Peak Oil - A Turning Point for Transport

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1 Introduction

Transport planning and research has been premised on a continuously growing supply of affordable crude oil. Since crude oil is the source of liquids fuels driving almost all forms of transport, this assumption requires scrutiny.

There is also a growing disconnect between stated goals to reduce carbon dioxide emissions and the assumption that strong economies will require increasing levels of transport based on fossil fuels. This disconnect is most likely to be resolved by an un-anticipated peak in oil supply. Petroleum resources, while large in number, are insufficient to meet growing demand.

Following a peak in production of crude oil, declining world production is likely within five years. In the absence of international agreements to cut consumption, oil demand will be forced down the only way the market knows – through yet higher prices.

The case for a near-term peak in world oil production rest on four key observations:

- Oil discovery is well short of consumption levels. While demand continues to increase, oil discovery rates are on a declining trend, which they have exhibited for several decades despite technological advances.
- Stated OPEC oil reserves are not audited or verified. The latest assessment of two of Saudi Arabia's largest fields lends considerable weight to the view that reserves in OPEC countries are substantially over-estimated.
- Unconventional oil resources are volumetrically large but limited in their sustainable production rates. Objective reports cast doubt on high-end expectations.
- Proper assessment of depletion, and recognition of the number of countries where production is already in terminal decline, underpins predictions of a near-term peak in global oil production.

This paper will expand on these four points in turn, to build a detailed assessment of why a peak in global oil production is likely within five years. In doing so, the uncertainty and inadequecy of available information relating to world oil reserves and future production potential will also be highlighted.

The transport industry and research community face many challenges in the years ahead. Planning for and adapting to a declining world oil supply is likely to be the most significant.

Definitions & Abbreviations

- *Gb : Giga barrels.*
- *mn b/d: Million barrels per day.*
- *NGLs: Natural Gas Liquids*
- *Unless otherwise stated, reserves here refer to P50 estimates, ie. proven plus probable. Also referred to as 2P, these are 'best' estimates, which are just as likely to be exceeded as not. P90 (3P) 'proven' reserve estimates are those which have a 90% chance of being exceeded. P10 (1P) 'possible' estimates have only a 10% chance of being exceeded.*

2 World Petroleum Assessment and Supply Forecasts

In 2000, the United States Geological Society issued its World Petroleum Assessment, covering the thirty year period 1995-2025 (Table 1). The resource estimates from this study are widely quoted to support the argument that oil production can continue to expand.

Table 1: USGS (2000) Resource Assessment (Conventional oil and NGLs)

World Petroleum Assessment 2000 1995-2025 Forecast (Mid Case)	
Cumulative Production to 1995	717 Gb
Undiscovered Resources	939 Gb
Remaining Reserves	959 Gb
Reserve Growth	730 Gb
Total Oil Endowment	**3345 Gb**

It is illustrative at this point to review how the OECD energy agencies prepare their forecasts. Their long-term approach is based on the above USGS level of ultimately recoverable resources, depletion rates and reserve growth, but only for non-OPEC regions. The International Energy Agency (2004) state clearly:

> *"OPEC conventional oil production is assumed to fill the gap between non-OPEC production and non-conventional and total world oil demand."*

In other words, the energy agencies extrapolate demand forward and then forecast (albeit based on optimistic resource assessments) how much of that demand can be met from non-OPEC countries. It is then boldly but openly assumed that production from OPEC countries will fill the large and growing gap between demand and non-OPEC supply.

An objective assessment of OPEC reserves provides no basis for this assumption. Extrapolating demand forward is not a fit-for-purpose technique and will logically fail to anticipate peak oil leaving the global economy unprepared.

The following sections examine these USGS estimates for Discovery, Reserves and Reserves Growth to indicate that our total resource base is not as large as claimed.

3 Oil Discovery

Figure 1 shows the trends in discovery and production of oil since 1930, using reserves backdated to field discovery date (Longwell, ExxonMobil 2003). The changing relationship between discovery and production is clear:

- The largest fields were discovered in the USA and Middle East from the late 1930's to 1960's.
- Worldwide discovery peaked in 1964 and now continues on a steadily declining trend.
- Every year since 1984, discovery has been lower than production.
- Currently, one barrel of oil is discovered for every four that are produced.

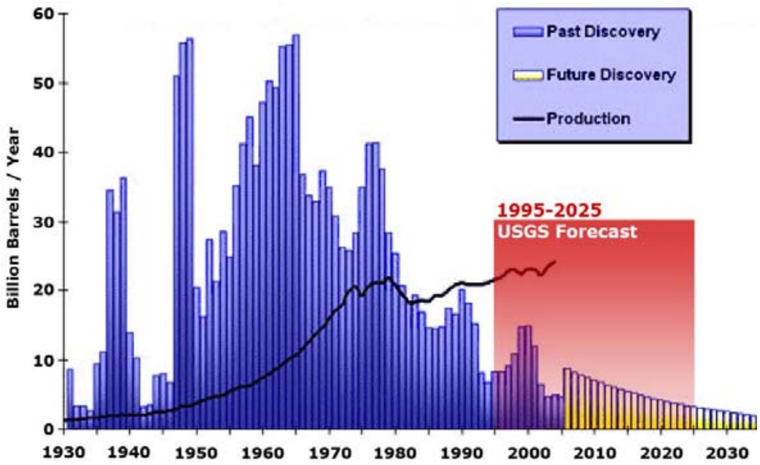


Figure 1: World Oil Discovery Trend

The USGS forecast of 939Gb implies an average discovery of 31.3Gb per year over their forecast period. Figure 1 shows that current trends are running well below this level. Discovery over the thirty year forecast period is likely to be less than one third of the USGS estimate.

4 Reserves

4.1 Ghawar

Ghawar is the largest oil field in Saudi Arabia and by far the largest field in the world (fig. 2). At 164 miles long and up to 16 miles wide, there isn't a single other field that is close in terms of size or reserves. It was discovered in 1948 and has been the mainstay of Saudi oil production. Production, until recently, was up to 5 million barrels of oil per day. In 2004, approximately 7% of the world's crude oil was supplied from this one giant field.

Reservoir properties are very good in the north, but get worse in the southern field sections. After more than fifty years of production, the northern sections especially are now very mature.

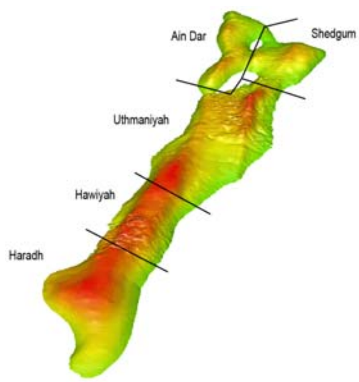


Figure 2: Ghawar field components

Detailed assessments have not been made available for any Saudi Arabian fields since nationalisation of the oil companies in 1980. However, Mearns (2007) and Staniford (2007) have pulled together data from numerous oil industry technical papers to provide a unique assessment of the state of oil depletion in this, the world's largest oil field.

A key example of the data used to complete this analysis is shown in Figure 3. Here, the progressive movement of water through a cross-section of the field illustrates how much of the original 'dry' oil in the reservoir has already been produced. With two years of intense production since the last simulation date, it is apparent that the volume of dry oil at the top of the reservoir is now very small and that the Uthmaniyah section of Ghawar is largely 'watered out'.

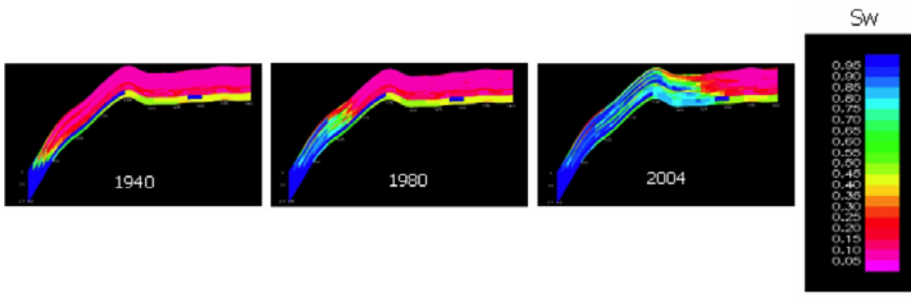


Figure 3: Water saturation in Uthmaniyah (pink = oil, blue = water)

By combining similar data sources providing information about porosity, permeability and initial and final water saturation throughout the reservoir, Mearns and Staniford have compiled a detailed study of the remaining reserves for the world's largest and most important oil field. Mearns' results are presented in Table 2.

Table 2: Depletion Levels in Ghawar

	Ain Dar	Shedgum	Uthmaniyah	Hawiyah	Haradh
Initial Reserves (billion barrels)	22	11	37	14	13
2006 Reserves (billion barrels)	1.7	3.7	4.3	10.3	7.1
Level of Depletion	92%	67%	88%	25%	47%
Max Production (million barrels per day)	1.0	1.0	1.5	0.6	0.9

In the Ghawar oil field, 90% of the initial oil reserves have been consumed from the two largest sections of the field, which accounted for half of the maximum production capacity. The ability to maintain past production rates from poorer quality southern sections, let alone meet expectations for growth, must be called into question.

Oil production in Saudi Arabia has been declining since mid-2005, while prices have been at record levels. OPEC claim that oil stocks in OECD countries justify the quota cuts. However, it is likely that this is partly involuntary and a result of production declines in Ghawar and other mature Saudi fields (fig. 4).

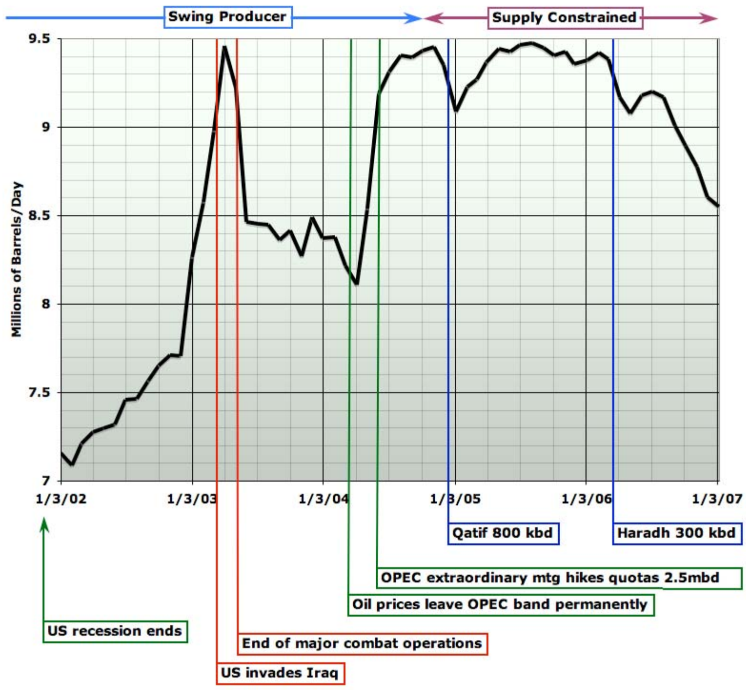


Figure 4: Saudi Arabia Production 2002-2007

4.2 Saudi Arabia

The work of Staniford and Mearns has culminated in a new and unprecedented assessment of oil reserves in Ghawar and Abqaiq, two of the world's largest oil fields. Their assessment can be combined with additional information sources to produce a revised estimate of reserves in the OPEC countries.

In “Giant Oil and Gas Fields”, Carmalt and St John (1986) published a list of the largest five hundred oil and gas fields known at the time. This included field size estimates for 24 major fields in Saudi Arabia (table 3).

Staniford (2007) revises the field size estimate for Ghawar up to 97 billion barrels (Gb). It is likely that much of this increase has occurred in the southern sections of Ghawar, especially Haradh which has only been extensively drilled and developed since 1986. It is significant that, despite this additional development, the total field size estimate has only increased by 17% in two decades. Mearns (2007) base case analysis revises Abqaiq reserves to 14.8 Gb, which represents a 16% increase on the 1986 estimate.

Table 3: Saudi Arabia Oil Field Size Estimates

Field Name	**Discovery Year**	**Size** billion barrels (Gb)
Ghawar	1948	82.0
Safaniya	1951	36.1
Manifa	1957	17.0
Abqaiq	1941	12.8
Berri	1964	12.0
Zuluf	1965	10.6
Khurais	1957	8.50
Abu Sa'fah	1963	7.50
Shaybah	1968	7.00
Qatif	1945	6.00
Marjan	1967	4.58
Khursaniya	1956	4.10
Jaladi	1978	3.00
Harmaliyah	1972	2.00
Abu Hadriya	1940	1.84
Dammam	1938	1.50
Fadhili	1949	1.00
Mazalij	1971	0.68
Rimthan	1974	0.60
Abu Jifan	1973	0.56
Lawhah	1975	0.55
Maharah	not listed	0.50
Jana	1967	0.50
Barqan	1969	0.25
TOTAL		**221**

That the Carmalt and St John estimates are only modestly lower than these two new estimates, is encouraging, but not all that surprising given that most of the listed fields were already 20-40 years old and extensively appraised at the time of their study.

While some fields may come in below the 1986 expectations, which is to be expected among a mix of P50 estimates, others may yield yet larger percentage increases. At this stage it is reasonable to extend the observed average increase to the other 22 fields in the list. While this is based on results from only two fields, the sample covers 43% (82+12.8/221) of the total oil resource estimate in Table 3 so it is quite significant. The result is in an additional increase of 21 Gb in the size of the other listed fields (in addition to 14 in Ghawar and 2 in Abqaiq), bringing the revised sub-total to 259 Gb.

The cumulative additional resource in very much smaller fields and those discovered since 1986, of which the Hawtah trend fields are the only known significant oil find, are estimated to amount to 6 billion barrels.

This yields a total initial reserves estimate for Saudi Arabia of 265 billion barrels.

Cumulative production of crude oil and condensate to end of 2006 is 120 Gb. Therefore, 46% of initial reserves have been produced, with end 2005 reserves of 140 Gb (2P / P50). This is fully 124 short of the 264 billion barrels stated by OPEC and widely reported as Saudi Arabian 'proven' reserves (BP, 2007).

The 1979 staff report to the US Senate Subcommittee on International Economic Policy on "The Future of Saudi Arabian Oil Production" supports the figures in the 1986 paper. Aramco (prior to nationalisation and operating in line with standard US industry practice) estimated to the senate subcommittee that Saudi Arabia had 2P reserves of 177 Gb and 3P reserves of 245 Gb (proven plus probable plus possible).

Cumulative production to the time of the report was 35 Gb, so the corresponding initial reserves estimates were 212 Gb (2P) and 280 Gb (3P). Seven years later, Carmalt and St John's combined assessment was 9 Gb higher, which provides confirmation that their field sizes were close to consistent with Aramco's best estimates at the time.

It is all but impossible that minimum initial reserves of 384 Gb could be valid, but that is what Saudi Arabia imply with 120 Gb of cumulative production to date and 264 Gb still claimed as 'proven' reserves.

On the other hand, it is encouraging that the new figure presented here (265 Gb) falls within the range identified by Aramco in 1979. After three decades of field development, it is perhaps not surprising that the new estimate falls in the high end of their range, but as the fields become increasingly mature, the opportunity for further gains diminishes.

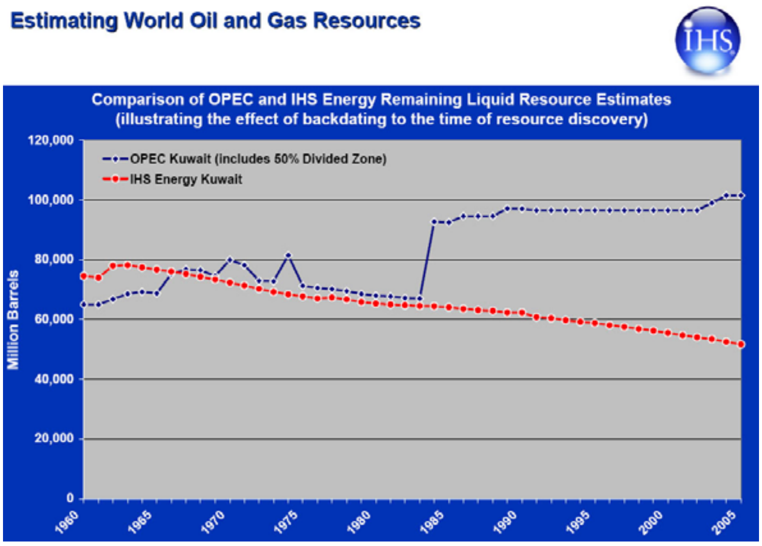
4.3 Kuwait and the United Arab Emirates

Importantly, it is not only Saudi Arabia for which there is evidence that reserves have been grossly overstated. Quoted reserves for the six largest OPEC members, and large upward revisions during the 1980's in particular, give cause for concern. The International Energy Agency (2004) has supported this interpretation, saying that “the hike in OPEC countries’ estimates of their reserves was driven by negotiations at that time over production quotas, and had little to do with the actual discovery of new reserves.”

More revealing is data from IHS (Chew, 2006), in this case specifically for Kuwait (fig.5). IHS manage the largest oil industry database of international field reserves and production. Their data suggests that Kuwait's reserves are barely half the 101 billion barrels reported publicly.

Further confirmation comes in the IEA's definitive World Energy Trends 2005 – Middle East and North Africa (2005). They estimate remaining proved and probable (2P) reserves in Kuwait (including half share of Neutral Zone) at 54.9 billion barrels from 9 named and two 'other' fields. For the UAE, proven and probable reserves (2P) are put at 55.1 billion barrels from 9 named fields and one 'other'. These estimates for the end of 2004 are sourced from IHS Energy and IEA databases.

Figure 5: IHS Reserves Estimates for Kuwait



4.4 OPEC 12

Reserves in Iran, Iraq and Venezeula are likely overstated to a similar degree, given their involvement in the 'quota wars' of the 1980's (Bentley, 2006). Reserves for other OPEC members Algeria, Indonesia, Libya, Nigeria, Qatar and now Angola are accepted as stated, with the caveat that they are also not provided with any form of audit or verification that they meet external reporting standards.

Claimed OPEC reserves are overstated by approximately 358 Gb (table 4). They are, with a high degree of certainty, rather much closer to 557 billion barrels than the 915 claimed. Combining this with the BP Statistical Review (2007) non-OPEC conventional oil reserves estimate of 293 Gb yields a global estimate of 850 billion barrels, well short of the 1208 assumed.

Table 4: Stated and Revised OPEC Member Reserves (Conventional oil and NGLs)

OPEC Country	OPEC 2006	Revised Assessment	Difference
Saudi Arabia	264.2	140	124.2
Kuwait	101.5	54.9	46.6
United Arab Emirates	97.8	55.1	42.7
Sub-total	**464**	**250**	**214**
Iran	136.3	combined estimate	combined estimate
Iraq	115		
Venezuela	80		
Sub-total	**313**	**169**	**144**
Sub-total OPEC-6	**777**	**419**	**358**
Total OPEC-12	**915**	**557**	**358**

The implications of this 358 billion barrel reserves shortfall for global forecasts of petroleum supply cannot be overstated. With cumulative consumption at 1110 Gb and reserves of 850 Gb, well over half our conventional oil reserves base has been consumed. An enormous and unlikely boost from large new discoveries and 'reserves growth' would be required if global conventional oil production is going to hold its current level for much longer.

5 Technology & Reserves Growth

In assessing the potential for reserve growth to increase world resource estimates, the USGS studied apparent field size increases over time in the mature oil producing regions of the United States and applied an observed 44% growth to worldwide remaining reserves and cumulative production.

This method firstly neglects the significant role that the US reporting environment had on perceived increases. As production and field development proceeds, publicly stated proven reserves are necessarily revised upwards, towards the initial 'proved plus probable' estimate. The real average increase in P50 reserves is therefore significantly lower than 44%.

Secondly, the manner in which oil fields are developed now bears no comparison to the early days of the US industry and leaves a lot less to gain. This difference has arisen largely because North American (USA and Canada) mineral rights are vested in the landowner, while almost everywhere else in the world they are vested in the Government. Since the 1970's, and in contrast to early North American experience, new fields have generally been unitized and fully delineated, with secondary recovery in place where appropriate from day one.

As a result of this fundamental difference in ownership and approach it is quite inappropriate to apply this reserve growth experience to non-North American reserves. Development of deep water and smaller fields has only strengthened this trend towards optimized recovery from early in field life. Consequently, there has been relatively little reserves growth observed in the last decade.

The third significant fault in the USGS method was to indiscriminately apply a reserve growth figure to all current reserves and cumulative production. Several categories of fields can be identified where this is not appropriate:

- the large fraction of fields, where secondary recovery facilities are in operation or strong natural pressure support is present. Future reserves increments are the additional contribution that could be achieved by tertiary recovery.
- those fields where tertiary recovery mechanisms are already operating. Prospects for further reserve growth in this category are limited.
- fields at or near the end of their producing lives, especially those decommissioned or de-pressurized in a switch to gas production. Isolated fields may be successfully redeveloped but average increase in reserves will be low.
- gas/condensate fields where confidence in ultimate liquid production is higher and possibilities for enhanced recovery are generally limited to lowering wellhead pressure.

Using these categories, a new estimate of potential reserve growth is presented in Table 5. These are theoretical gains that may not all be realized, even over a period of several decades. It is necessarily an approximate estimate but dramatically improves on the simple (and probably inappropriate) extrapolation used by the USGS. Furthermore, their estimate of 730 billion barrels of reserve growth over the thirty year study period describes an annual reserves increase of 2.5%. Internal company estimates of annual growth in field reserves are closer to 0.2%. The USGS result is ten times higher than that used within the industry and must be called into question.

Table 5: Assessment of Reserve Growth
(conventional oil and NGLs, billion barrels)

Field Category	Maturity of Reserves Estimates	Potential for Reserve Gains	Average Reserve Growth	Cumulative Production & Reserves	Potential Reserve Growth
Not yet in production *eg Kashagan*	Very Low	High	33%	150	**50**
Primary recovery only[a]	Low	High	25%	310	**80**
Secondary recovery active[b,c] *eg Ghawar*	High	Moderate	10%	900	**90**
Tertiary recovery active *eg Cantarell*	Very High	Limited	5%	200	**10**
Near or at end of field life *eg Brent*	Very High	Limited	5%	400	**20**
Total				**1960 Gb**	**250 Gb**

a) Primary recovery is often used for initial field production, with pressure maintenance applied once sufficient field experience has been accumulated. Effectively, most fields move from primary recovery to secondary recovery (where required) within a few years of start-up.
b) This category includes fields where aquifer support achieves strong pressure maintenance, eg. Burgan, Kuwait.
c) Gas/condensate fields are assumed to have potential liquids reserves growth of 10% on average and are therefore included in the same category as fields with secondary recovery.

6 Conventional Oil Resources

Revised estimates for discovery, reserves and reserves growth of conventional oil from the previous sections are presented in Table 6. This can be contrasted with that of the USGS assessment in Table 1. At the end of 2006 the world had consumed just 33% of the USGS 3345 billion barrel resource estimate. However, even their optimistic estimate is insufficient to provide for another twenty years of expanding production.

Table 6: Assessment of Conventional Oil Resources (conventional oil and NGLs, end 2006)

Category	Billion Barrels
Cumulative Production	1110[a]
Remaining Reserves	850[b]
Reserves Growth	250
Undiscovered	200
Total	**2410**
Remaining	**1300 (54%)**

a) Jackson, Cambridge Energy Research Associates (2007)
b) BP Statistical Review (OPEC-12: 915, subtract 358 overstated =557; non-OPEC:293).

According to this revised assessment, the world has in fact consumed 46% of a resource of 2410 billion barrels of crude oil and natural gas liquids. Being nearly halfway through our conventional oil resource, there is very little scope for production to expand. It is not surprising that attention turns to the prospects for production from unconventional sources.

7 Unconventional Oil

Historical expectations about the rate at which conventional oil reserves can be turned into production do not hold for large unconventional oil resources. Reporting the two collectively also obscures alarming trends that would otherwise be apparent in the category of conventional oil reserves.

The highly respected energy advisor Wood Mackenzie (2007) expects Canadian tar sands production to reach 4 million barrels per day by 2020. With a slightly lower 3.3mn b/d day target for tar sands, the Oxford Institute of Energy Studies (2005), among other industry observers, forecast all unconventional oil production to reach 6.5 million barrels per day by 2020 (fig. 6). This is well short of the 25 million barrels per day that high end forecasters Cambridge Energy Research Associates (2007) predict in the same time frame.

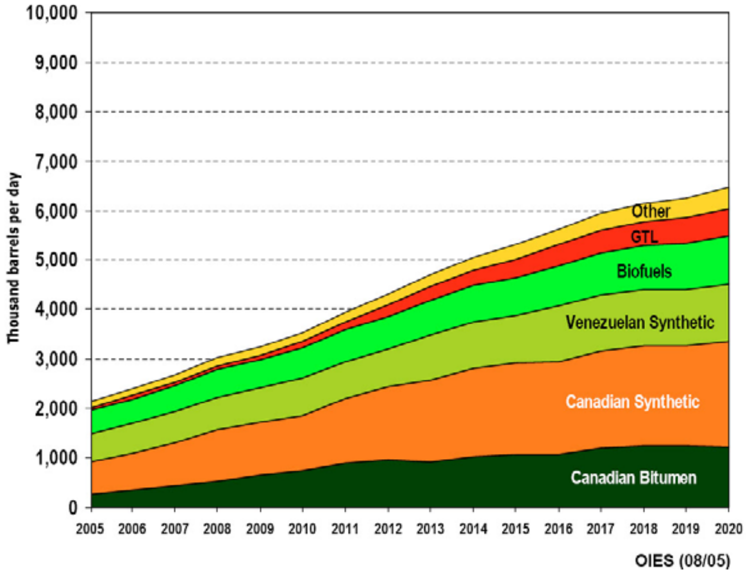


Figure 6: Unconventional Oil Production Forecast

Capital and operating costs continue to rise and projects have been delayed and even shelved as a result. Production is falling behind previous forecasts. Concerns about the demand for water and gas and impact on the local environment are all constraining further growth. Unconventional oil production will continue to expand, but there are significant downside risks. High-end forecasts are unlikely to be met.

8 Depletion

With hindsight, it is clear that the oil industry in America in the early 1970's and the North Sea in the late 90's failed to anticipate their respective production peaks because they under-estimated the role of depleting mature oil fields in dragging down net production. Naturally enough, the industry and media focus on the positive news; field development and discoveries, new technologies and moves to extract unconventional resources.

But every year, with no threat of delays or cost overruns, depletion eats away at the potential of every producing field. When the balance between these two shifts in favor of depletion, peak oil will have past. Reporting only on the positive news reduces our ability to anticipate this peak. In Figure 7, the Energy Information Administration (2006) illustrate this balance between countries where production is expanding against just some of those where production is already in outright decline.

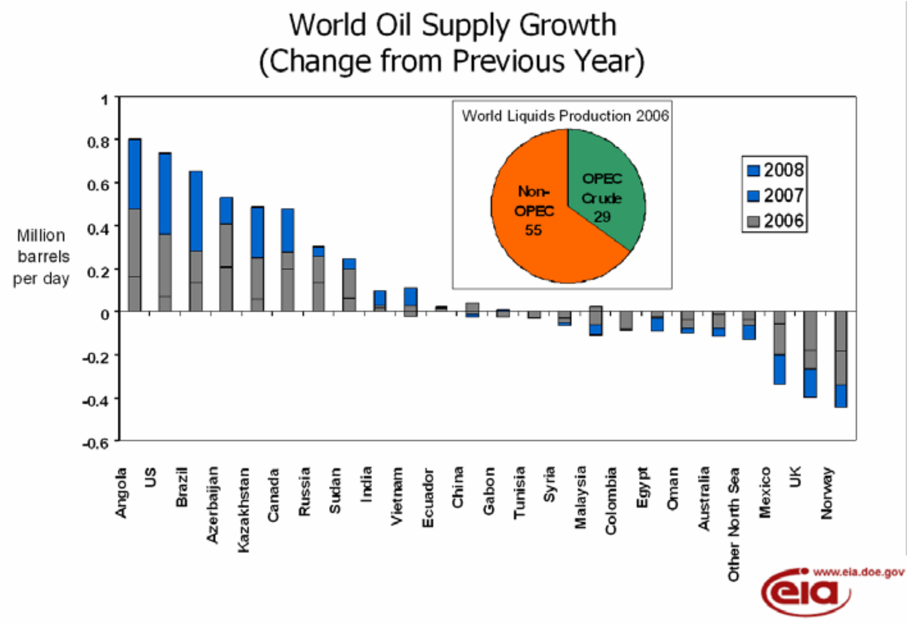


Figure 7: Balance between countries with expanding and declining production

The Megaprojects report from Skrebowski (2007) identifies projects with a total capacity of 3.2mn b/d that were expected on stream in 2006 (including unconventional oil). This is split roughly equally as 1.6mn b/d each from OPEC and non-OPEC producers.

For non-OPEC countries, the production gain recorded by the EIA was 300,000 b/d in 2006. This means non-OPEC producers lost 1.3mn b/d to depletion last year; despite intensive efforts, production from mature fields suffered substantial declines.

OPEC producers recorded an annual decline of nearly 500,000 b/d in 2006. This can only partly be accounted for by quota cuts planned for the last two months of the year. Either OPEC producers chose to withhold production through a period of strong demand and sustained high prices, or depletion is running at least equally high in OPEC as in the rest of the world. The earlier analysis of the Ghawar and Abqaiq fields suggests the latter is more likely.

The world picture then is that crude oil and condensate production fell 200,000 b/d compared to 2005. Growth in Natural Gas Liquids and other liquids was just able to hold total supply flat.

Despite a historically high level of industry activity, it looks increasingly clear that new capacity and ongoing field development work is now barely sufficient to offset depletion. Capacity constraints leading to project delays are unlikely to ease in the short-term. The sort of increased production flows the world needs to underpin economic growth may no longer be possible.

9 Conclusion

Peak oil presents a profound challenge; one completely at odds with demand based forecasts of growth in energy consumption, such as those provided by the EIA (fig. 8). The poor standard of fundamental information relating to reserves and future production makes it easy to deny or obfuscate the likelihood of a near-term peak in global oil production. This situation needs to be improved with mandated international requirements for transparent reporting of oil reserves and field level production statistics.

The low level of new discoveries limits the extent to which the industry can continue delivering a high level of new capacity. Meanwhile, there is a real danger that decline rates in mature regions will continue to increase. The balance between these two may tip in favor of depletion sooner than expected. That conventional crude oil production was lower in 2006 than the previous year, despite intensive industry efforts, provides strong evidence for this view.

As Hirsch *et al* (2004) have noted, preparing for peak oil requires two decades of intensive, government coordinated effort. This paper signals that beginning those urgent efforts now to address the problem would be prudent.

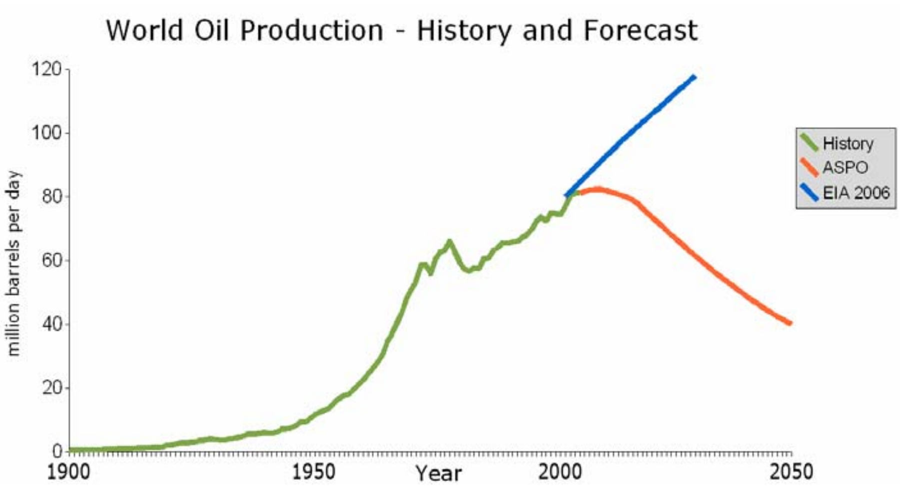


Figure 8: Diverging forecasts for World Oil Production

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