World oil and gas resources: status and outlook – A rational attempt at an emotional issue

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Keywords: Oil, gas, oil reserves, gas reserves, worldwide resources, E&P, exploration, peak oil, peak gas, Hubbert curve, alternative energy, hydrocarbons, unconventional hydrocarbons, oil price, technology, seismic, fossil energy.

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Summary
Only about $^1/_4$ of the world's estimated ultimately recoverable oil resources and $^1/_6$ of the ultimate gas resources have been produced until today. The present strain in the supply and demand balance of hydrocarbon resources is therefore not primarily a problem of geological reserves of oil and gas. It is mainly caused by bottlenecks in the capacity of production and transport infrastructure resulting from underinvestment by the industry in the 90's. This is difficult to rectify in the short term, given the long lead-time needed to bring new developments on stream.
Very significant reserve additions are expected not only from the still existing exploration frontiers (e.g. in the deepwater and the Arctic) but even more so from new hydrocarbon detection tools, advanced recovery technology and from unconventional oil and gas resources. The latter group is a part of the over 90% of hydrocarbons that were generated in the subsurface but not trapped in conventional prospects.
This still solid resource situation should buy the world the time required to develop alternative and economically competitive fuels. Large contributions from new energy sources are needed before the middle of this century to stem the unsustainable rate of oil and gas demand growth in developing countries and to counter the increasing environmental concerns. The end of the hydrocarbon age will not come with the depletion of geological oil and gas reserves in the ground; it will come when a better, cleaner and affordable energy becomes available.

Zusammenfassung
Nur $^1/_4$ der gesamten geschätzten, gewinnbaren Ölressourcen und etwa $^1/_6$ der Gasressourcen der Erde wurden bis jetzt gefördert. Die zurzeit beobachteten hohen Ölpreise und die Spannungen im Gleichgewicht zwischen Angebot und Nachfrage von Öl und Gas sind nicht primär das Resultat zu knapper geologischer Reserven, sondern werden verursacht durch Engpässe in der Produktions- und Transport-Infrastruktur, eine Spätfolge von ungenügenden Investitionen der E&P Industrie in den 90'er Jahren. Diese Situation ist kaum kurzfristig zu lösen, in Anbetracht der langen Zeiträume, die zur Entwicklung neuer Felder benötigt werden.
Wesentliche neue Öl- und Gas-Volumen werden nicht nur vom immer noch beträchtlichen Explorationspotential erwartet (z.B. Tiefwasser und Arktis), sondern werden vor allem durch technologische Fortschritte ermöglicht, wie z.B. eine direkte Erkennung von Kohlewasserstoffen im Untergrund oder Techniken, die eine viel höhere Ausbeute in den Feldern erlauben. Sehr grosse, weitgehend ungenutzte Ressourcen liegen in so genannten unkonventionellen Öl- und Gas-Akkumulationen. Sie sind ein Teil der weit über 90% der Kohlewasserstoffe, die in den Sedimentbecken der Erde zwar generiert, aber nicht in konventionellen Strukturen gefangen wurden.
Die immer noch relativ solide Ressourcen-Situation sollte der Welt die Möglichkeit geben, um noch vor der Mitte diese Jahrhunderts alternative, wirtschaftlich konkurrenzfähige Treib- und Brennstoffe zu entwickeln die benötigt werden, um den langfristig nicht haltbaren, hohen Öl- und Gas-Wachstumsraten in den Entwicklungsländern entgegenzuwirken und um der Umweltproblematik Rechnung zu tragen. Das Ende des Zeitalters der Kohlewasserstoff-Verbrennung wird nicht durch die Erschöpfung der geologischen Reserven bestimmt werden, sondern durch die Verfügbarkeit eines besseren, umweltfreundlicheren und erschwinglichen Brennstoffes.

Résumé
A l'échelle mondiale seulement $^1/_4$ des ressources pétrolières ultimement récupérables et environ $^1/_6$ des ressources de gaz ont été extraites jusqu'à présent. Le prix élevé du brut et le déséquilibre actuel entre la production et la demande en hydrocarbures n'est pas un problème de réserves géologiques. Il est surtout le résultat d'une capacité de production insuffisante, qui a son origine surtout dans un manque d'investissement de l'industrie pétrolière dans les années 90. Cette situation est difficile a rectifier a court terme, vu les périodes très longues qui sont typiques pour la découverte et la mise en production d'un gisement.
D'importantes quantités supplémentaires d'huile et de gaz seront encore découvertes par l'exploration (par exemple en mer profonde et dans l'Arctique). Mais c'est surtout le progrès de la technologie pétrolière qui permettra un perfectionnement dans la détection directe des hydrocarbures et une exploitation beaucoup plus efficace des champs. A cela s'ajoutent de très grandes ressources non-conventionnelles, représentant une partie des hydrocarbures générés dans les bassins sédimentaires, estimée à plus de 90%, et qui n'a pas été piégée dans des structures conventionnelles.
Ces ressources probables devraient donner au monde le temps nécessaire de développer des carburants et des fuels alternatifs avant le milieu de ce siècle. Ceci est nécessaire pour freiner la croissance exponentielle de consommation d'énergie fossile dans les pays en voie de développement et pour contrôler les problèmes d'environnement. La fin de l'âge des hydrocarbures fossiles ne sera donc pas déterminée par l'épuisement des ressources géologiques mais par la disponibilité d'une nouvelle énergie qui sera meilleure, plus écologique et économiquement compétitive.

1. Introduction

As this paper is being written, the price of a barrel of crude oil is moving towards USD 150/bbl and by the time this bulletin is published it may be anywhere between USD 50 and USD 200, a paradise for speculative predictions. Hydrocarbon (HC) reserves play a central role in the issue about oil prices; the ultimately recoverable HC resources – combined with the forecast of demand – determine the eventual reach of HC or, as some may call it, the end of the HC age. Forecasts of HC reserves and forecasts of oil prices, have something in common: they have nearly always been wrong. Poor accuracy of prediction has affected all the pundits, be they from the oil industry, from academia, from official institutions like the US Geological Survey and the International Energy Agency or from organisations like the Association for the Study of Peak Oil and Gas.
The famous publication of the Club of Rome «Limits to Growth» (Meadows 1972) deserves the credit of having been the first global study to highlight that the use of natural resources is finite and that the exponential growth of exploitation and consumption of raw materials can lead the world at some stage into acute shortages and economic turmoil. Predictions were also made for hydrocarbons and – like all the other forecasts – they were later proven to be far off target (Tab. 1).

After a continuous rise in the 60's and 70's the reserves/production ratio (R/P) has been stable above a value of 40 years for the last two decades and the ratio for gas has even been on a 50% higher plateau for more than 25 years. This implies that over the past decades the growing world consumption has been continuously replaced. The reach of HC, as defined above, is not fully representative of the true availability of oil and gas, since it ignores future growth of consumption. However, since the ratio also neglects all future discoveries, improved recovery rates and the contribution from unconventional HC, it can be safely stated that the actual reach of HC will be considerably longer than what the above R/P figures, provided by BP, suggest; this is about the only valid reserve prediction that can be made. However, the likely availability of HC for this century and probably beyond does not imply business as usual since it does not in itself ensure that a steeply rising demand can be met.

The present paper tries to take the discussion about HC resources out of the ideological or sometimes «religious» domain. The study attempts to present some of the important geological and technical facts and discusses the impact of key controlling factors on the reserve question. In the interest of the larger picture, the article does deliberately not focus on geological and technical aspects alone and reflects also some of my personal experiences. The main elements, like remaining exploration potential, enhanced recovery or unconventional HC are discussed from different viewpoints, a certain duplication is therefore unavoidable.

2. The signals of change

In mid 2008 we are looking at a strained system, where demand, HC production and the capacities in the industry experience some difficulties to stay in equilibrium and where the worldwide HC business is undergoing major changes and readjustments. Signals of such change can be detected in a range of areas:

- The oil price has in the past 12 months moved faster and higher than what any expert would have predicted only 2-3

	Oil	Gas
Predictions Club of Rome 1972	31 years	50 years
BP Review of World Energy 2008	42 years	60.3 years

Tab 1: Predictions of reach for hydrocarbons.

years ago. The world of the USD 10-15 oil is less than 10 years past und thus still part of the recent memory and experience of managers that guide and plan the industry today and who often have difficulties to cope with such a radically different scenario. Interestingly, however, the mid 2008 price of USD 145 is only 40% higher in real terms than the price of 1979 (time of the last major oil shock) and even at this level one litre of crude still costs significantly less than bottled water.

- Prices for prime exploration acreage have reached levels that are an order of magnitude higher than in the early 2000. Bonuses of over 100 MM USD are paid for blocks in the deepwater of the Gulf of Mexico and internationally active NOCs (Sinopec and Petrobras) have recently paid a one billion USD signature bonus for a block in Angola.
- Prices for technical services in the industry have risen more steeply than the oil price. From 2003 to 2007 finding costs/BOE have risen by over 220% while crude prices rose by some 110% over the same period. According to an early 2008 study by John S. Herold Inc. and Harrison Lovegrove & Co. Ltd. the higher costs of Exploration and Production (E&P) activities (e.g. services, acquisition costs and boni and larger government take) have resulted in a conspicuous deterioration of earnings: the industry had much better margins at USD 30/bbl (some 30%) than at an oil price of USD 90/bbl (about 10%).
- National Oil Companies (NOC): Since 2000, buoyed by very high cash flows, NOC's have become the largest players in the international arena. This happens at the expense of the traditional big oil companies. The influence of the majors has been strongly eroded and, with heir access to reserves and acreage being restrained, most struggle to replace production. The majors – until the 1990's still the uncontested masters of the oil world – control now only a small part of the worldwide oil, although they operate larger volumes. The 10 largest private E&P companies make up for only 18% of the world production and own a mere 5-6% of the world reserves (BP 2008, S. Hoffmann 2008). This share is being further eroded, as recent attacks by e.g. Russian authorities on valid long-term contracts held by Shell, Exxon and BP illustrate. At a smaller scale, also the large utility companies are contesting the ground of the traditional players.
- Acute shortages of technical staff affect most of the E&P activities. The industry still suffers from the effects of the «sunset image» reputation that the E&P companies had wrongly acquired amongst students in the 80's and 90's, an image that has until now slowed down enrolment in geosciences and an adequate supply of academic talents. Shortages of graduates in Europe and the US are increasingly being compensated by Asian and Russian recruits.
- Renewable energy investments are soaring. The big (mainly European) oil and gas companies belong, not surprisingly, to the largest investors in renewable energy. Many of these companies have already started the transformation from oil companies into energy corporations in the widest sense.

3. The facts

Over the past decades, the E&P industry has experienced several conspicuous changes and trends that influence the reserve balance often in opposite ways. A steady decline in annual reserve volumes that are being added by exploration is evident since the 60's. The trend to finding smaller volumes per discovery has, at least partly, been compensated by much higher wildcat success rates, more effective appraisal of discoveries and significantly higher recovery factors in the fields.

These improvements are almost exclusively due to technological progress. Seismic, has experienced quantum leaps of improvements in imaging the subsurface. It is now possible to detail individual sedimentary bodies and reservoirs, recognize even very minor faults (displacements in the metre range) and map Direct HC Indications (DHIs). Improvements in processing have also allowed to pinpoint the real position of these features in the subsurface with much higher accuracy. In the area of field development, the improvements in drilling and production technology have been equally dramatic, often allowing production of a multiple of the volumes that were previously extracted by conventional methods only.

3.1 Developments with negative impact on supply

Exploration discovery volumes have been declining steadily. New reserve additions through exploration have fallen from some 60 Billion bbls/y in the peak years of the 1960's to only 15-20 Billion bbls/y in the 1990's. It is remarkable, however, that the annual discovery volumes have stabilized at this level for the past 10-15 years (Fig. 1).

The average size of discoveries has also decreased from annual averages in excess of 500 Million bbls/field found in the 40's to 60's, when super-giants like Burgan or Ghawar were discovered in the Middle East, to an average field size of 40-60 Million bbls in recent years.

Global liquids production tripled from some 10 Billion bbls/y in the 60's to almost 30 billion bbls/y now. Production volumes exceeded additions from exploration discoveries since the late 80's but interestingly this gap has not grown during the last 10 years.

3.2 Developments with positive impact on supply

Exploration success rates have been steadily rising and have made up partly for the declining field volumes (Fig. 2). The improvement is largely due to progress in geophysics where advances in acquisition techniques (e.g. 3D, long cable, wide azimuth) and in processing (e.g. extraction of seismic attributes, coherence cubes, Prestack Depth Migration) have led to a quantum leap in the

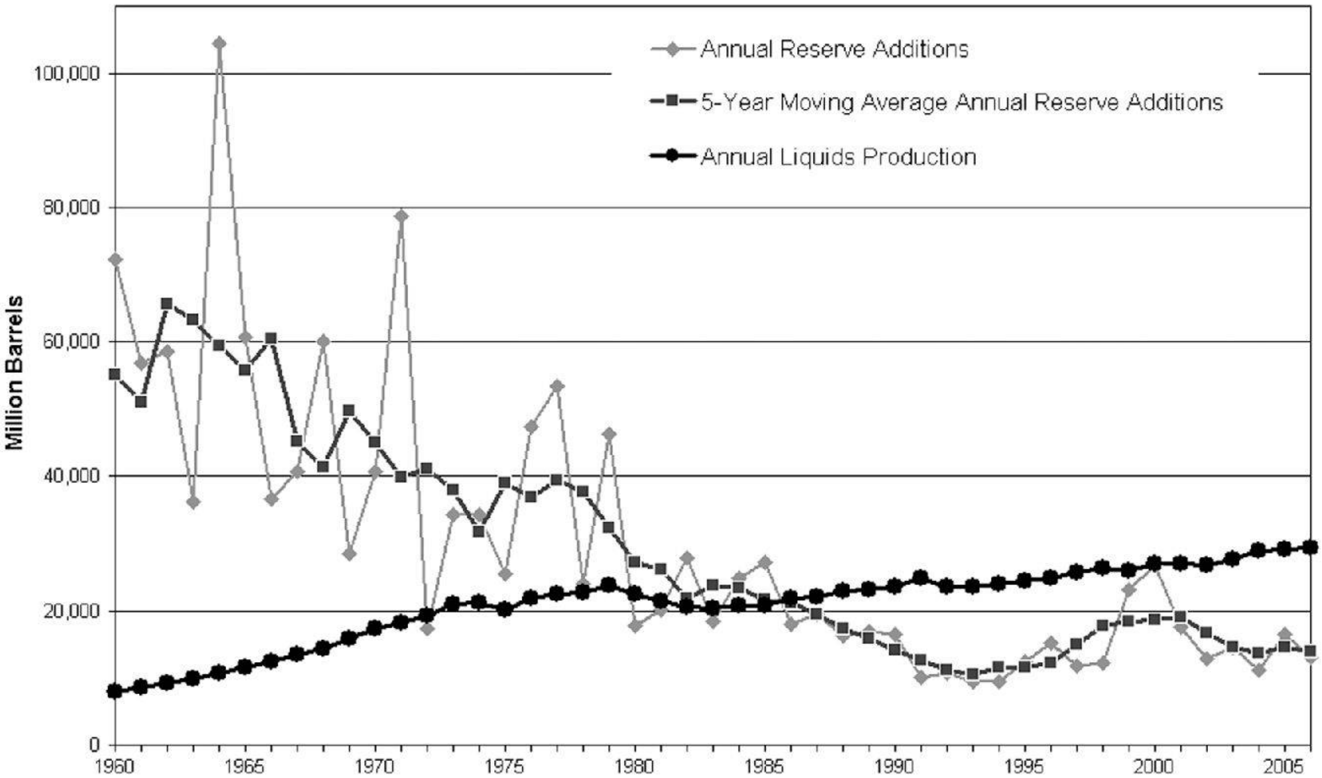


Fig. 1: World oil discoveries vs. production 1960 to 2006. Note relatively stable gap after 1995 (courtesy K. Chew IHS).

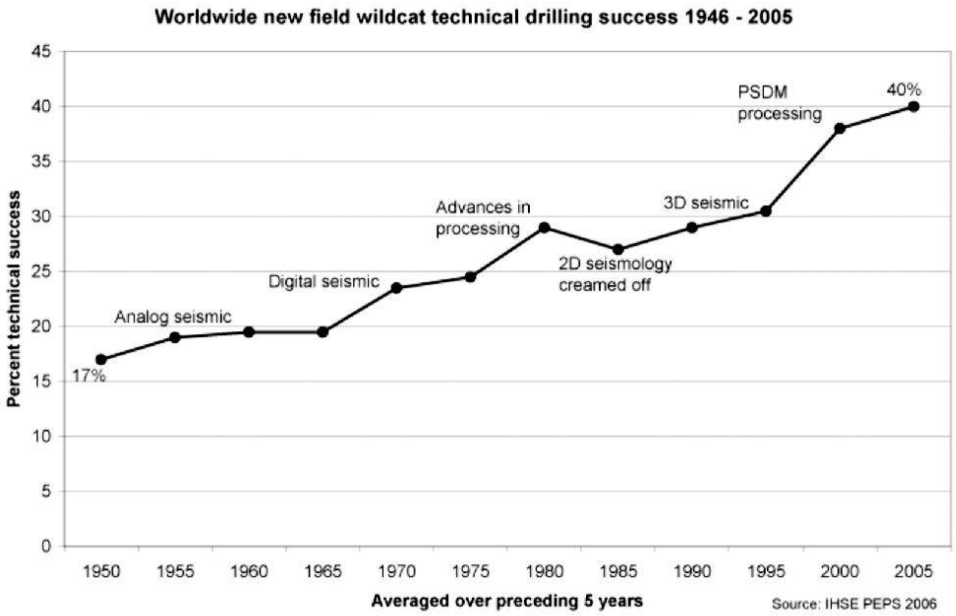


Fig. 2: Exploration wildcat technical success rates 1946 - 2005 and impact of developments in seismic technology (adapted from K. Chew, IHS).

quality of seismic imaging of the subsurface. Wintershall had been exploring the Dutch North Sea in the 80's and 90's with an average success rate below 30%. The main challenge in prospect mapping was the often very complex tectonics that could not be adequately unravelled even by 3D seismic. In the late 90's the processing technique of Prestack Depth Migration became available at commercial rates and allowed for the first time a precise imaging and location of subsurface geometry. As a consequence, 33 exploration wells, drilled between 1999 and 2003, had an economic success rate of 55% – this in an area perceived as one of the most mature in the North Sea (Fig. 3).

Technological improvements have doubled the worldwide exploration success rate

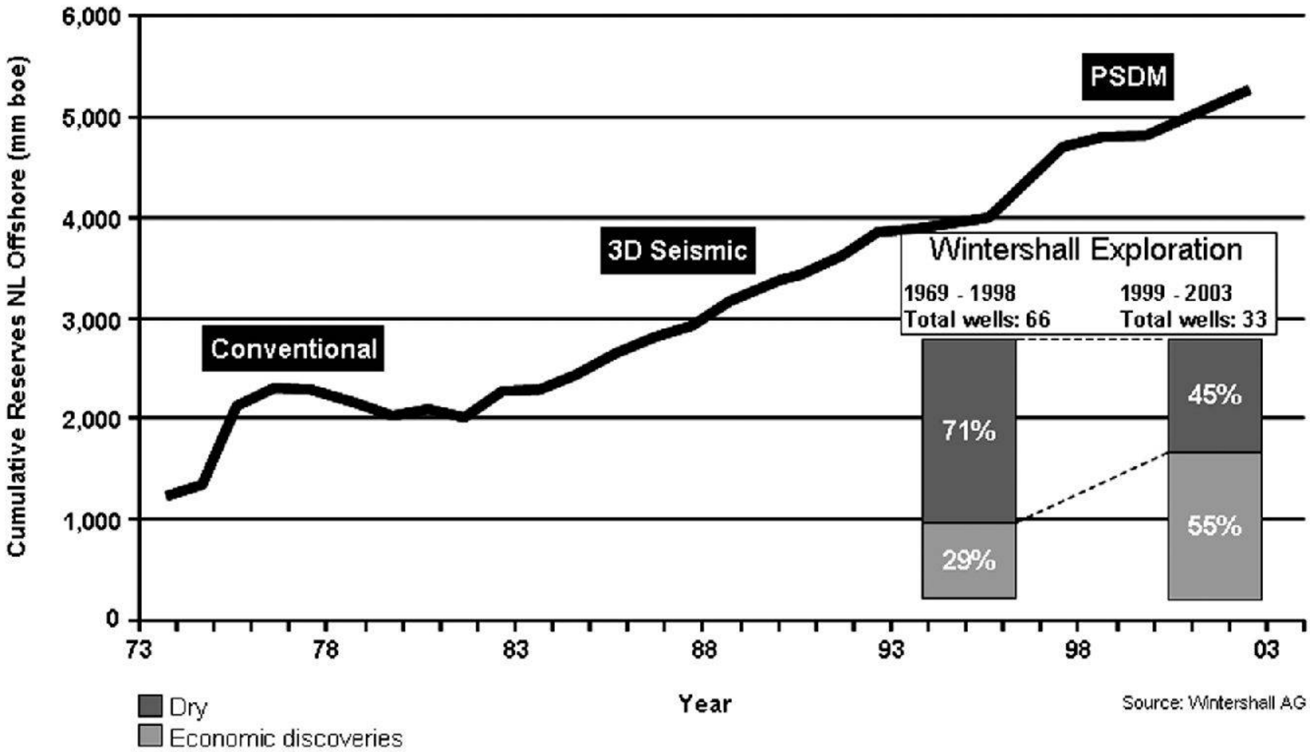


Fig. 3: Netherlands offshore: cumulative reserve additions, improvements in seismic and Wintershall exploration success rates. PSDM: Prestack Depth Migration (Courtesy Wintershall AG).

from less than 20% in the 50's and 60's (nevertheless the time when most of the giant field discoveries were made) to the present 40%. What makes this achievement even more impressive, is the fact that this improvement, like in the Netherlands, has been achieved against the background of increasingly mature and creamed HC basins. While many of the large fields of the past could hardly have been overlooked (many were surface anticlines that did not even require seismic) the new geophysical tools allow now increasingly detailed mapping of small or subtle closures or e.g. the imaging of complex salt tectonics.

We cannot ignore, however, that while technology provides us with a more effective creaming of the plays, many of the new, significant discoveries are made in increasingly difficult and operationally expensive terrains: e.g. Atlantic deep water, partly in excess of 3000 m water depth; extremely shallow water with fluctuating sea levels (Caspian Sea) or the Arctic, where global warming is leading to a rapid increase of ice-free areas. The developing costs/bbl in these new areas can be 10 - 20 times more expensive than for example in the traditional fields of the Middle East, which now still provide the bulk of world production. The world is replacing cheap oil with increasingly expensive oil and gas; this alone must have a major impact on prices.

Field recovery rates have increased continuously for the past decades. High precision horizontal wells and long-reach wells, some in excess of 10 km, achieve better drainage of reservoirs and allow to tap targets that were so far inaccessible. Improved drilling techniques (e.g. under-balanced), together with new seismic imaging and advanced stimulation techniques, allow a much higher depletion of the fields. These improvements will continue and should contribute significantly to future reserve growth. In northern Germany Wintershall is producing the Emlichheim heavy oil field, which was discovered in 1943 and had reached the peak of primary production in 1950. For the past 65 years the field has been maintained on plateau by repeated and improved secon-

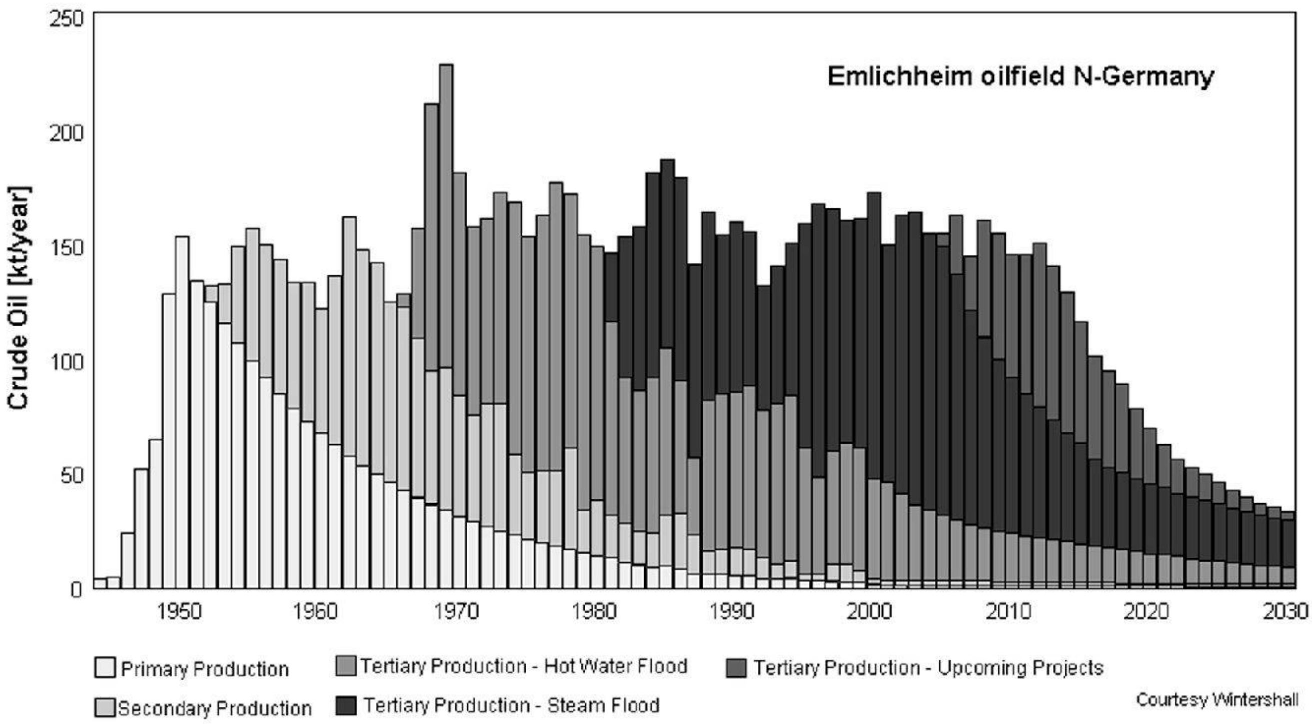


Fig. 4: Impact of enhanced oil recovery. Emlichheim heavy oil field North Germany. Thanks to continuously improving technology Emlichheim has been producing at economic rates for over 60 years, increasing the recovery rate from 7% to 33% (courtesy Wintershall AG).

dary and tertiary recovery measures; final decline is only expected after 2013. The field will eventually have experienced an extension of field life by some 50 years and will have improved the recovery factor almost 5-fold from 7% to 33% (Fig. 4).
Enhanced recoveries are also a result of combining accurate seismic imaging with high precision horizontal drilling. In 2008, Maersk, a champion in drilling and producing of difficult, low permeability carbonate reservoirs, have drilled a well in the North Sea with a horizontal section of 10.9 km, all within a reservoir that has a thickness of only 6-7 metres (First Break 2008, Vol. 26, p. 43). This opens the way to recovery rates that were unthinkable only a few years ago.

3.3 Reserves/Production Ratio (R/P)

Improved technology is the main reason why the reach of the reserves of oil and gas has stayed at approximately the same level (> 40 years for oil and > 60 years for gas) for the past 10-15 years (Fig. 5). More remarkably, there has never been any significant and sustained decline of the reserve reach of either oil or gas since the beginning of the last century, an observation that should, however, not necessarily be extrapolated into the future.

3.4 Unconventional hydrocarbons

Ten years ago large scale commercial production of unconventional HC was a dream. Now it is a reality, technically maturing and highly profitable. Unconventional oil has become a dominant factor in Venezuela with the exploitation of the Orinoco heavy oil deposits and in Canada with the Athabasca tar sands. In Venezuela, production from the Orinoco belt has been negligible until after 2000, when the rise in oil prices started to trigger high investments and a steep growth in output, that will reach 1 Million bbls of crude/day by the end of 2008, amounting to over $^1/_3$ of Venezuela's total oil production (Fig. 6). Similarly the tar sands are the prime reason why Canada's oil production is now 30% higher than 10 years ago. Challenges remain on the environmental side, in the use of water and gas and in the overall energy efficiency (Orinoco heavy oil production still consumes about $^1/_3$ of the energy that is gained by the exploitation).
In unconventional gas, shale gas developments and deep-basin tight gas contributed in 2007 46% of total domestic US gas supply (31% tight sands, 9% Coalbed Methane CBM, 6% shale gas) with potential reserves in US amounting to 160 TCF (Ken Chew, IHS).
In the United States big efforts are being made by the Industry recently to develop shale gas. One of the most prominent plays,

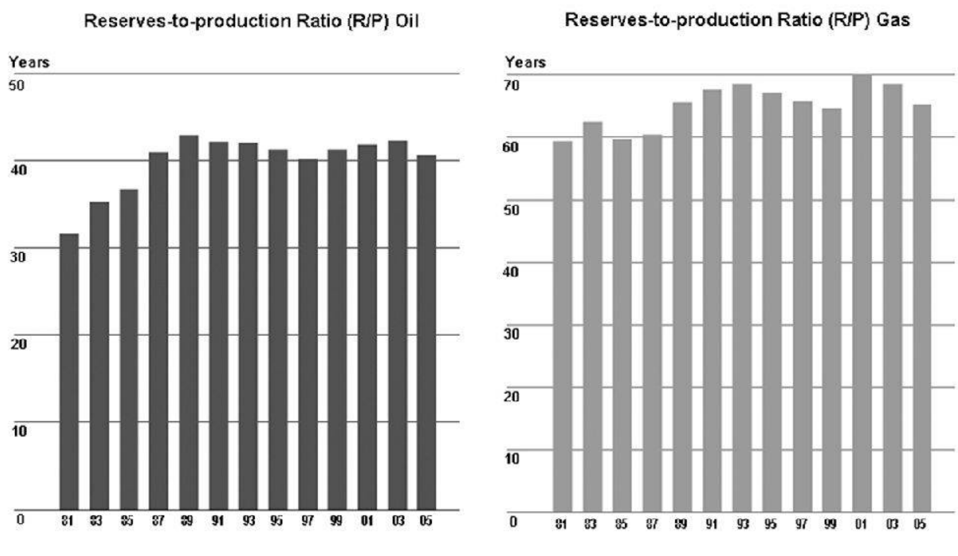


Fig. 5:
Reserves to Production Ratio (Reach) for oil and gas 1981 - 2005 (source: BP Statistical Review of World Energy 2007).

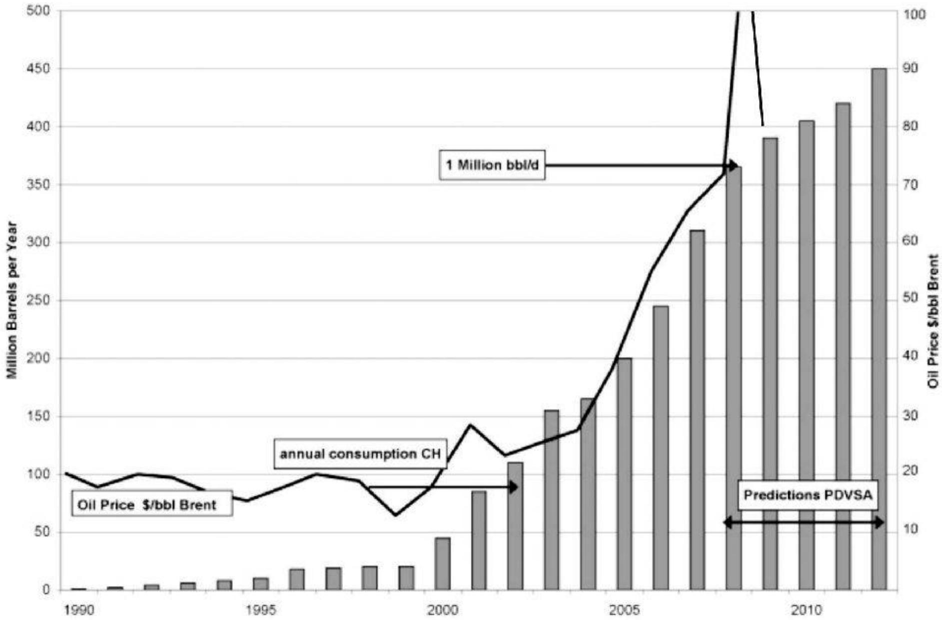


Fig. 6:
Venezuela heavy oil production and oil price. History and prediction to 2012 (adapted from K. Chew, IHS).

the Barnett Shale in Texas has so far produced over 3.7 TCF of gas and saw in 2007 alone the drilling of 1750, mostly horizontal development wells, against only 160 wells drilled in the year 2000 (Durham 2008). In Australia and China, CBM is being developed rapidly, India is likely to follow. In China, with its enormous coal reserves, covering still 70% of total energy need, CBM has a high potential of becoming one of the prime sources of domestic gas supply.

4. Factors controlling the reach of reserves

4.1 Price

The present high crude prices are likely to curb demand in wasteful societies like the US and in the non-oil-producing development countries where gasoline may become unaffordable to many users. Steep price increases have already once, after the oil shock of the late 70's, led to a worldwide decrease in consumption (Fig. 7).

Higher prices will in principle also allow a much more intensive use of advanced and often expensive technology. However, since the largest part of world oil reserves and production is now controlled by National Oil Companies (NOCs) the formula of «higher revenues = more investment in technology» is not necessarily valid anymore. Most NOCs are being used by their own governments as cash-cows to fund other investments and fill the state chests. In the past, NOCs have been notoriously bad in improving or even maintaining their oil and gas infrastructure and only few have invested domestically in new frontier technology (in international operations they perform more closely to standards of the private sector). This is a niche where the Majors and independent international companies still have an important role to play.

Although more money is being spent on exploration, the impact is not guaranteed. Previous periods of high oil price, e.g. in the early 80's after the Iranian Revolution, showed that success rates decreased in times of easy exploration money, since opportunities were screened less rigorously: a poor exploration play remains a poor play and a poor investment, irrespective of the oil price and the geologist's pets, the so called «high risk – high reward prospects», do very rarely or never materialize. A very significant impact of the higher prices can, however, be expected from higher investments in field developments, enhanced recovery and unconventional hydrocarbons.

4.2 Consumption

While high oil prices may dampen the consumption in developed countries and in some non-oil-producing third world countries, it is unlikely that they will stop the rise of consumption in the large Asian consumer areas, particularly in India and China. In these countries oil and gas consumption per capita is still at a very low level (Tab. 2).

In 1995, when I left Beijing after an assignment of a few years in China, only one in 12 000 inhabitants owned a private car. A mere 10 years later the ratio was 1:120, an increase by a factor 100 but still representing a car ownership level that is worlds apart from Europe or America. Growth in developing countries will go on and will drive demand.

	BBL Oil/day/1000 inhabitants	BBL Oil/year/person
US	71	26
Switzerland	36	13
China	5	1.8
Chad	0.15	0.05

Tab 2: Per Capita oil consumption 2004 (Source: Nationmaster.com).

Consumption will also be controlled by the environmental acceptability of burning fossil fuel and by the price put on CO_2 production. This will undoubtedly lead to a curbing of consumption in the developed countries, largely through increased energy efficiency and a switch to renewables. As an example: over 50% of new home heating systems installed 2007 in Switzerland were thermal pumps, of which about half extract their energy geothermally from the subsurface (source: Schweizerische Vereinigung für Geothermie). This trend will continue and is likely to replace most oil and possibly even gas heating in the foreseeable future, albeit at the price of higher electricity consumption.

oil	+ 12.8%
gas	+ 31.5%
coal	+ 36.6%

Tab 3: Increase in production of fossil energy 1997- 2007 based on oil equivalents.

Energy conservation in the industrialized countries is likely to be more than compensated by growth in the second and third world. Global demand for oil and gas is therefore likely to continue rising, at least for the next 2-3 decades (Fig. 7). When addressing the environmental downsides of oil and gas it is interesting to note that, contrary to common belief, worldwide coal consumption (the fuel with the highest output in CO_2) has risen more rapidly in the past 10 years than consumption of oil and gas (Tab. 3, BP 2008).

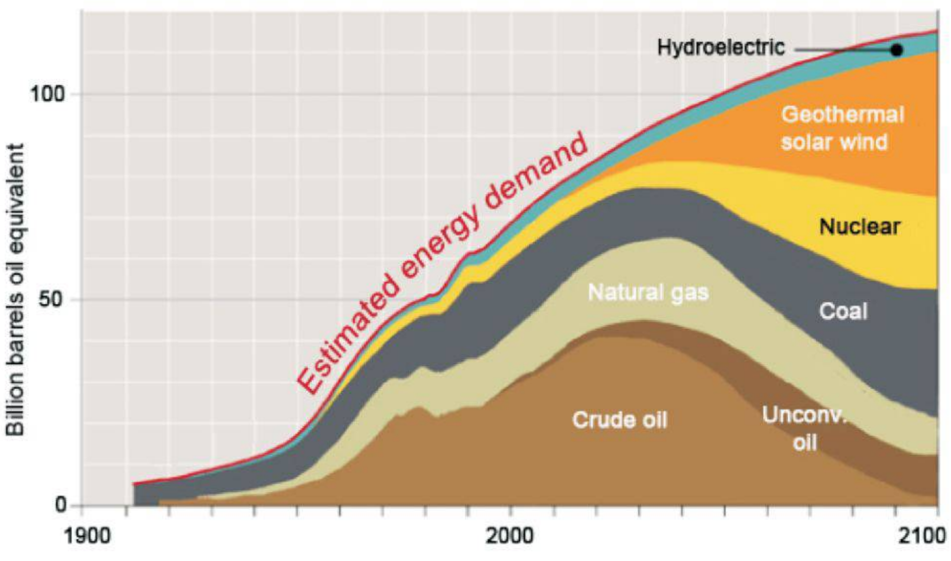


Fig. 7:
World energy demand and supply 1900 to 2100. Note: this figure should only been used to illustrate general trends but is not an authority on absolute figures for the different energy sources. E.g. the future share of nuclear is not only a question of resource availability but one of political and environmental acceptance (updated and modified after Ed-wards 1997).

4.3 Technology

As mentioned in section 3 above, technology has been able to compensate partly for the creaming of classical HC provinces by providing more accurate exploration tools and highly improved development and recovery techniques. This trend will continue and may well allow the world to stabilise the plateau of the R/P ratio for several more years. Technological improvements are by far the most important driver for the replacement of reserves, far ahead of other factors like oil price. A few areas deserve to be mentioned:

Seismic remains the main tool for locating hydrocarbons and imaging traps in the subsurface. Increasingly this will allow mapping of subtle and stratigraphic traps and e.g. accumulations under masking strata, like salt or basalt. Major progress is being achieved in the direct mapping of HC (so called Direct HC Indicators, DHI). In field developments, 4D seismic (repeated seismic 3D surveys over a longer time interval) has become a common tool to monitor the depletion of a field and to spot undrained compartments. Further progress in seismic methods will have an important impact on future exploration success rates and field development (Figs. 8 to 10).

New geophysical methods: Electromagnetics and several direct HC indication tools still play a minor role but new techniques, like «Low Frequency Passive Seismic» have produced encouraging initial results and may have the potential to develop into a standard HC detection tool. Passive seismic surveys have not only succeeded in indicating presence of HC but have recently provided additional information on the precise location and depth. Together with modern seismic, such new tools could revolutionize the industry and impact reserve growth. It has to be acknowledged, however, that so far all new geochemical and geophysical tools have at best been providing supporting evidence, without ever becoming a reliable, dominating exploration tool, comparable to seismic.

Enhanced recovery methods: Improved methods for field development and recovery have led to a continuous growth in the ultimate recovery of old fields. This growth in

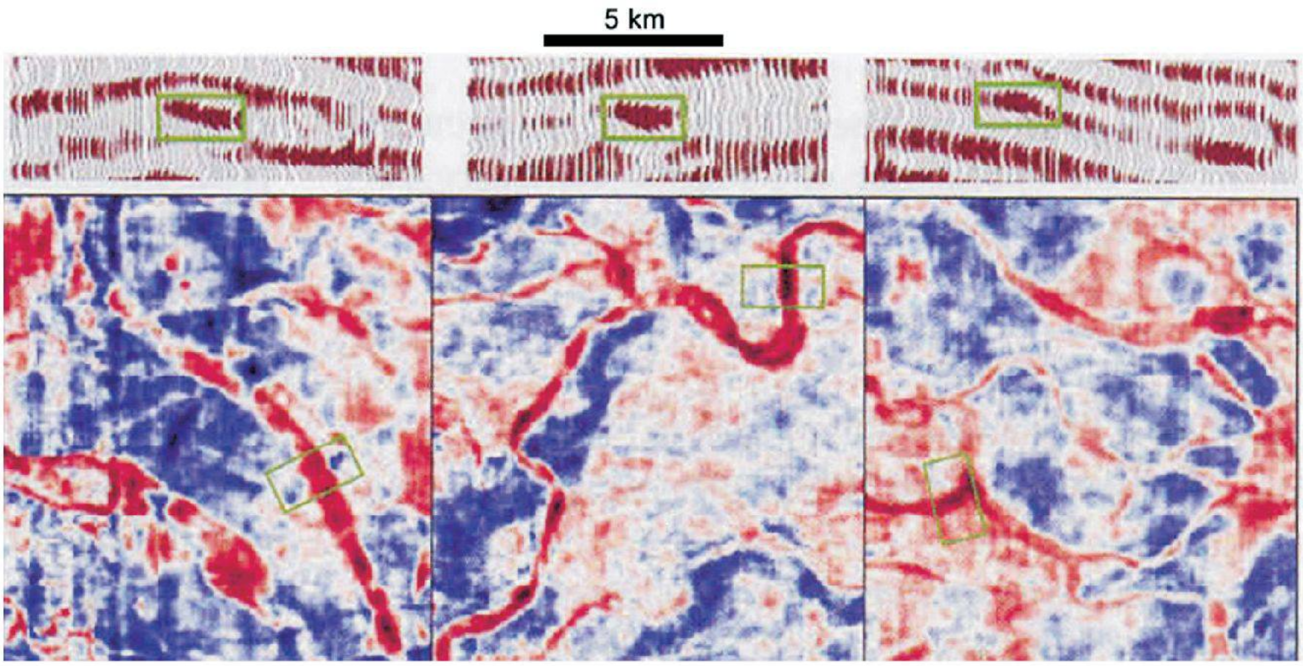


Fig. 8: Progress in seismic imaging: reservoir identification. Special processing and attribute displays enhance subtle features like the river channels, shown only as small anomalies in the sections at the top (Chopra & Marfurt 2007).

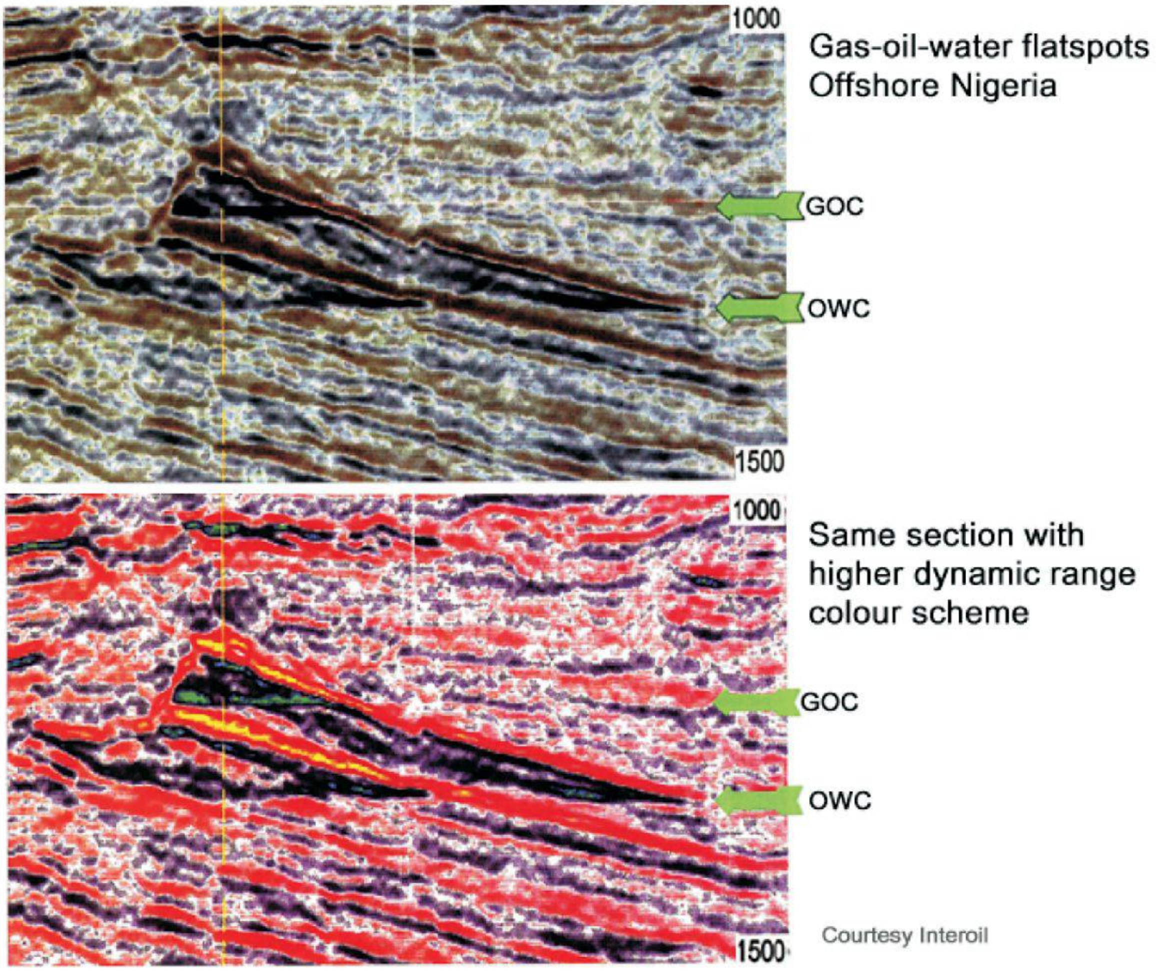


Fig. 9: Progress in seismic imaging: Direct Hydrocarbon Indications (DHI), offshore Nigeria. Note high definition of both gas/oil (GOC) and oil/water (OWC) contacts (Brown 1999).

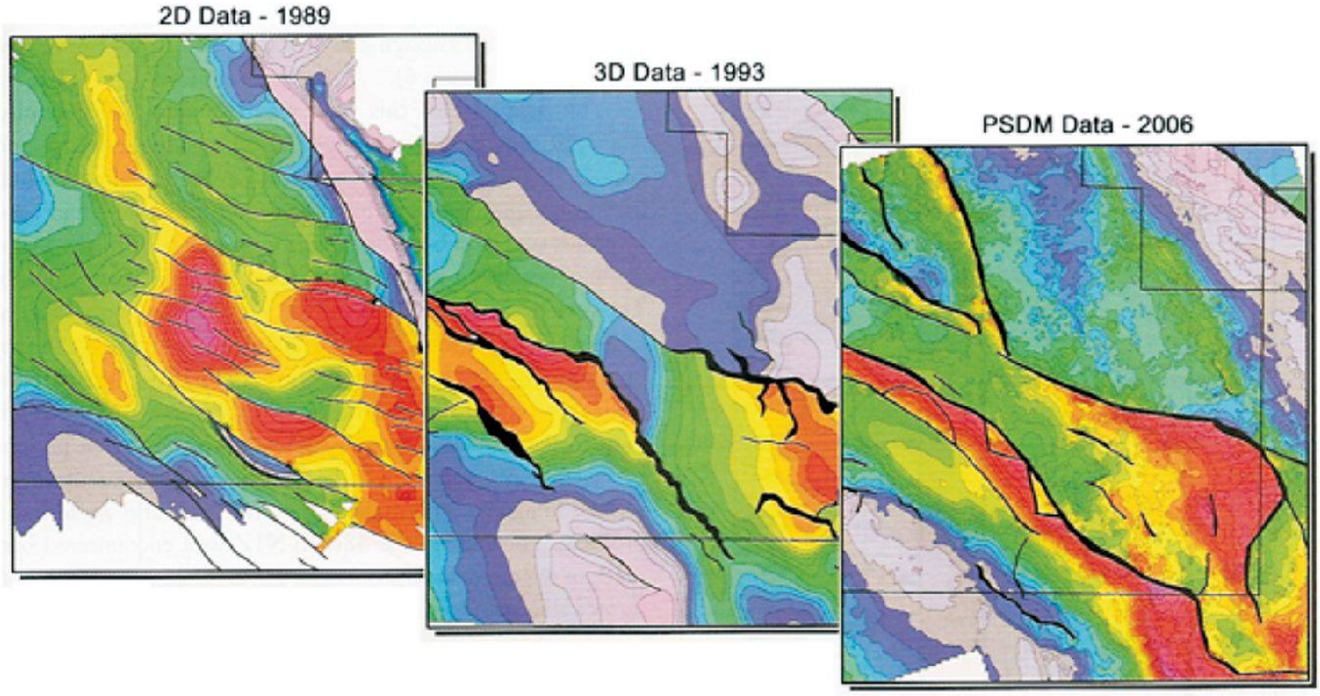


Fig. 10: Progress in seismic imaging: structural definition. Different interpretations of a North Sea field, based on 2D seismic, 3D seismic and Prestack Depth Migration (PSDM). Note dramatic difference/improvement introduced by PSDM, showing that 2D and conventional processing of 3D was not able to resolve a complex tectonic pattern (Elam 2007).

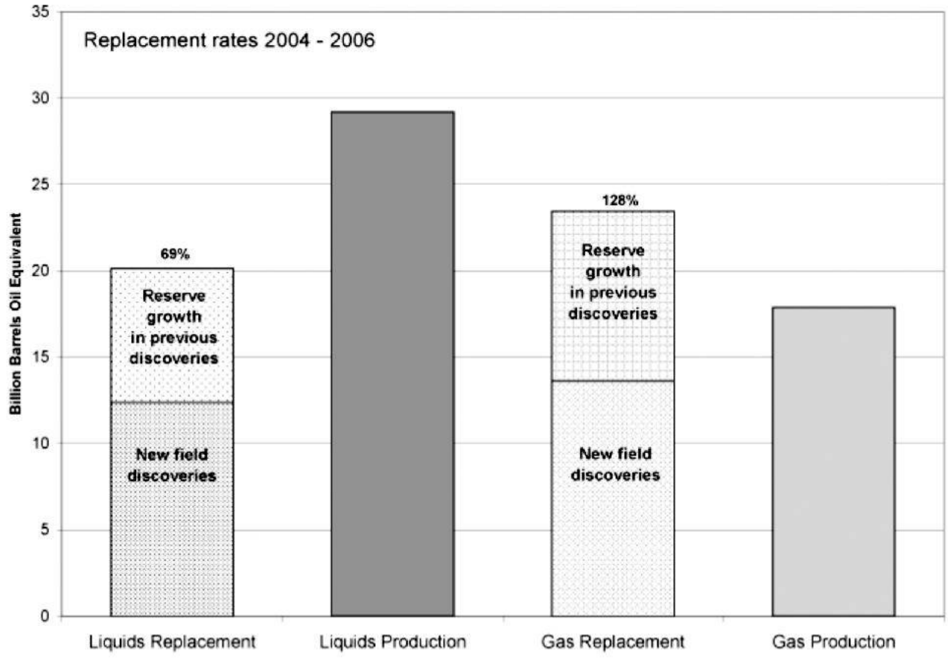


Fig. 11: Worldwide reserve additions through new field discoveries (exploration) and growth in fields 2004 - 2006. The additional volumes discovered in old fields and/or through higher recovery factors (technology driven) contribute a very important share to the replacement of production (courtesy K. Chew, IHS).

fields accounts now already for some 35-40% of total reserve replacement (Fig. 11). Still, about $^2/_3$ of the oil discovered remains in the ground and recovering more of these «lost resources» is probably the main challenge of the coming years. Given that the present remaining discovered oil reserves amount to over 1200 Billion bbls (Fig. 12) an increase of the present recovery factor from the present 35% to 45% would provide some 345 Billion bbls of additional oil and would extend the reserve reach by 11-12 years at the rate of the present production. A 45% recovery factor may be a stretched target, but we can assume that enhanced recovery will add a minimum of 10 years to reserve life. This is in line with the more cautious assumptions by IHS who assume an increase to a recovery factor of 42%, providing the additional 312 Billion bbls shown in Fig. 12 below. Additions through enhanced recovery will be not as important in gas, where already now a 75% recovery factor is assumed.

4.4 Potential for future exploration

Mature areas: A large part of future discoveries will come from near-field exploration in

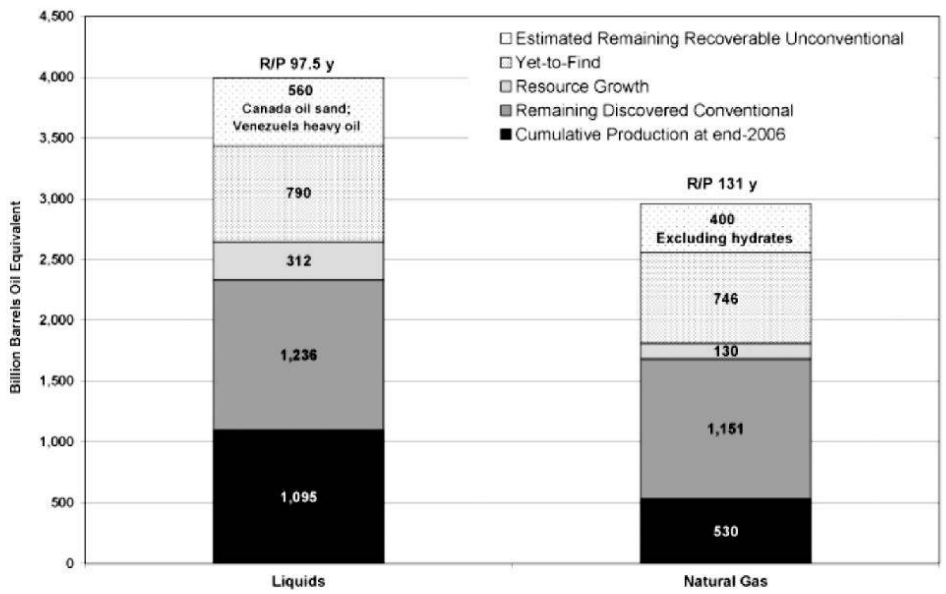


Fig. 12: Estimated ultimately recoverable world hydrocarbon resources (Courtesy K. Chew, IHS, R/P ratios added, using data from BP 2008).

well-known, supposedly mature HC provinces. Experience has shown that, with improving technology, rich HC basins will nearly always provide additional resources. Even in the US, where exploration maturity is highest, there is no such thing as a prolific but today fully explored (creamed) oil or gas province. The majority of the HC discovered in the US over the last decades comes from complex, subtle or stratigraphic traps or originates from unconventional plays and deep water. It is safe to assume that in other parts of the world, where such plays often have not even been touched yet, very large additional volumes will be discovered in analogue plays.

Greenfield exploration (Fig. 13): Large new exploration volumes can still be expected from the Atlantic deep water and perhaps one day from other similar settings (Indian Ocean?). The West African deep water plays are far from mature and in Brazil the new ability to accurately image structures below the salt is opening a new multi billion bbl play.
A new area with large promises is the Arctic. Global warming has in the last 25 years reduced permanent ice cover from 10 million km^2 to 6 million km^2, thus freeing for exploration an area as large as the surfaces of Libya and Algeria combined. For the first time the receding ice cover gives access to vast shelf areas with river deltas that in their onshore parts belong already to the world's biggest known HC provinces (Alaska, Northern Canada, Siberian offshore). It is estimated that some 25% of all yet to be discovered HC are located in the Arctic offshore (Scott 2008).
NOC controlled areas: Areas that were in the past exclusively or predominantly explored by National Oil Companies have often a large remaining exploration potential. NOCs were meant to produce revenue for the state and were therefore generally very risk-averse and technology-shy. In Libya gas was not explored for until recent years and in the rich basins of Siberia stratigraphic traps, tight reservoirs and overpressured zones remained largely unexplored, the latter because Russian rigs were in the past not equipped to handle high pressures (Dolson, BP 2008).

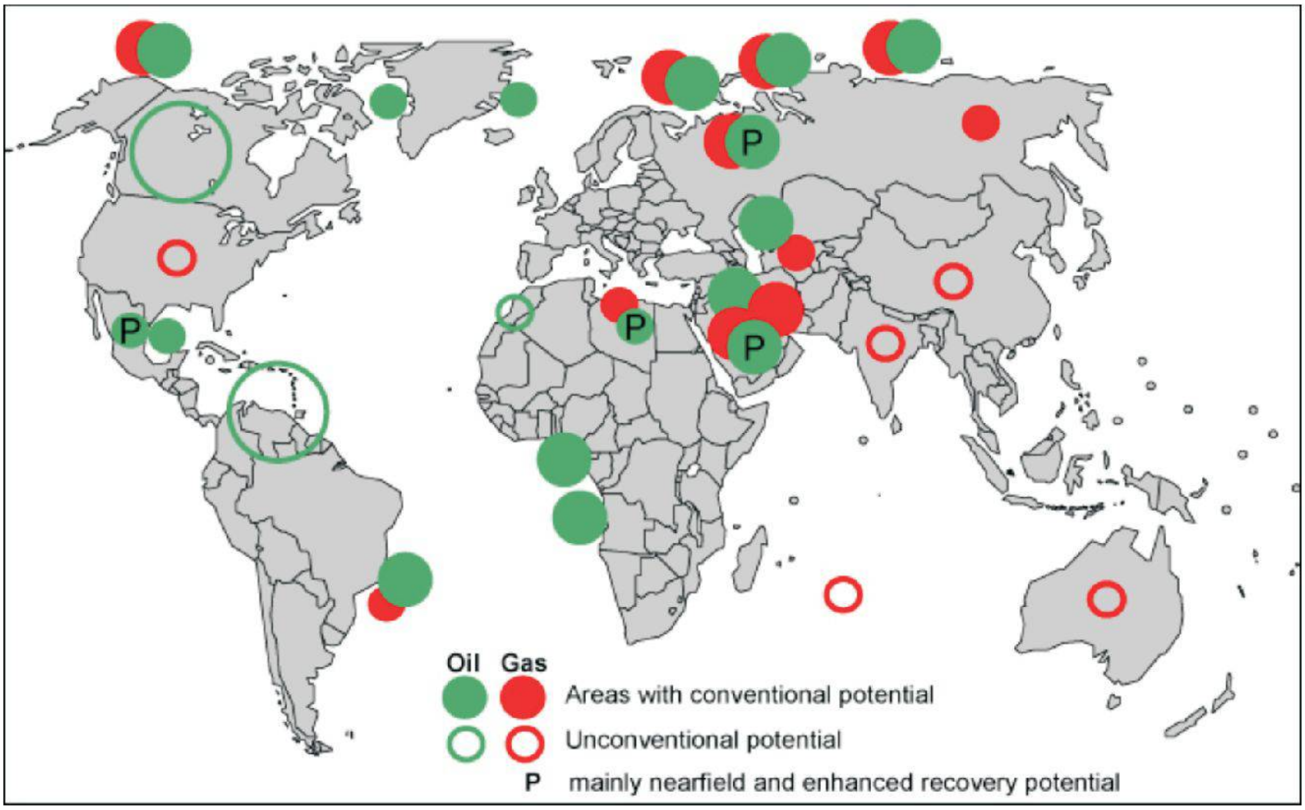


Fig. 13: Locations of future oil and gas resource additions. A qualitative indication of prime areas of future exploration potential, infield and nearfield additions and unconventional HC.

Gas has also had a low priority in many of the major oil producing countries. As an example of many, Nigeria – in spite of a government law requiring total elimination of flaring by 2008 – is this year still flaring some 20-25 BCM/year (source IHS), which is $^1/_3$ of its entire gas production and could cover close to 5% of total European consumption. Eliminating flaring and venting is thus in itself a source of very substantial additional gas volumes. Until the last decade little gas exploration took place in the Middle East (except for Qatar and possibly Iran) and in many African oil producing countries.

In Russia, the long neglected offshore is becoming the new frontier, particularly for gas. The Stokhmanskoye field in the Barents Sea with possible reserves of up to 3800 BCM (over 7 times the annual consumption of the EU) was already discovered in 1988 but will be developed only in the next decade, after almost 25 years of inactivity. Increased offshore exploration and development will boost Russian offshore gas production from almost zero now to some 180 BCM/year by 2025, i.e. more than double the annual gas consumption of Germany (Stavskiy et al. 2007).

4.5 Unconventional Hydrocarbons

Waste zones – the geological reason behind unconventionals. Hydrocarbon habitats are very wasteful systems: in most producing basins of the world only a few percent of the total generated HC find their way into commercial accumulations. In the North Sea the conventionally trapped portion is about 1% (Fig. 14). The remaining HC have leaked out to surface or – especially in the case of oil – got stuck in the source rock, in low permeability waste zones or in the cap rock. In prolific areas, like the North Sea, huge volumes of oil, amounting to several 10 times the volume of conventionally trapped accumulations, but also of gas are still present in the sediments of the basin, often unfortunately in low permeability rocks.

In the US some of these resources are already being produced (tight gas, deep basin gas, shale gas, Green River oil shale). In 2007 over 4000 wells, were drilled in the US in shale gas plays. Such deposits will also become attractive in other parts of the world, through further advances in technology and with prices, allowing to spend more per barrel recovered. If in the North Sea and in the NW European onshore only a tiny fraction of this «waste zone oil» or e.g. a small fraction of the huge tight gas accumulations in the Carboniferous could be tapped, this would add decades of further European HC production.

Volumetric impact of unconventionals:

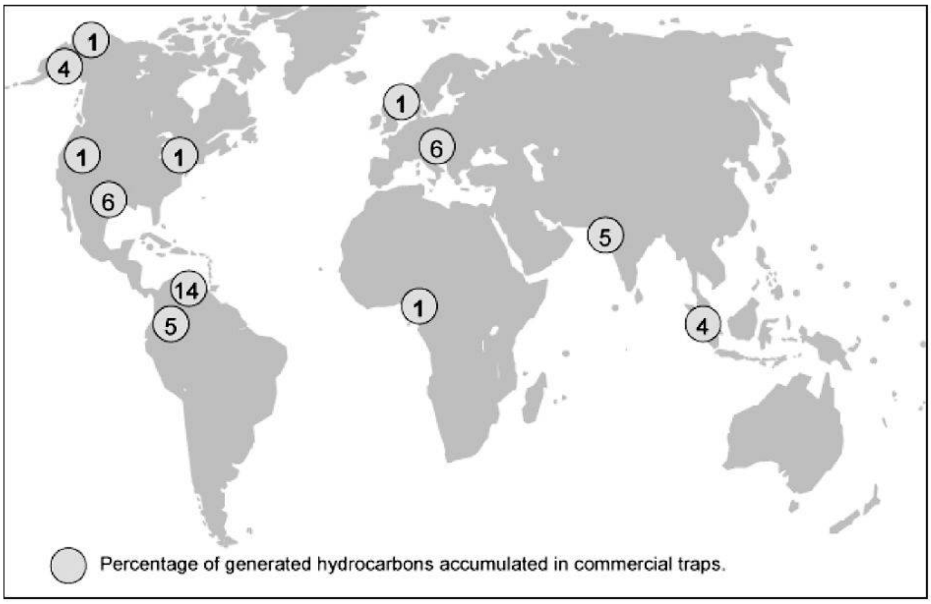


Fig. 14:
The inefficient HC systems: only a few percent at best of the generated oil and gas ends up in commercial traps. The 14% given for Venezuela contain also some of the Orinoco heavy oil and are therefore not representative for conventional HC accumulations (courtesy G. Hollmann, EON-Ruhrgas).

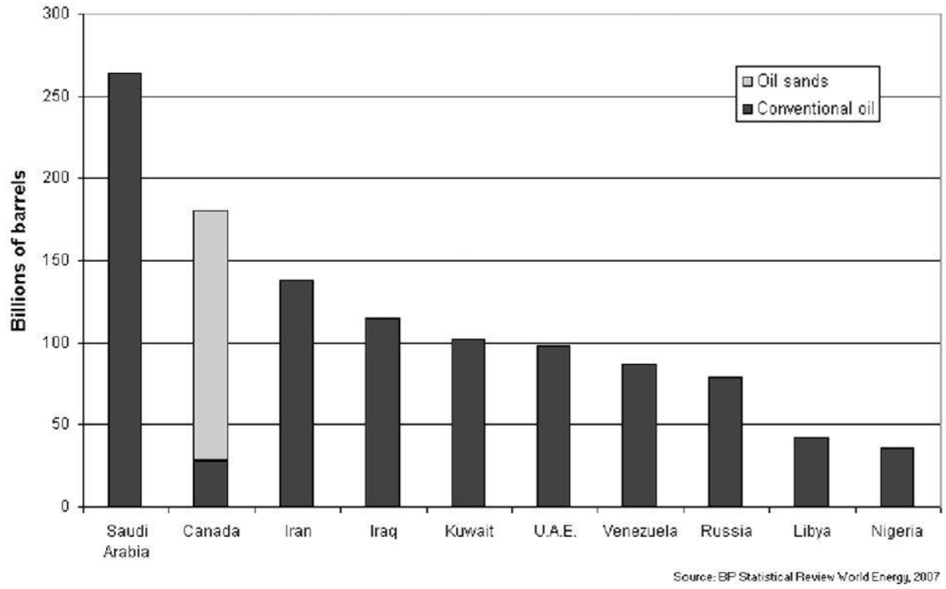


Fig. 15:
The top 10 oil reserve holders of the world. Including its estimated heavy oil resources of the Orinoco belt Venezuela would also rank among the top three (source: BP 2008).

Unconventional HC have been studied for decades but have only become a serious factor in the worldwide reserve replacement with the oil price boom after 2000. The impact of these resources will change the world map of HC reserves. When unconventional oil reserves are included, Canada becomes the world's second largest oil reserve holder after Saudi Arabia but far ahead of Iran, Iraq and Kuwait (Fig. 15). The Canadian oil sand reserves of 152 Billion bbls are taken from the BP 2008 Statistical Review of world Energy and are defined as «Established reserves less reserves under active development», the total Canadian resources could therefore be much larger. Including heavy oil, Venezuela would equally rank among the top reserve holders. Resource estimates for the Orinoco Belt by PdVSA amount to 272 Billion bbls (20% recovery from 1360 Billion bbls in place); if only half of this is achievable, Venezuela would rank as the world number two reserve holder.

Canada and Venezuela stand out as the two by far largest holders of unconventional oil resources and it is difficult to see at this moment any other areas in the world that can, in the short to mid term, rival the potential of these two countries (though the thoughts on waste zones, expressed above, need to be kept in mind worldwide).

The situation with gas is different. While important production of unconventional gas is now mainly located in North America (46% of domestic gas production), there are plenty of potential unconventional gas plays all over the world. The significant and growing reserve additions achieved in the US are an indication of what is likely to happen worldwide, as soon as conventional gas resources decline. Unconventional gas (including CBM) is going to play a major role in future and the 400 BOE attributed to this category by IHS may well prove conservative. CBM alone is claimed by some experts to have a worldwide potential of about 6000 TCF in place and about 700 TCF recoverable being over 10% of the total world conventional gas reserves (statement made by Arrow Gas, one of the prime CBM players in Australia and Asia, APPEX conference, London 2008).

A category repeatedly quoted as a future source are the Gashydrates, located mainly below seabed in coldwater oceans. While the in-place volumes are huge (estimated at > 100 000 TCF by Colett 2008), nobody has been able to demonstrate an acceptable method that would allow a commercial recovery of these resources, since the deposits have very low pressures and low flow rates, far below requirements of offshore production. Gashydrates have been the eternal teasers of the unconventional gas scene and it is highly questionable whether they will ever be more than an academic consideration. For this reason they have been left out of all the resource statistics in this paper.

4.6 The problem of reserve definitions

There is considerable discussion about the reliability of reserve figures. There are official regulations and standards by the Society of Petroleum Engineers (SPE) and by the US Security and Exchange Commission (SEC). While international companies generally adhere to these regulations and many, especially of the smaller and medium companies, have their reserves certified independently by third-party specialists, the NOCs and the various government agencies are not obliged to stick to these rules in their declarations.

Reserves generally are classified into proven, probable and possible reserves (with decreasing certainty) and SEC regulations accept only proven reserves as company assets.

The international companies are in general very conservative with booking reserves. A study by Klett & Gautier 2005 shows that in the North Sea out of 62 fields assessed between 1985 and 2000 only 7 experienced decreases in the estimate of ultimate reserves while 55 fields showed, partly very substantial increases in reported and certified reserves over this period. In 2003 a study by Wintershall, also for the North Sea, came to the conclusion that in most fields not only the proven but also the probable reserves were ultimately produced and that even the less certain, possible reserves materialized in far over 50% of the fields. The much publicised reserve issue that Shell struggled with in 2004, was in the end not a question of presence or absence of reserves, but one of reserve classification.

An issue more difficult to resolve is the fact that some Middle East OPEC countries have in the last 20 years announced large reserve increases that were never fully verified (e.g. Iran added some 30 billion bbls in 2002), fuelling the suspicion that these increases were primarily done for the purpose of increasing the country's production quota within the OPEC organization. This is indeed an issue that needs to be watched. However, the countries with the biggest such «growth anomalies», Saudi Arabia, Iran, Iraq and U.A.E, are also countries with some of the biggest potential for reserve growth through new development and production technologies and resumption of the long neglected exploration. Their increases in reserves may therefore well be justified.

5. Outlook

5.1 Peak oil and gas

The Peak Oil Theory, based largely on the studies by K. Hubbert in the 1950's and 1960's, implies that volumes of oil discoveries and production follow a regular distribution curve and that, on the basis of past exploration results, the rise and fall of production can be predicted.

Timing of World Peak Oil Production has been predicted repeatedly. The Peak was first announced for 1989, then for 1997, 2004, 2010 and is now predicted by some peak oil publications as «before 2020». Why this inaccuracy of prediction? While the Hubbert curve is certainly a valid theoretical tool, users (and mis-users) often ignore that the curve is truly valid only for a single basin or a single play in a mature basin or area. New breakthroughs in exploration or production technology can and will alter the curve. Production history worldwide is a composite of many superimposed Hubbert curves that are offset in time and have different amplitudes, thus leading to continuous modification of the simple Gaussian distribution (Hubbert himself recognized this but proposed that these thousands of curves would eventually equalize out in an overall smoothed worldwide curve).

Also the best known example, the Hubbert curve for the US (though relatively accurate over the time of the «conventional» onshore and shelf exploration and production) could not escape such major modifications: the big discoveries in the deep water of the Gulf of Mexico, that provide today 25% of the US production, could not be foreseen by Hubbert. This new growth curve needs to be added to and extends the original forecast of US production (Fig. 16). Hubbert made the first detailed prediction of the peak of US production in 1962, only some 5.5 year prior to the peak that he predicted. It turned out that his prediction was 2.5 years early and too low by about 0.6 Billion bbls (analysis K. Chew). Today the total US Liquids production including Deep Water Gulf of Mexico, Alaska and Natural Gas Liquids (NGL) is some three times higher than the detailed Hubbert prediction. Hubbert, increasingly aware of the higher complexity of forecasts, stated in his later work that «there was no reason that the curve had a single maximum or that it be symmetrical» (Hubbert 1982).

Peak Oil predictions do not adequately account for the impact of new technology. Every year, better exploration and better production methods are adding sizeable volumes to fields that were discovered many decades ago. Thus the initial exploration curve (on which the production forecast is based) keeps growing, requiring a continuous adaptation and further postponement of the production peak. A good example is the oil production in the North Sea where peak production was first forecast for the late 80's and where production was significantly

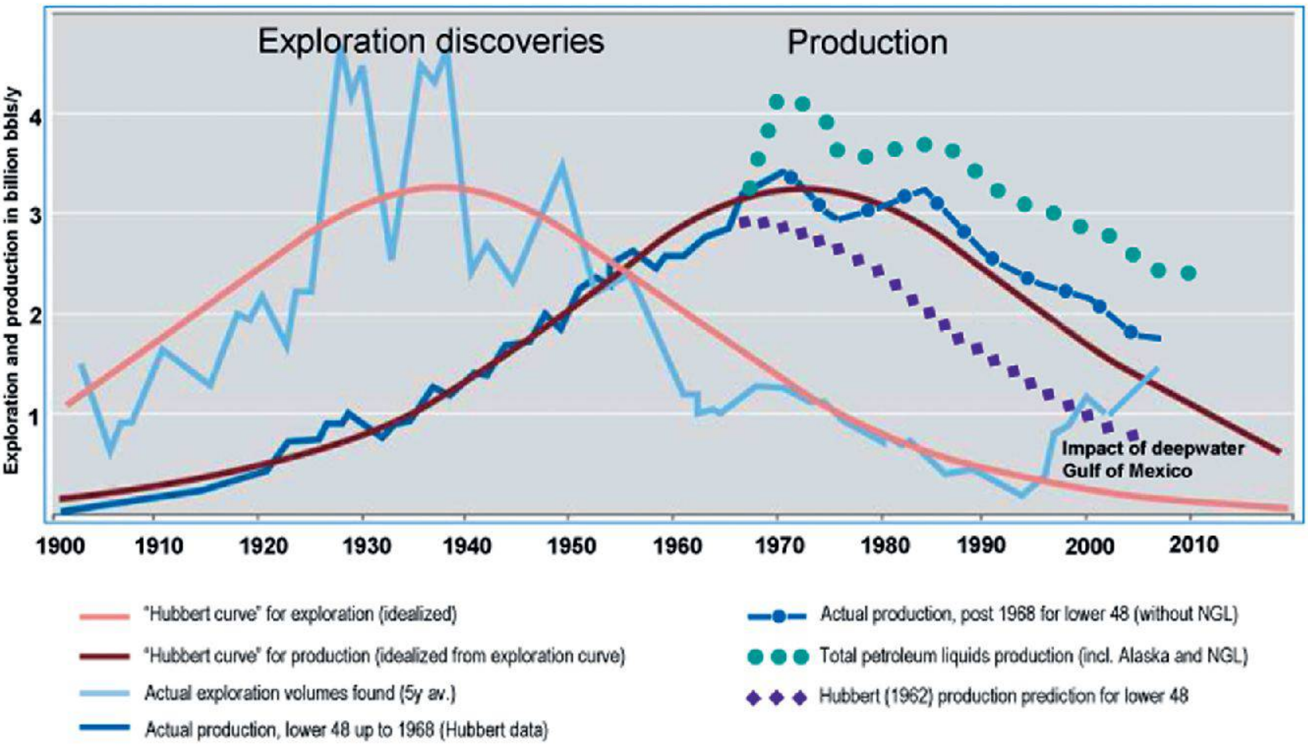


Fig. 16: Peak of oil exploration and production volumes in the US. Note significant deviation from the theoretical curve for both exploration and production volumes, largely caused by technological improvements and new plays (Deep Water). Production pre-1965 is almost exclusively from conventional fields lower 48. Note strong deviation of the idealized production curve (often used in Peak Oil predictions) from the detailed Hubbert (1962) forecast. Actual oil production for lower 48 is at present more than double the detailed Hubbert forecast and total US liquid production including Alaska and Condensate (NGL) amounts at present to about three times the Hubbert prediction (Courtesy Schweizerische Erdölvereinigung with data from International Energy Agency. After 1968 adapted und updated for production total US and for post-2000 Gulf of Mexico exploration with data from Official Energy statistics US Government, EIA, BP 2008 and Ken Chew, IHS).

extended by technological progress to eventually peak in the early 2000 (Fig. 17).
For the above reasons the Hubbert curves consistently predict production peaks too early, at too low peak volumes and with strongly overestimated field decline rates (worldwide 7% decline assumed vs. the actual 3-4%). Hubbert curves are also often misused for things that they are not meant for, i.e. prediction of HC production volumes in (exploration-wise) immature basins, for which the method has not been designed, as stated by Hubbert himself. World peak oil curves, based on the Hubbert method, are, in summary, a too simplistic representation of a highly complex system and lead to over-pessimistic forecasts.

World Oil has published a compilation of different forecasts, made in 2007, of the timing of world peak oil by E&P insiders and critical outside institutions and individuals (R.L. Hirsch 2007):

- Prediction of Peak Oil 2005 – 2010: A group of 13 authors, mostly retired oil company geologists, amongst whom the main promoter of Peak Oil, Collin Campbell, who predicts the Peak for 2010. Most experts in this group have had little exposure to the quantum leaps in oil and gas technology during the last 10-15 years.
- Prediction of Peak Oil 2010 – 2020: 12 institutions, consulting and finance companies (e.g. Merril Lynch, Wood Mackenzie, PFC Energy). The only oil company in this group is Total, predicting peak oil production for 2020.
- Prediction of Peak Oil after 2020: A group of 8, mostly heavy weight oil and financial institutions (Shell, Exxon, BP, EIA, CERA, UBS) with predictions of peak oil between 2025 and post-2030. No peak is seen by Exxon Mobil and OPEC.

The Peak Production for gas is expected for the year 2043 (Mohr & Evans 2007) with a total gas production of 6.5 TCM/year, i.e. more than double the 2007 production of 2.94 TCM.
The question of the peak production of oil and gas is more of psychological than economical interest. What is relevant for the supply security and for the price development is

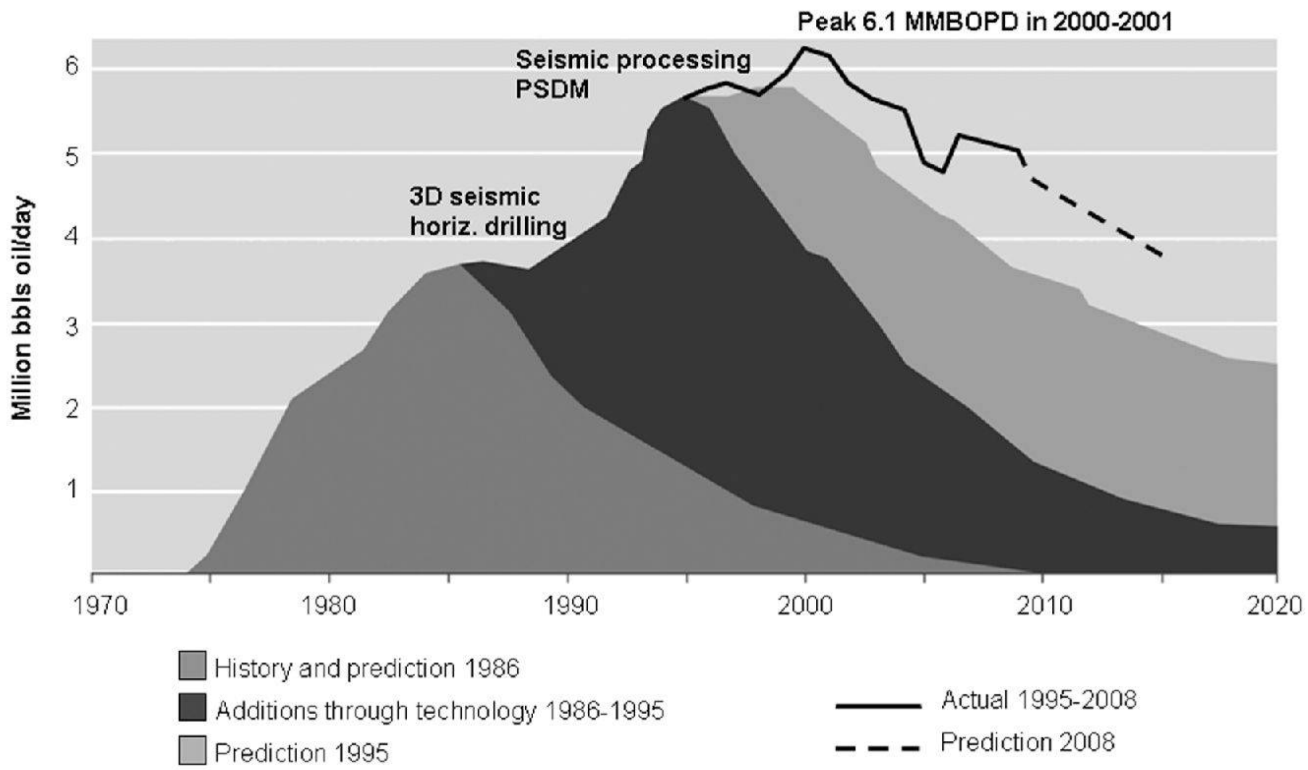


Fig. 17: North Sea oil production. Forecasts and actual production. Delay of peak. (source: Schweizerische Erdölvereinigung and BP 2008, adapted with data from IHS).

not the peak of oil or gas production but the point at which demand is outpacing the ability of the Industry to grow the required production capacities. This may happen well before the peak production is reached and can be caused either by temporary capacity limitations of the infrastructure, like now, or – more seriously – when demand is allowed to grow at a pace that is definitely outstripping the capabilities of growing worldwide supply (see below). A more likely scenario than a simple peak of oil production is a prolonged «roller-coaster-high», where spikes of tight capacity and high prices trigger lower demand growth and thus more capacity and lower prices and vice versa. A similar high with ups and downs has already been observed after the early 1980's price hike.

5.2 Ultimately recoverable resources and production scenarios

The estimate of ultimate recoverable global resources of oil and gas, provided by Ken Chew of IHS is probably currently the best available attempt at quantifying the hydrocarbon volumes that are likely to be extracted economically from this planet (Fig. 12). The figures are based on IHS's extensive worldwide technical database and a wealth of data obtained from the Industry. The results are considerably more conservative than those of the US Geological Survey but are well in line with more cautious industry reports, like the BP Statistical Review 2008.

Discussion of magnitude of resources

Reserve growth: Presently known proven oil reserves are likely to grow by at least 25% through an increase in recovery factor, triggered by new technology and higher revenues (allowing application of technologies that would not have been economic at lower oil prices).
Future exploration discoveries: Estimates of yet to find volumes may appear high at over 60% of presently proven reserves for both oil and gas. The expectations become more realistic if we consider that gas exploration has been severely neglected in many major oil producing countries, that significant exploration potential for oil and gas remains in many NOC dominated countries and that very substantial volumes remain in stratigraphic plays, subtle traps, in the deep sea and in the so far inaccessible Arctic.
Unconventionals are a major part of future resources with a potential amounting to 45% of present proven oil reserves and 35% for gas. While the growth of unconventional HC has been most impressive over recent years it is questionable whether such a pace can be maintained in the face of environmental concerns and the heavy drain on other resources (mainly gas and water), although major progress has been achieved in this domain leading to steeply decreasing water and energy use. In Venezuela the production costs/bbl for heavy oil have dropped by over 70% since 1990 in spite of steeply rising service costs. Given the fact that only Venezuela and Canada have been included in the IHS estimate of unconventional oil resources, the ultimately recoverable volumes will almost certainly be higher (e.g. Tarfaya oil shales in Morocco).
Total ultimate volumes for unconventional gas may eventually also be higher than the 400 Billion BOE assumed by IHS, especially if higher recovery factors in Coal Bed Methane should boost reserves or if tight gas in e.g. NW Europe could be commercially developed.

Reach of oil and gas

The reach can be calculated on the basis of the IHS ultimate resource estimates and the 2007 production, as reported by BP (Tab. 4). Note: The BP production figures are net of

	Ultimate Resources	Production 2007	Reach R/P
Oil	2894 billion BOE	29.75 billion BOE	97.5 years
Gas	2422 billion BOE	18.50 billion BOE	131 years

Tab 4: The reach of ultimately recoverable oil and gas.

re-injected gas and flaring, actual production of gas is thus higher. For this reason, the reach for gas is probably rather in the range of 120-125 years. The above figures do not take into account future growth or decline of demand.

Production growth scenarios

Even though the total ultimate resources may look comfortable (remaining oil resources are almost three times higher than all the crude produced to date and gas resources that are 4-5 times larger than total historic production) they only buy the world a «breathing space» of a few decades.

Growth over the last 10 years (1997-2007) averaged about 1.2% for oil and 2.8% for gas (BP 2008). Unlimited continued growth of oil production by 1% annually would theoretically exhaust all ultimately recoverable oil resources in 69 years (with an annual growth of 2% oil production would double in 36 years and exhaust all resources in 55 years). For gas a theoretical unlimited growth of 2% annually would lead to doubling of production also in 36 years and exhaust resources in 67 years.

Curves with much more modest/realistic growth scenarios are shown in Fig. 18. Both scenarios start with growths that are below the recent gradient, assume flattening over the next decades and then go into a controlled decline, not exceeding 2%/y. These scenarios reach production maxima for oil in 2032 and for gas in 2047. Both scenarios would ensure a declining but still substantial oil and gas production into the early next century. The assumptions made are, however, still too optimistic since in both curves the resources are exhausted well before approaching low production levels (below 1 billion BOE/y). The scenarios should be seen as sensitivities, they indicate that the recent growth rates will be difficult to maintain beyond a few decades and that an additional exponential growth of consumption in development countries would be unsustainable.

A controlled decline appears only possible if growth rates of demand can be reduced to zero well before the mid of this century. This would also ensure enough remaining resources for supply of oil and gas as chemical feedstock in the future. Over 3 Billion BOE of oil and gas are being used annually by the chemical industry, implying that, at the present consumption level, over 300 Billion BOE or some 10% of the ultimate HC resources would be needed to supply the chemical industry for the next hundred years; however, demand for feedstock will probably last much longer.

Compared to the production levels of 2007 the curves in Fig. 18 show a further increase in

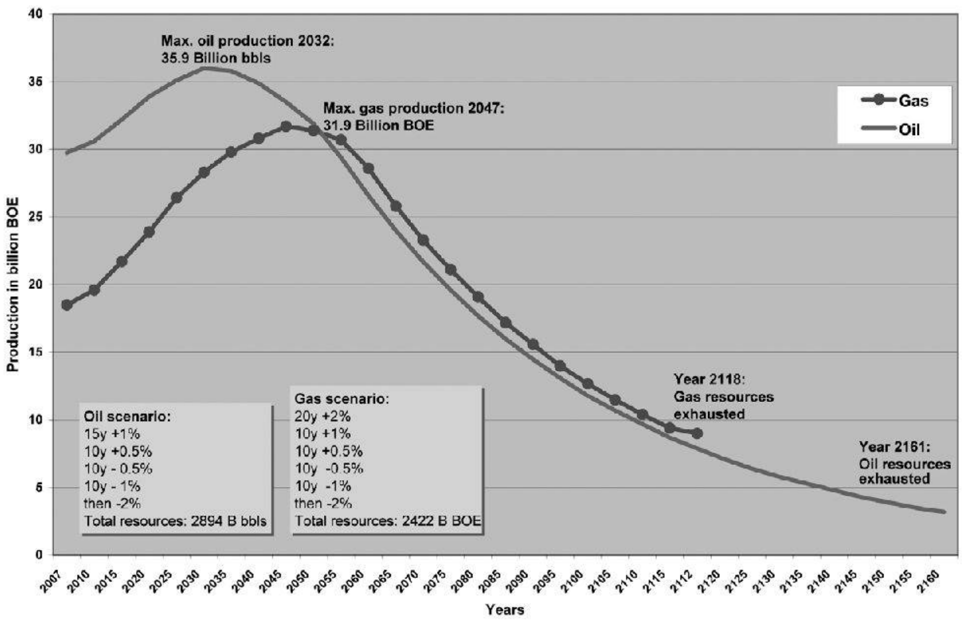


Fig. 18:
Possible scenarios for the future production levels of oil and gas, based on the total ultimately recoverable resources given in Fig. 12.

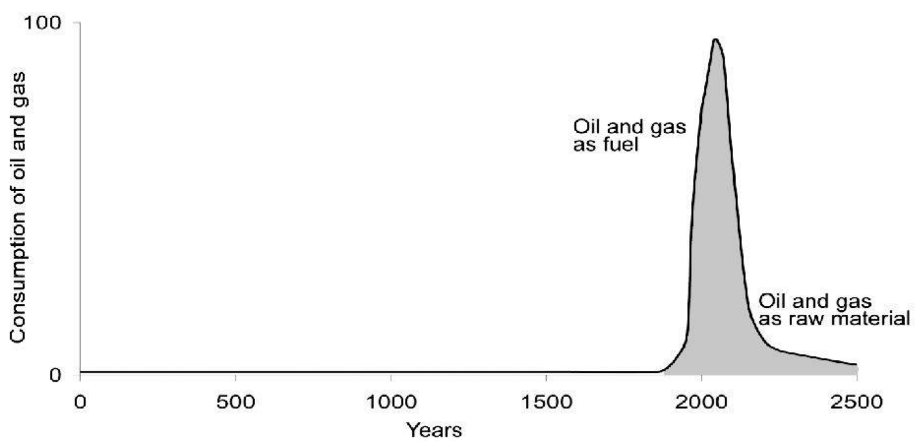
world oil production by 20% (2032) and of gas production by 72% (2047). The corresponding substantial increases in CO_2 production are likely to be a major political issue. Possible constraints on consumption in developed countries through CO_2 regulations may help compensate for the almost inevitable further growth of HC fuel consumption in developing nations where often the only short to mid term alternative is coal.

5.3 Capacity of the industry to supply oil and gas

Presently proven oil reserves are larger than all the crude that has been produced to date. For gas, the proven reserves are even about twice as large as the past cumulative production (Fig. 12). There is enough oil and gas in the ground to satisfy today's demand and a modest growth for 2-3 decades. The present strain on the worldwide oil market is therefore not a result of geological availability of HC resources or of proven reserves but is mainly a matter of infrastructure and capacities.

In the 90's and early 2000, when oil prices were low, insufficient investments in development, production facilities or treatment and transport capacity have been made. The large projects of oil and gas development have very long lead times from discovery to plateau production and the effects of underinvestment are felt only after 10 years or more. As a consequence of this lack of investment, overcapacity in the OPEC countries has been eroded from some 6.5 million bbls /d in 2002 to < 1 Million bbls/d in 2004, the year the oil prices started their steep ascent (it is now about 1.5 Million bbls/d according to the Energy Information Admini-stration, EIA, of the US government). A small capacity margin implies that the Industry has not the flexibility to respond quickly to major disruptions of supply, be they of political, technical or meteorological origin. This shortage of capacity is primarily caused and aggravated by the increasing control of the oil and gas supply by NOCs who, contrary to the international oil companies, are often known for under-investing and for neglecting long-term planning, development and innovation. Investments by private international oil companies can only partly remedy the situation since less than 25% of worldwide reserves is open to private capital (Gould 2008).

A critical factor is the magnitude of capacity growth that can be sustained by the system. Worldwide depletion rates for oil fields average some 4% according to IHS and about 2.9% according to Schlumberger (Gould 2008). If one adds to this an annual growth in demand of at least 1%, this amounts to 4-5% of present production levels, implying a required annual addition of 3-4 Million bbls/day of new production. A growth of some 1 Million bbls/day of additional production capacity every year may be conceivable at most from unconventionals, implying that a further 2-3 Million bbls/ day capacity have to be added every year from new conventional discoveries and higher recovery



Consumption oil and gas: 100 units equal 60 Billion BOE / year (2007 ca 48 Billion BOE)

Fig. 19:
The Hydrocarbon Age. World Hydrocarbon consumption against historic time. Note remaining production tail, required to supply chemical industry with raw material.

rates. However, for unconventional oil a 1 Million bbls/day annual capacity growth is a stretched target; even the present high production increases in Canada and Venezuela are far below that mark and mounting environmental concerns may slow development. In Venezuela the increase in heavy oil production has been more than offset by the decline in the production of conventional oil, again a result of serious underinvestment by an NOC.

6. Conclusions

- The present strain in the supply and demand balance is not an indication of insufficient geological resources of oil and gas in the ground but is mainly caused by bottlenecks in the capacity of production infrastructure and the speed at which new discoveries can be developed and brought on stream. The problem is, at least partly, caused by underinvestment in the industry in the 90's, particularly in NOC dominated countries.
- Only about $^1/_4$ of the world's ultimate oil resources and about $^1/_6$ of the ultimate gas resources have been produced and for both oil and gas the presently proven reserves are larger than the entire cumulative production to date.
- The estimated ultimately available resource volumes provide a sufficient cushion that should allow the world a controlled transition to a non-hydrocarbon fuelled economy in this century. Sensitivities indicate, however, that the growth rates encountered since the 90's (average 1.2% for oil and 2.8% for gas) cannot be maintained for an extended time and that a zero growth and subsequent decline needs to be achieved before the middle of this century.
- Substantial HC volumes will still be produced a 100 years from now, but probably exclusively as a feedstock for the chemical industry (using today about 6.5% of all oil and gas production) and not as fuel for the energy sector (Fig. 19). A significant part of the HC resources needs to be preserved for future feedstock use.
- In spite of the still relatively comfortable resources situation, the world will have to make major efforts to develop alternative fuels in the coming decades, if only to stem the present, probably unsustainable demand growth in developing countries and to counter the growing environmental concerns. This will require investments at a scale not experienced by most countries in any project before. The oil and gas industry will have to play a major role in this, both because of its technical skills and its financial capabilities.
- Important for the impact on the economy is not the time of peak oil or gas production but the point at which growth in demand is outstripping the ability of the Industry to increase production capacity. This situation can occur well before the production peak. Apart from political and environmental factors, this point is largely controlled by technical innovation and the ability to invest heavily in the hydrocarbon sector. Investments of some USD 120 Billion/year are required over the coming years, climbing to some USD 240 Billion/year by 2020 to ensure the capacity of the oil and gas sector can cope with the demand (John S. Herold & and Harrison Lovegrove, Global Upstream Review 2008; Gould 2008, Schlumberger chairman). Unconventional hydrocarbons will play an increasing role in such investments.
- For geoscientists and engineers the next decades are probably the most challenging time since the oil and gas history has started and their skills will be in demand like never before.
- The hydrocarbon age will not end for geological reasons, i.e. with the depletion of oil and gas resources in the ground, but when a better, cleaner and affordable energy becomes available.

Acronyms and terms

BOE: Barrel Oil Equivalent; BBL: Barrel; BCF: Billion (10^9) Cubic Feet; BCM: Billion Cubic Metre; CBM: Coalbed Methane; Creaming: the phenomenon that in a given HC province the largest fields are generally found early and that further exploration meets with diminishing return; DHI: Direct Hydrocarbon Indications; E&P: Exploration and Production; Industry: here always meant as the Oil and Gas Industry; Lower 48: the US without Alaska and Hawai; M: Thousand; MM: Million; Majors: The group of the largest, multinational private oil and gas companies (Exxon-Mobil, Shell, BP, Chevron, Total); NOC: National Oil Companies; NGL: Natural Gas Liquids; TCF: Trillion (10^{12}) Cubic Feet; TCM: Trillion Cubic Metres; USD: US Dollar; 2D: Two dimensional seismic; 3D: Three dimensional seismic; 4D: Four dimensional seismic (with time component).

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