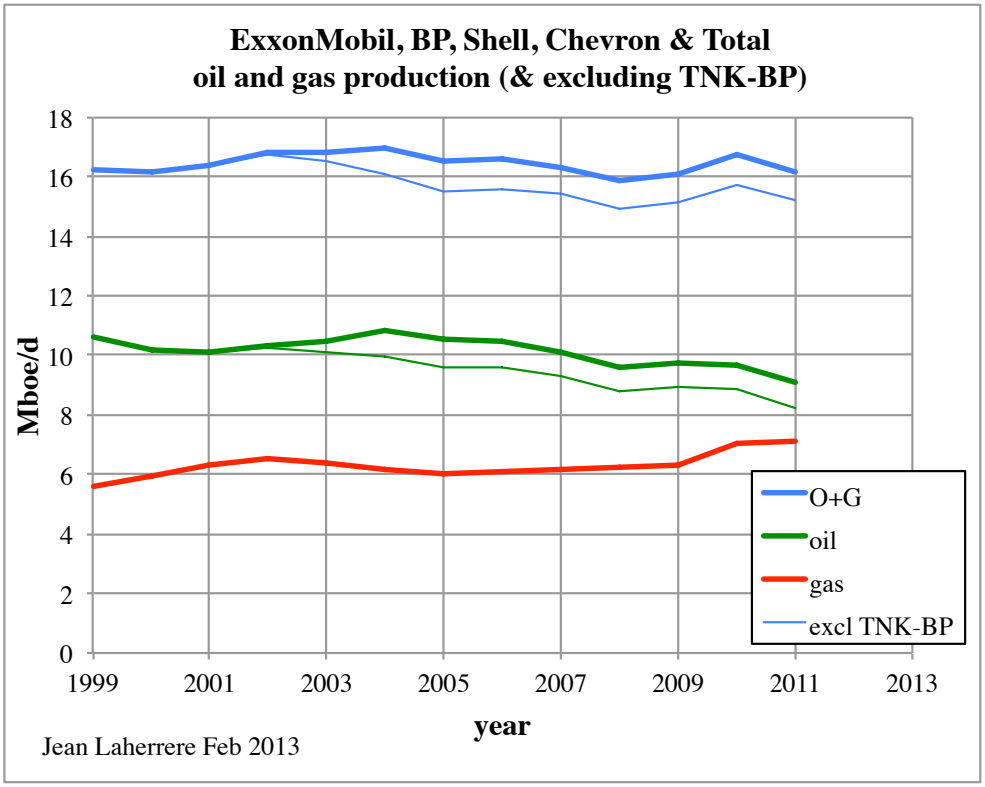
Jean Laherrère 25 February 2013

IOCs productions and forecasts: Why are forecasts always too optimistic?

-ExxonMobil, BP, Shell, Chevron and Total

From annual reports, annual net productions for ExxonMobil, BP, Shell, Chevron and Total are plotted. IOCs (International Oil Company) sites are poor with archives, in particular with forecasts.

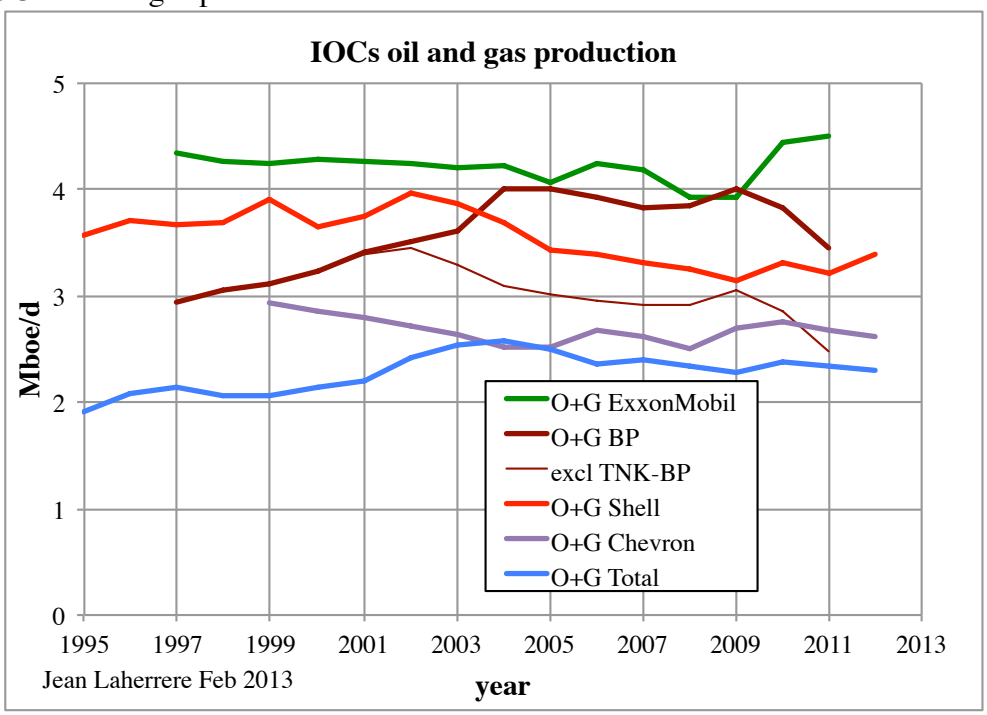
Figure 1: ExxonMobil, BP, Shell , Chevron & Total oil & gas production oil and gas production



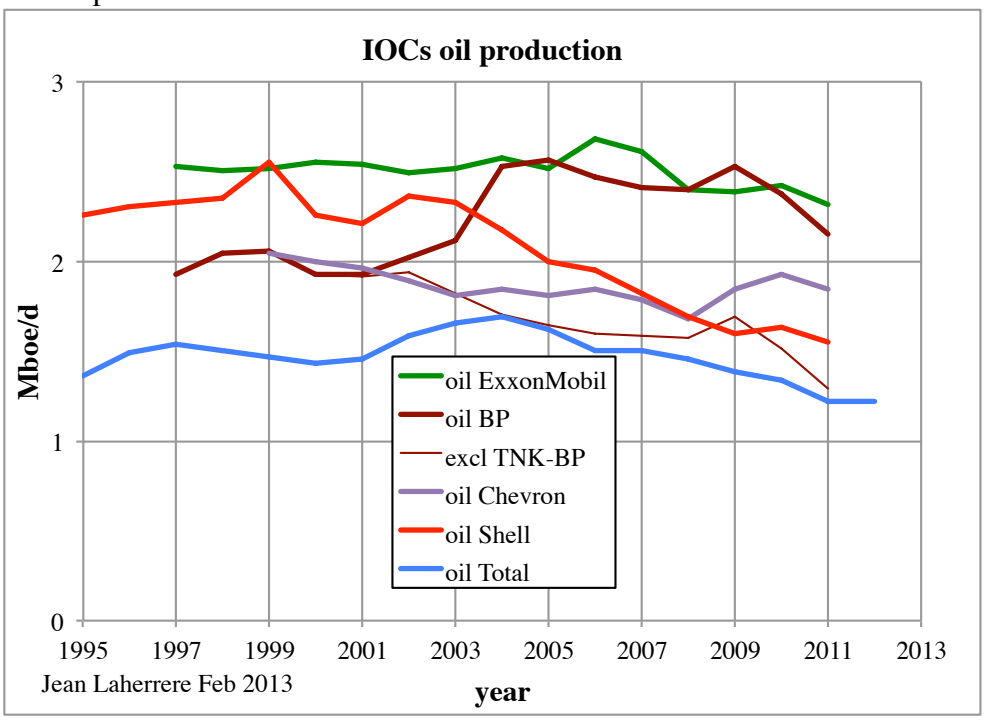
The five IOCs oil & gas production is almost flat, small decrease for oil and small increase for gas, but excluding TNK-BP, oil & gas production declines since 2002

The detail by company is more chaotic

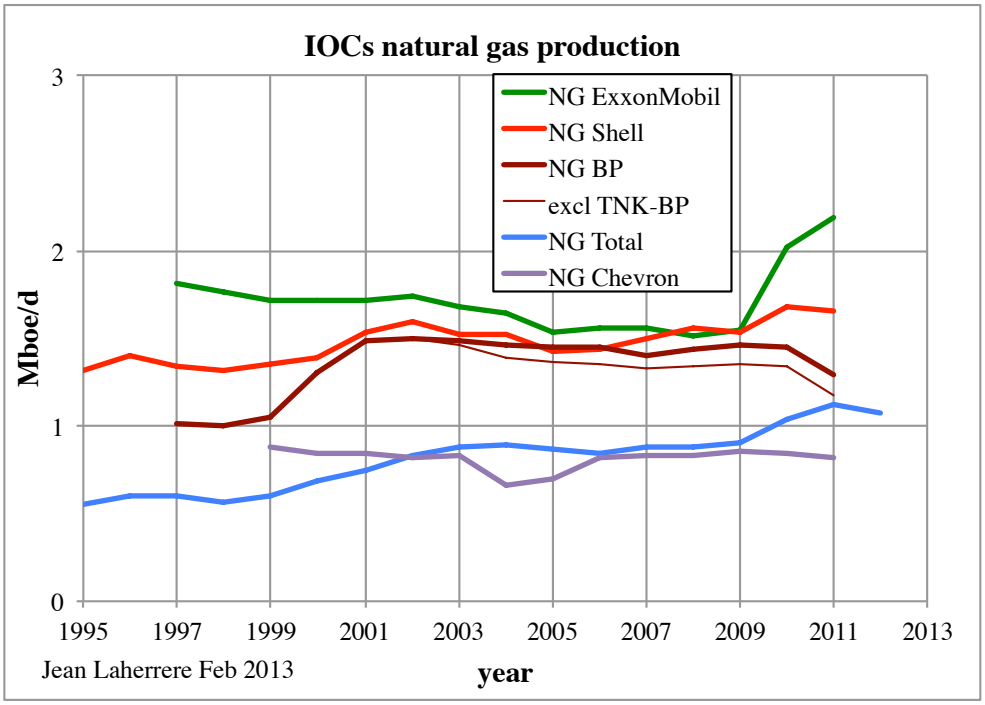
Figure 2: IOCs oil and gas production



BP includes TNK-BP, but BP was obliged in 2012 to sell TNK-BP to Rosneft in exchange for shares.
All IOCs oil productions are in decline in 2011
Figure 3: IOCs oil production



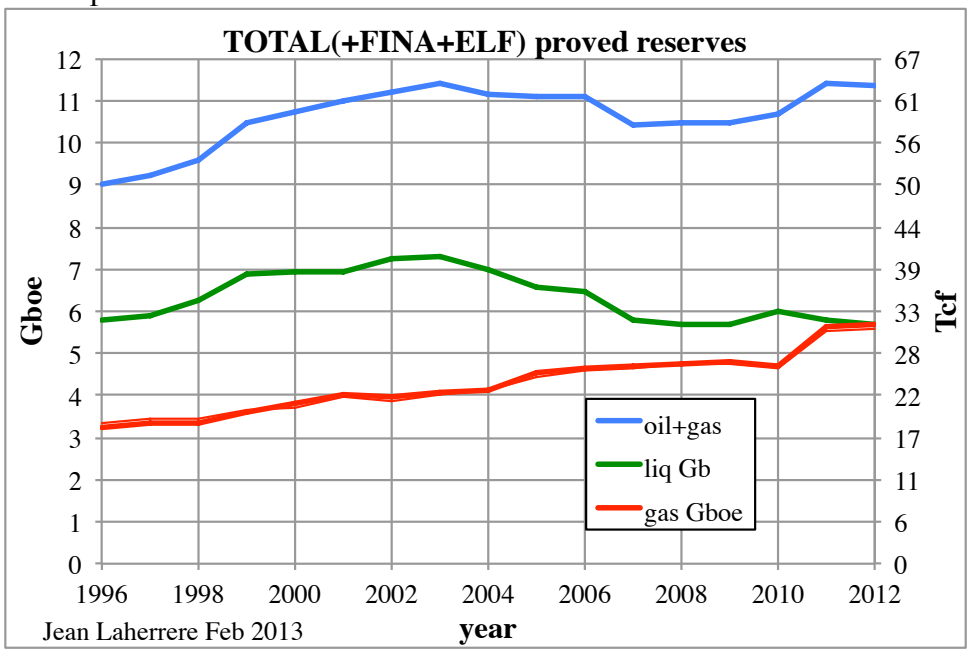
IOCs report the oil volume they are entitled to receive from production sharing contracts (PSC like in Indonesia) The amount they produced could stay flat but, when oil price increases, the amount of cost oil and profit oil that they received is reduced. The prime goal of the PSC was to be out of taxes, avoiding any future change in the taxes and fight between the finance ministry and the energy ministry. The goal of this paper is to compare real production and forecasts, and IOCs should foresee the oil price changes and the impact of PSCs.
ExxonMobil has sharply increased its gas production since 2009 thanks to Qatar and US shale gas (where CEO Tillerson stated “we are losing our shirts” after a very expensive acquisition)
In 2011 all IOCs have increase NG production since 1997 except Chevron.
Figure 4: IOCs gas production



-TOTAL

Total (with the acquisition of FINA and ELF) oil & gas reserves are plateauing since 2003, when oil reserves are on the decline. In 2012 Total oil reserves equal gas reserves gas.

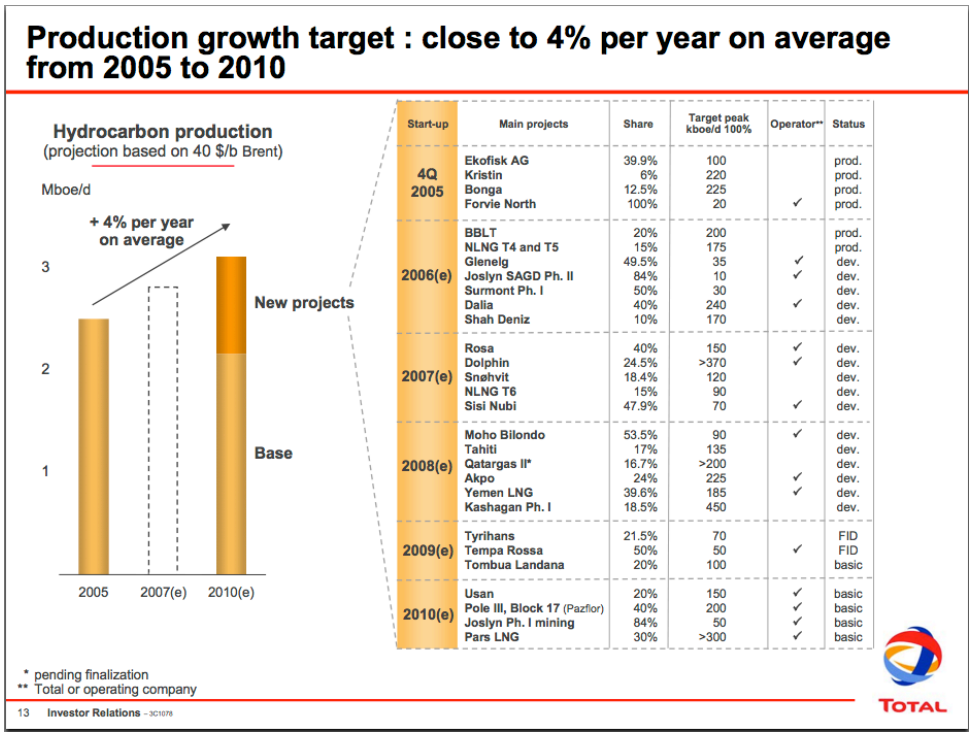
Figure 5: TOTAL proved reserves



In TOTAL publishes production forecasts in its annual results and outlook.

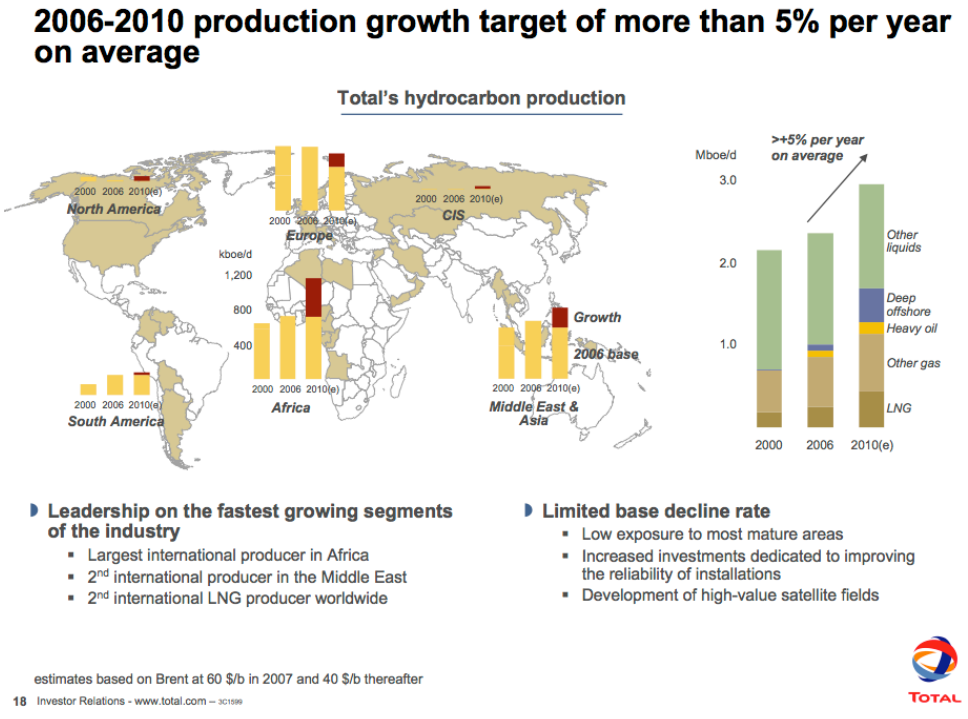
TOTAL 2005 outlook hopes a growth of 4% from 2005 to 2010, justified by the list of new developments

Figure 6: Total 2005 outlook: production growth target of 4%/a

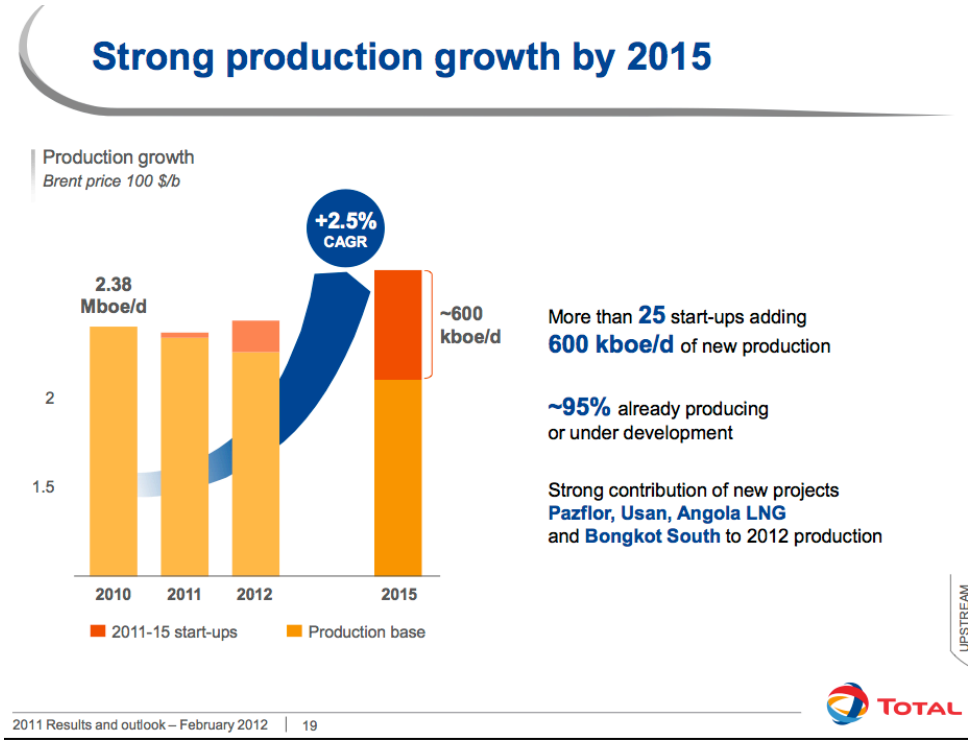


Total 2005 outlook forecasted Kashagan field starting in 2008 (Total 2012 forecast = 2013) and Tempa Rossa (Italy) in 2009 (Total 2012 = 2016)

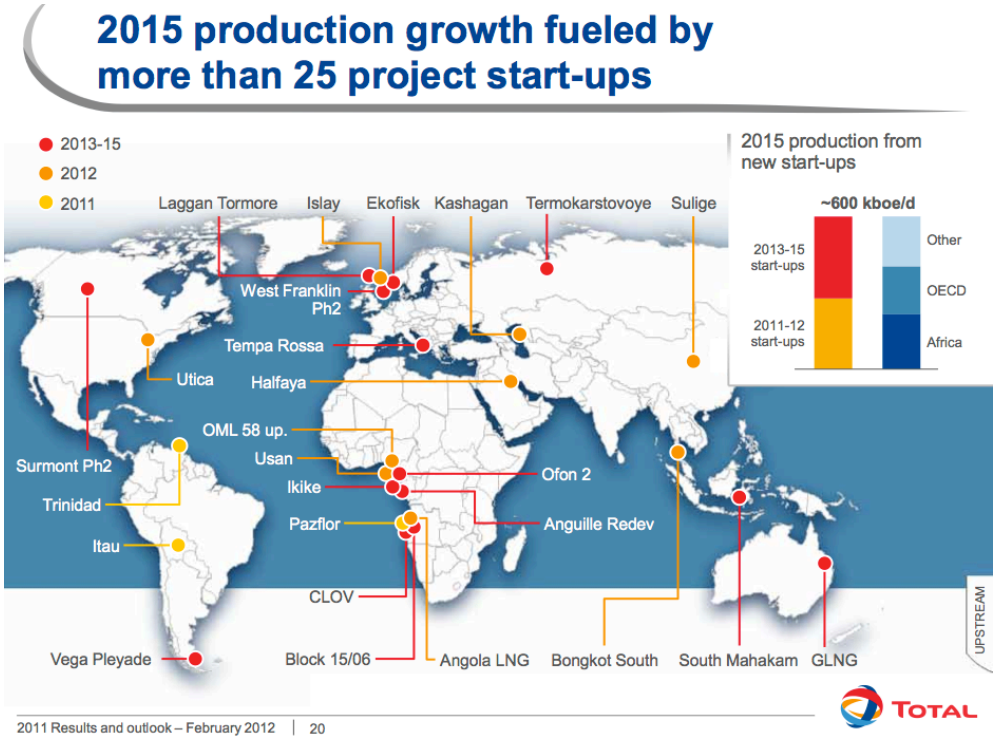
TOTAL 2006 outlook increases production growth at 5% from 2006 to 2010
Figure 7: Total 2006 outlook: production growth target of 5%/a



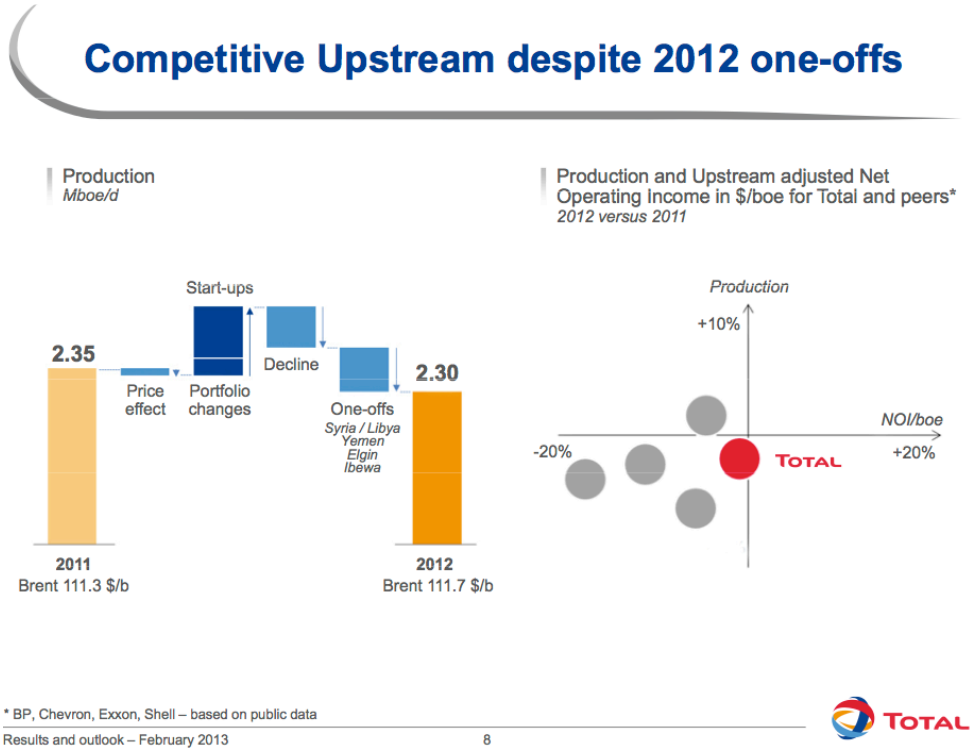
TOTAL 2011 outlook claims a strong growth by 2015
Figure 8: Total 2011 outlook: strong production growth by 2015



2015 production growth is fueled by more than 25 project start-ups adding 600 kboe/d
Figure 9: Total 2011 outlook: 25 project start-ups by 2015

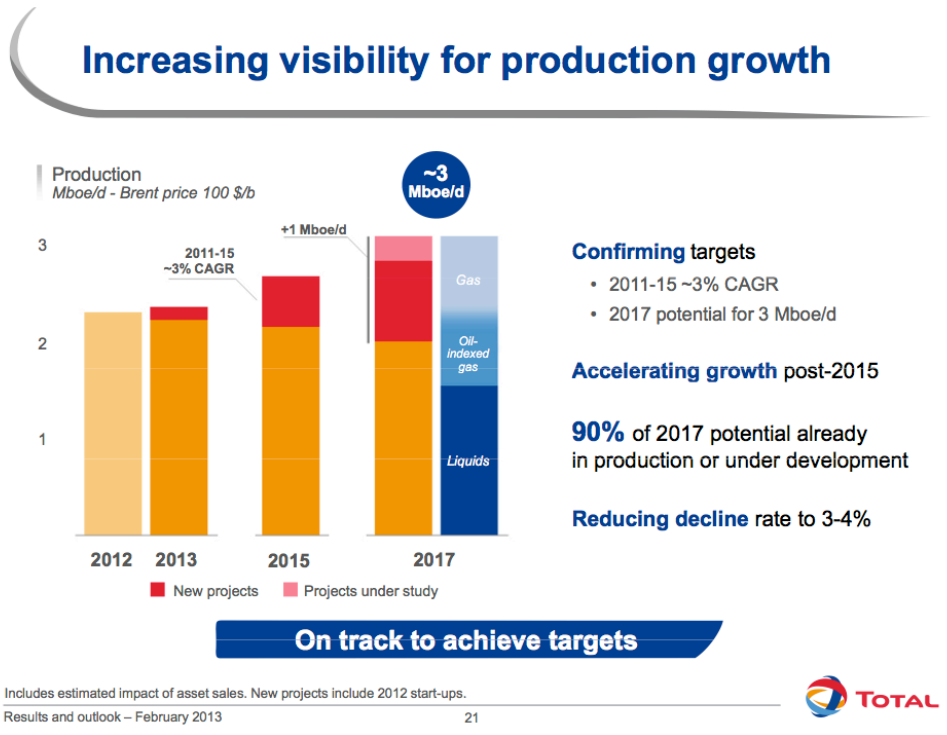


TOTAL 2012 (February 2013) outlook explains why 2012 is down: the forecast start-ups were there but also there were unexpected decreases on Syria, Libya, Yemen, Eglin, Ibewa
Figure 10: Total 2012 outlook: why 2012 is down



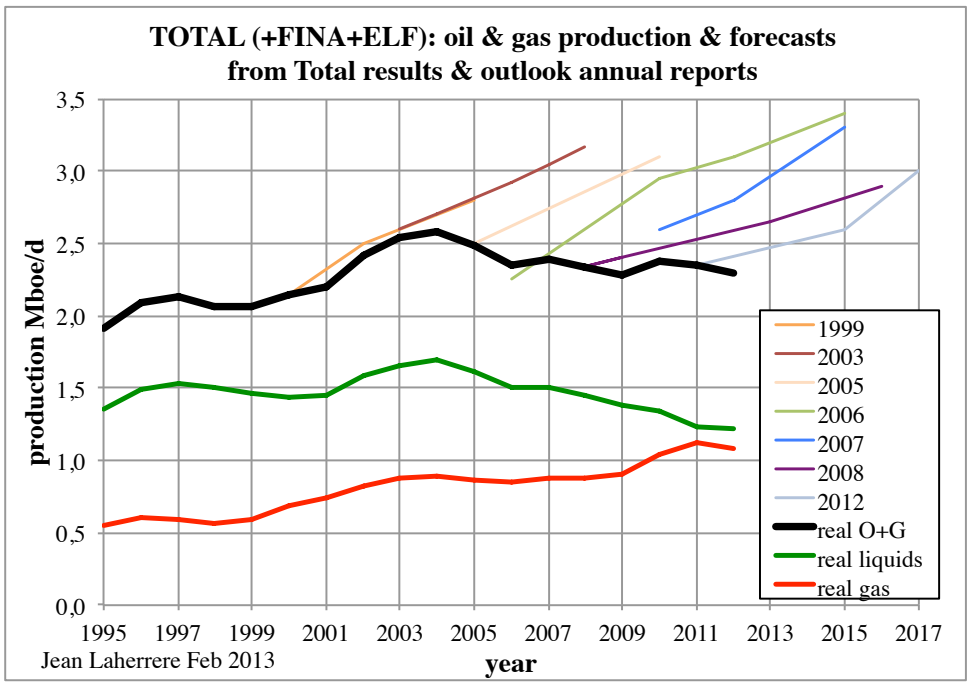
Despite the occurrence of unexpected in 2012, TOTAL believes that negative events will not occur anymore in the future and that 2017 production will grow to 3 Mboe/d

Figure 11: Total 2012 outlook: 2017 will grow to 3 Mboe/d



The plot of TOTAL oil & gas real production and the forecasts shows clearly that TOTAL is always too optimistic by forgetting to foresee unexpected bad events like they occur in 2012. TOTAL is right in forecasting positive events, but wrong in not allowing bad events: it is obvious looking by the forecasts since 1999 that TOTAL should provide also negative growth for bad events.

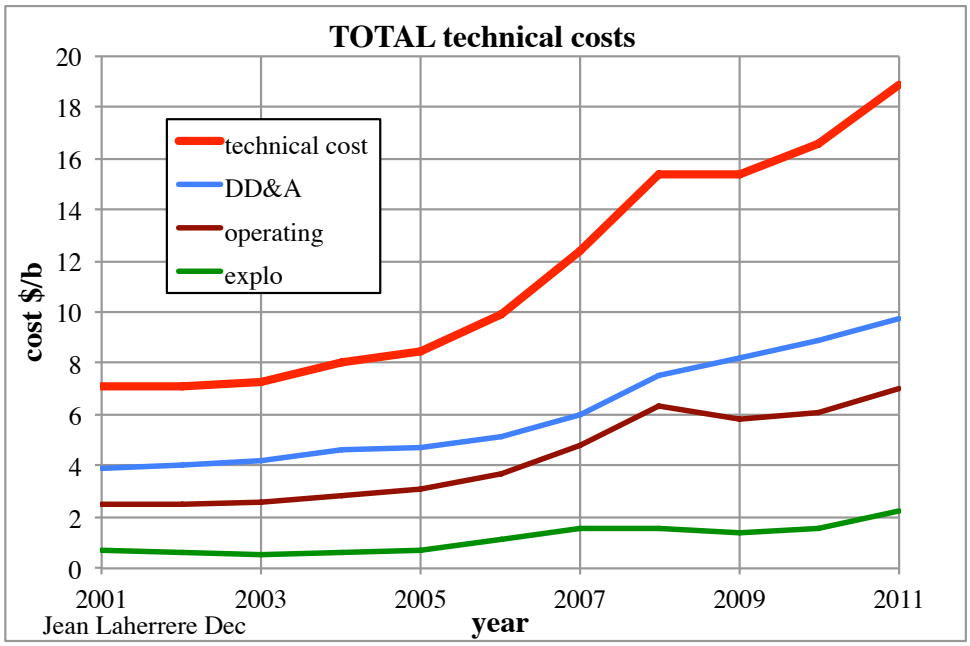
Figure 12: TOTAL oil & gas production and forecasts



Total publishes its technical costs (following SEC rules) which have increased from 7 $/boe in 2001 to 19 $/boe in 2011

In 2011 exploration cost was only 2 $/boe, when operating cost was 7 $/boe and DD&A (depreciation, depletion and amortization) was 10 $/boe. The general and administration costs are not published!

Figure 13: Total technical costs



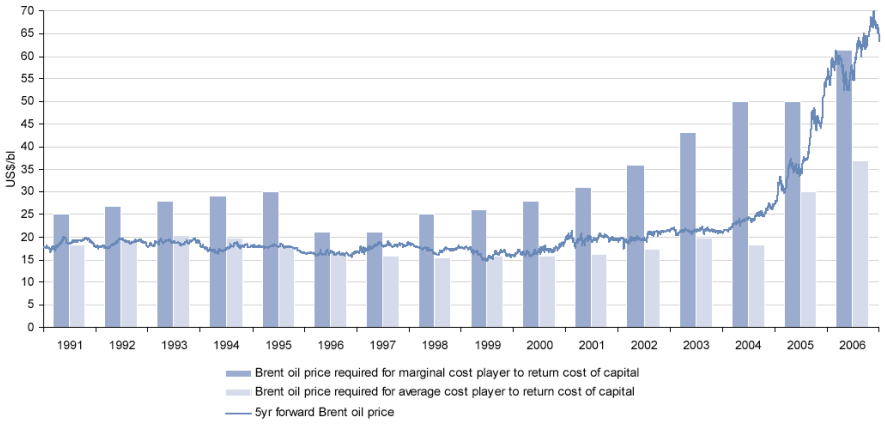
This cost has to be compared to the break even point, which is reported by Goldman Sachs for the period 1991 to 2006, being in 2006 from 35 to 60 $/b (compared to Total technical cost at 10 $/b)

The average cost (in grey) started to rise in 2005 like then oil price.

What is important for Total technical cost is the increase in % being 270% from 2001 to 2011

Figure 14: E&P cost in a Total paper from Goldman Sachs study 1991-2006

Rise in long-dated prices supported by sharp rise in E&P cost structure
(Goldman Sachs)



Source: Company data, Goldman Sachs Research estimates.

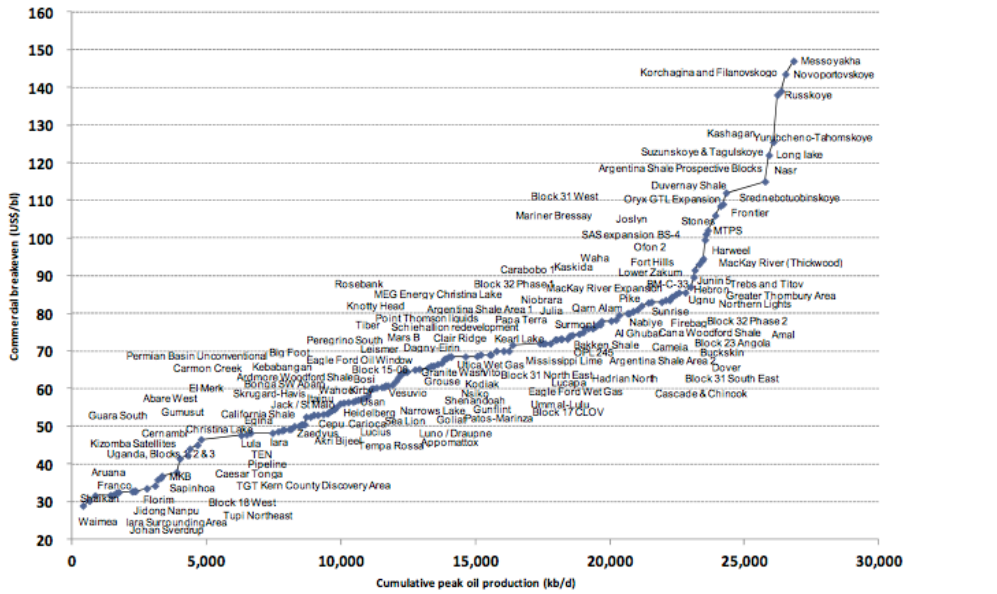
TOTAL

And also in 2012 of 360 recent oilfields ranging from 30 to 145 $/b

Figure 15: breakeven of 360 non-producing & recent onstream oilfields from Goldman Sachs

Exhibit 8: Marginal Top 360 oil fields require US$100/bl+ oil price

Breakeven of non-producing and recently onstream oil assets



Our estimates for breakeven prices do not include the costs of acreage acquisition or exploration that, if included, would lead to higher breakeven commodity prices. This can be particularly material for North American onshore resource plays.

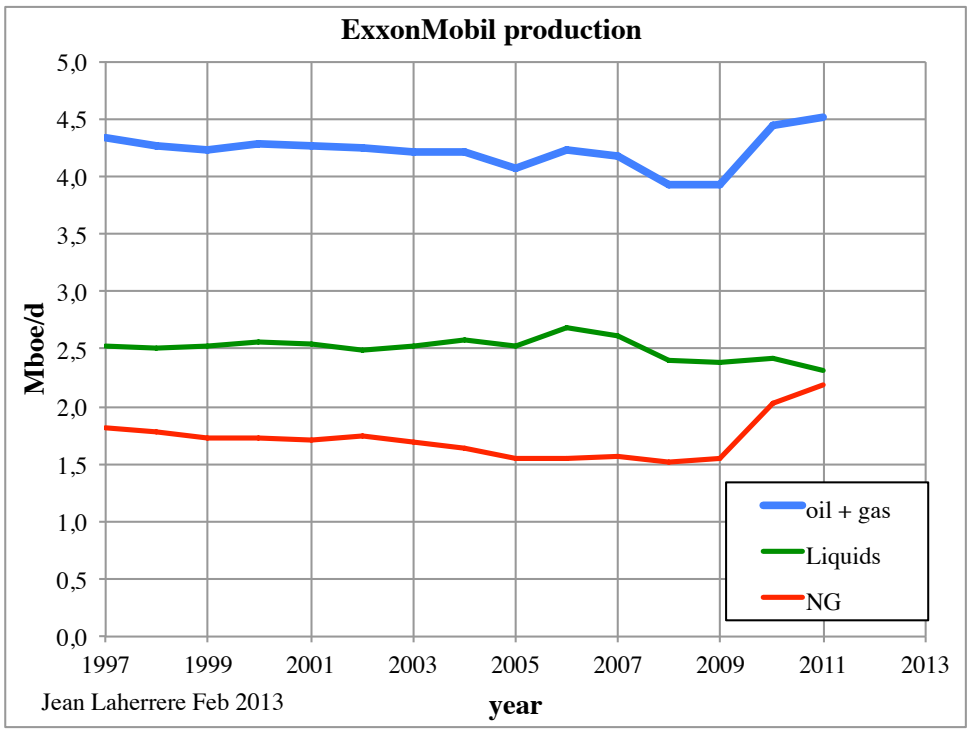
Source: Goldman Sachs Research estimates.

Kashagan breakeven is estimated at 125 $/b

-ExxonMobil

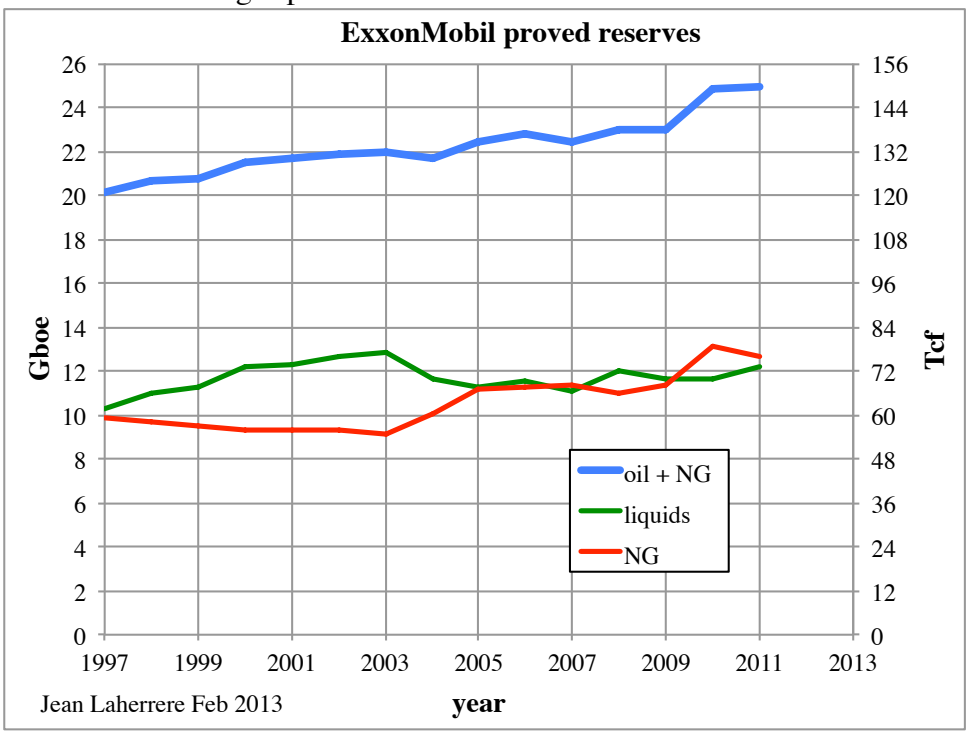
ExxonMobil oil production is almost flat since 1997, but NG production increases thanks to Qatar and shale gas

Figure 16: ExxonMobil oil and gas production



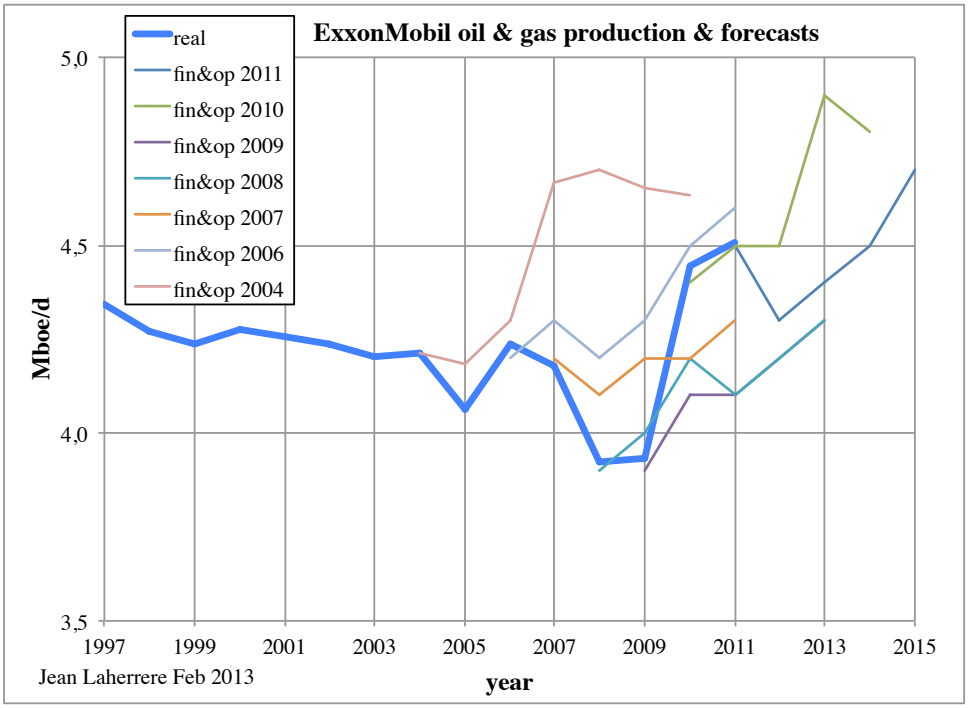
ExxonMobil proved reserves has slightly increased since 1997, with gas being higher than oil since 2010. Gas reserves are down in 2012 when production is up

Figure 17: ExxonMobil oil & gas proved reserves



ExxonMobil provides forecasts in the financial and operating review report.

Figure 18: ExxonMobil oil & gas production and forecasts



Like Total, ExxonMobil forecasts provides all the projected new fields production, but only the good expected events and no bad unexpected ones. They are too optimistic on timing, in particular in 2004. where Thunder Horse was assumed to start in 2005 (real 2008); Kashagan and Tempa Rossa were assumed to start in 2008 (now 2014 and 2016) and Hebron Canada in 2008 (now 2017).

Figure 19: ExxonMobil 2005 major development projects

Major Development Projects

Expected Project Start-Ups

	ExxonMobil Working Interest (%)	Target Peak Production (Gross) Liquids (kBD)	Gas (MCFD)	
2004				
Angola – Kizomba A	40	250	–	■
Canada – Sable Energy Tier 2 – South Venture	60	10	140	■
Chad – Bolobo	40	60	–	■
Norway – Sleipner West Alpha North	32	15	195	●
Norway – Sleipner West Compression	32	20	250	●
Qatar – RasGas Train 3	29	30	725	▲
U.K. – Goldeneye	39	30	260	●
U.K. – Scoter	44	5	125	●
2005 (Projected)				
Angola – Kizomba B	40	250	–	■
Azerbaijan – Azeri-Chirag-Gunashli (ACG) Phase 1	8	325	–	●
Nigeria – Bonga	20	200	150	●
Qatar – Al Khaleej Gas Phase 1	100	50	600	■
Qatar – RasGas Train 4	34	45	740	▲
Russia – Sakhalin-1 (Chayvo) Phase 1	30	250	1,000	■
U.K. – Arthur	70	5	120	■
U.S. – Thunder Horse	25	250	200	●
2006 (Projected)				
Angola – Dalia	20	225	–	●
Azerbaijan – ACG Phase 2	8	465	–	●
Canada – Syncrude Upgrader Expansion	25	110	–	●
Kazakhstan – Tengiz Phase 1	25	300	100	●
Malaysia – Guntong Hub	50	35	715	■
Nigeria – Amenam / Kpono Gas Project	10	25	235	●
Nigeria – East Area Additional Oil Recovery	40	115	20	■
Nigeria – Erha	56	150	–	■
Norway – Fram East	25	40	50	●
Norway – Kristin	11	140	500	●
U.S. – Princess Phase II	16	25	65	●
U.S. – Ursa Pressure Maintenance	16	35	15	●
2007 (Projected)				
Angola – Kizomba C	40	250	–	■
Angola – Rosa Area	20	140	–	●
Norway – Njord Gas Export	20	15	185	●
Norway – Ormen Lange	7	30	2,000	●
Norway – Statfjord Late Life	21	65	350	●
Qatar – RasGas Train 5	30	45	740	▲
U.K. – Caravel	29	5	170	●

	ExxonMobil Working Interest (%)	Target Peak Production (Gross) Liquids (kBD)	Gas (MCFD)	
2008+ (Projected)				
Angola – LNG	14	50	965	●
Angola – Kizomba D	40	125	–	■
Angola – Lirio-Cravo	20	115	–	●
Angola – Perpetua-Zinia-Acacia	20	125	–	●
Angola – Plutao-Saturno	25	110	–	●
Australia – Greater Gorgon/Jansz Project	*	10	1,500	●
Australia – Kipper/Tuna	41	25	270	■
Azerbaijan – ACG Phase 3	8	260	–	●
Canada – Hebron	38	165	–	●
Canada – Kearl	100	100	–	■
Canada – Mackenzie Gas Project	57	10	850	■
Indonesia – Banyu Urip	*	165	20	■
Italy – Tempa Rossa	25	50	20	●
Kazakhstan – Kashagan	17	1,200	–	●
Kazakhstan – Tengiz Expansion	25	220	–	●
Nigeria – Bonga Ullage	20	140	100	●
Nigeria – Bonga SW	20	85	65	●
Nigeria – Bosi Oil	56	110	–	■
Nigeria – East Area Natural Gas Liquids	51	40	–	■
Nigeria – Satellite Projects	40	125	–	■
Nigeria – Usan	30	150	–	●
Norway – Skarv/Idun	12	85	500	●
Norway – Tyrihans	8	70	380	●
Papua New Guinea – PNG Gas Project	26	20	415	■
Qatar – Al Khaleej Gas (Future Phases)	100	95	1,050	■
Qatar – Qatar GTL	100	165	1,440	■
Qatar – Qatargas II Train 4	30	80	1,250	▲
Qatar – Qatargas II Train 5	18	80	1,250	▲
Qatar – RasGas Trains 6 & 7	30	140	2,500	▲
U.S. – Alaska Gas Project/Point Thomson	36	70	4,500	*
U.S. – Piceance Tight Gas (Initial Phase)	100	2	400	■
U.S. – Western Region Development (Orion)	36	55	–	●

Major Global LNG Terminal Activity

	ExxonMobil Working Interest (%)	Primary Market	Supply Source
2007-2009 (Projected)			
Italy – Adriatic Terminal	45	Italy	RasGas
U.K. – South Hook Terminal	30	U.K.	Qatargas II
U.S. – Gulf Coast Terminal	30	U.S.	RasGas

Operatorship:
■ = ExxonMobil Operated ▲ = Joint Operation ● = Operated by Others

*Under negotiation – Not applicable

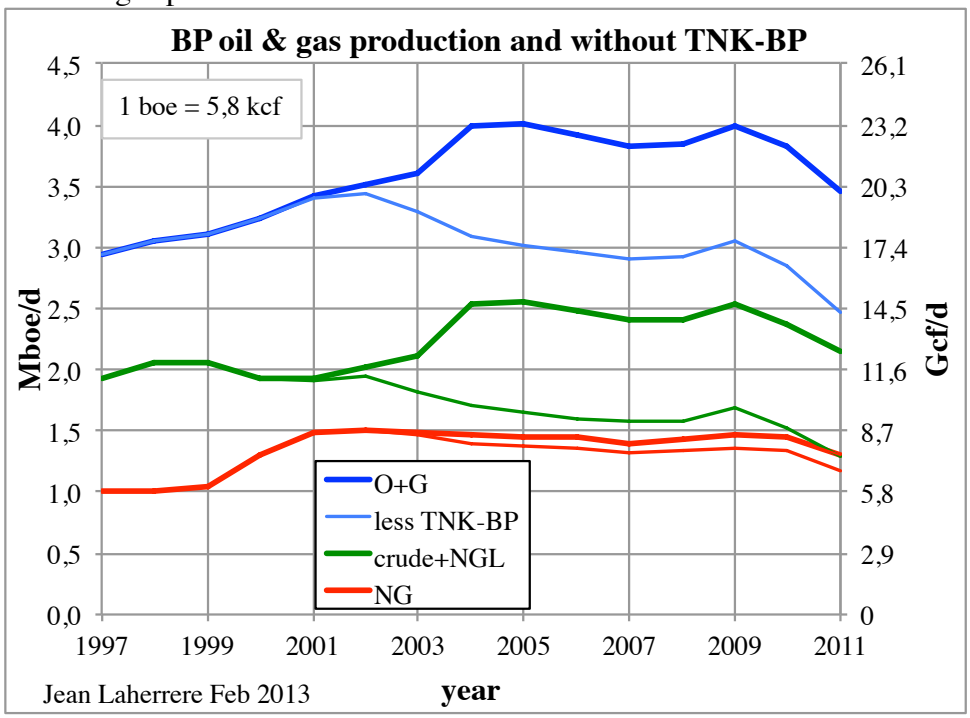
Supporting ExxonMobil's LNG efforts, regasification terminals are being progressed consistent with project demands. In addition to new-build terminals in the United Kingdom, Italy, and the United States, ExxonMobil continues to evaluate third-party terminals.

EXXON MOBIL CORPORATION • 2004 FINANCIAL & OPERATING REVIEW

-BP

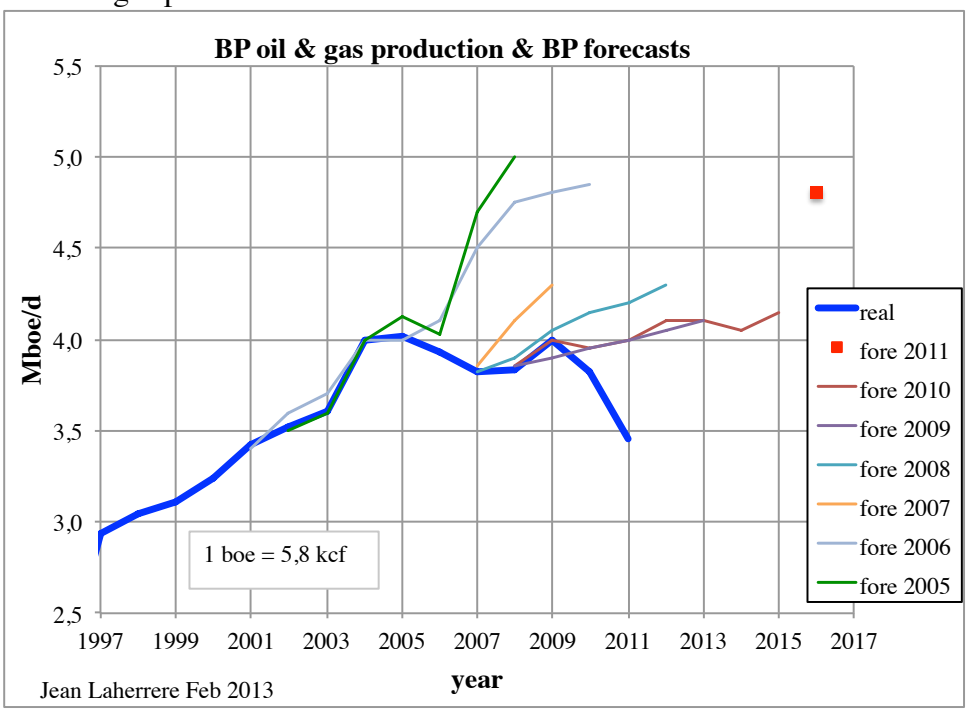
BP production is plotted with and without TNK-BP, which was sold in 2012. BP was obliged also to sell more assets after Macondo blow out

Figure 20: BP oil & gas production and without TNK-BP



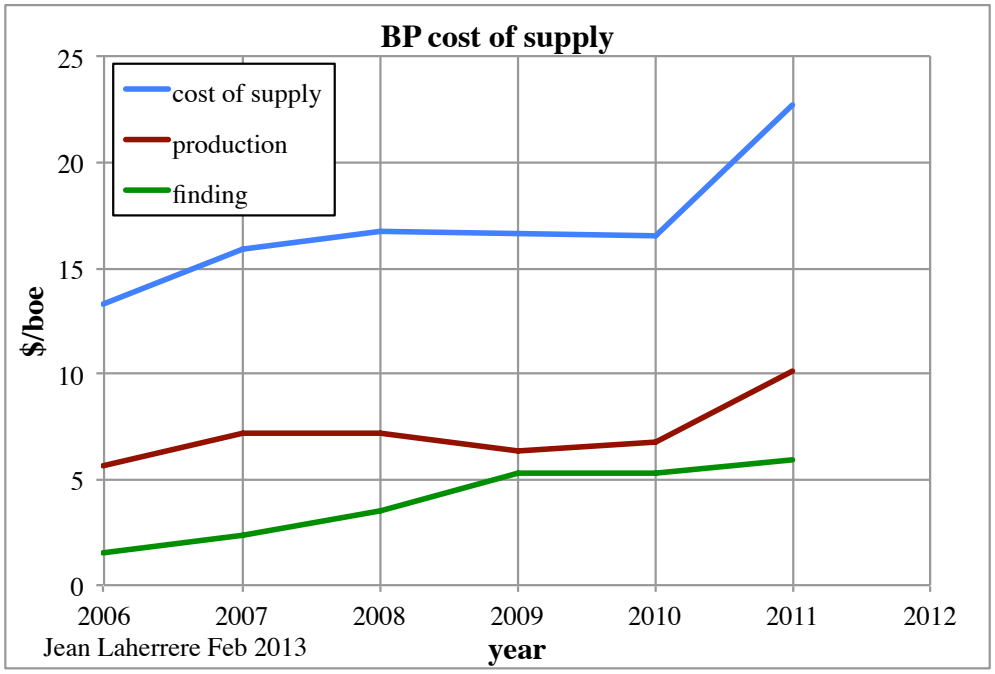
BP forecasts in 2004, 2005 1 2010 were much too high, as likely the 2011 forecast for 2017

Figure 21: BP oil & gas production and forecasts



BP reports cost of supply with only finding and production forgetting all the rest.

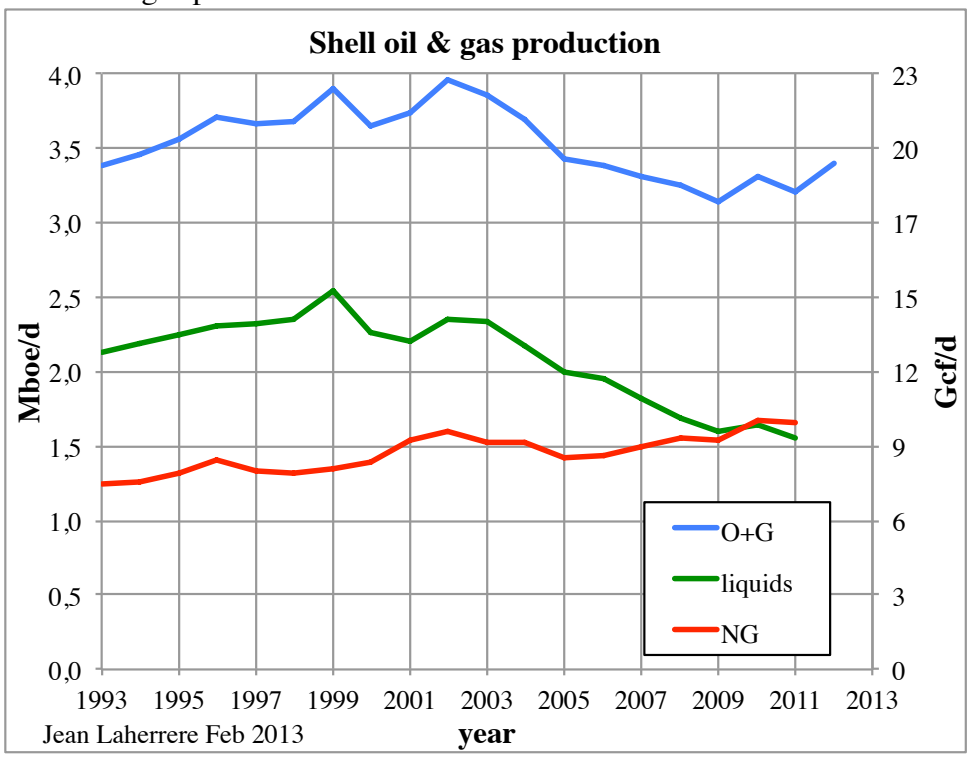
Figure 22: BP cost of supply



-Shell

Shell oil & gas production has peaked in 2002, but gas production is rising since 1993 when oil production is declining since 1999. In 2011 Shell has produced more gas than oil.

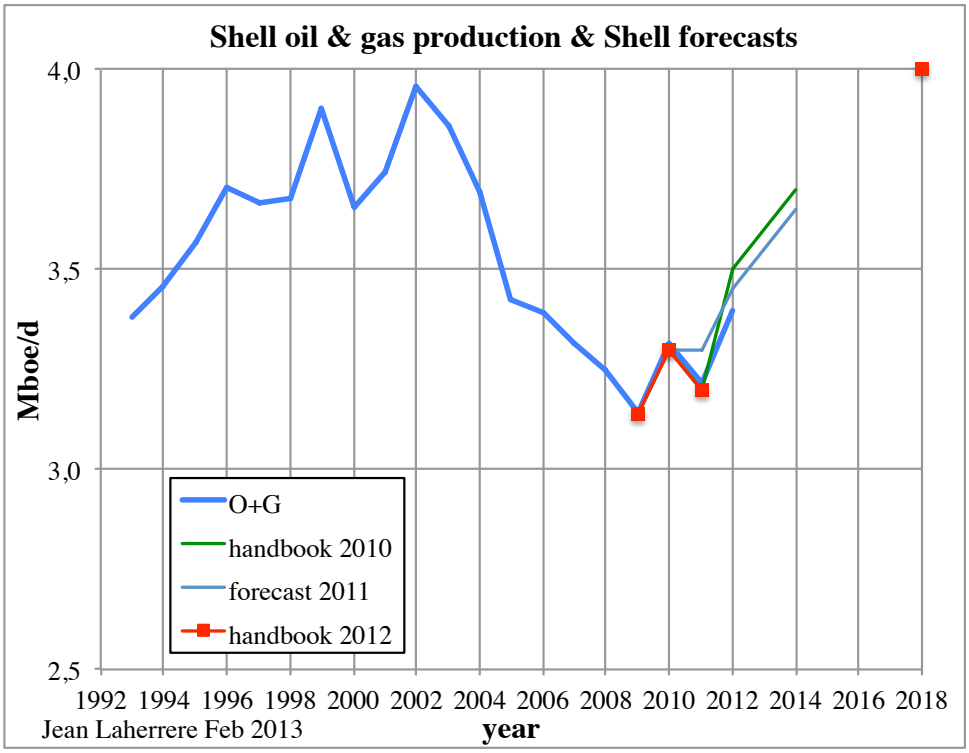
Figure 23: Shell oil & gas production



Shell has published many papers on world scenarios but their goals are to find funny names, but without any values on world production. It was mainly a literature exercise.

Shell is very quiet on forecasts on their own production before 2010. Their recent forecasts with 4 Mboe/d in 2018 looks very optimistic, but time will tell

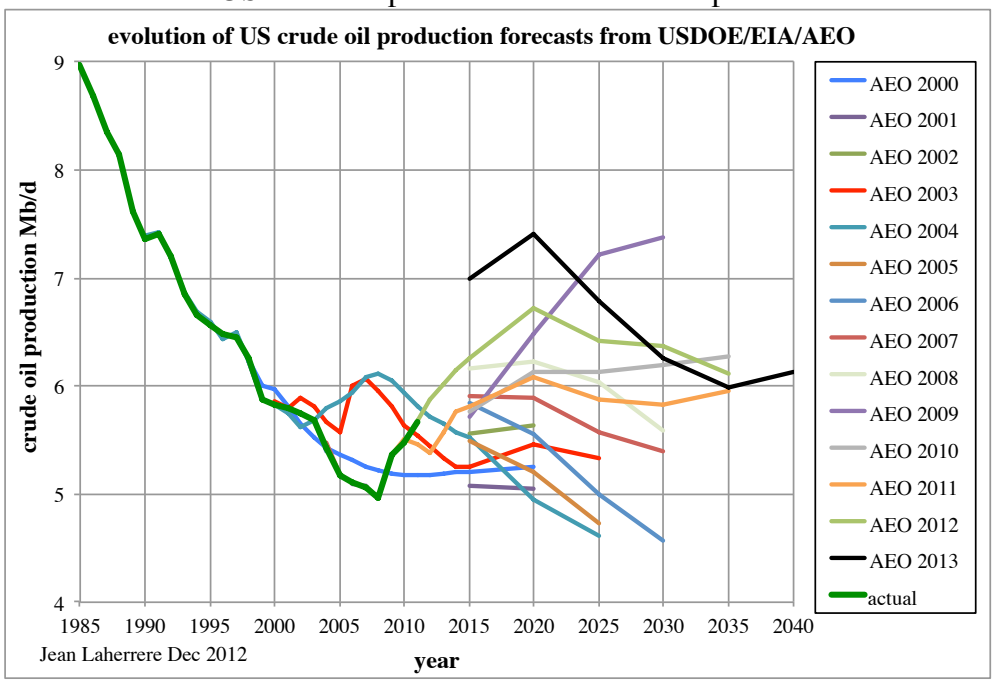
Figure 24: Shell oil & gas production & Shell forecasts



-USDOE/EIA forecasts on US & world oil production

EIA AEO forecasts on US oil production from 2000 to 2013 are plotted and they were too high except since 2009 with the tight oil. It is likely that AOE 2013 peak in 2020 at 7.3 Mb/d is too high.

Figure 25: EIA evolution of US crude oil production forecasts compared to real data



David Hughes 2013 displays EIA world oil production forecasts from 2000 to 2011

For 2020 the estimate went down from 120 Mb/d for AOE 2001 to 92 Mb/d for AOE 2010!

Figure 26: world oil production and EIA forecasts (D. Hughes 2013)

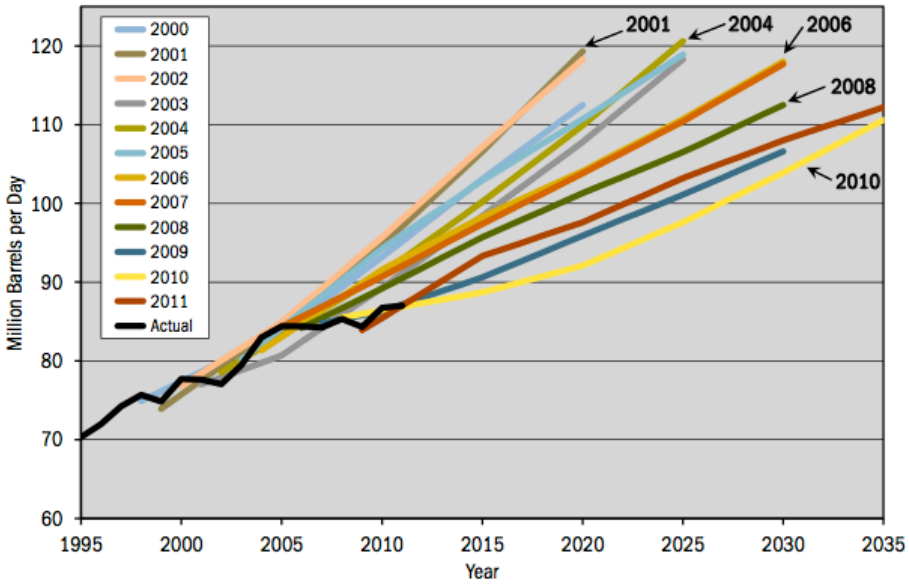


Figure 25. World oil production EIA 2000-2011 forecasts to 2035, compared to actual production, 1995-2011.[35]
Most cases invariably overestimated actual 2011 production.

-Canada official forecasts for Alberta bitumen

Hughes 2013 displays Alberta bitumen production forecasts from ERCB (2005 to 2012) & NEB and these forecasts were also too high.

Figure 27: ERCB & NEB forecasts for Alberta bitumen production

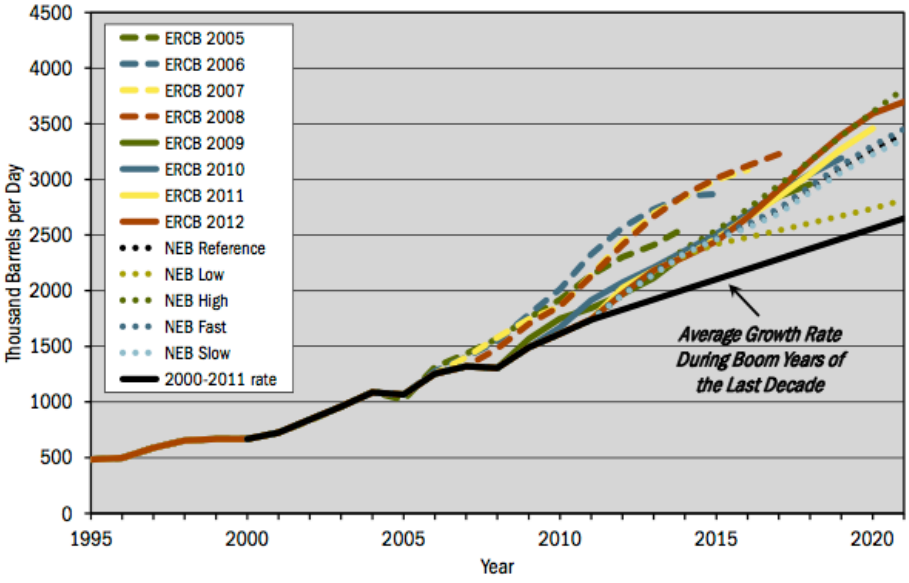
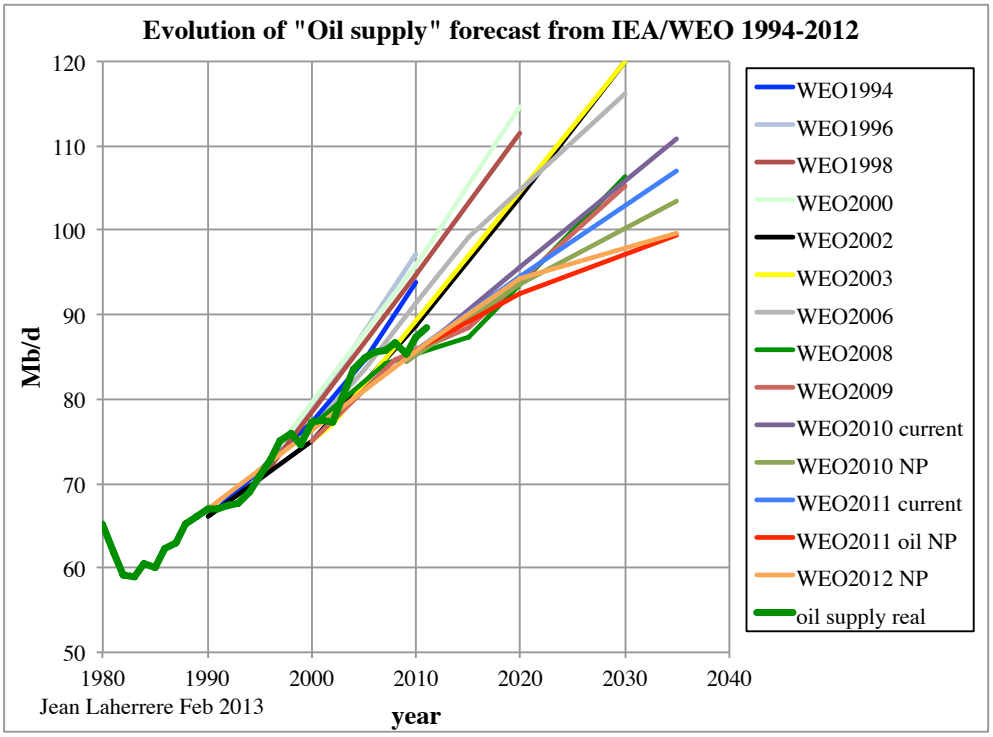


Figure 87. Alberta bitumen production forecasts, ERCB (2005-2012) and NEB (2011) compared to projection of actual 2000-2011 growth rates, through 2021.[181]

-IEA world oil supply forecasts

IEA WEO oil supply forecasts from 1994 to 2012 are plotted and show that most are too optimistic

Figure 28: IEA evolution of oil supply

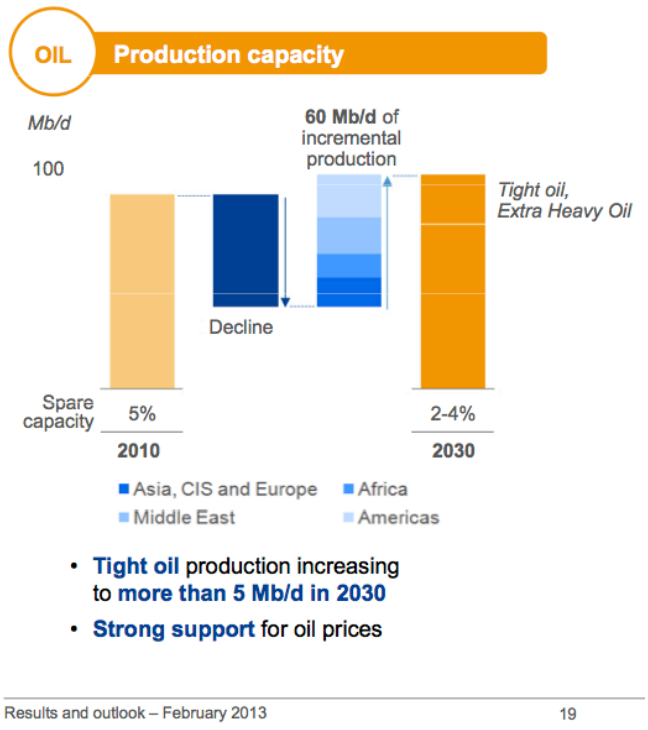


-world oil production forecasts by IOCs

Total forecasts world oil production capacity being 5% in 2010 but only 2-4% in 2030.

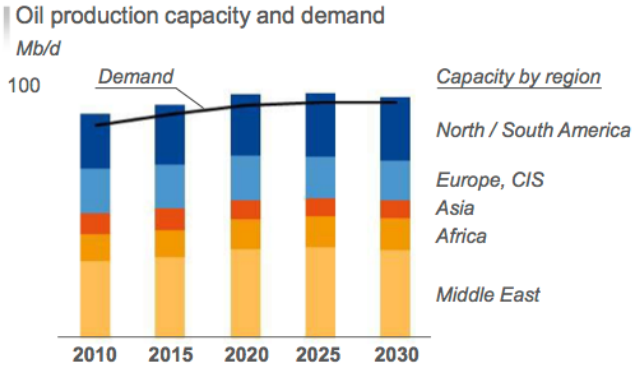
Production capacity is a very unreliable data and varies widely with sources. But ambiguity prefers it to production value!

Figure 29: TOTAL 2012 outlook for world oil production capacity



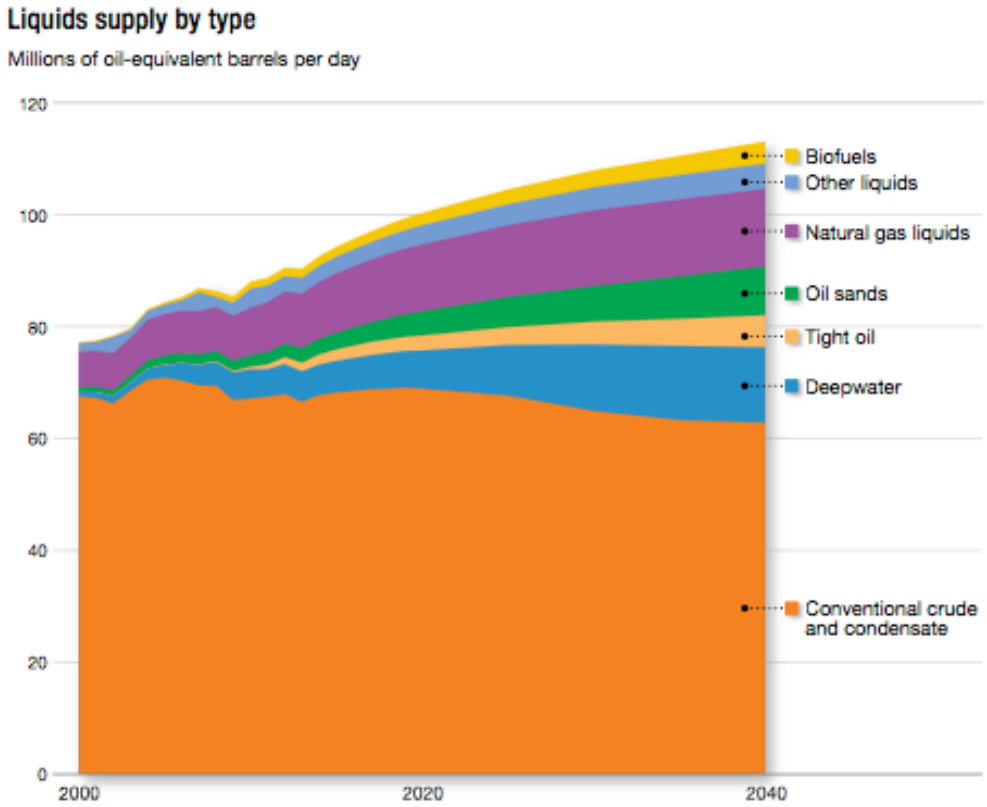
Total 2012 outlook for the oil production capacity shows a plateau from 2010 to 2030 with a peak in 2020-2025, where the variation is less than the accuracy of the data.

Figure 30: Total 2012 outlook: world oil production & demand



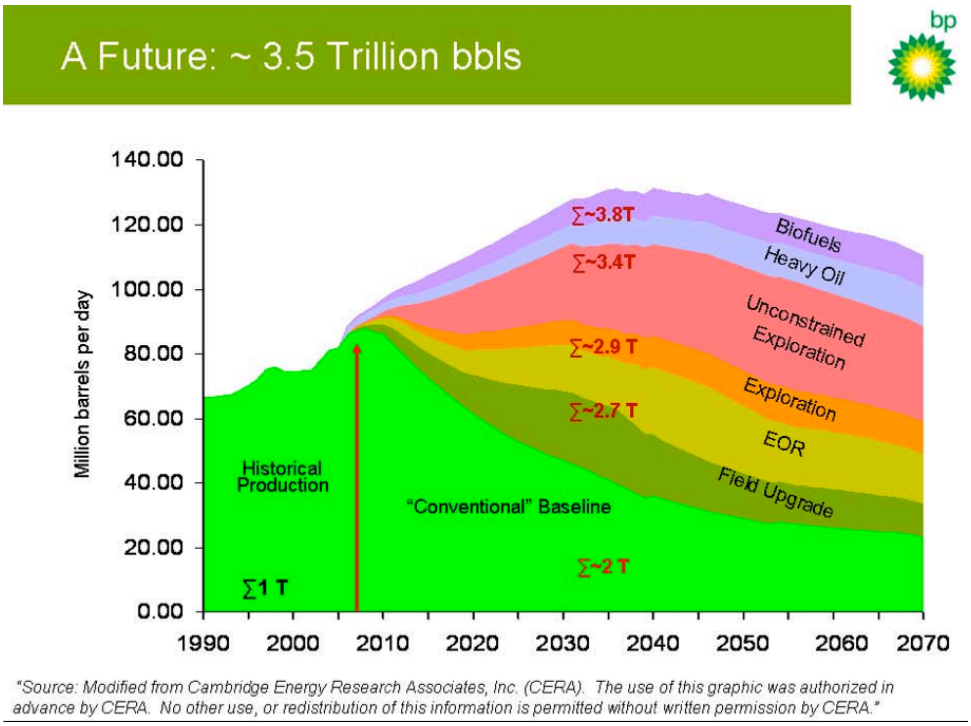
Contrary to Total, ExxonMobil does not forecast any peak, but conventional crude and condensate did peak in 2005.

Figure 31: ExxonMobil 2013 the view to 2040 liquids supply 1990-2040



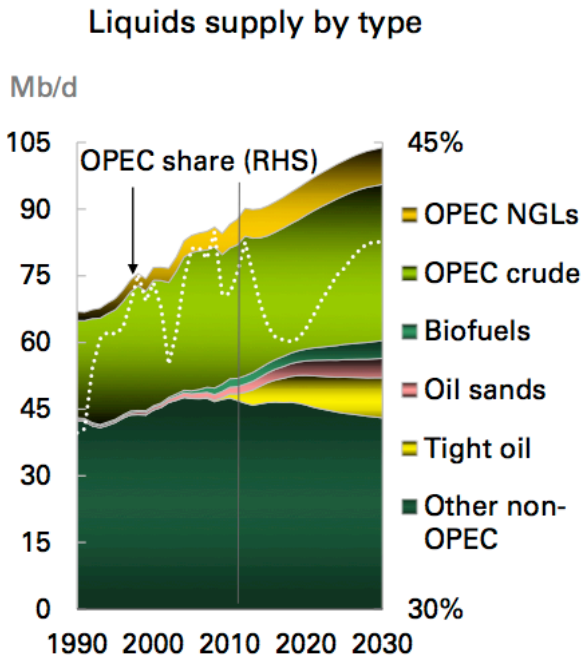
BP in 2007 forecasted oil supply peaking in 2035 at 130 Mb/d, using CERA optimistic outlook

Figure 32: BP Koonin 2007 oil production forecast



But BP (Jan 2013) Energy outlook 2030 forecasts only oil supply in 2030 at 100 Mb/d (30 Mb/d less than in 2007 CERA forecast)

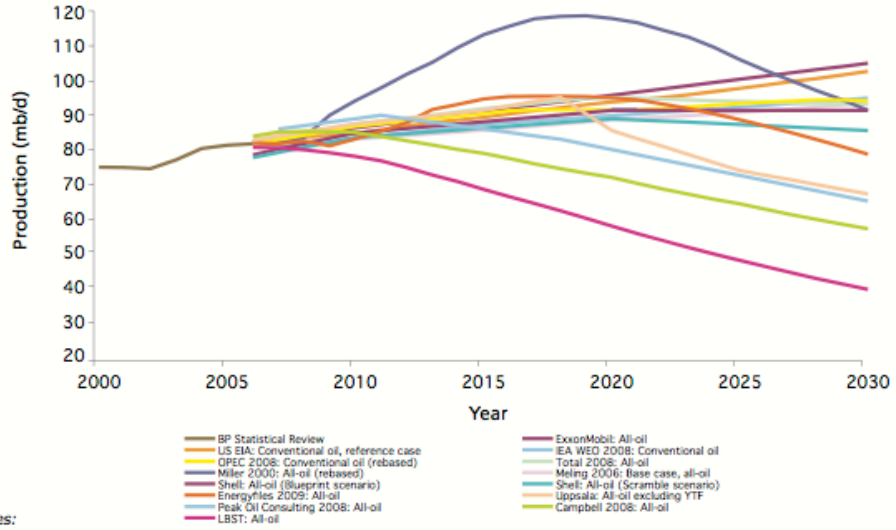
Figure 33: BP 2013 oil production forecast



UKERC 2009 (Global Oil Depletion An assessment of the evidence for a near-term peak in global oil production) displays a range of forecast for 2030

Figure 34: UKERC 2009 comparison of 13 forecasts of all-oil production to 2030

Figure 7.2 Comparison of thirteen forecasts of all-oil production to 2030



Notes:

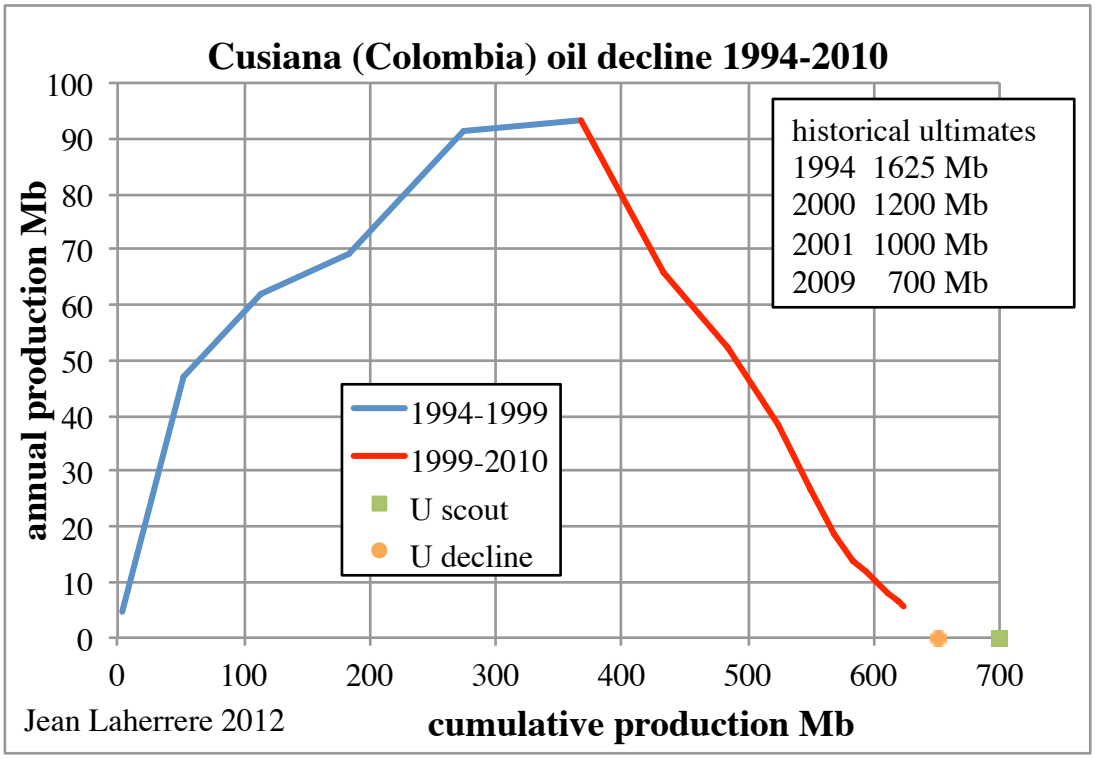
- Annual global production from 2000 to 2007 taken from BP (2008).
- Forecasts refer to all-oil as far as possible, but coverage of liquids does not always coincide.
- The OPEC and Miller forecasts exclude NGLs. These forecasts have been 're-based' here to match the BP production figure for 2007. Since the estimated production of NGLs is assumed to remain fixed until 2030, these forecasts may be downwardly biased.

It is obvious that most of forecasts are too optimistic because the future new production was expected sooner than in reality and because unexpected political events. It is well known in exploration that when geologists present the estimated reserves range estimate of a prospect to the management, the mini value is too optimistic for a small prospect (if not it will be refused), but for a large prospect the maxi value is reduced in fear to appear too optimistic to then management. It was the case for Cusiana prospect, where the maxi was estimated a being a little less than a giant: at 490 Mb, but in fact the field is a giant.
For frontier projects the initial cost estimate is always presented with the minimum case with no expected problems but, it is known with Murphy's law, problems always occur and at the end it is the mean value which prevails. It is known as the McNamara (Robert S. 1916-2009)'s law on cost and time delay increase.

-**Mac Namara's law**
In my paper Laherrère J.H. 2008 «Advice from an old geologist-geophysicist on how to understand Nature» presentation Statoil Oslo 14 August http://aspofrance.viabloga.com/files/JL_Statoil08_long.pdf one of the errors is stated as :
-to forget about time constraints
Time is the most important constraint of Nature (after resources): there is no way to make a baby in one month with nine women.
McNamara law: after being in charge of NASA, has issued a law where, in frontier areas, the initial project versus reality: cost has to be multiplied by pi and time by e (Euler number = 2,7). This law is verified in many exotic projects such as the Centre Pompidou in Paris, TransAlaska pipeline, presently with Kashagan in the Caspian sea. The problem of cost is usually resolved easily because more money can be found, but lost time is lost for ever. The explanation of such law is that in frontier area the range of uncertainty is as large as cost and, in order to have the project accepted, only the minimum value is given and at the end the expected value = mean occurs and is about 3 times the minimum (see Bourdaire J.M., R.J.Byramjee, R.Pattinson 1985 "Reserve assessment under uncertainty -a new approach" Oil & Gas Journal June 10 - p135-140, where the ratio between minimum and mean is about 3 in a lognormal distribution).

There are many examples of final costs being over three times the initial cost, but the examples on the time delay are more confused, but McNamara multiplier by e = 2.7 can be found on Total and

ExxonMobil on Kashagan and Tempa Rossa, explaining that the optimistic planning is the cause of over-estimate in future production.
Sometimes the discrepancy comes from too optimistic reserves estimates and Cusiana oil field is a good example.
My paper explains this reserve negative growth: Laherrère J.H. 2007 «Production future, réserves des combustibles fossiles» Mastere OSE Ecole des Mines de Paris Sophia Antipolis 17 oct.
http://aspofrance.viabloga.com/files/JL_Sophia17oct07.pdf
Translation
Cusiana in Colombia is also a good example of negative reserve growth because I personally participated in its discovery. BP was the operator because Total management did refuse to operate when first taking the farm out from Triton, fearing to have its manager kidnapped (the rig was partially destroyed during drilling) and we were equal partners with BP
During the drilling, at two occurrences, being after a VSP (vertical seismic profile) before reaching the reservoir (reservoir assumed to be absent by confusing the deck of the rig and the datum plane of the seismic survey) and after logging the reservoir (reservoir assumed to be tight like the nearby well with oil shows) BP operator recommended twice to abandon the well.
But in charge of Total exploration techniques, my team decided to pursue the drilling and to test, and BP did follow, which led to discovery. After discovery, the minor partner Triton reported Cusiana reserves at 3 Gb, BP at 1.5 Gb and Total at 1 Gb. Th epresent oil decline indicates about 650 Mb. The decline is sharp, because the operator was under terrorist pressure.
Figure 35: Cusiana (Columbia) oil decline 1994-2010



BP has sold in 2010 Cusiana to Ecopetrol & Talisman (but BP still operates Cusiana until 2016).
Cusiana is also a giant gas field with 3.5 Tcf reserves

-Conclusion
The industrial age, which started our consumption society, is based on cheap energy from fossil fuels. Our society is so used to growth (measured with a very poor indicator being the GDP which represents expenditures and not wealth) that no one wants to foresee decline. But fossil fuels reserves are limited like the earth. Peak oil is a bad term in official agencies. However the IEA has recognized that the conventional oil production has peaked around 2006, but high hopes are now put on unconventional oil and gas.

Most of the graphs in this paper show clearly that forecasts are almost always too optimistic, because a poor estimate of the planning of future production, ignoring the Murphy's law and also often because a too optimistic estimate of reserves.
Bad events are never taken into account.
Despite their poor performance in reporting their production outlook, IOCs continue to do so.
It is the same for official agencies like IEA or USDOE/EIA.
The main conclusion is that those forecasts should be considered as very optimistic cases, which could happen only is everything goes well, which corresponds to a very small probability.

IOCs, IEA and EIA forecasts may not be wrong, but it is likely that they are unlikely.