that affect the behaviour of the organisations involved. Those concerned about ‘peak oil’ argue that the nature of the conventional oil resource leads to production from a region rising to a peak and then declining. While numerous factors can modify this pattern to varying – and sometimes significant - degrees, the ‘peaking’ of oil production can nevertheless be observed in an increasing number of regions around the world (Brandt, 2007). One of the first countries to experience such a peak was the United States, whose production history is illustrated in Figure 1.3. This peak was famously anticipated 15 years

[1] Excluding biofuels and refinery gains.
[2] The 2007 World Energy Outlook forecast 116 mb/d in 2030.

earlier by M. King Hubbert (1956), whose analytical approach has subsequently become a central theme of the peak oil debate.

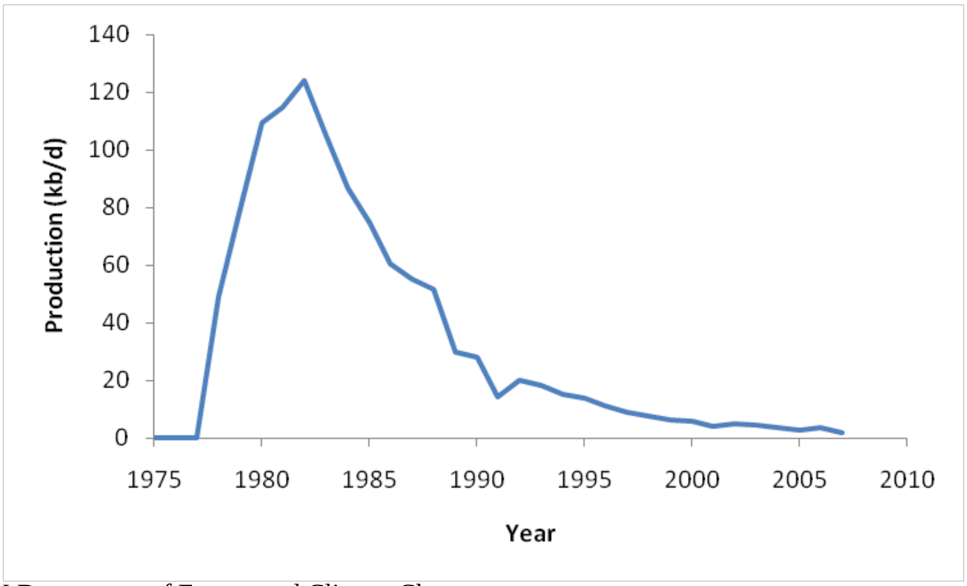
Figure 1.3 Oil production history of the United States



Source: IHS Energy
Note: Annual production of crude oil, condensate, natural gas liquids and extra-heavy oil from all US states.

Three ‘physical’ features of the oil resource contribute to the peaking of regional oil production, although their influence is invariably mediated by economics and politics. First, production from individual fields normally rises to a peak or plateau, after which it declines as a result of falling pressure and/or the breakthrough of water. While each field will have a unique (and not necessarily smooth) production profile as a result of both its physical characteristics and the manner in which it is developed and managed, the same broad pattern is generally observed. As an example, Figure 1.4 shows the production history of the Thistle field in the North Sea.

Figure 1.4 Production cycle of the Thistle field in the North Sea



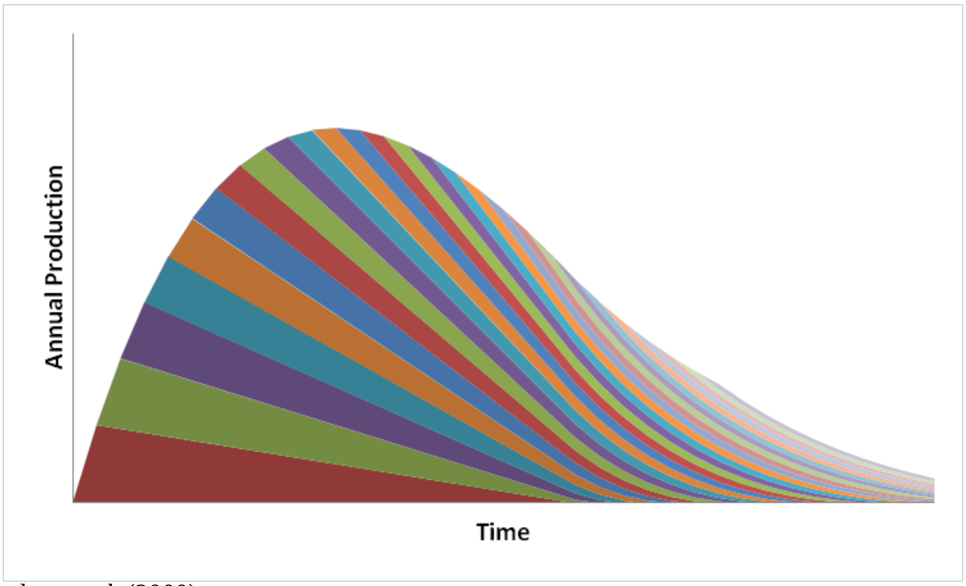
Source: UK Department of Energy and Climate Change

Second, most of the oil in a region tends to be located in a small number of large fields, with the balance being located in a much larger number of small fields. This pattern can be observed at all levels of aggregation from individual basins to the entire world. For example, the IEA (2008) estimates that there are some 70,000 oilfields in production worldwide, but in 2007 approximately half of global production derived from only 110 fields, one quarter from only 20 fields and as much as one fifth from only 10 fields. Indeed, as much as 7% of production derived from a single field - Ghawar in Saudi Arabia. Around 500 ‘giant’ fields account for around two thirds of all the crude oil that has ever been discovered.

Third, these large fields tend to be discovered relatively early in the exploration history of a region, in part because they occupy a larger surface area. Subsequent discoveries tend to be progressively smaller and often require more effort to locate. Again, this broad pattern can be observed at all levels, although it is always modified by technical, political and economic factors, such as restrictions on the areas available for exploration. As an illustration, over half of the world’s ‘giant’ fields were discovered more than fifty years ago, while less than one tenth have been discovered since 1990 (Robelius, 2007).

The implications of these features of the oil resource can be illustrated with the help of a simple model (Figure 1.5) (Bentley, *et al.*, 2000). Here, each triangle represents the production from a single field, with one field being brought into production each year. It is assumed that fields are developed in declining order of size, with each field being 10% smaller than the previous. The result is that, at some point, the additional production from the small fields that were discovered relatively late becomes insufficient to compensate for the decline in production from the large fields that were discovered relatively early, leading to a regional peak in production. Under these assumptions, the peak occurs when around one third of the resources in the region have been produced. Since it also occurs when there are large quantities of reserves in the producing fields, reserve to production (R/P) ratios are relatively stable and new fields are continuing to be discovered, the peak may not necessarily be anticipated.

Figure 1.5 Stylised model of a regional peak in oil production



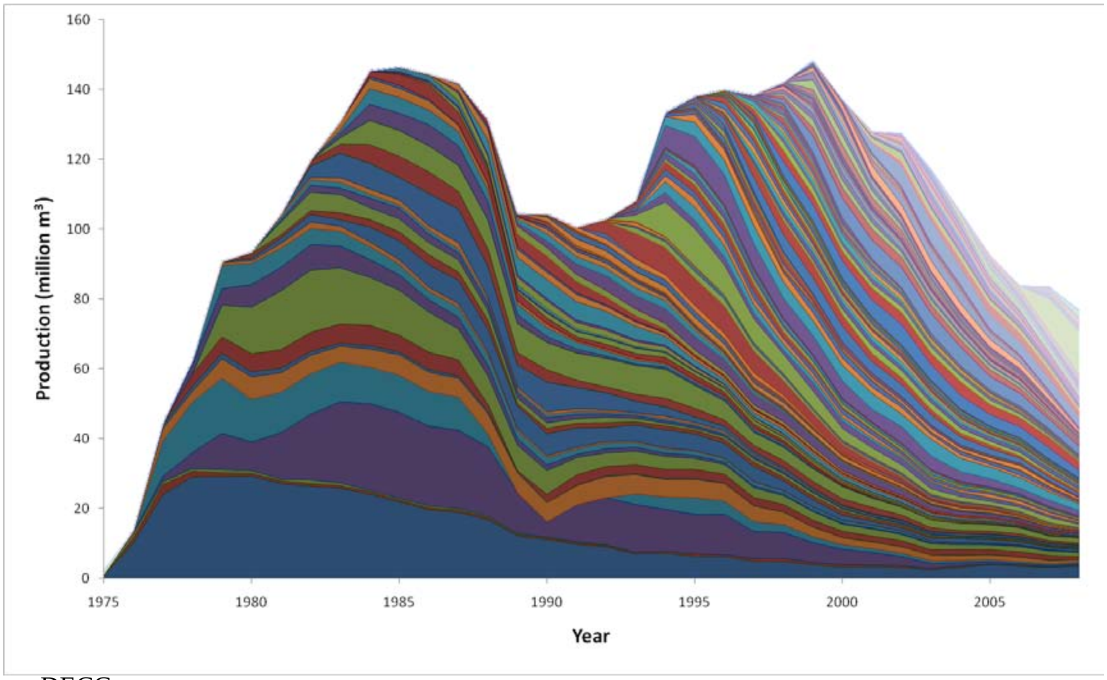
Source: Bentley*, et al.* (2000)

This simple model is robust to assumptions about the production profile of individual fields, the field size distribution and the rate at which fields are brought in production, *provided* it is assumed that the larger fields are developed relatively early (Stark, 2008). Empirical observation suggests that this is frequently the case, although numerous complications intervene. A good illustration is the production history of the UK continental shelf (UKCS), shown in Figure 1.6. While the peak in production in the mid-1980s was linked in part to the Piper Alpha disaster and the remedial safety work that followed, the subsequent peak in 1999 was largely driven by the declining size of newly discovered fields.[3] The peak was not anticipated by many analysts, despite the UK being one of the few countries where accurate field-by-field data are available in the public domain.

The peak oil debate therefore hinges upon whether the regional and global peaks in production can be anticipated given what is known about the size and distribution of oil resources. But given the complex mix of geological, technical, economic and political factors that affect oil production, this question is far from straightforward.

[3] The collapse in oil prices in the late 1990s and the subsequent reduction in exploratory drilling may also have been a contributory factor. But the price rises in the first decade of the 21st century have not reversed the production decline.

Figure 1.6 Oil production in the UKCS by field



Source: DECC

1.4 Objectives and scope of the report

The specific objectives of this report are to:

- clarify the conceptual, definitional and methodological issues relevant to the 'peak oil' debate;
- identify the strengths and weaknesses of different approaches to estimating the size of oil resources and to forecasting future oil supply;
- highlight the degree of uncertainty associated with key issues and assess their relative importance;
- summarise and compare contemporary forecasts of oil supply and identify the reasons for their different conclusions;
- identify the main research and data gaps; and
- assess the risk of the global supply of conventional oil being constrained by physical depletion before 2030.

The period to 2030 was chosen because the main controversy is not whether the global supply of conventional oil will reach a peak and ultimately decline, but when this is likely to occur. While 'optimistic' forecasts of future supply (including the IEA) do not anticipate a peak before 2030, most 'pessimistic' forecasts anticipate a peak before 2020 with several analysts arguing that the peak has already occurred.

The report focuses on *conventional oil*, because this is anticipated to provide the bulk of the global supply of liquid fuels in the period to 2030 and because its resource base is substantially depleted. A peak in conventional oil supply will only be associated with a peak in liquid fuels supply if 'non-conventional' sources are unable to substitute in a sufficiently timely fashion. While the economic potential of non-conventional fuels is of critical importance, it is beyond the scope of this report. The boundary between conventional and non-conventional sources is variously drawn on the basis of the physical characteristics of the resource, the location of the resource, the economic viability of extraction and/or the method of extraction, with some definitions implying a fixed boundary and others a movable one. While many analysts question whether such a distinction is meaningful, it is routinely used by those concerned about peak oil. The definitions used in this report are discussed further in Section 2.

The report also focuses on the broadly 'physical' factors that may restrict the rate at which conventional oil can be produced, including the production profile of individual fields, the skewed size distribution of those fields and the typical sequence in which they are discovered and produced. While each of these is mediated by economic, technical and political factors, the extent to which these can overcome the physical constraints is greatly contested. Oil supply also depends upon a much wider range of economic, political and geopolitical factors and several of these may pose a significant challenge to global energy security, even in the absence of 'below-ground' constraints (Box 1.2). What is disputed, however, is whether physical depletion is *also* likely to constrain global production in the near-term, even if economic and political conditions prove more favourable. In practice, these 'above ground' and 'below ground' risks are interdependent and difficult to separate. Nevertheless, this report focuses primarily on the latter since they are the focus of the peak oil debate. The report does *not* investigate the broader risks to supply security, such as those identified in Box 1.2, although their importance cannot be overstated. Neither does it assess the potential consequences of supply shortages or the feasibility of different approaches to mitigating such shortages, although both are priorities for future research.

Box 1.2 Political and economic constraints on expanding global oil supply

- Increasing concentration of reserves and production in a small number of Middle Eastern and North African countries who may lack the incentive to expand production at the rate forecast by the IEA and other bodies.
- Erosion of excess production capacity in OPEC countries, the limited incentives to expand that capacity and the consequent vulnerability of the global market to supply disruptions (e.g. from weather events or terrorist activity)
- Growing skills shortage resulting in part from the age profile of the oil industry workforce.
- Refinery bottlenecks and the mismatch between available processing capacity, the increasing proportion of heavy and sour crudes and the changing demand for oil products.
- Increased investment in exploration and production being taken up by the rising cost of equipment, materials and skilled manpower.
- Continuing political instability in key producing regions such as Nigeria and Iraq.
- The rise of 'resource nationalism' in several producing countries (e.g. Russia) which may further restrict the ability of independent oil companies (IOCs) to access low cost resources and potentially lead to less efficient exploitation of those resources.

Sources: Jesse and van der Linde (2008); Stevens (2008); IEA (2008); Gately (2004)

1.5 How the assessment was conducted

The topic for this assessment was selected by the TPA Advisory Group which is comprised of senior energy experts from government, academia and the private sector. The Group's role is to ensure that the TPA function addresses policy-relevant research questions. The Group noted the persistence of controversy about this topic, the existence of widely diverging views and the mismatch between the relative neglect of the issue and its potential importance. It was considered that a careful review of the relevant evidence could help to clarify the reasons for the diverging views, encourage more constructive dialogue between the 'opposing camps' and make the issues more accessible to a non-technical audience.

As with all TPA assessments, the objective is *not* to undertake new research on oil depletion, but instead to provide a thorough review of the current state of knowledge. The general approach is informed by the systematic review techniques prominent in medicine and other fields (Box 1.3). Following this model, the assessment began with a *Scoping Note* that summarised the debate on global oil depletion and identified the potential contribution that a TPA assessment could make (Sorrell, 2008). This identified several sources of controversy including: the conflict between different disciplinary perspectives (e.g. geologists and petroleum economists); the confusion over key definitions, such as the appropriate interpretation of reserve estimates; the lack of access to relevant data; the uncertainty over the data that is available; and the disputes over the validity and appropriate use of different methodological approaches. The objectives of the assessment were designed with these issues in mind.

Box 1.3 Overview of the TPA approach

The TPA approach is informed by a range of techniques referred to as *evidence-based policy and practice*, including the practice of *systematic reviews.* This aspires to provide more robust evidence for policymakers and practitioners, avoid duplication of research, encourage higher research standards and identify research gaps. Core features of this approach include exhaustive searching of the available literature and greater reliance upon high quality studies when drawing conclusions. Energy policy presents a number of challenges for the application of systematic reviews and the approach has been criticised for excessive methodological rigidity in some policy areas (Sorrell, 2007). UKERC has therefore set up a process that is inspired by this approach, but is not bound to any narrowly defined method or technique.

The process carried out for each assessment includes the following components:

– Publication of Scoping Note and Assessment Protocol.
– Establishment of a project team with a diversity of expertise.
– Convening an Expert Group with a diversity of opinions and perspectives.
– Stakeholder consultation.
– Systematic searches of clearly defined evidence base using keywords.
– Categorisation and assessment of evidence.
– Review and drafting of technical reports
– Expert feedback on technical reports.
– Drafting of synthesis report
– Peer review of final draft.

An Advisory Group for the project was established (Annex 1) and the Scoping Note circulated to key stakeholders. This led to further recommendations on the appropriate scope and focus of the assessment, including the relative weight to be given to different sources of evidence. While all TPA assessments give priority to peer-reviewed literature, the nature of the current topic necessitates the inclusion of a broader range of studies. It was also agreed to include some data analysis using a country-level database supplied by IHS Energy, together with direct contacts with a number of energy modelling teams. The agreed approach was set out in an *Assessment Protocol* (Sorrell and Speirs, 2008)

The assessment began with a systematic search for reports and papers related to the assessment question (See Annex 1). This revealed over 900 publications, each of which was categorised and assessed for relevance and not all of which were used. A project team was formed comprising a mix of in-house staff and external consultants who were assigned to individual tasks. The full results of the assessment are reported in seven *Technical Reports* that are available to download from the UKERC website, namely:

- *Technical Report 1*: Data sources and issues
- *Technical Report 2*: Definition and interpretation of reserve estimates
- *Technical Report 3*: Nature and importance of reserve growth
- *Technical Report 4*: Decline rates and depletion rates
- *Technical Report 5*: Methods of estimating ultimately recoverable resources

- *Technical Report 6*: Methods of forecasting future oil supply
- *Technical Report 7*: Comparison of global supply forecasts

The present report presents the main findings of the assessment and highlights the policy implications and priorities for further research.

1.6 Structure of the report

This synthesis report is structured as follows:

Section 2 (*Reading the fuel gauge*) introduces the key definitions and data sources relevant to this topic, presents some basic data on production and reserves and discusses how reserve estimates may best be interpreted. It highlights the important distinction between proved (1P) and proved and probable (2P) reserve estimates, together with the difficulties in aggregating those estimates and concludes that the publicly available data is not ‘fit for purpose’ in examining oil depletion.

Section 3 (*Enduring controversies*) discusses four issues that play an important role in shaping future oil supply and which continue to be a focus of controversy, namely: a) how oil resources in a region are distributed between different sizes of field; b) why estimates of the size of fields are found to grow over time and whether this may be expected to continue in the future; c) how rapidly the production from different categories of field may be expected to decline; and d) how rapidly the remaining resources in a field or region can be produced.

Section 4 (*Looking beneath*) examines the methods available for estimating the ultimately recoverable resources (URR) in a region, focusing in particular on the extrapolation of historical trends in production and discovery. Such techniques are widely used by those concerned about peak oil and regularly criticised by those that are not. It assesses the strengths and weaknesses of these methods and the level of confidence that can be placed in the results.

Section 5 (*Looking ahead*) describes and compares the various approaches to forecasting future oil production. The relative merits of these approaches are fiercely debated and the results are often significantly different. It again assesses the strengths and weaknesses of these methods, the level of confidence that can be placed in the results and the implications of this for the peak oil debate.

Section 6 (*How much do we have?*) examines the various estimates of the global URR of conventional oil, focusing in particular on the work of the US Geological Survey (USGS) and some recent studies that have updated their estimates. It shows how such estimates have increased over time and examines their implications for global supply forecasts.

Section 7 (*Possible futures*) compares and evaluates fourteen contemporary forecasts of global oil supply. It highlights the importance of the explicit or implicit assumptions regarding the URR of conventional oil and the aggregate post-peak production decline rate. It then draws some conclusions on the risk of a near-term peak in global production.

Finally, Section 8 summarises the key conclusions from the assessment, identifies the main research needs and highlights some important policy implications.

2 Reading the fuel gauge - measuring oil supply and resources

The world lacks a reliable gauge with which to measure oil depletion. Problems are created by the inconsistent definitions of relevant variables, the paucity of reliable data, the frequent absence of third-party auditing of that data and the corresponding uncertainty surrounding the data that is available. The difficulties are greatest where they matter most, namely the oil reserves of OPEC countries. But they also apply at a much more basic level, such as uncertainties over the amount of oil produced by a given country in a given year. The resulting confusion both fuels the peak oil debate and creates substantial risk in relying on any particular set of numbers. This section seeks to clarify some of the relevant definitions, identify the strengths and weaknesses of different data sources and highlight some of the difficulties that may result. Further information is contained in *Technical Reports 1* and *2*.

Section 2.1 clarifies the different types of hydrocarbon liquids and proposes a working definition of the term 'conventional oil'. Section 2.2 introduces some of the measures associated with oil production and discoveries and assesses the relative usefulness of 'proved' (1P) and 'proved and probable' (2P) reserve estimates in examining resource depletion. Section 2.3 compares the sources of data on production and reserves and provides some background information on global oil supply. Section 0 examines how reserve estimates are produced and highlights the multiple factors that influence reported figures while Section 2.5 looks more closely at the treatment of uncertainty and the difficulties of aggregating reserve estimates. Section 2.6 reviews the currently used reserve classification schemes and the prospects for greater harmonisation in reserve reporting. Section 2.7 concludes.

2.1 What is Oil?

What is commonly termed 'oil' represents a heterogeneous mix of liquid hydrocarbons derived from a range of sources. Several subcategories of oil are commonly defined, but the boundaries between them are not fixed and they are not always distinguished in the available data. The most important subcategory is *crude oil,* defined as:

> "...a mixture of hydrocarbons that exist in liquid phase in natural underground reservoirs and which remain liquid at atmospheric temperature and pressure." (EIA, 2006).

The composition of crude oil varies from one region to another and typically includes unwanted impurities such as sulphur and metals. Crude oil is normally classified by its density, measured in units of American Petroleum Institute (API) Gravity, with higher API indicating less dense oil.[4] It is common to distinguish between light (>30°API), medium (20°-30°API) and heavy (<20°API) crude, but different sources use different criteria in making these distinctions.[5] Light crude oil has a higher ratio of hydrogen to carbon atoms, making it easier to transport and refine and allowing greater production of more valuable products such as gasoline and kerosene. Crude oil is also classified by its sulphur content, with high sulphur crudes being termed 'sour' and low sulphur crudes 'sweet'. Light and sweet crudes trade at a premium, due to both increasing demand for light products and

[4] The API scale ranges from 10° (equal to the density of water) for the heaviest conventional oils to more than 45° for the lightest.
[5] Sandrea and Sandrea (2007) estimate that 29% of proved oil reserves are light crude, 57% medium and 14% heavy.

regulatory restrictions on sulphur emissions. Pricing is normally based upon standard reference crudes, such as West Texas Intermediate.

Crude oil can be refined into more than a hundred different products,[6] with the mix depending upon both the composition of the crude and the available refinery processes. As a result, the volume of crude supply provides no guarantee that the demand for a particular product can be met. The volume of products normally exceeds the volume of crude inputs to a refinery, with the difference (2.1mb/d in 2007) being referred to as *refinery gains*. Data on the supply of liquid fuels takes into account these gains (as well as stock changes and operating fuel) so differs somewhat from data on the production of those liquids.

Data on crude oil production is complicated by the fact that many natural gas wells also produce liquids in the form of *condensate* (i.e. hydrocarbons that condense to liquids at surface temperatures and pressures) while many oil wells also produce associated natural gas. Condensate produced from the associated gas at oil wells is normally combined with crude oil in production data while the condensate from gas wells is included in the data for *natural gas liquids (NGLs).* These are light hydrocarbons that are either liquid at normal temperatures and pressures, or can be relatively easily turned into a liquid with the application of moderate pressure. NGLs comprise both condensate and lighter hydrocarbons such as butane and propane which are liquified at natural gas processing plants. Since they are a by-product of natural gas production, the future supply of NGLs will be determined by the demand for gas, the opportunities available for expanding gas production and the average 'wetness' of that gas.[7] Gas resources are less developed than crude oil resources, so physical depletion should be less of a constraint on future NGL production. But only a portion of NGLs can be blended into transport fuels.

According to the IEA (2008; 2009b), the global production of crude oil and condensate averaged 70.2 million barrels per day (mb/d) in 2007, or 84.6% of the global production of liquid fuels (82.9 mb/d).[8] Production of NGLs averaged 10.5 mb/d, or 12.7% of the total. The remaining 2.2 mb/d (2.7%) was made up of extra heavy oil, oil sands, coal-to-liquids (CTLs), gas-to-liquids (GTLs) and biofuels (see Box 2.1 and Figure 2.1). Commonly used data sources group and subdivide these different liquids in different ways: for example, the IEA classify Venezuelan extra heavy oil as crude oil but the US Energy Information Administration (EIA) classifies it as 'other liquids'. Where possible, we use the following terminology (Figure 2.2):

Conventional oil: crude oil, condensate and natural gas liquids (NGLs).

Non-conventional oil: extra-heavy oil, oil sands, oil shales.

Non-conventional liquids: non-conventional oil plus GTLs, CTLs and biofuels.

All-oil: conventional and non-conventional oil.

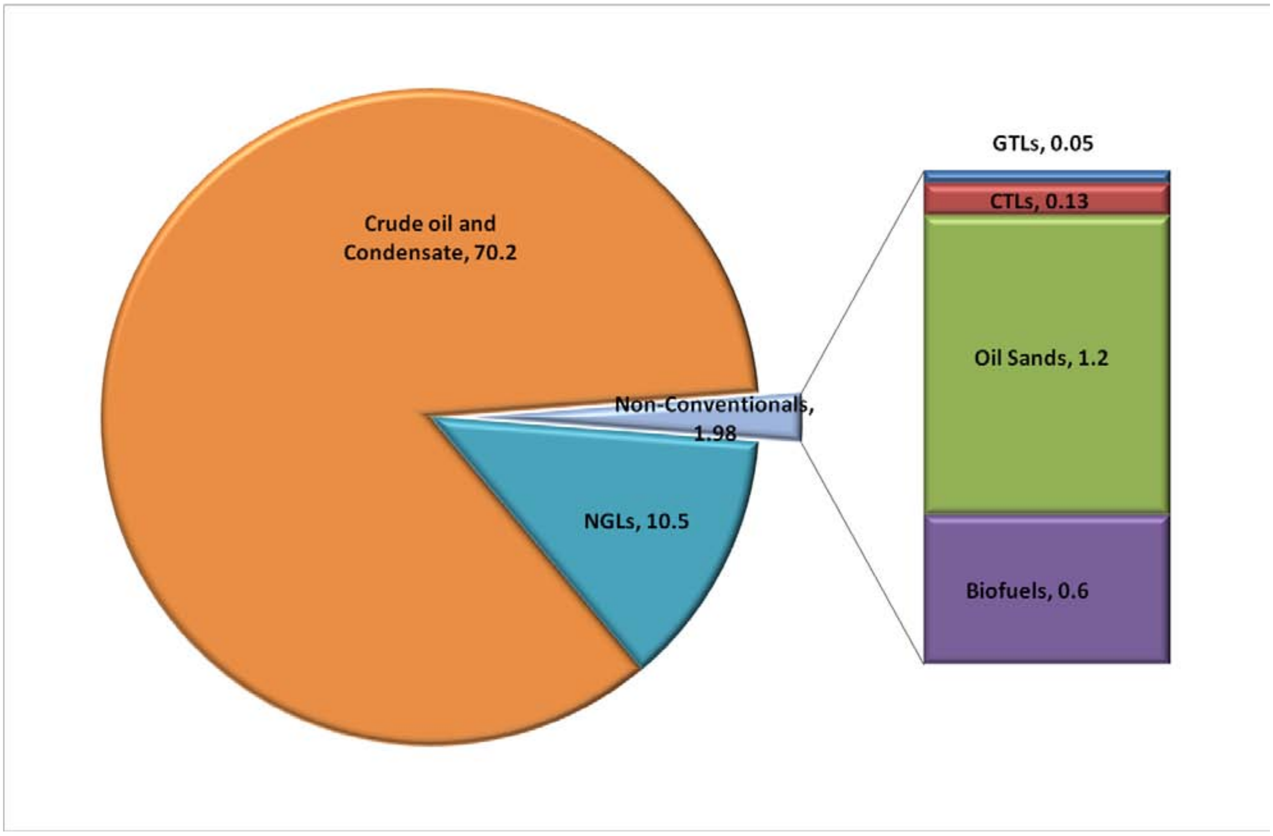
All-liquids: all-oil plus GTLs, CTLs and biofuels.

[6] Including: light products such as gasoline and naphtha; middle distillates such as kerosene and diesel; residual fuels such as heavy fuel oil; and specialities such as bitumen, lubricants and coke.

[7] We estimate that, or an energy equivalent basis, the current ratio of NGLs to gas production is approximately 15% (BP, 2008; EIA, 2007)

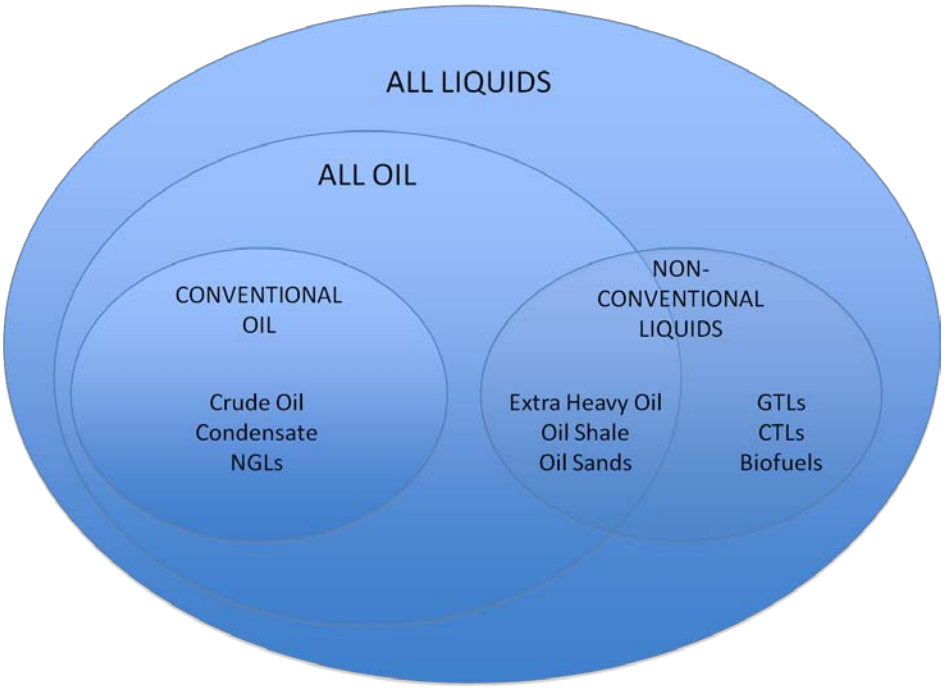
[8] Global production is derived by adding 0.6 mb/d of biofuels to the 82.3 mb/d of liquid fuels production reported by the IEA (2008). Refinery gains are excluded.

Figure 2.1 Breakdown of 2008 liquid fuels production



Source: IEA (2008)

Figure 2.2 Proposed classification of hydrocarbon liquids



The contribution of non-conventional liquids to total production has increased over time and is expected to continue to increase in the future. However, the IEA projects that crude oil and condensate will still provide around three quarters (75.2 mb/d) of global liquids production in 2030, with NGLs providing another fifth (~20 mb/d or double the production in 2007) (IEA, 2008). Excluding biofuels, non-conventional liquids accounted for less than 2% of global all-liquids production in 2007 (1.6 mb/d) and the IEA expect them to contribute less than 10% in 2030 (8.8 mb/d). If crude oil depletes more rapidly than the IEA anticipates, the relative and absolute contribution of non-conventional liquids may be expected to increase. However, numerous technical, economic and environmental constraints make a rapid expansion of production challenging (Hirsch, *et al.*, 2005). For example, Söderbergh *et al.* (2007) estimate that a 'crash programme' to develop the Canadian oil sands could deliver only 5 mb/d by 2030 which represents less than 6% of projected global production.

Box 2.1 Non-conventional liquid hydrocarbon fuels

Extra heavy oil is commonly defined as oil having an API gravity less than 10°, although this definition is not consistent. Because of its high viscosity it has to be produced using steam injection, which is capital and energy intensive. Most current production is from the Orinoco belt in Venezuela, but large deposits are also found in other regions such as China and Russia.

Oil sands (or *tar sands*) are sandstone impregnated with bitumen. Most current production is through open-cast mining, but in-situ methods using steam injection are being developed to access deeper deposits. The resulting bitumen may be marketed directly or upgraded to a synthetic crude transportable by pipeline (*syncrude*). Most global production derives from Canada, but large deposits are also found in Russia, China, Romania, Nigeria and the US.

Oil shale is a fine-grained sedimentary rock containing significant amounts of kerogen - a solid mixture of hydrocarbons from which liquids can be extracted by mining and crushing the rock, heating to a high temperature, driving off a vapour and distilling. Shell is developing an in-situ process involving underground electrical heating which could both improve the recovery factor and reduce environmental impacts (Brandt, 2008). But the resource remains costly to exploit in economic, energy and environmental terms and is unlikely to make significant contribution to global liquids production over the next 20 years.

Gas-to-Liquids (GTLs) are derived through the liquefaction of methane using the Fischer-Tropsch process. This involves steam reforming of natural gas to produce carbon monoxide and hydrogen followed by catalysed chemical reactions to produce liquid hydrocarbons and water. The product mix depends upon the temperature and catalyst used and the economics may be more favourable when no pipeline facilities are available. Major GTL projects are currently underway in Qatar.

Coal-to-Liquids (CTLs) are derived through the gasification of coal followed by a Fischer-Tropsch process. Research is also being carried out on direct conversion through dissolution of coal in a solvent followed by catalytic cracking. CTL plants are under development in China and the US but a major drawback is their high capital costs and carbon emissions.

Biofuels are transport fuels derived from biological sources. Commonly this consists of either ethanol produced through the yeast fermentation of sugar or starch-rich arable crops, or biodiesel derived from seed oils or recycled oils. Second generation cellulosic processes using non-food feedstocks offer greater promise in the longer term.

2.2 Measures of production, discovery and reserves

2.2.1 Production

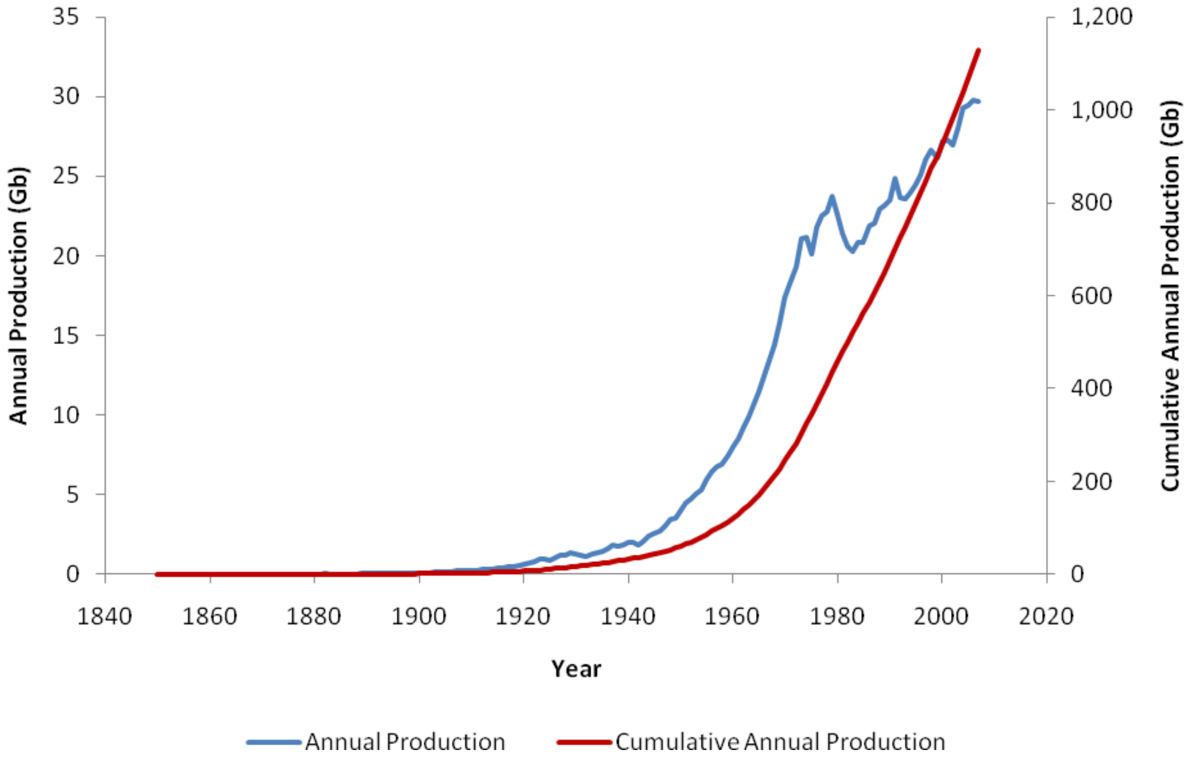
Oil production, discoveries and reserves are commonly reported on a volumetric basis (barrels of oil) but this can be misleading (Box 2.2). For example, NGLs have a lower energy content per unit volume than crude oil, so a shift towards the former will reduce the energy available from a given volume of liquids supply. Changes in the energy return on investment may also be important (Box 1.1), but are not visible in the available data.

Box 2.2 Units of Measurement

> Oil is typically measured on a volumetric basis in either barrels (b or bbl) or cubic meters (m^3). A barrel is equivalent to 42 US gallons or 159 litres. The abbreviations kb or Mbbl (thousand barrels), mb, MMbbl (million barrels) and Gb or Gbbl (billion barrels) are also commonly used.
>
> Oil may also be measured on a weight basis in metric tonnes. The weight of a barrel depends on the source and hence composition of the oil and can vary between 6.0 and 8.0 barrels per tonne. For NGLs, the corresponding figures are 10.0 and 13.5 b/tonne (Karbuz, 2004). Many analysts use a standard conversion factor of 7.33 b/tonne for crude oil, but the use of different conversion factors can lead to widely different estimates of the volume or weight of oil production.
>
> The gross heat content of a barrel of oil is similarly variable, but typically lies around 1700kWh for conventional oil. This forms the basis of the barrel of oil equivalent (boe) definition, which is a unit of energy measure corresponding to a standardised heat content of a barrel of oil (6.1 GJ). This is commonly used to combine oil and gas data into a single measure, but 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, it is not always clear which definition is being used.
>
> The variation in the composition and density of crude oil has a significant impact on the aggregation and interpretation of production and reserve data. This is compounded by the use of inconsistent and sometimes inaccurate conversion factors when aggregating dissimilar liquids through the use of boe. Karbuz (2004) has shown how relatively small differences in the assumed conversion factors can make a very large difference to aggregate estimates of the volume, weight or heat content of oil production. These difficulties account for some of the discrepancies between different data sources.

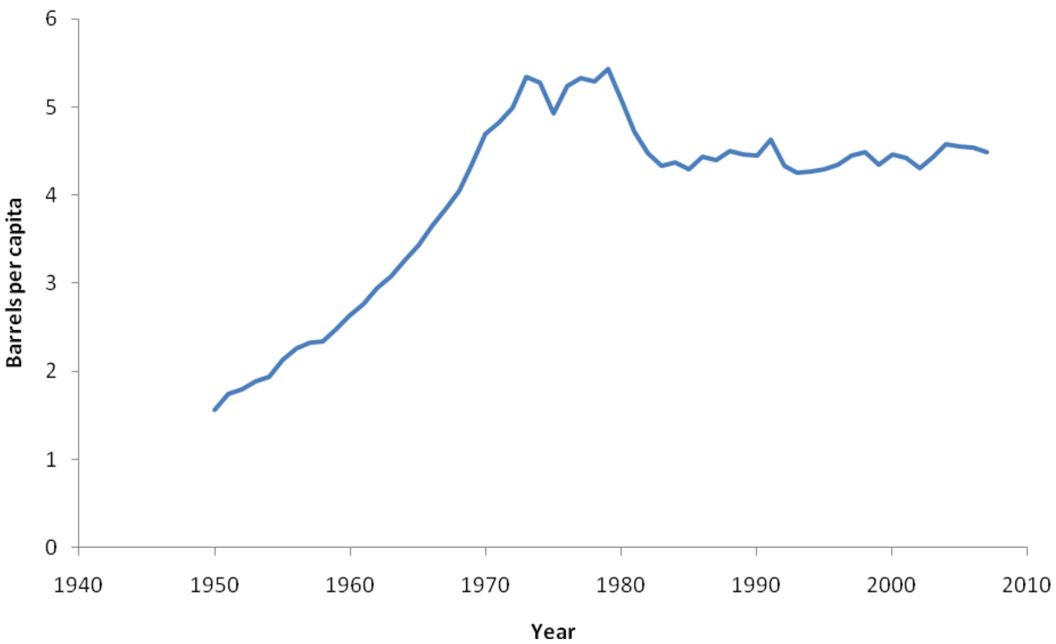
Oil production at the country, regional or global level is normally measured in million barrels per day (mb/d) or billion barrels per year (Gb/year) while cumulative production is measured in billion barrels (Gb). Global production of conventional oil (as defined above) averaged 80.7 mb/d in 2007, or 29.5 Gb/year, while global cumulative production was approximately 1128 Gb. (IEA, 2008) Since 1995, global production has grown at an average of 1.5%/year (albeit with considerable variation from year to year), with one quarter of cumulative production occurring over the last ten years and 59% since 1980 (Figure 2.3). At current rates of production, the world uses as much conventional oil as the UK has ever produced (24 Gb) in only ten months and as much as the US has ever produced (226 Gb) in eight years. On a per capita basis, global oil production peaked at 5.5 barrels per person in 1979 and has remained around 4.5 barrels per person since the mid-1980s (Figure 2.4). For comparison, the US currently consumes around 25 barrels per capita.

Figure 2.3 Global trends in oil production



Source: IHS Energy
Note: Includes crude oil, condensate, NGL, LPG, heavy oil and syncrude from oil sands.

Figure 2.4 Global trends in per capita oil production

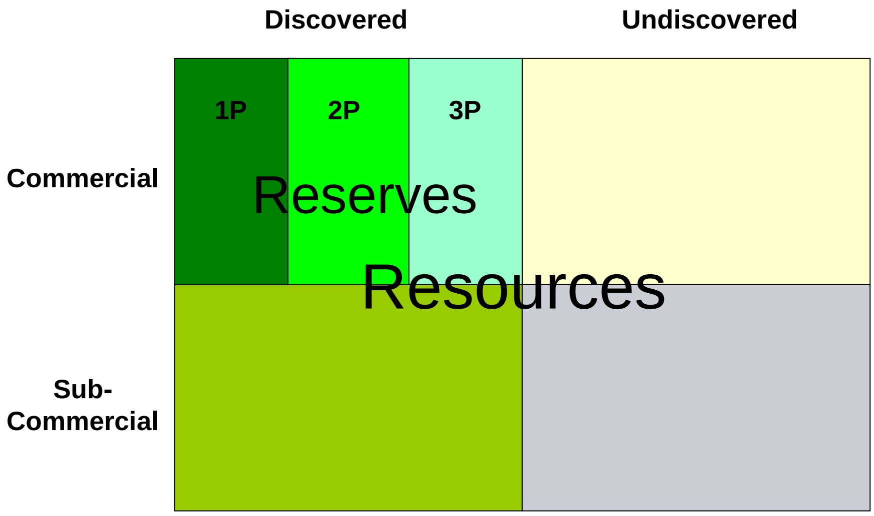


Source: IHS Energy; US Census Bureau
Note: Includes crude oil, condensate, NGL, LPG, heavy oil and syncrude from oil sands.

2.2.2 Reserves

Oil reserves are those quantities of oil in known fields which are considered to be technically possible and economically feasible to extract under defined conditions. Reserves must be distinguished from *resources* which are the total quantities estimated to exist, including those in known fields which are not considered economically feasible to extract as well as those in undiscovered fields. This distinction is commonly illustrated by the so-called 'McKelvey Box' (Figure 2.5).

Figure 2.5 Oil resources and reserves

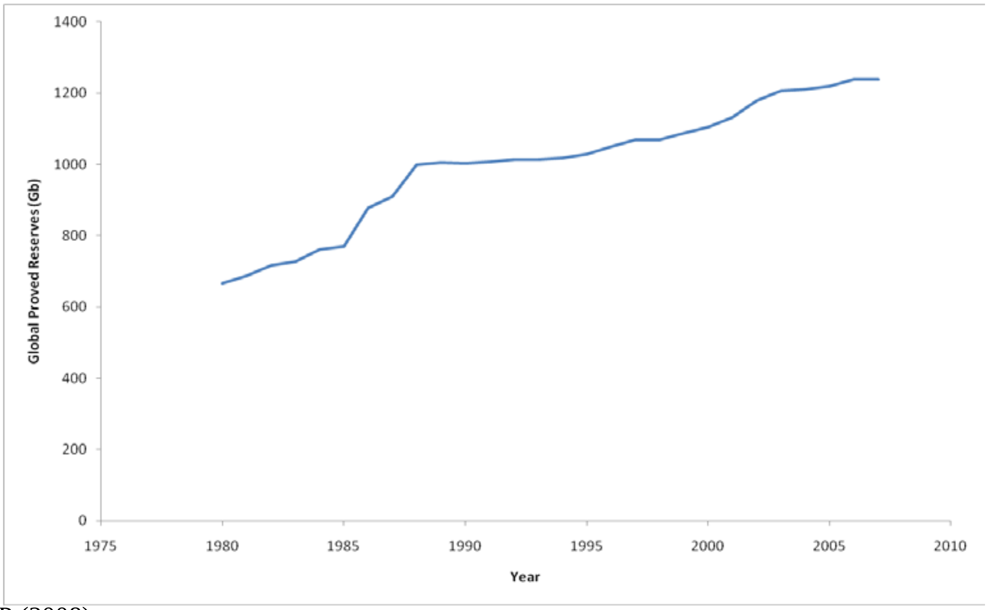


Source: McKelvey (1972)

Estimates of oil reserves are inherently uncertain since they rely upon information and assumptions about the geological features of an oil field, the technology of resource extraction and the economics of oil production. Reserve estimates are commonly quoted to three levels of confidence, namely *proved* reserves (1P), *proved and probable* reserves (2P) and *proved*, *probable and possible* reserves (3P) although these terms are interpreted in different ways (see below). Regional oil reserves will be reduced by production and increased by the discovery of new fields while company reserves will be further affected by mergers and acquisitions. In addition, both may be either increased or reduced by *revisions* to the reserve estimates of known fields as a result of better geological understanding, improved extraction technology, variations in economic conditions or changes in reporting practices. Changes in reserves over time are commonly referred to as *reserve additions*, although the changes could be either positive or negative. A headline financial indicator is the *replacement ratio*, or the ratio of reserves additions to production.

According to BP (2008), global proved (1P) reserves of conventional oil at the end of 2007 were approximately 1240 Gb, or slightly more than cumulative production. In principle, global proved and probable (2P) reserves should be larger that this, but according to an authoritative industry source (IHS Energy) they are approximately the same (IEA, 2008).[9] The possible reasons for this discrepancy are discussed further below. Global reported 1P reserves have increased steadily since the mid-1980s, despite increasing production (Figure 2.6). Global trends in 2P reserves are less clear, since the data is not readily available in the public domain.

Figure 2.6 Global trends in proved oil reserves



Source: BP (2008)

2.2.3 Cumulative discoveries

The sum of cumulative production and reserves is commonly referred to as *cumulative discoveries*. Depending upon the data available, it may be possible to estimate cumulative 1P, 2P or 3P discoveries. Both the BP Statistical Review and IHS Energy estimate global cumulative discoveries of conventional oil to be around 2370 Gb, although their reserve definitions and coverage of liquids do not coincide.

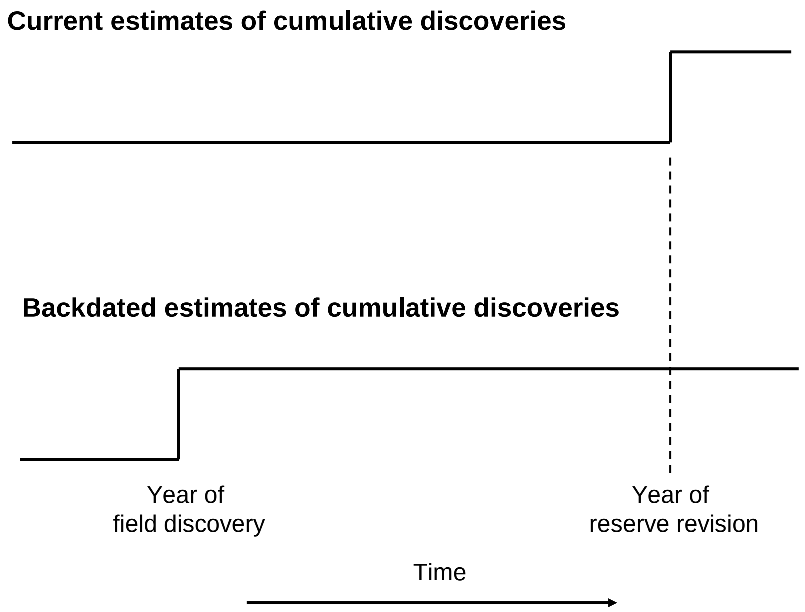
Unlike reserve estimates, cumulative discovery estimates will not be changed by production since this merely transfers resources from one category (reserves) to another (cumulative production). However, cumulative discoveries will be increased by the discovery of new fields and may be either increased or reduced by revisions to the reserve estimates for known fields. The latter is commonly referred to as *reserve growth* since estimates are normally revised upwards rather than downwards. However, a more accurate term is *cumulative discovery growth*, since reserves are continually being depleted by production. An alternative terms is ‘ultimate recovery growth’ since what is growing are the estimates of what will ultimately be recovered from the field or region. Reserve growth is a critical issue for future oil supply and is discussed further in Section 3.

A major source of confusion is the common practice of *backdating* cumulative discovery estimates. While some data sources record reserve revisions in the year in which they are made and make no adjustment to the data for earlier years, others *backdate* the revisions to

[9] This hides large discrepancies in the estimates for individual countries. For example, the IHS Energy estimates are significantly smaller than the BP Statistical Review’s for UAE, Libya and Kuwait but greater for Russia and Saudi Arabia.

the year in which the relevant fields were discovered (Figure 2.7). The logic of the first approach is that the reserves did not become 'available' for production until the estimate was revised and therefore should only appear at the time of the revision.[10] The logic of the second approach is that the reserves are contained in a field that was discovered many years earlier, so backdating provides a more accurate indication of what was 'actually' found at that time as well as what will ultimately be recovered from that field. Both of these approaches have their merits, but the difference between them is not always appreciated.

Figure 2.7 Current versus backdated estimates of cumulative discoveries – treatment of reserve revisions



Note: With current estimates, reserve revisions increase the cumulative discovery estimates in the current year. With backdated estimates, these revisions are backdated to the year in which the relevant field was discovered and hence increase the cumulative discovery estimates for all intervening years. The treatment of newly discovered fields is the same in both cases.

2.2.4 Discoveries

The term *discovery* is ambiguous since it may mean:

- the recoverable resources contained in fields that are newly discovered within a particular time period; or
- the change in cumulative discoveries from one period to the next.

These are not necessarily the same, since reserve growth at existing fields will contribute to 'discoveries' under the second definition even if no new fields are found. Unfortunately, it is not always clear which definition is being used and most data sources do not allow the

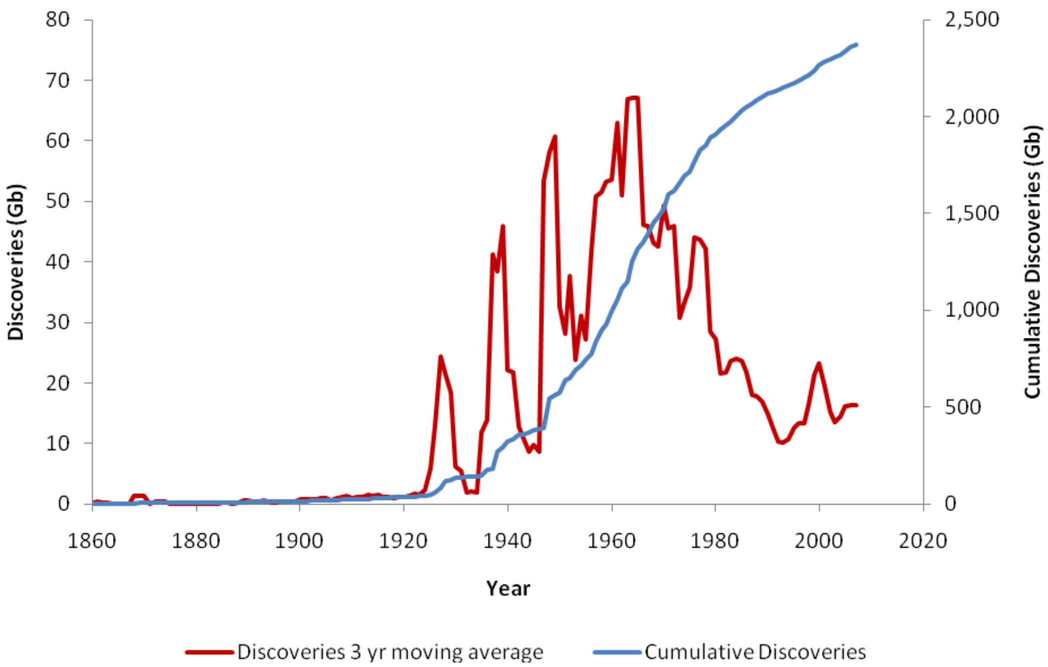
[10] For example, the world's largest gas field (in Qatar) was discovered in 1971 but the reserves in the Iranian section were neither known nor accessible until they were drilled in 1991. For Mills (2008), backdating these revisions to 1971 is like ascribing the discovery of California to the landing of Columbus in the Bahamas in 1492.

resources contained in newly discovered fields to be distinguished from reserve growth at existing fields.

Figure 2.8 shows a time series of backdated cumulative discoveries, together with a time series of backdated 'discoveries' based upon the second definition. This suggests that most of the world's conventional oil was discovered over a 35 year period from 1946 through to 1980. Discoveries peaked in the 1960s and have fallen steadily since, although with an upturn around the turn of the century.

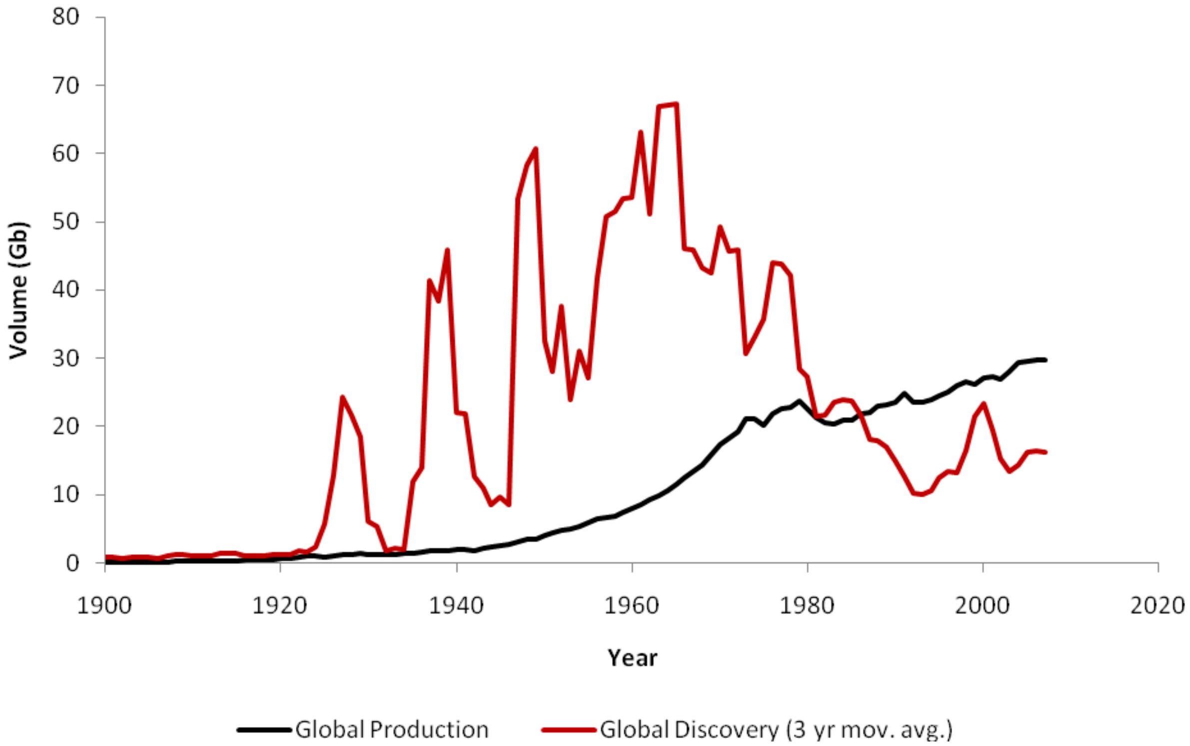
Figure 2.9 compares global production with global 'discoveries' as defined above. This widely cited graph suggests that since 1980 we have produced more oil than we have discovered each year. But this does *not* mean that we have produced more oil than we have added to reserves each year. Indeed, annual 1P and 2P reserve additions have exceeded annual production over most of this period owing to a combination of new discoveries and revisions to the estimates for existing fields (BP, 2008; Stark and Chew, 2005). This cannot be established from Figure 2.9 since revisions made in the current year are distributed between the earlier years according to the date of discovery of the relevant fields. As a result, the graph is somewhat misleading.

Figure 2.8 Global trends in backdated discoveries and cumulative discoveries



Source: IHS Energy
Note: Includes crude oil, condensate, NGL, LPG, heavy oil and syncrude. Based upon backdated 2P reserve estimates.

Figure 2.9 Global trends in production and backdated discoveries



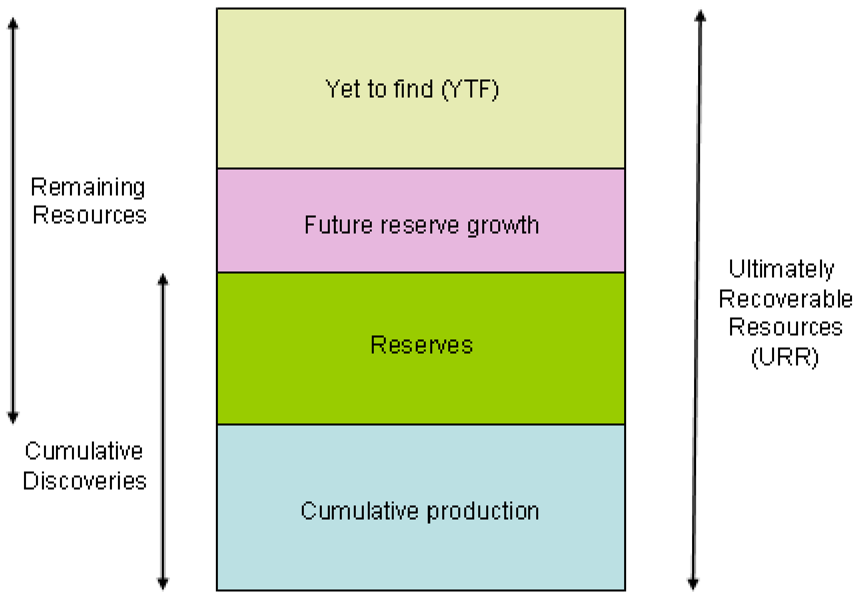
Source: IHS Energy
Note: Includes crude oil, condensate, NGL, LPG, heavy oil and syncrude. Discoveries based upon backdated 2P reserve estimates. While discoveries have fallen over time, the graph is potentially misleading since the discoveries for different years have not been estimated on a consistent basis. For example, the estimates for 1957 include 50 years of reserve growth, while the estimates for 2006 include only one year. This helps explain why comparable graphs published at different times have slightly different 'heights' and shapes for the backdated discovery data (e.g. Campbell, 2002b).

2.2.5 Ultimately recoverable resources

Ultimately recoverable resources (*URR)* represent the amount of oil that is estimated to be economically extractable from a field or region over all time – from when production begins to when it finally ends. In practice, however, many estimates of regional URR relate to a shorter timeframe. For example, Campbell imposes a cut-off date of 2070 for his URR estimates in order to remove a 'long tail' of relatively small volumes of production while a widely cited study by the US Geological Survey (USGS) imposes a cut-off date of 2025 (Campbell and Heapes, 2008; USGS, 2000).

For individual fields, the URR represents the sum of cumulative discoveries and estimates of future reserve growth. For a region, the URR represents the sum of cumulative discoveries, future reserve growth at known fields and the volume of oil estimated to be economically extractable from undiscovered fields - commonly termed the *yet-to-find (YTF).* The *remaining recoverable resources* for a region are all the recoverable resources that have yet to be produced, or the sum of reserves, future reserve growth and the yet-to-find (Figure 2.10). These three categories are progressively more uncertain. Estimates of the global URR for conventional oil fall within the range 2000 to 4300 Gb or two to four times cumulative production through to 2007. As illustrated in Figure 1.2, estimates of the global URR for all-oil are several times larger.

Figure 2.10 Components of ultimately recoverable resources (URR)

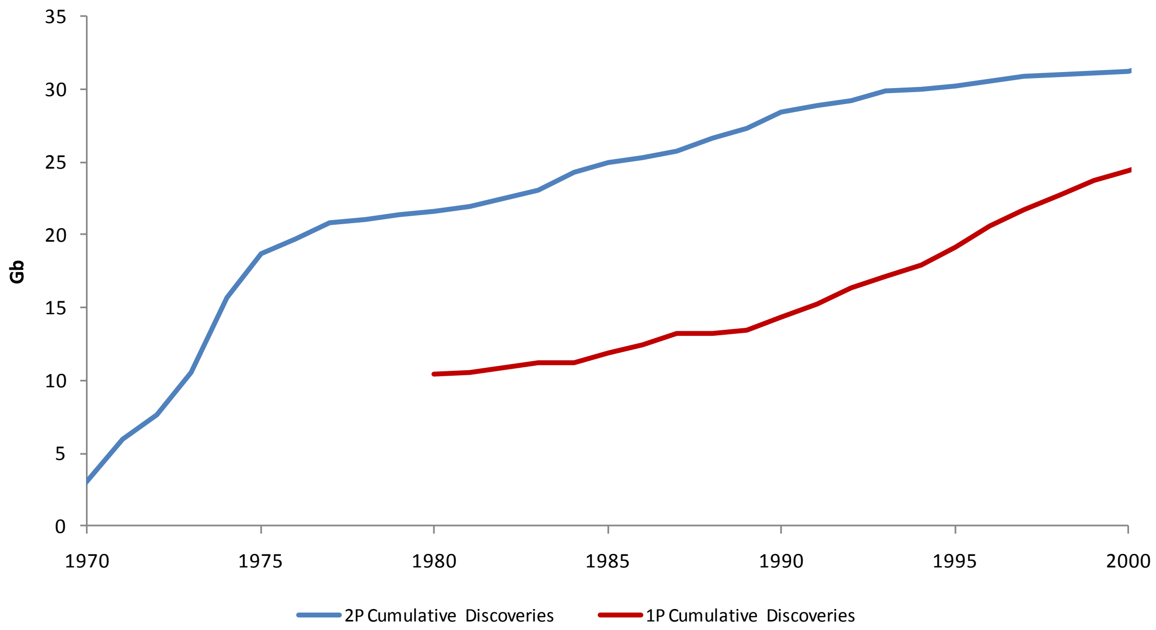


2.2.6 Measuring oil depletion

Estimates of these four categories of oil resources are available from a number of data sources, but the information that can be derived will depend upon the definitions that are used. In particular, *backdated estimates of cumulative 2P discoveries can provide more information about resource depletion than current estimates of cumulative 1P discoveries* (Bentley, 2009; Bentley, *et al.*, 2007; Campbell and Laherrère, 1995). This is illustrated in Figure 2.11 which compares these two variables for the UK. The 'backdated 2P' curve suggests diminishing returns to exploration, largely as a result of the diminishing size of newly discovered fields. This curve appears to be trending towards an asymptote of 30-35 Gb which is commonly taken as an estimate of the regional URR (see Section 4). But since more reserve growth may occur in the future, the 'height' of the cumulative discovery curve is likely to change over time (Figure 2.12). Hence, to accurately estimate the URR, the cumulative discovery curve must be 'corrected' to allow for future reserve growth.

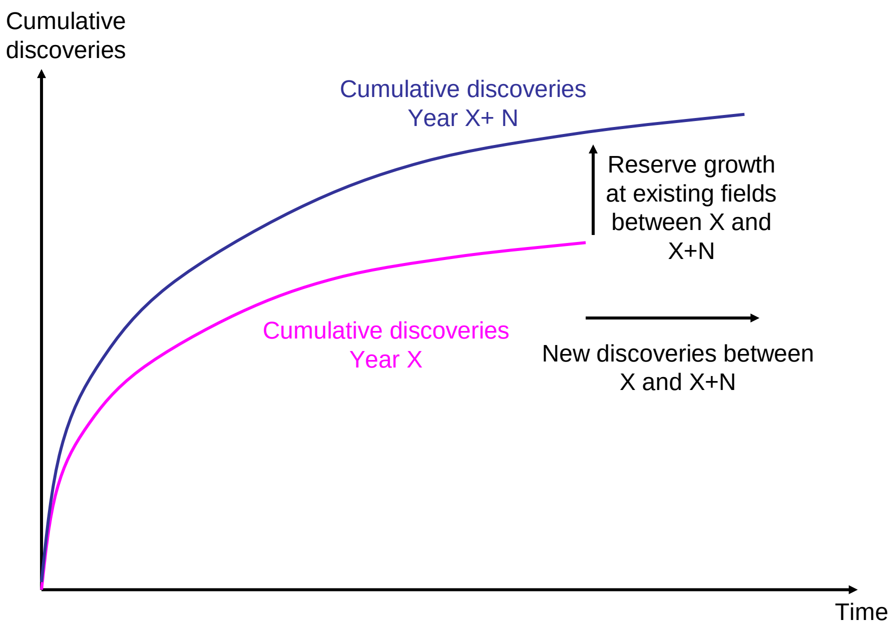
The backdated 2P curve for the UK (Figure 2.11) suggests that more than half of the URR had already been produced by 1999. Given the simple model of Section 1, this suggests that a near-term peak in production may be expected, even in the absence of data on individual fields (the peak actually occurred in 1999). The same information is more difficult to obtain from the 'current 1P' curve since this does not indicate diminishing returns to exploration and hence does not provide a good basis for estimating the URR. This is *both* because the 1P data underestimates recoverable reserves (see below) *and* because these estimates are not backdated to the date of discovery of the field. Hence, analysts using backdated 2P data should be better placed to forecast a forthcoming peak in production then analysts using current 1P data. Disputes over a near-term peak are therefore linked in part to reliance upon different data sources (Bentley, *et al.*, 2007).

Figure 2.11 Two ways of presenting UK cumulative discoveries - backdated 2P versus current 1P



Source: IHS Energy; BP (2008)

Figure 2.12 Effect of reserve growth on backdated estimates of cumulative discoveries



2.3 Sources of data and key figures

A variety of sources provide data on oil production and reserves at the global, country, regional and individual field level. These use different definitions and generally provide different estimates, despite compiling information from the same primary sources (Karbuz, 2004). The most useful data is only available from commercial organisations at considerable cost.

Box 2.3 summarises the publicly available sources of global data, while Table 2.1 compares their coverage with that of the Petroleum Economics and Policy Solutions (PEPS) database provided by IHS Energy. The PEPS database is available under contract and provides time-series data on oil and gas production and reserves for 180 countries, together with information on drilling activity and other relevant variables.[11] Regional data is available from a variety of sources,[12] but only the US, UK, Norwegian and Australian governments publish data on individual fields. In addition, Nehring Associates maintain a database of US fields and Uppsala University maintain a database on ~500 of the world's 'giant fields' (Robelius, 2007).[13] Comprehensive databases covering the majority of the world's fields are maintained by Wood Mackenzie and IHS Energy[14] but these are very expensive. The IEA and USGS publish aggregate estimates that are based in part upon IHS Energy data.

Box 2.3 Publicly available sources of global data on oil production and reserves

International Energy Agency (IEA) publishes production data in the monthly Oil Market Report (OMR) and the annual World Energy Outlook (WEO) (IEA, 2008; 2009b). For forecasting purposes, the IEA relies on third party assessments of recoverable reserves.

Energy Information Administration (EIA) focuses mostly on the US oil market but also provides international statistics. The most useful of these is the International Petroleum Monthly which provides data on regional and global production, oil demand, trade and stocks (EIA, 2008b).

Oil and Gas Journal (OGJ) provides global production and reserve estimates in the final issue of each year (Radler, 2007). The OGJ reserve estimates are commonly quoted by other sources.

World Oil publishes global data on production and reserves in August or September every year (WorldOil, 2007).

BP Statistical Review provides a comprehensive and widely quoted compilation of global energy statistics, gathered through a combination of primary sources, third party sources, other data providers (particularly OGJ and World Oil) and independent assessments (BP, 2008).

OPEC Secretariat maintains its own figures regarding Member's reserve and production and these are used by most other data sources since they do not have direct access to the relevant National Oil Companies (NOCs) (OPEC, 2008). OPEC also provides global reserves data.

[11] PEPS is the continuation of statistics maintained by 'Petroconsultants' before its purchase by IHS Energy in 1996. The former provided the basis for an influential publication by Campbell and Laherrère (1995).

[12] Including the American Petroleum Institute (API), the American Association of Petroleum Geologists (AAPG), Baker Hughes the International Petroleum Encyclopaedia and several national governments.

[13] Defined as fields with ultimately recoverable resources exceeding 0.5Gb or fields that have produced more than 100 kb/d for over a year.

[14] The IHS field-level database forms the basis of the PEPS country-level database.

Table 2.1 Comparison of global data sources on oil production and reserves

Source	Reserves Data	Grouping of liquids in production data	Liquids excluded
IEA Oil Market Report	No	• Crude oil, condensate, NGLs[1], non-conventional[2], • Refinery gains • Other Biofuels[3]	None
EIA International Petroleum Monthly	No	• Crude oil, condensate, NGLs, other liquids[4], refinery gains • NGLs reported separately	None
BP Statistical Review	Proved	• Crude oil, oil shale, oil sands, condensate, NGLs (aggregated)	CTLs, GTLs, biofuels
Oil and Gas Journal	Proved	• Crude oil, condensate, syncrude (aggregated)	NGLs, CTLs, GTLs, biofuels
World Oil Magazine	Proved	• Crude oil, condensate, syncrude (aggregated)	NGLs, CTLs, GTLs, biofuels
OPEC Annual Statistical Bulletin and Oil Market Report	Proved	• Crude oil, condensate, NGLs[5] (aggregated) • Refinery gains	CTLs, GTLs, biofuels
IHS Energy PEPS database	Proved and probable	• Liquids (crude oil, condensate, NGLs, LPG, heavy oil, syncrude)	CTLs, GTLs, biofuels

Source: IEA (2009b), EIA(2008b), BP (2008), IHS Energy, Oil & Gas Journal, World Oil Magazine
Notes: Precise definition and coverage of liquids is not always made clear.

1. NGLs reported separately for OPEC.
2. Including biofuels, oil sands, oil shales, CTLs, GTLs and blending components such as MTBE.
3. Biofuels from sources outside Brazil and US.
4. Biofuels, CTLs, non-oil inputs to MTBE, orimulsion and other hydrocarbons (EIA, 2008b)
5. NGLs reported separately for OPEC.

Key differences between the public domain sources and the industry databases are that:

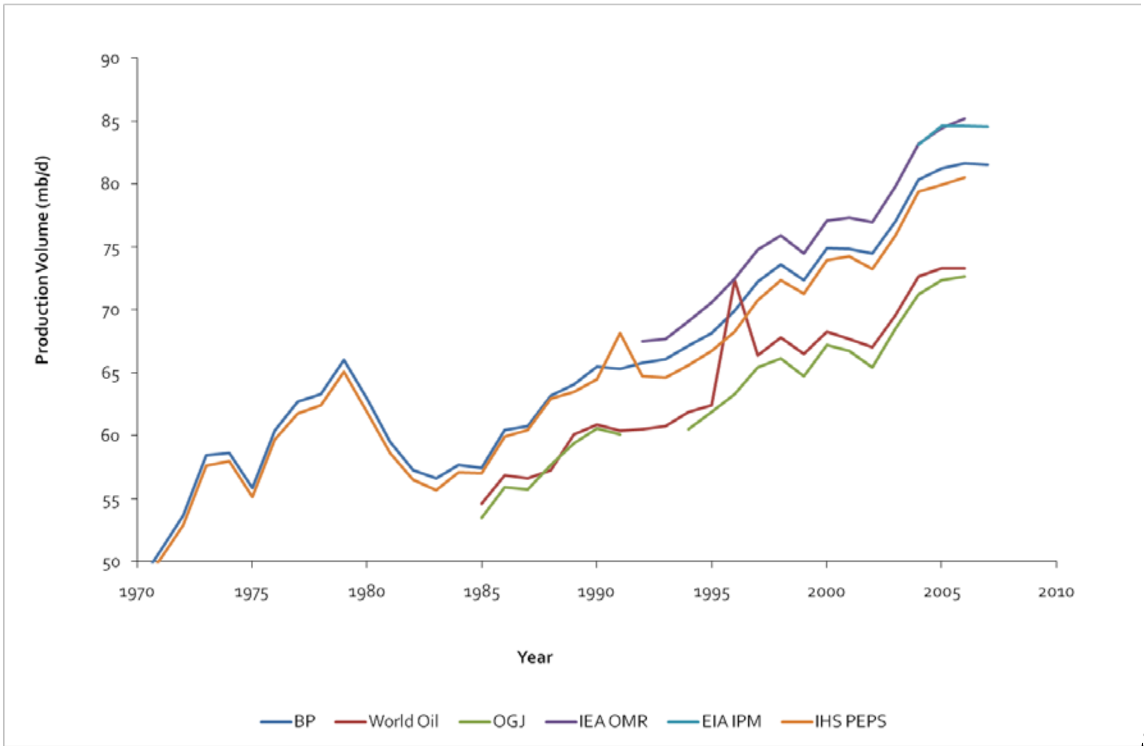
- the former provide 1P reserve estimates while the latter provide 2P estimates;
- the former provide current estimates of cumulative 1P discoveries while the latter provide backdated estimates of cumulative 2P discoveries;[15] and
- the former rely heavily upon data supplied by national governments, while the latter derive information from a wider range of sources, with more attempt to verify their accuracy.

The relative merits of these different data sources is much debated (Bentley, *et al.*, 2007), but the cost and confidentiality of the industry databases makes comparison difficult. Many analysts of global oil supply rely upon their own, proprietary databases which are even less accessible to third parties (Campbell and Heapes, 2008; Miller, 2005; Smith, 2008). Since these are based in part on the industry databases, they contain backdated estimates of cumulative 2P discoveries.

[15] The US is treated differently in the industry databases, since the reserve estimates are based upon the reporting requirements of the Securities and Exchange Commission (SEC) and reflect a conservative interpretation of 1P reserves (see Section 3). As a result, the industry databases are likely to underestimate global 2P reserves (the US accounts for 2.4% of the total). Also, an important consequence of backdating reserve revisions is that a time-series of ‘current’ 2P reserves can only be constructed using successive editions of the industry databases.

Figure 2.13 compares estimates of global oil production from six data sources. The differences are largely explained by the differing coverage of liquids (Table 2.1). The differences are somewhat larger in the case of 1P reserve estimates (Figure 2.14) owing in part to the use of competing reserve classification schemes. Major sources of discrepancy include the differing treatment of Russian reserves in the early 1990s,[16] the differing treatment of the Canadian oil sands after 2002[17] and the upward revisions to the reserve estimates for several OPEC countries in the 1980s. For example, Iraq's reserves increased by 57% in 1986 while the UAE's increased by 195% despite little or no exploratory drilling. While many commentators discount such revisions as being politically motivated with little or no connection to physical resources (Campbell, 2002a), it is possible that the reserves of some of these countries had previously been underestimated. Figure 2.15 shows the regional distribution of proved reserves, highlighting the global importance of the Middle East producers.

Figure 2.13 Global oil production trends from different data sources



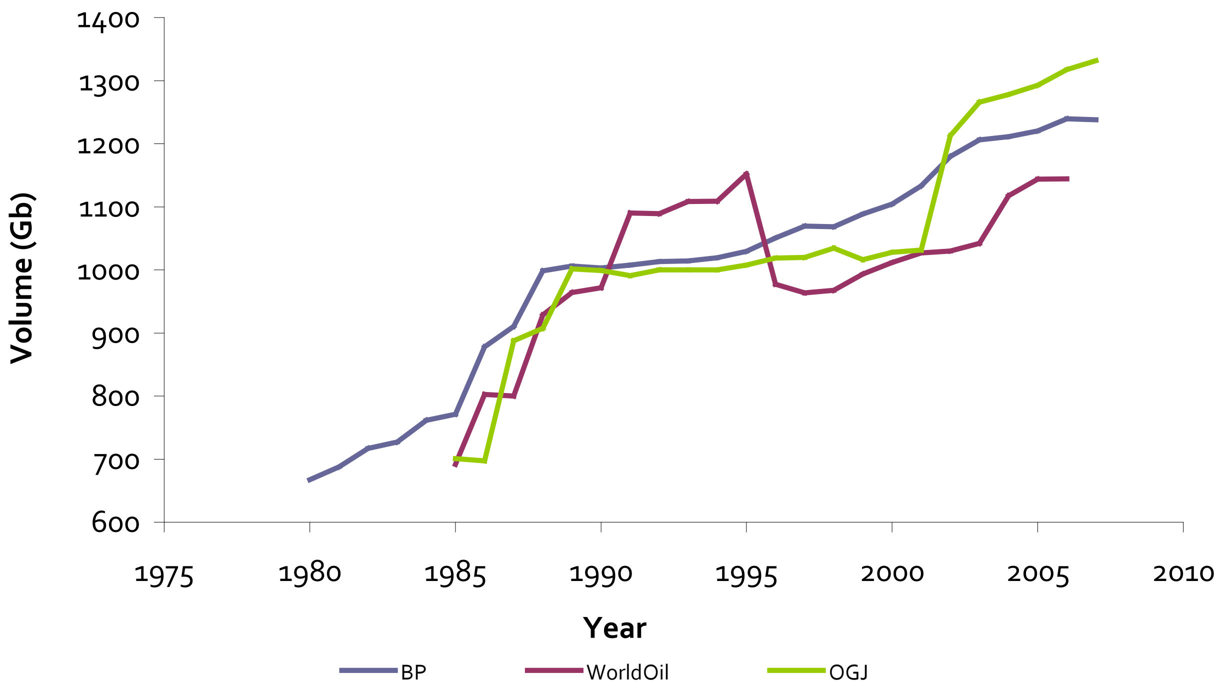
Sources: BP Statistical Review, World Oil, Oil and Gas Journal, IEA Oil Market Report, EIA International Petroleum Monthly and IHS Energy PEPS database

Notes: OGJ and World Oil only include crude oil, condensate and syncrude. BP Statistical Review and IHS Energy also include NGLs. IEA and EIA also include refinery gains, CTL, GTL and biofuels.

[16] The World Oil figures reflect a change from one reserve reporting system to another and back again.

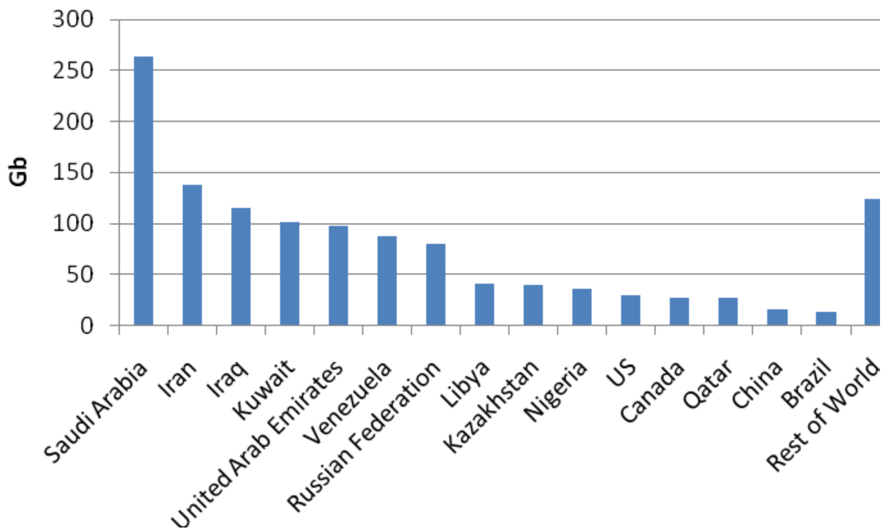
[17] In 2002, the OGJ included 174.8 Gbbl of Canadian oil sands reserves for the first time. But the BP Statistical Review and World Oil include only 21 Gbbl, representing those resources which are 'under active development'.

Figure 2.14: Global proved reserve trends from different data sources



Source: BP Statistical Review, OGJ, World Oil

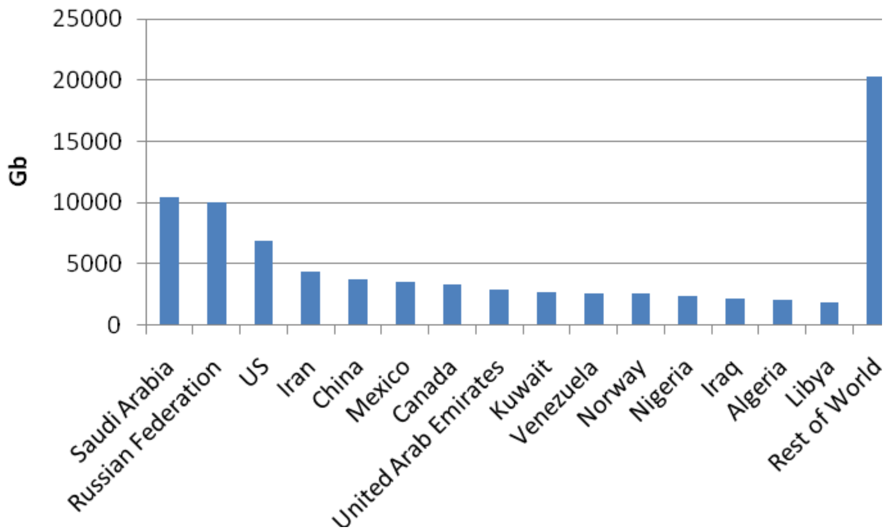
Figure 2.15 Regional distribution of proved reserves



Source: BP Statistical Review, OGJ, World Oil

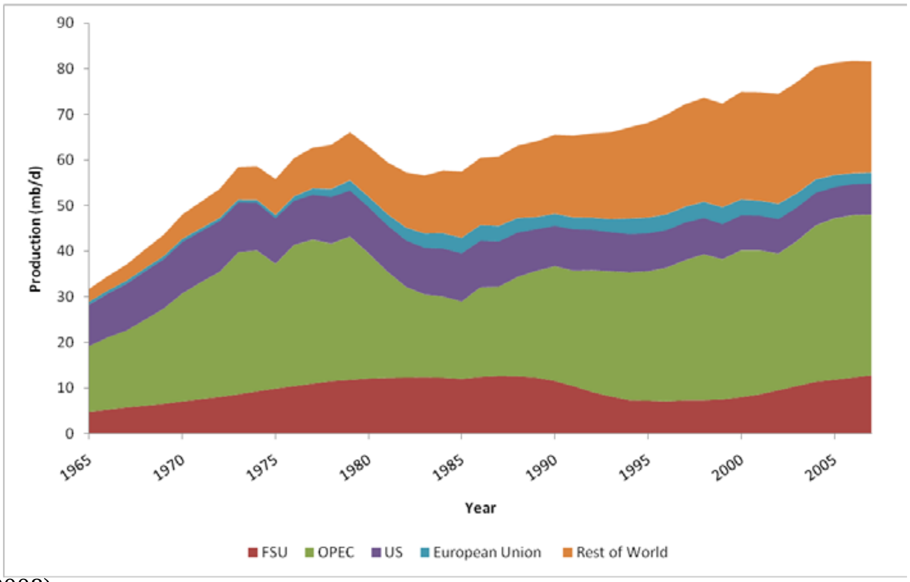
Around 100 countries produce oil, but forty nine countries accounted for 98.9% of all-oil production in 2007, seven countries accounted for more than half while four (Saudi Arabia, Russia, the US and Iran) accounted for 39% (Figure 2.16). OPEC is growing in importance (Figure 2.17) and it is anticipated that the Middle East will increasingly dominate global production (IEA, 2008). Twenty eight countries have increased production over the last five years, while twenty eight countries have experienced production declines (Figure 2.18). Russia accounted for the most of the growth in non-OPEC production over this period, but future expansion may be obstructed by physical, investment and political constraints (Janssen, 2005). It is frequently claimed that around 60 countries are past their peak of production compared to only a handful in the 1970s (Figure 2.19). But many of these countries make only a tiny contribution to global production (e.g. Senegal), in some cases the peak may be primarily the result of economic and political factors (e.g. Poland) and with appropriate investment some producers could potentially exceed their earlier peak (e.g. Iraq).

Figure 2.16 Share of world all-oil production by country



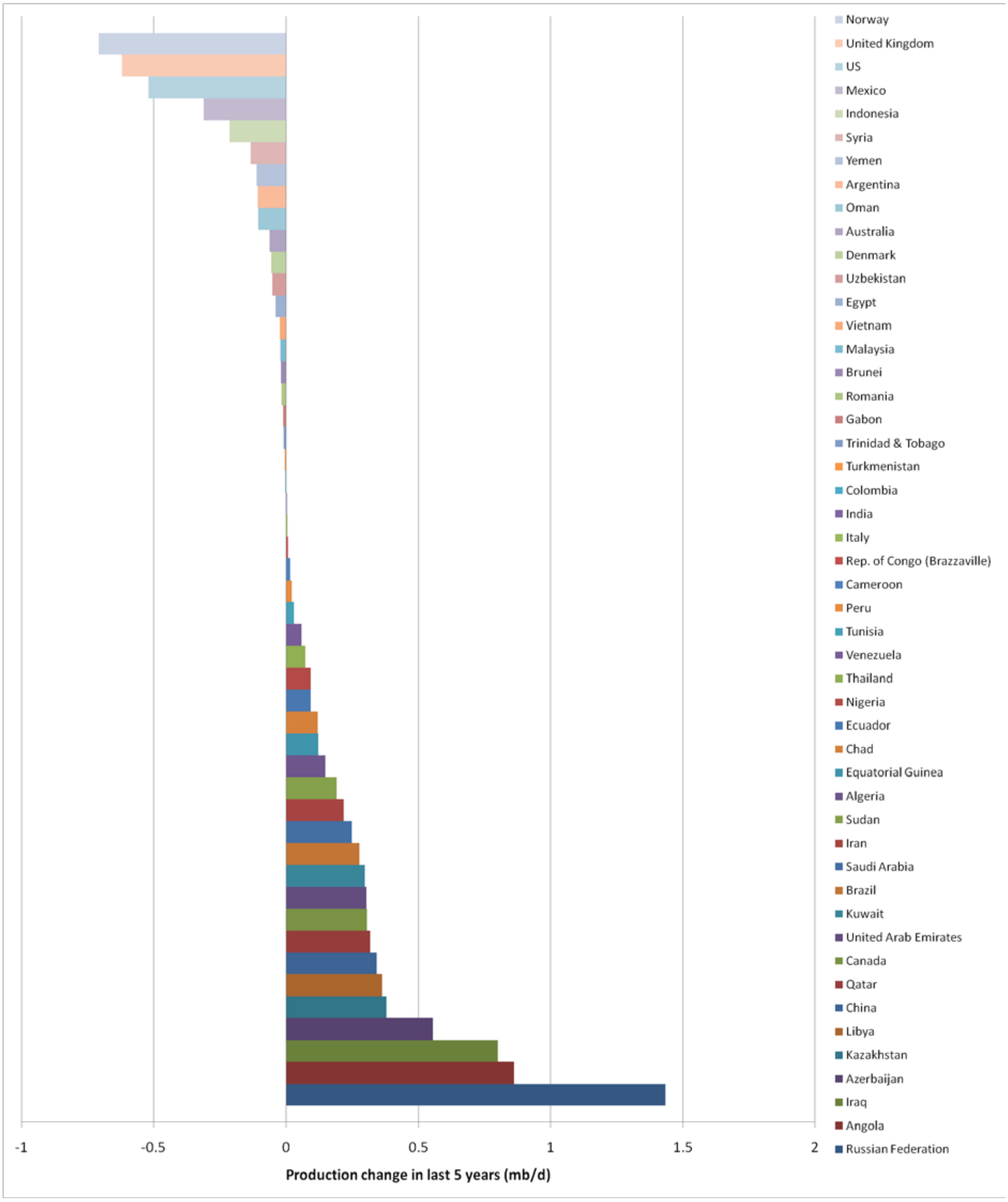
Source: BP (2008)

Figure 2.17: Share of world all-oil production for selected regions.



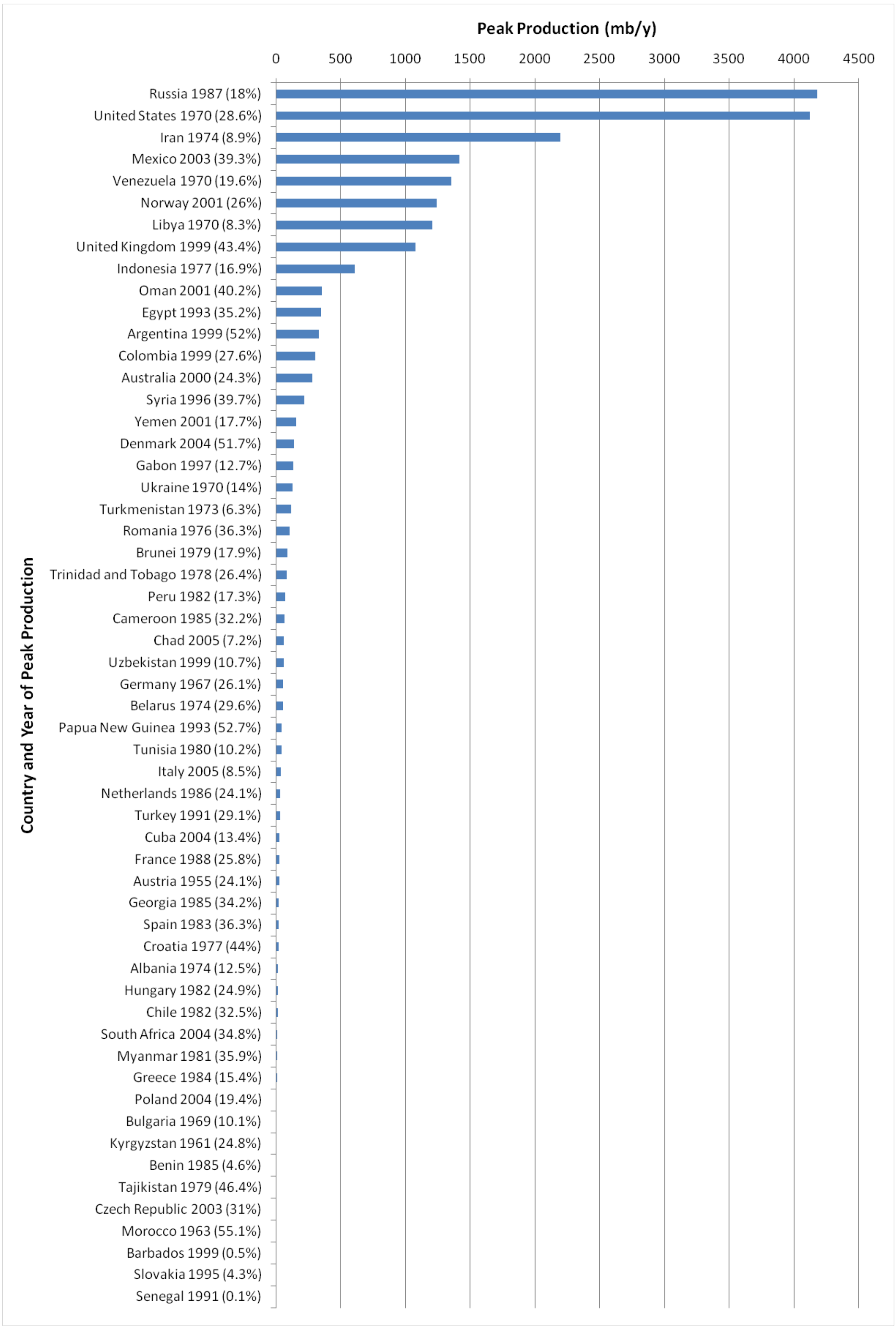
Source: BP (2008)
Note: European Union excludes Estonia, Latvia and Lithuania prior to 1985 and Slovenia prior to 1991.

Figure 2.18: Change in all-oil production over the last 5 years for top 49 producing countries.



Source: BP (2008)

Figure 2.19 The expanding group of post-peak producers



Source: BP (2008); USGS (2000)
Note: Shows year of peak production and estimated percentage of the USGS (2000) estimate of URR that was produced by the date of peak. In some cases (e.g. Poland), peak production may be primarily the result of economic and political factors rather than physical depletion and some countries (e.g. Iraq) may subsequently be able to increase production above the previous peak.

Perhaps the greatest source of controversy in the peak oil debate is the definition and size of oil reserves. The following sections explore this in more detail, including how reserve estimates are produced, how uncertainties are expressed and how such estimates are reported.

2.4 Estimating and reporting reserves

Reserves are estimated for individual wells, reservoirs or fields (Box 2.4) and then aggregated to companies or regions. The process involves judgments about how much oil is in the ground, how much is technically possible and economically viable to extract and how much to declare publicly as reserves. Given the multiple uncertainties, significantly different estimates are legitimately possible for the same field (Mitchell, 2004b).

Box 2.4 Reservoirs and fields

- *Reservoir*: A reservoir is a subsurface accumulation of oil and/or gas whether discovered or not, which is physically separated from other reservoirs and which has a single natural pressure system. An alternative term for reservoir is ‘pool’.
- *Field*: A field is an area consisting of a single reservoir or multiple reservoirs of oil and gas, all related to a single geological structure and/or stratigraphic feature. When projected to the surface, the reservoirs within the field can form an approximately contiguous area. Oil fields may either be discovered, under development, producing or abandoned and the number of wells may range from one to thousands. The classification of a field may change over time, with previously distinct fields being merged into one large field, and larger fields being broken down into smaller ones.

Sources: Klett (2004); Drew (1997)

The first stage is to estimate the *oil originally in place* (OOIP) through a mix of seismic surveys (to map geological features), direct and indirect measurements of reservoir properties (e.g. viscosity, porosity, permeability) and computer simulation (Barss, 1978; Speers and Dromgoole, 1992). Initial estimates of OOIP can be highly uncertain, especially with geologically complicated and heterogeneous fields, but the accuracy improves as fields are developed.

The second stage is to estimate the *recovery factor*, or the fraction of OOIP that can be produced with current or anticipated technology (IEA, 2008; Speers and Dromgoole, 1992). A distinction is normally made between *primary recovery*, where oil is produced under its own pressure; *secondary recovery*, where physical lift is used or water or natural gas is pumped in to maintain pressure, and *tertiary* or *enhanced oil recovery* (EOR) where gas, solvents, chemicals or heat are added with the aim of raising pressure, reducing viscosity, displacing water and/or improving the movement of oil. These are traditionally applied in sequence, with EOR currently accounting for some 3% (2.5 mb/d) of global production. Reserve estimates are sensitive to the recovery method and hence recovery factor assumed, but only a subset of EOR techniques may be appropriate for particular fields.

The third stage is to estimate the *economic viability* of recovery which depends on the current and anticipated future price of oil, the estimated capital and operating costs of extraction, assumptions about tax treatment and other factors. Companies traditionally combine these geological, engineering and economic uncertainties to produce ‘low’, ‘best’ and ‘high’ estimates of recoverable reserves, which broadly correspond to the 1P, 2P and 3P classifications introduced above. These will be used internally, but generally will not be released into the public domain since they may prejudice commercial negotiations (Mitchell, 2004a).

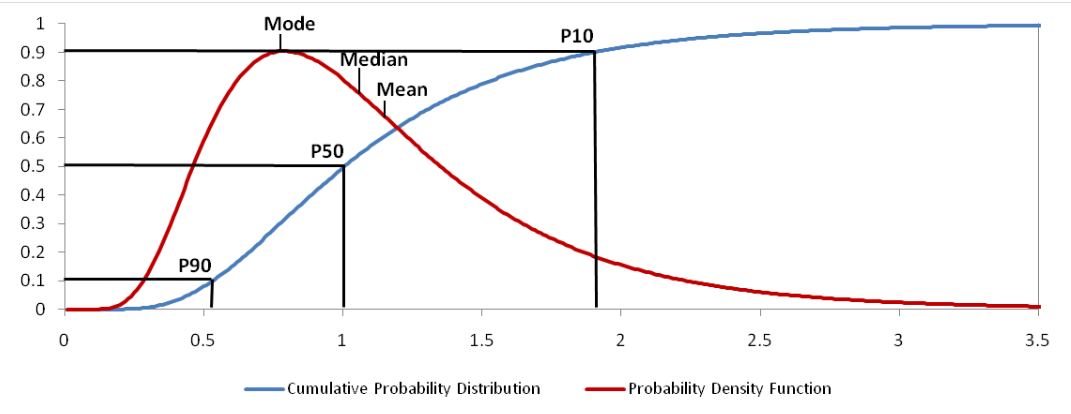
The final stage is *reserve reporting* for regulatory, accounting or other purposes. It is unusual to report anything other than 1P estimates and in the absence of a clear, consistent and widely enforced international standard, the definitions and approaches to reserve reporting vary widely from one country to another and from one company to another. The reserve reports of independent oil companies (IOCs) are closely scrutinised and can affect stock valuations, debt ratings and project financing (Arnott, 2004).[18] National oil companies (NOCs) are less sensitive to market conditions but can have political motives for choosing particular definitions and interpretations. For example, in the 1980's, the reported 1P reserves of OPEC countries increased by 80% (~300 Gb) in response to negotiations over production quotas and have since remained unchanged for periods of up to a decade (Bentley, *et al.*, 2007; Salameh, 2004). Hence, public reserve declarations provide only a partial and distorted picture of actual reserve holdings.

2.5 Assessing uncertainty in reserve estimates

The traditional 1P, 2P and 3P categories provide some indication of the margin of error in reserve estimates but fail to quantify the degree of uncertainty. A better approach is to estimate a *probability distribution* of possible outcomes (Figure 2.20) by assigning probabilities to the geological, engineering and economic parameters and combining these within a Monte Carlo simulation (Schulyer, 1999). The estimated distribution tends to narrow as production proceeds and information improves and the measures of central tendency tend to increase over time (reserve growth).

Probabilistic estimates allow identification of a *P90* quantity which has a 90% probability of being exceeded, a *P50* quantity which has a 50% probability of being exceeded, and a *P10* quantity which has a 10% probability (SPE, 2007). These are often equated with the 'deterministic' low (1P), best (2P) and high (3P) estimates of recoverable reserves (Table 2.2) but the latter may be produced in a different way.

Figure 2.20 Probability and cumulative probability distribution of recoverable reserves



Note: The probability density function (red line) represents a statistical distribution which in this example is skewed to the left. In the context of reserve estimates, there is no probability of there being a negative volume of

[18] In January 2004, Shell announced that it was revising its reserve reporting and reduced its proved reserves by 3.9 Gb. This led to an immediate 7% fall in its share price and the subsequent resignation of its chief financial officer. A subsequent investigation found that executives in the exploration and production division had exaggerated the size of reserves and failed to act when it became clear the estimates were unrealistic.

oil, but there is a high probability of reserves being somewhere between 0.5 and 2 units, and a small probability of there being a much large amount. The P90, P50 (median) and P10 estimates all represent points on the cumulative distribution function (blue), which is the integral of the probability density function. The vertical scale refers solely to the cumulative distribution.

Table 2.2 Deterministic and probabilistic terminologies associated with oil reserves estimation.

Type of estimate	Deterministic terminology	Probabilistic terminology	Statistical description
Low	Proved (1P)	P90	10^{th} percentile
Best	Proved and probable (2P)	P50	Median
High	Proved, probable and possible (3P)	P10	90^{th} percentile

The probabilistic interpretation is recommended by several international organisations (SEC, 2008; SPE, 2007; UN, 2004) and while it highlights the conservative nature of 1P estimates (i.e. they should be exceeded in 90% of cases) actual estimates may not coincide with the P90 interpretation. For example, Jung (1997) found that the Canadian interpretation of 1P reserves is closer to P60 while a study of US data suggests P65 (Laherrère, 2001). 'Best' estimates should be easier to produce than low or high estimates, but their appropriate interpretation will depend upon the particular reserve classification scheme that is used. Some schemes do not specify a statistical definition of a `best' estimate, others implicitly assume it to be the median (P50) and others allow either the median, mode or mean to be used (UN, 2004). These three measures will only coincide if the probability function is normally distributed and may be significantly different if it is skewed (see Figure 2.20). In practice, the probability distribution is commonly found to take a *lognormal* form which is skewed to the left (Bloomfield, *et al.*, 1979; Quirk and Ruthrauff, 2006).[19] In these circumstances, the mode is less than the median which in turn is less than the mean.

The common practice of adding reserve estimates can lead to significant errors (Cronquist, 1991; Jung, 1997; Pike, 2006; Ross, 1998). For example, suppose one company owns reserves R1 which are estimated to have (P10, P50, P90) = (20, 10, 1) Gb and another company owns reserves R2, also with (20, 10, 1) Gb, and the two companies merge. It is *not* then generally true that the new company will have reserves (40, 20, 2) Gb - this is in fact an *underestimate* of the true P90, an *overestimate* of the true P10, and will only be a correct estimate of the P50 if the median is equal to the mean.

Pike (2006) illustrates the logic behind this with the example of two dice. If a single dice is thrown, the probability of the outcome exceeding one is 83% (5 out of 6). In other words, the P83 figure is 1.0. But if two dice were thrown, the probability of the outcome exceeding two is 97% (35 out of 36). So the P97 figure is 2.0. The corresponding P83 figure is 4 (6 out of 36), or twice the simple arithmetic aggregation of the two individual P83 figures. Hence, by simply adding the individual P83 figures, the probability of the combined score exceeding two would be significantly underestimated (the probability is actually 97% and not 83%).[20] In a similar manner, the sum of the 1P (P90) estimates of the oil reserves of two fields would be an *underestimate* of the actual 1P figure for the two fields combined (see also Box 3.1).

[19] A random variable (x) is lognormally distributed if $\ln(x)$ is normally distributed. This is commonly the outcome of the multiplicative rather than additive combination of independent variables which may be the case in petroleum formation (Capen, 1976; Drew, 1997; Limpert, *et al.*, 2001).

[20] Although helpful, this example is strictly incorrect because the P83 of one die (the number which has an 83% or 5 in 6 chance of being exceeded) is not well-defined and could in fact be any number between 1.0 and 1.9999.

Box 2.5: Aggregation of probabilistic reserve estimates

Assume that the probability distributions of reserves in two fields are independent and that there is a 90% probability of the first exceeding 1Gb and an independent 90% probability of the second exceeding 1Gb. However, the sum of the two could also exceed 2Gb by having one field perform slightly worse and the other a lot better. Hence, the probability of total reserves exceeding 2Gb is:

$$P(\text{R1 exceeds 1 Gb})*P(\text{R2 exceeds 1 Gb}) + \int [P(\text{R1 exceeds 1 Gb by X})* P(\text{R2 falls short of 1 Gb by less than X})]dX$$

The second term represents the degree of overlap of the two distributions. The probability of both fields independently exceeding 1Gb is 0.9 x 0.9 = 0.81, but the probability of the sum exceeding 2Gb will be greater than this. A simple summation of the P90 estimates (which gives the probability of R1 + R2 exceeding 2Gb as 0.9) may be an over or underestimate of the true P90 according to the shape of the distributions. If a normal distribution is assumed, it will be an underestimate.

Alternatively, if the two reserves are not completely independent (e.g. they are part of the same geological formation or are developed in parallel) an under- or over-estimation of one is likely to be associated with an under- or over-estimation of the other. In this case the above calculation is complicated by a weighting factor indicating how closely the two distributions are linked.

Aggregation is especially important for 1P estimates since these are the most widely used. When 1P (P90) reservoir data is aggregated to a whole field, field data to a whole company or country and national data to global estimates, there will be a systematic underestimation of the actual 1P figure. Each addition increases the degree of underestimation, with the result that the global estimates are likely to be the most biased. Hence, not only do 1P estimates provide a conservative estimate of likely recoverable resources, but the degree of conservatism is further reinforced by the aggregation process that is normally employed. The result is likely to be a set of numbers which significantly understate the amount of oil likely to be produced (Pike, 2006). These numbers are also more likely to increase over time (Figure 2.6).

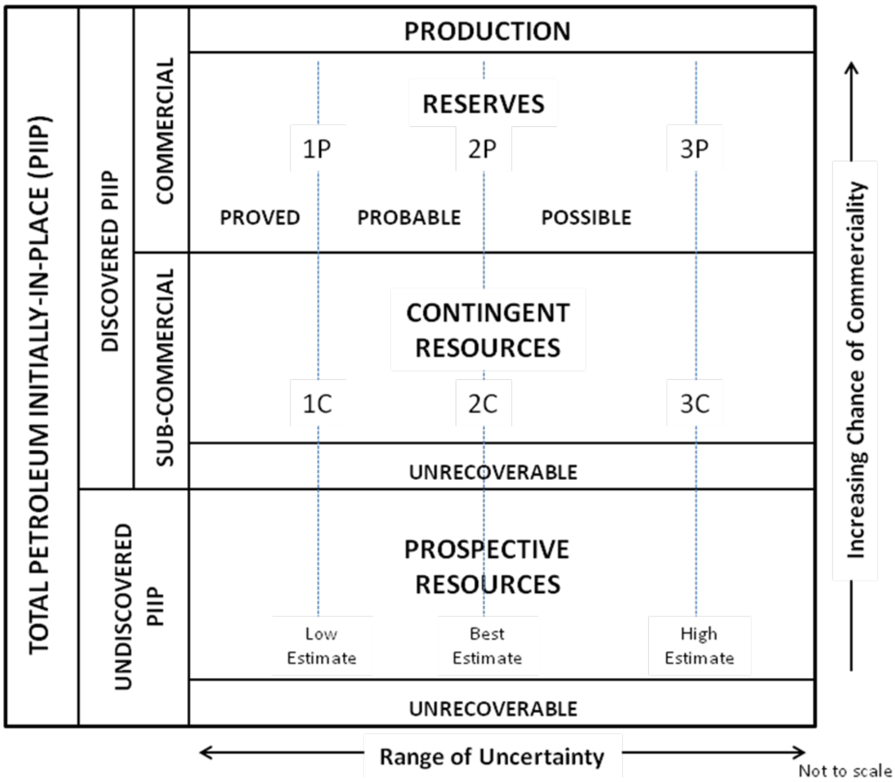
The same conclusions may not apply to the aggregation of 2P estimates since the outcome will depend upon both the probabilistic interpretation of these estimates (i.e. whether they correspond to the mean, median or mode) and the shape of the relevant probability distributions. Simple addition is only valid if they represent mean estimates, but it is more common to interpret 2P estimates as the median (P50). If the median lies below the mean (e.g. Figure 2.20), simple addition could also lead to an underestimate of aggregate 2P reserves. However, the error should be smaller than with 1P reserves and is unlikely to be consistent from one dataset to another.

2.6 Reserve classification schemes

There are multiple systems for classifying reserves, most of which are based upon the McKelvey Box (Figure 2.5). Cronquist (1991) compared 25 schemes and found that 19 used the term 'proved', 16 used 'probable' and 13 'possible'. Only nine used probabilistic definitions of these terms and these did not always agree. 'Proved' and 'probable' were commonly identified with a 90% and 50% probability of being exceeded, while definitions of 'possible' were both less frequent and less consistent. This disparity highlights the difficulty of aggregating estimates from different sources.

The petroleum industry has made several attempts to standardise definitions, but with limited success to date. An important step forward was the Petroleum Resources Management System (PRMS, Figure 2.21)[21] which distinguishes between recoverable reserves, contingent resources and prospective resources, with each being subdivided according to the level of uncertainty (WPC, 2007). The PRMS uses the 1P, 2P and 3P terminology, but allows both deterministic estimates based on qualitative guidelines and probabilistic estimates based on P90, P50 and P10. It also allows both arithmetic summation and statistical aggregation and hence could lead to different results depending upon the particular method used.

Figure 2.21 The Petroleum Resource Management System



Source: SPE (2007)
Note: Reserves are commercially recoverable by the application of projects to known accumulations under defined conditions. Contingent resources are potentially recoverable from known accumulations, but where the applied projects are not yet considered mature enough for commercial development due to one or more contingencies. Prospective resources are potentially recoverable from undiscovered accumulations by application of future development projects.

A competing, three-dimensional classification has been proposed by the UN (Ahlbrandt, *et al.*, 2003; UN, 2004). This distinguishes between economic viability (E), field project status (F) and geological assessment (G), with further subclasses for each.[22] Although widely used for the classification of other mineral resources, this scheme seems unlikely to be adopted by the petroleum industry.

An important and influential classification scheme is provided by the US Securities and Exchange Commission (SEC) which requires the disclosure of audited 1P reserve estimates by US-listed companies (SEC, 2008). These account for a quarter of global production and

[21] Jointly proposed by the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC), and the Society of Petroleum Evaluation Engineers (SPEE).
[22] For example, a well-developed, economically viable project with well-characterised geology would be E1 F1 G1.

include the majority of IOCs.[23] The SEC definitions are conservative since they are intended to provide confidence to investors in future revenue streams. They make no reference to probabilistic estimates and do not allow for future technical developments or changes in economic and operating conditions. Also, since they only include reserves within the production range of a well, reserve estimates appear to grow as more wells are drilled, contributing to reserve growth that is partly an artefact of the reporting convention.

The SEC requirements are undergoing substantial revisions and from 2010 will incorporate probabilistic definitions and allow reserves to be estimated in the absence of contact to a well (SEC, 2008). Declaration of 2P reserves will also be permitted, but unfortunately this remains optional.

In sum, while reserve classification schemes are becoming more harmonised the current proposals have several drawbacks and are a long way from being comprehensively adopted. To the extent that NOCs continue to report un-audited estimates using their own definitions, IOCs continue to report only highly conservative 1P estimates and both are influenced by economic and political considerations, the assessment of global oil depletion will remain handicapped by inadequate data.

2.7 Summary

The main conclusions from this section are as follows:

- Liquid fuels are not subdivided in a consistent way and the disagreements between both data sources and oil supply forecasts result in part from their differing coverage of those fuels. However, what is commonly termed conventional oil is anticipated to dominate global liquids supply over the next 20 years.
- Since 1993, the world has produced half as much oil as was produced in the preceding century and now uses as much oil as the UK has produced (24 Gb) in only ten months. Estimates of the level of depletion of global conventional oil resources (i.e. the proportion of ultimately recoverable resources that have already been produced) vary between 28% and 56%. On a per capita basis, global oil production peaked in 1979.
- The ultimately recoverable resources for a region represent the sum of cumulative production, declared reserves, future reserve growth and yet-to-find resources. Data on the first two categories are available from a number of sources, but at the global level none of these agree. Estimates for the other two categories are necessarily very uncertain.
- While terms such as ‘proved’, ‘probable’ and ‘possible’ reserves are widely used, they are defined and interpreted in different ways. Probabilistic reserve estimates offer significant advantages (including allowing retrospective evaluation of the accuracy of estimates) but remain insufficiently used.
- There are multiple reserve classification schemes in use around the world and only limited progress towards standardisation. Only a subset of global reserves is subject to formal reporting requirements and this is largely confined to the reporting of highly conservative 1P estimates. Various economic and political influences on reserve reporting further compromise the reliability of published figures.

[23] A number of NOCs (e.g. Saudi Aramco) also claim to follow SEC guidelines but in the absence of third-party auditing it is not clear whether this is actually the case.

- Disputes over a near-term peak in oil production result in part from the use of different data sources. Publicly available data sources provide estimates of 1P reserves and record reserve revisions in the year in which they are made, while the industry databases provide estimates of 2P reserves and 'backdate' revisions to the date of discovery of the relevant fields. Both approaches have merits, but the latter is more suited to estimating the ultimately recoverable resources of a region and can provide more information about resource depletion and the risk of a near-term peak in production. At present, the differences between these approaches remain insufficiently understood and the disagreements between different data sources remain insufficiently explained.

- The common practice of adding 1P estimates to form a regional or global total is likely to significant underestimate actual 1P reserves. Aggregation of 2P estimates should introduce less error but this may be either positive, negative or zero depending upon the interpretation of the estimates and the shape of the underlying probability distributions.

- As a result of inappropriate aggregation, global 1P reserves could be larger than the 1240Gb reported by BP (2008) – potentially offsetting the overestimation of OPEC reserves that is claimed by some authors (Campbell and Heapes, 2008). At the same time, the industry estimates of global 2P reserves are approximately the same as the BP Statistical Review estimates of global 1P reserves, suggesting either that the former have been underestimated or the latter overestimated. Since the discrepancies between these data sources vary both in magnitude and sign from one country to another, the global totals should be treated with considerable caution.

- Publicly available 1P reserve data is poorly suited to the purpose of assessing global oil depletion. While industry databases are better in this regard, they are expensive and subject to strict confidentiality requirements. Audited estimates of 2P reserves for most of the world's oil fields would transform the peak oil debate. But in the absence of such data, supply forecasts must rely upon assumptions whose level of confidence is inversely proportional to their importance. The uncertainties are greatest for those countries which hold the majority of the world's reserves.

3 Enduring controversies – field sizes, reserve growth and decline rates

The dispute between 'optimists' and 'pessimists' over the future of global oil supply is underpinned by equally polarised disagreements over a set of more technical issues. Given the complexity and multi-dimensional nature of this topic, the existence of such disagreements is unsurprising. However, the situation is made worse by the inadequacy of the publicly available data and the scope this creates for competing views and interpretations. Improved data on individual fields could go a long way towards resolving such disagreements, but this seems unlikely to become available in the foreseeable future. Nevertheless, there is potential for increasing the degree of consensus in a number of areas and some progress has already been made. This section looks in more detail at four of these issues, namely:

- *Field size distributions*: how oil resources in a region are distributed among different sizes of field and the relative proportion of resources contained within very large and very small fields.
- *Reserve growth*: why estimates of the size of fields tend to grow over time and how much growth may reasonably be expected in the future.
- *Decline rates*: how rapidly the production from different categories of field is declining and how this may be expected to change in the future.
- *Depletion rates:* how rapidly the remaining recoverable resources in a field or region can be produced.

More comprehensive examinations of these topics can be found in *Technical Reports 3*, *4* and *5*.

Section 3.1 examines field size distributions, including the importance of large fields, the size distribution of discovered fields and the contribution of small fields to future global oil supply. Section 3.2 examines reserve growth, including the relative contribution of different factors to reserve growth, the forecasting of reserve growth and the growth observed in industry databases since 1995. Section 3.3 summarises the current state of knowledge on decline rates, including definitions and models of decline rates, illustrative examples and current estimates of global average decline rates. Section 3.4 clarifies the relationship between decline rates and depletion rates and shows how the latter provide constraints on viable supply forecasts. Section 3.5 concludes.

3.1 Field size distributions

Methods of resource assessment and supply forecasting frequently rely upon assumptions about the size distribution of oil fields within a region, where 'size' refers to the estimated URR of each field. It is generally assumed that the majority of resources are contained within a small number of large fields which tend to be discovered relatively early. This rule seems broadly applicable at levels ranging from individual ‘exploration plays’[24] to the entire world. However, the precise form of the size distribution varies from one region to another and is a long-standing focus of dispute (Drew, 1997; Kaufman, 2005; Laherrère, 2000a). Of particular interest is the proportion of resources contained within very large and very small fields, since the former dominate current oil production and the latter are expected to become increasingly important in the future.

3.1.1 The importance of large fields

One of the first global surveys of crude oil fields was by Ivanhoe and Leckie (1993) who grouped fields into ten size categories on the basis of their estimated URR (Table 3.1). The 370 fields with a URR exceeding 0.5 Gb (i.e. >7 days current global production of crude oil) represented less than 1% of the total number of fields but accounted for three quarters of cumulative discoveries. Of particular importance were the 42 ‘super-giant’ fields with a URR exceeding 5 Gb (i.e. >73 days current global production) with the largest (Ghawar in Saudi Arabia) having a URR of ~140 Gb (~5 years current global production). The 1300 fields with a URR exceeding 0.1 Gb represented only 3% of the total but accounted for 94% of cumulative discoveries. The remaining 39000 fields accounted for less than 6% of the total and individually contributed only a tiny fraction of global production.

Table 3.1: Ivanhoe and Leckie’s estimates of the size distribution of the world’s oilfields

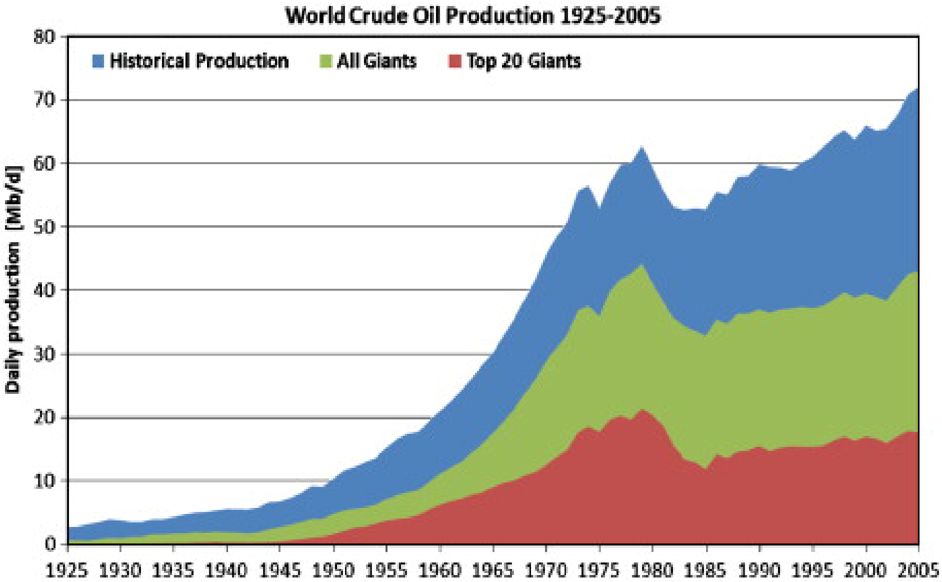
Category	**Estimated URR (mb)**	**No. in world**
Megagiant	>50,000	2
Supergiant	5000-50,000	40
Giant	500-5000	328
Major	100-500	961
Large	50-100	895
Medium	25-50	1109
Small	10-25	2128
Very small	1-10	7112
Tiny	0.1-1	10849
Insignificant	< 0.1	17740
Total		**41164**

Source: Ivanhoe and Leckie (1993)

Similar results were obtained by Robelius (2007), who provided an updated analysis of the world's ‘giant’ oilfields using data from a variety of sources. Robelius estimates that there are ~47500 oil fields in the world, 73% of which are in the United States.[25] Only 507 (~1%) of these are ‘giants’, with an estimated URR of more than 0.5 Gb, of which 430 are in production and 17 under development. Robelius estimates that the 100 largest fields account for 45% of the global production of crude oil (see Figure 3.1) while the giants as a whole account for approximately two thirds of global cumulative discoveries. Half of these giants were discovered more than 50 years ago.

[24] A ‘play’ is an area for petroleum exploration that has common geological attributes and lies within some well-defined geographic boundary.
[25] These figures demonstrate that much more exploration has taken place in the US compared to other regions of the world. This has implications for the relative suitability of different resource assessment methodologies (Section 4) and suggests there could be unexploited potential outside of the US.

Figure 3.1 The estimated contribution of giant oilfields to global crude oil production



Source: Robelius (2007)

Simmons (2002) defines giant fields as those producing more than 100 kb/d (i.e. 0.14% current global production of crude oil).[26] He estimates that there are 116 giants under this definition which in 2002 accounted for approximately half the global production of crude oil. The smallest 62 of these fields accounted for only 12% of production while the largest 14 accounted for over 20%.

The most up-to-date estimates are provided by the IEA (2008) who use Ivanhoe's classification system and rely largely upon the IHS Energy database. They estimate that 70,000 oil fields were in production in 2007, but around 60% of crude oil production derived from 374 fields (54 supergiant and 320 giant). An additional 84 giant fields were either under development or 'fallow'. Approximately half of global production derived from only 110 fields, 25% from only 20 fields and as much as 20% from only 10 fields, with Ghawar accounting for a full 7% (Table 3.2). Most of the 20 largest fields have been in production for several decades and 16 of them are past their peak of production. The world's second-largest oil field, Canterell, peaked in 2003 and its production has since declined by ~70%.

Hence, while the precise numbers may be uncertain, it is clear that around 100 oil fields account for up to half of the global production of crude oil, while up to 500 fields account for two thirds of cumulative discoveries. Most of these fields are relatively old, many are well past their peak of production and most of the rest will begin to decline within the next decade or so. The remaining reserves at these fields, their future production profile and the potential for reserve growth are therefore of critical importance for future global supply.

[26] Höök, *et al.* (2009b) estimate there are 20 giant fields under Simmons' definition which are not giant fields under Ivanhoe's definition.

Table 3.2 The ten largest oil fields in the world

Field	Country	Onshore/ offshore	Year of discovery	Year of peak production	Peak production kb/d	2007 production kb/d
Ghawar	Saudi Arabia	On	1948	1980	5588	5100
Canterell	Mexico	Off	1977	2003	2054	1675
Safaniyah	Saudi Arabia	On/off	1951	1998	2128	1408
Rumalla	Iraq	On	1953	1979	1493	1250
Burgan	Kuwait	On	1938	1972	2415	1170
Samotlor	Russia	On	1960	1980	3435	903
AHWAZ	Iran	On	1958	1977	1082	770
Zakum	Abu Dhabi	Off	1964	1998	795	674
Azeri-Chirag---Guneshli	Azerbaijan	Off	1985	2007	658	658
Priobskoye	Russia	On	1982	2007	652	652
Total						**14260**

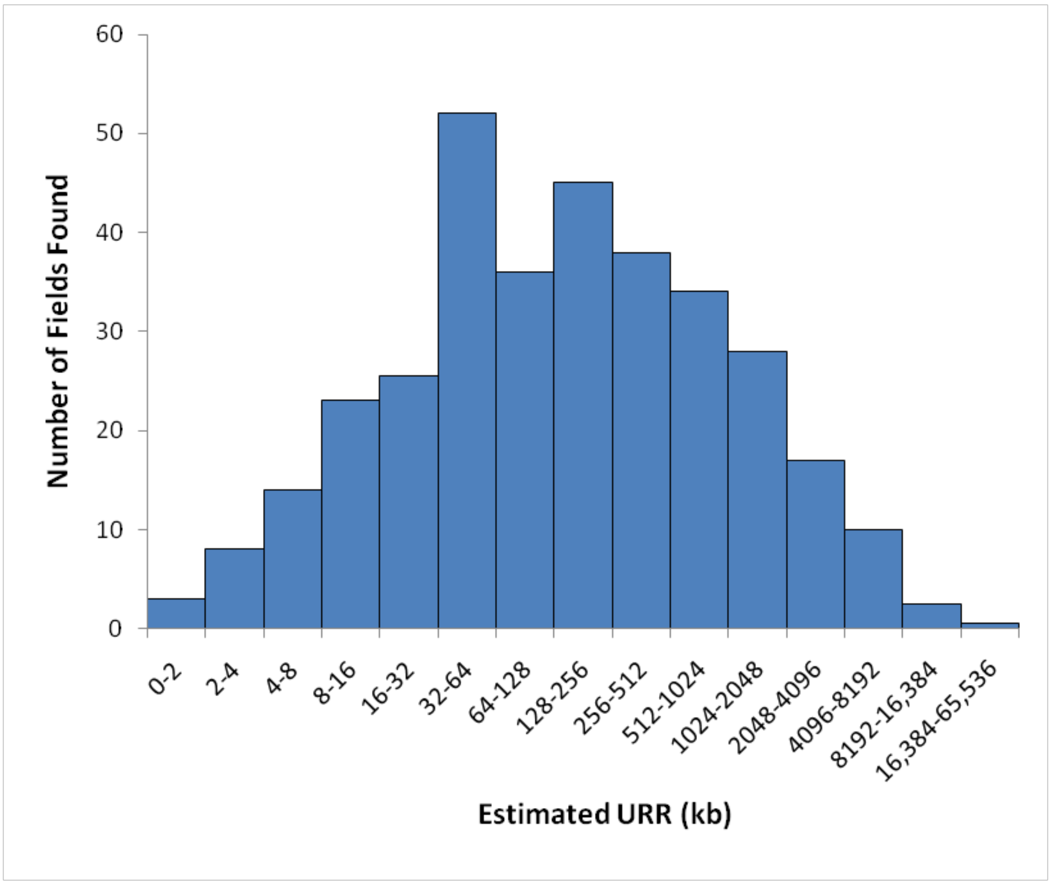
Source: IEA (2008)
Note: Data as of 2007, so 'peak' in 2007 may indicate that production is still increasing.

3.1.2 The contribution of small fields

The size distribution of the population of oil fields in a region can be inferred from the size distribution of the sample of discovered fields. Arps and Roberts (1958) were among the first to observe that this typically took a *lognormal* form - in other words, the frequency distribution of the logarithm of discovered field sizes resembled a normal distribution (Figure 3.2). This observation was subsequently supported by several studies, including McCrossan's (1969) analysis of reservoir sizes[27] in Western Canada and studies of US data by Kaufman (1963) and Drew and Griffiths (1965).

[27] These results indicate that skewed size distributions apply as much to reservoirs within fields as to fields within larger regions.

Figure 3.2 Oil and gas field size distribution for the Denver basin in 1958



Source: Adapted from Arps and Roberts (1958) and Drew (1997).

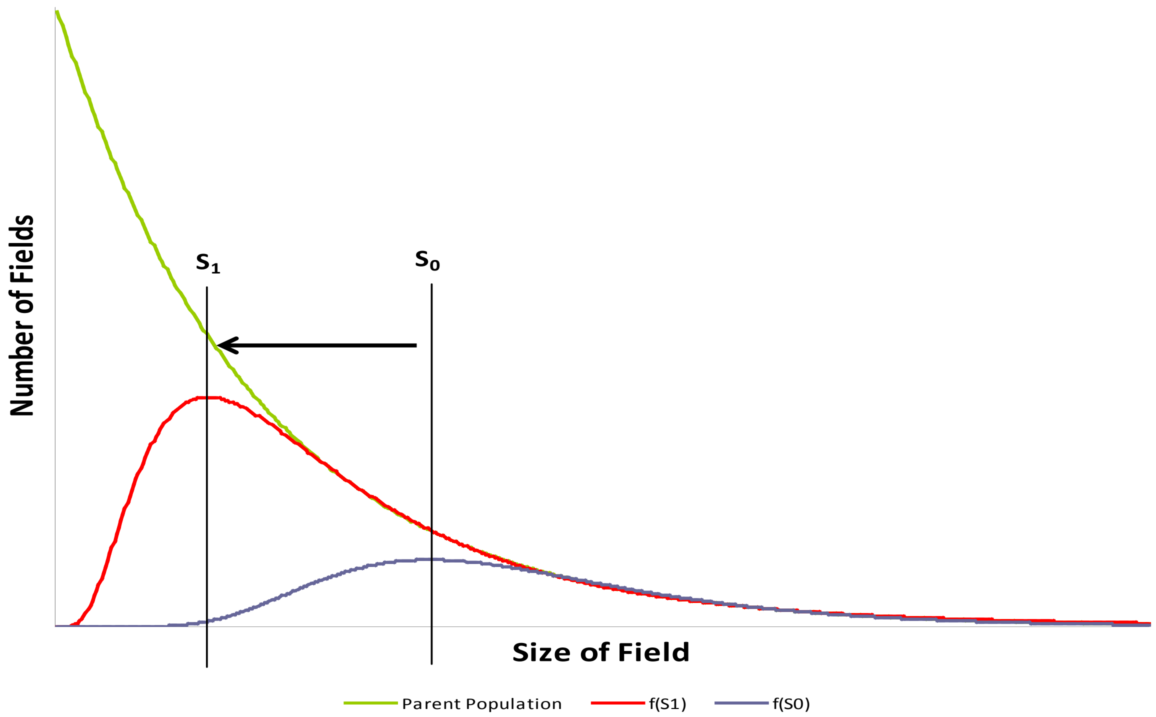
The notion that oilfields followed a lognormal size distribution became conventional wisdom during the 1960s and 1970s and subsequently formed the basis of some highly sophisticated 'discovery process models' (Forman and Hinde, 1985; Kaufman, 1975; Lee and Wang, 1983). This was despite the difficulties in drawing inferences from a relatively small sample of fields that may be unrepresentative of the population as a whole (Bloomfield, *et al.*, 1979; Kaufman, 1993). In particular small fields are likely to be underrepresented in such samples because they are less economic to develop - so-called 'economic truncation' (Arps and Roberts, 1958; Attanasi and Drew, 1984; Drew*, et al.*, 1988; Schuenemeyer and Drew, 1983). The lognormal distribution may therefore result from the under-sampling of small fields (Figure 3.3). As exploration proceeds, technology improves, oil prices rise and/or costs fall, these fields should become increasingly economic to find and develop, causing the modal size of the sample of discovered fields to fall. This process has been observed in many oil-producing regions, including the Permian basin in Texas (Cramer Barton and La Pointe, 1995; Drew, 1997).[28] Additional sampling bias may be introduced by the tendency to discover the larger fields first (Power, 1992).[29]

[28] Comparable inferences can be drawn from cross-sectional data, since the minimum viable field size varies widely from one region to another (Drew and Schuenemeyer, 1993; Drew*, et al.*, 1982).

[29] Power (1992) simulated the discovery of fields from a theoretical population that had a 'power-law' size distribution with progressively more fields in each of the smaller size classes (Figure 3.3). He found that, as the number of exploratory wells increased, the sample size distribution evolved towards the population distribution. However, lognormality was found to be an acceptable model for the sample size distribution over a wide range of measures of exploratory effort even without 'economic truncation' being imposed.

On the basis of these and similar observations, Drew and colleagues proposed that the population field size distribution was more likely to take a 'power-law', or 'Pareto' form (see Box 3.1). If this is the case, a plot of the number (*N*) of fields exceeding a particular size (*V*) on logarithmic scales should approximate a straight line (Figure 3.4). In contrast, if the size distribution is lognormal, this plot would be curved. While curved plots are more commonly observed in practice, this is partly the result of biased sampling.

Figure 3.3 How the undersampling of small fields may lead to a lognormal frequency distribution of the size of discovered fields



Note: Green line indicates 'power-law' size distribution of the population of fields. Blue line indicates the approximately lognormal size distribution of the sample of discovered fields at time t_0. Red line indicates size distribution of the sample of discovered fields at $t_1 > t_0$ when changes in economics and technology have lowered the size threshold for economically viable fields.
Source: Drew (1997)

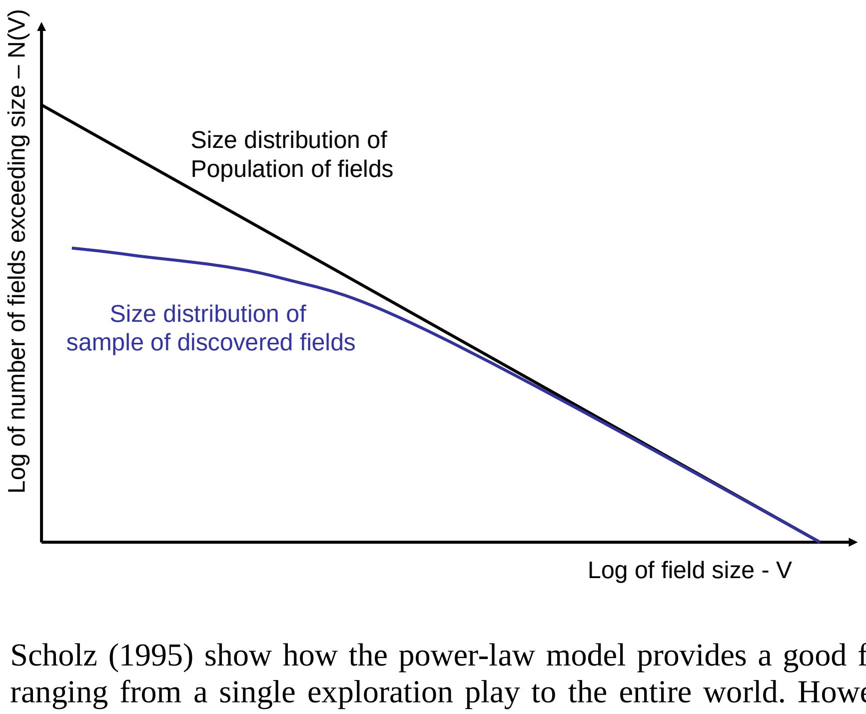
Box 3.1: Power-law field-size distributions and Zipf's law

Let *N*(*V*) represent the number of fields that exceed a particular size *V*. A power-law field size distribution is given by: $N(V) = AV^{-\alpha}$, where *A* is a scaling factor and α defines the shape of the distribution. Hence, a plot of the natural log of *N* against the natural log of *V* should approximate a straight line with slope $-\alpha$: $\ln N(V) = \ln A - \alpha \ln V$ (Figure 3.4). Barton and Scholz (1995) fitted this equation to data from six regions and found values of α ranging from 0.8 to 1.0. If $\alpha \leq 1.0$, the volume of oil in each field size class will decrease as the size class itself decreases, but as α tends towards 1.0, small fields will account for increasing proportion of the URR.

Power-law distributions are also termed 'Pareto distributions', after Vilfredo Pareto (1897) who represented income distribution in a similar way. They belong to a family of distributions known as 'probabilistic fractals' which have their roots in the work of Mandlebrot (1977). Indeed, Mandlebrot (1962) was the first to propose that oil resources could be modelled with a power-law and demonstrated this by an analysis of US oil fields. Davies and Chang (1989) have criticised the power-law model, but it has been widely used to assess the petroleum resources of the US (Houghton, *et al.*, 1993; Mast, 1989).

Power-law distributions are related to 'Zipf's law' which describes a relationship between the size and 'rank' (*N*) of discrete phenomena (Merriam, *et al.*, 2004; Zipf, 1949). When oil fields are ranked in descending order of size so that the largest is rank 1, Zipf's law states that the product of the rank and size is approximately constant($N(V) * V \sim k$). The applicability of Zipf's law is usually investigated by plotting field size (*V*) as a function of field rank (*N*), while the applicability of a Pareto distribution is usually investigated by plotting cumulative frequency (*N*(*V*)) as a function of field size (*V*) (Adamic and Huberman, 2002). The two approaches are equivalent.

Figure 3.4 Log-log plot of cumulative frequency versus field size, illustrating the difference between theoretical population distribution and observed sample distribution



Barton and Scholz (1995) show how the power-law model provides a good fit to data from six regions ranging from a single exploration play to the entire world. However, Laherrère

(1996a; 2000a) argues that "….natural data gives rise to curved, not linear plots." and shows how a quadratic cumulative frequency distribution (a 'parabolic fractal') can often provide a better fit. The curvature of these plots typically reduces over time as more small fields are found.

The proportion of the URR contained in smaller, undiscovered fields may be estimated by fitting one of these functions to the size distribution of discovered fields and extrapolating to smaller field sizes. The proportion will be greater with a power law distribution, smaller with a parabolic fractal and smaller still with a lognormal. For example, Barton and Scholz (1995) fitted a power law to six regions and estimated that undiscovered small fields contained between 9% and 31% of the regional URR (excluding fields smaller than 30 kb). Corresponding estimates are not available at the global level, but are likely to be sensitive to the minimum size threshold assumed. While technical improvements and higher prices should make more small fields viable, there will always be a lower limit imposed by the energy return on investment. As a result, many small fields will never contribute to global supply, especially in offshore regions. The competing estimates of the number of small fields are therefore of less significance to future global oil supply than the potential for increased recovery from the giant fields.

3.2 Reserve Growth

Reserve growth has been defined as: "...the commonly observed increase in recoverable resources in previously discovered fields through time." (Klett and Schmoker, 2003a). As described in Section 2, a more accurate term to describe this phenomenon would be cumulative discovery growth or estimated ultimate recovery growth since it is this which is growing rather than declared reserves. Reserve growth currently accounts for the majority of reserve additions in most regions of the world and is expected to continue to do so in the future. It is therefore of considerable importance for future global oil supply. However, it remains both poorly understood and the subject of controversy.

3.2.1 Sources of reserve growth

The multiple factors that contribute to reserve growth can be grouped under three headings, namely geological, technological and definitional.

Geological factors represent an increase (or decrease) in the estimates of *original oil in place* (OOIP) for a reservoir, field or region as a result of improved geological knowledge. For example, new reservoirs or extensions to previous reservoirs may be discovered or a better understanding of the volume, shape and characteristics of reservoirs may be obtained through the use of seismic and other techniques. In some cases, smaller fields that were previously classified as separate may be merged into larger fields as exploration proceeds (Drew, 1997). This process may affect the historical data from which reserve growth is estimated, but it does not represent the growth of OOIP for an individual field.

Technological factors represent those activities which increase the estimated recovery factor, or the proportion of the OOIP that is both technically possible and economically viable to recover. This can result from better characterisation of reservoirs and optimised drilling as well as from the application of improved recovery technologies. Recovery factors can be as high as 80% for high permeability reservoirs, though the estimated global average is around

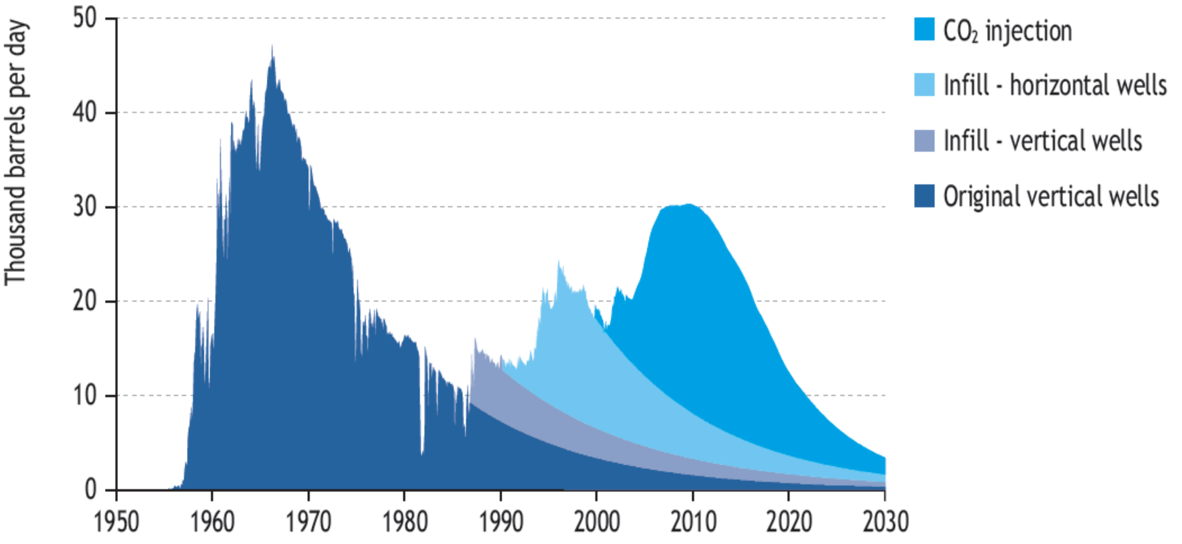
34% (IEA, 2008).[30] It is common to distinguish between *primary recovery* where oil is recovered under its own pressure; and *secondary recovery* where active pumping or water/gas injection is employed to increase reservoir pressures and the flow of oil to the surface. In many cases there is also scope for substantially improving the recovery factor through the application of *enhanced oil recovery* (EOR) techniques (Box 3.2) whose suitability will vary with the type, accessibility and characteristics of the reservoir. Extensive use of EOR in the US has led to recovery factors that are ~5% higher than the global average and there is considerable scope for application in other regions of the world. In principle, each percentage increase in the global average recovery factor could add some 80 Gb to global reserves, or nearly three years of current production. But while the potential may be large, improving the global average to 50% could take 'much more than two decades' to achieve (IEA, 2008).

Box 3.2.Enhanced oil recovery techniques

There are three broad groups of EOR techniques (NPC, 2007):

- *Thermal* methods introduce heat, typically in the form of steam to reduce viscosity, partially 'crack' heavy oil and/or increase pressure. They are particularly suitable for heavy oil but their use has declined since the mid-1980s.
- *Gaseous* methods inject carbon dioxide, nitrogen or other gases at high pressure to reduce viscosity, achieve 'miscibility' (a homogeneous solution), displace water, sustain pressure and mobilise a larger proportion of the oil. CO_2 injection is the fastest growing form of EOR and is very effective for light oil. While many applications use natural sources of CO_2, future projects may be linked to carbon capture and storage (CCS) technologies.
- *Chemical* methods inject various compounds to reduce the 'interfacial tension' between oil and injected water. These are not widely used and tend to be complicated, unpredictable, costly and sensitive to reservoir characteristics.

The IEA (2008) use the example of the Weyburn field in Canada (see below) to illustrate what can be achieved with EOR – in this case with additional vertical and horizontal drilling followed by CO_2 injection. But it is not clear how widely this example can be reproduced.



Source: IEA (2008)

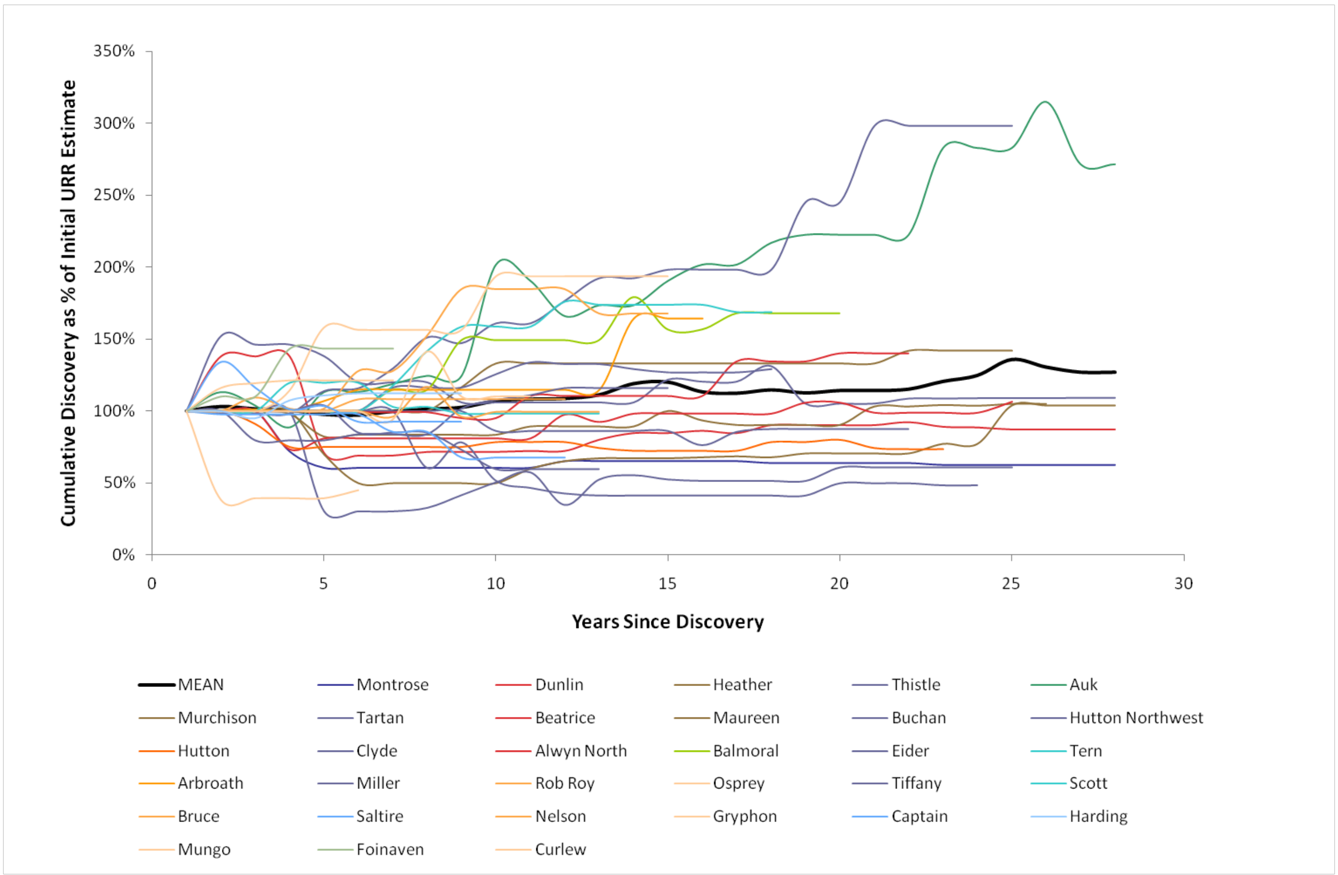
[30] The recovery factor is the ratio of the estimated URR to the estimated OOIP. Estimates of regional and global average recovery factors should be treated with caution (IEA, 2005). For example, Laherrère (2006) uses IHS data to estimate a global average recovery factor of only 27%.

Definitional factors comprise a mix of definitional, legal, economic and political influences which influence reserve estimates but are independent of either the OOIP or recovery factor. These include changes in reserve classification schemes, such as occurred in Russia in the 1990s and are currently underway in the US, and the practice of excluding reserves at discovered fields that have yet to receive production sanction. There may also be an implicit shift in definitions over time as a result of changes in personnel, operators and reporting cultures. All reserve definitions require assessment of economic viability, so changes in technology, oil prices and other economic conditions may also affect the volume of declared reserves.

The amount of reserve growth should depend upon the particular definition of reserves on which the cumulative discovery estimates are based (e.g. 1P or 2P). Reserve growth may be particularly high for cumulative discovery estimates based upon 1P reserves since these typically underestimate the URR. Reserve growth should be smaller for cumulative discovery estimates based upon 2P reserves and if these correspond to median (P50) estimates of URR, we would expect cumulative discovery estimates to be downgraded as frequently as they are upgraded. However, analysis suggests that this is not the case. With respect to 1P, 2P and 3P reserve estimates Drew (1997) notes that: "…the irony …….is that all three sets of numbers are pessimistic – they all grow with the passage of time" (Drew, 1997)

Figure 3.5 and Figure 3.6 show the change in cumulative discovery estimates for fields in the UK Continental Shelf (UKCS) (Figure 3.5). These estimates were published by the UK government and we take them to be similar to 2P. For large fields, the mean estimate of cumulative discoveries increased by approximately 50% over 27 years, while none of the individual estimates decreased in size. If this is the case for 2P data from other regions of the world, we may expect significant reserve growth in the industry databases. However, smaller fields in the UKCS grew by only 20% over this period while many fields discovered since 1980 have shown a reserve decrease (Figure 3.6).

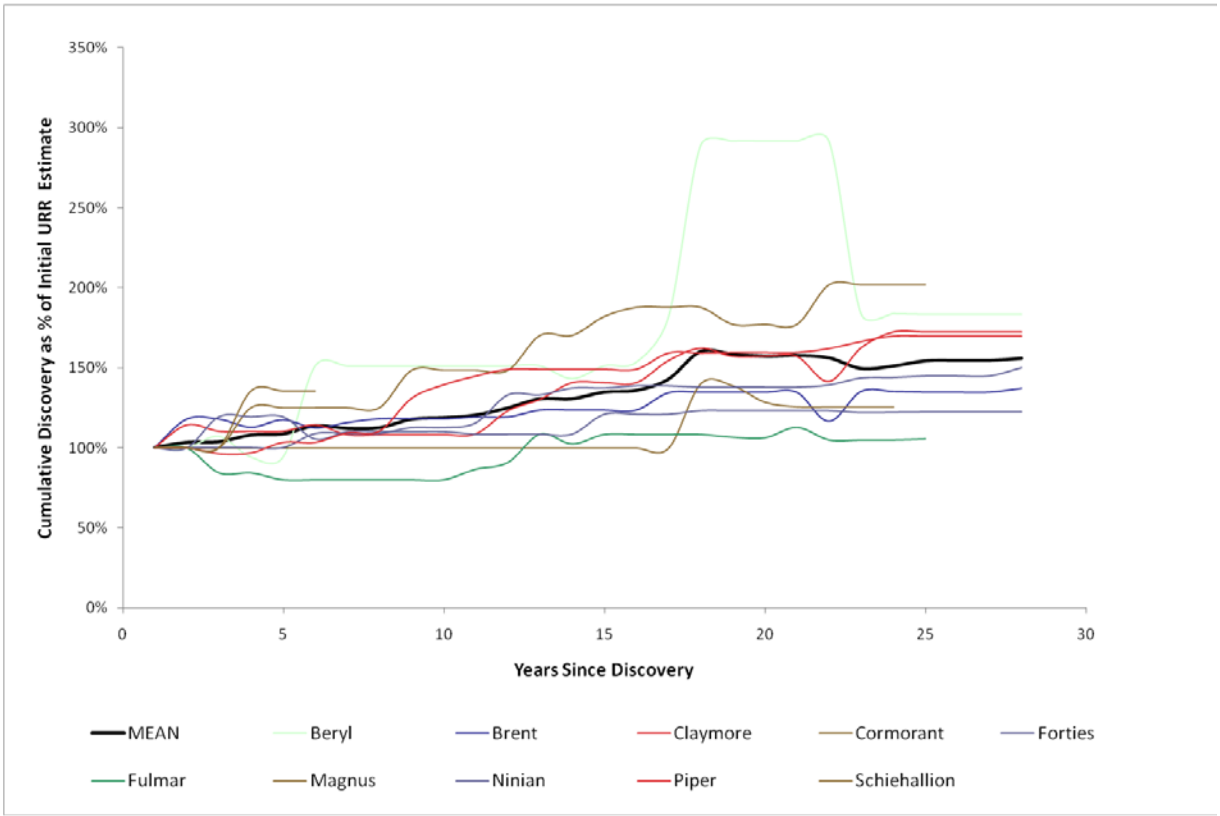
Figure 3.5: Reserve growth in oil fields larger than 0.5 Gb in the UKCS



Source: BERR

Note: Horizontal axis represents years after first production. Vertical axis is cumulative discoveries for each field, expressed as a percentage of the initial declared reserves. The heavy black lines is the simple arithmetic means of percentages, un-weighted by volume. This data series is no longer published by the UK government, in part because of inconsistencies in reporting between different operators.

Figure 3.6 Reserve growth in oil fields smaller than 0.5 Gb in the UKCS



Source: BERR
Note: Horizontal axis represents years after first production. Vertical axis is cumulative discoveries for each field, expressed as a percentage of the initial declared reserves. The heavy black lines is the simple arithmetic means of percentages, unweighted by volume. This data series is no longer published by the UK government, in part because of inconsistencies in reporting between different operators.

3.2.2 Estimating and forecasting reserve growth

Reserve growth can be estimated by comparing the initial booking of reserves for a specific field, with the sum of cumulative production and declared reserves for subsequent years. But the required data is only publicly available for a limited number of regions around the world. The industry databases contain estimates of cumulative 2P discoveries for most of the world's fields, but these are inaccessible to most analysts (Section 2). Also, industry databases from concurrent years are required and there are questions about their completeness prior to 2000.

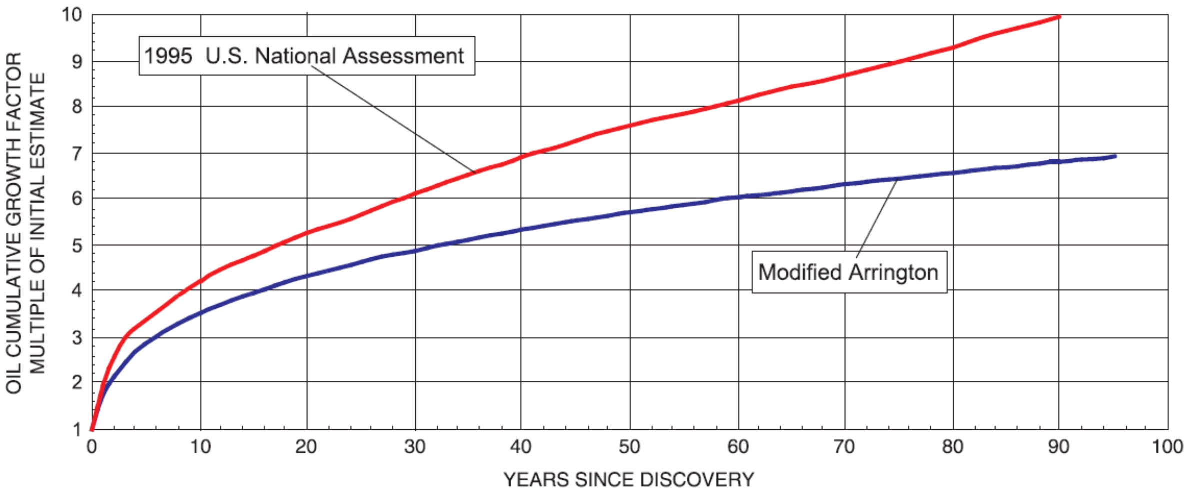
Reserve growth has been most closely studied in the United States, where it accounted for 89% of the additions to US proved reserves over the period 1978 to 1990 (Attanasi and Root, 1994).[31] While reserve growth also occurs in other regions of the world, the evidence base is much thinner.[32] But despite being systematically investigated more than 40 years ago (Arrington, 1960), reserve growth was relatively neglected before the 1980s (Drew, 1997).[33] An important stimulus to further investigation was the retrospective examination of discovery forecasts for the US, which were found to have systematically underestimated future

[31] Relevant references include Verma (2003; 2005), Schmoker (2000), Nehring (1984), Attanasi and Root (1994), Root and Mast (1993), Schuenemeyer and Drew (1994) and Klett (2005).
[32] Relevant references include Klett (2005), Klett and Gautier (2005), Gautier and Klett (2005), Gautier, *et al* (2005), Klett and Schmoker (2003b), Klett and Verma (2004), Verma (2000; 2003; 2005), Verma and Ulmishek (2003), Verma, *et al.* (2004; 2001), Watkins (2002), Sem and Ellerman (1999) and Odell (1973)
[33] Exceptions in this intervening period included the work of Hubbert (1967), Arps, *et al.* (1971), Marsh (1971), Pelto (1973) and several Canadian studies (OGCB, 1970).

discoveries as a result of neglecting reserve growth at known fields (Drew and Schuenemeyer, 1992).[34]

Future reserve growth can be estimated through the creation of *reserve growth functions* based upon the measured growth of a statistically significant sample of fields (Root and Mast, 1993). Both annual and cumulative growth functions can be calculated and used to convert current estimates of cumulative discoveries into future estimates for a specified year, with the amount of growth depending solely upon the age of the field. Figure 3.7 shows two growth functions estimated for onshore US oil fields (Attanasi and Root, 1994; Verma, 2005). Both show rapid growth in the years' immediately following discovery and although growth subsequently slows, it is still continuing some 80 years later. Such findings are typical for US 1P data: for example, Lore, *et al.* (1996) found that the estimated size of offshore fields in the Gulf of Mexico doubled within six years of discovery and quadrupled within 40 years, while a later study by Attanasi (2000) suggested an eight-fold growth in 50 years.

Figure 3.7 Cumulative reserve growth functions for US 1P reserve data



Source: Verma (2005)

While many US studies estimate growth functions from the date of field discovery (e.g. Attanasi, 2000), much of the development work that contributes to reserve growth occurs after production has commenced – which may be several years later (Klett, 2005). Hence, several authors estimate growth functions from the date of first production (Forbes and Zampelli, 2009; Sem and Ellerman, 1999; Watkins, 2002). Both approaches use age as the sole explanatory variable for reserve growth and hence neglect time-varying factors such as oil prices which could change the rate of growth by modifying the incentives for development drilling. The importance of economic factors was demonstrated by Forbes and Zampelli (2009) who found a strong positive correlation between gas prices and reserve growth in gas fields in the Gulf of Mexico, together with a negative correlation between operating costs (as measured by water depth) and reserve growth.

[34] The forecasting methodology relied upon estimates of the size of known fields but failed to adjust these to allow for future reserve growth. Since these fields subsequently doubled in size within less than ten years, the volume of new discoveries was greatly underestimated.

3.2.3 Variations in reserve growth

Reserve growth may be expected to vary between different regions and between different ages, sizes and types of field. While there is little systematic evidence available, some useful pointers can be obtained from the existing literature.

First, reserve growth varies widely between fields within the same region. For example, an analysis of 934 fields in the Gulf of Mexico found that approximately half grew over the period 1975 to 2002, one fifth shrank and the rest showed no significant change (Grace, 2007). Attansi and Root (1994) found that 'low quality' (notably heavy oil) fields grew five times more than conventional fields, while a study of 300 US fields showed that significant reserve growth was largely confined to fields with solution gas drive, heavy oils and low permeability in which techniques such as steam injection, hydraulic fracturing and CO_2 injection had been employed (Tennyson, 2002). This disparity makes the use of regional or global average growth functions problematic. Nevertheless, while the reserve growth for a particular field may be either positive or negative, the cumulative result for large groups of fields is invariably positive with 1P data.

Second, reserve growth also varies significantly from one region to another, even when they are geologically similar. For example, studies show significantly greater reserve growth in Norwegian offshore fields than in either UK or Danish fields (Klett and Gautier, 2005; Sem and Ellerman, 1999; Watkins, 2002). Possible explanations for this include differences in field development practices, reserve definitions, reporting practices, treatment of NGLs and economic and regulatory conditions both between countries and over time. Similarly, Verma and Ulmishek (2003) found that lack of investment contributed to West Siberian fields growing much slower than US fields of the same size.

Third, the source and extent of reserve growth varies over the life of a field. It seems likely that early stage reserve growth is more influenced by growth in OOIP while later stage growth is more influenced by changes in recovery factors (Beliveau and Baker, 2003). Growth is frequently very rapid immediately after field discovery reflecting continuing delineation of the reservoirs, but once production is well-established growth derives more from implementation of EOR, optimisation of well spacing and improved understanding of reservoir characteristics (Verma and Ulmishek, 2003).

Fourth, large fields grow more than small fields (see Figure 3.5 and Figure 3.6). For example, Verma and Ulmishek (2003) found that Siberian fields with a URR exceeding 1 Gb doubled in size in 19 years, while smaller fields increased by only 19% over the same period. The production-weighted average for all fields was a 95% increase, since larger fields dominate total reserve additions. Similarly, Grace (2007) found that growing fields contained 80% of the discovered hydrocarbons in the Gulf of Mexico and were on average six times larger than fields that shrank. One possible explanation is that smaller fields are more completely explored before the confirmation of reserves, leaving less scope for growth in the estimated OOIP, or that reserve reporting practices differ between large and small fields. But Grace also found that the dominant mechanism of reserve growth was the discovery of new reservoirs which is more likely to occur in large fields.[35] These results suggest that reserve growth may decline in the future (in both absolute and percentage terms) as the average size of new discoveries declines. However, other studies have found no statistically significant correlation

[35] There were 78 single reservoir fields, of which 33 shrank in size, 27 were static and 18 grew.

between field size and reserve growth (Forbes and Zampelli, 2009; Klett and Gautier, 2005).[36]

Finally, some evidence suggests that onshore fields grow by more than offshore fields (Watkins, 2002) and older fields grow by a greater proportion than more recent discoveries. For example, Forbes and Zampelli (2009) find a shift to a lower 'reserve growth regime' in the Gulf of Mexico after 1987, following the more widespread use of 3-D seismic techniques that allowed more accurate estimation of the size of newly discovered fields. Again, these results suggest that reserve growth may decline in the future as a greater share of production derives from newer fields that are more likely to be located offshore.

3.2.4 Estimating global reserve growth

Most analysis of reserve growth has taken place in the US, where the SEC rules require the reporting of a particularly conservative interpretation of 1P reserves that is confined to oil that is in contact with a well. As a result, authors such as Laherrère (1999a) argue that the primary source of observed reserve growth is conservative reporting.[37] In contrast, 'optimists' such as Mills (2008) highlight the historic and potential contribution of improved technology.

This disagreement was brought to a head by the publication of the USGS World Petroleum Assessment in 2000 which provided an authoritative estimate of the global URR of conventional oil (see Section 6). The USGS had previously considered that cumulative 2P discovery data provided a reasonable estimate of the URR of discovered fields, but a growing body of evidence indicated that this assumption was incorrect. For example, the cumulative 2P discoveries for 186 giant fields outside the US were found to have increased by 26% between 1981 and 1996 (USGS, 2000). The 2000 study therefore included explicit allowance for reserve growth for the first time. The USGS multiplied the cumulative 2P discovery estimates for non-US fields by growth factors that depended upon the age of the field. The latter in turn were derived from a growth function estimated from US data on cumulative 1P discoveries, owing to the lack of adequate data from other regions of the world (Attanasi, *et al.*, 1999; Gautier, *et al.*, 1995). This process added 654 Gb to the mean estimate of the global URR which was equivalent in size to the estimated yet to find resources.[38]

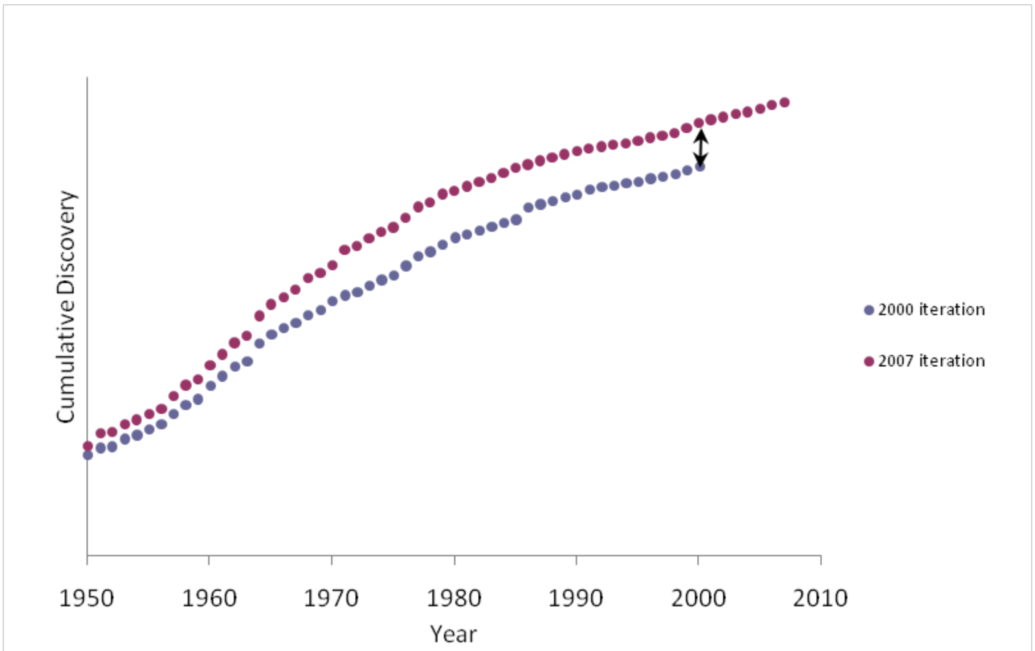
The USGS acknowledged the limitations of this approach and assumed a triangular probability distribution to account for the associated uncertainty. The application of a 1P growth function to 2P data could lead to an overestimate of recoverable resources, but subsequent examination suggests that the USGS assumptions have worked remarkably well. For example, Klett *et al.* (2005) found that a total of 171 Gb had been added through reserve growth at non-US fields between 1995 and 2003, or more than twice the reserve additions through new discoveries. This suggests that 28% of the mean USGS estimate for non-US reserve growth had been added to in the first 27% of the assessment time frame (1995-2025). Similarly, Stark and Chew (2005) found a global total of 465 Gb of reserve growth between 1995 and 2003, of which 175 Gb was attributed to 'classic' reserve growth and the remainder to 'new and revised data'. This distinction suggests that much of the apparent reserve growth

[36] Forbes and Zampelli (2009) study the same region as Grace (2007), but focus on gas fields.
[37] Reserve growth in the US may also be influenced by the production restrictions imposed in the 1950s and 60s ('pro-rationing') and by the underestimation of field size in the early days of exploration owing to inferior geophysical techniques.
[38] This corresponds to a 44% growth in the estimated URR of crude oil fields discovered before 1995 and a corresponding 56% growth in NGL resources.

could derive from factors such as the inclusion of previously omitted fields in the industry databases and from revised estimates of fields where the data was poor. The biggest growth in absolute terms derived from Middle East fields where the reserves data is particularly uncertain.

To check whether the rate of reserve growth observed by Klett *et al.* is being maintained, we compared the 2000 and 2007 iterations of the IHS Energy PEPS database (Figure 3.8). The results suggest that cumulative 2P discoveries for pre-2000 fields grew by 11% over this period. The global figure includes US and Canadian data which is not comparable with the rest of the database since it is based upon 1P reserves. If the US data is removed, pre-2000 fields are estimated to have grown by 13.9% between 2000 and 2007, suggesting that the rate of non-US reserve growth has *increased* in recent years. The percentage reserve growth varies widely from one country to another (Table 3.3) with the largest contribution in absolute terms deriving from Saudi Arabia and Iran (Figure 3.9). Interestingly, most of the growth derives from fields discovered before 1986, with very little growth in the more recently discovered fields (Figure 3.8).

Figure 3.8 Reserve growth in the IHS Energy PEPS database between 2000 and 2007



Source: IHS Energy
Note: Arrow indicates reserve growth for fields discovered before end 2000.
ource
Source: IHS Energy
Note: Y-axis labelling withheld on grounds of confidentiality.

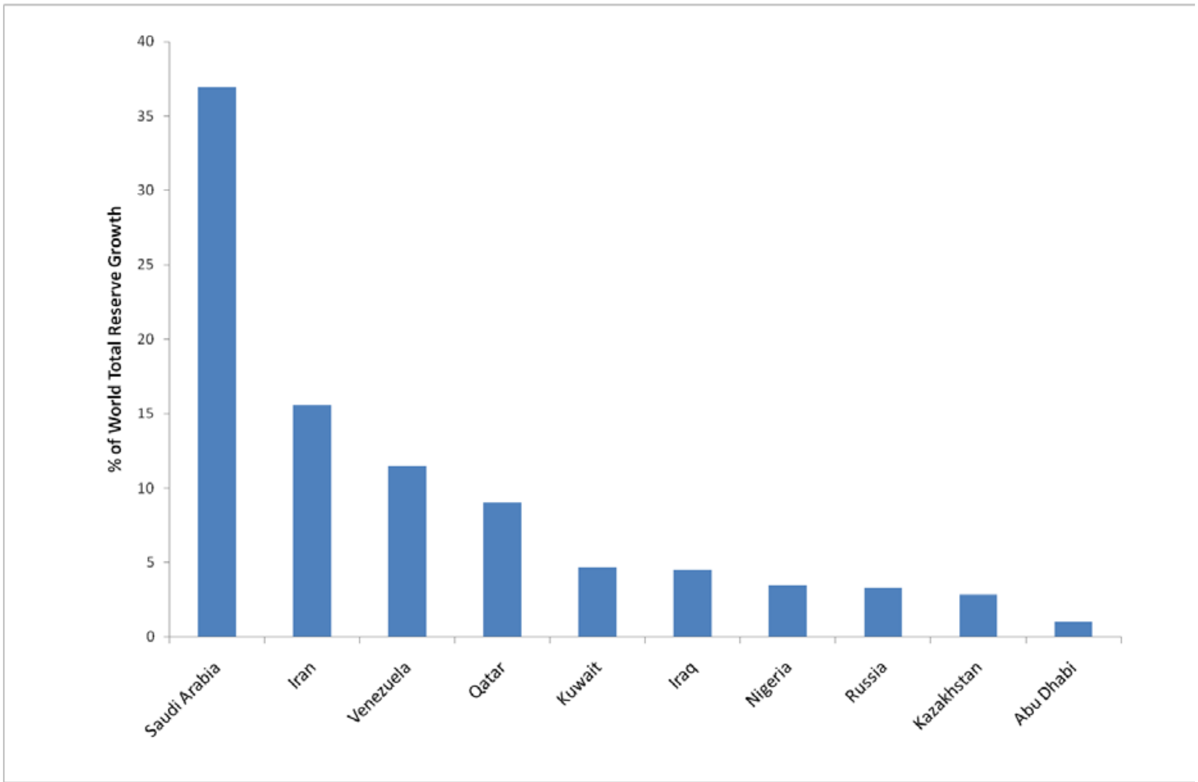
Table 3.3 Contribution of large producers to global reserve growth between 2000 and 2007

Country	% growth 2000-2007	% global reserve growth
Saudi Arabia	27.5	37.0
Iran	23.5	15.6
Venezuela	22.5	11.5
Qatar	102.4	9.0
Kuwait	12.5	4.7

Iraq	8.5	4.5
Nigeria	15.8	3.5
Russia	3.0	3.3
Kazakhstan	20.1	2.9
Abu Dhabi	3.2	1.0

Source: IHS Energy

Figure 3.9 Contribution of large producers to global reserve growth between 2000 and 2007



Source: IHS Energy
Note: Percentage of global reserve growth for top ten oil-endowed countries ranked by remaining reserves.

In summary, though the actual rates may be contested, it is clear that significant reserve growth is observed in cumulative discovery estimates based upon both 1P and 2P reserves. With 2P data, the global average reserve growth observed since 1995 seems broadly in line with the assumptions made by the USGS (2000). However, the global average is strongly influenced by reserve growth in countries with the largest reserves where there is less confidence in the accuracy of the data. Also, it is far from clear that the observed trend in reserve growth will be maintained in the future. Reserve growth appears to be greater for larger, older and onshore fields, so as global production shifts towards newer, smaller and offshore fields the rate of reserve growth may decrease in both percentage and absolute terms. At the same time, higher oil prices may stimulate the more widespread use of EOR techniques that have the potential to substantially increase global reserves. The suitability of such techniques for different types of field and the rate at which they may be applied remain key areas of uncertainty.

3.3 Decline Rates

An important determinant of future investment needs is the rate of decline of production from currently producing fields. Supply forecasts are more sensitive to assumptions about the rate of decline than to assumptions about future oil demand, but the former have generated controversy owing to lack of data (Simmons, 2000). Fortunately, three recent studies have put a great deal of data into the public domain. This section examines the nature of production decline, summarises evidence on the rate of decline from different categories of field and highlights the implications.

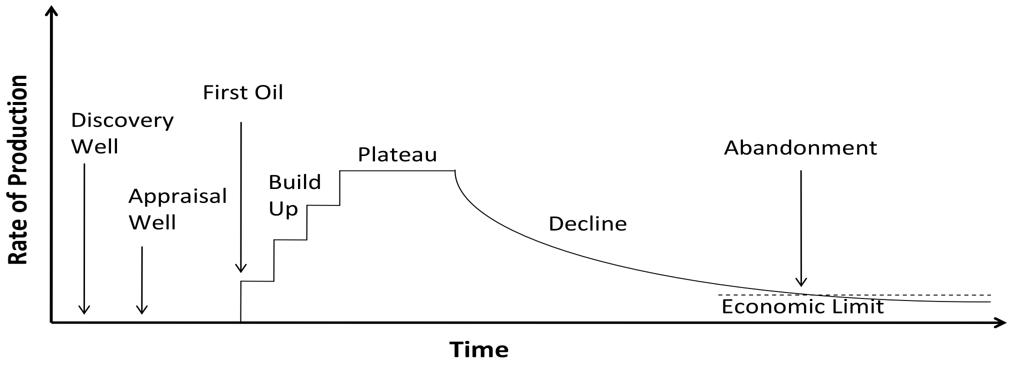
3.3.1 Analysis of production decline

The production cycle of individual fields can vary widely depending upon their geology and location and the manner in which they are developed (Figure 3.10). As a field is brought on-line, its rate of production typically rises rapidly to a peak which may extend into a multi-year plateau as a consequence of the limited capacity of pipelines and other surface facilities and/or the steady development of the field through additional drilling.[39] The length of plateau tends to be greater for large fields and the production cycle can be complicated by interruptions and the introduction of new technology. But at some point, the rate of production will begin to decline as a result of falling pressure and/or the breakthrough of water.[40] Typically, more than half of the recoverable resources of a field will be produced during the decline phase.

The term ‘decline’ is loosely applied at various levels of aggregation, including single wells, reservoirs, fields, basins and countries. When applied to a region, it is important to distinguish between the *overall* decline rate which refers to all currently producing fields, including those that have yet to pass their peak, and the *post-peak* decline rate which refers to the subset of fields that are in decline. Since the production cycle of individual fields is rarely smooth (e.g. a ‘bumpy’ plateau), the point at which decline begins can be ambiguous. Some analysts also estimate *natural* decline rates which exclude the effects of capital investment.

[39] This involves trade-offs. For example, larger piplelines increase up-front costs, but speed production which allows rapid recovery of those costs. However, decline then begins earlier, thereby reducing the period the pipeline can operate at capacity and increasing operating costs. Conversely, smaller pipelines reduce up-front costs, lengthen the plateau, increase the time the pipeline can be operated at a capacity and slow the conversion of oil to cash.
[40] In mature fields, the ‘water-cut’ may represent 90% or more of the volume of produced liquids.

Figure 3.10 Stylised production cycle of an oil field



Source: Höök (2009)

Production from individual wells, reservoirs and fields is usually assumed to decline exponentially at a constant rate, although there is no physical law requiring this and the rate of decline often falls during the later stages of the production cycle. Empirical equations to model production decline were first developed over a century ago and have since seen wide application (Box 3.3).[41] The exponential model is the most widely used, but it can underestimate production during the later stages of a field's life.

Box 3.3 Empirical equations to model production decline

Production decline from oil wells was first modelled by Arnold and Anderson (1908) and subsequently by Cutler (1924) and Larkey (1925) among others. These early studies were consistent with primary recovery being driven by the expansion of natural gas. Contemporary decline curve analysis has its roots in Arps (1945), who introduced empirical curves defined by three variables: the initial rate of production ($Q'(t_0)$), the curvature of decline (β) and the rate of decline (λ).

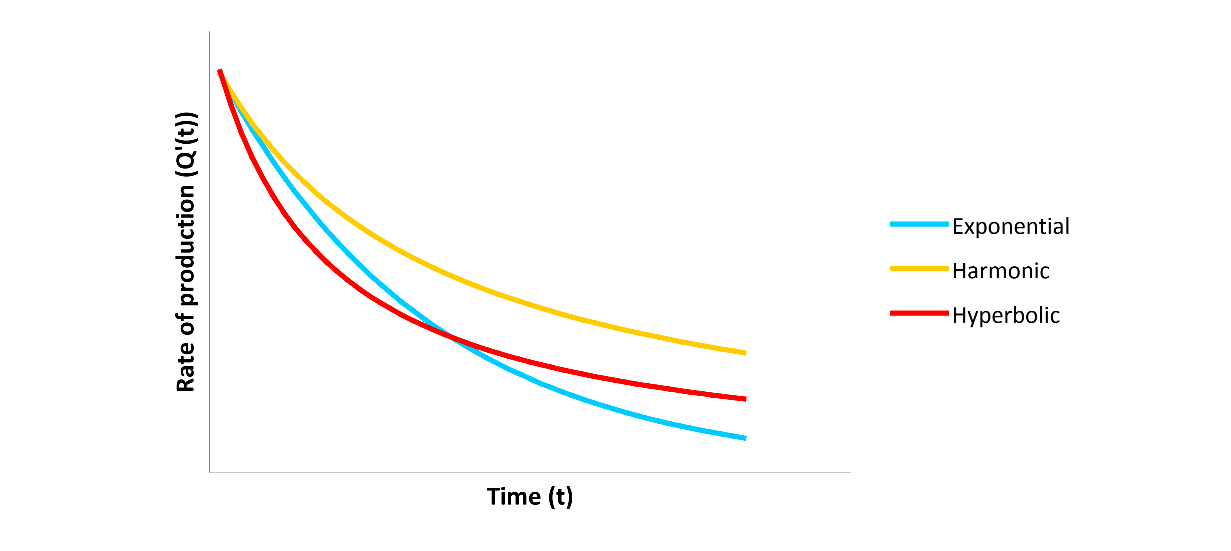
The general *hyperbolic* equation for the rate of production is: $Q'(t) = \dfrac{Q'(t_o)}{(1+\lambda\beta(t-t_0))^{1/\beta}}$

If $\beta = 0$, this reduces to *exponential* decline: $Q'(t) = Q'(t_o)e^{-\lambda(t-t_0)}$

If $\beta = 1$, this reduces to *harmonic* decline: $Q(t) = \dfrac{Q'(t_0)}{(1+\lambda(t-t_0))}$

Decline models have since been developed in a variety of ways, including linearised curves (Li, 2003; Luther, 1985; Spivey, 1986), and the econometric analysis of residuals (Chen, 1991). Kemp and Kasim (2005) found that a logistic curve provided a better fit for UKCS fields. Decline curves are commonly used to estimate the URR of a field (Section 4.3).

[41] See for example Chaudhry (2003), Porges (2006) and Guo, *et al.* (2007).

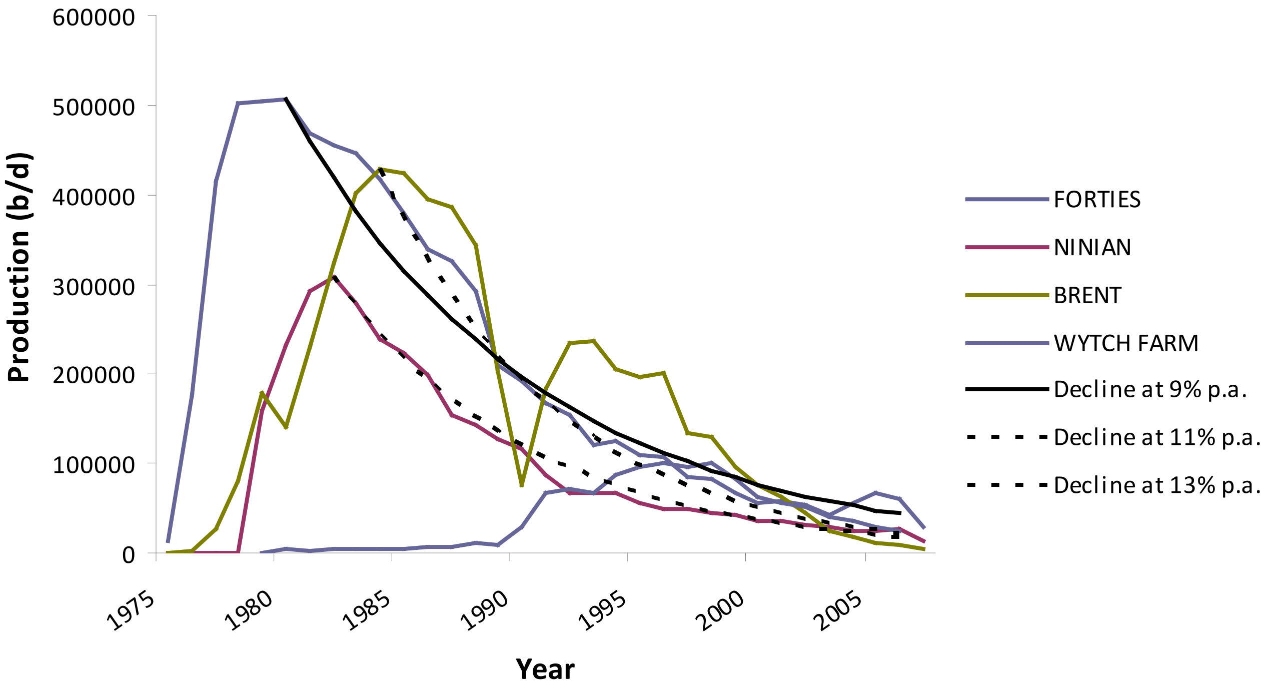


As an illustration, Figure 3.11 shows production profiles for the UK's three largest offshore fields (Forties, Brent and Ninian) and its largest onshore field (Wytch Farm). Forties can be approximated with a 9%/year exponential decline, Ninian by 11%/year, and Brent a poor fit of around 13%. Wytch Farm's decline rate is similar to the off-shore fields, but more oil was produced pre-peak.

Figure 3.12 shows the annual production for a group of 77 UKCS fields which peaked in or before 1996.[42] This gives an estimate of ~12.5%/year for the aggregate post-peak decline rate. At least 60% of cumulative production occurred during the decline phase and these fields are still producing. Figure 3.13 suggests that younger UKCS fields have steeper decline rates, but since these fields are also smaller on average, the observed trend relates to both the size and age of the field.

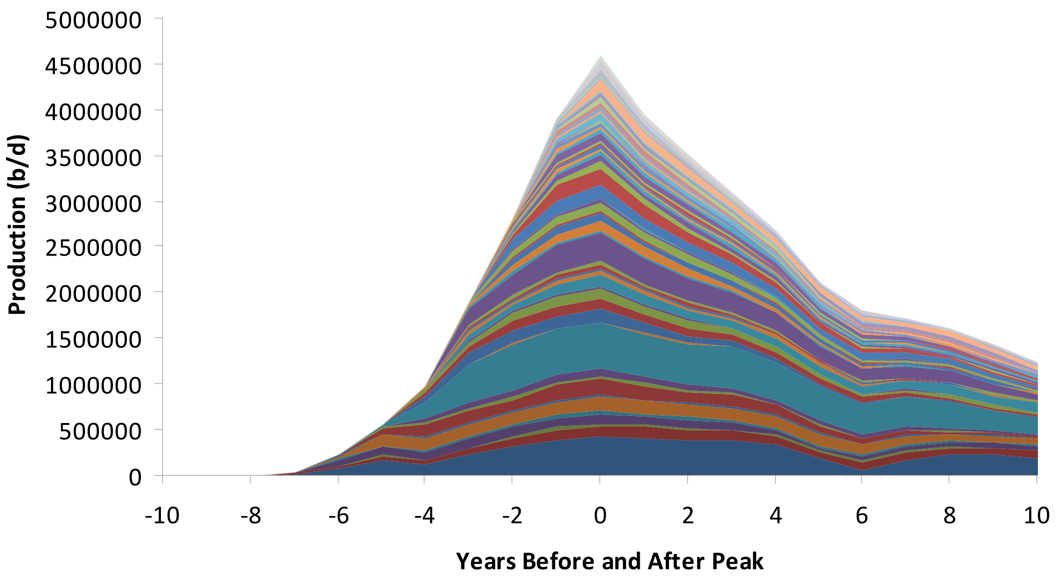
[42] This excludes the Piper Alpha field where production was interrupted for several years following a disastrous explosion in 1988. The entire UKCS industry was required to carry out a significant programme of safety inspection and upgrading which interrupted exploration and contributed to the earlier peak in UKCS production.

Figure 3.11 Production from four UK oil fields fitted by three exponential decline models



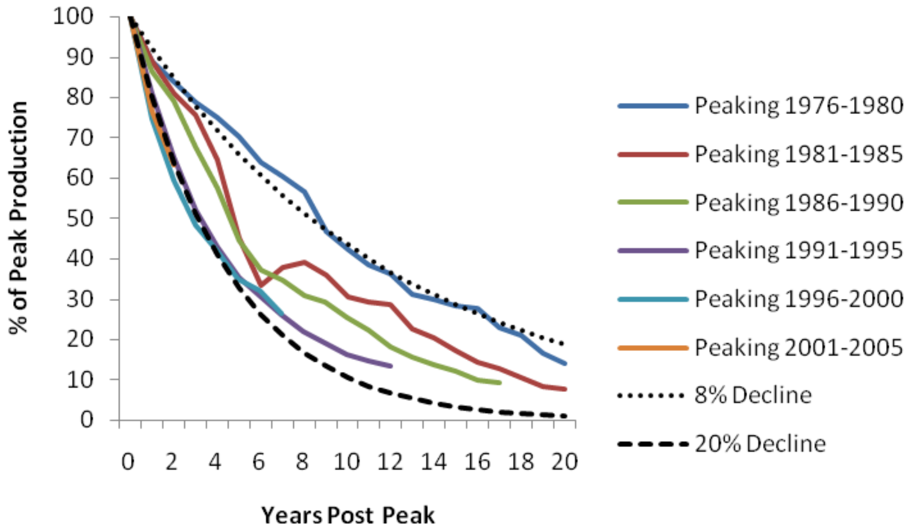
Source: BERR

Figure 3.12 Production from UK offshore fields which peaked before 1997, stacked by peak year



Source: BERR

Figure 3.13 Decline curves for UK offshore fields entering peak at 5 year intervals



Source: BERR
Note: Mean field size: 1976-80: 874 mb; 1981-85: 582 mb; 1986-90: 405 mb; 1991-95: 88 mb; 1996-2000: 80 mb; 2000-2005: 70 mb

3.3.2 Regional and global average decline rates

Three studies have estimated decline rates from a globally representative sample of fields (Table 3.4). While each study uses a different sample, they all include the giant fields which account for around half of global production. Unfortunately, the studies use competing definitions and different approaches to production weighting.

Table 3.4 Comparison of global decline rate studies

	IEA	Hook *et al.*	CERA
No. of fields in sample	651 (54 supergiant, 263 giant, 334 large)	331 (all giant)	811 (400 large and above)
No. post-peak fields	580[1, 2]	261[3]	-
% of total production of crude oil in sample	~58%	~50%	~66%
Cumulative discoveries of crude oil in sample	1241 Gb	1130 Gb	1155 Gb
Definition of plateau	Production >85% of peak	Production >96% of peak	Production >80% of peak
Definition of onset of decline	After year of peak production	After last year of plateau	After last year of plateau
Production weighting	Cumulative production[4]	Annual production	Annual production

Source: IEA(2008), CERA (2008) and Höök, *et al.*(2009; 2008; 2009a; 2009b).
Notes:
1. 101 fields in plateau (production >85% of peak), 117 fields in 'phase 1 decline' (production >50% of peak), 362 fields in 'phase 3' decline (production <50% of peak)
2. 387 onshore, 264 offshore, 185 OPEC and 466 non-OPEC.
3. 261 onshore, 214 offshore, 143 OPEC and 188 non-OPEC.
4. IEA weights by annual production when estimating historical trends in decline rates.

These studies estimate the production-weighted decline rate of their sample of post-peak fields to be 5.1%/year (IEA), 5.5%/year (Hook *et al.*) and 5.8%/year (CERA) (Table 3.5). The production-weighted decline is less than the average decline because fields with higher production tend to be larger and decline more slowly. The studies also agree that:

- Decline rates are lower for OPEC fields and particularly for Middle East fields (Table 3.5). This is partly reflects differences in average size, but also quota restrictions and disruptions from political conflict.
- Decline rates are higher for offshore fields (Table 3.5). These tend to be produced at higher rates in order to recover their higher fixed costs, leading to higher peaks, shorter plateaus and steeper declines.
- Decline rates are lower for larger fields and are particularly low for the super-giant fields in the Middle East (Table 3.6). Large fields reach their peak later than small fields, but also produce a greater proportion of their URR during the decline phase (IEA, 2008).

Table 3.5 Estimates of production-weighted aggregate decline rates for samples of large post-peak fields (%/year)

Parameter	IEA	Höök, *et al.*	CERA
Onshore	4.3	3.9	-
Offshore	7.3	9.7	-
Non-OPEC	7.1	7.1	-
OPEC	3.1	3.4	-
Total	**5.1**	**5.5**	**5.8**

Source: IEA(2008), CERA (2008) and Höök, *et al.*(2009; 2008; 2009a; 2009b).
Note: Studies use different data sets, definitions and methods of production weighting. Details missing for CERA since we do not have access to the full study.

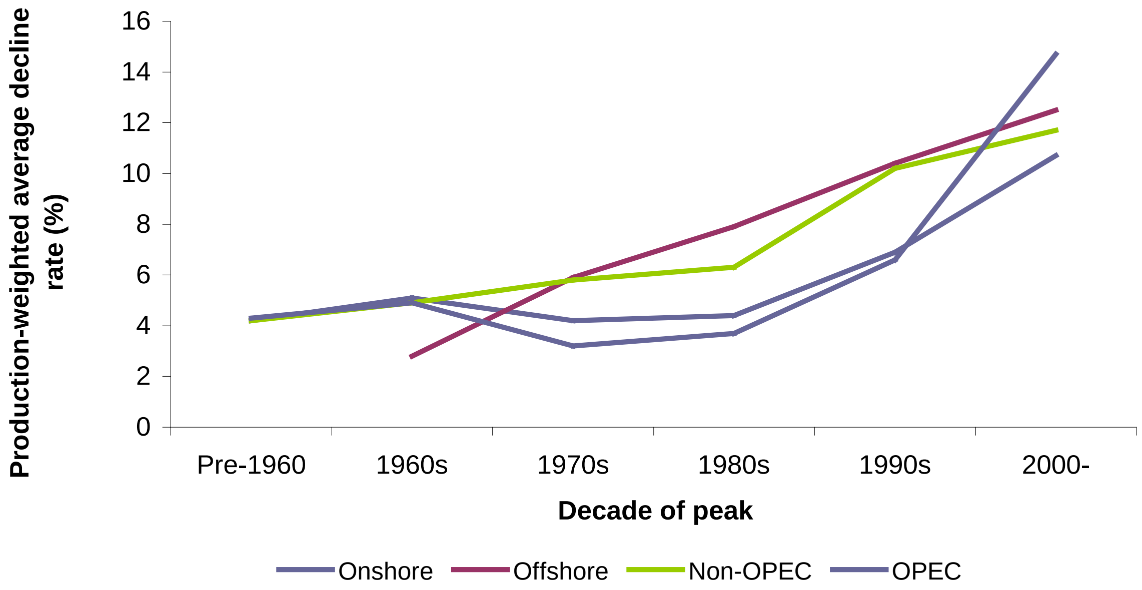
Table 3.6 IEA estimates of aggregate production-weighted decline rates for different sizes of post-peak field (%/year)

	Total	Supergiant	Giant	Other
Onshore	4.3	3.4	5.6	8.8
Offshore	7.3	3.4	8.6	11.6
Non-OPEC	7.1	5.7	6.9	10.5
OPEC	3.1	2.3	5.4	9.1
All fields	**5.1**	**3.4**	**6.5**	**10.4**

Source: IEA(2008)
Note: The production-weighted decline rate is 1.4% in decline phase 1, 3.6% in decline phase 2 and 6.7% in decline phase 3. The production-weighted average for phase 1 is strongly influenced by Ghawar. The production-weighted sample average for post-plateau fields is 5.8%.

Importantly, both the IEA and Höök, *et al.* find decline rates to be significantly higher for newer fields (Figure 3.14). The IEA argues that newer fields build up more quickly to a higher plateau that is maintained over a shorter period of time, but Höök, *et al.* (2009a) show that the length of plateau for giant fields has *increased* together with the proportion of the remaining recoverable resources produced prior to peak. They argue that new technology allows the plateau to be maintained for extended periods of time, but at the cost of more rapid decline following the peak (see also Gowdy and Roxana, 2007). The collapse of production at Canterell following extensive use of nitrogen injection is a notable example.

Figure 3.14 Evolution of production-weighted giant oilfield decline rates over time



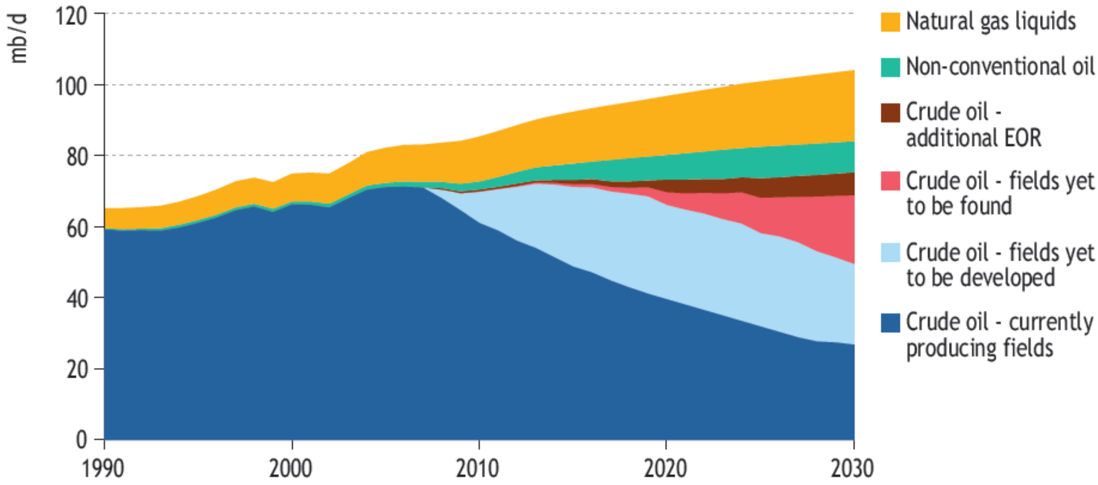
Source: Höök, *et al.*(2009b)
Note: Figures for most recent decade less certain since sample of fields is much smaller

The above figures are likely to underestimate the global average decline rate for *all* post-peak fields since the mean size of each sample of fields is greater than that of the global population. Under the optimistic assumption that that decline rate for smaller fields is the same as that for the sample of large fields (10.4%), the IEA estimate a production-weighted global average decline rate of **6.7%/year** for all post-peak fields.[43] With capital investment reduced as a result of the 2008 economic recession, production from these fields may decline by more than this in 2009.

This decline in production needs to be replaced by investment in EOR at producing fields (Box 3.2), the development of 'fallow' fields or the discovery and development of new fields. But to estimate the additional capacity required each year it is necessary to know either the proportion of production from post-peak fields, or the production-weighted aggregate decline rate of *all* fields, including those in build-up. Both figures are absent from the IEA study and they appear to calculate the capacity requirements incorrectly.[44] We estimate the latter figure to be ~**4.1%/year** which compares to CERA's estimate of 4.5%/year.[45] This implies that approximately 3 mb/d of capacity must be added by new investment each year, simply to maintain production at current levels – equivalent to a new Saudi Arabia coming on stream every three years. An additional 1 mb/d will be required each year to meet the IEA's forecast of demand growth (Figure 3.15).

[43] They further estimate that this is 2.3% less than the production-weighted natural decline rate for these fields. The latter is estimated to have grown by 1% over the last five years.
[44] The IEA appear to multiply the production-weighted decline rate of post-peak fields (6.7%) by global crude production (70 mb/d) to estimate an annual loss of output of 4.7 mb/d. But the correct procedure is to use the production-weighted aggregate decline rate of *all* fields, including those in build-up.
[45] The IEA provide this figure for OPEC (3.3%) and non-OPEC fields (4.7%) so we simply weight by 2007 production to obtain a global average. The result appears consistent with the IEA's graphs (Figure 3.15).

Figure 3.15 IEA forecast of global all-oil production to 2030



Source: IEA (2008)

A critical question for supply forecasting is how global average decline rates may be expected to develop in the period to 2030. Most existing fields will enter decline over this period, with a growing proportion of production from younger, smaller and offshore fields. The IEA expects the production-weighted global average decline rate of post-peak fields to increase to 8.5%/year by 2030, leading to an estimated loss of 61% of current capacity (43 mb/d) (Figure 3.15). However, Höök, *et al.* (2009a) consider this estimate to be optimistic, given the trend towards increasing decline rates in the giant fields and the observed tendency for the production-weighted decline rate to converge on the (higher) average rate (Höök and Aleklett, 2008).

In summary, the global average decline rate of post-peak fields is at least 6.5%/year and the corresponding decline rate of all currently producing fields is at least 4%/year. Both are on an upward trend as more giant fields enter decline, as production shifts towards smaller, younger and offshore fields and as changing production methods lead to more rapid post-peak decline. Significant investment is needed simply to offset the underlying natural decline rates and if this is not forthcoming (for example, as a result of the economic slowdown) decline rates will increase. While future trends in decline rates are difficult to forecast, a case could be made that the IEA's assumptions are optimistic. If so, more than two thirds of current crude oil production capacity will need to be replaced by 2030, simply to keep production constant. Given the long-term decline in new discoveries (Figure 2.8), this will present a major challenge even if 'above-ground' conditions prove favourable.

3.4 Depletion rates

Decline rates are a measure of the change in the rate of production of a field from one year to the next. They should not be confused with *depletion rates* which are a measure of the rate at which the recoverable resources of a field or region are being produced. The depletion rate of individual field is defined as the ratio of annual production to some estimate of recoverable resources, where the latter could be the 1P reserves, the 2P reserves, the remaining recoverable resources (i.e. allowing for future reserve growth) or the URR. When defined in relation to 1P reserves, the depletion rate is simply the inverse of the more familiar reserve to production (R/P) ratio. While decline rates can be measured precisely, depletion rates are based upon uncertain resource estimates which vary between sources and over time - with higher resource estimates leading to lower estimates of depletion rates.

Höök (2009) defines the depletion rate as the ratio of annual production to remaining recoverable resources, where the latter is calculated by subtracting cumulative production from an estimate of the URR. He then shows the close links between the depletion rate and the decline rate of a field. The depletion rate generally increases during the build-up and plateau phase as reserves are produced. Once decline begins, the depletion rate either remains constant or falls - provided the URR estimate remains unchanged. If decline is exponential the depletion rate equals the decline rate, while if decline is hyperbolic the maximum depletion rate is reached just prior to the onset of decline. Höök, *et al.* (2009b) show that the maximum depletion rate of giant oil fields typically falls within a relatively narrow band, with a production-weighted mean of 7.2%/year (Table 3.7). As with decline rates, the maximum observed depletion rate is higher for offshore fields and lower for OPEC fields.

Höök, *et al.* (2009b) also estimate the *depletion at peak*, or the proportion of URR produced at the onset of field decline. The production-weighted mean of their sample of giant fields is 37%, with the average being higher for offshore fields and lower for OPEC fields. A similar analysis is conducted by the IEA (2008) who find values ranging from 15% for large fields to 25% for small offshore fields. These results demonstrate that *production from most fields begins to decline when less than half (and often less than one third) of their recoverable resources have been produced*. The IEA estimates that giant fields are on average 48% depleted, with the regional average varying from 37% in the Middle East to 78% in North America.

Table 3.7 Estimated depletion at peak and annual depletion rate at peak for giant oil fields

	Depletion at peak	Depletion rate at peak
Onshore	34.1%	5.8%
Offshore	44.0%	11.0%
Non-OPEC	37.4%	8.7%
OPEC	31.5%	5.3%
All fields	**36.8%**	**7.2%**

Source: Höök, *et al.* (2009b)
Notes:
Depletion rate = Ratio of annual production to estimated remaining recoverable resources
Depletion = Ratio of cumulative production to estimated ultimately recoverable resources
All figures production-weighted

Depletion and depletion rates can also be estimated at the regional level, although the uncertainty on the recoverable resource estimates will necessarily be greater since they also include the YTF. Of particular interest are the values at peak for the countries that have passed their peak of production (Figure 2.19). Using the USGS estimates of regional URR for 37 post-peak countries (see Section 6), we estimate a simple mean for depletion at peak of 22%, a production-weighted mean of 24% and a maximum of 52%.[46] In other words, *most countries appear to have reached their peak well before half of their recoverable resources have been produced*.

[46] Since the USGS only estimate reserve growth at the global level, this was allocated between countries in proportion to their estimated URR excluding reserve growth. Post-peak countries for which URR estimates were not available were excluded, as was Russia. It is important to note that timing of the peak of production for many of these countries may be influenced by factors other than physical depletion and in some cases the peak may subsequently be exceeded.

In a similar manner, we estimate the mean depletion rate at peak for these countries to be 2.1%/year, the production-weighted mean to be 1.9%/year and the maximum to be 5.2%/year (for Bulgaria which is an outlier).[47] In other words, *the maximum depletion rate for a region has typically been much less than 5%/year.* Also, the average depletion rate over the full production cycle is typically much lower than the maximum rate. At present, the global average depletion rate is approximately 1.2%.

This analysis suggests that there are physical, technical and economic constraints on both the rate of depletion for a field or region and the proportion of the URR that can be produced prior to the peak. Hence, both measures can provide a useful 'reality check' on supply forecasts (Aleklett, *et al.*, 2009). Specifically, a forecast that implies depletion rates that are significantly higher than those previously experienced in other oil-producing regions will require careful justification. The same applies to forecasts that delay regional peaks of production until significantly more than half of the URR of that region has been produced. However, the usefulness of these 'rules-of-thumb' depends very much upon the accuracy of the estimates of resource size.

Depletion rates can also provide a useful bridge between estimates of the rate of reserve growth and/or new discoveries and the rate of production. While it is common to estimate reserve additions in Gb/year, to translate this into a feasible rate of production it is necessary to multiply by an assumed depletion rate. If the product of the two is less than the capacity anticipated to be lost through production decline, then aggregate production in a region may be expected to fall. For example, a global average decline rate of 4.1% implies an annual loss of 2.9 mb/d or ~1.0 Gb/year of production capacity. This capacity needs to be replaced by a combination of developing fallow fields, reserve growth at existing fields and new discoveries simply to maintain production at current levels. Using a peak depletion rate of ~5.0%/year, this leads to a requirement for ~20 Gb/year of reserve additions from these sources if global production is to be maintained. If instead the depletion rate of these resources is only 1.2%/year (the current global average for all production), reserve additions of ~80 Gb/year are required. As demand grows and decline rates increase in the medium to long-term, either the rate at which reserves are added from these sources, or the rate at which they are depleted needs to increase. However, the former runs counter to the trend of declining discoveries (Figure 2.8) while the latter is subject to physical, engineering and economic limits.

3.5 Summary

- Around 100 oil fields account for up to half of the global production of crude oil, while up to 500 fields account for two thirds of cumulative discoveries. Most of these fields are relatively old, many are well past their peak of production and most of the rest will begin to decline within the next decade or so. The remaining reserves at these fields, their future production profile and the potential for reserve growth is therefore of critical importance for future global supply.
- The proportion of total resources contained within small, undiscovered fields continues to be disputed. While the observed lognormal size distribution of discovered fields is partly

[47] We estimate the depletion rate at peak for the UK to be 4.4% assuming a URR of 43 Gb. In contrast, Aleklett, *et al.*(2009) estimate a depletion rate at peak of 6.9% assuming a lower URR of 35 Gb. This discrepancy highlights the sensitivity of these estimates to the assumed URR.

the result of sampling bias, there is insufficient evidence to conclude whether a 'linear' or 'parabolic fractal' better describes the population size distribution. Moreover, while technical improvements and higher prices should make more small fields viable, many of the smallest will remain uneconomic to develop and the exploitation of the rest will be subject to rapidly diminishing returns. As a result, the competing estimates of the resources contained in small fields should be of less significance to future supply than the potential for increased recovery from the giant fields.

- Reserve growth is real, significant and not primarily the result of conservative reporting. Contrary to the claims of some 'pessimists', significant reserve growth continues to be observed in cumulative discovery estimates based upon 2P reserves. This suggests that reserve growth from improved geological knowledge and recovery techniques should make a major contribution to future global oil supply.

- The global average reserve growth observed since 1995 seems broadly in line with the controversial assumptions made by the USGS (2000). However, the global average is strongly influenced by reserve growth in countries with both the largest reserves and the poorest quality data. Also, reserve growth appears to be greater for larger, older and onshore fields, so as global production shifts towards newer, smaller and offshore fields the rate of reserve growth may decrease in both percentage and absolute terms. At the same time, higher oil prices may stimulate the more widespread use of EOR techniques that have the potential to substantially increase global reserves. The suitability of such techniques for different sizes and types of field and the rate at which they may be applied remain key areas of uncertainty.

- A critical determinant of investment needs and future supply is the rate of decline of production from existing fields. The production-weighted global average decline rate of post-peak fields is at least 6.5%/year and the corresponding decline rate of all currently producing fields is at least 4%/year. Both are on an upward trend as more giant fields enter decline, as production shifts towards smaller, younger and offshore fields and as changing production methods lead to more rapid post-peak decline. More than two thirds of current crude oil production capacity may need to be replaced by 2030, simply to keep production constant. At best, this is likely to prove extremely challenging.

- There are physical, technical and economic constraints upon the rate of depletion of a field or region, although estimates of these rates are contingent upon uncertain estimates of the size of recoverable resources. Historically, the maximum observed depletion rate has been ~6% for onshore giant fields and ~11% for offshore giant fields, while for regions the maximum observed rate is ~5%. The average depletion rate over the production cycle is typically much lower than this. Hence, supply forecasts that assume or imply higher depletion rates are likely to require careful justification.

- To date, most giant fields and most countries appear to have reached their peak well before half of the recoverable resources have been produced. Hence, supply forecasts that assume or imply the production of more than half the resources of a region prior to the start of decline will also require careful justification. In addition, development patterns that delay the peak may be associated with more rapid post-peak decline.

- Depletion rates can be used to estimate the required rate of reserve additions from new discoveries, the development of fallow fields and enhanced recovery at existing fields. If the *average* depletion rate for these new resources is as high as the *maximum* depletion rate previously seen in any oil-producing region, reserve additions of at least 20 Gb/year will be required to compensate for the decline in production from existing fields. With lower depletion rates, a significantly higher rate of reserve additions is likely to be required. Moreover, as demand grows and decline rates increase, this figure will need to increase even further.

4 Looking beneath - methods of estimating ultimately recoverable resources

This section examines the methods for estimating the ultimately recoverable resources (URR) in a region, focusing in particular on the extrapolation of historical trends in production or discovery. Such techniques are widely used by those concerned about ‘peak oil’ and regularly criticised by those that are not. A comprehensive examination of these techniques is contained in *Technical Report 5*.

Section 4.1 discusses the relevance of URR to future oil supply, while Section 4.2 summarises the methods available to estimate the URR. Sections 4.3 to 4.5 investigate the techniques based upon the extrapolation of historical trends in more detail, including their historical origins, contemporary application and major strengths and weaknesses. Section 4.6 uses illustrative data from a number of oil-producing regions to assess whether these techniques produce consistent results, while Section 4.7 highlights some of the statistical issues raised and shows how they may be addressed. Section 4.8 concludes.

4.1 The importance of ultimately recoverable resources

The peak oil debate is primarily about the *rate* of global production rather than the absolute size of the oil resource. But despite this, disputes over the size of the resource play a very prominent role. This is because, other things being equal, larger estimates of URR lead to more optimistic forecasts for future oil supply, and vice versa (Bartlett, 2000). While some economists (e.g. Adelman, 1991) reject the notion that such estimates can play a useful role in supply forecasting, they are central to the work of Hubbert and of subsequent authors such as Campbell (1997) and Laherrère (2003; 1999b).

Hubbert forecast future supply by fitting a curve to historical data on oil production and projecting this forward using an estimate of the regional URR to constrain the area under the curve (see Section 5). Without this constraint, such projections would be more difficult to perform, especially for regions that have yet to reach their peak of production (Caithamer, 2008). However, provided exploration in a region is relatively advanced, such ‘curve-fitting’ techniques can also be used to *estimate* the URR.

Any estimate of URR requires specification of the hydrocarbons covered, the timeframe for which the estimate is made, the relevant technical and economic assumptions and the associated range of uncertainty. Lack of clarity over such issues, together with the tendency to produce single value estimates, explains much of the ongoing controversy (Rogner, 1997). While not always treated as such, URR is an endogenous variable: for example, increasing prices should make marginal resources more profitable as well as inducing technical improvements that reduce production costs, improve recovery factors and allow access to previously inaccessible resources. At issue is whether such developments can be expected to significantly increase the recoverable resources from a region, or whether only marginal increases may be expected. This in turn will depend upon the characteristics of the region and the timeframe under consideration. If technical or economic constraints mean that resources are only accessible in the long-term, they may have little or no influence on the timing of peak production, although they could reduce the rate of post-peak decline.

Estimates of URR may be developed for levels of aggregation ranging from individual wells to the whole world (Box 4.1), with different techniques being more or less suitable for different levels. Aggregate estimates may be derived from estimates developed at lower levels, but only mean estimates can be summed arithmetically (Section 2). Estimates are frequently made at the country or regional level, but these typically encompass several geologically distinct areas (see Box 4.1) that may also extend into neighbouring countries or regions. The lack of geological homogeneity within such boundaries can greatly complicate resource assessments when only aggregate data is used (Charpentier, 2003).

Box 4.1 Geological levels of aggregation in petroleum resource assessment

- *Petroleum Well*: A well may be drilled to find, delineate and produce petroleum, with some wells being drilled to inject fluids to enhance the productivity of other wells. The URR of a producing well is typically calculated by extrapolation of its past performance, using standard formulae for decline curves (Arps, 1945; Chaudhry, 2003).
- *Petroleum Reservoir/Pool*: A reservoir is a subsurface accumulation of oil and/or gas whether discovered or not, which is physically separated from other reservoirs and which has a single natural pressure system.
- *Petroleum Field*: A field is an area consisting of a single reservoir or multiple reservoirs, all related to a single geological structure and/or stratigraphic feature. Individual reservoirs in a single field may be separated vertically or laterally but form an approximately contiguous area when projected to the surface. Oil fields may either be discovered, under development, producing or abandoned and the number of wells in a producing field may range from one to thousands.
- *Petroleum Prospect*: A prospect is a geological anomaly that has some probability of containing pools of recoverable hydrocarbon and is considered to be a suitable target for exploration. The boundaries of a prospect may also be influenced by legal and economic considerations, such as the availability of leases for exploration.
- *Petroleum Play*: A play is an area for petroleum exploration, containing a collection of prospects which share certain common geological attributes and lie within some well-defined geographic boundary.
- *Petroleum Basin*: A basin is a single area of subsidence which filled up with either sedimentary or volcanic rocks and which is known or expected to contain hydrocarbons. Sedimentary basins are the primary source of petroleum, as a result of organic carbon being progressively buried, heated and compressed.
- *Petroleum System*: A petroleum system is "….the essential elements and processes as well as all genetically related hydrocarbons that occur in petroleum accumulations whose provenance is a single pod of active source rock" (Magoon and Sanchez, 1995). The concept was first introduced by Dow (1972) and now forms the basis of the resource assessments conducted by the USGS.
- *Petroleum Assessment Unit* An assessment unit (AU) is a volume of rock within a petroleum system that is sufficiently homogeneous, both in terms of geology, exploration considerations, accessibility and risk to be examined with a particular resource assessment methodology. An AU may coincide with a single petroleum system, or the latter may be broken down into several AUs.

- *Petroleum Province*: A province is an area with common geological properties relevant to petroleum formation. Adjacent provinces might have the same original rocks, but be considered separate because they have different histories. A province may contain a single basin or petroleum system or several similar basins/systems. A province is the largest entity defined solely on the basis of geological considerations that is relevant for resource assessment. Globally, the USGS (2000) identified 937 provinces, of which 406 were known to contain petroleum and 76 were estimated to contain 95% of discovered resources.

Sources: Energy Information Administration (1990); Klett (2004); Magoon and Sanchez (1995)

4.2 Overview of techniques

There are a variety of methods for estimating URR and many variations on the basic techniques. The appropriate choice depends upon the nature of the region under study and the data and human resources available. The most reliable estimates are likely to be derived from a combination of methods (Ahlbrandt and Klett, 2005; Divi, 2004).

Most of the methods associated with Hubbert may be characterised as producing single-value estimates from the extrapolation of curves fitted to historic data on cumulative discovery or cumulative production for aggregate regions such as an oil-producing country. There is relatively little use of geological or other information and the methods are simple to apply using data that is often available in the public domain. In contrast, the methods used by the USGS and others produce probabilistic estimates from geological assessments of disaggregate regions, with extensive use of geological information and statistical techniques (USGS, 2000). These methods are complex and resource-intensive and rely upon extensive data sources that are often inaccessible to third parties. This characterisation is an oversimplification, however, as there are considerable overlaps between the two, especially for regions that are at a relatively mature stage of exploration and production (Drew and Schuenemeyer, 1993).

For less-explored regions, estimates must rely upon the geological analysis of seismic and other data. A traditional approach, commonly applied at the basin level, is to estimate hydrocarbon volumes by multiplying the estimated sedimentary volume by an estimated yield in barrels per cubic kilometre (Gautier, 2004; Weeks, 1952; White and Gehman, 1979). For unexplored areas, the values for such calculations are based upon measurements from geologically similar regions where more information is available. Other approaches are applied at lower levels of aggregation and typically use Monte Carlo methods to multiply estimates or measurements of variables such as pore volume, porosity and oil saturation (Capen, 1976). Data may only be available for a subset of these variables and for unexplored areas (e.g. the Arctic), such estimates must necessarily have large confidence bounds. In Hubbert's view:

> "…. it is easy to show that no geological information exists, other than that provided by drilling, that will permit an estimate to be made of the recoverable oil obtainable from a primary area that has a range of uncertainty of less than several orders of magnitude." (Hubbert, 1982)

Estimates may also be made by combining the expert judgment of several geologists (Baxter, *et al.*, 1978). Typically, each geologist reviews the relevant information and then estimates either a single value or a probability distribution for each of the relevant factors which are then combined into a probability distribution that reflects the full range of opinions (Gautier, 2004; White, 1981). This method is appropriate for all levels of aggregation and data availability and can accommodate exploration constraints and other factors that may be poorly handled by other methods (Charpentier, et al., 1995b). However, it lacks transparency and relies heavily on the knowledge and objectivity of the individual assessors.

For well-explored regions, more reliable estimates can be obtained by using data on discovered fields.[48] There are three approaches:

- *Field-size distributions:* Estimates of URR may be derived by combining data on the sample of discovered fields with assumptions about the size distribution of the underlying population of fields (Section 3). For example, if a power-law size distribution is assumed, undiscovered resources may be estimated by plotting a cumulative frequency distribution on a log scale, fitting a linear regression, extrapolating this to smaller field sizes and calculating the area under the curve (Cramer Barton and La Pointe, 1995). This estimate is sensitive to the point at which the observed size distribution is curtailed when fitting the curve, as well as to assumptions about the minimum viable field size and appropriate size distribution (Charpentier, *et al.*, 1995a; Laherrère, 2000a). An alternative approach plots cumulative discoveries as a function of the rank of the field (where the largest field is rank 1) and estimates the URR from the asymptote to which the curve is trending. This approach has much in common with the 'discovery projection' technique described below.[49]
- *Discovery process modeling*: These involve statistical analyses of the number and size of discovered fields as a function of either time, the discovery sequence or some measure of exploratory effort, such as the number of exploratory wells drilled (Arps and Roberts, 1958; Forman and Hinde, 1985; Kaufman, 1975; Meisner and Demirmen, 1981). This is sometimes combined with assumptions about the field size distribution and/or information about field location (Schuenemeyer and Drew, 1994). Several of these models simulate a probabilistic law governing the process of new field discovery and can be used to provide forecasts of the number, size and sequence of future discoveries together with the anticipated success rate of exploratory drilling (Power and Fuller, 1992a; b).
- *Curve-fitting*: These use regression techniques to fit curves to the historic trends in discovery or production in a region and extrapolate the curves to estimate the URR. The explained variable may be cumulative production, the rate of production, cumulative discoveries or the rate of discoveries ('yield'), while the explanatory variable may either be time or some measure of exploratory effort, such as the cumulative number of exploratory wells drilled. A major advantage of curve fitting techniques is that they do not require data on individual fields. Curve fitting was pioneered by Hubbert (1956; 1959; 1962; 1982) and has subsequently been adopted and developed by numerous analysts, including in particular those concerned about 'peak oil' (Campbell, 2002a; Cleveland and Kaufmann, 1991; Imam, *et al.*, 2004; Laherrère, 2003; Mohr and Evans, 2008).

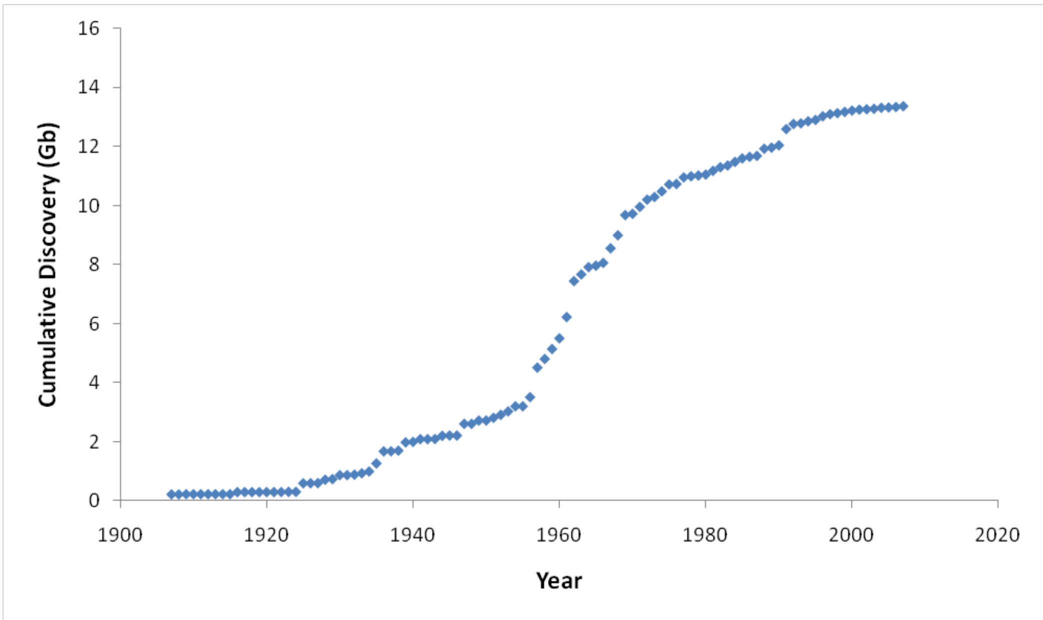
These three 'extrapolation' techniques all assume that: the field size distribution is highly skewed, with the majority of oil being located in a small number of large fields; and that large

[48] Geological assessments are often considered to produce relatively optimistic estimates, while techniques based upon the extrapolation of historical trends may be more conservative. However, few studies have systematically compared the results obtained. Ahlbrandt and Klett (2005) found considerable variation in the results of seven methods applied to seven regions, with some methods (e.g. Pareto size distribution) being consistently optimistic.

[49] If the discovery rate was constant and if fields were discovered precisely in descending order of size, the field-rank and discovery projection techniques would be identical.

fields tend to be discovered relatively early, with subsequent discoveries being progressively smaller and often the product of increasingly greater effort. These features should be reflected in both the size distribution of discovered fields and the 'shape' of the discovery or production cycle. For example, Figure 4.1 plots cumulative discoveries in a region as a function of time. As the average size of newly discovered fields falls, the curve trends towards an asymptote which can be taken as an estimate of the regional URR. All of the curve-fitting techniques rely upon patterns such as this.

Figure 4.1 Cumulative discovery in a region as a function of time



Source: IHS Energy
Note: Name of region withheld on grounds of confidentiality.

The extrapolation techniques are best applied to geologically homogeneous areas that have had a relatively unrestricted exploration history (e.g. without areas being closed to exploration for legal or political reasons). If this is not done, the mixing of different populations of fields or the opening up of new areas for exploration (e.g. new plays within a basin) can lead to inconsistencies in the time-series and undermine the basis for estimating size distributions and extrapolating historical trends (Wendebourg and Lamiraux, 2002).[50] But even if the region is geologically homogeneous, various technical, economic and political factors (e.g. the advent of horizontal drilling in Texas) can lead to structural breaks in a time-series (Harris, 1977).[51] Since all historical trends reflect the net effect of physical depletion, technical change and numerous economic, political and institutional influences, the extrapolation of those trends can only be expected to provide reliable URR estimates if physical depletion *outweighs* the other influences - and continues to do so in the future. This condition will not apply in all oil-producing regions[52] although depletion should become increasingly important as exploration proceeds. Assumptions about future reserve growth can

[50] The same applies to exploratory depth. Shallow fields are usually more extensively explored and exploited before deep fields, so shallow fields may be over-represented and deeper fields under-represented in the distributions of discovered fields (Harris, 1977).
[51] Exploration is very rarely unrestricted in aggregate regions. For example, the US imposes far fewer restrictions than most countries, but the Arctic National Wildlife Refuge, the eastern Gulf of Mexico, much of the western offshore and many onshore areas in the Rockies are off-limits for environmental reasons (Mills, 2008).
[52] For example, Managi, *et al.* (2005) shows how technical improvements have more than offset resource depletion in the Gulf of Mexico, leading to steady increases in the yield from exploratory drilling over the last 35 years.

also have a major influence on the results of all three methods (Drew and Schuenemeyer, 1992).

The remainder of this section focuses upon *curve-fitting* techniques which are the most widely used owing to their simplicity and the relative availability of the relevant data. These techniques estimate URR by extrapolating historical trends in aggregate data, but they vary in their choice and definition of the explained and explanatory variables (Table 4.1). Other variables can and should be included in the specification, but generally are not (Section 4.7). The following sections discuss each group of techniques in turn.

Table 4.1 Classification of curve-fitting techniques by their choice of explained and explanatory variables

Group	**Technique**	**Explained variable**	**Explanatory variable**
Production over time	Cumulative production projection	Cumulative production	Time
	Production projection	Rate of production	Time
	Production decline curve	Rate of production	Cumulative production
Discovery over time	Cumulative discovery projection	Cumulative discovery	Time
	Discovery projection	Rate of discovery	Time
	Discovery decline curve (time)	Rate of discovery	Cumulative discovery
Discovery over exploratory effort	Creaming curve	Cumulative discovery	Exploratory effort
	Yield per effort curve	Rate of discovery *wrt* exploratory effort	Exploratory effort
	Discovery decline curve (effort)	Rate of discovery *wrt* exploratory effort	Cumulative discovery *wrt* exploratory effort

Notes:

- The terms used to label these techniques are not standardised.
- Rate of production is the first derivative of cumulative production with respect to time. Alternative terms are the rate of change of cumulative production, or more simply production. Similar comments apply to the rate of discovery, although here the derivative may be with respect to either time or exploratory effort.

4.3 Production over time techniques

The simplest, although not the most reliable, method of estimating URR uses non-linear regression[53] to fit a curve to time-series data on cumulative production. This curve may take a variety of forms with its shape being defined by three or more parameters, one of which corresponds to the URR. Hubbert (1982) assumed a *logistic model* (Box 4.1) which implies that cumulative production will initially grow exponentially, but the rate of growth will fall and eventually decline to zero as the URR is approached.[54] The curve is defined by three

[53] Non-linear regression is straightforward with modern computer technology, but the earlier literature uses simpler methods such as the linear transformation of the functional form followed by a linear regression (Hubbert, 1982). If the production or discovery cycle is well advanced (as in Figure 4.1), it is possible to estimate the URR through visual identification of the asymptote to which the curve is trending (Bentley, 2009).

[54] Hubbert (1982) begins with an assumed parabolic relationship between production and cumulative production and uses this to derive a logistic equation for cumulative production over time. But this formal derivation came more than twenty years after he first referred to the logistic model (Hubbert, 1959; Sorrell and Speirs, 2009).

parameters, representing the URR, the ‘steepness’ of the curve and the midpoint of the growth trajectory, with the production cycle being obtained from the first differential of this curve. The URR may also be estimated by fitting a curve to the production data, although the result may well be different (Carlson, 2007). While a ‘bell-shaped’ production cycle is commonly referred to as a ‘Hubbert curve’, Hubbert repeatedly stated that it need not take this form.[55]

[55] “…There is no necessity that the curve….have a single maximum or that it be symmetrical. In fact, the smaller the region the more irregular in shape is the curve likely to be....” (Hubbert, 1982).

Box 4.2 The Hubbert logistic model of oil depletion

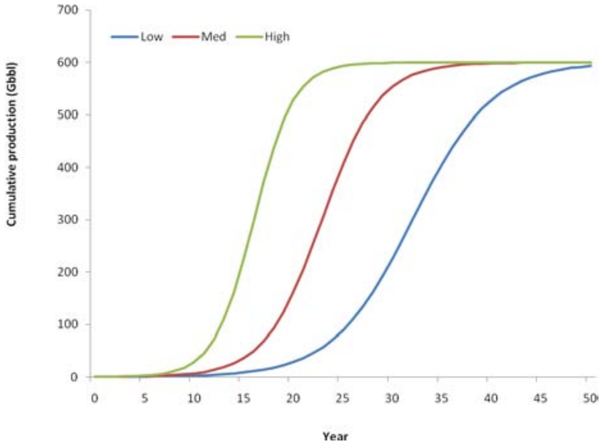
The key features of the Hubbert logistic `model are that:

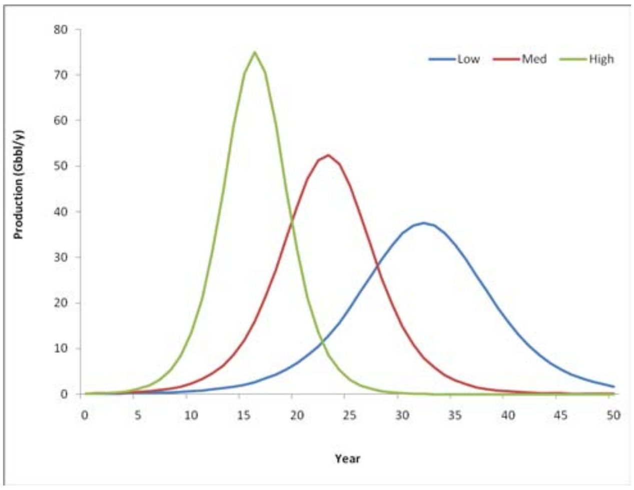
- o Cumulative production is modelled with a logistic function
- o Production is modelled with the first derivative of the logistic function;
- o The production profile is symmetric (i.e. maximum production occurs when the resource is half depleted and its functional form is equivalent on both sides of the curve);
- o Production increases and decreases in a single cycle without multiple peaks.

- Hubbert (1959; 1982) noted frequently that these were only simplifying assumptions to allow tractable analysis.
- Hubbert's model for production is defined mathematically as follows:

$$Q(t) = \frac{Q_\infty}{1+e^{-a(t-t_m)}} \qquad Q'(t) = \frac{dQ(t)}{dt} = \frac{aQ_\infty e^{-a(t-t_m)}}{\left(1+e^{-a(t-t_m)}\right)^2}$$

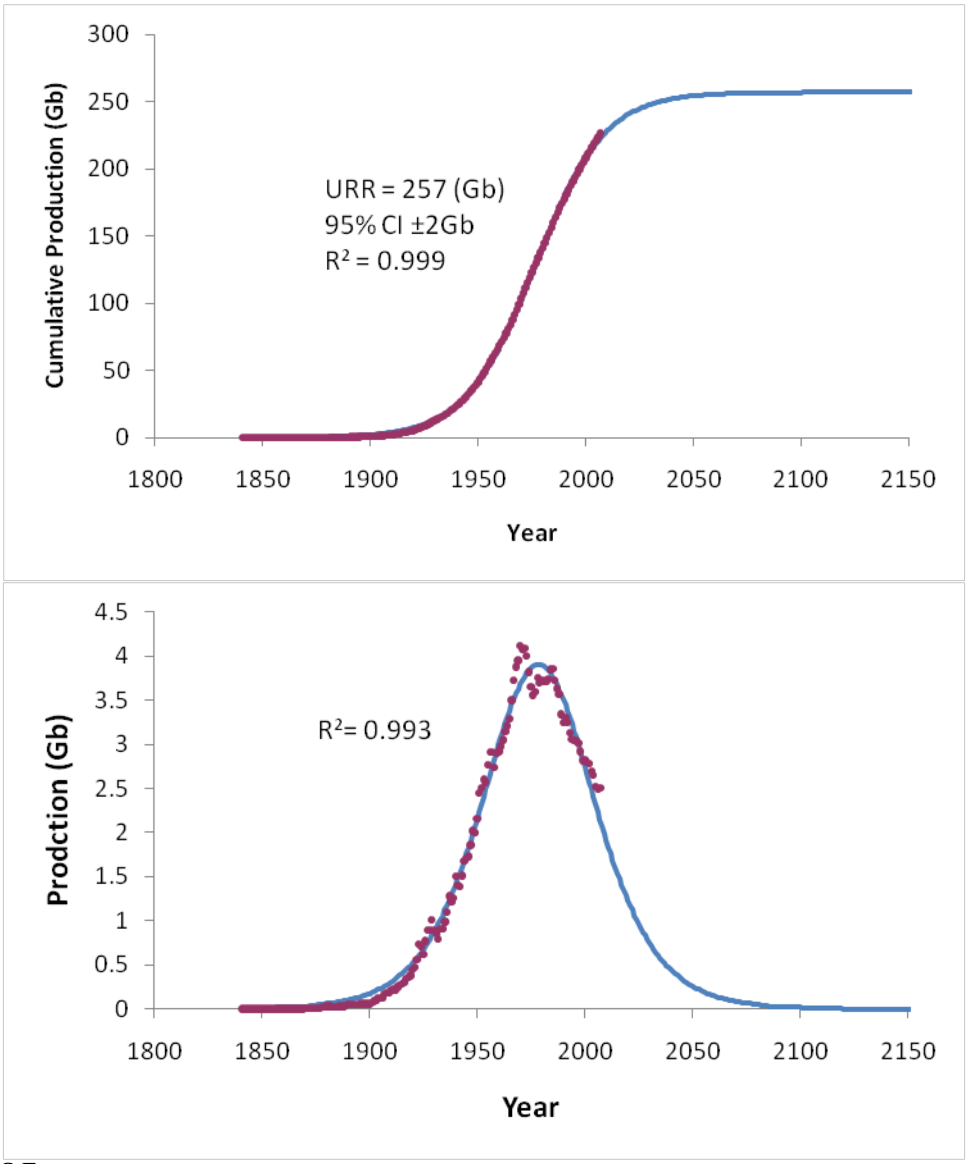
- Where *Q(t)* is cumulative production; *Q'(t)* is production; Q_∞ is the URR; *a* defines the 'steepness' of the cumulative production curve; and t_m specifies the time when cumulative production reaches one half of the URR
- The diagram shows the resulting cumulative production cycle (top) and production cycle (bottom)





Curve-fitting to production trends should be more reliable if production has passed its peak and is only viable if the rate of increase of production has passed its peak (i.e. the point of inflection on the rising production trend). US data fits the logistic model relatively well (Figures 3.4) despite covering a period that includes two world wars, several recessions, two oil shocks, revolutionary changes in technology and the opening up of new oil-producing regions. In contrast, the logistic model provides a relatively poorly approximation to the production cycle for most other oil-producing regions, especially when this occurs over a shorter period of time (Brandt, 2007).

Figure 4.2 A fit of the logistic model to US production of conventional oil



Source: IHS Energy
Note: Data for all US states, including crude oil, NGLs, condensate and heavy oils ($<10^0$ API)

The logistic is one of a family of symmetric and asymmetric curves that are widely used to model growth processes (Meade, 1984; Tsoularis and Wallace, 2002).[56] One of the few that has been applied to oil depletion is the *cumulative normal*, which Bartlett (2000) fitted to US production data. While there is no robust theoretical basis for choosing between these models, there are a variety of reasons for expecting the production cycle to be asymmetric. For example, production could decline rapidly after the peak as the large fields are depleted,

[56] Alternatives including the generalised logistic (Nelder, 1971), Bass (Bass, 1969), Gompertz (Moore, 1966) and bi-logistic (Meyer, 1994) as well as the cumulative normal, lognormal, Cauchy and Weibull distributions (Meade, 1984; Wiorkowski, 1981b).

or could decline more slowly if EOR techniques are used. Brandt (2007) analysed 74 oil producing regions and found that the rate of production increase exceeded the rate of decline in over 90% of cases, suggesting that an asymmetric model may be more appropriate. But when Moore (1962) fitted an asymmetric *Gompertz* function to US data he obtained a URR estimate that was almost twice as large as that from the logistic model for a comparable goodness of fit. Very similar results were later obtained by Wiorkowski (1981b)[57] and Cleveland and Kaufmann (1991).[58] This highlights a generic weakness of curve fitting techniques, namely: *different functional forms often fit the data comparably well but give very different estimates of the URR* (Ryan, 1966).

Production cycles often have more than one peak as a result of economic, technical or political changes or the opening up of a new region (Laherrère, 2000b). For example, Illinois experienced two production cycles as a consequence of early developments in exploration technology (Hubbert, 1956). Laherrère (2004) argues that most countries have several cycles of discovery and production and are best modelled by two or more curves. If each curve represents the production of resources from a geologically homogeneous region, the aggregate URR may be derived from the sum of estimates from the individual curves. Several authors have followed this approach approach (Imam, *et al.*, 2004; Mohr and Evans, 2007; Patzek, 2008; Reynolds and Kolodziej, 2008) and any cumulative production trend could in principle be decomposed into an arbitrary number of logistic curves (Meyer, *et al.*, 1999). But the better fit of a more complex model may not be justified statistically,[59] and the results will be unreliable if further cycles are expected in the future. This highlights a second generic weakness of curve-fitting techniques, namely: *their inability to anticipate future cycles of discovery and production in aggregate regions*.

If cumulative production grows logistically, a plot of the ratio of production to cumulative production as a function of production should be approximately linear (Hubbert, 1982). If a linear regression is fit to this data, the URR may be estimated by extrapolating and identifying the intersection with the cumulative production axis (Figure 4.3). This straightforward technique was popularised by Deffeyes (2005) and is sometimes termed 'Hubbert Linearisation' (HL). While methodologically straightforward, it is equivalent to fitting a logistic curve to cumulative production and hence will be unreliable if (as is usually the case) cumulative production departs from the logistic model.

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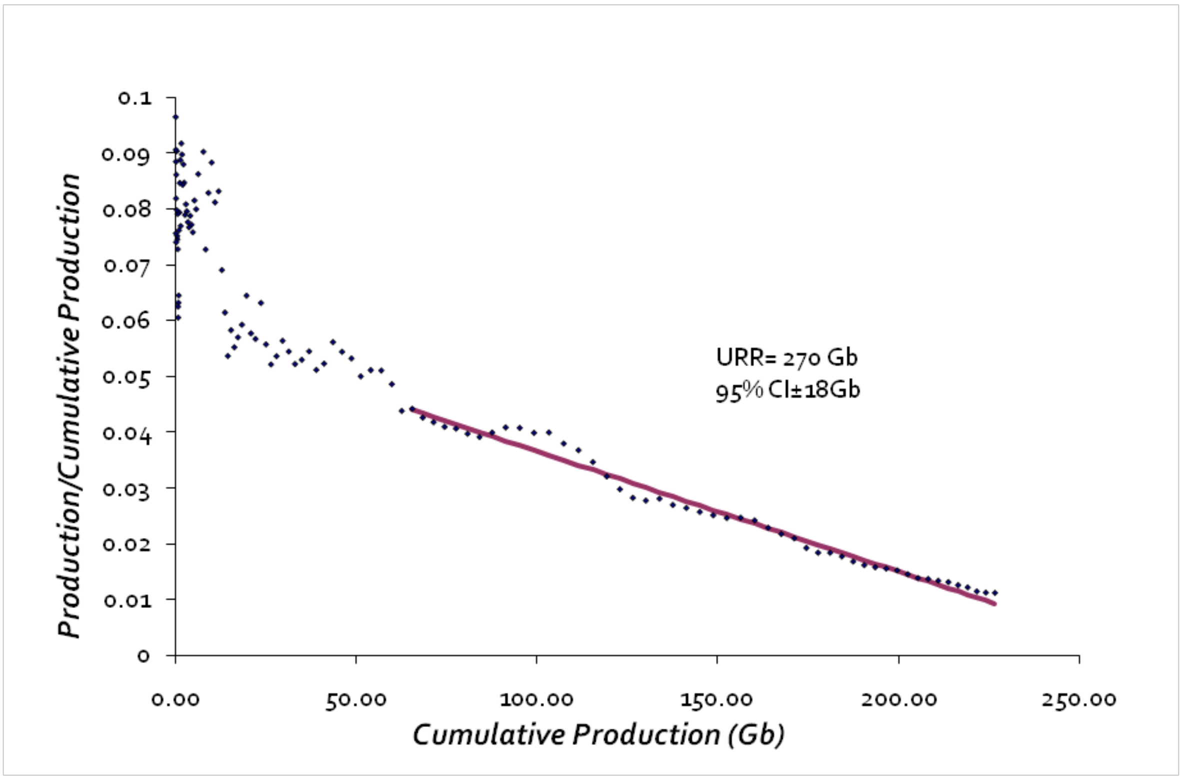
[57] Wiorkowski (1981b) compared a 'Generalized Richards' model (which can take an exponential, logistic, or Gompertz form depending upon the parameters chosen) with a cumulative Weibull and found that they fit US cumulative production data equally well but led to significantly different URR estimates (445 Gb and 235 Gb respectively).

[58] Cleveland and Kaufmann (1991) fitted a logistic curve to US production data through to 1988 and found that the adjusted R^2 changed only from 0.9880 to 0.9909 as the value of URR varied from 160 to 250 billion barrels.

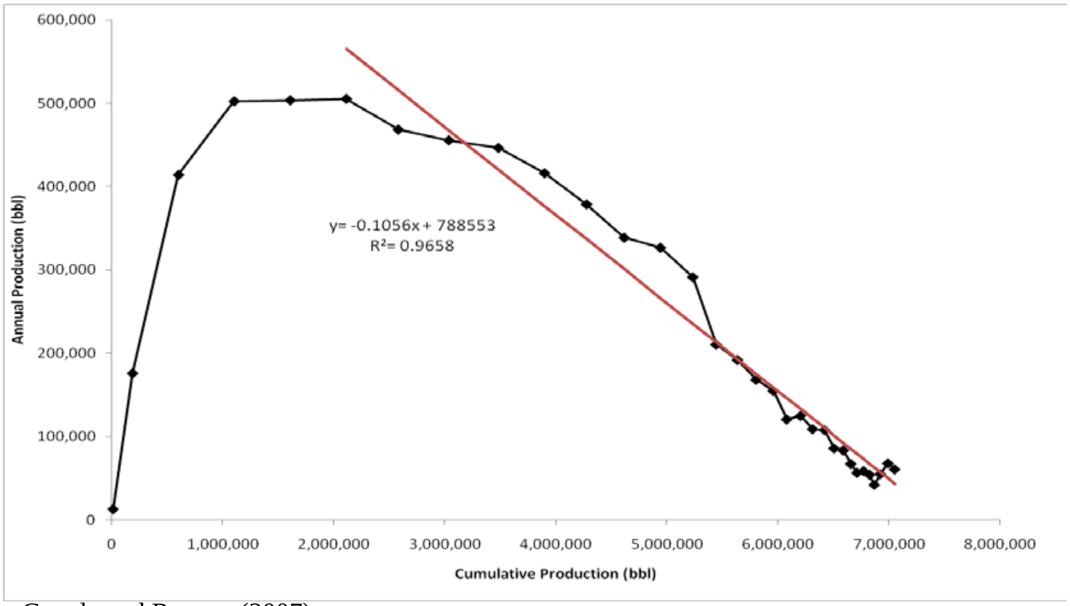
[59] A useful rule of thumb is to ensure there are at least ten data points per parameter (Motulsky and Christopoulos, 2004), but many published examples of curve-fitting do not meet this criterion (e.g. Campbell and Heapes, 2008; Laherrère, 2002a; 2004).

Figure 4.3 'Hubbert Linearisation' of US oil production



The linearisation technique is closely related to the *decline curve analysis* used by reservoir engineers to project the future production of individual wells or fields (Section 3.3). If exponential decline is assumed (Section 3), the URR for the field may be estimated by plotting production against cumulative production, fitting a linear regression and extrapolating this until it crosses the cumulative production axis (Figure 4.4). This technique is widely used, but alternative functional forms for decline rates should also be investigated since the exponential model can underestimate the URR (Kemp and Kasim, 2005; Li and Horne, 2007). Nevertheless, a 'production decline curve' for an individual field may be expected to be lead to more reliable estimates of URR than an equivalent technique for an oil-producing region.

Figure 4.4 Linearisation of exponential production decline for the UK Forties field



Source: Gowdy and Roxana (2007)
Note: The introduction of EOR techniques in 1986 appears to have only temporarily increased production in this field without having a significant impact on the URR. Gowdy and Roxana (2007) observe similar patterns in the Yates field in Texas and at Prudhoe Bay in Alaska, where EOR appears to have increased production at the expense of steeper decline rates in later years. Whether this conclusion applies more generally is a topic of considerable dispute. The Weyburn field in Canada (Box 3.2) provides a useful counter-example.

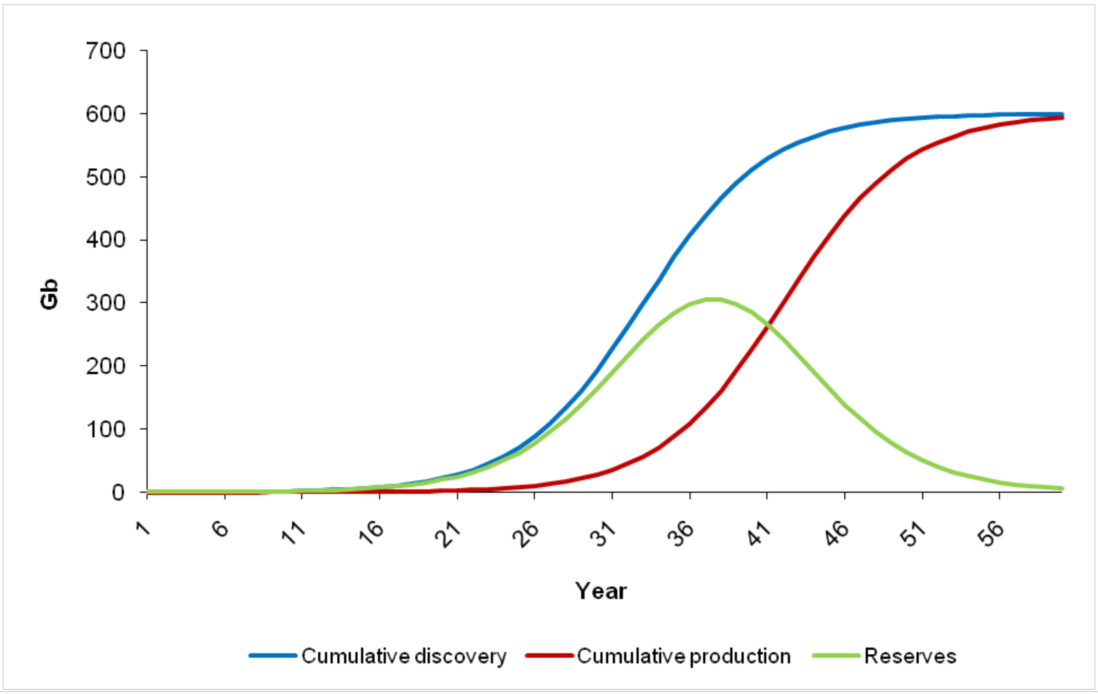
In sum, curve-fitting to production trends is straightforward and relies upon data that is readily available, relatively accurate and free from the complications of reserve growth (see below). But while these techniques may sometimes provide reliable estimates in regions that are well past their peak of production, they have important drawbacks including: the lack of a robust basis for the choice of functional form; the sensitivity of the estimates to that choice; the risk of 'over-fitting' multi-cycle models; the inability to anticipate future production cycles; and the neglect of economic, political and other variables that have shaped and will continue to shape the production cycle. These drawbacks are also shared by the discovery-based techniques described below.

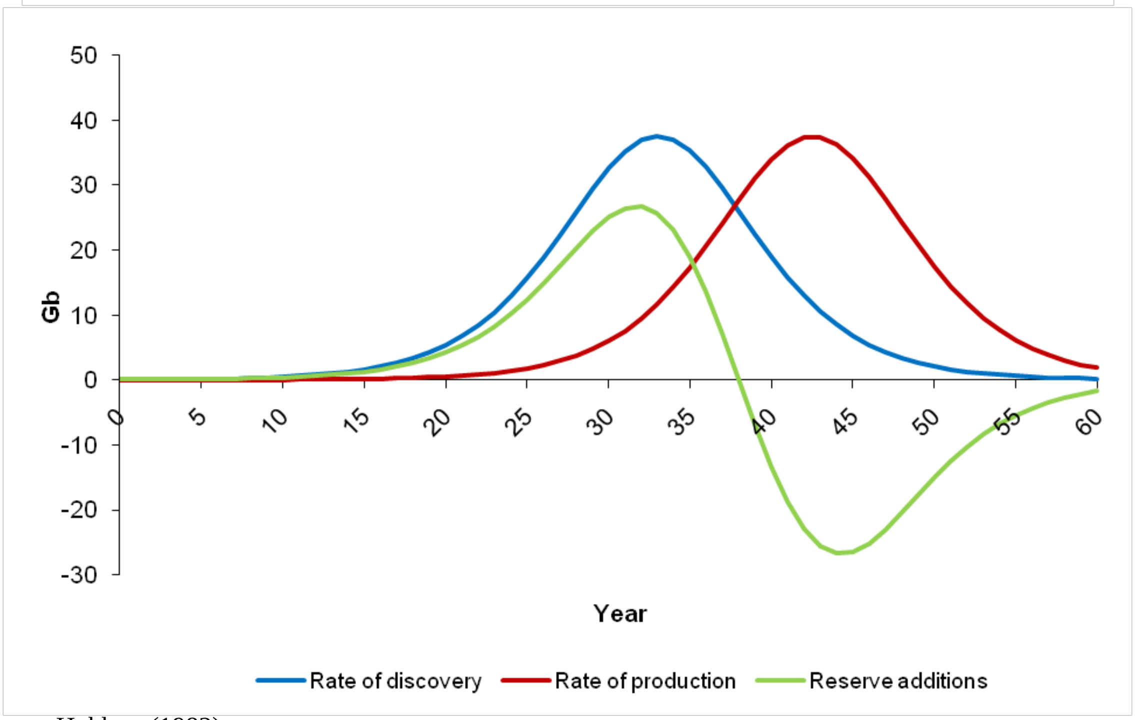
4.4 Discovery over time techniques

Curve-fitting to discovery trends was first introduced by Hubbert (1962; 1966; 1982) and has since been employed by other authors, including Laherrère (2003; 2004; 1999b; 2005). These techniques have much in common with those described above and raise a comparable set of issues and concerns. In principle, the extrapolation of discovery trends should provide more reliable estimates of the URR because the discovery cycle is more advanced. However, discovery data is less accessible and reliable than production data and, unlike the latter, is estimated to different levels of confidence (e.g. 1P or 2P).

Hubbert's discovery projections were based upon the idealised life-cycle model illustrated in Figure 4.5 (Hubbert, 1959). Hubbert assumed that both cumulative discovery and cumulative production grew logistically, with the former preceding the latter by some time interval. Since the peak rate of discovery precedes the peak in production, identification of the former could form a basis for predicting the latter.

Figure 4.5 Hubbert's idealised lifecycle model of an oil-producing region





Source: Hubbert (1982)
Note: Cumulative discoveries are calculated from the sum of cumulative production and declared reserves. When reserves reach their maximum value, production (which is still increasing) is equal to discovery (which is decreasing).

Hubbert (1962) fitted a logistic curve to US data on cumulative 1P discoveries and used this to estimate a URR of 170 Gb. Subsequent studies confirmed this estimate (Hubbert, 1966; 1968; 1974; 1979; 1982) but several authors questioned Hubbert's results. For example, Ryan (1965; 1966) fitted logistic curves to US production and discovery data and found they led to widely different estimates for the URR. He also showed that much larger estimates could be cited with equal justification and that the estimates increased rapidly with the addition of only a few more years of data. Cavallo (2004) recreated Hubbert's original dataset and found that the R^2 for the best-fitting models changed only from 0.9946 to 0.9991 as the value of URR varied from 150 to 600 Gb. Similarly, Cleveland and Kaufmann (1991) found Hubbert's results to be highly sensitive to the length of data series chosen.

The assumption that the discovery cycle takes the same form as the production cycle appears neither necessary nor plausible - although it works fairly well for the US when 1P data are used.[60] The factors influencing discovery at different points in time are likely to be different from those influencing production at a later point in time and the skewed field-size distribution would be expected to (and frequently does) lead to a sharply rising cumulative discovery cycle and an asymmetric discovery cycle (Nehring, 2006b). For similar reasons, there is unlikely to be a predictable time-lag between the peaks in discovery and production.

While Hubbert used 1P reserves to form his cumulative discovery estimates, subsequent authors use 2P reserves from industry data sets (Bentley, *et al.*, 2007; Campbell, 1997; Laherrère, 2004). Since these are generally larger than 1P estimates, they should lead to a higher estimate of the URR. Also, cumulative discovery estimates tend to increase over time even if no new fields are found as a result of reserve growth at existing fields. To take account of this, Laherrère (1996; 2002) and others use *backdated* estimates which are typically larger than those made at the time of field discovery as a result of reserve growth in the intervening period.[61] Hubbert (1967) was one of the first to develop backdated estimates, but did not use these for discovery projection. A discovery cycle based upon backdated estimates will be a different shape from one based upon current estimates and will have a different date for the peak in discoveries.

Backdated estimates provide a more accurate picture of what was found at a particular time and are also more suitable for estimating the URR since the cumulative discovery curve is more likely to trend to an asymptote. But they can be misleading since the sizes of fields discovered at different times will not have been estimated on a consistent basis (i.e. they will reflect differing amounts of reserve growth). For the same reason, both the height and shape of the curve will change over time and it will not represent the *ultimate* resources that were found since more reserve growth can be anticipated in the future (Figure 4.6). Hence, to provide reliable estimates of the URR, backdated discovery data should be adjusted to allow for future reserve growth (Drew and Schuenemeyer, 1992; Root and Mast, 1993). While there will be uncertainty regarding the appropriate growth function to use, the failure to do this may lead to underestimates of the URR.[62] Campbell and Laherrère claim that such adjustments are unnecessary, since 2P estimates should not change much following field

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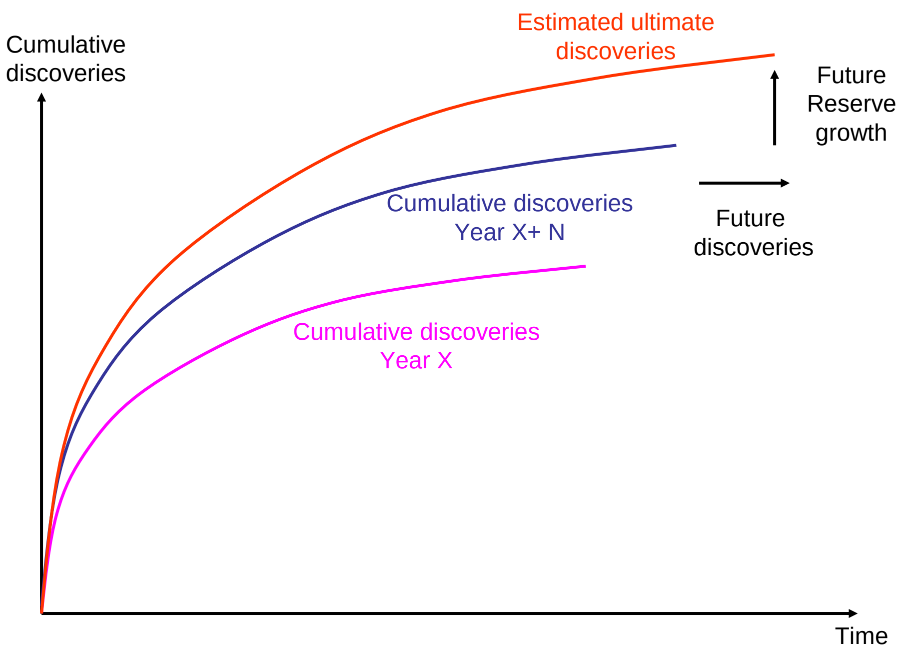
[60] "…..Because petroleum exploration in the US began very early, because the initial exploration and discoveries occurred in what has proved to be relatively minor basins, because early drilling technology was very limited in its drilling depth capabilities, and because discoveries in the major basins only hit their stride between 1910 in 1950, the US comes closest to a symmetric discovery curve of any major oil producing country or region." (Nehring, 2006b)

[61] Backdated cumulative discoveries may be represented by $B(t_d,t)$, where t_d is the time of field discovery and t is the time when the estimate is made. The backdated rate of discovery is given by: $B'_{t_d}(t_d,t) = \frac{\partial B(t_d,t)}{\partial t_d}$ while the rate of change of backdated cumulative discovery estimates with respect to the time of the estimate is given by: $B'_t(t_d,t) = \frac{\partial B(t_d,t)}{\partial t}$. A plot of $B'_{t_d}(t_d,t)$ versus t_d for a particular value of t represents a backdated discovery cycle, while a plot of $B'_t(t_d,t)$ versus t for a particular value of t_d represents a growth function. See *Technical Report 5* for a full analysis of the relationships between these variables.

[62] Lynch (2002) likens the neglect of future reserve growth to: "…. comparing old orchards with newly planted saplings and extrapolating to demonstrate declining tree size.".

discovery. But this is inconsistent with the available data (Section 3.2) and also contradictory, since if 2P estimates are relatively stable there should be no advantage in backdating.

Figure 4.6 The impact of reserve growth on discovery projections



The complications introduced by reserve growth are illustrated by Nehring's study of the Permian Basin and San Joaquin valley in the US - which have both been producing oil for more than 80 years (Nehring, 2006a; b; c). Nehring employs backdated 1P cumulative discovery estimates and corrects these with Hubbert's (1967) growth function to estimate the ultimate resources discovered in each time interval. When using data through to 1964, the corrected cumulative discovery curve for the Permian Basin suggests a URR of 27.5 Gb, compared to only 19 Gb with the uncorrected data. But when using data through to 2000, the URR estimate is 37% larger and the estimated date of peak discovery has moved back in time. While Hubbert's growth function predicts substantial reserve growth, it nevertheless underestimates the growth that actually occurred - especially for the older fields. Nehring comments:

> "…the continuous upward movement in the [corrected] cumulative discovery curve makes this curve useless as a tool for predicting the ultimate recovery. Estimates of ultimate recovery derived from cumulative discovery curves are only valid if one can guarantee that there will be no further increases in the ultimate recovery of discovered fields……….no such guarantee can be made." (Nehring, 2006b)

This example could be unrepresentative, however. Proved reserve estimates would be expected to grow by more than the 2P estimates and Nehring relies upon a growth function that is nearly 40 years old and is only applied to the most recent 30 years of data – despite more recent growth functions being available (Verma, 2003; 2005). In addition, the observed reserve growth derives primarily from CO_2 injection in large fields of low permeability and such techniques may neither be suitable nor available in other fields and regions. But Nehring highlights an important problem that is common to all techniques that rely upon discovery data.

4.5 Discovery over effort techniques

If data is available, exploratory effort should provide a better explanatory variable than time, since the corresponding rate of discovery[63] should be less affected by time-varying factors such as changes in tax regimes. Hubbert (1967) was one of the first to fit curves to discovery data as a function of exploratory effort and variants of this approach have subsequently been employed by other authors (Campbell, 1996; Cleveland, 1992b; Ivanhoe, 1986; Laherrère, 2002a). This approach is also the basis of *discovery process modelling* (Box 4.3), which was first introduced by Arps and Roberts (1958) and has subsequently been widely used by the USGS and other organisations (Drew, 1997; Drew and Schuenemeyer, 1993; Power and Fuller, 1992a). Both methods rely upon backdated discoveries and require some method for estimating future reserve growth, but only the latter needs data on individual fields.

[63] The backdated rate of discovery with respect to exploratory effort is given by $B'_{\varepsilon_d}(\varepsilon_d, t) = \frac{\partial B(\varepsilon_d, t)}{\partial \varepsilon_d}$, where ε_d represents the cumulative exploratory effort at the time of field discovery.

Box 4.3 Discovery process modelling

Arps and Roberts (1958) investigated the history of oil discovery in the east flank of the Denver-Julesburg basin in Colorado. The combination of a geologically homogeneous region, unrestricted exploration and a relatively large sample of wells and fields made the area an excellent candidate for statistical examination. Their classic paper introduced discovery process modelling, provided one of the first pieces of evidence for a lognormal field-size distribution and highlighted the importance of sampling bias. Versions of their approach have subsequently enjoyed widespread use in resource appraisal, most notably by the USGS.

Arps and Roberts grouped discovered fields into 15 size categories and estimated a relationship between their URR and surface area. They postulated that the probability of an exploratory well finding a field of a particular size class must be proportional to the product of the number of undiscovered fields of that size remaining and the average surface area of such fields. They estimated a negative exponential relationship between the number of discoveries in each size class and the cumulative number of exploratory wells and used this to estimate the size distribution of undiscovered fields, the future discovery rates for different sizes of field and the regional URR. Although simple in structure, the Arps-Roberts model has subsequently produced accurate forecasts for a number of exploration plays, basins and provinces, including the Denver-Julesburg basin itself (Attanasi, *et al.*, 1981). The USGS has employed versions of the model in their assessment of the oil and gas resources of the United States (Drew and Schuenemeyer, 1993). Modifications include specifying discovery efficiency as a function of field size (Drew, 1997), assuming a power-law size distribution for small fields to correct for sampling bias (Root and Attanasi, 1993) and correcting the field size estimates to allow for future reserve growth (Drew and Schuenemeyer, 1992; 1993).

A more sophisticated approach models the discovery process as sampling without replacement from an underlying population of fields, with the probability of discovery being proportional to the size of the field divided by the sum of sizes of remaining fields (Barouch and Kaufman, 1975). The assumed field size distribution is that which maximises the likelihood of the observed discovery sequence having occurred. Smith and Ward (1981) use this technique to successfully forecast discoveries in the North Sea, although this is not a geologically homogeneous region and the authors neglect problems of sampling bias in the size distribution of discovered fields (Smith, 1980; 1984; Smith and Ward, 1981). In a study of Canada's Scotian Shelf, Power and Fuller (1992a; b) found the probabilistic approach provided more accurate forecasts of future discoveries than other competing models.

Discovery process models have a stronger theoretical basis than simple curve-fitting and may potentially provide more reliable estimates of URR for the regions in which they can be applied. However, there has yet to be a comprehensive synthesis of research in this area and the existing literature appears patchy. While numerous authors have developed variations on the basic themes,[64] the techniques appear to be little used outside North America and there is a lack of comparative studies on their relative performance. The methodological sophistication of these models and the need for data on a statistically significant number of fields presents a significant barrier to their more widespread use. They also share many of the same drawbacks as simple curve fitting, such as requiring assumptions about future reserve growth and paying insufficient attention to economic and political influences on exploration (Power and Jewkes, 1992; Walls, 1992).

There are number of different ways of measuring exploratory effort,[65] although the choice will be largely dictated by data availability. The most common metric (the cumulative

[64] For example, Meisner and Demirmen (1981); Rabinowitz (1991), Arps et al. (1971), Forman and Hinde (1985), Lee and Wang (1983; 1985; 1986), Lee (2008), Fryer and Greenman (1990) and Power and Fuller (1991).

[65] Including the cumulative length of exploratory drilling (Hubbert, 1967), the total number of exploratory wells (Ryan, 1973), the number of successful exploratory wells (Moore, 1962), the cumulative length of successful exploratory wells

number of 'new field wildcat' wells - NFWs) may not be the best, however, since much reserve growth derives from development rather than exploratory drilling (Cleveland, 1992b). There are also difficulties with accounting for the delays between drilling and reserve additions and in distinguishing between the search for oil and the search for gas resources (Byrd, *et al.*, 1985).

A 'creaming curve' is a plot of backdated cumulative discoveries against exploratory effort (Figure 4.7),[66] while a 'yield per effort' (YPE) curve is a plot of the rate of discovery against exploratory effort (i.e. the first derivative of the creaming curve) (Figure 4.8). Provided yield declines as exploration proceeds, an estimate of the URR may be derived from the asymptote of the former, the integral of the latter or the corresponding parameters in the fitted curves. Changes in yield represent the net effect of changes in the success rate (the fraction of exploratory wells drilled that yield commercially viable quantities of oil) and changes in the average size of discovered fields. Evidence suggests that the success rate in most regions has declined only relatively gently, if at all, indicating that improvements in exploration technology have partially or wholly offset the anticipated decline in the success rate as a result of the declining number of undiscovered fields (Forbes and Zampelli, 2000; Meisner and Demirmen, 1981).[67] But since large fields generally occupy a larger surface area, they tend to be found relatively early even if drilling is random (Arps and Roberts, 1958).[68] In contrast, the average size of discovered fields in many regions has fallen by an order of magnitude since the early days of exploration. Hence, declining YPE is most likely to be the result of falling average field-sizes.

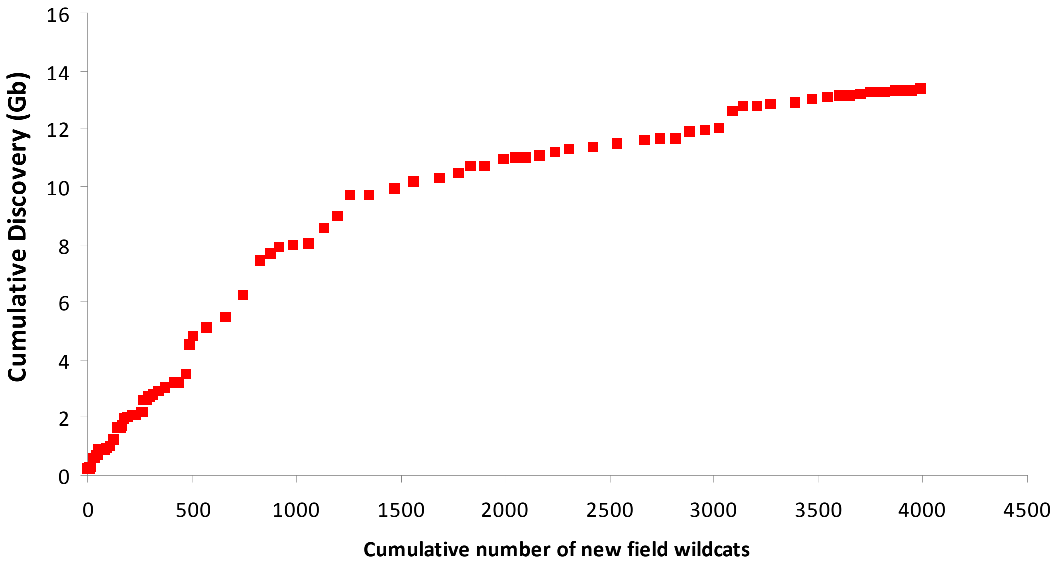
(Stitt, 1982) or the cumulative length of all wells (i.e. both exploratory and development) (Cleveland, 1992b). A distinction may also be made between the first exploratory well to be drilled ('new field wildcats' or NFWs) and subsequent wells.

[66] Laherrère (2004) states that the creaming curve was invented by Shell in the 1980s, but variants of this approach have been used in the oil industry for much longer (Arps, *et al.*, 1971; Arps and Roberts, 1958; Harbaugh, *et al.*, 1995; Odell and Rosing, 1980). Two employees of Shell published a paper on 'the creaming method' in 1981, but this describes a highly sophisticated (and not widely used) discovery process model that relies upon Monte Carlo simulation of trends in both success rates and average field sizes and assumes a lognormal field size distribution (Meisner and Demirmen, 1981).

[67] The IEA (2008) reports that, over the last 50 years, the global average success rate has increased from one in six exploratory wells to one in three. Similarly, Lynch (2002) reports that the average success rate in the US increased by 50% between 1992 and 2002 and Forbes and Zampelli (2000) report that the US offshore success rate doubled between 1978 and 1995. In an econometric analysis, Forbes and Zampelli (2000) estimate that, over the period 1986-1995, technological progress increased the US offshore success rate by 8.3%/year.

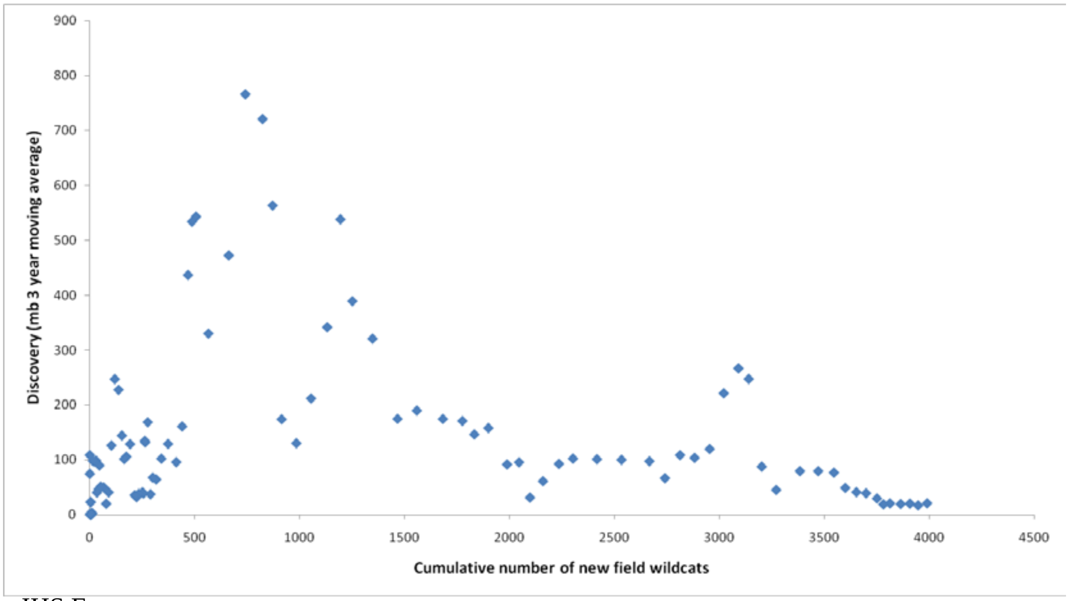
[68] Although Menard and Sharman (1975) found that early exploratory activity in the US performed worse than would be expected from a random search because oil companies avoided areas that they (erroneously) thought could not contain oil.

Figure 4.7 Example of a 'creaming' curve



Source: IHS Energy
Note: Name of region withheld on grounds of confidentiality.

Figure 4.8 Example of a yield per effort curve



Source: IHS Energy
Note: Name of region withheld on grounds of confidentiality.

Hubbert's investigation of YPE curves was developed in response to Zapp (1962), who used exploratory effort as an explanatory variable but assumed that the yield would remain unchanged, leading to an unrealistically large estimate for the US URR (590Gb). Zapp's approach was subsequently adopted by Hendricks (1965), who simply assumed that the yield would decline linearly. In contrast, Hubbert (1967) based his forecast of future yield upon a detailed analysis of past trends, which showed a negative exponential decline.

Hubbert (1967) fitted a negative exponential curve to his estimates of YPE in the lower 48 US states and estimated a URR of ~170Gb, consistent with his estimates from production and discovery projection But Harris (1977) showed that Hubbert's method violated standard statistical procedures, placed excessive weight on the last (and most uncertain) data point and led to systematically biased estimates. The only reason Hubbert's estimate was consistent with his earlier work was that the discovery rate had increased - something which Hubbert considered to be both anomalous and temporary. Harris also showed that a YPE curve for an aggregate region such as the US will not necessarily be exponential, even if the trends for individual regions are exponential. As a result, the URR estimated from a curve fit to aggregate data will be different from the sum of the estimates from curves fit to regional data.

More recent work has used creaming curves rather than YPE curves. Laherrère (2002a; 2004; 2002b) has estimated creaming curves for all regions of the world and found they tend to rise steeply in the early stages of exploration, reflecting the discovery of small number of large fields. He fits 'hyperbolas' to this data, but rarely provides either the functional form or the goodness of fit. Smooth curves (e.g. Figure 4.7) may be the exception rather than the rule, however. For example, Sneddon *et al.* (2003) show how the YPE in an exploration play typically exhibits two or three plateaus and provide some technical reasons for why this may be the case.[69] While diminishing returns to exploratory effort are widely observed at the play level, the same may not always be observed at larger geographical scales because regions are frequently developed in order of ease of exploration and development rather than size (Charpentier, 2003). For example a combination of geological accessibility and improvements in exploration technology led to the largest play in the Michigan basin being developed relatively late (Charpentier, 2003). Similar phenomena are reported by Wendebourg and Lamiraux (2002), who find two exploration cycles in the Paris basin. While a creaming curve estimated using data through to 1986 leads to a URR estimate of 15Mt, a similar curve estimated using data through to 1996 leads to a much larger estimate of 46Mt. The larger the geographical region, the more significant this problem could become. Laherrère (2003; 2004) addresses this through the use of multi-cycle models, but provides little statistical support for his choice of curves and in some cases the appropriate number is unclear.[70]

The potential for further exploration cycles cannot be established from the statistical analysis of historical data, but only from a detailed evaluation of geological potential and exploration history. For small, geologically-defined regions where exploration is well advanced, the probability of new cycles may be relatively low, while for large, politically-defined regions, which are partly unexplored (e.g. owing to the depth of drilling required, or geographical remoteness, or political restrictions) the probability may be much higher. The reliability of curve-fitting therefore depends heavily on the assumption that any new exploration cycles will have only a small impact on aggregate resources - either because there will be few such cycles or because the discovered resources will be relatively small. While this judgement may be reasonable for many regions around the world, it remains problematic for key regions such as Iraq. Unfortunately, these are precisely the regions that account for a significant proportion of the global URR.

[69] Although the case for such plateaus is not always supported by rigorous statistical analysis (Cleveland and Kaufmann, 1997).

[70] For example, Laherrère (2003) models the oil and gas resources of the Middle East with two creaming curves but in a subsequent paper this has increased to four (Laherrère, 2004). The choice appears to be largely determined by the 'shape' of the data, with interpretation in terms of exploration history being made *ex post*.

In sum, while exploratory effort should provide a better explanatory variable than time, curve-fitting techniques must still be used with care. Common difficulties include the inaccuracy of the relevant data, the uncertainty about future reserve growth, the apparent sensitivity of estimates to the choice of functional form, the existence of multiple exploration cycles and the inability to anticipate new exploration cycles in the future. Overall, these difficulties appear more likely to lead to *underestimates* of the regional URR.

4.6 Consistency of curve-fitting techniques

We investigated the reliability of curve fitting techniques with the help of illustrative data from ten oil-producing regions.[71] The data was taken from the IHS Energy PEPS database and includes annual estimates of production, backdated 2P discoveries and the number of new field wildcat wells. The regions include both individual countries and groups of countries, with all but one (Region B) apparently past their peak of discovery and five past their peak of production. Since the objective was to test the reliability of curve-fitting techniques as currently used (e.g. Laherrère, 2004), we did *not* correct the discovery estimates to allow for future reserve growth.

We estimated the URR for each region using production decline curves, cumulative discovery projections and creaming curves. In each case, we investigated the consistency of the estimates obtained with different lengths of data series, different choices of functional form and different numbers of curves, and also compared the estimates produced by each technique. For illustrative purposes, we judged two sets of results to be consistent if the mean URR estimates differed by less than 20% of the cumulative production (Q_{2007}) or cumulative discoveries (D_{2007}) in a region through to 2007. A more or less stringent definition of consistency would not significantly change the results, since most estimates were found to be either broadly consistent or substantially different. The full results from these tests can be found in *Technical Report 5*. Some of the main findings are summarised below.

First, the results raise concerns about the reliability of the URR estimates from curve-fitting techniques, at least when (as is usually the case) they are applied at the country or regional level with data that has not been corrected for future reserve growth. In particular, we observed that: a) in only one of the regions examined were the mean URR estimates consistent between all three curve-fitting techniques; b) variations in the length of time series, functional forms and number of curves led to inconsistent results more often than consistent results; and c) the degree of inconsistency in the URR estimates was frequently very large. While estimates were more likely to be consistent for regions at a later stage of their discovery and/or production cycle, inconsistent results were frequently obtained for mature regions as well.

Different functional forms were often found to fit the data equally well,[72] but to provide substantially different estimates of URR. This is illustrated in (Figure 4.9) which shows cumulative discovery projections for each region using both logistic and Gompertz functional forms. Taking Region E as an illustration, the difference between the R^2 for each model is

[71] The names of the regions are withheld due to data confidentiality.
[72] Goodness of fit was measured using simple R^2. However, we recognise that this is not the best measure to use when comparing 'non-nested' models, such as a logistic versus a Gompertz (Kennedy, 2003).

only 0.003 but the URR estimates differ by a third.[73] The results also show that simple curve fitting can lead to mean URR estimates that are less than the cumulative discoveries (e.g. Region J). The estimates only converge when regions are at a relatively late stage in their discovery cycle when the asymptote of the curve is clearly apparent (e.g. Region I). As a result, estimates made at earlier stages in the discovery cycle can lead to significantly different results (see Figure 4.10). Contrary to expectations, a logistic or Gompertz functional form was found to be more appropriate than an exponential in all the regions examined, but the choice can bias the results (e.g. the Gompertz model provides higher estimates in all cases).

[73] The mean difference in the URR estimates from the two models was 59% of the cumulative discoveries through to 2007 (ranging from 1% to 362%), but the mean difference in R^2 estimates was only 0.001.

Figure 4.9 Cumulative discovery projection results

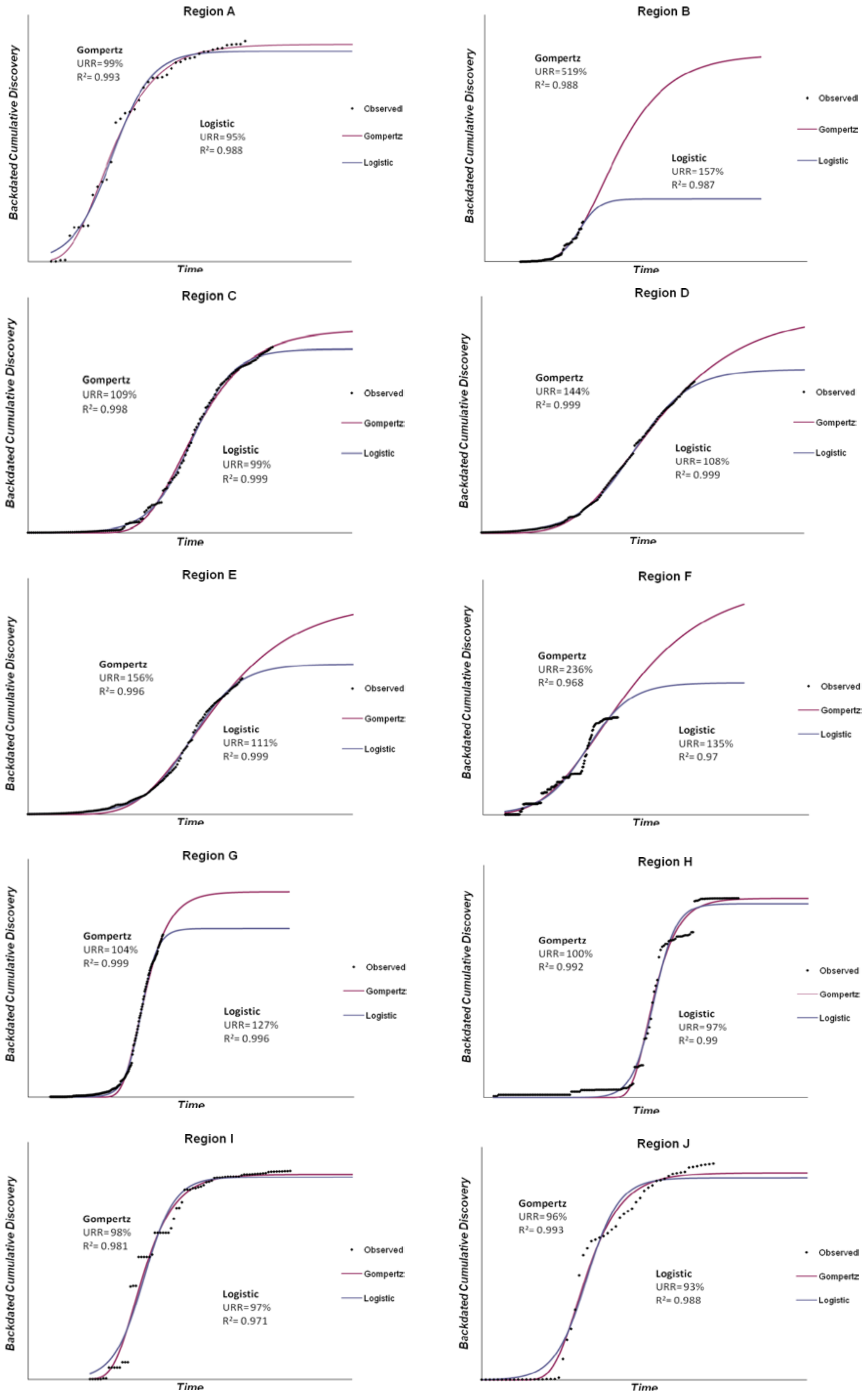
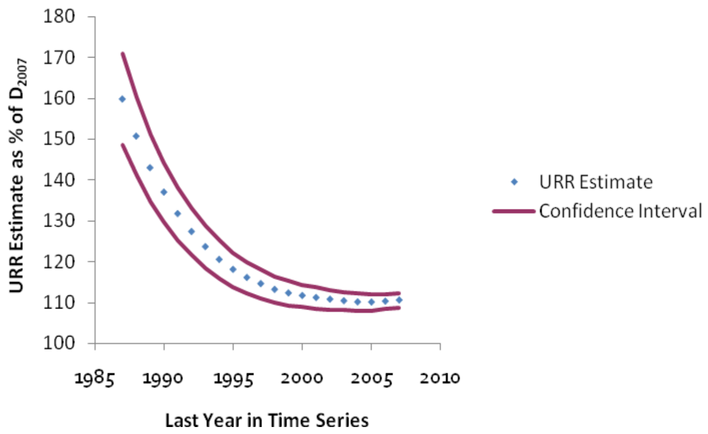
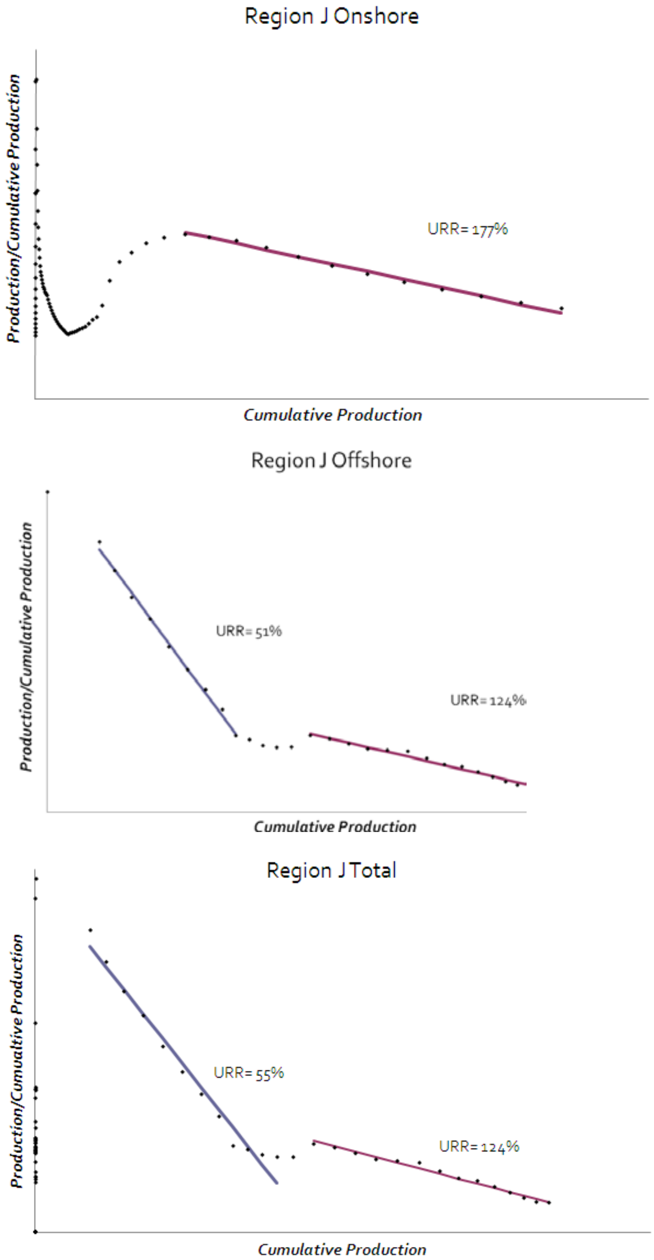


Figure 4.10 Cumulative discovery projection for Region E using logistic model – sensitivity to length of data series



The production decline ('Hubbert Linearisation') technique was found to be particularly unreliable and the results suggest a systematic tendency to underestimate the URR. As an illustration, Figure 4.11 shows the results for Region J. While the onshore data 'settles' into an approximate linear relationship that can be modelled by a single linear regression, the corresponding data for both offshore and the region as a whole exhibits 'trend breaks' that may result from additional cycles of exploration and production. If this technique had been used at an earlier stage of the production cycle (i.e. prior to the trend break) it would have led to a significant underestimate of the regional URR. Trend breaks of this form were observed for six of the ten regions using aggregate data and for all of the regions using either onshore or offshore data (or both). The frequency of such breaks gives little confidence that the decline curves will remain stable in the future.

Figure 4.11 Production decline curves for Region J



Our results also do not support the claim that creaming curves are generally more reliable than discovery projections. Notably, the creaming curves for four of the regions do not exhibit asymptotic behaviour, although in two of these cases the corresponding discovery projection was asymptopic. Once again, the results were sensitive to the particular functional form assumed (see Figure 4.12) and while three of the regions could be fit with either one or two creaming curves, the corresponding URR estimates were significantly different (see Figure 4.13). Without a detailed knowledge of the exploration history of a region, it is difficult to justify one choice over the other.

Figure 4.12 Creaming curves for Region A using exponential and hyperbolic functional forms

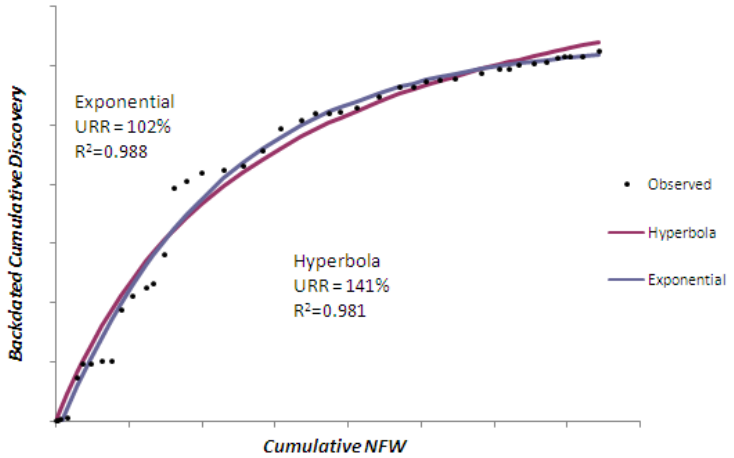
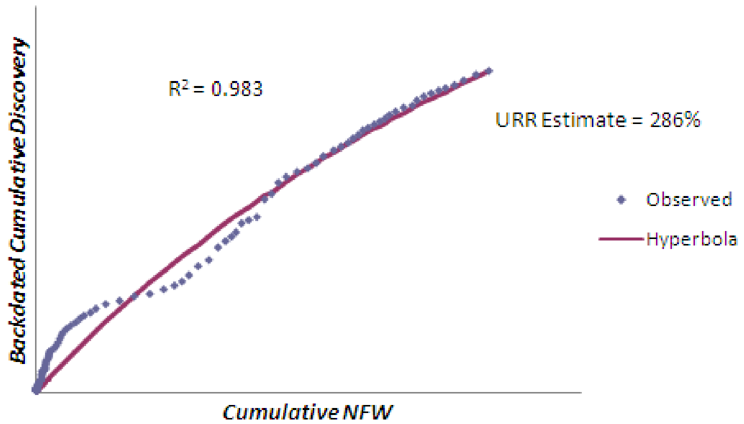
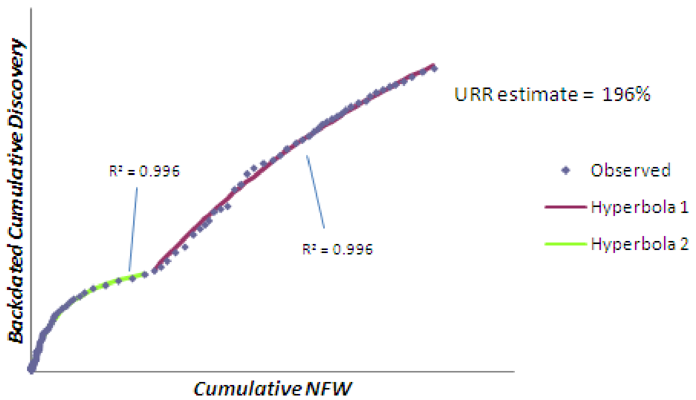


Figure 4.13: Creaming curve for Region E fitted with one (top) and two (bottom) hyperbola





The primary reason for these inconsistent results is that the techniques are being applied to large and geologically diverse regions that lack a consistent exploration history. In addition, we did not always distinguish between onshore and offshore regions, the data source did not classify exploratory holes as either oil or gas, and we did not correct the discovery data to allow for future reserve growth. Future applications of curve-fitting should therefore address each of these problems as far as the available data permits. Nevertheless, the results are sufficient to demonstrate the limitations of curve-fitting technique as currently used and suggest that the associated URR estimates should be treated with caution.

4.7 Reconciling curve-fitting with econometrics

Curve-fitting techniques assume that the ‘shape’ of the production or discovery cycle can be estimated from the historical data and that this shape will not be significantly affected by any future changes in prices, technology and other relevant variables. As a result, there has been a tendency to neglect these variables, despite the potential errors that may result. For example, low oil prices and political constraints may restrict production when resources are abundant, while high prices may stabilise or increase production when depletion is advanced. As a result, many applications of curve-fitting techniques are likely to suffer from missing variable bias and/or serial correlation of the error terms. This could lead to biased estimates of model parameters (including URR), underestimates of the associated standard errors and overestimates of the model goodness of fit. Several examples of this are provided in *Technical Report 5*.

These problems may potentially be addressed by including one or more ‘lags’ of the dependent variable within the model specification (e.g. making production in the current year a function of production in one or more previous years), but the re-specified model may not necessarily lend itself to the estimation of URR. A more promising approach is to include some of the economic and political determinants of discovery and/or production within the model specification. This effectively gives a ‘hybrid’ of a curve-fitting approaches to estimating URR and econometric approach to estimating future oil discoveries (Walls, 1992; 1994). The latter originated with Fisher (1964), who estimated equations for exploratory activity, success rate and the average size of discovered fields as a function of oil prices, past average discovery size and lagged dependent variables. Many variants have followed,[74] but these have mostly focused upon forecasting discoveries rather than estimating URR and are also likely to be biased since they ignore the geological determinants of discoveries and production (Power and Fuller, 1992b).

A good example of a hybrid model is Kaufmann (1991), who fits a logistic model to US cumulative production and then uses an econometric model to account for the deviations between predicted and actual production. This formulation assumes that geologic and physical factors cause oil production to rise and fall over the long-term, while economic and political variables (e.g. legal restrictions on production)[75] lead to short-term variations around this underlying trend. This model provides a much better fit to US production over the period 1947 to 1985, but estimates of the URR require assumptions about the future values of the relevant economic and political variables. Pesaran and Samiei (1995) argue that Kaufmann’s model is biased because the estimation of URR in the first stage does not take into account the effect of economic factors which only enter the analysis in the second stage. They avoid this by modifying the logistic model to allow for the dependence of URR on a number of economic and other variables and re-formulating it to eliminate problems of serial correlation. Their model explains over 98% of the variation in US production over the period 1948-1990 and leads to a higher estimate of the URR. However, the oil price elasticity of

[74] For example, Epple and Hansen (1981), MacAvoy and Pindyck (1973), Walls (1994) and Mohn and Osmundsen (2008).
[75] For example, between 1957 and 1968, the ‘prorationing’ decisions of the Texas Railroad Commission shut in more than 50% of Texan oil-producing capacity.

URR is both symmetric and independent of time (e.g. the same before and after the peak) which seems implausible.

In a significant innovation, Kaufmann and Cleveland (2001) include average US production costs as an explanatory variable and hence remove the need to assume a particular functional form for the production cycle. The empirically estimated U-shaped average cost curve mirrors the bell-shaped production curve and represents the net effect of resource depletion and technical change – with steeply rising costs after 1970 indicating accelerating depletion (Cleveland, 1991). This model accounts for most of the variation in US oil production between 1938 in 1991 and highlights the importance of economic and political variables in determining the ‘shape’ of the discovery or production cycle:[76]

> "….Hubbert was able to predict a peak in US production accurately because real oil prices, average real cost of production, and decisions by the TRC coevolved in a way that traced what appears to be a symmetric bell-shaped curve for production over time. A different evolutionary path for any of these variables could have produced a pattern of production that was significantly different from a bell shaped curve.....In effect, Hubbert got lucky." (Kaufmann and Cleveland, 2001)

But while this model overcomes a key weakness of curve-fitting techniques (i.e. the arbitrary choice of functional form), it may not be applicable for other regions owing to the lack of data on production costs. Moreover, if it is to be used to estimate the regional URR, some assumption is required about future trends in production costs. In addition, while Hubbert may have ‘got lucky’ in forecasting the date of peak production, it is much less clear whether accounting for economic variables will make a significant difference to the estimated URR.

If the required data is available, very similar approaches can be used to modify and improve any of the curve fitting techniques. For example, Cleveland and Kaufmann (1991; 1997) modify Hubbert's exponential model of YPE to account for short-term changes in oil prices and the rate of drilling. Their equation provides a much better fit to historical trends and shows how periods of relative stability or increases in YPE were associated with changes in the rates of drilling and/or oil prices. But again, depletion dominates in the long-term, implying that the revised model may not significantly change the estimates of URR (Kaufmann and Cleveland, 1991).

Some authors attempt to separate the effect of technical change from that of resource depletion (Iledare and Pulsipher, 1999; Power and Jewkes, 1992). For example, in their study of YPE in the Gulf of Mexico, Managi, *et al.* (2005) model depletion by cumulative discoveries and technical change by an index of the annual number of innovations adopted by the offshore industry, weighted by their relative importance (Managi, *et al.*, 2004; NPC, 1995). The results show that the pace of technical change has increased since 1975, greatly expanding the area of exploration and leading to a YPE in 2000 that is comparable to that achieved 50 years previously. While the geological diversity of the Gulf of Mexico contributes to this result, a more likely reason is that exploration has been geographically restricted in the past, owing to a combination of the technical difficulties of deep-water drilling and changing licensing regimes (Priest, 2007). As a result, fields have not been found in the approximate declining order of size that is normally assumed.

In sum, while hybrid models improve upon standard curve fitting, they may be more suitable for short-term supply forecasting than for estimating URR. The latter requires assumptions

[76] Cavello (2004; 2005a; b) reaches a very similar conclusion through a more qualitative argument.

about the future values of the relevant explanatory variables and despite their better fit to historical data it is not obvious that hybrid models lead to substantially different estimates of URR. However, they do allow the dependence of URR on energy prices and other factors to be directly explored.

Hybrid models may still lead to misleading conclusions if applied to regions that lack either geological homogeneity or a consistent exploration history and may still be vulnerable to missing variable bias since it is impractical to include more than a subset of the variables that could affect production and/or discovery trends (e.g. tax rules, leasing decisions, geographical restrictions on exploration, production/import/export quotas etc.) (Lynch, 2002). Also the required data is frequently either lacking or unreliable and is rarely available at the level of disaggregation required. Problems such as these may partly explain why there are so few ‘hybrid’ studies and why the available studies are largely confined to the United States.[77]

4.8 Summary

The main conclusions from this section are as follows:

- There are a variety of methods for estimating URR and many variations on the basic techniques. ‘Geological’ techniques are more appropriate for relatively unexplored regions while ‘extrapolation’ techniques are more appropriate where exploration is advanced. The confidence bounds on these estimates are commonly very large and the few studies that compare different techniques show that they can lead to quite different results.
- The extrapolation techniques differ in degree rather than kind and share many of the same strengths and weaknesses. But a key practical difference is that field-size distribution and discovery process techniques require data on individual fields, while simple curve-fitting only requires aggregate data. All assume a skewed field size distribution and diminishing returns to exploration, with the large fields being found relatively early. But these assumptions will only hold if depletion outweighs the effect of technical change and if the region is geologically homogeneous and has had a relatively unrestricted exploration history. This is frequently not the case.
- Many applications of curve-fitting take insufficient account of the weaknesses of this technique, including: the inadequate theoretical basis; the sensitivity of the estimates to the choice of functional form; the risk of overfitting multi-cycle models; the inability to anticipate future cycles of production or discovery; and the neglect of economic, political and other variables. In general, these weaknesses appear more likely to lead to underestimates of the URR and have probably contributed to excessively pessimistic forecasts of oil supply.
- Curve fitting to discovery data introduces additional complications such as the uncertainty in reserve estimates and the need to adjust estimates to allow for future reserve growth. The common failure to make such adjustments is likely to have further contributed to underestimates of resource size.
- Tests of curve fitting techniques using illustrative data from a number of regions have shown how different techniques, functional forms, length of time series and numbers of

[77] A notable exception is Dées, *et al.* (2007)

curves can lead to inconsistent results. But while this raises concerns about the reliability of such estimates, the degree of uncertainty may be expected to decline in the future as exploration matures.

- Some of the limitations of curve fitting may be overcome with the use of hybrid models that incorporate relevant economic and political variables. But despite their better fit to historical data, such models may not lead to substantially different estimates of the URR.
- These limitations do not mean that curve fitting should be abandoned, but do imply that its applicability is more limited and that the confidence bounds on the results are wider than is commonly assumed. Where possible, resource assessments should employ multiple techniques and sources of data and be informed by knowledge of the geological characteristics and exploration history of the region. They must also acknowledge the uncertainty in the results obtained.

5 Looking ahead - methods of forecasting future oil supply

This section describes and compares various approaches to forecasting future oil production. The relative merits of these approaches are fiercely debated and the results are often significantly different. A full examination of this topic is contained in *Technical Report 6*.

Section 5.1 outlines simple models of oil production, including reserve-to-production models and curve-fitting models. Section 5.2 describes simulation models, which represent the mechanisms of oil discovery and production with more complex functions. Section 5.3 discusses bottom-up models, which build aggregate projections using data-rich models of regional and field-level production. Section 5.4 describes models based upon optimal depletion theory, together with the econometric analysis of historical trends. Lastly, Section 5.5 concludes with synthesizing thoughts and critique.

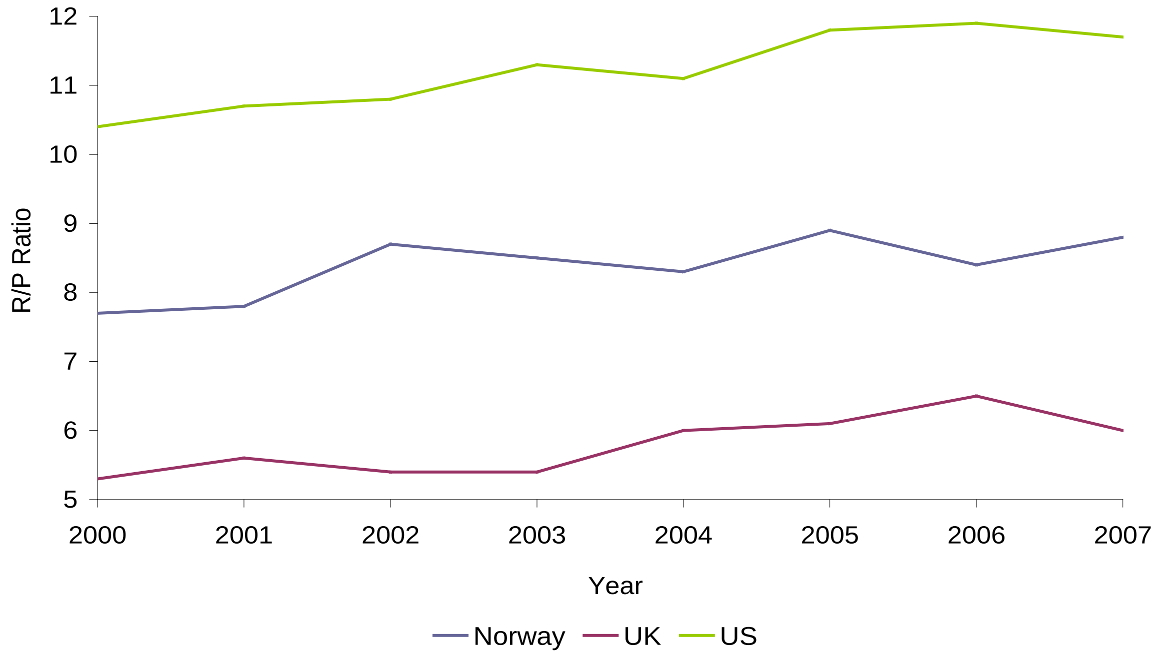
5.1 Simple models of oil depletion: reserve-to-production ratios and curve-fitting

The simplest models of future oil production are based upon reserve-to-production (R/P) ratios. With these models, the number of years until reserve exhaustion is calculated by dividing an estimate of remaining recoverable resources (typically 1P reserves) by current production. Although such ratios are widely quoted as a measure of confidence in future oil supply,[78] they provide little useful information about the future production profile since they imply that production can remain constant until the point of exhaustion and then collapse to zero. The limited usefulness of R/P ratios is indicated by the fact that they often remain constant or even increase during periods in which production in a region peaks and declines (Figure 5.1).

A more legitimate use of R/P ratios is that described in Section 3, namely the concept of depletion rates. These are simply the inverse of the R/P ratio (i.e. the P/R ratio), but most commonly defined using 2P reserves for an individual field or estimates of remaining recoverable resources for an oil-producing region (i.e. including the YTF).There are technical and economic limits to the rate of depletion from a field or region, implying lower limits on R/P ratios (Höök, 2009). Defined in this way, R/P ratios constrain the rate of production from a field or region rather than providing assurances about the longevity of future supply.

[78] For example, in 2008 Tony Hayward, the CEO of BP, commented that: "….Myth No. 2 is that the world is running out of hydrocarbons. Not so. The world has ample resources, with more than 40 years of proven oil reserves." The same figure is used by Wicks (2009) to support the argument that the level of remaining resources presents no risk to future global oil production. Both comments display little understanding of the mechanisms of oil peaking.

Figure 5.1 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.

Somewhat more complex and realistic are curve-fitting models of oil production, which have been used since the 1950s. A variety of models exist, but their general approach is as follows:

1. Define a mathematical function to statistically fit to historical production data.
2. Include constraints to improve the quality of model fit.
3. Fit the constrained model to historical data and use this to project future production.

These approaches are very similar to the production projection techniques for estimating URR, described in Section 4. In production projection, the curve-fitting is constrained only by the assumed functional form and the historical data, while in forecasting, the curve fitting is further constrained by assumed values for the URR and/or other parameters. In both cases, the models vary in the particular mathematical function that is assumed (including whether this is symmetrical or asymmetrical) and in the choice of single or multiple curves.

5.1.1 Curve-fitting models

In March 1956, Hubbert (1956) produced his, now well-known projection of future US oil production, utilizing a bell-shaped curve (Box 4.2). He forecast that US oil production would peak between 1965 and 1970 depending upon the value of the URR used to constrain the curve (150 and 200 Gb, respectively) (Hubbert, 1956). While some have argued that Hubbert's projection was unprecedented, others were studying oil depletion at the time. For example, Ayres (1953) forecast that the peak of oil production in the United States would occur in 1960 or 1970 depending on the level of ultimate recovery (100 or 200 Gb respectively), while the 1952 study *Resources for Freedom* predicted peaks in 1963 and 1967 in two scenarios (PMPC, 1952).

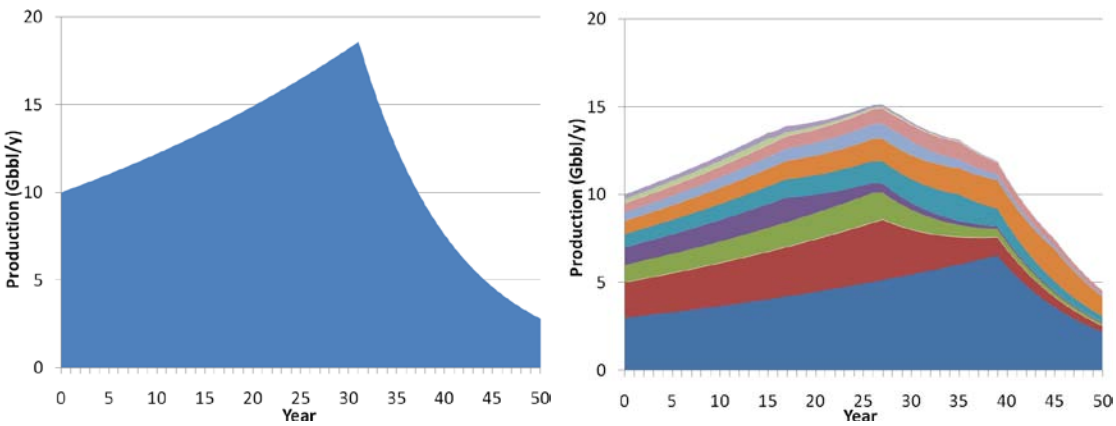
Despite encountering widespread opposition, Hubbert's forecast was subsequently shown to be accurate when United States production peaked in 1970. Hubbert subsequently developed comparable curve-fitting techniques to estimate the URR rather than rely upon exogenous assumptions. But while he used variants of the logistic model over the next 25 years, it was not until 1980 that he published a full derivation (Hubbert, 1982).

A variety of Hubbert-like curve-fitting models have since been developed which use Gaussian, exponential and other functions to forecast future production. These models share properties of the original Hubbert method while relaxing or altering some of its assumptions.

A notable projection of global oil production using an exponential functional form was made by analysts from the US Energy Information Administration (EIA) (Wood, *et al.*, 2000). This utilizes probabilistic estimates of remaining recoverable resources taken from the USGS (2000) within a globally-aggregated exponential depletion model and produces unrealistically sharp peaks and very rapid post-peak production declines. In another model, Hallock *et al.* (2004) use a modified exponential methodology that smoothes production near the peak, resulting in a rounded peak and less severe declines. While the EIA model indicates dates for the global peak from 2021 to 2112, Hallock *et al.* conclude that conventional oil will begin an irreversible decline before 2037.

It has long been observed that the production from individual fields often declines exponentially (Section 3.3) and there is some evidence for exponential decline within larger aggregated regions (Pickering, 2008). But a key problem with exponential models is the interaction between aggregation and decline rates (Cavallo, 2002). In the EIA model, production increases until the *global* ratio of remaining recoverable resources to production reaches the target value, after which production is forced to decline. This is very different from a model where each country, basin or field behaves individually according to the same rule (see Figure 5.2). Also, the EIA model assumes a depletion rate of 10% following the peak, which is justified on the basis of US experience. But this analogy is inappropriate since the latter relates to a ratio of proved reserves to annual production, while the numerator in the EIA model is the USGS (2000) estimate of remaining recoverable resources.

Figure 5.2 Difference between aggregate exponential decline (left) and disaggregate exponential decline (right)



Note: Decline rate is same in each case, but applied individually to a number of sub-regions in the right figure.

In contrast to models where production rises and falls in a single cycle, multi-cycle and multi-function models attempt to recreate the non-smooth production profiles observed empirically. Multi-cycle models have been developed by Laherrere (1999b) and Patzek (Patzek, 2008), who fit the sum of a number of independent logistic curves to production data. In theory, each additional cycle represents the production of a well-defined resource that can be differentiated from the main body of production. Mohr and Evans (2007; 2008) built multi-function models that exhibit disruptive changes from one function to another.

Multi-cycle models suffer because the better fit of a more complex model is not always justified by the additional model complexity. Another problem is that additional cycles are inherently unpredictable. They might be enabled by advances in exploration technology, such as drilling at greater depths, or by new production technologies such as CO_2 injection. Lynch (2003) argues that this technique "destroys the explanatory value of the bell curve" because "not knowing whether any given peak is the final one renders [predictions] useless". More charitably, it suggests that curve-fitting techniques need to be combined with geological and technical knowledge, in order to estimate the probability and magnitude of any future production cycles.

5.1.2 Difficulties with curve-fitting models

Using exogenous estimates[79] of URR to constrain curve-fitting models can be problematic because estimates of global and regional URR have often been too low. This is typically because the volume of YTF resources has been underestimated by the use of simple curve-fitting techniques and/or future reserve growth has either been ignored or underestimated through the use of inappropriate growth functions (Lynch, 1999; 2003; Nehring, 2006a; b; c).[80] Another more fundamental problem is that URR is frequently interpreted as a fixed constraint in curve-fitting models while in practice it is an endogenous variable that depends in part upon economic conditions (Adelman and Lynch, 1997). If oil suddenly became less

[79] Caithamer (2008) argues that there is not enough information in pre-peak production data to generate stable values of URR for use in projections. This situation improves the further into the production cycle a region becomes, as the possibilities for divergent futures become increasingly narrow.
[80] For example, Lynch (2003) notes that Campbell increased his value of global URR from 1,575 Gb in 1989 to 1,950 Gb in 2002.

valuable, the same physical endowment of resource deposits would result in a lower URR. Alternatively, if oil substitutes fail to materialize, future consumers would be willing to pay more for a unit of petroleum and URR will grow with no change in the physical properties of the resource. However, the amount of growth will ultimately be limited by the energy return on investment.

Researchers disagree about the seriousness of these difficulties. Some argue that we can accurately estimate the regional and global URR for conventional oil (provided backdated 2P cumulative discovery estimates are available) and that these estimates are unlikely to significantly change in the future (Bentley, *et al.*, 2007). Others argue that URR estimates will continue to grow and also that hydrocarbons will increasingly be produced from resources that are currently excluded from estimates of URR (McCabe, 1998; Mills, 2008).

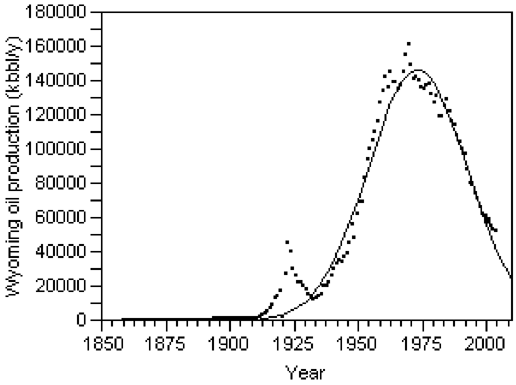
Most of the other difficulties in using curve-fitting to forecast production are analogous to those faced in using such techniques to estimate the URR (Section 4). For example, there is no robust theoretical basis for choosing a logistic or any other functional form and the results can be sensitive to the particular choice that is made. Rehrl and Freidrich (2006) develop a simple model that generates logistic *discovery* behaviour from the interaction of geological information and physical depletion, but it does not follow that *production* will necessarily follow a logistic path as well. In free market conditions under ample demand, it is reasonable to assume that oil discovered will be promptly brought into production, resulting in a fairly consistent lag between discovery and production. But in reality, economic and political constraints can greatly alter the timing of investment and production.

Other authors use the central limit theorem (CLT) to justify bell-shaped models, but there are difficulties in applying the CLT to oil production curves (Babusiaux, *et al.*, 2004; Brandt, 2007; McCabe, 1998). The CLT acts to generate a normal distribution when distributions that are independent of one another are summed or averaged. While regional or field-level production curves *are* summed, they are not independent. Production from oil fields is determined in part by the physical conditions in those fields and in part by the decisions of producers who face common stimuli such as global crude prices; local, regional, and global transport costs; and national politics. Given that there is some degree of independence between producers, some smoothing will occur with aggregation. But historical evidence suggests that this smoothing power is limited. The result is that while some regional production curves are well-approximated by bell-shaped profiles, a good number deviate from the bell shape. Some are significantly more pointed than the bell-curve (Brandt, 2007; Hirsch, 2005), while many others have multiple peaks (Hubbert, 1956; Laherrere, 2003; Patzek, 2008). Brandt (2007) compared symmetric and asymmetric versions of a bell-shaped model, a linear model and an exponential model to the data from 139 oil producing regions. To illustrate how excellent the fit to these disparate models can be, Figure 5.3 shows regional production curves that were each best fitted by one of the six tested models.

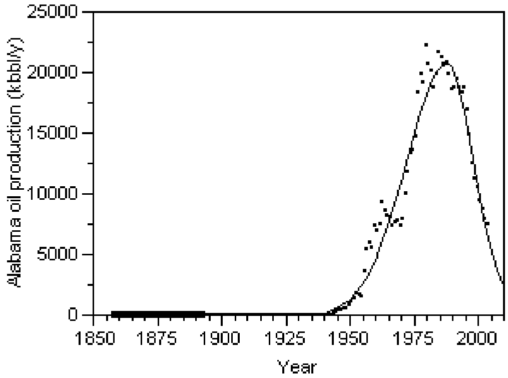
Lastly, the common assumption of a symmetric production cycle is only poorly supported by empirical observation. Using the USGS (2000) estimates of remaining recoverable resources, we analysed 55 post-peak countries and found an average level of depletion of only 25% at the start of decline (Section 3). In other words, most countries appear to have reached their peak well before half of their recoverable resources have been produced. This suggests an asymmetric production profile, but relies upon estimates of the regional URR which are inherently uncertain. Since URR estimates are likely to increase over time, estimates of the level of depletion at peak are likely to fall.

Brandt (2007) fitted an exponential model to 67 out of 74 post-peak regions and found that the median rate of decline (2.6%) was approximately 5% less than the median rate of increase (7.8%). This analysis suggests that production profiles tend to be slightly asymmetric, with slower rates of decline than rates of increase – as may be expected from the stylised model presented in Section 1. Since the mean rate of decline (4.1%) was significantly less than the production-weighted mean (1.9%), Brandt's results also suggest that decline is slower in larger regions. However, changing economic conditions may mean that regions that have yet to reach their peak may not follow the same production pattern.

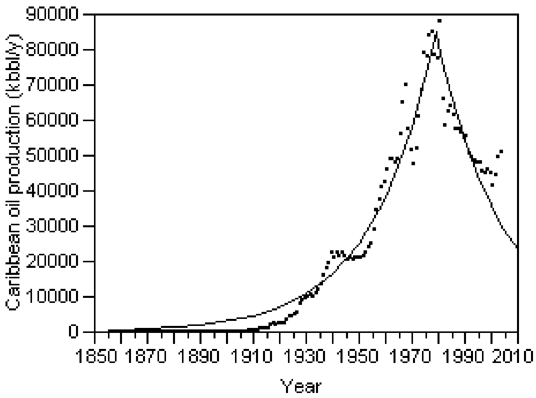
Figure 5.3 Six model types applied to regions where they were found to be the best fitting model (Brandt, 2007)



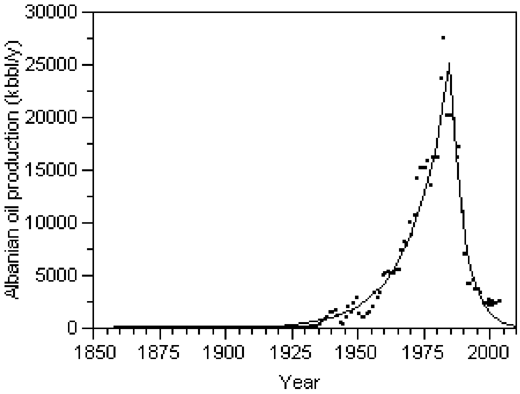
A. Gaussian



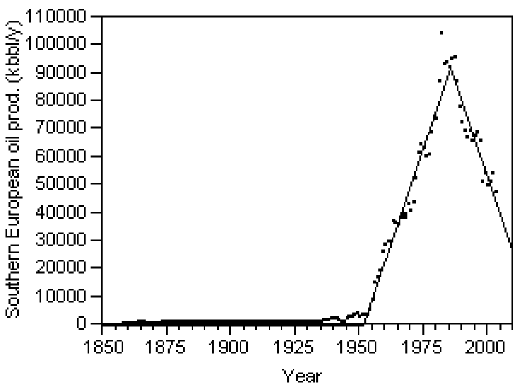
B. Asymmetric Gaussian



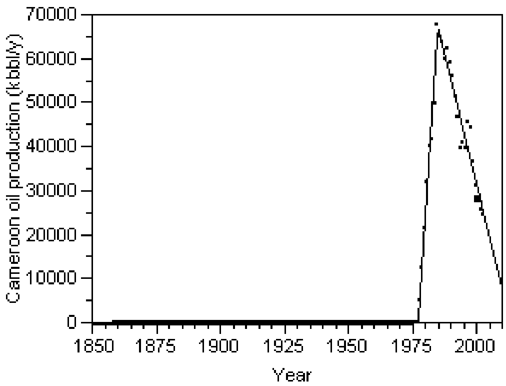
C. Exponential



D. Asymmetric Exponential



E. Linear



F. Asymmetric Linear

5.2 Systems simulation: resources, discovery rates, and technologies

Simulation models explicitly represent the underlying physical and/or economic mechanisms that govern oil discovery and extraction, thereby letting the shape of the production cycle emerge from these mechanisms rather than specifying the functional form beforehand. This approach remedies a key problem of curve-fitting models, namely that "…no cause-and-effect relationship exists between time and the exploitation of crude oil" (Taylor, 1998).

The simplest simulation models are scarcely more complex than simple curve-fitting. For example, Bardi (2005) built a model based on the work of Reynolds (1999) in which the resource finding and extraction process involves agents searching for resources over a number of model years.[81] Probabilities govern resource discovery based on the level of cumulative discoveries and a technological function that improves finding capabilities over time.

Davis (1958) produced the earliest complex simulation of oil discovery and development. He projected future reserve additions based on exploratory effort, and assumed a fixed annual depletion rate of the reserves. Thus, instead of the function being constrained by an exogenous and fixed estimate of URR, it is fully incorporated into an economic model of discovery and production. Because reserves are discovered over time with a constrained production path, the sharp peaks of exponential models do not occur. Davis' model predicted a peak and decline in US oil production between 1964 and 1973.

Later models used methods of *system dynamics*, which focuses on the importance of rates of change and feedbacks between the many parts of the oil extraction system (an early example is Naill, 1973b). In the more sophisticated models, undiscovered oil is not a static quantity, but is the product of the estimated resource base and a parameter called *fraction discoverable* (Davidsen, *et al.*, 1990; Sterman, *et al.*, 1988). The fraction discoverable increases as oil companies invest revenues in exploration technologies.

Other models attempt to simulate the substitutes for conventional oil that will be used after a peak in oil production (Basile and Papin, 1981; Edmonds and Reilly, 1983). For example Greene *et al*. (2006) project demand for liquid fuels using a recursive demand function, allowing simultaneous solution of all years of the model, and resulting in a smooth transition to substitute fuels. Production cost is modelled with a logistic function which causes an increase in production cost as a resource becomes depleted.[82]

5.2.1 Difficulties with simulation models

Simulation models require the quantification of a large number of relationships and correlations, often in the face of conflicting or nonexistent data. Consider, for example, the 'fraction discoverable' parameter of the Davidsen *et al.* (1990) model. This represents the fraction of oil deposits that are theoretically discoverable at any time, defined as a function of

[81] In Reynolds' model, the agents are shipwrecked islanders and the resource is defined as tins of provisions washed ashore and buried at different depths in the sand.
[82] The logistic model is consistent with Cleveland's (1991) empirical estimates of US production costs

cumulative investment in exploration technology. Such a relationship would ideally be empirically derived, but this is likely to be impossible.

Also, simulation models can be unstable and finely balanced between positive and negative feedbacks. If positive feedbacks in the model are too strong, the result can be rapid growth and sudden, very rapid decline. This effect is evident in Naill's (1973a) results, and is common in system dynamics models of resource depletion.[83] The more gentle declines observed in real-world production data are due to mitigating factors (e.g. negative feedbacks) that exist in the real world but are absent from such models. This lack of inertia and negative feedbacks has also caused simulation models to overestimate the ease of a transition to substitute fuels (as seen in both Sterman *et al.* (1988) and Basile and Papin (1981)). Finally, simulation models generally lack empirical validation, in that simulated production is rarely compared with the historical record in a statistically meaningful fashion.

5.3 Bottom-up models: building up oil depletion from lower levels

Bottom-up models use detailed modelling of project, field or regional production to 'build up' projections of production from larger regions (such as a nation or the world). Bottom-up modelling has become an increasingly prominent method but relies upon detailed and often confidential data sources such as that provided by IHS Energy (Bentley and Boyle, 2008).

The most widely published regional bottom-up model is that of Campbell and co-authors, produced since the mid-1990s (Campbell, 1995; 1996; 2004; Campbell and Heapes, 2008). This model was originally produced using a proprietary database from Petroconsultants SA that was subsequently purchased by IHS Energy (Bentley and Boyle, 2008). Campbell uses a number of curve-fitting techniques to estimate the URR of individual producing countries and subtracts cumulative production to determine whether a country has produced more than 50% of its URR. If so, production is assumed to continue at the current depletion rate, defined as the fraction of the remaining recoverable reserves produced each year. Most of the remaining countries are assumed to produce at a fixed growth rate until the mid-point is reached, while five Middle East producers are assumed to keep production constant until their depletion rate rises to ~3%, - following which they decline. While this approach is simplistic, it does have some empirical support (Jakobsson, *et al.*, 2009). However, Campbell's predicted date of peak production has shifted steadily forward over time: in the 1995 version, the peak is projected before the year 2000, while more recent versions predict peak production after 2010 (Campbell and Heapes, 2008). This tendency suggests a generic weakness in this approach.

More robust results could potentially be obtained from field-level rather than regional models. For example, Smith (2008) maintains a model based on field-level data where this is available, and otherwise on a variety of data sources aggregated at the operator, basin, or country level (Box 7.1). Production at existing fields is projected using historical field decline rates, including allowance for expected EOR projects. For undeveloped fields, production is based upon announced plateau levels or the capacity of facilities modified where appropriate by the announced URR of the field which is assumed to incorporate future reserve growth. Thus, a simple 'mid-point peak' assumption is not used. Very similar approaches are adopted

[83] The classic example of "overshoot and collapse" is the World3 model (Meadows, *et al.*, 2004). Other resource depletion models built in this framework suffer from similar problems, such as the general natural resource utilization model of Behrens (1973).

by Miller (2005) and PFC Energy using globally comprehensive databases of individual fields.

A third approach is represented by Skrebowski (2004; 2005; 2006; 2007), who maintains a database of oil field development projects above a threshold size ('megaprojects'). Because large projects have long lead times and provide the majority of new oil output, this approach provides considerable insight into the likely short-term increases in capacity. These are offset against demand forecasts and assumptions about the rate of production decline from existing fields. Skrebowski's approach removes some uncertainty in the 3-5 year period of capacity addition, but is much less suitable for medium to long-term forecasts. A more detailed discussion of these and other bottom-up models is given in *Technical Report 7*.

5.3.1 Difficulties with bottom-up models

Campbell's bottom-up model has a number of important limitations, including a narrow definition of conventional oil; the tendency of curve-fitting techniques to underestimate the URR (Section 4); the statistical weakness of the particular techniques used;[84] and the simple mid-point peaking assumption. As a result, Campbell's supply forecasts have consistently proved to be pessimistic. In contrast, the field-level models seem to hold considerable promise for accurate short- to medium-term projections of future production. By accounting for decline and investment at individual fields, these models remove uncertainty about the proper functional form for the aggregate production cycle. Instead, this emerges directly from the summing of individual field-level production projections which can generally be modelled with greater confidence, provided access is available to the relevant data.

Unfortunately, all uncertainty about the future is not removed by modelling at the field level. In fact, the proliferation of data that gives these models their strength also results in the need for many more assumptions. For example, what is the appropriate decline rate for each modelled field? Also, it is difficult to anticipate and model the effect of projects that could lessen the decline rate at existing fields, such as infill drilling, workovers and EOR projects. This 'stealth oil' is difficult to capture because it is a distributed response across tens of thousands of oil fields to technical change and higher oil prices. If, as seems likely, the potential for such projects is underestimated, the resulting supply forecasts are likely to be too pessimistic.

The literature describing these models is not always of high quality. Most articles are not peer reviewed, partly because they rely on proprietary databases augmented with the modeller's judgment and experience. This makes the models susceptible to criticism and renders them difficult or impossible to reproduce (Lynch, 2003).

5.4 Economic models of oil depletion

Economists understand natural resources and depletion differently from geologists or reservoir engineers. Rather than focusing on physical aspects such as decline rates and field-size distributions, economists focus on investment, optimal extraction paths and the effects of

[84] As an illustration, Campbell and Heapes (2008) use 'Hubbert Linearisation' to estimate the URR for Libya. But the extrapolation does not follow the actual data points in any obvious way and the first derivative of the logistic curve bears no relation to the actual production data. Similar problems are apparent in many of the regions examined and the report provides no data on functional forms, confidence intervals or goodness of fit.

oil prices. We first describe optimal depletion theory (ODT)[85] and then describe some econometric models of oil depletion.[86]

5.4.1 Optimal depletion theory

The primary concern of exhaustible resource economics is resource allocation over time. That is, *should we consume resources now or consume them later*? Hotelling (1931) formalized the key insight underlying optimal depletion theory (ODT), namely: rational resource producers should equate the future value of a unit of resource in the ground with the value they would receive if the resource was extracted and the profits invested. This suggests that the value of a unit of resource in the ground, less marginal extraction costs, should rise at the rate of interest.

The simplest ODT models focus on optimal production of a single resource with production costs that do not vary with depletion. The optimal production path typically starts at its highest point and declines over time due to the declining present value of production in future years. Such a path obviously does not reproduce historically observed behaviour (Krautkraemer, 1998), but ODT models have been extended in a variety of ways (Box 5.1). Holland (2008) illustrates that extended ODT models can in some circumstances result in production paths with peaks. He argues that at least four ODT model features can cause peaking behavior:

1. Demand increases over time, inducing producers to delay extraction to later time periods even given the disincentive resulting from discounting of future profits.
2. Technological change results in decreases in production cost that temporarily outweigh the disincentive due to discounting (e.g., Slade, 1982).
3. Exploration for new deposits occurs (e.g., Pindyck, 1978).
4. Production moves to new sites or new resource types over time.

Given that all four of these causal features exist in the oil industry, this development arguably bridges a gap between what ODT suggests is economically optimal and what has occurred in reality.

Box 5.1 Extensions of optimal depletion theory

Optimal depletion models have been extended as follows:

- Depletion increases the marginal cost of production, causing the value of the resource to increase at less than the rate of interest (Fisher, 1979).
- Production cost varies with time, as due to technological change (Slade, 1982). If cost declines with time, this model results in price paths that are “U-shaped” and production profiles with peaks. This occurs because technological change brings down production costs rapidly in the early years of an industry, after which depletion causes cost increases. Cleveland (1991) provides empirical evidence for this in the case of the US.
- Producers explore for and deplete a number of deposits of uncertain size (see the model of Pindyck (1978) and successors). The resulting oil price path can be U-shaped, and if the initial reserves are small (as in the oil industry), extraction first increases and then decreases after a peak.
- Depletion can be modeled as a transition to substitute fuels such as oil sands. In economic jargon, these substitutes are called “backstop” resources. (Nordhaus, 1973).

[85] See Krautkraemer (1998) for a comprehensive review of the ODT literature.
[86] Kaufman (1983) and Walls (1992) provide useful, if less recent, reviews of the econometric literature.

5.4.2 Econometric models of oil depletion

Econometric models are data-rich statistical models that project supply and demand primarily from economic variables such as price and extraction cost (Kaufman, 1983; Pindyk and Rubinfeld, 1998). The relationships between these variables are estimated empirically through regression analysis of historical trends in oil discovery and production.

Econometric models of oil and gas supply were first developed by Fisher (1964) and numerous variants have since followed.[87] A key weakness of earlier models was that they did not include information about the geological nature of oil resources, such as the field size distribution. In addition, the performance of these models was often poor: some parameters had unexpected magnitudes and signs (Erickson and Spann, 1971; Walls, 1992), and the results were often not robust when revaluated (Dahl and Duggan, 1998; Kaufman, 1983).

Later came more sophisticated 'hybrid' models which combined economic variables with geological, physical, or regulatory ones. These models vary in the extent to which they represent economic and non-economic factors. Their application to estimating URR was described earlier in Section 4.[88]

Some hybrid models are structured as comparatively minor modifications of traditional econometric models (e.g., Moroney and Berg, 1999), while others augment curve-fitting models with a limited number of economic variables. The first such attempts were by Uri (1982), who modified Hubbert's logistic model to make URR a function of oil prices and technological change, thereby addressing the economic critique that URR is not static. Kaufmann (1991) augmented the logistic model in a different way, by using economic and political factors to model the deviations between predicted and actual US production. Pesaran and Samiei (1995) improved upon both by making the URR parameter in the logistic model a function of the same economic and political variables as used by Kaufmann and re-specifying this model to eliminate problems of serial correlation.

While all of these approaches accurately reproduce historical production trends, they continue to assume a particular functional form for the production cycle. The more recent model by Kaufmann and Cleveland (2001) improves upon this by including the average real cost of production from Cleveland's (1991) long-term historical analysis as one of the input variables. The inclusion of average production costs (which rose sharply before the peak in production in 1970) removes the need to assume a logistic or other functional form for the production cycle and provides an excellent fit to historical data. As noted earlier, Kaufmann and Cleveland use this model to argue that "Hubbert got lucky" in his prediction of the 1970 peak, because a different path of oil prices or production restrictions would have altered both the shape of the production cycle and the date of the peak - although the likely size of the difference remains unclear. Moreover, to use the Kaufmann and Cleveland model as a basis for forecasting requires assumptions about the future evolution of production costs which introduce uncertainties of its own.

5.4.3 Difficulties with economic models

Optimal depletion models are intentionally simple so as to permit their being solved analytically. A result of this simplicity is that these models lack empirical grounding. Another

[87] See the reviews of Kaufman (1983), Dahl (1998) and Walls (1989) for more information on Fisher-type models.
[88] Walls (1994) and Dahl (1998) survey these models in detail.

fundamental difficulty of ODT is the assumption that resource producers are knowledgeable about the extent and nature of resource deposits. This assumption is implicit in the fact that ODT requires resource producers to optimise net present value over all model years (Howarth and Norgaard, 1990). In contrast, Reynolds' (1999) model of uncertain exploration suggests that the oil price can increase very rapidly after the peak in production, as depletion can 'sneak up' on the oil market because of incomplete knowledge of resource availability. This seems a more accurate representation of real-world behaviour and has some important policy implications (Kaufmann and Shiers, 2008).

Econometric models have a much firmer empirical grounding than ODT and can provide impressive agreement with the historical data. However, these models have their own shortcomings. Kaufman (1983) argues that they "have not done well" at predicting production more than few years in advance, most likely because "the functional forms employed in most econometric models do not conform closely to the physical character of exploration, discovery and production." Lynch (2002), on the other hand, calls their long-term forecasting performance "abysmally bad", in part because technological change is often not included to compensate for depletion. While some models have attempted to incorporate technical change, it is difficult to find adequate measures for the complex process of technological diffusion (Managi*, et al.*, 2004).

The fidelity of even the best econometric models is generally fragile and predictions made with these models typically fare poorly only a few years beyond the fitted data. This is because even the most complex econometric model can be swamped by a large number of omitted variables for which data is generally unavailable. The values of these omitted variables will change in future years, stymieing predictions based on parameters estimated from historical data (Lynch, 2002). While modern cointegration techniques can mitigate this problem to some extent, future changes in omitted variables can still undermine the accuracy of forecasts.

5.5 Synthesizing thoughts on depletion models

5.5.1 Model classification and trends across model types

The models reviewed above vary widely in a number of ways. We classify these models, across four dimensions in which the models vary, namely:

- Intellectual orientation and type of reasoning applied (e.g. physical or economic);
- Scale of model (e.g. field-level or global);
- Model formulation (e.g. theoretical or mechanistic);[89] and
- Overall model complexity.

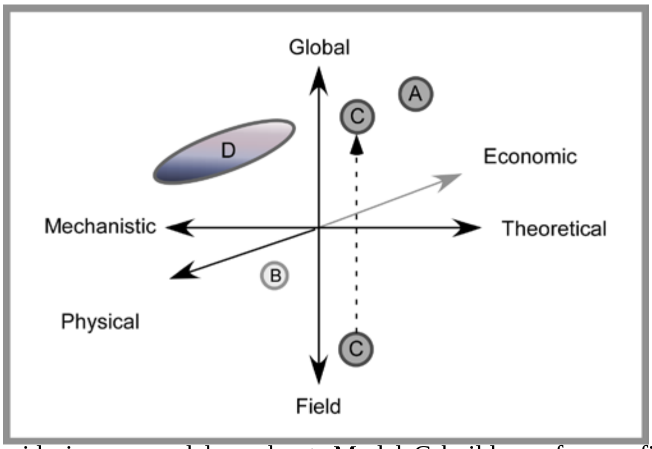
Technical Report 6 includes a comparison of over 40 models along these dimensions, while Figure 5.4 plots three of these dimensions along with example models.

[89] Theoretical models rely on general, simple functions relating oil production to a small number of input parameters, generally with time as the key independent variable. In contrast, mechanistic models have functions representing detailed economic, technological, or physical aspects of the oil production process.

The models discussed above occupy nearly all quadrants of the space shown in Figure 5.4. For example, curve fitting models tend to cluster on the right side of this figure, while simulation and econometric models tend to fall on the left side. Also, models do not necessarily fit clearly in one classification along a given dimension. For example, a number of models exist that combine economic and physical reasoning.

Turning to the examples in Figure 5.4, Model A is a global, theoretical model that is based on physical aspects of oil production, such as Hubbert's global logistic model. In the opposite quadrant, Model B is an economic and mechanistic model that operates at a regional scale, such as Fisher's sub-national econometric model of oil and gas exploration. Model C, on the other hand, 'builds' from one quadrant to another. An example is Smith's bottom-up model, which uses field-level data to build up a global projection of oil availability. Alternatively, Model D includes both economic and physical characteristics simultaneously in a mechanistic framework. An example of this might be the simulation model of Greene *et al* (2006).

Figure 5.4 Different model types classified in three dimensions



Note: Models A and B reside in one model quadrant. Model C builds up from a field-level basis to project global production. Model D straddles economic and physical portions of the diagram.

Although not plotted in Figure 5.4, models also vary significantly in their complexity: R/P models are the simplest, while simulation models and some econometric models require numerous data inputs and project the production of multiple fuels. The full review and classification in *Technical Report 6* shows a general tendency for models to become more complex over time and to incorporate both physical and economic characteristics - as in example Model D.

Another important trend is that a number of models with divergent intellectual underpinnings have produced peaked production profiles without explicitly forcing the production cycle to fit a particular functional form. That is, these models generate a rise and fall in production over time from other, more fundamental physical and economic assumptions. Specifically:

1. System dynamics of resource extraction and depletion show rounded peaks (Naill, 1973b; Sterman, *et al.*, 1988).
2. Oil transition simulations under perfect foresight show non-bell-shaped peaks (Basile and Papin, 1981; Greene, *et al.*, 2006).
3. Probabilistic finding models show peaking behavior resulting from the declining probability of new discoveries (Bardi, 2005; Reynolds, 1999).

4. Extended economic optimal depletion models show optimal production cycles with rounded peaks (Holland, 2008).

5.5.2 Model fit as an indicator of predictive ability

It is often assumed that models which fit historical data more closely will better predict future production. Unfortunately, the fit of a model cannot be judged entirely with standard statistical measures such as R^2 because this will nearly always increase when a model is made more complex by adding additional parameters (NIST/SEMATECH, 2008). For example, a multi-cycle logistic model will always fit better than a single cycle model because each cycle adds more flexibility to the model, allowing it to fit the data points better. For these reasons, statistical measures used to compare models must take into account the complexity of each model, such as *Adjusted* R^2, which accounts for the number of parameters in the model, or *Akaike's Information Criterion* (AIC), which allows for the comparison of model fit across divergent models (Motulsky and Christopoulos, 2004). Although well established, these measures are not widely used in the oil depletion literature.

Some additional characteristics of good model fits include:

- *A priori* scientific justification for using a model, because models are most useful when they can *explain* what they are modelling in terms of scientific theory or experience. (Burnham and Anderson 2002).
- Small residuals (i.e. the difference between the model and the data points being fit), subject to physically sensible constraints on the free parameters. Curve-fitting procedures minimize a measure of the overall divergence between model and data, such as the sum of squared residuals.
- Residuals that are normally distributed, with a consistent standard-deviation over time and with few consecutive runs of positive or negative values (i.e. no 'serial correlation'). Formal tests exist to determine whether a fit has each of these characteristics.

Given the complexities involved, it is not surprising that empirical analyses of model fit were not performed during the initial controversy surrounding Hubbert's work.[90] One of the first comprehensive analyses was by Wiorkowski (1981a), who compared a flexible function to the cumulative Weibull function for use in estimating the URR. He found that production data could not, on their own, suggest a superior general model for projecting resource availability.

Brandt (2007) compared the fit of six simple (3 and 4 parameter) curve-fitting models to 139 oil production curves at a variety of scales (US states and regions, countries and multi-country regions). He used AIC to compare symmetric and asymmetric versions of a Gaussian bell-shaped model, a linear model and an exponential model. The Gaussian (bell-shaped) model was found to be the most useful of the symmetric models, but was not generally applicable to all regions.

As far as we are aware, there are no empirical comparisons between broad model types (e.g. curve-fitting vs. econometric) in the published literature.

[90] Kaufman (1983) notes that in the 1950s and 1960s "[no] comparison [was] made, based on accepted statistical principles, of the relative qualities of fit to the data or of the predictive accuracies of possible alternative models."

5.5.3 The problem of prediction

Existing models have been very poor at forecasting global oil production, and many predictions of a global peak have come and gone without confirmation (although forecasts of a distant peak may eventually prove to be equally wrong). Such poor outcomes result not so much from the problems of oil supply models, but from the fact that forecasting is much more difficult than fitting functions to historical data. Even after the fact, the clear interpretation of the success or failure of a predictive effort is not easy (see Box 5.2).

Box 5.2 The case of Hubbert's prediction of a peak in US oil production

- Hubbert's prediction of a peak in US production in 1970 was based on his high value of URR which he considered to be less likely.
- Although Hubbert's analysis is the most well-known, no fewer than 7 estimates from the 1950s predicted a peak in US production within 10 years surrounding the actual peak (see Table).
- There are two possible interpretations of this fact: one could argue that this proves that Hubbert's method was not extraordinary, as other authors using other methods came as close to predicting the peak date. Or, one could emphasize that a variety of methods produced projections clustered in a band around the actual peak date.
- The more favorable interpretation implies that the future of US oil production could be generally outlined some 10-15 years beforehand using quantitative methods. Such an interpretation is controversial because curve-fitting models contain little causal or mechanistic detail, and are therefore unappealing from a scientific perspective.
- An important fact is that all of these studies underestimated the URR for conventional oil. Cumulative US production has already exceeded 200 Gb and significant reserves still remain. Thus, production has not dropped as quickly as Hubbert (or the other authors above) thought that it would (Jackson 2006), and the US curve is somewhat asymmetric.
- The level of exploration, accessibility to reserves, and governance factors are much more heterogenous on the global scale than they were in the United States in the 1950s. These differences make drawing conclusions about the predictive ability of models from Hubbert's 1956 prediction difficult at best.

Predictions of peak US oil production of the 1950s.

Author	Year of estimate	Early peak date	Late peak date	URR (Gb)
PMPC	1952	1963	1967[a]	NA
Ayres	1952	1962	1964[b]	100
Ayres	1953	1960	1968-1970	100 / 200
Hubbert	1956	1965	1970[c]	150 / 200
Ion	1956	1965	1975[d]	NA
Pogue	1956	1970	1972[b]	165
Davis	1958	1964	1973	NA

a – p. 103.
b – These dates come from a single prediction, but it is difficult to determine the precise year of peak production from the figure.
c – In the article text, Hubbert states, "about 1965" and "about 1970", so we use these dates. It is difficult to determine precise peak years from the figure.
d – Table on p. 83 shows production in 1955, 1965, and 1975. Total production is equal in 1965 and 1975, implying that the overall peak is between these years.

One important fact is that the feasibility of prediction varies with the type of prediction desired: if one wishes to predict basin-level production of multiple hydrocarbon products in the year 2050, no model can provide a useful answer. But if one wishes only to predict the order of magnitude of global crude oil production next year (e.g. will it be approximately 1

Gb, 10 Gb, or 100 Gb?), or only the century of peak oil production, then no mathematical model is needed.

We require predictive models in intermediate cases where the answers are neither hopeless nor obvious. Our judgment with respect to the predictive value of the reviewed models is as follows (noting that these topics are the source of much current debate):

1. Simple curve-fitting models can provide a rough understanding of future production, *assuming a given level of URR* and *no significant shocks to the system*. This understanding is likely to be sufficient to predict the decade of peak production for an estimate of URR, given these caveats.
2. More-detailed mechanistic models (e.g. bottom-up, econometric), exhibit greater fidelity in reproducing historical data and are therefore likely to be more useful for near-term predictions. But this advantage wanes for long-term forecasts because they are over-specified and ‘brittle’ with respect to uncertainties.
3. There is no justification for making precise and detailed predictions (e.g. the exact year of peak production) with any of the surveyed mathematical models. The many uncertainties involved make such predictions of limited value unless the uncertainties, sensitivities and confidence intervals are clearly expressed.

Note that there are numerous caveats regarding the first point: decadal accuracy using a bell-shaped model for a well-defined resource type is reasonable under restrictive assumptions. These assumptions include that demand growth and production are unhindered by political interference or economic disruption. Also, they are contingent on the estimate of URR, which is itself subject to considerable uncertainty (Section 4). But consumption is so high during the years of peak production that minor variations in the estimated URR, or minor hiccups or delays due to political or economic factors are unlikely to significantly affect the forecast date of peak (Bartlett, 1978). However, major disruptions (e.g. the oil crises of the 1974 and 1979), or major errors in the estimated URR (e.g. many hundreds of Gb at the global level) could cause greater than decadal errors in the forecast date of peak production.

Complex mechanistic models (e.g. econometric models) have clear advantages in reproducing short-term fluctuations in historical oil production because they have more degrees of freedom to allow the fitting algorithm to more closely match predictions to data. Unfortunately, it is not clear that these advantages hold for long-run forecasts.

Uncertainty necessarily increases as the time scale of the forecast increases, thus increasing a model’s reliance on assumptions. In a simple model, these assumptions are visible and open to ready critique. The more complex the model is, the more these proliferating assumptions counteract the benefit of the model’s increased detail. If a model requires hundreds of long-term assumptions about future discoveries or field-level recovery rates, prudence and parsimony suggest that a simpler model may be more appropriate.

5.5.4 Complexity and the purpose of modelling

Once a model surpasses a relatively low level of complexity, there is a tendency to add additional features to address its shortcomings. This approach cannot be relied on to produce more accurate forecasts (Smil, 2003). This is because many aspects of the real world must, by necessity, be left out of any model, and what is included in a model must necessarily be greatly simplified.

Out-of-model effects – features of the world that are not included in the equations – are technically infinite in number. Though most such effects will be unimportant, enough will exist in any model to cause significant deviations between model forecasts and observed behaviour. These include technical features of discovery and production, together with 'human factors', such as political disruption, war and conflict, changes in institutional structure or regulation, or demand discontinuities. Many such effects are smoothed by the actions of the market, but significant deviations have occurred often in the past and are certain to happen again.

The second fundamental problem with complexity as a modelling strategy is that as functions are added, model formulation and data limitations often require them to be in a highly simplified form. For example, Krautkraemer (2003) notes that econometric models "have not coped well with what appear to be basic nonlinearities in the relationship between unit supply cost and reserves." Econometricians typically assume log-linear or linear relationships to allow tractable models to be built, but these only approximate real world behaviour. An example of poor data availability is given by Greene, *et al.* (2006): the rate of increase of extraction costs as a function of depletion is equal for all regions and fuels. This is unlikely to be an accurate assumption, but the data on which to base a better assumption is unavailable.

Increasing model specificity and complexity is an activity subject to rapidly diminishing returns. It generally does little to improve the reliability of forecasts, and can have significant detrimental impacts on the understanding and insights gained.

5.5.5 Moving forward: improving oil depletion modelling

A key opportunity to improve oil supply modelling exists in better integration of physical and economic modelling techniques. The need for this integration arises from asking the question: *what resources will be used to meet liquid fuel demand after the peak in conventional oil production ?*

Many models leave this question aside entirely. This focus on conventional oil (regardless of how 'conventional' is defined) neglects the fact that we already produce oil from a wide range of deposits using a variety of technologies. That this is already occurring is emphasized by economists, who argue that a peak in conventional production will result in significant oil price increases, which will induce investment in a variety of alternative resources. We do not live in a depletion-or-substitution world, but a depletion-*and*-substitution world.

Non-conventional liquids are already produced in quantities in excess of 2.0 mb/d, or more than 2.5% of all-liquids production. Recognizing this, the important factors to model become the *rate* at which production capacity for non-conventional liquids can be built relative to the rate of decline of conventional oil production (Hirsch, *et al.*, 2005), and how costly it is to access, extract, and upgrade these liquids into refined fuels. This need to account for *both* depletion and substitution in oil supply models points to a clear strategy for improving supply modelling: include both physical and economic aspects of the problem in integrated models.

5.6 Summary

The main conclusions of this section are as follows:

- Existing approaches to forecasting future oil supply vary widely in terms of their theoretical basis, inclusion of different variables, level of aggregation and complexity. Each approach has its strengths and weaknesses and no single approach should be favoured in all circumstances. Unfortunately, little work has been carried out to compare the performance of different models, or to compare the results from the same model over time.
- Curve-fitting models are straightforward and widely used and they build upon empirical experience in many oil-producing regions. But they lack an adequate theoretical basis; are sensitive to the choice of functional form, neglect key variables and can perform poorly as a result. Econometric models exhibit a superior ability to match historical data, but it is not clear that this ability translates to more accurate forecasts of future production. Hybrids of curve-fitting and econometrics offer promise, but can also have the disadvantages of both. Simulation models are attractive because they attempt to reproduce the physical and economic mechanisms that govern oil production, but they can be overcomplicated and unstable and frequently lack both empirical validation and sufficient data for parameterisation. Finally, bottom-up models using field or project data may provide the most reliable basis for near-term forecasts, but the existing models are hampered by their reliance on proprietary datasets and associated lack of transparency and necessarily require a large number of assumptions.
- Basic mathematical analysis suggests that peak projections of decadal accuracy are likely to be possible for an assumed level of URR, assuming no significant disruptions to the global oil market. But given the potential for political, economic, or technological disruptions, no model can provide estimates of great precision. Increasing model complexity does little to address this problem and is subject to rapidly diminishing returns.
- Future models must incorporate both economic aspects (such as resource substitution) and physical aspects (such as resource characteristics or technologies) in order to improve the understanding provided. Work has already begun in this direction.

6 How much do we have? – global estimates of the ultimately recoverable resources of conventional oil

Global estimates of the ultimately recoverable resource (URR) of conventional oil play a prominent role in the peak oil debate, with larger estimates underpinning more optimistic forecasts of future supply. The methods used to derive these estimates can range from simple curve-fitting to in-depth evaluations of the geological characteristics of petroleum systems. While such estimates have grown over time, there is little sign of any consensus emerging. Since analysts frequently use different definitions of conventional oil, together with different assumptions about economic and technical viability and the time horizon over which the resources will be developed, there is a considerable risk of 'comparing apples and oranges'.

This section provides an overview and evaluation of global URR estimates and assesses their implications for future global oil supply. Section 6.1 compares some estimates that have been made in the past and illustrates how these have changed over time. Section 6.2 summarises the methods and results of the most influential study to date, the USGS World Petroleum Assessment 2000, and evaluates whether the experience since 2000 is consistent with these estimates. Section 6.3 summarises how the USGS estimates have recently been updated by the IEA and Aguilera, *et al.* (2009). Section 6.4 identifies the implied range of uncertainty over this variable and the implications for future global supply. Section 6.5 concludes.

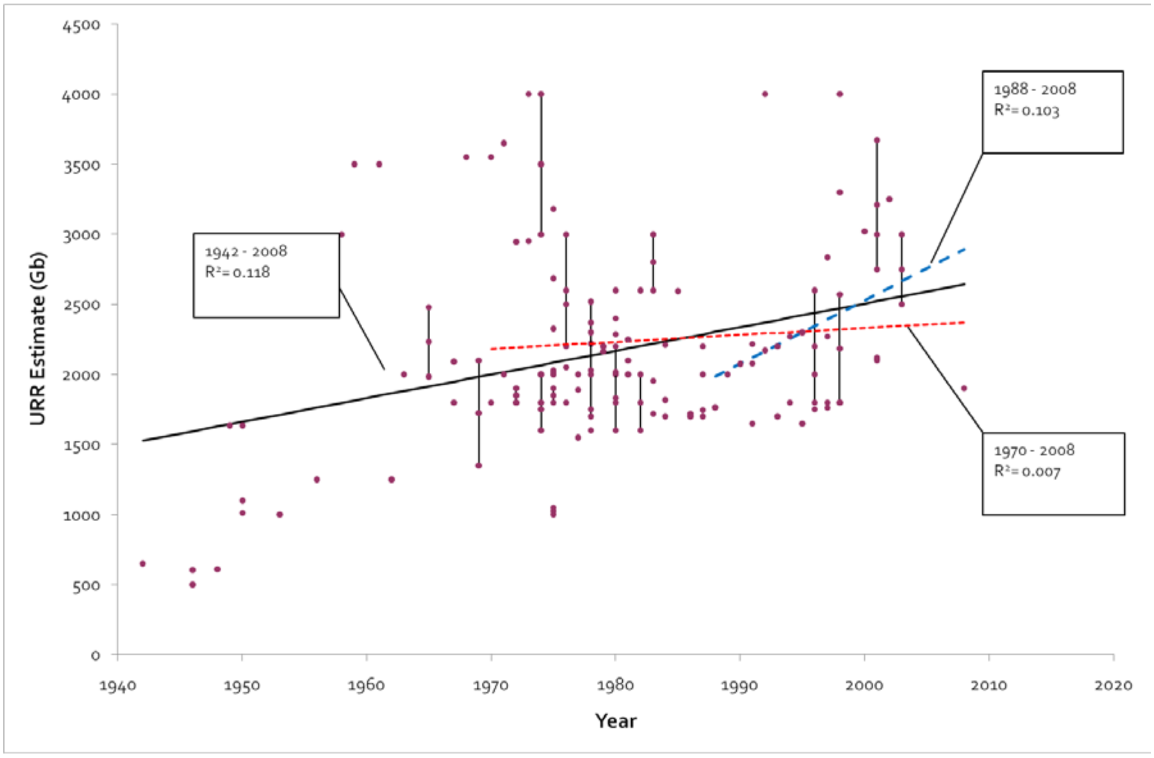
6.1 Trends in global URR estimates

In 1920, Eugene Stebinger of the USGS estimated the global URR of conventional oil to be only 43 Gb (White, 1920). By 1942, Stebinger had increased his estimate to some 600 Gb (Pratt, 1942). Since this time, at least one hundred estimates of the global *URR* have been published from a variety of sources, including several repeated estimates by the same institutions or individuals (Salvador, 2005). These estimates are summarised in *Technical Report 5* and illustrated in Figure 6.1. Most recent estimates cluster in the range 2000 Gb to 3000 Gb which compares with cumulative production through to 2007 of 1128 Gb and cumulative 2P discoveries of 2369 Gb (IEA, 2008).[91] This latter figure is higher than some contemporary URR estimates although these often relate to a narrower definition of conventional oil and/or exclude some of the declared reserves of OPEC countries in the belief that these are overestimated.

A linear regression can be fit to these estimates (Figure 6.1) to suggest that they have increased by around 17 Gb/year between 1942 and 2007. However, the fit is very poor and it would be wrong to attribute much significance to this trend given the difficulties of comparison. In particular, most of the recent estimates include NGLs while the earlier ones do not.

[91] This figure includes conventional oil, extra-heavy oil and oil sands.

Figure 6.1 Global URR estimates over the last 70 years



Source: Salvador (2005), Andrews and Udall (2003)

Campbell (1991; 1997) provides some of the most pessimistic estimates of the global URR and uses these to support forecasts of an early peak in global production. He uses multiple techniques to estimate the URR for individual countries and then aggregates these to the global level. Campbell relies upon backdated estimates of cumulative 2P discoveries derived originally from the Petroconsultants (now IHS Energy) database and does not adjust these to reflect future reserve growth. He also significantly downgrades the reserve estimates for OPEC countries and uses a restrictive definition of conventional oil ('regular oil') that excludes 'deepwater' (>500m), 'polar oil' and NGLs. Campbell's most recent estimate for regular oil is 1900 Gb (Campbell and Heapes, 2008) which is less than two thirds of the USGS 2000 estimate for conventional oil (see below) and 469 Gbs less than cumulative 2P discoveries of conventional oil (IEA, 2008).

By contrast, one of the largest estimates of the global URR is by Miller (1992) who adopts an unconventional approach, referred to as the 'global oil system'. With this model, the total oil in place is estimated from the balance between oil generation, oil seepage to the surface, thermal cracking and loss from the source rocks over geological time. The recoverable resource is estimated as a proportion of the oil in place, using assumptions about recovery factors. Miller concludes that a URR of 3960 Gbs is plausible, excluding heavy oil and tar sands.

6.2 The USGS World Petroleum Assessment 2000

The most comprehensive and authoritative estimates of global URR are from the US Geological Survey (USGS) which has published five global assessments since 1980 (USGS, 2000). Each uses a combination of methods to estimate the URR of geologically homogeneous regions which are then aggregated to the level of the world as a whole. The most recent assessment was published in 2000, following 100 person-years of effort by a team of 41 geoscientists over a period of five years (Ahlbrandt, 2002; USGS, 2000). The results were significantly larger than previous USGS estimates and several commentators have disputed their validity (Laherrère, 2001). They nevertheless underlie projections of global oil supply by bodies such as the International Energy Agency (IEA, 2008) and the Energy Information Administration (EIA, 2008a).

6.2.1 Methods

The World Petroleum Assessment 2000 (USGS 2000) considered resources that had the potential to be added to reserves between 1995 and 2025 using existing technology.[92] This required assumptions about technical and economic viability and implies that the results could both *underestimate* the global URR (since some resources may only be technically and economically accessible in the longer term) and *overestimate* resource availability up to 2025 (since political and other constraints may prevent resources from being accessed and exploited). Although the estimates will be referred to as the global URR in what follows, these important caveats should be borne in mind.

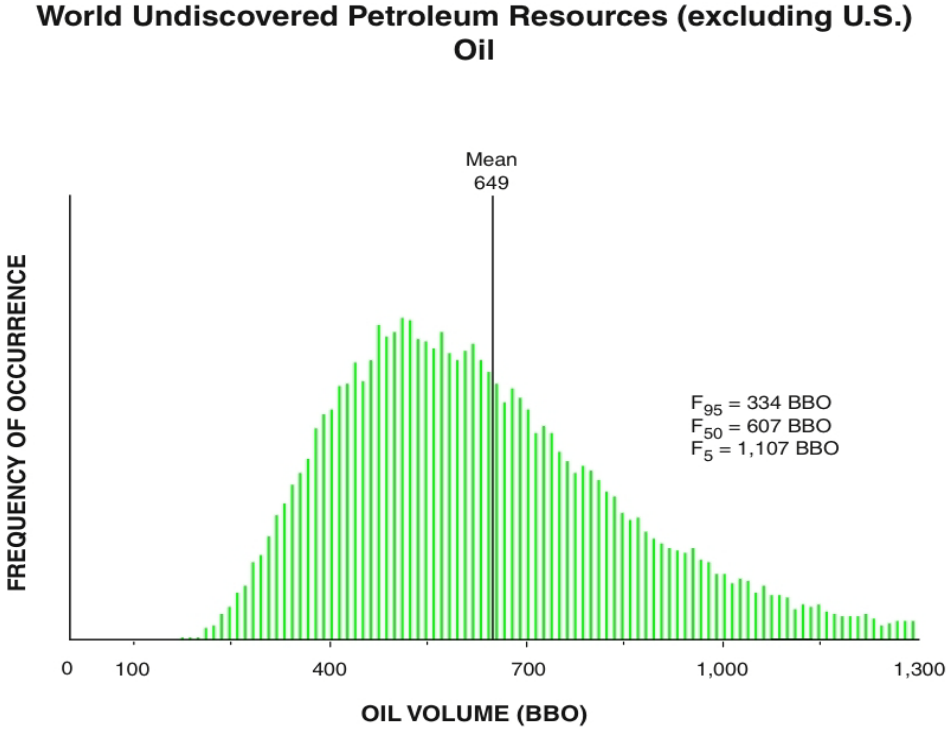
The USGS assessed seven regions in depth using a common methodology and combined these with previous estimates for the United States (MMS, 1996; USGS, 1995) to obtain a figure for the world as a whole. It divided the world into 937 petroleum provinces, 406 of which were known to contain petroleum resources (354 outside the US and 52 within the US). An additional five provinces were considered likely to contain petroleum, but only three of these were included in the assessment (North Barents, Provence, and the East Greenland Rift) giving a total of 409. Formal assessments were made of 128 non-US provinces, 76 of which contained 95% of the world's discovered petroleum (USGS, 2000).[93] By implication, 528 provinces were excluded altogether from the assessment, presumably because they were considered unlikely to contribute to global oil supply over the 30 year time horizon of the study.

The assessment of undiscovered resources was based upon a mixture of geological assessments and discovery process modelling. These provided estimates of the minimum, mode and maximum number of undiscovered fields, together with their minimum, median and maximum size. These provided inputs to a Monte Carlo simulation which derived probabilistic estimates of the size of undiscovered resources assuming a shifted lognormal field size distribution (Charpentier, 2005). The results for crude oil in the assessed provinces outside the US are illustrated in Figure 6.2. It is notable that the mean estimate (649 Gb) is greater than the median (607 Gb) which in turn is greater than the mode, and that the 95% confidence interval is very large (334 Gb to 1107 Gb).

[92] Previous USGS assessments did not specify a particular time span.

[93] The 128 provinces were divided into 270 Assessment Units (AUs, see Box 4.1) and assessments were made of 246 AUs that were judged to be 'significant' on a world scale. The study excluded non-conventional resources such as the Canadian oil sands and imposed a minimum field size, which ranged from 1 to 20 million boe depending upon the individual AU.

Figure 6.2 USGS estimates of undiscovered crude oil resources outside the US



Source: USGS (2000)
Notes: Crude oil only - excludes NGLs. BBO=Gb.

Since the study used a baseline of 1st January 1996, the estimates of cumulative discoveries were already five years out of date by the time the study was published. Similarly, the estimates of 'undiscovered' resources refer to resources that had the potential to be added to reserves between 1996 and 2025. Hence, a portion of this had already been discovered by the time the study was published.

6.2.2 Results

Table 6.2 and Figure 6.3 summarises the USGS 2000 mean estimates of the global URR of conventional oil. The main points are:

- The mean estimate of URR was **3345 Gb**, of which 90.3% (3021 Gb) was for crude oil and the remainder NGLs. This represented a 47% increase on the previous USGS estimate (2273 Gb) which derived from both the inclusion of reserve growth for the first time and a significant increase in the estimated size of NGL resources.
- The mean estimate for undiscovered conventional oil was 939 Gb, or 28.1% of the estimated URR and 35.6% of the remaining recoverable resources. This is 48% larger than the mode estimate in the previous USGS assessment (471 Gb), but the 95% confidence interval is large (495 Gb to 1589 Gb) and the probability distribution is positively skewed (Figure 6.2).
- Assuming a constant discovery rate, the mean estimates imply that an average of 31 Gb could be found each year between 1996 and 2025. This compares to an average of 14 Gb in the previous ten years (1986-1995) and 22 Gb in the previous twenty years (1976-1995). In other words, these potential reserve additions could only be achieved through a major turnaround in global exploration success, which has been declining fairly

continuously since the mid 1960s (Figure 6.4). Whether this decline is a result of physical depletion, restricted access to the most promising areas or price-induced reductions in exploration activity is disputed (Bentley, 2002; Mills, 2008). In practice, each is likely to have played a role.

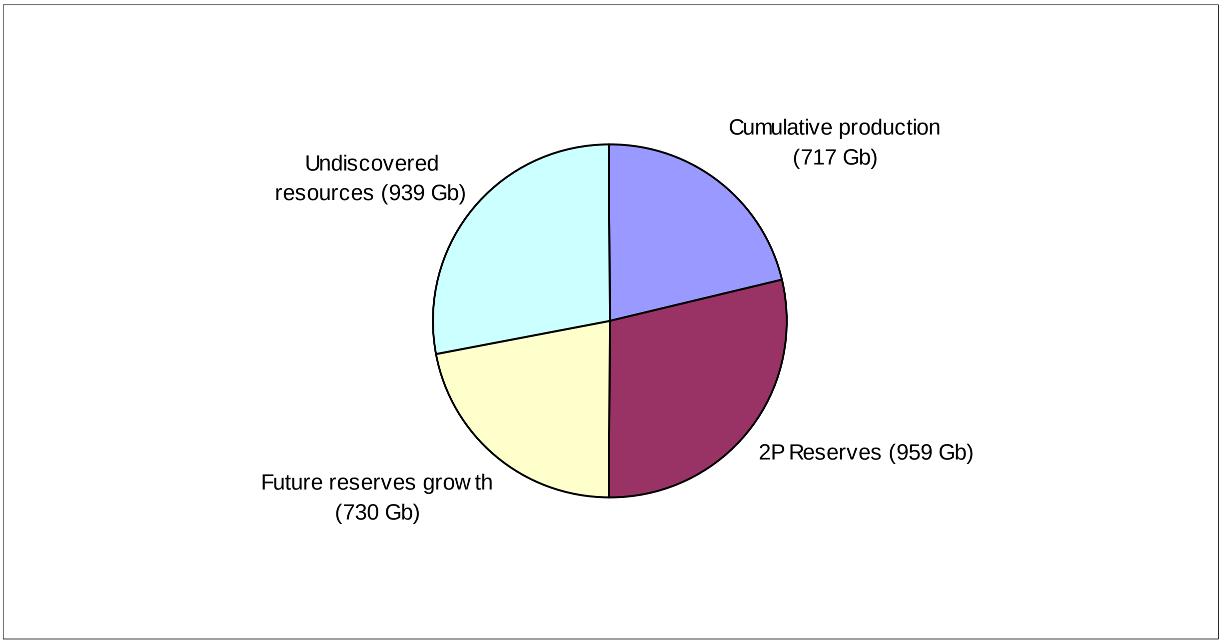
- The mean estimate for reserve growth was 730 Gb, or 21.8% of the estimated URR and 27.8% of the remaining recoverable resources. Hence, reserve growth at existing fields was expected to contribute almost as much to future reserve additions as new discoveries.
- Only 21.4% (717 Gb) of the mean estimate of URR had been produced through to January 1996. However, with cumulative production through to December 2007 of 1128 Gb, this figure has now increased to 33.7%, with the growth in annual production averaging 1.5%/year.
- If consumption continues to grow at an average of 1.5%/year, the midpoint of the mean estimate of URR (1672 Gb) would be reached around 2024 (with production at 103 mb/d). The midpoint would be reached later if demand grew more slowly or earlier if it grew more rapidly. It could also be reached earlier if new discoveries and/or reserve growth deliver less than the mean estimate of potential reserve additions. More importantly, various factors may prevent reserve growth and new discoveries from contributing to reserve additions at the *rate* that is required.

Table 6.1 USGS 2000: mean estimates of global URR for conventional oil (Gb)

	US conventional oil	**World (non-US) crude oil**	**World (non-US) NGLs**	**World Total conventional oil**
Cumulative production	171	539	7	**717**
Remaining 2P reserves	32	859	68	**959**
Reserve growth	76	612	42	**730**
Undiscovered resources	83	649	207	**939**
URR	**362**	**2659**	**324**	**3345**
Remaining recoverable resources	*191*	*2120*	*317*	*2628*

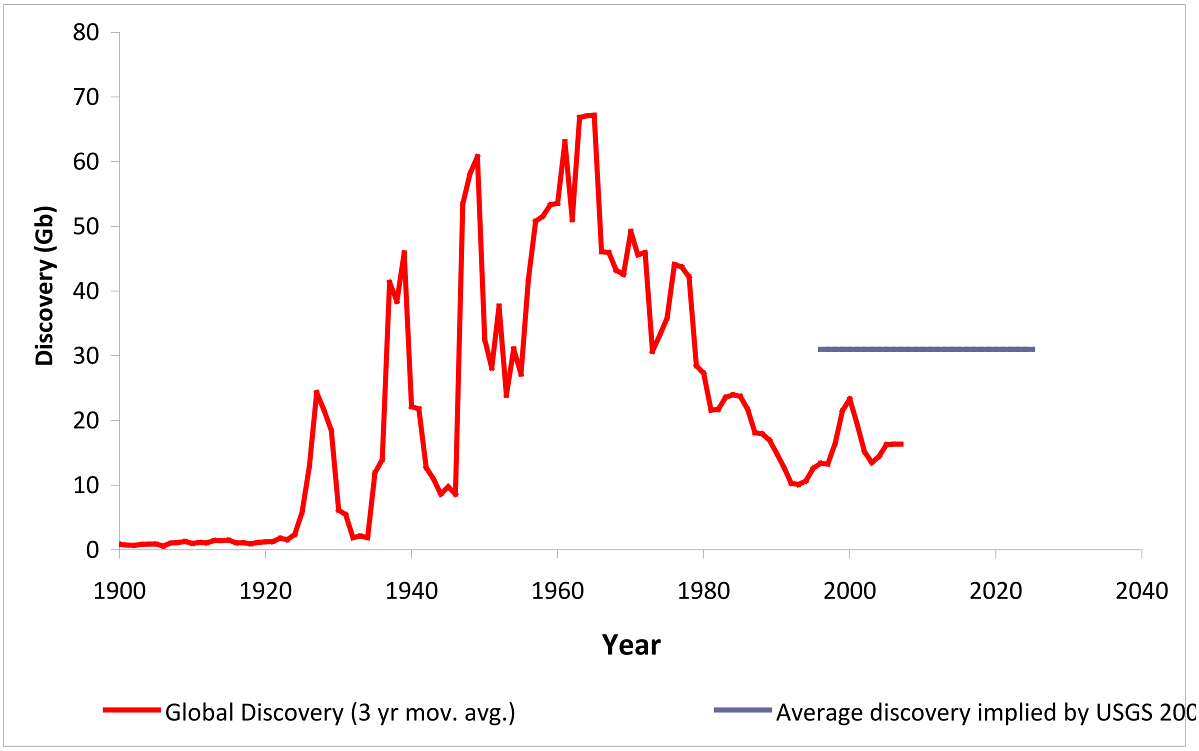
Source: USGS (2000)
Note: All figures refer to January 1996.

Figure 6.3 USGS 2000: components of the estimated global URR for conventional oil (mean values)



Source: USGS (2000)

Figure 6.4 Comparing historical trends in backdated 2P discoveries with those implied by the USGS 2000 for the period 1995-2025



Source: IHS Energy; USGS (2000)

The most controversial aspects of the USGS 2000 study were the assumptions about reserve growth (Laherrère, 2001). This had been excluded from previous global assessments owing to insufficient data. However, this neglect was becoming increasingly inappropriate, given that reserve growth appeared to be accounting for an increasing proportion of global reserve additions. Using the Petroconsultants database, the USGS (2000) found that the cumulative 2P discoveries for 186 giant fields outside the US had increased by 26% between 1981 and 1996. This was greater than would have been predicted by the reserve growth functions estimated from US oil fields, despite the Petroconsultants database containing 2P reserves data while the US function was estimated from 1P data. Hence, the neglect of non-US reserve growth no longer seemed viable.

In contrast to the assessment of undiscovered resources, the methodology for estimating reserve growth was relatively crude. Since the available data was considered inadequate to estimate reserve growth functions for regions outside the US, the USGS chose to apply a single US reserve growth function to *all* oil and gas fields throughout the world.[94] This gave estimates of the 'grown size' (by 2025) of each field that had been discovered before 1996. To reflect the uncertainty in these estimates, the USGS assumed a symmetrical triangular probability distribution, with a minimum value of zero.[95] As noted in Section 3, considerable debate has since arisen over the validity of applying US growth functions in this way. The USGS notes that its approach may *overestimate* reserve growth if the criteria for reporting non-US reserves was less restrictive than in the US (as they are), if reserves are overstated in some countries (as seems likely), or if non-US fields provide more accurate initial reserve estimates (thus reducing the potential for future growth). At the same time, the approach could *underestimate* reserve growth over the next 30 years if non-US fields benefit from better technology than that which determined the historical US growth function, or if these fields have not been developed as fast as US fields of the same age. In the absence of good data, there is room for a range of views on the net effect at the global level.

6.2.3 Evaluation

The USGS have evaluated the 'accuracy' of their assessment through to December 2003 (i.e. 27% of the 1995-2025 assessment period) (Klett, *et al.*, 2005). They estimated that only 69 Gb (8 Gb/year) of oil had been discovered in the 128 assessed non-US provinces, or less than 11% of the mean estimate of undiscovered resources (649 Gb) for those provinces. Assuming a constant discovery rate, a total of 173 Gb should have been discovered by 2003 or 27% of the undiscovered resource. In other words, real-world oil discoveries outside the US were less than half of what was 'expected' over this period.[96]

Klett *et al*. (2005) highlight a number of possible reasons for this, including limited access to the most promising regions such as Iraq, Iran[97] and Libya, political and economic instability in Russia and the Central Asian republics, and low oil prices during the late 1990s leading to historically low rates of exploratory drilling and no exploration at all in key regions such as

[94] The function was a weighted average of the oil and gas field functions used in the 1995 US national assessment (Attanasi, *et al.*, 1999; Gautier, *et al.*, 1995).
[95] Arguably, a minimum value of less than zero should have been used to reflect the possibility that 2P estimates could fall over time.
[96] This is often cited in support of the argument that the IHS overestimated the global YTF. But it could equally be used in support of the argument that Campbell and Heapes (2008) underestimate the global YTF, since it suggests that 60% of their total (114 Gb) has been found in the last eight years. But again, Campbell and Heapes are using a narrower definition of conventional oil.
[97] Although, Iran had the largest amount of discoveries between 1993 and 2002.

Greenland and the Mexican Gulf of Mexico.[98] But an additional reason for the apparently low discovery rate may be that the 69 Gb figure represents a 2003 estimate of the cumulative 2P discoveries of the previous eight years and therefore has *not* been adjusted for future reserve growth. If this adjustment was made, the 'actual' discoveries may be closer to the 'forecast' discoveries. For example, the 'modified Arrington' reserve growth function (Figure 3.7) projects a quadrupling of the initial estimate of URR in 20 years, with the majority of the increase occurring in the first ten years (Verma, 2005). This would increase the discoveries estimate from 69 Gb to ~200 Gb which would imply that real-world discoveries were significantly *more* than what was 'expected' between 1995 and 2003, despite the low oil prices. Hence, whether and by how much the discovery estimates should be adjusted to reflect future reserve growth is of critical importance.

In contrast to new discoveries, reserve growth at existing fields appears to be tracking the USGS projections relatively well. Klett *et al.* (2005) conclude that a total of 171 Gb had been added through reserve growth by 2003, which is 28% of what was expected over the full 30 years and more than twice the reserve additions through new discoveries. Our analysis of reserve growth between 2000 and 2007 (Section 3) confirms this and suggests that the US reserve growth function works relatively well when applied to 2P data - at least at the global level. However, some of the apparent reserve growth in the IHS database may result from changes in reporting practices or the inclusion of previously omitted fields. Also, companies may have preferred to invest in reserve growth rather than exploration, since it represents a low-cost, minimal-risk strategy. If so, reserve growth may have been 'front-loaded' by investment and could diminish in later years.

The most uncertain estimates in the USGS 2000 assessment were for relatively unexplored regions of the world, such as the East Greenland Rift where formidable natural difficulties are likely to constrain the rate at which resources can be exploited. Similarly, much of the Arctic was excluded from the assessment, presumably because it was considered unlikely to contribute to global supply before 2025. However, in an updated Arctic assessment in 2008, the USGS provided a mean estimate of 134 Gb of undiscovered petroleum liquids (90 Gb oil and 44 Gb NGLs) (USGS, 2008). This would increase the global URR for petroleum liquids by 3.7% and the remaining recoverable resources by 5.5%.

There are also large areas of the world that remain poorly explored, including parts of Africa, the offshore regions of Kenya and Namibia, large parts of Libya and the Middle East, and offshore regions of Argentina, Colombia, Peru, Venezuela and Mexico. Many of these were excluded altogether from the USGS assessment, while exploration in many of the included regions was restricted by various political, economic and technical constraints. If the latter continue, the potential reserve additions identified by the USGS will not be realised before 2025, even if the resource is actually there. This in turn could contribute to supply difficulties occurring at an earlier date.

[98] For example, some 46 exploration wells were drilled in the UKCS in 1998, but following the price crash this fell to only 15 in 1999 (Mills, 2008). Globally, the number of drilling rigs peaked at around 6000 in 1981 but subsequently fell to around 1000 in 1999. The large price increases between 2000 and 2008 have stimulated increased exploration activity, but the increased investment has been partly taken up by price inflation (driven in part by shortages of equipment) and the long lead times for producing new equipment has prevented a rapid increase in exploration capacity (IEA, 2008).

6.3 Recent global URR estimates

6.3.1 The IEA World Energy Outlook 2008

An updated assessment of the global URR of conventional oil using a timeframe from 2007 to 2030 was presented by the IEA in its World Energy Outlook 2008 (IEA, 2008). This updated the USGS 2000 study with information from IHS Energy, a recent evaluation of the USGS 2000 assessment (Klett, et al., 2007), additional information from the USGS and the IEA’s own databases and analyses. The results for total petroleum liquids are summarised in Table 6.2 and Figure 6.5.

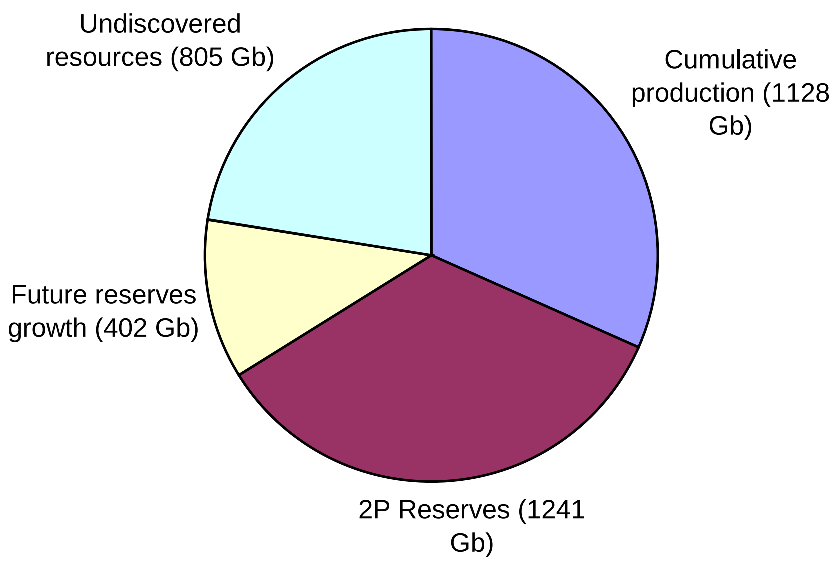
The most notable point is that the IEA estimate the global URR for conventional oil to be **3577 Gb** which is 6.9% *larger* than the earlier USGS estimate. The mean estimate of remaining recoverable resources is 2448 Gb, or 68% of the URR. Remaining 2P reserves are estimated to have increased by 29% since 1996 which indicates that reserve growth and new discoveries have more than offset the 411 Gb of production over this period. The remaining contribution from reserve growth is estimated at 402 Gb (16% of remaining recoverable resources), while that from undiscovered resources is estimated at 805 Gb (33% of remaining recoverable resources). The estimates of reserve growth and undiscovered resources are lower than in the USGS 2000 study, in part because a proportion of both have already been converted into production and/or 2P reserves. It is also notable that 86% of the remaining recoverable resources are estimated to lie outside the OECD, with the majority being located in the Middle East, North Africa and the Former Soviet Union.

Table 6.2 IEA 2008 WEO: mean estimates of global URR for petroleum liquids (Gb)

	OECD	**Non-OECD**	**World**	**% diff from USGS 2000**	**OECD as % of total**
Cumulative production	363	765	1128	57.3%	32.2%
Remaining 2P reserves	95	1147	1241	29.4%	7.7%
Reserve growth	27	375	402	-44.9%	6.7%
Undiscovered resources	185	620	805	-14.3%	23.0%
URR	**670**	**2907**	**3577**	**6.9%**	**18.7%**
Remaining recoverable resources	*307*	*2142*	*2448*	*-52.8%*	*24.7%*

Source: IEA (2008)

Figure 6.5 IEA 2008: components of the estimated global URR for conventional oil



The estimates in Table 6.2 exclude 'conventional oil produced by unconventional means', but the precise definition of this category is unclear. The IEA also provides a long-term oil supply cost curve which includes this category and gives the following estimates of remaining recoverable resources:

- Conventional oil: 2100 Gb
- Enhanced oil recovery (EOR): 400 - 500 Gb
- Deepwater and ultra deepwater: 160 Gb
- Arctic: 90 Gb

The cost curve gives a lower estimate of the remaining recoverable resources of conventional oil (2100 Gb) than indicated in Table 6.2 (2448 Gb). The reason for this is unclear, but could be due to the omission of NGLs from the cost curve. If so, the implied mean estimate for the latter is 348 Gb.[99] Combining these estimates and adding the implied contribution from NGLs leads to a *higher* estimate of total remaining recoverable resources (3148 Gb) and implies a URR for conventional oil of **4276 Gb** which is significantly larger than the figure in Table 6.2. Indeed, the URR implied by the IEA supply curve is one of the largest estimates seen to date. However, the IEA forecasts a cumulative contribution of only 24 Gb from EOR before 2030 which is less than 12% of the estimated potential. Similarly, it forecasts that only 14% (114 Gb) of the undiscovered resources will be found before 2030.

[99] This is larger than the corresponding estimate in the USGS 2000 study (317 Gb), despite significant production of NGLs in the intervening 12 years.

6.3.2 Inclusion of additional provinces

A comparably optimistic assessment of the global URR is provided by Aguilera, *et al.* (2009). Their estimate is also based upon the USGS 2000 study but (unlike the IEA) they do not update the USGS figures to allow for production, discoveries and reserve growth since 1996. Instead, they increase the USGS estimates in two ways.

First, they argue that the USGS study underestimates total resources because it excludes 528 provinces in regions such as the Arctic, Antarctic and sub-Saharan Africa. To estimate the resources in these provinces, they fit a 'variable size distribution' model to the assessed provinces, extrapolate this curve to give an estimate of the global URR and subtract the USGS estimates to obtain a mean estimate of 593 Gb of oil contained in the unassessed provinces. This is equivalent to one fifth of the remaining recoverable resources identified by the original USGS study. By including estimates for these provinces, they potentially obtain a better estimate of the 'long-term' global URR.

Second, they assume that reserve growth also applies to undiscovered resources. Using the USGS reserve growth functions, they adjust these estimates upwards by as much as 50% for both the assessed and unassessed provinces.

The net result of these two adjustments is an estimate of 3516 Gb for remaining recoverable resources and **4233 Gb** for the URR.[100] This figure is comparable to that implied by the IEA's supply curve (see above), but derived through an entirely different route. Since Aguilera, *et al.* make no explicit assumptions about EOR, a combination of their approach with the IEA's assumptions could lead to an even more optimistic estimate for the global URR.

Aguilera *et al.*'s approach is questionable in a number of respects. First, it may be unreasonable to assume that all of the 937 provinces contain recoverable liquids and many of those that do are likely to remain relatively inaccessible in the medium-term for either technical or political reasons. Second, the unassessed provinces are significantly smaller (in resource size) than the assessed provinces, raising serious questions about both the economic viability of extraction and the net energy yield. Third, the application of reserve growth multipliers to the mean estimates of undiscovered resources seems difficult to justify. These multipliers were derived from studies of existing (frequently very old) fields, they relate to original estimates of field size derived from exploratory drilling, and they reflect factors such as conservative initial reporting and improvements in recovery technology over the past 50 years. In contrast, the estimates of undiscovered resources are based largely on geological information, already contain wide confidence intervals to reflect uncertainty and are implicitly based upon assumptions about recovery factors that reflect modern technology. Since the USGS state that their undiscovered volumes are already 'grown', Aguilera *et al.* appear to be 'double counting' future reserve growth for these resources.

While the studies by Aguilera *et al* and the IEA have 'pushed the envelope' of global URR estimates, their relevance to medium-term forecasts (e.g. up to 2030) of global oil supply is questionable. This is because the issue is not simply whether the resource is there, but whether it can or will be accessed sufficiently quickly to contribute to global oil supply in the

[100] Since Aguilera, *et al.* are working with the original USGS data (which applies to 1996), the URR is estimated here by adding Aguilera, *et al's* estimate of remaining recoverable resources to the USGS figure for cumulative production through to 1996.

near- to medium-term. Hence, even if the more optimistic URR estimates are correct, this may not make any difference to the timing of the global oil supply peak, although it may slow the rate of post-peak decline. The following section explores this relationship between stocks (global URR) and flows (global production) in more detail.

6.4 Implications for future global supply

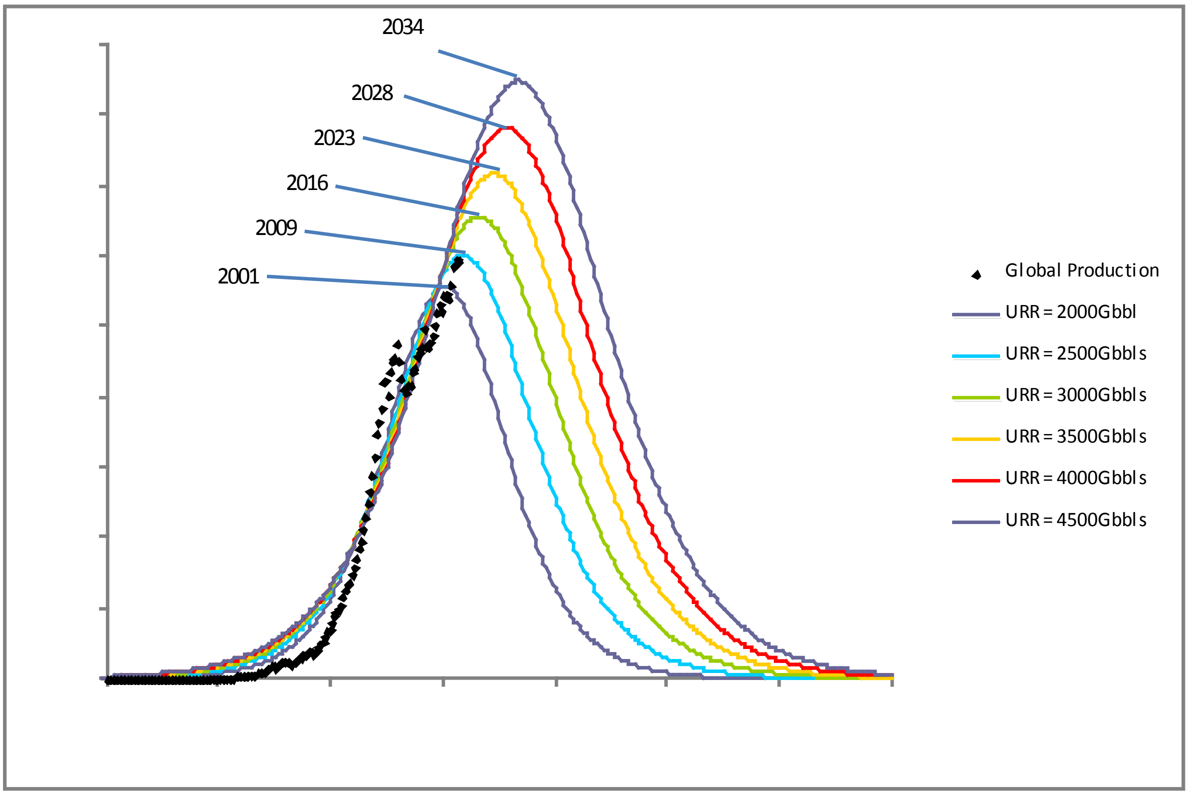
Contemporary estimates of the global URR for conventional oil fall within the range **2000-4300 Gb**, while the corresponding estimates of the quantity of remaining recoverable resources fall within the range **870 to 3170 Gb**. In other words, the highest estimate of remaining recoverable resources is four times larger than the lowest estimate. While the lower end of this range results in part from an narrow definition of conventional oil, the upper end may result from excessively optimistic assumptions about reserve growth, undiscovered resources and/or the future potential of enhanced oil recovery. The degree of uncertainty is likely to remain high for the foreseeable future and this leads to a corresponding uncertainty in the projections of future global oil supply.

It is useful to explore the implications of this uncertainty with the help of a simple logistic model of oil production. By assuming a range of values for the global URR, we can investigate the sensitivity of the date of global peak production to the size of the global resource.[101]

Figure 6.6 shows the results using assumptions for the global URR ranging from 2000 Gb to 4500 Gb. For an estimate of 2500 Gb, the model gives peak production in 2009 at a level of 30 Gb/year (82 mb/d), while for an estimate of 4500 Gb, it gives peak production in 2032 at a level of 42 Gb/year (115 mb/d). Hence, with this model, a 125% increase in the size of the URR (or a 260% increase in the size of the remaining resource), delays the date of peak production by only 23 years. Put another way, increasing the global URR by one billion barrels delays the date of peak production by only 4.7 days. To delay the date of peak production by one year would require the addition of some 78 billion barrels to the global URR, which is two and half times greater than global production in 2007 and almost seven times greater than global discoveries in that year.[102] To put this in perspective, the discovery of resources equivalent to those of the entire United States would delay the global peak by less than four years.

[101] Earlier investigations along these lines have been conducted by Bartlett (2000), Carlson (2007a; b) and Brecha (2008; Brecha, *et al.*, 2007) among others.
[102] This is likely to be an overstatement, since the discovery figure has not been corrected for future reserve growth.

Figure 6.6 The peaking of global conventional oil production under different assumptions about the global URR - simple logistic model



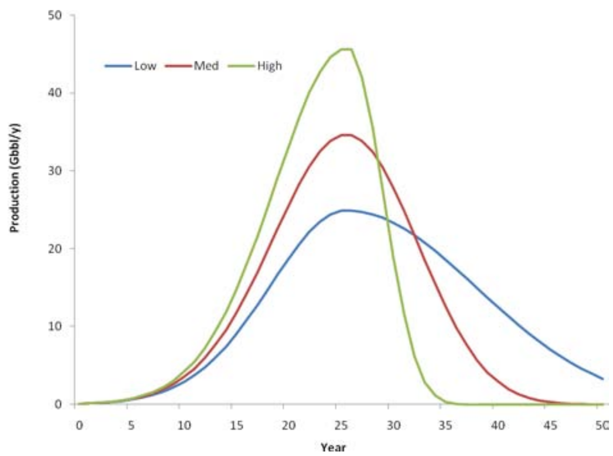
These results suggest that the range of uncertainty over the date of peak production must be less than the range of uncertainty over the size of the resource. However, future demand may not reach the levels indicated in the 'late peak' scenarios and the global production cycle is very unlikely to follow the symmetric logistic model. For example, it is possible that production could decline rapidly as the giant fields are depleted and production shifts towards much smaller fields. Alternatively, production could decline more slowly as price signals provide incentives for demand reduction and enhanced oil recovery and as major producers restrict exports to maximise the size and longevity of revenues. Hence, uncertainties about the size of the global URR are compounded by uncertainties about the future shape of the global production cycle.

Kaufmann and Shiers (2008) address these uncertainties through sensitivity testing. By combining different assumptions about the global URR with assumptions about the rate of change of production before and after the peak (Figure 6.7), they generate 64 possible scenarios for the global production of conventional oil. As with the simple logistic model, they find that large differences in the assumed URR lead to relatively small differences in the timing of peak production. In particular, *for 53 of 64 scenarios, the date of peak production lies between 2009 and 2031*. For any given value of URR, changing the initial growth and decline rates has relatively little effect on the date of the peak (Figure 6.7).

Their results imply that delaying the peak in global oil production beyond 2030 requires a combination of a large URR (e.g. at least 3000 Gb), slow rates of production increase prior to the peak and/or a relatively steep post-peak decline rate. Only three of their scenarios give a peak after 2040 and these require all three assumptions to hold. This form of asymmetry in the production cycle seems unlikely and could also have serious implications once the peak is passed. The majority of scenarios show annual production falling by 10 mb/d within 5 to 10 years after the peak which is equivalent to the current output of Saudi Arabia. Later peaks imply faster rates of decline which in turn implies that substitutes must be developed faster and/or demand must fall more rapidly. Kaufmann and Shiers also considered scenarios with two peaks, but the URR constraint implies either that the annual rate of production for the second peak is much lower than that for the first peak, or that production declines very rapidly after the second peak. More rapid decline may also result if the peak is extended into a multi-year plateau. Hence, the single peak scenario may to some extent be considered a ‘best case’.

However, an important weakness of the Kaufmann and Shiers study is the failure to consider lower rates of demand growth. The production of all-liquids fell in 2008 as a result of the economic recession and is anticipated to fall further in 2009 and possibly beyond. Considering only the constraints imposed by the size of the conventional oil resource, the result may be to delay the peak by several years - as did the earlier ‘oil shocks’ of the 1970s. However, the recession has also led to the cancellation of many upstream projects which could lead to near-term supply constraints (IEA, 2009a).

Figure 6.7 Illustration of the asymmetric production model of Kaufmann and Shiers (2008)



Note: Cumulative production sums to ~600 Gb in all cases. The initial rate of growth and rate of decline before and after the peak are (0.51, 0.165), (0.545, 0.545) and (0.575, 2) for the low, medium and high cases, respectively.

6.5 Summary

The main conclusions from this section are as follows:

- Estimates of the global URR for conventional oil vary widely in their methods, assumptions and results. Comparison is complicated by the differing definitions of ‘conventional oil’ and the more pessimistic estimates of the global URR result in part from a particularly narrow definition. Further difficulties arise from the use of competing reserve definitions and differing time-frames for the definition of URR, together with the uncertainty surrounding OPEC reserves and the inconsistent treatment of reserve growth. The information currently available does not allow strong constraints to be placed on the last two variables.

- Although global URR estimates have been trending upwards for the last 50 years, the estimate of 3345 Gb by the USGS (2000) represented a substantial departure from the historical trend – being 47% larger than the previous USGS estimate. While the USGS have yet to repeat their global assessment, more recent estimates by the IEA (2008) and Aguilera, *et al.* (2009) have been even more optimistic – implying a URR in excess of 4000 Gb.

- The USGS has been widely criticized for its assumptions about global reserve growth. However, subsequent analysis indicates that these have proved broadly 'correct' in that they are consistent with the reserve growth observed in the IHS database. Also, while the rate of new discoveries appears to be lower than 'anticipated' by the USGS, this is partly a consequence of restrictions on exploration in the most promising regions, price-induced reductions in exploration activity and the failure to adjust the discovery estimates to allow for future reserve growth. Hence, the repeated assertions that the USGS study is 'discredited' are at best premature.

- The 2008 IEA World Energy Outlook estimates the global URR to be 3577 Gb, but the inclusion of 'conventional oil produced by unconventional means' increases this figure to 4276 Gb. Aguilera, *et al* (2009) arrive at a comparably optimistic estimate (4233 Gb) by including the resources contained within provinces excluded from the USGS study together with generous assumptions about future reserve growth. However, the IEA estimate relies upon a large contribution from EOR that they anticipate will take decades to be realised while some of Aguilera *et al's* assumptions appear very questionable.

- Overall, contemporary estimates of the global URR for conventional oil fall within the range **2000-4300 Gb,** while the corresponding estimates of the quantity of remaining recoverable resources fall within the range **870 to 3170 Gb**. This wide range leads to a corresponding uncertainty in the projections of future global oil supply and the date of peak production.

- In a simple logistic model, increasing the global URR by one billion barrels would delay the date of peak production by only 4.7 days. This result is not substantially changed if a more sophisticated model is used, that allows for varying degrees of asymmetry in the global production cycle (Kaufmann and Shiers, 2008). For a range of assumptions about the size of the global URR and the rate of change of production before and after the peak, the date of peak production is found to lie between 2009 and 2031. Delaying the peak beyond 2030 requires optimistic assumptions about the global URR combined with a relatively steep post-peak decline rate and/or slower rates of demand growth than are conventionally assumed. Forecasts that predict no peak before 2030 should be evaluated on this basis. However, since the global economic recession has reduced demand, the date of the 'resource-constrained' peak is likely to be delayed. At the same time, the recession has inhibited upstream investment which could lead to supply constraints in the near-term.

- Even if the larger URR estimates are correct, it does not necessarily follow that the resource can or will be accessed at the rate required to maintain global production at a particular level. If these resources can only be accessed relatively slowly at high cost, supply constraints could inhibit demand growth. Furthermore, if key producers lack the incentive to maximize production, demand growth could be constrained further – especially in the importing countries. Hence, the primary issue for the period to 2030 is the *rate* at which the resource can be accessed and produced.

7 Possible futures – a comparison of global supply forecasts

This section compares and evaluates some contemporary forecasts of global oil supply and also reviews earlier forecasts to provide an historical perspective. It highlights the importance of the explicit or implicit assumptions regarding the ultimately recoverable resource (URR) of conventional oil and the post-peak production decline rate. A more detailed comparison of these forecasts is provided in *Technical Report 7.*

Following an introduction, Section 7.2 summarises some of the forecasts made between 1956 and 2005, while Section 7.3 provides an overview of fourteen contemporary forecasts of global oil supply. Section 7.4 discusses the global URR of conventional oil that is assumed or implied by these forecasts, while Section 7.5 provides a framework in which the assumptions behind each forecast can be compared. Section 7.6 discusses how the rate of reserve additions from new discovery and reserve growth could impact on the forecast timing of peak production, while Section 7.7 summarises the main lessons from the comparison. Section 7.8 concludes.

7.1 Approach

Forecasts of global oil supply are produced by models of varying degrees of complexity that seek to capture the multiple determinants of oil supply and/or oil demand. There has long been a dichotomy between models which forecast no insurmountable supply difficulties before 2030, and those which forecast that the world is at or near the peak of oil production. This section seeks to shed some light on this dichotomy by comparing fourteen forecasts of the future of global oil supply up to 2030. Nine of these forecasts predict a peak in conventional oil production before 2030, while five do not. Each of these forecasts is produced by a different model and a wide range of approaches (or combinations of approaches) is used. While bottom-up models predominate, several of the models encompass more than one of the categories identified in Section 5.

The comparison focuses primarily on forecasts of *conventional oil* supply up to 2030. More pessimistic forecasts of conventional oil supply imply the need for either demand reduction or the more rapid development of substitutes - which could be challenging (Hirsch, *et al.*, 2005). However, most of the models also include bitumen and syncrudes from the Canadian oil sands and some include other non-conventional liquids. We have deducted the latter from the forecast production totals wherever possible.

The comparisons are at a relatively high level, focusing on general aspects of the models rather than providing definitive statements on their accuracy or completeness. Several significant models are not included, either because the individuals or organisations could not be contacted or because they were unable to collaborate for commercial or other reasons.[103] However we do not consider that these omissions materially affect the overall conclusions.

[103] Notable omissions include PFC Energy, Cambridge Energy Research Associates (CERA), the World Energy Council and some international oil companies.

7.2 Historical Oil Forecasts

In the discussion of oil depletion it is frequently asserted that 'all past oil forecasts have been incorrect'. This view is partly informed by pronouncements from the 1970s that the world was likely to 'run out' of oil in about 30 years and partly 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 (Box 7.1). In general, the poor record of long-term energy supply forecasting suggests the need for humility (Craig, *et al.*, 2002).

Box 7.1 Examples of overly optimistic forecasts of oil supply

- Zapp (1961) estimated a URR of 590 Gb for the Lower 48, while Moore (1971) estimated a URR of 587-620 Gb. For comparison, the most optimistic contemporary estimate of the US URR (including Alaska) is 362 Gb (USGS, 2000)
- 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.
- 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.
- Eysell (1978) estimated that a 1% rise in real oil prices would increase discoveries by 2.9-3.7%. Given the large increase in real oil prices, discoveries have not come close to the levels implied by this elasticity.

The 1970s view of oil 'running out' in 30 years was largely based on the global proved reserve to production ratio. But this ignored the large volume of oil already then discovered but classed as probable reserves, the oil yet-to-find, and that to be realised by improving recovery factors. Not surprisingly, even in the 1970s it was recognised that a better approach to forecasting was to use simple 'curve-fitting' techniques constrained by the estimated global URR. In the 1970s, the general consensus was for a URR for conventional oil of around 2000 Gb. Assuming a simple logistic model of global supply, this implied that production could continue to increase for some 30 years until reaching a peak around the year 2000 (Figure 7.1). Table 7.1 lists a number of the forecasts that have used such techniques to forecast a peak in global oil production.

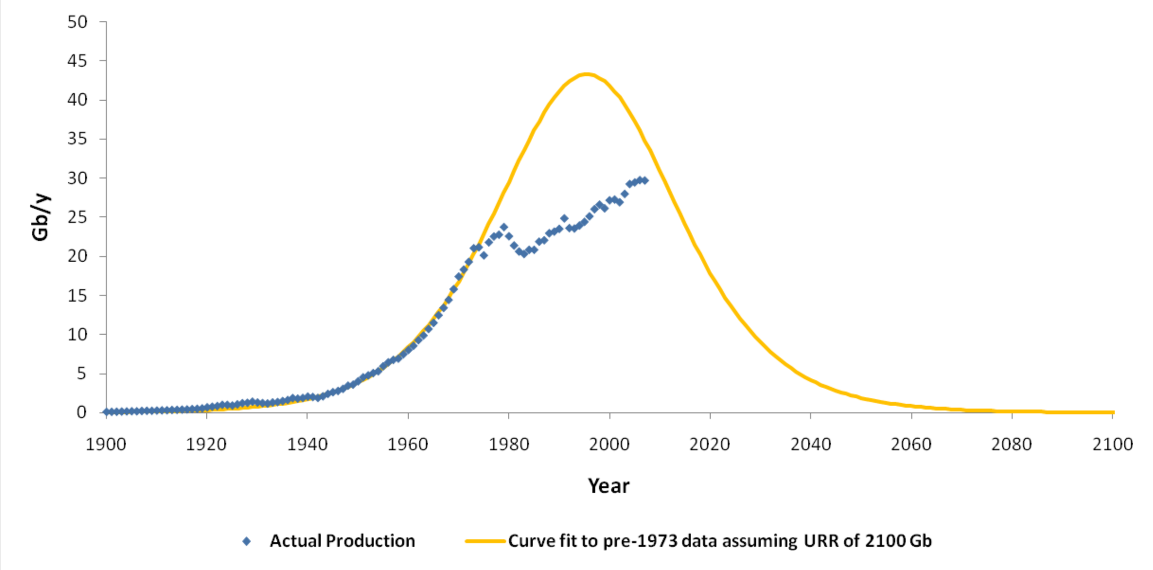
In the event, the anticipated global production increase, leading to a Hubbert-type peak, did not take place. This was largely because of the demand responses and fuel substitution that followed the 1973 and 1978 oil price shocks (Figure 7.1). Campbell (2005) argues that, had these been factored in, a simple curve-fitting model with a URR of about 2000 Gb would have predicted the peak for the global production of conventional oil as occurring around 2010.

Table 7.1 Selected forecasts of global oil production, made between 1956 and 2005, which gave a date for the peak

Date	Author	Liquids covered	URR (Gb)	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."
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
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."
1995	Petroconsultants	Conventional oil excluding NGLs	1800	About 2005
1996	Ivanhoe	Conventional oil	~ 2000	About 2010
1998	IEA	Conventional oil	2300 (reference case)	2014
2004	PFC Energy	Conventional & non-conventional oil		2018
2005	Deffeyes	Conventional & non-conventional oil		2005

Source: Bentley and Boyle (2008)

Figure 7.1 Pre-1973 logistic forecast of global oil production compared to actual production



These early models have been variously criticised for their inability to capture both demand-side and supply-side responses to higher prices, their overly pessimistic assumptions about the global URR of conventional oil and their excessively mechanistic approach. But the purpose of the models was to assess the consequences of some very simple assumptions over a thirty year time horizon, and most authors acknowledged the uncertainty in such forecasts. Moreover, curve-fitting models constrained by an assumed global URR are increasingly being replaced by more disaggregate approaches. These typically derive global forecasts from the sum of field or regional forecasts, relying upon explicit assumptions about decline rates and estimating the global URR as an output rather than an input. However, most continue to neglect the determinants of oil demand and pay insufficient attention to economic variables.

Opposed to these 'peaking' calculations were forecasts that oil production would be sufficient to meet forecast demand for the foreseeable future (generally out to 2020 or 2030). Table 7.2 summarises some of the more recent of these 'non-peaking' forecasts. The methodologies and assumptions used by these models differ in a number of respects from the 'peaking models' and typically include more detailed modelling of energy demand and less attention to the determinants of oil supply in general and geological constraints in particular. Some of these forecasts make explicit assessments about recoverable resources, while others do not. Several of them mix 1P and 2P reserves data, calculate future global reserve growth on the basis of historical experience in the US, accept OPEC's declared reserves and rely upon the USGS 2000 estimates for the global URR. Each of these assumptions has been a focus of dispute.

Table 7.2 Selected forecasts of global oil production that forecast no peak before 2030

Date	**Author**	**Liquids covered**	**URR (Gb)**	**Forecast date of peak**	**Global production (mb/d) 2020**	**2030**
1998	WEC/IIASA-A2	Conv. Oil		No peak	90	100
2000	IEA: *WEO 2000*	Conv. Oil	3345	No peak	103	-
2001	US DoE EIA	Conv. Oil	3303	2016 / 2037	Various	
2002	US DoE	Conv. Oil		No peak	109	-
2002	Shell Scenario	Conv. & NonConv. Oil	~4000	Plateau: 2025 - 2040	100	105
2003	WETO study	Conv. Oil	4500	No peak	102	120
2004	ExxonMobil	Conv. & NonConv. Oil		No peak	114	118
2005	IEA: *WEO 2005* Reference Sc. Deferred Invest.	Conv. & NonConv. Oil		No peak No peak	105 100	115 105
2007	IEA: *WEO 2007* Reference Sc.	Conv. & NonConv. Oil		No peak	-	116

Source: Bentley and Boyle (2008)
Note: Conv: conventional. NonConv.: non-conventional.

An important example is that of the IEA, who recognised the possibility of global oil peaking in their *World Energy Outlook 1998* (Table 7.1). This view changed in *World Energy Outlook 2000* (Table 7.2), partly as a result of the more optimistic assessment of the global URR of conventional oil presented by the USGS (2000). The most recent *World Energy Outlook 2008* represents a significant departure, incorporating as it does much more detailed modelling of the behaviour of individual fields. This has contributed to a more pessimistic view of future supply, with the level of investment required to meet the forecast demand now being described as “daunting”. The IEA now expect the supply of conventional oil to reach a plateau by 2030.

A number of analysts rule out any need to examine the oil resource base, on the grounds that economic forces will ensure that supply meets demand and encourage a relatively smooth transition to greater end-use efficiency and substitute fuels (Bentley and Boyle, 2008). But while it is true that supply will always meet demand at some price, the question is whether the price rise will be sufficiently slow and predictable to allow economies to adjust, or sufficiently rapid and unpredictable to cause disruption and shortage. 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 the lead times required to displace a significant portion of current production. Each of these requires analysis and modelling.

7.3 Overview of current oil forecasts

Now we turn to contemporary forecasts of global oil production. The fourteen models analysed in this study are listed in Table 7.3, together with summary data about the liquids that are covered, whether demand is modelled explicitly, the general approach to modelling oil supply, and whether a peak in the production of conventional oil is forecast before

2030.[104] Full descriptions of each model are provided in *Technical Report 7,* and the main parameters and assumptions (in so far as they can be identified) are summarised in Table 7.5.[105] It is important to note that all the forecasts reviewed here were developed *prior* to the global economic recession in 2008 and hence do not reflect the subsequent reductions in upstream investment and global oil demand.

[104] The data for each model were either gathered from published literature or by approaching the author(s). Descriptions were written and submitted to the authors for comment and approval (see the Annex of *Technical Report 7*). Feedback and corrections were received for all but one of the models which is much appreciated.

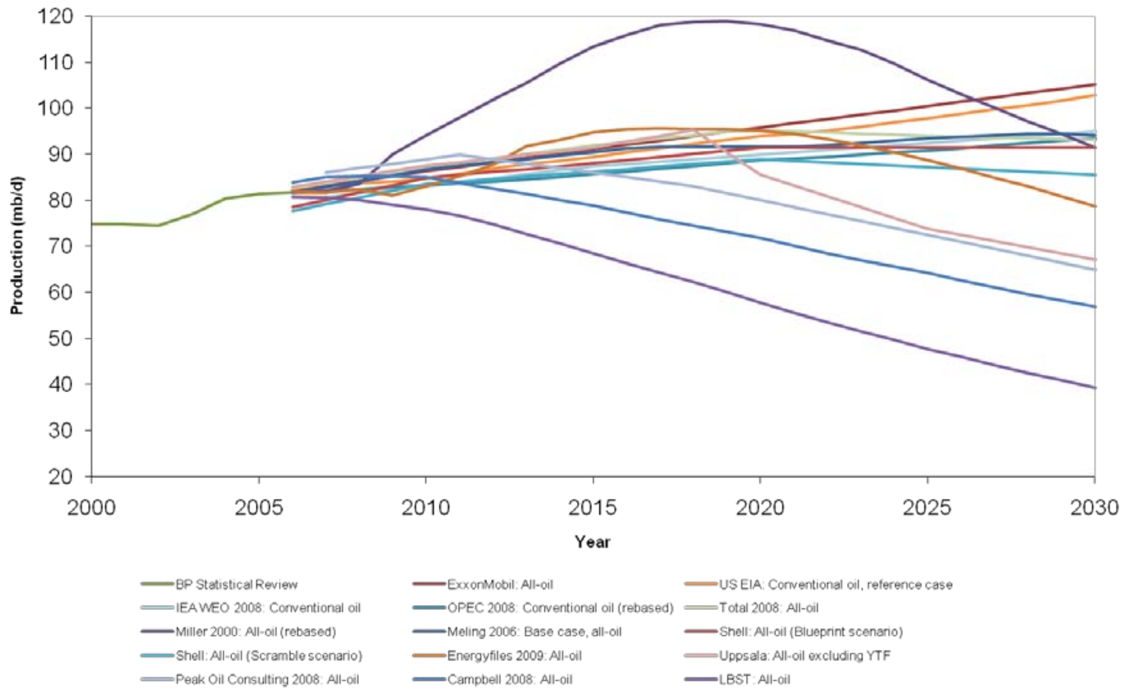
[105] We also obtained the views of ENI and BP on future global oil supply. ENI does not publish quantitative forecasts, but it rules out the possibility of a peak in the global production of oil ‘for the foreseeable future’. BP acknowledges an eventual peak in conventional oil supply, but gives neither a date nor a level of production for this. The company implies that the peak is beyond 2030, and forecasts global all-liquids production in 2030 to be in the range 95-105 mb/d, saying that this level is ‘sustainable’. BP notes a conventional oil YTF of at least 300-400 Gb, and agrees with the USGS assessment of global reserves growth, citing a figure of up to 700 Gb.

Table 7.3 Forecasts compared in this study

Category	Model	Liquids covered	Detailed demand modelling?	Approach to supply modelling	Conventional oil peak forecast before 2030?
International	IEA	All-liquids	Yes	Bottom-up; incremental supply constrained 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	Assumes mid-point peaking	Yes
Oil companies	Shell	All-liquids	Yes	Bottom-up by field or country, demand constrained	Yes (demand driven)
	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 (little detail provided)	No
Consultancies	Energyfiles	All-oil	No	Bottom-up by field or basin	Yes
	LBST	All-oil	No	Bottom-up by field or region. Simple curve-fitting for pre-peak countries	Yes
	Peak Oil Consulting	All-oil, GTL and biofuels,	No	Top-down for current production, bottom-up for new production	Yes
Universities and individuals	Colin Campbell	All-oil	No	Bottom-up by country. Assumes mid-point peaking and 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	Crude oil (excluding NGLs and some condensate)	No	Bottom-up by field	Yes

Figure 7.2 plots thirteen of the global forecasts of all-oil while Table 7.4 compares the estimates of cumulative production through to 2030 (BGR is omitted owing to insufficient data). In the few cases where alternative scenarios are provided only the 'base case' is shown. However, two scenarios are shown for Shell.

Figure 7.2 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.

Table 7.4 Comparison of thirteen forecasts of all-oil production to 2030

	Production in 2030	Cumulative production 2008-2030	Total cumulative production to 2030	
	mb/d	**Gb**	**Gb**	**% of IEA (2008) estimate of URR**
IEA WEO 2008	95.0	747	1897	53.0
OPEC 2008	93.5	738	1930	52.8
US EIA	102.8	780	1888	53.9
Shell (Blueprint)	91.4	748	1898	53.0
Shell (Scramble)	85.6	724	1874	52.4
Meling (StatoilHydro)	94.1	764	1914	53.5
Total	93.1	773	1923	53.8
ExxonMobil	105.2	796	1946	54.4
Energyfiles	78.6	748	1898	53.1
LBST	39.3	504	1654	46.3
Peak Oil Consulting	65.0	670	1820	50.9
Campbell	60.0	609	1759	49.2
Uppsala	67.1	697	1847	51.6
Miller	91.5	888	2038	57.0

Notes:
- Cumulative global production to 2007 taken from BP (2008).
- Forecasts refer to all-oil as far as possible, but coverage of liquids does not always coincide.
- Miller and OPEC forecasts 're-based' to include an estimated contribution from NGLs.
- IEA (2008) estimate the global URR of conventional oil to be 3577 Gb, but many of the forecasts use different assumptions.

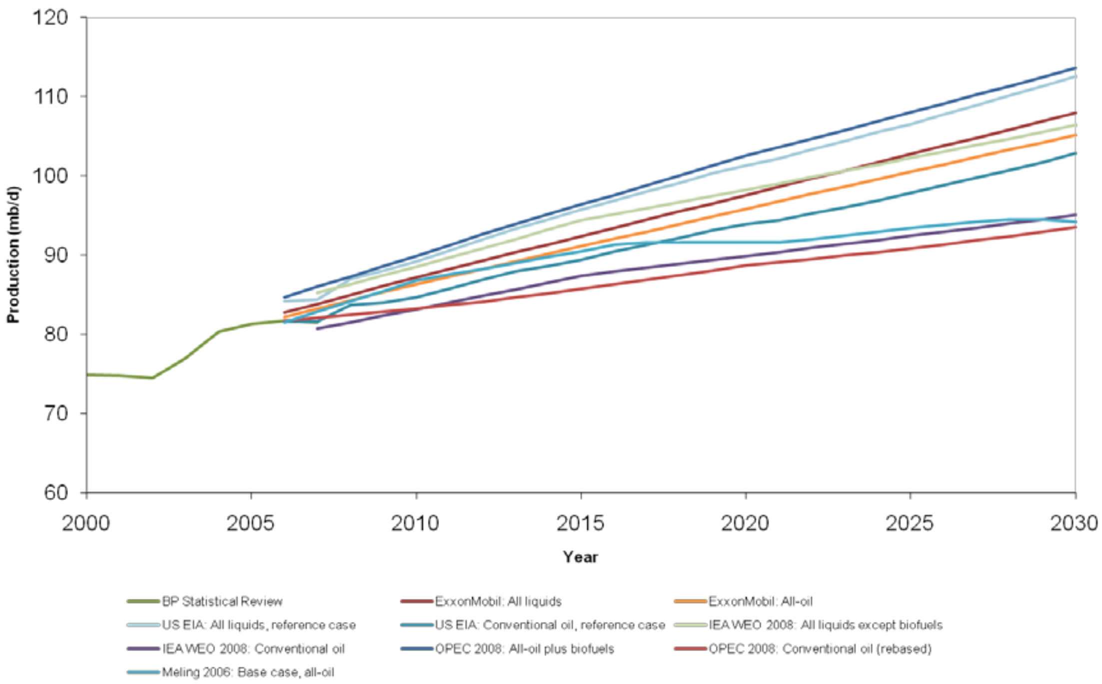
As Figure 7.2 shows, the highest forecast production of all-oil in 2030 is over two-and-a half times the lowest, while the range of forecast peak date ranges from the immediate past to the indefinite future. It may seem remarkable that detailed studies can reach such different conclusions.

One cause for this range is that the forecasts include different liquids. All the forecasts include light, medium and heavy crude oil, but not all include extra-heavy oil and for Miller and OPEC the contribution of NGLs has been estimated. However, this only explains a relatively small proportion of the difference.

There are two groups of forecasts in Figure 7.2. The first group indicates an approximately linear growth in the production of all-oil to 2030, such that if the modellers foresee a peak it is beyond the end of their forecast. These 'quasi-linear' forecasts are from the IEA, US EIA, OPEC and Exxon[106] and are illustrated more clearly in Figure 7.3, which also shows the corresponding forecasts for all-liquids (i.e., including CTLs, GTLs and biofuels). Each of these forecasts is driven primarily by demand modelling and allocates sources of supply to fill this demand. Meling's model is superficially similar, reaching a peak in 2028, but the modelled supply fails to match the assumed demand from 2011 onwards.

[106] BP and ENI are in broad agreement with these forecasts.

Figure 7.3 'Quasi-linear' forecasts of all-oil and all-liquids to 2030



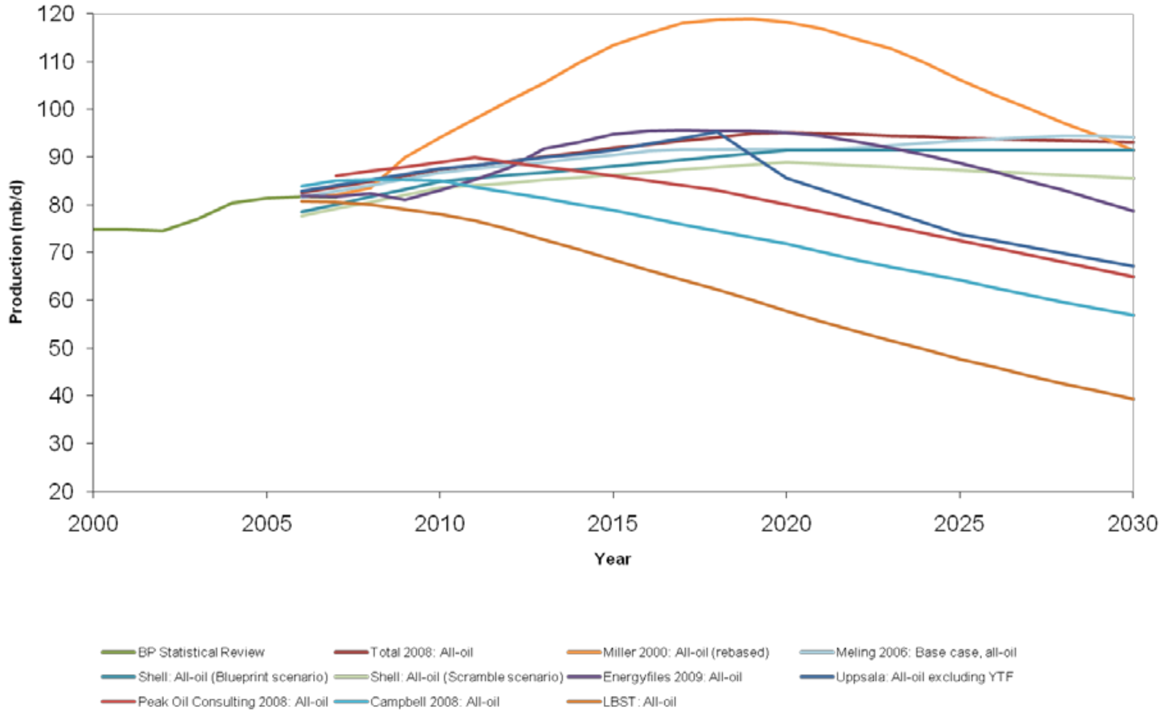
The second group of forecasts indicates some form of peak before 2030, followed by a decline. These are illustrated separately in Figure 1.4. Shell is the only one of this group to explicitly model oil demand, and their scenarios are unique in that the all-oil peak is driven by declining demand due to efficiency improvements and substitution rather than by constrained supply. Shell offers two scenarios, 'Scramble' where all-oil production declines after 2020, and 'Blueprints' where production levels off at that time. Shell's forecasts of all-liquids production are not well-defined but do not appear to reach a peak until after 2050.

The remaining models use exogenous assumptions for demand growth and a combination of simple curve-fitting and bottom-up methods at the country, field or project level to forecast future supply. The LBST, Campbell, Peak Oil Consulting, Uppsala, Total and Energyfiles forecasts initially follow the rising demand before falling away. Meling's forecast peaks late but does not meet the assumed 1.6%/year demand growth beyond 2011. Miller's forecast is specifically not a forecast of actual production, but of the maximum production 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 likely demand, before falling away.

The annual rate of post-peak decline of global all-oil production (the 'aggregate' decline) is variously forecast by the peaking models to be 0.2% (Total); 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); 2.6% (Meling); 3.3% from 2025 (Miller); and 3.5-4.0% (LBST). The URR of these peaking forecasts is variously defined,[107] but ranges from 1840 Gb (LBST) to 2450 Gb (Campbell), 2800 Gb (Miller) and 3149 Gb (Meling).

[107] It is usually for conventional oil, but may sometimes exclude NGLs or include a portion of the oil sands resource.

Figure 7.4 ‘Peaking’ forecasts of all-oil production to 2030



Despite the multiple inconsistencies in the coverage of liquids and the wide differences in methodology and assumptions, it is possible to compare the forecasts by focusing on a limited number of key variables. The following two sections do this by examining: first, the assumed or implied global URR of conventional oil; and second, the interaction between the URR, the forecast date of peak production and the aggregate decline rate following the peak.[108]

[108] As described in Section 3, this is the net outcome of the average decline of post-peak fields, the production from fields in plateau and the contribution of new fields which are coming on-stream.

Box 7.2 Illustration of a 'peaking' forecast – Energyfiles

Energyfiles maintains a detailed model for forecasting regional and global petroleum supply, based upon field-level data where available and otherwise on data aggregated at the operator, basin or country level. Demand is not modelled and is simply assumed to grow at a fixed rate.

Detailed profiles of cumulative production are created at the field, basin or country level according to data availability, and are extrapolated by balancing the constraints of past decline rates, regional decline rates and estimates of 'most likely remaining reserves'. For producing fields, the latter are obtained by extrapolating past decline rates while for undeveloped fields they are based upon announced expected plateau levels or the capacity of facilities, modified where appropriate by announced expected reserves. NGL production is estimated directly from similar profiles of future gas production. This approach is assumed to incorporate future reserve growth.

Yet-to-find resources are estimated through the analysis of the geology and discovery history of basins and plays, with onshore and offshore treated separately. The current estimate of 250Gb is only one third of the USGS mean estimate, in part because some areas (e.g. the Arctic) are considered unlikely to contribute to global supply in the medium-term. Energyfiles assumes that YTF resources in countries past or near their peak will have little influence on the timing of the global peak. However they may reduce the rate of post-peak decline.

In the forecast reviewed here, Energyfiles projects a global all-oil production peak of 95 mb/d around 2017 assuming a relatively high demand growth of 1.8%/year The conventional oil URR is estimated at 2685 Gb and the aggregate post-peak decline rate is estimated at 2.0%/year by 2022 and 3.0% by 2030.

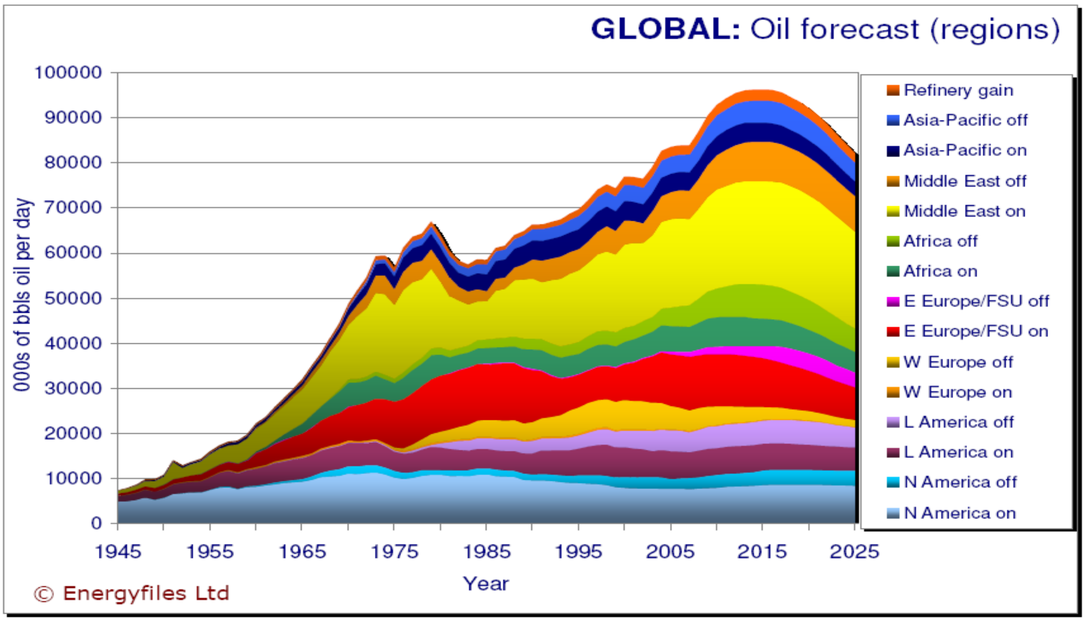


Table 7.5 Summary of the main parameters and assumptions used by each forecast

Category	Model	Oil demand growth	Date of global peak	Production in 2030 (mb/d)[109]	URR (Gb)	YTF (Gb)	Reserve growth (Gb)	Decline rates
International organisations	IEA	1.3%/year 2008-2015 0.8%/year 2015-2030.	No peak. Conventional oil plateau by 2030.	106.4 mb/d all liquids excluding biofuels	3577 Gb.	805 Gb	402 Gb	Detailed modelling gives average production-weighted managed decline rate of 6.7%/year for post-peak fields.
	OPEC	1.14%/year after 2012	No peak	113.6 mb/d all-liquids	3345 Gb.	Accepts USGS	Accepts USGS	Natural field decline rate 4-5%/year
National organisations	US EIA	1.16%	No peak.	112.5 mb/d of all-liquids, 109.8 mb/d excluding biofuels	Not given	Not given	Not quantified	Not given
	BGR (2006)	Not given	~ 2020	Not given	2979 Gb .	632 Gb.	Not quantified	Not given
Oil companies	Shell	No growth after 2020 (Blueprints). Decline after 2020 (Scramble)	No peak for all-liquids ~2030 (Blueprints) and ~2020 (Scramble) for all-oil	85.6 mb/d all-oil (Scramble) 91.4 mb/d all-oil (Blueprints)	Modelled in-house but not given	Modelled in-house but not given	Assumes improvements in recovery factors, but not quantified	Modelled in-house but not given
	Meling (StatoilHydro)	1.6%/year	2028 (base case)	94.1 mb/d all-oil	Unstated, but probably 3149 Gb	309 Gb.	520 Gb.	We calculate aggregate post-peak decline of 2.6%/year
	Total	1.4%/year	2020	93.1 mb/d all-oil	Not given	200-370 Gb.	Raising mean global recovery factor by 5%	We estimate aggregate post-peak decline of 0.2%/year
	ExxonMobil	~1.4%/year	No peak	105.2 mb/d all-oil	Implicitly follows USGS - 3345 Gb	Not given	Not given	Not given

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

Category	Model	Oil demand growth	Date of global peak	Production in 2030 (mb/d)	URR (Gb)	YTF (Gb)	Reserve growth (Gb)	Decline rates
Consultancies	Energyfiles	1.8%/year	2017	78.6 mb/d all-oil excluding refinery gains	2685 Gb	250 Gb.	Not given but incorporated in model methodology	Aggregate global production decline 2%/year by 2022 and 3%/year by 2029. Field decline 5-30%/year depending on size and location
	LBST	Not given	2006	39.4 mb/d all-oil	1840 Gb	Not given	Not given	We calculate an aggregate post-peak decline rate of 3.5-4.0%/year
	Peak Oil Consulting	Not used	2011-2013	65 mb/d all-oil	Not estimated	Not estimated	Not given	Currently 4.5% from existing producing fields. Aggregate post-peak decline 2.0%/year by 2025 and 2.3%/year by 2030
Universities and Individuals	Campbell	Not given	2008	57.0 mb/d all-oil	2425 Gb, all-oil, produced by 2100. 1900 Gb regular oil	114 Gb, 'regular' oil	Not given, assumed small in terms of impact on peak.	We calculate an aggregate post-peak decline rate of 2.1%/year
	University of Uppsala	Not modelled	2008-2018	67.1 mb/d all-oil	Not given	Not given	Assumed to contribute little	Field decline rates of 6-16%/year
	Miller	Not modelled	2013-2017 (2019 given unlimited investment)	91.5 mb/d all-oil excluding NGLs	2800 Gb	227 Gb	0.2%/year cumulative increment in production	Aggregate post-peak production decline of 3.3%/year by 2025

7.4 The assumed or implied global ultimately recoverable resource of conventional oil

Only eight of the models make explicit assumptions about the global URR and these cover a wide range (Table 7.5). While most of these assumptions are for conventional oil, the comparison is not straightforward because the coverage of liquids does not always coincide. However, we will refer to conventional oil in what follows.

Those models which forecast a peak before 2030 estimate the URR of conventional oil to be in the range 1840-3150 Gb, while the three models which forecast no such peak and also provide estimates for the URR suggest larger values of 3345-3577 Gb. As described below, the 'non-peaking' forecasts may be compatible with lower estimates of the URR, but only if conventional oil production declines very rapidly after the peak.

The global URR can be broken down into five constituents that are associated with differing levels of uncertainty (Figure 7.5). These are as follows:

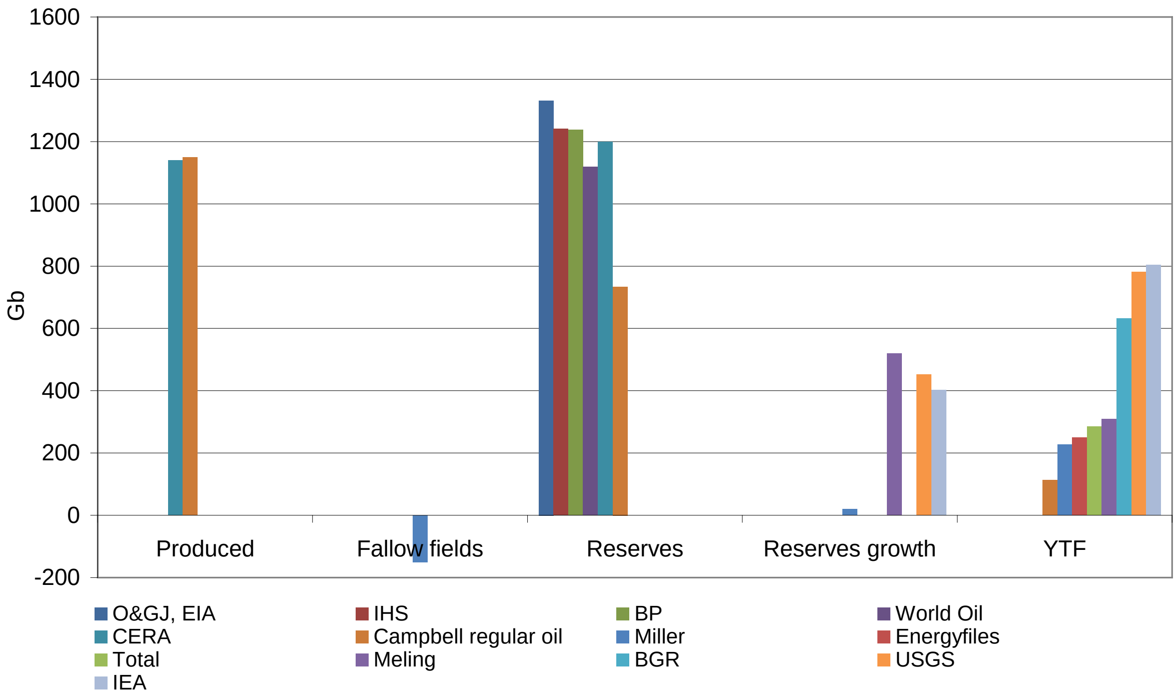
- *Cumulative production:* There is little scope for large differences in estimates of cumulative production. We use a value of 1150 Gb for December 2008.
- *Reserves:* The model estimates for global reserves range from 734 Gb to 1332 Gb, but the liquids covered and reserve definitions do not always coincide. Sources of variation include the adjustment of regional estimates downwards to correct for potential misreporting and the differing treatment of NGLs and oil sands. Nearly all the models implicitly or explicitly use 2P reserves, although there is ambiguity in some cases. The smallest estimate (734 Gb) is from Campbell, who discounts much of the reported Russian and Middle East reserves and also excludes extra-heavy oil, oil sands, deepwater fields, polar fields and NGLs. If Campbell's estimate is excluded, the difference between the largest and smallest reserve estimate is 210 Gb.
- *Fallow Fields:* These fields are discovered but not currently scheduled for development. The IEA (2008) estimates that there are 257 Gb[110] of conventional oil 2P reserves (i.e. 20% of the total) in 1874 known but undeveloped fields and they forecast cumulative production of 220 Gb from these fields by 2030. But Miller argues that up to half of these reserves may not be developed, since they are contained in small, isolated or complex fields that were discovered more than 20 years ago.[111]
- *Reserves Growth:* Campbell takes reserve growth as essentially zero, holding that the industry databases provide fairly accurate estimates of the URR of individual fields. Some models, such as Energyfiles and Miller, take fairly conservative values for reserve growth, while others implicitly accept the USGS mean estimate of 730 Gb for a reference year of 1995. The IEA's 2008 update of the USGS estimates gives a smaller value of 402 Gb, in part because of cumulative production in the interim.
- *Yet-to-Find:* The model estimates for YTF range from 114 Gb to 805 Gb – a difference of some 690 Gb. Some models do not specify YTF directly, referring only to the global URR. Direct estimates include (in order): Campbell 114 Gb ('regular' oil); Miller 227 Gb (crude oil); Energyfiles 250 Gb; Meling 309 Gb; BGR implicitly 623 Gb; and IEA 805

[110] 133 Gb in OPEC countries and 125 Gb in non-OPEC.
[111] 135 Gb were discovered more than 10 years ago, 104 Gb more than 20 years ago and 64 Gb more than 30 years ago.

Gb (all conventional oil). For comparison, BP estimates a YTF of 300-400 Gb. Forecasts relying upon the USGS estimates imply a YTF comparable to that assumed by the IEA.

In conclusion, the models differ largely in their assumptions for reserve 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).

Figure 7.5 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.

7.5 The interaction between ultimately recoverable resources, the aggregate decline rate and the date of peak production

Here we introduce a way of comparing the different forecasts in terms of the key assumptions they make, explicitly or implicitly, for conventional oil production.

Production forecasts for conventional oil vary in two basic respects, namely the area beneath the curve and the ‘shape’ of the curve. Since conventional oil is a finite resource, production forecasts must rise over time to a peak or plateau and then fall away.[112] Even forecasts of quasi-linear production growth up to 2030 must eventually peak and decline. For forecasts extending sufficiently far into the future, the area under the curve represents the URR.

The production forecast can be divided into a growth phase and a decline phase, and perhaps a plateau phase. A change in the height and date of the peak implies a change in either the area under the curve or the shape of the curve. The differences between the various forecasts can therefore be viewed as differences in the assumed URR, the growth rate and/or decline rate and the shape of the peak or plateau. Some of the forecasts use an explicit URR and/or shape of the production curve as input parameters, while others generate one or both as an output. But all can in principle be assessed according to how these parameters compare and whether they can be considered realistic.

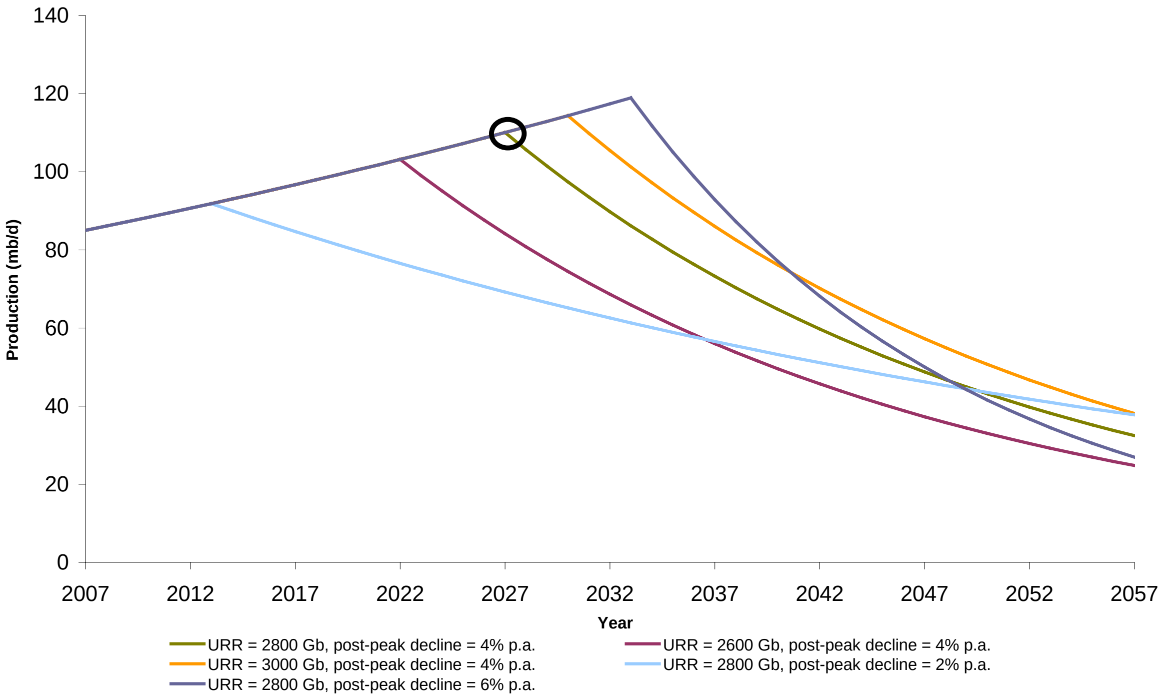
The interplay between the URR, peak date and post-peak decline rate is shown in Figure 7.6. Here all the other parameters have been fixed at values typical of the forecasts studied, specifically:

- 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).
- Production continues for 100 years after peak, and the cumulative production by then is the effective URR. Figure 7.6 shows URRs of 2600, 2800 and 3000 Gb.
- 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 modelled growth rates in the majority of the forecasts (Table 7.5), 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 (Figure 7.1). 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, 2009a).

[112] While multiple peaks are possible, a more plausible scenario is a multi-year plateau in which production fluctuates by a few percentage points (Hirsch, 2008).

Figure 7.6 The effect on the date of peak of varying the URR and the post-peak aggregate decline rate

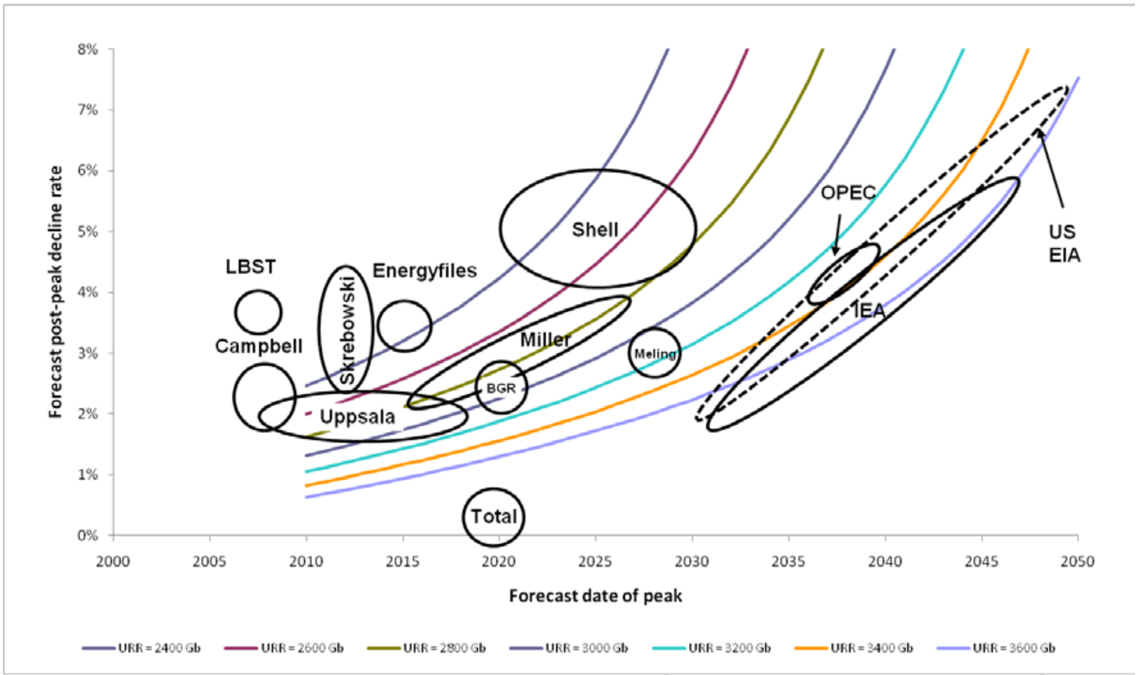


Note: The circled point, for example, indicates the date of the production peak (in 2027) that results from an assumed growth rate of 1.3%/year, a URR of 2800 Gb and a decline rate of 4%/year For a given growth rate and URR, a slower aggregate decline forces an earlier peak and vice-versa.

Figure 7.6 can be re-formulated to focus on three of the key parameters, namely the URR, the aggregate post-peak decline rate, and the date of peak. This is done in Figure 7.7, which plots post-peak decline rate against peak year, where potential URR values are shown by an array of iso-lines. Once values are assumed for any two of these parameters, the value of the third is determined - provided the rate of increase in production prior to the peak is held fixed. Thus any forecast which specifies two of the three parameters can be plotted in this space. Even where a forecast provides only one parameter, by making reasonable assumptions the forecast can also be put in this space, albeit in the form of a region, the constraints of which are set by the assumptions made.

Figure 7.7 shows thirteen of the forecasts as ellipses in this space (Exxon provides insufficient information to allow their forecast to be located). The ‘quasi-linear’ forecasts that show no peak in conventional oil production appear to the right of 2030, while the ‘peaking’ forecasts appear to the left. The assumptions made in constructing these ellipses are summarised in Box 7.3 and Box 7.4. As far as possible, the forecasts are limited to conventional oil, plus current oil sands production. While the required assumptions do not match each forecast in detail, the overall picture remains sufficiently robust to be useful.

Figure 7.7 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 (see Box 7.3 and Box 7.4).

The peaking forecasts are relatively easy to locate on Figure 7.7 (see Box 7.3). 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.

The quasi-linear forecasts are more difficult to locate, since the relevant information is not always provided (see Box 7.4). 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 (Section 3.3), 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 – and as described in Section 3, this is subject to constraints. Taken together, these considerations constrain the minimum decline rate that can be considered reasonable, although precisely what that should be open to debate. We consider that decline rates of less than 2.5%/year would be difficult to justify beyond 2030.

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. Lower decline rates imply more optimistic assumptions for the global URR (e.g. 3000-3600 Gb for 3%/year), but if this is set to more conservative levels the required decline rate appears both inconsistent with the current evidence (Section 3) 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.

Hence, one way of comparing global supply forecasts is to identify the assumed or implied global URR and aggregate decline rate and to assess the plausibility of these assumptions. Some priority should therefore be given to obtaining the data which constrain these parameters. We anticipate an improvement in the understanding of decline rates at every scale, building upon the recent studies by the IEA (2008), Höök, *et al.* (2009b) and others (Section 3). Unfortunately, a consensus on the global URR appears much less likely in the near-term.

Box 7.3 Assumed or implied URR, decline rate and date of peak for the peaking forecasts

- Campbell forecasta a peak in 2008 with an all-oil URR of 2450 Gb. The post-peak aggregate decline rate is about 2%/year, which is the lowest of all the forecasts except for Total and is one reason for the early peak.
- The Peak Oil Consulting model focuses on near-term production up to 2016, where the supply of oil from identified new projects is offset by the decline in production from existing fields. Near-term supply is tightly constrained by the lead time of major projects, because those which will come on-stream within this period must already be committed.
- Energyfiles forecasts a peak in 2017 with a URR of 2685 Gb (Box 7.2).
- Miller's bottom-up field-by–field model is unique in estimating the absolute maximum production that can be achieved, regardless of cost or demand. The URR is 2800 Gb and the peak is around 2018. Because this models the maximum possible production, the potential excess before 2018 is likely to be deferred, leading to a later peak. However, Miller questions whether all of the fallow fields will be developed.
- The BGR forecast 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%/year
- Total forecasts a peak of all-oil at 2020. Although the decline rate and the URR are not stated, we calculate the post-peak aggregate decline to be 0.2%/year This implies a URR of at least 4500 Gb which may be consistent with Total's assumptions. Alternatively, the aggregate decline rate may steepen after 2030.
- Uppsala University forecast a peak between 2008 and 2018. They do not state a URR or an aggregate post-peak production decline rate and assume that the YTF will have no effect on the date of the peak. Their forecast indicates an initial rapid aggregate decline which finally levels off to just under 2%/year
- Meling's forecast has a peak in 2028 and a URR of about 3150 Gb.
- The LBST forecast uses the smallest explicit value of the URR (1840 Gb), and estimates that the peak has already occurred. The aggregate post-peak decline rate is between 3.5 and 4%/year
- Shell suggests that the peak for all-oil production is around 94 mb/d in 2030 in the *Blueprints* scenario, and around 91 mb/d in 2020 in the *Scramble* scenario. Shell uniquely forecast a decreasing demand for conventional oil, by assuming a widespread introduction of electric vehicles.

Box 7.4 Assumed or implied URR, decline rate and date of peak for the quasi-linear forecasts

- 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.[113] 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).[114] Here we use 8% as the upper limit for 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.

[113] The difference of some 6% (and rising) of global production in 2030, or 2.1 Gb/year, would have to be found from reserve 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.

[114] 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 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.

Box 7.5 Different ways of estimating the global aggregate decline rate

- OPEC and the IEA measure or estimate actual field decline rates and adjust these for their expectations of EOR to give an aggregate global decline rate from existing fields. This is then offset by modelling the development of fallow fields and discovery of new fields.
- Some quasi-linear models appear to use an estimate for URR, and assert that any peak will come after a specified date. This then defines what the minimum decline rate must be.
- Some models estimate the depletion rate of a region and use this to support forecasts of how production rates will evolve and decline as the rate of discovery declines.
- Some field by field models such as Energyfiles extrapolate the historical decline rates of post-peak fields in a region to all pre-peak and yet-to-find fields. In these models, the aggregate decline in production is an output, not an input.
- Some authors argue that the global field decline rate will converge on the decline rate of super-giant fields. Unfortunately there is almost no public data on the behaviour of these fields. The production from most of them has also been deliberately controlled up and down to fulfil OPEC quotas, so that there may be very little reliable data on their natural decline rates at all.

7.6 The impacts of rates of discovery, reserves growth and depletion on the date of peak

An alternative approach to judging the plausibility of the forecasts is to ask how realistic is the assumed or implied URR for conventional oil and the date of peak given the historical trends in both new discoveries and reserve growth. Building upon the earlier analysis in Section 3 and Section 6.4, we present some simple ways of looking at this issue.

7.6.1 'Mid-point' peaking

One approach is to use the long-established rule of thumb that production in a region peaks when 50% of the URR has been produced. Using the URR estimates from the USGS (2000), we can investigate this rule by estimating the depletion at peak for 37 countries that have passed their peak of production.[115] This gives a simple mean of 22%, a production-weighted mean of 26% and a maximum of 52%. In other words, most countries to date appear to have reached their peak of conventional oil production well before 50% of their (USGS estimate of) URR has been produced.

At end 2007, the global cumulative production of conventional oil was 1128 Gb and the annual production in 2007 was 80.7 mb/d. If we take the IEA (2008) mean URR estimate of 3577 Gb and assume production growth of 1.3%/year, then the date of 'mid-point' peak is 2027. Larger resources and/or a slower rate of production growth would delay the mid-point while smaller resources and/or more rapid growth would bring it forward. With the possible exception of Total, none of the forecasts assume or imply a larger mean estimate of URR and most assume production growth of around 1.3%/year. Since historical experience suggests

[115] Since the USGS only estimate reserve growth at the global level, this was allocated between countries in proportion to their estimated URR excluding reserve growth. Post-peak countries for which URR estimates were not available were excluded, as was Russia. It is important to note that timing of the peak of production for many of these countries may be influenced by factors other than physical depletion.

that the mid-point rule may be optimistic, this simple calculation sounds a cautionary note to the quasi-linear forecasts.

7.6.2 The 'PFC rule'

An alternative approach is to apply the empirical rule proposed by PFC Energy that production peaks in most regions when cumulative production reaches 60% or less of cumulative 2P discoveries. We can investigate this rule by estimating the ratio of cumulative production to cumulative discoveries at peak for 54 countries that have passed their peak of production.[116] This gives a simple mean of 38% and a production-weighted mean of 36%. In other words, most countries to date appear to have reached their peak of production well before 60% of the cumulative discoveries have been produced.

To apply the PFC rule at the global level, we need an estimate of the future rate of 2P reserve additions through new discoveries and reserve growth. Using the IHS Energy database, the rate of discovery of conventional oil can be estimated at approximately 15 Gb/year over the last 5 years,[117] or roughly half the current annual rate of production. Using the same data source, Klett, *et al.* (2005) estimate that reserve growth added an average of 22 Gb/year between 1996 and 2003, while our analysis in Section 3 suggests an average of 33 Gb/year between 2000 and 2007.[118]

In 2007, the global ratio of cumulative production to cumulative discoveries was approximately 48%. Assuming a new field discovery rate of 15 Gb/year (i.e., no further decline) the expected date of peak production can be estimated from the PFC rule using different assumptions for demand growth and the contribution from reserve growth (Table 7.6). These calculations suggest that to postpone the peak beyond 2030 requires sustaining annual 2P reserve additions around 35 Gb/year, even for low rates of annual demand growth (1%/year). It also implies a URR of at least 3200 Gb. To do the same with higher rates of demand growth requires correspondingly higher rates of annual reserve additions and a larger URR. Since discovery is on a long-term declining trend (Figure 2.8), there are questions over the future scope for reserve growth (Section 3) and historical experience suggests that the 'PFC rule' may be optimistic, this also sounds a cautionary note to the quasi-linear forecasts.

[116] Cumulative production and 2P discovery estimates were taken from the IHS database. The US was excluded since 2P discovery estimates were not available.

[117] As described in Section 2, this could be an underestimate since it does not take into account future reserve growth.

[118] Forecasts of reserve growth may also be made with reference to recovery factors. Combining cumulative 2P discoveries of 2369 Gb, with the standard (although uncertain) estimate for global average recovery factor of 35% gives an estimated original-oil-in-place (OOIP) for discovered fields of 7540 Gb. Assuming that an average of 50% recovery can be achieved in 50 years leads to an estimated annual reserves growth from discovered fields of 22 Gb/year (and URR from these fields of 3770 Gb compared to the 2771 Gb assumed by the IEA). If an average of 50% recovery can be achieved within 30 years, annual reserve growth would increase to 38 Gb/year. A better approach would be to assess the recovery potential of individual fields as a function of technology and expenditure, but to our knowledge, no such study has been attempted at the global level.

Table 7.6 Applying the PFC 60% rule to forecasts of global cumulative production and cumulative discoveries

Demand growth (%/year)	New discoveries (Gb/year)	Reserve growth (Gb/year)	Date of peak production	Cumulative discoveries at peak
1.0	15	0	2021	2593
1.0	15	20	2032	3269
1.0	15	30	2044	4071
1.5	15	0	2020	2577
1.5	15	20	2029	3161
1.5	15	30	2039	3841
2.0	15	0	2020	2577
2.0	15	20	2027	3089
2.0	15	30	2034	3611

7.6.3 Depletion rates

A third approach is to investigate the *depletion rates* (i.e. the ratio of annual production to remaining recoverable resources) implied by the different forecasts and to assess whether these are consistent with historical experience. As described in Section 3, depletion rates reflect physical, technical and economic constraints on the *rate* of extraction of oil fields and regions, with the maximum depletion rate typically occurring near the peak of production. At the regional level maximum depletion rates have typically been less than 5%, with the most rapid depletion occurring in offshore basins (Aleklett*, et al.*, 2009; Höök, 2009; Jakobsson*, et al.*, 2009).

The IEA (2008) is the only quasi-linear forecast that provides sufficient detail to allow depletion rates to be estimated for different categories of field. The IEA projects 114 Gb of new discoveries by 2030 (5 Gb/year) and forecasts these fields producing 19 mb/d by 2030 with cumulative production of 46 Gb (Aleklett*, et al.*, 2009). This implies an aggregate depletion rate of 10% (and rising) from these resources by 2030, which far exceeds the historical experience of any oil-producing region. A comparable analysis for fallow fields suggests even higher depletion rates of 12-13% (and rising) by 2030.[119] In addition to the physical constraints, it is questionable whether OPEC producers would have the incentive to deplete these resources at the rates implied (Dées*, et al.*, 2007; Gately, 2004). But the use of more realistic depletion rates would either imply an earlier peak or require higher rates of discovery and reserve growth. By implication, the same conclusions are likely to apply to the other quasi-linear forecasts.

7.6.4 Bottom-up modelling

Since all these rules are very approximate they should be used with considerable caution. A better approach may be to model the production expected from existing and yet-to-find fields under realistic assumptions of production cycles, discovery rates and likely recovery gains from improved technology. Several of the bottom-up models do this, although their specific assumptions need to be made more transparent and the sensitivity to those assumptions more

[119] Aleklett*, et al.* (2009) argue that "…. the IEA do not seem to be aware that there are physical constraints on the rate of extraction from oil reservoirs". But the standard field production profiles estimated by the IEA (2008) provide a clear demonstration of such constraints.

carefully explored. Nevertheless, the fact that all of these models forecast a peak occurring before 2030 provides a further note of caution to the quasi-linear results.

7.7 Discussion

The comparison of forecasts is far from straightforward owing to the lack of transparency of several of the models, the inconsistencies in the definition and coverage of different liquids and the wide range of methods and assumptions that are used. With the notable exception of Shell, all of the models are used for 'single-value' forecasts and none have been employed to explore a wider range of plausible socioeconomic scenarios. Comprehensive sensitivity testing is essential given the degree of uncertainty over many of the relevant variables, but apart from high and low oil price assumptions it remains the exception rather than the rule.

Nevertheless, contrary to initial impressions, there is a degree of convergence appearing in the forecasts reviewed. Although the range of modelling approaches is wide, the range of dates for the final peak can be closely linked to different explicit or implicit assumptions for the URR and/or post-peak global aggregate production decline rate. The other differences are arguably either secondary or are components of these two parameters. Even some of the quasi-linear models now foresee a levelling off of conventional oil production around 2030. We anticipate that this convergence will continue as better constraints become available, leading to a greater consensus on plausible oil supply futures.

While the above analysis largely excludes non-conventional liquids, the uncertainties for policy-makers concern not only the timing of the peak of conventional oil but also the availability and cost of substitute fuels. Given the speed and scale of substitution that is likely to be required, both the economic potential of non-conventional liquids and the associated lead times deserve urgent and careful study.

For short-term forecasting, the approach of groups such as Peak Oil Consulting appears fairly robust given the lead times on major new projects.[120] However, none of the forecasts reviewed take into account the impact of the global economic recession. If demand recovers over the next two to four years, constraints on oil supply may well occur leading to price spikes (IEA, 2009a). However, these will largely be the result of delayed upstream investment rather than physical depletion.

For medium to long-term forecasting, the number and scale of both 'below-ground' and 'above-ground' uncertainties multiply, making precise forecasts of the date of peak production unwarranted. Nevertheless, it is possible to form some judgment of the plausibility of forecasts that delay the peak of conventional oil until after 2030. These would appear to require some combination (although not all) of the following conditions:

- lower rates of demand growth than are currently assumed (e.g. 1%/year);
- a global URR that is at least 3000 Gb and possibly greater than the mean estimate of the USGS (~3600 Gb);
- fairly rapid decline in production following the peak (e.g. 3%/year or more);
- cumulative production at the date of peak that exceeds 50% of the global URR (i.e. much greater than previously observed in the majority of post-peak regions);

[120] The delay between a major new discovery been announced and the first production flows currently averages 6.5 years. For major offshore fields, the delay can be significantly longer.

- cumulative production at the date of peak that exceeds 60% of cumulative 2P discoveries (i.e. much greater than previously observed in the majority of post-peak regions);
- an annual rate of new discoveries over the period the 2030 that equals or exceeds that achieved over the last decade (i.e. reversing the trend of the last 40 years, despite the declining size of newly discovered fields);
- an annual rate of reserve growth over the period to 2030 that that equals or exceeds that achieved over the last decade (despite the growing share of newer, smaller and offshore fields that have less potential for reserve growth);
- depletion of these resources at an *average* rate that is much higher than the *maximum* rate previously achieved in any oil-producing region; and
- favourable 'above-ground' conditions, including appropriate incentives for investment, sufficient access to prospective areas, political stability and so on in all the major oil-producing regions.

'Quasi-linear' forecasts need to either demonstrate how such conditions can be met or why they do not apply. In our judgment, most of these conditions appear optimistic and more so in combination. This, together with the analysis in Section 6 leads us to the conclusion that *a peak of conventional oil production before 2030 appears likely***.**

Forming a judgement on the timing of peak production in the interim is more difficult. Section 6 concluded that larger estimates for the global URR may be reasonable and hence the assumptions of some of the 'peaking' forecasts overly pessimistic. However, a mix of above and below ground constraints could prevent these resources from being developed at the rate that is required. Also, most of the models do not capture the complex interactions between supply and demand, the likely consequence of which is to turn a sharp peak into a 'bumpy plateau'. The current economic recession may delay the point at which physical depletion leads to supply constraints, but if demand recovers relatively soon the difference is unlikely to be more than a few years. For similar reasons, climate policy seems unlikely to have a significant impact in the medium-term, given the anticipated growth in oil demand in China, India and other industrialising countries. The ability of the oil market to signal an impending peak also deserves to be questioned, given the dependence of current production on a small number of large fields that may soon enter rapid decline (Kaufmann and Shiers, 2008; Reynolds, 1999). The US provides an instructive precedent here: extraction costs remained steady or declined between 1936 and 1970 as production tripled, but then increased more than fourfold within a decade after the peak (Cleveland, 1991). If a similar pattern occurs at the global level, the world is likely to be unprepared.

Given these complexities, we suggest that *there is a significant risk of a peak in conventional oil production before 2020*. As noted in Section 1, the UK is one of many countries that are failing to give serious consideration to this risk.

7.8 Summary

The main conclusions of this section are as follows:

- Comparison of global oil supply forecasts is hampered by the lack of transparency of many of the models, the inconsistency in the definition and coverage of liquids and the range of methods and assumptions used. There is considerable scope for improving consensus by revealing and comparing key assumptions, by systematically exploring the sensitivity of forecasts to those assumptions and by explicit consideration of uncertainties when presenting results. Models of oil supply need to be better integrated with models of oil demand and there is a need to move beyond single-value forecasts toward the broader exploration of wider range of plausible socioeconomic scenarios.

- Despite the apparent divergence between 'peaking' and 'non-peaking' forecasts, a degree of convergence is now becoming apparent. Although the range of approaches is very wide, the forecasts reviewed here rest largely upon different explicit or implicit assumptions for the global URR and/or post-peak aggregate production decline rate of conventional oil. It seems likely that most models would give similar results if they used or implied similar values for these parameters. Hence, priority should be given to constraining these parameters to a greater degree than at present.
- The short term future of oil production capacity, to about 2016, is relatively inflexible, because the projects which will raise supply are already committed. Reasonable short-term forecasts for any region can be constructed using widely available public data. The primary issue for the short term is the cancellation and delay of these projects as a result of the economic recession and the consequent risk of supply shortages when demand recovers.
- For medium to long-term forecasting, the number and scale of uncertainties multiply, making precise forecasts of the date of peak production unwarranted. Nevertheless, we consider that forecasts that delay the peak until after 2030 rest upon several assumptions that are at best optimistic and at worst implausible. Such forecasts need to demonstrate either how these assumptions can be met or why the conditions identified here do not apply. On current evidence, we suggest that *a peak of conventional oil production before 2030 must be considered likely***.**
- It is more difficult to form a judgment on the timing of peak production in the interim, given the multiple 'above' and 'below' ground factors involved. On balance, we suggest that *there is a significant risk of a peak in conventional oil production before 2020*. Given the potentially serious consequences of supply constraints and the lead times to develop alternatives, this risk should be given urgent consideration.

8 Conclusions, research needs and policy implications

8.1 Conclusions

The main conclusions of this report are as follows:

1. **The mechanisms leading to a 'peaking' of conventional oil production are well understood and provide identifiable constraints on its future supply at both the regional and global level.**
    - Oil supply is determined by a complex and interdependent mix of 'above-ground' and 'below-ground' factors and little is to be gained by emphasising one set of variables over the other. Nevertheless, fundamental features of the conventional oil resource make it inevitable that production in a region will rise to a peak or plateau and ultimately decline. These features include the production profile of individual fields, the concentration of resources in a small number of large fields and the tendency to discover and produce these fields relatively early. This process can be modelled and the peaking of conventional oil production can be observed in an increasing number of regions around the world.
    - Given the complex mix of geological, technical, economic and political factors that affect conventional oil production, anticipating a forthcoming peak is far from straightforward. However, supply forecasting becomes more reliable once access is available to the appropriate data and the range of 'possible futures' becomes more constrained once the resource is substantially depleted. This is increasingly the case at the global level.

2. **Despite large uncertainties in the available data, sufficient information is available to allow the status and risk of global oil depletion to be adequately assessed.**
    - Publicly available data sources are poorly suited to studying oil depletion and their limitations are insufficiently appreciated. The databases available from commercial sources are better in this regard, but are also expensive, confidential and not necessarily reliable for all regions. In the absence of audited reserve estimates, supply forecasts must rely upon assumptions whose level of confidence is inversely proportional to their importance – being lowest for those countries that hold the majority of the world's reserves.
    - Data uncertainties are compounded by errors in interpretation and the slow progress towards standardisation in reserve reporting. For example, it is statistically incorrect to simply add the estimates of 'proved' reserves from different oil fields to obtain a regional total. Doing so may lead to an underestimation of reserves at the regional and global level which could potentially offset any overestimation of those reserves by key producing countries. Hence, the debate on oil depletion would benefit from improved understanding of the nature and limitations of the available data.

3. **There is potential for improving consensus on important and long-standing controversies such as the source and magnitude of 'reserves growth'.**

- The distribution of conventional oil resources between different sizes of field is increasingly well understood. Although there are around 70,000 oil fields in the world, approximately 25 fields account for one quarter of the global production of crude oil, 100 fields account for half of production and up to 500 fields account for two thirds of cumulative discoveries. Most of these ‘giant’ fields are relatively old, many are well past their peak of production, most of the rest will begin to decline within the next decade or so and few new giant fields are expected to be found. The remaining reserves at these fields, their future production profile and the potential for reserve growth are therefore of critical importance for future supply.
- Estimates of the recoverable resources of individual fields are commonly observed to grow over time as a result of improved geological knowledge, better technology, changes in economic conditions and revisions to initially conservative estimates of recoverable reserves. This process appears to have added more to global reserves over the past decade than the discovery of new fields and it seems likely to continue to do so in the future. While the contribution of different factors to ‘reserve growth’ varies widely between different fields and regions, it does not appear to be primarily the result of conservative reporting.
- Reserve growth tends to be greater for larger, older and onshore fields, so as global production shifts towards newer, smaller and offshore fields the rate of reserve growth may decrease in both percentage and absolute terms. At the same time, higher oil prices may stimulate the more widespread use of enhanced oil recovery techniques. The suitability of these techniques for different sizes and types of field and the rate at which they may be applied remain key areas of uncertainty.
- The oil industry must continually invest to replace the decline in production from existing fields. The average rate of decline from fields that are past their peak of production is at least 6.5%/year globally, while the corresponding rate of decline from all currently-producing fields is at least 4%/year. This implies that approximately 3 mb/d of new capacity must be added each year, simply to maintain production at current levels - equivalent to a new Saudi Arabia coming on stream every three years.
- Decline rates are on an upward trend as more giant fields enter decline, as production shifts towards smaller, younger and offshore fields and as changing production methods lead to more rapid post-peak decline. As a result, more than two thirds of current crude oil production capacity may need to be replaced by 2030, simply to prevent production from falling. At best, this is likely to prove extremely challenging.
- Oil reserves cannot be produced at arbitrarily high rates. There are physical, engineering and economic constraints upon both the rate of depletion of a field or region and the pattern of production over time. For example, the annual production from a region has rarely exceeded 5% of the remaining recoverable resources and most regions have reached their peak well before half of their recoverable resources have been produced. Supply forecasts that assume or imply significant departures from this historical experience are likely to require careful justification.

4. **Methods for estimating resource size and forecasting future supply have important limitations that need to be acknowledged.**
   - The ultimately recoverable resources (URR) of a region depend upon economic and technical factors as much as geology and can only be estimated to a reasonable degree of confidence when exploration is well advanced. Although widely criticised, simple

'curve-fitting' techniques for estimating URR have an important role to play when field-level data is not available and also have much in common with more sophisticated methods such as 'discovery process modelling'. But they are best applied to well-explored and geologically homogeneous areas with a consistent exploration history. Since many regions do not meet these criteria, errors are likely to result.

- Many analysts have paid insufficient attention to the limitations of curve-fitting techniques, such as the sensitivity of the estimates to the choice of functional form, the frequent neglect of future reserve growth and the inability to anticipate future cycles of production or discovery. This has led to underestimates of regional and global URR and has contributed to excessively pessimistic forecasts of future supply.

- Methods of forecasting future oil supply vary widely in terms of their theoretical basis, their inclusion of different variables and their level of aggregation and complexity. Each approach has its strengths and weaknesses and no single approach should be favoured in all circumstances. Bottom-up models using field or project data provide a fairly reliable basis for near to medium-term forecasts, but many existing models are hampered by their reliance on proprietary datasets, lack of transparency, neglect of economic variables and requirement for multiple assumptions. Sensitivity testing and the presentation of uncertainties remain the exception rather than the rule.

- The timing of a global peak (or plateau) in conventional oil production may be estimated to within decadal accuracy assuming a particular value for the global URR and no significant disruptions to the oil market. But given the potential for political, economic, or technological disruptions, no model can provide estimates of great precision. Increasing model complexity does little to address this problem and is subject to rapidly diminishing returns.

5. **Large resources of conventional oil may be available, but these are unlikely to be accessed quickly and may make little difference to the timing of the global peak.**
    - Although estimates of the global URR of conventional oil have been trending upwards for the last 50 years, the most recent estimates from the US Geological Survey (USGS) represent a substantial departure from the historical trend. Contemporary estimates now fall within the range 2000-4300 billion barrels (Gb), compared to cumulative production through to 2007 of 1128 Gb. This wide range leads to a corresponding uncertainty in global supply forecasts. But despite their apparent optimism, assertions that the USGS estimates are 'discredited' are at best premature. Global reserve growth appears to be matching the USGS assumptions and although the rate of new discoveries is lower than implied by the USGS, the size of these discoveries may have been underestimated and there are continuing restrictions on exploration in some of the most promising areas.

    - The timing of the global peak for conventional oil production is relatively insensitive to assumptions about the size of the global resource. For a wide range of assumptions about the global URR of conventional oil and the shape of the future production cycle, the date of peak production can be estimated to lie between 2009 and 2031. Although this range appears wide in the light of forecasts of an imminent peak, it may be a relatively narrow window in terms of the lead time to develop substitutes. In this model, increasing the global URR by one billion barrels delays the date of peak production by only a few days (for comparison, the cumulative production from the UK is approximately 24 Gb). Delaying the peak beyond 2030 requires optimistic assumptions about the size of the recoverable resource combined with a slow rate of demand growth prior to the peak and/or a relatively steep decline in production following the peak. These considerations constrain the range of plausible global supply forecasts.

- Although more optimistic estimates of the global URR of conventional oil appear plausible, much of this is located in smaller fields in less accessible locations. If (as seems likely) these resources can only be produced relatively slowly at high cost, supply constraints may inhibit demand growth at a relatively early stage. Demand growth may also be constrained if the national oil companies that control much of these resources lack the incentive or ability to invest.

6. **The risks presented by global oil depletion deserve much more serious attention by the research and policy communities.**
   - Much existing research focuses upon the economic and political threats to oil supply security and fails to either assess or to effectively integrate the risks presented by physical depletion. This has meant that the probability and consequences of different outcomes has not been adequately assessed.
   - The short term future of oil production capacity, to about 2016, is relatively inflexible, because the projects which will raise supply are already committed. Reasonable short-term forecasts for any region can be constructed using widely available public data. The primary issue for the short term is the cancellation and delay of these projects as a result of the 2008 economic recession and the consequent risk of supply shortages when demand recovers.
   - For medium to long-term forecasting, the number and scale of uncertainties multiply making precise forecasts of the timing of peak production unwarranted. Nevertheless, we consider that forecasts that delay the peak of conventional oil production until after 2030 rest upon several assumptions that are at best optimistic and at worst implausible. Such forecasts need to either demonstrate how these assumptions can be met or why the constraints identified in this report do not apply. On the basis of current evidence *we suggest that a peak of conventional oil production before 2030 appears likely and there is a significant risk of a peak before 2020*. Given the lead times required to both develop substitute fuels and improve energy efficiency, this risk needs to be given serious consideration.

8.2 Research needs

There is remarkably little contemporary research examining either the risks of a near-term peak in global production or the potential economic, social and environmental consequences. Hence, there is considerable scope for improving knowledge in a number of areas. The following highlights some priorities for future research.

1. **Key parameters that influence global oil supply can and should be estimated to a greater level of confidence**
   - Estimates of the global URR of conventional oil have very wide confidence bounds and the most authoritative estimates are increasingly out of date. While a revised global assessment may be unlikely in the near term, there is a need to update the

assessments for key regions and to evaluate these estimates in the light of regional and global trends in new discoveries and reserve growth.

- The industry databases contain sufficient information to assist in a detailed examination of the experience with reserve growth in different regions of the world. In combination with individual field and regional studies, it should be possible to examine how patterns of reserve growth vary between different sizes and types of field and how they are influenced by economic conditions. This information could be used to underpin more accurate projections of future reserve growth, together with the associated supply forecasts.
- The potential for enhanced recovery at the giant oil fields is of considerable importance for future supply. A detailed technical and economic evaluation of the potential of different technologies, including the lead times involved, would be of great value.
- Understanding of decline rates and depletion rates has improved considerably, but the inconsistencies within and between the available studies require further clarification. Of particular importance is how the average decline rate of post-peak fields may be expected to change over the period to 2030.

2. **Different approaches to studying oil supply and resource depletion need to be more effectively integrated.**
    - Where possible, resource assessments should employ multiple techniques and sources of data and acknowledge the uncertainty in the results obtained. Some of the limitations of curve-fitting may be overcome with the use of hybrid models that use econometric techniques to incorporate relevant economic and political variables.
    - Projections of global oil supply needs to move beyond 'single value' forecasts to a more exploratory examination of competing socioeconomic scenarios. Consensus may be improved by comparing the assumptions of different models and systematically exploring the sensitivity of forecasts to those assumptions. Models should seek to reflect both economic and physical determinants of oil supply and to integrate the determinants of both supply and demand. Forecasting a 'gap' between the modelled supply and assumed demand is as unhelpful as modelling demand and simply assuming that supply will be available.
    - Threats to energy security have interrelated physical, economic and political dimensions which need to be assessed in an integrated fashion. For example, a combination of resource depletion, insufficient incentives for upstream investment and rising internal demand within producing countries could have a significant and potentially rapid impact on the volume of oil available for export.
    - There are grounds for questioning whether oil markets can be relied upon to signal global oil depletion in a sufficiently timely fashion and whether adequate investment in improved efficiency and substitute fuels is likely to be induced. Hence, the behaviour of oil markets in relation to depletion and new investment deserves close examination.
3. **Urgent consideration should be given to the potential consequences of global oil depletion and the options for mitigation.**
    - A peak in conventional oil supply will only be associated with a peak in liquid fuels supply if 'non-conventional' sources are unable to substitute in a sufficiently timely

fashion. But there are major uncertainties regarding the availability, cost and environmental impacts of non-conventional fuels and good reasons to question their potential. Given the speed and scale of substitution that is likely to be required, the technical and economic potential of non-conventional fuels and the associated lead times require careful study.

- Climate policy assessments are usually conducted with little or no reference to oil depletion and frequently rely upon optimistic assumptions about future oil prices. But the transition from conventional to non-conventional fuels is unlikely to be smooth and could have both positive and negative consequences for carbon emissions. Hence, there is a need for more careful assessment of the impact of oil depletion on climate policy and vice versa. This includes the impact of higher oil prices on efficiency improvements, fuel substitution and economic growth.
- The envelope of possible futures includes scenarios in which conventional oil production falls very steeply (e.g. 3-6%/year). This is well beyond that previously experienced, as well as that currently considered within energy and climate policy scenarios. Further analysis is required to assess the plausibility of such scenarios and the measures that can be taken to either prevent their occurrence or mitigate their effects.

8.3 Policy implications

The evaluation of different mitigation options is beyond the scope of this report. However, three general comments may be made.

- First, it seems likely that mitigation will prove challenging owing to both the scale of investment required and the associated lead times.[121] For example, a report for the US Department of Energy argues that large-scale programmes of substitution and demand reduction need to be initiated at least 20 years before the peak if serious shortfalls in liquid fuels supply are to be avoided (Hirsch, *et al.*, 2005). While this report overlooks many important mitigation options (e.g. public transport, electric vehicles) it also assumes a relatively modest post-peak decline rate (2%/year) and ignores environmental constraints. Hence, even 2030 may not be a distant date in terms of developing an appropriate policy response.
- Second, although many mitigation options are consistent with climate policy, the economic impact of oil depletion could create strong incentives to exploit high-carbon non-conventional fuels which could undermine efforts to prevent dangerous climate change. For example, converting one quarter of the world's proved coal reserves into liquid fuels would result in emissions of around 2600 billion tonnes of carbon dioxide (CO_2), with less than half of these emissions being potentially avoidable through carbon capture and storage. This compares to recommendations that total future emissions should be less than 1800 billion tonnes if the most likely global warming is to be kept to 2^oC (Allen, *et al.*, 2009). Hence, early investment in low-carbon alternatives to conventional oil is of considerable importance.

[121] As an illustration, most of the forecasts reviewed in Section 7 project annual reductions in conventional oil production of a least 2%. This is the energy equivalent of 100 nuclear power stations the size of Sizewell B (1 GW) or three times the global installed capacity of wind power (assuming a 30% load factor).

- Third, investment in large-scale mitigation efforts will be inhibited by oil price uncertainty and volatility and seems unlikely to occur without significant policy support. This investment can be encouraged by measures comparable to those being established within national climate programmes. But greater and more rapid change than is currently envisaged could potentially be required. For this to become politically feasible requires both improved understanding and much greater awareness of the risks presented by global oil depletion.

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Annex 1: Project team, Expert Group and contributors

Project Team

The assessment was led by the Steve Sorrell of the Sussex Energy Group (SEG) at the University of Sussex and Jamie Speirs of the Imperial College Centre for Energy Policy and Technology (ICEPT). The contributors were:

- Erica Thompson, Department of Earth Science and Engineering, Imperial College (*Technical Reports 2* and *3*)
- Adam Brandt University of California, Berkley, (*Technical Report 6*)
- Richard Miller, Independent Consultant (*Technical Reports 4* and *7*)
- Roger Bentley, Department of Cybernetics, University of Reading (*Technical Report 7*)
- Godfrey Boyle, Director, Energy and Environment Research Unit, The Open University (*Technical Report 7*)
- Simon Wheeler, Independent Consultant (*Technical Report 7*)

Expert Group

The Expert Group was chosen for its combination of academic and commercial expertise on relevant aspects of oil supply. It met twice during the course of the project, providing input to the initial framing of the issues, literature search, synthesis and drafting. The members were as follows:

- Dr Roger Bentley, Department of Cybernetics, University of Reading
- Dr Ken Chew, IHS Energy
- Dr Richard Miller, Independent Consultant
- Professor John V. Mitchell, Associate Fellow, Energy, Environment and Development Programme, Chatham House
- Chris Skrebowski, Director, Peak Oil Consulting
- Dr Michael Smith, Chief Executive, Energyfiles
- Professor Paul Stevens, Senior Research Fellow, Energy, Environment and Development Programme, Chatham House
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- Professor Robert Kaufmann, Centre for Energy and Environmental Studies, University of Pennsylvania
- Dr Lucia van Geuns, Deputy Head, Clingendael International Energy Programme.

Annex 2: Technical Reports

The results of the full assessment are contained in five in-depth Technical Reports, as follows:

Technical Report 1: *Data sources and issues*
Jamie Speirs and Steve Sorrell

Technical Report 2: Definition and interpretation of reserve estimates
Erica Thompson, Steve Sorrell and Jamie Speirs

Technical Report 3: *Nature and importance of reserve growth*
Erica Thompson, Steve Sorrell and Jamie Speirs

Technical Report 4: *Decline rates and depletion rates*
Richard Miller, Steve Sorrell and Jamie Speirs

Technical Report 5: Methods of estimating ultimately recoverable resources
Steve Sorrell and Jamie Speirs

Technical Report 6: Methods of forecasting future oil supply
Adam Brandt

Technical Report 7: comparison of global supply forecasts
Roger Bentley, Richard Miller, Godfrey Boyle and Simon Wheeler

These reports are all available to download from the UKERC website.