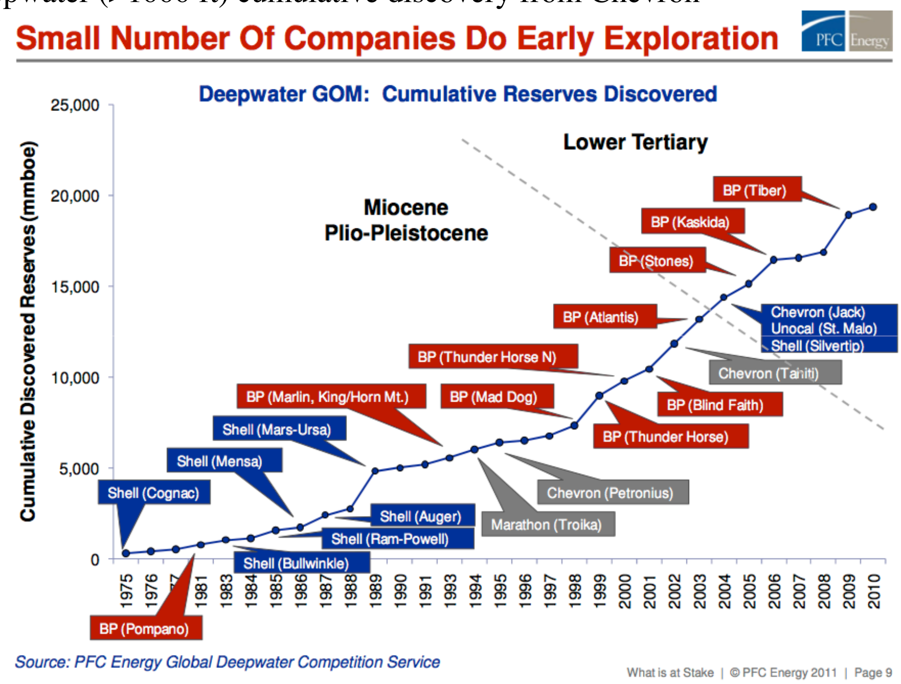
Deepwater GOM: reserves versus production
Part 2: Atlantis, Mad Dog & others (deep and shallow)

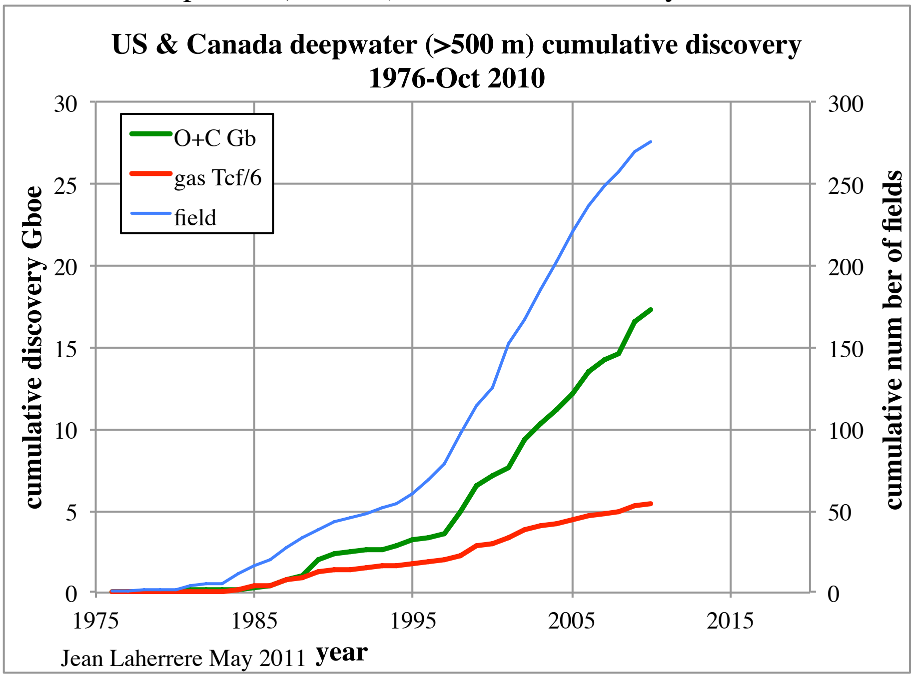
In the deepwater GOM, BP (in red) has the highest number of major discoveries as shown in this graph from PFC (R.West 2011), with in particular Atlantis and Mad Dog. Shell (in blue) is the second discoverer by number. The cumulative oil & gas discovery displays a typical S curve, but where is the asymptote?

Figure 29: Deepwater (>1000 ft) cumulative discovery from Chevron



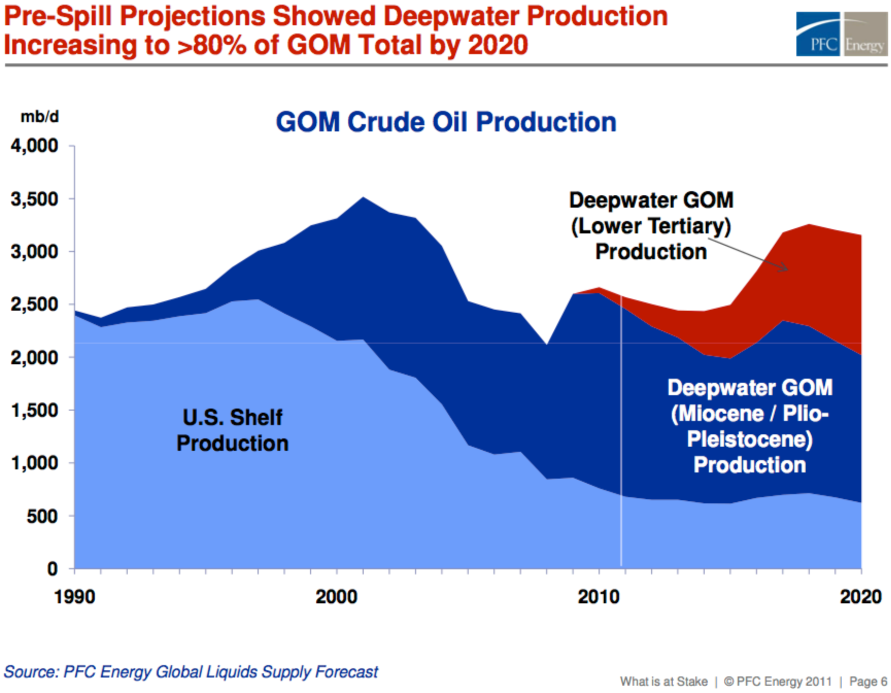
The cumulative deepwater (>500 m) discovery for US & Canada at fall 2010 was 18 Gb for oil and 30 Tcf for gas.

Figure 30: US & Canada deepwater (>500 m) cumulative discovery

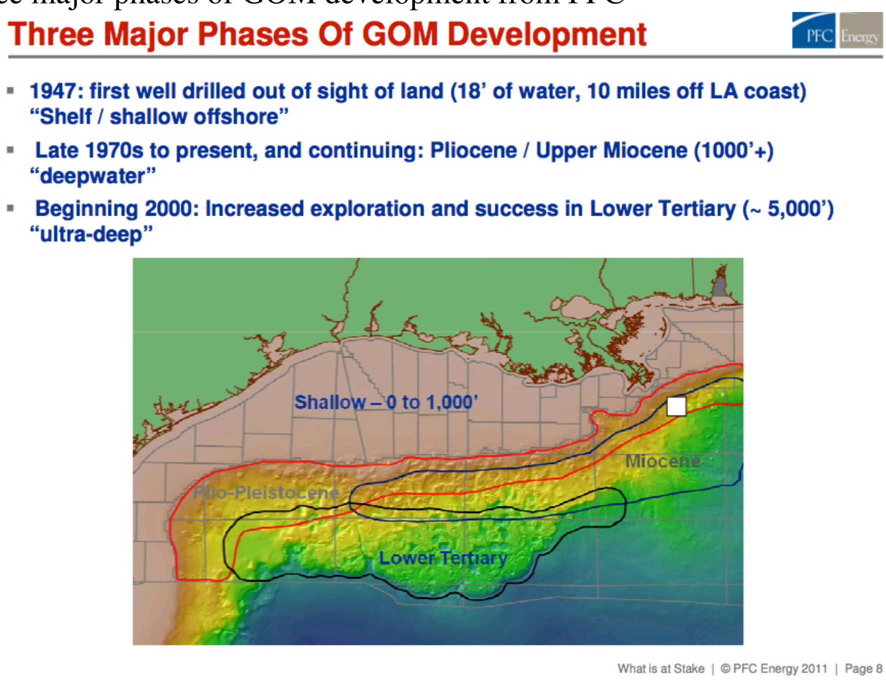


PFC forecasts a GOM production with a new peak in 2018 due to Lower Tertiary

Figure 31: GOM crude oil production 1990-2020 from PFC



The following map shows the three phases of GOM exploration :
-1947: shelf-shallow offshore
-late 1990s Pliocene/Upper Miocene deepwater >1000 ft
-beginning 2000: Lower Tertiary ultra deep >5000 ft
Figure 32: Three major phases of GOM development from PFC



The deepwater reserves (EUR) & oil-in-place (OIP) are reported by Joseph Lach Vice President, Reservoir Management "knowledge reservoir" "Final Report to IOR for Deepwater Gulf of Mexico" December 15, 2010 http://www.rpsea.org/attachments/contentmanagers/2730/07121-1701-Final_Report-12-15-10_p.pdf
Figure 33a: Mature fields (1979-1999) deepwater EUR and OOIP from Lach

RPSEA Project 1701 – IOR in Deepwater Gulf of Mexico

Table 9: Mature oil fields (1979 – 1999) with OOIP and forecast EUR and ROIP

Field	First Production Year	Number of Significant Reservoirs	OOIP (MMSTB)	RF	Oil EUR (MMSTB)	Gas EUR (BSCF)	Well Count[1]	Total EUR (MMBOE)	Recovery/ Well[2]	Remaining (MMBOE)
Cognac	1979	5	395	16.8%	66	557	46	162	4	2
Lena	1988	6	212	20.7%	44	212	43	80	2	2
Bullwinkle	1989	5	340	39.1%	133	170	19	162	9	26
Jolliet	1989	11	265	13.7%	36	136	20	60	3	4
Amberjack	1991	6	264	28.6%	75	70	38	88	2	8
Pompano	1994	6	448	32.0%	143	251	39	186	5	21
Auger	1994	5	288	47.9%	138	324	20	194	10	0
Prince	1994	0	49	18.1%	9	9	5	10	2	3
Cooper	1995	7	183	1.0%	2	5	4	3	1	0
Mars	1996	16	3391	29.8%	1011	1096	23	1200	52	584
Ursa	1996	3	1326	29.8%	395	634	11	504	46	154
Llano	1996	6	360	8.6%	31	73	2	44	22	5
Manatee	1996	2	47	27.7%	13	9	2	15	7	4
Rocky	1996	0	10	45.3%	5	7	1	6	6	0
Ram-Powell	1997	4	404	32.7%	132	966	17	299	18	82
Troika	1997	2	292	56.2%	164	326	7	220	31	3
Neptune	1997	4	137	42.5%	58	107	17	77	5	5
Salsa	1998	6	196	32.0%	63	254	5	106	21	16
Baldpate	1998	5	189	49.7%	94	244	9	136	15	14
Morpeth	1998	3	110	35.3%	39	36	4	45	11	17
Arnold	1998	2	71	27.6%	20	17	3	23	8	1
Genesis	1999	10	437	30.9%	135	186	15	167	11	42
Macaroni	1999	7	181	8.3%	15	28	3	20	7	4
Manta Ray	1999	4	120	19.5%	23	18	2	27	13	22
Allegheny	1999	4	110	40.2%	44	81	4	58	15	8
Angus	1999	1	68	56.5%	38	57	3	48	16	3

Notes:

1. Oil and gas producers are counted.
2. Total EUR is applied for calculation.
3. There are three wells counted in Mars which have been converted to injectors.

Figure 33b: new oil fields (2000-2009) EUR from Lach

RPSEA Project 1701 – IOR in Deepwater Gulf of Mexico

Table 10: New oil fields (2000 – 2009) with OOIP and forecast EUR and ROIP

Field	First Production Year	Number of Significant Reservoirs	OOIP (MMSTB)	RF	Oil EUR (MMSTB)	Gas EUR (BSCF)	Well Count	Total EUR (MMBOE)	Recovery/ Well	Remaining (MMBOE)
Europa	2000	6	305	29.3%	89	126	7	111	16	53
Petronius	2000	3	233	57.2%	133	192	15	166	11	23
Hoover	2000	1	141	45.4%	64	76	6	77	13	10
King764	2000	2	50	24.7%	12	15	1	15	15	3
Black Widow	2000	1	21	52.5%	11	10	1	13	13	1
Brutus	2001	6	369	38.0%	140	188	8	173	22	69
Crosby	2001	6	197	19.1%	38	50	3	46	15	2
Oregano	2001	2	58	39.8%	23	35	3	29	10	5
J.Bellis	2001	2	40	15.4%	6	5	4	7	2	0
Typhoon	2001	2	68	40.2%	27	38	4	34	9	0
Ladybug	2001	2	32	32.1%	10	11	2	12	6	2
Marshall	2001	1	24	34.4%	8	7	2	9	5	2
Horn Mountain	2002	2	320	34.7%	111	103	8	129	16	36
Nansen	2002	4	152	45.8%	70	416	12	141	12	29
Aspen	2002	6	150	19.3%	29	29	4	34	8	2
King	2002	2	135	54.2%	73	100	3	90	30	15
Boomvang North	2002	2	72	48.6%	35	50	5	44	9	4
Hack Wilson	2002	1	35	29.7%	10	14	1	13	13	4
Drysdale	2002	1	30	26.7%	8	11	2	10	5	6
Lou Gerhig	2002	1	30	26.5%	8	8	1	9	9	2
Madison	2002	1	26	38.1%	10	7	1	11	11	0
Medusa	2003	6	370	12.2%	45	48	8	53	7	12
Princess	2003	2	295	26.6%	79	130	3	101	34	52
Gunnison	2003	5	137	17.7%	24	177	13	55	4	7
Matterhorn	2003	3	77	16.8%	13	22	7	17	2	0
Habanero	2003	2	75	23.5%	18	32	2	23	12	1
Herschel	2003	2	75	24.2%	18	22	1	22	22	10
Boris	2003	2	42	28.1%	12	19	2	15	8	0
Zia	2003	1	30	23.3%	7	5	1	8	8	2
Holstein	2004	8	526	45.1%	237	243	13	279	21	229
Front Runner	2004	9	385	8.6%	33	33	5	39	8	18
Kepler	2004	2	184	71.7%	132	149	2	158	79	81
Magnolia	2004	3	162	18.7%	30	96	8	47	6	17
Devils Tower	2004	3	110	28.8%	32	30	9	37	4	7
Ariel	2004	5	94	64.9%	61	82	3	75	25	35
Triton	2004	2	85	25.9%	22	15	2	25	12	7
Glider	2004	2	50	23.6%	12	9	2	13	7	5
Marco Polo	2004	1	31	31.9%	10	13	6	12	2	2
Dawson	2004	1	15	10.0%	2	4	1	2	2	1
Mad Dog	2005	2	937	27.2%	255	139	8	279	35	229
K2	2005	3	450	16.4%	74	59	3	84	28	55
Swordfish	2005	1	50	39.0%	20	73	1	32	32	13
Lorien	2005	1	36	30.6%	11	11	2	13	6	3
Constitution	2006	6	275	11.1%	31	46	6	39	6	23
Gomez	2006	1	49	36.9%	18	57	3	28	9	13
Ticonderoga	2006	2	35	24.8%	9	8	3	10	3	1
Sw Horseshoe	2006	1	20	11.9%	2	3	1	3	3	1
Shenzi	2007	3	2006	15.0%	300	120	10	321	32	305
Atlantis	2007	5	1385	40.3%	558	361	8	620	78	603
Neptune (At)	2007	2	535	23.4%	125	25	6	129	22	128
Deimos	2007	7	428	30.0%	128	105	3	147	49	138
Cottonwood	2007	1	15	64.1%	10	43	2	17	9	14
Thunder Horse	2008	8	1895	34.5%	653	518	9	742	82	741
Blind Faith	2008	5	610	11.5%	70	50	4	79	20	79
Power Play	2008	1	10	3.9%	0	4	1	1	1	0
Tahiti	2009	4	1384	28.9%	400	160	5	428	86	428

Note:

1. Some fields are will drill new wells in the future, such as Thunder Horse and Atlantis. The values of recovery/well are current approximations.

The three significant digits on recovery factor make me wondering about the understanding of the author on the accuracy of such estimate! OIPs are uncertain, even at the end of the field, and the accuracy of RF is about 10%, meaning that only the first digit can be considered as reliable: it is why RF are often reported as rounded (30%) or as fraction (one third).

The 45 largest developed fields in deepwater GOM are reported in this graph, showing the ultimate with remaining: Mars, Thunder Horse, Shenzi, Atlantis, Ursa, Tahiti, Mad Dog,
Figure 34: GOM deepwater: 45 largest oilfields from Lach

RPSEA Project 1701 – IOR in Deepwater Gulf of Mexico

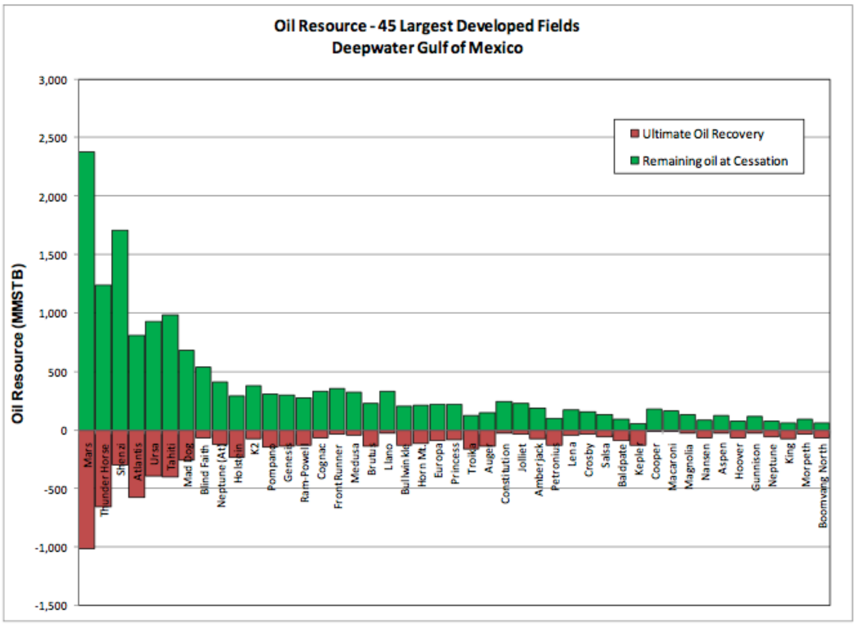
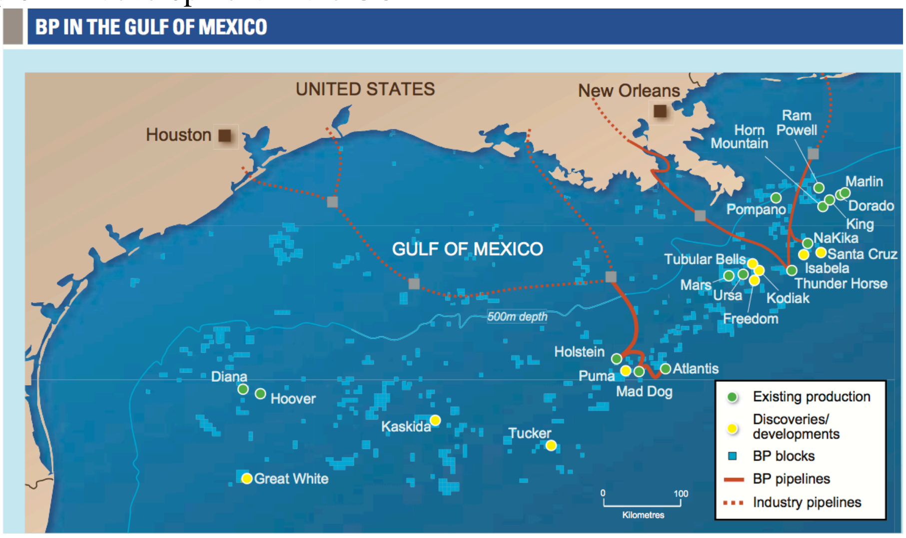


Figure 43: Forecast ROIP at cessation of production for 45 largest developed Neogene fields

After Thunder Horse and Mars/Ursa, let's study other large fields, next with Atlantis operated by BP as shown in the next map

Figure 35: map of BP development in the GOM

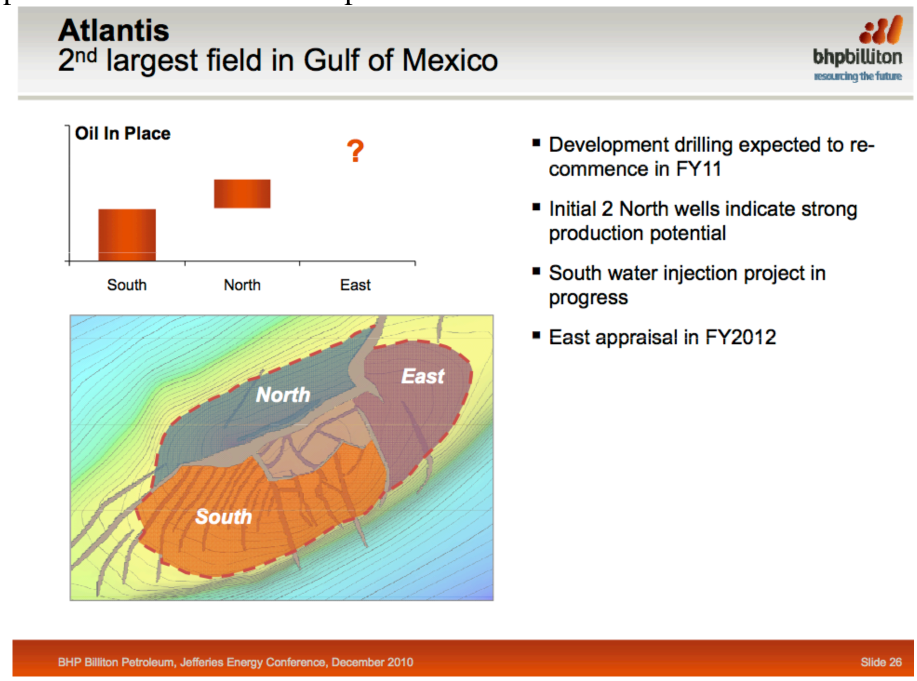


-Atlantis

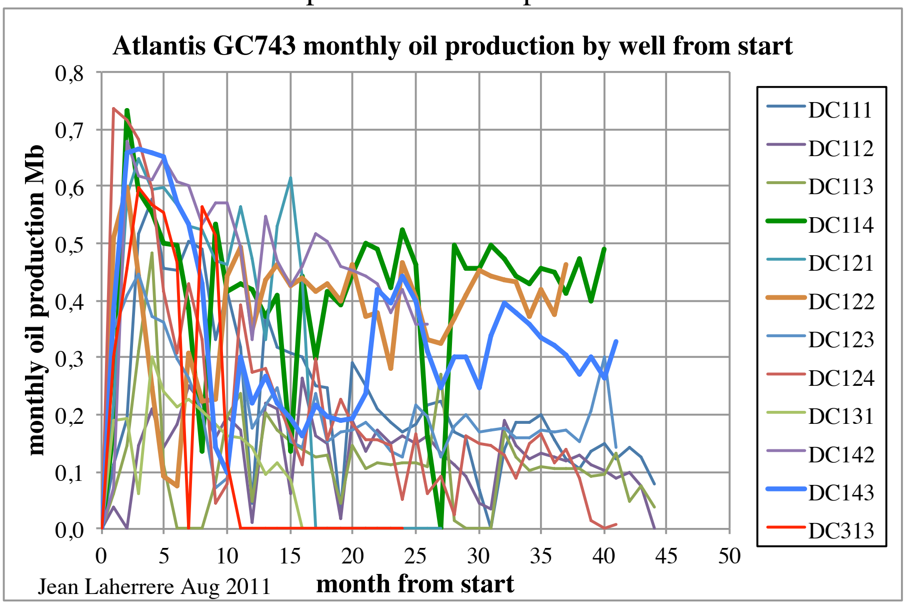
The Atlantis field (also known as the Green Canyon 743) includes in fact Green Canyon blocks 699, 700, 742, 743, and 744 and is located the Central Gulf of Mexico about 190 miles south of New Orleans, Louisiana. BP and BHP Billiton jointly acquired leases on these blocks under OCS Sale 152 (held on May 10, 1995). BHP retains a 44% working interest in the project, and BP is the designated operator. The oil field was discovered in 1998 by the Ocean America semi-submersible, mobile drilling rig operating in a water depth of 1 870 metres (6 140 ft). The Atlantis platform began production from two wells in October 2007. The Atlantis North Flank began production in July 2009.

By 2010, there were twelve production wells. Twenty wells were planned, including 16 producers and four water injection wells.

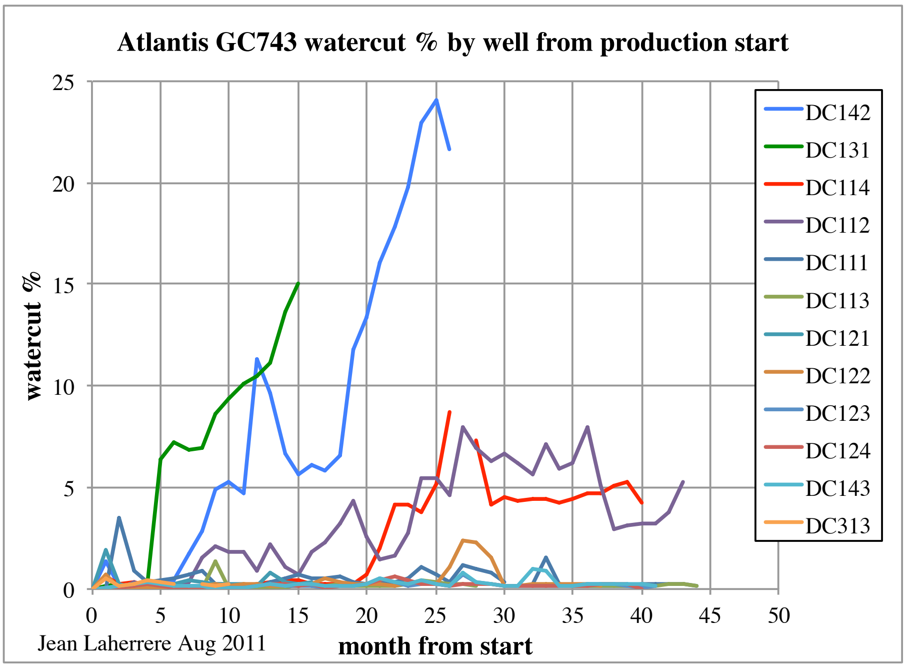
BHP is presenting more data on Atlantis than BP. Atlantis is a structure with different compartments. New development will resume in 2011 and in 2012 appraisal of the East compartment.
http://www.bhpbilliton.com/home/investors/reports/Documents/121202jefferiesGlobalEnergyConferenceJmyPresentation.pdfFigure
Figure 36: map of Atlantis different compartments from BHP



Up to May 2011 the 12 producing wells (in addition DC102 did not produce anything) plotted monthly from the production start displays different behaviour: some decrease, others like DC114, DC122 do not decrease.
Figure 37: Atlantis individual well oil production from production start

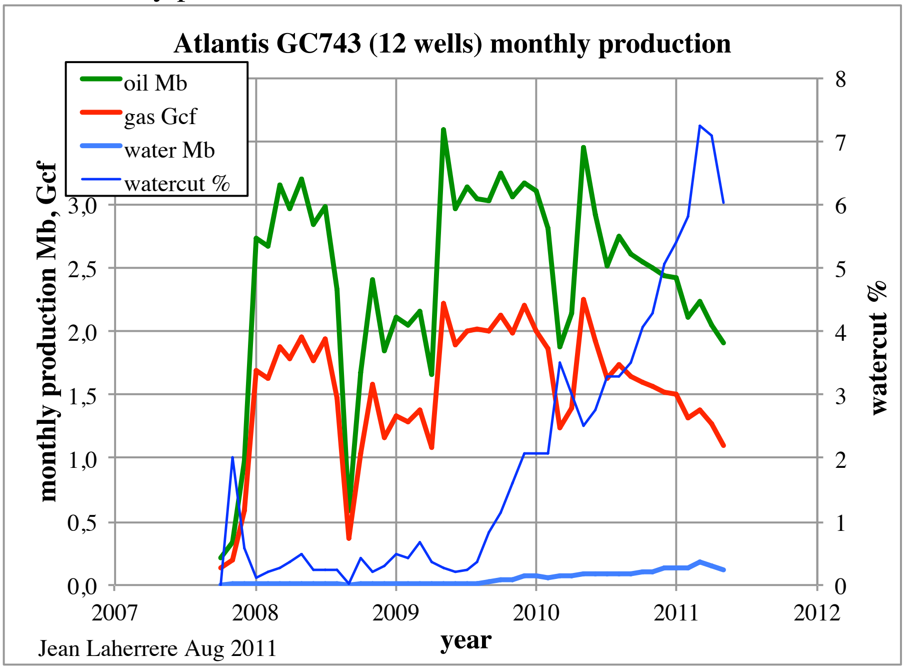


The watercut of those 12 wells behaves also quite differently: DC142 increases to 24% after 25 months; DC131 to 15% after 15 months; DC114 is stable at 5% after 40 months; DC112 went up and down and up at 5% at 43 months; all other wells have less than 2 %. Such low watercut is surprizing when looking at the BHP map with many faults.
Figure 38: Atlantis individual well watercut from production start



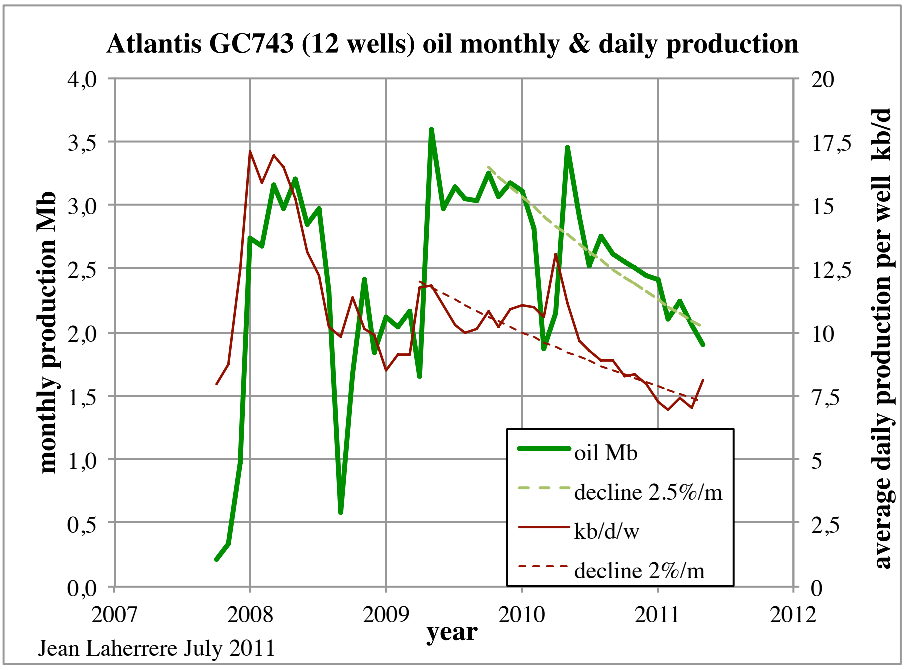
The global monthly production is chaotic but with a decline for oil since May 2010 when watercut increases sharply from mid 2009 but to only 7%, which is small compared to the world average of 75%.

Figure 39: Atlantis monthly production



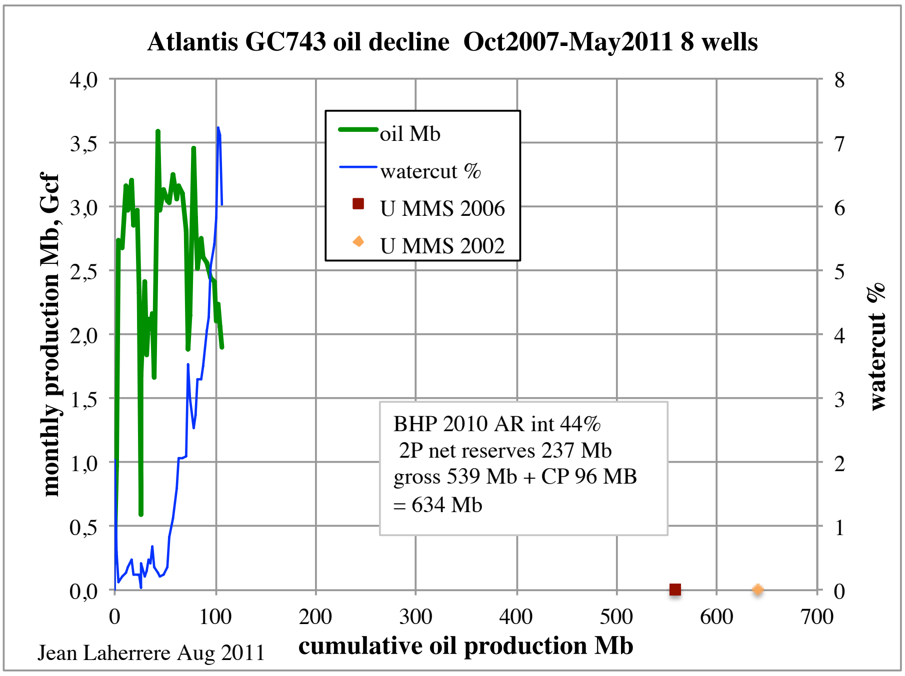
The monthly oil production shows a decline of 2.5% per month since 2010, when the average daily production per well peaked at 18 000 b/d in 2008, declined sharply and since mid 2008 has a slower decline around 2% per month.

Figure 40: Atlantis oil monthly and daily (per well) production



Again this trend is with the present wells and any new drilling will change the trend

The following monthly global production versus cumulative production is hard to extrapolate lacking the plan for future drilling.
BP is very slow to resume drilling after Macondo blow out compared to other operators: for the first half of 2011, Shell had 16 drilling permits approved, Chevron had 23, BHP had 15, Exxon has had 11 and BP had nil.
Figure 41: Atlantis oil decline



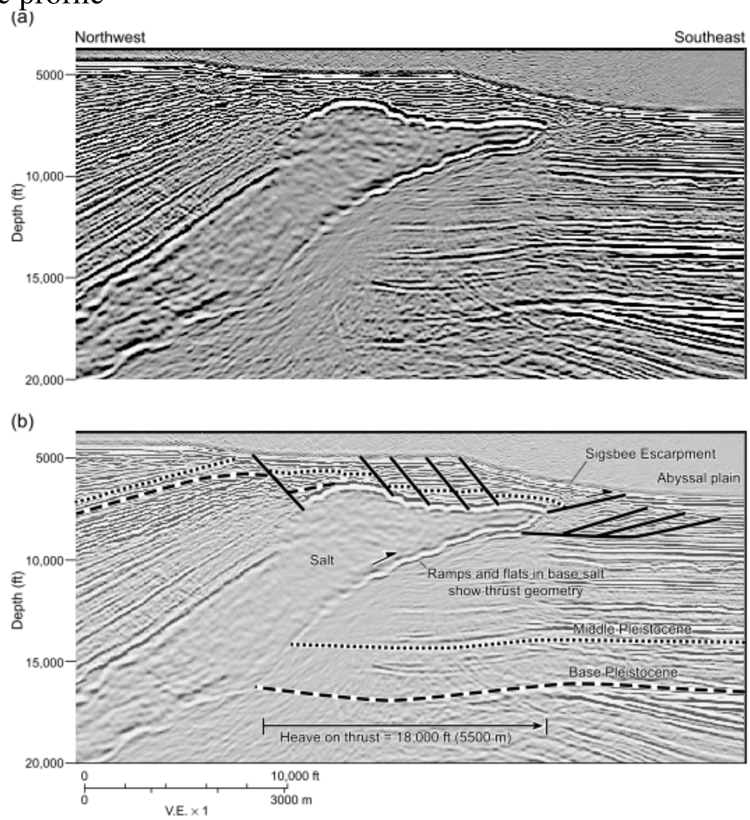
MMS has estimated Atlantis oil initial reserves at 641 Mb at end 2002, but 559 Mb at end 2006.
BHP in their annual report 2010 stated their net (44%) oil 2P reserves at 237 Mb (539 Mb gross), adding the cumulative production at end 2010 of 96 Mb. The initial reserves are 634 Mb for BHP.
Lach (2010) has an estimate EUR at 558 Mb.

Oil decline could be extrapolated only when all the compartments are drilled and the East compartment seems to be still undrilled.
It is likely, as unlikely, that Atlantis will be a giant oilfield (500 Mb).

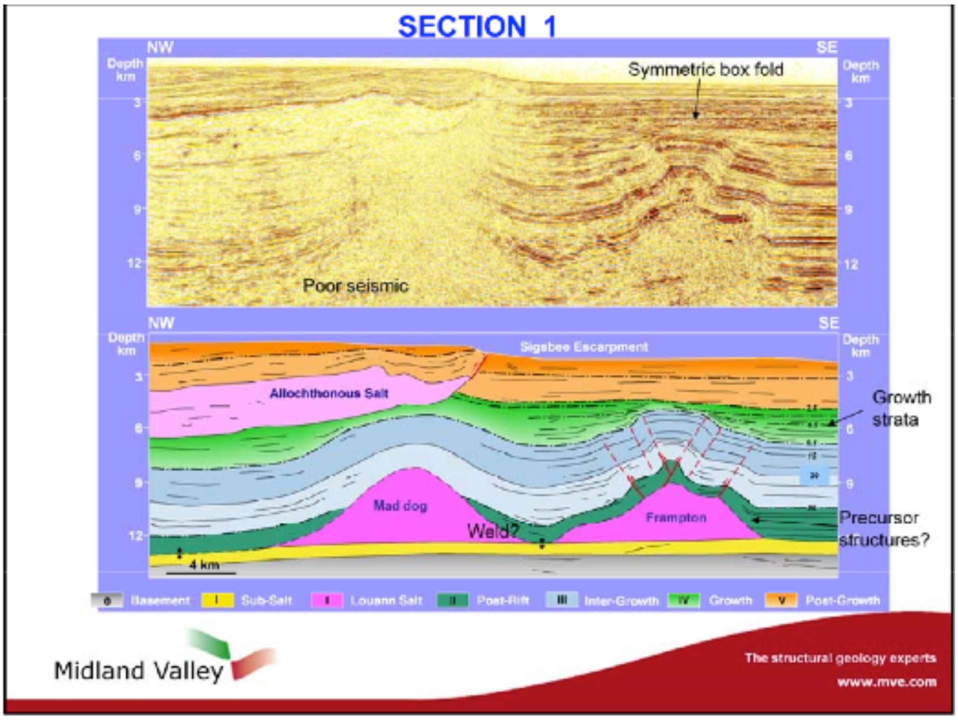
-Mad Dog

The Mad Dog field, discovered in 1998, is located in Western Atwater Foldbelt, Gulf of Mexico, approximately 190 miles south of New Orleans, USA. The field is operated by BP, which has a 60.5% share, BHP Billiton 23.9% and Chevron 15.6%. It is listed as GC826 by MMS. The drilling unit is located in 5 000 ft to 7 000 ft of water in Green Canyon blocks 825, 826 and 782, about 150 miles southwest of Venice, Louisiana. The gross estimated reserves are in the range of 200 to 450 million barrels of oil equivalent. The facility can produce around 80 000 b/d and 60 Mcf/d.
A well extending towards the southern region of the field known as 'Mad Dog Southwest Ridge" was drilled in March 2005. The well was appraised in July 2009. Drilling results identified around 280 ft of hydrocarbons at Miocene sand and an oil column of over 2 200 ft.
In 2008, another well known as A-7 extending towards the western region of the field identified a hydrocarbon column over 2 500 ft and 275 ft of net pay.
The field is presently developed by 12 wells.
The Mississippi fan fold belt is characterised by basinward-verging anticlines and associated thrust faults. Mad Dog is one of a number of discoveries occurring in the western portion of the fold belt, where shallow salt tongues have flown over some of the folds, making seismic imaging difficult.
A seismic profile was shown by Hudec et al AAPG 2006) as a trap below a salt canopy.
Figure 42: Mad Dog seismic profile

Figure 14. (a) Uninterpreted and (b) interpreted versions of a prestack depth-migrated seismic section across the Sigsbee Escarpment near the Mad Dog discovery, Green Canyon area, northern Gulf of Mexico. Proprietary paleontologic data from wells above, below, and in front of the salt sheet allow confident correlation of horizons from the sheet's roof to the abyssal plain. Basal Pleistocene strata in the roof have been thrust over the abyssal plain by 5500 m (18,000 ft), driven by gravity spreading of the salt canopy. Seismic data are courtesy of BP.



A simplified interpretation was presented by Grando et al (AAPG 2008) as an anticline trap on a salt diapir (pink) below an allochthonous salt. The seismic below the salt is described as poor!
Figure 43: Mad Dog interpretation by Grando et al



A detailed interpretation of the structure (profile & map) was presented by Dias et al (AAPG 2009).
On the profile, the structure is faulted with a wet compartment (graben) in the middle
Figure 44: Mad Dog cross section from Dias et al

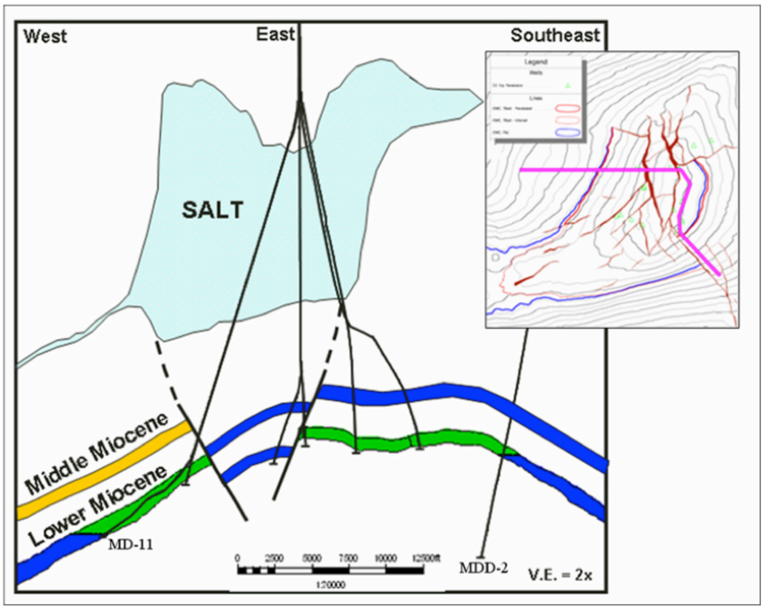


Figure 2. Schematic structural cross section of the Mad Dog Field, showing intersected oil-water contacts and trapping mechanism.

On the map 14 wells are located and a tilted (red) and a flat oil-water (blue) contact are mapped
Figure 45: Mad Dog map from Dias et al

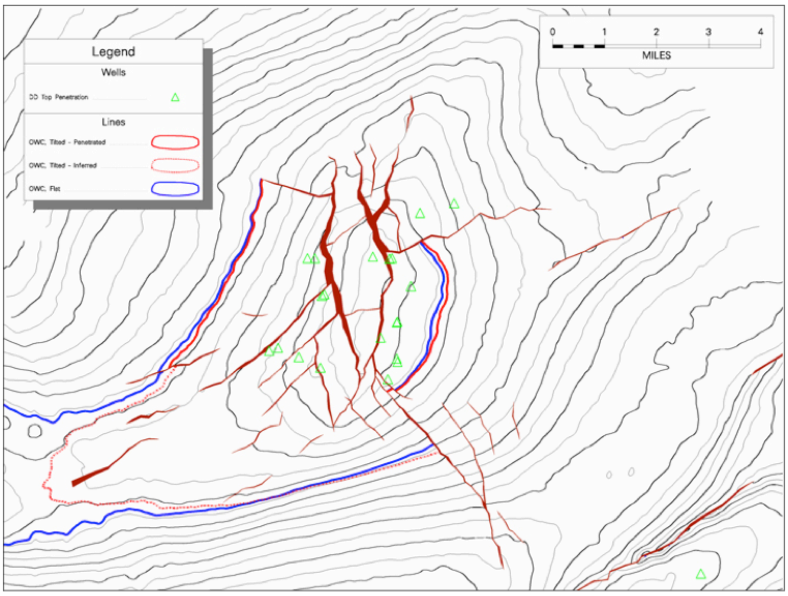
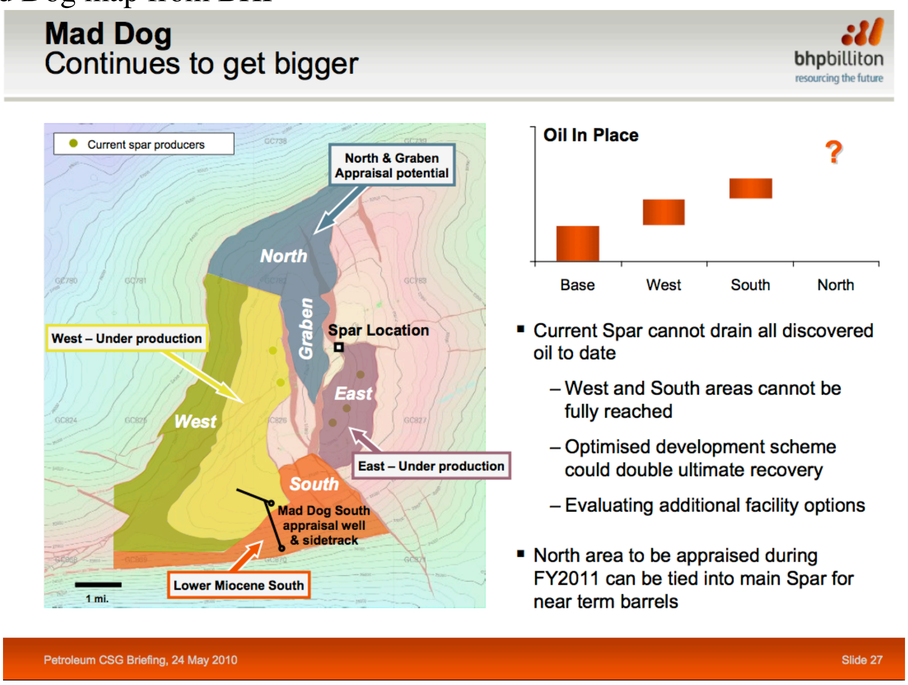


Figure 3. Structural contour map of the Mad Dog Field showing a tilted oil-water contact (red) and a flat oil-water contact (blue).

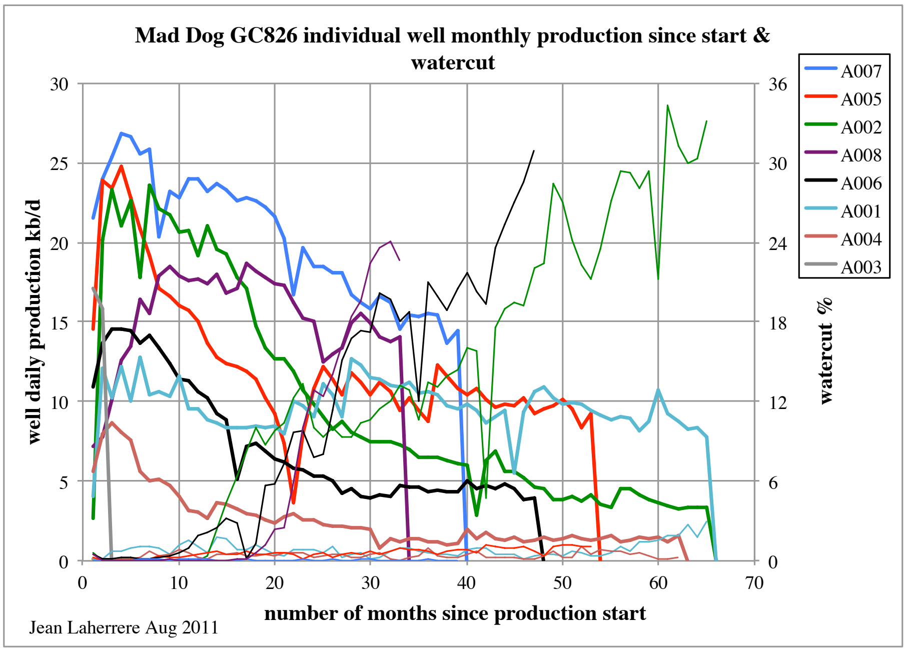
BHP (Dec 2010) shows the increase of potential with the South and West being out of reach of the present Spar platform. The North was planned to be appraised in 2011.
http://www.bhpbilliton.com/home/investors/reports/Documents/121202jefferiesGlobalEnergyConferenceJmyPresentation.pdf

Figure 46: Mad Dog map from BHP



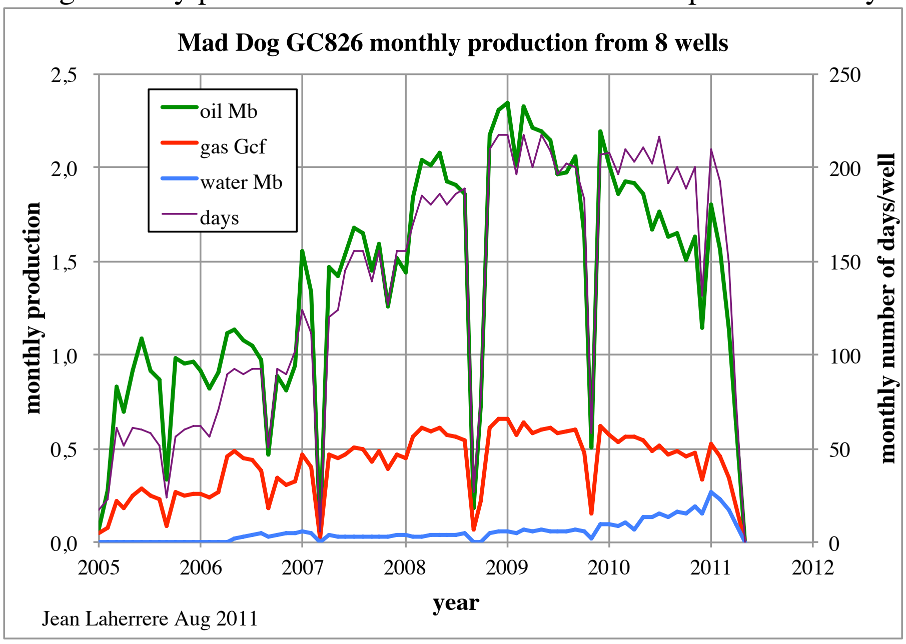
Contrary to Atlantis the MMS well monthly oil production (8 wells) from production start decreases in parallel, but the watercut increases over 30% after 50-60 months when the majority of wells stays very low.

Figure 47: Mad Dog individual well oil monthly production & watercut



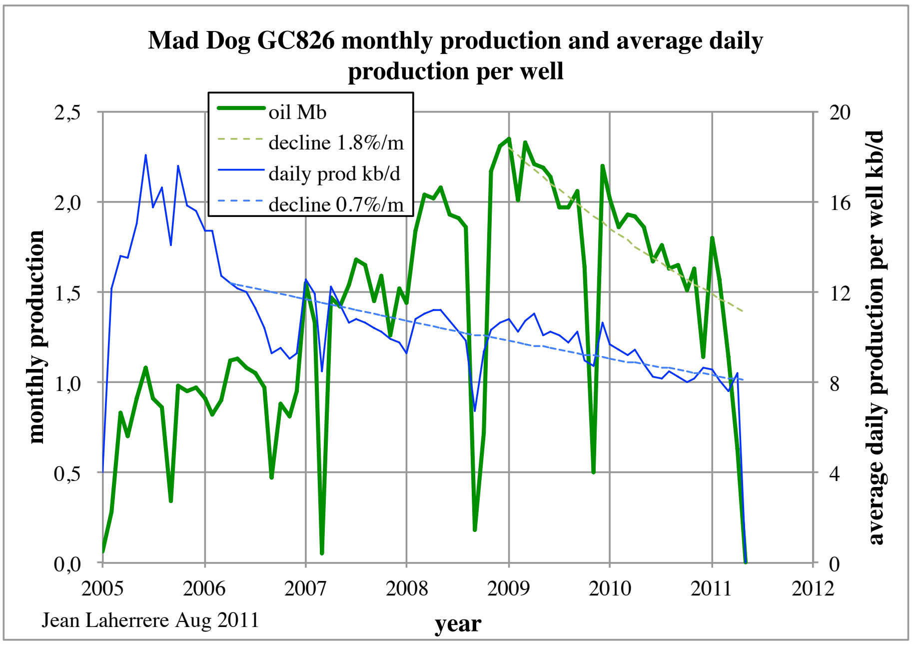
The global monthly production for oil, gas & water with the total number of production days shows (outside an almost annual stop for maintenance: in May 2011 the production is zero) an increase from 2005 to the peak at the beginning of 2009 and almost symmetrical decline.

Figure 48: Mad Dog monthly production from 8 wells & number of production days

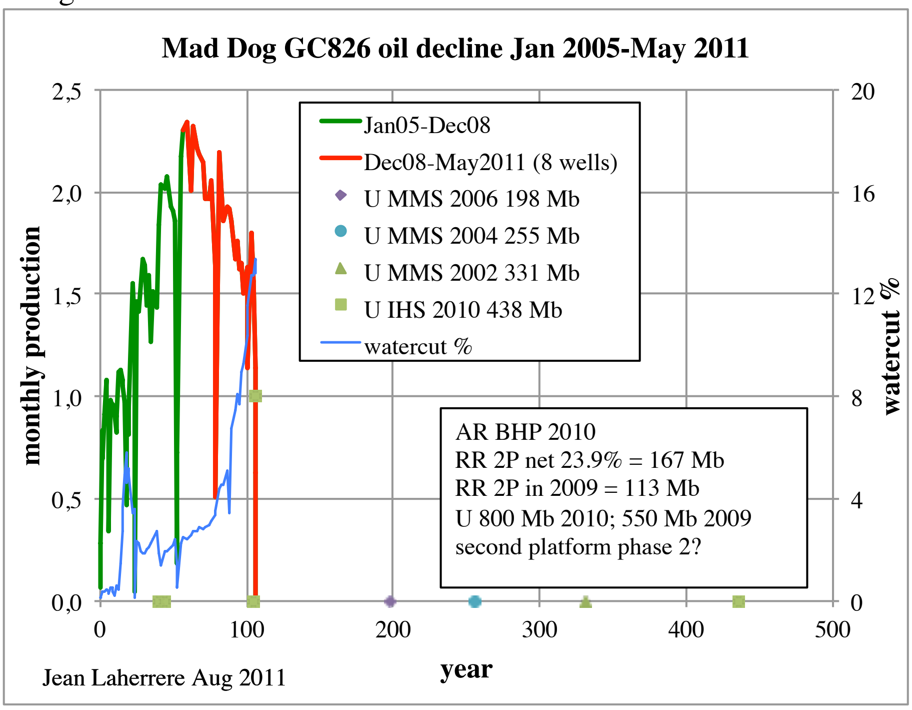


The monthly oil production, which peaks in Jan 2009 (2.3 Mb), is plotted together with the average daily production, which peaks at 17 000 b/d in mid-2005. Monthly oil global production declines at about 1.8 % per month; when the average daily production per well declines at only 0.7% per month.

Figure 49: Mad Dog monthly oil production & average daily production per well



The Mad Dog monthly oil production is plotted versus the cumulative oil production with the various ultimate. It is amazing to see MMS estimates decreasing from 2002 at 331 Mb to 2006 at 198 Mb, when BHP claims about an initial reserves of 800 Mb (167 Mb net + 101 Mb cum prod) in 2010, with a sharp increase from 2009 estimate of 550 Mb (113 Mb net + 80 Mb cum prod). IHS 2010 estimate is 438 Mb (255 Mb in 2004, 195 Mb in 2003, 193 Mb in 1999).
Lach (2010) reports EUR 255 Mb.
It will be interesting to see the next B0EMRE oil & gas reserves estimate at end 2007
Past production cannot yet tell which ultimate is right, because the full structure is not yet completed appraised!
Figure 50: Mad Dog oil decline



In my presentation at Copenhagen Dec 2003 on International conference on Oil Demand, Production and Costs - Prospects for the Future -The Danish Technology Council and the Danish Society of Engineers "How to estimate future oil supply and oil demand? "
http://www.hubbertpeak.com/laherrere/Copenhagen2003.doc

I studied the oil depletion at end 2000 of several oilfields of the GOM: EI330, WD030 and SP027. It is interesting to update those three fields.

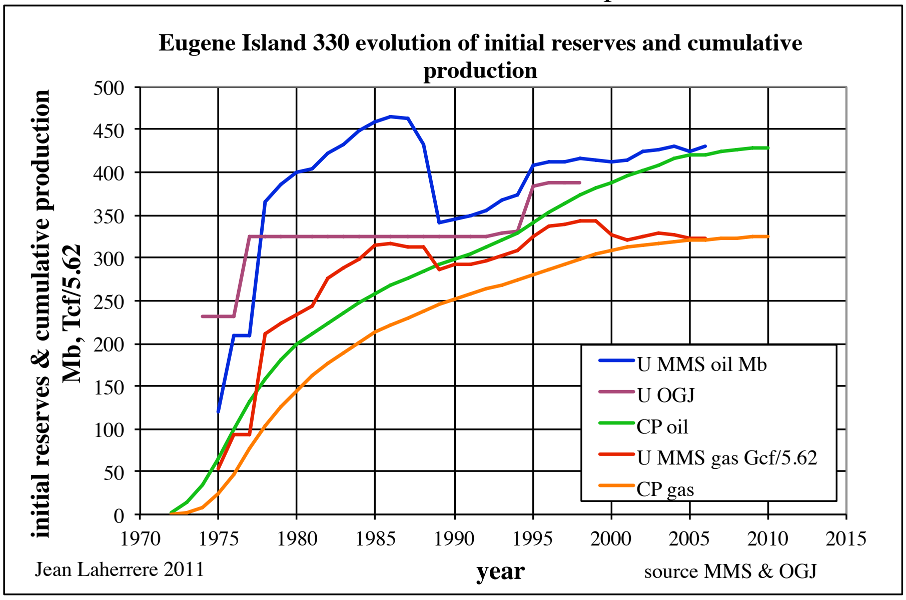
-Eugene Island 330 = EI330

This GOM field is famous because a 1999 Wall Street Journal article started a controversy about its oil rate depletion with a **refilling from a deep source.** The astronomer T.Gold claimed that the oil was abiogenic coming from the mantle, and that EI330 refilling from the mantle explains the large increase (300 Gb) in the Middle East of OPEC reserves during the second half of the 80s (due in fact by their fight on the quotas).

EI330 was discovered in Dec. 1971 by Pennzoil and Shell in shallow water (247 ft) and started production in Sept. 1972. In 1983 up to nine platforms were installed. It peaked around 100 000 b/d in 1976 for a short time: in 1976 EI330 was the largest offshore producer (31 Mb). But it declined sharply by 2 % per month to 1983, then the decline slowed to less than 1% per month to 1992 and the production started to increase and peaked again in 1996 when the mystery of EI330 was in many newspapers. The WSJ was wrong by stating that "the reserves have rocketed to more than 400 Mb from 60 Mb". MMS initial reserves estimates were 120 Mb in 1975, 460 Mb in 1986, 350 Mb in 1989 and 410 Mb in 1996: it is difficult to see a rocket, it is behaving more like a drunk fly.

The following graph shows for oil & gas the evolution of the ultimate reserves estimated by MMS and OGJ and the cumulative production. No mystery except that MMS reserve estimate was chaotic!

Figure 51: EI330 evolution of initial reserves and cumulative production



The explanation of the mystery on increase production is geological.

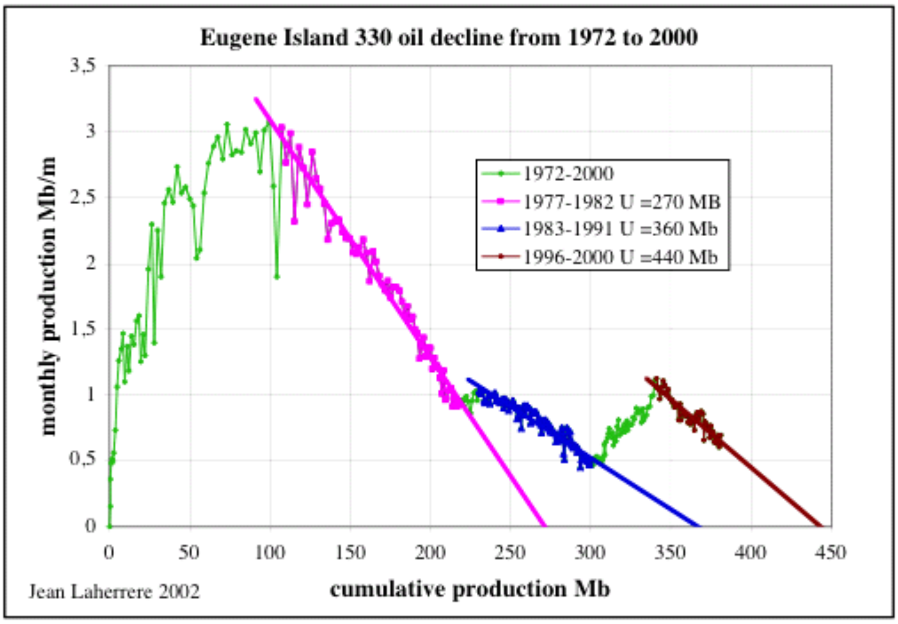
EI330 trap is against one of the largest fault in the GOM. After large production the pressure (in particular in some overpressured reservoirs = Lentic) has dropped and these Plio-Pleistocene reservoirs are easily in communication from the deep source-rock. The migration between source-rock and trap takes usually a long time: here the assumed refilling starting in 1992 was quick (few years) in geological time.

I wrote «Oil and gas: what future? » Groningen 21 November 2006

www.hubbertpeak.com/laherrere/groningen.pdf http://aspofrance.viabloga.com/texts/documents

There is another example of exceptional positive reserve growth, which, is Eugene Island 330 in the Gulf of Mexico. 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 to the source rock and 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 11: ***Oil decline of Eugene Island 330 (US Gulf of Mexico) 1972-2003***



A thesis (B.B.Stump, Pennsylvania State University Dec 1998) studied overpressures in some EO330 reservoirs.
Laurel L. Alexander and Peter B. Flemings AAPG Dec 1995 v79 n°12 p1737-1756 "Geologic Evolution of a Pliocene–Pleistocene Salt-Withdrawal Minibasin: Eugene Island Block 330, Offshore Louisiana" explains the formation of EI330 reservoirs and trap with this large fault.
Figure 52: EI330 schematic diagram on the evolution of the geological three phases

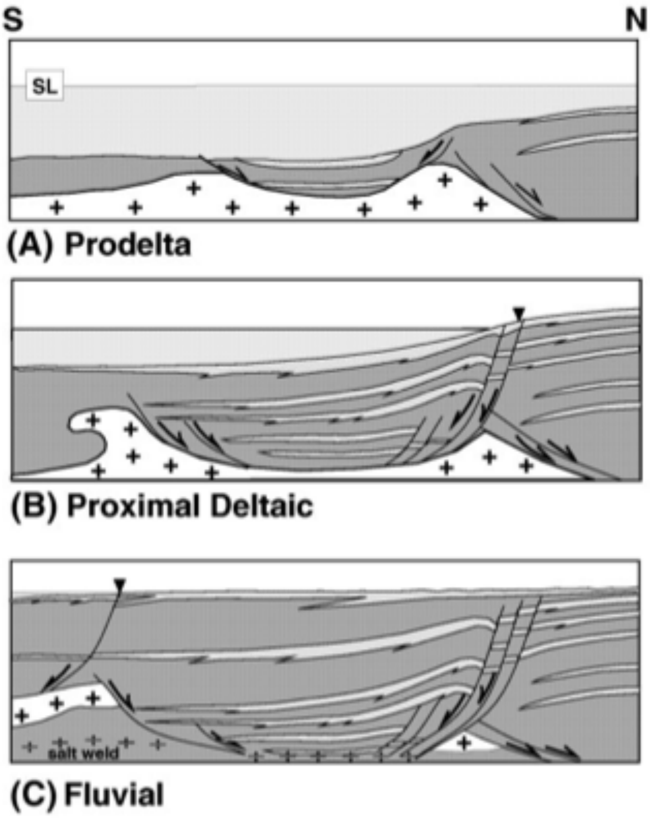
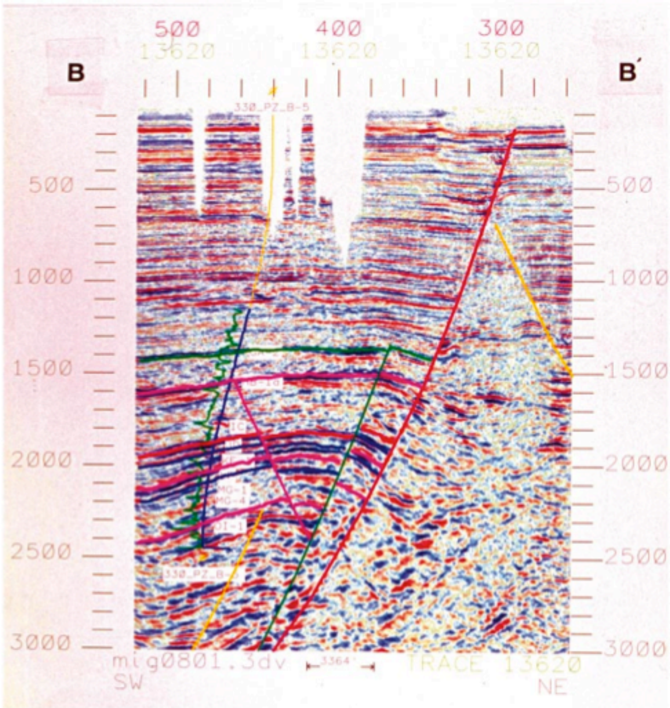


Figure 14—Schematic diagram of the three-phase evolution of the EI-330 minibasin, which began prior to 2.8 Ma and continues to the present time.

In AAPG March 1998 the same L.L. Alexander displays a seismic profile with the A (red) fault which goes from the deep towards the surface

Figure 53: EI330 seismic profile with the A (red) fault

Figure 3—Seismic profile BB′ showing fault F (lavender), fault B (green), fault A (red), and the main reservoirs of the EI-330 field. The tops of the sands correlate to the maximum amplitude of the troughs (red).



EI330 is also called SEI330 = South Eugene Island block 330
"Reservoir fluids and their migration into the South Eugene Island Block 330 reservoirs, offshore Louisiana" Steven Losh, Lynn Walter, Peter Meulbroek, Anna Martini, Lawrence Cathles, and Jean Whelan AAPG Aug 2002 V86, n°8, p1463-1488
Figure 54: EI330 structure map on sand OI-1

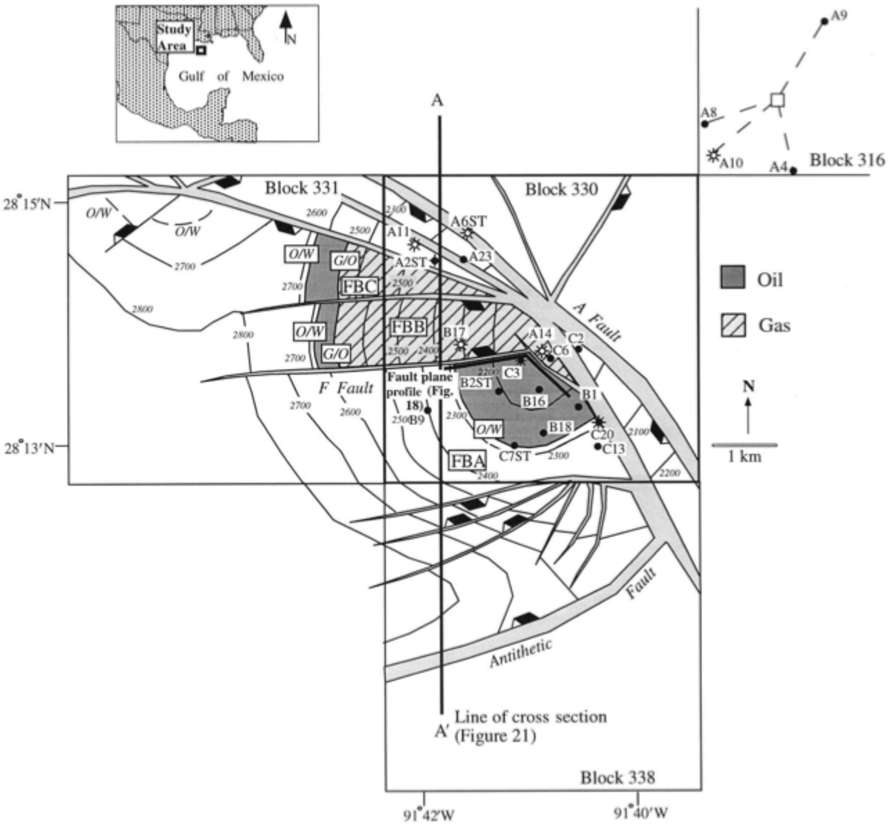


Figure 1. Location map, showing wells from which brine samples were collected. Structure contour map is on top of OI-1 sand, modified from Holland et al. (1990), with contours and fault pattern in Block 338 modified from Alexander and Flemings (1995). Contours are in meters subsea true vertical depth (TVD).

It was a study in 2004 to use SEI330 for CO2 sequestration (M.D.Zoback).

Figure 55: GOM infrastructure with EI330 (SEI330) (red =oil pipe, green = NG pipe) in 2000

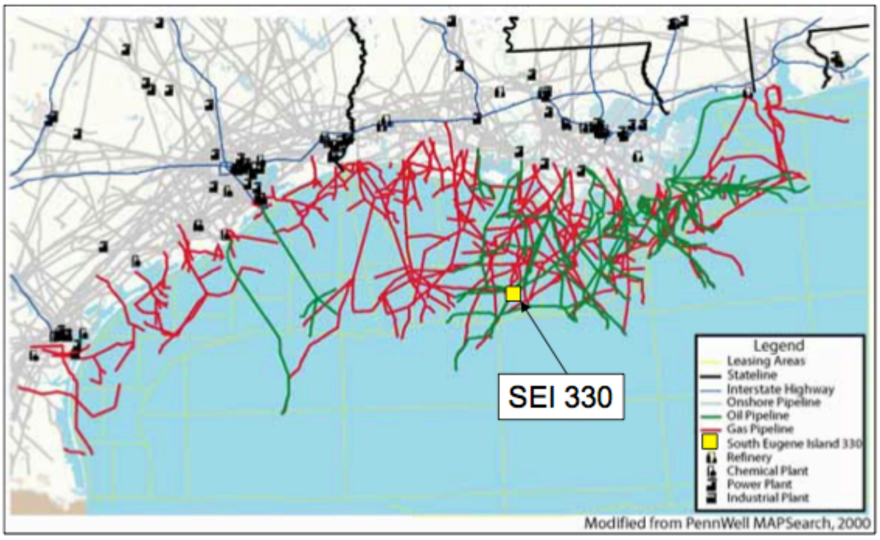


Figure 6: Map of the U.S. Gulf Coast and Gulf of Mexico and some of the existing infrastructure in the region[20]. Oil pipelines are in green, gas pipelines in red, and onshore pipelines in gray. The black figures are possible sources where anthropogenic CO_2 that could be captured and separated for sequestered in the Gulf of Mexico. In yellow is the location of our case study site, South Eugene Island Block 330.

The following diagram shows the pressure of some reservoirs between the overburden and hydrostatic pressure.

Figure 56: EI330 pressure diagram

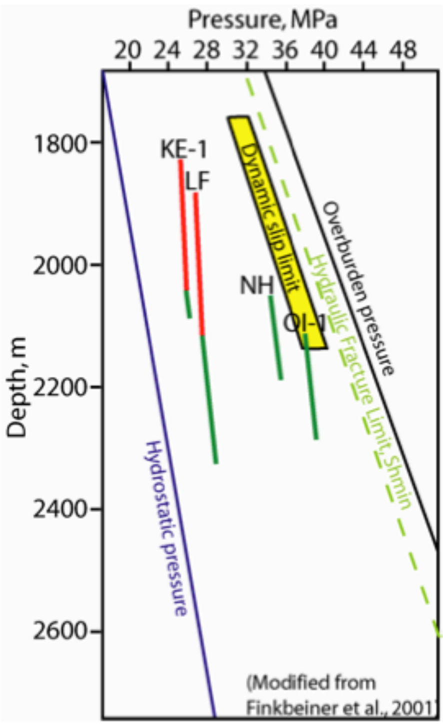


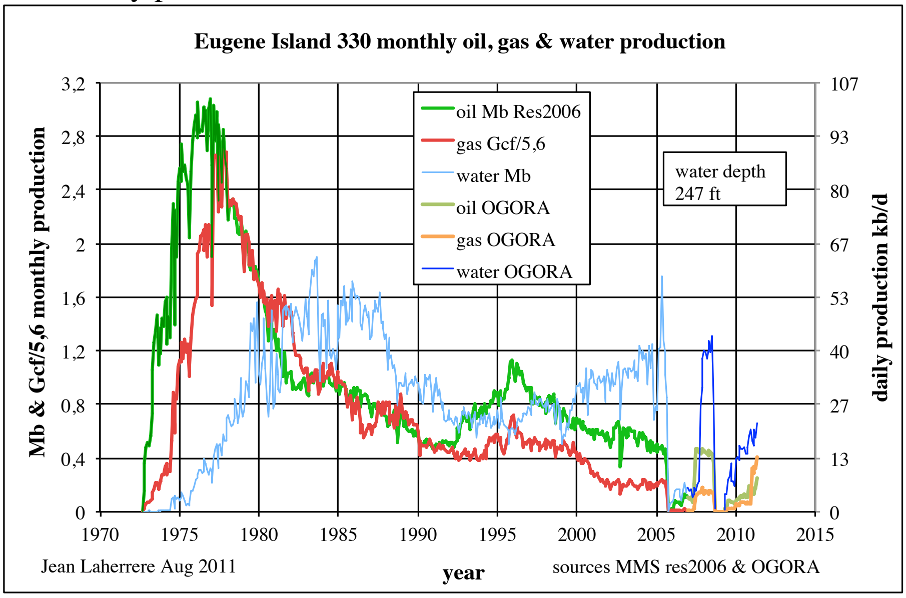
Figure 11: Pressure vs. depth plot of SEI 330 Fault Block A. The oil column in the OI-1 sand appears to be controlled by the dynamic slip limit, while the other shallower sands are not limited by that dynamic control. See text for more explanation.We are developing

This explain when a reservoir is depleted lowering the pressure, the lack of pressure attracts the migration and recharge of oil through the A fault from the deep source–rock to the reservoir. But the present data shows that the recharge was limited.

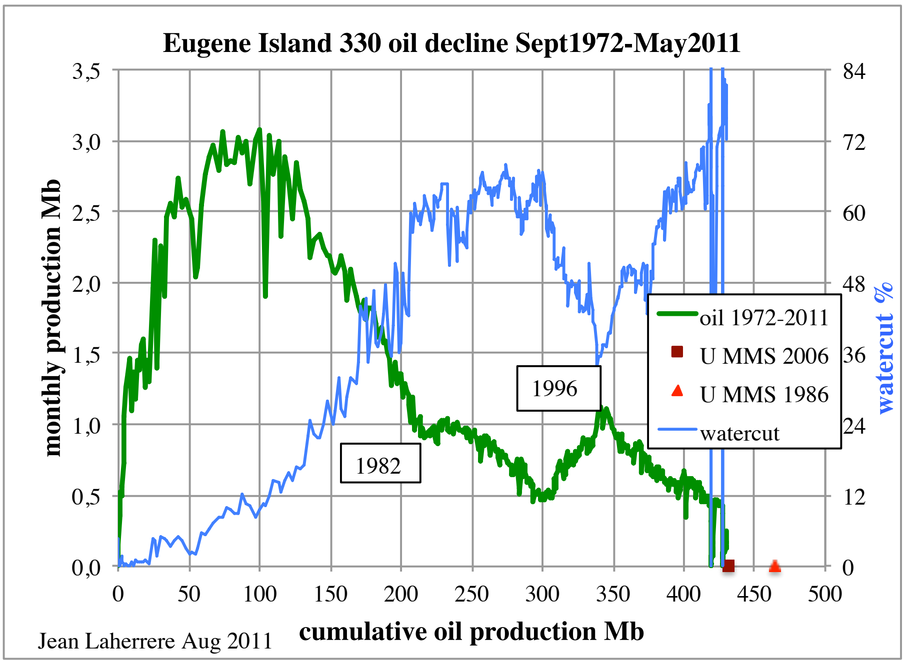
The compilation of every GOM field production is given by MMS in their estimate of oil and gas reserves, but the last report is dated 2009 for end of 2006. As mentioned in part 1, I went to BOEMRE site where there are several (3) reports by unit or per lease and I used the shorter one being per unit which reports only field monthly oil, gas and water..
But for EI330 I got for 2006 unit monthly oil production ten times less than from reserves data. To find the discrepancy I went to the production per lease which details the production broken down into crude oil and condensate (also gas-well gas and casing gas) and I found that the per unit data reports only a part of the data.
For example for 201001 lease G02115 total for the month of January:
-unit file page 837 reports only **one well** B015 with 149 b for oil and zero water
-lease file PBOGORAL page 1834 reports **30 wells** with a total of 15 915 b for oil, 145 907 kcf for gas and 90 443 for water
-production file PBP9152A page 1243 reports **20 wells** reports 15 766 b for oil, 149 for condensate, 129 268 kcf gas-well gas, 16 639 kcf casing gas and 90 443 for water

The unit file is incomplete and gives wrong data .
I was obliged to go to the file OGORA, which is much voluminous (5031 pages for 2006 in pdf).

The oil, gas and water monthly production displays the two oil peaks in 1976 and 1996, with a collapse in 2005 with Katrina, followed by a recovery!
Figure 57: EI330 monthly production

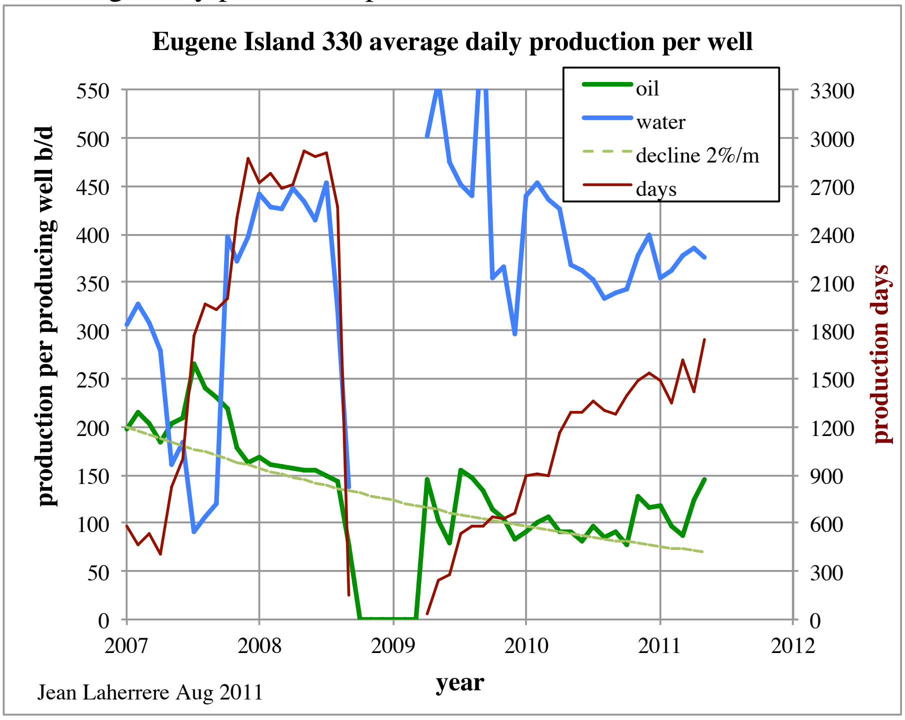


The monthly oil production versus cumulative production shows that the field is close to depletion and that the initial reserves estimated by MMS 2006 could be few MB too short, but MMS 1986 is likely too high.
Figure 58: EI330 oil decline, watercut and ultimates



The recent data (OGORA) allows to plot the average daily production per well from 2007 to now, and the decline from 2007 (200 b/d/w) to now (about 100 b/d/w) is about 2%/month.

Figure 59: EI330 average daily production per well



It is likely that the field will be abandoned in few years.

-Ram-Powell VK956

Lach (2010) presents Ram-Powell as a complex structure and low recovery factor (20 %)

Figure 60: Example 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 “perched water”!
Figure 61: Ram-Powell N sand with “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.

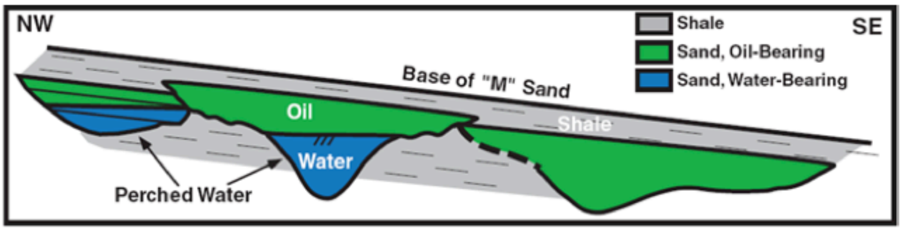
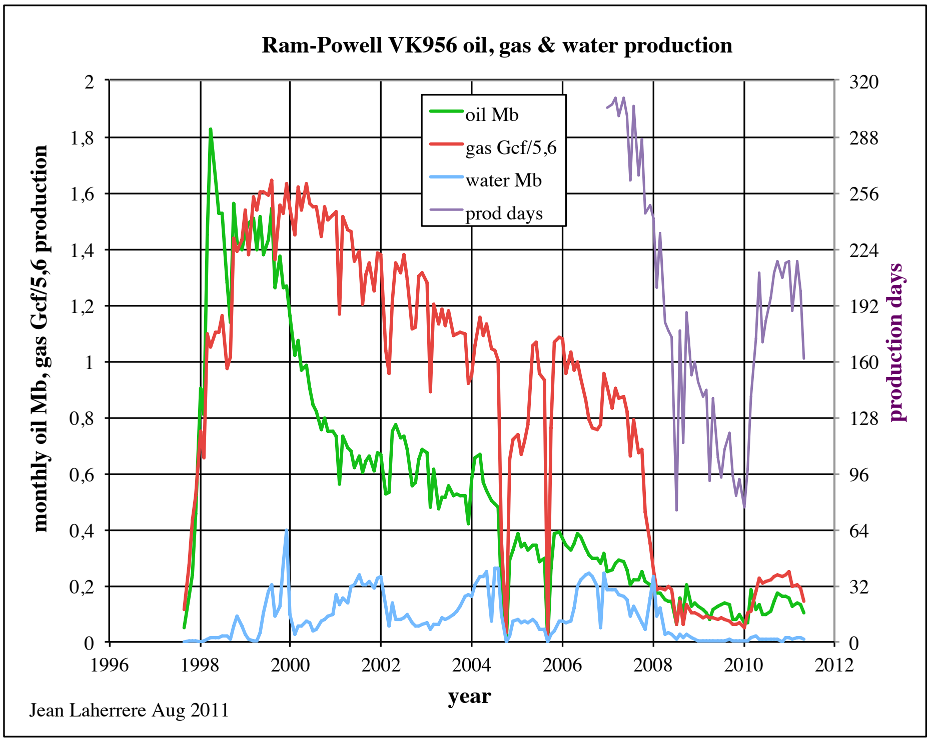


Figure 40: Perched water in channel sand, Ram Powell N reservoir (Kendrick, 2000)

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.

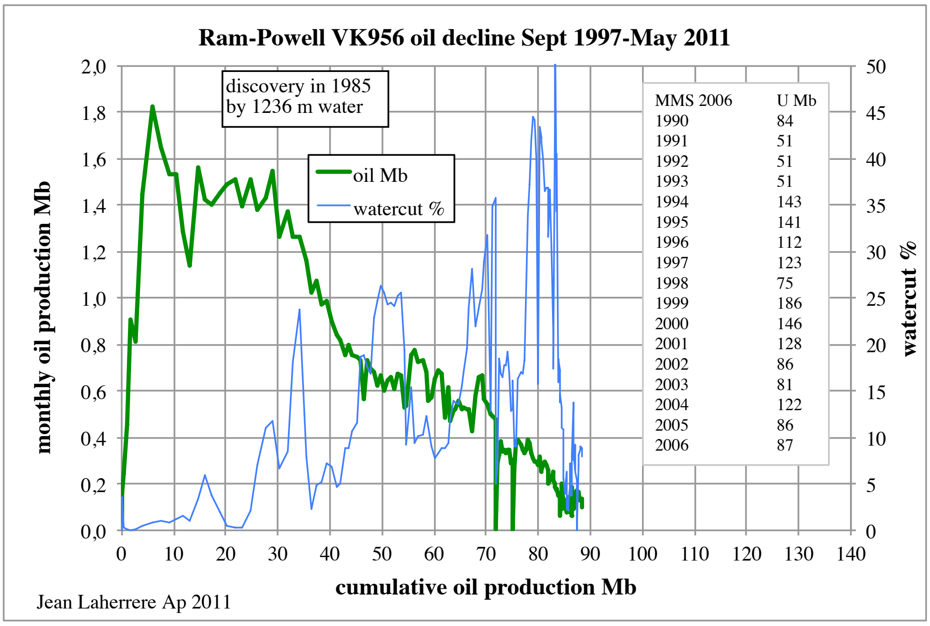
The monthly production displays a peak in 1999 followed by a sharp decline and since 2001 a constant decline
Figure 62: Ram-Powell monthly production



From the oil decline extrapolation, the ultimate is likely to be about 100 Mb, when MMS estimates vary chaotically from 1990 to 2006 from 51 to 186 Mb, last being 87 Mb (too short). Lach 2010 reports 132 Mb.

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

Figure 63: Ram-Powell oil decline

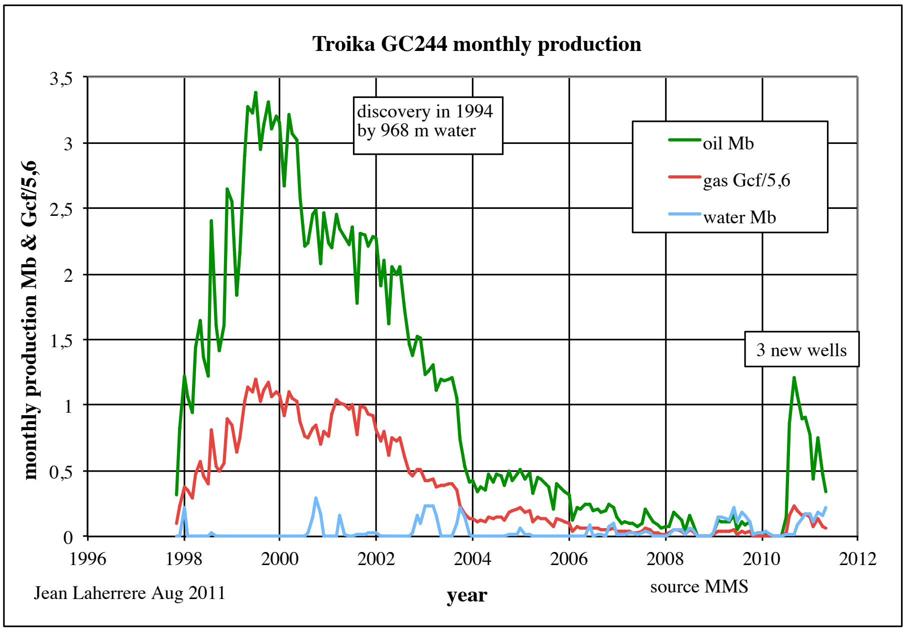


-Troika GC244

Lach (2010) (figure 58) presents Troika as a strong aquifer and high recovery factor (60%) contrary to Ram-Powell

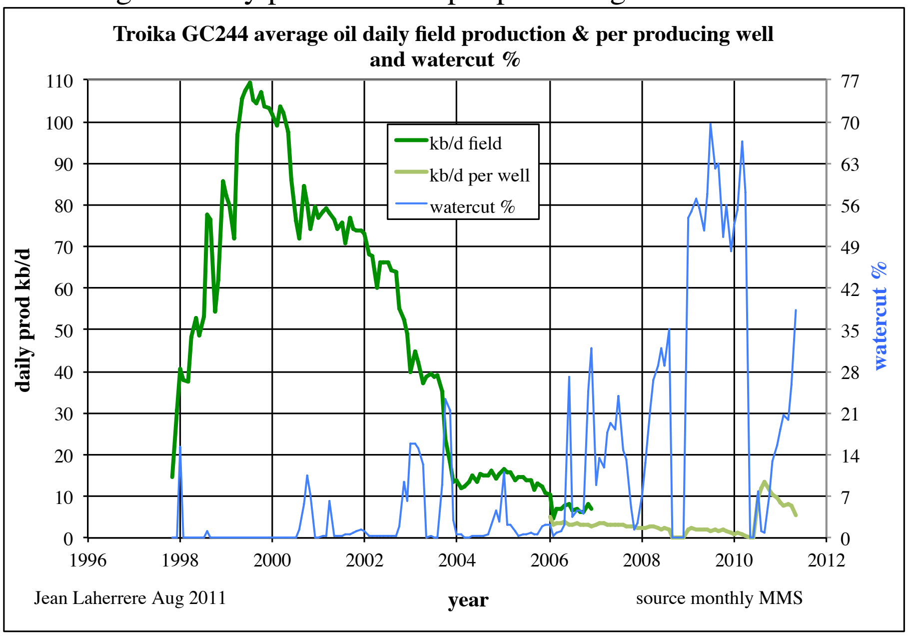
Troika oil monthly production is by steps, peak 3.2 Mb in 1999, first step 2.3 Mb in 2001, second step at 0.4 Mb in 2004, third step 0.2 in 2006 and new peak with 3 new wells in fall 2010.

Figure 64: Troika monthly production



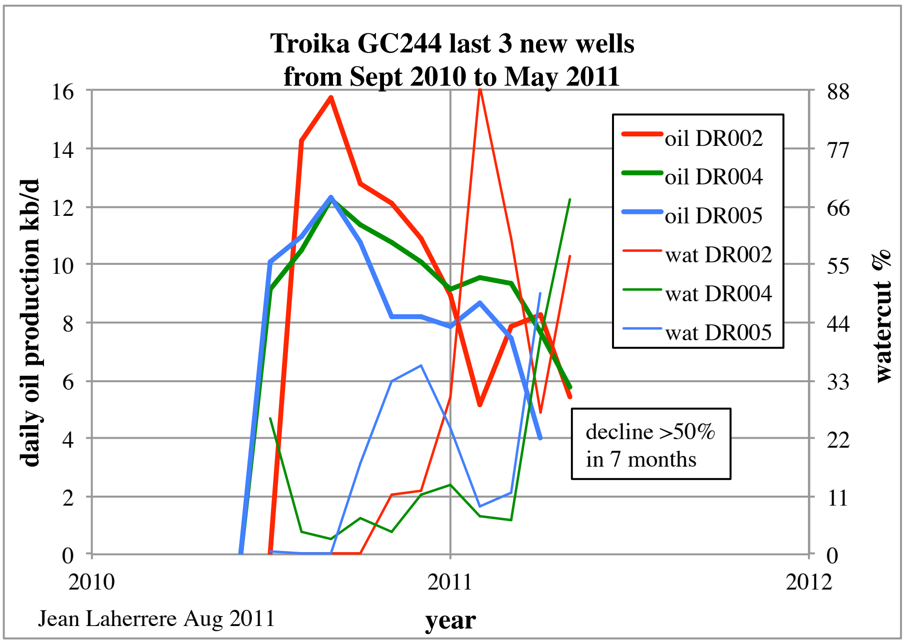
The Troika average daily production peaked in 1999 at over 100 000 b/d and the watercut went up to over 60% before abandoning old wells

Figure 65: Troika average oil daily production & per producing well as watercut %



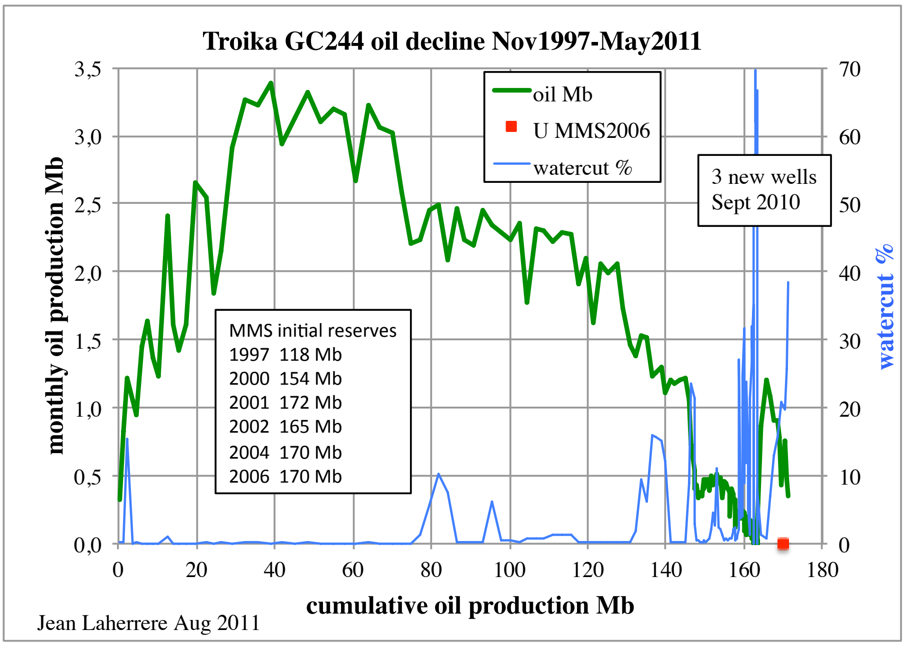
The oil production of the last three wells shows a decline of 50% in 7 months. It is obvious that it is the last burst!

Figure 66: Troika last 3 wells from Sept 2010 to May 2011



Troika oil decline is close to depletion with a cumulative production of 170 Mb when MMS 2006 was about this value, but Lach's ultimate was 164 Mb (a little short).

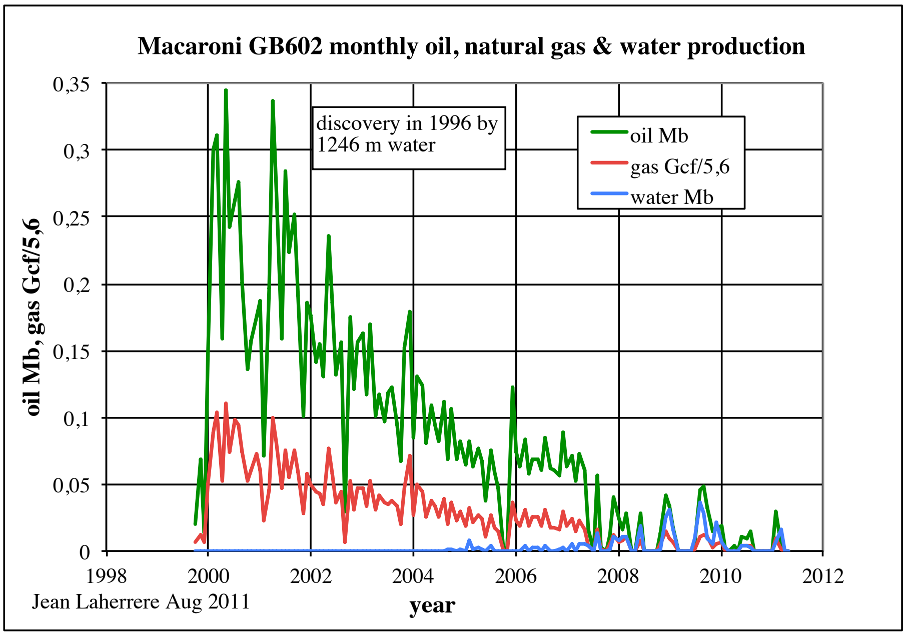
Figure 67: Troika oil decline and watercut



-Macaroni GB602

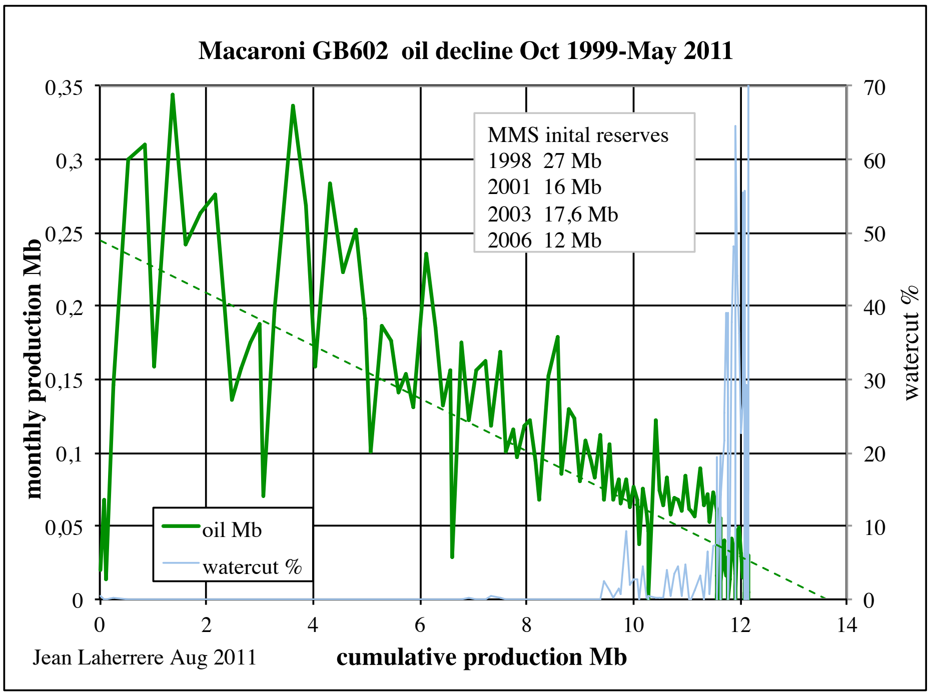
Macaroni was one of the first deepwater field discovered by Shell in 1996 by 1246 m of water in Pliocene sands. The oil production peaked quickly and declined sharply, since 2007 sporadic oil production with high watercut

Figure 68: Macaroni GB602 monthly production



The end is near with an ultimate of less of 13 Mb compared to the estimate of 27 Mb in 1998

Figure 69: Macaroni GB602 oil decline

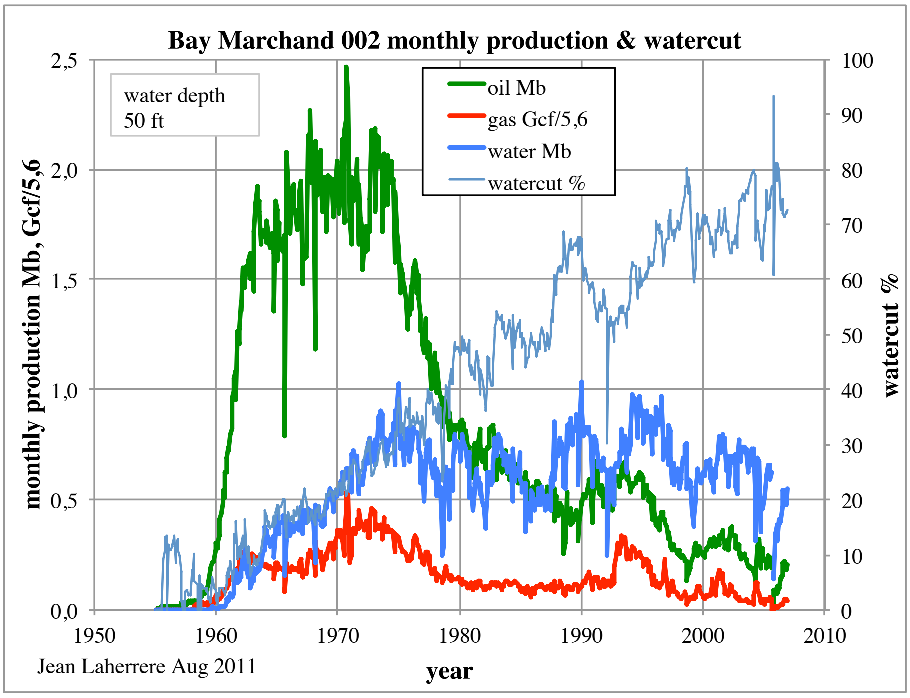


-Bay Marchand 002 (BM002)

Bay Marchand 002 found in 1949 in shallow water was estimated in 1970 by OGJ to have near 800 Mb of reserves against 530 Mb now.

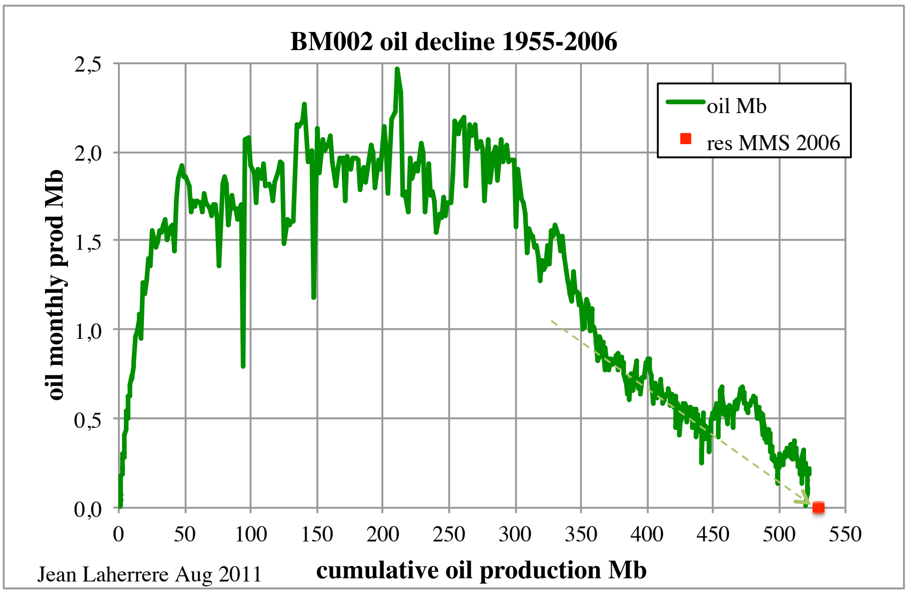
The plateau was fairly long (10 years) and the decline fairly smooth and long with regular watercut increase, being now close to 80%

Figure 70: Bay Marchand 002 monthly production



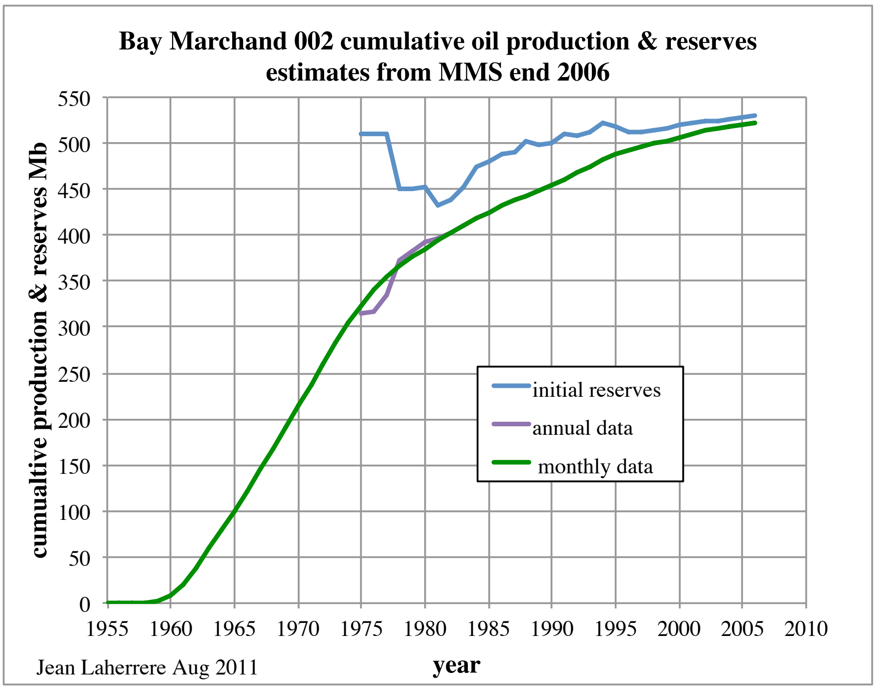
The oil decline since 1980 trends towards 530 Mb which is the 2006 reserves estimate

Figure 71: Bay Marchand 002 oil decline



The oil cumulative production is plotted from MMS 2006 annual data and monthly data. Initial MMS reserves started with 510 Mb in 1975, declined to 430 Mb in 1982 and now is 530 Mb close to the cumulative in 2011. The field seems to be close to be depleted.

Figure 72: Bay Marchand 002 cumulative oil production & initial reserves from MMS 2006

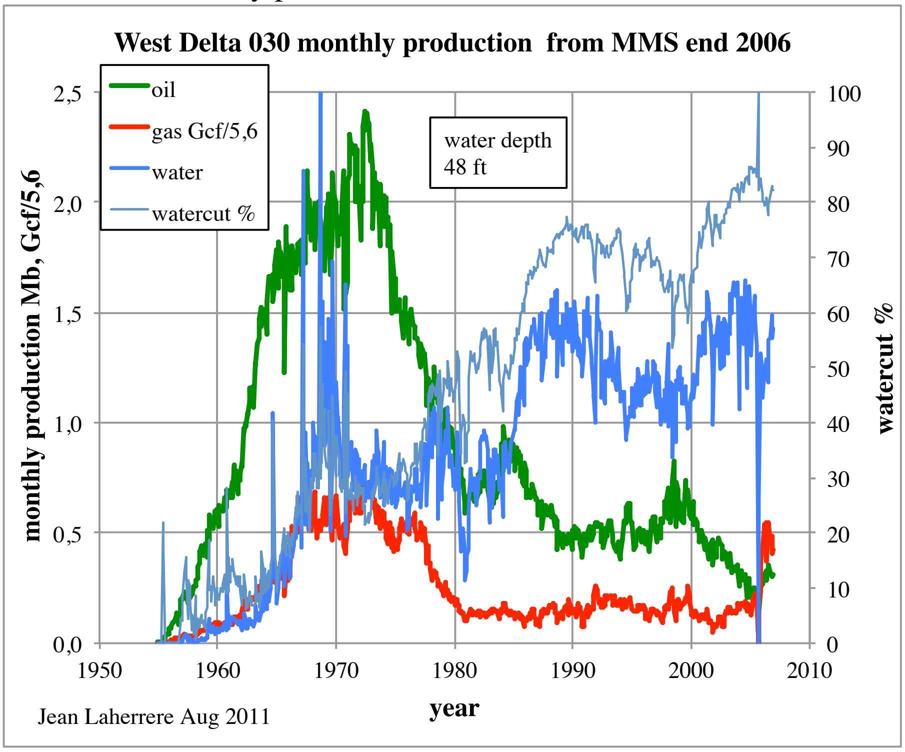


It is obvious that the annual data from 1975 to 1981 is wrong compared to the more harmonious monthly data

-West Delta 030 (WD030)

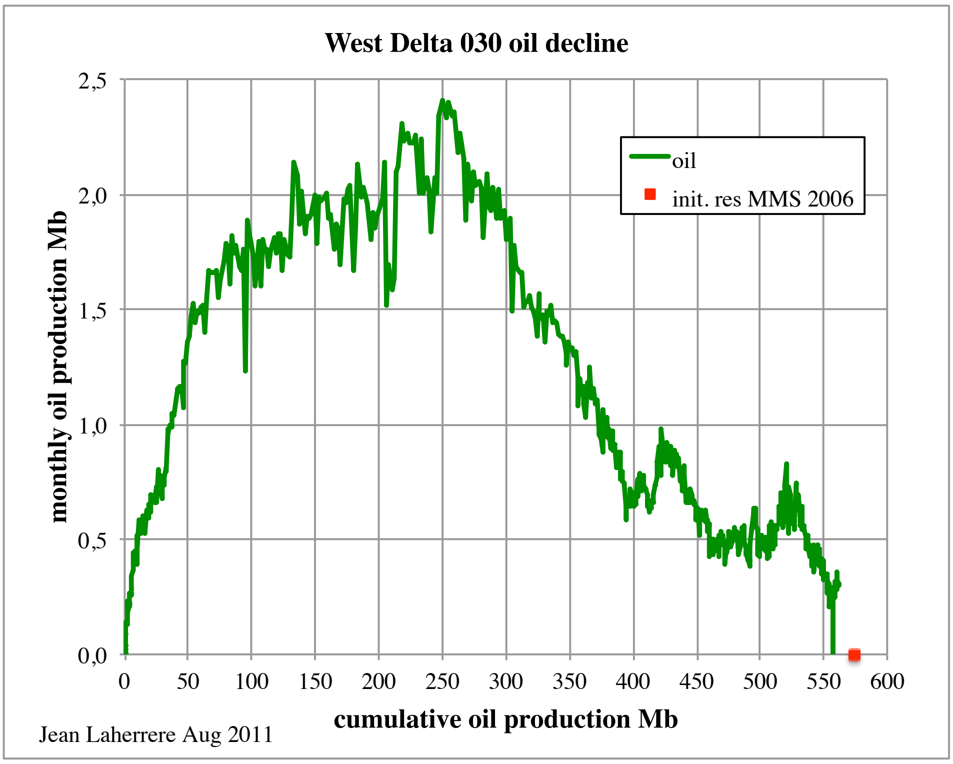
West Delta is a shallow oil field like BM002 found in 1949 and its production looks similar in decline with two minor increases when new drilling brought

Figure 73: West Delta 030 monthly production



Like BM002 WD030 is close to the end with an ultimate at 570 Mb

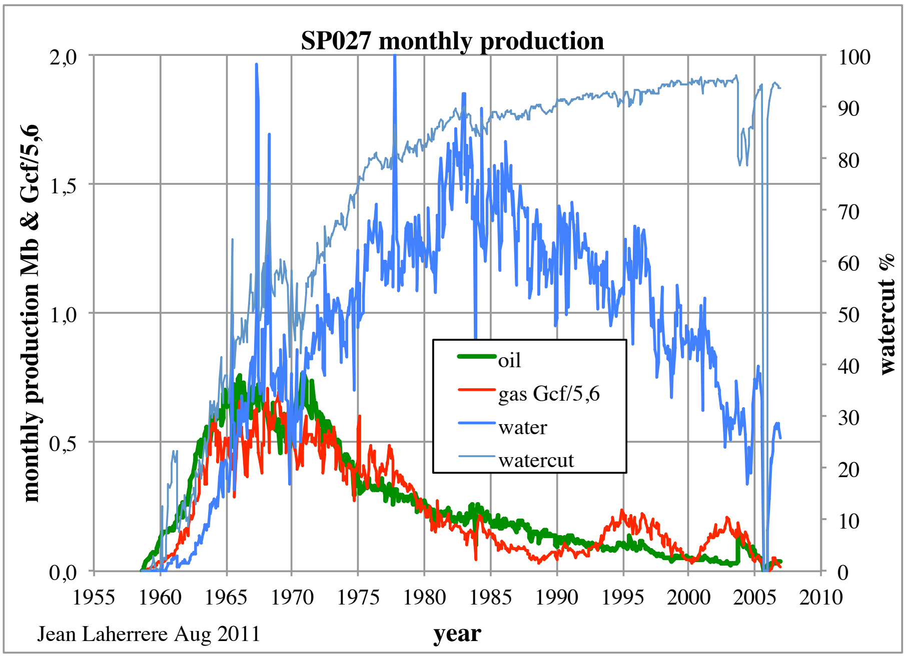
Figure 74: West Delta 030 oil decline



-South Pass 027 (SP027)

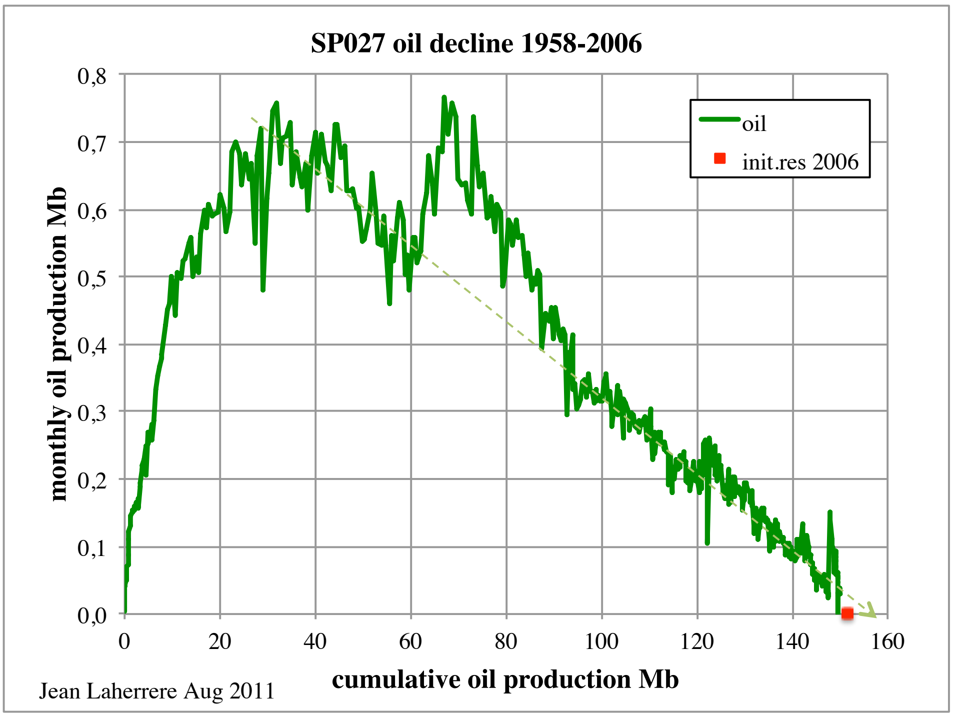
South Pass 027 was found in 1954 in shallow water (64 ft) with reserves at 152 Mb has a bumpy plateau but a smooth decline but rapid watercut increase.

Figure 75: South Pass monthly production & watercut %



SP027 oil decline since 1975 to 2006 is in line with the decline (1966-1970) within the plateau.

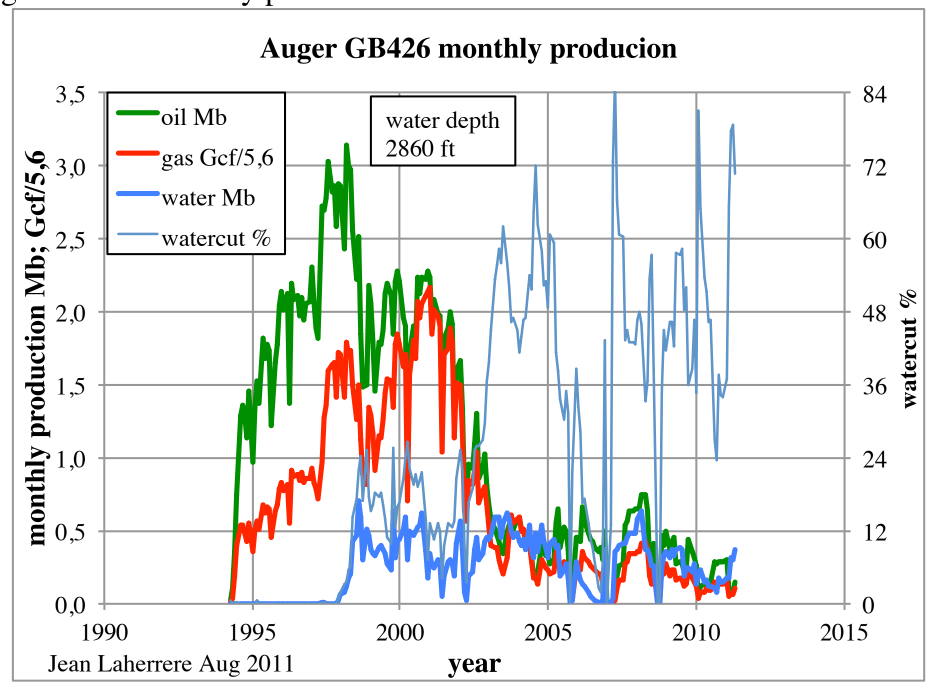
Figure 76: South Pass oil decline



Out of 2006 data SP027 looks close to the end, but the last barrels are still economical in 2011 for the platforms after 53 years. On the BOEMRE report OGORA for 2011 up to May 2011 out of 1452 pages, SP027 covers 35 pages with 1031 lines (851 lines with zero production). During these 5 months, SP027 involves 2 operators, 7 leases, 198 wells, but only 31 wells were producing in May 2011 for 0.017 Mb of oil and 0.47 Mb of water (817 producing days) for an average of 21 b/d per well with a watercut of 96%.

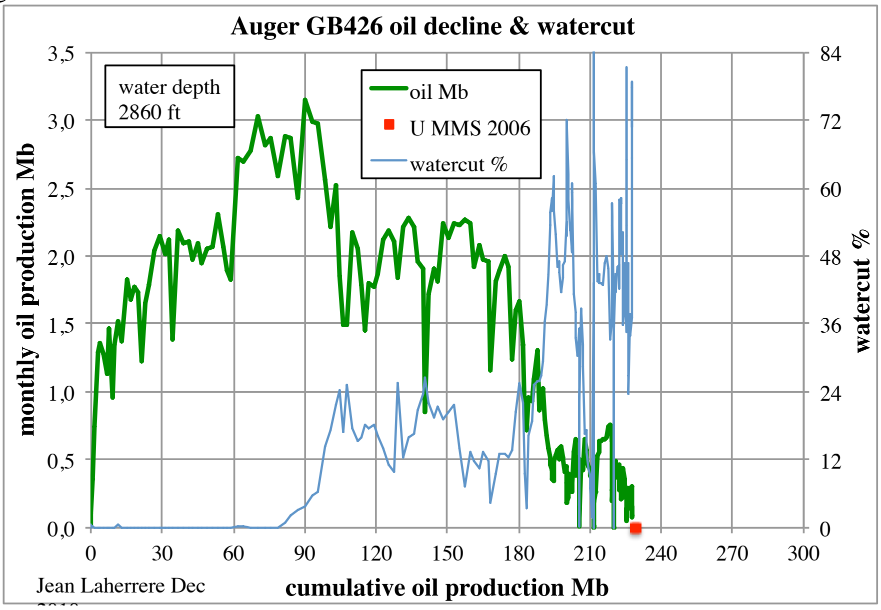
-Auger GB426

Auger was found in 1987 by 2860 ft water depth, operated by Shell. Oil production peaked in 1997 showing steps in the increase and the decrease.
Auger is produced through a TLP (Tension Leg Platform) platform
Figure 77: Auger GB426 monthly production & watercut



Since 2002 the decline is steep, about 2% per month

Figure 78: Auger oil decline

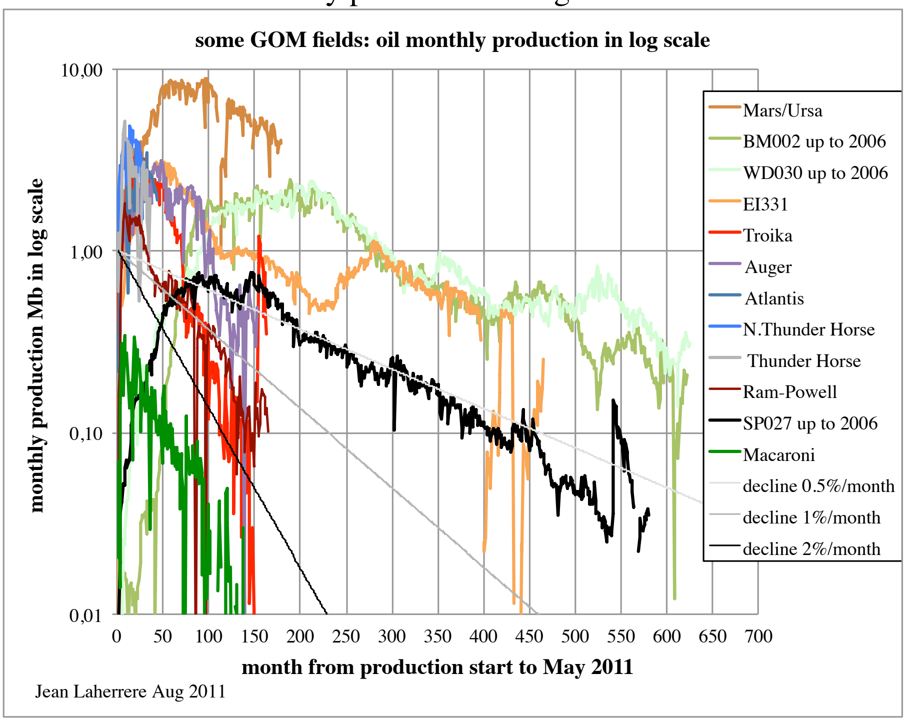


Present cumulative oil production is close to 2006 reserves estimate with a low monthly production, does it mean that the field is depleted? Maybe not for the TLP platform (which collects several fields around like Llano and soon Cardamon), because Shell has proposed last March to drill 3 exploratory wells on the same lease and this proposal was approved by the BOEMRE: it is the first approval after Macondo blow out.

-synthesis

All the monthly oil production of the above fields are plotted from production start in the following graph together with lines showing a monthly decline of 0.5 %, 1 % & 2% (corresponding to an annual decline of 6 %, 11.5 % & 21.5 %)

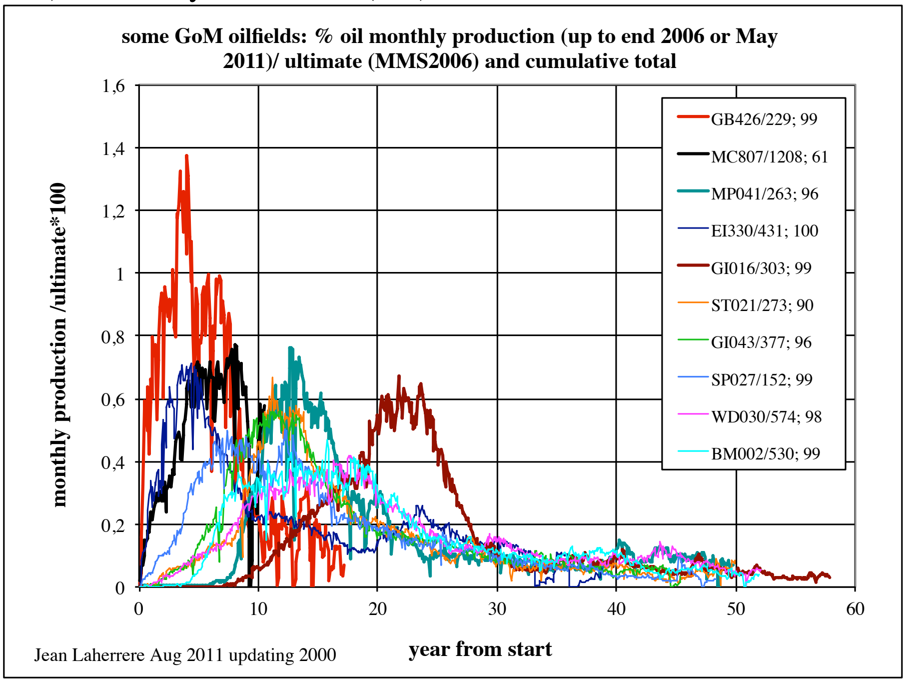
Figure 79: some GoM fields: oil monthly production in log scale



The shallow water fields like BM002, WD030 and EP027 present a long peak (100 months) starting at least after 50 months and a monthly decline around 0,5%, when the deepwater peak starts quickly, is short and the monthly decline is about 1%

In 2000 I plotted the monthly oil production of several GOM fields in percentage of their ultimate, it means that the area below the curve should be the same for each field, being equal to 100 when the field is abandoned. The cumulative addition at the end of the curve is given in the title and the graph is updated to now

Figure 80: some GoM fields: percentage of the monthly production (from production start up to end 2006 or May 2011) divided by its ultimate (Mb)

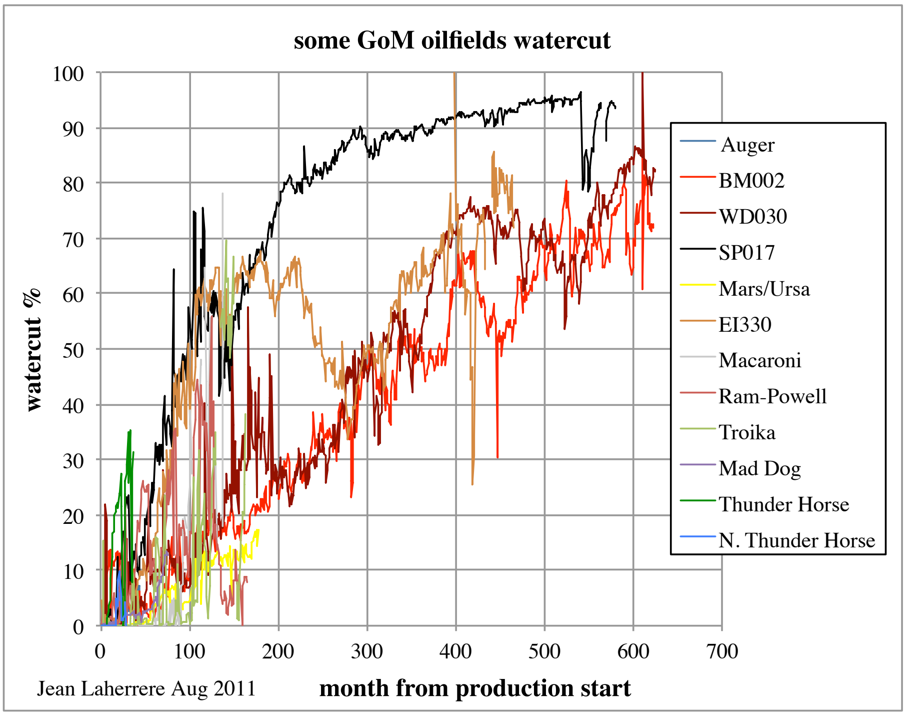


All of these fields have produced more than 96% of its ultimate, except MC807 = Mars/Ursa (61%). The peak of oil production occurs few years after production start for deepwater at a level of over 1% of ultimate per month like for Auger GB426 but about 0.7% for Mars/Ursa.

Shallow water displays a peak about 0,6% (MP041, GI016) but the peak occurs after ten years (even 20 years for GI016)

The watercut of the GoM fields is variable depending upon the reservoir, the trap. Watercut is not a problem onshore. On deepwater the economical threshold is different from shallow water.

Figure 81: some GoM fields: watercut %



-Conclusion

Forecasting future deepwater (>500 m) oil production needs to estimate the ultimate using the creaming curve of past discoveries as shown in figure 3 where then plot trends towards 150 Gb. It is necessary to check if the reported discoveries reserves are well estimated and the best place to do so is the Gulf of Mexico where all production data are freely available, unfortunately on not the easiest way.

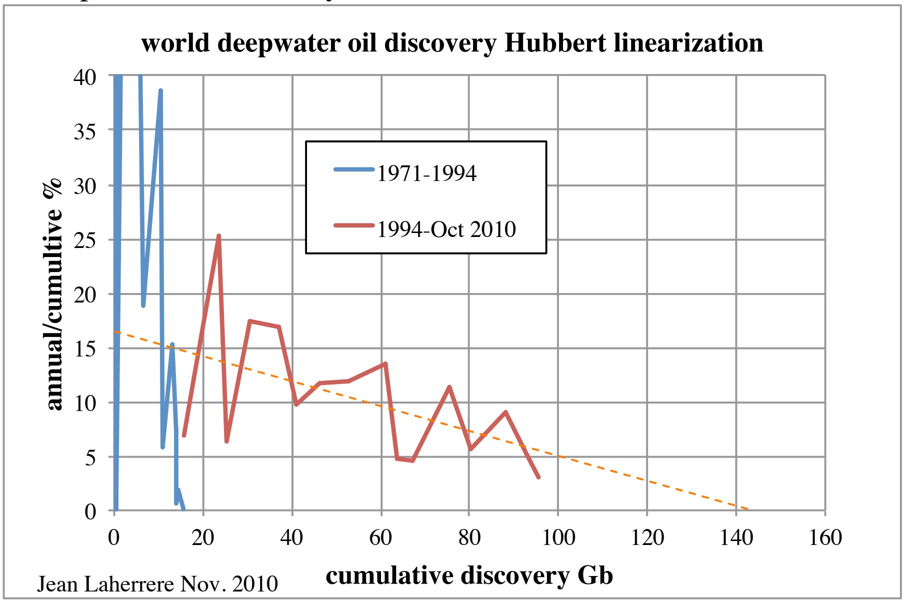
Most of shallow fields are largely depleted and the estimates published as end 2006 are reliable, when compared to the cumulative production trend. Their average decline is about 0.5 % per month or 6 % per annum.

Deepwater fields display a sooner peak and a sharper decline about 2 % per month or 22 % per annum. Deepwater production needs because of sharp decline more wells to be drilled despite that most of d the drilling is planned to be done at the beginning 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 to have a reliable extrapolation of past production.

But it seems that the past discoveries of figure 3 will not change much and so the extrapolation if no new cycle occurs.

The Hubbert linearization (poorly reliable) trends towards 150 Gb.

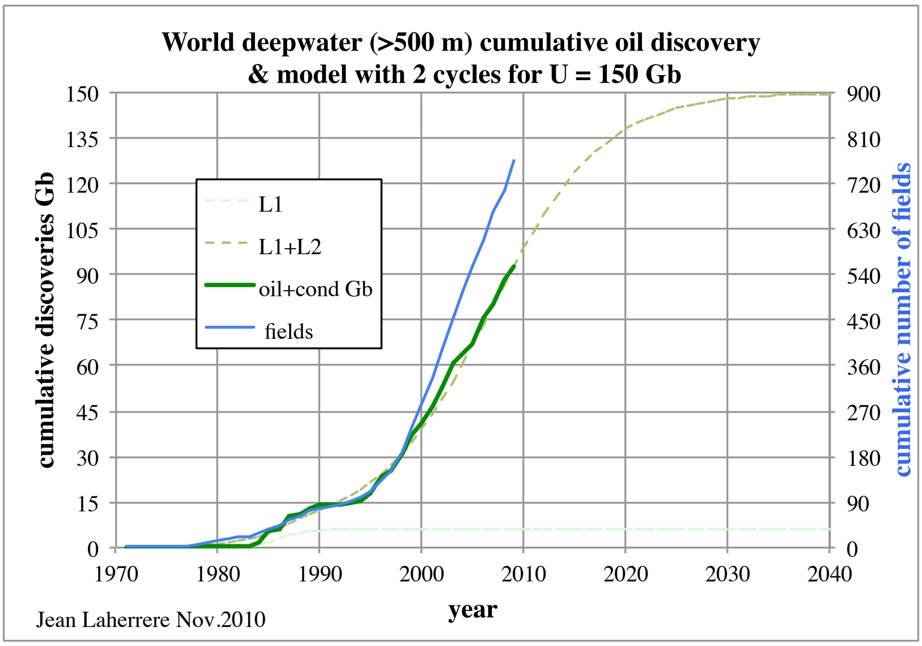
Figure 82: world deepwater oil discovery Hubbert linearization



Colin Campbell using the same definition of deeper than 500 m estimates the deepwater ultimate at 100 Gb in 2010.

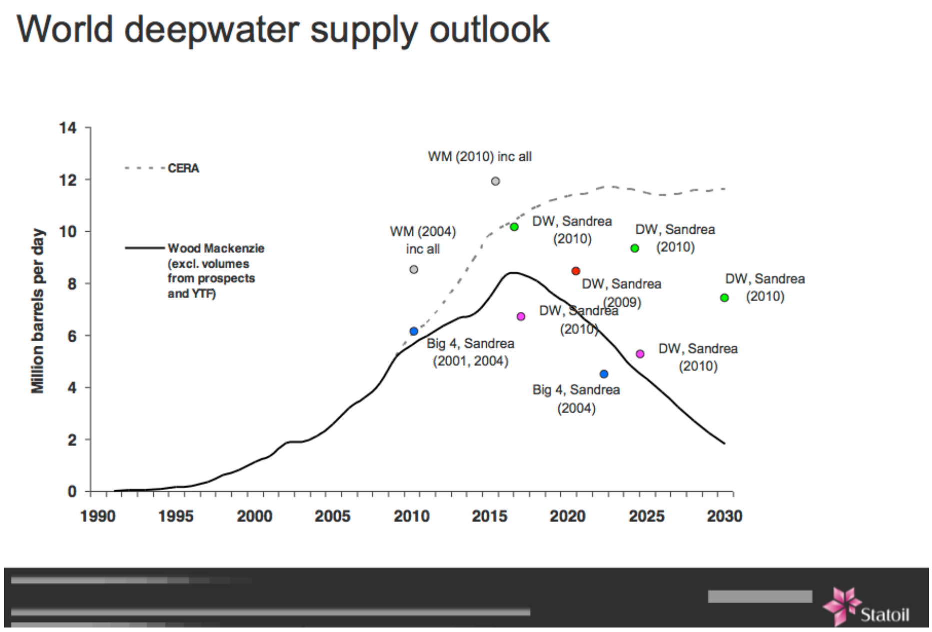
The world deepwater cumulative discoveries versus time is extrapolated with a S curve towards 150 Gb.

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



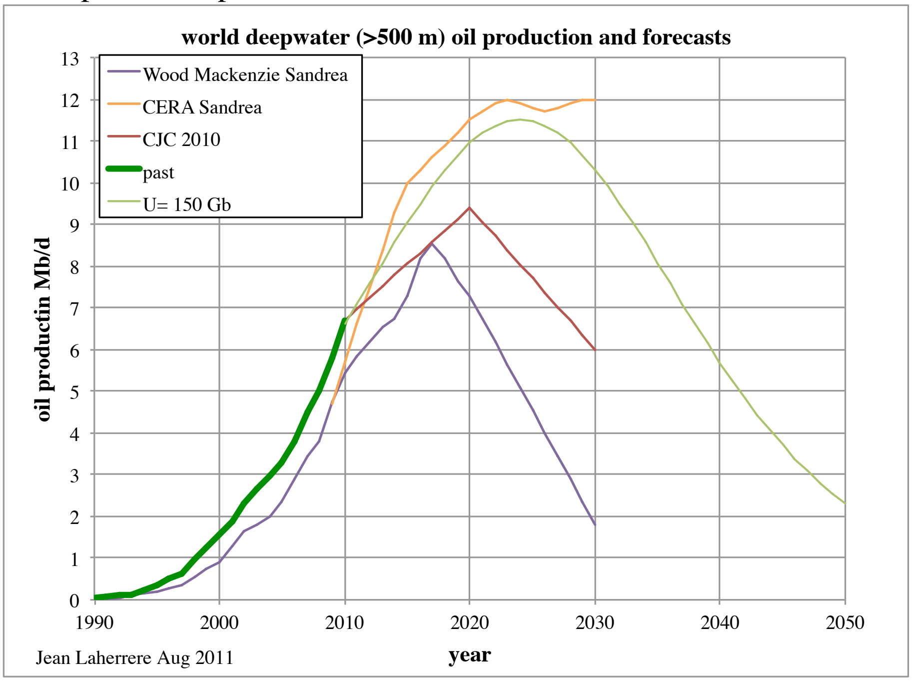
Forecasting the world deepwater annual oil production is difficult because first the past production is not fairly available (many different definitions of deepwater) and because the large fields of subsalt Brazil are likely difficult to produce (high pressures and lack of aquifer drive) and very expensive. But Petrobras seems to handle the development fairly well, but having an almost monopoly is not good.

I.Sandrea VP Statoil has presented (IEF Nov. 2010) "Potential Consequences of the Gulf Oil Spill on Future Offshore/Deepwater Oil Developments" the forecasts from Wood Mackenzie (WM) from present projects with a peak around 2017 at over 8 Mb/d and a steep decline down to 2 Mb/d in 2030, in contrary to CERA which goes up to 12 Mb/d plateau from 2020 to 2030.
Figure 84: world deepwater oil supply outlook from I.Sandrea EIF 2010



It is hard to get a reliable past deepwater production because the different definitions for deepwater. The deepwater production is about 6.7 Mb/d in 2010 and using the ultimate of 150 Gb the model gives a peak about 11.5 Mb/d around 2024 and about 2 Mb/d in 2050. This forecast with 150 Gb is close to CERA forecast, but higher than WM (limited to present projects) and also Campbell (U = 100 Gb).

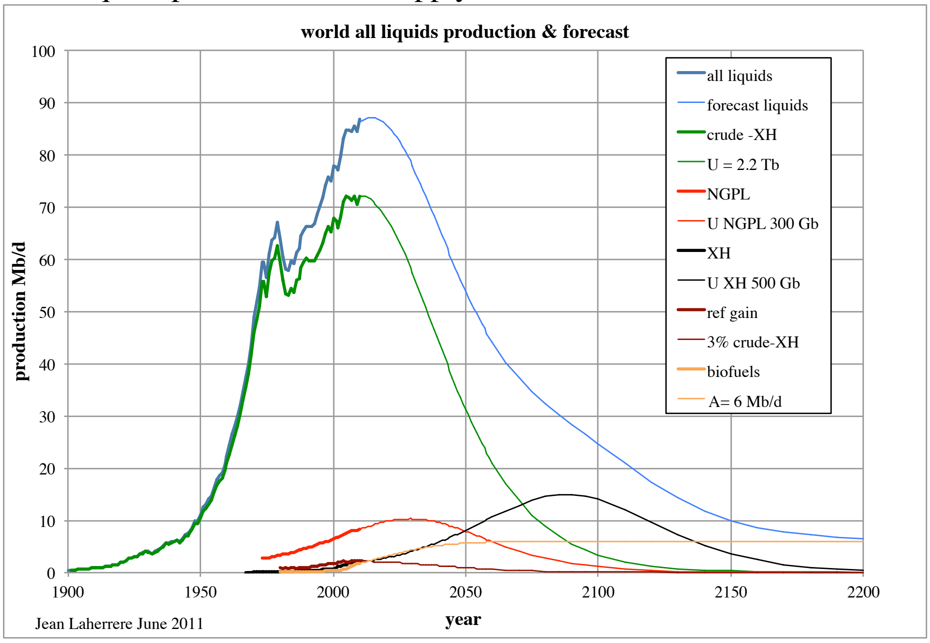
Figure 85: world deepwater oil production & forecast for U = 150 Gb and CERA & WM



This deepwater forecast is in fact included in my forecast of crude oil excluding extra-heavy of figure 1 for an ultimate of 2200 Gb.

My forecast for all liquids is still unchanged after this study

Figure 86: world all liquids production = oil supply from EIA data



The present bumpy plateau since 2005 around 87 Mb/d to now with a variation of 2 Mb/d (which is equal to the accuracy of the value = difference between EIA and IEA or OPEC values) will continue for few years before a significant decline.

The still going economical and financial crisis can disturb this bumpy plateau.