International Journal of Energy Technology and Policy
Sent on November 21, 2001

" Will the natural gas supply meet the demand in North America? "

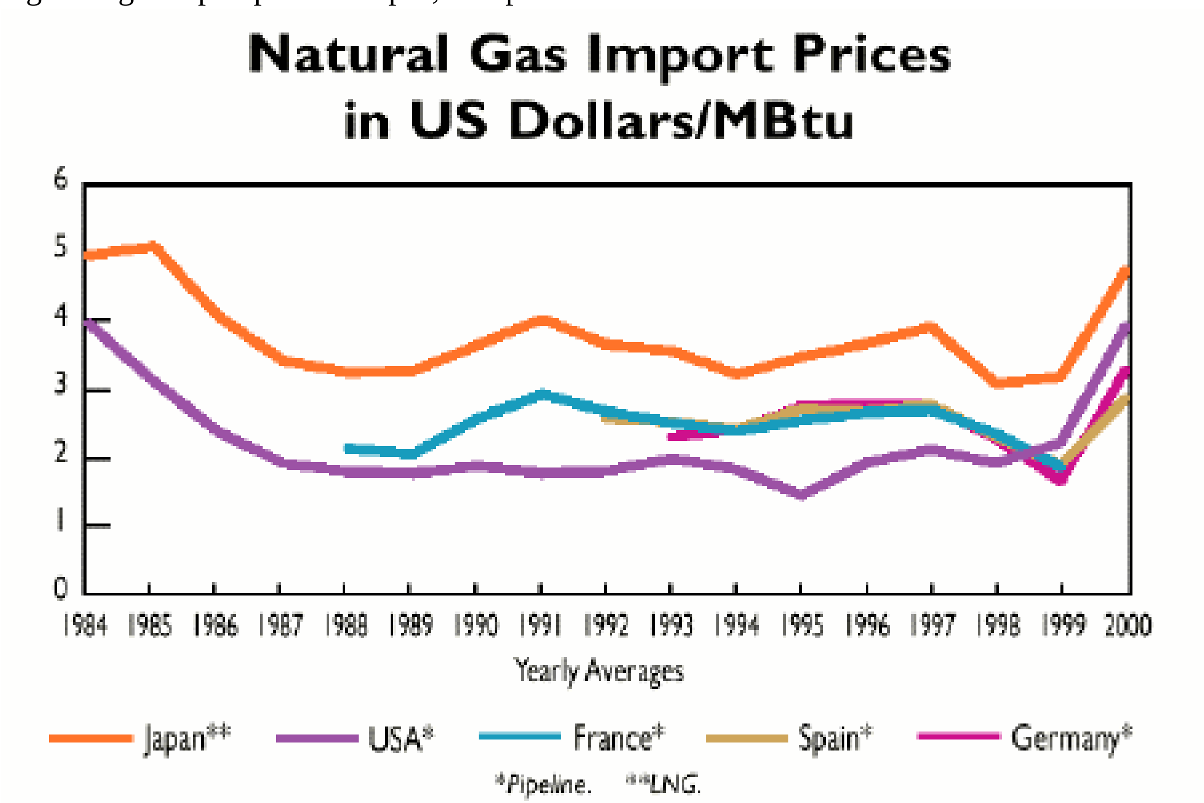
Jean Laherrere e-mail: jean.laherrere@wanadoo.fr

The goal of this paper is to deliver to the reader a large number of graphs in order to allow him to choose the ones that he consider as important to make his own opinion. Graphs from data are more important than statements which are mainly interpretation and political. But the problem is that the data are fairly unreliable.

There is only one oil market as oil is cheap to transport around the world for about 1$/b, but gas is 6 to 10 times more expensive to transport and there are three main gas consumer markets: North America, Europe, and Asia Pacific. But the Persian Gulf will become a fourth producing centre. Gas supply in North America is only local when excluding imported LNG, which is a very small part.

The graph from IEA WEO 2001 shows clearly that the gas import price in Japan from 1987 to 1997 was about 3.5 $/MBtu when it was about 2.5 $/MBtu in Europe and only 2 $/MBtu in the US. But in 1999 & 2000 US gas was more expensive than in Europe.

Figure 1: gas import prices in Japan, Europe and US.



The calorific value of gas varies with the producing country (from IEA/WEO 2001) and as the oil equivalent (assuming 1toe=42 GJ and a gravity of 33°API (0.86) or 1 toe= 7.3 boe).

gross calorific value	MJ /m3	toe/1000 m3	boe/kcf
Netherlands	33.3	1.26	6.1
Russia	37.6	1.11	5.4
Uzbekistan	37.9	1.10	5.3
Saudi Arabia	38	1.10	5.3
Canada	38.1	1.10	5.3
US	38.3	1.09	5.3
UK	39.3	1.07	5.2

Indonesia	40.6	1.03	5.0
Norway	41	1.02	4.9
Algeria	42	1.00	4.8

The US and Canada gas is in the middle of the range between the low calorific gas in the Netherlands and the rich gas in Algeria.
In 1999 US supply was 85% from production and 15% net import with LNG covering only 1%.

1999	production		net imports		total supply		Canada Imports	LNG
Gcf/d	52.1	9	61.5	10.3	0.4			
Tcf/a	19.0	3.3	22.4	3.8	0.1			
% supply		85	15	100	17	1		

The last gas crisis in North America was due to a shortage of local supply as most of the gas comes from the US and Canada, Mexico being and will be more and more a net importer. The low price for oil and gas at end of 1998 led to a shortage of investment in drilling.
Technology has enabled huge progress in producing gas cheaper and faster, and the decline rates of gas wells have increased sharply over the last 30 years and are now about 50%/a. Most new gas wells are needed not to fulfil the demand increase, but to prevent the supply to decrease because of the drastic decline of present producers. The sharp increase in gas prices at the end of 2000 leads to a decrease in gas demand in 2001, which then resulted in a drop in price.
Future production (in fact the remaining reserves) has to be studied from the past discoveries, the past production and from the estimate of the undiscovered.
We are going to analyse the reliability of the data (political versus technical) for the three countries (US, Canada and Mexico), the pattern of discovery (creaming curve), the field size distribution (parabolic fractal), the correlation between annual discovery and annual production after a certain time shift, and last the modelling of future production from ultimate.
We will study first the present situation and second the forecast for future production

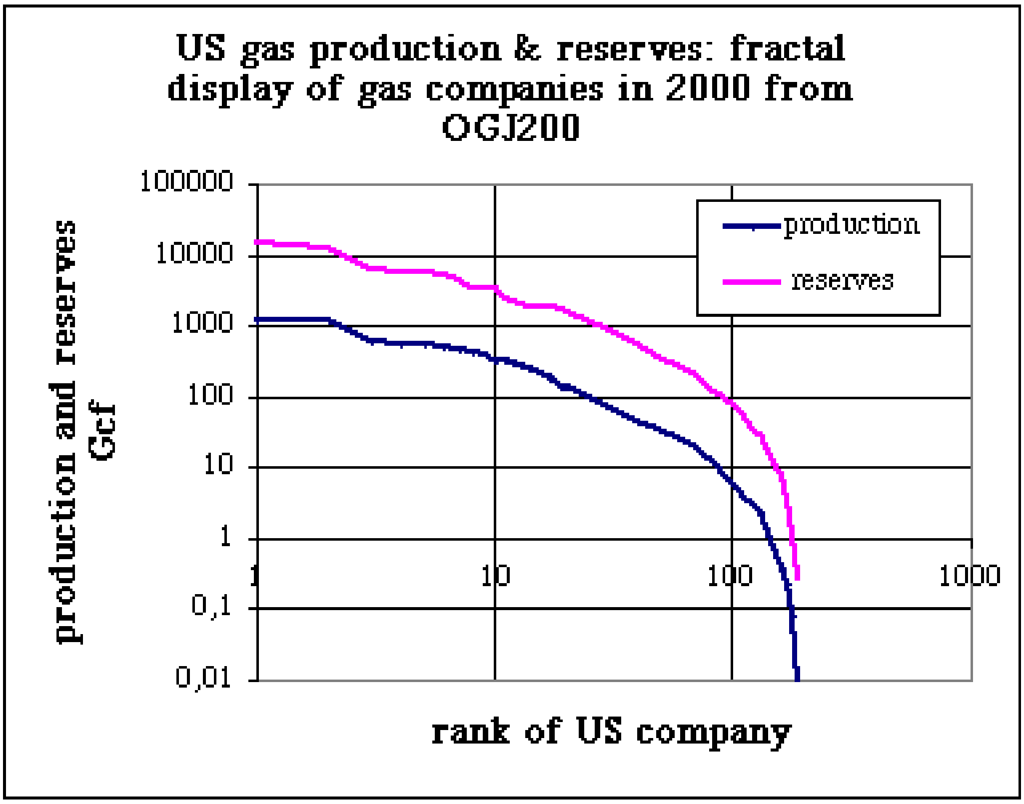
-US

-Present situation

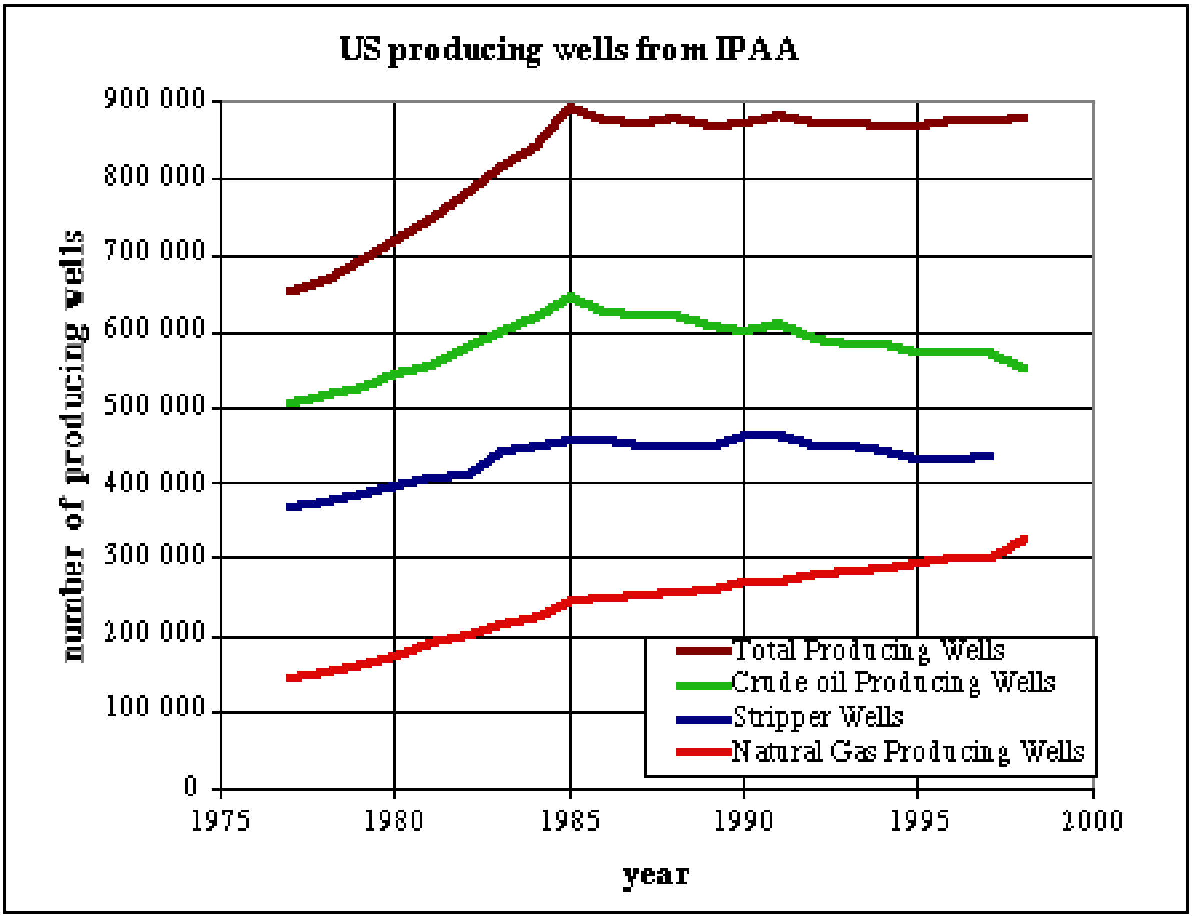
-data and reliability

-number of producers and wells

Oil & Gas Journal (OGJ -Oct 1, 2001) lists the 200 US companies (OGJ200) which produced in 2000 11.5 Tcf (58% out of 19.7 Tcf total production) from 119 Tcf of proved reserves (71% out of 167 Tcf). It means that there is a very large number of gas producers (in thousands as the difference of 8.2 Tcf is produced by companies producing less than 0.01 Tcf/a), quite different from countries outside North America where the number of gas producers is limited to a few tens. The distribution of annual production and reserves listed by rank of decreasing size) displays a fractal distribution in figure 2:
Figure 2: US gas producers: fractal distribution



Gathering the data from so many companies is quite difficult and inaccurate.
The USDOE provides a large set of data (it is the best available source of data on the world's oil and gas industry) on US production and for the rest of the world. Unfortunately the quality of these data is questionable.
If the number of gas companies is by thousands, the number of producing gas wells is by hundreds of thousands as shown in figure 3.
Figure 3: Number of US producing wells

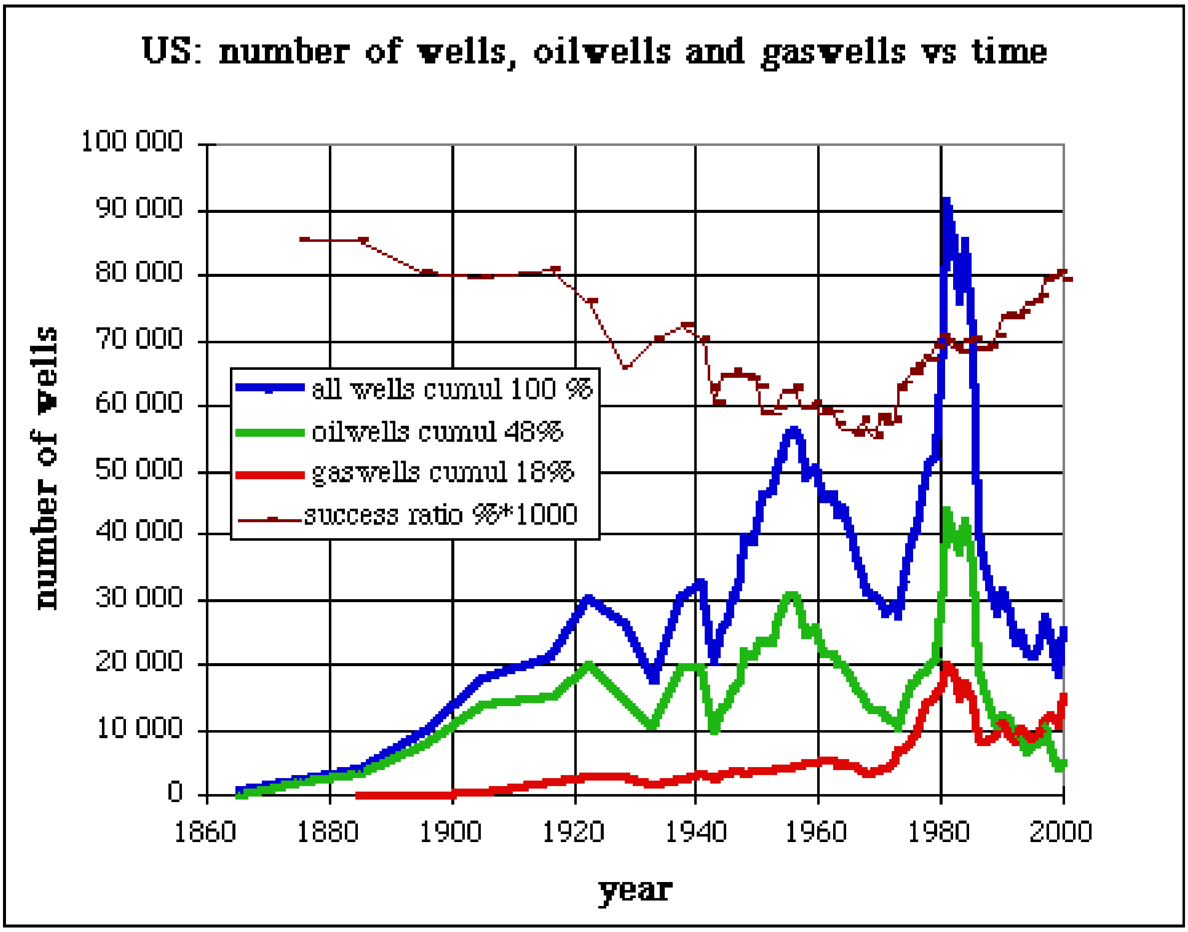


From 1985 to 1998, the number of producing oil wells decreased from 650 000 down to 550 000 in 1998 when the number of gas wells increased from 250 000 to 315 000.

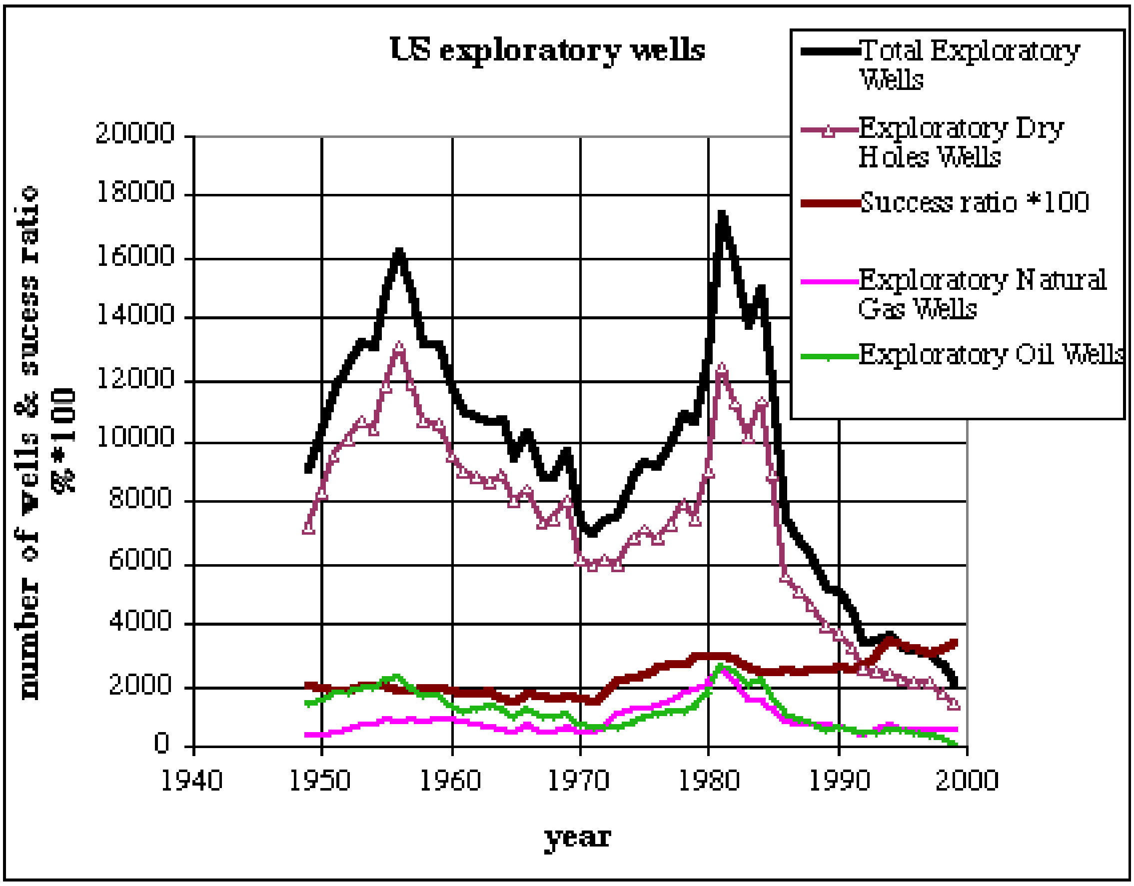
But the number of wells drilled in US up to 2000 is about 3.5 million with 48% being oil wells and 18% being gas wells. But these wells are either development wells or exploratory wells which can be in part New Field Wildcats (NFW) and these wells can result either in oil wells, gas wells or dry wells.

The number of all wells drilled in the US peaked in 1920 (with 30 000), 1940 (30 000), 1955 (55 000) and 1980 (90 000 with 40 000 oil wells and 20 000 gas wells), but the number went down with the price of oil and gas between 1986 and 1996. The number of gas rigs went from 400 in 1996 to a peak of 600 in 1998 down to 350 mid-1999 and now at 1000 mid 2001.

Figure 4: Number of all wells from 1860 to 2000



The success ratio in gas development, which was 85% in 1880, decreased to 55% in 1970 and rises again up to 80% in 2000.
The success ratio in gas exploration, which was around 20% in 1950, has increased to 35% in the second half of the 90s. More and more exploratory drilling is closer to development drilling.
Figure 5: Number of exploratory wells from 1950 to 2000



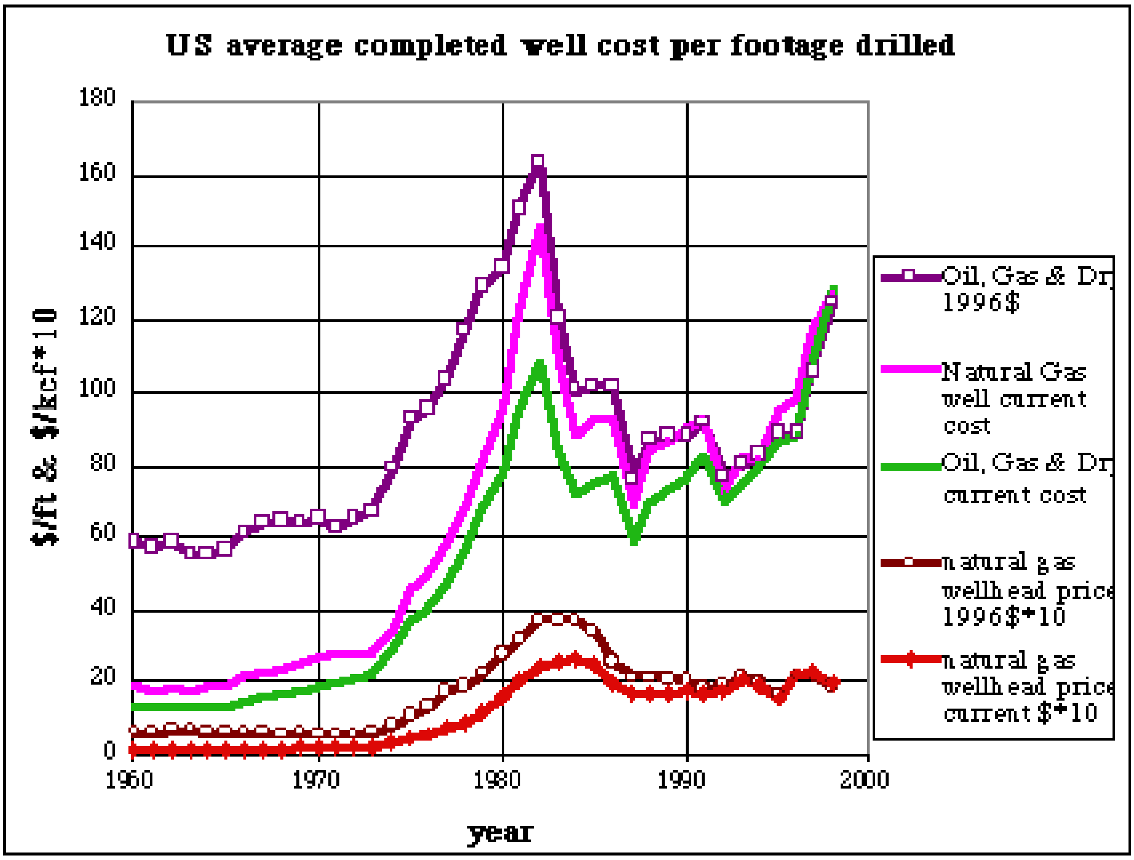
Reporting the number of wells is unreliable as in 1998 USDOE corrected the reported number of gas wells for 1996 being 560 and not 943. The 1996 success ratio was corrected from 45% down to 32%.

The number of New Field Wildcats (roughly half of the exploratory wells), which was about 9000 in 1956, went down to 5000 in 1970, up to 9000 again in 1981 and down to 1000 in 1995. But the NFW success ratio (from USDOE) has increased from 10% during the 50s and 60s to over 20% in the 90s. The maturity of the exploration is up, more data and better seismic exploration leads to higher success ratio, but finding smaller field size for both oil and gas.

The last DOE/EIA annual report in 1999 is more up to date and slightly different. The success ratio for the second half of the 90s is about 30%.

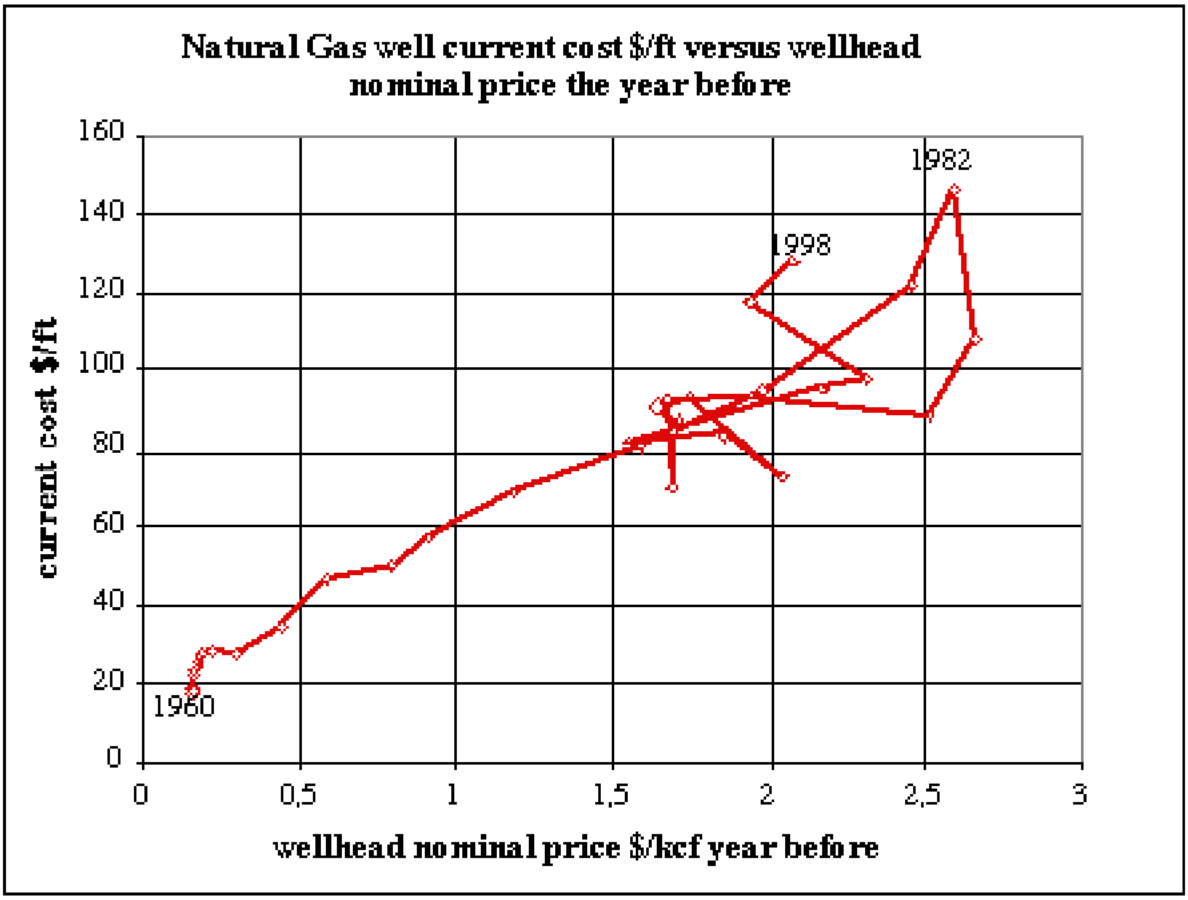
It is interesting to note that the US cost of drilling varies sharply up and down. The cost for gas wells is slightly higher than for oil wells. The cost of drilling in $/ft has increased sharply since 1992 from 80 $/ft to more than 120 $/ft in 1998.

Figure 6: US average completed well cost per footage drilled



The cost varies with the wellhead price as shown in the next graph.

Figure 7: Gas well current cost in $/ft versus nominal wellhead price in $/kcf the year before

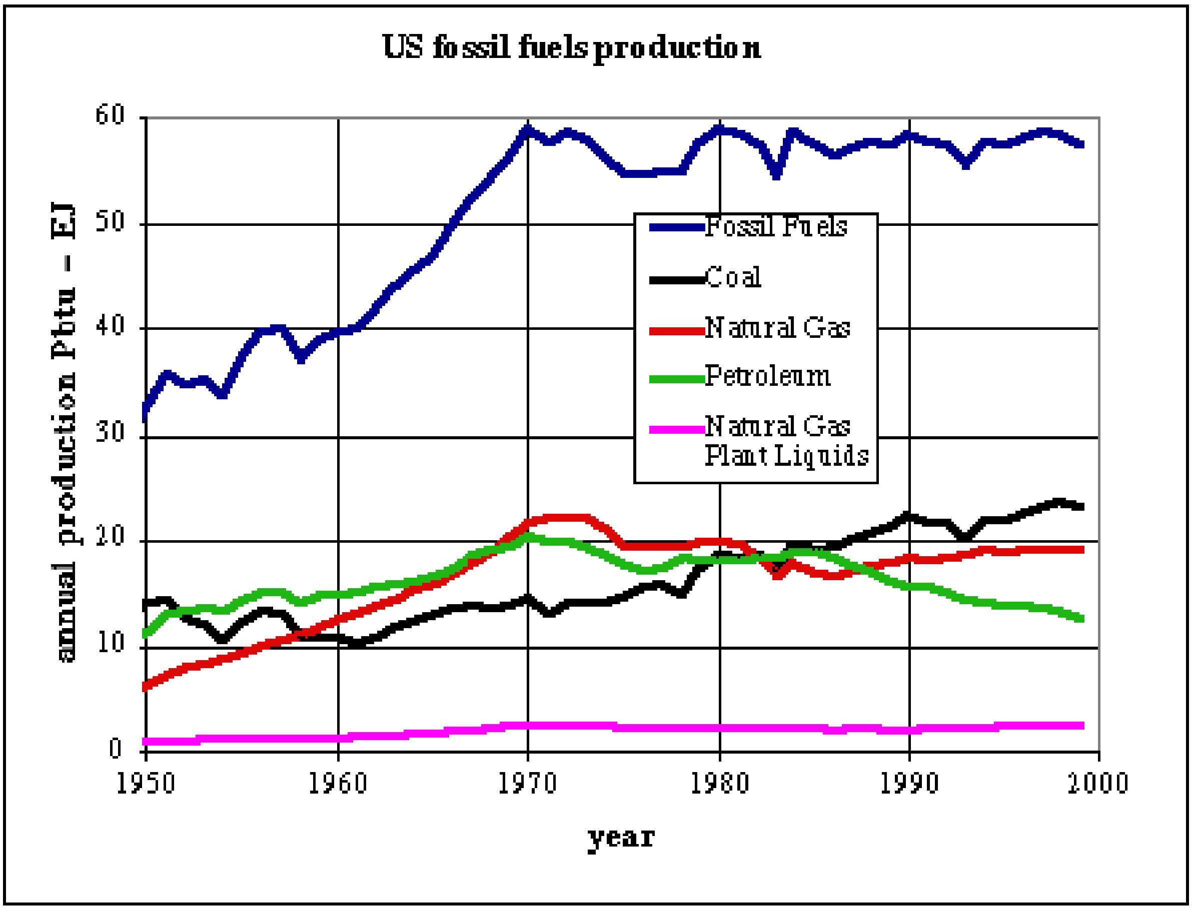


It seems that there is a good linear relationship between drilling cost and wellhead price and that the technological progress does not show up too much!

-production

The US fossil fuels production is almost flat since 1970, as shown in figure 8 (given in PBtu (10E15 Btu) close to EJ (exajoule, close to Tcf or Gb/6)).

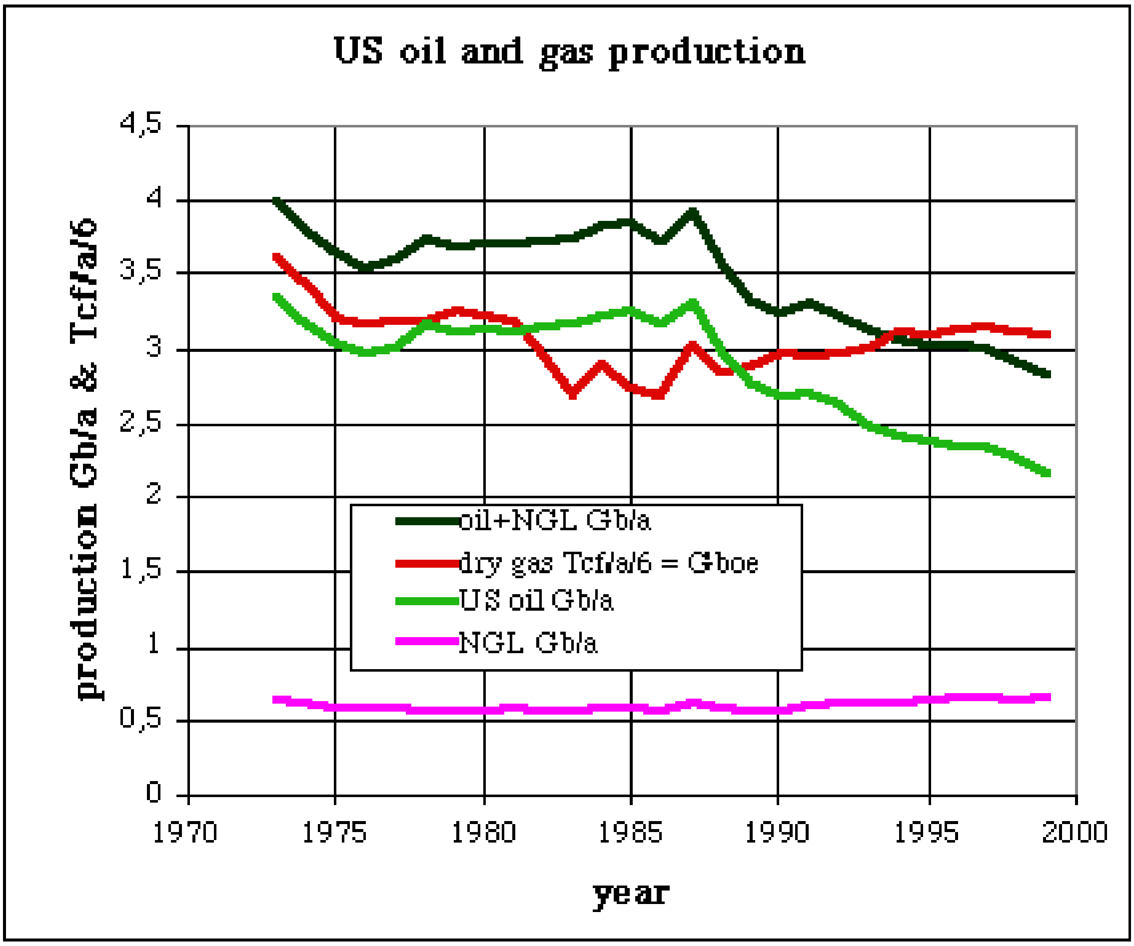
Figure 8: US fossil fuels production



The decline of oil is compensated mainly by the increase of coal and partly of gas since 1985 (after the peak of 1972).

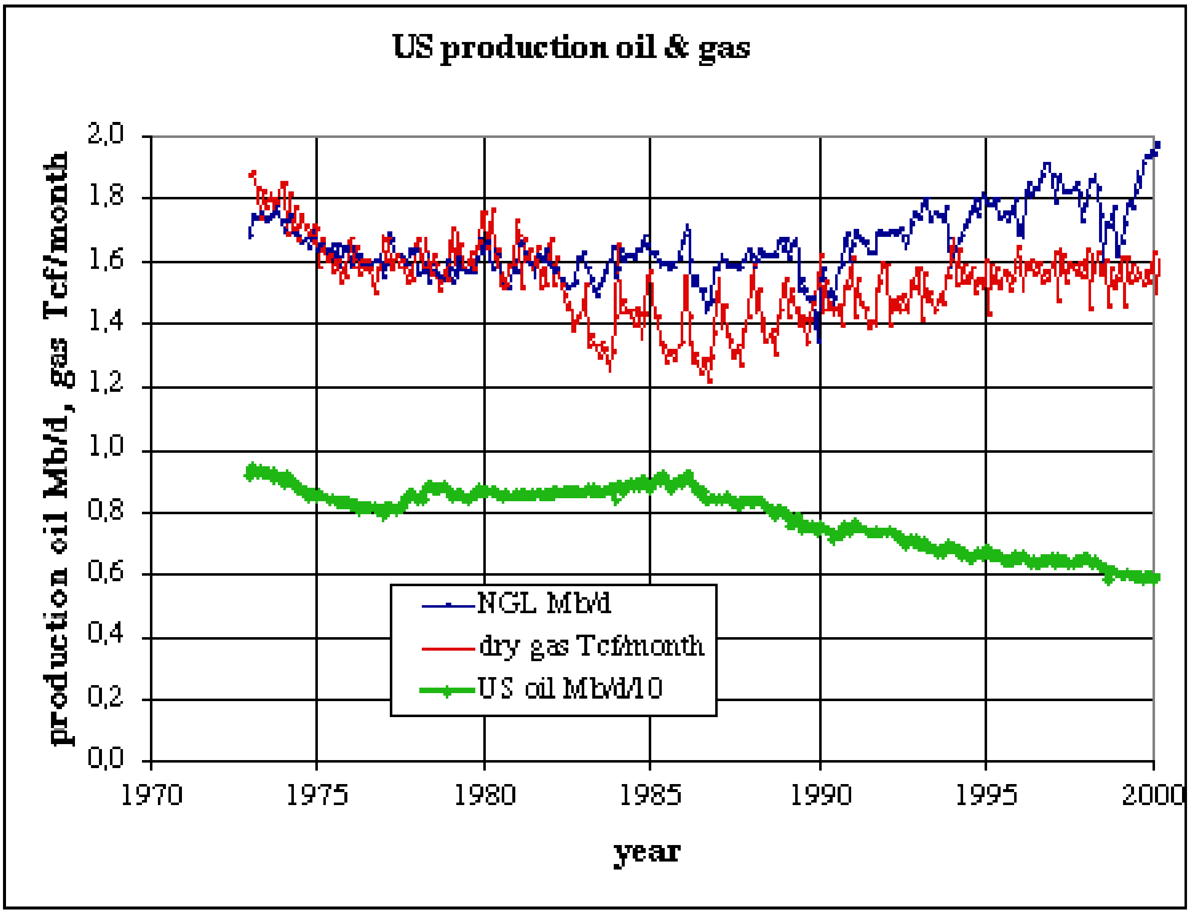
The detail of oil and gas production in Gb and Tcf is given in figure 9 and figure 10:

Figure 9: US oil & gas annual production



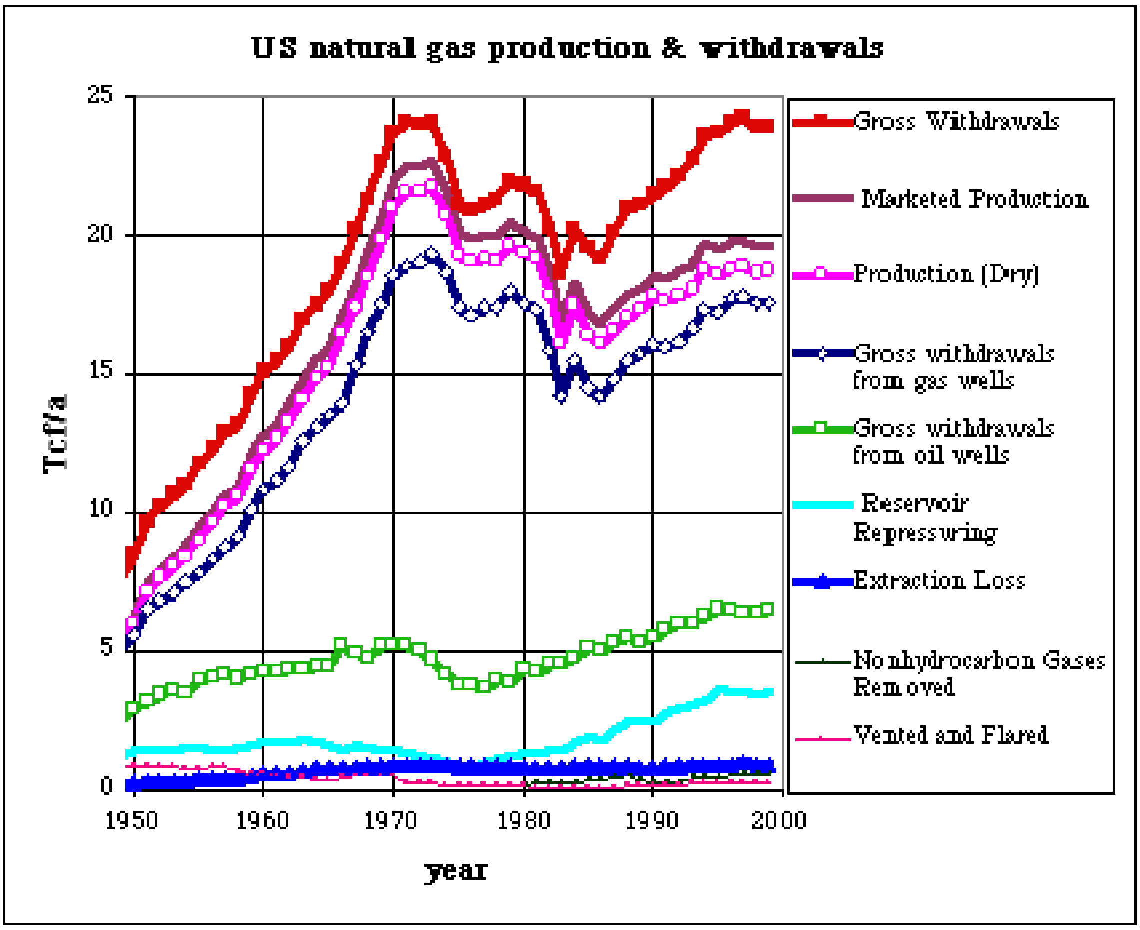
The monthly production (Mb/d and Tcf/month) in figure 10 shows that the NGL in Mb/d was equal to the gas in Tcf/month from 1973 to 1982 but increases since 1982 as gas plants stripped of more liquids which was more valuable than staying into gas.

Figure 10: US oil & gas monthly production

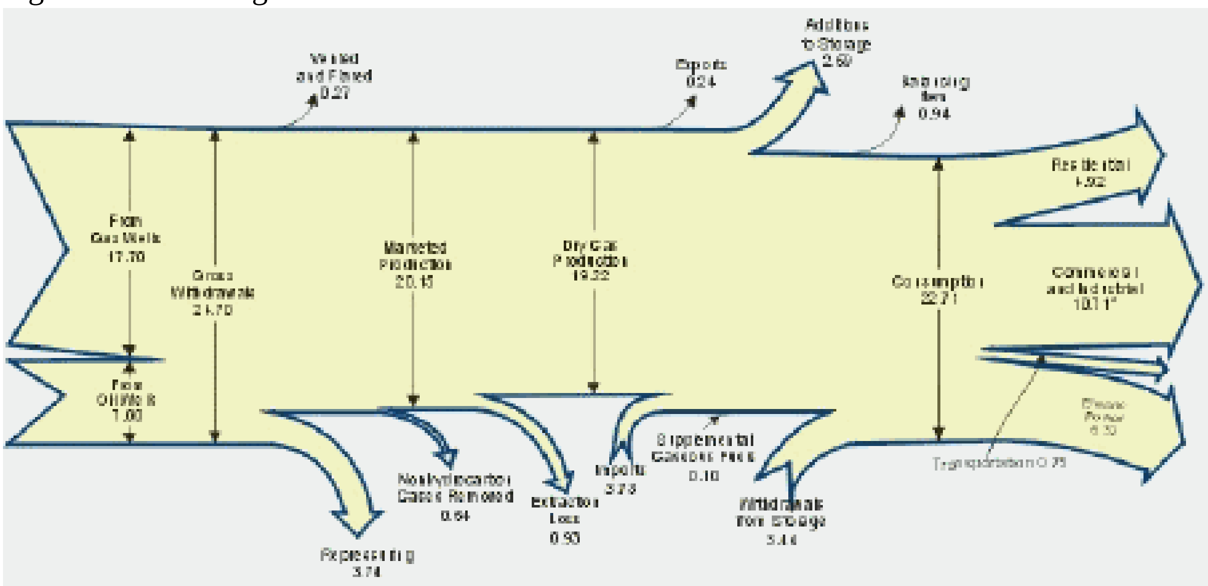


The big problem with gas production statistics is that very often it is not indicated if the production is gross withdrawal, marketed wet or marketed dry. Most of the times when not indicated it is assumed to be dry production. The difference is quite large as shown in figure 11 between gross withdrawal and dry production:

Figure 11: US gas production and withdrawals



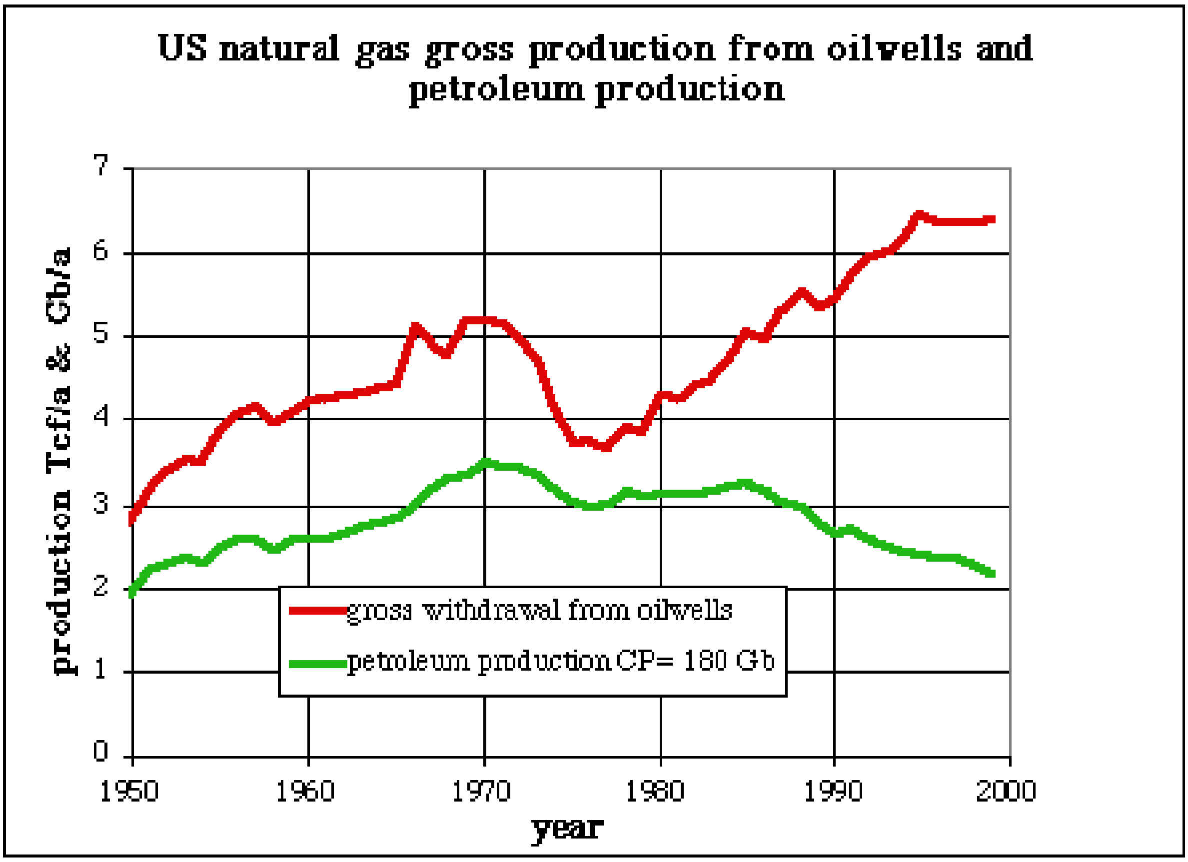
USDOE/EIA gives the 2000 gas flow as below in
http://www.eia.doe.gov/emeu/aer/diagrams/diagram3.html:
Figure 12: US 2000 gas flow



The gross withdrawal is 24.7 Tcf/a and dry production only 19.2 Tcf/a (78%).
3.7 Tcf (15%) is repressured, but 3.4 Tcf is drawn from storage. It is not specified where the gas is repressured (field or storage). If it is in storage it should be compensated by the withdrawal from the storage. The reference data should be raw (gross) and not dry production.

Gas production from gas wells and gas production from oil wells are shown in figure 11 and to study in detail the evolution of the associated gas production from oil wells is compared to oil production in figure 13.

Figure 13: Gas production from oil wells and petroleum production



It is striking that associated gas production was in line with oil production from 1950 to 1979 but from 1979, oil declines when gas increases.

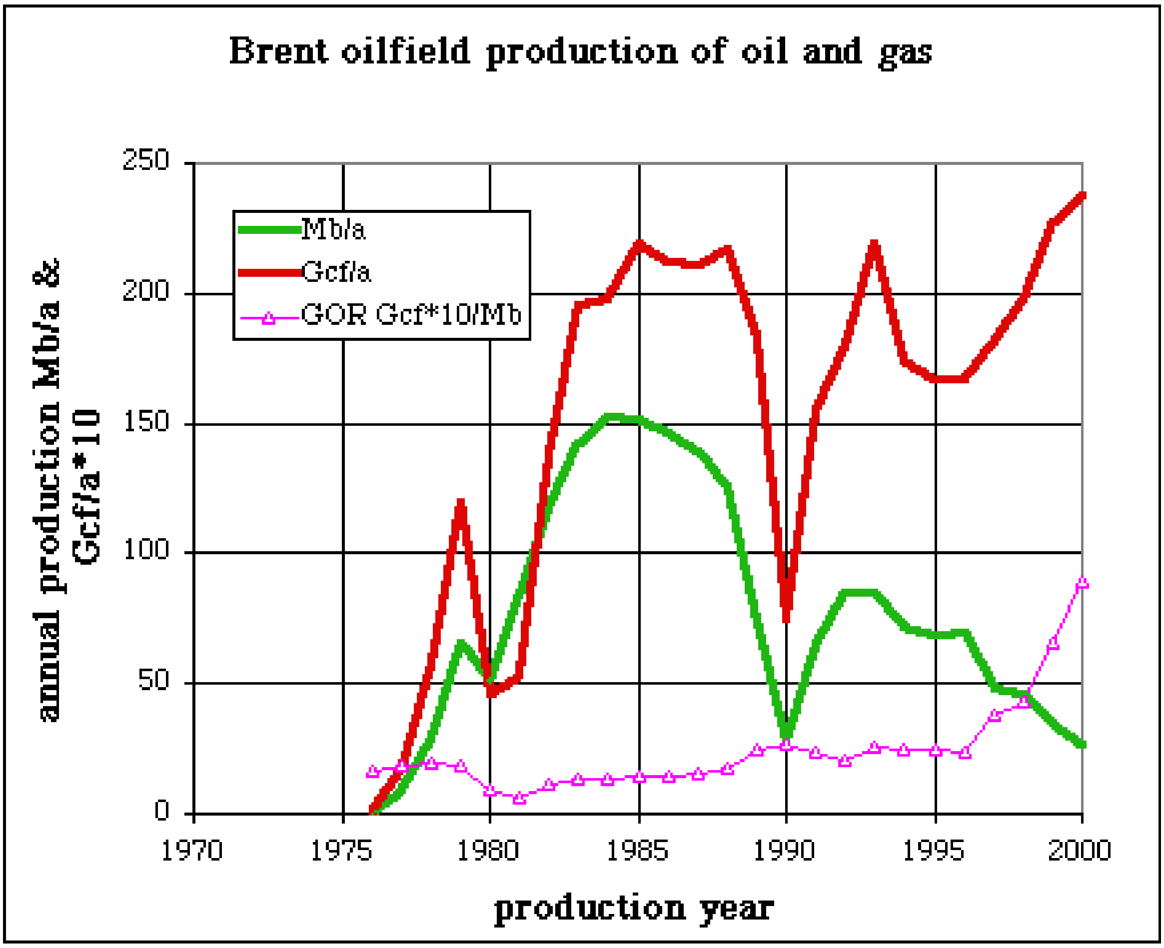
In his book "Alternative energy resources" in 1976, James Hartnett gave on page 35 his forecasts on oil & gas US production until 2020. He forecasted for oil a continuous decline of the Lower 48, a new cycle with Alaska Prudhoe Bay since 1975 and another cycle due to EOR (Enhanced Oil Recovery), expecting 2.1 Gb/a in 2000 for conventional oil and another 1 Gb/a for EOR. In fact oil US production was at 2.1 Gb/a, but the dreams of EOR did not come true. But for natural gas he forecasted also Alaskan production in addition to declining Lower 48 with a total of 15 Tcf/a in 2000 and an additional 12 Tcf/a for new techniques (27 Tcf/a in 2000), but all declining since 1985. In fact North Slope gas is not there, total production for 2000 was about 18 Tcf (dry), but rising since 1985. Hartnett was all wrong.

Why has gas production been increasing since the trough of 1985? It comes in part from gas wells but also surprising in part from oil wells, despite the decline of oil. As shown in figure 13, gas production from oil wells rises from 1985 when oil declines sharply: Why?

It is well known that at the end of an oilfield associated gas production rises. The increase of gas production from oil wells seems to indicate the near end of most US oilfields. This behaviour was not forecast by most of the experts.

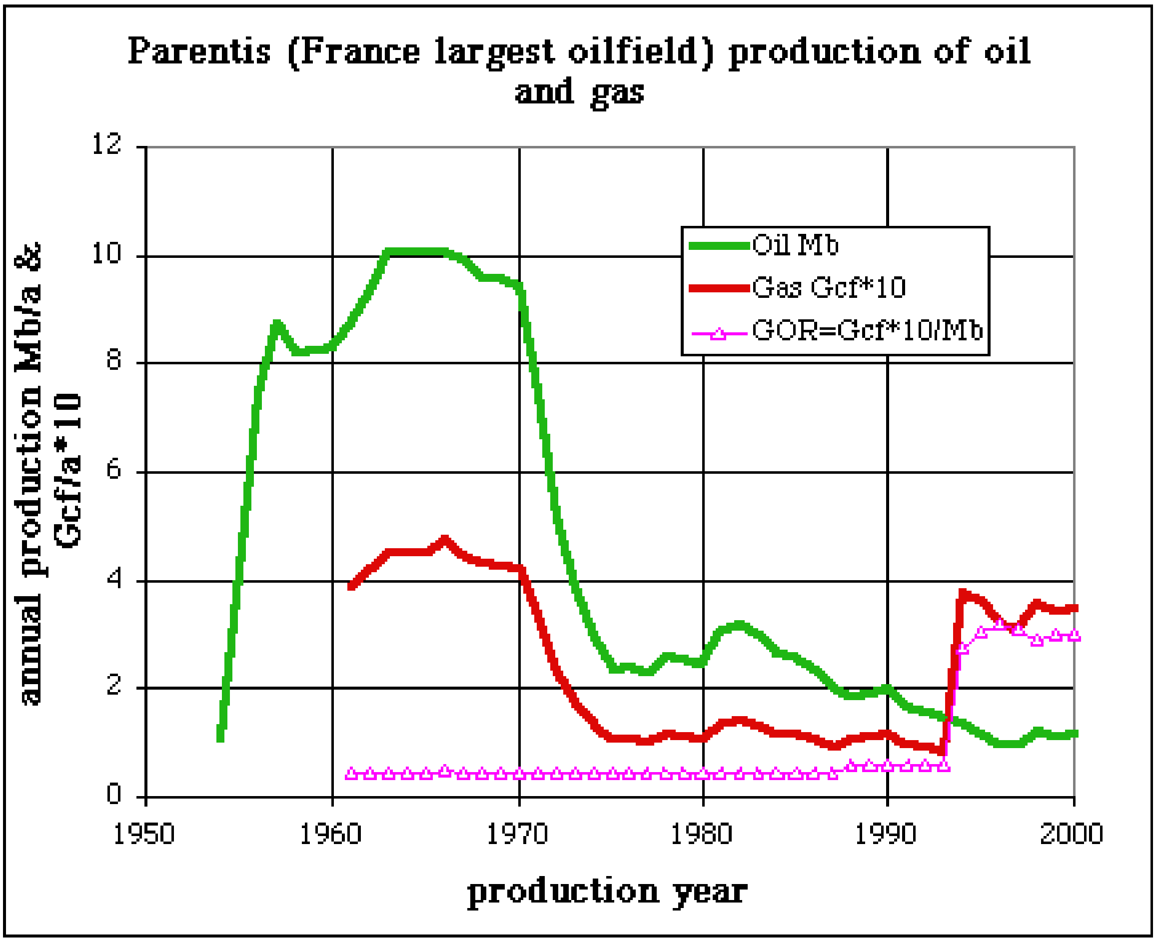
One good example of increasing associated gas with declining oil is shown with Brent oilfield in UK and Parentis oilfield in France

Figure 14: Brent oilfield production of oil and gas



From 1996 oil declines and gas rises sharply. GOR (gas oil ratio) jumps from 2,5 to 8 Gcf/Mb.

Figure 15: Parentis oilfield production of oil and gas

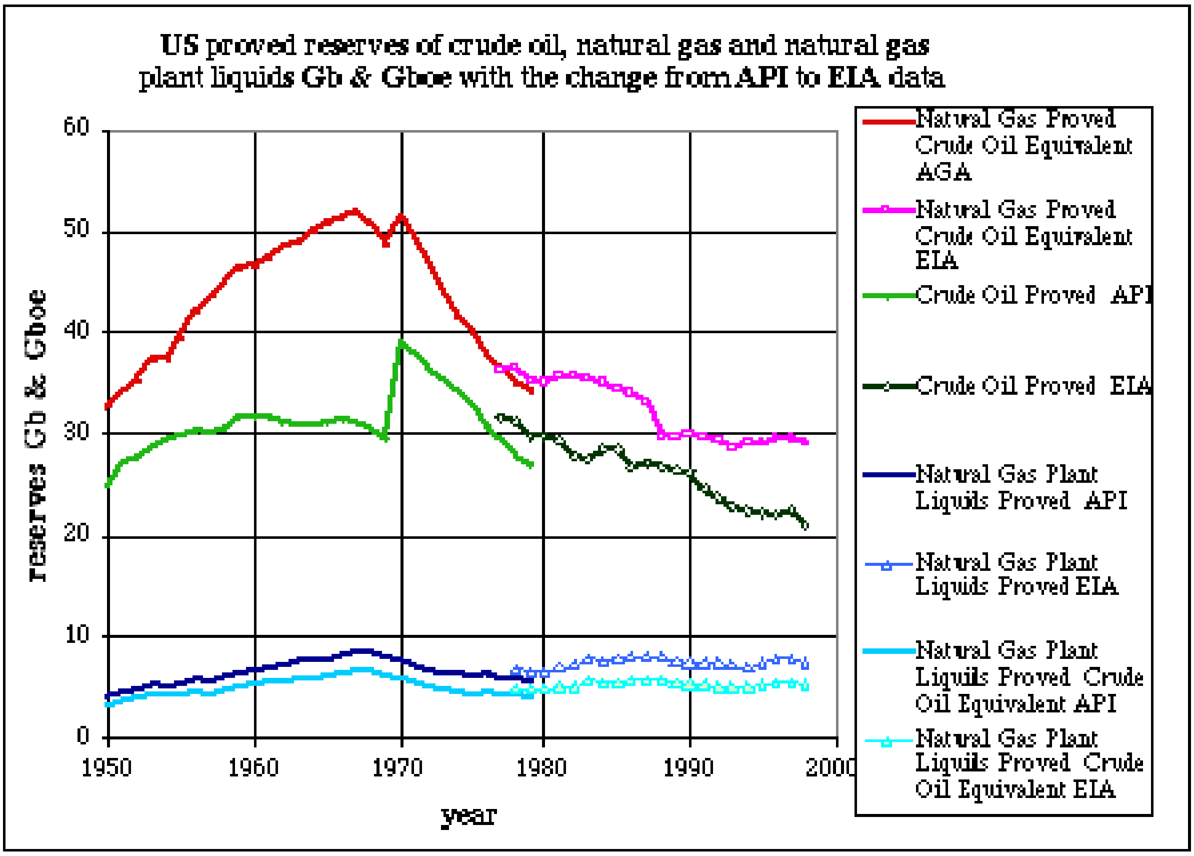


From 1993 GOR jumps from 0,05 Gcf/Mb to 0.25, when the oil production keeps declining.

-Reserves

The remaining reserves (which are future production) vary by author. USDOE data shows a change in value in 1979 when they took over the duty of reporting from API (American Petroleum Institute) and AGA (American Gas Association).

Figure 16: Remaining US reserves



In the US to comply with the SEC (Securities & Exchange Commission) listed companies have to report only proved reserves (estimated with reasonable certainty to be commercially recoverable,), omitting probable reserves. In the rest of the world reserves are reported as proven+probable. Under the SPE/WPC/AAPG rules, proved reserves are defined as "*a high degree of confidence*" under the deterministic approach or with a "*90% probability to be equalled or exceeded*" under the probabilistic approach. "*Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves*". There is a contradiction in the deterministic approach where probable being as likely or unlikely i.e. 50%, when in the probabilistic approach it is proved+probable being 50%.

The poor US practice on proved reserves leads to a very strong revision and the concept of reserve growth, whereas using the mean (or expected value) reserves for proven+probable results statistically in no growth.

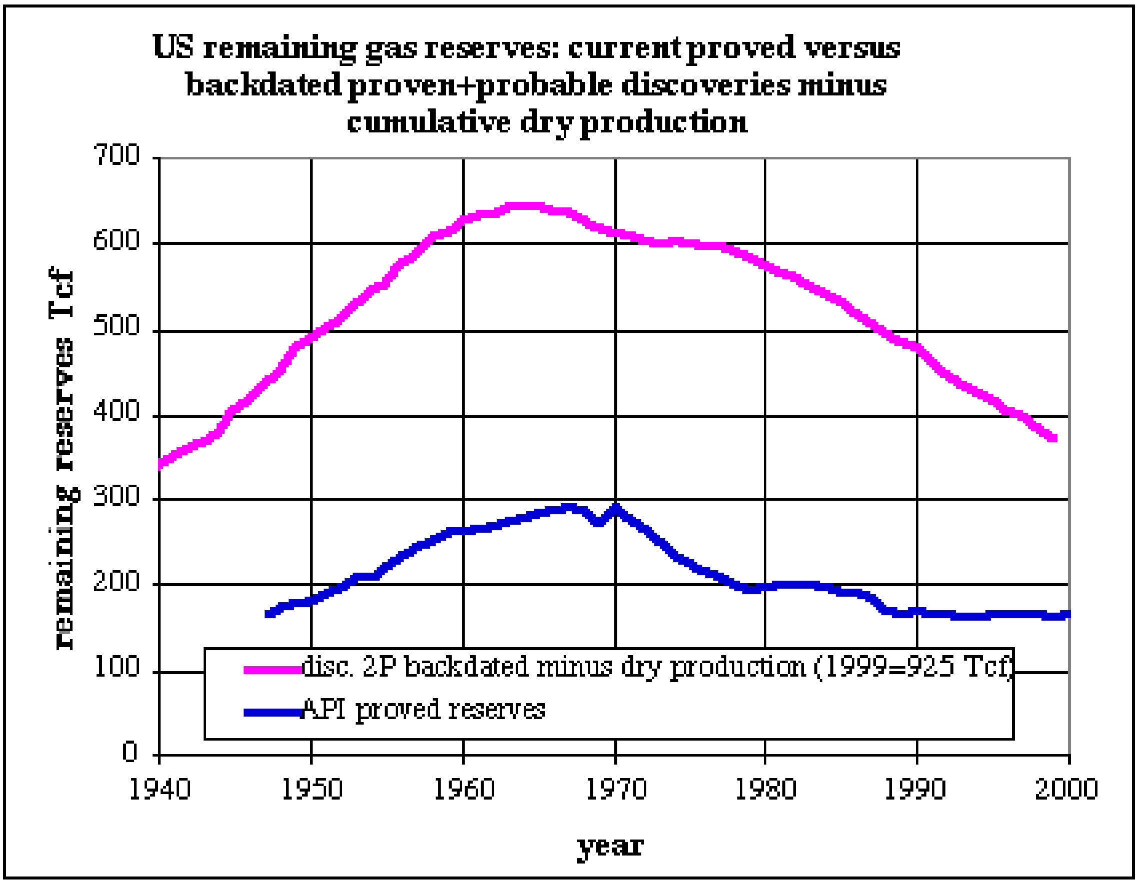
The experts are clear:

Ross 1998 wrote: "*The term "reserves" often is treated as if it were synonymous with "proved reserves". This practice completely ignores the fact that any prudent operator will have, at least internally, estimates of probable and possible reserves"*

DeSorcy 1993 for the Canadian Standing Committee on Reserve Definition wrote: "*There are currently almost as many definitions for reserves as there are evaluators, oil and gas companies, securities commissions and government departments. Each one uses its own version of the definitions for its own purposes*"

Capen, one of the best US experts in reserve definition, wrote in 1996: *"An industry that prides itself on its use of science, technology and frontier risk assessment finds itself in the 1990s with a reserve definition more reminiscent of the 1890s" "illegal addition of proved reserves"*

It is amazing to find in the oil and gas industry so much advanced technology such as the deepwater and so much obsolete practice such as using the old term of bbl (being the blue barrel: why blue?) or refusing to use the system of international units (SI) (it was the cause of the lost of the Mars Climate Orbitor which crashed when NASA sent instructions of thrust in newtons when Lockheed has built it in pounds), still using M for thousand when the layman uses Y2K and not Y2M. Most of US gas producers refuse the probabilistic approach in estimating the reserves, as they use only area (spacing) in acre, net pay in foot and recovery as cubic foot per acre-foot from the closer field, or often ten times the annual production!
One of the biggest mistakes in dealing with proved reserves is that aggregation of the proved field reserves does not give the proved reserves of the country or a basin, it underestimates it. But every official agency or media does it. Only the addition of "mean" field reserves corresponds to the "mean" reserves of the country.
The comparison between the current proved remaining reserves and the backdated mean (proven+probable) reserves (corrected using MMS reserve growth model) shows a large difference in volume and in decline rate. The "mean" reserves have declined since 1965 and the slope is constant since 1980 at 2.5%/a, whereas the current proved stays flat since 1988.
Figure 17: US remaining gas reserves: current proved versus backdated mean



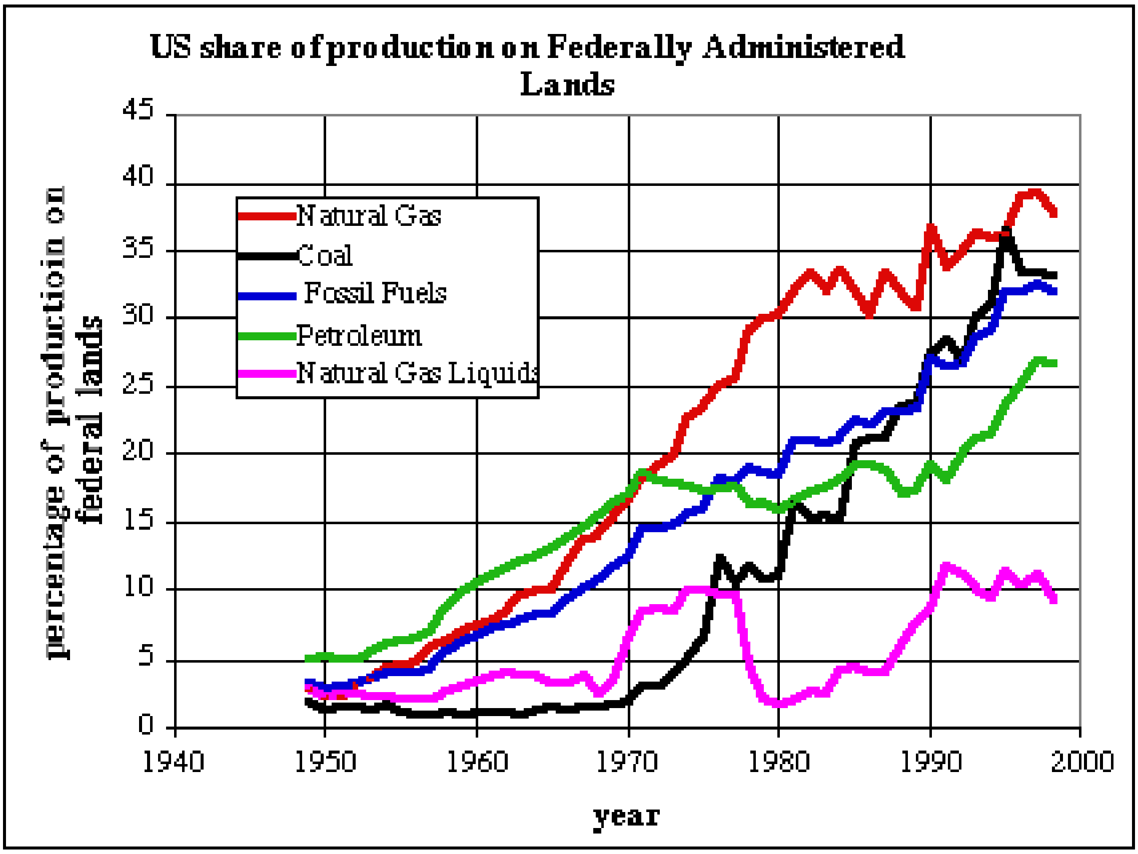
The biggest problem in forecasting US production is the poor quality of the reserves data because of the SEC rules and the conservatism of the gas industry in reporting data.

-Gulf of Mexico

Data is difficult to gather onshore US because of the number of producers and confidentiality of the data - gas is owned by the landowners. It seems that the situation should be better in the federal waters of the Gulf of Mexico = GOM OCS (Outer Continental Shelf) where oil and gas is owned by the Federal Administration (selling leases to private companies) and productions are managed by the USDOI MMS (Minerals Management Services).

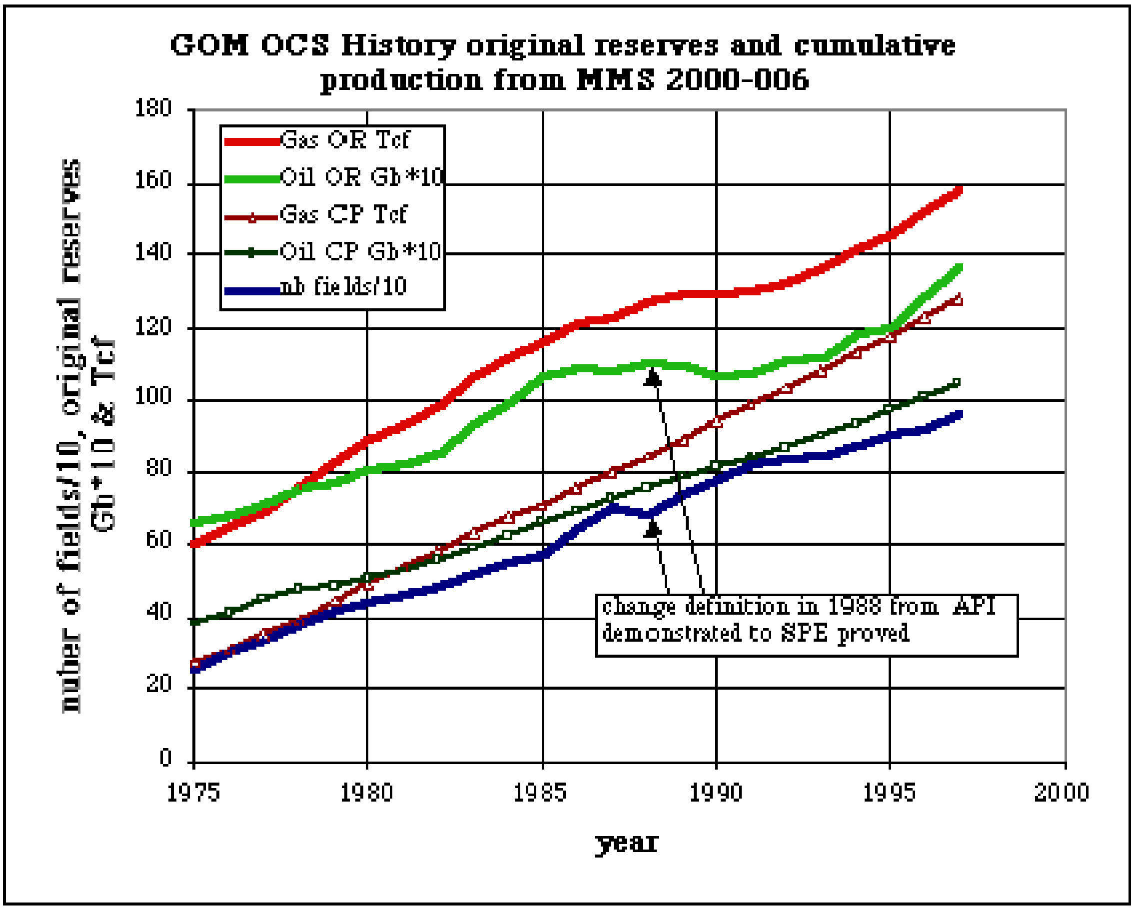
It is surprising to see the increase of the federal lands in the production of fossil fuels from 3% in 1950 to more than 30% in 1998 and it is likely to continue in the future and to increase more if the access to federal lands is more open to exploration and production.

Figure 18: percentage of production in federal lands



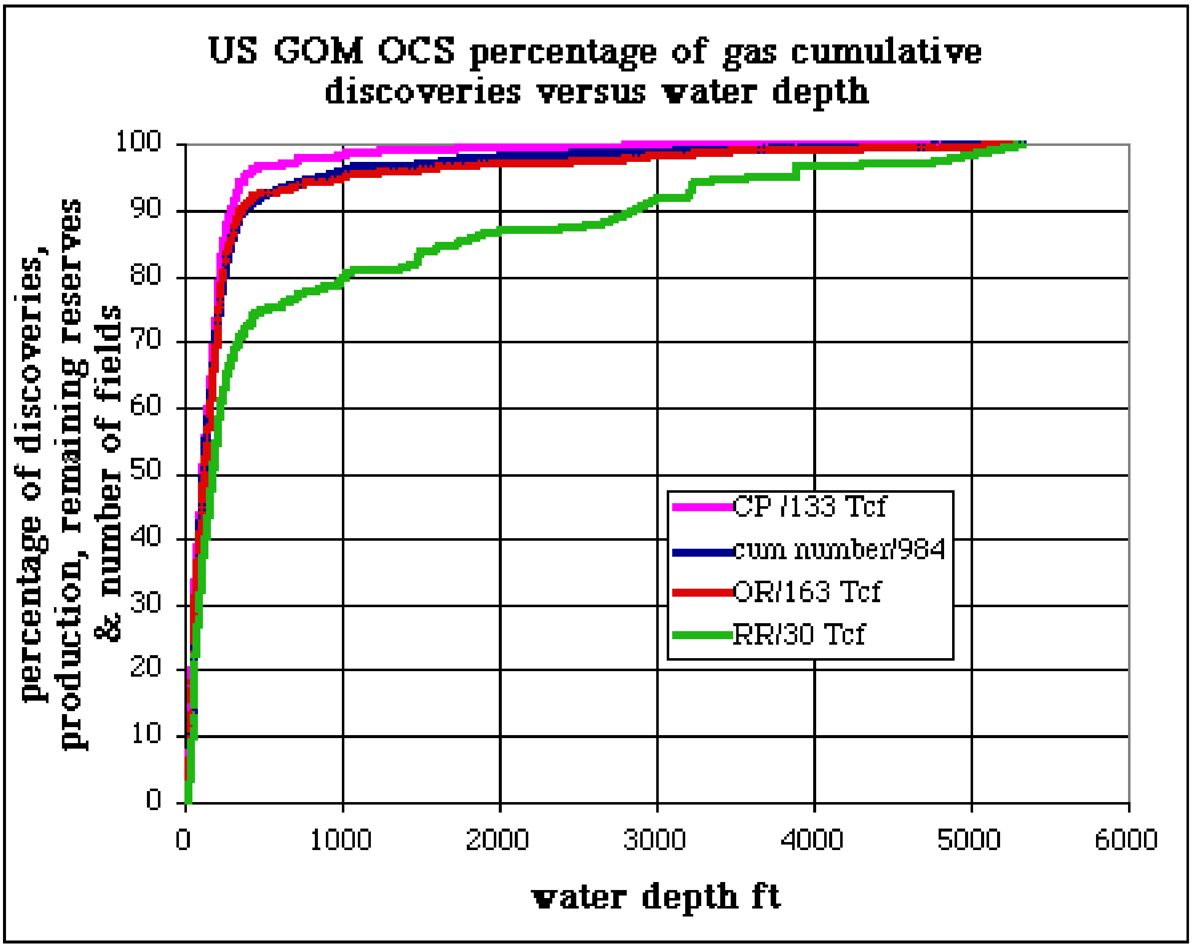
Reserves have been changed in the 80s because of the change in definition from API (American Petroleum Institute) to SPE (Society of Petroleum Engineers) rules

Figure 19: GOM OCS: evolution of original reserves and production



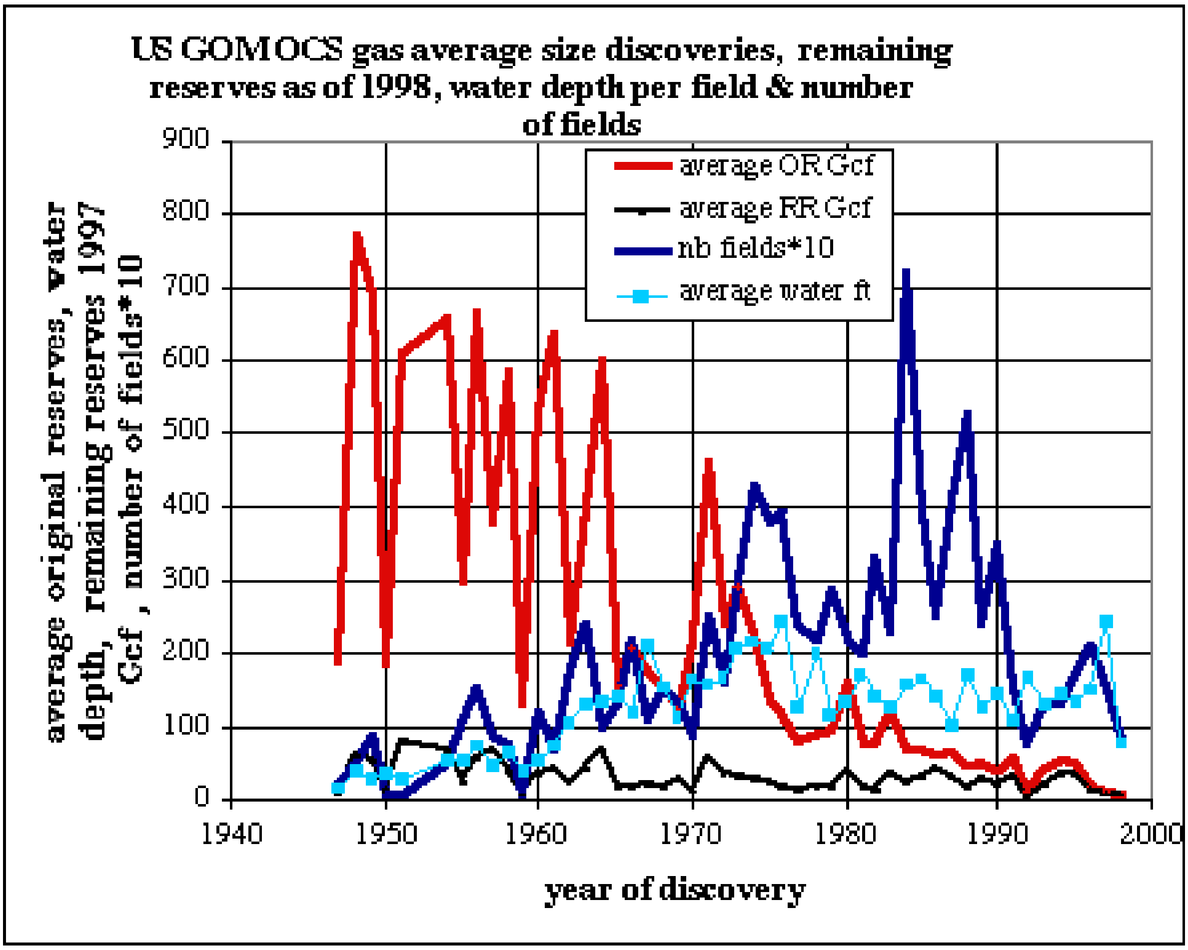
The incomplete MMS data gives a distribution of gas reserves and production versus water depth, which shows that gas is mainly in the shallow waters.

Figure 20: GOM percentage of gas discovery and production versus water depth from MMS



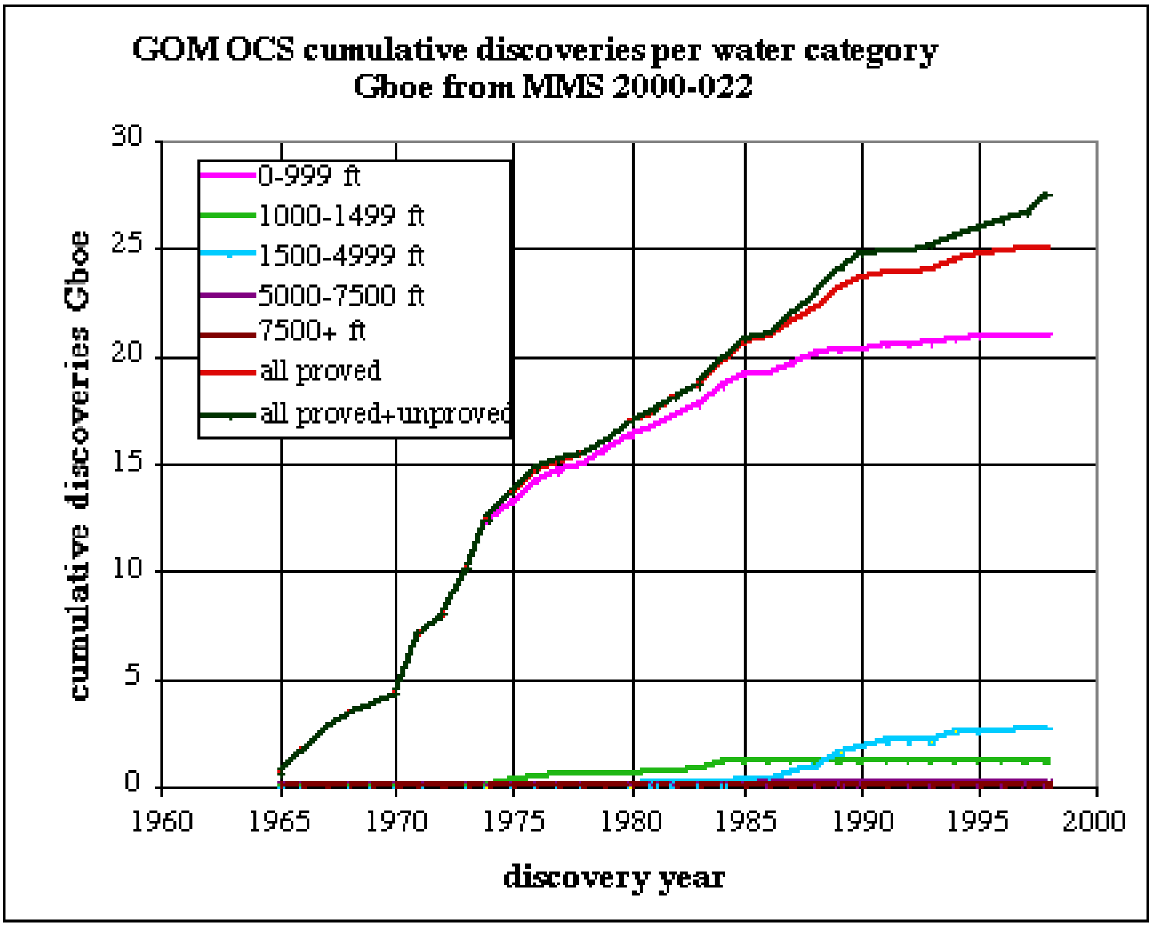
The MMS data displays a peak in the annual number of discoveries (in the graph the number is multiplied by 10) around 1984 (70) and that the average size of the original reserves which was around 0.6 Tcf in the 50s has sharply declined since 1973. The average water depth of the discoveries, which was around 200 ft in the 70s, is around 150 ft in the 80s and the first half of the 90s.

Figure 21: GOM OCS: annual average size and number of gas discoveries from MMS



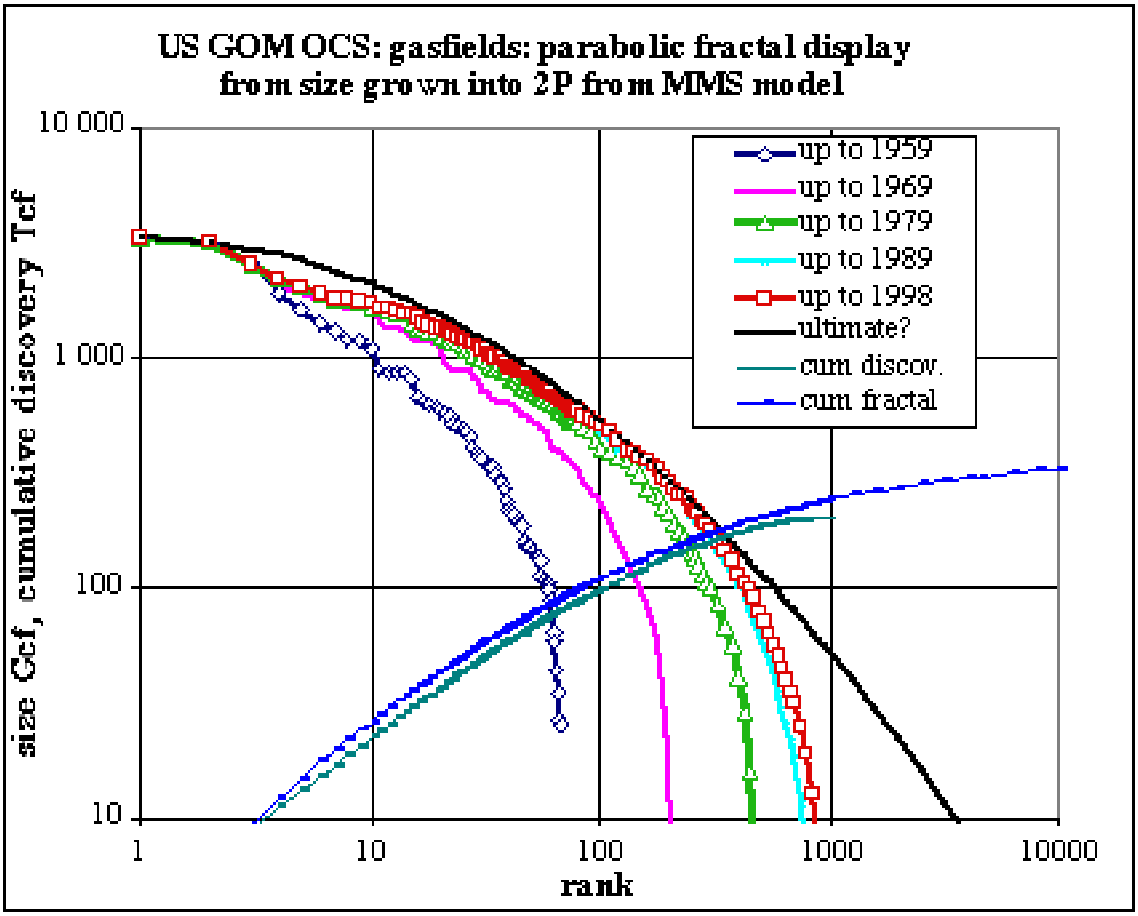
The cumulative gas discoveries (from MMS) shows that the main part comes from water depth less than 1000 ft, but this part decreases since 1980.

Figure 22: GOM OCS cumulative gas discoveries detailed by water depth from MMS



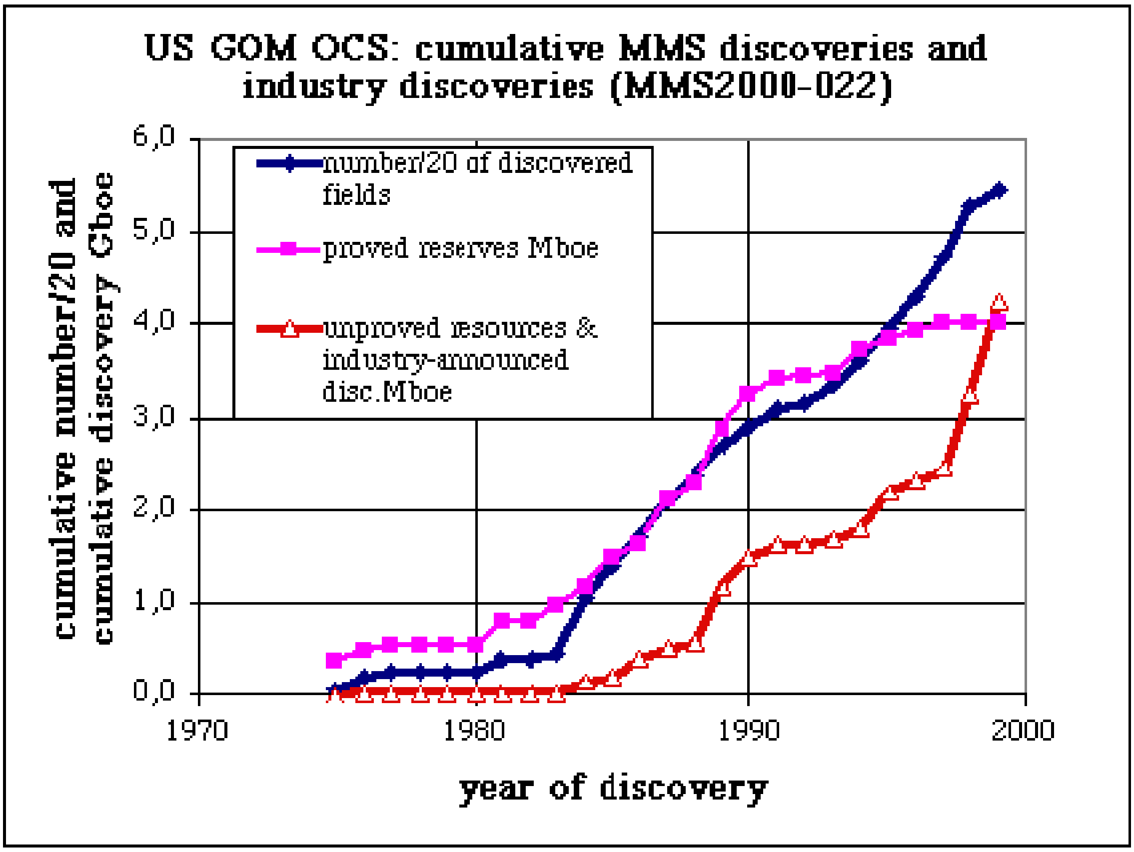
The MMS proved gas field (984 fields) reserves grown to 2P (or mean) with MMS reserve growth factor (the first year estimate is multiplied 50 years later by 4.5) are plotted with a fractal display (rank of increasing size versus field size in a log-log graph) for each decade. This graph shows that the largest fields are found first and that an ultimate curve can be drawn.

Figure 23: GOM gas field size from MMS: fractal display



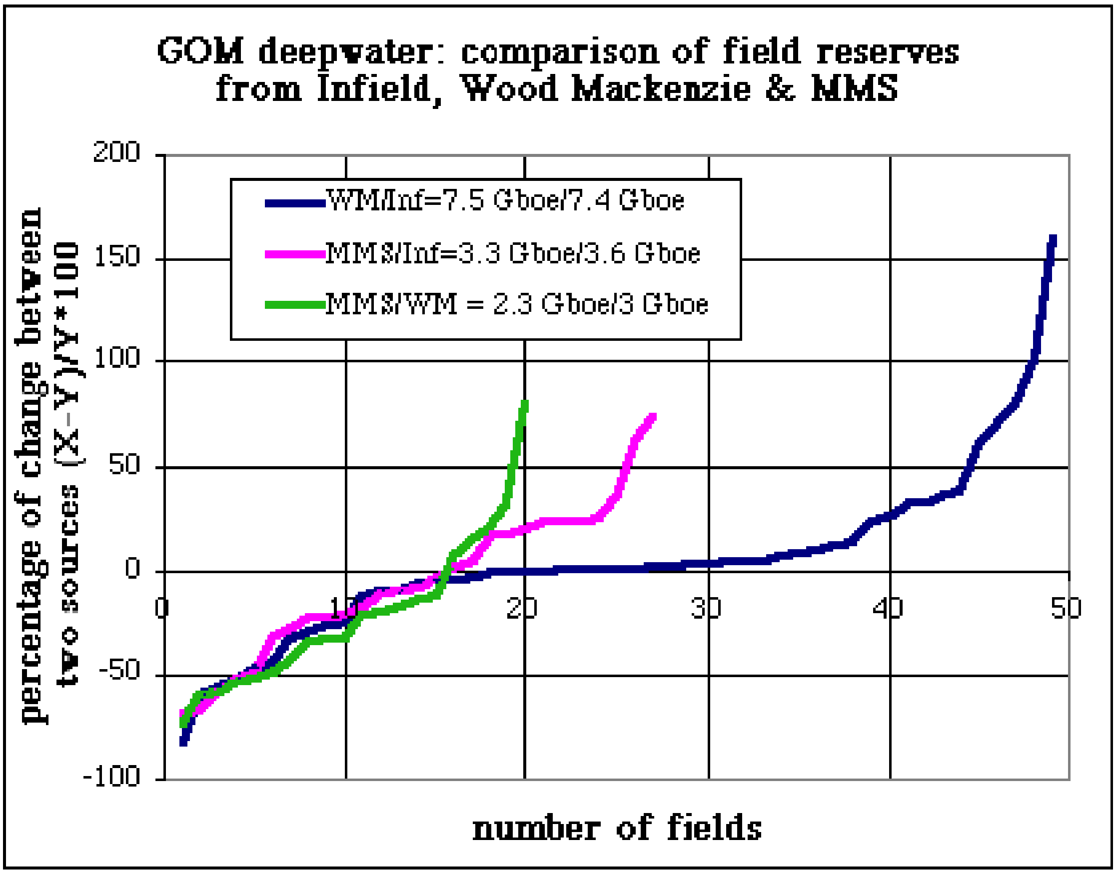
MMS provides on the web the data up to1998 giving the detail of the evolution of every field since 1975 in the GOM OCS, totalling 984 fields. Unfortunately the huge database (197 pages) on reserve history shows on the first page for the first field cumulative oil declining at the fifth line (for 1979), meaning that the annual oil production was negative (which is impossible!). It is obvious that operators sent flawed data (change in grouping?) to MMS, which did not bother to check if it is correct.

Figure 24: GOM OCS: MMS proved & industry unproved discoveries



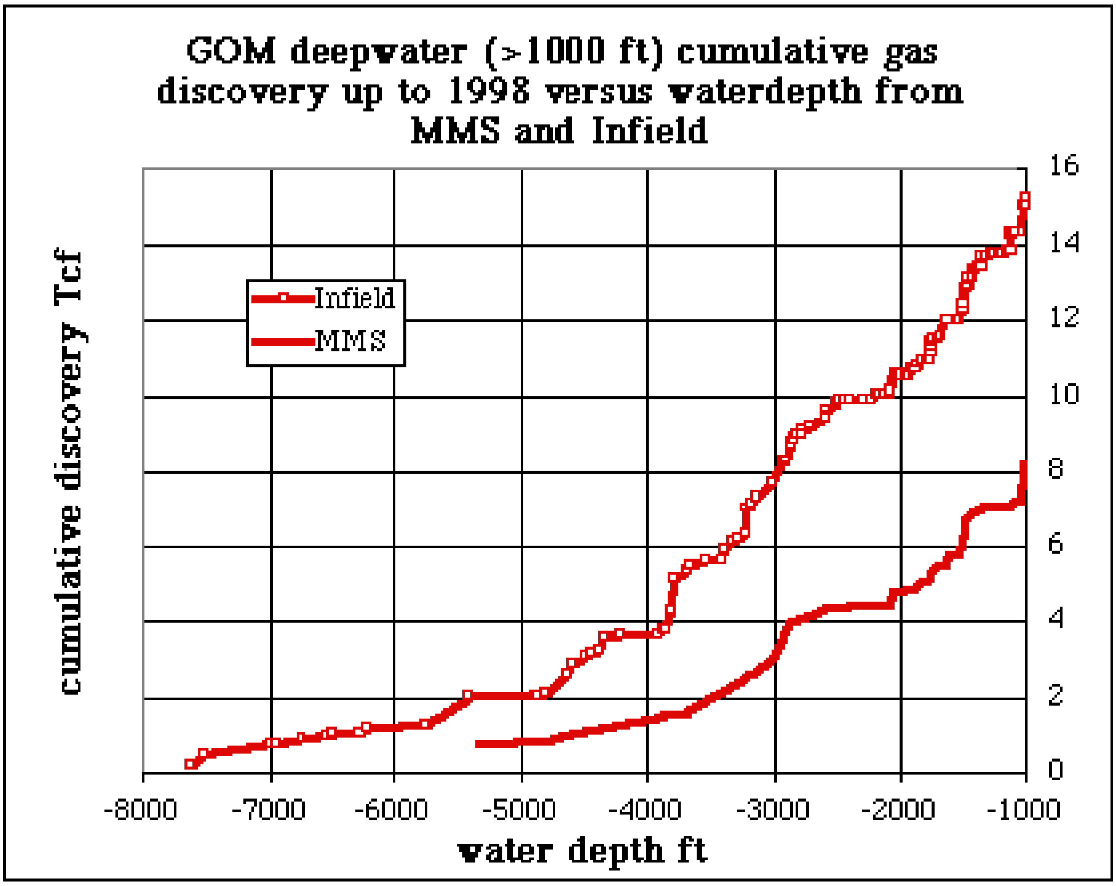
We have compared for the deepwater of the GOM the data given as oil equivalent (initial) reserves from MMS, Infields and Wood Mackenzie (WM). The comparison for the same field between two files X and Y is given in percentage of change ((X-Y)/Y*100) and the percentage is ranked by increasing percentage. The plot shows that the change varies from —80% to +150%. The total of the reserves for about 50 fields is 7.5 Gboe for Wood Mackenzie and 7.4 Gboe for Infields, being close, but the difference was larger when compared with MMS. For 20 fields MMS total is 2.3 Gboe when WM is 3 Gboe. For 27 fields MMS total is 3.3 Gboe when Infields is 3.6 Gboe.

Figure 25: GOM deepwater: comparison of field reserves from Infield, Wood Mackenzie and MMS



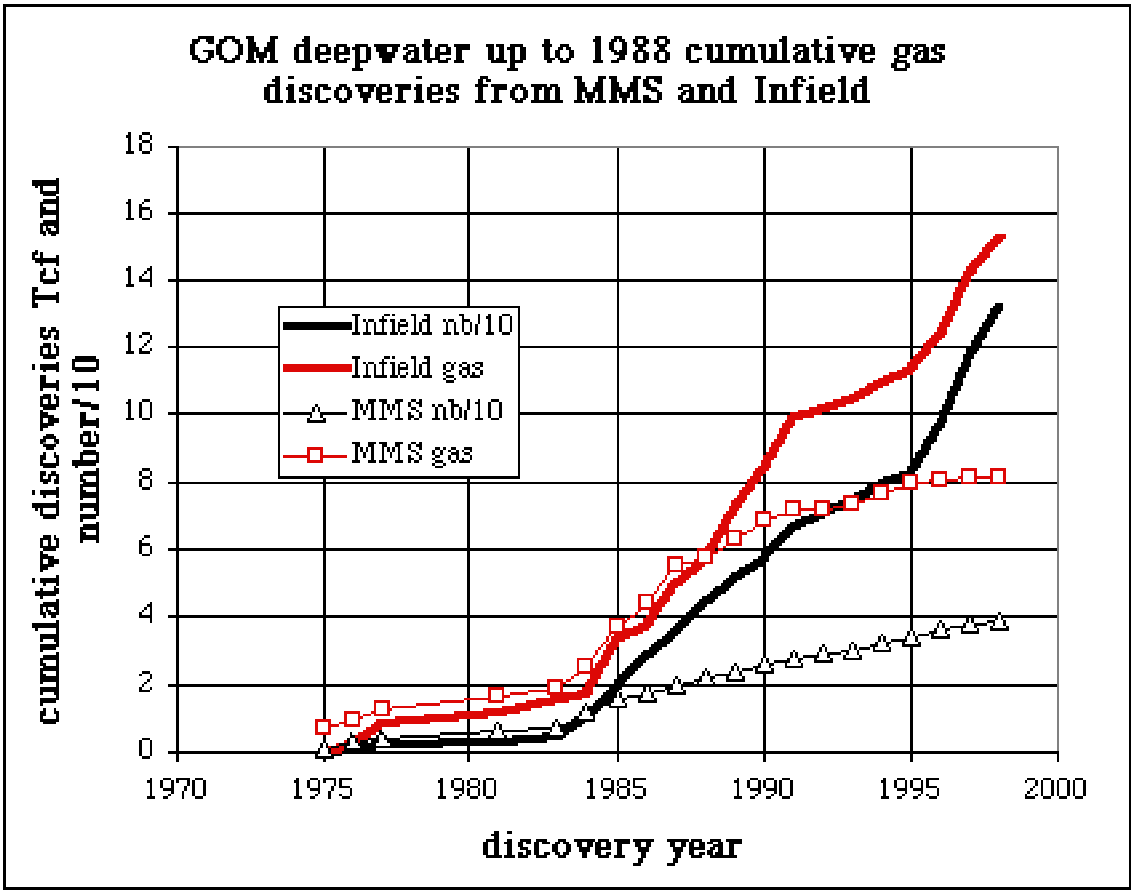
When these databases are plotted as cumulative discovery versus time, the discrepancy is huge. For deepwater (>1000 ft) the cumulative discovery up to 1998 is 15 Tcf for Infield, but 8 Tcf for MMS.

Figure 26: cumulative gas discovery up to 1998 versus water depth from Infield and MMS



It is obvious that MMS database is incomplete having only 39 fields against 132 fields for Infields. The plot versus time shows that the discrepancy starts in number since 1985 and in discovery since 1988

Figure 27: cumulative gas discovery versus time from Infield and MMS



MMS is incomplete and late to report, now only up to 1998.
To get updated data, it is necessary to rely on published papers such as Dodson in Offshore January 2001. Gas production is flattened since 1990 with less than 5 Tcf/a and oil has risen since 1990 because of the deepwater.
Figure 28: GOM oil & gas production up to 2000

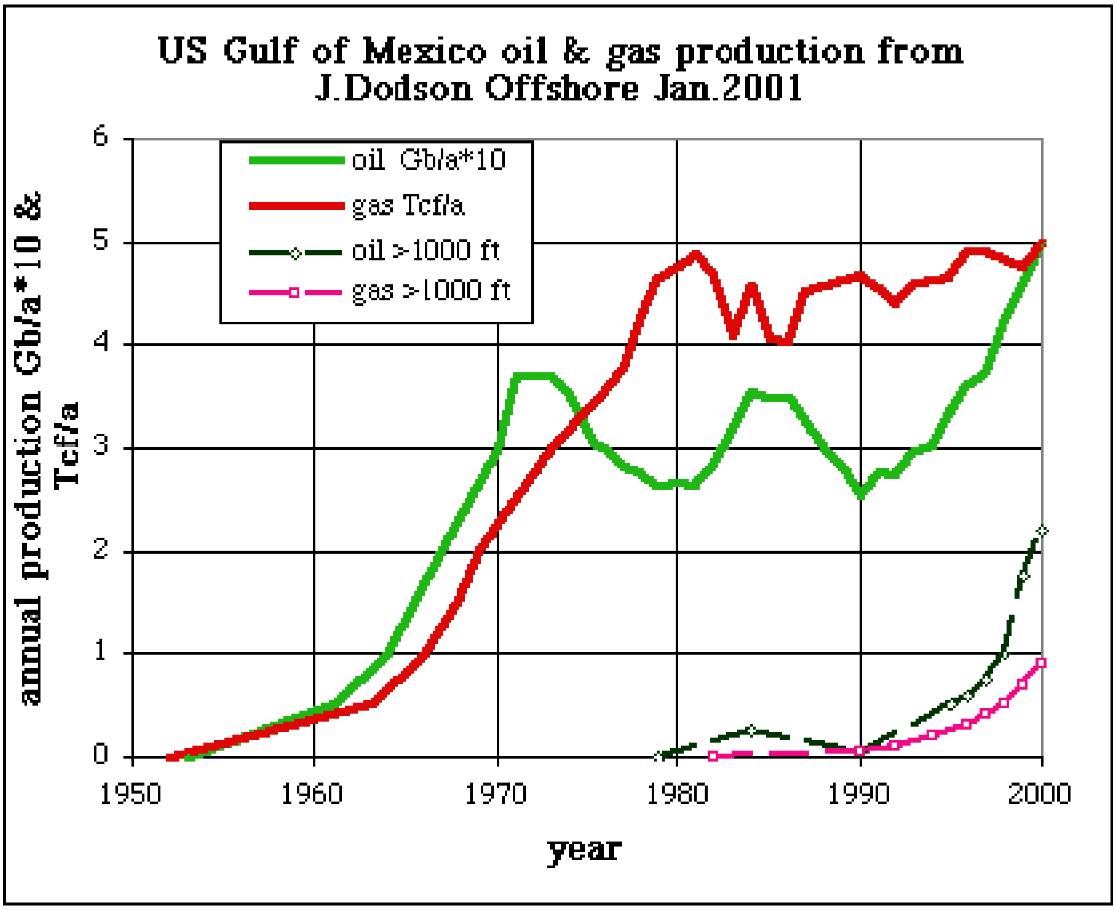


Figure 29: decline of GOM production from gas wells from 1972 to 1998
http://www.eia.doe.gov/oiaf/servicerpt/depletion/table_g1.html

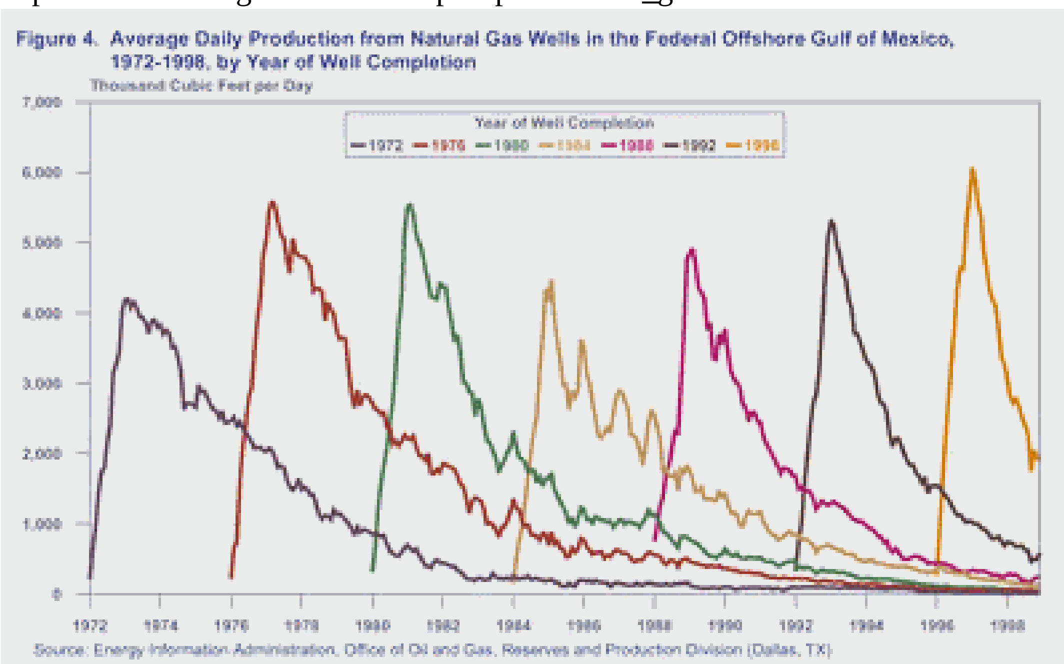


Table G1. Average Production from Wells in the Federal Offshore Gulf of Mexico, 1972 to 1996

Year	Peak Production kcf/d	Percentage of Peak Production 23 Months Later
1972	4 198	0.633

1976	5 591	0.648
1980	5 533	0.502
1984	4 477	0.591
1988	4 915	0.497
1992	5 294	0.417
1996	6 070	0.314

Source: Energy Information Administration, Office of Oil and Gas, Reserves and Production Division (Dallas, TX).

-Reserve growth

In 1981, faced with the unreliability of the so-called proved reserves, the USGS (in an assessment of undiscovered conventional oil and gas as of end 1979), called them measured reserves, and called inferred reserves the expected additions on these measured reserves, which is now called reserve growth by the new team.

Reserve growth is the most important problem in assessing the US oil & gas potential, as a proper approach needs to deal with "mean" values, called "proven + probable" in most of the countries outside the US and Canada.

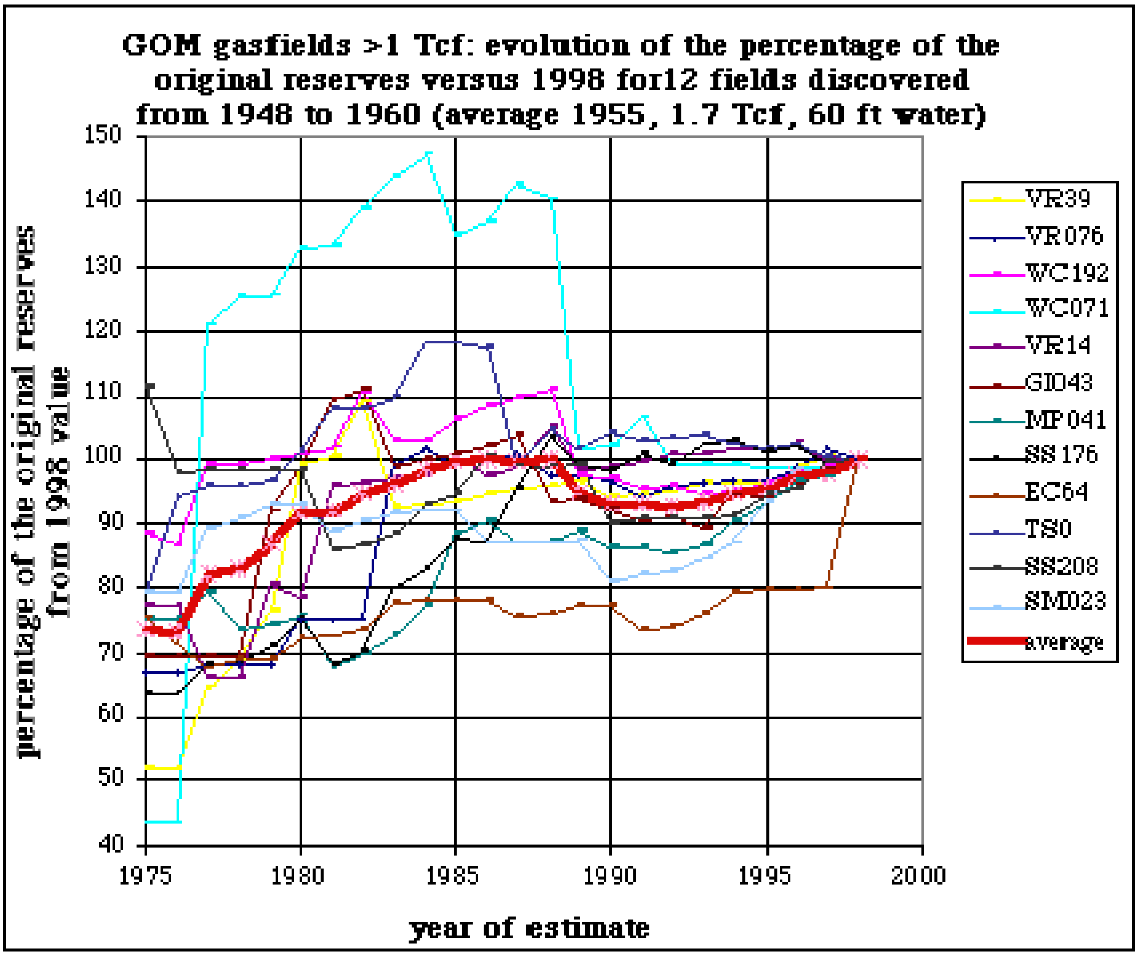
Technology allows cheaper and faster production, seldom to increase the conventional reserves (but in contrast to unconventional oil and gas). The best proof is that the depletion rate of gas wells has increased drastically over the last 20 years, being now over 50%/a in the GOM.

What is wrong is the US practice of estimating reserves because the SEC rules prohibit reporting probable reserves as is done in the rest of the world. It is why from 1988 to 1999 new gas field discoveries represent only an average of 5% of the total reserves additions, and the revisions of the past discoveries represents 95%, meaning that the past estimates are pretty lousy. US practice for reporting reserves is very poor (as obsolete as the punched cards of the last presidential elections!). This poor practice leads to a strong reserve growth wrongly attributed to new technology when in fact it is due to poor methodology. But such practice allows oil & gas companies to report growth even without any discovery and they love it.

The evolution of the percentage of the original reserves versus the reported value in 1998 for 12 largest gas fields discovered from 1948 to 1969 (average year of discovery 1955 and average water depth 60 ft) shows a large range of variation but the average rises sharply from 1975 (first year of data) to 1985, then the estimate went down following the counter shock of 1986 to return in 1998 to the 1985 value.

It means that the evolution is stabilised and no significant reserve growth should be expected statistically, but despite that some fields can still vary up or down.

Figure 30: GOM gas fields: evolution of original reserves with time

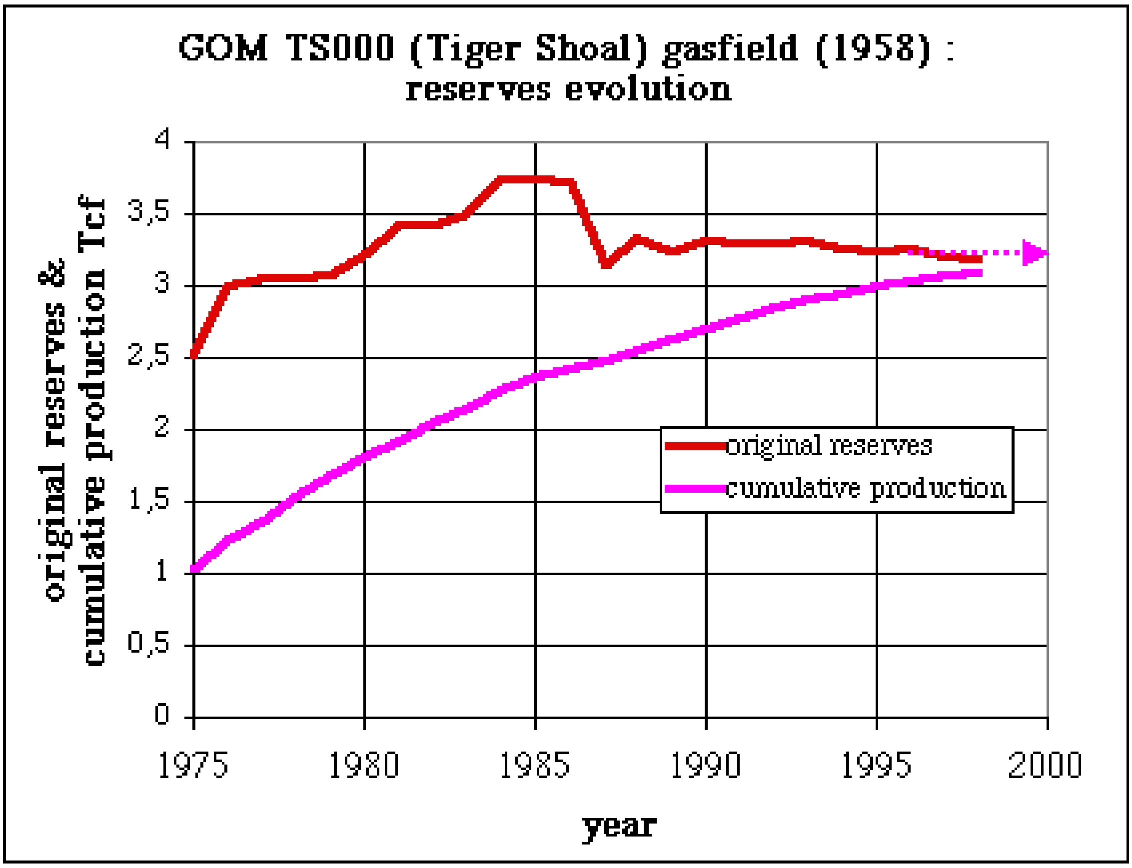


The deepwater production has really only started since 1990 as shown in figure 28 and the behaviour in these new conditions is still immature. Some deepwater development have shown some disappointment as the Shell Macaroni field (developed with subsea equipments peaking at 15 000 b/d instead of the 35 000 b/d expected)

The study of the production of individual mature fields shows a different story from what is reported as reserves. The three largest GOM gasfields (all found before 1958) are TS000 (Tiger Shoal), VR014 (Vermilion) and VR039 with about 3 Tcf each.

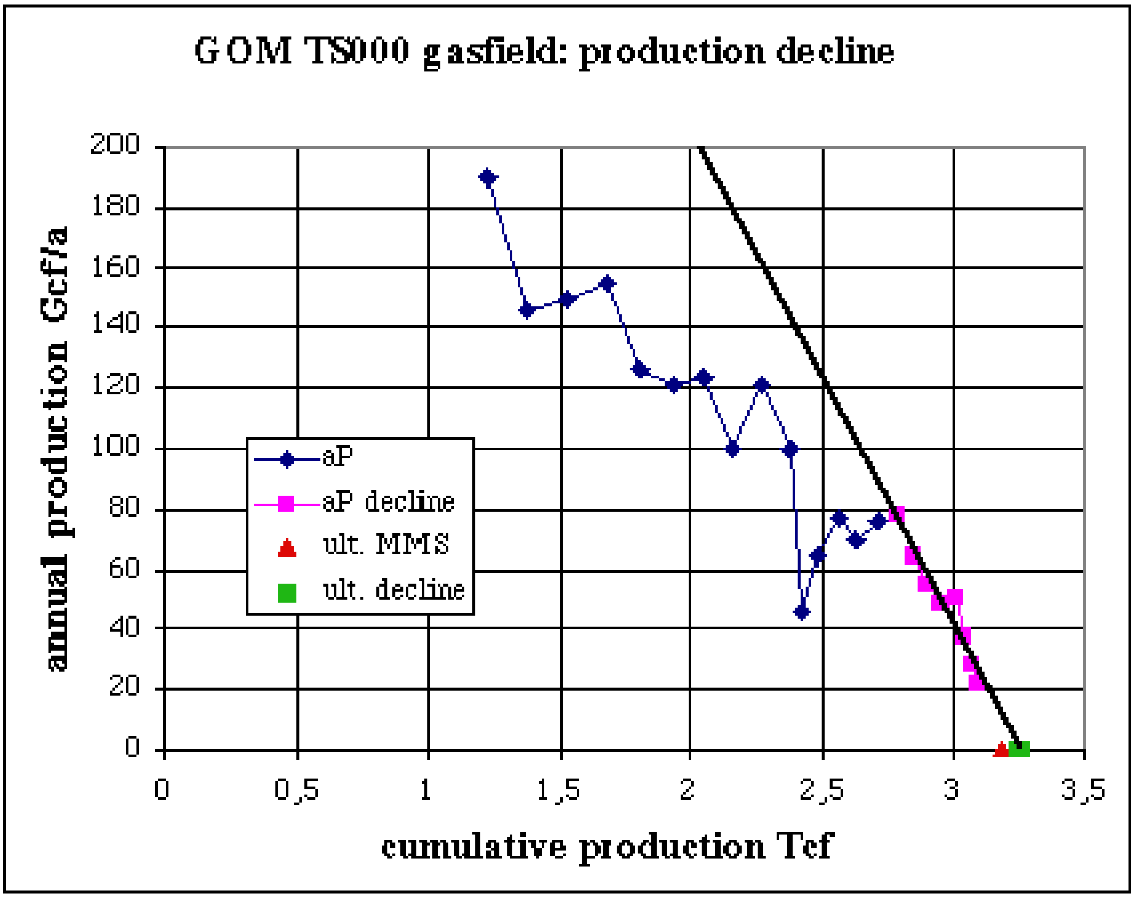
The evolution of original reserves given by MMS since 1975 shows that for TS000 (found in 1958) by 13 ft of water) the ultimate was about 3.7 Tcf around 1985 to go down to 3.2 Tcf in 1998. The evolution of the ultimate with up and downs is not smooth, likely coming from goals varying with years.

Figure 31: GOM Tiger Shoal gas field: reserves evolution

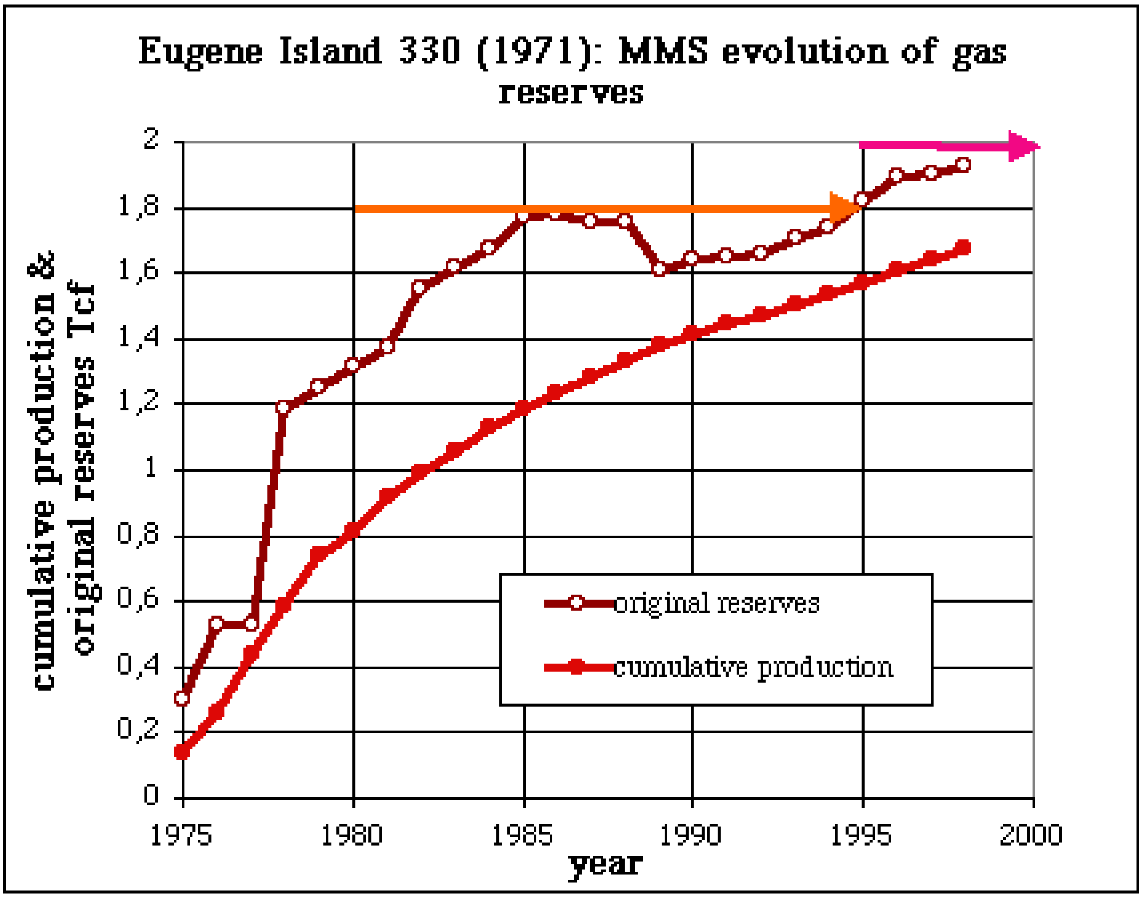


The analysis of the annual production versus cumulative production shows a decline from 1975 to 1990 giving an ultimate around 3.5 Tcf (explaining the 3.7 Tcf in 1985) but since 1991 the depletion has been accelerated and the present ultimate is around 3.3 Tcf against MMS estimate of 3.18 Tcf

Figure 32: GOM Tiger Shoal gas field: production decline



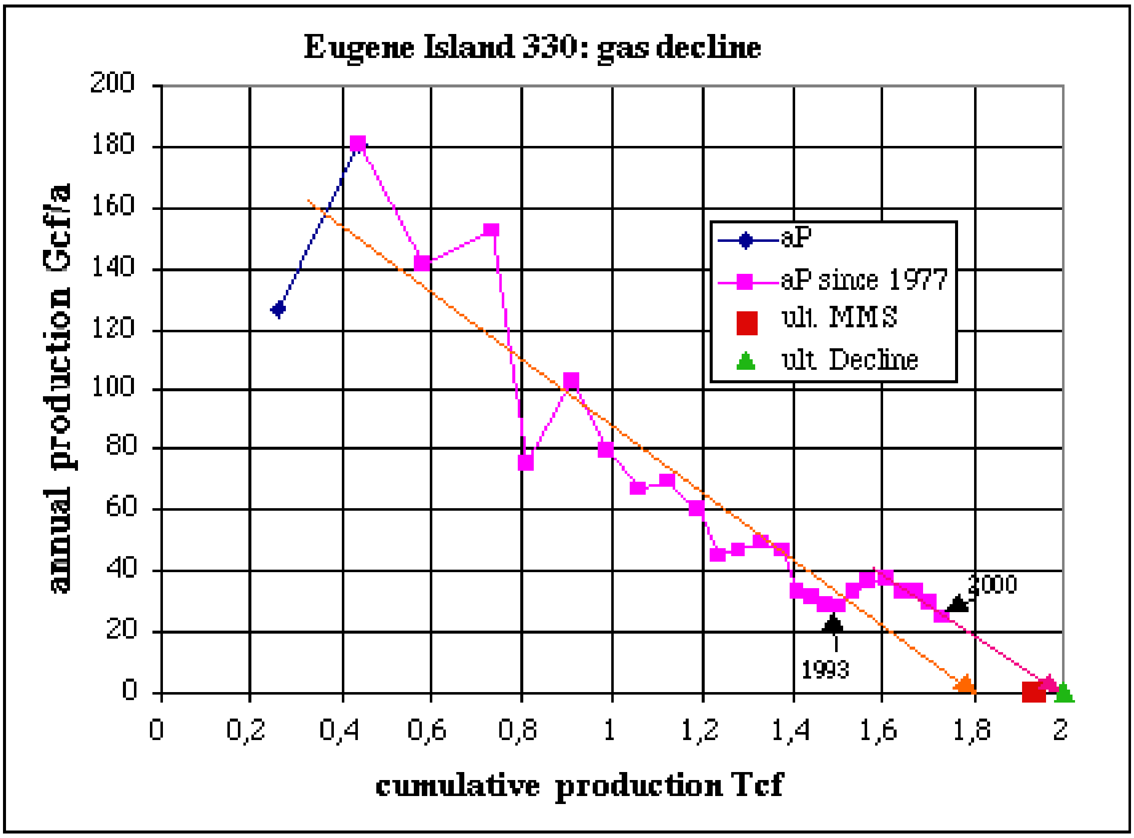
The fourth largest gas reserves Eugene Island 330 oilfield (found in 1971 in 246 ft of water and in 1998 the largest oil and gas original reserves with 760 Mboe) is interesting as this field was taken by the Wall Street Journal (Cooper 1999) as the example of refilling of reserves and to wonder about a deeper origin for oil, and to explain the huge increase in the Middle East reserves in the second half of the 80s. In fact, because of the large depletion of pressure, this field seems to have been charged again from the source-rock, by one of the largest (the Red Fault) and best faults in the GOM studied by many university seismic surveys in 4D (http://www.ldeo.columbia.edu/4d4/talks/expl/index.html). But again the first oil estimates reported to MMS seem odd and different from OGJ estimates and the increase in1995 due to an increase in annual production is minor compared to the decrease of 1988. An analysis of the pressure should explain the recharge of the reservoir. The difference between MMS and OGJ on the cumulative production seems to be mainly discrepancies between 1977 and 1979.
Figure 33: GOM Eugene Island 330 field: gas reserves evolution



The new increase in annual oil production starting in 1993 peaked in 1996 and declined again. The last value plotted for 2000 is only an estimate from the month of May in MMS last report. The pre 1993 ultimate estimate from the decline was about 350 Mb, after the recharge the estimate is now about 400 Mb (416 MMS & 389 OGJ).

As for oil production, the EI 330 associated gas production declined since 1977 to 1993 to rise until 1996 and declined again. Before 1993 the ultimate could have been estimated at about 1.75 Tcf, after the recharge the present decline rate suggests (questionable value for 2000 as only for one month) the ultimate is about 2 Tcf (1.93 Tcf MMS)

Figure 34: GOM Eugene Island 330: gas production decline



In the DOE/EIA annual report 1997 the reserve growth on federal offshore is given as 33 Tcf

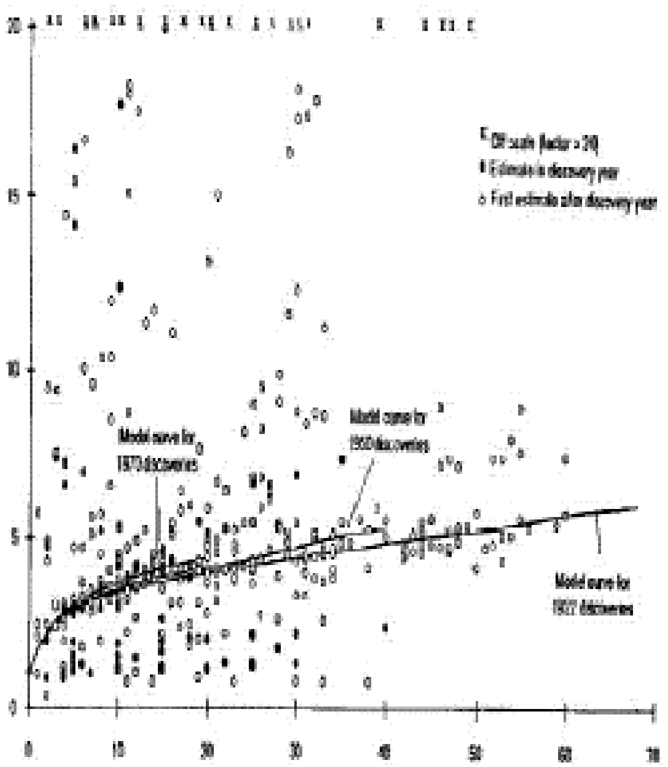
Annual report DOE/EIA 1997	Crude Oil	Natural Gas (Dry)	Natural Gas Liquids
	Gb	Tcf	Gb
Lower 48 States			
Discovered			
Proved Reserves (EIA, 1997)	17	157	7
Reserve Growth - conventional, onshore+State offshore (USGS 1991)	**47**	**290**	**13**
Reserve Growth - conventional, Federal Offshore (MMS, 1995)	**2**	**33**	**NE**
Unproved Reserves, Federal Offshore (MMS, 1996)	2	4	NE
Undiscovered, Technically Recoverable			
Conventional, onshore + State off (USGS, 1993)	**22**	**190**	**6**
Continuous-type - sandstone, shale, chalk	2	308	>2
Continuous-type - coalbeds	NA	50	NA
Federal Offshore - conventional (MMS, 1994).	21	142	>2
Subtotal	113	1174	NA

We believe that it is completely wrong to measure the reserve growth as a ratio of the estimate of proved reserves at discovery year. The estimate is only reliable after a few appraisal wells. Furthermore the proved reserves depend on the number of wells drilled and it is better to wait for the complete development of the field to assess the real value of the proved reserves. In the past when API was in charge of reporting the reserves, the first six years after discovery were considered as unreliable. Offshore the development is decided only after appraisal wells and the only reliable estimate should be the first one at the decision of development which in fact is decided not on "proved" reserves but on "mean" reserves, if not the size of the development is underestimated costing money later.

Proved values are the values reported to the outside but the technical values, which are different, are kept confidential in house. In the North Sea a study by BP and the DTI show that the proven+probable used in UK shows less reserve growth (see Laherrere 1999). A

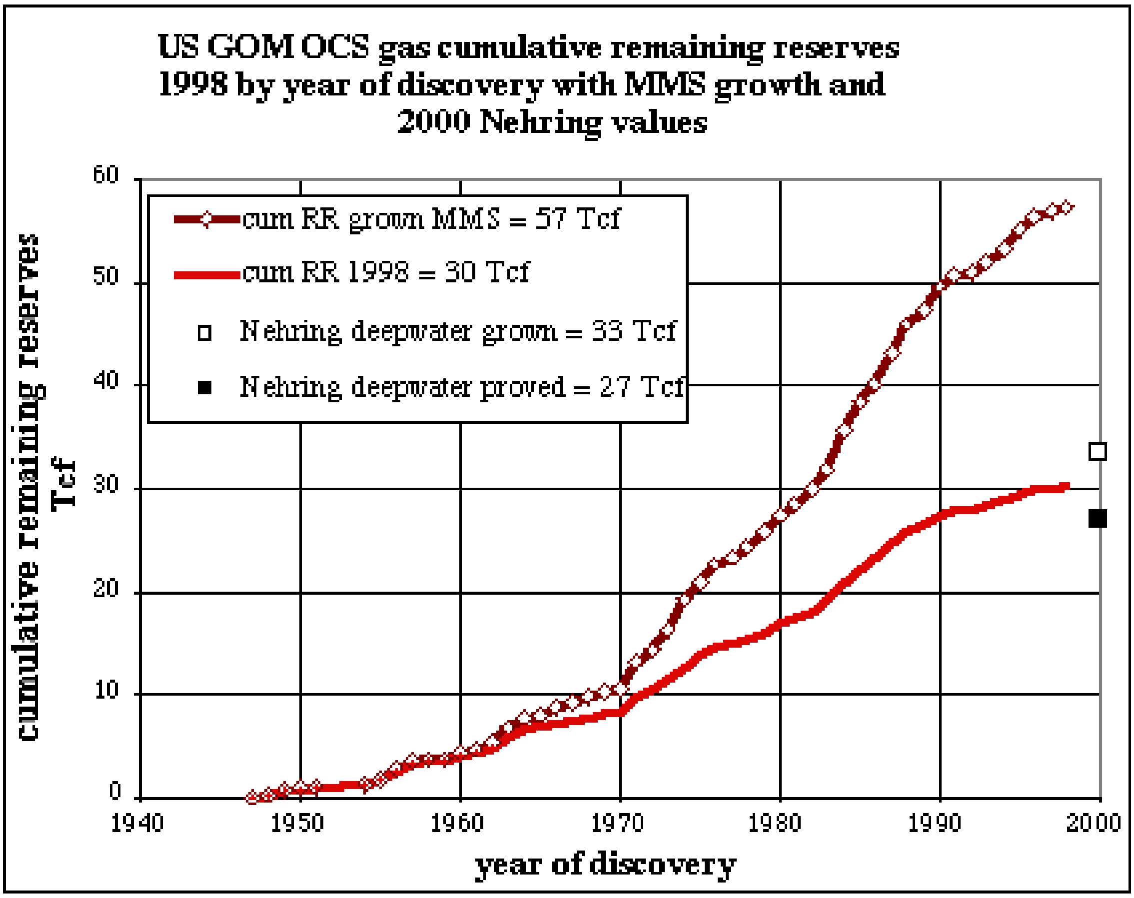
recent study by Wood Mackenzie (1999) consider the year zero as the development year and the "reserves creep" before. In fact the reserves estimates 4 years before the development were 13% higher. They increase for the first 8 years then decrease but increase again to reach a value 25% higher 13 years later.
A gas study in 1992 by the National Petroleum Council gave the following graph, which displays an erratic cloud from 0 to 30 times multiplier for the 60 years period. They draw a curve within this cloud but it could be any curve!
Figure 35: NPC 1992 study: Gas reserve growth

Figure FE5. Observed Growth Factors and URA Model Projections for the NPC Sample Fields



Source: Energy Information Administration, Office of Oil and Gas. Derived from National Petroleum Council, "Report of the Reserves Appreciation Subgroup to the Source and Supply Task Group, 1992 National Petroleum Council Natural Gas Study" (Washington, DC, August 1992), unpublished open file text, Figure 14.

From more recent data in the GOM MMS claims that the first year estimate has to be multiplied by about 4.5 to get the ultimate recovery 50 years later.
In his Jan. 2001 article in *Offshore* Nehring studies the Gulf of Mexico (GOM)'s reserves and, contrary to the USGS, he gives the proved as well as the proved plus probable (by growing the proved by about 30% after a few years and then stopping the growth, which is completely different from the 2000 USGS lower 48 reserve growth or the MMS reserve growth).
Figure 36: GOM gas remaining reserves proved and grown from MMS and Nehring

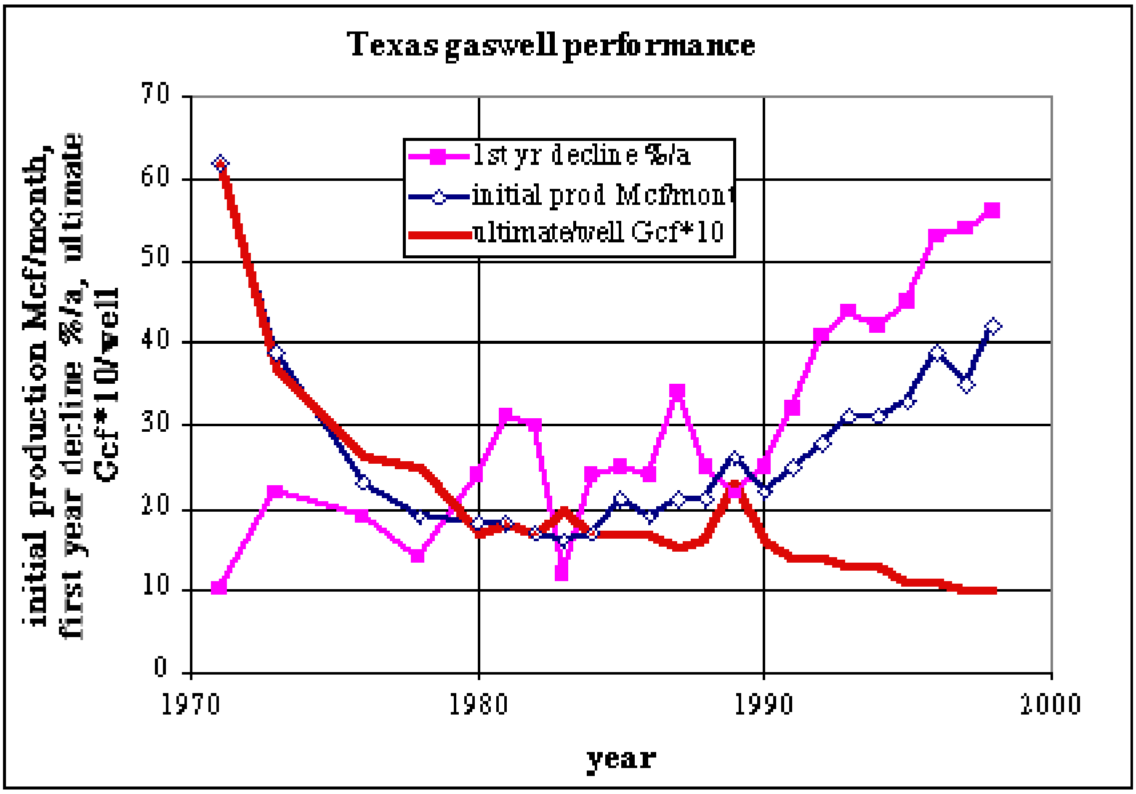


Nehring increases by 20% to get grown (from 27 to 33 Tcf for deepwater) when MMS model grows OCS by about 90% (from 30 to 57 Tcf)

The claim of increasing the reserves because of technology is confused with increasing the initial production. If initial production are improved with new technology, the subsequent decline is also increased sharply as shown in figure 29 for the GOM and in fact the ultimate recovery per well decreases as in the study for gas in Texas.

Gary Swindell 1999 provides the Texas gas well performance from 1971 to 1998 with an initial rate (first month) being 52 Mcf/month in 1971 decreasing to a low of 15 Mcf/month in 1983 and increasing again through 1998 up to over 40 Mcf/month. The increase beginning in 1989 correlates with the acceleration of horizontal drilling in the Austin Chalk fields of Giddings and Pearsall Fields. Increases prior to that are likely due to improved, high volume fracturing technology and high productivity in South Texas drilling. But the first year decline has increased from 10%/a in 1971to over 55%/a in 1998. The ultimate per well decreases continuously (except 1989) from 6 Gcf/w in 1971 down to 1 Gcf/w in 1998.

Figure 37: Texas gas performance from 1971 to 1998



It is obvious from the technical data that technology allows for conventional gas to produce faster and cheaper but hardly to increase reserves. Reserve growth is mainly due to poor reporting when using proved reserves, but the use of "mean" reserves allows statistically to avoid reserve growth.

Generally speaking, all studies assume that gas production will grow thanks to new technological developments, as if the simple extrapolation of the past production trends was missing this aspect. This is of course untrue because technology has improved over time in the past and this improvement is an integral part of the past production profile. So, the addition of a "technology improvement" should be understood as an extra improvement compared to its natural evolution with the general increase of the productivity of the factors. Given the fact that the level of prices is supposed to remain at the level of the 90s, this extra improvement cannot be attributed to prices. So, where does it come from?

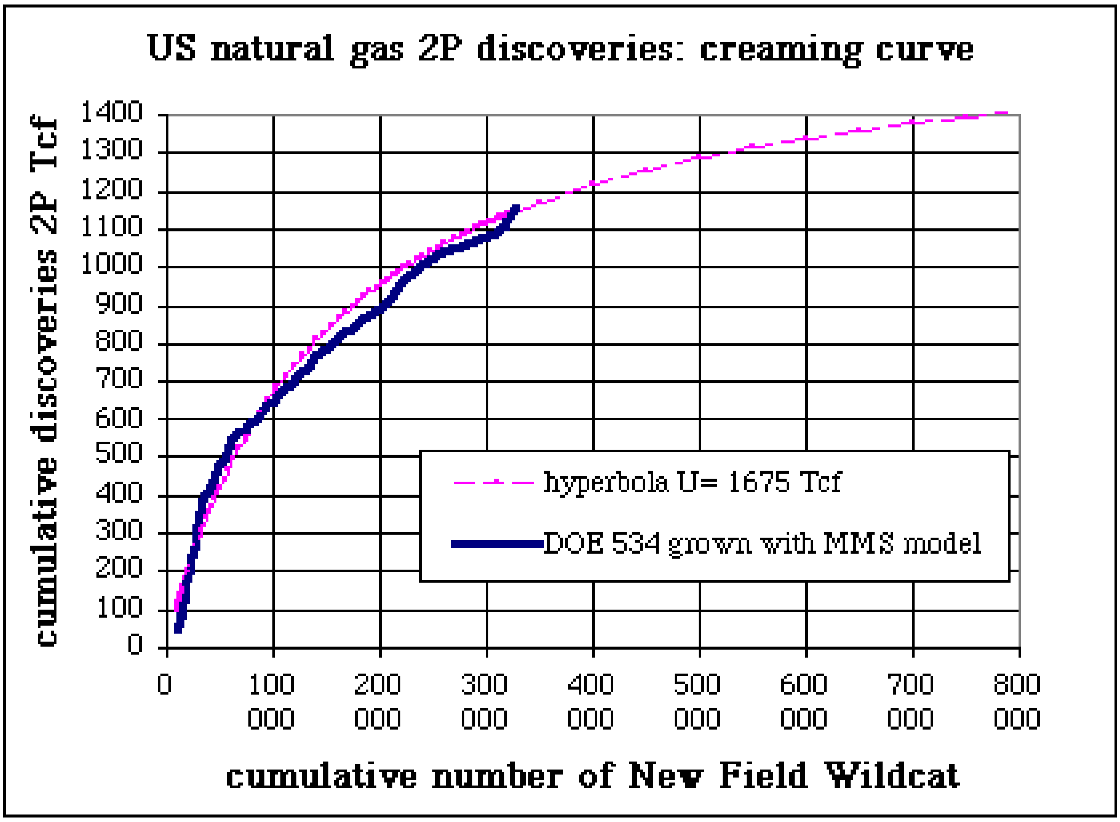
In short, in all these forecasts, there is a contradiction between the evidence of a supply problem arising from past production trends and the optimistic assumption that technology will reverse these declining trends. In fact, unless the price environment changes significantly (an hypothesis that none of the NPC, GRI, DOE,…forecasts anticipates) it is difficult to admit that the trend of technology improvements (that is included in the past production, for instance with the growth of non-conventional gas or that from deep offshore), will suddenly accelerate and be the "deus ex machina".

In conclusion, if one dismisses the possibility of the opening of federal lands that are presently closed to exploration, and if one considers that, unless prices rise significantly, technology will only continue the same steady trend of progressive improvement as before (with no "silver bullet"), future production will continue to decline, possibly at an accelerating rate**.**

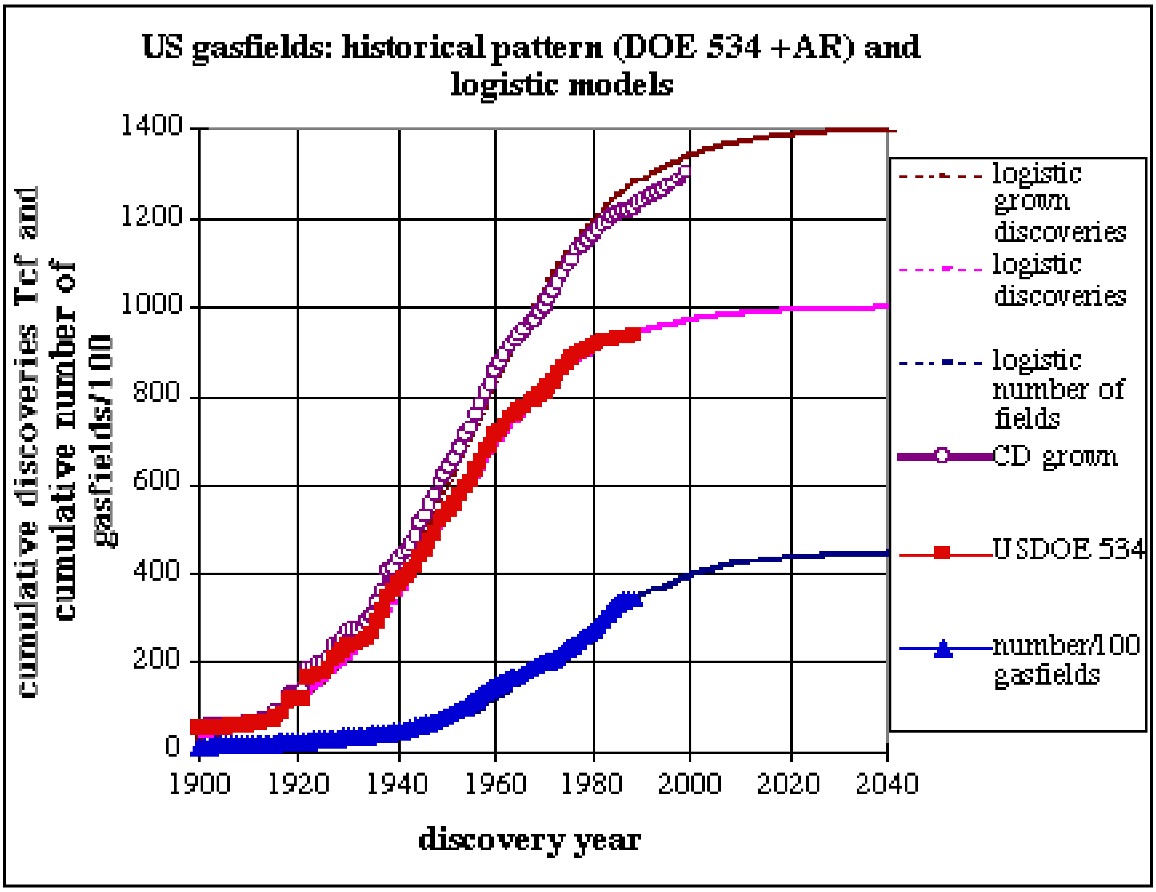
-Creaming curve

US all

The creaming curve (concept from Shell) represents the cumulative discoveries versus the cumulative number of new field wildcats. It displays the classic law of diminishing returns in mineral exploration. Usually it displays one or several hyperbolas.
Up to 1998 1150 Tcf of "mean" discoveries has been found with 320 000 NFW. The modelling shows that doubling the present number of NFW will increase only the total discoveries up to 1400 Tcf.
Figure 38: US gas discovery: creaming curve



The cumulative discoveries versus time is disturbed by the stops and gos of exploration, for an active exploration it displays a logistic curve trending toward an asymptote of 1400 Tcf.
Figure 39: US gas fields cumulative discovery modelled with logistic curve
In this graph, the number gasfields/100 means that the number of fields is divided by 100: the number trends towards 42 000.

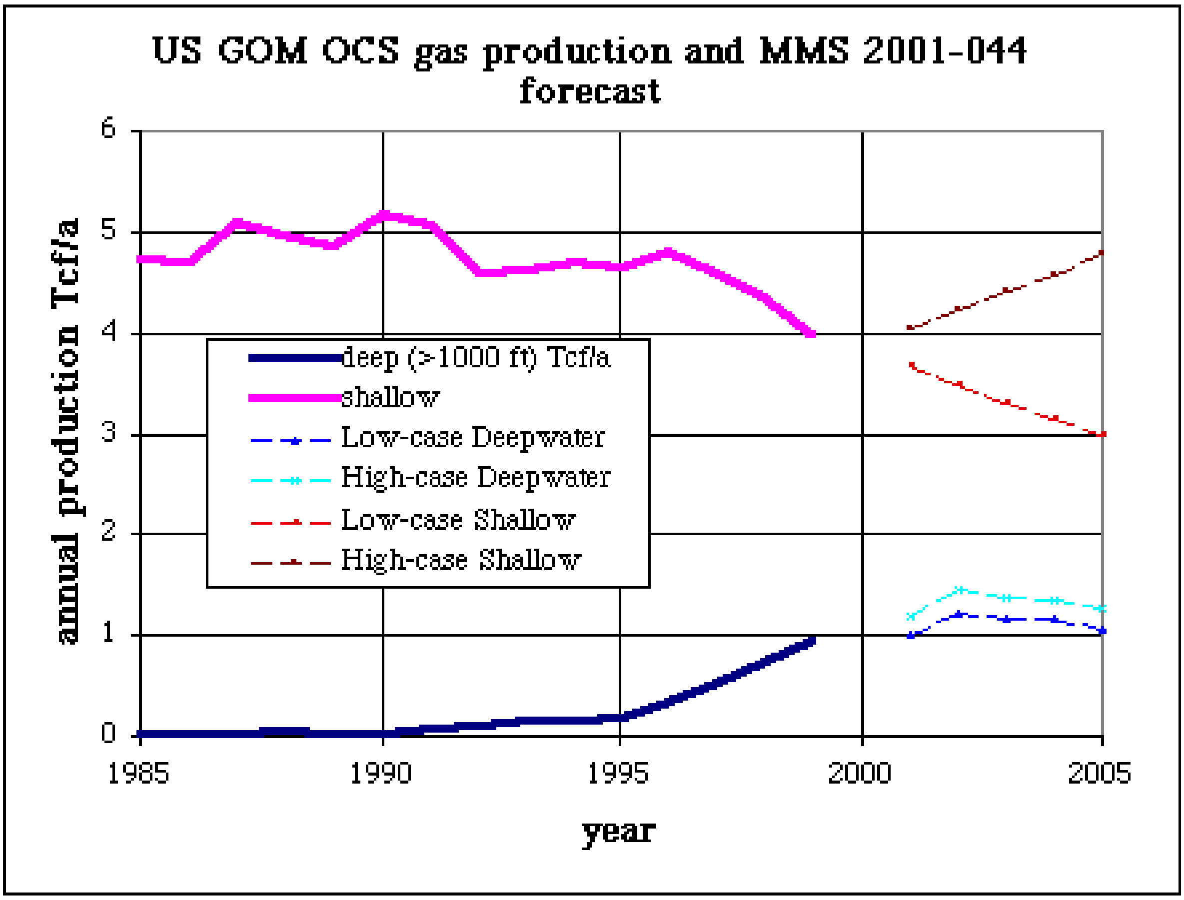


-Forecast

-GOM

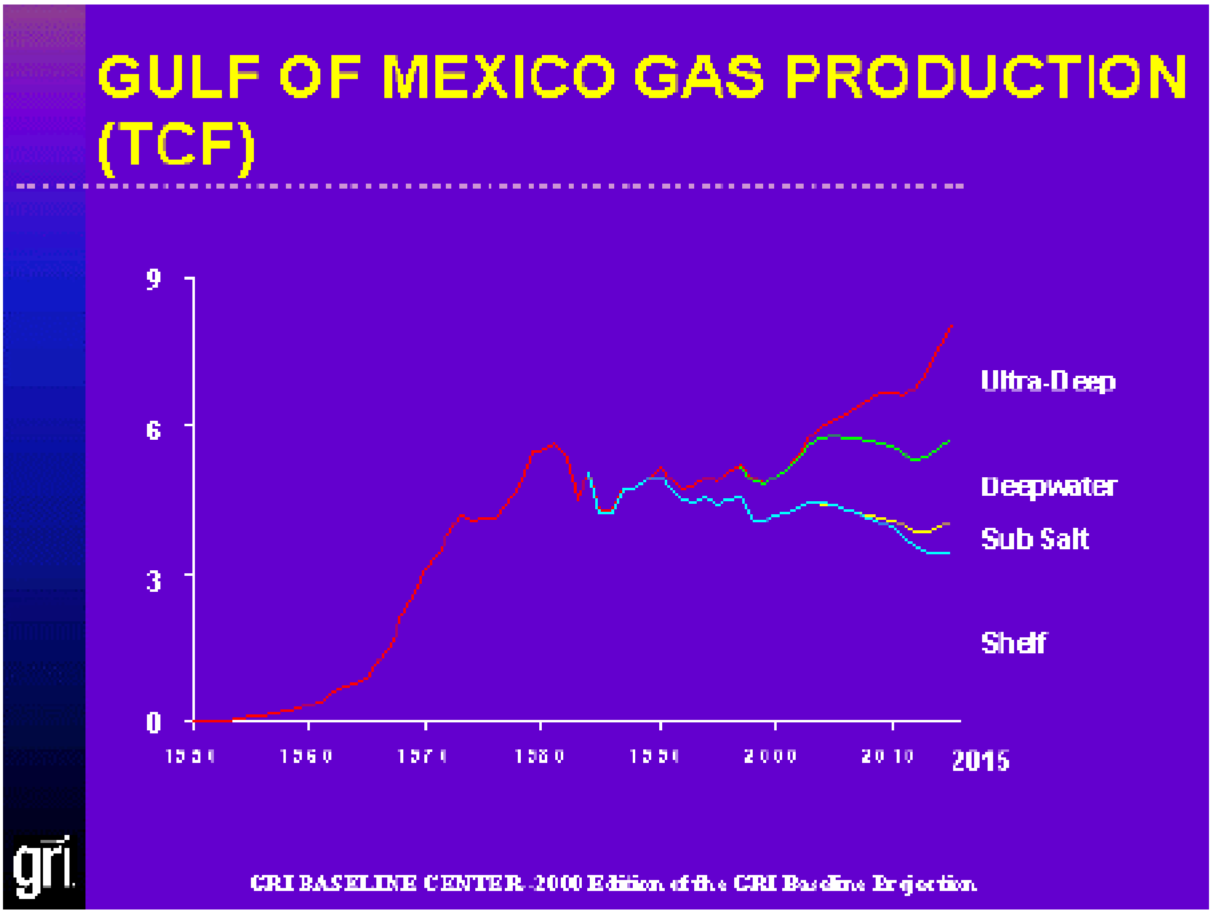
MMS forecasts for 2000 to 2005 that gas production in shallow water will continue in average to decline and in deepwater to start to decline in 2003.

Figure 40: MMS forecast for gas production 2001 to 2005



A 2000 report from Gas Research Institute (GRI, now GTI = Gas Technology Institute) "The long term trends in US gas supply and prices" (Cocheter 2001) illustrates with the following graph that Gulf of Mexico gas production shows a continuous decline from the shelf since its peak of 1970, and the rise of the deepwater since 1990. GRI adds in its forecast the arrival of a sharply rising ultra-deep production. The GRI deepwater gas production peaking around 2005 is in line with Nehring's assessment, but not this new concept of ultra-deep gas production, which is contrary to the finding that the deeper the water, the less gas there is.

Figure 41: GRI forecast for the GOM



Cocheter gives the breakdown by areas for 2015:

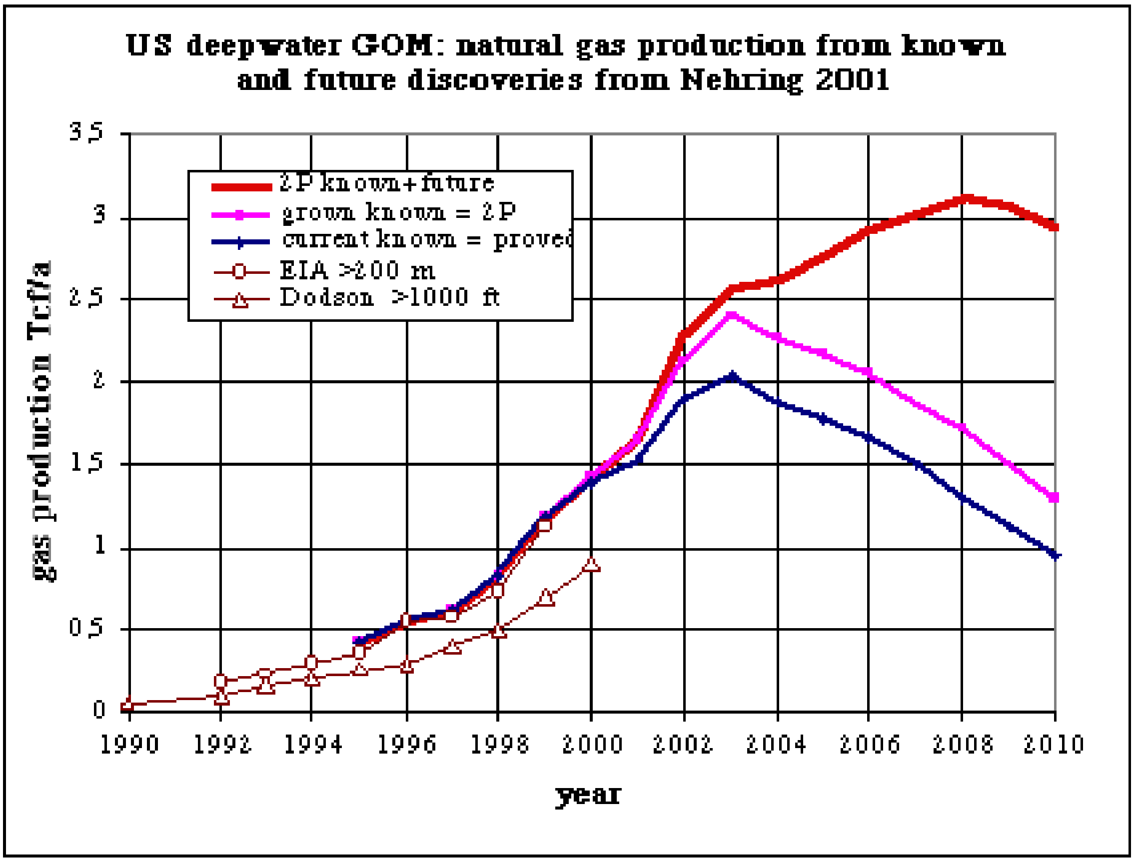
figure 7 production Tcf	1998	2015
Lower 48	**19**	**27.8**
West	0.3	0.4
Rocky Mountains	2.9	4.9
Permian	4.3	4.8
S.Texas/Louisiana	5.1	5.7
GOM	4.9	8.1
East	1.5	4
Alaska	**0.5**	**0.7**
Canada	**5.6**	**7.7**
BC	0.6	1.1
Alta Sask Manitoba	5	6
Eastern Canada	0	0.6

The USDOE/EIA AEO 2001 and GRI forecasts for US gas production show a drastic break from the trend of the past 10 years production.

Nehring's forecast (Jan. 2001) for deepwater GOM gas production from his estimated resource of 56 Tcf (current discoveries = 27 Tcf) is a peak in 2008 at 3 Tcf/a. Unfortunately Nehring did not define what he calls deepwater. For the MMS deepwater is more than 1000 ft but from the next graph it seems that Nehring's definition is less than 1000 ft, it is close to EIA values which take deepwater at 200 m. MMS federal agency is obliged (?) to use the SI unit and the deepwater royalties are defined with water depth in meter and the leases are classified as: 0-200 m, 201-400 m, 401-800 m, 801-1000 m and >1000 m. For some with the progress of the drilling, deepwater starts at 500 m or even 1000 m.

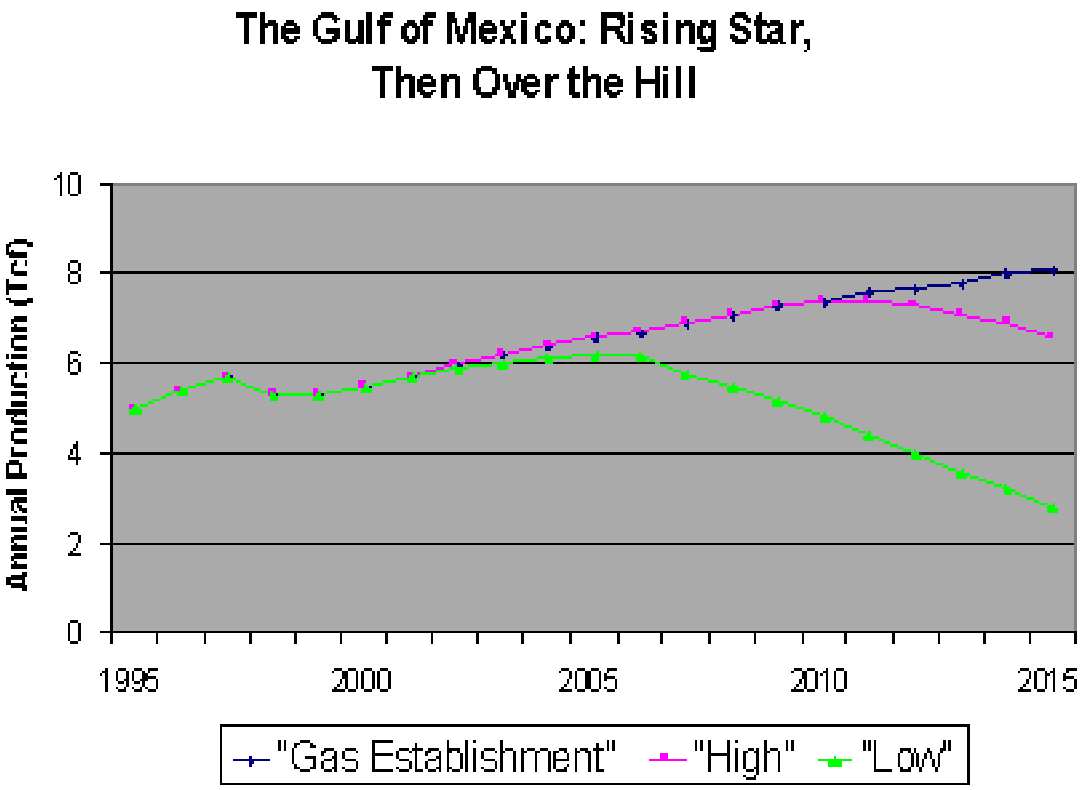
Nehring describes the difference between the continental shelf where about 65% of the oil and gas reserves are gas, and the deepwater where gas represents only 30% of the oil and gas reserves. There is less gas in the deepwater because of the low thermal gradient, which creates low temperatures in the gas generation zone. For the GOM deepwater Nehring sees a peak in 2008 at 3 Tcf/a.

Figure 42: US deepwater GOM: natural gas production from known and future discoveries up to 2010 from Nehring



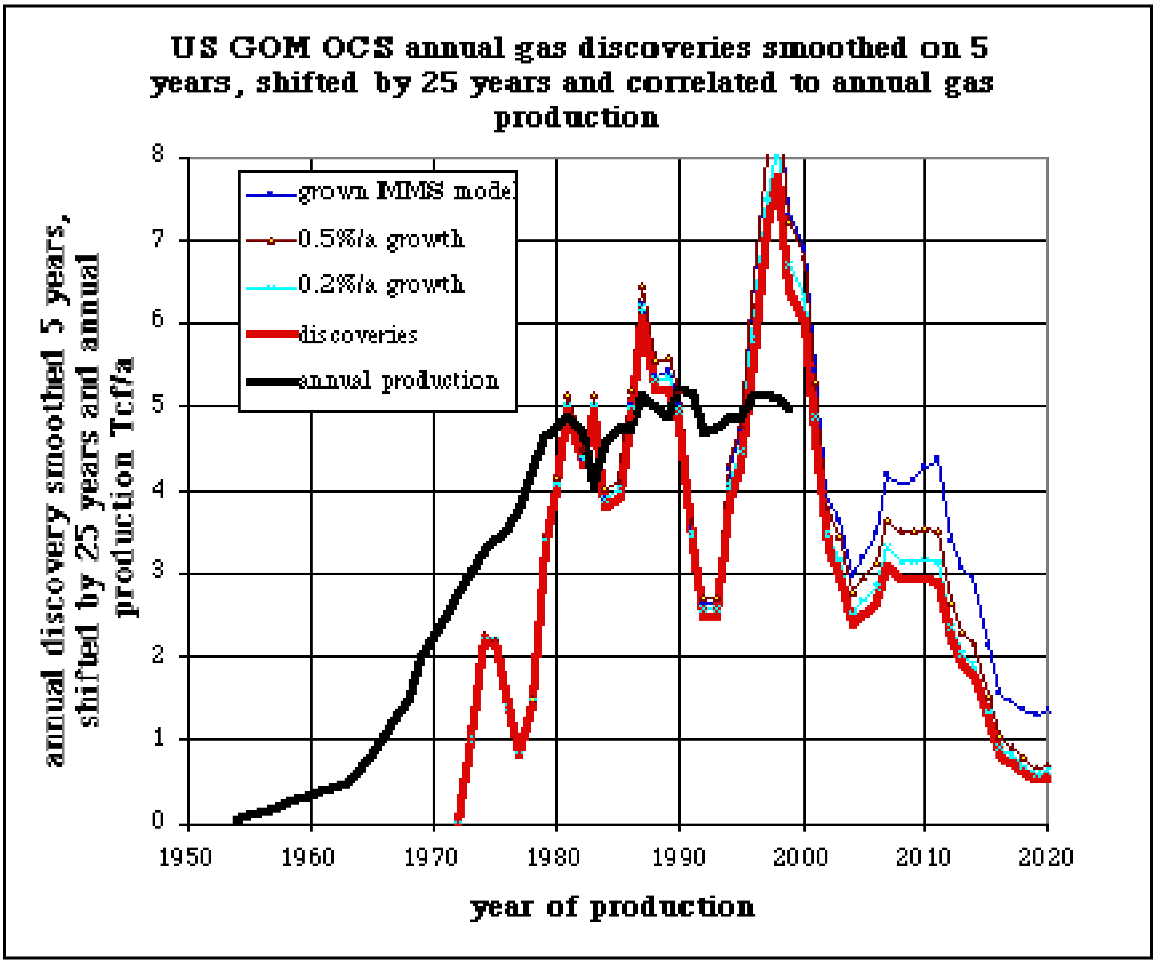
Nehring (March 2001) in "Gulf of Mexico Rising Star; then over the Hill" said that the anticipated US supply in 2010 would be short by 3-4 Tcf. For the global GOM, he sees a peak (average high and low) around 2007 about 6.5 Tcf/a.

Figure 43: Nehring forecast for the GOM

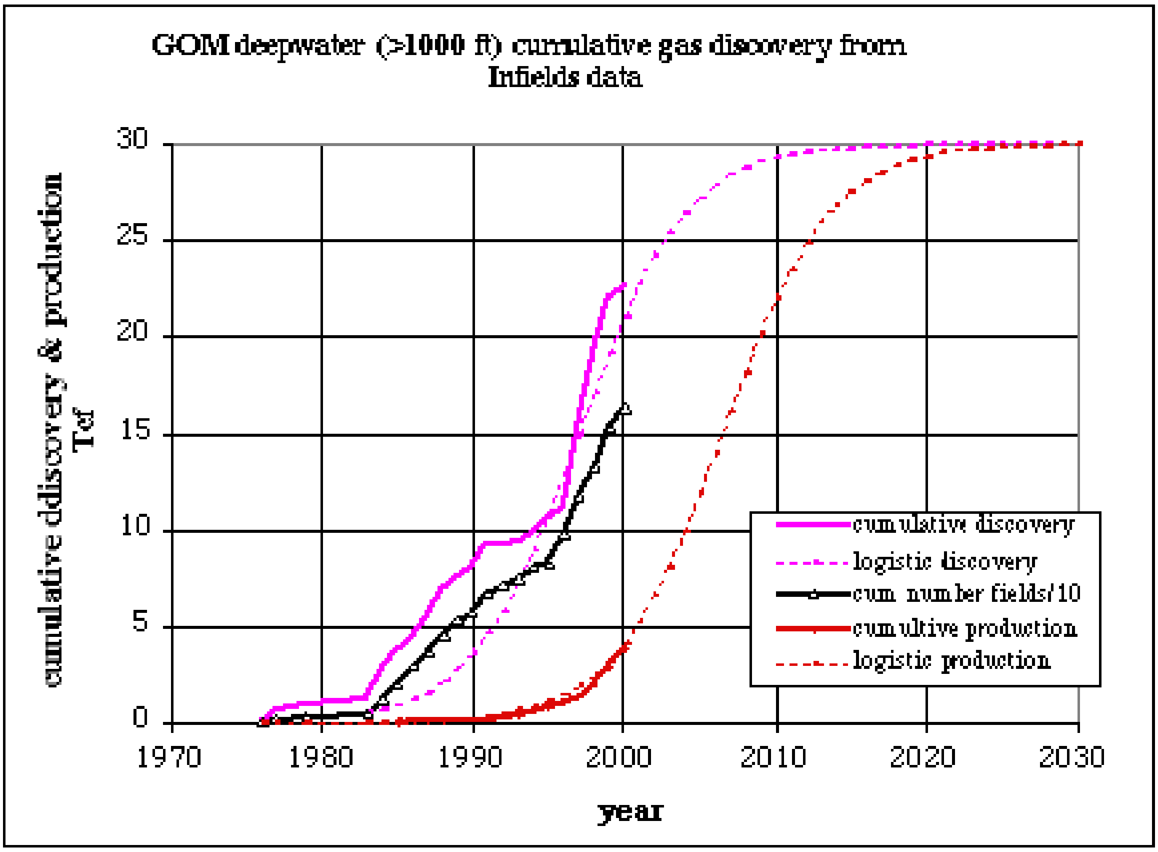


The MMS " mean " discovery is plotted on graph 44 as annual discovery and shifted in order to get the best fit with annual production. The fit is best for 25 years and this shift allows forecasting the future production using the last 25 years of discovery. The fit looks good despite the unreliable data (not so much for old data) and it is obvious that the annual gas production has been steady (new data more unreliable) for the last 20 years and production will soon decline sharply.

Figure 44: GOM (from MMS): annual production and annual discovery shifted by 25 years



For the GOM deepwater (>300 m), the most complete file from Infields is used to model with the same logistic curve the cumulative discovery and cumulative production. The model is not very good for discovery because of the ups and downs of deepwater exploration. An ultimate of 30 Tcf is used to model it as deepwater holds only one third of gas compared to oil when it is the contrary on the shelf where gas represents two thirds compared with oil. This change is well explained by Nehring (Jan. 2001) because the low thermal gradient below deepwater.
Figure 45: GOM deepwater modelling cumulative discovery and cumulative production from Infields data. The cumulative number of fields is divided by 10.

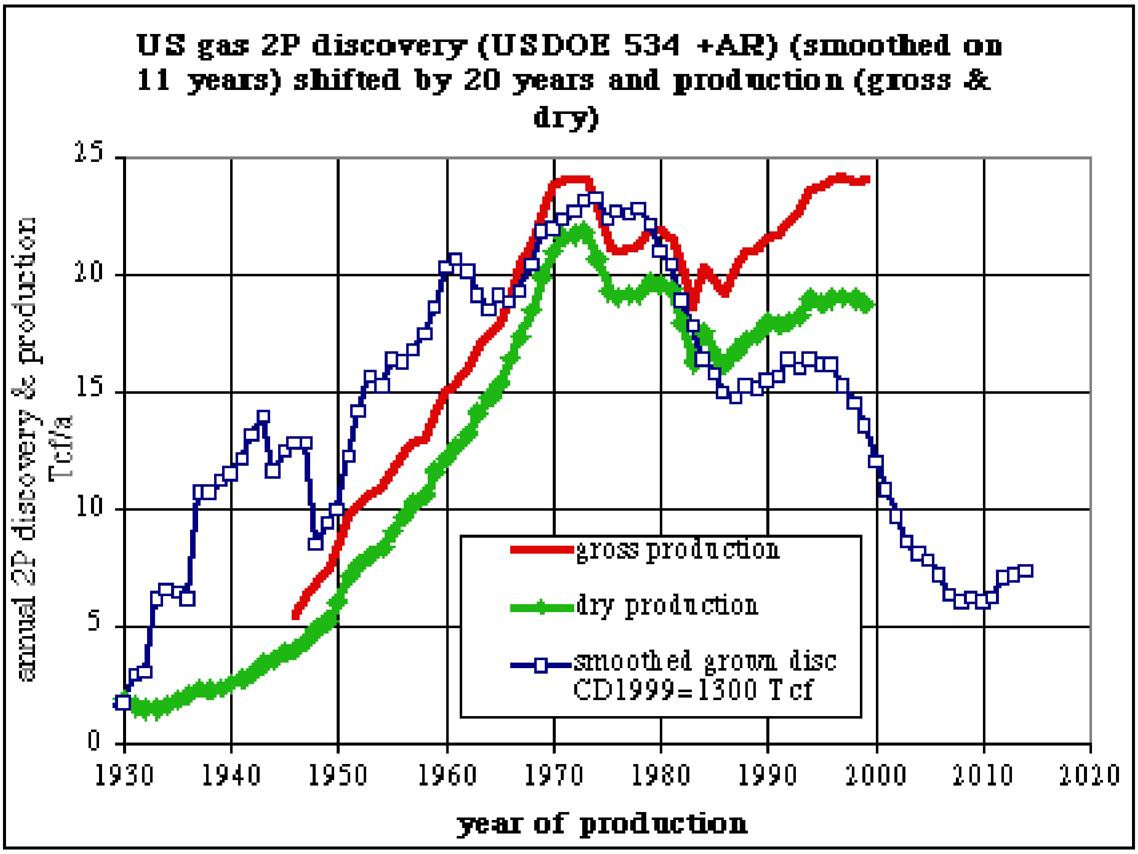


From this graph discovery seems to have passed the midpoint and gas production will do so around 2005.

-US all

The correlation of annual production with shifted annual "mean" discovery shows a fair fit for a shift of 20 years. The problem is that it is not known if the reserves are estimated as raw or dry gas.

Figure 46: US gas production and "mean" discovery shifted by 20 years

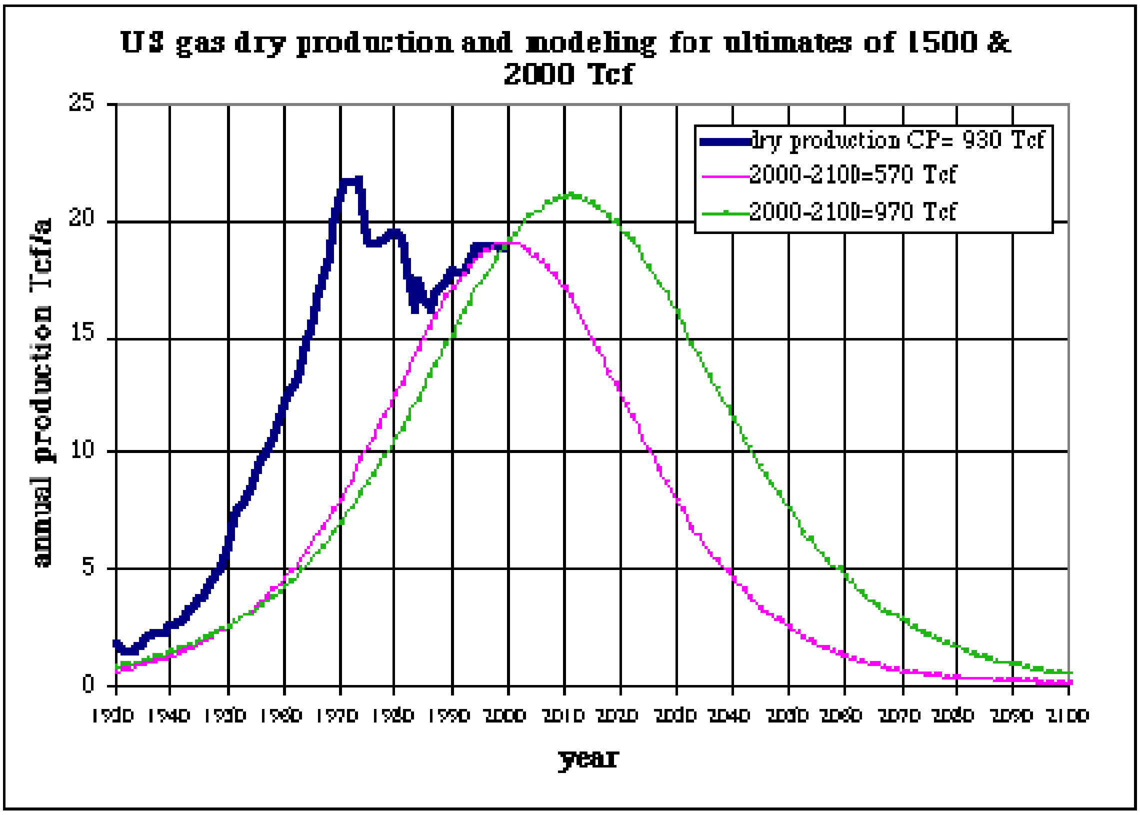


This shift of 20 years allows forecasting that for the next 20 years US gas production will decline.

Using ultimates is another way. The creaming curve of figure 36 suggests an ultimate less than 1500 Tcf for conventional gas. As the unconventional gas ultimate is less than 400 Tcf (see below) the maximum ultimate is less than 2000 Tcf.

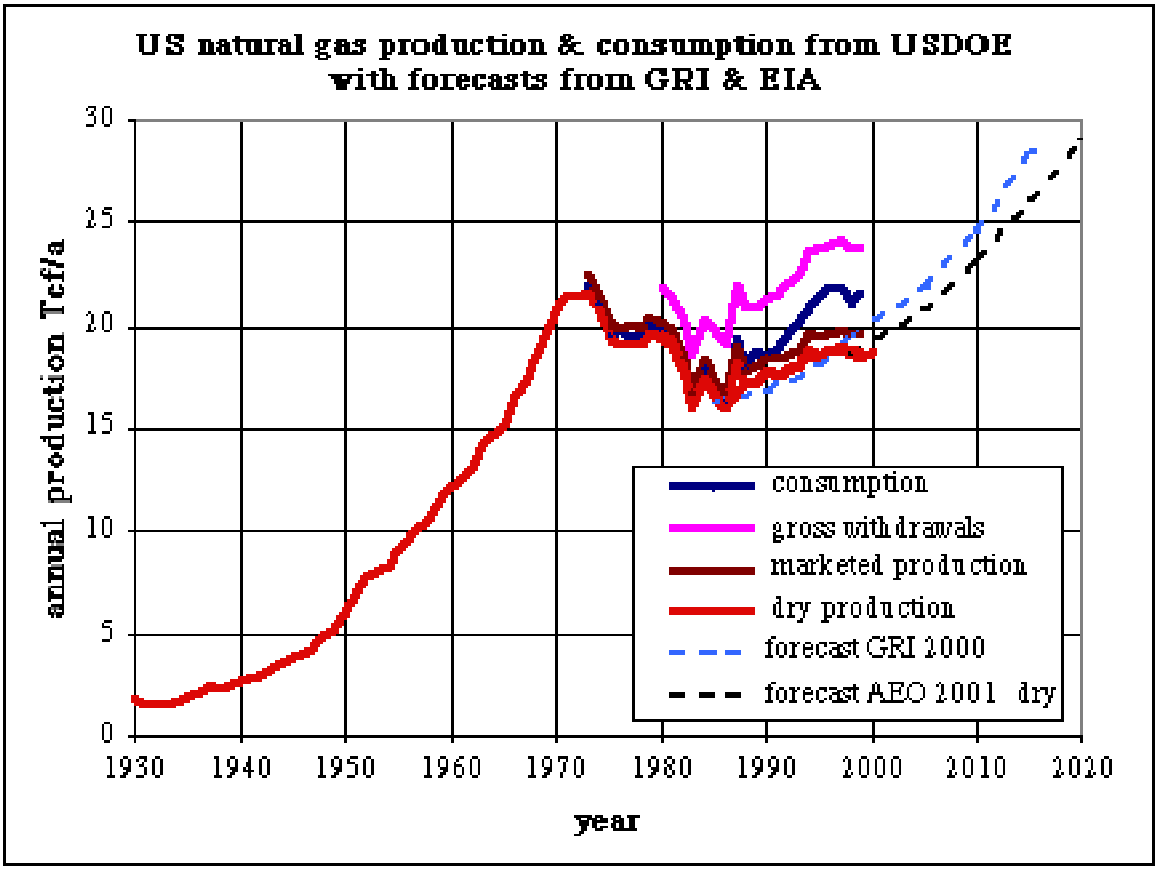
The modelling with ultimates shows either a decline around 2000 for U=1500 Tcf or 2000 - 2100 = 570 Tcf and a coming peak in 2010 for U= 1900 Tcf or 2000 - 2100 = 970 Tcf.

Figure 47: US gas production modelled with ultimates 1500 Tcf and 1900 Tcf



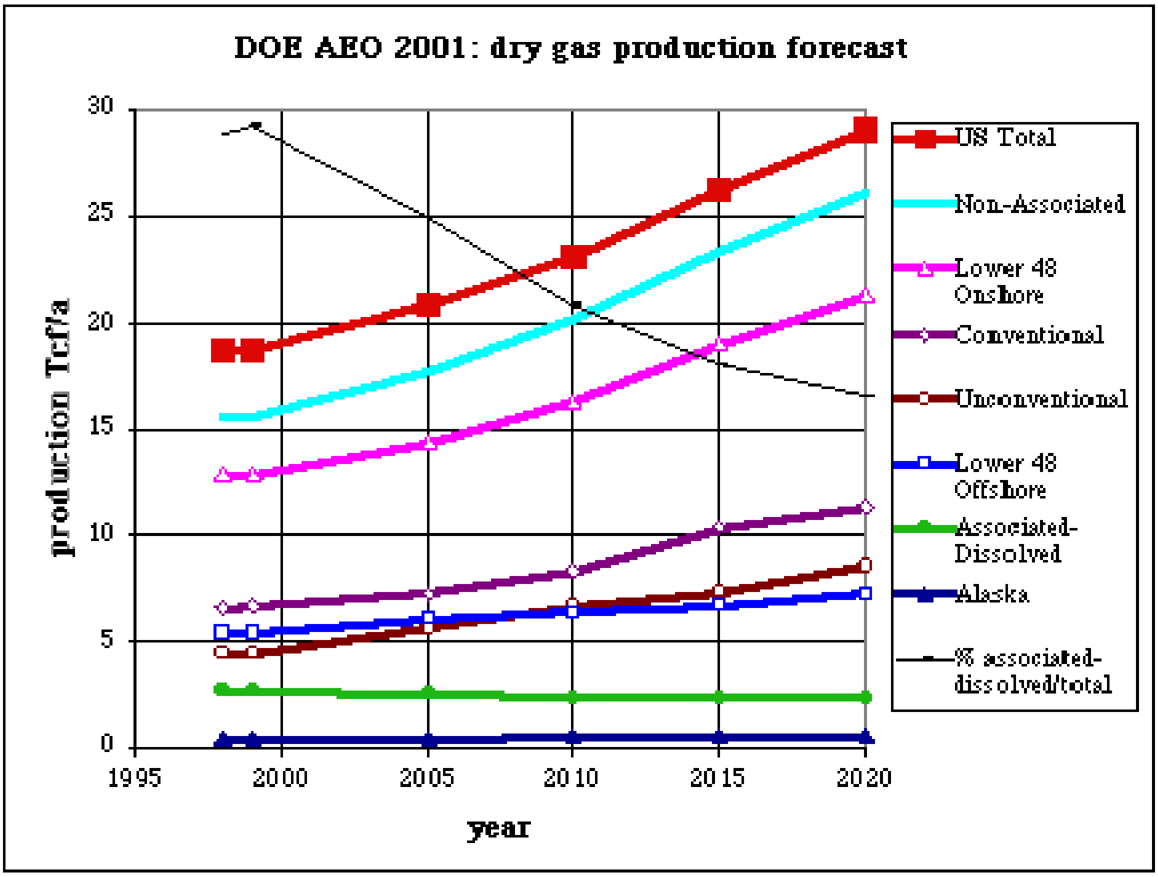
Our forecast is far from the one by the official agencies.

Figure 48: US gas production with DOE/EIA and GRI forecasts



The detail of the gas production is given

Figure 49: USDOE dry gas forecast up to 2020



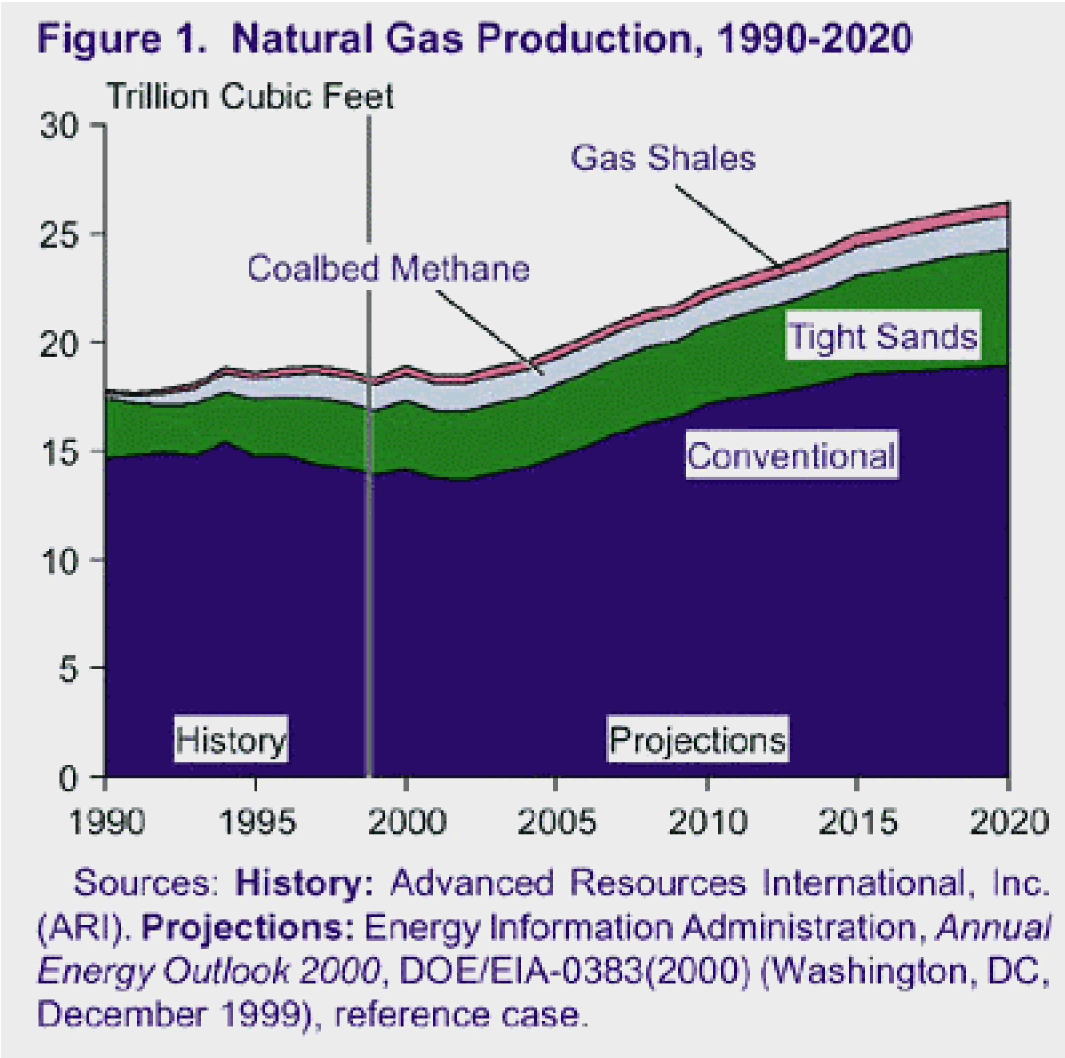
The bulk of the 10 Tcf increase in US production from 1999 to 2020 is from the lower 48 onshore non-associated (8 .8 Tcf) and half of it from unconventional

AEO 2001	from 1999 to 2020
Lower 48 wellhead price	+1 $1999/kcf
Dry production	Tcf
U.S. total	**+10.4**
Lower 48 onshore	**+8.4**
Associated-Dissolved	-0.4
Non-Associated	8.8
Conventional	4.7
Unconventional	4.1
Lower 48 offshore	**+1.8**
Associated-Dissolved	0.1
Non-Associated	1.7
Alaska	**+0.1**

-US unconventional gas

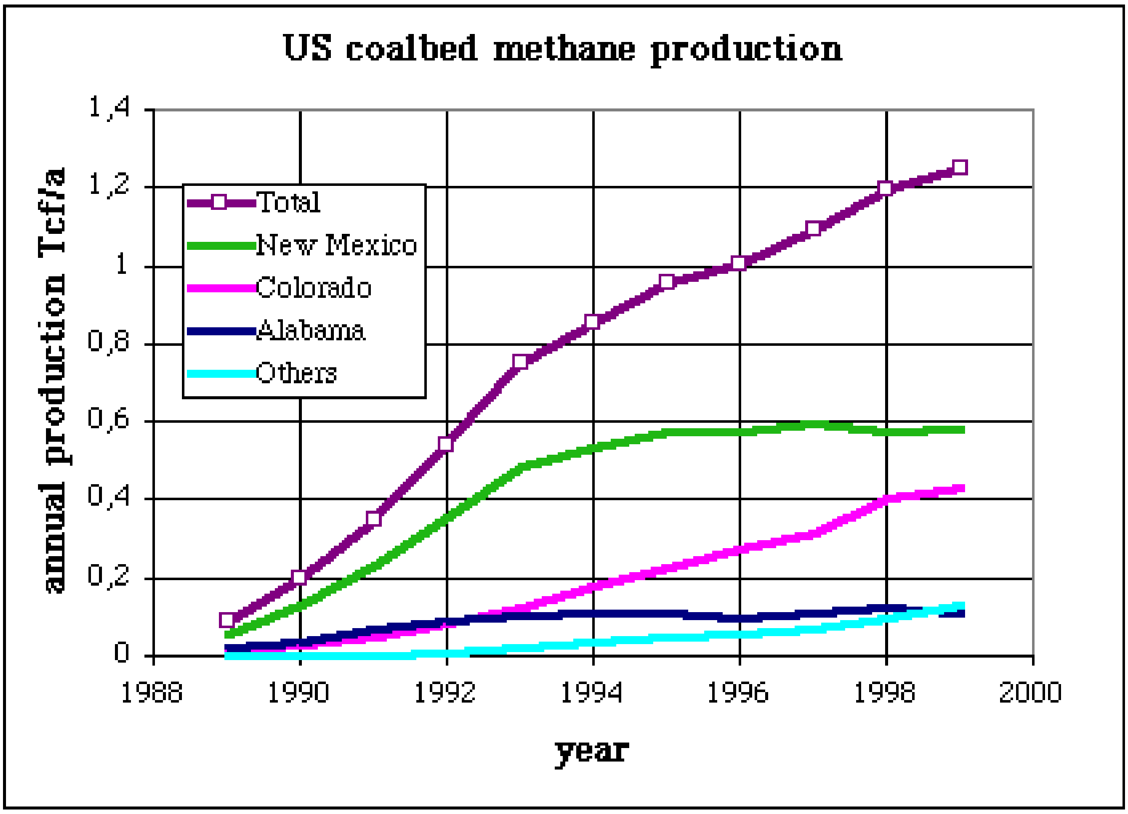
The forecast on unconventional gas production is found at EIO 2000:
http://www.eia.doe.gov/oiaf/analysispaper/images/uncon_fig1.jpg
US unconventional gas production comes presently mainly from tight sands and one fourth from coalbed methane (CBM), but the increase from 1999 to 2020 is slightly less than in EIO 2001.

Figure 50: US gas production 1990-2020 from EIO 2000



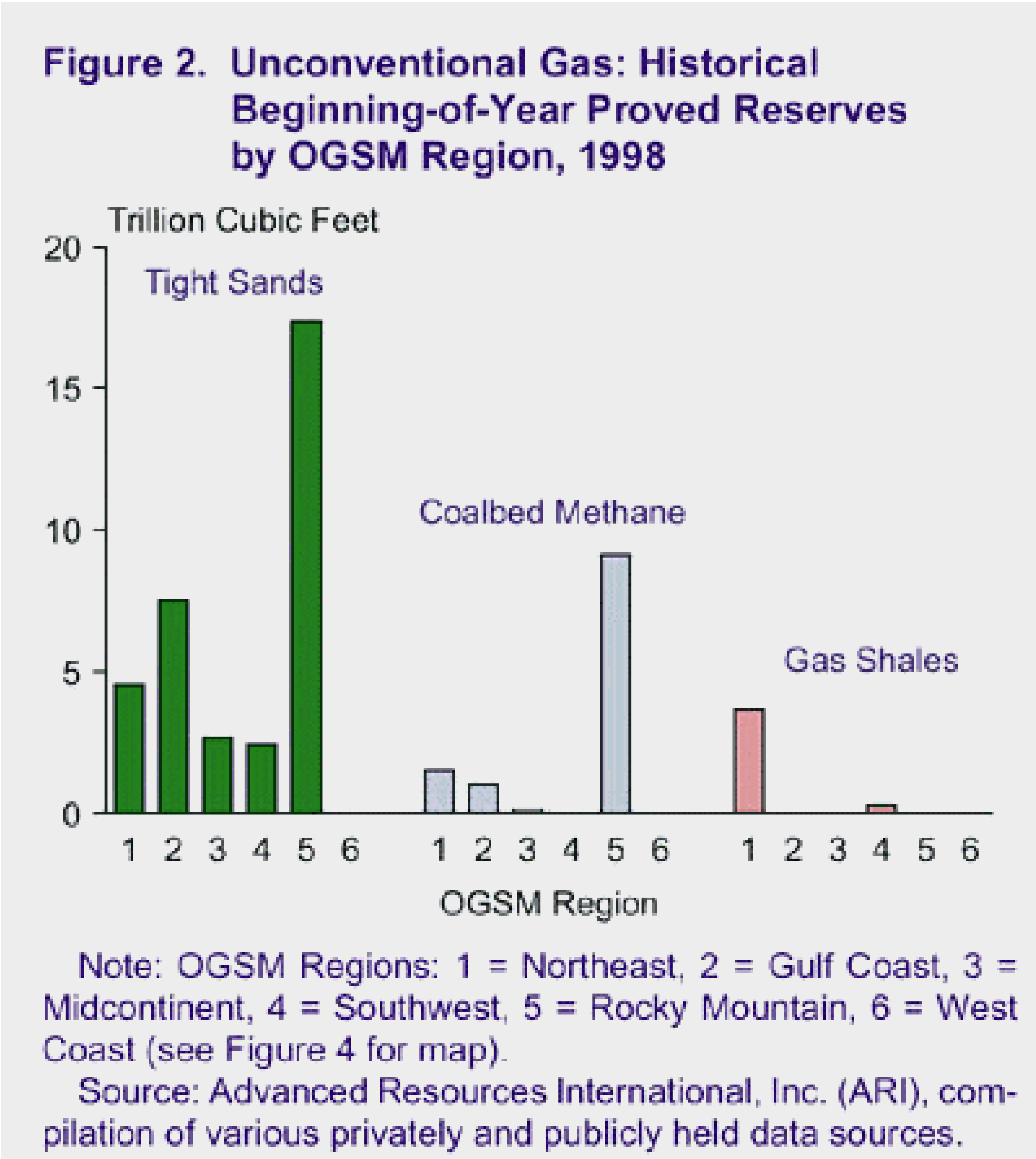
The amount of proved unconventional gas is about 50 Tcf with two thirds in tight sands and the rest mostly coalbed methane (CBM). CBM has been in the beginning mainly from the San Juan basin (New Mexico) which is now peaking and the rising basin is with Colorado.

Figure 51: US CBM production



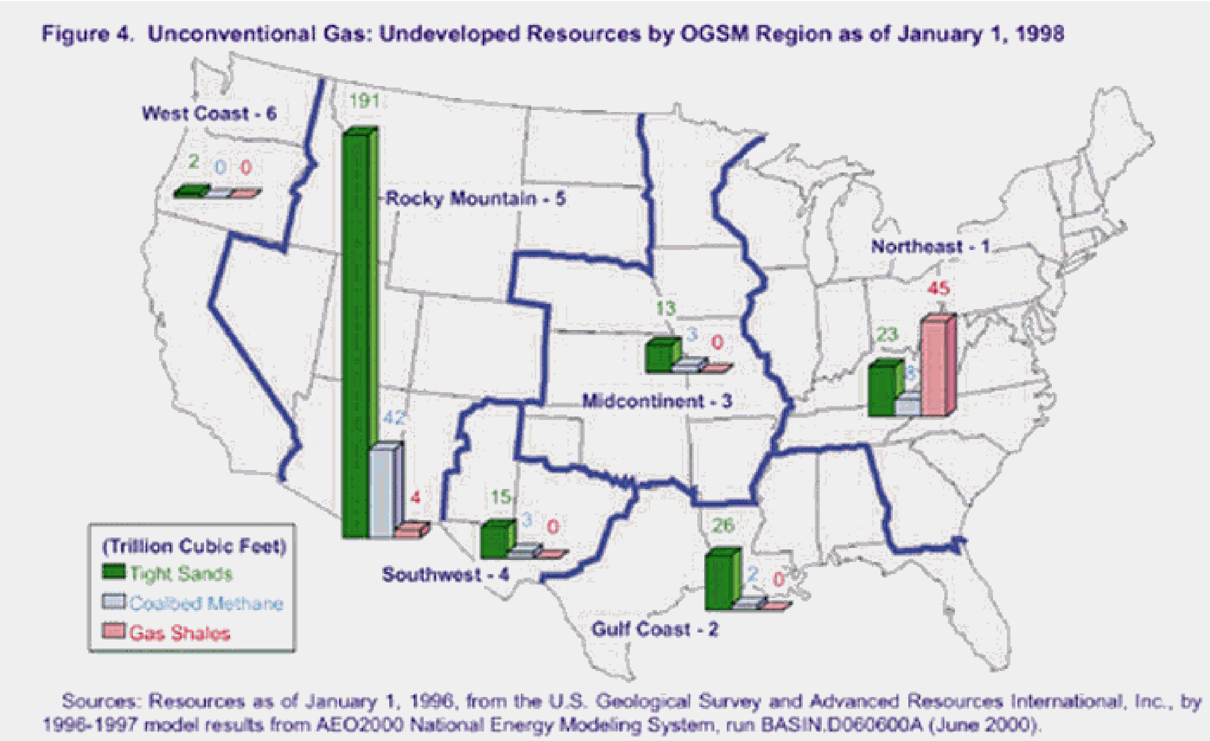
The proved reserves of unconventional gas are about 34 Tcf in tight sands, 13 Tcf in CBM and 4 Tcf others.

Figure 52: US unconventional gas proved reserves



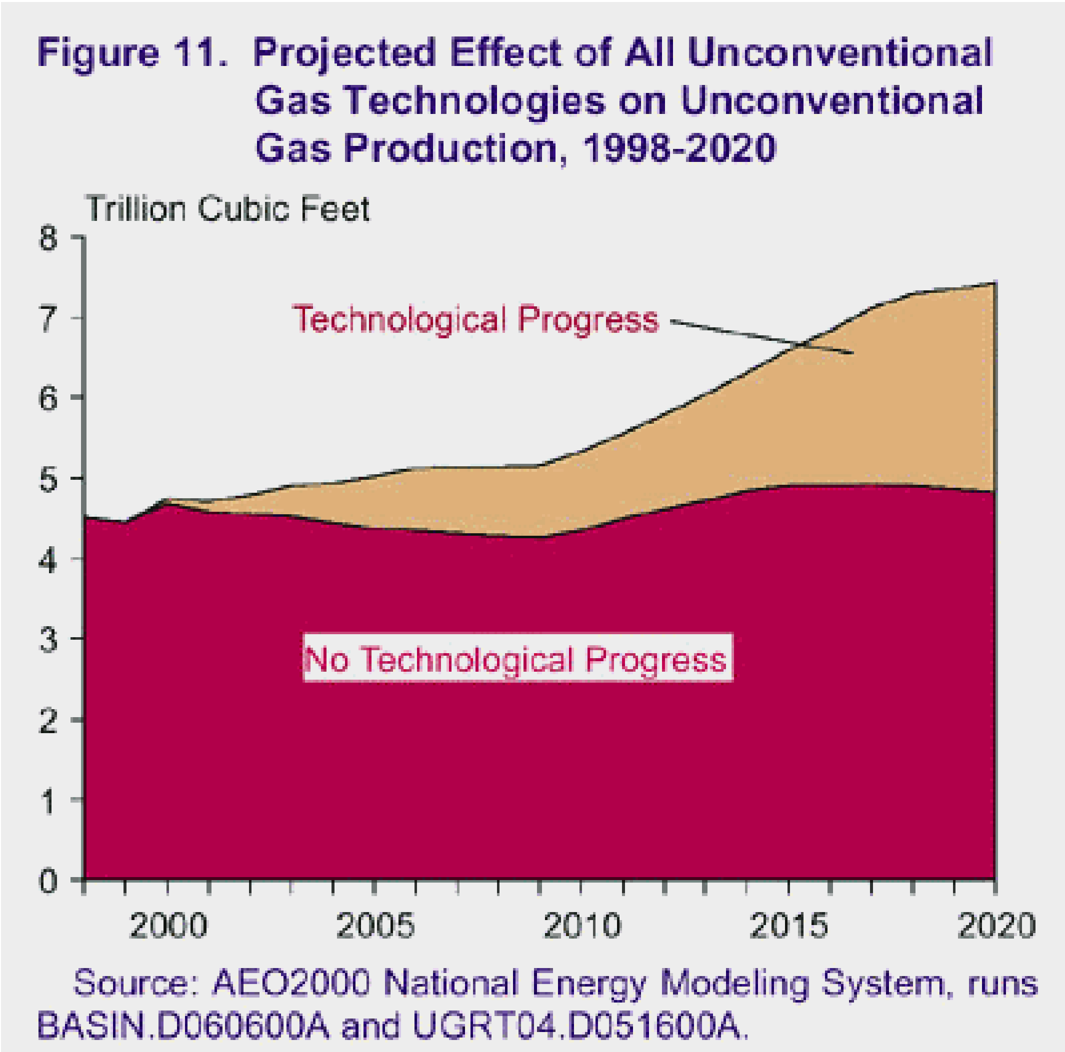
The amount of unconventional gas in undeveloped resources is about 370 Tcf with 70% in tight sands and the location is shown in the next graph.

Figure 53: US unconventional gas undeveloped resources



The production of unconventional gas is now at 4.5 Tcf/a with USDOE EIO 2000 forecast in 2020 between 4.5 and 7 Tcf/a depending on the degree of technology. It is far from the 4.7 Tcf of increase from 1998 to 2020 from EIO 2001. These reports lack continuity and homogeneity.

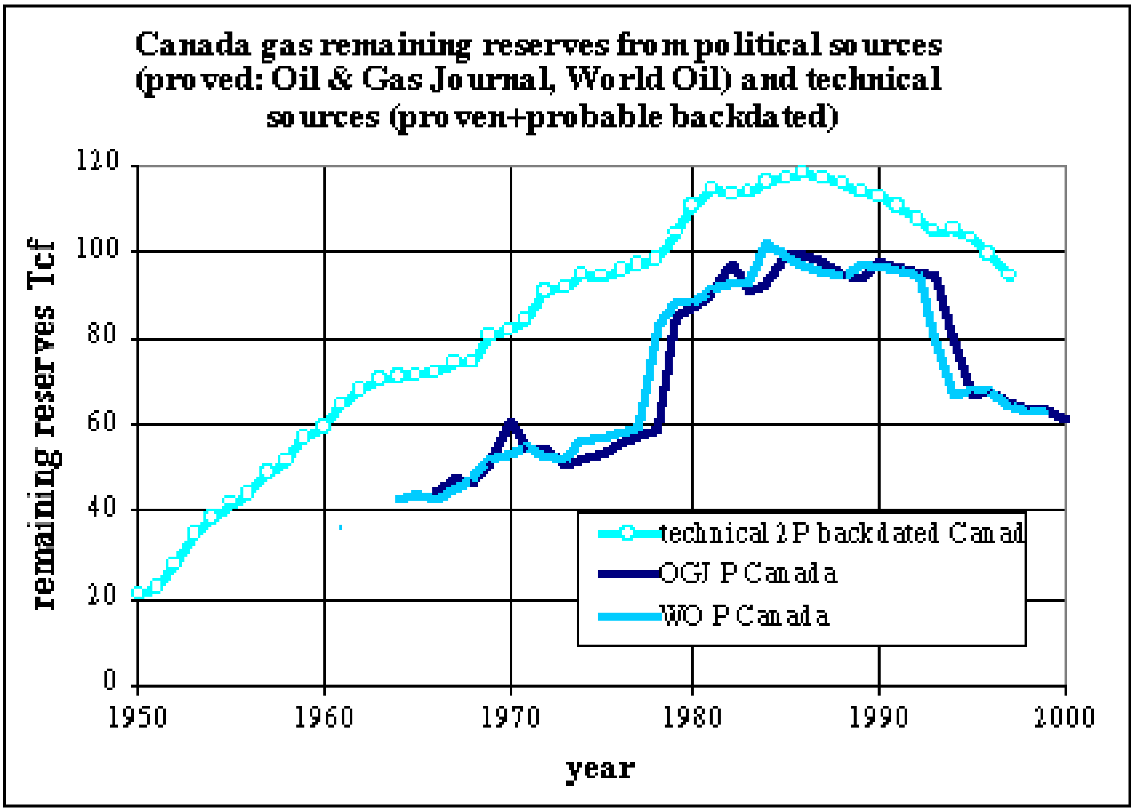
Figure 54: US unconventional gas production 1998-2020 from USDOE EIO 2000



Unconventional gas will not be the alternative to the declining conventional present fields. Future discoveries will only compensate for the decline of the present fields.
In conclusion the US gas production is forecast by official agencies to increase by around 10 Tcf in the next 20 years but it is more to satisfy the forecasted demand which is now with the present recession very questionable. There are many plans for new electric plants requiring a large amount of new gas, but many projects will fail and the demand will be much less than actually forecasted
More likely, US gas production will stay stable for a while before declining.
Any growth of the US demand has to be filled from imports from Canada or by LNG.

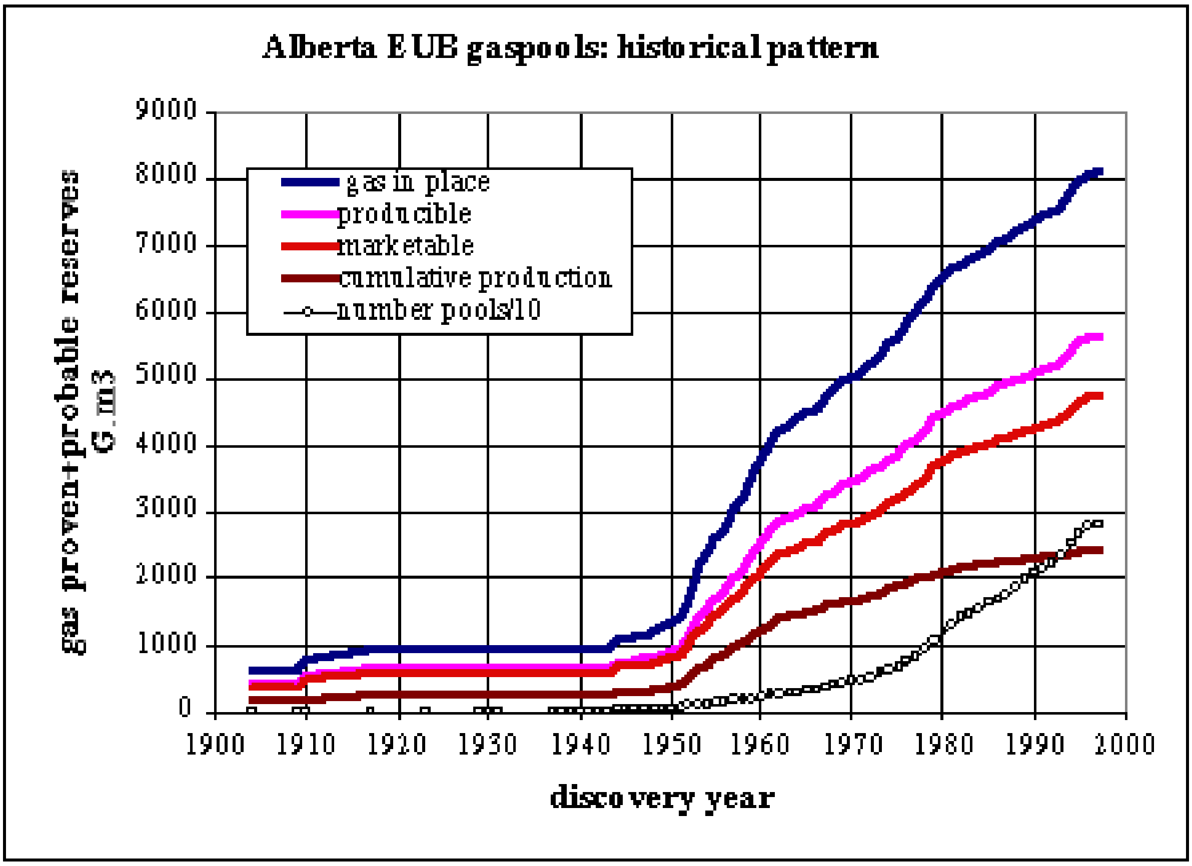
-Canada

The Canadian remaining gas reserves are reported (current proved) to be around 60 Tcf while they were close to 100 Tcf 8 years ago, with a drastic drop in 1993. This drop seems to be mainly a reporting problem as the technical reserves ("mean" backdated) shows a peak around 120 Tcf in 1986 declining slowly to 90 Tcf in 1997.
Figure 55: Canada remaining gas reserves from political sources (current proved) and technical sources (proven+probable backdated)



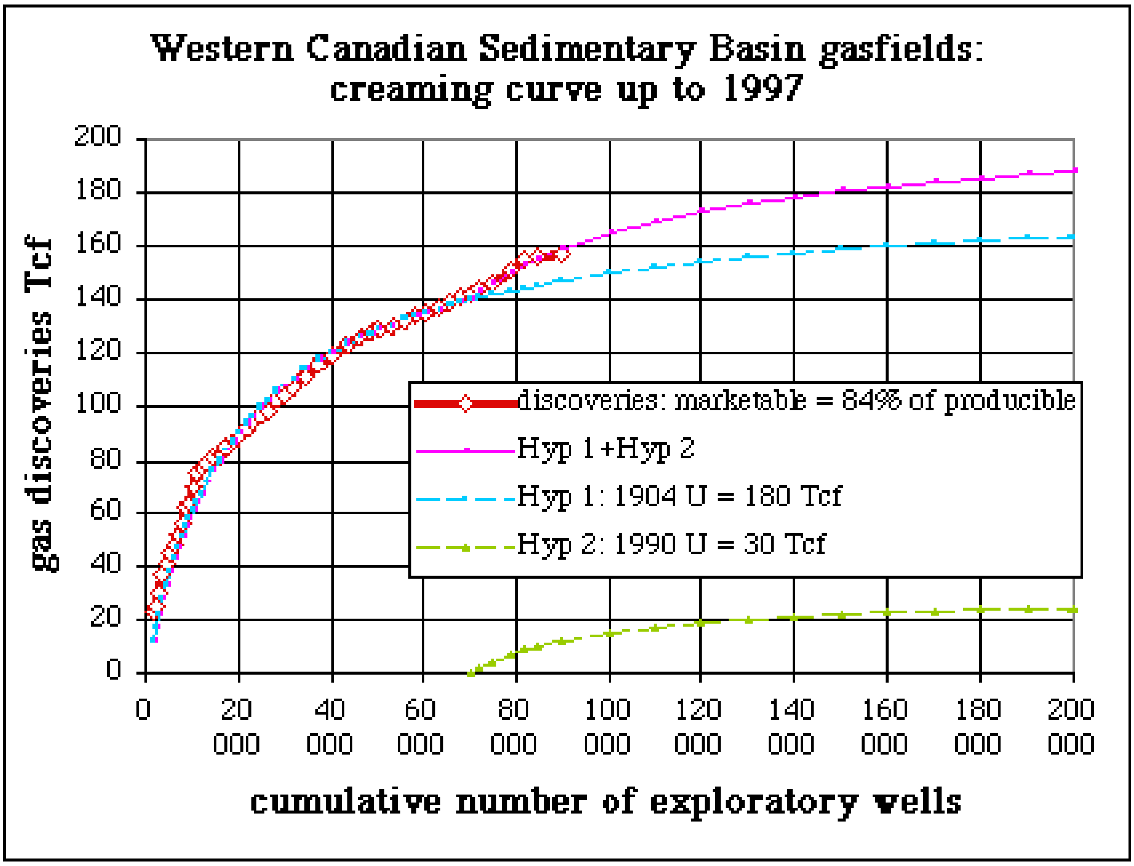
The historical pattern of gas pools in Alberta from 1900 to 2000 shows a drastic increase in gas cumulative discovery starting in 1950 (Leduc reefs discovery), a slow down during the 80s, but an increase in the 90s.

Figure 56: Alberta gas pool cumulative discovery and production



The creaming curve for the Western Canadian sedimentary Basin displays two hyperbolas, one since 1904 and a second one in 1990 (I do not see any clear reason!). Up to 1997, about 160 Tcf has been found with about 90 000 exploratory wells. But the hyperbolic model shows that only less than 30 Tcf will be added when drilling another 90 000 additional exploratory wells, and only 40 Tcf with 200 000 additional wells, far from the 88 Tcf potential for undiscovered from 200 000 new wells from the Canadian Gas Potential Committee (CGPC), needing another hyperbola. It is difficult to foresee the drilling of 200 000 new wells in the coming 30-40 years when it took 100 years to drill 90 000 exploratory wells in the past.

Figure 57: Western Canadian sedimentary basin: creaming curve up to 1997



Cocheter for GRI gives the breakdown of their production forecast for US and Canada for 2015:

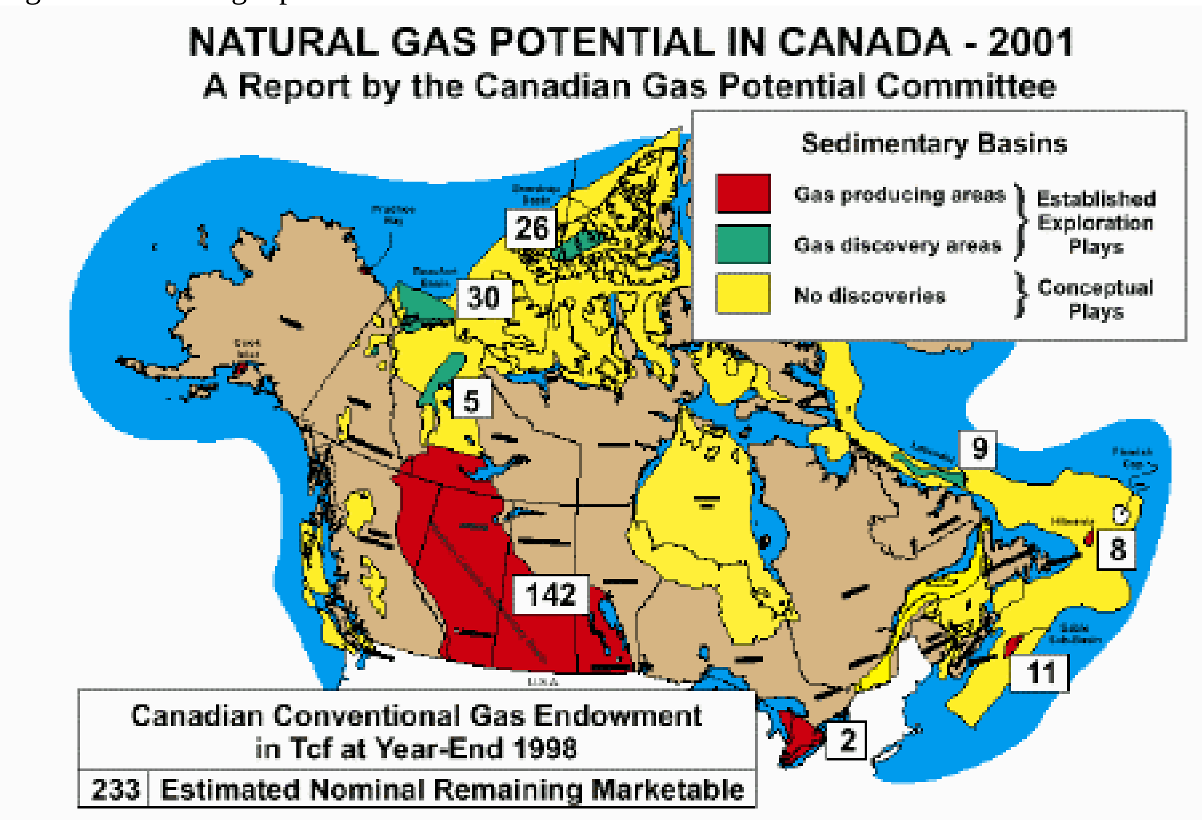
GRI 2000 fig. 7

dry production Tcf	1998	2015
Lower 48	**19**	**27.8**
Alaska	**0.5**	**0.7**
Canada	**5.6**	**7.7**
BC	0.6	1.1
Alta Sask Manitoba	5	6
Eastern Canada	0	0.6

GRI hopes that Canada gas production will grow by 2.1 Tcf from 1998 to 2015. The 1999 NEB (National Energy Board) was more optimistic with its scenario case 1 producing 9 Tcf in 2015 (3 Tcf increase) rising to 10 in 2025 and the other scenario case 2 peaks at 8 Tcf in 2015 (2 Tcf increase) and down to 7.5 Tcf in 2025.

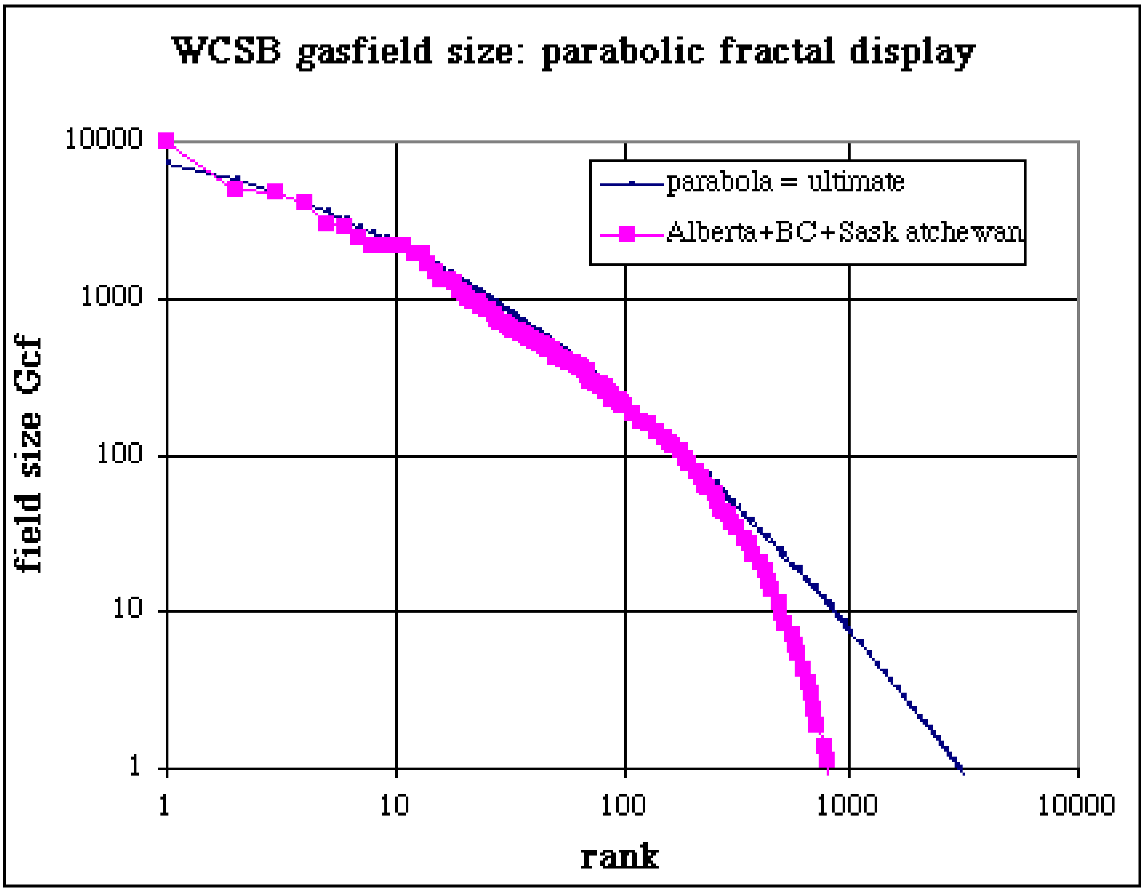
But drastic changes have occurred after the California gas shortage.

The Canadian Gas Potential Committee (CGPC) has released their new report on Sept 11, 2001. It is a drastic change from their previous report in 1999, cutting their estimate by about half. It seems to be a reaction towards the demand from the US for Canada to fill their gas need. Canada does not want to be obliged to produce too quickly their gas supply to satisfy the US hunger for gas. (See below on the NAFTA Act)
http://www.canadiangaspotential.com/2001report/mediarelease.html
Figure 58: Canada gas potential from CGPC



Canadian Gas Potential Committee wrote:
<<As of end 1998 there remained 233 Tcf of nominal marketable conventional gas resources, but without economic consideration.
The Western Canada Sedimentary Basin held an estimated 54 trillion cubic feet of gas reserves plus 88 trillion cubic feet of undiscovered nominal marketable gas, a total of 142 trillion cubic feet. The Western Canada resource represents 61 percent of the remaining marketable gas in Canada.
The Committee estimated that the 150 largest undiscovered pools are high-impact exploration targets that range in size from 40 billion to 1 trillion cubic feet. This attractive group of prospects contains about one quarter of the marketable gas potential in Western Canada. Another 25 per cent of the potential is expected in 3,000 pools that range in size from 2.5 billion to 40 billion cubic feet. An additional 40 percent of the nominal marketable gas is expected from 65,000 smaller pools, the study said.
At current rates of discovery in Western Canada, as many as 200,000 exploration wells, twice as many as have already been drilled, may be required to tap the undiscovered conventional gas potential, the Committee said
The near frontiers of Canada, namely offshore Nova Scotia, the Mackenzie Corridor and the Mackenzie Delta, hold an estimated 35 trillion cubic feet of discovered and undiscovered nominal marketable gas. This is about 15 percent of Canada's total marketable gas,

Non-conventional gas sources, such as coalbed methane, may provide important gas supplies, but will require extensive research into production methodologies. The successful conclusion of active pilot production studies is critical before a reserve potential can be estimated. <<
CGPC uses a forecasting method called Petromines where they introduce the undiscovered fields in the holes of their distribution size-rank distribution. Theoretically it is justified when the accuracy of the discovered size is good, but it is not the case.
We prefer to combine the parabolic fractal with creaming curve (figure 57) to forecast undiscovered. CGPC forecasts 150 pools yet to discover over 40 Gcf in the WCSB. Our forecast is about less than this number.
Figure 59: WCSB gas field size: parabolic fractal display

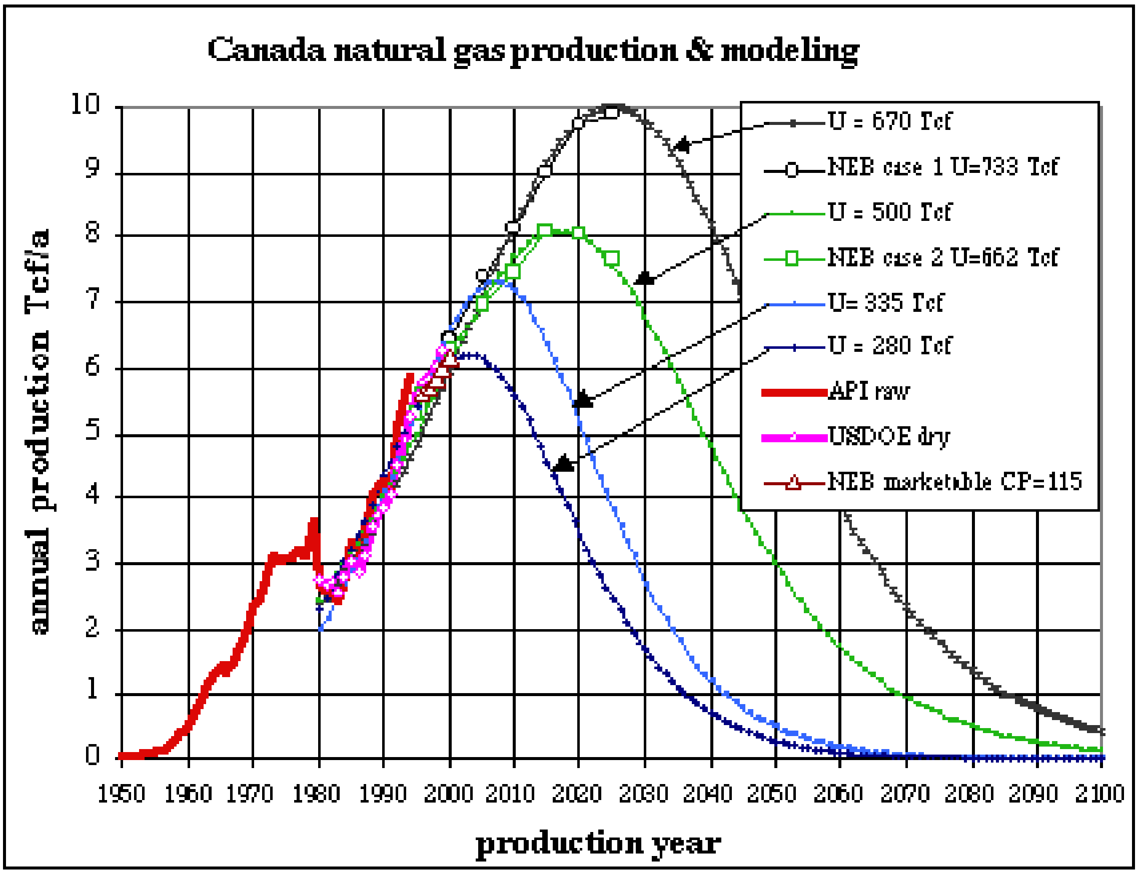


The comparison between the 1999 study (NEB with two estimates) and the new estimate CGPC is striking.

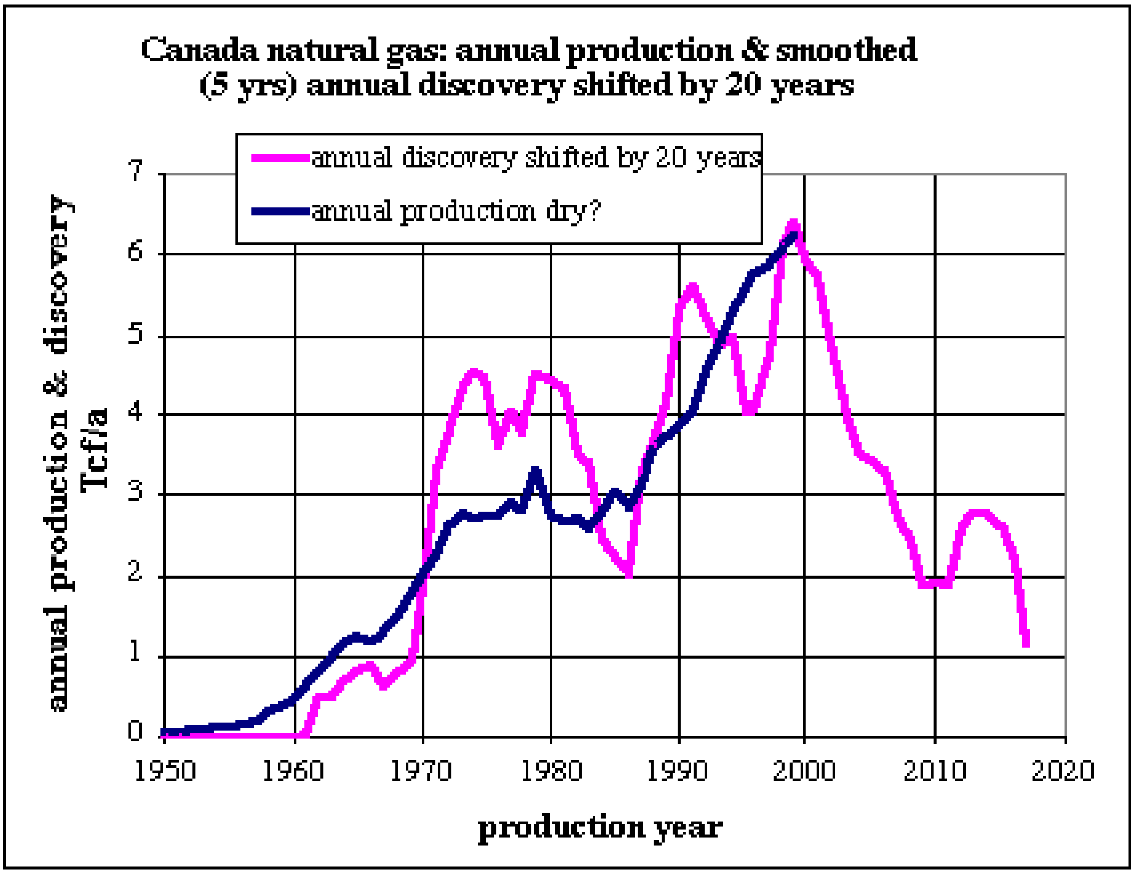
Tcf	NEB 1999 ultimate 1	NEB 1999 ultimate 2	CGPC 2001
WCSB Conventional	335	265	249
WCSB Unconventional	75	75	0
Other Conventional	20	20	32
Frontier	303	303	61
Total Canada	733	662	342

CPGC is pessimistic on the frontier areas and on unconventional gas.
But the USGS 2000 report, which is very optimistic, adding for the world during the next 30 years 8536 Tcf of conventional gas (4976 undiscovered and 3560 reserve growth), is very pessimistic on Canada, giving less than 25 Tcf of undiscovered. USGS did not give for Canada any reserve growth (which should be on the same ratio as the US), as Canada uses also proved reserves, when the rest of the world uses proven+probable. Using the US ratio of reserve growth over known discovery, Canada could have a reserve growth of 60 Tcf, as US

has 355 Tcf of reserve growth for 854 Tcf produced as of 1996 and 172 Tcf remaining, when Canada has produced 67 Tcf produced as of 1996 with 118 Tcf remaining proved.
But USGS forecasts 81 Tcf undiscovered in East Greenland!
The modelling of future production with the different ultimates is shown on next graph.
Figure 60: Canada gas production with NEB forecasts and modelling

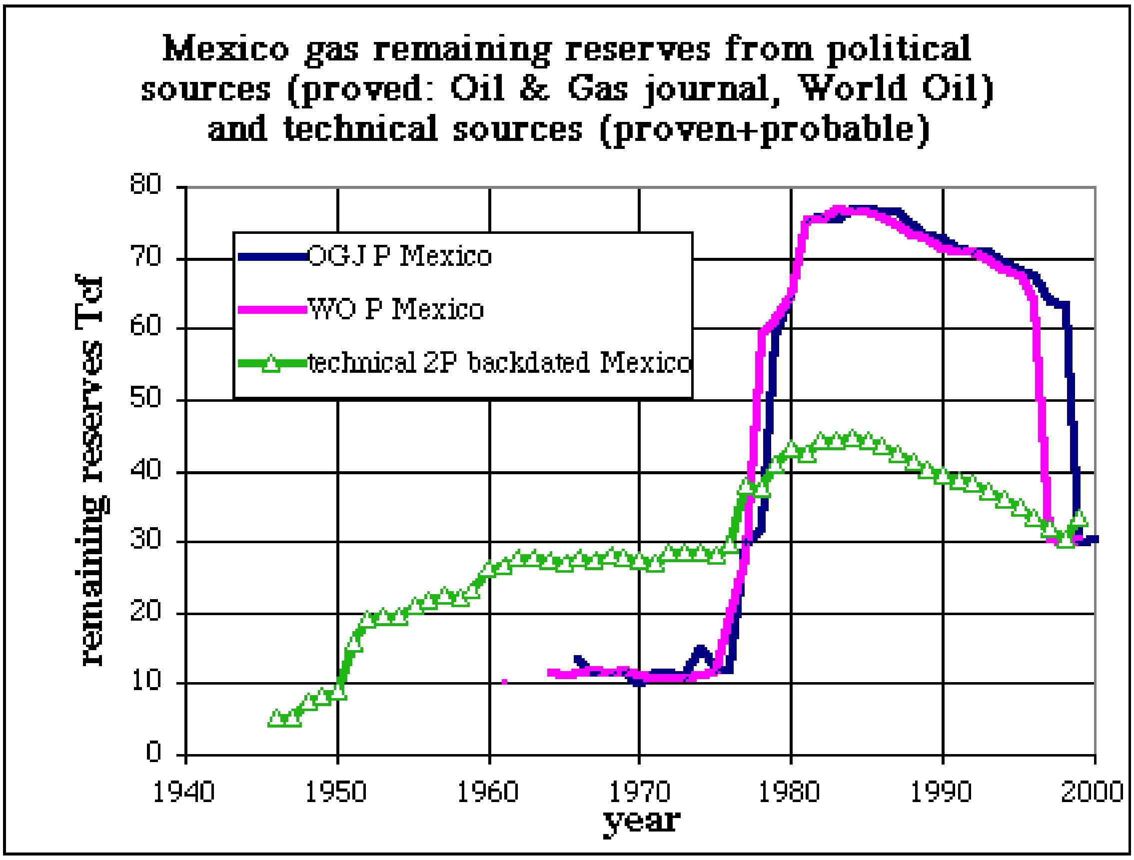


In fact the NEB case 1 peaking at 10 Tcf/a in 2025 corresponds to an ultimate of 670 Tcf and not 733 Tcf. Case 2 peaking at 8 Tcf/a in 2017 corresponds to an ultimate of 500 Tcf and not 662 Tcf. The new ultimate of 340 Tcf corresponds to a peak at 7.3 Tcf/a in 2007 and a peak at 6.2 Tcf/a in 2003 corresponds to an ultimate of 280 Tcf.
The comparison of annual production and shifted mean discovery gives a fair fit for a shift of 20 years. This shift allows guessing that the present production will peak soon and decline sharply.
Figure 61: Canada gas production and discovery shifted by 20 years



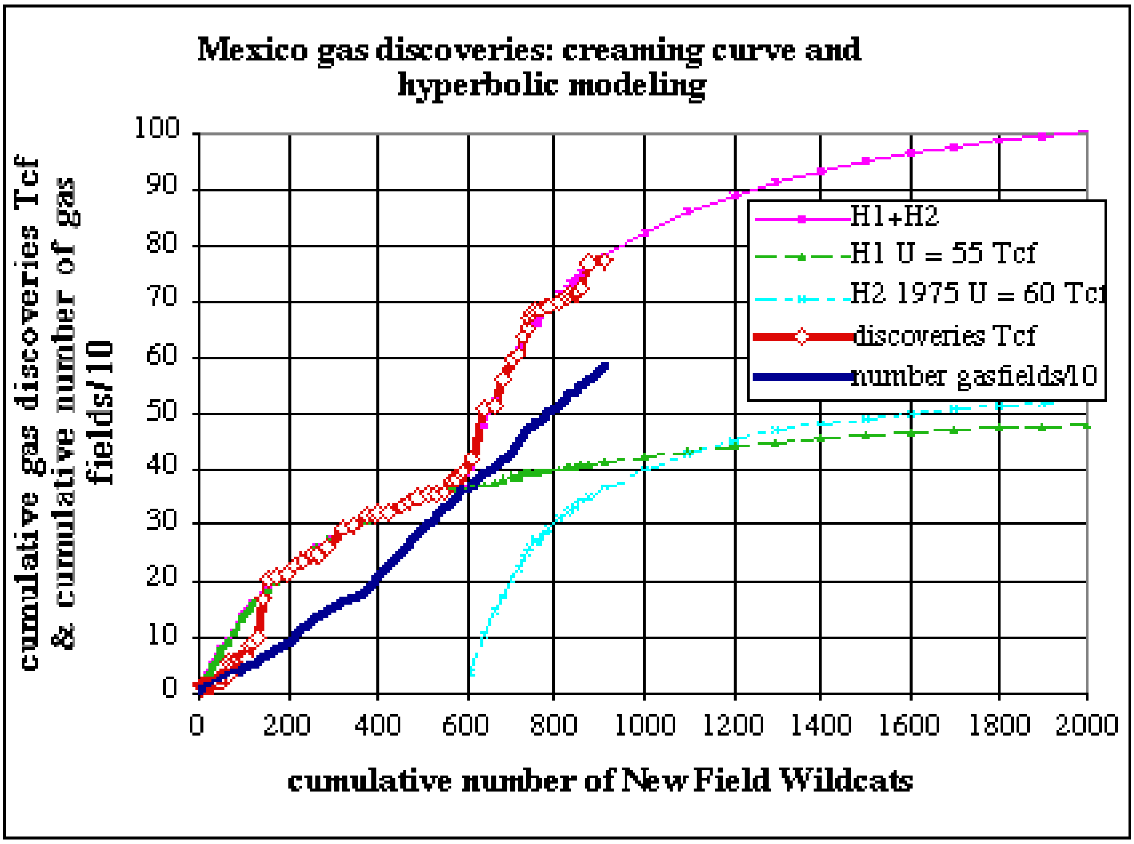
Stark 2001 in the IHS mid 2001 Review is pessimistic on the gas production because of the fast decline in productivity. He wrote:
<<Similarly, deterioration in Alberta gas well productivity is evident in Figure 6 by significant increases in decline rates and decrease in peak production volume between 1990 and 1999. Correspondingly, the USGS in its World Petroleum Assessment 2000 dropped its estimate of Western Canada gas resources to 19 Tcf. This compares to an estimate of about 170 Tcf by a Canadian source. <<
In conclusion the Canadian gas production is likely to peak soon and will not fulfil the forecasted demand from the US. Further more Nikiforuk (2001) in "The next gas crisis" is pessimistic about the supply and mentions that "*the oil sands, the source of Canada's future oil supply, by 2020, will be hogging nearly 25% of Alberta's gas production in order to fire the boilers to heat the water that melts the tarry sands into usable oil*"

-Mexico
Mexico was for a long time in dispute with the USGS on their reporting of reserves, these being over-estimated in order to have good loans from the IMF and World Bank. The remaining gas reserves from political sources dropped in the last few years from 65 Tcf down to 30 Tcf (after signing the NAFTA Agreement). The technical data (mean backdated) shows a decline from a peak of 45 Tcf in 1083 down to 30 Tcf in 2000.
Figure 62: Mexico gas remaining reserves from technical sources (current proved) and technical data (backdated proven+probable)



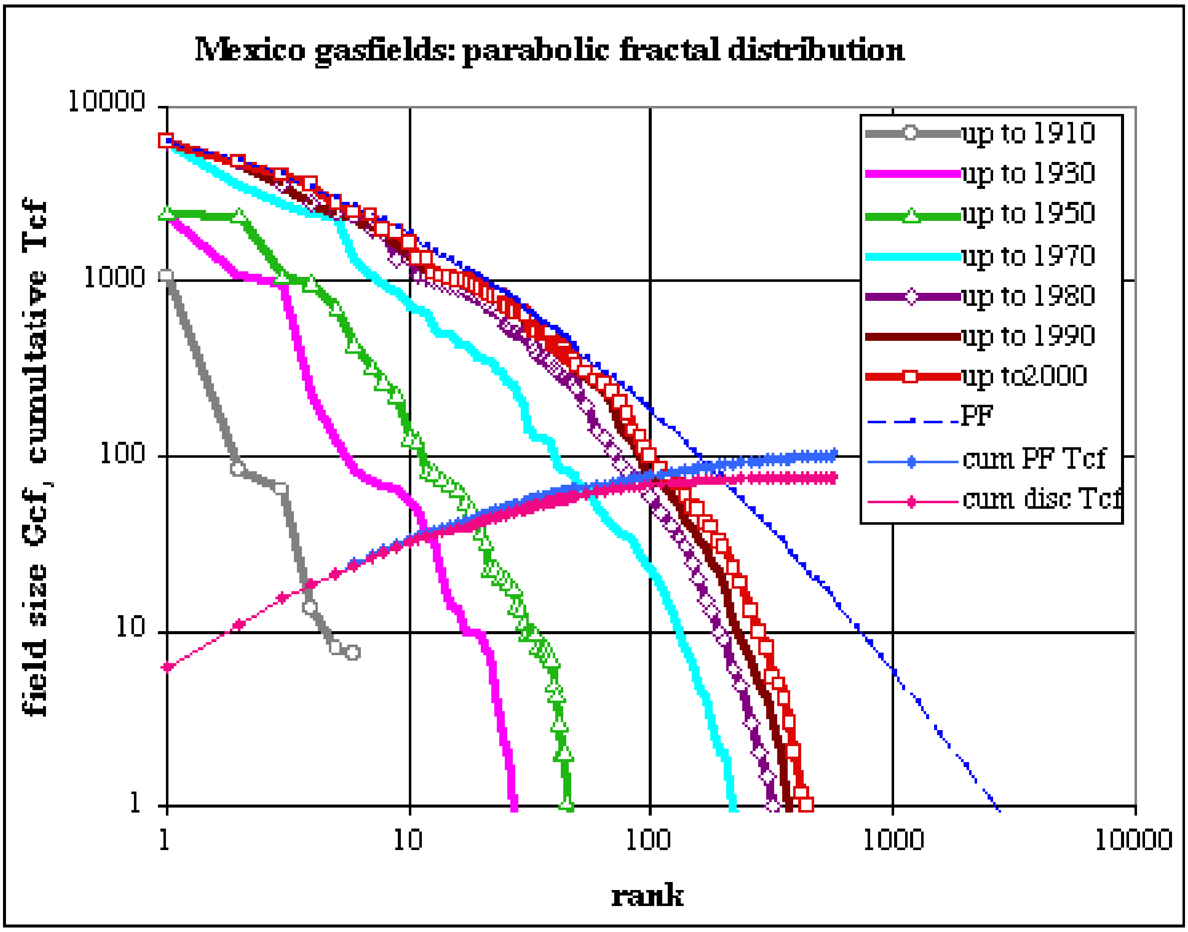
The cumulative discovery versus cumulative number of New Field Wildcats displays two cycle hyperbolas (second cycle starting in 1975) trending towards an ultimate of 100 Tcf when more than doubling the number of wildcats.

Figure 63: Mexico gas discovery: creaming curve



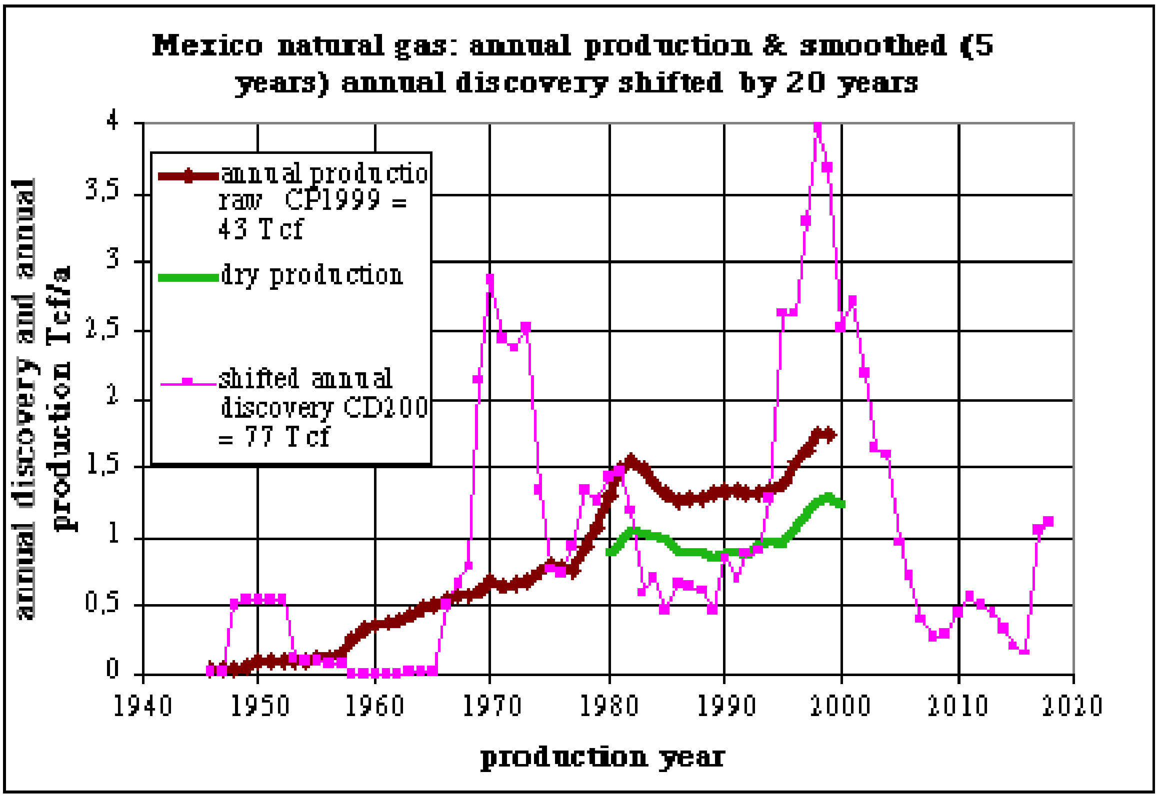
The display in fractal format (size-rank, log-log) with the distribution for each decade shows that in 1980 most of the largest gas fields (>1 Tcf) were found and that for the last 20 years most of the discoveries have been fields less than 1 Tcf. The parabola extrapolating the largest fields allows estimating the ultimate around 100 Tcf as for the creaming curve.

Figure 64: Mexico gas fields: parabolic fractal distribution and ultimate



The correlation of the annual gas production with the shifted gas discovery is fair for a shift of 20 years as shown in the next graph. It looks again that the gas production will peak soon and will decline.

Figure 65: Mexico gas production and discovery shifted by 20 years



As our estimate of ultimate is around 100 Tcf and that the cumulative production up to 2000 is around 50 Tcf it is the mid-point and close to peak.
All the previous graphs for Mexico were for conventional gas, but there is no great potential for unconventional gas.
It is assumed by almost everybody that Mexico is unable to increase its production and will be obliged to import more gas to fill its growing demand.

-East Greenland

As Greenland belongs to North America, it is necessary to present this country.
There are some gas discoveries in the Labrador Sea in Canadian waters, but none in the West Greenland. Because good source-rocks outcrop in East Greenland and there is some comparison with the potential of North Sea the USGS in their 2000 report on undiscovered estimates that there is 47 Gb of oil and 81 Tcf of gas. We believe (Laherrere 2000 on USGS) that this estimate is very unlikely first to occur and second to be developed, given the obstacles to bring gas to consumers from this remote area, covered with ice during 10 months each year.
It is better to forget Greenland in the North America gas supply.

-US+Canada+Mexico

Using the dry production as the reference data is misleading as the balance of injection and withdrawal from the storage is not taken into account. It is unknown where the gas is repressured (field or storage). Raw (gross) production should be taken as the base, but it is not always available. USDOE recognises that they do not have a homogeneous database of raw and dry production for North America (Andy Dikes personal communication). As for reserves, it is unknown if they are estimated as dry or gross future production!
Nevertheless, it is interesting to obtain global graphs for the three countries.
In 1994 USGS estimated that the three countries have an ultimate for conventional gas of 2.1 Pcf. In 2000 USGS wanted to distinguish reserve growth (it was included in the 1994 study)

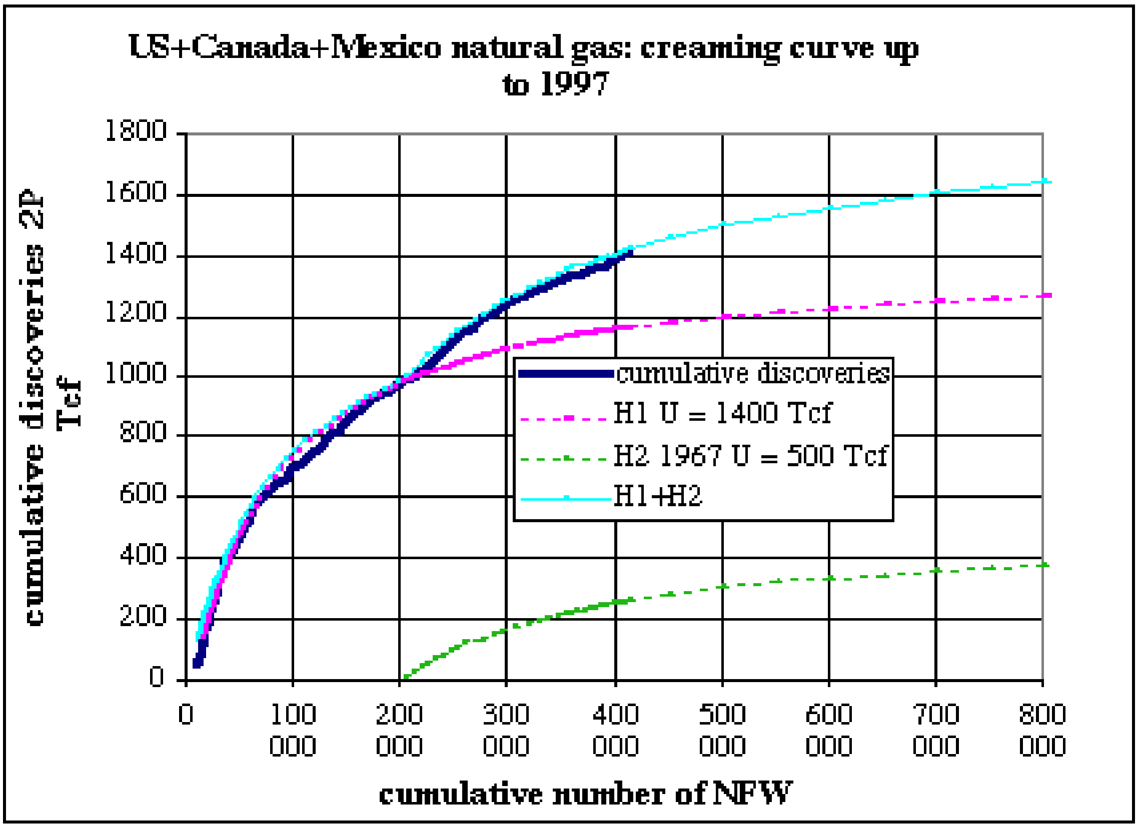
as an important part for the US that they wanted to extrapolate to the rest of the world globally without giving the detail by country. The comparison is impossible, but it is obvious that US gas potential was greatly increased, and Canada and Mexico greatly decreased.

conventional	USGS 2000	USGS 1994	
gas	disc+undisc	reserve growth	disc+undisc
US	1553	355	1438
Canada	210	?	609
Mexico	118	?	247
North America	1881	?	2121

It is obvious that poor reporting on known reserves, and production (raw or dry), leads to a poor estimate of the ultimate discovery.

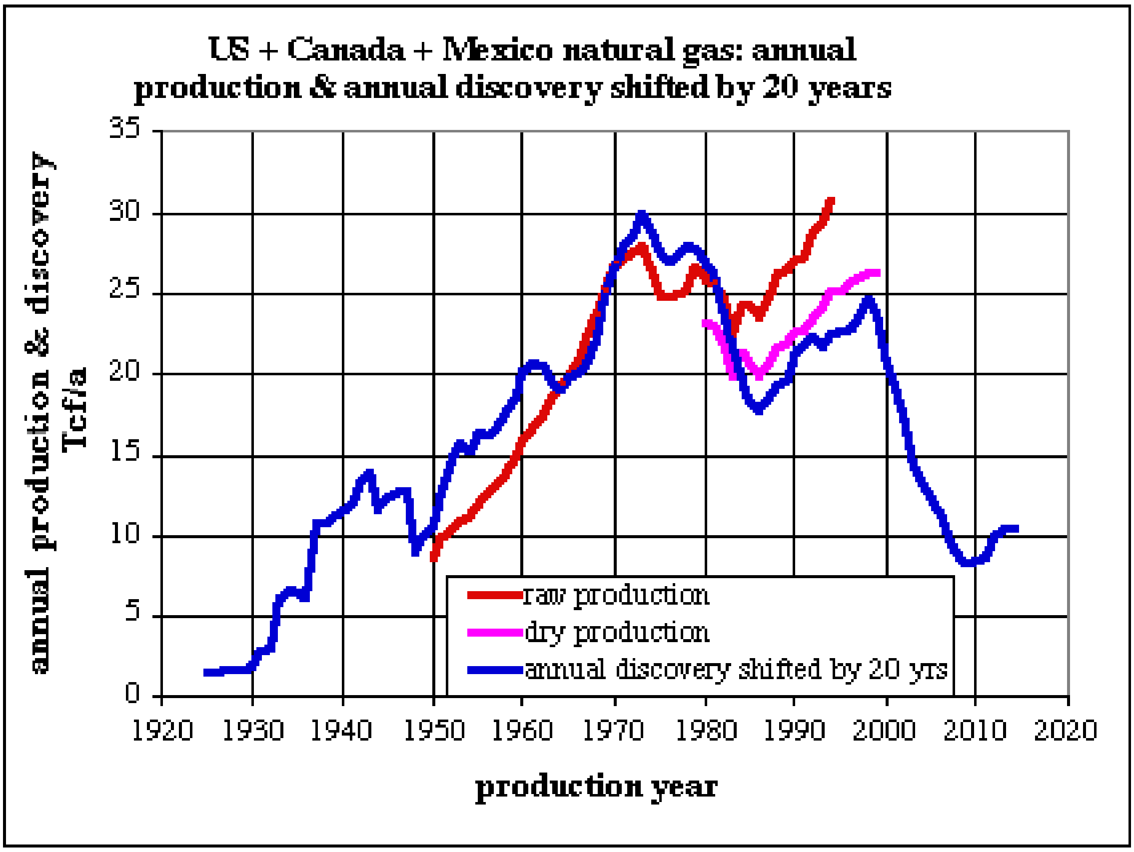
From the poor data by fields which has been corrected (with a very poor reserve growth model) to obtain the mean value for reserves, the creaming curve displays two hyperbolic cycles, the second starting in 1967. Up to 1997 1400 Tcf has been discovered with about 400 000 new field wildcats. The potential from drilling another 400 000 wildcats is less than 300 additional Tcf.

Figure 66: US+Canada+Mexico gas mean discovery: creaming curve



The correlation of the annual production (raw or dry) with the shifted discovery is fairly good for a shift of 20 years. This shift allows extrapolating future production towards a very soon peak and a fairly steep decline for the present decade.

Figure 67: US+Canada+Mexico gas production and shifted mean discovery by 20 years



-Conclusion on the local gas supply of North America

If official reports from governmental agencies are optimistic on the gas supply to fill the demand, it is obvious that the demand is based on very optimistic assumptions on both the price and the volume.

But technicians have a more pessimistic view on the supply estimate, such as Nehring or IHSE.

The IHSE mid-2001 report by Stark (2001) writes:

<<EIA believes that supplies will be adequate to cover predicted 4.6% (1.03 Tcf) growth in demand that would accompany an economic rebound in 2002. Recent extrapolations from IHSE databases indicate that even current levels of Canadian and US gas directed drilling could be pressed to cover a 1.03 Tcf increase. If so, US gas supply and demand margins would narrow and increase the likelihood for higher prices by the end of 2002. <<

But it seems that the gas future demand is based on optimistic growth based on cheap price (2$/Mcf in 2020) and large resources of conventional and unconventional gas.

I f the local future supply declines as technical data shows, the price will go up and the demand will immediately decrease as it did this summer after the peak on gas price of the past winter (this decrease of demand was not forecasted by any economist). Much has been written on the blackouts of California due to capping the retail electric power price under so-called industry deregulation. But most economists thought that this price cap was no problem as they have only in mind a decrease in price (GRI 2000 forecasted 1.94 $1998/Mbtu in 2015!). Increase in price is politically (as well as economically) incorrect! We are living in a culture of growth, needing lower prices!

The increased need for energy in North America is forecasted to come mainly from gas, mainly for electricity. But there are other alternatives than gas. First coal and in figure 8 showing the US fossil fuels production it is clear that coal production is rising in 2000 to a level never reached. Coal projects for electric plants were slow because of the Kyoto agreement which is now rejected by the US. Secondly there are nuclear plants and the rejection of nuclear by the US consumers seems to be less after the blackouts in California. Nuclear is safer (less deaths) than the gas consumption (numerous blow outs) outside the waste problem which can be solved

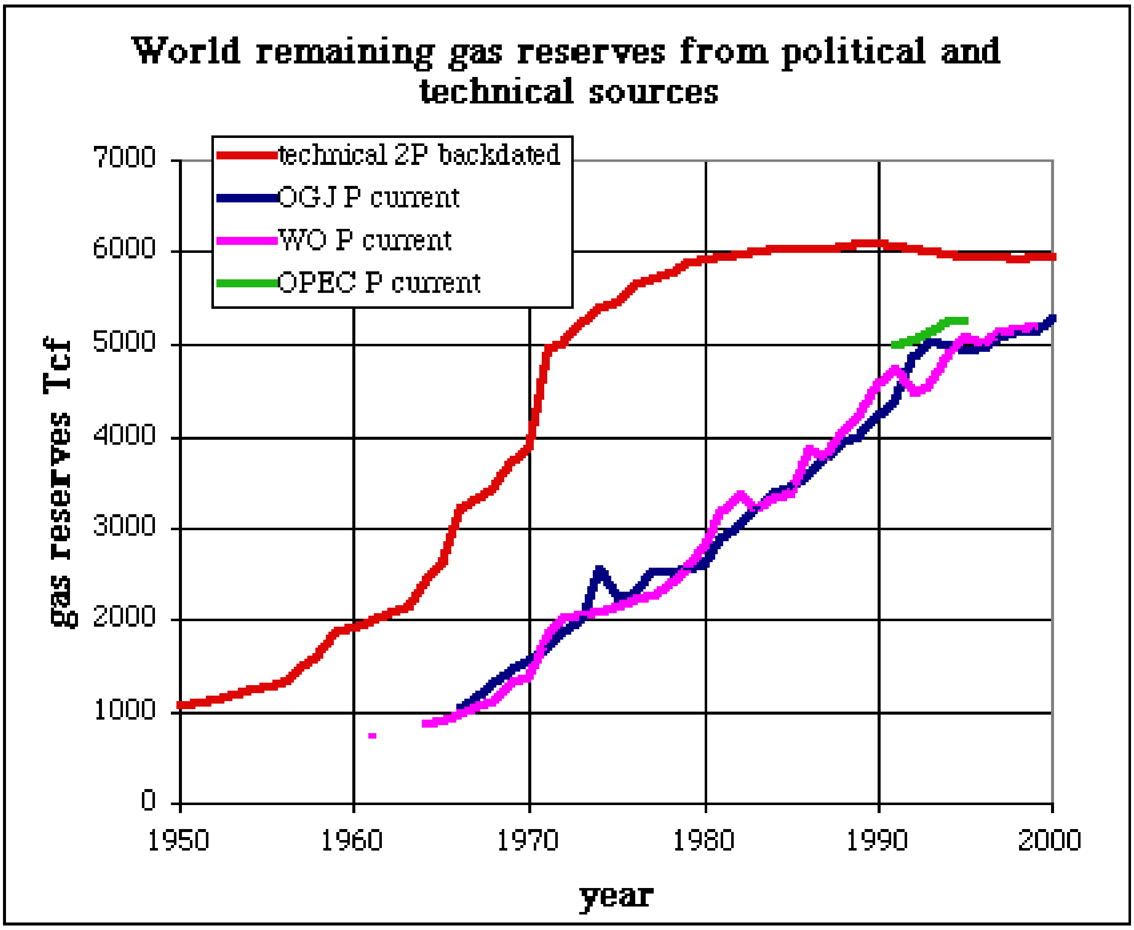
We feel that the gas demand will be less, and the gas supply will be able to satisfy it from the local production and from increased LNG from the rest of the world. The gas potential outside North Americas is studied in the following chapter.

-Potential of importing gas to North America from the rest of the world

-World

The reporting of conventional gas reserves shows a rising trend from political sources and a levelling from technical sources at around 6 000 Tcf (6 Pcf) since 1980.

Figure 68: World remaining gas reserves from political sources and technical sources

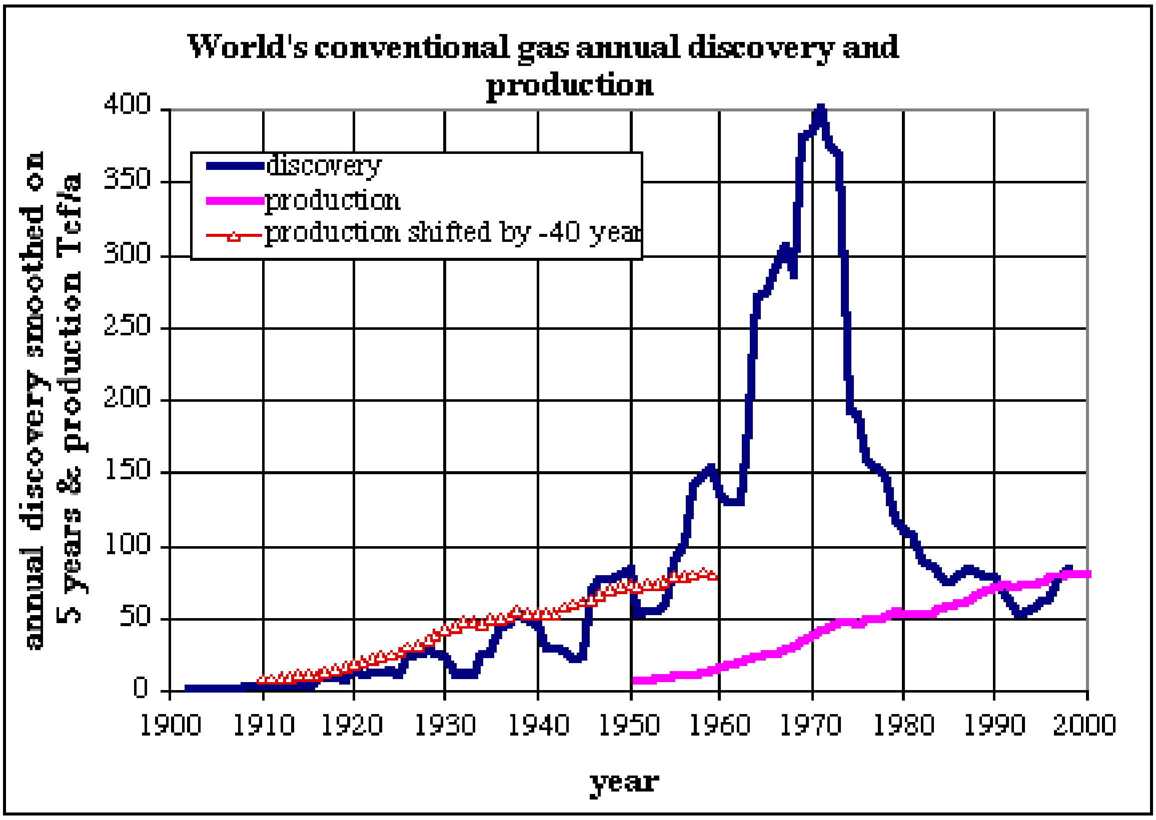


The correlation between annual conventional gas discovery and production is not very good. We plotted also the production curve by shifting it backward by 40 years to fit with the discovery curve. The fit is fair.

Up to now, 9 Pcf has been discovered and only 2.5 Pcf has been produced.

There are many stranded gas fields waiting to be developed, because the low price of gas and high cost of the transport. But the situation is improving, in Nigeria gas has been flared for decades but now LNG plants have been built.

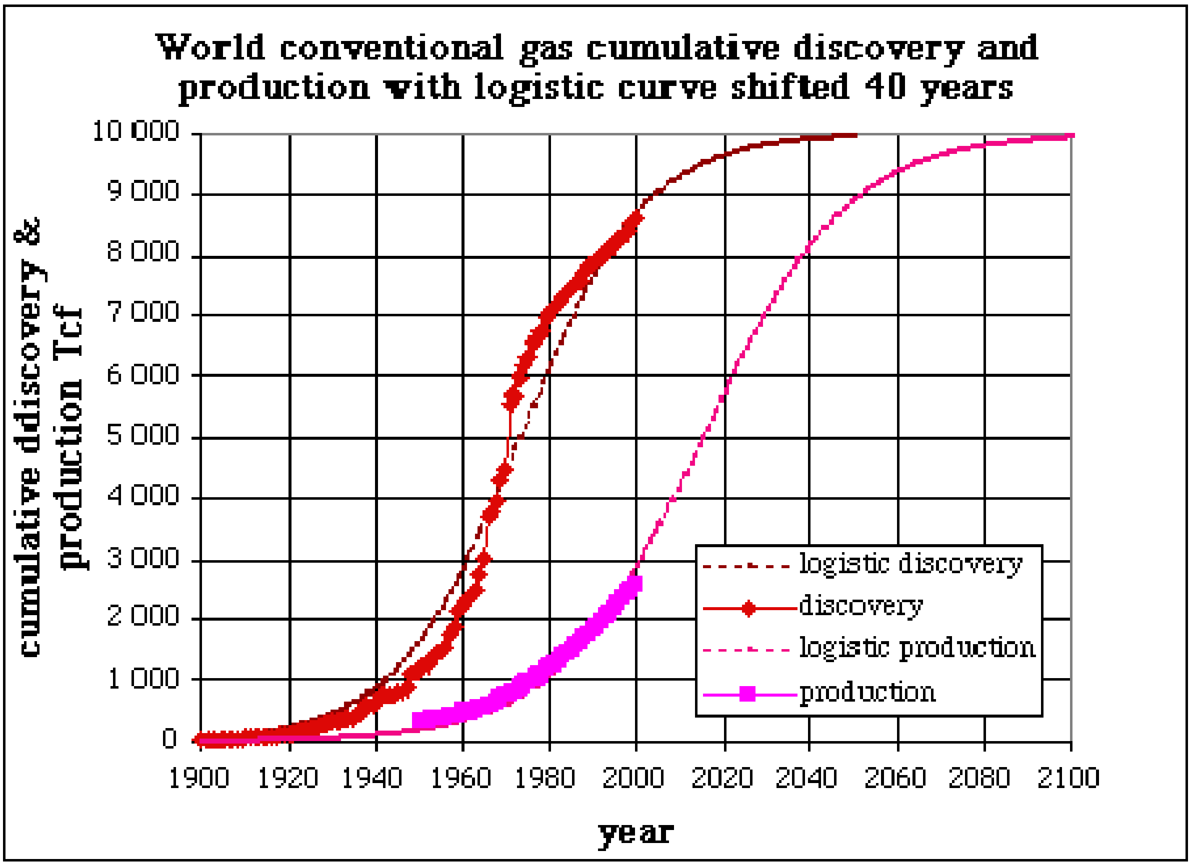
Figure 69: World gas annual discovery and annual production



It is better to compare cumulative production and discovery and to model them with the same logistic curve. The best fit for a logistic curve occurs with a shift of 40 years.

The fit of the logistic with the discovery curve is not too good during the 70s as a very large volume of gas have been discovered in the two most prolific places for gas: Western Siberia and Middle East. In 1971 the world's largest gas field was discovered in Qatar as North Field with its extension in Iran being South Pars. This field is at least three times bigger than the second largest gas field being Urengoi in Western Siberia. But Urengoi is declining since 1987 and has produced now about 50% of its ultimate. North Field is just beginning to be developed. But large gas export developments need political stability and the Middle East is barrels of powder!

Figure 70: World conventional cumulative gas production and discovery

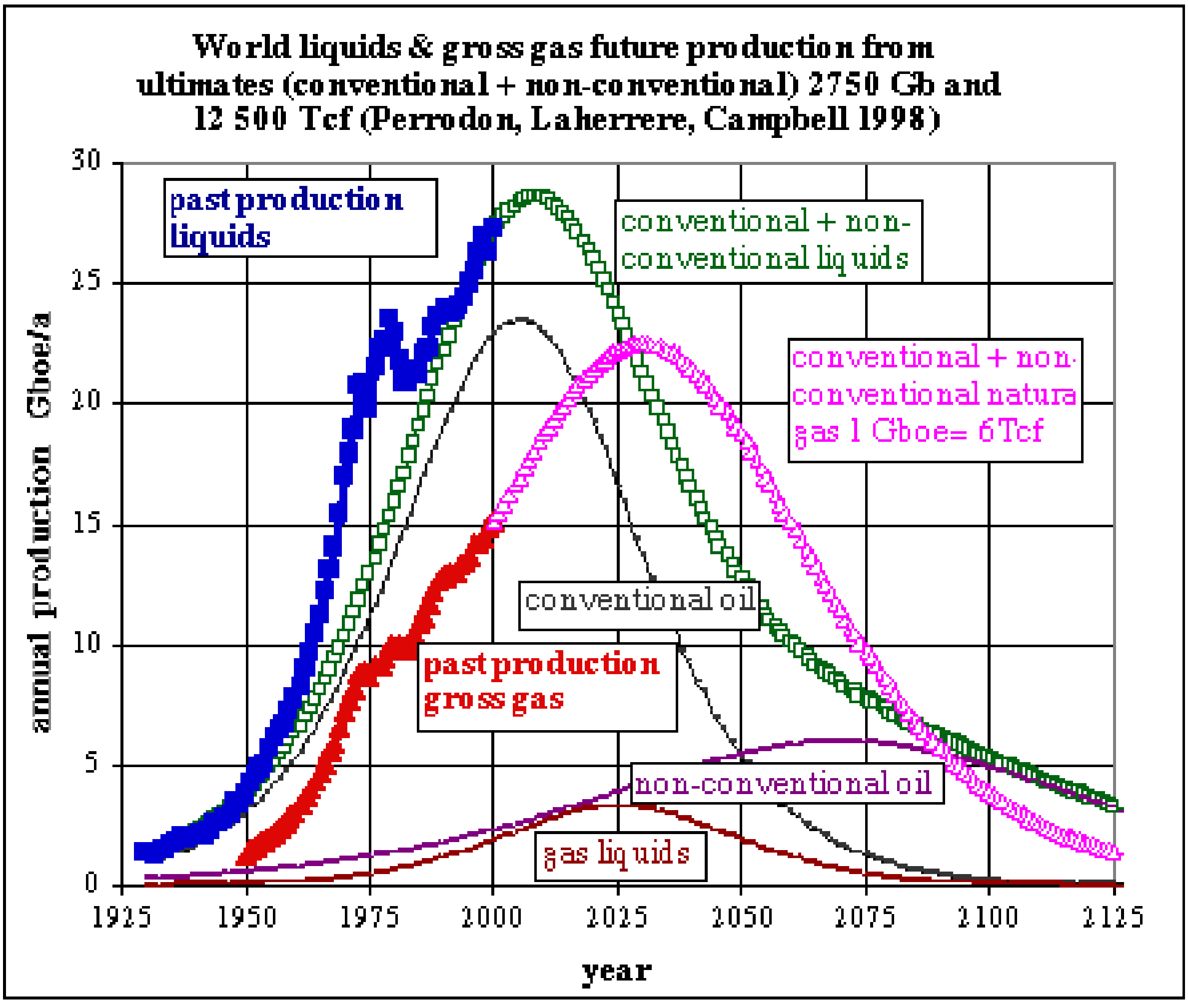


We have modelled with a logistic curve assuming that the ultimate is 10 Pcf. This ultimate is the result of 4 large reports written with three other retired geologists during 8 years, dealing with more than 80% of the world's individual fields and the main Petroleum Systems of the world. The fit with past production is good and forecasts that the peak (mid-point at 5 Pcf) will be reached around 2015.

In front of the coming peak for oil (in fact the second as world's oil consumption has peaked already in 1979 and took 15 years to reach back this level), there are many articles on the potential of gas-to-liquids techniques (GTL) as an alternative for oil with gas peaking well after oil. If some gas is converted into oil, there will be less gas for electric plants. GTL is still on the pilot stage (Shell Bintulu in Malaysia) as economics were not to good up to now. GTL looks good when the price of oil is high and when the value of the gas is very little (it could be negative as in Nigeria when flared (penalties). If gas prices goes up, the economics of GTL will suffer. It is likely that GTL will be a useful addition to the declining oil but will not change much the decline of liquids

But consumption curves must include every component, as unconventional oil and gas and even refinery gains. Our ultimate for liquids is 2.8 Tb and for gas 12.5 Pcf (Perrodon et al 1998). The modelling of future production forecasts a peak for liquids before 2010 and for gas around 2030 about 23 Gboe/a or 140 Tcf/a.

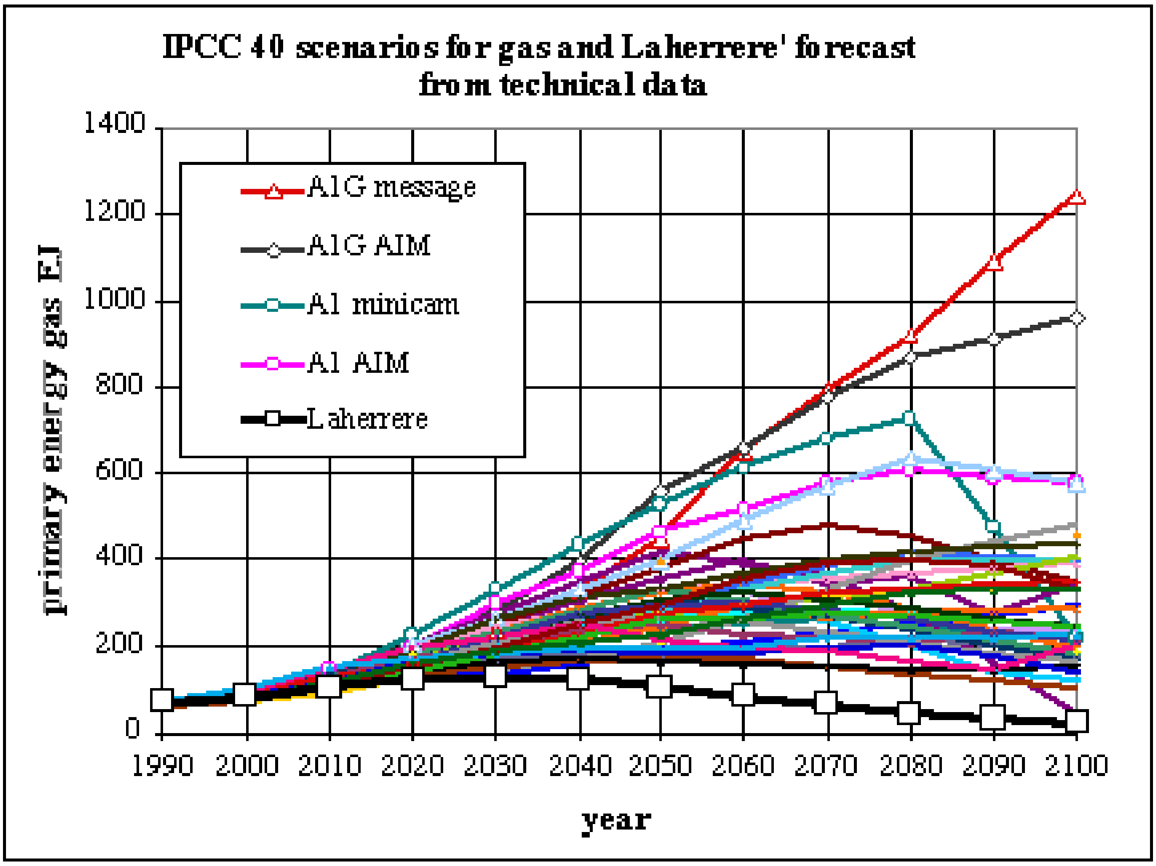
Figure 71: World liquids and gas production 1925-2125



It is obvious that the world has enough gas reserves for the next 20 years to help North America to solve their need for gas before finding alternatives to their declining gas production. Import of LNG from outside North America is the easiest and quickest answer to their local gas shortage

It is amazing to find that the IPCC 2000 scenarios are based on very unlikely assumptions made by IIASA (Laherrere 2001 on IIASA gas perspectives). The 40 gas scenarios cover a very broad range but unfortunately exceed the most likely scenario based on technical data (figure 71) as shown in the next graph (consumption given in EJ = 10E18J Å Tcf/a)

Figure 72: IPCC 2000 gas consumption scenarios compared to forecast from technical data



It means that the IPCC 2000 conclusions are as unlikely as their assumptions are based on the concept of very abundant resources and cheap price. They confuse reserves and recoverable resources with resources as volume in place. They confuse wishful thinking with reality.
It is very important that the academic agencies work on better data. IPCC has to work again on their modelling with better assumptions on future hydrocarbon production.

-Global conclusion

Most of official forecasts on North America gas supply and demand are questionable. The main reason is that the scenarios are based on the concept of abundant resources and cheap oil and gas, but also on unreliable data. The 10$/b for oil in 1998 is mainly due to the "missing barrels". The IEA reported an underestimated demand and an overestimated supply, giving a wrong impression of abundance.
Before improving forecasting methods (which needs to be taken out of political pressures), it is necessary to improve the data collected by the USDOE and MMS by changing the rules of reserves reporting with the SEC.
The demand (for oil and gas) as forecasted by official agencies is unlikely to occur (high price will increase energy savings as in 1979) and the gas supply will be much less than forecasted as shown by most of the graphs, but the balance for gas can be solved with the import of LNG. Energy savings can be both by using less energy (change of behaviour such as driving less) and improving efficiency (change of equipments).
The additional demand for electricity can also be filled with coal and nuclear, if renewables cannot do it.
We hope that our goal to inform the reader with many graphs has been partly fulfilled, and has brought some light on the North America gas supply.

References:

-Adams T.D., Kirby M.A. 1975 "Estimate of world gas reserves" 9th WPC

-Blair A. 2000 "Special message" World Economic Forum Annual Meeting 2000 Davos, Switzerland http://www.asiamedia.ucla.edu/Davos2000/Speeches/Blair.htm
-Campbell C.J, Laherrere J.H. 1998 "The end of cheap oil" Scientific American March p80-85
-Canadian Gas Potential Committee 2001 "Canada’s natural gas future to remain in Western Canada" Sept. 11, http://www.canadiangaspotential.com/2001report/mediarelease.html
-Capen E.C. 1996, "A consistent probabilistic approach"; SPE Reservoir Eng. Feb. 1/1
-Cochener J.C. 2001 "The long term trends in US gas supply and prices" Oil and Gas Journal, January 22 p
-Cochener J.C. 2000 "Long-Term Trends in U.S. Gas Supply and Prices: 2000 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2015" Gas Research Institute devenu Gas Technology Institute
-Cooper Ch. 1999 "Odd Reservoir Off Louisiana Prods Oil Experts to Seek a Deeper Meaning ; Something mysterious is going on at Eugene Island 330" Wall Street Journal April 16 http://oralchelation.com/faq/wsj4.htm)
-DeSorcy G.J. et al 1993 "Definitions and guidelines for classification of oil and gas reserves" Canadian Standing Committee on reserves definitions, JCPT vol 32 n°5, May -p10-21
-Goodwin S. 1980 "Hubbert’s curve" Country Journal Nov p56-61.
-Hartnett J. 1976 "Alternative energy resources" 1976 Academic Press http://www.searchanddiscovery.com/documents/stark/index.htm
-Laherrère J.H. , A.Perrodon 1995 "Contribution à l’estimation des réserves ultimes" Pétrole et Techniques -n°398 - Nov-Déc -p53-56
-Laherrere J.H. , A.Perrodon, C.J.Campbell 1996 "The world’s gas potential" Petroconsultants report July, 200p, CD-ROM
-Laherrere J.H. 1996 "Distributions de type fractal parabolique dans la Nature" Comptes Rendus de l’Academie des Sciences- T.322 -Série IIa n°7-4 Avril p535-541 http://erebus.phys.cwru.edu/phys/courses/p196/cheap/p196eocopg1.gif or http://www.oilcrisis.com/laherrere/fractal.htm
-Laherrere J.H. 1999 "Parabolic fractal, creaming curve improve estimate of US Gulf réserves" Offshore Magazine May p113, 114, 177
-Laherrere J.H. 1999 "Reserve growth: technological progress, or bad reporting and bad arithmetic?" Geopolitics of Energy 22/4 April p7-16 http://dieoff.com/page176.htm
-Laherrere J.H. 2000 b "Is the USGS 2000 assessment reliable ? " Cyberconference by the World Energy Council, May 19, Strategic Options http://www.energyresource2000.com
-Laherrère J.H. 2001 "Estimates of Oil Reserves " IIASA International Energy Workshop June 19-21 2001 Laxenburg http://www.iiasa.ac.at/Research/ECS/IEW2001/pdffiles/Papers/Laherrere-long.pdf
-Laherrère J.H. 2001 "Comments on "Global Natural Gas Perspectives" by Nakicenovic, et al (paper published by the International Gas Union for the Kyoto Council and the International Institute for Applied Systems Analysis, October 2-5, 2000) http://www.hubbertpeak.com/laherrere/ngPerspective/index.html
-Laherrère J.H. 2001 "Comments on "Challenges and Concepts for Long Term Oil and Natural Gas Supply Modeling" Presented by Vello A. Kuuskraa at PEW Workshop on Oil and Gas Markets Stanford Energy Modeling Forum #19 Snowmass, CO August, 2001 http://www.oilcrisis.com/laherrere/Kuuskraa/
-Milkov A.V, R. Sassen 2001 "Economic Geology of the Gulf of Mexico and the Blake Ridge Gas Hydrate Provinces" GCAGS Transactions 2001
-National Energy Board 1999 :" Canadian Energy - Supply and Demand to 2025, Appendix 5: Natural Gas" http://www.neb.gc.ca/energy/sd99/a2.xls
-Nehring R. 2001 a " The Gulf of Mexico : rising star or over the hill ? in "The Natural Gas Frontier: 2015 and Beyond " Annual Energy Outlook 2001 Conference, March 27

-Nehring R. 2001 b "Gulf of Mexico: Reservoir temperatures, low thermal gradient limit US Gulf's deepwater gas potential" Offshore, January
-Nikiforuk A. 2001 "The next gas crisis" Canadian Business August 20, p28-30, 39
-Perrodon A., J.H. Laherrere, C.J.Campbell 1998 "The world's non-conventional oil and gas" Petroleum Economist March report 113p see http://textor.com/cms/dPEWNC.html
-Richebacher K, 2000 "Euro travails" http://www.gold-eagle.com/editorials_00/richebacher100600.html
-Ross J., 1998, "Non standard reserves estimates lead to resource underestimation"; Oil & Gas Journ. Mar 2
-Rozendal R.A. 1986 "Conventional US oil and gas remaining to be discovered; estimates and methodology used by Shell Oil Company" AAPG studies 21
-Stark P. 2001 " Petroleum Industry Perspective: Mid-Year 2001" AAPG Sept.
-SPE/WPC 1997: "SPE/WPC reserves definitions approved" JPT May p527-528
-SPE/WPC/AAPG "Petroleum Resource Definitions" March 16, 2000
-Swindell G.S 1999 "Texas Production data show rapid gas depletion " Oil & Gas Journal, June 21, p61 http://oil.server4.com/tx-depl.htm
-USDOE/EIA-0534 1990"US oil and gas réserves by year of field discovery" Aug. "
-USGS 2000: "World petroleum assessment 2000 —description and results" 16th WPC, summary: http://energy.cr.usgs.gov:8080/energy/WorldEnergy/weppdf/sumworld.xls, 4 CD-ROM: USGS DDS-60,
-Whelan J. 1996, http://www.williamsinference.com/energy.html Volume 14, No. 2 - May
-Wood Mackenzie 1999 "UK upstream report 316" Sept
-Woronuk R.H. 1999 " Canadian gas supply: going up? or down? " Canadian Gas Potential Committee & Gas Energy Strategies Inc. (GESI)
http://tabla.geo.ucalgary.ca/NatGasCan/opipaper.pdf