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# "Future of oil supplies"

Jean Laherrère
*Les Pres Haut 37290 Boussay France*
*E-mail: jean.laherrere@wanadoo.fr*

**-Abstract:**

Oil is so important that publishing reserve (even production) data has become a political act. Most of the dispute between the so-called pessimists (mainly retired geologists) and the optimists (mainly economists) is due to their using different sources of information and different definitions. The pessimists use technical (confidential) data, whereas the optimists use the political (published) data. OPEC quotas are based on the reserves, explaining why its members raised their reserves from 1986 to 1990, adding about 300 Gb of oil reserves when only about 10 Gb was actually discovered during this period. There is consensus on neither the reserve numbers, nor the definition of terms, such as oil, gas, conventional, unconventional, reserves. The latter term may variously refer to current proven values or backdated mean values. The US practice is completely different from that in the rest of the world, being conservative to satisfy bankers and the stockmarket. By contrast, the FSU practice was over-optimistic being based on the maximum theoretical recovery, free of technological or economic constraints. All published data have to be re-worked to be able to compare like with like. Unfortunately confidentiality and politics make it difficult to obtain valid data.

The uncertainties relating to future oil production result mainly from the poor quality of the data, as the modelling of the natural distribution fits fairly well with the past. However, consumption depends on human behaviour and economic criteria. World oil production reached a first peak in 1979, taking 15 years to return to its previous level. The peak of US oil production was in 1970 following the peak of discovery during the 1930s, when measured as a "mean" value and not the "proved" value as required by SEC rules. The world oil discovery peaked during the 1960s and production, referring to all hydrocarbon liquids, could peak during the 2010s at about 90 Mb/d if there is no constraint in the demand. The official forecast from the IEA/USDOE of 120 Mb/d in 2020 or 2030 seems too optimistic in front of the currently indicated poor economic performance, and seems almost impossible in term of supply. Many graphs are shown, illustrating past trends as a basis for modelling the next 30 to 50 years. The often used ratio of R/P (remaining reserves over annual production) being presently about 40 years is a meaningless ratio, and cannot be extrapolated for the future. The growth in recovery factor is also a misleading concept as the statistics are very poor. New "technology", which in fact is not new being as much as thirty years old for horizontal wells and 3D seismic, is being used already in most producing fields. It allows cheaper and faster production but does not add to the reserves themselves in conventional fields. However new techniques are necessary to produce the extra-heavy oils and the deepwater fields. But since reserves should be reported only when actual developments are in sight, the estimates in fact anticipate these techniques. We illustrate oilfield declines and show how to estimate the ultimate discovery from creaming curves by continent and fractal distribution. The Hubbert concept is used but refined with several cycles. The data on Iraq are also discussed. Finally the future world oil production up to 2050 (detailing OPEC and Non-OPEC) is illustrated and compared.

Oil price forecasts from the USDOE are shown, but price forecasts are almost impossible (none has succeeded on a long run) because they involve human behaviour, which is mainly irrational. People want to believe in Santa Claus on many subjects (eternal growth, technology, hydrogen, etc.).

**Questions**:

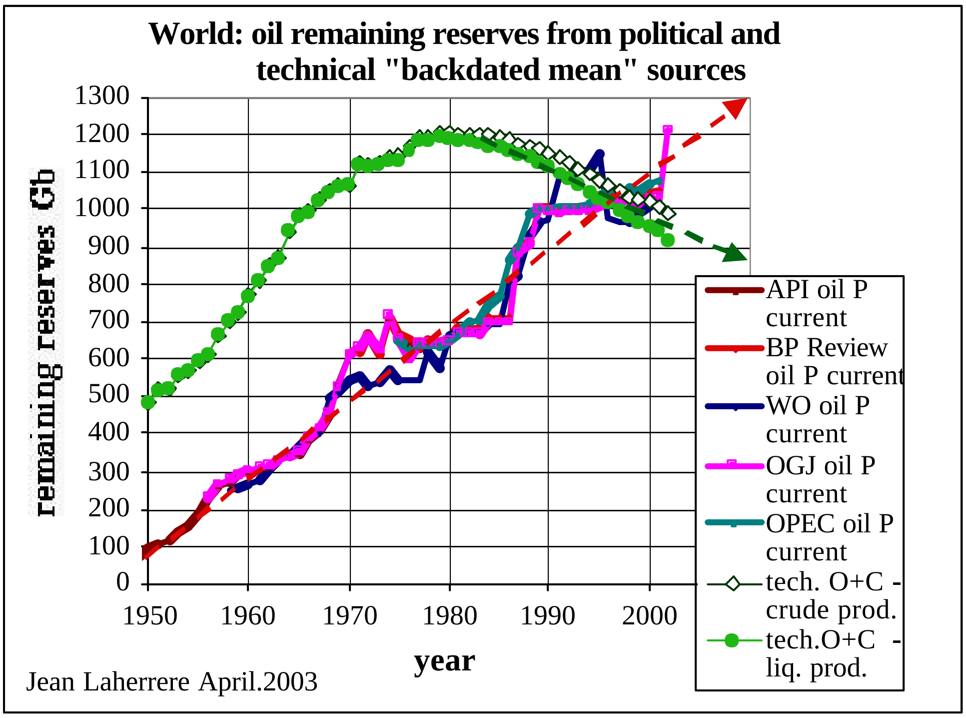
Is there any substitute for oil in sufficient quantity, especially for transport, when oil production peaks? How will Americans, who consume twice per capita as much energy as the Europeans, behave in the face of the end of the cheap oil? Will oil be priced in euro in the Middle East?

-**Definitions and data:**

They vary greatly and cause much misunderstanding.
"**Oil** "either refer to crude oil only, or include condensate (a liquid condensing naturally from gas); natural gas liquids extracted in gas plants (NGPL); synthetic oil (from tarsands); and finally refinery gains (the volume of refined products is larger than the crude from which they are made). The term, NGL, groups together ethane, propane, butane (called also LPG together with propane), pentane and heavier C5+, natural gasoline and condensate. The term "**petroleum**" is also used sometimes for oil alone, but sometimes includes natural gas. In brief, current oil production is variously reported as 65 Mb/d for crude oil, but including condensate for some countries, or as 75 Mb/d for all liquids.
**Reserves** are also badly defined. Reserves can be the "proved" value to comply with SEC (Securities & Exchange Commission) rules, omitting the known probable reserves. Since most companies are quoted on Wall Street, proved reserves are usually reported, even if other national practices are different.
Oil companies usually have several sets of reserve estimates, depending on the use or destination. So-called Proved reserves could be conservative estimates when the goal is to provide growth. But they could be optimistic when the goal is to establish OPEC quotas. In the late 1980s, OPEC countries added as much as 300 Gb to their reported "proved" reserves although only about 10 Gb were added from new discovery. Reserves can be the "mean" estimate used by technicians to plan a development. These technical estimates are compiled in several industry databases. They are commonly described as having a probability of 50 % (P50 or median value), meaning that the risks that they will turn out higher or lower are equally matched, but in fact economic studies use the "**mean**" or expected value (usually around P40). Revisions to a large number of "mean" reserves should be statistically neutral.
"Political" data can be described as the current proved value, reporting the latest revised estimates. The US annual additions to oil reserves comes more than 90% from revisions of the past discoveries, showing that these estimates are quite poor. By contrast, the technical data report the present "mean" estimates backdated to the year of discovery. Under this practice, annual additions come only from new discovery.
Reserves published as "proved" by Oil & Gas Journal (OGJ), World Oil, BP Statistical Review, American Petroleum Institute and OPEC, can be called "political" (or financial). Technical data from the industry are assumed to be "mean" values. If not, the data have to be corrected (increased or decreased), as we did respectively for the FSU and US reported values. The FSU estimates are reported under a classification termed ABC1, as presented by Khalimov at the 1979 WPC, but in 1993 Khalimov stated that these values were strongly exaggerated because they assumed a maximum theoretical recovery factor. When FSU oil reserves were evaluated by Western consultants, it was found that these values have to be reduced by 30%. In this paper FSU reserves are reduced by 30% from reported values. The US reserves have been backdated once by the USDOE-EIA in their report 1990-0534. These values up to 1990 and the new discoveries from the annual report beyond have been increased to a "mean" value, using the MMS (Mineral Management Service) reserve growth factor. Extra-heavy oils are excluded (the industry database lists them for Orinoco plants, but not for Athabasca plants). The resulting data for the world used in this paper (called the technical data) gives a homogeneous and unique file.

The following graph shows the world's remaining reserves for the period 1950-2002, comparing the published data with the corrected mean values. Given the many uncertainties, it is surprising that the Oil and Gas Journal (OGJ) and World Oil report such exact estimates quoted as for 2001 as respectively 1 028.132 385 Gb and 1 004.125 3 Gb, when they should clearly be rounded. For 2002, OGJ quotes 1 212 880.852 Gb, again with unrealistic accuracy,

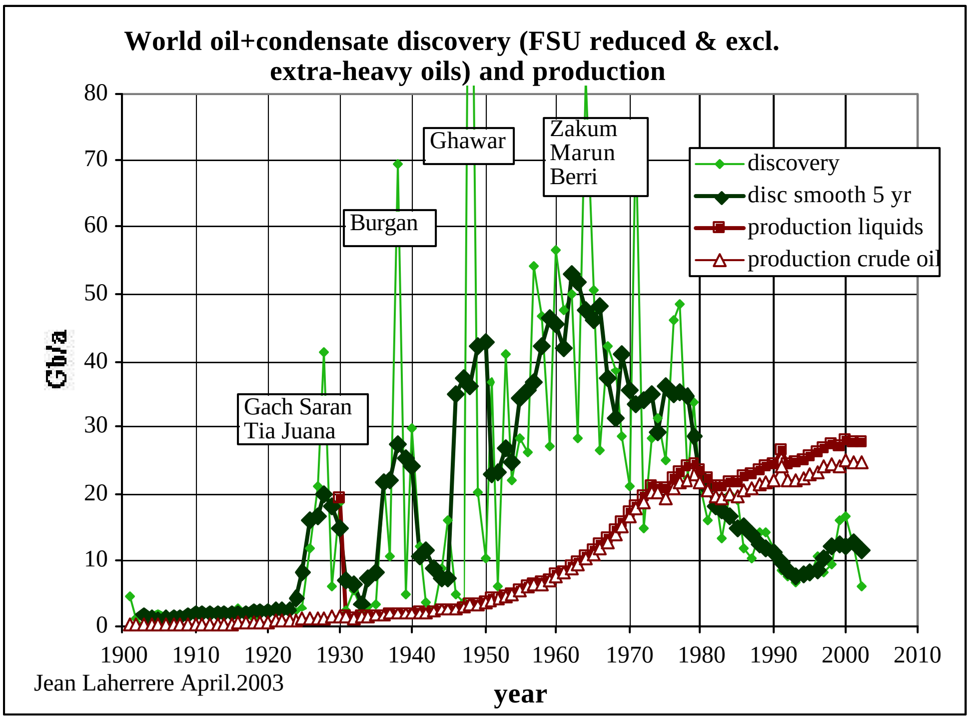
after adding 175 Gb in Canada for the tarsands (extra-heavy oils). In fact they have changed the definition as in the past unconventional reserves were excluded. They also decreased Mexico's reserves by 14 Gb to comply with the Nafta rules. Canada is now listed in the OGJ as second highest reserve holder with 180 Gb second only for Saudi Arabia with 259 Gb, when all the media claim that it is Iraq with 112 Gb. As the BP Statistical Review, published annually in June (taken by almost all economists as the prime reference), reproduces usually OGJ figures, the ranking of Iraq as second in media will change soon.
In fact OGJ has changed the definition of their so-called proven reserves by adding what was considered before as unconventional. It may be logical to add them as they are being produced in significant quantities, but if so, the Extra Heavy oils of the Orinoco should also be included. They have the same density as the Athabasca deposits, which are mined at the surface, but much less viscous because they lie at a depth of 500 to 1500m in a reservoir with a higher temperature. The Orinoco extra-heavy oils are produced with horizontal wells without any steam at a initial production over 1000 b/d/w. PDVSA reports that the range of Orinoco recoverable resources as 100-300 Gb, in the same range as Athabasca..
The technical remaining oil reserves are taken from the aggregation of the present mean field estimate (oil + condensate), backdated to the year of discovery., after deduction of the cumulative oil production today. There are two alternative values, corresponding respectively first to the production of crude oil (with some condensate as for the US) and second, to the production of liquids gathers crude oil, natural gas liquids (including condensate which is in the reserves), synthetic oil (which should be excluded or unconventional reserves should be included when data are complete) and refinery gains (increase of volume from the crude oil in the refinery treatment). In fact the true value is in between.
-Figure 1: World remaining reserves from political and technical (reducing FSU and excluding extra-heavy oils) sources




Furthermore the world "proved" (considered as a minimum) reserves do not correspond with the addition of the" proved" reserves from every country as is done. They correspond to a higher value, as it is unlikely that the real value corresponds to the minimum for every country. Monte Carlo simulation is necessary to obtain a correct proved aggregation. Only the

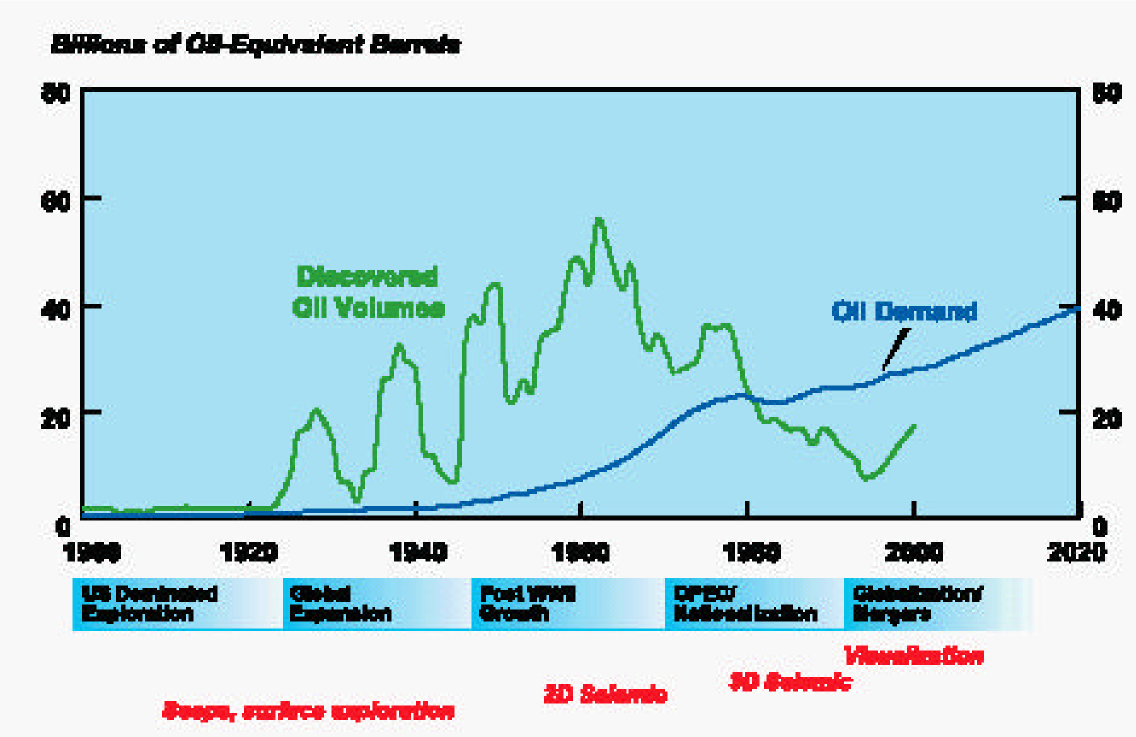
world mean reserves corresponds to the addition of all mean country reserves. In the USGS 2000 study Monte Carlo simulation for undiscovered oil gives for the world outside US the minimum value (F95) of 334 Gb when the addition of the 8 regions minimum gives only 179 Gb. The difference is huge! Capen (1996) called illegal the addition of proved reserves.
The reserves of a country corresponds to the addition of the reserves of every field only if these reserves represent the mean value.
It is noteworthy that the technical mean values present a consistent trend which has been in continuous decline since 1980, whereas the reported "proved" estimates are erratic in a general upward trend. Extrapolating the trends to 2010 would give 850 Gb for the mean value compared with as much as 1300 Gb for the reported estimates. It explains why so many analysts have been misled and confused.
It is surprising to note that the mean estimates of reserves stand at about 950 Gb in 2002, which is not far from the reported "proved" estimates by World Oil; which should correspond to a 90 % probability according to the definitions of the professional bodies SPE/WPC/AAPG – (this again is wrong and confuses). Yet, positive revisions in the United States from 1977 to 2000 average 65%, and negative revisions average 35%. In fact, the last two annual reports for the Gulf of Mexico from MMS indicate that the revisions to the thousand fields on the Outer Continental Shelf are negative. Furthermore, the last 2001 USDoE annual report for all US indicates that the negative revisions are larger than the positive revisions (leading to a probability less than 50%). It implies that future reserve growth in the US will be negative, contrary to the estimate by the USGS 2000.

The technical world annual mean oil+condensate discovery displays several cycles when smoothed, but before 1950 there were exceptional discoveries in Middle East and Venezuela. The annual production is plotted for both crude oil and for the all liquids. The 2 Gb lost during the Gulf war in Kuwait in 1991 is taken into account, whereas it is ignored in the USDOE data.
-Figure 2: world annual discovery for oil + condensate (excluding extra-heavy oils) and smoothing on 5 years



My assessment is in very good agreement with Exxon-Mobil discovery plot by Longwell 2002: "The future of the oil and gas industry: past approaches, new challenges".
The peak of the remaining reserves in 1980 results of the negative balance since that date between discovery and production as shown in the following graph.

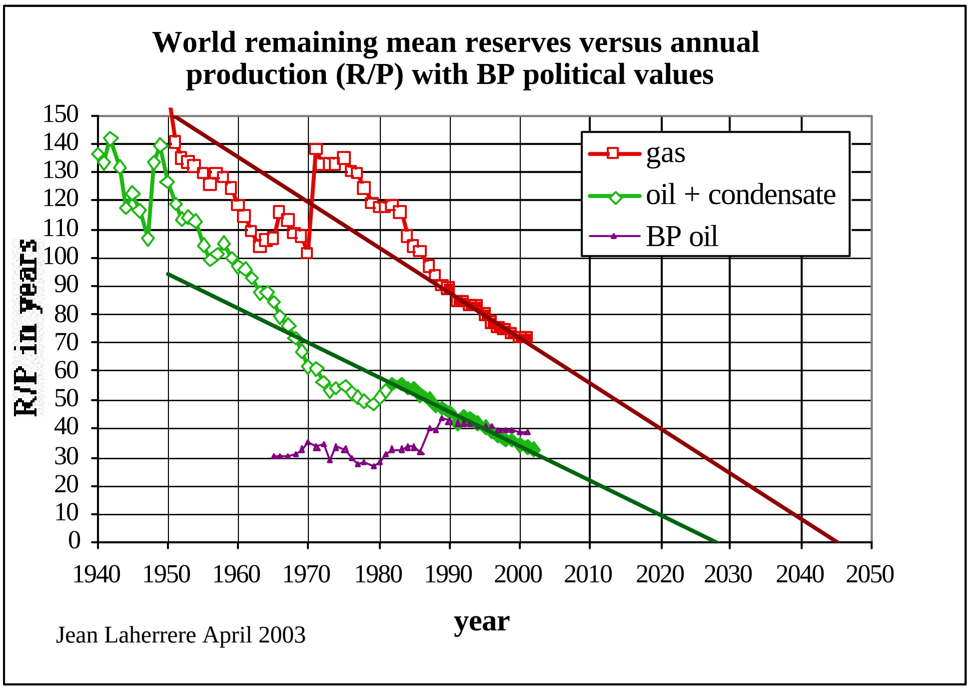
-Figure 3: Exxon-Mobil world annual oil discovery




**-Reserves over production ratio**

It is common practice to report security of supply as the ratio of remaining reserves to annual production (R/P) quoted in years, claiming that current reserves of 1000 Gb could support current production at 25 Gb/a for 40 years. This comforting picture does not bear analysis. Based on remaining mean reserves (cumulative mean oil+condensate discovery minus cumulative liquids production), the world has experienced a drastic reduction of R/P ratio from 140 years in 1940 to 30 years in 2000. Furthermore, extrapolation of the decline of the last 20 years means that the reserves will have been exhausted before 2030, far from the comforting picture of sustaining current production for 40 years. It is amazing to see the difference with the R/P from BP where R are the proved reserves, this proved current R/P was flat at 30 years and moved up around 1987 to 40 years when the OPEC members added 300 Gb (without almost no new discovery), competing between themselves to increase their quotas computed from reserves.

-Figure 4: World R/P for oil (liquids) and gas




In the case of gas, R/P ratio has declined from 150 years in 1950 to 70 years in 2000, which by extrapolation implies exhaustion in 2045, meaning that production cannot be sustained for 70 years. The general gas discovery trend was interrupted by the discovery in 1971 of the world's largest field in terms of oil and gas combined, namely the North Field of Qatar, with its extension into Iran, named South Pars, which contains about 1500 Tcf of gas and 60 Gb of condensate.

It is evident that R/P is a poor indicator and should be ignored.

**-Status of production**

For the world outside US+Canada, over 30 % of the total number of fields are still at a discovery status, but they represent only 3% of total oil discovery, 6% of total condensate discovery and 7% of total gas discovery. The percentage of fields in production is only 55% but representing 90 % of total oil, 84 % of total condensate and 79 % of total gas.

| World outside US+Canada Production status | % Oil discovery | % Gas discovery | % Condensate discovery | % number of fields |
|---|---|---|---|---|
| Production | 90 | 79 | 84 | 55 |
| Developing | 3 | 6 | 4 | 3 |
| Awaiting development approval | 1 | 3 | 1 | 3 |
| Appraising | 2 | 5 | 5 | 7 |
| Discovery | 3 | 7 | 6 | 31 |
| No data | 1 | 0 | 0 | 1 |
| Total | 100 | 100 | 100 | 100 |

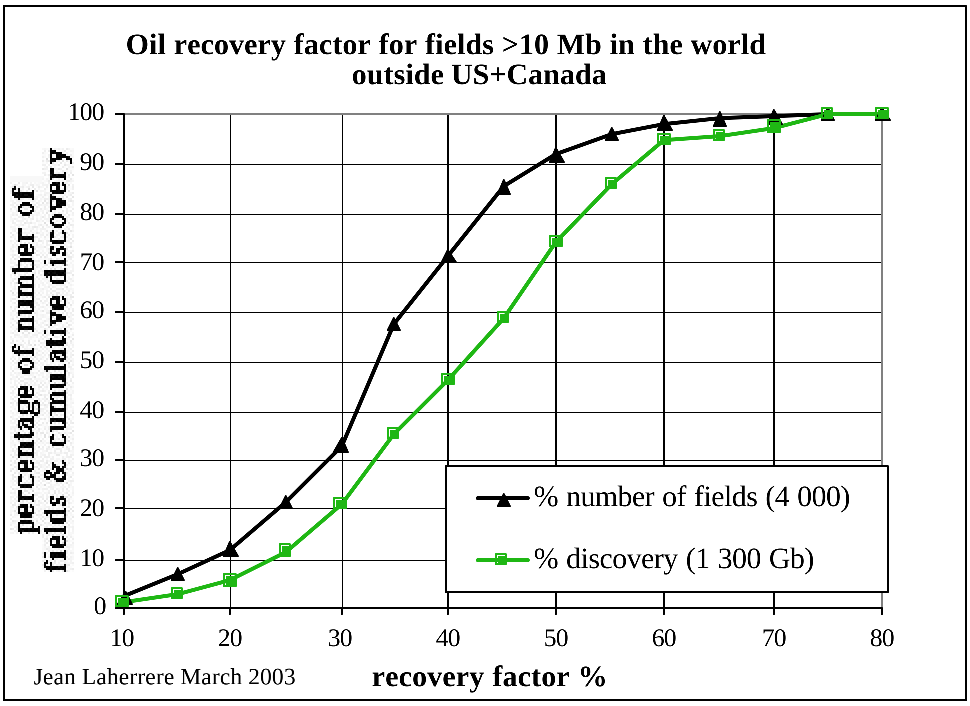
**-Recovery factor**

Recovery factor is an unreliable and promotional ratio.

Many authors claim that the technological progress increases the recovery factor, and that the recovery factor of presently 30 % can be increased to 45%, but such claims cannot be justified on statistical global data nor individual fields.

For the world outside US + Canada the, reported recovery factor (from about 4000 fields over 10 Mb representing 1300 Gb or 70% of total world discovery) varies from 3% to 80% as the most important factor is the geology of the reservoir. 3% occurs in fractured tight reservoirs when 80% can be achieved for very porous reefs. The second factor is the status of the fluid: one-phase oil, oil with dissolved gas drive, oil with gas cap and oil with aquifer.

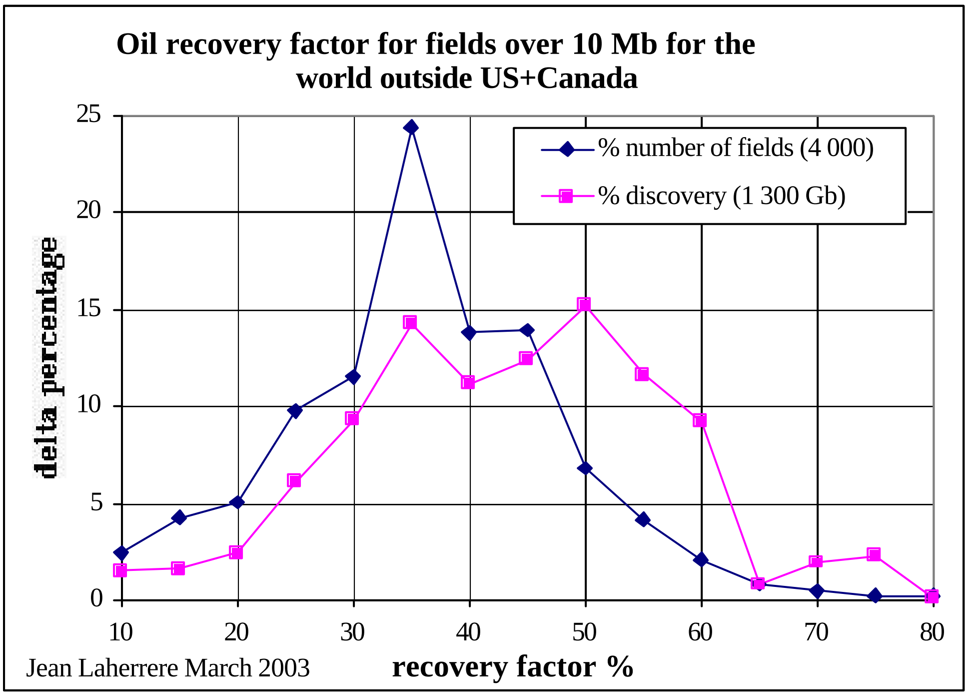
Figure 5: Oil recovery factor for 4000 oilfields (>10 Mb) in the world outside US+Canada




Most of the time, only one value is given for the recovery when a large range should be reported. Furthermore, the average could be the mean or the median (50 % frequency) or the mode (most likely). Also the recovery average can be computed on the number of fields or the discovery (initial reserves) values (the most representative). On the figure 5 the median could be either 33 % (number) or 42 % (reserves).

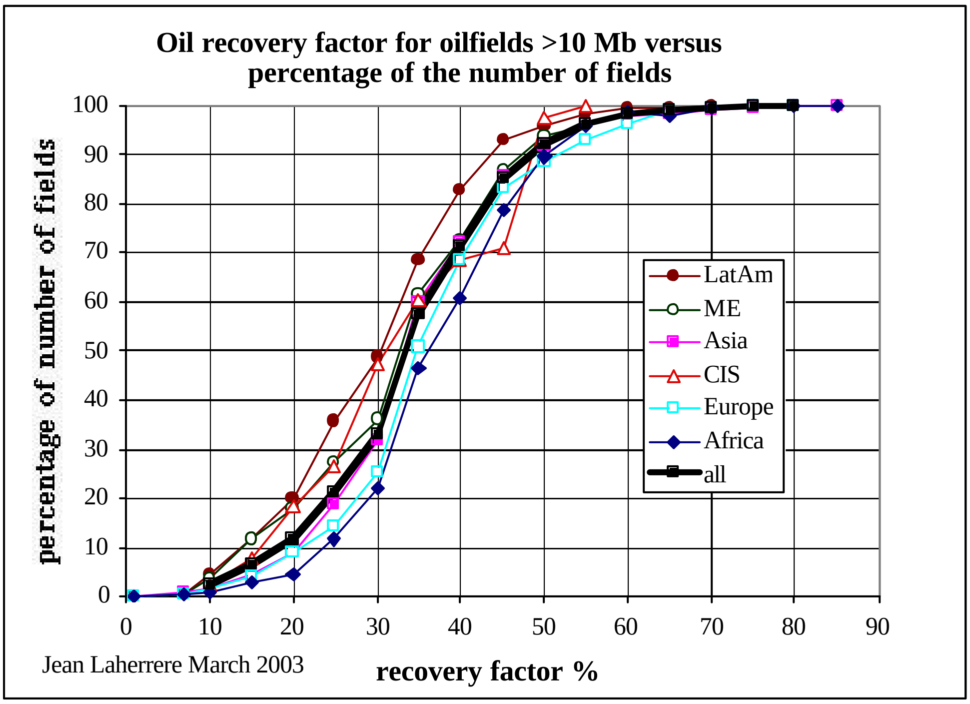
In the following graph giving the derivative, it is obvious that for the number of fields the peak is around 35% but for the reserves there are two peaks and the average is about 45%

Figure 6: derivative of figure 5




The plot of the recovery factor varies with continent, the best curve being Africa and the worst Latin America

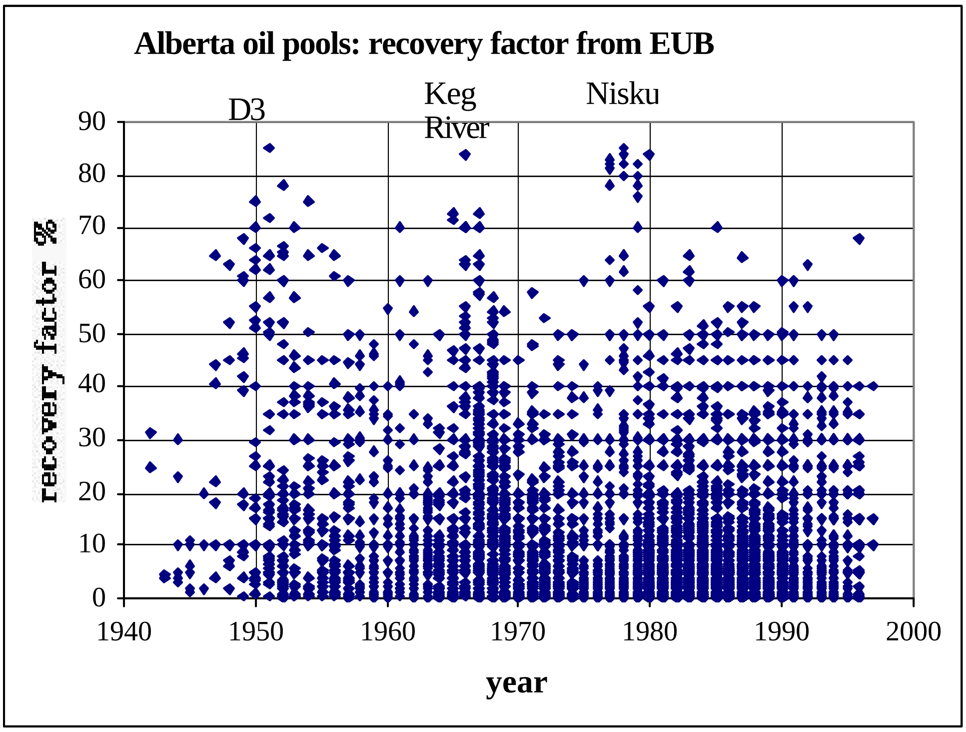
Figure 7: Oil recovery factor for fields >10 Mb by continent




One of the best areas for precise reserve data is Alberta (as almost every field is on lease given by the province), but unfortunately it is too precise as the data are given by pools (subdivision of a field by reservoir). The data are published by the Alberta Energy Utility Board and give the recovery factor which is fairly accurate as there are many wells and seismic. The plot of the recovery factor by discovery year of the pool displays for the high recovery (very porous reefs) a cyclic up and down. Each cycle is controlled by a new play of reefs (the first being the famous Leduc reef in the 1950s, followed by the Keg River

(Rainbow) cycle in the 1960s and the last being the Nisku cycle in the 1980s. These very porous (and thick) reefs are characterised by a very recovery factor of about 85 %, which is due to a very favourable geology and not new technology. But it is worth noting that in this province the same level of technology is used by every producer, so the large range of recovery, including very many low recoveries, shows that the main parameter is the geology as the physical status of the fluid, but not the technology.

Figure 8: Recovery factor for oil pools in Alberta versus time



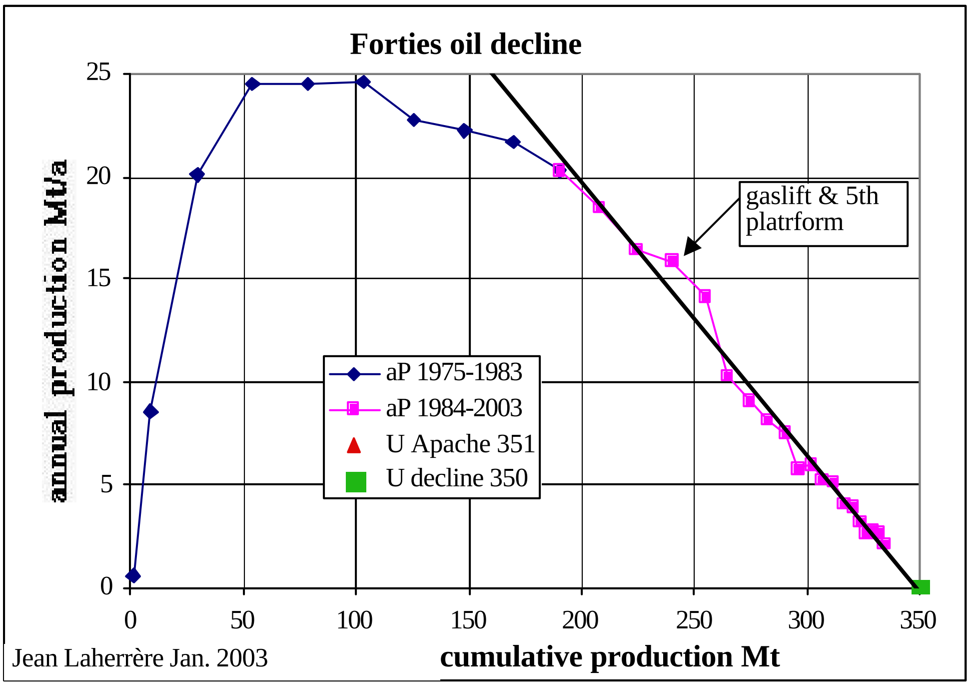

The recovery factor is mainly used for reporting the efficiency of the field, and is published more to promote a field or a company, than for scientific knowledge. It is the ratio of the ultimate value of the reserves versus the volume of the oil in place in the field. But if the reserve estimates are subject to be increase over time in parallel with the decline of the production, the oil-in-place is estimated only with the data from wells and seismic. Accordingly, if there is no more drilling or seismic carried out, the accuracy of the oil-in-place does not change at all. The most frequent values are the rounded one: 30 %, 40 % and also 33.33%, showing the inaccuracy of this ratio. It is not used anymore by reservoir engineers to assess the reserves. In the IFP manual "Basics of reservoir engineering" by R. Cosse 1993 the recovery is only reported as statistics. In most advanced assessments, the field to be developed is broken down in a large number of cells (up to a million). The reservoir parameters (thickness, porosity, permeability, saturation, pressure, temperature) and the production of the field over its entire life is simulated with the help of the physical laws (on pressure, volume and temperature) and efficient computers. Several schemes of development are studied and for each the total production at the end of the field life is taken as reserves. The oil-in- place does not enter into in this simulation assessment and is a unreliable guess. Those who believe that technology can drastically improve the recovery factor forget that the characteristics of the reservoir and the oil, which are the most important factors, cannot be changed. Furthermore most of the present oilfields are produced with the most advanced techniques (as for instance Ghawar is estimated with a recovery factor of 60% and produces with 200 horizontal wells despite the claim of 30% by Yamani in Saudi Arabia.

If technology can improve the reserves of a field, it means that the decline can be reduced when the new technology is applied. Unfortunately those who claims the increase do not show any field with a decrease in decline. Technology allows a conventional field to produce faster and cheaper, but does not add to the reserves. It is different for unconventional fields.

**-Oil decline by field**

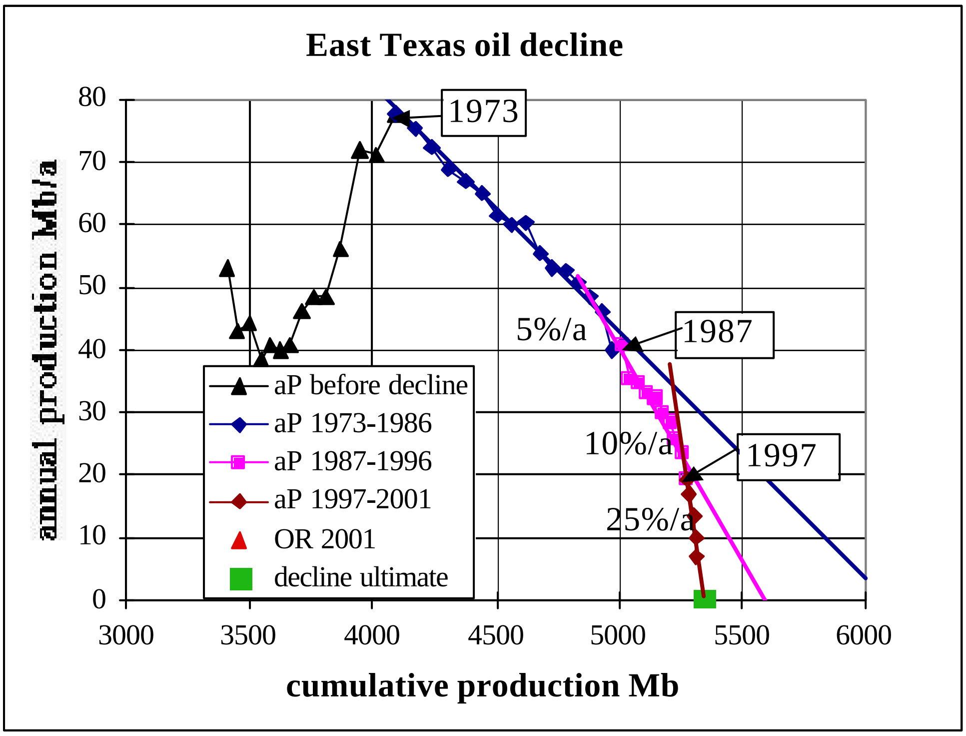
I have shown, more than five years ago, the case of the Forties field where new technology (airlift) and new investment (5th platform) in 1987did increase the production for two years, but did not increase at all the reserves. In 2003 BP sold Forties to Apache, meaning the end of the North Sea for majors

Figure 9: Forties (UK) oil decline pattern

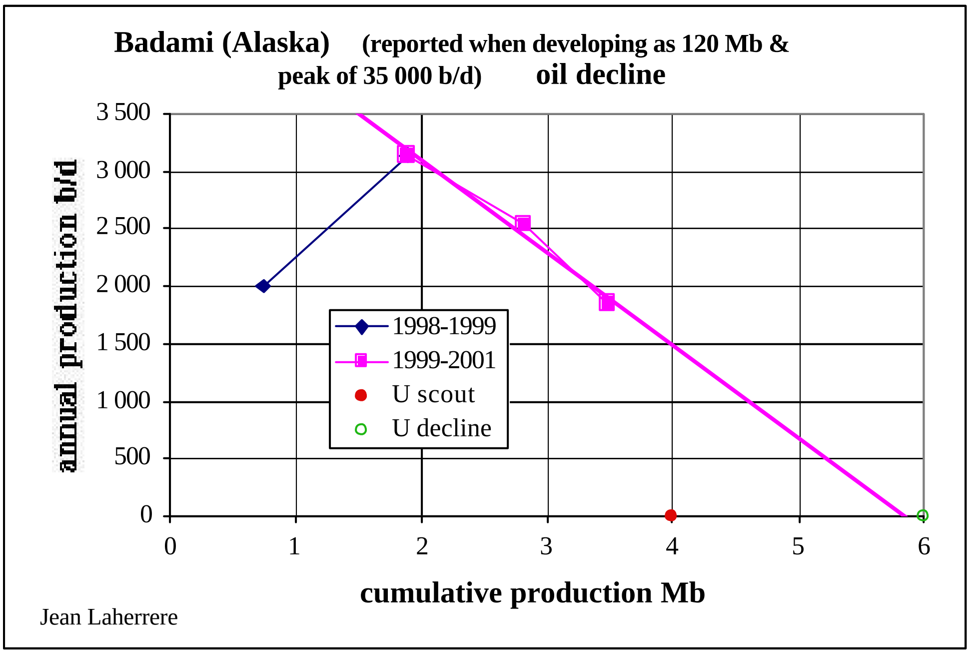



Oil decline started in 1984, but in 1987 and 1988, oil production was higher than the previous decline, but in 1989 the production went back to the older decline trend. And this trend has remained constant until now, with the last point being the forecast for 2003 by Apache. The trend gives an ultimate of 350 Mt, or about 140 Mb remaining reserves as estimated by Apache.

East Texas oilfield (the largest oilfield in the Lower 48 US) is now declining at 25% per year since 1997. Before, the decline was 10 %/a from 1987 to 1996 and 5 %/a from 1973 to 1986. The ultimate recovery was estimated at 6 billion barrels from 1970 to 1990 but is now estimated at 5.35 Gb . In fact, it is a typical case of large negative reserve growth.
All the US technology cannot change the geology of the reservoirs. Reserve growth as dreamed by the does not work!
Figure 10: East Texas oil decline

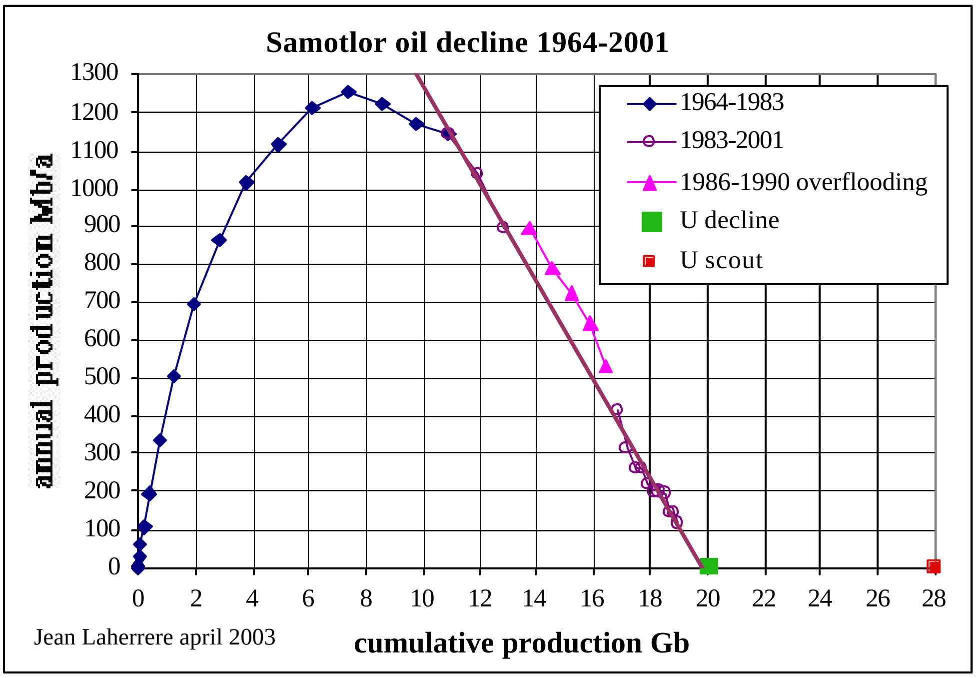



BP has just announced that they are about to shut-down their Badami Field in Alaska after a cumulative production of 4 Mb, when at the time of development (wit a cost of over US$ 300 million) it was reported to have reserves of 120 Mb, forecasting a peak production rate of 35 000 b/d. In fact the peak was 3200 b/d.
Badami oilfield is located between Prudhoe Bay and the ANWR (Alaska National Wildlife Refuge). The ANWR is presently proposed by the Bush government to be drilled in order to increase the security of the nation, despite that BP stated that ANWR is of little importance.
BP has the confidential data of the KIC well, drilled in 1985 on the Indian lands of the ANWR. The USGS (Open file 98-34), without the crucial data of KIC, has estimated in 1999 the potential for technically recoverable resource from 5.7 to 16 Gb with a mean of 10.3 Gb.
From this study, USDOE (SR/O1G/2000-02) has forecasted ANWR to reach a peak between 1 and 1.3 Mb/d within 20 years from start. It seems that the Badami failure to the west, as the results in the Mackenzie delta in Canada to the east, dims this optimistic (political) forecast.
Figure 11: Badami (Alaska) oil decline showing an ultimate of 6 Mb after a peak at 3 150 b/d, when it was reported to hold 120 Mb & a peak of 35 000 b/d before development



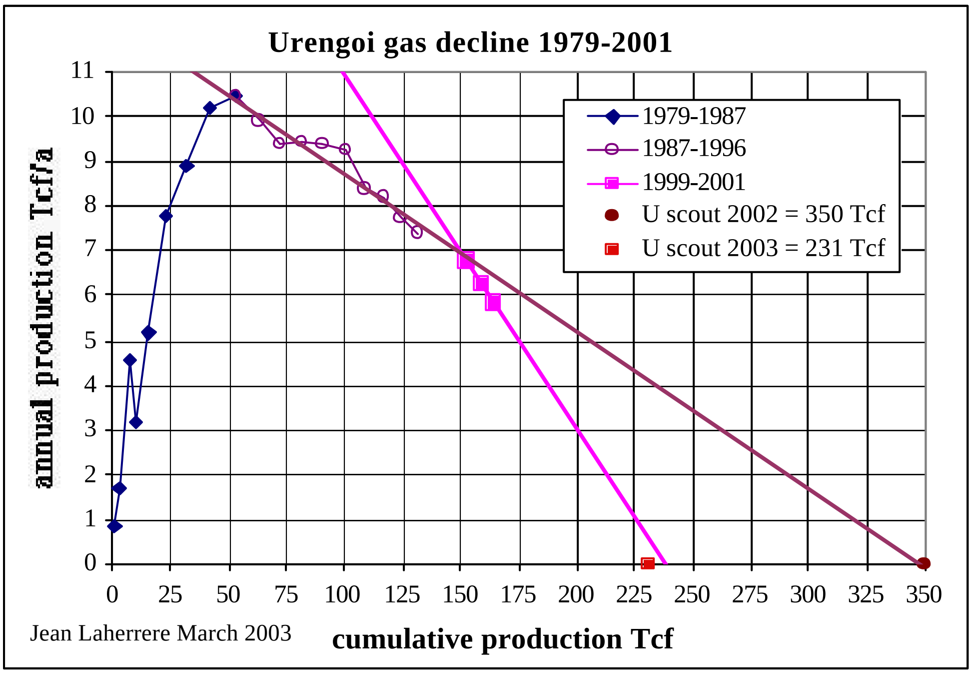

Oil reserves are still secret in Russia (subject to a penalty of 7 years of jail), but the official values are in fact widely known, being given under the Soviet classification ABC1. Certification have shown that they are overestimated by about 30%. The estimate from the decline confirms it in particular for the largest oilfield Samotlor (discovered in 1960). The scout ultimate is 28 Gb, but extrapolating the decline from 1983 to 2001 gives a value of 20 Gb. It is interesting to note that from 1986 to 1990 the field was overproduced by over-flooding to reach the goals of the Gross Plan, but as in the case of Forties, the decline resumed its previous trend in 1991 after the FSU break up.

Figure 12: Samotlor decline



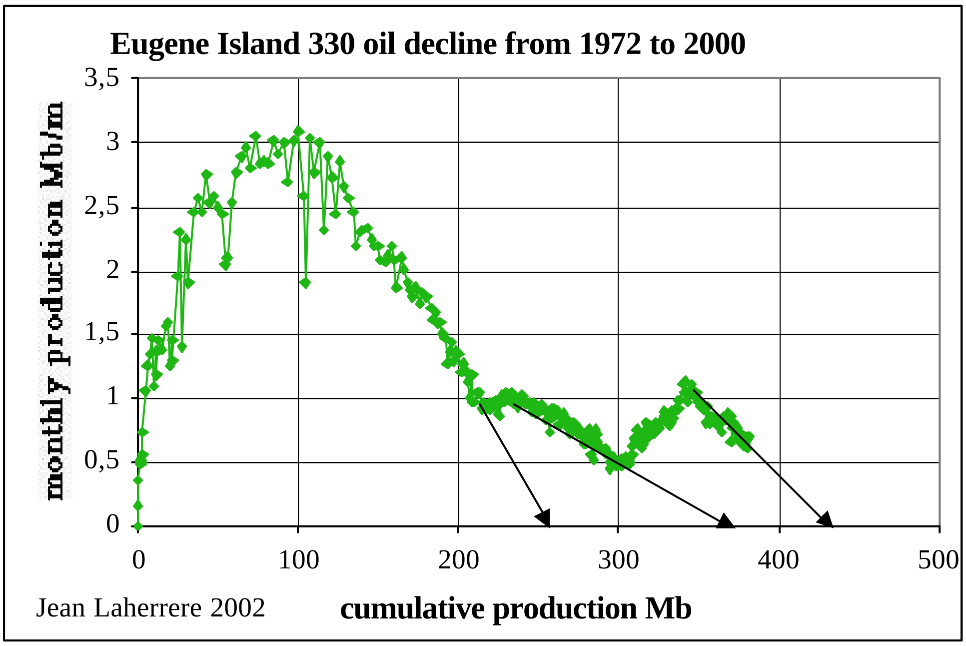

The reserves of the Urengoi Field, the largest gasfield in Russia, decreased from 350 Tcf to 231 Tcf confirming that gasfields have also to be reduced by about 30% (Russian gas reserves are not secret).

Figure 13: Urengoi (Western Siberia) gas decline




The only clear example of significant decreasing decline (save where due to previous poor management) that could be found after reviewing about 2200 fields of over 100 Mb, is Eugene Island 330 in the Gulf of Mexico.

Figure 14: Eugene Island 330 oil decline




This increase in reserve estimate is so unusual that it led to an article in the Wall Street Journal by Christopher Cooper on April 16, 1999 entitled "Oil: a renewable resource? -Odd reservoir off Louisiana Prods Petroleum Experts To Seek a Deeper Meaning" suggesting that oil was coming from deeper sources (as for Gold's theory from the mantle) explaining the large increase in the Middle East during the 1980s ! It is really nonsense.

In fact, the Eugene Island oil and gas field is flanked by the largest and best known fault in the Gulf (the Red Fault), which puts the reservoir in direct communication with the source-rocks. Evidently, the rapid depletion of the reservoir dropped the pressure allowing it to be recharged that oil and gas from the source-rocks. But the declines have resumed, adding (from 370 Mb to 420 Mb) only about 10 % in the total reserve value. If the field had been produced with a smoother way, the decline should have been less leading to the same ultimate. But in financial term it is more profitable to produce quicker provided that the reservoir is not damaged by water coning in the process.

**-Field size**

The areal extent of fields with reserves of oil and gas greater than 100 Mboe outside the US+Canada on which data are available number 2100. The area per field varies from 42 km2 (Europe) to 236 km2 (CIS) with an average of 140 km2. The Middle East fields outnumber the other continents with a size per field of 3 Gboe, compared with an average of 0.7 Gboe.

World outside US+Canada : fields over 100 Mboe reported with field area

| region | number fields | field area km2 | O+C Gb | O+C+G Gboe | Mboe/ km2 | Gboe/ field | km2/ field |
|---|---|---|---|---|---|---|---|
| Middle East | 260 | 51 628 | 779 | 1224 | 24 | 3,0 | 199 |
| Europe | 291 | 12 093 | 65 | 140 | 12 | 0,2 | 42 |
| Africa | 341 | 21 563 | 138 | 207 | 10 | 0,4 | 63 |
| CIS | 544 | 128 203 | 293 | 686 | 5 | 0,5 | 236 |
| Latin America | 365 | 47 041 | 168 | 230 | 5 | 0,5 | 129 |
| Asia | 340 | 39 286 | 77 | 158 | 4 | 0,2 | 116 |
| all with field area | 2141 | 299 816 | 1520 | 2646 | 9 | 0,7 | 140 |
| all majors | 2724 | | 1646 | 2882 | | 0,6 | |
| % | 79 | | 92 | 92 | | | |

The large amount of reserves in the Middle East is mainly due to the large volume of oil per square kilometer, reflecting the very good evaporite seals. The late Jurassic and Cretaceous source rocks themselves are not particularly thick or rich. Generation (measured by the source potential index, see Laherrere, Perrodon, Demaison 1994) is only 10-25 tHC/km2, compared with 40 in the Campos (Early Cretaceous source rock or Gippsland (Late Cretaceous source rock), and 15 in North Sea (Late Jurassic source rock). The area of the generating kitchen is 600 000 km2 compared with 15 000 in Campos and 70 000 in North Sea.
The good seal gives a high efficiency ratio (reserves versus volume of hydrocarbons generated by the petroleum system) of 1.4 %, compared with 0.2 in the Campos, 0,4 in Gippsland and 1 in North Sea (also good seal), but 0.03 % in Paris basin (Early Jurassic source rock.

**-Reserve growth: static or dynamic?**

The USGS introduced in their study of 2000 the concept of world reserve growth based on proved reserves, when previous USGS world estimate (Ch. Masters) were working on "identified" reserves.
Masters WPC 1994 wrote: <<*Hence, though growth is a reality to be considered in many areas, it will not significantly affect overall Reserves quantities as presently calculated*.<<
The US practice has to comply with the SEC (Securities and Exchange Commission) rules which recognise only Proven Reserves, omitting Probable Reserves, whereas in the rest of the world Proven and Probable reserves are recognised. Accordingly, the USGS was mistaken in applying the US practice , which gives reserve growth, to the world as a whole. It is as if one were to compare the temperatures of the main world cities, using Fahrenheit degrees for the US and Celsius degrees for Europe. Over the past 25 years, USDOE annual reports for the whole United States, show that over 90% of the reserve additions came from revisions of the

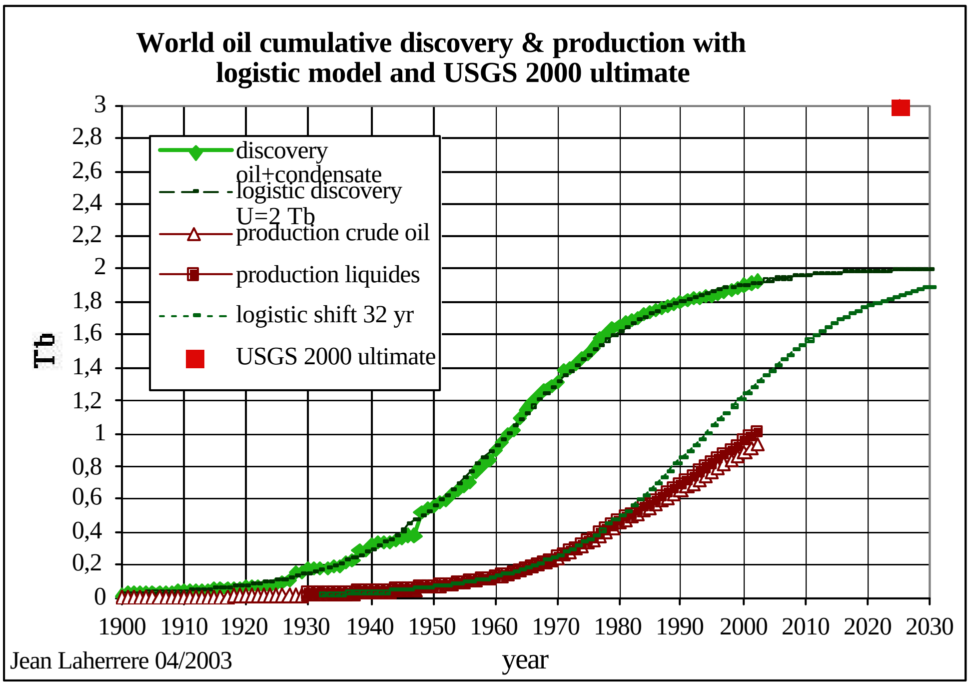
past discoveries. The positive revisions were about double the negative revisions, meaning that the probability of existence of these reserves was about 65 %. For the first time, the USDOE reports in 2001 that negative revisions of past estimates exceed positive revisions, indicating that the growth of reported US reserves has come to an end and that the reported present US estimates correspond to the mean values. There are now many examples in the world of decreasing reserves, and this trend will increase as many undeveloped discoveries will be written off as uneconomic when production of the main fields ceases as in the North Sea, where there are over 300 undeveloped discoveries.

Many objects that the backdated mean values are a static concept, when the reserve growth considers a dynamic concept. But reserve growth in the US is the goal of the proved reserves to satisfy the bankers and the shareholders but it result of a bad reporting. Using mean (proven + probable) value provides statistically no growth, many field reserves can increase and there are immediately reported, but more field reserves decrease or are still undeveloped and the write off will be taken only at the abandon of the production of the basin. The sometimes impression of growth for mean value is just also a question of reporting. The so called dynamic concept is due to bad reporting. The last USDOE reports and the difficulties for the major international companies to replace their production (PIW April 14, 2003) confirm that this dynamic is lost in the US and elsewhere.

### -Ultimate oil estimates

There are several ways to estimate the ultimate recovery. The cumulative mean discovery trend may be extrapolated using a simple logistic curve. It is instructive to compare cumulative discovery with cumulative production, as oil has to be discovered before being produced. The pattern is usually the same after a time-shift. The shift for world oil production (crude oil and liquids) was around 32 years until 1973, the date of the first oil shock. There was no close correlation afterwards because supply was artificially constrained.

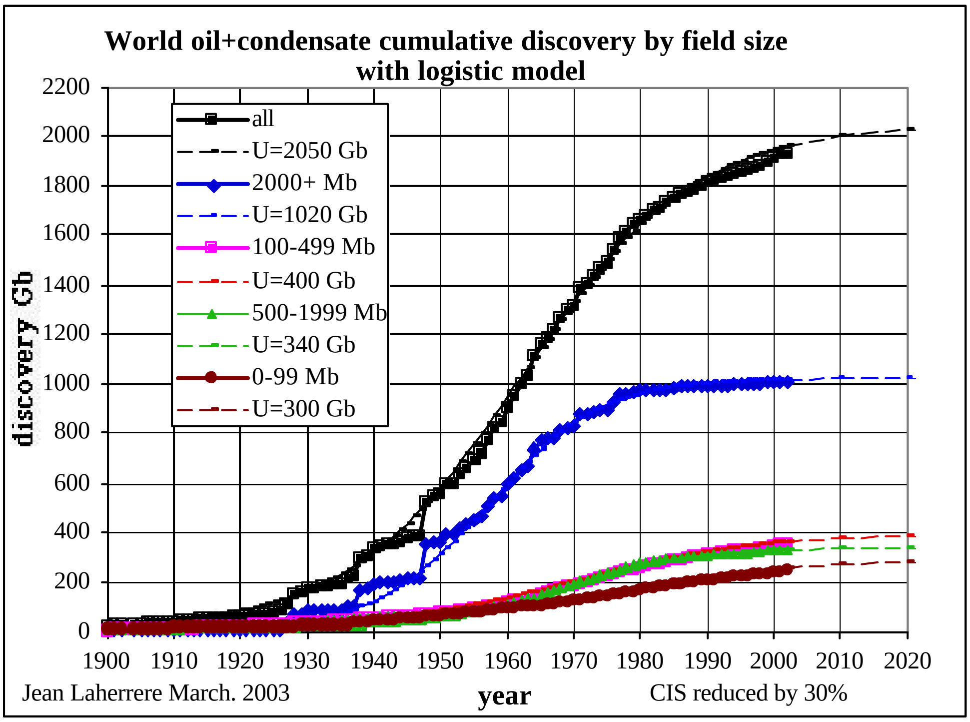
Figure 15: World oil +condensate discovery (FSU corrected and excluding extra-heavy oils) with logistic model which fits production after a shift of 32 years




The USGS 2000 estimate of the conventional oil+NGL to be discovered in 2015 being 3 Tb (in fact the published value is more accurate being 3012 Gb) is plotted on this graph and looks very hard to fit with the past discovery. Any claim of the present curve being changed with a dynamic reserve growth is not confirmed by the previous chapter on reserve growth.

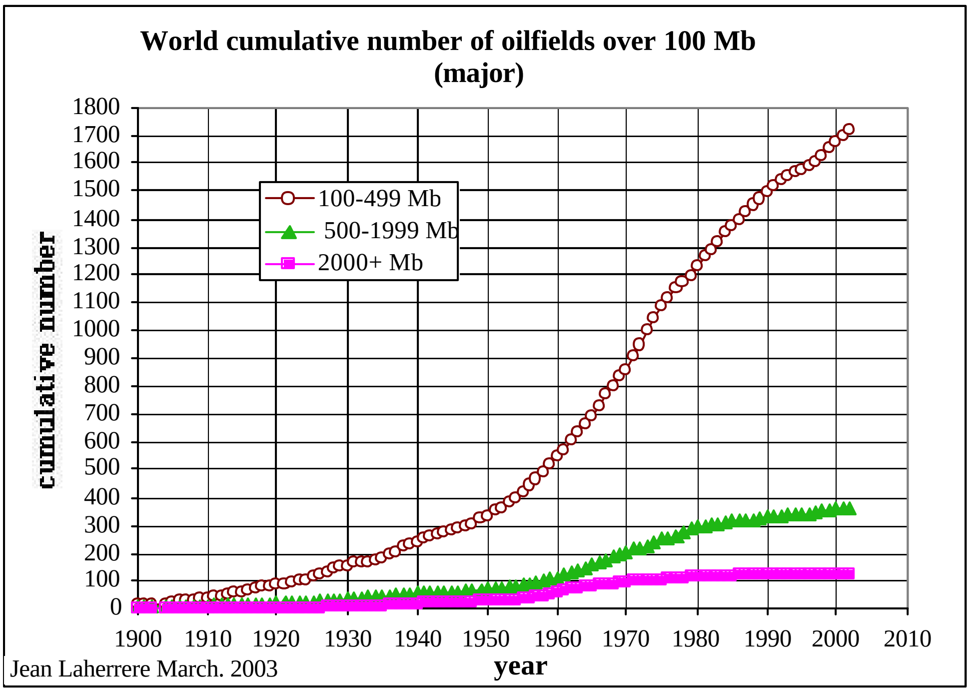
The cumulative world oil discovery by field size shows that the fields over 2000 Gb has flattened since 1980 with 1000 Gb (about 50 % of total discovery). The fields 500-1999 Mb as 100-499 Mb have reached the same level around 350 Gb and the fields 0-99 Mb have reached only 220 Gb but still rising.

Figure 16: World oil+condensate cumulative discovery by field size with logistic model

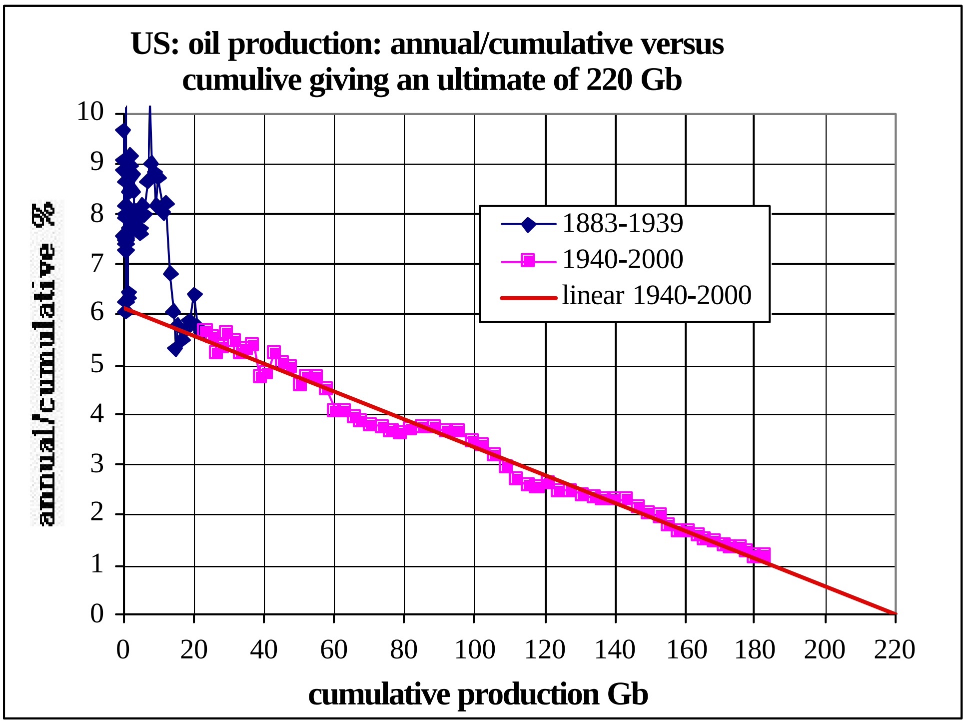



The same breakdown but for the number of fields shows clearly that the 100-499 are rising in number, when the larger fields are flattening.

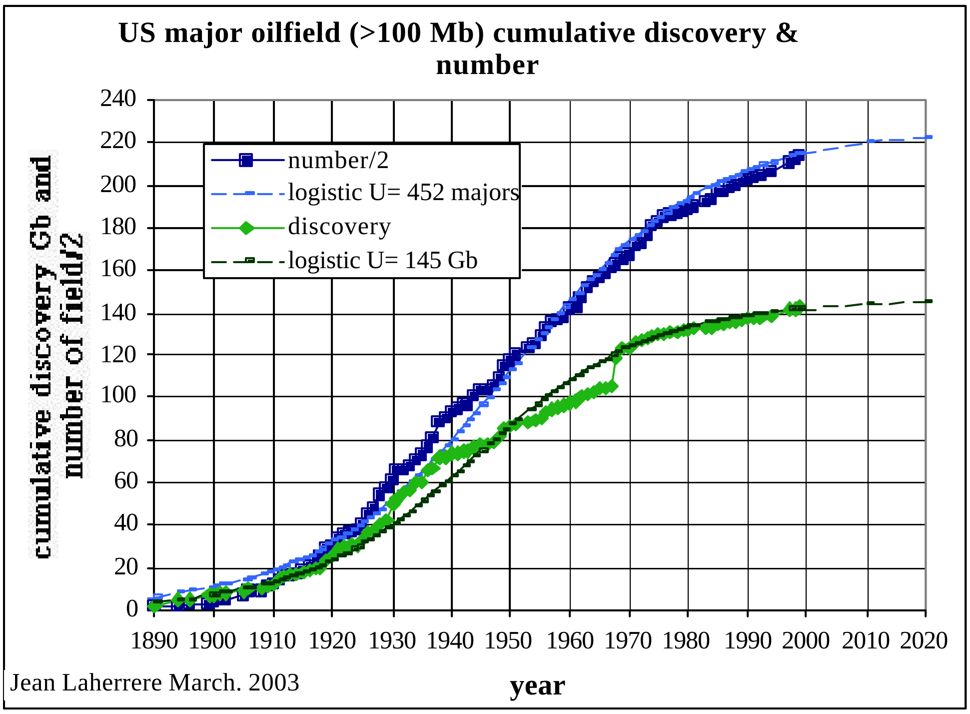
Figure 17: World cumulative number of fields over 100 Mb (major)



The extrapolation of the annual/cumulative versus cumulative production (or discovery) can deliver the ultimate when the annual curve follows a derivative of the logistic curve
For the US, the extrapolation of the production gives an ultimate of 220 Gb.
Figure 18: US oil production: annual/cumulative versus cumulative production giving an ultimate of 220 Gb




The US ultimate is about 220 Gb when the total discovery is about 185 Gb from over 20 000 fields. But the major oilfields (>100 Mb) already discovered numbers about 430 (2 %) fields totalling about 140 Gb (75 %) and the ultimate is about 460 major fields with 150 Gb.
Figure 19: US major oilfields (>100 Mb) cumulative discovery & number of fields

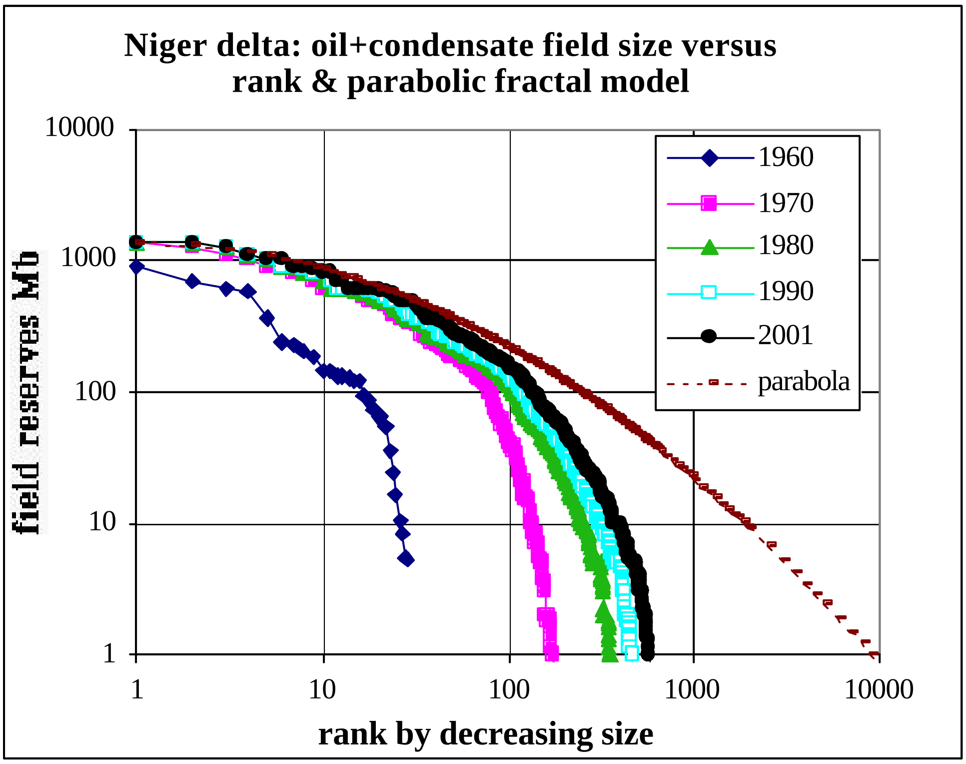


**-Fractal display**

For a Petroleum System, the fractal display of the field size versus rank of decreasing size trends toward a parabola (Laherrere 1996). It gives an indication of the full distribution of discovered and undiscovered fields, but is subject to an economic cut-off for small fields

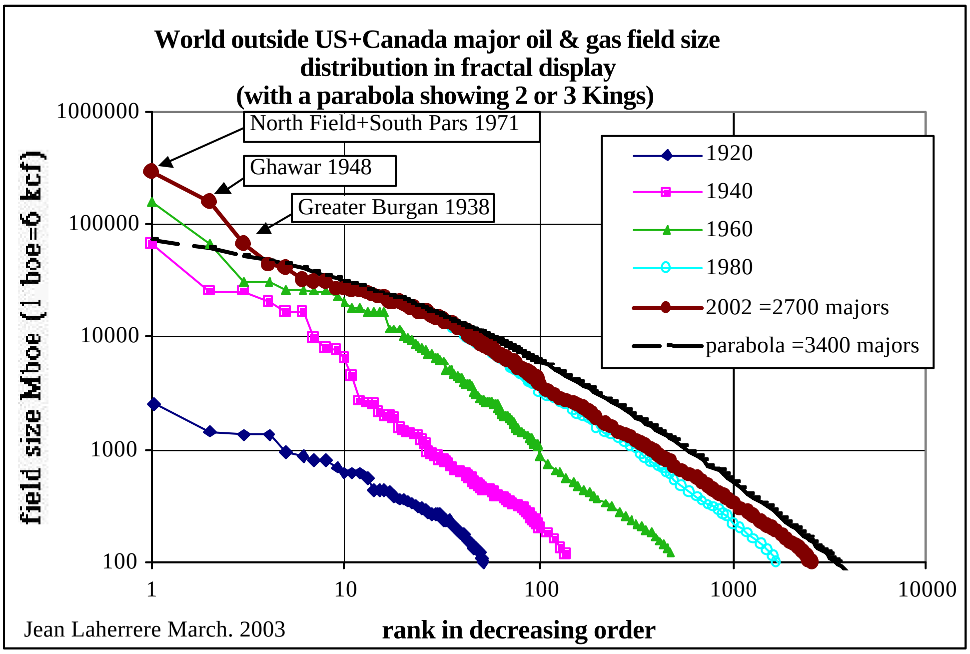
The display for the whole natural Petroleum System, such as the Niger delta, shows clearly that the largest fields are found first, and the new finds are trending towards a parabola curve

Figure 20: Niger delta oil +condensate field size versus rank fractal display



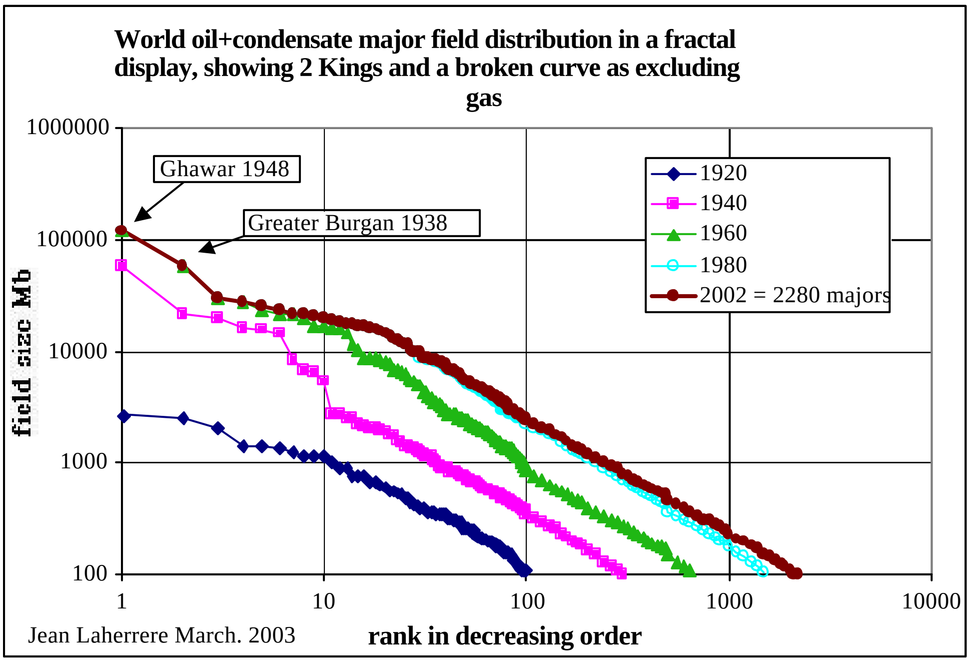

The display for the world outside US+Canada oil and gas fields shows also a parabolic pattern except for the first two ranks (North Field/South Pars and Ghawar) which are tilted "King and Queen", being head and shoulders above the rest.

Figure 21: World outside US+Canada major oil and gas fields: fractal display




The same display for oil, only but for the world, confirms that Ghawar is a King, but also Great Burgan as Queen

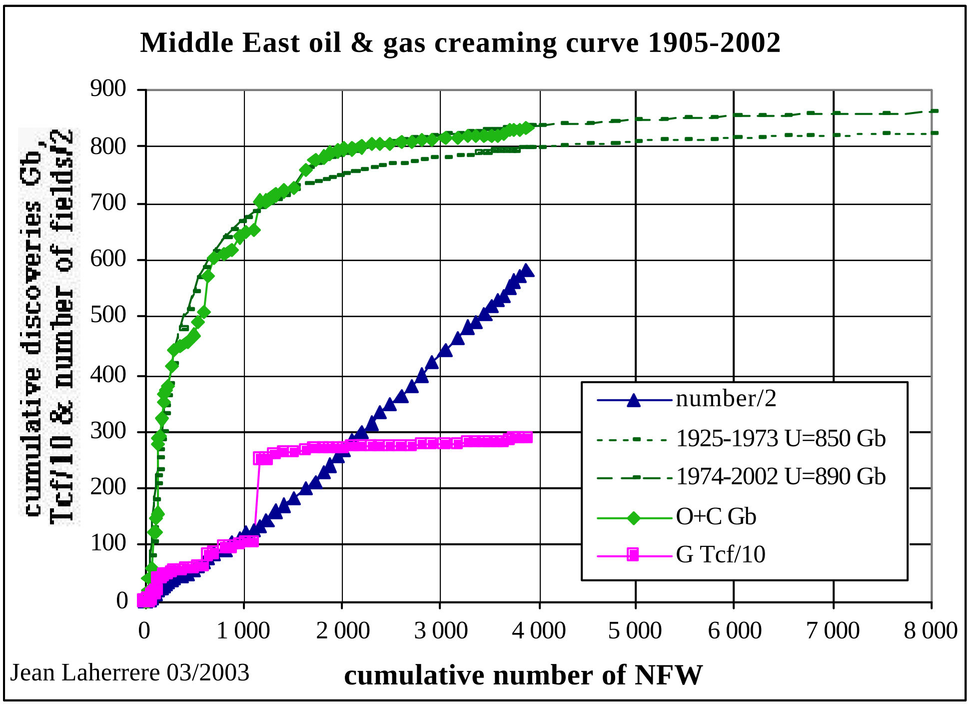
Figure 22: World oil+condensate major fields: fractal display




**-Creaming curve**

Plotting cumulative discovery versus time with a logistic curve is not a very satisfactory way to assess the ultimate, as the curve is disturbed by fluctuations in the level of exploration, especially during wars or depressions. A better approach is to use a creaming curve showing cumulative discovery versus the cumulative number of New Field Wildcats (NFW). The trend can be normally well modelled with several cycles of hyperbola. In the case of the Middle East, for example, oil + condensate can be easily modelled with two hyperbolas, giving an ultimate of about 850 Gb, assuming that no new cycle occurs. It implies that less than 20 Gb will be discovered in the future, requiring drilling double the present number of wildcats. To find more would require the discovery of an entirely new "geological cycle", which is not very likely as there is no deepwater.

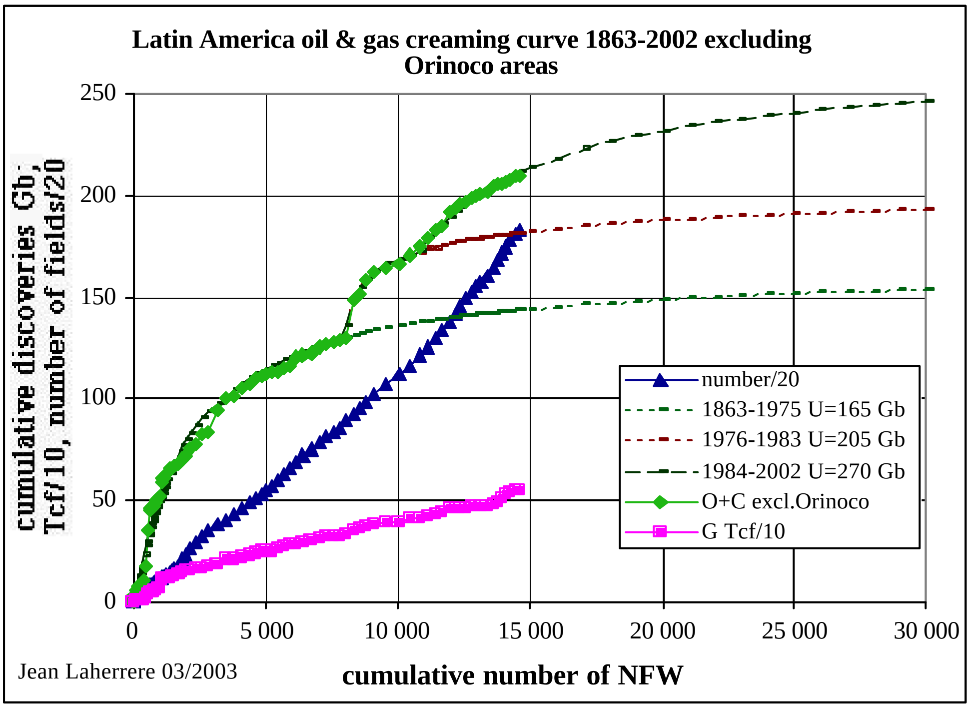
-Figure 23: Middle East discovery: creaming curve from 1905 to 2002




It is widely claimed that the Middle East is under-explored, having a huge potential. But such claims ignore the fact that the first 710 Gb had been discovered by 1977 by only 1700 wildcats in 420 fields and that the 2000 subsequent wildcats found only 50 Gb in 730 fields. Average field size has declined from 1700 Mb prior to 1977 to 70 Mb afterwards. It is evidently a concentrated geological habitat with most of its oil in a small number of very large fields.

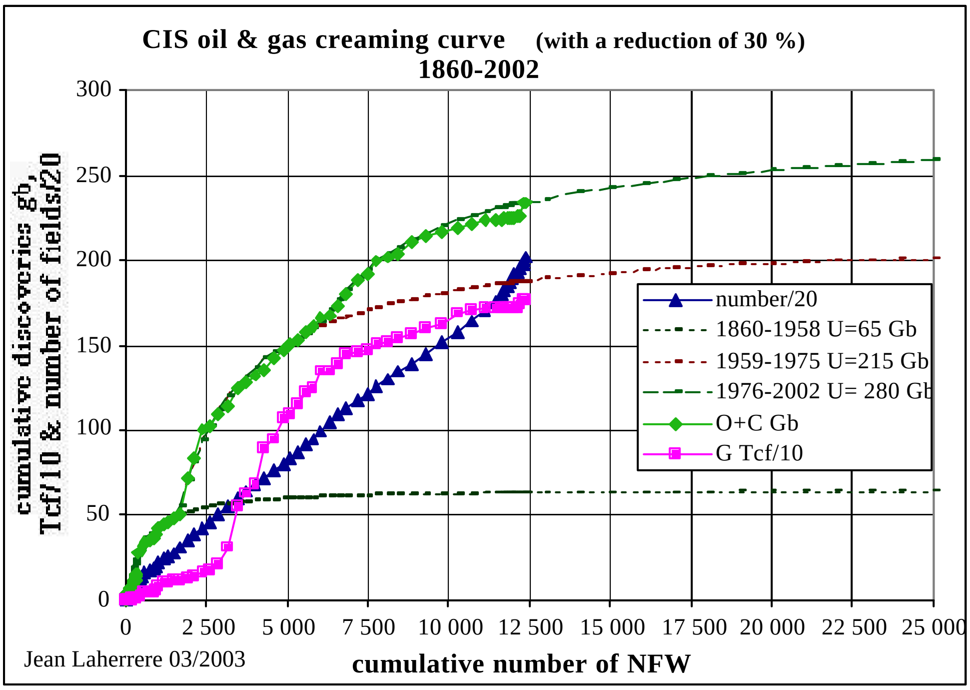
Latin America displays a three-cycle plot with an oil ultimate of around 250 Gb

Figure 24: Latin America discovery: creaming curve



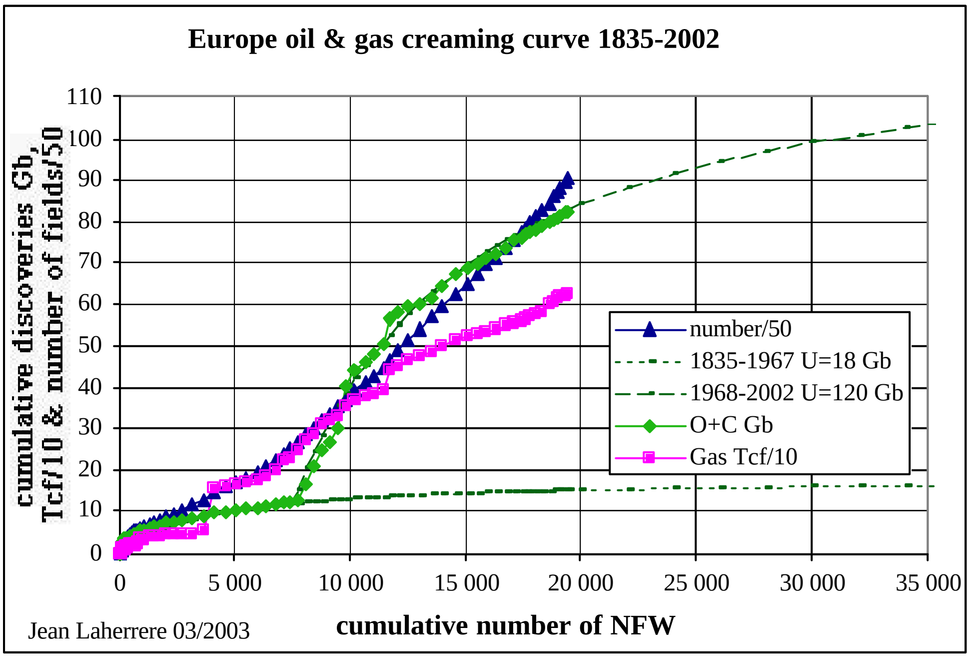

CIS (after applying 30 % reduction) also shows three oil cycles. The oil ultimate is around 260 Gb if no new cycle occurs (Arctic?)

Figure 25: CIS discovery: creaming curve



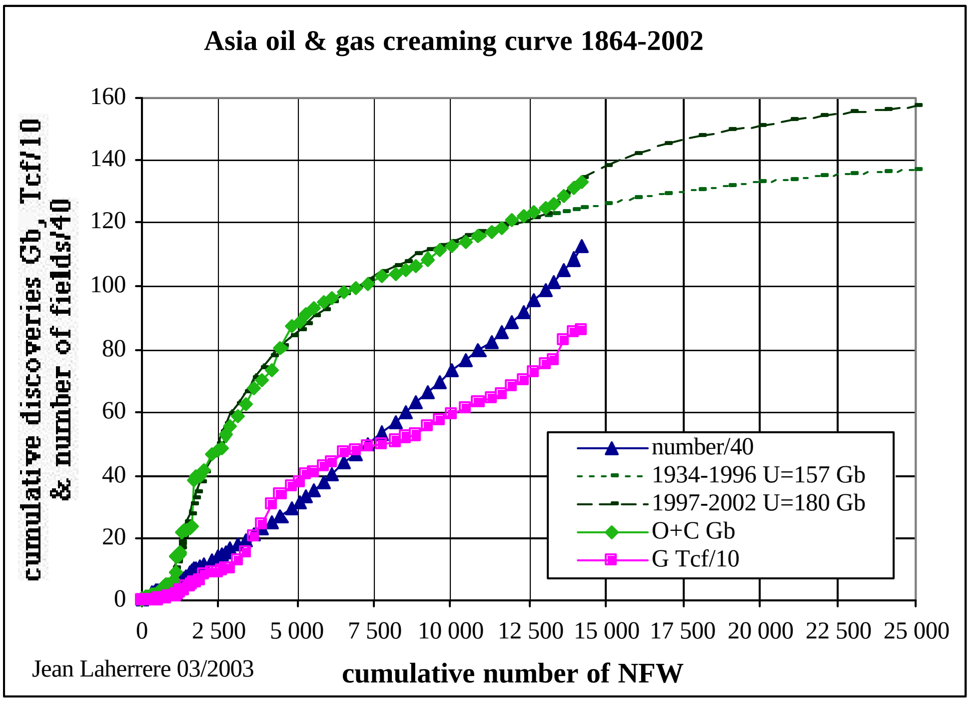

Europe displays two cycles, representing respectively the onshore and the offshore, giving with an ultimate of 105 Gb, assuming that no third cycle, occurs which is now most unlikely.

Figure 26: Europe discovery; creaming curve



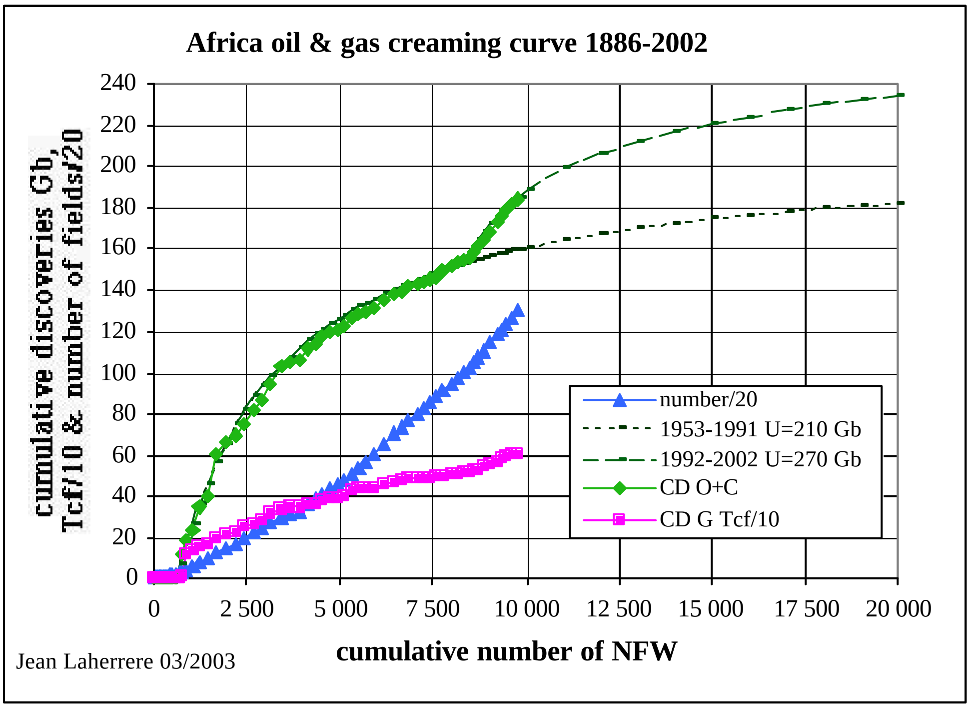

Asia displays a two cycles with an ultimate of 160 Gb, if no new cycle

Figure 27: Asia discovery: creaming curve



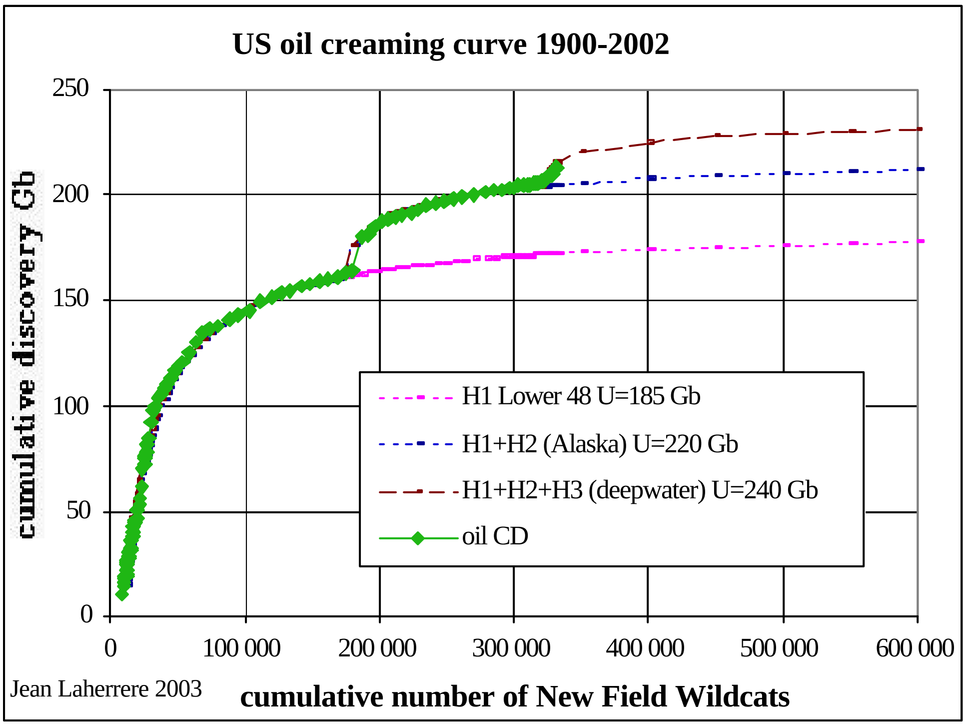

Africa displays two cycles, the second being East Sahara and the deepwater, giving an ultimate of 235 Gb.

Figure 28: Africa discovery: creaming curve




The US creaming curve displays three cycles (Lower 48, Alaska and deepwater), giving an ultimate of 230 Gb. The US is the only country (with Canada) were reserve growth could be significant, despite that the proved estimates are corrected to obtain mean values by using a growth function which can be underestimated (but also overestimated).

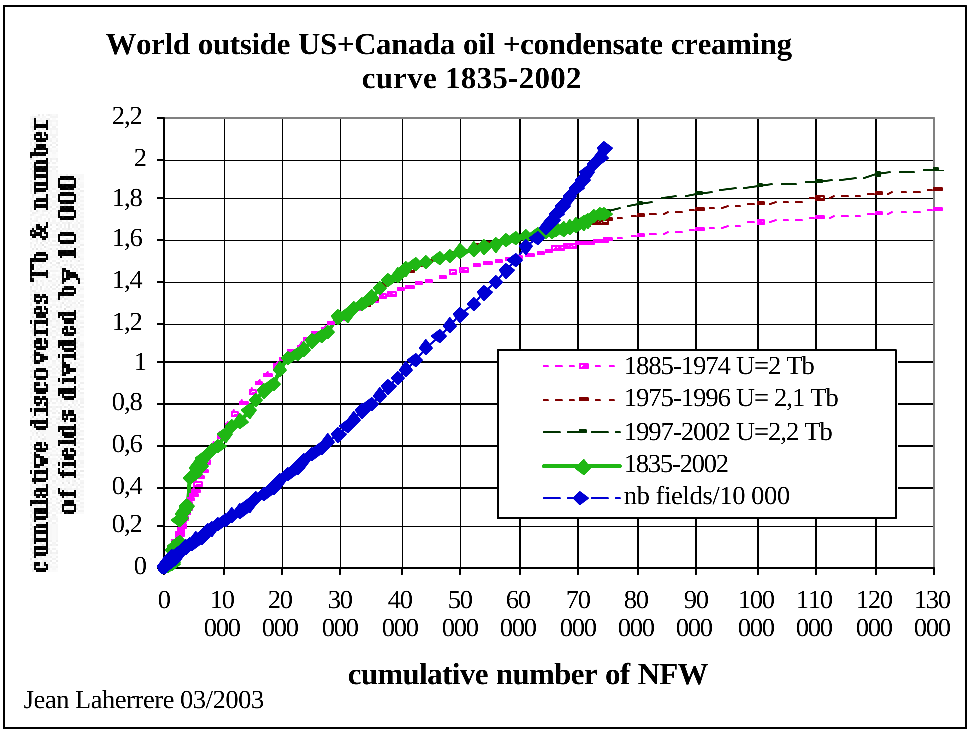
Figure 29: US oil creaming curve




The oil+condensate creaming curve for the world outside US+Canada can be modelled with three hyperbolas giving an ultimate about 2000 Gb. The most striking feature, apart from the flattening of the curve, is, in contrary, the rise of the number of discoveries. By 2002, over 20

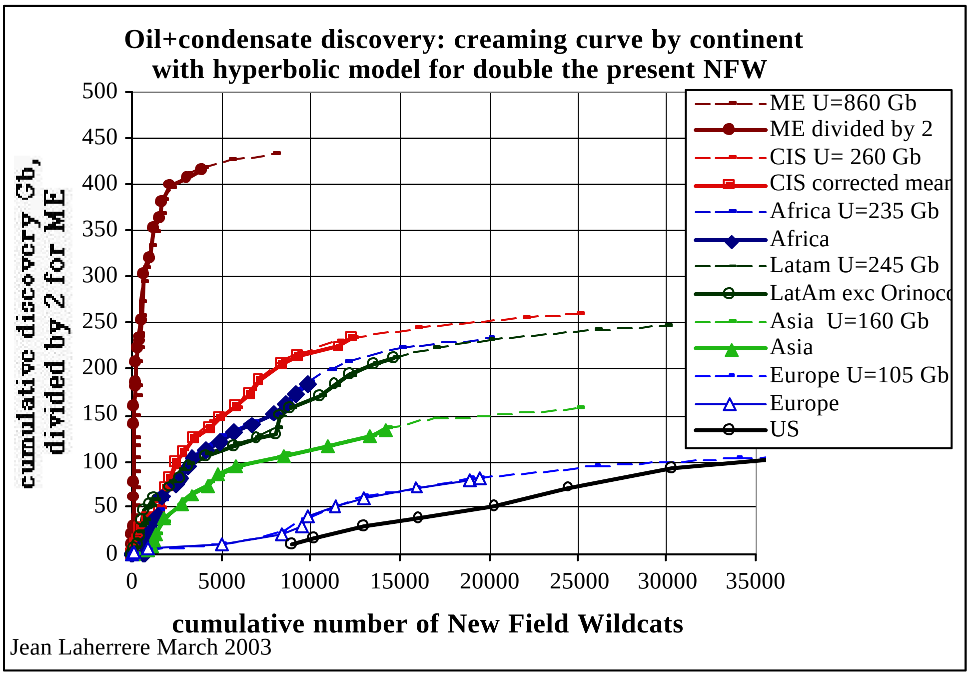
000 discoveries had been made by 75 000 wildcats (NFW), giving an average success ratio of about 30 %, increasing to 40 % over the past ten years.

Figure 30: World outside US+Canada oil+condensate creaming curve

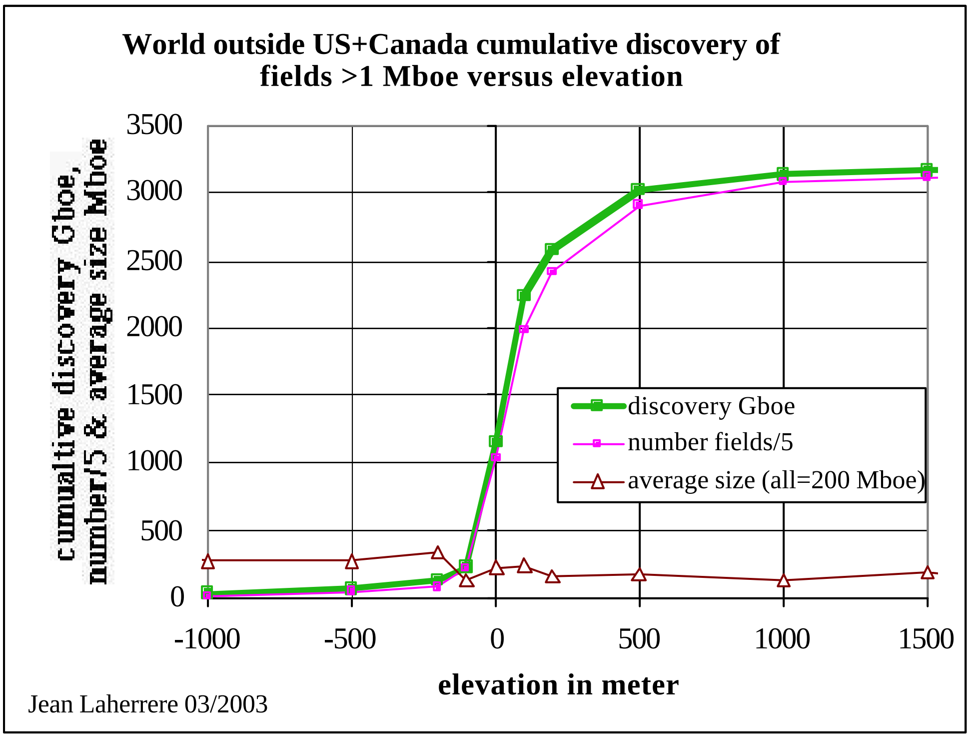



The comparison of the oil creaming curves by continent with the same scale shows the relationships well. The richness of the Middle East (divided by two on the graph) stands out. CIS, Africa and Latin America are similar. The performance in Asia has been poor and that in Europe still worse. The United States is at the bottom of the scale. Its discovery of about 210 Gb took as many as 330 000 wildcats, fifteen times more than in Europe (where the definition of wildcat may be narrower).

Figure 31: Oil+condensate discovery: creaming curve by continent



It is instructive to plot cumulative discovery versus the height above or below sea level. More than 90% of the discovery was between minus 200 metes offshore and 500 meters onshore.
Figure 32: world outside US+Canada cumulative discovery of major fields versus elevation



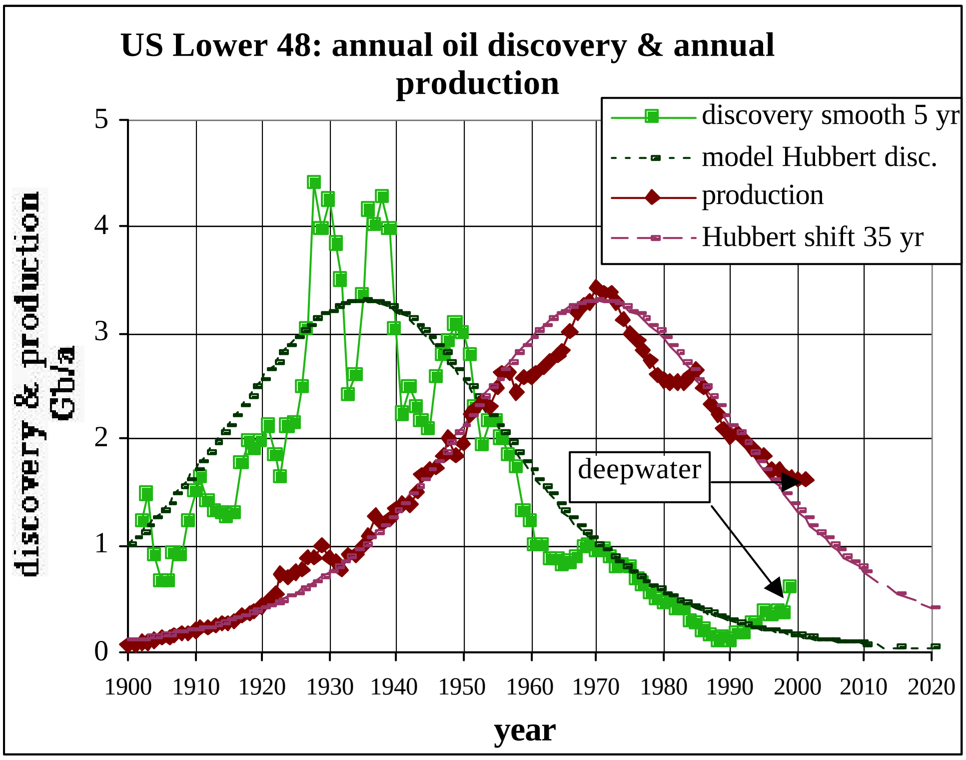

### -Forecasting future oil production

**-Hubbert curve**

In 1956, King Hubbert predicted that the US oil production would peak around 1970. He was widely criticised, but oil production did peak in 1970. Hubbert claimed simply that oil has to be discovered before it can be produced, and that the production curve will resemble the discovery curve after a certain shift.

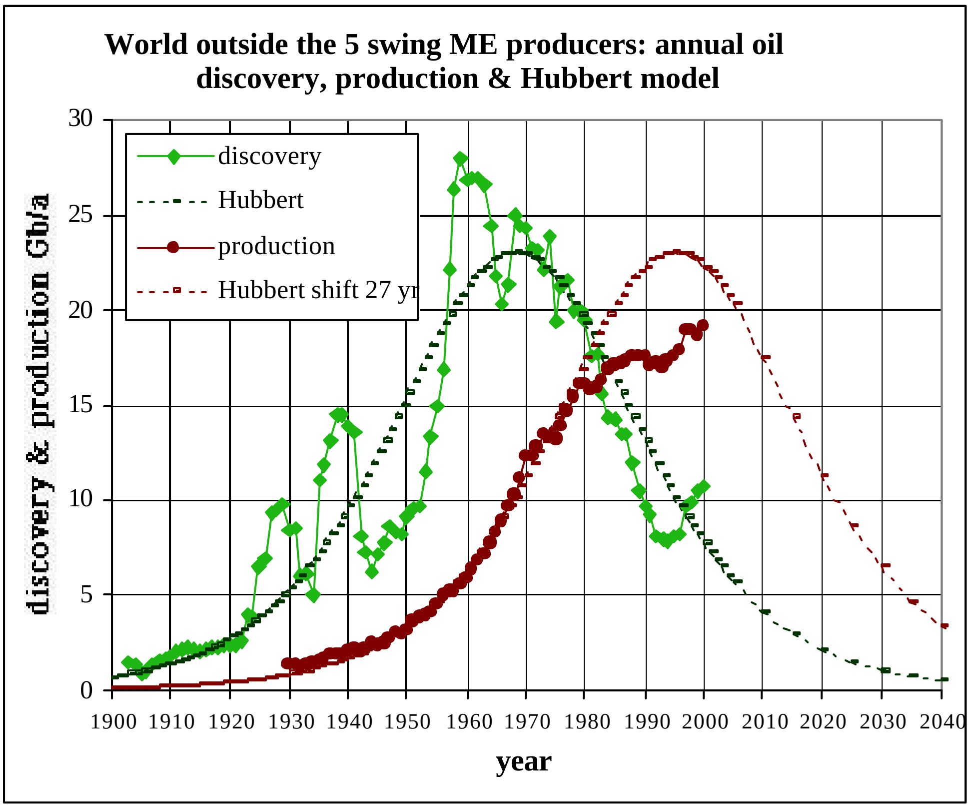
The mean discovery for the Lower 48 displays a symmetrical curve. This is due to the large population of fields and the effects of the Central Limit Theorem whereby the sum of asymmetrical distributions (field production pattern) becomes symmetrical. It can be modelled by a bell-shaped curve, being a normal curve or a Hubbert curve (which is a derivative of the logistic function). Both curves are similar. The oil production curve fits well with the discovery Hubbert model when shifted by 35 years. The last years for discovery and production depart from the model, being a new cycle corresponding to the deepwater, as was Alaska

Figure 33: US lower 48 oil annual oil discovery and production with discovery model



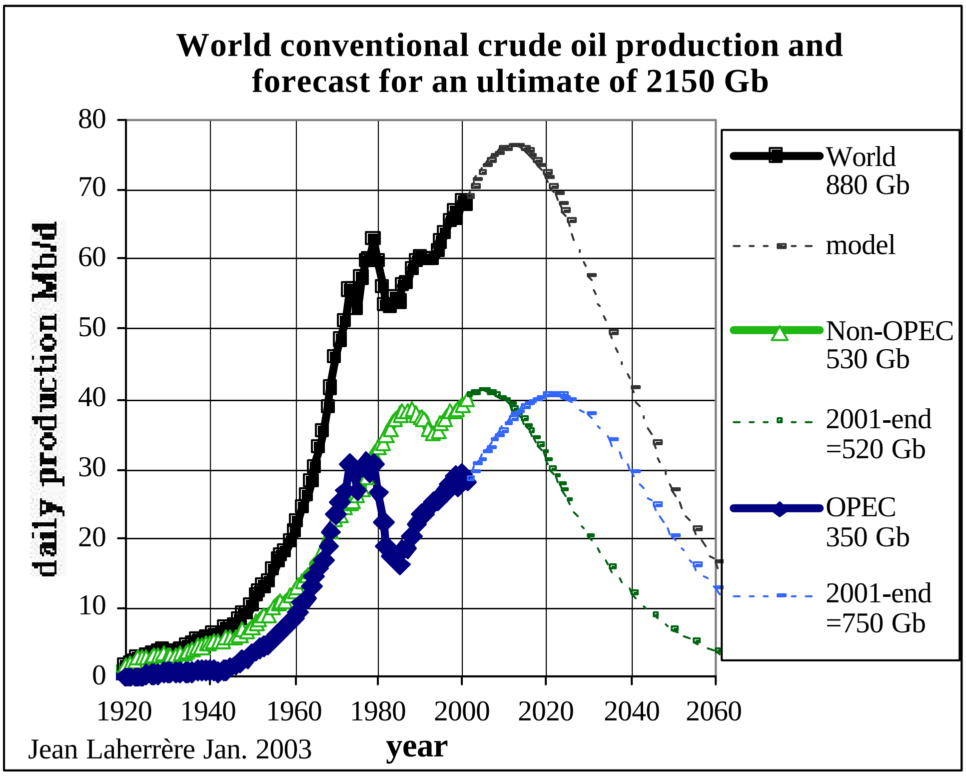

The world outside the Middle East 5 swing producers, namely countries which do not produce at full capacity (Saudi Arabia, Kuwait, Iran, Iraq, UAE) displays a oil discovery curve not far from a Hubbert curve and the oil production curve matches after a shift of 27 years from 1930 to 1980. But the production is lower after the 1979 oil shock because of the demand constraint (quotas).

Figure 34: World outside the ME 5 swing producers: annual oil discovery & production



A study (Laherrere 2002 b) presented at the International Workshop on Oil Depletion at Uppsala, Sweden, sub-divided the world into three zones: OPEC, FSU and the Rest-of-the-World. Production has been subject to political constraints in the first two zones, but was at full capacity elsewhere. The ultimate recovery and future production for each zone were modelled with several normal curves (or Hubbert curves). The result based on an ultimate of 2150 Gb (as in the previous graph) is shown in the next graph, distinguishing OPEC (ultimate 1100 Gb) and Non-OPEC (ultimate 1050 Gb). This study was based on 2002 data. The new 2003 data, excluding the extra-heavy oils in Venezuela, gives a lower ultimate for conventional oil, but we keep the 2002 estimate to provide some possible new cycles from frontier exploration .

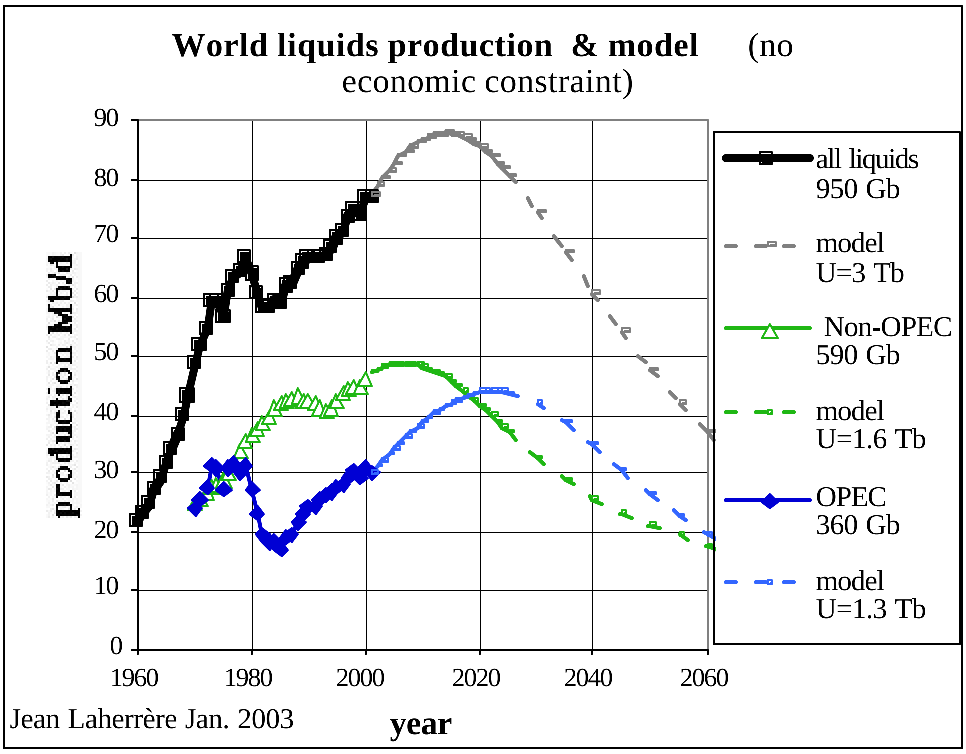
-Figure 35: World conventional oil future production for an ultimate of 2.2 Tb




Liquids other than conventional oil are the Orinoco extra-heavy oils, Athabasca tarsands, synthetic oils, NGL, and refinery gains. They may be modelled also by estimating the ultimate from past production. Such a plot shows that future production of all liquids could peak around 2015 at 90 Mb/d, far from the official forecasts of the USDoE and IEA (about 120 Mb/d in 2020).

We keep our ultimate at 3 Tb despite the new data giving a lower value, as it is a rounded value which corresponds to the high uncertainty of this estimate.

-Figure 36: World liquids production for an ultimate of 3 Tb

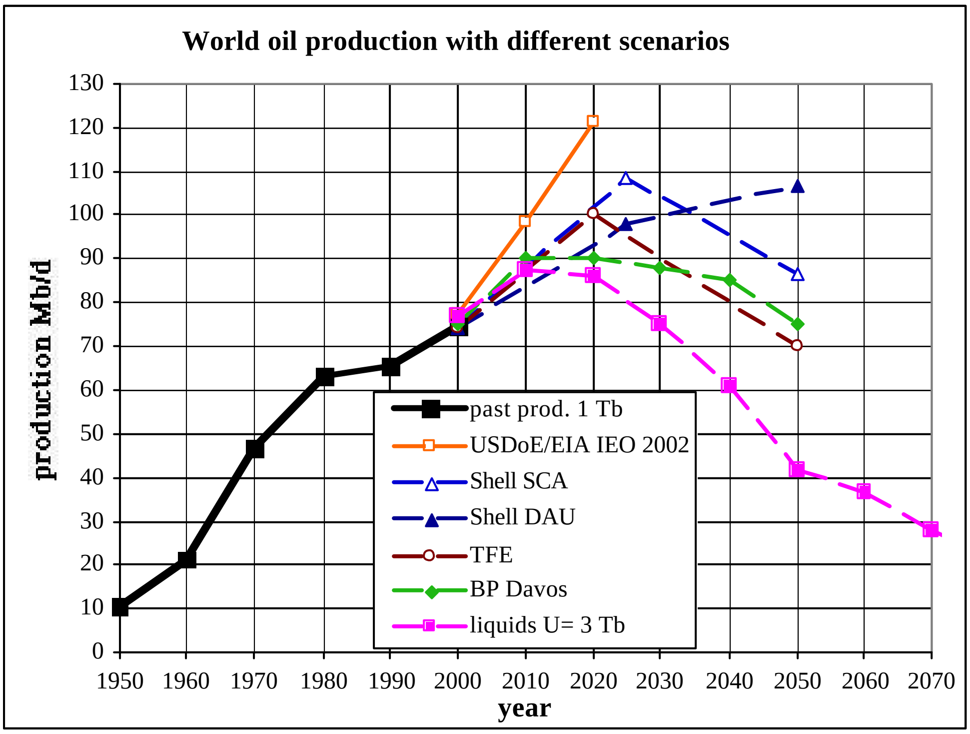



This model assumes that the only constraint is from the supply. But demand also plays a part as was demonstrated in 1979 when oil production declined from an earlier peak because the demand fell as a result of high oil prices. It took fifteen years before production climbed back to its previous level. It follows that if the present economic recession is protracted, demand could stay level for the next ten years, giving an irregular production plateau of around 80 Mb/d. If supply is constrained by demand in this way, then the decline need not start before about 2020.
Many criticise the use of Hubbert curve, but it is a very convenient way to present a possible scenario of future production, better than the scenario of constant growth (followed by constant decline after an angular peak) as presented by the USDOE/EIA (Wood 2000).

Whereas supply may be readily forecast thanks to physical and geological criteria, consumption depends on human behaviour. The potential for energy savings is as great now as it was in 1973. But energy savings after 1973 occurred largely because the forecast was for higher price on the long term. Presently the long term forecast is for lower oil price and energy savings are neglected. When energy efficiency on car is improved, people move to a larger car or air conditioning (Jevons paradox).

**-Other oil forecasts**

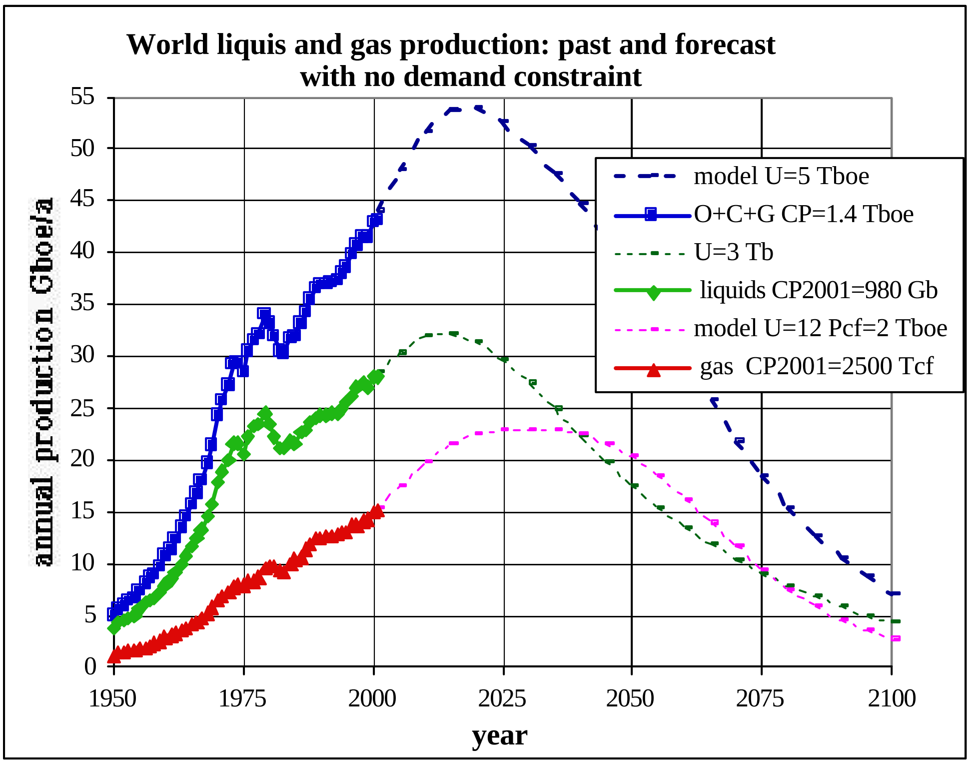
The next graph compares our scenario, assuming no demand constraint, with the scenarios Shell, BP, TFE (Bauquis 2001), and USDoE-EIA IEO 2002
-Figure 37: comparison of oil production scenarios




**-Oil and gas combined production**

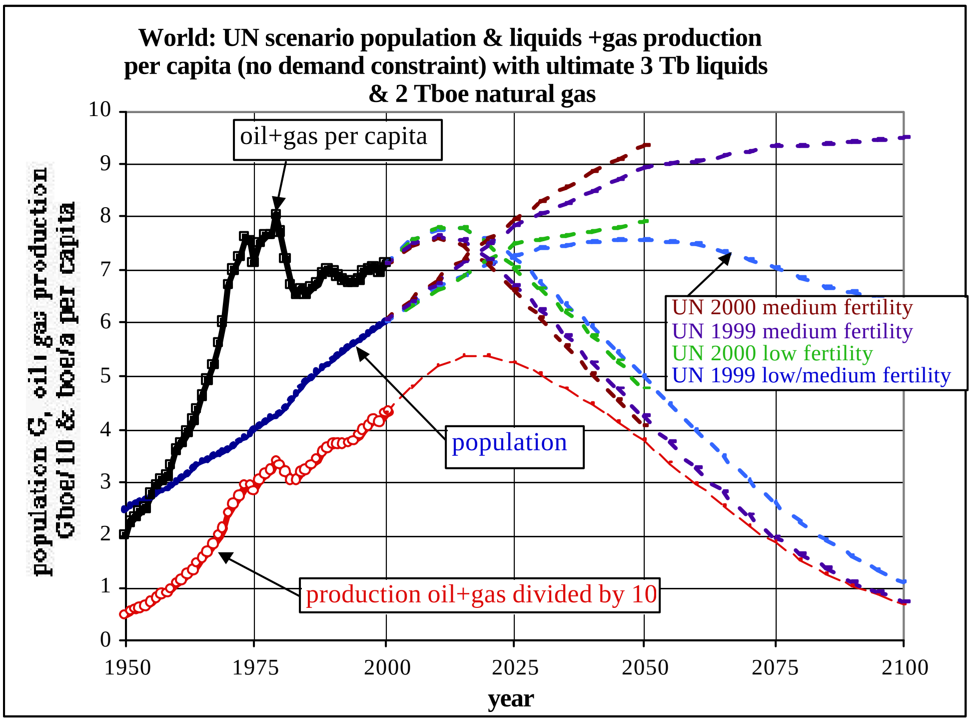
The forecast for all hydrocarbons, adding all liquids and all gas, using the calorific equivalence (6 Tcf = 1 Gboe), is given in the following graph

–Figure 38: World all hydrocarbons production and forecast




The ultimate of all hydrocarbons is about 5 Tboe (3 for liquids and 2 for gas), reaching peak, if there is no demand constraint, around 2025 at 55 Gboe/a, which is about 20% more than at present.

-Figure 39: World's oil and gas consumption per capita and forecast of possible supply




## -Iraq

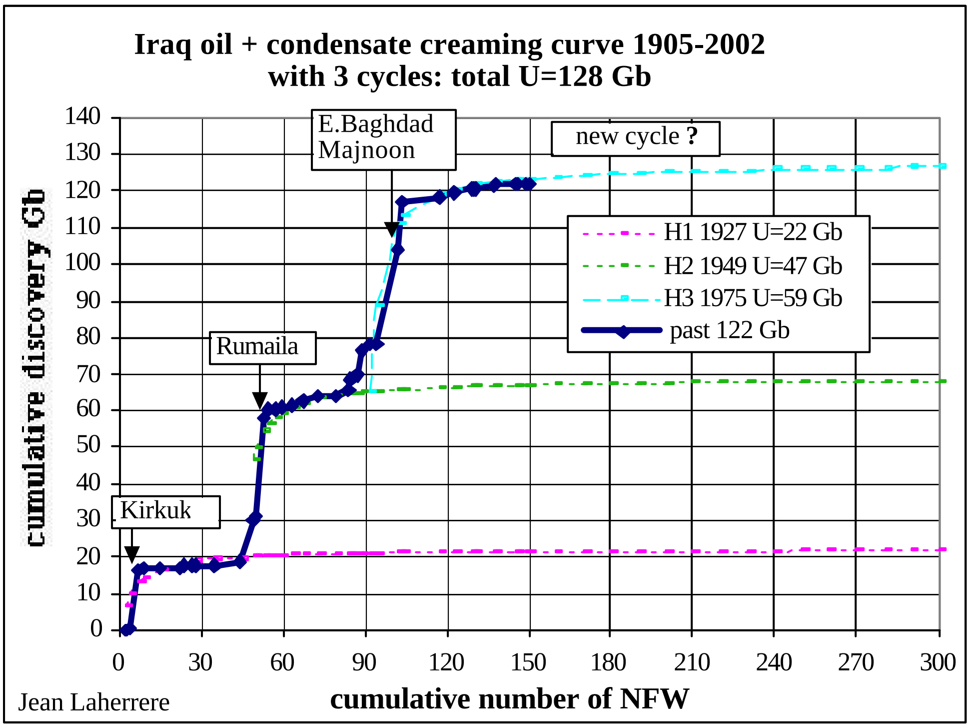
It is worth studying Iraq in particular in view of its current importance. It is no surprise to find that the technical data give a different picture from that published in the media.

There are about 96 discoveries, containing123 Gb, and 23 fields are in production holding about 85 % of the total discovered

| Production Status | number fields | Discoveries Gb |
|---|---|---|
| Production | 23 | 105 |
| Developing | 27 | 13 |
| Appraising | 15 | 1 |
| Discovery | 29 | 3 |
| No data | 2 | 0 |
| Total | 96 | 123 |

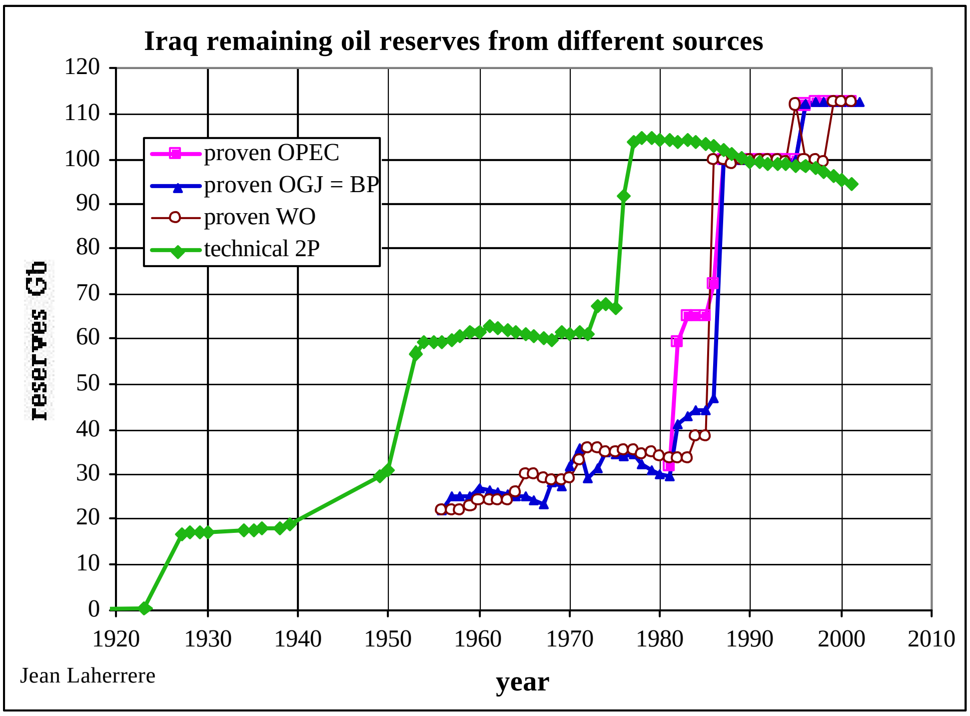
The creaming curve from technical sources displays three cycles, reflecting production from Kirkuk, Rumaila, and last E.Bagdad & Majnoon, The indicated ultimate recovery is 128 Gb. The only question is the possibility of another cycle in an under explored area such possibly the Western desert

Figure 40: Iraq creaming curve with 3 cycles giving an ultimate of 128 Gb, excluding a new cycle




The published remaining reserves are political, as coming from the government and proceedings by step and levels, in contrary from the technical sources.

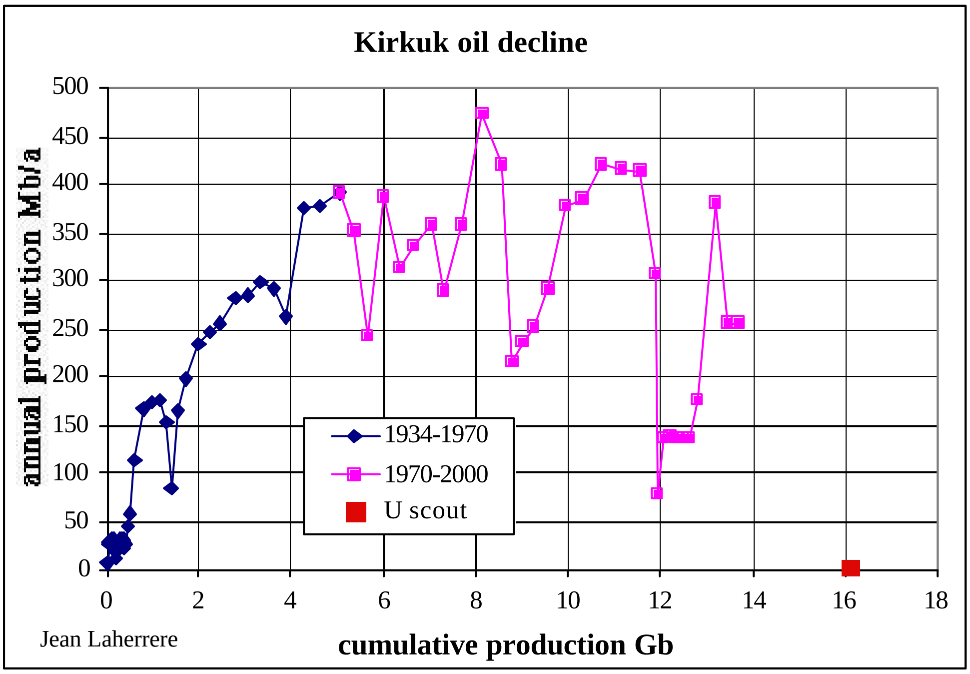
Figure 41: Iraq remaining reserves from different sources




The World Oil comments in 2001 and 2002 on the 112.5 Gb report: "*reserve figures are claimed by the government, but cannot be verified, and should be considered as highly questionable*"

In the media, Iraq is presented as having112.5 Gb, being the second largest oil reserve country after Saudi Arabia with 259.3 Gb, but in fact this is mistaken as the Oil & Gas Journal in its

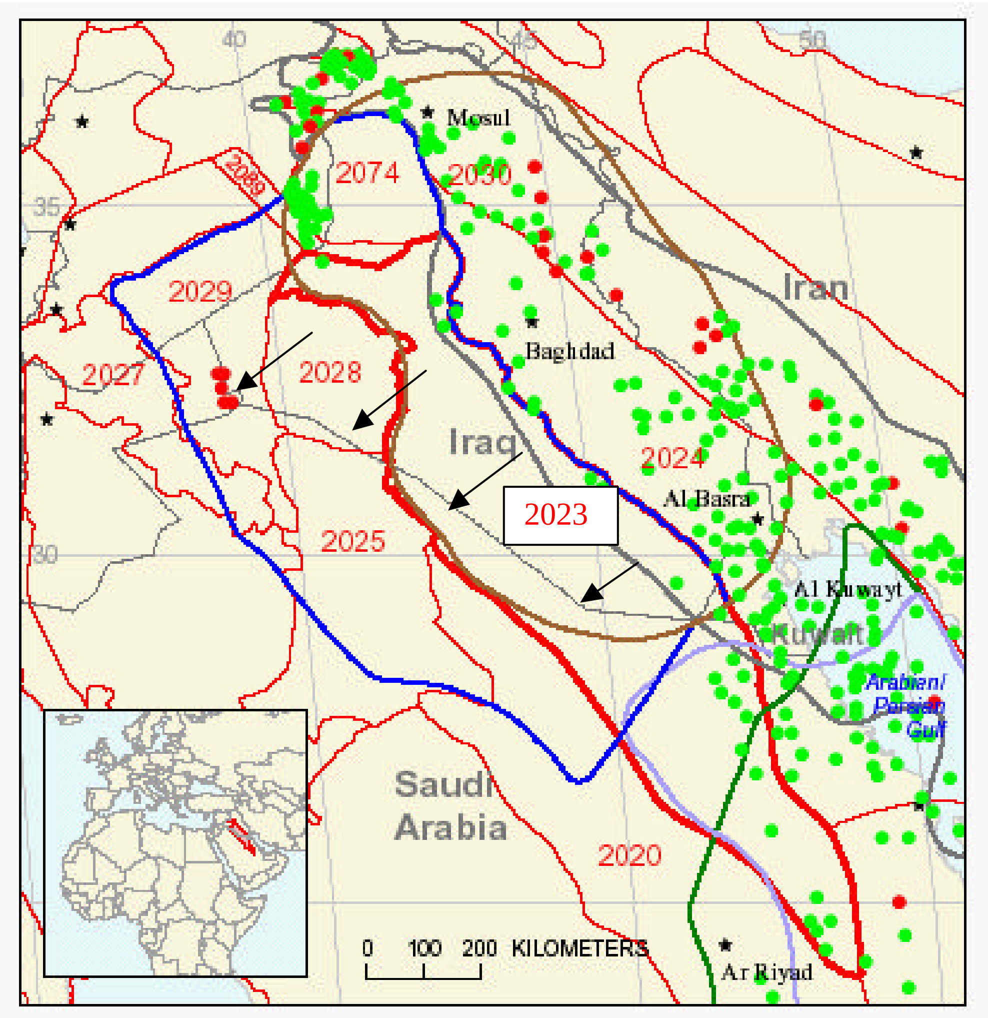
last survey (December 2002) added 175 Gb to Canada (by adding the Athabasca tarsands as mentioned above) which is now the number two in front of Iraq..
The best way to check Iraq's reserves estimate is to display the oil decline by field.
Unfortunately the annual production data are incomplete and disturbed by both OPEC quotas and several wars.
It is impossible to estimate the ultimate of Kirkuk from the continuous data from 1934 to 2000 being too erratic for the last 25 years, and the reported 2 Gb remaining reserves is possible, but the range could be 1 to 10 Gb.
Figure 42: Kirkuk oil decline




-Undiscovered
The USGS has studied the boundaries of every petroleum system on the world. Its 2000 study believes that the Western Desert is covered by the following provinces (as shown in the map) with the estimate in undiscovered oil given in Gb for each petroleum system (PS):

| | F95 | Mean | F5 |
|---|---|---|---|
| -Western Desert | | | |
| -province 2023 Widyan basin-Interior platform | | | |
| with 232301 Paleozoic PS (blue): | 0.4 | 1.6 | 3 |
| with 202302 Jurassic PS (brown) | 1.5 | 4.6 | 8 |
| -province 2028 Rutbal uplift | 0.015 | 0.05 | 0.1 |
| -province 2029 Wadi-Surban basin (only gas) | 0 | 0 | 0 |
| -all Iraq | 14 | 45 | 84 Gb |

Figure 43: Western Desert: map of Petroleum Systems from USGS 2000:




from USGS digital data series DDS-60

In fact the concessions offered in the Western Desert exclude the area with fields except for Abu Khaimah on Block 8. The northern part of the Western Desert (Blocks 5, 6, 7) is shown by the USGS to offer a very small, if any, oil potential, and the southern part a potential of about 5 Gb (mean), extending partly in Saudi Arabia.

The IFP Panorama 2003 (Giannesini) reported undiscovered Iraq potential of 60-200 Gb looks very optimistic. One could accept the high value with a low probability of 5 % or less, but it is difficult to accept the low value of 60 Gb which is supposed to represent a 95% probability of existing. A value of 10 Gb should be more reasonable. And the mean estimate of 45 Gb by USGS 2000 seems reasonable, but optimistic in view of the creaming curve.

**-Oil price and oil cost**

Most published oil costs quoted in dollars per barrel are undefined and unreliable. They represent mainly the operating cost and not the real cost which should include the cost of negotiation, bonuses, exploration (successful and unsuccessful), development, operating, management, transport, amortisation (with rules), discounting (with rate), financing, royalties and finally taxes. The cost has to be discounted over the total period of the exploration and production (could be over 100 years).

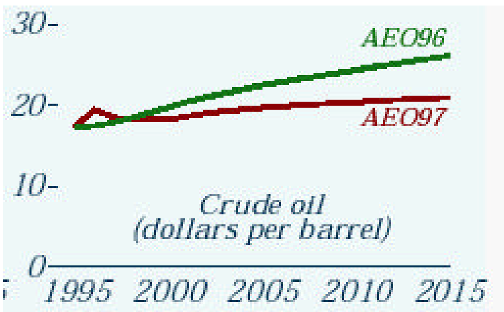
The only reliable costs are development costs reported in dollars per barrel per day as related to a well-defined project carried out in a short period (one or two years), where costs are published through tenders, for a known plateau (peak). Development costs are about 1000 $/b/d when cheap, 5000 $/b/d when expensive, 10 000 $/b/d is for deepwater and for the future reported projects in Iran (Azadegan) and Kuwait, and over 25 000 $/b/d for tarsands and extra-heavy oils (but with a peak of 30 years compared to few years in deepwater).

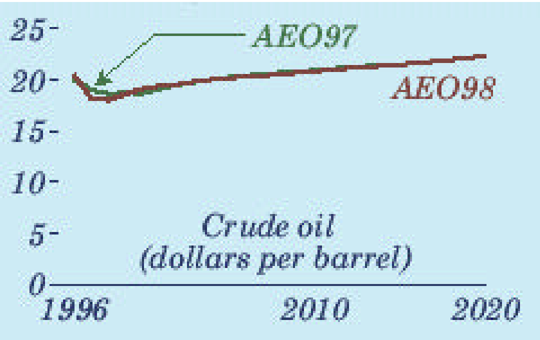
Most economists propose that the oil price trend should reflect the marginal cost, not realising that it is an unreliable operating cost. As huge amount of oil is discovered first, operators when they have recovered their investment are pushed to accept low price, furthermore when oil price behaves chaotically.
It would be better if oil producers should instead try to sell their production at the substitute price on equal conditions. Oil has replaced coal even though coal is cheaper than oil, but that is because oil is much more convenient than coal and worth a premium.

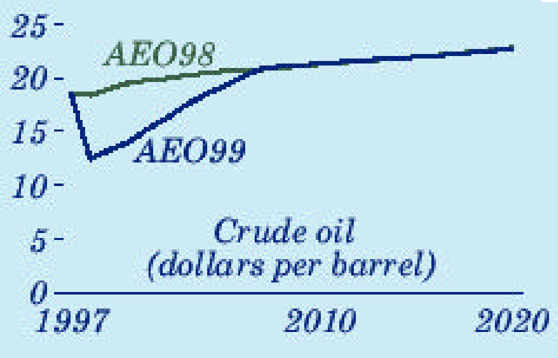
Many Americans believe that Middle East should produce at full capacity, complaining about OPEC prorationing, but they forget that OPEC was created in the image of the Texas Railroad Commission. In 1931, when oil was selling at 10 cents a barrel, troops were sent into the East Texas oilfield to make sure that wells were shut in so are to support price at a dollar a barrel. It is normal for a producer to restrain his production to avoid a sharp decline in price. Usually dumping (selling below cost) is forbidden, but determining oil cost is a difficult task. Oil is in fact often being dumped in Saudi Arabia, which belongs to the House of Saud and where the budget is financed mainly by oil revenues. To ask Saudi Arabia to produce at full capacity is like asking the car industry to produce at full capacity, which would deliver 60 million cars a year much more than the 45 millions being built. No one in America would dream of requiring Detroit to step up car production to maximum capacity, but they have no hesitation in demanding that Saudi Arabia should produce oil at capacity.

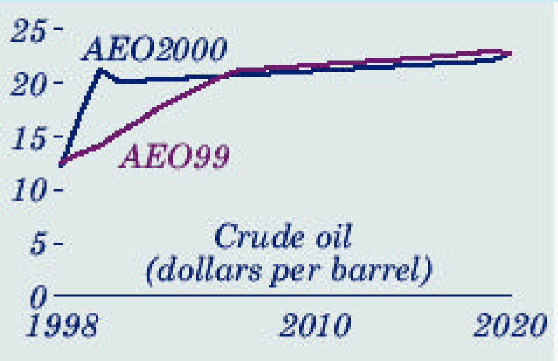
Forecasting oil price seems almost impossible, as almost every past forecast proved erroneous. Oil price depends upon the behaviours of the consumer, the buyer and the seller, which are mainly irrational. And it is also based on wrong data.

The past forecasts by USDOE/EIA in their annual energy outlook are good examples of poor estimates from AEO1996 to AEO2003
Figure 44: oil price forecast from USDOE from 1996 to 2003




25
20
15
10
5
0
AEO97
AEO98
Crude oil
(dollars per barrel)
1996
2010
2020


25
20
15
10
5
0
AEO98
AEO99
Crude oil
(dollars per barrel)
1997
2010
2020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AEO2000
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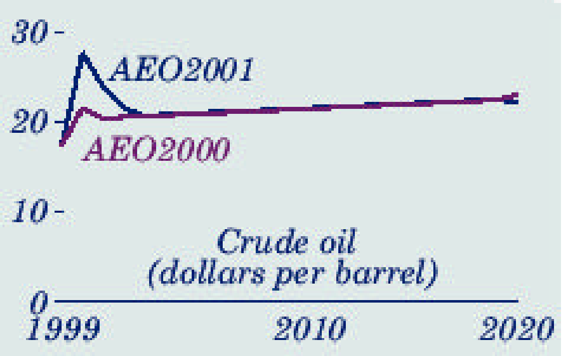
Crude oil
(dollars per barrel)
1998
2010
2020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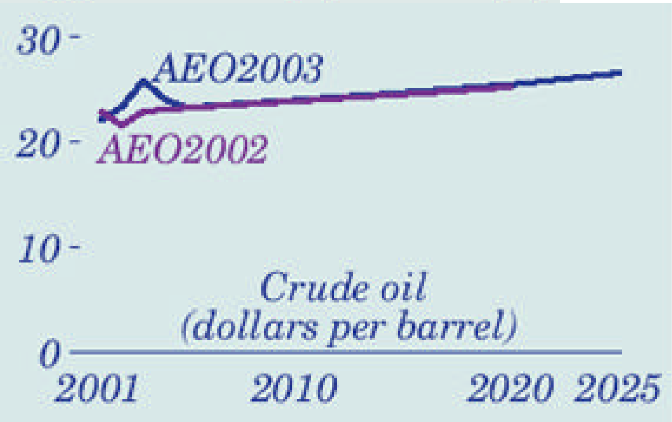
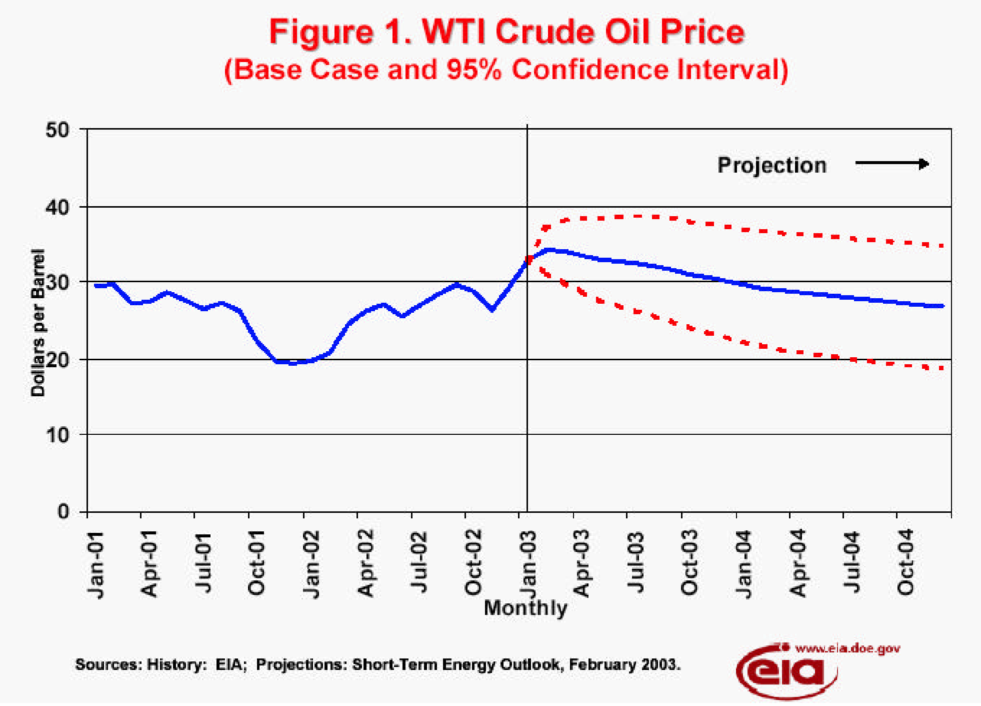
AEO2001
AEO2000
Crude oil
(dollars per barrel)
1999
2010
2020


30
20
10
0
AEO2003
AEO2002
Crude oil
(dollars per barrel)
2001
2010
2020
2025

As the American way of life is based on cheap energy, the official policy is always to forecast no drastic increase. Catastrophes are always reported natural and unpredictable, so none is responsible!

The rather narrow range (20-35 $/b) for WTI forecasts for the next year from the EIA is curious insofar as it supposed that the coming Iraq war will have no impact, one way or another and that the OPEC mechanism around 25 $/b will stay in 2004.

Figure 45: oil price forecast from USDOE for 2003 & 2004




### -Oil substitute

In the world energy mix oil represents about 40 %, but road transport in 2000 consumed about 40 % of the oil. The situation is confused as the energy equivalence varies drastically from one agency (or country) to another, as 1 MWh varies from 0,086 toe to 0,26 toe depending upon taking the input or output, as the efficiency of a electric plant is from 30 to 40 %),

In the short and medium term, nothing can substitute for oil in adequate quantity. The electric car is a failure. The number of cars running with natural gas has not increased because it gives lower power and requires a fuel tank twice the size of that for gasoline. Adding water to diesel fuel (aquazole in France: 85 % diesel, 13 % water and 2 % additives) reduces the pollution, but clearly gives less power.

Apart from conventional oil, synthetic oil can be made from coal by the Fischer-Tropsch synthesis, which was used by the Germans during the Second World War and in South Africa during their oil embargo. Petroleum can also be produced by Gas-to-Liquids (GTL) technology but so far production is confined to pilot plants (Shell Bintulu). Fuel can also be produced from biomass in the form of alcohol. In fact, alcohol was considered by experts, such as Henry Ford, in the 1920s as the fuel of the future for cars. We may note the following quotation (Kovarik 1998): *"When Henry Ford told a New York Times reporter that ethyl alcohol was "the fuel of the future" in 1925, he was expressing an opinion that was widely*

*shared in the automotive industry. "The fuel of the future is going to come from fruit like that sumach out by the road, or from apples, weeds, sawdust -- almost anything," he said. "There is fuel in every bit of vegetable matter that can be fermented. There's enough alcohol in one year's yield of an acre of potatoes to drive the machinery necessary to cultivate the fields for a hundred years."*
Hemp was also a good source, before being prohibited in 1937.

Some argue that ethanol from corn needs more energy to produce than it contains (Pimentel 1998), but the US Department of Agriculture claims the contrary. Alcohol from biomass, which is three times more expensive than gasoline, is mainly economic because of subsidies. Brazil has been making alcohol from sugar cane since 1975, but it has evidently not been a success as cane production fell from 82 Mt in 1990 to only 35 Mt in 1999. France is using alcohol made from beets (150 GJ/ha) but needs 0.8 toe fossil fuel to produce 1 toe. In the case of colza (50 GJ/ha) it needs 0.5 toe fossil fuel to produce 1 toe. The efficiency is estimated to be between 10% (in this case 90% of the produced energy has to be invested to produce a new volume) and 50% (Janvovici 2002).

Furthermore all the cultivated areas of the world are not enough to produce the amount of alcohol needed for the world's population of cars, assuming that the net energy should be positive. It is strange to think that thirty years ago, pilot plants were built to produce food (proteins) from oil (BP in Lavera in France) and now food (cereals) is used to produce a substitute for oil.

**-Hydrogen**

Hydrogen is not a source of energy but a carrier, as is electricity. Hydrogen has a long industrial history. In 1996, the US (Hoffman 2001) produced 3 Tcf/a of which 1.2 was used to make ammonia (fertilisers), 1.1 was used by refineries and 0.3 was used to produce methanol. Natural gas production in the United States was then 18.8 Tcf/a, which is only six times less than now.

The first car with an internal combustion engine was developed running on hydrogen by Isaac de Rivaz in 1805. In 1957, a B-57 has flown with liquid hydrogen. The history of hydrogen fuel is a long one but has not been a success for transport. Many believe that it will change in the future with the help of technological progress. But the efficiency is still very poor when compared to oil. From well to wheel the efficiency for diesel is 21-23 %, and for hybrid vehicles 27-34 %, whereas for fuel cell with hydrogen it is 5.5-13 % (electrolysis) and 18-31 % (methanol)

Rifkin (2002) dreams about a hydrogen internet, where hydrogen with fuel cells (associated with information technology) can be used everywhere to be both user and producer of energy. But this sounds like mainly wishful thinking.

If new nuclear plants with high temperature reactors are widely used in the long-term future to supply electricity, they can also provide hydrogen in their off-peak time, which could be carbonised to supply synthetic oil. It could easily replace declining oil supply for transport without any change in the distribution.

**-Euro versus dollar, barrel versus tonne?**

Many articles believe that the Iraq war has mainly for oil: not so much for the oil itself, but to add marginal supply sufficient to depress the price of oil by controlling the whole Middle East (in particular the explosive situation in Saudi Arabia). The United States runs a huge annual trade balance deficit of over 500 billion dollars, more even than the military budget. Accordingly, the US economy is effectively run on borrowed money, which is possible as the dollar represents more than 60 % of the world trade. Saddam Hussein posed a threat to this system as he decided in 2000 to quote oil sales in the euro, especially if OPEC as a whole were to follow his example. The Iraq war, whatever its declared motives, will ensure that oil will be still quoted in dollar by barrel and not in euro per tonne.

## -Conclusion

There are several alternative ways to model oil supply. The main problem is not the model, but the data which are flawed as a result of poor reporting practices for confidential, financial or political reasons. The shock of 1979 was caused by bad data (Yergin 1991), as was the collapse down to 10 $/b of 1998, which was caused by the IEA so-called “missing barrels” (Simmons 2001).

Good supply forecasting will be achieved only when good data become available and openly published. But forecasting the demand is another issue. It seems that recessions and recurring price shocks may lead to irregular demand over the next few decades.

Nevertheless, oil production will have declined significantly around 2020, when substitutes will be needed in large quantities. It is unlikely that renewable energy can replace oil to any large extent, and the proportion coming from synthetic oil derived from coal or nuclear (via hydrogen) is uncertain.

Another important question for tomorrow is whether oil will be priced in the dollar or the euro, the barrel or the tonne. It will depend of who controls the Middle East, which is the main issue of today. Will OPEC survive?

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