



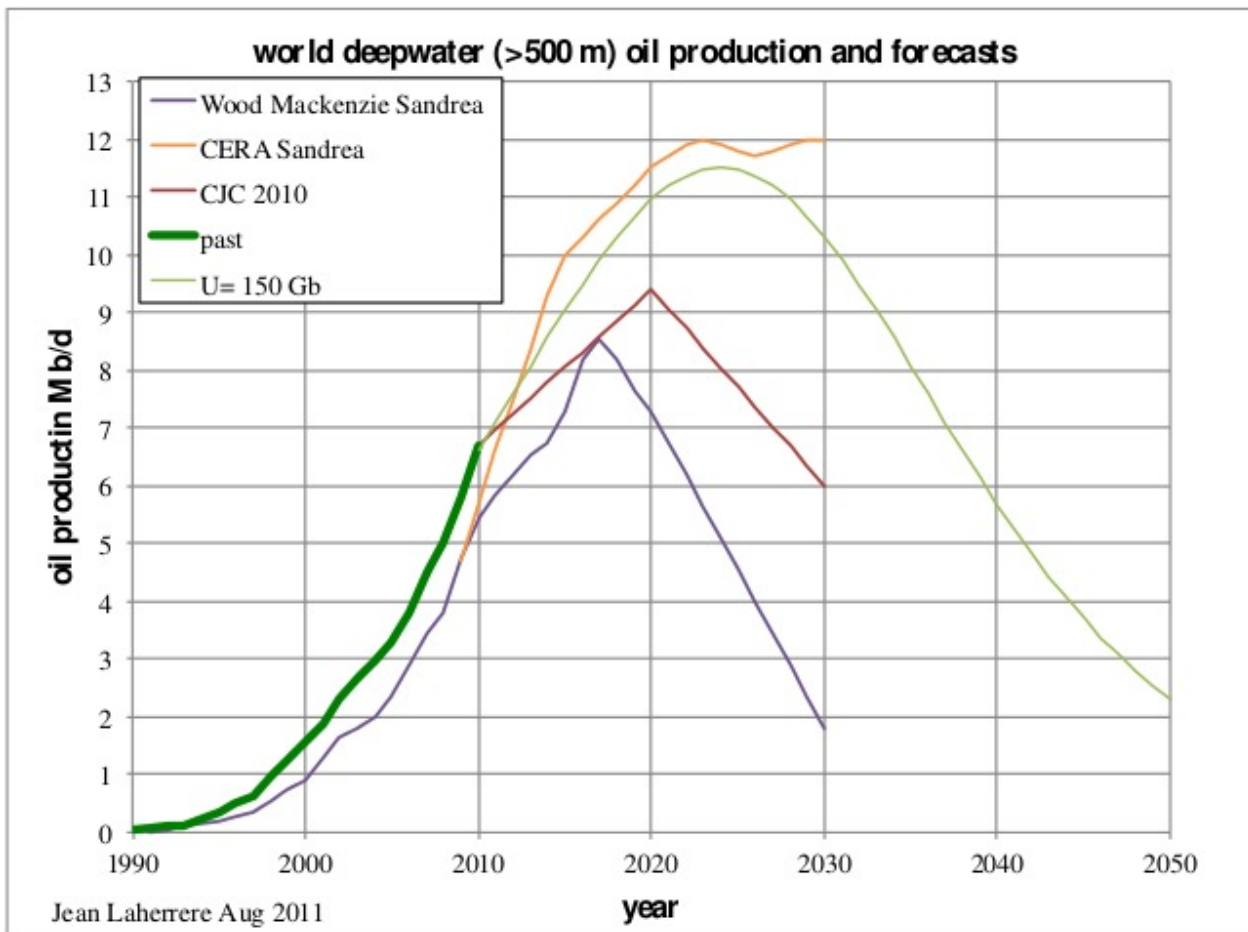
Deepwater GOM: Reserves versus Production - Part 3: Older Fields and Conclusion

Posted by [Luis de Sousa](#) on November 23, 2011 - 6:30am

Topic: [Geology/Exploration](#)

Tags: [deepwater](#), [forecast](#), [gulf of mexico](#), [jean laherrère](#), [shallow water](#) [[list all tags](#)]

This is the third and final post on this series on the Gulf of Mexico (GOM) by [Jean Laherrère](#), a long-time guest contributor to TheOilDrum. The goal of this series is to compare the evolution of reserves estimates in the GOM with the actual production figures that show the oil decline, thereby investigating the reliability of reserve estimates. In this third installment, Jean looks into older and shallower fields as a term of comparison to synthesize his finds and assesses the impact on his world all liquids forecast. The first installment analysed data on [Thunder Horse & Mars-Ursa](#) and the second [Atlantis, Mad Dog & Eugene Island](#).



Update: Prompted by the comments, Jean sent an additional graph with cumulative Deepwater discovery and production, to be found at the of this post.

In the [2010 report by J. Lach](#), referenced in part 2, the Ram-Powell field is presented as a complex structure with a low recovery factor, 20%.

Figure 60: Examples of Neogene reservoirs by Lach.

Table 8: Example mature Neogene reservoirs and oil recovery mechanisms

Class	Field	Reservoir	Primary Depositional Facies	OOIP (MMSTB)	Oil RF	API Gravity	GOR (SCF/STB)	ϕ / K (frac/md)
High RF, strong aquifer	Troika	S10	Sheet sand	254	60%	38	1660	0.30/1700
	Auger	S	Sheet sand	189	45%	37	1950	0.29/1100
	Bullwinkle	J	Sheet sand	209	45%	27	1000	0.30/1200
Moderate RF, high compaction and mod. aquifer	Genesis	N3L	Channel sand	93	37%	28	1027	0.29/300
	Pompano	M83C-85A	Channel sand	196	47%	34	1000	0.30/1130
	Medusa	T1B	Channel sand	111	40%	30	900	0.28/1290
Depositional and structural complexity	Ram Powell	N	Channel sand	84	20%	35	1400	0.29/825
	Front Runner	FR-46D	Sheet sand	100	23%	28	815	0.26/870
	Marco Polo	M10-M60	Channel sand	31	25%	32	800	0.30/600
Waterflood from start	Petronius	J1	Sheet sand	92	52%	31	700	0.29/490
	Horn Mountain	M	Channel sand	279	40%	33	800	0.28/300
Middle Miocene with limited drive energy	K2	M20	Sheet sand	374	20%	30	600	0.21/700

He described the N sand with the term “perched water”!

Figure 61: Ram-Powell N sand described as “perched water”.

6.1.1.3 **Low Oil Recovery in Complex Depositional and Structural Geology**

The Ram Powell N, Front Runner FR-46D, and Marco Polo M10-M60 reservoirs have all experienced a rapid decrease of oil rate due to reservoir complexity. The N sand has been described (Kendrick, 2000) as a channelized reservoir where development well drilling penetrated "perched" water at structurally high locations (Figure 40). Subsequent drilling of the A-5 horizontal well, in an attempt to avoid the perched water and connect up multiple channels sand members (Bramlett and Craig, 2002) showed the stratigraphic complexity of a stacked channel complex. Current oil recovery is only 20% of OOIP.

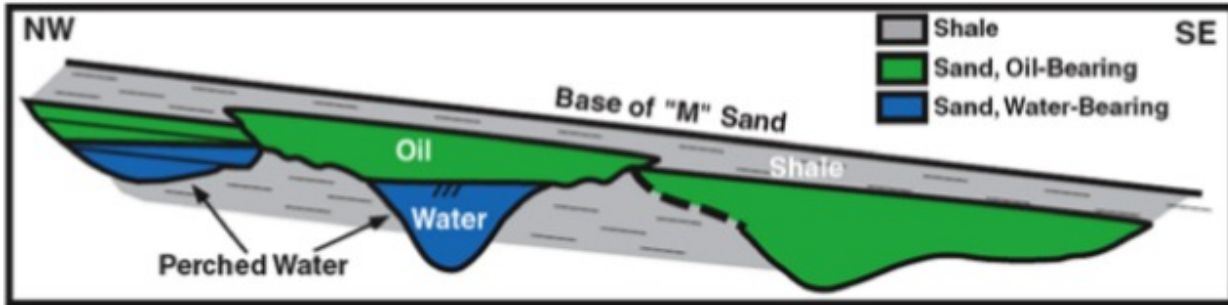
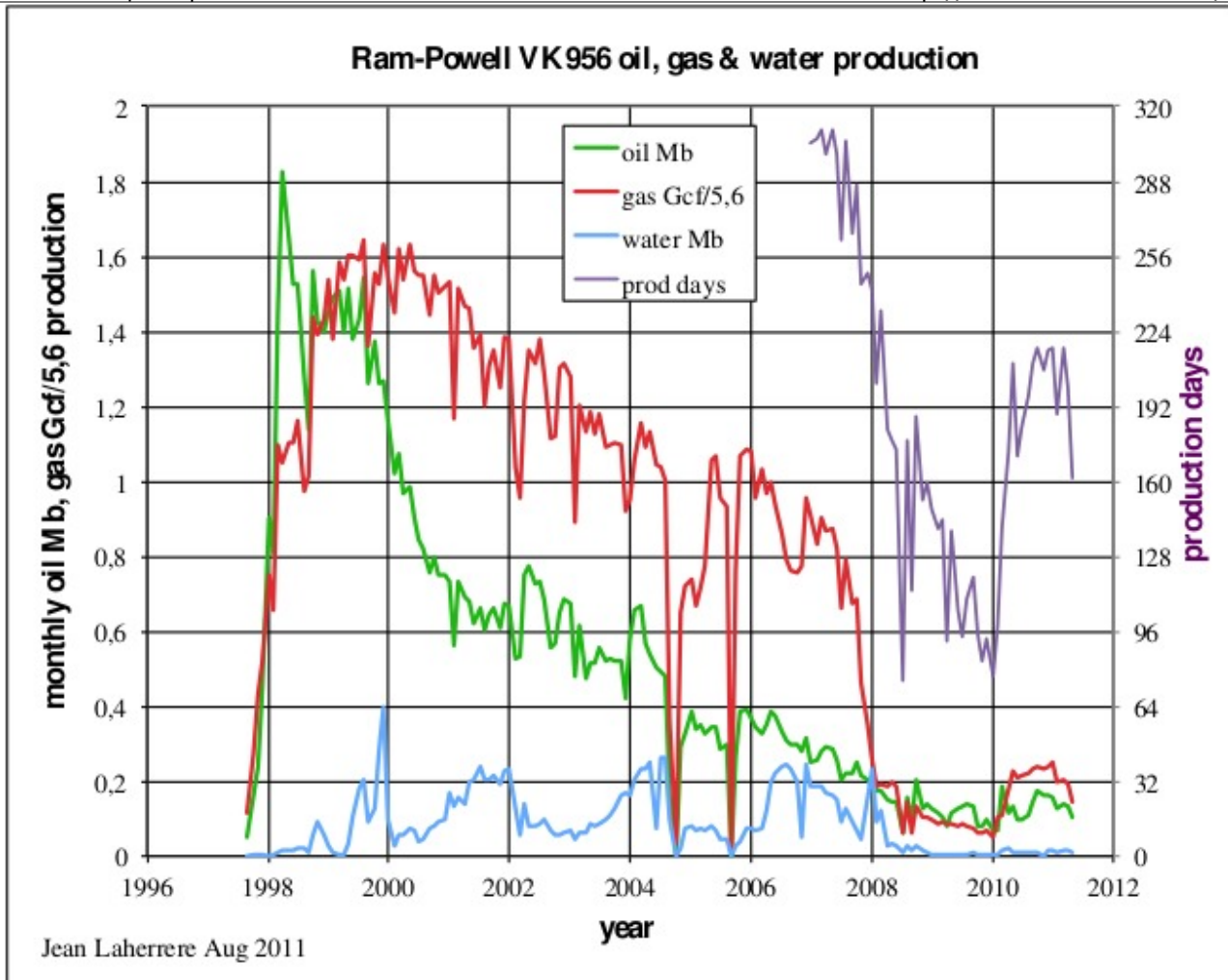


Figure 40: Perched water in channel sand, Ram Powell N reservoir (Kendrick, 2000)

The Front Runner FR-46D reservoir was penetrated by multiple wells during appraisal drilling and was interpreted as thick and laterally extensive sheet sand. Production from two wells declined quickly demonstrating poorer connectivity of oil in-place due either to sub-seismic faulting or depositional complexity. The forecast oil RF is 23% of OOIP.

The monthly production displays a peak in 1999 followed by a sharp decline and since 2001, a less steep and constant decline.

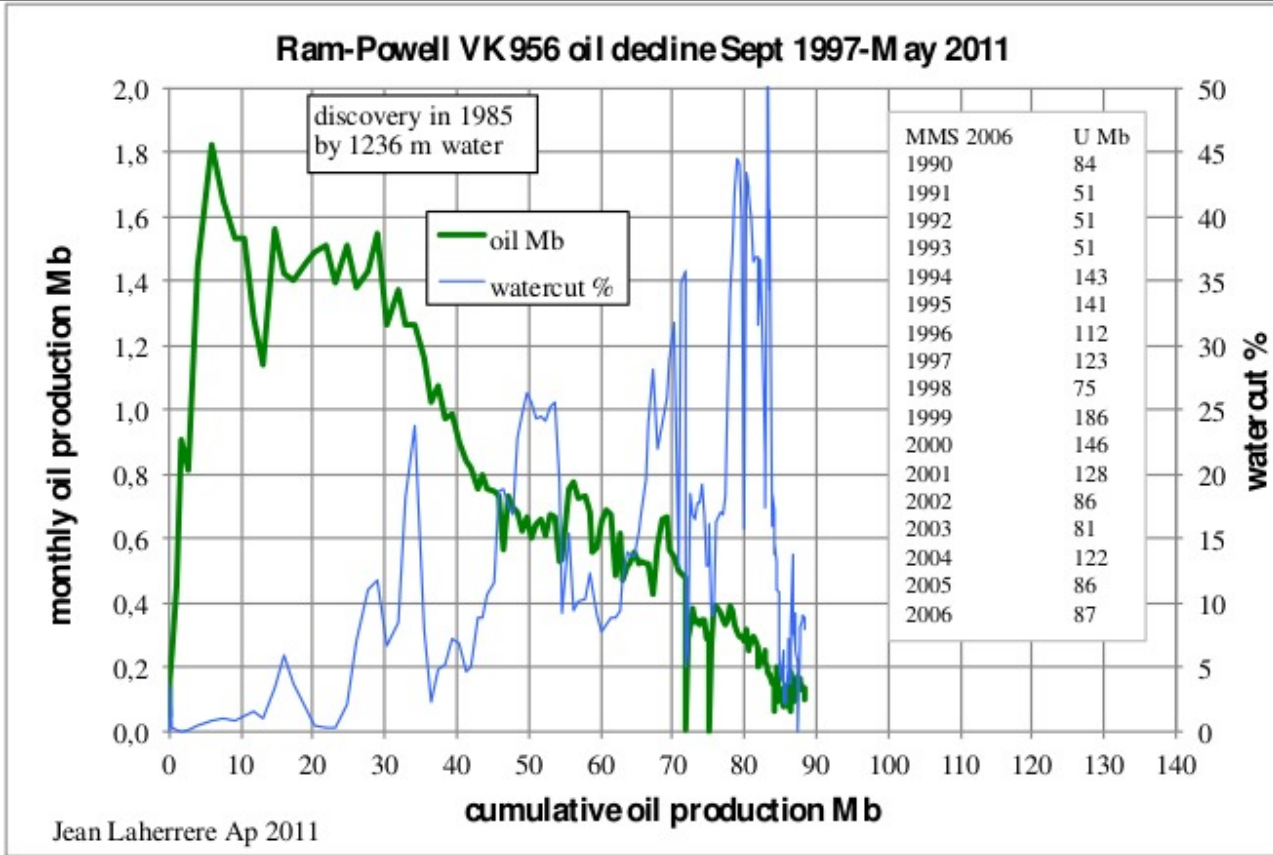
Figure 62: Ram-Powell monthly production.



From the oil decline extrapolation the ultimate is likely to be about 100 Mb. Meanwhile, the estimates by the MMS have varied chaotically between 1990 and 2006, from 51 to 186 Mb, the latest one being 87 Mb (too small); Lach (2010) reports 132 Mb.

Watercut has increased up to over 40% but dropped in recent months.

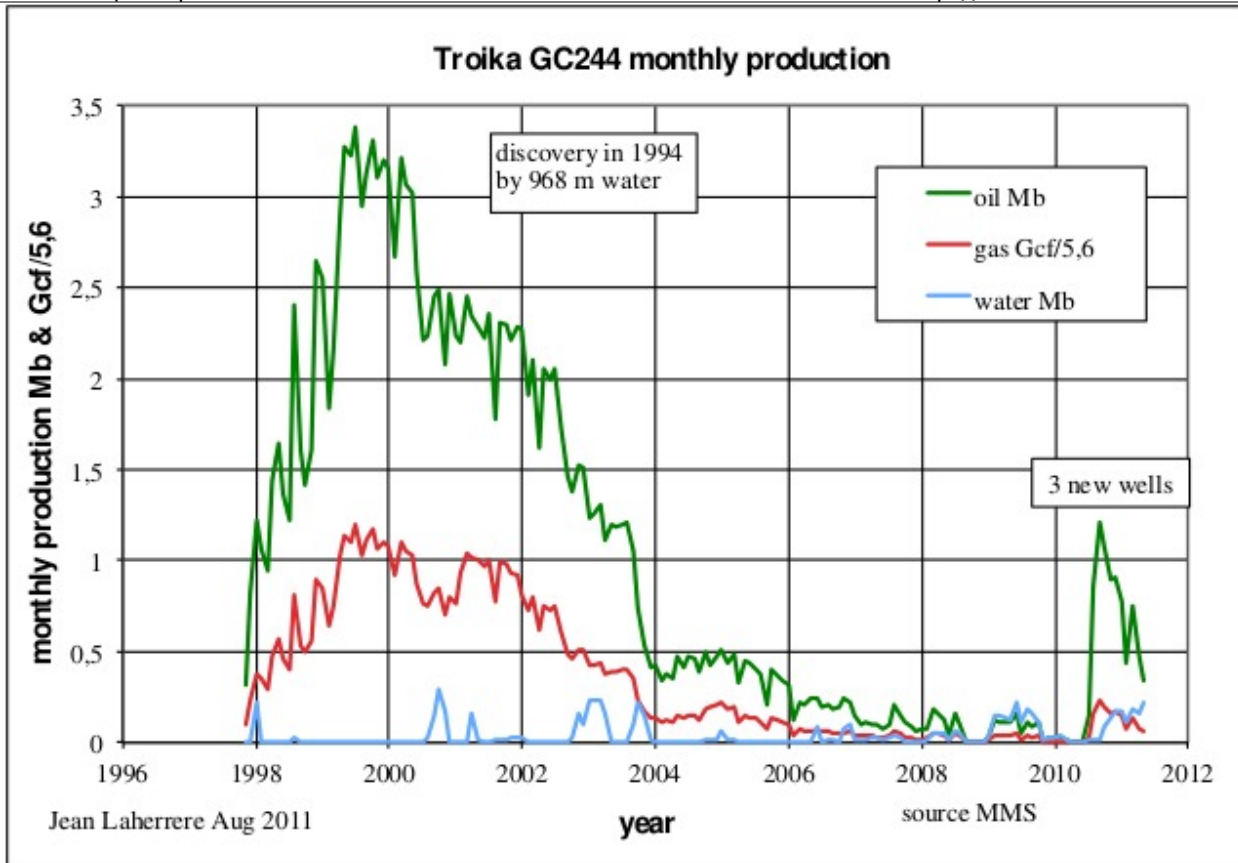
Figure 63: Ram-Powell oil decline.



Troika GC244

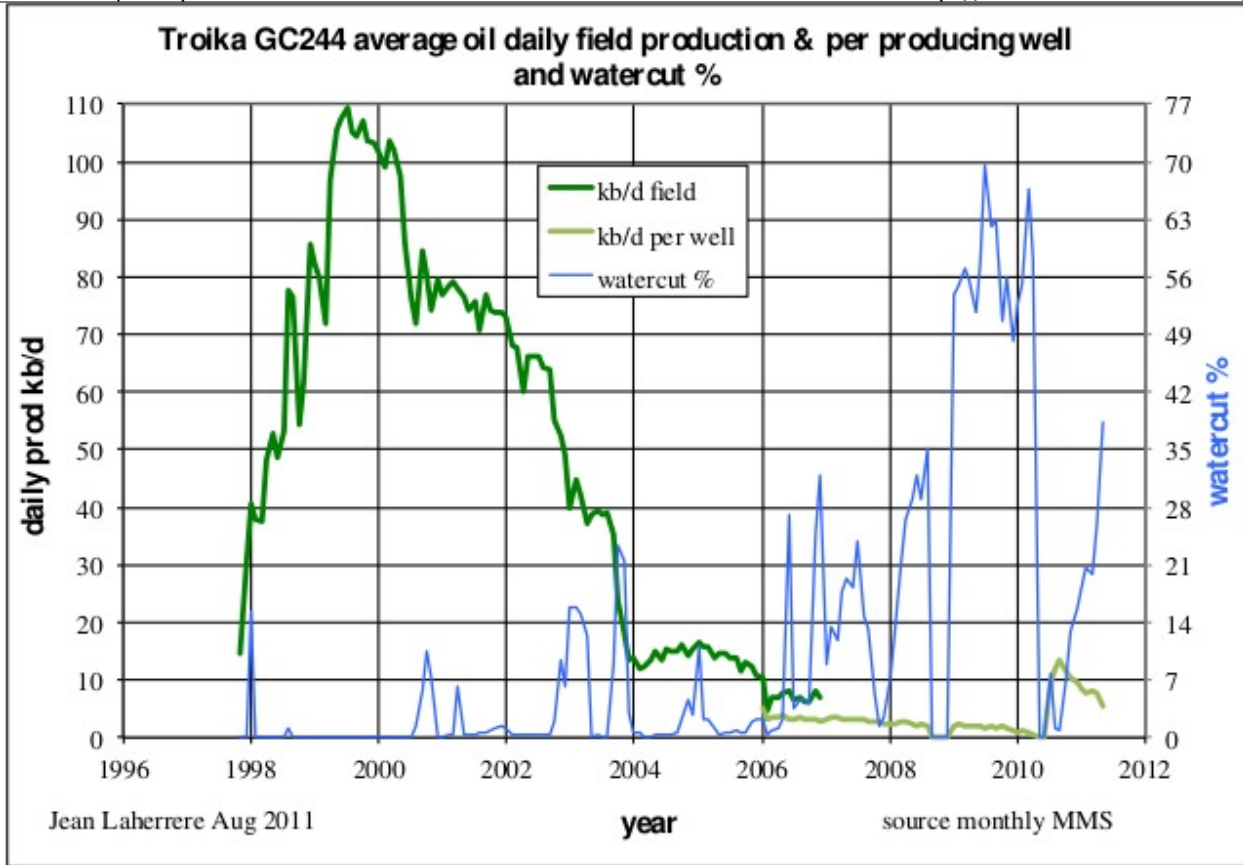
Lach (2010) presents Troika (in figure 58) as a strong aquifer with a high recovery factor (60%), contrary to Ram-Powell. The field's monthly oil production shows several downward steps, after peaking at 3.2 Mb in 1999. The first step down to 2.3 Mb took place in 2001, a second step down to 0.4 Mb happened in 2004, and a third step to 0.2 Mb in 2006. With the addition of 3 new wells in 2010, production rose to a new lower peak.

Figure 64: Troika monthly production.



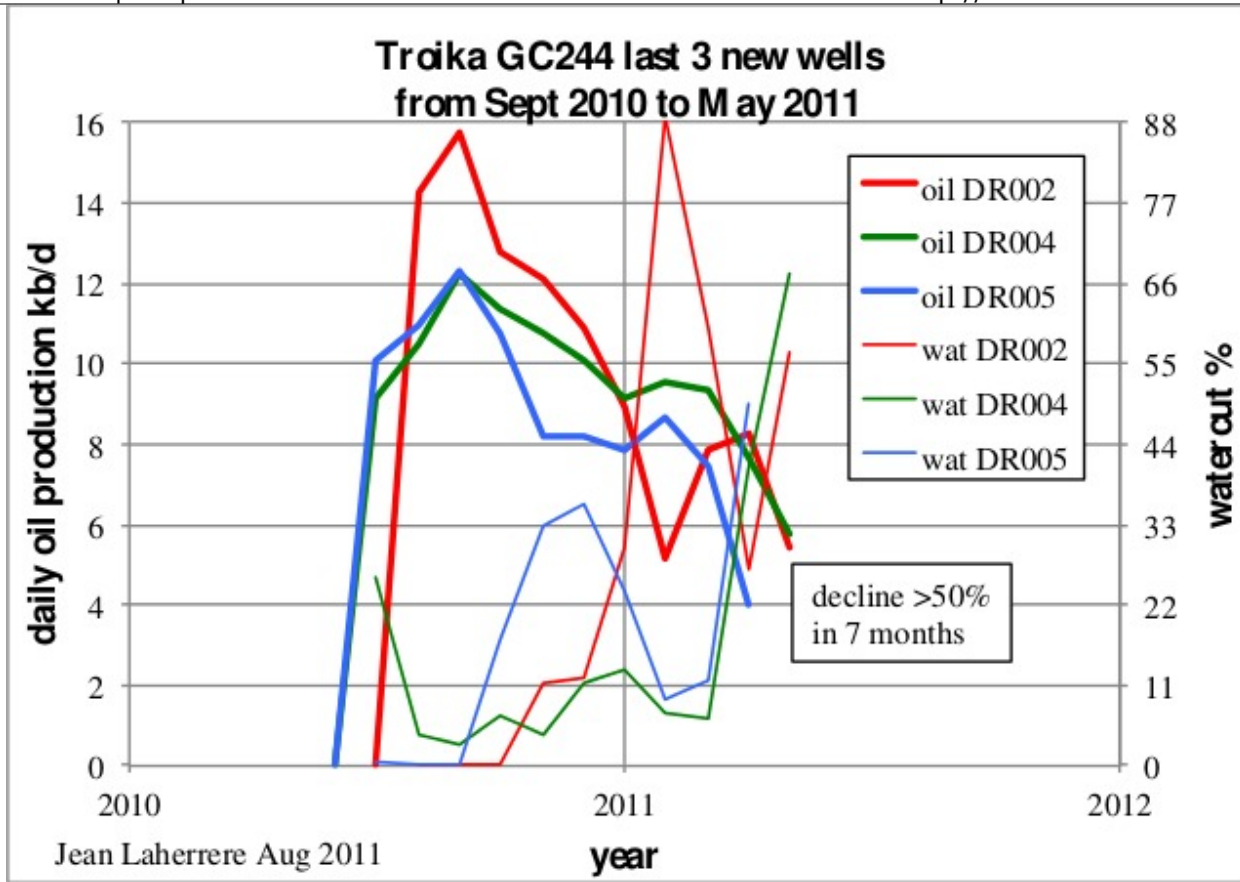
Troika's average daily production peaked in 1999 at over 100,000 b/d; the watercut start rising after that as the field depleted and eventually went over 60%, before old wells were abandoned.

Figure 65: Troika: average daily oil production, average daily production per well and watercut.



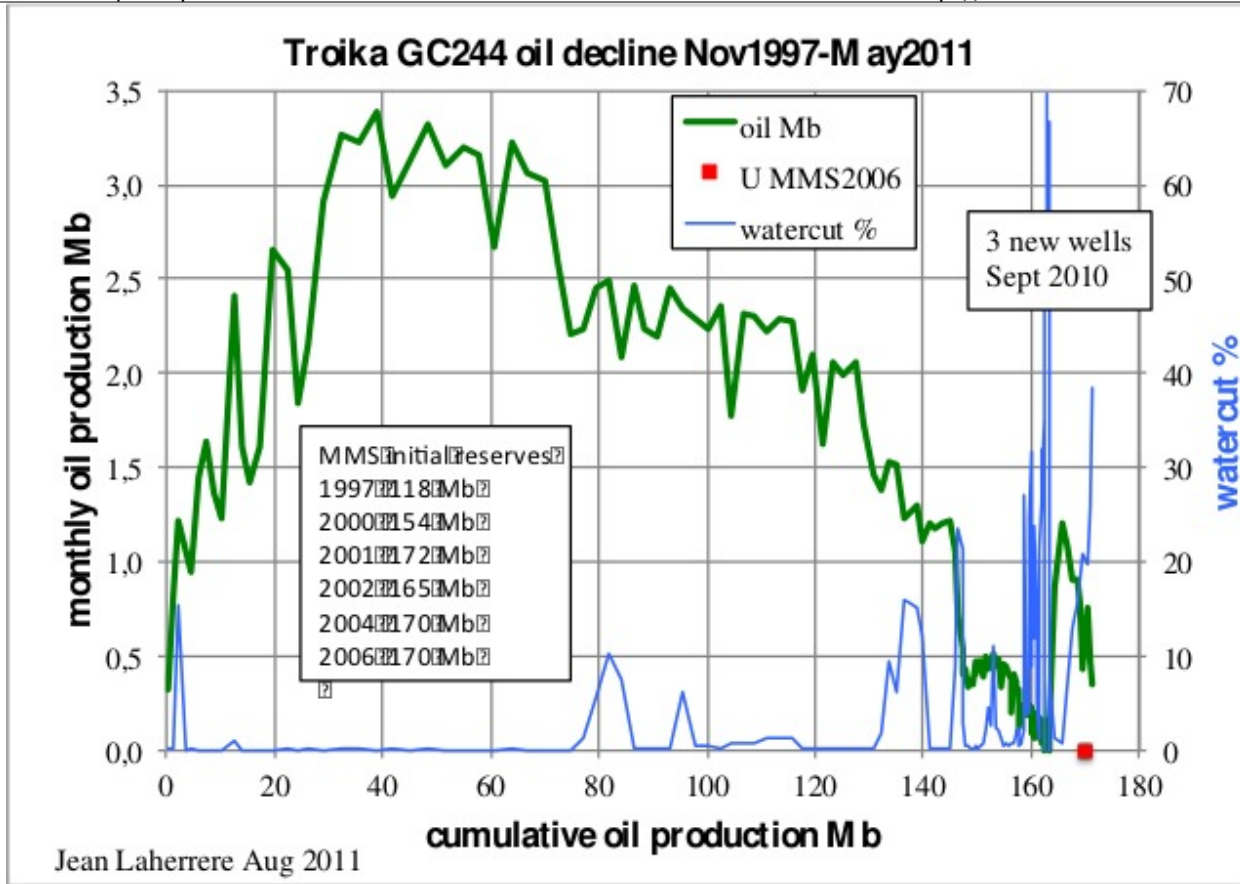
The oil production of the last three wells shows a decline of 50% in 7 months. It is obvious this is the last burst!

Figure 66: Troika, last 3 wells from September of 2010 to May of 2011.



The oil decline at Troika is close to total depletion, with a cumulative production of 170 Mb. The estimate by MMS in 2006 was close to this value, but Lach's ultimate was 164 Mb (a little short).

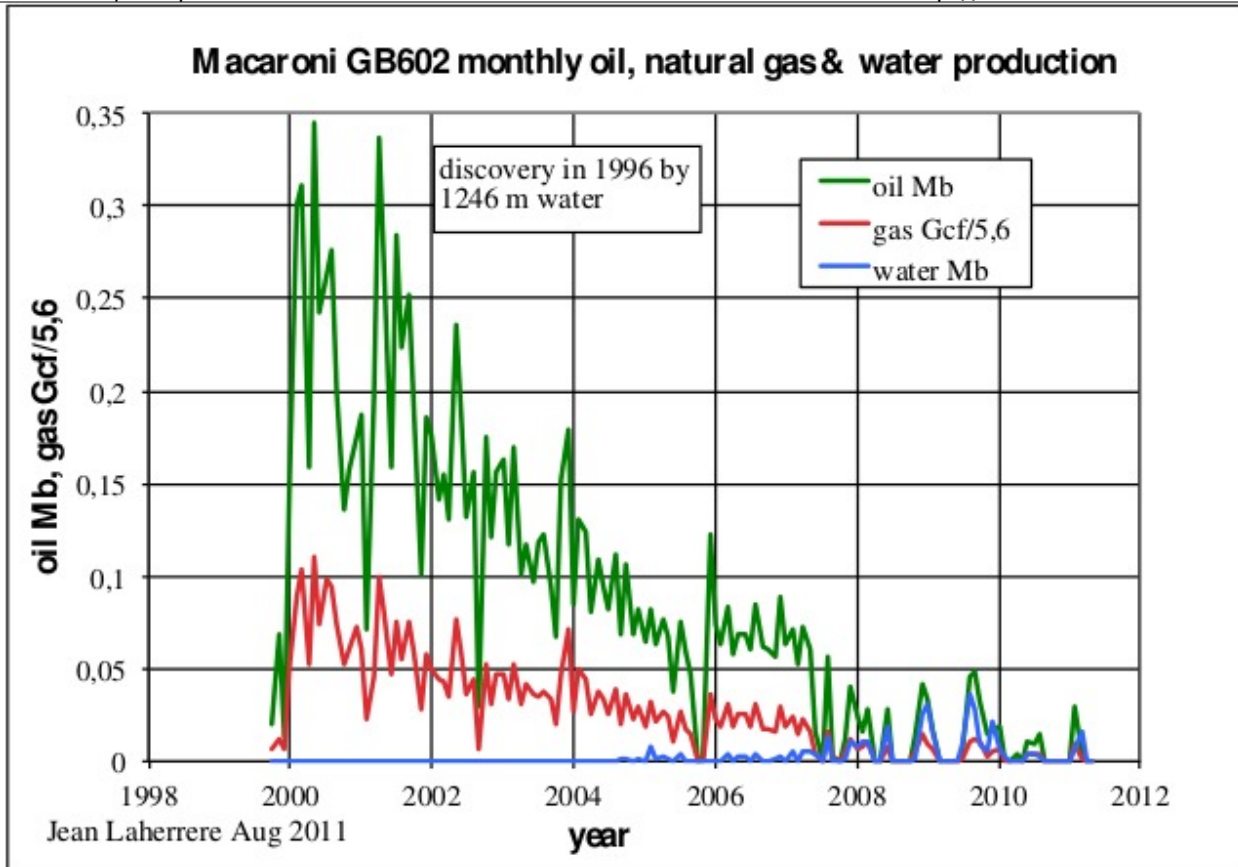
Figure 67: Troika oil decline and watercut.



Macaroni GB602

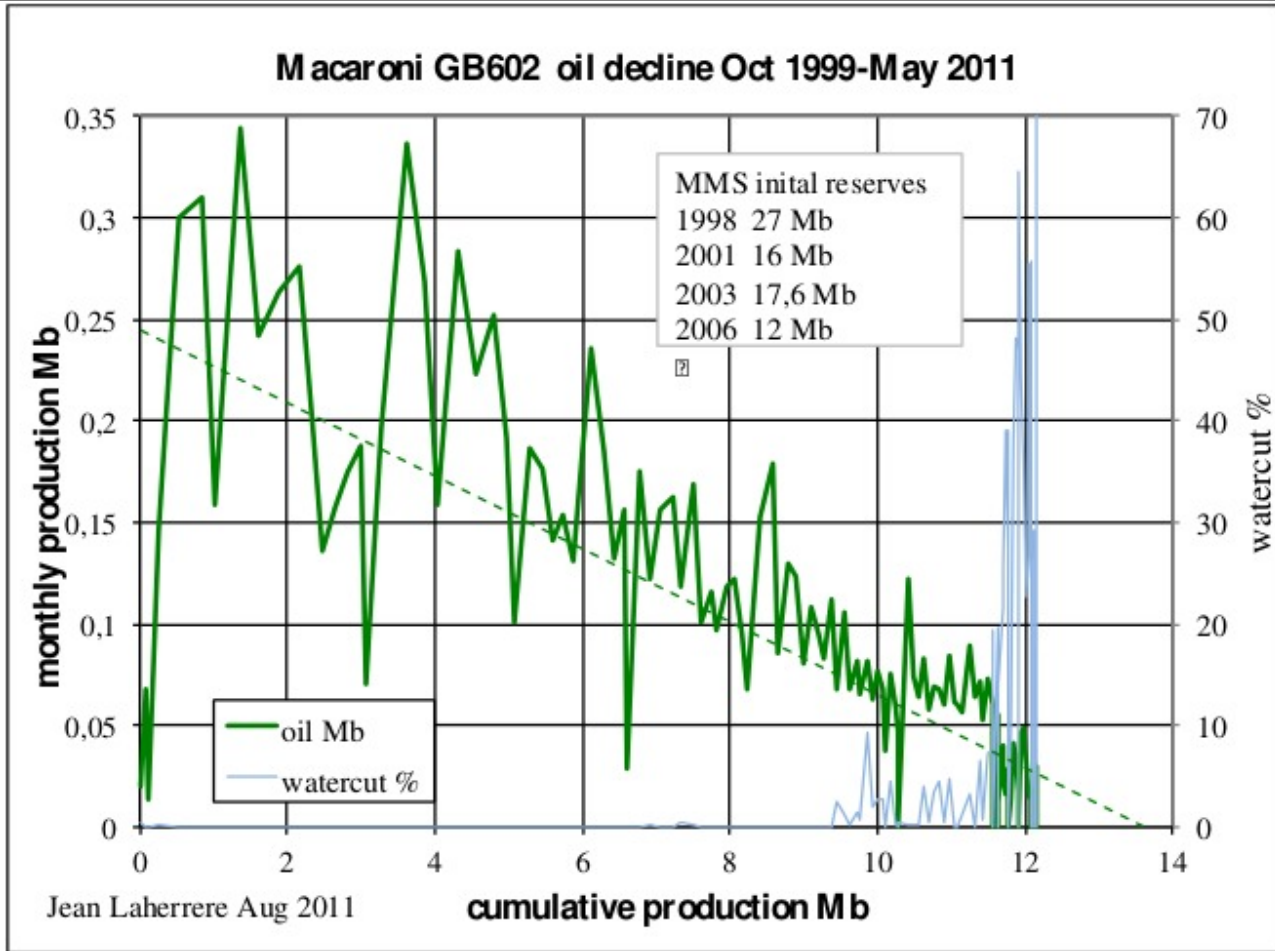
Macaroni was one of the first deepwater fields discovered by Shell, in 1996, under 1246 m of water in Pliocene sands. Oil production peaked quickly and declined sharply; since 2007 production has been sporadic and with high watercut.

Figure 68: Macaroni GB602 monthly production.



The end is near, with an ultimate of less than 13 Mb, compared to the estimate of 27 Mb in 1998 by the MMS.

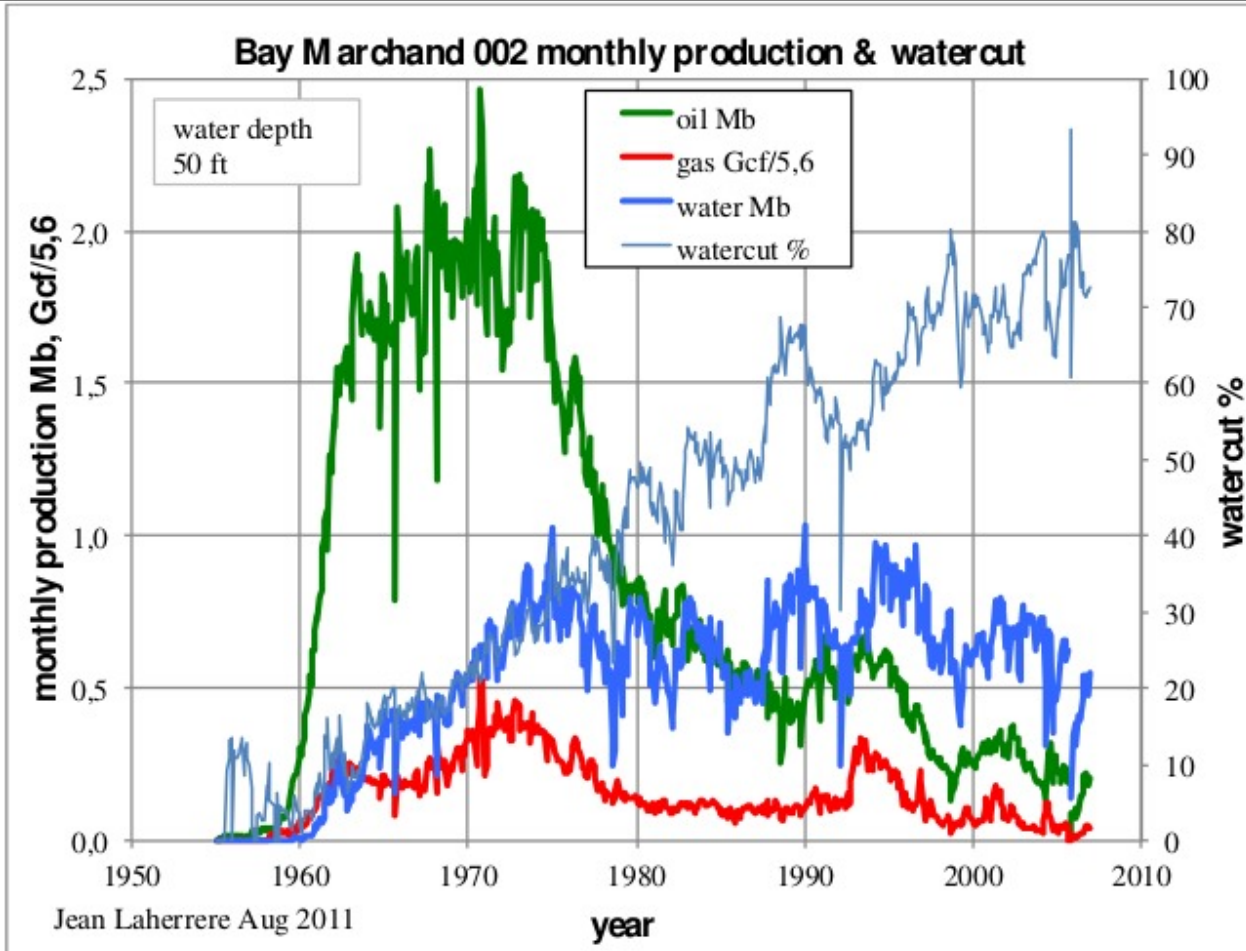
Figure 69: Macaroni GB602 oil decline.



Bay Marchand 002 (BM002)

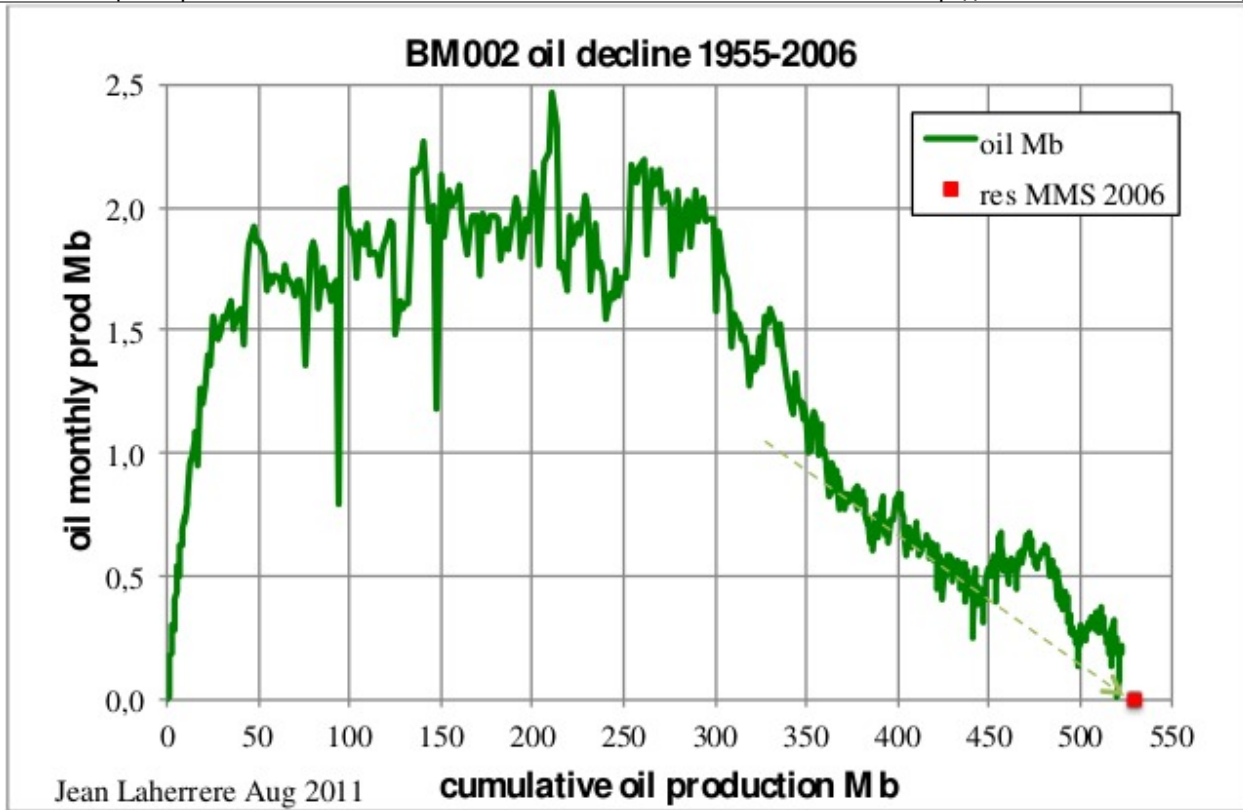
Bay Marchand 002 was found in 1949 in shallow waters; in 1970 the OGJ estimated reserves to be near 800 Mb, but today that outlook is down to 530 Mb. The production plateau was fairly long (10 years) and the decline fairly smooth and long, with a regular watercut increase, now close to 80%.

Figure 70: Bay Marchand 002 monthly production.



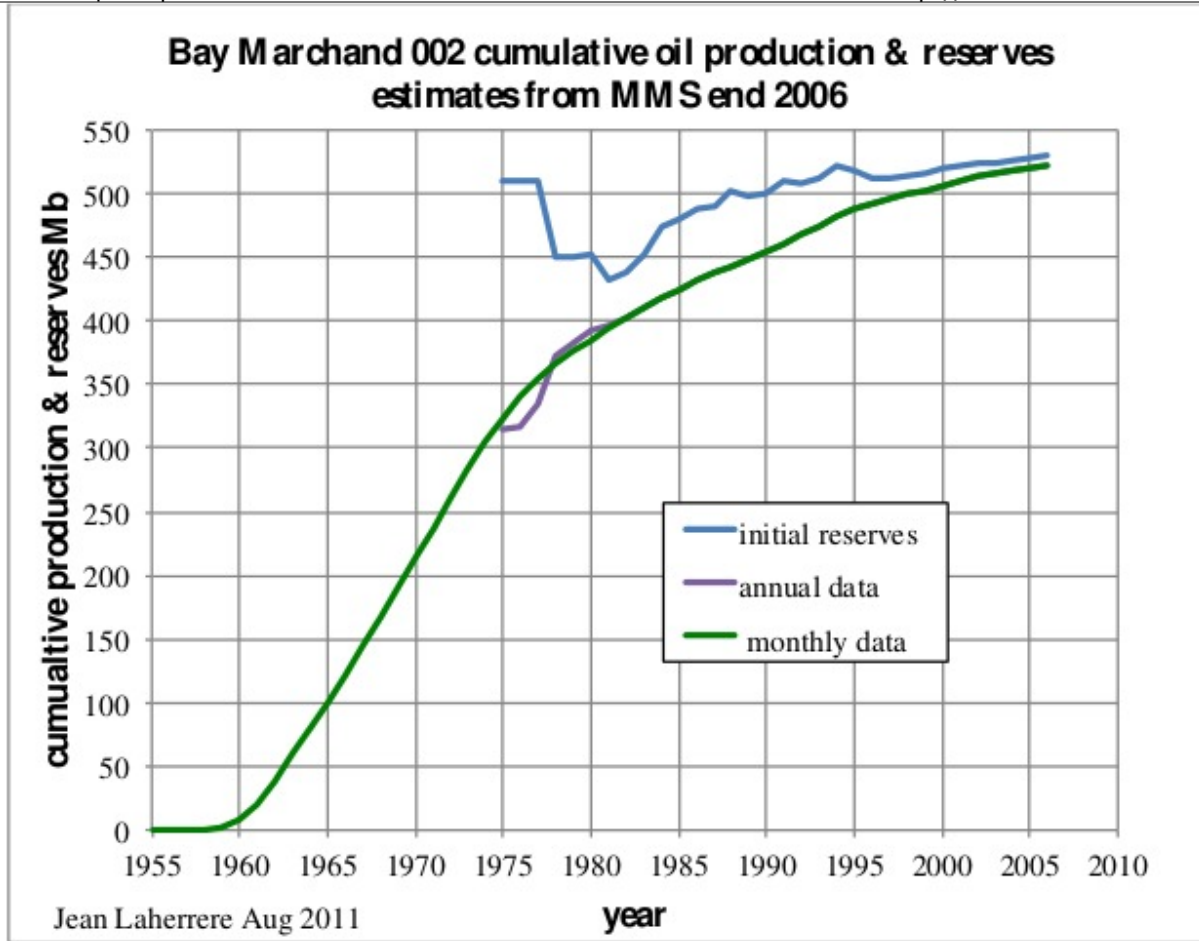
The oil decline since 1980 trends towards 530 Mb, which coincides the 2006 reserves estimate by the MMS.

Figure 71: Bay Marchand 002 oil decline.



Cumulative oil production is plotted next, from the MMS 2006 annual and monthly data. The initial MMS estimate was 510 Mb in 1975, it then declined to 430 Mb in 1982 and is now at 530 Mb, very close to cumulative production in 2011. The field seems to be close to total depletion.

Figure 72: Bay Marchand 002 cumulative oil production and 2006 reserve estimate by the MMS.

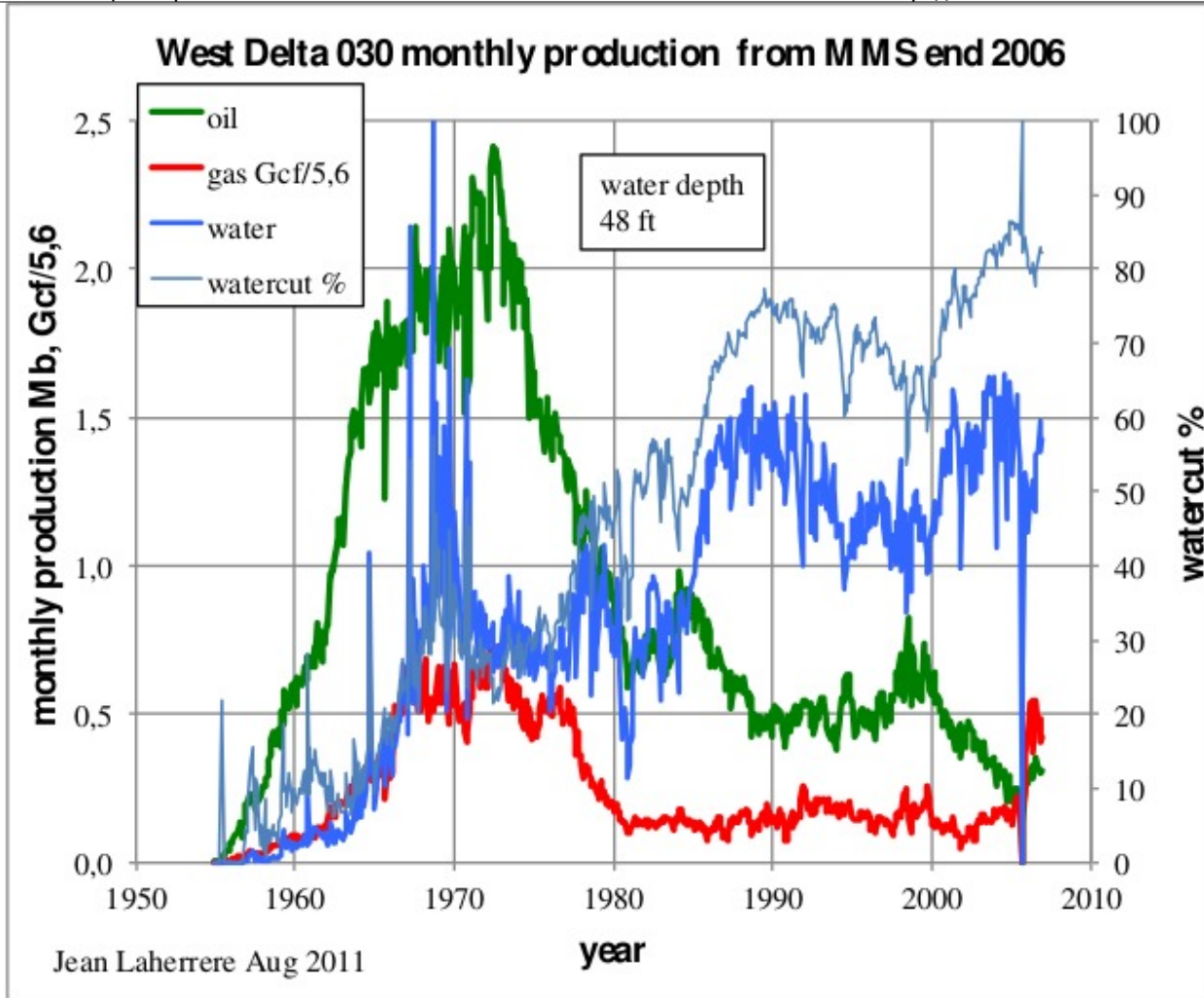


It is obvious that the annual data from 1975 to 1981 is wrong compared to the more harmonious monthly data.

West Delta 030 (WDo30)

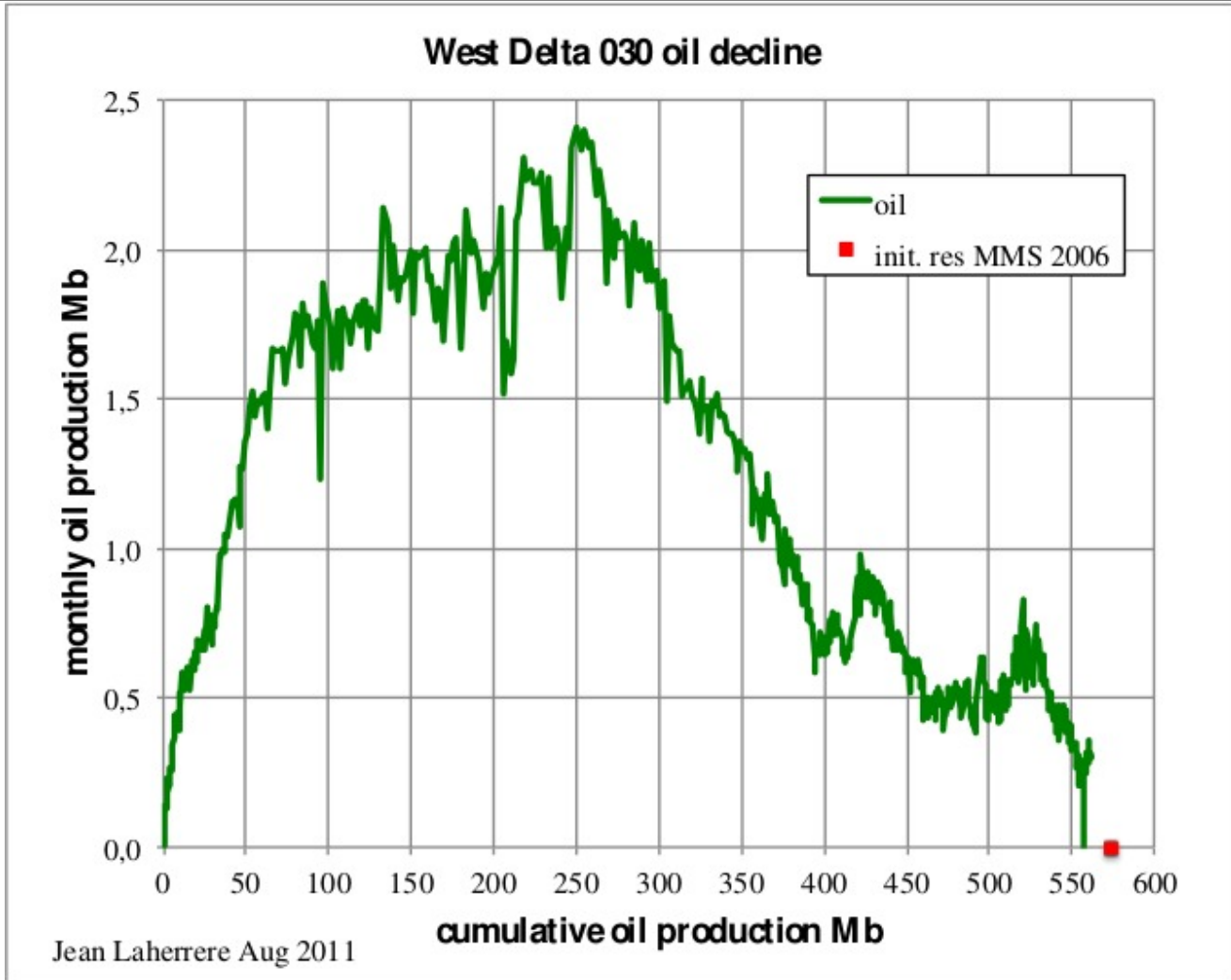
West Delta is a shallow water oil field found in 1949. It is similar to BM002, yielding the same type of decline profile, in spite of two minor increases when new drilling temporarily suspended the overall trend.

Figure 73: West Delta 030 monthly production.



Like BM002, WDO30 is close to the end of its life with an ultimate at 570 Mb.

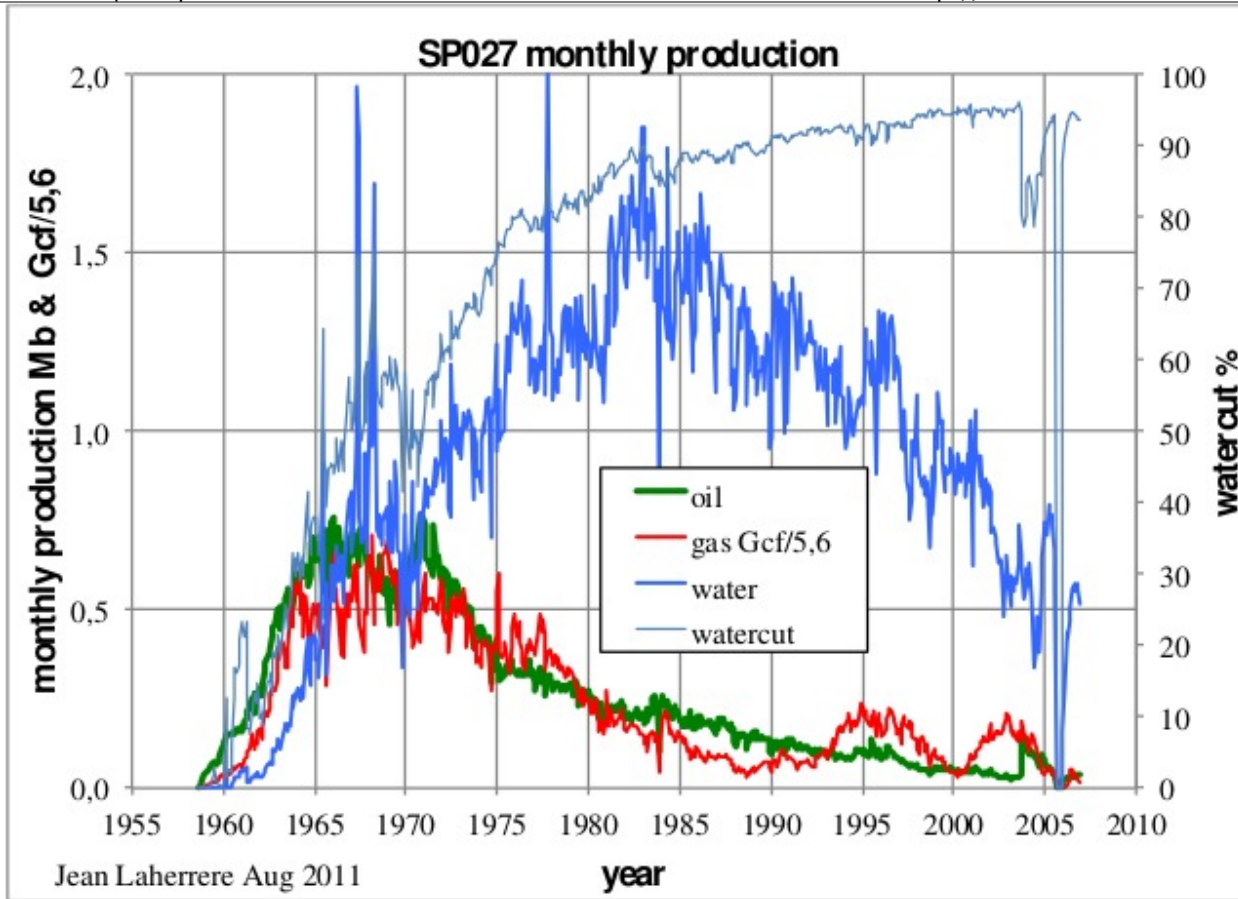
Figure 74: West Delta 030 oil decline.



South Pass 027 (SP027)

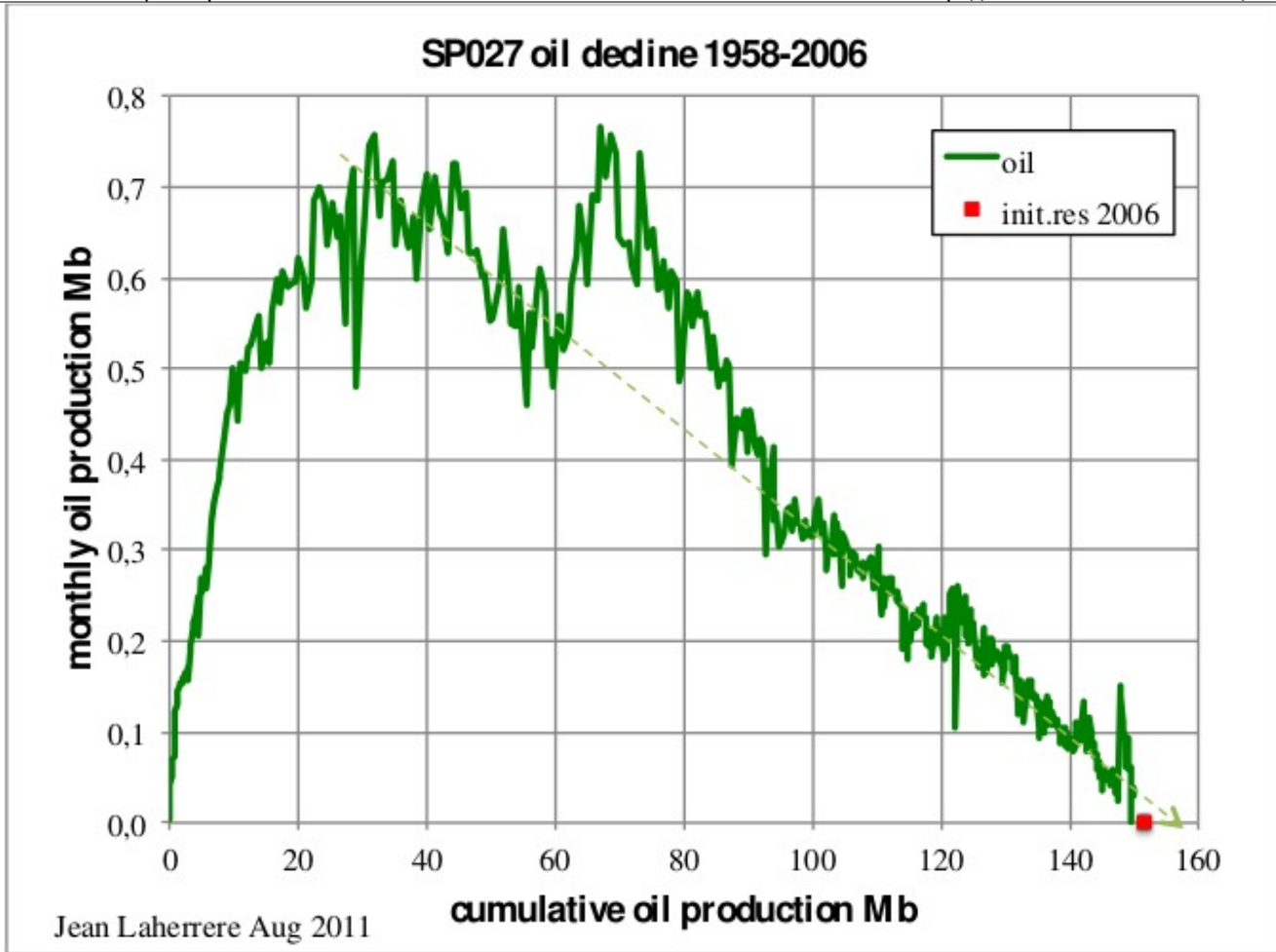
South Pass 027 was found in 1954, also in shallow water (64 ft deep), with reserves around 152 Mb. It yielded a bumpy plateau for less than decade and a half, during which watercut rose rapidly; afterwards a long and smooth decline ensued.

Figure 75: South Pass monthly production and watercut.



The oil decline segment from 1975 to 2006 is in line with the small decline period between 1966 and 1970, within the plateau.

Figure 76: South Pass oil decline.

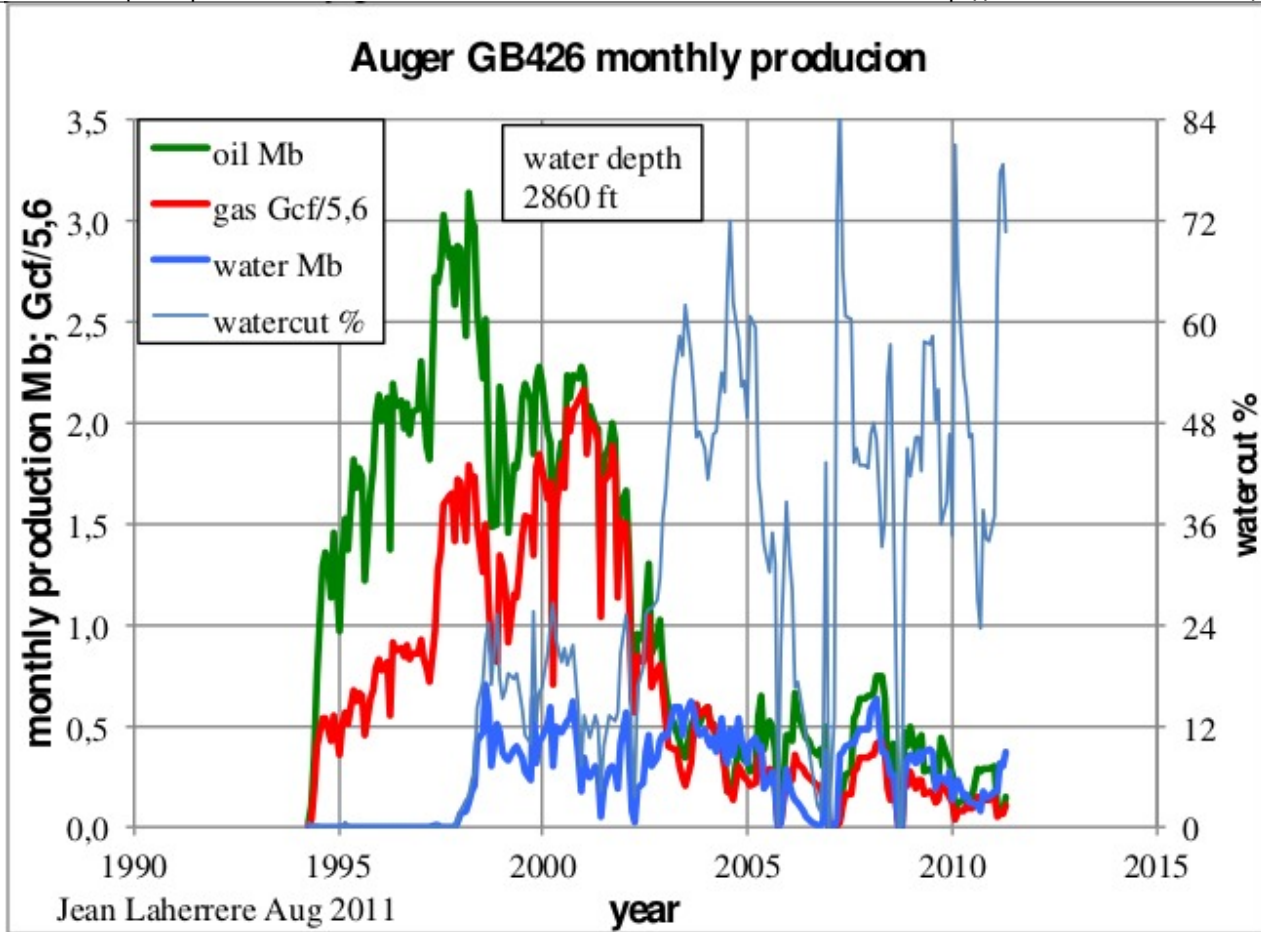


Looking at the 2006 data, SP027 seems close to the end, but the last barrels are still economical in 2011 with the platforms in place, after 53 years of production. On the BOEMRE 2011 OGOR report, SP027 covers 35 pages out of 1452 up to May of 2011; the data for this field totals 1031 lines, of which 851 are with zero production. During these 5 months, SP027 involved 2 operators, 7 leases and 198 wells, though only 31 of these were actually producing in May; the figures total 0.017 Mb for oil and 0.47 Mb for water, averaging 21 b/d per well in 817 days of production, with a watercut of 96%.

Auger GB426

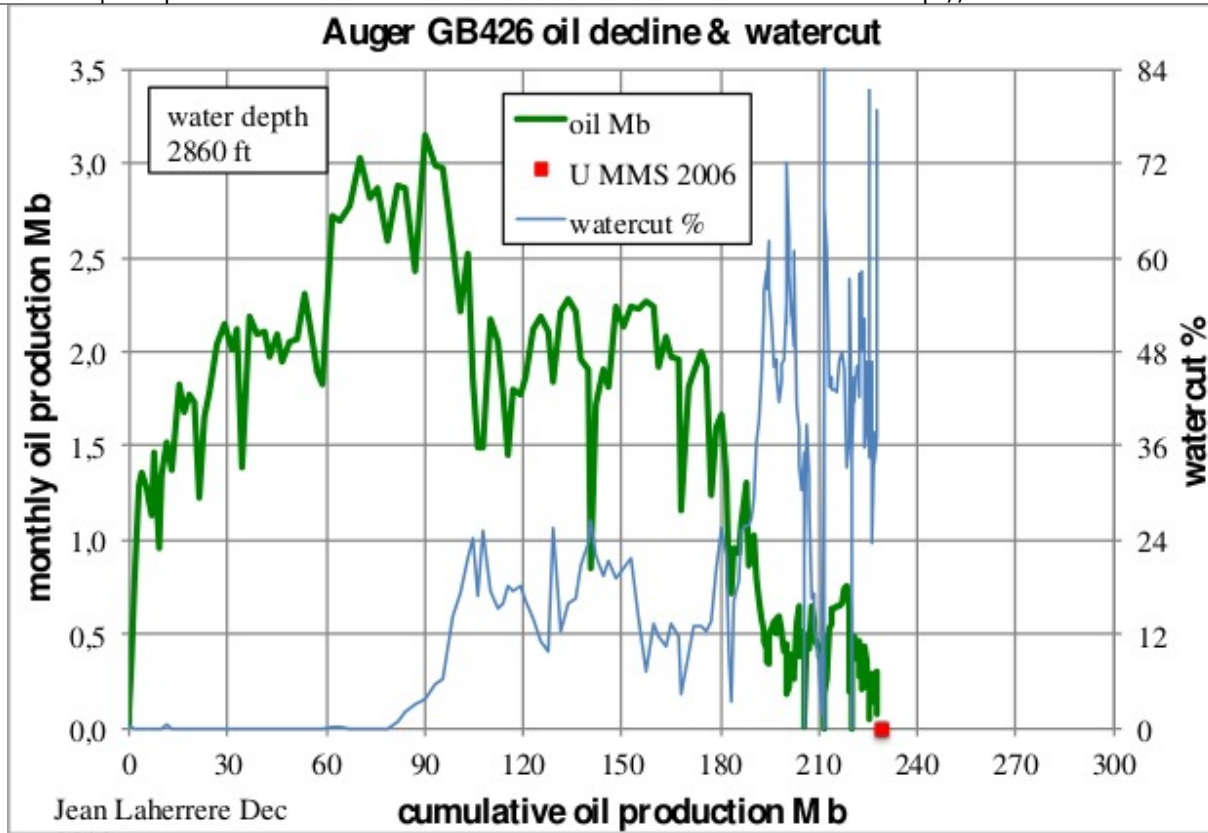
Auger was found in 1987 under 2860 ft of water; oil production peaked in 1997 with several steps taking place both during production rise as during the decline. Operated by Shell, Auger is produced through a Tension Leg Platform (TLP).

Figure 77: Auger GB426 monthly production and watercut.



Since 2002 the decline has become rather steep, about 2% per month.

Figure 78: Auger oil decline.

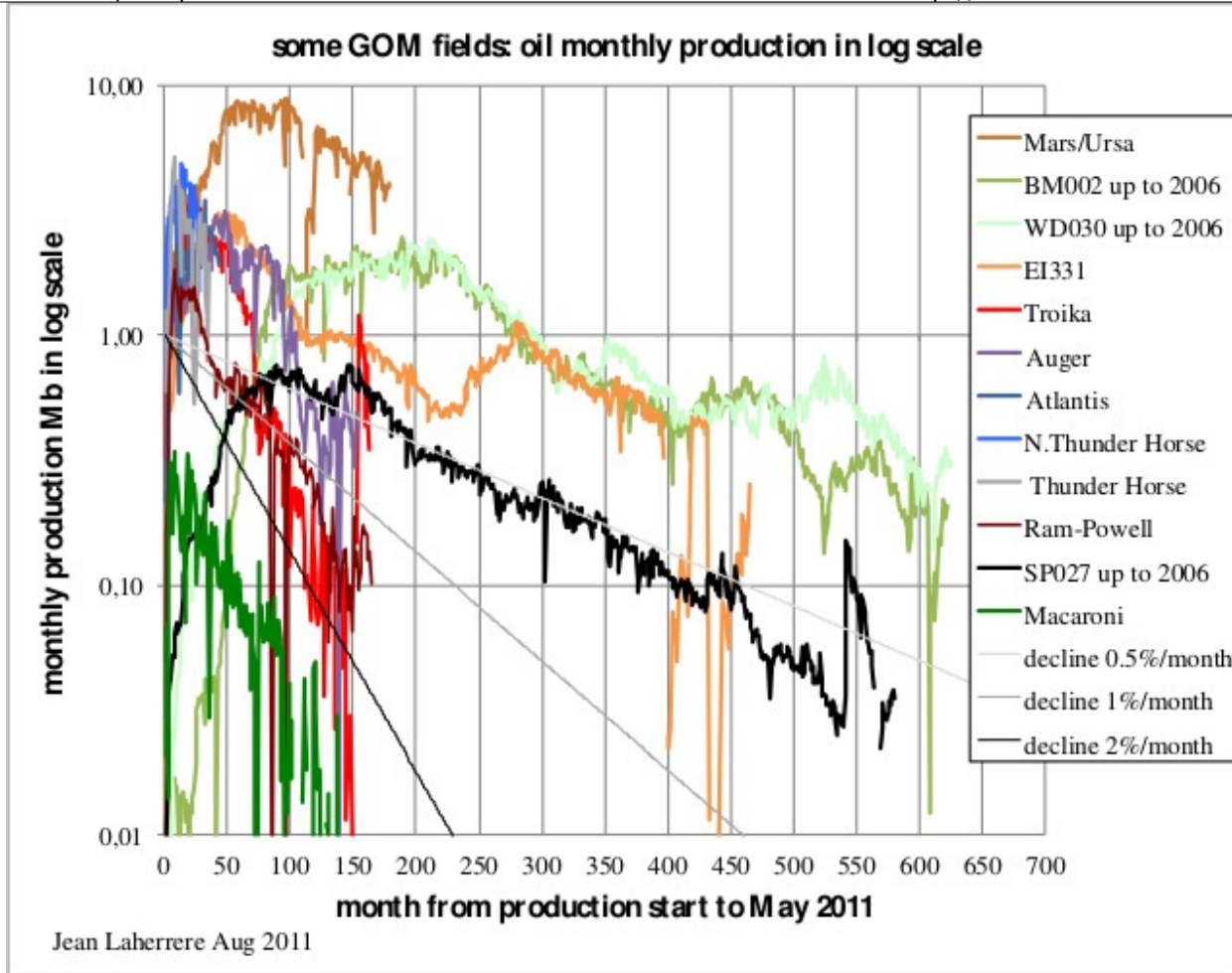


Present cumulative oil production is close to the 2006 reserves estimate by the MMS; with such a low monthly production, does it mean that the field is depleted? Maybe not for the TLP, which collects oil from several fields in the premises, like Llano and soon Cardamon. Shell has proposed last March to drill 3 exploratory wells on the same lease and got the approval by the BOEMRE; it is the first approval after the Macondo blow out.

Synthesis

The monthly oil production of the all the fields analysed in this series is plotted from production start in the following graph. In the graph are also included lines showing a monthly decline of 0.5%, 1% and 2% for comparison (corresponding to an annual decline of 6%, 11.5% and 21.5%).

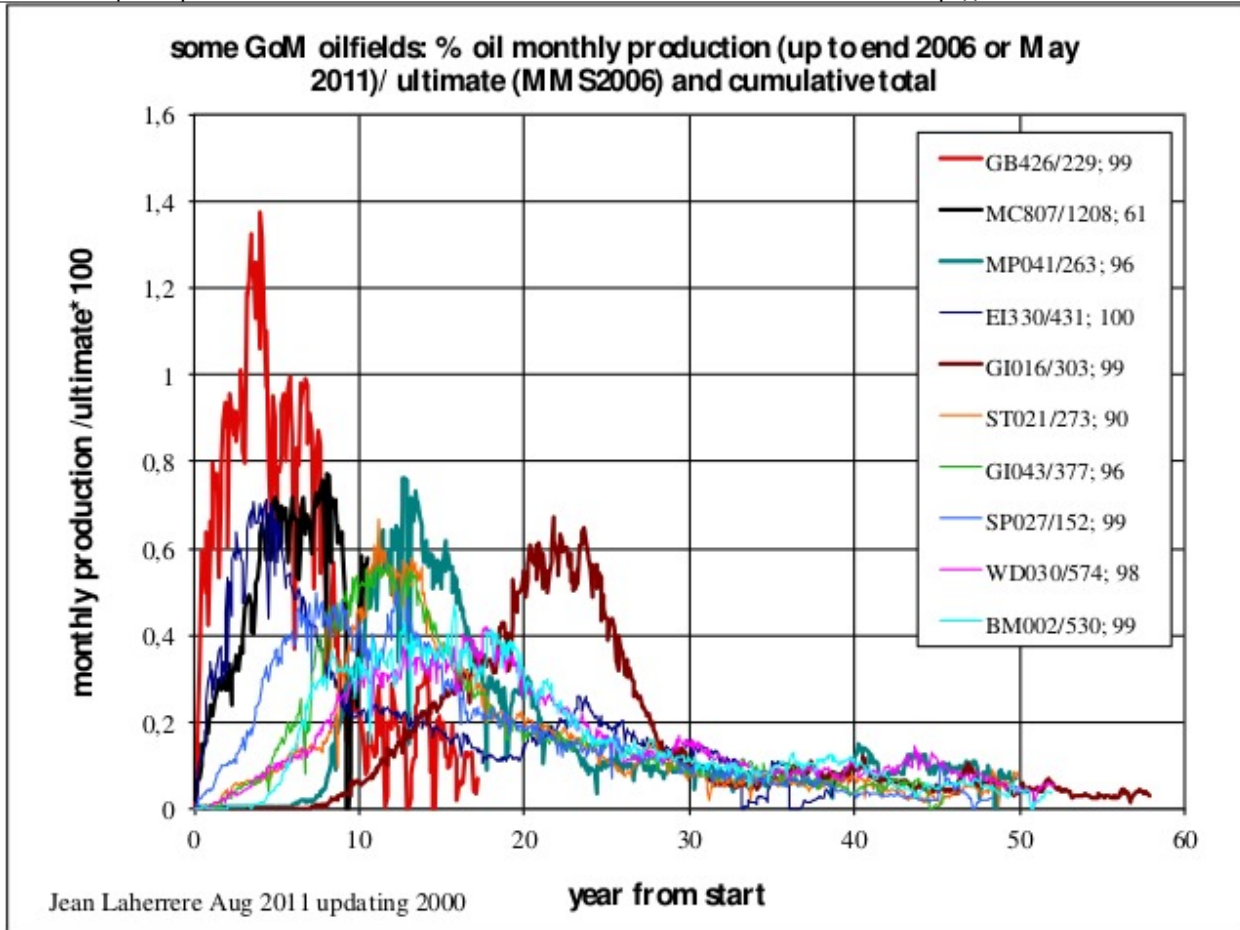
Figure 79: Monthly oil production in log scale for several GOM fields.



Shallow water fields like BM002, WD030 and SP027 present a long plateau of maximum output (around 100 months), starting at least 50 months after production start; for these fields monthly decline is slower, around 0.5%. In contrast, deepwater fields peak earlier and do not describe a plateau, usually going into decline shortly after, with higher monthly decline rates, around 1%.

In 2000 I plotted the monthly oil production of several GOM fields in percentage of their ultimate, meaning that the area below the curve should be the same for each field, being equal to 100 when the field is abandoned. Here I update that graph, where the cumulative addition at the end of the curve is given in the legend.

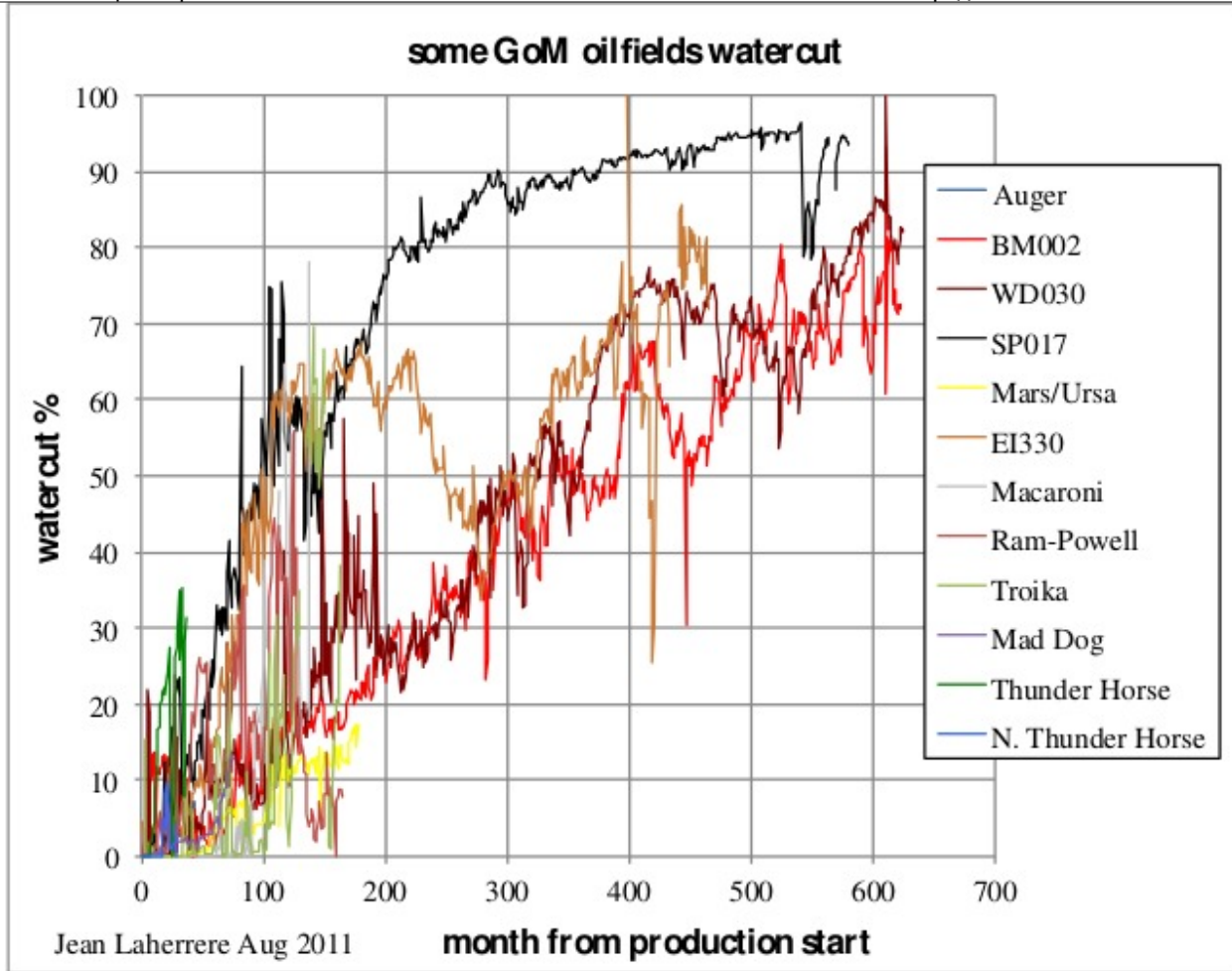
Figure 80: Percentage of monthly production of selected GOM fields (from production start up to end 2006 or May 2011) divided by its ultimate (Mb).



All these fields have produced more than 96% of their ultimate, except Mars/Ursa (MC807), presently at 61% of its ultimate. The peak of oil production occurs a few years after production start for deepwater fields and at a level below 1% of the ultimate per month; the exception is Auger (GB426). Shallow water fields typically display lower peaks, at about 0.6% (e.g. MPO41, GI016) but much later, at least ten years after production start (even 20 years for GI016).

The watercut of the GOM fields is variable depending upon the characteristics of the reservoir, especially the trap. Watercut is not a problem onshore, but from this analysis it is apparent that a watercut threshold dictates the economic viability of an offshore field; this threshold seems also different from deepwater to shallow water fields.

Figure 81: Watercut for selected GOM fields.

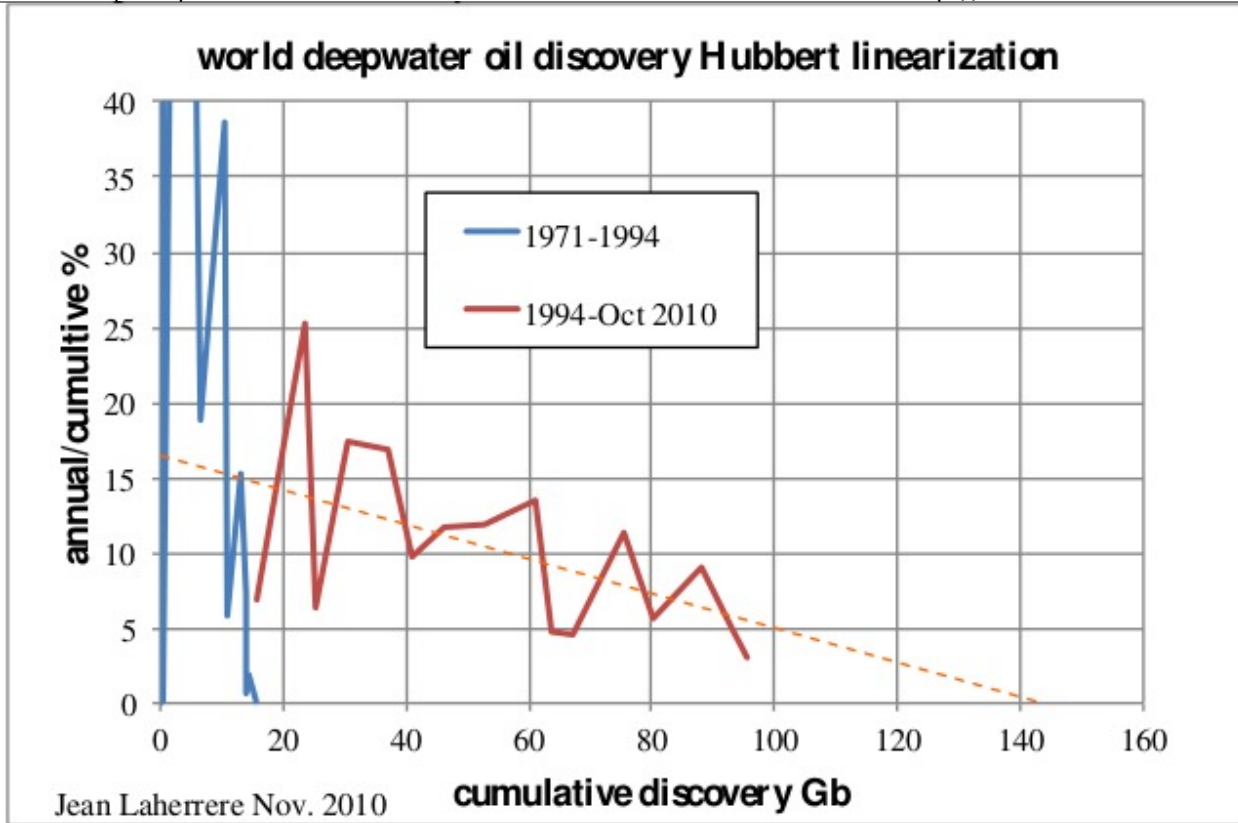


Conclusion

Forecasting future deepwater (over 500 m deep) oil production needs first an estimate of the ultimate, which can be done using the creaming curve of past discoveries, as shown in figure 3 (in [part 1](#) of this series). At this moment this plot trends towards 150 Gb, but it is necessary to check if the reported discoveries are well estimated and the best place to do so is the Gulf of Mexico, where all production data are freely available, though unfortunately not in the easiest way.

Most of shallow water fields are largely depleted and the estimates published by the end of 2006 are reliable when compared to the cumulative production trend. The average decline for these fields is about 0.5% per month or 6% per annum. Deepwater fields display an earlier peak and a sharper decline, about 2% per month or 22% per annum. Because of this sharp decline, Deepwater fields require more wells to be drilled, despite most of the drilling being planned beforehand in these very expensive platforms. The estimated reserves look fair, but the lack of data on future drilling from the operators (in particular BP) prevents a reliable extrapolation from past production. But it seems that past discoveries presented in figure 3 will not change much, and so neither the extrapolation; only a new cycle of discoveries can change this outlook. The Hubbert linearization (poorly reliable) trends towards 150 Gb.

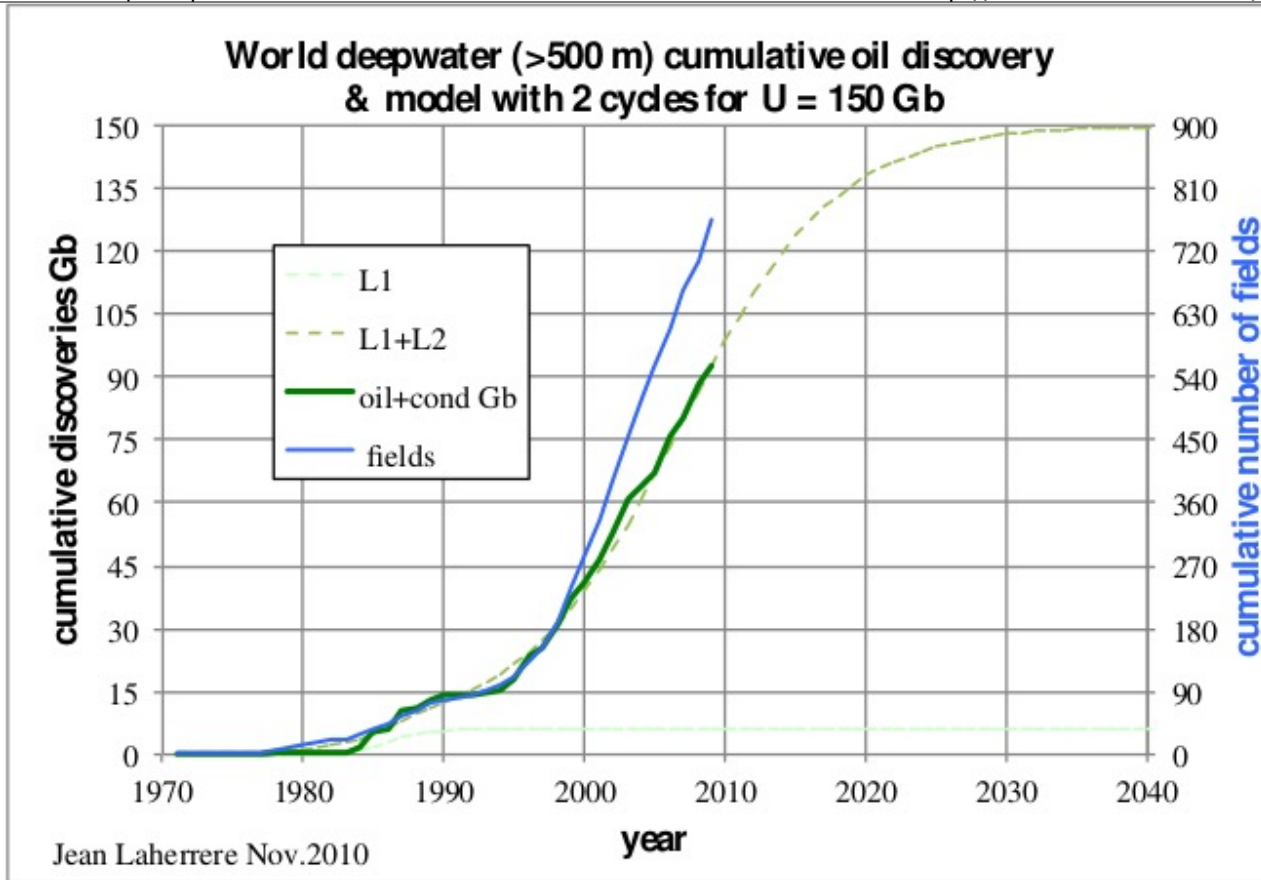
Figure 82: Hubbert linearization for world deepwater oil discovery.



Colin Campbell, using the same definition of deepwater (over 500 m deep), estimated the ultimate at 100 Gb in 2010.

The following graph presents world deepwater cumulative discoveries versus time and the extrapolation with a S curve towards 150 Gb.

Figure 83: world deepwater oil discovery & model two cycles for an ultimate of 150 Gb.

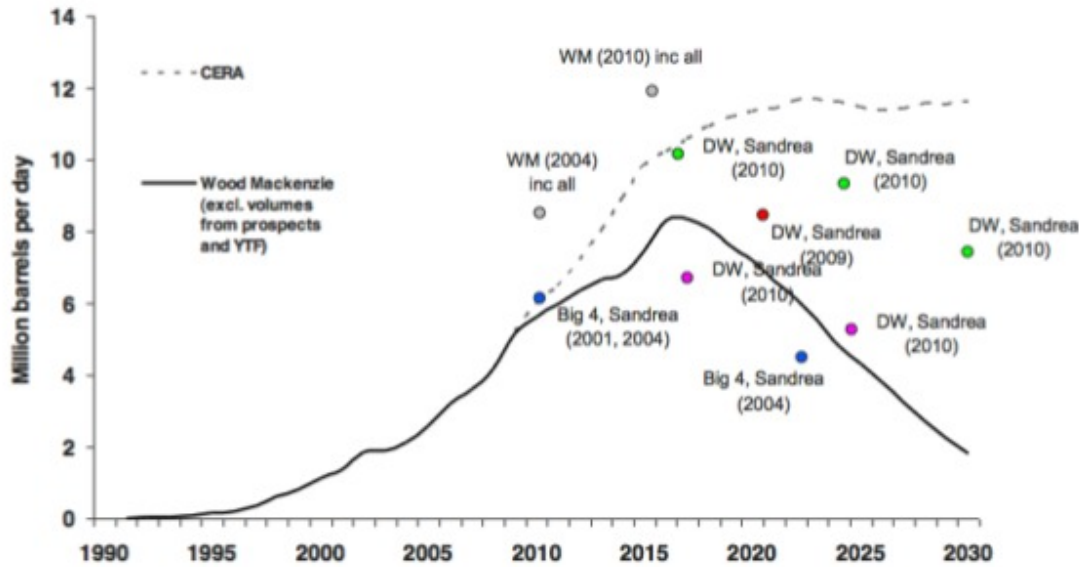


Forecasting the annual world deepwater oil production is difficult, first of all because past production is not easily available (with many different definitions of deepwater) and secondly, because the large subsalt fields of Brazil will likely be difficult to produce (high pressures and lack of aquifer drive) and very expensive. So far Petrobras seems to have handled the development fairly well, though having a quasi-monopoly is not good.

I.Sandrea, Vice-President of Statoil, in a presentation to the IEF in 2010 entitled "[Potential Consequences of the Gulf Oil Spill on Future Offshore/Deepwater Oil Developments](#)", showed the forecasts from Wood Mackenzie (WM) and CERA for Deepwater. Taking into account only present projects, WM forecasts a peak around 2017 at over 8 Mb/d and a steep decline down to 2 Mb/d in 2030. This contrasts with the forecast by CERA, which goes up to a 12 Mb/d plateau from 2020 to 2030.

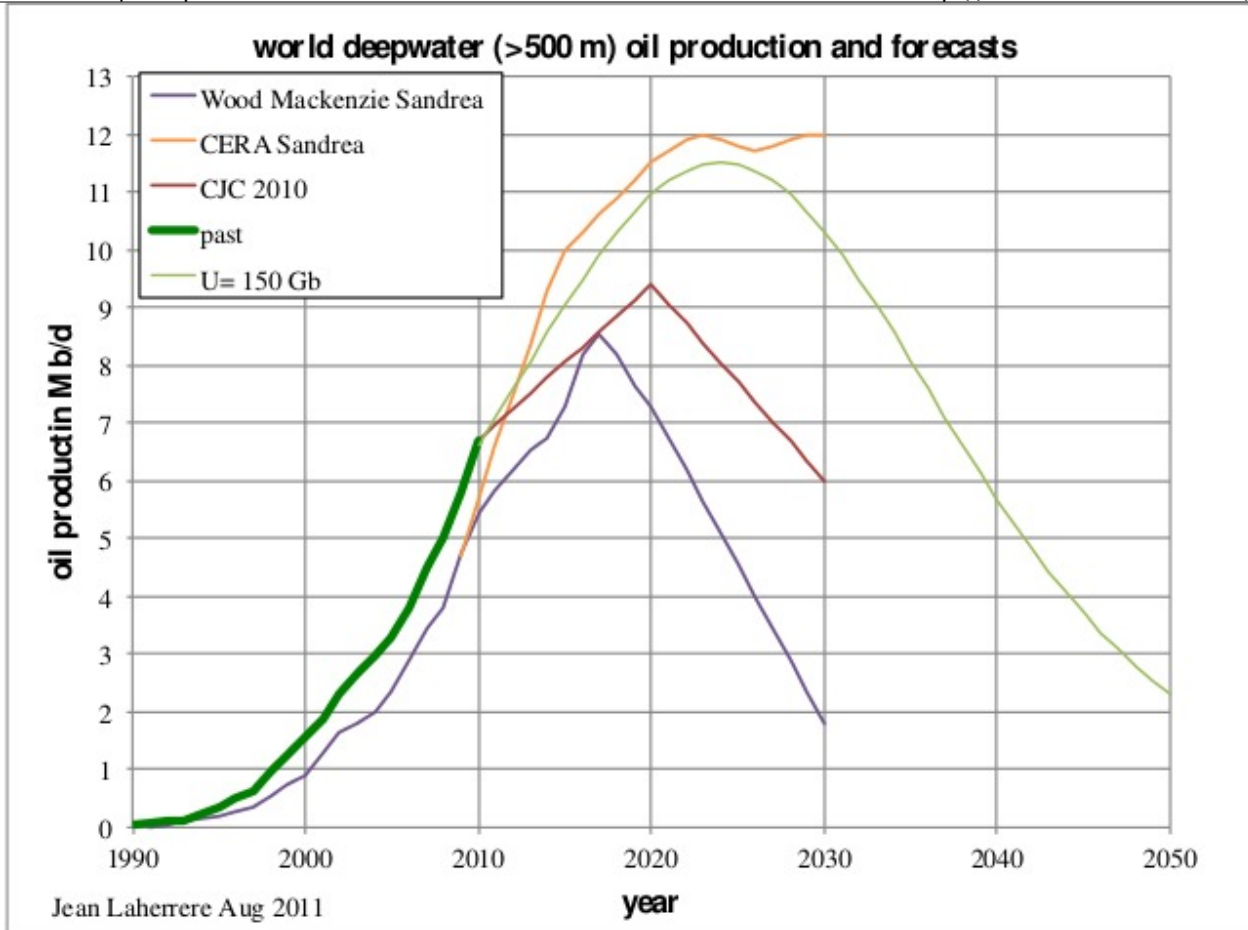
Figure 84: World deepwater oil supply outlook from I.Sandrea (EIF 2010).

World deepwater supply outlook



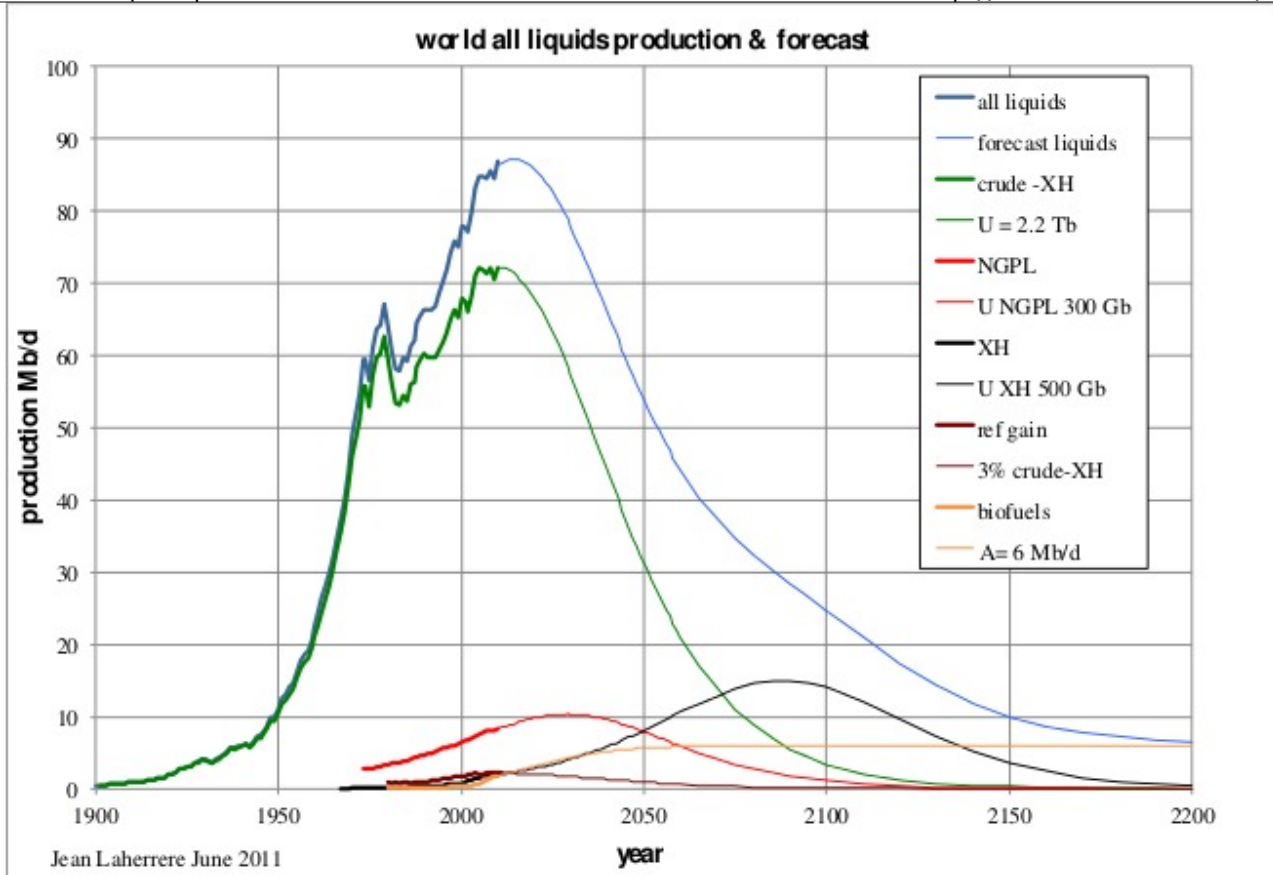
Assuming deepwater production at about 6.7 Mb/d in 2010 and using the ultimate of 150 Gb the model produces a peak at 11.5 Mb/d around 2024, declining to 2 Mb/d by 2050. This forecast with 150 Gb is close to the CERA forecast, higher than WM (limited to present projects) and also higher than Campbell's (U = 100 Gb).

Figure 85: World deepwater oil production and forecast for an ultimate of 150 Gb, compared with the forecasts by CERA and WM.



This deepwater forecast is in fact already included in my forecast of crude oil excluding extra-heavy presented in Figure 1, with an ultimate of 2200 Gb. Thus my forecast for future all liquids production remains unchanged after this study.

Figure 86: World all liquids production (matching the definition of oil supply by the EIA).

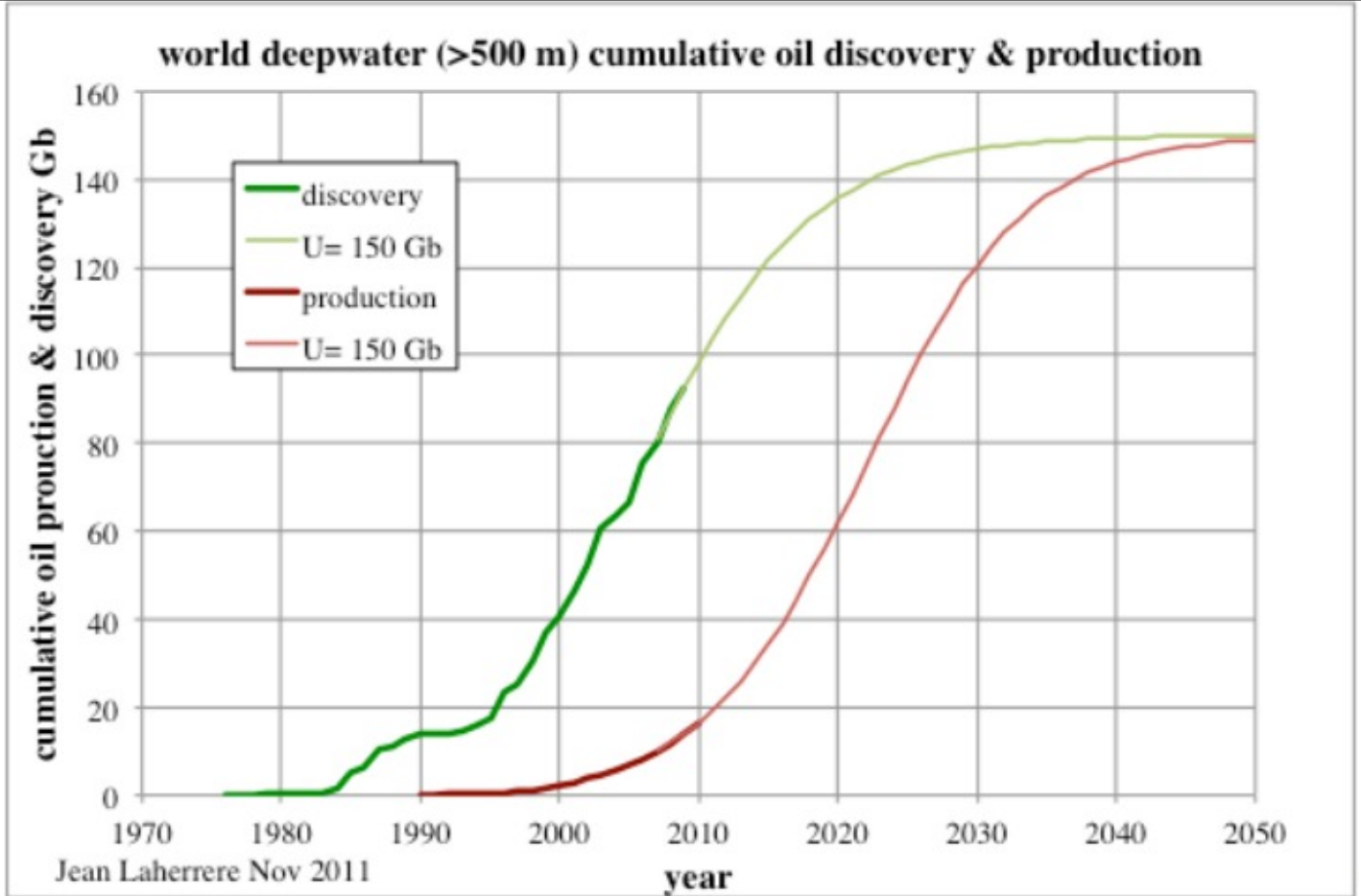


All liquids production has been describing a bumpy plateau since 2005 around 87 Mb/d, with a variation of 2 Mb/d (which is equal to the accuracy of the data, about the difference between EIA, IEA or OPEC values). This plateau will continue for a few years before a significant decline takes place. Nevertheless, the ongoing economical and financial crisis can disturb this bumpy plateau.

Addendum

At the request of [Paul Nash](#), Jean sent yet one more graph with the Cumulative curves for the World Deepwater. As usual these graphs speak for themselves.

Figure 87: World Deepwater Cumulative Discovery and Production.



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