

## Chapter 2

# Explaining Peak Oil: What It Is, and Why It Happens

This chapter explains the concept of ‘peak oil’. The term, as used in this book and also generally, refers to the point at which the production of oil from an oil field, a region, or the world as whole reaches a maximum and then subsequently declines due primarily to *limitations of resource availability*. Note that there can be several such ‘resource-limited’ maxima in the production history of a field or a region; in a field for example from the application of new technology or a significant increase in oil price; and likewise in a region, for example from successive phases of discovery.

The term therefore generally does not refer to a peak in production that occurs due to ‘above-ground’ factors, such as demand reaching a maximum, a country limiting access to the development of its oil, or the imposition of quotas or similar constraints on production.

The physical and economic reasons for a peak in oil production, the shape of the production profile before and after the peak, and usually also the economic significance of the peak, are very different in the case of an individual oil field, a region that contains many fields, and the world as a whole. Moreover, the economic significance of peak will be different if it applies to conventional oil only, or to conventional plus non-conventional oil, or to ‘all-liquids’.

Definitions used in this book for different categories of oil, and for extraction techniques, are set out in Annex 1. Importantly, recall from above that *conventional* oil is defined here as essentially *oil in fields*, i.e., primarily mobile oil that has migrated from a source rock to a discrete field (and usually one having an oil-water contact). The reason this definition is adopted is twofold: the generally intrinsically lower cost of this type of oil as already discussed; and because the physical factors that drive production of this oil result in the peak of production in a region as occurring typically when roughly only half of the region’s total recoverable oil has been produced; the so-called ‘mid-point’ peak.

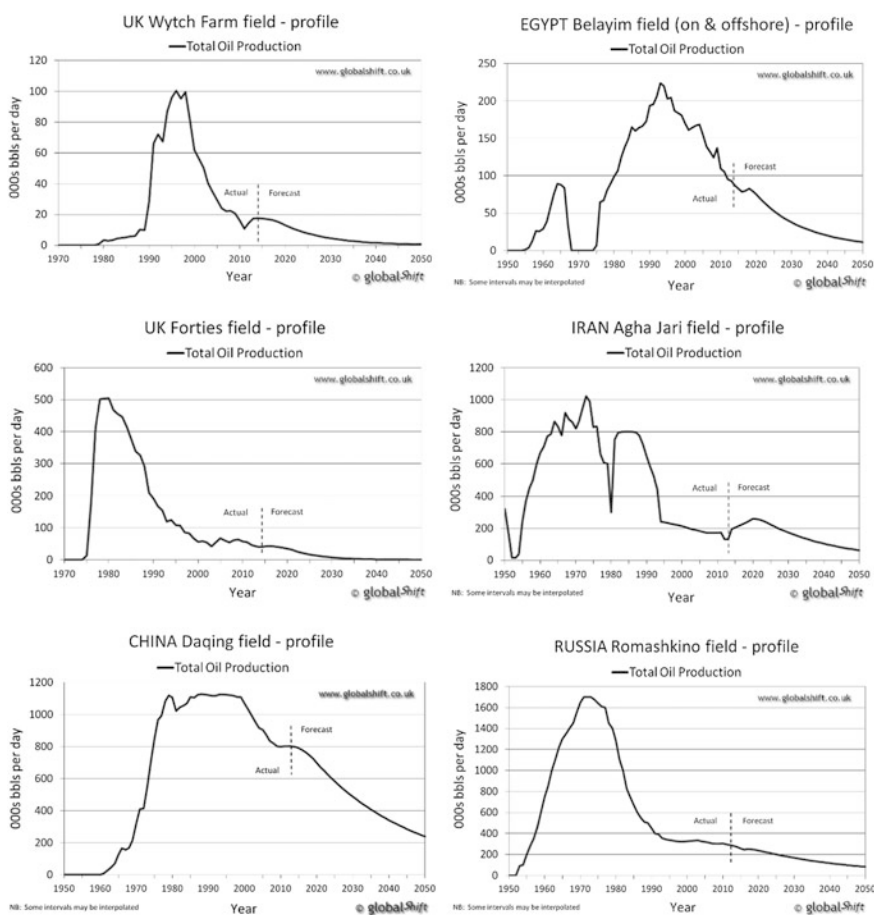
In this chapter and the next we look primarily at the production of *conventional* oil, and look in turn at peak in individual oil fields, in regions, and then in the world as a whole. We start by examining the production peak in fields.

## 2.1 The Production Peak in an Individual Oil Field

### 2.1.1 Typical Field Production Profiles

The production profiles of *individual oil fields* can vary considerably. Figure 2.1 gives examples of fairly typical production profiles for a range of field sizes and locations.

Figure 2.1 includes the ‘fairly slowly up and down’ production of larger older fields such as Romashkino, but with a very long production tail; the quickly up (then long decline) of relatively modern offshore fields such as Forties, where speed of financial return is important given the high up-front investment; and the relatively long plateaus of both a ‘heavily-worked’ field like Daqing (and where output was probably judged more important than rate of return), and of a large Middle East



◀ **Fig. 2.1** Oil field production profiles, for a range of field sizes and locations.

*Top left* Wytch Farm, UK's largest on-shore oil field (though in fact much of the field is offshore, reached by horizontal drilling). Relatively low production until the infrastructure fully in place. Relatively short plateau (at  $\sim 100,000$  b/d) followed by long steady decline, small recent late recovery. Note the distinction in this plot (and others in this Figure) between actual and forecast data.

*Top right* Belayim field, one of Egypt's largest fields. This field has both onshore and offshore production zones. Note loss of production due to 1967 war. Relatively symmetric climb to peak (at  $\sim 225,000$  b/d) and decline (though part of this is forecast).

*Centre left* Forties, UK's largest field. Rapid rise in production to a short plateau at 500,000 b/d; long decline with some late recovery.

*Centre right* Aghajari, large Iranian field discovered 1938, in production 1940. Note production fall post-1978, presumably due to the revolution; and expected moderate future recovery from planned gas injection. General profile: relatively long approximate plateau (at up to just over 1 Mb/d) that is typical of large Middle East fields. Field output in decline once it had produced roughly half its likely recoverable oil.

*Lower left* Daqing, China's largest field. Discovered 1959, in production 1960 with Russian technical assistance. The Chinese are justifiably proud that despite forecasts to the contrary they held production on plateau (at  $\sim 1.1$  Mb/d) for some 20 years, through the use of water-flood, infill drilling (it is a braided channel field with many separate sandstone reservoirs), and latterly chemical additives. But the field is now well into decline.

*Lower right* Romashkino, one of Russia's largest fields, discovered in 1948. Roughly symmetric production rise (to  $\sim 1.7$  Mb/d) and decline, but with a long production 'tail'.

Source Globalshift Ltd.; 2015

field, Aghajari, where supply was constrained over many years for a variety of reasons (for a general explanation for long-term global oil supply constraints see Bentley and Bentley 2015a, b). For other examples of field production profiles, the 'regional by-field' plots of Figs. 2.7, 2.10, 2.13, 2.18 and 2.19 below include the profiles for over a hundred fields.

As these examples indicate, the production profiles of the majority of all fields show production rising fairly early to peak (or a short plateau), and then a long period of decline. Note that the production rate at peak or plateau in part reflects the size of the pipeline and other infrastructure taking oil from the field, and this, in turn, is optimised to maximize field profit over time, which includes consideration of future expected oil price. Note also that in recent years both primary and secondary recovery techniques are often employed from the outset.

For all classes of fields production eventually declines, driven usually by a combination of physical constraints. These include loss of field pressure, reduction in oil volume for wells to access (set by the reducing length of the oil column), increasing water cut if water-drive is used, and by increasing drive-fluid bypass of the oil within the reservoir (where the drive fluid may be naturally occurring, or injected). In turn these factors reflect the specific characteristics of the production techniques use, and of the reservoir itself where the latter include the rock-oil or oil-water interface characteristics, and, importantly, inhomogeneities within the reservoir. As can be seen in Fig. 2.1 and the other Figures quoted, *production peaks in fields when typically somewhere between about a quarter to a half of the field's recoverable oil has been produced.*

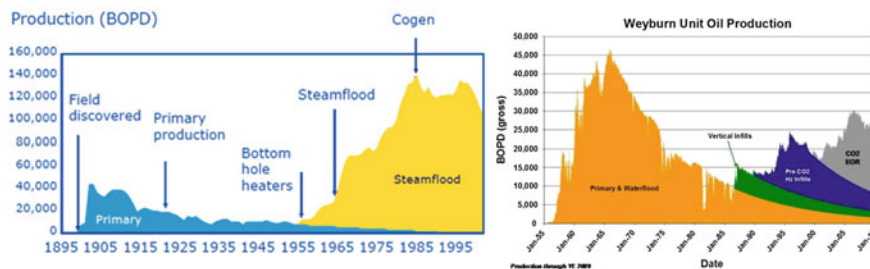
### 2.1.2 Other Field Production Profiles

However not all fields show this ‘typical’ profile, and two significant exceptions need attention. These are:

- (i) Old and very old fields, especially if difficult to produce in some way

Old and very old fields, and especially those difficult to produce, often have distinct production phases, and multiple peaks, as different types of production technology are used across the field’s life. One such field is the Kern River heavy oil field in California, discovered in 1899 but which did not peak until the 1970s; see Fig. 2.2, left. (Note that by the definition used in this book, Kern River counts as a non-conventional oil field as its heavy oil—at least in the later stages of production—requires heating to reduce viscosity.) Another such field with an atypical production profile is Weyburn in Saskatchewan, discovered in 1955, which illustrates the large gains sometimes possible from the application of enhanced oil recovery (EOR) techniques; Fig. 2.2, right.

These two fields are often quoted by ‘peak oil’ sceptics to show the large gains in yield that technology can achieve, and hence to illustrate—in their view—the intrinsic error of forecasts that assume relatively fixed volumes of recoverable oil. Kern River and Weyburn are quoted, for example, in Mills (2008), pp. 84 and 87 respectively; Kern River in Maugeri’s comment in *Science* (2004); while Weyburn



**Fig. 2.2** Two fields with atypical production profiles.

*Left* Production of Kern River heavy oil field (13° API) in California, discovered in 1899. Long decline from primary production, then significant increase from the use of bottom hole heaters and subsequently steam injection. Today the field has many thousands of wells, achieving an average of ~15 bbl/day per well.

*Source* Chevron (from Google Images).

*Right* Production from the Weyburn field, Saskatchewan, discovered in 1955, showing large gains from CO<sub>2</sub> injection. (See Fig. 2.24, below, for IEA estimate of the total quantity of oil likely to result from use of this EOR technique.)

*Source* Cenovus Energy (from Wikipedia)

(but correctly, to show gains possible from EOR in specific fields) is in the IEA's *Resources into Reserves* (2013), p. 75. While such fields do exist, and are important to understand, they are far from common in number, and not significant in volume of oil compared to the global total.

- (ii) Very large fields under the control of OPEC countries (and often the 'Seven Sisters' before that).

By contrast, the second class of 'atypical' fields is indeed fairly common, and because of the field sizes, very important. These are the larger OPEC fields, such as Aghajari above, where fields tend to have long flat profiles, partly due to their size alone, but mainly due, later, to OPEC quotas; and, earlier, to commercial restrictions on production to help limit global over-supply (Yergin 1991). In addition, production in such fields has often been punctuated in response to quota changes, or external events such as politics or war. The impact of these fields is discussed more fully in the sections below on regional and global peak.

### ***2.1.3 Examining Field Decline, and Hence Field 'Ultimate' by a Linearised Decline Curve***

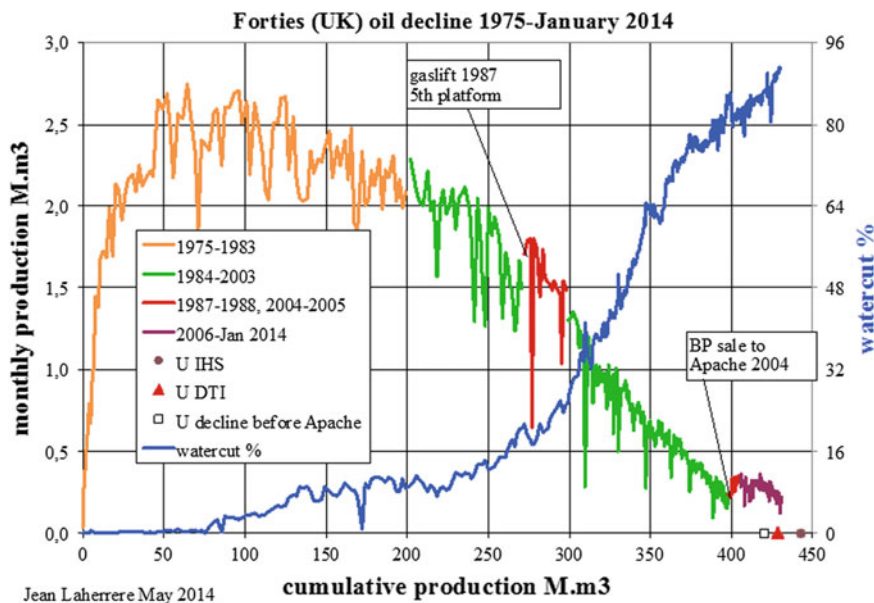
Note that there is a useful way to analyse the decline in a field. This is to plot the field's production versus its cumulative production (as opposed to vs. date, as for example in Fig. 2.1). This approach is shown in Fig. 2.3 for the UK Forties field:

On such a plot exponential production decline becomes a straight line, and in practical examples extrapolation of this (roughly) straight line to the abscissa indicates, *ceteris paribus*, the likely maximum quantity of oil that the field will yield, i.e., the field's ultimately recoverable resource (URR). In Fig. 2.3 three such possible 'ultimates' are shown, all close together; with the gain in yield following sale of the field by the original owner (BP) being clearly visible.

Another example of this approach is given later as Fig. 2.16 for the Samotlor field; and similar informative plots are available in Hall and Ramírez-Pascualli (2013) for the following fields: Cantarell (Mexico); East Texas and Prudhoe Bay (USA), Brent and Statfjord (North Sea), Yibal (Oman) and Cusiana (Colombia).

### ***2.1.4 Economic Constraints on Raising a Field's Production Post-Peak***

The physical constraints listed above that drive field production decline lead in turn to economic constraints on how quickly the field's oil might be produced once its production peak is past. Many techniques exist to raise production from a field in decline, but these are usually costly and often only slow the rate of decline; see the



**Fig. 2.3** Linearised plot of field decline: Example of the Forties field. Unlike a normal production plot of production versus date, this approach plots production (here as monthly data) versus cumulative production, and hence linearises the decline curve if the decline is exponential.

#### Notes

- Colours indicate production at different time periods.
- U IHS: URR estimated by IHS Energy.
- U DTI: URR estimated by the UK Dept. of Trade and Industry (data now from DECC).
- Right-hand scale shows increase in ‘water cut’ (water co-produced with oil as a result of water drive) over time, as a percentage of field total all-liquid (oil plus water) production.

Source J. Laherrère

general literature on reservoir engineering such as Muggeridge et al. (2014), or references such as Jakobsson et al. (2012) or Aleklett (2012). For specific fields see the examples of Magnus and Ula fields in Muggeridge et al.; or the Forties field shown here in Figs. 2.1 and 2.3. Operators of such fields optimising net present value therefore often find that even at high oil prices only relatively little extra oil (compared to the field total) can be produced profitably. UK production post-1999, where the total of production from all fields fell steeply despite the real-terms oil price rising over five-fold, from under \$20/bbl to over \$100/bbl, provides a good example of this (Fig. 2.10).

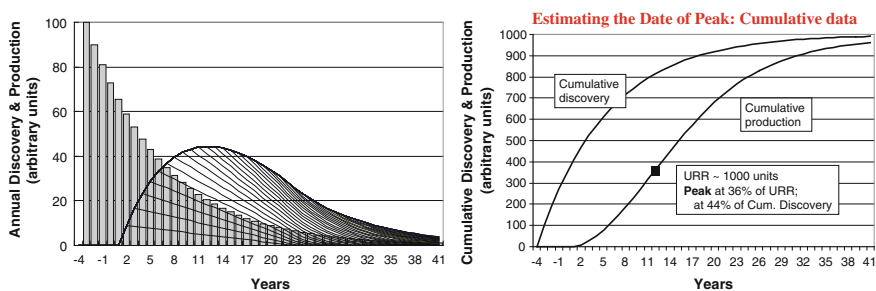
Note however that the quantity of ‘extra oil’ that can be produced from fields as the technology advances and if the oil price rises is important and needs to be understood, even if it perhaps does not affect the dates of peak by much. This is discussed in Annex 4, in the section on ‘Reserves growth’.

## 2.2 Conventional Oil Production in a *Region* (i.e., a Group of Fields)

Now we turn from peak in an *individual field* to considering the peak of conventional oil production in a *region* containing a group of individual fields. Here two new factors enter the discussion: the field size distribution in the region, and the amount of conventional oil in the region that has not yet been discovered. Field size distribution is critical because the volume distribution of *conventional* oil in a basin is usually very asymmetric, with most of the oil being in a relatively small number of large fields. Such fields tend to be more easily found than smaller ones, and also brought on-stream earlier.

### 2.2.1 A Simple Model of Oil Discovery and Production in a Region

To understand the mechanisms that drive peak in a region consider a very simple model that reflects the trend of oil discovery and production that is typical of most regions. This is illustrated in Fig. 2.4. The grey bars indicate the assumed field size distribution in the region, with the largest field containing 100 units of oil, the next 90 % of this, and so on. The model is also simple in that it assumes that exploration effort allows only one field to be found a year, and that the fields are found in size



**Fig. 2.4** A simple model of conventional oil discovery and production in a region.

*Left* Shows the field size distribution and discovery sequence (grey bars), and each field's subsequent production (triangles), where each field is assumed to take 4 years from discovery to production. The plot is to-scale such that for example the volume of oil shown as discovered for Field 1 (leftmost grey bar, 100 units) is the same as indicated for Field 1 production (the lowermost production triangle, which starts in Year 1, reaches 9.09 units/yr. in Year 2, and falls to zero by Year 23).

*Right* The same data for discovery and production, but on a cumulative basis. The *resource-limited* peak in production (at Year 12) is denoted by the small solid square

order. That is, as the Figure shows, the largest field is found in Year  $-3$ , the next largest in Year  $-2$  and so on.

The model then assumes that it takes four years for a field to get into production. Thus production of the largest field starts in Year 1, the next largest in Year 2, and so on.

Finally the production profile assumed for each field is also simple: production rises over the first year, reaches a peak in the second year, and then declines linearly thereafter, with a total life of 22 years. The plot is to-scale, so that the total area (i.e., volume of oil) under the production curve for the each field is the same as that shown by its corresponding discovery bar.

On these assumptions, the total production curve for the region emerges. As can be seen, in this case the region reaches a peak when about one-third of the region's total oil has been produced. Despite the simplicity of this model, this general 'whale-back' shape for a region's production curve of conventional oil is surprisingly valid. It roughly matches what has occurred in the majority of the sixty or so oil producing countries that are past their conventional oil peak, provided they avoided major disruptions in production, and also the profile given by Hubbert in his early publications and in interviews on film.<sup>3</sup> Examples of 'real-world' production graphs for a number of countries split by field are given in Figs. 2.7, 2.10, 2.13, 2.18 and 2.19 below; while production graphs (but not split by field) for virtually all oil producing countries are in variously Hallock et al. (2014), Campbell (2013), or on the Globalshift Ltd. website ([www.globalshift.co.uk](http://www.globalshift.co.uk)).

The left graph of Fig. 2.4 is very telling. It shows the main drivers of the peak of conventional oil production in a region, and explains why this *production typically reaches a maximum when something approaching only half or less of the region's total conventional oil has been produced*. Importantly, as the graph shows, the peak in a region is driven by:

- the asymmetry in oil location: most of the oil is in a small number of large fields;<sup>25</sup>
- the fact that these large fields tend to be discovered first;
- production in individual fields declines;
- more fields are being discovered, but they contain much less oil, and hence production in the region peaks.

Note that as long as many new fields are being discovered that contain significant quantities of oil, then the added production of these fields can offset the decline from earlier fields. The *resource-limited* peak of conventional oil production in a region thus occurs only when discovery in the region is well into decline. It is for this reason that knowing the true discovery history of a region is key to understanding the region's potential for future production.



### 2.2.2 *Realities Behind This Simple Model*

Of course the above model is over-simple, and in reality basins—and even more so larger regions—can be complex; and new plays can open up as the geological knowledge and technology advances. In such cases the discovery trend for a region can display ‘multiple asymptotes’, and it takes geological and engineering knowledge to judge when overall discovery in the region is drawing to a close, as in the Gulf of Mexico for example.

Moreover, the simple assumptions of the model reflect an interweaving in the real world of geology, engineering and economics. The rate that fields are discovered in a region, and then brought on-stream, is affected by the geology of how easy the big fields are to find versus the smaller later ones; how fast the geological and engineering knowledge of fields builds up; and the economics that determines the initial search effort, the rate that fields are brought into production, and their production histories. It is possible, for example, for a surge of small fields to be brought on-stream rapidly, as happened with the UK in 1998 when the oil price was low and companies sought to maintain revenues by production increases. But overall the model is reasonable in capturing the essence of oil discovery and the resulting production.

Note that the key feature of any realistic oil ‘discovery-and-production’ model for conventional oil is that the volume of oil discovered in fields in a basin typically gets less over time. In the simple model of Fig. 2.4 this occurs because discovery is restricted to one field per year, and since fields are discovered in size order the discovery volume per year automatically falls. In another example, Bardi and Lavacchi (2009) propose a simple two-equation model that relates oil production to capital expended, where an increasing quantity of capital is required over time for a given quantity of production. With suitable parameters the model replicates the Hubbert curve; but it can also be applied to other resources, and can capture the falling energy-return ratios of many resource extraction histories.

The Global Energy Systems Group at the University of Uppsala has modelled the size distribution of fields in a region, their discovery rate, and time-to-production on the basis of appropriate probability distributions to generate the expected production profile of the region, and is currently improving these models. Many other oil production models have also been proposed, see for example the review by Brandt (2009). The majority of these models tend to generate a roughly Hubbert or ‘whaleback’ regional production curve over time.

Finally, Hall (private communication) postulates that the fall-off over time in the volume of oil discovered in a region is a *direct consequence* of the increasing amount of energy required to search for, and to bring on-stream, the progressively smaller fields in the region.

### 2.2.3 Summarising Findings from This Simple Model

Summarising the findings from this simple model of oil discovery and production of *conventional oil* (oil in fields) in region we can say:

- (a) The resource-limited peak of conventional oil production in a region is caused by *adding the output of successive fields, where the later fields are generally smaller than the earlier*. This reflects the fact that the size distribution of fields in most areas is very skewed, with most of the oil being held in a relatively small number of large fields that tend to get found first.
- (b) The peak occurs once *discovery has declined significantly*; and indicates the point at which reduced output from the early fields is no longer compensated by increased production from the later. The typical shape of the regional production curve is driven by the profile of decline in individual fields, primarily from field pressure loss, reduction in effective oil column, and possibly from increasing drive fluid bypass. In the case of this simple model, the peak of discovery is 16 years before the production peak.
- (c) If a region sees significant separate phases of discovery, such as on-shore followed by offshore, then production may also show *a number of resource-limited peaks*, each reflecting a different discovery phase.
- (d) Finally, it is important to recognise that the production peak is *counter-intuitive*. This is because the peak occurs, as Fig. 2.4 shows, when:
  - production has been trending steadily upward;
  - the remaining reserves are large (and generally low-cost, as know-how and infrastructure are in place for their development);
  - discovery is continuing;
  - technology is improving, and hence recovery factors likely to be increasing.

## 2.3 Predicting the Peak of Conventional Oil Production in a Region by Combining the ‘Peak at Mid-Point’ Rule with the 2P Discovery Trend

Now we turn to the question of what the simple model of Fig. 2.4 can tell us about *how to predict* the production peak in a region.

It is a truism to state that oil cannot be produced unless it has been discovered. To examine the *discovery* trend in a region, and in turn to understand the scope for future production, the data in the model of Fig. 2.4 (left) are best presented as a cumulative plot, Fig. 2.4 (right).

As this shows, in this simple model about 50 % of the final discovery has already occurred by the time production of the first field starts in Year 1. And by the time

production peaks in Year 12 the discovery curve has turned well towards its asymptote. In the real world also, and critical for prediction purposes, a region's discovery asymptote is usually clear well before the production peak has occurred.

The next step is to apply the approximate 'peak at mid-point' rule. This says that the '*resource-limited*' production peak of oil production in a region typically occurs when roughly half of the region's URR has been produced; and where the region's URR is given by the asymptote of discovery.

This key idea is worth restating: To be able to predict when a region's '*resource-limited*' peak of conventional oil production is likely to occur the region's *discovery trend* can be combined with the 'peak at mid-point' rule. (As already mentioned, the discovery trend needs to be based on the oil-industry 2P data, not the misleading public-domain 1P data.)

Figures 2.6, 2.9, 2.12, 2.15 and 2.17, give examples of this approach for a range of countries. These Figures give the oil-industry 2P oil discovery data for these countries, and also their oil production, as both annual and cumulative plots. These plots allow the date of peak conventional oil production to be estimated, whether this peak is past or in the future.

### 2.3.1 The IHS Energy 'PEPS' Data

A number of the Figures used in the discussion below present data from the IHS Energy 'PEPS' dataset, and are provided with the company's permission. In understanding 'peak oil', these data (or the equivalent from other industry 2P data sources) are key, and it is important to understand how they are generated, and hence their reliability.

A consultancy to assemble oil field data was set up by Harry Wassall in 1956, originally based in Havana. This became Petroconsultants S.A. when the headquarters moved to Geneva in 1968, and it was later bought out by IHS Energy in 1996. The company's database collects, *inter alia*, data on oil and gas wells, and fields, from around the world, and aims to give global coverage. The data are 'scout', in that they are assembled by company employees scouting for information from a wide variety of sources. In the early days (and to some extent still today) this was done mostly by personal contact within the oil companies; and where often the latter, not allowed legally to discuss data with rival organisations, were happy to share data with the consultancy in exchange for access to data which the other companies were willing to supply.

When the 'Reading Oil Group' first encountered the issue of 'peak oil' in about 1995, much of our effort went into understanding the data that the various proponents for and against peak oil were using. It became clear that while other commercial oil and gas field datasets existed at that time (and more now), that of Petroconsultants' was generally seen by the oil industry as preeminent, especially in its degree of international coverage. These data were the basis of the Petroconsultants' studies that led to the Campbell and Laherrère 1998 *End of Cheap*

*Oil* article, and were used in the USGS Year-2000 Assessment, and probably in subsequent assessments. Though the data are widely purchased by oil companies, the full dataset has been seen as too expensive to purchase by some of the national and international energy agencies.

Over several years, our 'Reading Oil Group' had useful conversations with Dr. George Leckie of Petroconsultants, who at that time was responsible for entering many of the estimates of oil and gas field size into the database. These estimates were seen as specifying the most likely amount of oil or gas a field would produce over its lifetime, in light of both currently committed infrastructure and technology and what might reasonably be assumed in future. Such estimates were taken to reflect the nominal 'mean', or proved-plus-probable (2P), values for each field, and hence contrasted sharply with the proved-only (1P) data that oil companies were required to report publically under SEC rules.

Since the production by the individual fields was also recorded, cumulative production for a field can be deducted from the estimate of field size to give the field's remaining 2P reserves. In addition, for each field the company registers the field's date of discovery. Moreover, because the data are notionally statistically mean values, data for individual fields can be added arithmetically within the dataset to yield basin, country and global totals.

Then, since the aim was (and is) to capture 2P information on all fields globally (except for non-frontier US and Canada, where the data are only 1P), a picture is generated of how much oil or gas has been discovered in a region at a given date, and hence determine the region's corresponding trend of 'true' (2P) oil or gas discovery over time. It is these 2P discovery data, and the corresponding production data, that are given by country in the Figures below.

One problem however arises with these data, at least as far as analysis is concerned. The company (almost certainly like other data providers) was generally requested by customers for the best *current* estimates of the size of fields. This meant that if a revised estimate for the original size of a field became available, the database was simply updated with this new number. That is, for example, data in the database for the year-2000 (as given in the Figures below) reflects year-2000 knowledge of the size of fields, and not the estimates made at the dates the individual fields were discovered. Such data are said to be 'backdated'; and where, as a result, information on how the estimate of a field's size has changed over the years (its 'reserves growth') has become lost; unless earlier versions of the database are accessed, which can sometimes be done. Recently, IHS Energy has begun recording the change in field size by date in some fields; but a 'phone call to the company a short while back confirmed that such 'reserves growth' data are not yet available on a global basis.

A second aspect of the data that analysts need to be aware of is that originally the data were largely (or entirely) only for oil in fields (i.e., for conventional oil). Today, with the growth of production of the non-conventional oils, the database contains information on the oil volume expected from *specific projects* of non-conventional oil production. As a result, for example for the Canadian tar sands, estimates of the volume to be produced from announced projects are available in the database, but not (and quite correctly so) estimates of the total

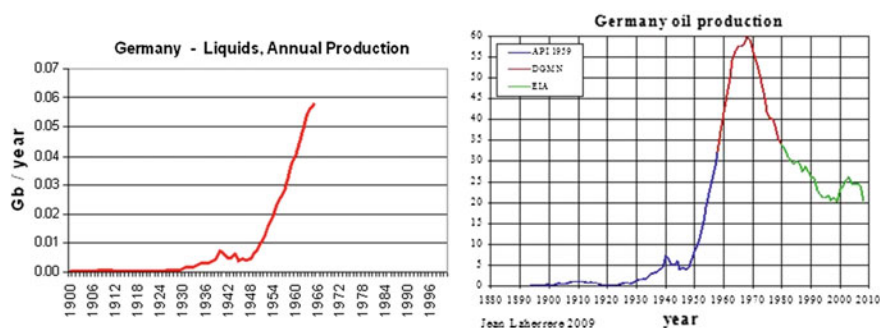
amount of tar sands oil potentially recoverable, despite the fact that all this oil might be classed as ‘discovered’, in the sense that its general location is already known.

The extensive exploration and production data (on well, field, project, seismic and related statistics) are held by IHS Energy in their Edin database, and this is updated on a continuous basis. The data in the company’s ‘PEPS’ database, such as those used below, are extracted from Edin at a by-country level on an annual basis.

Incidentally, readers may be curious why ‘PEPS’ data only to the year 2000 are given in the Figures below. The answer is simple: release of these data needs permission from the company, and this has only been given for the Figures provided here. However, as these show, by the year 2000 the 2P discovery trends in these countries (and, indeed, for virtually all oil-producing countries globally) were past their respective ‘discovery-trend’ inflection points; signifying that the rates of discovery in these countries were in decline by that date, such that in these (and in nearly all) countries, provision of later data would not change the overall trends of decline in discovery by much.

### 2.3.2 Oil Discovery and Production in Germany

With this information in hand, we can now look first at Germany, as this is an example of a country where its oil production peak is long past. We cover Germany in some detail as it illustrates most of the principles that underlie the peak of conventional oil production in a region. We start with Fig. 2.5 (left), which shows German ‘liquids’ production (here, meaning crude oil plus NGLs) from 1900 to the mid-1960s.



**Fig. 2.5** Germany: Annual production of ‘liquids’ (i.e., crude oil plus NGLs).

*Left chart* Production 1900 to the mid-1960s.

*Source* IHS energy, with permission.

*Right chart* production 1880–2008.

*Source* Jean Laherrère (colours indicate data sources, as listed)

As can be seen in the left chart of Fig. 2.5, there was a small peak in German fossil oil production during World War 2, but the main feature was the rapid growth of production in the subsequent years. At the end-date of this chart probably most analysts would be tempted to extrapolate this production trend on upwards. Not only was this production trend looking robust, but at that date Germany had plenty of oil left in proved reserves; discovery was known to be continuing (indeed she had not yet discovered her largest field); and technology—particularly tertiary recovery—was being introduced that was significantly raising recovery factors in existing fields. Every reason, one might think, to expect production to keep rising.

Needless to say, such an expectation would have been very unwise, as shown in Fig. 2.5 (right), as production immediately peaked. But a key question is then raised: was this peak the country's conventional oil *resource-limited* peak, or was it due to other causes? Maybe the government limited oil production because of environmental concerns over drilling; or pro-rationed output due to regional or global over-supply as happened in the US; or tried to raise the oil price in the manner of an OPEC-style quota; or was oil production in Germany simply too expensive, and the country found it easier to obtain her oil from cheaper sources outside?

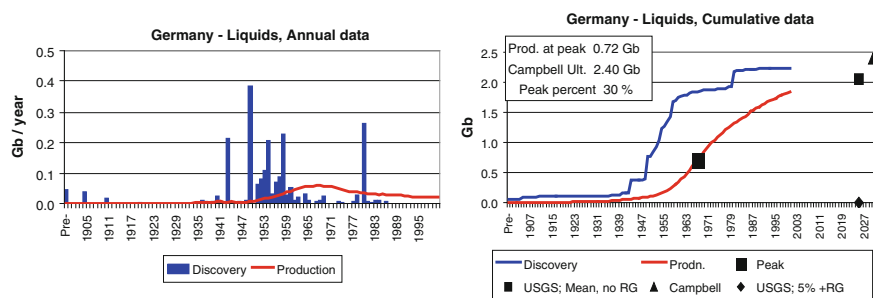
This reflects a serious problem with observing only oil *production* data: the data may show a production peak but is this peak *resource-limited*, such that production must continue to decline; or are there other factors at work, and production can go back up? The answer lies in examining the oil *discovery* data, and this is done in Fig. 2.6.

In Fig. 2.6 (left), the blue bars show the amount of oil discovered (as measured by 2P data) in Germany for each of the years shown, while the red line gives the corresponding amounts of oil produced in these years. As the blue bars show, some oil was discovered in the country before 1900, but the bulk of the country's oil was discovered in the 1940s and 1950s, where this was due to the introduction of the use of seismic. The large Mittelplate field (included in the large blue bar for discoveries made in 1980) was a late find, made in Germany's rather small offshore area that then became open for exploration. As can be seen in Fig. 2.6 (right), Germany's cumulative on-shore trend of 2P discovery had flattened out since about 1960; and when combined with the oil offshore, since 1980.

As the Figure makes clear, the production peak seen in Fig. 2.6 (left) was indeed *resource-limited*, at least in the sense of being driven directly by the amount of oil that had been discovered up to the year 2000. Had more oil been discovered, this production peak could have been higher or later; if less discovered, then lower or sooner. Simple as that: discovery controls production; once you know discovery, you know the limit to corresponding future production.

In terms of comparing Germany's output to the simple model of Fig. 2.4, we can ask: what was happening at field level? This is shown in Fig. 2.7.

On the basis of Fig. 2.7, clearly the model of Fig. 2.4 is an over-simplification for these larger mostly on-shore fields. The numbers of years before field peak is reached is often quite long, and hence not almost immediately as with the triangular production profiles of the simple model. But the general mechanism of peak—of a



**Fig. 2.6** Germany: Oil-industry ‘2P’ data on oil discovery, and production; 1900–2000. Data are for the IHS Energy definition of ‘liquids’; here meaning crude oil plus NGLs.

#### Left chart

- *Blue vertical bars* Annual 2P oil discoveries. Data are year-2000 backdated data; i.e., reflecting information available at the year 2000. Volume discovered prior to 1900 is indicated as ‘Pre’. Large late find is the Mittelplate offshore field in 1980. Peak of discovery in ~1950.
  - *Red line* Annual production. Peak of production was in 1967.
- Note* In this chart (and in the equivalent charts below) the width of the ‘discovery’ bars (blue) is set to one year; so that the area of these bars and the corresponding final area under the production curve (red) will be equal if all the oil discovered is eventually produced.

#### Right chart Cumulative plot of the same data.

- *Blue line* cumulative backdated 2P discovery.
  - *Red line* cumulative production.
- This plot indicates that the production peak (indicated by the solid medium-sized square) is indeed *resource-limited* based on the quantity of oil discovered to the year 2000; with the peak occurring at ~30 % of a URR that would seem reasonable from extrapolation of 2P discovery. (Also shown, URR estimates from the USGS and Campbell, see text.)

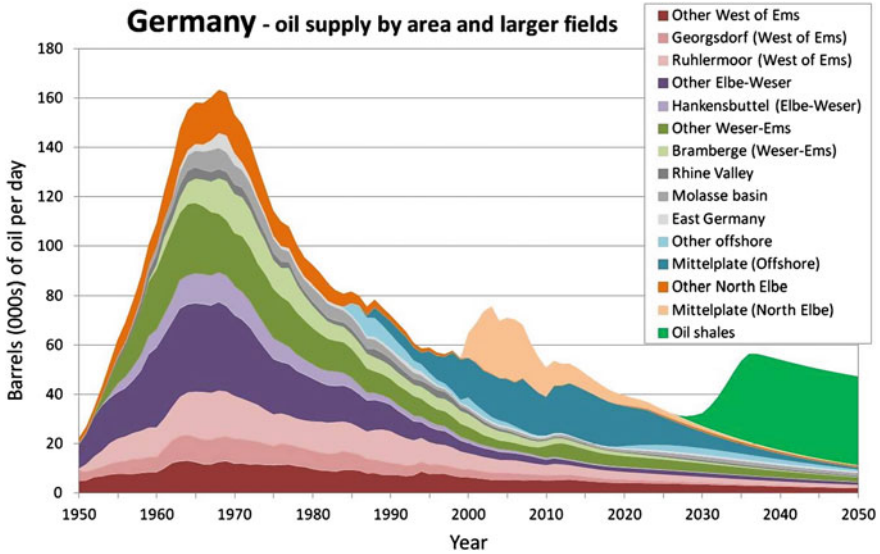
Source IHS energy ‘PEPS’ year-2000 dataset, with permission

number of the larger fields on-stream early, plus the later decline in these fields—is clear. Also note in this Figure the decline that would have occurred in Germany’s oil production had Mittelplate had not come to the rescue.

### 2.3.3 Could There Be a Later Peak? I.e.: Is the 2P Discovery Trend a Reliable Indicator of URR?

Now we address an important question: Is the 2P discovery trend reliable, in the sense that extrapolation of this trend gives a useful indication of a region’s conventional oil ‘ultimate’ (URR)? This depends on there not being large new discoveries of conventional oil waiting over the horizon. The only way to answer this question is to ask the petroleum geologists what more conventional oil is likely to be found in the region.

In Fig. 2.6 (right) two geologically-based estimates of Germany’s conventional oil ‘ultimate’ are given: that of the USGS in its year-2000 assessment, where the



**Fig. 2.7** Germany: Oil production by largest fields in regions, and by other fields in these regions. Actuals: 1950 to ~2013; Forecast: ~2013–2050.

*Notes* Largest fields are Georgsdorf, Ruhlermoor, Hankensbuttel, Bramberge, and the Mittelplate primarily offshore field. Indicative production from oil shales shown coming on-stream later.

*Source* Globalshift Ltd

‘mean, no-reserves-growth’ estimate is shown by a small square at 2025; and that of Colin Campbell, an estimate at about the same date, shown by the triangle at 2030.

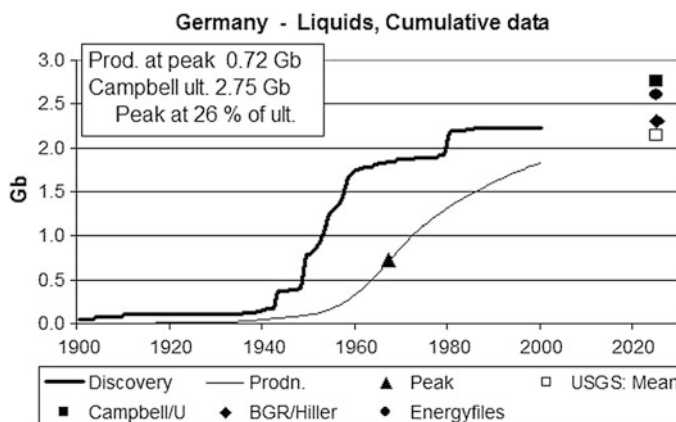
As can be seen both estimates are in general agreement with each other, and with a reasonable extrapolation by eye of the cumulative 2P discovery trend up to the year 2000. Thus on the basis of these two estimates, we can say that in the case of Germany extrapolation of the 2P discovery trend does indeed give a reasonable estimate of URR; and hence, using the ‘peak at mid-point’ rule, in turn allow an estimate to be made of the region’s date of peak conventional oil production. (Note that as the USGS data sum only basins evaluated, their URR estimate may have excluded Germany’s offshore.)

In order to underline this relationship between extrapolated discovery and URR, in Fig. 2.8 three further geologically-based estimates of Germany’s conventional oil ‘ultimate’ are plotted.

The URR estimates shown in Fig. 2.8 all apply only to conventional oil, and are:

- BGR’s 1997 assessment of estimated ultimate recovery (‘EUR’): 2.3 Gb;
- USGS’ year-2000 median assessment on a ‘non-grown’ basis, incl. NGLs: 2.14 Gb (may exclude N. Sea fields, as mentioned above);
- Campbell/University of Uppsala end-2004 model, excl. NGLs: 2.75 Gb. [Note that this URR is thus up from the earlier estimate of Fig. 2.6 (right) of 2.4 Gb;





**Fig. 2.8** Germany: Cumulative oil liquids discovery (2P data), and production, 1900–2000; and estimates of that country’s conventional oil ‘ultimate’ (URR).

*Sources* Discovery and Production: IHS Energy, with permission; ‘Ultimates’: BGR (1997), USGS (2000), Campbell/Uppsala, (2005), Energyfiles (2005).

#### Notes

- The date of the production peak is marked with a triangle.
- URR estimates made around the year 2000 are shown against the year 2025, as notionally this was the end-year that applied to the USGS estimate. In practice all four ‘ultimates’ refer to much later dates. Three of the groups recognise that future extraction technology and policies are unknown, so specifically caution that their URR estimates should not be seen as definitive estimates of ‘true’ ultimates (i.e. original endowments of recoverable conventional oil when extraction terminates). Instead the estimates refer to quantities of oil considered recoverable over reasonably long time spans. The USGS said they evaluate oil that will be available for discovery by 2025 (though there has been ambiguity about this date). The Campbell/Uppsala model no longer lists ultimate, but ‘Regular conventional’ oil production to 2075; (‘Regular conventional’ oil here excludes polar, deepwater, very heavy oils and NGLs). Energyfiles’ URR 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

and compares to the later estimate of Campbell (2013) for Germany’s ‘Regular conventional’ oil of 2.50 Gb (vs. cumulative production to 2010 of this oil of 1.96 Gb).]

- Energyfiles end-2004 assessment: 2.6 Gb.

As the Figure shows, these ‘ultimates’ are in rough agreement with each other, and with the apparent asymptote of the 2P discovery curve. The geologists were therefore fairly certain that no significant new quantities of conventional oil would be found in Germany, where this reflected both geological knowledge and over a hundred years’ of discovery effort and technological progress.

Note also that like other regions of the world, Germany, despite having applied enhanced oil recovery (EOR) techniques since 1985, still had (and has) a considerable amount of oil judged currently unrecoverable in existing fields. However,

barring some extraordinary new recovery technique, Germany by the year 2000 was judged close to the end of her conventional oil: at  $\sim 2.0$  Gb Germany's total production by that date having consumed about 80 % of her estimated recoverable original endowment of this oil.

In comparison to the 'mid-point' rule, Germany's production peak occurred at only 26 % (not 50 %) of the Campbell/Uppsala ultimate of 2.75 Gb. But the peak reflected only the *on-shore* fields being produced at that date, so the peak occurred at about 35 % of the apparent on-shore discovery asymptote, of about 2 Gb.

In summary, Germany is an example of a region where there would seem to be little scope remaining for new discoveries; where total recoverable conventional oil is now nearly fully depleted; and where its conventional oil production peak in 1967 was indeed *resource-limited*.

We have examined the case of Germany rather fully in order to set out the principles of using 2P discovery data to investigate a region's production peak. Next we look—rather more briefly—at the 2P discovery and production data for a number of other countries.

### 2.3.4 Oil Discovery and Production in the UK

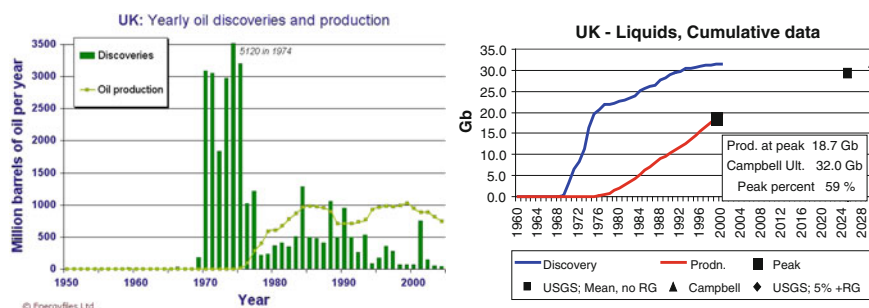
Figure 2.9 applies to the UK, and shows the oil-industry 2P discovery data, and also production. The left chart gives annual data to 2004, and the right chart the equivalent data (albeit from a different industry source) to the year 2000 in cumulative format.

As can be seen, the UK has had two oil production peaks, with the trough between these being caused mainly by safety work carried out on all fields following the Piper-Alpha disaster in 1988. Lesser factors for this production trough include the 2-year work-over on Brent due to high gas production; the fall in oil prices post-1984; anticipated changes in petroleum revenue tax that may have delayed the start-up of new fields; and—as Laherrère notes—the secondary peak in discovery in the late 1980s, as indicated in Fig. 2.9 (left). Without this 'trough', production most likely would have risen to a peak in the early 1990s. As it was, the UK's conventional oil resource-limited peak occurred in 1999, at 59 % of Campbell's estimate of URR.

To compare to the simple model of Fig. 2.4, Fig. 2.10 gives the corresponding plot of UK production broken down by field.

As the Figure shows, except for the 'trough', this plot of a region of mainly offshore fields is more like the simple model of Fig. 2.4 than the corresponding plot for Germany, which is primarily of onshore fields. This is not surprising, as the simple model was originally devised from examination of UK data.

Although discovery is not broken out by field in Fig. 2.9 (left), the pattern of UK discovery roughly matches that of Fig. 2.4; once a small initial field had been discovered in 1969, nearly all the very large fields were discovered fairly rapidly thereafter. As can be seen, the explanation is supported that peak is caused by a



**Fig. 2.9** UK: Oil-industry '2P' data on oil discovery, and production.

*Left chart* Oil-industry '2P' data on oil discovery, 1950–2004.

- Green vertical bars Annual 2P oil discoveries (data are year-2004 backdated; i.e., reflect information available at 2004). Peak of discovery in early 1970s. The medium-sized late find is Buzzard, discovered in 2001.
- Green dotted line Annual production. Peak of production in 1999.

*Source* Energyfiles Ltd. with permission.

*Right chart* Cumulative plot of the similar data, 1960–2000.

Data are for IHS Energy definition of 'liquids'; here meaning crude oil plus NGLs.

- Blue line Cumulative backdated 2P discovery.
- Red line Cumulative production.

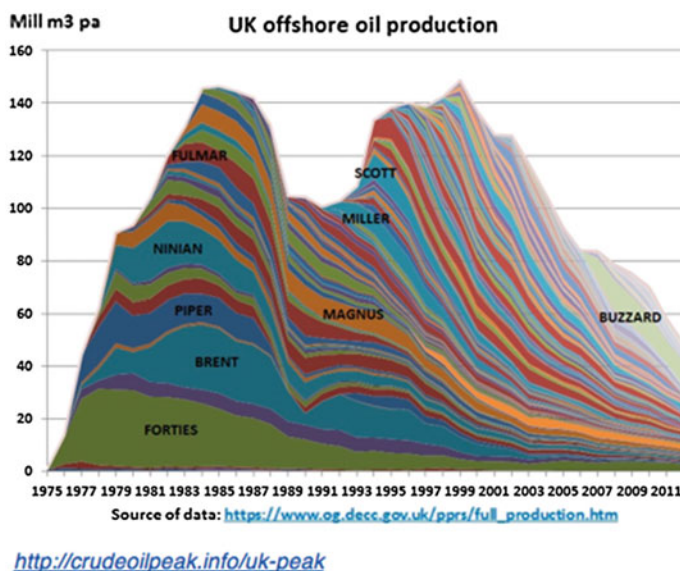
This plot indicates that the production peak (indicated by the solid medium-sized square) is indeed *resource-limited* based on the quantity of oil discovered to the year 2000; with the peak occurring at 59 % of a URR that would seem reasonable from extrapolation of 2P discovery. (Also shown, URR estimates from the USGS and Campbell, see text.)

*Source* IHS Energy 'PEPS' year-2000 dataset, with permission

region's large fields mostly getting into production first and then declining. In addition, by comparing the volume discovered with the volume produced, and using the 'peak at mid-point' rule, it was clear that the 1984 peak was not resource-limited, while the 1999 peak would appear to be.

But now we have to return to the important question raised above for Germany. How are we sure that the UK's 1999 peak was indeed resource-limited? This is clearly the case if based on the oil already discovered by that date; but how do we know that the UK does not have big new plays of conventional oil waiting in the wings that will yield enough oil to surpass the 1999 peak? As already mentioned, this situation can occur where the historical discovery data (the 'creaming curve' vs. time) indicates an apparent asymptote, but where this asymptote increases as a major new play enters the scene.

The answer, as already mentioned in connection with Germany, is that knowledge of peak cannot be based *solely* on discovery data, it must also include geological appraisal. It is recognised that the latter will always be judgement, and that the chance of future large finds cannot be known with certainty. But a great deal of geological knowledge now exists for much of the world's likely oil plays, and as explained later, *globally* the discovery of conventional oil in new fields has been



**Fig. 2.10** UK: Production by field, 1975–2011.

*Notes*

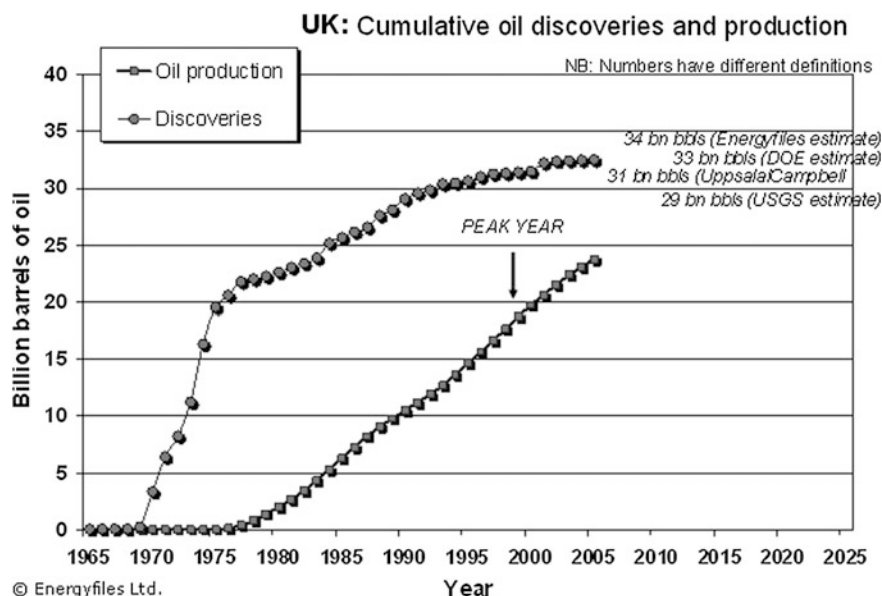
- Compare Forties output to the decline plot of Fig. 2.3.
- Note loss of output, and later restoration, of Piper output; and significant reductions and recoveries in other large fields due to associated safety work; and also the Brent work-over.
- Numerous small late fields cannot compensate for the decline of the early major fields.

*Source* M Mushalik (see website cited on the Figure)

falling for about half a century, so the scope for surprises in terms of big new discoveries is now judged generally as rather small.

Note however that in the UK's case, as elsewhere, even for conventional oil there are still significant future *potential* sources of oil. Some experts suggest that there remain quite large quantities of UK oil undiscovered in subtle stratigraphic traps; there is certainly still potential in the deeper Atlantic; and there is known to be a large amount of oil currently in-place in existing fields deemed unrecoverable with today's technology and oil price.

But geological and reservoir knowledge says it is virtually certain that none of this UK oil, where it exists, can be developed rapidly enough to push production back up past the 1999 peak. The subtle traps, if they hold significant amounts of oil, will need highly calibrated seismic to find, 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 (EOR) in existing fields have already seen much trial and analysis. Overall, combining the UK's 2P discovery data with geological knowledge indicates that the country's *conventional* oil peak in 1999 was indeed *resource-limited*.



**Fig. 2.11** UK: A second plot of '2P' oil discovery, and production, displayed on a cumulative basis. Also shown are four estimates for the UK's conventional oil 'ultimate'. The UK Department of Energy's estimate ('DOE') is from 1974; the others are more recent: USGS in year 2000; and Campbell/University of Uppsala and Energyfiles Ltd. estimates made about 2005. The USGS year-2000 and Campbell/Uppsala estimates exclude NGLs (these add ~4.5 Gb); the USGS estimate also excludes UK West of Shetlands basins. [Note Campbell (2013) estimates 'Regular conventional' URR as 32 Gb; and cumulative production to 2010 as 24.7 Gb.]

Source Energyfiles Ltd.

Figure 2.9 (right) brought out this point by giving two estimates of the UK's ultimately recoverable conventional oil resource (URR); that of the USGS Assessment of year-2000; mean value and without allowance for reserves growth, and Campbell's of about the same date, both ex-NGLs. As with the case of Germany, these estimates are close to each other, and also broadly in agreement with the value that might be expected from extrapolating by eye the backdated industry 2P discovery data. Three further estimates of the UK's conventional oil URR are given in Fig. 2.11. The earliest is a UK government DoE 'Brown Book' estimate made back in 1974 (see Annex 2); and the more recent are those from University of Uppsala/Campbell and Energyfiles Ltd, both made around 2004. As the Figure shows, these 'ultimates' are again in close agreement with each other, and with the asymptote of the '2P' discovery creaming curve.

### 2.3.5 *Expecting (and not Expecting!) the UK Production Peak*

Given that nearly all of the UK's large fields, and over half of the UK's total oil, had been discovered by the time offshore production started in 1975, it is not surprising that realistic estimates of the UK's conventional oil ultimate were available from an early date. These included the UK Department of Energy's 1974 estimate of 4500 million tonnes (33 Gb) shown in Fig. 2.11; and see also the additional early URR estimates given in Annex 2.

Then using the 'mid-point' rule—well known and well understood at the time—it was easy to predict that UK production would peak at, or probably a bit before, the point where about half of this (i.e., 16.5 Gb) had been produced. Looking at Fig. 2.11, this meant around the mid-1990s if the slowdown due to the 'production trough' is ignored. It was this understanding of the likely date of peak—well known within the industry—that allowed a 1976 UK research study for the government to note that the date of the world oil peak (at "about [the year] 2000") would not be far behind that of the UK peak (UK Department of Energy 1976, p 12).

However, somehow this information on the UK peak got lost. In about 1997 and 1998 our small *ad hoc* Oil Research Group at the University of Reading tried several times to warn the UK's Dept. of Trade and Industry (DTI) of the coming *global* peak of conventional oil production, where our line of argument was simple: 'You understand the mechanism behind the coming UK peak, and you know that this is close; the world peak works in rather the same way, and the 2P discovery data show that is fairly close also'.

Unfortunately, this argument fell completely flat. The concept of 'mid-point peak' had been forgotten (and not just in the UK), and a deep myth had developed instead based on the evolution of *proved* reserves. In the UK, for example, UK *proved* reserves had held steady since about 1980 at between 4 and 5 Gb, despite annual production being nearly 1 Gb/y for most of this period (Annex 2). As a result, this nearly two decades of there apparently being only roughly '5 years' supply' of UK oil remaining (plus corresponding data for other countries) had fooled nearly all analysts (including many within the oil industry, and most within the UK government and also at the IEA) into thinking that this 'replacement of reserves' was primarily due to improvements in technology; with horizontal drilling and 4-D seismic being widely cited. Our arguments about the proximity of the global oil peak were therefore seen as baseless, because the DTI were convinced that the UK peak itself was still many years away; and that afterwards production would decline only gradually anyway, because of future gains in technology. (For a fuller discussion of these meetings with the UK's DTI and with other government bodies, see Chap. 4 of Campbell (Ed.) 2011.)

Nevertheless, despite the DTI's scepticism, the UK peak was indeed close. Today we can give the UK as an example of a country where, for *conventional oil*,

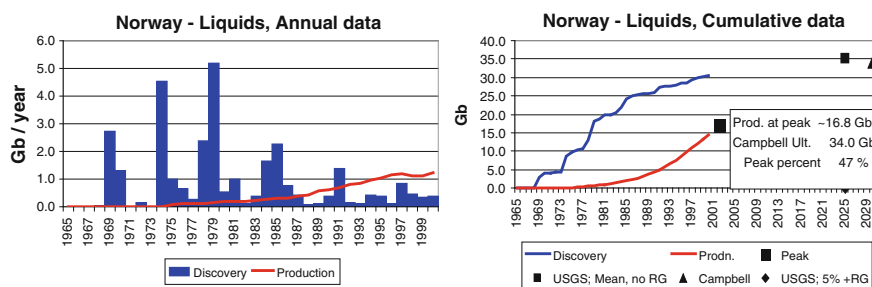
only modest scope remains for new discoveries, where the likely total recoverable quantity of this oil is judged well over half depleted, and where the country's resource-limited oil production peak of this oil is past.

### 2.3.6 Oil Discovery and Production in Norway

Next we look at comparable graphs for Norway. These are given in Figs. 2.12, 2.13 and 2.14, and indicate similar findings to those for the UK and Germany.

As Fig. 2.12 shows, Norway's discovery has come in 'lumps'; while her production rose to 1997 and then fell slightly. Production then peaked in 2001 (as shown by the medium-sized square in the cumulative chart). The latter plot indicates that this production peak was indeed resource-limited, if based on the quantity of oil discovered to the year 2000; with the peak occurring at 47 % of a URR that would seem reasonable from extrapolation of 2P discovery.

Note that Norway, despite her closer involvement with the oil industry via her government share of StatOil, had, like the UK, serious issues in the early years with the misleading evolution of her proved reserves, and only later got the proper presentation of the reserves data sorted out.



**Fig. 2.12** Norway: Oil-industry '2P' data on oil discovery, and production; 1965–2000. Data are for the IHS Energy definition of 'liquids'; here meaning crude oil plus NGLs.

*Left chart:*

- Blue bars Annual 2P oil discoveries (data are year-2000 backdated; i.e., reflect information available at 2000). Peak of discovery in ~1980.
- Red line Annual production. (Peak of production was just after the end of this plot, at 1.25 Gbly in 2001.)

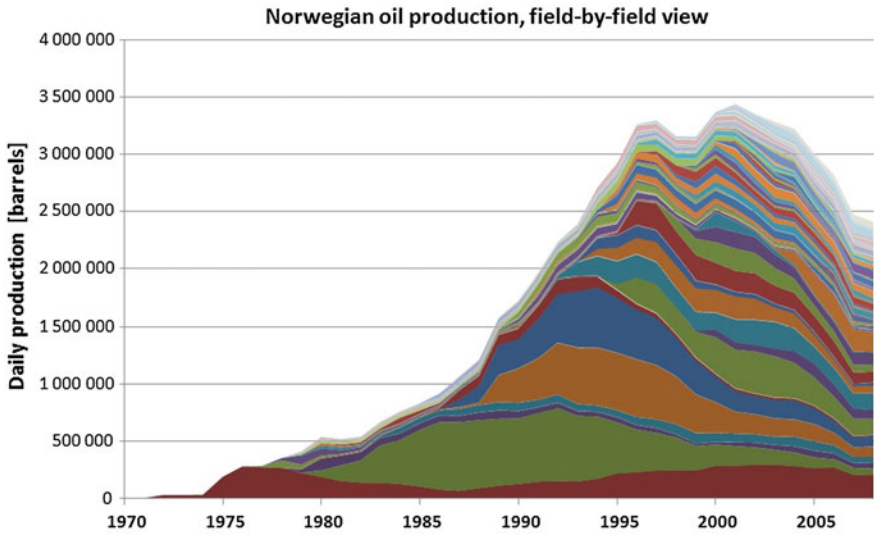
*Right chart* Cumulative plot of the same data.

- Blue line Cumulative backdated 2P discovery.
- Red line Cumulative production.

Also shown, URR estimates (made about the year 2000) from USGS and Campbell.

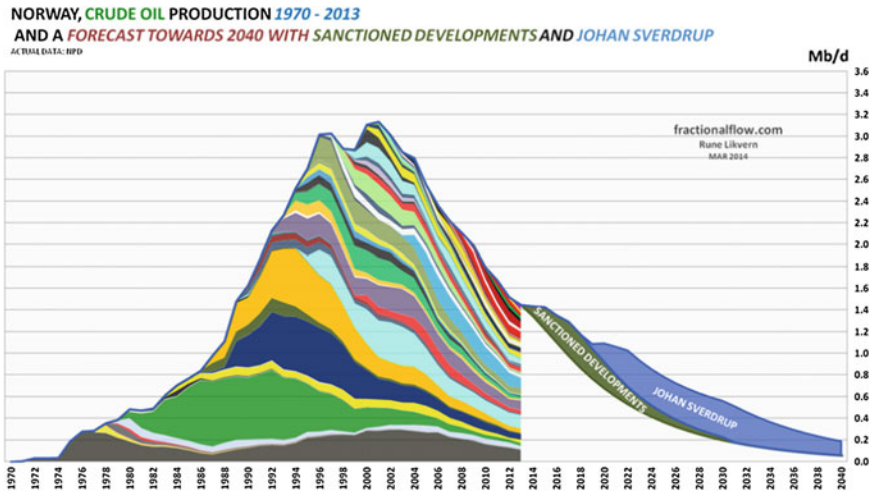
[Note Campbell's later estimate of Norway's 'Regular conventional' URR is unchanged, at 34.0 Gb; while he has corresponding cumulative production to 2010 as 23.5 Gb. (Campbell 2013).]

Source IHS Energy 'PEPS' year-2000 dataset, with permission



**Fig. 2.13** Norway: Oil production by field, 1970–2008.

Source M. Mushalik; website: <http://crudeoilpeak.info>



**Fig. 2.14** Norway: Production, 1970–2013, and forecast to 2040.

Source Rune Likvern, (fractionalflow.com), March 2014, and see caveat on this website re possible higher future production; reproduced from M. Mushalik website: <http://crudeoilpeak.info>



Figure 2.13 presents Norway's production on a by-field basis, while Fig. 2.14 includes similar data plus a forecast of production to 2040.

As Fig. 2.13 shows, the individual field profiles are quite variable, and (at least for the larger fields) are less like those indicated in the simple model of Fig. 2.4 than was the case with UK field production. Nevertheless the same general mechanism driving the resource-limited peak of conventional oil production in a region is clear: decline of the large early fields not being compensated after peak by the production of the numerous later but smaller fields.

In summary, Norway is like the UK, a country where for *conventional* oil it is almost certain that only modest scope remains for new discoveries, where her original recoverable stock of this class of oil would seem to be well over half depleted, and hence her *resource-limited* production peak of this class of oil is past; Fig. 2.14.

### 2.3.7 Oil Discovery and Production in Indonesia, Russia and Iraq

Up to now we have looked at the production peak of conventional oil in a region via four examples: a simple model; in a small oil producer well past peak (Germany), though with enough fields to illustrate the fundamental mechanism of peak; and in two relatively large oil producers (the UK and Norway), but where their fields are totally or predominately offshore, and hence reflect fairly recent technology (that since the 1970s) from the outset.

To understand peak in a region more fully, we need also to look at large producers with a longer production history, and here we choose Indonesia, Russia and Iraq. Our research group in both the Oil Depletion Analysis Centre (ODAC) in London, and at the University of Reading, has examined the year-2000 IHS Energy 'PEPS' 2P discovery and production histories for the majority of all significant oil-producing countries, including these three, but permission to release these data has been given only for Indonesia. Nevertheless, useful observations can be made for all three countries. In each case, the main questions to ask are:

- Has the region seen one or more peaks in production?
- Were these peaks generated by politics, price, or commercial considerations; or instead by hitting the region's recoverable conventional oil *resource limit*, based what has been discovered to-date?
- Could the region see a future, higher production peak? I.e.: Do the petroleum geologists think there is potential for sufficient new conventional oil discoveries to raise future production above the earlier peak (or, equivalently, the reservoir engineers think there might be adequate gains from recovery factor increases to do the same)?

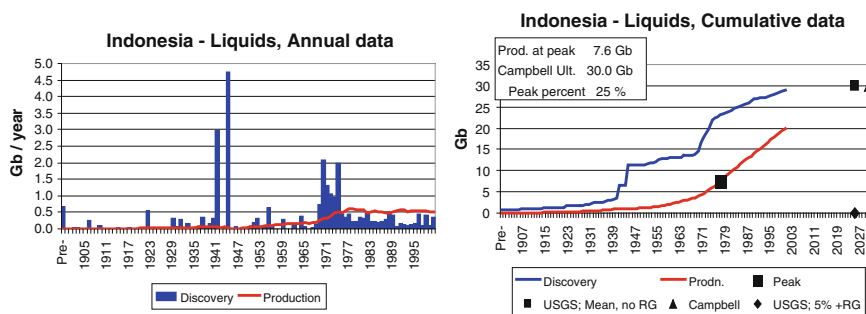
We look at these countries in turn:

## Indonesia

The IHS Energy ‘PEPS’ data for Indonesia to 2000 are given in Fig. 2.15.

As Fig. 2.15 shows, up to the year 2000 Indonesian production had given no clear indication of peak, having remained roughly on-plateau since 1973 (and only starting to fall off post 2003). So the question is why did Indonesia not exhibit one or more peaks as in the earlier examples given above? The explanation is that the country has seen several phases of discovery: two main phases (in terms of volume discovered) in onshore oil, in the early 1940s, and in the 1970s; and a substantial phase of discovery of offshore oil, starting from the late 1960s, and tailing off from about 1995. Production thus reflected this succession of discovery phases.

So again the important question is: Is Indonesia anywhere near her resource-limited production peak for conventional oil? We can answer this from Fig. 2.15 (right). With cumulative production by 2000 at 20 Gb, and the USGS, Campbell, and extrapolation of discovery estimates for URR all agreeing



**Fig. 2.15** Indonesia: Oil-industry ‘2P’ data on oil discovery, and production; 1900–2000. Data are for the IHS Energy definition of ‘liquids’; here meaning crude oil plus NGLs.

### Left chart

- **Blue bars:** Annual 2P backdated oil discoveries (i.e., reflect discovery information available at 2000). Two main discovery phases are indicated: in the 1940s, and the 1970s.
- **Red line** Annual production. No significant production peak; plateau from ~1973. (As more recent data indicate, this plateau extended to 2003, following which there has been a significant decline in production.)

### Right chart Cumulative plot of the same data.

- **Blue line** Cumulative backdated 2P discovery; the main two phases of discovery (the first onshore, the second a combination of onshore plus offshore) are clear from the ‘steps’ in the discovery curve.
- **Red line** Cumulative production. Medium-sized square indicates the approximate onset of the production plateau.

Also shown are URR estimates for Indonesia conventional oil, from the USGS year-2000 assessment (mean, no reserves growth value); and from Campbell (for ‘Regular conventional’ oil). These estimates, at 30 Gb, are in agreement with a rough extrapolation by eye of the discovery trend. [Campbell (2013): ‘Regular conventional’ URR: 32 Gb; cumulative production to 2010: 24 Gb.]

Source IHS Energy ‘PEPS’ year-2000 dataset, with permission

at  $\sim 30$  Gb, clearly the country is *well past* her resource-limited conventional oil maximum on the basis of the ‘peak at mid-point’ rule.

It was this level of depletion, and hence declining production, that caused Indonesia to initially withdraw from OPEC in 2009 (though she has recently been given approval to re-join). Note that the country’s resource-limit should not have come as a surprise; it could be predicted from about 1980, the date by which the combination of both onshore and offshore 2P discoveries had begun to tail off (Fig. 2.15, right), and hence the country’s likely total URR could be established with reasonable confidence; and hence also the likely date of the country’s *resource-limited* conventional oil production maximum.

### **Russia**

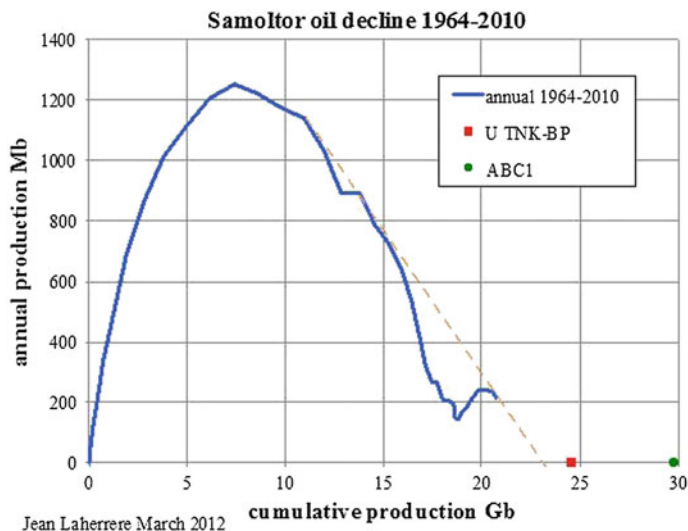
Although no IHS Energy ‘PEPS’ year-2000 charts can be given here, examination of the data shows a clear drop-off for Russia in both backdated 2P discovery, and production, in the eight or so years prior to the year 2000; where these reductions were due to the collapse of the Soviet Union. Both discovery and production have recovered to some extent subsequently.

But what about Russia’s peak production: Is it anywhere near? Campbell’s estimate at the year 2000 of Russia’s ‘Regular conventional’ ultimate, was 200 Gb, where this was significantly lower than either the USGS year-2000 mean estimate for Russia’s conventional oil ultimate, excluding reserves growth, at  $\sim 310$  Gb, and the apparent asymptote of the discovery trend at the same date, suggesting around the same figure. This difference was for two reasons: Firstly, Campbell excludes Russia’s polar oil in this ‘ultimate’. But secondly, and importantly, Campbell (like Laherrère and some others) judges that much of the Russia discovery data are in fact 3P (proved-plus-probable-plus-possible), rather than 2P; see Fig. 2.16.

As Fig. 2.16 shows, the TNK-BP estimate of the field’s URR is much more in line with the linearised production decline trend than the ABC1 value held in some industry databases; and note that the TNK-BP estimates *includes* considerable future work to maintain field production. For additional discussion of this topic, see Laherrère (2015).

If we use the Campbell year-2000 estimate for Russia’s ‘Regular conventional’ oil, and with her cumulative production to that date being  $\sim 120$  Gb, it was clear from the ‘mid-point’ rule that the country could not be far from its production peak of this class of oil. This was despite the fact that many analysts at the time were predicting that Russia production would see large increases, and come to the rescue of declining production in many countries elsewhere.

Campbell’s more recent estimate as of 2010 of Russia’s ‘Regular conventional oil’ ultimate is higher, at 230 Gb; while Laherrère’s estimate for Russia’s all-conventional oil URR is about 250 Gb. When these are set against the country’s cumulative production to 2010 of about 150 Gb (Campbell 2013, p149), Russia’s peak production of both of these classes of oil would seem to be almost certainly past. And, like the previous examples given, the date of this peak could have been predicted for a long time; Russia’s 2P discovery trend having started to fall from about the mid-1960s.



**Fig. 2.16** Russia ‘Linearised decline’ plot of the Samotlor field: Production versus Cumulative production.

*Notes*

- Annual: Annual production.
- U TNK-BP: Estimate of field URR from TNK-BP.
- ABC1: Field URR held in some industry databases; often treated as proved-plus-probable (2P), but more likely proved-plus-probable-plus-possible (3P).

Source J. Laherrère, 2012

## ***Iraq***

Now we look at discovery and production in Iraq. Here the year-2000 ‘PEPS’ data show three distinct ‘steps’ of oil discovery, corresponding roughly to the major discovery plays of Kirkuk, Rumailia, and East Baghdad. The question naturally is: Does Iraq have a lot more oil to discover? Many analysts have looked to the Western desert to yield much.

But when the USGS were asked to re-visit their year-2000 assessment for Iraq in greater detail they looked thoroughly at source rocks, traps, and possible migration paths, but stuck more-or-less to their year-2000 assessment of ultimate (Ahlbrandt 2003). The mean ‘non-grown’ value of the latter at 145 Gb was close to Campbell’s year-2000 value of 135 Gb, and also close to the asymptote of the cumulative discovery trend based on what had been found to that year. Campbell’s later (2013) estimate of Iraq’s ‘Regular conventional’ URR, as of 2010, has fallen somewhat, to 115 Gb, but this does not change the picture much.

This is because Iraq’s cumulative production is still relatively small, reaching some 34 Gb in 2010 (Campbell 2013), or around 40 Gb by end-2015. So although Iraq is unlikely to have much more conventional oil than already discovered, only about one-third of this has been used so far, and hence sufficient remains to support

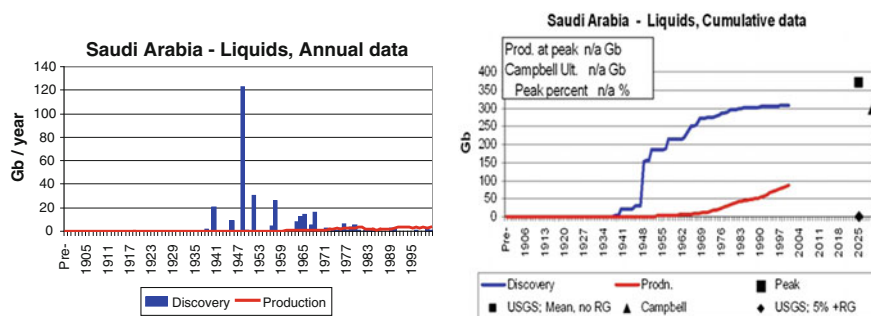
the country's development for many years to come. However her production *peak* is probably not too far away; if her production rises fairly soon to a plateau of 6 Mb/d as some foresee, then on the simple 'mid-point' rule the country's peak of conventional oil would be in just over a decade or so.

Iraq is thus an example of a region where the conventional oil production peak, though not past, is also not so very distant. Note that given the USGS view that not much more conventional oil remains to be discovered in Iraq in new fields, her ultimate—and hence her resource-limited production peak—could have been estimated from about the last 'step' in the cumulative discovery curve, which occurred some forty years ago, around 1976.

### 2.3.8 Oil Discovery and Production in Saudi Arabia

Finally, to complete our survey of how regions behave in terms of 2P discovery and hence their production peak, we look at perhaps the most significant producer not yet past peak, Saudi Arabia. Here the relevant 'PEPS' year-2000 data are given in Fig. 2.17.

As the Fig. 2.17 (left) shows, Saudi Arabia's oil discovery is dominated by the super-giant field Ghawar in 1948, with other finds relatively considerably smaller.



**Fig. 2.17** Saudi Arabia: Oil-industry '2P' data on oil discovery, and production; 1900–2000. Data are for the IHS Energy definition of 'liquids'; here meaning crude oil plus NGLs.

*Left chart:*

- *Blue bars* Annual 2P discoveries (data are year-2000 backdated, so reflect information available at this date). The earliest find was in 1938 at the Dammam well No. 7 (now modern day Dahahran); but the country's super-major discovery was Ghawar in 1948, with relatively little discovered since 1970.
- *Red line* Annual production. Early peak at 10.3 Mb/d in 1980, and rough plateau from 1990. [More recent data show the absolute peak in production to-date is in 2015.]

*Right chart:*

- Cumulative plot of the same data, plus two estimates made around the year 2000 of Saudi Arabia's conventional oil 'ultimate'. [Note Campbell (2013): 'Regular conventional' URR estimate unchanged at 300 Gb; cumulative production of this class of oil to 2010: 117 Gb.]

Source IHS Energy 'PEPS' year-2000 dataset, with permission

Production has been variable over time, mainly due to the imposition of quotas. The questions we are seeking to answer, of course, are: What is the country's likely future production; and how close is peak?

To answer these we first need to know how well the simple model of Fig. 2.4 applies to the large Middle East producers such as Saudi Arabia. A number of people, including for example Dr. Adnan Shihab-Eldin (former Acting Secretary General for OPEC), have questioned the applicability of the simple model of Fig. 2.4, which captures the main drivers for the peak in countries like the UK, to large Middle East producers. This is a sensible question, as the latter have oil discovery and production characteristics quite a bit different to countries like the UK. Specifically, in the large Middle East producers:

- There is usually one, or a small number of, extremely large fields, and then a succession of smaller, more typically-distributed fields in terms of size.
- This one, or a few, extremely large fields have normally been held on-plateau for long periods (rather than rising fairly quickly to peak production and the declining); but also, from time to time, they have seen wide excursions in production resulting from OPEC quotas, or civil or military unrest.
- Some of these countries, and Saudi Arabia especially, have considerable amounts of oil remaining in untapped ('fallow') fields, waiting to come on-stream once the very large fields go into decline.
- Finally, oil exploration in these countries is financially different from those where commercial companies pay for exploration. This is because, since expropriation, exploration expenditure and field upgrades in these large producers often has to be paid for in real funds, not as '10-cents-on-the-dollar' tax-deductible expenditure as was the case when the oil companies were in control.

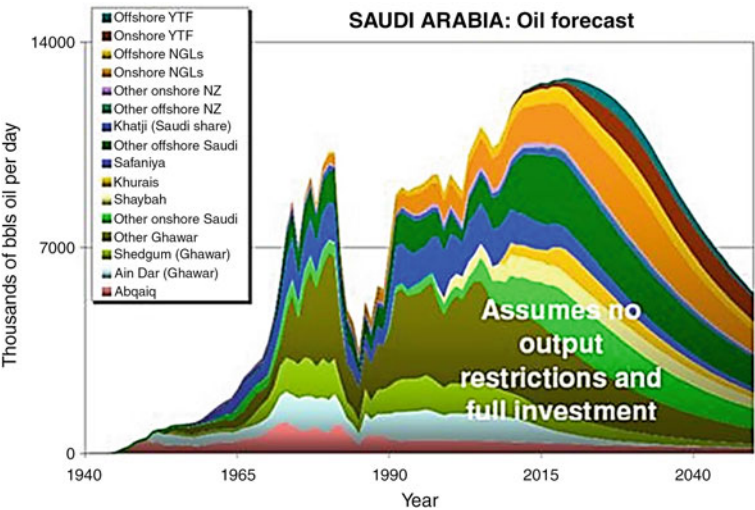
To see if the simple model of Fig. 2.4 applies to a producer such as Saudi Arabia, we need to look in detail at the country's typical field profiles; and also at the estimates for URR. We start with field profiles.

#### *Field profiles:*

We can examine the country's field profiles via two publically-available bottom-up by-field forecasts for Saudi Arabian production dating from 2008, given in Figs. 2.18 and 2.19.

Of particular importance in these forecasts is the expected production profile of Ghawar. This field has seen reportedly excellent work in terms of water injection wells along the field flanks, and one reservoir engineer familiar with the field suggests that production will 'go out like a light' at the end of this injection phase. However, the field is far from homogenous along its length, and both the above two forecasts indicate instead that Ghawar's production will tail off over time in a typical exponential fashion.

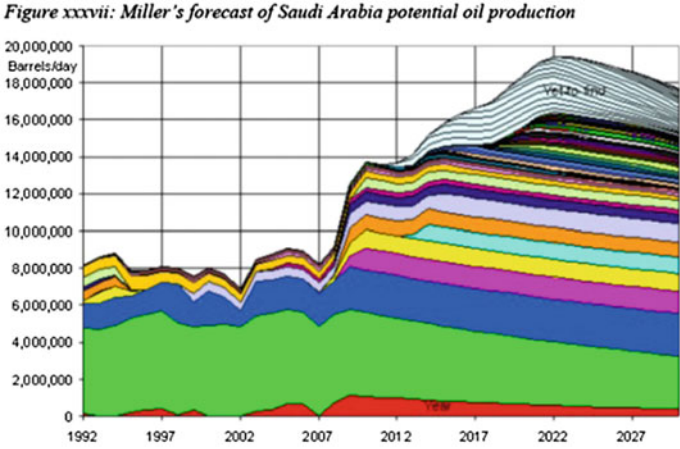
In the Energyfiles Ltd. forecast, other fields are also shown with exponential decline in output; this is in contrast to the Miller forecasts (over a shorter period) which shows the *large* other fields as holding a relatively flat output to the end of the forecast period, with smaller fields (and the yet-to-find fields) showing typical field decline.



**Fig. 2.18** Saudi Arabia: Forecast, made in 2008 by Energyfiles Ltd., of production by field, and field type, to 2050.

*Note* Ghawar production is shown as three separate components.

*Source* Annex of Technical Report 7, UKERC Global Oil Depletion study, 2009



**Fig. 2.19** Saudi Arabia: Forecast, made in 2008 by R. Miller, of production by field to 2030.

*Note* Ghawar production is represented by the light green field second from bottom.

*Source* Annex of Technical Report 7, UKERC Global Oil Depletion study, 2009

In terms of total output, the two forecasts give significantly different results: Energyfiles predicts a peak in production at about 12 Mb/d occurring in about 2020; while Miller forecasts a much higher peak, at nearly 20 Mb/d, occurring around the



same date. The explanation for the difference is that Miller's forecast includes the 'Miller bump' in production, due to bringing on rapidly all the country's currently fallow fields (UKERC 2009). But Miller reports (private communication) that he thinks such a situation unlikely, and would probably support the more cautious view shown in the Energyfiles' forecast.

The main conclusion from these two forecasts is that the underlying mechanism of Fig. 2.4 of resource-limited oil peaking in a region—the result of adding the output from large early fields, and then from smaller fields—is expected to operate in the same fundamental way for the large Middle East producers as for countries already past peak, such as the UK. There is a caveat however: with their long flat production profiles of large fields, regions such as these very large producers would be expected to see peak later, in terms of percentage of URR, than is typical for the more normal 'unconstrained-production' producers, such as the US, UK, or Norway; so resulting in peak production *at mid-point of the URR or a bit after*, rather than more typically for other regions of peak at mid-point or a bit before. (Incidentally, for forecasts for Saudi Arabian production by the IEA and EIA made at the same date see Annex 5.)

Next we look at the second part of the puzzle for predicting Saudi Arabia's output: estimates of her likely conventional oil URR.

#### *What URR to assume for Saudi Arabia?*

There is disagreement (indeed, true uncertainty outside of the country) on what is Saudi Arabia's likely URR for conventional oil.

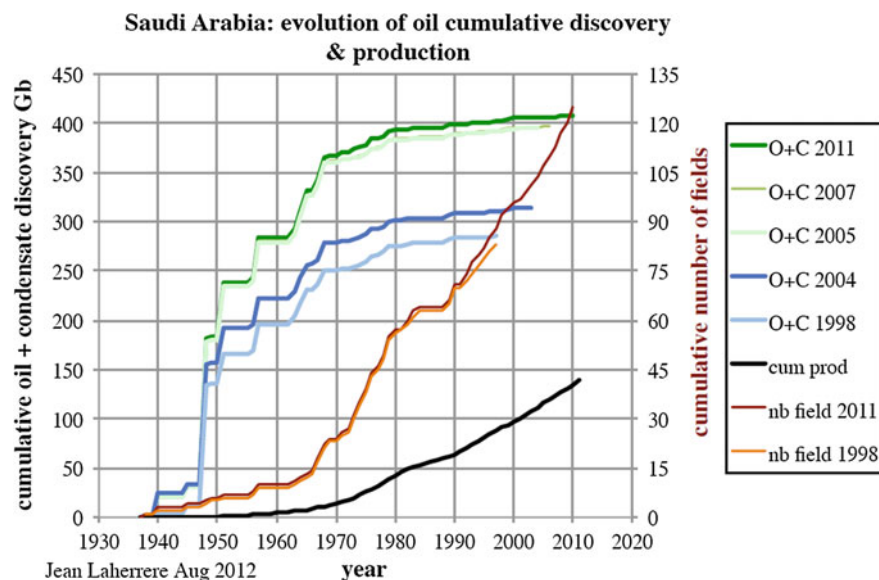
Though some authors foresee very large volumes of oil yet to be discovered in the country, based in part on the relatively few exploration wells (only somewhat under 200 'new-field wildcats') that have been drilled to-date; among petroleum geologists there is—perhaps surprisingly—only modest uncertainty over the country's yet-to-find quantity, where this is generally taken as not especially large compared to that discovered to-date. This is due to the region's geology of large salt-sealed anticlines which are fairly easy to map via seismic, and where oil from the source rock concentrates at the top of these, with little oil expected between. As a result the apparent asymptote of discovery to-date, for example, as shown in Fig. 2.17 (right), is generally taken as a reasonable indicator of URR.

Instead, the greater uncertainty on the size of the ultimate hinges on knowing the true 2P quantity of oil *already discovered* in the country; where some authorities take a higher figure, and some, such as Campbell, Laherrère and others, a lower. The explanation for this lies in Fig. 2.20.

Figure 2.20 shows several trajectories for the apparent Saudi Arabia 2P cumulative discovery curve from an industry source, as generated at five different dates spanning 1998–2011. Specifically for example, the curve at 1998 indicates an 'extrapolated-by-eye' URR of  $\sim 300$  Gb, while the three curves from 2005 and later indicate the equivalent URR at about 400 Gb or a bit higher.

The curves thus provide (a rather extreme) example of one aspect of apparent 'reserves growth' in some of the industry data. While many cases of reserves growth in a field or region can be a significant, due to improved technology or an





**Fig. 2.20** Saudi Arabia: Backdated notionally ‘2P’ cumulative oil discovery data from an industry source, as reported over a number of different years spanning 1998–2011; also cumulative production (*both left-hand scale*); and cumulative number of fields (*right-hand scale*).

*Legend*

- O+C: Oil plus condensate, plus year when data reported.
- cum prod: Cumulative production to 2011.
- nb field: Number of fields discovered, plus year when data reported; right-hand scale.

Source J. Laherrère, Aug. 2012

increase in oil price (see discussion in Annex 4, section 3), and hence need to be taken into account in oil forecasting, in this case Laherrère has a different explanation for the large gain in apparent URR. He notes that IHS Energy is possibly now obliged to report Saudi Aramco official reserves estimates for the country, such that IHS Energy’s cumulative discoveries for Saudi Arabia currently stand at about 400 Gb as shown in Fig. 2.20; and hence in agreement with the country’s reported end-2011 remaining *proved* (1P) reserves of 265 Gb, plus cumulative production to the same date of ~140 Gb. Previously Petroconsultants (IHS Energy’s predecessor company) had reported a much lower number for Saudi Arabia cumulative 2P discovery, closer to the 300 Gb shown in Fig. 2.20 for the 1998 data. Also shown on this plot are estimates for the number of fields at two different dates, indicating that it was not the addition of new fields that explains the discrepancy. Further details supporting this view from Laherrère are given in Laherrère (2015).

So what URR should we use for estimating Saudi Arabia’s date of conventional oil peak? Figure 2.17 (right), vintage 2000, indicates the USGS year-2000 estimate for URR (mean, no reserves growth, ex-NGLs) was ~370 Gb; while Campbell’s estimate of the same date for ‘Regular conventional’ oil (ex-NGLs) was 300 Gb.

Since the USGS year-2000 estimate was made on the basis of 1994 Petroconsultants' data, and hence was quite a bit above the 2P discovery trend at that date, the argument was possibly made that Saudi Arabia had had no great need to explore for more oil while quotas were in place. Campbell's subsequent 2010 data (Campbell 2013) still holds the URR at 300 Gb (ex-NGLs), while the cumulative production (also ex-NGLs) to that date was 117 Gb. (This contrasts with the country's cumulative production to 2011, including NGLs, being  $\sim 140$  Gb as shown in Fig. 2.20) Adding another 5 years of production to the 2010 data puts Campbell's cumulative production today at  $\sim 135$  Gb, indicating, if the mid-point rule is used, that Saudi Arabia's peak would be in only four years or so; although as explained above, for large Middle East producers it may be reasonable to expect peak somewhat later than mid-point.

Nevertheless, this provides a warning of the coming supply difficulties. If instead, the 'including NGLs' cumulative production to-date value of 155 Gb is used, and this is combined with an assumed higher URR (incl. NGLs) of, say, 430 Gb, then Saudi Arabia's 'mid-point' peak is expected in 2030; but see also the by-field forecasts of Figs. 2.18 and 2.19 which put the production peak earlier, around 2020 or so.

In either case, note that Saudi Arabia's backdated 2P cumulative discovery data had substantially flattened out by about 1970 (Fig. 2.17 right), allowing reasonable forecasts of her likely date of production peak to be made from that date, provided a view was taken on the accuracy of the 2P discovery data used.

### 2.3.9 *Summary of Findings on Peak Conventional Oil Production in Regions*

In summary, in this section on explaining the peak of conventional oil production in *a region*, we have examined the mechanism for peak as indicated by a simple model, and looked at past or future peaks in a number of countries as follows: Germany (a small producer well past peak); the UK, Norway and Indonesia (medium producers past peak); Russia (a large producer at or close to peak); and Iraq and Saudi Arabia (large Middle East producers whose production peaks are in the future, though not so very far away). Table 2.1 summarises these findings, and includes data for the US and the world, as supplied elsewhere in this book.

Despite these differences in their dates of peak production as given in this Table, the common factor of all these countries—and indeed of virtually all regions globally—is that their dates of peak *discovery* of conventional oil (oil in fields) are well past, as indicated by the inflection points in their backdated cumulative 2P discovery curves.

This in turn permits the simple approach to be applied of extrapolating this discovery trend (combined with geological knowledge to indicate possible new

**Table 2.1** Dates of Peak 2P discovery of conventional oil compared to peak in production

	C'bell ~ 2000 (Reg. cv. oil)	USGS 2000 (Cv. oil ex- NGLs)	C'bell 2010 (Reg. cv. oil)	C'bell cum. prodn. to 2010 (Reg. cv.)	Cum. prodn. to end 2015 (Reg. cv.)	C. Pr. 2015 as % C'bell URR	Main oil loc'n.	Date of peak discvy. (All-cv. oil)	Date of peak prodn. (All-cv. oil)
	URR	URR	URR						
	(Gb)	(Gb)	(Gb)	(Gb)	(Gb)	(%)	(On/off)	(Year)	(Year)
<i>Notes</i>	<i>1</i>	<i>2</i>	<i>3</i>	<i>4</i>	<i>5</i>	<i>6</i>	<i>7</i>	<i>8</i>	<i>9</i>
<i>Country</i>									
Germany	2.4	2.1	2.5	1.96	2.05	82	On	1950s	1967
UK	32	29	32	24.7	26.3	82	Off	Mid-1970s	1999
Norway	34	35	34	23.5	26.9	79	Off	1970s	2001
Indonesia	30	30	32	24.0	25.6	80	All On Off	'40s, 70s '40s, 70s '60s-95	1977 <sup>a</sup>
Russia	200	303	230	150	165	72	On	1960s	1987 <sup>b</sup>
Iraq	135	145	115	34	40	35	On	Var.	-
Saudi Arabia	300	371	300	117	135	45	On	1948	-

(continued)

Table 2.1 (continued)

	C'bell ~ 2000 (Reg. cv. oil)	USGS 2000 (Cv. oil ex- NGLs)	C'bell 2010 (Reg. cv. oil)	C'bell cum. prod. to 2010 (Reg. cv.)	Cum. prod. to end 2015 (Reg. cv.)	C. Pr. 2015 as % C'bell URR	Main oil loc'n.	Date of peak discvy. (All-cv. oil)	Date of peak prodn. (All-cv. oil)
	URR	URR	URR						
	(Gb)	(Gb)	(Gb)	(Gb)	(Gb)	(%)	(On/off)	(Year)	(Year)
USA	260	286	200	179	194	97	On	Mid-1930s	1970
World	~2000	2307	2000	1093	~1220	~60	On	1960s	2005 <sup>c</sup>

Also shows: Cumulative production of 'Regular conventional' oil to end-2015 versus Campbell's 2010 estimate of URR for this class of oil

#### Notes

1: Campbell 'Regular conventional' oil is 'All-conventional' oil less: deepwater, polar, very heavies, NGLs. *Source* Personal communications and Campbell publications

2: USGS Year-2000 Assessment data: Mean values, ex-NGLs, no adjustment for reserves growth. *Source*: USGS (2000)

3: *Source* Campbell (2013)

4: *Source* Campbell (2013)

5: Production data from BP *Stats. Rev.*, for 2011–2014, plus for 2015 estimated; and multiplied by a guessed 80 % if the country or region in question is currently producing significant quantities of non-'Regular conventional' oil

6: Cumulative production to end-2015 of 'Regular conventional' oil (estimated as above) as a percentage of the Campbell 2010 URR estimate for this class of oil

7: Main location of the country's oil, onshore or offshore

8: Date of peak '2P' discovery of 'All-conventional' oil

9: Date of peak production of 'All-conventional' oil

<sup>a</sup>Indonesian production was roughly on plateau: 1977–1996

<sup>b</sup>Date of this Russian peak was prior to the economic collapse of the FSU, but Russia's recoverable conventional oil resource base is now such that a significantly higher future peak in production is no longer possible

<sup>c</sup>This is the peak date of global 'Regular conventional' oil. The global peak date of 'All-conventional' oil is less certain, see text

For more recent USGS data, see Annex 4

plays) to estimate each region's likely conventional oil URR; and hence using the approximate 'mid-point' rule to predict the date of peak production.

Now we turn to a different and important question: how to predict the date of peak conventional oil production *for the world as a whole*.

## 2.4 Peak of *Global* Conventional Oil Production

Predicting peak conventional oil production for the world is different to predicting peak in a region. If a given region peaks, the world's supply of oil can be met by production ramping up in other regions, as has happened many times in the past; most notably when US Lower-48 conventional oil production peaked in 1970, with enough production to more than compensate coming from new, but already-discovered, regions such as Alaska, the North Sea, and in Mexico, Russia and elsewhere. To understand the global peak of conventional oil two new factors need to be considered: the comparative *cost* of conventional oil production from different regions and for different classes of oil, and also the global *price* of oil.

The comparative costs are needed because as one region or class of oil goes into decline (or is restricted into the market for political or other reasons), conventional oil from other regions or classes may replace it; the price of oil needs to be known to see if this is high enough to support such marginal production.

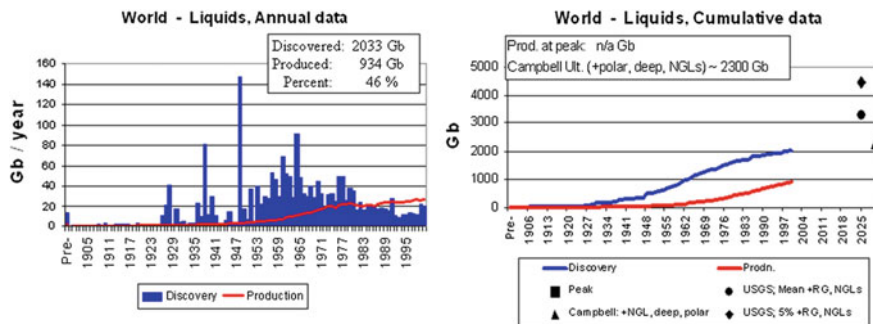
### 2.4.1 *IHS Energy Year-2000 Global Discovery and Production Data*

First however, in looking at the data for the global peak we start with the familiar IHS Energy year-2000 backdated 2P discovery and production plots; here for the world as a whole, as given in Fig. 2.21.

To understand the background to the global peak, these plots are worth examining in detail.

In the left plot the discovery of Ghawar in 1948 is clearly visible, as is the bulk of global conventional oil discovery which occurred in the period from 1950 to 1990, where this resulted from increasing knowledge of the geology and physics of 'oil systems', and from the widespread use of seismic techniques (and specifically digital seismic from about the mid-1960s).

But the plots also clearly set out the global availability of oil throughout this century. As the left plot shows, certainly from about 1925 onwards and probably before, the rate of discovery of conventional oil ran well ahead of oil production, and as a consequence this put a large quantity of oil in the 'global oil bank' in the form of 2P reserves. (Recall that this left plot is 'to-scale', in the sense that the total



**Fig. 2.21** World: Oil-industry ‘2P’ data on oil discovery, and production; 1900–2000. Data are for the IHS Energy definition of ‘liquids’; here meaning crude oil, NGLs, tar sands oil and Venezuela heavy oil. (The IHS Energy definition includes shale (‘light-tight’) oil and also oil from kerogen, but relatively little of these classes of oil were produced up to 2000.)

*Left* Annual backdated 2P discovery: vertical bars Annual production: line.

*Right* Same data on a cumulative basis.

Data from IHS Energy year-2000 ‘PEPS’ database, with permission

area covered by the blue bars by a given date measures oil discovered in the same units as the area under the red line gives total oil consumed by the same date.)

This happy supply situation started to change at the date at which the rate of conventional oil being discovered peaked, and then started to decline, as indicated by the inflection point in the discovery curve in the right (cumulative) plot. As this shows, the *rate of global discovery of conventional oil in new fields peaked in the mid-1960s*; a key fact, still not sufficiently known, in understanding future global oil production. But, even so, in the mid-1960s, annual discovery, though it had peaked, was still running ahead of annual production, so the 2P reserves ‘in the bank’ were still increasing, although progressively more slowly.

This global oil supply situation changed yet again in about 1980, the critical date at which global production finally caught up with rate of global discovery of oil in new fields (see the left plot). At this date the 2P global reserves ‘in the bank’ started to decline. But as the right plot shows, even by the year 2000 there was still a large quantity of these reserves remaining; at just over 1000 Gb, representing about 40 years’ worth of global production at that date.

With this information in hand, we can now address the question of the approximate date of the global production peak of conventional oil.

The right plot of Fig. 2.21 shows three estimates from the year 2000 of the world’s conventional oil URR (but note that the definitions of these estimates are different to those in the similar previous by-country plots). These estimates are:

- Campbell’s year-2000 estimate for global ‘Regular conventional’ oil, but here also *plus* deepwater and Arctic oil, plus NGLs; URR ~2300 Gb (triangle, at ~2030).

- USGS year-2000 mean estimate for the global URR of ‘all conventional oil’ (including NGLs) and here *including* upward adjustment for reserves growth; URR = 3345 Gb (circle, at ~2025).
- USGS year-2000 corresponding ‘5 % probable’ estimate (again including NGLs plus adjustment for reserves growth); URR ~4400 Gb (diamond, at 2025).

Notes:

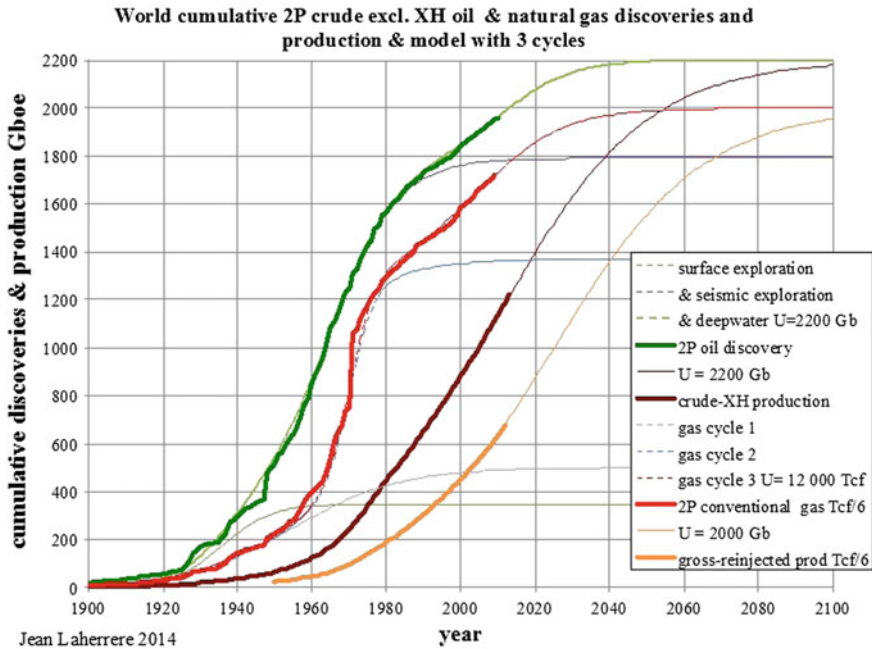
- Campbell’s URR would seem to be below the ‘extrapolated 2P discovery’ line. This is because as mentioned earlier he, like Laherrère, discounts some of the OPEC and FSU oil in the industry datasets.
- Both the USGS year-2000 URR estimates shown include reserves growth, the USGS in its Year-2000 Assessment having applied reserves growth functions globally for the first time (see Annex 4). While such growth is certainly technically possible, as can be seen from this plot these ‘assessed’ URR estimates were out of line with extrapolation of the global 150-year 2P backdated discovery trend. For such very large extra amounts of conventional oil (~1000 Gb in the ‘mean’ case; and ~2000 Gb in the ‘5 %’ case) to become available early enough to avert a global peak appeared very unlikely to many observers at that date.

On these data, it was already clear in 2000 that the World was close to its peak of conventional oil production if the ‘peak at mid-point of URR derived from extrapolated 2P discovery’ rule was applied. Extrapolating the cumulative 2P discovery and production lines forwards indicated that the global peak of conventional oil production was likely to occur around the year 2010. Indeed, as the Figure shows, based on the peak of discovery in the mid-1960s it had been clear for a long time that the global peak of conventional oil was likely to occur roughly around the year 2000, or not long after.

### 2.4.2 *More Recent Data on Global 2P Oil Discovery and Production*

Now we look at more recent data for global backdated 2P oil discovery and production. Figure 2.22 gives these data as supplied by Jean Laherrère for crude oil, but excluding NGLs and extra-heavy oil (the latter mainly tar sands and Orinoco oil); and also the data for gas.

As the Figure shows, Laherrère’s ‘exploration geologist’ view of the likely extrapolation of the backdated cumulative 2P discovery curve indicates a ‘medium-term’ URR for global ‘conventional’ oil (crude less extra heavies, less NGLs) of ~2200 Gb. On this basis, and using the ‘peak at ~ mid-point’ rule, and comparing to cumulative production shown for this class of oil to end-2013 of ~1230 Gb, the ‘expected’ date of peak for this oil would have been ~2005; in general agreement with the apparent actual date, see Chap. 4.



**Fig. 2.22** World: Cumulative 2P Backdated Oil Discovery 1900–2010, and forecast to 2100; Cumulative Oil Production, 1900–2013, and forecast to 2100. (Also shown are the corresponding discovery and production data for gas.)

- *Leftmost line* Laherrère’s judgement of ‘most probable’ backdated 2P cumulative global discovery data for crude oil plus condensate, less extra heavy oil (the latter mainly Athabasca tar sands and Orinoco oil), and not including NGLs.
- *Next left line* Corresponding data for gas, calculated as Tcf/6.
- *Next leftmost line* Cumulative global production of crude oil less extra heavy oil and NGLs.
- *Rightmost line* Cumulative global production of gas, Tcf/6.

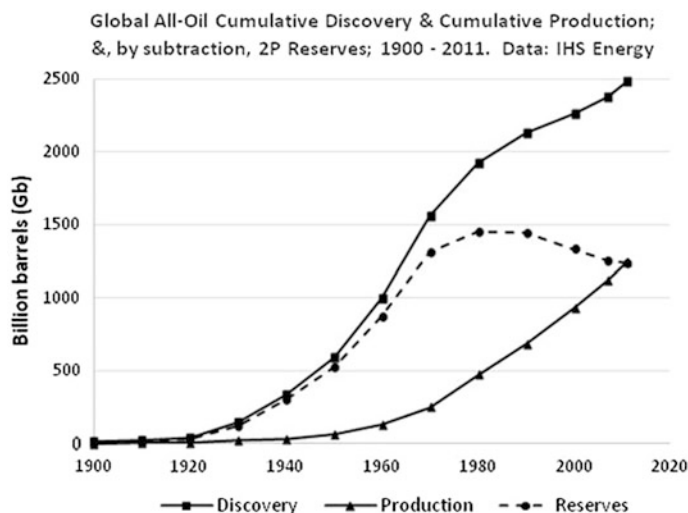
Laherrère writes: ‘The 2P discovery data reflect data from industry ‘scout’ sources, but reduced by: 300 Gb to allow for overstatement of the OPEC Middle East original reserves data (as confirmed by Sadad Al-Husseini, former VP Aramco, 2007 Oil & Money conference London); by 30 % of the FSU data (~ 100 Gb) to allow for the datasets ABC1 holding probably closer to 3P than 2P data (as indicated by field decline plots, see e.g., Fig. 2.16, and by Gazprom audits in annual reports); and by 200 Gb to allow for Orinoco 2P discovery data reflecting non-conventional oil.’

Source J. Laherrère

Alternatively, one can use the PFC Energy ‘peak at 60 % of discovered’ rule, and estimate the global peak date for conventional oil ex NGLs. On the basis of the data shown here, 60 % of current 2P discovery (at 1950 Gb) is ~ 1170 Gb, which predicts peak somewhat later, at ~ 2011–2012.



In comparison to Fig. 2.22, Fig. 2.23 gives the corresponding IHS Energy data for global oil discovery and production up to 2011 for the company's 'Liquids' category, which includes NGLs, light-tight oil, extra-heavy oil (the latter mainly tar sands and Orinoco oil), and oil from kerogen, but excludes GTLs, CTLs and biofuels.



**Fig. 2.23** World: Cumulative 2P backdated oil discovery, and cumulative oil production (also hence 2P Reserves by subtraction), 1900–2011.

#### Notes

- The plot shows IHS Energy 'Liquids' data, stated to include: "crude oil, condensate, NGLs, liquefied petroleum gas, heavy oil and syncrude". The data thus include light-tight oil, and oil from tar sands and Orinoco oil, but exclude GTLs, CTLs, biomass, and refinery gain.
- The plot is generated by reading data at 10-year intervals from Fig. 7 of Miller and Sorrell (2014) for cumulative discovery from 1900 to 2007, and from the corresponding Fig. 3 for cumulative production over the same period. Included in this plot are the data for end-2011 as given in the text of the Miller and Sorrell paper.
- Data are 2P, except for the US and Canada non-frontier areas, where the data are proved ('1P') data. The 2P data are backdated, in that they reflect information available to the IHS Energy as of 2007 (for the discovery curve), and to 2011 (for the final discovery data point). Reserves are calculated here (as done also by IHS Energy) by subtracting cumulative production from cumulative discovery.
- IHS Energy data are for oil in *fields* for conventional oil; and as announced in *projects* for non-conventional oils. The 'up-tick' in global discovery of this 'all-oil' visible from about the year 2000 (and hence the slowing in the fall-off of 2P reserves) is due to increasing inclusion of data for tar sands projects, and subsequently for US shale (light-tight) oil projects. Data are hence largely for conventional oil up until about the year 2000, after which significant amounts of tar sands and Orinoco projects were included, and most recently also data for 'light-tight' oil projects.
- As the plot shows, the global proved-plus-probable (2P) all-oil reserves at end-2011 were ~1250 Gb. This contrasts to the corresponding end-2011 value for global *proved* only (1P) all-oil reserves (from *BP Stats.*) of 1652 Gb. The difference is partly the amount of non-conventional oil included in the two sets of reserves figures, but is mainly due to the likely overstatement of Middle East OPEC *proved* reserves

In Fig. 2.23 the global discovery of *conventional* oil (incl. NGLs) might be judged (based on the pre year-2000 trend) to be heading for an asymptote URR around 2500 Gb, and where hence the production mid-point, and hence production peak, of this value is around 2011. As noted, the reasons for the difference in the data between Figs. 2.22 and 2.23 are due to the inclusion of different categories of oil, and to Laherrère's view on the need to pull down industry 2P discovery data for the FSU, some Middle East countries, and Venezuelan Orinoco oil.

Note that on the Fig. 2.23 data, as in Figs. 2.21 and 2.22, one can see that the rate of global discovery of conventional oil peaked in about the mid-1960s; and the volume of global 2P reserves in about 1980, the latter at about 1450 Gb if NGLs are included.<sup>26</sup>

Now we turn to the first of the two additional issues that bear on the date of *global* peak that were identified earlier: the comparative costs between different regions and classes of conventional oil. The data for this are given in Fig. 2.24.

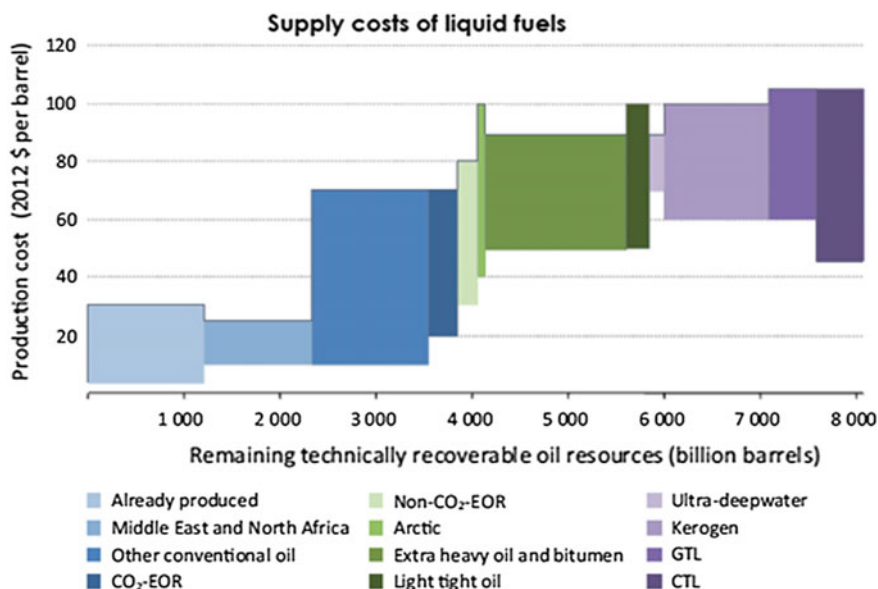
### 2.4.3 Recoverable Volumes Available of Different Types of Oil as a Function of Cost

Figure 2.24 is from the IEA and gives estimates, as of 2013, of the remaining quantities of oil available from different categories of oil versus their production cost ranges.

As Fig. 2.24 shows, and as would be expected, conventional and non-conventional oil from different sources come at different ranges of costs. The first six categories shown (up to 'Arctic'), and also 'Ultra-deepwater', refer to mainly conventional oil as we define here. The other five categories are either classed here as 'other-oils' (Extra heavy, Light tight and Kerogen), or as 'other liquids' (GTLs & CTLs). The plot includes only fossil resources, so does not include biofuels.

In an ideal free market all the cheapest oil shown in Fig. 2.24 would be produced first. In practice in some regions, especially in some MENA and other countries following 'resource-nationalism' policies, conventional oil production has been limited by restricting international exploration or production access, or held back to support a higher oil price, or kept in reserve "for our grandchildren". Also at times in these and other countries oil has not been available due to strife or war. As a result of these 'above-ground' factors, conventional oil production peaks have occurred in some of the higher cost oil regions earlier than would have been the case.

Nevertheless, despite such effects, charts like Fig. 2.24 have long seemed reassuring to many oil analysts. For example, the UK's Department of Trade & Industry refuted talk of a global peak by pointing out—based on a 2008 version of this chart—that: "There is more than enough oil available to meet foreseeable demand". This view might seem natural enough; after all this chart shows ~7000 Gb of recoverable oil of all types remaining, with a century-and-a-half of production having produced only ~1250 Gb. But this view is naïve. The correct way to read a chart like this as follows:



**Fig. 2.24** Estimated global remaining technically recoverable volumes of oil available, by category (in Gb), versus Production cost range (in \$2012/bbl).

*Notes*

- EOR: Enhanced oil recovery; *MENA* Middle East and North Africa; GTL: Gas to liquids; CTL Coal to liquids.
- Volumes of oil potentially available are shown by length along the x-axis, not by the area indicated.
- [Incidentally that there are two types of chart that indicate production cost of oil versus category. One is this type, where volumes of recoverable oil are indicated together with their production cost ranges. The second type shows global oil production at given date by category versus cost make-up. An example by IHS-CERA assuming a 15 % rate of return for investment is given in Miller and Sorrell (2014). This indicates that current oil production costs range from \$22/bbl for Middle East oil to \$160/bbl for ‘upgraded Canadian tar sands mine’ oil. Some estimates put current Middle East production costs as significantly higher than these IHS data. In addition, other studies look at the *price* needed from oil exports to balance national budgets of major exporters; these suggest that the ‘financially required oil prices’ are currently around \$100/bbl and above.<sup>4</sup>]

Source IEA *Resources into Reserves*, 2013

- Understand ‘mid-point’ peaking of conventional oil production, so on the data shown here expect the global peak of conventional oil when ~1925 Gb has been produced (i.e., half of the ~3850 Gb URR resulting from summing the ‘Already produced,’ MENA, Other conventional, Arctic, plus Ultra-deepwater; and excluding EOR as this usually comes on only late in a region’s life). At the current production rate of ~30 Gb/yr., and with 1250 Gb already produced by 2012, the global all-conventional oil ‘mid-point’ peak is expected roughly 20 years from this date, depending on the rate of demand growth.

- (b) Then recognize that production of much of the MENA oil will probably not increase significantly—despite current trends—for resource-national reasons.
- (c) So look instead for the ‘mid-point’ of total non-MENA conventional oil. On these data this occurs when 1370 Gb has been produced (half of  $\sim 2740$  Gb); i.e., in about 4 years’ time from 2012.
- (d) Note also that a global URR of 3850 Gb for conventional oil (incl. NGLs but excluding EOR) is judged by some as being too high, at least if compared to extrapolated discovery, and hence in terms of the likely date of peak. Such analysts estimate the total production of conventional oil (incl. NGLs) out to the year 2100 (i.e., approximately the global URR) as being from 500 to 1400 Gb lower than the IEA’ 3850 Gb (excluding reserves growth) number.
- (e) Hence conclude, correctly, that the steep rise in the price of oil since 2004 has been driven by the slowing increase in global *conventional* oil production resulting from proximity to its peak, which in turn has forced the world to obtain the marginal barrels needed to meet growing oil demand from the expensive oils shown to the right of the graph.
- (f) And, finally, recognise, that these more expensive oils also tend to have poor energy returns on energy invested (indeed a major factor in why they are costly to produce); and can face other constraints to their production such as permitting, water requirement, CO<sub>2</sub> emissions, and volume of waste if produced by mining.

Next we look at the second factor mentioned above that needs consideration when predicting the global peak date of conventional oil production, that of the price of oil itself.

#### ***2.4.4 Impact of the Price of Oil on the Availability of Oil***

The price of oil is important because as this rises exploration is encouraged and oil that was previously uneconomic can be brought to market. Economists have made much of this dynamic, though usually citing the flawed apparent replacement of the proved reserves data to prove their case (see Chap. 5). The proper question is: At a given oil price *by how much* can conventional oil production increase?

The detailed answer must come from reservoir engineers; and is also a function of date as technology advances with time. Some answers *by field* have been illustrated above, and we have also partial answers at least by region (and also globally) from the roughly decade of high oil prices (above \$50/bbl in today’s money) from 1974 to 1985, and a second decade of prices above this level from 2005 to 2015. Based on these data—for example, for US Lower-48 production over the first period, and the UK production for the current period—the answer is ‘*by not much*’, though admittedly the economists may have a valid point in saying that a decade is probably not enough for new exploration plays and production paradigms to come fully into effect.

Overall however, on the above field data and regional data, it would seem unwise to expect a high price, even \$100/bbl, to bring on very much in the way of extra conventional oil. Moreover, the price cannot go too high: as we know fairly solidly from both the earlier and the current period of high oil prices, that a price much above \$50/bbl in today's money slows economic activity, and reduces oil demand at least in the developed countries; while above about \$100/bbl in real terms it would seem to lead to global recession.

### 2.4.5 *Summary of Global Peak of Conventional Oil*

In summary, in this section examining the likely date for the peak of global conventional oil production, we can say:

- This date is not yet known for certain.
- In part it depends on:
  - how conventional oil is defined; e.g., with or without: NGLs, EOR, heavy oil (other than tar sands) needing thermal treatment, etc.;
  - the extent that the small number of mostly Middle East 'swing' producers decide (or not) to rein in their potential production to 'save oil for the grandchildren';
  - the extent and rate that currently fallow fields are brought on-stream;
  - and the impact that a sustained high oil price (of, say, >\$100/bbl) would have on the use of in-fill drilling, extra use of EOR, etc.
- But as Figs. 2.21–2.24 show, and also the forecasts of Chap. 4, the *date for the global peak of conventional oil production cannot be too far into the future.*

## 2.5 Peak of the Global Production of 'All-Oil', and 'All-Liquids'

So now we must turn from examining the date of peak of global *conventional oil* production to the peak for the global production of *all-oil*; and also that of *all-liquids*, where the latter includes GTLs, CTLs and biofuels.

Here a key point from the IEA data in Fig. 2.24 is that as the global peak of conventional oil production approaches, and hence the scope for increases from its production starts to tail off, the world is forced to use increasing volumes of the non-conventional sources to satisfy any increase in demand. And since, as indicated in the Figure, these sources are generally more expensive to produce than conventional oil, the overall oil price is expected to rise to the level of the marginal barrel required. As mentioned earlier, this marginal-barrel price is currently roughly around \$100/bbl, although the highest IHS-CERA value given in the Miller and

Sorrell (2014) paper quoted earlier is  $\sim \$160/\text{bbl}$  for ‘Canada oil sand mine upgraded’ oil assuming a 15 % rate of return.

At some later date, once the peak of global conventional oil production is past and the decline in the production of this oil has settled in, modelling shows that global production of this oil is likely to fall at between about 2 and 3 % annually. This figure reflects an average decline of around 5 % annually from post-peak fields being partially offset by increasing production from late fields coming on-stream. A 2–3 % decline in conventional oil represents an annual loss of global production of about 1.5–2.0 Mb/d; i.e., a decade’s decline will give a loss of around 15 Mb/d. If the extra supply from the non-conventional oils and other liquids is not enough to offset this loss, and meet potential rising demand in addition, then global ‘oil shocks’ are inevitable unless demand for oil is curtailed by other factors. We look at forecasts of this supply in Chap. 4.

For a list of past and expected peak dates of production of ‘all-liquids’ by country from one company’s forecast model, that of Globalshift Ltd., go to [www.globalshift.co.uk](http://www.globalshift.co.uk).

## 2.6 The Second Half of the Oil Age

Colin Campbell, a noted analyst in the field, calls the new era of global oil supply that we are entering ‘The Second half of the Oil Age’. Given that for the century and a half of the ‘First half of the Oil Age’ the world used primarily conventional oil from oil fields, what would indicate the start of the ‘Second half’?

There are several candidates to mark this transition point. Arguably the ‘Second half’ starts at the point that we are facing now, where the world’s ability to *increase* production of conventional oil becomes insufficient to meet its increasing demand for oil. It is true that currently some of the conventional oil that could come to market is being held back by some suppliers, but taking this constraint into account and also recognising that most suppliers of conventional oil are now past their ‘mid-point peaks’ in production, for some years now the world has required increasing production of the non-conventional oils (primarily natural gas liquids, tar sands oils, shale oil from fracking, and biofuels) to make up for what conventional oil in fields cannot supply. This in turn pushed up the price of oil since 2005 to levels that damaged global economic activity.

A later point for entry into the ‘Second half of the Oil Age’ is when the global production of conventional oil stops increasing and goes into decline, driven primarily by lack of recoverable resource of this type of oil. At the time of writing (Summer 2015) it is not clear whether this point has been passed—the IEA has perhaps suggested it was passed in 2006—or if it will be some time in the future; the date in part depends on how ‘conventional oil’ is defined, and also on the extent that oil producers find the application of enhanced oil recovery measures in conventional oil fields to be profitable. But when this point occurs, the increased production from

the non-conventional oils must not only be enough to meet increased demand, but also to offset the decline in the production of conventional oil.

This leads to the final point in time where entry to the ‘Second half of the Oil Age’ becomes apparent. As mentioned, the expected fall in the global production of conventional oil, once past its ‘resource-limited’ peak, is likely to be of the order of 2–3 % per year. It is not clear that production of the non-conventional oils can take up the slack, nor at what price; and a number of forecasting models suggests that this may not be possible (Chap. 4). If this is indeed the case, i.e., if insufficient non-conventional oil production comes forward, then global oil production *in total* declines, and the ‘Second half of the Oil Age’ is well and truly here.

For forecasting oil production, so far in this book we have largely relied on the rule of thumb of ‘peak at mid-point’. This is an extremely valuable and generally robust approach, but necessarily only a broad approximation. The next chapter gives a brief history of some of the more accurate approaches that have been used.

Introduction to Peak Oil

Bentley, R.W.

2016, IX, 196 p. 34 illus., 8 illus. in color., Hardcover

ISBN: 978-3-319-26370-0