ELSEVIER

Energy Policy 35 (2007) 6364–6382

ENERGY POLICY

www.elsevier.com/locate/enpol

Assessing the date of the global oil peak: The need to use 2P reserves

R.W. Bentley[a,*], S.A. Mannan[b], S.J. Wheeler[b]

[a]Department of Cybernetics, The University of Reading, Reading RG6 6AY, UK
[b]c/o Department of Engineering, The University of Reading, Reading RG6 6AY, UK

Received 18 December 2006; accepted 6 August 2007
Available online 18 September 2007

Abstract

Combining geological knowledge with proved plus probable ('2P') oil discovery data indicates that over 60 countries are now past their resource-limited peak of conventional oil production. The data show that the global peak of conventional oil production is close.

Many analysts who rely only on proved ('1P') oil reserves data draw a very different conclusion. But proved oil reserves contain no information about the true size of discoveries, being variously under-reported, over-reported and not reported. Reliance on 1P data has led to a number of misconceptions, including the notion that past oil forecasts were incorrect, that oil reserves grow very significantly due to technology gain, and that the global supply of oil is ensured provided sufficient investment is forthcoming to 'turn resources into reserves'. These misconceptions have been widely held, including within academia, governments, some oil companies, and organisations such as the IEA.

In addition to conventional oil, the world contains large quantities of non-conventional oil. Most current detailed models show that past the conventional oil peak the non-conventional oils are unlikely to come on-stream fast enough to offset conventional's decline. To determine the extent of future oil supply constraints calculations are required to determine fundamental *rate limits* for the production of non-conventional oils, as well as oil from gas, coal and biomass, and of oil substitution. Such assessments will need to examine technological readiness and lead-times, as well as rate constraints on investment, pollution, and net-energy return.

Keywords: Oil supply; Proved reserves; Probable reserves

1. Introduction

This paper sets out to counter the view expressed in a recent article in this journal: *Oil scarcity*: *What have the past three decades revealed*? (Watkins, 2006). It does this by setting out the two very different datasets generally used to examine the global depletion of conventional oil.[1] If one uses the proved plus probable (also called '2P') data held in industry datasets for measuring oil discovery, then these indicate that the *resource-limited* peak in the global production of conventional oil is imminent. But if *proved reserves* ('1P') data are used a very different picture emerges, one that supports a cohesive economic view ruling out any near-term threat to global oil supply. It is 1P data that were used in Watkins' paper.

Other topics covered below include a common 'economic view' of depletion, the extent of reserves growth, the correctness of past oil forecasts, factors affecting the date of the conventional oil peak, and the expected date of the conventional gas peak. The paper concludes by listing some of the problems raised by conventional oil and gas depletion that call for deeper analysis.

The discussion starts by examining the two very different oil reserves datasets.

2. Industry 2P oil discovery data

Industry data on the amount of oil discovered in individual fields are held by national and private oil companies; by data companies such as IHS Energy

*Corresponding author. Tel.: +44 118 378 6796; fax: +44 118 378 8220.
E-mail address: r.w.bentley@reading.ac.uk (R.W. Bentley).

[1]Conventional oil here includes all flowing oil from primary and secondary extraction, plus NGLs. Also included is oil from current or planned tertiary extraction. Excluded are very heavy oils (e.g., Orinoco), and oil from tar sand, shale, coal, gas, or biomass.

0301-4215/$ - see front matter
doi:10.1016/j.enpol.2007.08.001

(formerly Petroconsultants), Wood Mackenzie, Energyfiles, and PFC Energy; and by petroleum and mineral institutes such as Germany's BGR and France's IFP. Such data are not generally held by organisations such as the IEA, the US' EIA, or IIASA.

The estimated amount of oil recoverable from an oil field is usually held by oil companies as a range of values ranked by probability. But in the data companies' datasets, the size of a field is frequently held as just a single figure, representing the amount of oil judged likely to be extracted from the field over its life. This figure generally assumes no major change over time in the field's currently anticipated final recovery factor, and the number is often termed the field's 'proved plus probable' estimate. If this estimate changes then a new figure is stored for the field, and the data are said to be 'backdated', as this new value shows against the field's original discovery date.

Some analysts see these industry '2P' ultimately recoverable data as usually fairly close to true 'P50' (50% probable) estimates, those as likely to see a decrease as an increase over the lifetime of the field.

Combining 2P discovery data with geological knowledge indicates that about two-thirds of the world's oil-producing countries are now past their *resource-limited* peak of conventional oil production, and hence in terminal production decline (Energyfiles Ltd., 2006). Some are small producers, but Chevron (2005) reports that production is in decline in 33 of the world's 48 largest oil-producing countries (see also Campbell/Uppsala, 2005). Large countries past peak include the US, Iran, Libya, Indonesia, UK, and Norway. In addition, Russia is past its conventional oil mid-point if not technically past peak. 2P discovery data show that many more countries will soon go past peak, including major producers such as China and Mexico (see e.g., PFC Energy, 2005; Energyfiles Ltd., 2006; Campbell/Uppsala, 2005; Miller, 2004; Skrebowski, various dates).

Germany provides a good example of how 2P discovery data, coupled with geological knowledge, indicates that a country is past its *resource-limited* production peak of conventional oil.

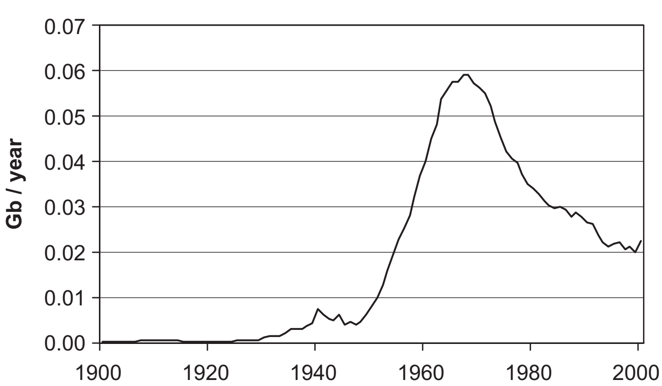

Fig. 1. Germany: Annual production of petroleum liquids (oil plus NGLs), 1900–2000. *Source*: IHS Energy.

Fig. 1 shows oil liquids production in Germany from 1900 to 2000. Production has clearly gone over some kind of peak, but maybe this was an artefact of economic conditions or government policy over this period. And maybe there are large amounts of new oil in Germany waiting to be discovered. Fig. 2 addresses these questions by adding the 2P annual discovery data. As can be seen, discovery controls production, and the peak was a direct result of the amount of oil that was found. If more oil had been found the peak would have been higher or later; if less it would have been lower or earlier. The same data are shown in Fig. 3, but with discovery plotted as a 5-year average to allow the eye to better judge how discovery has driven production.

Government policy can be an important factor, of course. German discovery might have been limited if exploration had been restricted for certain periods (as is the case for some countries), or in certain regions (as is the case with the US today). And production would have been affected if Germany had set pro-rationing in place, as in the US before 1970, or applied quotas such as OPECs. But the fundamentals apply: once the amount of discovered oil is

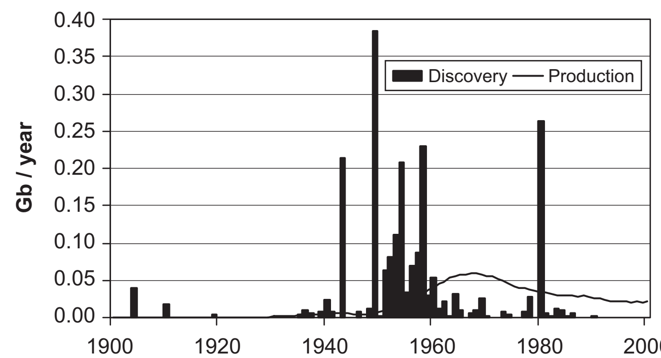

Fig. 2. Germany: Annual '2P' discovery and production of petroleum liquids (oil plus NGLs), 1900–2000. '2P' discovery shown by vertical bars, production by the line. The bars are set to be a 'full year' in width, so the area covered by the bars on the graph corresponds to total quantity of oil discovered. This quantity can be compared with the total volume of oil produced, indicated by the area under the line. *Source*: IHS Energy.

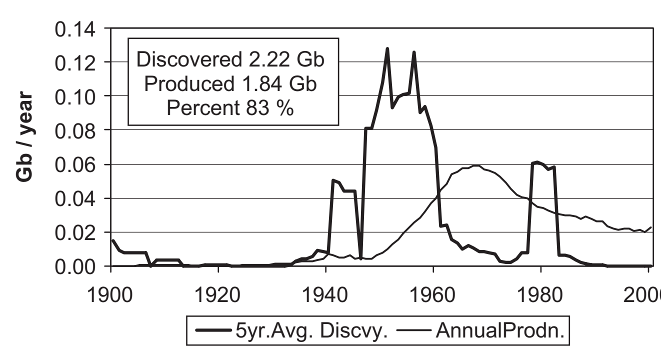

Fig. 3. Germany: Data same as in Fig. 2, but with '2P' discovery plotted as rolling 5-year average to allow the eye to better judge the connection between discovery and production. *Source*: IHS Energy.

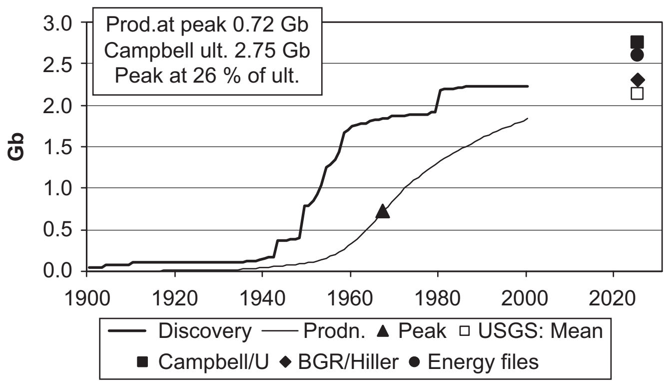

Fig. 4. Data same as in Fig. 2, but plotted on a cumulative basis. Estimates for Germany's conventional oil 'ultimates' are shown against the year 2025. This is notionally the year that applies to the USGS estimate, but in practice all four 'ultimates' probably refer to much later dates. Campbell/Uppsala exclude NGLs. USGS 'ultimate' is the mean estimate on a 'non-grown' basis. As USGS data sum only basins evaluated this total may exclude Germany's offshore. *Sources*: Discovery & Production: IHS Energy; 'Ultimates': see text.

known from the 2P data, an upper limit is also known for what can be produced and when.[2]

The question then remains as to whether Germany has much new oil to find. This can only be answered fully by combining the information from Germany's falling discovery trend with geological knowledge. The big finds of the 1940s and 1950s were due to the introduction of seismic data, while the large late find in 1980 was in Germany's rather small offshore area that became open for exploration. Fig. 4 shows the same data as previously, but on a cumulative basis. As can be seen, Germany's 2P cumulative discovery trend (its 'creaming curve') has been flattening out since about 1960.

Note that Fig. 4 is a 'creaming curve' vs. time. A more powerful curve is the true 'creaming curve', which plots cumulative discovery against number of exploration wells ('new field wildcats'). Such a curve removes from the discovery trend political difficulties in accessing a region, changes in tax regime and so on, and simply measures discovery volume against drilling effort. The curve's great strength therefore is its ability to allow a fairly reliable projection to be made of what is likely to be discovered in future vs. increasing exploration wells drilled.

Estimates for the total amount of recoverable oil in Germany potentially accessible by a fairly distant future date have been made by various geological groups. Such estimates are loosely termed 'ultimates' because they approximate the country's ultimately recoverable reserves. These estimates are best illustrated on a plot like Fig. 4, which here presents four estimates for Germany's 'ultimate' (where Gb is billion barrels):

- BGR's 1997 assessment of estimated ultimate recovery ('EUR'): 2.3 Gb (BGR, 1997);
- USGS' year-2000 median assessment on a 'non-grown' basis, incl. NGLs: 2.14 Gb (USGS, 2000);
- Campbell/University of Uppsala end-2004 model: 2.75 Gb (Campbell/Uppsala, 2005);
- Energyfiles end-2004 assessment: 2.6 Gb (Energyfiles, 2003 to date).

Note that some of these data (for example, Campbell/Uppsala) exclude NGLs. Moreover, three of the groups recognise that future extraction technology and policies are unknown, so specifically caution that their figures should not be seen as definitive estimates of 'true' ultimates (i.e. original endowments of recoverable conventional oil when extraction terminates). Instead the data refer to quantities of oil considered recoverable over reasonably long time spans. The USGS say they evaluate oil that will be available for discovery by 2025 (though there has been ambiguity reported around the meaning of this date). The Campbell/Uppsala model no longer lists ultimate, but 'total regular oil production to 2075' ('regular' oil here excludes polar, deepwater, very heavy oils and NGLs; in this model these latter oils are assessed separately, and summed in the production totals). Energyfiles quantifies oil that will have been produced by 2145. The BGR is the only organisation that uses the label 'estimated ultimate recovery', but probably would apply the same caveat as the others if asked.[3]

As Fig. 4 shows, the above 'ultimates' are in reasonable agreement with each other and with the apparent asymptote of the 2P discovery curve. The geologists are therefore pretty certain that no significant new quantities of oil will be found in Germany, where this reflects both geological knowledge and over a hundred years' of discovery effort and technological progress.

Like other regions of the world, Germany, despite having applied enhanced oil recovery (EOR) techniques since 1985, still has a considerable amount of oil judged currently unrecoverable in existing fields. However, barring some extraordinary new recovery technique, Germany is now close to the end of its conventional oil: at ~2.0 Gb Germany's total production to date has consumed about 80% of its recoverable original endowment.

So where do economics come into this picture? Economic factors are important, of course. A higher oil price encourages exploration, brings on economically marginal fields, permits more expensive recovery, and

[2] A simple model of oil peaking is given in Bentley (2002a) and a slightly more detailed one in Smith (2005).

[3] It was a surprise to both Ahlbrandt of the USGS and Campbell that their 'ultimates' turn out to be very close for many countries, though not particularly close here for Germany; (personal communications). The reason is simple. Their yet-to-find numbers can be quite dissimilar, with the USGS' 'general basin oiliness' yet-to-finds often being quite a bit larger than the Campbell/Uppsala combination of geological knowledge with extrapolation of creaming curves—'what the drill bit has found'. But as yet-to-finds are now quite small for nearly all countries, USGS and Campbell estimates of country 'ultimates' are usually quite similar, once 'non-regular' categories of oil are added back into the Campbell/Uppsala data.

reduces demand. But in a country well past peak the effects are small. More exploration just moves the country a bit further along the declining discovery trend; the economically marginal fields are known, and are usually small or difficult; more expensive recovery techniques can be identified and their impacts calculated. In general, though each country needs specific analysis, the ability of a higher oil price to significantly impact the geologically based estimates of ultimate is limited.

Another example of using 2P discovery data to predict production is the UK. As Fig. 5 shows, here also the 2P discovery data explain the subsequent production trend. But, as with Germany, knowing that that the UK's 1999 production peak was *resource-limited* depends on combining the UK's long-term falling discovery trend with geological knowledge.

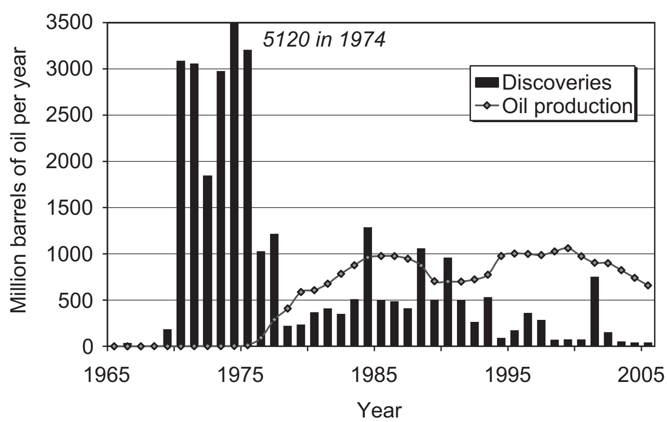

Fig. 5. UK: Annual '2P' discoveries and production. Includes NGLs. Note that 1974 discovery is off-scale. *Source*: Energyfiles Ltd.

The UK still has several significant future potential sources of oil. It may have quite large quantities still undiscovered in subtle stratigraphic traps; it may have significant new potential towards the deeper Atlantic; and it certainly has large amounts of oil in place that are currently deemed unrecoverable. But geological and reservoir/production knowledge says it is virtually certain that none of this oil, if it exists, can be found rapidly enough to push UK production back up past the 1999 peak. The subtle traps, even if they hold significant amounts of oil, will need highly calibrated seismic data to be found, and so will not be found rapidly; the deeper Atlantic will offer surprises but is not thought especially prospective due to poor source rock and traps, while the many routes to improved recovery in existing fields have already seen much trial and analysis. Overall, as with Germany, the UK's 2P discovery data coupled with geological knowledge indicates that the country's resource-limited conventional oil peak is past.

Fig. 6 gives the UK's cumulative plot and includes a UK government 'Brown Book' estimate of the 'ultimate' made back in 1974, plus more recent estimates from Campbell/Uppsala, USGS (mean, non-grown), and Energyfiles. As with Germany, these 'ultimates' are in reasonable agreement, and with the apparent asymptote of the discovery creaming curve. In translating these 'ultimates' into credible production profiles the UK's peak should have come as no surprise at all.

This again is not, however, to ignore the impact of price. The UK's large early offshore fields were discovered before

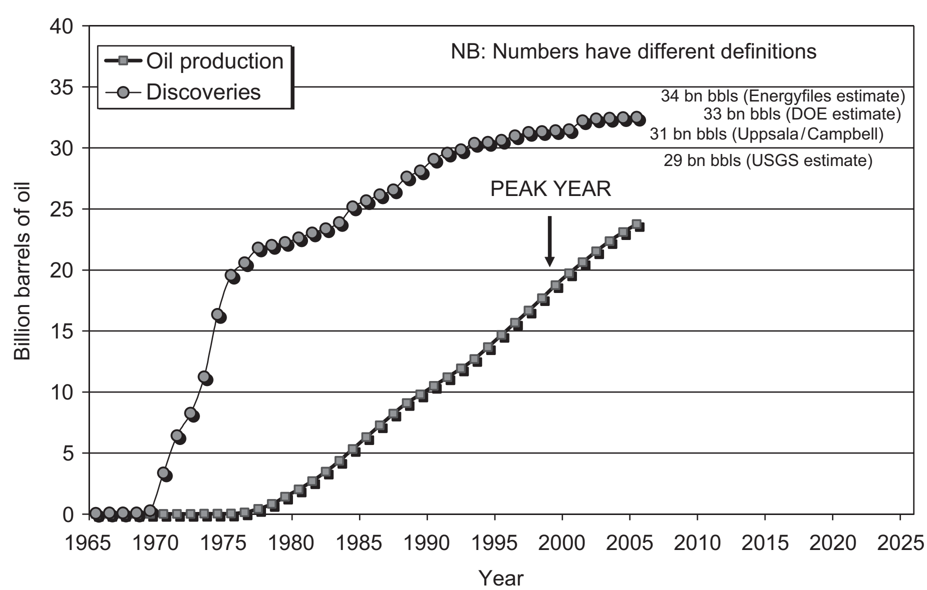

Fig. 6. Data same as in Fig. 5, but shown on a cumulative basis. Various estimates for the UK's conventional oil 'ultimate' are also shown. The UK Department of Energy's estimate ('DOE') is from 1974; the other estimates are recent. The Campbell/Uppsala and USGS estimates exclude NGLs (these add ~4.5 Gb). The USGS estimate also excludes UK's West of Shetlands basins. *Sources*: Discovery & Production: Energyfiles; 'Ultimates': see text. The reason that the UK Department of Energy's estimate made in 1974 for the UK 'ultimate' could be so accurate—before UK offshore production had even started—was that by 1974 most of the big fields had already been discovered, as Fig. 5 shows, such that the 2P discovery creaming curve plus geological understanding could give a reliable indication of the oil likely to be found.

the 1973 price shock, by which point the discovery trend had set in, and credible estimates of ultimate had become possible. But the speed of exploiting these finds, and hence production, would almost certainly have been less had the oil price remained low. For any given region the 2P discovery says what has been found, and the 2P creaming curve says what is likely to be found. Production profiles then set out the *maximum* likely rate that these fields can be produced. This information gives the *resource-limited* production rate for the region. It does not say that this production will actually be obtained, as politics, a low price, or other factors can always slow the production.

In terms of the impact of price, a recent detailed study by Kemp (2006) forecasts UK oil production out to 2035 under assumed prices of $25/bbl and $40/bbl. This price difference increases UK production, but does so fairly modestly, adding about 10% to the UK's cumulative production by the forecast's end. For reference, Energyfiles' forecast of UK production out to 2025 is given in Fig. 7.

Fig. 8 provides yet another example of how 2P discovery data predicts the resource limit to production, that of Egypt. Here the IEA notes: "Egypt's oil production has been in decline since it peaked at 980 kb/d in 1993, nearly one-third higher than today. This has occurred despite efforts to attract investment and to introduce measures such as enhanced oil recovery. Future oil finds are likely to be small-scale, insufficient to halt the overall decline in production." (IEA, 2005a).

Analyses of this type, combining 2P discovery data with geological knowledge, have been applied to all the world's oil-producing countries by a number of groups (e.g., Petroconsultants, 1995; BGR, 2002; Energyfiles reports, 2003 to date; Miller, 2004; Campbell, 2005; PFC Energy, 2005). As mentioned above, these studies show that about two-thirds of the world's oil-producing countries are now past their resource-limited conventional oil production peak.

As examples we have the following:

	Peak of 2P discovery	Peak of production
US	1930s	1971
Germany	1950s	1967
Egypt	1960s	1993
UK	1970s	1999
Norway	1970s	2001

A full list of discovery and production peak dates by country for 'regular oil' from the Campbell/Uppsala model is available at www.peakoil.net. In addition, a graphic of the 60 or so countries past their 'all liquids' peak, based on Energyfiles data, can be seen at www.lastoilshock.com/map.html, and an updated list can be purchased from the company.

Figs. 9 and 10 give the corresponding plots for the world as a whole. Fig. 9 shows that the world is living off its past exploration success, with the large finds from the 1940s to the 1970s being drawn down since about 1980, the historical turning point when global production began to exceed new-field 'non-grown' discovery. The cumulative plot of Fig. 10 shows that the world's consumption has reached about half of its discovery of conventional oil to date. This plot also shows how very high are some of the estimates of global 'ultimate', particularly the 'grown' estimates, when compared with the long-run global 2P discovery trend.

Such 2P discovery data coupled with geological knowledge can be used to predict the future of global conventional oil production. Calculations of this sort are included in the models listed in Section 6. These indicate that the global peak of conventional oil production is expected between about 2005 and 2015.

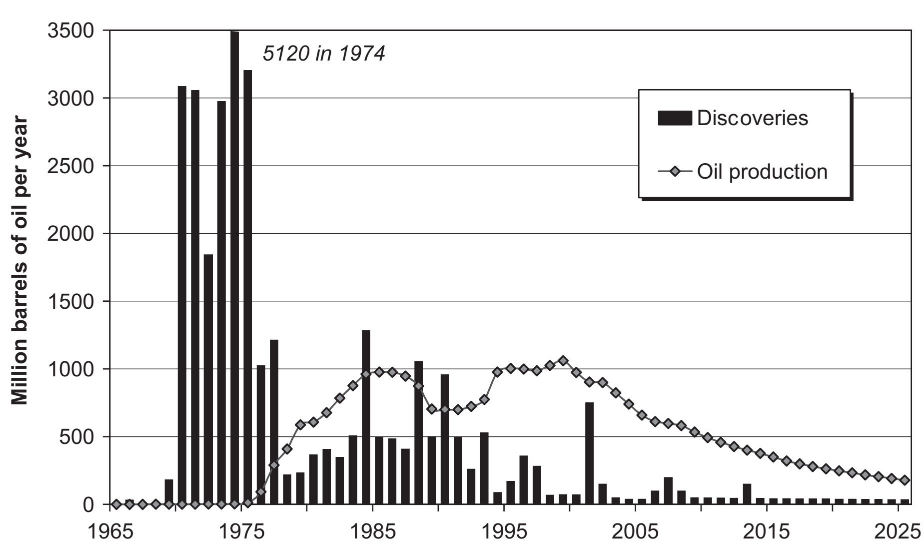

Fig. 7. Forecast for liquids production for the UK, including NGLs. Note the simplified assumptions for discoveries post-2005. *Source*: Energyfiles Ltd.

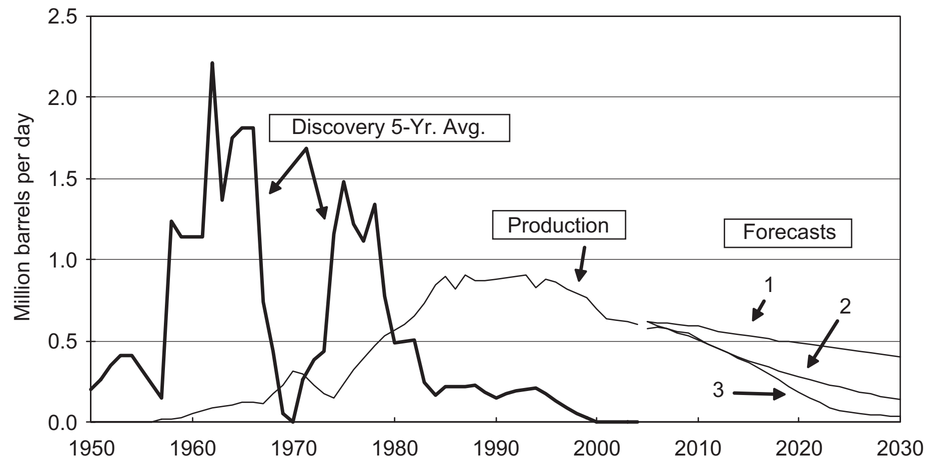

Fig. 8. Oil discovery and production data for Egypt. Discovery and production data are from PFC Energy public presentations. Discovery data are shown as a 5-year smoothed curve. Note that discovery has continued at a low rate beyond the data shown in this plot. The discovery data match reasonably those held in the IHS Energy 2000 'PEPS' database. Forecasts 1 and 3: IEA *World Energy Outlook*, 2005 data, ratioed down 12% to match PFC Energy 2004 production. N.B: IEA data include 'all oil', i.e. oil, NGLs and condensate. Forecast 3 is for production from existing fields and those awaiting development. Forecast 1 includes in addition the IEA's assessment of production from future reserves additions ('reserves growth') plus future discoveries. Forecast 2: Energyfiles Ltd. data, ratioed down by 17% to match PFC Energy 2004 production. This forecast includes Energyfiles' assessment of future discoveries.

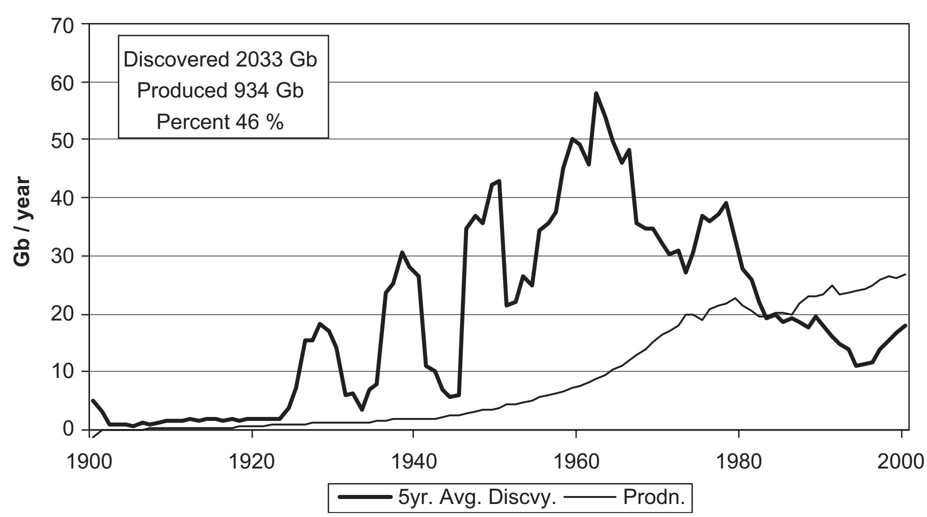

Fig. 9. World '2P' discovery and production of petroleum liquids (oil plus NGLs), 1900–2000. Discovery shown as a 5-year rolling average. Discovery prior to 1900 shown against 1900. *Source*: IHS Energy. For an updated version of this figure, giving annual discovery (which has fallen off significantly since the level shown here for the year 2000) see the latest *ASPO Newsletter* at www.peakoil.net.

2.1. Getting access to the aggregate 2P data

In the past, those who doubted the near-term conventional oil peak have complained—with at least some justification—that as they could not get to see the industry data, they could not judge the data's correctness, nor that of the conclusions drawn (e.g., Lynch, 2005).

'Proved plus probable' reserves data for *individual fields* are available from numerous industry and government sources. But the difficulty is of realistically assembling and assessing these often disparate field data to give credible country, regional, and world totals. Such totals are necessary if conclusions on overall discovery rate are to be drawn. It is for the onerous but vital task of assembling reliable 2P field data that the data companies, in part, get paid.

Full datasets by field from most data companies are expensive. IHS Energy's suite of world data plus analysis, for example, has an annual licence fee in excess of \$1 million. Fortunately much cheaper *aggregate* industry 2P data on oil discovery are available, and useful amounts of the 2P data, in various adjusted forms, are now also available in the public domain.

IHS Energy provides a global set of oil and gas 2P discovery and production data *by country* (rather than by field) that can be purchased for about \$5000; this is the resource part of their 'PEPS' dataset. The UK company Energyfiles is another good source for such data. They

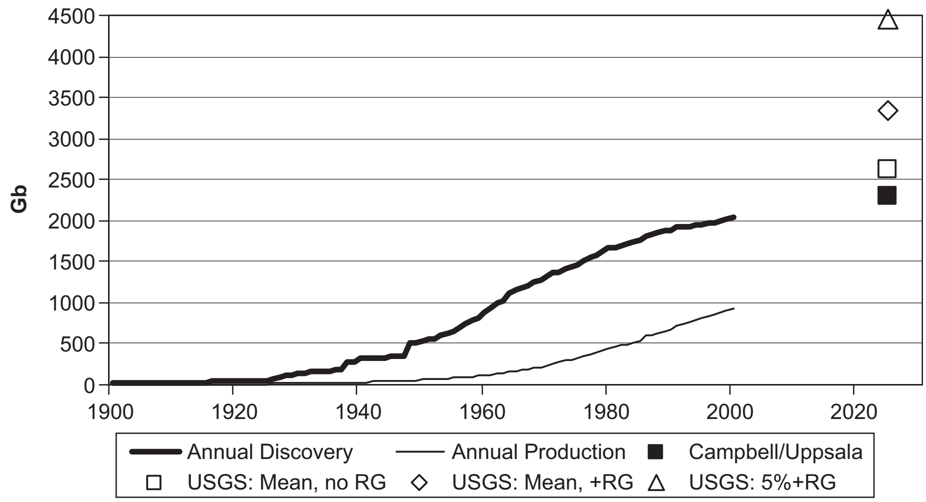

Fig. 10. Data same as in Fig. 9, but shown on a cumulative basis. Estimates for the world's conventional oil 'ultimates' are shown against the year 2025; see comments for Fig. 4. USGS 'ultimates' include NGLs; 'no RG' = assuming no reserves growth; '+RG' = including reserves growth; '5%' = estimate with 5% probability (high estimate). The Campbell/Uppsala ultimate shown here is their 'regular' oil 'ultimate' plus this paper's estimated additions for polar, deepwater, and heavy oils (but not tar sands, etc.), plus NGLs. Note that the big finds of Burgan (Kuwait, 1938) and Ghawar (Saudi Arabia, 1948) are visible on this plot. As the plot also shows, the global rate of 2P discovery has been in decline since the mid-1960s. Sources: Discovery & Production: IHS Energy; 'Ultimates': see text.

provide comprehensive data on an inexpensive basis and include forecasts of future production. Energyfiles' global report, including access to the underlying country descriptions and data, costs about $4000. Both datasets give invaluable information about the current state of global oil and gas depletion, and are within the budgets of most company research departments and academic groups.[4]

Though analysts can buy these data they are not allowed to publish results except with permission (as granted here for Figs. 1–10). By contrast, increasing amounts of aggregate 2P data are available in the public domain. Such data can be drawn from a variety of industry sources, and may be adjusted if the authors judge the underlying data to be over- or under-stated. Despite such adjustments, 'public-domain' aggregate 2P data are a key resource for the analysis of hydrocarbon depletion.

Such public-domain aggregate 2P data are available from the following:

- Data companies, in the form of publicity material. This information is generally sparse, but can be extremely valuable.[5]
- Some governments. Both the UK and Norway provide 2P data publicly via the web; and field data for the US Gulf of Mexico are available from the US' MMS.
- USGS assessments. The year-2000 assessment, for example, gives end-1995 2P reserves by country from the IHS Energy dataset (USGS, 2000).
- The IEA *World Energy Outlook*, 2005, which gives IHS Energy data for a limited number of Middle East and North African ('MENA') countries (IEA, 2005a). These data are however of key significance, see Table 1 below.
- A wide variety of publications by Jean Laherrère (various dates).[6]
- The Campbell/Uppsala model, available on the ASPO website: www.peakoil.net. The 2P reserves data here apply to 'regular' oil (i.e., exclude polar, deepwater, very heavy oils and NGLs), are based on a variety of sources, and are usually adjusted for perceived over- or under-reporting in the industry databases.
- Various books by Colin Campbell, and the monthly 'country analyses' in the *ASPO Newsletters*. These reflect the same data as in the Campbell/Uppsala model. Plots are provided of discovery vs. production, but as discovery is usually to its own scale the numbers need to be read off and re-plotted if graphs like Figs. 1–10 are to be generated. *ASPO Newsletters* to date have reported on 43 countries.

3. Proved reserves

3.1. The poor quality of proved reserves data

We now turn from the industry 2P data to the proved reserves ('1P') data. The latter are quite unusable for

[4]There are probably other companies that provide aggregate 2P discovery data relatively inexpensively. The authors are happy to add to the above list if additional data sources are made known to us.

[5]PFC Energy's publicly available plot of Egyptian oil 2P discovery and production, Fig. 8, contradicts Maugeri's contention (Maugeri, 2004) that Egypt disproves the Hubbert curve. PFC Energy data show that Egypt's graph is typical of countries past peak, with 2P discovery peaking first, and then production.

[6]Laherrère terms 2P data 'technical' or 'scout' data as they are technically based and are available from information-scouting companies such as Petroconsultants (now, IHS Energy).

Table 1
Proved reserves from BP's *Statistical review*, and '2P' reserves (Gb)

Year	UK	Norway	USA	FSU	China	UAE	Iran	Iraq	Kuwait	S.Arabia	Venez.
Proved ('1P') reserves											
1960			38.4	31.5			35.0	27.0	65.0	53.0	18.5
1965			39.4								
1966			39.8								
1967			40.0								
1968			39.3								
1969			37.8								
1970			46.7								
1971			45.4								
1972			43.1								
1973			41.8								
1974			40.6	83.4	25.0						
1975	16.0	7.0	38.9	80.4	20.0	32.2	64.5	34.3	71.2	151.8	17.7
1976	16.8	5.7	37.3	”	”	31.2	63.0	34.0	70.6	113.2	15.3
1977	19.0	6.0	35.5	75.0	”	32.4	62.0	34.5	70.1	153.1	18.2
1978	16.0	5.9	33.7	71.0	”	31.3	59.0	32.1	69.4	168.9	18.0
1979	15.4	5.8	32.7	67.0	”	29.4	58.0	31.0	68.5	166.5	17.9
1980	14.8	5.5	31.9	63.0	20.5	30.4	57.5	30.0	67.9	168.0	18.0
1981	14.8	7.6	36.5	”	19.9	32.2	57.0	29.7	67.7	167.9	20.3
1982	13.9	6.8	35.1	”	19.5	32.4	55.3	41.0	67.2	165.3	21.5
1983	13.2	7.7	34.5	”	19.1	31.8	51.0	43.0	66.7	168.9	24.9
1984	13.6	8.3	34.5	”	”	31.9	48.5	44.5	92.7	171.7	25.8
1985	13.0	10.9	35.9	61.0	18.4	32.4	47.9	44.1	”	171.5	25.6
1986	5.3	10.5	35.1	59.0	”	32.4	48.8	47.1	94.5	169.2	25.0
1987	5.2	14.8	35.4	”	”	96.2	92.9	100.0	”	169.6	56.3
1988	4.3	10.4	34.7	58.5	23.6	”	”	”	”	172.6	58.1
1989	3.8	11.6	33.6	58.4	24.0	98.1	”	”	97.1	257.6	58.5
1990	3.8	7.6	33.8	57.0	”	”	”	”	97.0	260.0	59.0
1991	4.0	7.6	33.7	”	”	”	”	”	96.5	260.3	59.1
1992	4.1	8.8	32.1	”	”	”	”	”	”	”	62.6
1993	4.6	9.3	31.2	”	”	”	”	”	”	261.2	63.3
1994	4.5	9.4	30.1	”	”	”	89.3	”	”	”	64.5
1995	4.3	8.4	29.9	”	”	”	88.2	”	”	”	”
1996	4.5	11.2	30.2	65.5	”	97.8	93.0	112.0	”	261.5	64.9
1997	5.0	10.4	29.8	65.4	”	”	”	112.5	”	”	71.7
1998	5.2	10.9	30.5	”	”	”	89.7	”	”	”	72.6
1999	5.2	10.8	28.9	”	”	”	”	”	”	263.5	”
2000	5.0	9.4	29.7	65.3	”	”	”	”	”	261.7	76.9
2001	4.9	9.4	30.4	65.4	”	”	”	”	”	261.8	77.7
2002	4.7	10.3	30.4	60[a]	18.3	”	”	”	”	”	77.8
2003	4.5	10.1	29.4	71.2	17.1	”	133.5	115.0	99.0	262.7	77.2
2004	4.5	9.7	29.4	72.3	”	”	132.5	”	”	”	”
2005	4.0	9.7	29.3	74.4	16.0	”	137.5	”	101.5	264.2	79.7
Proved plus probable ('2P') reserves											
USGS	9.7	13.5	–	151.6	24.5	57.2	71.3	77.6	54.3	214.9	29.6
C/U	9.3	13.9	~45	113.0	24.3	49.5	59.9	62.2	63.0	146.7	34.6
IEA						55.1		98.7	52.3	289	

Notes: Heavy line indicates step-change in reserves. Ditto mark (”) indicates value identical to previous year. UAE = Abu Dhabi. Dubai, Ras-al-Khaimah, Sharjah. Neutral Zone split between Kuwait and Saudi Arabia. Proved reserves are at year-end. Older US data: US 1950 $R/P = 13$ yrs; 1960 $R/P = 12$ yrs. Venezuela proved reserves includes some Orinoco oil. Note Saudi Arabia anomaly in 1976. Units: Gb.

[a] Russian Federation (changed from Former Soviet Union, FSU). 2P data: USGS: IHS Energy end-1995 'ultimately recoverable reserves' (URR) from USGS year-2000 Assessment. As noted in the text, IHS Energy does not hold 2P data for the US. C/U: End-2004 ~'2P' reserves as given in the Campbell/University of Uppsala model (see www.peakoil.net). IEA: IHS Energy data as given in IEA *World Energy Outlook 2005*.

calculating future oil production as they exhibit serious degrees of under-reporting, over-reporting, and non-reporting. In addition, if a probability is assigned to proved reserves, then it is generally misleading to add these reserves and assume the same probability for the aggregate.

Taken together, these problems with the 1P data have not been adequately recognised by much of the energy modelling community and have led to very significant errors in analysis.

3.1.1. Under-reporting

It has been known for a very long time that the proved reserves data for a field, a company, or a region are usually very conservative numbers. Proved reserves generally report only the oil that is *just about to be brought to market*, rather than reflecting *the total amount of oil that has been discovered*. (The latter quantity, as explained above, is tallied by the 2P numbers.) US' SEC rules define the restrictions for many oil companies on what proportion of their fields' remaining discovered oil can be included in the reported 1P reserves data.

Confusion between the 1P and 2P datasets is widespread, however, and has fuelled nearly every aspect of the oil depletion debate—as exemplified by Watkins' paper mentioned at the outset. The IEA, IIASA, and IFP, for example, have all published tables listing proved reserves alongside 2P reserves without any comment on the datasets' intrinsic differences, while both a fairly recent EU *Energy Security Green Paper* and a UK *Energy White Paper* have assumed naively that proved reserves provide meaningful estimates of the total remaining discovered oil.

BP's widely respected annual *Statistical Review of World Energy* makes the same mistake. It defines proved reserves as "…those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions". This is wide of the mark, as proved reserves usually report quantities of oil *well below* what can be recovered with reasonable certainty under existing conditions.

Some examples will illustrate this point.

For the past 20 years the UK's proved reserves have hovered consistently around 4–5 Gb, see Table 1. By stark contrast, the industry data for the UK's 2P reserves stood at 20 Gb in 1980 and have been falling steadily since. Today they stand at about 10 Gb, still twice the proved reserves number.[7]

Norway is another example. In its early history the Norwegian Petroleum Directorate (NPD) calculated the country's reserves simply by totalling oil company submissions of SEC-defined proved reserves. But later the NPD realised that, with little in the way of new finds or improved recovery, the country had produced far more oil than the proved reserves could account for. The NPD switched in 1995 to reporting *all* categories of reserves, including 2P data and on up to the higher, less probable, estimates.

But the best example of the consistently conservative nature of proved reserves is the US. Here the reserves numbers have changed hardly at all for decades, staying broadly in the ~30–40 Gb range, with a slight peak after the reserves of Prudhoe Bay were included. Once again, the reason is because proved reserves do not report the *total* oil discovered, but simply that portion judged close to production under SEC rules. On a rolling basis, as the existing proved reserves were produced, the companies put in the investment and infrastructure needed, and gained the permissions, to bring the next tranches of discovered oil close to market, and hence within the SEC definition. As a consequence, the US R/P ratio has also stayed virtually constant over the period, at around 10 years.

Note that for the US, IHS Energy does not hold 2P data. The company generates 2P reserves for other countries by totalling its 2P field discovery data and subtracting cumulative production. But for the US they add cumulative production to *published proved* reserves, to generate what in effect are 'proved discovery' data. This difference is clear when a cumulative plot like Fig. 4 is generated for the US. For nearly all other countries the backdated cumulative 2P discovery in such a plot shows a steep rise resulting from large early finds. In the US the 'proved discovery' curve simply stays just ahead of production—by the R/P ratio of about 10 years—for virtually the whole of the more than 100 years' of data.

Laherrère points out, however, that US 'proved and probable' data are available up to 1988 in the US DoE/EIA-0534 1990 report, where for more recent discoveries, which by volume are mostly offshore, the fairly mild MMS three-fold growth factor can be applied.

In summary, *proved reserves* for a field, a company, or a region are usually significantly under-reported when compared with the actual quantity of discovered oil remaining. Table 1 compares 2P reserves data from industry sources with proved reserves. As can be seen, the UK, Norway, US, FSU, and China are all 'normal' countries, i.e., countries where 2P reserves are larger than the proved reserves.

3.1.2. Over-reporting

A second serious problem with the proved reserves data is the opposite of the above. For the main Middle East OPEC countries, their 2P reserves data held by industry are considerably *smaller* than their public domain proved reserves. This anomaly was due to the 'quota wars' increases of the late 1980s, where allowable production under OPEC's quota was driven in part by the size of a country's reported proved reserves. As Table 1 shows, the changes adopted by the countries were dramatic, doubling proved reserves overnight in a number of countries and

[7] Table 1 shows the dramatic fall in apparent UK reserves in 1986, when proved reserves were reported by the BP *Statistical Review* instead of the 'proved plus probable' reserves. The table also shows that this more realistic estimate of reserves (though probably still not all-field 2P data) stood at 19 Gb in 1977.

trebling them in the case of Abu Dhabi. In total, the increases added 300 Gb to global proved reserves. Not surprisingly, Laherrère calls the proved reserves in these countries 'political' data. Companies whose data on Middle East OPEC 2P reserves are considerably *below* the corresponding published proved reserves include IHS Energy, PFC Energy, and Energyfiles.[8]

A number of analysts, apparently unaware of the reason for the OPEC increases in proved reserves, interpreted these as representing genuine recent additions to the global oil supply, either from discoveries or from revisions. In 1997, at a key IEA meeting, Laherrère and Campbell gave presentations about global oil peaking based on 2P data. Odell then said: "Now let's use some real data" and put up the global proved reserves data from DeGolyer and MacNaughton (see ⟨www.demac.com⟩). Because this sequence of reserves included the 'quota wars' jumps, the increase in proved reserves over the period was greater than the global cumulative production. From this, Odell concluded that the world was "running into oil". The same analysis has been presented by others, including BP's Davies (Davies and Weston, 2000).

Table 1 includes the 2P data for the OPEC countries where these reserves are smaller than their proved reserves.

3.1.3. Non-reporting

The third problem with proved reserves, and now perhaps the most serious, is non-reporting. Each year in recent years, proved reserves for the majority of countries have not changed, with these static data sometimes running for a decade or more, see Table 1.

Odell suggested that these static data indicated countries where discovery plus revisions had coincidentally matched production for the years in question (private communication). Given the exactness of reserves that repeat, and the number of occasions involved, this explanation is infeasible. Enquiries some years back to the *Oil and Gas Journal* and *World Oil* (private communications) indicated that the static data were generated when the countries in question had either not replied to the survey forms sent out, in which case the journals published the prior year data, or had returned forms identical to the prior year.

3.1.4. Statistical addition

The final major problem with proved reserves relates to their addition. If a probability is assigned to proved reserves, such as 90% approximately, then it is incorrect—and can be very misleading—to add these reserves and assume that the same probability applies to the aggregate. Only adding via the underlying probability distribution, either analytically or via a Monte Carlo method, can give the correct result.

Overall, the key idea to retain about proved reserves is that for the majority of countries in the world, and especially the large producers, the data have no bearing at all on the quantity of recoverable discovered oil that remains to be extracted.

3.2. Determining the date of peak from proved reserves data

Not surprisingly, the date at which a country will go over its production peak cannot be determined simply from its proved reserves data; additional analysis is needed as set out in Section 5.1. As Table 1 shows, none of the US 1971, UK 1999, or Norway 2001 peaks can be deduced simply from the proved reserves data. This is because leading up to the peak, and likewise following, the proved reserves stay at roughly the same level.

Despite these data making clear that proved reserves give no direct information about peak, it was said by one of the 'running into oil' protagonists that there could be no credence to oil peaking until there had been several years' fall in world's proved reserves. This view is not sensible. The date at which data-driven analysis of peaking could be undertaken first was when sufficient regions (primarily US states) were past the peak for the mechanism of peaking to become clear. Analysis of this sort was carried out by Hubbert in the 1940s. Confidence about the predicted date of global peak became fairly solid in the 1970s, once global 2P discovery was on the decline and its trend clear. The date at which rational planning for global decline should probably have started was in the 1980s, once the 2P reserves began to fall.[9] For most regions, waiting until

[8]Campbell's speculation on these 'quota wars' increases may be revealing. He notes that:

- Kuwait's proved reserves (excluding the Neutral Zone) at the end of 1983 were 64 Gb, by which date she had produced a total of 22 Gb of oil. In 1984, her reserves jumped to an exact 90 Gb. This therefore looks like approximately the *total* of oil she had discovered (i.e., reserves plus cumulative production). As oil prices were low at the time, this increase allowed Kuwait to increase her production quota within OPEC.
- Kuwait increased her reserves again slightly, to 91.9 Gb, in 1986, and it may have been this second increase that triggered some of the other OPEC countries to follow suit the following year. Abu Dhabi went 0.3 Gb higher to 92.2 Gb; Iran an exact 1 Gb higher (to 92.9 Gb); and Iraq to a well-rounded 100.0 Gb. Venezuela, who at least had some genuine Orinoco oil to include, roughly doubled her reserves to 56.3 Gb.
- Saudi Arabia held reserves steady over this period, but, to maintain quota, was herself forced into an increase 2 years later. This increase, to 255 Gb, again in Campbell's estimation, reflects roughly the *total* discovered oil, i.e., reserves plus cumulative production.

If these speculations are correct, then the consequences for global production are severe.

[9]Fortunately many useful steps *were* taken in the 1970s and 1980s: significant research was started on energy efficiency (smaller US cars, for example); on alternative hydrocarbons such as shale; and on a wide range of renewable energies. Humankind is lucky that this knowledge is now available. On the other hand, more could have been done. The US SERI report under Denis Hayes (Kelly, 1981) following the 1970s oil shocks pointed out that if the US took a set of sensible energy-supply and energy-saving decisions it could wean itself off imported oil by about 2000. Continuing with imported oil has probably been the cheaper near-term

proved reserves start to decline is to wait until the peak is long past.

3.3. Misleading conclusions from using proved reserves data

Does it matter that proved reserves have been reported conservatively?

It has mattered a great deal, and is the prime reason that the oil depletion debate is taking place at all. What looks at first blush like a staid and respectable policy on reserves reporting has had serious side-effects.

Most of these have resulted from the mistaken belief that proved reserves are a reasonable measure of the oil remaining at a given date. For example, in the 1970s many believed that the world would 'run out of oil' in about 30 years, as it had 30 years' of proved reserves left. Today, with 40 years' of proved reserves remaining, the impression widely held is that oil forecasting is therefore unreliable. The real explanation, that the 1970s' proved reserves data simply took no account of the known probable oil, nor of the yet-to-find, is still largely unrecognised.

For the same reasons it has become accepted that it is difficult to measure the amount of oil in a reservoir. In fact the oil-in-place in structures is usually known quite accurately, especially if quoted statistically across a range of related fields, while the predicted recovery factor of a specific method today is also usually broadly correct. For large fields today, the assessed quantity of recoverable oil is an output of detailed finite-element modelling.

As another example, the observation that reserves are frequently replaced without significant new discoveries is widely explained by the likes of the IEA or the UK's DTI as being due to advances in technology, including directional drilling and 3-D seismic knowledge. The IEA's use of a graph showing an apparent three-fold increase in the amount of oil in the North Sea between that deriving from 1986's 'proven technology' and from 1999's 'new technology' is one such example (IEA, 2005b). The graph shows '1986's proven technologies' as recovering ~22 Gb, whereas all technologies to 1999 recover ~66 Gb.[10] These numbers were almost certainly generated by adding 1986 North Sea cumulative production to 1986 *proved* reserves (see data for the UK and Norway in Table 1), and likewise for 1999. But by 1986 all of Europe's large oil fields had been found (see national data, or, e.g., the figure on p. 390 of Campbell (2005)), and examination by the USGS, BP, and others of North Sea reserves growth in 'proved plus probable' reserves has shown nothing remotely approaching a three-fold increase, see Section 5.

Another example of the IEA being ill-informed on the nature of proved reserves is Fig. 1.8 in the same report. This gives the trend of global total proved reserves that corresponds to the data in Table 1. Despite this graph therefore compounding the effects of growth over time of conservative proved data with OPEC 'quota wars' increases and with many years of static data, the IEA concludes: "Technology may even unlock access to previously unrecoverable hydrocarbons. In fact the level of 'remaining reserves' of oil has been remarkably constant historically, in spite of the volumes extracted each successive year … The addition of new reserves has therefore roughly compensated for consumption." It is serious that so late in the day the IEA has not yet gained a proper understanding of the data it uses. Proved reserves say nothing about the true volumes discovered and no useful conclusions can be drawn by looking at their evolution. The IEA ought to have known this long ago.

Not surprisingly, a detailed examination of growth in *individual fields*, as carried out by Laherrère and others, shows that much of the apparent technology-driven growth is explained simply by conservative original reporting, either of proved reserves or of 'production engineering' estimates of proved plus probable reserves.

Another misleading outcome of conservative reserves reporting is that analysts such as Adelman maintain that the very long run of almost constant US proved reserves demonstrates that investment is the *primary determinant* of reserves. This view holds that investment can always turn 'resources into reserves', and that the size of the underlying resource is of no concern, being both 'unknown and unknowable'.

This viewpoint, as discussed earlier, has an element of truth. Under SEC rules it is investment—or at least the intention to commercialise—that brings already-discovered oil into the proved reserves category. Where the analysis falls down is in failing to recognise that the real size of the US reserves has long been known, and that their long-term decline is also well documented. To get at these real reserves the proved reserves have to be 'grown', as Hubbert had shown (Section 5.1). Hubbert showed, for example, that US Lower-48 'grown' discovery per foot drilled had declined inexorably since the 1930s. It is hard to imagine that anyone who has looked at this graph could think that the size of the underlying resource was not a key factor setting the shape of subsequent US production.

However, this 'resources into reserves' view is deeply embedded, and has recently had an extraordinary exemplar. The IEA's report with effectively this title (IEA, 2005b) correctly identified the large amounts of hydrocarbons in the world, but missed the significance of the peaking of conventional oil. The report concluded, for

(*footnote continued*)
option ("the wisdom of the market"), but there is a case to regret that this other route was not taken. By ignoring President Carter's "moral equivalent of war", the economic significance of the Middle East helped set the context for two real wars, while the presence of foreign troops in Saudi Arabia was one factor in the rise of terrorism. The costs of imported oil can be high.

[10]The source given is the European Network for Research in Geo-Energy, courtesy of Shell. This IEA graph is very similar to one published by the IEA in 2002 that had been produced by a UK consultancy for an EU report, using IFP input for the data (presumably simply with the IFP supplying standard proved reserves data). That none of these participants distinguished between proved and proved and probable reserves in generating or using the graph is telling.

example, that: " … none of this [peak oil discussion] is a cause for concern. Hydrocarbon resources around the world are abundant, and will easily fuel the world through its transition to a sustainable energy future. What is badly needed, however, is capital investment …"[11] The report does refer to decline in existing fields, and notes that: "Most [non Middle East OPEC] countries have passed their peaks in conventional oil production, or will do so shortly." It also has a section ('Box 2', pp. 38–39) on peak oil, but concludes that "discussion of these [peak oil] questions is outside the scope of this [report]".

It is useful that the IEA is now looking at aspects of the total oil resource, but omission of the conventional oil peak is a serious oversight. This is especially so given the efforts of many well-informed people to encourage the IEA towards an understanding of peaking, including its own former staff (Wigley, Miller and Bourdaire) and outside organisations. Until the IEA achieves solid comprehension of the issue, there is little chance of cohesive multi-national action on the oil supply problems that peaking is likely to bring.

The fundamental reason for the IEA's lack of understanding of the oil-peaking mechanism is almost certainly due to the evolution of an 'economic view' of oil supply, as explained next.

4. An 'economic view' of oil supply

The broad set of misunderstandings described above, driven largely by treating proved reserves as a useful measure of remaining oil, fed into a cohesive 'economic view' on oil supply. This view is summarised in the Appendix. Its main tenets are as follows:

- Price, investment and technology are the main drivers of supply, not resources.
- Past forecasts failed because they assumed the resource base to be fixed.
- Should supply difficulties be approaching, they will be signalled by rising price (the lack of such a signal was one of the main arguments in Watkins' paper) and by falling proved reserves.
- Any supply difficulties that may occur will be most efficiently corrected by the market—short-run increases in price will limit demand and bring on adequate new supplies.

Those who hold this view see it as having been solidly corroborated by history:

- The 1970s' price shocks turned out to be simply political, and were not driven by resource shortage as was widely believed at the time (again, see Watkins' paper).
- OPEC did not remain in the driving seat, and the oil price did not continue to escalate as many had forecast. Instead the higher prices brought in competing sources of oil, and the price fell.
- Despite recurrent predictions of shortage, proved reserves have consistently been replaced.

History in fact tells a very different story:

- The 1970s' shocks were driven fundamentally by the US peak, but no authoritative body at the time thought that oil exhaustion was close. It was widely documented that the peak (not *exhaustion*) would not occur before about 2000 (see Section 6, below).[12]
- With the world still on the up-side of the Hubbert curve, excess production was indeed likely that would limit OPEC's power for a time. Importantly, much of this new oil (Alaska, North Sea, new Mexican fields, and so on) had been found *before* the oil shocks (not after, as even a former chairman of Shell commented).
- As already discussed, proved reserves replacement gives almost no information about real reserves, nor about future supply.

However, such is the academic standing of this 'economic view', and its degree of apparent support by history, that it has held almost complete sway within the world's oil companies, at oil conferences, and in the corridors of power now for about the last 20 years. Moreover, this view removed the need for any quantitative analysis of depletion, so over most of this period there have been extraordinarily few analysts—certainly fewer than 10 in total worldwide, across all of industry, academia, government and independent—who were quantitatively

[11]The report's key charts on the size of the various resources (Figs. ES.1 and 1.5) may be on the optimistic side. OPEC Middle East reserves at about 1100 Gb, including technological progress, may be based on working from the current proved data, rather than the smaller 2P reserves. A total conventional oil-in-place of about 6000 Gb may result from assuming a 35% global recovery factor, whereas Laherrère indicates that this is probably nearer 50% on a volume basis. Hydrates are still far from a known quantity, they may well disappoint. Overall, however, these data are fairly reasonable; the world is blessed with large resources of hydrocarbons. For other estimates on global quantities of hydrocarbons see e.g., Hubbert's papers; Perrodon et al. (1998); Harper (1999); Bentley (2002a); and energy textbooks.

[12]The influence of the US peak on the 1970s' shocks is often not recognised, despite the underlying facts being well documented (see, for example, D. Yergin's *The Prize* (Yergin, 1991)). In the early 1970s, 90% of the world's oil came from just three regions: the US, Russia, and OPEC, with Russian oil largely dedicated to the Communist Bloc. Prior to the US peak, OPEC had several times tried cutbacks to force an increase in what it felt to be an unfairly low price for its 'once-for-all' endowment, but each time the US raised its pro-rationing allowances to compensate. However, post the US peak, this option was no longer possible, and OPEC was in the driving seat. When political upsets (the Yom Kippur war, and later the Iranian revolution) triggered cutbacks, global shortages resulted. Note that for the degree of this connection between the US peak and the 1970s' shocks to be quantified, the size of OPEC cutbacks and the spare capacity in US pro-rationing need to be examined. In terms of understanding the 1970s' shocks, it is worth recalling that though the world still had large amounts of conventional oil in the ground, and a large non-conventional resource, this could not prevent the shocks. As today, the constraint was *rate of supply*, not total resource.

examining the production limits set by the size of world's recoverable resources of conventional hydrocarbon.

Also, as a result of the dominance of this 'economic view', any modelling over this period that was resources-based and that did not explicitly include the effects of price and technology was dismissed out-of-hand by the economists. In return, the many studies by the economists where the resource base was treated as effectively infinite—only the demand needed modelling—were dismissed by the geologists. For about 20 years there has been almost complete lack of dialogue between these two groups when assessing future global hydrocarbon supply.

One fairly recent high-profile example of the 'economic view' was in a *Newsweek* special issue on energy, April 8–15, 2002. Here the opening article contains many misunderstandings, mostly down to confusing 1P with 2P reserves. Doubting the Bush Administration's warning of the "worst energy-supply crisis since the 1970s", the article says, for example:

- We know there's a lot more oil worldwide now than in the 1970s. … surveys that once estimated total global reserves at 650 billion now find more than a trillion barrels.
- At present-day consumption rates, it looked in 1970 as if oil would run out in 33 years—that is, next year. This year, the same calculation puts the day of reckoning in 2046.
- In the US … extending the expected life of reserves [means that] … the threat of a shortage is receding …
- The US is also increasingly immune to oil shocks. In 1980, … the US spent 8% of GDP on oil, and the shock produced a deep recession. In 1999, prices spiked by a similar magnitude, but the US had cut oil costs to 3% of GDP, and many economists believe it's no accident that the recession was surprisingly mild. 'There's no question we're less vulnerable today' …

To end this section, a recent quote from BP's Chief Economist, Peter Davies, shows that this 'economic view' is alive and well. Davies (2004) has: "… the world has since produced 80% of the proved reserves of 1980—and we are still left with 70% more reserves than when we started—as a result of exploration successes and new technologies. … There is no global oil resource or reserve shortage. Oil production continues to be replaced-through a combination of new discoveries and extensions and additions." Though Davies makes no reference to conservative reporting of proved reserves as the primary reason for this apparent reserves replacement, he does elsewhere refer to peaking and to the OPEC late-1980s' increases, an advance on previous speeches.

5. Reserves growth

Reserves growth is a complex topic, and needs careful analysis. As used here, and generally, reserves growth refers to the increase over time in the reported original volume of recoverable oil in a specific field or group of fields.[13]

5.1. 'Reporting' reserves growth

Odell reported an average of nine-fold growth in field size over the total field life for Western Canadian fields (Bentley et al., 2000). In the US, six-fold field growth was used for on-shore fields and three-fold for offshore. Such very large growth factors were to be expected because of the conservative nature of proved reserves reporting. In particular, reserves growth was the norm under SEC rules for large fields as increasing portions of the original field were brought closer to market; for example, by being drilled up with additional production wells.

In the US in particular, the situation on reserves growth has historically been dogged by a range of problems, including multiple ownership of fields, initial technical ignorance of the real size of many of the early fields, and use of rules of thumb for field estimation, such as calculating size from field depletion on an assumed R/P ratio of 10! (Note that SEC rules recognise two categories of proved reserves: proved producing—estimated future production from current wells; proved undeveloped—estimated future production; from, e.g., yet-to-be-drilled infill locations.) Laherrère has plotted revisions to US proved reserves data, comparing the proportion of positive to negative revisions, and concludes that for both oil and gas the proved reserves are getting close to P40 (statistically equivalent to mean) numbers. In effect, the scope for US proved reserves to be revised upward by eating into 'proved and probable' reserves is coming to an end. It should not be forgotten, however, that added to these 'reporting issues' are real technology gains, although often from introducing water-flood and other now-standard technologies already factored in when estimating the ultimate yields of current fields.

By contrast, where proved reserves apply to *a group* of fields, other factors can also apply. In the case of the UK for example, much of the small size of the proved reserves was almost certainly due to exclusion of discovered fields that had not yet received government production sanction. As time moved on, such newer fields received sanction and were added to the proved reserves data, which therefore stayed roughly constant as the remaining reserves of the older fields declined through production.

Analysts like Hubbert recognised the need to 'grow' the proved reserves of fields if a realistic estimate was to be obtained of the amount of oil the fields would yield over their lifetime. One method used the historical sequences of proved reserves and production data to generate 'proved' discovery by year. These annual numbers were then

[13] The term 'field growth' is less ambiguous since 'reserves growth' is sometimes used—for example by PFC Energy—to mean an increase in a region's reserves *including* the discovery of new fields.

increased by the amounts that past experience has shown likely for fields of different ages, thus generating realistic 'grown' discovery data. Hubbert used such data in a number of powerful analyses, including the telling statistic on US discovery per foot drilled mentioned above. The latter showed that the US lower-48 'grown' discovery had peaked in the 1930s and fallen dramatically since.

5.2. 'Real' reserves growth

All the above refers to what might be called 'reporting' reserves growth. Of great interest also is technical or 'real' reserves growth, where a field yields more oil over time due to better knowledge of its reservoir, or the introduction of a technology that increases its recovery factor, such as waterflood or tertiary recovery. A higher oil price can of course contribute directly to such real reserves growth, by bringing in a procedure that was previously uneconomic for the field in question.

A key question is: How much real reserves growth do we expect in the industry 2P data?

Some analysts such as Campbell have expected little. After all, the 2P figure is supposed to be a good estimate for each field's ultimately recoverable reserves ('URR'), i.e., the amount of oil that will have been extracted when the field is finally shut in. In the IHS Energy database, these field URRs include the reasonable application of current and expected technology to the field. But globally the *theoretical scope* for recovery improvement is very large indeed, as averaged across all fields the world currently recovers only something like 50% by volume (about 35% vs. number of fields) of its total conventional oil-in-place.

In answering the question of how much real reserves growth to expect in 2P data, it must be recognised that, as mentioned earlier, much of industry 2P data, including those held by IHS Energy, are 'backdated', meaning that when the size of a field is revised the new information replaces the old. Since the database holds this information against the year that the field was discovered, the change appears as an increase to the world's discovery at that date. To see how the size of a specific field has changed, one therefore needs to access past database records for the field in question. Systematic studies of this type have been carried out for the North Sea and a few other regions, but more such studies are needed.

In general, therefore, real reserves growth in the industry data currently needs to be assessed by other means; for example by looking at plots of field production vs. cumulative production to see whether step changes appeared in the extrapolated URRs, or by considering the impact of specific changes in recovery technology. The oil company studies known to this author suggest fairly modest numbers for real reserves growth once secondary recovery is in place. However, this is also an area that merits more detailed research.

Finally, in examining real reserves growth, Laherrère (private communication) points out the importance of distinguishing reserves growth reported for most oil fields with that for fields from heavy oil. For example, the case of increased oil recoverable from the Midway-Sunset field is often quoted. But this field was discovered in 1894 and contains large quantities of heavy oil. Significant increases in recoverable oil for this field are not surprising given the use over the intervening century of improved methods for the extraction of this oil.

5.3. The USGS' perspective on reserves growth

In its year-2000 Assessment, the USGS included for the first time data on reserves growth, and these numbers have proved controversial, especially since bodies such as the IEA and the 'WETO' study group based their forecasts on the USGS estimates of global 'ultimate' that incorporated this reserves growth.

The primary aim of the periodic USGS global oil and gas assessments is to estimate the total amounts of oil "available for discovery" in specific basins over a realistic time period, and to sum these to country and regional totals. However, the USGS does at the same time generate estimates of 'ultimates' for countries, by adding the yet-to-find estimates to IHS Energy 2P reserves data and cumulative production. For previous assessments the USGS explicitly discounted the need to 'grow' the global 2P reserves data, stating that in most parts of the world they judged the 2P numbers to be reasonable estimates of the 'ultimate reserves' of existing fields. This approach changed in the USGS year-2000 assessment, with quite large reserves growth factors, based on US field-growth experience (for proved reserves) being applied to countries outside the US (with 'proved plus probable' reserves). This process added 690 Gb in total to the mean globally assessed 'ultimate'. The USGS did note, however, that they were unsure how to model reserves growth outside the US, and that they took this approach more to raise awareness of the issue than to be certain that it would give the correct results.

How realistic is it to use USGS year-2000 'grown' data when assessing world peak? The USGS was reportedly much encouraged in the wisdom of including large reserves growth factors when an initial study by IHS Energy found that its backdated global 2P discovery data, after taking out the discovery of new fields, had shown very large increases—in total by some 464 Gb-over the period 1995–2003 (Chew and Stark, 2004). This was initially taken by the USGS and others as proof of on-going very significant real reserves growth around the world, i.e., of large knowledge- and technology-driven increases in recovery factors across the globe.

However, one needs to take into account that as this 464 Gb of growth applied to global *aggregate* discovery data, any one of a number of other reasons could also generate such increases, such as originally excluding certain countries or fields, subsequently including new classes of oil, or switching to different datasets. IHS Energy therefore examined their data more closely. They looked, for example, at the US data (which are proved, and hence expected to grow); at the FSU data, for which new data sources had become available; and at the Middle East numbers, where these were known to be very uncertain. As a result, the company stated that only about 175 Gb of the 464 Gb "seems a reasonable ball-park estimate… that can properly be attributed to the ['real'] resource growth mechanism in pre-1995 discoveries during the period 1995–2003," (Chew, private communication). However, IHS Energy cautioned that "It is impossible to quantify with accuracy the true contribution of the 'resource growth' phenomenon."

Nevertheless, the company noted that when this growth is added to the new field and new pool discoveries, of 144 Gb over the same period, this represented a 133% replacement of global liquids production. Note that Wood Mackenzie's dataset carries a total world 2P discovered quite a bit lower than IHS Energy's, the main difference apparently being a more conservative assessment of oil availability reporting technical/commercial reserves vs. IHS Energy's 'geological' reserves.

So the question remains as to how much 'real' (technology-driven) reserves growth will occur in the industry datasets in future, and, crucially, how much of this 'extra oil' will get developed in time to have any effect on the global date of peak.

To examine reserves growth in more detail, the USGS initially looked at reserves growth in UK and Norwegian fields. Here, changes over time in the public domain 'proved and probable' reserves data were examined, and the increases identified (Klett and Gautier, 2005). However, even these data need to be examined carefully.

On the basis of IHS Energy data, large fields in the UK have shown an average reserves growth of about 50% over the long term; smaller fields have shown a smaller growth, of about 20%; while fields discovered since 1980 have generally shown a reserves decrease. Similar growth factors turn up for fields in other *non*-North-American countries although the data are rather sparse. Increases of this sort of magnitude are significant and need proper handling in the modelling, but are far smaller than the many-fold growth factors encountered when the US *proved* and Canadian *developed* data are examined.

Secondly, it has long been known that for large fields early public-domain 'proved plus probable' reserves are usually on the conservative side, as for example with Prudhoe Bay in the US and Forties in the UK. Such early conservatism reflects engineering pragmatism on the size of infrastructure to be built early in a field's life, and also perhaps a wish to avoid being over-optimistic to the market on an asset should problems arise later.

More recently, the USGS has completed a good piece of work, looking in detail at field reserves growth in the IHS Energy dataset (Klett et al., 2005). Like the IHS study mentioned above, this also found significant growth, of 171 Gb of traceable reserves growth globally excluding the USA and Canada over the 8-year period 1996–2003. Though very useful, even here caution is needed because the bulk of the growth identified was in fields in a relatively small number of regions, including significant growth in the Middle East fields, where evolution of the field size data is known to be problematic.

For this reason, and because of the fewer large fields being discovered (where initial size estimates are often conservative) and the greater number of small fields (where reserves growth is smaller, or even negative)—see the UK data quoted above, and the reducing scope for recovery improvement in the large existing fields, it is reasonable to expect future 2P reserves growth to be on a declining trend.

6. Reliability of past oil forecasts

Watkins' article suggests that past oil forecasts had been misleading; his thesis is that this was because of an inability of the forecasters to 'comprehend oil as an economic commodity'. He stated, for example, that "the dominant opinion in the mid-1970s and beyond was of looming oil shortages that would lead to very heavy reliance on OPEC". But, as Table 2 shows, those forecasts based on estimates of the *global conventional oil ultimate* (rather than *reserves*) recognised that global oil production would continue to rise for roughly another two decades before peaking around 2000. This view was reflected in energy textbooks written at the time. The fears of oil shortage in the 1970s were largely based on thinking that the then-proved reserves indicated the total oil remaining, not understanding that additional oil would be forthcoming from probable reserves, improved recovery factors, and oil yet-to-find.

For reference, Table 3 lists recent forecasts that see no peak within their forecast horizon. For the assumptions behind the forecasts in Tables 2 and 3, see Bentley (2002b) and Bentley and Boyle (in press).

7. Is the peak right now, or should we expect a mini-glut of oil?

Finally, in discussing the coming resource-limited peak in the global production of conventional oil, it is useful to ask whether this is right now, as for example Deffeyes (2003) suggests,[14] or whether a 'mini-glut' of oil should be expected over the next few years. If the peak is indeed not yet past, the world is still on the up-side of the Hubbert curve, with potential excess capacity.

Based on the resource data in most current models (BGR, Energyfiles, PFC Energy, Campbell/Uppsala, BP's Miller), the answer is that a mini-glut is expected. In these

[14]Deffeyes uses the 'later-Hubbert' technique of linearization of the logistic curve. *A priori*, one should not expect great precision from this method, as world production with major discontinuities due to the 1973 and 1978 oil shocks has not followed a pure logistic-derivative curve. Nevertheless, a strength of the Hubbert curve is its robustness in date of peak to changes in input parameters, and Deffeyes' analysis provides a reasonable quantitative warning of what is likely to occur.

Table 2
Results of oil forecasts that see a peak (or current plateau)

Date	Author	Hydrocarbon	Ultimate Gb	Date of global peak
1972	ESSO	Pr. Cv. oil	2100	"Increasingly scarce from ~2000."
1972	Report: UN Confr.	Ditto.	2500	"Likely peak by 2000."
1974	SPRU, UK	Ditto.	1800–2480	n/a
1976	UK DoE	Ditto.	n/a	"About 2000"
1977	Hubbert	Cv. oil	2000	1996
1977	Ehrlich et al.	Ditto.	1900	2000
1978	WEC/IFP	Pr. Cv. oil	1803	n/a
1979	Shell	Ditto.	n/a	"Plateau within the next 25 years."
1979	BP	Ditto.	n/a	Peak (non-communist world): 1985
1981	World Bank	Ditto	1900	"Plateau ~turn of the century."
1992	D. Meadows et al.	Ditto	1800–2500	n/a
1995	Petroconsultants, '95.	Cv. oil (xN)	1800	About 2005
1996	Ivanhoe	Cv. oil	~2000	About 2010.
1997	Edwards	Pr. Cv. oil	2836	2020.
1997	Laherrère	All liquids	2700	n/a
1998	IEA: *WEO 1998*	Cv. oil	2300 ref.case	2014
1999	Magoon of the USGS	Pr. Cv. Oil	~2000	Peak ~2010.
2000	Bartlett	Ditto.	2000 and 3000	2004 and 2019, respectively.
2002	BGR (Germany)	Cv.&Ncv. oil	Cv.: 2670	Combined peak in 2017.
2003	Deffeyes	Cv. oil[a]		'Later-Hubbert' method ~2005.
2003	P-R Bauquis	All liquids.	3000	Combined peak in 2020.
2003	Campbell/U. Uppsala	All h'carbons		Combined peak ~2015.
2003	Laherrère	All liquids	3000	n/a
2003	Energyfiles Ltd.	All liquids	Cv: 2338	2011 (if 2% demand growth).
2003	Energyfiles Ltd.	All h'carbons		Comb'd pk. ~2020 (if 0% growth).
2003	Bahktiari model.	Pr. Cv. oil		2006–7
2004	Miller, BP- own model	Cv.&Ncv. oil		2025: All poss. OPEC prodn. used.
2004	PFC Energy	Cv.&Ncv. oil		2018-base case

Notes: Table is not complete, one notable omission is the WAES study from the late 70s/early 80s.
Pr.: Probably; Cv.: Conventional; xN: ex-NGLs; +N: incl. NGLs; All liquids: Conv. and Non-conv. oil plus NGLs; All h'drocabons: Conv. and Non-conv. oil and gas.
'Ultimate': ultimately recoverable reserves (URR); is equal to the recoverable portion of the original total in-place resource. Gb: billion barrels. *Sources*: See Bentley (2002a, b).
[a]Probably all-oil.

Table 3
Results of some oil forecasts that see no near-term peak

Date	Author	Hydrocarbon	Ultimate (Gb)	F'cast date of peak (by study end-date)	World prod. Mb/d	
					2020	2030
1998	WEC/IIASA-A2	Cv. oil		No peak	90	100
2000	IEA: WEO 2000	Cv. oil (+N)	3345	No peak	103	–
2001	US DoE EIA	Cv. oil	3303	2016/2037	Various	
2002	US DoE	Ditto		No peak	109	–
2002	Shell Scenario	Cv.&Ncv. oil	~4000[a]	Plateau: 2025–2040	100	105
2003	'WETO' study	Ditto	4500[b]	No peak	102	120
2004	ExxonMobil	Ditto		No peak	114	118
2005	IEA: WEO 2005					
	Reference Sc.	Ditto		No peak	105	115
	Deferred Invest.	Ditto		No peak	100	105

[a]Shell's ultimate of 4000 Gb is composed of: ~2300 Gb of conventional oil (incl. NGLs); plus ~600 Gb of 'scope for further recovery' (SFR) oil; plus 1000 Gb of non-conventional oil.
[b]WETO's ultimate of 4500 Gb is for conventional oil only; it starts with a USGS figure of 2800 Gb, then grown by assuming large and rapid recovery factor gains to 2030. Mb/d: Million barrels per day.

models increased production from a number of regions including deep offshore US and Africa, from Kazakhstan and Russia, and from new tar sands plant more than offset the decline in production elsewhere. This is also the current view of CERA, who are very confident of increasing supply out to at least 2015.

The situation, however, is not so clear-cut.

On the up-side, in addition to the already discovered fields listed above, the current high oil price will certainly bring on more marginal fields, as well as in-fill drilling and workovers in the mainstream fields as happened during the previous oil shocks. Moreover, demand will also be dampened or even reduced. This implies 'mini-glut'. The effect on price will then be controlled by how well OPEC can manage supply, since the new sources of oil will all need to be produced to their maximum to see adequate returns on investment.

On the down-side, however, Skrebowski—who has some of the same data as CERA—sees a lower level of supply, asking whether the oil that undoubtedly exists can in fact come on-steam as fast as expected. Current information from rig analysts and the like support this more pessimistic view.

But the biggest reason to ask if the peak may be sooner than most current models predict is that they may all be using over-estimated Middle East reserves. This is a serious potential problem as Simmons (2005) and Zagar (2005) have highlighted. Moreover, as the data indicating the approaching peak become ever clearer, it may well be that producers will switch, as they did during the 1970s' shocks, to a 'conservation' strategy—slower, high-priced, low-investment production—rather than the current high up-front production strategy.

8. The production peak for conventional gas

The expected date of the global resource-limited production peak for conventional gas can also be generated by combining 2P discovery data with geological knowledge. This puts the date of peak perhaps between 2020 and 2030, but where this date depends on the amount of gas infrastructure—pipelines and ships—that the world decides to build. Gas reserves, historically, have had less confusion associated with them than oil reserves. This is partly because the recovery factor is usually quite high (allowing less scope for real reserves growth), and because large-scale commercial production of gas is fairly recent, so weakness in historical definitions plays a smaller part. But in interpreting the discovery trend, one needs to be clear about when South Pars/North field was actually discovered. And, as with oil, there is a range of non-conventional sources, including tight gas and gas in brine aquifers—and the disputed volumes of methane hydrates—that need evaluation in terms of the realistic future 'all-gas' production rate.

9. Conclusions, and current problems that merit analysis

In conclusion, it can be seen that a key contention of Watkins' paper, that "oil is more plentiful now in an economic sense than in 1973", is incorrect. It is a view based in part on observing 30 years of upward trend in 1P reserves. The error here is in not realising that the 2P data have given *exactly the opposite message* over the same period. While one can understand how this misunderstanding came about, simple checking of the 1P data would have revealed many of the errors. It has been unfortunate also that the evolution of the 1P data fitted so well the economists' cohesive 'oil-as-inventory, resources-into-reserves' model. As a result, those geologists who were reporting the conclusions starkly evident in the long-run 2P discovery creaming curves of virtually all the world's oil-producing countries were seen as 'economically illiterate', intellectually bound to an apparently disproved fixed resources model, and their findings dismissed as a consequence.

It is essential that this dispute is now put behind us and we join in examining the consequent issues. These include the following:

- Better understanding of the past, in particular the proved reserves definitions used by governments, and true 2P reserves growth factors by region and field type.
- Better modelling of the conventional oil peak.
- Rates of availability of non-conventional oils and oil substitutes, including examining technological readiness and lead-times, as well as investment, pollution and net-energy production-rate constraints.
- Rate limits to energy change in general.
- Prediction of CO_2 emissions in the light of conventional hydrocarbon depletion, where consequent reductions may be outweighed by the move to more carbon-intensive fuels such as coal and coal-to-liquids.
- Impact of higher intrinsic energy costs (not price) on national GDPs.
- The ability of the market to cope with diminishing supplies of conventional hydrocarbon fuels.
- The use of integrated energy-system models.

These topics are discussed in more detail in the full version of Bentley (2006).

Acknowledgements

This paper is based in part on Bentley (2006). The authors are grateful for reviews of that paper by Jean Laherrère, Colin Campbell, Michael Smith, David Fleming and John Burton.

Appendix. Summary of an 'economic view' of oil depletion

A number of influential energy economists have espoused the following ideas to varying degrees. Discussion of most of these topics has been given in the main article above; additional notes are given below.

1. The cost of any mineral reflects a race between depletion of its resource and mankind's increasing technological skill at extraction. To date, for no significant mineral has this race been lost, and empirical

data indicate that the long-term extraction cost of nearly all minerals has always fallen. There is no reason to expect oil to be an exception.

2. The price of oil indicates future supply. Currently neither price nor more detailed economic metrics indicate approaching supply difficulties. These indicators will give sufficient warning should such difficulties approach.[15]
3. Markets function very well. Were an oil shortage to be imminent, the increasing price of oil would increase exploration, exploitation of currently uneconomic fields, recovery factors, use of alternative oils, and substitution away from oil. These changes, in combination with a fall in demand also driven by price, would bring the market back into balance. In essence, oil (and energy also) is simply a commodity; supply is best left to the market.[16]
4. For most countries, the cost of oil is only a small percentage of GDP; even a substantial rise in oil price will have only a modest impact on their economies.
5. There are over 40 years' of proved oil reserves. This is secure, known oil extractable at today's prices. More oil will also be found. Any potential oil supply problem must be many decades into the future.
6. There are still plenty of places to look for oil. Large oil discoveries have been made in the Caspian, deep offshore, etc., and there are still many promising oil basins that have seen little exploration.
7. Moreover, the bulk of 'new oil' comes not from discovery, but from revisions and extensions to existing fields. Such 'reserves growth' will be a key contributor to future supply.
8. Indeed, oil reserves are merely 'inventory'. Oil companies keep a given number of years' supply on their books, and as supply falters more of the effectively infinite oil resource base gets turned into reserves. The data confirm that this has always happened in the past.
9. In addition, there exist vast resources of non-conventional oil. These include 300 billion barrels of recoverable oil each in the Orinoco basin and Athabasca, with the total in-place oil resource at these sites amounting to several trillions of barrels. There is an even larger amount of oil in shale deposits around the world. This distribution is expressed by a 'resource pyramid', with a small volume of low-cost oil at the top, and an ever-increasing volume of more expensive, or otherwise less desirable oil, further down the pyramid.[17]
10. Should the supply of oil itself ever become difficult, it can be substituted by gas, of which there are large stranded supplies; by gas-to-liquids, biofuels and other oil substitutes; and, if the need arises, by coal. Large volumes of gas hydrates may also prove economically extractable.
11. Virtually none of the bodies one would expect to warn of impending supply shortages are currently predicting any risk to supply. These include oil companies and consultancies, as well as authorities such as the IEA, the US EIA or the USGS.

In addition to the above general views, some economists have offered the following specific criticisms of the geologists' calculations:

12. Geologists rely on industry data that are not in the public domain. Analysts cannot check that these data are correct, nor that the geologists are interpreting them correctly.
13. The geologists ignore the effects of price and technology gain. Without such obvious feedbacks, simple geology-based modelling is without validity.
14. Past oil forecasts have all been wrong. Thirty years ago it was believed that oil would run out in 30 years, today the world has 40 years worth of reserves. It is foolish of the geologists to forecast oil's future on the basis of an assumed fixed volume of oil.
15. The 'Hubbert curve', used by some geologists in their modelling, is a poor match to actual production.
16. The geologists who forecast a near-term oil production decline have shown a steady upward revision in the resource volumes they assume.

Taken together, the above is an impressive list. It appears to give almost incontrovertible evidence that no near-term oil supply problems lie ahead. Instead—as has been shown in the main body of this paper—the majority of these arguments do not stand up to detailed examination, and, where partly true, they need quantification if they are to usefully contribute to forecasting oil's future.

[15]The lack of a price signal for oil peaking has been widely quoted, at least up to about mid-2004. What the economists say in the face of the recent price rises is not yet fully clear, though Chinese demand and lack of refinery capacity are mentioned. In terms of understanding the price signal, it is useful to recognise that it is very difficult for the price to reflect other than the *near-term* supply/demand balance. This is because when selling any widely traded commodity it is hard for sellers to hold out when prices fall, even if it is only in the short term. Note however that sequestration of Middle East assets from the commercial oil companies by the nationals, followed by OPEC quotas, meant that higher-cost oil (North Sea, Alaska, and now deep offshore) has been produced, while lower-cost Middle East oil has remained in the ground. Had the 'seven sisters' remained in control, it is likely that a steady oil price rise would have taken place as the cheap oil depleted first. Incidentally, there was a price signal before the 1970s' oil shocks, but this was small and ignored.

[16]See comments on Lord Lawson's views of 'energy as a commodity' in Bentley et al. (1999).

[17]In terms of the 'resource pyramid' concept, oil is not like a conventional mineral with an infinite continuum of lower concentration ores. For *conventional* oil there is a well-defined water boundary in most reservoirs below which there is no oil: oil comes in packets. So the 'lower concentration ores' are simply the smaller fields, and here it is easy to extrapolate both field size and discovery rate to calculate how much will be found with any specified discovery effort. Additionally, oil is not a mineral such as gold or aluminium, which if really needed can be extracted at high cost; oil is not worth extracting if this requires more energy than it yields. These special aspects of oil require economists to be cautious when applying general resource theories.

References

Bentley, R.W., 2002a. Global oil and gas depletion: an overview. Energy Policy 30 (3), 189–205.

Bentley, R.W., 2002b. Oil forecasts, past and present. Energy Exploration & Exploitation 20 (6), 481–492.

Bentley, R.W., 2006. Global Oil and Gas Depletion—A Letter to the Energy Modelling Community, IAEE Newsletter, second quarter 2006, 6–14. Full version available from the author as: Global Oil Depletion—An Open Letter to the Energy Modelling Community.

Bentley, R.W., Boyle, G.A. Global Oil Production—Forecasts and Methodologies. Accepted for publication by Environment and Planning-B.

Bentley, R.W., et al., 1999. The Oil Future—A Very Different View. Newsletter of the Interenational Association for Energy Economics, fourth quarter.

Bentley, R.W., et al., 2000. Perspectives on the future of oil. Energy Exploration & Exploitation 18 (2–3), 147–206.

BGR, 1997. See: K. Hiller, Future World Supplies and Constraints. Erdöl Erdgas Kohle 113, Jahrgang, Heft 9, September 1997, pp. 349–352.

BGR, 2002. Reserven, Ressourcen und Verfügbarkeit von Energierohstoffen. Bundesanstalt für Geowissenschaften und Rohstoffe, Hanover, (German Federal Institute for Geosciences and Natural Resources).

Campbell, C.J., 2005. The Oil Crisis, Multi-Science Publishing, Brentwood, UK, See also: Campbell, C.J., The Essence of Oil & Gas Depletion. Multi-Science Publishing, Brentwood, UK, pp. 233–254. (Contains invaluable graphs of oil discovery and production by country and region. World output and a summary of results are given on pp. ix–x.)

Campbell/Uppsala, 2005. Data from study by C.J. Campbell in association with the University of Uppsala: 〈www.peakoil.net〉.

Chevron, 2005. Chevron oil company advertisements in the global press, August 2005 (see 〈www.willyoujoinus.com/issues/alternatives〉) quoting Vital Signs, Worldwatch Institute, 2005, 30p.

Chew, K., Stark, P., 2004. Consultancy Report: World Petroleum Trends—1994 to 2003, Version 4.4; 22 October 2004. IHS Energy, Geneva, Switzerland.

Davies, P., 2004. Energy in Focus. World Energy Review, August 2004, pp. 14–17.

Davies, P., Weston, P., 2000. Oil Resources: A Balanced Assessment. Energy Forum Conference: 'Running on Empty? Prospects for World Supplies'. Rice University, Houston, May 19, 2000.

Deffeyes, K., 2003. Hubbert's Peak. Princeton University Press, Princeton, NJ.

Energyfiles Ltd., 2006. 'Oil and Gas 2006: Global Ten-year Projection', available from: 〈www.info@Energyfiles.com〉.

Energyfiles Reports, 2003 to date. (a) Smith, M.R. The World Oil Supply Report 2004–2050, third ed., Douglas-Westwood Ltd. (Note: Laherrère classifies this as "a good update of the 1995 Petroconsultants report"; (b) Smith, M.R., The World Gas Supply Report 2004–2025, first ed., Douglas-Westwood Ltd.; (c) Web: 〈www.Energyfiles.com〉, e-mail: admin@Energyfiles.com.

IEA, 2005a. World Energy Outlook. International Energy Agency, Paris, 322pp.

IEA, 2005b. Resources to Reserves. International Energy Agency, Paris.

Harper, F., 1999. Ultimate hydrocarbon resources in the 21st century. Presentation at AAPG Conference on Oil and Gas in the 21st Century, 12–15 September 1999, Birmingham, UK.

Kelly, H. (Ed.), 1981. A New Prosperity: Building a Sustainable Energy Future, the SERI Solar/Conservation Study. Brick House, Andover, MA.

Kemp, A., 2006. Presentation at Energy Institute, London, November 7, 2006.

Klett, T.R., Gautier, D.L., 2005. Petroleum Geoscience 11 (2), 179–190.

Klett, T.R., et al., 2005. An evaluation of the US Geological Survey World Petroleum assessment 2000. AAPG Bulletin 89 (8 August 2005), 1033–1042.

Laherrère, J., various dates. See papers at 〈www.oilcrisis.com〉 and elsewhere.

Lynch, M.C., 2005. In: The New Pessimism About Petroleum Resources: Debunking the Hubbert Model (and Hubbert Modelers). See 〈www.gasresources.net/Lynch(Hubbert-Deffeyes).htm〉; section entitled: Opaque Work, Unproven Assertions.

Maugeri, L., 2004. Oil: Never cry wolf – why the petroleum age is far from over. Science 304, 1114–1115.

Miller, R.G., 2004. BP unofficial model. Presented at Institute of Energy, Northern Ireland Branch Meeting, 24th February 2004; also private communications.

Perrodon, A., Laherrère, J.H., Campbell, C.J., 1998. The World's Non-Conventional Oil and Gas. The Petroleum Economist, London.

Petroconsultants, 1995. The World's Supply of Oil, 1930–2050. Petroconsultants S.A., Geneva, authors Campbell, C.J. and Laherrère J.H. For an accessible article summarising these findings, see: Campbell, C.J., Laherrère, J.H. The End of Cheap Oil. Scientific American, March 1998, pp. 60–65.

PFC Energy, 2005. Presentation at the 'Global Oil Depletion Debate', Energy Institute, London, 2005; also personal communications.

Simmons, M., 2005. Twilight in the Desert. Wiley, New York.

Skrebowski, C., various dates. See the annual updates of 'Large Field Projects' and accompanying summaries by C. Skrebowski in Petroleum Review (various editions). Energy Institute, London.

Smith, M.R., 2005. Putting paid to unrealistic demand predictions. Petroleum Review, October 2005, Energy Institute, UK, pp. 32–34.

USGS, 2000. United States Geological Survey, World Petroleum Assessment 2000; 〈http://pubs.usgs.gov/dds/dds-060/〉.

Watkins, G.C., 2006. Oil scarcity: what have the past three decades revealed? Energy Policy 34, 508–514.

Yergin, D., 1991. The Prize: The Epic Quest for Oil, Money and Power. Simon and Schuster.

Zagar, J., 2005. Saudi Arabia-Can it Deliver? In: Proceedings of the Fourth International Workshop on Oil Depletion, Lisbon, Portugal, May 2005. Centro de Geofísica de Évora, University of Évora, Portugal, pp. 30–31.