Lecture Notes in Energy 34

Купить книгу "Introduction to Peak Oil"

R.W. Bentley

Introduction to Peak Oil

Springer

Chapter 1
Introduction

1.1 The Purpose of this Book

For some years now the process of supplying the world with oil has been getting more difficult. Global production of *conventional oil* (the normal oil found in oil fields) is close to its *resource-limited maximum*, and to meet additional demand the world has had to turn increasingly to the production of non-conventional oils, such as tar sands oil and shale ('light tight') oil. This transition has led to a significant rise in the price of oil, and will probably at some point, possibly fairly soon, lead to an overall decline in global oil supply. The aim of this book is to explain the underlying causes for this fundamental change in oil supply, and also why the change is still not widely understood.

1.2 The Importance of Oil, and Hence the Difficulty of Transition

We start however by considering the importance of oil, and hence why a transition in its supply will not be easy.

Oil is a lifeblood of the modern economy, and it makes up the largest part of the world's traded energy, some one-third of the total. In particular oil fuels nearly all the extensive, cheap transport that is a major contributor to today's efficient global economic activity, whether in the production of food or goods, or provision of the services that we rely on. As most people appreciate, if oil is not available in the short term food does not get to the shops, nor workers to their jobs, and society is at risk. This was amply demonstrated during the European 'fuel protests' of 2000.

However the problems we face as global oil supply becomes increasingly difficult are somewhat different. This is because, first, oil can be substituted by other forms of energy in almost any activity. Aeroplanes, for example, can fly on biofuels

R.W. Bentley, *Introduction to Peak Oil*, Lecture Notes in Energy 34,
DOI 10.1007/978-3-319-26372-4_1

or liquid hydrogen; trucks be run on compressed natural gas; cars on gas or electricity; houses and offices be heated and cooled by electricity or by other fuels; and industrial chemicals produced from gas, coal or biomass, or directly from solar energy using ubiquitous feedstocks. Second, given sufficient warning, society can choose to change its activities and priorities so as to use less oil.

But several factors make the current transition to a world of expensive oil, and in time to a world of less oil, both difficult and painful.

The first is simply the very large quantity that we use. As mentioned, oil is currently the world's largest traded energy, and finding adequate substitutes to allow the world to replace this amount of energy over any medium timeframe looks technically very difficult, and also expensive in terms of the investment required. For example, the quantity of currently available biofuels falls far short of what is needed to replace oil; the global supply of *conventional* gas will see its own resource restrictions fairly soon; both coal and nuclear face significant constraints on increased production; and while the *potential resource* of solar energy is more than adequate, transitioning to this on a large scale has severe restrictions of cost and energy return when compared to the energy supplied by oil.

A second factor to consider in the coming energy transition is the impact of the price of oil on economic activity. For the half-century from 1920 to 1970 oil was very cheap, averaging about \$15/barrel ('\$/bbl') in today's money (its 'real-terms' price), and as a result the global use of oil expanded rapidly, and economic wealth in parallel. Later, for the nearly two decades between 1986 and 2003, the average real-terms price was about double, at \$30/bbl, and the growth of oil use was slower, but still substantial. Only for the two periods from 1974 to 1985, and since 2004, has the oil price been significantly higher, reaching at times a real-terms price of \$100/bbl or more. In both these periods the high price has resulted in considerable damage to the world's economy. Going forward the on-average high oil price that results from increasingly difficult supply is expected to continue to impact global economic activity; and hence also the world's ability to fund the increasing energy efficiency, and production of new energies, that will be required.

A third factor that makes transition away from oil likely to be difficult is the lower energy return of many of the alternatives. Energy return compares the energy generated by an energy source to that required to produce this energy. For quite a number of the alternatives to oil their energy returns are considerably less than that for oil.

An important final factor to consider is CO_2 emissions. While the oil we use today is no angel in this regard, some of the alternative fuels emit greater levels of CO_2 per unit of energy generated. As seems now well established, a significant percentage of all the world's oil, gas and coal must be left in the ground if the global limit of 2 °C warming is to be avoided.

This book does not look, however, at these broader issues of global all-energy supply; nor at what energy transition rates are possible; and nor at the likely corresponding levels of economic activity. These topics are complex, and require detailed modelling, and also generally better data than are currently available (particularly on energy return by energy source, and hence on corresponding net-energy limits to transition rate) to have a clear view of how the world's energy future can play out.

Instead this book looks at the simpler question of the future availability of oil, and in particular that of 'conventional oil'.

1.3 Conventional Oil Versus Non-conventional Oil

In understanding the rise in oil price since 2004, and also the limits to future oil supply, an important distinction to make is between the production of *conventional* oil and that of *non-conventional* oil.

Oil exists in many forms. It can be found at the land surface or on the seabed as oil seeps; in degraded form in tar pits and in extensive areas of tar sands; as oil's precursor, kerogen, still in the original rock in which it was laid down (and from which it needs retorting to yield 'oil shale' oil); and as light, flowable oil, either still captured in the original rock (as 'shale oil', that needs hydraulic fracturing, 'fracking', to release it); or after having migrated to an open-pored reservoir of rock (an oil field), from which it can be extracted by drilling.

It is this last class of oil, *the relatively light, flowable oil in fields* that is generally classified as conventional oil, and where the bulk of oil production currently, and by far the largest part historically, has been of this class of oil.

By contrast, non-conventional oil tends to be found in extensive regions (within which there may be 'sweet spots'), and where flow to a production well is not possible without significantly changing the nature of the oil itself (for example, by heating to reduce viscosity, addition of a solvent, or retorting), or that of the surrounding material (such as mining the sand in which the oil is contained, or by fracturing the rock in which it is trapped). Non-conventional oil thus includes very heavy oil, oil from tar sands and Venezuela's Orinoco fields, shale ('light tight') oil and oil produced from kerogen by retorting.

Oil, in addition, can be produced from yet other sources. It can come from the physical transformation of some of the gas from gas fields, as either condensate or natural gas liquids ('NGLs'); by chemical transformation of gas from a variety of fossil sources (yielding gas-to-liquids, GTLs), or similarly from coal (coal-to-liquids, CTLs); or alternatively from biomass, either directly as biofuels, or by chemical or biological change from a variety of types of biomass.

Note that NGLs are often included in conventional oil (though in this book we try to break them out separately where possible), while the oil produced from GTLs, CTLs and biomass is often classed as 'other liquids'. Annex 1 gives more detailed definitions.

To see why this distinction between classes of oil is important, we need to ask the following question: Why over a century and a half has the world, in the main, used conventional oil (i.e. oil in fields), rather than oil from the many other sources that exist, and where some of the latter (such as oil from biomass, and from coal and kerogen) were used extensively before conventional oil came to dominate?

The answer is simple: Up to now the oil in fields has usually been far cheaper to produce than these other oils. The reason for this generally lower cost of conventional oil relates principally to flow rate, and energy return.

Flow rate

As noted above, oil in fields is concentrated geographically and flows easily, and hence often yields large flow rates when produced by relatively simple drive mechanisms, such as own pressure, gas drive or water flood.

For example, while the 1859 Drake well, the first commercial oil well in the US, yielded up to about 20 barrels of oil per day ('b/d'), only 2 years later the first major US gusher yielded 4000 b/d, and in 1901 the Spindletop field in Texas flowed at 100,000 b/d. Admittedly in these early years such flows were often short-lived, but subsequent large fields typically have yielded over 500,000 b/d for considerable periods; while the Middle East giants produce 1 million b/d and above, and the world's largest field, Ghawar, averages over 5 million b/d. Thus once located, conventional oil from large oil fields has generally been cheap to produce due to relatively easy production methods and high flow rates.

As a result, while 'the petrol tank in your car does not care' what type of oil (conventional or non-conventional) is used, the user certainly does. The user would far prefer conventional oil at its pre-1973 long-term average real-terms price of $15/bbl, or even at its post-1985 real-terms average price (up to the 2004 increase) of $30/bbl, than to have to pay the ~$60/bbl production cost for US light tight oil,[1] or the more than $160/bbl for 'Canada oil sand mine upgraded' oil, currently estimated by IHS-CERA (see Fig. 16 of Miller and Sorrell 2014); or the production cost—whatever it will be—of retorted kerogen oil plus carbon capture, or of synthetic fuel made from electrolysis of water plus CO_2.[2]

Energy return

Another way to look at the relative ease of production of conventional oil is in terms of its energy return; nearly all of the non-conventional oils have lower energy returns. Though the data are hard to establish unequivocally, Guilford et al. (2011) and Hall (personal communication) suggest for example that in the US the ratio of energy return to energy invested (EROI) for conventional oil was about 30:1 in the 1930s, rising to 40:1 in the 1970s as scale increased and technology improved, and subsequently falling with production of the more difficult conventional oils, such as deep offshore or Arctic oil, to an average ratio of perhaps 14:1 today. By contrast, nearly all non-conventional oils have lower energy ratios; tar sands, for example, being quoted as having ratios of from 1.5 to 8:1, and corn ethanol as only perhaps 2 or 3:1 (probably higher in Brazil, and in some cases perhaps negative). Since Hall et al. (2009) and Lambert et al. (2014) calculate that modern society will have difficulty in functioning if its fuels have energy ratios of less than perhaps 5–10:1, the current transition from mainly conventional oil to increasing quantities of non-conventional oil is significant, and needs to be understood.

1.4 Oil Reserves Data: Proved Versus Proved-Plus-Probable

Recognising the difference between conventional and non-conventional oil is one part of understanding the current transition in oil supply, but by far the largest reason why this transition has been poorly understood has been confusion over the data, and in particular the reserves data.

The reserves of an oil field or a region estimate the amount of recoverable oil remaining at a given point of time, and the problem lies with the differences between the *proved* oil reserves (the so-called '1P' data), and the *proved-plus-probable* reserves (the '2P' data); see Bentley et al. (2007). The following two sections discuss this topic briefly, and it is discussed more fully in Annex 2.

1.4.1 Proved ('1P') Oil Reserves

Where annual summary tables of oil reserves data are given in the public domain they are usually of proved (1P) reserves, as for example in the BP *Statistical Review of World Energy*, the annual tables in *World Oil* or the *Oil & Gas Journal*, or on the US Energy Information Administration (EIA) website. Although such reserves data are used in company reports they have been extraordinarily misleading on the actual quantity of oil discovered, especially in the past, and they generally cannot be used to forecast oil production despite many analysts having done just this. (For an exception to this rule see Bentley 2015a). The issues with the proved reserves data are as follows:

Understatement

The term 'proved' reserves would seem to indicate solid, reliable data. The BP *Statistical Review* for example quotes such reserves as: '*Generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions*'.

In fact, this has been far from the case. Historically, proved reserves have been *very much less* than the quantities that 'with reasonable certainty can be recovered', where the latter were far better indicated by the oil industry's proved-plus-probable (2P) reserves data.

In the US and Canada in particular, the apparent size of individual fields, as given by their estimated initial proved reserves, has often grown massively over their lifetimes, typically from five to over ten times their original estimated volumes.

There are many explanations for this, but 'drilling-up' of early fields is likely a major factor, as under SEC rules proved reserves can largely refer only to oil in communication with existing wells. Though the US and Canada have typically shown the largest such proved reserves 'reserves growth', the phenomenon applies to many regions around the world. In the UK, for example, the total oil proved reserves have long stood at only about half the value given by the industry data for 2P reserves.

For *regions*, proved reserves will also be underestimates due to summation. This is because simple addition of any high-probability data, such as proved reserves, significantly underestimates the total at the same probability level.

Naturally, over time, as fields get produced, the conservative proved reserves data generally grow to become close to 2P estimates. This is now the case for many —but by no means all—oil-producing countries.

Overstatement

But the opposite problem also exists, where proved reserves are almost certainly significantly overstated.

Though most countries' public domain proved oil reserves are, as one would expect, smaller than the industry 2P data, in some anomalous but important cases the reverse is true, and the country's published 1P reserves significantly exceed the industry 2P reserves. These cases are mainly the result of the OPEC 'quota wars' step-changes in proved reserves that occurred in the 1980s, when OPEC's allowed production of individual members was based in part on the size of their reserves. This issue has been written about extensively, and may constitute an over-reporting, above the correct 2P reserves, by as much as $\sim$300 Gb, close to a third of remaining conventional oil reserves.

Non-statement

Finally, in the main public-domain 1P databases (e.g. BP *Stats. Review*, or from the *Oil & Gas Journal*), the data on proved reserves are frequently not updated annually, and can remain static for sometimes very long periods of time. (For example, in the end of 2014 *O&GJ* data for 106 oil-producing countries, 66 reported no change in proved reserves during 2014.) For this reason also, such 1P data are significantly in question; and more importantly *trends* in these data are misleading.

1.4.2 Oil Industry Proved-Plus-Probable ('2P') Reserves Data

Now we turn to the proved-plus-probable ('2P') reserves data. Such data can be gathered for individual oil fields from a wide variety of published industry and government sources, but with considerable effort, as has been done for example by Richard Miller, Michael Smith at Globalshift Ltd., and Robelius and others at the University of Uppsala.

Large commercial *by-field* 2P datasets can instead be purchased from firms such as IHS Energy, Wood Mackenzie, PFC Energy and Rystad Energy. Here the data have been assembled and checked, and there is also much additional proprietary information. Such datasets tend to be very expensive. Fortunately, simpler 2P datasets are available at moderate cost. Certain by-field data can be purchased from Globalshift Ltd., and possibly from Peak Oil Consulting, Richard Miller and Uppsala University. In addition, extremely useful *by-country* 2P data are available from IHS Energy's 'PEPS' database, where researchers should use the version with data back to 1834 (but note that US and Canada non-frontier data are only 1P).

Some collected 2P data now are in the public domain. For conventional oil, adjusted global and by-country data are given by Laherrère on websites and elsewhere (including in this book, and as a chart in *The Oil Age,* January 2015); while charts for adjusted 'Regular conventional' oil for a wide range of countries, and including essays on the associated petroleum geology, are given in Campbell (2013). (In the latter, the key graphs are the 'Status of Oil Depletion' plots. These give, by-country, the cumulative backdated 2P discovery data to show how much oil has been found; the country's cumulative production; and also Campbell's judgement of the country's ultimately recoverable resource ('URR'). Evolution over time of a country's 2P reserves, and yet-to-find, are given by the differences between these data.)

Excellent plots of past and forecast production (but not of discovery) for all oil-producing countries, based on detailed by-field 2P data, are free on the Globalshift website (www.globalshift.co.uk). In addition, Rystad Energy's UCubeFree facility gives past and future production by-country, based on their estimates of 2P data.

Comparison of the evolution over time of global 1P oil data with 2P is given in Annex 2. Today, for *conventional* oil, the size of global 1P reserves is roughly the same as that of the 2P reserves. This is because the overstatement of OPEC 1P reserves is roughly matched by the understatement of the 1P reserves in most other countries. Nevertheless, in general 1P reserves data should *not be used* for understanding the future of oil production, and especially not their very misleading evolution over time. The data presented in the graphs and analyses given below are in general *2P data*, drawn from a variety of oil industry datasets.

1.5 Structure of This Book

Now we turn to the structure of this book:

Chapter 2 explains the concept of 'peak oil'. As used in this book, and also fairly generally, the term refers to the maximum in the production of oil that results from the *physical and economic characteristics* of an oil resource. It is shown that such peaks have very different causes, profiles and impacts depending whether they refer to peak of production in a field, in a region, or to the world as a whole. Similar differences also hold true if the peak refers to production of conventional oil only, or to that of 'all-oils' or 'all-liquids'.

Chapter 3 gives a brief history of some of the main forecasts of peak conventional oil production that have been made over the years. Such forecasts can be generated by a variety of approaches, including the 'mid-point' rule, PFC Energy's '60 %' rule, mirroring of production to discovery, Hubbert linearisation, summing logistic curves, or by detailed 'bottom-up' calculations by field.

Chapter 4 then examines oil forecasts from a variety of fairly recent sources to ascertain the likely dates for the global peak of the various types of oil, both conventional and non-conventional. It is shown that in contrast to the widely held view that 'all oil forecasts have been wrong', for over 40 years nearly all oil forecasts that have been based on an understanding of resource limitations have been substantially correct in predicting that the peak in the global production of conventional oil would occur roughly around the year 2000. Much greater attention should have been given to these technically based warnings of significant transition in the global oil supply.

Chapter 5 then turns to the question of why the concept of 'peak oil' has been so poorly understood, both in the past and still today. The primary reasons have been:

- As already mentioned, reliance on the very misleading proved reserves data; and in particular on the apparent *replacement* of these proved reserves over time.
- Not understanding the significance of the 'mid-point peak' in production.
- Reliance on global URR estimates significantly higher than that indicated by the trend of 'proved-plus-probable' (2P) oil discovery.

Chapter 6 sets out some caveats, and then summarises the book's main conclusions. Finally, a number of annexes are given; these give greater detail on topics in the main chapters, and also discuss briefly a number of topics not covered in the main text. The latter include the relationship between peak oil and climate change; peak oil demand; and the global peak of conventional gas production.

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 wold as a whole. We start by examining the production peak in fields.

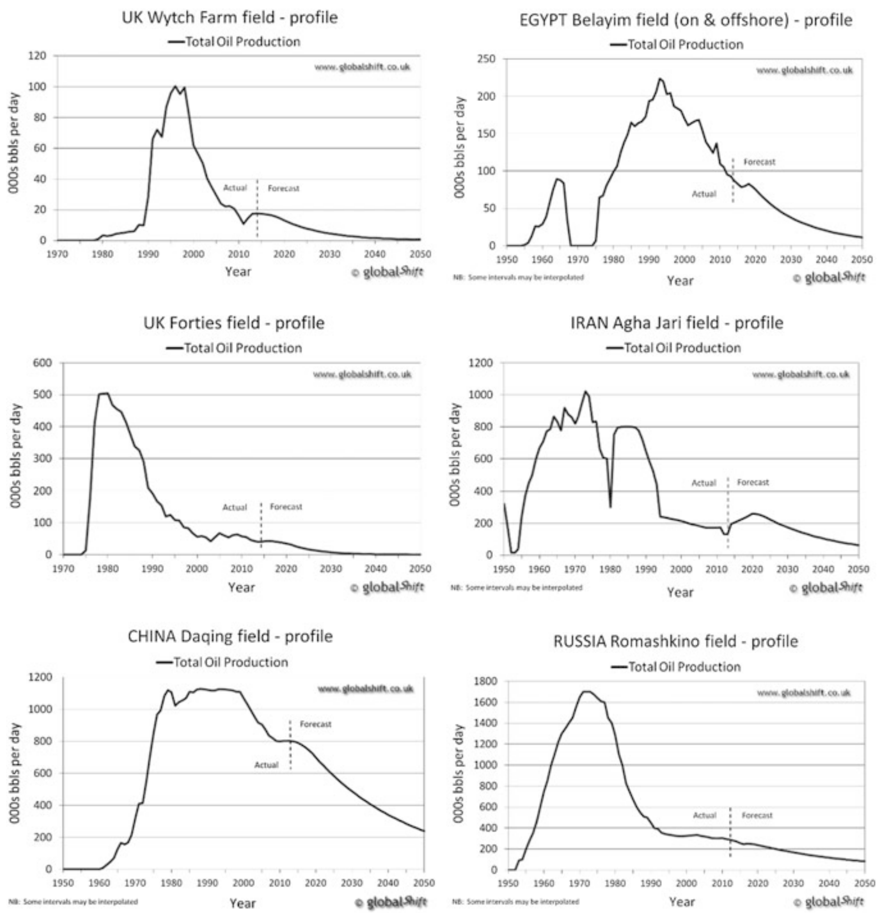
R.W. Bentley, *Introduction to Peak Oil*, Lecture Notes in Energy 34,
DOI 10.1007/978-3-319-26372-4_2

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, UKs 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 ~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 ~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 ~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 ~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

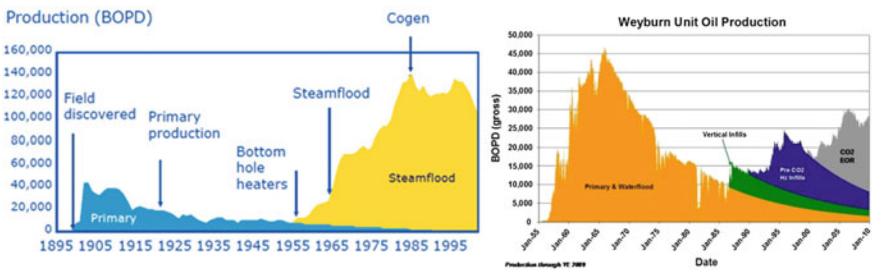


Fig. 2.2 Two fields with atypical production profiles.

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_2 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

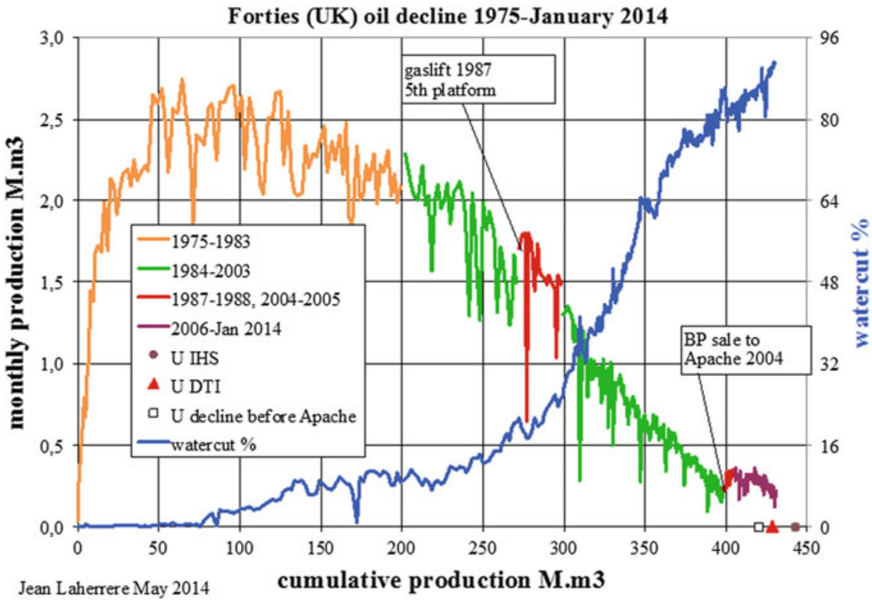


Fig. 2.3 Linearised plot of field decline: Example of the Forties field. Unlike a normal production plot of production versus date, this approach plots production (here as monthly data) versus cumulative production, and hence linearises the decline curve if the decline is exponential.

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

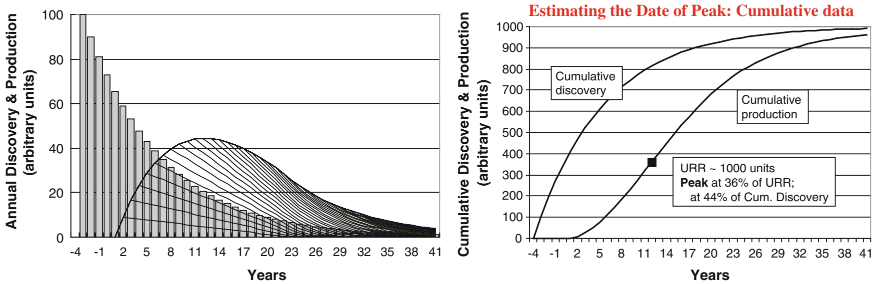


Fig. 2.4 A simple model of conventional oil discovery and production in a region.

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.[3] 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).

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;[25]
- 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.