International Geological Congress 11 August 2008 Oslo Petroleum Geoscience GEP-03

Why are remaining oil & gas reserves from political/financial sources and technical sources so different?

Jean Laherrere ASPO France

This paper is a long text which is the base of the presentation after reduction to stay within 30 minutes

Abstract

Published remaining oil reserves (USDOE) are mainly for OPEC countries and have been rising for the last 50 years, whereas confidential technical *mean* field data has been declining since 1980. There is no consensus on reserve definition and the conventional SEC 1978 rules for financial data are inappropriate for estimating the remaining sub-surface reserves. Russian classification of reserves relies on the maximum theoretical recovery, while proved reserves are assumed to rely on the minimum. The competition between OPEC members for quotas based on reserves leads to a status quo or only increased reserves, which often fails to take into account reserves deletion from production. In fact, the 300 Gb OPEC increase during the 80s is now described by S.al-Husseini, former VP Aramco, as speculative resources. Technical operator reserves are confidential (except in the UK, Norway and US federal), but can be obtained from scout companies. Global compilation of heterogeneous reserves data requires correction to obtain mean values which are assumed by definition not to grow statistically. If they grow, it means that evaluator's approach is incorrect. Reserve growth occur mainly on proved values because the omission of probable reserves and incorrect aggregation. Correction needs to check the operator estimate by extrapolating the decline of major mature fields. Unfortunately available databases are incomplete for field annual production, cumulative production. There are large discrepancies on oil and gas ultimate recovery. Many studies rely only on past production, using Hubbert linearization. The best approach is to extrapolate creaming curves (cumulative backdated mean discoveries versus cumulative number of new field wildcats (NFW), but few have access to this data. The yet-to-find, obtained from subtracting the cumulative known discoveries from the estimated ultimate, is usually below the inaccuracy of these discoveries. Discrepancy of reserves estimates only occurs when fields are almost depleted, in particular after a large increase in decline for the last few years (East Texas, Brent). Instead of one value, reserve estimate should be reported as minimum, mean value and maximum. Forecasting future production is relatively easy for conventional oil and gas fields, but more difficult for unconventional fields, where it depends more on the size of the tap than on the size of the tank. Even if ultimate geological reserve estimates allowed us to forecast a smooth production peak, constraints from demand, investment, political factors will likely transform the "peak" into a bumpy plateau. Most major oil and gas fields are in decline. Estimates, for these fields, of annual production data is often straightforward, but unfortunately not available in all countries. Norway and the UK provide such field data, a policy that should be followed in all countries. Such changes are required if we are to effectively manage our vital energy reserves.

Most of published oil & gas data is politically or financially motivated and is therefore not reliable. Technical data is mostly confidential and can only be bought from *scout* companies

-Reporting data

-productions

-OPEC production for each member country is ruled by quotas, but because OPEC members have been cheating on quotas, OPEC past oil production figures are flawed and unreliable. Real data on oil transported by tankers must be bought from spy companies (Petrologistics in Geneva). Real data on field production and field reserves must be bought from IHS (former Petroconsultants), which is the only company to provide worldwide data, and others.
-words such as **energy, oil, reserves, resources, conventional, proved, probable, light, heavy, reasonable, sustainable, dangerous are badly or not defined on purpose**

Oil can be defined from regular oil (Campbell 66 Mb/d in 2007excluding heavy <17°API, polar and deepwater) to all liquids (85 Mb/d in 2007) including refinery gain and synthetic oils (CTL, GTL & BTL). Some limit liquids to crude and NGL (EWG).
Conventional is defined very differently by USDOE/EIA (Caruso June 2008) as flowing easily from vertical wells (most modern fields extract oil using horizontal wells) to discrete fields with well defined hydrocarbon-water contacts (USGS since 1995), leaving unconventional to continuous-type accumulations where hydrocarbons occur regionally with no obvious seals or traps, very low permeabilities and abnormal pressures.
In fact heavy oil corresponds better to a viscosity range than a gravity range. "Hard Truths" NPC 2007: *World Petroleum Congress defines heavy oil as oil whose gas-free viscosity is between 100 cP and 10 000 cP at reservoir temperature*
Extra-heavy (heavier than water >1 or <10°API) oil Athabasca and Orinoco oil have the same gravity (8°API) but completely different viscosity (1000 000 cP against 1500 cP) because of different reservoir temperature (11°C against 53°C). Orinoco can be produced in cold conditions whereas Athabasca cannot.

Data is either flawed by finance (stock market) or politics (quotas), or it is simply missing. Ambiguity is often favoured on purpose

-2006 production data

Oil and liquids: oil 2006 production can vary from regular (former conventional) oil as defined by Campbell (66 Mb/d) to crude oil (73 Mb/d) and finally to all liquids including NGLs, synthetic oils from coal (CTL), biomass (BTL), and refinery gains (85 Mb/d).

World oil production for 2006	definition	Mb/d
OGJ Oil & Gas Journal	oil	72.647
WO World Oil magazine	crude/condensate	73.330 139
BP Statistical Review	liquids (excl BTL. CTL)	81.663 310 979 140 2
USDoE (Depart of Energy)/EIA	crude oil	73.573 844 712 166 8
	all liquids	84.597 461 4
IEA International Energy Agency	oil	85.4

The number of significant digits is ridiculous in front of the real accuracy of the data

-end 2006 reserves

There is no consensus on oil reserves:
Published proved reserves at end 2006

Oil Gb	OGJ	BP	WO
World	1 317.447 415	1208.241 771 870 77	1 144.358 3
Russia	60.000 000	79.540 120 55	74.435
Norway	7.849 300	8.498 950 855 699 31	7.070
Canada	179.210 000	17.092 716 140 2	25.591 3
China	16.000 000	16.271 3	16.255 6

There is no consensus on oil reserves definitions with 4 systems in use:

- **US:** all energy companies listed in the US stock market are obliged by the SEC (1978 rules) to report only proved reserves (**1P**), assumed to be the **minimum;** these reserves are audited. SEC is presently changing the rules allowing the report of probable in 2009
- **OPEC:** because quotas depend upon reserves, OPEC members report proved reserves (**1P**), which corresponds to their wish since it is not audited.
- **FSU classification**: ABC1 (Khalimov 1979) reports **maximum** theoretical recovery, being about equal to proven plus probable plus possible (**3P**). Khalimov in 1993 stated that Russian reserves were *grossly exaggerated*.

- **Rest of the world:** SPE/WPC (1997) classification, definition and guidelines (I was a member of the task force) reports reserves as proven plus probable (**2P**), close to the **expected value** used to compute the net present value of the development, when decided.

In front of uncertainty, probabilistic approach should be the rule, but the deterministic approach is used by many because reluctance and poor knowledge of probability and SEC rules.
But in deterministic approach, it is wrong to add up the field proved reserves to get the country proved reserves, and to add up the proved country reserves to get the world proved reserves, because proved is assumed to be close to the minimum and it is unlikely that all items would be at the minimum. The addition underestimates the global proved value. Only mean field (country) values can be added to obtain the mean country (world) values.

The compilation of IHS field reserves estimates (OPEC reduced by 300 Gb =speculative resources of al-Husseini 2007 and FSU reduced from 3P to 2P), CAPP and USDOE/EIA (0534-90 plus annual reports) backdated annual discoveries, allows to plot the world remaining reserves from technical sources, whereas USDOE uses current proved reserves (enquiry OGJ upon national agencies). Scout companies are increasingly obliged to introduce in their field estimates the value reported by NOCs when officially available, in order to not upset these very important new clients.
For years I have corrected FSU ABC1 by multiplying it by 0.7 to get 2P. On 16 June 2008 Gazprom stated that their reserves ABC1 were 29.8 G.m3, but when audited by DGMN 2P were 20.82 G.m3 or 70%, exactly my correction, however Miller & Lents audit was 2P = 22.4 G.m3 or 75%. I shall stick to 70%

Figure 1: World remaining oil reserves from political and technical sources 1940-2007

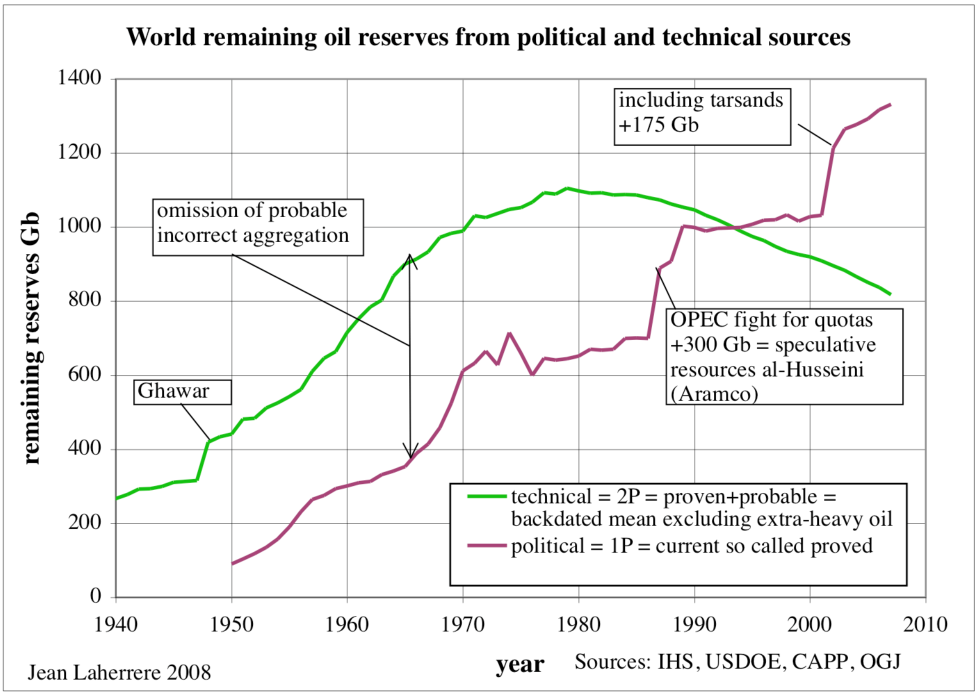
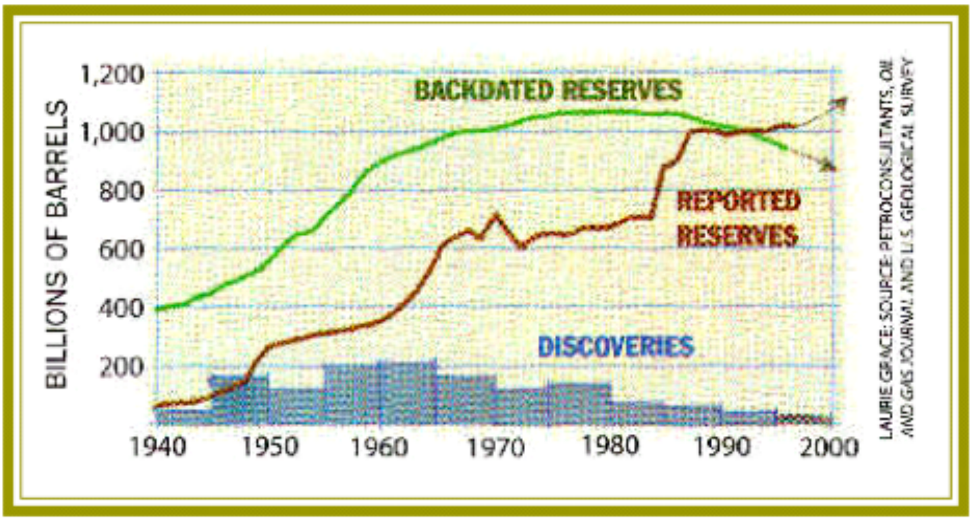
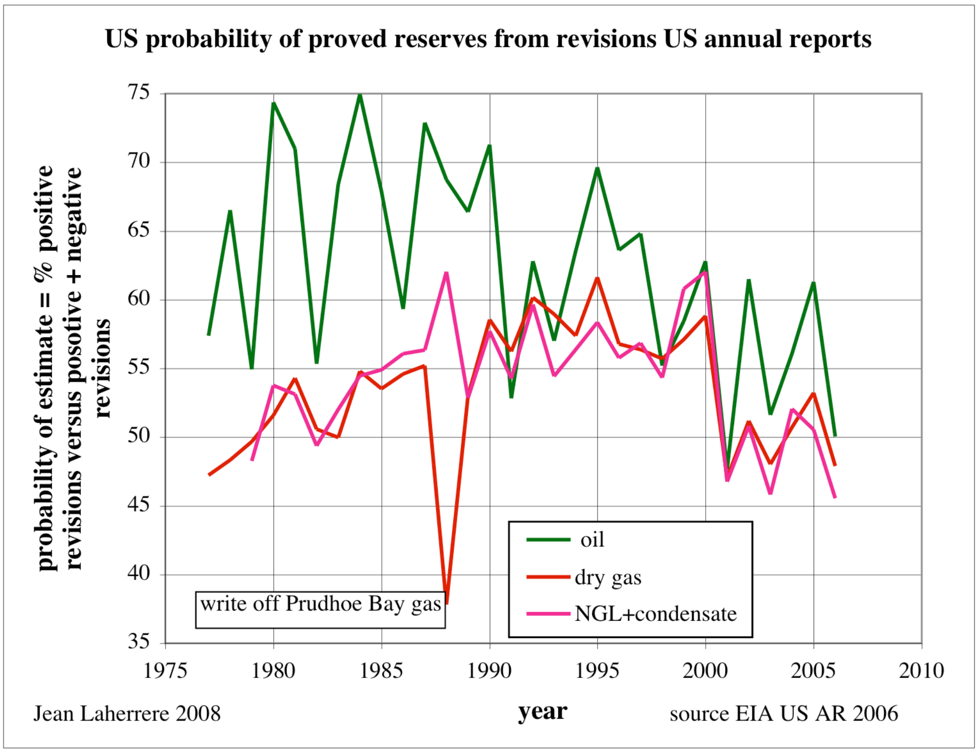


Figure 2: Same plot in Scientific American March 1998 Campbell C.J, Laherrère J.H. "The end of cheap oil" 1940-1996

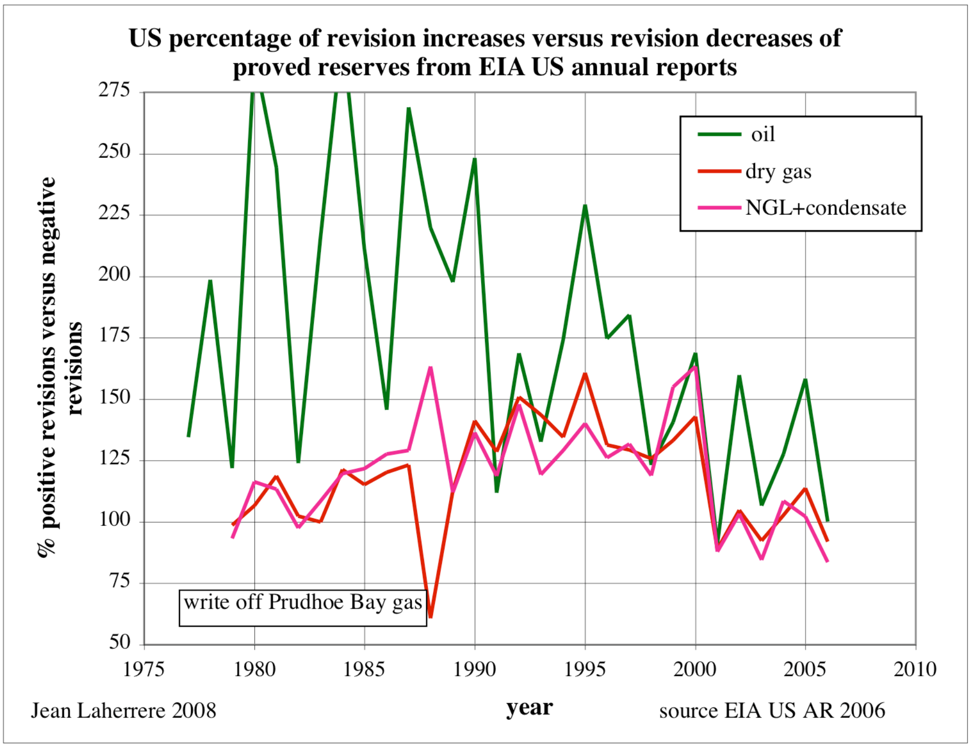


The two arrows indicated the forecasted divergent trends which were right, but not divergent enough.
National estimates quoted by OGJ and then by USDOE has for goal to always showing a rise, like Business As Usual, to please politicians and bankers.

The revisions of proved reserves in US annual reports easily give the probability of the estimate by plotting the percentage of positive revisions versus the sum of positive plus negative revisions. From 1977 to 2006, the probability is decreasing, in 2006 below 50% where the negative revisions are higher than the positive revisions, which means that the reserve growth is over.
Figure 3: Probability of the US proved reserves from revisions of USDOE annual reports 1977-2006



Another way to look at the positive and negative revisions for those who do not like probability
Figure 4: Percentage of revision increases versus revision decreases of US proved reserves from USDOE annual reports 1977-2006



The reported scout field estimates, assumed to be the operator value can be verified by plotting the decline of production of all mature major fields which provide reliably projectable decline. The ultimate estimate from decline is compared with the evolution of reported ultimate (cumulative production + remaining reserves) values.
The most reliable databases are the MMS GOM field (last being 2004), the UK (DTI & BERR) and Norway (NPD) data.
Having access to annual field decline we plotted all (thousands) mature major fields. Plotting decline can be disturbed by quotas (OPEC) or war or incomplete data, therefore only a part can be reliably extrapolated
We found that most of the time ultimate reserves from reliable declines are lower than ultimates reported by operator (found in the scout databases), and they are higher in a few cases, each time explained by exceptional geological conditions (Ekofisk = compaction of the chalk, Eugene Island 330 = reservoir in connection to source-rock thru a large fault).
Most claims that technology can increase reserves, if it is the case it should be shown on the plot by a decrease of the decline. Most of the time decline does not decrease, but increase, mainly at the end of production (Brent, East Texas).
In conventional fields, the use of techniques such as horizontal multi-drains increase the production and the peak but at the detriment of the total recovery (Yibal, Rabi-Kounga)
Many examples of field decline (annual production versus cumulative production) are shown below, with ultimates & cumulative production versus time, and also oil, gas and water production versus time.
Many fields are plotted in order to show the range of patterns and the difficulty of estimating an average decline, as to show the evolution of ultimate estimates.
Many studies on producing fields decline were published (CERA, IEA) giving precise value, but that is on a limited number of fields, on bad data and also constrained by OPEC quotas, and the accuracy of this average (about 5%/a) is highly questionable. The impact of technology (worsening future decline) is hard to assess for future declines.
Because ultimate estimates vary, for many fields positive reserve growth or negative reserve growth can be quoted depending the date of reference. But most of the time reserve growth is negative.

-Field decline:

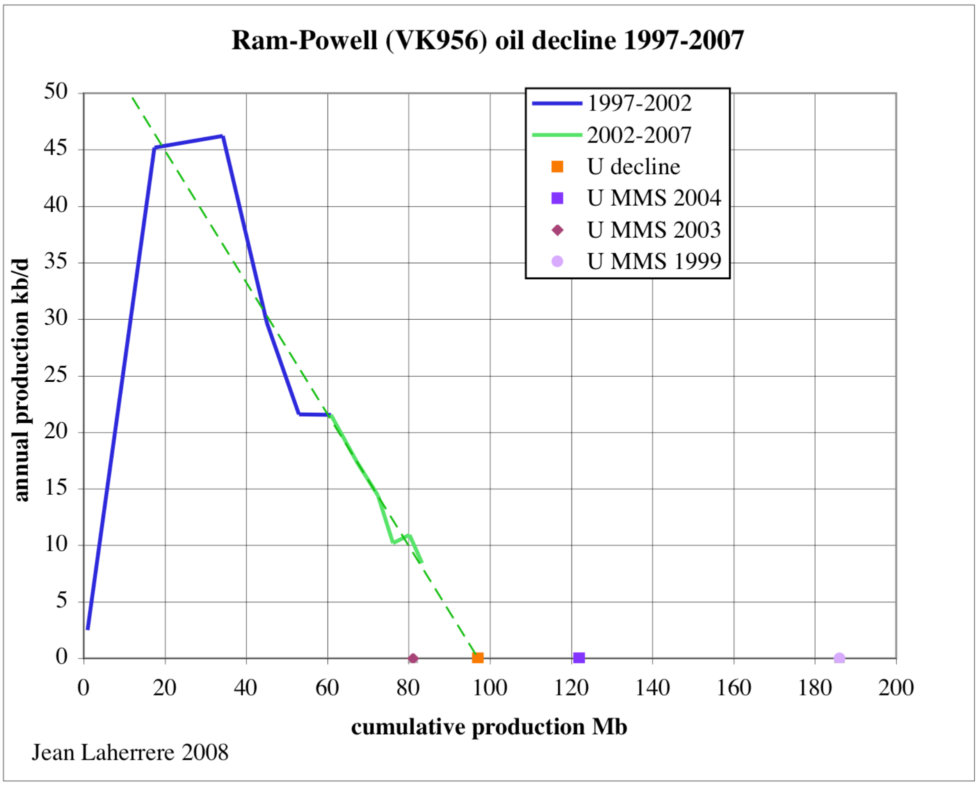
-US

-Gulf of Mexico (GOM)

-Ram-Powell

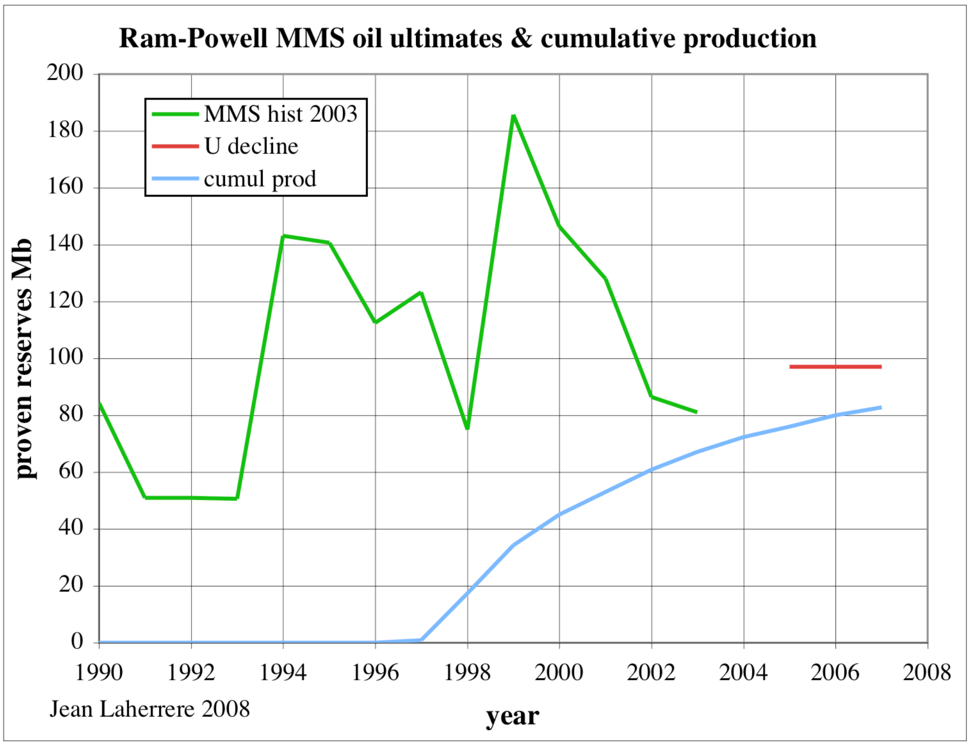
Ram-Powell (VK 956), found in 1985, is one of the first deepwater (988 m) production already in steep decline since 2002

Figure 5: Ram-Powell (VK956) oil decline 1997-2007



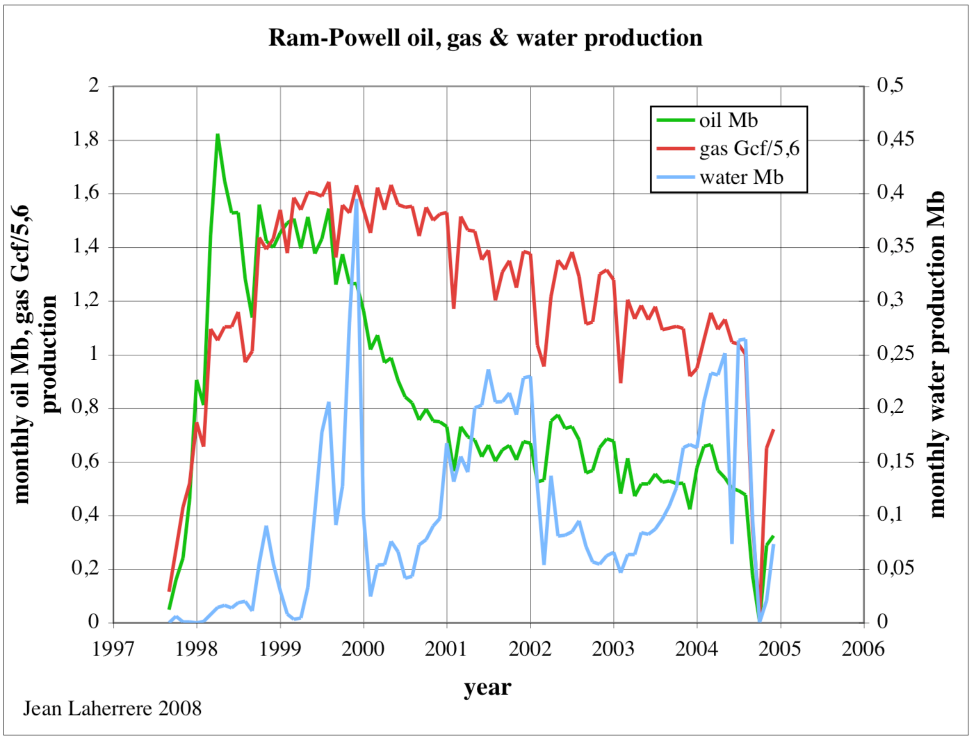
The evolution of the MMS ultimate is chaotic between 50 to 180 Mb when extrapolation of the decline is close to 100 Mb

Figure 6: Ram-Powell MMS ultimates and cumulative production



Natural gas production declines with oil production, but water production is erratic

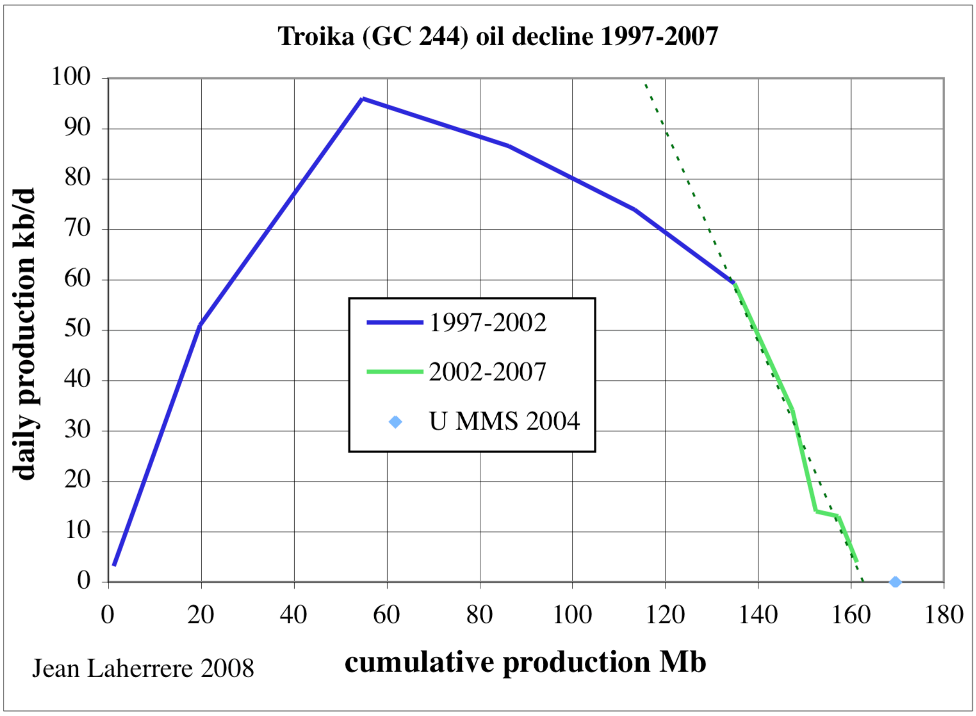
Figure 7: Ram-Powell oil, gas & water production



-Troika

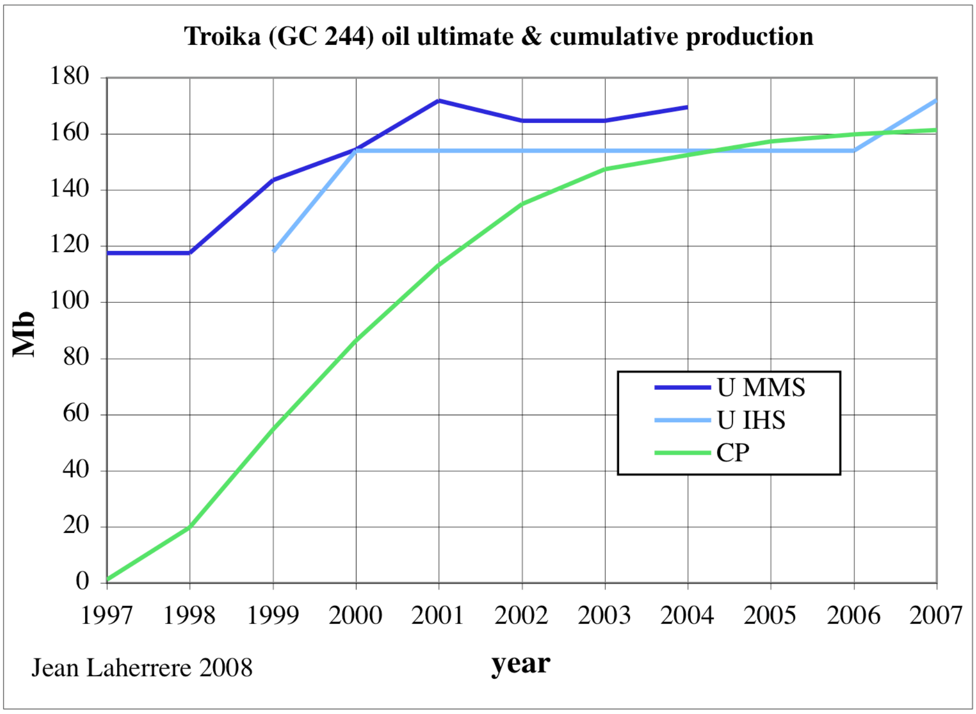
Troika (GC 244), found in 1994 at 817 m water depth, has been in decline since 1999 and steep decline since 2002

Figure 8: Troika (GC244) oil decline 1997-2007



Since 2000 oil ultimate estimates from MMS or IHS does not differ much form the extrapolation of the decline.

Figure 9: Troika (GC244) MMS proved reserves, IHS 2P reserves and cumulative production



-Mars and Ursa

Mars (MC 807), found in 1989 at 1026 m water depth, is the largest GOM discovery. The oil production was disturbed in 2005 by the Katrina hurricane and the damaged platform was repaired when production was stopped. Furthermore the Mars Platform MC807 also produces the nearby Ursa field (MC 810 found in 1990 at 1184 m) and MMS reports only the combined production, when IHS reports both fields separately.

The production decline is hard to extrapolate.

Figure 10: Mars-Ursa (MC807) oil decline 1996-2007

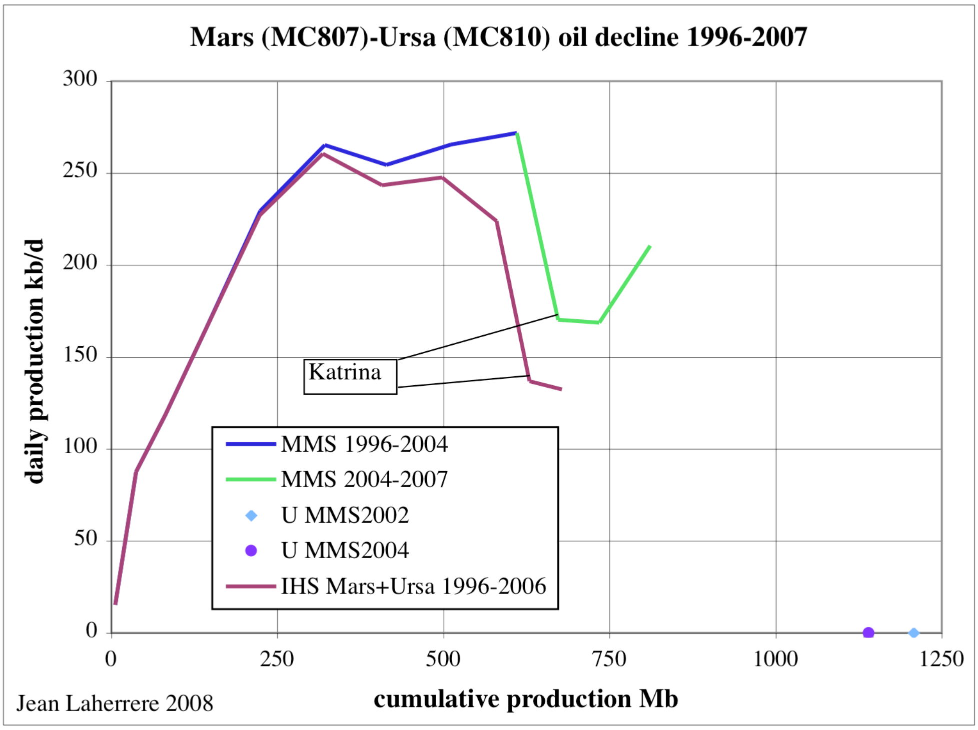


Figure 11: Mars-Ursa oil production

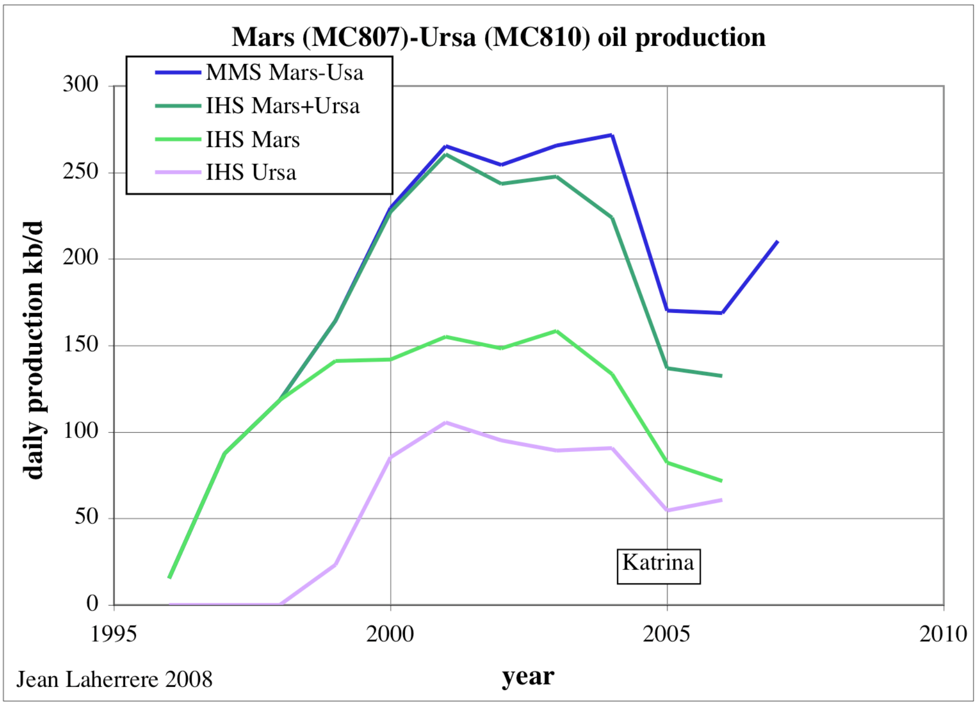
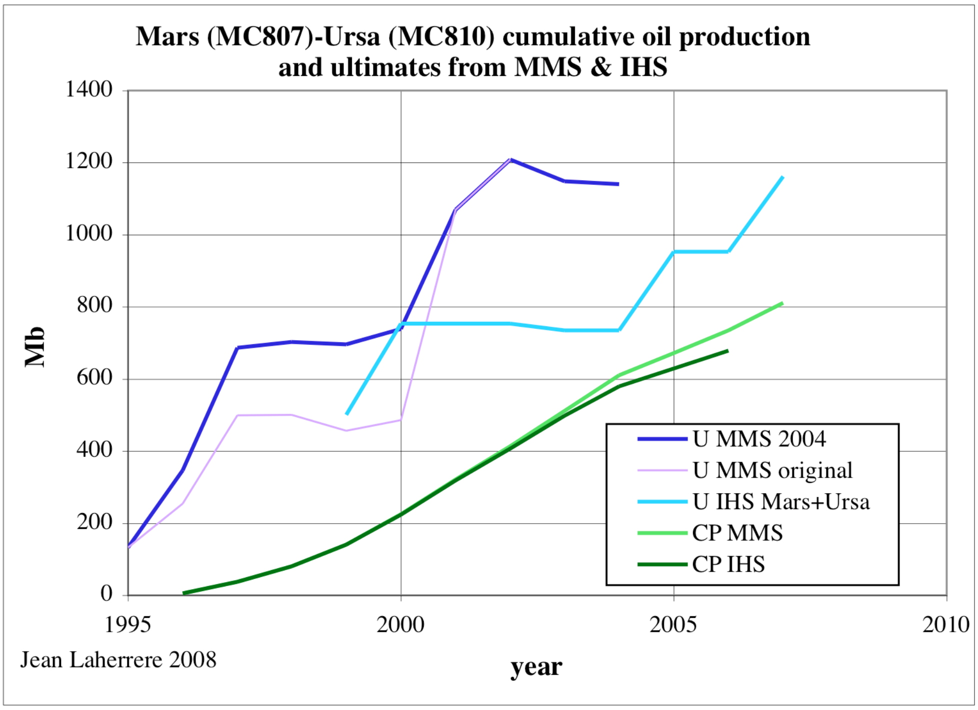


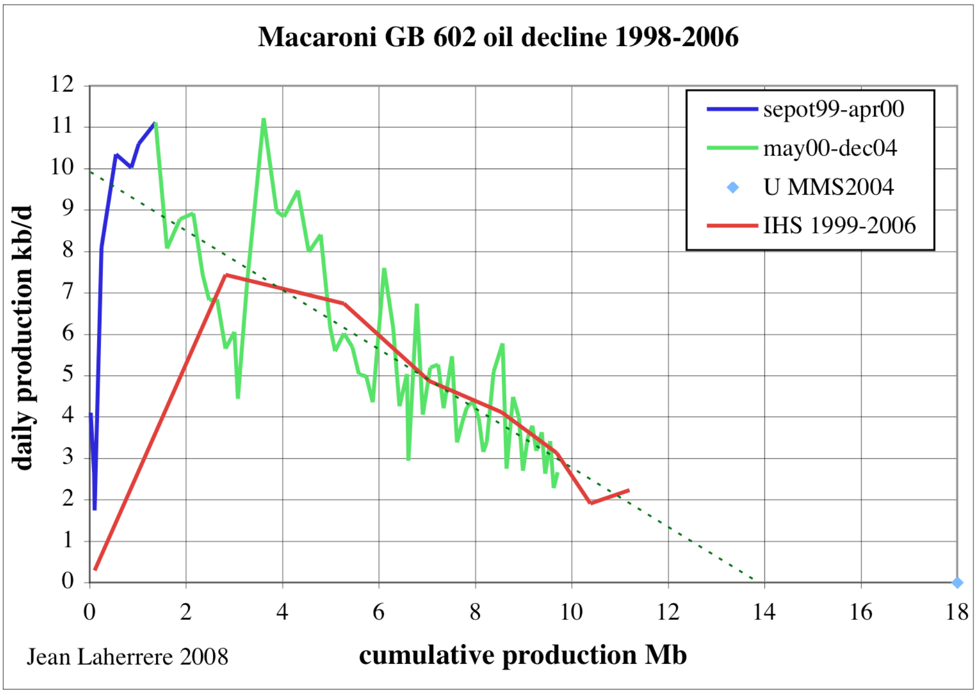
Figure 12: Mars-Ursa MMS & IHS ultimates and cumulative production



-Macaroni

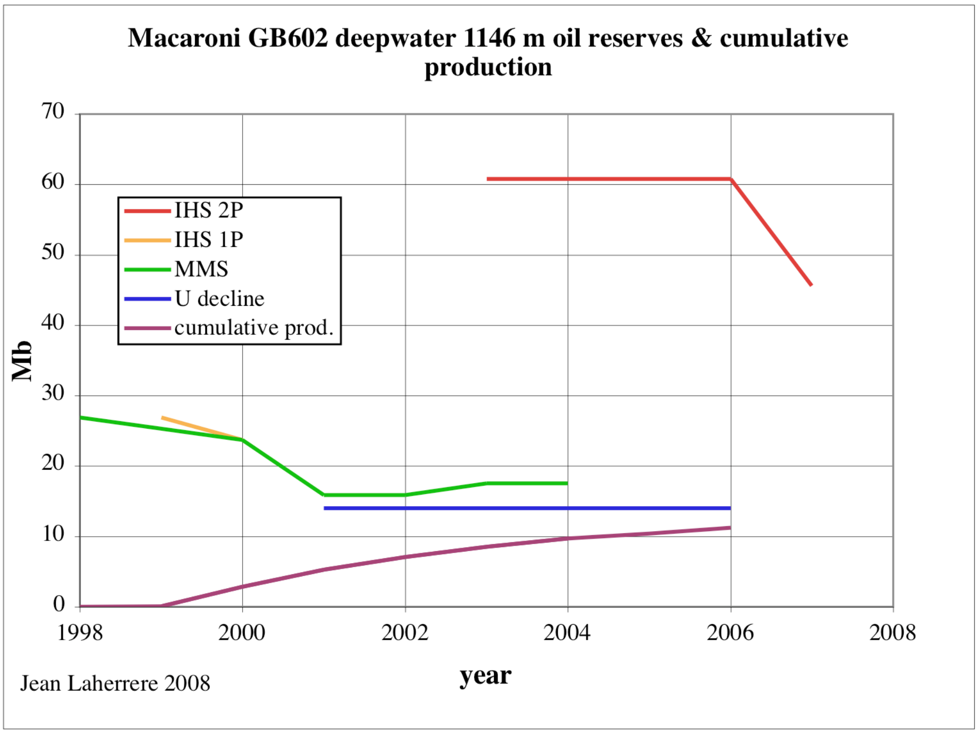
Macaroni (GB 602), found in 1996 at over 1100 m water depth, was a disappointment and the ultimate from extrapolation of the decline is much less than expected.

Figure 13: Macaroni (GB602) oil decline 1998-2006



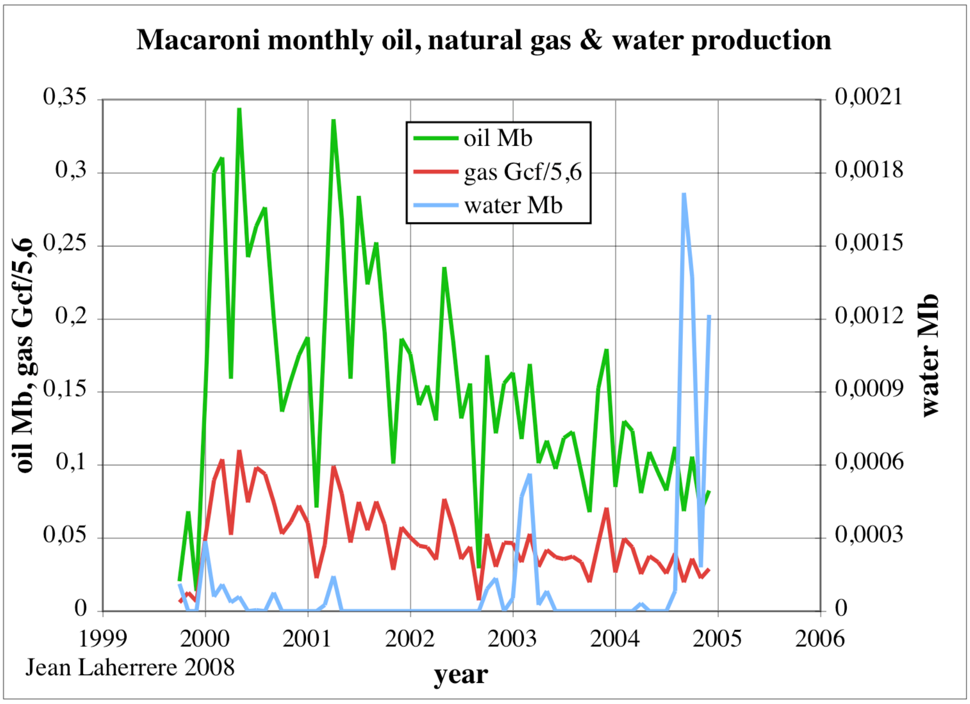
MMS and IHS oil reserves were too optimistic

Figure 14: Macaroni (GB602) oil reserves and cumulative production



Natural gas production correlates well with oil, but water production is erratic

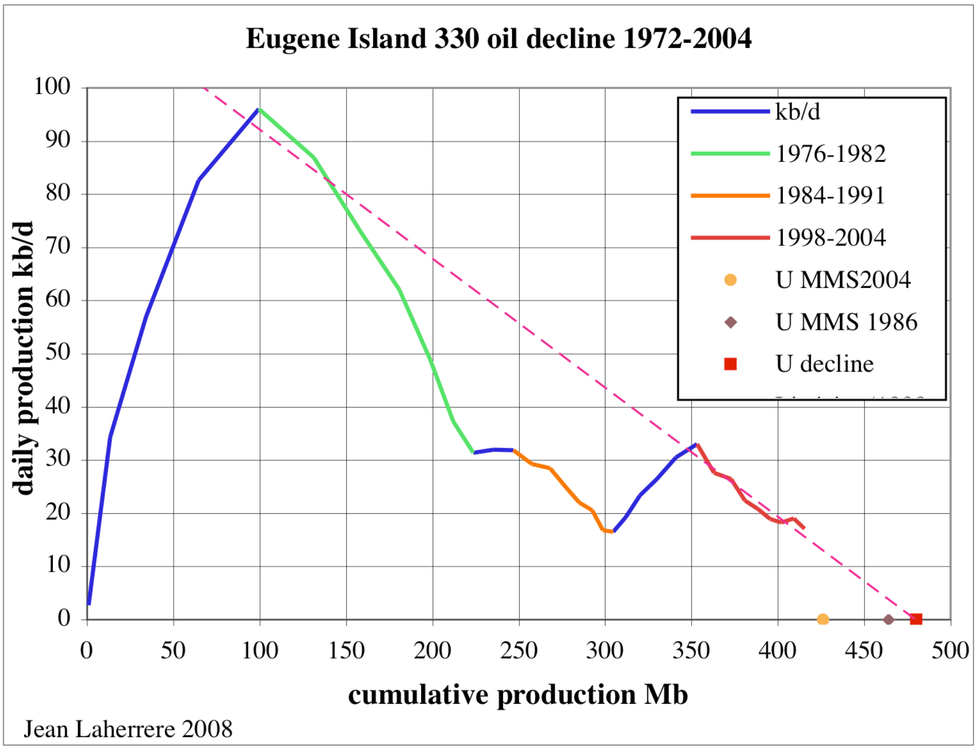
Figure 15: Macaroni (GB602) oil, gas & water monthly production



-Eugene Island 330

Eugene Island 330 (second largest GOM field), found in 1975 at 75 m water depth, is one example of exceptional positive reserve growth due to special geological conditions = reservoir connected to the source-rock, (the second one is Ekofisk due to the compaction of the chalk reservoir with pressure decline). The largest fault in the area called the Red Fault (studied on the web by several universities) allows the reservoir to be directly in communication with the source rock, so that when the pressure dropped the reservoir was fairly quickly recharged by the source-rock. In 1999 Wall Street Journal (Cooper) stated from this example that oil was coming from the mantle making oil renewable and almost unlimited.

Figure 16: Eugene Island 330 oil decline 1972-2004



So oil decline displays an increase of reserve but official proved reserves show a decrease from 1987 to 2003!

Figure 17: Eugene Island 330 MMS & IHS oil ultimates and cumulative production

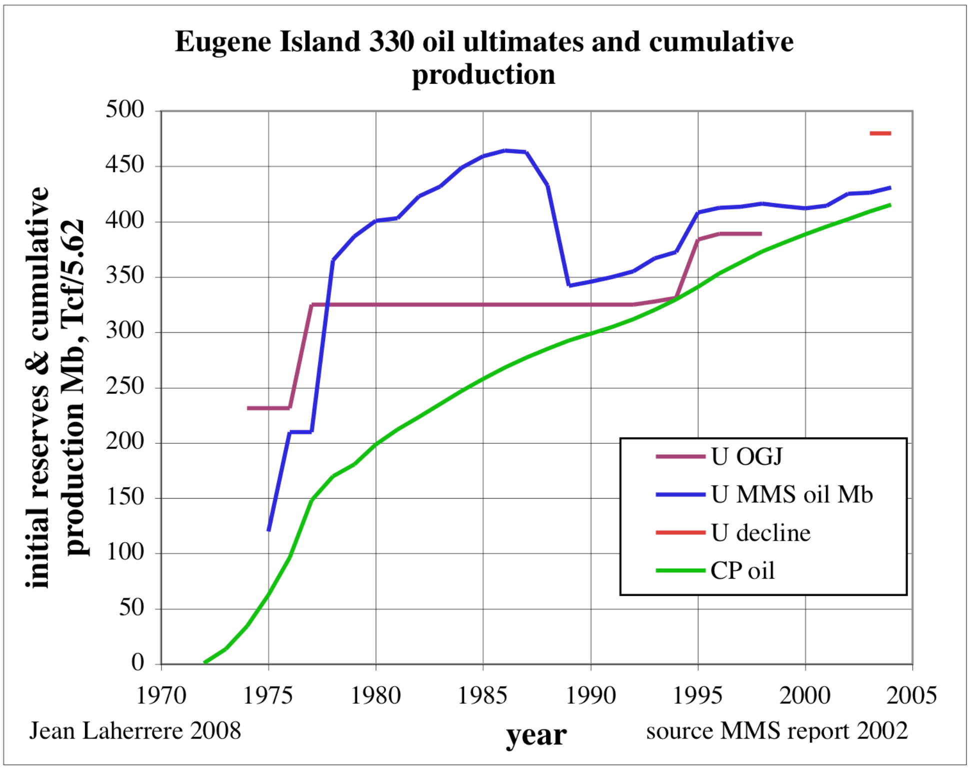
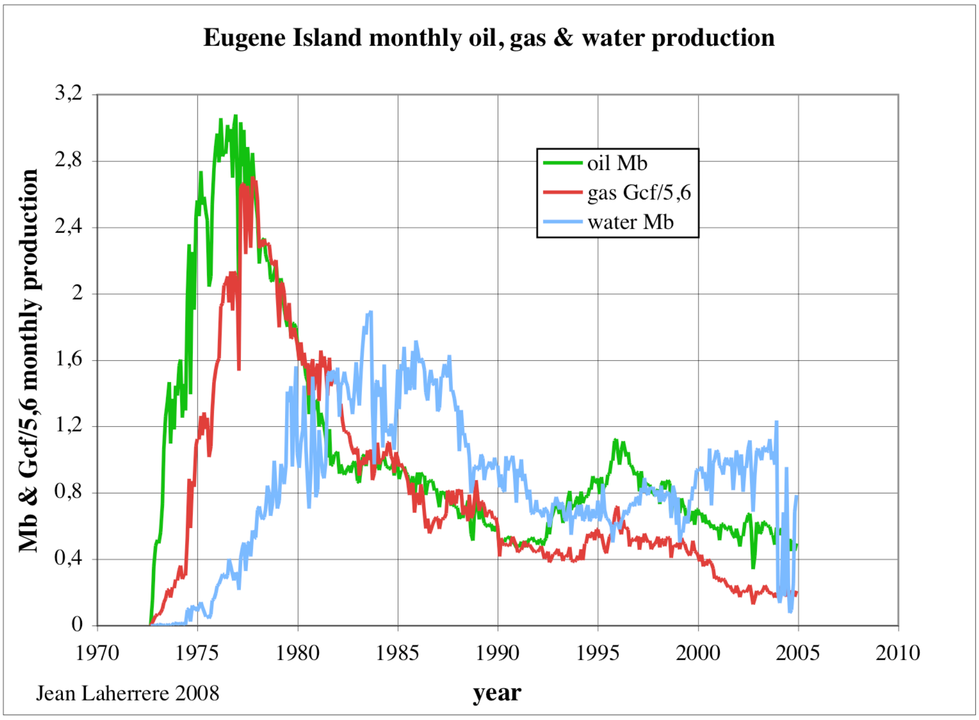


Figure 18: Eugene Island 330 oil, gas & water monthly production

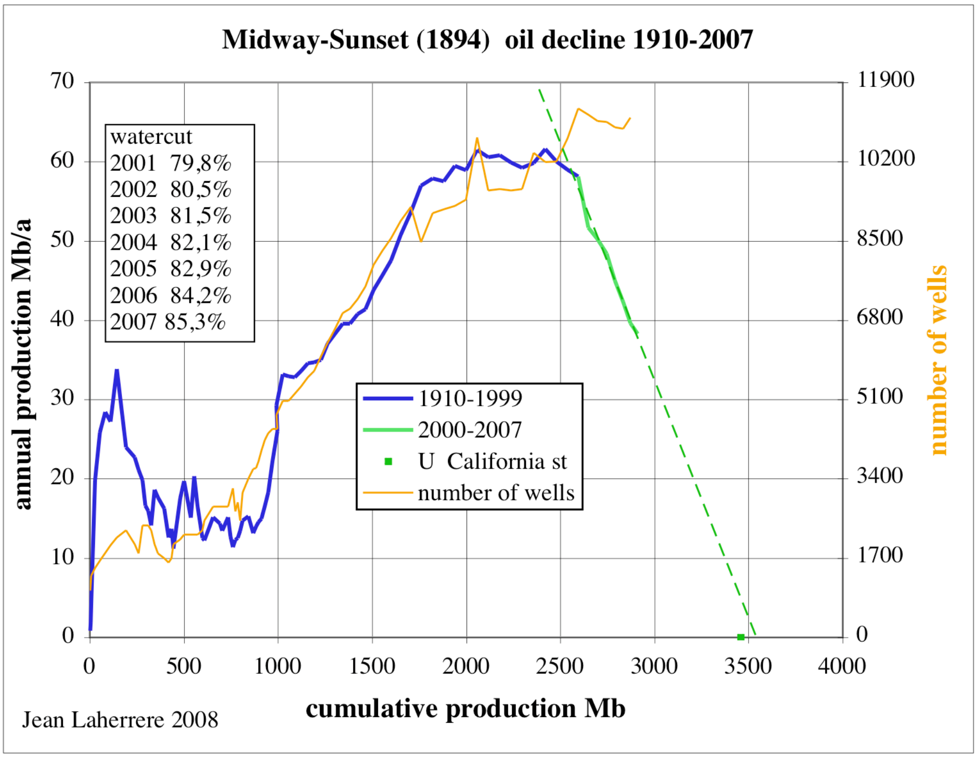


-California heavy oil fields

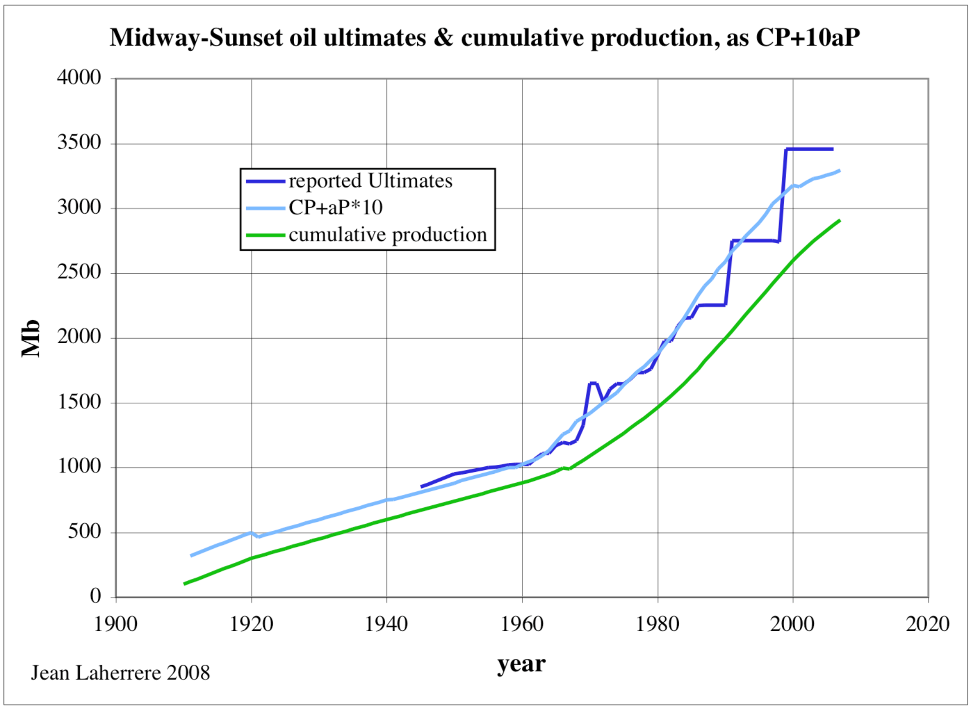
-Midway-Sunset

Californian heavy oilfields are often presented as examples of large reserve growth, but these fields are unconventional produced with steam for a very long time and developed progressively, growing

with more drilling and time. These unconventional old fields cannot be taken as reference to judge conventional new fields.
Midway-Sunset, found in 1894, peaked in 1997, more than 100 years later. The increase in production follows, up to the peak, the increase in number of wells drilled
Figure 19: Midway-Sunset (1894) oil decline as number of producing wells 1910-2007



This kind of reserve growth during a century cannot be extrapolated to deepwater fields produced within about 10 years such as Mars.
In the US the rule of thumb for estimating remaining reserves is to multiply by ten the annual production (or R/P =10), so the cumulative production (CP) plus ten times annual production (aP) is plotted: most of the time it is close to reported proved reserves.
Figure 20: Midway-Sunset oil ultimates and cumulative production, as CP+10aP



-Kern River

Kern River, found in 1899 with 13°API oil, started to decline only 100 years later (like Midway-Sunset).

Figure 21: Kern River (1899 13°API) oil decline 1900-2006

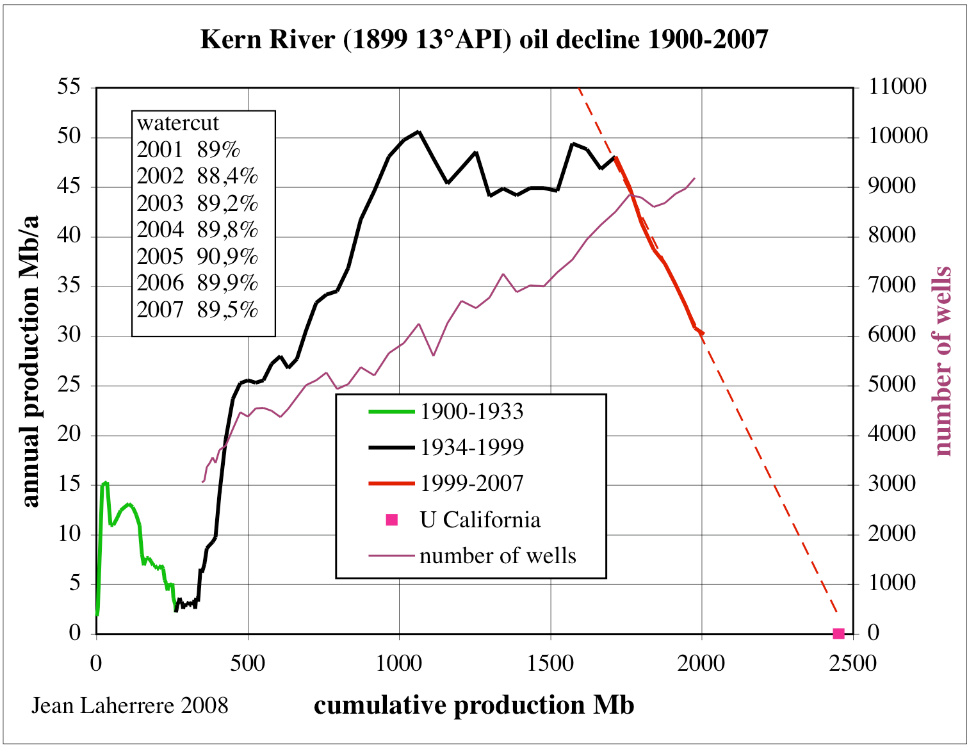
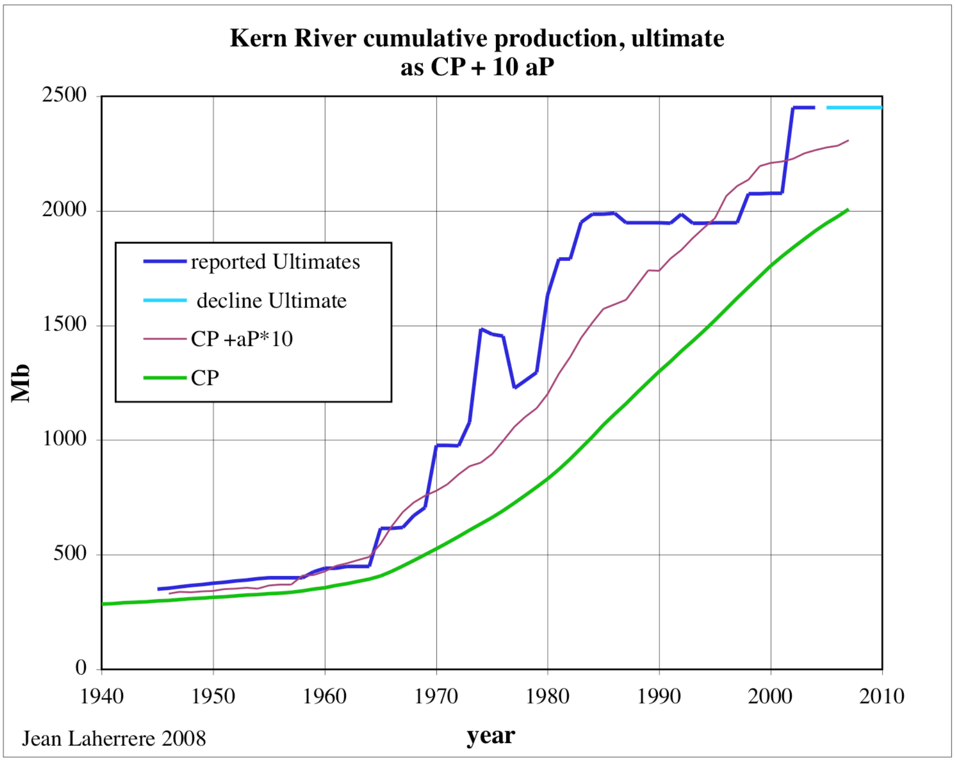


Figure 22: Kern River ultimate, CP+10aP & cumulative production

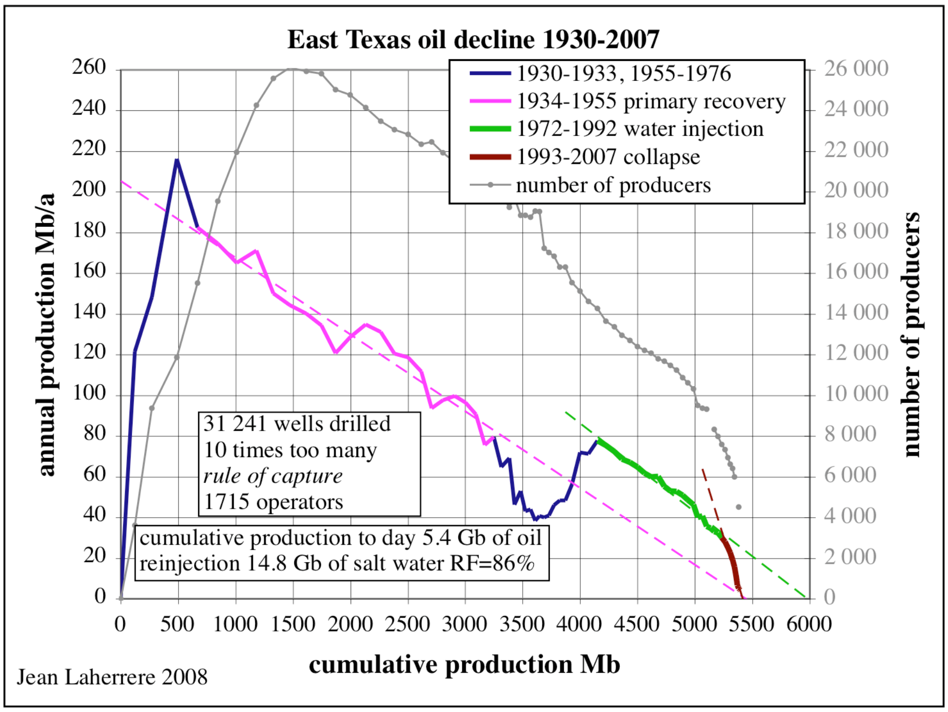


-Texas

-East Texas oilfield

East Texas oilfield, the largest oilfield in the USL48, reached a peak in 1932 and declined using only primary recovery because the very large number of operators (over 1700), trending towards an ultimate of 5500 Mb. Because the law of capture (some deviated to steal the neighbour's oil) too many wells were drilled (over 31 000 wells) giving 4 acre/well spacing, when a spacing of 40 acre/well should have been enough because the good quality of the reservoir. In the 70s, unitization and water injection started, raising the production with a decline (1972-1992) parallel to the primary recovery time but trending towards an ultimate of 6000 Mb. But in 1993 the decline worsened trending again back to 5500 Gb. Technology allows to produce quicker but nothing more. In fact technology improvement leads to false hope. East Texas is almost depleted, having produced 5400 Mb of oil with an injection of 14800 Mb of salt water. The recovery factor is very high = 86% and reliable because the huge number of wells gives an accurate view of oil in place

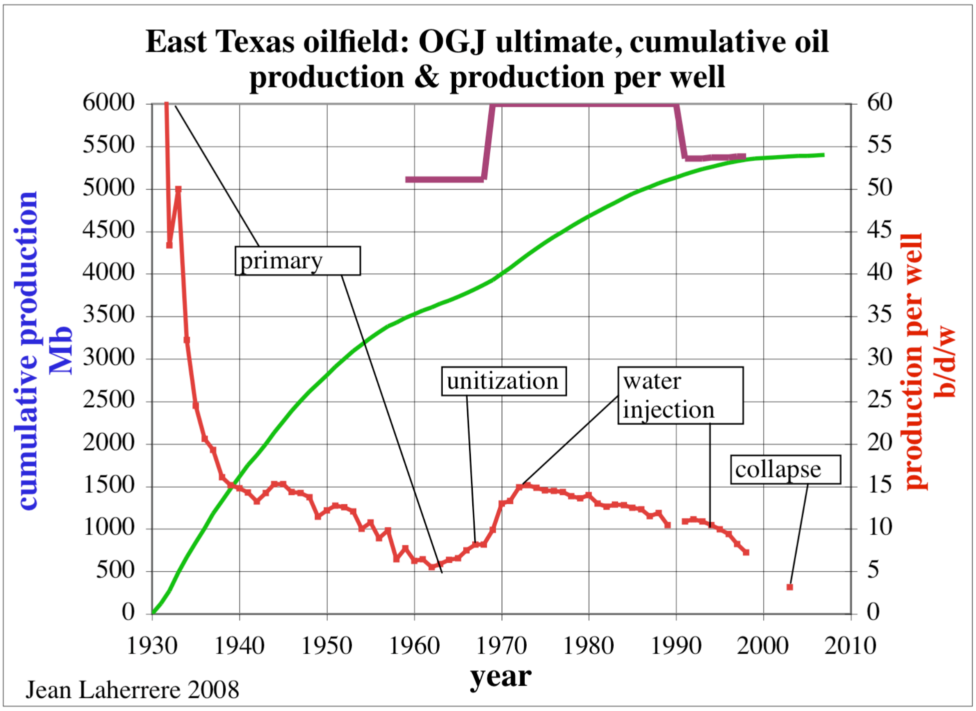
Figure 22: East Texas oil decline 1930-2007



From 1970 to 1990 oil ultimate was believed to be 6000 Mb, but the 1993-2007 collapse cooled it down to 5500 Gb

Production per well was about 60 b/d/w in the beginning, dropping to 5 b/d/w, when unitization and water injection increased it to 15 b/d/w diminishing slowly up to 1992, then dropping to present 3b/d/w

Figure 23: East Texas ultimate cumulative production & production per well



East Texas is a good example of large negative reserve growth, thanks to technology.

-Yates

Yates is quoted as one example of CO2 EOR success, but in fact EOR (polymer, steam and CO2) with infill has just slowed down the decline. Marathon in 2002 has sold Yates to Kinder Morgan, meaning that the left potential was small.

Figure 24: Yates oil decline 1927-2007

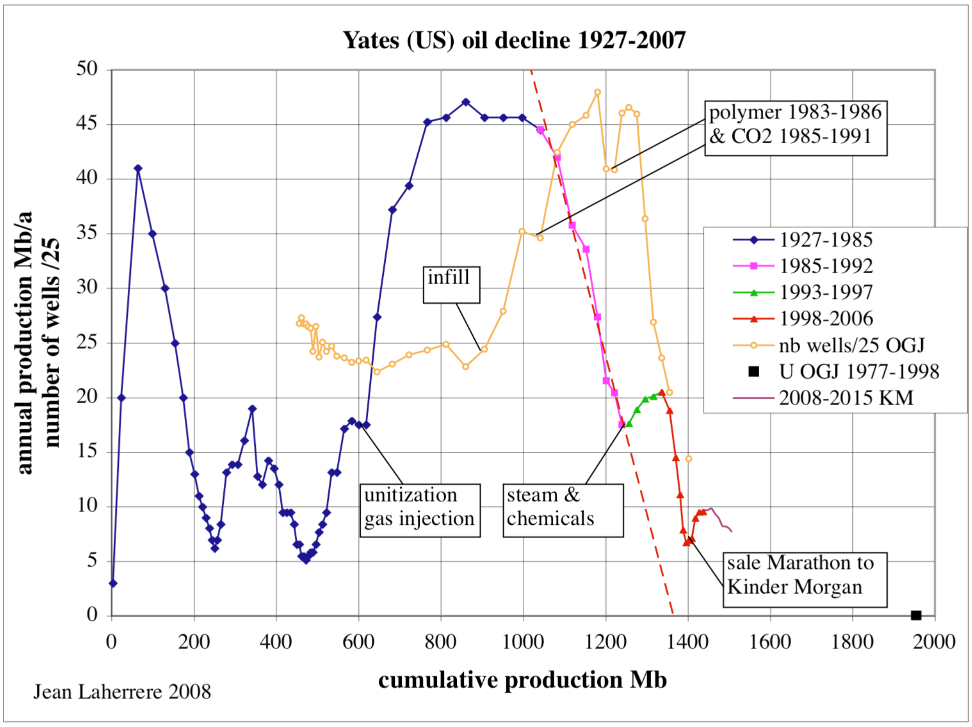
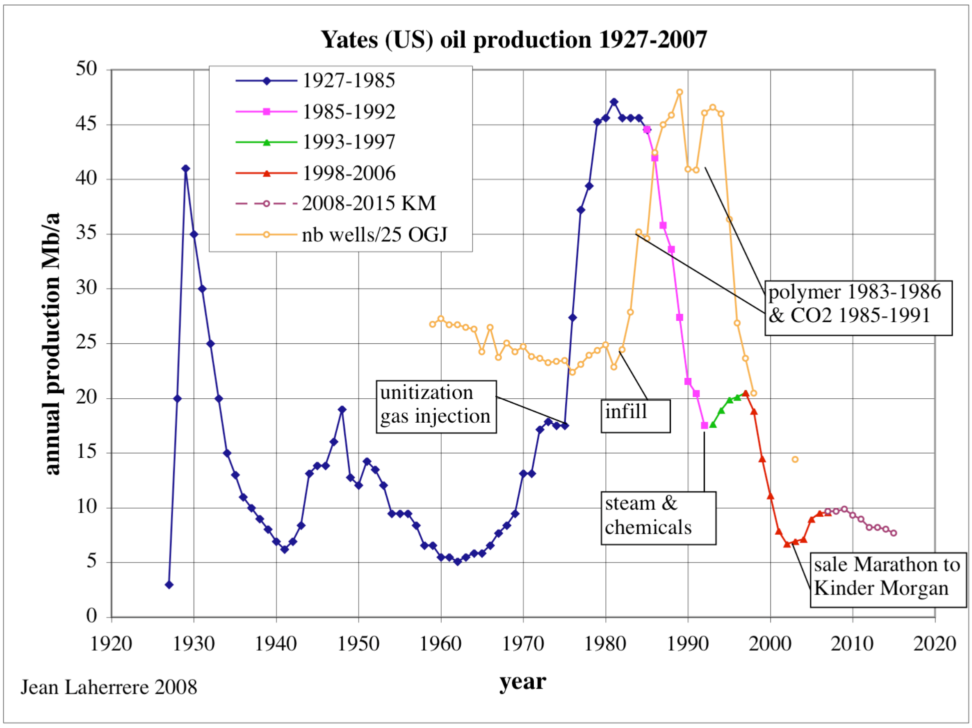
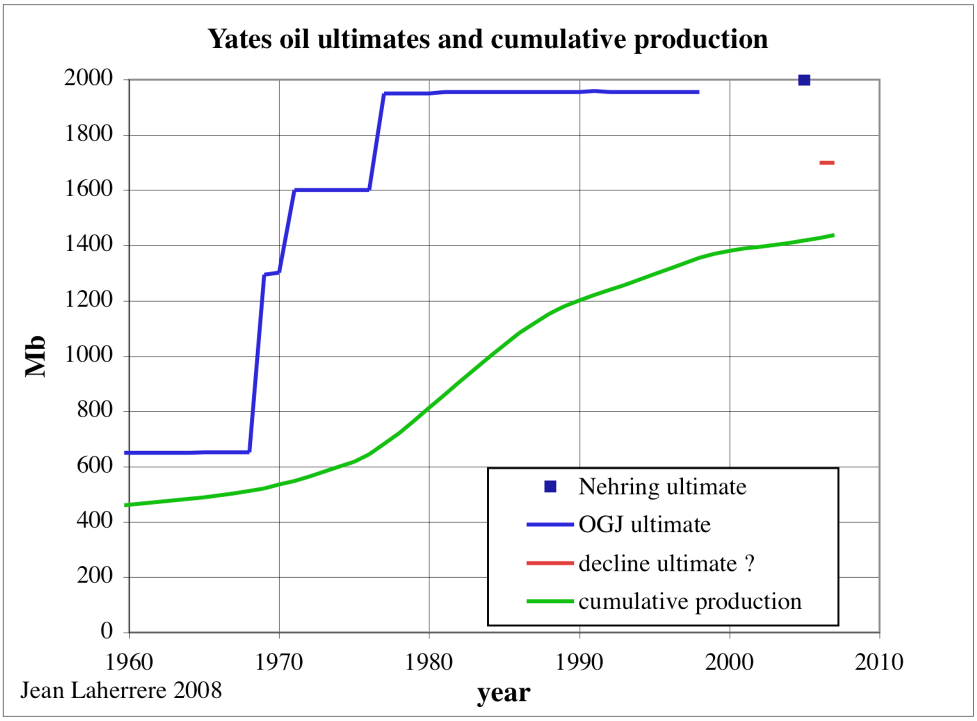


Figure 25: Yates oil production



In fact oil decline tends towards an ultimate (1700 Mb) smaller than the OGJ reported estimate (1955 Mb) or Nehring (2000 Mb) estimate.

Figure 26: Yates oil ultimates & cumulative production



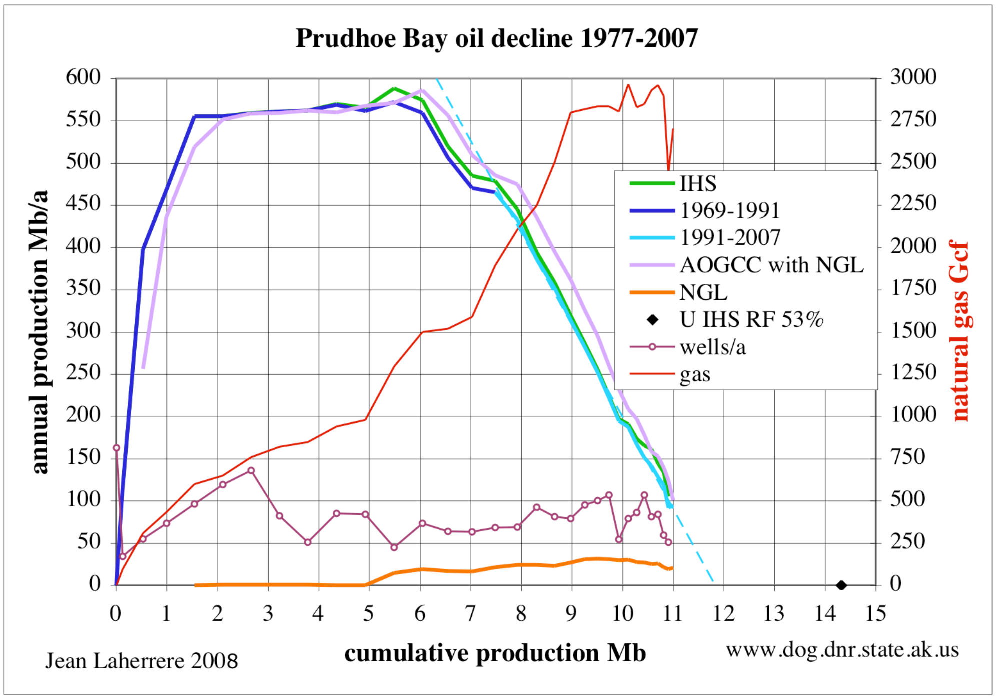
Likely Yates will be another example of negative reserve growth

-Alaska

-Prudhoe Bay

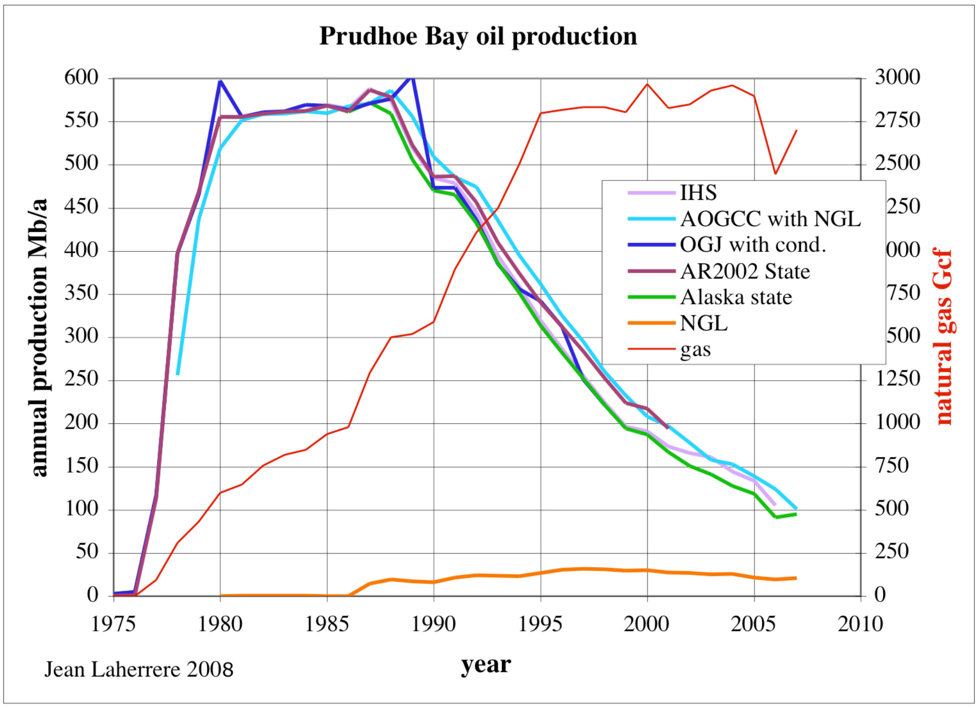
Prudhoe Bay is the largest US oilfield, where production flattened from 1980 to 1990 at 1.5 Mb/d because of the size of the pipeline and declined regularly (270 000 b/d presently). The Transalaska pipeline is rusting (leaks last year) and a minimum is needed to keep it running.

Figure 27: Prudhoe Bay oil decline 1977-2007



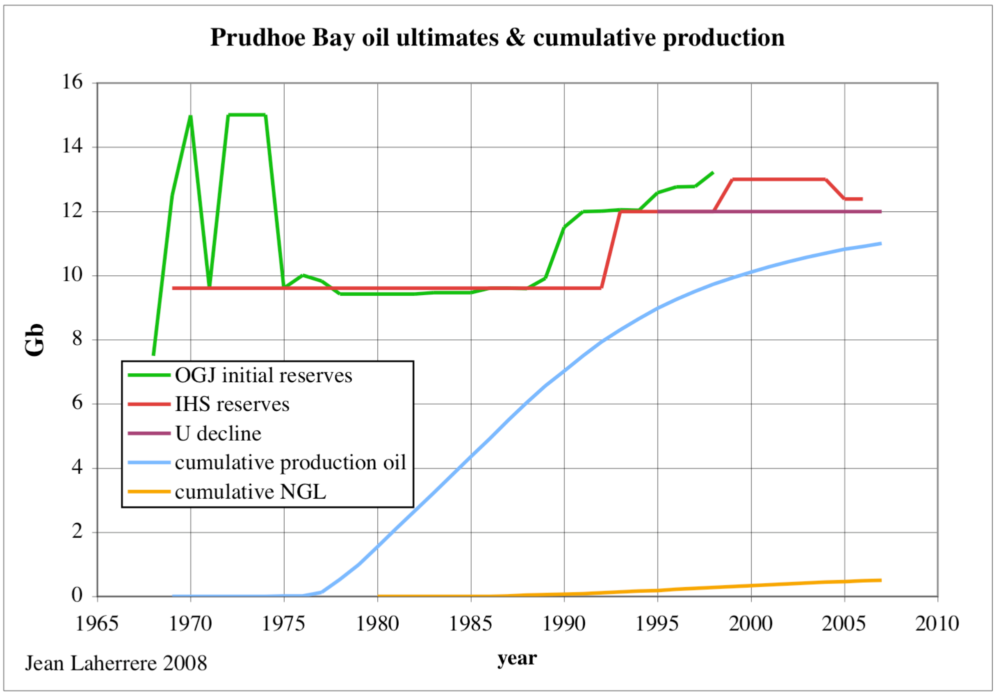
In production reporting, there is often confusion between oil and liquids, with a significant difference because of NGPL

Figure 28: Prudhoe Bay oil and liquids production



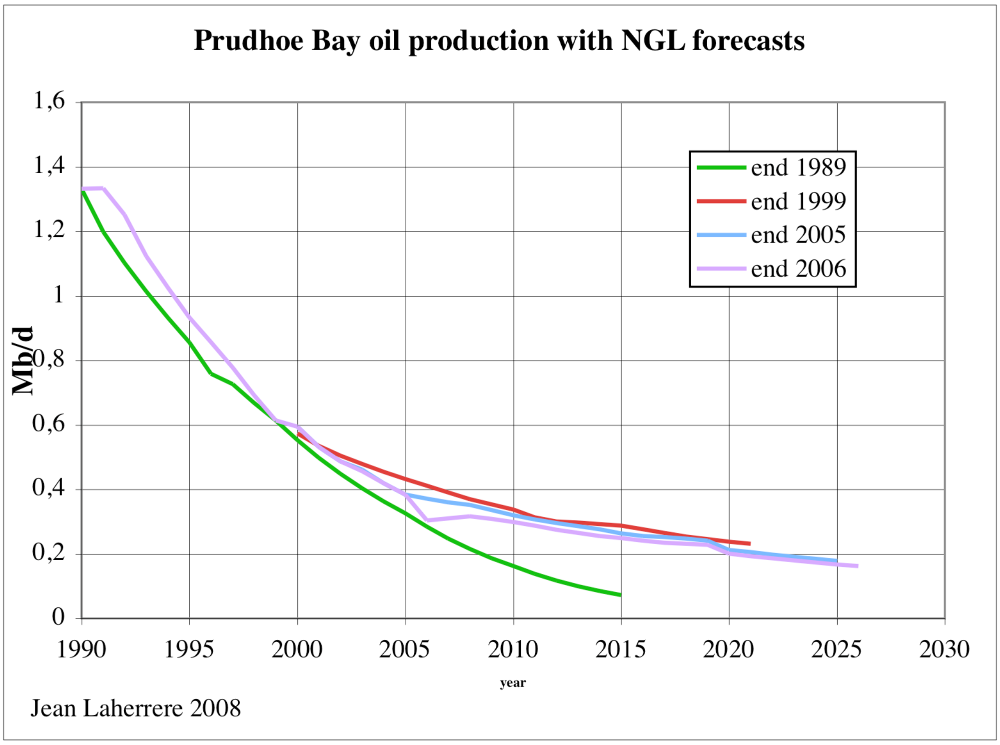
Prudhoe Bay ultimate was estimated at the beginning by a range of 10-20 Gb by geologists (optimistic because they have the right to be wrong by drilling 9 dry holes out of 10 wildcats) and 9,6 Gb by petroleum engineers (always conservative because they have to be right). The present ultimate (crude only) is about 12 Gb.

Figure 29: Prudhoe Bay ultimates and cumulative production



Oil production forecast in 1989 was pessimistic, but last estimates (1999 to 2006) do not vary trending towards 180 000 b/d in 2025

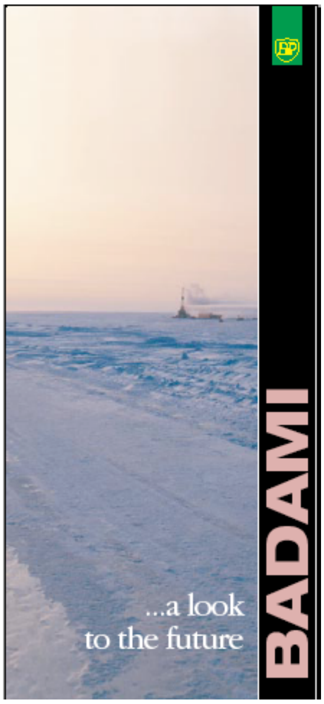
Figure 30: Prudhoe Bay oil production forecasts with NGL

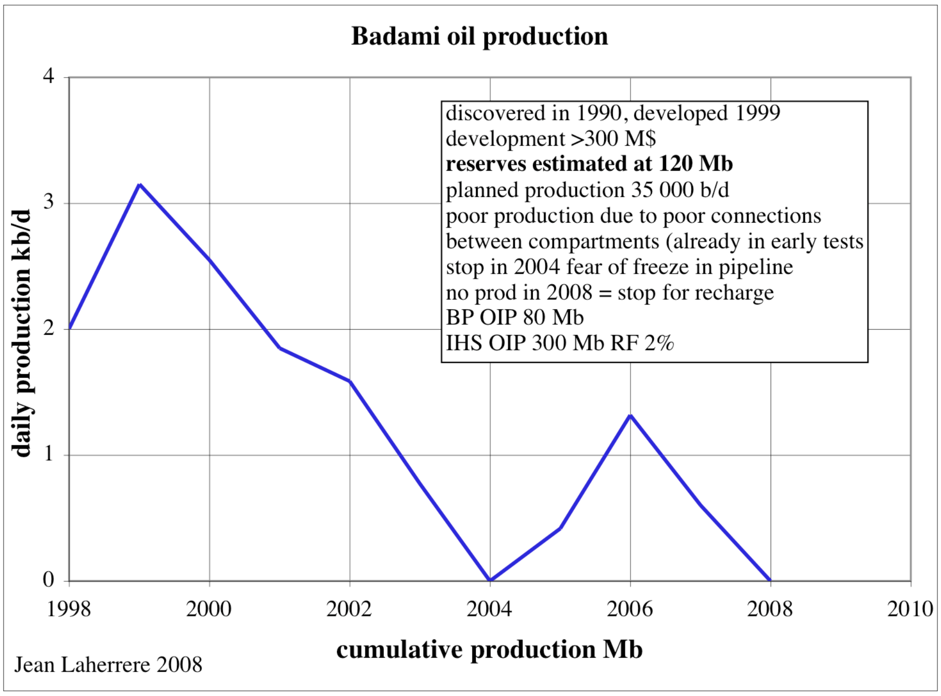


-Badami

Badami is the closest production to ANWR and was a flop. Badami was developed by BP for over 300 M$, assuming 120 Mb reserves and a peak at 35 000 b/d. Production peaked at 3100 b/d and declined after one year, because of poor connections between compartments (visible in exploratory tests but ignored). Badami was closed in 2004 because the production was not enough to prevent the freeze of the pipeline. BP produced again in 2005 and 2006 at a maximum of 1200 b/d and closed it again in 2008, waiting for a possible recharge! The ultimate is now put at 6 Mb by IHS with a cumulative production at 5.2 Mb. Oil in place is reported at 80 Mb by BP and at 300 Mb by IHS.

Figure 31: BP report Figure 32: Badami oil production





followed by part 2