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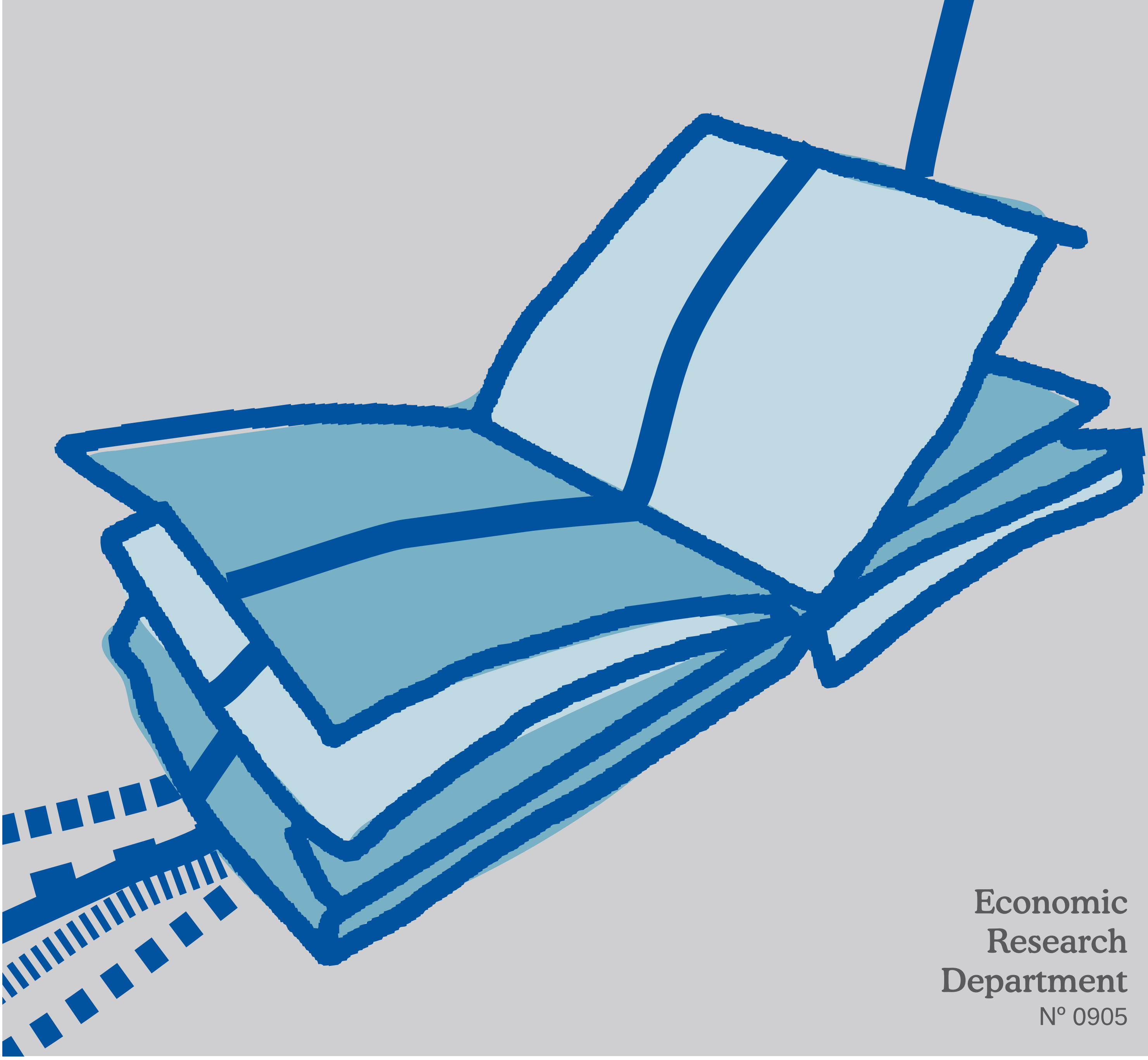

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Main sources of uncertainty in formulating potential growth scenarios for oil supply

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Abstract

The purpose of this paper is to provide an informed contribution to the existing debate on the topic of peak oil and the future sustainability of the prevailing dominant energy model. More specifically, the primary objective is to heighten general awareness of the high levels of uncertainty currently plaguing the future physical potential of global oil supply. The main sources of uncertainty pinpointed in this analysis are rooted, on the one hand, in the general shortage of verifiable information on the volume of existing reserves and, on the other, in our collective hazy knowledge regarding the current rate of decline of the world's oil supply. The reliability of available estimates concerning these two variables has been clearly thrown into doubt by the poor quality and availability of the source data employed.

JEL codes: Q31, Q32, Q38

Key words: Oil reserves, rates of decline, oil, peak oil, Hubbert peak theory, future oil production.

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1. Introduction

Petroleum is an energy-rich hydrocarbon that formed millions of years ago. Since its discovery towards the middle of the nineteenth century, nations worldwide have been struggling to harness it in increasing volumes, so much so that it now forms the backbone of the current energy model. Despite the efficiency gains reported over the last thirty years, the global populace remains heavily dependent on oil to cover over a third of its energy needs, a figure that increases further in more developed economies and reaches its zenith in the transportation industry, where oil accounts for 95% of total energy consumption.

The availability of abundant oil supplies at reasonable prices is, therefore, an absolute must to ensure the healthy running of the global economy and international trade. Nevertheless, whereas oil consumption has increased by over 43% over the last thirty years, the volume of newly discovered conventional oil reserves has slumped by over 50%. In stark contrast to a replacement ratio of 2:1 towards the end of the seventies (two barrels of oil discovered for each barrel consumed), we are currently witnessing a ratio perhaps even worse than 1:3 (three barrels of oil consumed for each barrel discovered).

Despite the fact that oil is indeed an abundant natural resource, its finite nature, coupled with our limited extraction capabilities (as it currently stands, we are only able to extract 35% of the total oil discovered in the subsoil) and the sharp growth in global demand, would all suggest that world oil production could well peak on a global scale within the next two decades, unless we witness major technological improvements and/or a significant reduction in consumption.

Different parties have put forward widely divergent estimates on the probability of this scenario occurring (diverging also on the approximate date on which it could occur). As will be seen, this is largely due to the shortage of reliable information on the value and current state of the main independent variables required to reach an accurate estimate of future oil supply. Of these variables, we would highlight the quantity and quality of estimated oil reserves and the rate at which global production will decline in the future due to natural causes.

In the nineteen fifties, the North American geologist K. Hubbert came up with a theory (coined Hubbert peak theory or simply peak theory), which he used to forecast peak production within the US. To elaborate further, Hubbert claimed that by the mid-seventies U.S.[1] oil production would hit its global maximum at around 3.5 million barrels per day (Mbd). Although actual maximum production in fact turned out to be 4.5 Mbd, the peak did indeed occur in 1970, much to the surprise of many. This fact, combined with the two oil crises of 1973 and 1980, led to rapidly increasing concern and alarm over the question of future oil supply. However, these concerns all but vanished in the wake of the low oil prices prevailing from the mid-eighties onward all the way to the start of the twenty-first century, together with the development of major OECD oil wells.

Between 2005 and 2008, the spike in the price of commodities, particularly oil (Brent barrel prices hit an all-time high of 147 dollars in July 2008), once again brought the issue to the fore and placed it firmly on the front page of political agendas and international economics. Yet the devastating global financial and economic crisis unleashed in the summer of 2008 brought about a sharp and unexpected u-turn in global demand. In less than four months, oil prices plummeted by more than 60% to return to levels not witnesses since 2005.

Although the pressing need to address looming oil challenges has resided considerably in the short term due to the foregoing, most experts still remain concerned about the long term outlook. On the one hand, we can be sure that the current situation of “low” prices (i.e. below the average marginal cost of production, estimated at roughly 70 dollars/barrel), together with the difficulties most oil companies are experiencing in obtaining funding, are combining to foster a scenario of low investment, which could considerably weaken the industry’s future capacity to meet renewed demand following the current recession (ITPOES, 2008). On the other, the stagnation we are seeing in the production of conventional crude since 2005 has rekindled the debate on the validity of the Hubbert peak theory (Korpela, 2006).

We are dealing with an immensely polarised debate. At one end of the spectrum, we have a group made up mostly of retired geologists and engineers who have been brought together under the Association for the Study of Peak Oil (ASPO, founded in 2000), along with other similar non-governmental organisations.[2] This group,

[1] Excluding Alaska

[2] The Oil Depletion Analysis Centre (United Kingdom), The Uppsala Hydrocarbon Depletion Study Group (Sweden), Energywatchgroup (Germany).

which we will refer to as "pessimistic", believes that the global volume of remaining conventional oil reserves is less than generally accepted by, for example, organisations as important as the International Energy Agency (IEA). The pessimists also consider it highly unlikely that discoveries of new reserves will have the required significance to reverse the downward trend we are seeing in the replacement ratio. All this has led them to the conclusion that peak global production of conventional oil is on the near horizon (if indeed we haven't passed it already), and although they are quick to underscore the importance of non-conventional oil (such as natural gas liquids and tar sands), they believe that their potential will be seriously hindered by economic and environmental factors. As a result, they conclude that world oil production (including conventional and non-conventional sources) could reach its global peak before 2030, at levels of between 90 and 100 Mbd.

On the other side of the debate, we have the detractors from peak theory, or the "optimists", who maintain that historic estimates of future global oil supply were proven systematically biased downwards (Lynch 2001). The sceptics are mostly economists who uphold the validity of official figures on reserves and rates of decline and essentially trust that technological advances and prevailing price signals will spur on global oil production to beyond the 110-Mbd mark in 2030. Some experts even posit that peak oil will not result from supply restrictions, but rather from slackening demand stemming from efficiency gains and/or the replacement of oil with alternative superior energy sources, as was the case with coal in the first half of the twentieth century (Smil, 2005).[3]

Although traditionally speaking this latter group had previously boasted the tacit support of industry and most analysts and public bodies, the oil shock experienced between 2005 and 2008 actually tipped the scales in favour of the less optimistic advocates. In addition to the vast range of books written on the subject of *peak oil*,[4] we mustn't forget the warnings of the IEA and numerous analysts, as well as concerns voiced by a growing number of oil companies.

Regardless of the exact date on which global peak oil production will be reached (a topic in its own right not covered by this document), the mere possibility that world oil production could peak within the next twenty years represents (in conjunction with the fight against climate change) the greatest hurdle facing global risk management in the history of modern economics (Hirsch, 2005). If demand is unwilling or unable to react in time, the potential outcome of a prolonged energy shortage could lead to major geopolitical and economic unrest, with associated costs far outstripping those we would incur from adopting preventing measures (WEC, 2007).

[3] Proponents of this idea can find excellent backing in the famous words of Sheikh Zaki Yamani, a prominent former minister of the OPEC, when he claimed *"the stone age came to an end not for a lack of stone, and the oil age will end, but not for a lack of oil"*.
[4] For further illustration, see Porter 2006.

2. Peak oil theory

Practically all of the world's oil reservoirs are typified by an extraction curve characterised by an initial stage (growth), in which production increases, an intermediate stage (plateau), during which production levels off, and a final stage (decline), at which time production drops. Bear in mind that the specific timeline of each curve tends to vary, depending on geological, technical and economic variables, and all too often maximum economic returns take precedence over optimum recovery conditions both technically and geologically speaking.

Oil extraction entails a gradual loss of pressure from inside the well, which must be combated by turning to increasingly complex and expensive techniques. This entails additional consumption of resources, which in turns drags down the Energy Returned on Energy Invested ratio (EROEI)[5]. As the EROEI erodes the profitability of the operation (both financially and in terms of energy), the point can be reached where it is no longer profitable to continue stepping up production. From this time onward, the oil field enters the mature phase, characterised by an initially constant and subsequently declining primary recovery volume. Upon reaching the point when the effort required to produce one barrel of oil outstrips the profit obtained from selling it, the best decision is simply to close down the oil field, even though there may still be petroleum in the subsoil.[6]

Smaller oil fields and/or those located offshore (particularly in deep waters) are typically exploited more rapidly and more aggressively, meaning that they reach their peak more quickly and at higher production levels (measured as a percentage of reserves) than larger/onshore oil fields. These fields therefore reach their peak having produced a higher percentage of their reserves, so that the subsequent decline in production is accordingly more pronounced (IEA, 2008).

If we combine the production curves of all the oil fields of a given region, placing the larger and more profitable fields at the start and the smaller ones towards the end (as tends to be the case when exploring and developing most oil-producing regions), we obtain a bell-shaped curve depicting global production. In 1956, Hubbert formulated this curve for the US, explaining that production growth obeyed the laws of logistics as follows:

$$dQ/dt = aQ(1-Q/Q_0)$$

[5] The Energy Returned on Energy Invested ratio (shortened to EROEI) can be defined as the amount of final energy (oil barrels) obtained per unit of equivalent energy expended in the extraction process.

[6] The first oil extractions in the middle of the nineteenth century were able to provide 50 barrels of oil for each barrel consumed in the recovery, transport and refinery process. Since then, the ratio has been gradually narrowing as companies have had to drill for less accessible petroleum. As it currently stands, we recover between one and five barrels of crude for each barrel expended in the process.

where Q is cumulative production at each reference date t, dQ/dt is the production volume at each reference date t, Q_0 is the total volume of estimated reserves initially-in-place and k is a parameter that reflects the maximum potential production growth rate. Given that the right side of this equation is a parabola whose maximum point is reached at $Q_0/2$, the model predicts that peak oil will occur when half of the initial reserves (Q_0) have been depleted (Korpela, 2006).

With the help of this theory, Hubbert was able to forecast when U.S. oil production would peak, although he was some way off in his prediction for global peak oil, which he claimed would be reached between 1995 and 2000. Proponents of Hubbert's theory put this deviation down to the existence of distorting factors, specifically various restrictions on investing and production, which were barely evident when Hubbert developed his model. Hubbert was therefore unable to anticipate the drop in global oil production and demand in the wake of the 1973 and 1980 crises, nor the resulting raft of policies implemented by the OPEC in an attempt to curb supply, nor for that matter the more recent advent of deep water oil reservoirs and other non-conventional products in global oil supply. Far from invalidating Hubbert's model and all the forecasts based thereon over the years, the "pessimists" believe that the shortcomings described above simply reflect the intrinsically unpredictable nature of what the future holds in store.

Applying this method to currently available information on the volume of global oil reserves initially-in-place (between 2,000 and 2,500 Gb, of which between 800 and 1,300 Gb are estimated to remain), conventional oil would peak somewhere between 2005 and 2013 (Korpela, 2006). According to data from the U.S. Energy Information Administration, production of conventional crude has remained unchanged at around 75 Mb since 2005 (WEC, 2007). As a result, followers of Hubbert theory have now turned their attention to when exactly peak oil will be reached.

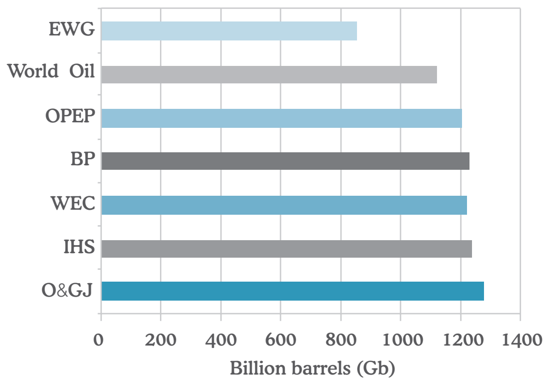
In order to answer this question, we must firstly analyse the main variables that have a bearing on potential future production, leaving aside possible financial and/or geopolitical restrictions. It is advisable in this respect to highlight the volume of existing reserves (how much petroleum we can recover up to the cut-off) and the expected rates of decline (the speed at which production decreases for wells that have already peaked). As we will see, it is impossible to obtain consistent estimates in either case, which has a very negative bearing on the reliability of future supply scenarios.

3. Oil reserves

Of the total oil resources identified in the world's subsoil, current technology only allows us to recover around a third. This volume of potentially recoverable resources, known as *reserves*, is simply the total expected future production. We therefore have no way of knowing the exact volume until the well has been closed down. In the absence of any write-ups of initially estimated reserves, the volume of remaining reserves of an oil field at any given time is equal to this estimated volume initially-in-place less cumulative production to date.

There are various bodies that publish estimates of world oil reserves, most of them private companies. As illustrated in the following chart, the various published figures place remaining reserve volume at around 1,100 to 1,300 billion barrels (Gb). There is a far from insignificant difference of 200 Gb between the lowest and the highest estimates, which in fact comes close to the estimated reserves of Saudi Arabia and equates to over six years of worldwide oil consumption on a global scale.

Estimates of conventional oil reserves (year-end 2007)



Source: IEA 2008, ASPO 2008, Enerdata 2006 and EWG 2008

The main differences between the published figures on existing reserves are largely due to three causes. Firstly, we are missing a clear distinction between *conventional oil* and *non-conventional oil*. The existence of inconsistent definitions for each concept has given rise to significant differences in reserve estimates for countries with vast amounts of non-conventional resources, such as Canada and Venezuela. Secondly, there are key differences in the definition that different countries afford to the concept of *proven reserves*. In the strictest sense, only a small percentage of reserves (US, United Kingdom, Norway and a few other nations) have been effectively *proven*, whereas it is highly likely that all remaining reserves refer to reserves strictly classified as *proved and probable* (Laherrère, 2006). Lastly, there is widespread suspicion that a number of the more prominent OPEC oil producers hiked their oil reserve figures *ad-hoc* in the nineteen eighties, with an aggregate effect of close to 300 Gb, approximately one quarter of the current estimate of remaining global reserves (WEC 2007, IEA 2008, EWG 2007).

3.1 Conventional oil vs. non-conventional oil

The starting point for any assessment is to define the object to be measured. Petroleum (from the ancient Greek word *petrelaion*, meaning "rock oil") is a viscous and relatively dense liquid made up of chains of hydrocarbons of various lengths (from C_5H_{12} to $C_{42}H_{86}$). The particular manner in which these different chains are arranged results in various different kinds of petroleum, which can then be refined to produce a wide variety of end products. The greater the prevalence of short chains, the greater the quality of the extracted oil (in terms of viscosity and density) and the more energy-rich the end products obtained (chemical compounds used within the petrochemical industry, petrol, diesel and kerosene). Longer hydrocarbon chains, in contrast, provide a greater volume of products but with a lower energy value (lubricating oils, fuel oil for heating and electricity production, or bitumen for paving and roof insulation).

When these products are burned for final use, the hydrocarbon chains are converted, together with oxygen from the air, into carbon dioxide (CO_2) and water (H_2O), while releasing an enormous amount of thermal energy. The longer the chains, the greater the release of contaminating emissions, particularly CO_2.

Lastly, there is a common misconception that petroleum accumulates in underground pockets, whereas in reality it tends to be trapped inside the pores of limestone or sandstone formations. The more viscous and dense it is, the more difficult it becomes to extract the petroleum from these pores and pump it to the surface.

Bearing in mind all these geological and physicochemical variables, we can identify the following types of petroleum or oil:

1. Crude or "light" oil: low-density oil that flows freely from the subsoil through the use of classic pumping technologies. The most important remaining reserves are located in the Middle East and Russia. These

offer the lowest extraction costs, at around 5 to 20 dollars per barrel on average.

2. Natural gas liquids (*NGL*): liquid hydrocarbons that are found in natural gas fields and flow to the surface during the gas extraction process. These include propane, butane, ethane, pentane, natural gasoline and other condensates.

3. Petroleum stored under the sea (*offshore*): light crude located at depths of 400m to 1500m, or often deeper than 1500m (*super-deep water*). The main reserves are found in Brazil, the US, Angola and Nigeria. Although the extraction costs vary enormously, they tend to be significantly higher than for conventional crude (64 dollars/barrel for US offshore reservoirs in 2006, according to EIA figures).

4. Polar oil (or *Arctic oil*): light crude found primarily in hard-to-access Arctic zones that generally present a high ecological value.

5. Heavy oils, with high or very high densities:

   5.1. Heavy and extra heavy oil: flows to the surface very slowly, if at all. Requires special infrastructures and production and transport techniques that consume huge amounts of energy and water. Venezuela (Orinoco) and Canada (Alberta) boast the largest resources identified to date.

   5.2. Tar sands: mixtures of sand, water and heavy hydrocarbons (bitumen). They are extracted in compact strips using surface mining techniques. Once brought to the surface, the bitumen is extracted from the rocks and sand. The process is highly intensive in terms of energy and water and produces a considerable amount of contaminating emissions and waste in the form of sand and rock. The largest reserves are located in Canada (Alberta).

6. Synthetic oils, obtained from:

   6.1. Shale oil: shale is a compact sedimentary rock with properties similar to clay. It is impregnated with an organic material known as kerogen, which, once heated to very high temperatures (500ºC), can be converted into a liquid fuel with properties akin to low-quality coal. The shale is extracted through mining techniques, and the whole process is extremely energy and water-intensive, as well as being environmentally unfriendly. Large amounts can be found in the U.S. (Colorado, Utah, Wyoming).

   6.2. Other products obtained from: coal (coal to liquids, or CTL), natural gas (gas to liquids, or GTL) and biomass (biomass to liquids, or BTL). Through the use of laboratory techniques, certain products can be converted into liquid fuels with more or less similar properties to petrol and diesel.

Crude oil (category 1) is what has been largely extracted to date. It currently supplies roughly 85% of oil demand worldwide (EIA, 2007).

Natural gas liquids (category 2) have also been produced en masse for many years and currently account for approximately 11% of the world's oil demand (WEC, 2007).

The other types of petroleum cannot be produced using conventional recovery techniques, either due to problems accessing them or other logistical constraints (categories 3, 4 and 5.2), or because they require different extraction techniques more akin to traditional mining approaches (categories 5.1 and 6.1), or alternatively special synthesis techniques (category 6.2).

Most geologists include light crude and NGL (categories 1 and 2) within the *conventional oil* category, whereas remaining categories are treated as *non-conventional oil*. This classification is used by the World Energy Council (WEC, 2007), the Association for the Study of Peak Oil (ASPO, 2007), the Energy Watch Group (EWG, 2007) and the IEA, although the latter also classifies more accessible offshore and polar oil as conventional oil (IEA, 2008).

That said, the most commonly used databases tend to work around a more economics-oriented definition, according to which conventional oil is that which can be extracted profitably based on current techniques and prices (non-conventional oil would encompass what's left).

Although on the face of it, this definition appears more straight-forward and intuitive, the downside is that it actually draws a subjective and wobbly line between both categories of oil. Expected returns, coupled with the evolution of financial variables, such as the cost of capital, production costs and oil prices, are key inputs. The higher the expectations of the evaluator, the more non-conventional oil will instead be labelled as conventional, and vice-versa.

3.2 Proved, probable and possible reserves

As mentioned above, the *resources* of an oil field reflect the amount of oil that this could contain, whereas *reserves* measure the part of these resources that could be extracted in the future. Drawing an accurate line between resources and reserves is of paramount importance when establishing realistic limits for future production scenarios.

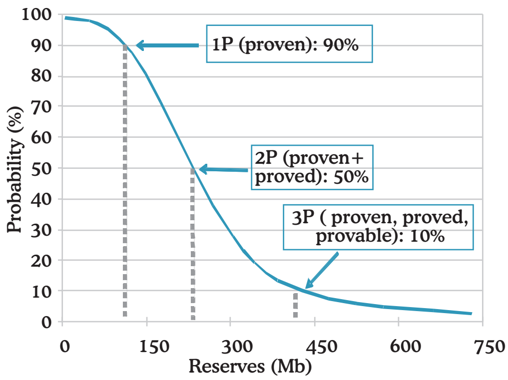
The reserves of an oil field are essentially a percentage of the resources identified (the so-called *recovery factor*), which depends largely on the porosity and permeability of the rock structure in question. There are major differences between the recovery factors observed at different wells. The most permeable and porous rock can boast recovery factors of 85%, while less porous structures will struggle to get past 10%. The average recovery factor worldwide is considered to be 35% (Falcone et al., 2007).

There is currently no generally accepted international standard dictating the minimum requirements needed to prove the existence and quantity of identified oil (and gas) resources, and enabling us to measure and classify estimated reserves (IEA, 2008). The methodologies proposed by the United Nations (1997 and 2004) were ignored by the petroleum industry, which instead opted to formulate its own classification system. In 2001, the Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC) and the American Association of Petroleum Geologists (AAPG) reached an agreement to create a standard for classifying reserves based on their probability of occurrence under commercial conditions. This system, as subsequently updated in 2007, has been coined the Petroleum Resources Management System (PRMS) and draws a distinction between different reserves: *proved, probable and possible.*

Proved reserves (1P or P90) are those for which the extraction probability under commercial conditions amounts to at least 90%, whereas *probable* and *possible* reserves have an assigned a minimum probability of 50% and 10% respectively. By adding *probable* reserves to *proved* reserves, we get the aggregate *proved and probable* reserves (2P or P50), whose cumulative probability of occurrence is 50%. Lastly, the combined total of *proved, probable and possible* reserves gives us the broadest aggregate figure for reserves (3P or P10), whose aggregate probability of occurrence is 10%.

As illustrated in the following chart, proved reserves (1P) afford us a conservative estimate of the potential reserves to be found in a given reservoir.

Reserve distribution at an oil field



Source: BBVA ERD and EWG 2007

The proved reserves (1P) of this particular oil field equal 110 million barrels (Mb), although the greatest probability of actual occurrence (mode) climbs to around 200 Mb, with the median standing at 250 Mb (2P), more than twice the value of the proved reserves.[7] When total reserves for a given country or region are calculated by adding the proved reserves of all its reservoirs, we are in fact underestimating the expected value (or median) of potential future production for the country or region. For this reason, and from a statistical standpoint, adding and comparing reserves between regions on the basis of 1P figures is the wrong path to take. Instead, we should employ 2P figures, which are much closer to the expected mean value of the reserves of a particular field or region.

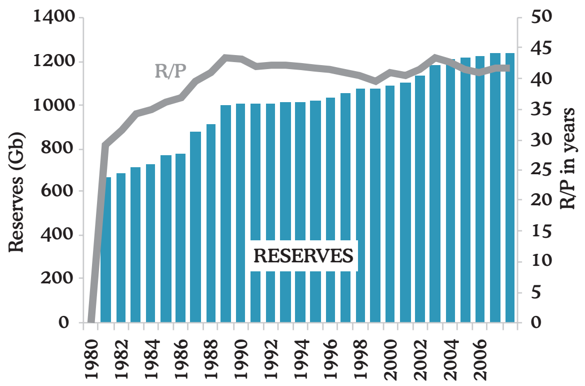
Although there is no widely accepted definition of what is meant by "commercial conditions", it is clear that variations in assumptions made regarding recovery costs, the geology of the reservoir, available technology, access to the markets and final price, amongst other factors, can prompt 2P reserves to be reclassified as 1P (for example, a drop in costs or an increase in the forecast price may result in a reclassification of *probable* reserves to *proved*, or vice-versa).

[7] As we are not dealing with a symmetric distribution (almost never occurs in these cases), the median does not coincide with the mean, although it does measure the closest point to the latter.

Considering that aggregate 1P affords a "prudent" assessment of reserves, the US Securities Exchange Commission has, for many years, been requiring all oil companies operating in the country to publish their proved reserves (1P), a practice which has since been adopted by most international oil companies worldwide. It is interesting to note, however, that these companies continue to base their internal strategic exploration and production decisions on 2P reserves.

As a result, and in an attempt to offset the downward bias inherent in proved reserves, many producing companies and countries often write up their proved reserve figures. When taken as a whole, this practice has helped to create the illusion that global petroleum reserves have been steadily on the up over recent decades, as depicted in the following chart formulated from British Petroleum figures (Statistical Review of World Energy 2008).

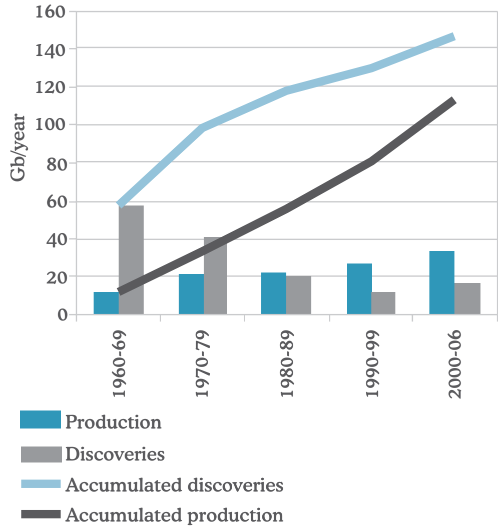
Evolution of the conventional world oil reserves according to BP data (LHS), and R/P ratio (RHS)



Source: BP Statistical Review 2008

According to these figures, the reserves-to-production ratio[8] has remained firmly just above the 40-year mark for two decades, suggesting that pace of reserve replacement and extraction has been progressing apiece. However, the last major discoveries occurred towards the end of the sixties and, as a general rule, the number of new discoveries has failed to keep up with annual oil production since the end of the eighties, as illustrated by the following chart.

Evolution of conventional oil production and new discoveries (average value by decade)



Source: AIE 2008

Over the last 30 years, exploration has only accounted for 50% of newly reported proved reserves, a percentage which has slumped to 35% over the last 10 years (IFP 2007). In fact, and as pointed out by the IEA itself, most of the increase in observed reserves is not due to new discoveries, or for that matter improvements in techniques and economic conditions, but can instead be put down to reserve revaluations, especially within the OPEC, where the value of reserves became a key factor in assigning production quotas at the start of the eighties (IEA 2008, Petroleum Review 2004).

3.3 "Public" data vs. "technical" data

Existing statistical sources on oil reserves can be divided into two groups. In the first group, we have the databases prepared by the *Oil and Gas Journal* (OGJ) and *World Oil* (WO) from information provided directly by oil producing companies and/or nations. As they are either free or relatively easy to access, they are often referred to as "public" databases. These are the most popular and commonly cited sources of the likes of the IEA, the EIA and OPEC itself. Similarly, British Petroleum chiefly relies on the information published by these sources when preparing its well-known yearly statistical report *BP Statistical Review of World Energy*.[9]

Despite their popularity, these databases present a series of drawbacks. Firstly, they fail to pinpoint what reserves

[8] The reserves-to-production ratio (R/P) is generally used to make a quick and approximate calculation of the number of years over which it will be possible to maintain current oil production levels. That said, it presents a number of serious drawbacks that are increasingly rendering its use ill-advised. To elaborate, the ratio is based on the unlikely event that production volume will remain unchanged year after year until the reserves are depleted, at which time production cuts off completely.

[9] In its yearly statistical publication, BP clearly states that the information contained therein comes from various sources consulted (O&G, WO, OPEC) and that it does not, therefore, necessarily reflect the views of the company itself regarding the value of the reserves.

aggregate exactly they employ. They generally refer to proved reserves, which they define as those quantities that *"can be recovered with a reasonable likelihood of success under existing economic and operating conditions"* (BP 2008), without specifying whether the "reasonable" likelihood is 90% (as under the PRMS system) or some other.

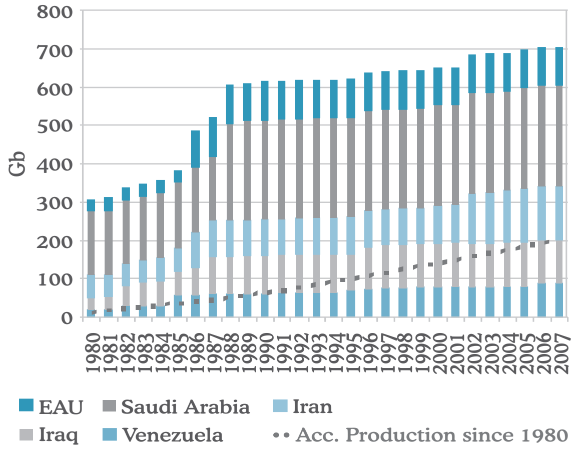
Depending on the reporting country, reported reserves may therefore be closer to the 1P aggregate (most countries from the OECD), the 2P aggregate (most of the remaining countries) or even 3P (Russia) (Laherrère 2001, WEC 2007).[10]

Given the high strategic and political value attached to reserves, reserve figures are kept strictly confidential in most countries around the world (except for the U.S., the United Kingdom and Norway). This makes it practically impossible to verify the accuracy of the information that oil producers furnish to the companies responsible for preparing the public databases, detracting from the credibility of their estimates.

We can find a clear example of this in the saga of strategic write-ups reported in OPEC during the nineteen eighties, which led to an increase in estimated 1P reserves of 300 billion barrels (300 Gb), despite the absence of any major discoveries or significant technological advancements. The successive waves of revaluations can be put down to the agreement reached in 1982 within OPEC, under which the production quotas for each country were to be calculated thereafter on the basis of their reserves. There is evidence to suggest that from 1982 onward, a number of countries started to report the value of their original reserves instead of remaining reserves, whereas others directly inflated their reserves as required in order to ensure they'd be awarded their desired production quota (WEC, 2007; Salameh, 2004).

Moreover, the following chart confirms the fact that since 1990 figures on reserves for most OPEC countries have remained unchanged, which is somewhat surprising in the face of steadily increasing production.[11] In order for this to be possible, the volume of oil produced by each country year after year would have to have been equivalent to the volume of newly discovered reserves (or those reclassified following operating or economic improvements) for each country and year, a multiple event that can be deemed improbable in light of the extensive scope of the sample.

Evolution of the crude oil reserves of main OPEC countries



Source: Energy Watch Group 2007 (based upon data from BP 2006)

In contrast, "technical" databases manage to sidestep most of the drawbacks associated with public databases, although not all of them. These databases are prepared by *IHS* (formerly Petroconsultants) and *Wood Mackenzie* (WM) by following a procedure that involves compiling and aggregating technical data on 2P reserves from thousands of oil fields worldwide. Given that we are dealing with high-value added individual statistics, these sources are not readily accessible by the wider public (yearly subscription costs can reach 1,000,000 dollars, clearly demonstrating the strategic value of thorough reserve data).

By working with 2P aggregates, these databases eliminate a significant chunk of the strategic bias typically associated with public databases. They also backdate their reserve estimates to the year of discovery (i.e., they allocate new average reserve estimates retroactively to the initial year of discovery and/or investment), thereby ensuring that possible adjustments are not confused with new discoveries.

At present, figures published by IHS and WM place global reserves at around 1,200 Gb, not far off the 1,237 Gb reported by BP in 2008, for example. That said, we mustn't forget that BP figures (public) allegedly refer to proved or 1P reserves, whereas IHS or WM figures (technical) refer to 2P reserves, which, as explained above, paint a better picture of the expected value of actual reserves. Adjusting

[10] As already seen, the U.S. and most developed countries tend to publish 1P reserves pursuant to the PRMS system. In contrast, Russia employs the ABC1 classification system, under which, according to experts, overstates the equivalent in 2P reserves by approximately 30% (WEC, 2007).
[11] This is a legitimate phenomenon that has ravaged the OPEC. Over recent years, the reserves of 37 oil producing countries have remained unchanged (Robelius 2007).

the technical figures on 2P reserves by a conversion factor of 75% gives us the technical 1P equivalent, which would be between 25% and 44% less than public 1P figures (Robelius, 2007).

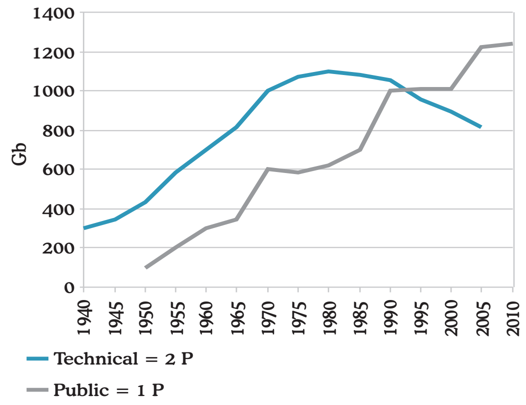
Despite the foregoing, and although still more reliable than public figures, technical data still come up against certain problems. Numerous experts admit that although the results obtained by Petroconsultants at the outset were highly reliable due to the close (albeit informal) ties among the multinational oil giants, the quality of the information would have decayed substantially over recent years due to deteriorating relationships with private industry and the greater clout of state-owned oil companies (WEC, 2007).[12]

In the absence of a better alternative, some independent experts have resorted to working with modified versions of the technical databases, either using the original Petroconsultants data and adjusting it to take on board reported production and new discoveries (ASPO), or combining current IHS or WM data with qualitative information obtained through formal or informal channels (Energy Watch Group).

The following chart, taken from Laherrère 2006, depicts the comparative evolution of O&GJ public data versus the technical data estimated by Laherrère himself.

[12] IHS is the current owner of consultancy firm Cambridge Energy Research Associates (CERA).

Evolution of world oil proven reserves: technical vs. public data



Source: Jean Laherrère 2006

As we can observe, public reserves were much lower than technical reserves up until 1985. This can largely be put down to the fact that the former reflect the 1P aggregate, whereas the latter refer to 2P. Nevertheless, technical reserves start to tail off from 1980 onward due to the effects of cumulative production and the decreasing volume of discoveries. Over the same period, public reserves remained stable and even experienced slight increases. The gap between the two shrinks to nothing as we reach 1990, in the wake of the large-scale readjustments reported within OPEC in the mid-eighties (300 Gb). From then onward, public figures remain unchanged, whereas technical data continue to fall due to the steadily decreasing replacement ratio. On a final note, we can see how O&GJ figures leapt significantly in 2000, spurred by the inclusion of Canadian tar sands (179 Gb). Curiously, this jump is not reflected in the other public databases, as illustrated in the following chart.

Oil reserves in Canada - most recent estimates (Gb)

	Canadian government (AEUB)	BP	OGJ	World Oil	IHS	EWG
Proven conventional and LNG		7		5		
Tar sands: proven/under development	21	21		20.6		
Total proven reserves	**21**	**28**	**179**	**26**	**15**	**17**
Conventional identified resererves						
Tar sands identified reserves	152	152				
Total identified reserves	**152**	**152**				
Total reserves	**173**	**180**	**179**	**26**	**15**	**17**

Source: IEA 2007, EWG 2007, EIA 2008

On the other hand, in the case of OPEC, there is greater consistency among public sources, which place total proved reserves at around the 750Gb mark. As demonstrated in the following chart, the most pessimistic estimates (adjusted technical figures) would wipe up to 50% off the figures upheld by OPEC, based on "public" databases, and widely relied on by most international bodies and economic analysts.

Crude oil reserves in main OPEC countries (Gb)

Country	Oil & Gas Journal (a)	BP Statistical (b)	Campbell (c)	Bakhtiari (d)	IHS	EWG
Iran	132.5	132.5	69	35 - 45	134	44
Iraq	115	115	61	80 - 100	99	41
Kuwait	101.5	99	54	45 - 55	51.6	35
Saudi Arabia	264.3	262.7	159	120 - 140	286	181
U.A.E	97.7	97.8	44	40 - 50	56.6	39
Total	**711**	**707**	**387**	**320 - 390**	**627.2**	**340**

Source: Bakhtiari 2006(based upon different sources: a) O&GJ, 19 December 2005; b)BP 2005; c) ASPO, February 2006; d) Bakhtiari, February 2006).

3.4 Future improvements to the recovery factor

Although each oil field presents its own unique recovery profile, we can identify three generic yet distinct phases from a technical standpoint.

During the first stage, production steadily increases while the field is being gradually constructed and extended to reach its optimum projected size. In this phase, the natural internal pressure of the well bore is enough to pump petroleum to the surface through conventional "primary recovery" techniques (vertical wells). Over time, however, this pressure drops off and the recovery level begins to deteriorate. As a general rule, this first stage accounts for between 10% and 20% of the petroleum present in the reservoir.

Economic conditions permitting, recovery will move to the second stage, where an attempt is made to restore the internal pressure of the well. To achieve this, companies resort to secondary recovery techniques, which include the use of special recovery pumps and water flooding or gas injections (natural gas). This stage tends to recover a further 10% to 20% of the petroleum identified in the subsoil. One of the main side effects of using these secondary recovery techniques is that they increase the volume of water present within the well, which, in turn, increases the amount of water obtained per unit of liquid recovered (a variable known as *water cut*).

When the techniques employed during the second stage prove insufficient and/or the water cut is too pronounced, recovery may move on to a third stage, where much more sophisticated and expensive tertiary or *enhanced oil recovery* techniques are employed. These techniques attempt to modify the chemical properties of the petroleum to reduce its viscosity and make it easier to separate from the rock. The process essentially involves injecting chemical compounds or gases such as CO_2, and applying a range of different thermal heating techniques. Use of enhanced oil recovery allows for recovery of a further 15% of existing resources in the reservoir, albeit at a relatively high cost and with a notable reduction in EROI, which is why its use tends to be limited to already mature fields, those with high operating and maintenance costs (offshore, polar, etc.), or non-conventional oil fields at which the primary recovery factor is heavily reduced.

On average, making full use of all available techniques (provided this proves commercially viable), the global oil industry is able to extract between 27% (Laherrère, 2006) and 35% (Schulte, 2005) of the total resources identified in the subsoil. It is worth noting that this *recovery factor* is not a technical parameter, but rather an estimate of the quotient between observed cumulative production and resources initially-in-place. This means that the greater the uncertainty shrouding the quality of available information on resources and production, the less reliable our estimates on the recovery factor will be.

The range of projections on how the recovery factor will pan out is making it difficult to estimate production potential. Just as the discovery of, and successive improvements to, secondary and tertiary recovery techniques have boosted the recovery factor in the past, this process expected to prove ongoing in the future. According to the IEA, an increase of just one percent in this factor would lead to an 80 Gb jump in global oil reserves (equivalent to 10% of the least optimistic estimate on proved reserves worldwide). This means that an increase of fifteen percent in the recovery factor (to bring it to 50%) would practically double current global reserves reported by public sources (IEA, 2008). That said, the IEA itself has warned that it could take several decades for this to become a reality. In fact, the global model underpinning the European Commission's *World Energy Technology Outlook* project (the POLES model) assumes a recovery factor of 47% for 2050. While some experts consider it unlikely that we will ever reach this scenario (Laherrère, 2006), others are even more upbeat and point to future recovery rates of over 50% (Smil, 2005).

3.5 Potential for new discoveries

At a given recovery factor, oil reserves can also increase when new resources are discovered. One of the main reference points in this field is the last report published in 2000 by the U.S. Geological Survey (USGS). This particular report paints three scenarios, under which planet Earth would have reserves initially-in-place of between 2,000 and 4,000 Gb.

- ✓ **Scenario P95**: resources initially-in-place of 2,300 Gb. Assigned probability: 95%.
- ✓ **Scenario P50**: resources initially-in-place of 3,200 Gb. Assigned probability: 50%.
- ✓ **Scenario P5**: resources initially-in-place of 4,000 Gb. Assigned probability: 5%.

Irrespective of the scenario, roughly 1,000 Gb had already been consumed by 2000, suggesting that remaining reserves stood at between 1,300 and 3,000 Gb in 2000.[13] These estimates refer to both discovered and as-yet undiscovered reserves, whose overall probability of occurrence varies depending on the scenario. Taking the central (P50) scenario as an example, proved reserves account for 50% of total resources, whereas unproved reserves and undiscovered resources represent 17% and 35%, respectively, of the total.

The USGS study has come in for considerable criticism from ASPO for years and, more recently, from the Energy Watch Group (EWG, 2007). The main criticism levelled at the study concerns the fact that actual occurrence of the scenarios put forward (particularly the P95 scenario, although also the central one) entails a very optimistic view of the volume of future discoveries, an outlook in marked contrast with the downward trend observed in recent decades.

The central scenario, for example, assumes that we will discover 800 Gb of additional reserves, nearly triple current reserves in Saudi Arabia. For this to happen, we would need to discover the equivalent of 20 Gb a year between 2000 and 2030. Since 2000, however, the actual average yearly volume of new discoveries has failed to get past 17 Gb (IEA, 2008; EWG, 2007).

For this very reason, the more pessimistic observers believe that the best present estimate regarding the amount of conventional oil we will be able to extract in the future (2P reserves) is more in the region of 1,000 Gb.[14] In contrast, more optimistic groups believe that the central USGS scenario is in fact feasible and that we will still be able to recover around 2,000 Gb.

3.6 A brief note on the future potential of non-conventional oil

It is estimated that the world has between 6,000 and 7,000 Gb of non-conventional oil, mostly found in Canada (2,700 Gb), the U.S. (2,600 Gb) and Venezuela (1,200 Gb). That said, estimated reserves come in much lower at around 600-700 Gb (173 Gb in Canada, 270 Gb in the U.S. and 160 Gb in Venezuela). The implied recovery factor (10%) is much lower than that associated with conventional oil due to the specific characteristics of this kind of oil, as already explained in section 3.1 above.

There are also numerous limitations stemming from the intensive energy requirements, high levels of resulting contamination and the low commerciality of extracting non-conventional oil.

[13] Since then, over 200 Gb have been consumed.

[14] Remember that the 2P reserves aggregate has a 50% cumulative probability of occurrence.

Firstly, the process is extremely water and energy-intensive. For example, Canada, the world's leading producer of non-conventional oil, has already encountered water and natural gas supply problems for its tar sand recovery operations. More specifically, rising natural gas prices are jeopardising the continuing viability of numerous projects. It is estimated that Canada will need to consume more than twice its current natural gas reserves to be able to extract all the tar sand reserves present in its subsoil (Robelius, 2007). In light of these concerns, Canada has been weighing up the merits of constructing a number of nuclear power plants based on the best-case scenario that it could quadruple its current production of non-conventional oil by 2030, thereby bringing its current one million barrels a day to 4-5 million in 2030. This would account for roughly 5% of estimated global demand for 2030.

The heavy dependence on energy and water unfortunately entails a hefty environmental impact. Specifically, the process generates vast amounts of greenhouse gas emissions (three times above those associated with conventional oil recovery operations in Canada for example), and likewise requires proper management of the rock waste produced by the extraction process (approximately 1 ton of rock per barrel).

Economic and environmental restrictions are particularly pronounced in the case of shale oil production in the U.S.. The resulting EROEI is very weak and the economic and environmental costs simply too high to predict any more than 1-2 million barrels a day in 2030.

Looking to Venezuela, the need to develop the necessary infrastructures to step up production of extra-heavy oil from within the Orinoco Belt could prove to be a major hurdle unless investment conditions improve in the region. With this in mind, the region is not expected to produce more than 4 million barrels a day in 2030 (Robelius, 2007).

On a final note, future projections for deep-water oil production remain very promising up to 2012, with maximum production expected to come in at 10 Mbd. From 2012 onward, however, production will drop off sharply and will plummet to under 2 Mbd in 2030 (Robelius, 2007).

Combining all currently available information, neither the IEA nor the EIA expect non-conventional oil to contribute much more than 10 Mbd in 2030, somewhat less than 10% of demand for the year according to the latest IEA estimates (106 Mbd).

However, it is interesting to note that whereas with conventional oil, barrel prices play only a minor role when it comes to bringing about an increase in reserves, in the case of non-conventional oil, oil price trends are key. Higher oil prices boost the commerciality of oil production with tar sands, oil shale, biofuels or synthetic fuels.

Nevertheless, even against a backdrop of high oil prices, one of the main factors dragging on development of non-conventional oil is likely to be the huge environmental costs involved. If the fight against climate change continues and efforts to reduce emissions proliferate, the future of non-conventional oil appears bleak, unless significant progress is made on carbon capture and storage technologies. Even if such progress is made, it is highly likely that the total cost of the entire process, ranging from oil extraction to final carbon sequestration, will prove prohibitively high, forcing us to turn to other sources of alternative energy, such as second generation biofuels, electricity or hydrogen.

4. Structure of current production and rates of decline

Returning our attention to conventional oil, and even if we employ enhanced recovery techniques, there will come a point when the volume of oil extracted from a reservoir begins to drop off, whether due to geological factors or simply because upping production is no longer commercially viable. The oil field is said to achieve maturity at this stage. Over the initial years of this mature stage, oil field production remains relatively unchanged following a kind of undulating plateau pattern. The number of years during which a field can remain in this state varies enormously, depending on its natural features and the operating profile applied. For example, in the case of very large onshore oil fields, production can remain in the plateau stage for decades (IEA, 2008). Yet sooner or later, production will succumb to the laws of physics and/or economics and will begin to wane, marking the start of the decline stage.

The yearly rate at which production declines (known as the rate of decline or depletion rate) depends on the age of the oil field, its geomorphologic features and the operating profile applied. This rate is key to obtaining accurate estimates on the future production potential of existing infrastructures, and the extent to which the latter must be expanded to supply projected future demand.

If we are to obtain a reliable yardstick of the global rate of decline, we must have individual and broken-down information on the production profiles of all the oil fields that are contributing to current oil supply. This would encompass roughly 70,000 fields, all presenting different characteristics and each at its own operational stage (growth, plateau, decline). Although such a database has not been constructed yet, work has been conducted to bring us one step closer to the global rate of decline by extrapolating (taking the necessary precautions) the rates observed in those oil fields for which we already have sufficient information.

The two most noteworthy initiatives were rolled out recently. The first was conducted by specialist consultancy CERA (an IHS company). The main conclusions were published in the 2007 *Finding the Critical Numbers* report (restricted access). The second was carried out by the IEA, with the conclusions published in the latest World Energy Outlook (WEO) edition for 2008 (public access).

In its report, the IEA presents an in-depth analysis of the historical production performance of 798 oil fields worldwide, which jointly account for 60% of current global production.[15] The report concludes that the size of the fields (measured in terms of their 2P reserves), coupled with their location (onshore or offshore), are the two main driving forces behind production. The greater the size, the lower the level of maximum production reached (peak) and the less the observed rate during the decline stage. The observed rates of decline are clearly more pronounced in smaller and offshore oil fields, particularly those operating at great depths.

Of the 70,000 oil fields in existence worldwide in 2007, a mere 110 accounted for over 50% of global conventional oil production[16] and, surprisingly, 27% of this oil was recovered from just 20 super-giant fields, as depicted in the following table (IEA, 2008).

[15] This database includes all 54 of the world's *super-giant* oil fields (fields with 2P reserves initially-in-place of over 5 Gb), as well as 263 of the 320 *giant* oil fields (2P reserves above 0.5 Gb). Of the 481 remaining fields, 285 are classified as *large* (2P reserves of above 0.1 Gb) and represent over 50% of this kind of field worldwide. The remaining fields making up the 798 total are small fields (with less than 0.1 Gb of 2P reserves). According to the IEA, the main source of primary information consulted to compile the database was IHS.

[16] 70.2 million barrels a day. Excluding natural gas liquids (NGL).

Field	Country	Location	Classification by 2P reserves	Year of discovery	Peak annual production		2007 production	% World conventional oil poduction	Status at 2007
				Year	Year	kb/d	kb/d		
Ghawar	Saudi Arabia	Onshore	Super-giant	1948	1980	5,588	5,100	7%	Plateau
Cantarell	Mexico	Offshore	Super-giant	1977	2003	2,054	1,675	2%	post-peak
Safaniyah	Saudi Arabia	On/off	Super-giant	1951	1998	2,128	1,408	2%	post-peak
Rumaila N&S	Iraq	Onshore	Super-giant	1953	1979	1,493	1,250	2%	post-peak
Greater Burgan	Kuwait	Onshore	Super-giant	1938	1972	2,415	1,170	2%	post-peak
Samotlor	Russia	Onshore	Super-giant	1960	1980	3,435	903	1%	post-peak
Ahwaz	Iran	Onshore	Super-giant	1958	1977	1,082	770	1%	post-peak
Zakum	Abu Dhabi (UAE)	Offshore	Super-giant	1964	1998	795	674	1%	post-peak
Azeri-Chirag-Guneshli	Azerbaijan	Offshore	Super-giant	1985	2007	658	658	1%	Plateau
Priobskoye	Russia	Onshore	Super-giant	1982	2007	652	652	1%	Plateau
Top 10						**20,300**	**14,260**	20%	
Bu Hasa	Abu Dhabi (UAE)	Onshore	Super-giant	1962	1973	794	550	1%	post-peak
Marun	Iran	Onshore	Super-giant	1964	1976	1,345	510	1%	post-peak
Raudhatain	Kuwait	Onshore	Super-giant	1955	2007	501	501	1%	Plateau
Gachsaran	Iran	Onshore	Super-giant	1928	1974	921	500	1%	post-peak
Qatif	Saudi Arabia	On/Off	Super-giant	1945	2,006	500	500	1%	Plateau
Shaybah	Saudi Arabia	Onshore	Super-giant	1968	2003	520	500	1%	Plateau
Saertu (Daquing)	China	Onshore	Super-giant	1960	1993	633	470	1%	post-peak
Samotlor (main)	Russia	Onshore	Super-giant	1961	1980	3,027	464	1%	post-peak
Fedorovo-Surguts	Russia	Onshore	Super-giant	1962	1983	1,022	458	1%	post-peak
Zuluf	Saudi Arabia	Offshore	Super-giant	1965	1981	677	450	1%	post-peak
Top 20						**30,240**	**19,163**	27%	

Source: IEA 2008

As we can see, the world's twenty largest oil wells have already reached their peak and 70% of them have actually entered the decline stage (post-peak). The report also confirms that approximately 35% of conventional oil production worldwide comes from wells that were commissioned before the nineteen seventies.

After due analysis of the production profiles of all the oil fields included in its database, the IEA concludes that 48% of 2P reserves initially-in-place have already been recovered. Fields that have been in operation for longer periods and/or had their oil extracted more aggressively will experience sharper rates of decline. In a similar vein, the observed rate of decline is greater the smaller the size of the field or if the field is located offshore, particularly in deep waters. Large fields tend to take nearly twice as long to peak in comparison to smaller fields, while reporting comparatively lower peak production levels (calculated as a percentage of their reserves). In the decline stage, their production also drops off less abruptly.

In order to estimate the worldwide observed rate of decline, the IEA bases its calculations on the average observed rate for all oil fields in the sample that have entered the stage of decline (a total of 580), leading it to a value of 5.1%. Given that most fields included in the report are either *super-giant* or *giant*, and in light of the high negative correlation between observed rates of decline and the size of the wells, the IEA has applied an offsetting upward correction factor to estimate the global observed rate of decline. The remaining fields worldwide (over 69,000) have therefore been assigned a rate of decline of 10.4%, the same as that observed in the smaller fields covered by the study. As these fields are in fact *large* (having reserves of 0.1 Gb or more), the IEA warns that the global observed rate of decline reached from its estimates should be considered a lower limit for the actual value.

The results point to a 6.7% *observed*[17] rate of decline for all fields worldwide that are currently in decline. The IEA offers no clues as to the percentage of global production that is currently in decline, making it impossible to estimate the appropriate global average rate for making comparisons with other references. That said, based on the assumed profile for formulating its estimates of conventional oil recovered from existing wells up to 2030, we can deduce an average global rate of decline of 4-5%. This finding coincides with the 4.5% estimated by CERA in 2007, although this is not entirely surprising when we consider that both analyses were based on similar information (both from IHS). Let us not forget, however, the lower limit proviso that the IEA itself attached to its estimate. Although the latter figures are certainly less worrying than the initial figure of 6.7%, what this study does reveal is the need to revise upwards the rates of decline of 3-4% which were used until very recently by most long-term supply projections.

[17] The *observed* rate mustn't be confused with the *natural* rate of decline, the latter being the rate that would have been observed had no investments been made to curb the decline of the wells. According to the IEA, the actual rate of decline would be between two and five percent above the *observed* rate.

5. Conclusions

This report has attempted to outline some of the reasons why current official projections concerning future oil supply should be treated with caution. More precisely, we have analysed the importance of the volume of conventional oil reserves and the rates of decline in production, and we have also seen how the shortage of verifiable high-quality information on these two variables plays a central role.

The poor quality of available information on reserves is largely due to the strategic nature of such data, the lack of an international classification standard and the total non-existence of control mechanisms enabling us to verify the accuracy of the figures provided by oil producing nations. The contrasting global estimates available today present 2P figures that vary by up to one billion barrels (1000Gb). To provide some idea of the impact this can have on oil supply, suffice to say that the most pessimistic and most optimistic scenarios are 15 to 25 years apart in their prediction of when we will hit global peak oil (Hallcock et al. 2004). In light of the foregoing, and until we are able to overcome the bulk of these problems, available data on reserves must be treated with extreme caution.

In relation to the natural rate of decline for the purpose of predicting supply, although the latest report published by the IEA on world energy (World Energy Outlook 2008) features the most thorough public analysis yet undertaken, its conclusions are less illuminating than originally hoped, due, once again, to the serious limitations affecting available data.

As if the dire shortage of verifiable information on current reserves and rates of decline was not enough, we also have widespread uncertainty surrounding the future evolution of new discoveries and recovery rates, as well as the important role that technological improvements and oil prices could play. Looking ahead to 2030, IEA projections place global oil demand at around 106 Mbd (assuming an average annual growth of 1%). This implies cumulative oil consumption of 800 Gb up until 2030, equivalent to more than 80% of the remaining reserves of conventional oil as estimated by the pessimistic group, and somewhere over half of reserves according to the optimists.

If we make a simple and conservative calculation of future oil production needs (based on quite conservative assumptions such as an average annual growth in demand of 0.05% and an average rate of decline of 3% yearly), global oil demand in 2030 would stand at 96 Mbd (for comparison, the IEA projects a 106 Mbd demand for the same horizon). Note that, in order to supply this volume of demand, we would need to expand net production capacity by 83 Mbd (20 Mbd to cover the increase in demand and 63 Mbd to offset the drop in production), equivalent to eight times the current installed capacity of Saudi Arabia.

If the required investments therefore are not made, a scenario of oil price and supply instability is a distinct possibility, coupled with a gradual worsening of conditions once the current world recession recedes. Longer term, we will also need to witness a sharp drop in demand or an unexpected increase in reserves if we hope to meet the oil demands of all economies worldwide.

In both cases, technology must take centre stage by enhancing energy efficiency and the use of alternative energies to petroleum, or by paving the way for new discoveries or improvements to the recovery factor. The longer world economies take to recognise the current situation and take the steps required to encourage rational energy consumption and to make the gradual transition from petroleum to alternative energies, the greater the risks and costs will be in the wake of global peak oil.

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